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Comprehensive Report to Congress:

Proposals Received in Response to the Clean Coal Technology III Program Opportunity Notice

U.S. Department of Energy
Assistant Secretary for Fossil Energy
Washington, DC 20585

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CONTENTS

EXHIBITS

I. EXECUTIVE SUMMARY

This report is a comprehensive overview of the projects selected and all proposals received in response to the Program Opportunity Notice (PON) for Clean Coal Technology III (CCT-III) Demonstration Projects (solicitation number DE-PSO1-89FE61825). The Department of Energy (DOE) issued the solicitation on May 1, 1989. Through this PON, DOE solicited proposals to conduct cost shared clean coal technology projects to demonstrate innovative, energy efficient technologies that are capable of being commercialized in the 1990s. These technologies must be capable of (1) achieving significant reductions in the emissions of sulfur dioxide (SO_2) and/or the oxides of nitrogen (NO_x) from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner.

The CCT-III PON is the third of a series of five solicitations being conducted by DOE as part of the Clean Coal Technology Demonstration Program. This is a technology development program jointly funded by government and industry. It will take the best and most promising of the advanced clean coal technologies and, over the next decade, will move them into the commercial marketplace through demonstration. These demonstrations will be at a scale large enough to generate the data (from design, construction, and operation) necessary for the private sector to judge their commercial potential and to make informed commercial decisions.

CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

The Clean Coal Technology Demonstration Program is aimed at selecting advanced coal based technologies that have been proven to work at smaller scales and moving them into large-scale demonstrations, where their market viability and commercial-scale performance can be assessed. Candidate projects are selected for direct financial assistance for a specific period of design, construction, and operation. The project sponsor, who must contribute at least half the costs of the demonstration effort, is then responsible for commercialization of the technology. The government receives revenues based on the sale or licensing of the demonstration technologies over a period of years in order to recoup some of the taxpayers' investment.

The program currently consists of three parts: Clean Coal Technology I (CCT-1), Innovative Clean Coal Technology (CCT-II), and Clean Coal Technology III (CCT-III). Each corresponds to a solicitation for industry proposed, cost shared demonstration projects. A total of 11 projects comprise CCT-1. CCT-II currently has 15 projects. Thirteen projects were recently selected under the CCT-III solicitation -- the subject of this report.

CLEAN COAL TECHNOLOGIES

Clean coal technologies, compared to current technologies, have the potential to increase the efficiency at which coal is converted to usable energy, to minimize environmental impacts associated with the use of coal, and to reduce substantially the costs at which this energy is made available.

Current technologies achieve emissions control with some trade-offs. For example, flue gas desulfurization (scrubbers) can remove 90 percent of the sulfur pollutants from the combustion gases of coal, but scrubbers are very costly and have virtually no effect on NO_x emissions. Scrubbers also consume a portion of the power plant's energy, thereby reducing the overall efficiency and raising the cost of electricity. Moreover, scrubbers produce massive amounts of waste that are difficult to handle and are environmentally damaging if not disposed of properly. Conventional coal cleaning has a limited ability to remove sulfur impurities, typically only 10-30 percent of the total sulfur in coal, and therefore cannot achieve the more stringent Clean Air Act standards by itself. Coal switching (from high-sulfur to low-sulfur coal) cannot be used to meet the new standards and, even if applied to existing plants, often results in diminished boiler performance and increased costs (because low-sulfur coal is typically more expensive than high-sulfur coal).

Advanced clean coal technologies, however, offer the opportunity to produce usable energy at costs much lower than current technology. Of equal importance, clean coal technologies open the door to a future of sustained reductions in the acid rain precursors SO_2 and NO_x while enabling greater use of a vast energy resource -- coal.

Among these advanced clean coal technologies are concepts such as (1) fuel upgrading, including coal cleaning/upgrading and mild gasification; (2) SO_2 and NO_x emissions control, including advanced flue gas desulfurization, sorbent injection, low NO_x combustion, post-combustion NO_x control, and combined SO_2/NO_x control; and (3) advanced combustion including atmospheric fluidized-bed combustion, pressurized fluidized-bed combustion, slagging combustion, and integrated gasification combined-cycle. The successful outcome of the Clean Coal Demonstration Program would result in the development and commercialization of a new suite of advanced clean coal technologies.

The common thread running through the many advanced clean coal concepts is the ability to use a variety of domestic coals more efficiently while better protecting the environment. Several of these concepts have the added advantage of boosting an existing power plant's electrical output, possibly forestalling expensive investment in new power generating capacity. Many can be added in modular fashion to match more closely a utility's supply and demand requirements. Advanced clean coal technologies can offer opportunities for significantly reducing, or perhaps eliminating, the threat of acid rain damage in the future, while at the same time create the capability to solve the anticipated problems of meeting requirements for increased power production capacity.

CONTENTS OF THIS REPORT

The subject of this Comprehensive Report to Congress is the response to the CCT-III PON. Chapter II presents the CCT-III projects selected for negotiation leading to award. It also contains an overview of the CCT-III PON and a summary of the proposal evaluation process. Chapter III provides an overview of the technologies and the geographic locations of the proposed projects.

The environmental considerations which are an integral part of the Clean Coal Technology Program are explained in Chapter IV. It outlines the strategy for addressing the requirements of the National Environmental Policy Act (NEPA) as well as the strategy for monitoring and documenting the environmental performance of the demonstration projects during implementation.

Appendix A contains technical descriptions of clean coal technologies that are commercially available as well as those under development in the public and private sectors. Appendix B contains additional project information about each of the 48 proposals submitted.

II. THE CLEAN COAL TECHNOLOGY III PON AND PROJECT SELECTION

On September 27, 1988, Public Law 100-446, "An Act Making Appropriations for the Department of the Interior and Related Agencies for the Fiscal Year Ending September 30, 1989, and for Other Purposes" (the "Act"), was signed into law. This Act, among other things, provides funds to conduct cost-shared Clean Coal Technology III (CCT-III) projects for the design, construction, and operation of facilities that would demonstrate the feasibility of future commercial applications of such "... technologies capable of retrofitting or repowering existing facilities ...." On June 30, 1989, Public Law 101-45 was signed into law. This statute required that CCT-III projects be selected no later than January 1, 1990.

Public Law 100-446 appropriates a total of $575 million for the CCT-III projects. Of these monies, $6.906 million are required to be reprogrammed for the Small Business and Innovative Research Program (SBIR) and $22.548 million are designated for Program Direction Funds for costs incurred by DOE in implementing the CCT-III program. The remaining, $545.546 million was available for award under the PON. The budget is shown in Exhibit 1.

Exhibit 1

Budget for Clean Coal Technology III

Available for Award	$ 545,547,000
SBIR	6,905,000
Program Direction	22,548,000
Total Appropriation	$ 575,000,000

On August 29, 1989, DOE received 48 proposals in response to the CCT-III solicitation. The selection of 13 projects was announced on December 21, 1989 by the Secretary of Energy, Admiral James D. Watkins, U.S. Navy, Retired. In this press briefing, the Secretary stated he had recently signed a DOE directive setting a 12 month deadline for the negotiation and approval of the 13 cooperative agreements to be awarded under the CCT-III solicitation. Immediately following the selection announcement, DOE officials briefed the selected proposers on the negotiation process and emphasized that their full cooperation would be needed to meet the Secretary's deadline.

A chronology of the major events related to the CCT-III solicitation is listed in Exhibit 2.

Exhibit 2

Chronology of Major Events Related to the CCT-III Solicitation

Public Law 100-446 Enacted	September 27, 1988
Public Meeting, Cheyenne, WY	December 2, 1988
Public Meeting, Denver, CO	January 18, 1989
Public Meeting, Dallas, TX	February 2, 1989
Public Meeting, Atlanta, GA	February 16, 1989
Source Selection Official Designated	February 27, 1989
Source Evaluation Board Established	March 2, 1989
Draft PON Issued for Public Comment	March 15, 1989
Public Comments Received	March 31, 1989
Final PON Issued	May 1, 1989
Preproposal Conference	May 18, 1989
Preproposal Conference Proceedings Issued	May 31, 1989
Public Law 101-45 Enacted	June 30, 1989
Additional Questions and Answers Issued	July 12, 1989
Last Questions and Answers Issued	August 8, 1989
Closing Date for Receipt of Proposals	August 29, 1989
Selection Statement Signed	December 19, 1989
Selections announced to the public	December 21, 1989

PUBLIC MEETINGS

DOE convened four public meetings to obtain views, comments, and recommendations on the forthcoming CCT-III solicitation. The meetings took place in Cheyenne, Wyoming on December 2, 1988; Denver, Colorado on January 18, 1989; Dallas, Texas on February 2, 1989; and Atlanta, Georgia, February 16, 1989. Each meeting included a plenary session during which DOE officials made introductory remarks and presented program overviews. Attendees then broke into small discussion groups to discuss issues pertaining to the CCT-III solicitation. At the conclusion of the group discussions, attendees reconvened in a closing session which included a presentation by senior DOE procurement officials, highlights and recommendations from the group discussions, and a question and answer period. Published proceedings from these meetings are available.[1]

ISSUANCE OF THE CCT-III PON

DOE issued a draft PON for public comment on March 15, 1989. DOE received a total of 26 responses from the public. The final PON was issued on May 1, 1989. The final PON took into consideration the public comments on the draft PON. Notification of its availability was published in the *Federal Register* and the *Commerce Business Daily* on March 8, 1989.

The Office of Clean Coal Technology/Fossil Energy has a Source List of over 1600 companies and organizations who have expressed an interest in the Clean Coal Technology Program. In addition to the parties who requested copies of the two previous CCT solicitations, the Source List contained those who responded to the *Federal Register and Commerce Business Daily* notices announcing the draft and final PONs for CCT-III, and those who attended the public meetings held shortly before the draft PON was issued. Each person on the Source List received copies of the draft and final PONs.

To enable prospective proposers to gain a better understanding of the objectives of the CCT-III PON and to receive answers to written questions submitted regarding the PON, a Preproposal Conference was held in Washington, D.C. on May 18, 1989. Attendees were given the opportunity to submit written questions during the meeting. Prospective proposers received three mailings after the PON was issued:

(1)	The Preproposal Conference Proceedings (Including Questions and Answers #'s 1-87)	May 31, 1989
(2)	Additional Questions and Answers (#'s 88-92)	July 12, 1989
(3)	Additional Questions and Answers (#'s 93-98)	August 8, 1989

[1]*Summary Proceedings: Public Meetings for Views and Comments on the Conduct of the 1989 Clean Coal Technology Solicitation,* Report No. DOE/FE-0140, U.S. Department of Energy, July, 1989; *Summary Proceedings: Meeting on Increasing Western Participation in the 1989 Clean Coal Technology Solicitation*, Report No. DOE/FE-0113, December, 1988

THE EVALUATION PROCESS

In announcing the selection of proposals for negotiation leading to awards, the Source Selection Official, in his Selection Statement, provided an overview of the process used to evaluate the proposals received. Evaluations were performed by the Source Evaluation Board (SEB). The following description of the evaluation process is excerpted from the Selection Statement.[2]

1. PON Objective

As stated in PON Section 1.2, the objective of the CCT-III solicitation was to obtain "proposals to conduct cost shared Clean Coal Technology projects to demonstrate innovative, energy efficient technologies that are capable of being commercialized in the 1990's. These technologies must be capable of (1) achieving significant reductions in the emissions of sulfur dioxide and/or the oxides of nitrogen from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner."

2. Qualification Review

The PON established seven Qualification Criteria and provided that, "In order to be considered in the Preliminary Evaluation Phase, a proposal must successfully pass Qualification." The Qualification Criteria were as follows:

(a) The proposed demonstration project or facility must be located in the United States.

(b) The proposed demonstration project must be designed for and operated with coal(s) from mines located in the United States.

(c) The proposer must agree to provide a cost share of at least 50 percent of total allowable project cost, with at least 50 percent in each of the three project phases.

(d) The proposer must have access to, and use of, the proposed site and any proposed alternate site(s) for the duration of the project.

(e) The proposed project team must be identified and firmly committed to fulfilling its proposed role in the project.

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[2]*Selection of Proposals for the Demonstration of Clean Coal Technologies; Program Opportunity Notice DE-PS01-89FE61825*, signed December 19, 1989 by the Source Selection Official, Jack S. Siegel, Deputy Assistant Secretary for Coal Technology, pages 3-8.

(f) The proposer agrees that, if selected, it will submit a "Repayment Plan" consistent with PON Section 7.4.

(g) The proposal must be signed by a responsible official of the proposing organization authorized to contractually bind the organization to the performance of the Cooperative Agreement in its entirety.

2. Preliminary Evaluation

The PON provided that a Preliminary Evaluation would be performed on all proposals that successfully passed the Qualification Review. In order to be considered in the Comprehensive Evaluation phase, a proposal must be consistent with the stated objective of the PON, and must contain sufficient business and management, technical, cost, and other information to permit the Comprehensive Evaluation described in the solicitation to be performed.

3. Comprehensive Evaluation

Technical Evaluation Criteria

The Technical Evaluation Criteria were divided into two major categories: (1) the Demonstration Project Factors were used to assess the technical feasibility and likelihood of success of the project, and (2) the Commercialization Factors were used to assess the potential of the proposed technology to reduce emissions from existing facilities, as well as to meet future energy needs through the environmentally acceptable use of coal, and the cost effectiveness of the proposed technology in comparison to existing technologies.

The Demonstration Project Factors are identified below:

(a) Technical Readiness

(b) Adequacy, Appropriateness, and Relevance of Demonstration

(c) Environmental, Health, Safety, Socioeconomic, and other Site-Related Aspects

(d) Technical and Management Approach and Organizational Capability

The Commercialization Factors are identified below:

(a) Environmental Performance at Existing Facilities

(b) Environmental Performance While Addressing Future Energy Needs

(c) Commercialization Plan

Business and Management Evaluation Criteria

The PON established the following Business and Management Evaluation Criteria:

(a) Funding Plan, Capability to Fund the Demonstration

(b) Financial Commitment to the Project

Cost Evaluation

The PON provided that the Cost Estimate would be evaluated to determine the reasonableness of the proposed cost. Proposers were advised that this determination "will be of minimal importance to the selection," and that a detailed cost estimate would be requested after selection. Proposers were cautioned that if the total project cost estimated after selection is greater than the amount specified in the proposal, DOE would be under no obligation to provide more funding than had been requested in the proposer's Cost Sharing Plan.

Relative Importance of Evaluation Criteria

The PON indicated that the Technical Evaluation criteria are three times as important as the Business and Management Evaluation criteria. The PON provided that the Technical Evaluation criteria would be given the following weights:

Demonstration Project Factors			
Technical Readiness	30%		
Adequacy, Appropriateness, and Relevance of the Demonstration	20%		
EHSS and other Site-Related Aspects	5%		
Technical and Management Approach and Organizational Capability	5%		
SUBTOTAL - Demonstration Project Factors		60%	
Commercialization Factors			
Environmental Performance at Existing Facilities	20%		
Environmental Performance While Addressing Future Energy Needs	10%		
Commercialization Plan	10%		
SUBTOTAL - Commercialization Factors		40%	
TOTAL			100%

The PON advised proposers that the evaluation would result in a numerical score for each proposal against each of the Technical Evaluation criteria.

With respect to the Business & Management Evaluation criteria, the PON specified that the Funding Plan, Capability to Fund the Demonstration criterion would be somewhat more important than the Financial Commitment to the Project criterion. Further, the evaluation in this category would result in adjectival ratings of each proposal against each of the Business & Management Evaluation criteria. The SEB's evaluation plan provided that a consensus adjectival rating of the Business & Management proposals would be prepared which would be the appropriately weighted average of the adjectival ratings for both criteria.

Given the large number of proposals received and the short statutory deadline for completing the evaluations and making the selection decision, no written or oral discussions with proposers were conducted.

Program Policy Factors

The PON advised proposers that the following program policy factors could be used by the Source Selection Official to select a range of projects that would best serve program objectives:

(a) The desirability of selecting projects that collectively represent a diversity of methods, technical approaches, and applications.

(b) The desirability of selecting projects in this solicitation that contribute to near term reductions in transboundary transport of pollutants by producing an aggregate net reduction in emissions of sulfur dioxide and/or the oxides of nitrogen.

(c) The desirability of selecting projects that collectively utilize a broad range of U.S. coals and are in locations which represent a diversity of EHSS, regulatory, and climatic conditions.

(d) The desirability of selecting projects in this solicitation that achieve a balance between (1) reducing emissions and transboundary pollution and (2) providing for future energy needs by the environmentally acceptable use of coal or coal-based fuels.

The word "collectively" as used in the foregoing program policy factors, was defined to include projects selected in this solicitation and prior clean coal solicitations, as well as other ongoing demonstrations in the United States.

Other Considerations

The PON provided that in making selections, DOE would consider giving preference to projects located in states for which the rate-making bodies of those states treat the Clean Coal Technologies the same as pollution control projects or technologies. This consideration could be used as a tie breaker if, after application of the evaluation criteria and the program policy factors, two projects receive identical evaluation scores and remain essentially equal in value. This consideration would not be applied if, in doing so, the regional geographic distribution of the projects selected would be altered significantly.

4. National Environmental Policy Act (NEPA) Strategy

The strategy for compliance with the National Environmental Policy Act of 1969 that was developed for the Clean Coal Technology Program was continued in CCT-III. It is consistent with the Council on Environmental Quality (CEQ) NEPA regulations (40 CFR Parts 1500-1508) and the DOE guidelines for compliance with NEPA (52 F.R. 47662, December 15, 1987). As part of the evaluation and selection process, this strategy resulted in the publication and consideration of a Programmatic Environmental Impact Statement (DOE/EIS-0146, November 1989), and the SEB's report on its project-specific environmental review of each of the 48 proposals received in response to the PON. DOE will prepare project-specific NEPA documentation for each selected demonstration project.

Programmatic Environmental Impact Statement

On November 3, 1989, DOE issued "Clean Coal Technology Demonstration Program: Final Programmatic Environmental Impact Statement," DOE/EIS-0146 (PEIS). The U.S. Environmental Protection Agency (EPA) announced the availability of this document in a notice published in the *Federal Register* on November 14, 1989 (54 F.R. 47127). The Record of Decision approving the PEIS was published in the *Federal Register* on December 14, 1989 (54 F.R. 51313)

The proposed action evaluated in the PEIS was the selection of projects, proposed under the PON, to demonstrate Clean Coal Technologies. The PEIS analysis included an evaluation of environmental consequences of widespread commercialization of successfully demonstrated Clean Coal Technologies. The PEIS evaluates the environmental impacts of 22 types of clean coal technologies. To summarize very briefly, the PEIS concluded:

> ...[R]epowering and retrofit--New Source Performance Standards (NSPS) capable clean coal technologies could lead to a significant reduction in SO_2 and NO_x ...in 2010. Repowering technologies are the only category in which all technologies could lead to a measurable reduction in CO_2. The amount of solid waste generated ...varies with each technology, ranging from a maximum increase of 23% to an equivalent decrease relative to that of the no-action alternative. Commercialization of the clean coal technologies would have a beneficial effect on air quality and could contribute to amelioration of current impacts of acidic deposition. Impacts on CO_2 emissions from clean coal technologies would be a direct function of the quantity of coal burned; thus, if commercialization of clean coal technologies results in changed use of coal resources, the technologies would contribute to a change in CO_2 emissions. PEIS, at iii.

CCT-III Pre-Selection Project-Specific Environmental Review

The second element of the NEPA strategy available was the SEB's December 1, 1989 report, "Clean Coal Technology III Pre-Selection Project-Specific Environmental Review." This report, developed for internal agency use only, evaluated the specific environmental, health, safety, and socioeconomic (EHSS) effects associated with each of the proposed demonstration projects. The SEB's report summarized the strengths and weaknesses of each proposal relative to the EHSS criteria, discussed any available alternative sites and/or processes, and describes potential environmental impacts, mitigation strategies, and permitting requirements.

SELECTION DECISION

After considering the evaluation criteria, the program policy factors, and the NEPA strategy as stated in the PON, the Source Selection Official selected 13 projects as best furthering the objectives of the CCT-III PON. These projects are listed in Exhibit 3. Brief summaries follow for each selected project. Abstracts of all proposals received are contained in Appendix B.

1. AirPol Inc.

AirPol Inc., along with its parent company, FLS miljo of Denmark, the Tennessee Valley Authority and other future sponsors, proposes to demonstrate the applicability of gas suspension absorption (GSA) for Flue Gas Desulfurization on U.S. coals. The technology would be most suitable for FGD retrofit to existing industrial and small utility coal-fired boilers.

The heart of the GSA system is a vertical reactor where flue gas is contacted with a suspended solids mixture consisting of lime, reaction products and fly ash. Most of the solids are recycled to the reactor via a cyclone while the exit gas stream passes through an electrostatic precipitator or baghouse prior to release to the atmosphere. The lime slurry is injected at the bottom of reactor and is regulated with a variable speed pump controlled by acid gas concentration measurements in the inlet and outlet gas streams. Dilution water is controlled by on-line measurements of exit flue gas temperature. The solids collected from the suspended particulate control device and cyclone unit are recombined and are disposed in a landfill. The objective of this project is to demonstrate the applicability of GSA to U.S. coal.

2. Air Products and Chemicals, Inc. and Dakota Gasification Company

The proposed project is to design, construct and operate a 500 tons per day (TPD) methanol facility. The proposed project would use the "Liquid Phase Methanol Process" (LPMEOH) to produce methanol from a coal-derived synthesis gas. The demonstration project would be located at the existing Great Plains coal gasification facility in Mercer County, North Dakota.

The LPMEOH technology was developed specifically to be used with integrated gasification combined cycle (IGCC) facilities to reduce capital costs and to improve flexibility of electric power production by storing energy in the form of methanol. Methanol produced at Great Plains by the LPMEOH process will be used in tests to demonstrate its suitability for boiler, turbine and transportation fuel applications.

3. Alaska Industrial Development and Export Authority

The Alaska Industrial Development and Export Authority (AIDEA) proposes to build the Healy Cogeneration Project, a new coal fired power and process heat generating facility at a site near Healy, Alaska. The facility will be based on a new power plant design which features innovative integration of the advanced TRW slagging combustor and a heat recovery system coupled with both high and low temperature emission control processes.

The proposed demonstration facility will be an important step toward fuel diversification of Alaska's electrical energy system which currently relies principally on oil. The project will utilize 300,000 tons/yr of blended Alaskan sub-bituminous and waste coal having 0.2% sulfur and 18% ash, and will produce 50 MWe net of electrical power with potential to provide process heat to an adjacent coal drying pilot facility. In the demonstration phase, additional Alaskan coals of various quality will also be tested.

4. The Babcock and Wilcox Company

The objective of the proposed project is to demonstrate the cost-effectiveness of a newly developed low NO_x cell burner in reducing NO_x emissions from cell-fired utility boilers. Such boilers produce approximately 20% of the NO_x emissions from all U. S. sources.

The demonstration project would be a 605 MWe retrofit at the Dayton Power and Light Company's Stuart Station, Unit No. 4, in Aberdeen, Ohio. The demonstration project will replace all 24 two-nozzle cell burners with the newly developed low NO_x cell burners. NO_x emission and performance data before and after the conversion would be acquired and analyzed to determine NO_x reduction and impact on boiler performance.

5. Bechtel Corporation

The confined zone dispersion (CZD) process involves injecting lime slurry into the flue gas duct ahead of the electrostatic precipitator (ESP). The process produces a non-toxic dry waste. In this proposed CZD demonstration, a new duct will assure a residence time of about 2 seconds. The proposed program includes a 6-month test with different types of absorbents and atomizers to verify the effect on SO_2 removal and the capability of the existing ESP for control of particulate emission and opacity. After this testing period, a one-year continuous demonstration, fully automated and integrated with the regular operation of the power plant, will be conducted.

6. Bethlehem Steel Corporation

The proposed project is to design, construct, and operate a retrofit to a blast furnace producing 7500 tons of hot iron per day. The demonstration will be conducted at the Burns Harbor, Indiana, steel mill of Bethlehem Steel Corporation.

The technology to be demonstrated employs granular coal in the air blast fed to a blast furnace used in iron production. Using coal in the air blast would reduce the amount of coke required in ironmaking. If the demand for coke were substantially reduced, there could be a significant reduction in SO_2, NO_x, and other noxious emissions from coke ovens.

7. CRSS Capital, Inc., and TECO Power Services Corporation

The proposed project is to design, construct and operate a 120 MW Integrated Gasification Combined Cycle (IGCC) plant at the site of an existing utility plant in Tallahassee, Florida. The demonstration project will include commercially available Lurgi Mark IV dry bottom gasifiers, a GE MS series gas turbine and a GE developmental hot gas clean up system. The electric power generated from the demonstration plant will be purchased, in whole or in part, by the City of Tallahassee.

8. Dairyland Power Cooperative

Dairyland proposes to construct and operate a Pressurized Circulating Fluid Bed coal combustor with a combined cycle gas turbine to produce steam to repower two older existing turbine generators. The estimated capability of the repowered units will be 40 megawatts of electricity. The PCFB chosen for installation will be designed and furnished by Pyropower Corporation, San Diego, California.

In this fluidized bed system, coal combustion occurs as the burning particles "float" as a suspended mixture in the combustion air. Limestone, introduced with the coal, reacts chemically during combustion to reduce the emission of sulfur dioxide. The relatively low operating temperature within the combustor will serve to diminish the release of oxides of nitrogen (NO_x).

9. ENCOAL Corporation

The proposed project is to design, construct and operate a 1000 TPD demonstration plant using the liquids from coal (LFC) process technology. The demonstration project would be at the Triton Coal Company's Buckskin Mine in Campbell County, Wyoming.

The LFC process involves the mild gasification of coal at moderate temperatures and near atmospheric pressure to produce a solid, Process Derived Fuel (PDF), and a liquid, Coal Derived Liquid (CDL). The LFC process chemically modifies the feed coal to generate the two new fuel forms and also removes most of the moisture and some of the sulfur, depending on the sulfur form in the feed coal. The proposer claims that the PDF and CDL products are suitable for use at existing power plants, and that the CDL has potential use as refinery feedstock for petrochemicals and transportation fuels.

10. Energy and Environmental Research Corporation

The proposed project is to demonstrate the combination of Gas Reburning and Low NO_x Burners in a wall-fired utility boiler. The demonstration project would be at the Public Service Company of Colorado's (PSCCO's) Cherokee Power Station Unit No. 3, in Adams County, Colorado.

Gas Reburning involves cofiring 15 to 20 percent natural gas which creates a slightly fuel rich zone in the furnace so that oxides of nitrogen produced by the coal combustion are "reburned" and reduced to molecular nitrogen. Low NO_x Burners reduce the production of oxides of nitrogen through a combination of coal and air injection staging, and rate of coal/air mixing. Low NO_x Burners are fully commercial for wall-fired boiler applications. The proposer claims the combination of Gas Reburning and Low NO_x Burners is compatible and synergistic, and will achieve greater NO_x reduction than the individual technologies.

11. LIFAC - North America, a joint venture of Tampella Ltd., and ICF Kaiser Engineers, Inc.

The proposed project is to design, construct, and operate a LIFAC flue gas cleaning system for removing sulfur dioxide at a 60 MW utility boiler. The demonstration project would be a retrofit application at Richmond (Indiana) Power and Light's Whitewater Valley Unit No. 2 generating station.

The LIFAC technology provides the ability to reduce sulfur dioxide emissions 75% to 85%. Limestone is injected into the upper furnace with a humidification chamber installed between the air preheater and ESP to complete the removal process.

12. MK-Ferguson Company

The proposed project is to design, construct, and operate a regenerable flue gas cleaning system employing the NOXSO process on an existing 115 MW coal-fired boiler. The demonstration would take place at Ohio Edison's Niles station.

The NOXSO process employs a porous solid adsorbent that removes SO_2 and NO_x from flue gas. Subsequently the adsorbed pollutants are removed in a sorbent regeneration step. Sulfur is recovered either in the elemental form or as sulfuric acid, both marketable products. Nitrogen oxides are recycled to the boiler and converted to molecular oxygen and nitrogen.

13. Public Service Company of Colorado

The proposed project is to demonstrate reductions in SO_2 and NO_x emissions by using a combination of technologies: Low NO_x burners and urea injection for NO_x reductions, and dry sorbent injection (sodium and calcium sorbents) for SO_2 reductions. The demonstration site would be the Public Service Company of Colorado's (PSCCO's) Arapahoe Steam Electric Generating Station, Unit 4, located in Denver County, Colorado.

Commercially available Low NO_x Burners are capable of 40% to 50% reduction of NO_x. Low NO_x Burners with overfired air are capable of 70% reduction of NO_x. Urea injection in full-scale tests have shown 35% to 70% reduction on NO_x. Both sodium and calcium dry sorbent injection in full-scale tests have shown 70% reduction of SO_2. The proposer claims that the combined demonstration technologies should be capable of greater than 70% reductions in NO_x and SO_2.

Exhibit 3

CLEAN COAL TECHNOLOGY III PROJECTS
SELECTED BY THE DEPARTMENT OF ENERGY

Proposer	Technical Approach	Project Location
Airpol, Inc.	Flue Gas Clean-Up/Sorbent Injection; recycle of unreacted lime to improve sulfur capture efficiency	West Paducah, McCracken County, Kentucky
Air Products and Chemicals, Inc. and Dakota Gasification Company	Indirect Liquefaction; liquid phase methanol production	Beulah, Mercer County, North Dakota
Alaska Industrial Development and Export Authority	Slagging Combustion; advanced combustor with high and low temperature emission control	Healy, Alaska
The Babcock & Wilcox Company	Low NO_x Burner; replacement burner for cell-fired boilers	Aberdeen, Adams County, Ohio
Bechtel Corporation	Flue Gas Clean-Up; confined zone dispersion process, injects lime slurry ahead of solid removal step	Seward, Indiana County, Pennsylvania
Bethlehem Steel Corporation	Direct coal injection into blast furnace	Burns Harbor, Porter County, Indiana

Exhibit 3 (Continued)

CLEAN COAL TECHNOLOGY III PROJECTS
SELECTED BY THE DEPARTMENT OF ENERGY

Proposer	Technical Approach	Project Location
CRSS Capital, Inc. and TECO Power Services Corporation	Integrated Gasification Combined-Cycle; fixed bed gasifier with hot gas clean-up	Tallahassee, Leon County, Florida
Dairyland Power Cooperative	Pressurized Fluidized Bed Combustion; circulating fluid bed	Alma, Buffalo County, Wisconsin
ENCOAL Corporation	Mild Gasification; low pressure pyrolysis to produce liquids and char	Gillette, Campbell County, Wyoming
Energy and Environmental Research Corporation	Advanced Combustors; gas reburn for NO_x control	Denver, Adams County, Colorado
LIFAC - North America, joint venture of Tampella Ltd. and ICF Kaiser Engineers, Inc.	Flue Gas Clean-Up/Sorbent Injection; limestone injection	Richmond, Wayne County, Indiana
MK-Ferguson Company	Flue Gas Clean-Up; regenerble desulfurization	Niles, Trumbull County, Ohio
Public Service Company of Colorado	Flue Gas Clean-Up/Low NO_x Burner; low NO_x burners with urea injection for NO_x control and dry sorbent injection for SO_2 control	Denver, Denver County, Colorado

III. DESCRIPTIONS OF CCT-III PROPOSALS RECEIVED

Forty eight proposals were received in response to the CCT-III PON. The proposals exhibited substantial diversity in terms of such dimensions as technologies embraced, project size and duration, geographic distribution, type of coal used, and environmental and commercialization characteristics. The following discussion provides an overview of the technologies and the geographic distribution of the proposals received. This discussion provides only limited information on the characteristics of the proposal; the reader is referred to Appendix B for summary descriptions of each proposed project.

TECHNOLOGIES PROPOSED

The proposed projects generally can be assigned to one of the major advanced technology categories: Atmospheric Fluidized Bed Combustion (AFB), Advanced Combustion (COM), Flue Gas Clean-Up (FGC), Industrial (IND), Integrated Gasification Combined-Cycle (IGCC), New Fuel Forms (NFF), and Pressurized Fluidized Bed Combustion (PFB). These categories and the number of proposals received in each category are shown in Exhibit 4.

Exhibit 4

Distribution of Proposals by Technology Category

Technology Category	Code	Number of Proposals
Atmospheric Fluidized Bed Combustion	AFB	6
Advanced Combustion	COM	6
Flue Gas Clean-Up	FGC	13
Industrial	IND	6
Integrated Gasification Combined-Cycle	IGCC	3
New Fuel Form	NFF	12
Pressurized Fluidized Bed Combustion	PFB	2

Exhibit 5 identifies the proposer and technical approach associated with each proposal.

Exhibit 5

PROPOSED TECHNICAL APPROACHES BY TECHNOLOGY CATEGORY

Technology	Proposer	Technical Approach
Advanced Combustion	Alaska Industrial and Export Authority	Slagging combustor; advanced combustor with high and low temperature emission control
	The Babcock and Wilcox Company	Low NO_x Burner; replacement burner for cell-fired boilers
	Coal Tech Corp.	Low NO_x Burner; air cooled combustor
	Energy and Environmental Research Corporation	Advanced combustion; gas reburn for NO_x control
	Energy Systems Associates	Advanced combustion; gas reburn for NO_x control
	Pedco, Incorporated	Advanced combustion; rotary kiln combustor

Exhibit 5 (Continued)

PROPOSED TECHNICAL APPROACHES BY TECHNOLOGY CATEGORY

Technology	Proposer	Technical Approach
Atmospheric Fluidized Bed Combustion	Arctic Slope Regional Corporation	Circulating fluid bed with external bed heat exchangers for power production and district heating
	City of Independence, MO	Circulating fluid bed with external bed heat exchanger
	L.C. Energy Consortium	Dual fluid bed system
	Manitowoc Public Utilities	Test of high chlorine coals
	Modular Power Plant Limited Partnership	Advanced fluid bed for combustion of coal waste
	Westwood Energy Properties Ltd. Partnership	Circulating fluid bed
Pressurized Fluidized Bed Combustion	Dairyland Power Cooperative	Circulating fluid bed
	Public Service Company of Indiana, Inc.	Coal-fired carbonizer with circulating fluid bed

Exhibit 5 (Continued)

PROPOSED TECHNICAL APPROACHES BY TECHNOLOGY CATEGORY

Technology	Proposer	Technical Approach
Flue Gas Clean-Up	Airpol, Inc.	Sorbent Injection; recycle of unreacted lime to improve sulfur capture efficiency
	Bechtel Corporation	Confined zone dispersion process; injects lime slurry ahead of solid removal step
	Corn Products, a unit of CPC International Inc.	Sorbent Injection; entrained combustion, furnace sorbent injection with fly ash reinjection
	Duke Power	Sorbent Injection; dry injection of hydrated lime for SO_2 and particulate emission control
	Ebara Environmental Corporation	Electron beam radiation of flue gas to remove SO_2 and NO_x
	Energy Partners, Inc.	Lime Injection Multi Stage Burner (LIMB) micronized coal system
	LIFAC - North America, a joint venture of Tampella Ltd. and ICF Kaiser Engineers	Sorbent Injection; dry injection of hydrated lime for SO_2 and particulate emission control

Exhibit 5 (Continued)

PROPOSED TECHNICAL APPROACHES BY TECHNOLOGY CATEGORY

Technology	Proposer	Technical Approach
Flue Gas Clean-Up	Lin Technologies, Inc.	Sorbent Injection; test solid waste for wide scale utilization
	MK-Ferguson Company	Regenerable desulfurization
	Public Service Company of Colorado	Low NO_x Burner; low NO_x burners with urea injection for NO_x control and dry sorbent injection for SO_2 control
	Ralph M. Parsons Company	Catalytic reduction of flue gas to recover sulfur
	Sanitech, Inc.	Novel sorbent for SO_2 and NO_x removal
	University of Cincinnati	Sorbent Injection; spray dryer for SO_2 removal

Exhibit 5 (Continued)

PROPOSED TECHNICAL APPROACHES BY TECHNOLOGY CATEGORY

Technology	Proposer	Technical Approach
Integrated Gasification Combined-Cycle	CRSS Capital, Inc. and TECO Power Services Corporation	Fixed bed gasifier with hot gas clean-up
	LBD and Richmond, Indiana Industrial Associates	2-Step gasification approach
	Midland Cogeneration Venture and California Carbide Company	High temperature, low residence time entrained flow reactor with in-bed sulfur capture
Industrial	Bethlehem Steel Corporation	Direct coal injection into blast furnace
	CYCLEAN, INC.	Advanced coal preparation; microwave radiation for removal of pyrites
	Energotechnology Corp. and Westmorland Energy, Inc.	Coal Cleaning; Atmospheric Fluidized Bed
	Geneva Steel	Iron making; direct iron reduction to eliminate coke production
	International Fuel Cells Corporation	Fuel cells; molten carbonate fuel cells
	M-C Power Corporation	Fuel cells; molten carbonate fuel cells

Exhibit 5 (Continued)

PROPOSED TECHNICAL APPROACHES BY TECHNOLOGY CATEGORY

Technology	Proposer	Technical Approach
New Fuel Form	Air Products and Chemicals, Inc. and Dakota Gasification Company	Indirect liquefaction; liquid phase methanol productions
	Calderon Energy Company	Mild Gasification; pressurized pyrolysis for production of methanol and char
	Char-Fuels Associates Limited Partnership	Mild Gasification; high pressure hydrodisproportionation process for production of liquids and char
	ENCOAL Corporation	Mild Gasification; low pressure pyrolysis to produce liquids and char
	Frontier Energy Corporation	Coal-oil coprocessing
	LBD and Industrial Associates	Mild Gasification; first step of a two step gasification process to produce clean gas and char
	LBD and Industrial Associates	Mild Gasification; second step of two step process to produce clean medium Btu gas without use of oxygen

Exhibit 5 (Continued)

PROPOSED TECHNICAL APPROACHES BY TECHNOLOGY CATEGORY

Technology	Proposer	Technical Approach
New Fuel Form	Marshall Owen Enterprises, Inc.	Mild Gasification; low temperature carbonization to produce a solid product for the residential market
	Metrix International Corporation	Coal Cleaning; production of a coal log for the residential market
	Minnesota Power & Light Company	Advanced Coal Preparation; moderate temperature, high pressure hydrothermal reforming
	Peabody Holding Company	Mild Gasification; two stage pyrolysis to produce liquids and char which is used for power production
	University of North Texas	Atmospheric Fluidized Bed Combustion; cofiring of coal with refuse derived fuel

GEOGRAPHIC DISTRIBUTION

The proposed projects in the 48 proposals covered each of the major coal producing regions. Exhibit 6 lists the geographic location of the project site for each proposal submitted. Exhibit 7 identifies the project site locations of the 13 projects selected for CCT-III.

Exhibit 6

GEOGRAPHIC LOCATIONS OF PROJECT SITES

State	Proposer	Project Site
Alaska	Alaska Industrial Development and Export Authority	Healy, Alaska
	Arctic Slope Regional Corporation	Nome and Kotzebue, Alaska and Western Arctic Coal Region
California	International Fuel Cells Corporation	Montebello, Los Angeles County, California
Colorado	Energy and Environmental Research Corporation	Denver, Adams County, Colorado
	Marshall Owen Enterprises, Inc.	Between Paonia & Somerset Near Bowie, Delta County, Colorado
	Public Service Company of Colorado	Denver, Denver County, Colorado

Exhibit 6 (Continued)

GEOGRAPHIC LOCATIONS OF PROJECT SITES

State	Proposer	Project Site
Florida	CRSS Capital, Inc. and TECO Power Services Corporation	Tallahassee, Leon County, Florida
Illinois	Corn Products, a Unit of CPC International Inc.	Bedford Park, Cook County, Illinois
	CYCLEAN INC.	Georgetown, Texas and Pearl, Illinois Williamson County, Texas and Pike County
	Energy Partners, Inc.	Rochelle, Ogle County, Illinois
	M-C Power Corporation	Chicago, Cook County, Illinois
	Peabody Holding Company	Carbondale, Jackson County, Illinois
	University of Cincinnati	Argonne, DuPage County, Illinois

Exhibit 6 (Continued)

GEOGRAPHIC LOCATIONS OF PROJECT SITES

State	Proposer	Project Site
Indiana	Bethlehem Steel Corporation	Burns Harbor, Porter County, Indiana
	Ebara Environmental Corporation	Indianapolis, Marion County, Indiana
	LBD and Richmond, Indiana Industrial Associates	Richmond, Wayne County, Indiana
	LBD and Industrial Associates	Evansville, Warrick & Pike Counties, Indiana
Indiana	LIFAC - North America, a joint venture of Tampella Ltd, and ICF Kaiser Engineers, Inc.	Richmond, Wayne County, Indiana
	Lin Technologies, Inc.	Richmond, Richmond County, Indiana
	Public Service Company of Indiana, Inc.	Terre Haute, Vigo County, Indiana
Kentucky	Airpol, Inc.	West Paducah, McCracken County, Kentucky

Exhibit 6 (Continued)

GEOGRAPHIC LOCATIONS OF PROJECT SITES

State	Proposer	Project Site
Louisiana	LBD and Industrial Associates	Lake Charles, Calcasieu Parish County, Louisiana
Michigan	Midland Cogeneration Venture and California Carbide Company	Midland, Midland County, Michigan
Minnesota	University of North Texas	Virginia, St. Louis County, Minnesota
Missouri	City of Independence, Missouri	Independence, Jackson County, Missouri
New Hampshire	L.C. Energy Consortium	North Rochester, Stratford County, New Hampshire
North Carolina	Duke Power Company	Terrell, Catawba County, North Carolina

Exhibit 6 (Continued)

GEOGRAPHIC LOCATIONS OF PROJECT SITES

State	Proposer	Project Site
North Dakota	Air Products and Chemicals, Inc. and Dakota Gasification Company	Beulah, Mercer County, North Dakota
	Minnesota Power & Light Company	Center, Oliver County, North Dakota
Ohio	The Babcock and Wilcox Company	Aberdeen, Adams County, Ohio
	Calderon Energy Company	Bowling Green, Wood County, Ohio
	Frontier Energy Corporation	Painesville Township, Lake County, Ohio
	MK-Ferguson Company	Niles, Trumbell County, Ohio
	Pedco, Incorporated	Cincinnati, Hamilton County, Ohio
	Ralph M. Parsons Company	St. Mary's, Auglaize County, Ohio
	Sanitech, Inc.	Kent, Portage County, Ohio

Exhibit 6 (Continued)

GEOGRAPHIC LOCATIONS OF PROJECT SITES

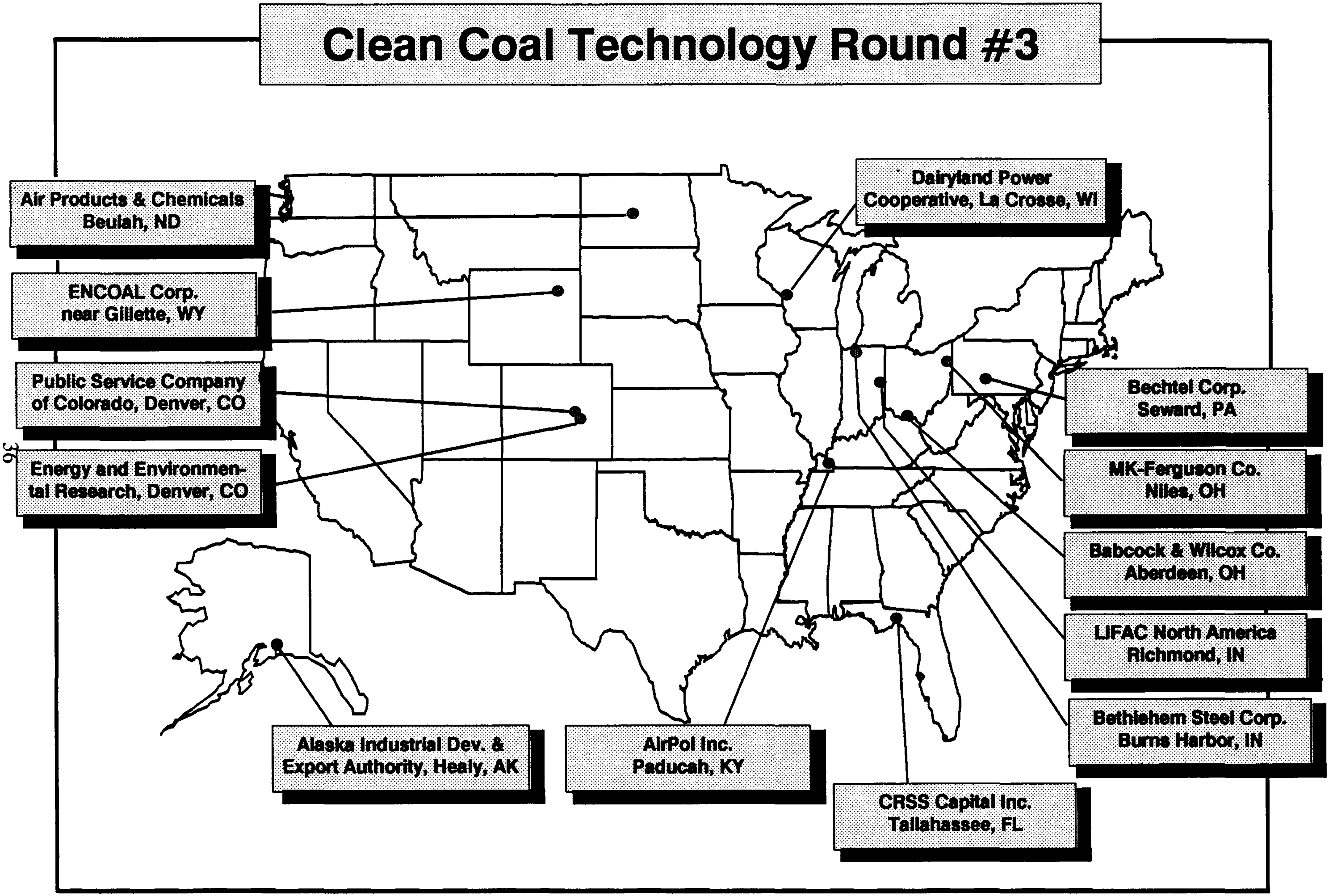
State	Proposer	Project Site
Pennsylvania	Bechtel Corporation	Seward, Indiana County, Pennsylvania
	Coal Tech Corp.	Lester or Oaks, Delaware/ Montgomery County, Pennsylvania
	Energy Systems Associates	Elrama, Washington / Allegany County, Pennsylvania
	Modular Power Plant Limited Partnership	Homer City, Indiana County, Pennsylvania
	Westwood Energy Properties Ltd. Partnership	Frailey, Schuykill County, Pennsylvania

Exhibit 6 (Continued)

GEOGRAPHIC LOCATIONS OF PROJECT SITES

State	Proposer	Project Site
West Virginia	CRSS Capital, Inc. and TECO Power Services Corporation	Hillsboro, Pocahontas County, West Virginia
	Energotechnology Corp. Westmorland Energy, Inc.	Eccles, Raleigh County, West Virginia
	Metrix International Corporation	Charleston, Kanawha County, West Virginia
Wisconsin	Dairyland Power Cooperative	Alma, Buffalo County, Wisconsin
	Manitowoc Public Utilities	Manitowoc, Manitowoc County, Wisconsin
Utah	Geneva Steel	Vineyard City, Utah County, Utah
Wyoming	Char Fuels Associates Limited Partnership	Glenrock, Converse County, Wyoming
	ENCOAL Corporation	Gillette, Campbell County, Wyoming

Exhibit 7


Clean Coal Technology Round #3
Air Products & Chemicals Beulah, ND
ENCOAL Corp. near Gillette, WY
Public Service Company of Colorado, Denver, CO
Energy and Environmental Research, Denver, CO
Alaska Industrial Dev. & Export Authority, Healy, AK
AirPol Inc. Paducah, KY
CRSS Capital Inc. Tallahassee, FL
Dairyland Power Cooperative, La Crosse, WI
Bechtel Corp. Seward, PA
MK-Ferguson Co. Niles, OH
Babcock & Wilcox Co. Aberdeen, OH
LIFAC North America Richmond, IN
Bethlehem Steel Corp. Burns Harbor, IN

IV. ENVIRONMENTAL CONSIDERATIONS

The Clean Coal Technology Demonstration Program has a strong environmental orientation. The objective of the CCT-III solicitation is to demonstrate innovative, energy efficient technologies that can be commercialized in the 1990s. As stated in PON Section 1.2, "these technologies must be capable of (1) achieving significant reductions in the emissions of SO_2 and/or NO_x from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner." A number of approaches have been implemented to keep environmental considerations an integral part of clean coal demonstrations. These approaches involve two kinds of environmental activities. One involves the NEPA strategy, and the other involves monitoring environmental and health impacts and performance. These two types of activities are explained below.

NEPA STRATEGY

The overall strategy for compliance with NEPA includes both programmatic and project specific environmental impact considerations, during and subsequent to the selection process. These have and will ensure that environmental factors are fully evaluated and integrated into the decision-making process in order to satisfy DOE's NEPA responsibilities.

As part of the evaluation and selection process, proposers were required to submit both programmatic and project-specific environmental data as a discrete part of the proposal. DOE independently evaluated the environmental data and analyses submitted by proposers, developed supplemental information, and performed analyses as necessary to support reasoned decision-making. Major elements of the NEPA strategy are summarized below.

Programmatic Environmental Impact Statement

DOE prepared a Programmatic Environmental Impact Statement (PEIS) on the Clean Coal Technology Demonstration Program which was provided to the Source Selection Official for his consideration in selecting CCT-III projects. The final PEIS was published on November 3, 1989, drawing upon a draft PEIS published in June 1989, and the Programmatic Environmental Impact Analysis completed for the CCT-II solicitation and published in September 1988.[3] Comments on the scope of the PEIS were sought in a *Federal Register* notice dated February 7, 1989. The PEIS evaluates two alternatives: "no action," which assumes the CCT Program is not continued and conventional coal-fired technologies with conventional flue gas desulfurization controls continue to be used; and a "proposed action," which assumes that CCT Program projects are selected for funding and successfully

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[3] *Clean Coal Technology Demonstration Program Final Programmatic Environmental Impact Statement*, U.S. Department of Energy, November, 1989; *Clean Coal Technology Demonstration Program Draft Programmatic Environmental Impact Statement*, U.S. Department of Energy, June, 1989; *Innovative Clean Coal Technology Programmatic Environmental Impact Analysis*; U.S. Department of Energy, September, 1988.

demonstrated technologies undergo widespread commercialization by the year 2010. The analyses of environmental consequences focuses on changes to four parameters of concern: SO_2, NO_x, CO_2, and solid wastes. An upper bound of change to each of these four parameters was estimated for each of 22 generic clean coal technologies separately, assuming full penetration of potential markets.

Comment letters were received on the draft PEIS. DOE responses to these comments were provided in an appendix to the final document, and the text of the final PEIS was modified where appropriate. After the required 30-day waiting period following issuance of the final PEIS, a Record of Decision to proceed with the CCT Program was published in the *Federal Register* on December 14, 1989 (54 F.R. 51313).

Project-Specific Environmental Review

For proposals that underwent comprehensive evaluation, DOE prepared and considered, before the selection of proposals, an environmental impact analysis that focused on environmental issues pertinent to decision-making. The analysis summarized the strengths and weaknesses of each proposal against the environmental evaluation criteria, including (1) a discussion of alternative sites and/or processes reasonably available to the proposer, (2) a brief discussion of the environmental impacts of each proposal, (3) practical mitigating measures, and (4) a list of permits that must be obtained in implementing the proposal, to the extent known. Due to the confidential content of this document, it is not available to the public.

Post-Selection NEPA Review

Upon award of federal financial assistance, proposers are required to submit additional environmental information.[4] This detailed site and project-specific information will be used, along with independent information gathered by DOE, as the basis for site-specific NEPA documents to be prepared by DOE for each selected project. Such NEPA documents will be prepared, considered, and published in full conformance with the Council on Environmental Quality's (CEQ) NEPA regulations and in advance of a decision by DOE to share costs beyond preliminary design.[5]

Federal funds from the Clean Coal Technology Demonstration Program will not be provided for detailed design, construction, operation, and/or dismantlement until the NEPA process has been completed successfully.

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[4]The required information was specified in Appendix J, "Information Requirements for the National Environmental Policy Act," of the CCT III PON.

[5]CEQ's NEPA regulations are in 40 CFR Parts 1500-1508; DOE guidelines were published in 45 Federal Register 20 (694), 1980.

Selected proposers will prepare the necessary information and submit it to DOE in a self-contained *Volume of Environmental Information* which will include:

- A summary of environmental, health, safety, and socioeconomic information and analysis

- A description of the environmental setting of the proposed project, including a physical description of the project site and environmental conditions

- A description of the project's facility requirements (e.g., resources and offsite facilities), overall plant site and setting, and plant/process residuals (e.g., discharges and waste storage)

- A discussion of the impacts and consequences of the project at the selected site, plans for offsetting such impacts, and a summary and ranking of the consequences according to risk to project implementation

- An identification and preliminary assessment of the major environmental laws and regulations (federal, state, and local) for which compliance will be necessary prior to implementation of the project

- Information for assessing the project's impacts, if any, on water resource requirements and water availability

ENVIRONMENTAL MONITORING REVIEW

DOE views the identification and characterization of areas of concern and the development of an information base for the assessment and mitigation of impacts associated with the replication of clean coal technology projects to be a fundamental purpose of environmental and health monitoring and an important component of the demonstration project. Monitoring should identify the environmental constraints and/or advantages of potential commercial versions of the demonstrated technology. In addition, environmental monitoring may be necessary to detect any environmental and health problems requiring remedial actions, and to confirm the performance of environmental mitigation measures implemented as part of the project. Towards these ends, DOE requires that the participant (i.e., selected proposer) perform a broad range of monitoring activities related to potential environmental and health impacts of the project and technology.

Monitoring activities are documented in the form of an Environmental Monitoring Plan (EMP).[6] The EMP is developed, in consultation with DOE. It is subject to revision and updating as the project progresses. The EMP is described below.

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[6]Guidelines for development of the EMP were provided in Appendix N, "Environmental Monitoring Plan Guidelines," of the CCT III PON.

Environmental Monitoring Plan

The EMP reflects additional monitoring requirements that may be identified in the NEPA process. The plan specifies the details regarding sampling locations, monitoring parameters, and sampling and analytical procedures. Development of the EMP is expected to take place along with the design of the project.

The EMP contains the following information:

- o **EMP Purpose and Scope**--Definition of the overall approach to the monitoring and measurement activities
- o **Project/Process Description**--Technology description, process flow diagrams, process and discharge streams, and pollution control systems
- o **Environmental Characterization**--Plans for developing an information base for identification, assessment, and mitigation of environmental problems associated with the replication of the technology, including definition of the parameters that establish process operating conditions and determine environmental discharge characteristics
- o **Compliance Monitoring**--Identification of permits, conditions of permits, and monitoring requirements of permits in terms of type of monitoring and timing
- o **Supplemental Environmental Impact Monitoring**--Specific monitoring plans to identify and confirm selected environmental impacts and predicted performance
- o **Integration of Monitoring Activities**--A break down of specific monitoring activities by project phases and monitoring media to avoid redundancy in the monitoring
- o **Data Management and Reporting**--Description of the data management system to be used, reporting schedule, report contents and format, and types of analyses

APPENDIX A

TECHNOLOGY DESCRIPTIONS

ADVANCED COMBUSTION

DESCRIPTION

A coal combustor is a device in which coal and oxygen are combined or burned to produce usable heat (thermal energy). In the context of the DOE program in Advanced Combustion Technology, coal combustors include those devices which can be added or used to retrofit an existing furnace or boiler and or used as entirely new, stand-alone combustion devices.

Coal combustors in varying sizes and configurations have been used by the industrial and utility sectors for years. However, the full realization of their performance potential has been limited by environmental constraints imposed by the New Source Performance Standards (NSPS). The high operating temperatures result in the production of unacceptable levels of nitrogen oxides (NO_x); sulfur in the coal produces unacceptable levels of sulfur oxides (SO_2).

An advanced combustor is a device that will control or remove sulfur, nitrogen oxides, and particulate matter from coal-derived fuel before combustion gases are injected into retrofitted oil or gas boilers or heaters, or will meet emissions requirements as a stand-alone combustion device. Typical of these projects is the advanced slagging combustor which seeks to control: (1) particulate emissions by converting ash into molten slag which is removed before injection into the boiler or heater, (2) NO_x formation by staged combustion to suppress temperatures, and (3) SO_2 formation by the injection of alkali compounds during combustion. These slagging combustors are suitable for incorporation either in new designs or in large retrofit applications in the heavy industrial and utility market (50 million Btu per hour or greater) in boilers and process heaters. Research also is in progress to develop advanced combustors for light industrial, commercial, and residential sectors.

ENVIRONMENTAL CHARACTERISTICS

Advanced combustion technologies reduce emissions in the combustion process through advanced combustor design, boiler modification, or the introduction of sorbents into the combustor. Additional removal can be achieved by using coal preparation before combustion or five gas cleanup after combustion.

One advanced combustion technology under development involves slagging combustors that offer the potential to reduce SO_2 emissions by 70-90 percent when burning coal. This reduction is achieved by introducing limestone or some other sorbent into the combustor or into the combustion gases exiting the combustor after the slagging stage. A high degree of slag and sulfur capture in the same stage have proved difficult to achieve.

If a sorbent is injected into the hot combustion gases, or if significant amounts of sorbent are carried into the boiler, a baghouse or electrostatic precipitator (ESP) can be used to remove particulates from the products of combustion. Between 80 and 90 percent of the ash can be rejected as slag. NO_x is reduced in the slagging cyclone combustor by combustion staging (i.e., the combustor is operated sub-stoichiometrically, with combustion being completed in the boiler, where additional air is introduced). Overall, NO_x can be reduced by 50-70 percent relative to wall-fired, pulverized-coal combustors. Slagging combustors also have the potential to replace existing cyclone boilers, which are very high NO_x emitters, and where technological alternatives for achieving NO_x reductions on existing cyclone boilers are limited because they cannot be fitted with commercially available low-NO_x burners.

Other technologies can be used in advanced combustion systems to achieve environmental goals. Deep physical coal cleaning prior to combustion generally can reduce sulfur emissions by 40-60 percent (depending on the ratio of pyritic to organic sulfur in the coal), without the need for capital-intensive modification to the boiler. Particulate emissions can be reduced because the quantity of ash flowing into the ESP or baghouse is reduced; however, ash composition (and gas composition) can be affected, which might decrease ESP efficiency. Reburning in the boiler in conjunction with the staged cyclone combustor can further reduce NO_x.

The use of coal mixtures could further enhance the attractiveness of advanced combustors by providing an acceptable method for storing, handling, and feeding fuel. The production of some coal-water mixtures involves fine grinding, thereby lending itself to deep benefication, so the use of these fuels could further improve the environmental performance of advance combustors.

STATUS OF DEVELOPMENT AND WORK IN PROGRESS

Current methods of burning coal to produce usable thermal energy include:

1. Circular and cell burners used on conventional pulverized coal boilers of up to 165 million Btu per hour.

2. Spreader stokers which direct coal into the furnace over a fire bed with a uniform spreading action, permitting the fine particles to burn in suspension as the larger particles fall to the grate for combustion in a fast burning bed.

3. Underfed stokers in which coal is fed from a hopper by a reciprocating ram to a central section called a retort. Conveying mechanisms move the coal upward in a spreading motion over the air inlets (called tuyeres) where it is burned with the ash passing on to a dumping grate.

4. Water-cooled and vibrating stokers which consist of a tuyere grate surface mounted on, and in contact with, a grid of water tubes interconnected with the boiler's circulating systems for positive cooling. Coal is fed to the grate where it is burned as it passes along the grate to the rear of the stoker, where ash is dumped into an ash pit.

5. Traveling grate stokers in which the entire grate moves, acting as an endless belt on which the coal burns as it is conveyed to the rear of the furnace where the ash is dumped.

6. Cyclone combustors which use crushed rather than pulverized coal and which complete the combustion process outside the boiler. Air is injected into the combustor tangentially, imparting a swirling motion to the incoming coal. Ash is fused in the combustion process and removed from the combustor as molten slag.

Cyclone combustors can use the abundant and relatively inexpensive surplus of high-sulfur, high-ash, low-fusion-temperature coals. Recent developments have shown that such combustors can operate in a staged manner to control the formation of NO_x during the combustion process while still rejecting most of the ash as slag. These capabilities of cyclone combustors have resulted in a renewed interest in this technology by DOE's Advanced Combustion Technology Research Program.

Department of Energy Program

The current research and development (R&D) program was initiated to develop advanced combustion technology for use in utility, industrial, commercial, and residential applications. In late 1986 and 1987, DOE awarded 13 contracts, 9 of which comprise the current Advanced Combustion Technology Research Program. The 9 contracts are listed below by application and concept.

Heavy Industrial/Utility:

- Babcock & Wilcox/Cyclone Retrofit for Industrial Boilers

- Combustion Engineering, Inc./High-Efficiency Coal Combustion System

Light Industrial:

- Management and Technical Consultants, Inc. (MTCI/Pulse Coal Combustor (Resonance Tube) for Industrial Boilers and Heaters
- University of Tennessee Space Institute (UTSI/Coal Combustion System for Industrial Boilers

- Vortec Corporation/Coal-Fired Glass Melting Process Heater

- Otisca Industries/Development of a Burner Management System and Flame Safety Standards

Commercial:

- o Catholic University/Vertical Vortexing Combustor for Space/Water Heating Applications (Cold Flow Modeling)

- o U.S. Navy Civil Engineering Laboratory/Vertical Vortexing Combustor: for Space/Water Heating Applications (Hot Testing)

Residential:

- o Management and Technical Consultants, Inc. (MTCI/Coal-Fired Pulse Combustor (Resonance Tube) for Residential Space Heating

- o Tecogen, Inc./CWM-Fired Residential Warm Air/Hot Water Heating System

PROJECTS IN PROGRESS

The DOE report of February 1989, *Annual Report: Clean Coal Technology Demonstration Program*,[1] identified three projects in the advanced combustors technology category which are part of the Clean Coal Technology Program. Descriptions are provided in the aforementioned report. Two of the three projects, Coal Tech and TRW, previously were supported as part of the Advanced Combustion R&D Program. The projects are:

- o Coal Tech Corporation/Advanced Cyclone Combustor Demonstration Project

- o TRW, Inc./Advanced Slagging Coal Combustor Utility Demonstration Project

- o TransAlta Resources Corporation LNS Burner for Cyclone-Fired Boilers Demonstration Project

Coal Tech Corporation: Coal Tech's advanced cyclone combustor is an air-cooled cyclone combustor of the slagging type. SO_2 control is achieved by injecting limestone with coal into the burner. NO_x control is achieved by operating the first combustion stage with an oxygen deficiency. Ash and particulates are controlled through slag capture.

Coal Tech's combustor concept was tested extensively from 1975-1981 at the 1 million Btu/hour pilot scale, as part of a DOE - and utility-sponsored R&D program. After 1981, the development of the combustor was continued at Coal Tech Corporation.

The proposed project will demonstrate the performance, reliability, and suitability of the advanced, air-cooled, slagging cyclone combustor in retrofit applications. The size of the

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[1]Source: *Annual Report: Clean Coal Demonstration Program*, (DOE/FE-0125), U.S. Department of Energy, February, 1989.

combustor used in this project--30 MM Btu/hr--is directly suitable for some industrial boilers. Currently, the project is in Phase III (operation and data collection) where the objective is to conduct parametric studies for 900 hours on 2% and 4% sulfur coals.

TRW, Inc.: The TRW Slagging Combustor System (SCS) is designed for retrofit or for new applications to utility or industrial boilers. It is applicable for retrofit to coal-designed boilers. The slagging combustor is attached directly to an existing boiler.

Two sites are involved in this project: the Orange and Rockland Utilities Company Lovett Station Unit No. 3, and TRW's test site in Cleveland, Ohio. At the Lovett Station, a 69 MWe boiler will be retrofitted with four 160 MMBtu/hr slagging combustor systems. At the Cleveland site, a waste sorbent recycle system will be added, and limestone calcining techniques will be established to reduce sorbent usage so that process economics can be optimized while NSPS requirements are satisfied.

TransAlta: TransAlta Resources Corporation of Alberta has acquired Rockwell International's Low NO_x/SO_2 burner (LNSB) technology. The LNSB development program was initiated in 1979, a spin-off of research conducted for the U.S. space program. Theories developed at Rockwell indicated the possibility that both sulfur dioxide and nitrous oxides production could be reduced to near zero in combustion, and bench scale studies verified the theoretical predictions. Subsequent pilot scale studies (25 million Btu per hour) continued to verify the original theory.

The LNSB is a three-stage, entrained-flow slagging combustion system. Sulfur is captured by injecting limestone in a fuel-rich primary stage. In the second fuel-rich stage, gaseous nitrogenous compounds, including NO_x, are converted to molecular nitrogen. In the second stage, combustion temperatures are sufficiently high to allow removal of molten slag which includes the captured sulfur in a glassy ash matrix. Finally, in the third stage, excess air is added to complete combustion.

This project will demonstrate an LNSB and a coal pulverizer system retrofitted to the 33-MWe cyclone boiler at Southern Illinois Power Cooperative's Marion Plant in Marion, Illinois. Two LNSB's each rated at 200 million Btu per hour, will be retrofitted to the existing Babcock & Wilcox cyclone boilers and are expected to reduce both NO_x and SO_2 emissions by up to 90%.

APPLICABILITY OF THE TECHNOLOGY TO RETROFITTING, REPOWERING, OR MODERNIZING EXISTING FACILITIES

Advanced combustion technology offers the capability for retrofitting large industrial and utility boilers that are oil-, gas-, or coal-fired. Retrofitting large coal-fired boilers with advanced combustors can reduce emissions of acid rain precursors. Additionally, retrofitting can extend the life of a coal-fired boiler or heat exchanger because the gases entering the boiler are cleaner. Retrofitting is primarily applicable to industrial and utility boilers; for smaller applications replacement is likely to be more appropriate.

Advanced combustion technology has the potential of replacing oil- and gas-fired combustion units in large residential and commercial applications. These combustors are new units and are designed to replace an existing oil- or gas-fired unit.

COAL LIQUEFACTION

DESCRIPTION

Coal liquefaction produces useful liquid fuels from all domestic coal resources (bituminous, subbituminous, and lignite). There are two primary methods of coal liquefaction: (1) indirect liquefaction (coal gasification followed by conversion to liquid fuels) and (2) direct liquefaction (conversion of the complex organic solid structures in coal directly into liquid fuels). These methods are discussed below.

Indirect Liquefaction

Indirect liquefaction involves the following: the gasification of coal to produce a raw synthesis gas, water-gas shift reaction to adjust the H_2/CO ratio of the synthesis gas, gas cleanup, and the liquid synthesis process itself. A major challenge in process conception and design is to couple these stages in the most economic, thermally efficient manner.

Coal-derived synthesis gas is produced at high thermal efficiency by modern gasifiers that use the minimum amounts of oxygen and steam feed. The gas so produced has a low H_2/CO ratio, i.e., in the range of 0.6 to 0.7. Because of the significant contribution of gasification to the total cost of indirect liquefaction, the ideal synthesis reaction would accept such feed ratios directly. Unfortunately, neither traditional Fischer-Tropsch processes nor methanol-forming processes will accept a low H_2/CO feed ratio. In either case, the water-gas shift reaction would first have to be applied to increase the H_2/CO ratio to 2 or higher. However, this leads to a loss in thermal efficiency.

The best known approach to indirect liquefaction is the Fischer-Tropsch technology, which is the basis for the largest commercial liquefaction facilities in the world. These facilities are operated in South Africa by the South African Coal, Oil and Gas Co., Ltd., (SASOL). The new SASOL II and III plants employ dry ash Lurgi Mark IV gasifiers of German design and fast fluid (entrained recirculating) bed Synthol Fischer-Tropsch synthesis reactors developed by SASOL based on technology originally provided by the U.S. firm, M.W. Kellogg. This combination of steps at SASOL is capable of delivering clean fuels including a large percentage of gas and petrochemicals with an efficiency approaching 60 percent.

Since 1983, the Tennessee Eastman Company has operated the only coal-to-methanol plant in the United States. A single Texaco gasifier (plus one back-up) processes 900 tons per day of coal to produce methanol as an intermediate in the production of methyl acetate and acetic anhydride. In New Zealand, gasoline is commercially produced from natural gas via synthesis gas/methanol followed by the Mobil MTG process.

Direct Liquefaction

In direct liquefaction, ground coal is slurried with a recirculated process-derived oil and reacted under high temperature in a hydrogen atmosphere. The liquefaction reactions can be carried out in the presence or absence of catalysts and in a single reactor or in multiple reactor stages. At some point in the process sequence, following coal dissolution, mineral matter and unconverted coal solids must be removed from the process. Solids removal technology is an important aspect of liquefaction processing. Liquid products and recycle solvent are recovered by distillation. Middle distillate and heavier liquid products can be used directly as turbine fuel and/or fuel oil. Material that boils in the same temperature range as petroleum-derived naphtha has been shown to be an excellent feedstock for refining to yield high octane gasoline. Middle distillate and heavier liquid products also can be upgraded, using petroleum refining technology, to a broad spectrum of high quality, specification liquid fuel products.

Four direct liquefaction processes have been tested through the pilot-plant stage: (1) Exxon Donor Solvent, (2) H-Coal, (3) Solvent Refined Coal-I (SRC-I), and (4) SRC-II. Each was developed in the mid- to late-1970s and uses a single reactor stage. These processes are described below.

1. Exxon Donor Solvent--The Exxon Donor Solvent process liquefies coal in a hydrogen-donor solvent produced in a separate catalytic hydrogenation reactor. Pulverized coal slurried in recycled donor solvent is mixed with hot hydrogen and passed through the main (liquefaction) reactor. Recycled process solvent, circulating first through the catalyst vessel, picks up hydrogen atoms and then passes into the liquefaction reactor and "donates" the hydrogen to the dissolved coal--hence the name "donor solvent."

   The products leaving the main reactor are separated. Hydrogen for reuse is recovered from the gas through cryogenic separation. An atmospheric distillation step yields a slate of light, middle, heavy distillate, and solid residue fractions. A portion of the middle distillate is used to produce the donor solvent. The residue proceeds to vacuum fractionation, which yields additional distillate, spent solvent range distillate, and vacuum residue. This residue, which contains unconverted coal and ash, may be gasified to produce hydrogen for the liquefaction.

2. H-Coal Process--The H-Coal process (developed by Hydrocarbon Research, Inc.) is a direct catalytic hydroliquefaction process for converting coal into hydrocarbon liquid fuels. Depending on the operating scheme, the product may be all distillate (syncrude mode) or high-boiling-point boiler fuel including deashed residue (fuel oil mode).

   The properly sized and dried coal feed is mixed with recycled slurry and process-derived solvent (normally a part of the heavy distillate oil product). The coal/oil slurry, along with part of the recycled hydrogen, is preheated to initiate the coal dissolution, and then introduced to the bottom of an ebulated-catalyst bed reactor. The remaining hydrogen feed is preheated and introduced to the bottom of the reactor.

   The gas, liquid, and coal/oil slurry are separated and further processed to meet the specifications of the process recycle streams as well as hydrotreated and stabilized to meet commercial specifications. The coal/oil slurry is partially concentrated in a hydroclone system. The hydroclone underflow and portions of the heavy distillate oil are used to slurry the fresh coal feed. Further oil recovery and solids concentration from the hydroclone are achieved through vacuum distillation of this stream in the syncrude mode and through solvent precipitation and critical flashing in the fuel oil mode. The vacuum bottoms, containing mostly unreacted coal and ash, are gasified to produce the hydrogen for the process.

3. Solvent Refined Coal--The Solvent Refined Coal process is a noncatalytic (thermal) process for converting high-sulfur, high-ash coals to nearly ash-free, low-sulfur fuel. The process has two different modes of operations: SRC-I which yields a solid fuel and SRC-II which yields primarily distillate liquid fuels.

   o In SRC-I, properly sized dried coal is slurried with a process-derived solvent. The slurry, mixed with hydrogen, is preheated and sent to the reactor. The reactor effluent is sent to the vapor-liquid separation stage. Hydrogen (for recycle), fuel gas, and eventually sulfur are recovered from the primary gaseous stream. Process solvent and other liquid components are removed from the separator slurry, and the remaining slurry is sent to a deashing step in which it is separated into a molten carbonaceous product stream and a solid residue stream. The residue stream is gasified to produce make-up hydrogen.

   o SRC-II is a modification of SRC-I and produces primarily liquid fuels instead of solids. SRC-II uses proportionally more hydrogen than the SRC-I process and also uses a residue containing slurry recycle (ash in the slurry acts as a catalyst) to achieve higher conversion of coal to liquid products. A portion of the ash slurry is removed from the recycle stream and fractionated to produce distillates. The heavy residue is gasified to produce make-up hydrogen.

ENVIRONMENTAL CHARACTERISTICS

Indirect Liquefaction

The environmental characteristics of indirect liquefaction processes are essentially the same as the environmental characteristics of surface coal gasification technologies. The environmental benefit of the gasification technologies is that the gaseous sulfur and nitrogen compounds can be removed before combustion or chemical manufacture using either wet scrubbing or high-temperature absorption/adsorption processes.

Hydrogen sulfide removal can be achieved through chemical or physical absorption after gas cooling or by adsorption on metal oxides at high temperature (1000 °F to 1200 °F). These processes can remove more than 99 percent of the gaseous sulfur compounds before combustion of the gases. The sulfur species absorbed in chemical solutions (cold cleanup) can be recovered as elemental sulfur or converted to sulfuric acid. From the metal-oxide adsorption process (hot cleanup), the sulfur compounds can be recovered as sulfur or converted to sulfuric acid or solid sulfates (such as calcium sulfate), which ultimately can be disposed of in a landfill.

In addition, sulfur compounds can be captured with the gasifier through the addition of limestone (or dolomite). Using this method, capture levels of approximately 90 percent are possible, and further capture ("polishing") can be achieved by treating the fuel gas with a metal oxide adsorption process to exceed 99 percent of total sulfur removal.

Nitrogen compounds (principally ammonia) are generated in the gasification process and, depending on the gasifier operation temperature, are contained in varying amounts in the synthesis gas. The highest ammonia levels are produced in the lowest temperature reactor, i.e., fixed-bed gasifiers; lesser amounts are produced in fluid-bed reactors; and the lowest amount in entrained reactors (which have the highest operating temperature). The nitrogen compounds are easily removed in cold cleanup systems by dissolution in water and subsequently recovered as salable ammonia. After cold cleanup, fuel gas contains only traces of ammonia, and upon combustion, the NO_x emissions are far below current New Source Performance Standards (NSPS). With hot gas cleanup systems, the ammonia passes through into the fuel gas and NO_x emissions must be controlled by combustion modifications or external processes. In either treatment, the fuel gas can meet current NSPS.

The principal solid waste from the gasifier is coal ash, which can be disposed of in the same manner as coal-fired boiler ash. When limestone is injected into the gasifier, the solids will contain calcium sulfides, and it will be necessary to oxidize these solids to convert sulfides to sulfates, which are inert and can be disposed of in landfill.

Catalytic synthesis of liquid products such as methanol or Fischer-Tropsch products creates no significant emissions. When methanol is co-produced with electricity, a portion of the synthesis gas is converted and the methanol condensed. The remaining unreacted fuel gas (mostly CO) is burned in a turbine with a steam bottoming cycle. Since cold cleanup systems must be used to eliminate essentially all sulfur, nitrogen, and particulates (which will poison the synthesis catalyst), the fuel gas being fired to the combustor is also free of these compounds. Thus, the exhaust gases from the turbine/boiler will be low in NO_x (below NSPS) and SO_2 and will be free of particulates. Stored methanol can be used in peaking or transportation fuel applications. Methanol combustion in turbines has been used by utilities. The process is very low in NO_x emissions and is free of sulfur and ash. Fischer-Tropsch products can substitute for conventional refinery-produced diesel and gasoline fuels with potentially very low SO_2 and NO_x emissions.

Direct Liquefaction

Direct liquefaction technologies generally involve hydrocracking of the coal molecules, either thermally, or catalytically, to produce smaller molecules. These smaller molecules can be upgraded to specification fuels where essentially all heteroatoms (sulfur, nitrogen and oxygen) are removed by reaction with hydrogen.

Emissions from the plants can be reduced effectively through proper design. Sulfur is converted to salable elemental sulfur. Oxygen in the coal is generally reacted with hydrogen to form water. Nitrogen is hydrotreated to form salable ammonia. Mineral matter ends up in the vacuum bottoms product which can be used to produce hydrogen in a gasifier or burned in a boiler.

In either case, the mineral matter is converted to a refractory-like slag or to fly ash products that are expected to be nonhazardous. Waste water treatment technologies, such as those used in refineries or in coal gasification plants, can be used to eliminate nearly all phenols, ammonia, and other compounds. The plants can be designed to reuse waste water (zero discharge) with blowdowns evaporated to small quantities of solid salt products that can be disposed of at approved sites.

Coal liquefaction technologies provides liquid fuels from coal for a wide variety of market applications. Both direct and indirect liquefaction can be used to produce finished fuels that are virtually indistinguishable from petroleum products.

STATUS OF DEVELOPMENT AND WORK IN PROGRESS

Indirect Liquefaction

Primary objectives of the DOE Indirect Liquefaction Program are to (1) achieve more selective and economic yields of liquid fuels and (2) achieve better utilization of coal-derived gas feedstock. To accomplish these objectives, the program supports research that identifies and investigates processes based on:

1. New catalysts or biocatalysts able to utilize low hydrogen/carbon monoxide syngas, thereby taking advantage of the new, efficient gasifiers now under development in the United States

2. New or modified catalysts with the selectivity to produce desirable liquids either in a single stage or via chemical intermediates in a two-stage synthesis process

3. Thermally efficient reactors with improved temperature control and heat recovery compared with reactors currently available for indirect liquefaction reactions

Successful research will permit a significant reduction in the cost of each of the following major process areas downstream of the coal gasification step:

1. Cleanup and shift of the new syngas to provide required feedstock for the synthesis step

2. Recycle of gas to the reactor to maintain proper gas composition and reactor temperature

3. Conversion of syngas feedstock to desirable liquids

4. Separation and refining of produced liquids to marketable products

The broad-based research program now in place includes laboratory-scale research to investigate the mechanisms of known catalyst components and new catalyst systems with higher selectivity, stability, resistance to poisoning, and overall productivity. Projects also are under way at the laboratory scale to develop data required to realize the technical and economic potential of performing the synthesis reaction in a liquid phase. Multiphase reactors are used in this research and in hydrodynamics studies of advanced reactor designs.

Two process concepts have been scaled up from laboratory scale for further development and evaluation in proof-of-concept facilities. The larger project was an international one with a pilot plant located in West Germany. This project has been successfully completed. The plant used an advanced fluid-bed reactor system to convert, very efficiently, 100 barrels per day of methanol to high octane gasoline. A second mode of operation to produce light olefins for conversion to diesel fuel and/or gasoline also has been successfully accomplished.

The second proof-of-concept development effort involves the production of methanol from a simulated coal-derived synthesis gas. The facility, located at La Porte, Texas, produces about 35 barrels per day of methanol using a liquid phase reactor system, and has operated successfully in a single pass mode utilizing CO-rich synthesis gas.

Direct Liquefaction

The technical viability of direct coal liquefaction has been demonstrated. Processes capable of producing the entire slate of liquid fuels currently derived from petroleum crude are available. However, those processes that are ready for commercialization are currently not economically competitive with petroleum-derived fuels. Therefore, new process concepts or substantial improvements to existing approaches are necessary before economic viability can be achieved.

DOE's Coal Liquefaction Program has identified the major improvements needed for advanced processes to become more economically competitive. These targets are:

1. Achieve 10-15 percent higher yields than those achieved by already demonstrated processes.

2. Realize up to 30 percent savings in capital and operating costs through improvements in ease of operation and reductions in process severity and complexity

3. Reduce heteroatom content by 40-50 percent and/or increase the hydrogen content in the liquid product by 10 percent compared to already demonstrated processes

4. Implement process modifications or new process concepts capable of producing liquid products that are comparable in bioactivity to their petroleum analogs.

Staged liquefaction is an advanced process that provides improved, lower cost technology. Several processes based on this approach have completed bench-scale development and have been or are being evaluated at the Advanced Coal Liquefaction R&D Facility in Wilsonville, Alabama. More advanced, staged-liquefaction technology options are being developed at the bench scale.

Another process concept under evaluation is coal-oil coprocessing. In this concept, coal is slurried in residual fuel oil rather than recycle solvent, and both coal and petroleum residuals are converted to high quality fuels in subsequent processing. This concept offers the potential for significant cost reduction by eliminating or reducing internal recycle oil requirements. As a result, there is a much higher net throughput of product per unit of plant capital investment. It also offers the potential for accelerating the introduction of coal-derived liquid fuels into the marketplace by utilizing, to a substantial degree, existing petroleum refining facilities and technology. This will allow the introduction of coal-based liquid fuel in an evolutionary manner and delay the requirement for new, capital intensive, liquefaction facilities. This work is being conducted at the bench scale.

PROJECTS IN PROGRESS

One project has been identified in the coal liquefaction technology category; The project is listed below.

Project in Progress

Project	Site
Ohio Ontario Clean Fuels Inc. Oil/Co-Processing Liquefaction	Warren, OH

RELATIONSHIP BETWEEN THE R&D PROGRAM AND THE CCT PROGRAM

The Prototype Commercial Coal-Oil Coprocessing Project (Ohio Ontario Clean Fuels, Inc.) is one of the CCT-I projects. The data being generated in DOE's Coal Liquefaction Program can be used to evaluate the design of this project. In turn, operational data from the project can serve to focus the R&D effort to overcome problems that hinder advancement of the state-of-the-art of the technology and its optimization for commercial application.

APPLICABILITY OF THE TECHNOLOGY TO RETROFITTING, REPOWERING, OR MODERNIZING EXISTING FACILITIES

Coprocessing technology can be used to retrofit existing petroleum refineries, and this is the main reason why the technology is being developed. Coal and ash handling facilities would be retrofitted to existing heavy oil refinery processing equipment. At an appropriate crude-oil-to-coal price differential, this would allow a refiner to reduce the cost of feedstocks while increasing the production of high-quality liquid fuels from scarce and/or expensive crude oil supplies.

Indirect liquefaction could be used to retrofit facilities having existing coal gasification technology or to retrofit and modernize existing non-coal-derived synthesis gas facilities. Liquefaction reactors would be added downstream of the synthesis gas cleanup train, providing a relatively low-cost conversion of coal-derived or other gas to high-quality liquid fuels.

Direct liquefaction is suitable for retrofitting and modernizing existing refinery or chemical processing facilities to utilize coal feedstocks. The existence of ancillary facilities and utilities at these sites and the elimination or reduction of complex siting and environmental requirements adds to the attractiveness of this approach. Products for direct liquefaction, indirect liquefaction, and coprocessing all can be used for retrofitting/refueling a coal-, gas-, or oil-fired boiler in repowering applications.

COAL PREPARATION

DESCRIPTION

Coal preparation and waste recovery processes utilize technologies to separate the ash-forming mineral matter and sulfur from coal and high-carbon residues. Excess moisture may also be removed from lower rank coals. These impurities or unwanted constituents vary widely from coal seam to coal seam as well as from coal to coal. As a result, cleaning technology and economics are closely linked to the specific feed coal. In addition to removing sulfur and ash, the preparation process crushes and grinds the coal to provide the customer with a product improved in quality and consistency over the as-mined coal. Advanced coal cleaning techniques have the potential to provide a much cleaner coal which could be utilized in new markets, with significant applications additional to the now dominant utility and large industrial markets.

Coal preparation (or benefication) processes can be classified into two broad categories: (1) physical preparation and cleaning and (2) chemical/biological cleaning. The commercial practice of coal cleaning currently is limited to physical separation of the impurities based on differences in the specific gravity and mass of coal constituents (e.g., gravity separation processes such as jigs, heavy media cyclones, tables, etc.) and the differences in surface properties of the coal and its mineral matter content (e.g., froth flotation). These physical coal cleaning processes can remove up to about 50 percent of the total sulfur with thermal recoveries over 80 percent, depending upon the characteristics of the specific coal being processed.

Physical coal cleaning methods can be very effective in removing pyritic sulfur and mineral matter from coal. The more finely coal is ground, the greater the liberation of impurities not chemically bound to the coal matrix. However, when coal is ground to fine sizes (between 28-325 mesh) and ultrafine sizes (finer than 325 mesh) conventional physical cleaning techniques become progressively more difficult and less effective. Also, physical cleaning methods leave untouched the organic, chemically bound sulfur. Newer approaches to physically cleaning finely ground coal use special additives and unique flotation cell designs to remove even more mineral matter and pyritic sulfur. Electrostatic techniques to clean dry coal are also under development. This technology relies on inducing charges of opposite polarity on coal particles and particles of mineral matter to accomplish separation.

Both pyritic and chemically bound organic sulfur are converted to SO_2 when coal is burned. Because existing physical cleaning technology removes only the pyritic sulfur contained in the mineral matter, research is under way on advanced chemical and biological techniques to remove organically bound sulfur. Chemical treatment has the potential to remove (1) virtually all pyritic sulfur, including finely divided and dispersed pyritic sulfur that may not be removed by physical treatment, (2) virtually all of the organically bound sulfur, and (3) virtually all the associated mineral matter. Organic sulfur removal is of particular importance because it represents, on average, about one-third to one-half of the total sulfur in domestic coals. Research on chemical cleaning methods and modification of coal shows considerable technical potential for removing nearly all of the ash and both forms of sulfur. At this stage of development, however, the costs of chemically cleaning coal are much greater per ton of product than costs associated with conventional coal cleaning technology.

ENVIRONMENTAL CHARACTERISTICS

Coal cleaning technology is becoming more important to coal producers, utilities, industrial customers, and to the public as the search continues for cost-effective means or reducing emissions of SO_2. For a coal user, clean coal can increase the efficiency of, or reduce the requirement for, post-combustion emission controls such as flue gas desulfurization (scrubbers).

Utility and large industrial boilers that, because of their age, are not required to meet New Source Performance Standards (NSPS), burn significant amounts of medium-and high-sulfur coal which may produce emissions of up to 4 pounds of SO_2 per million Btu. For much of this coal, over 60 percent of the total sulfur is in pyritic form, thus susceptible to removal by deep physical coal cleaning techniques. The remaining sulfur is organic in nature and requires other techniques, including chemical treatment, for removal.

Commercial, as well as advanced, physical coal preparation processes (described elsewhere in this section) produce a reject stream consisting chiefly of ash (clays and pyrites, which are iron sulfide compounds) with varying amounts of residual coal.

When chemicals are used in a coal benefication process, the environmental requirements are process- and site-specific. Process economics, as well as environmental concerns, dictate that those chemicals which are not consumed be recovered and recycled. Various chemicals (for example, hydrocarbons) may be used to control the surface properties of particles of coal and minerals to affect separation characteristics and the final degree of physical cleaning. Chemical benefication technologies being developed can remove organic as well as pyritic sulfur by treating the coal with inorganic caustic solutions and acids. These chemicals are recovered and regenerated, and any residue in the coal product is neutralized.

Pyritic sulfur, removed by physical coal cleaning processes, is not changed in chemical form, and remains in the ash as insoluble iron and sulfur compounds. However, sulfur removed by chemical treatment is usually converted to gaseous hydrogen sulfide or to a water-soluble sulfate which can then be converted to useful forms, such as fertilizer and elemental sulfur.

As new processes are developed, process and waste streams are characterized so that appropriate environmental controls can be incorporated into the final process configuration.

STATUS OF DEVELOPMENT AND WORK IN PROGRESS

The status of the various coal preparation technologies ranges from those currently used by industry (as in the case of some physical benefication process) to advanced research concepts being explored in laboratory settings (as in the case of microbial treatments). Current research and development investigations range from pilot plant efforts sponsored by industrial groups (such as Homer City Coal Quality Development Center) to proprietary process development in industrial research centers and laboratory investigations by universities and government laboratories.

DEPARTMENT OF ENERGY PROGRAM

DOE is a major sponsor of both physical and chemical coal preparation research. Some of the work is performed in-house at DOE's Pittsburgh Energy Technology Center (PETC). Research indicates that coal from advanced cleaning processes will burn more cleanly than most coals currently fired in industrial boilers or industrial processes, and existing boilers, with or without modifications, will be able to accept coals cleaned by advanced cleaning methods. As advanced coal cleaning technologies are further developed and commercialized, more U.S. coals will be cleaned. Coal preparation techniques will be applicable to both new and retrofit installations. Descriptions of DOE-sponsored work in progress follow. These activities include (1) physical benefication, (2) chemical and biological benefication, and (3) support studies and ancillary operations (explained below).

Physical Benefication

Advanced physical coal cleaning methods of interest are focused primarily on the potential for increased cleaning efficiency of ultrafine coal (finer than 325 mesh). Laboratory float-sink tests indicate the theoretical potential to remove over 90 percent of both ash forming minerals and pyritic sulfur from ultrafine coal. This is a significant improvement over results with a coarse coal feed. DOE and the Electric Power Research Institute (EPRI) are cooperating in selecting and developing coal cleaning technologies for testing at the Coal Quality Development Center operated by EPRI at Homer City, Pennsylvania. The technologies for grinding ultrafine coal and processing or handling the clean product are being considered at the same time. PETC has found that advanced physical coal cleaning techniques could play a cost-effective role in reducing SO_2 emissions from pre-NSPS utility boilers. To facilitate near-term commercialization, the Clean Coal Research Initiative (CCRI) was established in 1988. This initiative focuses on the most promising three technologies: selective coalescence, heavy liquid cycloning, and microbubble flotation. The intent of CCRI is to conduct the necessary research and engineering development to bring these three technologies to commercial viability by 1992. The status of the technologies supported by DOE are summarized below:

1. Heavy Liquid Cyclone--In this process a heavy liquid (typically an organic chemical) is used to effect separation of mineral matter from the coal in a cyclone. Separation can be achieved for a wide range of coal particle sizes using a heavy liquid intermediate in specific gravity between the coal and the impurities. Development of commercial applications based on using this heavy liquid cyclone technique to clean ultrafine coal has been hampered by recovery system cost, liquid loss, liquid toxicity, corrosiveness, and other factors. However, recent developments have demonstrated that many of these problems can be mitigated. Continued investigations are appropriate for evaluating

process operating parameters to establish viability at this scale and the potential viability of the process at commercial scale. This technology is being developed further by CCRI.

2. Froth Flotation--This technique for physical coal cleaning takes advantage of differences in surface properties of particles in an aqueous slurry to achieve separation. Coal is generally more hydrophobic than its impurities and can be floated to the surface by finely dispersed air bubbles and removed as cleaned product, while the more hydrophilic mineral matter particles sink and are removed as waste. A frothing agent and collector may be used to facilitate removal of the coal particles. This technology is widely used in industry today to beneficiate moderately fine coal. However, current state-of-the-art technology does a poor job of separating ultrafine particles. Further laboratory research is required on understanding and modifying the surface properties of these particles and on novel systems for achieving efficient separation.

   Research has shown great promise for using microbubbles to enhance the separation efficiency of very fine particles. Work is continuing at the laboratory scale, as well as at the proof-of-concept scale, to determine the viability of microbubble technology in novel flotation circuits and devices. This technology is also a commercialization candidate under CCRI.

3. Selective Coalescence--In this application, an agglomerating agent in a turbulent aqueous phase takes advantage of differences in surface properties between coal and its impurities to agglomerate (or coalesce) coal particles while the impurities remain suspended in the water. At ultrafine coal sizes, the liberation of impurities is greatly improved over that with coarser particles. Laboratory tests have shown excellent ash removal efficiency, but removal of pyritic sulfur particles is not necessarily good with current selective coalescence techniques.

4. Electrostatic/Magnetic Separation--Electric and/or magnetic fields can be applied to fine coal as a means to separate coal from its impurities. Differences in electric charge or differences in magnetic susceptibility cause the mineral matter and the coal to separate when passed through these fields. Past research on magnetic separation has been marginally successful because of the low-level magnetic susceptibility of the mineral matter. New research efforts have been initiated to investigate electrostatic and improved magnetic separation techniques.

Chemical Benefication

Organic sulfur in coal is chemically bound to the coal, thereby requiring a chemical (or biochemical) reaction to separate it from the coal matrix. Promising coal preparation technology areas that employ chemical reactions in some way have been identified and are currently being pursued. The current status of these areas is summarized below:

1. Molten-Caustic Leaching--In this process finely ground coal particles are exposed to a molten caustic. This exposure results in chemical leaching which removes over 90 percent of the total sulfur and mineral matter from the coal. The cleaned coal is separated from the spent caustic and impurities through water washing and filtration. The spent caustic is separated from contaminants and regenerated for reuse. Favorable test results have been obtained at the bench scale of each of the modules that could comprise an integrated, continuously operating system. Testing of a bench-scale integrated unit to demonstrate the feasibility of continuously operating such a system began in 1989 and will be continued in 1990.

2. Pretreatment of Coal to Improve "Cleanability"--Historically, coal cleaning to remove ash has been applied to run-of-mine coal which had only been physically modified (ground and screened) prior to physical cleaning. Past research has attempted to determine if specific physical changes to the coal, such as specialized grinding or electrostatic charging, could be used to enhance the ability of subsequent cleaning technologies to remove mineral matter and sulfur. The objective of the current research is to identify chemical modifications to coal or char that would result in enhanced "cleanability" of the resultant solid stream from various feed coals.

Biological Benefication

Biological approaches to coal preparation represent some of the most innovative and advanced efforts currently being considered. In theory, biological processes offer the potential of achieving essentially complete sulfur removal at conditions of ambient or near ambient operation, and with low energy requirements. At the same time, process development difficulties (e.g., process control, media/microbial systems stability, product consistency) present significant problems in research and development.

Success in microbial desulfurization (using bacteria in the laboratory to remove organic sulfur from coal) has recently been reported. The development of bacterial desulfurization processes requires highly specific bacterial cultures having the desired performance characteristics (e.g, sulfur removal efficiency, growth rate, reliability in process conditions). Current activity focuses on the isolation of naturally occurring bacterial strains and molecular biological enhancement. Preliminary bench-scale work to investigate the validity of this concept is currently being carried out under this program.

Other biological approaches involve exploration of non-bacterial systems (e.g., fungal systems for benefication of low rank coals). In addition to direct use of microbes in vitro coal processing systems, other processes have been proposed which would employ microbial growth in batch systems, followed by extraction of desired enzymes and injection of enzyme extract into the in vitro coal processing systems. Such two-stage process approaches could allow for potential advantages in both biological process control and in reduction of the residence time required in the coal cleaning systems.

Support Studies and Ancillary Operations

As research continues on advanced concepts for cleaning coal, parallel research on problems and techniques that are common to many of the benefication processes can make significant contributions to generally advancing the state of the coal cleaning art.

The ability to characterize feed coal and cleaned coal accurately and quickly is important to the coal industry, but is dependent upon the development of advanced sophisticated techniques. This being pursued under the DOE program.

Coal grinding, which is an ancillary operation to coal cleaning, requires a large amount of costly energy and desirable ultra-fine grinding requires even more energy. Since grinding and cleaning are usually accomplished in an aqueous medium, special techniques are required for dewatering finely ground coal and coal product. Special techniques also are required to remove excess water, as well as ash, from certain low rank coals, and the coal product should not readily absorb moisture after the initial drying phase. These are the research areas supported by DOE under the heading of "Support Studies and Ancillary Operations."

PRIVATE SECTOR PROGRAM

Industrial research and development efforts are focused largely on physical coal cleaning improvements, specially flotation techniques, cycloning, and agglomeration. EPRI supports a number of coal cleaning projects related to requirements of the electric utility industry. At Homer City, Pennsylvania, EPRI operates a coal cleaning test facility and DOE cooperates with EPRI in testing advanced concepts at this site. A number of companies are investigating improvements in existing technology. Commercial coal cleaning facilities are operated by coal producers or by large coal customers, particularly electric utilities.

PROJECTS IN PROGRESS

A number of significant coal preparation research and development or demonstration projects are being undertaken nationwide. EPRI tests advanced physical coal cleaning processes at its Coal Quality Development Center (CQDC) at Homer City, PA. This facility is considered state of the art for proof of concept (POC) scale testing. Under a cooperative agreement with EPRI, DOE sponsors testing of selected advanced physical coal cleaning processes at the CQDC.

Under the DOE Clean Coal Research Initiative (CCRI) selected advanced physical coal cleaning technologies are being developed through POC scale testing and preliminary design of commercial scale systems. The following projects will carry out POC scale testing under the engineering development portion of this initiative.

Company	Technology	Site
So. Co. Services	Selective Agglomeration	Wilsonville, Alabama
Kaiser Engineering	Microbubble Flotation	Marietta, Ohio

Under the DOE sponsored Clean Coal Technology Program three coal preparation projects have been selected for demonstration. Under the first round solicitation- CCT I - the following two coal preparation project contracts are under negotiation:

Company	Technology	Site
Combustion Eng.	Combustion Testing Cleaned Coal	Several Sites Nationally
Western Energy Co.	Evaporative Drying Low Rank Coal	Colstrip, Montana

From the second round solicitation - CCT II - one project contract is under negotiation:

Otisca Industries	Selective Agglomeration	Syracuse, New York

RELATIONSHIP BETWEEN THE R&D PROGRAM AND THE CCT PROGRAM

The Coal Preparation Program is developing advanced coal cleaning systems capable of reducing SO_2 emissions from coal combustors. These systems can be stand alone or integrated with flue gas cleanup or advanced combustor systems depending on cost and performance parameters of a specific application. It is expected that future CCT solicitations will receive proposals based on technology developed under the DOE Coal Preparation Program.

APPLICABILITY OF THE TECHNOLOGY TO RETROFITTING, REPOWERING, OR MODERNIZING EXISTING FACILITIES

A coal preparation plant is normally a stand-alone unit which can be constructed at mine mouth, at a central processing point, or at a customer's facility. Physically and technically a coal cleaning facility can readily be used to retrofit, repower, or modernize existing facilities, space permitting.

In order to optimize the economic and technical contribution of a planned coal cleaning plant to utility operation, for example, an analysis of the overall cleaning facility plus power plant system is necessary. The feed coal must be considered in selecting the cleaning technology and major pieces of equipment. Also some assurance is required that the cleaned coal product is a satisfactory fuel for the existing, or planned, combustion equipment. The final emissions of sulfur dioxide and particulates will be controlled by adjusting downstream cleanup to take advantage of the cleaner coal feed. The system's operating cost and/or emissions will be reduced if the components are properly integrated. These benefits can be achieved with a properly integrated coal cleaning facility providing a fuel of lower ash and sulfur content. Such a clean fuel may reduce the transportation costs and will lower erosion and corrosion of boiler tubes, reduce the generation of waste on site, and improve the efficiency and reliability of the boiler plant. The requirement for post-combustion cleanup will be reduced or possibly eliminated under certain conditions.

Coal preparation technology also can be used at locations where high carbon-content residues or reject materials are available to reduce the ash and sulfur content of those residues, thereby increasing the supply of cleaner fuel.

FLUE GAS CLEAN-UP

DESCRIPTION

Currently available options for SO_2 control during coal utilization consist primarily of physical coal cleaning, switching to low-sulfur coal, and flue gas cleanup. Each has associated advantages and disadvantages. Physical coal cleaning is already in wide practice where it is presently economic to do so. However, the capability to reduce significantly the sulfur content of coals by conventional coal preparation is limited because only some of the inorganic sulfur contained in the mineral portion of the coal can be removed.

Switching to low-sulfur coals, although likely to be the lowest cost option available, also has a number of potential disadvantages. Analyses show that the high-sulfur coal industry would be severely affected. Fuel costs could increase both as a result of greater demand as well as higher transportation costs. Coal characteristics such as hardness, ash content, and heating value also differ from one coal to another, which could result in problems such as exceeding particulate control standards and causing plant derating. Substantial plant modifications could be necessary in order to compensate for the different characteristics of low-sulfur coal.

The third major approach is to clean the flue gases. Flue gas cleanup technology involves control of SO_2, NO_x, and particulate emissions released during coal combustion. In the case of SO_2 (mainly sulfur dioxide with a few percent of sulfur trioxide), many processes have been proposed as ways to reduce their concentrations in combustion gases. As a general rule, these processes can remove 80-90 percent of the sulfur oxides from combustion flue gases containing 0.2-0.3 percent of these oxides. Flue gas treatment processes may be divided into two broad categories: wet and dry, depending upon whether the SO_2 absorbent is in a liquid or dry solid form. The processes can also be divided further into non-regenerative and regenerative types.

In wet processes, SO_2 is removed from the flue gases by scrubbing with an aqueous solution or slurry. To avoid vaporizing the water and associated problems, the gas must be cooled before it enters the scrubber. Several different types of scrubbers have been designed to achieve intimate contact between the gas and the scrubbing (absorbing) liquid. Although liquid-gas scrubbing is simple in principal, several problems arise in practice. These problems include deposition of scale, especially with a slurry scrubber; blockage or plugging of the demister; and corrosion and erosion of the equipment.

The equipment for dry desulfurization of flue gases is generally simpler than the equipment used for wet scrubbing. However, reaction of SO_2 with a dry sorbent generally is slower than with a solution or even a slurry. To overcome this drawback, dry scrubbers may be larger in size in order to expose a large surface area of solid absorbent to the flue gases.

The new flue gas cleanup technologies that are under development and/or demonstration can be divided in two generic process categories: (1) dry sorbent injection and (2) post-combustion gas cleanup. The first category, dry sorbent injection, involves the injection of a dry SO_2 sorbent such as limestone or hydrated lime directly into the combustion zone to capture SO_2 in situ. The second category, post-combustion gas cleanup, involves the reaction of sorbents in slurry, aqueous liquor, or dry powder form in the combustion gas stream downstream of the boiler to capture SO_2 following combustion.

In NO_x control, work to date has focused on combustion modification (air staging) and flue gas treatment. Both approaches have now been commercialized. Air staging is characterized by low cost but has limited potential (on the order of 50-60 percent maximum NO_x removal). Flue gas treatment, on the other hand, offers high effectiveness but with costs that are presently considered prohibitive in the United States. Recently, increased emphasis has been placed on another approach to combustion modification termed variously as reburning, fuel staging, or in-furnace NO_x reduction. The process involves the injection of fuel into combustion gases, followed, after a suitable residence time, by the addition of sufficient air at a somewhat lower temperature (roughly 1000 °C) to complete the combustion process. Modifying the combustion process in this manner destroys NO_x contained in the original combustion stream.

The reburning process is very complex. The potential for NO_x reduction appears to be a function of a relatively large number of process parameters, including temperature, relative fuel split between the primary combustion zone and the reburning zone, primary and reburning zone air-to-fuel ratios, gas residence time in the reburning zone, and the nitrogen content of the reburning fuel. If not correctly implemented, NO_x can actually be generated in the reburning zone from the reburning of fuel-bound nitrogen. In addition, the potential exists for reducing combustion efficiency as the result of incomplete fuel combustion. To realize the full potential of this technology, further research is required to improve understanding of the mechanisms involved, identify the free radical species of primary interest, and enhance the generation of these free radical species.

Some work is also being supported on the development of novel cleanup processes with the capability of simultaneously removing 90 percent of both SO_2 and NO_x. Some of the process under development include the electron beam/ammonia, fluidized-bed copper oxide, moving-bed copper oxide, NOXSO, and a modified lime spray dryer approach.

ENVIRONMENTAL CHARACTERISTICS

Currently available post-combustion cleanup technologies for SO_2 control essentially consist of using either wet limestone scrubbers or lime spray dryers. Wet limestone-based scrubber processes are most commonly used because limestone is much less expensive than alternative reagents, such as lime; and the cost differential becomes magnified as the sulfur content of the coal increases. The increasing use of forced oxidation in conjunction with limestone scrubbing generates a gypsum product that is readily dewatered and negates many of the problems

associated with the handling and disposal of a thixotropic sulfite sludge. The potential also exists for reducing capital cost through elimination of dewatering equipment. Utilities must, however, cope with the fly ash disposal problem, which is compounded by the flue gas desulfurization (FGD) waste disposal problem. Limestone scrubbers are effective (in excess of 90 percent SO_2 control) but are relatively expensive to purchase and operate. Reliability and availability have also been problem areas in addition to the waste handling and disposal.

The spray dryer can offer advantages over the commercially available limestone scrubbers especially for retrofitting where space requirements and land available for waste disposal can limit the application of wet scrubbers, or where remaining boiler life is low. Spray dryers generally have lower capital costs than scrubbers. The spray dryer cleanup systems capture SO_2 by contacting the hot flue gas with a finely atomized lime slurry in a spray dryer vessel. The water in the slurry is evaporated by the heat in the flue gas and the SO_2 reacts with the lime to form a dry calcium sulfite/sulfate products. The solid product plus ash is collected in the electrostatic precipitator (ESP) or baghouse. The resulting dry solids product is more manageable than the sludges produced in many wet scrubbing processes. These solids can be disposed of in suitable landfills. If high concentrations of unreacted alkalis remain, however, special consideration may be needed in its disposal. It should be noted also that application of the lime spray dryer processes to high-sulfur coals is in a relatively early stage of development, although it can now be considered commercially proven for use with low-sulfur western coal. More compact and somewhat less complex than the wet limestone scrubbers, the spray dryer's economic advantages over limestone scrubbers decrease with increasing coal sulfur content as a result of higher reagent costs.

Regenerable scrubbing processes do not produce a throwaway solid waste, but instead produce salable products such as elemental sulfur or sulfuric acid. In the dry sorbent approach, a solid absorbent is used to absorb SO_2 and NO_x. Upon regeneration at higher temperatures using a reducing gas, sulfur and nitrogen compounds are stripped off. These compounds are subsequently destroyed or converted to salable products using commercially available technologies. Consequently, regenerable systems avoid the growing problem of disposal of the solid wastes experienced by traditional flue gas cleanup technologies.

STATUS OF DEVELOPMENT AND WORK IN PROGRESS

Dry Sorbent Injection

The limestone injection multistage burner (LIMB) is an emerging technology that is currently undergoing research and development at the bench, pilot, prototype, and demonstration plant levels. The thrust of ongoing research is to identify those factors that govern system performance so that the removal efficiency can be optimized. An important aspect of this goal is the normalization of all site-specific factors to develop widely applicable process designs.

The Environmental Protection Agency (EPA), EPRI, DOE, and private industry are funding research being conducted by domestic and international boiler suppliers to optimize low- NO_x combustion/alkali injection techniques. Several major test programs have been completed or are being contemplated to conduct the following:

1. EPA is supporting major demonstrations. A commercial-scale demonstration of LIMB on a wall-fired boiler is now in progress. A project for a full-scale tangentially fired LIMB demonstration is also under way.

2. DOE funded a test of sorbent injection on a pulverized coal boiler using low-sulfur western coal. Preliminary analysis of the data showed favorable results.

3. Conoco funded testing on an industrial pulverized coal boiler. The demonstration yielded favorable results with respect to performance objectives. Further testing was also performed on sorbent injection in the duct upstream of the ESP.

4. Internationally, a number of countries are conducting research. Two significant contributors are Canada and West Germany; three jointly funded test programs have been completed or are under way in Canada, and two commercial LIMB facilities were placed in service in West Germany.

Post-Combustion Gas Cleanup

Advances in post-combustion gas cleanup are being made with respect to both process improvements and advanced processes. These improvements and processes can be applied to new plants or can retrofit existing facilities if space and economic constraints permit.

Numerous activities are being conducted by both the private and public sectors to improve the operation of existing emissions control systems. These process improvement activities include the following:

1. For existing FGD systems, research efforts focus on the use of organic acids or magnesium salts to enhance SO_2 removal efficiency and reagent utilization. Results indicate that a removal efficiency of 95 percent can be achieved at reduced operating costs.

2. For existing and new FGD systems, research is being conducted on reducing fresh water consumption and cleaning up wastewater discharges. The private sector, in conjunction with EPRI, is conducting research to reduce FGD water consumption, including recycling, biological control, and integrated water systems for power plants.

3. For SO_2 control, a promising low-cost of the FGD option is dry injection of sodium-based sorbents in the flue gas before the fabric filter. EPRI has demonstrated this process, which is applicable to both new and existing low-sulfur coal facilities, in a full-scale facility. Additional research is proceeding on high-sulfur coal applications for use with ESPs for improved waste fixation and disposal, for system optimization, and for use with lower cost alternative reagents. Based on the success of this process development, a 112-MW

commercial-scale demonstration was conducted at the Colorado Springs R.D. Nixon Plant, and the Public Service Company of Colorado has announced the use of a dry injection system for a new 500-MW coal-fired unit.

4. In the area of NO_x control, most of the work to date has focused on combustion modification (air staging) and flue gas treatment. Both approaches have now been commercialized. Reburning is being evaluated in the United States and Japan. Experimental results suggest that the combination of reburning with conventional air staging can result in NO_x reduction levels approaching those now attainable only through relatively expensive flue gas treatment processes.

5. For particulate control, research efforts are centered on performance improvement and optimization. In response to concerns related to trace element and inhalable particulate emissions, substantial emphasis is being placed on the removal of submicron-sized particles. Examples of these research efforts include electrostatic, electromagnetic, and sonic horn augmentation for fabric filtration; two-stage ESP; and use of additives.

In the area of advanced processes, significant long-term research is currently under way in combined SO_2/NO_x control, SO_2 control, NO_x control, and particulate control as described below.

1. Research and development activities in combined SO_2/NO_x flue gas cleanup are focusing on the development of processes capable of simultaneously controlling SO_2 and NO_x at the 90 percent level. Some of the relatively more mature processes that have been or are under development include: (1) electron beam/ammonia injection, (2) fluidized-bed copper oxides, (3) NOXSO, and (4) a modified lime spray dryer approach. The current development status of these technologies ranges from bench-scale to proof-of-concept. Additional process concepts currently in the early laboratory stage of development include the moving-bed copper oxide, electrochemical and membrane-based removal processes.

2. For advanced SO_2 control technologies, the primary emphasis is on reagent regeneration and salable product processes to eliminate or minimize solid waste disposal problems. The Flakt Boliden (sodium citrate reagent) and CONOSOX (potassium salt reagent) processes are in pilot-scale development, with commercial availability projected for the late 1990s. Advanced limestone/gypsum FGD processes, which produce marketable gypsum through forced oxidation of the spent slurry, are being developed for application in the United States. A 23-MW prototype of the Chiyoda Thoroughbred 121 process was successfully tested.

3. For post-combustion NO_x control, the selective catalytic and selective noncatalytic reduction systems are the most advanced. Pilot-scale systems of these two technologies have been tested on coal-fired power plants and found to be effective. However, these processes are more expensive than combustion modification, and major improvements are needed in the process control subsystem, extension of catalyst life, and elimination of ammonia leakage.

4. In the area of particulate control, DOE has a number of projects under way to improve the capability for removing respirable particulates. Approaches being pursued include acoustic agglomeration, particle precharging, centrifugal separation, and chemical conditioning.

PROJECTS IN PROGRESS

There are eight projects in the flue gas cleanup technology category; The projects are listed in the following table.

Projects in Progress

Project	Site
Babcock & Wilcox Co./Tests of Limestone Injection Multistage Burner and Sorbent Duct Injection	Lorain, OH
Energy & Environmental Research Corp. Reburning & Sorbent Injection In Utility Boilers	Springfield, Hennepin, & Bartonville, IL
Commonwealth Edison/Copper Oxide Regenerable Flue Gas Desulfurization System	Kincaid, IL
TVA Spray Dryer/Electrostatic Precipitator Pollution Control Device	Paducah, KY
University of Illinois/Wet Flue Gas Desulfurization System	Champaign, IL
Babcock & Wilcox Co. (Ohio Edison's Toronto Station)/Post-combustion SO_2 Control	Jefferson, OH
Columbia Gas System Corp./Catalytic Reduction Process for Coal Flue Gas	Columbus, OH
New York Electric and Gas/High Sulfur Test Center	Somerset Station, Niagara, NY

RELATIONSHIP BETWEEN THE R&D PROGRAM AND THE CCT PROGRAM

The first successful full-scale testing of hydrated lime in furnace sorbent injection processes was accomplished under the DOE research and development program in flue gas cleanup. The use of hydrated lime has since been adapted by the Babcock & Wilcox Company and Energy and Environmental Research Corporation in CCT-I projects. The hydrate addition at low temperature (HALT) process currently being developed under the DOE Flue Gas Cleanup Program will provide important data to the Coolside process being used by the Babcock & Wilcox Company and to the duct injection process for SO_2 control in cyclone furnaces being used by the Energy and Environmental Research Corporation.

In return, test facilities being developed in these two CCT-I projects could provide for future full-scale demonstration of technologies under development in DOE's Flue Gas Cleanup Program. Technologies that could be demonstrated include advanced reburning concepts for NO_x control, improved boiler sorbents for SO_2 control, and in-duct injection of hydrated lime slurries.

APPLICABILITY OF THE TECHNOLOGY TO RETROFITTING, REPOWERING, OR MODERNIZING EXISTING FACILITIES

Dry-sorbent-based processes, such as furnace injection (LIMB) and duct injection (Coolside), have been conceived primarily with retrofitting in mind. Duct injection of hydrated lime slurries also falls into this category. Advanced flue gas desulfurization processes and combined SO_2/NO_x processes generally are geared toward new construction. Applicability for retrofitting needs to be determined on a site-specific basis.

FLUIDIZED-BED COMBUSTION

DESCRIPTION

Fluidized-bed combustion (FBC) technology derives its name from the vigorous fluid-like agitation that takes place inside a boiler. The technology comprises two broad categories: (1) atmospheric fluidized-bed (AFB) combustion, which operates at or near atmospheric pressure on the fireside, and (2) pressurized fluidized-bed (PFB) combustion, which operates at a fireside pressure of 90-300 pounds per square inch (gauge). An FBC boiler is a combustion chamber for converting the chemical energy of coal or waste products into thermal energy for process heat, steam, or electricity. FBC boilers offer two major advantages over conventional stoker-fired and pulverized-coal boilers: (1) control of SO_2 and low-NO_x emissions by virtue of limestone addition and low combustion temperature in the combustion chamber, thereby eliminating the need for scrubbers, NO_x control burners, or elaborate combustion modifications, and (2) fuel flexibility allowing the burning of a range of solid fuels with widely varying ash, sulfur, and moisture contents by the presence of a large mass of hot bed material.

In a fluidized bed, solid, liquid, and/or gaseous fuel, together with inert material (for example silica sand, sulfated limestone and ash from the fuel), are kept suspended in a combustion chamber through the action of fluidizing air distributed below the bed. The fluidization state can be achieved through either the bubbling-bed or circulating-bed concept. The bubbling-bed has a low fluidization velocity within the combustor. The circulating-bed concept through high fluidization velocity allows high solids carry-over and returns some of the retendable solid particles to the combustor for additional burning.

ENVIRONMENTAL CHARACTERISTICS

Fluidized-bed combustion technologies burn coal to produce steam and/or electricity for utility and industrial use while reducing SO_2 or NO_x emissions within the combustor. Fluidized-bed combustion for both AFB and PFB provides in situ SO_2 and NO_x emissions control. The operating temperature of the combustion process is below the thermal NO_x formation point. The injection of a carbonate sorbent (calcite or dolomite) into the bed of the combustor results in the capture of SO_2 released during the combustion process. The only downstream pollution control equipment needed is for particulate matter. DOE data from numerous operating hours show that FBC technology readily meets current NO_x and SO_2 standards and that existing New Source Performance Standards (NSPS) for particulate emissions can be met using an electrostatic precipitator or fabric filter.

The secondary environmental impacts associated with FBC are similar to those of conventional coal combustion. The FBC processes generate an inert dry solid waste material containing coal ash, unused sorbent (calcined limestone), and spent sorbent (calcium sulfate). This waste is removed from the process as spent bed material along with the collected particulate matter and may be disposed in landfills or be sold for industrial or agricultural applications.

STATUS OF DEVELOPMENT AND WORK IN PROGRESS

ATMOSPHERIC FLUIDIZED-BED COMBUSTION

AFB technology is commercially available now for large industrial boiler applications (200,000 lbs/hr steam and greater). Commercial units are offered by 17 U.S. boiler manufacturers, and approximately 130 units are either operating or committed to construction. However, economic applications of fluidized-bed combustion in the smaller sizes that are required for light industrial and commercial/institutional applications are not commercially available. AFB systems in these size ranges would allow coal to be substituted for oil and gas in these important market sectors. The major emphasis of DOE's current AFB program is to develop AFB technology for these market applications.

Department of Energy Program

The objective of DOE's AFB program is to develop the systems technology by 1992 so that the private sector can demonstrate and commercialize coal-fired AFB systems for the industrial, commercial, and residential sectors that are capable of economically generating process steam, indirect and direct heating, and on-site electric power as a means of displacing oil and gas.

The AFB program consists of the following major elements: (1) industrial applications, (2) advanced concepts, (3) special applications, and (4) technology development, each of which is explained below:

1. Industrial Applications--Demonstration units (Rivesville, Georgetown, Shamokin, Great Lakes, Wilkes-Barre, and East Stroudsburg) were supported in industries with large potential uses for the technology. These units, co-funded by DOE, were operated by industry and illustrated performance in the host industry. Work in industrial applications is essentially complete. All that remains is some monitoring, collecting, and evaluating of operational results from the demonstration units. This will expand the data base for determining technical, economic, and environmental characteristics.

2. Advanced Concepts--To broaden market penetration into the industrial sector (75,000-200,000 lbs/hr steam), AFB concepts are needed that offer significant improvements in economics and performance. Such advanced concepts designs have been evaluated, and two (Kellogg and Battelle) are being tested for the potential to reduce capital costs to 20-30 percent less than those for conventional FBC systems. Bench-scale testing for the Kellogg concept was completed in September 1986. Bench testing of the Battelle concept was 1988.

   In 1988, two new contractors (Riley Stoker and York Shipley [now Donlee]) were selected under a competitive solicitation to develop new advanced concepts. Work on these projects will continue the effort to address the application of atmospheric fluidized-bed technology to the small boiler market.

In June 1988, Good Samaritan Hospital, in conjunction with Skelly and Loy, York Shipley, and the Pennsylvania State University, was funded to develop a coal-burning circulating FBC hospital waste incinerator.

3. Special Application--Projects involve market analyses, system and economic studies, and design and testing of special AFB applications. The focus is primarily on light industrial, commercial, and institutional applications that are less than 50,000 lbs/hr steam. In 1988, four contractors were selected under a competitive solicitation to develop concepts for special applications. Each project includes market analysis, system and economic studies, and testing through proof-of-concept of an innovative AFBC design.

4. Technology Development--Activities provide the basic system support needed to advance and broaden the state-of-the-art of AFB. Technology development is aimed at investigating, testing, and analyzing technical issues and data for AFB technology and providing research and development support for prototype systems so that industry can efficiently undertake commercialization.

Private Sector Program

The Electric Power Research Institute (EPRI) has taken the initiative in adapting AFB to utility scale. The three utility demonstrations of AFB supported by EPRI are listed below:

1. Colorado-Ute, Nucla Station, 110 MW--A new circulating fluidized-bed boiler was built to repower an existing 36-MW steam turbine/generator and power a new 74-MW steam turbine/generator. The plant achieved full load operation in March 1988. Parties involved in this project included Colorado-Ute, Pyropower, Stearns Catalytic, Peabody Coal, Westinghouse, EPRI, and the National Rural Electric Cooperative Association. DOE completed negotiations resulting in the project's inclusion in CCT-I.

2. Northern States Power, Black Dog Station, 125 MW--This retrofit of an existing 100-MW pulverized coal boiler, upgraded to 125 MW with a bubbling fluidized-bed design, became operational in 1986. Participants include Northern States Power, Foster Wheeler, Stone and Webster, and EPRI.

3. Tennessee Valley Authority, Shawnee Station, 160 MW--A new AFB boiler is being used to repower and extend the life of an existing 160 MW steam turbine generator through the installation of a bubbling fluidized-bed design partially supported by DOE. Full-scale operation was achieved in April 1989.

Additionally, a new 150-MW circulating fluidized-bed combustion boiler system with an external heat exchanger is under construction in Robertson, Texas for Texas-New Mexico Power. This utility plant is scheduled to be operational in January 1990.
Industrial applications have also been demonstrated. A 190,000-lbs/hr steam circulating AFB unit has been in operation at a California Portland Cement Company plant since 1985. Other AFB units in excess of 300,000 lbs/hr steam are being used by Archer-Daniels-Midland, General Motors, Scott Paper, Westwood Energy, Gilberton Power Company, Signal, A.E. Staley, and Fort Howard Paper.

PRESSURIZED FLUIDIZED-BED COMBUSTION

The objectives of DOE's PFB Program are to (1) develop a U.S. technology base for scientific and engineering technology data to support private sector efforts to demonstrate and commercialize the first PFB systems for electric power generation in the early 1990s, and (2) extend the state-of-the-art by developing advanced PFB concepts. The goals desired are substantial improvements in cycle performance (approaching 45 percent), and at least 20 percent reduction in the cost of electricity as compared with the cost from conventional coal-fired power plants with flue gas desulfurization.

The PFB process is not as technically mature as AFB. Significant research and development has been conducted on PFB, however, and work has progressed to the point where sufficient data are available to design and construct a prototype PFB coal-fired demonstration plant. If all goes according to plan, industry should be able to proceed with pilot scale testing by the mid- to late-1990s.

Department of Energy Program

DOE's 17-year-old research and development program in PFB has made significant progress. Major advantages of the technology have been identified, and industry is now moving to build prototype systems which will lead to commercialization.

The research and development activities supporting the program are embodied in two categories:

1. PFB Technology Base--Projects are being aimed at developing a U.S. technology base, through proof-of-concept, to support private sector efforts to demonstrate and commercialize prototype PFB systems for electric power generation. Current PFB activities supporting the development of these prototype systems are summarized below.

    o Follow-on work at Grimethorpe in the United Kingdom (U.K.) involved developing pilot scale data on combustor performance, using a coal-slurry feed system and an updated, U.S.-designed heat-exchanger tube-bundle furnished by Foster Wheeler Development Corporation. Additionally, DOE will obtain project "core" data from the National Coal

Board (U.K.)-funded program as well as data from an advanced hot gas cleanup device provided for the project by EPRI.

- o The New York University test facility evaluated components, and tested and evaluated design alternations and changes in operating parameters which enhance process combustion and environmental performance. The facility also conducted proof-of-concept testing of advanced hot gas cleanup devices.

- o Metal wastage studies at the Morgantown Energy Technology Center (METC) and other organizations include erosion/corrosion (in-bed heat exchangers, gas turbine blades) experimental testing and predictive modeling.

- o METC in-house activities include systems evaluation, PFB data base activities, combustion performance, and testing of in-house reactors (both hot and cold).

- o Hot gas cleanup activities involve construction and system testing that integrates control and hot gas cleanup devices into a PFBC system located at the Tidd demonstration plant in Brilliant, Ohio.

2. Second Generation, Advanced Cycle Concepts--Foster Wheeler has initiated a multiphased project consisting of conceptual designs and cost estimates, experimental testing of key critical process components (pyrolyzer, circulating PFB, cross-flow filter, and topping combustor), and operating and evaluating an integrated subpilot test facility. M.W. Kellogg is developing and studying an alternate advanced PFBC concept which will provide coal fired commercial PFBC systems.

Private Sector Program

EPRI is characterizing several PFB cycles with the goal of identifying and recommending a program to accelerate technology demonstration. EPRI is also participating in the Grimethorpe effort by providing funding for the design and testing of an advanced hot gas cleanup device.

The American Electric Power Service Corporation Teamed with ABB-STAL and Babcock & Wilcox in a program which is constructing a PFB demonstration plant at the Tidd Station near Brilliant, Ohio. As part of the program, the team completed operation of a component test facility in Malmo, Sweden, to verify boiler design conditions projected for the Tidd Plant.

The City of Stockholm completed a design study and has initiated construction of a PFB boiler installation at a nearby cogeneration plant. It will produce 235 MW heat and generate 133 MW electricity using two PFB modules supplied by ASEA-PFB. Additionally, ASEA-

PFB has initiated construction of a 79 MWe PFB combined-cycle power plant for ENDESA at its Escatron Station near Madrid, Spain.

The United Kingdom joined with West Germany and the U.S. in cofunding the International Enrrgy Agency (IEA)/Grimethorpe project. In the United Kingdom, other principal PFB developments were achieved at the Coal Utilization Research Laboratory (CURL) facility which included several small test units. These were used in DOE-sponsored coal-water slurry and elevated pressure (20 atm) combustion test programs. The CURL facility has been dismantled, and the 20-atm testing unit was relocated to the National Coal Board's Stoke orchard (U.K.) facility.

PROJECTS IN PROGRESS

There are 14 projects in the fluidized-bed combustion technology category; A list of the projects follows.

Projects in Progress

Project	Site
American Electric Power Service Corp./Pressurized Fluidized-Bed Combustion Combined Cycle Utility	Brilliant, OH
Tennessee Valley Authority/160-MW Atmospheric Fluidized-Bed Combustion Demonstration Plant	Paducah, KY
20-MW Atmospheric Fluidized-Bed Combustion Pilot Plant	Paducah, KY
Anderson Clayton Foods Co./Dual Fluidized-Bed Boiler Retrofit	Jacksonville, IL
Archer-Daniels-Midland/108-MW Circulating Fluidized-Bed Cogenerators (5)	Decator, IL
Northern States Power/Atmospheric Fluidized-Bed Combustion Utility Conversion (Black Dog Unit No. 2)	Minneapolis, MN
Colorado-Ute/Circulating Atmospheric Fluidized-Bed Demonstration Plant	Nucla, CO
Wisconsin Electric Power Company/ Atmospheric Fluidized-Bed Retrofit of Four Coal-Fired Units (500 MW Total)	Oak Creek, WI
Texas-New Mexico Power Company/Circulating Utility Retrofit Fluidized-Bed Boiler	TBD (expected in Robertson Co., TX)
General Motors Corporation/27-MW Circulating Fluidized-Bed Cogeneration Unit	Pontiac, MI
Gilberton Power Company/Anthracite-Culm-	West Mahanoy

Fired Cogeneration Plant	Township, PA
Combustion Engineering & Lurgi Corp./ 27-MW Circulating Fluidized-Bed Cogeneration Plant	Reading, PA
Air Products & Chemicals, Inc./49-MW Circulating Fluidized-Bed Cogeneration Plant	Stockton, CA
Applied Energy Services/180-MW Circulating Fluidized-Bed Cogeneration Plant	Montville, CT

In addition, two projects have been identified in Europe:

- o SEP/ASEA-PFBC 130-MWe and 210-MWt Bubbling Bed PFBC Cogeneration Plant (Stockholm, Sweden).
- o Endesa/ASEA-PFBC and BWE/79-MWe Bubbling Bed PFBC Power Generation (Madrid, Spain).

RELATIONSHIP BETWEEN THE R&D PROGRAM AND THE CCT PROGRAM

Under CCT-I, as an extension of their earlier work described in the previous section, the American Electric Power Service Corporation has been selected to demonstrate a utility application of PFB combined cycle technology at the Tidd Station near Brilliant, Ohio. The project will retrofit the coal-fired power plant (no longer in use) to construct a 70-MW PFB combined-cycle demonstration plant. The plant will operate at 1580 °F and 12 atmospheres, with gases expanded through a gas turbine with a steam turbine bottoming cycle. The project will use technology developed by ASEA-PFB and marketed in the U.S. by ASEA Babcock PFBC (a joint venture between ASEA and Babcock & Wilcox).

Boiler design conditions for this demonstration project were verified at the team's Malmo, Sweden, test facility. Test data obtained from operation of the IEA/Grimethorpe project confirmed results of the Malmo tests. The current Grimethorpe program will provide data on coal/sorbent slurry feeding and combustion characterization using an updated, U.S.-designed, in-bed heat-exchanger tube-bundle. This technical information will be used in the detailed designing of the Tidd Station demonstration.

APPLICABILITY OF THE TECHNOLOGY TO RETROFITTING, REPOWERING, OR MODERNIZING EXISTING FACILITIES

ATMOSPHERIC FLUIDIZED-BED COMBUSTION

AFB technology offers the capability for retrofitting and repowering existing utility and industrial boilers. Benefits include emissions reductions, capacity increase, and plant modernization (life extension). Maximum use could be made of existing equipment, thereby saving the capital costs of building a new plant. Additionally, retrofitting would shorten construction time and greatly reduce the time required for permit and regulatory approval.

Retrofitting and/or repowering can be accomplished by either boiler replacement or modification. The Colorado-Ute, Nucla Station, is an example of boiler replacement; three existing stoker-fired boilers were replaced with a circulating fluidized-bed boiler. An example of boiler modification is the Northern States Power Project at the Black Dog Station (Minnesota). By retrofitting the Black Dog unit, which was designed for pulverized coal, the utility gained additional electric generating capacity while extending the life of a 35 year-old plant for an additional electric generating capacity while extending the life of a 35 year-old plant for an additional 25 years of operation. The project also resulted in considerable reduction in SO_2 and NO_x emissions as well as providing increased flexibility for burning numerous lower cost fuels. Additionally, the utility realized extremely favorable economic advantages because the cost of retrofitting was approximately one-quarter of the cost of a new pulverized coal-fired unit with a wet scrubber.

PRESSURIZED FLUIDIZED-BED COMBUSTION

PFB technology offers the capability to repower oil- and gas-fired boiler units (while switching them to direct high sulfur coal-burning) and to retrofit and/or repower existing coal-fired power plants. The American Electric Power Service Corporation's Tidd Station project is an example of retrofitting and repowering with PFB technology. The power plant's existing pulverized coal-fired boiler is being replaced with a pressurized fluidized-bed combustor. A gas turbine for combined cycle operation is also being added. In addition, repowering results in benefits such as maximum use of existing equipment, services, and sites, which saves capital costs, shortens construction schedules, and greatly reduces the time cycle for permit and regulatory approvals needed for a new power plant.

FUEL CELLS

DESCRIPTION

Fuel cells directly transform the chemical energy of a fuel (e.g, synthesis gas, reformed natural gas, reformed distillate fuel) and an oxidant (oxygen) into electrical energy. Each fuel cell includes an anode and a cathode separated by an electrolyte layer. In a typical fuel cell, fuel is supplied to the anode and air is supplied to the cathode to produce electricity, heat, and water.

Energy conversion in fuel cells is potentially more efficient (40-60 percent, depending on fuel and type of fuel cell) than traditional energy conversion devices. This is because fuel cells are not constrained by Carnot-cycle limitations and because electricity is generated directly in the fuel cell instead of going through an intermediate conversion step (i.e., burner, boiler, turbines, and generators). The fuel system efficiency can be increased further in cogeneration by using the byproduct heat of the reaction to generate steam or to heat water.

Coal is a target fuel for fuel cell power plants. A typical fuel cell system using coal as fuel would include a coal gasifier with a gas cleanup system, a fuel cell to generate electricity (direct current), a power processing section to convert direct current to alternating current, and a heat recovery system. The heat recovery system would be used to capture rejected thermal energy to produce additional electrical power in a bottoming cycle.

ENVIRONMENTAL CHARACTERISTICS

Fuel cells require very clean fuel to avoid contamination and degradation of performance; their tolerance to sulfur, particulate matter, and other contaminants is very low. Hence, during operation, emissions from fuel cells of air pollutants, suspended solids, solid wastes, and contaminated waste water are insignificant. The level of emissions from an integrated fuel cell/gasification combined-cycle system are similar to those emitted from coal gasification combined-cycle systems, except that combustion of the gas does not occur so NO_x and SO_2 production is negligible.

STATUS OF DEVELOPMENT AND WORK PROGRESS

The development of fuel cells in the United States has been under way for the past 25 years for high-technology applications such as the space program. During the 1970s, utilities began to investigate fuel cells as a potentially efficient, non-polluting alternative for generating power to meet load growth.

DOE is developing three types of fuel cells using different electrolytes: (1) phosphoric acid, (2) molten carbonate, and (3) solid oxide. Phosphoric acid systems are the most mature of these fuel cell systems and have the largest private-sector investment to date.

Within DOE's Phosphoric Acid Fuel Cell Program, two fuel cell applications are being emphasized: (1) electric utility systems and (2) on-site integrated energy systems. These two systems are designed for different sized applications, with the electric utility systems being in the multi-MW size range and the on-site systems in the 40-400-kW size range. Over 50 units of commercial prototype, phosphoric acid fuel cell (PAFC) power plants (200 kW) have been ordered and are expected to be ready for delivery in the early 1990s.

To date, PAFCs have been fueled by natural gas or naphtha, which is reformed to produced a hydrogen-rich fuel prior to being fed to the cell. Ongoing activities in PAFC development are described below:

1. International Fuel Cells Corporation (IFC), supported by DOE and the Electric Power Research Institute (EPRI), is completing the development of a commercial prototype 11-MW power plant. This would be the first fuel cell power plant intended for entry into the electric utility market.

2. Westinghouse, with DOE support, is also developing PAFC technology for utility power plants but is in an earlier stage of development than IFC. The present focus of the Westinghouse effort is on verifying fuel cell stack development goals and achieving the required performance and endurance levels in scaling up to the 100-kW-size stacks planned for the commercial prototype 7.5-MW power plant. The required performance has been demonstrated in laboratory stacks of up to 100-kW during short duration tests. Long term endurance and scale-up are being addressed. The Westinghouse effort is focused on developing a commercial scale 7.5-MW power plant with cofunding from the private sector.

3. DOE and the Gas Research Institute (GRI) have cofunded work to develop fuel cells for commercial and industrial applications. Under this program, IFC has made 46 field test installations of pre-prototype 40-kW on-site units for various applications. The DOE-GRI test program, completed in 1986, accumulated more than 350,000 operating hours of experience. The technical and economic data gathered from this program have been used to determine the most likely markets, applications, and unique design features for a commercial, on-site PAFC unit. Further development of technology for PAFC on-site applications is being performed by IFC.

The early commercial PAFC power plants are expected to operate on reformed natural gas or distillate fuels. Operating experience with these fuel cells is expected to pave the way for coal-based molten carbonate and solid oxide fuels that will operate at higher efficiencies.

While methane-fueled PAFC power plants are expected to have efficiencies of roughly 45-50 percent, coal-based molten carbonate fuel cell (MCFC) and solid oxide fuel cell (SOFC) power plants are anticipated to have efficiencies in the range of 50-55 percent. MCFC technology is currently in the early development stage and scale-up to full area stacks is in progress. Short stacks of up to 25 kW have been tested. Improvements are needed in cell life and tolerance to fuel contaminants such as sulfur. SOFC technology has been tested in single cells and in 3- and 5-kW modules. Improvements in solid oxide cell fabrication techniques and cell materials are needed to achieve repeatable long life. SOFC tolerance to sulfur in the fuel appears higher than that for other types of fuel cells, but more work is required to take full advantage of this feature. Molten carbonate and solid oxide fuel cells are not expected to reach the commercialization stage until about the year 2000.

PROJECTS IN PROGRESS

Fuel cell technology development and demonstration projects are being pursued in the United States under a variety of government and industry initiatives. Research is supported by DOE's Office of Fossil Energy under both the Office of Oil, Gas, Shale, and Special Technologies and the Advanced Research and Technology Development Program. Fuel cell research and demonstrations are also being supported by electric and gas utilities and utility organizations such as EPRI and GRI. Equipment manufacturers such as IFC, Westinghouse, and ERC are also pursuing active technology development programs.

APPLICABILITY OF THE TECHNOLOGY TO RETROFITTING, REPOWERING, OR MODERNIZING EXISTING FACILITIES

While a gas-fueled phosphoric acid fuel cell system is a possible candidate for retrofitting oil-fired, gas-fired, or coal-fired utility boilers for peaking and intermediate duty, more advanced fuel cell systems may supersede these applications. Future repowering applications of PAFC, MCFC, or SOFC fuel cells could potentially include the staged addition of fuel cells to the capacity mix. Being inherently modular, fuel cells are suited for incremental expansion or as replacements for older boilers and turbines. Whether fuel cells are employed in retrofitting or repowering applications, they are expected to deliver power to the utility grid at a higher efficiency than existing boiler and turbine equipment.

HEAT ENGINES

DESCRIPTION

Gas Turbine Engines

The gas turbine engine converts part of the energy of a hot gas stream to shaft horse power which can be used to generate electricity, pump liquids or gases, or drive vehicular or marine propulsion systems. Moreover, the excessive thermal energy can be used directly in industrial processing (cogeneration) or to generate additional electricity through a steam turbogenerator bottoming cycle (combined cycle).

Gas turbine power did not begin to penetrate the utility and industrial market to any significant extent until the mid-1960s. In 1966, installed capacity had reached only 2500 MW; by 1980, capacity had expanded to nearly 65,000 MW. Most of this growth occurred between 1965 and 1975.

The remarkable growth of gas turbine power in the 1960s was made possible by: (1) the development of a strong, progressive gas turbine manufacturing base in response to the rapid acceptance of gas turbine power by commercial airlines following World War II, and (2) an increasing recognition of the efficiency, cost, lead-time, and modularity advantages of gas turbine power in certain industrial and utility power applications. The equally remarkable reversal of gas turbine growth in the 1970s resulted from global price pressures. Gas turbine fuel sold for about $2.00 per million Btu in 1970; by 1975 prices had risen to $3.53 and by 1982 to $8.50. While current fuel costs are lower, the trend of costs for natural gas and petroleum-based fuels is upward. A less expensive alternative clean fuel is needed. Cost and/or availability limits consideration of natural gas to a few favorable geographic locations. Coal- or shale-derived liquids are limited by environmental and economic factors. It is clear, however, that coal, as the cheapest and most abundant raw material, offers significant potential as a source of a less expensive alternative fuel. To utilize this resource, clean coal technologies are required to produce coal-fueled gas turbine systems at a commercially competitive prices while meeting environmental standards.

Diesel Engines

The diesel is a high-compression, sparkless, internal combustion engine. Unlike the spark-ignition, gasoline-fired, internal combustion engine, the diesel burns lower cost fuel oils, e.g., No. 2 diesel fuel. The diesel will also accept, with suitable engine design modifications, heavier petroleum distillates, natural or medium-Btu gas, or liquid fuels derived from coal or oil shale providing they are thoroughly de-ashed and free of deleterious impurities.

The diesel offers major benefits in efficiency, load-following capability, compactness, and capital cost. These intrinsic advantages have earned distillate-fired diesel power a dominant position in critical U.S. and foreign transport, utility, and industrial applications. The development of a coal-fueled diesel could provide economic stability to the users and manufacturers of these engines.

ENVIRONMENTAL CHARACTERISTICS

Gas Turbine Engines

Coal-fired gas turbine power systems are expected to meet present environmental emissions regulations for particulates, NO_x, and SO_2. DOE studies indicate that exhaust gas cleanup systems, when applied to gas turbines, are uneconomical due to the high air flow. Therefore, control of emissions must be accomplished within the turbine by means of staged combustion to control NO_x, by gas stream SO_2 removal devices, and by high temperature filtering devices to control particulates.

Diesel Engines

Presently there are no emissions regulations pertaining to diesel engines. Because there is no opportunity to clean the working fluid within the engine, cleanup must be accomplished in the supplied fuel or in the engine exhaust, perhaps using a combination of highly beneficiated fuel and exhaust cleanup devices.

STATUS OF DEVELOPMENT AND WORK IN PROGRESS

Gas Turbine Engines

The direct firing of coal in gas turbines was attempted in the 1950s and 1960s, mainly in the United States and Australia. Inability to solve the serious erosion, corrosion, and ash deposition problems that were encountered forced the abandonment of these efforts. The gas turbine is extremely sensitive to certain fuel impurities, particularly compounds of sodium, potassium, calcium, sulfur, vanadium, lead, and other elements. Fuel specifications for high-efficiency, modern turbines operating at temperatures in the 1900 °F range restrict these impurities to a few parts per million (ppm) and, in the case of the most deleterious impurities (e.g., sodium), to less than 1 ppm. If these limits are exceeded, the system must be derated by reducing the operating temperature and periodically cleaning the turbine blades and vanes of accumulated deposits from impurities.

Refined coal liquids can be produced that meet turbine standards, but projected costs and market uncertainties have thus far deterred commercial development.

The current DOE program focuses on potentially lower cost coal-based fuel forms, i.e., minimally cleaned fuel gas and fine particulate coal in either dry power or slurry form. In addition to clean coal-based fuels, the program is investigating post-combustion cleanup techniques that could allow the burning of a poorer quality fuel while still protecting the power turbine.

Progress in both the gaseous fuel and the fine particulate coal approaches has been highly encouraging. Component development work has been initiated by major gas turbine engine manufacturers under a DOE contract in connection with the fuel gas approach. The fine particulate coal fuel concept research is concentrated on fuel quality, combustor design interactions, and their effects on turbine durability.

Diesel Engines

The principal problems with using lower quality, petroleum-based fuels in diesel engines relate to combustion deficiencies, corrosion, and wear. The combustion problem is associated with low cetane ratings (a general measure of the compatibility of diesel fuel combustion characteristics with engine operating requirements). The corrosion and wear problems are mainly associated with fuel-bound impurities and ash-forming minerals. In diesel fuel terminology, "lower quality" generally refers to residual oils or heavier distillates. When specially treated to remove harmful impurities and improve combustion characteristics, these fuels may be used instead of the conventional "clean" No. 2 diesel fuel. Research efforts both in private and government laboratories in the United States and Europe are taking this approach. European operators are using residual oil in large, slow-speed engines that are inherently more tolerant of lower quality fuels than the medium and high-speed engines that predominate in the United States. Railroads and other private sector and Federal programs (e.g., the Department of Transportation) are attempting to modify engine design and operating factors which would permit the use of specifically defined, lower cost, residual and blended fuels.

Because of long-range cost and supply uncertainties associated with these synfuel and petroleum-based alternatives, the DOE program is also looking at new coal-derived fuel forms. Coal was first evaluated as a fuel in diesel engines in Germany in the early 1940s. Coal dust was tried in a slow speed engine but excessive cylinder wear discouraged continuation. The coal used in these early tests did not have the benefits of present day "clean coal" technologies. The current DOE program is based on several of these advanced technologies (i.e., coal benefication, fine grinding, special fuels formulation, coal gasification, and hot gas cleaning). The coal-fired diesel work has progressed to preliminary test evaluation along with bench-scale research on combustion characteristics, fuel injection, and component wear. So far, this work has considered highly beneficiated, fine particulate coal-water slurries. Test evaluations of a coal slurry fuel have been made in slow- and medium-speed test engines; the fuel burned and successfully powered the engines. In addition, laboratory bench tests have been conducted to establish fundamental data relevant to engine design features required to utilize these fuels. Major U.S. diesel engine manufacturers are cost-sharing a program aimed toward definition of realistic fuel (both slurry and gaseous) and design requirements for the application of coal fuels to future diesel power systems.

PROJECTS IN PROGRESS

No specific projects in the heat engines category have been identified; however, the integrated coal gasification combined-cycle projects on surface coal gasification support gas and/or steam turbine development.

RELATIONSHIP BETWEEN THE R&D PROGRAM AND THE CCT PROGRAM

DOE's Heat Engines Program is now primarily investigating the direct combustion of coal in gas turbines and in diesel engines.

APPLICABILITY OF THE TECHNOLOGY TO RETROFITTING, REPOWERING, OR MODERNIZING EXISTING FACILITIES

Gas Turbine Engines

The extensive use of gas turbines in the utility market since the 1960s has resulted in several repowering applications. Repowering can be achieved by utilizing the heat in the exhaust of a gas turbine to generate steam, which in turn is used to run an existing steam turbine power plant; the original boilers are scrapped. The resulting configuration is a combined-cycle power plant. Adding the ability to burn a coal fuel makes the gas turbine even more attractive for repowering projects. The coal-burning gas turbine is, therefore, an excellent choice for repowering applications. Details, of course, depend on the specific repowering project.

As far as retrofitting or modernizing applications are concerned, it is entirely possible that, if the proper fuels are developed, an existing oil- or gas-fired gas turbine could be refitted to burn a highly beneficiated coal-water mixture. However, economics and fuel availability will be more significant factors that technology availability in a decision to make such a conversion.

Diesel Engines

There is no likely application of a coal-burning diesel engine for retrofitting, repowering, or modernizing existing facilities. Cost considerations are such that coal-fueled diesel engines are economic as originally installed equipment, but not as modifications to prior installations. However, the use of coal-derived liquids (e.g., from mild gasification) may be a possible alternative to diesel fuel.

SURFACE COAL GASIFICATION

DESCRIPTION

Coal gasification involves the conversion of the solid fuel, coal, and other carbonaceous materials into gas and liquid fuels through chemical reactions usually involving steam and oxygen or air. The gasification process provides a convenient mechanism for the removal of sulfur and ash from coal while producing the product gas, which is generally a mixture of hydrogen, carbon monoxide, methane, steam, carbon dioxide, nitrogen, and other minor impurities. The conversion of coal to product gas is accomplished by the introduction of an oxidizing agent (air and/or oxygen and/or steam) into a reactor vessel where this agent can come into intimate contact with a suitably prepared coal feedstock in a controlled reducing atmosphere. The composition of the product gas is greatly influenced by parameters such as temperature, pressure, and type of coal.

Once generated, the raw product gas leaving the reactor can be processed through a number of sequential gas treatment steps determined by the end use for the gas and environmental requirements. These gas treatment steps generally can be classified as low temperature or high temperature systems. Low temperature (i.e., 100 °F to 300 °F) systems most often are state-of-the-art technology representing relatively problem-free operation with high availability. On the other hand, high temperature (i.e., 800 °F to 1200 °F) technology is just reaching the demonstration stage and represents possible improvements in efficiency in future applications of some gasification technologies. This series of sequential steps that constitute a coal gasification process can be used to convert all types of coal into a wide range of products, including clean low- and medium-Btu gas suitable for industrial processes and power generation or a synthesis gas suitable for subsequent conversion into products that range from chemical feedstocks to high-grade transportation fuels.

Gasification of coal with air produces a low-Btu gas with heating values in the range of 125-150 Btu per standard cubic foot (scf). Gasification of coal with oxygen creates a medium-Btu gas with heating values in the range of 250-350 Btu per scf. Both can be used directly as fuel. Medium-Btu gas can be converted to hydrogen for ammonia synthesis or upgraded to a substitute natural gas with heating values of 950-1000 Btu per scf or used as a feedstock for chemical synthesis reactions yielding products such as methanol and ammonia.

Despite the variety in specific gasification processes, most are fundamentally similar in that they involve conversion (devolitalization and gasification) of coal to a mixture of hydrogen and carbon monoxide, called synthesis gas, for use as fuel or for further processing in an environmentally acceptable manner. Major energy applications in which this conventional coal gasification technology can be used include:

1. Production of electric power using integrated coal gasification combined-cycle systems

2. Production of (low- or medium-Btu) fuel gas for industrial processes

3. Production of synthesis gas for use as a chemical feedstock, manufacture of hydrogen, conversion to substitute natural gas, and as a feedstock for indirect coal liquefaction processes

4. Production of hydrogen for direct liquefaction

5. Disposal of solid wastes containing carbonaceous material

One variation of coal gasification involves pyrolytic conversion of coal in the absence of any oxidizing agent to a suite of value-added liquid, gaseous, and solid coproducts at relatively mild conditions of temperature (1000 - 1200 °F vs. 1800 - 2600 °F for conventional coal gasification) and pressure (atmospheric vs. 20 - 35 atmospheres for conventional coal gasification). This variation is called mild-gasification. Char, the major product of this mild gasification process, has value as a utility fuel or as a feedstock for production of form coke, metallurgical coke, activated carbon, smokeless fuel, or carbon electrodes. Through application of advanced processing and upgrading techniques, liquids from mild gasification can be converted to diesel fuel or octane enhancers. The gaseous coproducts can be used as feedstocks or burned to supply process heat for the pyrolytic gasification step of the system.

Liquids from mild gasification generally contain much lower sulfur content than the original coal feedstock and have a high hydrogen-to-carbon ratio for easy ignition and stable combustion; the sulfur content and hydrogen-to-carbon ratio of mild gasification liquid coproducts are similar to that of crude oil. Char from mild gasification is slightly enriched in ash over the original coal feedstock, but still contains an appreciable amount of volatile matter, which makes its combustion reactivity similar to that of coal. Projected applications of mild gasification include upgrading low rank coal to a char similar in properties to higher-rank bituminous coal, while simultaneously producing marketable liquid fuels. Mild gasification also applies to a preliminary process step in conventional coal gasification, where liquid coproducts add to the gasification plant's product slate, and char coproduct becomes gasifier feedstock instead of coal.

ENVIRONMENTAL CHARACTERISTICS

Conventional surface coal gasification technologies convert coal (in the presence of an oxidant--air or oxygen--and steam) to a fuel gas composed primarily of carbon monoxide and hydrogen. The fuel gas is burned in boilers to raise steam to generate electricity indirectly or in gas turbine combustors to generate electricity directly. If desired, the carbon monoxide/hydrogen mixture can be processed further to make ammonia or liquids such as methanol. In the production of the fuel gas from coal, the ash is discharged as dry solids, the fuel-bound nitrogen is converted to ammonia, and fuel-bound sulfur is converted to hydrogen sulfide and other organic sulfides such as carbonyl sulfide and mercaptans. The benefit of the gasification technologies is that the gaseous sulfur and nitrogen compounds can be removed economically and effectively before combustion.

Hydrogen sulfide removal can be achieved through chemical or physical absorption after gas cooling or by adsorption on metal oxides or their derivatives at high temperatures (1000 °F to 1200 °F). These processes can remove more than 99 percent of the gaseous sulfur compounds before combustion of the gases. The sulfur species absorbed in chemical solutions (cold cleanup) can be recovered as elemental sulfur or converted to sulfuric acid. From the high temperature processes (hot gas cleanup), the sulfur compounds can be recovered as sulfur (at great expense) or converted to sulfuric acid or solid sulfates (such as calcium sulfate), which ultimately can be disposed of in a landfill.

In addition, sulfur compounds may be captured within lower temperature gasifier technologies through the addition of limestone or dolomite. Capture levels of approximately 90 percent may be possible using this method, and further capture ("polishing") to exceed 99 percent total sulfur removal might be achieved by treating the fuel gas with a metal oxide adsorption process.

Nitrogen compounds (principally ammonia) are generated during the gasification process and, depending on the gasifier operating temperature, are contained in varying amounts in synthesis gas. The highest ammonia levels are produced in the lowest temperature reactor (e.g., fixed-bed gasifiers); lesser amounts are produced in fluid-bed reactors; and the lowest amount in entrained-bed reactors (which have the highest operating temperature). The ammonia compounds are easily removed in cold cleanup systems by dissolution in waste liquor streams and are subsequently recovered as salable ammonia for fertilizer applications. After cold gas cleanup, fuel gas contains only traces of ammonia, so that upon combustion the NO_x emission is far below current NSPS. With hot gas cleanup systems, the ammonia passes through into the fuel gas. Thus, NO_x emissions must be controlled by combustion modifications or external/internal NO_x removal processes when this fuel gas is combusted. In either treatment, the fuel gas can meet current NSPS.

When the fuel gas is burned in a gas turbine to produce electricity, the level of entrained particulate matter in the fuel gas must be controlled to a low level to protect the gas turbine and to meet current NSPS. The solids captured during gas cleanup are disposed of as solid wastes along with the primary ash from the gasifier. When the fuel gas is burned directly in a boiler, the suspended solids in the boiler discharge gas are controlled by conventional means. In this case, however, the level of input solids will be significantly below the level normally produced from direct coal combustion and removal will be to levels below current NSPS.

The solid waste from the gasifier will be coal ash, which can be disposed of in the same manner as coal-fired boiler ash. In fact, the solid waste from a high temperature gasification process is an inert material with many byproduct uses. When limestone is injected into the gasifier, the solids will contain calcium sulfides. It will be necessary to oxidize these solids to convert sulfides which are inert and can be disposed of in a landfill.

Mild gasification processes and some lower temperature conventional gasification processes produce condensable hydrocarbons. In lower temperature conventional gasification processes, using a cold-water cleanup system will require treatment of the wastewater to remove organic compounds before discharge. However, in systems employing hot gas cleanup processes, the gases are maintained at a high temperature (greater than 1000 °F) and burned directly at this temperature. The tars and oils produced are maintained in the vapor phase and decomposed during combustion.

STATUS OF DEVELOPMENT AND WORK IN PROGRESS

Gasification processes of all types are in operation in the United States and worldwide. Considerable research and development work is now in progress to produce advanced gasification systems that generate minimal environmental emissions and that are economically viable.

Even though the decline of oil prices in the 1980s has prompted a reassessment of priorities for the commercialization of processes, numerous demonstration studies have been completed or are under way, and a commercial plant for production of substitute natural gas and a plant for production of acetic anhydride have been put on-stream, as well as utility and industrial power generation projects. In several cases where a specific application of coal gasification technology could be identified, industry has assumed the responsibility for continuing the development of advanced gasifiers from the proof-of-concept stage into the demonstration phase. In other cases, the government has provided some form of support to stimulate further development. Some of these demonstration projects include:

1. Great Plains Gasification Project--Great Plains is a commercial facility in North Dakota using Lurgi gasifiers to produce 125 million Btu per day of substitute natural gas for commercial pipeline distribution. DOE provided a loan guarantee to assist industry in this venture. After successfully starting up and operating the facility, the partners in Great Plains Gasification Associates notified the government on August 1, 1985, that they were terminating their participation in the project and the partnership, and on that date defaulted on the Federal loan it received to build the plant. DOE paid off the approximately $1.6-billion of debt then outstanding, foreclosed on the collateral,

and, under Federal ownership, operated the facility until its sale to the Dakota Gasification Company on October 7, 1988.

2. Cool Water Coal Gasification Project--The Cool Water plant consumes 1000 tons per day of coal in a Texaco gasifier to produce synthesis gas for use in an integrated coal gasification combined-cycle system. The U.S. Synthetic Fuels Corporation provided price guarantees to this project. This plant is being operated in Daggett, California. The project demonstrated two versions of the technology: one for power generation and one for chemical synthesis gas generation.

3. British Gas Corporation/Lurgi Slagging Gasifier--The British Gas Corporation has constructed a commercial size gasifier at its Westfield Test Facility. The gasifier is being operated to confirm scale-up parameters and to define operating parameters for different coals.

4. Tennessee Eastman/Chemicals from Coal--A Texaco gasifier (900 tons per day) has been constructed at Kingsport, Tennessee, as part of a commercial plant. Demonstration of the gasifier and a process for the production of acetic anhydride from coal will continue.

5. High-Pressure High-Temperature Winkler Gasifier--Rheinbraun, Inc., of West Germany has constructed and is operating a demonstration-size (55 tons per hour) high-temperature, high-pressure Winkler gasifier as the first phase of a program to develop this gasifier and a process for producing methanol from coal.

6. Dow Syngas Project--An entrained-flow, coal-slurry fed plant (2400 tons per day) is being operated at Plaquemine, Louisiana. This project contains the world's largest gasification train (2400-3000 tons of coal per day). The process consists of a two-stage reactor concept to produce power, steam, and byproduct sulfur. This project is receiving price supports under a U.S. Synthetic Fuels Corporation agreement now monitored by the U.S. Treasury.

7. Shell Coal Gasification Process--An entrained-flow gasification plant (250-400 tons per day) designed to operate at high pressure and temperature to produce coal gas for power generation is operating at Deer Park, Texas. This plant is being developed by Shell Development Company.

In addition to these activities, DOE has supported the development of other advanced gasifier systems through the process-development-unit and pilot stages. Examples of these are the Catalytic Coal Gasification reactor; the fluidized-bed agglomerating ash gasifiers (e.g., U-Gas and KRW); and the CO_2 Acceptor and Hygas reactor systems.

These development activities have provided a variety of gasifiers and processes that offer a full range of operational as well as feedstock capabilities. Moreover, they have demonstrated the ability to convert coal into a variety of gaseous and liquid fuels as well as chemical feedstocks. Subsequent implementation of gasification technology will depend upon future energy demands and the availability of natural gas and oil to meet these demands as well as the environmental requirements of existing and future facilities. The aforementioned projects have defined the economic and environmental performance of those gasification technologies being demonstrated. Much of the information needed to perform a commercial evaluation is being made available.

PROJECTS IN PROGRESS

There are eight projects in the surface coal gasification technology category; descriptions are The projects are listed below.

Project in Progress

Project	Site
Allis Chalmers/KILnGAS Coal Gasification Project (co-funded with EPRI and the State of Illinois)	Wood River, IL
Dow Chemical Co./Dow Syngas Coal Combined Cycle Gasification	Plaquemine, LA
Cool Water Gasification Combined Cycle (construction privately financed)	Daggett, CA
Shell Oil Coal Gasification Demonstration Plant	Deer Park Complex Houston, TX
New Jersey Energy Associates/140-MW Cogeneration Plant using Coal-Derived Gas	Sayerville, NJ
Synfuels Genesis International & Dravo Corp./37-MW Coal-Fired Cogeneration Plant	Colstrip, MT

RELATIONSHIP BETWEEN THE R&D PROGRAM AND THE CCT PROGRAM

Technologies have been developed under DOE's research and development program funding including the Allis-Chalmers KILnGAS commercial module. DOE is funding activities at Texaco's Montebello facility which include design efforts that incorporate the Texaco gasifier with hot gas cleanup.

APPLICABILITY OF THE TECHNOLOGY TO RETROFITTING, REPOWERING, OR MODERNIZING EXISTING FACILITIES

Gasification offers the opportunity for retrofitting, refueling and/or repowering existing coal-gas- and oil-fired power plants with coal-derived fuel gas. Retrofitting/refueling applications would involve modifying an existing boiler to burn an alternative fuel (coal-derived fuel gas). Retrofitting an existing oil or natural gas boiler to use medium-Btu gas (300-500 Btu per scf) would require only minor modifications to the boiler and would result in no derating or loss of efficiency. Use of low-Btu gas (125-150 Btu per scf) would require considerably more modifications to the boiler and would probably result in derating and a lower efficiency. Repowering would involve the addition of one or more combustion turbines to an existing steam turbine power plant, which would result in increased capacity and reduced NO_x emissions.

Retrofitting or repowering provide for maximum use of existing equipment, thereby reducing capital costs. This would also extend the life of an existing plant, shorten construction schedules (compared to replacement with a new plant), and greatly reduce the time required for permit and regulatory approvals.

APPENDIX B

PROPOSAL FACT SHEETS

INDEX OF PROJECTS PROPOSED

INDEX OF PROJECTS PROPOSED (CONTINUED)

PROPOSAL FACT SHEET

Proposer:	AirPol, Inc.
Proposal Title:	10 MW Demonstration of Gas Suspension Absorption
Technology Category:	Flue Gas Clean-Up/Sorbent Injection
Coal Type:	Bituminous
Project Location:	Shawnee Test Facility West Paducah, McCracken County, Kentucky
Project Duration:	24 months
Estimated Total Project Cost:	$4,950,000
Estimated DOE Share:	40.0%
Estimated Proposer Share:	60.0%
Project Team Members:	AirPol Inc. FLS milijo a/s Tennessee Valley Authority

Proposal Summary:

AirPol Inc., along with its parent company, FLS miljo of Denmark, the Tennessee Valley Authority and other future sponsors, proposes to demonstrate the applicability of gas suspension absorption (GSA) for Flue Gas Desulfurization on U.S. coals. The technology would be most suitable for FGD retrofit to existing industrial and small utility coal-fired boilers.

The heart of the GSA system is a vertical reactor where flue gas is contacted with a suspended solids mixture consisting of lime, reaction products and fly ash. Most of the solids are recycled to the reactor via a cyclone while the exit gas stream passes through an electrostatic precipitator or baghouse prior to release to the atmosphere. The lime slurry is injected at the bottom of reactor and is regulated with a variable speed pump controlled by acid gas concentration measurements in the inlet and outlet gas streams. Dilution water is controlled by on-line measurements of exit flue gas temperature. The solids collected from the suspended particulate control device and cyclone unit are recombined and are disposed in a landfill. The objective of this project is to demonstrate the applicability of GSA to U.S. coal.

PROPOSAL FACT SHEET

Proposer:	Air Products and Chemicals, Inc. Dakota Gasification Company
Proposal Title:	Commercial Scale Demonstration of the Liquid Phase Methanol Process
Technology Category:	New Fuel Form/Indirect Liquifaction
Coal Type:	Lignite
Project Location:	Dakota Gasification Company Beulah, Mercer County, North Dakota
Project Duration:	75 months
Estimated Total Project Cost:	$213,701,857
Estimated DOE Share:	43.4%
Estimated Proposer Share:	56.6%
Project Team Members:	Air Products and Chemicals, Inc. Dakota Gasification Company

Proposal Summary:

The proposed project is to design, construct and operate a 500 tons per day (TPD) methanol facility. The proposed project would use the "Liquid Phase Methanol Process" (LPMEOH) to produce methanol from a coal-derived synthesis gas. The demonstration project would be located at the existing Great Plains coal gasification facility in Mercer County, North Dakota.

The LPMEOH technology was developed specifically to be used with integrated gasification combined cycle (IGCC) facilities to reduce capital costs and to improve flexibility of electric power production by storing energy in the form of methanol. Methanol produced at Great Plains by the LPMEOH process will be used in tests to demonstrate its suitability for boiler, turbine and transportation fuel applications.

PROPOSAL FACT SHEET

Proposer:	Alaska Industrial Development and Export Authority
Proposal Title:	Healy Cogeneration Project
Technology Category:	Combustion/Slagging Combustor
Coal Type:	Subbituminous
Project Location:	Usibelli Coal Mine Healy, Alaska Unorganized Borough, Alaska
Project Duration:	72 months
Estimated Total Project Cost:	$191,718,000
Estimated DOE Share:	48.6%
Estimated Proposer Share:	51.4%
Project Team Members:	Alaska Industrial Development and Export Authority Golden Valley Electric Association Joy Technologies Inc. Stone & Webster Engineering Corporation TRW Combustion Business Unit Usibelli Coal Mine, Inc.

Proposal Summary:

The Alaska Industrial Development and Export Authority (AIDEA) proposes to build the Healy Cogeneration Project, a new coal fired power and process heat generating facility at a site near Healy, Alaska. The facility will be based on a new power plant design which features innovative integration of the advanced TRW slagging combustor and a heat recovery system coupled with both high and low temperature emission control processes.

The proposed demonstration facility will be an important step toward fuel diversification of Alaska's electrical energy system which currently relies principally on oil. The Project will utilize 300,000 tons/yr of blended Alaskan sub-bituminous and waste coal having 0.2% sulfur and 18% ash, and will produce 50 MWe net of electrical power with potential to provide process heat to an adjacent coal drying pilot facility. In the demonstration phase, additional Alaskan coals of various quality will also be tested.

PROPOSAL FACT SHEET

Proposer:	Arctic Slope Regional Corporation
Proposal Title:	Remote Alaska Repowering Demonstration Project
Technology Category:	Fluid Bed Combustion/AFB
Coal Type:	Bituminous
Project Location:	Nome and Kotzebue, North Slope Borough, Alaska and Western Arctic Coal Region
Project Duration:	60 months
Estimated Total Project Cost:	$74,000,000
Estimated DOE Share:	48.0%
Estimated Proposer Share:	52.0%
Project Team Members:	Arctic Slope Consulting Group Mechanical Technology, Inc. Battelle Memorial Institute, Columbus Division Nome Joint Utility Kotzebue Electric Association

Proposal Summary:

The proposed project is to develop a coal mine, replace diesel powered electric generation plants with coal fired plants and provide district heating for the business sections of the cities. The demonstration project would be at Nome and Kotzebue two remote cities in Alaska.

The technology to be demonstrated is a circulating fluidized bed with external bed heat exchangers which supply compressed hot air for a 2.5 MWe expansion turbine and hot water for district heating. The replacement plant for Nome is expected to comprised of three units sized at 2.5 MWe each, for a total of 7.5 MWe. The Kotzebue plant will have two 2.5 MWe generating units. Each unit will be built as a module for shipment.

PROPOSAL FACT SHEET

Proposer:	The Babcock and Wilcox Company
Proposal Title:	Full-Scale Demonstration of Low NO_x Cell Burner Retrofit
Technology Category:	Combustion/Low NO_x Burner
Coal Type:	Bituminous
Project Location:	Dayton Power & Light's Stuart Power Station Unit No. 4, Aberdeen, Adams County, Ohio
Project Duration:	32 months
Estimated Total Project Cost:	$9,796,204
Estimated DOE Share:	48.4%
Estimated Proposer Share:	51.6%
Project Team Members:	The Babcock and Wilcox Company The Dayton Power & Light Company Electric Power Research Institute Ohio Coal Development Office Duke Power Company Tennessee Valley Authority Allegheny Power System New England Power Company Centerior Energy Corporation

Proposal Summary:

The objective of the proposed project is to demonstrate the cost-effectiveness of a newly developed low NO_x cell burner in reducing NO_x emissions from cell-fired utility boilers. Such boilers produce approximately 20% of the NO_x emissions from all U. S. sources.

The demonstration project would be a 605 MWe retrofit at the Dayton Power and Light Company's Stuart Station, Unit No. 4, in Aberdeen, Ohio. The demonstration project will replace all 24 two-nozzle cell burners with the newly developed low NO_x cell burners. NO_x emission and performance data before and after the conversion would be acquired and analyzed to determine NO_x reduction and impact on boiler performance.

PROPOSAL FACT SHEET

Proposer:	Bechtel Corporation
Proposal Title:	Confined Zone Dispersion Flue Gas Desulfurization Demonstration as a Commercial Unit at the Seward Station of Pennsylvania Electric Company (PENELEC)
Technology Category:	Flue Gas Clean-Up
Coal Type:	Bituminous
Project Location:	Seward Station, Indiana County, Seward, Pennsylvania
Project Duration:	36 months
Estimated Total Project Cost:	$8,510,200
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Bechtel Corporation Pennsylvania Electric Company (PENELEC)

Proposal Summary:

The confined zone dispersion (CZD) process involves injecting lime slurry into the flue gas duct ahead of the electrostatic precipitator (ESP). The process produces a non-toxic dry waste. In this proposed CZD demonstration, a new duct will assure a residence time of about 2 seconds. The proposed program includes a 6-month test with different types of absorbents and atomizers to verify the effect on SO_2 removal and the capability of the existing ESP for control of particulate emission and opacity. After this testing period, a one-year continuous demonstration, fully automated and integrated with the regular operation of the power plant, will be conducted.

PROPOSAL FACT SHEET

Proposer:	Bethlehem Steel Corporation
Proposal Title:	Blast Furnace Granulated Coal Injection
Technology Category:	Industrial/Iron Making
Coal Type:	Bituminous
Project Location:	Bethlehem Steel Corporation's Burns Harbor Plant Burns Harbor, Porter County, Indiana
Project Duration:	72 months
Estimated Total Project Cost:	$104,340,000
Estimated DOE Share:	30.0%
Estimated Proposer Share:	70.0%
Project Team Members:	Bethlehem Steel Corporation ATSI, Inc.

Proposal Summary:

The proposed project is to design, construct, and operate a retrofit to a blast furnace producing 7500 tons of hot iron per day. The demonstration will be conducted at the Burns Harbor, Indiana, steel mill of Bethlehem Steel Corporation.

The technology to be demonstrated employs granular coal in the air blast fed to a blast furnace used in iron production. Using coal in the air blast would reduce the amount of coke required in ironmaking. If the demand for coke were substantially reduced, there could be a significant reduction in SO_2, NO_x, and other noxious emissions from coke ovens.

PROPOSAL FACT SHEET

Proposer:	Calderon Energy Company
Proposal Title:	Demonstration of Calderon Method for: a) Repowering Existing Coal-Burning Facilities, and b) Providing for Future Energy Needs from Coal, by Co-Producing Electric Power and Methanol Cost Effectively in an Environmentally Acceptable Manner
Technology Category:	New Fuel Form/Mild Gasification
Coal Type:	Bituminous
Project Location:	Bowling Green, Wood County, Ohio
Project Duration:	58 months
Estimated Total Project Cost:	$215,050,000
Estimated DOE Share:	49.9%
Estimated Proposer Share:	50.1%
Project Team Members:	Calderon Energy Company Stearns-Roger Division The Alliance Machine Company Kickham Boiler & Engineering, Inc. A.P. Green Industries, Inc. Leeds & Northrup

Proposal Summary:

The proposed project is to design, construct and operate an integrated process to convert 1560 TPD of high sulfur Ohio coal into 87 MW electricity and 613 tons of methanol using the Calderon process. The project will be located at a greenfield site in Bowling Green, Ohio.

The Calderon Process operates at a pressure of 300 PSI and employs a coal pyrolysis step to produce rich gas for conversion to methanol and char. The char is gasified to produce a lean gas which is then combusted in a gas turbine to produce electric power.

PROPOSAL FACT SHEET

Proposer:	Char-Fuels Associates Limited Partnership
Proposal Title:	Dave Johnston CHARFUEL Demonstration Project
Technology Category:	New Fuel Form/Mild Gasification
Coal Type:	Subbituminous
Project Location:	Glenrock, Converse County, Wyoming
Project Duration:	34 months
Estimated Total Project Cost:	$27,996,724
Estimated DOE Share:	42.5%
Estimated Proposer Share:	57.5%
Project Team Members:	Char-Fuels Associates Limited Partnership The Babcock and Wilcox Company Stone & Webster Engineering Corporation Western Research Institute Richard W. Hanks Associates, Inc.

Proposal Summary:

The proposed project is to design, construct and operate a 150 TPD CHARFUEL fluidic fuel demonstration plant at the site of Pacific Power and Light's Dave Johnston Power Generation Station in Glenrock, Wyoming.

The CHARFUEL process is a high temperature, high pressure hydrodisproportionation (HDP) process to produce char and liquid products from coal. The char and liquid products are recombined into a slurry, the CHARFUEL fluidic fuel. The proposer claims that this fuel has the potential to replace high-sulfur coal in utility boilers.

PROPOSAL FACT SHEET

Proposer:	City of Independence, Missouri Power & Light Department
Proposal Title:	CFCR Cycle Demonstration at Blue Valley Station
Technology Category:	Fluid Bed Combustion/AFB
Coal Type:	Bituminous
Project Location:	Blue Valley Station, Independence, Jackson County, Missouri
Project Duration:	99 months
Estimated Total Project Cost:	$232,797,000
Estimated DOE Share:	38.0%
Estimated Proposer Share:	62.0%
Project Team Members:	City of Independence, Missouri (Power & Light Department) Stone & Webster Engineering Corporation Combustion Engineering Asea Brown Boveri

Proposal Summary:

The proposed project is to design, construct and operate a 107 MWe coal fired combined repowering (CFCR) cycle which has the potential to improve plant efficiency and operational flexibility. The demonstration project would be a repowering at the Blue Valley Station owned and operated by the City of Independence, Missouri.

The CFCR cycle utilizes an atmospheric circulating fluid bed (ACFB) combustor with an external bed air heater (EBAH). The steam from the ACFB is used in a conventional ranking cycle which powers a new 11.6 MWe topping steam turbine and repowers two existing 29.4 MWe steam turbines. ACFB solids are used to provide the hot compressed air in the EBAH to power two new hot air turbines (HAT) producing an additional 37.2 MW of electricity. The use of the EBAH permits the hot air cycle to be decoupled from the combustion process, allowing greater control and flexibility throughout the entire load range.

PROPOSAL FACT SHEET

Proposer:	Coal Tech Corp.
Proposal Title:	Demonstration of a 100MM BTU/HR Air Cooled Cyclone Coal Combustor on an Industrial Electric Power Plant
Technology Category:	Combustion/Low NO_x Burner
Coal Type:	Bituminous
Project Location:	Lester or Oaks, Delaware/Montgomery County, Pennsylvania
Project Duration:	48 months
Estimated Total Project Cost:	$21,398,288
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Coal Tech Corp. Burns & Roe Company

Proposal Summary:

The project will demonstrate retrofiting of an oil/gas designed package boiler converted to direct coal firing by using a patented air cooled coal combustor that replaces the oil/gas burner. The 48 month project, located in southeast Pennsylvania, will be a full scale commercial installation in an industrial boiler; between 8 and 9 MW of electric power will be generated for sale to a regional electric utility. The proposal claims that the air-cooled, coal-fired combustor will reduce nitrogen oxide and sulfur dioxide emissions.

PROPOSAL FACT SHEET

Proposer:	Corn Products, a Unit of CPC International Inc.
Proposal Title:	Steam Plant Repowering Utilizing Integrated Emission Control Technologies
Technology Category:	Flue Gas Clean-Up/Sorbent Injection
Coal Type:	Bituminous
Project Location:	Argo Plant Site Bedford Park, Cook County, Illinois
Project Duration:	60 months
Estimated Total Project Cost:	$104,000.000
Estimated DOE Share:	49.3%
Estimated Proposer Share:	50.7%
Project Team Members:	Corn Products, a Unit of CPC International, Inc. Sargent & Lundy TRW Flakt, Inc.

Proposal Summary:

Corn Products, proposes to demonstrate technologies that can be used to install new or to repower existing steam generating plants, thereby reducing NO_x, SO_2,. and suspended particulates air emissions.

The project will demonstrate the combined use of entrained coal combustion, furnace sorbent injection, and the ADVACATE fly ash reinjection process to minimize air emissions. Each of these technologies has independently demonstrated its capability for reducing emission levels. The proposed project offers the first opportunity to integrate the technologies in a single installation. Waste disposal requirements will be less complex than competitive technologies, in that most of the coal ash will be captured in the combustors as a nonleachable slag.

PROPOSAL FACT SHEET

Proposer:	CRSS Capital, Inc. and TECO Power Services Corporation
Project Title:	West Virginia IGCC Demonstration
Technology Category:	Integrated Gasification Combined-Cycle
Coal Type:	Bituminous
Project Location:	Hillsboro, Pocahontas County, West Virginia Alternative Site: Tallahassee, Leon County, Florida
Project Duration:	60 months
Estimated Total Project Cost:	$403,643,000
Estimated DOE Share:	30.0%
Estimated Proposer Share:	70.0%
Project Team Members:	CRSS Capital, Inc. TECO Power Services Corporation CRSS Services, a Division of CRSS, Inc.

Proposal Summary:

The proposed project is to design, construct and operate a 120 MW Integrated Gasification Combined Cycle (IGCC) plant located on a greenfield site near Hillsboro, West Virginia.

The demonstration project will include commercially available Lurgi Mark IV dry bottom gasifiers, a GE MS series gas turbine and a GE developmental hot gas clean up system. The proposed demonstration project will use low sulfur (0.5 to 1.0%) coal from nearby mines. The electric power generated from the demonstration plant will be dispatched to The Virginia Power Company grid via a 40 mile transmission line, construction of which is proposed as part of the demonstration project.

PROPOSAL FACT SHEET

Proposer:	CYCLEAN, INC.
Proposal Title:	Microwave Clean Coal
Technology Category:	Industrial\Advanced Coal Prep
Coal Type:	Bituminous
Project Location:	Georgetown, Texas and Pearl, Illinois Williamson County, Texas and Pike County
Project Duration:	24 months
Estimated Total Project Cost:	$6,000,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	CYCLEAN, INC. Western Illinois Power Cooperative, Inc. National Rural Electric Cooperative Assoc.

Proposal Summary:

The proposed project is to design, construct and operate a microwave tunnel and system to remove pyritic sulfur prior to combustion. The demonstration would take place at the Western Illinois Power (WIPCO) plant in Pearl, Illinois.

The process would subject finely ground coal to a high energy microwave field, and would control air or gas flow through the coal bed to optimize thermal decomposition of pyrites. The proposal claims the process would enhance the btu/pound energy content of the coal by removing moisture.

PROPOSAL FACT SHEET

Proposer:	Dairyland Power Cooperative
Proposal Title:	Alma PCFB Demonstration Project
Technology Category:	Fluid Bed Combustion/PFB
Coal Type:	Bituminous
Project Location:	Alma, Buffalo County, Wisconsin
Project Duration:	77 months
Estimated Total Project Cost:	$183,884,000
Estimated DOE Share:	48.0%
Estimated Proposer Share:	52.0%
Project Team Members:	Dairyland Power Cooperative Black & Veatch, Engineers-Architects Pyropower Corporation

Proposal Summary:

Dairyland proposes to construct and operate a Pressurized Circulating Fluid Bed coal combustor with a combined cycle gas turbine to produce steam to repower two older existing turbine generators. The estimated capability of the repowered units will be 40 megawatts of electricity. The PCFB chosen for installation will be designed and furnished by Pyropower Corporation, San Diego, California.

In this fluidized bed system, coal combustion occurs as the burning particles "float" as a suspended mixture in the combustion air. Limestone, introduced with the coal, reacts chemically during combustion to reduce the emission of sulfur dioxide. The relatively low operating temperature within the combustor will serve to diminish the release of oxides of nitrogen (NO_x).

PROPOSAL FACT SHEET

Proposer: Duke Power Company

Proposal Title: Full-Scale Demonstration of the HYPAS SO_2 and Particulate Matter Removal Process

Technology Category: Flue Gas Clean-Up/Sorbent Injection

Coal Type: Bituminous

Project Location: Marshall Steam Station, Catawba County, Terrell, North Carolina

Project Duration: 49 months

Estimated Total Project Cost: $46,806,029

Estimated DOE Share: 50.0%

Estimated Proposer Share: 50.0%

Project Team Members:
Duke Power Company
Electric Power Research Institute
Electric Power Technologies
Howden Canada
Flakt\Environmental Systems Division
ESEERCO
Consolidated Edison Company
New England Power Service
Radian Corporation
MONEX Resources, Inc.

Proposal Summary:

Duke Power will demonstrate the Hybrid Pollution Abatement System (HYPAS) at a 200 MW_e, coal-fired electric power generating station. HYPAS is a dry injection process for control of SO_2 and particulate matter emissions. The process consists of four steps: (1) removal of fly ash by an electrostatic precipitator (ESP); (2) evaporative cooling; (3) injection of hydrated lime and recycled by-products for reaction with SO_2; and (4) collection of the by-products in a pulse-jet fabric filter baghouse. The pulse-jet baghouse acts as a reactor to boost SO_2 removal and ensures high efficiency particulate control. The proposed site is representative of utility retrofit sites, including the need for moderate SO_2 removal, the need for particulate control upgrading, space constraints limited remaining life, and sale of fly ash.

PROPOSAL FACT SHEET

Proposer:	Ebara Environmental Corporation
Proposal Title:	Ebara Electron Beam Flue Gas Treatment Project
Technology Category:	Flue Gas Clean-Up/Salable By Products
Coal Type:	Bituminous
Project Location:	IPALCO's E.W. Stout Generation Station, Unit No. 7 Indianapolis, Marion County, Indiana
Project Duration:	53 months
Estimated Total Project Cost:	$46,443,320
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Ebara Environmental Corporation Indianapolis Power & Light Company

Proposal Summary:

The Ebara Electron Beam Flue Gas Treatment Project will demonstrate a novel capability of removing both sulfur oxides and nitrogen oxides simultaneously from the flue gas of a commercially operated, pulverized-coal utility boiler. Using this technology, the flue gas temperature is lowered in a spray cooler. After ammonia gas is injected, the flue gas is irradiated with high energy electron-beams in a process vessel. The active species generated during irradiation react with sulfur dioxide (SO_2), nitrogen oxides (NO_x) and ammonia (NH_3) in the gas to form dry particulates of ammonium sulfate and ammonium nitrate, which are captured in a byproduct collector.

The project will demonstrate a high removal efficiency of over 90 and 80 percent for SO_2 and NO_x in a single dry-type flue gas cleaning process. An alternative operating mode with comparatively low electron-beam energy use, to minimize overall cost per ton of SO_2 and NO_x removal, will be demonstrated as well. The Ebara E-Beam Process also produces a usable fertilizer byproduct.

PROPOSAL FACT SHEET

Proposer:	ENCOAL Corporation
Proposal Title:	ENCOAL Mild Gasification Demonstration Project
Technology Category:	New Fuel Form/Mild Gasification
Coal Type:	Subbituminous
Project Location:	Gillette, Campbell County, Wyoming
Project Duration:	42 months
Estimated Total Project Cost:	$72,564,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	ENCOAL Corporation Shell Mining Company The M.W. Kellogg Company SGI International

Proposal Summary:

The proposed project is to design, construct and operate a 1000 TPD demonstration plant using the liquids from coal (LFC) process technology. The demonstration project would be at the Triton Coal Company's Buckskin Mine in Campbell County, Wyoming.

The LFC process involves the mild gasification of coal at moderate temperatures and near atmospheric pressure to produce a solid, Process Derived Fuel (PDF), and a liquid, Coal Derived Liquid (CDL). The LFC process chemically modifies the feed coal to generate the two new fuel forms and also removes most of the moisture and some of the sulfur, depending on the sulfur form in the feed coal. The proposer claims that the PDF and CDL products are suitable for use at existing power plants, and that the CDL has potential use as refinery feedstock for petrochemicals and transportation fuels.

PROPOSAL FACT SHEET

Proposer:	Energotechnology Corp. and Westmoreland Energy, Inc.
Proposal Title:	Novel Power Plant Integrating Simple Coal Cleaning, A PC-Fired Boiler, A Smaller FBC Boiler and a Turbine/Generator
Technology Category:	Coal Cleaning/AFB
Coal Type:	Bituminous
Project Location:	Eccles, Raleigh County, West Virginia
Project Duration:	72 months
Estimated Total Project Cost:	$331,000,000
Estimated DOE Share:	36.5%
Estimated Proposer Share:	63.5%
Project Team Members:	Westmoreland Energy Inc. Energotechnology Corp.

Proposal Summary:

The proposed project is to design, construct, and operate a 200 MW coal-fired power plant complex. The demonstration would be at a greenfield site near Beckley, West Virginia. The novel technology consists of integrating a simple coal cleaning plant, a conventional pulverized coal-fired boiler equipped with a flue gas desulfurizer system, a second smaller fluidized bed combustor, and a single steam turbine/generator, condenser, and cooling tower.

PROPOSAL FACT SHEET

Proposer:	Energy Partners, Inc.
Proposal Title:	TCS/Babcock System Retrofit to Rochelle, Illinois Municipal Utility Plant
Technology Category:	Flue Gas Clean-Up/LIMB
Coal Type:	Bituminous
Project Location:	Rochelle, Ogle County, Illinois
Project Duration:	36 months
Estimated Total Project Cost:	$12,684,000
Estimated DOE Share:	48.7%
Estimated Proposer Share:	51.3%
Project Team Members:	Energy Partners, Inc. Rochelle Municipal Utility The Babcock and Wilcox Company Peabody Holding Company, Inc. Illinois Department of Energy & Natural Resources TCS, Inc. Federal Search, Inc.

Proposal Summary:

The proposed project is to design, build and operate a system consisting of pulverizers, solids transport means, and burners for retrofit installation at the Rochelle Municipal utility plant in Rochelle, Illinois. Coal and limestone are pulverized and co-fed to the boiler. Coal feed would be 250 tons/day.

The TCS/Babcock micronized coal system to be demonstrated employs a finely pulverized feed, having average particle size of about 20 micrometers. Sulfur dioxide is captured in the boiler by reaction with lime that is formed in situ from the limestone feed. Reduction of NO_x is achieved by using low NO_x burners.

PROPOSAL FACT SHEET

Proposer:	Energy Systems Associates
Proposal Title:	Demonstration of an Improved Reduced Eddy After Burn (REAB) Technology
Technology Category:	Combustion/Slagging Combustor
Coal Type:	Bituminous
Project Location:	Elrama, Washington/Allegany County, Pennsylvania
Project Duration:	41 months
Estimated Total Project Cost:	$2,600,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Energy Systems Associates The Babcock and Wilcox Company MTCI Company University of Arizona

Proposal Summary:

The proposed project will demonstrate the improved Reducing Eddy After Burn (REAB) technology. Duquesne Light Company will make available a 200 MW face-fired boiler in Elrama, Pennsylvania for the project.

REAB is an innovative approach to gas reburning with the objective of reducing nitrogen oxide emissions in boilers. The technology uses aerodynamically tailored fuel eddies to produce hydrocarbon radicals which in turn reduce nitrogen oxide to molecular nitrogen.

PROPOSAL FACT SHEET

Proposer:	Energy and Environmental Research Corporation
Proposal Title:	Evaluation of Gas Reburning and Low NO_x Burners on a Wall Fired Boiler
Technology Category:	Combustion/Gas Reburning
Coal Type:	Bituminous
Project Location:	Cherokee Station Denver, Adams County, Colorado
Project Duration:	43 months
Estimated Total Project Cost:	$14,472,117
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Energy and Environmental Research Corporation Public Service Company of Colorado

Proposal Summary:

The proposed project is to demonstrate the combination of Gas Reburning and Low NO_x Burners in a wall-fired utility boiler. The demonstration project would be at the Public Service Company of Colorado's (PSCCO's) Cherokee Power Station Unit No. 3, in Adams County, Colorado.

Gas Reburning involves cofiring 15 to 20 percent natural gas which creates a slightly fuel rich zone in the furnace so that oxides of nitrogen produced by the coal combustion are "reburned" and reduced to molecular nitrogen. Low NO_x Burners reduce the production of oxides of nitrogen through a combination of coal and air injection staging, and rate of coal/air mixing. Low NO_x Burners are fully commercial for wall-fired boiler applications. The proposer claims the combination of Gas Reburning and Low NO_x Burners is compatible and synergistic, and will achieve greater NO_x reduction than the individual technologies.

PROPOSAL FACT SHEET

Proposer:	Frontier Energy Corporation
Proposal Title:	Conversion of High Sulfur Ohio Coal and Heavy Oil to High Quality, Clean Liquid Fuels via the CCLC Co-Processing Technology, A Demonstration Project
Technology Category:	New Fuel Form Coal Oil Coprocessing
Coal Type:	Bituminous
Project Location:	Painesville Township, Lake County, Ohio
Project Duration:	366 months
Estimated Total Project Cost:	$410,000,000
Estimated DOE Share:	40.0%
Estimated Proposer Share:	60.0%
Project Team Members:	Frontier Energy Corporation Canadian Energy Developments Inc. Kilborn International Ltd.

Proposal Summary:

The proposed project is to design, construct and operate a plant to co-process coal and heavy oil for the production of higher value distillate fuel products. The plant would employ Canadian Coal Liquefaction Corporation (CCLC) co-processing technology and be situated at a greenfield site in Painesville, Ohio. The plant would process 1128 tons/day of Ohio No. 6 coal and 20,000 BPD of Alberta heavy oil to yield 33,900 BPD of distillate fuel and 20 MW of electricity for export.

In CCLC co-processing, a slurry of ground coal and heavy oil is hydrogenated at elevated temperature and pressure to produce liquid distillate products. Power is produced by burning residual liquids and carbon-containing, unreacted solids.

PROPOSAL FACT SHEET

Proposer:	Geneva Steel
Proposal Title:	COREX Ironmaking Process Demonstration Plant
Technology Category:	Industrial/Ironmaking
Coal Type:	Bituminous
Project Location:	Vineyard City, Utah County, Utah
Project Duration:	60 months
Estimated Total Project Cost:	$368,261,374
Estimated DOE Share:	33.0%
Estimated Proposer Share:	67.0%
Project Team Members:	Geneva Steel Deutsche Voest-Alpine Industrieanlagenbau GMBH

Proposal Summary:

The proposed project is to design, construct and operate a 770,000 TPY COREX (a proprietary ironmaking process) demonstration plant which will be incorporated into the operations of the Geneva Steel integrated steel plant at Vineyard City, Utah.

The COREX ironmaking process, developed by Deutsche Voest-Alpine Industrieanlagenbau GMBH ("DVAI"), is an ironmaking process with the potential to reduce environmental emissions and production costs. The COREX process has been tested in a 66,000 nominal tons-per-year (TPY) pilot plant in West Germany and in a 330,000 TPY plant at Iscor, South Africa, using a range of coals and iron ores. The COREX process has not been demonstrated in the United States.

Ironmaking by the traditional coke oven/blast furnace process creates a number of environmental concerns, principally associated with the coke-making process. The proposer claims the COREX process eliminates the need for coke-making.

PROPOSAL FACT SHEET

Proposer:	International Fuel Cells Corporation
Proposal Title:	Molten Carbonate Fuel Cell Demonstration Using Gasified Coal
Technology Category:	Industrial/Fuel Cells
Coal Type:	Various
Project Location:	Montebello, Los Angeles County, California
Project Duration:	96 months
Estimated Total Project Cost:	$69,150,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	International Fuel Cells Corporation

Proposal Summary:

The proposed project is to design, construct and operate a 1.85 MW Molten Carbonate Fuel Cell (MCFC) which would operate on on a fuel gas generated by the Texaco gasifier. The demonstration project will be adjacent to the existing Texaco pilot plant gasification facility in Montibello, California.

The MCFC technology uses carbon monoxide and hydrogen as fuel to convert it for DC electric power via electrochemical reactions. The DC electric power is then converted to AC. The proposer claims that demonstration of the 1.85 MW MCFC will establish the viability of the technology for a 277 MW plant which would require installation of 144 MCFC modules.

PROPOSAL FACT SHEET

Proposer:	L.C. Energy Consortium
Proposal Title:	Dual Bed FBC Burner with Future Coal Fired Hot Gas Generator (COHOGG) Spaulding Cogeneration Facility
Technology Category:	Fluid Bed Combustion/AFB
Coal Type:	Bituminous
Project Location:	North Rochester, Stratford County, New Hampshire
Project Duration:	62 months
Estimated Total Project Cost:	$58,000,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	L.C. Energy Consortium United Engineers and Constructors Electric Power Research Institute Energy Development Group Wormser Engineering Inc.

Proposal Summary:

The proposed project is to design, construct and operate a 20 MW coal-fired dual fluidized bed co-generation facility. The demonstration project would be located in North Rochester, New Hampshire on Spalding Fiber Co. property.

The dual fluidized bed technology is comprised of a shallow lower fludiized bed of sand and coal where the predominance of combustion occurs and a portion of the steam is generated. The balance of combustion and desulfurization take place in the shallow upper bed of limestone. The hot gases are then ducted into the boiler where the remaining useful heat is removed.

PROPOSAL FACT SHEET

Proposer:	LBD and Richmond, Indiana Industrial Associates
Proposal Title:	LBD 2-Stage Coal Gasification Plus IGCC at the Existing Richmond, Indiana Plant Site to Convert 1000 TPD Coal to 116 MW_6 Electric 116 MW_e Electric
Technology Category:	Integrated Gasification Combined-Cycle
Coal Type:	Bituminous
Project Location:	Richmond Power & Light Richmond, Wayne County, Indiana
Project Duration:	30 months
Estimated Total Project Cost:	$100,000,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	LBD and Richmond Indiana Associates

Proposal Summary:

The proposed project is to design, construct and operate a LBD 2-stage coal gasification process to convert 1,000 TPD coal to 116 MW electric power. The demonstration will be located at a Richmond Power and Light plant in Richmond, Wayne County, Indiana.

The LBD 2-stage coal gasification process has two separate processing steps. In the first step, coal is devolatilized to remove sulfur and other metallic impurities from the coal to produce "Syn-coal" and low Btu clean gas. In the second step, the "Syn-coal" is gasified to produce 300 Btu gas without using an oxygen plant. The proposer claims that the "Syn-coal" has several applications in water purification, as pigments, and as reinforcing agents in plastics.

PROPOSAL FACT SHEET

Proposer:	LBD and Industrial Associates
Project Title:	First-Stage Coal Gasification Process at Evansville, Indiana Plant Site to Convert 1000 TPD Coal as Mined or 1300 TPD Reject Coal to Syn-Coal and Some Electric
Technology Category:	New Fuel Form - Mild Gasification
Coal Type:	Bituminous
Project Location:	Evansville, Warrick & Pike Counties, Indiana
Project Duration:	30 months
Estimated Total Project Cost:	$50,000,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	LBD and Industrial Associates

Proposal Summary:

The proposed project is to design, construct and operate the LBD first stage coal gasification process to convert 1,000 TPD Indiana coal or 1,300 TPD reject coal to "Syn-coal" and electricity. The demonstration project will be located at Evansville, Indiana.

The LBD first stage coal gasification includes devolatilization of coal to produce 70% "Syn-coal" and clean low btu gas. The proposer claims that the "Syn-coal" has several industrial applications in water purification, as pigments, and asreinforcing agents in plastics. The LBD first stage coal gasification produces uniform and ash laden "Syn-coal" which can be transported long distances. Thus, such a plant could be located at the mine mouth sites.

PROPOSAL FACT SHEET

Proposer:	LBD and Industrial Associates
Proposal Title:	2-Stage Coal Gasification at Lake Charles, Louisiana Plant Site to Convert 2000 TPD Coal to Medium BTU Producer Gas
Technology Category:	New Fuel Form - Mild Gasification
Coal Type:	Lignite
Project Location:	Lake Charles, Calcasieu Parish County, Louisiana
Project Duration:	30 months
Estimated Total Project Cost:	$50,000,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	LBD and Industrial Associates

Proposal Summary:

The proposed project is to design, construct and operate the LBD 2-stage coal gasification process to convert 2,000 TPD lignite to medium Btu gas. The project will be located at Lake Charles, Louisiana.

The LBD 2-stage coal gasification process has two separate processing steps. In the first step, coal is devolatilized to remove sulfur and other metallic impurities from the coal to produce "Syn-coal" and low Btu gas. In the second step, the "Syn-coal" is gasified to produce 300 Btu gas without using an oxygen plant.

PROPOSAL FACT SHEET

Proposer:	LIFAC - North America, a joint venture of Tampella Ltd., and ICF Kaiser Engineers, Inc.
Proposal Title:	Demonstration of LIFAC at Richmond Power and Light's Whitewater Valley 2 Powerplant
Technology Category:	Flue Gas Clean-Up/Sorbent Injection
Coal Type:	Bituminous
Project Location:	Richmond, Wayne County, Indiana
Project Duration:	25 months
Estimated Total Project Cost:	$18,711,072
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	LIFAC - North America, a joint venture of Tampella, Ltd. and ICF Kaiser Engineers, Inc. Richmond Power and Light Electric Power Research Institute Black Beauty Resources LeFarge Construction Materials Peabody Holding Company, Inc.

Proposal Summary:

The proposed project is to design, construct, and operate a LIFAC flue gas cleaning system for removing sulfur dioxide at a 60 MW utility boiler. The demonstration project would be a retrofit application at Richmond (Indiana) Power and Light's Whitewater Valley Unit No. 2 generating station.

The LIFAC technology provides the ability to reduce sulfur dioxide emissions 75% to 85%. Limestone is injected into the upper furnace with a humidification chamber installed between the air preheater and ESP to complete the removal process.

PROPOSAL FACT SHEET

Proposer:	Lin Technologies, Inc.
Proposal Title:	Improved Lin SO_x and NO_x Removal and Waste Products Utilization Process
Technology Category:	Flue Gas Clean-Up/Sorbent Injection
Coal Type:	Bituminous
Project Location:	Richmond Power & Light Richmond, Richmond County, Indiana
Project Duration:	30 months
Estimated Total Project Cost:	$4,148,026
Estimated DOE Share:	47.0%
Estimated Proposer Share:	53.0%
Project Team Members:	Lin Technologies, Inc. Department of Commerce, State of Indiana Richmond Power & Light Ohio Department of Transportation Universal Concrete Products, Inc. Bronson Plating Company Department of Water & Sanitation, Butler, Indiana American Fly Ash Company Wiss, Janney, Elstner Associates, Inc. Sidney Diamond Associates

Proposal Summary:

The proposed 3 MWe scale project would demonstrate the Lin process for SO_x/NO_x removal from stack gases, and the production of useful by products. The proposed project might also demonstrate whether the product from the SO_x removal process, Linfan, could be used for large scale applications such as highway construction, sewage treatment, and concrete pipe manufacture. NO_x removal from stack gas will also be attempted by gas cooling and chemical reactions at the downstream side of the SO_x removal system.

The technology appears to be capable of retrofitting future existing utility or industrial boilers. The Lin process offers the potential to remove SO_x from stack gases yielded by burning high sulfur coals. Commercial application of the diverse by-products could ameliorate or help avoid waste disposal problems.

PROPOSAL FACT SHEET

Proposer:	M-C Power Corporation
Proposal Title:	Coal-Fired IMHEX Molten Carbonate Fuel Cells for Combined Cycle Repowering
Technology Category:	Industrial/Fuel Cells
Coal Type:	Bituminous
Project Location:	Chicago, Cook County, Illinois
Project Duration:	42 months
Estimated Total Project Cost:	$22,708,159
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	M-C Power Corporation Institute of Gas Technology (IGT) Combustion Engineering, Inc.

Proposal Summary:

The proposed project is to design, construct and operate two 250 KW Molten Carbonate Fuel Cell (MCFC) integrated modules. The MCFC is fueled by a fuel gas stream from a 24 TPD U-Gas coal gasification pilot plant using Illinois high sulfur coal. The demonstration project will be located at IGT's Energy Development Center in Chicago, Illinois.

The MCFC is an electrochemical device, similar to a battery, which produces electricity using clean fuel gas containing carbon monoxide and hydrogen. The proposer claims that the coal gasification/MCFC technology could be used to fully or partially repower existing power plants designed to use any type of fossil fuel.

PROPOSAL FACT SHEET

Proposer:	Manitowoc Public Utilities
Proposal Title:	Demonstration Firing of High Chlorine U.S. Coals Using Atmospheric Fluidized Bed Technology
Technology Category:	Fluid Bed Combustion/AFB
Coal Type:	Bituminous
Project Location:	Manitowoc, Manitowoc County, Wisconsin
Project Duration:	44 months
Estimated Total Project Cost:	$24,000,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Manitowoc Public Utilities Foster Wheeler Development Corporation Foster Wheeler Energy Corporation Lutz, Daily & Brain

Proposal Summary:

The proposed project will demonstrate the firing of high chlorine United States coals using atmospheric circulating fluidized bed (ACFB) technology in a repowering mode. Manitowoc Public Utilities (MPU), a Wisconsin Municipal Power Company, is presently constructing a 22 MWe ACFB boiler which would be used in this demonstration. There are approximately 80 billion tons of high chlorine coals in the Illinois Basin which are unusable in conventional boilers due to corrosion, fouling and emission problems.

Manitowoc Public Utilities is proposing to demonstrate the burning of five coals which range from 0.3 to 0.65 percent chlorine and varying levels of sulfur content to assess the effects on equipment corrosion, on operating and maintenance, and on emissions and ash residues. Manitowoc and the Wisconsin Department of Natural Resources also plan to assess positive agricultural uses from the ash residues.

PROPOSAL FACT SHEET

Proposer:	Marshall Owen Enterprises, Inc.
Proposal Title:	Carbonization Retort System Demonstration
Technology Category:	New Fuel Form/Mild Gasification
Coal Type:	Bituminous
Project Location:	Between Paonia & Somerset Near Bowie Delta County, Colorado
Project Duration:	36 months
Estimated Total Project Cost:	$71,873,147
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Marshall Owen Enterprises, Inc. Coalite Group PLC Colin Henson Troy L. Leaper

Proposal Summary:

The proposed project is to design, construct and operate a first-of-a-kind commercial plant for the manufacturing of a smokeless fuel from coal for use in fireplaces and wood/coal burning stoves. The plant would be sited in Delta County, Colorado.

The process is a low temperature carbonization of coal, or mild gasification, in a continuous retort, and produces a tar oil as a co-product. The proposer claims the solid smokeless fuel can be marketed in Colorado as a replacement fuel, and the tar oil can be upgraded and sold for a variety of liquid fuel and chemical feedstock uses.

PROPOSAL FACT SHEET

Proposer:	Metrix International Corporation
Proposal Title:	Coal Log and Method
Technology Category:	New Fuel Form/Coal Cleaning
Coal Type:	Cannel Coal
Project Location:	Charleston, Kanawha County, West Virginia
Project Duration:	120 months
Estimated Total Project Cost:	$900,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Metrix International Corporation Joseph P. Titlow Homer R. Withrow Norman Kilpatrick William B. Scruggs

Proposal Summary:

The objective of the proposed project is to demonstrate the commercial viability of producing and selling coal logs made from Cannel coal (low sulfur, high Btu coal indigenous to West Virginia). The coal logs would be produced from crushed coal held together in a relatively loose configuration by selected polymers. Demonstration of the manufacturing process will take place in Charleston, West Virginia.

This project is aimed primarily at the residential market (including heating, cooking and decorative), but the proposer claims other domestic markets could be penetrated. These markets include small industrial boilers, small power plants, ski resorts, and outdoor sports facilities.

PROPOSAL FACT SHEET

Proposer:	Midland Cogeneration Venture, and California Carbide Company
Proposal Title:	Flash Desulfurization Gasification of Coal Demonstration Plant
Technology Category:	Integrated Gasification Combined-Cycle
Coal Type:	Bituminous
Project Location:	Midland, Midland County, Michigan
Project Duration:	60 months
Estimated Total Project Cost:	$51,434,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Midland Cogeneration Venture California Carbide Company

Proposal Summary:

The proposed project is to design, construct and operate California Carbide Company's Flash Desulfurizing Gasification (CCC-FDG) plant. The plant will convert 200 TPD Illinois No. 6 coal to clean low-Btu (171/SCF) gas. The clean low-Btu gas is then blended with the natural gas feed of the Midland Cogeneration Venture's 1370 MW combined cycle plant. The demonstration plant will be located in Midland, Michigan.

The CCC-FDG process uses ultra high high temperature radiative heat transfer at about 4000°F to carry out coal gasification in presence of finely divided coal and limestone particles in an entrained flow reactor with short residence time. The proposer claims that coal gasification at these conditions produces chemically clean fuel gas and environmentally harmless slag.

PROPOSAL FACT SHEET

Proposer:	Minnesota Power & Light Company
Proposal Title:	ELFUEL Demonstration of Low-Rank Coals
Technology Category:	New Fuel Form/Advanced Coal Prep
Coal Type:	Lignite
Project Location:	Center, Oliver County, North Dakota
Project Duration:	84 months
Estimated Total Project Cost:	$146,000,000
Estimated DOE Share:	47.0%
Estimated Proposer Share:	53.0%
Project Team Members:	Minnesota Power & Light Company BNI Coal Ltd. Institute of Gas Technology Electric Power Research Institute Bechtel Corporation

Proposal Summary:

The proposed project is to design, construct and operate an 80 TPH demonstration plant using the Enhanced Low-Rank Fuel (ELFUEL) process. The demonstration project would be at a greenfield site in Oliver County, North Dakota, adjacent to the present mining operations of BNI Coal, Ltd.

The ELFUEL process is a moderate temperature, high pressure hydrothermal reforming process which reduces the moisture content of the feed lignite or low-rank coal, and produces a demoisturized solid product with a higher energy content. The proposer claims the ELFUEL product is well suited for use at existing power plants burning lignites and subbituminous coals.

PROPOSAL FACT SHEET

Proposer:	MK-Ferguson Company
Proposal Title:	Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System
Technology Category:	Flue Gas Clean-Up/Copper Oxide
Coal Type:	Bituminous
Project Location:	Niles, Trumbull County, Ohio
Project Duration:	54 months
Estimated Total Project Cost:	$66,249,696
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	MK-Ferguson Company NOXSO Corporation W.R. Grace & Co.

Proposal Summary:

The proposed project is to design, construct, and operate a regenerable flue gas cleaning system employing the NOXSO process on an existing 115 MW coal-fired boiler. The demonstration would take place at Ohio Edison's Niles station.

The NOXSO process employs a porous solid adsorbent that removes SO_2 and NO_x from flue gas. Subsequently the adsorbed pollutants are removed in a sorbent regeneration step. Sulfur is recovered either in the elemental form or as sulfuric acid, both marketable products. Nitrogen oxides are recycled to the boiler and converted to molecular oxygen and nitrogen.

PROPOSAL FACT SHEET

Proposer:	Modular Power Plant Limited Partnership
Proposal Title:	Homer City Modular Fluidized Bed Power Plant Project
Technology Category:	Fluid Bed Combustion/AFB
Coal Type:	Coal Waste
Project Location:	Homer City, Indiana County, Pennsylvania
Project Duration:	60 months
Estimated Total Project Cost:	$46,000,000
Estimated DOE Share:	41.0%
Estimated Proposer Share:	59.0%
Project Team Members:	Modular Power Plant Limited Partnership Rubenstein Engineering, P.C. J.A. Jones Construction Co. Laramore, Douglass and Popham Dynalytics Corp. Deutsche Babcock Werke Aktiengesellschaft

Proposal Summary:

The proposed project will demonstrate the ability of the Deutsche-Babcock Werke Circofluid TM boiler to burn local waste coals and to reduce SO_2 and NO_x well below current EPA requirements.

The demonstration project will be a new facility in Homer City, PA. located at the former DOE Bi-Gas facility. It will make use of the existing infrastructure, and the existing coal handling equipment. The boiler will provide 140,000 PPH of 1415 psi 950 F steam to a 17 MW Turbine Generator. The electricity will be sold to the Pennsylvania Electric Company.

The Circofluid TM Boiler incorporates the advantages of AFB's and CFB's into an advanced compact fluidized bed boiler well suited for modular construction techniques. During a two year demonstration operating period, data will be gathered using a wide range of waste bituminous coal located in the immediate vicinity of the facility.

PROPOSAL FACT SHEET

Proposer:	Peabody Holding Company, Inc.
Proposal Title:	Integrated Mild Gasification with Circulating Fluidized-Bed Combustion for Steam and Power Generation
Technology Category:	New Fuel Form/Mild Gasification
Coal Type:	Bituminous
Project Location:	Southern Illinois University - Carbondale Carbondale, Jackson County, Illinois
Project Duration:	63 months
Estimated Total Project Cost:	$119,453,700
Estimated DOE Share:	47.0%
Estimated Proposer Share:	53.0%
Project Team Members:	Peabody Holding Company, Inc. Bechtel Corporation Combustion Power Company, Inc. Institute of Gas Technology Southern Illinois University at Carbondale

Proposal Summary:

The proposed project is to design, construct and operate an Integrated Mild Gasification-Circulating Fluid Bed Boiler (IMG-CFB) to convert 445 TPD West Virginia high sulfur coal into 12 MW electricity, 146,000 lb/hr low pressure utility steam and potentially marketable solid and liquid co-products. The demonstration project will be located on the Southern Illinois University campus in Carbondale, Illinois.

The IMG-CFB process uses a two-stage mild gasification reactor to produce liquid products and char at atmospheric pressure and at about 1200°F. The char is then burned in Combustion Power's circulating fluid bed boiler. The proposer claims that the liquid co-product could be sold as chemical feed stock, and that solid char could be used as smokeless fuel or as a substitute for metallurgical coke in steel industry.

PROPOSAL FACT SHEET

Proposer:	Pedco, Incorporated
Proposal Title:	Industrial Demonstration of the Pedco Rotary Cascading Bed Boiler
Technology Category:	Combustion/Rotary Kiln
Coal Type:	Bituminous
Project Location:	Cincinnati, Hamilton County, Ohio
Project Duration:	24 months
Estimated Total Project Cost:	$ 5,285,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Pedco, Incorporated PMC Specialties Group, Inc. Zurn Industries, Inc. Ohio Department of Development/Coal Development Office North American Rayon Corporation

Proposal Summary:

The purpose of the proposed project is to expand the demonstration program currently in progress for the modification and relocation of the Pedco Rotary Cascading Bed Boiler (RCBB). The demonstration project which had begun at the Hudepohl Brewery in Cincinnati, would be relocated to the PMC Specialties Group, Inc. plant in Hamilton County, Ohio (metropolitan Cincinnati).

The RCBB is a small industrial boiler (10,000 lbs. steam/hour). The proposer claims this technology can remove greater than 90% of the SO_2 produced during combustion (using limestone), and can hold NO_x to minimal levels through control of temperatures in the combustion zone.

PROPOSAL FACT SHEET

Proposer:	Public Service Company of Colorado
Proposal Title:	Integrated Dry NO_x/SO_2 Emission Control System
Technology Category:	Flue Gas Clean-Up\Low NO_x Burner
Coal Type:	Bituminous
Project Location:	Denver, Denver County, Colorado
Project Duration:	44 months
Estimated Total Project Cost:	$24,549,478
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Public Service Company of Colorado Stone & Webster EngineeringCorporation The Babcock & Wilcox Company Electric Power Research Institute Fossil Energy Research Institute Western Research Institute Colorado School of Mines

Proposal Summary:

The proposed project is to demonstrate reductions in SO_2 and NO_x emissions by using a combination of technologies: Low NO_x burners and urea injection for NO_x reductions, and dry sorbent injection (sodium and calcium sorbents) for SO_2 reductions. The demonstration site would be the Public Service Company of Colorado's (PSCCO's) Arapahoe Steam Electric Generating Station, Unit 4, located in Denver County, Colorado.

Commercially available Low NO_x Burners are capable of 40% to 50% reduction of NO_x. Low NO_x Burners with overfired air are capable of 70% reduction of NO_x. Urea injection in full-scale tests have shown 35% to 70% reduction on NO_x. Both sodium and calcium dry sorbent injection in full-scale tests have shown 70% reduction of SO_2. The proposer claims that the combined demonstration technologies should be capable of greater than 70% reductions in NO_x and SO_2.

PROPOSAL FACT SHEET

Proposer:	Public Service Company of Indiana, Inc.
Proposal Title:	Wabash River Clean Energy Project
Technology Category:	Fluid Bed Combustion/PFB
Coal Type:	Bituminous
Project Location:	Wabash River Generating Station Terre Haute, Vigo County, Indiana
Project Duration:	67 months
Estimated Total Project Cost:	Business Confidential
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	Public Service Company of Indiana, Inc. Allison Gas Turbine Division/General Motors Company Foster Wheeler Development Corporation Gilbert Commonwealth AMAX Coal Enterprises

Proposal Summary:

The Wabash River Clean Energy Project would demonstrate a Foster Wheeler coal-fired carbonizer/circulating pressurized fluidized bed combustion system. The demonstration would take place near Terre Haute, Indiana, at the Wabash River Generating Station which is owned and operated by Public Service Company of Indiana. The demonstration plant would produce approximately 11 MWe of electrical output.

The power production cycle consists of an integrated coal gasification, fluidized bed combustion and gas turbine system. In this two-stage system, coal is fed to a pressurized carbonizer producing a low-Btu fuel gas and char. The char from the carbonizer is fed to the fluidized bed combustor to generate hot gas. The hot gas and fuel gas are combined and burned in the gas turbine's combustion system. High inlet temperature to the gas turbine is designed to improve the heat rate which, in turn, would improve power production economics.

PROPOSAL FACT SHEET

Proposer:	The Ralph M. Parsons Company
Proposal Title:	Parsons FGC Process Demonstration Project
Technology Category:	Flue Gas Clean-Up
Coal Type:	Bituminous
Project Location:	St. Mary's Municipal Power Plant, St. Mary's, Auglaize County, Ohio
Project Duration:	48 months
Estimated Total Project Cost:	$34,243,000
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	The Ralph M. Parsons Company

Proposal Summary:

The objective of the proposed project is to demonstrate a flue gas cleanup (FGC) process which the proposer claims is capable of reducing 99% of the SO_2 and NO_x, with no waste products. The project will treat gas produced in the 10 MW, No. 6 boiler at St. Marys Municipal Power Plant located in the city of St. Marys, Auglaize County, Ohio.

The proposer's FGC process is an adaptation of technology that has been used successfully in commercial plants (non-utility) treating sulfur plant tail gases. The process includes: (1) simultaneous catalytic reduction of SO_2 to H_2S and NO_x to elemental nitrogen in a hydrogenation reactor, (2) recovery of H_2S from the hydrogenation reactor effluent gas, and, (3) production of sulfur from H_2S-rich gas.

PROPOSAL FACT SHEET

Proposer: Sanitech, Inc.

Proposal Title: NelSorbent Dry Scrubbing Demonstration Project

Technology Category: Flue Gas Clean-Up/Copper Oxide

Coal Type: Bituminous

Project Location: Kent State University, Kent, Portage County, Ohio

Project Duration: 36 months

Estimated Total Project Cost: $8,000,000

Estimated DOE Share: 50.0%

Estimated Proposer Share: 50.0%

Project Team Members: Sanitech, Inc.
Fluor Daniel, Inc.
Kent State University
Ohio Edison Company

Proposal Summary:

The proposed project will demonstrate the preparation and use of NelSorbents, a new class of granular SO_2/NO_x sorbents made from magnesia and vermiculite. Nelsorbent preparation would be demonstrated at the proposer's facilities in Twinsburg, Ohio. The SO_2/NO_x sorption and sorbent regeneration operation would be demonstrated on a 7.5 MWe boiler at Kent State University's boiler plant in Kent, Ohio.

The Nelsorbent process consists of four elements: (1) sorbent preparation; (2) simultaneous SO_2 and NO_x sorption; (3) sorbent regeneration, and (4) spent sorbent by-product utilization. The proposer claims high SO_2 and NO_x removal rates at low cost due to easy retrofit, little or no waste stream and by-product sales.

PROPOSAL FACT SHEET

Proposer:	University of Cincinnati
Proposal Title:	Demonstration of Ammonia Enhanced Spray Drying for Control of SO_2 from Combustion of High Sulfer Coal
Technology Category:	Flue Gas Clean-Up/Sorbent Injection
Coal Type:	Bituminous
Project Location:	Argonne National Laboratory Argonne, DuPage County, Illinois
Project Duration:	12 months
Estimated Total Project Cost:	$1,563,385
Estimated DOE Share:	50.0%
Estimated Proposer Share:	50.0%
Project Team Members:	University of Cincinnati Raphael Katzen Associates Dr. Wayne T. Davis, University of Tennessee Argonne National Laboratory

Proposal Summary:

The purpose of this demonstration is to test a $Ca(OH)_2/NH_3$-based spray dryer system for removal of SO_2 from high sulfur coal. The demonstration would take place at the Argonne National Laboratory, Boiler No. 5 (176 tpd, 20 MWe).

The proposer claims this system will achieve 90% SO_2 removal on high sulfur coals and also will permit regeneration of the NH_3 by physical/chemical treatment of the waste created in the process.

PROPOSAL FACT SHEET

Proposer:	University of North Texas
Proposal Title:	The Reduction of SO_2 and NO_x by Cofiring Binder Densified Refuse Derived Fuel with Coal in Power Plant Boilers
Technology Category:	New Fuel Form/AFB
Coal Type:	Western sub-bituminous, Eastern bituminous, lignite, anthracite
Project Location:	City of Virginia Power Plant Virginia, St. Louis County, Minnesota
Project Duration:	72 months
Estimated Total Project Cost:	$112,330,000
Estimated DOE Share:	39.0%
Estimated Proposer Share:	61.0%
Project Team Members:	University of North Texas Virginia Department of Public Utilities Reuter, Incorporated Argonne National Laboratory City of Virginia (Minnesota)

Proposal Summary:

The proposed project is to demonstrate the cofiring of coal with binder-densified refuse-derived fuel (bdRDF) in three types of boilers. The demonstration would take place at the electric generating station in the city of Virginia, Minnesota.

BdRDP is prepared in pellet form by compressing municipal solid waste with calcium hydroxide (lime) binder. The resultant fuel, which is low in sulfur, would be co-fired with coal, typically replacing 25% of the coal on a BTU basis. Sulfur dioxide emissions are expected to be reduced because of the low sulfur content of the bdRDF and the presence of the lime, a getter for SO_2. The proposer also expects some reduction of NO_x emissions.

PROPOSAL FACT SHEET

Proposer:	Westwood Energy Properties Ltd. Partnership
Proposal Title:	Westwood Generating Station Standardized CFB Module Demonstration
Technology Category:	Fluid Bed Combustion/AFB
Coal Type:	Anthracite Culm
Project Location:	Westwood Station, Schuykill County, Frailey, Pennsylvania
Project Duration:	48 months
Estimated Total Project Cost:	$71,000,000
Estimated DOE Share:	39.0%
Estimated Proposer Share:	61.0%
Project Team Members:	Westwood Energy Properties, Ltd. Partnership CRSS Services, Inc. - Engineering Group

Proposal Summary:

The proposed project is to construct and operate a 35 MWe enhanced performance circulating fluidized bed module (CFBM) made up of standardized components. The demonstration project will be a repowering of an existing CFB in Frailey Township, Pennsylvania owned and operated by Westwood Energy Properties Ltd., Partnership.

The CFBM incorporates the best features from the evolving CFB technology, improved fuel preparation and ash handling systems into a standard package that has the potential to significantly reduce CFB system costs and construction schedules.