

SLIPSTREAM PILOT-SCALE DEMONSTRATION OF A NOVEL AMINE-BASED POST-COMBUSTION TECHNOLOGY FOR CARBON DIOXIDE CAPTURE FROM COAL-FIRED POWER PLANT FLUE GAS

Topical Report:

FINAL TECHNO-ECONOMIC ANALYSIS OF 550 MWe SUPERCRITICAL PC POWER PLANT WITH CO₂ CAPTURE USING THE LINDE-BASF ADVANCED PCC TECHNOLOGY

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Executive Summary

This topical report presents the techno-economic evaluation of a 550 MWe supercritical pulverized coal (PC) power plant utilizing Illinois No. 6 coal as fuel, integrated with 1) a previously presented (for a subcritical PC plant) Linde-BASF post-combustion CO₂ capture (PCC) plant incorporating BASF's OASE[®] blue aqueous amine-based solvent (LB1) [Ref. 6] and 2) a new Linde-BASF PCC plant incorporating the same BASF OASE[®] blue solvent that features an advanced stripper interstage heater design (SIH) to optimize heat recovery in the PCC process. The process simulation and modeling for this report is performed using Aspen Plus V8.8. Technical information from the PCC plant is determined using BASF's proprietary thermodynamic and process simulation models. The simulations developed and resulting cost estimates are first validated by reproducing the results of DOE/NETL Case 12 representing a 550 MWe supercritical PC-fired power plant with PCC incorporating a monoethanolamine (MEA) solvent as used in the DOE/NETL Case 12 reference [Ref. 2].

The results of the techno-economic assessment are shown comparing two specific options utilizing the BASF OASE[®] blue solvent technology (LB1 and SIH) to the DOE/NETL Case 12 reference. The results are shown comparing the energy demand for PCC, the incremental fuel requirement, and the net higher heating value (HHV) efficiency of the PC power plant integrated with the PCC plant. A comparison of the capital costs for each PCC plant configuration corresponding to a net 550 MWe power generation is also presented. Lastly, a cost of electricity (COE) and cost of CO₂ captured assessment is shown illustrating the substantial cost reductions achieved with the Linde-BASF PCC plant utilizing the advanced SIH configuration in combination with BASF's OASE[®] blue solvent technology as compared to the DOE/NETL Case 12 reference. The key factors contributing to the reduction of COE and the cost of CO₂ captured, along with quantification of the magnitude of the reductions achieved by each of these factors, are also discussed. Additionally, a high-level techno-economic analysis of one more highly advanced Linde-BASF PCC configuration case (LB1-CREB) is also presented to demonstrate the significant impact of innovative PCC plant process design improvements on further reducing COE and cost of CO₂ captured for overall plant cost and performance comparison purposes.

Overall, the net efficiency of the integrated 550 MWe supercritical PC power plant with CO₂ capture is increased from 28.4% with the DOE/NETL Case 12 reference to 30.9% with the Linde-BASF PCC plant previously presented utilizing the BASF OASE[®] blue solvent [Ref. 6], and is further increased to 31.4% using Linde-BASF PCC plant with BASF OASE[®] blue solvent and an advanced SIH configuration. The Linde-BASF PCC plant incorporating the BASF OASE[®] blue solvent also results in significantly lower overall capital costs, thereby reducing the COE and cost of CO₂ captured from \$147.25/MWh and \$56.49/MT CO₂, respectively, for the reference DOE/NETL Case 12 plant, to \$128.49/MWh and

\$41.85/MT CO₂ for process case LB1, respectively, and \$126.65/MWh and \$40.66/MT CO₂ for process case SIH, respectively. With additional innovative Linde-BASF PCC process configuration improvements, the COE and cost of CO₂ captured can be further reduced to \$125.51/MWh and \$39.90/MT CO₂ for LB1-CREB. Most notably, the Linde-BASF process options presented here have already demonstrated the potential to lower the cost of CO₂ captured below the DOE target of \$40/MT CO₂ at the 550 MWe scale for second generation PCC technologies.

1. Introduction

This topical report, prepared in accordance with the DOE requirements, consists of an Executive Summary, six Sections and four Appendices. While Section 2 briefly outlines the evaluation basis used in this study, including the methodology of calculating the COE and cost of CO₂ captured, Section 3 is divided into two subsections: the first provides background information related to the development of the BASF OASE[®] blue solvent technology, and the second subsection provides a simplified process flow diagram of the Linde-BASF advanced PCC technology and highlights the major innovations incorporated into the design of the PCC plant.

Section 4 begins by displaying a block flow diagram of an integrated 550 MWe supercritical PC power plant utilizing PCC with a brief description of the overall process and then provides key assumptions used in this study. The process integration options considered between a PC power plant and Linde-BASF PCC plant are also discussed.

Section 5 provides the detailed results of the techno-economic assessment (TEA) including COE and cost of CO₂ captured for each process case investigated. After highlighting the modeling approach and the methodology adopted for its validation, the performance results of a 550 MWe supercritical PC power plant integrated with the Linde-BASF PCC plant utilizing an advanced stripper interstage heater (SIH) configuration are presented. The PCC process features an enhanced Linde-BASF process configuration with optimized operating parameters and equipment arrangement. The performance indicators include comparisons of specific energy requirements for Linde-BASF PCC options versus the DOE/NETL Case 12 reference [Ref. 2], and demonstrate the superior performance of the proposed technologies. This section also provides detailed material and energy balances for the overall integrated PC power plant equipped with PCC, as well as of the water-steam-power generation island of the plant, for cases LB1 and SIH. The performance summary details all elements of auxiliary power consumption along with net plant efficiencies, and also highlights all major environmental benefits of the Linde-BASF PCC technologies.

Evaluation of the resulting COE and cost of CO₂ captured for a 550 MWe supercritical PC power plant equipped with PCC starts with a presentation of the methodologies used to estimate the total plant cost

(TPC) for the PCC plant, and the TPC and total overnight cost (TOC) of a supercritical PC power plant integrated with PCC. The incremental reduction in COE and cost of CO₂ captured when progressively advanced PCC technology options are used for a supercritical PC steam cycle, as compared to the DOE/NETL Case 12 reference [Ref. 2] utilizing standard MEA solvent-based PCC, is quantified.

The TEA is completed with concluding remarks emphasizing the substantial benefits of the proposed Linde-BASF advanced PCC technology integrated with a large-scale supercritical PC power plant.

2. Evaluation Basis

For each case presented in this study, AspenTech's Aspen Plus V8.8 software has been used as a generalized platform for the rigorous mathematical modeling, simulation, design, and optimization of the integrated PC power plant equipped with PCC unit. BASF's proprietary software package has been utilized for the detailed modeling, analysis, and optimization of the amine-based PCC plant options. The resulting key process performance indicators have been used to determine the incremental capital charges for the power plant (with respect to the DOE/NETL Case 12 reference [Ref. 2]) by utilizing estimated scaling parameters, while the capital cost estimate for the Linde-BASF PCC technology is based on in-house proprietary costing tools and experience from recent proposals and studies. A previously developed Linde thermodynamic model for solid fuels, consistent with a previously Linde-configured Unisim computational platform, has been used in this study to reproduce thermodynamic and physical properties of Illinois No. 6 bituminous coal, as shown in Exhibit 2-1. Within Aspen Plus V8.8, the STEAMNBS and Peng-Robinson property packages are utilized for calculations involving the power plant steam cycle and CO₂ compression, respectively.

Exhibit 2-1. Design Coal		
Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg	27,113	30,506

HHV, Btu/lb	11,666	13,126
LHV, kJ/kg	26,151	29,544
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
Mercury	0.13 ppm	0.15 ppm (dry)
Total	100.00	100.00

Site characteristics, raw water usage, and environmental targets are identical to those detailed in Section 2 of the DOE/NETL Case 12 reference [Ref. 2].

The methodology for calculating the COE over a period of 20 years used in this study is, again, identical as in the DOE/NETL Case 12 reference for 2011 [Ref. 2 and Ref. 7], where COE is used instead of LCOE for cost performance assessment purposes:

$$COE = \{ (CCF) * (TOC) + OC_{FIX} + (CF) * (OC_{VAR}) \} / [(CF) * (aMWh)]$$

In addition, the cost of CO₂ captured is calculated using:

Cost of CO₂ Captured =

$$\{ COE - COE_{reference} \} \$ / MWh / \{ CO_2 \text{ Captured} \} \text{ tonnes} / MWh$$

Interpretation of all abbreviations is provided in the appendix.

The following economic parameters are used for COE and cost of CO₂ captured calculations:

DOE/NETL Case 12 reference (2011) Capital Charge Factor (CCF) = 0.1240

The economic assumptions used to derive the above values are summarized in Exhibit 2-14 and Exhibit 2-15 of the DOE/NETL Case 12 reference [Ref. 2]. Consequently, the calculated COE and cost of CO₂ captured values in this study have been expressed in 2011\$ to be able to consistently evaluate the influence of the novel PCC technology on the incremental reduction of COE, as compared to the DOE/NETL Case 12 reference (2011\$). Additionally, for this study, the total overnight costs (TOC) of

the entire PC plant integrated with PCC technology are calculated using the same methodology as in the DOE/NETL Case 12 reference [Ref. 2]:

$$TOC = TPC + \text{Preproduction Costs (PPC)} + \text{Inventory Capital (IC)} + \text{Initial Cost for Catalyst and Chemicals (ICCC)} + \text{Land \& Other Owner's Costs (LOOC)} + \text{Financing Costs (FC)}$$

Where: 1) TPC is the total capital cost of the complete PC plant integrated with PCC; 2) PPC are the sum of costs of 6 months labor, 1 month maintenance materials, 1 month non-fuel consumables, 1 month waste disposal, 25% of 1 month's fuel cost, and 2% of TPC; 3) IC are the costs of 60 day supply of fuel and consumables at 100% CF plus 0.5% of TPC in spare parts; 4) ICCC is the cost of 0.193% of TPC; 5) LOOC are the costs of 0.0459% of TPC (Land) plus 15% of TPC for other owner's costs; and 6) FC are the costs equivalent to 2.7% of TPC [Ref. 2].

3. BASF-Linde 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 CO₂ recovery from low-pressure, dilute flue gas streams from power plants and industrial processes, combined with the joint Linde/BASF collaboration since 2007 in designing and testing resulting advanced PCC technology, including the work entailed in the previous Linde techno-economic report from May, 2012 [Ref. 6]. This section provides the highlights of the key characteristics of BASF's OASE[®] blue process, along with Linde-BASF PCC plant design innovations.

3.1. BASF OASE[®] Blue Technology

With climate change becoming an increasing concern globally, BASF's gas treatment team is actively leveraging its expertise to become a leading contender in the race to make carbon capture and storage (CCS) commercially viable. Over the years, BASF's gas treatment portfolio has continuously expanded. Beyond extensive offering in technology and gas-treating chemicals, the world's largest chemical company can supply additional technical support services, such as customized onsite training of its customers' personnel on the optimized operations of gas treatment processes and equipment. It recently began marketing its entire gas-treating portfolio under the trade name OASE[®], where OASE[®] blue is the brand for flue gas carbon capture. The team considers CCS as the most-effective measure in the mid-term to combat further increase of CO₂ emissions into the atmosphere. Based on over 250 gas treatment reference plants in 2004 in ammonia, oxo-syngas, natural gas, and liquefied natural gas applications as well as experiences in iron ore gas and selective sulfur gas treatment, it was decided at that time to systematically develop new chemical solvent technologies targeting the specific requirements of large-

scale carbon capture applications. Besides low pressure and large volume systems that need to consider emissions to meet environmental requirements, there is the additional challenge of very low driving forces for CO₂ mass transfer. The oxygen-containing atmosphere is aggressive to amines, and high energy efficiency is absolutely critical for the success of such CO₂ processes. Consequently, the most important parameters for the development are energy demand, cyclic capacity, solvent stability, reactivity, volatility, environmental sustainability, and availability.

BASF's screening process assessed over 400 substances, which were pre-selected based on molecular weight, vapor pressure, alkalinity, and safety data. About half of the candidates were further investigated for vapor-liquid equilibrium, reaction kinetics, and stability data. About 20 component mixtures were then subjected to a proof-of-concept run in BASF's mini plant where the complete capture process is verified. This valuable tool can show early on in development whether or not a chemical solvent has the potential for further testing at the pilot-scale using real power plant off gases containing CO₂.

In parallel, BASF monitored the energy industry's approaches towards carbon capture and also contributed to several research projects within the 6th and 7th integrated framework programs of the European Union. During the CASTOR and CESAR projects, the BASF team exchanged experiences with the relevant players in the community and transferred significant gas treating know-how from the petrochemical industry to the energy and energy-related institutes.

Together with Linde, BASF is a partner in a pilot project steered by RWE Power at German energy provider's Coal Innovation Center in Niederaussem, Germany, near Cologne. The post-combustion pilot plant on coal-fired off gas in Germany was constructed, commissioned, and started up in 2009. Despite the rather small dimensions and capacity to capture only 7.2 tonnes of CO₂ per day from a flue gas slipstream of the power plant, several critical issues were successfully tested. In particular, reliable data on energy consumption and long-term stability were generated, which helped to serve as an experimental basis for the Linde-BASF PCC plant tested in Wilsonville, AL at NCCC in 2015 and 2016.

Based on this work and the invaluable feedback of know-how from over 300 plants operating with OASE[®] technology, BASF can already guarantee excellent performance at today's state of development. Process performance parameters proven through past experience include CO₂ capture rate, flow rate/capacity, reboiler duty, process emissions, circulation rate, and CO₂ purity. Today, an OASE[®] blue process can be safely and reliably operated to achieve these main objectives. Incorporation of the OASE[®] blue technology with an advanced PCC process design and equipment configuration offers substantial further potential for process optimization improvements and cost reductions, which are investigated in this study.

3.2. Post Combustion Capture Plant

The PCC plant is designed to recover 90 percent of the CO₂ contained in the flue gas downstream of the flue gas desulfurization (FGD) unit, purify it (> 99.9 vol% CO₂, < 10 vol. ppm O₂), 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) with sulfur dioxide (SO₂) Polishing Scrubber, Flue Gas Blower, CO₂ Absorber with Interstage cooler, Water Wash unit, Solvent Stripper with Reboiler, and CO₂ Compression and Drying. The design and operation of these PCC plant components, along with options for PC power plant heat integration, are described in more detail below. A simplified process flow diagram of the LB1 PCC plant is shown in Exhibit 3-1, in which BASF OASE[®] blue technology is used along with a series of advanced equipment and process design options incorporated into the overall Linde-BASF PCC plant design with the final goal of minimizing the energy requirements for CO₂ removal and compression, as per DOE/NETL Case 12 reference conditions [Ref. 2]. A couple of noticeable process configuration variations and improvements include an integrated DCC, Absorber and Water Wash units, and a flue gas blower located downstream of the absorber, which is discussed below in more detail along with other process integration and optimization options outlined in Section 4.3. For the scientific purposes of this report in demonstrating state-of-the-art technology improvements for CO₂ capture, a process flow diagram of the Linde-BASF PCC plant incorporating BASF OASE[®] blue solvent technology with an advanced SIH configuration is shown in Exhibit 3-2. As illustrated in Exhibit 3-1, the novel Linde-BASF PCC design fully integrates the DCC unit with the Absorber and Wash units within one shared column. The DCC has two functions: (1) to cool down the incoming flue gas stream to a temperature suitable for efficient CO₂ absorption, and (2) to provide an aqueous solution of sodium hydroxide (NaOH) to reduce the SO₂ concentration in the gas entering the absorber to as low a level as possible to minimize solvent degradation due to the formation of SO₂-amine complexes. Lastly, a process flow diagram of the Linde-BASF PCC plant coupled with BASF OASE[®] blue solvent technology along with a main CO₂-lean/CO₂-rich heat exchanger bypass integrated with cold CO₂-rich exchanger bypass configuration (LB1-CREB) is shown in Exhibit 3-3. The LB1-CREB process option offers substantial energy savings compared to the SIH configuration due to increased heat recovery, but the impact of potential capital cost increases of the LB1-CREB design (due to the addition of multiple heat exchangers) compared to the SIH option needs to be further evaluated.

The feed stream to the PCC plant is water-saturated flue gas from the FGD unit, typically at atmospheric pressure and a temperature of 120 to 140°F (approximately 50-60°C). An aqueous solution of NaOH is injected into the water-NaOH circulation loop, and then sprayed at the top of the DCC unit. More than 90% of the incoming SO₂ is scrubbed from the vapor-phase via counter-current contact of the chilled

aqueous NaOH solution with warm flue gas. The liquid from the bottom of the DCC bed is fed to a circulating pump; the excess water, condensed from the flue gas, along with dissolved Na_2SO_3 , is withdrawn from the loop and sent to an acid neutralization and water treatment facility, while the majority of the aqueous NaOH solution in the recirculation loop is cooled with water. In the case of PC power plants, an integrated cooling water system is used to supply cooling water to all process units, including the PCC and CO_2 compression plants.

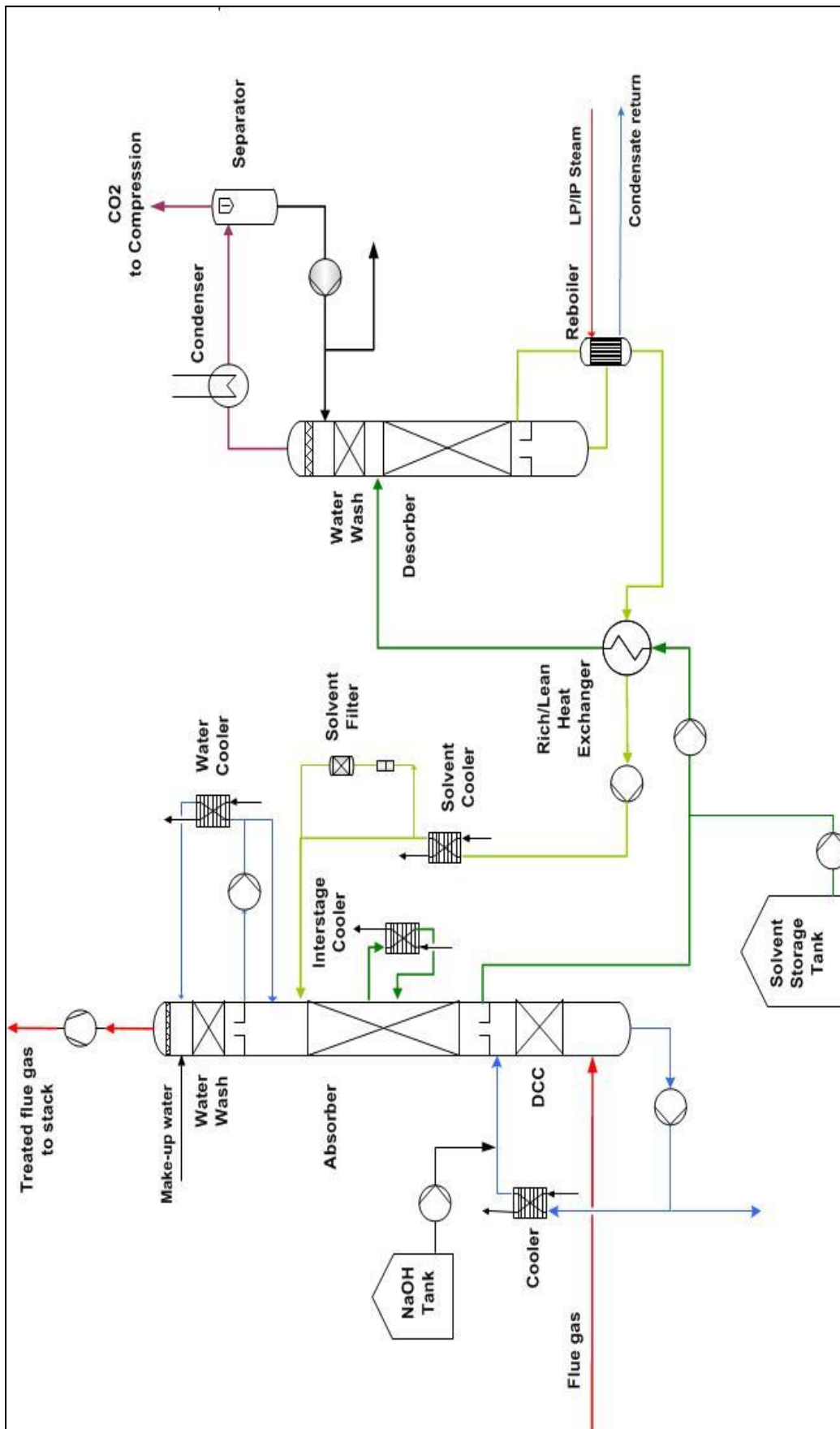


Exhibit 3-1. Simplified Process Flow Diagram of Linde-BASF Post Combustion Capture Technology (LB1)

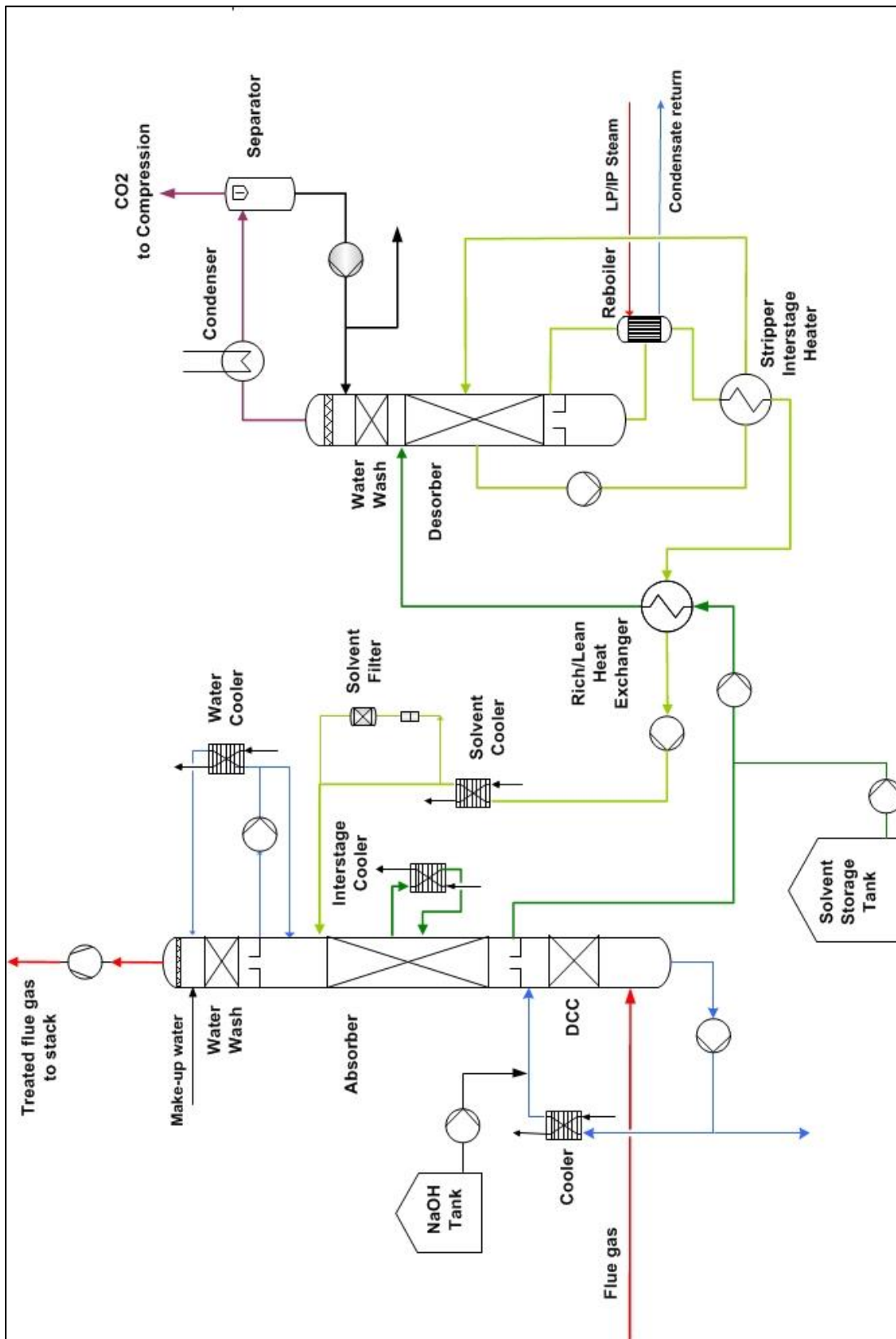
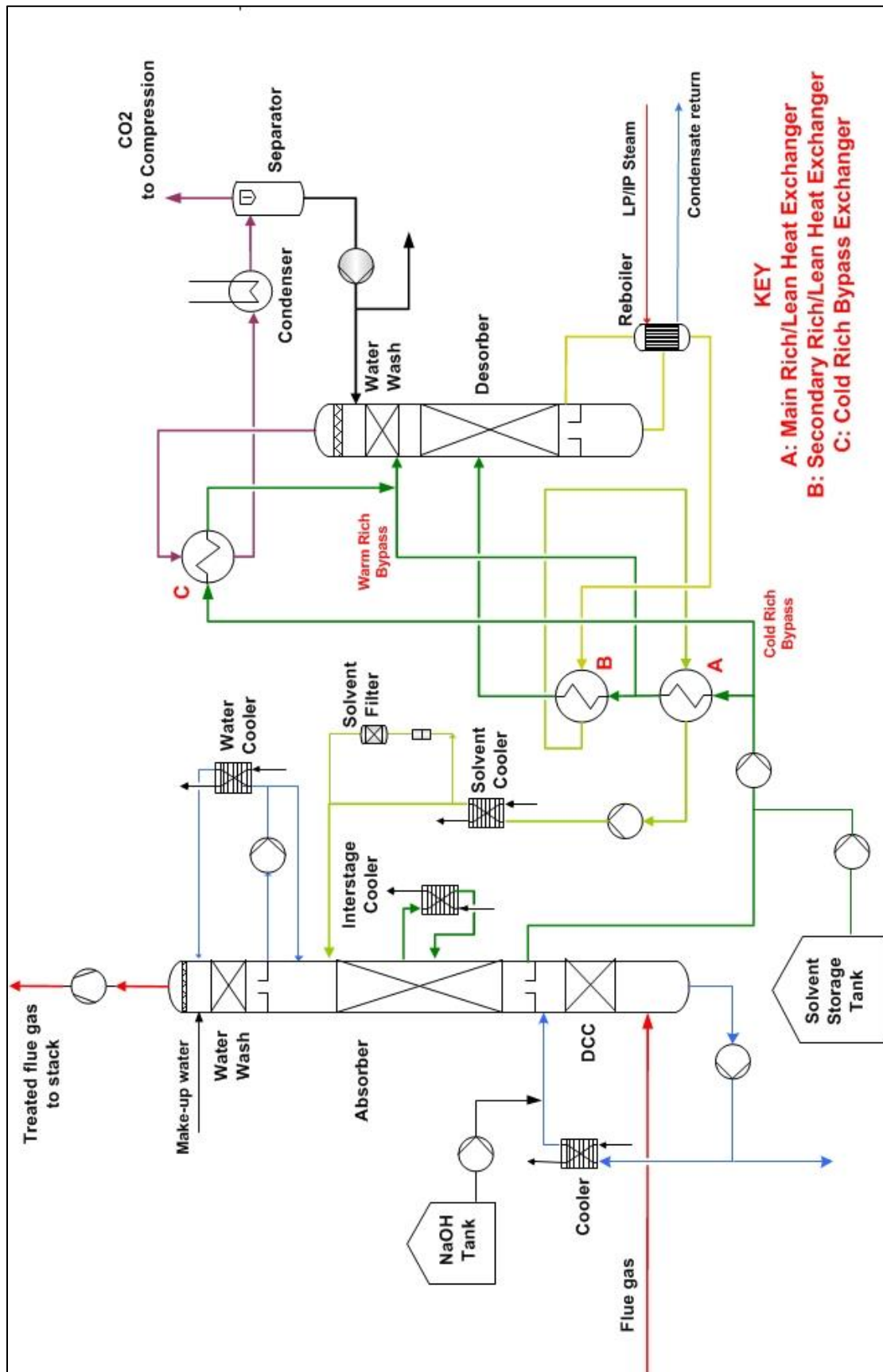


Exhibit 3-2. Simplified Process Flow Diagram of Linde-BASF Post Combustion Capture Technology with Advanced Stripper Interstage Heater Configuration (SIH)



As quantified in more detail later in Exhibit 5-1, the following benefits for the Linde-BASF PCC process options (integrated with 550 MWe-net supercritical PC power plant) are derived from the proposed configuration of directly-connected DCC and Absorber units, along with the flue gas blower positioned downstream of the absorber column.

- Significantly reduced cooling duty requirements (~30% reduction for LB1 case and 43% reduction for SIH case), since it is not necessary to cool down the flue gas stream beyond the CO₂ absorption requirements, as is normally done to compensate for a significant temperature rise (up to 30°F) across the flue gas blower.
- Notably reduced separation system electrical power requirement (~13% for both LB1 and SIH cases), due to the substantially lower molar flowrate of CO₂-depleted flue gas downstream of the absorber, as compared to the flue gas flow upstream of the absorber; the difference being 90% absorbed CO₂ from the flue gas within the absorber bed into the BASF OASE[®] blue solvent.

CO₂ Absorber with Interstage Cooler. The CO₂-lean BASF OASE[®] blue amine-based solvent flows down through the absorber bed and absorbs CO₂ from the flue gas, which flows from the bottom to the top of the column and to the water wash unit. Since the exothermic chemisorption reaction of CO₂ with amine-based solvents increases the temperature of the flue gas and consequently reduces the equilibrium content of CO₂ in the liquid-phase, it is of utmost importance to maintain a low, relatively constant temperature throughout the entire absorber. In addition to cooling the CO₂-lean amine solvent solution within an external cooler before it is injected to the top of the absorber, a significant solvent temperature rise within the column can be efficiently suppressed by the use of an interstage cooler, as shown above in Exhibit 3-1. Linde's gravity-driven interstage cooler design eliminates the need for an external interstage cooler pump, and consequently leads to a simplified design as well as a reduced capital cost for the absorber with interstage cooler.

The Linde-BASF PCC technology also utilizes the most advanced structured packing for the absorber to promote efficient hydraulic contact of gas and liquid phases, which along with increased CO₂ reaction rates with BASF's OASE[®] blue solvent, facilitates a fast approach to equilibrium CO₂ concentration in the liquid-phase. Consequently, the capacity of the absorber, one of the most critical parameters for a large-scale CO₂ absorption plant, is dramatically increased. In addition, the advanced structured packing reduces the pressure drop across the column, which in turn decreases the flue gas blower capital cost and electrical power consumption. The structured packing selection was determined by optimization of

various structured packing options offering higher capacities while trading off on the mass-transfer efficiency.

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 as well as design improvements upstream of the PCC plant that minimize solvent-carrying aerosol formation in the flue gas to the CO₂ absorber. The CO₂-depleted flue gas that leaves the absorber bed still carries a small amount of solvent. Cold water sprayed from the top of the wash unit effectively scrubs the solvent from the flue gas - an effect that is enhanced by a significantly reduced equilibrium composition of the solvent components in the vapor-phase as a result of the reduced outlet temperature at the top of the absorber. An external plate-and-frame heat exchanger in the water recirculation loop transfers the required cooling duty to the absorber water wash sections from the cooling water supplied by the central cooling water system.

Solvent Stripper with Interstage Heater (SIH Configuration). The CO₂-rich solvent, heated upstream of the stripper column in the rich/lean heat exchanger, enters the solvent stripper column section consisting of two packed-beds. The reboiler at the bottom of the stripper column uses the heat of condensation of low-pressure steam (5 bara) to vaporize CO₂ and water from the CO₂-concentrated solvent. Counter-current flow of the CO₂-rich liquid-phase from the top of the stripper and the solvent-depleted vapor-phase rising from the reboiler facilitates separation of the CO₂ from the solvent in the stripper. A small fraction of solvent carried from the top of the stripper bed is removed from the CO₂ stream in the wash section positioned above the stripper bed. The CO₂ stream saturated with water is significantly cooled in the condenser. Its vapor phase, containing more than 95% of CO₂, is separated from the liquid-phase inside the separator and flows to the CO₂ compression section, while condensed water is recirculated back to the top of the wash section. Depending on the operating conditions or needs, a surplus of condensed water could be re-routed to the absorber, or discharged to the water treatment facility.

The most energy-intensive aspect of amine-based CO₂ capture is low-pressure PC boiler steam consumption within the stripper reboiler for solvent regeneration. BASF's OASE[®] blue advanced amine-based solvent significantly reduces the energy demand for solvent regeneration. This energy demand reduction consequently increases the power plant efficiency and substantially decreases both the cost of produced electricity and the cost of CO₂ captured, as discussed and illustrated in Section 4.

In addition to the significant benefits of the OASE[®] blue solvent technology towards reducing the overall energy consumption of the PCC process, a novel process configuration (SIH) for the stripper column is investigated in this study that takes advantage of heat recovery options from the solvent within the column. In the proposed SIH design for this study shown in Exhibit 3-2, a semi CO₂-lean solvent reheater is added to the stripper column that heats up solvent taken from an intermediate position in the stripper using hot CO₂-lean solvent from the bottom of the stripper column reboiler and then injects this re-heated and vaporized semi CO₂-lean solvent back into the stripper column at an optimal packing location. Overall, this process modification allows for a substantially more linear temperature profile within the stripper column, minimizes heat losses along the column length, and prevents re-absorption of CO₂ by cooler lean solvent in the upper half of the stripper column – all of which significantly reduce the steam consumption per metric tonne of CO₂ captured and subsequent energy penalty of the PCC process on the PC steam cycle and power plant performance/cost of produced electricity. Though it is not shown in Exhibit 3-2, the Linde-BASF advanced PCC technology also allows for the option to heat additional solvent within the stripper by employing an interstage heater equipped with low pressure steam to heat cooled semi CO₂-lean solvent along the length of the stripper column. The heater can use lower-temperature steam (possibly generated from power plant waste heat) than the reboiler, and thus reduce demand for the LP steam typically extracted from the steam turbines, which ultimately leads to higher efficiencies in power plants equipped with PCC units. Related process integration with heat recovery options for the interstage heater is discussed in more detail in Section 4.3.

Advanced Main Rich/Lean Exchanger with Cold Rich Bypass Exchanger Configuration. While the SIH configuration provides improved energy savings for the PCC process compared to LB1, one final process configuration (denoted as LB1-CREB) was evaluated in this study, which has the potential to further improve the energy efficiency and overall performance of the Linde-BASF PCC technology. As shown in Exhibit 3-3, the LB1-CREB configuration recovers heat from the hot CO₂ and water vapor stream leaving the top of the stripper column to warm the cold CO₂-rich solution stream bypassing the main CO₂-rich/CO₂-lean heat exchanger. By bypassing part of the cold CO₂-rich solution to the main rich-lean exchanger, the latent heat of steam in the CO₂-rich vapor can be partially recovered. In addition, a fraction of the warmed CO₂-rich solution from the main CO₂-rich/CO₂-lean heat exchanger is diverted from the secondary rich-lean exchanger to mix with the CO₂-rich solution heated by the hot CO₂ and water vapor stream leaving the top of the stripper column. The secondary rich-lean exchanger is used to provide additional heat recovery from stripping steam for the main flow of CO₂-rich solution entering the stripper column. The warm CO₂-rich bypass is drawn from the main rich-lean exchanger and fed to the top of the stripper. The temperature of the warm CO₂-rich solution is chosen as its bubble point. The

remaining heat in the CO₂ is recovered with bypassing cold CO₂-rich solution in the cold CO₂-rich exchanger. Overall, applying the warm CO₂-rich bypass makes the heat transfer driving force between CO₂-rich solution and hot CO₂ vapor smaller in both the stripper and CO₂-rich heat exchanger when steam is condensed. Heat recovery optimization of the LB1-CREB configuration involves varying the CO₂-lean solution loading, the cold CO₂-rich bypass rate, and warm CO₂-rich bypass rate [Ref. 9]. A final simulation analysis of the LB1-CREB process option has been shown to reduce the specific energy consumption of the PCC process to as low as 2.1 GJ/MT CO₂. Due to the currently uncertain capital cost impact of the added heat exchanger area and any additional pump work or electricity required for the LB1-CREB process, a rigorous capital and operating cost estimate for the LB1-CREB PCC process was not evaluated in this study, as is shown for Linde-BASF PCC process options LB1 and SIH. Hence, only a high-level analysis of the specific steam energy consumption and associated impact on an integrated 550 MWe coal-fired power plant was performed for the LB1-CREB PCC process configuration discussed in this study.

Balance of Plant. The remaining process elements of the PCC plant design, including lean/rich solvent heat exchanger, lean and rich solvent circulating pumps, lean solvent cooler, makeup supplies of solvent, NaOH and water, as well as utility filters remain the same as for the typical, commercial CO₂ recovery plant configuration. Heat and power management and its integration with a PC power plant are discussed in more detail in Section 4.3.

4. Supercritical 550 MWe PC Power Plant with CO₂ Capture

This study evaluates a single reheat, supercritical cycle, 550 MWe PC power plant with CO₂ capture, using DOE/NETL Case 12 [Ref. 2] as a reference for the power plant steam cycle design and flue gas conditions. Brief process highlights and major assumptions used in this study are presented below.

4.1 Brief Process Description

Exhibit 4-1 highlights the major process units and streams of a supercritical PC power plant integrated with a PCC unit. Coal (stream 6) and primary air (streams 3 & 4) are introduced into the boiler through the wall-fired burners. Additional combustion air (streams 1 & 2) is provided by the forced draft fans, while a small amount of ambient air, which leaks into the boiler due to slightly sub-atmospheric pressure, is accounted for by stream 5.

Flue gas from the boiler, after passing through the selective catalytic reduction (SCR) unit for nitrogen oxides (NO_x) control and air pre-heater (stream 8), enters a baghouse for fly ash removal (stream 9). Induced draft fans force flue gas flow (stream 11) into the FGD unit for the removal of SO₂, before it is

introduced to the PCC plant (stream 16), which is described in more detail in Section 3. A low-pressure steam supply (stream 17) required for the PCC reboiler duty is extracted from the intermediate- to low-pressure (IP-LP) steam turbine crossover pipe, as shown in Exhibit 4-1. The condensate (stream 18) from the PCC plant is returned to the PC boiler feedwater heater system. The PC boiler produces high-pressure steam (stream 24) by boiling and superheating feedwater (stream 23), and also reheats the exhaust stream (stream 25) from the high-pressure turbine to produce the feed steam (stream 26) for the IP turbine. A potential novel innovation is the use of an added flue gas heat recovery unit (HRU) upstream of the FGD that increases the overall efficiency of the PC plant integrated with PCC. This HRU could be implemented in the supercritical power plant if the benefit of the added heat recovery it provides outweighs any additional capital costs required. The HRU was not included in the cost analysis for the supercritical power plant described in this report to provide a direct comparison between the Linde-BASF technology cases and the DOE/NETL Case 12 reference.

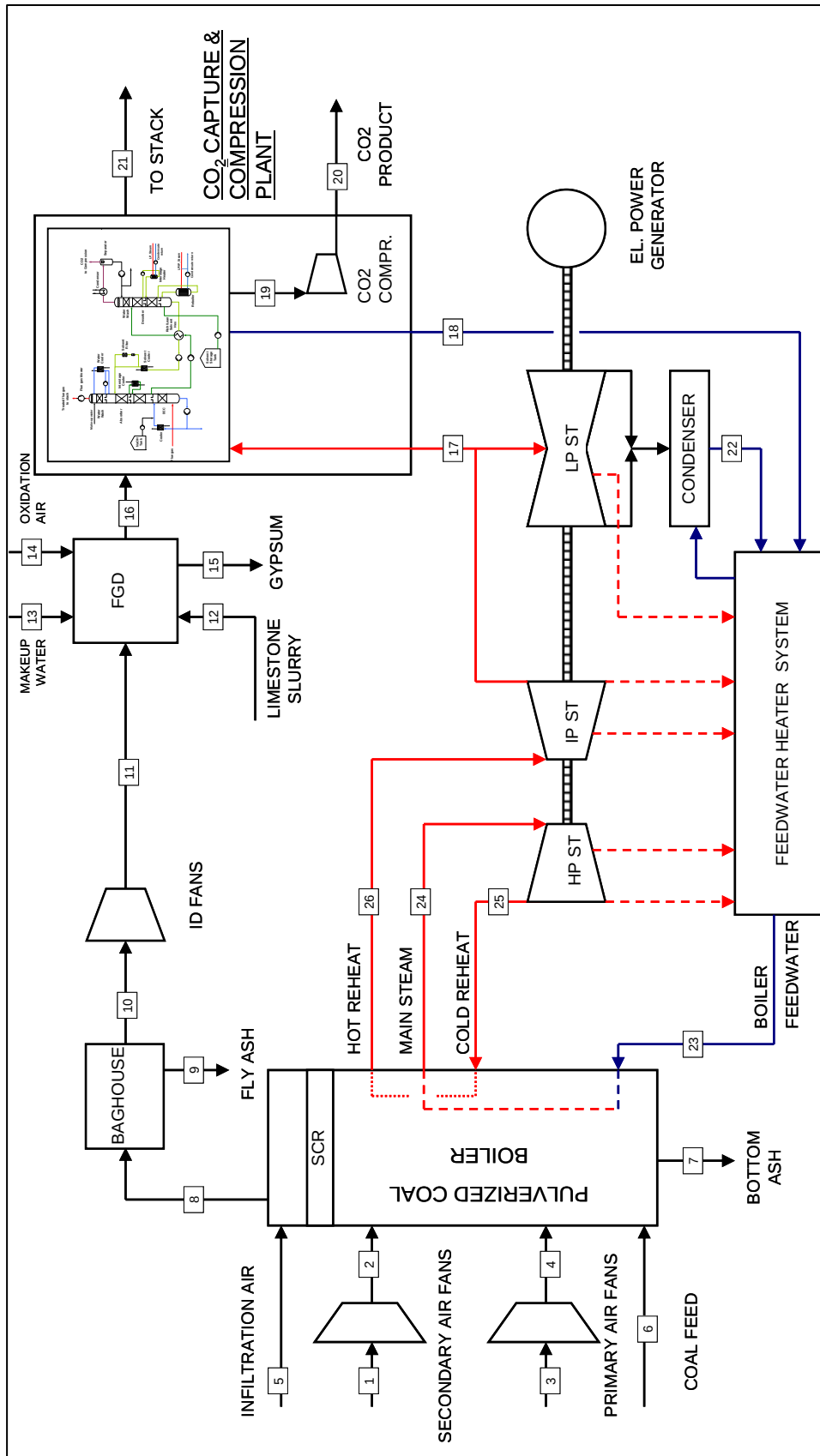


Exhibit 4-1. Block Flow Diagram of Supercritical PC power plant with CO₂ Capture and Compression

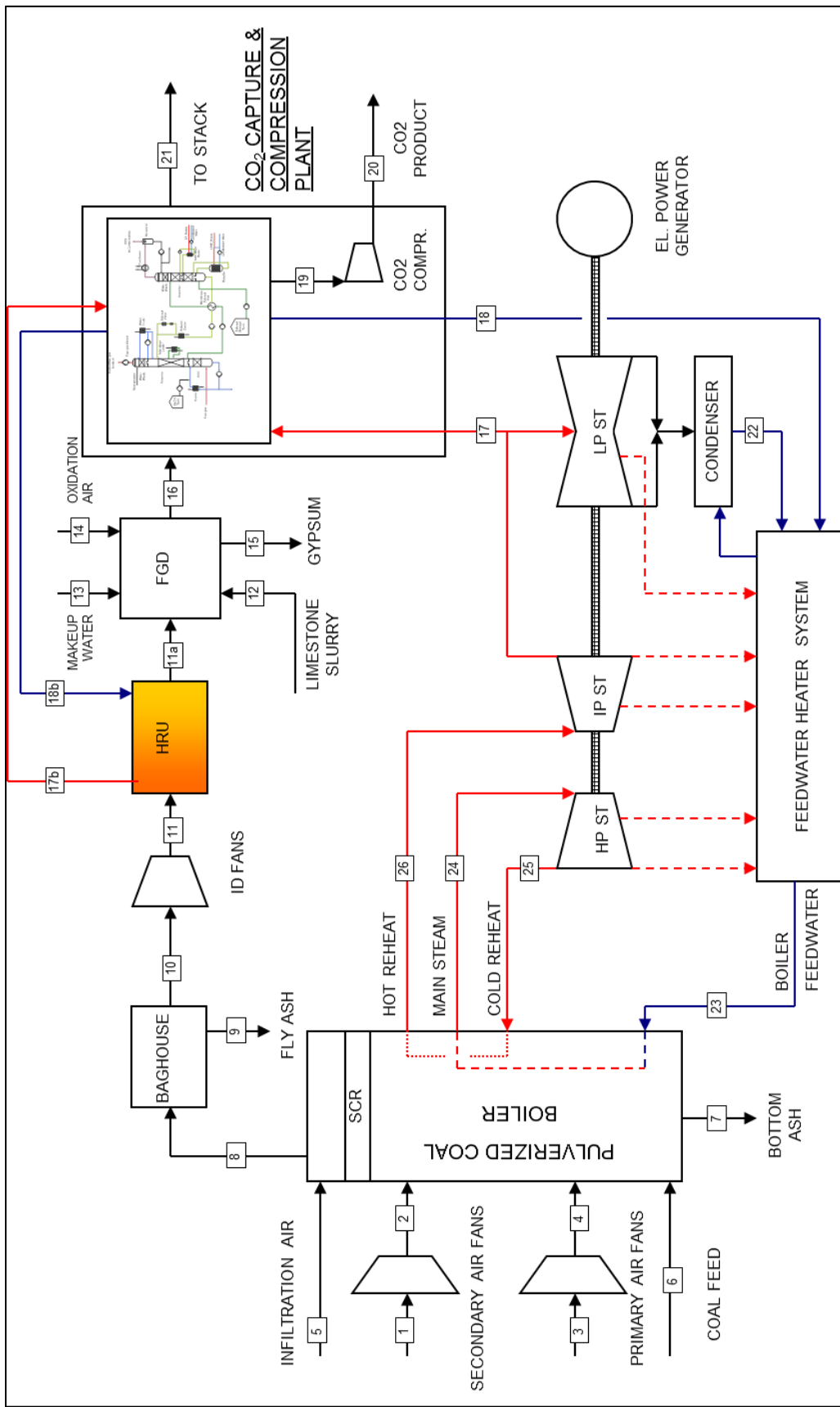


Exhibit 4-2. Block Flow Diagram of Supercritical PC power plant with CO₂ Capture and Compression utilizing optional flue gas heat recovery unit (HRU) upstream of FGD

4.2 Key System Assumptions

Exhibit 4-3 summarizes the key system assumptions used in this study, which are identical to those used in the DOE/NETL Case 12 reference [Ref. 2].

Exhibit 4-3. Supercritical PC Plant Study Configuration Matrix	
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3500/1100/1100)
Condenser Pressure, mm Hg (in Hg)	50.8 (2)
Boiler Efficiency, %	88
Cooling water to condenser, °C (°F)	16 (60)
Cooling water from condenser, °C (°F)	27 (80)
Stack temperature, °C (°F)	32 (89)
SO₂ Control	Wet Limestone with Forced Oxidation
FGD Efficiency, %	98
NO_x Control	LNB w/OFA and SCR
SCR Efficiency, %	86
Ammonia Slip (end of catalyst life), ppmv	2
Particulate Control	Fabric Filter
Fabric Filter efficiency, %	99.8
Ash distribution, Fly/Bottom	80% / 20%
Mercury Control	Co-benefit Capture
Mercury removal efficiency, %	90
CO₂ Control	BASF OASE [®] Blue Technology
CO₂ Capture, %	90
CO₂ Sequestration	Off-site Saline Formation

4.3 Process Integration Options

As the DOE/NETL Case 12 reference [Ref. 2] demonstrates, 90% CO₂ capture from a 550 MWe supercritical PC power plant increases the energy (coal) demand by approximately 38.2% above a 550 MWe power plant without CO₂ capture. BASF's OASE[®] blue technology consisting of an amine-based solvent in combination with innovative Linde-BASF PCC plant designs leads to reduced energy penalties of integrated supercritical PC power plant with PCC of more than 35% relative to the reference MEA-based process described in the DOE/NETL Case 12 reference. Further reductions of more than 9%

(overall 45% reduction from DOE/NETL Case 12 reference to optimum process option shown in this study) of incremental energy for PCC can be achieved by exploring and optimizing various process integration options.

Most of the existing subcritical PC power plants do not have steam turbine cycles with pressures and temperatures specifically designed and optimized for PCC units. This detail changes for supercritical PC plants, as described with DOE/NETL Case 12 reference [Ref. 2], where steam for the PCC plant (Case 12) is extracted from an IP-LP crossover pipe at 73 psia and 586°F, steam conditions which can be directly utilized for PCC CO₂ regeneration since the Linde-BASF PCC plant design requires LP steam (about 5 bara or 73 psia) for solvent regeneration. The previous TEA report for a subcritical steam cycle [Ref. 6] utilized a PCC design configuration that takes advantage of the availability of IP-LP steam at a significantly higher pressure and temperature (167 psia and 743°F) than are required for CO₂ regeneration in the solvent stripper column. As mentioned in our previous report [Ref. 6], a very efficient integration option for a subcritical steam cycle is to utilize a Back-Pressure Steam Turbine (BPST) to expand steam from greater than 10 Bara to less than 6 Bara, which can generate a significant amount of electrical power and reduce power withdrawal from the PC power plant for the PCC and CO₂ compression units. The supercritical steam cycle has an innately lower extraction pressure and temperature for PCC steam; therefore, this BPST design used for subcritical steam cycles is not needed nor assessed in this report. However, one very efficient integration option that applies to the supercritical steam cycle (and also mentioned in our previous report [Ref. 6]) is to partially recover sensible heat from the warm flue gas stream before it enters the FGD unit and use this heat to generate a significant amount of LP steam (< 4 bara or 58 psia). While it may increase the overall capital cost of the PC power plant integrated with PCC, this heat recovery can effectively reduce PCC reboiler steam requirements for solvent regeneration through use of an external steam-driven interstage heater for the stripper column, a configuration that also significantly reduces FGD water consumption. Linde has a pending patent application with the U.S. Patent and Trade Office for this configuration [Ref. 4]. Exhibit 4-1 illustrates the supercritical PC plant integrated with PCC discussed first in Section 4.3., while Exhibit 4-2 provides details of the PC plant integrated with PCC utilizing heat recovery from the flue gas upstream of the FGD, as described above. Sections 5.2 and 5.3 provide quantification of the resulting benefits of each configuration and address the limits for techno-economically-viable waste heat recovery.

5. Techno-Economic Evaluations

5.1 Modeling Approach and Validation

Detailed techno-economic evaluations have been accomplished by utilizing Aspen Plus software as a generalized computational platform for rigorous calculations of physical and thermodynamic properties of water, steam, and multi-component mixtures, along with related material and energy balances around each individual unit operation of the integrated power plant with CO₂ capture system. Specifically designed for parametric studies of key PCC process parameters, BASF's proprietary chemical process simulation package has been used for final, accurate predictions of mass and heat transfer rates, as well as for the kinetics of complex chemisorption reactions between CO₂ and solvent components. Resulting performance parameters of the optimized PCC plant have been fully integrated with the Aspen Plus simulation of the PC power plant supercritical steam cycle to produce a complete model of the entire power plant with PCC to investigate the benefits of PCC energy performance improvements on the overall power plant energy performance in addition to capital and operating costs.

The first step in validating the modeling approach was to reproduce material streams and related energy balances around the PC boiler, as reported in DOE/NETL Case 12 reference [Ref. 2]. As detailed in the previous TEA report for small-scale pilot [Ref. 6], it has been previously confirmed by UniSim process simulation that the PCC plant-integrated PC steam cycle with incorporated Illinois No. 6 coal properties and feed rates successfully predicts the flowrates, pressures, and temperatures for high-pressure steam and reheated IP steam based on specified boiler feedwater and cold reheat stream flowrates, along with exactly the same composition and temperature of the flue gas, including bottom ash and fly ash content. As done previously in the 2012 TEA report [Ref. 6], the next step is to incorporate the specified performance of the wet FGD in order to accurately predict the flow, pressure, temperature, and composition of the feed stream to the PCC plant.

The most important step in verifying/calibrating the simulation model has been to tune the isentropic efficiencies of all steam turbines as well as CO₂ compressors to match the steam turbine power generation and CO₂ compression energy of the DOE/NETL Case 12 reference in order to reproduce the reported pressure, temperature, and flowrate values of all steam and liquid water streams in the steam-water cycle reported in the DOE/NETL Case 12 reference study. This tuning enables consistent energy performance comparisons of the Linde-BASF PCC technologies presented in this study against the DOE/NETL Case 12 reference and each other.

Exhibit A-1 in Appendix A provides the details of our overall simulation of Case 12 referenced in 2013 study [Ref. 2], while Exhibit A-2 provides all calculated pressure, temperature, and flowrate values within the steam-water cycle of Case 12, along with total produced power, net produced power, and net process efficiency.

5.2 Performance Results

A series of simulations were performed with various operating parameters of the PCC plant incorporating the Linde-BASF technology and with different levels of process integration with the PC power plant.

Two sets of performance results are presented in more detail for the following process configuration options:

- LB1 Option: Supercritical PC power plant integrated with Linde-BASF PCC plant that offers a PCC reboiler duty of 2.61 GJ/MT CO₂.
- SIH Option: Supercritical PC power plant integrated with Linde-BASF PCC plant utilizing advanced SIH design optimizing heat recovery in the PCC process to improve energy performance and offer 2.30 GJ/MT CO₂.

In addition to LB1 and SIH, a third option that further reduces the energy consumption of the Linde-BASF PCC plant has been evaluated. This option is summarized below.

- LB1-CREB Option: Supercritical PC power plant integrated with Linde-BASF PCC plant incorporating an advanced main CO₂ rich-CO₂ lean solvent exchanger and cold CO₂-rich exchanger bypass configuration that improves energy performance (allowing 2.10 GJ/MT CO₂ PCC reboiler steam consumption), but may increase capital costs, which needs to be further investigated [Ref. 8 and Ref. 9].

The Linde-BASF PCC plant is designed in all three cases to minimize energy requirements for CO₂ recovery and compression. As commented in Section 3, in addition to using the advanced, high-performance BASF OASE[®] blue solvent, the Linde-BASF technology also incorporates several novel design features, including an absorber with advanced high-performance packing, integrated DCC and wash units, gravity-driven interstage cooler, and flue gas blower downstream of absorber. While the absorber operates at slightly sub-atmospheric pressure, solvent regeneration is performed in the stripper

Exhibit 5-1. Specific energy demand for 90% CO ₂ capture and compression to 2215 psia			
Utility	NETL-MEA	Lind-BASF LB-1	Linde-BASF SIH
Reboiler Duty, (GJ/MT_CO ₂)	3.61	2.61	2.30*
Cooling Duty, (MSe _{hr})/(MT_CO ₂)	1.64	1.12	0.94
Electrical Power (kW _{hr} /MT_CO ₂)	119.9	102.95	104.16**
*Effect of stripper interstage heater: semi CO ₂ lean solvent is reheated by hot CO ₂ lean solvent exiting stripper			
**Effect of additional solvent pump for SIH configuration adds 636 kW of electrical power			

operating at 3.33 bara (48 psia) at the top of the column, which significantly reduces power requirements and capital cost for CO₂ compression. This 3.33 bara has been chosen to be the upper limit for stripper pressure considering the increasing solvent degradation expected at higher stripper temperatures, which correspond to higher stripper pressures. In addition, the water balance and energy consumption have been optimized by cooling the flue gas and lean amine solvent entering the absorber to 25°C, while maintaining the stripper condenser temperature at 40°C. The solvent circulation rate is also optimized for the above process conditions to minimize the heat requirement for solvent regeneration. Exhibit 5-1 summarizes the energy requirement elements for CO₂ capture and compression for the two main Linde-BASF process options described in this study. In addition, Exhibit 5-2 illustrates corresponding energy savings per metric tonne of CO₂ captured and compressed using the LB1 and SIH PCC technologies as compared to DOE/NETL Case 12 reference [Ref. 2].

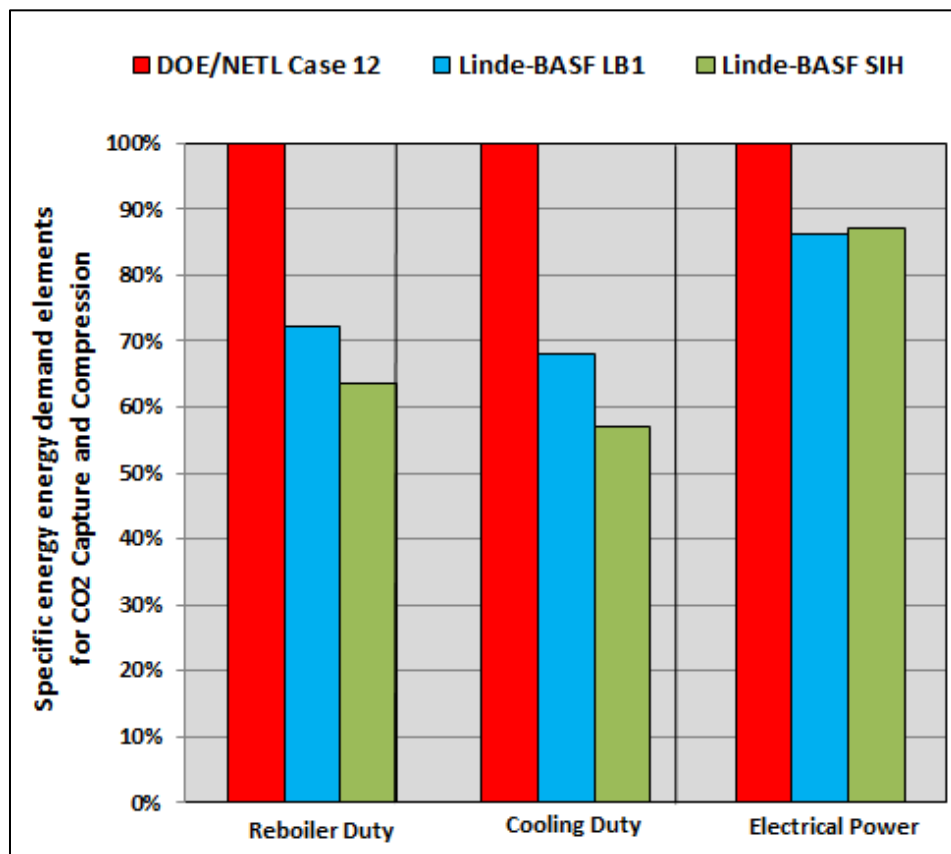


Exhibit 5-2. Specific energy demand elements for CO₂ Capture and Compression for Linde-BASF LB1 and SIH PCC technologies compared to DOE/NETL Case 12 reference

The BASF OASE[®] blue solvent itself reduces the reboiler duty by 21.7% relative to the DOE/NETL Case 12 reference. Further Linde-BASF LB1 case PCC process design improvements and optimization reduce PCC reboiler duty by an additional 6%. Finally, the advanced stripper interstage heater option (Linde-

BASF SIH) reduces the PCC reboiler duty by 8.6% compared to LB1 through efficient use of heat recovery in the stripper column. It is important to realize that the above savings for CO₂ capture and compression in terms of heating, cooling, and power requirements translate to a significant reduction in total energy required for the power plant integrated with PCC plant, leading to further reductions in overall size and cost needed for the power plant. Exhibit 5-3 illustrates the net reduction in coal consumption for a 550 MWe (net) power plant integrated with CO₂ capture and compression utilizing Linde-BASF PCC technologies as compared to the DOE/NETL Case 12 reference.

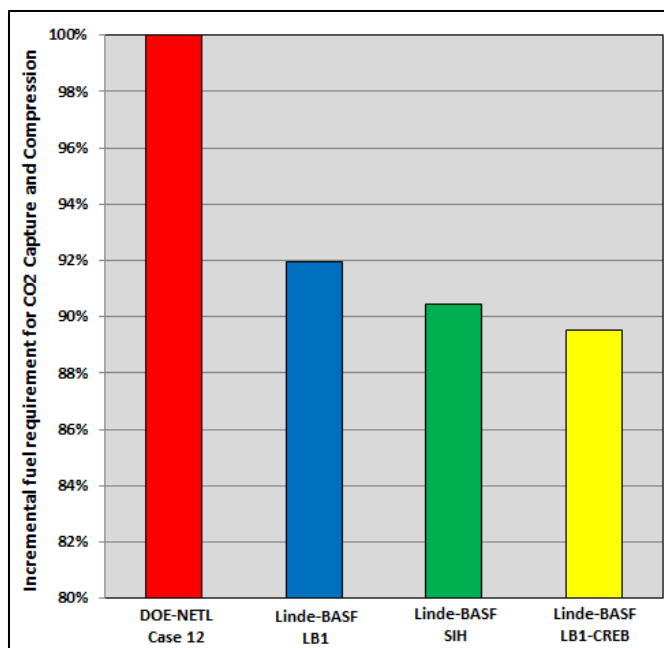


Exhibit 5-3. Effect of Linde-BASF PCC technologies on coal fuel requirement for 550 MWe supercritical power plant integrated with CO₂ Capture and Compression

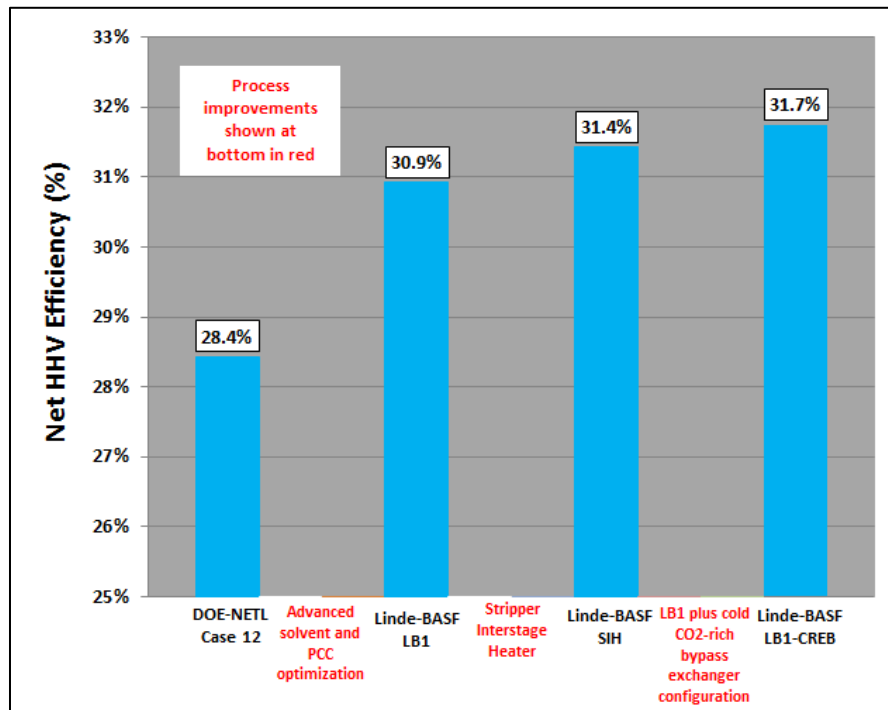


Exhibit 5-4. Incremental improvements in net plant HHV efficiency (%) from MEA-based PCC (DOE/NETL Case 12) to Linde-BASF processes

Exhibit 5-4 illustrates that the advanced BASF OASE[®] blue solvent and PCC plant optimization contribute the most to the overall plant efficiency increase. The optimization of PCC plant includes significantly reduced CO₂ compression energy downstream of the PCC plant due to solvent regeneration at higher pressure (3.33 bara) and condensation at low temperature (20°C), as well as optimized heat management and reduced energy consumption for the flue gas blower and solvent circulation pumps. The heat and power integration options (outlined in Exhibit 4-3) can also increase the net plant efficiency. As shown, the advanced stripper configuration for the Linde-BASF SIH PCC process increases the efficiency by an additional 0.5% for the supercritical PC steam cycle due to the substantial decrease in specific energy consumption for the PCC plant from 2.61 GJ/MT CO₂ to 2.30 GJ/MT CO₂. This specific energy reduction is a direct result of the enhanced heat recovery provided by the advanced stripper design utilizing an interstage heater that reheats the semi CO₂-lean solvent in the stripper column via hot CO₂-lean solvent leaving the stripper bottom without any added steam penalty. Exhibit 5-5 provides overall material and energy balances for a PC power plant integrated with Linde-BASF PCC technology for Case LB1, while Exhibit 5-6 provides detailed material and energy balances for the water-steam cycle of the corresponding power plant (LB1), along with total power production and net power plant efficiency values. Exhibits 5-7 and 5-8 provide the same set of information for Linde-BASF Case SIH, respectively, which explores the effect of the advanced stripper interstage heater configuration (shown in Exhibit 3-2)

on PCC steam consumption and stripper reboiler duty. To demonstrate the effect of the advanced Linde-BASF LB1-CREB case, an advanced CO₂ rich-CO₂ lean solution exchanger with cold CO₂-rich bypass exchanger configuration is used in the PCC process to optimize the heat recovery between stripping steam and the CO₂-rich solution. This LB1-CREB design significantly reduces overall PCC reboiler steam consumption (at the expense of higher capital costs needed for additional heat exchanger area) and overall energy penalties for integrating a PC power plant with PCC compared to DOE Case 12 reference.

Comparison of overall supercritical power plant with integrated PCC plant performances for DOE/NETL Case 12, Linde-BASF Option LB1, Linde-BASF Option SIH, and Linde-BASF Option LB1-CREB are summarized in Exhibit 5-9. Environmental indicators for the same three PCC options are summarized in Exhibit 5-10, including emissions of SO₂, NO_x, Hg, and particulate matter for the different cases.

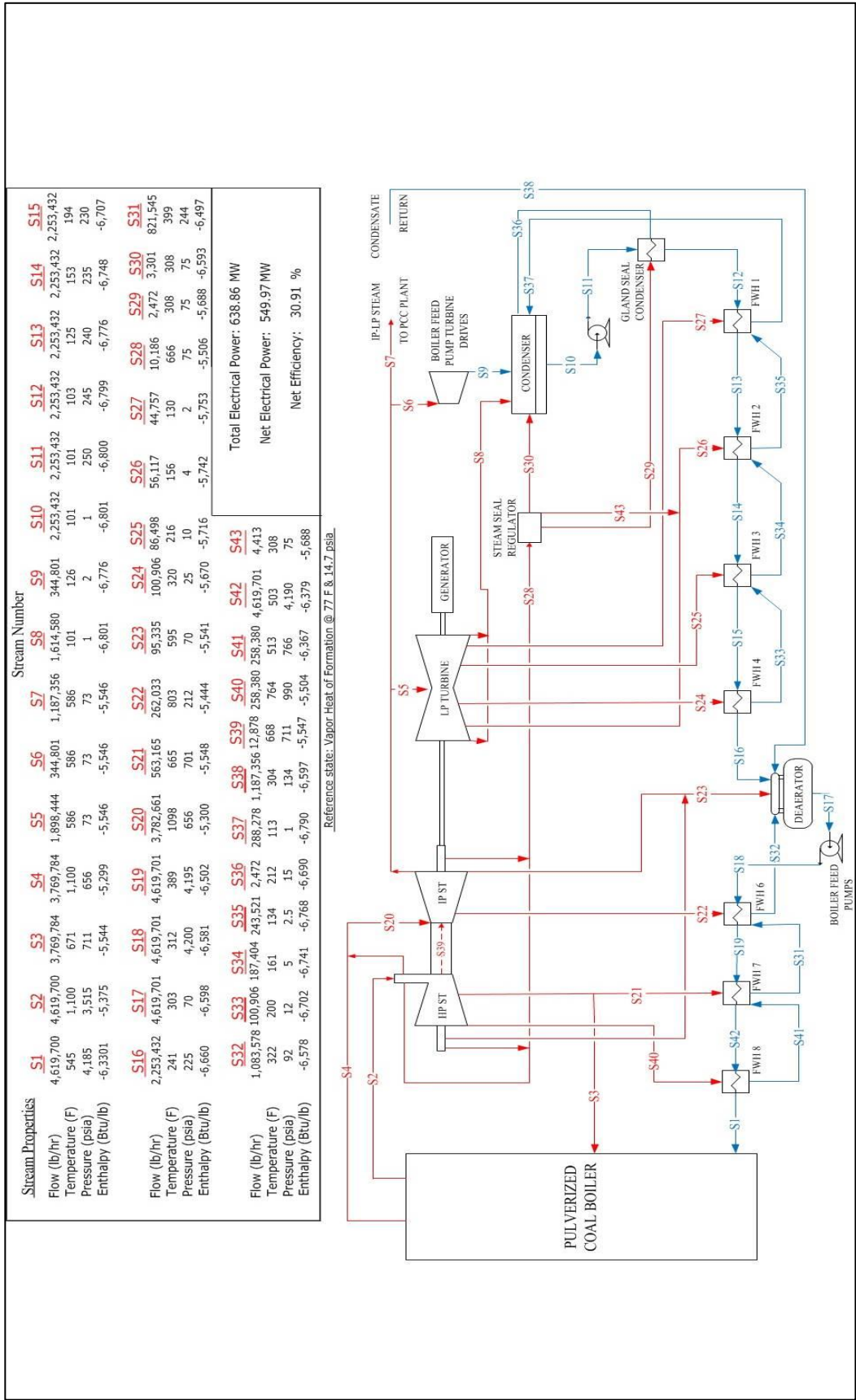


Exhibit 5-5. Heat and Mass Balance: Power plant with Linde-BASF PCC Technology - Case LB1

LB1-2011**Stream Properties**

	<u>S1</u>	<u>S2</u>	<u>S3</u>	<u>S4</u>	<u>S5</u>	<u>S6</u>	<u>S7</u>	<u>S8</u>	<u>S9</u>	<u>S10</u>	<u>S11</u>	<u>S12</u>	<u>S13</u>	<u>S14</u>	<u>S15</u>
V-L mol. fract.	1	1	1	1	1	0	0	1	0	1	1	0	0	1	0
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0000	0.0128	0.0000
CO2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000	0.0000	0.0005	0.0004
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000	1.0000	0.0062	0.9996
N2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000	0.0000	0.7506	0.0000
O2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000	0.0000	0.2300	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	135,555	135,555	41,641	41,641	3,133	0	0	190,751	0	190,751	190,751	6,861	27,334	1,975	506
V-L Flowrate (lb/hr)	3,911,727	3,911,727	1,201,641	1,201,641	90,413	0	0	5,673,558	0	5,673,558	5,673,558	123,593	492,430	57,342	9,117
Solid Flowrate (lb/hr)	0	0	0	0	0	520,222	10,089	40,356	40,356	0	0	52,632	0	0	81,357
Temperature (F)	59	66	59	78	59	59	59	337	59	337	360	59	59	357	136
Pressure (psia)	14.7	15.3	14.7	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.4	15.0	14.7	45.0	14.9
Enthalpy (Btu/lb)	13.0	14.8	13.0	17.5	13.0	-	-	140.8	-	132.8	138.8	-	-20.1	82.4	-
Density (lb/ft3)	0.076	0.078	0.076	0.081	0.076	-	-	0.050	-	0.049	0.052	-	62.622	0.149	-
Molecular Weight	28.86	28.86	28.86	28.86	28.86	-	-	29.74	-	29.74	29.74	-	18.02	29.03	-
V-L mol. fract.	1	1	0	1	1	1	0	0	1	1	1				
Ar	0.0081	0.0000	0.0000	0.0000	0.0000	0.0093	0.0000	0.0000	0.0000	0.0000	0.0000				
CO2	0.1350	0.0000	0.0000	0.9957	0.9981	0.0154	0.0000	0.0000	0.0000	0.0000	0.0000				
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
H2O	0.1537	1.0000	1.0000	0.0043	0.9981	0.1745	1.0000	1.0000	1.0000	1.0000	1.0000				
N2	0.6793	0.0000	0.0000	0.0000	0.0000	0.7737	0.0000	0.0000	0.0000	0.0000	0.0000				
O2	0.0238	0.0000	0.0000	0.0000	0.0000	0.0271	0.0000	0.0000	0.0000	0.0000	0.0000				
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000				
V-L Flowrate (lbmol/hr)	207,861	65,909	65,908	25,365	25,304	172,543	125,084	256,432	256,432	209,255	209,255				
V-L Flowrate (lb/hr)	5,992,760	1,187,356	1,187,356	1,113,495	1,112,379	4,879,265	2,253,432	4,619,700	4,619,700	3,769,784	3,769,784				
Solid Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0				
Temperature (F)	136	586	304	104	95	89	102	545	1,100	671	1,100				
Pressure (psia)	14.9	73.5	133.6	48.3	2,214.5	14.7	245.0	4,185.0	3,514.7	711.1	655.8				
Enthalpy (Btu/lb)	-1,331.6	-5,546.4	-6,596.6	-4,268.5	-3,946.3	-6,813.2	-6,799.1	-6,330.9	-5,375.0	-5,544.5	-5,299.1				
Density (lb/ft3)	0.07	0.12	57.21	150.95	49.71	0.07	62.01	48.31	4.32	1.16	0.72				
Molecular Weight	28.83	18.02	18.02	43.90	43.96	28.28	18.02	18.02	18.02	18.02	18.02				

Reference state: Vapor Heat of Formation @ 77 F & 14.7 psia. Reference State for Coal and Ash: Solid Heat of Formation @ 32.02 F & 0.089 psia

Exhibit 5-6. M&E Balances for Linde-BASF LB1 Option (in reference to Exhibit 4-1)

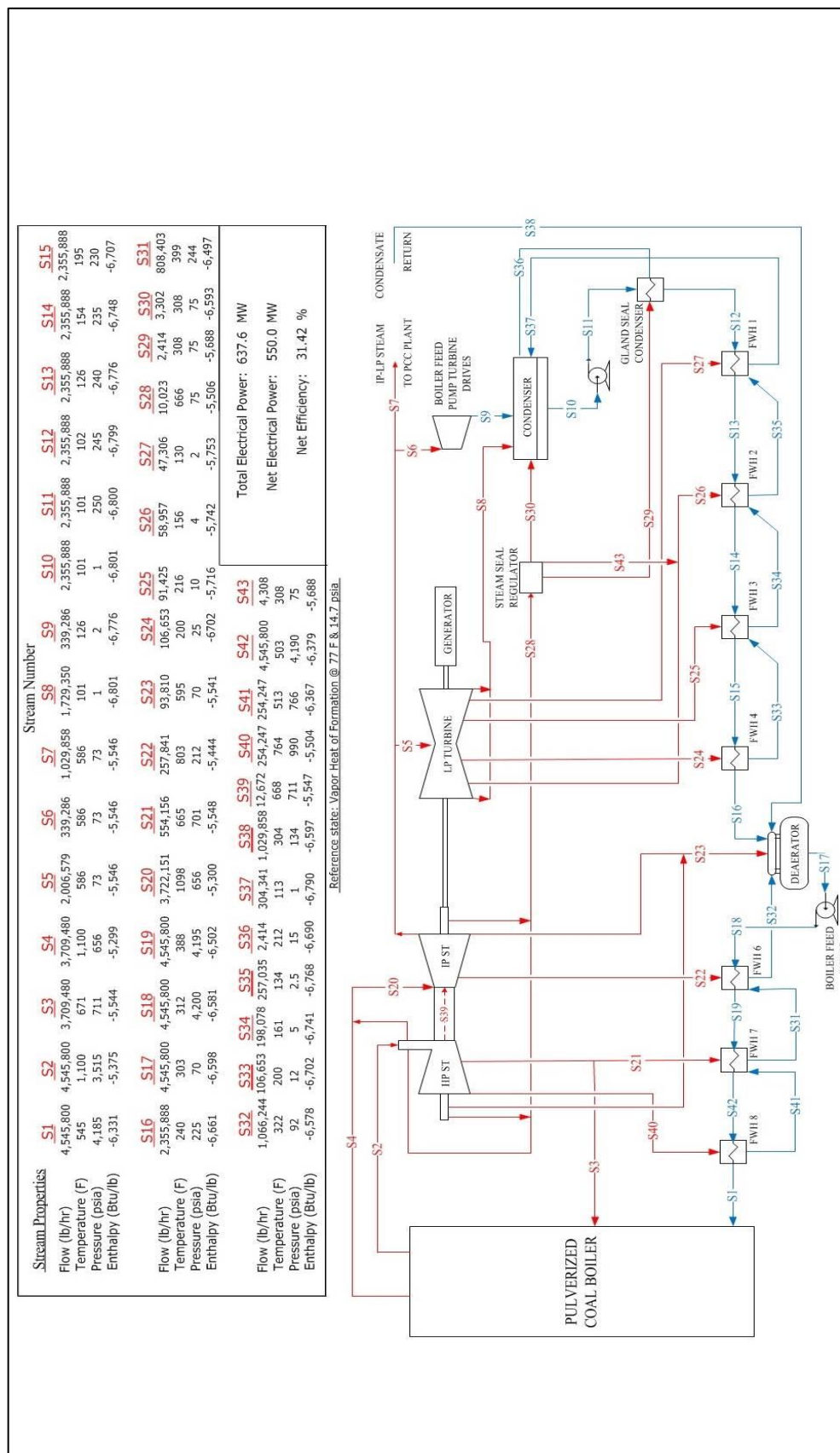


Exhibit 5-7. Heat and Mass Balance: Power plant with Linde-BASF PCC Technology - Case SIH

SIH-2011

Stream Properties

V-L mol. fract.

Ar

CO2

H2

H2O

N2

O2

SO2

Total

V-L Flowrate
(lbmol/hr)

V-L Flowrate
(lb/hr)

Solid Flowrate
(lb/hr)

Temperature (F)

Pressure (psia)

Enthalpy (Btu/lb)

Density (lb/ft3)

Molecular Weight

V-L mol. fract.

Ar

CO2

H2

H2O

N2

O2

SO2

Total

V-L Flowrate
(lbmol/hr)

VL Flowrate
(lb/hr)

Solid Flowrate
(lb/hr)

Temperature (F)

Pressure (psia)

Enthalpy (Btu/lb)

Density (lb/ft3)

Molecular Weight

	<u>S1</u>	<u>S2</u>	<u>S3</u>	<u>S4</u>	<u>S5</u>	<u>S6</u>	<u>S7</u>	<u>S8</u>	<u>S9</u>	<u>S10</u>	<u>S11</u>	<u>S12</u>	<u>S13</u>	<u>S14</u>	<u>S15</u>
V-L mol. fract.	1	1	1	1	1	0	0	1	0	1	1	0	0	1	0
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0000	0.0128	0.0000
CO2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000	0.0000	0.0005	0.0004
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000	1.0000	0.0062	0.9996
N2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000	0.0000	0.7506	0.0000
O2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000	0.0000	0.2300	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	133.387	133.387	40.975	40.975	3.083	0	0	187,700	0	187,700	187,700	6,751	26,897	1,943	498
V-L Flowrate (lb/hr)	3,849,148	3,849,148	1,182,418	1,182,418	88,967	0	0	5,582,795	0	5,582,795	5,582,795	121,616	484,552	56,425	8,971
Solid Flowrate (lb/hr)	0	0	0	0	0	511,899	9,927	39,710	39,710	0	0	51,790	0	0	80,055
Temperature (F)	59	66	59	78	59	59	59	337	59	337	360	59	59	357	136
Pressure (psia)	14.7	15.3	14.7	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.4	15.0	14.7	45.0	14.9
Enthalpy (Btu/lb)	13.0	14.8	13.0	17.5	13.0	-	-	140.8	-	132.8	138.8	-	-20.1	82.4	-
Density (lb/ft3)	0.076	0.078	0.076	0.081	0.076	-	-	0.050	-	0.049	0.052	-	62.622	0.149	-
Molecular Weight	28.86	28.86	28.86	28.86	28.86	-	-	29.74	-	29.74	29.74	-	18.02	29.03	-
V-L mol. fract.	1	1	0	1	1	1	0	0	1	1	1	0	0	1	0
Ar	0.0081	0.0000	0.0000	0.0000	0.0000	0.0093	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1350	0.0000	0.0000	0.9957	0.9981	0.0154	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.1537	1.0000	1.0000	0.0043	0.0019	0.1745	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.149	0.0000
N2	0.6793	0.0000	0.0000	0.0000	0.0000	0.7737	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0238	0.0000	0.0000	0.0000	0.0000	0.0271	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	204.535	57.166	57.166	24.960	24.899	169.601	130.772	252.330	252.334	205.907	205.907	6,751	26,897	1,943	498
VL Flowrate (lb/hr)	5,896,890	1,029,858	1,029,858	1,095,683	1,094,584	4,801,207	2,355,888	4,545,800	4,545,800	3,709,480	3,709,480	121,616	484,552	56,425	8,971
Solid Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	80,055
Temperature (F)	136	586	304	104	95	89	102	545	1,100	671	1,100	15.0	14.7	45.0	14.9
Pressure (psia)	14.9	73.5	133.6	48.3	2,214.5	14.7	245.0	4,185	3,514.7	711.1	655.8	-	-20.1	82.4	-
Enthalpy (Btu/lb)	-1,331.6	-5,546.4	-6,596.6	-3,759.5	-3,946.3	-6,813.2	-6,799.2	-6,330.9	-5,375.0	-5,544.5	-5,299.1	-	62.622	0.149	-
Density (lb/ft3)	0.07	0.12	57.21	0.21	49.71	0.07	62.01	48.31	4.32	1.16	0.72	-	18.02	29.03	-
Molecular Weight	28.83	18.02	18.02	43.90	43.96	28.31	18.02	18.02	18.02	18.02	18.02	-	18.02	29.03	-

Reference state: Vapor Heat of Formation @ 77 F & 14.7 psia; Reference State for Coal and Ash: Solid Heat of Formation @ 32.02 F & 0.089 psia

Exhibit 5-8. M&E Balances for Linde-BASF SIH Option (in reference to Exhibit 4-1)

Exhibit 5-9. Influence of PCC technology options on PC power plant performance					
Process Case	DOE NETL Case 11	DOE NETL Case 12	Linde- BASF LB1	Linde- BASF SIH	Linde- BASF LB1- CREB
TOTAL STEAM TURBINE POWER, kWe	kWe	kWe	kWe	kWe	kWe
	580,400	662,800	638,857	637,637	636,748
AUXILIARY LOAD SUMMARY					
Coal Handling & Conveying	440	510	469	461	457
Pulverizers	2,780	3,850	3,540	3,483	3,447
Sorbent Handling & Reagent Preparation	890	1,250	1,149	1,131	1,119
Ash Handling	530	740	680	669	663
Primary Air Fans	1,300	1,800	1,655	1,628	1,612
Forced Draft Fans	1,660	2,300	2,115	2,081	2,059
Induced Draft Fans	7,050	11,120	10,224	10,060	9,956
SCR	50	70	70	70	70
Baghouse	70	100	100	100	100
Wet FGD	2,970	4,110	3,779	3,718	3,680
PCC Plant Auxiliaries	-	20,600	10,890	10,716	10,605
CO ₂ Compression	-	44,890	33,768	33,227	32,882
Miscellaneous Balance of Plant	2,000	2,000	2,000	2,000	2,000
Steam Turbine Auxiliaries	400	400	400	400	400
Condensate Pumps	800	560	515	507	501
Circulating Water Pumps	4,730	10,100	9,286	9,138	9,043
Ground Water Pumps	480	910	910	910	910
Cooling Tower Fans	2,440	5,230	5,230	5,230	5,230
Transformer Losses	1,820	2,290	2,105	2,072	2,050
TOTAL AUXILIARIES, kWe	30,410	112,830	88,885	87,602	86,784
NET POWER, kWe	549,900	550,019	549,973	550,035	549,964
CO₂ Capture	0%	90%	90%	90%	90%
Net Plant Efficiency (HHV)	39.3%	28.4%	30.9%	31.4%	31.7%
Net Plant Heat Rate (BTU/kWh)	8,688	12,001	11,036	10,859	10,747
Condenser Cooling Duty (GJ/hr)	2,298	1,737	2,094	2,187	2,244
CO ₂ Captured (MT/hr)	0	548.38	504.19	496.12	490.97
CONSUMABLES					
Coal As-Received, kg/hr	185,759	256,652	235,971	232,196	229,790
Limestone Sorbent Feed, kg/hr	18,437	25,966	23,874	23,492	23,248
Thermal Input, kWt	1,400,162	1,934,519	1,778,854	1,750,398	1,732,262
Raw Water Withdrawal, m ³ /min	20.1	38.1	35.0	34.5	34.1
Raw Water Consumption, m ³ /min	16	29.3	26.9	26.5	26.2

As shown in Exhibit 5-9, the total auxiliary power requirements for all three Linde-BASF technology options are significantly lower than for the MEA-based PCC technology (DOE/NETL Case 12 reference). In addition, improved heat recovery through utilization of the advanced flash stripper configuration in

option LB1-CREB further reduces PC plant coal consumption and consequently leads to the highest net plant HHV efficiency of 31.7%.

Exhibit 5-10. Environmental benefits of Linde-BASF PCC Technologies				
Annual Air Emissions (85% Capacity Factor)				
Process Case	DOE NETL Case 12	Linde-BASF LB1	Linde-BASF SIH	Linde-BASF LB1-CREB
CO₂ (MT/Year)	453,763	417,195	410,521	406,268
NO_x (MT/Year)	1,561	1,435	1,412	1,398
Particulates (MT/Year)	290.0	266.6	262.4	259.6
Hg (kg/Year)	25.000	22.985	22.618	22.383
SO₂ (MT/Year)	36.0	33.1	32.6	32.2

The data set shown in Exhibit 5-10 confirms the superior air emissions performance of the proposed Linde-BASF PCC technologies compared with the MEA-based PCC option. The environmental benefits presented are consistent with demonstrated improvements in performance indicators, with emissions reductions for all key indicators/components (CO₂, NO_x, Hg and PM emissions reduced by 8%, 9.5%, and 10.5% for Linde-BASF Option LB1, Linde-BASF Option SIH, and Linde-BASF Option LB1-CREB, respectively, compared to DOE/NETL Case 12 reference). One important observation in Exhibit 5-9 is the small change in thermal input and coal feed rate (1-1.6%) with each technology improvement (LB1, SIH, and LB1-CREB) as compared to the much larger change in coal feed rate from Case 12 to LB1 (8%). This larger change in incremental coal feed rate from Case 12 to LB1 is a result of substantially higher CO₂ compression energy for Case 12 compared to LB1 (44.89 MW vs. 33.77 MW) and the other Linde-BASF cases in this study due to the lower inlet CO₂ compression pressure for Case 12 compared to the Linde-BASF cases (24 psia vs. 48 psia) and subsequent higher energy consumption for CO₂ compression for a pressure ratio of 2 per compression stage of each compressor. Additionally, for quantifying auxiliary loads for the PC plant integrated with PCC for each case, based on power plant data analysis, it was assumed that the auxiliary loads for SCR, Baghouse, Miscellaneous Balance of Plant, Steam Turbine Auxiliaries, Ground Water Pumps, and Cooling Tower Fans are nearly independent of the coal feed rate to the PC boiler. Hence, these auxiliary loads did not vary across any of the cases shown in this study.

5.3 Capital Cost Estimates

PCC Plant Design

The Linde-BASF PCC plant for this study proposes an optimized version of previously reported Linde-BASF PCC plant designs for several different European studies, where absorbers up to 18 m in diameter were anticipated [Ref. 3]. As discussed in Section 5.2, the Linde-BASF PCC technology reduces the coal feed rate and, consequently, the total flow rate of the flue gas entering the PCC plant by 8%, 9.5%, and 10.5% for LB1, SIH, and LB1-CREB, respectively, relative to the DOE/NETL Case 12 reference. With 90% CO₂ capture, these process improvements translate to 12,100 TPD (LB1), 11,907 TPD (SIH), and 11,783 TPD (LB1-CREB) CO₂ captured from a 550 MWe supercritical PC power plant, which makes it feasible to employ a PCC plant design using a single 18 m diameter absorber column with a single regenerator column through utilization of high-performance structured packing and an optimized hydraulic design, as illustrated in the 3D schematic in Exhibit 5-11 for the Linde-BASF PCC LB1 process configuration. The resulting plot area for the Linde-BASF PCC plant is approximately 180 m x 120 m. A two-train PCC design similar to DOE/NETL reference Case 12 would require a 40 to 50% larger footprint.

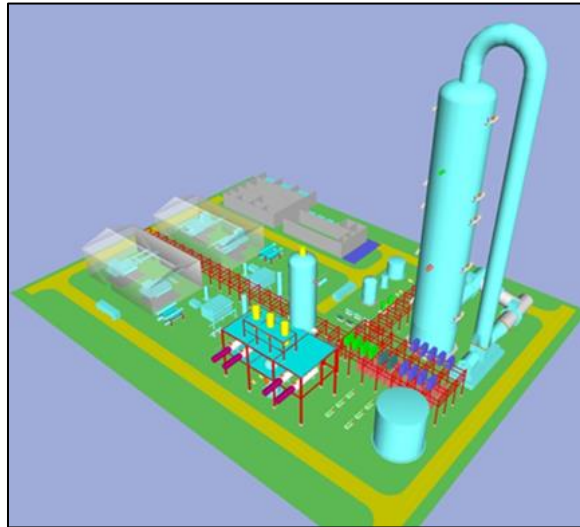


Exhibit 5-11. 3D image of Linde-BASF PCC plant design (LB1 option) for 550 MWe supercritical PC Power Plant

Depending on site conditions, plot area requirements/limitations, and the materials of construction for the PCC plant, a number of cost-effective PCC plant construction options can be considered for the first-of-a-kind (FOAK) commercial construction. Assuming certain site conditions and material costs, it can be more cost-effective to use site fabrication for the absorber column compared to shop fabrication if the column is constructed using concrete due to potentially reduced material and on-site labor costs if the use of a larger plot area for site fabrication does not negatively impact other work at the site. In contrast, a preliminary assessment conducted by Linde Engineering has shown that it can be more economical to use shop fabrication for the absorber in multiple trains if they are constructed using stainless steel and if the

larger plot area for site fabrication limits or hinders other critical work activities at the site. Using overall estimates provided by Linde Engineering in Dresden, Germany, the most cost-effective method for producing a FOAK commercial Linde-BASF PCC plant that recovers 90% of the CO₂ produced by a 550 MWe supercritical coal-fired power plant would be to use a 33 ft diameter stainless steel absorber and combined DCC divided into 3 separate trains. Using a reduced absorber diameter (33 ft (10 m) as compared to 57 ft (~18 m) from earlier designs) is well within Linde's experience in the design and construction of large columns from previous projects, and would significantly reduce process and project risks for a FOAK construction. A 3-train absorber column would require a relatively small stripper column diameter of 18 ft. For this case, it was determined that a single-train design be used for the stripper and CO₂ compression/drying sections to minimize costs. In reality, the combined DCC and absorber column are not completely 3 full trains. Several unit operations (including pumps and plate-and-frame heat exchangers for the water wash sections) will require multiple parallel units for the single-train design depending on the sizes of the various equipment items.

Shop fabrication of the large columns significantly reduces the time required for on-site column erection and also reduces interference with other construction activities at the site. In contrast to shop fabrication, site fabrication activities have the potential to occupy significantly more plot area at the site and could hinder several work activities in this area. Linde estimates that the overall erection time between the ordering of the column components and final erection would be 3-6 months shorter for shop fabricated columns compared to one large site-built column for a FOAK commercial PCC plant construction built using stainless steel due to more efficient use of labor resources and fewer negative impacts on the construction site.

The combination of the 3 train absorber/1 train stripper with CO₂ compression/drying would minimize risks for a FOAK plant assuming specific site area work conditions, especially considering construction cost, time, and resources. However, the 3 train absorber design requires slightly higher capital cost (10.2% higher) compared to the single absorber train design for the nth plant construction. Therefore, assuming it has minor impacts on other simultaneous work activities at the site construction, the full 1-train stainless steel absorber design is the most cost-effective option for the nth optimized PCC plant constructed after many similar plants of its kind have already been designed and built with comprehensive process and project learnings and findings implemented. Hence, the process and project contingencies associated with the nth plant configurations discussed in detail in this report would be significantly reduced compared to those for a FOAK commercial design and construction. The optimization just described indicating choice of steel columns is based on specific steel and concrete pricing and can change based on alterations in the relative pricing of these materials.

In this study, the capital costs of two nth plant configurations of the Linde-BASF SIH PCC process were evaluated for comparison purposes: one using a direct contact cooler (DCC) included inside the absorber column and using a blower downstream of the absorber (shown in Exhibit 3-2 in Section 3.2), and one with a DCC separate from the absorber column with a blower upstream of the absorber. As described in Section 3.2, the DCC is used in the PCC process to control the temperature of the flue gas entering the absorber column as well as reduce the SO₂ content in the flue gas through addition of NaOH in the cooling loop. Exhibit 5-12 shows the SIH process configuration with DCC separate from the absorber column and flue gas blower upstream of the absorber (SIH Scenario 2) for comparison with the SIH process option shown in Exhibit 3-2 (SIH Scenario 1). Three-dimensional (3D) plant models for SIH scenario configurations 1 and 2 are shown in Exhibit 15-13 and Exhibit 15-14, respectively.

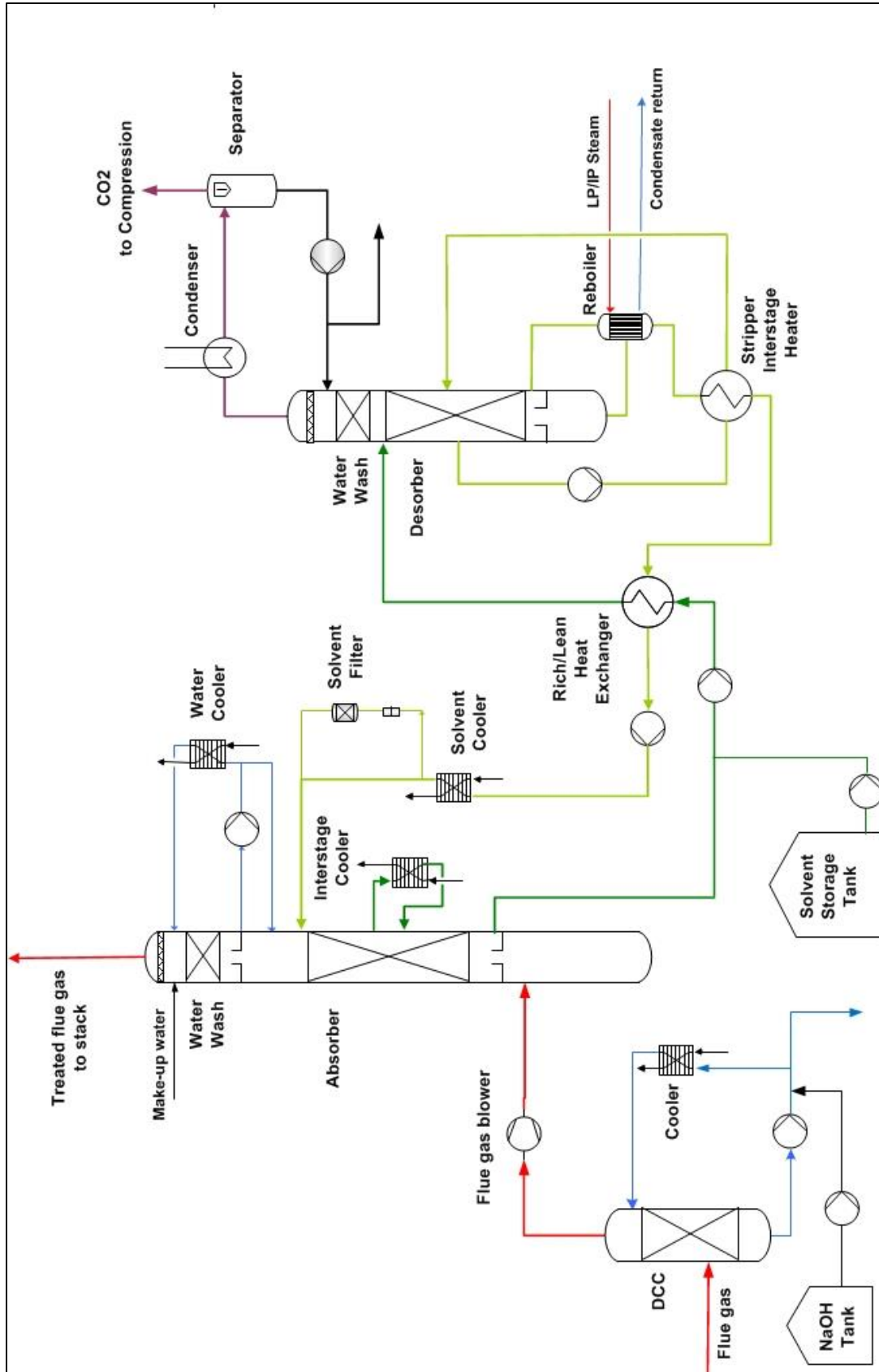


Exhibit 5-12. Linde-BASF SIH PCC process configuration with DCC separate from absorber column and blower placed upstream of absorber (SIH Scenario 2)



Exhibit 5-13. 3D image of Linde-BASF PCC plant design (SIH Scenario 1 configuration with DCC inside absorber and blower downstream of absorber) for 550 MWe supercritical PC Power Plant



Exhibit 5-14. 3D image of Linde-BASF PCC plant design (SIH Scenario 2 configuration with separate DCC and blower upstream of absorber) for 550 MWe supercritical PC Power Plant

As illustrated in Exhibit 5-14, the DCC is separated from the absorber column resulting in unnecessary added material cost for Linde-BASF PCC SIH Scenario 2 compared to Scenario 1. Additionally, the larger blower placed upstream of the absorber for SIH Scenario 2 further increases the capital cost of the process relative to Scenario 1, which can use a smaller blower downstream of the absorber in the treated gas line as shown in Exhibit 5-13 due to the reduced volumetric flow rate of the treated gas compared to flue gas stream.

PCC Plant Cost

The total plant cost (TPC) for the novel Linde-BASF PCC technology (for the nth plant design and construction) was estimated based on Linde's proprietary methodology of estimating the cost for new, commercial process plants, which included as many actual vendor quotes as available based on recent commercial proposals and studies. The accuracy of the final PCC plant cost was estimated to be within +/- 30% in this study. As per DOE/NETL requirements, the resulting TPC also includes 20% process contingency, as well as 4% project contingency, as shown in Exhibit 5-15. The 4% project contingency was determined based on a Linde-proprietary cost model for the PCC process at commercial scale for integration with a 550 MWe supercritical coal-fired power plant. This 4% project contingency was determined based on Linde's past experience with large engineering, procurement, and construction projects. This 4% is less than the 16.67% project contingency for CO₂ removal and CO₂ compression with drying capital costs shown in the DOE/NETL Case 12 reference (updated to 2011\$) due to the higher degree of project certainty and lower overall risk associated with using the Linde-BASF processes based on past experience from the successful engineering/design, construction, testing, and performance validation of the Linde-BASF PCC technology. As discussed, the capital costs of two different cases for the Linde-BASF SIH process configuration were evaluated, and the results are shown in Exhibit 5-15. The project contingency for these Linde-BASF PCC plant cost estimations is also based on an assumption that the plant would be constructed not as a first attempt, but after many previous PCC plant constructions, which would reduce the overall project risk due to a greater level of experience in managing engineering, procurement, and construction for the PCC projects. The process and project contingencies presented in this report are deemed appropriate in conjunction with built-in contingencies on individual process equipment from Linde data tables.

Exhibit 5-15. Linde-BASF PCC plant cost details								
Total Post-Combustion CO₂ Capture Plant Cost Details (\$x1000 of 2011\$)								
	Equipment Cost	Labor Cost	Bare Erect Cost	Eng. CM H.O. & Fee	Contingencies		Total Plant Cost	
					Process	Project	\$x1000	\$/kW
Linde-BASF PCC LB1 Option								
CO ₂ Removal System	130,475	51,495	181,970	27,194	37,473	10,554	257,191	468
CO ₂ Compression & Drying	39,517	18,709	58,226	3,036	0	2,476	63,738	116
Total	169,992	70,204	240,195	30,230	37,473	13,030	320,928	584
Linde-BASF PCC SIH Scenario 1 – Combined DCC and Absorber with Downstream Flue Gas Blower								
CO ₂ Removal System	123,824	45,151	168,974	31,322	37,473	10,192	247,961	451
CO ₂ Compression & Drying	41,675	13,997	55,672	4,582	0	2,147	62,401	113
Total	165,498	59,149	224,646	35,904	37,473	12,338	310,362	564
Linde-BASF PCC SIH Scenario 2 – Separate DCC and Absorber with Upstream Flue Gas Blower								
CO ₂ Removal System	129,166	47,171	176,338	32,063	37,473	10,556	256,430	466
CO ₂ Compression & Drying	41,675	13,997	55,672	4,582	0	2,147	62,401	113
Total	170,840	61,169	232,010	36,645	37,473	12,703	318,830	580

The reduced plant cost for both Linde-BASF PCC plant options for the capture and compression of CO₂ from a 550 MWe PC power plant is a result of the combined effects of an advanced PCC plant design (utilizing a single train CO₂ recovery plant with advanced design solutions and construction materials), and the reduced capacity of the PCC plant due to the increased overall efficiency of the PC power plant integrated with Linde-BASF PCC technology. Exhibit 5-16 shows the resulting reduction of TPC and its elements for the two Linde-BASF PCC options detailed in this study (LB1 and SIH (both scenarios)) with respect to the DOE/NETL Case 12 reference. As shown in Exhibit 5-16, Linde-BASF SIH Scenario 1 offers the largest cost reduction compared to the DOE/NETL Case 12 reference PCC plant. SIH Scenario 1 offers improved cost savings compared to SIH Scenario 2 due to the capital cost reduction afforded through combining the DCC and absorber column units (which results in reduced materials of construction) and reduced blower size allowed through placement of the blower downstream of the absorber. This downstream blower placement is cost-effective if the capital cost savings provided through use of a smaller blower are greater than the costs of any additional steel support structures that may be needed to support a downstream blower along with any extra piping needed. Typically, if the treated gas leaving the PCC plant is required to be routed to the power plant gas stack for environmental/regulatory

compliance reasons, then a downstream blower provides lower cost. The additional savings provided with the downstream blower were incorporated into the cost estimation of LB1 and SIH Scenario 1.

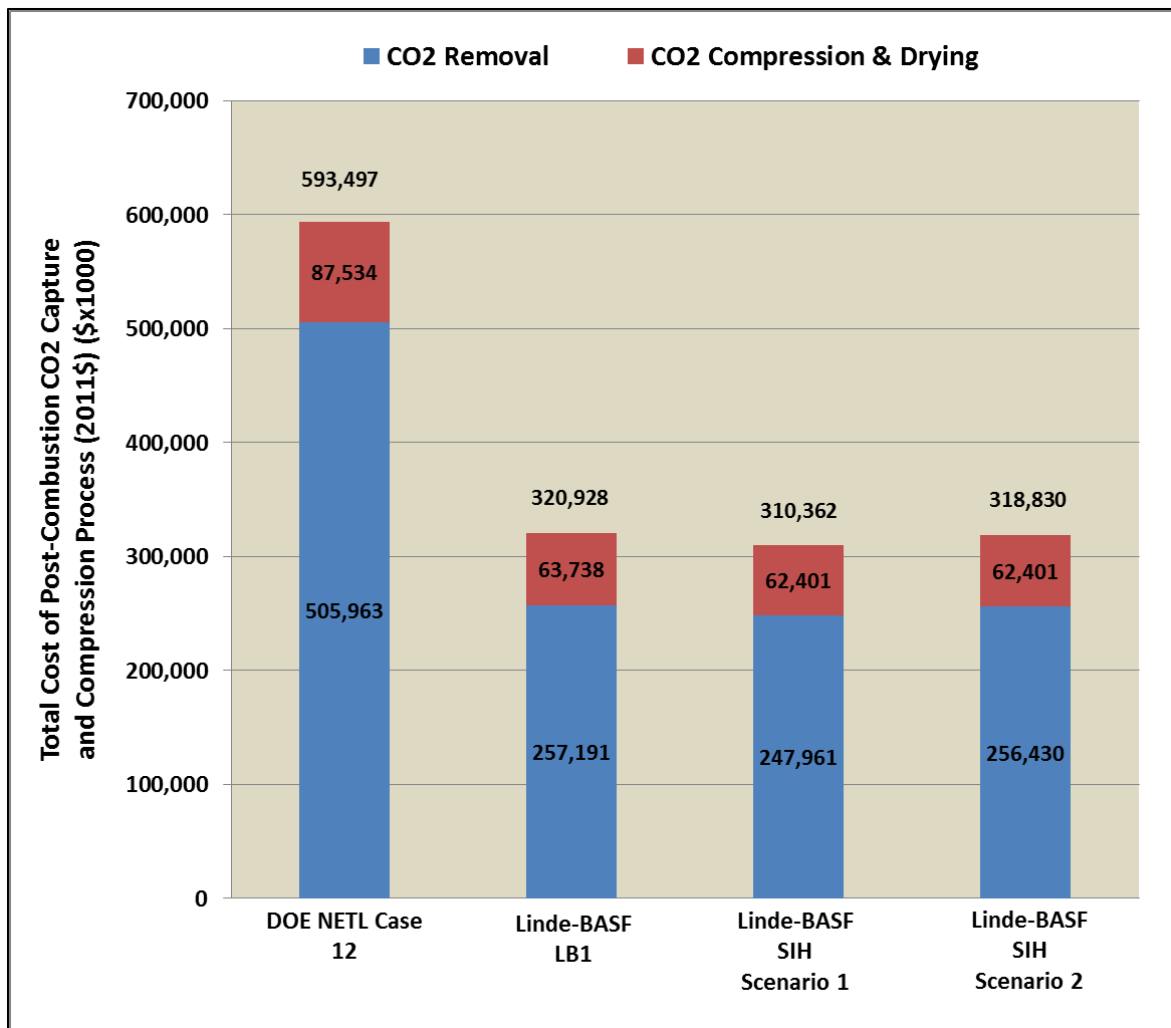


Exhibit 5-16. Comparison of Total Plant Costs (TPC) for PCC technologies (\$x1000) (2011\$)

550 MWe PC Power Plant Integrated with PCC (2011\$)				
	DOE NETL Case 12	Linde- BASF LB1	Linde-BASF SIH (Scenario 1)	Linde-BASF SIH (Scenario 2)
CO ₂ Captured (TPD)	13,161	12,100	11,907	11,907
CO ₂ Removal System (\$x1000)	505,963	257,191	247,961	256,430
CO ₂ Compression & Drying (\$x1000)	87,534	63,738	62,401	62,401
PCC Plant Cost (\$x1000)	593,497	320,928	310,362	318,830
Cost Reduction wrt Case 12 (%)	0.0%	45.9%	47.7%	46.3%

Because it provides reduced capital cost compared to Scenario 2, the SIH Scenario 1 process configuration is used as the standard SIH case for the rest of the cost analysis in Section 5 of this report.

Total Plant Cost Estimates

In addition to estimating the total cost for Linde-BASF PCC plant options LB1, SIH, and LB1-CREB with the methodology outlined above, it is also necessary to estimate the total cost of the PC power plant for each configuration in order to obtain the TPC value necessary for calculation of the COE (detailed in Section 2).

For this study, after consulting different sources of information, a frequently practiced approach to use estimated exponential scaling factors to calculate the cost of a plant with different capacity than the original plant with known cost was adopted. This approach was verified not only from reported TPC values from the DOE/NETL Case 12 reference for power plants with and without CO₂ capture, but also after completing a due diligence from the communications and actual cost information obtained from Santee Cooper for their commercial subcritical and supercritical power plants as already outlined in the 2012 report [6]. Most of the plant cost elements and proportions between different items remained very similar to those reported in the NETL study when compared on an equivalent basis, with the only significant exception being the site-specific cost that included foundations, buildings, miscellaneous civil expenses, etc. However, since the evaluation basis for this TEA are strictly defined and are identical as in the DOE/NETL Case 11 and Case 12 references [Ref. 2], the above mentioned difference for site-specific cost is not relevant for this study.

After carefully examining interdependences of reported cost elements by all equipment elements and resulting accounts from the DOE/NETL reference (Case 11 without PCC capture versus Case 12 with PCC capture) and from obtained information from Santee Cooper, it was concluded that as the first approximation, the TPC/TOC of the entire power plant (except independently estimated TPC/TOC for the PCC plant) can be scaled-down as a function of the coal feed rates used in different process options (denoted as SP-S for Single Parameter Scaling methodology). From the TPC elements for DOE/NETL reference Cases 11 and 12 [Ref. 2], a single exponential scaling factor of 0.669 was derived and used to estimate the TPC/TOC for a power plant integrated with Linde-BASF PCC technology, except for the PCC plant itself, for which, the TPC/TOC values for the two selected options (LB1 and SIH) were independently estimated (Total PCC Plant Cost shown is in Exhibit 5-15). A multiple parameter scaling methodology (MP-S) was described in the previous TEA submitted [Ref. 6], but it was later shown that

the relative difference between TPC derived using SP-S vs. TPC derived using MP-S was quite insignificant (~1%). Hence, only single parameter scaling was utilized for this study for the sake of simplicity. While it is understood that neither of the two approaches is perfect, it is believed that for this study the SP-S methodology facilitates consistent predictions of the incremental change in the capital cost of the integrated PC power plant with PCC when progressively improved Linde-BASF technologies are utilized as compared to the DOE/NETL Case 12 reference. Final itemized capital costs for a 550 MWe supercritical power plant integrated with Linde-BASF PCC technology innovations as compared to the DOE/NETL Case 12 reference are shown in Exhibit 5-17.

In Section 5.3, the TPC/TOC values for LB1, SIH, and LB1-CREB options were derived by scaling-down the cost of the entire power plant (except the PCC plant) with a single exponent scaling factor of 0.669 (as explained above), while Section 5.4 quantifies the impact of each TPC/TOC estimate, as well as different options for the CO₂ transport, storage, and monitoring (TSM) calculations, on the resulting COE and cost of CO₂ captured values. The capital cost for the LB1-CREB design incorporates the cost of additional heat exchangers and still provides an overall lower cost than the other designs presented in this study due to the increased PC power plant efficiency it affords. The higher power plant efficiency results in a smaller PCC plant needed to capture 90% of the CO₂ in the flue gas of the integrated PC plant.

Exhibit 5-17. Itemized Total Plant Capital Cost (\$x1000, 2011\$ price basis)				
Capital Cost Element	Case 12 (2011\$)	Linde-BASF LB1 (2011\$)	Linde-BASF SIH (2011\$)	Linde-BASF LB1-CREB (2011\$)
Coal and Sorbent Handling	56,286	53,209	52,638	52,273
Coal and Sorbent Prep & Feed	27,055	25,576	25,302	25,126
Feedwater & Misc. BOP Systems	123,565	116,811	115,558	114,755
PC Boiler	437,215	413,317	408,882	406,043
Flue Gas Cleanup	196,119	185,399	183,410	182,136
CO₂ Removal	505,963	257,191	247,961	243,415
CO₂ Compression & Drying	87,534	63,738	62,401	60,324
Heat and Power Integration	0	0	0	0
Combustion Turbine/Accessories	0	0	0	0
HRSG, Ducting & Stack	45,092	42,627	42,170	41,877

Steam Turbine Generator	166,965	157,839	156,145	155,061
Cooling Water System	73,311	69,304	68,560	68,084
Ash/Spent Sorbent Handling Syst.	18,252	17,254	17,069	16,951
Accessory Electric Plant	100,255	94,775	93,758	93,107
Instrumentation & Control	31,053	29,356	29,041	28,839
Improvements to Site	18,332	17,330	17,144	17,025
Buildings & Structures	72,402	68,445	67,710	67,240
TPC without PCC	1,365,902	1,291,242	1,277,387	1,268,517
PCC Cost	593,497	320,928	310,362	303,739
Total Plant Cost (TPC)	1,959,399	1,612,170	1,587,748	1,572,255
Preproduction Costs	60,589	53,070	52,476	52,098
Inventory Capital	43,248	39,283	38,753	38,415
Initial Cost for Catalyst and Chemicals	3,782	3,111	3,064	3,034
Land	899	740	729	722
Other Owner's Costs	293,910	241,826	238,162	235,838
Financing Costs	52,904	43,529	42,869	42,451
Total Overnight Costs (TOC)	2,414,731	1,993,728	1,963,801	1,944,814

5.4. Cost of Electricity

The COE and cost of CO₂ captured for PC power plants utilizing the proposed Linde-BASF PCC technologies have been calculated using the equations shown in Section 2, along with stated values of economic parameters that are identical to the methodology used in the DOE/NETL Case 12 reference. In addition, the cost analysis presented here uses unchanged unit costs of consumables shown in Exhibit 4-13 of the August 2012 DOE/NETL-341/082312 report with updated operating and maintenance (O&M) costs for the DOE/NETL Case 12 reference [Ref. 10]. The only exception was a unit cost for the BASF OASE[®] blue solvent, which has been estimated to be three times the unit price of the MEA solvent used

in the DOE/NETL Case 12 reference [Ref. 6]. In order to consistently compare the effects of new PCC technology on incremental COE values relative to the DOE/NETL Case 12 reference, all costs are expressed in 2011\$ (since the DOE/NETL Case 12 reference also used 2011\$). Exhibit 5-18 summarizes the major annual O&M cost elements for the reference Case 12 utilizing MEA-based PCC technology, and for the three selected Linde-BASF PCC options.

Exhibit 5-18. Summary of Annual Operating and Maintenance Expenses				
Annual O&M Expenses for 550 MWe PC Power Plant with PCC (2011\$)				
Cost Element	NETL_2011 Case 12	Linde-BASF LB1	Linde-BASF SIH	Linde-BASF LB1-CREB
Total Fixed Operating Cost	64,137,607	57,356,056	56,867,612	56,557,758
Maintenance Material Cost	19,058,869	18,017,114	17,823,784	17,700,023
Water	3,803,686	3,595,777	3,557,193	3,532,493
Chemicals (including solvent)	24,913,611	23,551,836	23,299,117	23,137,338
SCR Catalyst	1,183,917	1,119,204	1,107,195	1,099,507
Ash Disposal	5,129,148	4,848,789	4,796,760	4,763,454
By-Products	0	0	0	0
Total Variable Operating Cost	54,089,231	51,132,721	50,584,050	50,232,815
Total Fuel Cost (Coal @ \$68.60/ton)	144,504,012	132,858,628	130,733,327	129,378,772

Exhibit 5-19 shows incremental reductions in COE when switching from the DOE/NETL Case 12 reference technology to Linde-BASF PCC technology options (including LB1-CREB).

The following set of assumptions was used to create Exhibit 5-19:

- The TPC values for the entire power plant (except for the PCC plant) of each case were estimated by scaling-down the cost from the DOE/NETL Case 12 reference with the boiler coal feed rate and the derived value of a single exponential scaling factor of 0.669.

- The PCC plant cost, estimated from the latest vendors quotes received in 2012 and 2016, was expressed in 2011\$ using an average annual cost escalation factor of 2.34% from 2012 to 2016 for each year and extrapolating this escalation factor from 2012 to 2011 to derive the 2011\$ PCC costs.
- The CO₂ TSM was calculated by using \$10/metric tonne (MT) of CO₂, as required by the DOE for this award.

Exhibit 5-19 clearly demonstrates the COE reduction steps from \$147.25/MWh (DOE/NETL Case 12 reference) to \$125.51/MWh (LB1-CREB process option) for COE (including CO₂ TSM costs) afforded through application of the Linde-BASF PCC processes.

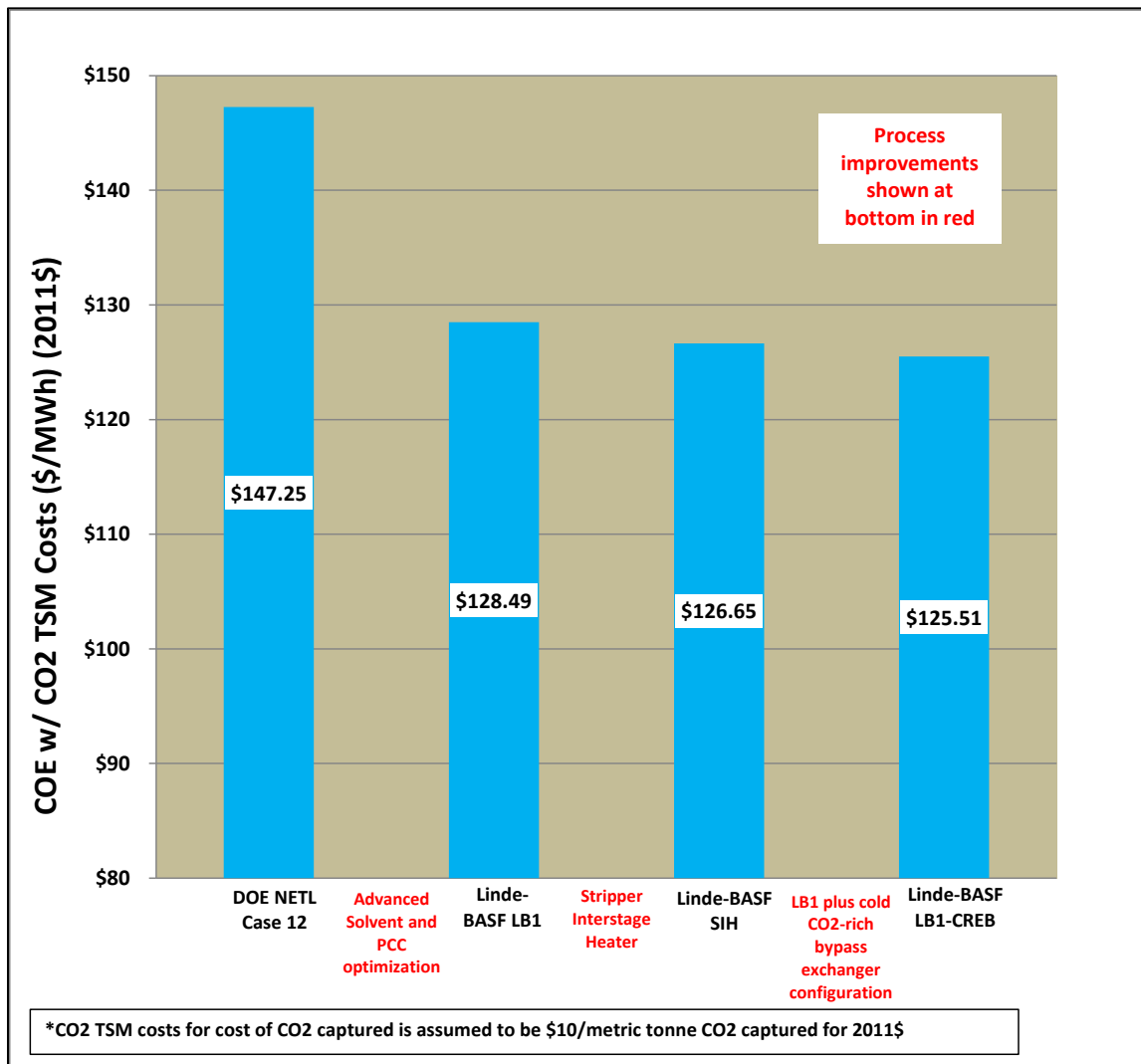


Exhibit 5-19. Incremental COE (w/ CO₂ TSM Costs = \$10/MT CO₂) reduction steps (SP-S methodology for TPC)

The very first step of \$18.76/MWh COE reduction comes from the superior performance and significantly reduced utility requirements required when the BASF OASE[®] blue solvent and higher CO₂ compression inlet pressure (48 psia vs 24 psia) are used relative to the DOE/NETL Case 12 reference, which is consistent with already demonstrated improvement of the net plant efficiency (Exhibit 5-4).

The next COE step reduction of \$1.84/MWh is a result of the significantly lower PCC steam consumption requirement for Linde-BASF SIH advanced stripper heat recovery configuration compared to Linde-BASF LB1 as described in Section 5.2 (2.3 GJ/MT CO₂ vs. 2.61 GJ/MT CO₂, respectively).

The third and final COE reduction step of \$1.14/MWh is a result of the further reduced specific PCC energy penalty from Linde-BASF SIH to LB1-CREB (2.3 GJ/MT CO₂ to 2.1 GJ/MT CO₂, respectively). As shown, the effect of LB1-CREB on reducing COE certainly justifies its implementation from an operational cost and steam consumption reduction standpoint.

The COE values of two of the presented Linde-BASF options (\$128.49/MWh and \$126.65/MWh for LB1 and SIH, respectively) clearly demonstrate significantly reduced financial penalties for CO₂ capture relative to the DOE/NETL Case 12 reference of \$147.25/MWh (calculated, for comparison purposes, using a consistent basis of \$10/MT of CO₂ for TSM costs, as required by DOE for this TEA).

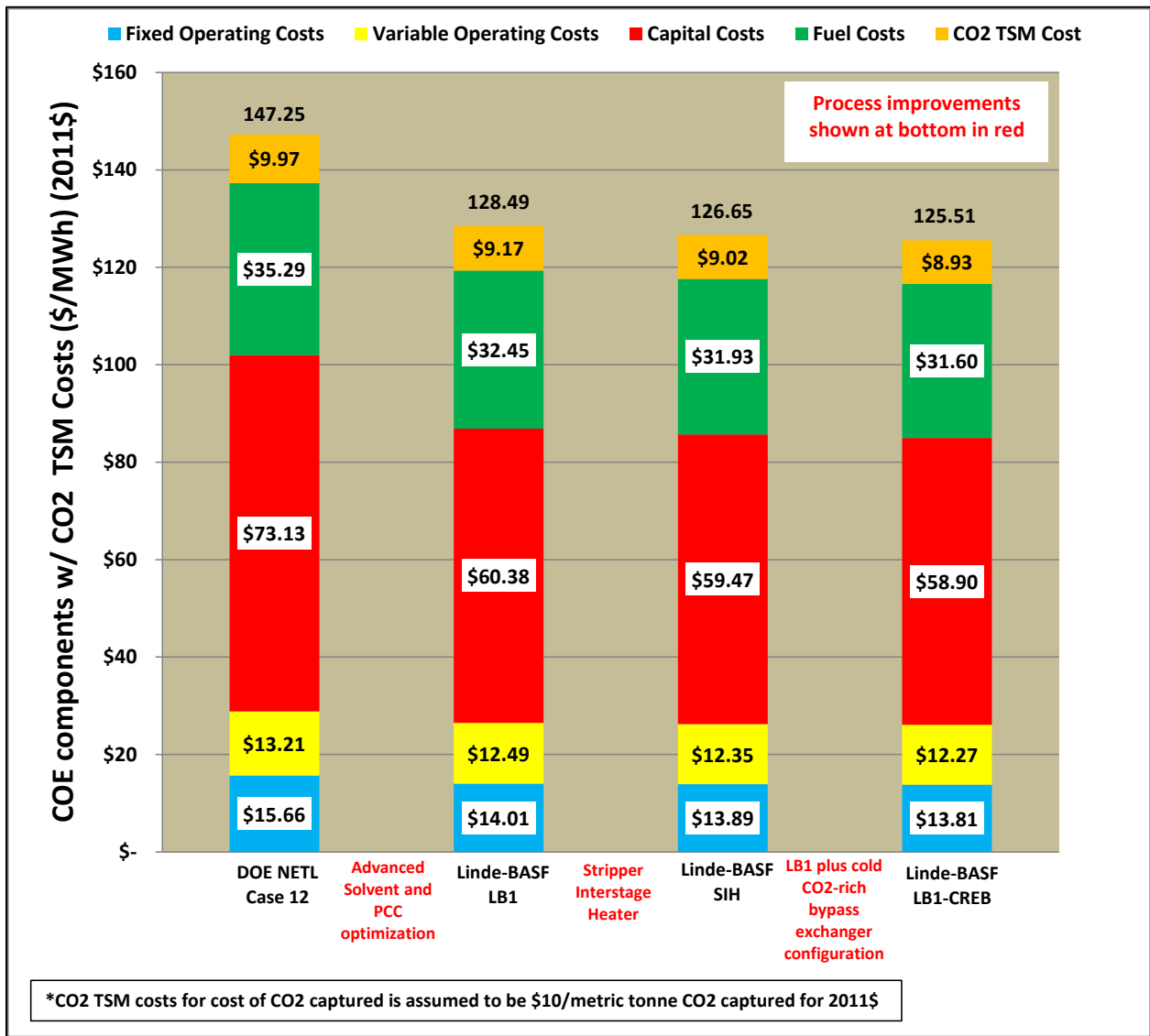


Exhibit 5-20. COE components (\$/MWh) for different PCC options (SP-S methodology for TPC; CO₂ TSM Cost = \$10/MT CO₂)

Relative to the COE value of \$80.95/MWh for a PC power plant without PCC option (DOE/NETL Case 11 reference [Ref. 2]), the utilization of Linde-BASF advanced PCC technology leads to incremental COE increases of 58.73% and 56.46% for the LB1 and SIH process options, respectively. The cost component breakdown for COE for each process configuration analyzed in this report is shown in Exhibit 5-20.

5.5 *Cost of CO₂ Captured*

The cost of CO₂ captured for each process configuration used in this study is presented in the following few exhibits. Cost of CO₂ captured was calculated using the methodology described in Section 2, and is used in conjunction with COE for assessing process financial competitiveness/attractiveness relative to DOE/NETL Case 12 reference. Exhibit 5-21 shows the cost of CO₂ captured for each process configuration discussed in this study. As shown, the large decrease in cost of CO₂ captured (\$/MT CO₂) from the DOE/NETL Case 12 reference to LB1 Linde-BASF option (a 25.92% reduction relative to the smaller overall reduction in cost of CO₂ captured from LB1 to LB1-CREB (4.65%)) can be attributed not only to the substantial reduction in specific PCC reboiler energy required for CO₂ capture (3.61 GJ/MT CO₂ for DOE/NETL Case 12 reference as compared to 2.61 GJ/MT CO₂ for LB1 decreasing to 2.1 GJ/MT CO₂ for LB1-CREB) as a result of using the BASF OASE[®] blue PCC solvent technology integrated with advanced Linde-BASF PCC process design innovations, but also the notable energy reduction provided by the reduced CO₂ compression requirements at the higher gas inlet pressure for CO₂ compression for the Linde-BASF cases vs. the DOE/NETL Case 12 reference (48 psia vs. 24 psia, respectively). These cost reduction factors are also mitigated by the fact that as power plant efficiency is increased (as a result of reduced auxiliary power loads afforded by each progressively improved Linde-BASF case), the flow rate of CO₂ produced decreases due to a reduced coal flow rate needed for power production. This decreased CO₂ production flow rate inherently increases the cost of CO₂ captured as well, resulting in smaller incremental reductions in cost of CO₂ captured for each Linde-BASF process improvement shown. A critical acknowledgement pertinent to future PCC process innovations is that full utilization of process option LB1-CREB has the potential to reduce the cost of CO₂ captured to \$39.90/MT CO₂, directly in line with the DOE target to reduce the cost of CO₂ captured from PCC technologies integrated with coal-fired power plants to below \$40/MT CO₂.

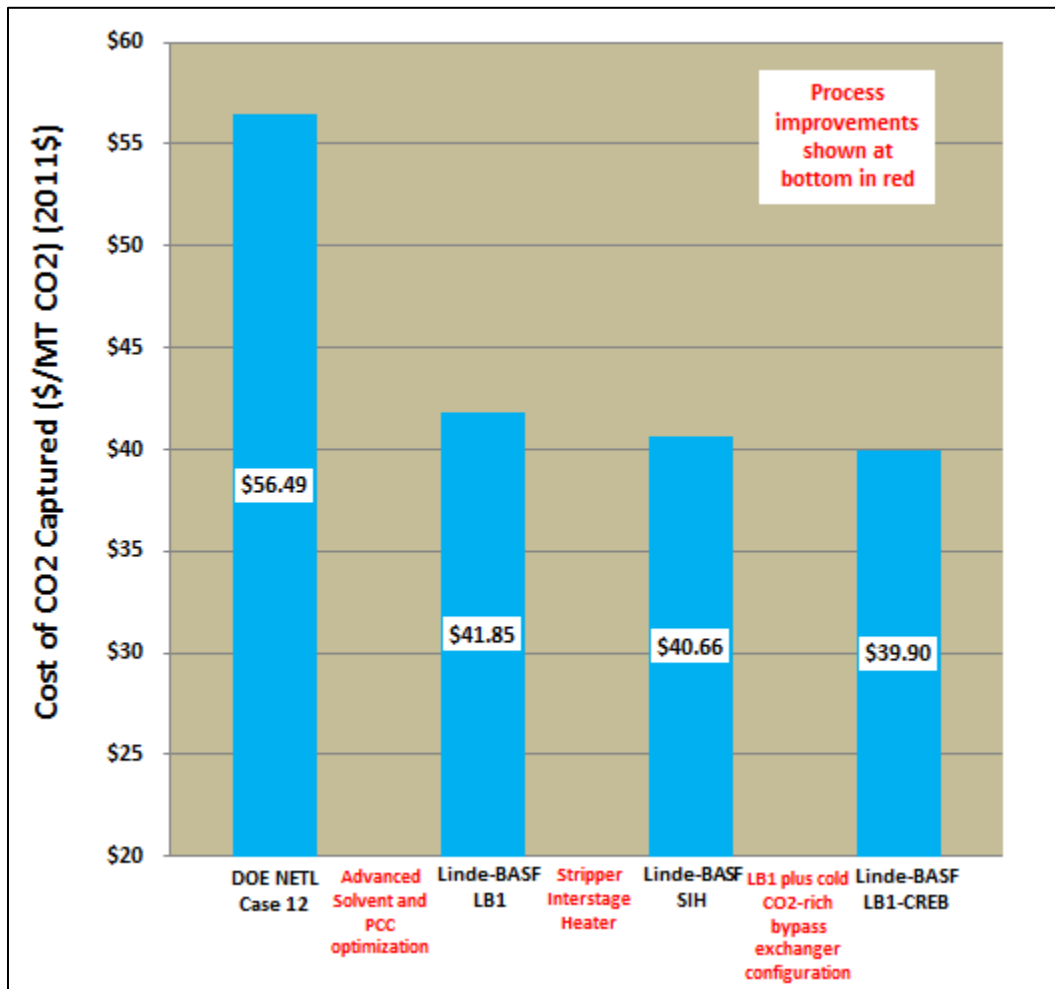


Exhibit 5-21. Cost of CO₂ captured (\$/MT CO₂) for different PCC options (SP-S methodology for TPC)

6. Conclusions

A rigorous simulation model to accurately predict material and energy balances, as well as power production and auxiliary consumptions for a 550 MWe supercritical PC power plant integrated with selected PCC technology options has been developed and verified against published results from the DOE/NETL Case 12 reference [Ref. 2].

A comprehensive set of simulations of different options for the post-combustion capture and compression of 90% of produced CO₂ from a 550 MWe PC power plant was performed. The performance results obtained confirm the superior performance of Linde-BASF PCC technology, compared with reference Case 12 [Ref. 2]. Specific utility energy requirements (reboiler heating duty plus cooling duty) for the PCC plant with the Linde-BASF LB1 and SIH process options are reduced by more than 27% compared to the MEA-based DOE/NETL Case 12 reference, and reduced as much as 42% when Linde-BASF

process option LB1-CREB is utilized. These savings translate to an impressive reduction (13.4 – 14.1%) of incremental energy for CO₂ capture and compression for the 550 MWe supercritical power plant when compared with baseline Case 12 (Exhibit 5-3).

The Linde-BASF PCC technology options, integrated with a 550 MWe supercritical PC power plant, lead to increased net power plant efficiency from 28.4% reported in reference Case 12 to 30.9% (LB1) and to 31.4% (SIH) (Exhibit 5-4).

The increased efficiency and innovative, cost-effective design of the Linde-BASF PCC plant lead to significant reductions in total plant cost for the overall PCC plant integrated with 550 MWe coal-fired power plant (17.72% reduction for the LB1 option and 18.97% reduction for the SIH option) when compared with DOE/NETL Case 12 reference (Exhibit 5-17).

The calculated COE for a 550 MWe PC power plant with CO₂ capture and compression is \$18.76/MWh to \$21.75/MWh lower than in DOE/NETL Case 12 reference (Exhibits 5-16 and 5-17).

Calculated COE values of \$128.49/MWh and \$126.65/MWh for LB1 and SIH options (including \$10/MT CO₂ TSM costs), respectively, while utilizing SP-S methodology for TPC estimates, are equivalent to incremental COE increases for CCS of 58.73% (LB1) and 56.46% (SIH), respectively, relative to the \$80.95/MWh estimated for a 550 MWe power plant without CO₂ capture.

The cost of CO₂ captured decreases from \$56.49/MT CO₂ for the DOE/NETL Case 12 reference to \$41.85/MT CO₂ and \$40.66/MT CO₂ for Linde-BASF options LB1 and SIH, respectively. Incorporating LB1-CREB technology further reduces the cost of CO₂ captured to \$39.90/MT CO₂, directly in line with the DOE target to reduce the cost of CO₂ captured from PCC technologies integrated with coal-fired power plants to less than \$40/MT CO₂.

Acknowledgements:

George Booras of Electric Power Research Institute (EPRI) for reviewing the draft version of this report and providing valuable comments.

Appendices

- **Abbreviations**

aMWh	Annual net megawatt-hours of power generated at 100 percent capacity factor
CCF	Capital Charge Factor for a levelized period of 20 years
CF	Plant Capacity Factor (0.85 in this study)
DCC	Direct Contact Cooler
FGD	Flue Gas Desulfurization
LB1	Linde-BASF PCC option previously reported [Ref. 6] upgraded to supercritical PC power plant using BASF OASE [®] blue solvent technology and advanced PCC process [Ref. 6]
SIH	Linde-BASF PCC option using BASF OASE [®] blue solvent technology with advanced stripper interstage heater PCC process configuration
LB1-CREB	Linde-BASF PCC option using BASF OASE [®] blue solvent technology with advanced main CO ₂ -rich/CO ₂ -lean heat exchanger and cold CO ₂ -rich bypass exchanger design [Ref. 8 and Ref. 9]
COE	Cost Of Electricity, \$/MWh
PCC	Post Combustion Capture
SP-S	Single Parameter Scaling methodology for TPC estimates
TPC	Total Plant Cost, \$
TOC	Total Overnight Cost, \$
MT	Metric tonne
TPD	Metric tonnes per day
TSM	CO ₂ Transportation, Storage and Monitoring

- **List of Exhibits**

Exhibit 2-1. Design Coal

Exhibit 3-1. Simplified Process Flow Diagram of Linde-BASF Post Combustion Capture Technology (LB1)

Exhibit 3-2. Simplified Process Flow Diagram of Linde-BASF Post Combustion Capture Technology with Advanced Stripper Interstage Heater Configuration (SIH)

Exhibit 3-3. Simplified Process Flow Diagram of Linde-BASF Post Combustion Capture Technology with Advanced Main CO₂-Rich/CO₂-Lean Solution Exchanger and Cold CO₂-Rich Bypass Exchanger Configuration (LB1-CREB)

Exhibit 4-1. Block Flow Diagram of Supercritical PC power plant with CO₂ Capture and Compression

Exhibit 4-2. Block Flow Diagram of Supercritical PC power plant with CO₂ Capture and Compression utilizing flue gas heat recovery upstream of FGD

Exhibit 4-3. Supercritical PC Plant Study Configuration Matrix

Exhibit 5-1. Specific energy demand for 90% CO₂ capture and compression to 2215 psia

Exhibit 5-2. Specific energy demand elements for CO₂ Capture and Compression for Linde BASF LB1 and SIH PCC technologies compared to DOE/NETL Case 12 reference

Exhibit 5-3. Effect of Linde-BASF PCC technologies on coal fuel requirement for 550 MWe supercritical power plant integrated with CO₂ Capture and Compression

Exhibit 5-4. Incremental improvements in net plant HHV efficiency (%) from MEA-based PCC (DOE/NETL Case 12) to Linde-BASF processes

Exhibit 5-5. Heat and Mass Balance: Power plant with Linde-BASF PCC Technology - Case LB1

Exhibit 5-6. M&E Balances for Linde-BASF LB1 Option (in reference to Exhibit 4-1)

Exhibit 5-7. Heat and Mass Balances: Power plant with Linde-BASF PCC Technology – Case SIH

Exhibit 5-8. M&E Balances for Linde-BASF SIH Option (in reference to Exhibit 4-1)

Exhibit 5-9. Influence of PCC technology options on PC power plant performance

Exhibit 5-10. Environmental benefits of LINDE-BASF PCC Technologies

Exhibit 5-11. 3D Image of Linde-BASF PCC Plant Design for 550 MWe PC Power Plant

Exhibit 5-12. Linde-BASF SIH PCC process configuration with DCC separate from absorber column and blower placed upstream of absorber (SIH Scenario 2)

Exhibit 5-13. 3D image of Linde-BASF PCC plant design (SIH Scenario 1 configuration) for 550 MWe supercritical PC Power Plant

Exhibit 5-14. 3D image of Linde-BASF PCC plant design (SIH Scenario 2 configuration) for 550 MWe supercritical PC Power Plant

Exhibit 5-15. Linde-BASF PCC plant cost details

Exhibit 5-16. Comparison of Total Plant Costs (TPC) for PCC technologies (\$x1000) (2011\$)

Exhibit 5-17. Itemized Total Plant Capital Cost (\$x1000, 2011\$ price basis)

Exhibit 5-18. Summary of Annual Operating and Maintenance Expenses

Exhibit 5-19. Incremental COE (w/ CO₂ TSM Costs) reduction steps (SP-S methodology for TPC; CO₂ TSM Cost = \$10/MT CO₂)

Exhibit 5-20. COE components for different PCC options (SP-S methodology for TPC; CO₂ TSM Cost = \$10/MT CO₂)

Exhibit 5-21. Cost of CO₂ for different PCC options (SP-S methodology for TPC)

Exhibit A-1.M&E Balances for DOE/NETL Case 12 reference (in reference to Exhibit 4-1)

Exhibit A-2. Heat and Mass Balance DOE/NETL Case 12 reference using MEA-based PCC

- **References**

- [1] “Cost and Performance Baseline for Fossil Energy Plants – Volume 1: Bituminous Coal and Natural Gas to Electricity”, DOE/NETL-2007/1281 Study, Final Report, Rev. 1, (May 2007)
- [2] “Cost and Performance Baseline for Fossil Energy Plants – Volume 1: Bituminous Coal and Natural Gas to Electricity”, DOE/NETL-2010/1397 Study, Final Report, Rev. 2a, (September 2013)
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- [5] S. Jovanovic, R. Krishnamurthy, “*Optimized Integration between Power Generation and Post Combustion Capture Plants*”, Linde NOI # IA0241, 2011; USPTO Provisional Patent Application, Docket No P12A003, 2012
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- [7] Summers, William Morgan, DOE/NETL, “*Cost Estimation Methodology for NETL Assessments of Power Plant Performance*,” DOE/NETL-2011/1455, August 2011.
- [8] Rochelle, Gary; Madan, Tarun; Lin, Yu-Jeng. “*Apparatus for and method of removing acidic gas from a gaseous stream and regenerating an absorbent solution*” United States Patent Application. Pub. No.: US 2015/0246298 A1, September 3, 2015.
- [9] Rochelle, Gary; Madan, Tarun; Lin, Yu-Jeng. “*Regeneration with Rich Bypass of Aqueous Piperazine and Monoethanolamine for CO₂ Capture*” I&EC Research, February 18, 2014.
- [10] “Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases”, August 2012. DOE/NETL-341/082312.

- **Model Validation**

The validation of the modeling approach described in Section 5.1 is presented in a form of detailed material and energy balances calculated for DOE/NETL Case 12 reference in the following two exhibits:

Case 12																
Stream Properties																
V-L mol. fract.	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10	S11	S12	S13	S14	S15	
Ar	1	1	1	1	1	0	0	1	0	1	1	0	0	1	0	
CO2	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0000	0.0128	0.0000	
H2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000	0.0000	0.0005	0.0004	
H2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
N2	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000	1.0000	0.0062	0.9996	
O2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000	0.0000	0.7506	0.0000	
SO2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000	0.0000	0.2300	0.0000	
Total	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000	0.0000	0.0000	0.0000	
V-L Flowrate (lbmol/hr)	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
V-L Flowrate (lb/hr)	147,437	147,437	45,291	45,291	3,408	0	0	207,471	0	207,471	207,471	7,462	29,730	2,148	550	
Solid Flowrate (lb/hr)	4,254,595	4,254,595	1,306,967	1,306,967	98,338	0	0	6,170,854	0	6,170,854	6,170,854	134,426	535,592	62,368	9,916	
Temperature (F)	0	0	0	0	0	565,820	10,973	43,893	43,893	0	0	57,245	0	0	88,488	
Pressure (psia)	59	66	59	78	59	59	59	337	59	337	360	59	59	357	136	
Enthalpy (Btu/lb)	14.7	15.3	14.7	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.4	15.0	14.7	45.0	14.9	
Density (lb/ft3)	13.0	14.8	13.0	17.5	13.0	-	-	140.8	-	132.8	138.8	-	-20.1	82.4	-	
Molecular Weight	0.076	0.078	0.076	0.081	0.076	-	-	0.050	-	0.049	0.052	-	62.622	0.149	-	
	28.86	28.86	28.86	28.86	28.86	-	-	29.74	-	29.74	29.74	-	18.02	29.03	-	
V-L mol. fract.	S16	S17	S18	S19	S20	S21	S22	S23	S24	S25	S26					
Ar	1	1	0	1	1	1	0	0	1	1	1					
CO2	0.0081	0.0000	0.0000	0.0000	0.0000	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000					
H2	0.1350	0.0000	0.0000	0.9961	0.9985	0.0179	0.0000	0.0000	0.0000	0.0000	0.0000					
H2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000					
N2	0.1537	1.0000	1.0000	0.0039	0.0015	0.0383	1.0000	1.0000	1.0000	1.0000	1.0000					
O2	0.6793	0.0000	0.0000	0.0000	0.0000	0.9013	0.0000	0.0000	0.0000	0.0000	0.0000					
SO2	0.0238	0.0000	0.0000	0.0000	0.0000	0.0316	0.0000	0.0000	0.0000	0.0000	0.0000					
Total	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000					
V-L Flowrate (lbmol/hr)	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000					
V-L Flowrate (lb/hr)	226,080	99,037	99,037	27,582	27,516	170,387	108,697	278,909	278,909	227,597	227,597					
Solid Flowrate (lb/hr)	6,518,034	1,784,175	1,784,175	1,211,096	1,209,902	4,800,109	1,958,210	5,024,628	5,024,628	4,100,215	4,100,215					
Temperature (F)	0	0	0	0	0	0	0	0	0	0	0					
Pressure (psia)	136	556	304	69	95	89	103	545	1,100	671	1,100					
Enthalpy (Btu/lb)	14.9	73.5	133.6	23.5	2,214.5	14.7	245.0	4,185.0	3,514.7	711.1	655.8					
Density (lb/ft3)	-1,331.6	-5,546.4	-6,596.6	-4,283.6	-3,946.3	-6,813.2	-6,798.8	-6,330.9	-5,375.0	-5,544.5	-5,299.1					
Molecular Weight	0.07	0.12	57.21	0.12	49.71	0.07	62.00	48.31	4.32	1.17	0.72					
	28.83	18.02	18.02	43.90	43.96	28.17	18.02	18.02	18.02	18.02	18.02					

Reference state: Vapor Heat of Formation @ 77 F & 14.7 psia; Reference State for Coal and Ash: Solid Heat of Formation @ 32.02 F & 0.089 psia

Exhibit A-1. M&E Balances for DOE/NETL Case 12 reference (applies to Exhibit 4-1)

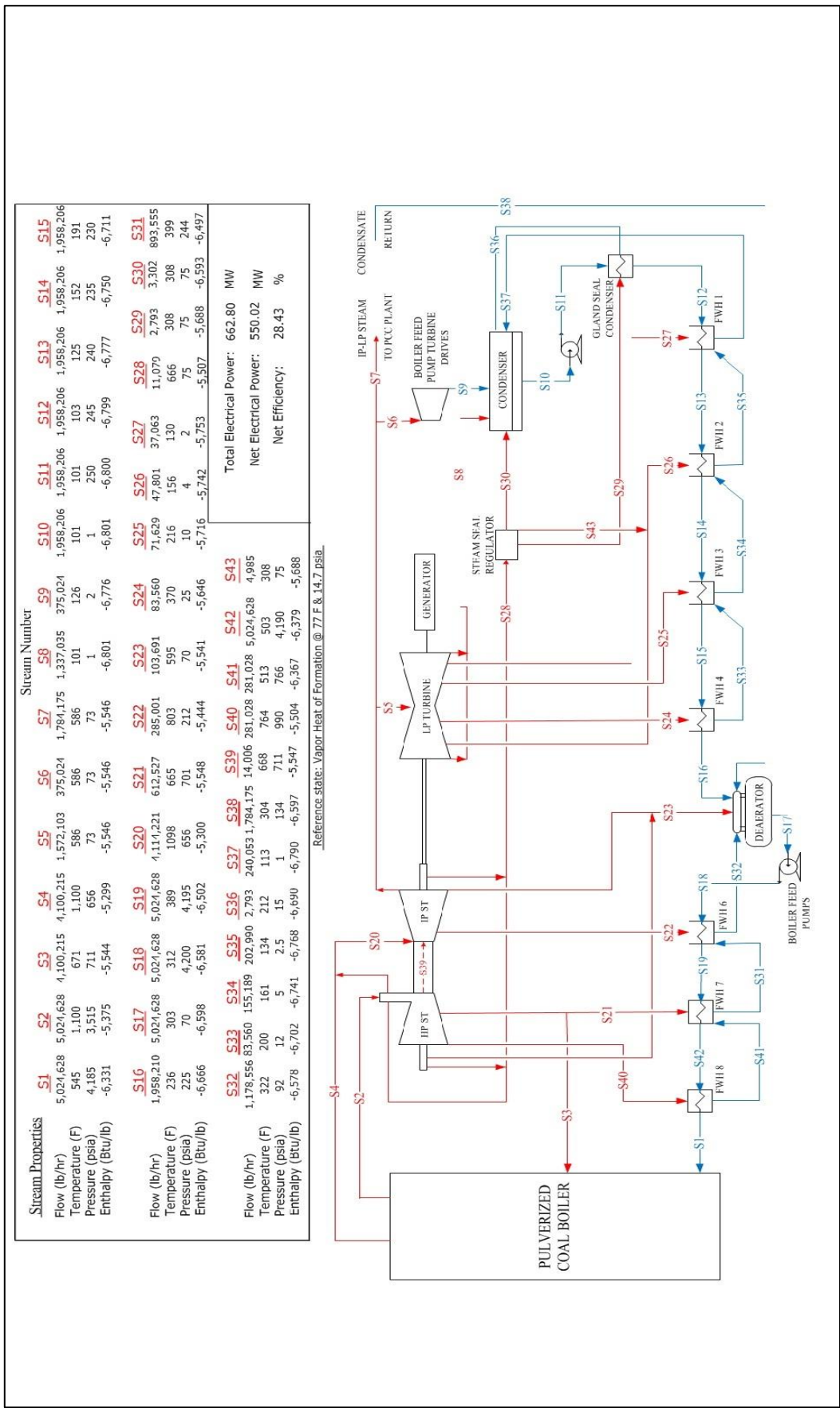


Exhibit A-2. Heat and Mass Balance: DOE/NETL Case 12 reference using MEA-based PCC