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COAL AND OIL-SHALE PROCESSING AND COMBUSTION. SUBPANEL REPORT V USED IN PREPARING THE AEC CHAIRMAN'S REPORT TO THE PRESIDENT

USAEC, WASHINGTON, D.C

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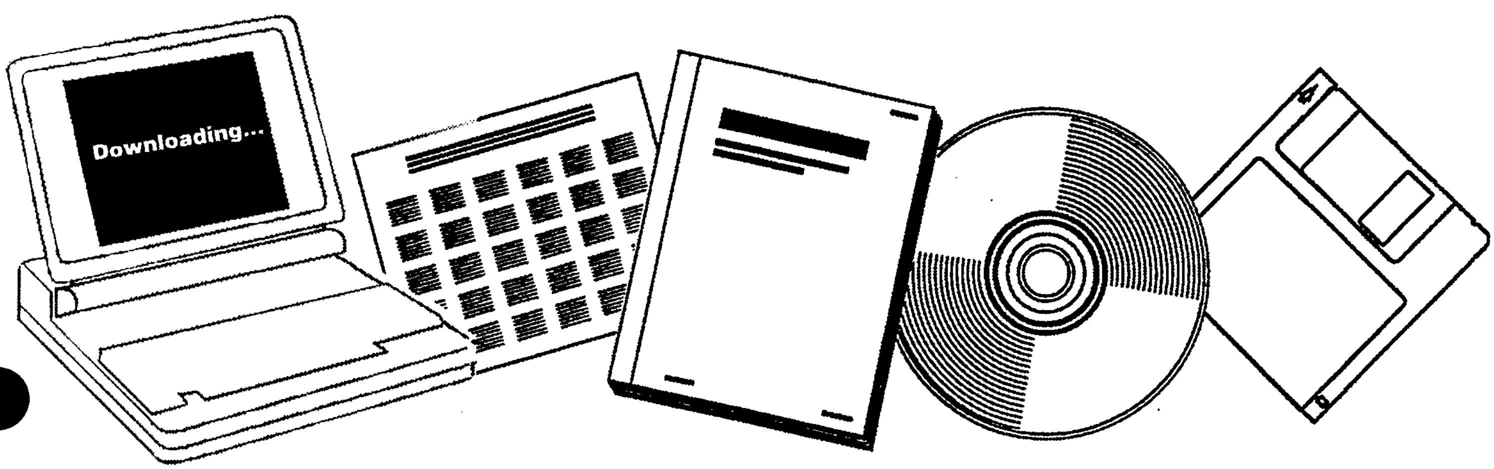

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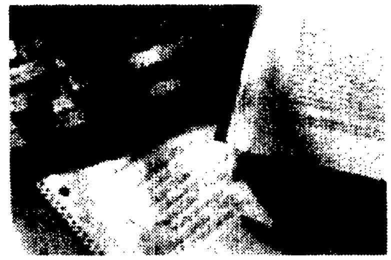

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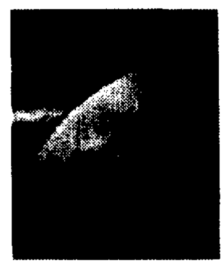

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U.S. DEPARTMENT OF COMMERCE
Technology Administration
National Technical Information Service
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COAL AND OIL-SHALE PROCESSING AND COMBUSTION

Introduction: Presently fluid hydrocarbon fuels are obtained in quantity only from petroleum and natural gas. Domestic sources, until recently, have provided the energy for the industrial growth of the country. Projections of consumption of fluid hydrocarbons indicate that substantial quantities will have to be imported, while at the same time domestic production may hold level or decrease. The only practical alternative sources of significant quantities of fluid hydrocarbons in the United States are coal and oil shale.

A large fraction of the world's resources of coal and oil shale is located in the United States. It is estimated that sufficient amounts are available to support our domestic needs for oil and gas for at least the next several hundred years, thus providing national self-sufficiency as soon as a suitable domestic processing and conversion industry for these energy sources can be established. As an alternative to the importation of large energy supplies, the United States then would be very favorably situated from a energy standpoint. However, to establish such an industry and to develop the technology necessary, a vigorous national effort is required.

Optimistic projections indicate that by 1985 an industrially supported oil-shale industry of about 1,000,000 bbl/day can be developed. From coal, about 1,000,000 bbl/day production of oil and 1.5 trillion cf/year of pipeline quality gas might be available by 1985, if the Federal government has a strong commitment to achieve that goal. Achievement of this goal would provide for rapid industrial expansion after 1985, but first the threshold must be overcome.

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During the near-term period, the development of reliable stack gas cleanup systems must be accomplished in order to insure that coal can be burned in central power plants in an environmentally satisfactory manner. Simultaneously new coal combustion techniques must be developed which have greater efficiency than conventional systems. Stack gas cleanup consumes from 3 to 7 percent of the power output of a plant. Pressurized fluidized bed combustion systems will be developed under this program which have the capability of higher thermodynamic efficiencies than conventional systems and also avoid the power losses in stack gas cleanup.

The proposed supporting research is an effort parallel with the coal gasification and liquefaction research and focuses sharply upon the equipment and material problems that are encountered in the hostile conditions used in these processes. Commercial development can only follow when there is reasonable assurance of reliable continuous plant operation. The solution to problem areas is usually less costly in the laboratory than in a pilot plant operation.

Proposed funding levels for the five subprograms included in this review are as follows:

BUDGET (Millions)	FY 75	FY 76	FY 77	FY 78	FY 79	TOTAL
Pipeline Quality Gas from Coal	35	161	32	21	16	265
Clean Liquid Fuels from Coal	75	100	75	75	50	375
Improved Combustion Processes	20	20	50	55	55	200
Improved Environmental Control	70	77	42	38	33	260
Support Research for Coal and Oil Shale	20	28	27	24	21	120
	220	386	226	213	175	1,220

PIPELINE QUALITY GAS FROM COAL

Goals and Objectives: The goals and objectives of this research and development program are to reduce to commercial practicality one or more environmentally acceptable methods of converting coal to pipeline quality gas and to develop the technology necessary for the establishment of a commercial coal-to-pipeline quality gas industry with due regard to environmental considerations by pilot plant testing and by constructing and operating a coal-to-pipeline quality gas demonstration plant.

Impact of Successful R&D on Energy Situation: Present estimates indicate that successful research and development will result in the operation of commercial (250-million cf/day) plants by 1981. It is estimated that pipeline gas from coal will contribute 1.5 trillion cf/year (1.5 quadrillion Btu) by 1985, accounting for 4% of the supply. This is expected to rise sharply to 7.5 trillion cf/year (7.5 quadrillion Btu) by the year 2000, accounting for 13% of the supply.

Specific Achievements Expected from Program: It is expected that this program will lead to pilot plant testing of the four advanced gasification processes (Hygas, CO_2-Acceptor, Synthane and Bi-Gas) and construction and operation of a demonstration plant which will test a selected process or a system combining the best features from several processes. After operation of the demonstration plant, sufficient data will be available for design and construction of commercial plants.

Budget (Millions):	FY 75	FY 76	FY 77	FY 78	FY 79	Total
Pilot Plant	27	20	10			57
Advanced R&D	4	8	2	1	1	16
Demonstration Plant	4	133	20	20	15	192
	35	161	32	21	16	265

Pilot plant funding includes support for Hygas, CO_2-Acceptor, Synthane and Bi-Gas. Advanced R&D consists of engineering evaluation as well as development of the Hydrane process, Liquid Phase Methanation, the Stirred-Fixed Bed and the Self-Agglomeration process. In addition to the funding shown for FY 75, $10 million is expected from industry for the Office of Coal Research - American Gas Association program. The demonstration plant program is projected to include additional funding from industry.

Also included in the above funds is continued back-up research to support the planned operations.

A breakdown of funds in terms of operating expenses and construction is as follows:

(Millions)	FY 75	FY 76	FY 77	FY 78	FY 79	Total
Operating Expense	16	25	32	21	16	110
Construction/ Equipment	19	136	—	—	--	155
	35	161	32	21	16	265

Program Plan and Content: The pipeline quality gas from coal program consists of the continued operation of the Hygas and CO_2-Acceptor pilot plants, the completed construction and subsequent operation of the Synthane and Bi-Gas pilot plants and construction and operation of a demonstration plant producing 50-150 million cf/day. The present schedule calls for operation of the Synthane pilot plant in 1974 and Bi-Gas by 1975. Construction of the demonstration plant (producing 50-150 million cf/day) is expected to start in 1976 and be completed in 1979. It is anticipated that commercial plant construction could be initiated soon thereafter by industry.

Present industry funding participation consists of 1/3 support of the OCR - AGA gasification program (Hygas, CO_2-Acceptor, Bi-Gas and Others). It is expected that industry will participate at least to this same extent in the construction and operation of the demonstration plant.

Technical Handicaps and Actions Suggested to Assist Program: The basic processes involved in coal gasification are not expected to present unsolvable engineering problems which has been a deterent factor in obtaining substantial funding commitments from industry in support of the program.

An environmental impact statement will be required for the demonstration plant. The plant will have a significant environmental impact since it will utilize large amounts of coal (1.5 million tons/year) and water (10,000 acre ft/year). This will have to be considered in site selection. Capital and manpower availability, material requirements and social impact are not expected to be substantial problems.

Other government action which would aid the R&D program would be favorable and definitive action by FPC in regulating price of SNG from coal (when mixed with natural gas) to remove present uncertainties concerning government policy in this area.

CLEAN LIQUID FUELS FROM COAL

Goals and Objectives: The goals and objectives of the clean-burning liquid fuels from coal program is the development of one or more processes for converting coal to a high-quality clean-burning boiler fuel. Such a fuel should be capable of further refining to produce a high-quality synthetic oil or a satisfactory motor fuel. The program will achieve this objective by careful operation, over a period of years, of a number of pilot plants that will include the direct hydrogenation of coal, extraction of coal, and the carbonization of coal.

By converting coal to a clean-burning liquid, the use of oil in power-plants can be eased. Natural gas, too, can be conserved for higher priority uses. With successful development, additional process units can be added to the pilot plants to further refine the coal liquids to produce diesel fuel, gasoline, and jet fuel.

Data will be collected and analyzed to provide engineering design information such that a demonstration plant can be designed and ready for construction by the fifth year of the program. The demonstration plant will seek to test a number of processes and process alternates at a single operational location. This test facility will have a capacity expected to be about 10 percent of a commercial-scale plant, i.e., 2,500--10,000 tons of coal per day. Plant products will include a high-quality synthetic oil, a low-sulfur boiler fuel, pipeline-quality gas, fuel gas, and byproducts related to the mining/processing operation.

Impact of Successful R&D on Energy Situation: Based upon this program, it is expected that plants with a total capacity of about 1.5 million barrels of liquid per day would be constructed over a period of about 10 years. On an annual basis these plants would provide 6.0×10^{15} Btu's with input into power generation, residential heating, commercial use, and industrial fuel.

As commercial development proceeds, about 1 trillion cu. ft. (1.0×10^{15} Btu's), 1/3 billion barrels of oil (2.0×10^{15} Btu's), and 68.6 million tons of reformed coal (2.2×10^{15} Btu's) would be added to the synthetic fuel capability of the Nation. In 1970 dollars, this would require an annual investment of $8--$10 billion per year in mine, physical plant, and supporting systems.

Specific Achievements Expected from Program: This program will clearly establish the feasibility of converting high-sulfur coal to a clean-burning liquid with a thermal efficiency of approximately 70 percent.

A ceiling price will be established on imported crude oil. If the reduction in imported crude price, as a result of this program, is only 50 cents per barrel, a projected 1985 use of 10-billion barrels/year, with 55 percent of the use met by imports would show an annual savings to the Nation of $2.75-billion. Further benefits will accrue in the form of gas production and a clean solid fuel for power purposes.

Budget (Millions)	FY 75	FY 76	FY 77	FY 78	FY 79	Total
Government	75.0	100.0	75.0	75.0	50.0	375.0
Industry	5.0	10.0	10.0	25.0	25.0	75.0
Total	80.0	110.0	85.0	100.0	75.0	450.0

Projects included are: Solvent Refined Coal; C.O.E.D.; Direct Hydrogenation (Synthoil and Other Catalytic processes); Fischer-Tropsch Synthesis; Clean Coke and Liquids; Cresap Testing, Research and Engineering Facility; Bench Scale R&D and Demonstration Plants. Demonstration plants represent the major funding outlay in the FY 77-79 period.

Program Plan and Content: To obtain data for the design of commercial-scale plants, a series of pilot plants will be designed, constructed, and operated. The pilot plants are expected to have capacities ranging from 1-10 tons/hour of coal, with most of the plants falling within the 5-10 tons range. The direct hydrogenation of coal will be studied in an ebullated bed plant (a liquid fluid bed system) and in several fixed catalyst systems. Low temperature carbonization of coal at atmospheric and elevated pressure will be investigated. The extraction of coal in a hydrogenation-donor process derived solvent as well as in the presence of hydrogen will be studied at the pilot-plant scale. Liquids produced by the various processes will be catalytically hydrogenated over a broad range of conditions to determine the best system.

To provide balance for the total system a concurrent supporting research program will be undertaken seeking better materials of construction and development of special items of equipment. Engineering and systems studies will proceed with the experimental program to insure early commercialization of the concepts investigated at the pilot plant level. One or more pilot plants combining processes with a synergistic effect will be designed, constructed, and operated. Typically, a plant might produce chemicals, fuel gas, a synthetic oil, a low-sulfur solid fuel (coke or coal), and perhaps include a power system as well.

As pilot plant data are available, they will be assembled and analyzed. During the second year of the program a commercial-scale-demonstration plant design will begin. The purpose of the design is to insure that the pilot plants produce the data needed for design of commercial-scale facilities. Individual processes will be related, one to the other, so that complementary process schemes can be incorporated into the final demonstration plant design. During this period the detailed environmental impact statement of the demonstration plant will be prepared.

<u>Technical Handicaps and Actions Suggested to Assist Program</u>: The conversion of coal to a liquid is not new. No technical obstacles are foreseen. The primary program need is the demonstration of process economics of the various methods to determine an economic, practical commercial optimum. The preliminary research work and the continuing supporting research should be funded by the Government. As projects proceed to the pilot plant stage, private funding should be sought to augment the funds shown. This will be difficult to obtain, but it is believed that $75 million can be obtained over the life of the program. As the projects move toward commercialization, it will be vital to have available modern mining systems capable of supporting coal synthetic fuel plants that require about 100,000 tons/day of coal. Funding for this research and development

is not included in this budget. In addition, policy decisions may be necessary to encourage industry to undertake the heavy capital investments demanded by commercialization.

IMPROVED COMBUSTION PROCESSES

Goals and Objectives: The goals and objectives of this program are to develop technology for utilizing the Nation's substantial coal reserves for electric power production and other industrial applications in an environmentally satisfactory manner and to achieve increased thermal efficiency and lower costs by use of fluidized-bed combustion and modification of conventional boilers.

Impact of Successful R&D on Energy Situation: It is estimated that, once fluidized-bed combustion is developed successfully, it will be applied to 0.2×10^{15} Btu (input) capacity by 1985, and 2.2×10^{15} Btu by 2000. This degree of implementation would result in a savings of $0.2 billion in plant capital costs by 1985, and $2.9 billion (cumulative) by 2000, compared to conventional boilers equipped with stack gas cleaning. The reduction in SO_x emissions would be 0.7 million tons in 1985, and 7.2 million tons in 2000, compared to the discharge from uncontrolled conventional boilers. The elevated-pressure systems should achieve a level of 41 percent in plant thermal efficiency resulting in a savings in coal utilization of as much as 5 million tons/yr by 2000 when compared to the present combustion system with an efficiency of about 38 percent. Application of combustor modification technology would improve fuel utilization efficiency by one percent or more, thus reducing energy requirements accordingly. More importantly, however, combustor modifications will provide the best technology for establishing and meeting standards for area sources. NO_x emissions, for example, may be reduced by up to 60 percent. Emission of hydrocarbons and polycyclic organic materials will also be significantly reduced from some processes.

Specific Achievements Expected from Program: This program plan will lead to the development and commercial scale demonstration of new and more efficient combustion systems, including development of an advanced boiler concept and modification of conventional boilers and industrial furnaces. The advanced boilers to be developed include two variations of the fluidized-bed combustion process (atmosphere and high pressure). Modifications to conventional coal and oil burning boilers and furnaces are included in the program planning and will result in optimization of rate and completion of combustion, reduction of critical flame temperatures, and dry (catalytic) methods for control of NO_x from stationary gas turbines.

BUDGET (Millions):	FY 75	FY 76	FY 77	FY 78	FY 79	Total
Pressurized Fluid-Bed	2	1	7	12	12	34
Atmospheric Fluid-Bed	8	4	37	37	37	123
Support R&D	6	6	2	2	1	17
Combustion Modifications	4	9	4	4	5	26
	20	20	50	55	55	200

Program Plan and Content: The program provides that a pressurized version of the fluidized-bed boiler will be tested at an existing 0.6 Mw pilot plant ($2 million test project, all Government-funded), followed by 30 Mw demonstration plant tests ($12 million Government, plus $12 million industry funds), and finally, full-scale testing of a 150 Mw module plant ($41 million Government, plus $36 million industry). The funding stipulation assumes that industry will support 50 percent of the cost of design and construction of the demonstration and full-scale module plant. The project is expected to be completed by the end of FY 81.

Based upon the more advanced stage of development and reduced technological difficulty, the atmospheric pressure fluid-bed boiler project will begin with construction and testing of a 30 Mw-level pilot plant ($18 million, all Government). This will be followed by construction and testing of a 400 Mw demonstration plant ($105 million Government, plus $105 million industry). The project will be completed by the end of FY 80.

The combustor modification program includes testing of candidate burner and combustor designs for utility and industrial boilers, industrial process furnaces, and utility gas turbines ($27 million Government plus 42 percent of total by industry). The major portion of this program is expected to be completed by FY 79. Gas turbine tests, including testing of a 50-75 Mw combined cycle demonstration plant will be undertaken and completed by the end of FY 82.

Government expenditure to completion for the total fluid-bed boiler combustor modification program is estimated to be $230 million, with post FY 79 costs at the $30 million level.

<u>Technical Handicaps and Actions Suggested to Assist Program:</u> Restraints on the success of fluidized-bed combustion systems include: (1) demonstration of sorbent regeneration and sulfur recovery, for those variations of the system involving regeneration; (2) demonstration of high-temperature, high-pressure particulate removal technolgy, for pressurized systems; and (3) demonstrating the operability of the integrated boiler systems on a large scale. Reluctance of boiler manufacturers and operators to build and install boilers radically different from what is currently commercial may be a

barrier to commercialization. Major restraints in combustion modifications will be eased by the demonstrations of efficiency and pollution reduction with satisfactory operating characteristics and equipment durability. It is expected that commercialization of fluid-bed boilers will introduce no more significant demand on manpower, money, social dislocation, and materials requirements than the use of conventional boilers.

IMPROVED ENVIRONMENTAL CONTROL

Goals and Objectives: The goals and objectives of this program are: (1) To improve the utilization of coal in direct combustion processes by reduction/control of pollutant and impurity emissions, (2) to provide environmentally acceptable control methods when converting coal and shale oil to pipeline quality gas, liquids, and clean fuels, (3) to reduce cost and environmental impact and increase availability of energy through byproducts/wastes recovery and utilization from coal and oil shale processing, (4) to develop and demonstrate improved and new methods for reduction of SO_x, particulates and hazardous pollutant emissions from the utility, industrial and commercial combustion of coal, (5) to improve physical coal cleaning techniques and to develop new chemical coal treatment methods that would result in maximum reduction of impurities, (6) to quantify the environmental problems associated with coal and oil shale processing to produce gaseous and liquid products and develop necessary control technology to assure establishment of an environmentally acceptable commercial industry, (7) to reclaim energy values contained in coal refuse and refinery residues of high-sulfur content, (8) to optimize reclamation of land surfaces disturbed by mining of energy fuels, and (9) to reduce coal and oil shale processing costs by recovery and utilization of mining refuse, process wastes and byproducts.

Impact of Successful R&D on Energy Situation: The attainment of the program goals will: (a) enable the continued use of the Nation's high sulfur coals for combustion purposes in an environmentally acceptable manner, (b) provide a basis for accelerating the coal base utility capacity to generate clean electrical energy, (c) develop needed environmental control that will assure the accelerate development and commercialization of the coal and oil shale processing conversion industry; and (d) increase utilization and recovery of byproduct values from waste and secondary materials.

Specific Achievements Expected from Program: Specific achievements that should be obtained in this program are:

Complete identification and quantification of pollutant occurrence, levels and rates in existing coal conversion pilot plants by the end of FY 1975.

Complete demonstration and long term reliability testing of two additional flue gas desulfurization (FGD) systems, complete evaluation and development of firm engineering data for specific process control techniques for reduction of pollutant emission from coal conversion systems, complete development investigations of processes for environmentally acceptable disposal of waste products and methods for reclaiming salable byproduct values from coal conversion processes, obtaining sufficient pilot plant data on chemical coal cleaning (desulfurization) to provide required engineering information for scaleup to demonstration size during FY 1976 and 1977.

Complete demonstration and reliability testing of four additional advanced FGD systems by 1978.

Complete the major FGD demonstration programs, complete development and demonstration of fast generation fine particulate control techniques for stationary combustion sources, and complete construction and initial operation of a demonstration plant that utilizes high sulfur coal cleaning refuse to generate electrical energy in an environmental acceptable manner by the end of FY 1979.

During the program period (1975-1979) continue improvement in physical cleaning of coal and reclamation of lands disturbed by mining of energy fuels.

Budget (millions):	FY 75	FY 66	FY 77	FY 78	FY 79	Total
Flue Gas Desulfurization	29	27	7	5	-	68
Particulate & Hazardous Emission Control	8	11	8	8	8	43
Fuel Cleaning	4	6	5	3	3	21
Fuel Conversion Control	15	19	13	13	13	73
Waste Disposal	14	14	9	9	9	55
	70	77	42	38	33	260

Program Plan and Content: This program is based on Federal support of the research and development program and industrial/Federal support of demonstration plants. The input of industrial/private expertise is maximized by contractual studies. This approach makes for effective transfer of information and development of industrial competence to carry out commercialization. The expected contribution from industry sources over the program period is as follows: flue gas desulfurization, $50 million; particulate and hazardous emission control, $20 million; fuel cleaning, $11 million; emission control from fuel conversion, $30 million; and waste disposal research, $39 million.

Technical Handicaps and Actions Suggested to Assist Program: The stated objective can only be achieved if maximum utilization of Federal and industrial/private expertise and capabilities are had. Additionally, industrial acceptance of these goals must be obtained and reinforced. Major restraints on the program are: availability of capital, maintaining a national desire to protect the environment, acceptance that recovery of fossil fuel energy and industrial expansion will cause major impact in "virgin" land areas even when a sincere effort is made to minimize these disturbances, maintaining continuity of existing efforts and organization since major changes in responsibilities could result in serious time delays and Federal policies that will provide positive influence and directions to achieve the stated goals.

SUPPORT RESEARCH FOR COAL AND OIL SHALE

Goals and Objectives: The goals and objectives of this program are:

1. Equipment development: To develop, independent of pilot plants, reliable coal injection systems and components for coal gasification and liquefaction.

2. Materials: To develop methods for service life prediction of materials under the highly erosive and corrosive conditions (temperatures to 3000° F and pressures to 1500 psi) found in coal processing systems and to develop superior materials and test methods for this purpose.

3. To develop low-cost, on-site processes for producing the hydrogen-rich gases essential for several coal processing schemes.

4. To develop a coherent technical, design and economic information base for coal processing.

5. To advance unit operations of coal processing and to develop new processes for producing fluid hydrocarbons from coal.

6. To develop improved catalysts for coal methanation, gasification and liquefaction reactions.

Reliability is not inherently built into the design of present coal gasification and liquefaction pilot plants. Rather, the processing concepts are being investigated and proven. Before commercial plants are built, there must be reasonable assurance of continuous operation in a reliable manner. To develop a coal processing industry and obtain national self-sufficiency in a minimum time, the problems of reliability of materials and equipment must be solved. It is usually less costly to solve these reliability problems in the laboratory than in pilot plant operations.

Impact of Successful R & D on Energy Situation: Additional information on the contribution of coal processing to the energy system is to be found in the other sections of the Coal and Oil Shale Processing and Combustion report. Pilot plant operations must be designed to demonstrate the concepts and process in question. This objective, although necessary, is not compatible with systematic improvement of equipment components, investigation of erosion and corrosion of the equipment, or the development of innovative processes. Pilot plant operations cannot be shut down for months while a new valve is designed. Rather, it is replaced. Thus, it becomes mandatory that parallel research be carried out seeking solutions to the problems that arise. The investment in supporting research should shorten the time and reduce the cost for commercial development.

Specific Achievements Expected from Program: The limited funds allocated ($20 million) do not permit optimal pursuit of all goals. At this level, only the most urgent problems can be attacked. The major emphasis on this funding level will be to achieve the goals and objectives numbered 1, 2, 3, and 4 with the uncertain assumption that industry will assume some funding responsibility for effort in achieving goals 5 and 6. The major thrust will be on those projects designed to increase reliability and enhance the probability of success of coal processing plants.

BUDGET (Millions):	FY75	FY76	FY77	FY78	FY79	Total
Equipment Development	5	8	8	7	7	35
Materials	5	8	8	7	7	35
Technical Data Base & Analyses	2	4	4	4	3	17
Hydrogen Production	2	4	5	4	4	19
Catalysis & Kinetics	3	2	1	1	0	7
Process Development	3	2	1	1	0	7
TOTAL	20	28	27	24	21	120

Larger expenditures are expected during its second and third years when laboratory equipment expenditures are expected to be higher. It is hoped that industry will put increasing emphasis upon catalyst and process development after FY 1975.

No significant construction costs are anticipated. Laboratory scale equipment will be required as follows:

(Millions)	FY75	FY76	FY77	FY78	FY79	Total
Equipment Costs (estimated)	3	8	6	3	0	20
Operating	17	20	21	21	21	100
TOTAL	20	28	27	24	21	120

Program Plan and Content

The plan is to start a number of parallel programs at laboratories where competence exists. Programs on equipment development will involve: coal injection systems for high pressure (lock hoppers, sealing devices, slurry pumps, etc.); improved filtration for coal liquefaction; and char and ash withdrawal systems. Programs on material development will involve:

development of short-time test methods for predicting long-time mechanical durability and reliability of materials in highly erosive and corrosive environments; development of better techniques for measuring critical properties; and selecting materials for coal processing equipment. Research on hydrogen production for use in coal conversion processes will involve laboratory scale investigations of: steam-oxygen process for hydrogen production from coal and residue chars; thermochemical cycles; electrothermal generation; and the steam-iron process. The purpose of this activity is to provide the information for selection of the best process for development. The technical, design and economic information base to be developed includes: properties of coal; kinetic and thermodynamic data on process chemistry of coal conversion including pollutant control; engineering data books on coal conversion; computer modeling; standard reference materials for trace pollutants; central information center; and analyses of economic and manpower implications of coal conversion programs.

Technical Handicaps and Actions Suggested to Assist Program: No major obstacles of a technical or policy nature are known which prevent implementation of this program other than the usual uncertainties involved in any R & D program.

UNITED STATES
ATOMIC ENERGY COMMISSION
WASHINGTON, D.C. 20545

Richard Pastore, Staff Director
Energy Reorganization Unit

SUBPANEL V, COAL AND SHALE PROCESSING AND COMBUSTION ENERGY R&D REPORT

Enclosed is a copy of the subject report for your review and submission to the Chairman of the AEC.

William Crentz
U.S. Bureau of Mines
Subpanel Chairman

Enclosure:
As stated

SUBPANEL V

COAL AND SHALE PROCESSING AND COMBUSTION

William Crentz, Subpanel Chairman
U.S. Bureau of Mines

October 27, 1973

Prepared for the Chairman U.S. Atomic Energy Commission in support of her development of a comprehensive Federal energy research and development program to be recommended to the President on December 1, 1973.

Subpanel #5 Coal and Shale Processing and Combustion

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SECTION II

Pipeline Quality Gas from Coal

PIPELINE QUALITY GAS FROM COAL

II. Status of the Technology

A. Present Status of Technology

No commercial high Btu gas from coal process exists today. The Lurgi fixed-bed gasifier is the only pressurized coal gasification system to reach commercial application to date. It does not produce high Btu gas, has low throughput is handicapped with relatively high investment costs and cannot handle fines or caking coals. For these reasons, a number of other processes are being developed. These are summarized in Table I.

Hygas, Bi-gas, CO_2 Acceptor, Self-Agglomerating Ash, and certain tests for utilizing the Lurgi process to produce a high Btu gas from U.S. coals are being funded on a 2/3 government (Office of Coal Research) and 1/3 industry (American Gas Assoication) basis. Synthane and Hydrane processes are totally government funded (Bureau of Mines).

Although the basic coal gasification chemical reactions are the same for each process, there are important differences in: method of feeding coal to the reactor, pretreatment of coal, reactor configuration, method of supplying heat for gasification reaction, and methanation scheme.

Several U.S. companies are presently planning the construction and operation of a number of commercial-sized (250 million cf/day) plants based on Lurgi technology, some of which may be in operation by 1976. A methanation step is presently being developed to upgrade the medium Btu gas (500-600 Btu/cf) to a high Btu product.

Table I. Processes for converting coal to high-Btu gas

Process	Agent	Status	Comments
Hygas	Institute of Gas Technology (IGT)	80 TPD pilot plant in operation	Fluidized-bed gasifier. Pretreatment necessary. Handles all coals. Char burned for power.
Consol Synthetic Gas (CSG) or CO_2 Acceptor	Consolidation Coal Company	40 TPD pilot plant in operation	Fluidized-bed gasifier. Low Presure (150-300 psi) process, design for western coals. Oxygen plant not required.
Synthane	Bureau of Mines	70 TPD pilot plant under construction, expected completion Aug. 1974.	Fluidized-bed gasifier. Char burned for power. Integral pre-treatment. Handles all coals.
Bi-gas	Bituminous Coal Research, Inc. (BCR)	120 TPD pilot plant under construction, expected completion early 1975.	Entrained/Slagging Gasifier. No pretreatment required. No by-product char. Handles all types of coal.
Hydrane	Bureau of Mines	Laboratory pilot plant development	Direct hydrogenation. No pretreatment necessary.
Self-Agglomerating Gasification Process	Battelle Memorial Institute (BMI)	Laboratory pilot plant being designed	
Lurgi	Lurgi	Lurgi gasification is already commercial. Methanation step now being developed on pilot plant stage to upgrade gas to hi-Btu value.	Fixed-bed gasifier. Cannot handle caking coals or coal fines. Low throughput.

The four major processes (Hygas, Synthan, CO_2 Acceptor, and Bi-gas) are scheduled for pilot plant testing until 1976 at which time a demonstration plant (50-150 million cf/day) will be built.

B. Barriers to Implementation of the Technology

1. Research

The following problem areas need attention:

a. Development of long lived, high throughput, sulfur ressistant methantion catalyst.

b. A better understanding of the kinetics of methanation reactions.

c. The development of a cheap scheme of producing hydrogen from coal or coal products (needed for direct hydrogenation processes, e.g., Hygas, Hydrane).

d. Metallurgical development of reactor materails capable of withstanding high presures, high temperatures, and corrosive and abrasive environments.

2. Development Barriers

The following problem areas need attention:

a. Development of pressurized (1,000 psi) coal feeding techniques.

b. Removal of char under high pressure, high temperature, corrosive and abrasive conditions.

c. The removal of tar to prevent plugging of the reactor.

d. The removal of large amounts of heat from the methanation catalyst bed.

e. Development of acceptable methods of burning char.

f. Handling of coal fines in the gasifier.

g. Disposal of large amounts of by-product elemental sulfur.

h. Field fabrication of large-scale reactor vessels.

i. Development of efficient large-scale mining operations along with effective mine reclamation.

j. Treatment of water pollutants, especially removal of phenols.

k. Grinding of coal to the correct size while minimizing production of fines.

Many of the R&D barriers will be given attention through a separately submitted subprogram of panel 5 entitled Supporting Research. This subprogram is designed to institute a research program specifically aimed at solving these problems relating to equipment, materials, and gasification chemistry.

3. Implementation Barriers

a. Water Resources - Commercial sized gasification plants require large amounts (10,000 acre ft-year) of water. Lack of adequate water resources could be a major impediment.

b. Social problems of large-scale gasification plants could be serious. Many areas are sparsely populated and plants will bring in many people for whom housing, schools, etc., would have to be found. Problems with Indian tribes could develop when the raw materials resources are on Indian land.

c. Financing of plants could be an impediment. Capital estimates start at $1,000/1,000 cf of daily capacity and this estimate is probably low. For the large number of gasification plants require, the total estimated capital will be very high.

d. Manpower problems - Large numbers of trained personnel (about 1,000 people/commercial plant; 500 for the plant and 500 for the mine), will be needed to run the plants.

e. Strip-mining problems. The amount of coal required for each plant will be very large (15,000-20,000 tpd) and much of it will be strip-mined. This could cause several problems with strip-mine reclamation and acid-mine drainage. Also, local, state and Federal regulations on strip-mining could become prohibitively restrictive.

f. Environmental Barriers - Air and water pollutants from gasification processes, although controllable to a large degree, could cause problems in areas where many plants will be located.

g. Uncertain government policies concerning pricing of natural gas and pricing of synthetic natural gas. The gas indusrty would prefer regulation at the point of origin but the present scheme of instituting price regulations when SNG is mixed with natural gas is confusing and awkward for the industry.

h. Foreign Fuel Prices - If foreign petroleum prices were to drop to a price where SNG would not be a competitive fuel, the incentive for R&D and construction of SNG plants would be eliminated.

C. Ongoing R&D Effort to Overcome Barriers

1. Present Levels

As shown in Table I, R&D is ongoing to solve the technical problems particular to each process. Present funding for all processes in about $40 million/year and is expected to be maintained at about this level until 1976 when a demonstration plant at the cost of about $200 million will be built.

2. Government/Private mix of funding and management

Except for Synthane and Hydrane processes which are totally government supported, the processes under development are supported on a 2/3 government-1/3 industry basis.

For Sythane and Hydrane, R&D is managed by government. For the other processes, management is jointly shared by government and industry.

3. Availability of results of foreign efforts

Only foreign R&D relating to advancing Lurgi technology is considered important for U.S. coal gasification technology.

III. Rational for Federal Involvement

A. Federal involvement is warranted because the risks and investment required in the development of such new technology prohibits action by industry alone.

B. Deregulation of natural gas would increase income for gas companies and enable companies to spend additional funds on coal gasification research.

Providing tax breaks and/or guaranteed loans and facilitating coal mining and reclamation on federal lands would help to stimulate national investment. Providing aid in obtaining capital for investment may be necessary.

C. Industries attitude is very sensitive to a number of changes:

1. Strip-mining legislation
2. Discoveries of large natural gas supplies
3. Regulated price of natural gas and of synthetic natural gas
4. Price of imported petroleum
5. Cost of borrowing capital

D. Other government actions required to support R&D:

1. Favorable and definitive action by FPC in regulating price of SNG from coal is necessary to remove uncertainties concerning government policy in this area.

   Clarification of background patents held by industry policy.

   Legislation relaxing prohibitively strict environmental regulations.

2. A governmental developed program for strip-mine reclamation is necessary so that reclamation techniques will be applied effectively when strip-mining to feed gasification plants begins on a large-scale.

IV. Objectives, Criteria and Priorities

A. Program Objectives

To develop the technology necessary for the establishment of a commercial coal to pipeline quality gas industry with due regard to environmental considerations.

To accelerate demonstration at a commercial scale by constructing and operating one or more coal to pipeline gas plants.

B. Criteria for setting priorities among programs.

Process favored are those with: most favorable overall economics, least detrimental environmental effects, applicable to the broadest range of American coals.

C. Rational has been to formulate a program to develop a process applicable to most U.S. coals in the earliest time possible with present funding.

V. Alternative R&D Program

A. An Accelerated/Orderly R&D Program

1. Schedule and Milestones

Pilot plants for Hygas and CO_2 Acceptor processes are currently operating. Sythane and Bi-gas pilot plants are currently under construction and will operate by late 1974 and early 1975 respectively. At least two Synthane and Bi-gas and maybe four pilot plants will operate through 1976. A demonstration plant (50-100 million cf/day; a commercial sized plant is envisioned to consist of three 80 million cf/day trains), based on one of the four processes or a combination of processes, will be designed in 1974 and construction is expected to start in 1975. A second demonstration plant is scheduled for design in 1976. With this schedule commercial plants are estimated to be operating by 1980.

In addition to these projects, other promising processes will be supported. These include the Agglomerated Ash Process, the development of Lurgi technology to produce high Btu gas and others. The Bureau of Mines Hydrane process will be developed. A Hydrane pilot plant design to produce 750,000 cf/day will be constructed in 1976. Also, a fluidized-bed system for combined shift and methanation reactions will be developed. A pilot plant for this process, capable of producing 1500 cf/hr. of SNG will be constructed and operated. In addition, a liquid methanation process will be investigated.

The design and construction and operation of a stirred fixed-bed coal gasification unit is proposed. This can be applied in the near-term (before 1981) since the fixed-bed technology is commercial and the stirring has been demonstrated on a pilot plant scale. This program will be integrated with the low-Btu gas program. The chances of success of each pilot plant operation are estimated to be high as is the likelihood of the successful operation of the demonstration plant. Other processes mentioned are estimated to have a lesser chance of success at this time because of their earlier technical stage of development.

2. Cost and Budget Projections

a. Projected Total Cost

Process	Year	Amount	Year	Amount
Hygas* (includes steam iron)	1975	$4.8 million	76-76	$7.1 million
CO_2 Acceptor	1975	4.9 million	75-76	4.9 million
Synthane	1975	7.2 million	75-77	17.2 million
Bi-gas*	1975	9.7 million	75-76	16.7 million
Hydrane	1975	1.0 million	75-79	26.0 million
Self Agglomerating*	1975	0.4 million	75-79	.600 million
Liquid Phase Methanation*	1975	1.0 million	75-79	5.0 million
Combined Shift and Methanation Reaction*	1975	0.2 million	75-79	1.1 million
Engineering Evolution	1975	0.9 million	75-79	1.35 million
Stirred Fixed Bed**	1975	1.0 million	75-79	5.0 million
Demonstration Plants (2)			75-79	400 million

b. For all processes except Synthane and Hydrane which are both totally Federally supported through the U.S. Bureau of Mines, the program supported 2/3 by the Federal Government and 1/3 by industry through the American Gas Association.

c. See Energy R&D Fact Sheets

A. The cost of constructing demonstration plants is difficult to predict since the exact process which will be demon-

*Plus 50 percent more from AGA.

**To be integrated with low-Btu gas fixed bed program.

strated is not yet known. The cost of newer programs (e.g., Hydrane, Self-Agglomerating Ash and others) are more difficult to predict than the costs of the more established programs. It is difficult to estimate whether future industry participation will increase beyond the present one-third level.

4. Management Plan

Synthan and Hydrane will be in-house efforts except for pilot plant construction and operation. All other processes will be by contract to industry, university, or private research institute groups. Management in each case will be joint government-industry.

2A. Minimum Program

1. The Minimum Program consists of the ongoing high Btu gas program being carried out within the Department of the Interior. It lags the accelerated/orderly program by about one year. This consists of all portions of the Accelerated/Orderly program except: accelerated pilot plant schedule, Hydrane pilot plant, combined shift and methanation reactions, and the second demonstration plant.

2. Cost and Budget Projections

See Accelerated/Orderly Program: delete funding for Hydrane pilot plant, and combined shift and methanation reaction, and the second demonstration plant.

3A. Maximum Program

1. A maximum program would consist of the Accelerated/ Orderly Program with the change that the demonstration program would be replaced with the construction of three commercial (250 million cf/day) size facilities. Construction would begin July 1, 1975.

2. Cost and Budget Projections

   Add to the cost of the Accelerated/Orderly Program, \$1.2 billion for the construction of three commercial plants and delete \$800 million which was allocated for the demonstration program.

B. Criteria Employed By Subpanel in Constructing Proposed R&D Program

1. Other possible programs considered

   a. Kellogg Company Molten Salt Gasification Process

   b. Applied Technology Corporation's Atgas Process

2. Criteria Used in Selecting Proposed Plan

   The proposed plan supports gasification processes which have the most promise of utlimately contributing to the development of a commercial high Btu gas from coal industry. The proposed plan has both short-term objectives for the development of commercial technology and long-term objectives for the demonstration of processes on a commercial scale. The approach of supporting four (or more) processes on a large (80 tpd) pilot plant scale should result in a process with the lowest cost and least detrimental effect on the environment. Other processes considered were judged too costly or too complicated to prove successful.

3. Projects of Special Merit

Projects for which pilot plants are operating or under construction.

C. Relationship of Other R&D to Progress in this Technology

1. Successful implementation is not dependent on other technology.

2. Certain liquefaction processes that require process H_2 depend on the development of an economic H_2 from coal process. Delays in the development of a cheap hydrogen process may delay certain liquefaction processes.

D. Acceptability of R&D Program

1. Environmental impact statements have been filed for for pilot plants. Other statements will be needed for additional pilot plants and for demonstration plants.

E. Other Costs and Benefits of the R&D Program

1. Potential spin-offs to other sectors

Processes developed in coal handling and conversion may be applicable to other synthetic fuel programs, e.g., liquid fuels from coal.

2. Potential uses of facilities and capital equipment

Facilities and capital equipment could be used in further coal conversion development.

3. Regret cost if program failed

About $600 million

4. Significant termination costs

None

VI. Implementation Plan to Follow Completion to Successful R&D Phases

A. Direct Benefits of Implementation

1. Natural gas companies would supply and market synthetic gas. Consuming sectors would be home heating and industry.
2. It is presently estimated that there will be a market for all synthetic natural gas produced in the near and mid-term future due to shortages of natural gas.
3. Implementation of R&D will decrease dependence on imported natural gas, LNG and propane.
4. A domestic SNG from coal industry will make the U.S. more independent of foreign energy sources.
5. Gasification actually is less efficient on a Btu basis compared with burning the coal. Gasification processes are about 60-70 percent efficient.

B. Proposed Schedule for Implementation

1. Present estimated point to: 1.2 trillion year cu.ft. by 1985 3.0 trillion year cu.ft. by 1990.
2. Constraints are: R&D progress, financing problems in obtaining capital, water resource problems in strip-mining and strip-mine reclamation. It is estimated that some of these constraints can be alleviated; whether they all can be alleviated is not yet known.
3. Successful implementation in the long term would decrease dependence on foreign energy for this country.

4. Gasification plants would be located in areas containing large coal reserves and sufficient water resources. Locations would probably also be near existing natural gas pipeline. In 1970 the American Gas Association identified 176 sites which satisfied the necessary requirement of coal and water. Of these sites, 59 were east of the Mississippi and 97 were west. Water resources and strip-mining restrictions would be the most serious limitations.

5. A large scale coal mining industry will be necessary.

C. Economics of Implementation

1. Estimated delivery price is $1 to $1.10/million Btu for western coal and $1.30 to $1.40 for eastern bituminous coal. (Assume utility-type financing and 10 percent return on rate base).

2. If SNG were used to produce electricity, the price of electricity would increase sharply. It is generally assumed that SNG from coal will be too expensive to use for electrical power generation.

3. Capital investment will be approximately $400 million for a plant producing 250 million cfd.

4. Projected impact on labor markets - It is estimated that a labor force of about 1,000 will be needed for each commercial sized plant.

5. Synthetic natural gas will alleviate imports and aid in the balance of payment significantly. In

1985, the savings in terms of balance of payment deficit will be at least $1 billion, and in 1990 at least $3 billion.

6. Assumptions underlying the above projections

   a. Future availability and price of natural resource inputs - Coal is generally assumed to be available but could be severely restricted depending upon local, state, and Federal strip mining regulations. Water resources are available at many sites but could be a problem in certain areas. Coal will cost $0.35/million Btu for deep mined bituminous and $0.17/million Btu for surface mined western coal. Cost of water resources is difficult to predict at this time and will vary considerably with location.

   b. Future price of energy - see VI C.

   c. Amortization of R&D added to price? No.

   d. Labor costs - Difficult to estimate at this time.

   e. Costs of capital - Each 250 million cf/day plant will cost about $400 million.

   f. Date of commercial availability - About 1980

   g. Useful lifetime and maintenance - 20 years

   h. Demand for output and capability for meeting demand - Present estimates show that demand will not be met until at least the year 2000.

   i. Potential Foreign Markets - Domestic demand is expected to consume all SNG produced.

D. Institutional Arrangements Required for Implementation

1. Optimum Government/Private Mix - 2/3 Government-1/3 Industry

2. Tax incentives and subsidies -

   When Commercial plants are constructed, tax incentives and/or guaranteed loans, would help increase number of plants being constructed. Aid in obtaining capital required would be a significant incentive.

3. Regulatory framework -

   New regulatory structures are currently being implemented by the F.P.C.

4. Availability of manpower - estimated to be a problem because:

   a. Many sites for locations are sparsely populated.

   b. Little trained manpower exists for gasification plants. Federal actions may be needed to develop the trained manpower needed and to solve the socio-economic problems arising out of rapid development of sparsely populated areas (housing, schools, etc.,).

5. Availability of capital

   Federal action may be needed to assure the availability of the large amounts of capital required.

6. Envrionmental Framework

   In a number of cases, the Federal Government will have to write the environmental impact statement for the pilot and demonstration plants. When commercial plants are built, the Federal Government can provide assistance in writing the statements.

E. Public Attitudes

1. Present public attitudes vary greatly. People in the east who need the gas are in favor of gasification, but many western groups and conservation groups are opposed to the massive strip mining and water usage required for coal gasification plants.

2. Anticipated changes in attitudes. As the energy crisis worsens, it is likely that general reaction will be less hostile to gasification plants. If strip mining reclamation efforts are successful, there will be less opposition.

3. Public Information. Intensive public education will be needed to convince many groups that gasification and associated strip mining can be done in an environmentally acceptable manner.

VII. Impacts of Implementation

A. Natural Resources Required

1. Quantities Required

For a commercial scale (250 million cf/day plant) Coal - 15,000-20,000 ton/day. Water - 10,000 acre-ft/year.

2. Size and type of available resources:

Ample coal is available but water resources may be a problem. The American Gas Association has found 176 sites for full-scale plants where sufficient coal and water exists.

3. Competition for these resources from other sectors:

Possible competition for coal power plants and coal liquefaction plants are not expected to be a serious problem.

4. Legal and regulatory restrictions:

   Strip mining regulations. Water rights subject to various regulations, especially on Indian lands.

B. Energy Inputs Required

1. Capital Investments: $1,000/1,000 cu.ft. of daily capacity.

2. Operation: 15-20,000 tpd of coal/year required. Operating cost for a 250 million cf/day plant is $43.4 million or $0.52/mcf.

C. Problems of Compatability with Existing National Energy System

Very compatabile

D. Environmental Impacts of Implementation

Environmental Statements will be needed for demonstration plants, and for fullscale plant gasification plants will be the source of air, water, and solid waste pollution.

E. Occupational Health and Safety Considerations

Mining is known to be a dangerous occupation although strip mining is significantly less dangerous than deep mining.

F. Other Factors

Many areas will be changed dramatically. Sparsely populated areas of the west will be subject to a large influx of people and land-use patterns will change radically. Rural areas may become relatively industrialized.

SECTION III

Clean Burning Liquids from Coal

CLEAN BURNING LIQUIDS FROM COAL

I. OVERVIEW

A. INTRODUCTION

This research subprogram is directed toward development of economically attractive processes for the conversion of coal to clear boiler fuel and to distillate type material. Alternate processes will be evaluated to establish their suitability for coals specific to various geographical areas of the country.

The primary objective of the program is to produce an environmentally satisfactory fuel that can be used in the generation of electric power in existing plants as well as new plants to be built in the future. The best process alternate must be extablished so that coal indigenous to a specific region can be used in that region with consequent reduction in demand for oil and natural gas.

B. R&D PROGRAMS

Description

The maximum rate program is based on the construction of four commercial-scale plants as rapidly as completion of detailed engineering will allow. Feedback from the ongoing pilot plant projects is included. The plants would have a minimum daily output of 100,000 barrels/day each, and would test the following alternate systems: (1) direct hydrogenation, (2) carbonization with hydrogenation of the resulting tar and complete gasification of char, (3) extraction with and without hydrogenation of the extract, and (4) gasification followed by Fischer Tropsch or related type synthesis. One of the above plants may involve a combination of two of the processes with the final determination to be made as the detailed engineering proceeds.

The second alternate, an "accelerated orderly" program, is based on immediate authorization of a modular demonstration plant whose purposed is to establish economic as well as engineering viability of direct hydrogenation, carbonization, extraction, and gasification/liquefaction.

The minimum viable program would delay a first demonstration plant to the 1978-80 period with completion of <u>all</u> smaller scale work before a commitment to engineering is made.

<u>Comparison</u>

Presuming success in one or more areas, the maximum program will produce 12 full-scale plants by 1985, with each of the 4 original plants expected to produce 2 second generation plants. Plant construction costs for this program are of the order of $3 billion with a 50 percent contribution from industry suggested.

The accelerated alternate program is expected to produce two commercial-scale plants by 1985 at a total experimental plant cost of $500 million with a 10-20 percent contribution from industry expected.

The minimum viable program will produce sound engineering data and information so that design of commercial plants could begin by 1985.

C. IMPLEMENTATION

<u>Size</u>

The production of clean liquid fuel from coal will insure continuting development of the power industry to meet national needs. Further process improvement can be expected to reduce pollutant content of the fuel to the barest minimum levels. This will lead to broad acceptance in the power industry for backfitting to older plants and use in the sophisticated advanced power conversion systems that will be available in the time period. Additionally, distillate type material will be used to extend supplies of domestic and imported crude oil tending toward a national energy self sufficiency. These plants will produce byproduct pipeline quality gas so that the total market penetration by the year 2000 is expected to be one third of the total energy consumption of the United States.

Schedule

Subsequent to 1985 we would anticipate the addition of about a trillion feet of gas and 300-400 million barrels of oil per year added to the synthetic fuel capacity of the country.

Potential Barriers

The financial requirements for the development of this industry are astronomical and funding for the plants is expected to be a problem. In the near term, engineering construction capability may well limit our national ability to build the plants. Natural resources are sufficient to meet the expected demand, but public acceptance of the necessary mining ventures will be necessary before general acceptance of synthetic fuel from coal is possible. Contrary to popular press opinion, water will not prevent or limit growth of the industry.

II. STATUS OF TECHNOLOGY

A. PRESENT

Conversion of coal to liquids and gas has a long history back to the turn of the century or thereabouts. Additionally, periodic upsets in the availability of oil and gas both here and abroad led to ups and downs in domestic and foreign research directed toward alternate coal conversion systems. As a result of this past work, the technological features of all processes are well established and variations in the features to produce lowest net product cost is the only feature that must be determined as a result of the program.

Barriers

Alternate processes are available with a broad background of research and development behind them. Implementation must await the determination of which of the processes are the most economic in the various geographic areas of the nation, with emphasis on the coal locally available and the regional energy markets to be served.

Current R&D

Current funding in coal liquefaction research is approximately $30 million per year. Each major coal liquefaction process is now, and has been, under investigation by various organizations within the public and private sectors. Principal efforts, in the recent past, have been funded by Interior Department's Office of Coal Research with major coal, oil and independent research organizations. The funds have been almost exclusively public funds, but current programs contemplate industrial participation at a minimum one third for all future projects.

III. RATIONALE FOR FEDERAL INVOLVEMENT

The development of national resources is clearly in the public's interest, but commercial companies cannot undertake to produce a liquid fuel from coal with all the attendant risks until the price of oil from the Middle East can be clearly established. It is suggested, therefore, that the magitude of this risk coupled with the ability of producing oil for less than 50¢/barrel in the Middle East clearly dictates Federal involvement as soon as possible to assure availability of an environmentally satisfactory fuel at the earliest possible date.

Alternatives can be offered to industry by providing Government purchase of the plant products at cost plus a normal profit margin. Another variation might provide low interest loans and/or rapid tax write-offs for synthetic fuel plants. Similar results might be achieved by imposition of import duty on foreign oil after some given total annual volume. It is suggested that industry must have some way of protecting their massive investments in these plants from cost reductions that are possible to the Middle Eastern oil rich nations. To insure rapid development of the industry, the Government should support appropriate state and national legislation to establish strip mine regulations and normally competing industries should be allowed joint ventures without being subject to antitrust prosecution.

IV. OBJECTIVES, CRITERIA AND PRIORITIES

A. DISCUSSION

The objective of this subprogram is to reduce to a commerical practicality one or more environmentally acceptable methods for converting coal to a clean liquid fuel. The processes or methods employed must be adaptable to a broad spectrum of coal ranging from lignite to high volatile, high sulfur coal with the primary emphasis on high sulfur bituminous coal.

An ancillary objective to the above goal is the development of all technology needed to establish a coal liquefaction industry subject to all environmental controls and regulations. Acceleration of commerical scale development is sought by constructing one or more coal liquefaction plants of commercial or demonstration plant size.

B. CRITERIA

This subprogram has a high priority since it attacks the core of the energy dilemma currently facing the nation by converting high sulfur environmentally unacceptable coal to low sulfur environmentally acceptable liquid or solid. Pressure for use of natural gas and oil will be lessened. Reduction of sulfur, in coal, is a less rigorous problem than conversion, of coal, to distillate and this is the first element of the subprogram. Additionally, this subprogram is an outgrowth and continuation of existing programs and will maximize the utilization of the existing coal pilot plants. Non-federal funding is currently available and additional funds are expected as the program proceeds. Total non-federal participation will be one third or greater.

V. ALTERNATIVE R&D PROGRAMS

A. Project Milestones are listed on the budget fact sheets for the three program levels.

Total cost for maximum program is $3.00 billion for four (4) full scale plants, each will have a capacity of 100,000 barrels of liquid product per day. $500.0 million will be devoted to the subproject Pilot Plant Program. Each plant ready for production will cost $750.0 million. These costs should be 50% government - 50% industry. The accelerated orderly program provides for construction of a modular demonstration plant with a total estimation cost of $500.0 million.

Additional Pilot Plant work - totaling $250.0 million is provided.

Costs to be split 80 percent government, 20% industry.

The minimum program delays construction of any large scale plants but includes all Pilot Plant work deemed necessary. Cost 90% government, 10% industry.

Industry funding could be provided by offering incentives to industry. Alternately, punitive measures could be used, tax on sulfur, a unit change to be applied by the government to energy research, etc.

The primary problem will be raising the industry contribution. If $2.0 to $3.0 billion is to be spent, the industry share will fall between $650.0 million and $1.5 billion. Industry is not expected to produce the type of funding without a spur of some sort.

Construction of four major plants required in the maximum rate plan will strain the construction capacity of major engineering firms. New coal mines are an additional potential problem. In each case manpower needs may be limiting.

At the three levels of funding the major portion of the work will be conducted in private industry. Government labs and the National labs will be utilized as well.

As viewed by the panel, the production of clean burning liquids is a vital part of a national program. The national program should include the other alternatives, such as Lo&Hi Btu gas, stack gas cleaning, etc.

This program is reasonably self contained but anticipates input from gasification and from resource assessment and mining.

IMPLEMENTATION	1985		2000	
Industry	(1) Acc/ord	(2) Max	(3) Acc/ord	(4) max
Coal	33×10^6 TPY	396×10^6 TPY	33×10^6 TPY	2.31×10^9 TPY
OUTPUT				
SRC	6.8×10^6 TPY	82×10^6 TPY	82×10^6 TPY	490×10^6 TPY
Boiler Fuel	19.8×10^6 BPY	238×10^6 BPY	238×10^6 BPY	1386×10^6 TPY
Motor Fuel	13.2×10^6 BPY	158×10^6 BPY	158×10^6 BPY	924×10^6 TPY
Pipeline Gas	132×10^9 CFPY	1584×10^9 CFPY	1584×10^9 CFPY	9240×10^9 CFPY
LPG	8.0×10^6 BPY	95×10^6 BPY	95×10^6 BPY	560×10^6 BPY
Elec. Power	11×10^9 KWHPY	131×10^9 KWHPY	131×10^9 KWHPY	770×10^9 KWHPY
ECONOMICS	(USING 1970 DOLLARS)			
Capital	$\$850 \times 10^6$	$\$10.2 \times 10^9$	$\$10.2 \times 10^9$	$\$59.5 \times 10^9$
Raw Materials				
Coal	35¢/mm Btu	35¢	35¢	35¢
Products				
SRC	75¢ "	75¢	75¢	75¢
Boiler Fuel	80¢ "	80¢	80¢	80¢
Motor Fuel	100¢ "	100¢	100¢	100¢
Pipeline Gas	95¢ "	95¢	95¢	95¢
LPG	90¢ "	90¢	90¢	90¢
POWER	8mils/KWH	8	8	8

Delay in this sub-program could well contribute to a major energy "Crisis" in the 1980-85 period.

VI. IMPLEMENTATION

B & C: Both the maximum and orderly program will produce measurable results by 1985. Estimates are: (continued on next page)

VII. IMPACTS OF IMPLEMENTATION

A. Resources (see above)

B. Capital (see above)

C. All products are compatible with and interchangeable with todays products.

C. Mining and plant products must be covered in the environmental impact statement.

SECTION IV

Oil Shale Processing and Development

OIL SHALE PROCESSING

II. STATUS OF THE TECHNOLOGY

Two major options are being considered for oil shale development: (1) mining followed by surface processing of the oil shale and shale oil, and (2) in situ (in-place) processing. Of the two options, only the mining surface processing approach is believed to have been advanced to the point where it may be possible to scale-up to commercial production in this decade. In situ processing is in the experimental phase; commercial application of this technique is not expected prior to 1980. The relative state of knowledge of the various operations required in oil shale processing is shown in Figure I.1/ It is apparent from this figure that various technical approaches are available for each phase of the operations, and no single system is likely to dominate the initial development of oil shale.

The most critical technical challenge in surface processing is that of raising oil shale to the pyrolysis temperature of 900°F. Several systems have been tested at the pilot level; the organization and level tested are given below:

Bureau of Mines - 150 tons/day (1950's)

Union Oil Company - 1,000 tons/day (1950's)

Colony Development Operation - 1,000 tons/day (late 1960's through 1972)

Petrobras (Brazil) - 2,500 tons/day (1973)

1/ Most of the refining operations shown in Figure I would be performed outside of the oil shale region, at refinery centers near markets for the products.

2

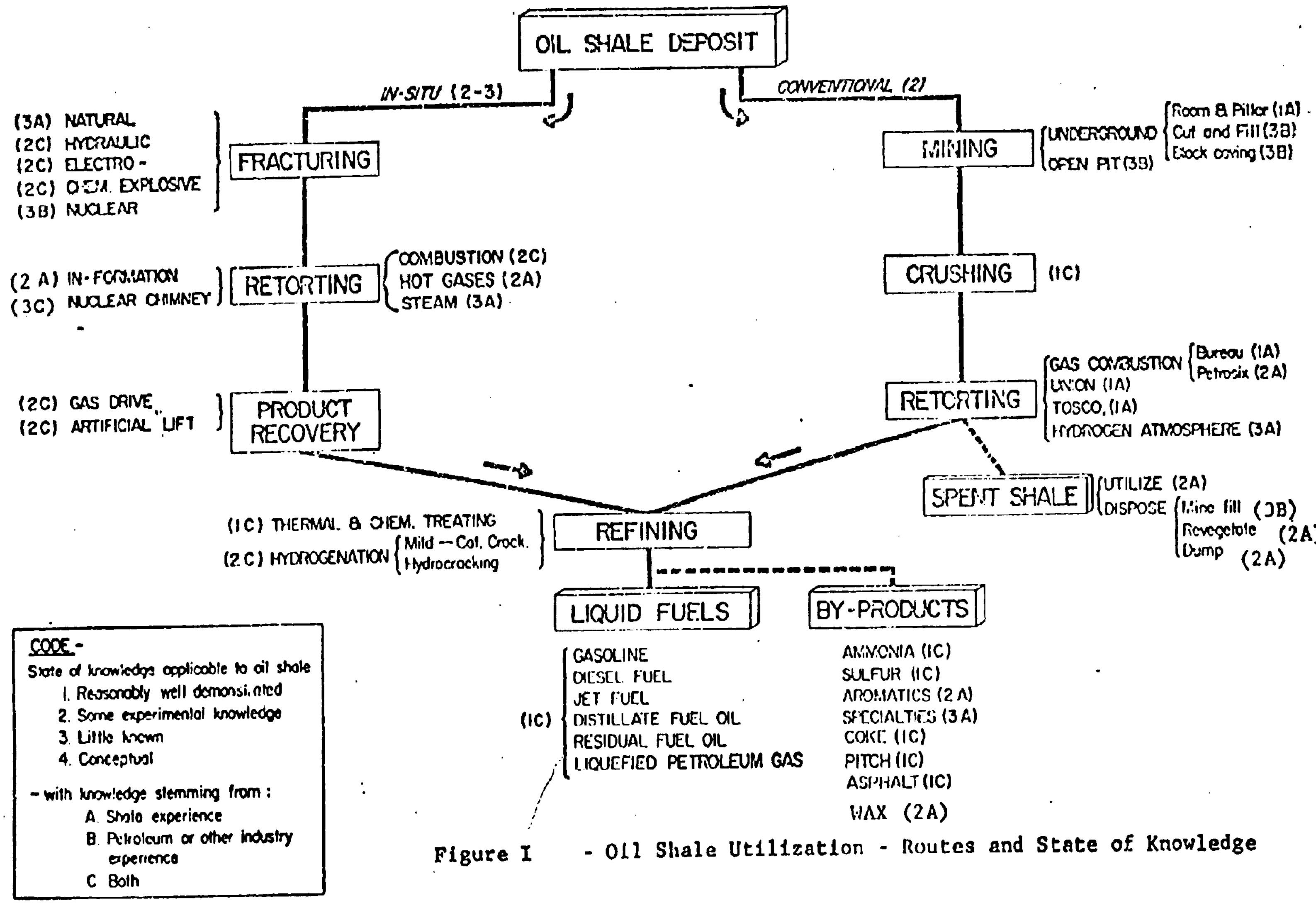


Figure I - Oil Shale Utilization - Routes and State of Knowledge

August 1972

Scale-up to 10,000 tons/day for each retort is needed to achieve commercial level production. Based on the past oil-shale experience and large-scale development in similar industries, achievement of commercial production should not prove an insurmountable problem and is well within the capability of private industry to undertake.

Barriers to Implementation of Technology--Production, once undertaken, is not expected to increase rapidly under normal circumstances. This conclusion is based not on technology, but on the risks inherent in pioneer minerals development where second generation operators are often more successful than the pioneer resource development company. The reasons for this are many, but relate directly to greater amounts of technical and operating information, proven mining and processing systems, established environmental controls and procedures, availability of specialized equipment, and the possible availability of trained personnel. It must be recognized also that initial development of oil shale is expected to be only marginally attractive economically, 10 to 13 percent on a discounted cash flow basis, on investments that would approximate $5,000 for each daily barrel of capacity. Thus, the smallest commercial complex, 50,000 barrels per day, would cost $250 million or more.

Future expectations concerning production costs, oil prices, the general state of the economy, and the availability and cost of capital will establish the economic parameters that must be considered by private industry. If, in combination, these are judged to be favorable, oil shale development may be initiated. However, development would probably be limited to a few plants by 1985 due to the economic risks inherent in pioneering development. Thus, under normal development, shale oil production might be limited to 100,000 to 250,000 barrels per day by 1985.

It is possible to accelerate this development and, considering the normal constraints of manpower and construction, production could approximate 750,000 to 1,000,000 barrels per day by 1985. Under emergency development characterized by wartime conditions, this rate may be accelerated to 1.3 to 1.5 million barrels per day by 1985. The strategy of accelerated oil shale development does not lie with technology, but rather is tied to ways of reducing or removing the economic risk involved in initial development. Means to achieve this accelerated development are available and are considered in Section V below under "alternatives."

Ongoing R&D--

Public R&D--Current oil shale research by the Federal Government approximates $2.5 million and is distributed between the Bureau of Mines and Geological Survey as shown in Table 1. The Bureau of Mines program emphasizes in situ processing of oil shale (about one-half of the total) and basic-oriented activities while that of the Geological Survey is focused on the nature of the resource and hydrologic investigations.

A series of field experiments has been underway by the Bureau of Mines for several years near Rock Springs, Wyoming, studying methods of fracturing and retorting the Tipton Member of the Green River formation. The interval of 25 gallon-per-ton material is about 20- to 40-feet thick and under from 50 to 400 feet of overburden at various locations in the test area.

Table 1 Current Oil Shale Research

	FY 1974 Funds (thousand dollars)
Department of the Interior	
Bureau of Mines	
In Situ Retorting - Field	361
In Situ Retorting - Other	656
Production of Clean Fuels	301
Process Variations and Products	441
Evaluation of Oil Shales	313
Subtotal	2,072
Geologic Survey	
Resource Investigations	321
Hydrologic Research	150
Subtotal	471
TOTAL	2,543

Colorado Oil Shale Environmental Planning (COSEP) Study

	Cost	Completion Date
Environmental Inventory and Impact (direct impacts of industrial development)	$160,000	7/31/74
Water Resources Management (Surface and subsurface water resource and impact study)	280,000	6/30/74
Revegetation and Surface Rehabilitation (Spent shale disposal and revegetation techniques)	130,000	12/31/74
Regional Development and Land Use planning (inventory existing communities and land use and developed alternate growth patterns)	145,000	1/ 1/74

Various methods of fracturing--hydraulic pressure, chemical explosives, and electricity--are being tested. Chemical explosives have been used both in liquid form, for detonation after being forced into naturally occurring or artificially-created fractures, and in pelletized solid form for detonation in well bores. A combination of techniques was used to obtain fracturing at a depth of about 75 feet in a small five-spot pattern which was then ignited for a combustion test in which about 190 barrels of oil were produced. A larger underground recovery test, covering about three acres, and at a depth of about 125 feet, achieved only limited success due to insufficient exposure of surface area. Another site is being prepared for in situ processing and combustion is to be initiated in FY 1974.

A number of studies are underway in support of this field experimentation. Among these are the operation of two rather large retorts, with nominal capacities of 10 and 150 tons, in which problems such as the retorting of random-sized pieces of shale, the minimum surface area required for the combustion needed to furnish the heat for retorting, and rates of retorting can be studied. More fundamental studies are concerned with effects of oxygen on oil shale at subretorting temperatures, mechanisms of transporting oil out of the shale particles, and the effects of pressure on the retorting process.

It appears that hydrotreating of some shale oil fractions will be required to lower shale oil nitrogen contents to acceptable levels for processing by certain refining methods such as catalytic cracking. Consequently, the Bureau is conducting a small-scale research project concerned with shale-oil hydrogenation. Research is also being conducted to determine how compositions of oils produced by this technique may compare with those from aboveground retorting.

Recognizing that the production of shale oil will have to be done without significant environmental degradation, some of the newer projects of the Bureau of Mines are concerned with environmental problems, principally related to contaminated waters and the composition of low Btu produced during retorting.

The Bureau's Denver Mining Research Center currently has a small cooperative effort with the Colony Development Operation where research in rock mechanics relating to design and stability of mine openings is being done. This effort is not funded under the oil-shale budget but is a part of a research program of a more general nature. The Denver Center also has contracted for a study of the current state of the art of mining oil shale including a listing of what appears to be problem areas requiring research.

The U.S. Geological Survey is active in geologic studies relating to location, grade, geologic setting, hydrology, associated minerals, and similar considerations for oil shales in the United States. Mapping and reporting are integral phases of this effort which currently is costing about $500,000 per year. Other Government agencies are studying possible environmental and other social effects of an impending oil-shale industry in Colorado, Utah, and Wyoming. These studies are largely non-experimental in nature and parts of larger activities, the largest of which is the Colorado Oil Shale Environmental Planning Studies (COSEP).

The COSEP studies are aimed at four areas: (1) revegetation and surface rehabilitation; (2) environmental inventory and impact; (3) water resource management; and (4) regional development and land use planning. The estimated cost and completion date for each is given in Table 1. Though the studies are being conducted specifically for Colorado's Piceance Creek Basin, much of the information developed will be applicable to development in Utah and Wyoming. It is expected that these studies, in which the Department of the Interior is an active participant, will provide additional information which will assist in efforts to mitigate environmental damage. Each of the four Colorado studies is scheduled for completion before 1975.

Private R&D—The major current industrial effort has been the research by Colony Development Operation, a joint venture involving The Oil Shale Corporation, Standard Oil of Ohio, Cleveland-Cliffs Mining, and, most recently, Atlantic Richfield. After termination of the original research program by Colony in the late 1960's, Atlantic Richfield Oil Company purchased a 10 percent interest from each of the three previous Colony members and was named project manager.

The Colony mine is a adit (horizontal) entry mine into the Mahogany Ledge shale beds. Mining capability probably exceeds 1,000 tons per day. The plant features The Oil Shale Corporations's TOSCO II retort and is reported to have a capacity of about 1,000 tons of shale per day. Both mine and plant were operated intermittently for a time and then were in essentially continuous operation for several months prior to shutdown of the plant in late April 1972. Operations are reported to have been primarily concerned with retorting with little effort on mining, although over 1 million tons of oil shale have been mined since 1965. However, in recognition of mining problems encountered during the most recent period of production, Colony is keeping the mine open to conduct several phases of mining research. Considerable research also has been done by Colony on environmental aspects of oil-shale operations, particularly in regard to stabilizing and vegetating spent shale deposits and in the socioeconomic aspects of oil shale development.

Public releases state that Colony's research results are being evaluated for the purpose of determining a future course of action. The forthcoming decision, expected in the near future, presumably will be whether or not to expand the present pilot operation to a commercial operation of some 50,000 barrels of oil per day.

Colony's R&D expenditures since Atlantic Richfield joined the group in 1969 have been stated to approximate $23.5 million; including the earlier experimentation, costs reportedly total about $55 million.

Also of current interest, Development Engineering, Inc., a Denver consulting firm, recently leased the Bureau of Mines experimental oil-shale facility near Rifle, Colorado, for research on retorting and related environmental considerations. This program is scheduled over a five-year term at a minimum cost of $2.5 million; the retort to be investigated is a modification of the Bureau's gas-combustion system.

Other recent industrial R&D activity of notable size has been concerned principally with in situ production. A three-year program was started in 1970 by Shell Oil Company to test a patented process for the extraction of shale oil by hot miscible fluids containing solubilizing agents such as hydrogen sulfide. Results and costs have not been publicized.

A combination of underground mining and in situ retorting is also being tested. This concept visualizes development of a strata of shale with suitable thickness of both in-place shale and overburden. Approximately 25 percent of the in-place shale would be mined by the room-and-pillar method, and transported aboveground for conventional surface retorting. The remainder would be fragmented, possibly by inducing falls using conventional explosives, to fill the mined-out voids and thus prepare a bed amenable to subsequent in situ retorting featuring either combustion or hot gas circulation heating methods. The initial test of this concept is now (1973) underway by Occidental Petroleum Corporation at a location near Debeque, Colorado. No information has been released on the results, but the test is known to involve direct combustion of the oil shale following explosive fracturing.

Many other companies continue studies and probably actual research activities on oil shale as indicated by an increasing flow of patents covering various aspects of oil shale technology; however, no information as to the scope and cost of these activities is available.

III. RATIONAL FOR FEDERAL INVOLVEMENT

Except for in situ and minerals processing, which are still in their infancy, Government involvement in oil shale processing technology is not believed to be needed. Rather, the principal role of Government is to provide the support work required to assure that this industry develops in a way that is environmentally acceptable, the elements of such a program are considered in the section which follows.

However, normal evolution of this new industry may require 10 or more years for the reasons discussed in part II above. Without Government involvement, substantial quantities of shale oil would not be available until after 1985. Therefore, it is considered necessary to accelerate oil shale development using the strategy outlined in Section V below.

IV. OBJECTIVES, CRITERIA, AND PRIORITIES

Oil shale research proposals have been distributed to various groups for review and recommendation. To place these in perspective, this panel has compiled a list of research needs related to oil shale development. This list, Table 2, necessarily overlaps the activities that will be suggested by several other panels, but is presented here to expedite the development of an integrated oil shale research program.

In essence, the principal activities relate those that will support commercial scale production; the first plant is expected to be on stream within the next 3 to 5 years. These activities include: (1) Solid waste management; (2) revegetation; (3) water management; and (4) fish and wildlife protection. Development of deep mine technology is needed, but it is not clear if this should be a Government effort. The leasing of tract C-b in Colorado under the Department of the Interior's prototype oil shale leasing program is expected to lead to the development of deep mine technology by private industry. In situ processing and minerals recovery technology can and should be accelerated with Federal funds.

The cost of this program will appear in separate reports by other panels, but the total is expected to approximate $25 million per year.

Table 2 Research Needs Related to Oil Shale Development

Solid Waste Management

Objective: Insure pile stability

Variables: Particle size, carbon content, degree of compaction, degree of cementation, chemical stabilization, water recovery from spent shale slurries; height of pile, angle of repose, characteristics of foundation material.

Objective: Control erosion/leaching

Variables: Amount and types of materials as a function of particle size, residual carbon and moisture, degree of compaction; cementation.

Revegetation

Objective: Create nutrient and topsoil structure

Variables: Particle size; carbon content; fertilization; topsoil/overburden addition; moisture control (mulching/irrigation).

Objective: Determine optimum species composition

Variables: Grasses; native browse and cover (mountain mahogany, shadbush, bitter brush); location.

Water Management

Objective: Develop regional hydrologic model

Variables: Aquifer characteristics; connections between aquifers; direction and rate of water movement; aquifer head; chemical quality and variation across region; points/amount of discharge; relationship between ground and surface water and amount of recharge.

Objective: Develop water management system

Variables: Amount/quality of water needed; response of hydrologic regime to ground water withdrawal; reinjection of excess water or other means of management.

Table 2 Research Needs Related to Oil Shale Development (Continued)

Wildlife Protection

Objective: Increase carrying capacity of off-site areas

Variables: Selective clearing of pinion-juniper, fertilization, soil structure mixing (topsoil, subsoil, etc.), and planting to stimulate browse species; protection of springs, and management of livestock grazing in critical wildlife areas.

Objective: To assess impact of development and use results to indicate fauna impacts

Variables: Construction and operation of facilities and ancillary urban development and the effect of these, including salinity increases, on changes in life history patterns, location, and abundance of key wildlife species such as the mule deer. This will require additional ecological research on specific habitat uses and habitat needs.

Deep Mining Technology

Objective: Develop technology that will permit maximum extraction of (1) the Mahogany zone and (2) the lower oil shale zones in the water-bearing areas of the Piceance Creek in Colorado

Note: This is the objective of leasing Tract C-b under the Department's Prototype Oil Shale Leasing Program.

Variables: Characteristic of the deposit, including degree of fracturing; amount, quality and movement of water; means of ground control; techniques of underground disposal of solid wastes.

In Situ Processing

Objective: Accelerate the rate of development (for liquid products) to point of commercial application by the early 1980's

Variables: Characteristic and depth of deposit; water; means of heating including direct combustion and indirect heating by hot gases; means of fracturing, control of process.

Objective: Produce gaseous products from oil shale and shale oil

Variables: Heat and rate of transfer, e.g., must be higher than those used to produce a liquid product; otherwise, variables same as those listed above.

Table 2 Research Needs Related to Oil Shale Development (Continued)

Minerals Processing

Objective: Develop economic process to recover alumina and soda ash from processed oil shale

Variables: Concentration of nahcolite and dawsonite; prior treatment of oil shale; leachates; water required and quality, including recycled effluent streams; environmental controls.

V. ALTERNATIVE R&D PROGRAMS

The role of Government in oil shale development should be reassessed over the next 6 to 12 months. A clear indication must be given that private industry is prepared to move forward with development. Should this not be forthcoming, steps should be taken to expedite the development of this resource. This would not necessarily take the form of Government R&D, but incentives that would reduce the economic risk inherent in any new capital-intensive development.

Three levels of activity are possible, depending on the perceived need for liquids from oil shale as compared to the environmental costs which have not yet been fully defined. In terms of the definitions given for this analysis, the expected output by 1985 for each level of activity is given below:

Program	1985 Expected Shale Oil Production, Million Barrels Per Day
Minimum	0.100 to 0.250
Accelerated/Orderly	0.750 to 1.000
Maximum	1.300 to 1.500

Subsequent sections of this section discuss each program and possible strategies.

Minimum Program--This program has been described immediately above. The research needs relate primarily to ways of mitigating environmental damage, e.g., research is needed in techniques of solid waste management, revegetation, water management, and wildlife protection. Technology must also be developed to extract oil shale from the deep zones found on public lands, and work on in situ processing should be accelerated to develop a viable option to surface processing. In addition, supplemental funding and staff to resolve present mineral title conflicts is necessary to assure continued availability of lands for development.

Under the normal evolutionary process of new technology development, this program would lead to no more than 100,000 to 250,000 barrels of shale oil per day by 1985. This panel believes this rate of progress is unacceptable considering the advanced stage of oil shale technology, the enormous resource base of 600 billion barrels contained in the high-grade deposits, and the Nation's current and future needs for oil. Accordingly, we have framed possible alternative programs that are designed to accelerate such development. These are considered below.

Accelerated/Orderly Program—This program is aimed at incentives needed to stimulate the construction of 3 to 5 commercial oil shale plants in this decade. Based on this experience, application of second generation technology should enable large scale development to occur after 1980, reaching 750,000 to 1,000,000 barrels per day by 1985.

Development under this program is expected to be constrained only by those factors that relate directly to construction: (1) plant design, (2) engineering and construction, and (3) capability to supply heavy mine and plant equipment. From analyses prepared by the National Petroleum Council and the Department of the Interior, the hiring and training of operating personnel, construction of plants and supporting urban facilities, and purchase and delivery of equipment from distant supply centers are the key ingredients to be considered.

Economic Incentives--Involvement by the Federal Government can take many forms, but support of product prices and/or guaranteed, nonrecourse loans would significantly enhance the economic viability of the initial oil shale plants. This involvement is not recommended for other than the initial plants since oil shale should be allowed to compete by itself with other supply options. The objective of this program is to provide those incentives necessary to move rapidly through initial development.

Price Support--This proposal would provide price stability for liquids produced from oil shale or other energy sources.

To implement such a demonstration program, the Government would announce in the Federal Register its willingness to entertain proposals whereby clean-burning solid, liquid, and/or gaseous fuels would be produced domestically in commercial quantities by processes not now commercial. The Government would indicate its willingness to make long-term negotiated contracts at least probable ultimate net cost, guaranteeing to buy the output of specified new domestic plants or modified idle domestic plants if such output could not be otherwise sold at the support price. Such contracts would contain detailed specifications covering the product to be bought, including appropriate premiums and penalties. Representative technologies sought, the range of product specifications, and the range of product prices to be considered in negotiations would be made public in advance of any negotiations. A cutoff date for initial filing of proposals would be specified. All long-term contracts would contain provisions whereby the Government could terminate the contract by paying the undepreciated (or unamortized) cost of the facility, thus that will affect the rate of return for oil shale development, the results of which are displayed in Table 3. As compared to the base conditions, changes in bonus payments, royalty rates, and depletion will have only small effects on the rate of return. Increases in the price of oil and expensing as a means of depreciation would significantly increase the return to be expected. However, a significant economic stimulus would be to finance the plant, in part, by funds borrowed at an interest rate below the overall yield of the project. This could be accomplished by Government-guaranteed loans that can also be made more flexible in interest rate and repayment schedule than those that may be obtained through more normal channels. It is of interest to note in Table 3 that money at 3 percent only increases the overall rate of return to 23.36 percent as compared to the 22.04 percent realized from 6 percent money. Thus, the economic impact is due to the ability to raise capital outside the equity market and not the rate charged on such borrowed capital. However, low cost loans will incur large front end investments and, therefore, Congressional appropriations. By contrast, the price stability program rests on borrowing authority which does not require Congressional approval. Additionally, political support of possible undesirable, low priority projects, would probably also occur. However, this can largely be offset by requiring large investments by the private sector; in the case of oil shale or coal conversion, this would total several hundred million dollars for each plant to be constructed. For these reasons, the loan course of action is not as desirable as the price stability approach described above, but is a feasible option.

Table 3 Rate of Return under differing assumptions - Oil Shale Plant

Base Case: Price $4 — Depletion 15%
Royalty $0.17/bbl — Depreciation 150%
Bonus - zero — Loan - zero

Rate of return 12.03.

Price	Rate of Return	% Change
$3	6.41	- 47
4 (base)	12.03	0
5	18.29	+ 52

Depletion	Rate of Return	% Change
10%	11.37	- 6
15%	12.03	0
22%	12.36	+ 3

Bonus	Rate of Return	% Change
$15 MM	11.34	- 6
15 MM (5 yr spread)	11.46	- 5
5 MM	11.78	- 2
5 MM (5 yr spread)	11.82	- 2
0 (base)	12.03	0

Depreciation	Rate of Return	% Change
str.-line	11.71	- 3
150% (base)	12.03	0
200%	12.33	+ 3
7% tax credit	12.52	+ 4
5 yr (except mine)	13.37	+ 11
Expensing	18.70	+ 55

Royalty	Rate of Return	% Change
$0.34	10.99	- 9
0.17 (base)	12.03	0
0.00	12.98	+ 8

Loan	Rate of Return	% Change
0 (base)	12.03	0
50% of capital @ 6%	22.04	+83
50 % of capital @ 3%	23.36	+ 94

BASIC ASSUMPTIONS

Discounted cash flow rate of return is based on: 100,000 barrel/day shale oil plant using room-and-pillar mine and first generation gas combustion 60' retort and shale at 30 gal./ton; cost $356.5 million, capitalized; operating $63.1 MM/yr, working capital $36.6 MM, State income taxes 5%, Federal 48%, depreciation of mine 10 years, retort and refinery 16, useful life of mine 10 years, retort and refinery 20, depletion not to exceed 50% of net; price includes oil and byproducts.

Legislation--If an oil shale industry is to expand to 1 million or more barrels per day, public lands will be required in addition to the six tracts considered under the Department of the Interior's prototype oil shale leasing program. The present limitation of 5,120 acres total must be eliminated to assure a scale of operation commensurate with future needs. Interior's proposal to Congress has been to increase holdings to 10,240 acres in any one State. However, this would probably still limit future operations by any single company. Therefore, to provide future flexibility, the limit could be based on a recoverable reserve of 1.5 billion tons of 30 gallon per ton oil shale per lessee. However, a provision should be added that when a lease is actually being developed, the acreage limitation on that lease should be removed. The company would then be in a position to plan for future development.

Another desirable legislative action includes provisions for mineral exchanges on an equitable basis. Although this can presently be accomplished under the Taylor Grazing Act, the provisions of that Act are not designed to accommodate the special problems involved in the establishment of mineral values for exchanges. The complex mineral ownership patterns in the oil shale area are the basis for this recommendation.

Legislation to assure lessee rights to adequate land use of offsite areas for roads, utilities, and disposal sites is presently provided under Special Land Use Permits. These permits are general in nature and do not recognize many of the special requirements that will accompany oil shale development. Clarifying legislation to assure these rights will be necessary to accommodate a mature industry if development is to be accomplished rapidly.

Maximum Program--This program would require the proposed research, economic incentives, and legislation discussed immediately above plus Government involvement to insure that adequate materials, labor, and auxiliary services are made available to support accelerated development. In essence, this program will remove the constraints described under the Accelerated/Orderly Program.

In implementing a maximum program, it should be recognized that this will require a National commitment to develop oil shale using economic and administrative governmental support similar to that used under conditions of a national emergency. Implicit in such a decision is that the need is so great that it far outweighs the environmental costs associated with development across the region. These costs have not yet been adequately defined, but initial development on private lands and development on public lands under Interior's prototype oil shale leasing program will provide data concerning the true environmental costs. A decision to implement this program should therefore be deferred until such data are available and can be incorporated into an environmental statement related to large-scale development on public lands.

Personnel and funding for such an effort is required. Although the primary responsibility for program implementation should be with the Department of the Interior, nearly every Federal Department would be called upon to furnish support under emergency conditions. Assistance from State and local governments would also be necessary to meet rapidly expanding urban developments in relatively rural areas. Thus, to administer a maximum program of oil shale development will require a professional staff and adequate support at all levels of Government.

VI. IMPLEMENTATION PLAN

The rate of oil shale development will depend upon the Government policy (or lack thereof) as set forth in Section V of this analysis.

At current value ($3.90 per barrel), shale oil will yield a marginally attractive rate of return of 10 to 13 percent on a discounted cash flow basis. Application of second generation technology and/or higher product prices will significantly enhance the overall economics.

The impact of the change in cost between first and second generation technology is reflected in figure I in data prepared by the Department of the Interior. These data reflect the cost to the Nation to develop alternative sources of oil (resource cost) and are not to be confused with selling price which will be higher. As indicated, shale oil is estimated to initially cost $3 to $4 per barrel. The "learning curve" impact due to oil shale development to the 1 million barrel per day level is projected to lower the resource cost to $2.25 to $3.00 per barrel (lightly shaded box). Second generation costs thus compare favorably with other domestic supply options which, by 1985, may increase significantly over the data presented in this figure which reflect current (1973) costs.[1/]

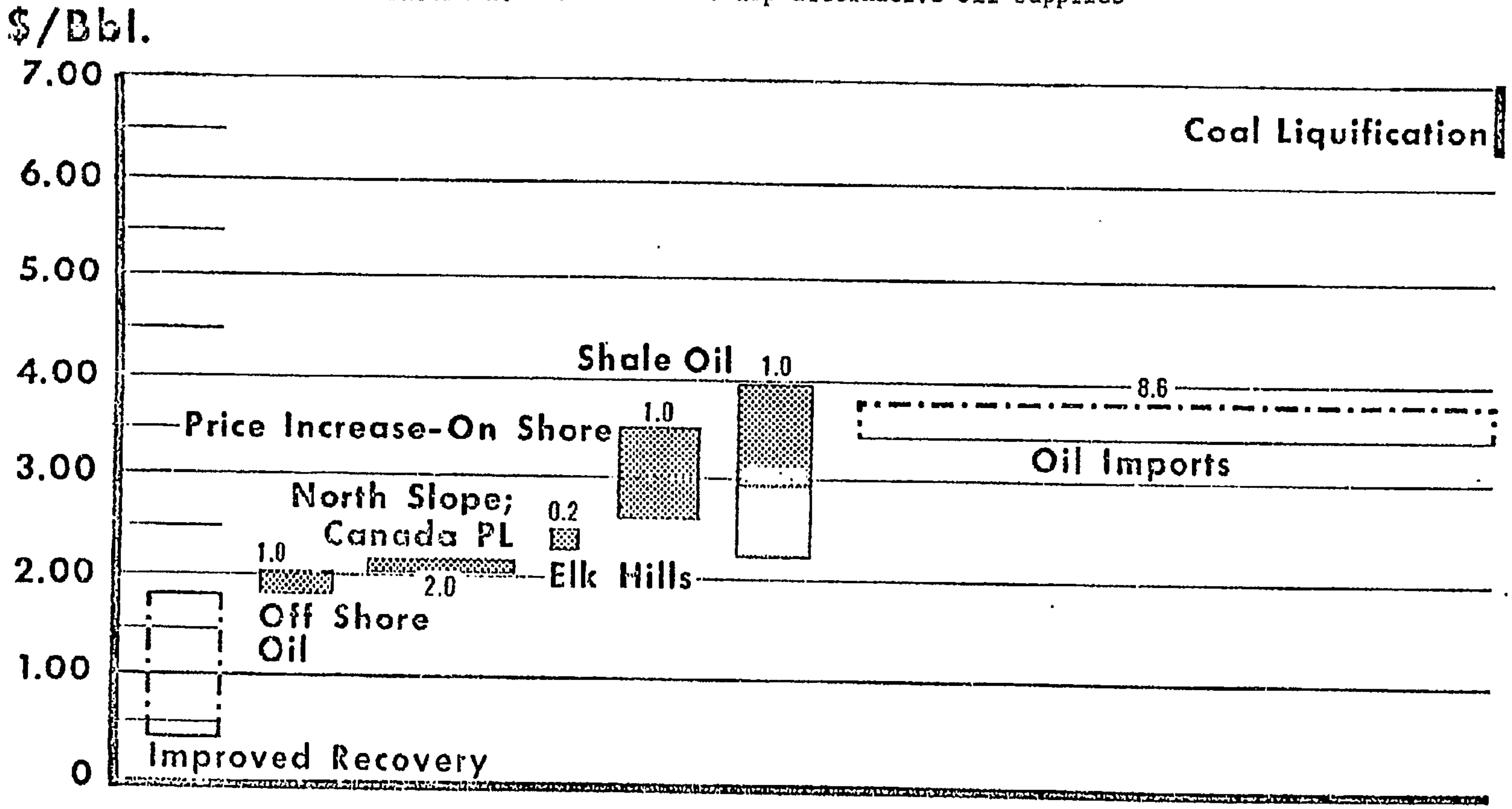
Implicit in the estimates that oil shale will increase to the 1 million barrel per day level by 1985 are the following key assumptions:

1. Public lands will be made available to support expanded production after 1980.

2. Several plants are on stream in this decade which will enable the application of second generation technology after 1980.

1/ The cost for oil imports is based on the expected 1975 cost of oil imports per agreements made between the oil exporting countries. The current cost is higher than is reflected in figure 1.

FIGURE 1. - Costs to develop alternative oil supplies



Resource Cost is cost to society for goods, labor, and capital

Includes: profit and payments to foreign Governments

Excludes: bonuses, rents, royalties, and taxes paid to domestic governments

Source: U.S. Department of the Interior

Failure to realize these assumptions would limit the amount of shale that may be produced by 1985 to a few hundred thousand barrels per day. Additional leasing of public lands is expected to require another environmental statement. The information gained by the support research suggested in this analysis and the results of initial development is absolutely essential if that statement is to withstand future court challenges.

The main barriers to oil shale development do not lie with technology. Rather, these barriers exist within the existing institutional framework and the public acceptance of this new industry. Both of these can be resolved with adequate advance planning using information appropriate for the task.

VII. IMPACTS OF IMPLEMENTATION

Oil shale development would produce both direct and indirect changes in the environment of the oil shale region in each of the three States where commercial quantities of oil shale resources exist--Colorado, Utah, and Wyoming. Many of the environmental changes would be of local significance, and others would be of an expanding nature and have cumulative impact. These major regional changes will conflict with uses of the other physical resources of the areas involved. Impacts would include those on the land itself, on water resources and air quality, on fish and wildlife habitat, on grazing and agricultural activities, on recreation and aesthetic values, and on the existing social and economic patterns as well as others. These impacts are fully considered in the Department of the Interior's six-volume Final Environmental Statement for the Proposed Prototype Oil Shale Leasing Program, September 1973.

The Final Environmental Statement contains evaluations for a prototype industry of 250,000 b/d and a mature industry of 1,000,000 b/d per day. In general, the prototype industry would produce localized environmental effects, whereas a mature industry would produce regional environmental effects. These regional effects could result in significant environmental consequences unless prototype development would prove that the effects on water, air, flora, and fauna could be mitigated within acceptable standards. Proving the concepts for development with effective environmental controls would be a prime objective of the prototype program.

The scale of development for the 250,000 b/d prototype program is estimated to produce 100,000 b/d from a surface mine, 100,000 b/d from underground mines and a possible 50,000 b/d for in-situ development. This development would create about 13,000 new jobs and bring 34,000 people into a region with a present population of about 119,000. It would require an investment of nearly one billion dollars in the next 10 years, which would create local tax revenues of about $33 million per year, State revenues of $22 million per year, and Federal revenues of $135 million annually.

The social impacts of increased urbanization could create a conflict of life style because of the present rural character of the region. Additional schools, transportation, health, and sanitation services would be needed, to cite a few of the major public requirements which would be imposed on the local and State governments. A mature industry of 1,000,000 b/d could approximately double the present population and would proportionately increase the other requirements which have been noted.

Impacts on land would involve 8 to 11 thousand acres for development and about 2 thousand acres for utility corridors. The sum of 10 – 13,000 acres represents about 0.1 of 1 percent of the know oil shale area in the region. A mature industry of 1,000,000 b/d would involve 75 – 80,000 acres of land, including the requirements for urban expansion. This figure represents about 0.5 of 1 percent of the oil shale lands that have been evaluated in the three-State area. Development of oil shale would alter the landscape in some areas and destroy vegetation during actual operations, thereby reducing the forage for grazing and wildlife habitat. Although the techniques for revegetation of mine waste disposal sites have been proven for grasses and similar growth with supplementary water and fertilizer, the techniques for revegetating the disturbed areas to their original ground cover have yet to be proven. The acreages shown above are the maximum estimated to be cumulatively disturbed over a 30-year period. Only a small portion of this would be affected at any one time.

The effect of oil shale development on water relates to not only the source of supply but to the quality of the water as well. Sources of water include both ground and surface water. The Piceance Creek Basin is known to contain substantial quantities of fresh and saline ground water that could be utilized for development. The prototype program has been designed to fully evaluate the effects of water production, leaching effects from drainage water of disposal sites, and the disposal of waste waters. Even though significant quantities of water would be required for the prototype development program, this fact should not significantly affect the quality of the water in the Colorado River System. A mature one million b/d industry has been estimated to require from 121 to 189 thousand acre feet of water annually. The magnitude of the difference between these estimates is due primarily to the inability at this time to fully evaluate the water requirements for mine waste disposal or upgrading of products. Methods of handling these problems can only be fully evaluated with development. Mature development with all water requirements supplied from the Colorado River System could increase the salinity of the water at Hoover Dam by 15 mg/liter or 1.5 percent, due to the consumptive use of better quality water in the upper basin. The effects of accidental mishaps, flooding and ground water utilization are evaluated in the report. Municipal waste from sewage or powerplants could pose a problem if proper precautions were not enforced for the increased urban development.

The effect on air quality from the prototype program would be expected to be local in character. There would be a reduction in air clarity and visibility in the area. Potential inversions of about 20 days per year for the region could create some effects on vegetation and wildlife in the area, but would be of short duration. All Federal, State and local air quality regulations would have to be met. Current technology indicates that these standards can be satisfied, except that yet to be determined are the new non-degradation requirements and whether any major industrial development can be undertaken for standards that have not been established. Those requirements could limit the size or prevent development.

During the prototype program, effects on wildlife would be created primarily by the impact of an influx of more people into the area, including the demands of the increased population for recreational activities such as off-road vehicle driving, hunting or fishing. Some losses from eliminated grazing or forage might occur from prototype development and in a few cases endangered wildlife species may be displaced. A mature industry would have a significantly greater impact on wildlife resources. As an example, it has been estimated that it would reduce deer populations in some areas by as much as 10 percent.

SECTION V

Improved Combustion Process

II. STATUS OF THE TECHNOLOGY

A. Present Status

The use of fluidized-bed combustion for the purpose of electrical power and industrial steam generation has come under study, in various forms, in a number of countries during the past twenty or more years. The major studies in this area have been conducted in the United Kingdom and the United States. The British investigation began about ten years ago; both the atmospheric and the pressurized versions of the process were studied on various experimental units, but no commitment was made to scale up. In this country, the atmospheric fluidized-bed combustion process has been tested on several experimental units, including one of 700 lb coal/hr, under OCR and EPA sponsorship; OCR is now preparing to pilot the process on a 30 MW unit. The pressurized system has also been tested, more recently, on a number of experimental units; a 0.63 MW "Miniplant" has been built by EPA, and will be started up later this year, operating at furnace pressures up to 10 atm. An adiabatic fluidized-bed combustion system, burning 100 ton/day of municipal refuse, is being tested by EPA, and will be converted to coal (about 2 MW equivalent) under OCR sponsorship.

Considerable effort has been directed toward modifying combustor processes for combustion efficiency improvement and pollution control. EPA and contract research organizations have studied combustion and modifications from fundamental through practical application levels. These studies have established the feasibility of modifications with considerable success; fundamental studies indicating potential new modifications and field studies producing significant pollution reductions in utility boiler operations.

B. Barriers to Implementation

Barriers in the fluidized-bed combustion system include: (1) demonstration of sorbent regeneration and sulfur recovery, for those variations of the system involving regeneration; (2) demonstration of high-temperature, high-pressure particulate removal technology, for pressurized systems; and (3) demonstrating the operability of the integrated boiler systems on a large scale. In addition, reluctance of boiler manufacturers and operators to build and install boilers so radically different from what is currently commercial may be a barrier to commercialization.

Major barriers for the combustion modifications will be removed by the demonstrations of efficiency and pollution reduction with satisfactory operating characteristics and equipment durability.

C. On-going R&D Effort

A total of about $1 million is currently being expended by the Federal Government to develop pressurized fluidized boilers. Additional funds are required, from either the Government or the private sector, if the 0.63 MW Miniplant is to be operated at an efficient pace, providing necessary design information on thepressurized system. OCR is conducting a $5.8 million effort to test the atmospheric fluidized combustion system on the 30 MW scale; 85% of the total program cost is being provided by the Government. The adiabatic coal-burning fluidized-bed combustion concept is scheduled for study under a $1.5 million Government-sponsored effort. Contacts have been established with researchers in this field in other countries, particularly Great Britain, although the amount of British-sponsored work in this area appears currently to be limited.

EPA has budgeted about $2 million for combustion modification studies during fiscal 1974. These studies cover a wide range of activities from fundamental research to field application, but this limited funding retards the rate of progress significantly.

III. RATIONALE FOR FEDERAL INVOLVEMENT

Development of the fluidized-bed combustion technology requires a substantial R, D&D financial outlay. The potential for establishment of a proprietary position is limited, thus making it difficult for a private firm to recoup such an R, D&D outlay in a reasonable period of time. Therefore, in order to assure development of fluidized-bed boiler technology on a timely basis, it is necessary for the Government to provide most of the R&D funds, and a reasonable fraction of the demonstration funds.

Federal involvement in the combustion modification area is necessary in order to ensure a systematic, comprehensive program in this area. Progress, particularly related to the area source applications would be non-existent without Government funds.

IV. OBJECTIVES

The generalized objective of the proposed research program is to develop, and accelerate commercial scale demonstration of, new and higher-efficiency combustion systems, including improved procedures for reducing discharge of pollutants.

V. ALTERNATIVE R&D PROGRAMS

A. Schedule and Costs of Alternative Programs

Milestone charts and annual budget projections are attached for each of: (1) an accelerated/orderly program; (2) a maximum program; and (3) a minimum program.

Accelerated/orderly program. A 300 MW pressurized fluidized-bed boiler plant, an 800 MW atmospheric plant and a 500 MW adiabatic system would each be demonstrated by the end of fiscal 1980. A model of the fluidized-bed combustion process would also be completed at that time. The pressurized system would be tested in the $3 million 0.63 MW Miniplant through FY 75; if this program is successful, the system will be tested in a $25 million, 30 MW plant program through FY 78, provided that 50% private support can be obtained; and, if 50% private support can again be obtained, a 300 MW pressurized plant will be built and operated at a cost of $125,000,000. The atmospheric-pressure system will be tested on the planned 30 MW plant by the end of FY 75, with subsequent demonstration on a $300,000,000, 800 MW plant; again, 50% private support is assumed. The adiabatic system is projected for testing on a 50 MW unit by FY 78, and demonstrated on a $160,000,000 500 MW plant (assuming 50% private support). The total cost to the Government of the entire proposed fluidized-bed combustion effort is $368 million.

Combustion modifications would be completed on demonstration industrial boilers in FY 78, and in industrial process furnaces in FY 79, at a total cost of $18.8 million (with about a one-third of that to be contributed by the private sector). Modifications would be demonstrated on a utility boiler in FY 78, at a cost of $17.0 million in addition to that already committed (with about 40% coming from industry). A 50-75 MW demonstration of modifications to gas turbine is scheduled for FY 81, with a cost to the Government of $4.8 million (plus about an equal amount from the private sector). The reformed fuels technology should be tested on a 1 MW system by the end of FY 78, with the full $3.2 million cost being provided by the Government. The total cost to the Government for the combustion modification program would be $29 million.

<u>Maximum program.</u> In the fluidized-bed combustion program, the three systems would be demonstrated about two years earlier than in the accelerated/orderly case. Also, in the case of the pressurized version, a larger demonstration plant would be built in an attempt to expedite commercialization. In the "maximum" alternative, it was assumed that design of the demo plant would begin early in FY 75, and that construction of the demo would begin as soon as possible after the design was completed. Due to the larger pressurized demo plant, and due to inefficiencies resulting from the expedited program, the total cost of the "maximum" program is projected to be about $516 million, 40% higher than the accelerated/orderly program.

A "maximum" program on the conventional modifications would result in a demonstration of that technology one to two years earlier than would the accelerated/orderly program, at a total cost of about $45 million. This 55% increase results from increased manpower requirements, co-current pilot-demonstration phases problems and general inefficiencies encountered in crash operations.

Minimum Program. A minimum program would result in delay of the demonstratic of the pressurized and atmospheric fluidized-bed boilers by up to a year, and would reduce the size of the demonstration plants; the adiabatic system program would be eliminated. Costs for the fluidized-bed program would be cut to about $202 million by these reductions. The conventional combustion modifications would be slowed in the minimum program so that this part of the effort would require 25% longer to complete, but funding at $29 million would still be required although spread out over a longer time frame (~ 2 years).

Generally, initial or smaller scale research would be conducted entirely at Government expense. Intermediate-scale testing would be conducted with some reasonable contribution from the private sector (15-50% of the total). Demonstrations would generally involve about 50% industry participation.

The bulk of the RD&D effort will be conducted by contractors under Government sponsorship.

B. Criteria Employed in Constructing Proposed Program

The fluidized-bed combustion process offers one of the major alternatives for new technology enabling "dirty" coals to be burned with improved economy and with acceptable environmental impact. Development of three variations of the process will provide future users with a selection from which to choose the variation which is optimum for their specific application, and will provide alternative fluidized-bed combustion technologies in the event that future development efforts show any one variation to be technically or economically undesirable.

The conventional combustion modification technology will enable improved fuels utilization, enable reduction of carbonaceous emissions, and will enable NO_x control more simply and less expensively than would be possible with an NO_x flue gas cleaning process.

C. Relationship of Other R&D

Perhaps the most important companion technology which must be developed in conjunction with fluidized bed boilers is high-pressure, high-temperature particulate cleanup technology. An elevated temperature and pressure cyclone system has been tested during the adiabatic fluidized-bed refuse burning test, mentioned previously. Granular bed filters are also under development. EPA is proposing additional work in this area.

Development of steam turbines capable of utilizing higher steam conditions would improve the thermal efficiency of fluidized boilers.

The combustion modifications program does not depend on the results of other efforts.

D. Acceptability of R&D Program

Few problems are foreseen regarding environment, safety or public acceptability associated with the R&D program per se. Adequate safety devices will be necessary in the fluidized boiler systems, especially for the pressurized fluidized boiler plants. Public reaction to the fluidized boiler demonstration plants will probably be the same as for any full-scale coal power plant. Environmental impact statements will be necessary for the 30 MW and the demonstration fluidized boiler plants.

VI. IMPLEMENTATION PLAN

A. Direct Benefits

It is projected that, when fluidized-bed boilers are developed, they will capture at least 25% of the market for new coal boilers. This implementation rate would result in 3000 MW (or 0.2×10^{15} Btu fuel input) installed capacity in 1985, and 40,000 MW (2.2×10^{15} Btu) in the year 2000. If anything, it would be expected that the implementation rate would be greater, due to a larger-than-projected utilization of coal for power generation, and to capture by fluidized boilers of a greater percentage of the coal-fired market. Fluidized boilers would enable the U. S. to utilize even the poorest and "dirtiest" grades of this country's substantial coal reserves, relieving U. S. dependence on foreign oil and gas. If future steam turbine developments enable operation of fluidized boilers at elevated steam conditions, system thermal efficiencies of up to 47% ultimately for the pressurized system, and 40% for the atmospheric system, could be achieved, compared to 37% efficiency for conventional systems; thus, more efficient utilization of the nation's coal reserves would result.

Combustion modification technology could be applied to most existing industrial and utility combustion processes, and to all new units. Application of this technology would improve combustion efficiency, thus resulting in more efficient utilization of fuel. Emissions of NO_x and of organics will also be reduced. Emission reductions for area sources will also be accomplished.

B. Economics

Fluidized-bed boilers will, according to current estimates, produce electricity at 11.7-13.1 mills/kwh, in a 600 MW plant with a 70% load factor, based upon 1970 dollars and 7.5% escalation/yr during construction. A conventional boiler costed on the same basis would produce electricity at 13.4 mills/kwh. The fluidized boiler installed capital cost is estimated to be $260-$310/kw for a 600 MW plant, compared to $337/kw for a comparable conventional unit. These estimates are based upon coal at 45¢/10^6 Btu, interest during construction of 7.5%, and fixed charges of 15%. Amortization of R&D is not included in the price. Commercial availability is expected in 1981. It would be envisioned that this technology would find a market in foreign countries, particularly those with poor quality coal reserves; thus U. S. balance of payments would be improved.

Combustion modifications might improve fuel utilization efficiency by perhaps 1 or more percentage points, thus reducing energy costs accordingly. The effect on total combustion system capital cost will probably not be substantial. Commercial availability is anticipated during the time period 1978-1981.

VII. IMPACTS OF IMPLEMENTATION

A. Natural Resources Required

Coal-fired fluidized-bed boilers will require 0.2×10^{15} Btu/yr of coal in 1985, and 2.2×10^{15} Btu/yr in 2000. These figures are small in comparison with the $30,000 \times 10^{15}$ Btu of estimated recoverable coal reserves in the U. S. These boilers will also require quantities of limestones/dolomites for SO_2 control; these minerals are available in large quantities throughout most of the U. S.

B. Compatibility with Existing System

Fluidized-bed boilers, and combustion modifications, should be readily compatible with the existing national energy system.

C. Environmental Impacts

Fluidized-bed boilers will meet all of the environmental standards.

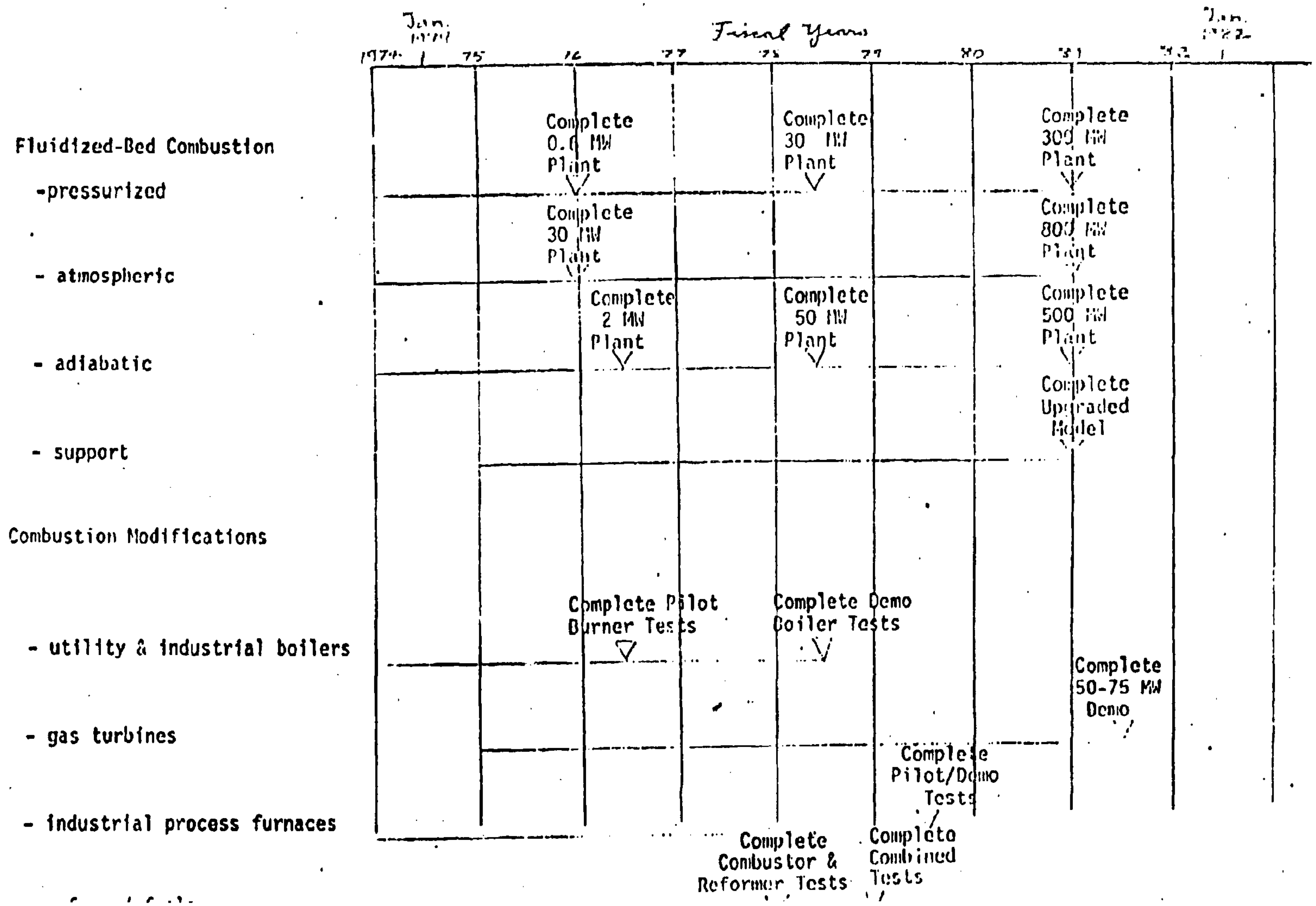
Pollutant	Emissions per 10^6 Btu
CO	0
SO_2	0.7 lb
NO_x	0.14 lb
Hydrocarbons	0
Particulates	0.02 lb
Thermal (water)	0
Thermal (air)	0.62×10^6 Btu
Ash	17.3 lb

Combustion modifications may reduce NO_x emissions by up to 60%. Emissions of hydrocarbons and polycyclic organic materials will also be reduced significantly from some processes. These modifications will provide the best technology for establishing and meeting standards for area sources.

ENERGY R&D PROGRAM FLOW CHART

PROGRAM NAME: Improved Combustion Processes

PROGRAM ALTERNATIVE: Accelerated/Orderly

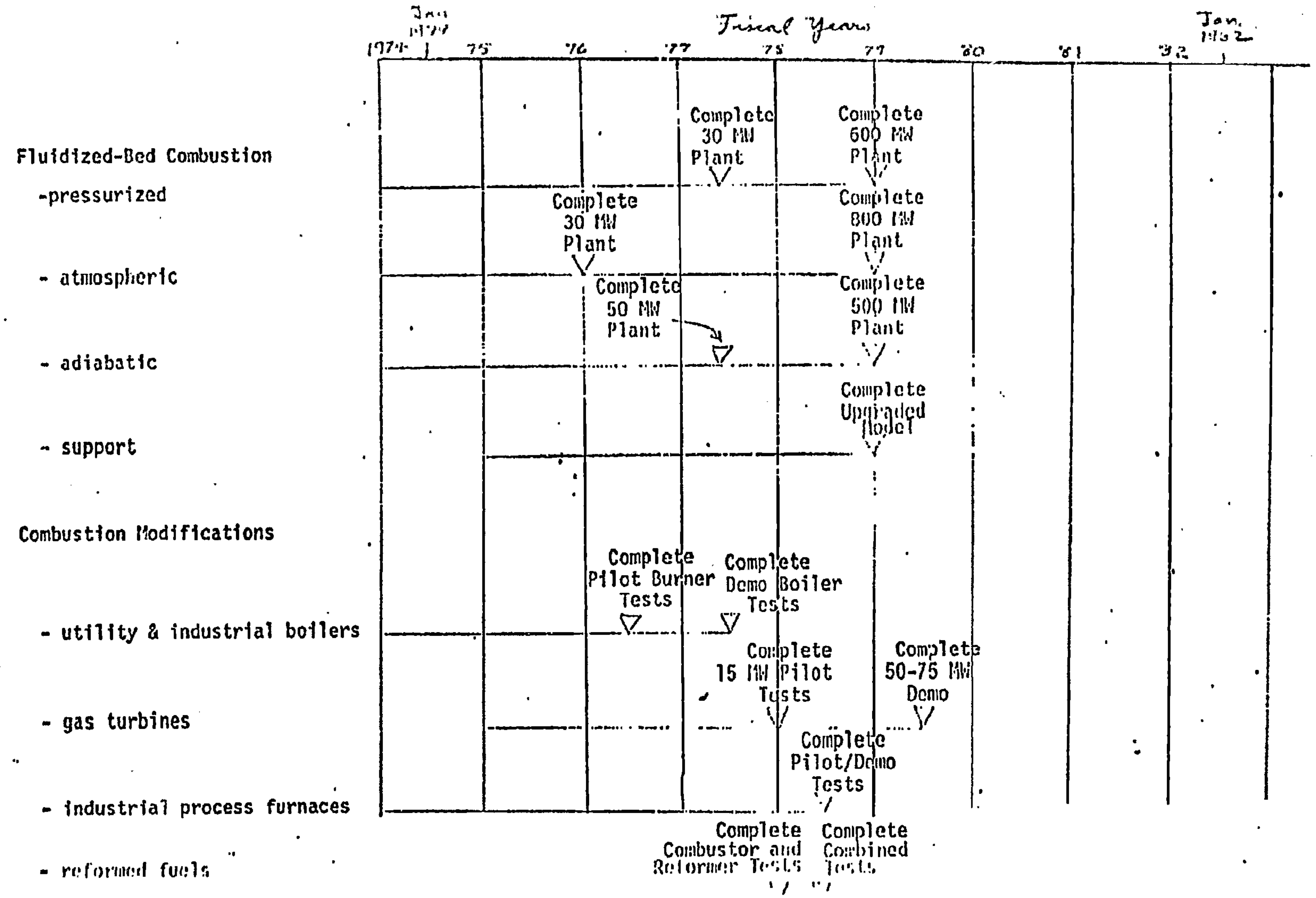


Form A

ENERGY R+D PROGRAM FLOW CHART

PROGRAM NAME: Improved Combustion Processes

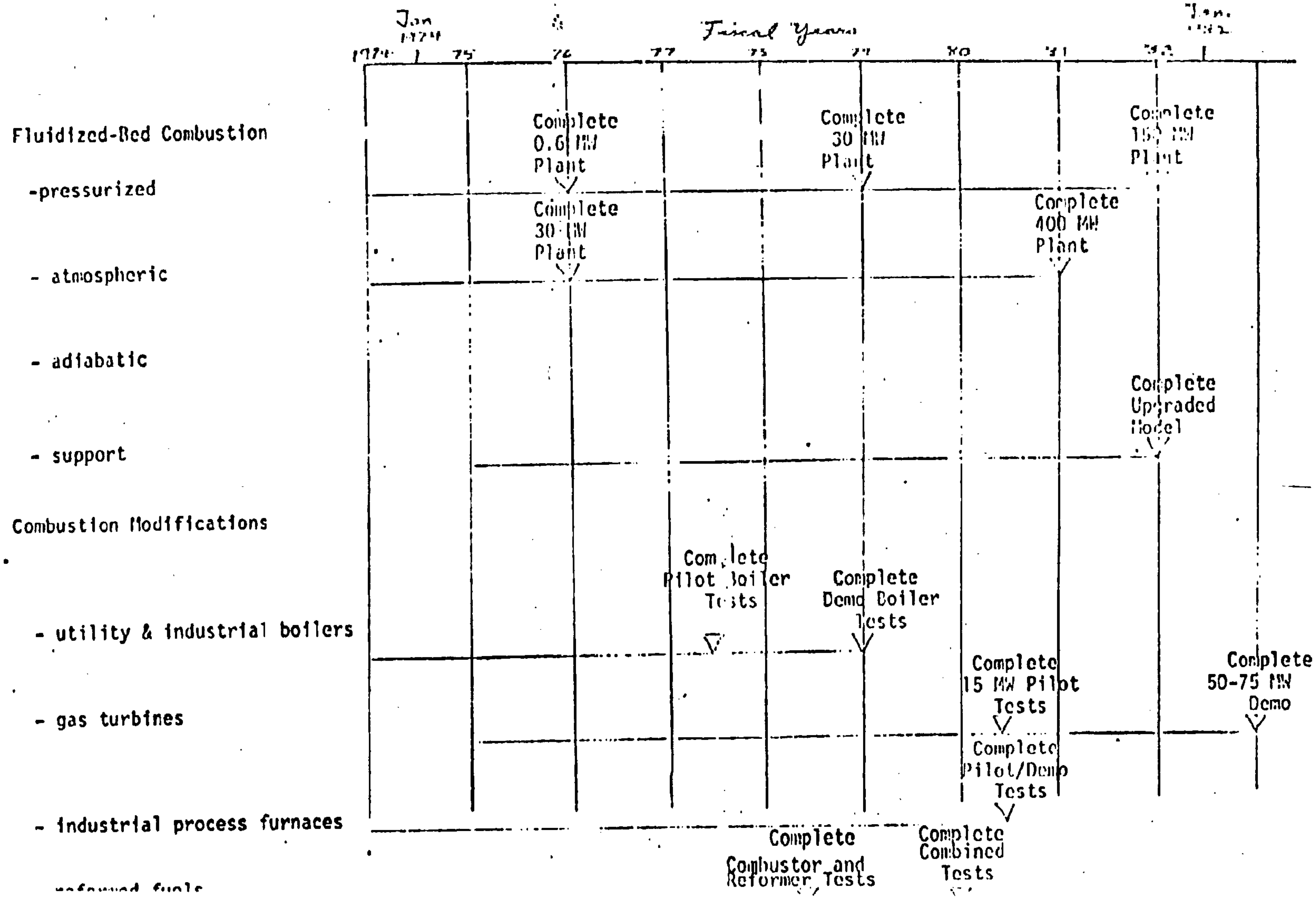
PROGRAM ALTERNATIVE: Maximum



ENERGY R&D PROGRAM FLOW CHART

PROGRAM NAME: Improved Combustion Processes

PROGRAM ALTERNATIVE: Minimum



FORM B

ENERGY R&D PROGRAM BUDGET SUMMARY

PROGRAM NAME: Improved Combustion Processes

PROGRAM ALTERNATIVE: Accelerated/Orderly

FEDERAL OBLIGATIONS

$ × 10^6

PROGRAM ELEMENT	1975	1976	1977	1978	1979	1980-1989	1990-1999
Fluidized-Bed Combustion							
-pressurized*	1.8	1.3	12.2	26.4	20.4	20.0	
-atmospheric*	8.0	4.4	51.5	51.5	51.5	0 (not certain)	
-adiabatic*	3.0	6.0	6.1	5.2	3.7	75.0 (not certain)	
-support	5.8	5.8	2.0	2.0	1.5	3.0	
Combustion Modifications							
-utility and industrial boilers**	3.2	7.0	1.9	1.9	1.9	-	
-gas turbines*	0.8	0.8	0.8	1.4	1.0	-	
-industrial process furnaces*	0.3	0.6	1.6	1.3	1.3	-	
-reformed fuels*	0.8	1.4	0.5	0.5	-	-	

*Assumes 50% industry support for demo units.
**Assumes about 42% support by industry.

FORM B

ENERGY R&D PROGRAM BUDGET SUMMARY

PROGRAM NAME: Improved Combustion Processes   PROGRAM ALTERNATIVE: Maximum

FEDERAL OBLIGATIONS

$\$ \times 10^6$

PROGRAM ELEMENT	1975	1976	1977	1978	1979	1980-1989	1990-1999
Fluidized-Bed Combustion		56.4	[illegible]	[illegible]			
-pressurized*	8.1	~~40.4~~	89.6	~~30.0~~	)		
-atmospheric*	13.0	70.9	76.5	76.5	) [illegible]		
-adiabatic*	9.2	57.5	37.0	37.0	) ~~515.8~~		
-support	6.8	6.8	3.5	3.0	)		
Combustion Modifications							
-utility and industrial boilers**	8.6	12.7	4.8	1.7		)	
-gas turbines*	0.8	1.2	1.2	2.1	1.5	)	
-industrial process furnaces*	0.5	1.0	2.5	2.5		)	
-reformed fuels*	0.8	1.4	0.7	0.8		)	

*Assumes 50% industry support for demo units.
**Assumes about 42% support by industry

FORM B

ENERGY R&D PROGRAM BUDGET SUMMARY

PROGRAM NAME: Improved Combustion Processes

PROGRAM ALTERNATIVE: Minimum

FEDERAL OBLIGATIONS

$\$ \times 10^6$

PROGRAM ELEMENT	1975	1976	1977	1978	1979	1980-1989	1990-1999
Fluidized-Bed Combustion							
-pressurized*	1.8	1.3	7.2	11.4	12.4	24.0)	
-atmospheric*	8.0	4.4	37.0	37.0	37.0	--)	201.6
-support	5.8	5.8	2.0	2.0	1.5	3.0)	
Combustion Modifications							
-utility and industrial boilers**	2.9	6.3	1.7	1.8	1.8	1.3	
-gas turbines*	0.6	0.6	0.6	1.1	0.8	1.1	
-industrial process furnaces*	0.3	0.5	1.3	1.0	1.0	1.1	
-reformed fuels*	0.6	1.1	0.3	0.4	0.8		

*Assumes 50% industry support for demo units

**Assumes about 42% support by industry