Final Project Report

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National Energy Technology Laboratory

Engineering Design of a Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Linde Steam Methane Reforming H_2 Plant

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SUBMITTED BY
Linde Inc.
DUNS Number: 197-154-586
10 Riverview Drive
Danbury, CT 06810

PRINCIPAL INVESTIGATOR
Contact PI: Minish Shah
Email: minish.shah@linde.com
Phone: (716) 879-2623

Signature of Submitting Official: Minish Shah
Minish M Shah
Sr. Director, Clean Energy Technologies
Linde Technology

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DISCLAIMER

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Executive Summary

Linde carried out an initial engineering design study for a Linde-BASF advanced post combustion CO_2 capture technology to be installed at a commercial-scale steam methane reforming (SMR) hydrogen plant located in the US Gulf Coast. This pre-FEED equivalent study included following: (1) basic design, including specific project scope definition and design basis, (2) basic engineering, including development of process flow diagrams and heat & material balances, (3) inside the battery limit (ISBL) equipment and systems specification, (4) balance of plant outside the battery limit (OSBL) equipment and systems specifications, (5) technology maturation plan, (6) hazard and operability (HAZOP) review, (7) environmental, health and safety (EH&S) assessment and environmental permitting analysis, (8) constructability review, (9) ISBL and OSBL EPC cost estimation, and (10) commercial-scale techno-economic analysis including capital expenditures (CAPEX) and operating expenditures (OPEX) and CO_2 capture cost estimates.

Following are key takeaways:

- The CO_2 capture unit is designed for 95% CO_2 capture rate.
- The capacity of CO_2 capture unit for the SMR flue gas (base case) is 1.36 MM tpy. With flue gas from auxiliary boiler, the required capacity (step-off case) increases to 1.48 MM tpy.
- Single train design is technically feasible for the largest SMR hydrogen plant.
- Technology is ready to advance to commercial scale deployment for the SMR flue gas from the current technology readiness level (TRL) of 6 for the coal power plant.
- Based on the preliminary permitting analysis at the host SMR site, only permit amendment will be required at this particular site.
- The total CAPEX (or total overnight cost (TOC)) for the base case is estimated to be $450 MM.
- The total cost of CCS (CO_2 capture and storage) is estimated to be $71/t to $101/t depending on the financing assumptions.

This report includes engineering study objectives, technology status, design basis, process design and control, EH&S assessment and permitting analysis, equipment list, constructability review, CAPEX, OPEX and CO_2 capture cost estimates and technology maturation plan.

1. Engineering Study Objectives

The overall objective was to conduct an initial engineering design study for approximately 3,700 tonnes/day CO_2 capture plant to be installed at an existing Linde-owned commercial-scale steam methane reforming (SMR) plant. The specific goals of the project were to estimate CAPEX with +/- 25% accuracy, estimate OPEX and perform technoeconomic analysis to determine the cost of CO_2 capture.

2. Technology Status

Linde-BASF Post Combustion Capture Technology

The proposed advanced PCC technology is a result of BASF's comprehensive R&D efforts since 2004 in developing advanced amine-based solvents for efficient CO_2 recovery from low-pressure, dilute flue gas streams, combined with the joint Linde-BASF collaboration since 2007 in designing and testing resulting advanced PCC technology, including the work entailed in previous Linde techno-economic reports from 2017 [1] and 2021 [2]. BASF currently markets its entire gas-treating portfolio under the trade name OASE®, where OASE® blue is the brand for flue gas carbon capture. This section highlights the key characteristics of BASF's OASE® blue process along with Linde-BASF PCC plant design innovations.

The major milestones achieved so far, highlighted in Figure 1, include:

- Formulation and successful testing of BASF's advanced, amine based, OASE® blue solvent for efficient CO_2 capture from the flue gas from coal and natural gas-based power plants.
- Advanced PCC plant design targeted to minimize the cost of electricity (COE) from power plants with 90% CO_2 capture. Successful pilot demonstration at 0.45 MWe capacity level in Niederaussem, Germany and 1.5 MWe capacity level at the NCCC in Wilsonville, AL.

Based on this work and know-how from over 300 plants operating with OASE® technology, BASF can already guarantee excellent performance at today's state of development. Linde has extensive experience in designing and building some of the largest industrial plants in the world, including the 700,000 TPA plant for CO_2 removal from natural gas in Norway for reinjection into the offshore Snovit fields. With prior experience in CO_2 removal in other applications, Linde-BASF team is well positioned to scale up the proposed technology. Current Linde-BASF roadmap to a commercial PCC plant involves a scale-up of 7x flue gas volume from the small pilot to the large pilot and a 10x - 25x scale-up to a first commercial demonstration.

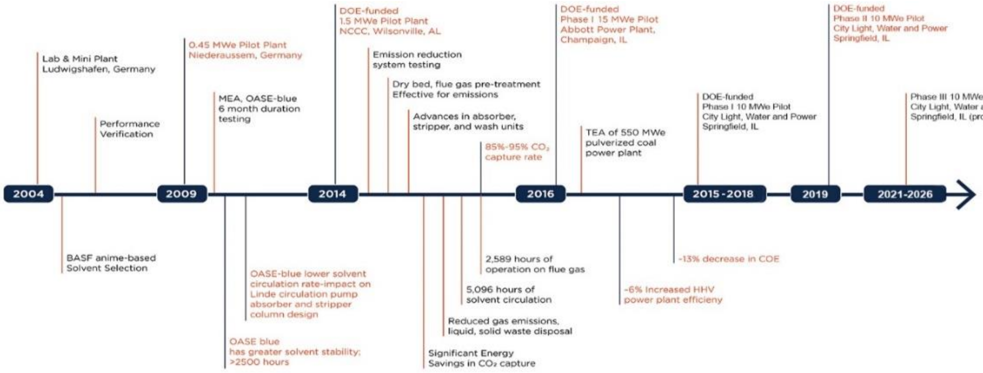


Figure 1. Linde-BASF Technology Milestones

2.1 Advanced Solvent Development

Solvent Candidates Screening

BASF screened 400 amine-based substances/solvents and their combinations over time through lab scale and mini pilot plant tests and selected the OASE® Blue solvent based on its superior performance with respect to energy demand, cyclic capacity, solvent stability, reactivity, volatility, environmental sustainability, and availability. A detailed publication of results comprehensive prescreening and evaluations of candidate solvents are provided in references [3, 4]. Following are key highlights:

- Based on vapor-liquid equilibria (VLE) measurements of CO_2 for selected solvents at targeted temperatures and approximate cyclic capacity and energy for CO_2 desorption, BASF's solvent showed up to 40% **higher cyclic capacity** than conventional MEA.
- Measurement of CO_2 absorption rates illustrated that the best solvents exhibited **fast kinetics** relative to MEA.
- The stability of selected solvents was evaluated in the presence of oxygen in addition to CO_2 and solvents with significantly **increased stability** relative to MEA were identified.

2.2 Pilot Plants

2.2.1 Niederaussem, Germany

In order to evaluate critical performance under more realistic conditions, Linde Engineering in cooperation with BASF and RWE Power designed and built a small pilot PCC plant integrated with RWE Power's 1,100 MW dry lignite fired power plant in Niederaussem, Germany, capable of recovering ~ 7.2 TPD of CO_2 from ~ 1,500 Nm^3/h flue gas slipstream. Main accomplishments from this pilot plant are summarized below [3, 4]:

- Total ~55,000 hours of
- BASF solvent enabled ~20% energy reduction for solvent regeneration.
- Solvent circulation rate was significantly reduced resulting in reduction in sizes of several equipment.
- Solvent degradation was much lower compared to MEA in 5,000 hr tests.
- Longer-term test (>24,000 hrs) confirmed reliability and consistency of performance.
- Dry bed configuration in absorber was found to be most effective in reducing amine aerosol emissions caused by dust particles.
- A number of material alternatives could be employed in different parts of the PCC unit in order to reduce capital cost of large commercial PCC plants [5].

2.2.2 National Carbon Capture Center (NCCC)

The Linde-BASF team designed, engineered, and built a 1.5 MWe PCC pilot plant at the NCCC to further advance the technology [6, 7]. Several new design features were incorporated in this plant. Key highlights from this demonstration are summarized in Table 1.

Table 1. Performance levels attained at Wilsonville.

Performance Attribute	Current achievement against target	Remarks
1. CO_2 capture rate	>90% per target	Achieved. Capture rate can be optimized for specific energy.
2. CO_2 purity	99.9% dry basis per target	Achieved. Low O_2 impurity level for EOR applications
3. Plant capacity	> 1.5 MWe per design target (>15,500 lbs/hr flue gas)	Achieved. Higher capacity testing performed over several time periods in 2015.
4. Regenerator steam consumption	~ 2.8 GJ/tonne CO_2 (same as Niederaussem consumption)	Energy as low as 2.7 GJ/tonne (intrinsic) CO_2 observed.
5. Emissions control validation	Validation of dry bed (BASF patented) operation per design	Detailed isokinetic measurements (flue gas & treated gas) performed.
6. Regenerator operating pressure	Testing and validation performed up to 3.4 bars	60 day long duration operation and testing was performed at 3.4 bars
7. Validation of unique features	(i) high-capacity packing, (ii) gravity driven intercooler, (iii) blower downstream of abs. (iv) unique reboiler design.	Design options for regenerator heat reduction through heat integration identified. Advanced stripper designs can result in <2.5 GJ/tonne.

2.3 Process Design Innovations

The PCC plant is designed to recover >90 percent of the CO_2 contained in the flue gas, purify it (> 99.9 vol% CO_2, < 10 vol. ppm O_2), dehydrate it (dew point temperature: -40 °F), and compress it to 2,215 psia. The major sections of the PCC plant are: Direct Contact Cooler (DCC), Flue Gas Blower, CO_2 Absorber with Interstage cooler, Water Wash unit, Solvent Stripper with Reboiler, and CO_2 Compression and Drying (Figure 2).

A – CO_2 Absorber with Interstage Cooler: Use of interstage cooler suppresses a significant solvent temperature rise within the column from the exothermic chemisorption of CO_2 and increases the equilibrium content of CO_2 in the rich solution leaving the absorber. This increases the cyclic capacity of the solvent and decreases the reboiler duty.

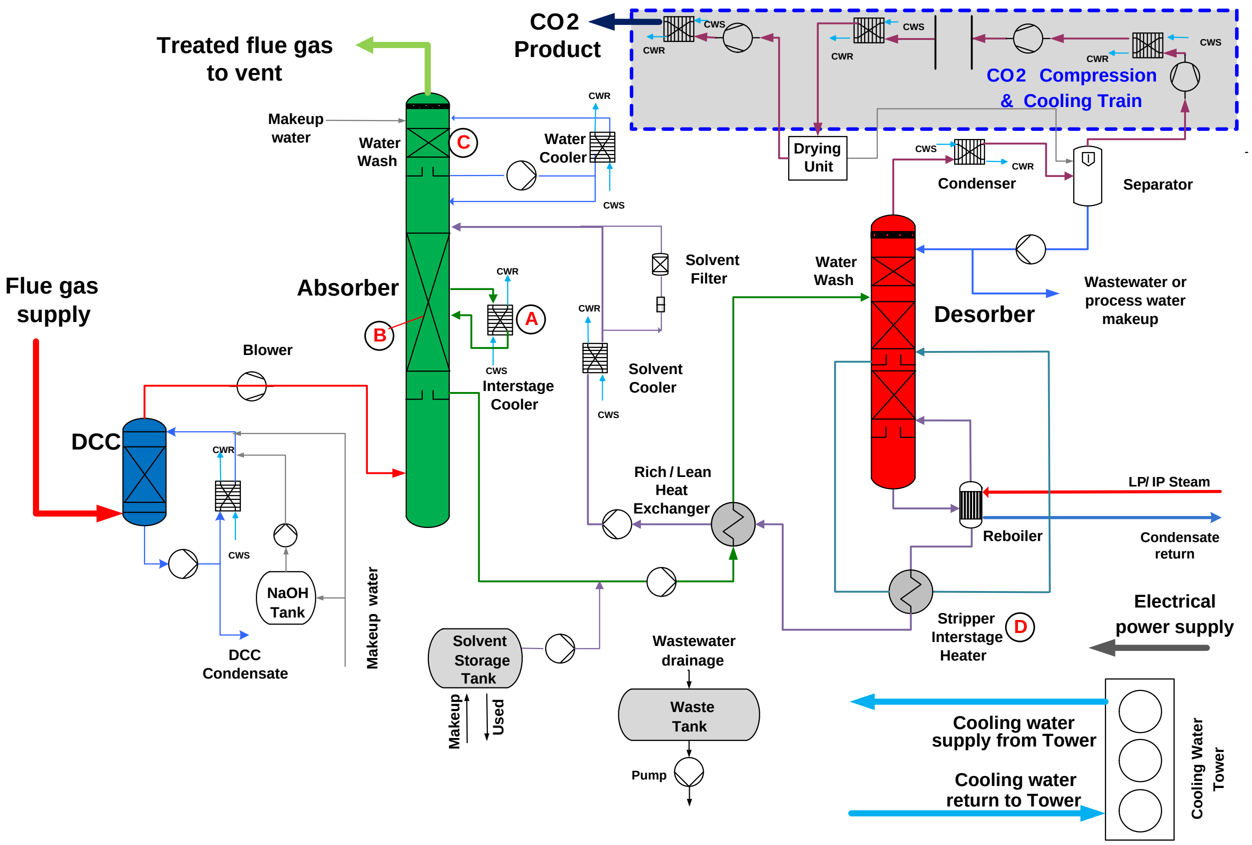


Figure 2. Linde-BASF Post-Combustion Capture Technology

B – Structured packing: The advanced structured packing increases the capacity of the absorber and reduces the pressure drop across the column.

C – Absorber Water Wash Section: An efficient reduction of the solvent losses and related reduction in the environmental emissions can be achieved by utilizing the water wash section positioned above the absorber bed.

D – Solvent Stripper with Interstage Heater (SIH Configuration): In the proposed SIH design, a semi-CO_2 lean solvent reheater is added to the stripper column that heats up solvent taken from an intermediate position in the stripper using hot CO_2-lean solvent from the bottom of the stripper column reboiler and then injects this re-heated semi-CO_2 lean solvent back into the stripper column at an optimal packing location. Overall, this process modification significantly reduce the steam consumption per metric tonne of CO_2 captured.

3. Design Basis

The engineering design of PCC unit is based on capturing 95% CO_2 from the SMR flue gas. With the target of 95% capture rate, the CO_2 capture capacity is ~1.4 MM tpy. The CO_2 capture plant is assumed to be a single train design. Some of the rotating equipment such as pumps are provided in duplicate for reliability. Steam drive is used for CO_2 compression train. Figure 3 shows the schematics of the base case. Steam for the PCC unit is supplied from two sources. The main source is excess steam from the SMR. This steam is typically exported to customer. For the engineering study, it is assumed that this steam can be diverted to the amine unit. Second source of steam is a new auxiliary boiler that will be installed as part of the carbon capture project. In the base case considered for the engineering design, CO_2 from the aux. boiler flue gas is not captured.

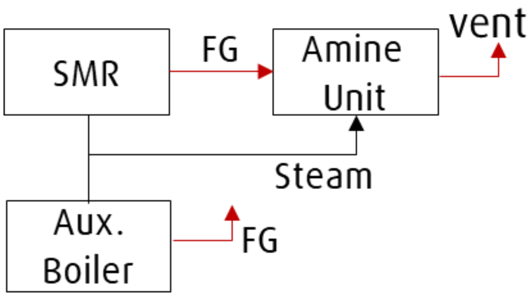


Figure 3. Schematics of Base Case used in the Engineering Design

A step-off case with CO_2 capture from both SMR and aux. boiler flue gas streams was evaluated as part of the technoeconomic analysis. Schematics of the step-of case is shown in Figure 4. The overall reduction in Scope 1 CO_2 emissions in this case is close to 95%.

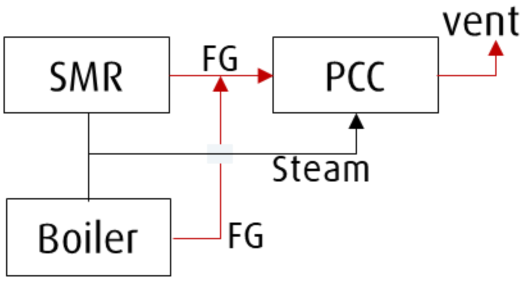


Figure 4 Schematics of the Step-Off Case

Figure 5 shows overall scope of the ISBL and OSBL equipment included in the PCC unit as well as the integration with the host SMR hydrogen plant. For all the connections between SMR and PCC unit shown in Figure 5, pipes and cables from tie-in points within the SMR hydrogen plant to the equipment in the PCC unit are within the scope of the PCC unit.

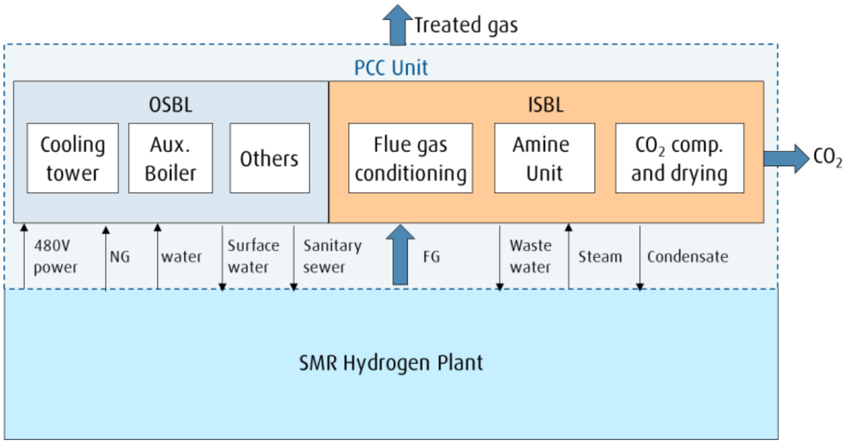


Figure 5. PCC Unit Scope and Integration with SMR Hydrogen Plant

Various other design basis details are described below.

3.1 General

Definitions and Abbreviations

ASCE	American Society of Civil Engineers
BFW	Boiler Feed Water
BL	Battery Limits
DES	Design: Data crucial for plant design
HHV	Higher Heating Value
HP	High Pressure
IBC	International Building Code
ISBL	Inside of plant battery limit
LHV	Lower Heating Value
LP	Low Pressure
OSBL	Outside of plant battery limit

3.2 Site Conditions

General Site Information

The plant is to be located at an existing Linde SMR site next to a Refinery on the Gulf Cost, USA. The site elevation is estimated 36 ft above sea level. An open plot on north side of the existing SMR is available for installation of the PCC unit. An L-shaped layout is used as shown later in the report with required plot area for constructed plant to be app. 13000 m². This specific proposal documents the design and site conditions for a PCC unit installed at specific SMR plant in Gulf Cost, USA. Following transportation limitation were defined based on the routing study for shipping large equipment.

Transport limitations		**Width**	**Height**	**Length**
Inside of country / to the site	ft	34	19	200
Max. allowable loads (weight)	lb	80,000		

Atmospheric Conditions

	Unit	**Min.**	**Max.**	**Average**
Atmospheric pressure	psia	14.7	14.7	14.7
Design Cold/Hot Day Temperatures	°F	26	100	
Relative humidity	%			68%
Record Minimum Dry Bulb Temp[1]	°F	3		
Record Maximum Dry Bulb Temp[1]	°F	109		

1. Record Min/Max temperatures are Texas/Louisiana specific

Severe Atmospheric Conditions

Other influences	☒ Yes: Gulf Coast Corrosive atmosphere, hurricanes, lightening
Marine environment	☒ (Distance to sea below 5,000 m)

Wind Design

Regulation		☒ ASCE 7
Max. velocity at ground level	mph	144

Snow Load

Regulation		☒ None
Max. load (for horizontal roofs)	N/m²	0

Rainfall

Average annual rainfall (Average over 100 years)	in	63.9
Maximum rainfall in 1 hour	In	4.8
Site subject to flooding	☒Yes	

3.3 Feedstock

The SMR flue gas condition is listed in Table 2. For equipment design in the amine unit, 10% higher flow was assumed. The heat and mass balances and utilities are estimated for the normal operating conditions.

Table 2. SMR Flue Gas Conditions

Property	Unit	Equipment Design	Normal Operating
Feedstock Composition			
Nitrogen $N_2 + O_2$ + Ar	mol%	61.6	61.6
Carbon dioxide CO_2	mol%	18.3	18.3
Water H_2O	mol%	20.1	20.1
SOx	ppmv max	0.02	0.02
NOx	ppmv max	8	8
NH3	ppmv max	10	10
CO	ppmv max	50	50
VOC	ppmv max	5	5
PM	ppmv max	15	15
Total (sum of the above)	mol%	100	100
Property	**Unit**		
Flow rate*	MMSCFD	450	409
Feedstock pressure at BL	psia	14.7	14.7
Feedstock temperature at BL	°F	320	318

*Wet Basis

3.4 Products

Table 3. Carbon Dioxide (CO_2) Product Specification

Composition	Unit	Design
CO_2	mol%	>95
Water	lbs/MMSCF	<30
Nitrogen	Mol%	<4%
Sulphur	ppmwt	<35
Oxygen	ppmwt	<10
Amines	ppmwt	<1
Property	**Unit**	**Min.**
Flow rate, CO_2 Capture target @ 95%, MT/day	MT/day	3730
Pressure at BL	psig	2300
Temperature at BL	°F	<120

3.5 Utilities

Piping connections to the Customer shall be on pipe rack or underground max. 1 m outside plant Battery Limits (BL). Electrical Battery Limit shall be located at the terminals of the incoming feeders/transformers within plant BL. Instrumentation Battery Limit (signal exchange to customer) shall be at the terminals in the plant's instrumentation room (cable to be provided by customer, cable pulling ISBL shall be done as part of EPC).

Demineralized Water

Required quantity of demineralized water is assumed to be available from the host site.

Boiler Feed Water

The condensate from the amine reboiler is recycled as boiler feed water to the host SMR plant and to the aux. boiler. About 10% of condensate is sent to water treatment in the SMR plant prior to use as boiler feed water.

Make Up Water for New Cooling System

Cold Lime softened, clarified, and filtered river water for use as make-up water to the cooling tower and to fill the firewater tank will be provided.

Cooling Water

A new cooling tower will be installed to provide cooling water as part of the OSBL scope. Makeup water to the cooling tower will be the clarified water as described above plus any suitable recycle water from the process. The cooling water design conditions are listed below.

	Minimum	**Normal**	**Maximum**	**Units**
Supply Temperature			90	ºF
Temperature Rise		15(1)	27(1)	ºF
Mechanical Design Pressure	150 min			psi(g)
Mechanical Design Temperature	150 min			ºF
Chlorides	950 max			ppm as Cl
Allowable Pressure Drop	10 max			psi(d)

Notes: 1. Assumed normal water temperature rise considers the entire facility cooling system (e.g. Cooling tower 'hot water temperature'). Maximum temperature rise applies to an individual cooling water exchanger only (and not the tower).

Steam Import for Start-up / supplied by SMR

Steam is available from existing SMR to cover a portion of steam needed for the amine unit. An auxiliary boiler will be installed as part of the OSBL scope to generate additional steam needed for the amine unit. The steam delivered to the amine unit will be at low pressure.

Potable Water

The Local municipality will provide potable water at the facility battery limits. Potable water will be used within the facility for sinks and eye wash / safety showers, in the facility and process areas

Fire Water / supplied by customer

Existing capacity is available for use.

Nitrogen

Existing capacity is assumed to be available for use in the PCC plant. Nitrogen to be used for inerting, plant start-up, and shutdown.

Instrument Gas / supplied by customer

An instrument air compression, drying, and receiver system shall be installed as part of the OSBL scope. The instrument air shall be backed up with vaporized liquid nitrogen for reliability and peak demand periods (e.g. startup, shutdown, etc.).

Natural Gas

Table 4. NG Conditions

Property	Unit	Min.	Max.	DES
Temperature (at B.L.)	°F			60
Pressure (at B.L.)	psig	550	862	550
Composition				
Methane	Mol%			95.08
Ethane	Mol%			2.79
Propane	Mol%			0.22
Butane	Mol%			0.08
Pentane	Mol%			0.02
Hexane	Mol%			0.02
Nitrogen	Mol%			0.58
Carbon Dioxide	Mol%			1.21
Total Sulfur as H2S	Ppmv		5	
Higher Heating Value	BTU/scf			1019.6
Lower Heating Value	BTU/scf			918.9

Electricity

Existing supply capacity at the battery limit of the host SMR site is sufficient for handling the additional power load in the PCC plant. The supply voltage is 13.8 kV. Transformers are also installed for the facility Medium and Low Voltage electrical equipment.

Instrumentation for B.L. connections

Minimum metering accuracy for transfer measurements:

Medium		Type	Accuracy [%]
(i)	Carbon Dioxide (CO_2)	product	+/- 1.0 %
(ii)	Make up Water (H2O)	feed	+/- 3.0 %

Online Analyzers of Products

The following list is related to B.L. streams only and does not show analyzers required for process control reasons.

Streams	Components
Feed, CO_2 Product and emissions	CO_2, H_2O, O_2, THC, SOx, NOx.

3.6 Limits for Effluents and Emissions as per local Regulations

Wastewater

All process wastewater (i.e. waste water from the water purification system, cooling tower blowdown, boiler blowdown, etc.) are collected in the waste water sump and discharged to the river via the customer's waste water line. Potentially contaminated storm water from curbed areas are routed by gravity to an oil-water separator. Oil free water is then routed to the wastewater sump and lift station. Cooling tower blowdown is treated on site to remove free chlorine prior to discharge.

Emissions to Atmosphere

Treated flue gas from absorber column will be vented to atmosphere. Local emission limits have to be specified. The reformer flue gas stack emission limits are as follows:

Environmental/authority limitations to be considered:	☐ No limitations required ☒ Yes, according below requirements	
	Maximum load	
NOx at 3 % O_2 in the dry flue gas max	ppmv	8
CO at 3 % O_2 in the dry flue gas.	ppmv	50
SOx calculated as SO2 at 3 % O_2 in the dry flue gas	mg/Nm^3	…..
NH_3 (in case of SCR)	ppm	10
Dust at 3 % O_2 in the dry flue gas	% max	5

4. Process Design

This section includes PFD (Figure 6), process description, stream summary, utilities, consumables, emissions and list of equipment.

4.1 Process Flow Diagram

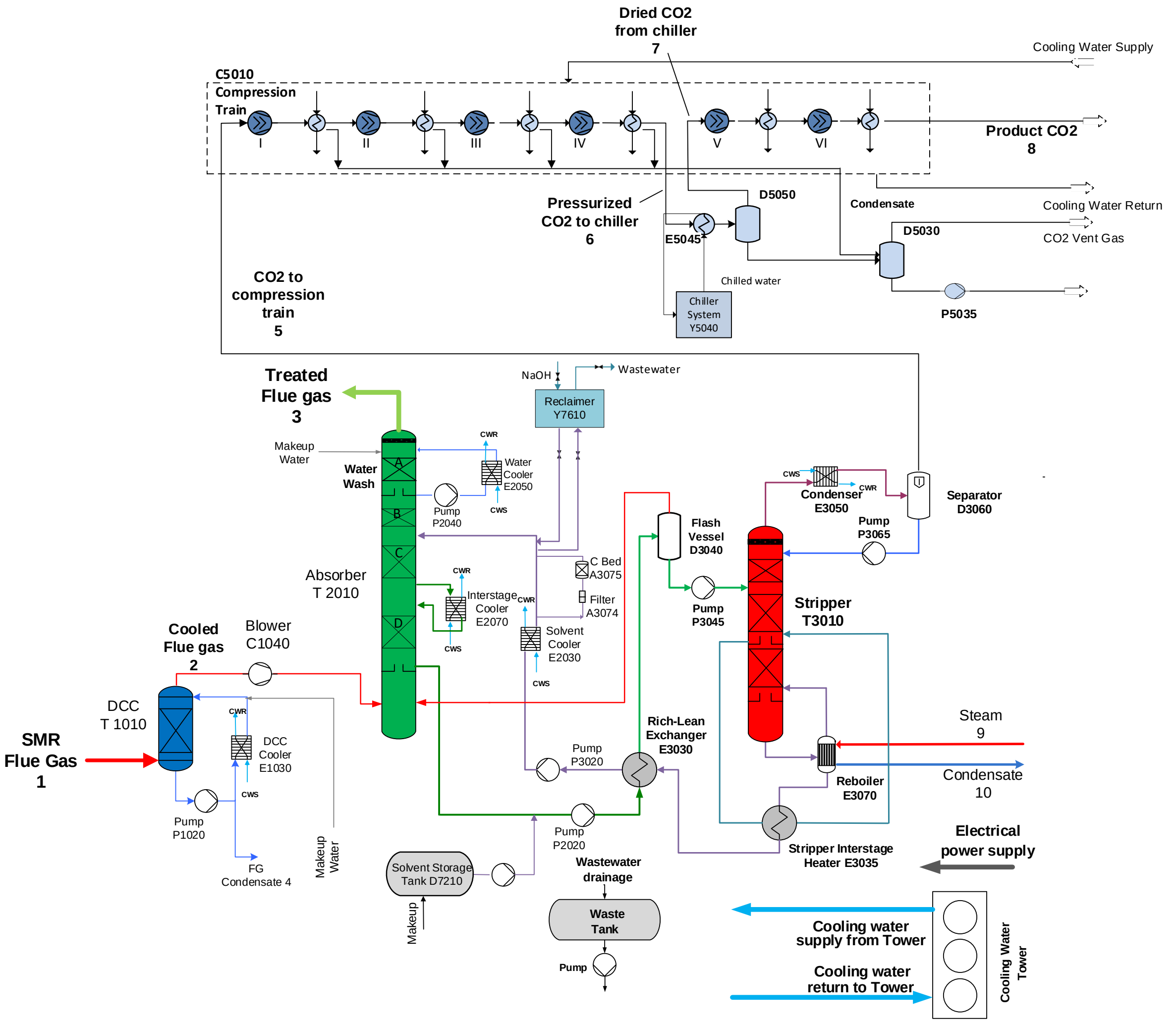


Figure 6. Process Flow Diagram

4.2 Process Description

Flue Gas Pre-Treating

The flue gas coming from a SMR plant enters the Direct Contact Cooler (DCC Column) T1010 where it is cooled down to the required inlet temperature of the downstream Absorber Column T2010. Circulating water is pumped by the DCC Circulation Pump P1020 to the top of the Direct Contact Cooler whereas the flue gas enters at the bottom of the Direct Contact Cooler. Thus, water passes in a counter current direction to the flue gas and removes heat from the gas stream. Circulating process water is cooled in the DCC Cooler E1030 by means of cooling water. Condensed water from the flue gas is routed to cooling tower as make-up water after required chemical pre-treatment.

After passing the DCC Column T1010, the cooled flue gas is pressurized by the Flue Gas Blower C1040 compensating the pressure drop of all upstream and downstream plant sections until the gas leaves the Absorber Column T2010 as treated flue gas to atmosphere.

CO_2 Absorption

The pressurized flue gas is fed to the bottom of Absorber Column T2010. Flash gas coming from the Rich Solution Flash Vessel D3040 is mixed with the flue gas. In the Absorber Column, the flue gas passes in a counter-current flow to the liquid washing agents. The Absorber Column consists of four different sections (A to D). The lower two sections (C & D) represent the CO_2 absorption part which is operated with the amine-based washing agent. In the CO_2 absorption part, 95% of the CO_2 is captured from the flue gas. The upper two segments (A & B) are divided into a "dry" bed section and a backwash section. Both upper sections are designed to reduce impurities (e.g. amine traces) out of the gas stream (emission control section). After passing the inlet of the Absorber Column the flue gas passes upwards through the absorption beds where two packed bed sections are promoting the mass transfer of CO_2 from the gas into the absorbing amine wash liquid. The temperature in this section increases due to the exothermic absorption process.

Amine solution entering the Absorber Column at the upper part of the CO_2 absorption section is collected below the first of the two packed beds on a chimney tray and is sent to the Absorber Interstage Cooler E2070 where the solution is cooled with cooling water. By reducing the temperature of the solution, the CO_2 absorption efficiency is increased. After passing the Absorber Interstage Cooler the solution is redistributed over the second absorption bed. A high-performance packing with low pressure drop and high mass transfer capacity leads to an optimized column diameter.

The emission control system consists of a “Dry” bed and a backwash section in the upper part of the Absorber Column. With the implementation of both bed sections, aerosol or particle emissions in the gas flow leaving the Absorber Column are effectively controlled and reduced. In the upper column bed, process water passes counter-current to the upstreaming gas flow. Wash water is circulated by the Absorber Wash Water Pump P2040 from the first chimney tray through the water-cooled Absorber Wash Water Cooler E2050. Demineralized water from battery limit is supplied to the wash water cycle to avoid the accumulation of amines in the water cycle and to adjust the water balance of the plant. The patented "Dry" Bed section operates only with the liquid overflow from the top packing section. Within the “Dry” bed section the liquid passes in counter current flow to the flue gas recapturing entrained droplets of amine solution out of the gas flow. Thus, the “Dry” bed section has a significant impact on meeting the low emission targets in the treated flue gas. CO_2-lean flue gas leaves the Absorber Column at the top and is sent to atmosphere as treated flue gas.

The CO_2-rich absorbent solution withdrawn at the bottom of the Absorber Column is fed by the Rich Solution Pump P2020 via the Rich/Lean Solution Heat Exchanger E3030 to the Rich Solution Flash Vessel D3040. In the Rich/Lean Solution Heat Exchanger E3030, rich solution is heated by lean solution leaving the Stripper Interstage Heater E3035.

Regeneration

By reducing the pressure in the Rich Solution Flash Vessel D3040, a small vapor fraction is generated consisting principally of dissolved gas components like Oxygen, Nitrogen etc. These components are separated from the rich solution flow and are recycled back to the Absorber Column. The recycled components leave the plant in the treated gas at the top of the Absorber Column.

The Rich Solution Booster Pump P3045 transfers the preheated rich solution from the Rich Solution Flash Vessel D3040 to the Stripper Column T3010. Regeneration of the amine solution is accomplished in the Stripper Column T3010 by releasing the absorbed CO_2. The Stripper Column consists of three packed bed sections. While the two lower sections are designed as stripping segments, the top section is the wash section run with process condensate from the Stripper Reflux Drum D3060.

The hot rich solution enters the upper section of the stripping section and passes counter-current to the ascending vapor, generated in the Reboiler E3070. The amine solution is collected on the chimney tray between both stripping sections. It is further heated in the Stripper Interstage Heater E3035 with hot lean solution leaving the Stripper at the bottom. The heated rich solution is fed back to the Stripper column above the lower stripping section and passes downwards counter-current to the vapor. The installation of the Stripper Interstage Pump P3025 and the Stripper Interstage Heater E3035 are integral part of the energy efficient process configuration that allows to significantly reduce the specific thermal energy consumption of the process.

Superheated LP steam is used to provide the regeneration heat in the Stripper Reboiler E3070. The required thermal duty of the reboiler is adjusted by regulating the steam flow. In the Reboiler, the LP Steam is condensed and steam condensate is recycled.

After leaving the Stripper Column, the wet CO_2 gas is cooled in the Stripper Condenser E3050 against cooling water. Condensate and CO_2 rich gas are separated in the Stripper Reflux Drum D3060. Whereas the condensate is returned to the top of the Stripper Column by the Stripper Reflux Pump P3065, the raw CO_2 is sent to the CO_2 Compression Unit.

Regenerated lean amine solution leaves the Stripper Column T3010 at the bottom. The lean solution is first cooled in the Stripper Interstage Heater E3035, by heating rich solution from the upper regeneration bed of the Stripper Column. The precooled lean amine solution is further cooled in the Rich/Lean Solution Heat Exchanger E3030 by heat exchange with rich solution coming from the Absorber

Column. Final cooling is achieved in the Lean Solution Cooler E2030, operated with cooling water. The lean solution is routed back to the Absorber Column by the Lean Solution Pump P3020. A portion of lean solution is routed over a Mechanical Filter S3074 and an Activated Carbon Filter A3075 which are used to eliminate solid matters.

CO_2 Compression and Drying

The raw CO_2 is compressed in the centrifugal, multi-stage CO_2 Compressor Unit C5010. The oil system and inter-stage Coolers are considered as part of the compressor unit.

The CO_2 compressor is divided in a low-pressure section, shown in PFD as stages I to IV and a high-pressure section, shown as stages V to VI. After compression in the low-pressure section, the CO_2 gas is cooled in the CO_2 Chiller Unit Y5040 against a refrigerant to reduce the water concentration in the gas flow. The generated condensate is separated in the Water Separator D5050 and sent to the Condensate Flash Vessel D5030. The gas leaving the Water Separator is sent back to the stage V and VI of the CO_2 Compressor Unit and is compressed to around 2300 psig.

Condensed water from the interstage coolers of the CO_2 Compressor Unit is sent also to the Condensate Flash Vessel D5030. The condensate collected in the Condensate Flash Vessel is level controlled and recycled to amine unit (not shown) via the Condensate Flash Vessel Pump P5035. Small amounts of CO_2 will be degassed from the condensate in the Condensate Flash Vessel and this gas is vented to atmosphere.

Utilities and Storage

RECLAIMING UNIT

During plant operation, the amine solution will degrade over time due to reaction with flue gas components as well as due to thermal stress. In the Reclaiming Unit Y7610, degradation products are selectively separated from the solvent allowing to reduce considerably the amine consumption (instead of bleed and feed).

A side stream of the lean solution is withdrawn downstream of the Lean Solution Cooler E2030 and continuously fed to the Reclaiming Unit Y7610. After reclaiming, the recovered amine solution is fed back to the process. Wastewater from the Reclaiming Unit is sent to battery limit. NaOH Solution required for the reclaiming process is stored in the NaOH Tank D7110 (not shown) and transferred to the reclaimer via an NaOH pump (scope of Reclaiming Unit).

STORAGE

Amine solution is fed into the PCC Plant by truck. A common Unloading station distributes the pure solution either to the Solution Storage Tank D7210 or to the Solution Make-up Vessel D7250 (not shown). The Solution Storage Tank D7210 is designed to store the whole plant solvent inventory. The Solution Make-up Vessel D7250 contains fresh OASE® Blue solution.

4.3 Heat and Mass Balances

Table 5 lists stream summary for major streams shown in Figure 6.

Table 5. Stream Summary

Stream No.		1	2	3	4	5	6	7	8	9	10
Description		SMR FG	Cooled FG	Treated FG	FG condensate	CO_2 to comp. train	Comp. CO_2 to chiller	Dried CO_2 from chiller	Product CO_2	Steam to reboiler	Condensate recycle
massflow	kg/h	592849	540696	386796	51934	157358	155741	155542	155542	192114	192114
massflow	lb/hr	1307006	1192029	852739	114495	346915	343349	342910	342910	423538	423538
mol flow	kmol/h	20392.06	17509.27	14071.03	2882.78	3633.24	3546.17	3535.61	3535.61	10663.93	10663.93
Flow	Nm^3/h	457059.4	392445.8	315382.4		81434.1	79482.4	79245.8	79245.8		
Flow	MMscf	409.4	351.6	282.5		73.0	71.2	71.0	71.0		
Flow	gpm				229						846
Temperature	°F	318.0	101.8	113.0	99.3	98.9	114.8	55.4	115.0	434.0	294.1
Temperature	°C	158.9	38.8	45.0	37.4	37.1	46.0	13.0	46.1	223.3	145.6
Pressure	bar	1.01	0.98	1.01	3.10	2.20	40.34	39.99	159.59	11.36	8.00
Pressure	psig	14.7	14.2	14.7	45.0	31.9	584.9	579.9	2314.1	164.7	116.0
Enthalpy	kW	24141	2022	2292	-36616	368	-959	-3082	-9883	17488	-113877
VFrac	kg/kg	1.00	1.00	1.00	0.00	1.00	1.00	1.00	0.00	1.00	0.00
Components mol%											
CO_2		18.3000	21.3133	1.3201	0.0000	97.3078	99.6425	99.9303	99.9303		
H_2O		20.0900	6.9341	9.3996	100.0000	2.6800	0.3469	0.0591	0.0591	100.0000	100.0000
$N_2 + O_2 + Ar$		61.6069	71.7500	89.2773	0.0000	0.0102	0.0105	0.0105	0.0105		
CO		0.0010	0.0012	0.0015	0.0000	0.0000	0.0000	0.0000	0.0000		
NO		0.0007	0.0008	0.0010	0.0000	0.0001	0.0001	0.0001	0.0001		
NO_2		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
SO_2		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
SO_3		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
NH_3		0.0009	0.0000	0.0000	0.0000	0.0019	0.0000	0.0000	0.0000		
CH_4		0.0005	0.0006	0.0007	0.0000	0.0000	0.0000	0.0000	0.0000		
Amine		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		

4.4 Process Performance

Overall performance summary is provided in Table 6. All estimated values are based on 100% load.

Table 6. Performance Summary

Production	**Base Case 1**	**Step-off Case 2**
CO_2 Capture rate, MT/day	3,731	4043
Consumption/T CO2		
Reboiler duty	2.7 GJ*	2.7 GJ*
Power	135 kWh**	136 kWh**
Water	400 – 460 gal	400 – 460 gal
Cooling tower blowdown	60 – 120 gal	60 – 120 gal
Wastewater (Amine unit)	0.85 gal	0.9 gal

*Partly provided by SMR steam

** Partly provided by steam drive

4.5 List of Equipment

Majority of ISBL and OSBL mechanical equipment are listed below.

Table 7. Equipment List – Case 1

Direct Contact Cooler (column)	1
Absorber (column)	1
Stripper (column)	1
Flue gas blower	
Heat exchangers	
DCC Cooler	2
Lean Solution cooler	2
Absorber water wash cooler	1
Absorber interstage cooler	2
Rich/lean solution heat exchanger	8
Stripper interstage heater	2
Stripper Condenser	2
Stripper reboiler	5
Pumps	
DCC Circulation pump	2
Rich solution pump	2
Absorber water wash pump	2
Lean Solution pump	2
Stripper Interstage pump	2
Rich Solution Booster pump	2
Stripper Reflux pump	2
Steam Condensate pump	2

Solution make-up pump	2
Slop vessel pump	2
Pit pump	2
Cooling water pump	4
Make-up water pump	2
Condensate flash vessel pump	2
BFW pump	3
Chilled water pump	1
Activated carbon bed vessel	1
CO_2 Compressor train	1
Amine reclaimer unit	1
Rich Solution flash vessel	1
Stripper reflux drum	1
Steam condensate drum	1
Condensate flash vessel	1
NaOH tank	1
Amine storage tank	1
Solution make-up vessel	1
Slop vessel	1
Chiller	1
Cooling tower	1
Aux. boiler	1

5. Environmental, Health and Safety Risk Assessment and Permitting Analysis

The post combustion CO_2 capture (PCC) process considered in this project will use aqueous amine solution as a solvent for separating CO_2 from flue gas. The health and environmental impacts are a concern for solvents in use today. This section summarizes results of an environmental, health, and safety (EH&S) risk assessment.

5.1 Effluents and Emissions

Summary of major emissions and effluents for Case 1 are shown in Table 8. Details are discussed in the following paragraphs.

Table 8. Major Emissions and Effluents – Case 1

Stream	**Flow**	**CO_2, vol. %**	**Impurities**	**Remarks**
Treated flue gas	852,740 lb/hr	1.3%	Traces of NOx, CO, NH_3, CH_4, VOC	Most impurities from flue gas pass through
Flash gas	76 lb/hr	92%	Traces of NH_3	
Aux. boiler flue gas	181,000 lb/hr	8.4%	NOx, CO, NH_3, CH_4	
Amine reclaimer effluent	2.2 gpm		Amine degradation products, amine	
Activated carbon	125,000 lb/yr		Amines, liquid HC and Anti Foam Agent	Replace once a year
Blowdown from cooling tower	150 - 300 gpm			
Blowdown from boiler	9 gpm			

Treated Flue Gas from Absorber Column T2010

Treated flue gas, as the major emission output, leaves the top of the Absorber Column T2010 and is directly released to the atmosphere.

NO and NO2 Emissions

BASF’s OASE® blue process is not a source of any additional NO_x emission. Due to the very low co- absorption of flue gas contaminants like NO_x, nearly the same amount of these components will be emitted.

NH_3 Emissions

Most of the ammonia in the Feed Gas (10 ppmv) will be removed in the DCC column and will be dissolved in the feed gas condensate. However, ammonia will be formed in the PCC process as a degradation product of the solvent itself. Due to the very low degradation rate of the amine, the expected content in the treated flue gas (vented gas) is below 5 ppmv (dry).

SO_2 and SO_3 Emissions

The OASE® Blue process is not a source of any additional sulfur emission. Due to the negligible SO_2 content in the flue gas (expected << 1 ppmv), no additional treatment for SO_2 is required upstream the Absorber Column T2010.

VOC Emissions

The small supplement of VOC emissions is due to the usage of the amine-based washing agent in the CO_2 capture process. The following components have to be considered for the VOC emission:

- Emissions of amines
- Emission of degradation products of the amines

Emissions of Amine

The expected concentration of amines in the Treated Flue Gas is below 0.5 ppmv (dry). The low amine emissions result from the design and application of the emission control system which is derived from the BASF/Linde technology development.

CO Emissions

The CO_2 capture process does not generate any additional CO. Further, the co-absorption of CO in the DCC Columns T1010 as well as in the Absorber Column T2010 can be neglected from a CO emissions perspective. Consequently, since CO is not generated and does not accumulate in the system, the amount of CO entering the PCC Plant equals the amount of emitted CO from the PCC plant.

Particle Emissions

The OASE® Blue process is not a source for an additional particle emission. The OASE® Blue process is not designed for capturing particle matter. Nevertheless, depending on the particle size a certain amount of particle matter will be removed from the flue gas in the DCC Columns T1010 and in the Absorber Column T2010.

Vent Gas from Condensate Flash Vessel D5030

A small vent gas stream (flashed gas out of Condensate Flash Vessel D5030) will be released during depressurization of condensate in the CO_2 Compression & Drying Unit. The flash gas is vented to atmosphere at safe location. The stream contains mainly CO_2 and some traces of soluble gases likes NH_3 and N_2.

Flue Gas from Auxiliary Reboiler

Flue gas from the auxiliary reboiler is assumed to be vented to atmosphere in the base case. In a step-off case to be evaluated separately, this flue gas will be mixed with the SMR flue gas for CO_2 capture.

Property	Unit	Value
Flue gas Composition		
Nitrogen $N_2 + O_2$ + Ar	mol%	73.5
Carbon dioxide CO_2	mol%	8.4
Water H_2O	mol%	18.1
SOx	ppmv max	1
NOx	ppmv max	8
NH3	ppmv max	5
CO	ppmv max	50
Total (sum of the above)	mol%	100
Property	**Unit**	
Flow rate	Lb/hr	181,000
Feedstock pressure at BL	psia	14.7
Feedstock temperature at BL	°F	295

Wastewater from Reclaiming Unit Y7610

The wastewater flow from the Reclaimer Unit Y7610 is described in the table below. A wastewater holding tank will be designed for this waste.

Parameter	**Unit**	**Reclaimer Waste Contaminated**
Flow	USGPM	2.2
Temperature	°F	105
Composition		
H_2O	wt%	95.5
Sodium (Na^{2+})	wt%	1.2
Anions as Formate	wt%	2.3
Amine	wt%	1.0

Blowdown from Cooling Tower and Boiler

Process wastewater from the boiler and cooling tower blowdowns is assumed to be routed to the customer at the facility battery limit. Potentially contaminated storm water from curbed areas is routed by gravity to an oil/water separator/lift station. Oil free storm water is then routed to the local retention pond.

Solid Waste

Activated Carbon Bed from A3075

Spent activated carbon has to be disposed externally (e.g. incineration).

5.2 Permitting Implications

The proposed project will be installed at the existing site. As a result, permitting analysis was carried out to determine changes needed to any of the existing permits.

The PCC Plant will take the entire Flue Gas stream from the SMR. The main source of emissions from the PCC Plant will come from the Absorber Column T2010 and the Auxiliary Boiler. A spreadsheet was created to track all the emission streams and to determine if we exceed the lowest achievable emissions rate (LAER) for any of these major components: NOx, CO, VOC, and NH3.

Calculations showed that we are not expecting to exceed the LAER for any of the components of concern. Since the amounts of emissions after adding PCC unit emissions were below the thresholds set in the original permit, it was concluded that new permit will not be required and only permit amendment will be necessary. Thus, emissions permit is not expected to be a topic of risk or concern during project execution.

Steps for air permit amendment

The overall plant emissions summary document would be completed by Linde, then provided to a 3rd party consulting company. The 3rd party consultant would provide the expertise for completion of the permit application, including the textual description, analysis, QA/QC of the emission calculations and final submittal of the air permit modification application to the state permitting authority for the existing SMR.

The total cost of this effort is expected to be approximately $35,000, pending no issues or complications. This cost covers both the NSR and Title V permits needed for the amendment to the existing air permit. Air permit application preparation will typically take 4 months. We expect it to take 12 months for completion after permit application submittal. This process can be expedited at an increased cost. After project is authorized, detailed information will be developed as part of the permit application, including any burner guarantees from the manufacturer for the auxiliary boiler and detailed documentation supporting the basis for the emission factors and data provided in the air permit application.

5.3 Solvent Properties

Technical information regarding the family of BASF OASE® solvents is protected by intellectual property rights. Therefore, the specifics of composition and select physical and chemical characteristics of the BASF solvent for the PCC technology constitute commercial trade secrets and are therefore not publishable. Selected OASE® blue solvent properties are provided as a summary in Table 9.

Table 9. Solvent Properties

Property/Effect	**Solvent data/Guidelines**
State of matter/Color/Odor	Liquid or solid (based on temperature), colorless, amine-like

Flammability	Not highly flammable. Aqueous OASE® blue solution in storage tanks can be exposed to atmosphere (stable under air blanket; inert atmosphere not necessary)
Temperature tolerance	Protect from temperatures below: 25 ºC The product can crystallize below the limit temperature. Protect temperatures above: 80 ºC It is not necessary to protect the packed product against exceeding the temperature indicated.
Stability and Reactivity	**Incompatible materials:** acids **Hazardous reactions:** Evolution of heat under influence of acids. **Decomposition products:** Possible thermal decomposition products: carbon monoxide, carbon dioxide, ammonia, nitrogen oxides **Thermal decomposition:** No decomposition if stored and handled as prescribed/indicated. **Corrosion to metals:** Corrosive effects to metal are not anticipated. **Oxidizing properties:** not fire-propagating **Possibility of hazardous reactions:** Evolution of heat under influence of acids **Chemical stability:** The product is chemically stable.

5.4 Safe Handling and Use

Table 10 lists guidelines for safe handling and use of solvent.

Table 10. Guidelines for Handling and Use

Property/Effect	**Solvent data/Guidelines**
Precautions	Avoid contact with eyes, skin and clothing Avoid inhalation of mists/vapors
Accidental release measures	**Personal precautions:** Avoid inhalation. Avoid contact with the skin, eyes and clothing. **Environmental precautions:** Do not discharge into drains/surface waters/groundwater.

	Cleanup: Cleaning operations should be carried out only while wearing breathing apparatus. Clean contaminated floors and objects thoroughly with water and detergents, observing environmental regulations. Collect waste in suitable containers, which can be labeled and sealed. Incinerate or take to a special waste disposal site in accordance with local authority regulations. For small amounts: Pick up with absorbent material (e.g. sand, sawdust, general-purpose binder). For large amounts: Pump off product.
Handling and storage	**Handling:** Ensure thorough ventilation of storage and work areas. Handle in accordance with good industrial hygiene and safety practice. When using do not eat, drink or smoke. Hands and/or face should be washed before breaks and at the end of the shift. **Protection against fire and explosion:** No special precautions necessary. The substance/product is non-combustible. **Storage:** Suitable materials for containers: Stainless steel 1.4301 (V2), Stainless steel 1.4401, Carbon steel (Iron), glass. Keep container tightly closed and in a cool place. Keep container dry. **Storage incompatibility:** Segregate from acids.
Exposure control and personal protection	**Personal protective equipment** **Respiratory protection:** Wear a NIOSH-certified (or equivalent) respirator as necessary. Observe OSHA regulations for respirator use (29 CFR 1910.134). **Hand protection:** Wear chemical resistant protective gloves. Manufacturer's directions for use should be observed because of great diversity of types. **Eye protection:** Tightly fitting safety goggles (chemical goggles). Wear face shield if splashing hazard exists.
General safety and hygiene measures	Handle in accordance with good industrial hygiene and safety practice. Females of childbearing age should not come into contact with the product. Avoid contact with skin. Avoid contact with eyes. Do not breathe spray. Eye wash fountains and safety showers must be easily accessible at each plant module level including ground level.

5.5 HAZOP Study

A HAZOP (Hazards and Operability Study) was conducted to ensure that the plant design is safe for operations. It uses a rigorous methodology used to qualitatively identify and address potential safety, health, environmental and asset risks. Following objectives were set:

- To systematically review the intended operation of the facility, and to analyze potential process safety and environmental hazards; specifically:
- To identify credible causes of incidents which could result in a release of highly hazardous materials
- The team will also note when a credible cause may lead to significant capital loss or major operational upsets (noted as equipment damage or operational issues only)
- To determine whether existing safeguards are adequate. If not, make recommendations to improve the design and/or operation of the process.

Various nodes on P&ID were defined. Each node is a small portion of the process that includes one unit operation, typically on major process equipment with related piping and instrumentation or a complete system (e.g. compressor including a suction drum, intercoolers). For each node, deviations from normal operation for various process variables (flow, temperature, pressure, level, concentration etc.) were analyzed for possible consequences. As an example, deviations for flow may include more flow, less flow, no flow and reverse flow. Likely causes and consequences for each of the deviations were discussed to identify hazard scenarios without taking credit for any safeguards. Severity and likelihood ratings were applied for each pair of causes and consequences. Based on these ratings, risk levels were identified for each hazard scenario and additional safeguards were incorporated in the design where needed. Overall, more than 130 recommendations were made by the HAZOP team and these were captured in a revised P&ID.

6. Process Control

The control philosophy for some of the complex control loops in the PCC unit is described here in brief. The detailed control narrative will be developed after commercial project is authorized. The following key control loops are covered:

- Flue Gas Blower Control
- Stripper and Absorber Control
- Auxiliary Boiler Controls
- CO_2 Compressor Suction Pressure / Surge Controls

6.1 Flue Gas Blower Control

The Flue Gas Blower is controlled via a variable frequency drive (VFD) which varies the flue gas flow to the Absorber. It maintains the pressure upstream of the DCC Column such that there is no impact on the draft pressure in the SMR convection section.

6.2 Absorber and Stripper Control

The main objectives are to control the Stripper Reboiler Heat Duty via LP steam flow, rate of amine solution regeneration, and level profiles of the Columns, while maintaining a 95% CO_2 capture rate. The primary means of satisfying these objectives is Stripper Level Control, and an empirical mathematical equation that relates the CO_2 feed flow to a corresponding reboiler LP steam flow and amine solution flow.

6.2.1 Stripper Reboiler

The steam flow setpoint is calculated using a mathematical correlation between the flue gas CO_2 feed flow and reboiler LP steam flow. This proportional correlation is developed based on different modelled cases and may be linear or a polynomial. The CO_2 Feed Flow is simply calculated by multiplying the CO_2 concentration by the flue gas flow at the inlet of the Absorber.

6.2.2 Amine Flow and Column Levels

For specifying the Stripper / Absorber Levels, and rich / lean amine flows, only two of these variables need to be controlled. In this process, the rich amine flow and stripper level are controlled, which means the lean solution flow rate will be adjusted to maintain the level in the Stripper, which also specifies the level for the Absorber.

The stripper level is simply controlled by modulating the lean amine solution valve to the Absorber with a direct acting controller. The rich amine flow is controlled based on a mathematical correlation with the CO2 feed flow.

6.3 Auxiliary Boiler Controls

The primary purpose of the Auxiliary boiler is to supplement steam for the Stripper Reboiler. The boiler level, fuel flow, and combustion air flow are key points of control in the Auxiliary Boiler.

5.3.1 Boiler Feed Water Control

Boiler feed water (BFW) stored in the Deaerator is treated and pumped to the Auxiliary Boiler. A level control valve simply adjusts the BFW flow to the boiler to maintain a level set point. The steam from the boiler is superheated to a temperature SP using a direct acting controller.

5.3.2 Combustion Controls

Fuel Control

The heat to the boiler is provided by combusting natural gas fuel. A flow controller controls the natural gas fuel flow to the boiler. This flow controller receives a master fuel requirement using a linear equation that simply increases fuel flow based on the CO_2 feed flow and the SMR steam flow.

Combustion Air Control

The combustion air flow is controlled by a flow controller that adjusts the damper on the forced draft fan. An excess air controller uses the NG fuel flow, excess air SP, and NG stoichiometric air to fuel ratio to determine a combustion air flow remote setpoint. Typically, the setpoint of the air to fuel controller is set to 10% excess air to optimize efficiency as well as ensure complete combustion. A linear equation based on CO_2 flow is finally used to ensure a minimum combustion air flow setpoint.

6.4 CO_2 Compressor Suction Pressure / Surge Controls

5.4.1 Surge Control

Surge is the operating point at which the centrifugal compressor's minimum flow limit is reached and this can damage the machine. To prevent this, an anti-surge recycle valve and PID controller are included that shall protect the machine by maintaining a minimum flow through the compressor based on a surge + bias line.

5.4.2 Suction Pressure Control

The suction pressure to the CO_2 compressor and stripper outlet pressure is controlled via a set of direct acting back-pressure controllers. Normally, the CO_2 compressor suction pressure controller will control using the inlet guide vanes (IGV) of the CO_2 Compressor.

7. Constructability Review and Layouts

Constructability review was conducted to review preliminary plant layout and determine changes required for ease of plant construction and operation. Some of the needs during plant construction are sufficient availability of space for any on-site fabrication of large equipment (e.g. amine solution storage tank, absorber and stripper columns), laydown areas for light and heavy equipment, access roads for light, medium and heavy hauls to deliver equipment to the site, crane locations, parking area for construction personnel. Needs during operation are ease of access to various equipment for monitoring and maintenance, trucking access for loading/unloading of consumables and waste (e.g. delivering amine solution, picking up waste activated carbon). Other general considerations for layout are clearances to power lines, efficient routing of pipe racks, routing of any underground piping, routing of electrical cables, ladders and platforms for certain equipment, site security and fencing and lighting plan. Based on these considerations, changes were made to location and orientation of some large equipment (amine absorber, cooling tower), routing of certain pipe racks, and routing of underground piping. Final construction laydown plan is shown in Figure 7.

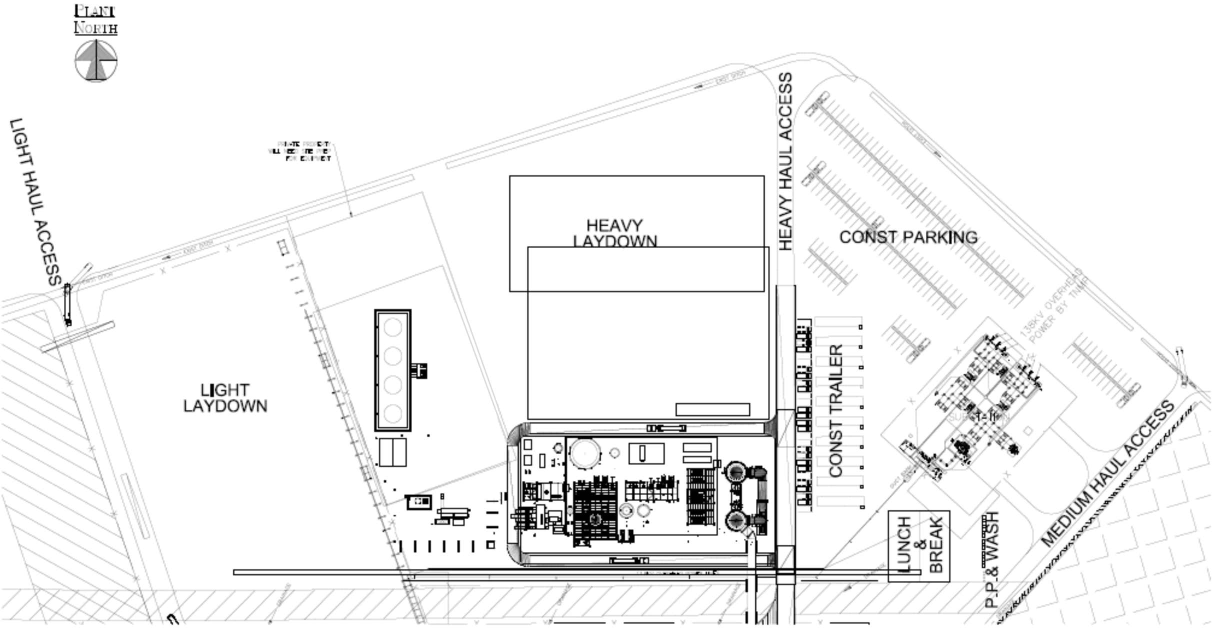


Figure 7. Construction Laydown Plan

Figure 8, Figure 9 and Figure 10 show plan view, front view and side view. Figure 11 shows a 3D model of the PCC unit.

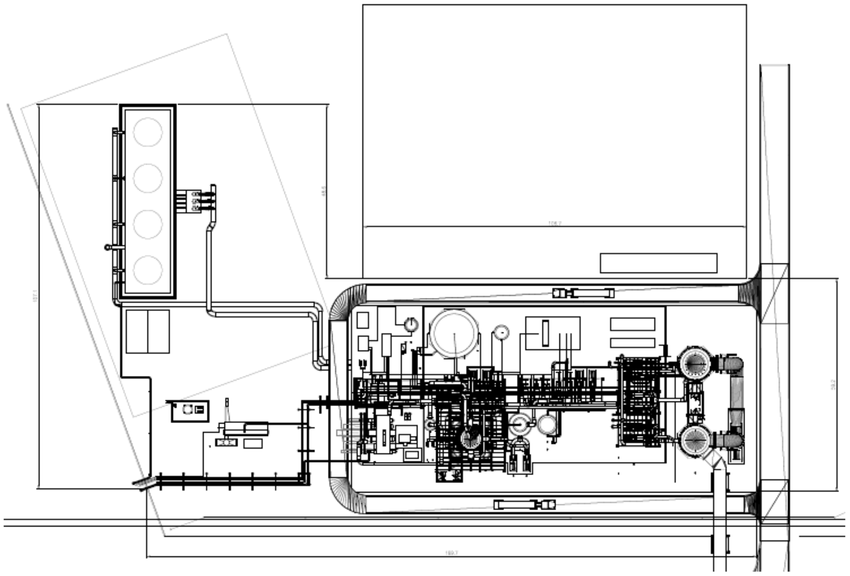


Figure 8. Plan View

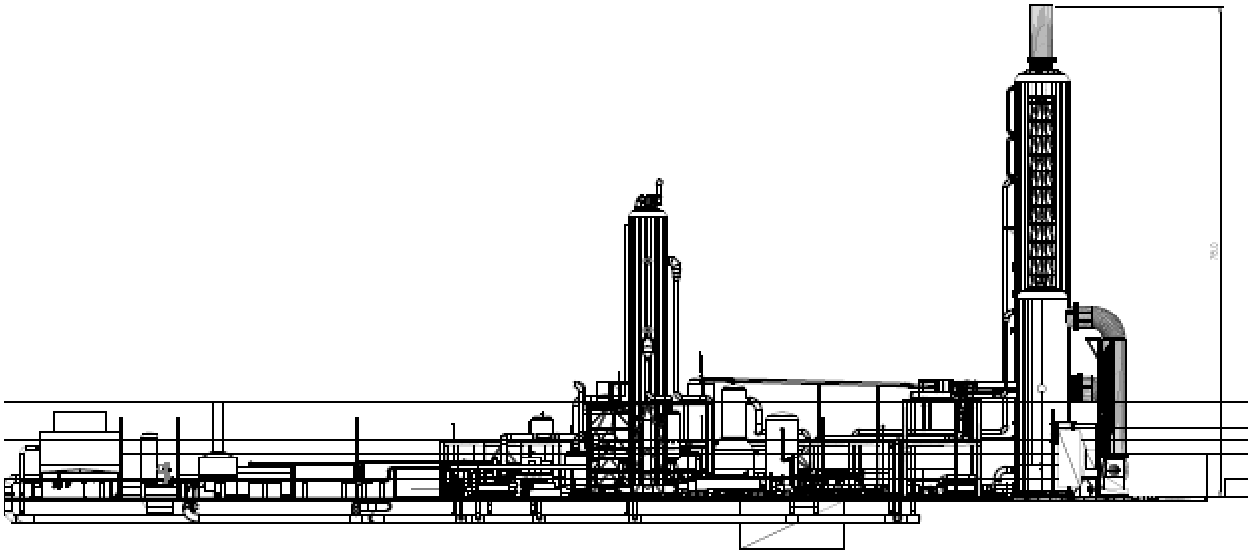


Figure 9. Front View – Looking North

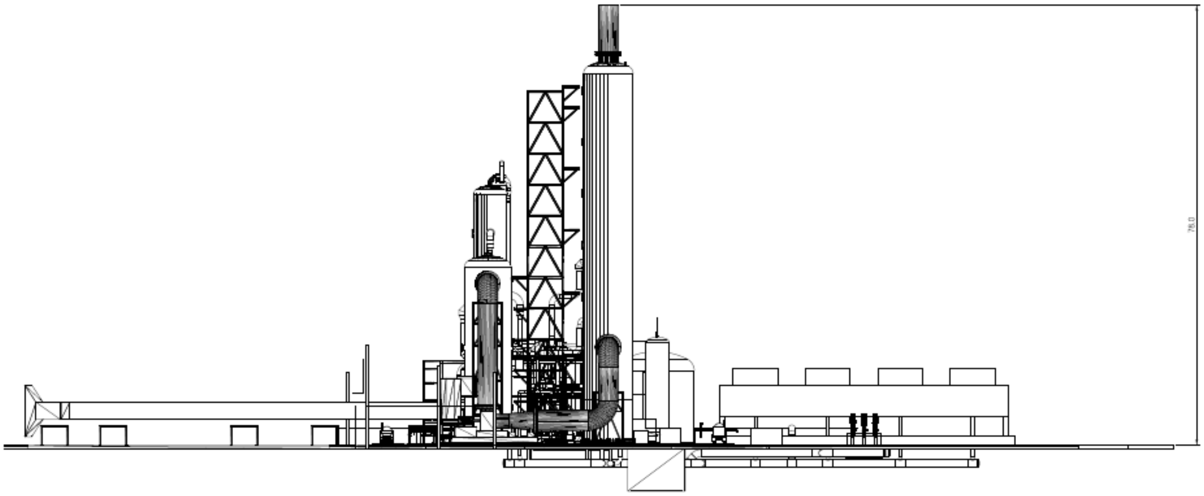


Figure 10. Side View – Looking West

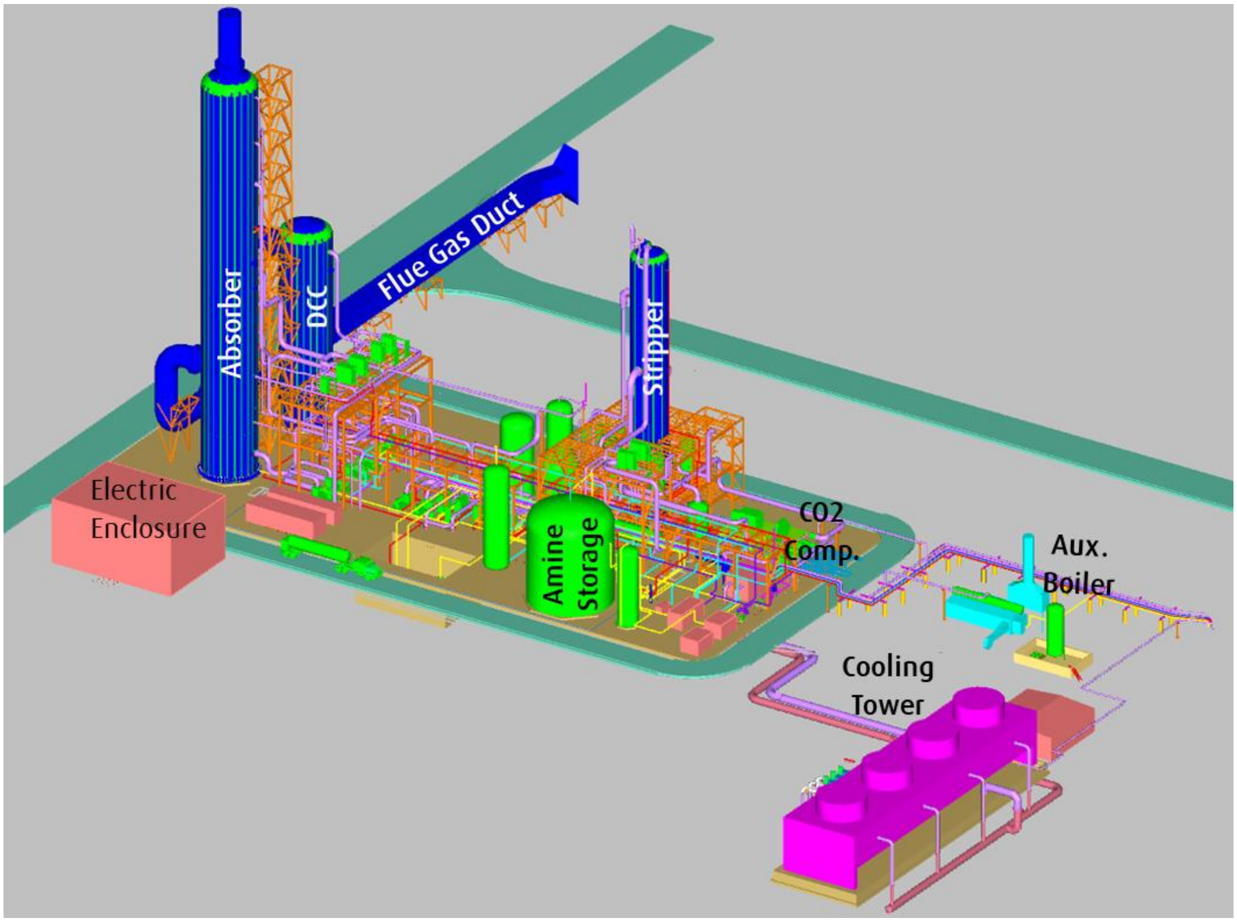


Figure 11 3D Model of the PCC Unit

8. Capital Costs

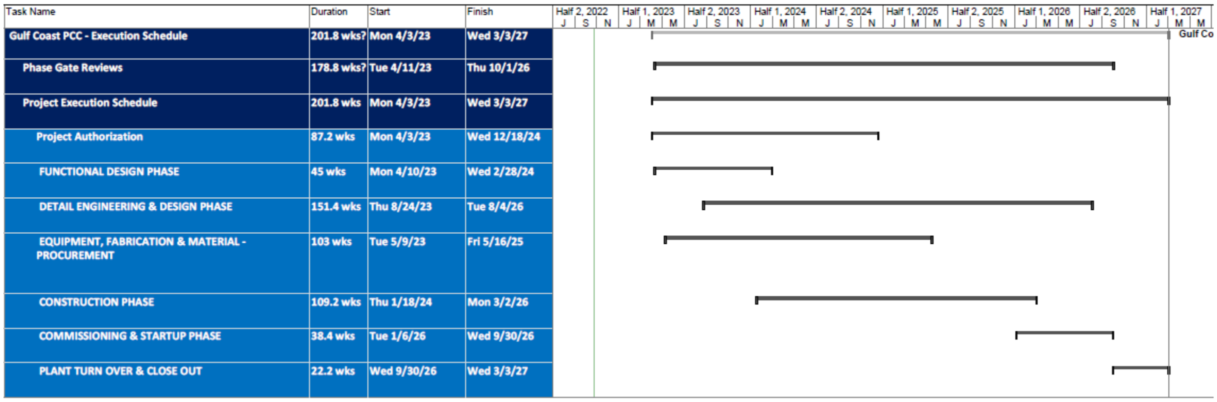
Capital costs were estimated with +/- 20% accuracy. It was assumed that equipment can be procured from anywhere in the world and engineering resources from Linde's offices in different countries can be used.

Equipment costs

Scope of equipment included all the ISBL and OSBL equipment, freight, initial fill of solvent and licensing fee. A detailed equipment list (see section 2.7) was prepared from the process flowsheet and heat and mass balances. Vendor quotes were received for >90% of equipment. At least three vendors were contacted for all the major equipment. Bid evaluations were conducted to select the quotes for inclusion in the CAPEX estimate. For certain smaller equipment, past references were used to estimate the costs. The electrical and controls equipment costs were estimated by Linde's internal experts. Freight costs were estimated based on logistics planning. List of spares needed was prepared and costs of spares were estimated. Certain pumps in the process were installed as 100% in-line spares.

Construction costs

A 3D model of the plant was developed and several constructability reviews were conducted to develop construction strategy. Materials takeoffs were defined for civil, mechanical and E&I (electrical and instrumentation) construction. The logistics plan for equipment delivery and an execution schedule were developed. A high-level project schedule is shown in Figure 12. Total duration from the project authorization to start-up is estimated to be 42 months. Labor costs were estimated based on local labor cost and productivity rates in the US Gulf Coast. Labor cost escalations over the project execution period were applied based on current trends.



Task Name	Duration	Start	Finish
Gulf Coast PCC - Execution Schedule	201.8 wks?	Mon 4/3/23	Wed 3/3/27
Phase Gate Reviews	178.8 wks?	Tue 4/11/23	Thu 10/1/26
Project Execution Schedule	201.8 wks	Mon 4/3/23	Wed 3/3/27
Project Authorization	87.2 wks	Mon 4/3/23	Wed 12/18/24
FUNCTIONAL DESIGN PHASE	45 wks	Mon 4/10/23	Wed 2/28/24
DETAIL ENGINEERING & DESIGN PHASE	151.4 wks	Thu 8/24/23	Tue 8/4/26
EQUIPMENT, FABRICATION & MATERIAL - PROCUREMENT	103 wks	Tue 5/9/23	Fri 5/16/25
CONSTRUCTION PHASE	109.2 wks	Thu 1/18/24	Mon 3/2/26
COMMISSIONING & STARTUP PHASE	38.4 wks	Tue 1/6/26	Wed 9/30/26
PLANT TURN OVER & CLOSE OUT	22.2 wks	Wed 9/30/26	Wed 3/3/27

Figure 12. Project Schedule

Engineering costs

Engineering resources were estimated for various disciplines that would be needed during different stages of project execution. Appropriate engineering labor rates were applied depending on which countries these resources are based in.

Owner's Costs

Owner's costs included cost of personnel and operating facilities during construction and commissioning. Property and insurance taxes were also included in this category.

Contingency costs

Risk analysis was carried out to determine contingencies required for the EPC costs. Table 11 lists major risks and mitigations for the project.

Table 11. Major Risks for the Project Execution

Category	**Risk**	**Mitigation**
Engineering Execution	Change in DoR (division of responsibility) leading to additional hours and schedule impact	Review DoR and execution strategy prior to proceeding to execution
Technology Development	Scale up of technology 40x to 70x	Include sufficient design margins
Technology Development	Design improvements applied on learnings from other projects/proposals	Continued communication with experts to determine if scope should be added
Construction Performance	Contractor availability, poor productivity	Apply learnings from recent execution of host SMR to attract productive craft

Schedule	Complexities of large scale construction	Early coordination and sequencing of contractors to minimize impact between trades
Logistics Planning	Concerns with river depth and availability of 50’ barge availability (2 within US)	Early in the project, complete survey on the river and book required barges
Commissioning	Large scale passivation of piping leading to large volume of contaminated water	Evaluate discharge of water to customer’s water treatment facility

On top of this, project level contingency cost was applied to cover unforeseen changes in scope, customer requirements.

The capital cost breakdown for Case 1 is shown in Table 12. The total CAPEX built up using Linde’s internal cost estimation methodology is equivalent to NETL’s definition of total overnight cost (TOC).

Table 12 Capital Cost of PCC Unit for Case 1

Category	**$MM**
Engineering	32
Equipment	110
Construction	217
Process Contingency	52
Owner's costs	10
Project contingency	29
Total Overnight Costs (TOC)	**450**

A step-off case was evaluated to estimate costs of achieving ~95% scope 1 CO_2 reduction by capturing CO_2 from both SMR and the aux. boiler flue gases. This case requires processing of ~18% more flue gas and capture of ~8% more CO_2 compared to the base case. The step-off case was evaluated at high level. PCC unit simulation was carried out to size major equipment and to estimate utilities. The TOC for this case was estimated to be $470 MM.

9. Technoeconomic Analysis

Carbon footprint results are summarized in Table 13.

Table 13. Carbon Intensity Summary

CI kg CO_2/kg H_2	No CCS	Case 1	Case 2
Scope 1	9.3	1.1	0.5
Scope 2	0.4	0.5	0.5
Scope 3 (Upstream NG & power)	2.4	2.6	2.6
Steam export credit	-1.4		
Total with steam credit	**10.7**	**4.2**	**3.7**
Total without steam credit	**12.1**	**4.2**	**3.7**

The cost summary for the base case 1 for two scenarios A and B are presented in Table 14:

Table 14. CCS Cost Breakdown for Case 1

	Case 1A	Case 1B
TOC, $MM	450	450
TASC/TOC multiplier	1.07	1.14
TASC, $MM	**481.5**	**513**
LCOCCS breakdown, $/T CO_2		
CAPEX recovery	$23.7	$55.4
Fixed costs	$12.1	$12.1
Variable costs	$24.8	$23.8
T&S	$10.0	$10.0
Total, $/T CO_2 captured	**$70.6**	**$101.3**
Total, $/T Scope 1 CO_2 reduced	$75.9	$109.1

The cost summary for the step-off case 2 for two scenarios A and B are presented in Table 14. The cost of CO_2 mitigation either on captured or avoided bases are slightly lower in Case 2 compared to those in Case 1, mainly due to slight economy of scale for a larger plant. Main difference is higher Scope 1 reduction and higher CAPEX investment in case 2 vs. Case 1.

Table 15. CCS Cost Breakdown for Case 2

	Case 2A	Case 2B
TOC, $MM	470	470
TASC/TOC multiplier	1.07	1.14
TASC, $MM	**503**	**536**
LCOCCS breakdown, $/T CO_2		
CAPEX recovery	$22.8	$53.4
Fixed costs	$11.7	$11.7
Variable costs	$24.8	$23.9

T&S	\$10.0	\$10.0
Total, \$/T CO_2 captured	**\$69.3**	**\$99.0**
Total, \$/T Scope 1 CO_2 reduced	**\$75.3**	**\$107.6**

10. Technology Maturation Plan Summary

10.1 Current Technology Readiness Level (TRL)

The current TRL of the Linde-BASF post-combustion CO_2 capture (PCC) process can be assessed in terms of the TRL of each of its key components/performance attributes that has been developed from the technology's conception. The developments to date have focused on coal-fired power plant flue gas, therefore TRL of key components of the Linde-BASF post-combustion CO_2 capture (PCC) process for SMR (steam methane reformer) flue gas are projected based on differences between coal-fired power plant and SMR flue gas streams as discussed below. As discussed below, TRLs for the SMR are same as that for coal-fired power plant, since SMR flue gas is a less challenging application for the technology compared to power plant application as SMR flue gas cleaner and is higher in CO_2 concentration compared to the coal plant flue gas (see Table 16).

Table 16. Comparison of Coal Power Plant and SMR H_2 Plant Flue Gases

	Coal-fired power plant	SMR H_2 plant
Temperature, ^oC	68 C (post SOx scrubber)	160 C (after ID fan)
Pressure	Ambient	Ambient
Composition (mol %):		
CO_2	~14%	~18%
$O_2 + N_2 + Ar$	~73%	~62%
H_2O	~13%	~20%
SOx	~40 ppm	<1 ppm
NOx	~80 ppm	~8 ppm
Mercury	present	0
Aerosols	significant	negligible

The 1.5 Mwe pilot plant (~30 tpd CO2) at the National Carbon Capture Center in Wilsonville, AL advanced the technology to TRL 6 [6]. A separate project (FE0031581) with the University of Illinois will advance the technology to TRL 7 [2]. Since process configuration of the PCC unit for a commercial scale SMR H2 plant is similar to the that for coal-fired power plant, the TRL advancements achieved for coal-fired power plants are applicable for the SMR H_2 plant.

10.2 Relating engineering study to maturation of technology

Linde and BASF have built many commercial scale amine units for a variety of applications. Majority of these applications involved separating CO_2 from high pressure streams in ammonia, coal gasification, hydrogen/syngas and natural gas processing plants. Separation of CO_2 from the flue gas sources differs from these applications with respect to following parameters: 1) pressure of flue gas is near-ambient resulting in lower driving force for separation 2) presence of oxygen in flue gas can degrade conventional amine solvents 3) presence of trace impurities such as SOx/NOx and particulate matter can affect the performance of solvent. Work done to achieve TRL 6 for the PCC technology have overcome these challenges and demonstrated key performance attributes such as CO_2 capture rate (>90%), CO_2 purity (>99.9%), low reboiler energy (~2.8 GJ/ton CO_2) and high regeneration pressure (up to 3.4 bar) [6, 7].

For the SMR flue gas application, next step in technology maturation plan is to build a first commercial scale CO_2 capture plant with EOR (enhanced oil recovery) or sequestration as an application. The CO_2 capture systems for commercial scale EOR or sequestration applications are likely to be in the range of 1000 – 4000 MT/day capacities. These systems are expected to cost >$100 MM and therefore such project can be undertaken only when commercially viable opportunity becomes available. While building such systems are well within the capabilities of Linde and BASF based on their prior experience and knowledge gained from the pilot scale demonstration of PCC technology developed for flue gas, detailed engineering design for SMR applications have never been undertaken and as a result, scale-up risks have not been identified. The work done in the current project has bridged this gap.

The current project developed engineering design of a full-scale commercial system. This study has created a foundation for building a large-scale commercial unit. It was determined that risks associated with scale-up to a very large-scale commercial implementation (>1000 tpd CO_2 capture capacity) are manageable. Following major risks for scale-up were considered for commercial readiness:

- Need for demonstration of key performance parameters at pre-commercial scale before going commercial such as solvent selectivity for CO_2, CO_2 capture rate, CO_2 purity and higher regeneration pressure.

  These parameters were proven at NCCC.

- Development requirement for any equipment required in a commercial scale plant.

  Based on the vendor responses, it was clear that multiple vendors are able to offer all the equipment necessary for a commercial scale plant.

- Performance risks such as ability to achieve design capture rate and reboiler duty.

  These risks will be managed by oversizing certain equipment in the amine unit to ensure that any underperformance can be overcome by adequate equipment capacity.

In parallel to the proposed work, a separate project is planned to advance this technology to TRL 7. This project is part of the potential Phase III of the project led by the University of Illinois with Linde as a partner, "Large Pilot Testing of Linde-BASF Advanced Post-Combustion Carbon Dioxide Capture Technology at a Coal-Fired Power Plant," DOE-NETL project FE0031581. This project involves building a prototype for 10 MWe scale coal-fired power plant. The results from this other project when available will help us further optimize the design for the SMR flue gas application and eliminate some of the risks for scale-up.

If we have an authorized SMR project before the large pilot operations data is available, the design margins we use could be larger than usual as scale-up factor (>40X for FG flow and >70X for CO_2 volumes) from the last proven capacity is large. After the large pilot is successfully demonstrated, we would adjust those margins to more appropriate level for scale-up of ~10X.

10.3 Post-Project Plans

Based on the work performed during this project, no technical showstoppers were identified. Linde considers this technology commercial ready for SMR flue gas application. The results from this project are being used for evaluating opportunities within Linde's fleet of H_2 plants. Performance risk in the first commercial plant will be managed by applying appropriate design margins and these margins will be decreased in subsequent installations. A key challenge that is identified for this technology is high CAPEX. One major opportunity for cost reduction is modularization of certain plant equipment and piping.

11. Conclusions

First comprehensive engineering design study was completed for retrofitting existing SMR H_2 plant with Linde-BASF advanced post combustion capture technology. From technology maturity perspective, the technology is ready for commercial deployment for world scale SMR hydrogen plants. The CO_2 capture capacity at 95% capture rate for the selected site is ~1.4 MM tonnes/yr. A single train design was the basis for the engineering study. Total CAPEX was estimated to be $450 MM. The total cost of CCS could vary significantly depending on the financial and project life assumptions. Two specific scenarios were evaluated to bracket the CCS costs. First scenario assumed low financing cost and 30 years project life and the second scenario assumed high financing cost and 15 years project life. The CCS costs for these two scenarios were $71 and $101/t CO_2, respectively. CAPEX charges dominated the overall cost of CO_2 capture for the second scenario. Potential exists to reduce CAPEX further based on lessons learned from this study. Irrespective of specifics of individual project, passing of IRA (inflation reduction act) will certainly improve the commercial viability of capturing CO_2 from hydrogen plants that are in the US.

References

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Appendix A. TEA Methodology

NETL's methodology for levelized cost was adapted for technoeconomic analysis [8, 9]. The levelized cost of CCS was estimated from CAPEX and OPEX estimates for the PCC unit. Real dollars are used as basis of all calculations. There are some differences in the approach used in this report vs. NETL methodology. These differences are noted where applicable. Two different scenarios for financing were evaluated. First scenario (A) is same as the one described in NETL's cost assessment on H2 production technology [8]. Second scenario (B) was defined based on 15 years project life and 100% equity financing. The cost of equity for Scenario B was assumed to be 7.84%, same as reported in NETL's QGESS for costs [9].

Table 17 Assumptions for Two TEA Scenarios

	Scenario A	Scenario B
Project life	30	15
Debt	38%	0%
Equity	62%	100%
Real $ cost of debt	5.15%	n/a
Real $ cost of equity	3.10%	7.84%

Finance structure and cost of capital for two scenarios are summarized in

Table 18. Real Rates Financial Structure for Two TEA Scenarios

Scenario	Type of security	% of total	Current Dollar Cost (Real)	Weighted average cost of capital (WACC)	After tax Weighted average cost of capital (ATWACC)
A	Debt	38%	5.15%	1.957%	1.453%
	Equity	62%	3.10%	1.922%	1.922%
	Total			3.879%	**3.375%**
B	Debt	0%	2.94%	0	0
	Equity	100%	7.84%	7.84%	7.84%
	Total			7.84%	**7.84%**

LCOCCS = LCC + LOM + LVC + LTS (all expressed in $/T CO_2). Equation 1

Where,

LCOCCS = levelized cost of carbon capture and storage

LCC = levelized capital cost

LOM = levelized O&M costs

LVC = levelized variable costs

LTS = levelized T&S (transportation & storage) costs

LCC:

LCC was calculated per following equations from NETL's QGESS report [9].

LCC = TASC * FCR /(Annual CO_2 volume in T (metric tons))

$$FCR = CRF/(1 - ETR) - ETR*D/(1 - ETR) \qquad \text{Equation 2}$$

$$CRF = ATWACC*(1 + ATWACC)^y/((1 + ATWACC)^y - 1) \qquad \text{Equation 3}$$

$$D = CRF*\sum_{n=1}^{z} \frac{d_n}{(1+ATWACC)^n} \qquad \text{Equation 4}$$

Where,
TASC = total as spent costs

FCR = fixed charge rate

CRF = capital recovery factor

ETR = effective tax rate

ATWACC = after tax weighted average cost of capital

D = present value of tax depreciation expense

d_n = tax depreciation fraction in year n [10]

z = number of years of depreciation (= y +1)

y = number of operating years

Calculations of FCR for two scenarios is summarized in Table 19.

Table 19. Fixed Charged Rate Calculations for Two TEA Scenarios

	Scenario A	Scenario B
CRF	0.053525	0.115691
D	0.034186	0.067699
FCR	0.060228	0.132326

Year	Depreciation fraction, d_n	$d_n/(1 + \text{ATWACC})^n$	Depreciation fraction, d_n	$d_n/(1 + \text{ATWACC})^n$
1	0.025	0.02418	0.05	0.046365
2	0.04875	0.04562	0.095	0.081689
3	0.04631	0.04192	0.0855	0.068175
4	0.044	0.03853	0.077	0.056934
5	0.0418	0.03541	0.0693	0.047515
6	0.03971	0.03254	0.0623	0.03961
7	0.03772	0.02990	0.059	0.034785
8	0.03584	0.02748	0.059	0.032256
9	0.03404	0.02525	0.0591	0.029962
10	0.03234	0.02320	0.059	0.027737
11	0.03072	0.02132	0.0591	0.025764
12	0.02994	0.02010	0.059	0.02385
13	0.02994	0.01945	0.0591	0.022154
14	0.02994	0.01881	0.059	0.020508
15	0.02994	0.01820	0.0591	0.01905
16	0.02994	0.01760	0.0295	0.008817
17	0.02994	0.01703		
18	0.02994	0.01647		
19	0.02994	0.01593		
20	0.02993	0.01541		
21	0.02994	0.01491		
22	0.02993	0.01442		
23	0.02994	0.01395		
24	0.02993	0.01349		
25	0.02994	0.01306		
26	0.02993	0.01263		
27	0.02994	0.01222		
28	0.02993	0.01182		
29	0.02994	0.01143		
30	0.02993	0.01106		
31	0.01497	0.00535		

TASC:

Calculations for TASC/TOC factors for two scenarios are calculated using following equations from NETL's QGESS cost report [9].

TASC/TOC = Escalation + Cost of funding

Where:

Escalation = $\sum_{n=1}^{y}\left[(1+i)^{(n-1)} * \%capital_n\right]$ Equation 5

Cost of funding = $\sum_{n=1}^{y}\left[WACC * (y-n+1) * (1+i)^{(n-1)} * \%capital_n\right]$ Equation 6

TASC/TOC for Scenario A is in Table 20.

Table 20. TASC/TOC for Three Years for Two Scenarios

Scenario	Cost year	Escalated cost	Cost of funding	WACC	Escalation	Capital expenditure
A	1	0.1	0.011637	0.03879	0%	10%
	2	0.6	0.046548	0.03879	0%	60%
	3	0.3	0.011637	0.03879	0%	30%
	Total	1.0	0.069822			
	TASC/TOC	1.07				
B	1	0.1	0.02352	0.0784	0%	10%
	2	0.6	0.09408	0.0784	0%	60%
	3	0.3	0.02352	0.0784	0%	30%
	Total	1.0	0.14112			
	TASC/TOC	1.14				

LOM:

For real $ basis with zero escalation, levelized O&M costs are same as annual O&M costs, i.e. levelization factor is 1. Annual O&M costs include all the fixed costs such as salaries of personnel, regular maintenance and replacement costs (maintenance material and labor) for plant equipment and operating facilities, taxes and insurance. In NETL's methodology, maintenance material costs are included in the variable costs. The annual O&M costs are assumed to be 3.3% of TOC/year. These costs exclude any consumables such as catalysts, chemicals or solvent, which are included in the variable costs.

LOM = Annual O&M costs/(annual CO_2 volume)

LVC:

The levelized variable costs include costs of all the utilities and consumables such as NG, steam, power, water, chemicals and solvent. In NETL's methodology, fuel cost contribution to levelized cost of product is itemized separate from the other variable costs. Only fuel price was assumed to be levelized fuel price (LFP) from the NETL report. Since steam was assumed to be a fixed multiple of NG cost, it was also priced at levelized cost. For scenario B, NG and steam prices were adjusted to account for change in levelization factor 15 years project life vs. 30 years in Scenario A. This adjustment was estimated by following the methodology for levelized fuel price estimate in the NETL report. Other costs were either taken from the NETL report or from Linde's estimates. These assumptions are listed in Table 21. Consumption of NG, steam, power and water are assumed to be proportional to CO_2 capture volume, while consumption of chemicals and solvent are assumed to be fixed annual volumes.

Table 21. Assumptions for Prices of Utilities and Consumables

	Scenario A	Scenario B
LFP for NG, $/MMBtu HHV	$4.42	$4.17
Power, $/MWh	$71.7	$71.7
Solvent	confidential	confidential
Water, $/1000 gal	$1.90	$1.90
Caustic soda (25% soln.), $/gal	$0.75	$0.75
Activated carbon, $/lb	$2.80	$2.80

LVC = (total annual variable costs)/(annual CO_2 capture volume)

LTS:

Levelized transportation & storage costs are assumed to be $10/T CO_2.

Using approach described above, the LCOCCS was estimated based on captured CO_2 volume as well as based on Scope 1 CO_2 emissions reduced (Scope $1_{\text{non-CCS}}$ – Scope 1_{CCS}).

Carbon Footprint Analysis

The CO_2 emission factors listed in Table were used to estimate carbon footprint.

Table 22. Emission Factors for NG and Power

Parameter	Emission factors
NG Scope 1 (direct), kg CO_2e/MMBtu HHV	53.15
NG Scope 3 (upstream), kg CO_2e /MMBtu HHV	12.77
Power Scope 2 (direct), kg CO_2e /kWh	0.4
Power Scope 3 (upstream energy production), kg CO_2e /kWh	0.15