Front-End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant

primary project goal

Southern Company Services Inc. is conducting a front-end engineering design (FEED) study for a carbon dioxide (CO_2) capture system based on Linde-BASF's aqueous amine solvent-based technology installed at an existing Southern Company natural gas-fired combined cycle (NGCC) power plant. A commercial scale (at least ~375 megawatt-electric [MWe]) CO_2 capture plant is being designed to achieve a high removal of CO_2 from the flue gas feed stream.

technical goals

- Select an NGCC generating plant as the host site for the FEED study based on a set of defined criteria (performance of the gas turbines, availability of space to house a carbon capture system, availability of utilities to support the system, suitability of the surrounding geology for enhanced oil recovery [EOR] or storage).
- Produce a design basis for the carbon capture system based on the specific site requirements, including flue gas composition, environmental requirements, and requirements for modularization.
- Complete a conceptual design package for the process area of the post-combustion capture plant and assess the logistics for solvent delivery required for a commercial-scale carbon capture plant.
- Complete design packages for mechanical, electrical, structural, instrumentation and control, and facilities engineering and assess the cost and logistics for constructability and site security.
- Utilize the cost and schedule estimates of equipment vendors and contractors to derive a total project cost and schedule estimate within ±15% error.

technical content

Linde and BASF have been jointly developing, optimizing, and testing an advanced post-combustion CO_2 capture technology since 2007. The Linde-BASF technology for capturing CO_2 from flue gas using the BASF OASE® blue solvent is a mature technology that has been tested in two pilot plants with different flue gas sources, covering a wide variety of flue gas compositions and impurities. The Linde-BASF aqueous amine solvent-based post-combustion CO_2 capture technology provides a solution for key challenges encountered by solvent-based carbon capture technologies, which include relatively high capital costs, significant parasitic energy requirements, and solvent stability and degradation issues.

The technology is based on a typical lean-rich solvent absorption/regeneration cycle for CO_2 capture, but leverages several key innovative features for both

program area:
Point Source Carbon Capture

ending scale:
FEED

application:
Post-Combustion Power Generation PSC

key technology:
Solvents

project focus:
Linde-BASF Amine Solvent-Based Technology Retrofit to NGCC Plant

participant:
Southern Company Services Inc.

project number:
FE0031847

predecessor projects:
N/A

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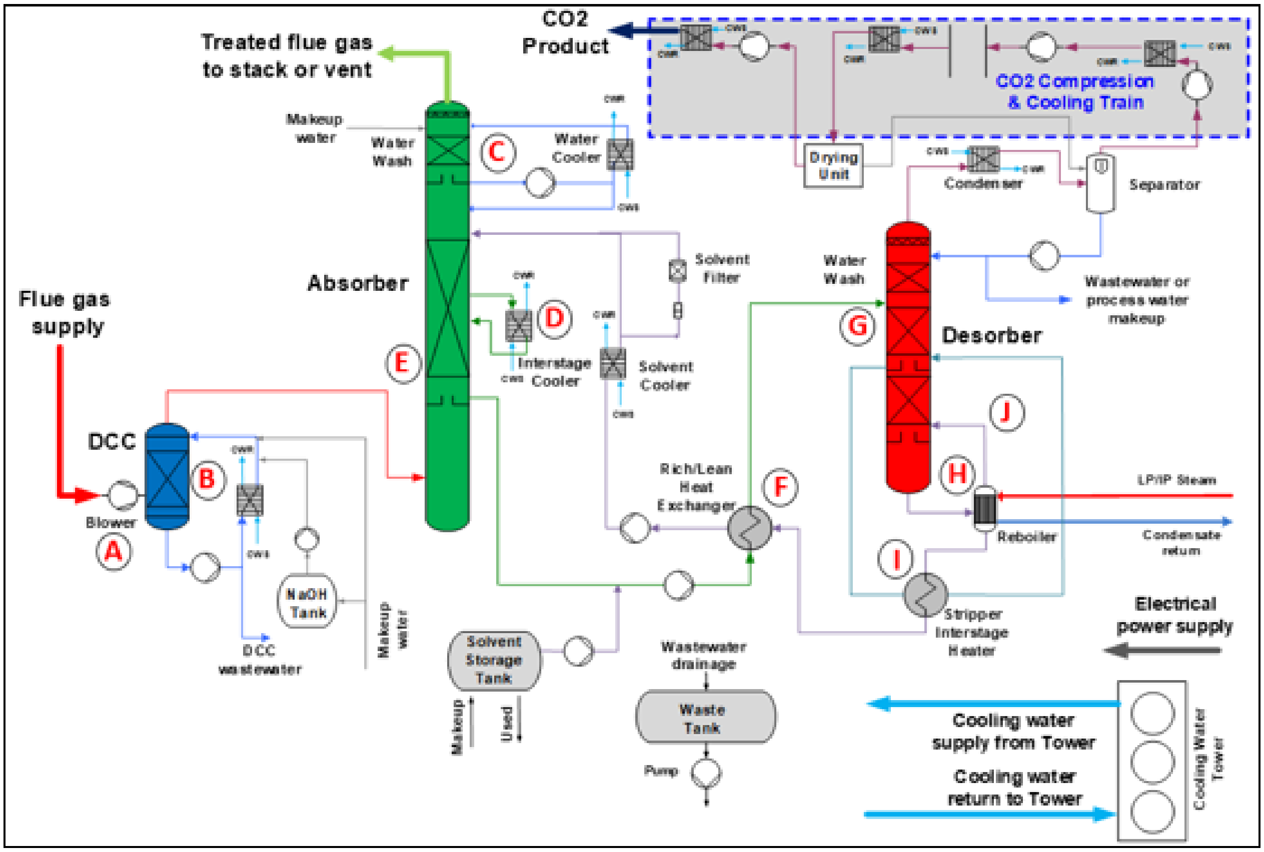
start date:
01.29.2020

percent complete:
90%

solvent and process optimization to reduce the cost of CO_2 capture from NGCC plants. The optimized properties of the OASE blue solvent led to capital and operating cost reduction due to efficient CO_2 capture from low pressure sources through favorable reaction kinetics and reduced reboiler steam energy consumption; better stability than monoethanolamine (MEA); and a lower solvent circulation rate. In addition to advances in solvent design, Linde has achieved significant improvements in process design, as outlined in Figure 1.



A. Flue gas blower provides sufficient pressure to overcome pressure drop across the direct contact cooler (DCC)/pre-scrubber and absorber. The blower location can be adjusted to minimize cost based on arrangement of equipment and piping at the NGCC site.

B. Integrated DCC/pre-scrubber to reduce sulfur oxides (SO_X) content below 5 parts per million (ppm) and simultaneously cool the flue gas stream to ~35–40°C.

C. Innovative and patented water wash section at the top of the column to reduce amine losses, even in the presence of aerosols. Dry bed configuration helps mitigate aerosol-driven amine losses.

D. A gravity-driven inter-stage cooler for the absorber that eliminates the need for a pump and related controls.

E. High-capacity structured packing reduces the absorber diameter, thereby enabling a larger single-train plant construction and greatly reduced capital costs.

F. Solvent-based heat exchanger designed to operate over a wide range of temperature approaches, which provides the opportunity to optimize the performance and capital cost trade-off.

G. Regenerator designed for operation at pressures up to 3.4 bara significantly reduces CO_2 compression energy and eliminates the bulky first stage of the CO_2 compressor, resulting in capital cost savings.

H. Innovative plate and frame design of the reboiler minimizes thermal degradation of solvent and provides for a lower solvent inventory and faster dynamics to respond to flue gas load and composition changes.

I. Stripper Inter-Stage Heater (SIH) enhances energy-efficient CO_2 stripping from the solvent by recovering heat from the lean solvent to provide intermediate reboil, thereby reducing energy consumption of solvent regeneration.

J. Variations of the stripper-reboiler flashing configuration, which are being evaluated to further minimize solvent regeneration energy.

Figure 1: Process flow diagram of Linde-BASF OASE blue post-combustion CO_2 capture technology.

A development timeline of the Linde-BASF technology is shown in Figure 2. Previous testing of a 0.45-MWe dry lignite-fired pilot plant incorporating the Linde-BASF technology has shown that the OASE blue solvent is more stable than MEA after 2,500 hours of testing. The process was also previously tested at 1.5-MWe-scale at the National Carbon Capture Center (NCCC) under the U.S. Department of Energy (DOE)-funded project DE-FE0007453, validating solvent stability and revealing a cyclic capacity 20% higher than MEA and regenerator steam consumption 25% lower than MEA. These results confirmed the ability of this technology to be cost-effective, energy efficient, and compact.

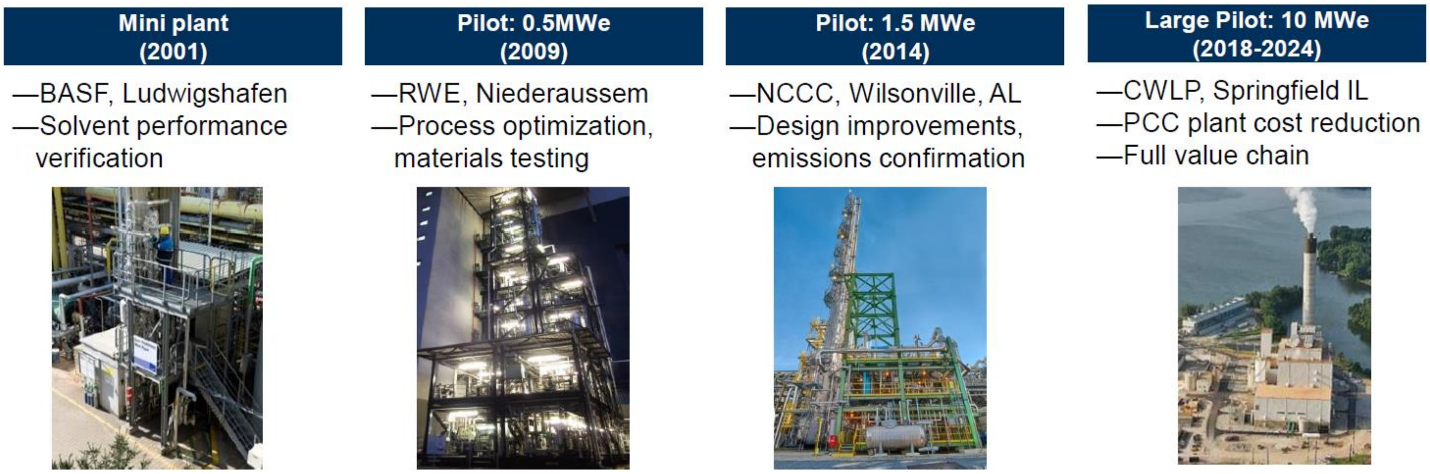


Figure 2: Linde-BASF post-combustion CO_2 capture technology development.

Milestones achieved thus far for the Linde-BASF post-combustion CO_2 capture technology applied to NGCC flue gas conditions are outlined in Figure 3. These include testing on an NGCC flue gas composition at the 0.45-MWe pilot-scale in Niederaussem, Germany; completion of a detailed FEED study on CO_2 capture from a 510-MWe NGCC power plant in 2011; and completion of a pre-FEED study for CO_2 capture at a 480-MWe NGCC power plant in 2018.

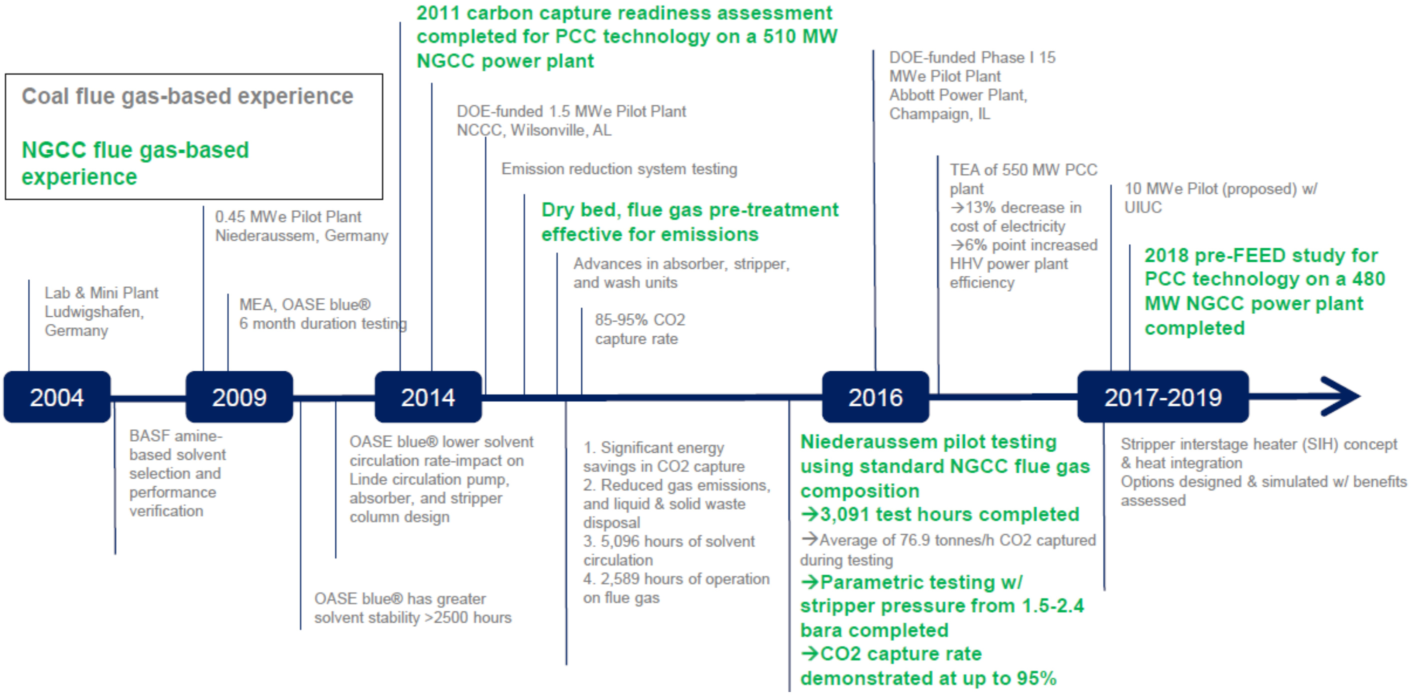


Figure 3: Milestones achieved by Linde-BASF post-combustion CO_2 capture technology.

The capital and operating costs determined from the previous pre-FEED and FEED studies are shown in Table 1. The studies were based on commercial Linde-BASF post-combustion CO_2 capture plants recovering 85–90% of the CO_2 in the flue gas supplied to the process from an NGCC power plant. All major process components were included in each study and the CO_2 product purity was specified at greater than 99 mol% (dry) with less than 100 parts per million (ppm) oxygen (O_2) content. Capital costs were estimated using Linde's proprietary cost estimation methodology for new commercial plants and were derived from databases of actual equipment quotes from vendors collected from recent projects. Capital costs for CO_2 capture plants integrated with NGCC plants are significantly higher compared to those integrated with coal-fired power plants due to the reduced flue gas CO_2 concentration in natural gas-derived flue gas (~4 mol% versus ~12% mol% CO_2 for coal-fired plants). This reduced flue gas CO_2 concentration necessitates a taller and larger diameter absorber column to achieve 90% CO_2 capture at low or ambient pressures. The optimum CO_2 capture rate at the host site will be defined in the FEED study to achieve an attractive cost option.

TABLE 1: ESTIMATED CAPEX, OPEX, AND COST OF CO_2 CAPTURED FOR LARGE-SCALE LINDE-BASF CO_2 CAPTURE AND COMPRESSION PLANT (550+ MWE) FOR NGCC BASED ON PAST LINDE STUDIES (COST YEAR=2019) (WITHOUT TRANSPORTATION AND STORAGE)

PCC Case	Linde-BASF PCC technology (no SIH)
NGCC Plant Net Power (MWe)	559
CO2 Product Flowrate (tonne/day)	4,848
Total installed CAPEX (PCC + compression) ($2019)	$428 MM
OPEX (variable + fixed) ($2019)	$54 MM/year
PCC specific reboiler duty (MJ/kg CO_2)	2.94
PCC plant electrical power consumption (MW)	38.3
Electricity price ($/MWh)	$57.60
Steam price ($/tonne)	$9.70
Cost of CO_2 captured ($/tonne CO_2) ($2019)	$56.80

The general approach for the FEED follows the methodology described in Figure 4.

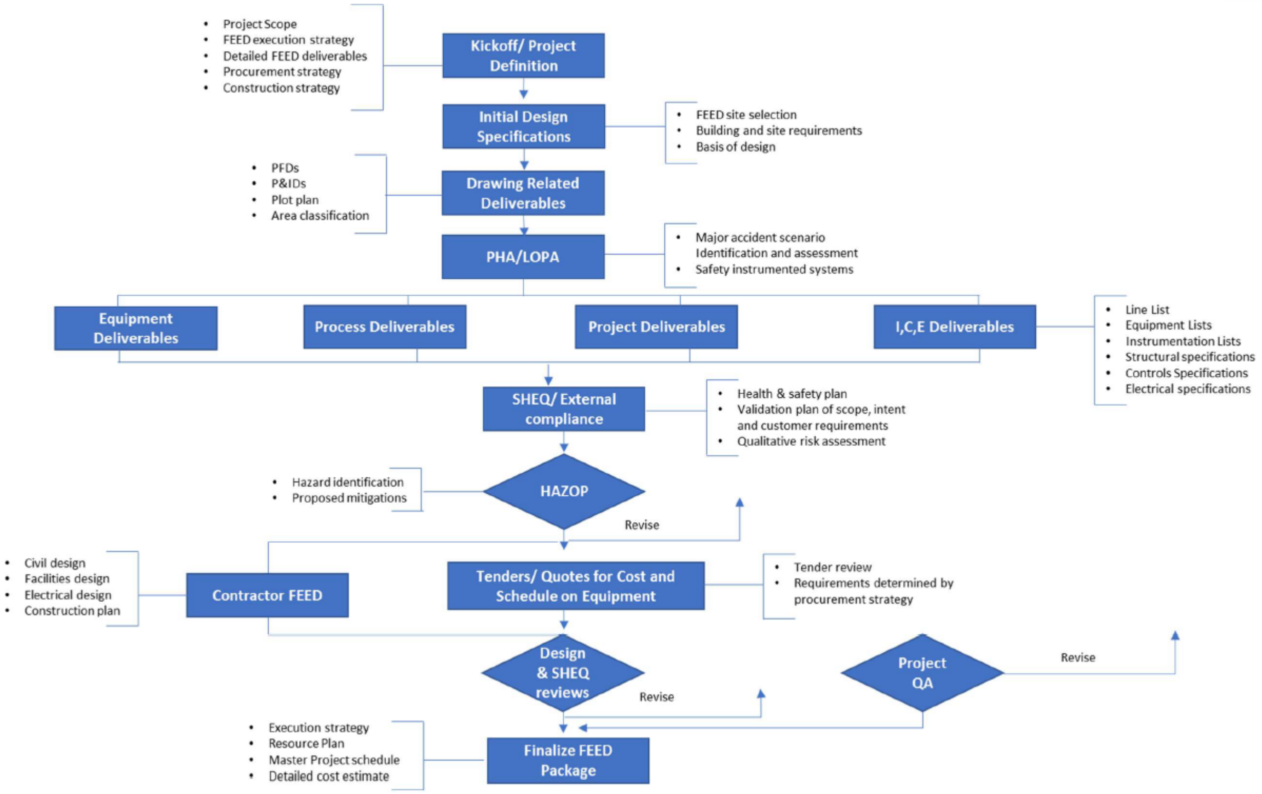


Figure 4: FEED approach.

Process designs that reduce the energy required for solvent regeneration through heat recovery integration are being optimized as part of the FEED study. Waste heat sources at the NGCC-fired host site can be leveraged to reduce the parasitic steam consumption of the CO_2 capture system and reduce the negative impact of the capture plant on power plant steam cycle efficiency or net electrical power generation. Sources include: (1) supplemental low- to medium-pressure steam from the power plant steam cycle in the range of 5–6 bara not currently used for electricity production can be redirected for use in the post-combustion CO_2 capture plant reboiler; (2) waste heat recovered from the hot flue gas upstream of the CO_2 capture plant after the heat recovery steam generator (HRSG) can be used to pre-heat CO_2-rich solvent entering the stripper column; or (3) external steam generation can reduce the steam input from the power plant. In addition, process optimization within the post-combustion CO_2 capture plant itself, including lean vapor compression (LVC) involving flashing of the CO_2-lean solution at the bottom of the stripper and redirecting the vapor after compression back to the bottom of the stripper, is an option that can substantially reduce the reboiler steam consumption for NGCC-fired CO_2 capture down to 2.4 gigajoules (GJ)/tonne CO_2 based on past FEED studies conducted for large Linde-BASF post-combustion CO_2 capture plants.

Linde has conducted extensive research on the management of flue gas aerosol particles that contribute to amine losses through the treated gas exiting the absorber, including both literature studies and aerosol measurements taken during testing of the Linde-BASF post-combustion CO_2 capture technology at NCCC. Experimentally, Linde has determined that if aerosol concentrations are less than 10^7 particles/cm^3 for particles ranging from 70–200 nanometer (nm) in diameter, there is no need for pre-treatment beyond a direct contact cooler (DCC)/pre-scrubber and dry bed wash section in the absorber to manage the aerosols. Aerosol concentrations are expected to be much lower for NGCC-derived flue gas than for coal-fired flue gas; therefore, typical emissions control measures have been integrated into the Linde-BASF CO_2 capture plant design.

Two Southern Company host sites are being evaluated in the first phase of the FEED study: Alabama Power Company's Plant Barry (Units 6 and 7), located in Bucks, Alabama, and Mississippi Power Company's Plant Daniel (Units 3 and 4), located in Moss Point, Mississippi. Each of the gas-fired combined cycle units (Units 6 and 7 at Plant Barry and Units 3 and 4 at Plant Daniel) produce a nominal 525 MWe (net). For either host site, equipment and operating modifications in the combined cycle to increase CO_2 concentration in the flue gas is a primary focus of the FEED study to minimize carbon capture costs. Cooling water capacity at both combined cycle plants is limited; therefore, evaluations of new cooling tower capacity versus air cooling are being performed in the FEED. For each site, steam supply to the carbon capture process may be available via extraction from the steam turbine, but the overall impact on the HRSG, steam cycle, and steam turbine is being evaluated during the FEED to determine the cost impact of extraction versus alternate steam production from a package boiler or cogeneration unit.

The FEED will provide a financial indicator of the costs of installation at an actual domestic NGCC power plant site and potentially illustrates that this capture system can be employed at operating commercial coal-fired power plants. The commercial FEED will provide a realistic framework for NGCC power plants to be built CO_2 capture-ready or to retrofit existing NGCC plants with an economical CO_2 capture system.

TABLE 2: SOLVENT PROCESS PARAMETERS

Pure Solvent	Units	Design Value
Molecular Weight	mol^{-1}	proprietary
Normal Boiling Point	°C	proprietary
Normal Freezing Point	°C	-5 to 25
Vapor Pressure @ 15°C	bar(a)	proprietary
Manufacturing Cost for Solvent	$/kg	proprietary
Working Solution		
Concentration	kg/kg	proprietary
Specific Gravity (15°C/15°C)	-	1.0 – 1.2
Specific Heat Capacity @ STP	kJ/kg-K	proprietary
Viscosity @ STP	cP	1.5 – 7.0
Absorption		
Pressure	bar(a)	0.9 – 1.1
Temperature	°C	30 – 60
Equilibrium CO_2 Loading	mol/mol	proprietary
Heat of Absorption	kJ/mol CO_2	proprietary
Solution Viscosity	cP	1.5 – 7
Desorption		
Pressure	bar(a)	1.6 – 3.4
Temperature	°C	125 – 140
Equilibrium CO_2 Loading	mol/mol	proprietary

Heat of Desorption	kJ/mol CO_2	proprietary
Module Design		
Flue Gas Flowrate	kg/hr	Designed for >375 MWe slipstream
CO_2 Recovery, Purity, and Pressure	% / % / bar	90%, >99.9% (dry), 3.4 bar(a)
Absorber Pressure Drop	bar	proprietary
Estimated Absorber/Stripper Cost of Manufacturing and Installation	$\frac{\$}{kg/hr}$	proprietary

Definitions:

Bar(a) – Unit used to indicate absolute pressure, where the reference pressure is absolute zero (i.e., not taking into account atmospheric pressure).

STP – Standard temperature and pressure (15°C, 1 atmosphere [atm]).

Pure Solvent – Chemical agent(s), working alone or as a component of a working solution, responsible for enhanced CO_2 absorption (e.g., MEA in an aqueous solution).

Manufacturing Cost for Solvent – "Current" is market price of chemical, if applicable; "Target" is estimated manufacturing cost for new solvents, or the estimated cost of bulk manufacturing for existing solvents.

Working Solution – The solute-free (i.e., CO_2-free) liquid solution used as the working solvent in the absorption/desorption process (e.g., the liquid mixture of MEA and water).

Absorption – The conditions of interest for absorption are those that prevail at maximum solvent loading, which typically occurs at the bottom of the absorption column. These may be assumed to be 1 atm total flue gas pressure (corresponding to a CO_2 partial pressure of 0.13 bar) and 40°C; however, measured data at other conditions are preferable to estimated data.

Desorption – The conditions of interest for desorption are those that prevail at minimum solvent loading, which typically occurs at the bottom of the desorption column. Operating pressure and temperature for the desorber/stripper are process-dependent (e.g., an MEA-based absorption system has a typical CO_2 partial pressure of 1.8 bar and a reboiler temperature of 120°C). Measured data at other conditions are preferable to estimated data.

Pressure – The pressure of CO_2 in equilibrium with the solution. If the vapor phase is pure CO_2, this is the total pressure; if it is a mixture of gases, this is the partial pressure of CO_2. Note that for a typical pulverized coal power plant, the total pressure of the flue gas is about 1 atm and the concentration of CO_2 is about 13.2%. Therefore, the partial pressure of CO_2 is roughly 0.132 atm or 0.130 bar.

Concentration – Mass fraction of pure solvent in working solution.

Loading – The basis for CO_2 loadings is moles of pure solvent.

Estimated Cost – Basis is kg/hr of CO_2 in CO_2-rich product gas; assuming targets are met.

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

		Composition						
		vol%					ppmv	
Pressure psia	**Temperature** °F	**CO_2**	**H_2O**	**N_2**	**O_2**	**Ar**	**SO_x**	**NO_x**
14.8	231	4	9	74	12	1	0.08	2

Other Parameter Descriptions:

Chemical/Physical Solvent Mechanism – Carbon dioxide in the flue gas chemically binds to the OASE blue aqueous amine-based solvent via an exothermic absorption step and this chemical bond is broken in the endothermic desorption step via heat provided by steam in the reboiler of the regenerator column, generating pure CO_2.

Solvent Contaminant Resistance – The OASE blue solvent is highly resistant against many contaminants in the flue gas, as shown in both parametric and long-term continuous tests (see Electric Power Research Institute [EPRI] report[1] for additional information).

Solvent Foaming Tendency – During the pilot plant operations, although anti-foaming injection was included in the design, its use was not found necessary.

Flue Gas Pretreatment Requirements – The pretreatment requirement includes reducing sulfur oxide (SO_X) in the flue gas to 2 to 5 ppm in order to limit solvent degradation and is implemented in a DCC in conjunction with flue gas cooling, typically by adding appropriate amount of sodium hydroxide corresponding to the SO_X present in the flue gas.

Solvent Makeup Requirements – The OASE blue solvent makeup rate is determined by the sum of the amine losses in the treated gas leaving the absorber column and the rate of solvent degradation during operation over time. Low makeup rates were observed during long-term testing well below an operationally manageable threshold. Low solvent makeup is expected at scale when processing flue gas from power plants with a baghouse filter for particulate removal or with upstream flue gas pretreatment for aerosol mitigation.

Waste Streams Generated – The main waste liquid stream is from the DCC where SO_X and nitrogen oxide (NO_X) are removed; this stream is typically handled in the power plant wastewater treatment facility. A small amount of solid waste is removed using an activated carbon filter and mechanical cartridge filter that are replaced at regular intervals. Since the solvent degradation observed in the pilot testing is small, no solvent reclamation unit is envisioned in the large scale.

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

Proposed Module Design – Free standing absorber and stripper columns will be tied into a modularized process skid. There will be associated containers for electrical equipment, analytical equipment, and process control.

technology advantages

- Exhibits a lower solvent circulation rate, reduced reboiler steam energy consumption compared to process using MEA solvent, reduced absorber diameter due to high efficiency packing, and lower downstream CO_2 compression cost due to the ability to operate at higher desorber pressures.
- BASF is the producer of the OASE blue solvent and the owner of the solvent technology. A major global player in the chemical industry, BASF has the capabilities to reliably produce and supply the OASE blue solvent in sufficient volumes needed for commercialization, thereby enabling application at scale by avoiding issues related to solvent manufacturing for large-scale commercial plants.
- The Southern Company-Linde-BASF partnership combines the necessary capabilities and experience to deliver the complete CO_2 capture technology value chain from solvent production to full-scale CO_2 capture plant engineering, procurement, and construction (EPC); commercial deployment; and long-term, continuous operations.

R&D challenges

- Carryover and emissions of amines and amine degradation products.
- Handling large volumes of process condensate from DCC.
- Disposal of spent activated carbon and filters can generate solid waste management issues.
- Designing for low liquid/gas ratios caused by lower CO_2 concentration in natural gas flue gas may result in below-target CO_2 capture rate and/or vapor and liquid maldistribution.
- Equipment scale-up associated with large vapor flows due to low CO_2 concentration.
- Engineering the liquid hydraulics and gas distribution in large manifolds needed for multiple absorbers.
- Integration of post-combustion CO_2 capture plant with host site.

status

The project team selected Plant Daniel (525 MWe) in Mississippi as the host site for the FEED study employing the Linde-BASF CO_2 capture technology. The basic design and engineering reports were completed with heat and material balances, process flow diagrams, preliminary process and instrumentation diagrams, and a steam source study. The FEED study report is being finalized, including a hazard and operability (HAZOP) review and engineering documents for mechanical and piping; instrumentation, controls, and electrical; civil and structural; and facilities. An estimate of the cost and schedule is also being prepared. A final FEED package with the engineering deliverables, cost estimate, and schedule will be submitted to DOE at the end of Q1 calendar year (CY) 2022. After project completion, a final report will be prepared and submitted in Q2 CY 2022, summarizing all project results and analyses, and making recommendations for future research and development.

available reports/technical papers/presentations

Lundsford, Landon, “Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant,” 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_Lunsford.pdf*.

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references

[1] BASF-Linde Post Combustion Carbon Capture Pilot Plant at the National Carbon Capture Center, 2016 Test Campaign Results, EPRI, February 2017.