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CLEAN COAL TODAY

A Newsletter about Innovative Technologies for Coal Utilization

News Bytes

The U.S. Department of Energy, Office of Fossil Energy (FE)/NETL is holding a Planning Workshop for Round II of the **Clean Coal Power Initiative** on August 26, 2003, at the Hyatt Regency at Pittsburgh International Airport. Details are available at www.netl.doe.gov/coalpower/ccpi.

Work is progressing on Environmental Impact Statements (EIS) for the **Clean Coal Power Initiative** projects selected for negotiation in January 2003. In May 2003, a well-attended public scoping meeting was held in Pottsville, Pennsylvania, on the Gilberton Coal-to-Clean Fuels and Power project. In June, 2003,

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In This Issue

DOE and State Department Hold First Sequestration Forum

As a first step in major new multinational cooperation in carbon sequestration technology, the Carbon Sequestration Leadership Forum held its first meeting June 23–25, 2003, in Tysons Corner, Virginia. The Forum, established by the U.S. Department of Energy and the State Department in February 2003, seeks (through data gathering, R&D, and joint projects) to improve carbon capture and storage technologies as a means for long-term stabilization of greenhouses gases in the atmosphere. The purpose of this meeting was to decide on an agenda and schedule for the Forum, and establish some type of management structure. High-level representatives from 14 countries (Australia, Brazil, Canada, China, Colombia, India, Italy, Japan, Mexico, Norway, the Russian Federation, South Africa, the United Kingdom, and the United States), as well as the European Commission and some 400 members of the international energy, business, and government communities, gathered in a series of stakeholder sessions and ministerial meetings. The third day of the conference featured a signing ceremony for the Forum charter. The charter, which is scheduled to stay in effect for 10 years, establishes a broad outline for cooperation with the purpose of facilitating development of cost-effective technologies for CO_2 capture and safe, long-term storage, while making these technologies available internationally. While there are several large-scale international CO_2 sequestration projects under way, this first-ever ministerial level sequestration forum underscores the new importance given to international cooperation as a pathway to a hydrogen economy.

U.S. Secretary of Energy Spencer Abraham addressing Carbon Sequestration Leadership Forum

The conference featured a number of high-profile speakers. Welcoming remarks were made by Jim Connaughton, Chairman of the Council on Economic Quality, and Paula J. Dobriansky, Under Secretary of State for Global Affairs. These were followed by keynote remarks delivered by Secretary of Energy Spencer Abraham. Other high-level DOE officials, including Under Secretary Robert Card, Assistant Secretary for Fossil Energy (ASFE) Carl Michael Smith, and Assistant Secretary for Policy and

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International Affairs Vicky Bailey, addressed the audience and also acted as moderators for various ministerial and stakeholders panels. Experts on international energy use and climate change also chaired panels and spoke on a variety of policy and technical aspects of sequestration.

Secretary Abraham characterized sequestration as offering "enormous payoffs," and expressed the hope that the Forum would lead to actual commercial projects instead of solely R&D and information sharing. He noted that, to date, governments and industry worldwide have spent a total of $110 million on 65 sequestration projects. Two of the international projects, Weyburn in Canada and Sleipner in Norway, are considered commercial. Secretary Abraham stressed the importance of an international multilateral approach, such as that offered by the Forum, in order to leverage commitment and eliminate duplication. Abraham explained sequestration in the context of DOE's larger efforts to move toward a hydrogen economy: a $1.7 billion hydrogen fuel initiative that includes the fuel cell powered "Freedom Car," and the proposed "FutureGen" plant; a 10-year $2 billion commitment to clean coal; an increased budget in energy efficiency; and a multilateral research project in fusion energy.

Over the three-day meeting, experts discussed the status of sequestration efforts, with some considering widespread deployment to be hampered by a variety of institutional and financial, and to a lesser degree, technical barriers. Participants at the meeting considered that successful outreach is vital — to communicate to the public and other stakeholders the benefits and relative low risk of the technology. Also noted was the need for participation of developing countries. Participants felt that government support, at least for the present, is needed until implementation of the technology, assisted by market incentives, can be profitable. DOE's Office of Fossil Energy Sequestration program, in fact, intends projects ultimately to be self supporting, while increasing the costs of electricity by 10 percent or less, and capturing at least 90 percent of emissions.

Toward this end, participants discussed the imperative to make sequestration projects "bankable" to lending institutions. Power system contracts are well understood, while CO_2 contracts are not. There also was much discussion of the need for the abated CO_2 to have a monetary value, to be established most likely by a system of trading permits. A robust trading contract was described as one way to lessen market risks.

Upcoming Forum meetings also will provide an opportunity to identify creative solutions for regulatory and legal impediments. Participants at the meetings stressed that stability and transparency in the system are essential to bring projects to fruition — both for financial support and stakeholder acceptance. Established regulations at the front end of a project are seen as important, possibly using innovative tools such as tradeable "green" certificates for carbon sequestration capacity additions. Also, some conference participants perceived that regulators may have a short-term perspective, which could create a bias against capture and sequestration. Legal issues important to those that were in attendance include sharing of intellectual property, ownership of the stored CO_2 down the line, and territorial boundary concerns.

On the technical side, discussions focused primarily on geological storage. It is anticipated that up to 300 years of CO_2 could be stored indefinitely in underground formations. A number of participants cited the proven value of public-private partnerships, and felt that such partnerships could do much to mitigate technology risks. Stakeholders emphasized the need to better evaluate the effectiveness of geological storage, and cautioned that multiple parallel demonstrations may be needed. Monitoring and verification protocols are particularly important to determine the fate of CO_2 underground and assuage public fears about leakage. The global geological potential must be assessed, and sources and sinks matched, possibly in a "hub" or eco-industrial park arrangement.

The next Forum meetings are scheduled for January 2004 in Italy and September 2004 in Australia. Policy and Technical groups organized at the Virginia meeting are working to prepare a roadmap, establish baseline data, rank issues according to priority, and develop formal mechanisms for coordination. Assistant Secretary Smith will chair the Policy Group, with Vice Chairs from Australia and Italy. The United States also will chair the Technical Group, with Canada and Norway as Vice Chairs. Forum proceedings are available at http://www.usea.org; and a Forum Web site is being developed. For information on upcoming Forum activities, contact the Secretariat at CSLFSecretariat@hq.doe.gov.

LOW-NO_x TESTING PRODUCES RESULTS

The U.S. Department of Energy, Office of Fossil Energy's National Energy Technology Laboratory (NETL) is teaming with industry and academia through its Innovations for Existing Plants (IEP) Program to research and develop advanced nitrogen oxide (NO_x) control technologies. The electric power generating industry is the second largest producer of NO_x in the United States, responsible for nearly 22 percent of the emissions. And coal-fired power plants produce 90 percent of the NO_x emitted by electric generators. NETL's objective is to have a portfolio of controls capable of meeting the 0.15 lb/10^6 Btu emission rate (a response to the revised National Ambient Air Quality Standards) at a 25 percent cost savings relative to selective catalytic reduction (SCR), the only technology now capable of such low emissions.

Alstom Power Inc.'s Boiler Simulation Facility

A REGULATORY PERSPECTIVE

The Clean Air Act Amendments of 1990 (CAAA) required major NO_x reductions in 1996 and 2000. Utilities met CAAA requirements largely by installing low-NO_x burners (LNB) that emerged from the Clean Coal Technology (CCT) Demonstration Program. These LNBs, currently installed in approximately 75 percent of the nation's coal burning power plants, use combustion modification techniques rather than post-combustion methods. LNB costs typically are $10–20/kW and roughly $100/ton of NO_x removed, whereas SCR costs range from $80–120/kW and up to $2,000/ton of NO_x removed. Consequently, the CCT program significantly reduced the cost of compliance and, through highly effective LNB performance, succeeded in reducing annual power plant NO_x emissions from 6.7 million tons prior to 1990 to 4.8 million tons in 2001.

Regulatory actions resulting from revised National Ambient Air Quality Standards (NAAQS) for ozone and $PM_{2.5}$ require source emission reductions of NO_x to 0.15 lb/10^6 Btu for much of the nation (NO_x is a precursor to both ozone and $PM_{2.5}$). In addition, caps proposed under the Clear Skies Initiative require some plants to reduce NO_x emissions to 0.15 lb/10^6 Btu and eventually to as low as 0.11 lb/10^6 Btu.

SCR is the only NO_x control technology capable of consistently achieving the 0.15 lb/10^6 Btu emission rate, with the drawback being cost. To achieve the emission reduction targets with combustion modification techniques alone requires sophisticated LNB design changes. LNBs use burner combustion staging to control the introduction of oxygen, which can lead to unacceptable unburned carbon (UBC) levels and carbon monoxide (CO) emissions under deep staging conditions. Boiler combustion staging, such as natural gas and coal reburning technology, has advanced as well. However, these technologies by themselves typically fall short of regulatory targets proposed under Clear Skies. In response to this ratcheting down of NO_x emissions, NETL has directed research at four projects pursuing NO_x reduction alternatives to SCR.

RICH REAGENT INJECTION FOR CYCLONE BURNERS

Rich reagent injection (RRI) is a NO_x control technique applicable to cyclone boilers. RRI leverages work carried out under the CCT program on natural gas and coal reburning. While comprising only about 8.4 percent of the U.S. coal-fired boiler population and capacity, cyclone boilers emit 20 percent of the coal-fired boiler NO_x emissions. The high emissions result from intense heat generated in the cyclone burners. Because these burners do not lend themselves to combustion modification, NO_x control requires boiler-level combustion staging, typically overfire air (OFA). RRI uses ammonia or urea reagent in the fuel-rich lower furnace to achieve additional NO_x reduction in a cyclone furnace that is equipped with OFA. The reagent injection accelerates the NO_x reduction rates that occur in the high-temperature, fuel-rich zone.

Reaction Engineering International (REI) has developed an enhanced chemistry model with their proprietary Computational Fluid Dynamics code, *GLACIER*, to guide the design of the reagent injection systems as well as to predict RRI performance. With additional support from EPRI's Cyclone NO_x Control Interest Group, field testing of RRI has been successfully completed at commercial scale on Conectiv's

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"NO_x Control" continued...

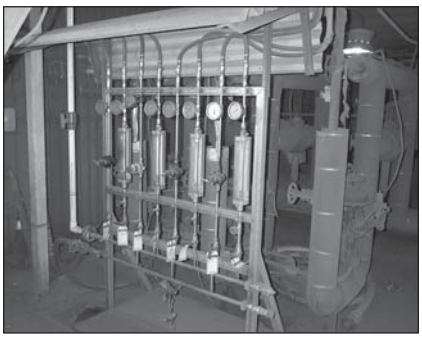
138-MW B.L. England Unit 1 and AmerenUE's 500-MW Sioux Unit 1.

At Conectiv's B.L. England Unit 1, OFA has reduced uncontrolled NO_x emissions from ~1.2 lb/10^6 Btu to ~0.5 lb/10^6 Btu. The existing urea-based selective non-catalytic reduction (SNCR) system has been shown to reduce these emissions an additional 30 percent, with less than 5 ppm ammonia slip. Field testing showed that RRI achieved the predicted 25–30 percent NO_x reduction beyond OFA levels with less than 1 ppm ammonia slip. In combination with SNCR, 55 percent NO_x reduction was achieved beyond OFA levels to yield NO_x emissions of 0.24 lb/10^6 Btu with less than 5 ppm ammonia slip. At Sioux Station, RRI met model predictions of 30 percent NO_x reduction from full load levels of 0.38 lb/10^6 Btu to 0.27 lb/10^6Btu. There was no measurable ammonia slip. Modeling suggests that further NO_x reductions are possible through modification of the flue gas recirculation system as well as through deeper staging.

Low-NO_x Firing for Tangential-Fired Boilers

ALSTOM Power Inc. recently completed a comprehensive pilot-scale study at its Boiler Simulation Facility to develop and evaluate LNBs for tangentially fired boilers, which represent roughly 40 percent of the U.S. coal-fired boiler population. ALSTOM's TFS 2000™ low-NO_x firing system served as the basis for comparison to other low-NO_x systems, and was the foundation upon which refinements were made to further improve NO_x emissions and related combustion performance.

ALSTOM evaluated a number of LNB subsystems under realistic boiler combustion system conditions at 50–60 million Btu/hr using three coals. Tests showed that both NO_x and combustion performance are a strong function of coal properties. The most reactive coal (Powder River Basin, or PRB) produced the lowest NO_x (0.08 lb/10^6 Btu), followed by the moderately reactive midwestern bituminous coal (HVB) at 0.11 lb/10^6 Btu, and a less reactive medium volatile eastern bituminous coal (MVB) at 0.17 lb/10^6 Btu. PRB use resulted in the lowest UBC and CO levels followed by the HVB and MVB. The combination of firing system modifications resulting in the lowest NO_x emissions was tagged as the Ultra Low NO_x Integrated System (ULNIS). In general, firing system modifications that reduced NO_x emissions also resulted in higher UBC levels. When NO_x and combustion efficiency were equally weighed, the standard TFS 2000™ set of operating conditions/system components gave the best results for the HVB and MVB coals, and the ULNIS gave the best results on the PRB coal.



Reagent distribution panel to control flow rates and air pressure at the RRI BC England Unit 1 test site. Flexible rubber hoses (at top) transported reagent and atomizing air to injectors

An economic evaluation, normalized to NO_x emissions of 0.15 lb/10^6 Btu by the trading of NO_x credits, assessed three technology options — TFS 2000™, ULNIS, and SCR — for three tangential-fired utility boiler retrofit options in the United States. Results showed that switching to a PRB coal, in concert with installation of either a TFS 2000™ or ULNIS, was the most cost-effective option (75–80 percent less than the cost of an SCR) if the cost of shipping the PRB coal was not prohibitive.

Integrated Low-NO_x Burners and SNCR for Wall-Fired Boilers

McDermott Technology, Inc. (MTI), the Babcock & Wilcox Company (B&W), and Fuel Tech teamed together to investigate an integrated NO_x control system for wall-fired boilers, which represent approximately 42 percent of the U.S. coal-fired boiler population. The system uses B&W's DRB-4Z™ LNB and Fuel Tech's NOxOUT® urea-based SNCR technology. Testing was conducted on several coals in B&W's 100-million Btu/hr Clean Environment Development Facility (CEDF) that simulates the conditions of large coal-fired utility boilers.

At full load conditions, the DRB-4Z™ LNB alone (without air staging) achieved NO_x emissions of 0.26 lb/10^6 Btu (187 ppm @ 3% O_2) with PRB coal, 0.30 lb/10^6 Btu (215 ppm @ 3% O_2) with Pittsburgh #8, and 0.40 lb/10^6 Btu (287 ppm @ 3% O_2) with Middle Kittanning coal.

NOxOUT® reduced baseline full load DRB-4Z™ NO_x levels to 0.19 lb/10^6 Btu (136 ppm @ 3% O_2) with PRB coal, 0.22 lb/10^6 Btu (158 ppm @ 3% O_2) with Pittsburgh No. 8, and

0.32 lb/10^6 Btu (230 ppm @ 3% O_2) for Middle Kittanning coal. The NO_x reduction was 25 percent for western subbituminous, 26 percent for Pittsburgh No. 8, and 18 percent for Middle Kittanning coal.

Economic analysis shows that when the DRB-4Z™ LNB with OFA and firing PRB coal achieves the 0.15 lb/10^6 Btu emissions, it has the lowest levelized cost at $389/ton of NO_x removed (70 percent less than SCR). If this same combustion scenario requires NOxOUT® to achieve the 0.15 lb/10^6 Btu emissions, levelized costs are $752/ton of NO_x removed (40 percent lower than SCR). Additional testing will be conducted with air staging (OFA) to verify the capability to achieve 0.15 lb/10^6 Btu emissions at the high furnace temperatures experienced in the CEDF.

OXYGEN-ENHANCED COMBUSTION

Praxair has developed a novel oxygen-based NO_x control technology that replaces a small fraction of the combustion air with oxygen, while improving combustion characteristics such as UBC. Experiments performed at ALSTOM Power's Industrial Boiler Simulation Facility sought to demonstrate that oxygen-based NO_x control when coupled with OFA can meet 0.15 lb/10^6 Btu emission rates with minimal impact on CO emissions and furnace performance. ALSTOM's commercial wall-fired RSFC LNB was used in these experiments. The burner was designed for a firing rate of 26 million Btu/h, and was typically fired at 24 million Btu/h for these tests.

Data from experiments with Illinois No. 6 coal show that even when baseline (air only) emissions are very low (0.15 lb/10^6 Btu), adding oxygen during combustion can drive NO_x emissions even lower to 0.11 lb/10^6 Btu. The data further show that reductions are relatively independent of the initial NO_x concentration. Data from experiments with Mingo Logan eastern bituminous coal show that the concept works even with lower volatile coal achieving 0.135 lb/10^6 Btu, and the way the oxygen is mixed greatly impacts NO_x reduction. Oxygen-based NO_x control also offers reduced UBC, increased boiler efficiency, and reduced fan limits. Preliminary economic analysis indicates that cost savings of 40–50 percent can be realized when compared to SCR.

FUTURE EFFORTS

Under the IEP program, efforts will continue toward developing technologies that enable ever lower NO_x emissions from existing boilers. The program will be issuing a solicitation in Fall 2003 targeting smaller, older, space-constrained plants that cannot readily accommodate SCR. These plants, with capacities of 300 MW or less, comprise 66 percent of the boilers in the United States.

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another scoping meeting — on the Western Greenbrier Coproduction Demonstration Project — was held in Charmco, West Virginia.

To encourage participation in the proposed **FutureGen** initiative (the world's first zero-emission coal-fueled plant to produce electricity and hydrogen), the U.S. Department of Energy Office of Fossil Energy has issued "A Prospectus for Participation by Foreign Governments in FutureGen." The document is available at www.netl.doe.gov.

UPCOMING EVENTS

August 26, 2003
Clean Coal Power Initiative Planning Workshop
Sponsor: NETL
Location: Pittsburgh, PA

October 28, 2003
2003 Conference on Unburned Carbon on Utility Fly Ash
Sponsor: NETL
Location: Pittsburgh, PA

October 29–30, 2003
2003 Conference on Selective Catalytic Reduction and Non-Catalytic Reduction for NO_x Control
Sponsor: NETL
Location: Pittsburgh, PA

November 17–19, 2003
Clean Coal and Power Conference* and *Second Joint U.S.-People's Republic of China Conference on Clean Energy
Co-Sponsor: DOE, CEED, NMA, EPRI, and CIBO
Location: Washington, DC

For information on these events, contact:
Kimberly Yavorsky
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CLEAN ENERGY SYSTEMS MEETS NEAR-ZERO EMISSIONS LEVELS

Applying advanced rocket engine principles, the Clean Energy Systems, Inc. (CES) gas generator offers the potential for coproducing high-efficiency, near-zero emission power and sequestration-ready carbon dioxide (CO_2). In September 2000, the Department of Energy's (DOE) National Energy Technology Laboratory (NETL) contracted with CES to design, fabricate, and test a 20-MW_t (10 MWe equivalent) gas generator. In February 2003 the project successfully met its goals of producing an essentially pollution-free drive gas composed of steam and CO_2 at temperatures and pressures up to 3,000 ºF and 1,500 pounds per square inch (psi).

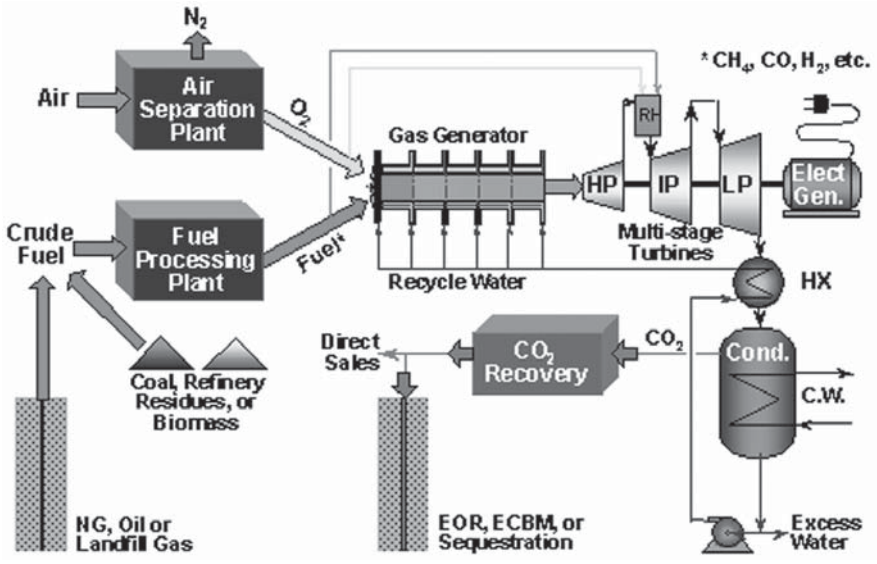
The CES technology adopts aerospace science to precisely mix oxygen and any clean gaseous hydrocarbon fuel in a near ideal stoichiometric ratio so that only CO_2 and water (in the form of steam) are produced. An air separation unit (ASU) provides oxygen for the process and removes nitrogen, which would otherwise produce unwanted nitrogen compounds, such as NO_x. Essentially pure oxygen combines with the clean fuel to produce a high-energy-density drive gas. Combustion incorporates both sufficient water (to moderate temperature) and a very slight excess of oxygen (to minimize carbon monoxide formation). Additional water is strategically injected in stages to increase steam generation and adjust the drive gas temperatures to end use requirements. The drive gas is composed of 90–95 percent steam and 5–10 percent CO_2 by volume.

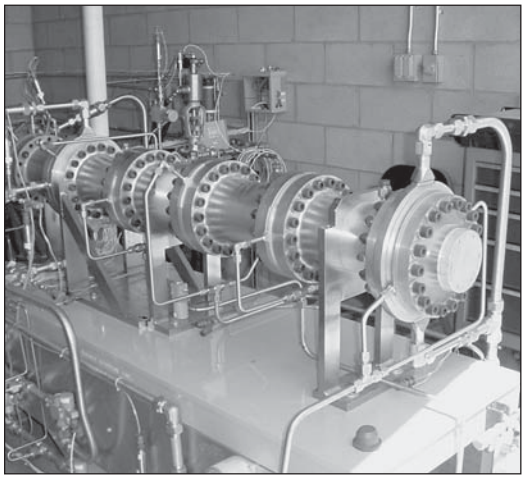
Key advantages of the CES process reside in its energy intensity and product gas composition. The energy intensity means that the gas generator can be very small (unlike boilers), which makes siting a CES unit easier than a conventional steam plant. The gas composition enables simple, low-cost CO_2 separation through steam condensation, and recycle of the water to satisfy process needs. In fact, the CES process is a net producer of water, an important factor since water use in power generation is fast becoming an environmental issue. The schematic (right) depicts the CES gas generator applied to power generation. Drive gas generated by the CES system passes through a high-pressure turbine, is reheated by direct firing with oxygen and fuel, and is directed to intermediate-pressure and low-pressure turbines in succession. The discharge gases enter a heat exchanger where residual heat in the turbine exhaust is recovered by the recycled water going to the CES gas generator. The cool exhaust gases then enter a condenser that naturally separates water from CO_2. Most of the water from the condenser is recycled to the CES gas generator. The balance of the high-quality water is available for any number of applications. The CO_2 is dried and compressed as required to meet end use needs.

PROCESS CONSIDERATIONS

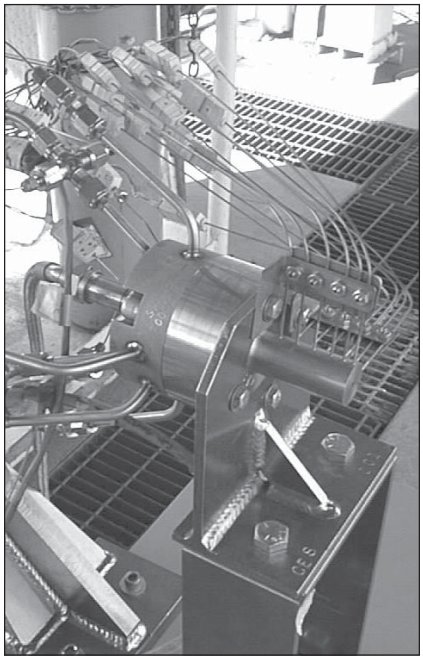
ASUs — an important component in the CES system — have long been established, and although relatively capital intensive, offer high reliability. Two major ASU manufacturers currently are engaged in an R&D partnership with DOE to commercially introduce next-generation ASUs by 2006. These next-generation ASUs apply gas separation membrane technology in lieu of energy-intense cryogenic processes. Capital and operating costs are projected to be dramatically reduced and reliability to remain high, given

CES GAS GENERATOR





Head-end view of 10-MW gas generator



Igniter assembly, used to start combustion in gas generator, as set up for testing at Aerojet's test facilities near Sacramento, California

the passive nature of the membranes (no moving parts). Moreover, other zero-emission concepts being considered, such as gasification-based systems, also use ASUs.

Any clean gaseous fuel can be used in the CES system. These include: piped natural gas and methane derived from landfills or coalbeds; reformed liquid fuels; and synthesis gas derived from gasification of solid feedstock, such as coal, biomass, and industrial and municipal wastes.

Current steam turbines cannot fully utilize the temperature/pressure regimes that the CES system is capable of delivering. To date there has not been a need, because there were no practical systems capable of delivering such energy. Advanced steam turbines under development can benefit from the CES gas generator. Typically, they are expected to operate at steam conditions near 1,200 ºF and 1,200 psi gauge (psig) (high-pressure turbine), and 2,200 ºF and 170 psig (intermediate turbine with reheater). CES is conducting exploratory talks with turbine manufacturers.

TEST RESULTS

Tests demonstrated successful operation of the CES ignitor over the prescribed ranges of pressure and mixture ratios. The ignitor provided repeatable, reliable performance through 100 ignitions. One of two main injector assembly designs, developed to provide the precise oxygen/fuel mix, operated successfully at both low power (20 percent of rated power) and at rated power (20 MW_t) in more than 95 valid tests and 664 seconds of cumulative operation. The CES gas generator was operated in both an uncooled configuration and cooled configuration. The uncooled configuration, a development tool, used diluent water to moderate combustion temperatures, but no downstream water injection to further cool the drive gas. In the uncooled configuration, the CES gas generator produced drive gases approaching 3,000 ºF at pressures greater than 1,550 psi absolute (psia). In the cooled configuration, the CES gas generator operated for more than 600 seconds at pressures ranging from 1,100–1,540 psia, and produced drive gases with temperatures as low as 600 ºF. The limited test durations were a consequence of the high demand for fuel, oxygen, and water at the 20-MW_t power level and the practical limitation on test facility fuel/oxygen and cooling capacities.

NEXT STEPS

Under a research contract with the California Energy Commission's Public Interest Energy Research program, CES is pursuing a project at a site in California. This project will allow a gas generator to be operated for long periods in order to evaluate durability and reliability, and enable design refinement while at the same time generating electricity in a power plant. Ultimately, for the power market, the CES gas generator will have to be integrated with steam turbines; and its operational, environmental, and economic performance will be evaluated to validate technical and environmental viability.

TWO NEW PPII PROJECTS MOVE FORWARD

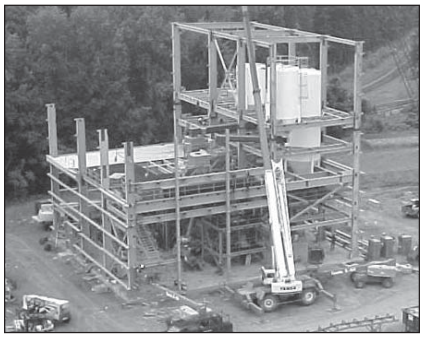
In recent months, two new projects awarded under the U.S. Department of Energy (DOE) Power Plant Improvement Initiative have begun construction. The PPII served as the precursor to President Bush's expanded program to develop advanced Clean Coal Technologies for the nation's power industry — the Clean Coal Power Initiative. In line with PPII goals to improve efficiency, reliability, and environmental performance of coal-fired plants, both projects would offer significant environmental benefits both at the sites and to potential commercial markets nationwide. One project, "Demonstration of Manufactured Aggregate Technology," broke ground in March 2003 and is being demonstrated by Universal Aggregates LLC. It is applicable to a wide range of flue gas desulfurization (FGD) wastes, including spray dryer wastes, which currently have no beneficial use and must be landfilled. The Universal Aggregates project will cost a total of $12.4 million, with DOE providing $7.2 million. That demonstration is to last 30 months. The second project, commissioned in April 2003, is the "Integrated Combustion Optimization System" offered by Sunflower Electric Power Corporation of Hays, Kansas. This technology would lower NO_x emissions at less cost compared to competing selective catalytic reduction (SCR) technology, while enabling higher power levels. DOE is providing $2.8 million for the 26 month Sunflower demonstration, with the project sponsor contributing the remaining $3.1 million.

UNIVERSAL AGGREGATES RECYCLES FGD BY-PRODUCT

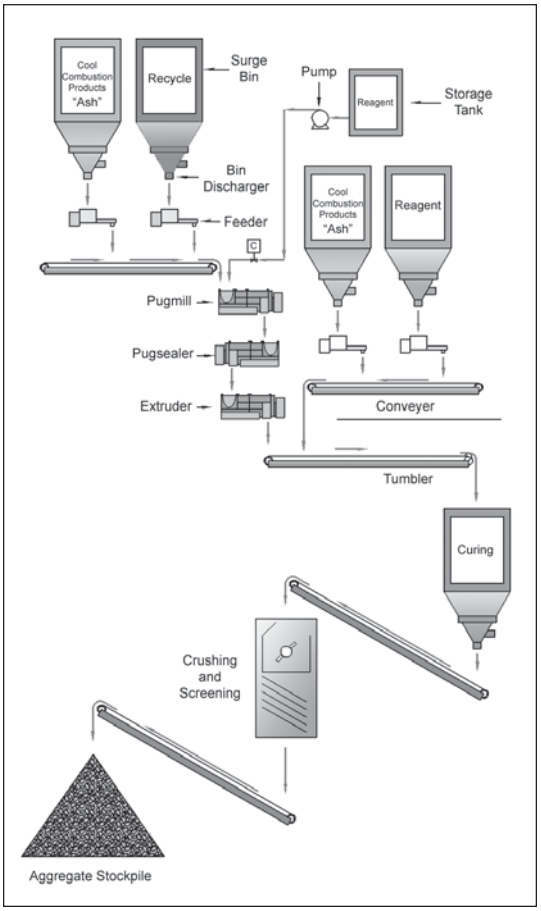
At a site adjacent to the Birchwood Power Partner's plant in King George County, Virginia, Universal Aggregates LLC, is to produce 167,000 tons per year of lightweight aggregate from 115,000 tons per year of spray dryer scrubber ash and bottom ash. The aggregate can be used in a variety of concrete-based products and asphalt paving material, and may be tailored to specific applications. Universal Aggregates was formed in January 2000 as a joint venture between CONSOL Energy, Inc. and SynAggs, Inc. to commercialize a patented technology developed by CONSOL Energy that converts coal combustion by-products (fly ash, bottom ash, boiler slag and FGD material, now totaling 100 million tons per year) from power plants into lightweight aggregate. P.J. Dick, Inc. will serve as the engineering contractor for the project. Production of aggregate is scheduled to begin in early 2004.

In the process (see schematic), spray dryer and bottom ash from the Birchwood Power plant are blended with additives in a mixer to produce a uniform granular material. This material is fed to an extruder that forces it through a metal die to form wet uncured pellets, which are then cut to a manageable length. The pellets are dried and hardened as they flow downward through a curing vessel designed to allow the solids to flow without clogging. The hardened pellets are crushed and screened to specification for sale as manufactured aggregates. The technology was developed with DOE participation in a 6-ton/day pilot plant located at CONSOL Energy's Research and Development Campus in South Park, Pennsylvania. That aggregate has been used successfully both at the CONSOL facility and on asphalt test strip roads in Florida.

As environmental standards become more strict, power companies are expected to install more scrubbers, increasing the market for tech-



Universal Aggregates construction progress at the Birchwood Power plant, King George County, Virginia



nologies than can recycle by-products. In fact, DOE expects that the Universal Aggregates process has a potential commercial application to 25 millions tons of spray dryer ash currently landfilled. DOE analysis also indicates that 25 spray dryer units across the country produce enough such wastes to justify building an on-site aggregate plant.

Construction, which began in March 2003, was delayed by a long winter and late spring, and now is expected to be completed in late 2003. Startup is expected in early 2004.

SUNFLOWER COMBUSTION OPTIMIZATION

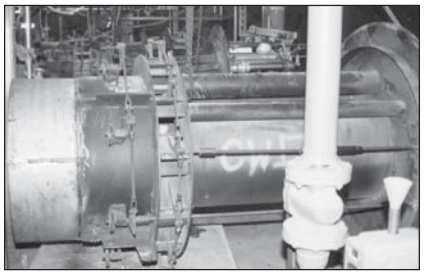
Until now, selective catalytic reduction (SCR) has been the preferred (and often the only) choice to meet the most stringent emission limits set by federal and state standards — less than 0.15 lb $NO_x/10^6$ Btu. The Sunflower Electric project, sited at Holcomb Station in Finney County, Kansas, hopes to provide an alternative method that can achieve lower emission rates of NO_x at reduced cost, thus saving money for the ratepayer. Holcomb station is equipped with first-generation low-NO_x burners that reduce NO_x emissions by 50 percent from uncontrolled levels.

Under the new PPII project, an array of state-of-the-art sensors, controls, and clean burning combustion modifications are to be installed and linked to sophisticated "neural network" software to oversee and optimize performance of all the processes together. Not only is the project expected to reduce NO_x emissions to 0.15–0.22 lb/10^6 Btu, but as an added benefit it is expected to enable increased power output by about 7 MW, all at a cost of less than half of the SCR-based NO_x control technology. It also eliminates the need for an expensive chemical plant (for SCR catalysts) at the station. While all individual components are commercially available, they have never before been linked under such a sophisticated system of controls.

GE Energy and Environmental Research Corporation, a unit of GE Power Systems, is providing the core technologies being demonstrated — a separated overfire air (SOFA) system, burner modifications, furnace sensors, coal flow measuring and control devices, and neural network controls. A 40 percent reduction in NO_x emissions is expected from the project, primarily from staged burning through the application of SOFA and burner modifications aimed at optimizing flame shape and stability. While the process may be applicable to all coal types, the low sulfur and high reactivity of Powder River Basin coals lend themselves to the SOFA-based staging and inexpensive burner modifications that are at the core of the pollution reduction project goal. Additional reductions of about 50 percent of the remaining NO_x are projected. In fact, a DOE analysis of potential markets of 8.4 GW for the combustion optimization system indicates that its commercialization could result in NO_x reductions near 46,000 tons per year, while saving power companies anywhere from $252–674 million, depending on the retrofit costs of installing SCR.

The coal flow measuring and control devices, the furnace sensors to define spatial distributions of key boiler parameters such as oxygen concentration and flue gas temperature, and the use of neural network controls will further minimize emission levels at the plant and optimize combustion efficiency. Balancing air flow and coal flow to individual burners is expected to reduce slagging and enable higher boiler loads and power output.

The Holcomb Station in Finnery County, Kansas is a 360-MW wall-fired boiler burning Powder River Basin coal



One wall-mounted low-NO_x burner at Sunflower Electric's Holcomb Station

The project is on schedule. Installation of the combustion optimization sensors package (for loss on ignition, furnace exit gas temperature, and CO) was completed in February 2003. Prior to a mid-March outage, tests were conducted utilizing the newly installed sensors package to provide baseline data on the Holcomb plant. Coal and ash samples were collected and analyzed to provide additional baseline data. The low-NO_x burner modifications also were completed. Shakedown of the coal flow sensors and other equipment continued through early June, and system optimization tests are planned for late 2003. The SOFA ports and advanced boiler optimization software will be installed in the Spring of 2004, with project testing to be completed by October 2004.

PROMISING PILOT TESTS FOR CMB TECHNOLOGY

Proof-of-concept tests recently completed by the U.S. Department of Energy (DOE) and ALSTOM Power Inc. of Windsor, Connecticut, on Circulating Moving Bed (CMB) technology have shown promise for scale-up with the eventual goal of demonstrating the technology at commercial scale. The technology uses a moving bed heat exchanger (MBHE) that heats the steam to the high temperature levels required for tomorrow's advanced power generation systems. The MBHE provides higher heat transfer efficiency per unit of material weight when compared to other types of boilers. Due to the compact heat transfer surface arrangement, CMB has the potential to significantly reduce capital and operating costs when compared to more conventional systems such as pulverized coal and fluidized-bed combustion, and could offer a promising alternative to these systems.

Pilot-scale tests at the 3-MW size and at commercial temperatures and pressures, were completed in March 2003 at ALSTOM's test facility in Connecticut. Pilot test emphasis has been on heat transfer capabilities, combustion performance, pollution reduction, and ash characterization. To carry out these CMB tests, ALSTOM's Multi-Use Combustion Test Facility (MTF) — now used to evaluate a variety of fuels and sorbents under a broad range of combustion conditions — was modified. DOE's National Energy Technology Laboratory funded 60 percent of the $2.97 million pilot-scale tests, and is co-funding follow-on tests at larger scale.

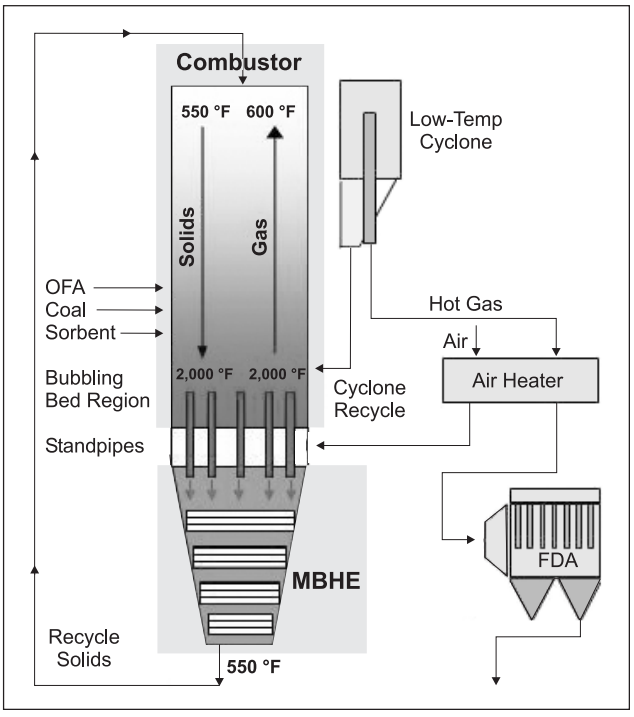
THE CMB PROCESS

The CMB combustion technology involves a novel method of solid fuel combustion and heat transfer wherein the combustion and heat transfer surfaces are completely separate. Since the MBHE environment is untouched by combustion gases, it does not have corrosion, erosion, and plugging problems common in conventional boilers, and thus enables use of "finned" tubes that have up to five times the surface area per linear foot compared to conventional boiler tubing. The need for less heat transfer surface enables a very compact heat exchanger design with reduced weight and cost. In addition, the 2,000 °F CMB temperature (higher than circulating fluidized-beds (CFB) 1,550–1,650 °F) makes possible working fluid temperatures as high as 1,750 °F. As shown in the accompanying schematic, the fuel (coal and a wide range of alternate fuels) is burned in the bubbling bed region of the combustor. Heat from the combustion products (upward flow) is exchanged with a flow of high-density solid particles falling downward through the upper combustor region. Solids have recovered the heat of combustion upon reaching the bottom of the combustor, and then are fluidized and transferred to a moving bed heat exchanger through standpipes.

Heat from moving particles is captured in a series of tubular moving bed heat exchangers that heat a working fluid, such as steam or compressed air. From the bottom of the heat exchanger, the cooled solids are transported back to the top of the combustor to restart the lower recycle loop. Sintered bauxite particles currently are used as the heat transfer solids media. Fly ash entrained in the flue gas flows upward and is captured by a cyclone. The captured solids are returned to the bubbling bed to reduce carbon loss. The SO_2 emissions are controlled primarily by a back-end cleanup system such as an ALSTOM Flash Dry Absorber (FDA). Limestone is calcined in the combustor for use in this sulfur cleanup system.

TEST RESULTS

Three test campaigns were completed in the MTF at temperatures ranging from 1,700–2,160 °F, which are those considered to give the technology a commercial edge. Tests were conducted on two bituminous



coals, and four sorbents with six different size distributions, as well as some with aqueous ammonia injection. Natural gas also was tested.

CMB economic benefits depend greatly upon the effectiveness of MBHE heat transfer, and test results at the MTF were extremely promising. Tests confirmed that combustion gases can be cooled in the combustor solely by heat transfer to a stream of falling particles, with gas and solid flow distribution being relatively uniform throughout the combustor. Over 20 gas-to-solids heat transfer tests were conducted in the first test campaign with warm air, natural gas firing, and coal firing. Heat transfer coefficients at MTF were up to 60 percent higher than those observed during smaller scale tests.

Results showed that bed ash agglomeration can be avoided over the range of commercial temperatures studied, and that the CMB can tolerate temporary temperature excursions. Two bituminous coals were fired for over 270 hours of operation at 2,000 °F or above. The Pittsburgh #8 coal, which has a very low ASTM ash fusion temperature, was fired for an additional six hours at elevated temperatures as high as 2,160 °F. No agglomerates were formed in the bed, and the bed remained well fluidized throughout the operation.

The pilot plant results to date show that combustion and environmental performance are satisfactory and can be further optimized to meet the performance targets for future advanced power plants. The combustion efficiency for the two coals ranged from 98.4–99.6 percent. One test was run at reduced load without any ash recycle from the cyclone. The combustion performance was slightly better than full-load operation with ash recycle. Further testing is needed to confirm this performance at full-load conditions, as operation without a cyclone would represent considerable cost savings for a commercial CMB boiler.

Excellent sulfur capture was demonstrated for the overall CMB system, including the combustor and back-end FDA system, while using fine limestone size distributions. Overall capture of 98 percent or greater was achieved with West Virginia bituminous coal at an approximate Ca/S molar ratio of 2:1 and using pulverized limestone. Additional tests with Pittsburgh #8 coal using pulverized sorbent with coarser size distributions yielded up to 96 percent sulfur capture at an approximate Ca/S molar ratio of 2:1. Coarse sorbent, however, had low in-furnace sulfur capture and only modest sulfur removal in the FDA.

According to the pilot tests, NO_x and SO_2 emissions are similar to state-of-the art CFB technology. N_2O emissions were extremely low during all tests (< 5 ppm), due to high temperatures in the lower furnace. NO_x emissions were as low as 88 ppm or 0.11 lb/10^6 Btu due to a combination of low excess air and deep staging. NO_x reductions of up to 40 percent were achieved when aqueous ammonia was injected. The reduction level was affected by injection location, local temperature and oxidizing conditions, and initial NO_x concentration. No ammonia slip was detected during the tests. Further NO_x reduction is thought to be possible through deeper staging, lower excess air, and optimizing SNCR injection.

CO emissions were typically in the 150–300 ppm range. CO apparently is generated in the upper furnace where the gas temperatures are low. Emissions tended to increase as the temperature in the upper furnace decreased. Techniques to reduce CO emissions will be evaluated in an upcoming MTF test campaign.

CONTINUED DEVELOPMENT WORK

The next phase of the joint NETL-ALSTOM work was initiated in April to continue development and scaleup of the overall CMB system. This two-year program will develop scaling relationships by building progressively larger models of the heat exchangers, and by developing new components unique to the CMB system. The program also will develop high-temperature finned tube designs and evaluate alternate mechanical designs and process improvements.

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CLEAN COAL TECHNOLOGY COMMERCIALLY PRODUCING METHANOL FROM COAL

One of the most successful U.S. Department of Energy (DOE) Clean Coal Technology projects — Air Products Liquid Phase Conversion Company, L.P.'s Liquid Phase Methanol (LPMEOH™) Process Demonstration Facility located in Kingsport, Tennessee — has completed its government-funded demonstration tests. The 69-month operating period ended as trouble-free as it began, achieving an impressive 97.5 percent mark for operational reliability. The facility that converts coal-derived synthesis gas into methanol could be the early forerunner of future coal plants that coproduce clean liquid fuels and chemicals in addition to generating power — a key goal of the DOE FutureGen project.

The project was selected by DOE to demonstrate commercial viability of the Air Products and Chemicals, Inc. LPMEOH™ Process to produce methanol from coal-derived synthesis gas. Methanol is a chemical feedstock for a variety of applications, and is being considered as a source of hydrogen for fuel cell systems. The LPMEOH™ Process can provide improved economics and added flexibility for a coal gasification complex coproducing both electric power and chemicals/fuels; and can play a key role in DOE's goal of eliminating environmental concerns by using coal as a secure, domestic feedstock to produce electricity, clean fuels including hydrogen, and chemicals.

Now in commercial operation at Eastman Chemical Company's Chemicals-from-Coal Complex, the LPMEOH™ demonstration facility successfully came on-stream on April 2, 1997, and quickly began to show its potential. Within four days, the design production rate of 80,000 gallons per day of methanol was achieved. An initial test at 115–120 percent of the design methanol production rate was attained four days later. Over the rigorous demonstration test period, tests were successfully completed under a variety of conditions anticipated in integrated gasification combined-cycle (IGCC)/coproduction applications. Tests included catalyst withdrawal and addition to maintain the desired methanol production rate, operation on a carbon monoxide-rich synthesis gas feed, "ramping" from standby to full load operation, and on-off operation.

In addition to achieving these key milestones, efforts also focused on simplifying the process and ensuring long-term catalyst life. The elimination of slurry pumps and improvements to the gas distribution system have enhanced operability of the reactor. Engineering and laboratory efforts focused on the removal of trace contaminants in coal-derived synthesis gas; and the development of a procedure to activate a full charge of catalyst within the reactor (*in-situ*) followed by temperature programming (the increase of reactor temperature as necessary to maintain the desired methanol production rate) could reduce the capital cost by as much as 10 percent.

Over the last six months of operation, these improvements demonstrated the potential to reduce the catalyst deactivation rate by more than one-half of the average value previously attained. This translates into a 25 percent reduction in variable cost — a significant benefit that could be realized by potential future customers of the technology.

Economic studies conducted by Air Products have shown that methanol can be coproduced with electric power in a coal-based IGCC configuration for less than 50 cents per gallon. The IGCC technology was successfully demonstrated in other clean coal technology projects where it was shown to be one of the cleanest and most efficient of 21st century power-generating options. These technologies, either individually or in combination, will be able to fill local needs for electric power, transportation fuels, and manufactured chemical products, all from a domestic — and locally produced — resource.

While Eastman used a majority of the nearly 104 million gallons of methanol produced as a chemical feedstock, methanol product-use testing also was conducted under the project. This demonstrated how a centrally located clean coal electric power plant with methanol coproduct could provide energy services to local communities. Product-use testing proved that coal-derived methanol, free of sulfur and other impurities, could be used as a replacement for petroleum in transportation, a peaking fuel in combustion turbines, a hydrogen source for small fuel cells, or a chemical feedstock.

The DOE Office of Fossil Energy's National Energy Technology Laboratory managed this demonstration of the LPMEOH™ Process as part of the Clean Coal Technology Program. The Air Products Liquid Phase Conversion Company, L.P., a partnership between Air Products and Eastman, was the private industry participant.

INTERNATIONAL INITIATIVES

NETL AND CHINESE INSTITUTE COOPERATE ON CO_2 SCRUBBING PROJECT

In Spring 2002, the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) began cooperating with the National Power Plant Combustion Engineering Technology Research Center (NPCC) in Shenyang, China on a "Study of CO_2 Sequestration by Spraying Concentrated Aqueous NH_3 and Production of a Modified NH_4HCO_3 Fertilizer." This project is being implemented under the R&D Protocol with the People's Republic of China.

The new project builds on work pursued separately by the two countries over the past several years, to use aqueous ammonia to capture CO_2 from flue gas. China is interested in producing ammonium bicarbonate (ABC) fertilizer for its vast agricultural sector, while the U.S. is focusing on developing an efficient process to capture CO_2 that could be sequestered. NETL began its efforts at the lab-scale looking for improved solvents to replace monoethanolamine (MEA) for CO_2 removal. CO_2 removal with aqueous ammonia has the potential to be less costly and less energy-intensive, offer increased adsorption capacity, and generate valuable mixed ammonium nitrate/ammonium sulfate fertilizer as a by-product. NETL researchers, who have a patent application in progress, recognized that the process could be readily adapted by heating the ABC product to regenerate the ammonia and to produce a concentrated stream of CO_2 that could be sequestrated. NPCC has proved the concept of producing fertilizer from flue gas in a pilot-scale coal combustion facility. Their work to date has focused on experiments rated at 20 kg/h of bituminous coal (about 0.60 million Btu/h) using actual flue gas to produce a mixed fertilizer. CO_2 capture efficiency ranged from 76.4 percent to 91.7 percent at 35 °C.

Results of the initial experiments by both organizations were reported at the Second National Conference on Carbon Sequestration held in Alexandria, Virginia during May 5–8, 2003. The next step in the cooperation is for the two organizations to visit each other's facilities. Lead researcher for NETL, Dr. James Yeh, is planning to visit NPCC in mid-October 2003, after which NPCC is considering a short-term placement of one of its researchers at NETL to work side by side with Dr. Yeh.

US-UK COLLABORATION IN CLEAN COAL TECHNOLOGY

Representatives from the U.S. Department of Energy (DOE) Office of Fossil Energy (FE) and the United Kingdom (UK) Department of Trade and Industry met in Pittsburgh, Pennsylvania on June 19–20, 2003, to pursue cooperative R&D activities under an Implementing Arrangement on Cleaner Coal Technology. The Implementing Arrangement, signed in March 2003 by DOE Secretary Spencer Abraham, aims to promote fuel diversity, environmental protection, energy security, and international trade, and follows a broad Memorandum of Understanding on energy R&D cooperation signed by the two countries in 2000.

The June meeting was organized to follow up on earlier discussions between experts from the two countries at DOE Advanced Research Meetings. Government representatives from both countries along with experts from several research institutions and industry met to explore collaboration in two priority areas of common interest — advanced materials and virtual plant simulations. Future meetings also may be held to develop collaborative projects in other coal-related areas.

With industry and academia, both sides are developing new and improved materials that can withstand the high-temperature environments of advanced coal processes. The two countries tentatively agreed to hold future workshops on alloys and smart thermal barrier coatings for gas turbine components, as well as on life prediction modeling for gas turbines. Shared activities possible in virtual plant simulation include developing a compatible platform to integrate the plant simulation programs being developed in the UK with those in FE's programs; incorporating computational fluid dynamics into system models: and adopting security controls to protect confidential and proprietary information.

STATUS OF ACTIVE CCT DEMONSTRATION PROJECTS

ENVIRONMENTAL CONTROL DEVICES

Southern Company, Inc. – *Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler.* The project, to evaluate the use of GNOCIS and other computerized process control software to further optimize operation of Plant Hammond Unit 4, ended on April 30, 2003. A final report is being prepared. (Coosa, GA)

ADVANCED ELECTRIC POWER GENERATION

City of Lakeland, Department of Water & Electric Utilities – *McIntosh Unit 4A PCFB Demonstration Project and McIntosh Unit 4B Topped PCFB Demonstration Project.* The project was terminated as of June 4, 2003. (Lakeland, FL)

JEA – *ACFB Demonstration Project.* Construction of Unit 2 at the Northside Station was completed in December 2001. The DOE demonstration planned has been delayed while JEA made repairs/modifications to Unit 2. (Jacksonville, FL)

Kentucky Pioneer Energy, L.L.C. – *Kentucky Pioneer Energy Project.* The Environmental Record of Decision was published in the Federal Register on February 4, 2003, completing the NEPA process. Presentations to the PSC Siting Board were completed and a decision on issuing a Certificate is due. A groundbreaking ceremony for the fuel cell portion of the project (relocated to Wabash River) took place on August 13, 2003. (Trapp, KY and West Terre Haute, IN)

Tampa Electric Co. – *Tampa Electric Integrated Gasification Combined-Cycle Project.* Tampa's Polk Power Station completed its operational period at the end of October 2001 with over four and one-half years of successful commercial operation. The Post Project Assessment is in review. (Polk County, FL)

COAL PROCESSING FOR CLEAN FUELS

Western SynCoal LLC (formerly Rosebud SynCoal® Partnership) – *Advanced Coal Conversion Process (ACCP) Demonstration Project.* In January 2003, Westmoreland Power, Inc. transferred ownership of Western SynCoal LLC to ENPRO, of Butte, Montana, to complete the Final Report for the ACCP Clean Coal Technology Demonstration Project. Western SynCoal LLC is working on the Final Report, expected to be completed in December 2003. (Butte, MT)

Air Products Liquid Phase Conversion Company, L.P. – *Liquid Phase Methanol Process Demonstration Project.* The Final Report for the Liquid Phase Methanol (LPMEOH™) Process Demonstration Project was issued in June 2003, and is available on the Clean Coal Technology Compendium at http://www.lanl.gov/projects/cctc/. Over the 69-month operating period, the facility achieved an impressive on-stream availability of 97.5 percent, and produced nearly 104 million gallons of methanol, all of which was accepted by Eastman Chemical Company for use in downstream chemical processes. The facility is now being operated in a commercial mode by Eastman to help satisfy its methanol feedstock requirements. Preparation of the Post-Project Assessment by the National Energy Technology Laboratory is under way. (Kingsport, TN)

INDUSTRIAL APPLICATIONS

CPICOR Management Company, L.L.C. – *Clean Power From Integrated Coal/Ore Reduction (CPICOR).* Preparation of the Environmental Impact Statement for the CPICOR project has been placed on hold. The CPICOR Management Company (CMC) continues to work toward arranging the financing necessary to move the project into Budget Period 2. CMC also continues to work closely with the Australian developers of the HIsmelt Process and iron/steel engineering firms to establish a process and mechanical design database for this project. The Cooperative Agreement has been extended to August 30, 2003 to allow time for arranging financing and for submitting the Continuation Application. Upon receipt and review of the Continuation Application to move into Budget Period 2, DOE will make a decision as to continuation of the project. (Vineyard, UT)

ThermoChem, Inc. – *Pulse Combustor Design Qualification Test.* The Final Report has been submitted and accepted by DOE, and the Cooperative Agreement is in the close-out process. The Post Project Assessment has been accepted and is available on the Clean Coal Technology Compendium. (Baltimore, MD)

PPII STATUS

Tampa Electric Company, Big Bend Power Station Tampa – *Network Sootblower Optimization Project.* Project came on line early 2003. Baseline testing was completed in May 2003, at which time parametric testing was initiated. Using a variety of trending tools the data generated from the parametric tests are being analyzed. Areas of interest were process optimization toward NO_x re-

duction and efficiency improvement. These preliminary observations are hinting at some excellent results. Nevertheless, more testing is necessary to further confirm the repeatability and validate some data collected to date. Parametric testing will continue at least through the summer of 2003. (Apollo Beach, FL)

Universal Aggregates, LLC – *Commercial Demonstration of the Manufactured Aggregate Processing Technology Utilizing Spray Dryer Ash.* The NEPA process has been completed for the site. The project has progressed through the design phase into construction. Ground was broken at the site on March 26, 2003, and construction has been proceeding smoothly. The site has been prepared, pilings have been driven, and foundations have been poured. Steel and vessel erection at the site began in late July 2003. The facility is expected to be ready for shakedown in January 2004. (King George, VA)

Sunflower Electric Power Corp. – The combustion optimization sensors package consisting of the Burner Profiler, LOI/FEGT Sensors, and CO sensors is operational. Data are being archived on the MKE computer and by EtaPRO, which also collects plant performance data. The coal flow monitoring system is operational and output is being archived by EtaPro. The system is performing well, but a wide degree of fluctuations is still being observed on Mill A. The low-NO_x burner modifications and coal-balancing dampers have been installed. The control logic for automating the dampers is under development. The Mill C dampers are in the process of being automated. A purge system has been installed on the dampers and the electrical work on the dampers is nearly complete. Boiler performance and emissions are being monitored. The Continuation Agreement is being prepared at this time. (Garden City, KS)

Otter Tail Power Company – *Demonstration of a Full-Scale Retrofit of the Advanced Hybrid Particulate Collector (AHPC) Technology.* The project came on line in October 2002. The first nine months of operation have shown very good particulate removal efficiency, but at the cost of higher system pressure drop. Performance testing has shown that the average collection efficiency of the AHPC is 99.997 percent. The outlet dust loading is almost two orders of magnitude lower than the guarantee limit of 0.002 gr/acf. However, AHPC system pressure drop also has exceeded guarantee limits and has resulted in premature bag replacement. The power plant was shut down in June to replace bags and perform ESP component maintenance. The plant has not been derated due to the AHPC since the June restart and the filter bags seem to have completed their initial conditioning period. Pressure drop performance will continue to be studied over the next several months. (Big Stone City, SD)

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