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June 30, 2017

Ms. Karlene Fine
Executive Director
ATTN: Lignite Research Development and Marketing Program
North Dakota Industrial Commission
State Capitol, 14th Floor
600 East Boulevard Avenue, Department 405
Bismarck, ND 58505-0840

Dear Ms. Fine:

Subject: EERC Proposal No. 2017-0102 Entitled "Project Carbon"

The Energy & Environmental Research Center (EERC) of the University of North Dakota is pleased to submit an original and one copy of the subject proposal in partnership with the U.S. Department of Energy, ALLETE, Minnkota Power, Mitsubishi Heavy Industries, and Burns & McDonnell. In addition to the $100 application fee, you will find an application soliciting your support of the research and development efforts required at the early stages of the larger effort to commercialize a transformational technology, potentially revolutionizing the use of lignite. The EERC is committed to coordinating the team effort and ensuring completion of the project as described in the proposal. Support from the Commission is imperative in the development of new technologies securing the future use of lignite in our state.

If you have any questions, please contact me by telephone at (701) 777-5114 or by e-mail at jlaumb@undeerc.org.

Sincerely,

Jason D. Laumb
Principal Engineer
Coal Utilization

Approved by:

Thomas A. Erickson, CEO
Energy & Environmental Research Center

JDL/kal

Enclosures

Lignite Research, Development and Marketing Program

North Dakota Industrial Commission

Application

Project Title: Project Carbon

Applicant: University of North Dakota Energy & Environmental Research Center

Principal Investigator: Jason D. Laumb

Date of Application: June 30, 2017

Amount of Request: $3,200,000

Total Amount of Proposed Project: $12,700,000

Duration of Project: 14 months

Point of Contact (POC): Jason D. Laumb

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ABSTRACT

Objective: The overall objective of Project Carbon is to enable carbon capture, utilization, and storage projects to move forward in the state of North Dakota by determining the best capture technology options and system configurations for an existing North Dakota lignite-fired system. Project Carbon will assess the final barriers relating to efficiency and economics for implementation of postcombustion capture on the existing fleet of power systems.

Expected Results: Project results will support development of Project Tundra. The results will address several important barriers, including capture system performance, aerosol mitigation, process economics, pre-FEED (frontend engineering and design) analysis, and efficiency.

Duration: The project is scheduled for 14 months with a start date of August 1, 2017.

Total Project Cost: The proposed budget is $12,700,000 with $2,500,000 coming from the U.S. Department of Energy (DOE) National Energy Technology Laboratory through the Energy & Environmental Research Center's (EERC's) cooperative agreement, an additional $6,000,000 anticipated from a submission to a DOE NETL funding opportunity announcement (FOA), $3,200,000 from the North Dakota Industrial Commission (NDIC) and $500,000 cash and $500,000 in-kind from industry partners.

Participants: The project lead is the EERC, and the project will be conducted in partnership with the NDIC through the Lignite Research Council and the Lignite Energy Council, DOE, ALLETE, Inc., Minnkota Power, Burns & McDonnell, and Mitsubishi Heavy Industries (MHI). This partnership pairs the expertise and drive of the lignite industry with that of the EERC experience in carbon capture to optimize the value of the project results and continue the development of commercial carbon capture projects in the state of North Dakota.

PROJECT SUMMARY

The long-term continued use of coal or any fossil fuel will likely depend on reducing its carbon intensity. CCUS (carbon capture, utilization, and storage) appears to be the most feasible option open to utilities in order to achieve such reductions, and North Dakota is fortunate to have proximal, large-scale storage potential in the form of enhanced oil recovery (EOR) in the state's conventional oil fields and in the Bakken shale play. However, even with these advantages, establishing a market where coal-powered utilities provide CO_2 to oil producers is still dependent on a cost-effective method for CO_2 capture. In addition to the cost of capture, other challenges are present in CO_2 capture technology market growth, solvent advancements, and the effects of the formation of aerosols.

The goal of this Energy & Environmental Research Center (EERC) project is to address the final barriers for implementing postcombustion carbon capture (PCC) on a lignite-fired unit. In order to meet the goal of the project, the following specific objectives have been identified:

- Identify economic and efficiency barriers to implementing commercial-scale carbon capture projects like Project Tundra.
- Identify challenges with implementing amine-based solvent technology.
- Identify measures to control the formation of aerosols through experimentation and modeling.
- Identify design, scale-up, and implementation challenges through the initiation of a pre-FEED (front-end engineering and design) study for implementation of PCC at Milton R. Young (MRY) Station.

Project deliverables will include information that can be used by vendors to design downstream equipment and determine capital, operating, and maintenance costs. The information will include:

- Preliminary design basis information relating to process flows, steam cycle impacts and equipment performance.
- Levels of aerosols in flue gas downstream of PCC technology.
- Operating parameters that will minimize the production of aerosols.
- Impacts of impurities on solvent loss and emissions.
- Identification of measures to control aerosol formation.

The EERC has structured Project Carbon in two parallel project efforts. Project 1 is entitled "Overcoming Barriers to the Implementation of Postcombustion Carbon Capture"; Project 2 is entitled "Initial Engineering, Testing, and Design for a Commercial-Scale, Postcombustion Carbon Dioxide Capture Project on an Existing Coal-Fueled Generating Unit." Project 1 comprises four tasks including the following: Task 1 – Advanced Amine Solvents, Task 2 – Economics of Carbon Capture, Task 3 – Aerosol Mitigation and Management, and Task 4 – Management and Reporting. Project 2 comprises four tasks including the following: Task 1 – Testing Demonstration at MRY; Task 2 – Refined Economic Assessment Specific to MRY; Task 3 – Pre-FEED Analysis; and Task 4 – Project Management and Technology Transfer. The duration of Project Carbon is anticipated to be 14 months. The proposed budget is $12,700,000 with $2,500,000 coming from the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), through the EERC's cooperative agreement, an additional $6,000,000 anticipated from a submission to a DOE NETL funding opportunity announcement (FOA), $3,200,000 from the North Dakota Industrial Commission (NDIC) and $500,000 cash and $500,000 in-kind from industry partners.

PROJECT DESCRIPTION – PROJECT CARBON

Objectives: The overall objective of Project Carbon is to enable CCUS projects to move forward in the state of North Dakota by determining the best capture technology options and system configurations for a North Dakota lignite-fired system.

Methodology: The ultimate goal of this project is to support subsequent commercial demonstration of PCC systems fueled by North Dakota lignite. Project Carbon comprises addressing the technical barriers and providing necessary pre-FEED information for commercial demonstrations to move forward. In order to meet the goals and objectives and support subsequent commercial demonstration, two projects, within Project Carbon, with four tasks each have been identified. While carbon capture is beginning to be demonstrated at facilities in the United States, unresolved challenges still need to be addressed in regard to fuel type and plant retrofitting. Lignite coal, especially North Dakota lignite, presents challenges that include the combination of sodium and sulfur content, ash content, NO_x reduction, and footprint limitations. Fuel chemical makeup is very crucial to the behavior of CO_2 capture technologies that may be employed, whether from the buildup of heat-stable salts, aerosol formation, degradation of solvents or solid sorbents, and subsequent solvent loss. In order to mitigate risk, these challenges need to be further investigated.

Existing plants requiring a retrofit to include CO_2 capture capability would currently rely on one of the following technology pathways:

- Advanced amine-based solvents
- Solid sorbents

- Hybrid systems comprising both sorbents and solvents

The amine-based solvent has been chosen for this project because it is available at quantities sufficient for the full scale. The EERC will work closely with technology owner Mitsubishi Heavy Industries (MHI) in Project Carbon. The scope of work for each of the two projects that make up Project Carbon follow.

PROJECT 1 – OVERCOMING BARRIERS TO THE IMPLEMENTATION OF POSTCOMBUSTION CARBON CAPTURE

Task 1 – Advanced Amine Solvents

Carbon capture is beginning to be demonstrated at facilities in the United States, but unresolved challenges still need to be addressed with regard to fuel type and plant retrofitting. Lignite coal, especially North Dakota lignite, presents challenges that include the combination of sodium and sulfur content, ash content, NO_x reduction, and footprint limitations. Fuel chemical makeup is very crucial to the behavior of CO_2 capture technologies that may be employed, whether from the buildup of heat-stable salts, aerosol formation, degradation of solvents or solid sorbents, and subsequent solvent loss. In order to mitigate risk, these challenges need to be further investigated.

Existing plants requiring a retrofit to include CO_2 capture capability would currently rely on one of the following technology pathways:

- Advanced amine-based solvents
- Solid sorbents
- Hybrid systems comprising both sorbents and solvents

The technology studied in this project will be the amine-based solvent. Both baseline technology and new advanced solvents will be evaluated. The EERC will work closely with technology vendors in this Task.

Pilot-Specific Evaluations

For amine-based systems, degradation and heat-stable salts are the main factors affecting solvent longevity and replacement frequency. The contribution of constituents in lignite coal is unknown in regard to these factors and should be evaluated further. To accomplish this, evaluation of solvents will be performed on the EERC's small industrial-scale CO_2 capture system. This system was the focus of the EERC's Partnership for CO_2 Capture (PCO_2C) Program and evaluated the performance of several solvents. In this proposed program, the investigation will focus on the formation of heat-stable salts and solvent degradation.

Investigations of amine degradation issues started many years ago, particularly focused on the formation of heat-stable salts, their mechanisms, and corrosion studies (Hofmeyer et al., 1956; Lloyd and Taylor, 1954; Rochelle and Chi, 2002; Rooney et al., 1997, 1998). However, most of these studies were based on natural gas treatment which does not have the full range of components found in coal flue gases. Many researchers have proposed different mechanisms for oxidative degradation of amines to yield different kinds of products based on both natural gas (Rooney et al., 1998) and simulated flue gases (Supap et al., 2001). Some of these studies have identified the need to include the reactions of other important flue gas components such as NO_x and SO_x in order to understand the full impact of flue gases on the degradation of amine solutions. Because of the complexity of the interactions, only oxidative degradation has received more attention (Bello and Idem, 2005; Howard, 1999; Supap et al., 2001).

As a result, an Integrated Aspen Plus model was developed under the PCO_2C Program to simulate processes involving the formation of heat-stable salts in alkanolamine solvents (Pavlish et al., 2010). The model was designed to represent typical operation conditions of the EERC's pilot-scale system. Intellectual property controls prevent utilizing proprietary fundamentals of solvents; therefore, this model utilizes actual performance data from the pilot system. Performing the analyses to look for heat-stable salt formation in the solvent during operation, along with solvent performance, yields the information necessary to run the model.

A series of up to 4 weeks of pilot-scale tests will be performed to examine the formation of heat-stable salts and the subsequent degradation of the solvent using North Dakota lignite or Powder River Basin coal as the source of the flue gas. The selection of the coal will be performed in conjunction with Task 2 – Economics of Carbon Capture. Evaluations will be performed with a baseline technology (monoethanolamine [MEA] or other), MHI's technology, and an advanced amine. The advanced technology may consist of one or more from MHI or other vendors, as determined by the project team. A combination of cyclone and pulverized coal-fired burners will be used based on development of a specific test plan with the project team.

Specific amine sampling during the pilot-scale evaluations includes heat-stable salt content, namely, nitrite, nitrate, sulfate, thiosulfate, chloride, formate, acetate, and oxalate. Identification of these salts will yield information as to the nature of the formation, whether it is from degradation of the solvent or interactions with SO_x and NO_x. Additionally, elements such as sodium, magnesium, potassium, mercury, and selenium will also be analyzed to determine if they are being bound in the solvent. The specific sampling techniques will include a combination of automated and manual techniques. MHI staff will be present during the campaigns involving its technology and will aid in the sampling efforts. Sampling efforts will also be conducted in concert with Task 3 to ensure a cohesive data set with aerosol samples.

Slipstream Evaluation

Slipstream evaluation of the technology will be conducted at the MRY Station near Center, North Dakota. Selection of a solvent-based system will allow for the use of the 0.05-MW_e, 1 ton of CO_2/day industrial-scale capture system constructed at the EERC. This system is skid-mounted and can easily be moved to the plant location. All safety requirements of the host site will be followed, sufficient training of all personnel working on-site will be conducted, and appropriate HAZOP (hazardous operations) procedures will be carried out to ensure safe operation.

Up to 3 months of work will be conducted on-site treating flue gas to separate the CO_2 24 hours a day. Selected solvents include advanced amines identified in the pilot evaluations, MHI's technology, and MEA (or other) to baseline the system. The work will be under a catch-and-release methodology where the CO_2 is separated to provide data on the process, but the captured CO_2 will be released back into the host's site stack. Each day, samples of solvent will be taken and analyses performed to determine the heat-stable salts and degradation products present in the solvent. Operational performance of the test system will be recorded, including steam use and capture efficiency, for evaluation. Information from on-site evaluation will be used in Task 2 – Economics of Carbon Capture to aid in the development of the economic aspects of carbon capture at the host site. This will include recommendations of any additional flue gas treatment that would be required for full implementation of carbon capture at the host site.

Like the pilot-scale evaluation, sampling can also occur that will supplement the work conducted under Task 3 – Aerosol Mitigation and Management. The specific test plan will be dependent on the pilot-scale evaluations and will be determined as part of the project. EERC engineers will work closely with MHI and MRY staff to ensure valid installation of the equipment as well as proper sampling protocols.

Reactor Modifications

The EERC's current amine solvent system will be modified to suit the needs of specific vendor solvents. A description of the test system can be found in Appendix B. EERC engineers will work closely with vendor staff to design and modify the unit prior to commencement of the pilot and slipstream evaluations. Specifically, MHI will provide a new proprietary demister section for the absorber column to replicate its technology. Additional modifications may be necessary to packing and column internals to ensure the proper orientation for MHI or other technology vendors.

Equipment: Several pieces of equipment are needed to accomplish this work. A portable Fourier transform infrared (FTIR) for gas analysis to provide real-time analysis of constituents of interest in the flue gas will be purchased along with a combustion gas analyzer rack. Additionally, for the integration of the test systems at the host site and to minimize the impact to the facility, an induced-draft (ID) fan and a steam generator will also be purchased, along with suitable piping, process controls, heaters, pumps, heat exchangers, wiring, and frame supports.

Task 2 – Economics of Carbon Capture

The overall economics of a carbon capture system are highly dependent on the technology utilized for capturing CO_2 from the flue gas. However, the specific performance of the system is not the only factor to consider when the best technology option is evaluated. Project economics will also depend on a host of factors independent of the solvent or sorbent chosen:

- Brownfield versus greenfield application
- Heat integration strategy
- Source of steam for the system
- Availability of natural gas

- Sourcing of electricity
- Compression strategy and heat integration
- Pipeline infrastructure
- Availability of EOR opportunities
- State and federal policy incentives
- CO_2 offtake agreements/guaranteed delivery
- Fraction of carbon captured
- Overall cost of CO_2 avoided
- Impact to local and state economies

The goal of this Task is to evaluate capture technologies demonstrated in Task 1 and develop an overall economic picture of a CCUS project at MRY Station in North Dakota. The optimal configuration of the system will be determined through a combination of process and system modeling efforts. Economics must consider both the overall efficiency of the capture unit and capital costs required for installation. The technology options that minimize the estimated first-year cost of electricity through a combination of capital cost payback and operating costs will be studied in further detail.

Technology readiness is also of critical importance when determining the overall configuration of the first capture plant in the state. While many novel technologies exist in various stages of development that may significantly reduce the energy required for CO_2 capture, the project team feels that the MHI solvent technology is one of the most promising commercial technologies because of its performance history and because it is being demonstrated at commercial scale. Solvents tend to be very energy-intensive when used for CO_2 capture, but development of advanced solvents has significantly reduced this energy penalty. Demonstration of the performance of advanced solvents and systems will be a critical path forward for economic capture of CO_2.

Retrofits to existing power systems (or brownfield applications) may be more challenging economically as compared to a greenfield application because new systems can be designed with carbon capture already integrated into the system. Steam cycle integration may be especially challenging in retrofit scenarios, and utilities may opt to install auxiliary boilers for steam generation. The EERC team will work closely with the overall project team to ensure the best options are evaluated for integration of the carbon capture system with MRY Station.

New Options for Heat Integration

A carbon capture system will require significant amounts of steam to regenerate the solvent or sorbent. The steam can be taken directly from the steam cycle, but this significantly impacts the total energy output of the power plant. This energy penalty could be significantly offset with integration of low-grade heat in the plant. The best opportunities for low-grade heat extraction would be from the flue gas stream prior to desulfurization and through intrastage CO_2 compressor cooling. The heat can be used to preheat solvent or sorbent prior to CO_2 stripping and reduce the overall energy needs for the system. The best heat integration options for MRY Station will be developed as part of this task.

A major consideration for the design of the capture system is determining the main source of heat for regeneration of the CO_2 capture solvent or sorbent. In the DOE baseline studies, low-pressure steam is taken from the steam cycle and used to regenerate the solvent. These studies represent greenfield plants where the steam integration can be designed into the overall steam cycle. For a retrofit situation, pulling steam from the steam cycle may not be an ideal situation and will lead to significantly reduced plant efficiency. As an alternative consideration, an auxiliary boiler likely fired on natural gas could be used to provide the necessary heat to regenerate the solvent. This provides the benefit of not having to interfere with the baseline operation of the plant. However, if natural gas is used to fire the auxiliary boiler, the price of natural gas and the CO_2 generated from the natural gas need to be considered in the overall evaluation. The boiler also represents an additional capital expenditure for the project. As part of this task, the costs and energy penalties associated with both auxiliary boilers and steam cycle integration will be evaluated. In conjunction with inputs from the project team, the best options will be evaluated.

Carbon capture systems typically require significant amounts of electricity to operate pumps and compressors. This load can represent over 10% of the gross power output of the plant. Several options exist for obtaining this power, including reducing the net output of the plant, obtaining power from the grid at market value, or installing a small generation system. A small natural gas-fired system may be able to produce both the steam and electricity needed for the CO_2 capture system but will also require a significant capital expenditure. The project team will evaluate the best options for powering the system as part of this task.

Compression and Pipeline Strategies

A single CCUS project will require a single pipeline for CO_2 transport. Depending on the design, the pipeline itself could serve as a CO_2 storage reservoir. If a pipeline is built with a larger diameter than needed, it could conceivably be used to deliver CO_2 when power plant operations are interrupted or be used as a temporary CO_2 reservoir for intermittency in oilfield operations. The excess capacity could be realized through increases and decreases in pipeline pressure, assuming that pressure is maintained above the minimum pressure required by the oil field. The excess capacity would require a larger capital investment but may be worth the cost if it can help to ensure a consistent supply of CO_2 to the oil field. This task will evaluate the capital cost trade-off and potential storage capacity of an oversized pipeline.

As multiple CO_2 capture projects are considered, and taking into account the geographical locations of power plants and oil fields in North Dakota, it is conceivable that a main CO_2 trunk line could be built that would connect to several power plants and oil fields. A system such as this could only be built through a strong partnership of utilities and oil companies and may also require state-level support. The benefit of such a system would be lower overall cost for CO_2 transport and increased reliability in CO_2 supply to the oil fields. The economics of such a system will also be considered in this task, taking into account the most likely locations for CO_2 capture. Up to two locations and reservoirs will be considered. The rate and duration of CO_2 to the EOR project and CO_2 storage capacity of each reservoir will be determined in order to adequately size a pipeline.

Fraction Capture Strategies and CO_2 Offtake Agreements

The fraction of CO_2 captured in a power plant will depend on a variety of factors. Carbon capture plants in North Dakota will be closely coupled with EOR, and agreements will be signed to guarantee delivery rates of CO_2 to the oil fields. Owing to factors such as planned and unplanned outages, load following, and seasonal variation, a project developer in North Dakota will have to make a decision as to the guaranteed annual delivery rate of CO_2. These CO_2 offtake agreements will likely include stipulations for fractions of the year during which there is a continuous stream of CO_2 delivered and annual tons of CO_2 delivered. Therefore, guarantees for CO_2 delivery will be based on the fraction of CO_2 capture that is achievable during the year. First-of-a-kind units will likely be deployed on baseload systems, thereby minimizing any load-following challenges, but future units may be required to follow daily changes in load. However, as multiple units are brought online, the concerns with guaranteed delivery may be reduced as redundancies will exist. In any scenario, the project team will need tools to determine the appropriate level of CO_2 to capture, and capital cost trade-offs will be evaluated to determine the appropriate size of the system.

Economic Impacts of Capture and Storage Projects

Significant economic benefits for the region can be realized through implementation of CCUS projects. As part of this task, the regional incentives for developing carbon capture at MRY Station will be developed for the specific scenarios evaluated. The EERC will use its existing system dynamics models to determine job creation, tax incentives, and indirect benefits of CCUS.

Application of Amine Technology

The results of the evaluations conducted in the above activities will be wrapped up into an overall site characterization study for MRY. The EERC team will build a process model specific to the MRY Station, which will be combined with a carbon capture model based on the performance of the chosen solvent. The model will address questions surrounding heat integration, compression, pipelines, partial capture, and overall economic impacts of the system. The EERC will work closely with MRY personnel to gather plant-specific data that can be used to develop a full mass and energy balance for the system. The EERC has baseline steam cycle models already developed that will be updated for the parameters and configuration specific to MRY. Additionally, existing absorber/stripper models will be used to evaluate the performance characteristics of the solvent. The EERC will work closely with vendor engineers to develop a model that accurately represents the CO_2 capture performance of the solvent technology. The mass and energy balance information gathered here serves as the baseline for determining costs of the system.

The characterization summary will include a techno-economic assessment of the project at MRY, and the EERC will work with project partners to aid in the development of the economic models. A techno-economic assessment provides overall capital and operating cost estimates for the system and includes the overall cost of CO_2 capture in $/ton. Cost and performance baseline studies published by DOE will serve as guidelines for the evaluations. The cost of CO_2 capture will include contributions from capital expenditures as well as incremental operating costs associated with the capture system and auxiliary components. Capital and operating costs for CO_2 transport, storage, and monitoring will also be included in the study. The impact of major cost and performance drivers will be evaluated through a sensitivity study that will consider changes in capital costs, fixed and variable operating costs, and electricity and CO_2 selling prices. The expected selling price for CO_2 is a major economic driver for a CO_2 capture system, and this will be evaluated in detail as part of the study.

The site characterization study will also include an evaluation of the current site logistics for providing additional cooling water, natural gas, electricity, and other utility needs as well as discharge and disposal logistics. Estimates will be made for footprint requirements, which will aid in developing recommendations for an overall site plan for the capture unit. Preliminary inputs for an environmental health and safety (EH&S) assessment will also be developed.

Assessment Tools

The project team will use Aspen Plus and Aspen Process Economic Analyzer to develop heat and material balances for power systems with CO_2 capture and to determine system costs. Annualized electricity costs and costs of CO_2 capture will be determined from these scenarios using the industry standard DOE methodology. These detailed process models will be used in conjunction with a system dynamics model to determine the cost impacts of day-to-day changes and long-term operation of the system. System dynamics studies will be used to assess the short- and long-term viability of potential CO_2 offtake agreements and develop a broader picture of the overall economic impact of the system.

Task 3 – Aerosol Mitigation and Management

An additional challenge to installation of CO_2 capture technologies on lignite coal is the formation of aerosols. The combustion of low-rank coals produces aerosols that consist mainly of alkali and alkaline-earth sulfates as well as some minor and trace elements. These aerosols and trace elements have the potential to penetrate air pollution control devices and impact the performance of solvent-based CO_2 capture systems. Testing at North Dakota lignite-fired power plants has found that the levels of aerosols on a number basis is on the order of 10^7 particles per cm^3 in the less than 100-nm range (Laumb et al., 2009) in the flue gas that would be routed to the CO_2 capture system. Testing conducted by Khakharia et al. (2015) found high emissions of solvent from amine-based capture systems when the number of aerosol particles was in the range of 10^7–10^8/cm^3. Coal-fired combustion systems produce aerosols in the form of SO_3 (McCollor et al., 2011) and alkali sulfates (Laumb et al., 2009) that form as a result of the condensation and reaction of flame-volatilized elements during gas cooling. Past testing conducted at the EERC has also shown that trace elements, including mercury, selenium, arsenic, lead, cadmium, antimony, and others, are vaporized during combustion. Most of the vaporized elements condense upon gas cooling and concentrate in the aerosol fraction of the ash (Benson et al., 1994) Many of these species, in addition to the problematic nature of aerosols on solvent emissions, have the potential to catalyze solvent degradation if they are allowed to build up in the solvent. Task 3 will endeavor to answer several questions:

- Which species cause the most aerosol formation, and how can they be removed?
- At what level will these fine particulates in the solvent cause significant degradation products?
- Which species are the most reactive with the solvent, causing the most degradation to occur?
- What methods of removal of the metals are most economical to prevent solvent degradation?
- What are the products of degradation for a specific solvent and capture system for lignites?
- Can the products of degradation be transformed back into viable CO_2 capture solvent?
- What are the potential costs of disposal of the removed degradation products?

The aerosol mitigation and management work will address aerosol formation and solvent degradation at the pilot scale, slipstream, and modeling. More information on each of these areas follows below.

Pilot-Scale CO_2 Capture System Measurements

To accomplish this effort, the team will utilize the EERC particulate test combustion system to test candidate coals under conditions representative of actual combustion conditions. This work will be performed in concert with the pilot-scale amine evaluation in Task 1. Aerosol sampling will be performed with a scanning mobility particle sizer (SMPS) and a Dekati 13-stage impactor. SMPS is a dynamic real-time particle sample size and distribution monitoring technique. The Dekati sampler will provide a measurement of the mass of aerosols that are sampled.

Solvent degradation will also be a focus of this work. Periodic sampling of the solvent will be undertaken to determine degradation of the solvent over time. Long-duration evaluation with continuous solvent use will be a focus of this task to determine the degradation of the solvent because of interaction with flue gas impurities. Special attention will be given to volatile elements including arsenic, selenium, mercury, lead, nickel, copper, and others. These volatile elements have the potential to increase in concentration in the solvent over time, degrading solvent performance and making disposal of the solvent problematic because of environmental regulations. The solvent will be analyzed for chemical changes that can lead to reducing the task of the solvent and its ability to capture CO_2. Analysis strategies to characterize the degradation products will be based on work conducted by Cuzuel et al. (2015). The methods used for amine degradation products will include liquid and gas chromatography coupled with various mass spectrometry ionization and detection modes. The inorganic material will be analyzed using inductively coupled plasma–mass spectroscopy. This information will be used to determine mechanisms of degradation and identify effective methods to reduce the solvent degradation process. The system will be used to find the most promising conditions that can be used to ameliorate solvent loss and degradation that can be moved to slipstream evaluation for validation prior to going to full scale. Data obtained in this task will also be used for EERC aerosol model validation.

Slipstream Measurements

To accurately reflect full-scale conditions, this work will also require the installation of the EERC pilot system at the MRY plant, in slipstream configuration, as described in Activity 1. A matrix of test conditions and sampling techniques for the facility will be formulated based on the pilot-scale evaluations. It is anticipated that SMPS and Dekati impactor sampling will be performed, at a minimum. This work will give the most realistic information to date on the formation of aerosols at the MRY facility. The test matrix will be performed, and the collected test data will be reviewed. Based on the information developed in this task as well as the previous field-measured data, the model developed in previous work will be updated and validated.

Modeling and Computer Simulation

All of the data collected in the pilot and slipstream campaigns will be utilized to support the modeling effort. The purpose of this modeling effort is to simulate the mechanisms of aerosol formation both from the combustion of lignite and those formed in the PCC systems. Aerosols formed in the combustion of lignite will be modeled as to the behavior of these aerosols as they travel through specific pollution control devices and their interactions and effect on other flue gas constituents, particularly aerosols forming in the PCC systems from the capture solvents, and the potential for induced amine aerosol formation the combustion-based aerosols may have on the capture solvents. This effort will aid in developing mitigation techniques for methods to reduce or prevent formation and emission. The models will build upon previous EERC modeling work in aerosol formation (Hamel et al., 2003) and work by Dr. Bowman of the UND Chemical Engineering Department (Bowman et al., 1997; Bowman and Eskelson, 2009). A plan will be developed based on discussions with the project sponsors for work to perform model validation at full scale and to deploy aerosol mitigation techniques in the field.

Task 4 – Project Management and Technology Transfer

The planning and management of all project activities will be performed by EERC personnel over the duration of the project period of performance. Task 4 also will include communication of project activities and direction with the project team to provide updates and obtain inputs that will be used to prioritize the project focus. Specific activities performed under Task 4 will include the preparation of quarterly progress reports according to NDIC requirements, the preparation of a comprehensive final report, and the planning and execution of project status meetings. Technology transfer activities will include, at a minimum, the presentation of results through these meetings and reports as well as presentations at relevant technical conferences. In addition, Task 4 will include facilitating the involvement of a NDIC designee, as available, in project meetings. Results of technical Activities 1 through 3, described above, will be provided in project meetings and reports.

PROJECT 2 – INITIAL ENGINEERING, TESTING, AND DESIGN FOR A COMMERCIAL-SCALE, POSTCOMBUSTION CARBON DIOXIDE CAPTURE PROJECT ON AN EXISTING COAL-FUELED GENERATING UNIT

We, as an industry, can't improve this technology to the point needed for application by all utilities until we address the barriers in Project 1 and identify/address the engineering challenges (Project 2) as we improve both the technology and its application in North Dakota. As such, this project, with the support of the state of North Dakota, will begin to pave the way for improving and implementing the application of this technology to the North Dakota lignite industry and allow all North Dakota lignite facilities to be better positioned for any needed application of future carbon capture technology.

The cash cost share for this scope is expected to come from a DOE FOA that has not been made public at the time of this submission. If the scope requested in the FOA does not fall in line with the below scope, a modification may be necessary to align the proposals. Initial indications are that $6,000,000 is going to be available for initial engineering, testing, and design-related work for a commercial-scale, PCC project on an existing coal-fueled generating unit. The results from such a project will be presented by DOE to both Houses of Congress, including an estimate of the costs required to fully retrofit an existing unit. The effort will complement Project 1 and is divided into four tasks, including Task 1 – Testing Demonstration at MRY, Task 2 – Refined Economic Assessment Specific to MRY, Task 3 – Pre-FEED Analysis, and Task 4 – Project Management and Technology Transfer.

Task 1 – Testing Demonstration at MRY

It is anticipated that additional testing will be needed following the slipstream evaluation in Project 1. The additional testing may include more advanced solvents (aqueous or nonaqueous), additional aerosol mitigation technologies, including the EERC's slipstream baghouse, or testing other mitigation technologies that are identified in Project 1.

Amine Testing

Additional amine studies (above and beyond those in Project 1) may be necessary. This portion of the work will be initiated after the first evaluations are done in Project 1, Task 1. The work will be completed while still in slipstream configuration from Project 1. A detailed test matrix will be generated by the project team based on efforts in Project 1.

Optimize Heat Integration at MRY

Heat integration is going to be vital to a carbon capture system's successful implementation and economics. The EERC, MRY, MHI, and engineers from Burns & McDonnell will work closely together in order to determine the most efficient way to integrate carbon capture at the MRY site.

Slipstream Baghouse Testing

Some have pointed to implementation of a baghouse to alleviate concerns related to aerosol emissions and their effect on PCC. To answer these questions, the EERC's slipstream baghouse will be installed at the MRY site. The exact location will be determined in concert with staff at MRY. Specific extractive sampling tests will involve U.S. Environmental Protection Agency (EPA) Method 5 for dust loading, as well as impactor sampling (13-stage Dekati) to determine the aerosol emissions both upstream and downstream of the baghouse. If the testing is conducted on clean gas (downstream of the electrostatic precipitator [ESP]), provisions may be necessary to inject material that may simulate the formation of a dust cake on the filters. The baghouse testing is expected to last approximately 3 months in order to get long-term evaluation of bag performance and aerosol emissions. A description of the baghouse system can be found in Appendix B.

Task 2 – Refined Economic Assessment Specific to MRY

The models developed in Project 1 will serve as the basis for performing a refined economic analysis of the project using the selected technologies and integration schemes. The cost estimates from the Project 1 analysis will be based on cost factors derived from DOE studies. For Project 2, costs will be updated for CO_2 capture at MRY using engineering estimates, vendor quotes, and known costs of operating units. This effort will form the basis of the pre-FEED study to be conducted in Task 3 by guiding the final technology selection. It is anticipated that specific capture information, aerosol mitigation techniques and overall MRY Unit 2 plant performance information will be integrated. Supporting plant equipment including water treatment, solvent reclamation, auxiliary supplies, and utilities consumption will all be evaluated in the refined estimate. This additional information will enhance the accuracy of the estimates and provide an important tool to utilize in the pre-FEED work conducted in Task 3 of Project 2. Task 3 will also provide vital information for the economic model as the project moves forward.

Task 3 – Pre-FEED Analysis

The work in this task will include initiation of many of the pre-FEED activities necessary to move forward with a postcombustion capture project on a lignite facility. EERC engineers will work closely with MRY, MHI, and Burns & McDonnell staff during this task.

Design Basis

A design basis will be chosen for a postcombustion capture facility at MRY Unit 2. The work will include specific site locations at the facility as well as capture efficiency and capture fraction. The project team will review coal analysis information, baseline boiler performance, flue gas flow rates and composition, and review the capture equipment performance determined in Project 1. Much of the information needed to complete this work will be provided by the results from the amine evaluations in Task 1 in Project 1.

Utility Requirements

Postcombustion capture technologies will require water, electricity, and steam. Strategies, locations of utilities and site specifics will be considered. The team will provide this information such that block flow and process flow diagrams that show interconnecting piping and utilities can be updated. The project team will work closely with staff at MRY to complete this work.

Flow Diagrams

Process flow and block flow diagrams will be created based on the chosen design basis and utility requirements. This process will aid in the creation of a major equipment list that can be fed into the modeling study and aid in costing information.

Risk Analysis

Any new project has risks associated with it, and certainly PCC. EERC staff, MRY staff, and Burns & McDonnell will compile a list of potential risks and consider the likelihood and impact of each event. A preliminary list may include siting, permitting, availability of equipment, availability of process consumables, and others.

Develop Permitting Strategy

An important consideration in any new project is consideration of necessary permits. This work will be done in concert with MRY environmental staff. All process effluents (air/water/waste) will be identified. Developing a time line on permitting will greatly affect the overall economics and timeliness of installing postcombustion capture.

Project Cost Estimate

Information gathered in Project 1, as well as within this task, will be used to develop a cost estimate for implementing PCC at MRY. This task will be completed by Burns & McDonnell and EERC staff. Specific considerations for the MRY site will include cold weather climate, labor costs, equipment delivery, fuel characteristics, and scaling for each capture scenario.

Task 4 – Project Management and Technology Transfer

The planning and management of all project activities will be performed by EERC personnel over the duration of the project period of performance. Task 4 also will include communication of project activities and direction with the project team to provide updates and obtain inputs that will be used to prioritize the project focus. Specific activities performed under Task 4 will include the preparation of quarterly progress reports according to NDIC requirements, the preparation of a comprehensive final report, and the planning and execution of project status meetings. Technology transfer activities will include, at a minimum, the presentation of results through these meetings and reports as well as presentations at relevant technical conferences. In addition, Task 4 will include facilitating the involvement of a NDIC designee, as available, in project meetings. Results of technical Activities 1 through 3, described above, will be provided in project meetings and reports.

Anticipated Results – Project Carbon

It is anticipated that the results of this project testing as described above will lead to further development of regional carbon capture projects such as Project Tundra. Project Carbon will provide necessary information surrounding the barriers to implementation of postcombustion CO_2 capture on a lignite-fired unit and necessary pre-FEED information This information will be used to clear the path for a commercial CO_2 capture system in North Dakota.

Facilities

The EERC has over 54,000 square feet of demonstration facilities. These facilities contain a variety of demonstration venues for a variety of technologies as well as space for construction of new pilot-scale components to fit client needs. Additionally, the EERC has been involved in many projects that are demonstrated off-site but require EERC technical and field sampling expertise. Much of the mechanical design and modeling of equipment and machinery for our demonstration facilities is done on-site in our in-house machine shop. This allows the EERC to demonstrate technologies in a more rapid, cost-effective way. A description of the EERC facilities to be used for the work under this project can be found in Appendix B. The modeling activities will be performed at the EERC with existing computing facilities and ASPEN simulation software. The slipstream aerosol work will be performed at the MRY Station.

Resources

A team of industry experts will perform the analyses, with the primary services provided by the EERC and its existing research facilities, modeling software, power industry experience, and carbon capture expertise. Industry sponsors ALLETE and Minnkota Power will provide additional project advisory services. Additional strength is added to the project team with technology owner (MHI) and owner's engineer (Burns & McDonnell) participation.

Techniques

The primary technique for data generation under this project will be experimental studies, including pilot and slipstream CO_2 capture studies. The EERC routinely conducts pilot-scale evaluations of coal conversion systems, CO_2 capture technologies, and emission control technologies. The project team will adhere to established test protocols to ensure representative data collection. Details are contained in the individual tasks above.

In addition to experimental data collection, this project will also update the performance and economic modeling projections utilizing specific data for the MRY Station. The team will utilize Aspen software as the primary modeling tool. Aspen software is a comprehensive process simulation tool and has modules to evaluate economics, kinetics, and heat and material balances for complex processes.

Environmental and Economic Impact

The project's environmental impact during the period of performance will be minimal because all experimental activities will be performed at permitted facilities. All current and planned pilot test systems at the EERC undergo an internal environmental compliance review and must maintain air quality compliance with the North Dakota Department of Health. As for the project's immediate economic impact, the bulk of funding for this program will be spent in North Dakota, thereby supporting employees and service providers in the region.

The long-term incentive for this project comes from providing technology solutions to North Dakota's lignite industry in the future. This industry is currently valued as having a $3 billion economic impact on the state as a business case is made for PCC and EOR. Large-scale CCUS appears to be the only feasible option that lignite users have to ensure viability of a lignite industry for years to come.

Project Justification

This specific project is needed to address the final barriers with regard to implementation of PCC on the current fleet of lignite-fired power plants. Investing in this project ensures that subsequent demonstrations will be better informed and more likely to succeed. The cost of later projects, such as Project Tundra, will also benefit by being provided key information relating to a pre-FEED study as well as information on specific carbon capture technologies.

Aside from the project's technical justification, it is also warranted because it is focused on creating a business case for carbon capture. By seeking a way to cost-effectively use lignite in a carbon-constrained world, this project supports the core process upon which the entire industry is built, that is, the sustainable combustion of lignite for power production.

STANDARDS OF SUCCESS

This project will reduce the technological risk associated with investing in a PCC system for lignite coal. It is a continuing step of measured due diligence to determine if retrofitting the existing fleet of lignite-fired power plants with PCC technology is economically viable. Successful outcomes for the project include the validation of previous design concepts and updating the pathway to further scale-up and demonstration of a complete lignite-fired postcombustion CO_2 capture project in North Dakota, like Project Tundra.

Quantifiable metrics for success come from the projected market needs as estimated by DOE NETL regarding the timescale and cost of carbon capture (U.S. Department of Energy, 2013). These targets have been established based on the needed metrics to keep coal-based power competitive in a carbon-constrained environment and extend to 2035. According to DOE NETL analysis, the following long-term performance goals for retrofitting coal-fired power generation facilities have been established.

- Develop postcombustion capture technologies that:
  - Are ready for demonstration in the 2020–2035 period (with commercial deployment beginning in 2025).
  - Cost less than \$45/tonne of CO_2 captured by 2025, dropping to \$30/tonne in 2035.

Under this project, pilot- and slipstream testing will be use to address technology barriers and provide necessary pre-FEED information for a retrofit PCC project. This information will be used to revise the technology's economic projections and readiness horizon in order to make comparisons to DOE NETL criteria, while ensuring readiness for Project Tundra.

BACKGROUND

The long-term continued use of North Dakota lignite is likely dependent on creating a business case for CCUS, that at the same time addresses societal desires to reduce carbon emissions. CCUS with EOR appears to be the most feasible option that utilities will have to sustain and grow the lignite industry, and North Dakota is fortunate to have proximate, large-scale storage potential in the form of EOR in the state's conventional oil fields and in the Bakken shale play. However, even with these advantages, establishing a market where lignite-powered utilities provide CO_2 to oil producers is still dependent on having a cost-effective method for CO_2 capture. In addition to the cost of capture, other challenges are present in CO_2 capture technology: market growth, solvent advancements, and the effects of the formation of aerosols.

Market Growth

The need for electric power globally and regionally is projected to grow. Based on U.S. Energy Information Administration (EIA) projections (2015), total electricity generation will increase by 24% from 2013 to 2040 but is highly dependent upon economic assumptions. For North Dakota, the growth in electricity demand projections ranged from a 15% increase in a low-economic-growth case to a 37% increase in a high-economic-growth case (KLJ, 2012) over the next 20 years (Figure 1). The range is between 3.2 to over 4 GW in increased demand by the year 2032. Meeting future growing energy needs through the use of coal is essential.

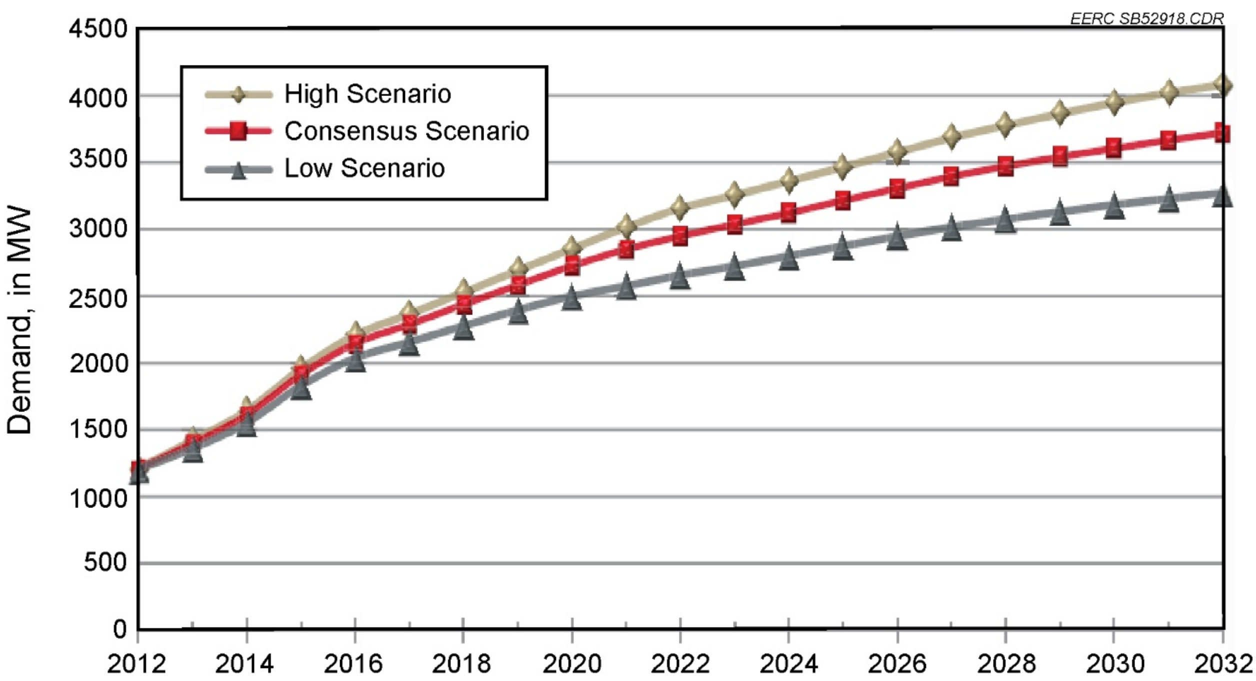


Figure 1. Williston Basin electrical demand for all regions (KLJ, 2012).

Globally, the use of coal is increasing. In an International Energy Agency (IEA) study, the demand for coal increased 4.3% from 7080 megatonnes in 2010 to 7384 megatonnes in 2011. The growth was mainly in non-Organization for Economic Cooperation and Development (OECD) countries such as China and India (International Energy Agency, 2013). The growth is in spite of the rapid increase in the use of nonfossil energy resources. Coal will continue to be a major source of energy production globally. In 2010, 43% of U.S. CO_2 emissions were produced from the combustion of coal. Across the global economy, coal-fired power generation was responsible for roughly one-fourth of the world's total CO_2 emissions. The use of high-efficiency power plants equipped with CCUS is a viable solution to decreasing carbon emissions.

Carbon dioxide CCUS from fossil fuel conversion processes is being pursued by many to address global climate change concerns and is one of the primary approaches to limit CO_2 emissions while producing sufficient energy to meet future growth. International Energy Agency (IEA) analysis shows that CCUS is an integral part of any lowest-cost mitigation scenario where long-term global average temperature increases are limited to significantly less than 4°C, particularly for the 2°C scenario (2DS). Figure 2 illustrates the rapid deployment of CCUS in order to meet the requirement for the reduction in CO_2 production in order to keep levels of CO_2 below the 2DS level. IEA (2013) is estimating that in order to limit the average temperature increase of Earth's atmosphere to 2°C by 2050, only 884 gigatons of CO_2 ($GtCO_2$) can be emitted between 2012 and 2050. CCUS from coal plants offers the most effective opportunity to meet the goal of a 2°C increase in temperature. Investing in development and deployment of CCUS is essential in managing risk. CCUS preserves the economic value of coal reserves and future utilization that is consistent with climate change objectives.

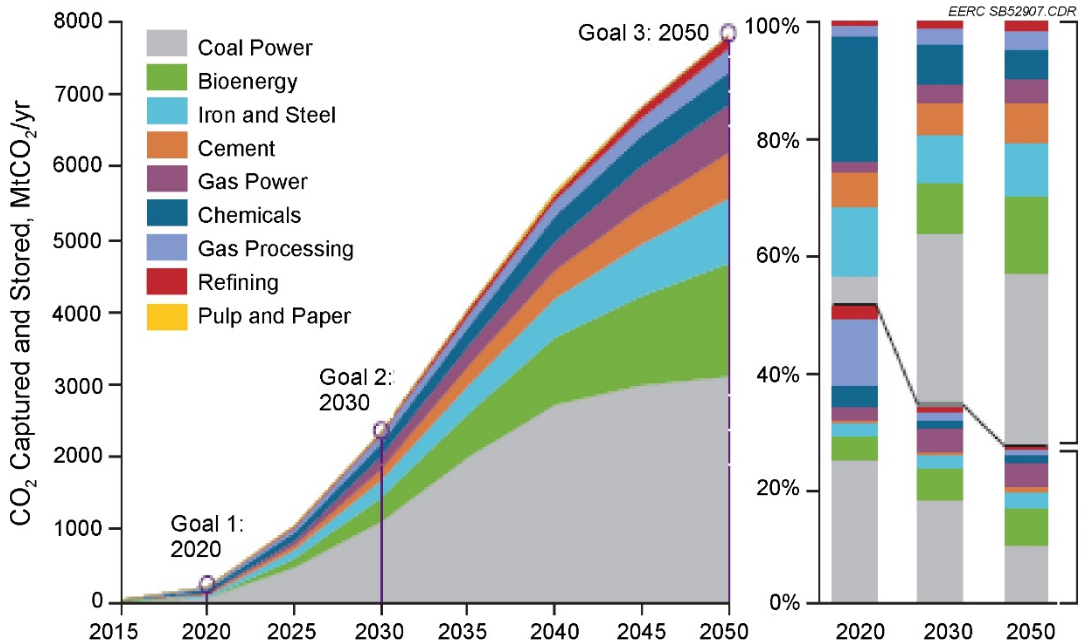


Figure 2. 2DS suggests a steep deployment path for CCUS technologies applied to power generation (International Energy Agency, 2013).

Increasing the production of domestic oil and lowering CO_2 emissions are two U.S. priorities in using CO_2 (Kuuskraa et al., 2011). EOR provides this opportunity, and if next-generation EOR is utilized, significant quantities of oil have the potential to be produced. Next-generation CO_2 EOR has the potential to provide 137 billion barrels of recoverable domestic oil, with about 67 billion barrels being economically recoverable at an oil price of \$85/barrel. The CO_2 storage capacity would be approximately 45 billion metric tons (~50 billion U.S. tons). The CO_2 required to recover the 67 billion barrels is approximately 20 billion metric tons (22 million U.S. tons). Estimates of 2 billion metric tons (2.2 billion U.S. tons) for currently available CO_2 are determined for natural sources and operating natural gas-processing plants. An additional 18 billion metric tons (~20 billion U.S. tons) from coal-fired power plants and other sources will be required.

Postcombustion Capture

Full-capture technologies for coal-fired power plants are postcombustion options. An illustration of postcombustion as a retrofit downstream of a sulfur dioxide scrubber system is shown in Figure 3.

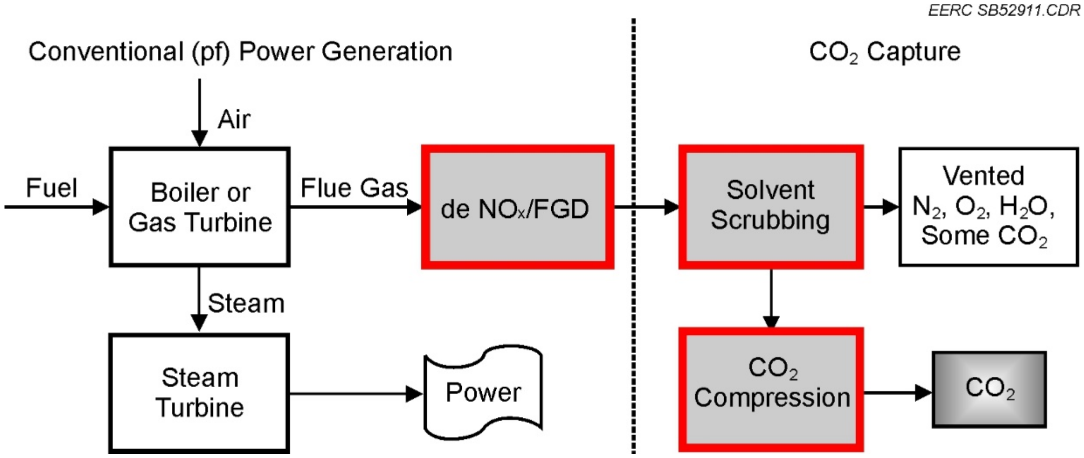


Figure 3. Postcombustion CO_2 capture systems (FGD is flue gas desulfurization).

PCC offers the greatest near-term potential for reducing power sector CO_2 emissions because it can be tuned for various levels of CO_2 capture. Postcombustion capture technologies are available for application on conventional coal-fired power plants. CO_2 capture processes include a range of technologies such as chemical solvents, solid sorbents, or membranes to separate CO_2 from the flue gas. These technologies are at various stages of development. Bhown (2014) summarized technology readiness levels (TRLs) for CO_2 postcombustion capture technologies. The ones with the highest TRL are the most advanced regarding technical feasibility, and they are mainly the absorbent (solvent) methods, as shown in Figure 4.

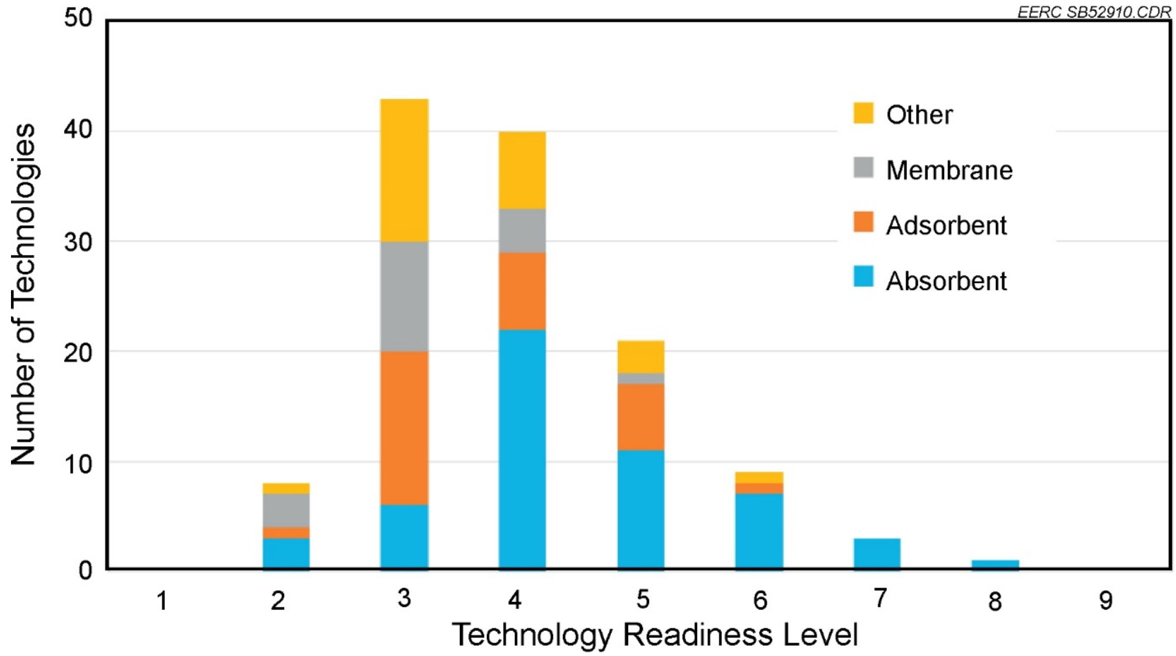


Figure 4. Histogram of the readiness of a technology (absorbent is the solvent-based technology).

Many solvent-based postcombustion commercial-scale projects are in the planning stages for demonstration scale-up, including the Alstom chilled ammonia process and several amine-based processes (e.g., Fluor [Econamine], ABB/Lummus, MHI, HTC Purenergy, Aker Clean Carbon, and Cansolv).

Several companies that have developed and tested CO_2 capture technologies have offered performance guarantees or made public statements regarding the technical feasibility of their systems for CO_2 capture from fossil fuel-fired power plants:

- Linde and BASF offer performance guarantees for CCUS technology.
- Fluor has developed patented CO_2 recovery EFG+ technology.
- MHI offers a CO_2 capture system that uses a proprietary energy-efficient CO_2 absorbent called KS-1™.
- Shell has developed the Cansolv CO_2 Capture System.

Table 1 provides a summary of commercial postcombustion CO_2 operations and projects that are currently in operation or under construction. These are solvent-based systems. The CO_2 in these projects has been geologically sequestered (GS), used in the food industry, used for EOR, and used to carbonate soda ash.

Table 1. Summary of Postcombustion Carbon Capture and Storage Projects

Project	Facility	Unit type	Size, MW	Capture,%	CO_2 Captured, tons/year	Fate of CO_2	Location
AEP/Alstom Mountaineer (2009)	EGU[1]	Coal-fired	30	90	100,000	GS	WV
AES Shady Point (1991)	EGU	Coal-fired	320	10	66,000	Food-grade	OK
AES Warrior Run (2000)	EGU	Coal-fired	180	10	110,000	Food-grade	MD
Petra Nova (2017 start-up)	EGU	Coal-fired	240	90	1,600,000	EOR	TX
SaskPower (2014)	EGU	Coal-fired	110	90	1,000,000	EOR	SK
Searles Valley Minerals (1978)	Soda/ash	Coal-fired			264,898	Carbonation	CA
Fluor Corp. (1991–2005)	EGU	Nat. gas	40	90	100,000	Food-grade	MA

[1] Electric generating unit.

DOE NETL conducted an economic feasibility study of CO_2 capture retrofits for the U.S. power plant fleet (Gerdes, 2014). Figure 5 illustrates its analysis of CO_2 capture on a tonnes-of-CO_2 basis. The estimated cost for retrofit CO_2 capture technology was $72/ton.

Aerosol Formation

Reactive solvent-based scrubbers such as those using amine-based solvents such as MEA, methyldiethanolamine (MDEA), piperazine (PIP), and various blends are a leading method to control CO_2 emissions from coal-fired plants (Dutcher et al., 2015; Le Moullec et al., 2014; Luis,

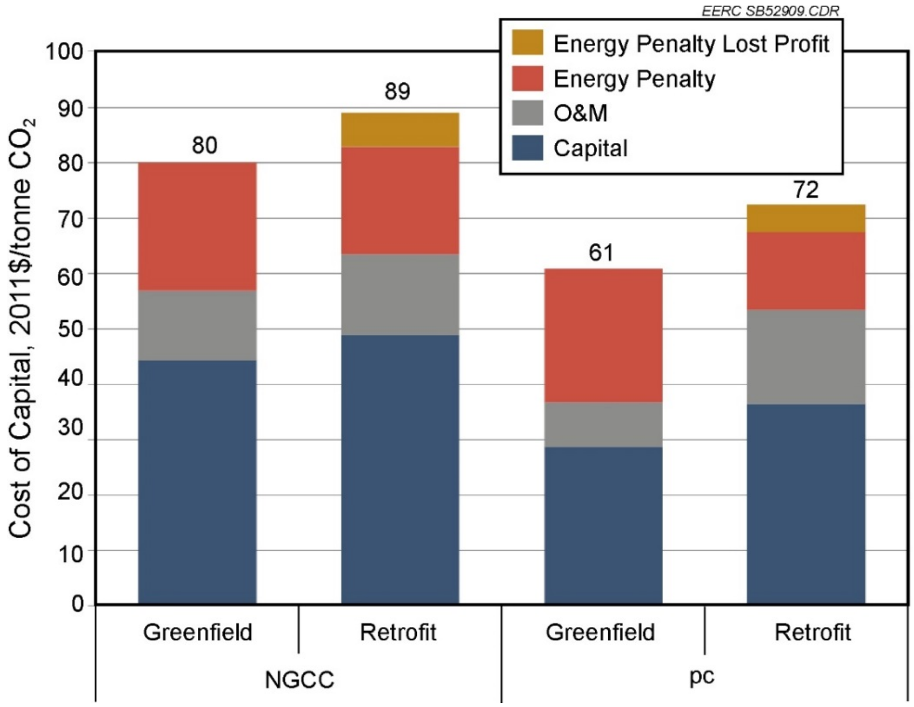


Figure 5. Cost of CO_2 capture using DOE NETL reference plant (Gerdes, 2014). NGCC is natural gas combined cycle, and pc is pulverized coal.

2016; Wu et al., 2014). During an amine-based PCC process, pretreated flue gas is contacted with aqueous amine solution in an absorber in a countercurrent fashion to remove CO_2. The CO_2-rich solution is then heated in a stripper/regenerator to release the captured CO_2, and the CO_2-lean solution is pumped back to the absorber for another cycle. Meanwhile the treated flue gas is water-washed and discharged.

Most of the above-identified amines are volatile and, therefore, can be emitted to the atmosphere via the treated flue gas stream. Several recent studies (Brachert et al., 2014; Fulk, 2016; Kamijo et al., 2013; Khakharia, 2015; Mertens et al., 2014) have identified substantial levels of solvent emissions from amine-based CO_2 scrubbers. Aerosol-based emissions on the order of grams per Nm^3 have been reported, and these emissions are attributed to the presence of particles such as sulfuric acid aerosol droplets in the flue gas entering the scrubber. Aerosol-based solvent emission is emerging as a key challenge in the realization of a full-scale absorption–stripping-based PCC plant.

The emission of solvent and its components can occur by means of i) vapor emissions due to the volatility, ii) carryover as a result of mechanical entrainment, and iii) aerosols. The first two means of emissions are well understood. Recently, aerosol-based emissions have been reported from typical PCC pilot plants (Kamijo et al., 2013; Khakharia et al., 2013, 2014a; Mertens et al., 2013, 2014). These studies indicate that aerosol-based emissions can be significant, on the order of grams/Nm^3, as compared to mg/Nm^{3}of vapor emissions. Moreover, they cannot be reduced by conventional countermeasures such as a water wash or a demister (Khakharia et al., 2014b). Therefore, these emissions can lead to environmental hazard and huge solvent losses, increasing the operating cost (Khakharia, 2015).

Aerosol-based emission in a CO_2 capture absorber is a multiparameter phenomenon (Khakharia, 2015). In the above study, the three main parameters identified were i) the particle number concentration, ii) the supersaturation, and iii) the reactivity of the amine. The aerosol particles, in the range of 10^7–10^8/cm^3, were made up of H_2SO_4 and H_2O and generated by homogeneous nucleation of gas-phase SO_3 in a combustion flue gas. Although small, the aerosol droplets offer a surface for heterogeneous nucleation.

As shown in Figure 6, there is a clear correlation of MEA emissions with the change in inlet aerosol (soot and H_2SO_4) number concentration. MEA emission increases from 100 to 200 mg/Nm^3 as the soot number concentration increases from ~10^4 to 10^6/cm^3 and again doubles from about 600 to 1100 mg/Nm^3, while the H_2SO_4 particle number concentration increases by 1.6 times from ~10^8/cm^3. It must be noted that the absolute MEA emissions from this capture unit would not be exactly the same as compared to a large-scale capture facility, as that strongly

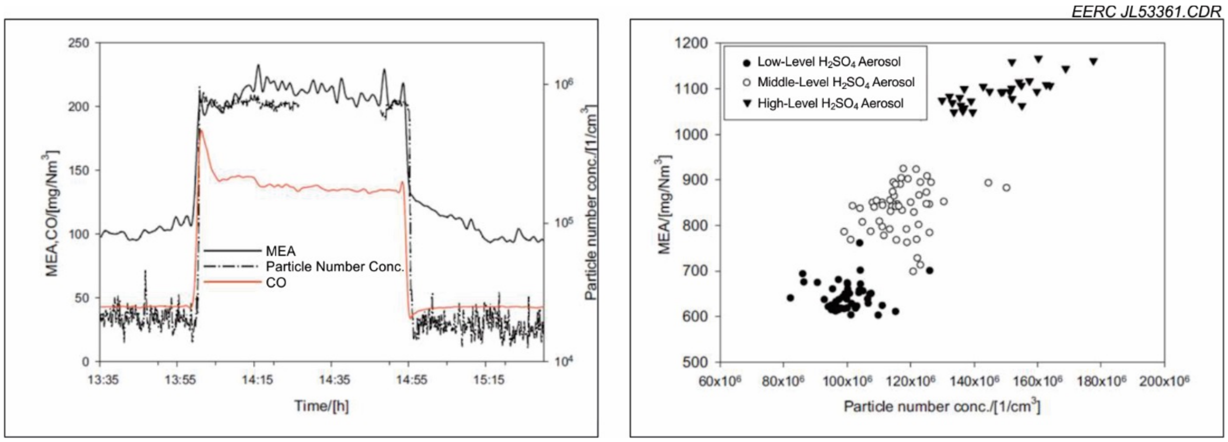


Figure 6. Left: amine emissions as a function of the number of soot (CO) particles (Khakharia, 2015); right: MEA emissions as a function of the amount of sulfuric acid aerosol particles (Khakharia, 2015).

depends on many factors, including its configuration and operating conditions, such as direct contact cooler, water wash section, lean pH, and absorber temperature profile.

In an MEA solvent absorber, the flue gas is heated up (60°–70°C) along the column because of the reaction of the solvent component with CO_2. At the top of the column, the flue gas comes in contact with cold lean solvent, typically at 40°C. This leads to a so-called temperature bulge, where the temperature reaches a maximum, typically at a distance of two-thirds of the total packing height from the bottom and further cools down at the top of the column. This can lead to a significant temperature difference between the gas and liquid phases, resulting in a supersaturated environment. In the presence of nuclei, and supersaturation in the flue gas, the volatile components can condense on these nuclei, leading to a growth of aerosol droplets. Aerosol-based emission of MEA decreases with increasing temperature of the lean solvent, while the vapor emission increases.

Degradation of amines used to capture CO_2 from coal combustion flue gas impacts reliable operation because of corrosion and fouling but also increases operating costs and environmental issues (Chen et al., 2011; Fytianos et al., 2016; Kittel and Gonzalez, 2014; Veltman et al., 2010).

Two main processes are involved in that degradation of amines that include thermal and oxidative. Excessively high temperatures cause thermal degradation, and oxidative degradation is due to the presence of oxygen, CO_2, and metal ions.

Extensive studies of degradation products of amines and the mechanism of their formation when exposed to coal combustion-derived flue gas have been conducted (Cuzuel et al., 2015; Gouedard et al., 2012, 2014; Rey et al., 2013). These papers discuss how the amines are degraded as a result of the reaction of flue gas species that include O_2, CO_2, NO_x, SO_x, and others to produce degradation products. Some of the degradation products are toxic. The degradation research efforts have been aimed at understanding thermal degradation (carbamate polymerization), oxidative degradation, and formation of heat-stable salts. The most rapid process is oxidative degradation because of oxygen levels in the flue gas of 4% to 5% and high reactivity of the solvent. In addition, dissolved metals can catalyze the oxidative degradation process (Goff and Rochelle, 2004). The formation of heat-stable salts are degradation products of oxidized amines that have reacted to form salts. Measurement of heat-stable salts is an indication of solvent degradation.

The accumulation of derived minor and trace elements in solvents exposed to coal combustion-derived flue gas has been examined by Schallert et al. (2013, 2014) and Nikolic et al. (2015). Nikolic et al. (2015) investigated the accumulation of arsenic, mercury, selenium, iron, nickel, and copper in selected amine-based solvents and found that the elements increase in concentration with time. They also noted that iron, nickel, and copper were found to accumulate less on one solvent as compared to others tested, indicating that the type of solvent may impact the rate of accumulation. Therefore, solvent metal interactions need further study to determine the potential to accumulate as a function of aerosol particulate matter consisting mainly of sodium, calcium, and sulfur (as sulfate) emitted from ESPs and wet FGD systems, when firing lignite in a cyclone-fired boiler (Laumb et al., 2009). In addition, some potassium, iron, and other elements are also present in the aerosol samples examined. Based on work conducted by Schallert et al. (2013), ash particulate (aerosols) captured in the amine solvent can release elements such as iron, magnesium, and calcium into the solvent and are a concern for solvent degradation by the formation of heat-stable salts. The solubility of the elements in the solvent was dependent upon the pH and CO_2 loading of the solvent. Schallert et al. (2013) also reported that in the stripper where the CO_2 level is reduced (increasing the pH), the solubility of the iron compounds was reduced, resulting in accumulation of deposits on stripper surfaces. Calcium was found to react with oxalate that also contributes to the formation of deposits on reboiler, potentially causing the formation of deposits that can cause plugging and, possibly, corrosion. In a further study, Schallert et al. (2014) found that the degradation of amine solvent was found to increase the mobility of manganese and vanadium.

It is clear that further research is needed with respect to the application of specific solvents to be utilized in direct contact with lignite-derived flue gas and the compositions specific to the ash and particulate in that flue gas stream. Determination of the impact of the species listed above in degradation of the solvent and the economics of that degradation are unknowns at this point. Many of the elements that have been shown to catalyze solvent degradation are present in lignite coals and can exacerbate solvent replacement economics. Understanding this issue is critical to the implementation of solvent-based CO_2 capture systems as applied to lignite-fired generation systems.

GOALS AND OBJECTIVES

The goal of this project is to address critical barriers and data gaps for implementation of postcombustion capture on the existing fleet of low-rank coal-fired power systems. In order to meet the goal of this project, the following objectives have been identified:

- Determine capture efficiency with baseline and advanced technology on lignite-derived flue gas.
- Perform thorough economic analysis of evaluated capture technology installed at a lignite facility.
- Determine the impact of aerosols on the efficiency and degradation products of carbon capture systems fired with low-rank fuels.
- Provide necessary pre-FEED analysis and economic data specific to the installation of PCC at MRY.

QUALIFICATIONS

EERC Team

The EERC is one of the world's major energy and environmental research organizations. Since its founding in 1951, the EERC has conducted research, testing, and evaluation of fuels, combustion and gasification technologies, emission control technologies, ash use and disposal, analytical methods, groundwater, waste-to-energy systems, and advanced environmental control systems. Today's energy and environmental research needs typically require the expertise of a total-systems team that can focus on technical details while retaining a broad perspective.

Mr. Jason Laumb, Principal Engineer, Coal Utilization Group Lead, will be the project manager and principal investigator (PI) on Project Carbon. Mr. Laumb will focus on ensuring the overall success of the project by providing experienced management and leadership to all activities within the project. Mr. Laumb will ensure that the project is carried out within budget, schedule, and scope. Mr. Laumb will also be responsible for effective communication with project partners and EERC project personnel. In addition, Mr. Laumb will be the PI for Task 4 of both projects. Other EERC key personnel include the following:

- Mr. John Kay, Principal Engineer, Emissions and Carbon Capture Group Lead, leads CO_2 capture testing at the EERC. For the proposed project, Mr. Kay will be the PI for all capture-related activities. Mr. Kay will also act in an advisory role for modeling activities, including review of the technology performance and cost results, with a focus on compatibility with DOE costing methods.
- Mr. Josh Stanislowski, Principal Process Engineer, Energy Systems Development, leads systems engineering work at the EERC. For the proposed project, Mr. Stanislowski will be the PI leading all modeling tasks and will act as a key interface with DOE NETL modelers as well as Burns & McDonnell for pre-FEED work.
- Dr. Steve Benson, Associate Vice President for Research, will lead the aerosol mitigation and management efforts. Dr. Benson will interface with Mr. John Kay to ensure the aerosol sampling is completed in conjunction with amine testing.

Mr. Tim Thomas, Vice President and Deputy General Manager with Mitsubishi Heavy Industries America, Inc. (MHIA), will be responsible for all MHI and MHIA activities on this project. Mr. Thomas will be the key interface between MHIA, MHI, and the EERC for capture system modifications and test protocol.

Mr. Ronald Bryant, Principal with Burns & McDonnell will be responsible for all Burns & McDonnell activities on this project. Mr. Bryant will be a key contact with the Project Carbon team and will aid in the pre-FEED study at MRY.

Industry Partners

The industry partners for this project are ALLETE, and Minnkota Power. ALLETE is the parent company of Minnesota Power and BNI Energy. ALLETE has had a presence in the North Dakota energy industry since it acquired BNI Coal (now BNI Energy) in 1988 and has been a partner in electric generation utilizing North Dakota lignite since the MRY Station Unit 2 was constructed in 1977. Past ALLETE research efforts have looked on using North Dakota lignite for emission control applications and developing previous lignite-fueled clean coal electric generation projects. Minnkota Power is also a co-owner and operator of the MRY generating station. The MRY Station is currently being considered for a postcombustion CO_2 capture retrofit under Project Tundra. Letters of support from the industry partners can be found in Appendix C.

VALUE TO NORTH DAKOTA

The continued use of lignite in North Dakota is highly dependent on creating a business case for the use of CO_2. The value of this project is that it supports retrofit technology to make low-carbon lignite utilization an economically attractive option. Without retrofit technology developments, carbon capture creates economic stresses on the continued use of coal in existing plant assets.

The North Dakota lignite industry, which has a $3 billion economic impact on the state, has been challenged by federal-level mandates to reduce the carbon intensity of power production. On August 3, 2015, the Clean Power Plan (CPP) was finalized as the rule establishing CO_2 emission limits for existing power plants (U.S. Environmental Protection Agency, 2015), and while a stay in the CPP's implementation was issued by the U.S. Supreme Court in February 2016, the plan is an indicator of constraints that the lignite industry could face in the future. This project will provide vital information to support a retrofit that can also enable a new CO_2 market to exist in the state whereby utilities that produce CO_2 can market it to oil producers for EOR. CO_2-based EOR creates a business case for carbon capture in North Dakota and readies the industry for future carbon constraints. Indeed, the key limitation to future widespread application of CO_2 EOR is in finding the supply of CO_2 (Burton-Kelly et al., 2014). North Dakota's unique combination of resources, including substantial CO_2 generation capacity and a proximate sequestration use suggests that the state has the potential to lead the development of sustainable coal utilization, which will be an increasing worldwide need in the years ahead.

MANAGEMENT

The EERC will serve as the lead organization for this project with Mr. Jason Laumb as the overall project manager. Mr. Laumb will ensure the overall success of this project by providing experienced management and leadership to all activities within the project. As project manager, Mr. Laumb will be responsible for the project being carried out within budget, schedule, and scope; he will also be responsible for the effective communication between all project partners and EERC project personnel. Resumes of key personnel are included in Appendix A. The management structure for this project is shown in Figure 7.

Once the project is initiated, the project team will engage in weekly conference calls to review project status and future directions. Quarterly reports will be prepared and submitted to project sponsors for review. Regular meetings will be held to review the status and results of the project and discuss directions for future work. A broad team approach is key to successful execution of this project.

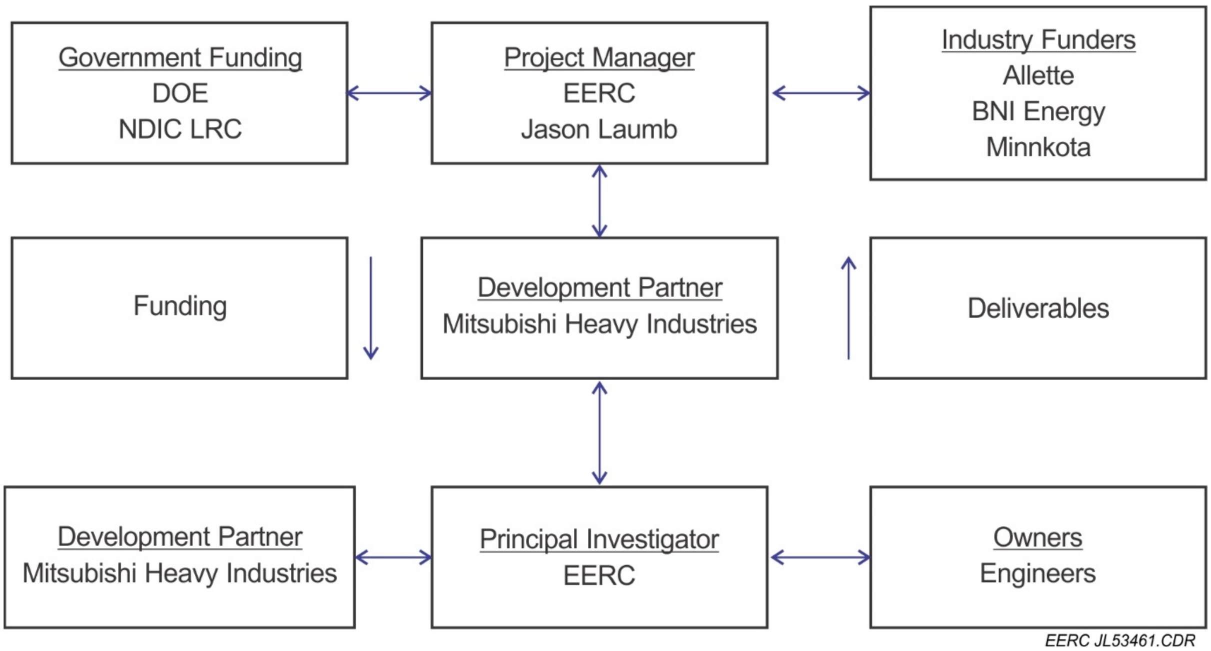


Figure 7. Project management structure.

Several milestones and decision points have been identified for the program. Milestones include the following for Project 1:

- M1 – Path Forward for North Dakota PCC Project Completed.
- M2 – Complete Preliminary Economic Analysis
- M3 – Identify Options for Aerosol Mitigation
- M4 – Initiate Slipstream Testing at MRY 2.

Milestones and decision points have also been identified for Project 2:

- M1 – Initiate Field Testing.
- M2 – Complete Pre-FEED Analysis
- M3 – Complete Integrated Economic Analysis of Retrofit at MRY

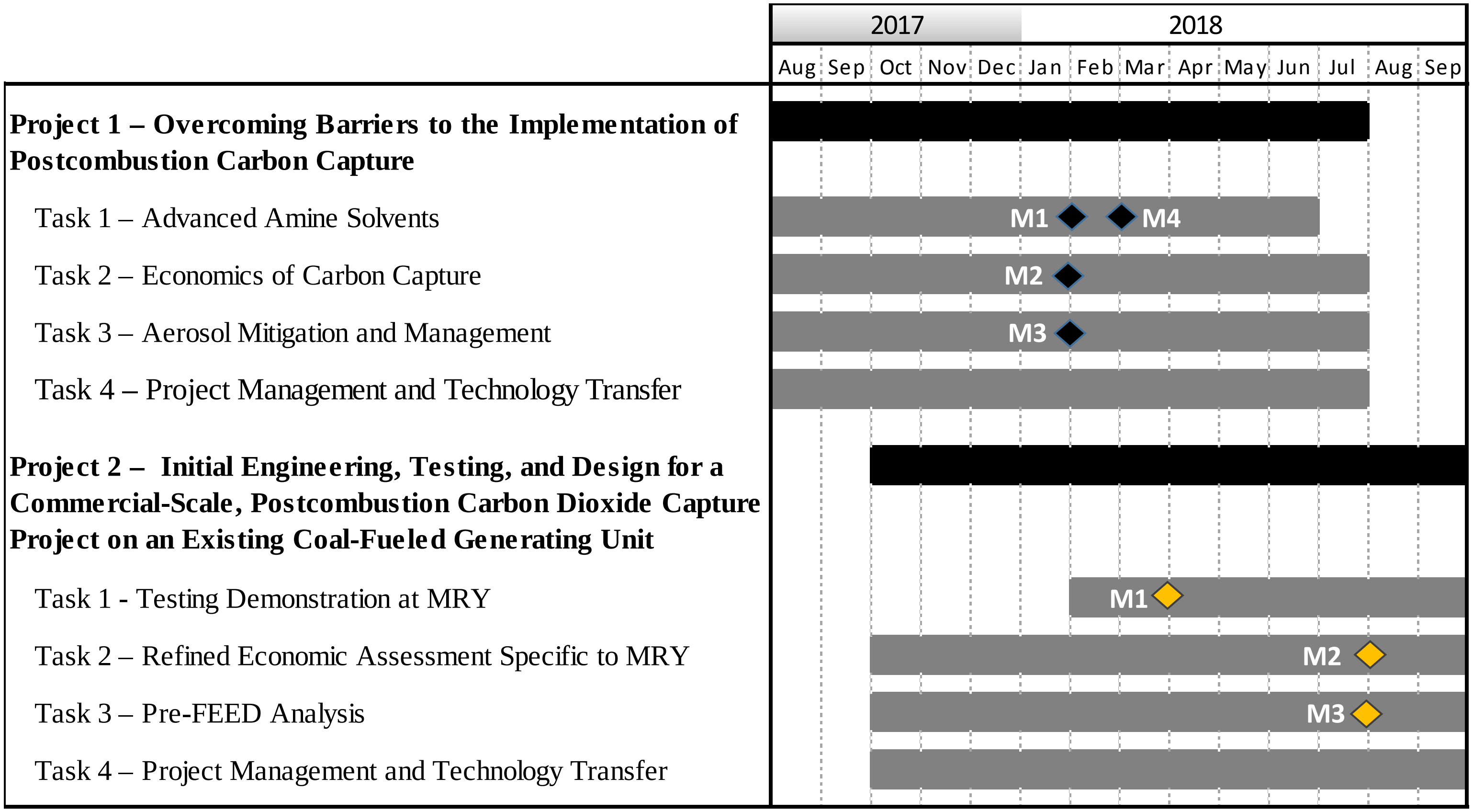
Project milestones and dates can be found in Figure 8. The milestones for Project 2 may be modified if instructions in the FOA dictate.

TIMETABLE AND DELIVERABLES

A time line for the project activities is shown in Figure 8. Project 1 is anticipated to be initiated by August 1, 2017, and completed by July 31, 2018. The Project 2 anticipated start date is October 1, 2017, with an end date of September 30, 2018, thus resulting in a 14-month period of performance for Project Carbon. The primary deliverable will be an integrated final report, due upon completion of the project. The final report will summarize the tasks described in the scope of work section.

Specific deliverables for the project are aligned to support continued development of Project Tundra. The EERC team will work closely with Burns & McDonnell, MHI, and the industry team to ensure all deliverables aid in the development of key steps in Project Tundra. Key deliverables include:

- Crucial data for amine capture technology applicable for use with North Dakota lignite.
- Develop an understanding of the expected emissions and performance of the applicable technology.
- Determine any additional flue gas cleaning that may be required prior to the carbon capture system to ensure economic operation.
- Provide the data necessary for a vendor to aid in design of full-scale carbon capture system to operate utilizing flue gas from a North Dakota lignite-fired plant.
- Identification of plausible mechanism resulting in aerosol formation (degradation products vs. nucleation).
- Methods to mitigate the formation of aerosols from PCC systems.
- Pre-FEED information specific to PCC at MRY, including a cost estimate.



Milestones Project 1 ◆	Milestones Project 2 ◇
M1 – Path Forward for North Dakota PCC Project Completed	M1 – Initiate Field Testing
M2 – Complete Preliminary Economic Model	M2 – Complete Integrated Economic Analysis of Retrofit at MRY
M3 – Identify Options for Aerosol Mitigation	M3 – Complete Pre-FEED Analysis
M4 – Initiate Slipstream Testing at MRY	

LR 6/29/17

Figure 8. Project schedule and milestones for Project 1 and Project 2.

The specific deliverables mentioned above will be presented to the project team in the form of a draft and final report. The draft report will be issued to the project team for comments prior to a project final report.

BUDGET

The proposed budget is $12,700,000 with $2,500,000 coming from DOE NETL, through the EERC's cooperative agreement, an additional $6,000,000 anticipated from a submission to a DOE NETL FOA, $3,200,000 from NDIC and $500,000 cash and $500,000 in-kind from industry partners. Table 2 provides a breakdown of labor categories and hours for the proposed work. The budget justification can be found in Appendix D. Table 3 presents a detailed budget. Several pieces of equipment are proposed to accomplish this work. A portable FTIR for gas analysis to provide real-time analysis of constituents of interest in the flue gas will be purchased along with a combustion gas analyzer rack. Additionally, for the integration of the test systems at the host site and to minimize the impact to the facility an ID fan and a steam generator will also be purchased, along with suitable piping, controls, wiring, pumps, and heat exchangers.

Because of the multiple DOE funding sources, it is requested that the state funding be made available immediately, with Project 1 and Project 2 allowed to be initiated, securing the cost share for each project. The ability to start Project 1 while gathering the remaining cost share

Table 2. Labor Categories and Hours

Labor Categories	**Hours**
Project Manager	1730
Principal Investigator	4829
Research Scientist/Engineer	43,649
Faculty	17
Senior Management	1265
Research Technicians	3490
Technology Dev. Operators	8920
Graduate Students	550
Technical Support Personnel	560
Total Hours	**65,010**

Table 3. Budget Breakdown

CATEGORY	PROJECT 1 NDIC SHARE	PROJECT 1 COST SHARE	PROJECT 1 TOTAL	PROJECT 2 NDIC SHARE	PROJECT 2 COST SHARE	PROJECT 2 TOTAL	PROJECT CARBON NDIC SHARE	PROJECT CARBON COST SHARE	PROJECT CARBON TOTAL
Total Labor	$ 965,311	$ 1,204,874	$ 2,170,185	$ 460,775	$ 2,428,037	$ 2,888,812	$ 1,426,086	$ 3,632,911	$ 5,058,997
Travel	$ 50,007	$ 58,785	$ 108,792	$ 60,000	$ 64,998	$ 124,998	$ 110,007	$ 123,783	$ 233,790
Equipment > $5000	$ -	$ 344,500	$ 344,500	$ -	$ 143,000	$ 143,000	$ -	$ 487,500	$ 487,500
Supplies	$ 66,814	$ 15,477	$ 82,291	$ 5,000	$ 10,150	$ 15,150	$ 71,814	$ 25,627	$ 97,441
Subrecipient – Mitsubishi Heavy Industries	$ -	$ 499,804	$ 499,804	$ -	$ 1,305,000	$ 1,305,000	$ -	$ 1,804,804	$ 1,804,804
Subrecipient – Burns & McDonnell	$ -	$ -	$ -	$ -	$ 250,000	$ 250,000	$ -	$ 250,000	$ 250,000
Communications	$ 238	$ 532	$ 770	$ 122	$ 215	$ 337	$ 360	$ 747	$ 1,107
Printing & Duplicating	$ 325	$ 1,198	$ 1,523	$ 300	$ 500	$ 800	$ 625	$ 1,698	$ 2,323
Food	$ -	$ 3,000	$ 3,000	$ -	$ 3,600	$ 3,600	$ -	$ 6,600	$ 6,600
Laboratory Fees & Services									
Natural Materials Analytical Research Lab	$ 34,336	$ -	$ 34,336	$ -	$ -	$ -	$ 34,336	$ -	$ 34,336
Analytical Research Lab	$ 124,072	$ -	$ 124,072	$ 125,265	$ -	$ 125,265	$ 249,337	$ -	$ 249,337
Combustion Test Service	$ 81,370	$ -	$ 81,370	$ -	$ 124,286	$ 124,286	$ 81,370	$ 124,286	$ 205,656
Particulate Analysis Lab	$ 20,592	$ 77,713	$ 98,305	$ -	$ 87,406	$ 87,406	$ 20,592	$ 165,119	$ 185,711
Fuel Preparation Service	$ 9,984	$ -	$ 9,984	$ -	$ -	$ -	$ 9,984	$ -	$ 9,984
Graphics Service	$ 2,016	$ 6,322	$ 8,338	$ -	$ 8,400	$ 8,400	$ 2,016	$ 14,722	$ 16,738
Shop & Operations	$ 16,874	$ 27,439	$ 44,313	$ 12,990	$ 23,382	$ 36,372	$ 29,864	$ 50,821	$ 80,685
Technical Software Fee	$ 89,856	$ -	$ 89,856	$ -	$ 90,720	$ 90,720	$ 89,856	$ 90,720	$ 180,576
Outside Lab	$ -	$ 10,000	$ 10,000	$ -	$ -	$ -	$ -	$ 10,000	$ 10,000
Total Direct Costs	$ 1,461,795	$ 2,249,644	$ 3,711,439	$ 664,452	$ 4,539,694	$ 5,204,146	$ 2,126,247	$ 6,789,338	$ 8,915,585
Facilities & Admin. Rate – % of MTDC	$ 738,205	$ 750,356	$ 1,488,561	$ 335,548	$ 1,460,306	$ 1,795,854	$ 1,073,753	$ 2,210,662	$ 3,284,415
Total Cash Requested – U.S. Dollars	$ 2,200,000	$ 3,000,000	$ 5,200,000	$ 1,000,000	$ 6,000,000	$ 7,000,000	$ 3,200,000	$ 9,000,000	$ 12,200,000
Total In-kind Cost Share	$ -	$ -	$ -	$ -	$ 500,000	$ 500,000	$ -	$ 500,000	$ 500,000
Total Project Costs – U.S. Dollars	$ 2,200,000	$ 3,000,000	$ 5,200,000	$ 1,000,000	$ 6,500,000	$ 7,500,000	$ 3,200,000	$ 9,500,000	$ 12,700,000

for Project 2 will allow for synergies between the two projects that will ensure timely completion of tasks.

MATCHING FUNDS

Matching funds totaling $9,500,000 for the proposed effort will come from industry ($1,000,000) and federal ($8,500,000) sources as shown in Table 3.

TAX LIABILITY

The EERC, as part of the University of North Dakota, is a state-controlled institution of higher education and is not a taxable entity; therefore, it has no tax liability.

CONFIDENTIAL INFORMATION

The MHI proposal in Appendix D contains confidential information.

APPENDIX A

RESUMES OF KEY PERSONNEL

JASON D. LAUMB
Principal Engineer, Coal Utilization Group Lead
Energy & Environmental Research Center (EERC), University of North Dakota (UND)
15 North 23rd Street, Stop 9018, Grand Forks, ND 58202-9018 USA
Phone: (701) 777-5114, Fax: (701) 777-5181, E-Mail: jlaumb@undeerc.org

Principal Areas of Expertise
Mr. Laumb's principal areas of interest and expertise include biomass and fossil fuel conversion for energy production, with an emphasis on ash effects on system performance. He has experience with trace element emissions and control for fossil fuel combustion systems, with a particular emphasis on air pollution issues related to mercury and fine particulates. He also has experience in the design and fabrication of bench- and pilot-scale combustion and gasification equipment.

Qualifications
M.S., Chemical Engineering, University of North Dakota, 2000.
B.S., Chemistry, University of North Dakota, 1998.

Professional Experience
2008–Present: Principal Engineer, Coal Utilization Group Lead, EERC, UND. Mr. Laumb's responsibilities include leading a multidisciplinary team of 30 scientists and engineers whose aim is to develop and conduct projects and programs on power plant performance, environmental control systems, the fate of pollutants, computer modeling, and health issues for clients worldwide. Efforts are focused on the development of multiclient jointly sponsored centers or consortia that are funded by government and industry sources. Current research activities include computer modeling of combustion/gasification and environmental control systems, performance of selective catalytic reduction technologies for NO_x control, mercury control technologies, hydrogen production from coal, CO_2 capture technologies, particulate matter analysis and source apportionment, the fate of mercury in the environment, toxicology of particulate matter, and in vivo studies of mercury–selenium interactions. Computer-based modeling efforts utilize various kinetic, systems engineering, thermodynamic, artificial neural network, statistical, computation fluid dynamics, and atmospheric dispersion models. These models are used in combination with models developed at the EERC to predict the impacts of fuel properties and system operating conditions on system efficiency, economics, and emissions.

2001–2008: Research Manager, EERC, UND. Mr. Laumb's responsibilities included supervising projects involving bench-scale combustion testing of various fuels and wastes; supervising a laboratory that performs bench-scale combustion and gasification testing; managerial and principal investigator duties for projects related to the inorganic composition of coal, coal ash formation, deposition of ash in conventional and advanced power systems, and mechanisms of trace metal transformations during coal or waste conversion; and writing proposals and reports applicable to energy and environmental research.

2000–2001: Research Engineer, EERC, UND. Mr. Laumb's responsibilities included aiding in the design of pilot-scale combustion equipment and writing computer programs that aid in the reduction of data, combustion calculations, and prediction of boiler performance. He was also involved in the analysis of current combustion control technology's ability to remove mercury and studying in the suitability of biomass as boiler fuel.

1998–2000: SEM Applications Specialist, Microbeam Technologies, Inc., Grand Forks, North Dakota. Mr. Laumb's responsibilities included gaining experience in power system performance including conventional combustion and gasification systems; a knowledge of environmental control systems and energy conversion technologies; interpreting data to predict ash behavior and fuel performance; assisting in proposal writing to clients and government agencies such as the National Science Foundation and the U.S. Department of Energy; preparing and analyzing coal, coal ash, corrosion products, and soil samples using SEM/EDS; and modifying and writing FORTRAN, C+, and Excel computer programs.

Professional Memberships
American Chemical Society

Publications and Presentations
Has coauthored numerous professional publications.

JOHN P. KAY
Principal Engineer, Emissions and Carbon Capture Group Lead
Energy & Environmental Research Center (EERC), University of North Dakota (UND)
15 North 23rd Street, Stop 9018, Grand Forks, North Dakota 58202-9018 USA
Phone: (701) 777-4580, Fax: (701) 777-5181, E-Mail: jkay@undeerc.org

Principal Areas of Expertise
Mr. Kay's principal areas of interest and expertise include applications of solvents for removing CO_2 from gas streams to advance technology and look toward transformational concepts and techno-economic assessments. He has 6 years of experience in field testing site management and sampling techniques for hazardous air pollutants and mercury control in combustion systems along with 10 years of experience utilizing scanning electron microscopy (SEM), x-ray diffraction (XRD), and x-ray fluorescence (XRF) techniques to analyze coal, fly ash, biomass, ceramics, and high-temperature specialty alloys. He is also interested in computer modeling systems, high-temperature testing systems, and gas separation processes and is a FLIR Systems, Inc.-certified infrared thermographer.

Qualifications
B.S., Geological Engineering, University of North Dakota, 1994.
Associate Degree, Engineering Studies, Minot State University, 1989.

Professional Experience
2011–Present: Principal Engineer, Emissions and Carbon Capture Group Lead, EERC, UND. Mr. Kay's responsibilities include management of CO_2 separation research related to bench-, pilot-, and demonstration-scale equipment for the advancement of the technology. This also includes the development of cleanup systems to remove SO_x, NO_x, particulate, and trace elements to render flue gas clean enough for separation.

2005–2011: Research Manager, EERC, UND. Mr. Kay's responsibilities included the management and supervision of research involving the design and operation of bench-, pilot-, and demonstration-scale equipment for development of clean coal technologies. The work also involved the testing and development of fuel conversion (combustion and gasification) and gas cleanup systems for the removal of sulfur, nitrogen, particulate, and trace elements.

1994–2005: Research Specialist, EERC, UND. Mr. Kay's responsibilities included conducting SEM, XRD, and XRF analysis and maintenance; creating innovative techniques for the analysis and interpretation of coal, fly ash, biomass, ceramics, alloys, high-temperature specialty alloys, and biological tissue; managing the day-to-day operations of the Natural Materials Analytical Research Laboratory; supervising student workers; developing and performing infrared analysis methods in high-temperature environments; and performing field work related to mercury control in combustion systems.

1993–1994: Research Technician, Agvise Laboratories, Northwood, North Dakota. Mr. Kay's responsibilities included receiving and processing frozen soil samples for laboratory testing of chemical penetration, maintaining equipment and inventory, and training others in processing techniques utilizing proper laboratory procedures.

1991–1993: Teaching Assistant, Department of Geology and Geological Engineering, UND. Mr. Kay taught Introduction to Geology Recitation, Introduction to Geology Laboratory, and Structural Geology. Responsibilities included preparation and grading of assignments and administering and grading class examinations.

1990–1992: Research Assistant, Natural Materials Analytical Laboratory, EERC, UND. Mr. Kay's responsibilities included operating an x-ray diffractometer and interpreting and manipulating XRD data, performing software manipulation for analysis of XRD data, performing maintenance and repair of the XRD machine and sample carbon coating machine, preparing samples for XRD and SEM analysis, and performing point count analysis on the SEM.

Professional Memberships
ASM International
American Ceramic Society
Microscopy Society of America

Publications and Presentations
Has authored or coauthored numerous publications.

DR. STEVEN A. BENSON
Associate Vice President for Research
Energy & Environmental Research Center (EERC), University of North Dakota (UND)
15 North 23rd Street, Stop 9018, Grand Forks, North Dakota 58202-9018 USA
Phone: (701) 777-5177, Fax: (701) 777-5181, E-Mail: sbenson@undeerc.org

Principal Areas of Expertise
Dr. Benson's principal areas of interest and expertise include development and management of complex multidisciplinary programs focused on solving environmental and energy problems associated with the development and utilization of fuel resources. These programs include 1) technologies to improve the performance of fuel resource recovery, refining, conversion and environmental control systems; 2) impact of fuel properties on combustion and gasification systems; 3) carbon dioxide separation and capture technologies, 4) advanced analytical techniques; 5) computer-based models to predict the performance of combustion and gasification systems; 6) technical and economic feasibility of fuel conversion technologies; and 7) state and national environmental policy.

Qualifications
Ph.D., Fuel Science, Pennsylvania State University 1987.
B.S., Chemistry, University of Minnesota, 1977.

Professional Experience
2015–Present: Associate Vice President for Research, EERC, UND. Dr. Benson assists the Vice President for Research in overseeing the activities of a team of scientists and engineers focused on research, development, demonstration, and commercialization of energy and environmental technologies. Dr. Benson has over 25 years of research and development experience in efficient and clean energy production systems.

2010–2014: Professor/Chair, Petroleum Engineering Department, and Director, Institute for Energy Studies, UND. Dr. Benson coordinated energy-related education and research activities that involve faculty, research staff, and students.

2008–Present: Professor, UND. Dr. Benson is responsible for teaching courses on energy production and associated environmental issues. Dr. Benson conducts research, development, and demonstration projects aimed at solving environmental, efficiency, and reliability problems associated with the utilization of fuel resources in refining/combustion/gasification systems that include transformations of fuel impurities, carbon dioxide separation and capture technologies, advanced analytical techniques, and computer-based models.

1999–2008: Senior Research Manager/Advisor, EERC, UND. Dr. Benson's was responsible for leading a group of about 30 highly specialized chemical, mechanical, and civil engineers along with scientists whose aim was to develop and conduct projects and programs on combustion and gasification system performance, environmental control systems, the fate of pollutants, computer modeling, and health issues for clients worldwide.

1994–1999: Associate Director for Research, EERC, UND, Grand Forks, North Dakota. Dr. Benson was responsible for the direction and management of programs related to integrated energy and environmental systems development. Dr. Benson led a team of over 45 scientists, engineers, and technicians.

1991–Present: President, Microbeam Technologies Incorporated (MTI). Dr. Benson is the founder of MTI, whose mission is to conduct service analysis of materials using automated methods. MTI began operations in 1992 and has conducted over 1450 projects for industry, government, and research organizations.

1989–1991: Assistant Professor of Geological Engineering, Department of Geology and Geological Engineering, UND. Dr. Benson was responsible for teaching courses on fuel geochemistry, fuel/crude behavior in refining, combustion and gasification systems, and analytical methods of materials analysis.

1984–1994: Senior Research Manager, Fuels and Materials Science, EERC, UND. Dr. Benson was responsible for management and supervision of research on the behavior of inorganic constituents in fuels in combustion and gasification.

1984–1986: Graduate Research Assistant, Fuel Science Program, Department of Materials Science and Engineering, Pennsylvania State University. Mr. Benson took course work in fuel science, chemical engineering (at UND), and ceramic science and performed independent research leading to a Ph.D. in Fuel Science.

1983–1984: Research Supervisor, Distribution of Inorganics and Geochemistry, Coal Science Division, UND Energy Research Center. He was responsible for management and supervision of research on coal geochemistry and ash chemistry related to inorganic constituents and mineral interactions and transformations during coal combustion and environmental control systems.

1977–1983: Research Chemist, U.S. Department of Energy Grand Forks Energy Technology Center, Grand Forks, North Dakota. He performed research on methods development for the characterization of coal and coal derived materials

Publications and Presentations
Editor of ten technical journal special issues
Author and coauthor of over 200 publications

Patents – Four patents issued and several applications pending:

7,574,968 – Method and Apparatus for Capturing Gas Phase Pollutants such as Sulfur Trioxide
7,628,969 – Multifunctional Abatement of Air Pollutants in Flue Gas
7,981,835 – System and Method for Coproduction of Activated Carbon and Steam/Electricity
8,277,542 – Method for Capturing Mercury from Flue Gas

Synergistic Activities

- Lignite Energy Council, Distinguished Service Award, Research & Development, 1997; College of Earth and Mineral Science Alumni Achievement Award, Pennsylvania State University, 2002; Lignite Energy Council, Distinguished Service Award, Research & Development, 2003; Lignite Energy Council, Distinguished Service Award, Government Action Program (Regulatory), 2005; Lignite Energy Council, Distinguished Service Award, Research & Development, 2008; Science and Technology Award, Impacts of Fuel Impurities Conference, 2014

- Provided testimony to the U.S. Senate Committee on the Environment and Public Works – Mercury Emissions Control at Coal-Fired Power Plants – 2008 and 2005

JOSHUA J. STANISLOWSKI
Principal Process Engineer, Energy Systems Development
Energy & Environmental Research Center (EERC), University of North Dakota (UND)
15 North 23rd Street, Stop 9018, Grand Forks, North Dakota 58202-9018 USA
701.777.5087 (phone); 701.777.5181 (fax); jstanislowski@undeerc.org

Principal Areas of Expertise
Mr. Stanislowski's principal areas of interest and expertise include coal and biomass gasification systems with an emphasis on novel syngas cooling, cleanup, and separation technologies. He has worked extensively with hydrogen separation membrane systems and liquid fuels catalysis. He is proficient in process modeling and systems engineering including techno-economic studies using Aspen Plus software. He has significant experience with process engineering, process controls, and project management. He has a strong background in gauge studies, experimental design, and data analysis.

Qualifications
M.S., Chemical Engineering, University of North Dakota, 2012.
B.S., Chemical Engineering, University of North Dakota, 2000.
Six Sigma Green Belt Certified, August 2004.

Professional Experience:
2015–Present: Principal Process Engineer, Energy Systems Development, EERC, UND, Grand Forks, North Dakota. Mr. Stanislowski works closely with the EERC management team to develop new programmatic directions to solve challenges in the energy industry. He manages projects in the area of gasification, CO_2 capture, and systems engineering.

2008–2015: Research Manager, EERC, UND, Grand Forks, North Dakota. Mr. Stanislowski managed projects in the areas of gasification, gas cleanup, hydrogen production, liquid fuel production, and systems engineering.

2005–2008: Research Engineer, EERC, UND, Grand Forks, North Dakota. Mr. Stanislowski's areas of focus included mercury control technologies and coal gasification. His responsibilities involved project management and aiding in the completion of projects. His duties included design and construction of bench- and pilot-scale equipment, performing experimental design, data collection, data analysis, and report preparation. He also worked in the areas of low-rank coal gasification, warm-gas cleanup, and liquid fuels production modeling using Aspen Plus software.

2001–2005: Process Engineer, Innovex, Inc., Litchfield, Minnesota.
– Mr. Stanislowski was responsible for various process lines including copper plating, nickel plating, tin–lead plating, gold plating, polyimide etching, copper etching, chrome etching, and resist strip and lamination. His responsibilities included all aspects of the process line including quality control, documentation, final product yields, continuous process

improvement, and operator training. He gained extensive knowledge of statistical process control and statistical start-up methodology. Mr. Stanislowski was proficient with MiniTab statistical software and utilized statistical analysis and experimental design as part of his daily work.

– Mr. Stanislowski designed and oversaw experiments as a principal investigator; wrote technical reports and papers, including standard operating procedures and process control plans; presented project and experimental results to suppliers, customers, clients, and managers; created engineering designs and calculations; and performed hands-on mechanical work when troubleshooting process issues. He demonstrated the ability to coordinate activities with varied entities through extensive project management and leadership experience.

1998–2000: Student Research Assistant, EERC, UND. Mr. Stanislowski worked on a wide variety of projects, including data entry and programming for the Center for Air Toxic Metals® (CATM®) database, contamination cleanup program development, using aerogels for emission control, and the development of a nationwide mercury emission model.

Publications and Presentations
Has coauthored several publications.

RON BRYANT, PE

Project Manager

Mr. Bryant currently serves as a senior project manager with Burns & McDonnell in the Energy Division. His primary responsibilities include coordination of multiple discipline design projects for fossil fuel power plant retrofit projects. His experience includes evaluation, design, and implementation of capital projects for the electric utility industry.

EDUCATION

- BS, Mechanical Engineering

REGISTRATIONS

- Professional Engineer (MO)

26 YEARS WITH BURNS & MCDONNELL

32 YEARS OF EXPERIENCE

Hawthorn, Iatan, LaCygne, Montrose and Sibley Generating Stations | Kansas City Power & Light

Kansas City, Missouri

Project director for a multi-site CCR and ELG compliance project. Burns & McDonnell performed studies to develop options for complying with CCR regulations and potential ELG regulations. Process modifications were designed to reduce CCR contact water. Detailed design for pond closures, bottom ash stack out slabs, and scrubber waste slurry basins were designed. Engineering was performed to install under boiler drag chain conveyors to convert units from wet bottom ash removal systems to dry bottom ash removal systems. The project included developing equipment procurement specifications, installation specifications, reviewing vendor and contractor submittals, and maintaining a document control and management system. As Project Director, Mr. Bryant is responsible for the execution of the engineering activities at all five sites.

Brown 3, Trimble 1 and Gent 1-4 Generating Stations | Louisville Gas & Electric – Kentucky Utilities

Louisville, Kentucky

Project director for a multi-site pulse-jet fabric filter and coal combustion residuals transport project. Burns & McDonnell was the Owners' Engineer for the installation of six PJFFs at three sites and the installation of two CCRT systems at two sites. The project included developing equipment procurement specifications, installation specifications, reviewing vendor and contractor submittals, and maintaining a document control and management system. As Project Director, Mr. Bryant was responsible for the execution of the engineering activities at all three sites.

Muskogee Units 4 & 5 Natural Gas Retrofit | Oklahoma Gas & Electric

Muskogee, Oklahoma

Project manager and is responsible for the schedule and design necessary to convert Muskogee Units 4 and 5 from coal to natural gas. The project consists of developing technical procurement documents and detailed mechanical, electrical, controls, structural, and civil documents for converting the units to natural gas. Each unit is rated at 550 MW nominal. The boilers are Alstom tangential-fired, each capable of 3,364,546 lb/hr steam flow at 2620 psig and 1005 Fwas responsible for developing preliminary design documents necessary to determine feasibility and cost to convert Muskogee Units 4 and 5 from coal to natural gas. The project consisted of developing process flow diagrams, general arrangement drawings, electrical one line diagrams, project schedule, and detailed cost estimates for converting Units 4 and 5 from coal to natural

RON BRYANT, PE
(continued)

gas. Each unit is rated at 550 MW nominal. The boilers are Alstom tangential-fired, each capable of 3,364,546 lb/hr steam flow at 2620 psig and 1005 F.

Wisdom Generating Station Unit 1 Natural Gas Retrofit | Corn Belt Power Coop

Spencer, Iowa

Project manager and was responsible for the evaluation and design to convert an existing pulverized coal fired unit to natural gas and fuel oil. The project included performing preliminary engineering, preparing general arrangement drawings, and developing costs estimates for converting the unit to natural gas and complying with NFPA 85 recommendations.

Combustion Turbine Relocation | NRG Energy

Houston, Texas

Project manager for providing Owner's Engineering services to assist NRG with relocating six combustion turbines to a new site in Galveston County, TX. Site development scope of services included detailed design of access road, , laydown areas, water supply, and gas supply. A storm water pollution prevention plan and ambient noise study was also performed. Foundation structural reviews were performed to determine suitability of foundations for the new site. Burns & McDonnell also reviewed contractor submittals and performed document control.

Air Emission Compliance Evaluation | Luminant

Dallas, Texas

Project manager and was responsible for the evaluation of air emission compliance strategies for multiple coal fired plant sites in Texas. The project included selecting various air pollution control technologies, performing preliminary engineering, preparing general arrangement drawings, and developing costs estimates for each type of technology at each plant site.

Ottumwa Generating Station | Alliant Energy

Ottumwa, Iowa

Project manager for the evaluation of plant improvement projects for the 673 MW coal fired unit. The project included developing multiple options for plant heat rate, MW, and reliability improvements. Each option was evaluated on technical and economical merit. A detailed report was prepared with recommended options to implement.

Milton R Young Generating Station | Minnkota Power Cooperative

Grand Forks, North Dakota

Project manager and had overall responsibility for the engineering, design, and startup of air pollution control systems on two lignite fired cyclone units. The systems include a new wet lime FGD scrubber system on a 250 MW unit, upgrades to an existing FGD scrubber system on a 475 MW unit, a new 550' reinforced concrete chimney with FRP liner, a dry flue gas to wet flue gas chimney conversion on an existing 550' chimney, and a new redundant lime preparation system serving both units. The project is being executed using a multi-contract approach.

RON BRYANT, PE
(continued)

Milton R Young Generating Station | Minnkota Power Cooperative,
Grand Forks, North Dakota

Project manager and was responsible for the engineering, design, and startup of two over-fire air systems on a 250 MW lignite fired unit and a 475 MW lignite fired unit.

Gibbons Creek Station | Texas Municipal Power Agency
Carlos, Texas

Project manager and was responsible for the investigation of LP turbine upgrade options at the 482 MW Gibbons Creek Station Unit 1. Predicted performance and cost estimates were developed for each option. Impacts on other plant equipment were examined. An economic analysis of each option was performed. A detailed report with recommended upgrades was prepared. Performance standards and scope of work for the design and installation of the LP turbine upgrade were developed. Bids were received and evaluated on technical and commercial merit. Technical review included evaluating design and performance expectations. The impact on other plant equipment was checked. An economic evaluation was performed to determine a net present value and payback period for each bid.

KIERAN MCINERNEY, PE, CEM

Project Manager and Development Engineer

As a development engineer in Burns & McDonnell's Energy Division, Mr. McInerney has experience in both supply side and demand side energy management. His duties include project management, technical feasibility, economic analysis, conceptual design, cost estimating, and strategic planning related to the development of energy generation projects and resource planning. He is also skilled in energy program management and strategic demand side management.

WEC Energy Group

March 2016 – Present

Project Manager for a reciprocating engine development project. Responsibilities include project management and consulting for technology assessment, conceptual engineering, specification development, technology selection, capital cost estimates, O&M cost estimates, life cycle cost analyses, schedule development, project definition, and ongoing support for O&M service agreement negotiations.

Confidential Client

March 2017 – Present

Project Manager for a reciprocating engine development project. Responsibilities include project management and consulting for technology assessment, conceptual engineering, feasibility studies, capital cost estimates, O&M cost estimates, life cycle cost analyses, schedule development, and ongoing support for project development.

Tucson Electric Power

January 2017 – February 2017

Project Manager for a technology assessment study evaluating simple cycle, reciprocating engine, combined cycle, wind, solar, and battery storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Confidential Client

August 2016 – January 2017

Project Manager for a reciprocating engine feasibility study. Responsibilities included project management, feasibility studies, site selection studies, conceptual design, capital cost estimate support, and O&M cost evaluation.

EDUCATION

- BS, Mechanical Engineering, Marquette University, 2003

REGISTRATIONS

- Professional Engineer (Colorado)
- Certified Energy Manager (CEM), Association of Energy Engineers

AWARDS/PUBLICATIONS

- Federal Energy and Water Management Award, U.S. Department of Energy, 2013

SPECIALTY

- Project Development
- Project Management
- Feasibility and Technology Studies
- Economic Evaluation
- Strategic Planning
- Cost Estimating
- Energy/Water Management
- Conceptual Engineering
- Mechanical System Analysis

4 YEARS WITH BURNS & MCDONNELL

14 YEARS OF EXPERIENCE

KIERAN MCINERNEY, PE, CEM
(continued)

Duke Energy
November 2016 – February 2016

Project Manager for a generic unit assessment study evaluating simple cycle, reciprocating engine, combined cycle, nuclear, landfill gas, wind, solar, and battery storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Basin Electric Power Cooperative
January 2017 – February 2017

Project Manager for a generic unit assessment study evaluating simple cycle, reciprocating engine, combined cycle, coal, nuclear, wind, solar, and battery storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Oklahoma Gas & Electric
July 2016 – November 2016

Project Manager for a generic unit assessment study evaluating simple cycle, combined cycle, and reciprocating engine technologies for greenfield and brownfield applications. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Confidential Client
March 2016 – May 2016

Technical Lead for an indicative bid estimate for a reciprocating engine generating station. Responsibilities included feasibility studies, technology selection, capital cost estimate support, and O&M cost evaluation.

Duke Energy
January 2016 – April 2016

Project Manager for a generic unit assessment study evaluating simple cycle, combined cycle, coal, fuel cell, landfill gas, wind, solar, compressed air storage, and battery storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Basin Electric Power Cooperative
January 2016 – April 2016

Project Manager for a generic unit assessment study evaluating simple cycle, reciprocating engines, combined cycle, coal, nuclear, wind, solar, and battery storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Old Dominion Electric Cooperative
October 2015 – February 2016

Project Manager for a generic unit assessment study evaluating simple cycle, reciprocating engines, combined cycle, coal, landfill gas, wind, solar, hydroelectric, fuel cell, and battery storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

KIERAN MCINERNEY, PE, CEM
(continued)

Confidential Client
July 2015 – December 2015

Development Lead for a heat rate improvement study at a coal-fired generation facility. Responsibilities included technical evaluation, economic analysis, and compliance review for potential heat rate improvement technologies.

Confidential Client
August 2015 – October 2015

Technical Lead for a generic unit assessment study evaluating simple cycle, combined cycle, and reciprocating engine technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Central Electric Power Cooperative
July 2015 – October 2015

Technical Lead for a generic unit assessment study evaluating reciprocating engine and simple cycle gas turbine generation options for peak shaving. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Rochester Public Utilities
June 2015 – August 2015

Development Lead for a technology selection project including reciprocating engines and simple cycle gas turbines. Responsibilities included targeted technology assessment and capital budget development.

Midwest Energy
July 2015 – September 2015

Technical Lead for a generic unit assessment study evaluating simple cycle, combined cycle, and reciprocating engine technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Confidential Client
April 2015 – May 2015

Development Lead for a power plant decommissioning study that encompassed the client's entire generation portfolio. Responsibilities included system analysis, logistics, and cost estimation.

South Mississippi Electric Power Association
April 2015 – July 2015

Technical Lead for a generic unit assessment study evaluating simple cycle, combined cycle, and reciprocating engine technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

KIERAN MCINERNEY, PE, CEM
(continued)

Duke Energy

January 2015 – April 2015

Development Manager for a generic unit assessment study evaluating simple cycle, reciprocating engines, combined cycle, coal, biomass, wind, solar, and battery storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, and performance estimation.

Public Services Enterprise Group

November 2014 - January 2015

Technical Lead for a generic unit assessment study evaluating simple cycle, combined cycle, reciprocating engine, wind, solar, and battery storage technologies. Responsibilities included technical report, capital cost estimation, O&M cost estimation, performance estimation, and conceptual design.

Confidential Client

August 2014 – November 2014

Development Engineer for a heat rate improvement study at a coal-fired generation facility. Responsibilities included technical evaluation, economic analysis, and compliance review for potential heat rate improvement technologies.

Confidential Client

May 2014 – October 2014

Development Engineer for an EPC project definition report of a simple cycle generation facility and a combined cycle generation facility. Responsibilities included project definition, specification development, performance evaluation, and cost estimating.

Kansas City Power & Light Company

March 2014 – February 2015

Mechanical Lead for a boiler fuel conversion analysis at two existing coal-fired generation facilities. Responsibilities include technical evaluation, economic analysis, strategic planning, and conceptual design for converting coal-fired boilers to consume alternative fuels.

Duke Energy

January – April 2014

Development Manager for a technical assessment study evaluating simple cycle, reciprocating engines, combined cycle, integrated gasification combined cycle (IGCC), pulverized coal, biomass, wind, and solar generation technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, performance estimation, and conceptual design.

Basin Electric Power Cooperative

October 2013 – April 2014

Development Engineer for a financial and technical evaluation of emissions control solutions for existing coal-fired boilers. Responsibilities include technical evaluation, economic analysis, strategic planning, and conceptual design for implementing NOx reduction technology.

KIERAN MCINERNEY, PE, CEM
(continued)

Confidential Client
November 2013 – January 2014

Development Engineer for an EPC capital cost estimate of a 1x1 natural gas combined cycle facility. Responsibilities included project definition, system evaluation, specification review, and capital cost estimation.

Confidential Client
October 2013 – January 2014

Development Engineer for an EPC project definition report of a generation facility including combined cycle and simple cycle technologies. Responsibilities included project definition, research, specification review, and performance estimation.

Vectren Corporation
September 2013 – October 2013

Development Engineer for a technical assessment study evaluating simple cycle, reciprocating engines, combined cycle, IGCC, pulverized coal, biomass, wind, and solar generation technologies, plus energy storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, performance estimation, and conceptual design.

Louisville Gas & Electric Company and Kentucky Utilities Company
September 2013 – October 2013

Development Engineer for a technical assessment study evaluating simple cycle, reciprocating engines, combined cycle, IGCC, pulverized coal, biomass, wind, and solar generation technologies, plus energy storage technologies. Responsibilities included project definition, capital cost estimation, O&M cost estimation, performance estimation, and conceptual design.

Timothy E Thomas
Vice President & Deputy General Manager
Mitsubishi Heavy Industries America

Overview
Mr. Thomas is currently Vice President & Deputy General Manager for the Environmental & Chemical Plant Division of Mitsubishi Heavy Industries America (MHIA) in Houston, TX. He is responsible for project development and implementation from initial concepts through project completion. He manages a staff of project and technical experts, and oversees multiple projects. Mr. Thomas has over 34 years of experience in project management, construction, engineering, and design associated with electric generating stations. Areas of expertise include CO_2 capture systems (CCS), flue gas desulfurization (FGD) systems, coal upgrading facilities, material handling systems, wastewater treatment systems, and particulate removal systems. Mr. Thomas has a degree in Mechanical Engineering from the University of Florida and has held PE licenses in various states.

Project Specific Experience
Project Director for the preparation of multiple studies on the application of MHIA's CCS technology on power plant applications. Primary focus on the application, feasibility, and of installing CCS on coal fired power plants and natural gas combined cycle units. Heavily involved in supporting MHI'sresearch initiatives including demonstration of MHI's High Efficiency System at Alabama Power's Plant Barry CCS demonstration facility (DOE funded project).
· Project Director for the design, procurement, construction and commissioning of a multi-million dollar Coal Upgrading facility in Southern Alabama. This demonstration project was first to apply Mitsubishi's coal upgrading technology in the United States.
Project Director from 2002 to 2013 for the design, procurement, construction, and commissioning of Flue Gas Desulfurization (FGD) systems at multiple TVA fossil fuel power plants. These installations completed at over $1 billion were provided to TVA through Advatech, a joint venture of URS and Mitsubishi Heavy Industries America. For this application, Advatech provided its proprietary single module, twin tower Double Contact Flow Scrubber (DCFS) technology in order to meet TVA requirements for sulfur removal and availability.
· Project Director for the FGD Conversion for Seminole Electric's Units 1 and 2. An outage driven project completed at $15 million - on schedule and within budget. Oversaw project development, execution, and implementation. Directed resources from various offices. Maintained a high level of client interaction and involvement.
· Project Director for the installation of a limestone preparation system for LG&E's Mill Creek Station. Scope included barge unloading, limestone storage and handling, vertical ball mill grinding systems, and slurry transport systems. A value-driven project completed at $20 million - on schedule and within budget. Oversaw project

development, execution, and implementation. Directed resources from various offices. Maintained a high level of client interaction and involvement.

· Project Manager for the conversion of LG&E's Mill Creek Station to produce a commercial grade gypsum by-product. Scope included preliminary engineering and design, economic evaluations and cost estimating for a barge loading system, forced oxidation equipment, primary and secondary dewatering modifications, limestone storage and handling, vertical ball mill grinding systems, and slurry transport systems. A value-driven project completed at $27 million - on schedule and within budget. Oversaw the efforts of a large engineering firm subcontracted by LG&E to perform detailed engineering and design. Maintained a high level of client interaction and involvement.

· Project Manager and Construction Manager for the FGD Conversion for NIPSCo Schahfer Station Units 17 and 18. A fast-track outage driven project completed at $30 million - on schedule and within budget. Totally responsible for project execution, implementation, cost, schedule, and technical decisions, managing the on-site efforts of a large engineering firm subcontracted to perform detailed design, procurement, and construction management.

· Project Engineering Manager during the $340 million FGD system retrofit for Pennsylvania Electric's Conemaugh Station Units 1 and 2. Managed development of systems design; design criteria; process and instrumentation diagrams; design calculations and equipment optimization; operating procedures and system descriptions. Managed review of vendor/manufacturer drawings and procedures. Inspected shop and on-site equipment prior to installation, and administered and developed performance testing protocol. Primary interface between client and vendors. Wrote all major client correspondence. Provided a high level of on-site support. Responsible for closing contract issues, analyzed contractor claims, prepared detailed evaluations, and coordinated responses with project management and client representatives.

· On-site Resident Engineer for the construction of JEA/FPL's St. Johns River Power Park, two 600 MW coal-fired generating units. Oversaw the installation of the FGD systems, electrostatic precipitators, and a wastewater treatment facility. Interpreted technical requirements; reviewed drawings; ensured successful coordination with other engineering disciplines; and reviewed, managed, and negotiated contract changes ranging in value up to $1 million.

Specialized Training

BS / 1983 / Mechanical Engineering / University of Florida

Chronology

Mitsubishi Industries America, Inc. – Vice President, Deputy General Manager, Project Director, 2013 to present

URS Corp. and Advatech LLC, Vice President, Project Director, Project Manager, 1996 – 2013

URS - Raytheon Engineers and Constructors – Ebasco Services, Project Engineering Manager, Principal Mechanical Engineer, Senior Mechanical Engineer, Mechanical Engineer, Sr. Associate Engineer, 1983 - 1996

APPENDIX B

DESCRIPTION OF EQUIPMENT

EERC FACILITIES – POSTCOMBUSITON TECHNOLOGY DEMONSTRATION

PARTICULATE TEST COMBUSTOR (PTC)

The PTC at the Energy & Environmental Research Center (EERC) is a stalwart pilot unit that has operated for almost 40 years. The PTC is a 550,000-Btu/hr (0.053-MW_e) pc-fired unit. It was installed in 1977 and was designed to generate fly ash representative of that produced in a full-scale utility boiler. The PTC also features either an adjustable-swirl burner or can be converted to cyclone burner and has the capability to fire any rank coal, natural gas, petcoke, biogas, biomass, liquid fuels, coal–water fuel, sludge, or municipal solid waste (MSW). The system is equipped to utilize a selective catalytic reduction (SCR) reactor for NO_x removal and either a wet flue gas desulfurization (WFGD) unit or a spray dryer absorber (SDA) to control SO_x. Particulate control is accomplished by either a baghouse or an electrostatic precipitator (ESP). Depending on the test requirements, any of these devices can be installed or bypassed. In addition, chemical components can be injected into the flue gas to produce any composition desired by a technology developer. These features enable the PTC system to provide the ultimate flue gas flexibility to meet specific client needs. A process flow diagram of the PTC is included in Figure A-1.

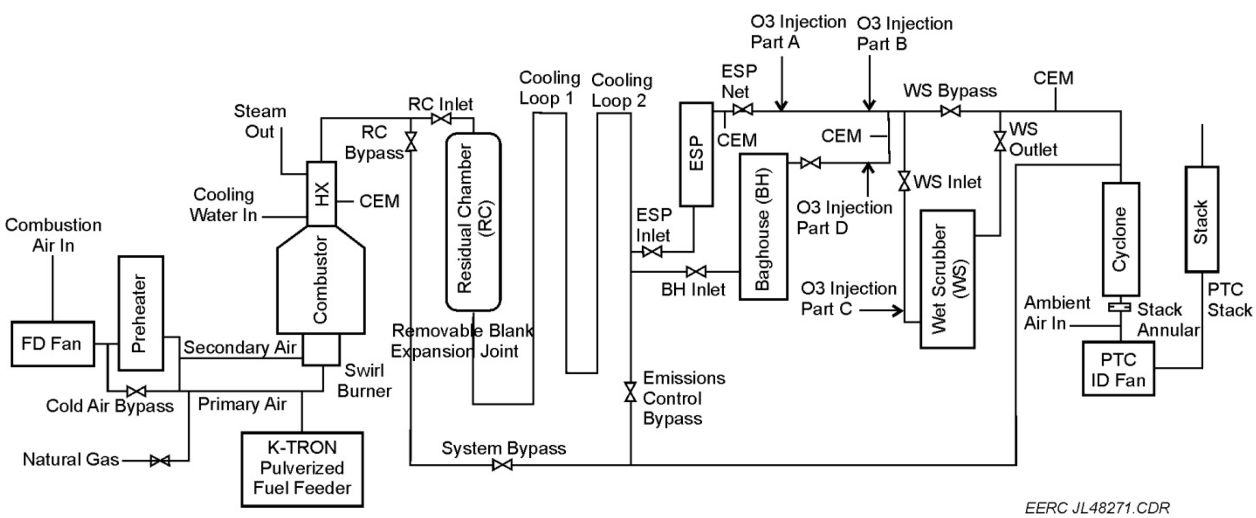


Figure A-1. Process flow diagram of the PTC system.

The PTC can produce flue gas at a rate of 125–249 kg/hr (275–550 lb/hr or 60–130 scfm) and is fully instrumented and computerized for efficient operation and data acquisition, which includes online analysis of the flue gas, including O_2, CO, CO_2, SO_2, and NO_x levels simultaneously at multiple locations. Additionally, options exist to measure particulate, trace metals, and organic pollutants. Each of the analyzers is regularly calibrated and maintained to provide accurate flue gas concentration measurements. Furnace exit gas temperatures (FEGTs) as high as 1371°C (2500°F) can be achieved.

Cyclone Functionality

The pilot-scale cyclone at the EERC was developed to validate fuel treatments and emissions of full-scale combustors used in power generation. The cyclone burner is fitted to the PTC furnace in place of the standard burner. The cyclone burner is preheated with natural gas and can fire any coal rank. The nominal firing rate is approximately 600,000 Btu/hr consuming 20–34 kg/hr (45–75 lb/hr) of coal. Solid and liquid additives can be injected into the fuel stream prior to combustion. The cyclone is a horizontal scroll type carrying fuel in with the primary air. Secondary air is supplied tangentially in the cyclone barrel, and overfire air is supplied above the cyclone exit in the PTC furnace, allowing the cyclone to operate with a stoichiometric ratio as low as 0.6. A slag tap in the burner throat allows molten slag to flow into a refractory-lined pot in the bottom of the PTC for later removal.

Solvent Testing System for CO_2 Capture

Numerous CO_2 capture technology evaluations have been conducted in the past 10 years using the PTC system. Testing has been done on selected CO_2 separation and capture technologies to develop key technical and economic information as a function of fuel type and system configuration. The bulk of this work was conducted under the EERC's Partnership for CO_2 Capture (PCO_2C) Program and counted among its partners some of the leading companies in the area of CO_2 capture.

The system, shown in Figure A-2, consists of three stainless steel (SS) 10-in.-diameter packed columns, two of which are absorbers and the third a solvent regenerator (stripper) column. The absorber columns are designed for maximum flexibility. Column height can be adjusted to meet the residence time needs of a particular solvent. Both random and structured packing are available and can easily be changed. When two absorbers are required, the columns are operated in series. A water wash column with a demister is used to monitor solvent slip and prevent entrainment of solvent in the exhaust stream. This arrangement also enables the impact of intermediate solvent cooling on technology performance to be determined. The entire system is highly instrumented to permit tight control and accurate, precise measurement of parameters. The columns are designed to handle a maximum of 249 kg/hr (550 lb/hr or 130 scfm) of flue gas generated by the EERC combustion systems.

The absorbers treat the flue gas in series, with the gas flowing from the bottom to the top of each column. The absorber columns combine to run in series, effectively doubling the total absorber packing height when compared to the single-column configuration. Total combined packing height for the absorber columns is 7.6 m (25 ft). A single absorption column can be run independently. Each column is instrumented with a series of thermocouples along its length. Both absorber columns also use a SS mesh demister in the top section to reduce solvent carryover with the flue gas.

Two heat exchanger sections are available to mitigate exothermic reaction within the columns. One heat exchanger is a 0.3-m (1-ft)-long liquid-cooled shell-and-tube and the other heat exchanger is a 0.6-m (2-ft) shell-and-tube section, primarily used to cool the gas exiting the column, helping to drop out any liquid that might otherwise be carried overhead.

Figure A-2. Carbon capture system.

The stripping column is a single 6.40-m (21-ft), 10-in.-i.d. stripping column. The column is instrumented with a series of thermocouples along its length. A piece of SS expanded mesh supports approximately 3.96 m (13 ft) of Koch–Glitsch IMTP 25 316L SS packing in the column. A custom-made liquid distribution plate rests on top of the packing below the rich solvent inlet. A demister is located inside the top section of the column. A back-pressure control valve is installed on the product gas line downstream of the reflux collection tank.

The capture system uses two cross-flow heat exchangers for solvent flow. One serves as the main heat exchange between rich and lean solvents, and the other is a smaller secondary cooler for the lean solvent stream before entering the absorber. Both are plate-and-frame-style heat exchangers manufactured by Tranter, with all 316 SS wetted surfaces. The cross-flow heat exchanger between lean and rich solvent streams has a heat-transfer area of 18.13 m^2 (195.2 ft^2). The typical approach temperature of this exchanger is 10°–12°C (18°–22°F). The lean cooler heat exchanger is used intermittently during testing to regulate temperature at the top of the absorber column.

The primary heat exchanger for regeneration energy input is a shell-and-tube-style heat exchanger manufactured by Weldon, Inc. The unit is operated with steam on the shell side and the process solvent on the tube side, running countercurrently to each other. Wetted parts on the heat exchanger are 304L SS. There are 28 tubes at 1.6-cm (5/8-in.) outside diameter (o.d.) × 18 BWG (Birmingham wire gauge). The shell is 178 cm (5 ft 10 in.) in length and 16 cm (6-5/16 in.) in diameter, with a wall thickness of 0.34 cm (0.134 in.). A secondary heat exchanger on the steam reboiler loop is a FlatPlate™ heat exchanger. This heat exchanger is water-cooled and ensures the steam fully condenses before manual condensation collection measurements.

Steam is provided by the University of North Dakota (UND) steam plant at approximately 9 bar (130 psig). Steam pressure can be reduced with a sliding-gate pressure regulator. Spot checks of steam flow are also conducted by measuring condensate flow from the system.

Magnetic-drive gear pumps are installed for rich and lean solvent streams. The gear pumps allow solvent flow rates as low as 1.1 lpm (0.3 gpm). Each pump is pressure-restricted by a valve installed downstream of the pump, reducing the possibility of cavitation in the pump head. The reboiler pump is a centrifugal pump. Each pump is driven by its own variable-frequency drive (VFD) which is controlled through the operation system user interface either manually or with an automatic PID (proportional integral derivative) control loop.

Magnetic flowmeters monitor rich solvent flow, intermediate rich solvent flow, and reboiler heater loop solvent flow. The existing solvent flowmeter measuring lean flow from the stripper to the top absorber column is a Coriolis flowmeter.

Solvent filters are used upstream of the lean pump and both rich pumps. A fourth filter is in place downstream of the reboiler pump. The filters are 100-μm cotton-wound cartridges on a 304 SS perforated support. Filters are replaced between each test run. The system can be run with the filters removed.

Data Generation

A vast amount of data are logged during operation of the pilot-scale unit. All data are logged to a computer at a user-defined interval that can be changed. Most information related to the operation of the combustion unit is logged at the combustor control station. Data related to the operation of the CO_2 capture system are logged at the capture system control station. The two systems are independent; therefore, the time stamps from both systems will not be precisely identical. The following pages give an example of the information that is collected.

Combustion System Data Log

Parameter	Units
Date	mm/dd/yyyy
Time	hh:mm:ss
Ambient Temperature	°F
Barometric Pressure	in. Hg
Air Preheater Temperature	°F
Precombustion Air Temperature	°F
Primary Air	
Temperature	°F
Static Pressure	in. W.C.
Differential Pressure	in. W.C.
Gas Flow	scfm
Secondary Air	
Temperature	°F
Static Pressure	in. W.C.
Differential Pressure	in. W.C.
Gas Flow	scfm
Primary Air + Fuel Temperature	°F
Excess Air	%
Combustor Static Pressure	in. W.C.
Combustor Outlet Temperature	°F
Combustor Exit Gas Composition	
CO_2	%
O_2	%
CO	ppm
SO_2	ppm
NO_x	ppm
ESP Flue Gas Inlet Temperature	°F
ESP Flue Gas Outlet Temperature	°F
ESP Voltage	kilovolt
Wet Scrubber Inlet Temperature	°F
Wet Scrubber Outlet Temperature	°F
Wet Scrubber Tank Temperature	°F
Wet Scrubber Differential Pressure	in. W.C.
CO_2 System Bypass	% open
Direct-Contact Cooler Inlet Temperature	°F
Direct-Contact Cooler Inlet Flow Differential Pressure	in. W.C.
Direct-Contact Cooler Inlet Flow Static Pressure	in. W.C.
Direct-Contact Cooler Inlet Gas Flow	scfm
Direct-Contact Cooler Outlet Temperature	°F
CO_2 Absorber Inlet	
Orifice Temperature	°F
Static Pressure	in. W.C.

Continued. . .

Combustion System Data Log (continued)

Parameter	Units
Differential Pressure	in. W.C.
Gas Flow	scfm
Gas Composition	
CO_2	%
O_2	%
CO	ppm
SO_x	ppm
NO_x	ppm
CO_2 System Outlet	
Orifice Temperature	°F
Static Pressure	in. W.C.
Differential Pressure	in. W.C.
Gas Flow	scfm
Gas Composition	
CO_2	%
O_2	%
CO	ppm
SO_x	ppm
NO_x	ppm
Date	mm/dd/yyyy
Time	hh:mm:ss
Flue Gas Flow	scfm
System Inlet Differential Pressure	in. W.C.
Absorber Column 1	
Lean Solvent to Absorber Inlet	°F
Inlet Gas Temperature	°F
Top-of-Column Temperature	°F
Upper Intermediate-Column Temperature	°F
Lower Intermediate-Column Temperature	°F
Bottom-of-Column Temperature	°F
Reservoir Level Indicator	in.
Rich Pump Return Output	%
Rich Liquid Flow	gpm
Column Inlet Pressure	in. W.C.
Column Static Pressure	in. W.C.
Absorber Intercolumn Gas Temperature	°F
Absorber Intercolumn Lean Solvent to Cooler Temperature	°F
Absorber Intercolumn Lean Solvent to Absorber 2 Temperature	°F

Continued…

CO_2 Capture System Log

Parameter	**Units**
Absorber Column 2	
Bottom Temperature	°F
Lower-Column Temperature	°F
Intercolumn Tube-and-Shell Heat Exchanger Inlet	°F
Intercolumn Tube-and-Shell Heat Exchanger Outlet	°F
Intermediate-Column Temperature	°F
Upper-Column Temperature	°F
Column-Top Temperature	°F
Level Indicator	in.
Rich Pump Control Output	%
Column Differential Pressure	in. W.C.
Offgas Pressure	psig
Offgas Flow	psig
Outlet Gas Temperature	°F
Rich Solvent-to-Heat Exchanger Temperature	°F
Rich Solvent-from-Heat Exchanger Temperature	°F
Rich Solvent-to-Stripper Inlet Temperature	°F
Rich Pump Return	%
Rich Solvent Flow	gpm
Stripper Column	
Bottom Temperature	°F
Lower-Column Temperature	°F
Lower Intermediate-Column Temperature	°F
Upper Intermediate-Column Temperature	°F
Upper-Column Temperature	°F
Top-of-Column Temperature	°F
Overheads-to-Condenser Temperature	°F
Column Level Indicator	in.
Column Pressure	psig
Control Output	%
Boilup Temperature	°F
Control Output	%
Condenser Cooling Water Flow	gpm
Vortex Flow	scfm
Coriolis Gas Flow	scfm
Coriolis Density	lb/gal
Coriolis Flow	gpm
Reflux	
Reflux to Stripper Temperature	°F
Drum Level Indicator	in.
Control Output	%
Liquid Flow	gpm
Pump Return	%

Continued…

CO_2 Capture System Log (continued)

Parameter	Units
Condenser Out Temperature	°F
Cooling Water-to-Condenser Temperature	°F
Cooling Water-from-Condenser Temperature	°F
Cooling Water-from-Lean Cooler Temperature	°F
Lean Solvent-to-Reboiler Feed Temperature	°F
Lean Solvent-to-Heat Exchanger Temperature	°F
Lean Solvent-from-Heat Exchanger Temperature	°F
Lean Solvent-to-Lean Cooler Temperature	°F
Lean Pump Return	%
Lean Solvent Flow	gpm
Lean Cooler Flow	gpm
Lean Solvent Pump Control Output	%
Reboiler	
Steam-to-Reboiler Temperature	°F
Condensate-from-Reboiler Temperature	°F
Pump Return	%
Steam Flow	lb/hr
Feed Flow	gpm
Steam Control Output	%
Control Output	%
Condensate Control Output	%
Water Wash Column	
Gas Inlet Temperature	°F
H_2O Inlet Temperature	°F
Gas Outlet Temperature	°F
H_2O Outlet Temperature	°F
Differential Pressure	in. W.C.
Liquid Flow	gpm
Level Indicator	in.
Pump Control Output	%
Pump Return	%
Cooling Control Output	%
Capture System Outlet Differential Pressure	in. W.C.

APPENDIX C

LETTERS OF SUPPORT AND LETTERS OF COMMITMENT

EERC
Energy & Environmental Research Center®
Putting Research into Practice

University of North Dakota
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www.undeerc.org

June 30, 2017

Ms. Karlene Fine
Executive Director
North Dakota Industrial Commission
600 East Boulevard Avenue
State Capitol, 14th Floor
Bismarck, ND 58505-0840

Dear Ms. Fine:

Subject: Cost Share for EERC Proposal No 2017-0102, Entitled "Project Carbon"

The Energy & Environmental Research Center (EERC) is conducting complementary research and development efforts under a multimillion-dollar 5-year Cooperative Agreement with the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) entitled "Joint Program on Research and Development for Fossil Energy-Related Resources." Through this joint program, nonfederal entities can team with the EERC and DOE in projects that address the goals and objectives of DOE's Office of Fossil Energy.

The proposed project to the North Dakota Industrial Commission (NDIC) Lignite Research Program entitled "Project Carbon" is a viable candidate for funding under this program. Therefore, the EERC intends to secure $2,500,000 of cash cost share for the proposed project through its Cooperative Agreement with DOE providing that NDIC commits $3,200,000 of cash cost share. In addition, Minnkota Power Cooperative, Inc., and ALLETE each will provide $250,000 in cash and $250,000 of in-kind contribution. The remaining $6,000,000 will be sought through an anticipated DOE funding opportunity announcement (FOA).

The EERC has already submitted the proposal to DOE (for the $2,500,000) and has received favorable feedback. Proposals submitted to DOE under this program receive expeditious consideration, and success rate is traditionally very high. However, there is no guarantee of approval.

As a cosponsor of the project, DOE would require access to all data generated and a royalty-free right to practice. However, certain project details can often be held confidential for some period of time.

Initiation of the proposed work is contingent upon the execution of a mutually negotiated agreement between EERC and each of the project sponsors.

If you have any questions, please contact me by phone at (701) 777-5157 or by e-mail at jharju@undeerc.org.

Sincerely,

John A. Harju
Vice President for Strategic Partnerships

JAH/kal

Allan S. Rudeck, Jr., President

Wade Boeshans, President & General Manager - BNI

June 29, 2017

Mr. Jason Laumb
Principal Engineer, Coal Utilization Group Lead
University of North Dakota
Energy & Environmental Research Center
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

Subject: EERC Proposal No. 2017-0102, "Project Carbon"

Dear Mr. Laumb:

This letter is in response to the Energy & Environmental Research Center's (EERC's) request for participation in the subject proposed project for which a proposal is being submitted to the North Dakota Industrial Commission (NDIC).

ALLETE is committed to working as an industry lead to develop a lignite-based post-combustion carbon capture project in continued support of the team comprised of ALLETE, Minnkota Power Cooperative, Mitsubishi Heavy Industries (MHI), Burns & McDonnell, DOE, NDIC, the Lignite Energy Council (LEC), and the EERC. The proposed effort will build off of a road map for the development of post-combustion carbon capture technology created by the project team.

ALLETE is pleased to offer support to the proposed program in the form of cash cost share of $250,000 and an additional in-kind amount of $250,000. It is understood that ALLETE's funding for this project will provide cost share to DOE; therefore, ALLETE hereby certifies that its cost-share funding will be comprised of funding received from nonfederal sources and will not be used as federal match on any other project.

We are confident that NDIC can support this project, as there is a significant need for development of post-combustion carbon capture with lignite for the industry in North Dakota, across the U.S., and throughout the world. Again, we express our support of the proposed project and look forward to working with NDIC, LEC, MHI, Minnkota Power Cooperative, Burns & McDonnell, DOE, the EERC, and other participants on this project.

Sincerely,

Allan S. Rudeck, Jr.
President
ALLETE Clean Energy

Wade Boeshans
President & General Manager
BNI Energy

Minnkota Power COOPERATIVE
A Touchstone Energy® Cooperative

PO Box 13200
Grand Forks, ND 58208-3200
1822 Mill Road
Grand Forks, ND 58203
Phone 701.795.4000
www.minnkota.com

June 26, 2017

Mr. Jason Laumb
Principal Engineer, Coal Utilization Group Lead
University of North Dakota
Energy & Environmental Research Center
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

Subject: EERC Proposal No. 2017-0102, "Project Carbon"

Dear Mr. Laumb:

On behalf of Minnkota Power Cooperative, Inc., this letter expresses our support for the subject Energy & Environmental Research Center (EERC) proposed project for which a proposal is being submitted to the North Dakota Industrial Commission (NDIC).

Minnkota is a not-for-profit electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. Formed in 1940, Minnkota provides wholesale electric energy to 11 member-owned distribution cooperatives located in eastern North Dakota and northwestern Minnesota under contractual relationships that extend through 2055. In addition, Minnkota serves as the operating agent for the Northern Municipal Power Agency ("NMPA"), a municipal joint action agency that serves as an energy supplier for 12 municipal utilities located within the Minnkota service area. In total, the Minnkota/NMPA "Joint System" provides electricity to more than 143,000 residential and commercial member consumers spanning over 34,500 square miles.

Considering the nature and length of our obligation to meet the needs of our member owners, Minnkota is keenly interested in continuing to assess and develop new technologies and solutions to support the lignite industry. There is a significant need for development of postcombustion carbon capture for the future of the industry in North Dakota. This proposal shows promise for our industry and our company.

Minnkota is pleased to offer support to the proposed program in the form of cash cost share of $250,000, and in-kind cost share of an additional $250,000. It is understood that Minnkota's funding for this project will provide cost share to DOE; therefore, Minnkota hereby certifies that its cost-share funding comprises funding received from nonfederal sources and will not be used as federal match on any other project.

We have confidence that the North Dakota Industrial Commission can support this project, as there is a significant need for development of postcombustion carbon capture with lignite for the industry in North Dakota. Again, we express our support of the proposed project and look forward to working with the North Dakota Industrial Commission, the Department of Energy, the Lignite Energy Council, Mitsubishi Heavy Industries, Burns & McDonnell, ALLETE, the EERC, and other participants on this project.

Sincerely,

Craig J. Bleth

Craig J. Bleth
Environmental Manager

APPENDIX D

BUDGET JUSTIFICATION

BUDGET JUSTIFICATION

ENERGY & ENVIRONMENTAL RESEARCH CENTER (EERC)

BACKGROUND

The EERC is an independently organized multidisciplinary research center within the University of North Dakota (UND). The EERC is funded through federal and nonfederal grants, contracts, and other agreements. Although the EERC is not affiliated with any one academic department, university faculty may participate in a project, depending on the scope of work and expertise required to perform the project.

INTELLECTUAL PROPERTY

The applicable federal intellectual property (IP) regulations will govern any resulting research agreement(s). In the event that IP with the potential to generate revenue to which the EERC is entitled is developed under this project, such IP, including rights, title, interest, and obligations, may be transferred to the EERC Foundation, a separate legal entity.

BUDGET INFORMATION

The proposed work will be done on a cost-reimbursable basis. The distribution of costs between budget categories (labor, travel, supplies, equipment, etc.) and among funding sources of the same scope of work is for planning purposes only. The project manager may incur and allocate allowable project costs among the funding sources for this scope of work in accordance with Office of Management and Budget (OMB) Uniform Guidance 2 CFR 200.

Escalation of labor and EERC recharge center rates is incorporated into the budget when a project's duration extends beyond the university's current fiscal year (July 1 – June 30). Escalation is calculated by prorating an average annual increase over the anticipated life of the project.

The cost of this project is based on a specific start date indicated at the top of the EERC budget. Any delay in the start of this project may result in a budget increase. Budget category descriptions presented below are for informational purposes; some categories may not appear in the budget.

Salaries: Salary estimates are based on the scope of work and prior experience on projects of similar scope. The labor rate used for specifically identified personnel is the current hourly rate for that individual. The labor category rate is the average rate of a personnel group with similar job descriptions. Salary costs incurred are based on direct hourly effort on the project. Faculty who work on this project may be paid an amount over the normal base salary, creating an overload which is subject to limitation in accordance with university policy. As noted in the UND EERC Cost Accounting Standards Board Disclosure Statement, administrative salary and support costs which can be specifically identified to the project are direct-charged and not charged as facilities and administrative (F&A) costs. Costs for general support services such as contracts and IP, accounting, human resources, procurement, and clerical support of these functions are charged as F&A costs.

Fringe Benefits: Fringe benefits consist of two components which are budgeted as a percentage of direct labor. The first component is a fixed percentage approved annually by the UND cognizant audit agency, the Department of Health and Human Services. This portion of the rate covers vacation, holiday, and sick leave (VSL) and is applied to direct labor for permanent staff eligible for VSL benefits. Only the actual approved rate will be charged to the project. The second component is estimated on the basis of historical data and is charged as actual expenses for items such as health, life, and unemployment insurance; social security; worker's compensation; and UND retirement contributions.

Travel: Travel may include site visits, fieldwork, meetings, and conferences. Travel costs are estimated and paid in accordance with OMB Uniform Guidance 2 CFR 200, Section 474, and UND travel policies, which can be found at http://und.edu/finance-operations (Policies & Procedures, A–Z Policy Index, Travel). Daily meal rates are based on U.S. General Services Administration (GSA) rates unless further limited by UND travel policies;

other estimates such as airfare, lodging, ground transportation, and miscellaneous costs are based on a combination of historical costs and current market prices. Miscellaneous travel costs may include parking fees, Internet charges, long-distance phone, copies, faxes, shipping, and postage.

Equipment: Several pieces of equipment are needed to accomplish the scope of work for this project. A portable FTIR (Fourier transform infrared) for gas analysis to provide real-time analysis of constituents of interest in the flue gas will be purchased as well as a Dekati 13-stage impactor for the measurement of fine aerosol. A combustion gas analyzer rack will also be purchased to measure flue gas chemistry. Additionally, for the integration of the test systems at the host site and to minimize the impact to the facility, a steam generator will be purchased. Along with these items, a Mobile CO_2 Sequestration System will be fabricated in order to complete testing at the host site. Some of the components included in this system are suitable piping, process controls, heaters, pumps, heat exchangers, wiring, and frame supports. Estimates are based on quotes and prior experience.

Supplies: Supplies include items and materials that are necessary for the research project and can be directly identified to the project. Supply and material estimates are based on prior experience with similar projects. Examples of supply items are chemicals, gases, glassware, spill containments, fittings, lubricants, IMPLAN Dataset, filter materials, data acquisition computer and software, controllers, scaffolding, nuts, bolts, piping, data storage, paper, memory, software, toner cartridges, maps, sample containers, minor equipment (value less than $5000), signage, safety items, subscriptions, books, and reference materials. General purpose office supplies (pencils, pens, paper clips, staples, Post-it notes, etc.) are included in the F&A cost.

Subrecipient – Mitsubishi Heavy Industries (MHI): MHI will work with EERC staff to design and modify the current reactor prior to the pilot- and slipstream evaluations. MHI will provide a new proprietary demister section for the absorber column to replicate MHI technology. MHI will also aid in the amine-testing portion of Project 1, as well as the pre-FEED analysis in Project 2.

Subrecipient – Burns & McDonnell: Burns & McDonnell will participate in the pre-FEED study in Project 2, with a focus on integration of the systems with Milton R. Young Station facilities.

Professional Fees: Not applicable.

Communications: Telephone, cell phone, and fax line charges are included in the F&A cost; however, direct project costs may include line charges at remote locations, long-distance telephone charges, postage, and other data or document transportation costs that can be directly identified to a project. Estimated costs are based on prior experience with similar projects.

Printing and Duplicating: Page rates are established annually by the university’s duplicating center. Printing and duplicating costs are allocated to the appropriate funding source. Estimated costs are based on prior experience with similar projects.

Food: Expenditures for project partner meetings where the primary purpose is dissemination of technical information may include the cost of food. The project will not be charged for any costs exceeding the applicable GSA meal rate. EERC employees in attendance will not receive per diem reimbursement for meals that are paid by project funds. The estimated cost is based on the number and location of project partner meetings.

Professional Development: Fees are for memberships in technical areas directly related to work on this project. Technical journals and newsletters received as a result of a membership are used throughout the development and execution of the project by the research team.

Operating Fees: Operating fees generally include EERC recharge centers, outside laboratories, and freight.

EERC recharge center rates are established annually.

Laboratory and analytical recharge fees are charged on a per-sample, hourly, or daily rate. Additionally, laboratory analyses may be performed outside the university when necessary. The estimated cost is based on the test protocol required for the scope of work.

Graphics recharge fees are based on an hourly rate for production of such items as report figures, posters, and/or images for presentations, maps, schematics, Web site design, brochures, and photographs. The estimated cost is based on prior experience with similar projects.

Shop and operations recharge fees cover specific expenses related to the pilot plant and the required expertise of individuals who perform related activities. Fees may be incurred in the pilot plant, at remote locations, or in EERC laboratories whenever these particular skills are required. The rate includes such items as specialized safety training, personal safety items, fall protection harnesses and respirators, CPR certification, annual physicals, protective clothing/eyewear, research by-product disposal, equipment repairs, equipment safety inspections, and labor to direct these activities. The estimated cost is based on the number of hours budgeted for this group of individuals.

Outside Laboratory: An outside laboratory will be utilized to provide and analyze flue gas sampling resins for the determination of amine slip and other solvent degradation products during pilot and slipstream testing. These are components and analysis that the EERC does not perform in-house. Estimate is based on past history and a verbal quote.

Freight expenditures generally occur for outgoing items and field sample shipments.

Facilities and Administrative Cost: The F&A rate proposed herein is approved by the U.S. Department of Health and Human Services and is applied to modified total direct costs (MTDC). MTDC is defined as total direct costs less individual capital expenditures, such as equipment or software costing $5000 or more with a useful life of greater than 1 year, as well as subawards in excess of the first $25,000 for each award.

Cost Share: Cash cost share will be provided by the U.S. Department of Energy National Energy Technology Laboratory, through the Energy & Environmental Research Center's cooperative agreement in the amount of $2,500,000. An additional $6,000,000 is anticipated from DOE NETL through a successful response to a funding opportunity announcement. Industry partners will provide $500,000 of cash cost share and $500,000 of in-kind. Industry partners include ALLETE Clean Energy and Minnkota Power Cooperative.

BURNS McDONNELL

June 28, 2017

Mr. Jason D. Laumb
Principal Engineer
Coal Utilization
Energy & Environmental Research Center
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

Statement of Interest to Provide Professional Engineering Services
Project Carbon

Dear Jason:

Burns & McDonnell is interested in supporting EERC and Minnkota Power during the carbon capture demonstration project at the Milton R. Young Generating Station. We understand that help with a pre-FEED analysis will be one of the first tasks.

Potential Scope of Services

Some of the services that Burns & McDonnell have proposed in previous carbon capture efforts at MRY outside of the MHI technology island include the following:

1. Perform plant site visits to coordinate design and to obtain existing information and drawings.
2. Estimate preliminary utility requirements to support Balance of Plant (BOP) equipment.
3. Determine BOP interconnection requirements:
    a. Flue gas supply and return.
    b. Steam supply and condensate return.
    c. Electrical power supply.
    d. Process water.
    e. Cooling water.
4. Develop Major Equipment List (MEL).
5. Prepare conceptual design drawings:
    a. General arrangement drawing incorporating MHI major equipment.
    b. BOP drawings for major mechanical and electrical systems.
    c. Major piping and electrical route drawings.
    d. Electrical one-line diagrams.
    e. Process flow diagrams.
6. Perform plant/system impact studies:
    a. Screening level performance assessment to estimate capacity and heat rate impacts of carbon capture implementation. This evaluation will be spreadsheet based. Heat balance software models are excluded.
    b. ID Fan impact study.
    c. Flue gas chimney impact study.

7. Identify and prepare list of potential risks and items that may prevent the project from being viable.
    a. Impacts to MRY2 plant operations, and plant performance (heat rate and output) due to process steam extraction and process auxiliary electrical load will be determined.
8. Develop top-down, screening-level cost estimate.
9. Prepare a Level 1 schedule for implementing project from development thru commercial operation.

Compensation

EERC has mentioned a potential budget of $250,000 for Burns & McDonnell services. The Scope of Services is yet to be defined. The final budget will be negotiated at the time the Scope of Services is defined.

Commercial

Burns & McDonnell proposes to perform the Scope of Services in accordance with the attached TERMS AND CONDITIONS FOR PROFESSIONAL SERVICES.

Thank you for the opportunity to assist EERC with Project Carbon. If you have any questions regarding this discussion, please contact me at 816-822-3023.

Sincerely,

Ron Bryant

Ron Bryant, P.E.
Principal, Energy
Burns & McDonnell Engineering Company, Inc.

MITSUBISHI HEAVY INDUSTRIES AMERICA, INC.
Environmental & Chemical Plant Division
20 Greenway Plaza Suite 600 Houston, TX 77046 Tel: (713)-351-6400 Fax: (713)-351-6450•

May 31, 2017

Mr. Jason Laumb
Principal Engineer, Coal Utilization Group Lead
University of North Dakota
Energy & Environmental Research Center
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

Subject: EERC Proposal No. 2017-0129, "Barriers to the Implementation of Postcombustion Carbon Capture"

Dear Mr. Laumb:

This letter is in response to the Energy & Environmental Research Center's (EERC) request for participation in the proposed project entitled "Barriers to the Implementation of Postcombustion Carbon Capture," a proposal being submitted to the U.S. Department of Energy (DOE).

Mitsubishi Heavy Industries America, Inc., ("MHIA") a wholly-owned subsidiary of Mitsubishi Heavy Industries, Ltd. of Japan ("MHI"), is pleased to join the project as a sub-recipient participating in pilot and slipstream amine testing and sampling activities. MHIA's scope of work will include test planning and amine emission measurements, evaluation and report for the KM-CDR Process™ during two weeks of pilot campaigns and one week at the Milton R Young slipstream site, as part of EERC's broader testing effort. Note most of this work will be performed by MHI as a sub-contractor to MHIA.

In addition to supports for the testing activities as described above, MHI and MHIA will support the design modification to the EERC's carbon capture system. MHI and MHIA engineers will work closely with EERC staff to ensure that the capture system closely resembles that which will be deployed in a commercial application.
We have confidence that the DOE can support this project, as there is a significant need for development of post combustion carbon capture with lignite for the industry in North Dakota. Again, we express our support of the proposed project and look forward to working with NDIC, LEC, Minnkota Power Cooperative, Allete Clean Energy, DOE, EERC and other participants on this project.

Sincerely,

Timothy Thomas
Vice President and Deputy General Manager
Direct: (713) 351-6402

APPENDIX E

REFERENCES

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