Large Pilot CAER Heat Integrated Post-combustion CO_2 Capture Technology for Reducing the Cost of Electricity

Final Technical Report

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Principal Authors:
Kunlei Liu, Heather Nikolic, Andy Placido, Lisa Richburg and Jesse Thompson
University of Kentucky, Lexington, KY

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University of Kentucky Research Foundation
109 Kinkead Hall, Lexington, KY 40506-0057

PRINCIPAL INVESTIGATOR
Kunlei Liu
+1-859-257-0293
kunlei.liu@uky.edu

U.S. DOE NETL PROGRAM MANAGER
Bruce Lani
+1-412-386-5819
Bruce.Lani@netl.doe.gov

SUBMITTED TO
U.S. Department of Energy National Energy Technology Laboratory

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ABSTRACT: The goal of this final project report is to comprehensively summarize the work conducted on project DE-FE0026497. In accordance with the Statement of Project Objectives (SOPO), the University of Kentucky Center for Applied Energy Research (UKy-CAER) (Recipient) has developed an advanced, versatile, 10 MWe post-combustion CO_2 capture system (CCS) for a coal-fired power plant, Louisville Gas and Electric Company's Trimble County Generating Station, using a heat integrated process combined with two-stage stripping and any advanced solvent to enhance the CO_2 absorber performance. The proposed project (Phase 1 and 2) will involve the design, fabrication, installation and testing of a large pilot scale facility that will demonstrate the UKy-CAER innovative carbon capture system integrated with an operating supercritical power plant. Specifically during Phase 1, the Recipient has provided all necessary documentation to support its Phase 2 down-selection including: the Project Narrative, the updated Project Management Plan (PMP), the preliminary engineering design, the Technical and Economic Analysis report (TEA) (including the Case 12 – Major Equipment List and submitted as a Topical Report), a Phase 1 Technology Gap Analysis (TGA), an Environmental Health and Safety (EH&S) Assessment on the 10 MWe unit, and updated Phase 2 cost estimates (including the detailed design, procurement, construction, operation, and decommissioning costs) with a budget justification.

Furthermore, the Recipient has proposed a combined modular and freestanding column configuration with an advanced absorber gas/liquid distribution system, an advanced solvent, with the integration of discrete packing, a smart cross-over heat exchanger, and a load and ambient condition following control strategy, all to address ten of 12 technology gaps identified during the Phase I work. If successful, the proposed heat integrated post-combustion CCS will pave the way to achieve the United States Department of Energy National Energy Technology Laboratory (U.S. DOE NETL) CO_2 capture performance and cost target, as indicated in the submitted TEA and summarized in this report.

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1) EXECUTIVE SUMMARY

1.1 Overview

Project Description: The UKy-CAER team proposed the construction of a 10 MWe large pilot scale, post-combustion CCS for a coal-fired power plant based on a unique combination of process intensification, heat recovery, and an advanced solvent, as illustrated in **Exhibit 1-1**. This project involved the design of a CCS located at the Louisville Gas & Electric (LG&E) Trimble County Generating Station in Bedford, Kentucky (KY).

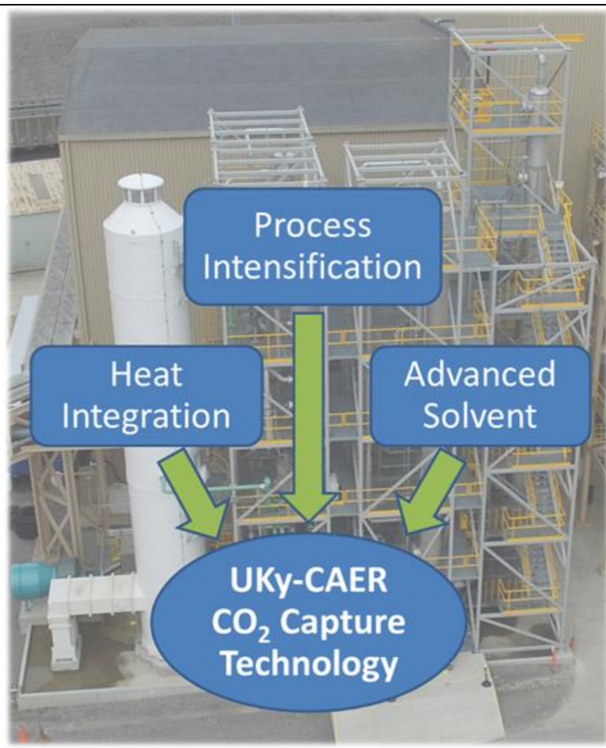


Exhibit 1-1. Three Novel Aspects of the UKy-CAER CCS.

Project Goals: As summarized in **Exhibit 1-2**, the novel concepts used in this study will improve the overall power generation plant efficiency by 3.6 percentage points and decrease the cost of electricity (COE) by \$19.56/MWh, 2011\$, including CO_2 transportation, storage and monitoring (TS&M) costs, when integrated with a CO_2 capture system, compared to U.S. DOE NETL Reference Case 12 (RC 12). The proposed CCS technology can be utilized to retrofit existing coal-fired power plants. The impacts of this large pilot scale project with respect to achieving the U.S. DOE NETL overall goals of this Funding Opportunity Announcement (FOA) are: (1) gathering and obtaining the required FOA; (2) demonstration of a low-cost post-combustion CO_2 capture process to improve the economics of a national greenhouse gas sequestration program; (3) demonstration of heat integration techniques that will improve overall power generation plant efficiency which can be applied with any second generation, advanced solvent; (4) development of protocol for solvent and water management from various slipstream testing sites to guide the commercial scale post-combustion CCS operation; and (5) maintaining a vibrant and low-cost power industry based on coal, and preserving our existing coal-fired electricity generation fleet.

Exhibit 1-2. Brief Comparison between U.S. DOE NETL RC 12 and UKy-CAER Advanced Solvent Case.

		RC 12	**UKy-CAER Advanced Solvent Case**	**Difference between Two Cases**
Net Plant Efficiency (higher heating value, HHV)	%	28.40	32.00	3.6 points
Cost of Electricity	2011$/MWh	147.27	127.71	19.56
CO_2 Transportation, Storage and Maintenance Costs	2011$/MWh	9.99	8.74	1.25

Overview of the Technology: The **first key aspect** of the UKy-CAER CCS is process intensification including a two-stage stripping process for solvent regeneration powered by heat rejected from the CO_2 compressor intercooling. This innovative approach includes the addition of a second stage air stripper, which is located between a conventional lean-rich crossover heat exchanger and a lean solution temperature polishing heat exchanger. This water-saturated air-swept stripper is used to reduce the solvent carbon loading to a very low level prior to returning the lean solution to the absorber, and simultaneously, the CO_2 enriched overhead stream generated is recycled back to the power generation boiler to boost the CO_2 concentration at the absorber inlet. The water-saturated air used for the stripping in this secondary stripper comes from regeneration of the water-rich, liquid desiccant stream, as described in the second key aspect.

The **second key aspect** of the proposed process is a heat-integrated cooling tower system which recovers heat rejected from the primary stripper overhead condenser, and additionally, from the boiler flue gas sensible heat. In this system, a conventional cooling tower is redesigned to include two sections. The top section, with 100% cooling water collection, provides the conventional evaporative cooling function. In the bottom section, a liquid desiccant stream is used to remove moisture from an ambient air stream before it passes to the top section. The working principle is that removing moisture will reduce the cooling air wet bulb temperature, which results in additional water cooling in the top section, thereby lowering the cooling water supply temperature to the turbine condenser and dropping the steam turbine back pressure for overall efficiency improvement. The water-rich liquid desiccant is then regenerated with recovered heat.

The **third key aspect** of the UKy-CAER CCS is the use of an advanced solvent, with a lower regeneration energy, higher CO_2 absorption capacity, and lower degradation rate when compared to the reference case solvent, 30 wt % aqueous solution of monoethanolamine (MEA).

The three novel concepts used in this study work together to improve the overall power generation efficiency to 32.0% when integrated with CCS and Hitachi's H3-1 advanced solvent, for example, and can be utilized for a Greenfield case or retrofitted into existing coal-fired power plants. Knowledge gained from this project with respect to many aspects of CCS, such as equipment scalability, process simplification/optimization, system compatibility and operability, solvent degradation and secondary environmental impacts, water management, CO_2 absorber temperature profile management, and potential heat integration can be easily applied to future commercial applications to achieve the current U.S. DOE NETL goals for post-combustion CO_2 capture.

1.2 Key Results

The successful completion of this project has the potential to provide many public benefits, tantamount among these will be the continued utilization of abundant and low cost United States (U.S.) coal for the production of reliable electricity, within a foreseen period while environmental concerns are affordably managed. Four major benefits from this project are listed here: 1) development of a cost effective approach to CO_2 capture from utility coal-fired units which can be applied with any second generation, advanced solvent; 2) reinforcement of confidence in the technology and compiled first hand-experience that can be shared with utility personnel; 3) expansion of the individual key technologies to a broad spectrum of problems associated with sour gas clean up, such as mass transfer enhancement and heat rejection reduction; and (4) providing general guidelines for packing selection while balancing the trade-off between absorber size, heat exchanger performance, solvent regeneration energy penalty and in-situ thermal compression. The testing and data collected at the 10 MWe scale will provide a clear path to develop >150 MWe commercial scale CO_2 capture units based on this technology.

Task 1: Project Management and Planning: UKy-CAER has successfully completed Phase 1 of this project on time and on budget. In addition, the following items were provided to U.S. DOE NETL during the course of the project: the TEA, the TGA, the 10 MWe preliminary process design, all process models used to complete the design, the EH&S Assessment, financial agreements, the host site agreement and quarterly reports. Additionally, UKy-CAER subsequently completed and submitted a thorough response to U.S. DOE NETL's request for more information.

Task 2: CCS Basic Process Specification and Design: UKy-CAER, with the help of team members Koch Modular Process Systems (KMPS), WorleyParsons (WP) and Louisville Gas and Electric and Kentucky Utilities (LG&E/KU), completed the preliminary 10 MWe CCS design to be located at the LG&E/KU Trimble County Generating Station. This design package included the integration requirements to the host utility such as steam supply, condensate return, flue gas supply and return, utility supply, waste management, mechanical, electrical and land considerations. Detailed specifications for each stream were compiled. The main streams associated with the CCS and the integrated cooling tower system, including flue gas supply and return streams, internal solution recirculation streams, and heat duties provided and rejected, were defined. The unit was designed to treat flue gas from the equivalent of a 10 MWe power generation unit. The unit will consist of freestanding reaction columns and all of the supporting heat exchangers, tanks, blowers, pumps, filters and carbon beds in a modular structure. Design activity completed during the project incorporates the full-train CCS design excluding CO_2 compression, the process concept and how it operates, process flow diagrams with major equipment items listed, and energy and material balances. A significant part of this task was to identify the currently available hardware, devices and modules for the major pieces of equipment required for this project, tie-ins with the host unit and the physical location of proposed facility. Work performed under this task also included the completion of several critical documents, including: the TEA, the TGA, a solvent sensitivity analysis and selection, and a packing sensitivity analysis and selection. The main product of this task was the completion of the preliminary CCS design and the corresponding cost estimate, which was below the U.S. DOE NETL budget ceiling set forth by this FOA.

TEA Summary: Three second generation, advanced solvents have been evaluated and their performances have been found to be very close in terms of mass transfer, energy consumption and chemical stability. Due to extensive data already in hand from another U.S. DOE NETL funded project (DE-FE0007395), Hitachi's H3-1 solvent was selected for use in the TEA.

The net efficiency of the proposed CCS integrated with a supercritical, pulverized coal (PC) power plant with CO_2 capture changes from 28.4%, with the RC 12 plant in the 2010 revised NETL baseline report, to 32.0%; while the energy consumption for CO_2 capture is achieved at 1030 Btu/lb-CO_2 captured as compared to 1530 Btu/lb-CO_2 captured in RC 12. The study also shows 50.8% less heat rejection associated with the carbon capture system, decreased from 3126 MBtu/hr in RC 12 to 1537 MBtu/hr for the UKy-CAER process.

The key factors contributing to the reduction of the COE with the proposed CCS technology were identified as CO_2 partial pressure increase at the flue gas inlet, thermal integration of the process and performance of the advanced solvent.

TGA Summary: An analysis was performed to identify and analyze high impact technology gaps that prevent affordable commercialization of solvent-based CCS systems for coal-fueled power generation units to meet the U.S. DOE NETL performance and cost targets. The identified gaps were based on the findings in previous UKy-CAER work at the lab, bench, and small pilot scales, as well as, data and information collected from other investigators, workshops, conferences, and information available in the public domain. Analysis of the components and subsystems that make the UKy-CAER heat integrated process unique has been provided along with research and development efforts required to reduce capital and operational costs of solvent-based CCS systems. Eight near-term and four long-term technology gaps were identified and detailed, including near-term gaps: (1) a cost effective solvent with high stability, high cyclic capacity and fast kinetics; (2) gas/liquid distribution to prevent channel flow; (3) waste management at the point of discharge (gas and liquid); (4) equipment sizing vs. operating costs; (5) material and methods of construction; (6) process intensification; (7) unit operation to maintain the performance; and (8) heat integration; and long-term gaps: (1) smart packing; (2) appropriate absorber temperature profile; (3) heat exchange; and (4) smart operations.

Preliminary CCS Design, Including Host Site Integration Summary: The preliminary design of the UKy-CAER 10 MWe CCS was conducted and divided into the CO_2 capture process itself, or inside boundary limits (ISBL) and the balance of plant (BOP), or outside boundary limits (OSBL), which includes the flue gas, steam, condensate and utility tie-ins to the power generation unit, and the civil, structural, electrical, and facilities portions of the complete design.

The CO_2 capture process, ISBL, design work includes an Aspen Plus® [1] model and complete heat and mass balance (H&MB) stream tables, the preliminary equipment general arrangement drawings and 3-dimensional layouts, preliminary process flow diagrams, the equipment list, solution volumes, system weights, and a CO_2 capture process cost estimate.

The BOP design, OSBL, work includes the following: a clear definition of the CCS boundaries and integration with the host site; stream tables for utility tie-ins; preliminary sizing and routing of the flue gas supply and return ducts; the steam supply and condensate return piping; the plant and potable water supply piping and the waste stream return piping systems; civil engineering concerns such as site clearing and erosion/sediment pollutions controls; structural engineering concerns such as preliminary structural design criteria; preliminary foundation design; preliminary design of tie in piping supports; electrical engineering preliminary design of the BOP electrical systems, such as the tie to the host site, cable specifications, transformers, motor controls, variable frequency drives, heat tracing, and electrical component housing buildings; the control room building and other outbuildings; the continuous emissions monitoring system; and a Class 3 BOP cost estimate.

Task 3: Complete EH&S Evaluation: A preliminary EH&S assessment was conducted by a subcontractor, Smith Management Group (SMG), in accordance with the requirements outlined in Attachment 4 of FOA-DE-0001190. During this initial effort, SMG gathered process specifications with regard to: air and water emissions, potential solid and hazardous wastes, solvent degradation byproducts, and possible side reactions that may occur within the 10 MWe carbon capture system. Accumulated waste products and the fate of contaminants from the feed gas stream and environmental degradation products were addressed including: bioaccumulation, soil mobility, and degradability. Conditions at the point of discharge were examined. Potential safety hazards were identified and accidental release plans were developed. Results and recommendations from the initial study indicated that no significant EH&S risks were identified that would adversely affect the implementation of the proposed project. Potential exposures and resulting health risks from low concentrations of nitrosamines generated from degradation of various amine-based solvents do not appear to be a significant risk, but additional investigation is warranted. The results of the assessment serve as a foundation for conducting additional investigation during the detailed plant design and operation to quantitatively evaluate and confirm the extent of potential EH&S impacts for the large pilot or full-scale operation.

Task 4: Host Site Selection and Financial Agreements: Based on the availability of necessary land, utilities and other balance of plant integration logistics, the host was selected to be LG&E/KU's Trimble County Generating Station in Bedford, KY and a detailed host site agreement was completed between the Recipient and LG&E and KU. Finally, the project cost share agreements from partners providing cost share were completed and submitted to the U.S. DOE NETL.

2) BACKGROUND AND TECHNOLOGY DESCRIPTION

2.1 Project Objective and Background

In order to meet U.S. DOE NETL performance and cost goals set forth in this FOA, the University of Kentucky Center for Applied Energy Research team will scale-up its 0.7 MWe small pilot, with its proven heat integration and mass transfer intensified process, to a 10 MWe post-combustion CO_2 capture system for a coal-fired power plant to address near and long-term technology gaps for near-future full-scale commercial deployment [3]. The recently completed project involved the design for future fabrication, installation and testing of a large pilot facility showcasing an innovative carbon capture system integrated with an operating power plant.

While constantly working to reduce the cost of CO_2 capture, the specific objectives of the proposed investigation were to: 1) quantify the benefits associated with the UKy-CAER process at the 10 MWe scale with process installation and system integration; 2) explore the potential complexity and problematic challenges for system integration; 3) transfer knowledge learned at the 0.7 MWe CCS to validate the UKy-CAER mass transfer intensification techniques for improved CCS performance, and the UKy-CAER heat integration techniques for improved overall power plant efficiency that can be applied with any second generation advanced solvent; 4) identify technology gaps that currently hinder commercial application of CCS technology and address those gaps in the CCS design; 5) data collection to support the TEA and EH&S Assessment for commercial scale deployment; and 6) provide scale-up data, and design and operational information for a commercial-scale demonstration of the same nature.

The successful development of the proposed technology will have a multitude of public benefits. Tantamount among these is the utilization of the abundant, low cost, U.S. energy resource, coal, for the production of reliable electricity within a foreseen period while the environmental concern is affordably managed and maintained. This will result in four major benefits: 1) the development of a cost effective approach to capture CO_2 from utility coal-fired units that can be applied with most second generation advanced solvents; 2) building confidence in the technology and collecting first-hand experience for utility personnel; 3) extending the individual key technologies to a broad spectrum of problems associated with sour gas clean-up, such as mass transfer enhancement and heat rejection reduction; and (4) providing general guidelines for packing selection and balancing the trade-off between absorber size, heat exchanger performance, solvent regeneration energy penalty, and in-situ thermal compression. The testing of and data collected from the 10 MWe scale will provide a clear path to develop >150 MWe commercial scale CCS units.

The UKy-CAER team proposed an advanced and versatile 10 MWe post-combustion CO_2 capture system for a coal-fired power plant using a heat integration process combined with two-stage stripping and is compatible with most second generation advanced solvents to enhance the CO_2 absorber performance. The proposed project involved the design for future fabrication, installation and testing of a large pilot scale facility that illustrates an innovative carbon capture system integrated with an operating supercritical power plant. The system will include modular equipment with built-in advanced controls to reduce the energy penalty for CO_2 capture, while also responding quickly to dynamic demand load changes and ambient condition variation. The UKy-CAER system will combine a short absorber with divided sections, intercooling and bottom pump around, an advanced liquid distribution system, a unique secondary emission mitigation strategy, and a 10 °C approach temperature for a lean/rich heat exchanger to simultaneously address capital cost, energy consumption and environmental impact. The proposed technologies work synergistically to achieve fast CO_2 absorption, and high CO_2 loadings and cyclic capacity, which allow the solvent regeneration to be performed at a relatively lower temperature to minimize the solvent degradation. This UKy-CAER technology will meet the U.S. DOE NETL goal of capturing 90% of the flue gas CO_2 with a 95% CO_2 purity at a levelized cost of electricity (LCOE) of 2011$161.93/MWh with an advanced solvent [7], a reduction of 29.5% on the incremental LCOE for CO_2 capture from RC 12 [3] at $186.74/MWh [7], and to achieve $50.7/tonne CO_2 captured, including compression but excluding transportation and storage, a reduction of 19.5% from RC 12 [3] at $63.0/tonne CO_2.

All deliverables for this project were met, as presented in **Exhibit 2-1**.

Exhibit 2-1. Project Deliverables.

	Task	Deliverable by Project Task	Date Accomplished
1	Task 1	Updated Project Management Plan	3/29/16
2	Task 1	Phase 1 Topical Report and Phase 2 Budget	3/29/16
3	Task 2	Phase 1 Technology Engineering Design and Economic Analysis	3/29/16
4	Task 2	Major Equipment List	3/29/16
5	Task 2	Phase 1 Technology Gap Analysis	3/29/16
6	Task 2	Phase 1 System Analysis Process Models	3/29/16
7	Task 3	EH&S Report	3/29/16
9	Task 3	Environmental Questionnaire for Phase 2	3/29/16
10	Task 4	Host Site Agreement	6/30/16
11	Task 4	Financial Agreements	6/30/16

In this project, second generation solvents are considered to be solvents that are non-corrosive, with low degradation rates and a regeneration energy 20-30% lower than 5 M MEA. Currently, second generation solvents demonstrated at the commercial scale include CANSOLV, manufactured by Shell Global and is in use at the SaskPower Boundary Dam Power Station in Saskatchewan, Canada, and KS-1^{TM} solvent, manufactured by Mitsubishi Heavy Industries (MHI) and is in use by the Petra Nova at NRG's W. A. Parish Generating Station near Houston, TX. There are other solvents that are near-to-commercial demonstration including CDRMax^{TM} manufactured by Carbon Clean Solutions, Ltd. (CCSL), H3-1 manufactured by Mitsubishi Hitachi Power Systems (MHPS) and HNC-5 manufactured by Huaneng Group.

Knowledge gained from the execution of DE-FE0007395, including the design, construction and operation of a 0.7 MWe small pilot scale CCS, has been applied to the 10 MWe large pilot scale CCS preliminary design. The 0.7 MWe UKy-CAER CCS has been in regular operation since May 2015, and has certainly been demonstrated in a real power generation environment, KU's E.W. Brown Generating Station in Harrodsburg, KY. The flue gas is collected just after the wet flue gas desulfurization (WFGD) unit. Steam is collected from the power generation cycle, cold reheat line and condensate is returned to the steam cycle loop. In order to prevent contamination of the steam, the conductivity of the CCS condensate return is continuously monitored and an automatic shutdown is in place if a value of $> 8\ \mu S/mL$ is exceeded. Plant service water, not de-ionized water, is used for all CCS process needs, including initial dilution of the amine solvent, initial dilution of the liquid desiccant and all make-up needs. Additionally, safe operation is conducted in accordance with all LG&E, Brown Station, and University of Kentucky policies and procedures, including the creation and practice of the following programs: Lock Out/Tag Out program, Chemical Inventory, Contractor Management, Personnel Training, Drug Testing, Laboratory and Hood Inspections, Equipment Preventative Maintenance, Laboratory Management, Chemical Hygiene and Waste

Management. Since May 2015, the plant has often been ran in 24/7 shifts, comprising of general operation in addition to start-up and shutdown procedures. All unique operation modes, as well as the specific requirements that address ambient conditions, have been documented in the Standard Operating Procedures (SOPs).

2.2 Process Description

The UKy-CAER team proposed a 10 MWe post-combustion CO_2 capture system for a coal-fired power plant using a heat integration process combined with two-stage stripping modeled directly after UKy-CAER's 0.7 MWe CO_2 capture system located at Kentucky Utilities (KU) E.W. Brown power plant in Harrodsburg, KY, shown in **Exhibit 2-2**.

Exhibit 2-2. UKy-CAER 0.7 MWe Post-Combustion CO_2 Capture System at E.W. Brown Generating Station, Harrodsburg, KY.

The UKy-CAER post-combustion CO_2 capture system for a coal-fired power plant is building on the traditional aqueous carbon capture technology with advanced heat integrations and three additional unique features. It is completely configured with the same type of components as U.S. DOE NETL RC 12 [3], with units such as columns, heat exchangers (shell-tube and plate-frame), pumps, blowers, and balance of plant. The UKy-CAER technology also utilizes an additional air-stripping column and auxiliary components to recover heat that is typically rejected to the environment in all conventional CCS technology via an integrated liquid desiccant loop, both of which are key differences from the conventional CCS configuration (one CO_2 absorber column and one stripping column).

The first important aspect of the proposed process is a two-stage stripping unit for solvent regeneration. This innovative approach includes the addition of an air-based second stage stripping process inserted between a conventional rich-lean crossover heat exchanger and a lean solution temperature polishing heat exchanger. The secondary stripper is powered by heat rejected from the conventional steam-heated (primary) stripper. The secondary stripper outlet stream is used as boiler secondary combustion air, consequently enriching the flue gas with CO_2 resulting in a lower energy penalty. The second important aspect is a heat-integrated cooling tower system, which recovers waste energy from the carbon capture system such as compressor inter-stage coolers. In this process, the cooling tower will be redesigned to include two sections – the top section with 100% cooling water collection for the conventional cooling function, and the bottom section to remove moisture from cooling air using a liquid desiccant solution – providing a cooler recirculation water for the steam turbine condenser. The working principle is that reducing the relative humidity of the cooling air will lower the turbine condenser cooling water temperature and thereby reduce the steam turbine back-pressure for power generation efficiency improvement. Similarly, a liquid desiccant loop can be deployed to remove moisture from the flue gas prior to the CO_2 absorber for a favorable temperature profile along the column, resulting in better performance.

The detailed integration of the proposed UKy-CAER technology with an existing commercial-scale power plant (Reference Base Plant in the U.S. DOE NETL-2007/1281 Report) [3] is illustrated in **Exhibit 2-3** and summarized as follows:

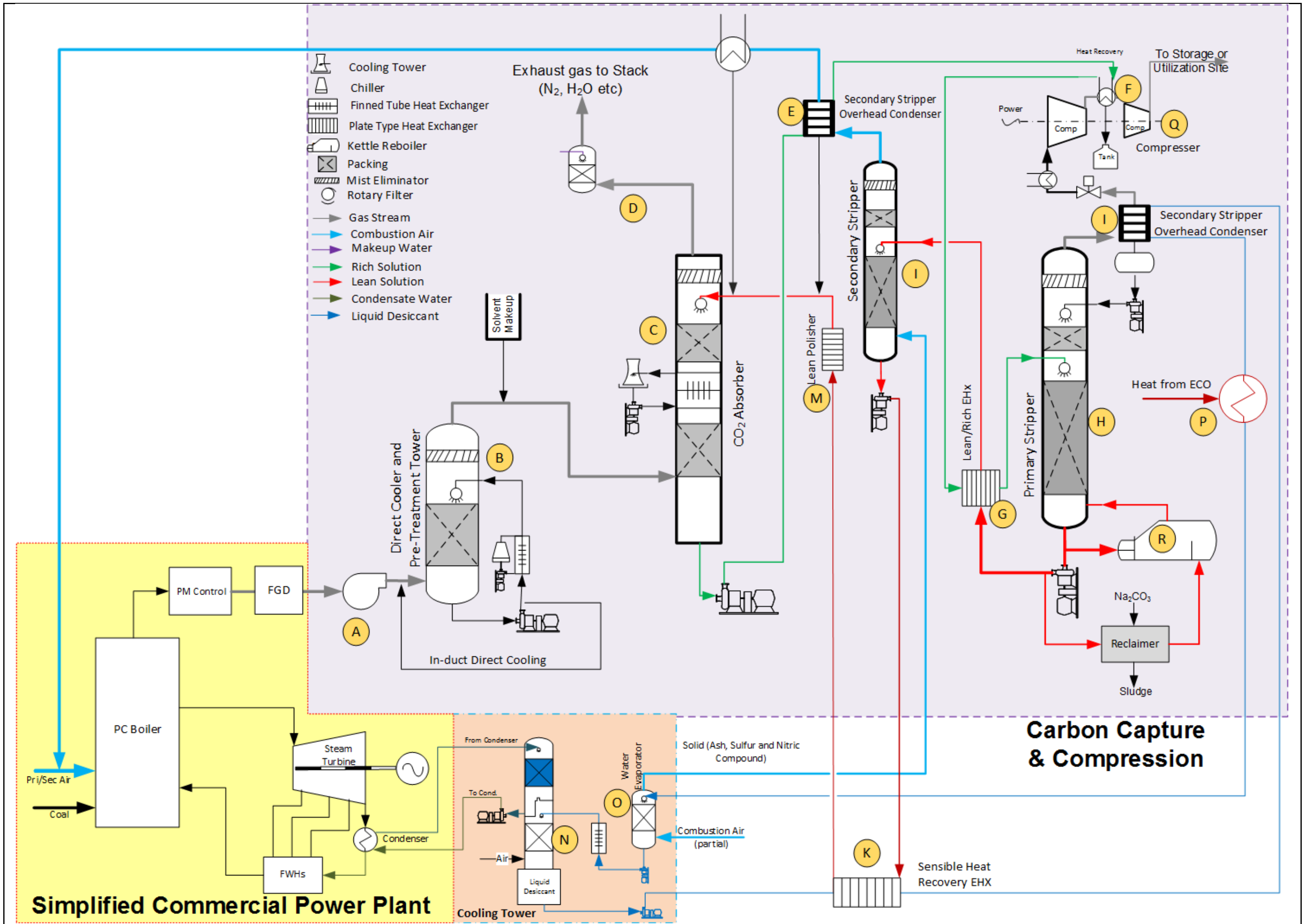


Exhibit 2-3. Detailed Integration of the Proposed UKy-CAER Technology into an Existing Commercial Scale Power Plant (Reference Base Plant in the U.S. DOE NETL-2007/1281 Report) [3].

1. The post-combustion CO_2 capture and compression block includes a direct contact flue gas cooler (DCC), a pre-treatment tower, a packed absorber column with a solvent recovery column, two packed-bed strippers with a reboiler and reclaimer, heat exchangers, pumps, and balance of plant equipment.
2. After the flue gas desulfurization unit (FGD), a booster fan (A) is used to overcome pressure drop before the direct contact cool and pre-treatment tower (B). The amount of caustic chemicals used in the pretreatment tower is reduced by removing water from the flue gas with a feed knockout vessel (not shown in **Exhibit 2-2**). At this point, the flue gas is saturated with water at a temperature of approximately 55 °C, water content of 17 vol %, and CO_2 concentration of 15-17 vol % of the total wet gas stream (note: vs. 13.5 % in U.S. DOE NETL report).
3. The flue gas then enters a counter-flow pre-treatment tower (B) using dilute caustic solution for further SO_2 polishing and removal of other flue gas contaminants to minimize solvent degradation and lower the steam required for solvent reclaiming. At this point, the flue gas SO_2 concentration is less than 10 ppm. The flue gas temperature will be in the range of 25-40 °C depending on the quantity of heat rejected by the in-line heat exchanger.
4. The SO_2-polished flue gas then enters the countercurrent flow CO_2 scrubber (C) with an intercooling heat exchanger, and bottom pump around section (pump around not shown in **Exhibit 2-3**) to react with the lean aqueous amine solvent. Cooling the solvent with the intercooler drives the CO_2 absorption rate and allows for greater solving loading in the column. The pump around increases the solvent residence time and also allows for greater solvent loading.
5. CO_2-depleted flue gas then will be treated in the top section of the absorber column (D) using flue gas condensate from the direct water contactor and make-up water to remove any residual solvent (vapor and aerosol). At this point, the flue gas is water saturated at approximately 42 °C.
6. After gaseous CO_2 is converted into aqueous carbon species, the carbon-rich solution exits the scrubber bottom, is pressurized, and is sent to a heat recovery unit (E) cooling the gaseous stream exiting from the secondary stripper (I) and the CO_2 compressor intercooler (F) for heat recovery (e.g. Heat Pump Loop I), and is then fed to the rich-lean crossover heat exchanger (G) for energy recovery from carbon-lean solvent.
7. After the crossover heat exchanger (G), the rich solution is sent to the pressurized, packed, conventional (primary) stripper (H) for solvent regeneration. This stage will require an external energy source to drive the steam reboiler (R). At the primary stripper exit, the gas stream primarily consists of CO_2 (70-75 vol %) and water vapor (25-30 vol %) at a pressure of approximately 3-5 bar and temperature of approximately 100-115 °C. The 10 MWe scale stripper column is preliminarily designed for 4-6.9 bar, with the final determination to be made during the detailed design phase.
8. After exiting the heat recovery units (I), in which the gas product stream is cooled by the liquid desiccant from the cooling tower (N) (e.g. Heat Pump Loop II) and steam turbine condensate, the CO_2 enriched gas stream will be pressurized to about 135 bar and intercooled (F) for downstream utilization or sequestration (Q).
9. The carbon-lean solution exiting the primary stripper (H) is sent to the crossover heat exchanger (G), where the heat will be recovered with the carbon rich solution, then sent to the top of an ambient pressure air-sweeping, packed column secondary stripper (I) to further reduce the carbon loading in the lean solution. Finally, it will be cooled (K) to

approximately 40 °C by the liquid desiccant from the cooling tower (N) and recirculating cooling water (M), and recycled to the scrubber. The water-saturated air used here comes from a liquid desiccant water evaporator (O, see 11 below).

10. The CO_2 enriched, secondary stripper outlet (E), with approximately 3-4 vol % CO_2 content will be fed to an air preheater and used as boiler combustion air.
11. In the cooling tower air path, ambient air enters the integrated cooling tower (N) from the bottom section where it contacts a liquid desiccant solution, reducing the water content of the air. The dried air will enter the top section to cool the recirculating water through evaporation as in a conventional process. The water-rich liquid desiccant will be collected at the bottom of the tank and preheated in the primary stripper condenser (I) and by heat recovered (P) from the power plant, before being sent to an air-blown evaporator (O) for regeneration. The water-lean desiccant will be cooled by steam turbine condensate or recirculating cooling water and a chiller prior to the next cycle. The high-temperature saturated air from the evaporator (O) will be fed to the secondary stripper (I) for CO_2 removal, as indicated in step 9 above.

Exhibit 2-4 is a process flow diagram (PFD) of LG&E Trimble County Generating Station Unit 1 (TC 1) specifically showing the existing environmental controls applied to the flue gas before CO_2 capture.

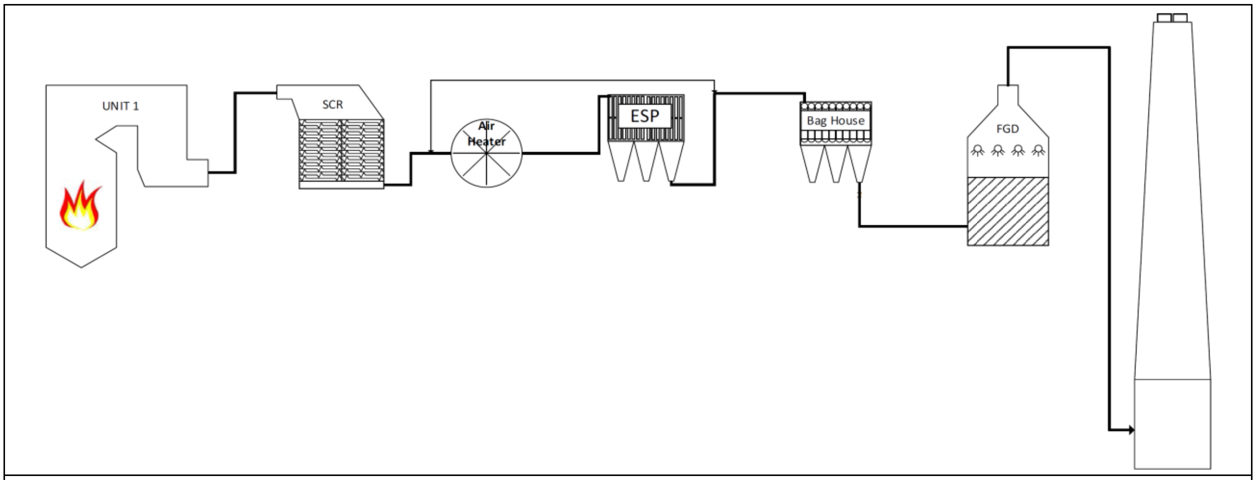


Exhibit 2-4. LG&E TC 1 PFD Supplied by LG&E/KU.

2.3 Technology Concepts

There are four technology concepts within the UKy-CAER CCS that have a synergistic effect on lowering the cost of CO_2 capture: heat integration, two stage stripping, enhanced absorber mass transfer and reducing the cooling water supply temperature.

Power and heat from the power plant are two important parameters with regard to a CO_2 capture facility. The solvent will have to be regenerated in order to release the CO_2 for utilization and to recycle the amine. The main source of energy for this process will be steam extraction from the power plant. Thus, reducing the amount of steam required for regeneration will reduce the energy penalty of the capture process. A closer examination of process efficiency improvements via heat integration is required to improve the economics. Unfortunately most of the heat available for integration is low-grade in nature which complicates the issue. In order to find new methods of lowering CCS costs, especially those from energy consumption, it is useful to consider the stripper steam requirement in light of an energy balance. This balance, $Q_{total}=Q_{des}+Q_{sens}+Q_{strip}$, has three elements: the heat of desorption of CO_2 (Q_{des}) (sometimes referred to as the heat of reaction), the solvent sensible heat (Q_{sens}), and the latent heat of evaporation for stripping in the regenerator outlet (Q_{strip}). The heat of desorption of CO_2 can be discounted because it is set by thermodynamics. Heat loss can also be discounted due to being a small percentage of the total energy input. The remaining balance of energy input has two elements: (1) the solvent sensible heat and (2) the latent heat of water evaporation.

1) The sensible heat may be determined using the simplified equation, $Q_{sens} = \frac{m}{\Delta\alpha} \cdot C_p \cdot \Delta T$ where m is the quantity of CO_2 captured, $\Delta\alpha$ is the carbon difference (cyclic capacity) in the solution between scrubber and stripper that is controlled by absorber size and stripping energy consumption, and ΔT is the approach temperature of the rich/lean heat exchanger between cold stream out and hot stream in, which is typically limited by capital investment of the heat exchanger. Increasing the solvent cyclic capacity, $\Delta\alpha$, leading to a lower sensible heat requirement is accomplished synergistically with the use of the secondary stripper, sending extra-lean solvent to the absorber inlet, and enhanced mass transfer in the absorber, increasing the rich loading.

2) In regards to the latent heat of water evaporation for stripping at the regenerator outlet (Q_{strip}), one unit of CO_2 stripped will require $\frac{P_{H_2O}}{P_{CO_2}}$ unit of water vapor (steam) as carrier gas, following the Gibbs free energy equations. The UKy-CAER CCS primary stripper is operated at elevated pressure, reducing the latent heat of evaporation for stripping and synergist ally saving on CO_2 product compression costs.

Heat Recovery:

The UKy-CAER CCS recovers heat, typically rejected to the cooling water or the environment from three locations: the steam-driven primary stripper overhead condenser, the lean amine polisher and the compressor inter-stage coolers. Relatively high-grade heat recovered from the primary striper overhead stream and the compressor inter-stage hot stream are used as a booster, with the assistance of heat from the secondary stripper overhead stream, to increase the temperature of the rich stream prior to entering the lean/rich exchanger, thereby boosting the lean solution temperature for CO_2 stripping in in the secondary stripper. Additionally, in the UKy-CAER CCS the secondary stripper also acts as a direct-cooling device for the lean solvent prior to entering the absorber polishing exchanger, reducing the cooling water duty.

Two Stage Stripping:

The stripping system consists of a conventional steam-driven stripper (primary) and an air-based stripper (secondary) for solvent regeneration to intensify the CO_2 absorption process in the scrubber. The air-based stripper is inserted between the conventional rich-lean crossover heat exchanger and the lean solution temperature polishing heat exchanger. This secondary stripper is powered by the heat rejected from the conventionally steam-heated primary stripper or the intercoolers between the CO_2 compressor stages and heat recovered by the CCS liquid desiccant loop. The secondary stripper outlet gas stream is used as boiler combustion secondary air. The recycling of CO_2 to the absorber inlet will yield a higher CO_2 concentration in the range of 15-17 vol % compared to 13.5 vol % in RC 12.

Enhanced Mass Transfer Flux Inside the Absorber:

In simple terms, $M = K_G \bullet A \bullet \Delta P_{CO2}$, where M is the CO_2 removal flux, K_G is the mass transfer coefficient, A is the active surface area and ΔP_{CO2} is the driving force by differential CO_2 pressure between gas and liquid phase. Clearly, with an increased ΔP_{CO2}, a higher flux will be achieved while other parameters are kept constant that could result in either a smaller absorber or more rich (C/N) solution ($P^*_{CO_2,scrub}$) at the absorber bottom outlet. The UKy-CAER CCS achieves a higher CO_2 driving force in two ways. First, with the use of an absorber pump around, and second, by increasing the gas inlet CO_2 concentration.

Assuming a pseudo first order absorption reaction at the gas-liquid interface, the dominant component of K_G is k'_g, which can be written as $k'_g = \frac{\sqrt{k_2 \cdot D_{CO2} \cdot [Am]}}{H_{CO2}}$, where [Am] is the free amine concentration in the liquid film on the packing surface. With the application of a pump around to control the bottom portion of the absorber, more of the amine will be freed; thereby increasing k'_g. In addition, high liquid flow will also increase the turbulence on the packing surface, so the diffusion resistance between reaction interface and bulk liquid will be reduced, as well. These two factors will result in a higher mass transfer coefficient, e.g. higher CO_2 mass flux from the gas to liquid solvent phase.

Another method to increase the CO_2 driving force and the loading of the rich solution is to increase the CO_2 concentration in the flue gas entering the absorber. The UKy-CAER process does this by using the secondary stripper to remove an additional 1-2% of CO_2 from the solvent, and then, routing the overhead stream, with the additional CO_2, back to the power generation boiler, resulting in an absorber flue gas feed that is doped with additional CO_2 to further increase ΔP_{CO2}. The secondary stripper functions through use of recovered heat that is otherwise typically rejected to the environment. Therefore, the amount of CO_2 recycled back to the boiler is dictated by the effectiveness of the secondary stripper.

Liquid Desiccant Impact on Cooling Water:

The liquid desiccant loop is designed to recover rejected energy from the CCS or heat from the boiler flue gas stream that has been demonstrated by DE-FE0007525 [4], the CCS project at Southern Company's Barry Station. In the UKy-CAER CCS, the cooling tower is designed to include two sections – the top section with 100% cooling water collection for conventional evaporative cooling of the recirculating water from the steam turbine condenser and the bottom section where a liquid desiccant is used to remove moisture from the ambient air prior to entering the top section. The working principle is that reducing the relative humidity of the cooling air will lower the turbine condenser cooling water temperature, and thereby, reduce the steam turbine back pressure for improved power generation efficiency. A similar liquid desiccant loop can be deployed to remove moisture from flue gas prior to entering the CO_2 scrubber, resulting in a favorable temperature profile along the absorption column. With such a design, a higher performance in a plant-wide plant heat, ventilation, air conditioning (HVAC) application may be expected.

2.4 Traits of the UKy-CAER CO_2 Capture Technology

There are several traits of the UKy-CAER CO_2 capture technology developed from many years of experimentation. This work has included simulations; lab, bench and small pilot testing; and the large pilot design presented in this report. A summary of these traits are presented in **Exhibit 2-5**.

Exhibit 2-5. Traits of the UKy-CAER CO_2 Capture Technology.

Trait	Experimentally Demonstrated	Scale Tested
Enhanced Absorber Mass Transfer	Yes	Bench and Small Pilot
Two Stage Stripping	Yes	Bench and Small Pilot
Two Stage Cooling Tower	Yes	Bench and Small Pilot
Heat Integration	Yes	Small Pilot
Advanced Solvent	Yes	Bench and Small Pilot
Smart Heat Exchangers	No	Large Pilot
Smart Controls	Yes	Small Pilot
Discretized Packing Selection	Yes	Commercial Scale for Distillation Industrial Bench Scale for CO_2 Capture
Advanced Absorber Liquid/Gas Distribution	Yes	Liquid Distribution at Commercial Scale for Utility WFGD
Flue Gas Direct Contact Cooler	Yes	Cooling Tower
Solvent Recovery System	Yes	CAER Bench Scale for CO_2 Capture

3) PROCESS SPECIFICATION AND DESIGN

3.1 CO_2 Capture System Design

With technical assistance and data collected from UKy-CAER, KMPS completed a basic process design. Detailed specifications for each stream have been compiled. The main streams include flue gas inlet/outlet streams, internal solution recirculation streams, and heat duty provided/rejected associated with the CCS and integrated cooling tower system. The unit has been designed to the equivalent of a 10 MWe power generation unit. The unit consists of reaction columns and all of the supporting heat exchangers, tanks, blowers, pumps, filters and carbon beds. In general, the materials for the process wetted equipment surfaces and the process piping are carbon or stainless steel depending on the fluid temperature. The utility piping will be made of carbon steel and re-enforced fiberglass.

Specification and Design Basis for ISBL of CO_2 Capture Unit:
Five process guarantees were established for the detailed design, fabrication and assembly of the UKy-CAER 10 MWe CCS, as listed below.

1. $\geq$ 90% CO_2 capture efficiency.
2. The cooling water return temperature will be $\leq$ 70 °F if the supply temperature is $\leq$ 90 °F, or 20 degrees less than the supply temperature if the supply temperature is $\geq$ 90 °F.
3. The amine content in the gas stream exiting the system $\leq$ 5 ppm.
4. The approach temperature for all heat exchangers $\leq$ 18 °F.
5. A noise level $\leq$ 80 db, so hearing protection may not be required during operations.

If the guaranteed conditions are not achievable, changes to the equipment would be made at the expense of the process/equipment designer.

CO_2 Capture Loop Design Basis:
1. Inlet Flue Gas Stream (pressure, temperature and composition from actual data provided by LG&E Trimble County Generating Station.):
    a. Pressure = 14.7 psia
    b. Temperature = 131 °F
    c. Flow Rate = 22,000 scfm
    d. Composition = 15 mol% H_2O, 13.5 mol% CO_2, 5 mol% O_2, 60-70 ppm SO_2, balance N_2
2. Other Design Guidelines:
    a. Gas stream exiting the top of pre-treatment tower must be <10 ppm SO_2 and have a temperature = 86-95 °F.
    b. The absorber intercooler must drop the solvent temperature by 15-20 °F.
    c. The maximum temperature of the lean solvent stream entering the absorber must be T_{max} = 104 °F.
    d. The gas stream returned to the plant stack must have a temperature $\leq$104 °F and pressure = 14.7 psia.
    e. The stripper system design pressure must be suitable for up to 75 psia operation.
    f. The temperature of the solvent stream entering the secondary air stripper can be achieved up to T = 200 °F.

Cooling Tower Loop:
1. Ambient Air Conditions
    a. Pressure = 14.7 psia
    b. Temperature = 86 °F
    c. Relative Humidity = 60%

OSBL of CO_2 Capture Unit:
The boundaries of the balance of plant design and cost estimate are as follows:
- Tie-ins to the plant services, including penetration and tie-ins to the ducts and existing power plant piping
- Tie-ins to the proposed large pilot scale CCS
- Wiring to major pieces of equipment including pumps and fans

- Control wiring to input/output (IO) boxes on modules

Items included in the BOP design:

- Spill containment foundation for the large pilot scale CCS modules and equipment
- Steam supply and condensate return piping
- Steam supply pressure reducing valve and regulator
- Pipe system supports
- Flue gas supply and return ducts
- Duct support structures
- Process and potable water piping
- Process materials loading dock
- Tie in to electrical services and supporting electrical equipment
- Electrical equipment housing shed
- Continuous Emissions Monitoring System (CEMS) equipment and housing shed
- Process control system
- Mobile control room, laboratory and maintenance area

Solvent Recommendation:

Three second generation advanced solvents were evaluated and recommended for selection, as summarized in **Exhibit 3-1**. All recommended second generation advanced solvents have similar performance, in terms of mass transfer, energy consumption, and chemical stability. Furthermore, the superior performance of the H3-1 and CCSL CDR-Max solvents have been confirmed at large pilot scales, for over a period of 3000 hours, in 2016 at the Sask Power Shand Station a 30 MWth Facility, and in 2015/2016 at Technology Centre Mongstad (TCM), 240T/D, respectively. Lessons learned from these large pilot scale projects pertaining to solvent behavior and system operation will be applied to the proposed project in order to minimize technical risks.

Exhibit 3-1. Second Generation Advanced Solvents Recommended For Successful Use with the UKy-CAER CCS, Compared to 30 wt % MEA Baseline.

	Hitachi H3-1	**CAER B3**	**CCSL CDR-Max**
Energy Penalty	27% savings	~20 - 25% savings	~30% savings
Solvent Circulation Rate	~35 - 45% reduction	~30% reduction	~40% reduction
Cyclic Capacity	~1.5X	~1.5X	~2X
Physical Properties: Viscosity Surface Tension	 2.5 – 3X ~0.6X	 ~1.5X ~1.0X	 3 – 3.5X -1.1X
Degradation Products	low	low	low

Testing Summary			
Performance Tests	Tested at various sites (bench and pilot-scales) including UNDEERC; National Carbon Capture Center (NCCC), Alabama; Sask Power Shand Power Station, Canada.	UKy-CAER bench and small pilot scale tests.	Pilot tests at various sites including CO_2 Plant at Sheffield, United Kingdon; EON Netherlands; NCCC, Alabama; and Mongstad, Norway.
Reboiler Based Solvent Regeneration Energy Performance Confirmed at **0.7 MWe** UKy-CAER CCS	**YES** 1020 – 1500 BTU/lb CO_2 captured upon conditions	**YES** 1070 to 1600 BTU/lb CO_2 captured upon conditions	**NO, But Confirmed at UKy-CAER, NCCC and TCM** 1160 to 1290 BTU/lb CO_2 captured

Stream Tables for PI&Ds, Equipment Sizing and Equipment Selection:
Aspen Plus® [1] process modeling studies were conducted to provide detailed mass and energy balances in order to provide a more accurate economic assessment of the proposed process. Process modeling was also used to optimize the proposed process, determine power plant integration strategies and conduct sensitivity analyses.

The first step of the design process involved adopting the UKY-CAER Aspen Plus® [1] model to the proposed 10 MWe process in order to determine the mass and heat balance associated with major equipment including reaction columns, rotary devices and heat exchangers. A screenshot of the Aspen Plus® [1] model of the proposed 10 MWe pilot unit is shown in **Exhibit 3-2**, with selected stream table components shown in **Exhibit 3-3**. The model was built with ion systems using chemical properties determined by e-NRTL-RK. The flue gas is based on flue gas composition from the host site. The flue gas flow was selected to be the 10 MWe equivalent. The output from the simulation has been treated as the upper limit of all equipment sizes. Specifications for each component and the overall system are based on industrial design considerations, general industrial practices and UKy-CAER experience. Experimental data was also used, when and where available. The stream tables generated from this design basis model were provided to the UKy-CAER module and process design contractor, KMPS, and BOP design engineering firm, WP for the preliminary design of the process with appropriate equipment and BOP sizing.

To simulate the proposed technology at the commercial scale, 10% of the total CO_2 captured is recycled to the gas inlet (from the secondary air stripper) to boost the incoming CO_2 content and enhance the absorption driving force within the absorber. The simulation targeted 40 ºC outlet for all streams cooled with cooling water, 40 ºC for the absorber intercooler, and 40 ºC for the flue gas outlet return to the stack. All heat exchangers targeted a 10 ºC approach temperature for either the cold or hot side depending on heat exchanger function.

Process Flow Diagrams:
Upon delivery of the Aspen Plus® [1] model to KMPS, the PFDs were developed for the 10 MWe large pilot scale unit and are shown in **Exhibit 3-4, A-D**. These PFDs only show the carbon capture system, and do not include the actual power generation train. The CCS unit relative to the power generation train is shown in **Exhibit 2-3**.

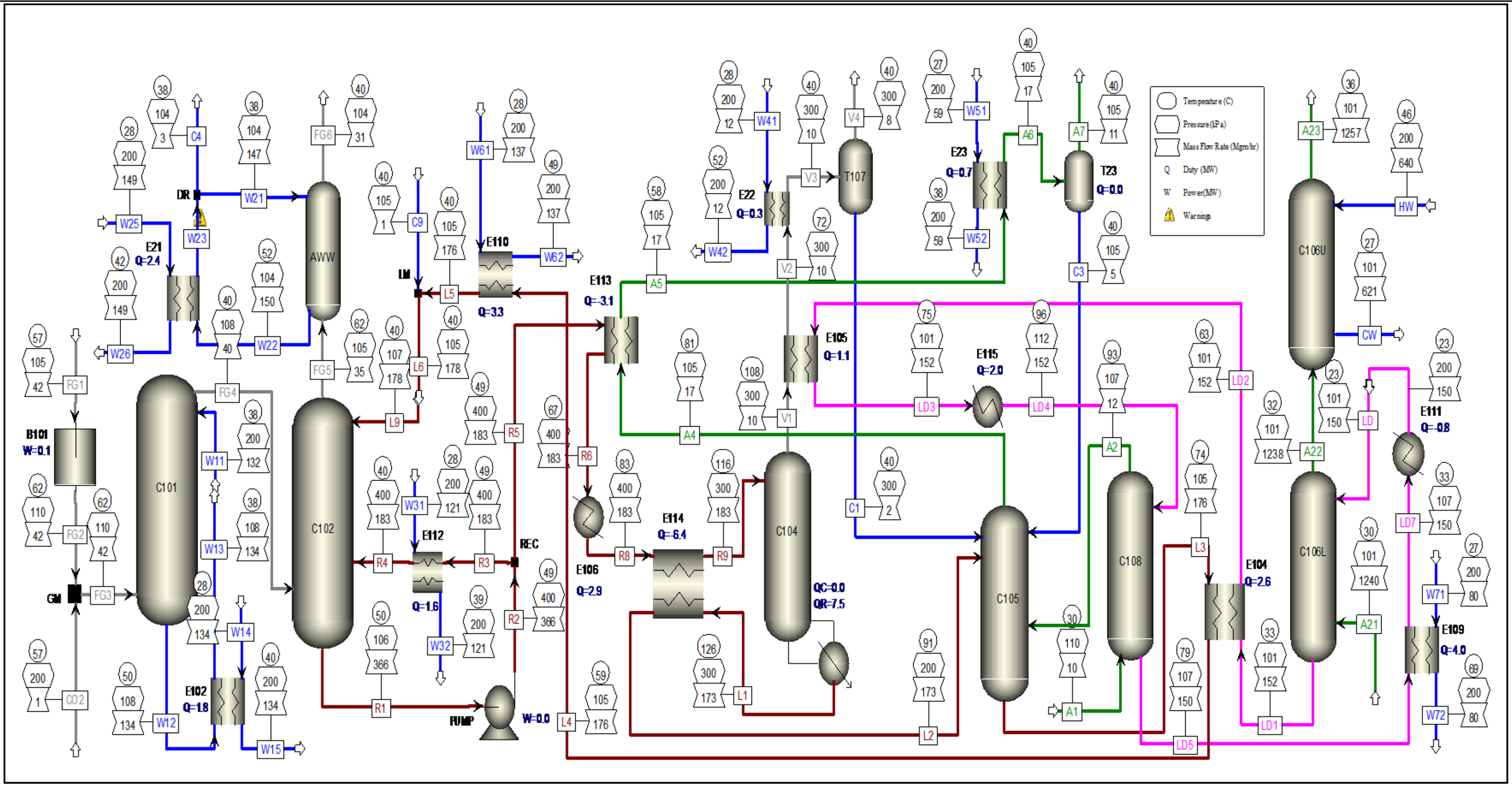
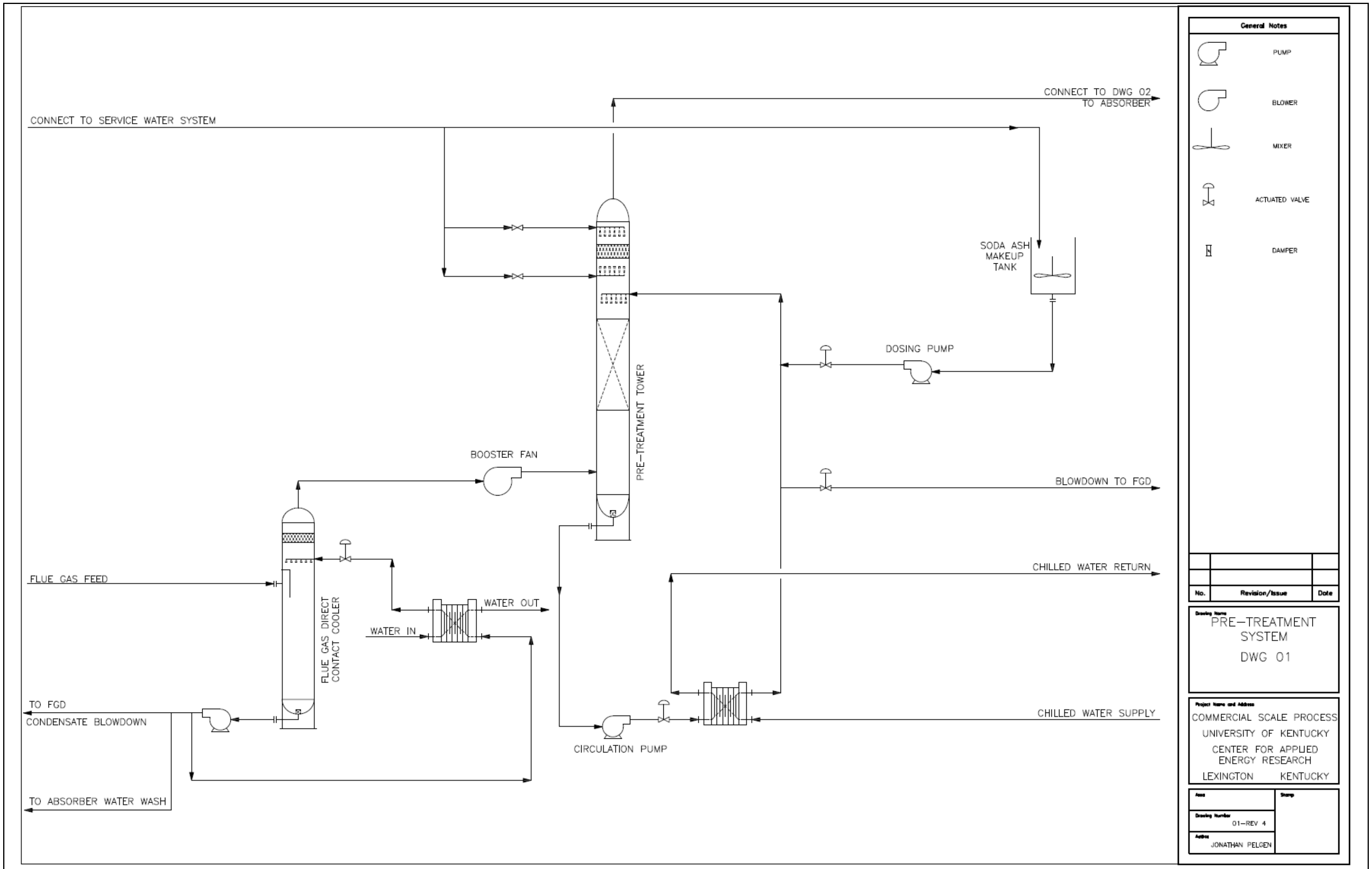
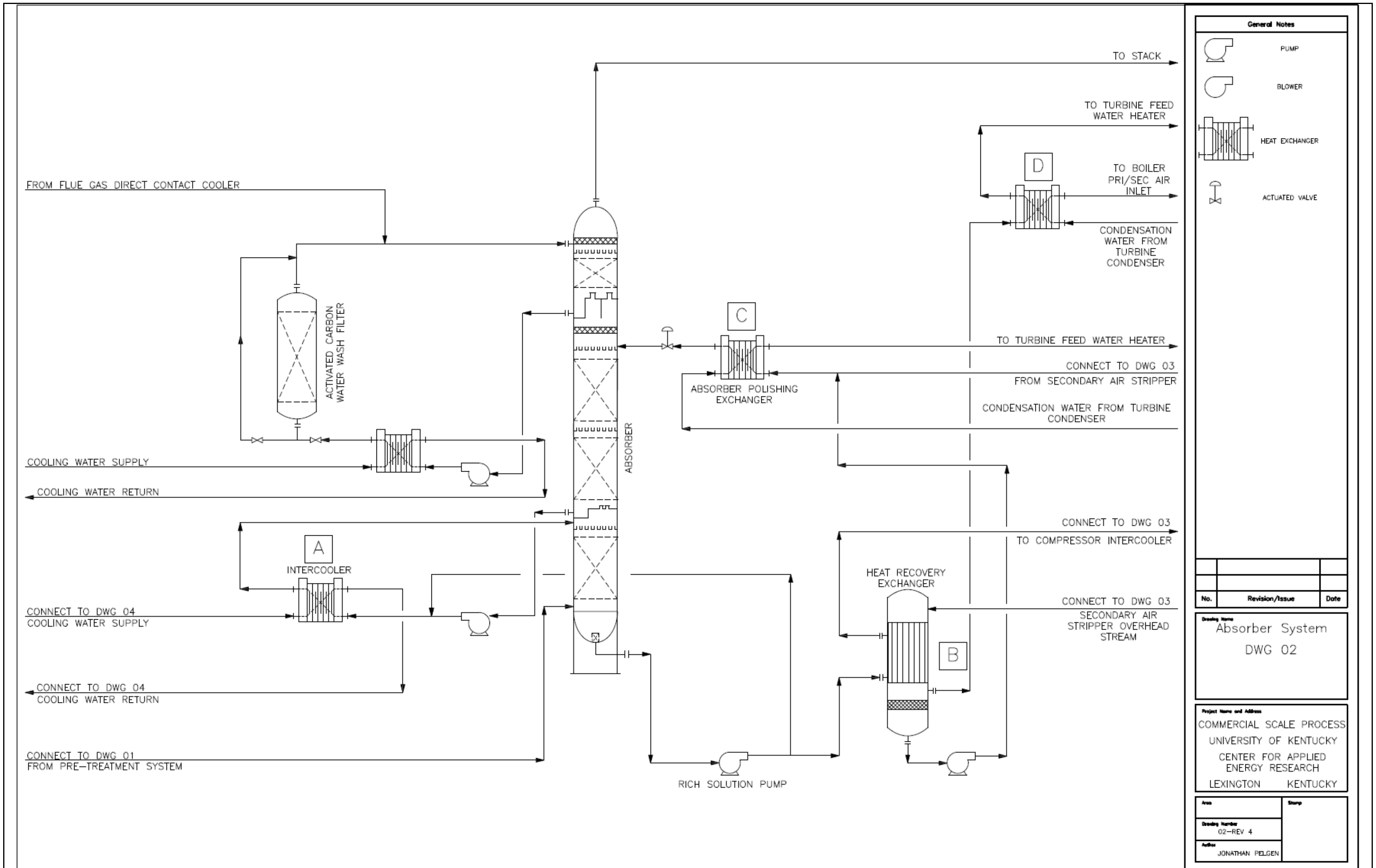


Exhibit 3-2. UKy-CAER 10 MWe Scale CO_2 Capture Process Aspen Plus® [1] Flowsheet.

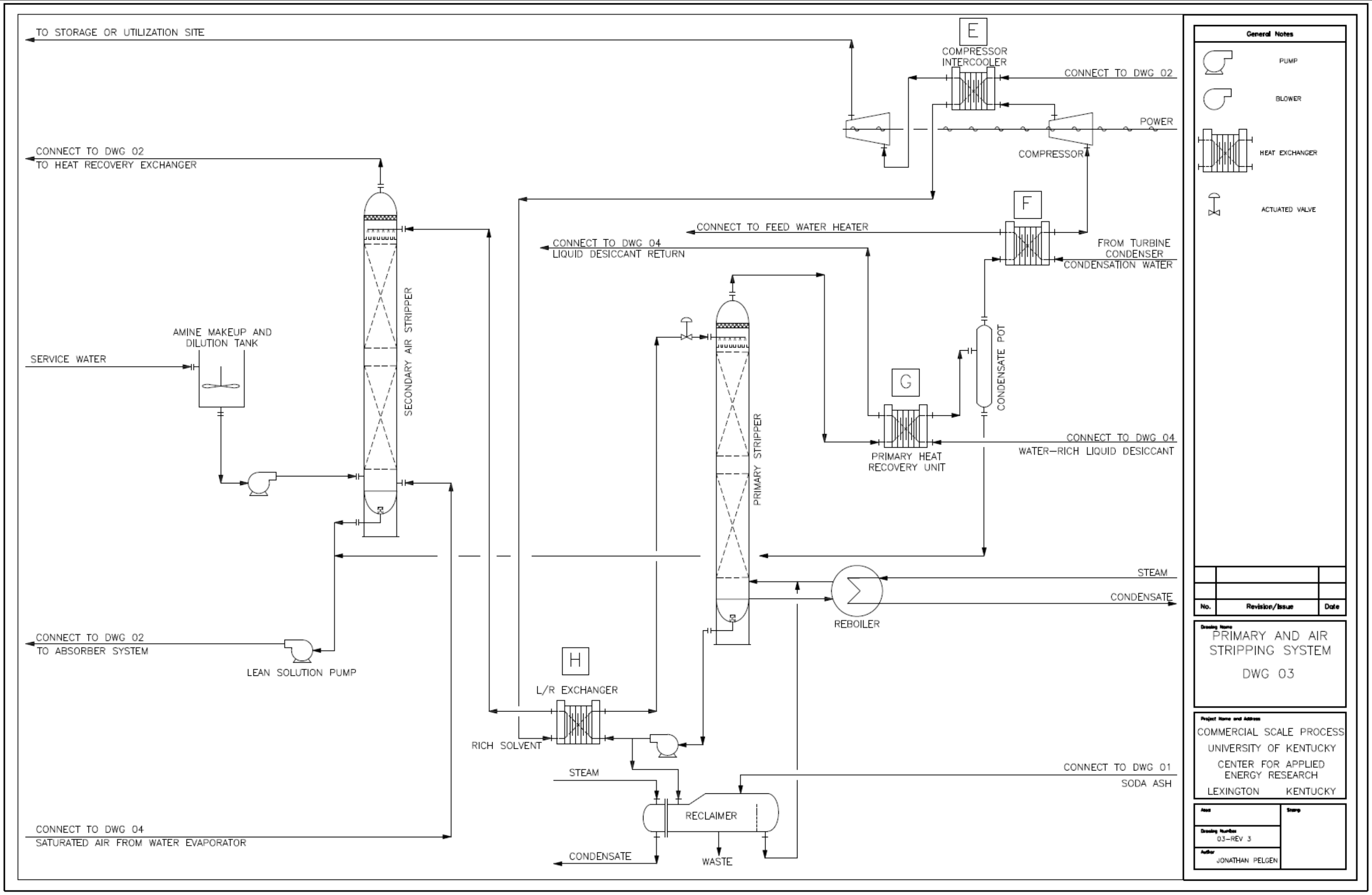
Exhibit 3-3. Selected Stream Table Details from Aspen Plus® [1] Model.														
Process Stream Description	**Secondary Air Stripper Overhead Stream after Condenser**	**CO_2 Recycle**	**Cooling Water From the Cooling Tower to the CCS**	**Flue Gas Inlet to Pretreatment Tower**	**Flue Gas Inlet To Absorber**	**Flue Gas Exit from Absorber**	**Flue Gas Exit from Water Wash Column**	**Cooling Water from the CCS to the Cooling Tower**	**Lean CO_2 Amine Stream after the Primary Stripper**	**Extra Lean CO_2 Amine Stream after the Secondary Air Stripper**	**Extra Lean CO_2 Amine Stream Entering the Absorber**	**Liquid Desiccant Stream Exiting the Cooling Tower**	**Rich CO_2 Amine Stream Exiting the Absorber**	**CO_2 Product Stream Exiting the Primary Stripper after the Overhead Condenser**
Process Stream Aspen Plus® [1] Model Identifier	A7	CO_2	CW	FG1	FG4	FG5	FG6	HW	L1	L3	L9	LD1	R5	V4
Mass Frac														
H_2O	0.044		1	0.095	0.041	0.134	0.046	1	0.643	0.658	0.660	0.604	0.619	0.010
CA^{++}												0.143		
Cl^-												0.253		
N_2	0.674			0.661	0.685	0.795	0.876							0.005
O_2	0.205			0.027	0.028	0.032	0.036							
MEA						0.001			0.140	0.136	0.132		0.016	
CO_2	0.076	1		0.206	0.234	0.025	0.027							0.984
MEA^+									0.086	0.079	0.080		0.144	
Total Flow (gal/min)	42,558	1,172	2,563	165,624	141,506	151,987	124,059	2,662	760	747	738	462	730	6,841
Temperature (°F)	104.0	134.6	80.2	134.6	104.1	143.9	104.0	115.4	259.1	164.6	104.0	90.7	120.3	104.0
Pressure (psi)	15.2	29.0	14.7	15.2	15.7	15.2	15.1	29.0	43.5	15.2	15.5	14.7	58.0	43.5
Vapor or Liquid	Vapor	Vapor	Liquid	Vapor	Vapor	Vapor	Vapor	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Vapor



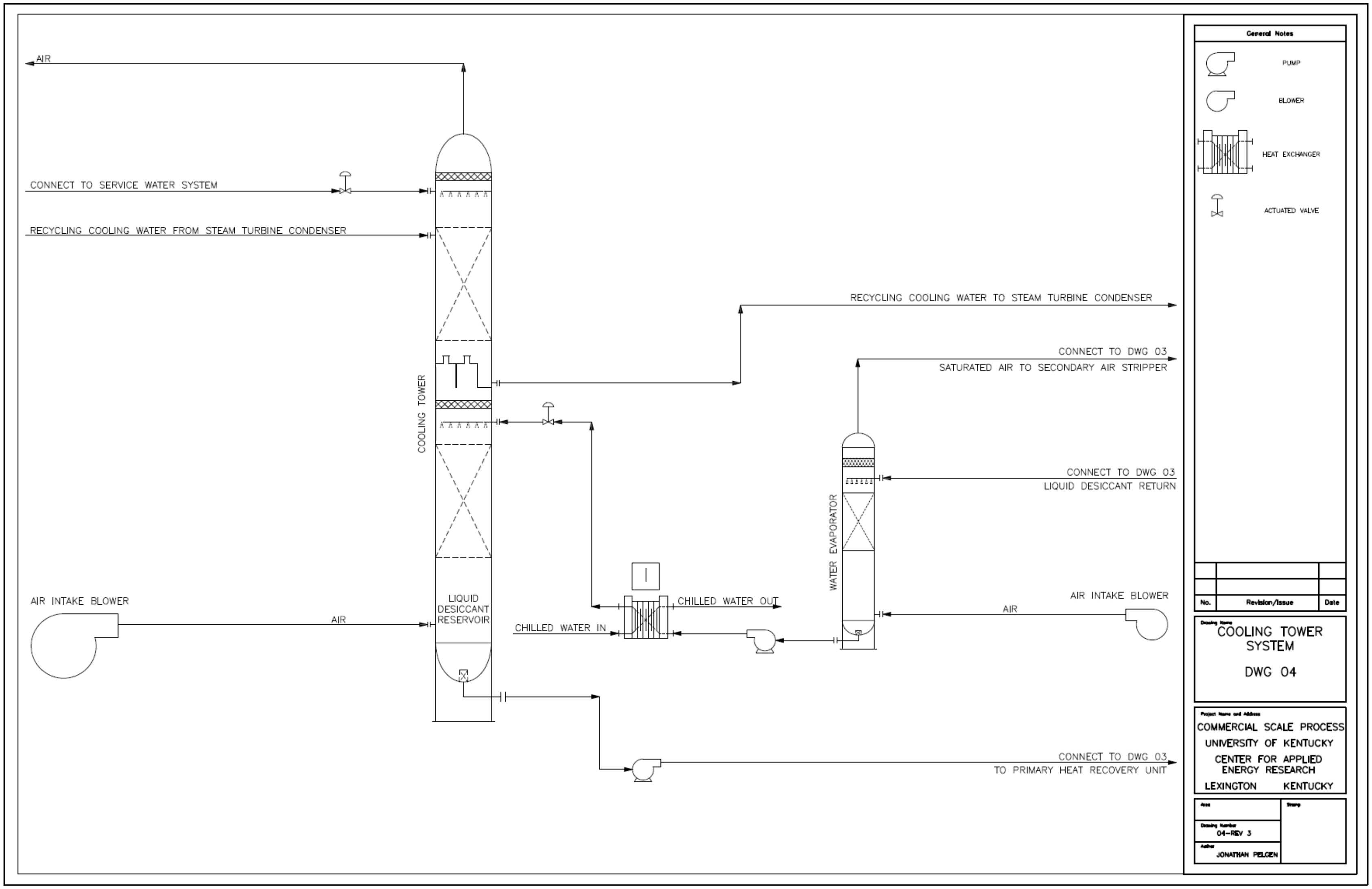
A: Pre-treatment Tower Block.



B: Absorber Block.



C: Stripping Block.



D: Cooling Tower Block.

Exhibit 3-4. UKy-CAER Post-combustion CO_2 Capture PFD.

10 MWe Piping and Instrumentation Diagrams (P&IDs), Equipment Selection and Equipment Sizing:

After the PFDs were finalized, KMPS then completed a set of P&IDs and the general arrangement design, with guidance from UKy-CAER. The UKy-CAER 0.7 MWe small pilot scale process, funded under cooperative agreement of DE-FE0007395, was used as a starting point and several process improvements were included. The P&IDs include details from the major equipment with preliminary sizing, all process instrumentation (temperature, pressure, level, flow, density, and pH), control loops, process lines with sizing, valving, pipe specifications, and liquid and gas sample points. Equipment and piping with electrical tracing and insulation specifications are also included. Lastly, a few column internal details were specified, including the packed sections, the liquid collection trays, the liquid distribution systems and mist elimination devices.

As an example, **Exhibit 3-5** shows the P&ID of the flue gas pretreatment step to remove the flue gas condensate and polish the SO_2 concentration to <10 ppm. An open-tower equipped with spray nozzles (V-101), a water-cooled heat exchanger (E-101), and a circulating pump (P-120) is installed upstream of pre-treatment tower to knock out the water from the saturated flue gas stream extracted from the power generation unit post WFGD. This provides two benefits: (1) a lower flue gas blower (B-101) requirement and (2) less chemical consumption in pretreatment tower (C-101). The addition of the feed knockout vessel (V-101) system addresses a problem noted at the 0.7 MWe small pilot scale, or the blowdown of approximately 50% of the unreacted, soda ash solution fed due to high levels of condensate.

A column with open packing and a mist eliminator (C-102), accompanied with a caustic preparation and feeding system (P-101 and P102), is installed to polish the SO_2 concentration in the flue gas to <10 ppm in order to minimize the heat stable salt formation in the downstream amine loop. In order to flexibly control the absorber temperature profile, a heat exchanger (E-102) is installed in the soda ash loop to adjust the flue gas stream (03-102) temperature.

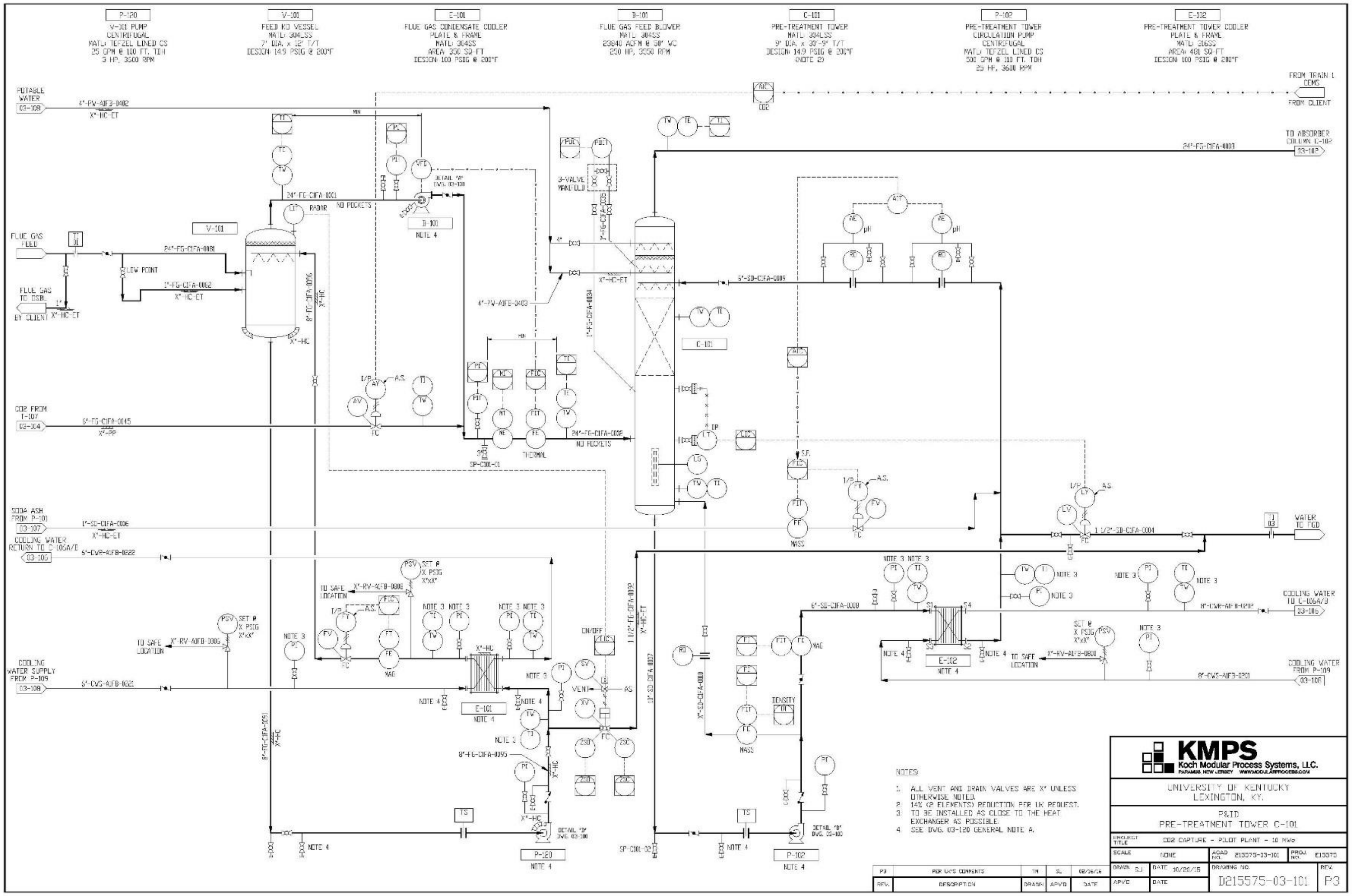


Exhibit 3-5. UKy-CAER Large pilot Scale Post-combustion CO_2 Capture System Pretreatment Step P&ID.

The final part of the design process performed by KMPS was the development of general arrangement drawings in a 3-dimensional format, showing the footprint and layout of the major process equipment, similar to **Exhibit 3-6**. A site survey was conducted by UKy-CAER and WP to verify that the equipment dimensions will function in the space available at Trimble County Generating Station. The three-dimensional (3-D) model provides a visible way to check equipment accessibility and special relations for ease of operations, such as verifying the accessibility of sample points, routinely actuated valves, instrumentation, pH probes, filters, drains, tanks, pressure safety valve (PSV) relief points, and safety shower/eye wash locations. The 3-D model proved to be useful during the 0.7 MWe detailed design phase as we were able to determine if sufficient space had been allocated for large equipment replacements, such as motors, and material handling, such as reclaimer waste drums.

The equipment list for the proposed 10 MWe large pilot CO_2 capture system was prepared by KMPS as part of the design package and is shown in **Exhibit 3-7**. The process includes 7 columns, 19 heat exchangers, 12 tanks and vessels, 4 blowers and 18 pumps. The equipment list also contains preliminary sizing information, operating and design conditions, materials of constructions, insulation and gaskets details.

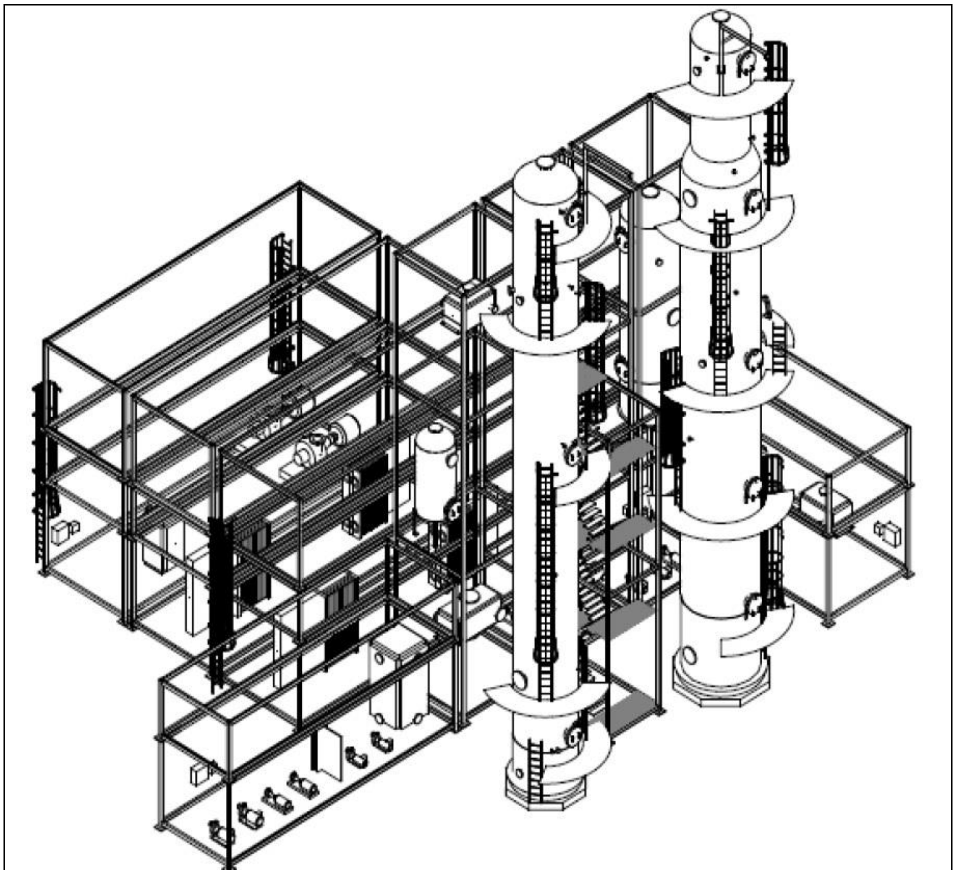


Exhibit 3-6. 3-D Model View of the UKy-CAER 10 MWe Unit.

Furthermore, KMPS estimated the system liquid volumes and dry equipment weights as part of the preliminary design package, shown in **Exhibit 3-8 and 3-9**, respectively. The system volumes were utilized for the complete, comprehensive EH&S Assessment and to budget materials costs. The dry equipment weights were needed to estimate the lifting requirements and construction costs.

Exhibit 3-7. 10 MWe CCS Equipment List Prepared by KMPS.

TAG	DESCRIPTION	P&ID	SIZE	OPERATING CONDITIONS	DESIGN CONDITIONS	MATERIAL	INSULATION	GASKETING
A-102	ADDITIVE INJECTION TANK AGITATOR	215575-03-107	3/4" DIA. X 28" LG SHAFT 4" DIA. IMPELLERS, 1/3 HP	N/A	N/A	316SS	N/A	MFG STD
A-108	SODA ASH MAKE-UP TANK AGITATOR	215575-03-107	3/4" DIA. X 32" LG SHAFT, 4 1/2" DIA. IMPELLERS, 3/4 HP	N/A	N/A	316SS	N/A	MFG STD
AF-103A/B	AIR FILTER	215575-03-106	316800 ACFM, ULTRASYNTHETIC MEDIA	N/A	N/A	CS	NONE	MFG STD
AF-104	AIR FILTER	215575-03-105	13871 ACFM, ULTRASYNTHETIC MEDIA	N/A	N/A	CS	NONE	MFG STD
B-101	FLUE GAS FEED BLOWER	215575-03-101	23840 ACFM @ 50" WC, 250 HP, VFD	N/A	N/A	304SS	NONE	MFG STD
B-103A/B	COOLING TOWER AIR BLOWER	215575-03-106		N/A	N/A	CS	NONE	MFG STD
B-104	WATER EVAPORATOR AIR BLOWER	215575-03-105	13871 ACFM @ 50" WC, 150 HP, VFD	N/A	N/A	CS	NONE	MFG STD
C-101	PRE-TREATMENT TOWER	215575-03-101		2 PSIG @ 110 °F	14.9 PSIG @ 200 °F	304LSS	NONE	GYLON 3500
C-102	CO_2 ABSORBER	215575-03-102		2 PSIG @ 120 °F	14.9 PSIG @ 200 °F	CS / 304LSS	NONE	GYLON 3500
C-104	PRIMARY STRIPPER	215575-03-104		25 PSIG @ 250 °F	50 PSIG / FV @ 350 °F	304LSS	X" HC	GYLON 3500
C-105	SECONDARY AIR STRIPPER	215575-03-105		2 PSIG @ 200 °F	14.9 PSIG @ 300 °F	304LSS	X" HC	GYLON 3500
C-106A/B	COOLING TOWER / DEHYDRATION TOWER	215575-03-106		0 PSIG @ 90 °F	2 PSIG + SH @ 150 °F	FRP	NONE	GORETEX
C-108	WATER EVAPORATOR	215575-03-105		0.5 PSIG @ 154 °F	2 PSIG + SH @ 180 °F	FRP	X" HC	GORETEX
CH-101	CHILLER SYSTEM	215575-03-109	2,100,000 BTU/HR / 450 HP TOTAL	N/A	N/A	316SS	N/A	N/A

DE-101	STEAM DESUPERHEATER	215575-03-109	43600 LB/HR STEAM @ 91 PSIG & 700ºF	N/A	150 PSIG, 800 °F	CS	X" HC	MFG STD
E-101	FLUE GAS CONDENSATE COOLER	215575-03-101	350 SQ FT / PLATE & FRAME	HOT SIDE: 25 psig @ 105 °F, COLD SIDE: 60 psig @ 90 °F	100 PSIG @ 200 °F	304SS	X" HC - SOFT REMOVABLE	EPDM
E-102	PRE-TREATMENT TOWER COOLER	215575-03-101	481 SQ FT / PLATE & FRAME	54 PSIG @ 110 °F	100 PSIG @ 200 °F	316SS	NONE	EPDM
E-103	C-102 WASH SECTION COOLER	215575-03-102		HOT SIDE: 80 psig @ 105 °F, COLD SIDE: 60 psig @ 90 °F	100 PSIG @ 200 °F	304SS	X" HC - SOFT REMOVABLE	EPDM
E-104	LEAN DESICCANT EXCHANGER	215575-03-103		85 PSIG @ 152 °F	100 PSIG @ 200 °F	316SS	NONE	EPDM
E-105	PRIMARY HEAT RECOVERY EXCHANGER	215575-03-104		SHELL: 25 PSIG @ XXX °F, TUBE: 20 PSIG @ 200 °F	SHELL: 50 PSIG @ 300 °F, TUBE: 50 PSIG @ 200 °F	SHELL: 316LSS, TUBE: 304LSS	SHELL: X"-HC, HEADS: X"-HC	GYLON 3500
E-106	RICH HEAT RECOVERY EXCHANGER	215575-03-103		150 PSIG @ 323 °F	212 PSIG @ 356 °F	304SS	X" HC - SOFT REMOVABLE	EPDM
E-107	PRIMARY STRIPPER REBOILER	215575-03-104	2203 SQ FT / SHELL & TUBE	SHELL: 100 PSIG @ 328 °F, TUBE: 25 PSIG @ 250 °F	SHELL: 150 PSIG @ 400 °F, TUBE: 100 PSIG @ 300 °F	SHELL: CS, TUBE: 304LSS	SHELL: X" HC, HEADS: X" HC	GYLON 3500
E-108	RECLAIMER	215575-03-104	784 SQ FT / SHELL & TUBE	SHELL: 25 PSIG @ 287 °F, TUBE: 100 PSIG @ 328 °F	SHELL: 100 PSIG @ 350 °F, TUBE: 150 PSIG @ 400 °F	SHELL: 304LSS, TUBE: 304LSS	SHELL: X" HC, HEADS: X" HC	GYLON 3500
E-109	LIQUID DESICCANT COOLER	215575-03-105		65 PSIG @ 130 °F	100 PSIG @ 200 °F	316SS	NONE	EPDM
E-110	ABSORBER POLISHING EXCHANGER	215575-03-103	434 SQ FT / PLATE & FRAME	85 PSIG @ 100 °F	100 PSIG @ 200 °F	304SS	NONE	EPDM
E-111	LIQUID DESICCANT CHILLER	215575-03-105	210 SQ FT / PLATE & FRAME	65 PSIG @ 130 °F	100 PSIG @ 150 °F	316SS	X" CC - SOFT REMOVABLE	EPDM
E-112	ABSORBER COOLER	215575-03-102		54 PSIG @ 137 °F	100 PSIG @ 200 °F	304SS	NONE	EPDM

E-113	SECONDARY HEAT RECOVERY EXCHANGER	215575-03-103	11250 SQ FT / SHELL & TUBE	SHELL: 160 PSIG @ 162 °F, TUBE: 15 PSIG @ 178 °F	SHELL: 200 PSIG @ 300 °F, TUBE: 50 PSIG @ 300 °F	SHELL: 304LSS, TUBE: 304LSS	SHELL: X"-HC, HEADS: X"-PP	GYLON 3500
E-114	LEAN / RICH EXCHANGER	215575-03-104	861 SQ FT / PLATE & FRAME	150 PSIG @ 244 °F	220 PSIG @ 300 °F	316SS	X" HC - SOFT REMOVABLE	EPDM
E-115	LIQUID DESICCANT PREHEATER	215575-03-105	152 SQ FT / PLATE & FRAME	75 PSIG @ 323 °F	150 PSIG @ 356 °F	316SS	X" HC - SOFT REMOVABLE	EPDM
E-116A/B	LD TANK HEATER	215575-03-107	25 kW EA / IMMERSION	N/A	N/A	304SS	N/A	N/A
E-117	AMINE STORAGE TANK HEATER	215575-03-108	15 kW / IMMERSION	N/A	N/A	304SS	N/A	N/A
F-102	RICH AMINE SOLUTION STRAINER	215575-03-103	3 1/2" DIAM x 8 3/8" LENGTH EA - DUPLEX / 50 MESH	187 PSIG @ 117 °F	210 PSIG @ 200 °F	CS BODY / 316SS BASKET	NONE	PTFE
F-103	CARBON FILTER	215575-03-103	6'-3" DIA. x 10'-3" T/T	30 PSIG @ 110 °F	210 PSIG / FV @ 250 °F	304LSS	NONE	GYLON 3500
F-104	CARTRIDGE FILTER	215575-03-103	8" DIA. x 46" OAL	175 PSIG @ 117 °F	210 PSIG @ 250 °F	304SS	NONE	EPDM
F-105	CARBON FILTER 2	215575-03-103	1'-8" DIA. x 10'-0" T/T	52 psig @ 142 °F	210 PSIG / FV @ 250 °F	304LSS	NONE	GYLON 3500
F-106	C-102 CARBON FILTER	215575-03-102	3'-6" DIA. x 10'-0" T/T	80 psig @ 105 °F	14.9 PSIG / FV @ 200 °F	304LSS	X"-HC	GYLON 3500
K-101	INSTRUMENT AIR COMPRESSOR	215575-03-110	XXXX	N/A	N/A	XX	NONE	MFG STD
P-101	DILUTE SODA ASH PUMP	215575-03-107	7.5 GPM @ 77 FT TDH, 3 HP / CENTRIFUGAL	N/A	N/A	316SS	X" HC - SOFT REMOVABLE	MFG STD
P-102	PRE-TREATMENT TOWER CIRCULATION PUMP	215575-03-101		N/A	N/A	TEFZEL LINED CS	NONE	MFG STD
P-103	RICH AMINE PUMP	215575-03-102		N/A	N/A	316SS	NONE	MFG STD
P-104	PRIMARY STRIPPER BOTTOMS PUMP	215575-03-104		N/A	N/A	316SS	X" HC - SOFT REMOVABLE	MFG STD

P-105	WATER WASH RECIRCULATION PUMP	215575-03-102		N/A	N/A	316SS	X" HC - SOFT REMOVABLE	MFG STD
P-106	WATER EVAPORATOR BOTTOMS PUMP	215575-03-105		N/A	N/A	TEFZEL LINED CS	NONE	MFG STD
P-108	SECONDARY STRIPPER BOTTOMS PUMP	215575-03-105		N/A	N/A	TEFZEL LINED CS	X" PP - SOFT REMOVABLE	MFG STD
P-109	COOLING WATER PUMP	215575-03-108		N/A	N/A	DUCTILE IRON	NONE	MFG STD
P-110A/B	LIQUID DESICCANT PUMP	215575-03-106		N/A	N/A	TEFZEL LINED CS	NONE	MFG STD
P-111	ADDITIVE INJECTION PUMP	215575-03-107	1 GPM @ 150 FT TDH, 1 HP / DIAPHRAGM	N/A	N/A	316SS/PTFE	X" HC - SOFT REMOVABLE	MFG STD
P-112	ABSORBER COOLER PUMP	215575-03-102	944 GPM @ 80 FT TDH, 40 HP, VFD / CENTRIFUGAL	N/A	N/A	TEFZEL LINED CS	NONE	MFG STD
P-115	CONDENSATE PUMP	215575-03-103	100 GPM @ 120 FT TDH, 7.5 HP / CENTRIFUGAL	N/A	N/A	CAST IRON	X" PP - SOFT REMOVABLE	MFG STD
P-116	DESICCANT MAKE-UP PUMP	215575-03-107	250 GPM @ 100 FT TDH, 20 HP / CENTRIFUGAL	N/A	N/A	TEFZEL LINED CS	X" HC - SOFT REMOVABLE	MFG STD
P-117	STEAM DESUPERHEATER PUMP	215575-03-109	50 GPM @ 68 FT TDH, 3 HP, VFD / CENTRIFUGAL	N/A	N/A	316SS	X" PP - SOFT REMOVABLE	MFG STD
P-118	SODA ASH MAKE-UP PUMP	215575-03-107	100 GPM @ 100 FT TDH, 5 HP / CENTRIFUGAL	N/A	N/A	316SS	X" HC - SOFT REMOVABLE	MFG STD
P-119	LEAN AMINE PUMP	215575-03-108	250 GPM @ 110 FT TDH, 15 HP / CENTRIFUGAL	N/A	N/A	TEFZEL LINED CS	X" HC - SOFT REMOVABLE	MFG STD
P-120	V-101 PUMP	215575-03-101	25 GPM @ 100 FT TDH, 3 HP / CENTRIFUGAL	N/A	N/A	TEFZEL LINED CS	X" HC - SOFT REMOVABLE	MFG STD
T-101	SODA ASH DILUTION TANK	215575-03-107	7'-6" DIA. x 9'-0" T/T, 3000 GALLLON	ATM @ 100 °F	ATM @ 250 °F	304LSS	X" HC	GYLON 3500

T-102	ADDITIVE INJECTION TANK	215575-03-107	2'-0" DIA. x 3'-0" T/T, 70 GALLLON	ATM @ 100 °F	ATM @ 250 °F	304LSS	X" HC	GYLON 3500
T-104	COOLING WATER HOLDING TANK	215575-03-108	11'-0" DIA. x 14'-0" T/T, 10,000 GALLLON	ATM @ 70 °F	ATM @ 110 °F	FRP	NONE	GORETEX
T-105A/B	DESICCANT MAKE-UP TANK	215575-03-107	12'-0" DIA. x 35'-5" T/T, 35,000 GALLLON EA	ATM @ AMBIENT	ATM @ 250 °F	316LSS	X" HC	GYLON 3500
T-107	CONDENSATE POT	215575-03-104	4'-0" DIA. x 6'-9" T/T	65 PSIG @ 200 °F	50 PSIG / FV @ 300 °F	304LSS	X" PP	GYLON 3500
T-108	SODA ASH MAKE UP TANK	215575-03-107	4'-4" DIA. x 5'-4" T/T, 500 GALLLON	ATM @ AMBIENT	ATM @ 250 °F	304LSS	X" HC	GYLON 3500
T-109	AMINE STORAGE TANK	215575-03-108	12'-0" DIA. x 29' -6" T/T, 25,000 GALLLON	ATM @ 100 °F	ATM @ 250 °F	304LSS	X" HC	GYLON 3500
T-110	SODA ASH STORAGE SILO / FEED SYSTEM	215575-03-107 1	2'-0" DIA. x 31' -6" T/T SILO, 10 kW HEATER / 5 HP FEED SYSTEM MOTORS	ATM @ AMBIENT	ATM @ 250 °F	CS	NONE	MFG STD
V-101	FEED KO VESSEL	215575-03-101	7'-0" DIA. x 12'-0" T/T	2 PSIG @ 140 °F	14.9 PSIG @ 200 °F	304LSS	X"-HC	GYLON 3500
V-102	STEAM DESUPERHEAT ER KO VESSEL	215575-03-109	4'-0" DIA. x 7'-0" T/T	85 PSIG @ 340 °F	200 PSIG @ 400 °F	CS	X" HC	GYLON 3500
V-103	STEAM CONDENSATE SURGE VESSEL	215575-03-109	4'-0" DIA. x 7'-0" T/T	70 PSIG @ 316 °F	200 PSIG @ 400 °F	CS	X" PP	GYLON 3500

Exhibit 3-8. UKy-CAER 10 MWe CCS System Volumes Prepared by KMPS.	
Solution	**Volume (gallons)**
Amine	22,000 Estimate includes Amine Make-up Tank volume; it **does not** include volume of temporary storage tank.
Liquid Desiccant	85,000 Estimate assumes **only one** Liquid Desiccant storage tank is **half full** with the fluid.
Soda Ash	6,700 Estimate includes Soda Ash Dilution and Make-up tank volumes.
Ethylene Glycol	1,500

Exhibit 3-9. UKy-CAER 10 MWe CCS Equipment Weights Prepared by KMPS.		
Tag	**Description**	**Weight (lbs)**
C-101	Pre-treatment Tower	15,500
C-105	Air Stripper	30,000
C-108	Water Evaporator (FRP)	7,000
T-104	Cooling Water Holding Tank (FRP)	3,400
T-105 A/B	Desiccant Make-up Tanks	9,300 each
T-109	Amine Storage Tank	15,000
T-110	Soda Ash Storage Silo	26,000
Weights are for lifting purposes and includes weight of the shell only. Packing and internals are not included, as they will be field installed.		

3.2 BOP Design

Host Site Selection: The proposed 10 MWe large pilot scale CCS will be installed at LG&E's Trimble County Power Plant near Bedford, KY. The physical location will be parallel to the Trimble County Unit 1 boiler and turbine building. The primary reasons for selecting this particular plant are several-fold. First and foremost, UKy-CAER has had many years of strong support from, and collaboration with the host utility, LG&E/KU. Its continued interest in providing an outstanding host site for the large pilot CCS is critical to the success of the project. Second, there is an available footprint of 2.5 acres of land in close proximity to steam and flue gas. Third, the priority for grid dispatch is of utmost importance, which will ensure up-time and availability for this project, and will account for the outstanding possibility for re-purposing and extending the service of the large pilot scale CCS to address other research needs after 2020 when this project is completed. The average capacity factor for TC 1, 2009-2016 is 77%.

With more intermittent renewable energy feeding into the grid and more natural gas energy (due to low gas prices), the service hours of coal units have been significantly reduced. Reduced demand for coal fired units could potentially impact this project schedule. However, TC 1 is a supercritical PC unit, and it is anticipated that Trimble County will be on first dispatch for electric generation, ensuring up-time and availability. TC 1 is equipped with air pollution control devices including an electrostatic precipitator (ESP), a new bag house, low NOx burners, a selective catalytic reduction

(SCR) unit, over-fired air (OFA), a WFGD unit and dry ESP. The completion of a full host site agreement with all authorized and appropriate signatures from both UK and LG&E/KU was completed during this project.

Flue gas, Steam and Condensate Tie-In Location Selection and Pipe Routing: The CO_2 capture facility will process flue gas from Unit 1 at the Trimble County Power Generation Station. Once processed, the flue gas will be returned to the main plant flue gas stream and emitted. The tie in locations for the supply and return ducts were determined based on requirements of the CO_2 capture system and the proximity to the CCS. Information gathered during a site visit in December 2015, was used to assess potential piping routes and support requirements.

Two tie-in locations were considered for the flue gas supply duct: after the baghouse blower and after the FGD.

The first location, after the baghouse blower, provides the benefit of a significantly shorter duct run and simpler access to the tie-in location. The primary disadvantages of this tie-in location are the significantly greater gas temperatures and the higher sulfur concentrations in the flue gas. While the duct run from the top of the WFGD building is significantly longer, the flue gas composition and temperature are more representative of that expected during the actual operation of a post-combustion CO_2 capture facility. Therefore, the tie-in location for the flue gas supply to the CO_2 capture unit was selected downstream of the WFGD for the proposed 10 MWe large pilot scale unit. This selected tie-in location is noted on the general arrangement drawing shown in **Exhibit 3-10.**

During the site visit, the route for the flue gas supply duct was assessed for potential obstructions. The primary obstruction observed was the recently added ducts to the baghouse which are also illustrated in **Exhibit 3-10**, the general arrangement drawing. During the assessment, a route under the ducts on either side of an existing truck route was identified as the preferred option. A duct diameter of 3 ft. was considered in evaluating these routes. An additional consideration in assessing and designing the structural support was maintaining sufficient clearance for the trucks moving along the current truck route.

The flue gas will be returned to the flue gas duct after the baghouse, but prior to the booster fan. The general arrangement, **Exhibit 3-10**, also includes this tie-in point location. This tie-in location allows for a short duct run, negative pressure at the tie-in point, and essentially no obstacles to the duct routing.

The tie-in locations for the steam supply and the associated condensate return are in the Unit 1 boiler building. The steam supply tie-in was selected to be the crossover duct from the (intermediate pressure) IP to (low pressure) LP steam turbines. The tie-in for the condensate return was designated to be the plant condensate tank. In routing both of these lines to the 10 MWe large pilot scale CCS site, consideration was given to the other buildings along the direct path and the heavy block wall of the boiler and steam turbine buildings. To avoid penetrating this heavy wall, the steam and condensate pipes were routed up to higher levels in the boiler building. At the higher levels, the walls are metal and can be penetrated with greater ease. The pipes are then routed along an adjacent roof and down to the demonstration unit. The pipes will need to be elevated to at least

20 ft. above grade from the boiler building to the modules in order to maintain clearance along the current truck route. These pipe routes and tie-in locations are shown in the general arrangement, **Exhibit 3-10**.

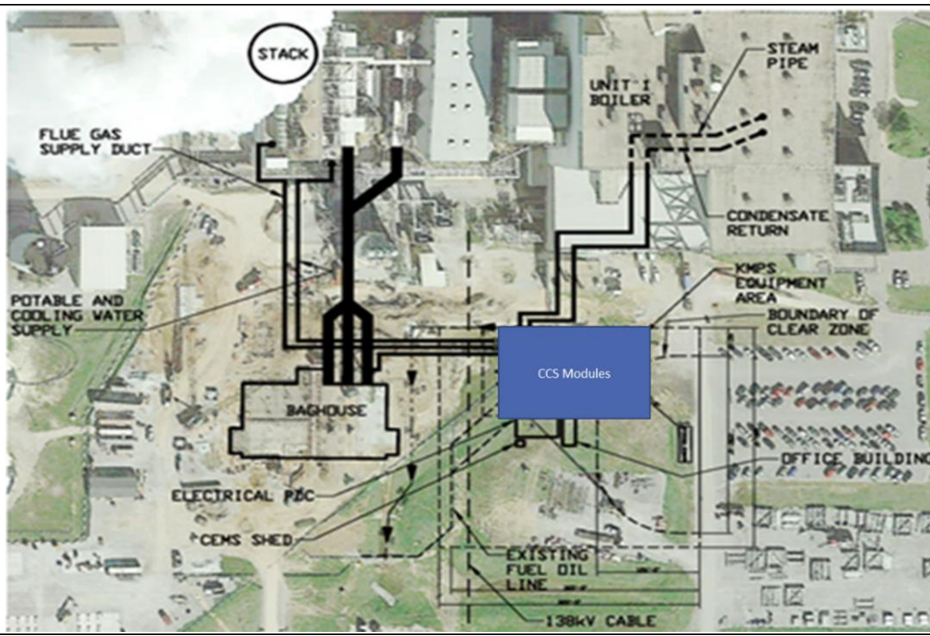


Exhibit 3-10. General Arrangement Drawing with Tie-In Locations and Pipe Routes.

Mechanical:

a) Flue Gas Supply and Return Duct: The flue gas supply duct starts from the top of the FGD building at the FGD exit, and ends at the flue gas pretreatment at the CO_2 capture system boundary. The flue gas supply duct uses fiberglass reinforced plastic (FRP) material. This selection is based on WP experience and recommendation from a duct vendor, Plasticon Composite. FRP has good resistance to corrosion and is more economical than stainless steel. For these reasons, FRP is selected for many commercial/industrial applications at coal fired power plants in the WFGD scrubbers and downstream. The flue gas supply duct is estimated to be 650 feet long and 3 feet in diameter.

   The flue gas return duct routes the treated flue gas from the CO_2 capture system boundary to the existing power plant baghouse fan inlet. This ductwork also uses FRP material and has an estimated length of 300 feet with a diameter of 3 feet.

b) Steam and Condensate Piping: Steam for the CCS will be taken from the crossover duct between IP to LP steam turbines. At full plant load, the steam pressure at the cross over duct will be approximately 178 psia and at a temperature of 700 °F. Approximately 42,000 lb/hr of superheated steam is sent from the crossover to the CO_2 capture system boundary through a nominal 8 inch carbon steel pipe. The pipe is estimated to be around 800 feet long. To meet the steam quantity and conditions (75 pisa / 338 °F) required by the process, a flow control valve, a pressure regulator and a desuperheater are required.

The condensate from the CCS will be returned to the power plant condensate tank through a nominal 4 inch carbon steel pipe. The condensate return pipe is approximately 1000 feet long.

c) Plant and Potable Water: Approximately 50 gpm process makeup water will be taken from the existing power plant potable water system. The pipe is nominal 4 inch carbon steel pipe and approximately 1000 ft. long.

d) Wastewater: Wastewater from the process includes 40 gpm of flue gas condensate and soda ash waste. A nominal 3 inch pipe of approximately 1000 ft. in length will route the wastewater from the CCS to the power plant FGD scrubbing solution.

Civil Engineering:

Site clearing will be required to prepare the pad for the KMPS supplied equipment and ancillary structures (electrical power distribution center (PDC), CEMS shed, and office building). The equipment and structures are located so as to avoid interference with an existing underground 138 kV cable, as well as maintaining the minimum 100 foot boundary clearance zone for the existing hydrogen storage tanks on the site. An existing fuel oil line will need to be relocated to make room for the CCS and balance of plant.

Erosion and sediment pollution controls will be constructed, stabilized and functional prior to general site disturbance. Appropriate best management practices (BMPs) will be implemented to eliminate the potential for accelerated erosion and/or sediment pollution. An existing swale that traverses the site will need to be partially filled-in to accommodate site construction. Storm drainage piping will be installed to maintain storm water conveyance. It appears the swale is also utilized for storm water volume storage. The equivalent impacted volume will need to be restored on site.

Structural Engineering:

a) Design Criteria: The site is located along the Ohio River in Trimble County, KY. The governing building code for this facility is the Kentucky Building Code (Tenth edition, revised June 2013). The Kentucky Building Code (KBC) is based upon the 2012 International Building Code with Kentucky specific amendments. The following are specific amendments in the KBC for Trimble County:
   - Ground Snow Load – 20 psf
   - Rain Intensity (100-yr, 1-hour duration) – 3.17
   - Seismic Accelerations – S_S=0.177 and S_1=0.096
   - Atmospheric Ice Loads – thickness=0.75”

   In addition to the KBC, the following parameters are based on the International Building Code:
   - Risk Category – III
   - Wind Speed – 120 mph (ultimate, 3-sec gust, 50-yr recurrence interval)
   - Exposure Category – C
   - Site Class – D (assumed based on limited geotechnical information)
   - Seismic Design Category – C

b) Foundations: Shallow spread foundations are suitable for lightly loaded structures such as pipe/duct racks and metal buildings with column loads less than 100-kips. A maximum allowable bearing pressure of 3000-psf was assumed based on available data. The flue gas duct loads were based on a 36” diameter FRP duct. Flue gas duct dead loads were assumed to be 250-plf. The steam and condensate pipe loads were based on a 12” pipe (steam) and a 4” pipe (condensate). Steam and condensate pipe dead loads were assumed to be 160-plf (total).

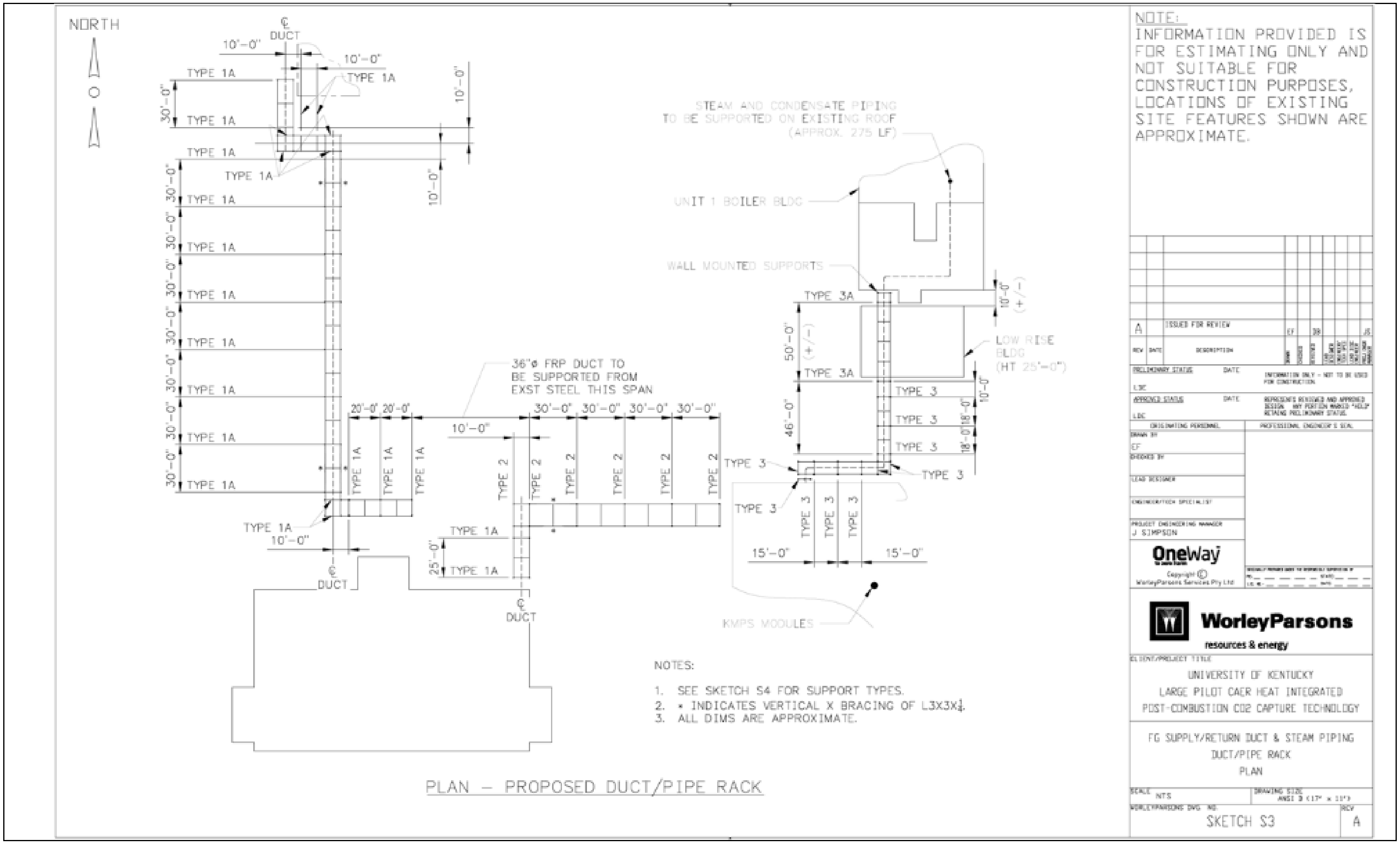
c) Foundations for CCS Equipment: The foundation design was based on an August 1, 2014 geotechnical exploration report prepared by AMEC Environment and Infrastructure, Inc. (Engineering and Technical Services Company) for the Unit 1 pulse jet fabric filter (PJFF) and Air Compliance Structures project. In addition to the report, AMEC and S&ME (Geotechnical, Civil, Planning, Environmental and Construction Services Firm) were consulted to gain a further understanding of soil conditions at the plant. Soil conditions are expected to be dense sand/gravel, poorly graded down to approximately 40-ft, with loose to medium dense sand beyond. No bedrock is expected.

The foundations for the KMPS supplied equipment were developed based on loads provided by KMPS. The loads include dead load, live load (100psf on platforms), operating liquid and flooded liquid. Seismic, wind, thermal and process operation forces were not included at this stage.

The final foundation designs will be able to contain major spills of solutions within the process system. Curbing and design for the major spill containment will be developed in detail during Phase II.

Based on the geotechnical report input, heavily loaded structures such as the tanks, fans and modules, will require deep foundations. In accordance with the AMEC report and conversations with AMEC and S&ME, auger cast piles are selected for the deep foundations. This foundation system was selected based on the magnitude of large loads, the amount of densely spaced columns, as well as equipment, and to avoid any differential settlements. The mat thickness for the foundation was determined to be 3.5 feet thick. Individual piers will be provided at each module column and for each tank and related equipment. Cast-in-place anchor bolts were selected for the larger equipment based on their increased capacity over post-installed anchors.

d) Support for Flue Gas Supply and Return Duct: The flue gas supply and return duct will be primarily supported on individual structural steel support frames or bents inter-connected to form a duct rack system. The steel frames are supported on shallow spread footings spaced at 30 ft. on-center. The duct is supported 20 ft. above grade to allow for vehicle traffic. The duct rack is designed to support both the supply and return duct from the CO_2 capture system boundary to the existing baghouse. The supply duct continues on individual support frames to the FGD building. At the FGD building, individual supports will be incorporated with the existing FGD structure. **Exhibit 3-11** illustrates the support of the flue gas supply and return duct over the proposed route. Details for the support structures are included in **Exhibit 3-11.**


NOTE:
INFORMATION PROVIDED IS FOR ESTIMATING ONLY AND NOT SUITABLE FOR CONSTRUCTION PURPOSES, LOCATIONS OF EXISTING SITE FEATURES SHOWN ARE APPROXIMATE.
NORTH
STEAM AND CONDENSATE PIPING TO BE SUPPORTED ON EXISTING ROOF (APPROX. 275 LF)
UNIT 1 BOILER BLDG
WALL MOUNTED SUPPORTS
LOW RISE BLDG (HT 25'-0")
36"ø FRP DUCT TO BE SUPPORTED FROM EXST STEEL THIS SPAN
KMPS MODULES
NOTES:
1. SEE SKETCH S4 FOR SUPPORT TYPES.
2. * INDICATES VERTICAL X BRACING OF L3X3X¼.
3. ALL DIMS ARE APPROXIMATE.
PLAN – PROPOSED DUCT/PIPE RACK
WorleyParsons
resources & energy
UNIVERSITY OF KENTUCKY
LARGE PILOT CAER HEAT INTEGRATED
POST-COMBUSTION CO2 CAPTURE TECHNOLOGY
FG SUPPLY/RETURN DUCT & STEAM PIPING
DUCT/PIPE RACK
PLAN
SCALE NTS
SKETCH S3
A
ISSUED FOR REVIEW
J SIMPSON

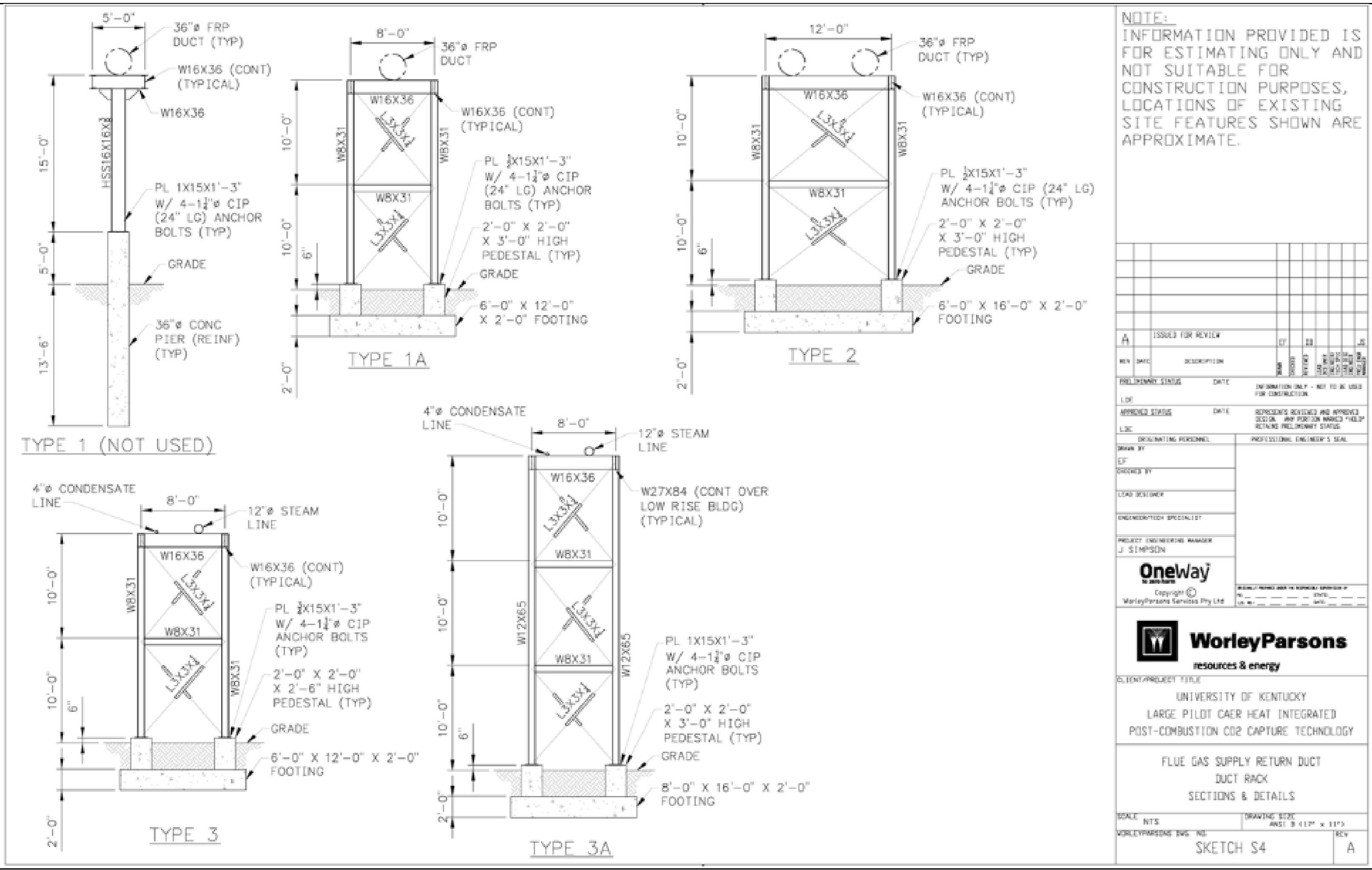


Exhibit 3-11. Duct and Pipe Support Design Details.

e) Steam and Condensate Return: The 12 in. diameter steam pipe and 4 in. diameter condensate pipe will be primarily supported on a continuous structural steel pipe rack system. The steel frames are supported on shallow spread footings spaced at 20 ft. on-center. The pipe rack is elevated 20 ft. above grade to allow for vehicle traffic. The pipe rack was designed to support both the steam and condensate pipe from the CO_2 capture system boundary to the existing Unit 1 Boiler Building. At the Unit 1 Boiler Building, individual supports will be incorporated with the existing boiler building structure. **Exhibit 3-11** also illustrates the support of the steam supply and condensate return piping over the proposed route. Details for the proposed support structures are similarly included in **Exhibit 3-11**.

f) Electrical PDC Foundation: The electrical PDC structure will be elevated above the grade and supported on 10 individual reinforced concrete piers (7'-0" tall). The piers will be supported on a concrete mat foundation supported on auger cast concrete piles to avoid any differential settlement. The electrical PDC structure was assumed to weigh 150,000 lbs with an overall footprint of 28 x 52 feet.

<u>Electrical Engineering:</u>

The electrical systems developed to support the modular CO_2 capture process equipment were designed by KMPS, in addition to the balance of plant equipment including the CEMS, heat tracing and other ancillary systems. The load list used to develop this system is provided in **Exhibit 3-12**. Items included in the balance of plant electrical scope are the tie-in to the main electrical service, cables, transformers, motor controls and variable frequency drives, a building to contain the electrical equipment and wiring to the KMPS modules.

The tie-in for the electricity was determined to be the Shelby Electrical Cooperative, which currently provides electricity to the Trimble County host site. Shelby was contacted during this design phase to determine if the load could be served by the existing capacity of the local distribution, as well as the characteristics of the service. Shelby modeled the impact of the proposed service on the local network and determined that there is sufficient capacity to support the proposed facility.

The information from Shelby was combined with the load list in **Exhibit 3-12** to develop the electrical system and equipment required to provide power the CO_2 capture equipment. The one line diagram for the facility, shown in **Exhibit 3-13**, illustrates the equipment requirements and system configuration. In this system, the medium voltage is set 4.16 kV, which is used to drive motors greater than 200 hp.

From the electrical equipment list, the layout of the PDC was developed to size the electrical shed, see **Exhibit 3-13**. The size and weight of the shed were used in determining the foundation requirements as described previously in the structural/civil engineering sections. For costing, allowances are included for climate control of the electrical equipment building.

TAG	DESCRIPTION	SIZE	HP	V	pf	eff	KW	KVAR	KVA	AMP	CABLE SIZE	PROTECTION	STARTER	X-SPACE	STACK
A-102	ADDITIVE INJECTION TANK AGITATOR	3/4" DIA. X 28" LG SHAFT 4" DIA. IMPELLERS, 1/3 HP	0.333	460	0.85	0.9	0.28	0.17	0.32	0.41	1-3/C-12	MCP	1	2X	
A-108	SODA ASH DILUTION TANK AGITATOR	3/4" DIA. X 32" LG SHAFT 4 1/2" DIA. IMPELLERS, 3/4 HP	0.75	460	0.85	0.9	0.62	0.39	0.73	0.92	1-3/C-12	MCP	1	2X	
B-104	WATER EVAPORATOR AIR BLOWER	13871 ACFM @ 50" WC, 150 HP, VFD	150	460	0.85	0.9	124.33	77.05	146.27	183.81	1-3/C-4/0	250AF CB		3X +12X	
E-115A	LD TANK HEATER	25 kW EA / IMMERSION		480	1	0.95	25.00	0.00	25.00	30.11	1-3/C-8	60AF CB		2X	
E-115B	LD TANK HEATER	25 kW EA / IMMERSION		480	1	0.95	25.00	0.00	25.00	30.11	1-3/C-8	60AF CB			
E-117	AMINE STORAGE TANK HEATER	15 kW / IMMERSION		480	1	0.95	15.00	0.00	15.00	18.06	1-3/C-10	30AF CB		2X	1&2
MISC	ELECTRIC HEAT TRACING	EHT (ASSUMED)		480	1	0.95	45.00	0.00	45.00	54.19	1-3/C-4	125AF CB		2X	
MISC	LIGHTING	LIGHTING (ASSUMED)		480	0.9	0.95	80.00	38.75	88.89	107.04	1-3/C-1/0	150AF CB	4	5X	
K-101	INSTRUMENT AIR COMPRESSOR	ASSUMED	200	460	0.85	0.9	165.78	102.74	195.03	245.08	2-3/C-2/0	MCP	5	7X	
P-101	DILUTE SODA ASH PUMP	7.5 GPM @ 77 FT TDH, 3 HP / CENTRIFUGAL	3	460	0.85	0.9	2.49	1.54	2.93	3.68	1-3/C-12	MCP	1	2X	
P-102	PRE-TREATMENT TOWER CIRCULATION PUMP	500 GPM @ 110 FT TDH, 25 HP / CENTRIFUGAL	25	460	0.85	0.9	20.72	12.84	24.38	30.63	1-3/C-8	MCP	2	2X	3
P-103	RICH AMINE PUMP	1540 GPM @ 250 FT TDH, 150 HP / CENTRIFUGAL	150	460	0.85	0.9	124.33	77.05	146.27	183.81	1-3/C-4/0	MCP	5	7X	
P-104	PRIMARY STRIPPER BOTTOMS PUMP	1800 GPM @ 100 FT TDH, 75 HP / CENTRIFUGAL	75	460	0.85	0.9	62.17	38.53	73.14	91.90	1-3/C-2	MCP	4	5X	4
P-105	WATER WASH RECIRCULATION PUMP	500 GPM @ 110 FT TDH, 25 HP / CENTRIFUGAL	25	460	0.85	0.9	20.72	12.84	24.38	30.63	1-3/C-8	MCP	2	2X	
P-106	WATER EVAPORATOR BOTTOMS PUMP	1044 GPM @ 85 FT TDH, 40 HP / CENTRIFUGAL	40	460	0.85	0.9	33.16	20.55	39.01	49.02	1-3/C-6	MCP	3	3X	5
P-108	SECONDARY STRIPPER BOTTOMS PUMP	1044 GPM @ 170 FT TDH, 75 HP / CENTRIFUGAL	75	460	0.85	0.9	62.17	38.53	73.14	91.90	1-3/C-2	MCP	4	5X	
P-110A	LIQUID DESICCANT PUMP	520 GPM @ 140 FT TDH, 30 HP / CENTRIFUGAL	30	460	0.85	0.9	24.87	15.41	29.25	36.76	1-3/C-8	MCP	3	3X	
P-110B	LIQUID DESICCANT PUMP	520 GPM @ 140 FT TDH, 30 HP / CENTRIFUGAL	30	460	0.85	0.9	24.87	15.41	29.25	36.76	1-3/C-8	MCP	3	3X	
P-111	ADDITIVE INJECTION PUMP	1 GPM @ 150 FT TDH, 1 HP / DIAPHRAGM	1	460	0.85	0.9	0.83	0.51	0.98	1.23	1-3/C-12	MCP	1	2X	
P-112	ABSORBER COOLER PUMP	944 GPM @ 80 FT TDH, 40 HP / CENTRIFUGAL, VFD	40	460	0.85	0.9	33.16	20.55	39.01	49.02	1-3/C-6	100AF CB		2X+12X	6&7
P-115	CONDENSATE PUMP	100 GPM @ 120 FT TDH, 7.5 HP / CENTRIFUGAL	7.5	460	0.85	0.9	6.22	3.85	7.31	9.19	1-3/C-12	MCP	2	2X	
P-116	DESICCANT MAKE-UP PUMP	250 GPM @ 100 FT TDH, 20 HP / CENTRIFUGAL	20	460	0.85	0.9	16.58	10.27	19.50	24.51	1-3/C-10	MCP	2	2X	
P-117	STEAM DESUPERHEATER PUMP	50 GPM @ 68 FT TDH, 3 HP / CENTRIFUGAL, VFD	3	460	0.85	0.9	2.49	1.54	2.93	3.68	1-3/C-12	30AF CB		2X+6X	8.00
P-118	SODA ASH MAKE-UP PUMP	100 GPM @ 100 FT TDH, 5 HP / CENTRIFUGAL	5	460	0.85	0.9	4.14	2.57	4.88	6.13	1-3/C-12	MCP	1	2X	
P-119	LEAN AMINE PUMP	250 GPM @ 110 FT TDH, 15 HP / CENTRIFUGAL	15	460	0.85	0.9	12.43	7.71	14.63	18.38	1-3/C-10	MCP	2	2X	
P-120	V-101 PUMP	25 GPM @ 100 FT TDH, 3 HP / CENTRIFUGAL	3	460	0.85	0.9	2.49	1.54	2.93	3.68	1-3/C-12	MCP	1	2X	
T-110	SODA ASH STORAGE SILO / FEED SYSTEM	HEATER (10KW)		480	1	0.95	10	0.00	10.00	12.04	1-3/C-12	30AF CB		2X	
		FEED SYSTEM MOTOR	5	460	0.85	0.9	4.14	2.57	4.88	6.13	1-3/C-12	MCP	1	2X	9
E-82	EVAPORATIVE CONDENSER			460	0.85	0.9	34.00	21.07	40.00	50.26	1-3/C-4	MCP	3	3X	
LATER	WATER PUMPS			460	0.85	0.9	10.00	6.20	11.76	14.78	1-3/C-12	MCP	2	2X	
R40A/B	REGENERABLE DRIERS HEATER	HEATER (45KW)		480	1	0.9	45.00	0.00	45.00	54.19	1-3/C-4	100AF CB		2X	
LATER	CO2 INSTRUMENT GAS HEATER	HEATER (5KW)		480	1	0.9	6.00	0.00	6.00	7.23	1-3/C-12	30AF CB		2X	10
LATER	1200HP VFD COOLING PUMP	ASSUMED	3	460	0.85	0.9	2.49	1.54	2.93	3.68	1-3/C-12	MCP	1	2X	
LATER	1200HP VFD COOLING PUMP	ASSUMED	3	460	0.85	0.9	2.49	1.54	2.93	3.68	1-3/C-12	MCP	1	2X	11

Exhibit 3-12. Electrical Loads for CO_2 Capture Facility.

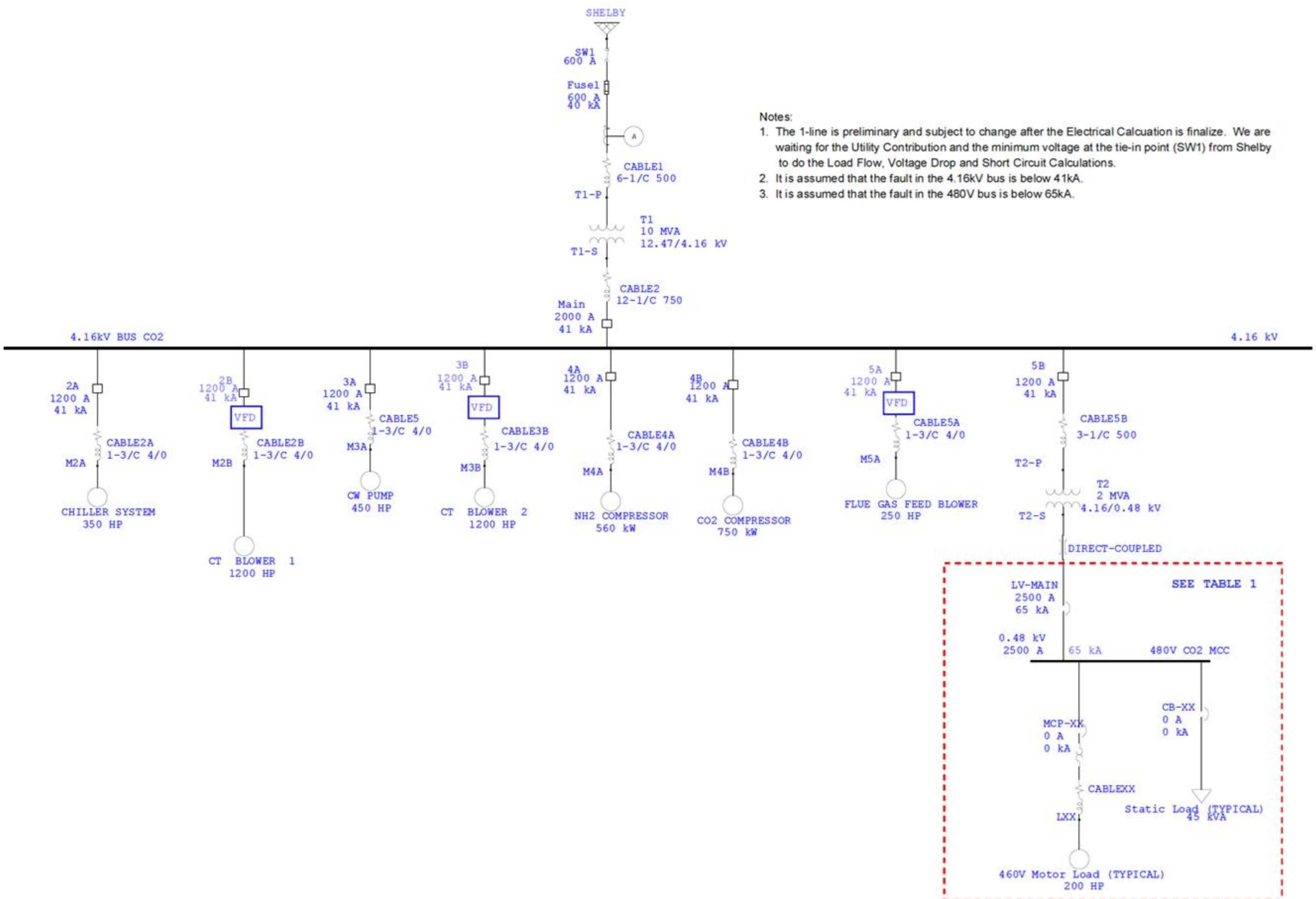


Exhibit 3-13. One Line Diagram for CO_2 Capture Facility.

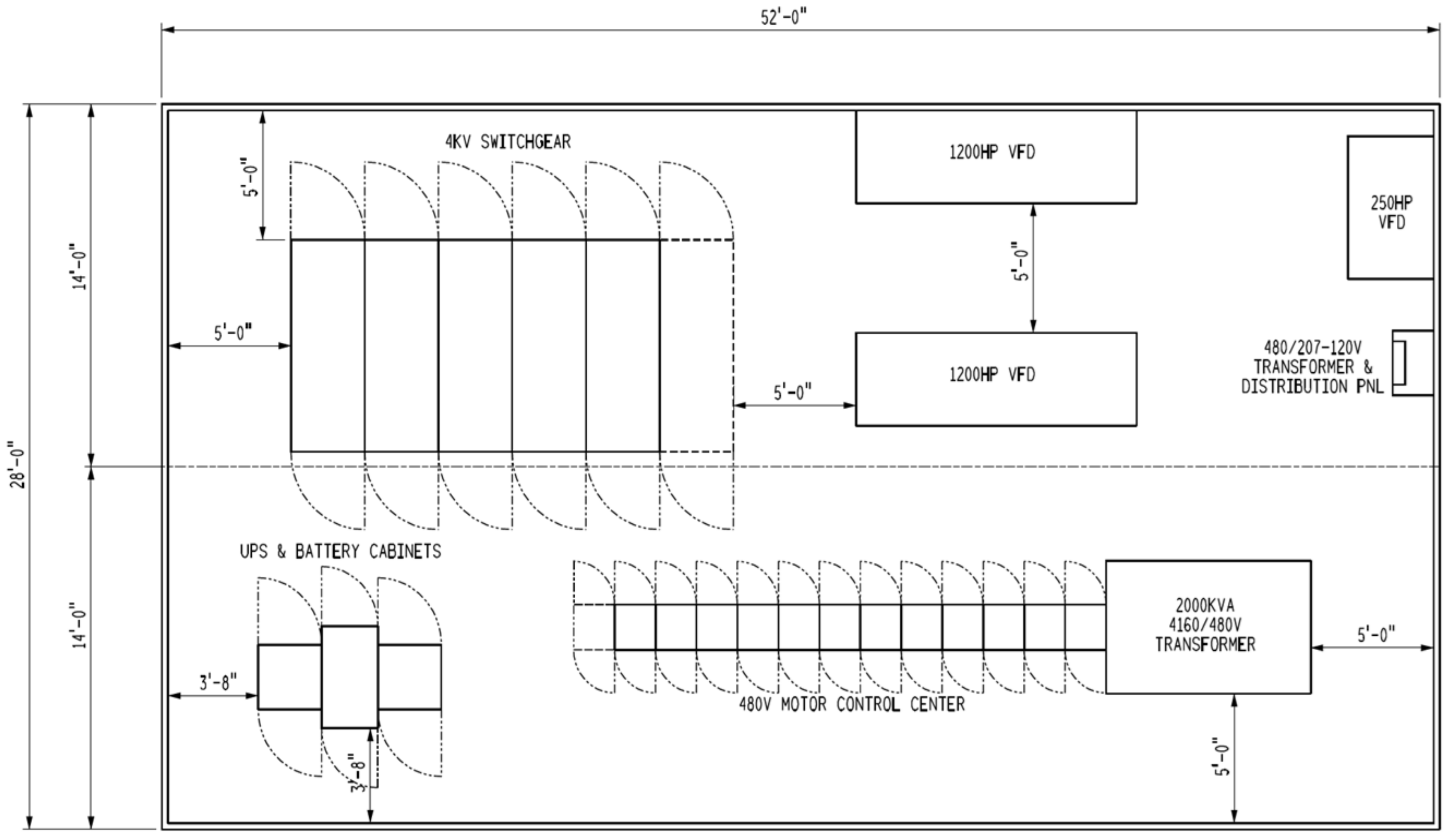


Exhibit 3-14. Power Distribution Center for CO_2 Capture Facility.

Other Components:

a) Office Building/Shed: The CO_2 capture facility will have a separate support building from the Trimble County facilities. The support building will contain the control room, laboratory, break room, and restrooms. Based on UKy-CAER's current experience with their 0.7 MWe CCS, a single wide trailer (60 x12 feet) does not provide sufficient space. For the proposed project at the Trimble County site, a double-wide trailer is specified.

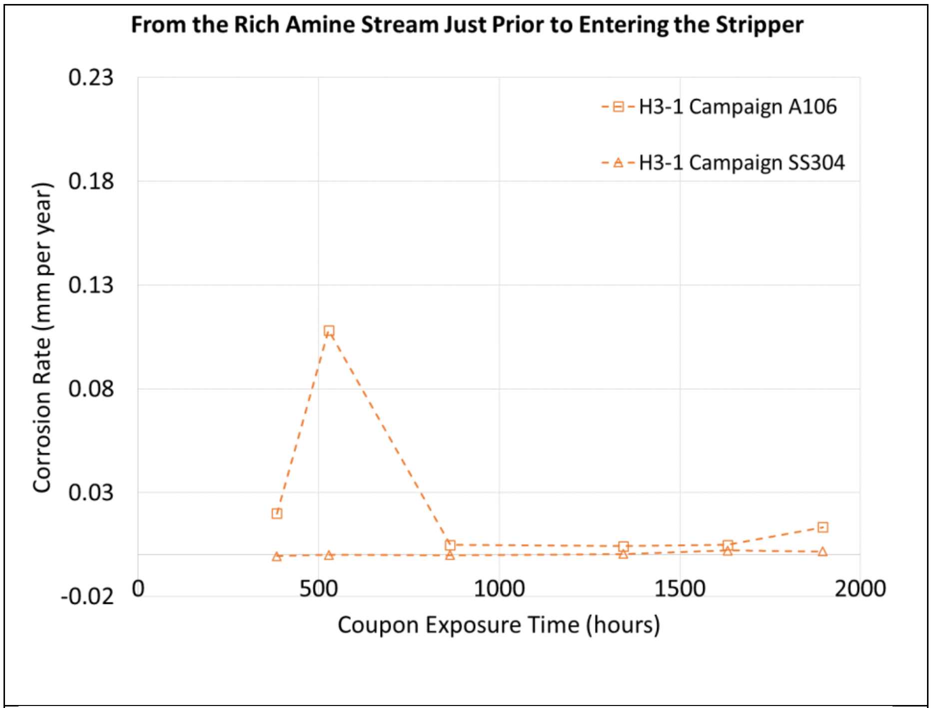
b) CEMS: CEMS equipment will be used to monitor the gas compositions at various points in the CO_2 capture process. For the proposed system design, a 5-train system is required. The continuous testing mode of Trains 1, 2 and 3 is required to constantly monitor the composition of the flue gas as it passes through the system and determine the capture efficiency. Train 4 monitors the gas composition on a periodic basis (once every 15 minutes) at three different locations. Train 5 is included as a spare for redundancy or if an additional sample location is needed during testing.

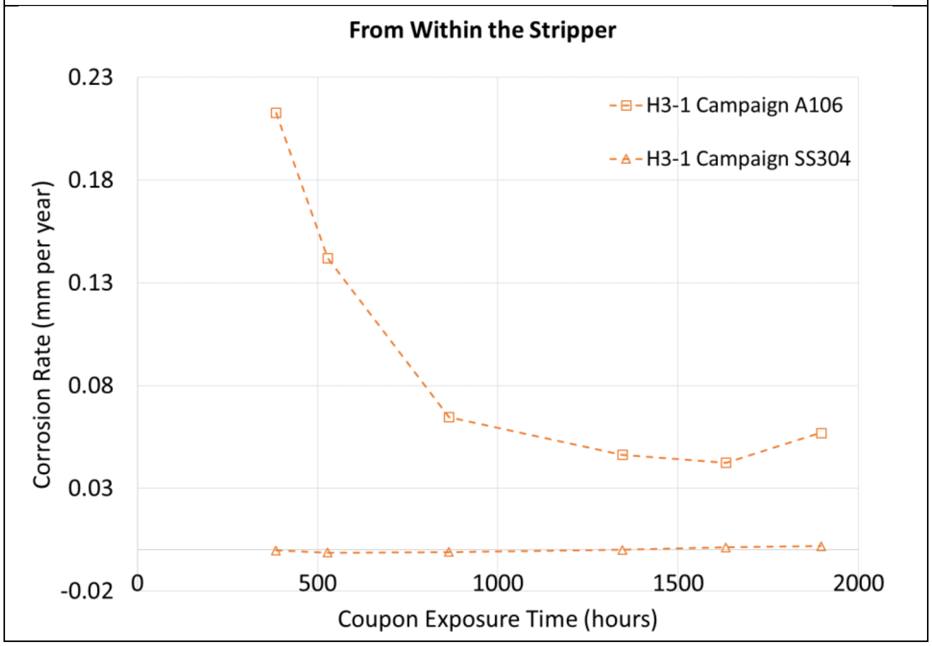
   Control Analytics, Inc. was contacted to support the design and costing of the CEMS equipment. Based on the suggestion of the vendor, dilution probes were selected for the testing of the gas streams. Please note that in this approach, the O_2 in the gas stream is determined by a zirconium oxide analyzer on the undiluted gas stream at the probe. This approach mitigates problems associated with condensation in the sample lines and allows for the periodic testing of several probes with a single set of analyzers. The quote received includes all probes, tubing, analyzers, controllers and equipment racks.

   The CEMS equipment will be placed in a separate shed equipped with climate control. Control Analytics provided a cost for the shed, which validated the allowance assigned by WorleyParsons.

Construction Material Consideration:

For post-combustion carbon dioxide capture operations at coal-fired power plants, capital expenditures for process units such as the absorber and stripper, as well as heat exchangers, and piping make up a significant percentage (approximately 60-70%) of the total cost of the process. Due to this cost, corrosion is an obvious concern as it could necessitate unit maintenance or even replacement in short periods of time. The findings from the corrosion study conducted under DE-FE0007395, shown in **Exhibit 3-15**, indicated that utilization of less expensive metals as materials of construction is a promising option for larger scale CO_2 capture projects. While only one absorber corrosion coupon location was examined in the study, its location in the column was near the temperature bulge (highest temperature location in the absorber) and at elevated carbon loading. Investigating the use of carbon steel as a material of construction on large pilot scale demonstration units could make CCS more affordable and provide utility companies with further real-world data for future design considerations. Accordingly, for the proposed large pilot scale unit, stainless steel will be used for the stripper column and other components with wet surface temperatures above 80 °C and carbon steel will be used for process units and piping that see lower temperatures, $\leq$ 80 °C.


From the Rich Amine Stream Just Prior to Entering the Stripper
0.23
0.18
0.13
0.08
0.03
-0.02
Corrosion Rate (mm per year)
0
500
1000
1500
2000
Coupon Exposure Time (hours)
H3-1 Campaign A106
H3-1 Campaign SS304


From Within the Stripper
0.23
0.18
0.13
0.08
0.03
-0.02
Corrosion Rate (mm per year)
0
500
1000
1500
2000
Coupon Exposure Time (hours)
H3-1 Campaign A106
H3-1 Campaign SS304

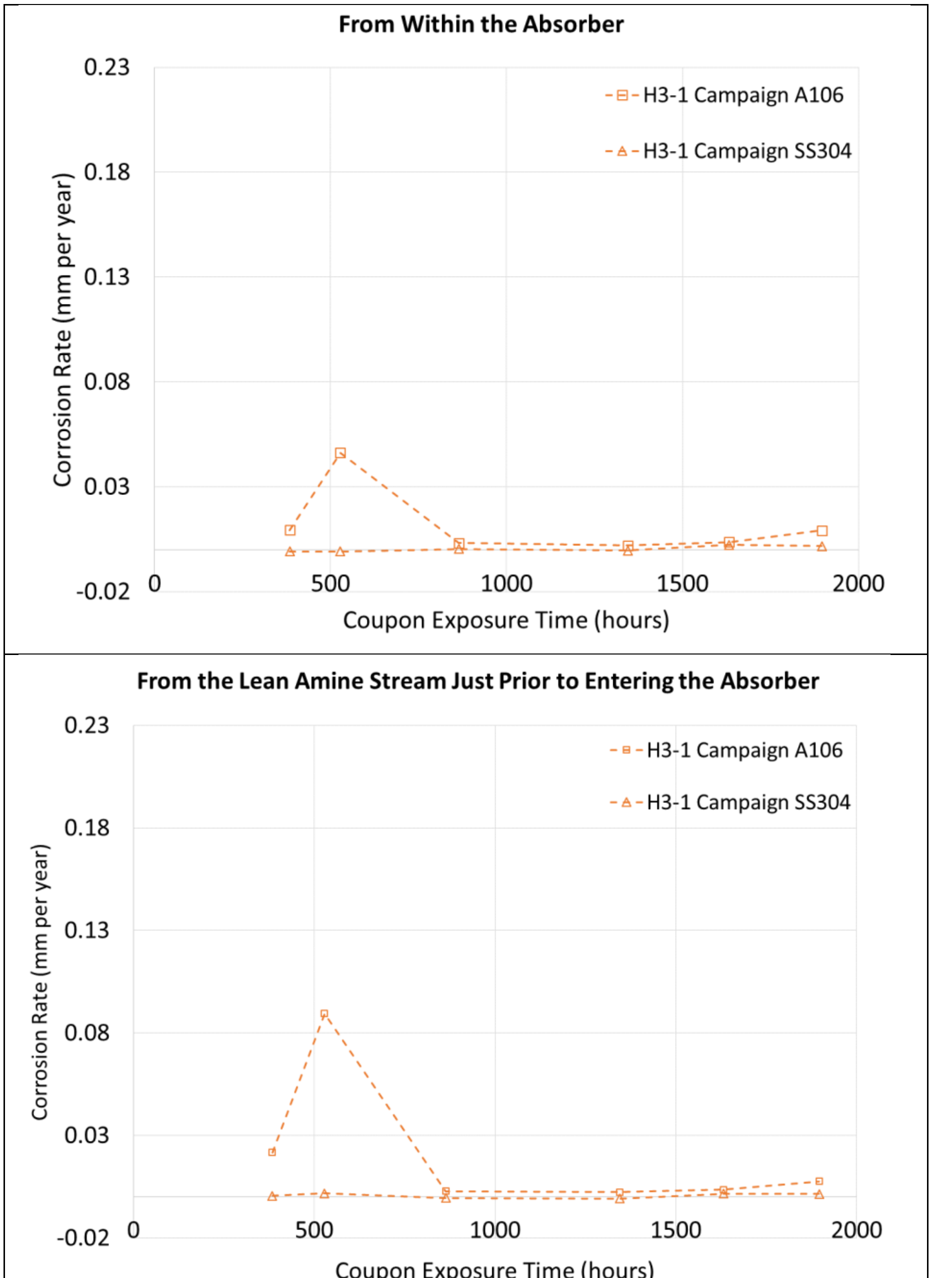


Exhibit 3-15. Corrosion Data from the H3-1 Campaign at the 0.7 MWe Small Pilot Scale CCS.

Cost Estimate:

KMPS and WP used their in-house engineering and cost model and database to conduct a Class III cost analysis as defined in "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries."

- Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to

40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists.

- Estimating Methods Used: Class 3 estimates usually involve more deterministic estimating methods than stochastic methods. They usually involve a high degree of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less significant areas of the project.

- Expected Accuracy Range: Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed these in unusual circumstances.

- With the above information used as a basis WP determined the cost of the 10 MWe CCS including the BOP to be ~$60,000,000.

Draft Operating Procedures and Safety Protocols:
In addition to the pilot design, UKy-CAER began development of operating procedures for the 10 MWe unit as well as safety protocols based on installation, operation and maintenance on the 0.7 MWe small pilot scale unit. Over 40 standard operating procedures (SOPs) have been developed through UKy-CAER's work on the small pilot scale, most of which will still be utilized during operation of the large pilot scale CCS.

These SOPs include:
- Startup
- Shutdown
- Normal Operation
- Winter Operation
- Instrument Calibration
- Mechanical Repairs
- Safety Protocols
- Waste and Material Handling

Below, the standard startup and shutdown procedures for safe operation are outlined. Startup and shutdown must follow these steps in order to prevent interlocks from tripping the system off or to prevent unsafe conditions:

Startup Procedure:
1) Start liquid desiccant loop (blowers first, then liquid circulation).
2) Start cooling water loop.
3) Start pre-treatment loop.
4) Start amine loop and balance the flows to each column.
5) Once all other loops are operational, then bring up the steam loop to heat system.
6) After steam is on and all loops are circulating, then turn on flue gas to the CCS.

7) Turn on the water wash for absorber and secondary stripper.

Shutdown Procedure:

1) Turn off flue gas to system.
2) Stop pretreatment loop circulation.
3) Shutdown steam.
4) Turn off desuperheater pump.
5) Stop amine liquid circulation.
6) Stop liquid desiccant circulation.
7) Stop cooling water circulation.
8) Stop liquid desiccant system blowers (B-103 and B-104).

Safety Protocols:

At the University of Kentucky (UK), the health and safety of people and the environment are managed like any key resource – by integrating every process with good management and leadership techniques. In order to meet our objectives, every employee is committed to working in a safe, environmentally conscientious manner. All employees are expected to take personal responsibility for their own safety, to be conscious of the safety of others, and to help identify potential hazards so that they can be corrected. Moreover, continuous evaluations of our processes occur, identifying ways to minimize our impact on the environment by reducing and recycling waste.

Safety is an integral part of UK's institution. The Division of EH&S is charged with providing UK employees with educational programs, technical assistance, and other services in related areas. All employees, upon starting employment at UKy-CAER, undergo a complete general safety training regimen that includes classes on lab safety, which includes personal protective equipment (PPE), hazardous waste, fire extinguisher use and respirator use. The general safety training program also requires all employees to pass a test upon completion of each class and to repeat yearly refresher classes, as a minimum. In addition to the general safety classes required for all employees, training classes specific to each employees essential job functions are required. For work on the UKy-CAER small pilot scale CCS (and subsequently the large pilot scale CCS project discussed in this report), the following safety training classes are mandatory:

- OSHA 30 Hour Training Program
- First Aid Certification
- LG&E/KU's Passport Safety Training
- Ammonia Awareness
- Lock out/Tag Out
- Ladder Safety

Additionally, as with any effective safety program, the University of Kentucky has a multitude of documents that are vital resources for maintaining a safe working environment. The most beneficial documents that specifically cover items pertaining to the operation and maintenance of amine based post-combustion CCSs are listed below with short content descriptions.

- Employee Safety Handbook: This Employee Safety Handbook is intended for **all** UK employees, full time and part time, regular and temporary, and all other UK employment categories (STEPS, student workers, etc.). It has been developed to provide employees, with answers to general questions concerning EH&S in the workplace.

- Chemical Hygiene Plan: Defines work practices and procedures to help ensure that laboratory workers at the University of Kentucky are protected from health and safety hazards associated with hazardous chemicals with which they work.

- Emergency Action Plan (EAP): Each department at the University must have a building emergency action plan to provide employees and visitors during and emergency. The EAP was developed for utilization with small and large pilot scale CCS using a model plan from the UK Office of Crisis Management and Preparedness.

- Spill Prevention, Control and Countermeasure Plan: Due to the use of potentially hazardous materials, a detailed plan to provide standards for the storage and usage of these components in order to prevent discharge was developed in an effort to protect employees and the University from violations of applicable laws and any associated fines.

Finally, safe operation will be conducted in accordance with all LG&E, and Trimble County policies and procedures, including the creation and practice of the following programs, which are already in place and being practiced at the small pilot scale CCS: Lock Out/Tag Out program, Chemical Inventory, Contractor Management, Personnel Training, Drug Testing, Laboratory and Hood Inspections, Equipment Preventative Maintenance, Laboratory Management, Chemical Hygiene and Waste Management.

4) TEA

4.1 TEA Methodology

The TEA, completed in accordance with the project requirements, compares the proposed UKy-CAER process with an advanced solvent, H3-1 in this case, to the U.S. DOE NETL Reference Supercritical Case (Case 12) [3]. The results compare the energy demand for post-combustion CO_2 capture and the net higher heating value efficiency of the power plant integrated with the post-combustion capture (PCC) plant. A levelized cost of electricity assessment was performed to assess the lifecycle costs of the options presented in the study.

Exhibit 4-1. U.S. DOE NETL RC 12 Design Basis [3].

Parameter	Value
CO_2 Removal from Flue Gas	>90% of carbon from fuel (net of CO_2 recycled to boiler)
CO_2 Purity	>95 vol %
CO_2 Delivery Pressure	2,215 psia
CO_2 Delivery Temperature	124 °F
Cost of CO_2 Transportation, Storage and Monitoring	$4.05/ton CO_2
Steam Extraction Location	Medium to Low Pressure Steam Turbine Crossover Line

Process Modelling: A team from Electric Power Research Institute (EPRI), led by Dr. Abhoyjit Bhown, working independently from the UKy-CAER team, constructed an Aspen Plus® [1] model of a complete power plant with the proposed UKy-CAER CCS. The team also completed the simulation portion of the preliminary TEA, generating the heat and mass balance stream table and sizing major equipment such as columns and heat exchangers, with input from Hitachi and UKy-CAER. The EPRI model was based on experimental results supplied by Hitachi including testing data collected at the NCCC located at Wilsonville, AL, additional lab-scale thermodynamic data collected at UKy-CAER, and testing data from the UKy-CAER 0.7 MWe scale CCS, in operation since the spring of 2015. A team from WP, led by James Simpson, also working independently from UKy-CAER, completed the cost analysis portion of the TEA using input directly from EPRI and in accordance with the guidelines set forth per DE-FOA-0001190, Attachment 3 (p. 116) [6], Answer 6 from Down-Select Question and Answer (QA) Post on 1/28/2016 [5], and follows the analysis documented in the U.S. DOE NETL Cost and Performance Baseline [3]. Additionally, a 30 wt % MEA process was simulated as the reference scenario to illustrate the advantages of the UKy-CAER heat-integrated process only.

The UKy-CAER CCS commercial scale plant model, originally created by Ron Schoff from EPRI in Aspen Plus® [1] in 2011 [1], was based on the reference plant from U.S. DOE NETL Reference Case 12 (RC 12) [3] keeping the coal feed rate constant, then revised in 2014, and verified in 2015 using 500-hr experimental data collected from UKy-CAER's 0.7 MWe small pilot unit installed at KU E.W. Brown Generating Station under cooperative agreement of DE-FE0007395. During the simulation and cost estimate, (1) Mellapak 250X was used for all columns associated with the carbon dioxide reaction, while 118 ft. of packing was applied for the absorber, and 75 ft. and 72 ft. of packing was assumed for the primary stripper, and secondary stripper, respectively; (2) 75% flooding point was selected to determine the column diameter; and (3) a minimum approach temperature of 15 °F (average 16-20 °F) was applied to all heat exchangers to simulate real-world equipment selection where low approach temperatures (5-10 °F) are commonly assumed for other CCS technologies, even though this has a negative effect on the CCS energy efficiency.

From the results of these efforts, EPRI and WP developed the LCOE estimates, compared the COE to a reference MEA case, and also evaluated the COE increase relative to U.S. DOE NETL goals. EPRI also estimated the expected plant equivalent availability based on estimated planned and scheduled outage rates. The impact of fuel costs, CO_2 compression technologies, solvent degradation and heat integration configurations on system performance and process economics were determined for each process to aid in the cost comparisons.

Equipment Sizing Methodology, Cost Estimating, and Financial Analysis Methodology:
The following describes the approach to sizing the major equipment in the CO_2 capture process.

Column Towers: Column towers, such as the CO_2 absorber and primary stripper, were identified as vertical towers with structured packed bed internals for the gas-liquid interface. Tower diameters are based on 75% of flooding velocity. Packing height is based on various correlations for unit-heights of mass-transfer. Total column height incorporates packing height along with any of the following if appropriate: sump depth, freeboard space coupled with mist eliminators and flow redistributors. No sparing was used and the number of units in operation is based on generic rules-of-thumb for column sizes. Design conditions are a standard function of operating conditions; typically 50 psia (3.4 bar) above operating pressure and 50 °F (27.7 °C) above operating temperature. All materials were specified as carbon steel except for the upper sections of the primary stripper, which was specified as 304 stainless clad.

Heat Exchangers: All heat exchangers are specified as plate and frame other than the reboiler, the reclaimer, and the secondary heat recovery exchanger, which has been identified as shell and tube type due to phase change involved during heat transfer between hot and cold streams. All heat exchangers were sized utilizing rate-based traditional log-mean temperature equations where the overall heat transfer coefficient was selected based on past experience and vendor quotes. Design conditions are a standard function of operating conditions; typically 50 psia (3.4 bar) above operating pressure and 50 °F (27.7 °C) above operating temperature. All materials were specified as stainless steel except those are operated below 60 °F.

Pumps: Pumps were sized based on dynamic head values that took column heights and friction pressure drop into account. Fluid properties and head values were used to calculate required motor power via traditional calculation procedures. As noted above, design conditions are a standard function of operating conditions and all materials of construction were specified as stainless steel for fluid temperatures greater than 70 °F, with the exception of carbon steel for the rich amine pump.

Cooling Tower: The basic sizing criteria for a cooling tower is the approach temperature, range and cooling duty. For this study, the cooling tower approach and range were kept the same as those used in U.S. DOE NETL Bituminous Coal Baseline study for comparison purposes. The cooling duty was based on the total cooling requirement for the power block and process plant. The GEA Group (Process Technology Firm) proprietary cooling tower sizing program was used to estimate the cooling tower size and fan power requirement. The liquid to air ratio for the cooling tower was selected to match the value used in the U.S. DOE NETL Baseline study. The packing of cooling tower is assumed to be film type.

It should be noted that the 8.5 °F (4.7 °C) of cooling tower approach temperature used in the U.S. DOE NETL Baseline study is very aggressive at 59 °F (15 °C) DB/60% RH ambient. Although this design approach temperature is achievable, it results in a very large cooling tower size and high capital cost. In addition, there is no performance improvement with this tight cooling tower approach because the terminal temperature difference (TTD) of the steam turbine condenser is at 21 °F (11.7 °C), which is much higher than the typical value for a cooling tower application. From both performance and economical points of view, about 18 °F (10 °C) approach temperature for the cooling tower and approximately 10 °F (5.6 °C) condenser TTD are more reasonable and optimal design parameters for the power plant cooling system cost estimating methodology.

Capital Costs: Capital costs were developed using a combination of commercial capital cost estimating software, factored equipment estimates, and WP in-house parametric models supplemented by WP's extensive in-house equipment cost database.
Aspen Plus® [1] In-Plant Cost Estimator software was used to develop the initial costs for most of the major equipment in the UKy-CAER CO_2 removal process. This includes reactor vessels, absorbers, and other specialized process equipment. Initial costs were subsequently scaled parametrically based on the current equipment list. The associated capital costs for bulk materials

and installation were developed by applying a factor to the established equipment cost to derive a total installed cost. Factors vary by type of equipment, metallurgy, and complexity, and conform to WPs standards.

Costs for other equipment and balance of plant items were developed via scaling and/or parametric modelling based on key project and equipment parameters. These were the primary methods used to estimate the capital costs of balance of plant equipment and systems whose costs are impacted by the change in CO_2 removal process from that used in Case 12 of the U.S. DOE NETL Bituminous Coal Baseline Study. Costs not impacted by the change in CO_2 removal process, and whose performance characteristics did not change from the U.S. DOE NETL Study remained the same as in the updated (to June 2011 dollars) costs for RC 12.

The total capital cost estimates include the cost of equipment, freight, and materials and labor for equipment installation and erection; materials and labor for construction of buildings, supporting structures, and site improvements; engineering, construction management, and start-up services (Professional Services); and process and project contingency. The estimate excludes owner's costs and is provided as "overnight" costs; that is, escalation to period of performance is excluded. Home office expenses and other owner's costs were based on an allocation included in the COE analysis.

Operating and Maintenance Cost Estimates: The operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the plant over its expected life. These costs include: Operating Labor and Maintenance (Material and Labor), Administrative and Labor Support, Consumables, Waste Disposal, Fuel, Co-Product or By-Products credit (that is, a negative cost for any byproducts sold).

Transport Storage and Monitoring: CO_2 transport storage and monitoring costs were estimated based on the quantity of CO_2 captured and the TS&M unit cost ($10.00 per ton of CO_2) used in the U.S. DOE NETL Bituminous Coal Baseline study RC 12.

Finance Structure, Discounted Cash Flow Analysis, and Cost of Electricity: The methodology and assumptions for the financial analysis are consistent with those presented for use on updating the base cases for the U.S. DOE NETL Bituminous Coal Baseline Report.

4.2 TEA Findings

The high-level performance results for the UKy-CAER CCS process with advanced solvent case are shown in **Exhibit 4-2**. In summary, the proposed project produces an extra 69 MW of generation, over the reference 550 MW, with the same coal feed rate as U.S. DOE NETL RC 12. Maintaining a constant coal feed rate with RC 12, allows the boiler size and conventional emission control devices to be kept the same. With respect to the UKy-CAER commercial scale plant size with advanced solvent, this results in a 12% electricity output increase in comparison to RC 12 (618.7 MW, net for the UKy-CAER CCS case and 550 MW, net for RC 12). The overall plant efficiency is increased with the UKy-CAER CCS by 13% (32.0% for the UKy-CAER CCS case and 28.4% for RC 12, HHV basis) because the UKy-CAER CCS uses two heat pump loops to recover the low quality heat conventionally rejected to the environment via cooling water, including heat recovered from the primary stripper overhead condenser and CO_2 compressor inter-stage coolers. The heat-integration and application of a second generation advanced solvent lowers energy consumption for CO_2 capture to 1030 Btu/lb-CO_2 as compared to 1530 Btu/lb-CO_2 in RC 12. The study also shows 50.8% less heat rejection associated with the carbon capture system, decreased from 3126 MBtu/hr in Case 12 to 1537 MBtu/hr for the UKy-CAER process.

The key factors contributing to the reduction of LCOE with the UKy-CAER CCS with an Advanced Solvent were identified as the CO_2 partial pressure increase at the flue gas inlet, thermal integration of the process and performance of the advanced solvent.

Exhibit 4-2. U.S. DOE NETL RC 12 Performance Summary [3] and UKy-CAER CCS with an Advanced Solvent Performance Summary Prepared by EPRI.

	RC 12	**UKy-CAER Advanced Solvent Case**
POWER SUMMARY		
Steam Turbine Pwer (Gross at Generator Terminals, kWe)	662,800	714,000
TOTAL (STEAM TURBINE) POWER, (kWe)	662,800	714,000
AUXILIARY LOAD SUMMARY (kWe)		
Coal Handling & Conveying	510	510
Pulverizers	3,850	3,850
Sorbent Handling & Reagent Preparation	1,250	1,260
Ash Handling	740	740
Primary Air Fans	1,800	1,810
Forced Draft Fans	2,300	2,770
Induced Draft Fans	11,120	10,700
SCR	70	70
Baghouse	100	100
Wet FGD	4,110	4,150
CO_2 Capture Systems Auxiliaries	20,600	20,570
CO_2 Compression	44,890	30,990
Miscellaneous Balance of Plant[2, 3]	2,000	2,000
Steam Turbine Auxiliaries	400	400
Condensate Pumps	560	800
Circulating Water Pump	10,100	7,590
Ground Water Pumps	910	680
Cooling Tower Fans	5,230	3,930
Transformer Losses	2,290	2,470
TOTAL AUXILIARIES (kWe)	**112,830**	**95,400**
NET POWER (kWe)	**549,970**	**618,730**
Net Plant Efficiency (HHV)	28.4%	32.0%
Net Plant Heat Rate (Btu/kWhr HHV)	12,002	10,668
Net Plant Efficiency Lower Heating Value (LHV)	29.5%	33.2%
Net Plant Heat Rate (Btu/kWhr LHV)	11,576	10,290
COOLING TOWER DUTY (10^6 Btu/hr)		
Condenser Duty	1,646	2,051

CO_2 Capture System Duty	3,126	1,537
TOTAL COOLING DUTY (10^6 Btu/hr)	4,772	3,588
CONSUMABLES		
As-received Coal Feed (lb/hr)	565,820	565,820
Limestone Sorbent Feed (lb/hr)	57,245	57,835
NOTES: 1. HHV of as-received Illinois #6 coal is 11,666 Btu/lb (27,135 kJ/kg) 2. Boiler feed pumps are turbine driven 3. Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads		

In **Exhibit 4-3**, the comparison of operating parameters and costs between the UKy-CAER CCS process with an Advanced Solvent case and U.S. DOE NETL reference cases are presented. For the UKy-CAER case, the LCOE is $161.93/MWH compared to $186.74/MWh, in 2011 dollars for RC 12, as listed in "Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases" used as per DE-FOA-0001190, Attachment 3 and Answer 6 from Down-Select QA Post on 1/28/2016. [5]

A summary of the key advantages of the advanced case for LCOE and other economic factors compared to the U.S. DOE NETL RC 12:

- A lower COE by $19.56 (including CO_2 TS&M costs), a 13.3% reduction, equivalent to a 29.5% incremental reduction compared to U.S. DOE NETL RC 12
- A lower LCOE by $24.81/MWh, also a 13.3% reduction, equivalent to a 29.5% incremental reduction compared to U.S. DOE NETL RC 12
- A lower cost of CO_2 captured by $12.96/tonne CO_2 (including CO_2 TS&M costs), a 19.5% reduction compared to U.S. DOE NETL RC 12
- A lower cost of CO_2 avoided by $28.10/tonne CO (including CO_2 TS&M costs)$_2$, a 29.3% reduction compared to U.S. DOE NETL RC 12

The comparison in operating parameters and costs between the DOE Reference Case 11 (RC 11) and RC 12, and the UKy-CAER CCS process with an advanced solvent is shown in **Exhibit 4-3**.

Exhibit 4-3. Comparison of Operating Parameters and Costs between the UKy-CAER CCS Process with an Advanced Solvent Case and U.S. DOE NETL Reference Cases Prepared by EPRI.			
	RC 11	**RC 12**	**UKy-CAER Advanced Solvent**
OPERATING PARAMETERS			
Net Plant Output, MWe	550.0	550.0	618.7
Net Plant Heat Rate, Btu/kWh HHV (kJ/kWh)	8,686 (9,164)	12,002 (12,663)	10,669 (11,256)
CO_2 Captured, lb/MWh (kg/MWh)	0 (0)	2,197 (996)	1,923 (872)
CO_2 Emitted, lb/MWh net (kg/MWh net)	1,768 (802)	244 (111)	249 (113)
COSTS			
Risk	Low	High	High
Capital Costs (2011$/kW)	1,981	3,563	3,039
Total Overnight Cost (2011$/kW)	2,452	4,391	3,754
Bare Erected Cost	1,622	2,744	2,354
Home Office Expenses	148	252	216
Project Contingency	211	446	374
Process contingency	0	121	94
Owners Costs	470	828	715
Total Overnight Cost (2011$x1,000)	1,348,511	2,415,011	2,322,340
Total As Spent Capital (2011$/kW)	2780	5006	4279
Annual Fixed Operating Costs ($/yr)	38,828,811	64,137,607	62,406,060
Variable Operating Costs ($/MWh)	7.63	13.35	12.47
Fuel			
Coal Price ($/ton)	68.60		

Exhibit 4-4. Comparison and Breakdown of COE between the UKy-CAER CCS Process with an Advanced Solvent Case and U.S. DOE NETL Reference Cases Prepared by EPRI.

	RC 11	RC 12	UKy-CAER with Advanced Solvent
COE (\$/MWh, 2011\$)	80.95	147.27	127.71
COE (\$/MWh, 2011\$), Omitting CO_2 TS&M Costs	80.95	137.29	118.97
CO_2 TS&M Costs		9.99	8.74
Fuel Costs	25.54	35.29	31.37
Variable Costs	7.74	13.21	11.54
Fixed Costs	9.48	15.66	13.55
Capital Costs	38.20	73.13	62.51
LCOE (2011\$/MWh)	102.65	186.74	161.93
Cost of CO_2 Captured (\$/tonne CO_2), Including CO_2 TS&M Costs		66.57	53.61
Cost of CO_2 Avoided (\$/tonne CO_2), Including CO_2 TS&M Costs		95.96	67.86
Cost of CO_2 Captured (\$/tonne CO_2), Omitting CO_2 TS&M Costs		56.53	43.58
Cost of CO_2 Avoided (\$/tonne CO_2), Omitting CO_2 TS&M Costs		81.49	55.17

A further breakdown of the cost quantities that comprise the COE is shown between the UKy-CAER CCS with an advanced solvent and the two U.S. DOE NETL base cases in **Exhibit 4-5**.

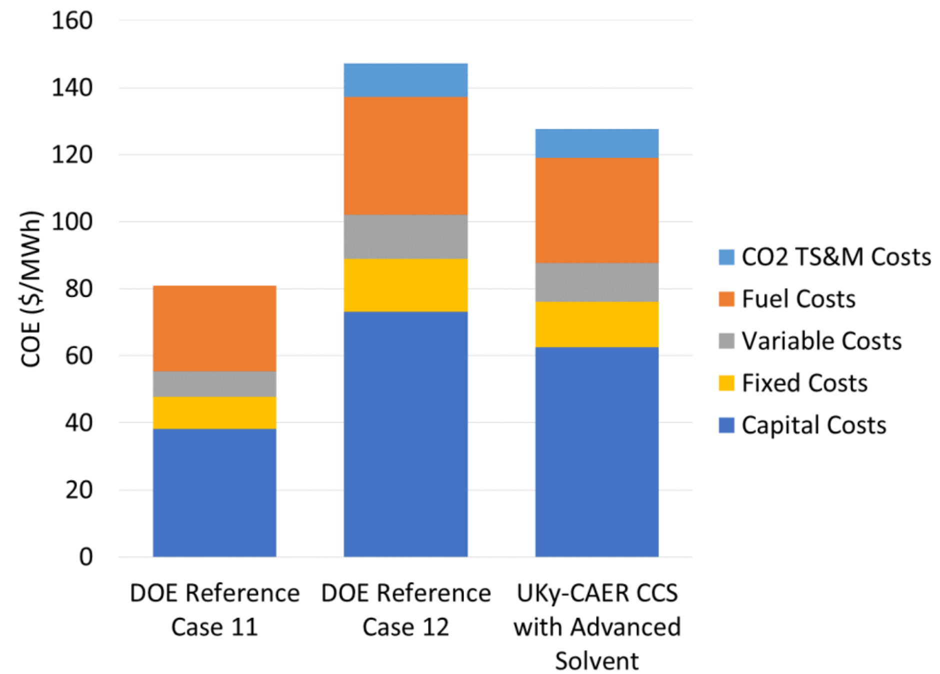


Exhibit 4-5. Comparison and Breakdown of COE (including CO_2 TS&M costs) for UKy-CAER CCS with an Advanced Solvent and U.S. DOE NETL Cases Prepared by EPRI.

The results from this TEA show that the proposed technology can be investigated further as a viable alternative to conventional CO_2 capture technology. The UKy-CAER CCS recovers heat, typically rejected to the cooling water or the environment from three locations: the steam-driven (primary) stripper overhead condenser, the lean amine polisher, and the compressor inter-stage coolers. Relatively high-grade heat recovered from the primary stripper overhead stream and compressor inter-stage hot streams, along with assistance from the secondary stripper overhead stream, are used to increase the temperature of the rich stream prior to entering the lean/rich exchanger, thereby boosting the lean solution temperature for CO_2 stripping in the secondary stripper. Additionally, in the UKy-CAER CCS, the secondary stripper also acts as a direct-cooling device for the lean solvent prior to being routed to the absorber polishing exchanger. In total 580.6 MBtu/hr is recovered from the CO_2 capture system to reduce the fresh steam extraction for solvent regeneration.

5) EH&S Assessment

An initial EH&SAssessment for the large pilot scale post-combustion CO_2 capture system at LG&E Trimble County Generating Station in Bedford, KY was conducted SMG, Lexington, KY in March 2016.

The EH&S Assessment was conducted to evaluate a conceptual plan for a large pilot scale (10 MWe equivalent slipstream), post-combustion CCS proposed by the UKy-CAER and to be installed at the LG&E Trimble County Generating Station near Bedford, KY. The assessment was funded by a grant from the U.S. Department of Energy, National Energy Technology Laboratory (Project Number DE-FE0026497). The objective was to determine if there were any unacceptable EH&S concerns that may prevent implementation or environmental permitting of the large pilot scale CCS. The scope of the assessment was limited to evaluation of proposed plans and information available from the UKy-CAER, LG&E, advanced solvent suppliers, Electric Power Research Institute and literature review for similar facilities and materials used. Preliminary process design and operation information was obtained from research conducted by the UKy-CAER. This information included: process flow diagrams; anticipated operating parameters; estimated raw material storage and consumption rates; data obtained from a similar, smaller scale (0.7 MWe) pilot plant at the KU E.W. Brown Generating Station near Harrodsburg, KY; and estimations for air emissions, wastes generated, wastewater discharges and human exposure to potentially toxic compounds used or generated.

The preliminary design for the large pilot scale CCS has flue gas pretreatment, CO_2 absorption with an aqueous, amine based solvent (advanced amine solvent) and CO_2 stripping modeled from UKy-CAER's 0.7 MWe pilot plant at E.W. Brown Generating Station. The process design includes a unique heat integration process combined with two-stage stripping. UKy-CAER will use and evaluate the performance of an advanced, proprietary scrubbing solvent (Hitachi H3-1 or other solvent with EHS properties similar to MEA. The H3-1 solvent is proprietary and its specific formulation was not available. Available material safety data sheets (MSDSs) for Hitachi H3-1 and MEA indicate no carcinogens identified by the International Agency for Research on Cancer (IARC), American Conference of Governmental Industrial Hygienists (ACGIH), Occupational Safety and Health Administration (OSHA) or National Toxicology Program (NTP) and no constituents on United States Environmental Protection Agency (U.S. EPA) Consolidated List of Chemicals Subject to the Emergency Planning and Community Right to Know Act (EPCRA), Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and Section 112 (r) of the Clean Air Act (CAA).

Exposure to the scrubbing solvent will be the primary employee health hazards from raw material handling, since the solvent is identified as corrosive and an irritant in concentrated form. In process, the solvent will be mixed with water, reducing the hazard, but employees will need to be aware of potential impacts (e.g., eye burns, skin irritant and inhalation irritant) and wear appropriate protective equipment. The remaining raw materials (e.g., sodium carbonate, calcium chloride and minor amounts of maintenance items) do not represent substantial health concerns, but appropriate precautions will need to be used to avoid accidents and injuries. Safety hazards will include potential exposure to noise, temperature, steam, pressure vessels, heights, slips, trips and falls, but these are not unusual for an industrial facility and can be managed with appropriate precautions to avoid accidents and injuries.

MEA and known degradation products, used as surrogates for the advanced solvent, were determined to pose little human toxicological or ecological risk in their raw material form. Estimated degradation products were also evaluated, including formation of nitrosamines, which are classified as potent human carcinogens. Generation of significant quantities of nitrosamines was deemed unlikely when using MEA based on data collected from the 0.7 MWe small pilot CO_2 capture system. Advanced amine solvents that contain more complicated amines may have a greater potential for nitrosamine formation and liberation. The actual degradation products of these solvents and their respective concentrations, as well as possible control measures, will need to be identified during preliminary design and operation of the large pilot scale CCS. From this information, a quantitative risk assessment can be completed and applied to a larger scale operation.

As presented in **Exhibit 5-1**, the system will release small quantities of the scrubbing solvent and associated degradation products after emission control units. Available information suggests that process air emissions will be below Kentucky permitting thresholds for criteria and hazardous air pollutants. Emissions generated from this proposed pilot plant do not appear to present any imminent environmental or health and safety concerns. Emissions from the large pilot scale CCS have been calculated to be an insignificant activity, as defined in 401 KAR 52:020 for CAA, Title V air permits, and therefore, should not require an air permit modification. However, the state should be notified of any new insignificant emission activity and this will need to be included in any air permit revision or renewal at the source. If testing during the pilot phase provides information that emissions will be significantly different than presented herein, reevaluation of permit requirements will be completed.

Exhibit 5-1. Regulatory Emission Summary Table (reproduced from Initial Environmental, Health and Safety Assessment Large Pilot Post-Combustion CO_2 Capture System, Appendix B, Table F.)

Regulated Air Pollutants	**Pilot PTE [1] (ton/yr)**	**401 KAR 52:070 [2] Registration of designated sources. Emission Thresholds**	**CAA, Title V Air Permitting Emission Thresholds**
Single Hazardous Air Pollutants (HAP)	0.34	2 tpy < PTE < 10 tpy	10 tpy < PTE
Combined HAPs	0.45	5 tpy < PTE < 25 tpy	25 tpy < PTE
CO	N/A	N/A	100 tpy < PTE
NOx	N/A	N/A	100 tpy < PTE
Lead (Pb)	0.00	N/A	0.6 tpy < PTE
VOC [3]	0.74	N/A	100 tpy < PTE
SO2	-0.90	N/A	100 tpy < PTE
PM10 [4]	0.99	N/A	100 tpy < PTE
Ammonia [112(r) RAP] [5]	4.63	10 tpy < PTE < 100 tpy	N/A

1. 10 MWe pilot post-combustion CCS plant maximum potential to emit (PTE) based upon operating 24 hours, seven days per week and 365 days per year (8760 hours/year).
2. 401 KAR 52:070. Registration of designated Sources, Section 1.(c) 3. emission threshold for a regulated air pollutant for which there is no applicable requirement.
3. VOC emissions include values listed Tables A-E above and 30.65 lbs of VOC emissions from the storage of amine solutions. See Tanks 4.09d Emissions Report in this Appendix for detailed calculations.
4. PM10 emissions are net, presuming reduction in flue gas entering pretreatment and absorber units.
5. Ammonia (anhydrous) is a regulated air pollutant under the CAA 112(r) Risk Management Program mandated for listing by Congress, but there is no applicable requirement for emissions of NH 3 from the pilot system because the quantity of anhydrous ammonia present is below the threshold quantity listed in Table 1 to §68.130. Furthermore, pursuant to 40 CFR

68.115(b)(1), the regulated substance (anhydrous ammonia) is present in a mixture (pilot gas process streams) below 1% by weight; therefore, the amount of the regulated substance in the mixture need not be considered when determining whether more than a threshold quantity is present at the stationary source.

The project construction area should be too small to require a separate construction permit for stormwater discharges. Regardless, the Trimble County Generating Station has a process wastewater/stormwater discharge permit that includes any construction disturbances within the permitted complex. Notification to the state may be required prior to site disturbance, and the pilot plant will be required to maintain site pollution prevention practices or best management practices consistent with those required by the power plant's wastewater discharge permit.

Make-up water required for the CO_2 absorber and pretreatment tower will be minor relative to the amount of water required to operate the power station. Make up water is planned to be obtained from Trimble County Generating Station's permitted water intake supply from the Ohio River and no additional permitting for, or acquisition of, make-up water will be required.

Process wastewater volumes will be relatively minor and primarily generated from the pretreatment tower. This wastewater is not expected to contain toxic constituents, but may require neutralization. Additional intermittent wastewaters will be generated from maintenance activities and equipment clean out. Pilot plant wastewaters are planned to be commingled with power plant wastewater of similar nature, treated and discharged to the Ohio River through an existing Kentucky Pollutant Discharge Elimination System (KPDES) wastewater discharge permit. Due to the anticipated wastewater volumes, contaminant concentrations and ultimate disposal method, wastewater management does not represent a significant environmental concern.

Estimated quantities and constituent concentrations were identified for process wastes, including spent solutions, spent filters, waste packing media, wash waters and maintenance materials. Some may be corrosive or contain toxic chemicals at concentrations that may require disposal as a characteristic hazardous waste. Appropriate waste characterization and management by permitted transporters and disposal facilities will minimize any potential impact.

The proposed project will occupy a small portion of the Trimble County Generating Station (~ 1 acre and < 0.05% of the site). No off-site activities are planned. Raw material reception and consumption are minor relative to quantities used by the power plant, as will be construction and operating employee traffic. By virtue of its size, types of activities, limited use of chemicals and location within the Trimble County plant site, no significant adverse community impacts are anticipated by operation of the proposed pilot plant.

From available information, no significant EH&S risks were identified that would adversely affect the implementation of the proposed project. Potential exposures and resulting health risks from low concentrations of nitrosamines generated from degradation of various amine-based solvents do not appear to be a significant risk, but additional investigation is warranted. The results of the assessment serve as a foundation for conducting additional investigation during the plant design and operation to quantitatively evaluate and confirm the extent of potential EH&S impacts for the large pilot or a full-scale operation. As data becomes available, this assessment will be modified to reflect that information.

6) COMMERCIAL VISION AND TECHNOLOGY GAPS

6.1 TGA Methodology

Carbon capture, utilization and storage (CCUS) is one of a multitude of important approaches to considerably reduce global CO_2 emissions. In order to meet the U.S. DOE NETL performance goal of 90% CO_2 capture with 95% CO_2 purity at a cost of less than \$40/tonne CO_2 captured and at an incremental cost of electricity 30% less than benchmark CO_2 capture approaches by 2030, significant progress and breakthroughs in cost-effective techniques for carbon capture are needed. More specifically, solvent-based systems, typically employing amine based chemical solvents are currently employed for industrial sour gas clean up. However, considerable advancements are still needed to remove CO_2 from the large volumes encountered at pulverized coal-fired power generating stations. The proposed advanced and versatile 10 MWe post-combustion CO_2 capture system uses a heat integrated process combining heat pump loops of a two-stage stripping and a liquid desiccant loop to recover the low quality heat available in the power plant and internal CO_2 capture system for boosting solvent performance and energy efficiency and will be compatible with any second generation, and beyond, solvent to enhance the CO_2 absorber performance. Aqueous-based carbon capture and storage (CCS) systems for coal fired power plants, such as the one being detailed in this report, do not present serious "show-stoppers" for commercial deployment as they have been tested at scales up to 160 MWe in SaskPower's Boundary Dam Power Station.

Despite over 30 years of development efforts, post-combustion solvent based capture still has yet to meet the desired performance targets for deployment into the utility sector at an affordable cost due to the large gas volumes and low CO_2 concentrations. Over 60 late stage post-combustion projects have been initiated, but only a handful have become operational so far [2].

Four aspects were used to identify and evaluate the high impact technology gaps that exist between the technologies at an early stage (Technology Readiness Level (TRL) 5-6) and the commercialization level (TRL 8-9): (1) the status of solvent based CO_2 capture research worldwide is used as an initial starting point in order to estimate technology maturity; (2) the requirements given by U.S. DOE NETL (U.S. DOE NETL performance and cost targets of 90% CO_2 capture, greater than 95% CO_2 purity and an increase in electricity of no more than 30%) are used as the final targets for commercialization at scales of 300-500 MWe, and potential further advantages to key technologies developed through this funded project (DE-FE0026497), which can advance the technology to commercial viability; (3) the performance and cost of electricity of a commercial power plant equipped with a CO_2 capture system obtained from system simulation, integration, and sensitivity studies and available in the public domain are used as references for technology development or selection. The UKy-CAER small pilot scale investigation has shown that the solvent's chemical and physical properties impact on mass transfer, heat recovery with loading change, balance between heat and mass transfer, and material costs are major factors in determining the capital and operating costs; and (4) the understanding of the sub-process and critical components (or technologies) are applied to help establish discrete criteria to meet the application requirements.

Exhibit 6-1 presents a summary of the technology gap analysis methodology and the results of the performed analysis. Tier 1 involves an overall breakdown based on cost of the general categories involved in aqueous solvent based CO_2 capture, while Tier 2 depicts the focus areas of the gap analysis and the actual technology gaps identified.

The UKy-CAER technical gap identification method was utilized to review the status of current research on solvent based CO_2 systems and identify key focus areas that have critical impacts on commercialization while also providing recommendations of general and technical specifications for each of the focus areas. As can be seen in **Exhibit 6-1**, two main areas can be used as the general commercialization factors to approach the U.S. DOE NETL Target: capital cost and operating cost. In addition, the relationship between the two costs also plays an important role. Specific sub categories such as mass transfer, energy consumption, fabrication and construction, process control and routine operation, scale-up effectiveness, secondary environmental impacts and CO_2 compression, were then evaluated to determine the status of current research and used as a basis for further evaluation. Upon further assessment, 7 focus areas were established to which specific technical gaps were correlated. These focus areas are: point of discharge and waste management, multi-variable controls, heat integration, intensified process, process design and enhancement, solvent properties, and advanced manufacturing and installation.

Furthermore, each of these focus areas contains a number of technology gaps that have been identified which must be addressed in order to meet the U.S. DOE NETL targets. For example, under the process design and enhancement area, several gaps such as equipment sizing versus energy consumption and channel flow are presented.

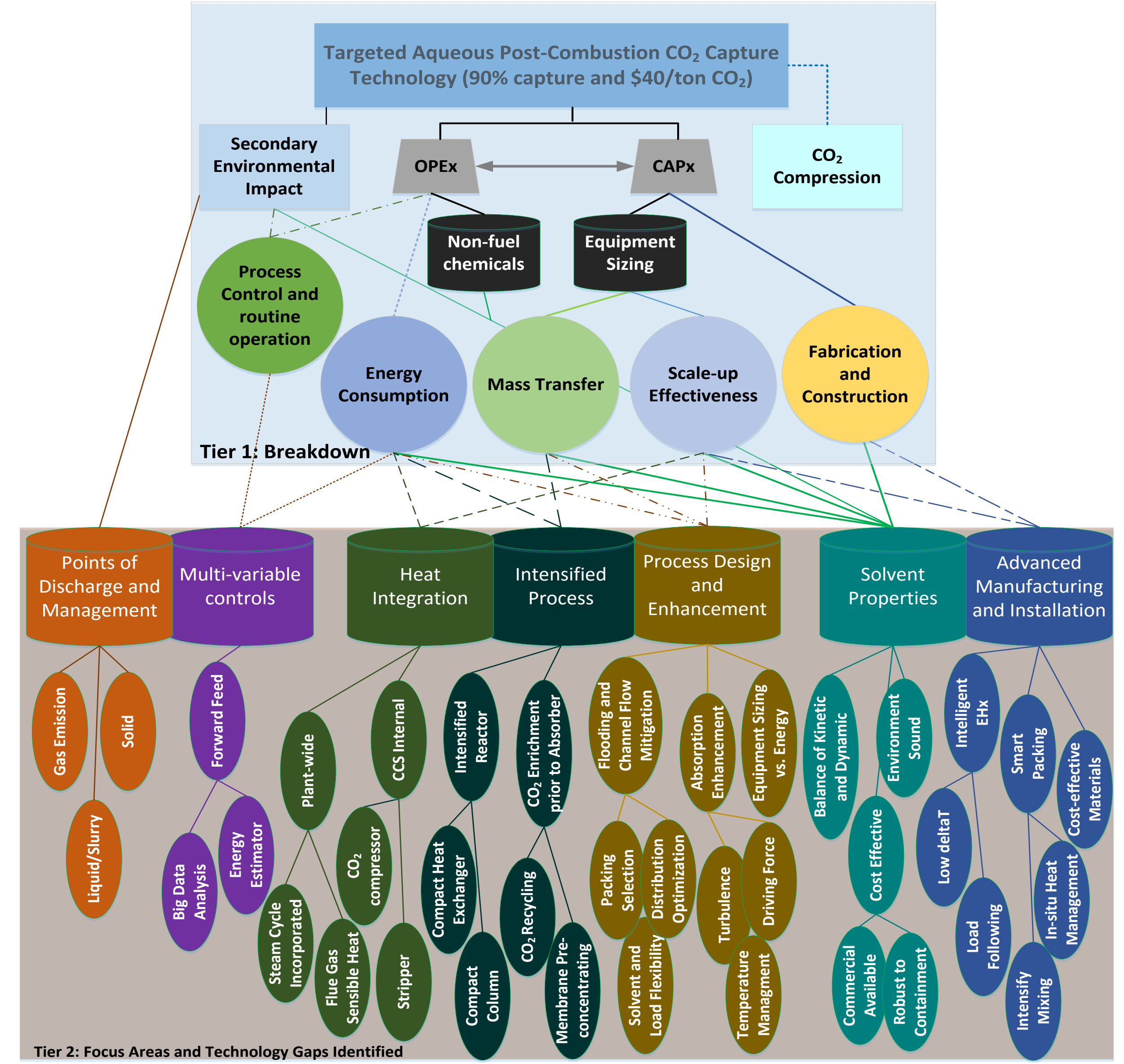


Exhibit 6-1. Overview of TGA Methodology, and Identified Gaps.

Based on the aforementioned considerations for scale-up and commercialization, twelve technical gaps were identified for solvent-based CCS systems including the UKy-CAER proposed large pilot scale CCS. The gaps identified by UKy-CAER are presented below:

Exhibit 6-2. Technical Gaps Identified in the TGA.			
	Technical Gap	**Methods of Resolution**	**Where Addressed**
Near-term Technical Gaps			
1	Cost effective solvent with high stability, high cyclic capacity and fast kinetics	Four methods of advanced solvent selection and development identified in the TGA.	Phase 2 of this Project
2	Gas/liquid distribution to prevent channel flow	Three methods of column gas/liquid distribution control identified in the TGA.	Phase 2 of this Project
3	Waste management and point of discharge (gas and liquid)	Five methods of waste management identified in the TGA.	Phase 2 of this Project and Other Work at UKy-CAER
4	Equipment sizing vs. operating costs	Four methods of equipment sizing identified in the TGA.	Phase 2 of this Project
5	Material and methods of construction	Two lower cost materials of construction and one advanced construction technique presented in the TGA.	Phase 2 of this Project and Other Work at UKy-CAER
6	Process intensification	Five new methods of process intensification presented in the TGA.	Other Work at UKy-CAER
7	Unit operation to maintain the performance	Three methods unit control and design presented in the TGA.	Phase 2 of this Project and Other Work at UKy-CAER
8	Heat integration	Two additional areas of heat recovery and one method to improve heat recovery presented in the TGA.	Phase 2 of this Project and Other Work at UKy-CAER
Long-term Technical Gaps			
9	Smart Packing	Methodologies for selection and application of advanced packing and two advanced design concepts presented in the TGA.	Phase 2 of this Project
10	Appropriate absorber temperature profile	Three methods of absorber temperature control presented in the TGA.	Phase 2 of this Project
11	Heat exchange	Two methods of heat exchange improvement presented in the TGA.	Phase 2 of this Project
12	Smart operation	Two methods improved operations and control presented in the TGA.	Other Work at UKy-CAER

In addition to the TGA on process equipment, results for a preliminary TEA of the proposed UKy-CAER process design using a rate-based model was investigated. The basis for the analysis was a nominal 500+ MWe power plant according to U.S. DOE NETL guidelines and parameters. The objective was to conduct process modeling studies providing detailed mass and energy balances to conduct a performance assessment of the proposed process, and then, to develop an associated equipment list based on the data. Also, a couple of modeling gaps are discussed, along with their subsequent treatment to ensure a truly representative model result. Furthermore, additional experimental data needed to improve the models' predictability were explored. From this analysis, it can be determined that gaps in the modeling parameters do exist; however, engineering manipulation and proper module specification will produce accurate models that are in agreement with experimental data.

6.2 TGA Findings

Based on the analysis of possible methods to close the critical gaps, it can be concluded:

- The proposed process, for aqueous amine CO_2 capture, is a promising technology for commercialization. This technology can provide advantages over conventional power generation with other CO_2 capture technologies in the long term.
- Prior to its scale-up and commercialization, successful demonstration at the large pilot scale is necessary and possible by addressing or narrowing the identified near-term technical gaps.
- Most of the long term technical gaps can be narrowed or addressed with the collaboration of industrial system manufacturers from the power generation, pollutant mitigation, chemical production, heat exchange, and packed column sectors.
- The TEA conducted for this project and validation of the UKy-CAER heat-integrated process coupled with an advanced solvent at the 0.7 MWe scale has paved a clear path toward achieving the U.S. DOE NETL Carbon Capture Program goals identified in DE-FOA-0001190 [2] with a cost reduction on incremental LCOE of 29.5% for CO_2 capture including the TS&M costs, which meets the 30% reduction target set forth by U.S. DOE NETL in this FOA, an achieved **\$43.58/tonne CO_2 captured excluding TS&M cost,** and a reduction of 22.9% from RC 12 [3] at \$56.53/tonne CO_2.

7) LESSONS LEARNED

The UKy-CAER has learned much during the execution of this project (DE-FE0026497). In addition, significant insight has been achieved from DE-FE0007395, which funded the design, construction, and operation of a 0.7 MWe small pilot scale CCS, and has subsequently been applied to the 10 MWe large pilot scale CCS preliminary design. During the course of the small pilot scale project, the UKy-CAER CCS technology was advanced to TRL 6. The 0.7 MWe UKy-CAER CCS has been in regular operation by UKy-CAER staff since May 2015, has accrued more than 3800 operational hours, and has certainly been demonstrated in an operating power generation environment at KU E.W. Brown Generating Station in Harrodsburg, KY. Since May 2015, the plant has often been ran in 24/7 shifts, comprising of general operation in addition to start-up and shutdown procedures. All unique operation modes, as well as the specific requirements that address ambient conditions, have been documented in the SOPs.

The design and construction of a 10 MWe large pilot scale facility comes with certain risks that must be managed – ranging from quality and safety, gas emission, liquid and solid by-product management, cost management, time management, scope and change management, procurement and contracts, personnel management, information management, and external influences, such as regulatory compliance and community relations. Hundreds of decisions must be made before and during new construction - decisions that will determine how successfully the facility will function when completed and how successfully it can be maintained once put into service. These decisions will also determine whether the project is completed on time and on budget. Below are several important lessons learned, through the completion of this project (DE-FE0026497), with sufficient details so that they can be applied to similar projects in the future.

1. *Large pilot scale CCSs (equivalent 10-25 MWe scale) will be large quantity hazardous waste generators and will need to make accommodations for meeting all related regulations*. Most amine solvents have a high propensity to degrade due to interactions with flue gas components such as limestone/fly ash, SO_2 and NO_2 or from thermal effects. Some degradation products must be removed from the solvent via a reclaimer. Based on operational experiences of 0.7 MWe carbon capture pilot units, it is almost certain that the waste from reclaiming solvent will be considered hazardous waste. This designation requires specific accommodations for storage, handling, disposal and notifications, which need to be included from the beginning of the design phase to ensure proper compliance. It should be noted here that disposal of hazardous material can add a considerable expense to the overall project budget.

2. *Frequent reclaiming may be necessary to keep the working solvent categorized as non-hazardous.* In the field of water treatment, amines have been widely used to remove metallic elements such as selenium, arsenic, and others. Accumulation of such elements, especially selenium and arsenic, has been reported in solvents from post combustion aqueous CO_2 capture processes at levels over RCRA limits, for instance 1 ppm for Se. To minimize the complications of accidental chemical spills from CO_2 capture systems, the host site power plant could require the working solution to be maintained as a non-hazardous material. This can be achieved with continuous or frequent batch operation of a thermal reclaimer to remove these metallic elements from the solvent.

3. *Costs of the advanced solvent need to be balanced with the savings from energy consumption.* During the solvent sensitivity and TEA study conducted by UKy-CAER, it was realized that advanced solvents are expensive and any economy of scale savings in production may not be realized due to high raw material costs. Therefore, when evaluating advanced solvents for use in large pilot scale systems (or bigger), a cost/benefit analysis is needed to verify that the expected energy savings more than offsets the additional cost to using a more standard solvent.

4. *Utilization of Engineering Procurement and Construction (EPC) services are important and they must satisfy the requirements of the host site and the technology developer (project prime) in a triangular relationship.* In order to ensure the design and construction of a pilot plant occurs on time and on budget, utilization of an EPC firm is vital. The EPC, while under contract to provide the technology developer's engineering design, procurement, and construction services, also must work with the host utility to meet host site requirements including established best practices that often exceed OHSA and other lawful requirements and

guidelines. In order to mitigate any potential delay and cost overruns, the scope and boundaries must be clearly defined at the beginning of the project and clearly understood by all parties. A representative from the host site must be included and integrated into the team from the beginning of the design/integration phase. This allows the host site to make sure all applicable site requirements are included up front, prior to construction phase.

5. *Utilities (electricity, water, and steam) supplied to large pilot scale CCS may generate complications for a utility in a regulated state.* The host site will need an approval from the governing agency for cost of power/steam supplied to the pilot scale CCS, if the host site is considering recouping costs associated with providing this steam and/or electricity to the project as cost share. Secondarily, established boundaries of electricity service territories may require the pilot scale CCS to tie-in to electrical power outside the host power plant, rather than utilizing a direct tie-in to the host auxiliary power panel.

6. *Advancing through the TRLs in small steps is necessary and jumps from the bench scale, plus modeling to the pilot scale is not recommended.* From UKy-CAER's extensive work in the CCS field over the last 10+ years, it has become evident that scale-ups should occur gradually for a number of reasons. First, at each scale new issues and solutions become apparent that were unknown at the previous scale. Second, each scale-up should build upon the lessons learned at the previous scale. Finally, following the TRL development plan provides good risk management for any technology. Specifically in the CCS field, there are many instances where attempting to jump from the model to a large pilot scale unit would produce a system that was significantly over built (columns much taller than would be required based on actual operational data). One specific example is based on UKy-CAER's recent experience. Based on simulation/modeling work performed at UKy-CAER, it is well known that the sizing of the packed columns is quite sensitive to three parameters: kinetic data, the flow model and packing selection, including correlations for mass transfer and interfacial area [8]. Using only the modeling data mentioned above, commercial scale systems similar in size to the large pilot would have very tall columns, over 100 ft. (30 m). However, based on actual operation data, it has been proven that columns much shorter than this are sufficient. Thus, reducing the capital costs of the CO_2 capture system while simultaneously proving that good risk management through the gradual progression through the TRLs is ideal.

7. *A mutually beneficial partnership between the CCS operations team and the host site is critical.* In general, the host site volunteers to assume risk associated with operations of an experimental pilot scale unit on their property for the benefit of advancing the technology, which has the potential to benefit society. Finding a utility that is forward looking to partner with onsite CCS units of significant scale is a necessity. UKy-CAER has been fortunate to have a strong business relationship with LG&E/KU for over a decade, including almost 3 years of small pilot scale CCS operation on their property. As a guest on the utility's property, it is essential that pilot scale CCS operations impact the host utility as little as possible in order to maintain an effective relationship.

8. *The integration of a large pilot scale CCS project into a coal-fired unit with capacity of less than 25 MWe or equivalent base load rating, may put the unit over the current CAA thresholds to be recognized as an electricity generating unit (EGU).* Due to the extensive steam requirement for solvent regeneration, and MWe-scale electricity requirement to run the auxiliary pumps/blowers of a CCS unit, extra coal will need to be burned if the unit nameplate net output is maintained to meet the external load demand. In this case retrofitting the unit with desulfurization, denitration and mercury removal shall be required on the top of installation CCS.

9. *The integration of a CCS project to a commercial coal-fired unit with an existing air permit may require permit modification to reflect the conventional pollutant concentration changes due to massive amounts of CO_2 being removed from the flue gas.* The change in the flue gas conditions without CO_2 going to the stack is significant, including a reduced in volumetric flow, gas velocity, and gas temperature. This may affect the design of a future stack and CEMS and the performance of an existing stack and CEMS. This may also impact the plume exiting the stack. The pollutant concentration calculations may also need to be altered taking into account the new flue gas conditions. All of these variables will need to be considered and evaluated by the host site before and during CCS design.

8) CURRENT LEVEL OF TECHNOLOGY PERFORMANCE

The performance of the proposed UKy-CAER heat-integrated process in terms of energy consumption for CO_2 capture has been confirmed with various solvents at the 0.7 MWe scale CCS facility at KU E.W. Brown Generating Station in Harrodsburg, KY, where a slipstream of actual flue gas is treated. This post-combustion facility has been operational since April 2015 and has accumulated approximately 3500 hours in the first 18 months of operation. Nearly 200 parameters (temperatures, pressures, flow rates, gas compositions, pH, etc.) are measured and recorded with the DeltaV process control software. The most relevant operating temperatures, pressures, gas stream CO_2 contents, absorber gas velocity, and L/G ratio, were taken directly from, or calculated from, the DeltaV data export files. Solvent carbon loadings are measured from liquid samples collected during steady state times and solvent working capacity is calculated from the measured carbon loadings. Solvent make-up rates are known directly from the solvent addition log.

The versatility and flexibility of the proposed process has been demonstrated with three solvents, as illustrated by the parameters summarized in **Exhibit 8-1**. Two long-term campaigns performed under Project DE-FE0007395 have been completed with 987 hours using 30 wt % MEA and 1228 hours using H3-1. During the H3-1 operational periods, 24-hour per day, 7-day per week operational capability was demonstrated and sustained with downtime being related only to the steam source power generation unit being offline, and for official UK-recognized Holidays. The third long-term campaign was conducted using a solvent developed by UKy-CAER, CAER B3.

Exhibit 8-1. Most Pertinent Process Parameters from One Steady State Condition from Each Solvent Campaign, MEA: 9/30/2015 from 21:15 to 23:15, H3-1: 4/26/2016 from 13:00 to 15:00, CAER B3: 9/29/2016 from 18:00 to 19:55.

			MEA		H3-1		CAER B3	
Description	**Instrument Tag**	**Units**	**Average Value**	**Process Variation**	**Average Value**	**Process Variation**	**Average Value**	**Process Variation**
Temperatures								
Absorber Gas Inlet Temperature	TI-C101-01	°F	81.2	≤ ± 0.4%	87.1	≤ ±1.2%	79.4	≤ ±2.0%
Absorber Lean Solvent Inlet Temperature	TI-E110-02	°F	101.5	≤ ± 2.2%	95.7	≤ ± 0.2%	81.9	≤ ± 0.6%
Absorber Solvent Outlet Temperature, Bottom of Column	TI-C102-04	°F	107.1	≤ ± 0.6%	113.4	≤ ± 0.6%	108.7	≤ ± 0.02%
Primary Stripper Rich Solvent Inlet Temperature	TI-C104-01	°F	219.1	≤ ± 0.9%	196.3	≤ ± 1.1%	225.3	≤ ±0.5%
Primary Stripper Lean Solvent Outlet Temperature	TI-C104-04	°F	258.6	≤ ± 0.2%	231.7	≤ ± 0.3%	248.1	≤ ± 0.2%
Lean/Rich Exchanger Hot End Approach Temperature	Calculated	°F	39.5	≤ ± 5.7%	35.4	+ 6.3% - 4.2%	22.8	≤ ± 3.9%
Secondary Air Stripper Lean Solvent Inlet Temperature	TIC-E114-01	°F	196.3	≤ ± 1.8%	189.5	≤ ± 1.2%	220.3	≤ ± 0.2%
Pressures								
Primary Stripper Operating Pressure	PIC-E105-02	psia	36.0	≤ ± 1.1%	36.0	≤ ± 1.0%	30.0	≤ ± 0.7%
Flow Rates								
Absorber Gas Inlet Flow	FIC-B101-01	ACFM	1400.0	≤ ± 1.0%	1300.1	≤ ± 0.6%	1299.8	≤ ± 0.8%
Absorber Solvent Inlet Flow	FIC-C102-01	lb/hr	29010.7	≤ ±1.1%	23592.9	≤ ± 1.2%	23600.4	≤ ± 0.8%
Primary Stripper Gas Outlet Flow, CO_2 Product Flow	FI-E105-01	ACFM	98.6	≤ ± 13.1%	65.6	≤ ± 2.2%	92.7	≤ ± 4.5%
Steam Flow to Primary Stripper Reboiler	FIC-E107-01	lb/hr	2145.1	≤ ± 1.8%	1344.4	≤ ± 2.3%	1692.8	≤ ± 1.3%
Air Flow to Secondary Air Stripper	FIC-B104-01	ACFM	399.9	≤ ± 0.8%	299.9	≤ ±1.4%	300.2	≤ ± 2.1%
Gas Compositions								
Absorber Inlet CO_2 Concentration	AI-C101-01	Dry, vol%	15.0	≤ ± 3.0%	14.0	≤ ± 3.5%	16.1	≤ ± 0.1%

Absorber Outlet CO_2 Concentration	AI-C102-01	Dry, vol%	1.8	≤ ± 11.0%	1.9	≤ ± 6.2%	1.42	+ 18.7% – 35.2%
Secondary Air Stripper Outlet CO_2 Concentration	AI-C105-01	Dry, vol%	2.0	≤ ± 5.9%	10.1	≤ ± 3.3%	5.0	≤ ± 6.8%
Solvent Loadings								
Rich Solvent C-loading	SP-1	mol/kg	1.86	≤ ± 5%	2.11	≤ ± 5%	2.26	≤ ± 5%
Lean Solvent C-loading	SP-2	mol/kg	1.14	≤ ± 5%	1.60	≤ ± 5%	1.47	≤ ± 5%
Extra-lean Solvent C-loading	SP-3	mol/kg	1.10	≤ ± 5%	1.35	≤ ± 5%	1.46	≤ ± 5%
Solvent Cyclic Capacity	Calculated	mol/kg	0.76	≤ ± 5%	0.76	≤ ± 5%	0.80	≤ ± 5%
Other Parameters								
Absorber Liquid to Gas Flow Ratio, L/G	Calculated	mass/ mass	4.5		4.0		4.0	
Absorber Gas Velocity	Calculated	ft/min	250.9		232.0		232.9	
Solvent Loss Rate due to Solvent degradation	Calculated	lb/ ton CO_2 captured	8.6		0.7		1.3	
System Performance								
Capture Efficiency	Calculated	%	90		88		92	
Solvent Regeneration Energy	Calculated	BTU/ lb-CO_2 captured	1472		1052		1290	

Hitachi H3-1 Advanced Solvent Evaluated at UKy-CAER 0.7 MWe CCS:

During the parametric campaign, 35 different steady state experiments were performed by deliberately varying process conditions [absorber L/G (3.1 and 3.7), absorber gas inlet CO_2 concentration (12%, 14%, and 16%), and primary stripper operating pressure (22, 30 and 36 psia)]. After steady state was achieved (requiring approximately 4 hours), it was maintained for about 2 hours before conditions were changed again. The key process parameters were averaged during the two hours of steady state time, with liquid sample collection occurring at the midpoint, to evaluate the process performance (CO_2 capture efficiency and solvent regeneration energy) associated with the condition and to analyze trends. During the H3-1 parametric campaign, the solvent alkalinity varied from 3.7 to 4.7 mol/L, the capture efficiencies ranged from 91-94%, and energy of regeneration fluctuated between 1020 – 1500 BTU/Ib CO_2 captured. **Exhibit 8.2** is a parity plot of the measured CO_2 stripped from the primary stripper and the calculated mass balance from CO_2 absorbed in the absorber minus CO_2 stripped from secondary stripper, and shows that a good mass balance closure is obtained. During the long-term campaign, process conditions were held constant for much longer periods of time, often several consecutive days, and liquid samples were collected three times in a 24-hour period. One steady state condition (4/26/2016 from 13:00 to 14:00) was chosen to represent the process performance on a long-term, continual basis.

During the portion of H3-1 long-term operation, in order to understand the impact of amine concentration on solvent emissions (including aerosols), thermal and oxidative degradation, as well as the limits of the solvent and process while maintaining 90% CO_2 capture and energy consumption associated with CO_2 capture, after 200 hour operation, UKy-CAER decided to not make-up the solvent until after approximately 800 running hours. As consequence, the solvent was allowed to become diluted during the long-term campaign due to amine emissions and water make-up needed for system continuous operation. This experiment has resulted in useful knowledge gained: a dilute solvent can have even better performance than at the specified concentration for a facility after construction. 90% CO_2 capture is still easily achievable with a low solvent regeneration energy due to a beneficial change in the solvent physical properties, such as lower viscosity, lower surface tension and better heat transfer. The solvent alkalinity (recommended at 5 mol/L) from the entire H3-1 campaign is shown in **Exhibits 8.3 and 8.4** along with the process performance results, CO_2 capture efficiency in **Exhibit 8.3** and solvent regeneration energy in **Exhibit 8.4**. Generally, a 90% CO_2 capture efficiency was obtained prior to the solvent alkalinity deceasing to about 3 mol/L. Beyond this point 90% CO_2 capture became difficult to achieve, but even as the alkalinity approached 1 mol/L, a capture efficiency of > 50% was still possible. As the solvent alkalinity decreased below about 4 mol/L, the solvent regeneration energy increased at constant absorber L/G flow rate ratio, but by increasing the absorber L/G, low solvent regeneration energies, of about 1000 BTU/lb CO_2 captured, were still achievable.

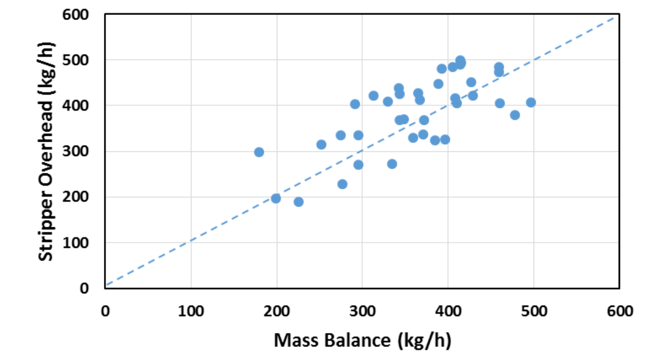


Exhibit 8-2. Mass Balance Between CO_2 Stripped from the Primary Stripper and that from CO_2 Removed in the Absorber Minus CO_2 Stripped in the Secondary Stripper.

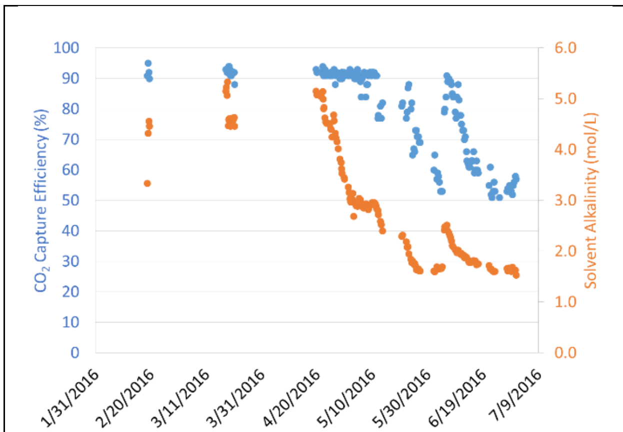


Exhibit 8-3. Solvent Alkalinity and CO_2 Capture Efficiency from the Entire H3-1 Campaign.

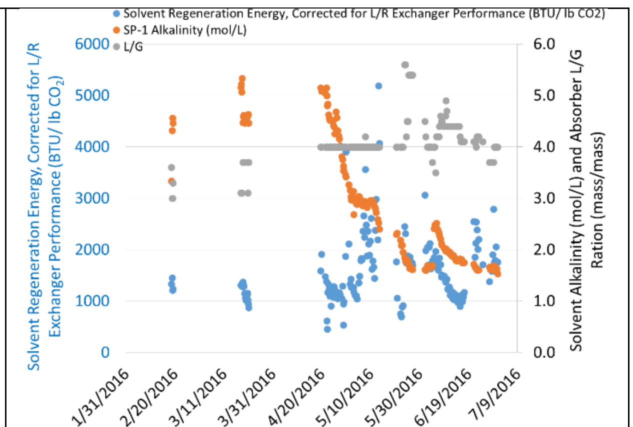


Exhibit 8-4. Solvent Alkalinity, Energy Consumption and Absorber L/G Flow Rate Ratio from the Entire H3-1 Campaign.

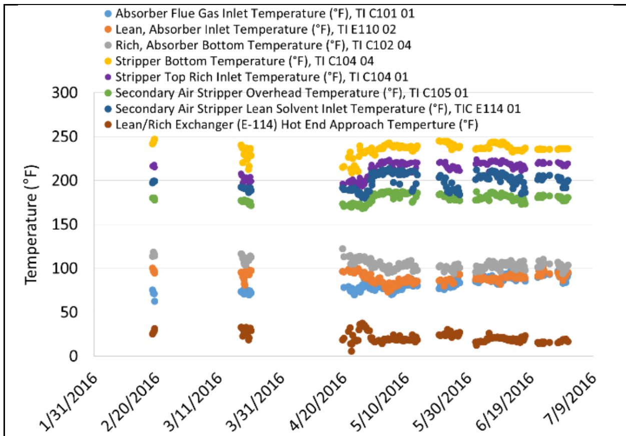


Exhibit 8-5. Process Performance Temperatures During Entire H3-1 Campaign.

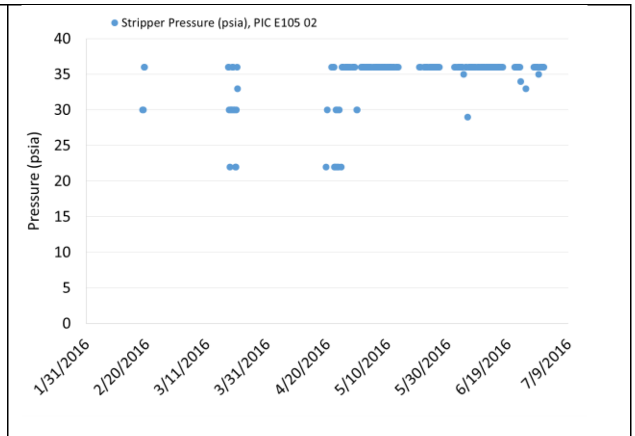


Exhibit 8-6. Stripper Pressure During Entire H3-1 Campaign.

The values of the parameters most pertinent to the process performance, as listed in **Exhibit 8.1**, during the entirety of the H3-1 campaign are shown in **Exhibits 8-5 through 8-10**, illustrating the variation of the conditions considered. Each point shown in these figures is averaged from two hour periods of steady state data. **Exhibits 8-11 through 8-16** show each of these process performance parameters during a selected steady state time, early on in the long-term campaign, illustrating the variation of the conditions at steady state. The average value and variations during these steady state times are also given in **Exhibit 8.1**, and in each case are less than 10%, with many being less than 1%.

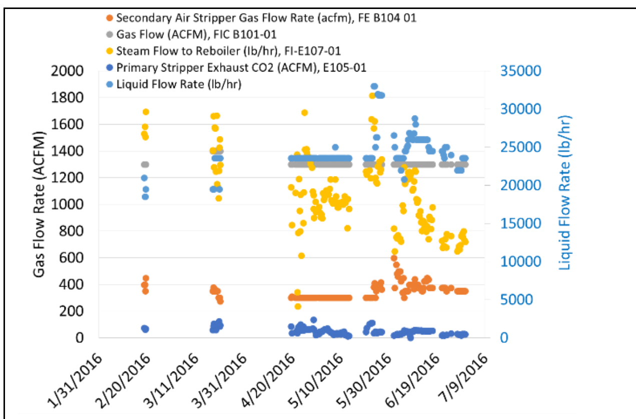


Exhibit 8-7. Gas and Liquid Flow Rates During Entire H3-1 Campaign.

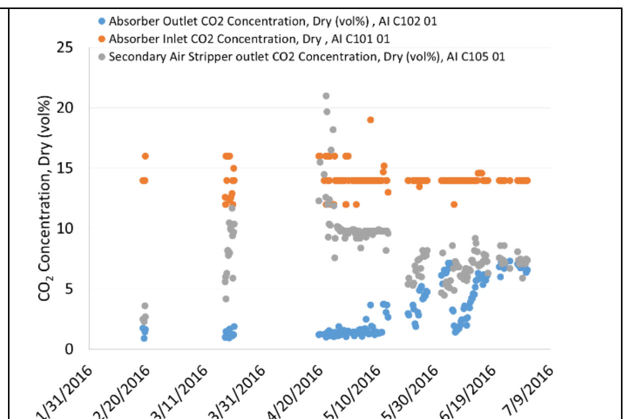


Exhibit 8-8. Gas CO_2 Composition During Entire H3-1 Campaign.

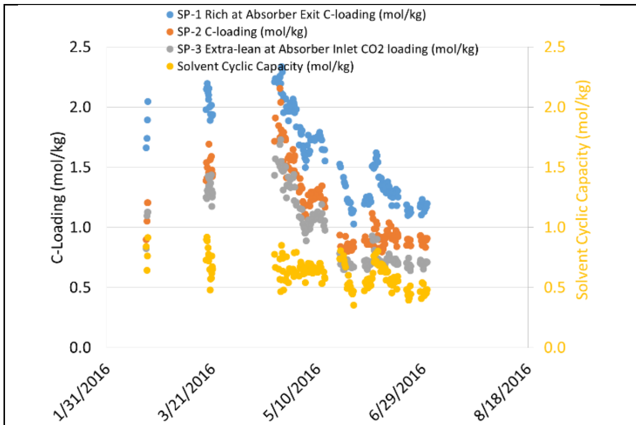


Exhibit 8-9. Amine Stream C-Loading During Entire H3-1 Campaign.

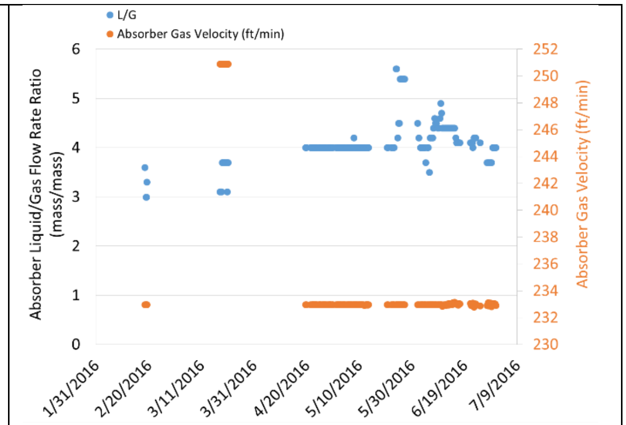


Exhibit 8-10. Absorber Liquid/Gas Flow Rate Ratio and Absorber Gas Velocity During Entire H3-1 Campaign.

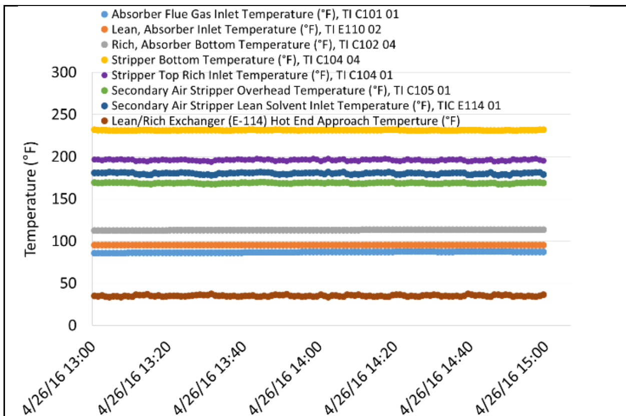


Exhibit 8-11. System Temperatures at one Steady State Condition, 4/26/2016 from 13:00 to 15:00.

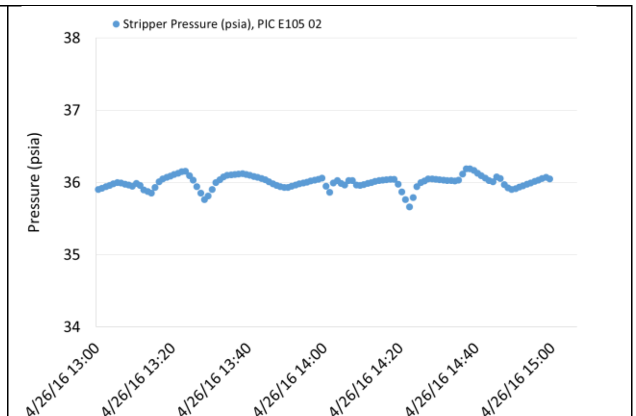


Exhibit 8-12. Stripper Pressure at one Steady State Condition, 4/26/2016 from 13:00 to 15:00.

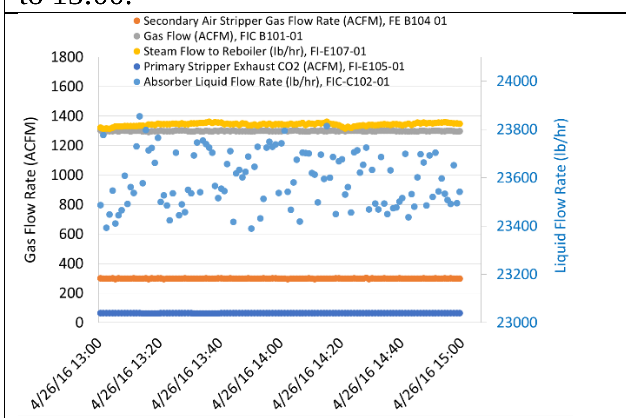


Exhibit 8-13. Gas and Liquid Flow Rates at one Steady State Condition, 4/26/2016 from 13:00 to 15:00.

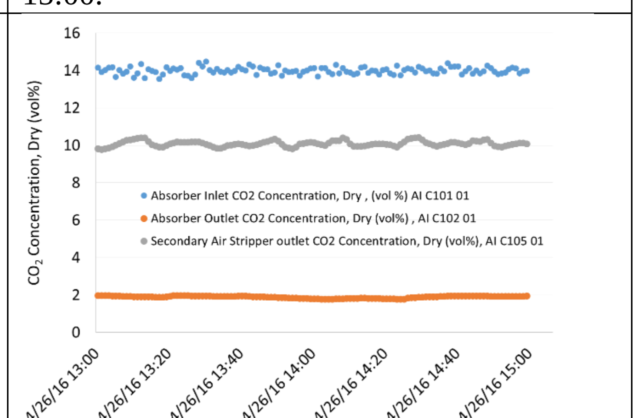


Exhibit 8-14. Gas CO_2 Composition at one Steady State Condition, 4/26/2016 from 13:00 to 15:00.

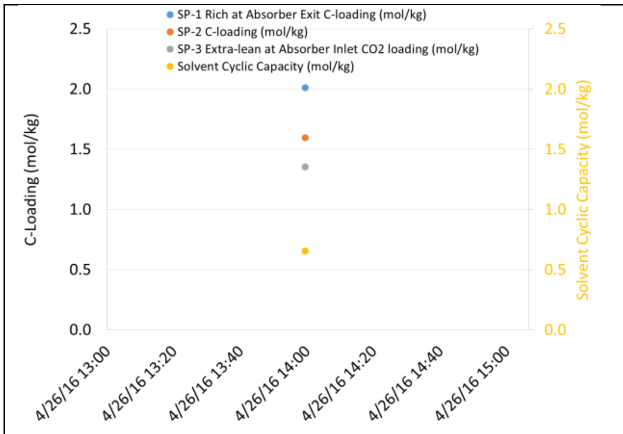


Exhibit 8-15. Amine Stream C-Loading at one Steady State Condition, 4/26/2016 from 13:00 to 15:00.

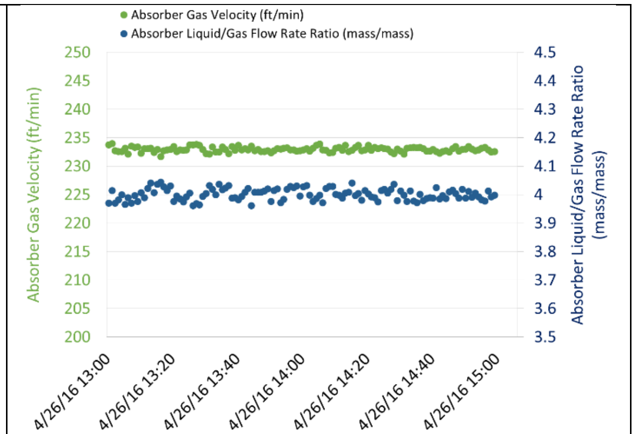


Exhibit 8-16. Absorber Liquid/Gas Ratio and Absorber Gas Velocity at same Condition, 4/26/2016 from 13:00 to 15:00.

9) LIST OF EXHIBITS

10) REFERENCES

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11) LIST OF ABBREVIATIONS AND ACRONYMS

3-D	three-dimensional
ACGIH	American Conference of Governmental Industrial Hygienists
AMEC	Engineering and Technical Services Company
BMP	best management practices
BOP	balance of plant
CAA	Clean Air Act
CCS	CO_2 capture system
CCSL	Carbon Clean Solutions, Ltd.
CCUS	CO_2 capture, utilization and storage
CEMS	continuous emissions monitoring system
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
COE	cost of electricity
DCC	direct contact cooler
EAP	emergency action plan
EGU	electricity generating unit
EH&S	environmental, health and safety
EPC	engineering procurement and construction

EPCRA	Emergency Planning and Community Right to Know Act
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FGD	flue gas desulfurization
FOA	funding opportunity announcement
FRP	fiber reinforced plastic
GEA	process technology firm
H&MB	heat and mass balance
HHV	higher heating value
HPSA	Hitachi Power Systems America, Ltd.
HVAC	heating, ventilation and air conditioning
IARC	International Agency for Research on Cancer
IO	input/output
IP	intermediate pressure
ISBL	inside boundary limits
KBC	Kentucky Building Code
KMPS	Koch Modular Process Systems
KPDES	Kentucky Pollutant Discharge Elimination System
KU	Kentucky Utilities
KY	Kentucky
LCOE	levelized cost of electricity
LG&E	Louisville Gas & Electric
LG&E/KU	Louisville Gas & Electric and Kentucky Utilities
LHV	lower heating value
LP	low pressure
MEA	monoethanolamine
MHI	Mitsubishi Heavy Industries
MHPS	Mitsubishi Hitachi Power Systems
MSDS	material safety data sheet
MWe	megawatt electric
MWth	metawatt thermal
NCCC	National Carbon Capture Center
NTP	National Toxicology Program
O&M	operating and maintenance
OFA	over-fire air
OSBL	outside boundary limits
OSHA	Occupational Safety and Health Administration
P&ID	piping and instrumentation diagram
PC	pulverized coal
PCC	post-combustion capture
PDC	power distribution center
PFD	process flow diagram
PJFF	pulse jet fabric filter
PPE	personal protective equipment
PSV	pressure safety valve
PTE	potential to emit

QA	question and answer
RC 11 `	Reference Case 11
RC 12	Reference Case 12
S&ME	Geotechnical, Civil, Planning, Environmental, Construction Services Firm
SCR	selective catalytic reduction
SMG	Smith Management Group
SOP	standard operating procedure
SOPO	Statement of Project Objectives
TC 1	Trimble County Unit 1
TCM	Technology Centre Mongstad
TEA	technical and economic analysis
TGA	technology gap analysis
TRL	technology readiness level
TS&M	transportation, storage and monitoring
TTD	terminal temperature difference
U.S. DOE NETL	United States Department of Energy National Energy Technology Lab.
U.S. EPA	United Stated Environmental Protection Agency
U.S.	United States
UK	University of Kentucky
UKy-CAER	University of Kentucky Center for Applied Energy Research
WFGD	wet flue gas desulfurization
WP	WorleyParsons