Front-End Engineering and Design: Project Tundra Carbon Capture System

primary project goal

Minnkota Power Cooperative is performing a front-end engineering and design (FEED) study to install a post-combustion carbon dioxide (CO_2) capture system at Square Butte Electric Cooperative's Milton R. Young Station, Unit 2 (MRY2), located near Center, North Dakota. Based on the results of pre-FEED studies of two leading commercial-ready carbon capture technologies, Fluor's Econamine FG Plus[SM] (EFG+) technology has been selected for installation.

technical goals

- Complete a FEED study for constructing the carbon capture system at MRY2, including balance of plant (BOP).
- Address final challenges to implementing CO_2 capture with studies to optimize plant efficiency.
- Finalize a permitting strategy for the overall project.
- Evaluate environmental, health, and safety (EH&S) concerns and mitigation approaches.
- Conduct a hazard and operability (HAZOP) review.
- Complete a FEED-level cost estimate and construction schedule.

technical content

Minnkota is executing a FEED study on the addition of Fluor's EFG+ technology to an existing power plant fueled by North Dakota lignite to deliver the engineering and design work needed to demonstrate the feasibility of a next-generation carbon capture system technology at world-scale. The FEED comprises a broader effort led by Minnkota, titled Project Tundra, which is an initiative to build the world's largest carbon capture facility in North Dakota and to implement carbon capture, utilization, and storage (CCUS) to preserve the use of lignite, support the CO_2 enhanced oil recovery (EOR) industry, and revitalize legacy oil fields.

The project team aims to substantiate the economics and engineering supporting the business case for construction and operation of Fluor's EFG+ technology to capture 90% (11,000 tonnes/day) of the CO_2 from the flue gas of the 477-megawatt-electric (MWe) MRY2, producing near "zero carbon" power with limited or no impact on the price of electricity.

Fluor's EFG+ technology is an advanced amine-based process tailored for removal of CO_2 from low-pressure, high-oxygen-containing flue gas (up to 15 vol%) and is used in more than 30 commercial plants worldwide to process flue gases derived from a variety of fuels. The basic plant configuration consists of a two-stage direct contact cooler (DCC) for flue gas cooling and sulfur dioxide (SO_2) removal, an absorber, a regenerator, and a compression and dehydration system to generate pipeline-ready CO_2, as shown in Figure 1. As the conditioned flue gas flows up the absorber, CO_2 is chemically absorbed into a circulating solvent stream flowing down the column. The CO_2-loaded solvent is then pumped from the bottom of the absorber, through a heat recovery exchanger where it is heated against hot

program area:
Point Source Carbon Capture

ending scale:
FEED

application:
Post-Combustion Power Generation PSC

key technology:
Solvents

project focus:
Econamine FG Plus Retrofit to Coal-Fired Power Plant

participant:
Minnkota Power Cooperative Inc.

project number:
FE0031845

predecessor project:
N/A

NETL project manager:
Andrew O'Palko
andrew.opalko@netl.doe.gov

principal investigator:
Gerry Pfau
Minnkota Power Cooperative Inc.
gpfau@minnkota.com

partners:
Fluor Enterprises Inc.; Burns & McDonnell; David Greeson Consulting; Hunt International Energy Services; ND Industrial Commission; EERC; Golder Associates; AECOM; Square Butte Electric Cooperative

start date:
10.01.2019

percent complete:
80%

CO_2-lean solvent, and into the top of the regenerator. As the solvent flows down the regenerator, it is contacted by steam, which strips the CO_2 from the solvent, producing an overhead mixture of steam and CO_2. The steam/CO_2 product is cooled, and the steam is condensed and separated from the CO_2 product. Hot CO_2-lean solvent from the bottom of the regenerator is pumped back through the heat recovery exchanger where it is cooled against the cold CO_2-loaded solvent before being returned to the top of the absorber.

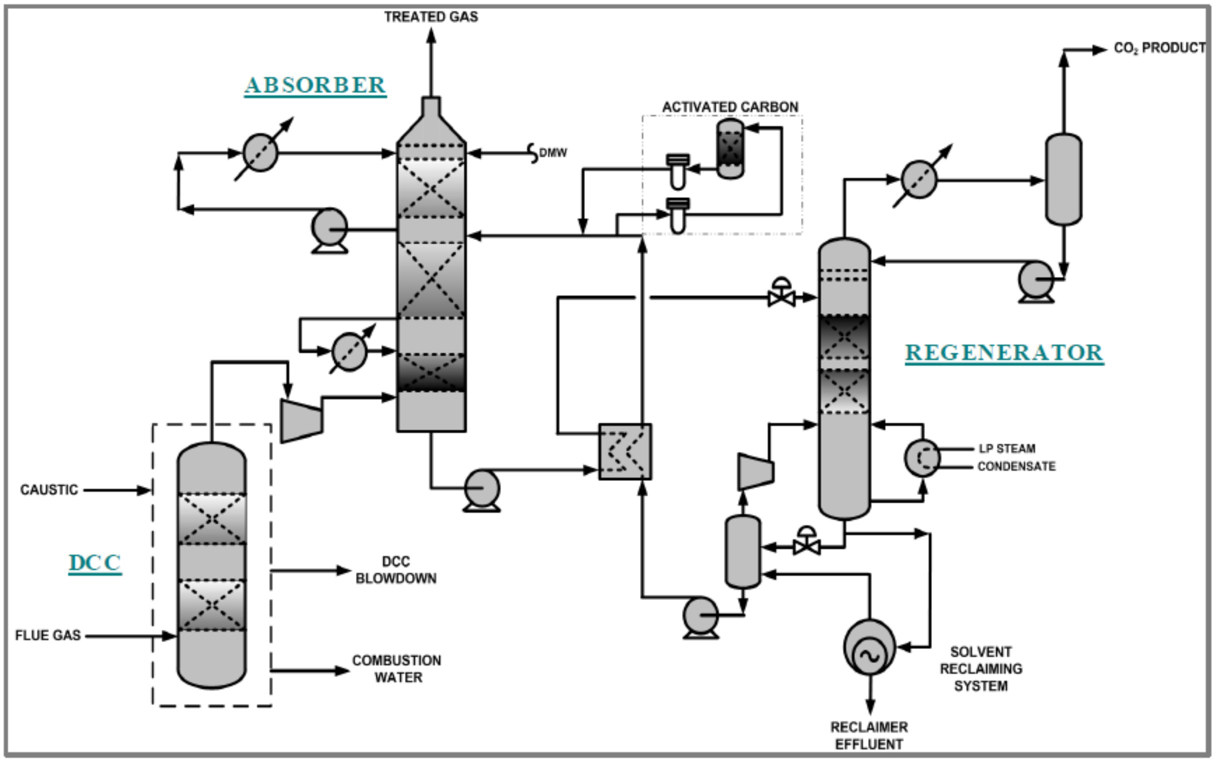

Figure 1: Schematic of Fluor's EFG+ CO_2 capture technology.

Advancements to progress the technology beyond the current state-of-the-art include steam cycle integration with advanced heat recovery to improve energy efficiency; methods for removing aerosols and a unique solvent maintenance system to minimize solvent degradation, thereby improving the environmental and cost profile; design of the world's largest capture facility (3.6 million tonnes/year, a twofold increase over any other facility) to capture greater economies of scale; optimization for cold climate performance; and establishment of the lowest levelized cost of capture attempted at world-scale.

Experience gained from Fluor's EFG+ demonstration plant in Wilhelmshaven, Germany, that captures 70 tonnes of CO_2 per day from a coal-fired power plant has enabled Fluor to make significant improvements to the process. Some of the unique features of the process design include:

- The EFG+ solvent is a proprietary formulation of primary amines with a regeneration steam requirement 30% lower than monoethanolamine (MEA).
- Fluor's patented two-stage DCC treats the flue gas in two sections, cooling the flue gas to harvest quality combustion knock-out water and removing SO_2 to single-digit part per million (ppm) levels.
- Fluor's patented absorber intercooling technology removes heat of absorption to increase the CO_2 carrying capacity of the solvent, reducing the net steam demand of the EFG+ process by 3–5%.
- A lean solvent flash/vapor compression configuration, in which the lean vapor compressor (LVC) recycles residual heat from the hot-lean solvent leaving the regenerator and transfers it back to the regenerator, resulting in a lower steam demand for the reboiler and reducing the total solvent regeneration energy requirement by approximately 10–15%.
- Minimized pressure drop in absorber due to advanced design of internals and packing in the DCC and absorber, thereby reducing the blower power by approximately 65% compared to conventional carbon capture plants.
- A solvent maintenance system (SMS) to remove heat-stable salts (HSSs) and other non-volatile degradation products in order to maintain solvent hygiene and performance.

Prior successful installations of the EFG+ process at a variety of facilities worldwide has prepared the project team for addressing new challenges, including processing a higher flue gas volume, effects from cold climate, and aerosols/solvent degradation concerns with using lignite coal-based flue gas.

The project team previously conducted a pre-FEED study to determine constructability, tie-in locations, preliminary pipe routings and interfaces, electrical interconnections, equipment specifications, capture system power requirements, geotechnical details, and control design. These components form the basis of the full FEED study, which will result in the following multidisciplinary design package:

- A FEED study report along with an electronic 3D model in SmartPlant® 3D.
- Material takeoffs (MTOs) exported from the 3D model for large-bore pipe lengths, fittings, flanges, valves, raceway, cables, and instrumentation; structural steel and concrete takeoffs developed from structural design software and sketches.
- An optimized general arrangement drawing.
- A tie-in list and location plan, with input from construction specialists during the detailed design phase; updates to process and instrumentation diagrams (P&IDs) with tie-in information.
- Detailed specifications for the major equipment packages.
- A Level 2 Process Hazard Analysis (i.e., HAZOP) report utilizing the overall P&IDs.
- A steam supply design.
- A fire protection study in accordance with National Fire Protection Agency codes and standards.
- An instrument control list with inputs and outputs and distributed control system (DCS) points, including cost specifications for all major instrument and control packages.
- Exploratory excavation plans and specifications to verify that proposed foundation and subsurface facilities are clear of obstructions.
- Preliminary foundation sketches to support equipment and ancillaries required for FEED cost estimates.
- Preliminary architectural drawings and sketches to support a cost specification for pre-engineered buildings and heating, ventilation, and air conditioning (HVAC), and obtaining budgetary quotes to support the FEED cost estimate.

Based on the pre-FEED study, a $50/tonne 45Q tax credit for CO_2 storage or a $35/tonne 45Q tax credit for EOR, plus projected CO_2 sales to oil companies for EOR operations, provides enough revenue to cover the capital, return on capital, and plant's operating costs, while yielding a near 10% return to tax equity. In addition, the cost of capture is expected to be $49/tonne CO_2, which is a 20% reduction from the cost of CO_2 capture at the Petra Nova facility, the U.S.'s first commercial post-combustion carbon capture system at a coal-fired power plant. The FEED study is the next step in verifying and optimizing these costs and projections to reflect the higher level of engineering and design and cost-estimating certainty.

For the BOP items, operating cost estimates will be developed through detailed studies involving Fluor, owner's engineer Burns & McDonnell, and Minnkota. Both the operating and capital costs for an EFG+ plant are dependent on a number of variables, including, but not limited to, plant location, site conditions, plant capacity, final configuration, modularization versus field erected, flue gas conditions, air versus water cooling, and cost of utilities such as steam and electricity.

Although the EFG+ technology and the chemistry of the process are the same regardless of scale, the process equipment in the EFG+ process must be designed to ensure that the EFG+ chemistry occurs efficiently. Specifically, the scale-up challenge is construction of large-diameter columns and achieving good gas/liquid distribution in the packing.

As part of the pre-FEED, the team evaluated natural gas-fired auxiliary boiler and steam turbine extraction scenarios. Early stages of the FEED study will choose which steam source will be utilized.

In addition to removing approximately 3.6 million tonnes per year of CO_2, the carbon capture facility installed at MRY2 will also be designed to remove approximately 2,200 tonnes of SO_2 annually. However, significant concentrations of alkali-derived aerosols have been measured at MRY2 during previous studies, which can impact both amine solvent emissions and degradation rates. Also, solvent emissions from the absorber may include ppm levels of amine and degradation byproducts in the form of ammonia and aldehydes. The combination of the aldehydes/amine may constitute a new major source of VOCs, which requires a Title V permit under the Clean Air Act. In the FEED, Fluor will evaluate the cost-effectiveness of solutions for removal of aerosols upstream of the absorber, thereby eliminating/mitigating the challenge of aerosol-exacerbated emissions of amine from the absorber. Preliminary air dispersion modeling was performed in the pre-FEED study to determine appropriate stack height, parameters, and location. In order to confirm that the site will not exceed National Ambient Air Quality Standards (NAAQS), an additional air dispersion model will be required using the final FEED study parameters, emissions, and layout.

An SMS will also be included in the EFG+ plant design for MRY2 to maintain favorable solvent purity and produce a small waste effluent stream that is collected and periodically hauled offsite for disposal. Furthermore, by maintaining low impurity levels in the solvent, undesired VOC emissions are reduced dramatically.

Wastewater produced by the EFG+ plant includes blowdown from the DCC (knock-out water and SO_2 scrubbing solution). The condensed water vapor from cooled flue gas is of high quality and can be used as cooling water makeup at MRY2 after minor treatment. After investigating the compatibility of existing MRY Station wastewater treatment, Minnkota concluded that disposal via a Class I injection well is the likely method of disposal for some of the effluents. The FEED study will include design and costing of a Class I well. The proposed changes will require the MRY2 plant to modify its National Pollutant Discharge Elimination System (NPDES) permit for industrial wastewater discharges.

Any plant constructed in North Dakota requires a winterization plan, as temperatures can reach to -40°C or less. Through the pre-FEED effort, the project team identified best practices for ensuring the plant remains efficient and operational during the winter months, including specifications for building foundation depth, insulation and material specifications, cold process startup/shutdown, and buried fluid lines.

Modularization is a key component of the construction strategy for Project Tundra, which includes a transportation study to determine module size and onsite fabrication requirements. A construction-driven strategy is key to schedule certainty, risk reduction, and cost-effective execution and delivery of the project.

Flue Gas Assumptions – Unless noted, average flue gas pressure, temperature, and composition leaving the flue gas desulfurization (FGD) unit (wet basis) should be assumed as:

Pressure	Temperature	Composition						
		vol%					ppmv	
psia	°F	CO_2	H_2O	N_2	O_2	Ar	SO_X	NO_X
13.5	141	10.2	20.5	65.1	6.9	0.80	42.7	148.3

Parameter Descriptions:

Chemical/Physical Solvent Mechanism – The absorption of CO_2 is a chemical reaction.

Solvent Contaminant Resistance – The solvent has very good resistance to contaminants in the flue gas aided by the solvent maintenance system.

Solvent Foaming Tendency – None.

Flue Gas Pretreatment Requirements – SO_2 removal and temperature control is required prior to the absorber.

Solvent Makeup Requirements – Estimated at 0.25 kg/tonne.

Waste Streams Generated – Solvent maintenance system waste, water treatment waste, and cooling tower blowdown.

Process Design Concept – Flowsheet/block flow diagram shown above in Figure 1.

Proposed Module Design – Will be determined based on results of a logistics/route study.

TABLE 2: POWER PLANT CARBON CAPTURE ECONOMICS

Economic Values	Units	Design Value
Cost of Carbon Captured	\$/tonne CO_2	\$16.60
Cost of Carbon Avoided	\$/tonne CO_2	\$16.60
Capital Expenditures	\$/MW	\$20.54
Operating Expenditures	\$/MWhr	\$22.58
Cost of Electricity	\$/MWhr	\$36.60

Definitions:

Data used:

- Average annual operating expenses (OPEX) for carbon capture system = $16.89/tonne (2025 dollars).
- Average annual CO_2 captured and avoided = 4,071,000 tonnes.
- Capital expenses (CAPEX) to place the capture system into service = $1.488 billion.
- MWe of treated flue gas = 486.5 MWe.
- Total OPEX over 20-year life of project = $1.636 billion.
- Host power plant trailing three-year average (2019–2021) cost of electricity (operations, maintenance, and fuel) = $35.6/MWh.

Cost of Carbon Captured – Projected cost of capture per mass of CO_2 captured under expected operating conditions.

Cost of Carbon Avoided – Projected cost of capture per mass of CO_2 avoided under expected operating conditions.

Capital Expenditures – Projected capital expenditures in dollars per unit of energy produced.

Operating Expenditures – Projected operating expenditures in dollars per unit of energy produced.

Cost of Electricity – Projected cost of electricity per unit of energy produced under expected operating conditions.

Calculations Basis – For this FEED study, the data are based on a specific plant – Minnkota Power Cooperative Milton R. Young Station.

Scale of Validation of Technology Used in TEA – While a formal TEA has not been completed, the economics are based on a full FEED study of a 486.5 MWe sized capture system, which is a scale up from the pilot scale tests at Technology Centre Mongstad.

Qualifying Information or Assumptions:

- Dollar values include escalation at 2%.
- Annual combined (host + carbon capture and storage [CCS]) capacity factor = 85%.
- All costs and production estimates are based on CO_2 delivered to the fence line of the CCS dehydrated and compressed to 1,500 pounds per square inch (psi) (i.e., “pipeline quality” ready for shipment).
- Transport and storage of CO_2 is not included in these numbers.

technology advantages

- Advanced solvent formulation with high CO_2 capacity and high absorption rate.
- Low pressure-drop packing in DCC and absorber has the potential to lower the power consumption for the blower by 65%.
- Large diameter column design for absorber and DCC reduces the number of absorption trains required, thereby lowering capital costs.
- Novel absorber intercooler configuration increases solvent loading and lowers the overall solvent circulation rate, further reducing power consumption and solvent loss.
- An LVC unit reduces the steam demand for solvent regeneration by 10–15%.
- Fluor’s proprietary SMS lowers overall solvent loss and makeup.
- Advanced reclaiming technology significantly reduces reclaimer waste.

R&D challenges

- Lignite coal-based flue gases, such as that produced at MRY2, contain alkali-derived aerosols and particulate matter that can have a detrimental impact on both amine solvent emissions and degradation rates.
- Integration into an existing facility poses many operating and plant layout challenges.

- Maintaining a proper water balance for the facility becomes a challenge.

status

The project team developed an optimized design manual of the carbon capture system, including analyses for integrating the carbon capture system with the plant's steam cycle or utilizing natural gas-fired auxiliary boilers. The gas-fired boilers were selected as the basis for the FEED study. The capture facility was increased in size to accommodate the flue gas from the gas-fired boilers, resulting in the ability to remove approximately 4.0 million tonnes of CO_2 versus the pre-FEED levels of 3.6. The boilers also allowed for additional flexibility in the operation by allowing a tie to the MRY1 unit flue gas duct for operation when MRY2 is offline. Design and integration of the carbon capture system with BOP was completed and a HAZOP review was conducted. Meetings were held with the North Dakota Department of Environmental Quality to discuss the requirements for air emissions and water discharge permitting. An initial permitting strategy was finalized to comply with air, water, and waste product regulations that will support permit applications. Project Tundra cost estimating has been completed, including preparation of a FEED-quality estimate, as well as a schedule for the engineering, procurement, and construction phases of the project. Initial efforts resulted in higher capital cost than anticipated, so a cost reduction effort was initiated to come up with various ideas to reduce costs along with rough estimates. One of the major cost increases was due to refinement of the gas-fired boiler capital and fuel costs. Preliminary efforts were initiated to look at the steam extraction in more detail.

A final report is being prepared, summarizing all project results and analyses and making recommendations for future research and development (R&D). Further refinement of cost-reduction ideas and steam extraction will need to take place outside the scope of this FEED study as the project proceeds.

available reports/technical papers/presentations

"Front-End Engineering & Design: Project Tundra Carbon Capture System," DOE Kickoff Meeting, November 12, 2019. *https://www.netl.doe.gov/projects/plp-download.aspx?id=10890&filename=Front-End+Engineering+%26+Design%3a+Project+Tundra+Carbon+Capture+System.pdf*.

"Front-End Engineering & Design: Project Tundra Carbon Capture System," presented at the 2020 NETL Project Review Meeting - CCUS Integrated Projects, August 17, 2020. *https://netl.doe.gov/sites/default/files/netl-file/20CCUS_Pfau.pdf*

"Front-End Engineering & Design: Project Tundra Carbon Capture System," presented at the 2021 NETL Carbon Management and Oil and Gas Research Project Review Meeting - Integrated CCUS Projects and FEED Studies, August 2, 2021. *https://netl.doe.gov/sites/default/files/netl-file/21CMOG_CCUS_Pfau.pdf*