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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

MANAGING EDITOR

Jerry E. Sinor
Post Office Box 649
Niwot, Colorado 80544
(303) 652-2632

BUSINESS MANAGER

Ronald L. Gist
Post Office Box 53473
Houston, Texas 77052
(713) 669-8800
Telex: 77-4350
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Montana Precision Mining to Test Skygas Process

In an agreement with Montana Precision Mining Ltd., an unnamed United States entity has agreed to fully fund testing of the Skygas process. Testing and demonstration of the process will be conducted by the Skygas process inventor at his plant in Libby, Montana. Skygas is a photo-electrokinetic process designed for converting solid and semi-solid wastes into a clean burning medium-BTU gas. The process and its development are discussed on page 1-2.

Production Tax Credits Allowed for Alternative Fuels Under New Energy Act

The 1992 Energy Policy Act includes a provision for Alternative Fuels Production Tax Credits for domestic production of alternative fuels, including those produced in clean coal refineries. The credits are currently calculated at $14 to $17 per ton of coal processed and are available until January 1, 2008. The projected dollar amounts of these credits over this period are summarized on page 1-5.

New EIA Outlook Through 2010 Projects Slow Growth in Energy Demand

Total energy consumption in the United States is expected to grow to between 102 and 112 quadrillion BTU by 2010, according to the Energy Information Administration's Annual Energy Outlook for 1993. The report evaluates seven scenarios that give high and low projections for, oil, gas, electricity and coal, based on assumptions regarding world oil prices, economic growth, and the United States gas and oil resource base. In all cases, energy demand is expected to grow at a much lower rate than overall economic growth. Key projections are summarized on page 1-6.

New GRI Forecast for 2010 Reduces Oil Price Outlook

The Gas Research Institute's 1993 Projections for Energy Supply and Demand forecast a 0.8 percent annual increase in total primary energy consumption over the next 2 decades. As discussed on page 1-8, highest growth is expected for natural gas, with consumption increasing at a rate of 1.2 percent per year. The cost of crude oil is projected to remain relatively flat in the near term, reaching only about $21 per barrel (1992 dollars) by 2000.

Battelle Forecasts $162 Billion Increase in R&D Spending in 1993

According to the annual Battelle forecast, United States research and development (R&D) expenditures are expected to reach $162 billion in 1993. Adjusted for inflation, this represents a real increase of less than 1 percent, and the R&D growth rate is expected to continue to decline. However, with the new emphasis on federal R&D funding as a means of supporting domestic economic growth and the pro-technology attitude of the Clinton Administration, Battelle is cautiously optimistic that the funding trend will be turning around. See page 1-9 for details of the forecast.
World Energy Demand Projected to More Than Triple by Year 2100

By the year 2100, a 3.3-fold increase in total world energy demand is expected. Lesser developed countries, that currently use the least energy per capita, will post the largest gains, increasing use by up to 58 times 1990 levels. Developed countries, which consume energy at the highest per capita rate, are estimated to increase energy use by only 25 percent over the 1990-2100 period. Energy demand, along with implications for energy resources and the environment, are discussed in the article on page 1-11.

Particulate Emissions Could Offset Global Warming From Fossil-Based CO₂

Most scientists involved in research on climate change believe that the earth will undergo some warming as a result of anthropogenic emissions which enhance the greenhouse effect. As summarized on page 1-15, a large body of evidence now indicates that anthropogenic sulfate emissions are mitigating some of the warming, and that increased cloudiness as a result of these emissions will further enhance night, rather than day, warming.

Beneficiation Prior to Hydroretorting Found Not to Cause Leaching Problems

A summary of the leaching characteristics of beneficiated and thermally processed Alabama shale is presented on page 2-2. United States Environmental Protection Agency Toxicity Characteristic Leaching Procedure (TCLP) test results showed that all elements were leached from the beneficiated shale samples at levels below the TCLP regulatory limits, indicating that the storage of raw or spent shale in embankments will not result in significant environmental impact.

Retort Temperature Found to be Most Important Influence on Oil Quality

A study to optimize processing of Australian Tertiary oil shales ranked seven major processing variables based on their relative impact on product yield and oil quality as follows (in order of most to least significant impact): retort temperature, solids residence time, steam concentration, char content in recycle solids, solids recycle ratio, recycle solids temperature and ammonia pretreatment. Details of the study are presented on page 2-2.

Oil Shale Mining Claims Status Updated

The Energy Policy Act of 1992 dramatically changed the way that unpatented oil shale mining claims will be treated by the United States Department of Interior from now on. In the article starting on page 2-13 there is a summary of the status of unpatented oil shale mining claims in the states of Colorado, Utah and Wyoming. Individual claimholders and the status of their claims are listed also.

Shell to Test AOSTRA SAGD Process at Peace River

Shell Canada Ltd. and Alberta Oil Sands Technology and Research Authority (AOSTRA) have agreed to share the costs of a project to improve the recovery of bitumen from Alberta’s oil sands near Peace River. AOSTRA will contribute 50 percent of costs, up to C$6.5 million, toward the project. As reported on page 3-1, AOSTRA’s Steam Assisted Gravity Drainage (SAGD) process and Shell’s enhancements to the process will be used to produce bitumen from the reservoir.
Orimulsion Gasification Plant Slated for Puerto Rico

Last year, Texaco Inc.'s Alternate Energy Group and Bitor America Corporation signed a letter of agreement to develop IGCC power projects using Texaco's gasification technology and Venezuelan Orimulsion as a feedstock. This partnership and Puerto Rican authorities are now negotiating a plan to build the world's first gasification plant fueled by Orimulsion in Puerto Rico. The plant, if built, would reduce the island's heavy dependency on oil imports. (See page 3-2.)

AOSTRA Makes Slurry Transport Data Base Available

As reported on page 3-3, a Slurry Transport Data Base, developed and maintained by AOSTRA Library and Information Services, is now available to the petroleum industry and research community. The database contains comprehensive information from over 1,200 source publications on fluid-solids transport.

AOSTRA Sees Need for More Upgrading Research

A study funded by AOSTRA indicates that by optimizing applications of emerging technologies, upgrading costs would be reduced by about $2.50 per barrel, and the value of the products would increase by about $1 per barrel, due to improved quality and higher yield. This would place product supply costs well within today's world price envelope for crude oil. The proposed upgrading research program is discussed on page 3-4.

AOSTRA Has 5-Ton-Per-Hour Mobile Taciuk Processor

AOSTRA is sponsoring a 5-ton-per-hour mobile pilot plant to showcase its Taciuk process (ATP), which simultaneously extracts and primary upgrades bitumen from oil sands. The ATP offers oil sands producers lower capital and operating costs, dry tailings disposal, oil sands grade insensitivity, mechanical simplicity, energy self-sufficiency and flexibility. The ATP will also be used to clean up oily wastes in Canada and the United States. AOSTRA hopes the project will prove the commercial viability of the ATP. Details of the process are presented on page 3-4.

Gasoline Reformulation Will Affect Canada's Synthetic Crude Oil Industry

The challenges facing Canada's synthetic crude oil industry in light of United States and Canadian fuel reformulation plans are discussed on page 3-7. Although synthetic crude has a lower sulfur content and no residuum when compared to conventional crude, its higher butane and aromatics content, and its lower cetane number will impact its ability to meet tighter fuel specifications. With additional hydroprocessing technology, the properties of transportation fuels produced from synthetic crude oil can be adjusted to meet new regulations, but not without significant cost.

CANMET Coprocessing Residue Beneficiated by Oil Phase Agglomeration

The results of a study to beneficiate the organic matter in CANMET's coal/heavy oil coprocessor residue using oil phase agglomeration is discussed on page 3-12. The effect of pH, conditioning agent, and oil characteristics were evaluated. Ash rejection levels of over 40 weight percent were achieved when No. 4 fuel oil was used as the bridging oil.
Nomenclature of Residuum Upgrading Reviewed

To eliminate some of the confusion associated with residuum upgrading terminology, a consistent set of definitions, along with terms often used as synonyms, was developed. These definitions are listed on page 3-13.

Orimulsion Hits Environmental Barrier in Britain

Tougher environmental controls will be required before British utilities can burn Orimulsion, a bitumen-based fuel imported from Venezuela. BP Bitor, which sells the fuel, maintains that, while Orimulsion contains more sulfur than most oil or coal, its overall emissions are less harmful. Orimulsion’s prospects may be further threatened by the backlash over proposed coal pit closures in the United Kingdom. British Coal Company’s submission to a coal pit review was contingent on limiting the burning of Orimulsion to the two small power stations covered by current consents. An article on page 3-15 covers details of the Orimulsion controversy.

Kennecott Buys Cordero Coal Mine

Kennecott recently agreed to purchase Cordero Mining Company from Sun Company for $120.5 million. The Cordero Mine is the seventh largest coal mine in the United States. This acquisition will position Kennecott as a major coal producer with 16 percent of the Powder River Basin’s coal production. See article on page 4-3.

DOE Receives 24 Proposals for Clean Coal Round V

The United States Department of Energy received 24 proposals for projects for possible funding through the fifth round of the Clean Coal Technology Program. The 24 candidate projects have a total proposed cost of $6.3 billion. A list of the proposed projects is presented on page 4-4.

DOE to Fund Advanced Gas Turbine Research

The United States Department of Energy has committed $8.5 million over the next 4 years for the research and development of new advanced gas turbine systems. The funding will be provided to a consortium of universities and industrial sponsors. The new systems promise to yield far superior efficiencies and cleaner performance, as discussed on page 4-5.

Two-Stage Direct Liquefaction Estimates Now at $38 Per Barrel

Under United States Department of Energy contract, Bechtel and Amoco have updated the design and economic analysis of a commercial-size direct coal liquefaction plant. An overview of the project is given on page 4-12. The baseline design case requires an equivalent crude oil price (ECOP) of $38.55 per barrel. The best case scenario, where hydrogen is generated by natural gas reforming, requires an ECOP of $36 per barrel.

Integration of Oxygen Supply Into IGCC Plant Could Save 4% on Capital Cost

Many utilities in Canada are considering Gasification Combined Cycle technology (GCC) for future expansion. A key component of GCC technology is the supply of oxygen to the gasification unit, which is normally supplied from a stand-alone air separation plant. By integrating the oxygen plant with the GCC facility, a 2 to 4 percent reduction in capital costs of a new facility can be realized. The integrated system is discussed on page 4-16.
Pre-Treatment Concepts Being Studied for Direct Liquefaction

A cooperative program to evaluate pre-treatment concepts for direct coal liquefaction is highlighted on page 4-19. The purpose of the program is to identify technologies which may improve the economics of coal liquefaction. Thus, emphasis is given to low-cost, low-rank coals. Five pre-treatment concepts are under evaluation including CO-H₂O pre-treatment, dispersed catalysts, solvent dewaxing, fluid coking, and oil agglomeration.

Combined Pyrolysis/CPFBC Shows Promise for Combined Cycle Applications

A concept for an advanced coal-fired combined cycle generating system is discussed on page 4-20. The system design goals include high efficiency, low cost of electricity, and low emissions. Research and development needs for each of the integrated subsystem components are identified.

EERC Summarizes Status of Conversion Technology for Fort Union Lignite

The long-term growth for lignite and subbituminous-rank coals will depend on converting these coals to environmentally-clean alternative fuel forms for electric generation, transportation, and value-added products. A survey of the status of conversion technology for Fort Union lignite was prepared by the Energy and Environmental Research Center. The survey is summarized on page 4-22.

Coal Solutions May be New Route to Upgraded Products

A new purification process, which uses potassium hydroxide to increase the solubilization of certain high-rank bituminous coals into N-methylpyrrolidone, is discussed on page 4-26. Using this process, under relatively mild conditions, carbon extraction reached 90 percent for one South African coal.

Petroleum Coke Proves Good Feedstock for Shell Gasifier

Petroleum coke is expected to be of increasing interest to United States utilities because of its decreasing cost and its suitability for coke gasification combined cycle power generation. Demonstrations in the Shell Coal Gasification Process yielded cold gas efficiencies up to 78.9 percent, and carbon conversions greater than 99 percent. The process also meets all current and anticipated environmental standards for gas, water and solids streams. The cost of electricity from petroleum coke in comparison with that from Pittsburgh No. 8, $0.051 versus $0.063 per kilowatt-hour, is also attractive. Details of the coke gasification demonstration are summarized in the article on page 4-28.

Tokyo Gas Has Bench-Scale Hydrogasifier Based on Rocket Engine Technology

A bench-scale flash hydrogasifier based on rocket engine technology developed at Rockwell International Corporation has been built and tested at Tokyo Gas Company. A schematic of the gasifier is presented on page 4-32. One of the major benefits offered by this process is an unusually high yield of BTX (benzene, xylene, toluene) liquids.

Endesa's IGCC Project in Puertollano, Spain Reviewed

The European Community Thermie program is supporting a 335 megawatt integrated gasification combined cycle powerplant being built at Puertollano, Spain. This project, reviewed on page 4-34, features a highly integrated concept where all the air necessary for the air separation plant is ex-
tracted from the gas turbine compressor at 14 bar. The waste nitrogen from the air separation unit is then mixed with the clean coal-gas feed to the turbine combustor. The plant is being designed to gasify a mixture of coal and petroleum coke and to be capable of switching to natural gas firing.

**Hydrothermal Dewatering Reduces Reactivity of Brown Coal for Liquefaction**

Hydrothermal dewatering (HTD), as a pre-treatment for brown coal liquefaction is discussed on page 4-37. HTD removes water from low-rank coals without evaporation. A program to evaluate the effect of HTD on liquefaction over a range of reaction conditions was conducted by the Coal Corporation of Victoria and the New Energy and Industrial Technology Development Organization. The results of the study indicate that hydrothermal dewatering may decrease the reactivity and increase the viscosity of coal/solvent slurries for brown coal liquefaction processing.

**Coal/Water Fuels are Commercialized in Japan**

In Japan, both the government and private industries have been supporting the commercialization of coal/water fuel (CWF) technology through basic research, pilot plants and long-term combustion demonstrations. A summary of the commercialization efforts at Okayama, Nakoso, Onahama and Ube is presented in the article on page 4-38. Fuel source diversification and the international oil situation are two of the motivating factors behind Japan's CWF commercialization efforts. On a normalized per metric ton basis, CWF, at US$78, can compete with heavy oil, at US$104, but cannot compete with Australian steam coal at US$48.

**Methanex to Acquire Fletcher Challenge**

Methanex plans to acquire the entire methanol operations of Fletcher Challenge Ltd., making it the world's largest methanol producer. After the transaction, Methanex will have production capability of 2.4 million tons of methanol per year plus marketing agreements for another 1 million tons. Details of the acquisition are summarized on page 5-1.

**NERA Forecast Shows Strong Increase in Natural Gas Prices**

As summarized on page 5-2, NERA forecasts moderate natural gas price rises through the mid-1990s, followed by increasing real wellhead prices which peak at $3.50 per thousand cubic feet between 2000 and 2005. United States gas consumption is expected to exceed 25 trillion cubic feet in 2005, making gas markets increasingly tight beginning in 1994 or 1995.

**New Direct Routes for Conversion of Natural Gas Described**

Research groups in California and Minnesota, working independently, have developed two new approaches to the catalytic conversion of methane, one yielding methanol and one yielding synthesis gas. The processes are described on page 5-3. Although neither approach is ready for commercial application, both offer new insights into the complex chemistry of methane conversion.

**Methane Dimerized in Microwave Plasma**

In a University of Connecticut study, methane was converted to ethane and ethylene in a microwave plasma reactor. The energy efficiency for driving this thermodynamically unfavorable reaction is between 2 and 8 percent. Methane conversions as high as 90 percent were observed. Details of the study are given on page 5-3.
CORPORATIONS

IGT ANNUAL REPORT DESCRIBES WORK ON OIL SHALE, COAL AND NATURAL GAS

In its 1992 Annual Report, the Institute of Gas Technology (IGT) reported on a number of projects involving synthetic fuel and related technologies.

Coal

The Illinois Department of Energy and Natural Resources and the United States Department of Energy (DOE) are cofunding a project for the construction and operation of a 24-ton per day process development unit (PDU) for IGT's MILDGAS process. The Institute worked with Kerr-McGee Coal Corporation and Bechtel Corporation on the process design. The PDU will produce multiple high-value products from coal, including metallurgical-grade form coke and binder pitches. These products will be evaluated by the industrial members of the team.

Sulfur Removal

IGT's ongoing efforts to produce more efficient and robust derivatives of the organic sulfur-removing bacterial strain IGTS8 have resulted in the development of mutants and genetically modified organisms with improved activity for removing organic sulfur from coal, crude oil, and petroleum products. The Illinois Clean Coal Institute (ICCI) and Energy Biosystems Corporation, licensee of the technology, are cofunding research in this area. To improve the strain, researchers are both using genetic engineering and evaluating classical microbiological approaches.

In a related ICCI project, IGT microbiologists demonstrated that the IGTS8 strain is an efficient agent for the biodesulfurization of the water-soluble fraction of coal that has been chemically treated. The goal of this project is to develop an integrated coal treatment process that would first modify the coal chemically to make it more responsive to the subsequent biodesulfurization.

In a program coordinated by IGT's Sustaining Membership Program (SMP) and the Gas Research Institute (GRI), IGT successfully demonstrated in a field test the merits of its integrated chemical/biological treatment (CBT) process for tar-containing soils obtained from manufactured gas plant (MGP) sites. The field demonstration, which was initiated in 1991 in the Midwest, together with another demonstration begun the following year at the same site with a different MGP soil, uses the land-farming method of soil remediation. Researchers are now planning a third field demonstration for a gas utility on the East Coast that will use a water-slurry system in bioreactors. This technique is significantly faster than the land-farming method for degrading pollutants. The current focus of the bench-scale tests in this program is to extend the application of the CBT process to include the in situ and ex situ bioremediation of soils contaminated with cyanides. IGT also conducted soil treatability studies for several other gas companies to determine the feasibility of using the CBT process to remediate soils from their MGP sites.

In a project funded by ICCI, IGT is studying the effects of sulfur dioxide partial pressure on the stabilization of sulfide-containing solids in a combustor. The data are necessary for the treatment of solid wastes from coal gasifiers that use in-bed sulfur capture by limestone and/or dolomite. The ICCI is also funding research on the regeneration of the spent sorbent to minimize the solid waste for coal gasification systems.

Other ICCI projects include the development of high-temperature sorbents for fuel gas cleanup and an advanced fluidized-bed combustor for high-efficiency coal-to-electricity conversion. For still another ICCI-funded project, IGT is evaluating a coal liquefaction approach that uses coal-derived liquids to increase the first-stage dissolution rate in two-stage direct liquefaction. Using advanced microscale screening techniques, engineers showed that liquids from the mild gasification and supercritical extraction of coal are significant promoters of key reactions during coal liquefaction. This is the first step in developing a method that improves the economics of producing transportation fuels from coal.

U-GAS

IGT continued to provide technical assistance in tests to Tampella Power Inc.'s 30-ton per day U-GAS coal gasification pilot plant in Finland. This fully integrated plant has been operated at the design capacity and pressure and has successfully demonstrated the key features of the process.

IGT also has an agreement for its U-GAS process with the Shanghai STCO International Trading Company and the Shanghai Coking and Chemical Company General of the People's Republic of China. Beginning in 1993, a series of U-GAS gasifiers will be brought on-line in phases at Wujin, China. Each unit will gasify 130 tons of coal per day to produce a low-BTU fuel gas. The first such unit on-line will be the world's first commercial-size U-GAS gasifier.

U-GAS was chosen in the fourth round of DOE's Clean Coal Technology Program for use in an integrated gasification/combined-cycle demonstration plant in Virginia. The plant will be built by TAMCO Power Partners, a partnership of units of Tampella Power Corporation and Coastal Power Production. DOE and TAMCO are cofunding the project.

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Oil Shale

IGT continued as the prime contractor for a multiyear DOE program on a pressurized fluidized-bed hydroretorting process for beneficiated Eastern oil shales. Researchers incorporated several novel elements into the process that provide hydrogen for hydroretorting, enhance oil yields, and remove sulfur and nitrogen from shale oil. Researchers are also trying to improve the efficiencies and reduce the costs of shale beneficiation. Subcontractors of IGT on this project include the University of Alabama Mineral Resources Institute and College of Engineering, the University of Kentucky Center for Applied Energy Research, and Tennessee Technological University.

Natural Gas

IGT's Chemical Research Services continued to survey gas quality in six major United States gas producing or marketing regions. GRI is funding this 3-year program to develop and field-test sampling and analytical methods for detecting trace constituents in natural gas. A new project task deals with the environmental impact of natural gas-fired powerplants. GRI has also given the Center for the Development and Evaluation of Calibration Fluids at IGT a 9-month extension on a 3-year study to provide calibration standards with certified composition for a wide range of natural gas samples.

IGT gathered base-line field-scale performance data for a membrane system to remove CO₂ from subquality natural gas at a gas-producing well operated by Dallas Production Inc. in Trinity County, Texas. The membrane system upgraded the gas to pipeline quality. This project will be continued at another site where data on the fate of methane, heavy hydrocarbons, H₂S, and CO₂ can be obtained at higher pressures and flow rates.

In a GRI/SMP-coordinated project, IGT is working to reduce the cost of removing acid gas and trace impurities from subquality natural gas through the use of a new solvent, N-formyl morpholine (NFM). Based on data obtained by IGT, process modeling was conducted independently by several outside research groups. The results show that the use of NFM can significantly reduce plant construction and operating costs.

Chemicals from Methane

IGT's catalysis group developed a biocatalytic methane co-oxidative technology to produce high-value chemicals. In this SMP/GRI-coordinated project, scientists are using methane to regenerate the biocatalyst in methane-using micro-organisms. The biocatalyst then oxidizes a select chemical feedstock to produce a high-value product. This biocatalyst is unique in that it can perform specific oxidations on a variety of feedstocks to yield products not easily produced by chemical or inorganic catalysts.

Montana Precision Mining to Test Skygas Process

Last September, Montana Precision Mining, Ltd. (MPML) announced that an agreement had been reached with a United States company involved in the waste-to-energy and cogeneration fields to fund specific testing of the Skygas process. The United States entity, who had requested to remain anonymous, has agreed to fully fund all operations to achieve successful test results from the gasification of wood chips, rubber tires and other carbonaceous wastes utilizing the Skygas process. Testing and demonstration of the process will be done by Skygas inventor A.C. Lewis at his plant in Libby, Montana.

Successful tests utilizing various types of carbonaceous wastes as feedstock were accomplished during the pilot plant stage of development in 1989. The Libby plant was closed in 1990 when commercialization of the process was taken over by Skygas venture partner Smogless S.p.A. of Milan, Italy.

The first Skygas commercial demonstration facility was completed in Italy by Smogless in December 1991 and the testing and debugging program began in January 1992. C. Romberg, MPML president, said that "we are using sludge, wood chips and refused derived fuels as feedstocks at our facility in Italy. Smogless currently is in the middle of a successful program to complete commercialization of the process. We have decided not to interrupt the program in Italy and therefore negotiated the startup of the Libby facility for specific testing purposes."

Romberg said that a sale of the first Skygas unit could happen shortly after successful tests results from the Libby site. Depending upon size, a typical Skygas unit could sell for $8 million to $10 million, estimated R. Little, MPML spokesperson.

The essential elements of the two-stage Skygas process are shown in Figure 1. Feed material is continuously fed through the top of a refractory lined primary reactor vessel containing three graphite electrodes. Gasification reactions are initiated by an electric arc established between the electrodes. These reactions involve the dissociation and activation of water originating both in the feed, and from the reservoir below the electrodes. The homolysis of water by the electric arc, produces highly reactive, free-energy hydrogen atoms and hydroxyl radicals. These free radicals cause a chain reaction of further dissociation of carbonaceous molecules.

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As shown in Figure 1, the Skygas process employs a secondary, attenuating reactor, to clean up and upgrade the primary reactor gases. In the secondary reactor, the liquids, carbon dioxide, methane and most of the higher hydrocarbons from the primary reactor, are converted into clean hydrogen and carbon monoxide, by reacting with dissociated water vapor and hot carbon in the bottom of the reactor.

Skygas is said to offer several important advantages over conventional waste-to-energy systems that employ combustion:

- Skygas systems are low cost.
- Skygas uses only one-fourth the amount of electrical energy as earlier plasma-arc processes.
- Skygas welcomes wet feedstocks of up to 50 percent water.
- Skygas produces an exceptionally clean medium-BTU gas that may be suitable for direct use in combustion turbines for the generation of electric power.
- Skygas produces no detectable dioxins in either the product gas, or the resulting ash, even when a municipal solid waste feedstock was artificially "spiked" with 2 percent PVC.

The Skygas venture partners include: Montana Precision Mining, Ltd., Spokane, Washington; Smogless S.p.A., Milan, Italy; Xytel Technologies, Mt. Prospect, Illinois; Enprotech Corporation, New York, New York, a subsidiary of C. Itch Group of Japan and Laidlaw Inc. of Canada.

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LURGI ANNUAL REPORT NOTES ACTIVITY IN GASIFICATION AND GAS CLEANUP

The Lurgi AG 1992 Annual Report highlights the company's activity in gasification and cleanup technology projects.

With CO₂ emissions and resource conservation becoming more of a concern, the future of fossil fuel-derived electricity will ultimately depend on further improvements in the overall fuel-to-power conversion efficiency.

Lurgi has taken up this challenge. In cooperation with Rheinbraun AG and Uhde GmbH, Lurgi is currently handling the basic engineering and permitting for the brown-coal-based integrated gasification combined cycle (IGCC) powerplant project (KoBra) of RWE Energie AG. The 300 megawatt powerplant operating on the Rheinbraun-developed High Temperature Winkler gasification process is scheduled to come on line at the beginning of 1996.
Lurgi is also pursuing an IGCC powerplant project to be implemented by Endesa in Spain. Bid preparation for the British Gas Lurgi gasification plant to be integrated into this European Community-sponsored project was under way last year. The pre-project was being jointly handled by Lurgi and British Gas.

These two projects testify to the growing interest in integrated gasification combined cycle powerplants worldwide, says Lurgi.

In the short and medium term, the Gas and Synthesis Technology Division expects an increasing demand for its entire range of processes consisting of the production of fuel gas and synthesis gases from gaseous and liquid fuels such as natural gas, naphtha and residual oils, and cleaning of these raw gases by physical or chemical washing processes including the recovery of elemental sulfur.

Several contracts were won last year for the modernization and enlargement of Lurgi-supplied town gas plants in Berlin to ensure safe operation of these plants until such time as Berlin has been completely switched to natural gas. The contracts also include a substitute natural gas plant built to safeguard supplies to those consumers which GASAG had already converted to natural gas feed.

In the field of methanol production, the American Cyanamid/Metallgesellschaft joint venture awarded Lurgi a basic engineering contract including a definitive cost estimate for the conversion of an ammonia plant into an 1,800 ton per day methanol plant. After the Tenneco conversion project, this will be the second time that Lurgi will have converted an ammonia plant into a methanol plant, using the Combined Reforming Process for syngas production.

Lurgi also won a contract from India to provide the basic engineering and supply special equipment for a 300 ton per day methanol plant. The project management for this plant will lie in the hands of Lurgi India.

Conservative analyses of methanol market trends suggest that 1 million tonnes of additional methanol will have to be produced annually over the coming 5 years to meet the demand above all for MTBE—an oxygenate that is used as a motor fuel additive. This extra demand requires the construction of several methanol plants for which intensive project work is already under way.

Lurgi's activities in the field of fuel gas purification for combined-cycle power stations were further reinforced. For the KoBra project of RWE Energie AG/Rheinbraun AG providing for the gasification of Rhineland brown coal, Lurgi contributed the engineering of the fuel gas purification system in combination with an Oxygen Claus Unit. Similar projects, some of them on the basis of heavy-oil gasification, are being intensively pursued in other countries.

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PRODUCTION TAX CREDITS ALLOWED FOR ALTERNATIVE FUELS UNDER NEW ENERGY ACT

The 1992 Energy Policy Act includes a provision for Alternative Fuels Production Tax Credits for domestic production of alternative fuels. To encourage investment in the production of qualified solid and liquid alternative fuels (such as those produced in clean coal refineries), United States producers of qualified alternative fuels are able to earn substantial federal income tax credits which can be used by the producers to directly offset their federal income tax liabilities. The credits can be first applied to income taxes due on profits from product sales by the plant. Remaining credits could then be applied to the producers' unrelated income tax liabilities.

The credits are presently calculated at $14 to $17 for each ton of coal processed, depending on the quality of the coal. The credits are adjusted for inflation each year by the United States Treasurer through the year 2007. Table 1 shows SGI International's projected dollar amount of credits for each ton of coal processed, assuming a starting base of $14 per ton as of 1993 and a 3 percent average annual inflation rate thereafter.

The tax credits provided for in the 1992 Energy Act can be claimed for alternative fuels produced and sold between January 1, 1993 and January 1, 2008; also, the production plant must be placed into service before January 1, 1997.

According to SGI, the net effect of the credits is that the anticipated net profits from the production and sale of qualified alternative fuels may be earned free of federal income tax obligations. Thus, the potential after-tax return to investors in these plants would be dramatically increased, which is expected to attract significant additional investment in the near term for clean coal project development programs throughout the United States.

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NEW EIA OUTLOOK THROUGH 2010 PROJECTS SLOW GROWTH IN ENERGY DEMAND

The Energy Information Administration's (EIA's) Annual Energy Outlook 1993 presents forecasts for energy prices, supply, demand, and imports over the period 1990 to 2010, and is summarized here.

The report evaluates seven scenarios that give high and low projections based on various assumptions. For the most part, the divergence among cases results from the uncertainties associated with the major sensitivity factors: world oil prices, macroeconomic growth, and the United States' oil and gas resource base.

Energy End Use

Total energy consumption in the United States is expected to grow to between 102 quadrillion BTU and 112 quadrillion BTU (including renewable fuels) by 2010. This growth reflects the moderating effects of energy conservation. Energy demand per unit of gross domestic product is expected to fall by between 0.7 and 1.0 percent per year. The introduction, adoption, and use of more efficient energy-using technologies in all sectors, because of the Energy Policy Act of 1992, and general improvements in technology should continue these trends.

Energy end uses considered in this report include buildings sector, industrial sector and transportation sector consumption. Natural gas and electricity continue as the primary sources of energy in the buildings sector over the forecast period. The projected industrial energy consumption, by energy source, is presented in Figure 1. After 1990, electricity, natural gas and petroleum show steady increases. The transportation sector will continue to depend almost completely on petroleum as an energy source, according to the EIA report.

Oil and Gas Outlook

Reliance on petroleum imports will rise from 42 percent of domestic consumption in 1990 to between 52 and 72 percent in 2010, depending on the level of oil prices. The additional imports will be needed because domestic oil production and refining will not keep pace with growing petroleum demands.

Based on worldwide projections for supply and demand, world oil prices, which averaged $18.70 per barrel in 1991, are projected to average between about $14 and $29 per barrel in 2000 (in 1991 dollars) and between about $18 and $38 per barrel in 2010. This wide range in oil prices is attributable to possible differences in OPEC production, non-OPEC production, and the demand for oil from the developing countries.

The composition of many petroleum products will change significantly over the forecast period because of Clean Air Act Amendments of 1990 mandates. Reformulated blends of gasoline will eventually replace traditional gasoline completely, utilities will phase out high-sulfur residual oil in favor of low-sulfur residual oil, and changing military jet fuel standards will result in a transition from naphtha jet fuel to the safer kerosene-type jet fuel used by commercial airlines, as a result of the Act.

Natural gas wellhead prices are expected to increase from a 1991 level of approximately $1.60 per thousand cubic feet.
(mcf), in 1991 dollars, to between $2.40 and $2.80 per mcf in 2000 and to between $3.20 and $4.40 per mcf in 2010. These projections are sensitive to assumptions about the rate of technology improvement in exploration and development and to uncertainty with respect to the size of the United States resource base. Also, imports (mainly from Canada) will become a more important feature of the domestic gas market over the next 20 years.

Natural gas consumption will grow through 2010, with gas maintaining a steady market share. Consumption growth will be spurred by new markets for natural gas, especially in combined-cycle electric generation, compressed natural gas vehicles, and commercial cooling, according to the report.

Electricity Outlook

Over the next 20 years, electricity will capture an increasing share of the total energy market. After growing from 24 percent in 1970 to 36 percent in 1990, the share of total primary energy consumed to produce electricity is expected to approach 39 percent by 2010, says the EIA. Relatively stable prices and consumers' desire for convenient, versatile electric appliances combine to stimulate increased consumption of electricity. End-use efficiency improvements dampen growth in energy consumption, but, even so, growth in the demand for electricity lags only slightly behind economic growth.

To meet this demand growth, between 149 and 245 gigawatts of new generating capacity will be needed by 2010. Coal-fired plants will continue to account for more than half of total electricity generation over the forecast period. Between 1990 and 2005, the majority of the new plants will be natural-gas-fired combined-cycle and turbine plants added to serve intermediate and peak-load requirements. After 2005, new coal-fired plants will be built to serve growing baseload needs. By 2010, gas-fired plants surpass nuclear as the second most important generating resource.

Coal Outlook

Having surpassed petroleum in 1984, coal now accounts for a greater share of United States primary energy production than any other fuel. Growth in coal-fired electricity generation, and a more than doubling of coal exports, are expected to stimulate strong growth in coal production over the next 2 decades. The changes in annual production of coal, natural gas and oil are presented in Figure 2. From just over 1 billion short tons in 1990, coal production will reach between 1.3 billion and 1.5 billion short tons by 2010, an annual increase of between 1.0 and 1.9 percent.

The electricity sector is projected to account for 97 percent of the increase in total United States coal consumption over the forecast period. The United States is also expected to regain its position as the world's leading coal exporter by 2010, with increased coal demand in Western Europe being met by United States coal producers, thus helping to reduce the domestic trade deficit.

Mine-mouth and delivered coal prices are projected to rise moderately over the forecast period, by 1.6 and 0.8 percent per year on average, respectively.

According to the report, the stringent sulfur dioxide emission restrictions of the Clean Air Act Amendments of 1990 will cause coal production to shift 110 million tons from medium- and high-sulfur coal to low-sulfur coal by 2010. For the most part, this shift is attributable to the sulfur dioxide emission reductions mandated for existing coal-fired generating capacity.
Carbon Emissions

Estimates of carbon emissions from fossil fuel combustion totaled more than 1.3 billion metric tons in 1990. By 2010, these emissions will reach an annual level of between 1.555 and 1.725 million metric tons, with a projected growth rate of 0.7 to 1.3 percent per year.

The transportation and utility sectors will continue to account for the bulk of carbon emissions, increasing from 435 to 556 million metric tons and from 481 to 681 million metric tons, respectively, over the next 2 decades.

NEW GRI FORECAST FOR 2010 REDUCES OIL PRICE OUTLOOK

The Gas Research Institute (GRI) recently released its 1993 edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010. GRI's baseline projection was developed independently using publicly available data and commercially available analytical models.

In addition to the baseline projection, GRI explored two alternative scenarios of the energy outlook. In one scenario, despite energy prices that remain low, energy demand is severely constrained by economic and policy factors. In the other, an optimistic view that increased gas supplies can be provided at low cost is carried to an extreme degree.

Total primary energy consumption is projected to increase at about 0.8 percent annually as illustrated in Figure 1, significantly less than the projected 2.1 percent per year growth in Gross Domestic Product (GDP) over the long term. The projection includes a steady improvement in energy efficiency over time. A portion of the projected need for increased levels of energy services will be offset by greater efficiencies in the technologies that convert primary energy into those services. The contribution from efficiency improvement reduces the total energy requirement in 2010 by about 30 quads below the requirement that would be implied by the current efficiency of energy use.

The constrained energy demand scenario results in no increase in total energy demand throughout the projection. The impact of constraints on energy demand are illustrated by the consumption of fuel for electricity generation (Figure 2). According to GRI's analysis, the outlook for electric power demand growth is a critical area of uncertainty in efforts to forecast the energy future.

GRI's baseline projections for petroleum, coal, nuclear, and gas demand are summarized here.
Petroleum

The oil price track adopted for the 1993 edition of the projection has been significantly reduced from that used in the 1992 and earlier versions of the projection. The United States refiner acquisition cost of crude oil is projected to remain relatively flat in the near term, reaching only about $21 per barrel (1992 dollars) by 2000. The real price in the year 2000 would correspond to a nominal price (the actual price seen in a given year) of about $28 per barrel. After 2000, real prices are projected to increase more rapidly as Middle East sources again dominate supply. The United States refiner acquisition cost in real dollars is projected to reach about $27 per barrel in 2010.

At these prices, United States primary petroleum consumption is projected to increase at a rate slightly less than that of total primary energy demand, from roughly 33 quads in 1990 to just over 37 quads by 2010. The increase is moderated by strong improvement in efficiency.

Industrial petroleum consumption is impacted by more competitive gas prices and lower projected levels of industrial production. In the electric utility sector, petroleum consumption will be moderated by the assumed success of demand-side-management programs in limiting electricity demand growth and also by improved generating equipment efficiencies. In the transportation sector, the projection assumes full implementation of the corporate average fuel economy standards and some further increases in other vehicle efficiencies.

With important contributions from technology improvement, domestic petroleum production (including natural gas liquids) is projected to hold steady at 9.2 million barrels per day between 1991 and 2010. Net petroleum imports grow from 6.5 million barrels per day in 1991 to 8.8 million barrels per day by 2010. This includes almost 2 million barrels per day of refined petroleum products.

Coal

Coal consumption is projected to increase at the rate of 0.8 percent per year, reflecting the impact of increasingly stringent environmental restrictions and load management programs by electric utilities. Electricity demand, including electricity generated and used by cogenerators, is projected to grow at 1.5 percent per year, which is considerably slower than the rate of growth in GDP. The major portion of the projected increase in coal consumption occurs after the year 2000 as new coal-fired generating units are added by utilities.

Nuclear

The projection assumes only the completion of the nuclear powerplants currently under construction and the continued operation of those plants that have not been affected by policy restrictions. By the end of 1991, almost 108 gigawatts of nuclear nameplate generating capacity were in place and operating. Nuclear nameplate capacity reaches a high of 110 gigawatts by 1995 before declining to 107 gigawatts by 2010 due to retirements.

Gas

Gas consumption is favorably impacted by the increasing concerns about the environment and the substantially lower natural gas prices adopted in the 1993 edition of the baseline projection. Primary gas consumption is projected to increase sharply from 1991 levels in the projection, growing at an annual average rate of 1.2 percent. This rate of growth is about 50 percent greater than the growth in overall primary energy consumption. Total primary gas demand is projected to grow from 19.9 quads in 1991 to 24.9 quads in the year 2010. Total delivered gas consumption (including gas synthetics and coal gas) is projected to grow from 20.0 quads in 1991 to 25.0 quads by 2010.

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BATTELLE FORECASTS $162 BILLION INCREASE IN R&D SPENDING IN 1993

Expenditures in calendar year 1993 for research and development (R&D) in the United States are expected to reach $162 billion, according to the annual Battelle forecast. This represents an increase of $4.6 billion (2.9 percent) over the $157.4 billion the National Science Foundation estimates actually was to be spent for R&D in 1992. Because part of the R&D increase will be absorbed by inflation—estimated to be slightly more than 2.0 percent for 1993—Battelle forecasts a real increase in R&D expenditures of less than 1 percent. This is considerably less than the 10-year average increase of 3.1 percent in real R&D since 1982.

"The economy shows signs of an upswing, but not enough to stimulate a strong growth in R&D investments," said Battelle President D.E. Olesen. "Shifting priorities in both government and industry, a slow business recovery, and a whole new spectrum of international opportunities and responsibilities have created uncertainties in R&D decision-making. However, the funding trend will be turning around. In order to meet future challenges in many other areas, we must invest in R&D, and in the capacity to utilize the results of research."

Sources of Funds

Industrial funding for R&D will account for 51.2 percent of the total. Industrial support is forecast to be $83 billion, up 2.4 percent from 1992. Battelle sees an increase of 2.8 percent in federal support for R&D, with funding expected to be $70.1 billion. This is 43.3 percent of the total.
is also most likely to support research and institute policies that will strengthen domestic economic growth."

The emphasis on federal R&D as a means of supporting domestic economic growth is evidenced in three initiatives that are expected to continue.

- Funding for many of the so-called "big science" programs—including the superconducting supercollider and the space station—are under close scrutiny, with some of these barely escaping total cancellation or suspension.

- Efforts to reshape the basic research missions of the National Science Foundation and the National Institute of Standards and Technology are being made in an effort to direct resources toward more immediate applied research programs.

- Efforts at developing collaborations between industry and the federal laboratories are being pursued more vigorously.

**Industrial Support**

Industrial support of research will continue to grow in areas related to electronics, communications, sensors, advanced machinery, and in fields directly influenced by the need for more energy-efficient products and processes.

Near-term industrial plans indicate that the slowdown in R&D may be stabilizing. Downsizing in all aspects of operations will have an adverse impact on R&D personnel levels. However, Battelle expects these moves to be offset by an increased interest in collaborative research programs. Furthermore, industrial postures in R&D spending will be influenced by the anticipation of a stronger federal government role in encouraging public/private partnerships, promoting permanent R&D tax credits, and enhancing the roles of the federal laboratories.

**Long-Term Outlook**

The R&D growth rate has been slowing and is expected to continue to decline, perhaps to the point of a decrease in real expenditures. A similar situation occurred 2 decades ago, with a very slow recovery. The Battelle forecast suggests that if there is a decrease in real expenditures, the real recovery will most likely occur more rapidly than before.

The trade imbalance and efforts to correct it, as well as efforts to expand markets in response to shifts in government priorities, could spur expanded R&D. In addition, the internationalization of markets will influence R&D expenditures as United States-based companies attempt to accommodate the different regulatory postures and consumer behaviors in other parts of the world. Whether such initiatives will be fruitful will be influenced by the impacts of general slow-

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**TABLE 1**

<table>
<thead>
<tr>
<th>DISTRIBUTION OF FEDERAL R&amp;D FUNDING</th>
<th>1993</th>
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<td>Department of Energy</td>
<td>15.0</td>
<td>9.3</td>
<td>9.8</td>
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</tbody>
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SYNTHETIC FUELS REPORT, MARCH 1993
downs in worldwide economic growth and in the availability of foreign currencies.

In the recent past, the environment that permitted greater rewards for short-term financial results, rather than technological innovation, had an adverse effect on R&D investment. However, the tenor of the federal budget for 1993 and the pro-technology attitude of the incoming administration give reason for a cautious optimism regarding R&D growth and accountability in the near future.

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WORLD ENERGY DEMAND PROJECTED TO MORE THAN TRIPLE BY YEAR 2100

The long-range impact of continued worldwide economic development on energy use, resources and the environment, through the year 2100 was discussed in a paper by S.W. Gouse, et al., published in the December 1992 World Energy Council Journal. This study took into account resource constraints, various energy per capita growth rates associated with different levels of economic development, aspirations of developing countries, and the historic changing characteristics of countries as they move through the development scale.

Methodology

The methodology used was to estimate future world energy demand based on the assumption that developing countries that currently have low energy consumption will mimic the growth in energy demand that has been experienced by countries ahead of them in development progression.

Primary commercial energy consumption per capita was the basic measure of energy used to make the projections. Energy from direct electric systems (nuclear, geothermal, etc.) was converted to equivalent primary energy by assuming a nominal efficiency of 34 percent. Total energy demand was obtained by multiplying projected energy per capita by population.

Energy per capita data from the World Development Report of 1990 published by the World Bank, was used to rank 130 countries in increasing order of per capita commercial energy use in the year 1988. Nine groupings of countries were identified: 0-25, 25-50, 50-100, 100-200, 200-400, 400-800, 800-1,600, 1,600-3,200 and 3,200 plus, on a kilogram oil equivalent (KOE) basis.

Estimates of World Energy Use

Under the scenario of no increase in efficiency, the lower 0-200 group of countries is estimated to increase its per capita commercial energy consumption by some 20 times over current levels whereas the Organization of Economic Cooperation and Development countries in the 3,200 plus group will not quite double per capita energy use from 1990 to 2010.

If it is assumed that there are no limitations of resources for coal, oil or gas, that there is the same market share of coal, oil, gas, nuclear and renewables as in 1990 (renewables are hydroelectric, geothermal, solar, wind, etc.) and that there is no improvement in energy conversion and end-use efficiency compared to 1990, the worldwide primary commercial energy consumption will increase from about 330' exajoules in 1990 to about 2,200 exajoules in the year 2100, nearly a 7-fold increase.

It is reasonable to assume that future energy conversion efficiencies for all phases from resource extraction through end-use will improve in the coming century. Conservation efforts also have the potential to significantly reduce primary energy use in residential and commercial application. Also, in the transportation sector, increased use of mass transit and considerably more fuel efficient vehicles can greatly reduce energy demand.

With the assumption that energy conversion and end-use efficiencies can be increased, it is assumed that after 33 years, existing equipment is replaced by new equipment that saves 33 percent of the energy. This 33-year cycle continues for another two cycles of continuing efficiency improvements saving an additional 16.6 percent and 8.3 percent of energy. The result of these cumulative efficiency improvements is to essentially reduce the total primary commercial energy demand worldwide by approximately one-half compared to the baseline "no improvement in efficiency" scenarios. Total energy demand by the year 2100 will then be about 1,100 exajoules, a 3.3 fold increase over current energy demand worldwide.

Two alternative projections of global energy demand were made in an effort to bracket a reasonable range for future energy demand. In the high alternative case, it was assumed that future growth in per capita energy consumption would follow the trend set by the population quartile having the highest energy growth rate in each group of countries. The trend established by the countries in the lower two population quartiles was used to obtain a low alternative projection.

Figure 1 shows the energy use projections for the baseline and the two alternative cases. Results are shown with and without the projected improvements in efficiency discussed previously. With efficiency improvements, the high and low projections of energy demand are 1,560 exajoules and 910 exajoules respectively, compared to 1,126 exajoules for the base case.

If the projected population increases are the correct order for the year 2100 and the lesser developed countries follow the energy/capita use progression analyzed above, then the...
lesser developed country groupings that currently use between 0-200 and 200-400 KOE per capita of primary commercial energy are estimated to increase their total primary commercial energy use 58 and 17 times respectively by the year 2100 even assuming substantial improvements in energy use efficiencies. Countries in the 3,200 plus KOE per capita group are estimated to increase their energy use by only 25 percent. This 3,200 plus group of countries that currently consume 70 percent of total world energy will use only 26 percent in the year 2100 (see Table 1).

Of the total world energy used in 2100, electricity can be the predominate form. It is quite feasible to assume that electric power could provide as much as 80 percent of world energy demand, which assumes that a considerable percentage of transportation energy would also be electric. If 80 percent of world energy was electric, then 880 exajoules of primary energy would be required to be generated. This would correspond to about 13,000 electric power stations worldwide with a capacity of 1,000 megawatts each.

The current market use percentage of primary energy resources used in the baseline scenarios are oil 39 percent; coal 29 percent; gas 20 percent; renewables 8 percent and nuclear 6 percent. Evaluation of scenarios involving other energy-use mixes resulted in the following conclusions:

- All energy resources, coal, oil, and gas, as well as nuclear and renewables, will be needed in the coming century to fuel world development.

- The potential contribution from biomass appears limited. Apart from the real problems of competing land use for food and water resources, it is not clear if using certain biomass systems are actually net energy positive or negative.

- There does not appear to be a real energy resource problem for at least the next 50 years, but after

### TABLE 1

**SUMMARY OF CURRENT AND ESTIMATED ENERGY USE IN THE YEAR 2100**

<table>
<thead>
<tr>
<th>Country Group (KOE/CAP)</th>
<th>Energy Use in 2100 (Exajoules)</th>
<th>% of Each Group in Year 2100</th>
<th>Energy Use in 1990 (Exajoules)</th>
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that, in the absence of a surprise, even if more oil and gas are found, the world had better be ready with acceptable nuclear- and solar-based technologies.

- No single energy technology can solve the upcoming energy problems that will face the world. Energy research and development cross-cutting between these separate technologies will be necessary to provide solutions, i.e., combine fossil/nuclear/renewables technologies into an integrated systems approach.

- Solar energy, particularly photovoltaic and electric energy storage research and development, will become important.

- Photovoltaic use in small-scale applications (residential, village) in developing countries will reduce requirements for large, central fossil generating facilities, and for long-range power transmission.

Environmental implications resulting from this study include:

- Sulfur dioxide emissions can readily be eliminated by using advanced control technologies. Short-term solutions, like retrofitting old technologies with scrubbers, do not make for sound environmental policy in the long term.

- Annual carbon dioxide emissions may not increase much over present values for the next 50 years if end-use efficiency improvements can be obtained and a modest increase in nuclear and renewables can be sustained.

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API ARGUES AGAINST PRESIDENT CLINTON'S PROPOSED BTU TAX

The American Petroleum Institute (API) summarized its position against President Clinton's proposed energy tax in statements released after the President publicly announced the plan in February.

The BTU-based energy tax, as proposed by President Clinton, is a tax that would be applied to all sources of energy except solar, wind and geothermal power. The tax would be based on the heat content of fuels measured in BTUs.

A tax of $0.257 per million BTU would be assessed on coal, natural gas and nuclear energy, and oil would be taxed at a higher rate of $0.599 per million BTU ($3.47 per barrel of oil). Hydroelectric power would be taxed at a rate determined by a United States Treasury Department formula based on its fossil fuel inputs. Renewable fuels would be exempted from the tax.

The Clinton Administration has projected that the tax will raise $22 billion a year when it is completely phased in on July 1, 1996, but according to API this estimate is far too low. Americans currently use about 6.2 billion barrels of oil annually, so a new tax of $3.47 per barrel would produce $21.5 billion in revenue just from oil. C.J. DiBona, president of the API, believes that the actual revenue generated by the energy tax is closer to $33 billion per year. That translates into an impact on a typical family, in terms of direct and indirect cost increases, of not the $320 per year the Administration estimated but something more like $475, says DiBona.

In addition, the BTU tax would place the greatest burden on lower- and middle-income Americans, who spend a greater proportion of their income on energy than do higher-income people. According to the United States Bureau of Labor Statistics, the average United States household spent 7 percent for energy, the poorest fifth of all families spent on average 22 percent on energy, and the wealthiest fifth spent about 4 percent of their incomes on energy.

The Clinton Administration's proposal attempts to make the tax fairer by adding an earned income tax credit for low-income families. But earned income tax credits would be better for low-income, inner city people living near subways than for those who live in rural or suburban areas and need cars to get to their jobs, says API.

DiBona cites a Treasury Department analyst, who is quoted as saying the bias between the $33 billion collected and the $22 billion in net revenue reflects assumptions about how the higher energy tax would affect such economic factors as jobs and incomes. Based on this argument, DiBona maintains that the loss over 5 years in gross domestic product resulting from such taxes, estimated at $170 billion, exceeds the direct revenues raised from such taxes. In addition the Clinton proposal will result in the loss of an estimated 700,000 jobs over 5 years, says DiBona.

According to API, the reason that a BTU-based tax would have such a tremendous negative economic impact is due to the importance of energy as an input to United States industries, especially energy-intensive industries such as steel, aluminum, lumber, and agriculture. API argues that with a BTU-based energy tax imposed in the United States, but not elsewhere in the world, United States products would become less competitive relative to comparable products produced in other countries, giving foreign producers and workers a competitive advantage.

Higher energy taxes would also impose greater burdens on the economies of states with more energy-intensive industries—and job losses in these areas would be disproportionately great, says API. Because energy-intensive in-
Industries are not distributed equally throughout the United States, about 3 times as much energy (in BTUs) is used to produce a dollar of goods and services in the energy-intensive economies of West Virginia, Wyoming, Texas and North Dakota than in New York, Connecticut, Massachusetts or New Hampshire. It takes 10 times as much energy in Louisiana as it does in the District of Columbia.

The BTU-based energy tax proposal would doubly tax oil so states that have economies that rely on oil more than on other fuels will be hit twice as hard by the proposed tax, argues API. The petroleum-intensive states that would bear the brunt of the BTU tax proposal are Louisiana, which uses more petroleum to produce each dollar of state economic output than any other state, Texas and Mississippi.

Impact on Oil Industry

API argues that singling out oil for the heaviest tax burden ignores the vital role oil plays in meeting the nation's energy and economic needs. API cites United States Department of Energy (DOE) statistics that in 1991, oil supplied 41 percent of the nation's energy. (American industries and individuals consumed the products from some 6.1 billion barrels of crude oil.) By the year 2010, DOE estimates that oil will supply 37 percent of the energy total.

API also cites low gasoline prices as evidence of its long-term competitive price relative to other fuels. As an example, in mid-summer 1992, United States motorists paid about $1.18 per gallon for unleaded gasoline. Twenty years ago, the typical motorist paid more—about $1.20 per gallon (in 1992 dollars).

People who want to decrease the country's dependence on oil argue that good substitutes are available and that shifting to them would be good for the country. They put forth a number of arguments that are at odds with the facts, says API.

Some people argue that higher energy taxes would discourage energy consumption and, thus, curtail dependence on oil imports and strengthen United States energy security. According to API, the proposed BTU tax would have relatively little effect on oil imports. Based on the most recent DOE projections, the proposed tax would shave import growth by less than one-tenth after 10 years. By the year 2000, Americans would still depend on foreign oil for three-fifths of their total oil requirements.

Some people also argue that by discouraging energy use, particularly oil use, higher energy taxes would protect the environment. However, API argues that many possible substitutes for oil also have the potential to harm the environment. For example, renewable fuels such as ethanol contribute their own environmental problems. Ethanol is made from corn, but growing corn can damage topsoil. Pesticides used in corn production can threaten streams and groundwater, and, as the United States Environmental Protection Agency has documented, using ethanol as a gasoline additive can contribute to air quality problems.

API also notes that great strides are being made to protect the environment while producing and using oil products. Under the Clean Air Act, lead has been removed from gasoline and auto emissions have been greatly reduced. Moreover, the new Clean Air Act Amendments of 1990 will produce further gains by requiring cleaner-burning gasolines and cleaner-operating refineries, says API.

API also contends that reducing fossil fuel use, specifically oil use, to reduce CO₂ emissions that are associated with global warming is not necessary because of the scientific uncertainties associated with global warming predictions. In addition, a reduction in oil use to preserve the United States' remaining supplies is not necessary, according to API, because the United States still has abundant supplies. API cites the most recent DOE study of domestic oil supplies which estimates that the nation has as much as 204 billion barrels of recoverable oil, assuming a price of $27 per barrel. This equals about 75 years of United States oil production at the current rate. (See related article in this issue of the Pace Synthetic Fuels Report.)

API's Alternative to the BTU-Tax

Since the mid-1960s, federal revenue, as a percentage of the Gross Domestic Product (GDP), has remained fairly constant, averaging 18.6 percent. Since 1965, it has fluctuated by barely 2.5 percentage points, between 17.4 and 20.1 percent of GDP. In contrast, federal spending, as a percentage of GDP, has grown over the same period from 17.6 to 23.5 percent last year. Since 1989, federal spending has risen more than twice as fast as revenue. Thus, according to API, reduced spending is the best solution to the deficit problem.

###

SYNTHETIC FUELS REPORT, MARCH 1993
ENVIRONMENT

PARTICULATE EMISSIONS COULD OFFSET GLOBAL WARMING FROM FOSSIL-BASED CO₂

Virtually all scientists directly involved in research on climatic change believe that the earth will undergo some warming as a result of the increase in human emissions that absorb infrared radiation, or enhance the "greenhouse effect." However, the magnitude of the effect is greatly debated. An extensive body of evidence now indicates that anthropogenenerated sulfate emissions are mitigating some of the warming, and that increased cloudiness as a result of these emissions will further enhance night, rather than day, warming. The compensatory cooling effect of these emissions was discussed in a paper by P.J. Michaels and D.E. Stooksbury published in the October 1992 issue of the Bulletin American Meteorological Society.

Researchers have hypothesized substantial radiative effects from industrial aerosol, through direct backscattering and increased cloud-condensation nuclei (CCN) that would tend to enhance low-level cloudiness. In combination, the effects could force net cooling at the current time, rather than warming. In fact, one body of research indicates that the current negative temperature forcing from sulfate aerosol, globally averaged, is comparable in magnitude to the current anthropogenic greenhouse forcing but opposite in sign.

It has also been demonstrated that the anthropogenenerated sulfate load in the Northern Hemisphere atmosphere now is equivalent to the maximum loading from the Tambora volcano, which has been associated with a 1 to 2°C cooling of short duration. A comparison of Northern and Southern Hemisphere temperature histories shows a striking difference that appears to be associated with the onset of world industrialization after 1950. Beginning in the mid-1950s, Northern Hemisphere temperatures stopped rising at the rate that characterized the 20th century, while those in the Southern Hemisphere continue to rise, though at a slightly lower rate than characterized the first half of this century.

In fact, if low-level cloudiness of industrial origin were increasing in a climatically significant fashion, we should see the following:

- Night warming should appear from the increase in both greenhouse gases and cloudiness.

- A counteraction of daytime warming should occur because of cloud albedo, and a consequent decrease should result in the daily temperature range.

- The greatest warming (night effect) of clouds should occur on (long) winter nights.

- The greatest cooling (day effect) should occur on (long) summer days.

- The least warming (night effect) should occur on (short) summer nights.

- The least cooling (day effect) should occur on (short) winter days.

- Cloudiness should be enhanced near the CCN source regions of North America and Eurasia.

- These effects should be concentrated in the industrial (Northern) Hemisphere.

Based on data from recent studies, Michaels and Stooksbury address each of these "hypotheses."

Examination of the maximum and minimum values from the United States Historical Climate Network (HCN) found that the daily range (difference between the two) has declined precipitously since 1950, and is now two standard deviations below the mean for the century. In that record, maximum values have actually declined while minimum values have risen. According to the authors, this behavior of the HCN is consistent with an enhanced greenhouse combined with the increases in cloudiness (of 3.5 percent) and reduced sunshine that have been documented across the conterminous United States.

An HCN-like dataset for the former USSR and Continental China, along with the United States HCN, now cover 42 percent of the landmass of the Northern Hemisphere. Area-weighted aggregate data from the three countries are presented in Table 1.

### TABLE 1

<table>
<thead>
<tr>
<th>Season</th>
<th>Mean Maximum (°C per 100 Years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>+0.6</td>
</tr>
<tr>
<td>Spring</td>
<td>+0.6</td>
</tr>
<tr>
<td>Summer</td>
<td>-0.4</td>
</tr>
<tr>
<td>Fall</td>
<td>-0.6</td>
</tr>
<tr>
<td>Annual</td>
<td>+0.05</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, MARCH 1993
The greatest warming (night effect) of clouds should occur in winter, when clouds have the greatest length of time to trap heat. In fact, when this record is aggregated, winter low temperatures show a warming of 1.8°C per 100 years, with 3.8°C in the former Soviet Union.

The greatest cooling (day effect) should occur in the summer, when clouds have the greatest length of time to reflect away radiation and counter greenhouse warming. Aggregated data demonstrate that summer days actually show a cooling trend of 0.4°C per 100 years. Summer warming stopped in the United States HCN at the time that the increase in CO₂ changed dramatically, according to Michaels and Stooksbury.

The least warming (night effect) should be on the short summer nights, when clouds have the least length of time to trap heat. This is also borne out by the aggregated data.

The least cooling (day effect) should occur on the short winter days, when clouds have the least length of time to reflect away radiation. There in fact has been a relative warming of winter days, although spring daytime temperatures have increased just as much (0.6°C).

Satellite data depict an increase in brightness in ocean-surface stratocumulus that heightens near CCN source regions of Asia and North America. The effect, in which reflectivity was increased by as much as 8 percent, persisted for thousands of miles downstream from the source regions. A “clean” swath of the South Pacific Ocean served as a “control” and showed no brightening.

In Australia night warming has also been greater than day warming (0.12°C per decade versus 0.06°C). This was also accompanied by an increase in cloudiness. While the night/day warming ratio is considerably less than what is observed in the Northern Hemisphere, it suggests that, even in the absence of much sulfate aerosol, an enhanced greenhouse may serve to direct a disproportionate share of warming into the night and associate with an increase in cloudiness. SO₂ emission density in Australia is approximately 2 orders of magnitude less than it is in Eastern North America or Western Europe.

According to Michaels and Stooksbury, it appears that scientists can continue to entertain at least seven of the eight hypotheses that are consistent with an increase in cloudiness and a generally benign greenhouse enhancement, although the effect is apparently not from sulfates alone. The fact that there are no misplacements between summer and winter in the day and night warming hypotheses further supports a relatively benign greenhouse enhancement.

####

SYNTHETIC FUELS REPORT, MARCH 1993
DOE STUDY FINDS U.S. LOW-COST OIL RESOURCE BASE TO BE LARGER THAN PREVIOUS ESTIMATES

At the request of the United States Department of Energy (DOE), an assessment of United States oil resources was made based on a review and analysis of recent major studies of the recoverable portion of the resource base and the qualitative judgment of a panel of experts from federal departments and agencies, state geological surveys, and industry. The total recoverable portion of the United States oil resource base was assessed, as of August 1992, and estimates are provided for undiscovered resources and reserve growth.

Four scenarios were developed using two price levels ($20 and $27 per barrel) and two levels of technology (existing and advanced). Four geographic areas were considered: the Lower-48 States onshore, the Lower-48 States offshore, Alaska onshore, and Alaska offshore.

The estimated total recoverable volume of crude oil in the United States ranges from 99 to 204 billion barrels, inclusive of 25 billion barrels of oil carried as proved reserves by the Energy Information Administration (EIA) at the end of 1991 (Table 1). The range in estimates of the remaining resource base recoverable under the given assumptions is equivalent to 35 to 75 years of continued United States crude oil production at the current annual rate of 2.7 billion barrels.

TABLE 1
UNITED STATES OIL RESOURCE BASE
(Billion Barrels, 1992 Constant Dollars)

<table>
<thead>
<tr>
<th></th>
<th>Existing Technology ($20/bbl)</th>
<th>Advanced Technology ($20/bbl)</th>
<th>Existing Technology ($27/bbl)</th>
<th>Advanced Technology ($27/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reserve Growth in Existing Fields</td>
<td>31</td>
<td>55</td>
<td>43</td>
<td>89</td>
</tr>
<tr>
<td>Undiscovered Resources</td>
<td>43</td>
<td>62</td>
<td>62</td>
<td>90</td>
</tr>
<tr>
<td>Proved Reserves at Year-End 1991</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>Total Resources</td>
<td>99</td>
<td>142</td>
<td>130</td>
<td>204</td>
</tr>
<tr>
<td>Cumulative Production at Year-End 1991</td>
<td>164</td>
<td>164</td>
<td>164</td>
<td>164</td>
</tr>
<tr>
<td>Ultimate Recovery</td>
<td>263</td>
<td>306</td>
<td>294</td>
<td>368</td>
</tr>
</tbody>
</table>

In the Oil Resources Panel's estimation of recoverable resources, both price and technology are significant and they are almost equivalent in their impact. The average estimate for recoverable volumes (total undiscovered resources and reserve growth) at both price levels was approximately two-thirds greater with the assumption of advanced technology than with existing technology.

Because the collective judgment of the Panel was that many of the discovery technologies will be applied at the reservoir level, advanced technology resulted in approximately an 80 to 100 percent increase in reserve growth estimates. Recoverable volumes from reserve growth were judged to be higher at $20 per barrel with advanced technology than at $27 per barrel with existing technology. Significantly, this shows that the use of advanced technology can have at least as much impact as price increases in terms of increasing resource recovery.

Future potential was estimated by the Panel to be nearly equally divided between reserve growth from existing, already discovered fields and new fields yet to be discovered. About two-thirds of the total remaining potential is onshore in the Lower-48 States, largely due to reserve growth from existing fields. About one-third of the total remaining potential is in offshore Lower-48 and onshore and offshore Alaska. These areas hold nearly half of the future discovery potential and most of the potential for giant field discovery.
The average estimates of the Oil Resources Panel were higher than the average of several previous estimates made in the past 5 years for overall future potential at the lower price level, and they were approximately the same at the higher price level (Table 2). In the case of reserve growth potential, the Panel's average estimates were, with one exception, lower than previous estimates. The Panel's estimates of future discovery potential with an oil price assumption of $20 per barrel were about 40 to 45 percent higher than previous estimates for the frontier areas of the United States offshore and Alaska, but 40 to 90 percent higher for the onshore Lower-48 States.

Only sensitivity to price and technology was considered in this analysis. Other factors may affect the potential for recoverable oil as estimated by the Oil Resources Panel. These factors include downsizing of research and development efforts in the private sector, access restrictions, environmental regulations, and premature field abandonment. The advanced technology scenarios pre-suppose that research and development will be done to realize that technology. This may not happen, as there has been a downsizing of research and development efforts in the private sector in recent years. Clearly, physical access to a resource is necessary if the resource is to be developed. Environmentally sound development of oil resources is a requisite, but if the costs of regulation added to other operating costs exceed the potential value of the resource, it will obviously not be realized and the oil actually recovered will be lower than the Panel estimates. Finally, the rate of abandonment of existing fields is critical. To the extent fields are abandoned before projected reserve growth is realized, resource potential will not be realized at the prices here assumed.

TABLE 2

<table>
<thead>
<tr>
<th></th>
<th>Existing Technology (Lower Price)</th>
<th>Advanced Technology (Lower Price)</th>
<th>Existing Technology (Higher Price)</th>
<th>Advanced Technology (Higher Price)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Undiscovered Resources</td>
<td>43 (31)</td>
<td>62 (38)</td>
<td>62 (52)</td>
<td>90 (61)</td>
</tr>
<tr>
<td>Reserve Growth</td>
<td>31 (24)</td>
<td>55 (62)</td>
<td>43 (53)</td>
<td>89 (121)</td>
</tr>
<tr>
<td>Total Resources</td>
<td>74 (55)</td>
<td>117 (100)</td>
<td>105 (105)</td>
<td>179 (182)</td>
</tr>
</tbody>
</table>

Note: The average of other recent estimates is in parentheses.

####
COMING EVENTS

MARCH 1-2, CALGARY, ALBERTA, CANADA – North American Natural Gas Conference

MARCH 1-3, WASHINGTON, D.C. – Improved Technology for Fossil Powerplants—New and Retrofit Applications

MARCH 9, CALGARY, ALBERTA, CANADA – 10th Annual Heavy Oil and Oil Sands Technical Symposium

MARCH 11-12, SALT LAKE CITY, UTAH – 17th Annual Symposium of the Rocky Mountain Fuels Society and 8th Symposium of the Western States Catalysis Club

MARCH 18-19, WASHINGTON, D.C. – Advanced Generation Technologies

MARCH 21-23, SAN ANTONIO, TEXAS – 91st Annual Meeting of the National Petroleum Refiners Association

MARCH 22-23, SALT LAKE CITY, UTAH – Spring Meeting of the Western States Section of the Combustion Institute

MARCH 24-25, BOCHUM, GERMANY – VDI Meeting on Advanced Energy Conversion and Application

MARCH 24-26, LONDON, ENGLAND – Second World Coal Institute Conference

MARCH 25-26, WASHINGTON, D.C. – Fourth Annual U.S. Hydrogen Conference

MARCH 28-APRIL 1, HOUSTON, TEXAS – Spring National Meeting, American Institute of Chemical Engineers

MARCH 28-APRIL 2, DENVER, COLORADO – 205th American Chemical Society National Meeting

MARCH 28-APRIL 2, DENVER, COLORADO – Symposium on Enhanced Oil Recovery

MARCH 29-31, OXFORD, UNITED KINGDOM – Symposium on Carbon Dioxide Disposal

MARCH 29-APRIL 2, CAMBRIDGE, UNITED KINGDOM – Joint Meeting of the British and German Sections of the Combustion Institute

APRIL 4-7, EDMONTON, ALBERTA, CANADA – Oil Sands–Our Petroleum Future

APRIL 5-8 CHICAGO, ILLINOIS – Fourth International Conference on Scientific and Policy Issues Facing All Governments

APRIL 19-21, PITTSBURGH, PENNSYLVANIA – American Mining Congress; Coal 93 Conference

APRIL 21, CALGARY, ALBERTA, CANADA – Heavy Oil Profitability

APRIL 21-28, HANOVER, GERMANY – Hanover Industrial Fair

APRIL 25-28, BOULDER, COLORADO – 20th International Energy Conference

APRIL 25-28, NEW ORLEANS, LOUISIANA – Annual Meeting of the American Association of Petroleum Geologists

APRIL 26-27, EDMONTON, ALBERTA, CANADA – Conference on Oil Sands Tailings Sludge

APRIL 26-29, CLEARWATER, FLORIDA – 18th International Technical Conference on Coal Utilization and Fuel Systems

APRIL 28-30, COLORADO SPRINGS, COLORADO – Annual Council on Alternate Fuels Spring Conference

MAY 4-6, LEXINGTON, KENTUCKY – Coal Prep 93 Conference

MAY 5-7, BARCELONA, SPAIN – Sixth U.S.-European Coal Conference
MAY 5-8, ANCHORAGE, ALASKA -- Fourth Alaskan Coal Conference

MAY 6-7, WASHINGTON, D.C. -- The Energy Daily's Coal Conference

MAY 8-13, SAN DIEGO, CALIFORNIA -- 12th International Conference on Fluidized-Bed Combustion

MAY 9-12, CALGARY, ALBERTA, CANADA -- Canadian Institute of Mining and Metallurgy 95th Annual Meeting

MAY 10-13, ST. LOUIS, MISSOURI -- 17th Biennial Low Rank Fuels Symposium

MAY 10-13, HELSINKI, FINLAND -- Symposium on New Coal Utilization Technologies

MAY 10-14, COLORADO SPRINGS, COLORADO -- 15th Symposium on Biotechnology for Fuels and Chemicals

MAY 10-14, ROLDUC, NETHERLANDS -- Third Rolduc Symposium: Coal Science and Technology

MAY 12-13, ESSEN, GERMANY -- Coal Gasification 1993 Conference

MAY 17-20, LONDON, UNITED KINGDOM -- 20th International Congress on Combustion Engines: CIMAL

MAY 18-20, ORLANDO, FLORIDA -- International Meeting on Coal Utilization and the Environment

MAY 24-27, CINCINNATI, OHIO -- 38th American Society of Mechanical Engineers International Gas Turbine and Aeroengine Congress

MAY 25-27, PARIS, FRANCE -- Power-Gen Europe 93

JUNE 13-18, BUFFALO, NEW YORK -- 21st Biennial Conference on Carbon

JUNE 13-18, DENVER, COLORADO -- 86th Annual Meeting of the Air and Waste Management Association

JUNE 15-17, WARSAW, POLAND -- Coal-Fired Powerplant Upgrade--1993

JUNE 20-24, NEW PALTZ, NEW YORK -- International Conference on Gas Hydrates

JUNE 22-24, LAXENBURG, AUSTRIA -- Meeting of the International Energy Workshop

JUNE 27-30, YOKOHAMA, JAPAN -- First International Conference on New Energy Systems and Conversions

JUNE 28-30, CALGARY, ALBERTA, CANADA -- Natural Gas: Realizing the Potential

JUNE 29-JULY 1, SUN CITY, REPUBLIC OF BOPHUTHATSWANA -- Eighth Pacific Rim Coal Conference in South Africa

JULY 5-9, CRACOW, POLAND -- International Conference on Energy Systems and Ecology

AUGUST 2-6, CHEYENNE, WYOMING -- Second Western Conference on Energy and the Environment

AUGUST 8-13, ATLANTA, GEORGIA -- 28th Intersociety Energy Conversion Engineering Conference

AUGUST 17-20, BAKU, AZERBAIJAN -- Second Baku International Symposium on Energy, Environment, Economy

AUGUST 22-27, CHICAGO, ILLINOIS -- 206th American Chemical Society National Meeting

SEPTEMBER 7-9, ATLANTA, GEORGIA -- Second Annual Clean Coal Technology Conference

SEPTEMBER 12-16, TOKYO, JAPAN -- JSME-ASME International Conference on Power Engineering: ICOPE-93

SEPTEMBER 12-17, BANFF, ALBERTA, CANADA -- Seventh International Coal Science Conference: ICSC

SYNTHETIC FUELS REPORT, MARCH 1993
SEPTEMBER 13-15, SINGAPORE – Power-Gen Asia Pacific 93

SEPTEMBER 13-17, CARQUEIRANNE, FRANCE – Fourth International Carbon Dioxide Conference

SEPTEMBER 18-21, WHISTLER, BRITISH COLUMBIA, CANADA – 40th Canadian Conference on Coal

SEPTEMBER 20-24, PITTSBURGH, PENNSYLVANIA – 10th Annual International Pittsburgh Coal Conference

SEPTEMBER 21-23, ALGHERO, SARDINIA, ITALY – Fourth International Symposium on the Biological Processing of Coal

SEPTEMBER 21-23, BOURNEMOUTH, UNITED KINGDOM – Seventh ASME Cogen-Turbo Power Congress

SEPTEMBER 27-29, GUILDFORD, UNITED KINGDOM – Second International Symposium on Gas Cleaning at High Temperatures

OCTOBER 3-6, OTTAWA, ONTARIO, CANADA – 43rd Canadian Chemical Engineering Conference

OCTOBER 17-21, KANSAS CITY, MISSOURI – International Joint Power Generation Conference

OCTOBER 17-21, KNOXVILLE, TENNESSEE – Eighth Symposium on Separation Science and Technology for Energy Applications

OCTOBER 18-22, SEOUL, KOREA – Fifth International Energy Conference

OCTOBER 20-22, WELLINGTON, NEW ZEALAND – Fifth New Zealand Coal Conference

OCTOBER 24-28, LEXINGTON, KENTUCKY – Fifth International Conference on Processing and Utilization of High Sulfur Coals

NOVEMBER 7-10, COLORADO SPRINGS, COLORADO – 10th International Symposium on Alcohol Fuels

NOVEMBER 16-18, DALLAS, TEXAS – Power-Gen 93

NOVEMBER 28-DECEMBER 3, NEW ORLEANS, LOUISIANA – Annual Winter Meeting of the Society of Mechanical Engineers
STUART PROJECT GETS APPROVAL FOR TAX DEDUCTIONS

As reported in the *Pace Synthetic Fuels Report* December 1992, page 2-1, Southern Pacific Petroleum (SPP) and Central Pacific Minerals (CPM) made a submission to the Industry Research and Development Board regarding the Stuart Shale Oil Project. The submission sought to qualify Stuart Stage 1 capital expenditure as research and development under the government's recently confirmed 150 percent tax deductibility concessions at the rate of 50 percent per year over each of the first 3 years of operations.

In December, the companies announced that the Board approved, in principle, elements of Stuart Stage 1 capital expenditure, which amount to approximately 90 percent of the total capital expenditure, as research and development and the tax deductibility of such expenditure has been confirmed, in principle, by the Australian Taxation Office. In both cases, approvals are subject to the development not differing materially from the companies' submission.

Additionally, similar approvals, in principle, have been received regarding operating expenditures for such research and development, which also qualify for 150 percent deductibility.

Accordingly, SPP and CPM are continuing with modification of the structure of the proposed financing arrangements for the project.

###
The preferred feedstocks for the Institute of Gas Technology’s (IGT) Pressurized Fluidized-Bed Hydroretorting (PFH) process are beneficiated Eastern United States oil shales. Before hydroretorting and after combustion the shale will be stored in large embankments. IGT and the Illinois Institute of Technology conducted tests to determine the physical and thermal properties and leaching characteristics of samples of beneficiated and thermally processed Alabama shale. The results of this study were presented at the 1992 Eastern Oil Shale Symposium held in Lexington, Kentucky in October, by M.C. Mensinger and J.S. Budiman.

Tests were conducted on raw, beneficiated, hydroretorted (PFH), hydroretorted and combusted (H&C), and hydroretorted and agglomerated (H&A) Alabama shale samples.

Physical Properties

The physical properties of the four shale samples showed considerable variability. The physical properties, evaluated include particle size, thermal conductivity, permeability, consolidation (compressibility), shear strength, compactability, and Atterberg liquid and plastic limit tests.

Permeability is the most important physical property with respect to the potential leaching of environmentally sensitive materials from a shale storage embankment. Permeabilities of the shale samples were in the range of $10^{-3}$ centimeters per second. The permeability of the H&C shale sample was the lowest at about $10^{-4}$ centimeters per second.

Chemical Properties

The test used to evaluate the leachability of the shale samples is the United States Environmental Protection Agency Toxicity Characteristic Leaching Procedure (TCLP). If the concentration of any trace element in the leachate from the TCLP test exceeds regulatory limits, the material is classified as hazardous and must be disposed of in suitably constructed and monitored landfills.

According to Mensinger and Budiman, the sulfur content of the shale affects its leachability. A shale high in sulfur will yield leachate that is more acidic. Thermal processing reduces the concentration of acid-forming components in shale and yields leachate that is less acidic.

Figure 1 (next page) shows the effect of hydroretorting on the leachability of metals from beneficiated shale. In the case of cadmium, chromium, and selenium, hydroretorting apparently reduces leachability. However, the leachability of arsenic appears to be somewhat enhanced by hydroretorting. The ratios for all elements are less than 0.04, except for those of selenium, which are less than 0.13.

Combusting the hydroretorted beneficiated shale does not significantly affect metal leachability except for that of selenium. Combustion reduced the leachate ratio for selenium from 0.096 (hydroretorted shale) to 0.026. Agglomeration of the hydroretorted sample further reduced the selenium ratio compared to that of the combusted sample from 0.026 to 0.013 (detection limit). Agglomeration also reduced the ratio for arsenic from 0.0156 (combusted shale) to 0.0014.

In general, beneficiation does not significantly affect metal leachability. However, hydroretorted beneficiated shale releases roughly 10 times more arsenic and selenium during the TCLP than does hydroretorted raw shale. The ratio for cadmium in agglomerated beneficiated shale was 0.12; that for the agglomerated raw shale was 0.01 (detection limit). These results should be confirmed, say the authors.

Overall, TCLP tests show that for all shale samples, neither silver, lead, nor mercury were leached at levels above the detection limit of the analytical technique used. Selenium levels were about 10 percent of the TCLP limit and all other elements were leached at less than 2 percent of the TCLP limit. All eight elements were leached from the feed and residue shales at levels below the TCLP regulatory limits. Therefore, these samples do not exhibit the toxicity characteristic, and spent shale from the PFH process can be safely disposed of in ordinary landfills, according to Mensinger and Budiman.

The authors recommend that large-scale lysimeter tests be conducted on bulk samples of hydroretorted and spent beneficiated shale to determine long-term leaching characteristics. Other elements, such as nickel and molybdenum, should also be analyzed in the leachate from TCLP tests.

###

RETORT TEMPERATURE FOUND TO BE MOST IMPORTANT INFLUENCE ON OIL QUALITY

As part of a study to optimize processing of Australian Tertiary oil shales, the relative importance of seven major processing variables on product yields and oil quality was determined. The results of the investigation were sum-
The seven process variables evaluated include:

- Retort temperature
- Solids recycle ratio
- Char content of recycle solids
- Recycle solids temperature
- Pre-treatment of recycle solids (e.g., with ammonia, steam)
- Solids residence times
- Steam concentration in the retort

The Plackett-Burman experimental design, one of the most efficient at detecting main effects of large numbers of variables with a minimum amount of experimentation, was used to screen these process variables.

Each variable was tested at two (low and high) levels: retort temperature at 510 and 560°C, recycle ratio at 1.3 and 3.0, char content of recycle solids at 0.0 and 5.0 weight percent, recycle solids temperature at 650 and 750°C, pre-treatment of recycle solids without and with ammonia, solids residence time in the pyrolyzing section at 10 and 16 seconds and steam concentration in the retort at 25 and 70 volume percent.

The CSIRO bench-scale integrated retorting/combustion oil shale (BIRCOS) facility at Lucas Heights, Australia was used to process the shale. An oil shale sample from the Stuart Box Cut, which was supplied by Southern Pacific Petroleum N.L. and Central Pacific Minerals N.L. was used in this study.

The significance of the effects of the process variables on product yields, organic carbon conversions and oil quality are summarized in Table 1. A significant effect is positive when...
TABLE 1
SIGNIFICANCE OF THE EFFECTS OF PROCESS VARIABLES
ON PRODUCT YIELDS, ORGANIC CARBON CONVERSIONS AND OIL QUALITY

<table>
<thead>
<tr>
<th>Process Variable</th>
<th>Retort T</th>
<th>Time</th>
<th>Steam Conc.</th>
<th>Char Content</th>
<th>Recycle Ratio</th>
<th>Recycle Solids T</th>
<th>NH₃</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Yield, % Fischer Assay</td>
<td>+99</td>
<td>+95</td>
<td>+95</td>
<td>NS</td>
<td>NS</td>
<td>NS</td>
<td>NS</td>
</tr>
<tr>
<td>Org. C Conversion to Char, %</td>
<td>-99</td>
<td>-95</td>
<td>NS</td>
<td>NS</td>
<td>NS</td>
<td>NS</td>
<td>NS</td>
</tr>
<tr>
<td>Org C. Conversion to Gas, %</td>
<td>+99</td>
<td>NS</td>
<td>-99</td>
<td>+95</td>
<td>+95</td>
<td>+95</td>
<td>NS</td>
</tr>
<tr>
<td>H₂ Yield, g/100g Dry Shale</td>
<td>NS</td>
<td>NS</td>
<td>NS</td>
<td>+99</td>
<td>NS</td>
<td>NS</td>
<td>NS</td>
</tr>
<tr>
<td>CO₂ Yield, g/100g Dry Shale</td>
<td>NS</td>
<td>NS</td>
<td>NS</td>
<td>+95</td>
<td>NS</td>
<td>+95</td>
<td>NS</td>
</tr>
<tr>
<td>C₁₋₄ Alkanes, g/100g Dry Shale</td>
<td>+95</td>
<td>NS</td>
<td>-95</td>
<td>NS</td>
<td>+95</td>
<td>+95</td>
<td>NS</td>
</tr>
<tr>
<td>C₂₋₄ Alkenes, g/100g Dry Shale</td>
<td>+99</td>
<td>NS</td>
<td>-99</td>
<td>+95</td>
<td>+95</td>
<td>+95</td>
<td>NS</td>
</tr>
</tbody>
</table>

Oil Quality

- Atomic H/C                                    | -95      | NS   | NS          | NS           | NS            | NS              | NS  |
- Sulfur, wt%                                   | NS       | NS   | NS          | NS           | NS            | NS              | NS  |
- Nitrogen, wt%                                 | +95      | NS   | NS          | NS           | NS            | NS              | NS  |

NS: Not significant
95: Significant (significant at a confidence level of 95%)
99: Highly significant (significant at a confidence level of 99%)

the value of the response increases as the value of the variable increases. It is negative otherwise.

Table 1 lists the variables in the order of importance from left to right. Retort temperature was the most important variable. It had a significant or highly significant effect on every response except for yields of hydrogen and carbon monoxide. To improve oil yields, only retort temperature, solid residence time in the retort and steam concentration in the retort had positive significant effects. The effects of other variables were not significant.

Retort Temperature

An increase in temperature from about 510 to about 560°C increased carbon conversions to gas and yields of oil and C₁₋₄ alkenes at a highly significant level, and yields of CO₂ and C₁₋₄ alkanes, nitrogen content of oil at a significant level. However, this temperature increase reduced carbon conversions to char at a highly significant level. In general, the trend of the temperature effects on yields of gases, carbon conversions to gas and oil quality observed in this work is consistent with those of previous data. However, the effects on oil yields and carbon conversions to char are different than previous data. These differences can be explained by the differences in the extents of the contact of oil vapor with combusted shale incurred in the retorts used.

In the fluidized-bed retort (used to generate earlier data), the shale feed rate, the fluidization velocity of steam and the amount of combusted shale in the retort are fixed. The good solids mixing nature of fluidized beds ensures that all combusted shale particles efficiently contact oil vapor produced in the emulsion phase of the bed. The extent of the contact of oil vapor with combusted shale is fixed and should be more or less independent of temperature.

In the gas-solid, cross-flow, moving-bed retort used in this work, where the oil vapor produced flowed radially out of the retort bed as the solids moved downward, the oil vapor did not necessarily contact all combusted shale which resided in the retort. At a certain temperature, the pyrolysis rate is sufficiently high for the conversion of kerogen to complete before the pyrolyzing shale reaches the end of the pyrolyzing section, and oil vapor produced will not contact combusted shale in the remaining bed of the pyrolyzing section. At a higher temperature, the "effective" pyrolyzing section is smaller and the oil vapor flows out of the section at a faster
rate; therefore, the extent of the contact of oil vapor with combusted shale is smaller, the vapor residence time in the bed is shorter and a significant reduction in the oil coking rate through this mechanism is expected.

Solids Residence Time

Solids residence time had a significant positive effect on oil yields and a significant negative effect on carbon conversions to char, while it did not have a significant effect on any other responses. This increase in the oil yield was therefore the direct result of lowering residual char, says Dung. Because the solids residence times used were very short, increases in oil yields at the expense of char in spent shale indicated that the pyrolysis of oil shale was not 100 percent completed, particularly at the extreme of the lower temperature (510°C) and the shorter residence time (10 seconds). However, in general, this data shows that the pyrolysis kinetics of Stuart oil shale was extremely fast.

Steam Concentration

High steam concentrations in the retort led to higher oil yields at a significant level and lower conversions of organic carbon to gas at a highly significant level. Lower carbon conversions to gas resulted from significant decreases in yields of carbon dioxide and C1-C4 alkanes and highly significant decreases in yields of C5-C9 alkenes. According to Dung, the association of higher oil yields with lower carbon conversions to gas at higher steam concentrations indicates that the reduction of oil coking within shale particles by steam in the BIRCOS retort was not the key mechanism. Further work is required to confirm this finding.

Other Variables

The main effects of shale recycle ratio, char content and temperature of recycle solids were not significant on yields and quality of oil and carbon conversions to char. This is due to the low extent of gas-solid contact in the BIRCOS retort, which has a maximum effective residence time of 10 to 16 seconds. These variables affected yields of gases only.

Conclusions

Dung concludes, the variables can be ranked in the following order in terms of the significance of their main effects on product yields, carbon conversions and oil quality: retort temperature, solids residence time, steam concentration, char content in recycle solids, solids recycle ratio, recycle solids temperature and ammonia pre-treatment. Pre-treatment of recycle solids with ammonia had no significant effect on all responses.

Retort temperature was the only process variable which affects the quality of oil (atomic hydrogen/carbon ratio and nitrogen content). Sulfur content in oil was independent of all variables.

#####

SECONDARY CRACKING OF OIL VAPORS ON COMBUSTED SHALE PARTICLES CONFIRMED

It is widely recognized that secondary reactions which are mainly associated with minerals during oil shale retorting have a marked influence on the product yields and compositions. To more clearly understand these phenomena, the secondary reactions of shale oil vapors produced from the pyrolysis (or hydropyrolysis) of Kentucky Cleveland oil shale were examined in a two-stage, fixed-bed reactor in flowing nitrogen or hydrogen at pressures ranging from 1 to 150 bar. The vapors from pyrolysis (first stage) were passed through a second stage which consisted of combusted shale, upgrading catalyst or neither. The results of this study were summarized in a paper by S.D. Carter, et al., of the University of Kentucky, Center for Applied Energy Research in Lexington, Kentucky.

One-Stage Results

Because the reaction conditions in the second stage were identical to the first stage, it was necessary to characterize the effects that sweep gas and total pressure have on the products from the primary pyrolysis reactions. The pyrolysis conditions can be categorized as either thermal pyrolysis or hydropyrolysis depending on the use of N2 or H2 as sweep gases, respectively. At increased total pressure during thermal pyrolysis, the carbon content of the spent shale increased only slightly. This reactive insensitivity toward coke formation as a function of oil-vapor partial-pressure is in general agreement with the observation that carbon deposition is primarily a function of the exposure time of a given solid to a given oil vapor.

The oil produced by single-stage thermal pyrolysis at 1 bar is characterized by a bimodal distribution of n-alkanes which span from C11 to C32 (see Figure 1). Figure 1a presents the results at 1-bar nitrogen pressure and Figure 1b presents the results at 150-bar nitrogen pressure. The solid bars represent single-stage operation and the open bars represent two-stage operation with combusted shale. The oil was high in molecular weight and relatively low in aromaticity (see Table 1). The effect of hydropyrolysis on the composition of the oil was to eliminate the high molecular weight n-alkanes in favor of a uni-modal distribution at smaller carbon numbers. The other effects of H2 pressure were to lower the C5 and C3 alkene/alkane ratios and to increase the aromaticity. The increase in aromaticity of the oil under elevated H2 pressure is due to the increase in overall organic carbon conver-

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Two-Stage Results

Carbon deposition in the second stage onto combusted shale in 1-bar nitrogen accounted for 4 percent of the carbon in the raw shale. Carbon deposition on the combusted shale at a pressure of 150 bar was essentially the same. A zero-order reaction rate mechanism in terms of oil-vapor partial-pressure for char formation is indicated under these conditions, say Carter, et al.

The heavy n-alkanes in the oil, when passed through combusted shale during thermal pyrolysis, largely disappeared (see Figure 1), and the aromaticity of the oil increased (see Table 1). These results can be explained by either coking or cracking reactions or both.

When the Ni/Mo catalyst was used as the second-stage substrate, nearly 17 percent of the carbon originally present in the raw shale was deposited onto the catalyst. This is consistent with the hypothesis that carbon deposition is controlled to a large extent by the available surface area of the substrate because the catalyst has a total surface area of 180 square meters per gram compared to 20 square meters per gram for the combusted shale. The conversion of such a large fraction of oil vapor to char did not, however, measurably affect the aromaticity or the molecular weight of the oil.

### TABLE 1

**RUN CONDITIONS AND SELECTED RESULTS FROM TWO-STAGE HYDROPYROLYSIS REACTOR**

<table>
<thead>
<tr>
<th>Run</th>
<th>Conditions</th>
<th>2nd Stage Substrate</th>
<th>1st Stage C Conversion (%)</th>
<th>Carbon Distribution (wt% C/wt% C in r.s.)</th>
<th>Oil MW (Wt%/Wt)</th>
<th>Aromatic Oil Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>N₂-1 bar</td>
<td>None</td>
<td>51.7</td>
<td>0.48 Char</td>
<td>0.39</td>
<td>370</td>
</tr>
<tr>
<td>14</td>
<td>N₂-1 bar</td>
<td>Ni/Mo</td>
<td>51.7</td>
<td>0.48 2nd Stage</td>
<td>0.27</td>
<td>250</td>
</tr>
<tr>
<td>16</td>
<td>N₂-1 bar</td>
<td>Combusted Shale</td>
<td>49.5</td>
<td>0.51 Char</td>
<td>0.27</td>
<td>250</td>
</tr>
<tr>
<td>18</td>
<td>H₂-150 bar</td>
<td>None</td>
<td>75.6</td>
<td>0.24 Char</td>
<td>0.61</td>
<td>320</td>
</tr>
<tr>
<td>17</td>
<td>H₂-150 bar</td>
<td>Combusted Shale</td>
<td>81.1</td>
<td>0.19 Char</td>
<td>0.67</td>
<td>180</td>
</tr>
</tbody>
</table>

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2-6
the oil, which would tend to suggest that the differences in oil quality caused by the second stage were produced as a result of cracking rather than coking reactions, say Carter, et al.

Hydrogen partial pressures of 50 and 150 bar effectively reduced carbon deposition onto the combusted shale to near zero, and oil yield was not seriously affected by the second-stage solids under high pressure hydrogen. According to the authors, it is, therefore, apparent that hydrocracking is the prime function of the combusted shale. The elimination of larger molecular weight n-alkanes, when the oil vapor is contacted with combusted shale, is evident in Figure 1. A significant decrease in the number average molecular weight and increase in the aromaticity of the oil are also indicated under these conditions (see Table 1).

Carter, et al. conclude that because high pressures did not significantly enhance carbon deposition, it appears that the coke formation rate is largely influenced by the rate of the surface reaction and the partial-pressure of oil-vapor has little or no effect. The effect of combusted oil shale in the second stage was to significantly lower the molecular weight and increase the aromaticity of the shale oil. The primary function of the combusted shale was to promote cracking. Hydrogen had the effects of increasing carbon conversion during pyrolysis and promoting a corresponding increase in aromaticity.

###

**EFFECTS OF MINERALS IN PROCESSING AUSTRALIAN OIL SHALES REVIEWED**

In recent years considerable effort has been devoted to the characterization and processing of the major oil shale deposits in Queensland, Australia. Variations in mineralogy are important in the selection of optimum process conditions for oil shales. A paper by J.H. Patterson reviews the main effects which the minerals have on processing and indicates how these influence the choice of process conditions. The paper was presented at the 1992 Eastern Oil Shale Symposium held in Lexington, Kentucky in November.

**Mineralogy of the Deposits**

The review considered nine major deposits and concentrated on minerals which are significant in processing. The selected deposits include eight Tertiary oil shales, Rundle, Stuart, Condor, Nagoorin, Nagoorin South, Duaringa, Lowmead and Yaamba, and the Cretaceous Julia Creek deposit.

The minerals of most significance in processing of Australian oil shales are smectite, kaolinite, calcite, siderite, pyrite and buddingtonite, says Patterson. The dominant mineralogy from a processing viewpoint is listed for each shale in Table 1.

**Relevance of Minerals in Processing**

Minerals are reactive during processing and are important in a number of ways: as sources of trace elements which are of environmental concern, as sources of valuable byproducts, by affecting heat requirements in the retort and combustor, by affecting gas compositions from the retort and combustor (sulfur and nitrogen gas emissions), and finally through their involvement in oil losses which arise from oil coking reactions on recycled combusted shales.

**Trace Elements**

Several trace elements of environmental concern, including arsenic, selenium and mercury, are partially mobilized to the oil, retort waters or retort gases during retorting. Trace metals which partially report to the oil, such as vanadium, nickel, iron and arsenic can poison catalysts in oil refining.

Partitioning study results suggest that account needs to be taken of vanadium, arsenic and iron in shale oil refining, and of arsenic and selenium in relation to disposal of retort waters. Julia Creek oil shale contains a number of trace elements which are well above normal abundance levels and are potentially hazardous to the environment and to occupational health including: arsenic, selenium, mercury, molybdenum, cadmium, thallium and uranium. This high metals content has been identified as an important factor in refining economics. Trace element abundance levels for other Australian oil shales are generally comparable or less than those for an average shale. Further work is needed in relation to establishing trace element levels in oils and especially retort waters from pilot plant testing under realistic process conditions.

**TABLE 1**

<table>
<thead>
<tr>
<th>THE KEY MINERALS FOR EACH OIL SHALE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rundle/Stuart</td>
</tr>
<tr>
<td>Condor</td>
</tr>
<tr>
<td>Nagoorin</td>
</tr>
<tr>
<td>Nagoorin South</td>
</tr>
<tr>
<td>Yaamba</td>
</tr>
<tr>
<td>Duaringa</td>
</tr>
<tr>
<td>Lowmead</td>
</tr>
<tr>
<td>Julia Creek</td>
</tr>
</tbody>
</table>

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Byproducts

For the Australian oil shale deposits considered there are four potential byproducts which might be derived from minerals: sulfur derived from pyrite, ammonia derived from buddingtonite, vanadium derived from vanadiferous clays and molybdenum as a byproduct of the recovery of vanadium.

The recovery of sulfur is an option for most oil shales but this is of greatest interest in relation to Julia Creek oil shale because of high S contents and the possibility of using SO₂ for leaching of the vanadium. However, recycle solid processes actually remove H₂S from retort gases, and thus preclude sulfur recovery. Iron oxides and/or lime in the combusted solids scavange the H₂S.

The recovery of vanadium from Julia Creek oil shale has been extensively examined. The abundance of vanadium is relatively high and established leaching methods for vanadium ores proved ineffective. Accordingly, new technology had to be developed. This required vanadium extraction from the vanadiferous clay in the presence of a great excess of calcite. A number of novel processes were eventually developed, based on controlling the decomposition of the vanadiferous clay and calcite in the combustor.

The mineralogical residences for molybdenum are not clearly established and mechanisms for recovery are therefore uncertain. Extractions of 75 and 95 percent were achieved by NH₄CO₃ leaching of agcd shale ash and Na₂CO₃ pressure leaching of outcrop shale respectively, but further work is needed on methods of recovering the molybdenum from the leach liquors.

Endothermic Reactions in the Retort

Many of the important minerals, including smectite, kaolinite, siderites, pyrite and buddingtonite are partially or fully decomposed endothermically in the retort. Thus heat requirements, and hence recycle ratios, can be reduced if these reactions can be avoided in the retort. Laboratory studies for Tertiary oil shales have demonstrated that dehydroxylation of kaolinite and smectite and decomposition of Mg-siderite can be transferred to the combustor by control of H₂O and CO₂ partial pressures in the retort. Dehydroxylation of clays has been found to be more significant than decomposition of siderite for Stuart, Rundle and Condor shales, but this may be reversed for Yaamba oil shale. Realistic estimates based on reducing clay decomposition from 75 to 25 percent indicate that recycle ratios might well be reduced by between 8 and 16 percent, which would increase oil yields by about 2 percent, says Patterson.

Avoidance of siderite decomposition may also have an additional beneficial effect on oil yields. Iron oxides derived from decomposition of Nagoorin siderite during retorting have been found to reduce oil yields in Fischer Assay testing. This is thought to result from catalytic effects of iron oxides in promoting dehydrogenation and aromization reactions. Oil losses associated with such reactions could be more significant for Yaamba and Condor oil shales which contain greater amounts of Mn-siderite and Ca-siderite. Such oil losses could also be greater for steam retorting, because increasing water vapor pressures lower siderite decomposition temperatures and can result in complete decomposition during retorting.

Further studies are needed of the kinetics of the decomposition of smectite and siderite type minerals under gas atmosphere conditions prevailing in modern retorts and combustors.

Endothermic Reactions in the Combustor

Decomposition of calcite and dehydroxylation of clays are the main endothermic reactions in the combustor. In most cases there is plenty of energy available from the residual carbon in the retorted shale. With Julia Creek oil shale, it is necessary to control calcite decomposition for vanadium recovery. However, this is secondary to oil production. Rather than minimizing calcite decomposition it was found that free CaO recycled to the retort could be reacted exothermically with CO₂ and H₂O. This contributes to the heat inventory of the retort and reduces the amount of hot recycle solids required. This process is a classic example of how processing schemes need to be tailored to the particular characteristics of an oil shale, according to Patterson.

Composition of Retort Gases

Other solid-gas reactions are important for the Tertiary oil shales. Iron oxides either formed by decomposition of siderite or recycled in the hot combusted solids can scavange H₂S from retort gases. However, the FeS formed is then oxidized to release SO₂ in the combustor and the final result may be increased SO₂ emissions in the flue gases.

Avoidance of siderite decomposition would maximize H₂S concentrations in retort gases for easy recovery and sulfur gas emission control purposes.

Composition of Combustor Gases

Control of SO₂ and NOₓ emissions are of some concern in relation to processing Tertiary oil shales. For most shales the minor amount of CaO present in siderite provides the only way to retain the sulfur in the combusted solids. For Nagoorin carbonaceous shale, some calcium is bound to car-
boxylic acid groups in the coal and this also traps sulfur as CaSO₄ in the shale ash. The temperature of fluidized-bed combustion has also been found to affect SO₂ emissions. Combustion at temperatures higher than 800°C results in rapidly increasing levels of SO₂ emissions.

The relatively low temperatures proposed for fluid-bed combustion should minimize NOₓ formation from N₂ and so it remains to consider sources from the shale. Buddingtonite provides the only source of inorganic or mineral nitrogen and thus Condor oil shale is the only one with a potential problem with unusually high NOₓ emissions. The kinetics of buddingtonite decomposition and the effect which this has on NOₓ emissions remains as an area which requires more research.

Oil Coking on Mineral Surfaces

Oil losses of 23 and 28 percent were observed for fluidized bed retorting (fully combusted shale at a recycle ratio of 2:1) for Stuart and Condor oil shales respectively. It has been demonstrated that this was caused by coking reactions on the recycle solids. The internal surface areas of Australian combusted shale are much greater (30 compared with 2 square meters per gram for Western United States recycle shales). The larger surface area arising from the predominantly clay matrices (smectite and kaolinite) of the Tertiary oil shales results in greater adsorption and ultimately coking of predominantly heavy oils on the recycle shale.

In addition, active acidic sites associated with the dehydroxylated clays are thought to be responsible for coke formation. Increases in organic carbon recoveries in oil, and trends in oil characteristics with shale grade (or inversely with mineral content), are also consistent with decreasing levels of acid-catalyzed oil coking reactions on clay mineral surfaces.

Clearly, the avoidance or minimization of secondary oil coking reactions would increase oil yields and be of considerable economic value. The CSIRO integrated retorting/combustion facility at Lucas Heights, specifically designed for optimum processing of the Australian Tertiary oil shales, includes a number of features to reduce oil coking losses, i.e., use of short solids residence times, minimization of oil vapor-recycle solid contact times, and the use of low recycled shale to raw shale ratios. Retorting at relatively high temperatures of 540 to 550°C appears optimum to minimize residence times for pyrolysis, to minimize recycle ratios and still avoid significant oil losses through thermal cracking. The results with the integrated facility have met expectations and yields of up to 107 percent of Fischer Assay have been achieved.

Patterson notes that while it is important to avoid oil coking reactions and increase oil yields, it is unfortunate that the product oil is then heavier and more difficult to refine. The heavy oil fractions (BP >340°C) are expensive to upgrade by hydrotreating and to refine by catalytic cracking/hydrocracking. Another approach is to recycle some heavy oils back to the retort, in order to crack/coke them to produce lower boiling point fractions. Results of testing in the CSIRO integrated facility have been encouraging with only a small net loss in the shale oil produced. this uses coking reactions on the recycled solids to accomplish some oil upgrading within the retort and to reduce the severity of hydrotreating which would otherwise be required.

###
WATER

OIL SHALE COMPANIES MAY SELL THEIR WATER TO LAS VEGAS

In February, Chevron USA and Getty Oil Exploration (a unit of Texaco) reached an informal agreement to build a major new reservoir in Western Colorado and then lease the Colorado River water downstream to Nevada.

The two oil shale companies want to pipe water from the Colorado River near DeBeque and store it in a natural basin 3 miles uphill on Roan Creek. The $200 million project, to be financed entirely by Nevada, would then lease the river flows to Las Vegas for up to 50 years. The project would supply 175,000 acre-feet a year, enough to accommodate the annual water needs of 700,000 people.

Project backers would pay Colorado $50 for every acre-foot of water delivered to Nevada for a total of $8.85 million a year. At the end of the lease, the project water would revert back to Chevron and Getty for use in oil shale development.

Colorado water officials are skeptical about the plan.

They express fears that interstate leasing of Colorado River flows ultimately could allow wealthy downstream water users to buy up Colorado farmland for valuable water rights, and prevent Colorado from consuming all water the state is legally entitled to under the Colorado River Compact.

Another big question is whether the project could obtain needed environmental approvals. Water lawyer A. Williams said the United States Army Corps of Engineers already has granted the project a key permit. He also said the United States Fish and Wildlife Service, which protects endangered fish species that live around the proposed project, earlier gave the reservoir required approvals.

However, according to J. Hamill of the United States Fish and Wildlife Service, major changes in the project likely will require another federal review. Since the Chevron-Getty reservoir first was considered, another resident fish, the razorback sucker, was added to the federal list of endangered species, and the area around the project has been proposed as critical habitat for the rare fish by federal biologists. Still, Hamill said, there was a chance the project could be structured to benefit the endangered fish by increasing streamflows during dry summer months.

The agreement will have a clause which allows the companies to repossess the water at any time for oil shale development provided they can supply Las Vegas with another water source.

###
RESOURCE

USGS EVALUATES SHALE-OIL RESOURCE IN EASTERN UINTA BASIN

In 1989, the Utah Division of State Lands and Forestry and the United States Bureau of Land Management asked the United States Geological Survey to make an assessment of the shale-oil resources of the Mahogany Zone of the Eocene Green River Formation on selected state and federal lands. This work was summarized in a report by J.R. Dyni, et al., presented at the 25th Oil Shale Symposium held in Golden, Colorado last April.

In this report, the lands evaluated for oil-shale resources include almost 900 square miles in the eastern part of the Uinta Basin, Uintah County, Utah. Oil-shale resources were also estimated for federal oil shale lease Tracts Ua and Ub, totaling 10,273 acres, which lie in the eastern part of the study area. The Green River Formation underlies most of the study area, and is divided into the basal Douglas Creek Member and the overlying Parachute Creek Member.

The Douglas Creek Member, about 1,200 to 1,900 feet thick, consists of nearshore-lacustrine sandstone, mudstone, siltstone, stromatolites, and chalky limestone that inter-tongue with open-lacustrine oil shale and marlstone in the lower part of the overlying Parachute Creek Member. In places, bituminous sandstones of the Douglas Creek underlie the Mahogany Zone and they could be mistaken for oil shales on profiles of Fischer Assay analyses of drill cores from the Douglas Creek Member.

The Parachute Creek Member contains most of the oil shale in the Green River Formation in the Uinta Basin. The member consists of brown to black oil shale, gray and yellowish-brown marlstone, thin beds of yellowish-brown siltstone, and numerous thin layers of tuff. The member ranges from about 500 to 1,200 feet in thickness. The Mahogany oil shale zone is a distinctive lithologic unit consisting of medium- to high-grade oil shale and kerogenous marlstone within the Parachute Creek Member which can be identified throughout a large part of the Uinta Basin.

The thickness of overburden above the Mahogany Zone ranges increases from zero on the south and southeast sides of the study area to about 3,600 feet in the north part of the area. The Mahogany Zone ranges from about 60 to 130 feet in thickness.

On the basis of shale oil yields, the Mahogany Zone can be divided into three units based on oil shale grade. The upper unit of the Mahogany Zone consists of 10 to 20 feet of oil shale that yields on average about 20 gallons per ton. It is underlain by 10 to 35 feet of lower grade oil shale that averages about 10 gallons per ton. The middle unit of the Mahogany Zone is about 21 to 55 feet thick and consists of medium- to high-grade oil shale that averages about 32 gallons per ton. Within the Mahogany Zone, this unit is the most likely sequence to be selected for mining. The richest bed in this middle unit is the Mahogany oil shale bed, a unit of brownish-black oil shale about 2 to 4 feet thick, that averages about 60 to 70 gallons per ton.

Variations in the grade of Green River oil shale are attributable largely to the effects of dilution of the organic matter with clastic sediments derived from streams entering the lake at different points around the margins of the lake basin. The grade of the oil shale is also influenced by deposition of syngenetic minerals, especially carbonates such as dolomite and calcite as well as evaporite minerals such as nahcolite; these minerals also dilute the organic content of the oil shale. Because of the broad expanse of the lake and low gradient of the depositional surfaces of the lake bottom, these processes tended to operate over considerable distances, so that lateral lithologic changes tended to be gradual except north of the basin depositional axis where changes from open to marginal lacustrine sedimentation are more abrupt. Such laterally persistent beds of oil shale and associated rocks permit the assessment of oil-shale resources with a much greater level of confidence than would be possible for other fossil fuels, such as coal.

The shale-oil resources of the Mahogany Zone were estimated from drill core and geophysical log data, using Kriging techniques. These data are summarized in Table 1. The sum of the estimated oil-shale resources in the 26 townships (896 square miles) is 75.7 billion barrels. The oil-shale resources on federal Tracts Ua-Ub total 1.66 billion barrels of oil.

Overall, the oil-shale resource increases from a low of about 50,000 to 55,000 barrels of shale oil per acre in the southwest corner of the study area northward toward the westward-trending depositional axis for the Mahogany Zone. Along the depositional axis, the Mahogany Zone thickens to about 130 to 135 feet and the oil-shale resource increases to about 190,000 to 210,000 barrels of shale oil per acre. In this area the thickening of the Mahogany Zone is attributable to increased amounts of organic matter and syngenetic carbonate minerals that were deposited in the axial portion of the Eocene Lake. A well defined belt of minimum thickness of the Mahogany Zone of about 60 to 75 feet trends northwest to east-southeast across the middle of the study area. This belt of thinner Mahogany coincides with a rather poorly defined trend of reduced oil-shale resources ranging from about 90,000 to 100,000 barrels of shale oil per acre.
<table>
<thead>
<tr>
<th>Township</th>
<th>S</th>
<th>E</th>
<th>Acres</th>
<th>KBPA&lt;sup&gt;1&lt;/sup&gt;</th>
<th>Bbls/Twp&lt;sup&gt;2&lt;/sup&gt; (in Millions)</th>
<th>Depth&lt;sup&gt;3&lt;/sup&gt; (Feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8 21</td>
<td>23,264</td>
<td>160.6</td>
<td>3,735</td>
<td>3,200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 22</td>
<td>23,675</td>
<td>170.8</td>
<td>4,043</td>
<td>3,200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 23</td>
<td>22,930</td>
<td>179.7</td>
<td>4,121</td>
<td>3,200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 24</td>
<td>22,894</td>
<td>183.6</td>
<td>4,203</td>
<td>2,400</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 25</td>
<td>20,821</td>
<td>178.4</td>
<td>3,714</td>
<td>1,800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 20</td>
<td>23,200</td>
<td>117.1</td>
<td>2,717</td>
<td>2,500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 21</td>
<td>23,570</td>
<td>146.0</td>
<td>3,442</td>
<td>2,500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 22</td>
<td>22,848</td>
<td>174.6</td>
<td>3,988</td>
<td>2,300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 23</td>
<td>23,058</td>
<td>192.7</td>
<td>4,442</td>
<td>2,400</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 24</td>
<td>22,985</td>
<td>184.9</td>
<td>4,251</td>
<td>1,900</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9 25</td>
<td>10,335</td>
<td>160.6</td>
<td>1,659</td>
<td>1,200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 20</td>
<td>24,125</td>
<td>84.6</td>
<td>2,040</td>
<td>1,800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 21</td>
<td>23,539</td>
<td>106.3</td>
<td>2,503</td>
<td>1,900</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 22</td>
<td>22,772</td>
<td>135.9</td>
<td>3,095</td>
<td>1,600</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 23</td>
<td>23,168</td>
<td>158.7</td>
<td>3,677</td>
<td>1,200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 24</td>
<td>22,971</td>
<td>166.9</td>
<td>3,835</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 20</td>
<td>22,936</td>
<td>75.8</td>
<td>1,739</td>
<td>1,200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 21</td>
<td>22,817</td>
<td>82.9</td>
<td>1,891</td>
<td>1,300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 22</td>
<td>23,239</td>
<td>95.7</td>
<td>2,224</td>
<td>1,300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 23</td>
<td>23,222</td>
<td>106.7</td>
<td>2,478</td>
<td>1,300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 24</td>
<td>22,683</td>
<td>117.4</td>
<td>2,687</td>
<td>800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12 20</td>
<td>23,075</td>
<td>68.6</td>
<td>1,584</td>
<td>1,200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12 21</td>
<td>16,617</td>
<td>77.6</td>
<td>1,290</td>
<td>800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12 22</td>
<td>22,996</td>
<td>93.7</td>
<td>2,156</td>
<td>800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12 23</td>
<td>21,682</td>
<td>108.2</td>
<td>2,345</td>
<td>600</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12 24</td>
<td>17,854</td>
<td>101.5</td>
<td>1,812</td>
<td>300</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>573,475 (896 sq. mi.)</td>
<td>75,671</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
1. Thousands of barrels of shale oil per acre
2. Total barrels of shale oil per township
3. Approximate average depth to top of the 25 gallon per ton resource
4. Federal Tracts Ua-Ub are located in T.10S., Ranges 24 and 25 E

###

SYNTHETIC FUELS REPORT, MARCH 1993

2-12
OIL SHALE MINING CLAIMS STATUS UPDATED

As discussed in the *Pace Synthetic Fuels Report*, December 1992, the Energy Policy Act of 1992 made dramatic changes in the way unpatented oil shale claims are to be handled from now on. Essentially, the Act created three classes of unpatented claim holders:

- Those who filed patent applications and received First Half Final Certificates prior to October 24, 1992 may obtain a complete final patent under the old procedures.

- Those who filed a patent application which had been accepted for processing but had not received First Half Final Certificate will be eligible, at most, for a patent limited specifically to the oil shale mineral rights.

- Those who had not filed patent applications will be given notice that they have 180 days to elect to either file an application or to maintain the unpatented claim. Either course of action will proceed under entirely new rules.

In December 1992, notices were mailed to claimholders falling in the third category above. They have until about June 1 to make their election. If they elect to file an application for patent now, and the application is ultimately successful, they will receive a limited title, for only the oil shale minerals, upon payment of "fair market value" for the oil shale and associated minerals. If they elect to maintain their status as holder of an unpatented claim, they will have to start paying a new fee of $550 per claim per year (they may also have to pay a rental of $100 per year as required by the Fiscal Year 1993 Appropriations Act for the United States Department of the Interior).

An overall summary of the status of oil shale mining claims in Colorado, Utah and Wyoming is given in Table 1. A listing of still-unpatented claims in Colorado for which applications had been filed prior to October 24 is given in Table 2. A listing of still-unpatented claims in Utah for which applications had been filed prior to October 24 is given in Table 3. There were no claims in Wyoming for which applications had been filed by the cutoff date.
TABLE 1
OIL SHALE MINING CLAIMS SUMMARY
(As of February 9, 1993)

Pending Mineral Patent Applications

<table>
<thead>
<tr>
<th></th>
<th>Colorado</th>
<th>Utah</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>15 Pending</td>
<td>15</td>
<td>13</td>
<td>0</td>
</tr>
<tr>
<td>Encompassing</td>
<td>in Colorado</td>
<td>in Utah</td>
<td>in Wyoming</td>
</tr>
<tr>
<td>207 claims</td>
<td>168 claims</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>for approximately 31,983 acres</td>
<td>for approximately 24,839 acres</td>
<td>0 acres</td>
<td>0 acres</td>
</tr>
</tbody>
</table>

28 Total applications pending for 375 claims, 56,822 acres

6 Applications in Colorado have First Half Final Certificate
10 Applications in Utah have First Half Final Certificate
12 Applications are in the patent application adjudication stage

Oil Shale Claims Not Under Patent Application

<table>
<thead>
<tr>
<th></th>
<th>Colorado</th>
<th>Utah</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>Claims</td>
<td>118</td>
<td>499</td>
<td>340</td>
</tr>
<tr>
<td>Encompassing</td>
<td>17,530 acres</td>
<td>73,430 acres</td>
<td>54,400 acres</td>
</tr>
<tr>
<td>Total claims</td>
<td>957</td>
<td></td>
<td></td>
</tr>
<tr>
<td>for approximately 145,360 acres</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Patented During the Period 1920 to 1960

<table>
<thead>
<tr>
<th></th>
<th>Colorado</th>
<th>Utah</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>Claims</td>
<td>1,779</td>
<td>512</td>
<td>35</td>
</tr>
<tr>
<td>Encompassing</td>
<td>264,093 acres</td>
<td>79,481 acres</td>
<td>5,514 acres</td>
</tr>
<tr>
<td>Total claims</td>
<td>2,326</td>
<td></td>
<td></td>
</tr>
<tr>
<td>349,088 acres</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Patented Pursuant to the Tosco Settlement Agreement in 1986

<table>
<thead>
<tr>
<th></th>
<th>Colorado</th>
<th>Utah</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>Claims</td>
<td>524</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Encompassing</td>
<td>81,896 acres</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Total claims</td>
<td>524</td>
<td></td>
<td></td>
</tr>
<tr>
<td>81,896 acres</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### TABLE 2

**COLORADO OIL SHALE MINING CLAIM STATUS**  
(As of February 9, 1993)

<table>
<thead>
<tr>
<th>Claimant</th>
<th>Claim Numbers</th>
<th>Acres</th>
<th>Status Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Harlan and Dorothy Hugg</td>
<td>C-35080</td>
<td>1,120</td>
<td>7 claims encompassing 1,120 acres. First Half Final Certificate issued 12-18-84. Mineral report recommended for contest 3-19-84.</td>
</tr>
<tr>
<td>C-36293</td>
<td>1,200</td>
<td>13 claims encompassing 2,000 acres. First Half Final Certificate issued 6-4-85. Mineral report recommended for contest 7-25-84.</td>
<td></td>
</tr>
<tr>
<td>Union Oil Company of California</td>
<td>C-39464</td>
<td>1,216</td>
<td>10 claims encompassing 1,216 acres. First Half Final Certificate issued 1-11-84.</td>
</tr>
<tr>
<td>Tosco</td>
<td>C-41836</td>
<td>1,880</td>
<td>12 claims encompassing 1,880 acres. First Half Final Certificate issued on 7-27-88.</td>
</tr>
<tr>
<td>Mt. Logan Company</td>
<td>COC-48471</td>
<td>963</td>
<td>6 claims encompassing 963 acres. First Half Final Certificate issued 4-13-90.</td>
</tr>
</tbody>
</table>

All of the following patent applications are in the "adjudication-of-application" stage.

<table>
<thead>
<tr>
<th>Claimant</th>
<th>Claim Numbers</th>
<th>Acres</th>
<th>Status Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orville Altenbern</td>
<td>COC-48472</td>
<td>1,320</td>
<td>9 claims encompassing 1,320 acres. Contest action initiated by BLM on 3-1-90, alleging failure to comply with the annual assessment work requirements.</td>
</tr>
<tr>
<td>Joan L. Savage</td>
<td>COC-48544</td>
<td>640</td>
<td>4 claims encompassing 640 acres.</td>
</tr>
<tr>
<td>COC-48944</td>
<td>1,440</td>
<td>9 claims encompassing 1,440 acres</td>
<td></td>
</tr>
<tr>
<td>Joan L. Savage and Isabell Prien</td>
<td>COC-48545</td>
<td>160</td>
<td>1 claim encompassing 160 acres. Contest action initiated on 10-11-90 for failure to comply with assessment work requirements.</td>
</tr>
<tr>
<td>John Herr, Neil Mincer, Jean and James Larson</td>
<td>COC-48558</td>
<td>10,240</td>
<td>64 claims encompassing 10,240 acres. Contest action initiated by BLM on 3-1-90, alleging failure to comply with the annual assessment work requirements.</td>
</tr>
<tr>
<td>Joan L., John W. Jr., Roy F., Marshall T., and Daniel W. Savage</td>
<td>COC-48968</td>
<td>716</td>
<td>6 claims encompassing 716 acres. Contest action initiated on 10-11-90 for failure to comply with assessment work requirements.</td>
</tr>
<tr>
<td>Roger W. Collinson</td>
<td>COC-51767</td>
<td>60</td>
<td>1 claim encompassing 60 acres.</td>
</tr>
<tr>
<td>Kenneth D. Kenney</td>
<td>COC-53362</td>
<td>2,720</td>
<td>17 claims encompassing 2,720 acres. Contest action initiated on 12-3-90 for failure to comply with assessment work requirements.</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, MARCH 1993
TABLE 3

UTAH OIL SHALE MINING CLAIM STATUS
(As of February 9, 1993)

<table>
<thead>
<tr>
<th>Name</th>
<th>Description</th>
<th>Status</th>
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</thead>
<tbody>
<tr>
<td>U-65275</td>
<td>All the following patent applications are in the &quot;adjudication-of-application&quot; stage.</td>
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<tr>
<td>Production Industries</td>
<td>1 claim encompassing 160 acres.</td>
<td></td>
</tr>
<tr>
<td>Corporation</td>
<td>U-66062</td>
<td></td>
</tr>
<tr>
<td></td>
<td>4 claims encompassing 360 acres.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>U-66063</td>
<td></td>
</tr>
<tr>
<td>Daniel Clark Hales</td>
<td>3 claims encompassing 384 acres.</td>
<td></td>
</tr>
<tr>
<td>U-66097</td>
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</tr>
</tbody>
</table>

###
STATUS OF OIL SHALE PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since December 1992)

ACORN PROJECT – (See Stuart Oil Shale Project)

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 cocombustants 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.

Since January 1993, the unit has been operated as a stand-by unit on coal and limestone. It is also available for co-combustion tests if desired.

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 would allow Chevron and Conoco to proceed with developing a commercial shale oil operation in the future when economic conditions so dictate.

Chevron and Conoco have joined with Lawrence Livermore National Laboratory (LLNL), DOE and other industrial parties to participate in a 3 year R&D project involving LLNL's Hot Recycled Solids oil shale process. Information obtained from this project may result in refinements to the STB process.

Chevron is continuing to develop and protect its conditional water rights for use in future shale oil operations at its Clear Creek and Parachute Creek properties.

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

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

The proposed 47,000 barrels per day project is 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 tons per day of 35 gallons per ton shale from a 60-foot horizon in the Mahogany zone. Development was suspended in October 1974.

A draft EIS covering the plant and a 196-mile pipeline to Lisbon, Utah, was released in December 1975 and the final EIS was later issued. EPA issued a conditional prevention of significant deterioration permit in November 1979. Land exchange was consummated on February 1, 1980. On August 1, 1980, Exxon acquired ARCO's 60 percent interest in the project for approximately $400 million. The preferred pipeline destination was changed to Casper, Wyoming, and the final EIS supplement was completed. Work on Battlement Mesa community commenced summer 1980. The Colorado Mined Land Reclamation permit was approved in October 1980.

C.F. Braun was awarded contract for final design and engineering of Tosco II retorts. Brown & Root was to construct the retorts. Stearns-Roger was awarded a contract for design and construction liaison on materials handling and mine support facilities. DOE granted Tosco a $1.1 billion loan guarantee in 1981.

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 phase down of the project and has sold the partially completed Battlement 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. Administration of ongoing site reclamation, maintenance, and environmental monitoring was transferred to the Houston, Texas office.

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

SYNTHETIC FUELS REPORT, MARCH 1993

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STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

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.

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 indicated that such a plant would have involved 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 conveyors to surface stockpiles. Spent shale is returned by conveyors 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 "Tines" 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 would require further treatment to produce a compatible oil refinery feedstock. Two 41,000 barrels per day upgrading plants are incorporated into the project design.

All aspects of infrastructure supporting such a project were studied, including water and power supplies, work force 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 indicated that there were no foreseeable infrastructure or environmental issues which would impede development.

Market studies suggested 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 was 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)

ESPERANCE OIL SHALE PROJECT - Esperance Minerals NL and Greenvale Mining NL (S-70)

In 1991 Esperance Minerals and Greenvale Mining announced they are planning to produce 200,000 tons per year of "asphaltine" for bitumen from the Alpha torbanite deposit in Queensland, Australia. The two companies believe they can produce bitumen that will sell for more than US$80 per barrel.

The Alpha field contains about 90 million barrels of reserves, but the shale in this deposit has a high yield of 88 to 132 gallons of oil per ton of shale.

SYNTHETIC FUELS REPORT, MARCH 1993
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

Recent studies have concluded that using new technologies to produce a bitumen-based product mix would be the most economically beneficial. Byproducts could include diesel fuel and aromatics.

ESTONIA POWERPLANTS – Estonian Republic (S-80)

Two oil shale-fueled powerplants, the Baltic with a capacity of 1,435 megawatts and the Estonian with a capacity of 1,600 megawatts, are in operation in the Estonia. These were the first of their kind to be put into operation.

About 95 percent of the oil shale output from the former USSR comes from Estonia and the Leningrad districts of Russia. 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 (Baltic oil shale) resources was begun by the Estonian government in 1918. In 1980, annual production of oil shale in the USSR reached 37 million tons of which 36 million tons come from the Baltic region. Recovered energy from oil shale was equivalent to the energy in 49 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. In 1991, annual production of oil shale in Estonia was 19 million tons. About 10 million tons were extracted from six underground mines and about 9 million tons from three open pit mines. The annual output from the underground mines ranged from 600,000 to 4.3 million tons, while the output from the surface mines ranged from 2.0 to 4.3 million tons. The recovered energy from this oil shale was the energy equivalent of 25 million barrels of oil.

Most extracted oil shale (85 percent) is used for power production rather than oil recovery. 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.

Pulverized oil shale ash is being used in the cement industry and for acid soil melioration.

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

The oil shale retorting industry in Fushun, China 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 percent 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 5.5 percent 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 has been 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 an existing petroleum refinery.

ISRAELI RETORTING DEVELOPMENT – (See PAMA Oil Shale-Fired Powerplant Project)

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 Inbid, 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 powerplant. Jordan has also investigated 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.
COMMERCIAL PROJECTS (Continued)

The final results showed 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. At that time a world oil price of $15.60 per barrel was needed to meet an internal rate of return on total investment of 10 percent.

In 1988, the Natural Resources Authority announced that it was postponing for 5 years the consideration of any commercial oil shale project.

KIVTTER PROCESS - Estonian Republic (S-120)

The majority of oil shale (kukersite) found in Estonia is used for power generation. However, 2.0 to 2.2 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 predominantly 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-equipping of the oil shale processing industry, a new generator was developed. The first 1,000 ton-per-day (TPD) generator of this type was constructed at Kohtla-Jarve, Estonia 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 9.6 meters, and its height is 21 meters. The operation of the 1,000 ton per day generator revealed a problem of carry-over of finely divided solid particles with oil vapors (about 8 to 10 kilograms per ton of shale).

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 under construction. Oil yield of 85 percent of Fischer Assay is expected. The construction of an installation comprising four 1,500 ton per day prototype generators with a circular semi-cooking chamber started at Kohtla-Jarve in 1988. At present, however, the construction has been suspended due to investment problems.

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

Pulverized oil shale ash is also finding extensive use in the fertilizer and cement industries.

Project Cost: Not disclosed

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

Construction of the Maoming 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 percent oil yield.

Two types of retort are used: a cylindrical retort with a 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.

Production at Maoming has been 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. The shale ash is also used in making cement and building blocks.

A 50 megawatt powerplant burning oil shale fines in three fluidized bed boilers has been planned and detailed compositional studies of the Maoming shale oil have been completed. These studies can be used to improve the utilization of shale oil in the chemical industry.

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

Mobil has indefinitely deferred development plans for its shale property located on 10,000 acres five miles north of Parachute. The United States Bureau of Land Management completed the Environmental Impact Statement for the project in 1986.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

MOROCCO OIL SHALE PROJECT -- ONAREP, Royal Dutch/Shell (S-150)

During 1975 a drilling and mining survey revealed 13 oil shale deposits in Morocco, including three major deposits at Timandit, 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 faced constraints of low oil prices and the relatively low grade of oil shale.

Construction of a pilot plant at Timandit was completed with 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 Petrolieres (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 gallons per ton 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 Timandit was conducted by Morrison-Knudsen.

The T3 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.

The project, inactive for some time, began being reconsidered in 1990 by the equal partners. The viability of a 50,000 barrel per day plant that would process 60 million tonnes of shale is under examination. ONAREP expects the cost of development to be around $24-25 a barrel.

Project Cost: $2.5 billion (estimated)

OCIDENTAL MIS PROJECT -- 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. 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 construction of a pilot plant at Timandit was completed with 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 Petrolieres (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 gallons per ton 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 Timandit was conducted by Morrison-Knudsen.

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Project Cost: $2.5 billion (estimated)

SYNTHETIC FUELS REPORT, MARCH 1993
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

At the end of the demonstration period, Occidental had hoped to bring the plant up to full scale commercial production of 2,500 barrels of oil per day.

Project Cost: $225 million for demonstration

PAMA OIL SHALE-FIRED POWERPLANT PROJECT - PAMA (Energy Resources Development) Inc. (S-270)

PAMA, an organization founded by several major Israeli corporations with the support of the government, has completed extensive studies, lasting several years, which show that the production of power by direct combustion of 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, therefore begun a direct shale-fired demonstration program. A demo plant has been 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 the Rotem oil shale deposit. The oil-shale-fired boiler, supplied by Ahlstrom, Finland, is based on a circulating fluid bed technology.

The 41 megawatt plant is a cogeneration unit that delivers 50 tons per hour of steam at high pressure. Low-pressure steam is sold to process application in a chemical plant, and electricity produced in a back-pressure turbine is sold to the grid. Commissioning was begun in August 1989 and oil shale firing began in October. Process steam sales began in November 1989 and electricity production started in February, 1990.

The unit is viewed as a demonstration project where tests will be performed over a three year period. During this time, the optimum operating parameters will be determined for scale-up to larger units.

PAMA and Israel Electric (the sole utility of Israel) have also embarked on a project to build a full scale oil shale-fired commercial powerplant, 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 demonstration plant

PARACHUTE CREEK SHALE OIL PROJECT – 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 was to be the market price or a contract floor price. If the market price is below the DOE contract floor price, indexed for inflation, Unocal would receive a payment from DOE to equal the difference. The total amount of DOE price supports Unocal could receive was $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.

In 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, production in November and December reached approximately 7,000 barrels per day.
At year-end 1990, Unocal had shipped over 45 million 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 was the first sustained period of profitability. Cost cutting efforts further lowered the breakeven point on operating costs approximately 20 percent.

In 1990, the United States Department of Treasury found no significant environmental, health or safety impacts related to the operations of Parachute Creek. Monitoring will continue through 1992.

On March 26, 1991, Unocal announced that production operations at the facility would be suspended because of failure to consistently reach the financial break-even point. Production ended June 1, 1991 and the project was laid up for an indefinite period.

Unocal has offered to sell the Parachute facility to the United States Department of Energy (DOE) as a research test facility but has received no commitment from DOE to date.

Colorado Clean Fuels Company has obtained approval from Garfield County Commissioners to refit Unocal’s shale oil upgrading plant for fuel processing. The plant will process natural gas into four products: methanol, smokeless diesel, naphtha and wax. The county commissioners approved the request after a public hearing on the matter.

The anticipated project development calls for, employing 40 to 110 workers, followed by operation startup employing 24 people. If the company obtains state and federal permits as well, the plant will be operational in 1993.

The company plans to produce 4,200 barrels of methanol per day from natural gas. In addition, 138 barrels per day of diesel fuel, 51 barrels per day of naphtha, and 1,111 barrels per day of wax will be produced.

Project Cost: Phase I - Approximately $1.2 billion

PETROSIIX – Petrobras (Petroleo 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 and 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. Studies at the pilot scale have been concluded.

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. Studies at the pilot scale have been concluded.

A multistaged fluidized bed pilot plant having an 8x8 inch square section was operated at Centec. Studies at this scale have been concluded.

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, produced 850 barrels per day of crude oil, 40 tons per day of fuel gas, and 18 tons per day of sulfur in 1990. The operating factor since 1981 until present has been 93 percent.

As of December 31, 1991, the plant records were as follows:

<table>
<thead>
<tr>
<th>Category</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations time, hrs</td>
<td>126,400</td>
</tr>
<tr>
<td>Oil Produced, Bbl</td>
<td>3,360,000</td>
</tr>
<tr>
<td>Processed Oil Shale, tons</td>
<td>7,070,000</td>
</tr>
<tr>
<td>Sulfur Produced, tons</td>
<td>568,130</td>
</tr>
<tr>
<td>High BTU Gas, tons</td>
<td>121,600</td>
</tr>
</tbody>
</table>

A 36-foot inside diameter retort, called the industrial module, has been constructed at Sao Mateus do Sul. Startup began in January, 1992. Total investment was US$93 million with an annual operating cost estimated to be US$39 million. With the sale of gas to Industria Ceramica do Parana (INCEPA) and anticipated revenue from products, the rate of return on the overall project is estimated to be about 13 percent.
COMMERCIAL PROJECTS (Continued)

In 1992, the Sao Mateus do Sul project was producing at 80 percent of the full-scale capacity. Total daily production is expected to reach 4,000 barrels of shale oil (at a cost of $223.50 per barrel), 140 metric tons of fuel gas, 50 tons of liquefied petroleum gas and 100 tons of sulfur.

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

<table>
<thead>
<tr>
<th>Product</th>
<th>Quantity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale Oil</td>
<td>3,570 Bbl</td>
</tr>
<tr>
<td>Processed Shale</td>
<td>7,800 tonnes</td>
</tr>
<tr>
<td>LPG</td>
<td>50 tonnes</td>
</tr>
<tr>
<td>High BTU Gas</td>
<td>132 tonnes</td>
</tr>
<tr>
<td>Sulfur</td>
<td>98 tonnes</td>
</tr>
</tbody>
</table>

Some 150 hectares of the mined area has been rehabilitated since 1977. 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 gas oil.

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

Project Installed Costs: $120 (US) million

RAMEX OIL SHALE GASIFICATION PROCESS—Greenway Corporation and Ramex Synfuels International, Inc. (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 Rock Springs pilot project. The formation was heated to approximately 1200 degrees F 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 also 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, however, Ramex moved the project to Indiana. A total of 7 wells were 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. 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. In November, 1989 Ramex completed its field test of the Devonian Shales in Indiana. The test showed a gas analysis of 47 percent hydrogen, 30 percent methane and little or no sulfur. Ramex contracted with a major research firm to complete the design and material selection of its commercial burners which they say are 40 to 50 percent more fuel efficient than most similar industrial units and also to develop flow measurement equipment for the project. Ramex received a patent on its process on May 29, 1990.

In 1990, Ramex also began investigating potential applications in Israel.

Ramex contracted with the Institute of Gas Technology in 1990 for controlled testing of its in situ process because the company's field tests of the process in wells in Indiana have been thwarted by ground water incursion problems. Questions that still need to be answered before the Ramex process can be commercialized are:

- How fast does the heat front move through the shale?
- How far will the reaction go from the heat source and how much heat is necessary on an incremental basis to keep the reaction zone moving outward from the source of heat?
- What is the exact chemical composition of the gas that is produced from the process over a period of time and does the composition change with varying amounts of heat and if so, what is the ideal amount of heat to produce the most desirable chemical composition of gas?
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

Once these questions are answered, the company will be able to calculate the actual cost per unit of gas production.

In 1992 Ramex announced a company reorganization and said that new laboratory tests were being arranged to improve its technology.

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)

The proposed project is on federal Tract C-a in Piceance Creek Basin, Colorado. A bonus bid of $210.3 million was submitted to acquire rights to the tract which was leased in March 1974. A 4-year modified in situ (MIS) demonstration program was completed at the end of 1981. The program burned two successful retorts. The first retort was 30 feet by 30 feet by 166 feet high and produced 1,907 barrels of shale oil. It burned between October and late December 1980. The second retort was 60 feet by 60 feet by 400 feet high and produced 24,790 barrels while burning from June through most of December 1981. Open pit mining-surface retorting development is still preferred, however, because of much greater resource recovery of 5 versus 2 billion barrels over the life of the project. Rio Blanco, however, could not develop the tract efficiently in this manner without additional federal land for disposal purposes and siting of processing facilities, so in August 1982, the company temporarily suspended operations on its federal tract after receiving a 5 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 was never 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 were flooded but were pumped out in May 1985 and June 1986 in accordance with plans approved by the Department of the Interior.

Rio Blanco operated a $29 million, 1 to 5 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. 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.

In 1992, Rio Blanco closed its Denver office and moved all activities to the site.

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 provide for:

Payment by Esso to SPP/CPM of A$30 million in 1985 and A$12.5 in 1987.
Each partner to have a 50 percent interest in the project.

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

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STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

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

The project is continuing at a low level with work in 1992 focusing on environmental land and resource management and further shale upgrading and processing studies.

Project Cost: US$2.65 billion total estimated

SHC - 3000 RETORTING PROCESS - Estonian Republic (S-230)

The SHC-3000 process, otherwise known as the Galoter retort, is a rotary kiln type retort which can accept oil shale fines.

Processing of the kukersite shale in SHC-3000 retorts makes it possible to build units of large scale, to process shale particle sizes of 25 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 semioke gas, and to extract valuable phenols from the shale oil water. Overall the air pollution (compared to direct oil shale combustion) decreases.

The two SHC-3000 units built in 1980 at the Estonian Powerplant, Narva, Estonia, with a capacity of 3,000 tons of shale per day are among the largest in the world and unique in their technological principles. However, these units have been slow in reaching full design productivity.

A redesign and reconstruction of particular parts 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 SHC-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 1980-1983 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 SHC-3000.

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

LO VGINPII (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.

In 1990, 374,000 tons of shale was used for processing and 43,600 tons of shale oil was produced. In 1991, 205,500 tons of shale were used to produce 24,000 tons of oil. At present, shale with an organic content of 26 percent is used for processing, the oil yield being about 12 percent per shale. The oil obtained contains 14 to 15 percent of gasoline fraction. Export of the oil produced is growing steadily—from 8,900 tons in 1990 to 24,300 tons in 1991.

By the end of 1991, 1,833,700 tons of shale was processed at SHC-3000 and 220,000 tons of oil had been produced.

STUART OIL SHALE PROJECT – Southern Pacific Petroleum NL and Central Pacific Minerals NL (S-210)

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.

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SYNTHETIC FUELS REPORT, MARCH 1993
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

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 and early 1987. The pilot plant program was carried out between June and October 1987.

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/CPM engaged two engineering firms to make independent, detailed studies of the shale oil project. The purpose of the studies is to provide potential financial backers with verifiable information on which to base technical judgment of the project. These studies were completed in early 1991. Both groups confirmed SPP/CPM's own numbers and endorsed the AOSTRA Taciuk Processor as the most effective retort for Queensland oil shale.

The overall SPP development plan includes three stages, commencing with a low capital cost, semi-commercial plant at 6,000 tonnes per day of high grade shale feed producing 4,250 barrels per day of oil. SPP/CPM have received proposals from two engineering firms for the construction of the 6,000 tonne per day plant. Once the retorting technology is proven the second stage plant at 25,000 tons per day of shale producing 14,000 barrels per day of syncrude from an intermediate grade will be constructed. Stage three is a replication step with five 25,000 ton per day units producing 60,000 barrels per day of syncrude from average grade shale, or approximately 15 percent of the projected Australian oil import requirement in the year 2000.

According to SPP, the estimated cost is US$110 million for the first stage demonstration plant to be located near Gladstone, including services connection and product storage. At 1990 prices for low sulfur fuel oil in Australia, it is said that operation of the demonstration plant will at least break even and possibly earn as much as 15 percent DCFROI. Stage 1 of the project will benefit from a recently announced tax exemption which will apply to about 40 percent of the plant's output. Refined products will be exempt from excise taxes amounting to US$0.2075 per liter for a total savings to the project of US$190 million over a 10-year period. The exemption was guaranteed until the year 2005.

However, the federal opposition party in Australia has announced that it will eliminate all excise on gasoline if elected to govern. SPP/CPM have held discussions with the opposition party to ensure preservation of the promised arrangements, but have not received any such assurance. Therefore, the companies are now assessing appropriate adjustments to the Stage 1 financing plans in case the opposition party does come to power.

In August 1992, the Australian Government presented a federal budget which provided for an increased commitment to research and development by continuing the present tax deductibility of 150 percent of such expenditure beyond June 30, 1993. It also removed a limit of $10 million on certain plant expenditures. These incentives, which incorporate a rapid depreciation on capital expenditure, are positive for the Stuart Stage 1 development if, under the proposed legislative amendments, capital and operating expenditure of Stage 1 qualifies as a research and development expenditure.

In December 1992, the companies announced that the Industry Research and Development Board approved, in principle, elements of Stuart Stage 1 capital expenditure, which amount to approximately 90 percent of the total capital expenditure, as R&D and the tax deductibility of such expenditure has been confirmed, in principle, by the Australian Taxation Office.

In parallel with these matters, the formal draft of the environmental study for Stuart Stage 1 was completed and given to the Queensland Government on October 21, 1992.

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

Project Cost: For commercial demonstration module A$110 million

YAAMBA PROJECT - Yaamba Joint Venture [Beloba Pty. Ltd. (10 percent), Central Pacific Minerals N.L. (3.3 percent), Southern Pacific Petroleum N.L. (3.3 percent), Shell Company of Australia Limited (41.66 percent), and Peabody Australia Pty. Ltd. (41.66 percent)] (S-240)

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.

SYNTHETIC FUELS REPORT, MARCH 1993
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

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.

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.

In December, 1988 Shell Australia purchased a part interest in the project. 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. 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 in the exploratory stage.

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 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 were undertaken.

During 1990, exploration and development studies at the Yaamba and Herbert Creek deposits continued. A program of three holes (644 meters) was undertaken in the Block Creek area at the southeast of the Herbert Creek deposit.

Project Cost: Not disclosed

R&D PROJECTS

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 5 years, been studying hot-solid recycle retorting in the laboratory and in a 1 tonne per day pilot facility and have developed the LLNL Hot Recycled-Solids Retort (HRS) 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. LLNL hopes to conduct field pilot plant tests at 100 and 1,000 tonnes per day at a mine site in western Colorado.

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 in a fluid bed prior to entering 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 are being studied at this scale in an integrated facility with no moving parts using air actuated valves and a pneumatic transport, suitable for scaleup. In April 1991, the first full system run on the 4 tonne per day pilot plant was completed. Since that time, the retort has successfully operated on both lean and rich shale (22-38 gallons per ton) from western Colorado. LLNL plans to continue to operate the facility and continue conceptual design of the 100 tonne per day pilot-scale test facility. LLNL has joined with a consortium of industrial sponsors for its current operations in a 3 year contract to develop the HRS process.

The ultimate goal is 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 three increase in vessel diameter over the previous scale, which is not unreasonable for solid-handling equipment, according to LLNL.

Each company in the consortium will contribute $100,000 per year over the next 3 years. LLNL has negotiated successfully with Chevron, Conoco and Amoco, and hopes to interest other industrial partners which will form a Project Guidance Committee.

Project Cost:  
    Phase I - $15 million  
    Phase II - $35 million
NEW PARAHO 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’s.

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 the initial market development phase of the commercial development plan was approximately $25 million, all of which was funded by Paraho. The major portion of the work conducted during this initial phase consisted 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 tons 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 96.5 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.

Eight test strips were constructed in Colorado, Utah and Wyoming. The test strips are being 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. Test strips were also completed on I-20 east of Pecos, Texas, in Michigan for a test section of I-75 near Flint, on I-70 east of Denver, Colorado and on US-59, northeast of Houston, Texas.

Paraho has proposed a $180 million commercial scale plant capable of producing 3,380 barrels of crude oil per day, of which 2,700 barrels would be shale oil modifier (SOM) and 680 barrels would be light oil to be marketed to refineries.

An economic analysis has determined that SOM could be marketed at a price of $100 per barrel if tests show that SOMAT can affect at least a 10 percent improvement in pavement life. A feasibility study suggests that Paraho can expect a 30 percent rate of return on SOMAT production.

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.

In December 1992 New Paraho announced that its pilot plant in Rifle, Colorado was currently producing 15 barrels of shale oil daily as part of a new SOMAT test marketing program started in September.

The first phase of the new test market program for SOMAT is expected to cost $1.2 million through 1993, produce enough SOMAT for 50 to 60 miles of asphalt roads and employ 15 people.

The test strip results have been encouraging and SOMAT is proving to be a superior road paving material, with distinct life-cycle cost advantages.

The oil shale asphalt, as a 10 percent additive to conventional asphalt, is far more resistant to water damage and aging than conventional asphalt. It adds about 10 to 15 percent to the cost of asphalt, but is a bargain compared to other asphalt modifiers that accomplish the same tasks and increase costs by 30 to 35 percent.

New Paraho has proposed a 7-month, $500,000 commercial evaluation program to assess the economic benefits of coprocessing used tires with oil shale. Initial experiments have demonstrated that retort operations can be sustained with used tires at 5 percent of the feedstock.

Project Cost: $3,700,000

NORTHLAKE SHALE OIL PROCESSING PILOT—Northlake Industries, Inc. and Uintah Basin Minerals, Inc. (S-315)

Northlake Industries, Inc. of Naples, Utah and Uintah Basin Minerals, Inc. have signed contracts pledging over $100 million to process Uintah Basin, Utah oil shale deposits with their QVR process.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

The Vernal District of the Bureau of Land Management (BLM) issued a land use permit to Northlake allowing access to the mine service building and surface oil shale stockpiles at the White River Oil Shale Project until June 1992. The surface stockpiles will be used in a pilot plant located off the White River site in Naples. The BLM permit is short-term only and does not allow further surface mining.

QVR is an acronym for "quality enhancement and viscosity reduction." A modular upgrading unit for this process incorporates added temperature and fluid controls into the pilot plant allowing for scaleup to production models. Northlake's QVR unit has performed over 1,000 hours of upgrading service on 8 to 14°API gravity heavy crude oil and refinery bottoms. The unit will be modified to study oil shale kerogen.

The QVR process was developed by Northlake over the last 10 years and provides a profitable method of recovering light, sweet crude from shale oil, tar sands and coal. The proprietary technique turns heavy oil at 10 to 13°API into oil with a 25 to 40°API.

If the development phase is successful, the company hopes to begin work on a 100,000 ton per day commercial production facility in 1994.

YUGOSLAVIA COMBINED UNDERGROUND COAL GASIFICATION AND MODIFIED IN SITU OIL SHALE RETORT—United Nations (S-335)

Exceptional geological occurrence of oil shale and brown coal in the Aleksinac basin has allowed an underground coal gasification (UCG) combined with in situ oil shale retorting. Previous mining activities of Aleksinac brown coal and development of oil shale utilization (see Yugoslavia Modified In Situ Retort—S-330, Synthetic Fuels Report, December 1990) served as principal support in establishing a development project aimed towards application of a new process, i.e. combination of UCG and in situ oil shale retorting to be tested for feasibility in a pilot UCG modulus. The project is a joint scientific and technological undertaking performed by Yugoslavian and American staff.

The objective of the approach is to develop a program to exploit the total Aleksinac energy resources to provide regional power and heating for Aleksinac and surrounding area using UCG technology and combining it with modified in situ retorting of oil shale as the immediate roof of the brown coal seam.

The development objectives are also to recover energy from residual coal left after conventional coal mining and to develop UCG technology and modified in situ oil shale retorting for Yugoslavian resources in general.

Project Cost: US$725,000
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<td>Yaamba Project</td>
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<td>Ramex Synfuels International</td>
<td>Ramex Oil Shale Gasification Process</td>
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<td>Rio Blanco Oil Shale Company</td>
<td>Rio Blanco Oil Shale Project (C-a)</td>
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<td>Royal Dutch/Shell</td>
<td>Morocco Oil Shale Project</td>
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### STATUS OF OIL SHALE PROJECTS
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<td>Maoming Commercial Shale Oil Plant</td>
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<td>Stuart Oil Shale Project</td>
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<td>Northlake Shale Oil Processing Pilot</td>
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III

oil sands
PROJECT ACTIVITIES

SHELL TO TEST AOOSTRA SAGD PROCESS AT PEACE RIVER

Shell Canada Limited and Alberta Oil Sands Technology and Research Authority (AOOSTRA) are joining forces in a commercial application of the latest in situ bitumen recovery technology at Shell's Peace River complex. The new project, jointly funded by Shell and AOOSTRA, will utilize AOOSTRA's Steam Assisted Gravity Drainage (SAGD) process and Shell's enhancements to the process.

Bridge financing to carry the project to June 30, 1994 will be provided by the other eight underground test facility partners (Amoco, Chevron, Conoco, Imperial, Japex, CNPC, Mobil, and Petro-Canada). In return, they will have ongoing access to the results of the project and world rights to the use of the technology developed. Shell and AOOSTRA will share the ability to license the technology worldwide. AOOSTRA will contribute half of the total cost, to a maximum of C$6.5 million, which it will recover through its share of revenues during the life of the project.

Shell's existing Peace River oil sands operation employs vertical steam injection wells, each surrounded by six production wells. In the new project, horizontal wells will be drilled parallel, one above the other, at a spacing of about 5 meters. The upper well of each pair is to be used to inject steam into the oil sands formation, heating the oil sands and liquefying the bitumen. Gravitational force then drains the bitumen to the production well, located about 10 meters below the injection well.

According to AOOSTRA, the SAGD process has important technical advantages over the recovery methods presently in use in the Peace River oil sands. Because the SAGD process is driven by gravitational force rather than steam pressure, little sand is carried into the production wells. This reduces wear on pumps and other production equipment and, in turn, improves production economics.

Work on the project is scheduled to begin in the spring of 1993 and pre-production steaming is scheduled to begin in August 1993. The new wells are expected to reduce unit production costs while increasing total bitumen production by about 1,000 barrels per day. Shell's Peace River operation currently produces about 10,000 barrels per day.

Shell representatives say that the company plans to expand its use of the SAGD process in the Peace River deposit if this venture proves successful. Shell has leases on 60,000 hectares in the area containing an estimated 14 billion barrels of bitumen.

POWER OUTAGE COSTS SUNCOR, EQUIPMENT UPGRADING UNDER WAY

Suncor Inc.'s oil sands plant in the Fort McMurray area of Northern Alberta, Canada was shutdown December 26 by power failures and arctic temperatures. Failure of a high-voltage electrical system killed power to boilers, and oil upgrading equipment froze. Temperatures of about -40°C and poor visibility hampered repair operations. On January 6, the company restored production to its previous average volume of 60,000 barrels per day. Suncor estimated repair costs at $8 million.

Despite this shutdown, 21.4 million barrels of synthetic crude were produced in 1992, Suncor's second-best year in the history of its oil sands upgrading operations.

Last fall, Suncor embarked on a program to reduce mining costs by $5 to $7 per barrel by late 1996, bringing the production of synthetic crude oil to a competitive level with conventional oil. (See Peace Synthetic Fuels Report, December 1992, page 3-1.) In January, Suncor awarded $53 million in contracts to upgrade its oil sands mining operation. Transwest Dynequip Ltd. will supply eight Dresser Haulpak 240-ton trucks and two Marion 58-cubic-yard shovels to the oil sands operation. MMD Mining Machinery Developments Ltd. and Wajax Industries Ltd. will supply additional equipment. All equipment is slated for delivery by October 1, after which it will be phased in to avoid disruptions to production, says Suncor.

In addition, Suncor is planning a partnership with one of three utilities—Canadian Utilities Ltd., TransAlta Utilities Corporation, and Florida Power and Light Company subsidiary National Power—to install new SO₂-reduction technology at its Alberta plant. One of those utilities may invest as much as C$135 million in the project. The result of such a deal could be a reduction of up to C$1.50 per barrel in the cost of producing and upgrading heavy oil at Fort McMurray. The chosen utility, which would take 50 percent interest in the project, would receive electricity and/or steam heat from the plant in return for its investment.

ORIMULSION GASIFICATION PLANT SLATED FOR PUERTO RICO

Last year, Texaco Inc.'s Alternate Energy group and Biter America Corporation signed a letter of agreement to develop Integrated Gasification Combined Cycle (IGCC) power projects using Texaco's gasification technology and

SYNTHETIC FUELS REPORT, MARCH 1993
Venezuelan Orimulsion as feedstock. Bitor America Corporation (Boca Raton, Florida) is a subsidiary of Petroleos de Venezuela, S.A., the Venezuelan government-owned oil company.

The letter agreement provides the conditions for a supply of up to 1.6 million metric tons per year of Orimulsion over a 25-year term. Orimulsion is a liquid fuel consisting of 70 percent natural bitumen, 30 percent water and a surfactant. Orimulsion is considered an attractive energy source for the Texaco Gasification Process because of its vast supply, its ability to be transported using conventional means, its high heating value (12,600 BTU per pound) and low viscosity.

The Texaco Gasification Process is unique because of its ability to utilize different feedstocks—including coal, heavy oil, petroleum coke, waste gas and other non-oil hydrocarbons such as Orimulsion—to produce a clean-burning synthesis gas for use in the petroleum industry, chemical manufacturing and electric power generation.

In addition, the Texaco Gasification Process, together with a combined-cycle power block, is considered a clean and efficient technology for generating electricity from these hydrocarbon feedstocks. Emissions of sulfur dioxide and nitrogen oxides would be well below United States federal standards and just a fraction of those of conventional coal plants.

Texaco has conducted a series of successful tests at its Montebello, California Research Laboratory, demonstrating the excellent performance of Orimulsion as a feedstock in the Texaco Gasification Process. Now, the Texaco/Bitor partnership and Puerto Rican authorities are negotiating a plan to build the world's first gasification plant fueled by Orimulsion in Puerto Rico.

Puerto Rico relies almost entirely, more than 95 percent, on imported oil for power generation. The 250-megawatt IGCC is seen as a way of reducing the island's dependency on oil at a time when the country's energy sector faces a potential crisis.

Electricity demand in Puerto Rico is swelling by approximately 100 megawatts per year. Officials say that unless additional power generation capacity is added within the next 5 years, serious brown-outs will plague the island. A spokesperson for Puerto Rico Electric Power Authority said that should the $500 million Orimulsion plant be built, it would provide about 10 percent of Puerto Rico's current peak demand for electricity.

###
SUNCOR REPORTS INCOME GAIN IN 4TH QUARTER

In January, Sun Company, Inc. released its 1992 fourth quarter earnings report. Suncor, Sun’s 68-percent-owned, fully integrated Canadian subsidiary, earned $10 million during the current quarter, an increase of $7 million from the 1991 fourth quarter (Table 1). Higher income from Suncor’s oil sands operations and conventional exploration and production activities was partially offset by lower income from its refining and marketing operations.

Oil sands income was up by $6 million from the 1991 quarter due to a 5 percent increase in synthetic crude oil production volumes, partially offset by a 4 percent decrease in synthetic crude oil prices. Oil sands production averaged 59.6 thousand barrels a day during the 1992 fourth quarter, while synthetic crude oil prices averaged $19.59 a barrel.

Canadian exploration and production income was also up by $6 million, largely due to increased gains from asset sales, lower operating and administrative expenses, and a 25 percent increase in natural gas sales volumes. Suncor’s refining and marketing earnings were down by $6 million due to lower margins.

For the full-year 1992, Suncor had a net gain of $5 million, compared with a net gain of $47 million in 1991. The decline in Suncor’s full-year income was caused by lower synthetic crude oil prices and volumes, an increased Crown royalty on synthetic crude oil production, and lower margins on refined product sales, as well as by the fact that in 1991 Suncor recorded a $6 million after-tax gain in refining and marketing from the sale of an ocean-going vessel and also had a favorable consolidating adjustment. Partially offsetting these declines were lower operating and administrative expenses.

Production of synthetic crude oil from the oil sands plant averaged 58.5 thousand barrels a day, the second best annual production, despite the impact of a fire at the plant in the second quarter. Oil sands production in 1991 averaged 60.6 thousand barrels per day.

NEW SOURCE OF BITUMEN FOR UINTAH COUNTY ROADS MAY BE NEEDED

Material from Asphalt Ridge, an outcrop of tar sands, or native asphalt, southwest of Vernal, Utah has been used to pave roads in Uintah County for the past 50 years. P. Fetch, Uintah County road supervisor, predicts that the present tar sand location has another 2 years for production after which the county will have to buy its road building material or find more reserve.

The county has the right to mine the 160-acre resource, under an agreement with Wembco, the company that owns the mineral rights. The material has to be used in Uintah County and cannot be sold. Of the 375 miles of paved roads in Uintah County, 21 miles are not with native asphalt.

Last December, A. Petrick, a Colorado engineer, reported that, based on preliminary findings, it might be profitable to mine the rich tar sand layer about 52 feet below the present asphalt pit. Petrick recommended that the county do extensive core drilling and some trenching in the area to determine the size of the reserve and if it is continuous. Uintah County mines about 25,000 tons from the asphalt pit in a year or about 15 vertical feet.

TABLE 1

EARNINGS PROFILE OF SUNCOR (AFTER TAX)
(Millions of Dollars)

<table>
<thead>
<tr>
<th>Three Months Ended December 31</th>
<th>1992</th>
<th>1991</th>
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<td>Oil Sands</td>
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<td>Refining and Marketing</td>
<td>(2)</td>
<td>4</td>
<td>(6)</td>
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<td>(3)</td>
<td>(4)</td>
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<tr>
<td>Net Finacing Expenses</td>
<td>-</td>
<td>-</td>
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</tr>
<tr>
<td>Total</td>
<td>10</td>
<td>3</td>
<td>7</td>
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</table>

AOSTRA MAKES SLURRY TRANSPORT DATA BASE AVAILABLE

As a result of concerted efforts by the Saskatchewan Research Council, the University of Saskatchewan, and Alberta Oil Sands Technology Research Authority (AOSTRA), the petroleum industry now has rapid access to a wealth of technical information on fluid-solids transport. The new Slurry Transport Data Base, developed and maintained by AOSTRA Library and Information Services (ALIS), has many potential applications, especially in the oil sands industry where large bulk quantities of liquid-solids mixtures...
are generated. The emergence of this industry since the mid-1970s, plus the drive for economic competitiveness, has led to a growing interest in slurry transport technologies.

The Slurry Transport Data Base contains comprehensive information from over 1,200 source publications on fluid-solids transport. ALIS is continually expanding the new database by the addition of current and backlog materials. The Slurry Transport Data Base encompasses all aspects of fluid-solids transportation developments including slurry transportation theory, flow predictions, commodities pipelined, design and operational factors, materials performance, government policies, and pipeline economics.

The Alberta Library and Information Services may be reached at 403 427 8382, Fax 403 427 3198.

AOSTRA SEES NEED FOR MORE UPGRADING RESEARCH

During the past 15 years, major strides have been made in improving the efficiency of bitumen extraction. It is now technically feasible to produce bitumen from previously untapped deposits, and in many cases the production cost is only one-third to one-half that of 15 years ago. However, while bitumen extraction costs have been greatly reduced, the cost of upgrading the bitumen to synthetic crude oil has not decreased much over this time period. The upgrading component accounts for more than two-thirds of the cost of producing synthetic crude. For new oil sands projects to be profitable, bitumen conversion costs must be reduced through technology development, and the quality of synthetic crude oil must be improved to enhance its marketability abroad.

A study funded by Alberta Oil Sands Technology Research Authority (AOSTRA) indicates that by optimizing applications of emerging upgrading technologies, upgrading costs could be reduced by about $2.50 per barrel. At the same time, the value of the products would be increased by about $1 per barrel due to improved quality and 2 percent higher yield. Proponents believe that these estimates of the potential benefits are conservative, but would still place product supply costs well within the world price envelope, even at today's prices.

A new upgrading research and development program has been proposed to ensure and hasten the development of improved conversion technologies suited to the Alberta industry. The program would also explore the potential benefits of establishing integrated refining and upgrading facilities.

###

AOSTRA HAS 5-TON-PER-HOUR MOBILE TACIUK UNIT

Last summer, a mobile oil sands pilot plant was commissioned in Calgary, Alberta, Canada, where it is demonstrating bitumen-extraction and upgrading capabilities that are expected to lower the costs of synthetic crude production. The Alberta Oil Sands Technology and Research Authority (AOSTRA) is sponsoring the 60-barrel per day (5-tonne-per-hour) unit in an effort to showcase its Taciuk process (ATP), one of several AOSTRA ventures with commercial potential. The C$4.5 million unit was constructed for AOSTRA by UMATAC Industrial Processes, a division of UMA Engineering Ltd. of Calgary.

The ATP, shown in Figure 1, consists of a single, horizontal, rotating vessel containing a concentric inner cylinder. Using an aerobic pyrolysis, the ATP vaporizes and thermally cracks organics in the feed. The process is energy self-sufficient, achieving sensible and reaction heat through combustion of a portion of the coke produced in the pyrolysis reaction. Ancillary facilities cool, condense and separate liquids, handle and discharge the clean solids, and treat gaseous emissions. Plant emissions meet or exceed environmental requirements. In addition, the bitumen extraction/upgrading process produces a bottomless cracked oil and dry tailings, eliminating the clay/water sludge problem, which has led to large tailings ponds at other oil sands operations. The self-contained plant is mounted on nine trailers, allowing transport to and operation in remote locations.

ATP reaches an 80 percent efficiency rating regardless of the amount of oil in the feed, making it more economical than current hot-water systems, which have to be selective of the type of oil sand that is used to reach a maximum efficiency of 87 percent.

Preliminary economic studies indicate the technology has the potential to reduce the supply cost of synthetic oil by 20 to 25 percent, compared with hot water and other mining, extraction and upgrading systems. D. Komery, AOSTRA director of technology transfer and commercialization, estimates the ATP can produce synthetic crude from several oil-based feedstocks for about $7 or $8 per barrel while hot-water extraction's supply costs are $12 per barrel.

In alternative applications, the system has been proven to be highly successful in cleaning up soils and other materials con-
FIGURE 1
THE AOSTRA TACIUK 5 TONNE PER HOUR MOBILE PLANT

SOURCE: AOSTRA

Plant Specifics:

- Capital Cost: $4.0 Million
- Construction Period: 9 months
- Trailer Weight (Max): 90,000 kg
- Trailer Size (Max): 15.2m x 3.7m x 4.4m
- Port Space Needed: 37m x 55m
- Direct Operating Staff: 5
- Processing Rate: 5 tonnes/hour

Units available for lease or purchase

SOURCE: AOSTRA

THE AOSTRA TACIUK 5 TONNE PER HOUR MOBILE PLANT

SOURCE: AOSTRA

 Camel contaminated by oily wastes. The United States Environmental Protection Agency (EPA) has approved the ATP. SoilTech of Porter, Indiana has remediated 40,000 tonnes of PCB- and oil-contaminated soil at the EPA Superfund site at Wide Beach, New York with a 10-tonne-per-hour mobile ATP, and has processed 15,000 tonnes at Waukegan Harbor, Illinois.

Australia's Southern Pacific Petroleum and Central Pacific Minerals have also entered into an agreement to construct a 6,000-barrel-per-day semicommercial demonstration plant in Queensland to process oil shales. The companies made the agreement after 1,600 tonnes of Australian oil shale were processed in the ATP pilot plant. The Chinese and Japanese have also expressed interest in the process, and AOSTRA has made a presentation to Nippon Steel.

Despite these encouraging international results, AOSTRA retains its primary focus of developing Alberta's oil sands, which contain an estimated 2.6 trillion barrels of bitumen in place.

NEW HYDROPROCESSING PROCESS DEFINED

SNC-LAVALIN Inc. (formerly Partec Lavalin, Inc.) of Calgary, Alberta, Canada and Unocal Process Technology and Licensing of Brea, California have signed an agreement to license a hydrotreating technology designed to integrate the CANMET Hydrocracking Process and Unocal hydrotreating technology.

The integrated process will be called the U-CAN Residcracking Process. The process produces high quality, finished products such as naphtha, diesel and gas oils from refinery residual oil, heavy oils or bitumen.

Conversion levels of as high as 95 percent can be achieved, according to SNC-LAVALIN. The U-CAN Residcracking Process combines well proven features of the CANMET Hydrocracking Process and Unocal's proprietary Unionfining Process.

SNC-LAVALIN and Unocal will jointly market and license the U-CAN Residcracking Process.

SYNTHETIC FUELS REPORT, MARCH 1993
ERCB ISSUES ORDERS AND APPROVALS IN OIL SANDS AREAS

The recent orders and approvals in the oil sands areas issued by Alberta’s (Canada) Energy Resources Conservation Board (ERCB) are listed in Table 1.

### TABLE 1

**SUMMARY OF OIL SANDS ORDERS AND APPROVALS**

<table>
<thead>
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<th>Order Number</th>
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<th>Description</th>
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<td>App 3369G</td>
<td>25 Nov 92</td>
<td>Experimental oil sands schemes</td>
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<td>28 Feb 93</td>
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<td>Lindbergh and St. Paul Sectors</td>
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<td>App 5742A</td>
<td>2 Nov 92</td>
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ENERGY POLICY AND FORECASTS

GASOLINE REFORMULATION WILL AFFECT CANADA'S SYNTHETIC CRUDE OIL INDUSTRY

In a paper presented at the Workshop for Reformulated Gasolines, held in Aylmer, Quebec, Canada last October, A.W. Hyndman, et al. summarized the challenges facing Canada's synthetic crude oil industry in light of changing transportation fuel specifications.

The production of Western Canadian light crude is in decline. Without a replacement of this conventional production with frontier or other new production, Canada will be forced to purchase offshore oil, where light, low-sulfur crudes are becoming increasingly rare and which could become increasingly expensive.

Synthetic crude oil has been foreseen as a replacement for declining supplies of light, sweet Canadian crude oils. However there are a number of significant differences between conventional crude oil and the synthetic crude produced by Syncrude. The most obvious differences are the very low sulfur content and the lack of a residuum or bottoms fraction in synthetic crude oil. Additional unique properties of synthetic crude oil relative to sweet, light conventional crudes are:

- There is less total naphtha.
- The naphtha contains lower nitrogen and sulfur levels.
- There is greater light gas oil (LGO) content.
- The LGO is characterized by lower sulfur and higher aromatics levels.
- There is a greater heavy gas oil (HGO) content.
- The HGO contains low sulfur, but higher nitrogen and aromatics levels.

These differences will impact the ability of synthetic crude oil refineries to meet reformulated fuel specifications.

Gasoline

The United States legislation, and any future Canadian legislation, could well place limits on Reid vapor pressure (RVP), benzene, other aromatics, and sulfur. Refiners processing synthetic crude may find themselves facing operating constraints different from those processing conventional crudes.

The move to reduce evaporative losses will force the reduction in gasoline RVP particularly in the summer season. The simplest way to reduce the gasoline pool RVP is to reduce butane content. The longer and colder winter conditions in Canada, compared with the United States, may result in shorter seasonal constraints; however, there would still be a reduction in butane used directly in the gasoline pool.

Synthetic crude oil manufactured by Syncrude contains 3.5 volume percent butane, somewhat more than most conventional crudes and substantially more when considered as a fraction of the naphtha cut. Surplus butanes must either be burned as low-value fuel, or reprocessed into higher-value components. The additional cost of butane fractionation and isomerization facilities to handle the large volume of butane may make synthetic crudes less attractive.

In order to reduce benzene levels to the 1.0 volume percent level required in the United States, or to the 0.6 volume percent level discussed for Canada, refiners can either remove benzene and benzene precursors from the reformer feed to be saturated in an isomerization unit, or they could remove benzene from the reformer product for use as a chemical feedstock. If the reformer feed is highly cyclic in nature, removal of the benzene precursors will probably not be sufficient. Synthetic heavy naphtha contains more than 56 percent cycloparaffins and alkylaromatics, which, in the past has made it a good reformer feed. The relatively small volume of heavy naphtha from synthetic crude will partially offset this problem.

Synthetic HGO has a considerably lower sulfur content than vacuum gas oils from conventional crudes. The fluid catalytic cracking (FCC) gasoline derived from synthetic crude will have correspondingly low levels of sulfur. As FCC severity is increased for greater yield of C4 and C5 olefins for alkylation, the gasoline yield from these units is expected to suffer. Because the yield of FCC gasoline is already low when processing synthetic HGO, the benefits of low-sulfur gasoline will be offset by lower gasoline yield.

Distillate Fuels

There are no proposed changes to jet fuel specifications. The authors assume however, that the maximum aromatics concentration of 22 volume percent (25 volume percent reported) will not be increased. Jet fuel aromatic content is usually the first constraint which refiners encounter as the proportion of synthetic crude is increased in the refinery feedstock. Some refiners can process as much as 15 to 20 percent synthetic crude when producing turbo fuel, but numbers near 12 volume percent are more common. A decrease in the jet fuel aromatic specification would decrease this percentage further, adversely affecting the marketability of synthetic crude of current quality.

It appears now that the majority of the United States will be adopting a dual-diesel fuel specification; a minimum
40 cetane index, or a maximum of 35 volume percent aromatics. The much more restrictive California specifications of 10 volume percent aromatics for large refineries and 20 volume percent for small refineries has not been adopted elsewhere. The 40 cetane index specification means that American refiners cannot take advantage of cetane improvers in their diesel fuel. The new specifications may not adversely affect synthetic crude in the United States unless more states follow the California lead and adopt more stringent specifications.

Currently, the Canadian Government is considering adopting a 40 cetane number specification for diesel fuels. While this means that synthetic crude LGO, with a cetane number close to 33, will be more disadvantaged in the Canadian market, the Canadian refiners can take credit for the use of cetane improvers. However, hydrotreating LGO to meet sulfur specifications will also improve its cetane properties. The heavy end of the current FCC gasoline fraction will probably be blended into the diesel pool to reduce gasoline sulfur and 90 percent boiling point. The heavy FCC gasoline from synthetic HGO will be very aromatic in nature and may further depress the pool cetane number.

A new diesel sulfur specification of 0.05 weight percent (500 ppm) will promote the use of synthetic crude. Synthetic LGO already meets the new specification, with sulfur levels ranging from 300 to 500 ppm. So long as sufficient high cetane number blending stocks are available to offset the low cetane number of synthetic crude LGO, the synthetic crude can be used to reduce the need for additional desulfurization and sulfur recovery plant capacity.

Conclusions

The authors believe that as a manufactured product, the properties of synthetic crude can be changed to meet the demand as specifications for final products become more restrictive, but not without costs. All the changes required involve the addition of more hydroprocessing technology. Aromatics can be reduced in both the jet fuel and diesel cuts. Nitrogen and aromatics, particularly polynuclear aromatics, can be reduced in the cracking feedstock (HGO). Sulfur can be reduced to very low levels, but more stringent specifications could increase capital and operating costs dramatically.
TECHNOLOGY

HORIZONTAL WELLS EFFECTIVE AT EXTENDING RECOVERY FROM CYCLIC STEAM OPERATION

Cyclic Steam Stimulation (CSS) has proven to be an attractive recovery process at Cold Lake. Shear failure and the resulting dilation of the sand by high pressure steaming results in high initial bitumen production rates and oil/steam ratios. However, decreasing effectiveness of pressure-related drive mechanisms as interwell communication increases; limitations in areal conformance; and a high residual bitumen saturation limit the ultimate recovery of this process. Utilizing horizontal wells as CSS performance declines takes full advantage of gravity drainage as a drive mechanism, increases the amount of wellbore in contact with the reservoir and lowers residual bitumen saturation. A pilot utilizing horizontal wells to extend recovery beyond the limits of CSS has been successfully implemented to test the technology, and was discussed in a paper by D.E. Courtnage and K.O. Adegbesan presented at the AOSTRA/Canadian Heavy Oil Association 1992 Conference held last June in Calgary, Alberta, Canada.

Imperial Oil's Horizontal Well Pilot 1 (HWP1) began operation in 1979 and was designed to evaluate and optimize steam assisted gravity drainage, first with a single horizontal well and then by completing a vertical steam injection well in 1980. Horizontal Well Pilot 2 (HWP2) began operation in 1985 intended to extend the technology developed with HWP1, including operation of a longer wellbore with multiple vertical injection wells. Horizontal Well Pilot 3 (HWP3) began operation in 1991 to test the feasibility of following CSS with horizontal wells to extend recovery.

Location of the Horizontal Wells

The authors believe that the most important aspect of the design of the pilot was locating the horizontal wells. There are four possible orientations which result from deciding whether the horizontal well should run parallel to the columns of CSS wells or parallel to the rows and whether they should run adjacent to the down hole locations of the CSS wells or mid way between them. Orientation alternatives were evaluated against three criteria: ability to establish communication with the existing steam chamber, total cost and the potential for increasing recovery through improved areal conformance.

Based on these criteria, it was decided to drill the horizontal wells parallel and adjacent to the rows of CSS wells. Now, the term "adjacent" needed to be defined. Based on observation well data from other pads at Cold Lake, a target of 0 to 5 meters was set, with consideration to be given to plugging back and redrilling a portion of the well should the expected separation exceed 10 meters. The HWP3 layout is illustrated in Figure 1.

There were two factors influencing the depth of the horizontal wells: the distance below the perforations, and geology. Combining these factors, the horizontal wells were targeted for approximately 2 to 4 meters below the bottom of the perforations of each CSS well.

Operating Strategy

The steam cycles will be continued, as if CSS was continuing without the horizontal wells, for at least as long as the wells can be pressured-up during steaming. This has two benefits: the pressure drive mechanisms will be utilized as long as possible and continuing to increase access can only be enhanced by the new well. After the wells will not pressure-up, an intermittent steaming strategy, between cyclic and continuous steaming, is most probable. This will allow maximum production by gravity drainage while minimizing heat losses to the wellbore during injection.

Performance Prediction

Simulations were done to predict performance with the addition of the horizontal wells. Results are shown in Figure 2. In the simulations, the horizontal well is added in cycle 9, the earliest the process could be implemented at the commercial sites. Initial oil/steam ratio (OSR) when the horizontal well is added is increased by approximately 0.11. Increase in recovery can be as much as 90 percent of CSS recovery depending on the OSR economic cut-off.

The results can only be viewed as directional because performance uncertainty increases as the cumulative steam volume,
to which performance is extrapolated, increases. The most steam that has been injected into any Cold Lake well is 180,000 cubic meters into HWP1. Extrapolating to twice that volume comes with significant unknowns.

Implementation Timing

According to Courtnage and Adegbesan, in making a decision to follow up CSS with horizontal wells, one critical factor becomes the timing of the addition of the horizontal wells. From the perspective of the pilot, the earlier the process could be implemented the longer the time available to assess the results before the maturing commercial CSS wells require a follow-up process. However, testing whether the chosen pilot site was at a reasonable stage of depletion and determining the commercial implementation timing to establish how much time was available for piloting were two important criteria.

Simulation was used to evaluate implementation timing. Managing the risks associated with both early and late implementation suggests that there is a window for implementation between 8th cycle and 12th cycle. In addition, if the implementation timing is extrapolated back to first cycle, the performance of utilizing horizontal wells from the beginning can be determined. Using a CSS type operating strategy, there is no benefit in operating horizontal wells from the start.

Results From HWP3

The biggest reservoir engineering consideration is the accuracy in drilling and locating the horizontal wells. The horizontal wells passed within the 5 meter target on 14 of the 20 wells and within the 10 meter target on 18 of the 20 wells.

Steam Chamber Communication

To assess the probability of being able to establish communication between the horizontal well and the steam chambers and to test assumptions on locating the wells, temperature surveys of the horizontal wells were done after drilling. Most of these temperatures were between 100 and 125°C, validating earlier assumptions and giving confidence that communication with the steam chambers will, in most cases, be established easily.
The plan for evaluating communication is to inject steam into the injection wells while the horizontal wells are producing. Changes in producing temperature, casing pressure and water/oil ratio will be signs of communication.

Production

Early production data are limited. Steam injection totaled 423,000 cubic meters of steam into the 20 injectors. After 200 producing days, approximately one-quarter of the producing cycle, cumulative production was 17,000 cubic meters of bitumen and 95,000 cubic meters of water for the four wells. Current bitumen and water rates are approximately 400 cubic meters per day and 650 cubic meters per day respectively. While these are consistent with original expectations, it is too early to assess the long-term performance of this pilot, say the authors.

One encouraging result has been that the volume of water produced is significantly less than would have been produced under CSS. Normally 50 percent of the steam volume has been produced back as water from the horizontal wells. Control of the produced fluid by limiting bottom hole temperature worked well. Bottom hole conditions changed gradually and, therefore, estimating bottom hole temperature was sufficient control. The authors assume that much more of the steam has remained in the reservoir resulting in increased heat retention and providing additional drive energy late in the cycle. The cost has been a lower average fluid production rate. This balance will be optimized in future cycles.

###

**TABLE 1**

**EFFECT OF PROCESS OPERATING VARIABLES ON NITROGEN CONCENTRATION**

<table>
<thead>
<tr>
<th>Variables Held</th>
<th>WHSV (h⁻¹)</th>
<th>T (K)</th>
<th>P(mPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>T, P</td>
<td>1.38</td>
<td>642</td>
<td>11.2</td>
</tr>
<tr>
<td>Nitrogen (ppm)</td>
<td>8,100</td>
<td>7,000</td>
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<td></td>
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<tr>
<td></td>
<td>1,200</td>
<td>3,400</td>
<td>4,900</td>
</tr>
</tbody>
</table>

NITROGEN REMOVAL FROM WHITEROCKS BITUMEN FOUND TO BE DIFFICULT

Due to the high nitrogen content (0.8 to 1.2 percent) of bitumen and bitumen-derived liquid from the Whiterocks oil sand deposit in the Uinta Basin of Eastern Utah, primary upgrading is required before the bitumen-derived liquid can be used as a refinery feedstock. The hydrotreating of Uinta Basin bitumens was discussed in a paper by D.C. Longstaff, et al., at the 1992 Eastern Oil Shale Symposium in Lexington, Kentucky.

The bitumen was hydrotreated in a fixed-bed reactor to determine the extent of upgrading, with particular emphasis on denitrogenation, as a function of process operating variables. The process variables investigated included the reactor temperature (641 to 712 K), the reactor pressure (11.2 to 16.7 MPa), the weight hourly space velocity (WHSV) (0.19 to 0.77 per hour), and the hydrogen partial pressure. The effect of the first-three variables on nitrogen is summarized in Table 1.

The effect of WHSV at a fixed temperature and pressure on the conversion of nitrogen is summarized in Table 1. These tests were conducted at 664 K and 13.6 MPa. According to Longstaff, et al., nitrogen conversion occurs according to pseudo-first order kinetics with a rate constant of 0.6 per hour.

The effect of reaction temperature at a fixed pressure and WHSV on the conversion of nitrogen is presented in Table 1. All experiments were conducted at a WHSV of 0.76 per hour and a pressure of 13.7 MPa. The slope of the
natural log of the first order rate constant for nitrogen conversion versus reciprocal temperature yields an activation energy of 93 kilojoules per mole for denitrogenation.

The effect of reactor pressure at fixed space velocity and reaction temperature on nitrogen is presented in Table I. The reaction temperature and WHSV were held constant at 663 K and 0.76 per hour, respectively, while the pressure varied from 11.2 to 16.7 MPa. The reaction order with respect to hydrogen partial pressure, beta, for nitrogen was determined to be 0.7. This value of beta is indicative of the importance that hydrogen plays in denitrogenation, say the authors.

Longstaff, et al., conclude that although substantial denitrogenation occurred during hydrotreating, the nitrogen levels in feed bitumen were so high that the nitrogen levels in the hydrotreated liquid product remained high.

###

**CANMET COPROCESSING RESIDUE BENEFICIATED BY OIL PHASE AGGLOMERATION**

CANMET's coal/heavy oil coprocessing unit yields a solid residue that contains all the ash originally associated with the feed coal as well as the added catalyst solids. Removal of these ash solids would make it possible to recycle the material to extinction, thereby increasing production of lighter oils. Also, it is desirable to separate selectively the siliceous matter so that the retained catalyst residues can be recycled with the pitch. The results of a study to beneficiate the organic matter in the coprocessor pitch residue using oil phase agglomeration is discussed in a paper by A. Majid, et al., presented at the 42nd Canadian Chemical Engineering Conference held last October in Toronto, Ontario, Canada.

The liquid phase agglomeration technique, developed at the National Research Council of Canada, is based on the preferential wetting of a specific solid component in liquid suspension, by a second, immiscible liquid (bridging oil). The liquid-phase agglomeration procedure begins by grinding the pitch residue to a particle size of about 10 micrometers. To make the surface of the ash hydrophilic, a conditioning agent is added to a slurry of water and ground pitch. Bridging oil is then added dropwise until discrete agglomerates are formed. The agglomerated pitch is then separated and ashed to determine the degree of beneficiation.

In this study, the effect of pH, conditioning agent, and oil characteristics on the beneficiation of pitch were evaluated.

**Figure 1**

**EFFECT OF pH ON BENEFICIATION OF COPROCESSING RESIDUE**

The pH of the slurry was adjusted either with HCl or with NH₃OH. The results are summarized in Figure 1, which is a plot of the weight percent ash rejection as a function of the pH of the slurry. Best ash rejection results were achieved in the pH range 4 to 5. Analysis of the ash and oil agglomerates showed that all of the iron was associated with the oil agglomerates. These results also showed that the agglomerates obtained under optimum ash rejection conditions did not contain any siliceous matter. According to Majid, et al., this suggests that the remaining ash consists of iron-based compounds desirable for their catalytic activity. The carbon recovery in most of these tests ranged between 80 to 90 weight percent.

**Effect of Conditioning Agents**

The conditioning agents used in this investigation included: tannic acid, sodium silicate, sodium hydroxide, sodium oxa-
late, hydrogen peroxide, copper nitrate, aluminum nitrate, and triethylamine. Only tannic acid, sodium silicate and hydrogen peroxide had any effect on the beneficiation process. The best results were obtained with tannic acid and sodium silicate, with ash rejection on the order of 35 weight percent.

Oil Characteristics

The type of oil used as the bridging agent is as important as its concentration in the agglomeration of hydrophobic materials. Lighter, more refined oils, with high paraffin content, are more efficient for selective agglomeration, especially when the rejection of siliceous material is an important consideration. In addition to their more desirable wetting properties, these lighter oils achieve efficient and economical coating of the organic particles during mixing. In this investigation most of the tests were carried out with Stoddard solvent, a reference oil normally used for comparison purposes. However, preliminary tests were also carried out with dodecane and fuel oil No. 4. The best results were obtained with fuel oil No. 4, with a 43 weight percent ash reduction.

Conclusions

The authors conclude that liquid phase agglomeration techniques were successfully applied to the selective agglomeration of organic matter and iron compounds from CANMET coprocessing residues. Most of the iron compounds were retained in the agglomerates, which reduces catalyst makeup requirements if the pitch is recycled. In addition, very little siliceous matter remains with the cleaned pitch. This suggests that most of the undesirable components of the solids present in CANMET coprocessing residues can be removed by an oil agglomeration technique.

# IN SITU COMBUSTION YIELDS SLIGHTLY UPGRADED PRODUCT

In a project sponsored by CANMET, oil samples collected from two wells at the in situ combustion pilot at Wolf Lake, Alberta, Canada over a 1 year period were physically and chemically characterized in detail. The properties of these samples were compared to those for oil from a core sample obtained prior to the initiation of the fireflood. The objective of this work was to assess the effects of the in situ recovery process on the quality of the produced oil, with particular emphasis on the subsequent upgrading process.

A number of analytical techniques were applied to the whole oils with four samples chosen for a fractionation by distillation and column chromatography. These fractions were characterized in detail by gas chromatography-mass spectrometry.

It was concluded that the quality of the oil produced from this in situ oxygen combustion process would not be expected to introduce any major problems in the subsequent upgrading of the oil. In fact, the properties of the oil suggest that the recovery process itself resulted in a small but significant amount of upgrading.

# NOMENCLATURE OF RESIDUUM UPGRADE REVIEWED

The terminology used to describe the various processes and procedures applied to the upgrading of the high-boiling fractions of conventional crude oil and bitumen is often confusing. The source of this confusion is often a simple misuse of terms according to normal scientific convention. A critical review of the common usage of various terms from the current literature and a suggested set of definitions were summarized in a paper by E.C. Sanford, of Syncrude Canada Limited, and published in the AOSTRA Journal of Research.

Sanford has identified commonly used synonyms to avoid, and has suggested the following definitions:

- **Topped Bitumen or Topped Crude Oil**: The high-boiling point fraction of a bitumen or crude oil which has been distilled to less than 524°C. The cut point should be stated (for example, 232°C + topped crude oil).

- **Residuum**: The 524°C+ fraction (or a specified higher cut point) of a crude oil or bitumen.

- **Pitch**: The liquid or semi-liquid product from the processing of a residuum (by any means), which boils above 524°C.

- **Tar**: The distillable oily products produced in the destructive distillation of bitumen or other organic substances.

- **Coking**: Process for the thermal breaking of bonds in petroleum liquids and semi-solids (mainly residua) which results in the formation of a complete range of products, from solid to gas, sometimes in the presence of steam.

- **Visbreaking**: Process for the thermal breaking of bonds in petroleum liquids and semi-solids (mainly residua) which is...
Catalyst is used to saturate double bonds and to remove sulfur, nitrogen, oxygen and metals, concurrent with the thermal cracking reaction.

Synonym, whose use is discouraged: jet cracking.

**Catalytic Cracking:** Process for the breaking of bonds in petroleum gas oils (which can contain up to 15 percent residua) utilizing an acid catalyst, and intended mainly to produce products in the gasoline boiling range.

**Hydrocracking:** Process for the thermal breaking of bonds in petroleum liquids and semi-solids (mainly residua), carried out in the presence of added hydrogen and/or a hydrogen donor solvent, with or without a dispersed metal sulfide additive or supported metal sulfide hydrotreating catalyst, which produces a complete range of gaseous, liquid and semi-solid products depending on feedstocks and reaction conditions, with minimum coke formation.

Synonyms, whose use is discouraged: hydropyrolysis, hydrovisbreaking.

The term "slurry-phase hydrocracking" describes hydrocracking in the presence of a finely-dispersed metal sulfide additive. Similarly the term "hydrogenolysis hydrocracking" is appropriate to describe processes where a hydrotreating catalyst is used to saturate double bonds and to remove sulfur, nitrogen, oxygen and metals, concurrent with the thermal cracking reaction.

**Catalytic Hydrocracking:** Process for the catalytic breaking of bonds in petroleum gas oils or residua, normally utilizing an acid catalyst and carried out in the presence of added hydrogen, which produces a complete range of gaseous and liquid products, depending on the feedstock, the catalyst and the process conditions.

Synonyms, whose use is discouraged: mild catalytic hydrocracking, catalytic hydropyrolysis, catalytic flash hydrocracking.

**Catalytic Hydrotreating:** Process for catalytically removing heteroatoms and metals from, and catalytically saturating olefins and aromatics in petroleum streams containing distillate and/or residua, generally utilizing supported metal sulfide catalysts and carried out under conditions where thermal cracking is minimal.

Synonyms, whose use is discouraged: hydroprocessing, hydropurification, and hydrosulfurization.

####
INTERNATIONAL

HEAVY OIL TO AMMONIA PLANT BEING BUILT IN INNER MONGOLIA

China's first large-scale ammonia plant to use the Shell/Lurgi gasification process is to be built in Inner Mongolia. The plant, a 330,000-tonne-per-year heavy-oil gasification unit, is to be built by Toyo Engineering, in collaboration with Mitsui and Company. The plant will be built at Huhehot City for the Inner Mongolia Chemical Fertilizer plant.

CHINESE ENGINEERS RECEIVE TRAINING AT UTF IN ALBERTA

In 1992 the China National Petroleum Corporation (CNPC) purchased a partnership in the Alberta Oil Sands Technology Research Authority (AOSTRA)-operated Underground Test Facility (UTF). At that time, AOSTRA undertook to provide a training program on the UTF Steam Assisted Gravity Drainage (SAGD) process for key CNPC personnel, as the first step in the transfer of UTF technology. CNPC plans to use the SAGD technology in petroleum deposits in China. Last fall, a team of AOSTRA's UTF experts delivered the training program, which included some 30 hours of technical presentations given at AOSTRA's Calgary offices and tours of the UTF and the Syncrude oil sands operations. In addition, the six engineers selected by CNPC to receive the training were provided with 90 technical reports, a new drilling video, and an updated catalog of UTF reports.

ORIMULSION HITS ENVIRONMENTAL BARRIER IN BRITAIN

Moves to introduce the fuel Orimulsion into Britain received a setback last fall when United Kingdom pollution inspectors indicated that they would not approve it without further environmental measures. Her Majesty's Inspectorate of Pollution did not detail the extra environmental measures required before it will grant permission, but they are expected to include flue gas desulfurization equipment.

Orimulsion is a bitumen-in-water emulsion made from heavy Venezuelan crude. It is sold by BP Bitor Ltd., a joint venture between British Petroleum plc and Venezuela's Petroleos de Venezuela.

Orimulsion has been denounced by environmentalists because of its sulfur content. The power generation industry accepts that it contains more sulfur than most oil or coal, but argues that its overall emissions are less harmful. According to M. de Oliveira, the chief executive of BP Bitor, "It is a fact that all present and proposed uses of Orimulsion comply in every respect with current health, safety and environmental legislation." In addition, Bitor maintains that 6 to 8 million tonnes per year of coal with higher sulfur emissions than Orimulsion are burned in Britain.

National Power has been seeking permission to burn the fuel at its power stations at Padiham, Lancs, and Pembroke.

The company hopes to burn 3 million to 4 million tonnes of the fuel a year. PowerGen plc has been burning Orimulsion for several years on an experimental basis without environmental controls at two stations in Kent and Cheshire. PowerGen burns about 1.5 million tonnes a year under permission granted under earlier pollution control regulations. The company is having to reapply under the new regulations.

Although Orimulsion is not a major market player in Britain's power generation sector, providing only 1.3 of the 100 million tonnes of coal equivalent used per year, it is cheaper than domestic coal. Thus, according to British Coal Corporation, consumption of the fuel could be significantly higher by 1997 if power generators decide to convert large oil-fired power stations to burn it.

The Department of Transportation and Industry (DTI) is currently reviewing British Coal Corporation's coal pits to determine whether there is a worthwhile market for United Kingdom coal and if some pits should be closed. British Coal Corporation's submission to DTI's coal review called for burning of Orimulsion to be limited to the power stations covered by current consents, which could threaten prospects for the fuel.
STATUS OF OIL SANDS PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since December 1992)

ASPHALT FROM TAR SANDS – James W. Bunger and Associates, Inc. (T-5)

J. W. Bunger and Associates, Inc. (JWBA) is developing a project for commercialization of Utah Tar Sands. The product of the initial venture will be asphalts and high value commodity products. 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 1990, JWBA completed a $550,000 R&D program for development of technology and assessment of markets, resources and economics for asphalt production.

Under this program funded by the U.S. DOE SBIR program, a 100-300 pound per hour PDU was designed and constructed. The unit has been operated to determine the effect of process variables and kinetic parameters. Recoveries of greater than 97 percent have been experienced. The unit has been operated to produce gallon quantities of asphalt for testing and inspection. A field demonstration unit of 200 barrels per day has been designed and costed. Results show a strong potential for profitability at 1990 prices and costs.

All candidate sites in the Uinta Basin of Utah are currently under consideration for development including Asphalt Ridge, P.R. Spring, Sunnyside and White Rocks. Unknown resource quality tends to increase required investment hurdle rates, however, and these factors must be offset by higher product prices. In 1990 JWBA initiated a program for value-added research to extract high value commodity and specialty products from tar sand bitumen. This program was initiated with an additional $50,000 in funding from DOE.

The commercialization plan calls for completion of research in 1992, construction and operation of a field demonstration plant by 1994 and commercial operations by 1996. The schedule is both technically realistic and financially feasible, says JWBA.

Project Cost: 
- Research and Development: $1.5 million
- Demonstration project: $10 million
- Commercial Facility: $135 million

BI-PROVINCIAL UPGRADE – Husky Oil Operations Ltd. (26.7%), Government of Canada (31.7%), Province of Alberta (24.2%), Providence of Saskatchewan (17.5%) (T-10)

Husky Oil has built a heavy oil upgrader located near the Alberta/Saskatchewan border at Wilton, near Lloydminster, Saskatchewan. The facility is designed to process 46,000 barrels per day of heavy oil and bitumen from the Lloydminster and Cold Lake deposits. The primary upgrading technology used at the upgrader is H-Oil ebullated bed hydrocracking followed by delayed coking of the hydrocracker residual. The output is 46,000 barrels per day of high quality synthetic crude oil, as well as 400 tonnes per day of coke and 235 tonnes per day of molten sulfur.

The project was completed in the early fall of 1992 and, as of December 31, 1992, has produced over 4 million barrels of synthetic crude oil, well ahead of forecast.

Currently, Husky's cost to produce synthetic crude from heavy oil is greater than its market value, but that is expected to change over the next several years.

The project includes a crude oil unit, hydrocracker reaction unit, fractionation unit, delayed coking unit, naphtha-jet hydrotreater, gas-oil hydrotreater, hydrogen plant, gas-recovery unit and sulfur-recovery unit.

Project Cost: 
- Upgrader Facility: C$1.6 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.

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.

A Solv-Ex pilot plant, located in Albuquerque, New Mexico, can process up to 72 tons of oil sands per day. It can also produce up to 25 barrels of bitumen per day, depending on the grade of oil sands processed. The quantity of bitumen recoverable from tar sands depends on its bitumen content, which typically ranges from 4 to 12 percent.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

In an 8-month test program, Solv-Ex processed approximately 1,000 tons of Athabasca tar sands material in process runs of low (6 percent of bitumen), average (8 to 10 percent), and high (12 to 14 percent) grade oil sands through the pilot plant. The test material was procured from a pit centrally located in the oil sands deposit on which the Bitumount Lease is located. Average percentage of bitumen recovered for the low, average and high grade sands were 75, 90 and 95 percent, respectively.

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 about 25 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 looking for potential financial partners to expand the project. The company plans to construct a modular Lease Evaluation Unit in Alberta at an estimated cost of $12 million.

BURNT LAKE PROJECT - Suncor Inc., Alberta Energy Company Ltd. and Canadian Hunter Exploration Ltd. (T-30)

The Burnt Lake in situ heavy oil project 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 close cooperation with Canada's military.

The multi-phase Burnt Lake project, which was proposed to use cyclic steaming, was put on hold in 1986 due to low oil prices, then revived in 1987. The project was again halted in early 1989. By then, 44 wells in two clusters and 7 delineation wells had been drilled and cased.

A pilot was initiated at these wells in 1990 to test the cold flow production technique whereby the bitumen is produced together with some sand using a progressive cavity pump. Initial results were encouraging. Since then, twelve wells have been put on production. Early production rates of 30 cubic meters per day per well have been achieved but the expected value is 17 cubic meters per day. The productivity in some wells appears to be limited by the capacity of the pumps. The pilot will be continued to obtain long term results.

If successful, the cold flow production process may replace the cyclic steam stimulation process for commercial development.

Burnt Lake is estimated to contain over 300 million barrels of recoverable heavy oil.

COLD LAKE PROJECT - Imperial Oil Resources Limited (T-50)

In September 1983 the Alberta Energy Resources Conservation Board (AERCB) granted Esso Resources Canada Ltd. (now Imperial Oil Resources Limited) 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.

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.

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 added 19,000 barrels per day in 1988, at a cost of $45 million. Production in 1990 averaged 90,000 barrels per day.

The AERCB approved Imperial's application to add Phases 7 through 10, which could eventually add another 44,000 barrels per day.

All construction was essentially completed in 1988 on the central processing plant and the field facilities for Phases 7 and 8 at a cost of C$220 million. In December 1990, Imperial announced plans to put Phases 7 and 8 into operation and begin steaming in March 1991.
COMMERCIAL PROJECTS (Continued)

In February 1991, Imperial made a decision to delay the startup of Phases 7 and 8, due to unfavorable market conditions. Conditions improved enough in 1992 to allow startup, and in October 1992, Imperial started steaming of Phases 7 and 8 wells. Bitumen production from these wells started in December 1992, and is expected to build to 20,000 barrels per day by July 1993.

Plant facilities for Phases 9 and 10 were completed in tandem with the Phases 7 and 8 plant. When suitable market opportunities materialize, Imperial will drill the wells to fully utilize this plant capacity, expanding production by a further 20,000 barrels per day.

Project Cost: Approximately $770 million for first 10 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. To date over 350 core holes have been drilled at the site to better define the resource.

Currently, the project has been suspended pending further notice.

DIATOMACEOUS EARTH PROJECT - Texaco Inc. (T-70)

Texaco placed its Diatomite Project, located at McKittrick in California's Kern County, in a standby condition in 1985, to be reactivated when conditions in the industry dictate. In 1991 the company is initiating steps to re-evaluate the technology needed to recover the oil and to evaluate the environmental compliance requirements for a commercial plant. Consideration will be given to restarting the Lurgi pilot unit.

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 Electromagnetic Oil Recovery, Inc. (T-80)

Electromagnetic Oil Recovery Inc. (EOR), formerly Oil Recovery Systems (ORS) Corporation, through its subsidiary, Uentech Corporation, sponsored research and development at the Illinois Institute of Technology Research Institute (ITIRI) 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, and process energy costs have been demonstrated at around $1/bbl, according to ORS.

Additional projects under way with EOR, Inc.'s technology include:

Canada Northwest Energy Ltd. installed an electromagnetic heating system within a well located near Lashburn, Saskatchewan in February 1989. Production averaged triple the production rate which existed before installation of the EOR system. Pan Canadian Petroleum Co., Ltd. has had a project ongoing since late 1990, with encouraging results for this heavy oil application. In Utah, an EOR system was installed in a well owned by GHP Corporation during December 1991. The system was designed to overcome production problems associated with an oil containing a large amount of paraffin. Also in Utah, EOR has been contracted by Coors Energy company to test the process in a field which experiences production problems associated with paraffinic oil. In Wyoming, Marathon Oil Company installed the EOR equipment within a well near Cody, Wyoming in late 1990. EOR was contracted by Shell to provide equipment and services to utilize the technology within a well in the Schoonebeek field of the Netherlands. The project resulted in EOR signing a contract for additional work for another Shell affiliate, Petroleum Development Oman. For Lagoven, EOR has been contracted to provide equipment and services for two wells in the Jobo Field of Venezuela, with startup scheduled for late summer of 1992. In Indonesia, a project is pending with Pertamina for a deep well which experiences paraffin related production problems. In Brazil, EOR's project is slowly expanding. Currently four additional wells have been equipped with the EOR system with positive results for Petrobras.
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. The primary oil sands targets in the area are the Lower Cummings and Clearwater sands of the Mannville Group. Additional oil sands potential is indicated in other Mannville zones including the Colony and the Sparky.

Oil production from current wells at Amoco’s Elk Point field totals 970 cubic meters per day.

Amoco Canada has several development phases of the Elk Point Project. Phase 1 of the project, which is now complete, involved 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. Continuous steam injection was discontinued in May 1990 and the pilot was shut in.

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 22 wells were drilled in 1990.

Future drilling at Elk Point is dependent on Phase 2 approval of the project. Phase 2 will continue to focus on primary production development and will allow for further infill drilling in the entire project area in all zones within the Mannville group. Some limited cyclic steam is planned in future years. Amoco’s application for Phase 2 is continuing through the application review and public consultation process in 1992.

ELK POINT OIL SANDS PROJECT — PanCanadian Petroleum Limited (T-100)

PanCanadian received approval from the Alberta Energy Resources Conservation Board for Phase I of a proposed three phase commercial bitumen recovery project in August 1986.

The Phase I project involves 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 148 wells were drilled by the end of 1990.

PanCanadian expected Phase I recovery to average 3,000 barrels per day of bitumen, with peak production at 4,000 barrels per day. Tentative plans called for Phase II operations to start up in the mid 1990’s with production to increase to 6,000 barrels per day. Phase III was to go into operation in the late 1990’s, and production was to increase to 12,000 barrels per day.

Experimental steam stimulation (50 cycles) and steamflood (one pattern) lasted until mid-1990. Results were not encouraging and therefore all steaming operations have been canceled. Another steaming process such as SAGD (Steam Assisted Gravity Drainage) may be attempted in the future but no plans are currently in place.

Although steaming has proved unsuccessful, primary production rates and cumulative recoveries are much better than originally anticipated. Recoveries as high as 12 to 20 percent on 40-acre and 10-acre spacing are expected utilizing slant wells from pads.

Current production is 4,500 barrels per day from 90 wells in 13 sections. Operating costs are approximately C$4 per barrel.

Project Cost: Phase I = C$62 Million to date
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

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 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 was 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.

On January 2, 1990, Greenwich successfully implemented its Plan of Reorganization which had been approved by the Court in November 1990. Under the terms of an agreement with the United States Treasury, successor to the Synthetic Fuels Corporation, the commitment for loan guarantees and price support was terminated.

January 1992 production was 410 barrels of oil per day.

Project Cost: Estimated $42.5 million

LINDBERGH COMMERCIAL PROJECT – Amoco Canada Petroleum Company Ltd. (T-120)

Amoco (formerly Dome Petroleum) began a commercial project in the Lindbergh area that would initially cover five sections and was planned to be developed at a rate of one section per year for five years. It was to employ "huff-and-puff" steaming of wells drilled on 10 acre spacing, and would require capital investment of approximately $158 million (Canadian). The project was expected to encompass a period of 12 years. Due to the dramatic decline of oil prices, drilling on the first phase of the commercial project was halted, and has forced a delay in the proposed commercial thermal development.

The company has no immediate plans for steaming the wells to increase production because this process is uneconomic at current prices.

The current focus has been development and optimizing of primary production. In 1990, 26 wells on 40-acre spacing were drilled for primary production. Again, due to low heavy oil prices, some limited drilling will take place in 1991. Primary production from the project is now averaging 6,200 barrels per day.

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 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. The project returned to production on a limited basis in the last quarter of 1989. Initial results were encouraging, says Murphy, but an expansion to full capacity depends on heavy oil prices, market assessment, and operating costs.

The project was shut-in in late 1991. Engineering reviews of current and alternate technologies are under way.

Project Cost: $30 million (Canadian) initial capital cost
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

NEWGRADE HEAVY OIL UPGRADE - NewGrade 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 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.

Consumers' 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 provided loan guarantees for 80 percent of the costs as debt.

NewGrade 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.

Operations include the processing of 50,000 barrels per day of heavy Saskatchewan crude with approximately 70 percent (35,000 barrels per day) being converted to a full range of refined petroleum products and the remaining 30 percent (15,000 barrels per day) being sold as synthetic crude.

Operations in 1992 have experienced a heavy crude oil charge ratio of up to 54,000 barrels per day, and the Atmospheric Residual Desulfurization (ARDs) unit has had a charge ratio of 32,000 barrels per day. The Distillate Hydrotreater/Hydrocracker routinely operates at up to 15,000 barrels per day.

The plant design capacities are: crude unit, 50,000 barrels per day; ARDS, 30,000 barrels per day; DH, 12,000 barrels per day.

Project Cost: $700 million

ORIMULSION PROJECT - Petroleos de Venezuela SA (PDVSA) and Veba Oel AG (T-145)

Venezuela's state-owned oil company, Petroleos de Venezuela SA (PDVSA), and Germany's Veba Oel AG plan to develop the heavy crude and bitumen reserves in the Orinoco Belt in eastern Venezuela. The two companies conducted a feasibility study to construct a facility capable of upgrading 80,000 barrels per day of extra heavy crude. Development plans for the next 5 years call for production of 1 million barrels per day.

About 60 percent of this production would be Orimulsion, a bitumen based boiler fuel. The remainder would be converted to light synthetic crude oil. PDVSA can produce and distribute 50,000 barrels of Orimulsion per day. Facilities are under construction that will boost production to 100,000 barrels per day in 1992.

PDVSA has joined forces with Mobil Corporation in 1992 to explore other options for marketing heavy crude in addition to Orimulsion.

In October 1991, the Kashima-Kita Electric Power Corporation of Japan began firing their generators with 700 tons per day of Orimulsion. Another Japanese utility, Mitsubishi Kasei Corporation, began working with Orimulsion in February 1992.

Recently, Venezuela's Ministry of Energy and Mines ordered PDVSA to scale back its program to develop Orimulsion in order to focus current efforts on light and medium crude.

Project Cost: $2.5 billion

OSLO PROJECT - Esso Resources (25 percent), Canadian Occidental (20 percent), , Gulf Canada (20 percent), Petro-Canada (15 percent), PanCanadian Petroleum (10 percent), Alberta Oil Sands Equity (10 percent). (T-150)

The OSLO joint venture was to be an 80,000 barrel per day oil sands mine and extraction plant 60 kilometers north of Fort McMurray, and an upgrader situated about 7 kilometers south of Redwater, near Edmonton. Production was scheduled to begin in 1996.

SYNTHETIC FUELS REPORT, MARCH 1993
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

On February 20, 1990 the Canadian federal government announced the withdrawal of its previous commitment to finance $1.6 billion of the $4.5 billion project. To the end of 1990, $75 million had been spent on project studies. In mid-1990, however, the Alberta government pledged to provide $47 million to complete the engineering phase. Alberta's contribution represented 36 percent of the estimated $130 million total cost for the engineering phase. The Canadian federal government contributed about $453 million, 35 percent of the total, for the engineering phase. The OSLO consortium funded the rest.

The engineering phase was completed by the end of 1991. Engineering work was focused on the Edmonton-area upgrader to be linked directly to OSLO's Fort McMurray bitumen production via pipeline. The pipeline is planned to be open to other operators to move their product. A second pipeline would return the diluent to the bitumen production facility.

If built, 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 sent to the upgrader by pipeline. 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.

According to OSLO, the OSLO reserves are large enough that a project could produce 200,000 barrels of synthetic crude oil per day for almost 50 years.

In early 1992 the OSLO partners decided that they could go no further with the project without government support. When the final work on technical design and environmental assessment was completed, the OSLO offices in Calgary, Alberta were closed. The project will not be built until economic conditions improve.

Project Cost: $4.5 billion estimated

PEACE RIVER COMPLEX - Shell Canada Limited (T-160)

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 a cost of $200 million, required the driling 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.


In 1989 production was increased to the design capacity of 1,600 cubic meters of oil per day. The Peace River complex completed its first full year of operating at capacity in 1990. Its 10 millionth barrel of bitumen was produced in March. Through a combination of increased bitumen production and reduced energy requirements, the unit bitumen production cost has been reduced to 30 percent of that averaged during the first full year of operation. The operation is producing about 10,000 barrels per day of bitumen. Ultimate recovery is projected at 55 percent of the bitumen in place.

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 expansion 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. The ERCB approval for PREP II was allowed to lapse, however, in December 1990. Continued world oil price uncertainty contributed largely to the decision not to seek an expansion.

Research into the application of a steam drainage process has led to the design of a two-well horizontal well demonstration project. The project will test the technical and economic feasibility of bitumen recovery utilizing surface-accessed horizontal wells, employing an enhanced steam assisted gravity drainage process. The project will be tied into existing Peace River complex facilities and is scheduled for startup in 1993.

Project Cost: $200 million for PREP I
$570 million for PREP II
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

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 allows Amoco to earn an interest in an additional 194,280 acres of adjoining oil sands lands through development of a commercial production project. The project is estimated to carry a capital cost of at least $1.2 billion and annual operating cost of $140 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. In 1990 Amoco announced it would drill two more wells to assist in engineering design work. Six hundred thousand dollars was planned to be spent on this effort in 1990.

A new steam injection heavy oil pilot was placed in production in early 1991. By the end of 1991, AEC expected to be testing more than 80 wells using various techniques, including a cold technique which employs specialized pumps.

In 1991, ERCB gave approval for seven horizontal wells to maximize bitumen recovery under a steam stimulation/gravity drainage process.

AEC expects its share of Primrose heavy oil production to grow to about 10,000 barrels per day over the next 5 years and double by the late 1990s.

Using a newly developed "cold production" technique, four wells have been producing for more than a year at rates averaging 140 barrels per day per well. This technique significantly reduces capital and operating costs as compared to steam injection techniques. Further testing of this technology continues in 1992.

AEC estimates that cold production technology could yield 6,000 barrels per day by 1993, with a planned expansion to 12,500 barrels per day in 1995.

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 was 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. The 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 Suncor 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 mixed 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 which is shipped to Edmonton for distribution.

In November 1991, Suncor applied to the ERCB to increase primary bitumen production as much as 2,000 cubic meters per day.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

After December 31, 1991, the royalty changed to be the greater of 5 percent of revenues or 30 percent of revenues less allowed operating and capital costs.

Sun Company, Inc. announced in early 1992 its intention along with partner Ontario Energy Corporation (OEC) to sell up to 45 percent interest in Suncor. Sun intends to reduce its 75 percent share to 55 percent and OEC would sell its entire 25 percent interest in Suncor.

The plant achieved record production levels in the first quarter of 1992, averaging 64,200 barrels per day, or about 250,000 barrels above the same period last year. Cash operating costs remained at 1991 levels of $14.25 per barrel.

In 1992 Suncor announced restructuring and operating changes aimed at reducing the cost of producing synthetic crude oil by $5 to $7 per barrel by 1996. Lowering production costs by that amount would increase the company's cash flow by $125 to $175 million per year and make synthetic crude oil competitive with Canadian conventional crude oil.

Suncor now has written agreements to acquire new mining leases in proximity to its plant that will allow the company to produce an additional 1 billion barrels of light synthetic crude oil. At the plant's current production rates, Suncor now has sufficient bitumen to supply the upgrader for at least 50 years.

To reduce mine operating costs, Suncor will introduce a more flexible and efficient mining method by mid-1994. The 25-year-old bucketwheel excavator systems will be replaced with a more modern system of large-scale trucks, power shovels and ore feed crushers at a cost of approximately $100 million. Truck and shovel mining equipment, which has reached unprecedented dimensions of size and scale in recent years, will enhance reliability and productivity and should result in significant gains in both production and cost savings. By mid-1994, Suncor believes these initiatives alone will reduce cash costs by approximately $3 per barrel of synthetic crude oil.

As part of the strategic review, Suncor conducted a commercial feasibility study of new technology which would reduce sulfur dioxide emissions from the utilities plant that supplies electricity and steam to the oil sands operation. The company estimates this will contribute to a further $1.50 per barrel reduction in cash costs. Suncor will invest $5 million to confirm engineering results and a preliminary cost estimate of $270 million.

The company expects to make the final decision to proceed by the second half of 1993.

Suncor will also be implementing other operating efficiencies and production improvements that are expected to result in a cash cost reduction of up to $2.50 per barrel. As an example, modifications will be made to the upgrader during a maintenance turnaround in 1993 that will boost production capacity to 68,000 barrels per day by 1994. Implementation of the plan means that employment levels will be gradually reduced. As the new mining method is introduced, employment will drop from 2,400 to about 2,000.

Project Cost: Not disclosed

SUNNYSIDE PROJECT – Amoco Production Company (T-200)

Amoco Corporation is studying 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. The pilot demonstrated that tar sands could be concentrated by selective flotation from 8 percent bitumen as mined to a 30 to 40 percent richness.

SYNTHETIC FUELS REPORT, MARCH 1993
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

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 (CSMRI) 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, Texas 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 canceled by Congressional action before giving any financial assistance to the project. 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.

As of 1992, GNC is still looking for financial partners, however, little progress has been made since the 1980's.

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 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 is 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.

The plant would be built at Sunnyside, Utah, near the City of Price.

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 Synco 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. Synco holds process patents in the U.S., Canada and Venezuela and is looking for a company to joint venture with on this project.

Project Cost: $350 million

SYNCRUDE CANADA, LTD. — Esso Resources Canada (25.0%); Petro-Canada Inc. (12.0%); Alberta Oil Sands Equity (16.74%); Alberta Energy Company (10.0%); PanCanadian Petroleum Limited (10.0%); Gulf Canada Resources Ltd. (9.03%); Canadian Occidental Petroleum Ltd. (7.23%); HBOG - Oil Sands Ltd. Partnership (Amoco Canada Petroleum Company Ltd.) (5.0%); Mitsubishi Oil Company (5.0%)(T-230)

Located near Fort McMurray, the Syncrude surface mining and extraction plant produces 165,000 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-buckethwheel reclaimer-conveyor systems; oil extraction with hot water flotation of the ore followed by dilution centrifuging; and upgrading by
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

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.

In 1990 production operating costs were about C$16 per barrel. Syncrude Canada Ltd. produced 11 percent of Canada's crude oil requirements in 1990.

In 1992, Syncrude announced that it is seeking approval from the Alberta Energy Resources Board (ERCB) to increase output by 28 percent. In addition, Syncrude is planning a C$4 billion, expansion of its oil sands operation.

Syncrude is requesting five amendments to its current ERCB approval:

- An annual production increase to 217,000 barrels per day of marketable hydrocarbon for the existing plant
- An extension to December 31, 1997 to begin construction of new facilities that would allow production to be increased to 250,000 barrels per day
- An extension of Syncrude’s production period to December 31, 2025
- The ability to process bitumen from off-lease sites and to ship bitumen from Mildred Lake to other processing operations
- The ability to use new technology, developed by Syncrude, for future mining and reclamation plans

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 and drilled over 34,000 feet of horizontal boreholes up to 2,000 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. However, only straight upward slanting holes are being drilled. Three Star estimates the Upper Siggins still contains some 35 million barrels of oil across the field.

The initial plans call for drilling one to four levels of horizontal boreholes. The Upper Siggins presently has 34 horizontal wells which compose the 34,000 feet of drilling.

Sixty percent of the horizontal drilling was completed by late 1990. Production was put on hold pending an administrative hearing to determine whether the mine is to be classified as gaseous or non-gaseous. The project was later classified as a gaseous mine due to the fact that the shaft penetrated the oil reservoir. As a result of the ruling, Three Star then drilled a vertical well to the underground sump room and began producing the mine conventionally with all the horizontals open. In 1992, Three Star will begin reworking the surface wells for injection purposes in order to pressure up the Upper Siggins.

Project Cost: Three Star budgeted $3.5 million for the first shaft.

WOLF LAKE PROJECT – Amoco Canada Petroleum (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 and 1,147 cubic meters per day in 1990. Continuing the trend, 1991 will see an average production rate of 1,167 cubic meters per day.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

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.

In early 1989, BP Canada and Petro-Canada delayed by 1 year the decision to start up the second phase. While the Wolf Lake 2 plant was commissioned in 1990, full capacity utilization of the combined project is not likely before the late 1990s when it is expected that higher bitumen prices will support the expanded operation and further development.

The new water recycle facilities and the Wolf Lake 2 generators are operational. Production levels will be maintained at 600 to 700 cubic meters per day until bitumen netbacks have improved. The Wolf Lake 2 oil processing plant and Wolf Lake 1 steam generating facilities have been suspended.

In September 1989, Wolf Lake production costs were reported to be almost C$22 per barrel, while bitumen prices fell to a low of C$8.19 per barrel in 1988. BP initiated a program to reduce Wolf Lake costs, which included laying off 120 workers, making improvements in process efficiency, and operating the plant at about 50 percent of capacity. These economic measures cut operating costs to C$10 to 12 per barrel.

In 1991, Wolf Lake production costs were less than $9 per barrel, and bitumen production averaged 4,225 barrels a day.

In early 1992, BP Canada and Petro-Canada sold their entire interests in the project to Amoco Canada Petroleum. No price was disclosed but both companies have written off their total $370 million investment in the project.

Project Cost:  
Wolf Lake 1  
$114 million (Canadian) initial capital  
(Additional $750 million over 25 years for additional drilling)

Wolf Lake 2  
$200 million (Canadian) initial capital

YAREGA MINE-ASSISTED PROJECT — Union of Soviet Socialist Republics (T-265)

The Yarega oilfield (Soviet Union) is the site of a large mining-assisted heavy oil recovery project. The productivity 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. In 15 years, 10 million tons of steam have been injected into the reservoir.

Three mines have been operated since 1975. 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. Construction of 4 new shafts is expected to bring production to over 30,000 barrels per day. Forty-one million barrels of oil were produced during the period 1975-1987. 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 pilot project began operation in December, 1981. The 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; and determine key performance parameters.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

The operator of the Athabasca In Situ Pilot Project is Husky Oil Operations Ltd. In 1990 three patterns were being operated: one 9-spot and two 5-spots. The central well of each pattern is an injector. Eight 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, according to Husky.

In 1990 the project passed the one million barrel production mark and at the end of January 1991 the project entered its final, winddown phase. The winddown phase consists of reducing the central steam injection to zero and continuing to produce until the end of April 1991. The project was shut down at the end of April 1991, after a majority of the technical objectives had been met.

In July 1991, all production, injection and observation wells were abandoned and the central facilities mothballed.

Project Cost:  Capital $54 million, operating $73 million

BATTRUM IN SITU WET COMBUSTION – Mobil Oil Canada, Unocal Canada Limited, Saskoil, Hudson's Bay Oil and Gas (T-280)

Mobil Oil Canada initiated dry combustion in the Batrum field, near Swift Current, Saskatchewan, in 1965 and converted to wet combustion in 1978. The combustion scheme, which Mobil operates in three Batrum 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. There are presently 18 burns in operation.

All burns have been converted to wet combustion and the air injection rate is 25 million cubic feet per day. Studies have been initiated to determine the feasibility of oxygen enrichment for the EOR scheme.

BUENAVENTURA COLD PROCESS PILOT— Buenaventura Resource Corp. (T-287)

Buenaventura Resource Corporation owns the exclusive license to use a patented process to 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.

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 was shipped to Utah in the fall of 1990 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.

CARIBOU LAKE PILOT PROJECT – Husky Oil Operations Ltd. (60 percent) and Alberta Energy Co. (40 percent) (T-310)

Husky Oil Operations Ltd. and Alberta Energy Co. 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.

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.

Construction at the Caribou Lake Pilot Project was completed in early 1991 and the operations phase of the project was begun. The Pilot consists of 25 cyclic steam/production wells, 75 MMBTU/hour steam generation capacity and associated oil treating and produced water clarification facilities. The total average output of the project was expected to be 1,200 barrels of heavy oil per day.

In 1992 the Caribou Lake Project was suspended indefinitely.

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 5-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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

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. Operations were suspended in 1988-89.

Production in the Celtic Multizone Test, an expansion of the Heavy Oil Pilot, consisting of 16 wells on 20 acre spacing, commenced with primary production in September, 1988. First cycle steam injection commenced May, 1989. This test operation is now part of the total Celtic field operation.

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 4th meridian.

The scheme would involve dredging of a cutoff meander in the Horse River some 900 meters from the Fort McMurray 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 was suspended in 1990 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.

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 fourteen single wells in 1988. Various zones have been 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 [see Iron River Pilot Project (T-440)] was constructed with operations beginning in March, 1988. To date, steam stimulation tests have been conducted in a total of 14 vertical wells.

Five vertical wells, all multizone completions, were still in operation in 1991; the remaining wells were suspended at the conclusion of their testing programs. No further steaming of the single wells is planned. A single zone, conduction assisted steam stimulation in a horizontal well began in mid-1989. This test was still operating in 1990.

Project Cost: Not disclosed

DONOR REFINED BITUMEN PROCESS - Gulf Canada Resources 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.

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STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

ASVAI-IL is a joint venture of three French companies—Elf Aquitaine, Total-Compagnie Francaise de Raffinage, and Institut Francaise du Petrole. The ASVAI-IL 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

EYEHILL IN SITU COMBUSTION PROJECT – Canadian Occidental Petroleum, Ltd., C.S. Resources Ltd. and Murphy Oil Company Ltd. (T-390)

The experimental pilot is located in the Eeyehill 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.

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 after 1988.

Production in 1990 continued at 500 barrels per day. The air compressors supplying combustion air were shut-in in June 1990.

Three horizontal wells were drilled in 1992, with one inside the fireflood boundaries. Production from the project peaked at 1,300 barrels per day.

Project Cost: $15.2 million

FORT KENT THERMAL PROJECT – Koch Industries and Canadian 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 converted from 1984 through 1988. Eventually most of the project will be converted 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 drilled. 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 1988 is approximately $35 million (Canadian).

In January 1989, it was announced that the project would be indefinitely suspended.

Project Cost: See Above

FROG LAKE PILOT PROJECT—Texaco Canada Petroleum (T-405)

The Frog Lake Lease is located about 50 miles northwest of Lloydminster, Alberta in the southeastern portion of the Cold Lake Oil Sands deposit. The lease contains a number of heavy oil producing horizons, but primary production rates are generally restricted to less than 5 cubic meters per day per well due in large part to the high viscosity of the oil.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

During the 1960's steam stimulation treatments were carried out on several wells on the Frog Lake lease but based on these tests it was concluded that conventional thermal recovery methods using steam are hampered by the thermal inefficiency associated with the thin sands.

In 1991 Texaco began preparing to apply electromagnetic heating to stimulate three Lower Waseca wells at Frog Lake. The wells were placed on production in late November 1990 and electromagnetic heating was scheduled to commence by mid-1991.

Upon completion of the tests in 1993 it is expected there will be sufficient data available to develop reliable economics for a commercial project. A reservoir simulator will be used to history-match test results and make predictions of production rates and ultimate recovery for various well patterns and spacing.

GLISP PROJECT – Amoco Canada Petroleum Company Ltd. (14.29 percent) and AO&FRA (85.71 percent) (T-420)

The Gregoire Lake In-Situ Steam Pilot (GLISP) was an experimental steam pilot located at Section Z-66-7W. Phase B operations were terminated in July 1991 due to financial limitations. Petro-Canada had participated in Phase A of the project, but declined to participate in Phase B which was initiated in 1990. The lease is shared jointly by Amoco and Petro-Canada. Amoco is the operator.

The GLISP production pattern consisted of a four spot geometry with an enclosed area of 0.28 hectares (0.68 acres). The process tested the use of steam and steam additives in the recovery of high viscous bitumen (1x10 million eP at virgin reservoir temperature). Special fracturing techniques were tested. Three temperature observation wells and seismic methods were used to monitor the in-situ process.

The project began operation in September 1985. Steaming operations were initiated in October 1986 to heat the production wellbores. A production cycle was initiated in January 1987 and steam foam flooding began in October 1988. Foam injection was terminated in February 1991. Steam diversion using low temperature oxidation was tested between April and July 1991. Operations at GLISP were suspended July 18, 1991.

Project Cost: $26 million (Canadian)

HANGINGSTONE 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 May 1, 1990. On September 4, 1990, Petro-Canada announced their official opening of the Hangingstone Steam Pilot Plant.

The production performance of the first cycle was said to be below expectations because of severe steam override. Cold bitumen influx into the wellbore also caused severe rodfall problems and pump seizure. Startup of 2 of the 13 Wells will be delayed until the in situ stresses are more favorable for the creation of a horizontal fracture system.

Some of the pilot wells are now in their fourth production cycle.

The Group owns 34 leases in the Athabasca oil sands, covering 500,000 hectares. Most of the bitumen is found between 200 and 500 meters below the surface, with total oil in place estimated at 24 billion cubic meters.

The Hangingstone operations are expected to continue until the end of 1992. According to Petro-Canada, total expenditures will reach $160 million by 1993. Expansion to an enlarged pilot operation or a semi-commercial demonstration project could result if the current project is deemed successful.

IMPERIAL COLD LAKE PILOT PROJECTS – Imperial Oil Resources Limited. (T-380)

Imperial operates two steam based in situ recovery projects, the May-Ethel and Laming 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 Lease No. 40. Imperial has sold data from these tests to several companies. The Laming pilot is located in Sections 4 through 8-65-3W4. The Laming pilot uses several different patterns and processes to test future recovery potential. Imperial expanded its Laming 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 3,100 cubic meters (about 19,500 barrels) per day of bitumen.

The pilots have been used for testing a variety of recovery, production and facilities technologies.

They continue to 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.

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STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

(Also see Cold Lake in commercial projects listing)

Project Cost: $260 million

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 and 3 observation 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 since 1988 and is expected to continue operation until 1992.

Project Cost: $14 million

KEARL LAKE PROJECT – See Athabasca In Situ Pilot Project (T-270)

LINDBERGH STEAM PROJECT -- Murphy Oil Company, Ltd. (T-470)

This experimental in situ recovery project is 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 continued. Production rates from the seven-spot area were encouraging, 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 capital, $2.5 million per year operating

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 (CTD) by reducing enrichment to 80 percent oxygen.

In the second year of CTD, further oxygen breakthrough was controlled by stopping injection, then injecting air followed by 50 percent O2. Lack of production response and corrosion caused the pilot to be shut in in mid-1990.

Project Cost: $22 million

MINE-ASSISTED PILOT PROJECT – (see Underground Test Facility Project)
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

MORGAN COMBINATION THERMAL DRIVE PROJECT -- Amoco Canada Petroleum Company Ltd. (T-490)

Amoco (formerly Dome) completed a 46 well drilling program (7 injection wells, 39 production wells) 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. All of the nine patterns have been ignited and are being pressure cycled using air injection.

A change of strategy with more frequent pressure cycles and lower injection pressure targets was successful for pressure cycle four. This strategy will be continued with pressure cycle five scheduled for this year. A conversion to combination thermal drive is still planned after pressure cycling becomes unfeasible due to longer repressuring time requirements.

The project started up in 1981 and is scheduled for completion in 1995.

Project Cost: $20 million

ORINOCO BELT STEAM SOAK PILOT—Maraven (T-500)

The Orinoco Belt of 54,000 km² was divided into four areas in 1979 to effect an accelerated exploration program by the operating affiliates (Corpoven, Lagoven, Maraven and Meneven) of the holding company Petroleos de Venezuela (PDVSA).

Maraven has implemented a pilot project in the Zuata area of the Orinoco Belt to evaluate performance of slant wells, productivity of the area, and well response to "Huff and Puff" steam injection in relation to a commercial development.

Twelve inclined wells (7 producers and 5 observers) have been drilled in a cluster configuration, using a slant rig with a well spacing at surface of 15 meters and 300 meters in the reservoir.

The 7 production wells, completed with openhole gravel packs, have been tested prior to steam injection at rates between 30 BPD and 200 BPD using conventional pumping equipment. Five wells have been injected, each with 10,000 tons of steam distributed selectively over two zones. After an initial flowing period, stabilized production on the pump averaged 1,400 BPD per well with a water cut of less than 3 percent.

With the information derived from the exploration phase, it was possible to establish an oil-in-place for the Zuata area of 487 billion STB.

PELICAN LAKE PROJECT -- CS Resources Limited and Devran Petroleum Ltd. (T-510)

CS Resources 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 (a horizontal record) was accomplished in December 1989 and January 1990. Four more horizontal wells were drilled in 1991 for a total of 17 horizontal wells.

All four 1991 wells contacted almost 100 percent of good quality reservoir throughout the horizontal section. The horizontal section of one well was 1,321 meters from intermediate casing point to total depth. A 496 meter lateral arm was completed off the horizontal section of a 1,137 meter main hole section. One "J" well was a limited success with a horizontal section of 907 meters.

The average drill, case and completion cost of the 1991 wells was $540,000. The wells took an average of 7.5 days to drill with the average horizontal section being 1,290 meters. The cost per horizontal meter has dropped from $1,240 per meter in 1988 to $420 per meter in 1991.

Special effort was made to keep the drilling program simple and cost-effective. A surface casing was set vertically at 110 meters, then the wells were kicked off and inclination was built gradually to 90 degrees at a rate of two degrees/10 meters. An intermediate casing was run and cemented before horizontal drilling commenced in the sand reservoir. Early production rates averaged 15 to 20 cubic meters per day, three to six times average vertical well figures. Four wells, drilled in 1988, rapidly produced with a disappointing, and unexpected high water cut, whereas no bottom water is known to exist in this particular area. However, the two subsequent horizontal wells have not had any free water problems.

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STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

Sand production has not been a major problem and the production sand content is lower than in surrounding vertical wells.

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. The remaining wells stayed 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 converted to steamflood in fall 1987.

In May 1989 all thermal operations had been terminated. The wells were abandoned with the exception of 13 wells that remain producing on primary production.

The use of horizontal wells is being tested. In 1991, an additional eight horizontal wells were drilled to about 1,000 meters in length.

Project Cost: Not Specified

PROVOST UPPER MANNVILLE HEAVY OIL STEAM PILOT – AOSTRA, Canadian Occidental Petroleum, Ltd., Esso, Resources Canada Ltd., Murphy Oil, Noreen Energy Resources Limited (T-530)

Noreen 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.

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.

The project was designed to be operated in four stages. The first stage was to place the wells on primary production, next to begin multicyclic steam stimulation, followed by a steam drive and finally a heat scavenging waterflood. The project was estimated to last approximately 10 years. The time frame for these four phases being:

- Mar/85 - Fed/86: Primary Production
- Apr/86 - Jun/89: Cyclic Steam Stimulation
- Jul/89 - Dec/92: Steam Drive
- Jan/93 - Dec/94: Heat Scavenging Waterflood

Overall, the cyclic production performance had an average incremental recovery of 17 percent over the three-year cycle phase. The average calendar day oil rates were slightly less than the 11.9 cubic meters per day originally forecast with oil steam ratios higher than the 0.55 forecast.

The next phase of the pilot is to follow-up the four cycle steam stimulation phase with a steam drive by way of continuous injection into the central well. Performance thus far has been encouraging with production being equal to or better than forecast and slightly higher than at the end of the cyclic phase. The steam drive performance in 1991 and 1992 will be important in determining the ultimate recovery process and pattern size to be chosen for the pool.

Project Cost: $14 million capital, $2.5 million per year operating
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 claims the advantages of high recovery of bitumen, low water requirements, acceptable environmental effects and low 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 totaling $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)

SOARS LAKE HEAVY OIL PILOT - Koch Exploration Canada 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. The project is designed to test cyclic steam simulation process.

Amoco Canada had been actively evaluating the heavy oil potential of its Soars Lake leases since 1965 when the company drilled two successful wells. 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 voidage in the reservoir prior to any further steam stimulations.

Further to extending the production cycle of the original pilot wells, Amoco Canada began testing the primary production potential of Soars Lake with six new wells drilled in June 1991.

In 1992 the project was transferred to Koch Exploration Canada.

Project Cost: $40 million

STEEP BANK PILOT PROJECT – Chevron Canada Resources (T-40)

Chevron Canada Resources has started a new pilot project utilizing the HASDrive (Heated Annulus Steam Drive) process to recover bitumen from the Athabasca Oil Sands. The pilot plant is located on Chevron's Steepbank oil sands lease located about 30 miles northeast to Fort McMurray, Alberta, Canada.

In the HASDrive process, a horizontal wellbore is drilled into the oil sands formation. Steam is circulated in the cased wellbore thereby transferring heat into the oil sand. Two vertical injection wells are used to inject steam into the formation at points along the heated horizontal channel (annulus), driving the heated bitumen toward a production well placed between the injection wells.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

The pilot includes two steam injection wells, one producing well, one horizontal HASDrive well, six temperature observation wells and four crosshole seismic wells.

Operations commenced November 1, 1991 with steam circulation in the horizontal well. Steam injection and production were both under way by March 1992.

Project Cost: $12.7 million

TACIUK PROCESSOR PILOT – AOSTRA and The UMA Group Ltd. (T-610)

AOSTRA has built a pilot for 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 UMATAIC 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 AOSTRA Taciuk Processor (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.

A comparable demonstration scale project is being considered 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 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 1993 or later. (See Stuart Oil Shale Project in oil shale status section).

A third area of application of the technology has been developed in the past 7 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 SoilTech, Inc. which is the United States licencee for the use of the technology in waste treatment. This plant has successfully treated 42,000 tons of PCB contaminated soil to remove the PCB contaminant. The removal treatment was by chemical dechlorination within the ATP unit and met standards of 2 ppm or less PCB for the remediated soil.

The 10 ton/hour soiltech plant is presently committed for use at the Waukegon Harbor Superfund site in Illinois. This is also a PCB treatment project, for the extraction of PCBs from 17,000 cubic yards of drained harbor slits.

In February 1991, AOSTRA commissioned the construction of a 5 ton per hour portable unit for use in Canada. It will to be available in the summer of 1992 to demonstrate oil production from tar sands and cleanup of oily waste sites in Canada.

Project Cost To Date: C$24 million (AOSTRA)

TANGLEFLAGS NORTH – Sceptre Resources Limited and Murphy Oil Canada 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 provided $3.8 million in funding under the terms of the Canada-Saskatchewan Heavy Oil Fossil Fuels Research Program.
R & D PROJECTS (Continued)

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 pilot 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. The expansion of the pilot project into a commercial operation involving up to 14 horizontal wells will hinge on future crude oil prices.

The strong performance of the initial well prompted Sceptre to initiate a project expansion which was completed during 1992. For this purpose a second horizontal producer well and an additional vertical injector well were drilled in the fourth quarter of 1990. Facilities were expanded to generate more steam and handle increased production volumes in early 1991. During 1992, two steam injectors were added and a third steam generator was brought into service. A peak project rate of 2,800 barrels per day was achieved in January 1993, and cumulative oil production reached 2,257 million barrels. As of mid-February 1993, an additional steam injector and another horizontal well had been drilled. The project now includes three horizontal producers and eight vertical steam injectors.

Project Cost: $13 million invested to 1993

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 southern 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 has been put on temporary hold.

Project Cost: Unknown

UNDERGROUND TEST FACILITY - 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., Japex Oil Sands Ltd., China National Petroleum Corporation (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 600 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 was to continue producing in a blowdown phase until the fall of 1990.

Both tests were 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 consists of three pairs of horizontal wells, with completed lengths of 600 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
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1992)

R & D PROJECTS (Continued)

5 meters above the producer. All six wells were successfully drilled in 1990/1991. The contractual obligations for Phase B operations will be completed by 1994. It is expected that Phase B will continue operation until 1996. Phase A produced over 130,000 barrels of bitumen.

Phase B steaming commenced in September 1991, then was shut-in temporarily to construct larger facilities. Production was slated to begin in December 1992. A decision regarding expansion to commercial production will be made after this period. Two thousand barrels per day of bitumen are expected to be produced by this method.

AOSTRA states that this new method of bitumen production is starting to look like a major technological breakthrough and that bitumen may eventually be produced for under C$7 per barrel, which would be less costly than most current in situ bitumen production.

In 1992 an agreement was reached with Syncrude Canada to process up to 2,000 barrels per day of bitumen through Syncrude's nearby upgrading facilities.

Project Cost: $150 million
## COMPLETED AND SUSPENDED PROJECTS

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GREAT PLAINS PRODUCTION REVENUE CONTINUES TO LOOK GOOD

Basin Electric Power Cooperative's 1992 Annual Report reported production milestones and excellent revenue for the Great Plains Synfuels plant. According to K. Janssen, Dakota Gasification Company (DGC) vice president, the purchase of the Great Plains Project in 1988 offered two continuing advantages for Basin Electric: a monthly benefit of more than $4 million to members as a result of the plant's continued operation and rights to the remaining half of the coal reserves at the Freedom Mine.

With about 500 million tons of lignite reserves, Freedom Mine can supply the synfuels plant and Antelope Valley Station with low-cost fuel well into the 21st century, he added.

As of March 1, the coal royalty on lignite mined from a federal tract at Freedom Mine was reduced from 12.5 percent to 2 percent. That reduced the 1992 production cost by $2.6 million or about $0.18 per ton, making coal from the mine less expensive, Janssen said. Fuel costs represent a significant part of the overall operating costs for DGC and Basin Electric.

In total, the net profit for 1991 was nearly $13 million. Through the first 6 months of 1992, profits were about $7.8 million, compared to $6.1 million for the same period in 1991. Since 1988, the plant has earned about $70 million in profits.

Those profits were achieved because good operations held down production costs. The plant established a new daily production record of 172 million standard cubic feet per day (mmcf/d) in December 1991. The plant averaged nearly 160 mmcf/d in 1992, compared to less than 150 mmcf/d in previous years. Almost all of the high production months have come in the past year as illustrated in Figure 1.

**FIGURE 1**

**GREAT PLAINS PROJECT 10 BEST PRODUCTION MONTHS**

(Natural Gas Monthly Averages)

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**SOURCE: BASIN ELECTRIC POWER COOPERATIVE**
Those figures are impressive, making the plant a financial and technological success in its first 4 years under DGC. However, Janssen said those achievements have to be tempered by several unknowns. Those uncertainties include volatile natural gas prices, gas contract disputes, and environmental compliance.

Prices have rallied from the lows of February 1992 and are expected to remain up for the winter. However, wellhead prices are projected to be below DGC's cost into the foreseeable future. Therefore, the gas contracts continue to be of great importance to the Great Plains project's future.

DGC and the United States Department of Energy (DOE) continue to press their lawsuit against the four pipeline companies that purchase the plant's output under long-term contracts. The lawsuit, brought in 1990, seeks a ruling as to the quantity of gas the pipelines are required to take. Additionally, DGC maintains that the pipeline companies have understated natural gas prices since July 1989, resulting in the prices paid DGC being lower than they should have been.

DGC is still working with the North Dakota State Department of Health in correcting the environmental deficiencies at the synfuels plant. DGC is proposing to install a wet scrubber to reduce sulfur dioxide emissions at a cost of about $100 million.

Last November, the National Park Service formally published its preliminary finding of no adverse impact in connection with a proposal to install a wet scrubber to reduce sulfur dioxide emissions at the Great Plains Synfuels Plant. The findings are related to the federally mandated Prevention of Significant Deterioration of air quality Class I areas in Western North Dakota—Theodore Roosevelt National Park near Medora and Lostwood National Wilderness Area, west of Minot.

The Health Department was expected to hold public hearings on the proposed project in January.

In addition, DGC is negotiating with DOE regarding the terms and conditions of financial assistance in the capital cost of constructing the pollution-control facilities. Last year, Congress authorized DOE to make additional funds available from project trust fund monies because the environmental project is more expensive than DOE stated when DGC purchased the plant in 1988.

Because of these uncertainties, DGC is evaluating other areas of revenue, including the possible conversion of part of the synfuels plant to making liquid transportation fuels.

####
KENNECOTT BUYS CORDERO COAL MINE

In February, Kennecott Corporation and Sun Company, Inc., jointly announced that Kennecott agreed to purchase Cordero Mining Company from Sun Company for $120.5 million. The purchase, which is subject to government approval, is expected to be completed by the end of March.

This acquisition follows on the heels of Kennecott’s recent purchase of Nerco Inc., and its Powder River Basin coal properties. It positions Kennecott as a major coal producer with about 16 percent of the Powder River Basin’s coal production. Kennecott’s estimated combined coal production will be 32 million tons per year and the company’s total Powder River Basin coal reserves will be 1,019 million tons.

The Cordero Mining Company operates the Cordero Mine in Wyoming’s Powder River Basin. This open-pit operation is the seventh largest in the United States. Since it opened in 1976, the mine has produced 148 million tons of high quality, low sulfur coal. “The mine produced 13.3 million tons of coal in 1992, but the potential is there to increase production, at little cost, to 17 million tons per year,” according to Kennecott president, G.F. Joklik. With a reserve of 385 million tons, Cordero has an expected mine life of 28 years at current production rates. Over 60 percent of the production from Cordero is sold on long-term contracts to power companies in the Midwest and Texas.

####
DOE RECEIVES 24 PROPOSALS FOR CLEAN COAL ROUND V

The United States Department of Energy (DOE) received 24 proposals for projects for possible funding through the fifth and final scheduled round of the Clean Coal Technology (CCT) Demonstration Program, last December. Through its CCT Program, DOE joins with private industry sponsors to aid in the commercial demonstration of promising new coal use technologies. Projects are selected through nationwide competitions, and government funding for the projects is limited to half the total cost of each project. To date, four rounds of the program are under way and 41 projects are active or have been completed in the CCT Program.

This round of the competition is emphasizing super-clean, high efficiency coal-based systems. The 24 candidate projects have a total proposed cost of nearly $6.3 billion, with nearly $2.3 billion requested from the federal government. DOE will make up to $568 million in federal matching funds available for the projects selected in this round of the program.

According to J.G. Randolph, Assistant Secretary for Fossil Energy, the large amount of proposed private sector cost-sharing, nearly 64 percent, is the most of any CCT round to date and is indicative of industry's continuing support for the CCT Program.

DOE expects to announce its selection by May 6, 1993. A listing of the proposals for consideration is presented in Table 1.

TABLE 1
CLEAN COAL TECHNOLOGY ROUND V PROPOSALS

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<tr>
<th>Proposer</th>
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<th>Total Cost ($ in Millions)</th>
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<td>Air Products &amp; Chemicals, Inc.</td>
<td>Calvert City Advanced Energy Project</td>
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<td>AirPol, Inc.</td>
<td>Compact, Clean, Coal-Fired Combined Cycle Turbine</td>
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<td>The Babcock &amp; Wilcox Co.</td>
<td>Integrated Gasification Pressurized Fluidized Bed Demonstration Project</td>
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<td>Liquid Fuel - IGCC/Repowering</td>
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<td>Clean Power from Integrated Coal/Ore Reduction (COREX)</td>
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<td>Charfuel Coal Refining Project</td>
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<td>Dakota Gasification Co.</td>
<td>Liquid Transportation Fuels From Coal</td>
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<td>Duke Energy Corp.</td>
<td>Camden Clean Energy Demonstration</td>
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<td>Easton Utilities and Arthur D. Little, Inc.</td>
<td>Demonstration of Clean Coal Diesel Technology at Easton Utilities</td>
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<td>Energotechnology Corp. and ABB Energy Ventures, Inc.</td>
<td>Integrated, Advanced Steam Conditions Coal-Fired Power Plant Demonstration Project</td>
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<td>Energy Resources &amp; Logistics</td>
<td>Greenbrier Clean Coal Project</td>
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Table 1 (Continued)

<table>
<thead>
<tr>
<th>Proposer</th>
<th>Project Title</th>
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<tbody>
<tr>
<td>Leas Industrial Associates</td>
<td>225 BTU Clean Coal Gas from Gasifier Without Use of Manufactured Oxygen</td>
<td>Not in Abstract</td>
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<tr>
<td>Lin Technologies, Inc.</td>
<td>The Improved Lin SO\textsubscript{x}/NO\textsubscript{x} Removal and Waste Products Utilization</td>
<td>$5,679,700</td>
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<tr>
<td>MHD Development Corp.</td>
<td>Billings MHD Demonstration Project</td>
<td>$520,000,000</td>
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<tr>
<td>Midwest Power Systems Inc.</td>
<td>Des Moines Energy Center Advanced PCFB Demonstration Project</td>
<td>$309,696,000</td>
</tr>
<tr>
<td>Mohawk Environmental Svcs.</td>
<td>Not Provided in Public Abstract</td>
<td>Not in Abstract</td>
</tr>
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<td>M-C Power Corp.</td>
<td>Fuel Cell Demonstration on Coal Gas at Wabash River Facility</td>
<td>$42,575,378</td>
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<td>Pennsylvania Electric Co.</td>
<td>Warren Station Externally Fired Combined Cycle Demonstration Project</td>
<td>$146,438,000</td>
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<td>Tennessee Valley Authority</td>
<td>Coproduction Demonstration Project (Integrated Gasification Combined Cycle/Fertilizer)</td>
<td>$782,577,595</td>
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<td>ThermoChem, Inc.</td>
<td>Pulse Stabilized Atmospheric Fluidized Bed Combustor</td>
<td>$29,317,673</td>
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<td>University of Minnesota</td>
<td>University of Minnesota Power Efficiency Project</td>
<td>$241,712,336</td>
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<tr>
<td>West Virginia CLC Corp.</td>
<td>Demonstration of Coal Liquids, Char and Coke (CLCC) Mild Gasification</td>
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DOE TO FUND ADVANCED GAS TURBINE RESEARCH

Anticipating an expanded role for natural gas in 21st century electric power generation, the United States Department of Energy's (DOE) Morgantown Energy Technology Center in Morgantown, West Virginia, recently committed $7.5 million over the next 4 years for research and development of new advanced gas turbine systems. The funding will be provided to a consortium of universities and industrial sponsors under the direction of the South Carolina Energy R&D Center at Clemson University, Clemson, South Carolina.

The consortium will concentrate on potential "barrier issues" involving the technology. The work will undergird a program that could eventually entail more than $700 million in government and private funding, more than one-third expected from industry.

"For utility powerplants, advanced turbine systems could result in 60 percent or higher efficiencies, a 50 percent improvement over present-day industry averages and a 15 percent improvement over state-of-the-art gas turbine systems," according to J.G. Randolph, DOE's Assistant Secretary for Fossil Energy. "These efficiencies translate into fuel savings, and, as a result, fewer carbon dioxide emissions. It also may be possible to cut nitrogen oxide emissions in half from those predicted from the turbines now being readied for use in the latter part of this decade," Randolph added.

The 11 universities who have agreed to participate as research performers include:

- Brigham Young University
- Clemson University
Carnegie Mellon University
- Mercer University
- Purdue University
- University of South Carolina
- University of Tennessee Space Institute
- Texas A&M University
- Vanderbilt University
- Virginia Polytechnic Institute and State University
- West Virginia University

The consortium will be open to additional universities.

Each contributing $25,000 per year, four manufacturers have joined the consortium: Allison Gas Turbines, General Electric's Power Generating Department, Solar Turbines Inc., Westinghouse Electric Corporation's Power Generating Business Unit. Fluor Daniel, a major engineering and construction company, has also committed to join the group.

The South Carolina Energy R&D Center planned a call for proposals to the consortium's university members in February. A board of the consortium industry representatives will define the research topics, evaluate the proposals and select projects for funding.

###
ECONOMICS OF MOLTEN CARBONATE FUEL CELLS LOOK PROMISING

A study to evaluate the technical, financial and marketing factors associated with the development and commercialization of powerplants utilizing molten carbonate fuel-cell technology was conducted by Fluor Daniel, Inc. and Energy Research Corporation (ERC), and funded by the United States Department of Energy (DOE). The results of this study were presented in a paper by D.T. Barot, et al., at the Fifth International Power Generation Conference held in Orlando, Florida last November.

Fuel cell technologies have been under development for several years and are now approaching the point of commercial development. Fuel cells convert the chemical energy of fossil fuels directly to electrical energy at higher efficiencies than conventional power cycles, and therefore, offer the potential of producing power at low heat rates and environmental emissions in comparison to conventional power generation technologies.

This study evaluated two different fuel price scenarios, three different powerplant designs and two different plant startup dates. The powerplant designs evaluated were:

- A Phase I powerplant designed to accommodate the future addition of a coal gasification plant but fueled with natural gas throughout its operating life
- A phased construction powerplant operating on natural gas in Phase I and primarily on coal (with natural gas backup) in Phase II
- A stand-alone natural gas-fueled powerplant designed to exclusively operate on natural gas

The powerplants studied were based on ERC's internally reforming carbonate fuel cells, which are capable of using both coal-generated syngas and natural gas as fuel. The fuel-cell power blocks for the Phase I and stand-alone natural gas-fueled plants consisted of 18 clusters of carbonate fuel cells of 10 megawatts each. Each cluster consisted of four 2.5 megawatt modules comprised of 12 fuel-cell stacks of 300 cells each.

The coal gasification block was based on Kellogg Rust Westinghouse (KRW) fluidized-bed gasification technology with hot gas cleanup sulfur removal. In addition to the fuel-cell clusters, the power block for Phase II (coal phase) included a fuel gas expander.

The carbonate fuel-cell technology was assumed to be commercially available in the late 1990s. The earliest plant startup date assumed was January 1, 2000.

The overall efficiency of the three powerplants was determined and compared. The Phase I and stand-alone natural gas-fueled carbonate fuel-cell powerplants (CFCP) are more efficient than the coal gas-fueled CFCP plant, with overall higher heating value efficiencies of 56 percent versus 50 percent.

On a 1991 dollars per kilowatt basis, the capital cost of each powerplant is about $1,000 per kilowatt. The cost of electricity for the three powerplants for two different plant startup dates (years 2000 and 2010) is compared in Figure 1. For the year 2000 startup date, operation of either the stand-
alone natural gas plant or the Phase I plant is the preferred option because these modes of operation result in lower cost of electricity (COE) for the powerplant operation. For the year 2010 startup date, phasing of natural gas to coal after 5 years gives the lowest COE. This is due to the greater price advantage of coal over natural gas in later years (years 2010-2030). From these data, the authors conclude that the operation of the phased construction powerplant is more cost-effective than operation of either of the two other powerplants if a plant startup date of the year 2006 or later is assumed under the DOE high natural gas price scenario forecast.

Table 1 compares the results of this study with the results of studies evaluating competing technologies. SO₂, NOₓ, and CO₂ emissions for the carbonate fuel-cell powerplants are extremely low and efficiencies are high compared to competing technologies such as conventional Pulverized Coal (PC) and Gasification Combined Cycle (GCC). However, capital costs for the KRW coal gasification hot-gas-cleanup carbonate fuel-cell system are higher. The generation of large quantities of solid waste is also characteristic of a KRW hot-gas-cleanup gasification system. Additional studies targeting alternatives for lower capital-cost gasification processes and configurations may reduce the capital cost to a more competitive value.

According to a survey of 31 utilities, the most important fuel-cell characteristics are operation and maintenance cost, capital cost, efficiency and high availability which determine the COE for the powerplant. Therefore, the COE is of utmost importance. Although environmental factors currently play only a small role in dispatching existing plants, they are viewed as being an important future factor in the decision to consider using carbonate fuel-cell powerplant technology.

The use of the combined cycle is considered the most important competing technology. Slightly less important are Integrated Gasification Combined Cycle (IGCC), Humid Air Turbine and Gas Turbine technologies. Beyond the year 2010, when the price of gas relative to coal is expected to increase, IGCC should become a much greater competitor, say Barer, et al.

**Table 1**

<table>
<thead>
<tr>
<th></th>
<th>Phased Construction Natural Gas/Coal Gasification</th>
<th>Conventional PC Plant (99.5% Sulfur Removal)</th>
<th>GCC Plant (99% Sulfur Removal)</th>
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</thead>
<tbody>
<tr>
<td>Net Power Production (MW)</td>
<td>220</td>
<td>260</td>
<td>250</td>
</tr>
<tr>
<td>Fuel</td>
<td>High-Sulfur Bituminous Coal</td>
<td>High-Sulfur Bituminous Coal</td>
<td>High-Sulfur Bituminous Coal</td>
</tr>
<tr>
<td>Heat Rate (BTU/kWh)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(HHV)</td>
<td>6,040</td>
<td>9,800</td>
<td>8,800</td>
</tr>
<tr>
<td>(LHV)</td>
<td>5,440</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Capital Cost, $/kW**</td>
<td>960</td>
<td>2,030</td>
<td>1,500</td>
</tr>
<tr>
<td>CO₂ Emitted (lbs/MWH)</td>
<td>697</td>
<td>1,514</td>
<td>2,000</td>
</tr>
<tr>
<td>SO₂ Emitted (lbs/MWH)</td>
<td>0.00025</td>
<td>0.0061</td>
<td>0.3</td>
</tr>
<tr>
<td>NOₓ Emitted (lbs/MWH)</td>
<td>0.0097</td>
<td>0.092</td>
<td>5.9</td>
</tr>
</tbody>
</table>

*Coal operation only—Phase II
**January 1991 costs at a Chicago, Illinois location

SYNTHETIC FUELS REPORT, MARCH 1993
Conclusions

The authors conclude that carbonate fuel-cell powerplants show promise as an efficient means of power generation with minimal impact on the environment. Phased construction offers utilities the option of starting operation on natural gas with limited pre-investment for coal gas operation and switching to coal in the future with additional capital investment when economics are favorable. In addition, to maximize potential installation, carbonate fuel-cell powerplant development should initially concentrate on sizes in the 2 to 50 megawatt range using natural gas as fuel.

IGCASH CONCEPT COULD BE COMPETITIVE WITH NATURAL GAS

The performance and economic characteristics of Integrated coal Gasification Compressed-Air Storage with air Humidification (IGCASH) powerplants, were discussed in a paper by A. Cohn and M. Nakhamkin, presented at the Fifth International Power Generation Conference in Orlando, Florida last November. IGCASH is a stand-alone intermediate/base-load capacity coal-fired powerplant concept, characterized by extremely attractive capital costs and operating costs which rival even state-of-the-art natural gas fired combined cycle plants at currently low natural gas prices.

The main features of the IGCASH powerplant concept include:

- The gasification system, turboexpander train, humidifier, recuperator, and water heater (high temperature components) operate continuously 24 hours per day, independent of power requirements by the grid.
- The IGCASH compressor train is electrically connected to the turboexpander train, sized for the full turboexpander power capacity, and is driven by the turboexpander train when electrical energy is not required by the grid.

Compressed air storage of grid power has been commercially available for a number of years. The concepts of self-contained powerplants integrating the compressed air storage techniques with coal combustion (coal gasification and fluidized bed combustion) have been investigated in previous Electric Power Research Institute (EPRI) projects and found to have only marginal economic attractiveness. A revised concept in which the compressed air is humidified in a saturator offers much more attractive prospects, and is the concept behind the IGCASH process. Because of the humidification only about 60 percent as much air needs to be compressed compared to dry systems for a given power output. This greatly decreases the time and energy required for compression and the capital costs of the storage system.

Stand-alone compressed air energy storage concepts with air humidification and fired with natural gas are termed NGCASH. The NGCASH plant has been shown to be competitive in cost and heat rate compared to combined cycle plants and advantageous with respect to fuel supply requirements, as it can dispatch cyclically while using a steady lower flow of natural gas.

The configuration that would have a combination of coal gasification and natural gas-fired expanders is termed CASHING—Compressed Air Storage with Humidification Integrated (gasification) and Natural Gas. This CASHING plant has been found to be attractive economically over a wide range of natural gas prices and competitive with the best natural gas-fired combined cycle plants even at current low natural gas prices.

The schematic of a CASHING plant is presented in Figure 1. The plant consists of an IGCASH plant integrated with a separate reheat-turboexpander train fired with natural gas (NGCASH).

The major operating features of the CASHING plant are as follows:

- The IGCASH plant operates continuously at full load.
- During hours when power to the grid is not required, the IGCASH turboexpander train drives the compressor train and charges the underground storage with compressed air for later use by both units.
- Both IGCASH and NGCASH units provide power to the grid during dispatch hours.

Economics

Estimated bus-bar power production costs (BBPPC) (fixed charges on the capital investment plus fuel and water costs), mills per kilowatt-hour, of a CASHING plant as a function of NGCASH dispatching hours per day and natural gas fuel costs, dollars per million BTU HHV, are presented in Figure 2. The horizontal axis of the figure has six scales describing dispatch energy and hours supplied by the NGCASH cycle, the IGCASH cycle and the total CASHING plant. The assumed economic factors are shown in the insert on this figure. The most significant assumption in this figure is that the NGCASH and IGCASH components have equal power outputs (250 megawatts each). It should be noted, that higher NGCASH/IGCASH power ratios improve the
CASHING plant economics. BBPPCs of a similarly dispatched natural gas-fired combined cycle plant are also shown.

Parametrically estimated specific capital costs (SCC) are $1,000 per kilowatt for the IGCASH plant and $200 per kilowatt for the NGCASH plant. For a 500 megawatt CASHING plant consisting of a 250 megawatt IGCASH and a 250 megawatt NGCASH plant, the SCC is $600 per kilowatt.

According to Cohn and Nakhamkin, the major conclusion which should be derived from Figure 2 is that even at a low natural gas price of $2.00 per million BTU (HHV), estimated bus-bar power production costs of a CASHING plant are only slightly higher than that of a combined cycle plant over a full range of dispatch hours. The break-even natural gas cost is approximately $2.10 per kilowatt. This shows that the predominately coal-based CASHING plant can compete with a combined cycle plant even at currently low natural gas fuel costs. This conclusion conflicts with the common perception that coal gasification plants can compete with combined cycle plants only when natural gas costs are well above $4.5 per million BTU HHV.

One of the most important features of a CASHING plant is its insensitivity to an increase in fuel prices. As shown in Figure 2, at 4,000 megawatt-hours of energy produced by the NGCASH component, a fuel cost increase from $2.00 per million BTU to $4.50 per million BTU results in an increase of the BBPPC of approximately 12 mills per kilowatt-hour (from 30 mills/kWh to 42 mills/kWh) for the CASHING plant versus an increase of approximately 23 mills per kilowatt-hour (from 29 mills/kWh to 50 mills/kWh) for a combined cycle plant. Comparative analysis of the six horizontal scales of Figure 2 demonstrates the extraordinary dispatching flexibility of a CASHING plant:

- A CASHING plant allows a significant increase in the total dispatch energy as compared with a stand-alone IGCASH plant.
- As NGCASH dispatch energy increases, the CASHING plant total dispatch energy also increases.
- For a given NGCASH dispatch energy, a number of combinations of power and dispatch hours can be envisioned to suit a given utility’s requirements.
Figure 2

CASHING COSTS AS A FUNCTION OF NGCASH DISPATCHING AND NATURAL GAS COST

As it was emphasized above, higher NGCASH/IGCASH power ratios improve CASHING plant economics.

Status of Equipment Availability for IGCASH

The IGCASH and NGCASH concepts utilize the following major components:

- Reheat expander train
- Intercooled compressor train
- Air saturators
- Recuperator and feedwater heaters
- Underground air storage
- Storage of the heat of compression

Of these, the reheat expander train and the storage of the heat of compression require development prior to the commercialization of the CASHING process. The other components are all commercially available today. The authors believe that the equipment required for the CASHING plant will be available for any practically scheduled project.

The analysis presented in this report is based upon low pressure (LP) expander firing temperatures of 2,070°F and greater. Two reheat turbomachinery trains of nominal 150 megawatts and 350 megawatts with firing temperatures of 2,070°F are being developed by Westinghouse for the IGCASH cycle under contract to EPRI/Energy Storage and Power Consultants, Inc. Westinghouse will also develop cost and performance information for an LP expander based...
upon the SOlE gas turbine with its current firing temperature of 2,350°F, and with possible future improvement to 2,500°F.

Asea Brown Boveri (ABB) has state-of-the-art technology and is expected to provide turbomachinery for the IGCASH concept. Dresser-Rand is currently working on upgrading their turboexpander inlet temperatures to current combustion-turbine levels.

Several practical options exist for the storage of the heat of compression. These options involve direct storing of hot water generated in the intercoolers and aftercooler in pressure vessels, or using an intermediate heat transfer fluid for storage. The cost and complexity of the storage is directly related to the desired storage temperature. Rough estimates for these methods indicate that these storage methods are expensive, but still are economically justified.

Cohn and Nakhamkin conclude that the developed IGCASH concepts based on an advanced combustion turbine show high efficiency (heat rate of approximately 8,450 BTU per kilowatt-hour) and promise lower specific capital costs (approximately $1,000 per kilowatt-hour) in comparison to other powerplant concepts with coal gasification. The significant reduction in specific capital costs, as well as total operating costs, makes a predominately coal-based CASHING plant competitive with a natural gas fired combined cycle plant.

###

**TWO-STAGE DIRECT LIQUEFACTION ESTIMATES NOW AT $38 PER BARREL**

In 1990, Bechtel Corporation and Amoco Oil Company were awarded a contract by the United States Department of Energy (DOE) to update the design and economics of a commercial-size direct coal liquefaction plant for Illinois No. 6 bituminous coal, based on the two-stage coal liquefaction technology practiced at the Advanced Coal Liquefaction Research facility in Wilsonville, Alabama.

The primary objectives of this study are: to develop a baseline design supplemented with certain alternate processing options to reflect coal cleaning, reactor configuration, hydrogen manufacture, and processing of liquefaction bottoms; to generate cost estimates and assessment of economics; and to develop a modeling package to predict the various processes and operation changes on the overall plant material and utility balances, operating labor, capital cost and economics. A paper presented by S.K. Poddar, et al., at the Ninth Annual International Pittsburgh Coal Conference, held in October in Pittsburgh, Pennsylvania, discussed the capital costs and economics of a commercial-size plant.

The baseline design is based on a Wilsonville pilot plant run. A simplified block flow diagram for the overall baseline case is shown in Figure 1.

Six options to the baseline design were evaluated. The options included alternatives for:

- Coal cleaning method—jig (baseline), heavy media separation, spherical agglomeration
- Reactor configuration—catalytic-catalytic (baseline), thermal catalytic, catalytic-catalytic with vent-gas separator
- Vacuum bottoms processing—Rose-SR (baseline), fluid coking
- Hydrogen production—Texaco coal gasification technology (baseline), steam reforming of natural gas

In addition, a seventh option was included where a naphtha reformer was integrated into the naphtha upgrading scheme.

The overall plant cost for each plant was estimated by summing the estimated costs of:

- Major equipment
- Bulk materials
- Subcontracts
- Direct labor
- Distributables (indirect costs)

Capital cost estimates for each option are summarized in Table 1. The lowest capital cost is for Option 6, where hydrogen is produced by natural gas reforming.

The results of the economic analysis conducted by Poddar, et al., show that the baseline design case requires an equivalent crude oil price (ECOP) of $38.55. A 25 percent reduction in plant capital costs reduces the ECOP by $5.90 per barrel whereas a 25 percent reduction in raw material costs decreases the ECOP by $2.95 per barrel. Other results of sensitivity analysis are shown in Table 2 (page 4-14).

For the best optional case, where hydrogen is generated by natural gas reforming, the crude equivalent price is $36.00 per barrel. However, as expected, this case is more sensitive to natural gas price. A 25 percent increase in natural gas price would reduce its $2.55 per barrel advantage over the baseline case to only $0.65 per barrel.

Poddar, et al., conclude that further advancement is necessary to make the direct coal liquefaction process economical. Both capital costs and raw material costs significantly impact on the direct coal liquefaction economics. Effort should be
BYPRODUCT DEVELOPMENTS PROVE DISAPPOINTING AT GREAT PLAINS

Since the inception of the Great Plains Gasification Project in the early 1970s, it was realized that in addition to synthetic natural gas (SNG), a host of liquid and gaseous byproducts could be produced and sold. Some of these, such as sulfur and anhydrous ammonia would be produced initially because they could be produced as marketable products as such without requiring further purification and also were required...
TABLE 2
SENSITIVITY STUDIES

<table>
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<th>Item</th>
<th>Base Value</th>
<th>Change</th>
<th>Sensitivity Case</th>
<th>$/Bbl</th>
<th>Delta</th>
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<td>+2.35</td>
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<tr>
<td></td>
<td></td>
<td>+25%</td>
<td>44.45</td>
<td>+5.90</td>
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<td></td>
<td></td>
<td>-25%</td>
<td>32.65</td>
<td>-5.90</td>
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<td>Total Installed Capital, MM$</td>
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<td>+25%</td>
<td>44.45</td>
<td>+5.90</td>
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<tr>
<td>Coal, $/Ton</td>
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<td>+25%</td>
<td>41.45</td>
<td>+2.90</td>
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<tr>
<td>Natural Gas, $/MMBTU</td>
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<td>+25%</td>
<td>41.45</td>
<td>+2.90</td>
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<td>Raw Material Cost</td>
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<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Coal, $/Ton</td>
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<td>-25%</td>
<td>35.65</td>
<td>-2.95</td>
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<tr>
<td>Natural Gas, $/MMBTU</td>
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<td>-25%</td>
<td>35.65</td>
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<tr>
<td>Raw Material Cost</td>
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</tr>
<tr>
<td>Coal, $/Ton</td>
<td>20.5</td>
<td>+25%</td>
<td>40.85</td>
<td>+2.30</td>
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<tr>
<td>Natural Gas, $/MMBTU</td>
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<td>40.85</td>
<td>+2.30</td>
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<td>Syncrude Premium</td>
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<tr>
<td>Owner's Equity, %</td>
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<td>100%</td>
<td>42.20</td>
<td>+3.65</td>
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<tr>
<td>Feed/Product Price Escalation %/Year</td>
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<tr>
<td>Coal</td>
<td>3</td>
<td>4.6</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas</td>
<td>3</td>
<td>6.5</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Crude Oil</td>
<td>3</td>
<td>5.9</td>
<td>29.85</td>
<td>-8.70</td>
<td></td>
</tr>
<tr>
<td>Increased Liquid Yields, bbl/day</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Naphtha</td>
<td>19,195</td>
<td>+10%</td>
<td>36.00</td>
<td>-2.55</td>
<td></td>
</tr>
<tr>
<td>Light Distillate</td>
<td>7,803</td>
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<td>-0.65</td>
<td></td>
</tr>
<tr>
<td>Heavy Distillate</td>
<td>21,635</td>
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<td>-8.30</td>
<td></td>
</tr>
<tr>
<td>Gas Oil</td>
<td>13,310</td>
<td>+10%</td>
<td>37.65</td>
<td>-0.90</td>
<td></td>
</tr>
</tbody>
</table>

To date, the only facilities built since Dakota Gasification Company (DGC) acquired the plant are krypton/xenon and phenol/cresylic acids from crude phenol. Over the last several years, an evaluation of what facilities would be needed, market supply/demand situations, and preliminary economics for each potential byproduct was conducted. The prospect for each byproduct was discussed in a paper by D. Pollock, presented at the Opportunities in The Synfuels Industry Symposium held in Bismarck, North Dakota last August.

Argon

When the original plant was designed and built, a conscious decision was made not to provide for argon draw-off taps in the Air Separation Unit (ASU). This decision was made to reduce project capital costs and stay within project budget and schedule.
A study made by the original design/constructor in 1989 showed that to install argon taps, a one-train shutdown for 12 to 15 days would be required for each of the two ASUs. Economic calculations showed that there would be too great a loss in SNG revenue to justify these extended shutdowns. An estimate for cold box modifications and building the argon purification and storage facilities was in the range of $18 to $20 million to produce about 100 tons per day of argon.

Market research indicated in the late 1989 to early 1990 timeframe that the argon supply/demand was near equilibrium, and that the DGC production of 100 tons per day could probably be absorbed. Subsequently, a number of new large air separation plants were announced, each with argon production. The supply/demand picture has changed to where there is now a surplus of argon production available as well as in the near future. Thus, it does not appear that DGC will proceed further with plans for argon production.

Naphtha

A relatively small naphtha stream, about 600 barrels per day, is produced from the Rectisol unit. This is a very aromatic-rich naphtha with about 65 to 75 percent benzene, toluene and xylene (BTX). It also contains a myriad of other compounds in smaller concentrations, e.g., olefins, diolefins and organic sulfur compounds (mercaptans, sulfides, disulfides, carbon disulfide) to mention a few. As such, Rectisol naphtha is non-salable in its existing form for refinery blending or petrochemical use because of its rank odor.

Considerable effort was spent in 1990 to 1991 in trying to demonstrate that hydrotreating would work successfully on Rectisol naphtha. Pilot plant runs were finally terminated after an unsuccessful effort to find catalyst/reactor conditions that achieved both the necessary degree of sulfur and nitrogen removal with an acceptable catalyst life.

Simultaneously, a study was conducted to determine capital and operating costs for a nominal 1,000 barrel per day naphtha hydrotreater. Capital costs were estimated to be about $15 million.

The supply/demand price situation for BTX was also studied during this period. In late 1989 to early 1990, benzene was selling for about $1.50 per gallon. Currently the price is under $1.10 per gallon. With the United States Environmental Protection Agency (EPA) mandating a maximum of 1 percent benzene in gasoline blends, refiners are limited by how much benzene can be added to increase octave numbers. It became apparent that if Rectisol naphtha was successfully hydrotreated, it would have to be sold into the petrochemical market where there is much cyclicitiy in product pricing as well as demand.

Due to the unsuccessful process development effort, the small quantity of Rectisol naphtha produced and the current relatively low pricing of benzene, it was decided to table any further work on naphtha until the situation changed.

Tar Oil

Tar oil is a complex mixture of hydrocarbons and heteroatoms which is condensed from the gasifier outlet raw gas in gas cooling and separated from raw gas liquor in gas liquor separation. Tar oil is currently used as boiler fuel.

Tar oil can be defined as consisting of three different boiling range cuts as follows:

- Tar oil naphtha, 10 percent by weight tar oil (up to 365°F boiling range)
- Tar oil phenolics, 25 percent by weight tar oil (365 to 470°F boiling range)
- Tar oil creosote, 65 percent by weight tar oil (above 470°F boiling range)

Tar oil naphtha is similar to Rectisol naphtha but with a somewhat lower BTX content. It is produced at about 350 barrels per day and, when added to the 600 barrels per day of Rectisol naphtha, would give about 950 barrels per day of combined naphtha. Tar oil naphtha also contains the unsaturates and heteroatoms that would need to be removed before having an acceptable naphtha for sale. Tests on Rectisol and tar oil naphtha blends were also unsuccessful as far as achieving an acceptable catalyst life at low sulfur and nitrogen levels.

Tar oil phenolics is a complex mixture of phenol, cresol, xylene, neutral oils and tar bases. Preliminary process development work done to date suggests that phenol and cresylic acids in the tar oil fraction require additional processing steps to achieve the degree of purity required to meet customer acceptance.

The higher boiling fraction of tar oil could be sold as wood preservative or creosote. In order to enter the creosote market, it is necessary to meet product specifications and obtain EPA registration. Additional laboratory work was done to obtain a product as close as possible to the American Wood Preservative Association (SWPA) specifications for P-2 wood preservatives. An AWPA committee approved DGC’s creosote as an AWPA-approved product defined as lignite creosote in a 50 percent blend with coal tar creosote. An extensive series of stake tests done to prove the efficacy of DGC creosote have shown that it is a superior product at economic levels of usage in preventing wood deterioration from microbiological attack.

The final hurdle to be overcome was to obtain EPA registration under the Federal Insecticide Fungicide and Rodenticide Act (FIFRA). Coal tar creosote had gone through a lengthy...
Thus, the byproduct development program at Great Plains economics improve. If gas prices remain low and the plant currently not developed probably never will be until world generate some additional revenue. Those byproducts cur-

byproduct projects currently in operation will continue to perhaps byproduct development would not provide addi-

proceeded in earnest by DGC, did the realization come that opportunity existed in the development, marketing and sale of facilities, including process and product development, and the market forces that control supply and pricing factors. Only since development and marketing of byproducts proceeded in earnest by DGC, did the realization come that perhaps byproduct development would not provide additional revenues as originally conceived.

Thus, the byproduct development program at Great Plains has proven to be somewhat of a disappointment. Those byproduct projects currently in operation will continue to generate some additional revenue. Those byproducts currently not developed probably never will be until world economies improve. If gas prices remain low and the plant operates at a loss, one possible solution for future profitability is conversion to liquid products.

An alternative GCC air separation configuration is the inte-

rated case, in which a portion of the air is extracted from

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INTEGRATION OF OXYGEN SUPPLY INTO IGCC PLANT COULD SAVE 4% ON CAPITAL COST

The Canadian utility industry is expected to install an average of 3,000 to 4,000 megawatts of new electrical generating capacity each year between now and the turn of the century. Given Canada's abundance of inexpensive coal coupled with its drive toward a cleaner environment, many utilities are considering Gasification Combined Cycle (GCC) technology as their choice for future expansion. A key component of GCC technology is the supply of oxygen to the coal gasification unit. This oxygen supply is traditionally from a stand-alone cryogenic air separation plant. Recent work by the Linde Division of Praxair indicates the potential to reduce capital costs and increase net power output through integration of the oxygen plant with the GCC facility. This was discussed in a paper by Dr.P. Dreisinger and R.F. Drnevich presented at the 42nd Canadian Chemical Engineering Conference held last October in Toronto, Ontario, Canada.

Coal Association and Canadian Electrical Association studies concluded that the total capital requirements for Canadian GCC facilities ranged from $1,686 per kilowatt to $2,439 per kilowatt (Canadian). In each of these feasibility studies, considerable attention was devoted to the gasifier block and combined cycle block, because together, they account for over 60 percent of the total capital cost. Many GCC feasibility studies treat the supply of oxygen as a utility which is delivered via a black-box process called air separation. The oxygen plant constitutes a sizeable capital investment (6 to 10 percent) and represents a major internal consumer of electricity from the GCC facility. Thus, any improvements to air separation plant design which could lead to either reduced capital and/or reduced power consumption would have a positive impact upon the overall feasibility of a particular GCC project.

GCC Oxygen Supply Options

In designing the oxygen supply system for GCC facilities, two different air separation plant concepts should be considered. The base case design has its own air compressor train, air purification system, cryogenic distillation cold box and oxygen compressor. Waste nitrogen is vented to the atmosphere.

An alternative GCC air separation configuration is the integrated case, in which a portion of the air is extracted from
the gas turbine air compressor and used as feedstock to the air separation plant. Conventional air purification, cryogenic distillation and oxygen compression equipment are then used to produce the desired amount of oxygen for the gasifier.

In addition to utilizing oxygen, the integrated case also recovers waste nitrogen from the air separation plant which is compressed, saturated and returned to the gas turbine for expansion. This return nitrogen is required to make up for the loss of mass flow to the gas turbine associated with air extraction. Through returning the nitrogen, gas turbine power output is maintained at its maximum rated level.

Overall, integrated air separation plants have the potential to eliminate the need for a feed air compressor in return for installing a more expensive nitrogen compressor and saturation system. Also, because integrated air separation plants are operated at higher pressures (200 psia), they are volumetrically smaller than conventional air separation plants which are typically operated at 80 psia. As a result, it is possible to realize both capital and power savings with an integrated oxygen plant.

**IGCC Performance**

Linde determined that the capital cost for an integrated air separation unit was 10 percent less in comparison to the cost of a stand-alone oxygen plant. Even after taking into account capital associated with nitrogen compression and saturation equipment, the net savings were still in the range of 5 percent. In addition, there was also a net increase in power output of 2.5 to 3.0 percent from the overall GCC facility.

In terms of investment costs, Linde's integrated air separation plant study indicated an overall 2 to 4 percent reduction of total dollars per kilowatt capital requirements for the GCC project. While not overwhelming, this reduction is certainly a step in the right direction toward making GCC facilities more cost-competitive with conventional pulverized coal power generating facilities.

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COUPLED GASIFIER/FUEL CELL WITH HOT GAS CLEANUP SHOWS HIGH EFFICIENCY

Carbonate fuel cells have attributes which make them ideally suited to operate on coal-derived fuel gas; some new opportunities for improved efficiency have been identified in integrated coal gasification/carbonate fuel cells which take advantage of low temperature catalytic coal gasification producing a methane-rich fuel gas, and the internal methane reforming capabilities of Energy Research Corporation's carbonate fuel cells.

The improved efficiency is obtained by recycling waste heat and spent fuel from a carbonate fuel cell anode back to a low-temperature catalytic gasifier. This virtually eliminates the energy release within the gasifier (normally obtained by combustion) which is needed to maintain gasifier temperature and drive the gasification reactions.

Three conceptual 200 megawatt advanced integrated gasification/carbonate fuel-cell systems, developed under United States Department of Energy/Morgantown Energy Technology Center sponsorship by Energy Research Corporation in conjunction with Fluor Daniel and the University of North Dakota/Energy and Environmental Research Center, were discussed in a paper by G. Steinfeld, et al., presented at the 1992 Fuel Cell Seminar held in Tucson, Arizona November 29 through December 2.

The system configuration is shown in Figure 1. This high methane-producing gasification system was found to result in higher efficiencies and lower projected costs than a high hydrogen-producing gasification system.

Fuel gas is produced by low-temperature catalytic gasification of coal requiring steam and hydrogen which is recovered from the spent fuel leaving the fuel-cell anode. Gas cleanup can be carried out either hot or cold followed by fuel gas expansion which recovers energy for power generation.

Clean fuel gas enters the DC power block where it is partially consumed in the anode. Spent fuel leaving the anode is shifted prior to entering a Hydrogen Transfer Device (HTD) which separates hydrogen from recycle to the gasifier. The HTD is based on phosphoric acid fuel-cell technology being tested at Energy Research Corporation. Spent fuel gas lean in hydrogen leaves the HTD and enters a catalytic burner which combusts any remaining hydrogen, CO, or CH₄ with excess air. The products of combustion enter the cathode side of the fuel cell where CO₂ and O₂ are partially con-
sumed by the fuel-cell cathode reaction. The cathode exhaust goes to the Heat Recovery Steam Generator (HRSG) where steam is produced for use by the gasifier, moisturization step, and the bottoming cycle.

Three system cases were evaluated based on the described system configuration. One case was based on a K₂CO₃ recoverable gasification catalyst with a cold gas cleanup system. The second case was based on an alternate disposable catalyst using CaCO₃ as a gasification catalyst with cold gas cleanup. The third case was based on a disposable gasification catalyst using CaCO₃ + Fe with a hot gas cleanup system. Heat rates of 6,377 to 6,748 BTU per kilowatt-hour (HHV) were estimated for these systems with the hot cleanup system producing the lowest heat rate. Efficiencies of 50.6 to 53.5 percent higher heating value were projected, with the hot gas cleanup technology yielding the highest efficiency.

Experimental testing was conducted to evaluate the gasification catalysts used as a basis for the three system study cases. The alternate catalysts (CaCO₃ and CaCO₃ + Fe) were shown to have significantly lower activity than assumed in the system study case.

Steinfeld, et al., conclude that advanced gasification carbonate fuel-cell systems based on catalytic gasification offer the potential of higher efficiencies compared to conventional systems. Additional development and testing is required to realize this potential.

### PRE-TREATMENT CONCEPTS BEING STUDIED FOR DIRECT LIQUEFACTION

The problems associated with the use of coal-derived fuels as substitutes for petroleum fuels are primarily of economic origin. The factors which most adversely affect the cost of coal liquefaction are the cost of hydrogen, the slow reaction kinetics, the high operating severity, and the cost of the raw feedstock. Under a United States Department of Energy project to evaluate new concepts which may lower these costs, a cooperative effort between the University of Kentucky Center for Applied Energy Research, Consolidation Coal Company (CONSOL), Sandia National Laboratories, and LDP Associates is under way.

The focus of this cooperative program is to evaluate pre-treatment concepts for direct coal liquefaction. The concepts to be evaluated were discussed in a paper by G.T. Hager, et al., at the Ninth Annual International Pittsburgh Coal Conference held in Pittsburgh, Pennsylvania last October.

Five pre-treatment concepts will be evaluated in this study. The use of low-rank coals is emphasized in this project due to their low cost and ability to produce high-quality distillates. The final results of this project will be tested on a larger scale in the Pittsburgh Energy Technology Center generic bench-scale liquefaction unit.

**CO-H₂O Pre-Treatment**

The main objective of the CO-H₂O pre-treatment program is to develop a methodology for pre-treating coal under mild conditions based on a combination of existing processes which have shown promise in improving process economics. The specific objectives of the CO pre-treatment process development are:

- Enhanced liquefaction activity and/or selectivity toward products of higher quality due to chemical modification of the coal structure
- More reactive downstream products due to less oxidative crosslinking
- Overall improvement in operability and process economics due primarily to a reduction in oxygen content and, correspondingly, reduced hydrogen consumption

**Dispersed Catalysts**

In laboratory experiments to simulate two-stage liquefaction, the presence of dispersed catalysts in both stages has been shown to improve conversion and product selectivity for both subbituminous and bituminous coals. Dispersed catalysts have been shown to significantly improve coal dissolution, minimize retrograde reactions, reach maximum distillate yields and better hydrogen efficiencies.

In larger scale liquefaction plants, the use of subbituminous coal feedstocks have necessitated the use of a dispersed iron catalyst to allow processing or to increase conversion. More active catalysts, such as molybdenum are prohibited by cost considerations. However, compared to molybdenum and other metals, iron is a relatively poor hydrogenation catalyst.

Efforts to increase this activity will focus on two major areas. The reduction of the particle size will increase the surface area per unit weight of catalyst and will also allow the catalyst better access to the internal regions of the macromolecular coal structure.

In addition, the use of promoter metals to modify the catalyst composition has been shown to have potential for greatly improving catalyst activity. For example, the effectiveness of an iron catalyst can be greatly improved by the addition of small amounts of molybdenum, such that the com-
Combination has the same, or higher, activity than with much greater concentrations of molybdenum alone. Other research has shown that titanium can promote the action of molybdenum, leading to significant increases in distillate production.

**Solvent Dewaxing**

While paraffinic and other saturated hydrocarbons are known to be produced in the liquefaction process, they have been shown to be poor hydrogenation solvents. By removing the paraffinic fraction prior to recycle, the hydrogen donor capacity of the solvent may be improved.

Several methods have been utilized in the petroleum industry to reduce saturated hydrocarbons from process streams, including urea adduction and ketone dewaxing. Laboratory experiments conducted by CONSOL research and development have demonstrated the feasibility of applying these two techniques to coal liquefaction.

**Fluid Coking of Coal Liquefaction Vacuum Bottoms**

The problem of solids removal from coal liquefaction product streams has been addressed by a number of techniques including filtration, hydrodones, vacuum distillation, critical solvent deashing, antisolvent deashing, and coking of the liquefaction vacuum bottoms product.

According to the authors, fluid coking, or its variant Flexicoking, is a more suitable technology than delayed coking due to the lower pre-heat temperatures required. The application of this technique to vacuum bottoms has been tested with favorable results. Analysis of the coker tars indicate that they respond readily to hydrogenation to produce excellent hydrogen solvent donor components. This research indicated the possible advantages of coupling fluid coking and hydrogenation to produce an improved hydrogen donor solvent while eliminating the problem of solids rejection.

**Oil Agglomeration**

Removing the unreactive solids from the feed coal prior to liquefaction reduces the magnitude of the solids separation step, and, thereby, reduces associated product losses. Mineral matter or ash particles in the system erode valves, pipes, and pumps and tend to collect in areas of low turbulence, reducing vessel volume and causing plugging. Further, ash increases the system load by occupying reactor volume, requiring larger reactors for the same ash-free coal throughput. Therefore, removing the ash prior to liquefaction may result in significant improvement in process economics.

Oil agglomeration is a well known technique for removing mineral matter from coal fines. The technique utilizes the difference in surface properties of the coal and mineral matter. Coal particles are generally hydrophobic while most mineral matter is hydrophilic. By mixing an aqueous solution of finely divided coal with an appropriate oil the coal particles become coated with oil and agglomerate. Most mineral matter remains in the aqueous phase and is easily separated from the agglomerated coal by mechanical means.

The application of oil agglomeration to the coal liquefaction process has certain distinct advantages. The coal grinding necessary for liquefaction produces a low cost for oil agglomeration. Also, oil agglomeration selectively retains the pyrite with the coal, which can be desirable, given the catalytic activity associated with pyrite. Finally, the recycle oil can be used as the agglomerating oil.

The feasibility of the oil agglomeration process for coal cleaning has been demonstrated for bituminous and sub-bituminous coals, and lignites. Ash rejections of up to 67 percent and organic recoveries near 100 percent were achieved using coal liquefaction derived solvents as the agglomerating oil. The technology has been utilized at a 50 ton per day commercial plant to clean bituminous coal fines.

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**COMBINED PYROLYZER/CPFBC SHOWS PROMISE FOR COMBINED CYCLE APPLICATIONS**

Coal-fired combined-cycle power generating systems have the potential for lower emissions and a lower cost of electricity (COE) than do conventional coal-fired steam cycles. Several coal-fired combined cycle systems are under development which use a Circulating Pressurized Fluidized Bed Combustor (CPFBC). A concept for an advanced coal-fired combined-cycle power generating system is currently being developed under United States Department of Energy (Pittsburgh Energy Technology Center) sponsorship. This high temperature advanced furnace (HITAF) system was discussed in a paper by J. Shenker and R. McKinsey, presented at the International Power Generation Conference held in Atlanta, Georgia last October.

The goal of the project is to develop a system that has an efficiency of at least 47 percent (based on the higher heating value of coal-fired) and a COE that is a minimum of 10 percent lower than a modern coal-fired plant conforming to new source performance standards. Emissions of NOx and SO2 are each to be no more than 0.15 pound per million BTU of fuel heat input; particulates are not to exceed 0.0075 pound per million BTU of fuel heat input. The initial system design must be capable of 65 percent heat input from coal, with an ultimate goal of 95 percent heat input from coal.
Process Description

A simplified process block flow diagram of the HITAF system is shown in Figure 1. The HITAF system differs from other pyrolysis-based systems primarily in the areas of char combustion and the transfer of heat to the gas cycle. In the HITAF system, char is burned in a pulverized-fuel combustor; other systems use fluidized beds. In the HITAF system, the gas turbine inlet air is indirectly heated to approximately 1,800°F in heat exchangers. The other systems under development heat the air directly for all or most of the air cycle heat duty.

Plant Design

A plant with a net power output of approximately 290 megawatts was chosen for an initial system analysis. A plant of this size would require two pyrolyzers and two secondary air heater furnaces. There would be one gas turbine, one steam turbine, and one char-fired furnace.

Of the 290-megawatt net power output, 51 percent is from the gas turbine and 49 percent is from the steam turbine.

FIGURE 1
SIMPLIFIED PROCESS FLOW DIAGRAM

The plant efficiency is about 48 percent on a higher-heating-value basis. Coal accounts for 65 percent of the plant heat input, with the remainder of the heat input from natural gas. The plant steam cycle conditions are 2,415 psia/1,050°F/1,050°F, and the gas turbine external combustor outlet temperature is 2,430°F. The plant performance is based on preliminary estimates of component performance.

Research and Development

Research and development are required to determine design information and operating parameters for some of the HITAF system components. The major subsystem components needing this type of development are the pyrolyzer, secondary air heater, char combustor, gas turbine external combustor, and air pollution control systems. These components are highly integrated; the design of any individual component must be optimized by taking into account its effect on other components and overall system operation. Because system design goals (high-efficiency, low CO₂, and low emissions) are sometimes in conflict, trade-off decisions need to be made.

Pilot plant pyrolyzers have been successfully operated at conditions similar to those that will be used in the HITAF system. The main focus of the pyrolyzer research and development in this program will be to characterize the fuel gas and char output streams under the specific HITAF conditions and to determine the heat and material balances for these conditions.

Research and development for the secondary air heater are primarily involved with developing a reliable design for elevated temperatures. Because tube temperatures will be out of the range where metal alloys can be used, much of the secondary air heater will be made from ceramic materials. This effort involves the selection of appropriate materials, thermal and structural design analysis, development of fabrication techniques, and laboratory testing of fabricated subassemblies. In addition, the characteristics of the flue gas in the secondary air heater need to be considered in relationship to the selection of secondary air heater materials.

The char combustor is another subsystem that requires development. Physical design, input requirements, and output stream compositions need to be determined. Research is in progress to determine this information for an entrained-coal combustor. This combustor is a low-NOₓ, slagging combustor that has a separately fired pre-combustor and a vortex-flow main combustion chamber. A slagging combustor is not the only option for the HITAF system. Arch-fired furnaces, commonly used for anthracite coal, have successfully fired char.

Analysis of the HITAF system indicates that the established emissions goals can be met with commercially proven systems such as a selective catalytic reactor followed by a
sodium sulfite/bisulfite scrubber. The thrust of the emissions system research and development will be to determine whether there are less efficient, but also less costly, systems that will achieve the emissions goals. Among the systems being evaluated are coal and char adsorption/catalytic reduction systems. The combination of a coal or char adsorption system with upstream sulfur removal by sorbent in the pyrolyzer and char-fired furnace may reduce emissions sufficiently and be less costly than a scrubber process.

The external gas turbine combustor performance affects cycle performance and NO\textsubscript{1} emissions. The main effect on the cycle is the allowable combustor air inlet temperature. A 1,800°F air inlet temperature will most simply achieve the goal of having 65 percent of the plant heat input from coal. Lower inlet temperatures would require incorporating steam reforming or other methods to lower the natural gas requirement. Tests have been successfully run with air inlet temperatures up to 1,600°F in an external combustor designed for the second-generation pressurized fluidized-bed combustor system. The design of an external combustor will be analyzed to determine whether 1,800°F air inlet temperature is feasible.

NO\textsubscript{1} generation has been successfully limited in more than one external combustor design by staging the combustion to form rich, quench, and lean zones. This technique should also be effective for the HITAF conditions.

The authors conclude that the HITAF concept is a promising way to utilize coal in a high-efficiency combined-cycle system. The various subsystems are highly integrated; thus the research and development efforts for the subsystems must also be integrated to yield an optimized plant design. Completion of the conceptual plant design and analysis is scheduled for early 1994.

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EERC SUMMARIZES STATUS OF CONVERSION TECHNOLOGY FOR FORT UNION LIGNITE

The Fort Union strata of the Northern Great Plains contain both lignite and subbituminous rank coals. Currently, these coals are mainly used for the generation of electrical power, and their use will increase in the near-term to meet clean air standards. In the long-term, however, and particularly for lignite, growth will depend on converting these coals to environmentally clean alternative fuel forms for electric generation and transportation, as well as value-added products. The status of conversion technology for Fort Union lignite was recently summarized in a special report by E.A. Sondreal, of the Energy and Environmental Research Center (EERC) in Grand Forks, North Dakota.

Properties of Fort Union Coals Affecting Conversion Processes

Fort Union coals possess the following unique properties that make them desirable feedstocks for most conversion processes.

- Low-rank coals remain dispersed and retain a highly reactive surface in high-temperature processes.
- Low-rank coals react more rapidly and at lower temperatures than bituminous coals in most conversion processes.
- Low-rank coals have high moisture contents. However, in some processes, the coal moisture can be used to advantage, as in the production of coal-water slurry fuel. In underground coal gasification, the high moisture content of lignite may be advantageous for promoting and controlling the gasification reaction.
- Some low-rank coals are highly friable and produce excessive amounts of fines during crushing, handling, and processing.
- Ash-forming constituents in low-rank coals include both extraneous grains of clay, quartz, pyrite, calcite, and other discrete minerals; and ion-exchangeable cations that are chemically absorbed on coal carboxylate or clay. The absorbed cations, which include part of the aluminum, iron, calcium, magnesium, sodium, and trace elements in the coal, affect processes in ways that are unique to low-rank coals.
- Ashes and slags from low-rank coal exhibit distinctive fusion, viscosity, and other phase properties in relation to their chemical and mineralogical composition.
- The low sulfur content of some Fort Union coals (typically 1 weight percent, compared to 2 to 5 weight percent for many bituminous coals) reduces the amount of sulfur that must be removed during processing and results in lower sulfur levels in products and emissions.

Fixed-Bed Gasification

Fixed-bed gasification, illustrated in Figure 1, has the inherent advantages of essentially complete carbon conversion, high thermal efficiency, and relatively low off-gas temperature due to the countercurrent flow of fuel and gaseous reactants.
Dry ash fixed-bed Lurgi gasifiers have been used in 19 plants worldwide, mostly on noncaking fuels similar to Fort Union coal. Lignite coals are an ideal feedstock in that they are more reactive than higher-rank coal at the relatively low operating temperature and are also noncaking. Lurgi gasifiers can be operated on either air or oxygen at pressures of up to 30 atmospheres. Because of their widespread application, including their successful use in the Great Plains plant, gasifiers of this design represent a standard against which newer designs will be compared.

A variation of the Lurgi dry-ash gasifier design has been developed for slagging operation. The slagging design has been successfully tested on coals of all ranks by the British Gas Corporation (BGC) in cooperation with United States sponsors and is being offered by BGC for commercial application. The research and development sponsored by the United States Department of Energy provides a support database on process effluents, byproducts, and waste treatment methods specifically for Fort Union lignite and subbituminous coals.

**Fluidized-Bed Gasifiers**

Fluidized-bed gasification as generically illustrated in Figure 1, operates on the principle of suspending coal, along with other solids present in the reactor, in turbulent motion in a high velocity upward flow of reactant gas. The turbulent environment provides excellent gas-solid contact, which rapidly heats entering reactants to the bed temperature and facilitates their intimate mixing and reaction.

The inherent advantages of fluidized-bed gasification include:

- Design flexibility for a wide range of coal feeds, including caking coals
- High specific gasification rates resulting from high rates of heat and mass transfer
- Possible in-bed sulfur removal using a limestone bed
- Good control of gasification temperature and other reaction conditions in one bed or a series of beds to accomplish particular stages of reaction
- High-product gas uniformity resulting from the highly turbulent mixing

Disadvantages are in the carry-over of coal fines, limited turndown capability due to the need to maintain fluidizing velocities, and the high temperature of the gas leaving the reactor at bed temperature.

Fluidized-bed designs with application to Fort Union low-rank coals include the German Winkler and high-
temperature Winkler, the CO$_2$ Acceptor, and the KRW-Westinghouse gasifiers. Fluidized beds also find application to low-rank coals in mild gasification processes used to produce char and byproducts and in catalytic gasification for production of hydrogen.

The CO$_2$ Acceptor process was developed for lignite and subbituminous coal with the goal of producing a nitrogen-free synthesis gas suitable for conversion to substitute natural gas using air rather than oxygen as the process oxidant. The process has demonstrated 99 percent carbon conversion and a cold-gas thermal efficiency of 77 percent.

The KRW-Westinghouse fluidized-bed gasification system tested at the scale of 35 tons per day at Waltz Mill, Pennsylvania, since 1972, offers high thermal efficiency based on its low steam and oxygen consumption. Carbon utilization in excess of 95 percent has been demonstrated for lignite.

**Entrained-Flow Gasifiers**

Entrained flow gasifiers, illustrated in Figure 1, rapidly convert pulverized coal to synthesis gas in a fraction of a second residence time by partial oxidation using air or oxygen at high temperatures of 1,370 to 1,925°C. The principal advantages of entrained flow gasifiers are in their conceptually simple design, good tolerance of caking coals, high throughput, high carbon conversion efficiency and thermal efficiency, essentially complete destruction of tar and oils, minimal wastewater treatment requirement, and flexibility for increasing operating temperatures well beyond the melting point of the ash.

The entrained flow gasifier designs that will have future application to Fort Union coals are the pressurized units developed since the 1970s by Texaco, Dow, and Shell.

Initial applications of pressurized entrained flow gasifiers are most likely in electric power generation using high-efficiency combined cycle systems, although this type of gasifier may also be used in some synfuels applications.

**Catalytic Gasification for Hydrogen Production**

EERC work on the catalytic gasification of low-rank coals has the goal of producing low-cost hydrogen, which is a key industrial gas linking coal gasification with the processing of petroleum, petrochemicals, ammonia-based fertilizers, and metals, as well as synfuels and power production. The hydrogen-rich gas produced would find its most economic applications in production of methanol, followed by sale of high-purity merchant hydrogen. Preliminary evaluation of catalytic gasification processes to provide fuel for a molten carbonate fuel cell for power generation indicates that efficiency of 54 percent (coal to electricity) could be achieved using a high-pressure gasifier producing a methane-rich fuel gas together with hot-gas cleanup.

**Mild Gasification**

Mild gasification is a variation of low-temperature carbonization that gasifies only a portion of coal to produce char, organic liquids, and combustible gas. Mild gasification is the first stage of a coal-refining process which produces primary char and liquid that can be upgraded to value-added products such as metallurgical and specialty carbons, liquid fuels, and chemicals. The gas is used for process heat and cogeneration of electricity.

The gasifier designs for mild gasification of low-rank coals used in the commercial FMC plant in Kemmerer, Wyoming and the EERC experimental facility employ staged fluidized beds, first to carbonize at about 480°C to obtain optimum liquid yield and quality, and then to devolatilize at higher temperatures approaching 815°C, to under 10 percent volatile content in the char. Results from current research indicate that the gasifying atmosphere, whether more or less inert or reducing based on use of hot flue gas, steam, or syngas, has only a marginal effect on liquid yield and quality.

**Liquefaction**

Synthetic liquid fuels can be produced either by gasifying the coal and then synthesizing higher hydrocarbons from the carbon monoxide and hydrogen produced, which is termed indirect liquefaction, or by direct reaction of hydrogen with coal in a process-derived solvent, termed direct liquefaction. Both types of processes are applicable to Fort Union coals, and both have reached an advanced stage of development. However, only the indirect process is used commercially, at the SASOL plants in South Africa. Three plants are currently operated based on Fischer-Tropsch synthesis of hydrocarbons from carbon monoxide and hydrogen. These plants use Lurgi gasifiers similar to those used by the Dakota Gasification Plant. The economics of indirect liquefaction can be considered to be roughly competitive with crude petroleum priced above $30 per barrel.

The estimated price of synthetic crude produced by direct hydrogenation of coal using current technology is $35 per barrel. During the past decade, the cost of producing syncrude has been reduced by approximately 25 percent through improvements in direct liquefaction technology that have increased distillate yields by 35 percent. Further improvements are projected to reduce the cost of syncrude to $25 per barrel by 1995.

The highest yields of distillate reported from integrated two-stage liquefaction of low-rank coals are 61 percent for Wyoming subbituminous coal and 50 percent for Texas lignite. This compares with a maximum yield of 78 percent distillate from Illinois bituminous coal. Theoretical maximum yields, assuming zero carbon rejection in the ash residue, are estimated to be about 81 percent for Illinois bituminous coal and 69 to 73 percent for lignite and subbituminous coals. Comparison of these yields indicates that the liquefaction of...
bituminous coal has come close to reaching its full yield potential, but that the liquefaction of low-rank coals, and lignite in particular, has not been fully optimized in the two-stage processes investigated to date.

**Low-Temperature Evaporative Drying**

The incentives for drying high-moisture United States coals are to reduce shipping costs and to allow the direct substitution of low-rank coals for bituminous coals in boilers designed for the latter. In the future, coal drying may play an important role in expanding existing markets for low-sulfur compliance coals from the Powder River, Fort Union, and Alaska coal-producing regions and in creating export markets for these coals.

Many processes are available for low-temperature evaporative drying where the coal temperature remains below about 93°C. The following are mature processes that are available for commercial applications:

- Parry entrained
- Rotating drum
- Fluidized bed
- Flash mill
- Steam tube

**High-Temperature Drying**

Drying processes that raise the temperature of the coal above 240°C permanently change the physical and chemical properties of low-rank coals and produce a product with a lower equilibrium moisture content. At these temperatures, tars migrate to the coal surface where, if the tars are not stripped from the coal by the drying medium, they effectively seal the micropores, greatly reducing the ability of the coal to reabsorb moisture. Evolution of CO₂ also reduces the capacity of the coal surface to chemically bind water by removing the hydrophilic carboxyl groups.

Numerous high-temperature drying processes have been developed using hot gas, steam, hot water, hot oil, or a combination thereof as the drying medium. The Fleissner and continuous Fleissner processes are commercially proven. The K-fuel process is proposed for a 350,000-ton-per-year plant.

The quality of the dried coal product depends more on temperature than on drying medium. Processes which partially carbonize the coal and pelletize the product using the released tar as a binder produce the most stable, dry product in terms of moisture absorption, friability, dust, and spontaneous heating. Processes in this category include one version of K-fuel, which operates at temperatures up to 400°C.

The higher cost of high-temperature drying must be offset by the economic value derived from improvement in product quality, if these processes are to compete with low-temperature evaporative drying.

**Coal-Water Fuels**

An alternative to drying high-moisture coals to produce a low-moisture solid product is to produce concentrated coal-water fuels (CWFs) from low-rank coals (LRCs). A process developed by the Energy and Environmental Research Center allows the production of CWFs from LRCs, with solids loadings comparable to those obtained with high-rank coals.

Hydrothermal processing or hot-water drying (HWD) includes coalification and changes the hydrophilic LRC to a hydrophobic material that has an equilibrium moisture content similar to a bituminous coal. Low-rank coal-water fuels also overcome the safety and handling problems associated with dried bulk LRC; i.e., there is no dust or any possibility for spontaneous combustion or explosion. In addition, CWFs can be pipelined as a concentrated fuel and used as an oil substitute, without costly dewatering units at the user's site.

In advanced applications, such as combustion turbines and/or diesel engines, the CWFs made from low-rank coals have demonstrated reactivity, in terms of carbon burnout, an order of magnitude higher than their bituminous counterparts. For low-rank coals, an enhanced friability after HWD yields particles that break into numerous, smaller, dried coal particles upon further heating. These highly reactive coal particles ignite readily and produce a stable flame. Another factor influencing the superior combustion properties of LRCs is their low fuel ratios (fixed carbon to volatile matter).

Combustion behavior of LRCWFs has been studied in EERC’s 550,000-BTU-per-hour combustion simulator and in a 1-million BTU per hour (280-kilowatt) turbine simulator. All the data to date has found LRCWF to be a potential substitute for fuel oil, with relatively minor modification of the combustors. Superior combustion characteristics of low-ash LRCWFs, in comparison to micronized bituminous CWFs, have also been demonstrated in both General Electric’s diesel and General Motor’s Allison turbine engines as part of the United States Department of Energy program to develop heat engines to run on coal.

Production costs are strongly coal and site dependent. Commercial production cost estimates for an 800,000-ton per year low-rank CWF plant range from $26 to $50 per ton of CWF, depending on cleaning and HWD.

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SYNTHETIC FUELS REPORT, MARCH 1993
WABASH RIVER PROJECT WILL ADVANCE DESTEC'S GASIFICATION TECHNOLOGY

In September 1991, the United States Department of Energy (DOE) selected the Wabash River Coal Gasification Repowering Project for funding under DOE's Clean Coal IV Program. The project, located in West Terre Haute, Indiana will demonstrate the repowering of an existing steam turbine-generator through the utilization of Destec's coal gasification process. The project was discussed in a paper by R.E. Maurer presented at the 1992 American Society of Mechanical Engineers Cogen-Turbo Conference held in Houston, Texas last September.

By repowering the existing steam turbine using a Coal Gasification Combined Cycle (CGCC) process, all aspects of the existing process are improved. Power generation increases from the current nominal 100 megawatt capacity to about 270 megawatts (net) and the plant heat rate is improved by 21 percent.

The power generation facilities included in the Wabash River Project will incorporate the latest advancements in combined-cycle system design at a cost of $1,200 per kilowatt. The project will incorporate an advanced gas turbine (General Electric MS 7001 F) with new design compressor and turbine stages, higher firing temperatures and higher pressure ratios. Integration between the Heat Recovery Steam Generator (HRSG) and the gasification facility has been optimized to yield higher efficiency and lower operating costs. In addition, repowering of the existing steam turbine will involve upgrading the unit in order to accept increased steam flows generated by the HRSG, thus improving the CGCC cycle efficiency, by using more of the available energy.

Gasification facilities improvements included in the technology envelope for the project are summarized as follows:

- The coal feed for the project will be high sulfur bituminous coal, thus demonstrating the environmental performance and energy efficiency of Destec's advanced two-stage coal gasification process on this fuel.

- Dry particulate removal and recycle will be demonstrated at full commercial scale.

- Syngas/recycle will provide fuel and process flexibility while maintaining high efficiency.

- A high pressure boiler will cool the hot raw gas by producing steam at a pressure of 1,600 psia.

- The slag-fines recycle system will recover most of the carbon present in the slag byproduct stream and recycle it back for enhanced carbon conversion. This also results in a higher quality byproduct slag.

- Fuel gas moisturization will be incorporated through the use of low-level heat utilizing a new concept different from that used before by Destec. Syngas moisturization will significantly reduce the amount of direct steam injection required for NOx control.

- Sour water produced by condensation as the syngas is cooled will be processed differently from the method presently used by Destec. This novel sour water system will allow more complete recycle of this stream, reducing water use and increasing efficiency.

- An advanced design oxygen plant producing 95 percent pure oxygen will be used by the project. This will increase the overall efficiency of the project by lowering the power required for production of oxygen.

A deep reduction of sulfur emissions, about 6.7 percent of the Clean Air Act Amendments of 1990 standards, and a reduction in NOx emissions will be realized by the Wabash River Repowering Project. This will eliminate the need for associated sulfur and ash-waste landfilling.

Maurer concludes that repowering existing utility steam turbines with CGCC offers a cost-effective and environmentally sound option to utilize existing utility sites. In the Midwest and Eastern regions of the United States, CGCC repowering will enable local high sulfur coals to continue to be used. By late 1995 the Wabash River Repowering Project will be demonstrating the performance of the GE-7F combustion turbine on syngas, plus the overall CGCC performance at the nominal 270 megawatt (net) power output.

COAL SOLUTIONS MAY BE NEW ROUTE TO UPGRADED PRODUCTS

The development of effective means of upgrading the organic part of coal by separating it from the inorganic part has long been the goal of coal chemists and engineers, with several processes having been studied in recent years. The aim of these studies has been to develop processes suitable for the manufacture of clean fuels or, after carbonization, of electrode carbons. A new purification process, prompted by the observation that relatively small additions of sodium hydroxide allow very high solubilization of certain high-rank bituminous coals into relatively cheap N,N-dimethylformamide (DMF) and similar solvents, was dis-
cussed in a paper by D.L. Morgan, presented at the 204th American Chemical Society National meeting in Washington, D.C. last August.

Small-Scale Extraction Results

The effect of adding potassium hydroxide (coal:solvent:KOH ratio 10:100:1.6) on the carbon extractibilities into N-methylpyrrolidone (NMP) of various South African coals is shown in Table 1. Coals of higher and lower dry, ash-free carbon content showed much lower extractabilities. The vitrinite concentrates were much more soluble than the corresponding inertinites. Coal B, a flotation concentrate rich in vitrinite, showed a remarkably high extractability considering the mild conditions employed, said Morgan.

The effectiveness of numerous solvents was examined using Coal A and potassium hydroxide in the same ratios as above. Amide solvents are seen to be generally effective, with dimethyl sulfoxide somewhat less so. Pyridine alone or with KOH was ineffective but the addition of the phase-transfer catalyst 18-crown-6 gave greatly increased extraction when five consecutive extractions were done. Hexamethyl phosphoric triamide was ineffective, even on addition of crown ether. Various amine, ether, polyether and alcohol solvents showed no great increase in solubility on the addition of potassium hydroxide/crown ether.

Similar results in both NMP and DMF were found when an equivalent amount of sodium hydroxide was used in place of potassium hydroxide. Lithium hydroxide was much less effective.

According to Morgan, the most significant points arising from these results are:

- The organic part of a variety of coals can be very effectively solubilized.
- Relatively cheap and volatile DMF may be used.
- Relatively cheap sodium hydroxide may be used.

Bench-Scale Extraction Results

Numerous bench-scale experiments aimed at defining process conditions for the extraction of Coal B have been done using DMF and NMP. The extraction curves show, in some cases after an induction period, a steadily decreasing rate of extraction until a final plateau is reached.

Morgan summarizes the more significant observations as follows:

The effect of air. The extraction is severely affected, with approximately half the potential extraction being obtained.

The effect of temperature. The rate increases rapidly with temperature. In NMP the time to completion ranges from 10 minutes at 180°C to 17 hours at 30°C. In DMF the time ranges from 60 minutes at 150°C to 24 hours at 30°C. An induction period is seen at lower temperatures.

The effect of alkali. Potassium hydroxide, in equivalent amounts, gives marginally faster extraction. In NMP and DMF the extraction rate increases with the use of finer NaOH. The quantity of sodium hydroxide required for maximum extraction in both solvents is about 10 percent of the mass of the coal.

The effect of phase-transfer catalyst. The addition of as little as 0.7 percent (of the mass of coal) of polyethylene glycol 400 increases the rate of extraction noticeably. The addition of 5 percent polyethylene glycol 400 decreases the time to maximum extraction at 90°C in DMF from 200 to 60 minutes.

The effect of stirring rate. The extraction rate increases with the stirring rate, but plateaus in the bench apparatus at about 1,500 revolutions per minute.

The effect of particle size. In both NMP and DMF there is a moderate effect at 30°C and no difference at 90°C when comparing coals -500 micrometers, +212 micrometers and -160 micrometers in size.

### TABLE 1

<table>
<thead>
<tr>
<th>Coal</th>
<th>% daf C</th>
<th>% Carbon Extraction</th>
<th>KOH Addition</th>
<th>% Carbon Extraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>86.8</td>
<td>8.6</td>
<td>80.5</td>
<td></td>
</tr>
<tr>
<td>B</td>
<td>88.5</td>
<td>5.0</td>
<td>90.3</td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>88.2</td>
<td>80.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>D1 Vitrinite</td>
<td>86.8</td>
<td>20.7</td>
<td>47.7</td>
<td></td>
</tr>
<tr>
<td>D1 Inertinite</td>
<td>86.2</td>
<td>5.4</td>
<td>13.4</td>
<td></td>
</tr>
<tr>
<td>D2 Vitrinite</td>
<td>87.0</td>
<td>19.0</td>
<td>57.0</td>
<td></td>
</tr>
<tr>
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<td>85.8</td>
<td>6.8</td>
<td>24.8</td>
<td></td>
</tr>
<tr>
<td>E1 Vitrinite</td>
<td>86.0</td>
<td>10.5</td>
<td>40.0</td>
<td></td>
</tr>
<tr>
<td>E1 Inertinite</td>
<td>86.3</td>
<td>5.7</td>
<td>16.1</td>
<td></td>
</tr>
<tr>
<td>E2 Vitrinite</td>
<td>88.8</td>
<td>6.3</td>
<td>86.1</td>
<td></td>
</tr>
<tr>
<td>E2 Inertinite</td>
<td>86.8</td>
<td>3.4</td>
<td>25.9</td>
<td></td>
</tr>
</tbody>
</table>
Coal Solution Properties

The solutions are dark brown in color. The DMF solution ranges in viscosity from 1.8 centipoise at 90°C to 3.5 centipoise at 30°C. Solutions in both solvents are unstable when exposed to atmospheric water and carbon dioxide. The NMP solutions have an indefinite stability when in closed containers, but the DMF solutions gel after a few weeks. The addition of acid or other solvents miscible with DMF and NMP leads to immediate precipitation of the coal-derived material.

Exploitation

Several uses for coal solutions and Refcoal, the purified dissolved organics recovered from solution, show promise. Refcoal would be a very clean fuel. The carbonization yield of Refcoal prepared from Coal B is 75 percent at 1,100°C making it an efficient carbon source. The low viscosity of the solutions makes it attractive as an impregnation medium. Higher-valued uses are being investigated—fibers can be spun from suitably treated solution and the solution can be used as a source of carbon of high reactivity for the carbothermal preparation of metal carbides and nitrides.

PETROLEUM COKE PROVES GOOD FEEDSTOCK FOR SHELL GASIFIER

It is anticipated that coke will be of increasingly greater interest to United States utilities because it can be used in an environmentally acceptable way as a feedstock for coke gasification combined cycle power generation. The gasification of petroleum coke in the Shell Coal Gasification Process (SCGP) was discussed in a paper by U. Mahagaokar, presented at the Power-Gen '92 Conference held in Orlando, Florida last November.

United States Coke Production

Petroleum coke production in the United States has increased dramatically over the last decade due to a changing trend in crude quality. Higher quality, low-sulfur crude supplies have gradually depleted, driving refineries toward lower quality, heavier crudes which are more abundant and cheaper. An oversupply of high-sulfur residual fuel oil has led refineries toward more coking, resulting in an increase in coke production from 3 tons in 1980 to 5 tons in 1990 per 1,000 barrels per day of crude refined, a dramatic increase of almost 70 percent.

Over the same time period, the fuel market for coke has been severely impacted by environmental laws which have become tighter in the United States and overseas. This influence, coupled with the increasing sulfur content of coke has led to a significant drop in demand and price, from about $37 per ton in 1985 to about $18 per ton in 1992.

As the 1990 Clean Air Act Amendments take effect, and sulfur emissions become heavily regulated, coke will become increasingly difficult to burn, and its price is likely to drop further, says Mahagaokar.

Properties of Petroleum Coke

Petroleum coke displays several unique characteristics as highlighted below:

- Low ash content, about 0.5 percent weight percent on a moisture-free basis
- Low oxygen content and low volatile matter
- High heating value and fixed carbon
- High sulfur content
- High Vanadium (V) and Nickel (Ni)

Petroleum Coke Gasification in SCGP-1

The composition of the syngas from petroleum coke is approximately the same as that from coals. Typically 90 percent is CO and H₂ with N₂, CO₂, H₂O, H₂S and COS accounting for all of the balance. The higher heating value of clean syngas was also the same as that from coals, approximately 300 BTU per standard cubic foot.

An important gasifier performance parameter is the cold gas efficiency (CGE) which is defined as the chemical energy in the syngas after removal of H₂S and COS divided by the chemical energy in the coke. CGE is influenced by the oxygen/coke ratio and the recycling of flyash. Higher oxygen/coke ratios result in higher CO₂ concentrations in the syngas and a greater release of heat as a result of the gasification reactions. The highest CGE achieved on petroleum coke was 78.9 percent. In a commercial plant, the lower CGE would be balanced by a credit for the sale of recovered sulfur typically sold for $75 to $100 per long ton.

A large part of the energy of the feed coke is converted into syngas chemical energy. Most of the remaining energy is recovered in the form of high pressure steam generated in the syngas cooler and gasifier membrane wall. This steam typically represents 15 to 17 percent of the feed coke energy. The sum of the energy in the syngas and the generated steam as a percentage of the energy fed to the gasifier (including burner steam) is called thermal efficiency. The high thermal efficiency of the process is evidenced by the fact that 94 to 97 percent of the incoming energy is recovered in the form of syngas and steam.

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Carbon conversion is a second indicator of the efficiency of a gasification process in converting coke to syngas. Petroleum coke requires a total oxygen to carbon ratio of 1.03 to 1.08, to produce a single pass carbon conversion in the normal operating rage of 97 to 98.5 percent. Recycling of the flyslag ensured almost complete utilization of the carbon in the coke. Even with the low volatile matter and low reactivity of petroleum coke, carbon conversions greater than 99.0 percent were achieved.

Environmental Performance

The Shell Coal Gasification Process can meet and exceed all current and anticipated environmental standards for gas, water, and solids streams. These results have addressed sulfur emissions, hazardous air pollutants (including trace metals), effluent characterization for organics and inorganic sulfur and nitrogen species, chronic and acute toxicity tests, and leachate testing of solids. In the environmental context, the properties that are unique to petroleum coke are its high sulfur content, and high vanadium and nickel content.

Coke's 5.2 percent sulfur concentration was the highest of any feedstock gasified at SCGP-1. It produced raw syngas with a sulfur species concentration greater than 1.5 percent, but the Sulfinit system was able to decrease the sulfur concentration to less than 25 ppm. This constituted 99.8 percent sulfur removal from the syngas.

Incoming coke has a concentration of 1,500 ppm V and 340 ppm Ni (71.8 percent and 7.4 percent on ash). Samples of the clean syngas from SCGP-1 showed that the V and Ni concentrations were below the detection limits of 2 and 7 parts per billion respectively. The effluent water also showed very low concentrations, with 0.6 ppm V and 0.9 ppm Ni. Practically all of the V and Ni was captured by the slag and clarifier solids. Metals captured by slag have been shown to be nonleachable due to the vitreous nature of slag.

Economics of Petroleum Coke Gasification

The capital cost of the petroleum coke-based plant is slightly higher ($1,390 per kilowatt versus $1,330 per kilowatt) due to small increases caused by a bigger oxygen plant (because higher oxygen/coal ratios are used), ash addition facilities, and bigger gas treating and sulfur recovery facilities (due to high sulfur content). The heat rate for petroleum coke is slightly higher (8,240 BTU per kilowatt-hour versus 8,070 BTU per kilowatt-hour) because of the lower cold gas efficiency resulting from the high sulfur content.

A comparison of the cost of electricity (COE) between Pittsburgh No. 8 and petroleum coke shows that the higher capital and operating and maintenance cost for petroleum coke is more than offset by the lower fuel cost yielding a net COE that is attractive--$0.051 per kilowatt-hour (if coke were $0.75 per million BTU) versus $0.063 per kilowatt-hour for Pittsburgh No. 8 coal.

If the price of coke doubles from $0.75 per million BTU to $1.50 per million BTU, the levelized COE rises to $0.062 per kilowatt-hour, but is still below that of Pittsburgh No. 8 coal. On the other hand, if the coke was available at zero cost (say in a situation where a refiner might have to pay for disposal of coke), the levelized COE would fall to an exceptionally attractive value of $0.04 per kilowatt-hour.

Mahagoorar concludes that petroleum coke is an excellent feedstock for power generation in a Shell Coal Gasification combined cycle powerplant.

###

COMBINATION SOLVENT EXTRACTION AND GASIFICATION PROCESS SHOWS ADVANTAGES

The results of a study to construct a coal conversion process in which solvent extraction, catalytic pyrolysis, and gasification of residue are combined to obtain clean carbonaceous solid, liquid and gases were discussed in a paper by Y. Nishiyama et al., presented at the Fifth Australian Coal Conference held in Melbourne, Australia last November.

A solvent extraction process at room temperature using a specially mixed solvent can produce an ash-free coal with a relatively small consumption of process energy. It would be even more attractive, if the residue of the extraction is utilized effectively as chemical resources. The chemical nature or the reactivity of the residue is not clear. In the described study, an integrated coal conversion process was examined to see whether the combination of such processes has some advantages when different types of coal are handled.

The three coals evaluated in the study are Lower Kittanning (LK), Illinois No. 6 (IL), and Loy Yang (LY).

Results

Several mixed solvent systems were examined with respect to their extraction ability-composition relationship. Also, the adaptability of such solvent to lower rank coals was clarified.

The extraction yields for three coals show maxima at 60 to 80 percent in N-methylpyrrolydine (NMP) fraction. The CS$_2$-NMP mixture can extract ash-free materials up to 44 percent for LK coal while the yields for lower rank coal were less than 20 percent. For LY coal, a mixture of methanol-NMP was found more effective to extract. Several other solvents were examined for LY-coal, but the extraction yield was 15 percent or less.

Several properties of the extracts and residues were compared with the raw coal. Elementary analysis showed small differences; the residues have more O and less C and H. Infrared spectra suggested the presence of more aromatics and hydroxyl groups in the residue than raw coal or extract, but
the differences are generally small. For the sake of comparisons in reactivity, residues of extraction at 15 to 25 percent yield were used.

The temperature and the evolution of volatiles were nearly the same between raw coal and the extraction residue in the slow heating. The product distributions were compared in the rapid heating pyrolysis among raw coals and extraction residues both with and without catalyst. Generally, raw coals and the extraction residues behaved rather similarly in pyrolysis. Nishiyama, et al., observed that the effect of extraction depended on the kind of coal. The presence of catalyst affected the product distribution somewhat; yields of tar decreased and gas increased for most cases. This can be attributed to the catalytic action for secondary decomposition of tar. The yield of char was little affected by the catalysts.

The composition of the gaseous product was affected by the extraction somewhat. The yield of light hydrocarbons from the extraction residue was smaller for LK and IL coals while it was larger for LY coal as compared to those from raw coals.

The pyrolysis residues were compared for their reactivities in gasification with raw coals. Some of the results for LK and IL coals are given in Figure 1. In the figure, O = raw coal, R = extraction residue and HP = residue of hydropyrolysis. Generally, the catalyst added before pyrolysis worked effectively for gasification; those chars without catalyst were gasified slowly.

For IL coal, specimens after extraction were gasified under the influence of catalysts more rapidly than those without extraction. The difference was negligible for LK coal. Further testing indicated that, in the case of lower rank coals, extraction residues are more easily gasified than unextracted ones, and in the case of higher rank coals, the differences are negligible.

This difference in the rate of gasification between extracted and unextracted residue could be ascribed to the presence of catalyst. First, the catalyst was loaded at the same amount in the raw coal basis; the extraction residue contains more catalyst in char basis. Second, the extraction residues can have a larger pore surface to load catalyst. This seems to be

![FIGURE 1](source: nishiyama, et al.)
the case for IL coal which originally had rather small pores and the extraction increased pore volume. Also, the electron microscope examination indicated some change in the surface roughness by the extraction; for LK coal, the surface of the residue was smooth, while it was rough for IL coal. It may be that extraction by powerful solvent results in the shrinkage of pores for higher rank coals which swell. However, for LY coal, which has relatively large pores, the extraction enhanced the gasification in spite of decrease in pore size. The behavior needs more investigation, say the authors.

Nishiyama, et al., conclude that the residue of solvent extraction using NMP-containing solvent was pyrolyzed and gasified efficiently when calcium or iron was loaded, especially for lower rank coals, though extraction yields were not so high. The combination of different conversion processes may be effective when coals of suitable kind are chosen.

####
TOKYO GAS HAS BENCH-SCALE HYDROGASIFIER
BASED ON ROCKET ENGINE TECHNOLOGY

A bench-scale process for the flash hydrogasification of coal was discussed in a paper by I. Takahashi and H. Uchida, presented at the 1992 International Gas Research Conference held in Orlando, Florida last November. The process is based on rocket engine technology developed by Rockwell International Corporation.

When compared to other processes being developed for synthetic fuels production, flash hydrogasification is of particular interest because it produces methane in a single-stage reaction with high efficiency, and simultaneously produces valuable aromatic liquids such as BTX and naphthalenes. Moreover, flash hydrogasification has the inherent benefits of greater flexibility in feedstock, higher efficiency, and lower product cost.

One of the key factors of flash hydrogasification is rapid mixing and heating of reactants. In this study, these conditions are achieved by employing the entrained flow reactor illustrated in Figure 1. Pulverized coal is introduced and atomized vertically from the center of the injector into the reactor. Four high-temperature (above 1,573 K) hydrogen jets impinge on the pulverized coal, resulting in a coal heating rate of 1,000 to 10,000 K per second.

The study evaluated the effects of reaction temperature, residence time, pressure, and hydrogen-to-coal ratio on the gasification of two types of coal: Taiheiyo, Japanese sub-bituminous coal, and Loyyang, Australian brown coal. Char and gaseous products were collected and analyzed for each set of reaction conditions.

The effect of temperature over the range of 973 to 1,223 K was evaluated. The total carbon conversion and the carbon conversion to methane increases with increasing temperature, while the carbon conversion to benzene reaches a maximum at around 1,173 K. The results suggest that the devolatilization of coal readily occurs at 973 K and that BTX can be produced from polycyclic aromatics below 1,173 K and be stable; however, cleavage of the benzene ring can take place rapidly above 1,173 K. Based on the ultimate and thermal analyses of hydrogasified products, the authors believe that at 1,173 K, 62 percent of the carbon in Taiheiyo coal can be hydrogasified to methane and benzene.

The effect of residence times from 1 to 20 seconds was evaluated. Under a given reaction temperature, the carbon conversion to methane and benzene increases with increased residence time, while the total carbon conversion is constant above 3 seconds. From this result, it can be concluded that the devolatilization of coal occurs rapidly, regardless of residence time (above 3 seconds), to produce methane, ethane, carbon monoxide and tar as the primary reaction products. At longer residence times, tar is pyrolyzed gradually to naphthalene, BTX and methane as the secondary reaction.

Reaction pressures of 1.1 to 3.0 MPa were evaluated. The total carbon conversion and the carbon conversion to methane and benzene increase gradually with increasing reaction pressure. Takahashi and Uchida assumed that higher reaction pressures are effective for coal hydrogasification be-
cause the presence of hydrogen close to the coal surface or pore contributes to pyrolysis of volatile matter to produce gases and light aromatics.

Hydrogen-to-coal ratios of 0.1 to 0.3 kilogram-mole per kilogram were evaluated. Below ratios of 0.15 kilogram-mole per kilogram, the total carbon conversion and the carbon conversion to methane and benzene increase gradually with increasing $H_2$/coal ratio. Above 0.15 kilogram-mole per kilogram, carbon conversions are constant. The authors believe that higher hydrogen-to-coal ratios are more favorable for hydrogasification, although the excess hydrogen does not have much affect on the devolatilization of coal.

The two types of coal are compared in Figure 2. The total carbon conversion and the carbon conversion to benzene of Loyyang are higher than those of Taiheiyo at temperatures between 973 and 1,223 K because Loyyang has more volatile matter than Taiheiyo (59 percent versus 43 percent). However, the carbon conversion to methane of Loyyang is lower than that of Taiheiyo. This result suggests that the content of volatile matter of the parent coal does not have a good relation to the product distribution. Detailed analyses of coal structures and their contribution to the reactivity may be necessary to clarify the correlation between the coal property and the product distribution.

###

**ENDESA’S IGCC PROJECT IN PUERTOLLANO, SPAIN REVIEWED**

The Puertollano Integrated Coal Gasification Combined Cycle (IGCC) demonstration project was reviewed in a paper by U. Sendin and G. Dupin presented at the Electric Power Research Institute's 11th Conference on Gasification Powerplants held in San Francisco, California last October.

The 335 megawatt powerplant project, led by Endesa, the Electricity Generating Company of Spain, is funded by the European Community Thermie program and the Elcogas.
A consortium of European utilities at US$857 million over a 5-year period from 1992 to 1996.

The aim of the project is to demonstrate the feasibility of a 335 megawatt IGCC powerplant with a wide range of bituminous coals. The technical objectives to be demonstrated are:

- Use of wide range of fuels
- Use of coal and natural gas without any modification
- Clean combustion
- High efficiency
- Economic aspects
- Reduction in waste products

The three key processes of an IGCC plant are the coal gasification island, the combined cycle and the air separation unit, the other installations being those of a conventional powerplant.

Gasification Island

The function of the gasification island is to convert the coal into a clean gas usable in a gas turbine. This island consists of the following main units:

- Coal preparation unit
- Gasification unit
- Sulfur removal unit
- Sulfur recovery unit

The gasification island provides 180,000 cubic meters per hour of clean gas at about 21 bar and 120°C. Main characteristics of this coal gas are:

- CO: 60 to 65 percent (volume)
- H₂: 22 to 23 percent (volume)
- Lower heating value: 10,500 kilojoules per standard cubic meter

Combined Cycle

The Puertollano combined cycle unit is designed to burn the coal gas in a gas turbine and to produce electricity. It will be the first "high temperature gas turbine" of about 190 megawatts to be utilized in an IGCC plant, as shown in Figure 1. The gas turbine will be able to burn either coal gas or natural gas in dual-fuel burners.

A heat recovery boiler recovers the heat in the flue gases at the exhaust of the gas turbine. The steam generator produces high-, medium- and low-pressure steam which drives a steam turbine to generate electric power. The steam produced in the gasification island is also used in the steam turbine.

The Air Separation Unit (ASU) unit will be designed to produce oxygen with 85 percent purity required for the gasification process and the nitrogen will be used for coal dust transport and inertization, as well as NOₓ control in the gas turbine combustion chamber.

Integration of the IGCC Plant

A good integration and optimization of the three main units is a key factor to increase the overall efficiency of the plant. The principal characteristics of this integration are:

- All the air necessary for the ASU (280,000 cubic meters per hour) is extracted at the outlet of the compressor of the gas turbine at 14 bar.
- The ASU operates at high pressure (distillate column at about 6 bar).
- The waste nitrogen (not used in the gasification island) is mixed with the clean gas to feed the burners of the gas turbine.
- The sensible heat in the air extracted from the compressor at 400°C is used to heat up the waste nitrogen and the demineralized water utilized to saturate the coal gas for NOₓ control.

The advantage of high integration with respect to overall thermal efficiency is about 1.5 percentage points compared to nonintegrated plants.

Environmental Considerations

The Puertollano IGCC plant will demonstrate that it is possible to burn coal with a low environmental impact:

- The NOₓ emissions are controlled by the saturation of coal gas and mixing of waste nitrogen before combustion.
- The SO₂ emissions are low, because above 99 percent of the sulfur contained in the coal is removed in the gasification island and separated as pure sulfur.
- The slag from the bottom part of the gasifier is vitrified into a glassy product that effectively encaps-
sulates the heavy metals into a nonleachable form. Fly ash entrained with the coal gas is recycled into the gasifier.

As a consequence of the higher thermal efficiency (+10 percent compared with a new coal-fired plant), a reduction of about 10 percent of CO₂ emissions compared to a modern coal-fired plant is observed.

Fuels

The design fuel is a mixture of Puertollano unwashed coal with petroleum coke in a ratio of 1:1 in weight. Though the plant will be optimized for this fuel, the IGCC plant will be designed to be able to test other types of fuels in the ranges listed in Table 1. The plant will also have facilities for different types of coal (storage, coal preparation, limestone, etc.).

TABLE 1

IGCC PLANT DESIGN SPECIFICATIONS

<table>
<thead>
<tr>
<th></th>
<th>Min</th>
<th>Design</th>
<th>Max</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Heating Value</td>
<td>4,500</td>
<td>5,386 Kcal/Kg</td>
<td>7,000</td>
</tr>
<tr>
<td>Moisture</td>
<td></td>
<td>9.4%</td>
<td>14%</td>
</tr>
<tr>
<td>Ash Content</td>
<td>5%</td>
<td>20.68%</td>
<td>25%</td>
</tr>
<tr>
<td>N₂ Content</td>
<td>-</td>
<td>1.36%</td>
<td>3%</td>
</tr>
<tr>
<td>S₂ Content</td>
<td>-</td>
<td>3.21%</td>
<td>4%</td>
</tr>
<tr>
<td>Cl Content</td>
<td>0</td>
<td>0.05%</td>
<td>0.5%</td>
</tr>
</tbody>
</table>
It is planned to have a 3-year demonstration period during which several types of coal will be tested. These tests are important for utility companies in order to foresee the performance of future IGCC powerplants. It is planned to test coals from the United Kingdom, Spain, France, United States, Germany and South Africa.

An important aspect of this IGCC plant is that it is to be designed not only to burn coal but also natural gas. As the construction of the combined cycle plant can be completed in about 3 years, using natural gas as fuel will allow:

- Commissioning of the combined cycle as soon as it is erected, independently from coal gasification
- Operation of the plant as a combined cycle with completion of the gasification island
- Increasing the flexibility of the plant for burning various fuels, which will give the plant a higher availability

The efficiency achieved with natural gas is over 50 percent, say the authors.

#####

JAPANESE LIQUEFACTION RESEARCH REVIEWED

The status of Japanese coal liquefaction projects was summarized in a paper by S. Katsushima, et al., at the Fifth Australian Coal Science Conference held in Melbourne, Australia last November.

The New Energy and Industrial Technology Development Organization (NEDO) was established in October 1980 to promote the research and development (R&D) of oil-alternative energy as an implementing agency of the Ministry of International Trade and Industry. In June 1990, promotion of R&D to be in harmony with the global environment was further added to NEDO's scope. The major R&D programs on coal conversion technologies in NEDO are the Brown Coal Liquefaction (BCL) project, the Bituminous Coal Liquefaction (NEDOL) project, the Coal-based Hydrogen Production project and the Integrated Coal Gasification Combined Cycle Power Generation (IGCC) project. The total budget for coal liquefaction projects in fiscal year 1992 was 113 billion yen, 1.9 billion yen for the BCL project and 8.9 billion yen for the NEDOL project.

Brown Coal Liquefaction Technology

The BCL process is a two-stage liquefaction process to obtain liquid fuel from Victorian brown coal. The process features slurry dewatering with low energy consumption, primary hydrogenation in suspended-bed reactors, high-efficiency solvent deashing, and secondary hydrogenation in fixed-bed reactors with durable catalyst. The 50 ton per day pilot plant was constructed in December 1985, and shutdown after 5 years operation. The key results of this operation are as follows:

- An oil yield of higher than 50 weight percent based on moisture- and ash-free coal (MAFC) was attained in spite of the oxygen content of over 25 weight percent in the coal. The recycle of both coal liquid bottom and hydrogenated deashed oil contributed to increases in the oil yield.
- Continuous and stable operation for 1,726 hours of all the units was achieved, demonstrating high reliability of the process. The cumulative operation of 10,500 hours was recorded with about 58,000 tons of raw brown coal processed.
- Operations of the plant, using both toluene and the process derived naphtha as deashing solvent, demonstrated ash contents below 1,000 ppm, a greater than 95 percent deashing rate.
- A new catalyst for the secondary hydrogenation reactor was developed to treat the highly aromatic and heteroatomic deashed oil. The reaction performance was tested for a total of 3,800 hours in the pilot plant without any significant deactivation.
- A new slurry dewatering process for Victorian brown coal was developed to improve the thermal efficiency for drying of the raw coal. A high rate of dewatering up to 95 percent was attained in the pilot plant.

A consolidation study of the BCL project is scheduled for completion by fiscal year 1993. The study consists of the following programs:

- Collecting and summarizing data obtained from the pilot plant
- Developing a process simulation program
- Establishing the scaleup technique for a demonstration plant

Bituminous Coal Liquefaction Technology

The NEDOL process is an economical process for liquefying subbituminous to low-rank bituminous coal. The characteristics of the process are as follows:

- High yield of light and middle distillates are obtained under mild reaction conditions. The target yield is higher than 54 weight percent.
Coal is liquefied in the presence of an active iron-based catalyst and a hydrogen donor solvent.

The heavy distillate of coal-derived liquid (boiling point 350 to 538°C), is recycled as solvent after hydrogenation in fixed-bed reactors.

The heat recovery system from the reactor effluent will improve the thermal efficiency.

The main objectives of the pilot plant operation are to confirm the NEDOL process performance and collect overall engineering data for scaleup. Once construction of the pilot plant, which began at Kashima in November 1991, is completed, a 3-year operation and research program will begin.

Supporting research for the NEDOL process has been conducted along with the design and construction of the pilot plant.

A 1 ton per day process supporting unit has been operated at Kimitsu, Chiba to examine the liquefaction characteristics in the NEDOL process. In 1991, the unit was operated for 96 days in total, processing Wyoming coal, and the following results were obtained.

- Higher than 50 weight percent of oil yield on MAFC was confirmed at 450°C.
- The effects of temperature and the amount of catalyst, which was synthetic iron sulfide, on product yield were studied.
- The properties of recycle solvent were investigated.
- The formation rate of sediments in the reactors was obtained.

Other research and development includes:

- Rheology of coal slurry
- Mechanism of coke formation in slurry pre-heater
- Pre-treatment of coal for liquefaction
- Development of highly dispersed iron-based catalyst for liquefaction
- Development of catalyst for the hydrogenation of recycle solvent
- Development of slurry letdown valve
- Upgrading of coal liquids

###

HYDROTHERMAL DEWATERING REDUCES REACTIVITY OF BROWN COAL FOR LIQUEFACTION

Hydrothermal dewatering (HTD) is a thermal treatment process which removes moisture from low-rank coals without evaporation, i.e., in liquid form. The process operates at temperatures of 250 to 374°C and pressures above saturated steam pressure to prevent evaporation. HTD has a number of potential advantages as a pre-treatment for brown coal liquefaction, including:

- Non-evaporative removal of over half of the moisture in the coal, reducing energy consumption and CO₂ emissions
- The possibility of slurry transport (pipelines or tankers) and storage (tanks) with improved safety and reduced environmental impact
- The removal of potentially troublesome inorganics (Na, Ca, Mg, Cl) with the evaporated water
- A reduction in reaction pressure and carbonate deposit formation in a liquefaction plant, resulting from CO₂ evolved during functional group decomposition

A research program was developed between the Coal Corporation of Victoria and the New Energy and International Technology Development Organization to evaluate the effects of HTD on liquefaction over a range of reaction conditions. The results of the program were discussed in a paper by P.J. Guy, et al., presented at the Fifth Australian Coal Science Conference held in Melbourne, Australia last November.

Properties of HTD Coals

The composition of the coal samples shows the expected trends with increasing HTD temperature, say Guy, et al., namely a decrease in volatile matter (and consequent increase in fixed carbon), an increase in elemental carbon, and a decrease in sulfur and oxygen, consistent with decarboxylation. These effects are most marked at the highest temperature.

Acid-soluble Na, Ca and Mg decrease with increasing treatment temperature, while chloride content remains essentially unchanged until 300°C is reached. According to the authors, this suggests that sodium is being removed from carboxylates at lower temperatures. As the multivalent cations, including Ca and Mg, are associated with the carboxylate groups, their enhanced release would be expected at the higher temperatures.

Acid-soluble aluminum also shows a marked decrease with increasing treatment temperature, possibly being incor-
porated into the coal in a less soluble form, as the total aluminum determined as Al₂O₃ remains unaffected by HTD. It is believed that incorporation of soluble aluminum additives into the coal structure during HTD has a beneficial effect in displacing other cations (Na, Mg, Ca) which are more prone to deposit formation.

CO₂ surface areas and micropore volumes increase with HTD temperature up to a peak between 250 and 300°C, where a decrease in pore volume occurs. HTD of slurries at lower temperatures (200 to 250°C) results in pore development due to the expulsion of volatile gases and water from the coal. At temperatures approaching 300°C, evolution of tars and resultant pore collapse starts to balance these increases in porosity. At 350°C, both tar formation and pore collapse are significant and the HTD coal thus produced has a lower micropore volume than conventionally-dried (CD) coal.

The effects of HTD on the properties of the dried coals are heavily dependent on both the coal and the processing conditions.

Hydroliquefaction

Table 1 shows the percentage conversions (based on the solid residue remaining after liquefaction) for CD and HTD coals.

Convertions for the CD coal were lower than expected. Previous experiments consistently yielded conversions of approximately 90 percent. It is believed that poor mixing in the rocking autoclave limited the conversion.

Brookfield viscosity measurements (30 to 100°C) showed that all HTD coal/solvent oil slurries exhibit a decrease in viscosity with temperature until 80 to 90°C where a sudden increase was observed. A possible explanation for the observed increase in viscosity is that oil is absorbed into the coal porosity at higher temperatures, causing coal swelling. The absorbed oil causes a reduction in the volume of free oil available for lubrication between particles and effectively increases the particle concentration in the oil.

In general, hydroliquefaction yield appears to decrease with increasing dewatering temperature. With increasing HTD temperature, the ratio of carbon oxides to hydrocarbons decreases steadily, reflecting the prior decarboxylation with increasing severity of HTD pre-treatment. As expected, more CO and CO₂ were produced from liquefaction of the CD coal than any of the HTD coals. Presumably HTD would have a beneficial effect on a continuous liquefaction plant by lowering the total pressure, say Guy, et al.

The authors conclude that hydrothermal dewatering (HTD) may decrease the reactivity and increase the viscosity of coal/solvent slurries for brown coal liquefaction processing. However further work is required to verify this.

###

COAL/WATER FUELS ARE COMMERCIALIZED IN JAPAN

The Japanese Government has been supporting Coal Water Fuel (CWF) technical development with subsidies at Wakamatsu, Wakayama, Tomakomai and Ube, where basic studies, pilot plant tests and long-term combustion demonstrations have been undertaken. In addition, private companies such as Japan COM, Ube Industries and JGC Inc. have accumulated their own CWF technology and experiences. These CWF commercialization efforts were discussed in a paper by N. Nagata, presented at the Opportunities in the Synfuels Industry Symposium held in Bismarck, North Dakota last August.

**TABLE 1**

| HYDROLIQUEFACTION CONVERSIONS
| (Percent Dry Coal Basis) |
|--------------------------|------------------------|
| Coal to Solvent Ratio    | CD  | HTD200 | HTD250 | HTD300 | HTD350 |
| 1:2                      | 70.5| 63.6   | 74.1   | 50.9   | 50.4   |
| 1:2.5                    | 75.0| 66.0   | 63.7   | 59.2   | 58.6   |

CD - Conventionally dried coal
HTD - Hydrothermally dewatered coal at temperature in °C

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4-38
CWF West Japan and Tayca

JGC Inc.'s CWF preparation plant, a joint venture with Chinese partners in Shijiu, Shandong, China, delivered its first shipment of 3,129 tons of CWF last March. This CWF was used in commercial combustion tests in a 45-ton per hour (steam) CWF-burning boiler at Tayca Company Ltd.'s Okayama factory. The boiler operates at 88 percent efficiency, consuming 7,280 kilograms of CWF per hour.

The Yanzhou coal used for this CWF typically has a maximum of 8 percent total moisture, 8 percent ash, 0.6 percent sulfur and 33.5 percent volatile material. The produced CWF has a net high heating value of 5,080 kilocalories per kilogram and a net low heating value of 4,750 kilocalories per kilogram.

The average price of the 5,279 tons of CWF imported in March and April of 1992 was reported at US$61.38 per ton, and the future price level can be estimated at US$60 plus or minus US$3 per ton. On a normalized 6,000 kilocalorie per kilogram basis, CWF, at US$78.10 per ton, competes favorably with heavy oil at US$103.68 per ton, but cannot compete with Australian steam coal at US$47.84 per ton.

Japan COM

Since January 1988, Japan COM Company Ltd. has been supplying as much as 70,000 tons per year of CWF, which has been burned together with coal and heavy oil by the No. 8 unit (600 megawatts) of the Joban joint thermal power station at Nakoso. In November 1991, Japan COM started the construction of a large-scale CWF preparation plant with an annual production capacity of 500,000 tons at the request of three utility companies: Tokyo Electric Power, Tohoku Electric Power and Joban Joint Thermal. The group decided to increase CWF combustion at the same No. 8 unit from 70,000 to 500,000 tons a year. This plan intends to promote both diversification and greater economization of fuels by changing the current fuel ratio of oil, coal and CWF (54, 40 and 6 percent) to a new ratio (20, 40 and 40 percent).

At Onahama, Japan COM is now preparing to mass produce CWF with its full-scale capacity of 870,000 tons a year. Hitachi Ltd., and Kawasaki Heavy Industries Corporation were each selected to construct a 50-ton per hour CWF manufacturing facility. A new slurry pipeline of about 9 kilometers is also under construction to connect the CWF plant with the Nakoso power station.

The project's total cost will be about ¥16.5 billion (approximately US$127 million).

Japan COM chose Australian coal as the most suitable material for its CWF. Out of the selected Warkworth, Moura, Mt. Thorley and Lemington coals, 350,000 tons per year will be used.

CWF with a pulp density of 70 percent will be produced by mixing coal and water in a ratio of about 8:2. The CWF has a heating value of 5,000 kilocalories per kilogram and an ash content of 10 percent. The CWF will be designed to allow easy transport, storage and stable combustion in the boiler. Consequently, a large-scale port facility and unloading, storage and handling facilities will not be necessary.

In the past, the barrier against commercialization of CWF has been its low economic competitiveness, says Nagata. However, today, considering the necessity of fuel-source diversification and the international oil situation, and also recognizing greater siting problems for new power stations, the decision to burn CWF at the Nakoso power station on a larger scale may have its real aim at securing a future power supply.

Ube Industries

Ube Industries Company, Ltd. completed a demonstration of its super-low-ash CWF in September 1991, after completing a series of studies on CWF combustion, facility performance and economics. A specially remodeled CWF boiler equipped with Ube designed CWF burners was used for the test. This research was financed by MITI to promote co-oil utilization technology as a demonstration project. During this test, Ube burned about 30,000 tons of both normal and deashed CWF. CWF preparation, storage and transportation tests were also carried out.

Coal densities of about 70 percent were observed for both normal and deashed CWF. The ash content was reduced from about 10 percent to between 1.0 and 2.5 percent in the deashed CWF. The lower heating value of the deashed CWF was slightly higher, at 4,700 to 5,000 kilocalories per kilogram, than in the normal CWF, at 4,300 to 4,600 kilocalories per kilogram.

Through the demonstration test at Ube, the following facts were confirmed:

- Fuel conversion from heavy oil to CWF fuel was found to be practically feasible by modification of a heavy-oil boiler at a maximum level which included an additional CWF feeding device and remodeling of both its burners and secondary super heater.
- Maximum derating of boiler output was 73 percent of original capacity.
- The handling characteristics of deashed CWF were proven to be close to that of heavy oil. In particular, the controllability of fuel flow was found to be equivalent to that of heavy oil.
- In using the deashed CWF, the anti-erosion durability of the related mechanical parts was
found to be much more ameliorated than with normal CWF.

####
ENVIRONMENT

RECOVERY FROM COAL GASIFICATION MOST EFFICIENT CO₂ REMOVAL TECHNIQUE

As part of the International Energy Agency Greenhouse Gas Research and Development Program, from 1991 to 1992, an exploratory research program on CO₂ removal was carried out in The Netherlands. The goal was to obtain a better understanding of the technical and economic feasibility of CO₂ recovery from flue and synthesis gases and the sustainable storage of CO₂ outside the atmosphere.

The main sponsors of the research program were the Ministry of Housing, Physical Planning and the Environment and the National Research Program on Global Air Pollution and Climate Change. The total budget was 1.5 million Dutch guilders (1Dfl = $0.6).

CO₂ Recovery Based on Coal Gasification

CO₂ recovery based on coal gasification shows the smallest decrease in efficiency of electricity production. In fact, efficiencies of over 36 percent can be attained in combination with CO₂ recovery as illustrated in Table 1. Two CO₂ recovery technologies were studied.

In the first case a shift reaction is applied after gasification resulting in a fuel gas which consists mainly of hydrogen and carbon dioxide. For separation of H₂ and CO₂ a number of options were studied: freezing out the CO₂, membrane separation, hydrogen recovery, physical absorption and chemical absorption. The best option is physical absorption (using selexol). The components for the favored shift/selexol concept are commercially available but were never applied in this combination. The technology is ready for demonstration.

The second IGCC (integrated gasification combined cycle) approach makes use of a gas turbine in which the fuel is combusted in a mixture of oxygen and recycled CO₂. The combustion products (mainly CO₂ and water) are expanded through the turbine section. After cooling and removal of the water, the CO₂ is recycled. Part of the compressed CO₂ is used in the gas turbine combustion chamber, the remainder is exported. As CO₂ is the main working fluid in

TABLE 1

KEY RESULTS FOR COMPLETE POWERPLANT CONCEPTS

<table>
<thead>
<tr>
<th>Type of Plant and Method of Recovery</th>
<th>Net Conversion Efficiency, %</th>
<th>Specific CO₂ Emission, g/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>IGCC: CO₂/O₂ Combustion (Texaco)</td>
<td>34.8</td>
<td>5</td>
</tr>
<tr>
<td>IGCC: CO₂/O₂ Combustion (Shell)</td>
<td>36.0</td>
<td>30</td>
</tr>
<tr>
<td>IGCC: Shift and Physical Absorption (Texaco)</td>
<td>36.4</td>
<td>139</td>
</tr>
<tr>
<td>Pulverized Coal: Chemical Adsorption (Retrofit)</td>
<td>29.7</td>
<td>105</td>
</tr>
<tr>
<td>Natural-Gas-Fired Combined Cycle: (Chemical Absorption)</td>
<td>44.9</td>
<td>86</td>
</tr>
<tr>
<td>Reference Coal-Fired Powerplant</td>
<td>42-43</td>
<td>800-820</td>
</tr>
<tr>
<td>Reference Natural-gas-fired powerplant</td>
<td>52</td>
<td>390</td>
</tr>
</tbody>
</table>
the gas turbine, the properties differ strongly from a conventional gas turbine. The results of integrating such a gas turbine in an IGCC plant are given in Table 1. Such a CO₂-gas turbine is not available at present. Starting such a costly development process is only justified if it gives clear advantages over the IGCC/shift/selexol process already described.

Chemical Absorption and Other Recovery Techniques

A number of options for CO₂ recovery were evaluated. In most cases chemical absorption using amines is the most attractive.

For the recovery of CO₂ from the flue gas of conventional coal-fired powerplants, the use of gas separation membranes is more expensive than chemical absorption, mainly due to the high power requirements for the compression of the flue gases. Gas absorption membranes are used in conjunction with chemical absorption liquids where the conventional absorption column is replaced by a membrane contactor. This modification could increase the conversion efficiency of the powerplant by about 0.5 percent.

For natural-gas-fired combined cycle powerplants the most cost-effective option is also chemical absorption, with an overall conversion efficiency of about 45 percent. An alternative is a powerplant based on a gas turbine using combustion in a CO₂/O₂ mixture. A system based on methane reforming of natural gas (to a large extent similar to an IGCC plant) was also investigated. Its efficiency was low—about 37 percent.

CO₂ Recovery in Manufacturing Industries

The 20 manufacturing plants with the largest CO₂ emissions in The Netherlands, together are responsible for about 20 percent of the total Dutch CO₂ emissions. The main sectors are refineries, iron and steel, petrochemical and fertilizer industries.

Carbon dioxide recovery can be accomplished in refineries equipped with a residue gasification unit. The gasification product is fed to a shift reactor to produce hydrogen for other refinery processes. The CO₂ that is coproduced can be recovered easily, to avoid about 25 percent of the CO₂ emissions in future refineries.

Another attractive option is available to the fertilizer industry. In producing ammonia, which is one of the main feedstocks for fertilizer production, about 50 percent of the CO₂ output of the fertilizer industry is already recovered. Part of this is utilized, the remainder is vented to the atmosphere. The CO₂ can be recovered by compressing this stream to transport pressures. Estimated mitigation costs are in the order of 20 Dfl per tonne of CO₂ avoided.

More costly options were identified in the iron and steel industry: recovery of CO₂ from blast furnace gas; and in the petrochemical industry: the use of low temperature waste heat (100 to 150°C) for supplying the reboiler duty of a chemical absorption process.

Storage of CO₂

According to one of the studies, CO₂ storage in aquifers is technically feasible. Extended simulations of the behavior of CO₂ have been carried out for sample reservoirs; in one of these aquifers 15,000 tonnes of CO₂ per day can be injected for 8 years. The Dutch subsurface contains a large number of aquifers that are potentially suitable. The total aquifer storage capacity for CO₂ is estimated to be 1.2 gigatonnes of CO₂.

The costs of injection are estimated to be 0.7 and 1.2 Dfl per tonne of CO₂ injected for aquifers above and below 1,000 meter depth respectively.
INCREASED COAL CONSUMPTION IN 1993 FORECAST FOR U.S.

United States coal consumption is expected to post gains by year-end 1993, while overall production is likely to maintain its 1 billion ton level, according to the National Coal Association's (NCA) 1993 forecast. The forecast, prepared by NCA's Economics Committee, is based upon gross domestic product (GDP) forecasts made last year prior to the presidential election. According to the GDP forecast, the economy is expected to grow at an annual rate of 2.6 percent during 1993.

The 1993 coal production and consumption forecast is presented in Table 1. The projected consumption for major markets is discussed here.

TABLE 1
NATIONAL COAL ASSOCIATION 1993 FORECAST
(Millions of Tons)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Domestic Markets</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Electric Utilities</td>
<td>786</td>
<td>795</td>
<td>1.15%</td>
</tr>
<tr>
<td>Coking Coal</td>
<td>34</td>
<td>34</td>
<td>0.00%</td>
</tr>
<tr>
<td>Industrial and Retail</td>
<td>82</td>
<td>82</td>
<td>0.00%</td>
</tr>
<tr>
<td>Total Domestic Markets</td>
<td>902</td>
<td>911</td>
<td>1.00%</td>
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<tr>
<td>Exports</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Canada</td>
<td>13</td>
<td>11</td>
<td>-15.38%</td>
</tr>
<tr>
<td>Overseas</td>
<td>93</td>
<td>88</td>
<td>-5.38%</td>
</tr>
<tr>
<td>Total Exports</td>
<td>106</td>
<td>99</td>
<td>-6.60%</td>
</tr>
<tr>
<td>Total Consumption</td>
<td>1,008</td>
<td>1,010</td>
<td>0.20%</td>
</tr>
<tr>
<td>Total Demand</td>
<td>1,009</td>
<td>1,005</td>
<td>-0.40%</td>
</tr>
<tr>
<td>Production</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>East</td>
<td>606</td>
<td>595</td>
<td>-1.82%</td>
</tr>
<tr>
<td>West</td>
<td>402</td>
<td>405</td>
<td>0.75%</td>
</tr>
<tr>
<td>Total U.S.</td>
<td>1,008</td>
<td>1,000</td>
<td>-0.79%</td>
</tr>
<tr>
<td>Imports</td>
<td>3</td>
<td>3</td>
<td>NA</td>
</tr>
<tr>
<td>Total Supply</td>
<td>1,009</td>
<td>1,005</td>
<td>-0.40%</td>
</tr>
</tbody>
</table>

Note: All data include anthracite
Sales to industrial users increased by 1.7 percent through mid-1992, a sharp improvement from the flat sales a year earlier. Sales to commercial users and to residential users were lower during the same period due to cooler than normal weather patterns. Both are forecast to increase their electricity use during 1993, assuming normal weather patterns.

**Metallurgical Coal**

Metallurgical coal use continues to be flat at approximately 34 million tons. Steel production improved in 1992, increasing 7.1 percent to 93.5 million tons. Domestic raw steel production will again increase in 1993 to a forecast 95 million tons. Pig iron production in 1993 is likely to approximate 53 million tons, the same level reached during 1992.

**Industrial/Retail**

Coal use by industry and for residential/commercial use in 1993 will remain level at the 1992 level, 82 million tons. Approximately 76 million tons of this total are used by industry, and 6 million are used for residential/commercial purposes. As in past years, the paper, cement, and chemical industries will use 60 percent of the coal burned directly by industry.

**Exports**

Although export tonnages have been the bright spot for United States coal producers in the last 3 years, both 1992 and 1993 will see a slight reduction in demand for United States coal on the overseas markets.

Metallurgical coal shipments to destinations overseas will decline slightly in 1993. The affected markets last year were Brazil, Belgium, France, Spain and Korea.

The 2 million ton decline in United States metallurgical coal demand in 1993 is expected to be spread over all markets. Overseas steam coal shipments are expected to drop slightly during 1993. The decline in demand for United States coal is widespread and is due to a slow economic recovery, high coal stocks on the ground, especially in Europe, and availability of coals from lower cost countries. This rather cyclical decline in demand for United States coal is expected to reverse by 1994 and 1995.

During 1993, United States shipments to Canada are likely to decline as Ontario Hydro brings on new nuclear capacity and the fate of the steel industry in Canada remains uncertain.
RECENT PUBLICATIONS

The following papers were presented at the Ninth Annual International Pittsburgh Coal Conference, October 12-16, 1992 in Pittsburgh, Pennsylvania:

Steedman, W.G., "Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal"


Pless, D.E., "Status of Tampa Electric Company's Polk Unit #1—IGCC Powerplant"

Motter, J.W., et al., "Pinon Pine IGCC Project—Overview and Update"

Mann, G.J., "The Wabash River Coal Gasification Repowering Project"

Silvonen, R.T., et al. "Toms Creek IGCC Demonstration Project"

Tiny, A.M., "Design, Construction and Startup of ENCOAL Mild Gasification Demonstration Plant"

Hippo, E.J., et al., "Coal Refining: A Concept to Produce New Coal Products"

Whelan, M.P., "Molten Carbonate Fuel Cell Development Status and Market Opportunities"


Vandervort, C.L., et al., "Development Status of a Utility-Scale Externally Fired Combined Cycle"


Hsu, B., et al., "Combustion Characteristics of Coal-Water Slurry Fuel in a Medium Speed Diesel Engine"


Robertson, A., et al., "Initial Second-Generation PFB Carbonizer Pilot Plant Test Results"

Sadowski, R.S., "Dual (Fully) Fired Integrated Gasification Combined Cycle (DF-IGCC)"

Haq, Z., et al., "Gasification for the Wilsonville Power Systems Development Facility"

Tsatsaronis, G., et al., "Thermoeconomics in Search of Cost-Effective Solutions in IGCC Powerplants"

Simbeck, D.R., et al., "Coal Gasification: Status, Applications and Technology"

Epstein, M., et al., "Experience with High Temperature Dust Filtration in Coal Gasification Systems"


Benham, C.B., et al., "A Decade of Research and Development in Fischer-Tropsch Applications"

Herman, R.G., et al., "Conversion of Coal-Derived Synthesis Gas to High Octane Oxygenates: Coupling Base-Catalyzed Alcohol Synthesis to Acid-Catalyzed Ether Synthesis"

Akkerman, A., et al., "Methanol Synthesis in Slurry and Trickle Bed Reactors"

Zoeller, J.R., et al., "Eastman Chemical Company Acetic Anhydride Process"
Poddar, S.K., et al., "Capital Cost and Economics of the Two Stage Direct Coal Liquefaction Plant"

McGurl, G.V., et al., "Development Strategy for Advanced Liquefaction Concepts"

Comolli, A.G., et al., "A Study of Reactor Configuration in Coal Liquefaction"

Hager, G.T., et al., "An Investigation of Pretreatment Concepts for Direct Coal Liquefaction"

Hirschon, A.S., et al., "Process Methods for Enhanced Coal Liquefaction"

Parker, R.J., et al., "Advanced Direct Coal Liquefaction Concepts—The CED/ARC Approach"

Cronauer, D.C., et al., "Effect of Temperature Upon Functionality Changes During Coal Liquefaction"

Gbordzoe, E.A., et al., "Development of a Pressurized Transport Gasifier by the M.W. Kellogg Company"

Saxena, S.C., et al., "Variation of Heat Transfer Coefficient in a Baffled Slurry Bubble Column as Applied to Indirect Coal Liquefaction"

Jagtoyen, M., et al., "Synthesis of Activated Carbons from Bituminous Coal Using H₃PO₄ and KOH"

Meyer, L.G., "The Charfuel Coal Refinery/IGCC Cogeneration Facility—Clean, Efficient, Economical Power and Products From Coal"

Ueda, F., et al., "Pressurized Two-Step Spiral Flow, Entrained Bed Gasification R&D (50t/d Pilot Plant R&D)"


Yin, X.-L., et al., "Hydrogenation of Carbon Dioxide Over Zeolite Supported Bimetal Catalysts"

Parfitt, D.S, et al., "The Use of Bimetallic Organometallic Compounds as Precursors of Dispersed Catalysts for Coal Liquefaction"

Ogunsola, O.I., et al., "Effect of Hydrothermal Treatment on the Pyrolysis Behavior of Alaskan Low-Rank Coals"

Zondlo, J.W., et al., "Preparation of an Ultra-Low Ash Coal Extract and Its Use for the Production of Carbon Products"

Stiller, A.H. ,et al., "Evaluation of a Novel Pyrite/Pyrhotite Catalyst for Coal Liquefaction"

Chen, W.J., et al., "Generation of Carbon Black From Coal"

Lacey, J.A., et al., "Operation of the BGL Gasifier at 70 Bar Pressure"

Ji, Y.-Y., et al., "Study on the Reaction Mechanism of Hydrogenation of CO₂ Over Ru-Cu Loaded Catalyst"

Yin, X.-L., et al., "Methanation of Carbon Dioxide Over Rey Zeolite Supported Ruthenium Catalyst"

Sarkar, S., et al., "Total Conversion of Coal Into a Binder"


Moodie, J., et al., "Gasification Modeling in the British Coal Topping Cycle Project"

Garland, R., "A Summary of Advanced Coal Fueled Power Generation Concepts"

Gbordzoe, E.A., et al., "Development of the M.W. Kellogg's Pressurized Transport Combustor for Power Applications"

Myrick, S., et al., "A 50 MW, Prototypical MHD Coal Fired Combustor"

Spencer, R.W., "Principal Scientific Uncertainties Related to Global Climate Change"

Bradley, R.A., "Climate Change: Recent International Developments"

Kinsman, J.D., "An Overview of Methods to Sequester Atmospheric Carbon Dioxide (CO₂) on Land and in the Oceans"

Holmes, C., "Global Climate Change Policy: Status and Prognosis"

South, D., et al., "Macroeconomic Impacts of Emission Reduction Strategies"

Drummond, C., "CO₂ Removal, Recovery and Disposal: Options and Costs"

Riemer, P.W.F., et al., "An Overview and Initial Results From the IEA Greenhouse Gas R&D Programme"

Grossman, S.L., et al., "Mechanism of Production of Molecular Hydrogen Associated With Low Temperature Coal Oxidation"

The following papers were presented at the Fifth Australian Coal Science Conference, held at The University of Melbourne, Australia, November 30-December 2, 1992:


Pearman, G.I., "Advances in Greenhouse Science: A 1992 Update"

Emerson, G.M., "Greenhouse: Sensible Response Options and Implications for the Coal Industry"

Graham, R.L., "Encouraging Innovation in the Coal Industry"

Katsushima, S., et al., "Present Status of Japanese Coal Liquefaction Projects"

Chan, J.S.T., et al., "Brown Coal Liquefaction Under Mild Conditions"

Numata, J., et al., "Overview of Research on Upgrading of Coal Derived Liquid in Japan"

Townsend, A.T., et al., "Catalyst Design for the Upgrading of Australian Coal-Derived Liquids"

Sakanishi, K., et al., "Combined Utilization of Solvent and Catalyst in the Liquefaction of Morwell Brown Coal"

Guy, P., et al., "Hydrothermal Dewatering as a Pretreatment for Brown CoalLiquefaction"

Okuyama, N., et al., "Study on the Mechanism of Solvent De-Ashing of Heavy Liquefaction Products"

Yanai, S., et al., "Operation Summary of Brown Coal Liquefaction Pilot Plant and Effect of Reaction Conditions on Yield"

Smith, B.E., "Hydroliquefaction of Australian Coals"

Nishiyama, Y, et al., "An Integrated Coal Conversion Process"


Huynh, D., et al., "Gasification of Latrobe Valley Brown Coals in a Fluidized-Bed Process"

Taylor, G.H., et al., "Gasification of Brown Coal: New Information From TEM"
Kelly, M.D., et al., "Pyrolytic Nitrogen Release From Australian Low-Volatile Coals"

Chen, J.Y., et al., "The Combustion Reactivity of Chars From Australian Low-Rank Coals"

Takanohashi, T., et al., "Structure of the Bituminous Coals Giving High Extraction Yields More Than 50% (DAF) at Room Temperature"

Ralph, J.P., et al., "Depolymerization of the Macromolecular Fraction of Lignite by Mesophilic and Thermotolerant Aerobic Microorganisms"


The following papers were presented at Power-Gen '92, the Fifth International Conference and Exhibition for the Power Generating Industries, held November 17-19, 1992 in Orlando, Florida:

LaHaye, P.G., "Emerging Technology to Keep Coal as the Fuel of Choice for Electric Utilities—Operating Gas Turbines in an Externally Coal Fired Combined Cycle"

Pell, J., "A Status Report on the Clean Coal Technology Program"


Thibeault, P.R., et al., "Coal Gasification—An Environmentally Acceptable Coal-Burning Technology for Electric Power Generation"

Mahagaokar, U., et al., "Gasification of Petroleum Coke in the Shell Coal Gasification Process"

Sundstrom, D.G., "The Repowering of Wabash River Station Unit No. 1 With Destec Energy Coal Gasification"


Walker, D.G., "The Clean Burning of Coal to Electricity"

Cohn, A., et al., "Performance and Economic Characteristics of Compressed-Air Storage With Air Humidification (CASH) Powerplant with Integrated Gasification and Natural Gas Firing"


Barot, D.T., et al., "Performance Cost and Marketing of 200 MW Carbonate Fuel Cell Powerplants Based on Coal/Natural Gas/Phased Construction"

Quimby, J.M., et al., "Hot Gas Cleanup Approaches for Emerging Combustion Technologies"

The following papers were presented at the Sixth International Conference on Gas Turbines in Cogeneration and Utility, Industrial and Independent Power Generation, held in Houston, Texas, September 1-3, 1992:

Baumann, P.D., et al., "Coal Gasification-Based Integrated Coproduction Energy Facilities"

Maurer, R.E., "Destec's Successes and Plans for Coal Gasification Combined Cycle (CGCC) Power Systems"

Rath, L.K., et al., "Research and Development Efforts at the Department of Energy Supporting Integrated Gasification Combined Cycle (IGCC) Demonstrations"

Baker, D.C., "Hazardous Air Pollutants and Other Trace Constituents in the Syngas From the Shell Coal Gasification Process"
STATUS OF COAL PROJECTS

COMMERCIAL AND R&D PROJECTS (Underline denotes changes since December 1992)

ACME COAL GASIFICATION DESULFURING PROCESS - ACME Power Company (C-9)

American Plastics and Chemicals, Inc. (APAC), based in Los Angeles, California, signed an agreement in 1990 to acquire the Acme Powerplant located in Sheridan, Wyoming. The Acme facility is a 12 megawatt coal-fired steam plant, which has been idle since 1977 when it was shut down in anticipation of new power generating facilities.

APAC formed Acme Power Company, a wholly-owned subsidiary, which will bring the Acme plant up to current environmental standards with appropriate emission controls prior to bringing it back on-line. The plant will initially operate in a conventional mode, using locally purchased coal. In addition to providing revenue through electric power sales, the plant, with its modular design, will provide for a long term commercial demonstration of the desulfurizing coal gasification process which APAC has optioned.

The project will demonstrate the commercial viability of the desulfurizing gasification technology and make it ready for the retrofit of other coal-fired facilities.

The APAC coal gasification process can emphasize either acetylene production from calcium carbide or power generation, depending on the coal-to-limestone ratio used. Increasing the limestone component produces byproduct calcium carbide, from which acetylene can be produced. Increasing the coal component results in byproduct calcium sulfide.

APAC's consulting engineers estimate that it will take about one year to bring the plant on-line after power sale contracts, environmental permits, and project financing have been put in place.

Project Cost: Undisclosed

ADVANCED COAL LIQUEFACTION PILOT PLANT AT WILSONVILLE - 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. The Department of Energy began cofunding Wilsonville in 1976.

The initial thrust of the program at the pilot plant was to develop the SRC-I process. That program evolved over the years in terms of technology and product slate objectives. Kerr-McGee Critical Solvent Deashing 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 hydrotreatment in the second stage accomplishes two distinct purposes; (1) higher-quality distillable 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 Deashing 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 distillates 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 hydrotreatment. 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 hydrotreatment 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.

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.

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COMMERCIAL AND R&D PROJECTS (Continued)

Work using the Amocat catalyst indicated the need to improve first 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. Further improvements for low-rank coal liquefaction were demonstrated using dispersed molybdenum catalyst in place of extracted catalyst in the first reaction. In addition to increasing productivity, the dispersed catalyst permits the use of a less expensive entrained flow (bubble column) reactor in place of the fluidized (sublublated) bed which is still required in the second reactor. Dosage of less than 200 ppm was effective, thus no catalyst recovery is required.

Project Cost: Construction and operating costs (through calendar 1990): $139 million

ADVANCED POWER GENERATION SYSTEM — British Coal Corporation, United Kingdom Department of Trade and Industry, European Commission, PowerGen, GEC/Aisthom (C-15)

British Coal Corporation is carrying out a research program to develop an advanced coal fired power generation system. In this system coal is gasified to produce a fuel gas which is used to drive a gas turbine. The waste heat recovery from the gas turbine is then integrated with a fluidized bed combustion steam turbine cycle.

The integrated system is expected to have an efficiency of about 48 percent.

At present the different technologies are being developed separately. A 12 tonne per day, air blown, pressurized, spouted bed gasifier developed at the Coal Research Establishment, Gloucestershire, started operating in 1990. This is providing design data for the next scale of plant.

The combustor, necessary to optimize the steam cycle and to burn unconverted carbon from the gasifier, is a CFBC.

At Grimethorpe, British Coal's large scale experimental PFBC has completed a program where a coal derived gas is passed through an experimental gas turbine. In conventional PFBC, coal is burned under pressure and the hot pressurized gases are fed directly into a gas turbine. However the operating temperature of a PFBC is usually only about 850°C to avoid sintering of the ash. This comparatively low temperature at the gas turbine inlet limits efficiency.

To overcome this, British Coal engineers proposed a topping cycle. It entails burning a coal-derived fuel gas in the gas in the gas turbine combustor, at a temperature to 1,260°C or more. In the Grimethorpe experiment the fuel gas was propane. In due course it will be provided by a spouted bed gasifier.

The gas turbine operation is funded by British Coal, United Kingdom Department of Trade and Industry, PowerGen, GEC/Aisthom and EPRI. The gasifier work is funded by British Coal and the European Community.

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 Johannesburg. 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.

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" 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 in this area 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 was started up at the Energy and Environmental Research Center in Grand Forks, North Dakota in the fall of 1990.

BEWAG GCC PROJECT - BEWAG AG, EAB Energie-Anlagen Berlin GmbH, Ruhrkohle Oel und Gas GmbH, and Lurgi GmbH (C-35)

BEWAG AG of Berlin, in cooperation with others listed, 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 195 megawatt pressurized circulating fluidized bed (CFB) combined cycle powerplant, with 95 megawatts obtained from the gasification, and 100 megawatts from the combustion section. As both sections may be operated individually, the 52 megawatt gas turbine could also operate on oil or natural gas.

An engineering study to investigate the general feasibility of both pressurized CFB gasification and the coupling of pressurized CFB gasification with atmospheric CFB combustion was concluded in 1986.

A second phase component testing program, costing DM12 million and supported by the German Ministry of Research and Technology, was carried out by a working group made up of BEWAG/EAB (Berlin), Ruhrkohle Oel and Gas GmbH (Boettrop), and Lurgi GmbH (Frankfurt), under the project leadership of EAB Energie-Anlagen Berlin GmbH.

In this study, the design risks of key components were eliminated by detailed tests at pressurized charging valves and the condenser for carbonized residues. The availability of hot gas cleaning was proved with test series at electrostatic precipitators and tube filters. The now finished study allows the enlargement to a scaled up powerplant. This powerplant design shows a low grade of complexity on the gasification plant (a result of the dry procedure in gas cleaning) and minimized demand of coal and lime quality. The emission of exhaust fumes is reduced by the well known low emission of the CFB coal combustion and the high efficiency grade of the combined cycle. The only residues are flue gases and ash. The flue gas does not need to be after-treated. As a result of these characteristics, the study found a minimal risk for investment.

BHEL COAL GASIFICATION PROJECT – Bharat Heavy Electricals Limited (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 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 of 25 to 45 percent by weight. The coals have high ash fusion temperature in the range 1,523-1,723°K. In the PEDU, coal is gasified by a mixture of air and steam at around 1,173°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 early 1989 and further test trials were conducted.

In Phase II of the fluidized bed coal gasification program, basic engineering of a demonstration scale 150 ton per day coal capacity gasification plant has been completed. The demonstration plant will be integrated with the existing 6.2 megawatt electrical gas turbine/steam turbine combined cycle plant.

Project Cost: Not disclosed
BHEL COMBINED CYCLE DEMONSTRATION PLANT – Bharat Heavy Electricals 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, testing various coals with ash content in the 25 to 40 percent range.

The test program on this plant has been completed and the plant’s performance has been evaluated. A comprehensive test program was initiated 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 Germany (C-60)

During operation of the pilot plant the process improvements and equipment components have been tested. The last improvement made being 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 of coal in more than 2,000 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 tons per cubic meter per hour. 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 sulfur 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 325,000 tons of heavy oil have been processed. A conversion rate over 90 percent and an oil yield of 85 percent have been confirmed.

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 Ministry of Research and Development of the Federal Republic of Germany.

Project Cost: DM830 million (by end-1987)

BRITISH COAL LIQUID SOLVENT EXTRACTION PROJECT – British Coal, British Department of Energy, European Economic Community, Ruhrkohle AG, Amoco (C-70)

British Coal is operating a 2.5 tons per day pilot plant facility at its Point of Ayr site, near Holywell in North Wales 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 carbon 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 dries and pulverizes the coal, then slurries it with a hydrogen donor solvent. The coal slurry is pressurized and heated, then fed to a digester that dissolves up to 95 percent of the coal. The digest is cooled, depressurized and filtered to remove mineral matter and undisolved coal. A fraction of the solvent washes the filter cake to displace the coal extract solution; residual wash oil is recovered by a vacuum that dries the filter cake.
COMMERCIAL AND R&D PROJECTS (Continued)

The coal extract solution is then pressurized, mixed with hydrogen and heated before being fed to the ebullating bed hydrocracking reactors.

The product from this stage is distilled to recover the recyclable solvent and produce LPG (propane and butane), naphtha and mid-distillate. A byproduct pitch stream is siphoned off although material in this boiling range is primarily returned to the digestion stage as part of the solvent. The remaining streams consist of light hydrocarbon gases and heterogases formed from the nitrogen and sulfur in the coal.


BROKEN HILL PROJECT - The Broken Hill Proprietary Company Ltd. (C-SO)

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 H$_2$ 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 percent and 55 percent (DAF) coal have been obtained, depending on coal feed and process type.

Batch micro-autoclaves (50 cubic centimeters) 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.

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 specialized 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&DP) administered by the Australian Federal Government.

This project has been completed. Experimental work ceased in June 1992.

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, tar, and char 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 seconds to 50 minutes), heatup rate (50 degrees C/second to 10 degrees C/second) 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 percent (MAP), and about 15 percent for subbituminous coal.

A process for producing clean carbon black and coproduct hydrogen-rich gas and liquid methanol competitive with current prices of oil and gas is being developed. The HYDROCARB process can use any carbonaceous feedstock including coal, char, biomass and municipal solid waste. HYDROCARB provides clean fuel for heat engines (turbines and diesels), and offers reduced CO$_2$ emissions.

Project Cost: $200,000
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

CALDERON ENERGY GASIFICATION PROJECT – Calderon Energy Company, United States Department of Energy (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) was completed in 1990. Test operation began in October 1990 and ran at 50 percent capacity during the early stages.

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 specified for an operating pressure of 350 psig as would be required to support combined cycle power production.

The pilot project, designed to process 25 tons of coal per day, is expected to operate for six to twelve months while operating data is gathered and any “bugs” in the system are worked out.

The federal government has contributed $12 million toward project costs, with another $1.5 million coming from the Ohio Coal Development Office.

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 V to build a cogeneration facility supplying 87 megawatts of electricity and 613 tons of methanol per day. The project did not receive funding, however, in Round III or IV. 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: Total Cost $242 million, PDU $20 million

CHARFUEL PROJECT – Wyoming Coal Refining Systems, Inc., a subsidiary of Carbon Fuels Corporation (C-110)

Wyoming Coal Refining Systems, Inc. (WCRS) has secured about half the financing required for a 150 ton per day Charfuel project at the Dave Johnston Powerplant near Glenrock, Wyoming. The plant would include gas processing and aromatic naphtha recovery with off-site hydrotreating and product quality verification.

The State of Wyoming has contributed $8 million and has committed to provide an additional $8.5 million in assistance, contingent on WCRS raising a certain amount of private capital. WCRS has secured over $4 million in capital and contributions.

WCRS has solicited the U.S. Department of Energy for funding under the Clean Coal Technology program but was turned down for support in Round 4 of the program in 1991.

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 may be 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. The char can also be used as a feedstock for integrated combined cycle gasification (IGCC). Additional products manufactured during the refining process would include ammonia, sulfur, methanol, MTBE, BTX, and aromatic naphtha.

WCRS has completed a program which verified the design of the injector/mixer system. This work was cofunded by the Department of Energy and conducted at the Western Research Institute in Laramie, Wyoming. WCRS is presently in the design phase of an 18 ton per day pilot unit which will integrate the Charfuel hydrcracker with commercially available processes to optimize the operating conditions for the 150 ton per day project as well as commercial facilities.

Wyoming officials have turned down a request from WCRS for an additional $2.5 million in low-interest loans from state funds saying that the requirement for matching funds has not been met.

Project Cost: $24.5 million

CHEMICALS FROM COAL – Tennessee Eastman Co. (C-120)

Tennessee Eastman Company, a manufacturing unit of Eastman Chemical Company, operates its chemicals from coal complex at Kingsport, Tennessee at the design rate of 1,100 short tons per day. The Texaco coal gasification process is used to produce the synthetic gas for manufacture of 1.2 billion pounds per year of acetic anhydride. Methyl alcohol and methyl acetate are produced as intermediate chemicals, and sulfur is recovered and sold.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

The completion of a $200 million expansion program in October 1991 added two new chemical plants to the original complex, doubling its output of acetyl chemicals from coal.

Project Cost: Unavailable

CHINA ASH AGGLOMERATING GASIFIER PROJECT — The Institute of Coal Chemistry, China (C-123)

The Institute of Coal Chemistry (ICC) of the Chinese Academy of Sciences is developing an ash agglomerating coal gasification process. The process is applicable to a wide range of coals including those with high ash content and high ash fusion temperature.

In 1983, a small scale pilot gasifier, or PDU, was set up. At first, different coals were gasified with air/steam as gasifying agents to make low heating value gas for industry. Later, coals were gasified with oxygen/steam to make synthetic gas for chemical synthesis. A pilot scale gasification system of 24 tons per day coal throughput was scheduled for startup in late 1990.

The gasifier is a cylindrical column of 0.3 meter inside diameter with a conical gas distributor and central jet tube on the bottom. The enlarged upper section is 0.45 meter inside diameter in order to settle out the gas-entrained coarse particles. The total height of the gasifier is about 7.5 meters.

Predried coal is blown into the gasifier after passing through the lockhopper and weighing system. Preheated air/steam (or oxygen/steam) enters the gasifier separately through a gas distributor and central jet tube. The coal particles are mixed with hot bed materials and decomposed to gas and char. Because of the central jet, there is high temperature zone in the dense bed in which the ash is agglomerated into larger and heavier particles. The product gas passes through two cyclones in series to separate the entrained fine particles. Then the gas is scrubbed and collected particles are recycled into the gasifier through standpipes. The fines recycle and ash agglomeration make the process efficiency very high.

Based on the PDU data and cold model data, a 1 meter inside diameter gasifier system was designed and constructed. It is to be operated at atmospheric pressure to 0.5 MPa with a coal feed rate of 1 ton per hour.

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 were finished. As the result of this stage, a conceptual design for a prototype unit will be made. This prototype plant will be operational in 1994 and in 1996 the basic project for the demonstration unit will be started. The demonstration unit is planned to be operational in 2001.

Project Cost: US$6.0 million up to the end of 1988. The next stage of development will require US$8 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°C. The 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 CIVOGAS pilot plant has been successfully operating for approximately 10,000 hours since mid 1984 and has been working mainly with subbituminous coals with ash content between 35 to 55 percent weight (moisture-free). 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.

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 Candita coal, the differences being mostly due to the relative contents of ash and moisture in the feedstock.

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 poly-vinyl chloride (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.

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 $690 million project forward. The project sponsor is continuing with engineering and financing efforts.

Project Cost: $690 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 1990s to produce urea if financing is found.

Project Cost: $20 million initial
$200 million eventual

CORDERO COAL UPGRADING DEMONSTRATION PROJECT – Cordero Mining Company (C-170)

Cordero Mining Company will demonstrate the Carbontec Syncoal process at a plant to be built near its mine in Gillette, Wyoming. The demonstration will produce 250,000 tons per year of upgraded coal product from high-moisture, low-sulfur, low-rank coals.

The project was selected by the United States Department of Energy (DOE) in 1991 for a Clean Coal Technology Program award. DOE will fund 50 percent of the $343 million project cost. However, the cooperative agreement is still being negotiated.

The Syncoal process converts high-moisture subbituminous coal into a high-BTU, low-moisture product. Hot oil and flue gas serve to heat the coal and to keep it in an inert atmosphere during coal processing. The hot oil seals the surface against moisture as well as preventing surface degradation during handling.
COMMERCIAL AND R&D PROJECTS (Continued)

It is expected that this upgraded coal product can be used by midwestern and eastern utilities that currently burn high-sulfur, high-rank coals to comply with stricter environmental regulations.

Near-term plans call for an expansion of the demonstration project to a 1 million ton per year plant. Long-term goals are for further expansion to produce 4 million tons per year of upgraded coal.

Project Cost: $34.3 million

CRE SPOUTED BED GASIFIER – British Coal, 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 was sponsored by the European Economic Community (EEC) under two separate demonstration grants. The results obtained 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 were 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 conducted 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 caloric 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. A range of commercial gasifiers with a coal throughput typically of 24 to 100 tonnes per day have been developed. 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.

Although OSC has yet to build the first commercial unit, interest has been shown from a large number of potential clients worldwide.

The application of the process for power generation is now being investigated. Various cycles incorporating a pressurized version of the spouted bed technology have been studied and power station efficiencies up to 47 percent (lower heating value basis) are predicted. A contract with the EEC to develop a pressurized version commenced in January 1989. A 12 tonne/day pilot plant capable of operating at pressures up to 20 bar has been constructed and commissioned at CRE. Commissioning of the plant was completed in June 1990 and extensive operation of the plant has been carried out since.

CRIEPI ENTRANIED FLOW GASIFIER PROJECT – Central Research Institute of Electric Power Industry (Japan), New Energy and Industrial Technology Development Organization (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 ton per day process development unit) adopting a dry coal feed system has been developed and successfully operated. This gasifier design will be employed as the prototype of the national 200 ton per day pilot plant. As of late 1992, the gasifier had been operated for 7,028 hours, and tested on 20 different coals.

Research and development on a 200 ton per day entrained-flow coal gasification pilot plant equipped with hot gas cleanup system and gas turbine has been carried out extensively from 1986 and will be completed in 1994.

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.

For the project to build a 200 ton 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 (IGCC)" with 10 major electric power companies and CRIEPI to carry out this project supported by MITI and NEDO.
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. Coal Gasification Tests began in June 1991 with the air blown pressure nitrogen entrained-flow gasifier. Tests will begin in 1992 for the hot gas clean-up system and a high temperature gas turbine of 1,260°C combustor outlet temperature.

Project Cost: 53 billion yen

DELAWARE CLEAN ENERGY PROJECT - Texaco Syngas Inc., 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 engineering and environmental studies for an integrated gasification combined cycle (IGCC) electrical generating facility. The project calls for the expansion of an existing powerplant adjacent to the Star Enterprise refinery in Delaware City, Delaware. The facility would convert over 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-1996 at an estimated cost of approximately $300 million (1990 dollars).

The project has the potential to reduce substantially overall emissions at the Delaware City facilities, more than double the current electric output and make use of the coke byproduct from 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 powerplant would be upgraded and expanded and would continue to operate as a cogeneration facility.

Project Cost: $250 - 300 million (1989 dollars)

DESTEC SYNGAS PROJECT - Louisiana Gasification Technology, Inc. a subsidiary of Destec Energy, Inc. (C-210)

The Destec Syngas Project, located in Plaquemine, Louisiana, began commercial operations in April, 1987, operating at rates up to 105 percent of capacity. As of January 1993 the project has completed 27,400 hours on coal, has produced 295 trillion BTU of on-spec syngas and has reached 2,400,000 tons of coal processed. A 90-day consecutive production record of 71.2 percent capacity was reached in October 1990. A 30-day consecutive production record of 99 percent availability and 89 percent capacity factor was reached in February 1992.

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 Unocal's Selectox sulfur conversion unit are also used. Oxygen is supplied by Air Products.

Construction of the plant was completed in 1987 by Dow Engineering Company. Each gasification module is sized to produce syngas to power 150-200 megawatt combustion turbines. 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.

In this application, the Destec Syngas 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: $72.8 million

DUNN NOKOTA METHANOL PROJECT - The Nokota Company (C-215)

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. $20 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.

Project Cost: $72.8 million
COMMERCIAL AND R&D PROJECTS (Continued)

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. 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 plans to work closely with local community leaders, informing them of the types and timing of socioeconomic 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 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 would be about 1,600 personnel at the plant and 500 personnel in the adjacent coal mine.

Nokota's schedule for the project 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: $2.6 billion (Phase I and II)
$0.2 billion (CO2 compression)
$0.1 billion (Pipeline interconnection)
$0.4 billion (Mine)

ELSAM GASIFICATION COMBINED CYCLE PROJECT - Elsam (C-218)

Elsam, the Danish utility for the western part of Denmark, in January 1991 submitted a proposal for the construction of a 315-megawatt integrated gasification combined cycle (IGCC) powerplant using the PRENFLO gasification technology. The utility proposes a 3-year test period under the Thermic program of the European Communities. The IGCC plant would be built as a joint project of the German Utility PreussenElektra and the Danish utility Sonderjylland's Hojspaendingsvaerk.

Elsam's proposal was dependent on financial support from the European Communities (EC). When the EC elected to provide funding to the Puertollano, Spain project, Elsam pulled out of the joint project.

Elsam is now working on two new 390-megawatt units, with 285 bar live steam pressure and a live-steam reheat temperature of 580°C. One unit can be fired with natural gas or coal; the second unit is coal fired. Commissioning of the two units is scheduled for 1998 and 1999, respectively.

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, received 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 government will fund 50 percent of the proposed $72.6 million total cost. The demonstration plant will utilize the LFC technology developed by SGI International.

The plant is designed to be 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 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 was 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{2}, NO\textsubscript{2}, CO, hydrocarbons and particulates. There will be no waste water and source water requirements will be very small.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

Ground was broken at the Buckskin mine site for the commercial process demonstration unit in late 1990. Work continued through the winter with the foundations being in place by early 1991. Construction was completed by mid-1992. The plant had been operated for several days by the end of 1992. 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.

The plant completed a 36-hour test run in June 1992 during which it operated at about 70 percent of its capacity. The solid and liquid fuels produced during the test met or exceeded the production specification.

Two companies have agreed to purchase the fuels produced at the ENCOAL facility. Wisconsin Power and Light has agreed to buy about 30,000 tons of the solid fuel for use at its coal-fired powerplants. TEXPAR Energy Inc. will buy up to 135,000 barrels per year of the liquid fuel that it will market to industries.

In June 1992, Zeigler Coal Holding Company signed a letter of intent to purchase Shell Mining Company, with a target closing date in October 1992. The ENCOAL project will not be affected by the change in ownership. The United States Department of Energy has approved funding for Phase III—plant operation and testing.

Estimated Project Cost: $72.6 million

FREETOWN IGCC PROJECT – Texaco Syngas Inc., Commonwealth Energy and General Electric Company (C-223)

The three companies have begun 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 and gasify roughly 4,000 tons of coal per day.

The plant will be one of the world's cleanest coal based powerplants with emissions levels of particulates, SO₂ and NOₓ significantly less than conventional coal plants and below state and federal emissions standards.

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.

Project startup was scheduled for late 1995, but as a result of the continued economic slowdown in the New England economy since 1991, which has led to a reduced demand for new electric power capacity in the region, the project partners have suspended further development activities.

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 received funding for 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 powerplants. 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 (C₅₋₉75 degrees 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 GmbH (GfK) of Saarbrucken, West Germany.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

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. An unsuccessful application was made for Clean Coal Technology (CCT) funds in Round III. The project intends to file an application for CCT funds in Round V.

GE HOT GAS DESULFURIZATION – GE Environmental Services Inc. and Morgantown Energy Technology Center (C-228)

This project was designed to demonstrate the operation of regenerable metal oxide hot gas desulfurization and particulate removal system integrated with the GE air blown, coal gasifier at the GE Corporate Research and Development Center in Schenectady, New York.

Construction of the demonstration facility was completed by 1990 and several short duration runs were done to allow a long duration (100 hour) run to be completed in 1991. The facility gasifies 1700 pounds per hour of coal at 280 psig. Outlet gas temperature ranges from 830-1150°F.

During a 4.5 hour period in a 60 hour run the hot gas cleanup system achieved an overall sulfur removal of 95.5 percent.

GERMAN IGCC POWERPLANT – Stadtwerke Duisburg (C-229)

The project for Stadtwerke Duisburg in Germany is based on the 1,200 TPD PRENFLIO gasifier and two Siemens V64 gas turbines.

A detailed site-specific study was performed together with Siemens/KWU and Linde. Capacity was approximately 170 MWe. After the decision by the European Commission in favor of the Puertollano Project in Spain, the management of Stadtwerke Duisburg decided to stop all activities.

GFK DIRECT LIQUEFACTION PROJECT – West German Federal Ministry for Research and Technology, Saarbergwerke AG, and GFK Gesellschaft fur Kohleverfiussigung MbH (C-230)

For the hydrogenation of heavy oils, mixtures of heavy oil and coal (Coprocessing) 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 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 Maschinen und Anlagenbau Grimma GmbH where an existing hydrogenation pilot-plant is presently being modified to the new concept. Operation began at the end of 1991.

Project Cost: Not disclosed

GREAT PLAINS SYN FUELS PLANT – 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 for a plant designed to produce 250 million cubic feet per day to be constructed by late 1981. However, problems in financing the plant delayed the project and in 1976 the plant design 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) Teaneco 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.
COMMERCIAL AND R&D PROJECTS (Continued)

STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

In January 1986, FERC issued an order approving the project. However, the United States Court of Appeals overturned the FERC decision. In January 1987, the North Dakota Court found the gas purchase agreements valid, that state law was not applicable and that plain-vanilla contract law applied. The court awarded the plaintiffs (DOE/DOJ) a summary judgment for foreclosure. A foreclosure sale was held and DOE obtained legal title to the plant and its assets on 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 had submitted the winning bid for approximately $85 million up-front plus future profit-sharing with the government. Two new Basin subsidiaries, Dakota Gasification Company (DGC) and Dakota Coal Company, operate the plant and manage the mine respectively. Ownership of the plant was transferred on October 31, 1988.

Under Dakota Gasification ownership, the plant has produced SNG at over 125 percent of daily design capacity. In 1989, DGC began concentrating on developing revenue from byproducts. On February 15, 1991, a phenol recovery facility was completed. This project will produce 35 million pounds of phenol annually, providing manufacturers an ingredient for plywood and chipboard resins. The first railcar of phenol was shipped in January 1991. DGC has signed contracts with three firms to sell all of its output of crude cresylic acids, which it produces from its phenol recovery project.

Construction of a facility to extract krypton/xenon from the synfuel plant's oxygen plant was completed in March 1991. Rare gases are to be marketed to the lighting industry starting in early 1991. DGC signed a 15-year agreement in 1989 with the Linde Division of Union Carbide Industrial Gases Inc. to sell all of the plant's production of the krypton/xenon mixture. The first shipment of the product occurred on March 15, 1991. Other byproducts being sold from the plant include anhydrous ammonia, sulfur and liquid nitrogen. Argon, carbon dioxide, naphtha and creosote are also potential byproducts.

In late 1990 DGC filed with the North Dakota State Health Department a revision to the applications to amend the Air Pollution Control Permit to Construct. The revised application defines the best available control technology to lower SO2 and other emissions at the plant.

In late 1990, DGC and DOE initiated a lawsuit against the four pipeline company purchasers contracted to buy SNG. The issues in these proceedings involve: the extent of the pipeline firms' obligations to take and provide transportation for SNG; whether the sales price of SNG has been underestimated; and whether the adjustment made by DGC to the rate the plant charges the pipeline companies to transport their SNG to a point of interconnection on the Northern Border Pipeline system is in accordance with contract terms.

Project Cost: $2.1 billion overall

SYNTHETIC FUELS REPORT, MARCH 1993

4-62
HOT GAS CLEANUP PROCESS — Southern Company Services, Inc. and United States Department of Energy (C-257)

Southern Company Services, Inc. (SCS) Birmingham, Alabama in 1990 began a five-year, $46 million effort to develop advanced gas cleaning systems that could be the final link between advanced coal-fired power generating concepts and the commercial marketplace.

Southern Company will build and operate a state-of-the-art test facility at Alabama Power Company's Wilsonville plant. When complete, this facility will be able to test innovative techniques for cleaning the gas produced by two advanced coal technologies—pressurized fluidized bed combustion and gasification combined cycle systems.

The new test facility at Wilsonville will move the hot gas cleanup techniques from laboratory research to integrated engineering tests. Actual gases from coal gasification or combustion will be used.

SCS has a cooperative agreement with DOE to construct and operate a nominal 50 ton per day coal feed facility for long-term testing of hot gas cleanup. The test facility will be designed to operate in either a gasification or a pressurized fluidized bed combustion (PFBC) mode with gas temperatures up to 1,800°F and a system pressure of 300 psi. The gas generator will be designed to operate with an Eastern bituminous coal and an alternate Powder River subbituminous coal. Researchers will be able to evaluate the performance of the cleanup devices while varying gas temperatures, gas pressures, particulate levels, particulate sizes and types of coal.

Design and construction of the test facility will take three years. Phase 1 of the project is the conceptual design which was initiated January 1, 1991. The detailed design in Phase 2 is expected to be completed by the fall of 1992. Construction of the facility is anticipated to last 15 months, with operations targeted to begin by January 1994. A nominal two years of testing are provided for in the cooperative agreement. Southern Company Services and M. W. Kellogg of Houston, Texas will design the facility, which will be built by Alabama Power Company and operated by Southern Electric International Inc. The Southern Research Institute will oversee the evaluation of the cleanup systems.

DOE is providing $36.8 million, or 80 percent of the contract's total cost. Southern Company Services, with support from the M. W. Kellogg Company and the Electric Power Research Institute, is providing the remaining $9.2 million.

DOE is currently sponsoring two other coal research efforts at the Wilsonville plant, a test facility for coal liquefaction technology and a unit that cleans coal before it is used.

Project Cost: $46 million

HUMBOLT ENERGY CENTER PROJECT — Continental Energy Associates and Pennsylvania Energy Development Authority (C-265)

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 (SPC) to enhance the facility. However, the SPC 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 135 megawatt anthracite refuse-fueled integrated gasification combined cycle 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. One hundred megawatts of power will be 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.

Project Cost: over $100 million

HYCOL HYDROGEN FROM COAL PILOT PLANT — Research Association for Hydrogen from Coal Process Development (Japan) (C-270)

In Japan, the New Energy and Industrial Technology 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 multipurpose coal gasifier for medium-BTU gas.

SYNTHETIC FUELS REPORT, MARCH 1993
The multipurpose 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. Construction of the pilot plant in Sodegaura, Chiba was completed in August, 1990. Operational research was to begin in 1991 after a trial run.

The key technology of this gasification process is a two-stage 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:

<table>
<thead>
<tr>
<th>Specification</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal feed</td>
<td>50 ton per day</td>
</tr>
<tr>
<td>Pressure</td>
<td>30 kg/cm² g</td>
</tr>
<tr>
<td>Temperature</td>
<td>About 1,800°C</td>
</tr>
<tr>
<td>Oxidant</td>
<td>Oxygen</td>
</tr>
<tr>
<td>Coal Feed</td>
<td>Dry</td>
</tr>
<tr>
<td>Slag Discharge</td>
<td>Slag Lock Hopper</td>
</tr>
<tr>
<td>Refractory Lining</td>
<td>Water-cooled slag coating</td>
</tr>
<tr>
<td>Dimensions Outer Pressure Vessel</td>
<td>2 Meters Diameter, 13.5 Meters Height</td>
</tr>
<tr>
<td>Carbon Conversion</td>
<td>98 Percent</td>
</tr>
<tr>
<td>Cold Gas Efficiency</td>
<td>78 Percent</td>
</tr>
<tr>
<td>1,000 Hours Continuous Operation</td>
<td></td>
</tr>
</tbody>
</table>

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 research is 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.

IGT MILD GASIFICATION PROJECT – Institute of Gas Technology (IGT), Kerr-McGee Coal Corporation, Illinois Coal Development Board (C-272)

Kerr-McGee Coal Corporation is heading a team whose goal is to develop the Institute of Gas Technology's (IGT) MILDGAS advanced mild gasification concept to produce solid and liquid products from coal. The process uses a combined fluidized-bed/entrained-bed reactor designed to handle Eastern caking and Western noncaking coals.

The 24 ton per day facility will be built at the Illinois Coal Development Park near Carterville, Illinois. The 3-year program will provide data for scaleup production of coproducts for testing, preparation of a detailed design for a larger demonstration unit, and the development of commercialization plans.

Kerr-McGee Coal Corporation will provide the coal and oversee the project. Bechtel Corporation will design and construct the process development unit, and Southern Illinois University at Carbondale will operate the facility. IGT will supply the technology expertise and supervise the activities of the team members.

The technology will produce a solid char that can be further processed into form coke to be used in blast furnaces as a substitute for traditional coke. Liquids produced by the process could be upgraded to make gasoline or diesel fuel or used to manufacture such materials as roofing and road binders, electrode binders, and various chemicals.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

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 III Program, M-C Power Corporation is going ahead with a demonstration project to repower an existing coal-fired powerplant 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 powerplants 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 $SO_2$ and $NO_x$, says M-C Power.

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 would be located at the Institute of Gas Technology's (IGT) 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 was scheduled to begin April 1, 1991 and will be completed September 30, 1994. Total estimated cost of the project is $22,700,000.

M-C Power is testing a molten carbonate fuel cell with a cross-sectional area of 11 square feet, the largest ever operated in the United States.

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. Production costs at the Pretoria plant are said to be 30 percent lower than conventional method costs.

Startup of the plant was in November 1989. 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 H$_2$) 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 degree C hot reducing gas produced in the reduction furnace, is 95 percent 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 1,500-1,700 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/Nm$^3$. Voest-Alpine says the pig iron quality matches that from blast furnaces, and that costs were $150 per ton in 1990.

Voest-Alpine has also recently patented several schemes involving a fluidized bed meltdown-gasifier (United States Patents 4,725,308, 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. (See Virginia Iron Corex Project C-613).

The COREX process is being marketed as an environmentally superior method of iron making and claims significant reductions in dust, $SO_2$ and $NO_x$ emissions compared to conventional methods.

During 1990 the plant ran at 100 percent design capacity.

K-FUEL COMMERCIAL FACILITY -- K-Fuel Partnership (C-290)

The K-Fuel process was invented by Edward Koppelman and developed further by SRI International between 1976 and 1984. In 1984, K-Fuel Partnership (KFP) was formed to commercialize the process. KFP owns the worldwide patents and international licensing rights to the process in the United States and 37 foreign countries. 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 800 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
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

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. K-Fuel was tested at Wisconsin Power and Light's (WPL) Rock River generating station near Beloit in south-central Wisconsin. The test was successful and Wisconsin Power has agreed to buy up to one million tons per year.

KFP, headquartered in Denver, Colorado, owns and operates a full demonstration facility and research center at the Fort Union Coal Mine near Gillette, Wyoming. The laboratory and pilot facility, which can produce 25 tons of K-Fuel per day, has been in operation since July 1988.

Wisconsin Power and Light plans to use K-Fuel at several of its facilities to meet new state and federal emission control requirements. The upgraded coal is also less expensive to ship and store due to its improved heating value.

WPL, through its wholly owned subsidiary called ENSERV Inc., has purchased an interest in the K-Fuel technology. A license for the use of the K-Fuel technology on coal only in North America was issued to Heartland Fuels Corporation (HFC), and ENSERV subsidiary. HFC made application for funding to DOE under Round 4 of the Clean Coal Technology program but did not receive support. HFC has since reached an agreement to merge its project with the ThermoChem project, which did receive DOE support, and expects to announce the beginning of construction soon.

Project Cost: $62 Million

KOBRa HIGH TEMPERATURE WINKLER IGCC DEMONSTRATION PLANT – RWE Energie AG (C-294)

RWE Energie AG, a sister company of Rheinbraun AG, has decided to build a combined-cycle power station with integrated gasification based on the High Temperature Winkler (HTW) technology. Raw brown coal with 50 to 60 percent moisture will be dried down to 12 percent, gasified and dedusted with ceramic filters after passing the waste heat boiler. After the conventional scrubber unit, the gas will be desulfurized and fed to the combined cycle process with an unfired heat recovery steam generator. This project is referred to as KOBRA (in German: Kombikraftwerk mit Braunkohlenvergasung, i.e. combined-cycle power station with integrated brown coal gasification).

The capacity of the KOBRA plant will slightly exceed 300 MWe. The question of whether oxygen or air will be used as gasifying agent has not yet been decided, but irrespective of this the fuel gas will be produced in this demonstration plant by two gasifiers, each having a throughput of 1,800 tons per day of dried lignite. The gas turbine will have a rated capacity of about 200 MWe, and the overall plant is expected to reach a net efficiency of 46 percent.

Beginning of construction is scheduled for 1993 and start up in 1995. The most important orders awarded so far were placed with the MAN company as the general contractor, the Uhde/Lurgi consortium for the engineering of the coal gasification system, and with the Siemens company for the delivery of the gas turbine (type 94.3). To implement this project, a task force comprising staff members of both RWE Energie AG and Rheinbraun AG started working in early 1990. To ensure that the plant can be constructed on schedule as from early 1993 and commissioned in late 1995, the orders relating to the desulphurization unit, the coal drying unit and some other large components were placed in 1990. Completion of the permit engineering is scheduled for mid-1992, so that building and operating permits can be applied for.

Of crucial importance for reaching a high overall efficiency is the coal drying system which reduces the moisture content of the raw brown coal to 12 percent. For this step, Rheinbraun's WTA process will be employed (WTA means fluidized-bed drying with internal waste heat utilization).

To demonstrate the technology, a plant having a capacity of 20 tons per hour of dried lignite will be started up in 1992 for testing purposes. Engineering of this project is being handled by Lurgi GmbH.

A successful test operation of the demonstration plant will provide the essential basis for the construction of commercial-scale power stations of this type. The start-up of a 600 MWe commercial-scale IGCC plant is scheduled for the turn of the century. This new generation of power stations will be characterized by a high overall efficiency, extremely low emissions, and low production costs.

LAKESIDE REPOWERING GASIFICATION PROJECT – Combustion Engineering, Inc. and United States Department of Energy (DOE) (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 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 $270.7 million project will span 10 years, including 5 years needed to test and operate the system. The plant will continue to provide power to the city as part of its commercial grid during the testing period.

Design work for the new integrated powerplant began in November 1990. The preliminary design package and plant cost estimates are complete. Gasifier groundbreaking is scheduled for September 1993, with initial coal-fired operation scheduled for mid-1995. Cold flow modeling of the gasifier internals and dry coal feed system continues.

DOE is providing $129.4 million, or 48 percent, of the project's total cost. The remaining funds will be provided by Combustion Engineering, City Water, Light & Power, and the Illinois Department of Energy and Natural Resources.

Project Cost: $270.7 million

LAFORTE ALTERNATIVE FUELS DEVELOPMENT PROGRAM – Air Products & Chemicals, Inc., Electric Power Research Institute, and United States Department of Energy (DOE) (C-330)

Air Products and Chemicals, Inc. is proposing a 36-month program to develop technologies for the conversion of coal-derived synthesis gas to oxygenated hydrocarbon fuels, fuel intermediates, and octave enhancers, and to demonstrate the most promising technologies in DOE's Slurry Phase Alternative Fuels Development Unit (AFDU) at LaPorte, Texas. With emphasis on slurry phase processing, the program will initially draw on the experiences of the successful Liquid Phase Methanol (LPMEOH) program. See completed project "LaPorte Liquid Phase Methanol Synthesis" in December 1991 Synthetic Fuels Report for details on the LPMEOH project.

In the spring of 1992, methanol produced using the LaPorte Liquid Phase Methanol Synthesis Process out performed commercial chemical-grade methanol in diesel engine runs. In a standard 100 hour test, 2,400 gallons of raw methanol from the LaPorte Plant were run through a typical bus cycle simulation.

The alternative fuels development program aims to continue the investigations initiated in the above research program, with the principal objective being demonstration of attractive fuel technologies in the LaPorte AFDU. The focus is continued in pilot plant operations after a 12-18 month period of plant modifications. Certain process concepts such as steam injection, and providing H2 via in situ water-gas shift, will assist in higher conversions of feedstocks which are necessary, particularly for higher alcohol synthesis.

Four operating campaigns are currently envisaged. The first will focus on increased syngas conversion to methanol using steam injection and staged operation. The second will demonstrate production of dimethyl ether/methanol mixtures to (1) give optimum syngas conversion to storable liquid fuels, (2) produce mixtures for both stationary and mobile fuel applications, and (3) produce the maximum amount of DME, which would then be stored as a fuel intermediate for further processing to higher molecular-weight oxygenates. Economic, process, and market analyses will provide guidance as to which of these scenarios should be emphasized. The third and fourth campaigns will address higher alcohols or mixed ether production.

In the laboratory, the principal effort will be developing oxygenated fuel technologies from slurry-phase processing of coal-derived syngas using two approaches, (1) fuels from syngas directly, and (2) fuels from DME/methanol mixtures. In fiscal year 1993, Air Products will demonstrate, at DOE's LaPorte Alternative Fuels Development Unit, the synthesis of methanol/isobutanol mixtures, which can be subsequently converted to MTBE. Preliminary economic analyses have indicated that isobutanol and MTBE from coal could be cost competitive with conventional sources by the mid to late-1990s.

Air Products has already demonstrated the unique ability of DME to act as a chemical building-block to higher molecular-weight oxygenated hydrocarbons. Air Products has also successfully developed and demonstrated a one-step process for synthesizing dimethyl ether (DME) from coal-derived synthesis gas. In this process, the reactions are carried out in a three-phase system with the catalyst suspended in an inert liquid medium. The liquid absorbs the heat that is released as the chemical reactions occur, allowing the reactions to take place at higher, more efficient rates and protecting the heat-sensitive catalyst necessary for the conversion process. This results in a 30 to 40 percent increase in the rate of methanol production.

Project Cost: $20.5 million FY91-FY93

LUBECK IGCC DEMONSTRATION PLANT – PreussenElektra (C-339)

The project of PreussenElektra/Germany has a capacity of 320 MWe net based on hard coal and a net efficiency of 45 percent. PRENFLO gasification technology has been chosen for the gasifier.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

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 375 tons per day Texaco gasifier at the 200 metric tons per day Lu Nan Ammonia Complex in Tengxian, Shandong Province. The gasifier was completed in 1991, and has replaced 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 (DOE) (C-370)

Since the mid-1980s, Coal Technology Corporation (CTC), formerly UCC Research Corporation, has been investigating the pyrolysis of coal under sponsorship of DOE’s Morgantown Energy Technology Center. This work initially was the development of a batch process demonstration unit having a coal feed capacity of 120 pounds per batch. The process produced coal liquids to be used for motor fuels and char to be potentially used for blast furnace coke and offgas.

In January 1988, DOE and CTC cost shared a $3,300,000 three-year program to develop a process demonstration unit for the pyrolysis of 1,000 pounds/hour of coal by a continuous process. This work involved a literature search to seek the best possible process; and then after small scale work, a proprietary process was designed and constructed. The unit began operating in February 1991. Test runs have been made with seven different caking bituminous coals and no major differences in coke making were observed.

In the CTC mild gasification process, coal is heated from ambient temperature to around 400°F in the first heat zone of the reactor, and then to 800 to 900°F in the second heat zone. Lump char discharged from the reactor is cooled in a water jacketed auger to 300°F. At present, the char is stored, but in an integrated facility, the cooled char would then be crushed, mixed with binder material and briquetted in preparation for conversion to coke in a continuous rotary hearth cooker. The moisture and volatile hydrocarbons produced in the reactor are recovered and separated in scrubber/condensers into noncondensibles gases and liquids.

The coal liquid and coke (CLC) mild gasification technology to be demonstrated involves the production of two products from bituminous caking type coals: coal liquids for further refining into transportation fuels, and formed coke for foundry and blast furnace application in the steel industry. The CLC process will continuously produce blast furnace quality coke within a 2-hour duration in a completely enclosed system. The coal liquids will be recovered at less than 1,000°F for further refining into transportation fuel blend stock.

The processing involves feeding coal into three of CTC’s proprietary mild gasification retort reactors operating at about 1,000°F to extract the liquids from the coal and produce a devolatized char. The hot char is fed directly into a hot briquette system along with additional coking coal to form what is called green briquettes. The green briquettes will directly feed into the specially designed rotary hearth continuous coking process for final calcining at 2,000°F to produce blast furnace formed coke. The small amount of uncondensed gases will be recirculated back through the system to provide a balanced heat source for the mild gasification retorts and the rotary hearth coking process. A total of 1,420 tons of coal per day will be used in the demonstration phase of this plant.

Three companies in Virginia have agreed to cosponsor this project as equity participants: Norfolk Southern Corporation, Coal Technology Corporation, and Rapoca Energy Company. The project was submitted to DOE under the Clean Coal Technology Program Round 4, but was not selected for funding.

Another proposal is being submitted to the DOE under Clean Coal Technology Program, Round V. This proposal has a planned coal feed rate of 500 tons per day. It has the advantage of an additional year of experimental operation of the 1,000 pound per hour process demonstration unit at Bristol, Virginia.

Project Cost: $40 million for the process demonstration plant in the Clean Coal Technology Program, Round V

MILD GASIFICATION OF WESTERN COAL DEMONSTRATION – AMAX, Western Research Institute (C-372)

AMAX is planning a 1,000 ton per day mild gasification commercial demonstration plant at its Eagle Butte Mine near Gillette, Wyoming. Inclined fluid-bed reactors will be used for drying and mild gasification. AMAX is studying ways to best market all of the char and liquid products produced.

The first liquid product, dirty pitch, will be marketed as a binder for carbon anodes used in aluminum production. A lighter fraction would be sold as chemical feedstock. The oil product will be used as diesel additive to run the heavy mine equipment or to spray on dry coal.
COMMERCIAL AND R&D PROJECTS (Continued)

Pre-feasibility 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. Amax has been developing a char-to-carbon (CTC) process to convert the char to pure carbon and activated carbon. Pure carbon is 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 research unit has been operating at Western Research Institute since January 1990. A 50 pound per hour CTC process demonstration unit was started up at Amax Research and Development in Golden, Colorado in 1990. A proposal was submitted to the U.S. Department of Energy in 1990 for design, construction, operation and evaluation of 20 ton per day integrated process development unit at Golden.

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 conducted.

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 led 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 characterizing the aluminum species responsible for promoting these reactions but further work is required.

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.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

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 780 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. Over 50 tonnes of coal was successfully gasified during 21 performance tests with a cumulative feeding time of 18 days. Continuous operation for periods of up to 67 hours was achieved.

A full-scale physical model of a 50 tonne per day development-scale Coal Hydrogenator was commissioned in 1992. This has enabled the scaleup of the hydrogenator to be studied. A range of coal injectors at feedrates of up to 50 tonnes per day have been successfully tested.

Under consideration as of 1993 is a 50-tonne per day demonstration plant to be built in Japan in cooperation with Osaka Gas.

Project Cost:  
Phase I	 $16 million  
Phase II	 $7.4 million

NEDO IGCC DEMONSTRATION PROJECT – New Energy and Industrial Technology Development Organization (NEDO) (C-408)

NEDO is studying integrated gasification combined cycle technology as part of a national energy program called the Sunshine Project. A 200 ton per day pilot plant has been constructed at the Nakoso power station site in Iwaki City, Fukushima Prefecture. The pilot began operating in March 1991.

The plant, which is designed to produce 42,900 cubic meters of synthetic gas per hour, is expected to operate for about 3 years using four different kinds of coal. The gasifier is an air blown, two stage entrained flow type with a dry-feeding system.

NEDO's goal is to develop a 250 megawatt demonstration plant by the year 2000 that has a net thermal efficiency greater than 43 percent and better operability than existing pulverized coal-fired plants. In order to obtain this goal, the development of the entrained flow gasification pilot plant will be followed by a fluidized bed gasification pilot plant.

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 (PDUs) 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.

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 (358 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, five different coals were processed in the bench scale unit with encouraging results.

Project Cost: 100 billion yen, not including the three existing PDU
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

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 at the Metallurgical Research Station 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 40 tons of iron. 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.

PETC GENERIC COAL LIQUEFACTION PLANTS—United States Department of Energy (DOE), M.W. Kellogg Company (C-457)

DOE's Pittsburgh Energy Technology Center (PETC) has awarded Kellogg a contract to engineer, fabricate, install and commission three generic pilot plants to be installed at the center. The plants, which will be skid mounted, include direct coal liquefaction, indirect coal liquefaction, and product upgrading units. These pilot plants will be used by PETC to test new concepts for improving these processes and will allow testing of new processes and catalysts by outside contractors who do not have facilities for such testing. The facilities are scheduled to be completed in 1994.

PINON PINE IGCC POWERPLANT — Sierra Pacific Power Company, M.W. Kellogg Company (C-458)

Sierra Pacific Power Company is planning to build an 80 MW integrated gasification combined cycle plant at its Tracy Powerplant site, east of Reno, Nevada. The plant will incorporate an air-blown KRW fluidized bed gasifier producing a low-BTU gas for the combined cycle powerplant. The demonstration project will have a heat rate of 9,500 BTU/kWh.

Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier through a lockhopper system. The bed is fluidized by the injection of air and steam through special nozzles into the combustion zone. Crushed limestone is added to the gasifier to capture a portion of the sulfur introduced with the coal as well as to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits along with the coal ash in the form of agglomerated particles suitable for landfill.

Hot, low-BTU coal gas leaving the gasifier passes through cyclones which return most of the entrained particulate matter to the gasifier. The gas, which leaves the gasifier at about 1,700°F, is cooled to 1,050°F before entering the hot gas cleanup system. During cleanup, virtually all of the remaining particulates are removed by ceramic candle filters, and final traces of sulfur are removed in a fixed bed of zinc ferrite sorbent.

In the demonstration project, a nominal 800 tons per day of coal is converted into 86 megawatts; support facilities for the plant require 6 megawatts, leaving 80 megawatts for export to the grid. The plant has a calculated heat rate of 9,082 BTU per kilowatt-hour (HHV). The project will be designed to run on Western subbituminous coal from Utah; operation with higher sulfur and lower rank coals also is being considered.

The U.S. Department of Energy (DOE) has agreed to fund half of the $270 million project cost. The project is funded by DOE through the Clean Coal Technology Program, Round 4. Sierra Pacific Power will fund the remaining 50 percent.

Foster Wheeler USA Corp. has been contracted to provide design, engineering, construction, manufacturing and environmental services for the project.


Project Cost: $270 million

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STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

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-I '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.

PRENFLO GASIFICATION PILOT PLANT – Krupp Koppers GmbH (KK) (C-470)

Krupp Koppers (KK) of Essen, West Germany (in United States known under the name of GK'F Gesellschaft fuer Kohle-Technologie) are presently operating a 48 ton per day demonstration plant and designing a 2,400 ton per day module for the PRENFLO process. The PRENFLO process is KK's pressurized version of the Koppers-Totzek (KT) flow gasifier. Detailed engineering has been completed for a 1,200 ton per day module.

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. In over 8,000 hours of test operation nine different fuels with ash contents of up to 40 percent were successfully used. All fuels used are converted to more than 98 percent, and in the case of fly ash recycled to more than 99.5 percent.

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 limestone and relies on high velocity transport reactors to achieve high conversion and low emissions.

DOE, in late 1990, awarded a contract to Southern Company Services, Inc. for addition of a Hot Gas Cleanup Test Facility to their Wilsonville test facility. The new unit will test particulate removal devices for advanced combined cycle systems and Kellogg's Transport gasifier and combustor technology will be used to produce the fuel gas and flue gas for the testing program. The reactor system is expected to process up to 48 tons per day of coal. [See Hot Gas Cleanup Process (C-257)].
COMMERCIAL AND R&D PROJECTS (Continued)

Kellogg has built a bench scale test unit to verify the kinetic data for the transport reactor system and has completed testing in both gasification and combustion modes, using bituminous and subbituminous coals. The results in both modes have verified the concept that reactors designed to process pulverized coal and limestone can achieve commercial conversion levels while operating at high velocities and short contact times. The test data have been used to support the design of the Wilsonville test gas generator, and another unit at UND/EERC.

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 combusted 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.

DOE has also approved the design, fabrication, installation and operation of a Process Development Unit (PDU) based upon Kellogg's Transport gasification process at the University of North Dakota, Energy and Environmental Research Center (UND/EERC). The unit will process 2.4 tons per day of pulverized bituminous coal.

DOE's Morgantown Energy Technology Center has awarded Kellogg a contract for experimental studies to investigate in-situ desulfurization with calcium-based sorbents. The testing, which will be conducted at Kellogg's Houston Technology Development Center, will investigate the effects of the sorbents on sulfur capture kinetics and carbon conversion kinetics, and the mechanism for conversion of calcium sulfide to calcium sulfate in second generation (hybrid) pressurized fluid bed combustion systems.

PUERTOLLANO IGCC DEMONSTRATION PLANT - Empresa Nacional de Electricidad, S.A. (ENDESA) (C-476)

The Spanish utility company ENDESA together with EDF/France, IBERDROLA/Spain, Hidroelectrica del Cantabrico/Spain, SEVILLANA/Spain, ENEL/Italy, and EDP/Portugal are involved in the Puertollano project. The project also has the European Economic Commission support, under the Thermie Program.

The proposed project has a capacity of approximately 300 MWe, which is influenced by the type of gas turbine selected (Siemens or Alstom). The PRENFO gasification technology has been chosen for the gasifier.

The plant configuration is single-train throughout. Using oxygen and steam, about 100 tons of coal per hour will be gasified. The required oxygen, approximately 90 tons per hour, will be produced in a single-train air separation unit. The resulting coal gas will be dedusted, desulfurized and saturated in a single-train configuration and then combusted in a single combustion turbine.

A 50/50 mixture of Puertollano coal and petroleum coke from the Puertollano Petroleum Refinery is intended to be the main feedstock for this project. Coals from England, Spain, France, the United States, China, Austria, Columbia, Germany, Poland and South Africa will also be tested over the 3-year demonstration period.

SO₂ Emission values of 10 mg/m³ and NOₓ values of 60 mg/m³ are expected in the exhaust gas (based on 15 volume percent oxygen).

Civil work is scheduled to begin in November 1992 with construction of the combined cycle components completed by December 1994. The gasification island is scheduled to be completed by December 1995, and commissioning with coal gas would take place in January 1996. The demonstration period, then, would be from 1996 to 1998.

RHEINBRAUN HIGH-TEMPERATURE WINKLER PROJECT - Rheinische Braunkohlenwerke AG, Uhde GmbH, Lurgi GmbH, 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 gasification 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.

The development was started at the "Institut für Eisenhüttenkunde" 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 tons 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 ton of brown coal (MAP) 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.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

After gasification tests with Finnish peat in the HTW pilot plant in the spring of 1984 the Kemira Oy Company of 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.

Rheinbraun constructed a 30 ton per hour demonstration plant for the production of 300 million cubic meters of 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/Bernearth briquetting plant is pipelined to DEA-Union Kraftstoff for methanol production. From startup in January 1986 until the end of December 1992 about 266,299 tons of dried brown coal, especially high ash containing steam coal, were processed in about 39,700 hours of operation. During this time, about 1,260 million cubic meters of synthesis gas were produced.

A new pilot plant, called pressurized HTW gasification plant, for pressures up to 25 bar and throughputs up to 6.5 tons per hour was erected on the site of the former pilot plant of Hydrogasification and started up in November 1989. From mid-November 1989 to early July 1990, the plant was operated at pressures between 10 and 25 bar, using oxygen as the gasifying agent. Significant features of the 25 bar gasification are the high specific coal throughput and, consequently, the high specific fuel gas flow of almost 100 MW per square meter. In mid-1990, the 25 bar HTW plant was modified to permit tests using air as the gasifying agent. Until the end of January 1993 the plant was operated for 8,753 hours at pressures of up to 25 bar, oxygen blown as well as air blown. Under all test and operating conditions gasification was uniform and trouble free.

Typical results obtained are: up to 95 percent coal conversion, over 70 percent cold-gas efficiency and 50 MW specific fuel gas flow per square meter air blown and 79 percent cold-gas efficiency and 105 MW specific fuel gas flow per square meter oxygen blown.

This work is performed in close co-ordination with Rheinbraun's parent company, the Rheinisch-Westfalisches Elektrizitätswerk (RWE), which operates power stations 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 powerplants. Based on the results of these tests and on the operating experience gained with the HTW pressurized plant, a demonstration plant for integrated HTW gasification combined cycle (HTW-IGCC) power generation is planned which will go on stream in 1996 and will have a capacity of 300 MW of electric power. The gas will be produced in one air-blown gasifier. See KOBRA HTW-IGCC Project (C-294).

From February to September 1992 tests with a German hard coal and with Pittsburgh No. 8 coal were successfully performed in the pressurized HTW gasification plant using oxygen and air as gasification agents as well. Within 543 hours of operation 728 tons of hard coal was processed.

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 course of more than 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 produced at these plants. At full production, their daily consumption of coal is almost 120,000 tons, of oxygen, 26,000 tons; and of water, 100 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 sulfur, produced for Sasol's Chemical Division, ammonia for the group's Fertilizer and Explosives Divisions, and propylene for the Polypropylene Division. The primary fuels produced by Sasol at Secunda are probably 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.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

The blending of synthetic gasoline with alcohols (ethanol as well as high fuel alcohols) presented a particular challenge to Sasol. Sasol erected 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 normal refinery fuel.

Sasol's Mining Division manages the five Sasol-owned collieries, which have an annual production in excess of 43 million tons of coal. The collieries comprised of the three Secunda Collieries (including the new open cast mine, Syferfontein), 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 program, process design, engineering, project management, and transfer of technology.

Sasol approved in 1990 six new projects costing $451 million as part of an overall $2.5 billion program over the next five years. The first three projects are scheduled for completion by January 1993.

Sasol has increased its production of ethylene by 55,000 tons per year, to a current level of 400,000 tons per year, by expanding its ethylene recovery plant at Secunda.

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.

A new facility is being built as Sasol One to manufacture paraffinic products for detergents. The other three newly approved projects, which will be located at Sasol's Secunda facilities, are:

An n-butanol plant to recover acetaldehyde from the Secunda facilities and to produce 17,500 tons per year of n-butanol is being built. The plant is expected to come on stream in January 1992.

Sasol will construct a delayed coker facility to produce green coke, and a calciner to calcinate the green coke to anode coke and needle coke. The anode coke is suitable for use in the aluminum smelting industry. They are scheduled to be in production by March 1993.

A flexible plant to recover 100,000 tons per year of 1-hexane or 1-pentone will be built to come online in January 1994.

Krypton and xenon gases will be recovered from the Secunda oxygen units.

A major renewal project at Sasol One includes an expansion of the fixed bed Fischer-Tropsch plant. The renewal also includes shutting down much of the synthetic fuels capability at this plant.

Project Cost*: SASOL Two  $2.9 Billion
SASOL Three  $3.8 Billion

*At exchange rates ruling at construction

SCOTIA COAL SYNFUELS PROJECT – DEVCO; Alastair Gillespie & Associates Limited; Gulf Canada Products Company; NOVA; Nova Scotia Resources Limited; and Petro-Canada (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 26,000 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 downsized 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 coprocessing technology have reduced the capital cost estimates to US$375 million. Net operating costs are estimated at less than US$20 per barrel.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

In late 1988 Hydrocarbon Research Inc. (HRI) was commissioned by Scotia Synfuel Ltd. to perform microautoclave and bench scale tests to demonstrate the feasibility of their co-processing technology using Harbour seam coal and several oil feedstocks. In early 1989, Bantrel Inc. (a Canadian engineering firm affiliated with Bechtel Inc.), was commissioned to develop a preliminary process design.

Scotia Synfuels and partners have concluded an agreement with the Nova Scotia government supported by the federal government for financial assistance on a $2.5 million coprocessing feasibility study. The study was completed in 1990.

Based on the test program results, material and energy balances were developed for a commercial facility. An economic model was developed to analyze a number of options. The model incorporated government investment support programs available in eastern Canada. The primary incentives were investment tax credits and loan financing.

Discussions on project financing continued in 1991 with the governments of Canada and Nova Scotia and private corporations.

Project Cost:
- Approximately $2.5 million for the feasibility study
- Approximately C$50 million for the plant

SEP IGCC POWERPLANT – Demkolec B.V. (SEP) (C-520)

In 1989, Demkolec, a wholly owned subsidiary of Samenwerkende Elektriciteits-Productiebedrijven (SEP), the Central Dutch electricity generating board, started to build a 253 megawatt integrated coal gasification combined cycle (IGCC) powerplant, to be ready in 1993.

SEP gave Comprimo Engineering Consultants in Amsterdam an order to study the gasification technologies of Shell, Texaco and British Gas/Lurgi. In April 1989 it was announced that the Shell process had been chosen. The location of the coal gasification(combined cycle demonstration station is Buggenum, in the province of Limburg, The Netherlands.

The coal gasification facility will employ a single 2,000 ton per day gasifier designed on the basis of Shell technology. The clean gas will fuel a single shaft Siemens V94.2 gas turbine (156 MWe) coupled with steam turbine (128 MWe) and generator. The coal gasification plant will be fully integrated with the combined cycle plant, including the boiler feed water and steam systems; additionally the compressed air for the air separation plant will be provided as a bleed stream from the compressor of the gas turbine. The design heat rate on internationally traded Australian coal (Drayton) is 8,240 BTU/kWh based on coal higher heating value (HHV).

Environmental permits based on NO emissions of 0.17 lb/MMBTU and SO emissions of 0.06 lb/MMBTU were obtained in April 1990. Construction began in July 1990 and start of operation is scheduled for September 1993. When operation begins, the Demkolec plant will be the largest coal gasification combined cycle powerplant in the world. Commissioning of the main plant system is scheduled to take place in January through July 1993.

After three years of demonstration (1994 to 1996), the plant will be handed over to the Electricity Generating Company of South Netherlands (N.V. EPZ).

Project Cost: Dfl. 880 million (1989)

SHANGHAI CHEMICALS FROM COAL PLANT – People’s Republic of 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 of methanol and 15,000 tons per year of acetate fiber. Completion is due in 1992.

SHOUGANG COAL GASIFICATION PROJECT – People’s Republic of China (C-527)

The Shougang plant will gasify 1,170 tons per day of Chinese anthracite using the Texaco coal gasification process. The gasification plant will produce fuel gas for an existing steel mill and town gas. The detailed design is being completed and equipment fabrication is underway. The plant is expected to be operational in late 1992.

SLAGGING 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 6 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. Byproduct 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 fijI. Gasification is substantially complete with a high thermal efficiency. A long term proving run on the gasifier was carried out successfully between 1975 and 1983. Total operating time was over one year and over 100,000 tons of coal were gasified.

A second phase, started in November 1984, was the demonstration of a 500 ton per day (equivalent to 70 megawatts) gasifier with a nominal inside diameter of 7.5 feet. Integrated combined cycle tests were 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 1,500°F, a compression ratio of 10, and a thermal efficiency of 31 percent. By 1989 this gasifier had operated for approximately 1,300 hours and had gasified over 26,000 tons of British and American (Pittsburgh No. 8 and Illinois No. 6) coals.

The 500-ton per day gasifier was operated at 25 bar until the end of 1990.

An experimental gasifier designed to operate in the fixed bed slagger mode at pressure up to 70 atmospheres was constructed in 1988. It was designed for a throughput of 200 tons per day. This unit was operated through 1991. Operation of the gasifier was excellent over the entire pressure range; the slag was discharged automatically, and the product gas was of a consistent quality. At corresponding pressures and loadings the performance of the 200-ton per day gasifier was similar to that of the 500-ton per day unit previously used.

As the pressure rises, the gas composition shows a progressive increase in methane and a decrease in hydrogen and ethylene, while the ethane remains fairly constant. The tar yield as a percentage of the dry ash free coal decreases with pressure. The cold gas efficiency, i.e., the proportion of the fuel input converted to potential heat in the output gas, was above 90 percent. The throughput increased approximately with the square root of the ratio of the operating pressures.

Project Cost: Not available

SYNTHESEGASANLAGE RUHR (SAR) – Ruhrkohle Oel and Gas GmbH and Hoechst AG (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 Synthesegasanlage Ruhr has been completed on Ruhchemie's site at Oberhausen-Holten.

The 800 tons per day coal gasification plant has been in operation since August 1986. The coal gases produced have the quality to be fed into the Ruhchemie's oxosynthesis plants. The gasification plant has been 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 Cost: DM220 million (Investment)

TAMPELLA IGCC PROCESS DEMONSTRATION — Tampella Power (C-565)

After having obtained the rights to the Institute of Gas Technology's fluidized bed gasification technology in 1989, Tampella Keeler began to design and initiate construction of a 10 MW thermal pilot plant at their research facilities in Tampere, Finland. The pilot plant is considered essential for determining operating parameters for specific coals and for continuing process development in the areas of in-gasifier sulfur capture and hot gas cleanup. The pilot plant will be operational in early 1991.

The pilot plant is designed so that alternative hot gas filters and zinc ferrite absorber/regenerator design concepts can be evaluated. The gasifier is 66 foot tall, with an inside diameter ranging from 2 to 4 feet. The gasifier will be capable of operating at pressures up to 425 psig.

After the pilot plant construction was underway, Tampella turned its attention towards locating a demonstration project in Finland and one in the U.S. A cogeneration project to be located at an existing papermill has been selected as the basis for the demonstration in Finland. The gasifier will have a capacity of 150 MW thermal which is equal to about 500 tons per day of coal consumption. The plant will produce about 60 MW of electricity and about 60 MW equivalent of district heating.

In September, 1991 Tampella received support from the U.S. Department of Energy (DOE) to build an integrated gasification combined-cycle demonstration facility, known as the Toms Creek IGCC Demonstration Project, in Coeburn, Wise County, Virginia (see project C-580, below). The Toms Creek Project will utilize Tampella Power's advanced coal gasification technology to demonstrate improved efficiency for conversion of coal to electric power while significantly reducing SO2 and NOx emissions.
COMMERCIAL AND R&D PROJECTS (Continued)

TECO IGCC PLANT – Teco Power Services, U.S. Department of Energy (C-567)

A 260 MW(e) coal-gas based combustion turbine combined cycle power generating system is planned for Lakeland, Polk County, Florida. The plant will include an integrated gasification system providing fuel to a conventional combustion turbine combined cycle base load unit.

The project, originally proposed as a 120 MW independent power project costing $400 million, was to be built on a site outside Tallahassee, Florida near the existing Arvah B. Hopkins Power Station. Public opposition and stalled negotiations with city officials forced Tampa Electric to change the location. A nominal 1,900 tons per day of coal will be converted to electricity. High-sulfur Illinois Basin coal will be used.

The integrated gasification combined cycle (IGCC) project is being developed by TECO Power Services (TPS), a subsidiary of Tampa Electric. TPS will develop the project under commercial terms and conditions using a United States Department of Energy program subsidy to reduce financial risks associated with the coal gasification phase of the plant.

The Texaco Gasification Process has been selected for integration with a combined cycle power block. Startup is expected in 1996.

Project Cost: $241.5 million

TEXACO COOL WATER PROJECT – Texaco Syngas Inc. and Air Products and Chemicals, Inc. (C-569)

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. Plant construction, which began in December 1981, was completed on April 30, 1984, within the projected $300 million budget. A 5-year demonstration period was completed in January 1989. See "Cool Water Project" in the December 1991 issue of the Synthetic Fuels Report, Status of Projects section for details of the original completed project.

Texaco plans to modify and reactivate the existing facilities to demonstrate new activities which include the addition of sewage sludge into the coal feedstock, production of methanol, and carbon dioxide recovery.

Texaco intends to use a new application of Texaco's technology which will allow the Cool Water plant to convert municipal sewage sludge to useful energy by mixing it with the coal feedstock. Texaco has demonstrated in pilot runs that sludge can be mixed with coal and, under high temperatures and pressures, gasified to produce a clean synthesis gas. The plant will produce no harmful byproducts.

Texaco will participate with Air Products, Chemical Inc. and the Department of Energy (DOE) to demonstrate the production of up to 150 TPD of liquid phase methanol (LPMEOH) under a U.S. Department of Energy Clean Coal Technology Round 3 award. Texaco also plans to recover approximately 200 TPD of liquid CO₂. Texaco has submitted permit applications to the California Energy Commission and the U.S. Environmental Protection Agency and has received Federal Energy Regulatory Commission designation as a Qualifying Facility Cogenerator. DOE will fund 43 percent of the $213.7 million project cost. The liquid phase methanol synthesis process is more efficient than the conventional gas phase process and is better suited for processing the gases produced by modern coal gasifiers. Producing methanol as a coproduct in combined cycle coal gasification facilities has distinct advantages. The gasifier can be run continuously at its most efficient level. During periods of low power demand, synthesis gas made by the gasifier would be converted to methanol for storage. At peak power demand, this methanol could be used to supplement the combustion turbine, thus lowering the size of the gasifier that would be required if the gasifier alone had to meet peak electrical demand.

The methanol produced in the demonstration will be tested both on-site at the Cool Water facility, and in off-site boiler and transportation applications, including bus and van pool tests in the Los Angeles, California and Charleston, West Virginia areas.

Based on the early 1993 economy and forecasts for natural gas price and availability in California, Air Products and Chemicals, Inc., Texaco Syngas Inc., and DOE have recognized that the combined Texaco Coal Water/LPMEOH demonstration project, as proposed, cannot compete economically with natural gas-fired electric power generation in California. Air Products and Chemicals, Inc. and DOE have agreed to consider options to restructure the project and to suspend project expenditures until an acceptable option is approved by DOE. The options being explored by Air Products and Chemicals, Inc. include restructuring the project through participation by the City of Los Angeles Department of Water and Power and relocating the project to an alternative site.

Texaco Syngas Inc. has initiated efforts to restructure the financing of the Texaco Cool Water Project and continues to negotiate with Southern California Edison Company for the power purchase agreement based on the California Energy Commission Committee Order dated November 2, 1992. Successful negotiation of the power purchase agreement, with necessary State of California
COMMERCIAL AND R&D PROJECTS (Continued)

approvals, would allow the acquisition of the Cool Water Gasification Facility, by Texaco Synras Inc. from Southern California Edison Company, to be completed.

Project Cost: $263 million for original Cool Water Coal Gasification Program
$213.7 million for commercial demonstration of the liquid-phase methanol process

TEXACO MONTEBELLO RESEARCH LABORATORY STUDIES – Texaco Inc. (C-571)

Texaco has a number of on-going coal gasification research and development programs at its Montebello Research Laboratory (MRL). MRL is a major pilot-scale process development facility which has been involved in gasification research since 1946. It currently has three gasifiers with rated capacities of 15-30 tons per day of coal. These units are also capable of feeding a wide range of other solid and liquid fuels.

MRL serves the dual purpose of doing research and pilot unit testing for the development of the Texaco Gasification Process (TGP), and obtaining data required for the design and environmental permitting of commercial plants. In recent years, the research emphasis has expanded to include the improved integration of the gasification process with the overall chemical or powerplant. This has involved the development of high temperature syngas cleanup technology (jointly funded by the U.S. Department of Energy), improved low temperature acid gas removal processes and engineering studies aimed at increasing the efficiency and reducing the cost of Texaco gasification based chemical and power generation plants.

In addition, the research also continues to expand the already wide range of feeds which can be gasified by the TGP. Recent work has included oily wastes, Orimulsion, contaminated soil, sewage sludge, plastics and tire oil, made by the liquefaction of used tires in waste oils, such as used motor oil.


ThermoChem will demonstrate Manufacturing and Technology Conversion International's (MTCI) pulse combustor in an application for steam gasification of coal. This gasification process will produce a medium BTU content fuel gas from subbituminous coal at Weyerhauser Paper Company's Containerboard Division mill in Springfield, Oregon. The fuel gas and byproduct steam produced by this demonstration unit will be used in the mill to offset use of existing hog-fuel boilers. The eventual replacement of all existing five hog-fuel boilers is contemplated.

This demonstration will be of an industrial size gasifier. The heat required for the gasification will be supplied by the combustion of cleaned gasification products (fuel gas) in numerous pulsed combustion tubes. The products of pulsed combustion are separated from the gasification products. Since no dilution of the byproducts of combustion or of gasified fuel gas occurs, a medium BTU content fuel (500 BTU/scf) gas will be produced. The turbulent nature of the pulsed combustor contributes to a high combustion heat release density and high heat transfer rates to the gasifier bed. The fluidized bed coal gasifier also offers high turbulence and heat transfer rates.

The objective of the ThermoChem project is the demonstration of a 420 ton per day (as-received coal) novel coal gasification unit. It will supply a product fuel gas with a heating value of 1612 million BTU/hr for boiler fuel. Use of the fuel gas in place of hog-fuel boilers will lower particulate emissions at the host facility. Another goal of the project is to determine whether gasification can be used on other potential energy sources, such as pulp-making byproducts.

The U.S. Department of Energy will fund 50 percent of the project under Round 4 of the Clean Coal Technology Program. Weyerhauser and ThermoChem will split the rest of the project.

Project Cost: $37.3 million

TOM’S CREEK IGCC DEMONSTRATION PLANT – TAMCO Power Partners and U.S. Department of Energy (C-580)

TAMCO Power Partners, a partnership between Tampella Power Corporation and Coastal Power Production Company will build an integrated gasification combined cycle powerplant in Coeburn, Virginia. The U.S. Department of Energy will fund 50 percent of the $291 million project under Round 4 of its Clean Coal Technology Program.

The project will demonstrate a single air blown fluidized bed gasifier, based on the U-GAS technology developed by the Institute of Gas Technology. The plant will burn 430 tons per day of local bituminous coal and produce a net 35 MWe. Power will be generated with two gasifiers (one coal gas fired, one natural gas fired), and one steam turbine.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

Project sponsors have had trouble finding a buyer for the project's power output. The partners expect to complete funding negotiations with DOE by the end of 1992.

Project Cost: $291.1 million

UBE AMMONIA-FROM-COAL PLANT - Ube Industries, Ltd. (C-590)

Ube Industries, Ltd., of Tokyo completed the world's first large scale ammonia plant based on the Texaco coal gasification process (TCGP) in 1984. 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 the 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 1,650 tons per day gasification plant has operated using four kinds of coal—Canadian, Australian, Chinese, and South African.

Over 2.5 million tons of feed including 200,000 tons of petroleum coke, had been gasified by 1990. 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 powerplants 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 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. Two variants are being tested for gas cleaning, whereby both wet and dry gas cleaning are being applied. These consist of:

- Wet gas cleaning to remove chlorine and fluorine by forming ammonia salts; dry salts are produced in an evaporation plant
- Dry removal of chlorine and fluorine in a circulating fluidized bed in which lime is used as a reagent

The test operation was finished in January 1991.

The future concept of a coal-based combined cycle powerplant links the partial coal gasification and the product gas cleaning with an innovative circulating fluidized bed combustor. In this process the product gas is freed only from dust, chlorine, and fluorine in order to protect the gas turbine materials. NO reduction and sulfur removal is carried out in the combustor.

Project Cost: Not disclosed

VICTORIAN BROWN COAL LIQUEFACTION PROJECT - Brown Coal Liquefaction (Victoria) Pty. Ltd. (C-610)

BCLV was operating a pilot plant at Morwell in southeastern Victoria to process the equivalent of 50 tonnes per day of moist ash free coal until October 1990. 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 Cosmo 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.

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STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

Construction of the drying, slurring, 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. The pilot plant was operated until October 1990, and shut down at that point.

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. The aim of the pilot plant was to prove the effectiveness of the BCLV Process which had been developed since 1971 by the consortium.

Work at the BCLV plant was moved in 1990 to a Japanese laboratory, starting a three-year study that will determine whether a demonstration plant should be built. NBCL is developing a small laboratory in Kobe, Japan, specifically to study the Morwell project.

Part of the plant will be demolished and the Coal Corporation of Victoria is considering using a part of the plant for an R&D program aimed at developing more efficient brown coal technologies. The possibility of building a demonstration unit capable of producing 16,000 barrels per day from 5,000 tonnes per day of dry coal will be examined in Japan.

If a commercial plant were to be constructed, it would be capable of producing 100,000 barrels of synthetic oil, consisting of six lines of plant capable of producing 16,000 barrels from 5,000 tonnes per day dry coal. For this future stage, Australian companies will be called for equity participation for the project.

Project Cost: Approximately $700 million

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT – Destec Energy, Inc. and PSI Energy Inc. (C-614)

Located in West Terre Haute, Indiana, the project will repower one of the six units at PSI Energy’s Wabash River power station. The repowering scheme will use a single train, oxygen-blown Destec gasification plant and the existing steam turbine in a new integrated gasification combined cycle configuration to produce 270 megawatts of electricity from 2,500 tons per day of high sulfur eastern bituminous coal. The plant will be designed to substantially out-perform the standards established in the Clean Air Act Amendments for the year 2000. The demonstration period for the project will be 3 years after plant startup.

The CGCC system will consist of Destec’s two-stage, entrained-flow coal gasifier, a gas conditioning system for removing sulfur compounds and particulates; systems or mechanical devices for improved coal feed; a combined-cycle power generation system, wherein the conditioned synthetic fuel gas is combusted in a combustion turbine generator; a gas cleanup system; a heat recovery steam generator; all necessary coal handling equipment; and an existing plant steam turbine and associated equipment.

The demonstration will result in a combined-cycle powerplant with low emissions and high net plant efficiency. The net plant heat rate for the new, repowered unit will be 8,740 BTU per kilowatt-hour, representing a 21 percent improvement over the existing unit while cutting SO₂ by greater than 90 percent and NOₓ emissions by greater than 85 percent.

The project was selected for funding under Round IV of the U.S. Department of Energy’s (DOE) Clean Coal Technology Program, and is slated to operate commercially following the demonstration period. DOE has agreed to provide funding of up to $198 million under the Cooperative Agreement.

Construction is scheduled to begin in early 1993 and be completed, with startup, by early 1995.

Project Cost: $396 million

WESTERN CANADA IGCC DEMONSTRATION PLANT – Coal Association of Canada, Canadian Federal Government, the Provincial Governments of Alberta, Saskatchewan, Ontario and British Columbia (C-615)

A C$1 million feasibility study, led by the Coal Association of Canada and begun in 1990, has selected a 240 MW facility to be designed around a General Electric 7001 F gas turbine to test integrated gasification combined cycle technology in Western Canada. The demonstration will also be the first in the world to test carbon dioxide recovery. The study was completed in mid 1991. Two companies, Nova Scotia Power and Saskatchewan Power are now considering the results of the feasibility study to determine whether or not to go ahead with a siting study for the project.

The project will incorporate a Shell entrained flow gasifier capable of using 2,400 tonnes per day of subbituminous coal and will also feature testing of a process that will recover 50 percent of the carbon dioxide from the gas stream prior to combustion. Capital cost is estimated around C$2,000/kW.

SYNTHETIC FUELS REPORT, MARCH 1993

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STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

WESTERN ENERGY ADVANCED COAL CONVERSION PROCESS DEMONSTRATION – Rosebud SynCoal Partnership, Western Energy Company, United States Department of Energy (C-616)

The United States Department of Energy (DOE) signed an agreement with Western Energy Company for funding as a replacement project in Round I of the Department's Clean Coal Technology Program. DOE will fund half of the $69 million project and the partners will provide the other half of the funding. Western Energy Company has entered a partnership with Scoria Inc., a subsidiary of NRG, Northern States Powers' nonutility group. The new entity, Rosebud SynCoal Partnership will be the project owner. Western Energy Company has retained a contract to build and operate the facility.

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 55 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 1 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.

Construction of the ACCP demonstration facility is complete and initial "turnover" of equipment started in December 1991. The DOE agreement calls for a 3-year operation demonstrating the ability to produce a clean, high quality, upgraded product and testing the product in utility and industrial applications.

Plant construction was completed ahead of schedule and, following shakedown activities, startup was achieved in early 1992. When in continuous operation, the plant will produce 1,000 tons per day, or 300,000 tons per year of upgraded solid fuel at full production.

Rosebud SynCoal Partnership is working with Montana Power Company's Corette plant to conduct an initial test burn using a Syncoal/raw coal blend. Northern States Power Company's Riverside plant will receive a 5,000 ton shipment to conduct an initial test burn of the unblended product. Dairyland Power has committed to use the next 5,000 tons for test burns at its Alma Station.

If 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.

Project Cost: $69 million

WUJING TRIGENERATION PROJECT – Shanghai Coking and Chemical Plant (C-620)

Shanghai Coking and Chemical Plant (SCCP) is planning 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. SCCP contracted with Bechtel on June 6, 1986 to conduct a technical and economic feasibility study of the project.

The 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 2 million cubic meters per day of 3,800 Kcal per cubic meter of town gas; 70,000 kilowatt-hours of electricity per year; 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 three phases.

In Phase 1, the production plan is further divided into 2 stages. In the first stage, 1 million cubic meters per day of town gas and 100,000 tons per year of methanol will be produced. The second stage will add another 0.7 million cubic meters per day of town gas and other 100,000 tons per year of methanol.

In November 1991, SCCP and Texaco Development Corporation signed an agreement for Texaco to furnish the gasifier, coal slurry and methanol systems. SCCP will import other advanced technologies and create foreign joint ventures at later stages for the production of acetic anhydride, formic acid, cellulose acetate and combined cycle power generation.

In March 1992, a foundation stone laying ceremony was performed at the plant site. Phase 1 is scheduled to be completed by June 1995.

Project Cost: 2 billion yuan
STATUS OF COAL PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

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 to 30 percent. In order to substitute coal briquettes for lump anthracite, the Beijing Research Institute of Coal Chemistry 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.

YUNNAN PROVINCE COAL GASIFICATION PLAN – People’s Republic of China (C-630)

China is building a coal gasification plant in Kunming, Yunnan Province, that will produce about 220,000 cubic meters of coal gas per day. Joe Ng Engineering of Ontario, Canada has been contracted to design and equip the plant with the help of a $5 million loan from the Canadian Export Development Corporation.
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METHANEX TO ACQUIRE FLETCHER CHALLENGE

Methanex Corporation, the largest marketer of methanol in North America, plans to acquire the entire methanol operations of Fletcher Challenge Ltd., a marketer of methanol from New Zealand and Chile, making Methanex the world’s largest methanol producer.

Fletcher Challenge will turn over three units to Methanex including: Petralgas, a 520,000-metric-ton-per-year facility located in New Zealand; Synfuel, another New Zealand chemical facility with a methanol capacity of 1.8 million tons or alternatively a gasoline capacity of 700,000 tons; and Cape Horn, an 800,000-ton unit in Chile, one of the world’s largest single-train methanol facilities. The Synfuel unit has a swing capacity to produce 450,000 tons of methanol. This capacity could increase to 900,000 tons per year during 1994 by the installation of additional distillation capacity.

In exchange, Methanex will issue approximately 74 million shares and $250 million in cash to Fletcher Challenge, which will give it 43 percent of the issued and outstanding common shares of Methanex.

"By completing this acquisition, Methanex continues to put its confidence in the future of the methanol industry, particularly with the emergence of MTBE to satisfy the mandated use of oxygenates in gasoline in the United States, following the passage of the Clean Air Act," according to B.N. Wade, president of Methanex.

After the transaction Methanex will have production capability of 2.4 million tons of methanol per year plus marketing agreements of another 1 million tons.

Over the next 18 months Methanex has plans for additional capacity of 1.2 million tons of production and further marketing arrangements of 600,000 tons. For Methanex, this latest move represents the culmination of a year of proposed acquisitions and joint ventures that could give it 25 percent of the world market, which would outstrip Saudi Basic Industries Corporation as the world’s largest methanol marketer.

BP PLANNING DEMONSTRATION PLANT FOR GAS CONVERSION PROCESS

British Petroleum Oil Company (BP) is actively pursuing a partner for its natural gas to liquid fuels process demonstration phase. BP hopes to complete a deal by mid-summer. The demonstration phase is expected to be a 15-month program. A successful demonstration will lead to construction of the first small-scale commercial plant. Commercial operations are targeted to begin within three years.

BP optimized its two-step conversion process in a United Kingdom pilot plant, one-one-thousandth the size of a commercial module. The process converts natural gas to synthesis gas to a variety of liquid hydrocarbons, including premium diesel, paraffinic naphtha or synthetic crude oil.
NERA FORECAST SHOWS INCREASE IN NATURAL GAS PRICES

National Economic Research Associates, Inc. (NERA) recently extended its natural gas reserves and production model and its gas demand forecasts to 2010 (see Figure 1). The current base case projects moderate price rises during the mid-1990s but continues to project that the real wellhead price of natural gas will approach $3.00 per thousand cubic feet by year 2000. NERA expects the real wellhead price to peak at around $3.50 per thousand cubic feet during the 2000 to 2005 period and decline somewhat thereafter as a result of increased gas supply and lower oil prices.

NERA’s analysis of United States electricity markets points to electric utility demand for more than 5 trillion cubic feet (tcf) of natural gas in 2000, 7.5 tcf in 2005 and nearly 9 tcf per year by 2010. Driven primarily by this explosion in gas demand by electric utilities, total United States gas consumption is expected to exceed 25 tcf in 2005 and reach 27 tcf in 2010. Even if net imports of natural gas approach 4 tcf in 2005 and reach 5 tcf per year by 2010, United States gas markets seem likely to be tight beginning in 1994 or 1995.

NERA calculations point to a precariously balanced gas market throughout the 1990s, with the Lower-48 State reserve to production ratio pushed down to 8.5 years through most of the period, even with steady growth in imports and a rapid turnaround in natural gas drilling.

Near-Term Outlook

A warm winter in the Northeast played into the hands of gas consumers, and a selling panic pushed prices down sharply in January. NERA does not expect to see spot wellhead prices move above $2.00 per thousand cubic feet again this winter. NERA’s spot price forecast for full-year 1993 is $1.71. Gas consumption is expected to rise about 3.2 percent this year and increase slightly less than 3 percent in 1994.
NEW DIRECT ROUTES FOR CONVERSION OF NATURAL GAS DESCRIBED

Researchers at Catalytica have reported a novel synthesis route from methane to methanol, sidestepping the production of synthesis gas (syngas). In separate work, scientists at the University of Minnesota (Minneapolis) have directly converted methane to syngas in a catalytic oxidation process that avoids steam reforming.

In one of the new approaches, a group at Catalytica headed by research chemist R.A. Periana uses mercuric ions to selectively catalyze conversion of methane to methanol via a methyl bisulfate intermediate in yields up to 43 percent. The reaction occurs in a homogeneous system at 180°C. Periana believes this is the first instance in which Hg(II) is used in electrophilic reactions of methane.

Keys to this chemistry are the novel use of Hg(II) as a catalyst for methane oxidation through an electrophilic displacement reaction, and production of the monoethyl ester of sulfuric acid as a precursor for methanol. The methyl bisulfate solution produced in the reaction can easily be hydrolyzed, and methanol separated by distillation. The Hg(II)-sulfuric acid system provides an important precedent for developing true catalytic systems for selective low-temperature oxidation of methane to methanol.

While still far from commercialization, this work which achieves dramatically higher yields than previously produced with catalytic oxidation provides hints that the catalytic conversion of methane to methanol could be economically feasible.

The second new process has been developed under the direction of chemical engineering professor L.D. Schmidt at the University of Minnesota. He produces syngases in a nearly 2:1 carbon monoxide/hydrogen ratio by direct catalytic oxidation of methane using oxygen or air over platinum or rhodium surfaces. Feed gases are near room temperature, and reactor residence times are short. The results show that rhodium gives consistently higher selectivities to hydrogen, lower temperatures, and higher conversions than does platinum.

The net result is that production of syngas over noble-metal catalysts is possible in high yields. Conversion of methane is almost complete, and selectivity for carbon monoxide and hydrogen is more than 90 percent.

METHANE DIMERIZED IN MICROWAVE PLASMA

The direct conversion of methane into ethane and ethylene in a microwave plasma reactor was reported in a paper by J. Huang and S.L. Suib at the 1992 International Gas Research Conference held in Orlando, Florida last November.

In a high frequency plasma reactor, significant concentrations of free radicals and excited species are generated in the discharge process. Many reactions that are kinetically difficult under thermal conditions may proceed easily in a high frequency plasma reactor. Using a plasma process to selectively activate C-H bonds serves as an example of a method for carrying out thermally difficult reactions. In addition, plasmas can drive thermodynamically unfavorable reactions. Thus, a plasma reaction is able to produce products more reactive than the reactants. In the plasma process for methane dimerization, oxidant is not needed to make the reaction thermodynamically favorable.

Results and Discussion

Two types of quartz plasma reactors were used in this study. One is an ordinary 0.375 inch quartz tube reactor. The other is a 0.25 inch vertex stabilized plasma reactor. Testing was conducted under the following conditions:

- Pressures from 10 to 100 millimeters Hg
- Methane flow rates of 48 to 367 milliliters per minute
- Power from 7.5 to 108 watts

At a pressure of more than 50 millimeters Hg, coke begins to deposit non-uniformly along the walls of the quartz tubing. The coke deposition increases with an increase of microwave power.

The major products under all conditions are ethane and ethylene with minor quantities of propane and propylene. Generally, the ratio of ethylene to ethane varies from zero to 0.5. Under optimum conditions, methane conversion can be as high as 90 percent. However, at this high conversion, excessive coke deposition is observed; and the plasma can only be maintained for less than 2 minutes. The methane conversion and the product distribution are the same for the two types of plasma reactors. However, the vertex stabilized plasma reactor has less coke deposition than the straight quartz tubing reactor and the plasma in the vertex stabilized reactor is more stable.
The relation between the total methane conversion and the experimental parameters, pressure, plasma power and flow rate, was fitted to an empirical relation, illustrated in Figure 1.

The authors calculated the energy efficiency for driving the thermodynamically unfavorable methane dimerization reaction to be between 2 and 8 percent. Here the energy efficiency is defined as the ratio of the minimum free energy required to convert methane to ethane and hydrogen to the actual microwave energy input into the reaction. Although the ratio of flow to plasma power influences energy efficiency, pressure is directly proportional to efficiency. Therefore, from an energy efficiency standpoint alone, high reaction pressure is desired. In addition, operating the reaction at atmospheric pressure is technologically much easier than operating at vacuum in industrial applications. Thus, Huang and Suib recommend further investigation of methane plasmas near or at atmospheric pressure.

The dependence of methane conversion to ethane or ethylene on the experimental parameters is more complex than that of the total methane conversion. As shown in Figure 2, the ethylene conversion curve has a maximum. The solid data points are for the vertex stabilized 0.25 inch quartz reactor and the open points are for the 0.375 inch straight quartz tube reactor. Under present experimental conditions, this maximum is fixed. However, the authors expect to be able to shift this maximum by using suitable catalysts.
STATUS OF NATURAL GAS PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since December 1992)

FUELCO SYNHYTECH PLANT — Fuel Resources Development Company (G-10)

Fuel Resources Development Company (FuelCo) held groundbreaking ceremonies in May 1990 for their Synhytech Plant at the Pueblo, Colorado landfill. The Synhytech Plant, short for synthetic hydrocarbon technology, will convert the landfills' methane and carbon dioxide gas into clean burning diesel fuel as well as naphtha and a high grade industrial wax.

The technology is said to be the world's first to convert landfill gases into diesel motor fuel. It was developed by FuelCo, a wholly owned subsidiary of Public Service Company of Colorado, and Rentech Inc. of Denver, Colorado. Fuelco is planning to invest up to $16 million in the project with Rentech having the option to purchase 15 percent of the plant. Ultrasystems Engineers and Constructors is designing and building the project.

The plant is expected to produce 100 barrels of diesel, plus 50 barrels of naphtha and 80 barrels of high grade wax per day. It is estimated that the Pueblo site will sustain a 235 barrel per day production rate for about 20 years. FuelCo estimates that diesel fuel can be produced for about $18 per barrel.

According to vehicle test results at high altitude, the Synhytech diesel was 35 percent lower in particulate emissions and produced 53 percent fewer hydrocarbons and 41 percent less carbon monoxide in the vehicle exhaust. It contains no sulfur and only low levels of aromatics, and no engine modifications are required. Plant construction was complete in December 1991 and the first crude product was produced in January 1992.

In December 1992 Public Service Company of Colorado said it was trying to sell its Fuel Resources Development Company subsidiary, along with the Synhytech pilot plant. While the Plant had a pre-tax value of about $24 million, Public Service plans to write off its entire investment in the facility.

Project Cost: $16 million

MOSSGAS SYNFUELS PLANT — South African Central Energy Fund (70 percent), Engen Ltd. (30 percent optional) (G-20)

In 1988 the South African government approved a plan for a synthetic fuel from offshore natural gas plant to be located near the town of Mossel Bay off the southeast coast. Gas for the synthesis plant will be taken from an offshore platform which was completed in 1991. The SASOL Synthol technology has been selected for the project.

Construction of the onshore plant is scheduled for completion in mid-1992. The complex is expected to produce its first products by the third quarter of 1992 and to be in full production by the third quarter of 1993. The product slate will be liquefied petroleum gas, 93 and 97 octane gasoline, kerosene and diesel.

The breakeven point for the project will be reached with crude oil prices of $35 per barrel. Engen is the project manager and will be the operator of the facility. The project was financed 80 percent by the Central Energy Fund and 20 percent by commercial loans.

Gas reserves, located in 350 feet of water, 55 miles off the Southeast coast of South Africa, are sufficient to operate the synthesis facility for 30 years at design rate.

Gas and condensate arrive onshore in separate pipelines. In the Natural Gas Liquid Recovery plant any hydrocarbons heavier than propane are removed from the gas stream yielding lean natural gas. The lean gas is fed to a two-stage methane reforming plant. The first stage consists of a tubular reforming plant which is followed by a secondary partial oxidation plant. The capacity of the three-train reforming plant would be sufficient for the production of 7,000 tons per day of methanol.

Using an iron-based catalyst, the synthesis gas from the natural gas reforming plant is catalytically converted to predominantly light olefinic hydrocarbons. The tailgas from Synthol is sent to the Tailgas Treatment plant where products (propylene, butylenes and C5+ condensate) are cryogenically removed before the gas is recycled back to a natural gas reforming plant. Hydrocarbons from Synthol are refined by conventional methods to produce the final fuels.

Project Cost: $4.2 billion
STATUS OF NATURAL GAS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

NEW ZEALAND SYNFAEELS PLANT - Fletcher Challenge, Ltd. (75 percent), Mobil Oil of New Zealand Ltd., (25 percent) (G-30)

The New Zealand Synthetic Fuels Corporation Limited (Synfuel) Motunui plant was the first in the world to convert natural gas to gasoline using Mobil's methanol-to-gasoline (MTG) process. Construction began in early 1982 and the first gallon of gasoline was produced in October 1985. In the first 8 months of commercial production the plant produced 448,000 tonnes of gasoline or about 35 percent of New Zealand's total demand for that period.

During the first two years of operation, the Synfuel plant suffered several shutdowns in the methanol units thus causing production shortfalls despite reaching the one million tons of gasoline mark in 1988. A successful maintenance turnaround and several improvements to the MTG waste water plant have improved efficiency considerably. In 1990 the plant produced about 12,000 barrels of gasoline per day. This is about 34 percent of New Zealand's gasoline needs.

The plant is located on the west coast of New Zealand's North Island in Taranaki. It is supplied by the offshore Maui and Kapuni gas fields. The synthetic gasoline produced at the plant is blended at the Marsden Point refinery in Whangarei. The plant is a tolling operation, processing natural gas owned by the government into gasoline for a fee. Synfuels, thus does not own the refined product.

Synfuel was owned 75 percent by the New Zealand government and 25 percent by Mobil Oil of New Zealand Ltd. However, the Petroleum Corporation of New Zealand (Petrocorp) entered an agreement with the New Zealand government to assume its 75 percent interest in the corporation. The New Zealand government had been carrying a debt of approximately $700 million on the plant up to that point. Petrocorp is owned by Fletcher Challenge, Ltd.

Since the change in ownership, a pipeline has been built between the Synfuel plant and the Petralgas methanol plant in the Waitara Valley. This addition means that, when the price of distilled methanol is high, a percentage of Synfuel crude methanol can be sent via the pipeline to Petralgas for distillation. When the price of gasoline is high, Petralgas methanol can be sent via the pipeline to Synfuel and be converted into gasoline.

The synfuel plant produced a record 562,000 tonnes of gasoline in the first 6 months of 1991. A percentage of crude methanol was pipelined to Fletcher's Petralgas plant to produce 186,000 tonnes of chemical grade methanol.

The plant was designed to produce 4,400 tonnes of methanol per day. Due to plant modifications, Synfuel is capable of producing 5,000 tonnes of crude methanol per day. Equally, the plant was designed to produce 570,000 tonnes of gasoline per year. Synfuel can produce over 630,000 tonnes of gasoline, or 34 percent of New Zealand's gasoline needs.

In February 1993, MethaneX Corporation of Canada said it would buy the methanol assets from Fletcher Challenge Ltd., in a transaction with an indicated value of US$730 million.

Fletcher Challenge would receive $250 million in cash and about 74 million common shares of MethaneX in the proposed deal. The transaction would make MethaneX the world's largest producer and marketer of methanol, and would make Fletcher Challenge the largest shareholder in the petrochemicals concern.

Following completion of the asset purchase and a share issue, Fletcher Challenge would hold about 43 percent of MethaneX's shares. The stake held by current leading shareholder Metalgesellschaft would fall to about 10 percent from its current 32 percent.

Fletcher Challenge, which owns the Cape Horn methanol plant in Chile, is the world's largest methanol producer, just ahead of Saudi Arabian Basic Industries Corporation.

SHELL MALAYSIA MIDDLE DISTILLATES SYNTHESIS PLANT - Shell MDS (60 percent), Mitsubishi (20 percent), Petronas (10 percent), Sarawak State Government (G-50)

The Royal Dutch/Shell Group is building the world's first commercial plant to produce middle distillates from natural gas in Malaysia. The $660 million unit is being built next to the Bintulu LNG plant in the state of Sarawak. The plant will produce approximately 500,000 metric tons of products per year from 100 million cubic feet per day of natural gas feedstock.

The operator for the project will be Shell MDS. The main construction contract was let to JGC Corporation of Japan. Site preparations began in late 1989, with completion scheduled for late 1992.

The Shell middle distillates synthesis process (SMDS) is based on modernized Fischer-Tropsch technology which reacts an intermediate synthesis gas with a highly active and selective catalyst. The Shell catalyst minimizes coproduction of light hydrocarbons unlike classical Fischer-Tropsch catalysts. Middle distillates will be the main product, but the plant will have operating flexibility so that while maintaining maximum output, the composition of the product package, which will contain low molecular weight paraffin waxes, can be varied to match market demand. Shell will use its own gasification technology to produce the synthesis gas.
STATUS OF NATURAL GAS PROJECTS (Underline denotes changes since December 1992)

COMMERCIAL PROJECTS (Continued)

Four reactors for the heavy paraffin synthesis unit, said to be the largest in the world, have been delivered to the plant site. These vessels were built in Italy, but overall construction is being handled by JGC Corporation of Japan.

Project Cost: $660 million