CLEAN COAL TECHNOLOGY

Clean Coal Power Initiative Round 1 Demonstration Projects

Applying Advanced Technologies to Lower Emissions and Improve Efficiency

A report on three projects conducted under separate cooperative agreements between the U.S. Department of Energy and:

- Great River Energy
- NeuCo. , Inc.
- WeEnergies

Cover Photos:

- Top left: Great River Energy's Coal Creek Station
- Top right: We Energy's Presque Isle Power Plant
- Bottom: Dynegy's Baldwin Energy Complex

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Executive Summary

Coal is both plentiful and affordable in the United States (U.S.) and is expected to maintain its nearly 50 percent share of total electricity generation as demand increases. Our nation's energy security and environmental management depend on the resolution of environmental concerns associated with increased coal use. Cost-effective and efficient technologies developed to ensure the environmentally clean utilization of this resource have been designated as "clean coal technologies."

Clean coal technology research and development (R&D) began in the 1970s. Many promising technologies had emerged by the 1980s, but were not implemented at the commercial scale due to the financial and technical risks associated with the first commercial-scale installation. A pathway to facilitate the further development of these technologies was initiated by Congress and implemented by the U.S. Department of Energy (DOE) in 1985 with the creation of the Clean Coal Technology Demonstration Program (CCTDP). The CCTDP forged cost-sharing partnerships between DOE, non-federal public entities, technology suppliers, and clean coal technology stakeholders to reduce the financial and technical risks preventing their commercial-scale implementation and demonstration.

Building on the successes of CCTDP, DOE implemented the Power Plant Improvement Initiative (PPII) in 2001 to focus on enhancing the reliability of the nation's power grid. PPII was followed by the Clean Coal Power Initiative (CCPI) in 2002.

The CCPI is an industry/government cost-shared partnership program that furthers efficient clean coal technologies for use in new and existing U.S. electric power generating facilities. CCPI is a technology demonstration program implemented through a series of solicitations (rounds) that target priority areas of interest to meet DOE's Roadmap goals. Technologies emerging from the program will help U.S. coal-fired electricity generating plants to meet both existing environmental objectives as well as those emerging in the near future. CCPI is planned and managed by the DOE Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL).

CCPI Round 1 (CCPI-1) criteria for candidate projects was very broad in that the solicitation was open to "any technology advancement related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives." CCPI Round 2 (CCPI-2) encouraged proposals to demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advancements that reduce mercury (Hg) and other power plant emissions. CCPI Round 3 (CCPI-3) required projects that could demonstrate the capture, recovery, and sequestration or beneficial use of carbon dioxide (CO_2) from coal-fired power plants.

Future CCPI rounds will build upon the successes of previous rounds, demonstrating advanced technologies that strengthen the nation's energy and economic security with minimal impacts to the environment and consumer.

This report describes three projects that have successfully demonstrated emissions and plant control system upgrades that support the CCPI-1 objective of ensuring that the U.S. has clean, reliable, and affordable electricity. The Baldwin Energy Complex project utilized an artificial intelligence (AI) system that increases the plant's thermal efficiency while reducing emissions. The Great River Energy (GRE) project increased boiler efficiency by reducing the fuel moisture content. The TOXECON™ project removed Hg from the flue gas stream without affecting the marketability of the fly ash.

The **Demonstration of Integrated Optimization Software at the Baldwin Energy Complex** project demonstrated the integration of advanced, on-line, combustion/emission control optimization software. The demonstration showed that an integrated process optimization approach can increase the thermal efficiency and reliability of the plant, with the concurrent benefit of a corresponding reduction of airborne emissions such as nitrogen oxides (NO_X), CO_2, and particulates.

The Cooperative Agreement for the project at the Baldwin Energy Complex was awarded on February 18, 2004. The project duration was 45 months and was completed on November 17, 2007. The project cost was $19,094,733 with a DOE share of $8,592,630 (45 percent). Project goals were met with the exception of the heat rate improvement target. However, it is believed that the heat rate goal could have been met had plant personnel not placed a higher priority on cyclone flame stability and NO_X reduction. To date, the participant has reported well over 50 sales of its optimization modules.

In GRE's **Increasing Power Plant Efficiency: Lignite Fuel Enhancement** project, waste heat from a power plant was used to lower the moisture content of the lignite fuel it consumes. Reducing the moisture content of the lignite increases the energy efficiency of the boiler, which means less fuel is required for a given load. Emissions reductions were achieved as a result of increased fuel quality, segregation of iron sulfide (pyrite) and mercury in the drying process, and increased oxidation of mercury resulting in greater mercury removal in the flue gas desulfurization (FGD) system.

A Cooperative Agreement for the Lignite Fuel Enhancement project was awarded on July 9, 2004. The project duration was 69 months with an operations completion date of March 2010. The estimated project costs were $31,512,215 with a DOE share of $13,518,737 (43 percent). The moisture content of the coal was reduced by the target amount of 8.5 percent, which resulted in a higher heating value (HHV) improvement from 6290 British thermal units/pound (Btu/lb) to 7043 Btu/lb. Also, the moisture removal process and the resulting increased fuel quality resulted in mercury (Hg) emissions being reduced by 41 percent, with NO_X and sulfur dioxide (SO_2) reduced by 32 and 54 percent, respectively. GRE has reported that 120 organizations have signed the necessary secrecy agreements to obtain detailed information on the technology. Some studies have been carried out to evaluate the technology for specific applications.

The **TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers** project (TOXECON™) was an integrated Hg, particulate matter, SO_2, and NO_X emissions control demonstration program for application on coal-fired power generation systems. The TOXECON™ process utilized sorbents that were injected into a pulse-jet baghouse to control emissions. The technology was configured to not affect fly ash quality and its potential to be sold for constructive use. **TOXECON™** has been installed at seven plants in addition to Presque Isle Power Plant (PIPP) and robust sales of the Hg Continuous Emissions Monitor (CEM) have been reported. The recently released new Hg standard is expected to provide additional impetus for future application.

The total project cost was $47,512,830, with DOE providing $23,756,415 (50 percent). The demonstration began operation in January 2006, and was completed in September 2009. The project achieved the emissions reduction goals of 90 percent for Hg and 70 percent for SO_2 individually; however, the concurrent reduction of these emissions through an integrated treatment process was not consistently achieved. All remaining project goals, except for NO_X reduction, were met.

Clean Coal Technology Demonstration Program (CCTDP)

According to the Energy Information Administration's Annual Energy Outlook 2011, the demand for electricity in the United States is projected to increase by 25 percent by the year 2035. Because coal is both plentiful and affordable, the generation of electricity from this abundant resource is expected to continue to account for nearly 50 percent share of total generation. The nation's energy and economic security and environmental quality depend on the resolution of environmental concerns associated with increased coal use. These concerns can be addressed through the development of technology-based solutions that ensure environmentally clean energy utilization. These solutions must be both cost-effective and efficient to support economic growth. This new generation of technologies has been designated as "clean coal technologies."

The R&D of clean coal technologies began in the 1970s, with many promising technologies having emerged by the 1980s. The technologies were, however, unproven in a commercial setting and not implemented due to financial and technical risks. A pathway was needed to prove their technical performance and cost competitiveness in a commercial setting in order to facilitate their acceptance and reduce the risk of implementation. This pathway was initiated by Congress and implemented by the DOE beginning in 1985 with the creation of the Clean Coal Technology Demonstration Program (CCTDP). The CCTDP forged cost-sharing partnerships among the DOE, non-federal public entities, technology suppliers, and other clean coal technology stakeholders to reduce the financial and technical risks preventing the demonstration and commercialization of these technologies. As a condition of participation, CCTDP demonstrations were required to be at a scale and in an operational environment sufficient to determine their potential for satisfying marketplace technical, economic, and environmental needs.

Building on the successes of CCTDP, DOE implemented the Power Plant Improvement Initiative (PPII) in 2001, which called for technologies that could be rapidly implemented to enhance the reliability of the

THE CLEAN COAL TECHNOLOGY PROGRAM

The DOE commitment to clean coal technology development has progressed through three phases. The first phase was the Clean Coal Technology Demonstration Program (CCTDP), a model of government and industry cooperation that advanced the DOE mission to foster a secure and reliable energy system. With 33 projects completed, the CCTDP has yielded technologies that provide a foundation for meeting future energy demands that utilize the vast U.S. reserves of coal in an environmentally sound manner. Begun in 1985, the CCTDP represents a total investment value of over $3.25 billion. The DOE share of the total cost is about $1.30 billion, or approximately 40 percent. The project industrial participants (non-DOE) have provided the remainder, nearly $2 billion.

Two programs have built on the successes of the CCTDP. The first is the Power Plant Improvement Initiative (PPII), a cost-shared program patterned after the CCTDP and directed toward improved reliability and environmental performance of the nation's coal-burning power plants. Authorized by the U.S. Congress in 2001, the PPII concluded with four successfully completed projects that focused on technologies enabling coal-fired power plants to meet increasingly stringent environmental regulations at the lowest possible cost. The total value of these projects is $71 million, with DOE contributing $31 million or 42.7 percent.

The second follow-on program is the Clean Coal Power Initiative (CCPI). Authorized in 2002, the CCPI had a goal of accelerating commercial deployment of advanced technologies to ensure that the nation has clean, reliable, and affordable electricity. The first CCPI solicitation (CCPI-1) was open to "any technology advancement related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives." Of five projects awarded, two were discontinued and three were successfully completed. The total cost of the five projects was approximately $121 million, with the DOE share being $54 million or 44.8 percent. In February 2004, the second CCPI solicitation (CCPI-2) was issued seeking proposals to demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advances that reduce mercury and other power plant emissions. In October 2004, four projects were selected. One project withdrew prior to award, one is complete, and two are ongoing. The three awarded projects are valued at over $4 billion with a DOE share of $322 million. On August 11, 2008, DOE issued the Funding Opportunity Announcement for the third solicitation (CCPI-3A). CCPI-3A specifically focused on the capture and sequestration, or beneficial reuse, of CO_2 emissions from coal-based electricity production (minimum 50 percent gross energy output as electricity). Following the passage of ARRA, DOE announced the re-opening of the third solicitation. On June 9, 2009, DOE issued an amendment that provided for a second application due date (CCPI-3B) of August 24, 2009. A total of $1.4 billion was made available for awards under CCPI-3A and -3B. Of the total amount, approximately $800 million was provided under ARRA with the remainder provided through the annual congressional appropriations process. Of the four projects awarded, one withdrew and three are ongoing. The three ongoing projects are valued at over $6 billion with a DOE share of approximately $1 billion.

nation's power grid. PPII was followed by the Clean Coal Power Initiative (CCPI) in 2002. CCPI ensures the ongoing development of advanced systems for commercial power production emerging from DOE's core fossil-fuel research programs.

CCPI Program

As coal is likely to remain one of the nation's—and world's—lowest-cost electric power resources for the foreseeable future, a new commitment to further reduce the environmental challenges of its continued use through even more advanced clean coal technologies is required. CCPI is an innovative technology demonstration program initiated to foster more efficient, advanced, clean coal technologies in the 21st century for use in new and existing electric power generating facilities in the U.S. CCPI solicitations began in 2002. As of this report, three solicitations have been issued (CCPI-1, CCPI-2, and CCPI-3). After the submission of proposals for the initial CCPI-3 solicitation (CCPI-3A), the solicitation was re-opened with minor amendments for a second round of proposals (CCPI-3B). Projects selected under CCPI-3A and -3B could be funded, in whole or in part, from funds appropriated under the American Recovery and Reinvestment Act of 2009 (ARRA).

CCPI builds on the successes of the original CCTDP and encompasses a broad spectrum of research and large-scale projects that target today's most pressing environmental challenges. CCPI is an industry/government cost-shared partnership that accelerates commercial deployment of advanced technologies to ensure a reliable and affordable supply of electricity while simultaneously protecting the environment. CCPI is planned and managed by DOE's Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL).

The CCPI mission is to enable and accelerate deployment of advanced technologies to ensure that the United States has clean, reliable, and affordable electricity. This mission is executed through the CCPI program goals of reinvigorating private sector development of new coal-based power technologies that can meet increasingly stringent environmental regulations, and establishing the technological foundation for "zero" emission coal-based energy facilities within the nation's power industry.

REGULATORY HISTORY

Title III of the 1990 Clean Air Act Amendments (CAAA) identified 189 substances emitted by fossil fuel combustion that may be toxic or hazardous. These 189 substances are usually referred to as hazardous air pollutants (HAPs) or air toxics. The CAAA required the Environmental Protection Agency (EPA) to evaluate these pollutants by source as well as their potential harm to human health and the environment. The EPA was also required to determine the need to control the emission of HAPs. DOE's NETL, in collaboration with the Electric Power Research Institute (EPRI), comprehensively addressed the CAAA requirements specific to the electric power industry with a series of projects from 1990 to 1997. In the course of these projects, it was found that non-mercury toxic metals were captured by existing particulate removal equipment and that they were emitted at or near their detection limit. These projects provided the majority of the data for two Congressionally-mandated EPA Reports to Congress. The first report, the "Mercury Study Report to Congress," was issued in 1997 and found that coal-fired power plants were the largest U.S. source of anthropogenic mercury emissions. The second report, the "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units–Final Report to Congress" was issued in 1998. This second report concluded that mercury from coal-fired power plants was the HAP of "greatest potential concern." This conclusion lead to the initial emphasis on regulating mercury and the development of mercury capture technologies and that additional research and monitoring was warranted for the other HAPs.

In 1999 and 2000, the EPA, in cooperation with DOE, issued an Information Collection Request (ICR). The purpose of the ICR was two-fold. One aim was to refine the mercury emission inventory from coal-fired power plants. The other was to determine the mercury control capabilities of existing and new, potentially viable technologies. In the same timeframe, the National Academy of Sciences (NAS) conducted an evaluation of the health impacts of mercury. Based on the ICR and the NAS evaluation, the EPA determined that there was a "plausible link" between emissions of mercury from coal-fired power plants and the bioaccumulation of mercury in fish, as well as animals that eat fish. Since consumption of fish is the primary pathway for human exposure to mercury, the EPA determined that it was necessary to reduce mercury emissions from fossil fuel combustion in power plants. The EPA issued its decision to regulate mercury in December of 2000.

The EPA issued the Clean Air Mercury Rule (CAMR) on March 15, 2005. This was the first regulation to specifically address mercury emissions from coal-fired power plants. The CAMR complemented the Clean Air Interstate Rule (CAIR), which was issued to reduce the emissions of NO_X and SO_2, since technologies designed to remove other pollutants often coincidentally remove some mercury. The net effect of these two rules was expected to be a 70 percent reduction in mercury emissions, which are currently estimated at 48 tons per year. The CAMR intended to create a market-based cap-and-trade program to reduce mercury emissions. The reduction would have taken place in two phases. Mercury emissions were to be capped at 38 tons per year in 2010. This level of emissions would have been achieved by coincidental mercury capture in technologies whose primary purpose is the control of other pollutants. By 2018, total mercury emissions from all coal-fired power plants were to be limited to 15 tons per year. In addition, new coal-fired units would have to meet New Source Performance Standards.

The CAMR was applicable to all coal-fired utility boilers with a heat input of 73 MW (thermal) or 250 million Btu per hour. Industrial cogeneration boilers would have been regulated if they sell over 25 MW of electrical power and more than one third of their maximum output to a power distribution system. In 2008, the D.C. Circuit Court vacated the CAMR and remanded the CAIR. The EPA Administrator signed a new rule on December 16, 2011, and it was published in the Federal Register on February 16, 2012. This rule, Mercury and Air Toxics Standards (MATS), regulates mercury, HCl, and a number of non-mercury air toxic metals emitted from power plants. These are antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), lead (Pb), manganese (Mn), nickel (Ni), and selenium (Se). MATS include separate standards for existing plants and new or refurbished generating units. Each unit is also regulated differently depending on whether it burns low rank or non-low rank coal. All power plants have three years to comply and the deadline can be extended one year by state agencies—an option expected to be broadly available.

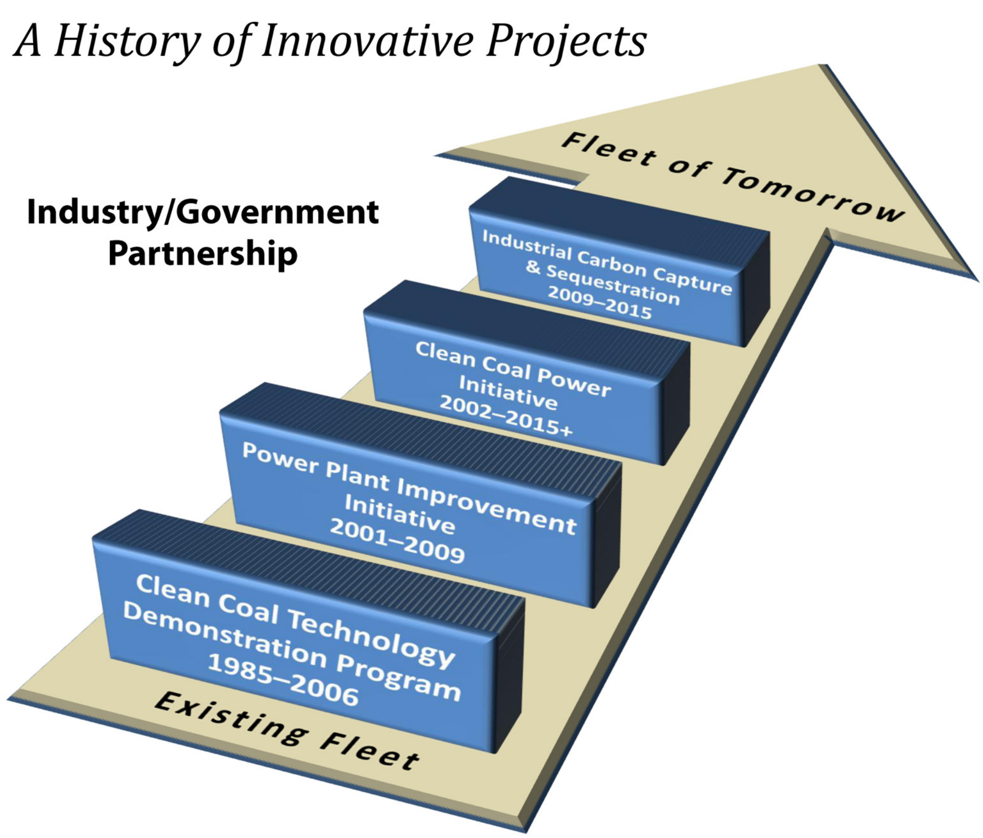
MATS establishes alternative quantitative emission standards, including SO_2 (as a surrogate for HCl). Filterable particulate matter serves as a surrogate for non-mercury air toxic metals, which can also meet a standard based on the total emissions of the eight non-mercury air toxic metals or the plant may meet a separate standard for each of these metals. The standards set work practices instead of numerical limits to limit emissions of organic air toxics, including dioxin/furan, from existing and new coal- and oil-fired power plants. In MATS the emission standards for new or refurbished plants are expressed as pounds per megawatt hours or pounds per gigawatt hours. Existing plants can meet standards based on either electric power output or the heat content of the coal fed to the boiler.

According to "Clean Coal Technology Programs: Program update 2006", CCPI Round 1 (CCPI-1) criteria for candidate projects was very broad in that the solicitation was open to "any technology advancement related to coal-based power generation that results in efficiency, environmental and economic improvement compared to currently available state-of-the-art alternatives." The broad approach taken by CCPI-1 was intended to benefit from the full range of technological advancements made since the last major clean coal technology solicitation had been issued in 1992. Of the eight projects initially selected under CCPI-1, five awards were made. Two of the awarded projects ended prior to successful completion. The remaining three projects are complete and are the subject of this report.

CCPI-2 encouraged proposals that demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advancements that reduce Hg and other power plant emissions. The choice of the CCPI-2 solicitation categories reflected DOE's judgment of the most pressing technological needs confronting the nation's power industry in the 2010 to 2020 time frame.

CCPI Round 3 (CCPI-3) required projects that could demonstrate the capture and sequestration or the beneficial use of carbon dioxide (CO_2) from coal-fired power plants. The technologies to be demonstrated could consist of new, integrated facilities or retrofits of existing plants. After an initial round of projects was awarded, a second round of projects was awarded under CCPI-3 in December 2009 with funds made available under ARRA.

The CCPI is closely linked with R&D activities paving the way for ultra-clean, fossil-fuel based energy complexes in the 21st century. The Clean Coal Technology Roadmap was developed in January 2004 with the cooperation of the coal and power industry to address short- and long-term coal technology needs, which support the clean coal initiatives. Projects selected under the CCPI advance efficiency, environmental performance, and cost competitiveness well beyond that of technologies that are currently in commercial service, which is consistent with the Energy Policy Act of 2005.



DOE's Coal Demonstration Programs

Demonstration of Integrated Optimization Software at the Baldwin Energy Complex

Introduction

A coal-fired power plant is a complex grouping of dynamic and interrelated systems. An effort to optimize one aspect of the operation of a system has the potential, in some cases, to adversely affect other operational aspects of the same or different systems. An example would be that reducing the heat rate of a power plant through an increase in combustion efficiency might also result in an increase in the rate of NO_x formation due to possible higher combustion temperatures. Therefore, overall plant optimization must include the ability to monitor individual systems and ensure their operation is not adversely impacted by changes in the same or related systems.

NeuCo, Inc. (NeuCo) of Boston, Massachusetts, demonstrated overall plant performance optimization by utilizing sophisticated computational techniques to increase power plant efficiency and reduce air emissions at the Dynegy Midwest Generation Baldwin Energy Complex (BEC). The BEC consists of three 600 megawatt electric (MWe) coal-fired units located in Randolph County, Illinois, which are designed to fire high-sulfur bituminous coal. All three units switched to Powder River Basin (PRB) coal in 2002 to reduce SO_2 emissions.

The Cooperative Agreement was awarded on February 18, 2004, and the project was completed on November 17, 2007. The project cost was $19,094,733 with a DOE share of $8,592,630 (45 percent).

Project Objectives

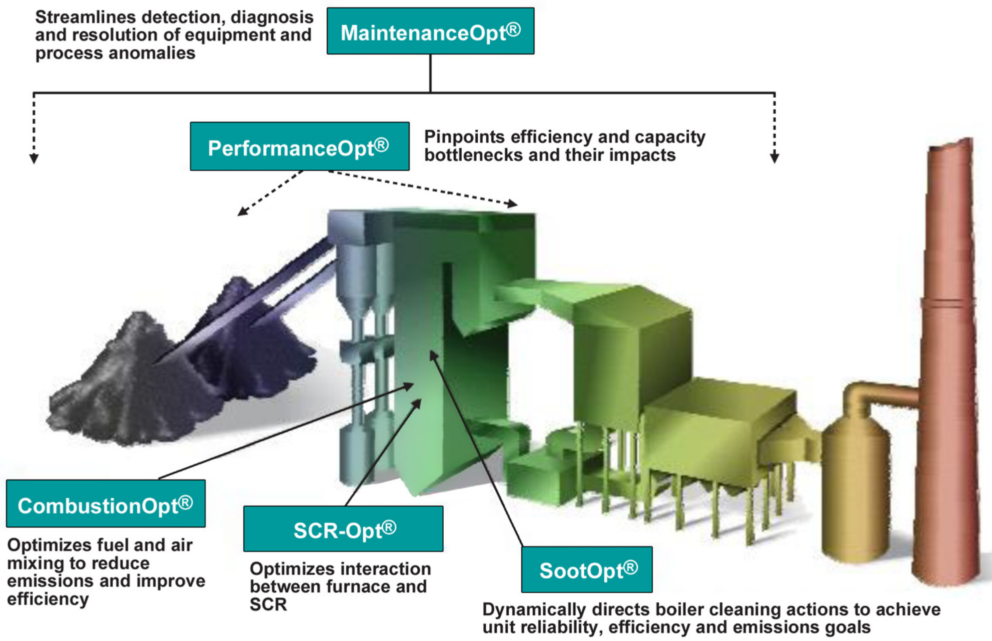
Project objectives were to reduce the BEC NO_x emissions by five percent, increase efficiency by 1.5 percent, and increase net annual electrical power production by 1.5 percent by improving reliability and availability. Additional objectives were to reduce greenhouse gases, Hg, and particulates, and to increase profitability through lower costs, improved reliability, and greater commercial availability. The overarching objective for the application of integrated optimization software to coal-fired power plant operations was to improve coal-based generation's emission profile, efficiency, maintenance requirements, and plant asset life such that the abundant coal resources of the United States remain viable well into the foreseeable future.

The need for integrated optimization software arose, in part, due to the dynamic complexity of the systems present in both modern and retrofitted coal-fired power plants. The optimization process differs significantly from that of normal power plant system operation. Typically, operators make occasional adjustments to the various controls to maintain a process output within an acceptable range based on their understanding of how the adjustment will affect unit performance. While this method keeps operating parameters within an acceptable range, it does not optimize unit operation. However, a control system with optimization capability can explore the relationships between the variables in a system and manage performance more dynamically. An integrated optimization system adds another level of control at the combined system level to optimize not only each system, but the overall performance of all managed systems as well. With the objective of integrated optimization in mind, five separate but integrated optimization modules were developed that addressed the following plant systems: combustion, sootblowing, selective catalytic reduction (SCR) operations, overall unit thermal performance, and plant-wide availability optimization.

Project Description

The NeuCo project at BEC consisted of the design, installation, and demonstration of five integrated AI-based optimization modules for coal-fired power plant operations. Performance optimization modules were developed and implemented for three plant systems: combustion, soot blowing, and SCR operations. In addition, supervisory modules were demonstrated for overall unit thermal performance and plant-wide maintenance optimization. The five individual optimization modules were linked together and coordinated by NeuCo's proprietary ProcessLink® technology.

These optimization modules, although separate, communicated through NeuCo's ProcessLink technology. The modules on Units 1, 2, and 3 did not use theoretical or empirical relationships to model respective unit operations, but rather the technology "learned" these relationships from actual unit operations. The learning capability of the technology was based on the use of neural networks (NNs), first principles, expert systems,



Overview of the Optimizers at BEC

direct search optimization, and fuzzy logic (FL) in addition to enterprise software and a robust calculation engine to link the individual optimization modules and achieve the optimum overall result.

The demonstration technology operated in two modes: closed loop and an advisory mode. The closed loop mode permitted the optimization modules to directly control the plant in real-time. The advisory mode provided guidance to the operator, who then decided whether or not to implement the technology.

CombustionOpt and SCR-Opt

CombustionOpt and SCR-Opt were tightly integrated and are described together. CombustionOpt and SCR-Opt used neural network technology to learn relationships among system variables without the need for prior understanding of what those relationships might be. Once the relationships were learned, CombustionOpt used this Information to change input variables to achieve the performance objectives determined by the plant operators. The learning process was ongoing and based on real-time and recent data so as to constantly update the relationship between system input variables and the desired performance objectives. Important system variable relationships for the CombustionOpt module included plant heat rate, the rate of NO_x formation in the furnace, and ammonia (NH_3) consumption for the SCR system installed on Units 1 and 2.

CombustionOpt calculated the control settings that improved the mixing of the fuel and air in the furnace in real-time for literally dozens of different dampers and actuators, leading to reduced furnace NO_x production while maintaining combustion efficiency. Additionally, the calculations were repeated every minute resulting in more numerous, but smaller changes based on current boiler conditions. Not only were process outputs kept within an acceptable range of operation, they were optimized within that range to meet performance objectives established by plant operators.

If a unit is equipped with an SCR, CombustionOpt and SCR-Opt are integrated to mix the fuel and air in the furnace to reduce furnace NO_x production and maintain critical combustion parameters such as combustion efficiency, while increasing SCR efficiency. The integrated goals of these models are to maintain Cyclone Main Flame Scanner Quality and reduce SCR inlet NO_x, which results in lower NH_3 flow to the SCR system. Therefore, by using an integrated control approach, both furnace and SCR performance are optimized.

SootOpt

A sootblowing operation utilizes steam (or other media) for cleaning the boiler tubes. It does so at the expense of unit efficiency because energy is required to generate the cleaning media. Sootblowing also results in wear on the boiler parts being cleaned. However, slagging and fouling can also result in lower furnace efficiency, increased NO_x production, and excessive flue gas exit temperatures. SootOpt optimized cleaning action effectiveness and achieved improved boiler performance by minimizing the energy expended to generate cleaning media.

SootOpt combined sophisticated optimization methods in conjunction with a control system to optimize the power plant boiler soot blowing operation. SootOpt replaced the traditional schedule-based and operator-controlled soot blowing philosophy, which was basically a disadvantageous hit-or-miss approach.

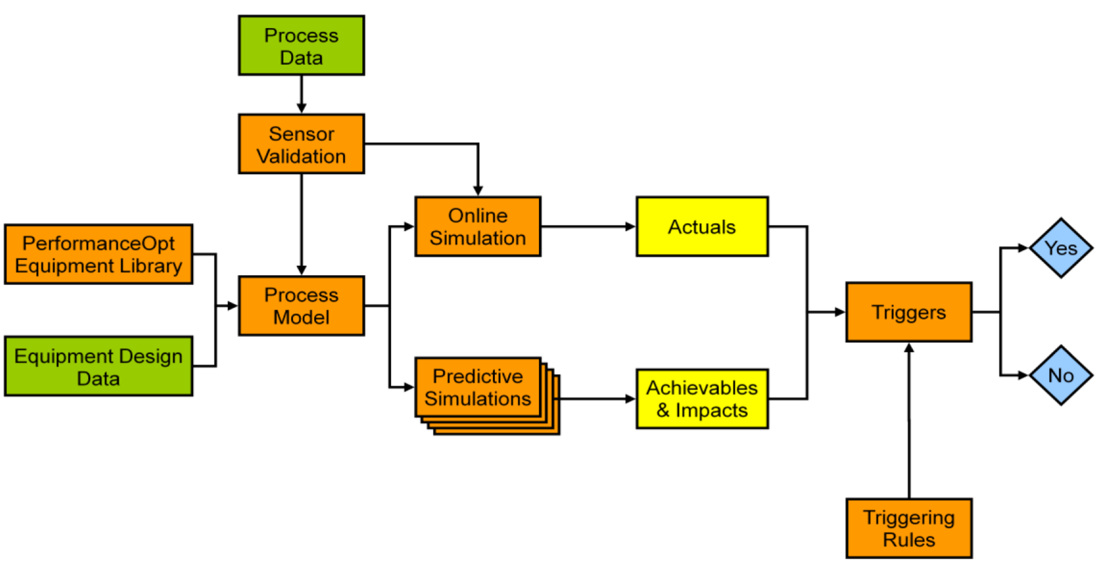
PerformanceOpt

PerformanceOpt provided a predictive performance management capability that identified efficiency and capacity losses so that operators could lower operating costs by remedying their cause. PerformanceOpt identified problems that were causing plant performance limitations by comparing actual plant performance to predicted performance. The predictive component of PerformanceOpt performed mass and energy balances on a minute-by-minute basis and computed the results for thousands of variables by utilizing a detailed first-principles model of the unit with scenario generation capability to quantify what was achievable under current operating conditions. PerformanceOpt continuously monitored key equipment and unit-level performance factors and detected, in real-time, when actual performance deviated from what had been predicted. For each problem identified, PerformanceOpt calculated the efficiency and capacity benefit that could be realized by resolving that problem. PerformanceOpt also ensured model accuracy and reliability through sensor validation mechanisms and equipment out-of-service logic.

MaintenanceOpt

MaintenanceOpt continuously monitored process and equipment data to identify anomalies that might indicate reliability, capacity, or efficiency problems. In addition to potential problem detection, MaintenanceOpt added value by suggesting the most likely causes of problems and estimating the impacts on efficiency, reliability, and capacity. These estimates formed a basis for MaintenanceOpt to prioritize the order in which to address the problems.

MaintenanceOpt provided plant engineers with a suite of diagnostic tools that assisted them with the process of problem correction and increased its effectiveness. Among the knowledge tools available were diagnostics, recommended actions, and the identification of potential



PerformanceOpt Components in Problem Identification

impacts and risks. MaintenanceOpt demonstrated the capability to detect both slowly developing problems as well as those that could have a critical near-term reliability impact. Sufficient information was available within MaintenanceOpt to assist plant engineers in determining the legitimacy of the problem—whether it is real or the result of a sensor malfunction. And finally, MaintenanceOpt supported the diagnosis and resolution of problems found by other optimizers such as PerformanceOpt, CombustionOpt, and SootOpt.

Results

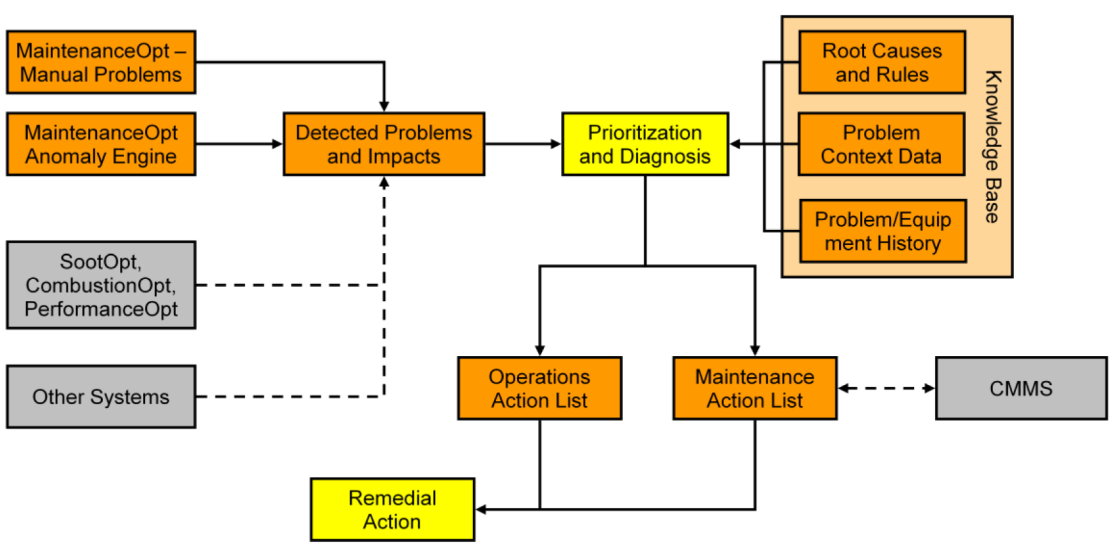
The optimizer modules were developed and refined during the project period. The optimization modules, in concert with NeuCo's proprietary ProcessLink® technology, directly controlled the plant in closed loop mode or advised plant operators of suggested actions in an advisory mode. The results discussed in this section were obtained with the technology operating in the closed loop mode.

Different combinations of the optimization modules were installed on each of the three BEC units. Unit 1, which is a cyclone-fired unit, was equipped with the CombustionOpt, SCR-Opt, PerformanceOpt, and MaintenanceOpt modules. Unit 2, which is also a cyclone-fired unit, was equipped with the CombustionOpt, SCR-Opt, SootOpt, PerformanceOpt, and MaintenanceOpt modules. Unit 3, a tangentially-fired unit, was equipped with CombustionOpt, SootOpt, and MaintenanceOpt modules.

The reported average NO_x emission reduction of between 12 and 14 percent exceeded the original goal of five percent. This significant reduction in NO_x emissions was attributed to a priority trade-off made by plant personnel that is discussed in detail later in this section. The modules attributed to the NO_x reduction actions were CombustionOpt, SootOpt, and SCR-Opt. An additional benefit was a drop in NH_3 consumption in the selective catalytic reduction (SCR) system.

NeuCo reported that the goal of increasing available megawatt hours (MWhs) by 1.5 percent was met through the information provided by the optimization modules for plant personnel use and by improved process management. The switch from high-sulfur, high-Btu Illinois coal to PRB coal had the potential to lower plant performance because of plant design and operating experience issues. With the optimization modules providing prioritized alerts and knowledge-based diagnostics for a wide array of plant equipment and process anomalies, it is reasonable to assume that the plant was able to avoid some of the unit output derating it might have encountered otherwise. Additionally, the demonstration technology also improved the management of cyclone flame quality through heightened monitoring of cyclone conditions, which likely avoided some degree of unit output derating resulting from cyclone slag build-up.

The goal of demonstrating commensurate reductions in greenhouse gases, mercury (Hg), SO_2, and particulates was achieved because of the improved heat rate brought about by reduced coal consumption.



MaintenanceOpt Workflow for Problem Detection, Diagnosis, and Resolution

The goal of achieving commensurate increases in profitability resulting from lower costs, improved reliability, and greater commercial availability was achieved as the direct result of the full or partial completion of all other goals. Improvement in plant heat rate resulted in less coal consumption, which ultimately led to reduced costs at constant net output. Also, reducing plant generation derates as a result of both improved operating knowledge and equipment/process management resulted in enhanced plant reliability and availability.

The application of the various performance optimization modules resulted in an overall improvement in plant heat rate of 0.7 percent. The 0.7 percent improvement was roughly half the target because competing priorities prevented full achievement of the goal. The two competing priorities were set by plant personnel. The first was to place a high priority on furnace cyclone stability/availability, as the cyclones were designed to operate with bituminous coal instead of the PRB currently used. The second was to place a higher priority on minimizing NO_x production. Given the flexibility of the modules to exceed the NO_x reduction goal, it is likely that the 1.5 percent heat rate improvement goal would have been achieved had NO_x reduction not been given a higher priority. An additional factor that may have contributed to the lower improvement in heat rate was the deteriorating fuel quality received by the BEC that may have resulted in an actual increase of the baseline heat rate had the optimization packages not been used.

Benefits

The NeuCo project demonstrated an artificial intelligence (AI)-based optimization technology that can be applied to many existing coal-fired power plant boilers as well as boilers fired by other fossil fuels. The modular optimization technology was integrated with plant instrumentation and controls and provided a flexible suite of controls and diagnostic functionality that enhanced plant operations, reduced emissions, and rendered maintenance activity more effective.

The technology demonstrated the ability to respond the priority placed on NO_x reduction by plant personnel by exceeding the NO_x reduction goal while still improving, but not meeting, the heat rate goal. It is believed that, had the objectives been prioritized differently, the project would have achieved the target NO_x reduction and heat rate improvement goals.

Baldwin Energy Complex

ARTIFICIAL INTELLIGENCE

Artificial intelligence (AI) is commonly defined as the science and engineering of making intelligent machines, especially intelligent computer programs. Relative to applications with coal-fired power plants, AI consists of aspects or considerations that deal with the following:

- Neural networks, which mimic the capacity of the human brain to handle complex nonlinear relationships and "learn" new relationships in the plant environment.
- Advanced algorithms or expert systems that follow a set of pre-established rules written in code or computer language.
- Fuzzy logic (FL), which involves evaluation of process variables in accordance with approximate relationships that have been determined to be sufficiently accurate to meet the needs of plant control systems.

Neural networks (NNs) are a class of algorithms that simulate the operation of biological neurons. The NN learns the relationships among operating conditions, emissions, and performance parameters by processing the test data. In the training process, the NN develops a complex nonlinear function that maps the system inputs to the corresponding outputs. This function is passed on to a mathematical minimization algorithm that finds optimum operating conditions.

Neural networks are composed of a large number of highly interconnected processing elements that work in parallel to solve a specific problem. These networks, with their extensive ability to derive meaning from complicated or imprecise data, can be used to extract patterns and detect trends that are too complex to be detected by either humans or other computer techniques. Neural networks are trainable systems that can "learn" to solve complex problems and generalize the acquired knowledge to solve unforeseen problems. A trained NN can be thought of as an expert in the category of information it has been given to analyze. Neural networks are considered by some to be best suited as advisors, i.e., advanced systems that make recommendations based on various types of data input. These recommendations, which will change as power plant operations change, suggest ways in which plant equipment or technologies can be optimized.

Advanced algorithms, on the other hand, are programmed to incorporate established relationships between input and output information based on detailed knowledge of a specific process. They are used by computers to process complex information or data using a step-by-step, problem-solving procedure. In particular, genetic algorithms provide a search technique to find true or approximate solutions to optimization problems. These algorithms must be rigorously defined for any computational process since an established procedure is required for solving a problem in a finite number of steps. Algorithms must tell the computer what specific steps to perform and in what specific order so that a specified task can be accomplished. Advanced algorithms are now part of the sophisticated computational techniques being successfully applied to power plants to increase plant efficiency and reduce unwanted emissions.

Fuzzy logic (FL), the least specific type of AI software, is equipped with a set of approximate rules used whenever "close enough is good enough." Fuzzy logic is a problem-solving control-system methodology that has been used successfully with large, networked, multi-channel computers or workstation-based data-acquisition and control systems. Fuzzy logic can be implemented via hardware, software, or a combination of both. Elevators and camera auto-focusing systems are primary examples of FL systems. Fuzzy logic stops an elevator at a floor when it is within a certain range, not at a specific point.

Fuzzy logic has proven to be an excellent choice for many control system applications since it mimics human control logic. By using an imprecise but very descriptive language, FL deals with input data much like a human operator. Fuzzy logic is very robust and provides a simple way to arrive at a definite conclusion based upon vague, ambiguous, imprecise, or missing input information. However, while the FL approach to solving control problems mimics human decision-making, FL is much faster. The FL model is empirically based, relying on operator experience rather than technical understanding of the system.

While the heat rate improvement goal was not met, a significant improvement was demonstrated, resulting in a potential fuel cost savings benefit. Further potential savings would be achieved by utilizing the system equipment performance diagnostic capabilities.

The demonstration of NeuCo optimization technology at the BEC resulted in improved reliability, higher output, and lower maintenance costs, but these benefits were difficult to quantify precisely. Environmental conditions and coal properties changes, as well as equipment wear and many other factors, could have obscured some portion of the optimization systems' benefits.

Improved reliability, reduced maintenance costs, and higher efficiency will not only benefit the power plant, but reduce consumer costs while the improved environmental performance contributes to a cleaner environment. The participant validated the technical and cost benefits described above by the sale of 57 optimization packages through December 31, 2011. These sales were all for application on coal-fired units. Although there is no available sales data, the participant has indicated that some of the optimization packages are capable of comparable or better improvements on other fossil fueled generating units.

Conclusions

The five plant optimization products developed and demonstrated during the course of the project have the potential to provide operational, economic, and environmental benefits for many types of power plant boilers. These systems operate with existing control equipment and sensors thus minimizing system installation cost. In addition, installation does not require substantial plant downtime.

NeuCo indicated that the payback period for the demonstration technology is well under a year for a typical U.S. fossil-fired plant. The actual benefits realized and payback period required may vary depending on the circumstances at specific power plants. The performance benefits, low cost, and inherent flexibility of the technology have generated significant interest within the fossil fuel-fired electrical generation industry.

Increasing Power Plant Efficiency: Lignite Fuel Enhancement

Introduction

U.S. lignite coals have a moisture content ranging from 25 to 40 percent, and can require approximately seven percent of the fuel heat input in the furnace to evaporate it. This level of moisture places additional requirements on power plants to compensate for higher fuel flow rates and the subsequent upstream and downstream effects (such as higher processing power requirements, higher maintenance, and lower plant efficiency) when compared to the use of eastern bituminous coals. Despite their high moisture content, western lignite coals, as well as subbituminous coals, are attractive due to their low cost, lower emissions when combusted, and high reactivity.

Coal dewatering and drying processes developed thus far are complex, expensive, and require high-grade heat to remove moisture. Consequently, these processes have not gained industry acceptance. A promising low-temperature coal drying process has been developed by Great River Energy (GRE) that utilizes plant waste heat to reduce the lignite moisture content in a fluidized bed dryer (FBD) at GRE's Coal Creek Station (CCS) in Underwood, North Dakota.

The National Environmental Policy Act (NEPA) requirement for the GRE project was met with an Environmental Assessment and issuance of a Finding of No Significant Impact (FONSI) on January 16, 2004. A Cooperative Agreement was awarded on July 9, 2004. The commercial demonstration completed operations in March 2010. The estimated project costs are $31,512,215. The DOE share is $13,518,737 (43 percent) and the GRE share is $17,993,478 (57 percent).

Coal Creek Station

Project Objectives

The overarching objective of GRE's project was to increase the value of lignite as a fuel by reducing its moisture content using an innovative coal dryer concept that conserved low grade heat from the power plant that would otherwise be discharged to the environment. The Lignite Fuel Enhancement project supported this objective through the demonstration of a 5 to 15 percentage point reduction in lignite moisture content (a moisture content reduction from approximately 40 to 30 percent, which is about 25 percent of the total moisture content) at GRE's CCS.

The project demonstration was conducted in two phases. During Phase 1, a coal dryer prototype was designed and installed at CCS Unit 2 and a testing program was initiated. The objectives of prototype testing were to acquire operating experience with the dryer, confirm pilot results, and quantify the effect of dryer operational parameters so that optimal performance would be achieved. An additional objective was to incorporate the lessons learned during prototype testing into the design of the dryers being installed during Phase 2 of the project. The prototype was operated from 2006 to 2009 to obtain data for the design of full-size dryers.

The Phase 2 project objectives were to design, build, and install a full-scale coal drying system on the nominal 546 MW Unit 2, and to conduct a full-scale, long-term, operational moisture reduction test. The moisture reduction testing included determining the magnitude of Unit 2 efficiency improvement, quantifying the emissions reduction, and assessing the effects of burning dried coal on unit operation.

Project Description

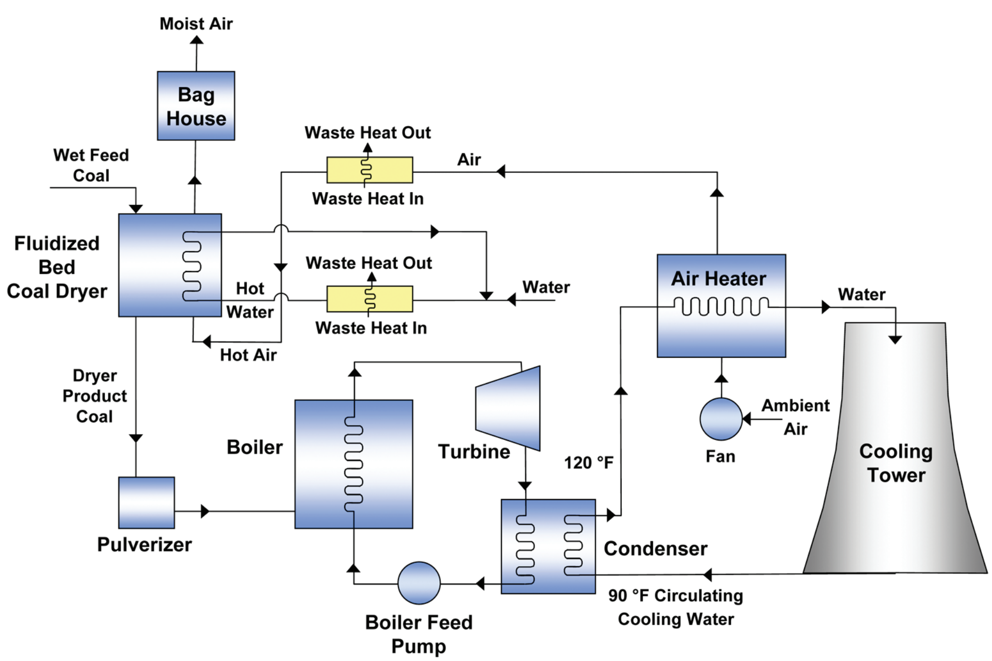
This project has its roots in lignite drying technology R&D conducted by GRE and others since the 1990s. As the R&D work progressed, GRE became convinced of the viability of the lignite drying concept. After identifying a fluidized-bed coal dryer (FBCD) in 2002 as their coal drying technology of choice, GRE submitted an application to DOE under CCPI-1 to continue development of the technology with the commercial demonstration of a prototype FBCD, and, using the lessons learned from the prototype, to develop and install a full-size coal drying system on one unit at CCS. A Cooperative Agreement was negotiated with DOE for funding under CCPI-1 in July 2004.

CCS is a two unit, lignite-fired power plant that supplies electricity to 38 member cooperatives in Minnesota. The plant consists of two identical tangentially fired Combustion Engineering (CE) boilers, each supplying a single steam turbine. Both units are nominally rated at 546 MW. The station burns approximately seven million tons of lignite per year. The design steam conditions are 1,005 degrees Fahrenheit (°F) for main and reheat steam temperature at 2,520 pounds per square inch-absolute (psia) throttle pressure. The CCS has eight pulverizers per unit (seven active and one spare). The station has two single-reheat General Electric G-2 turbines. The plant rejects heat to the environment through three mechanical draft cooling towers. Lignite, with an HHV of 6,200 Btu/lb and total moisture content of approximately 38 percent, is supplied from the nearby Falkirk mine.

In the lignite drying process cooling water leaves the condenser carrying the waste heat rejected by the steam turbine. Before the water reaches the cooling tower, where its heat would normally be discharged to the environment, it first passes through an air heater. In the air heater, a fan-driven air stream picks up some of the waste heat from the cooling water. The heated air is then sent to the FBCD, which is configured for two-stage drying to optimize heat transfer. Before arriving at the FBCD, the air stream picks up additional heat from the unit flue gas through another heat exchanger. The twice-heated air stream then enters the FBCD. After picking up moisture from the coal, the moisture laden air stream passes through a dust collector to remove coal dust liberated during the drying process before being discharged to the atmosphere. Additional heat is added to the FBCD through coils fed with water heated by the unit's flue gas. This additional heat is added to the FBCD to optimize fluidized bed operating characteristics. After leaving the FBCD, dried coal enters a coal storage bunker (not shown) before being sent to a pulverizer for size reduction prior to being delivered to the boiler.

The GRE project at CCS was implemented in two phases. The first phase of the project involved the installation and operation of one prototype dryer, rated at 112.5 tons/hour (225,000 lb/hour) capacity. The prototype dryer was designed to reduce the lignite moisture content from 38 percent to 29.5 percent, which corresponds to an increase in higher heating value from 6,200 Btu/lb to 7,045 Btu/lb.

The prototype coal drying system was designed with completely automated control capability, which included startup, shutdown, and emergency shutdown sequences. The heat input to the FBCD is automatically controlled to remove a specified amount of moisture from the lignite feed stream.



Schematic of Lignite Coal Drying Process

Following the prototype dryer installation and startup, around-the-clock operations and data collection began in March 2006. The moisture content of the lignite processed through the prototype coal drying system was reduced from about 38.5 percent to 29.5 percent. In addition to the measured reductions in SO_X, NO_X, and CO_2 emissions in the flue gas, two modes of Hg reduction were also achieved. First, the heavy components of lignite that were collected in the first stage of the dryer (and removed) possessed a higher Hg concentration, reducing the amount of Hg in the coal fed to the boiler. In addition, Hg oxidation was enhanced as coal moisture was reduced, thereby facilitating additional capture in the flue gas desulfurization unit. Both modes of reduced Hg emissions were confirmed with semi-continuous emission monitors at the inlet and outlet of the flue gas desulfurization unit.

GRE initiated design activities for full-scale dryers (135 tons/hr) in September 2006, which incorporated lessons learned from prototype operation. The full-scale dryer system design was completed in December 2007 and GRE subsequently installed four dryers on Unit 2. Due to the success of the prototype demonstration, GRE installed four more dryers on Unit 1 with its own funds. The final result was that Unit 1 and Unit 2 of the CCS were simultaneously retrofitted with lignite coal dryers.

Fabrication and on-site assembly were finished in May 2008 and major dryer internal components for the Unit 2 dryers were completed by December 2008. GRE completed the construction of the dryer system and began testing in late 2009.

Results

The project achieved the goal of lowering the moisture content of the lignite by 8.5 percentage points (approximately one fourth of the as-received moisture). Test results were obtained from the technology installed on Unit 1, which is identical to that of Unit 2. Unit 2 was out of service at the time of testing for reasons not associated with the lignite drying technology. During performance testing, Unit 1 provided the combined station load for Units 1 and 2 while also supplying extraction steam for an auxiliary process. This plant configuration resulted in an efficiency impact to the testing results that could not be accurately extrapolated to periods of normal operation. While those particular data could not be obtained by GRE, other data for moisture reduction and emissions were obtained.

The demonstrated 8.5 percent moisture reduction of the lignite resulted in an HHV improvement in the fuel from 6290 Btu/lb to 7043 Btu/lb. Also demonstrated were emissions reductions in Hg by 41 percent, NO_X by 32 percent, and SO_2 by 54 percent.

Benefits

Reducing the coal moisture content improved the lignite HHV, which arguably reduced unit heat rate. This improvement was due primarily to lower stack loss and decreased auxiliary power use (e.g., lower fan, pulverizer, cooling tower, and coal handling power). As the boiler efficiency increases and the auxiliary power requirement was reduced, additional electrical energy was available for export to the grid. The reduction in coal flow rate also produced an incremental improvement in coal handling and processing equipment wear rates, which resulted in a maintenance-related cost benefit.

Performance of the back-end environmental control systems (i.e., electrostatic precipitator) also improved with the use of reduced moisture coal in the furnace. The reduction in coal flow rate to the boiler resulted in a lower flue gas flow rate that gave the flue gas a longer residence time within the emissions control equipment, incrementally improving its performance. Similarly, the reduction in required coal-flow rate to the boiler and the resulting modified temperature profile within the boiler directly translated into lower emissions of NO_X, SO_2, and particulates. While not directly measured, CO_2 emissions were calculated to have been decreased by approximately 3.8 percent. Units equipped with wet scrubbers also exhibited a reduction in Hg emissions resulting from firing reduced moisture coal. This reduction resulted from an increase in the oxidation of elemental Hg to forms that can be removed in a scrubber.

A potential benefit of the coal drying system for new plants would be a reduction in capital costs. A decrease in the coal firing rate could result in smaller capacity requirements for coal handling and coal processing systems as well as those associated with combustion, flue gas transport, and flue gas cleaning.

The potential market for GRE's coal-drying technology is significant. Currently, more than 100 GW of U.S. installed capacity is burning coal with inherently high moisture content. This technology could not only reduce emissions from coal-fired power plants, but also extend abundant U.S. coal supplies, thereby enhancing the nation's energy security.

In 2009, GRE signed an agreement with Worley Parsons, an engineering firm, giving them preferred engineer status to license DryFining™, the trademark name for the technology. GRE will also process and ship DryFined coal to the Spiritwood Station nearing completion 10 miles east of Jamestown, North Dakota. By the conclusion of the project, GRE had 120 confidentiality agreements signed by vendors and suppliers of equipment and 19 by utilities. Companies in the United States, Canada, Australia, China, India, Indonesia, and Europe have signed GRE confidentiality agreements. These agreements are required before GRE will provide details of the technology to interested parties. In addition, three preliminary evaluations have been completed that show the comparative improvements that can be realized at those stations. DryFining™ earned the "Best Coal-Fired Project" award for 2010 from the editors of the prestigious *Power Engineering* magazine.

Conclusions

The operation of full-scale lignite drying equipment was demonstrated and the remaining project performance goals were met, which included an improvement in lignite quality and the reduction of emissions.

Typical PRB Coal Analysis

Property	Typical Value
Higher Heating Value, Btu/lb	9,052
Analysis, Weight Percent	
Moisture	25.85
Carbon	52.49
Hydrogen	3.65
Nitrogen	0.75
Sulfur	0.28
Ash	4.64
Oxygen	12.33
Chlorine	0.01

TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers

Introduction

Powder River Basin (PRB) coal has become widely used and is typical of other western subbituminous coals in that it produces a high percentage of elemental mercury (Hg) in the flue gas upon combustion. Elemental Hg is more difficult to remove from the flue gas stream than solid state oxides of Hg (the form more common in bituminous coals). The injection of powdered activated carbon (PAC) into the flue gas stream for Hg capture is one promising control technology.

A potential disadvantage of injecting PAC for Hg control in plants where PAC injection occurs upstream of the particulate control system is its impact on the salability of ash for making concrete. If the ash cannot be sold, it must be sent to a landfill, which increases the plant's operating costs and decreases available disposal capacity. The TOXECON™ configuration injects the activated carbon downstream from the primary ash collection equipment, thus ensuring the ash remains acceptable for sale.

DOE selected the TOXECON™ technology in 2003 as a CCPI-1 Hg control demonstration project. The demonstration was carried out at Wisconsin Electric Power Company's (We Energies) Presque Isle Power Plant (PIPP) located in Marquette, Michigan.

The total project cost was $47,512,830 with DOE providing $23,756,415 or 50 percent. We Energies provided the remaining 50 percent. NEPA was satisfied with a FONSI in September 2003. The demonstration began operation in January 2006 and was completed in September 2009.

Project Objectives

The project objectives were to demonstrate, over the long-term (three years), 90 percent removal of Hg from power plant flue gas using activated carbon injection; demonstrate a reliable Hg continuous emission monitoring system (CEMS) suitable for use in flue gas created by coal-fired power plants; advance commercialization of the technology through successful operation and integration with the power plant; evaluate trona (a naturally occurring sodium bicarbonate mineral) injection to reduce NO_x and capture 70 percent of SO_2 emissions via the new bag house; demonstrate recovery of Hg from the spent sorbent; reduce particulate matter (PM) emissions via the new bag house; and allow the continued reuse and sale of fly ash captured by the existing hot-side ESP.

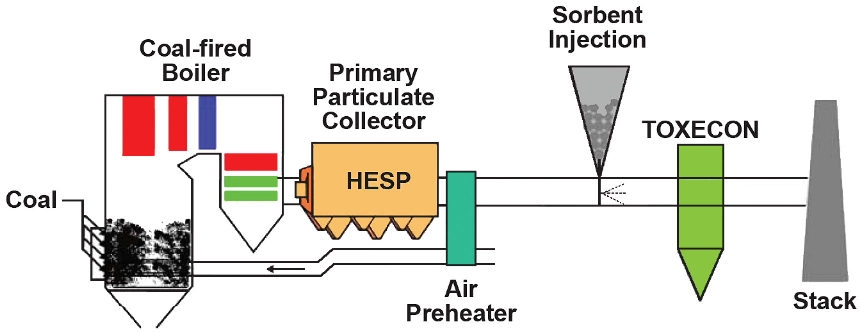
Project Description

The TOXECON™ demonstration technology was installed on the combined flue gas streams of PIPP Units 7, 8, and 9, which are rated at 90 MW each. There are a total of nine units at the PIPP site that were installed between 1955 and 1979. Units 7, 8, and 9 are of the Riley Turbo design and are dry-bottom, opposed-wall-fired boilers. Steam conditions at the superheater are 1625 psig and 1005 °F, and conditions at the reheater are 390 psig and 1005 °F. Each of the three units is equipped with Joy-Western hot side electrostatic precipitators (ESPs). NO_x emissions are managed with low-NO_x burners and a combustion optimization software package. SO_2 emission limits are met on Units 7, 8, and 9 by burning low sulfur PRB coal. The coal typically has an HHV of 9,052 Btu/lb, a sulfur content of 0.28 percent, and an average Hg content of 0.13µg/g.

For the demonstration at PIPP, the TOXECON™ technology was installed downstream of the air preheater. The TOXECON™ process consisted of two systems that included (1) a sorbent injection system that includes the in-duct injection lances and the sorbent receiving, handling, and storage facilities; and (2) a baghouse with secondary systems for ash removal and supplying compressed air for bag cleaning.

The TOXECON™ technology is intended for installation in a downstream location from an existing cold-side or hot-side ESP. When applied to a host plant that is configured with a hot-side ESP, the TOXECON™ system is installed immediately downstream of the air preheater. In the case of a cold-side ESP installation, the TOXECON™ system is located just downstream of the ESP.

Presque Isle Power Plant



TOXECON™ Flow Schematic at PIPP

The TOXECON™ installation at PIPP was relatively simple. The PAC system consisted of storage, transport, and injection subsystems. Because the PIPP installation includes a hot-side precipitator, PAC is injected downstream from each of Units 7, 8, and 9 air preheaters through three separate trains. The design and location of the PAC injection lances ensure thorough mixing of the PAC sorbent with the flue gas.

Each of the three PAC duct injection trains handled 200 lb/hr of sorbent material and consisted of a feed hopper, feeder, eductor, injection lance, and blower. The design injection rate of 216 lb/hr permitted optional reinjection of some PAC/fly ash from the baghouse. A similar injection train was also installed to evaluate the effectiveness of a sodium-based sorbent for the removal of 70 percent of SO_2 as well as some NO_X. After the sorbents were injected into the flue gas from Units 7, 8, and 9, the flows were directed to a single duct leading to the baghouse. Flue gas leaving the baghouse splits into three streams and is discharged through three separate flues enclosed by a single stack.

The PAC entrained in the flue gas captured some of the Hg present as the gas stream traveled to the baghouse. Once in the baghouse, the PAC and residual fly ash were removed from the gas stream by forming a dust cake layer on the surface of the bags. The PAC in the dust cake continued to remove Hg from the gas stream as long as it remained on the bags, which was also the case when sodium-based sorbent was used for SO_2 and NO_X control. Because removing the dust cake layer

TOXECON™ System Installed at PIPP

reduced collection efficiency, the design and operation of the baghouse maximized the amount of time the dust cake remained on the bags within the limits of sound operating practices.

At the beginning of the project in 2003, there were no Hg continuous emission monitors (CEMs) available that had Environmental Protection Agency (EPA) certification and could be operated independent of full-time technical support. As part of the project, Hg CEMs were developed and tested that could be reliably used in the power plant environment and measure Hg with good sensitivity.

Two thermal laboratory-scale technologies having the potential to remove Hg from TOXECON™ baghouse ash were identified during the first quarter of 2008. One of the processes used microwave energy as the energy source while the other used heated air. Both methods were reported to exceed 90 percent recovery of Hg from the baghouse ash in laboratory tests.

One laboratory study irradiated ash with microwave energy for three minutes under a nitrogen gas flow. The evaporated Hg was carried by the gas flow to a condenser. Mercury that was not condensed was scrubbed from the nitrogen with a potassium permanganate solution.

The second technology used a chemical absorbent to chemically capture Hg while it was in the gas phase. The chemical absorbent developed for this study exhibited excellent Hg capture performance; however, it proved too expensive for commercial applications. Subsequently, a commercially produced absorbent was identified and tested. The commercially available absorbent captured the Hg that was released from the fly ash by thermal desorption. The resulting sorbent/Hg material was found to be both thermally and chemically stable, presenting no risk to the environment.

Results

TOXECON™ performance testing confirmed a reliable minimum Hg removal rate of 90 percent from the flue gas leaving the hot-side ESP. This performance was verified using several different types of PAC. During testing, Hg removal was observed to vary inversely (linear) with baghouse temperature, which is a well-documented correlation in the TOXECON™ baghouse.

The goal of developing a reliable Hg CEM capable of operating in a power plant environment was met. Toward the conclusion of the demonstration, the CEM developed by Thermo Fisher and ADA-ES exhibited high availability for monitoring Hg at the inlet and outlet duct. It is commercially available from Thermo Fisher and has reportedly been selling well.

The baghouse and associated equipment were successfully integrated into plant operations. The spent PAC handling equipment was upgraded and the operation of the system was optimized during the demonstration project. Early in the project, there was a problem with hot embers/fires in the baghouse hoppers. A combination of laboratory work and operational adjustments corrected the problem and there was no recurrence during long-term testing.

Sulfur dioxide and potential NO_X removal rates were investigated by injecting trona ($Na_3H(CO_3)_2 \cdot 2H_2O$), a sodium-based sorbent, into the flue gas stream. While the goal of 70 percent SO_2 removal was met, there was no perceptible impact on NO_X emissions. When both trona and PAC were injected simultaneously, Hg removal efficiency decreased significantly, with a slight (approximately one percent) effect on opacity. Even with an increase in the brominated PAC injection rate [1.5 lb/MMacf (million actual cubic feet) to 4.5 lb/MMacf], achieving 90 percent Hg control while maintaining 70 percent SO_2 removal could not be consistently achieved.

The goal to recover 90 percent of Hg captured in the sorbent was met in laboratory tests. The Hg content in the consumed sorbents was reduced from 14.8 ppm to 0.252 ppm (98.3 percent reduction) after the microwave treatment methodology, which was one of the two methods identified to accomplish this goal. The other process used a natural gas-fired kiln and reduced the Hg content from 31 ppm to a level that was not measureable. The Hg released during these tests was captured by another process, leaving the sorbent and fly ash to be constructively reused.

The goal of increasing the plant's collection efficiency of PM [particularly for $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter)] was met due to the high capture efficiency of the baghouse.

The utilization goal for fly ash captured in the hotside ESP was met due to the introduction of PAC downstream of the primary particulate control device. While the actual utilization of fly ash was outside the scope of the project, the project goal to enable fly ash utilization by preserving its quality was met.

CONTROLLING MERCURY

While research continues to find better and cheaper ways to remove mercury from the flue gas of coal-fired boilers, electric generating units (EGUs) already have several viable options. The mercury found in flue gas can be found in several physical and/or chemical states. It can be in the form of elemental mercury vapor or in an oxidized state. These chemical states can either be attached to fly ash particles or free-floating. No matter which technology is used, elemental mercury is more difficult to remove than oxidized mercury.

The current leading technology specific to mercury removal consists of injecting powdered activated carbon (PAC) into the flue gas to adsorb the mercury. In some cases, the system itself is very simple, consisting of equipment to receive, handle, store, and inject the carbon. The carbon is injected into the flue gas between the air heater and the particulate control device. The particulate control device, either a baghouse or an electrostatic precipitator, removes the carbon and adsorbed mercury along with the fly ash. Continued use of the existing baghouse or ESP assumes that the existing particulate control device can handle the additional particulate load without degradation of performance. A disadvantage of this simple system is that the fly ash is contaminated with activated carbon. In 2004, approximately 40 percent of the fly ash was sold for constructive uses. Fly ash with high carbon content is difficult to sell and EGU operators are reluctant to risk losing their market, since they would incur disposal costs rather than receive payment for the fly ash. If the boiler being retrofitted with activated carbon injection (ACI) is equipped with a hot-side ESP, the power plant can install the ACI system downstream of the air heater and install a new particulate removal system to remove the PAC and any residual fly ash. A baghouse is generally preferred due to its high efficiency, especially for respirable particulates. This method ensures that the bulk of the fly ash removed by the existing ESP is not contaminated with additional carbon.

While ACI is the most effective method of capturing mercury, power plants can often achieve significant coincidental mercury removal with their particulate and SO2 controls. The effectiveness of achieving adequate mercury removal in equipment intended to control other pollutants varies significantly from plant to plant. As stated above, elemental mercury is less likely to be captured by any removal system, although ACI is less sensitive to the state of the mercury. The state of mercury in flue gas is affected by the type of boiler and coal and variations in boiler operation. Operators can influence the state of mercury in the boiler by optimizing combustion conditions to maximize oxidation of the mercury while maintaining satisfactory overall operation. By increasing the portion of the mercury that is oxidized, its removal in the ESP, baghouse, and/or flue gas desulfurization (FGD) system is enhanced.

Increased oxidation of mercury is also a co-benefit of a selective catalytic reduction (SCR) system. The SCR catalyst tends to oxidize a portion of the mercury in the flue gas, leading to higher removal rates in the particulate control system and/or the FGD system.

Benefits

The TOXECON™ process provides a technology pathway to significant Hg control and has the potential to widen the use of PRB, as well as other western subbituminous coals, especially in light of the Mercury and Air Toxics Standards (MATS) established in December 2011. Additional benefits are derived from the inherently high particulate removal efficiency of a baghouse. While trona injection resulted in a 70 percent reduction of SO_2, concurrent PAC/trona injection greatly reduced previously demonstrated Hg removal efficiency. However, it is anticipated that other sorbents will be able to be used to further control pollutants and be complementary to Hg removal efficiency.

The TOXECON™ process was configured to treat the plant flue gas after the bulk of fly ash is captured in the HESP, thus preserving its quality for use as a concrete additive as well as for other beneficial uses. A secondary benefit is the preservation of landfill capacity, as the fly ash will have a beneficial use and not require disposal.

As part of the TOXECON™ process design, the baghouse downstream of an existing ESP removes the injected sorbent and the adsorbed pollutants. An additional benefit of this configuration is the significant reduction of both $PM_{2.5}$ and $PM_{2.5}$ precursor emissions (e.g., SO_2).

The TOXECON™ process is considered suitable for application on 167 GW of coal-fired generating capacity and may prove to be the primary Hg control choice for western coals, especially when fired in units having hot-side ESPs. TOXECON™ systems were installed at seven plants in addition to PIPP. Although exact numbers are not available, it has been reported that a substantial market has developed for the Hg CEMS developed during this project. When the CAMR was vacated by the courts, there was uncertainty regarding the final Hg rule, which likely led to power plants deferring their decision on the selection of an Hg control technology. The final standards for Hg were published in mid-February 2012. The success of the TOXECON™ demonstration has provided the owners of those 167 GW with a viable technology to meet the three year deadline for compliance with the new Hg standard.

Conclusions

The TOXECON™ process demonstrated significant Hg control for units having a hot-side ESP and firing a western subbituminous coal. The technology should be applicable to all coal-fired power plants. The placement of the TOXECON™ baghouse downstream of the existing ESP preserved fly ash quality for beneficial use while removing Hg from the plant flue gas stream. Fly ash that is used constructively will not require disposal in a landfill, thereby eliminating disposal costs and conserving landfill space. The baghouse also removed much of the very fine particulate that passed through the ESP.

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CCPI-1 Program Conclusions

The goal of CCPI-1 was to "*advance technology related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives*." The three projects discussed in this report have directly contributed to the CCPI objectives through more efficient operation that extends the nation's abundant coal reserves, further reduces emissions, resulting in cleaner air, and lowers generation costs, which can help to keep electricity affordable. Below is a brief summary of the contributions of each CCPI-1 project.

- The plant optimization capability developed during the course of the Demonstration of Integrated Optimization Software at the Baldwin Energy Complex project could benefit many types of power plant boilers. The NO_x reduction target of five percent was exceeded and actually reached the 12 to 14 percent range, while heat rate improvement only reached half of the targeted improvement. However, the improvement achieved in heat rate should translate into slightly lower fuel consumption (and hence fuel cost) with a commensurate decrease in overall emissions. The demonstrated environmental, efficiency, and cost improvements confirm that the project has met the CCPI-1 program goals.

- The GRE Increasing Power Plant Efficiency: Lignite Fuel Enhancement demonstration has shown benefits from the full-scale coal drying system at Coal Creek Station (CCS) that utilizes waste heat. Lignite quality has improved and plant emissions have decreased due to a reduction in the amount of lignite being burned and the reduced Hg content of the fuel brought about by the density separation in the first drying stage. An additional benefit for new plants could be a reduction in capital costs due to subsystems being favorably impacted by decreased plant fuel requirements. These advancements demonstrate that CCPI-1 program goals have been achieved.

- TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90-MW Coal-Fired Boilers controls Hg and other pollutants in the flue gas stream with sorbent injection while preserving the marketability of the captured fly ash. A reliable Hg CEM, capable of withstanding harsh power plant conditions, was also developed during this project. The results obtained from this project contribute to the achievement of the CCPI-1 program goals.

The application of technologies resulting from the DOE CCPI-1 solicitation will help resolve environmental concerns regarding the increased use of coal. These contributions to coal's viability will help ensure that the United States continues to generate clean, reliable, and affordable electricity from this plentiful and valuable resource.

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Acronyms and Abbreviations

ACI	Activated Carbon Injection
AI	Artificial Intelligence
ARRA	American Recovery and Reinvestment Act
BEC	Baldwin Energy Complex
BTU	British thermal unit
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCPI	Clean Coal Power Initiative
CCS	Coal Creek Station
CCT	Clean Coal Technology
CCTDP	Clean Coal Technology Demonstration Program
CE	Combustion Engineering
CEM	Continuous Emissions Monitor
CO_2	Carbon dioxide
DOE	Department of Energy
EA	Environmental Assessment
EPRI	Electric Power Research Institute
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FBCD	Fluidized Bed Coal Dryer
FBD	Fluidized Bed Dryer
FE	Office of Fossil Energy
FGD	Flue Gas Desulfurization
FL	Fuzzy Logic
FONSI	Finding of No Significant Impact
g	Gram
GRE	Great River Energy
GW	Gigawatt
HAPS	Hazardous Air Pollutants
Hg	Mercury
HHV	Higher Heating Value
ICR	Information Collection Request
Lb	Pound
MATS	Mercury and Air Toxics Standards
MMacf	million actual cubic feet
NAS	National Academy of Sciences
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NH_3	Ammonia
NN	Neural Network
MW	Megawatts
MWh	Megawatt-hours
NO_X	Nitrogen Oxides
PAC	Powdered Activated Carbon
PIPP	Presque Isle Power Plant
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 microns in diameter
PPII	Power Plant Improvement Initiative
PRB	Powder River Basin
PSIA	Pounds per Square Inch Absolute
R&D	Research & Development
SCR	Selective Catalytic Reduction
SO_2	Sulfur dioxide
µg	Microgram
U.S.	United States
We Energies	Wisconsin Electric Power Company

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