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NOMENCLATURE

ACRONYMS AND ABBREVIATIONS

ACI	Activated Carbon Injection
AEP	American Electric Power
B&W	The Babcock & Wilcox Company
BWCC	B&W Construction Co.
BWRC	Babcock & Wilcox Research Center
BOP	Balance of Plant
BMB	Bottom Moving Bed
CCS	Carbon Capture Sequestration
CFB	Circulating Fluidized Bed
CDCL	Coal Direct Chemical Looping
CFM	Cold Flow Model
DOW	Division of Work
DL&P	Dover Light & Power
DOE	U.S. Department of Energy
EOR	Enhanced Oil Recovery
FD	Forced Draft
EPRI	Electric Power Research Institute
FGD	Flue Gas Desulfurization
FEED	Front End Engineering & Design
GC	Gas Chromatography (Chromatograph)
HAZOP	Hazardous Operation
IBHX	In-Bed Heat Exchanger
ID	Induced Draft
ICP	Inductively-Coupled Plasma
IRC	Industrial Review Committee
JM	Johnson Matthey
LCOE	Levelized Cost of Electricity
MFC	Mass Flow Controller
NETL	National Energy Technology Laboratory
NPT	National Pipe Thread
NDA	Non-Disclosure Agreement
ODSA	Ohio Development Services Agency

OSU	The Ohio State University
O&M	Operation and Maintenance
PSRI	Particulate Solid Research, Inc.
PCC	Post-Combustion Capture
PI	Principal Investigator
PDU	Process Development Unit
PFD	Process Flow Diagram
P&ID	Process & Instrumentation Diagram
PLC	Programable Logic Controller
PCI	Pulverized Coal Injection System
SEM	Scanning Electron Microscopy
SCR	Selective Catalytic Reduction
SBS	Small Boiler Simulator pilot facility
SDE	Spray Dryer Evaporator
TEA	Technical and Economic Analysis
TGA	Thermogravimetric Analysis
TMB	Top Moving Bed
TPC	Total Plant Cost
USC	Ultra-Supercritical
WBS	Work Breakdown Structure
XRD	X-Ray Diffractions

GENERAL

The Babcock & Wilcox Company (B&W) in collaboration with The Ohio State University (OSU), Johnson Matthey (JM), Dover Light & Power (DL&P), NtreTech LLC, and the Electric Power Research Institute (EPRI) has performed a pre-front end engineering & design (pre-FEED) study of a modular 10 MWe coal direct chemical looping pilot plant.

This report contains a summary of accomplishments, tasks, products, participants, collaborators, impacts, changes, problems encountered, and budgetary information. The write up is cumulative, which means that the summary of each quarter was kept in the text and new information was added as the project progressed. This is the final report for the project.

The US DOE Fiscal Year goes from October 1st to September 30$^{th.}$ DOE's Fiscal Years do not match with calendar years that span from January 1st to December 31st. This discrepancy, at times, created a misunderstanding on the quarterly numbering. The quarterly progress reports follow DOE's Fiscal Year for quarter numbering.

The US DOE uses budget periods to track the funding flow towards the project. However, budget periods do not necessarily match the fiscal year quarters. The information provided in the reports is identified using DOE's Fiscal Year and the corresponding quarter as FY#Q#, which matches the report identification code, with the except for the first two quarters. To avoid any confusion on the nomenclature used, the table below lists the current reports, the corresponding reporting period and the short identifier:

Reporting Period	Report Code	Short Identifier
04/01/2017-6/30/2017	DE-FE0027654-BP1Q3	-FY1Q3
7/01/2017-9/30/2017	DE-FE0027654-BP1Q4	-FY1Q4
10/01/2017-12/31/2017	DE-FE0027654-FY2Q1	-FY2Q1
1/1/2018-3/31/2018	DE-FE0027654-FY2Q2	-FY2Q2
4/1/2018-6/30/2018	DE-FE0027654-FY2Q3	-FY2Q3
7/1/2018-9/30/2018	DE-FE0027654-FY2Q4	-FY2Q4
10/1/2018-12/31/2018	DE-FE0027654-FY3Q1	-FY3Q1
1/1/2019-3/31/2019	DE-FE0027654-FY3Q2	-FY3Q2
4/1/2019-6/30/2019	DE-FE0027654-FY3Q3	-FY3Q3
7/1/2019-9/30/2019	DE-FE0027654-FY3Q4	-FY3Q4
10/1/2019-12/31/2019	DE-FE0027654-FY4Q1	-FY4Q1
1/1/2020-3/31/2020	DE-FE00276540-FY4Q2	-FY4Q2

On January 1, 2020, The Babcock & Wilcox Company relocated its operation from Barberton, Ohio to 1200 East Market Street, Akron, Ohio 44305.

This report <u>DE-FE00276540-FY4Q2</u> is the Final Scientific/Technical Report for the project.

ACCOMPLISHMENTS

During the first quarter (**FY1Q3**), the activities were limited to setting up the main award between The Babcock & Wilcox Company (B&W) and the Department of Energy (DOE). B&W worked on setting up the subcontracts with the various project participants. In parallel, The Ohio State University (OSU) submitted its proposal to the Ohio Development Service Agency (ODSA) to request funding to perform their scope of work of the project. ODSA reviewed, approved and awarded OSU the requested funds. B&W and OSU subcontract remained on hold awaiting OSU to secure its contract with ODSA. Other B&W subcontracts were being negotiated to be executed once the parties involved accepted the terms, scope of work, and deliverables for each subcontract.

After receiving approval from the project sponsors at ODSA and NETL to proceed with project activities while the contracts were being finalized, Johnson Matthey (JM) and OSU started work earlier in 2017 under subtask 3.6, Oxygen Carrier Commercial Manufacturing Development, to advance the commercial oxygen carrier manufacturing and avoid delays on the task deliverables. Availability of JM personnel was the main factor in driving this schedule. OSU further established all collaboration and disclosure agreements to transfer its proprietary oxygen carrier formulation to JM to assess its production at their facilities. A three-phase plan was outlined for the commercial manufacturing of OSU's oxygen carrier particles.

The work during the second quarter (**FY1Q4**) was limited to finalizing the subcontracts with the various project participants. OSU was awarded the requested funding from the Ohio Development Service Agency (ODSA) to perform their scope of work of the project. B&W subcontracts with OSU and the Electric Power Research Institute (EPRI) were finalized.

JM and OSU continued to work on subtask 3.6, Oxygen Carrier Commercial Manufacturing Development, to advance the commercial oxygen carrier manufacturing. A three-phase plan was outlined for the commercial manufacturing of OSU's oxygen carrier particles. OSU performed testing on the JM initial samples, and indicated that they were ready to move to Phase II of the particle development program. JM started sourcing various raw materials to help reduce the manufacturing costs of the oxygen carrier particles.

During the third quarter (**FY2Q1**), the commercial plant economic analysis was updated to include new developments regarding the price of fuel. Natural gas remains as the main competitor for power production, and a case has been proposed to determine how CDCL could become competitive against natural gas with carbon capture factored in.

To prepare the pilot facility for testing, a new approach to measure the particle level at high temperatures was developed. To accommodate operations with an air-compressor instead of the forced-draft (FD) fan, a new system for delivering hot air to the combustor was designed whereby the system would use a new air compressor and an existing accumulator tank in the Small Boiler Simulator (SBS) Pilot Facility area. The air flow would then be measured and controlled using new equipment. Quotes and equipment specifications for the air-compressor and air flow control equipment were requested from various vendors. Changes to accommodate the new air delivery system were determined to be minimal and planned to be performed during the subsequent quarter.

In the fourth quarter (**FY2Q2**), a new air delivery system using a diesel compressor was installed and verified for service. A pressure equalizing line was added in the coal feeding system to eliminate the sudden fluctuation due to pressure unbalance and improve the control of the feeding rate. An 8" hole was drilled on the cone section of the bottom reducer to better access the throat part during maintenance. Transducers for measuring differential pressure drops across the combustor bubbling cap, rotary valve, and coal injection nozzle were installed and connected. The alarm and trip lists were revised to eliminate unnecessary items, and the Programmable Logic Controller (PLC) program was updated accordingly.

After all the modifications were completed, a test campaign was performed on the 250 kWth CDCL facility from January 22 to February 2, 2018. The reactor vessel was heated up to full temperature successfully (1920 °F for combustor and 1690 °F for bottom reducer). Solid circulation was maintained at about 1500 lb/hr to 2500 lb/hr during heating up until full temperature was reached. Once the system reached the desired operating conditions and was deemed adequately steady, coal was injected into the reducer for three separate durations of 10 mins, 22 mins, and 31 mins, respectively. The coal feed rate was controlled at a low rate of 8 lb/hr to 9 lb/hr, corresponding to approximately 30 kWth of fuel input. Coal injection into the moving bed reducer was thereby demonstrated. Based on the gas concentration at the outlet of the reactor during the third feeding, coal volatiles conversion in the reducer was high (with CO levels below 200 ppm). Carbon slip into the combustor was not observed during the test. Temperature spikes in the moving bed reactor were observed during coal feeding, which very likely resulted from coal combustion with oxygen from air infiltration when operating under vacuum condition. Better sealing of the reactor, and operating the system at slightly positive pressure need to be considered during future testing. The operation had to shut down due to solid circulation issues observed after prolonged coal injection, and an air compressor trip. Results of the pilot test campaign are discussed below in more detail in the task summary section.

A kick-off meeting was held between OSU and Particulate Solid Research Inc. (PSRI). PSRI identified an existing 2D Cold Flow Model (CFM) for the study of coal distribution in the reducer and developed the methodology for simulating hot condition in cold mode. B&W and OSU have provided general information of the reactor as requested from PSRI.

In the fifth quarter (**FY2Q3**), B&W worked on a plan to perform additional pilot tests as part of Task 2 (250 kWth Pilot Testing). To mitigate the issues encountered during the previous pilot test, some modifications to the pilot facility were required. During this quarter, the modifications to the 250 kWth pilot facility that were planned included replacing the combustor bubble cap floor, installing electric heaters to preheat the combustor air, and purchasing an electric air compressor for supplying the combustor air. Further details on the planned pilot plant modifications are listed in the Task 2 section. During this quarter (**FY2Q3**), purchase orders were issued for the long-lead items to accommodate these planned changes and avoid any further project delays. Purchase orders for the air compressor and moly chrome flange were placed.

For Task 3, a preliminary design of one CDCL reactor module (2.5 MWe) was developed based on the heat and mass balance and the existing data from 250 kWth pilot testing. Steam cycle and heat integration were investigated, and an initial heat integration scheme was developed. Feasibility of B&W's pulverized coal injection (PCI) system for 10 MWe CDCL plant was verified. Mechanical functional specifications for the 10 MWe pilot facility were also documented. The design specifications for the system will be updated throughout the project. A technical designer was assigned to start engineering drafting of the CDCL modules at the host site.

In the sixth quarter (**FY2Q4**), B&W implemented all the modifications required on the 250 kWth pilot facility and completed a second test campaign (August 27, 2018 – September 10, 2018). Overall, the second test campaign was successful. The proposed milestones were mostly achieved. Continuous solid circulation at full temperature was maintained for 110 hours. Seven intermittent coal injections at minimum feed rate (10 lb/hr to 20 lb/hr) were conducted. The data on coal conversion, CO, NO_x and SO_2 emission, and particle attrition were obtained. The coal volatile conversion was very high, resulting in high CO_2 purity (> 90 %). Coal carry-over to the combustor was not detected. Particle attrition rate was also very low, 0.01 %/hr to 0.04 %/hr. New pilot facility additions were successfully operated as well. The system was heated up faster by preheating the reducer with hot air. The startup burner was better controlled, and the flame temperature was maintained in the target range, which is below the particle fusion temperature. Air infiltration was prevented by operating under slightly positive pressure. Heat loss in the reducer was reduced by insulation. Coal was more evenly distributed by adding a N_2 injection nozzle directly facing the coal injection nozzle. Long term operation of the unit with continuous coal injection was not achieved due to a blockage in the standpipe that occurred at the end of the test. Post-run inspection of the unit revealed that refractory pieces and particle agglomerates were blocking the standpipe section of the reactor. The cause and mechanism of the of the formation of these particle and ceramic agglomerates is being investigated. A third test campaign is planned to achieve the goal of long-term coal injection and operation.

For Task 3, the 10 MWe CDCL plant model was developed in Aspen®. The heat integration scheme was evaluated and updated with Aspen modeling. This information was used to perform preliminary sizing of the heat exchanger surfaces for the CDCL modules and the common convection passes. The heat integration was iterated in Aspen to be consistent with modifications that were recommended. Preliminary sizing was also performed for the main air heater and the pulverizer air heater. The 3D general arrangement drawings of the 10 MWe plant incorporated the main components of the system including the CDCL reactors, fuel preparation and delivery system, major piping, and downstream environmental equipment. Both the Aspen model and the 3D design will be updated as the project proceeds.

In the seventh quarter (**FY3Q1**), a no-cost extension proposal along with the change of scope of work and budget were submitted to the DOE. B&W and OSU completed a post-run inspection on the 250 kWth pilot facility. The agglomerates and refractory pieces were collected and analyzed by various methods. The conclusion for the cause of agglomeration was the failure of the standpipe due to partial blockage from the dislodged refractory pieces. Air infiltration in the standpipe caused air leakage into the reducer, where the air reacted with the coal and led to local hot spots. In order to detect air leakage to the reducer reactor, O_2 mapping throughout the Bottom Moving Bed (BMB) reducer and continuous O_2 monitor at important locations of the BMB reducer will be implemented in the third test campaign. In addition, B&W and OSU identified the required modifications to the pilot unit to ensure a long-term coal test. Detailed modifications could be found on the Task 2 section below. Most of the modification activities are in progress, and will be completed before the test run in the next quarter.

For Task 3, design of the heat exchanger surfaces was completed and incorporated into the 3D general arrangement drawing. Balance of plant equipment, including startup burner, air supply blower, air heater, coal/particle storage, coal/particle transfer and unloading, and ash silo and discharge, were specified. Downstream environmental equipment was designed. Utility requirements were calculated. Potential users for captured CO_2 near the Dover Light & Power (DLP) site were contacted and feedback was positive. B&W Construction Co. identified the construction sequence and will provide cost estimation for construction. P&IDs of the main CDCL loop were developed. Mechanical functional specification document was updated accordingly. Detail host site information was delivered to Nexant for greenfield cost estimation.

During the eighth quarter (**FY3Q2**), B&W received the approval for the no-cost extension and a change in the scope of work from DOE. The project was extended to September 30, 2019. B&W and OSU completed all the required modifications on the 250 kW_{th} CDCL pilot facility. A successful third test campaign with steady operation for 288 hours was accomplished. This included a long-term coal operation test with 35 hours of continuous coal injection. A high coal conversion of 95 % and high CO_2 purities of 97 % to 98 % were obtained from the reducer. The emissions of SO_2 and NO_x were measured to be 3000 ppm and 5000 ppm, respectively. Carbon carryover to the combustor was not detected. Oxidation of reduced particles in the combustor was indicated by a rise in the combustor temperature. Consequently, natural gas input, which was used to maintain a constant temperature in the combustor, was gradually reduced during the coal injection period. The attrition rate of oxygen carrier particles was measured to be 0.02 %/hr to 0.03 %/hr; which is lower than the value used for economic analysis. Parametric testing at higher loads reaching the nominal design capacity of 40 lb/hr was also successfully performed. The CO_2 purity at the higher loads was as high as 95 % to 99 %. The performance of the facility validated the 250 kWth pilot design and provided sufficient design information for the 10 MWe CDCL large pilot plant design. These tests go towards satisfying the Task 2 deliverables. The project team delivered the test results to the DOE and the project Industrial Review Committee (IRC) committee through webinar conference calls.

EPRI completed the assessment of the CDCL technology readiness level (TRL). At this time, it was concluded that the technology was in TRL 5, approaching TRL 6.

The preliminary cost for the supply, construction and commissioning of the 10 MWe CDCL plant at the Dover, Ohio host site was estimated to be \$64 million. EPRI reported the cost for the balance-of-plant (BOP) equipment for a greenfield site to be \$34 million, which will be the potential savings of using the Dover, Ohio site with its existing infrastructure and equipment.

During the ninth quarter (**FY3Q3**), B&W extended contracts with all the subrecipients to the DOE approved, no-cost extension date of September 30, 2019. A three-way non-disclosure agreement (NDA) was signed among B&W, OSU, and JM. The main effort during the quarter was focused on Task 3 (10 MWe Pilot Facility Design and Costing). B&W conducted a preliminary study on the distribution of coal in the 2.5 MWe CDCL reducer with CFD modeling. The effects of coal size and gas flow velocity were investigated. Results show that a high gas velocity of 15 ft/s is capable of achieving even distribution of coal particles that are smaller than 122 microns in particle size. However, larger coal particles ⩾122 microns tend to be carried to smaller distances and accumulate near the feed point thereby, not achieving the desired coal distribution over the oxygen carrier particles. The current study indicates that the design and arrangement of coal feed nozzles is very critical to the distribution of coal. Further work will mainly focus on the design and configuration of nozzles.

OSU reduced PSRI scope and decided to perform Subtask 2.2 (Design, Construction and Testing of Modular Cold Flow Model) within OSU. A cold flow model of the reducer reactor was designed and built by OSU. A study of the coal path in a moving bed of glass beads was performed. The study provided results that identify a suitable range of enhancer gas velocities to help fluidize coal particles within the reducer vessel without fluidizing or adversely affecting the metal oxide carrier particles. This is meant to improve particle-coal contact and achieve better distribution of particles in the moving bed. Additionally, this would help reduce the possibility of particles laying out on reactor wall surfaces.

The design of the 10 MWe CDCL primary loop components made use of novel/innovative approaches in the incorporation of steam generation surfaces, structural and other design features that are driven by scale-up considerations and anticipated commercial needs. A patent application has been prepared by B&W.

A risk analysis of the 10 MWe CDCL large pilot was drafted based on the current Hazardous Operation (HAZOP) analysis of the 250 KWth pilot unit. The risk analysis has been sent to OSU for further update.

JM developed and provided six different oxygen carrier samples to OSU for performance evaluations through lab-scale testing. One of the samples proved to be promising and was able to sustain reactivity over 100 redox cycles. However, the oxidation reaction required longer residence times. Further optimization on particle formulation will be performed.

The main effort in this quarter was focused on Task 4During subrecipients to March 31, 2020. the tenth quarter (**FY3Q4**), B&W received the approval of a no-cost extension from DOE and extended the contract of project (commercial design & economic evaluation). The 10 MWe CDCL process model was updated in Aspen by Ntre Tech LLC (Ntre Tech) to reflect the current approach on the design and operation of a 10MWe system. Model additions and enhancements were made on the Wet FGD, pulverizer air preheater and feed system, enhancer gas recycle and particulate control as well as in the overall arrangement of heat exchangers. Parametric evaluation was performed to assess and compare cold vs. warm recycle and mixed recycle configurations. Different recycle ratios were looked at as well. Ntre Tech is currently updating the process model of the commercial 550 MWe CDCL plant. Ntre Tech is communicating with EPRI on updating the Techno-Economic Analysis (TEA) of the commercial 550 MWe plant based on the newly released cost and performance baseline of bituminous coal to electricity from DOE.

JM delivered the cost estimate of oxygen carrier particles from large-scale production based on their wet granulation method. The estimated cost is in the range of $16.35 USD/kg to $22.64 USD/kg at a scale of 1000 ton/year, and $10.90 USD/kg to $15.09 USD/kg in the scale of 10000 ton/year. The main cost contributor is raw material cost, which accounts for near 50 % of the total manufacturing cost.

A cold flow model was built, and testing was performed to characterize the fluidization of coal particles in a packed moving bed of oxygen carrier particles. Coarse glass beads with a diameter between 1.5 mm and 2 mm were used to represent oxygen carrier particles and silica sand was used to represent fine coal particles for the experiments. The experiments showed that the pressure drop increases almost linearly with gas flow rate up to 0.15 m/s beyond which fluctuation is observed indicating that the minimum fluidization gas flow rate has been reached. This is consistent with other relationships of pressure drop versus flow for packed beds. The minimum fluidization velocity of fine particles in the bed of coarse particles is significantly higher than that of fines without any coarse particles (0.015 m/s).

During the eleventh quarter (**FY4Q1**), B&W updated the cost estimation for the commercial 550 MWe CDCL plant based on the current design. Due to the relocation of B&W, a lot of effort was focused on relocating the 250 kWth CDCL pilot facility and other government properties (the thermogravimetric analyzer (TGA) system and borescope). The additional funding required to relocate the 250 kWth pilot facility was estimated and requested of DOE.

During the twelfth quarter (**FY4Q2**), B&W and Ntre Tech finalized the cost estimate for the commercial CDCL plant. The cost analysis is consistent with the recent DOE study that provides the Cost and Performance Baseline for Fossil Energy Plants. The CDCL commercial plant was updated to 650 MWe to be similar to DOE's base plant. EPRI performed an evaluation of the levelized cost of electricity for the CDCL in Japan, Eastern Europe and China, with the purpose of developing a global business plan for the CDCL process.

During this final quarter and after careful review, the DOE was unable to provide additional funds to relocate the CDCL facility. With the assistance of the DOE, B&W drafted and submitted an equipment disposition plan for the CDCL facility. B&W prepared the SF-428 final property report forms and submitted them to the DOE for their review. In parallel, B&W prepared and submitted all close-out documents, including the Patent Certification Form, SF-425 Final Federal Financial Report, Annual Incurred Cost Proposal, Audit of For-Profit Recipients and Subject Invention Reporting. A Final Project Progress Report was prepared summarizing the project accomplishments and an abstract was submitted to the 2020 Clearwater Clear Energy Conference. The final project report was submitted to the DOE by April 30, 2020.

PROJECT PURPOSE, GOALS, OBJECTIVES, AND LIMITATIONS IN SCOPE

The overall project objective was to complete the Preliminary Front-End Engineering and Design (Pre-FEED) of a 10 MWe coal-direct chemical looping (CDCL) pilot plant. The design of the 10 MWe pilot plant would incorporate advanced combustion and emissions control features that have been verified through previous performance testing. Planned integration of the design with existing steam cycle and balance-of-plant equipment at a selected host site represented a substantial step towards the commercialization of CDCL technology. Also, the cost and schedule for the construction and operation of the 10 MWe pilot would be prepared. Additionally, an updated techno-economic analysis (TEA) would be conducted at the 550 MWe commercial scale to evaluate the ultimate cost and performance relative to the DOE goals of less than 35 % increase in cost of electricity and higher than 90 % of carbon capture.

More specific objectives of the proposed project were as follows.

1. Perform a front-end engineering and design study and cost estimate of a modular 10MWe pilot plant at the selected host site.
2. Develop an oxygen-carrier
3. Update the Techno-Economic Analysis (TEA) of the 550 MWe CDCL power plant.
4. Update the commercialization roadmap and risk assessment of the CDCL technology.

MILESTONE STATUS REPORT

Table 1. Milestone status report.

Fiscal Year	Milestone Number	Task.Subtask Number	Milestone Title/Description	Planned Start Date	Planned Completion Date	Actual Completion Date	Verification Method
1	1	1	Project Kick-Off Meeting	7/1/2017	8/1/2017	7/27/2017	Presentation File
1	2	1	NETL's CO2 Capture Meeting	8/1/2017	8/31/2017	8/16/2017	Presentation File
2	3	1	NETL's CO2 Capture Meeting	8/1/2018	8/31/2018	8/15/2018	Presentation File
3	4	1	NETL's CO2 Capture Meeting	8/1/2019	8/31/2019	N/A	Not Required
4	5	1	NETL's Peer Review Meeting	8/1/2019	10/30/2019	9/18/2019	Presentation, TMP, PTS Files
1,2,3,4	6	1	Quarterly Reports	4/1/2017	3/31/2020	4/30/2020	Quarterly Report
1	7	1	Updated Phase II Management Plan	7/1/2017	8/1/2017	11/15/2017	PMP Document
1,2,3,4	8	1	IRC Meeting	8/1/2017	3/31/2019	8/29/2017, 11/16/2018, 3/18/2019	Presentation File
2,3	9	2.1	250 kWt Pilot Testing Report	10/1/2017	9/30/2019	4/30/2018, 10/31/2018, 2/8/2019	Quarterly Report
2,3	10	2.2	Cold Flow Model Testing Report	10/1/2017	9/30/2019	1/31/2020	Quarterly Report
2,3	11	3.3	Design Basis Report	1/1/2018	7/31/2019	7/31/2019	Report Document
1,2,3	12	3.5	Oxygen Carrier Commercial Manufacturing Report	4/1/2017	9/30/2019	2/17/2020	Quarterly Report
2,3	13	3.6	Design Functional Specifications	10/1/2017	7/31/2019	7/31/2019	Report Document
4	14	2.3	Emission Performance and Environmental Control Report	9/1/2019	3/31/2020	4/30/2020	Final Report Document
4	15	5.2	Pilot Demonstration Decision Point Go/No-Go	9/1/2019	3/31/2020	4/30/2020	Final Report Document
4	16	5.1	Final Report and Close Out Documents	7/1/2019	3/31/2020	4/30/2020	Final Report Document

TASK SUMMARY

Task 1. Project Management and Planning

Project management activities in the first quarter (**FY1Q3**) were focused mostly on securing the contract with NETL and setting up the subcontracts with the various entities. Substantial progress was made in establishing all subcontracts. There were some challenges given that Johnson Matthey is a foreign entity with different governing laws and exceptions. B&W and JM reached a resolution on this and other issues and proceeded to move forward with the subcontract.

Progress was also made on the EPRI subcontract. There were some issues regarding the definition of cost-share and work scope. The parties reached resolution two and the subcontract continued to progress forward.

OSU and B&W subcontract also reached the final negotiation stages. The holdup of the OSU and B&W subcontract at this time was primarily due to the delays OSU was experiencing in securing the ODSA funding. However, the ODSA proposal was accepted and awarded and OSU continued to work with the State of Ohio to execute their contract. Approval was granted to OSU to allow for reimbursements on project expenditures while the contract was being finalized.

During the second quarter of the project (**FY1Q4**) most of the subcontracts reached their final negotiation and were executed. The OSU subcontract was executed on July 27, 2017. The subcontract with EPRI was authorized and executed on Aug 8, 2017. The Johnson Matthey subcontract was authorized. All terms were negotiated and expected to be executed by both parties early in the subsequent quarter.

The project held on July 27, 2017. kick-off meeting was Project sponsors and project participants met at the Babcock & Wilcox's Research Center. A brief review of the project status and project plan were presented. The budget, schedule and objectives of the project were discussed and reviewed by the participants. Given the current project delay, it was recommended that Task 2 activities start as soon as possible to avoid further delays. B&W would then advise the DOE of any changes in the project schedule.

An IRC meeting was held on August 29, 2017. The meeting was held at the Babcock & Wilcox Research Center. During the meeting, OSU and B&W presented the status of the technology and the proposed work plan. A session was held to request feedback from the various industrial attendees. The following industries were represented: American Electric Power (AEP), Duke Energy, CONSOL Energy, EPRI, Johnson Matthey, Tri-State Generation and Transmission. Also, project sponsor representatives from NETL and ODSA attended the meeting. A copy of the presentation was provided to the attendees and to the DOE.

During this quarter (**FY2Q1**) a meeting was held with OSU at B&W's research center on Oct 11, 2017 to discuss the forthcoming operations of the CDCL pilot facility. During the meeting, it was agreed that the combustion air controls and delivery system needed to be upgraded. A new system would be installed to deliver air into the CDCL combustor using compressed air instead of the forced-fan (FD) blower. The proposed changes were aimed at improving the combustor operation and make the CDCL system more reliable. The new system required minimum changes. A new control valve, pressure regulator and flow measurement device would need to be installed. The air compressor would be connected to an existing compressed-air tank accumulator near the CDCL unit.

In quarter **FY2Q1**, Jinhua Bao was assigned to take over Chris Poling's responsibilities as project manager. Jinhua Bao would assist the principal investigator, Luis Velazquez-Vargas, in managing and coordinating the project work.

In the fourth quarter (**FY2Q2**), a few meetings were held between B&W and OSU to review and discuss the results from the pilot operation, the problems encountered, possible solutions and required actions in preparation of the next test campaign, as well as a review of the budget. It was agreed that another test campaign was necessary to demonstrate the CDCL technology at the scale of 250 kWth. In order to eliminate the problems we encountered during previous operation of the system, the next campaign would need to operate the pilot facility at a slightly positive pressure to prevent air infiltration. An electric air compressor with Watlow heaters would be used to deliver air to reduce the commissioning cost. The burner would be operated lean to reduce the peak flame temperature to avoid formation of agglomerates. Modifying the downstream quench system, sealing the reducer, and modifying the gas sampling system are required before the next test run.

A kick-off meeting was held between OSU and PSRI on March 23, 2018 regarding the studies of reducer and combustor CFM, which was followed by a conference call on March 29, 2018. Subtask 2.2 (Design, Construction, and Testing of a Modular CFM) was initiated. The scope and focus of the CFM study was discussed and agreed upon. PSRI developed their initial plan of using the existing 2D cold model for coal distribution studies. Process information was provided by B&W and OSU.

In the fifth quarter (**FY2Q3**), a Work Breakdown Structure (WBS) and Division of Work (DOW) were developed for this project. Special consideration was given to clearly define work to be performed under this award and the sister project DE-FE-0031582 in order to avoid duplication of scope. The WBS and DOW developed were based on B&W's project management system used in our commercial projects.

B&W submitted a request to the DOE for budget and scope-of-work change to allocate additional funds towards Task 2. An additional pilot test was needed to acquire design data to support Task 3 efforts. The scope change requested by B&W would not adversely affect the primary objectives of the program. B&W would continue to work with OSU, JM, DL&P and the EPRI to perform the pre-Front End Engineering & Design (pre-FEED) study of a modular 10 MWe coal direct chemical looping pilot plant.

In order to allocate funding towards the modifications and the additional testing of the pilot unit in Task 2.0, B&W proposed to reduce efforts on the following tasks and subtasks:

1. Task 1: Project Management & Planning. Efforts on project management had been lower than originally estimated. Project management efforts might therefore be further reduced due to the compressed schedule and the reduced efforts requested for Task 3.

2. Subtask 3.1: Host-Site Selection and Agreement. This subtask would no longer be performed under this program. Host-site selection and agreement would be performed under the program DE-FE0031582. For design and costing purposes, the site of Dover Light & Power Municipal Plant would be assumed. Further, it would be assumed that the CDCL would provide additional power to the exiting host site. The pre-FEED would not consider the repowering or retrofit case.

3. Subtask 3.6.4. Integration of Pilot Facility with Existing Design. The recipient proposed to evaluate integration of the CDCL unit with the host site's existing infrastructure. However, the recipient would reduce the level of effort for this task and assume that additional power would be provided with the CDCL unit. The Recipient would identify host site requirements for the 10 MWe pilot facility.

4. Subtask 3.6.7: System Control Specifications. The level of effort to develop a control system was reduced. The Recipient would use project DE-0001543 to develop a high-level plan for the operation of the 10 MWe unit based on the design of the commercial unit. The operation of the pilot facility was expected to resemble the operations proposed for the commercial modules. A scaled down version of the control system would be costed based on the commercial CDCL plant design.

5. Subtask 3.6.8. Hazard Design and Hazard Operation (HAZOP) Analysis. The recipient would reduce the level of effort on the Hazard Design and Hazard Operation Analysis. The recipient would perform a risk analysis with reduced number of high-risk scenarios. The recipient would then use the HAZOP analysis and information from the 250 kWth pilot facility to select cases and propose additional cases based on the integration of the modular design with the 10 MWe pilot facility. The Recipient would limit the analysis to only the CDCL process and not include interactions with the host site on this risk analysis.

6. Subtask 3.6.10 Foundations and Steel Structural Support. Since the Recipient has experience and expertise in designing and estimating costs, foundation and structural steel supports on commercial projects, the Recipient would therefore limit the scope of the design and use its experience to develop a budgetary cost estimate of the foundations and structural steel for the 10 MWe CDCL pilot plant.

7. Subtask 3.7.1. Balance of Plant Specifications and Modifications. The recipient would develop the balance of plant for a new 10 MWe pilot facility and reduce the level of effort by limiting the scope to the case of providing additional power to the host site and not address a repowering scenario.

8. Subtask 3.7.2. Environmental Control Equipment and CO_2 Capture. The Recipient would reduce scope in the assessment of CO_2 control measures. The system would be designed to be CO_2 control ready but not incorporate CO_2 compression and sequestration.

9. Subtask 3.7.3. Waste Treatment and Disposal. The Recipient would develop proper waste treatment and disposal equipment specifications for additional power supplied by the10 MWe pilot facility. Future efforts could use the equipment specifications and compare it against existing equipment at the host site to determine if further optimization would be feasible.

10. Task 4 Refine Commercial Plant Design and Economic Evaluation: Requested changes to Task 4 were minimal.

11. Task 5 had no proposed scope changes.

Generally, the proposed changes to the scope of work for Task 3 and Task 4 described above were on tasks that complemented the design of the CDCL system. B&W had experience costing structural steel, and balance of plant equipment that required no new developmental efforts. Hence, proposed changes to the scope of work with the purpose of increasing Task 2 efforts were to reduce the level of effort in these areas. On the other hand, areas that were specific to the design of the CDCL system which contained higher degree of risk and required new development, such as the modular design, heat and material balances, design specifications, technology readiness assessment, oxygen carrier manufacturing, CDCL integration with the steam cycle, controls and operation among others were given priority and would be performed.

A status meeting between B&W and OSU was being held every Tuesday through conference calls, to discuss the progress on the pilot facility modifications. A teleconference meeting with EPRI was held on June 15, 2018, for mutual update on progress made. The scope of work was discussed and action items were determined during these meetings.

B&W performed a site visit to the selected host site on June 27, 2018 to evaluate terminal points for the 10 MWe pilot facility.

The principal investigator attended and presented the results of the work performed under this award at the 43rd International Technical conference on Clean Energy held from June 3rd to 8th, 2018. The presentation was well received.

In the sixth quarter (**FY2Q4**), after discussion with DOE, it was agreed to maintain the original work scope. B&W would attempt to complete the original work scope as stated in the statement of work. B&W however would continue to perform testing on the 250 kWth pilot facility to acquired performance information required for the design of the chemical looping large pilot facility. Testing on the 250 kWth pilot facility at B&W's research center and pursuing the full scope of work would reduce the risks associated with the commercialization of the chemical looping technology.

In the sixth quarter, the efforts focused on completing the planned modifications and conducting the second pilot test campaign. The second pilot test was conducted from August 27, 2018 to September 10, 2018. In the second campaign, the unit was successfully operated, and seven intermittent coal injections were successfully performed. Important data for the 10 MWe CDCL plant design was obtained, as discussed in Subtask 2.1. However, the test campaign was stopped by a blockage in the standpipe. The long-term coal injection was not performed in this test run. B&W is working with DOE on the plans for a third test campaign to achieve the long-term coal injection and operation objective.

The project manager, Dr. Erik Albenze, from DOE visited B&W Research Center on August 30, 2018 to tour the 250 kWth pilot facility. The project manager observed the second test campaign and held discussions with B&W and OSU on the various chemical looping projects. Conference calls were held on September 13th and 26th between B&W, OSU, and DOE to provide a brief update to DOE project managers on the test campaign and corresponding results.

B&W performed a few site visits to the selected host site to work out the general arrangement of the 10 MWe CDLC plant in 3D, including the main CDCL reactor, the ducting, the pulverized coal injecting system, and the downstream environmental equipment.

The principal investigator attended and presented the project status and progress at the NETL CO_2 Capture Technology Project Review Meeting on August 15, 2018. A B&W representative attended and presented at the 5th International Conference on Chemical Looping on September 24-27, 2018. Both presentations were well received.

In the seventh quarter (**FY3Q1**), B&W requested the DOE for changes on the scope of work and budget as proposed in the fifth quarter (FY2Q3). The purpose of the changes was to allocate funding for the third test campaign. Due to the additional testing performed on the program and the delay in getting design data for the pilot unit, B&W requested a 6-month no-cost extension to DOE. If approved, the project would extend to September 30, 2019.

During this quarter, the work focused on understanding the formation of agglomeration, developing strategies for a long-term operation, and preparing the 250 kWth facility for the third test campaign. Meetings between B&W and OSU were held on a regular basis to address the modifications and design changes required on the reactor.

An Industrial Review Committee (IRC) meeting was held through WebEx on November 16, 2018. Various industrial attendees were represented: AEP, Duke Energy, CONSOL Energy, EPRI, Johnson Matthey, Tri-State Generation and Transmission. Project team members and representatives from the DOE/NETL office participated in the meeting as well. During the meeting, results from the second test campaign were discussed and progress on the design of the 10 MWe was presented by the project Principal Investigator (PI). The presentation was well received and discussed. Feedback from industry committees was encouraging.

During this quarter, every Thursday, B&W held review and design meetings on the steam cycle heat integration and P&IDs. B&W worked with EPRI on identifying the scope of work for Nexant. Information about the existing main equipment, site, building and structure at DL&P was provided to Nexant for a greenfield cost estimation.

During the eighth quarter (**FY3Q2**), the change in the scope of work and budget was submitted to DOE, which also allocated funding for the third test campaign, was approved. The request of a 6-month no-cost extension was approved as well. The project was extended to September 30, 2019.

A successful third test campaign on the 250 kWth facility was performed. The unit was operated steadily for the scheduled two-week time frame and was even able to recover from a momentary black plant trip. Long-term operation using Ohio bituminous coal was achieved. Coal was injected for an accumulated duration of 62 hours. Parametric testing was accomplished which included a wide range of coal loadings up to the nominal design capacity. This testing led to the conclusion of Task 2.

B&W and OSU provided updates of the third test campaign to DOE on February 19, 2019 and requested additional funding for future testing on the facility.

An industrial review committee meeting was held via WebEx on March 18, 2019. Various industrial attendees were represented including: AEP, Duke Energy, CONSOL Energy, EPRI, Johnson Matthey and Tri-State Generation and Transmission. Project team members and representatives from the DOE/NETL office participated in the meeting as well. During the meeting, results from the third test campaign were discussed and recent progress on the design of the 10 MWe was presented by the project PI. The presentation was well received and included numerous questions and discussions.

During the ninth quarter (**FY3Q3**), since B&W's no-cost extension was approved by DOE, B&W extended project contracts of all subrecipients to September 30, 2019. A three-way NDA was signed among B&W, OSU, and JM. Due to company reorganizations during the previous quarter that impacted project personnel, B&W requested approval on April 5, 2019 from the DOE to increase OSU's scope of work for the amount of $350,000. B&W authorized a change in OSU's scope on June 10, 2019. OSU in-turn subcontracted Ntre Tech to conduct some of the additional scope of work.

B&W held a teleconference with EPRI on June 12, 2019 to discuss the status of EPRI's activities and the remaining scope assigned to EPRI.

The project manager attended and presented the recent results of the project at the 44th International Technical Conference on Clean Energy held from June 16 to 21, 2019. The presentation was well received.

During the tenth quarter (**FY3Q4**), B&W received the approval of a no-cost extension from DOE and extended the contract of project subrecipients to March 31, 2020. B&W was not awarded the Phase II work for the 10 MWe CDCL FEED project, which was a complimentary project to this Pre-FEED program.

The DOE IDAES team had an on-site meeting with OSU and B&W at the B&W Research Center on August 22, 2019. The status of the CDCL technology, testing and simulation tools and facilities used by the development and application of the IDAES simulation platform were discussed during the meeting. The team tour of the 250 kWth CDCL pilot.

In September of 2019, JM delivered a report on their cost estimation efforts regarding the large-scale manufacture and supply of oxygen carrier particles based on their wet granulation method.

In the eleventh quarter (**FY4Q1**), B&W and OSU participated and presented at the DOE/NETL peer-review meeting on October 24, 2019. The presentation was well received. Feedback provided by reviewers was positive and encouraging. During the meeting, B&W and OSU presented the need for additional funding to address critical technology gaps to advance the technology.

Due to relocation of B&W's facilities, B&W requested the relocation of the 250 kWth CDCL pilot facility to a B&W site in Lancaster, OH. The budget for disconnecting and relocating the 250 kWth pilot was estimated by B&W construction company and a request was submitted to DOE. Sensitive equipment, such as the TGA were dismantled, packed, and made ready for transport to a new location.

During the last quarter (**FY4Q2**) and after careful review, DOE was unable to provide additional funds to relocate the CDCL facility. Hence, B&W project management activities focused on evaluating various scenarios related to the management of the CDCL pilot facility and equipment. B&W prepared and submitted an equipment disposition plan to the DOE. DOE reviewed and approved B&W's proposed plan. Due to the lack of funds to relocate the facility, B&W will make the CDCL facility inoperable and abandon it on site. B&W, however, will relocate key components to the new location to be used as part of the next CDCL facility in a latter DOE-sponsored project. Other project management activities were related to prepare and submit the project close-out documents as stated in the contract, including the final project report.

Task 2. 250 kWth Pilot & Cold Flow Model Testing

Subtask 2.1. 250 kWth Pilot Testing

No activity during the first quarter (**FY1Q3**).

The pilot unit was fully inspected during the second quarter (**FY1Q4**). All particles were taken out from the unit. The particles were sieved to remove any agglomerates and then placed in drums. Further tests would be conducted to assess their reactivity. About 8 drums of particles were recovered to be put into service again once they have been tested.

The combustor reactor was opened and inspected. Some particles were found agglomerated and attached to the side of the combustor near the interface of the natural gas burner and the combustor. These agglomerates were most-likely formed during the first test campaign when the combustor bed experienced defluidization. The agglomerated particles were removed. Particle agglomeration is not expected under normal operating conditions of the combustor. The combustor reactor was then reassembled, insulated and reconnected to the remaining system components. A subcontractor was hired to torque the combustor to the correct specifications.

All other parts of the unit were inspected with a boroscope for any possible damage. The unit was found to be in good condition for subsequent testing. The refractory had some fine cracks that are normally expected when the unit is heated to high temperature. These finer cracks are healthy since they allow for the expansion of the refractory during further heating and help prevent further cracking.

In the third quarter (**FY2Q1**), after reviewing data from previous pilot operations, it was observed that the low combustor air delivery pressure of the forced-draft fan was a major operating problem. The pressure fluctuations in the combustor caused a constant variation in the amount of combustion air, which affected the fluidization in the combustor reactor. During a review meeting with OSU, it was agreed that for the upcoming operations, the combustion air delivery and control system needed to be upgraded.

Plans to install a new compressed air system for delivering the combustion air were made. The new system would be able to deliver air into the CDCL combustor using a compressor instead of a forced-draft fan blower. This system should improve operations and make the system more reliable. The new system would require minimal changes. The compressor would be connected to an existing air-tank accumulator near the CDCL unit. The new system would, however, require a new control valve, pressure regulator and flow measurement device.

In the third quarter (**FY2Q1**), the new air-delivery system was designed. These instruments were specified and quotes from various vendors were requested. Once final decisions were made, the instruments were purchased during the quarter. Due to long lead times, the system would be installed in the subsequent quarter. All piping and mechanical installation was expected to be performed by B&W personnel. After the full installation of the equipment, the electrical installation would be performed by outside contractors.

During the fourth quarter (**FY2Q2**), the following equipment modifications were made to the 250 kWth CDCL pilot facility: 1) update to the combustion air controls and delivery system to improve operations and reliability of the system; 2) addition of a pressure equalizing line for the coal feed system to control the feed rate more precisely when operating the unit under vacuum conditions; 3) drilling an 8-inch hole on the reducer cone section to provide easier access to the hopper part of the reactor for maintenance; 4) acquisition of additional pressure sensors to measure pressure drop across the combustor bubble cap, rotary valve, and coal injection nozzle; 5) revision of the alarm and trip list to make necessary additions, remove redundant or unnecessary items and updating the PLC program accordingly.

Main Equipment Modifications

The new combustor air system delivers air into the CDCL combustor using an air compressor instead of the FD fan blower used previously. While, the piping required minimum changes, a new control valve, pressure regulator and flow measurement device were added. These items were specified and purchased during the previous quarter but the installation with an existing compressed-air tank accumulator near the CDCL unit occurred during this quarter. All piping and mechanical installation was performed by B&W personnel. The electrical installation was performed by an outside contractor.

Initially, an electric air compressor was specified to supply the compressed air to the combustor. However, due to erroneous compressor performance specifications provided by the compressor supplier, the electrical compressor was unable to supply the required volume of air. Hence, the supplier provided an emergency diesel-driven air compressor specified at 1600 cfm at 125 psi for the test campaign. During the test campaign, diesel was delivered daily by a fuel-delivery service contractor. Due to the switch of the air supply system from the forced-draft fan to the air compressor, the unit could be operated at a higher pressure, making the combustor operation more reliable.

The coal feed system was also modified. It was observed during previous runs that when operating under vacuum conditions, a sudden and unexpected weight loss in the coal hopper occurred. This indicated that the coal hopper was at higher pressure than the reducer vessel and when the rotary valve was turned on, an uncontrolled rush of gas and coal was entrained to the reducer to equilibrate the pressure. The rotary valve should seal against 30 psig pressure differential, but this proved not to be the case. Hence, to correct for the imbalance in pressure between the coal hopper and the reducer reactor, a pressure equalizing line (3/8-inch copper tubing) was connected between the top of the coal hopper and inlet of the rotary valve. The pressure equalizing line would allow the coal feeder to operate normally establishing the ability to control the coal feed rate to the desired value without the sudden and uncontrolled surge in coal feed when components are started.

Additionally, the inlet hose of the coal feed hopper was sealed with a gate valve to provide the means to replace coal drums during operation. A N_2 blanket (1 scfm to 2 scfm) was introduced to the top of the rotary valve to guard against air leakage into the system during operation and to help control the coal feed rate at low levels by creating a local high-pressure spot. The modified feed system was further verified by testing at various vacuum conditions. A steady feed rate as low as 5 lb/hr could be achieved when the unit operates at a pressure range from -5 inH_2O to -25 inH_2O.

An 8-inch hole was drilled carefully without damaging any surrounding refractory on one side of the reducer cone section by our mechanical subcontractor to gain access to the cone section of the Bottom Moving Bed (BMB) reducer. During testing, the hole was sealed using a matching ceramic plug fabricated by B&W Research Center personnel.

Additional pressure probes and transmitters were installed and wired to measure the pressure difference across the combustor bubble caps, the rotary valve, and the coal injection nozzle.

The alarm and trip list was reviewed and revised by the team to address changes in the system. Unnecessary and redundant items were removed from the list. The PLC program was then updated to incorporate the changes.

First Pilot Test Campaign (January 2018)

A pilot test campaign was performed from January 22nd to February 2nd, 2018 after making the required modifications. The objective of this campaign was to 1) reach high temperatures suitable for coal gasification; 2) inject coal at a low feed rate (< 10 lb/hr) and thereby successfully demonstrate the CDCL process with coal input. The detailed results are discussed below.

1) Temperature Profile

The temperature profile of the 250 kWth pilot unit in the January 2018 (Jan-18) test campaign can be found in **Figure 1**. The location of the various thermocouples is shown on the control screen in **Figure 2**. As seen in **Figure 1**, the heat-up of the system was quite slow. This is because the reducer has a large thermal inertia due to the thick refractory lining and because heat is transferred to the reducer with the hot circulating particles. To heat up the combustor reactor to 1742 °F took about 130 hrs, and 165 hrs to for the top of the BMB reducer to reach 1768 °F. A steady temperature of 1920 °F was reached at the combustor, 1905 °F at the Top Moving Bed (TMB) reducer, 1690 °F at the top of the BMB reducer, and 1500 °F at the bottom of the BMB reducer. The temperature decreased from the top to the bottom of the reducer gradually due to heat loss. In the period of 175 hrs to 182 hrs, pulverized coal was injected into the reducer during three time intervals, which will be discussed later.

In **Figure 1** we can see that there were two periods where temperature dropped significantly, these were at around 85 hrs and 190 hrs. Both temperature drops were caused by burner trips. At 85 hrs the burner tripped due to water backflow into the reducer reactor from the quench system. The burner had to be temporarily shut off to fix the water backflow issue. It was found that the cooling water injection nozzle was delivering excess water and the excess cooling water was flowing towards the reducer reactor. To solve this problem, part of the quench system was modified to allow for ambient air to be pulled in through an open port to partially or fully provide the needed quench of the hot exhaust gas. Due to the change in the quench system, the unit operating pressure at the Reactor outlet increased from -14 inH_2O to -4 inH_2O at a constant Induced-Draft (ID) fan demand setting. At 190 hrs, the second temperature drop was caused by a loss in solid circulation due to a temporary plug in the standpipe. The system recovered later and solid circulation was reestablished. At 245 hrs, the air compressor tripped due to freezing of the compressor drain line which occurred overnight. Correspondingly, solid circulation was lost. After few hours, the compressor was put back into service. However, the solid circulation could not be reestablished due to a plug in the standpipe. Due to several operating issues encountered after the compressor trip, the unit was programmed to shut down. Lastly, in order to find out the coal distribution in the reducer, coal was injected into the reducer without solid circulation before shutting down the unit completely.

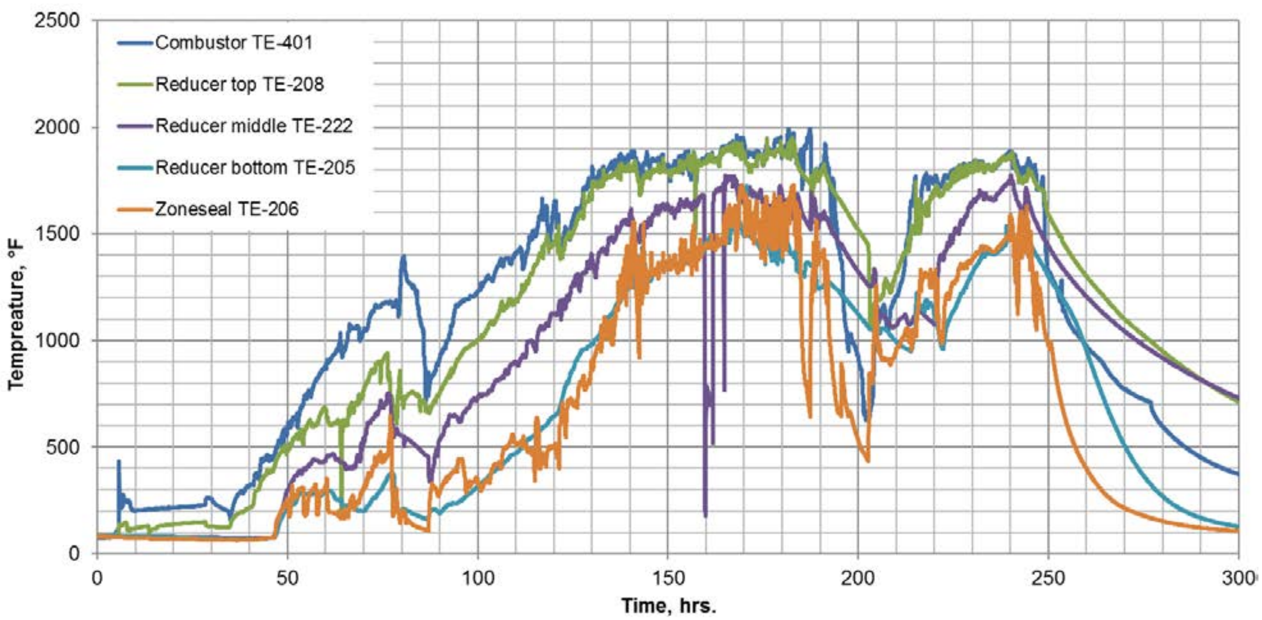


Figure 1. Temperature distribution throughout the reactor vessel.

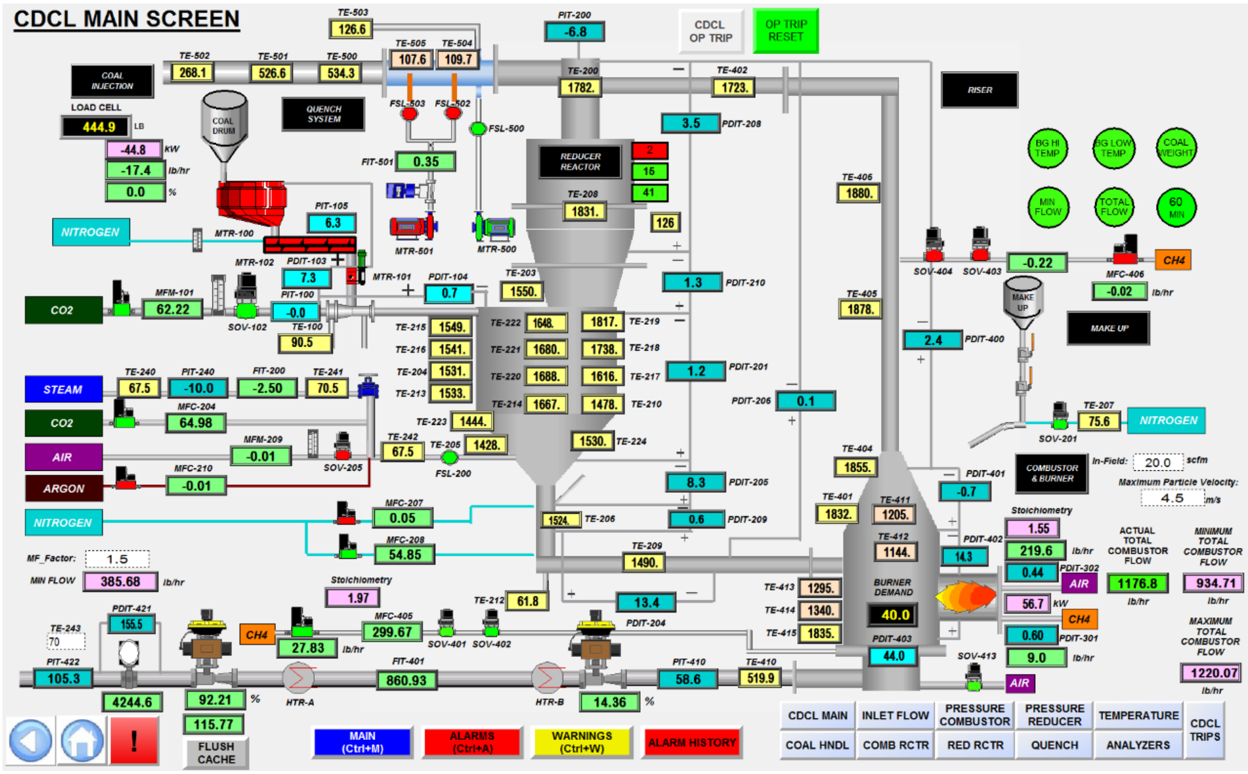


Figure 2. CDCL main control screen.

Figure 3 shows the temperature profile in the reducer reactor. The temperature (horizontally) across the top of the BMB reducer varied slightly. Generally, the west side was hotter than the east side. This was mainly because the west side was right below the outlet of the Top Moving Bed (TMB) reducer, where hot particles are introduced. The lateral temperature difference was approximately 100 °F. It's worth pointing out that at the very beginning of the heat up period, the east side of the reducer heated up first before the west side (see period between 45 hrs to 50 hrs in **Figure 3**). This could be because the hot particles slid toward the east side first when exiting from the TMB reducer.

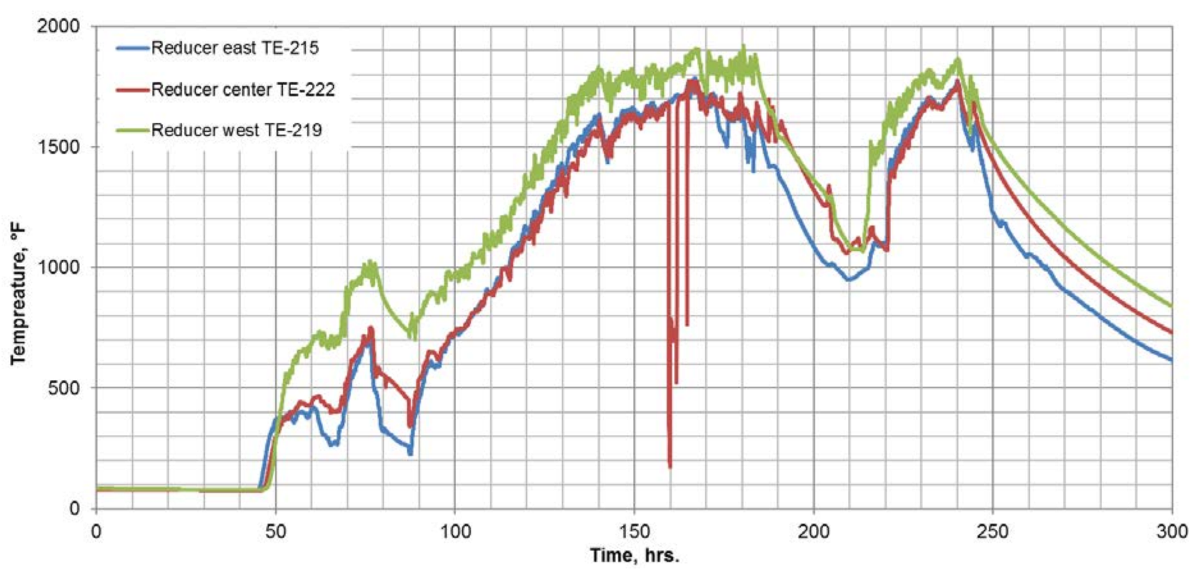


Figure 3. Temperature difference across the Bottom Moving Bed reducer.

2) Combustor Operation

Figure 4 displays the natural gas demand from both the burner and the injection port at the bottom of the combustor. The combustor was warmed up to approximately 300 °F with preheated air for the first 40 hrs before turning on the startup burner. The natural gas demand was ramped up gradually. The amount of burner air was adjusted at the same time, to maintain the stoichiometric ratio above 1.2. When the combustor outlet temperature reached the natural gas autoignition temperature (1100 °F), natural gas was injected at the bottom of the combustor. As the amount of natural gas injected into combustor bottom increased, the natural gas demand of the burner was backed down to maintain the same thermal input. The total natural gas demand was about 70 %, when the combustor reached full temperature. **Figure 5** shows the calculated burner stoichiometry and flame temperature during startup (40 hrs to 120 hrs). As the amount of burner natural gas was increased, the stoichiometry dropped, while flame temperature increased. The burner was fired to a stoichiometry as low as 1.27, corresponding to a flame temperature of 2995 °F. We suspect that this temperature is causing some oxygen-carrier particle agglomeration in the combustor. To prevent particle agglomeration in future runs, the team recommends operating the burner under leaner conditions thereby maintaining a lower flame temperature.

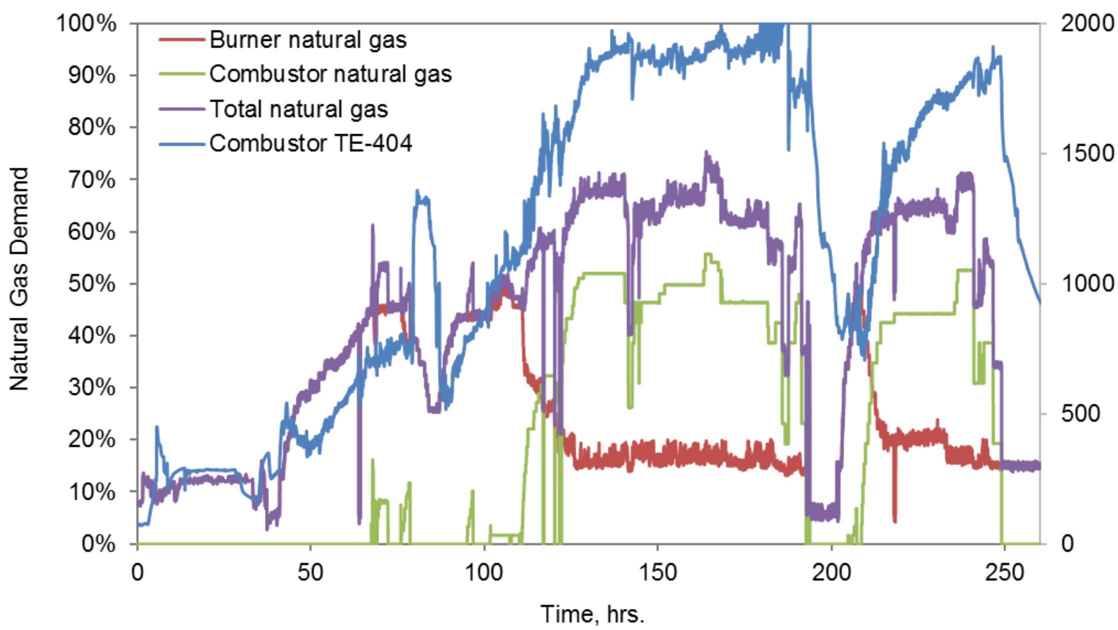


Figure 4. Natural gas demand.

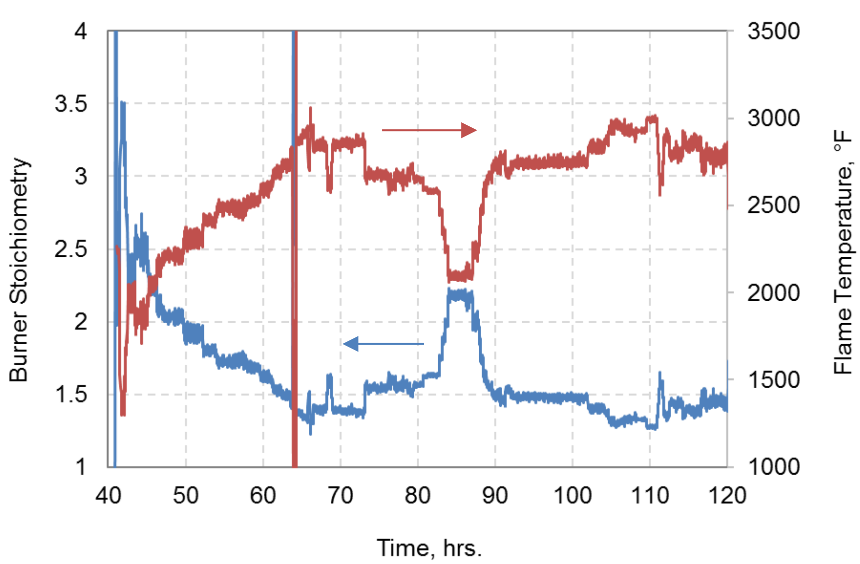


Figure 5. Burner stoichiometry and flame temperature during startup.

3) Pressure Balance

Figure 6 gives the pressure balance of the reactor loop at 170 hrs, when the reducer was operated steadily under vacuum conditions. The moving bed reducer has the lowest pressure while the bottom of the standpipe has the highest pressure. The pressure neutral point was located in the riser and the standpipe. The combustor was operated in positive pressure while the reducer was operated at negative pressures most of the time.

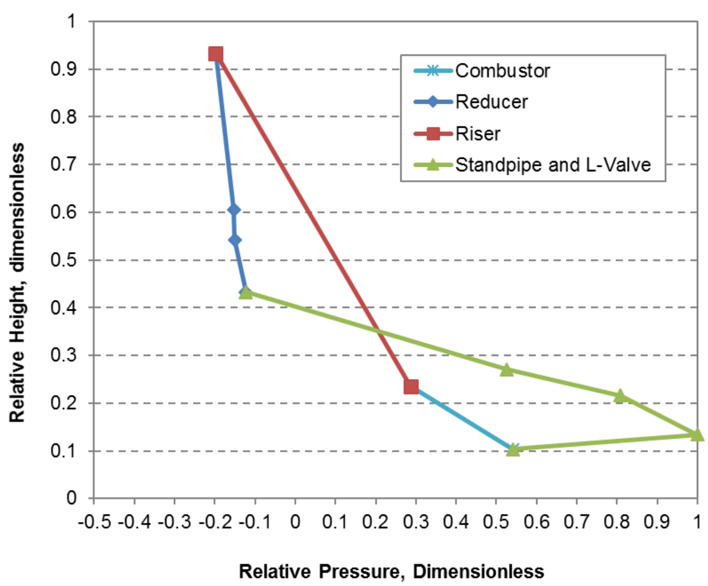


Figure 6. Pressure balance during steady operation at 170 hrs.

4) Combustor Fluidization and Solid Circulation

During the test run, the solid circulation rate was measured with the B&W's patented IsoKinetic Feed system (IKF). **Figure 7** shows the solid circulation rate measurements taken as well as the combustor temperature for reference. Fluidization in the combustor started at the same time as heating up, to obtain uniform heat transfer and avoid particle agglomeration. When the combustor temperature reached about 500 °F, solids started to circulate by controlling N_2 flow to the L-valve and Zone-seal. Through solid circulation, the reducer was heated up by the inlet hot particles. As the entire unit heated up gradually, solid circulation rate tended to increase due to the gas expansion in the L-valve. At the full temperature, solid circulation rate was measured to be between 1500 lb/hr to 2500 lb/hr in most circumstances, meeting the design requirement.

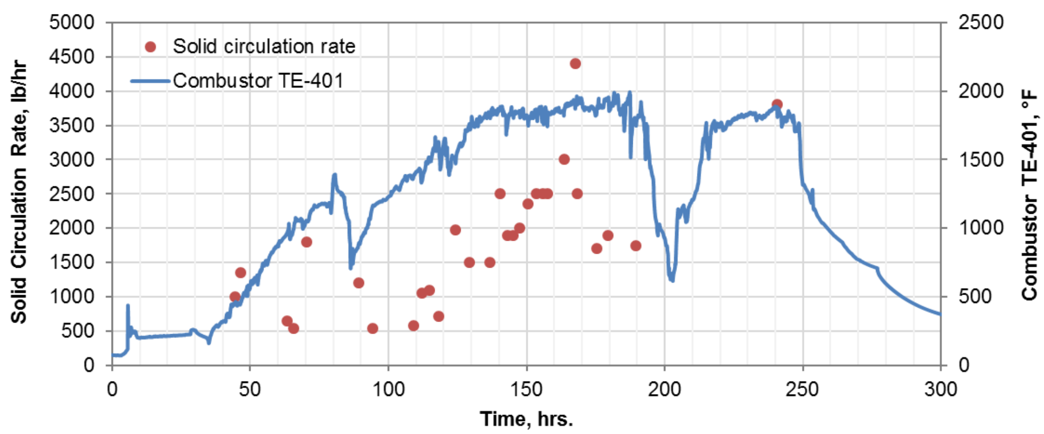


Figure 7. Measured solid circulation rate.

Figure 8 gives the actual combustor air flow and the operating combustor flow. The figure has two operating lines, one is the minimum combustor flow demand based on the minimum air flow for entrainment of solids out of the combustor, and the maximum flow to prevent particle carryover from the unit. The total combustor flow includes the flow of primary air, drain air, burner air, burner natural gas, and natural gas injection from combustor bottom. At low temperatures, for example 500 °F, the total minimum combustor flow demand is about 50%, and this decreases as temperature increases. The difference in air flow demand for minimum and maximum also decreases with temperature as well. At full temperature the demand is only 20 %. As can be seen in **Figure 8**, the air flow demand during the test run was maintained within the minimum and maximum flow demand curves most times.

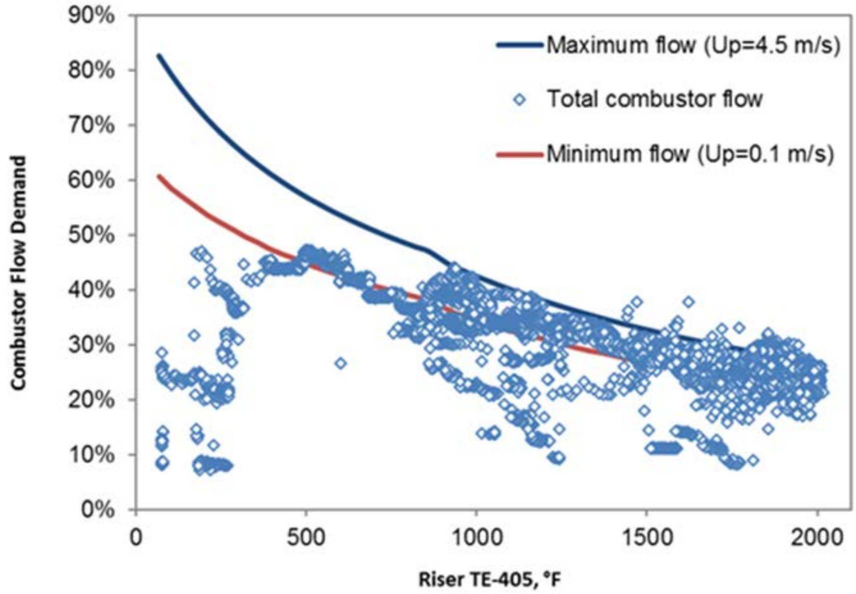


Figure 8. Actual combustor flow and particle entrainment operation limit.

Figure 9 shows the solid fraction in the riser during operation. The solid fraction was calculated based on the solid circulation rate and particle velocity. In most circumstances, the solid fraction in the riser was calculated to be in the range of 0.05 % to 0.2 %. It's worth noting that the solid entrainment is very sensitive to gas flow rate and particle size. Both **Figure 8** and **Figure 9** assume that 1) the average particle size is 1.4 mm, and 2) the total combustor flow is 300 lb/hr more than the instrument recorded value. The correction on gas flow rate is to prevent calculations of negative solid fractions. The combustor and riser operations were within the design limits of solid entrainment.

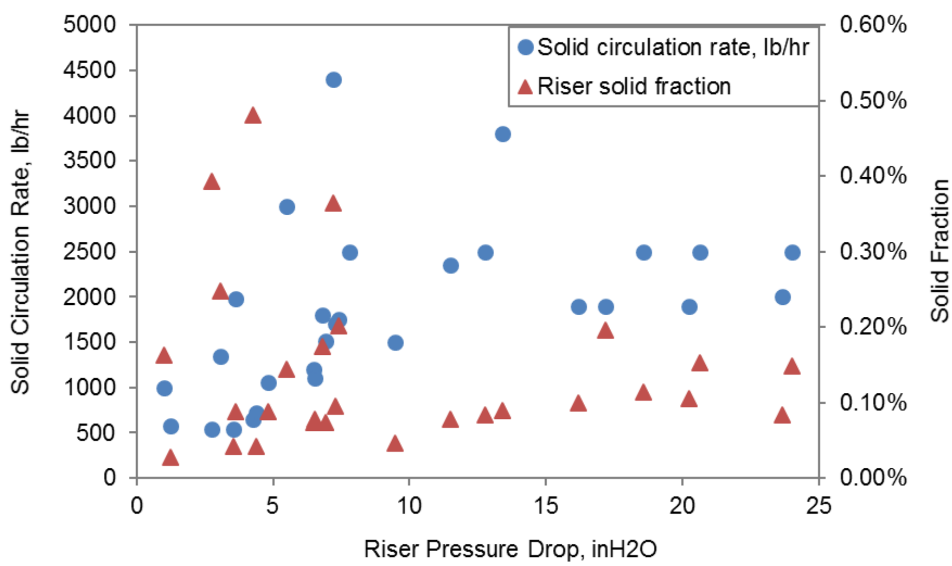


Figure 9. Solid circulation and solid fraction in riser as a function of the pressure drop in riser.

Attrition rates are important measurement since it will have a large impact on the overall cost estimate of commercial units. Given the various factors involved during the operation of the pilot, particle attrition data should be taken as indication only and should not be taken as a true measurement. Attrition data should be recorded under steady state operation and under reduction and oxidation. However, a preliminary particle attrition rate was obtained. At the end of the test, particles collected by the downstream baghouse were weighed. The total particle loss was 2818 lbs. These particles were collected under a wide range of conditions and may have come from other sources other than particle attrition, such as flyash. A preliminary attrition rate was estimated to be 0.18 %/hr based on the total particle loss and the reactor inventory. The actual attrition rate is expected to be much lower during steady state conditions.

5) Coal injection

Pulverized coal (<100 µm) was fed to the reducer reactor at three different time intervals, 10 min, 22 min, and 31 min. The coal was pneumatically sent into the reactor using CO_2 gas at a flow rate of 60 slpm. The feed rate was controlled to 9.6 lb/hr for the first injection period, and to 8 lb/hr for the last two injection periods. **Figure 11** shows a closeup view of the temperature profiles during the coal injection period. As the coal was fed into the reactor, temperature spikes at the hopper section of the Bottom-Moving-Bed reducer were observed. As shown in **Figure 11**, in the first feeding, the thermocouples TE-205/223/224 indicated an increased in temperature of 205 °F, 370 °F, and 190 °F, respectively. After the first feeding, TE-224/223/224 kept fluctuating; the fluctuating range and frequency of TE-224 was higher than TE-205/223. The increase of TE-205/223 later was not as high as in the initial injection. Based on these measurements, it is difficult to infer the coal distribution or coal reaction behavior inside the reducer reactor. However, the coal reaction with metal oxide is endothermic. Hence, the increase in temperature observed during the coal injection is very likely to be caused by some air infiltration in the reducer reactor. The reducer reactor during coal injection was operating under vacuum condition therefore, any leak in the reducer can result in air infiltration.

The oxygen distribution before coal injection in the reducer was mapped and shown in **Figure 10**. Overall, there was about 0.5 % oxygen in the BMB reducer. Individual locations had peak O_2 concentrations of 1.15 %. The oxygen concentration measured before coal injection was low enough not to cause any major temperature spikes. However, the system seems to be sensitive to localized high oxygen concentration spots. To avoid air infiltration in the reducer reactor during future tests, it is recommended that the reducer is operated at slightly positive pressure.

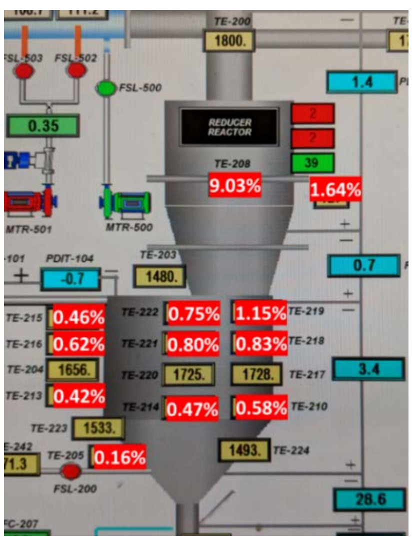


Figure 10. Mapping of O_2 concentration in the reducer (unit operation pressure -4 inH_2O).

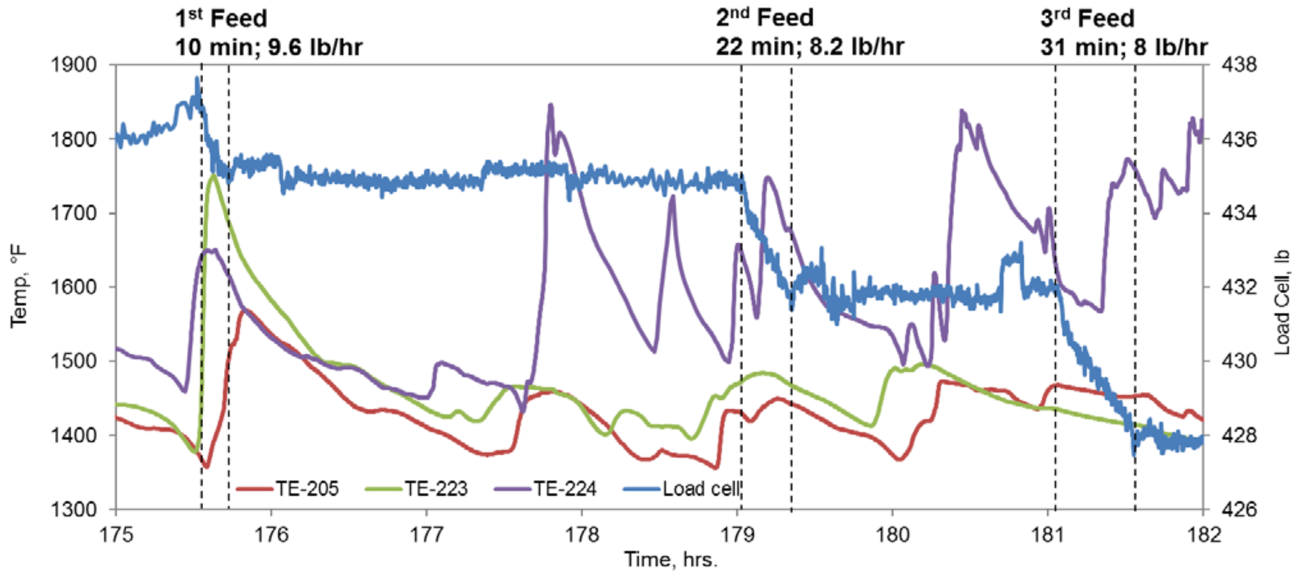


Figure 11. Temperature fluctuation during coal injection during three injection periods.

Figure 12 shows the gaseous concentration of carbon species at the outlet of the reducer and outlet of the combustor during the third coal-feeding injection period. The concentration of CO at the outlet of the reducer was as low as 200 ppm, indicating a high coal volatile conversion ratio. The CO_2 concentration at the outlet of the reducer increased from 64 % to 70 %. The corresponding carbon conversion turned out to be approximately 10 %. CO_2 concentration at the outlet of combustor kept constant at about 6 % during the third feeding. Carbon slip into the combustor was not observed in this test, indicating a high carbon capture efficiency. Note that the coal injection period was not enough to reach steady state conditions. During steady state conditions, coal residence time will increase and higher values should be observed.

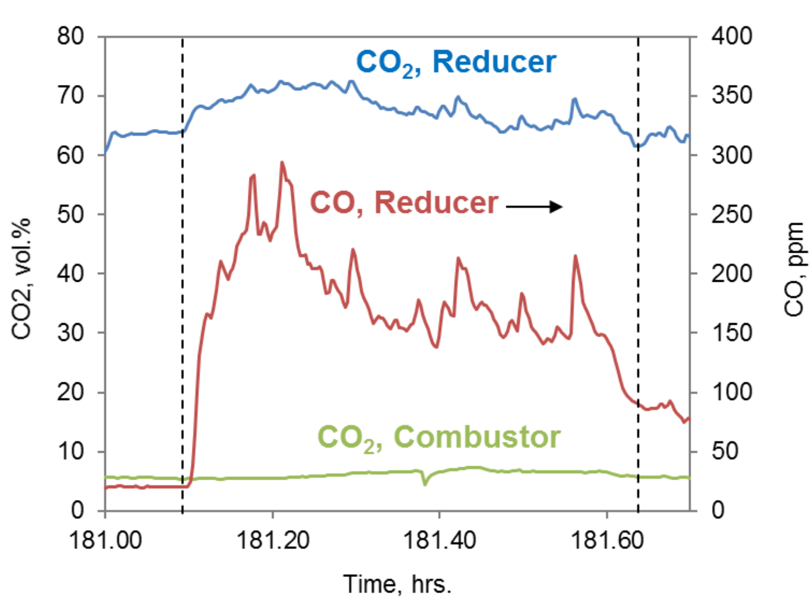


Figure 12. Gas profile from Reducer and Combustor during the third coal feeding.

6) Post-commissioning Inspection

Leakage: after the Jan-18 test campaign, the reactor was cooled down to ambient temperature. The entire system was pressurized to approximately +20 inH_2O to perform a leak check. Leakage was checked by spraying soap water on the surface of the vessel and ports. It was found that the NPT fittings of the thermocouple couples TE-210/205/213 and the 8-inch maintenance port were leaking. These were determined to be the most likely places where air infiltration occurred during the test campaign. A thorough leak check would be performed again before the next test campaign.

Coal distribution: At the end of the test run, coal was injected into the unit without solid circulation to observe coal distribution inside the reducer. After the reactor was cooled down, a small pile of coal was observed towards the east side wall sitting on top of the particle bed. The coal was not buried among particles, which might be because solids were not circulating when injecting the coal. However, the location of this coal points to the most-likely flow path of the injected coal. Based on these results, the coal injection nozzle would be modified to try to better disperse the coal on the bed of particles for future tests.

Particle discharge: The particles were discharged from the drain port at the bottom of the L-Valve. During discharge, small particle and coal agglomerates were found near the end. Subsequent X-Ray diffraction (XRD) analysis on the particle agglomerates showed that they contained elements from the oxygen carrier particles. No carbon was detected in these particle agglomerates. This implies that the agglomerates might come from the combustor side, instead of forming from interactions with the coal.

The reducer discharge was recorded with a video camera. After the videos were analyzed, it was noted that during discharge of the reducer, the particle flow pattern was funnel flow, instead of mass flow. This particle flow pattern in the reducer is attributed to the hopper section angle and the opening area of the standpipe. The funnel flow pattern may explain the lateral temperature difference observed in the reducer. A more uniform temperature distribution in the reducer could be obtained by increasing the cone section angle to greater than 70°. A total of about 8 drums of particles were recovered from the reducer. The drums were labeled, and particles were sampled for further characterization before use in a subsequent test.

Structure: The reactor vessel was inspected using a borescope after particle discharge. A few slight cracks were observed on the reducer refractory. Two other moderate cracks were seen on the combustor refractory wall due to the higher operation temperature. These cracks will be monitored but are not large enough to affect future operations. The bubble cap floor on the windbox was found in good condition. There were a few big agglomerates sitting on the bottom flange, which could have formed from hot spots when injecting natural gas directly at the bottom of the combustor. The startup burner and the burner tip were found in good condition as well. Some particle agglomerates were also observed at the exit of the startup burner. These agglomerates could have formed during periods of high burner demand in the combustor. To avoid particle agglomeration during subsequent tests, the burner and the bottom natural gas injection should be operated under leaner conditions to maintain a lower flame temperature.

During the fifth quarter, (**FY2Q3**) work was focused on defining and estimating the proposed changes to the pilot facility. The major modifications proposed to the 250 kWth facility are listed below:

1) Replace the combustor lower flange, air distributor and connecting piping (currently made of carbon steel) to higher-alloy material to accommodate higher inlet air temperatures.
2) Install electric heaters to preheat the combustor air to a target temperature of 1100 °F. This will reduce the startup burner demand which in turn will reduce the flame temperature.
3) Purchase and install an air compressor to increase reliability on the source for combustion air and avoid costs associated with compressor rental. An air compressor will also allow us to test the unit at ambient temperature and study the operation, coal injection and circulation of solids.
4) Replace filters connected to the sampling ports to reduce air infiltration.
5) Seal the 8-inch maintenance port in the reducer with high temperature sealant to reduce air infiltration.
6) Modify the quench system to introduce forced-air and reduce the amount of quench water, to allow reducer operation under positive pressure.
7) Externally insulate the reducer vessel to reduce the heat loss through walls and further increase the temperature in the reducer and thereby improve the gasification reaction rate.
8) Test coal distribution in a cold flow model and improve coal injection nozzle orientation and position for even dispersion.
9) Develop a retractable particle make-up system to avoid any intrusion on the stand pipe during operation.
10) Install a source of hot-air for preheating the reducer reactor. Preheating of the reducer reactor may reduce the time to bring the system to temperature for coal injection, thereby allowing more testing time at reaction conditions.
11) Install two electronic load cells at the discharge of the baghouse to monitor attrition rate
12) Install a particle drop out before the baghouse to capture entrained particles from the system.
13) Install a natural gas injection system at the bottom of the combustor for better heat management of the combustor reactor.

After all the modifications were implemented, B&W performed an additional test campaign. The test campaign focused on evaluating the conversion of Ohio bituminous coal which is what is currently used at the Dover Light & Power municipal plant. The objectives of this test were to:

a) Shakedown the system with the new modifications to the unit and adjustments to the control interface.
b) Accelerate the heat up process of the pilot unit.
c) Reach temperatures higher than 1650 °F at the bottom of the Bottom Moving Bed reducer.
d) Maintain smooth solid circulation without particle agglomeration.
e) Inject Ohio coal at a low feed rate, approximately 10 lb/hr. Attempt to maintain long term operation under coal injection.
f) Evaluate coal conversion, CO_2 capture efficiency and particle attrition rate among other performance parameters.

After the second test campaign, the test data would be analyzed, documented, and reported. The unit would be inspected and prepared for the next operation. Minor modifications to the unit or auxiliary systems might also be conducted to improve operations.

Milestone of the Second Test Campaign: Achieve good performance with Ohio bituminous coal. The specific goals for the second test campaign were:
1. Stable solid circulation
2. Coal conversion > 80 %
3. CO_2 capture efficiency > 80 %
4. Attrition rate < 0.1%/hr

Note: It is worth noting that coal conversions of less than 100 % and CO_2 purities of less than 100 % were considered acceptable at this stage of the design. Higher coal conversions and CO_2 purities would be achieved once an effective coal and particle residence time were determined based on the results of the test campaign. Design of the 10 MWe CDCL reducer and combustor reactors would then be adjusted to improve expected performance once the experimental parameters are evaluated. The plan was to carry out an assessment based on the results obtained to determine if satisfactory evaluation of the critical performance of the unit under coal were obtained, which would then end Task 2 activities while continuing with Task 3. If however it was determined that additional experimental data would be needed, the project team, with the assistance from the DOE/NETL, the IRC members and other project sponsors, would evaluate the best approach to resolve any outstanding issues to meet project objectives.

Second Pilot Test Campaign (August 2018)

The second pilot test campaign was performed in the sixth quarter (**FY2Q4**), from August 27th to September 10th, 2018 after implementing all the proposed modifications listed above. The detailed experimental results are discussed below.

1) Temperature Profile

Figure 13 shows the temperature profile of the second pilot test campaign. The unit was heated up to full temperature (1950 °F) within 90 hours. By preheating the reducer with hot air, the unit can be heated up faster. The temperature of the bed is $\leqslant$ 200 °F as particles move down the reducer, which is much less than the previous test campaign which experiences a drop of 400 °F to 450 °F. This was attributed to the external insulation around the reducer vessel. The sudden jump of the zone seal temperature (TE-206) was due to the position of the thermocouple which was adjusted to measure temperatures deeper into the bed and have a better measure of the particle temperature at the outlet of the reducer. Continuous solid circulation at the high temperature was maintained for 110 hours. A total of seven intermittent coal injection tests were performed during stable operation. At the end of the operation, solid circulation was lost due to the blockage in the standpipe, and consequently, the unit had to be shut down. Post-run inspection found a few chunks of refractory and agglomerated particles in the reducer. Investigation on the particle agglomeration is in progress.

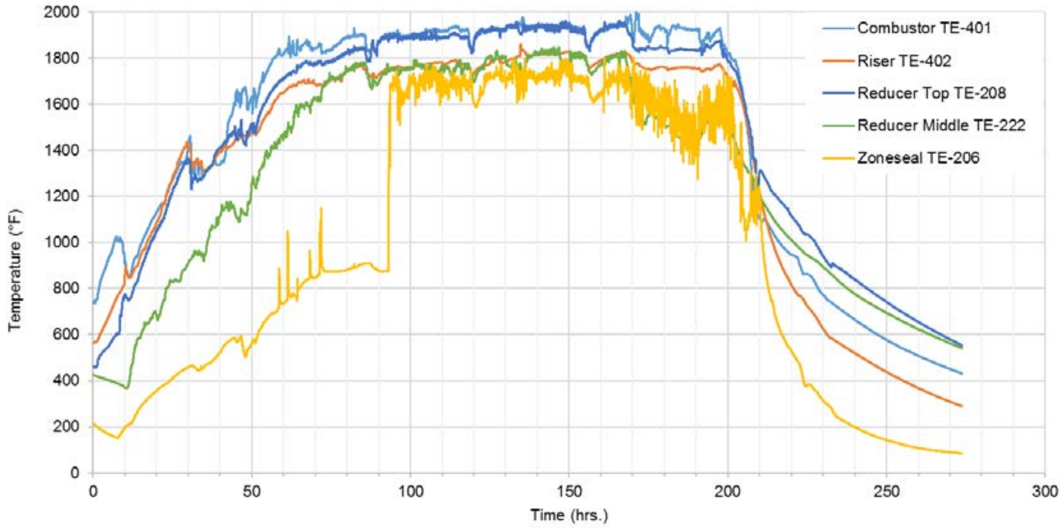


Figure 13. Temperature distribution throughout the reactor vessel.

2) Combustor Operation

The combustor was first heated up to nearly 1000 °°F with only preheated air. After that, the startup burner was turned on, and the demand of the startup burner was gradually increased until the combustor temperature reached 1100 °F to 1350 °F exceeding the natural gas auto ignition temperature. At this point, direct natural gas injection from the bottom of the combustor was initiated. The required amount of natural gas was gradually switched from startup burner to the direct NG injection system at the bottom of the combustor. The combustor was then heated up to the target temperature. In order to help evenly distribute the NG injection in the combustor bottom and prevent local hot spots, a high-grade-alloy distribution nozzle was placed at the same height as the air bubble caps. Correspondingly, the reducer was heated up to 500 °F by hot air first and then gradually brought to the full temperature by circulating the hot particles from the combustor. **Figure 14** shows the operation of the startup burner. The air-to-fuel stoichiometry of the startup burner was mostly maintained between 1.7 to 2.5; much higher than during the previous test campaign. The corresponding flame temperature was much lower as well. Lower flame temperatures reduce the chance of agglomeration of particles. Overall, the operation of the combustor was successful. The flame temperature was well controlled, and the distributor for the combustor bottom NG injection functioned as designed.

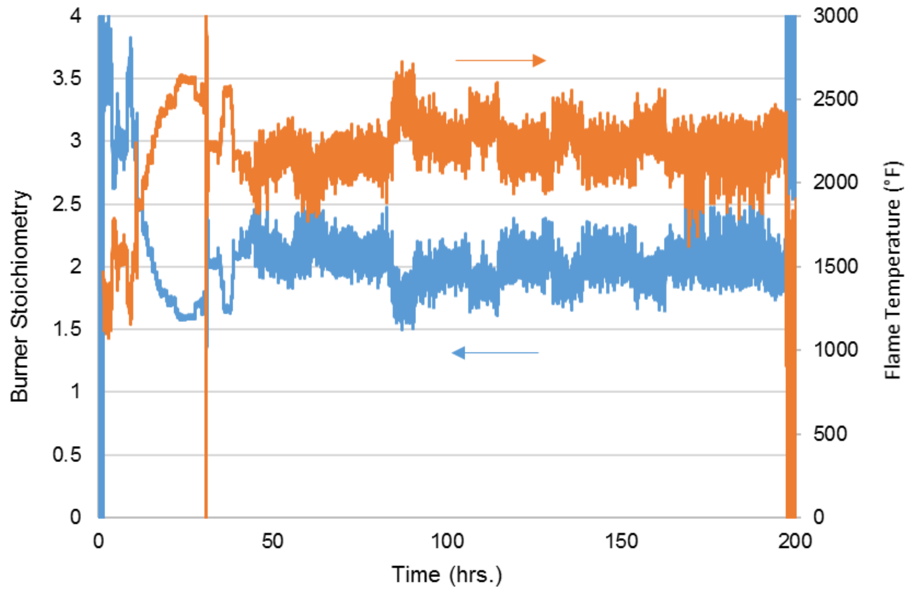


Figure 14. Burner stoichiometry and flame temperature.

3) Pressure Balance

Figure 15 shows the pressure balance during steady operation at 120 hrs. Most parts of the reactor were operated under slightly positive pressure, which was different from the previous run. This successfully prevented air infiltration into the reducer (**Figure 16**), which had caused severe issues during the previous run.

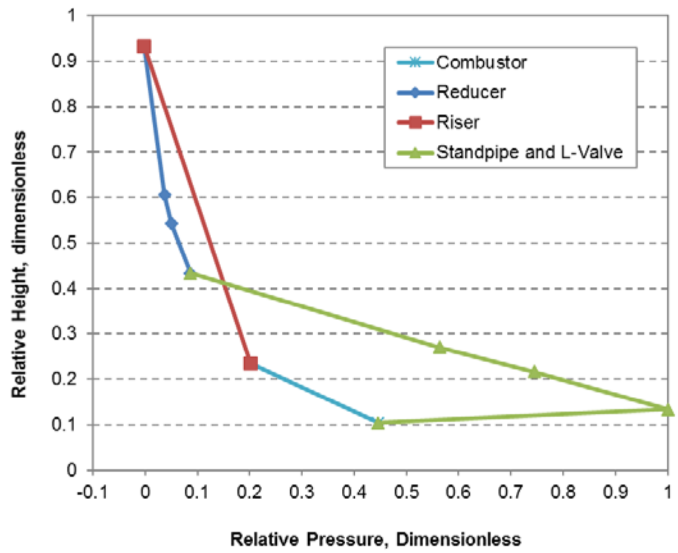


Figure 15. Pressure balance during steady operation at 120 hrs.

Figure 16 shows the oxygen mapping across the reducer reactor. Measurements were taken at the thermocouple locations since they were designed to have double function. Significant efforts were taken to ensure the gas analysis system had no leaks that could indicate a false reading of oxygen in the reducer reactor. As can be seen, oxygen concentrations were below the detection limit.

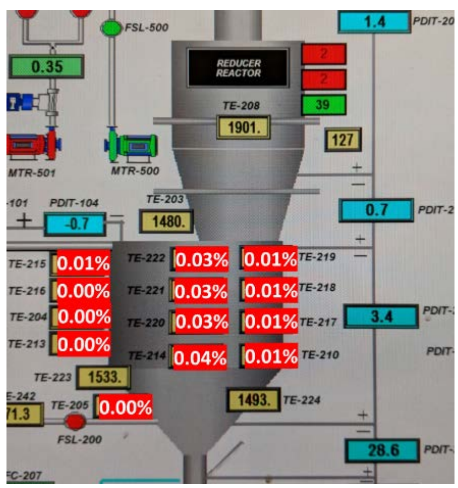


Figure 16. Mapping of O_2 concentration in the reducer (unit operation pressure -0.4 inH_2O)

4) Solid Circulation

Figure 17 shows the solid circulation rate measured with the iso-kinetic particle makeup device. The circulation rate was controlled in a wide range of 2000-6000 lb/hr with the L-valve aeration flow. **Figure 17** shows also the temperature of the combustor to indicate the time of the experiments where the measurements were taken. Particle residence time at the circulation rate of 3000 lb/hr and 5000 lb/hr were calculated in Table 2. This residence time will be used as the design basis for the 10 MWe design.

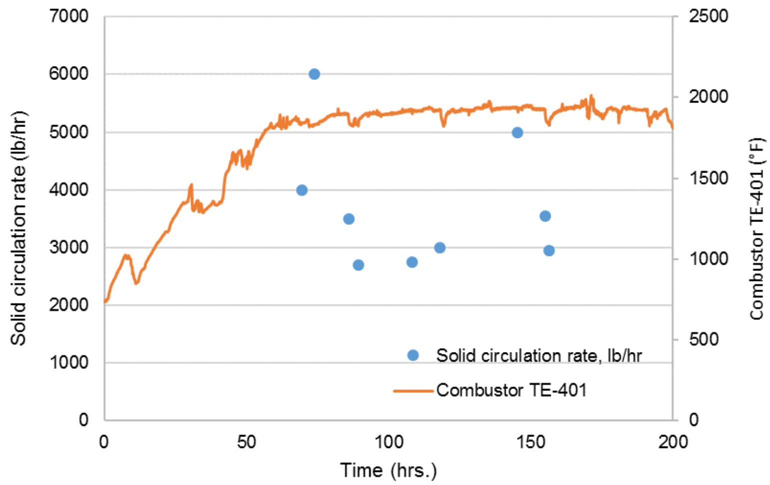


Figure 17. Measured solid circulation rate.

Table 2. Particle residence time.

Particle circulation rate (lb/hr)	3000	5000
TMB residence time (min)	39.5	23.7
BMB residence time (min)	88.9	53.34
Combustor residence time (min)	12.14	7.29

5) Coal Injection

Seven intermittent injections of Ohio bituminous coal were carried out in the second pilot test campaign, as summarized in Table 3. The coal feed rate was controlled at minimum value of 10 lb/hr to 20 lb/hr. The interval time between two injections was kept long enough to observe the system's response and wait for the gas profile and temperature to recover. **Figure 18** shows the typical gas profile at the top of the reducer reactor after the third coal injection. The CO concentration at the top of the reducer was less than 20 ppm, corresponding to very high conversion of volatile hydrocarbons and high purity of CO_2 (> 99 vol.%) in the reducer outlet stream. Formation of NO_x and SO_2 can be detected during coal injection period, proving that NO_x and SO_2 were derived from the fuel. The balance of carbon, nitrogen, and sulfur for the third coal injection can be found in **Figure 19**. The total converted carbon was equivalent to the total fed carbon, indicating a complete carbon conversion in the reducer without carbon carry over into the combustor. The conversion of N to NO_x and S to SO_2 was 21 % and 52 %, respectively. The balance for N, and S were not fully closed, which could be due to the experimental errors working at this scale, or due to the lack of measurement of certain species of N and S at the outlet of the reactor. N and S balances are more sensitive to errors due to the lower concentration.

Figure 20 shows the temperature change after the third coal injection, which was observed in other coal injections as well. After coal injection, temperatures in the east side (the coal injection side) of the BMB reducer decreased by 150 °F to 200 °F and the combustor temperature increased by 15 °F to 20 °F, as summarized from all the seven coal injections conducted during this test campaign. The temperature drop in the BMB reducer is caused by the endothermic reaction or by a slower solid flow or a combination thereof. The temperature increase in the combustor is very likely to be caused by the exothermic reaction of the reduced particles since there was no evidence showing coal carry-over to the combustor.

Table 3. Summary of Ohio bituminous coal injection.

	Time	Duration (min)	Coal Feeding Rate Settings (lb/hr)
1	9/3/2018 10:15-10:25	10	10
2	9/3/2018 17:38-17:58	20.4	10
3	9/4/2018 11:45-12:15	30	10
4	9/5/2018 04:41-05:11	30	20
5	9/5/2018 18:24-18:40	16	20
6	9/5/2018 22:59-23:25	26	20
7	9/6/2018 01:19-01:57	38	20

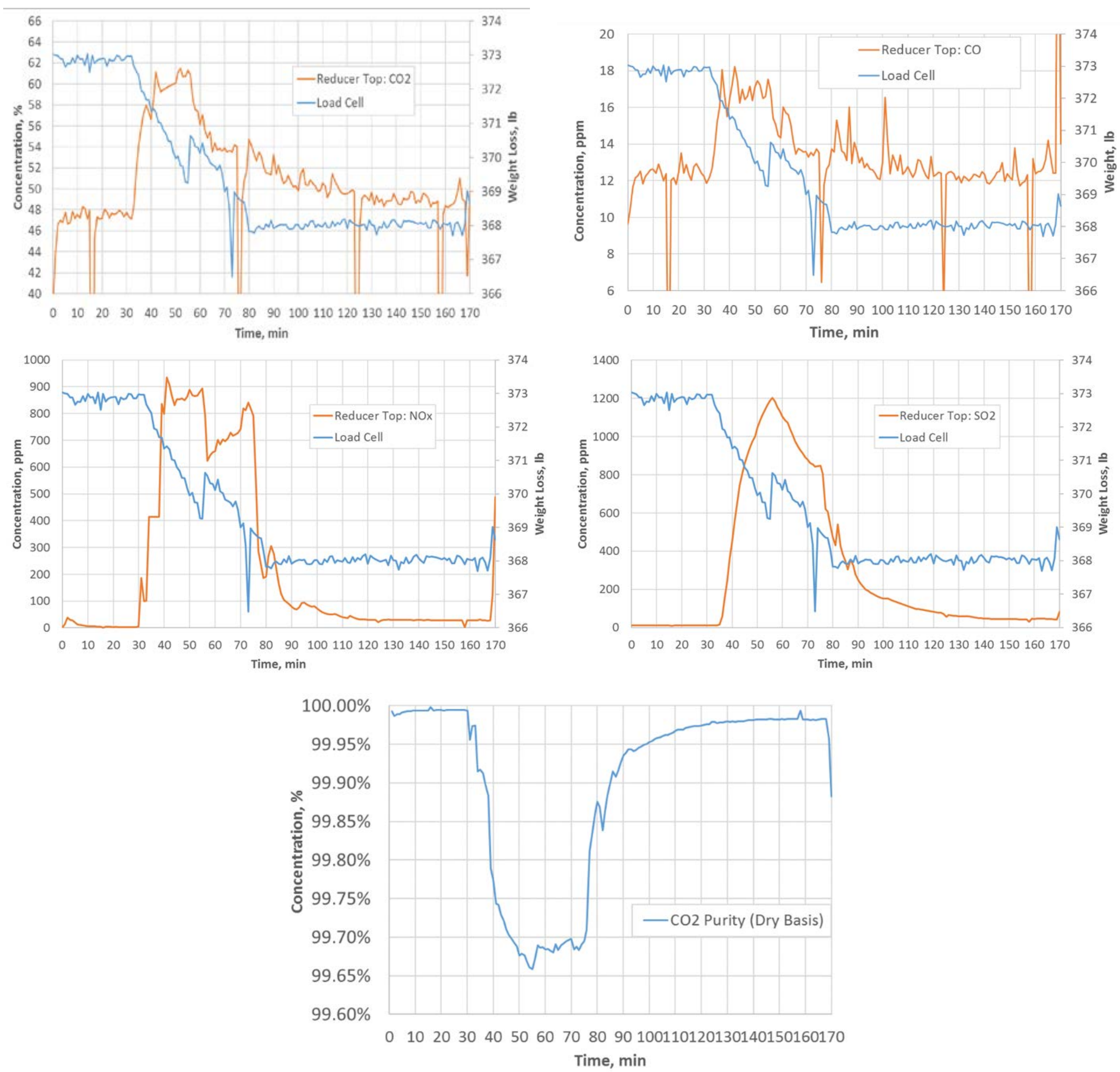


Figure 18. Gas profile from Reducer during the third coal injection.

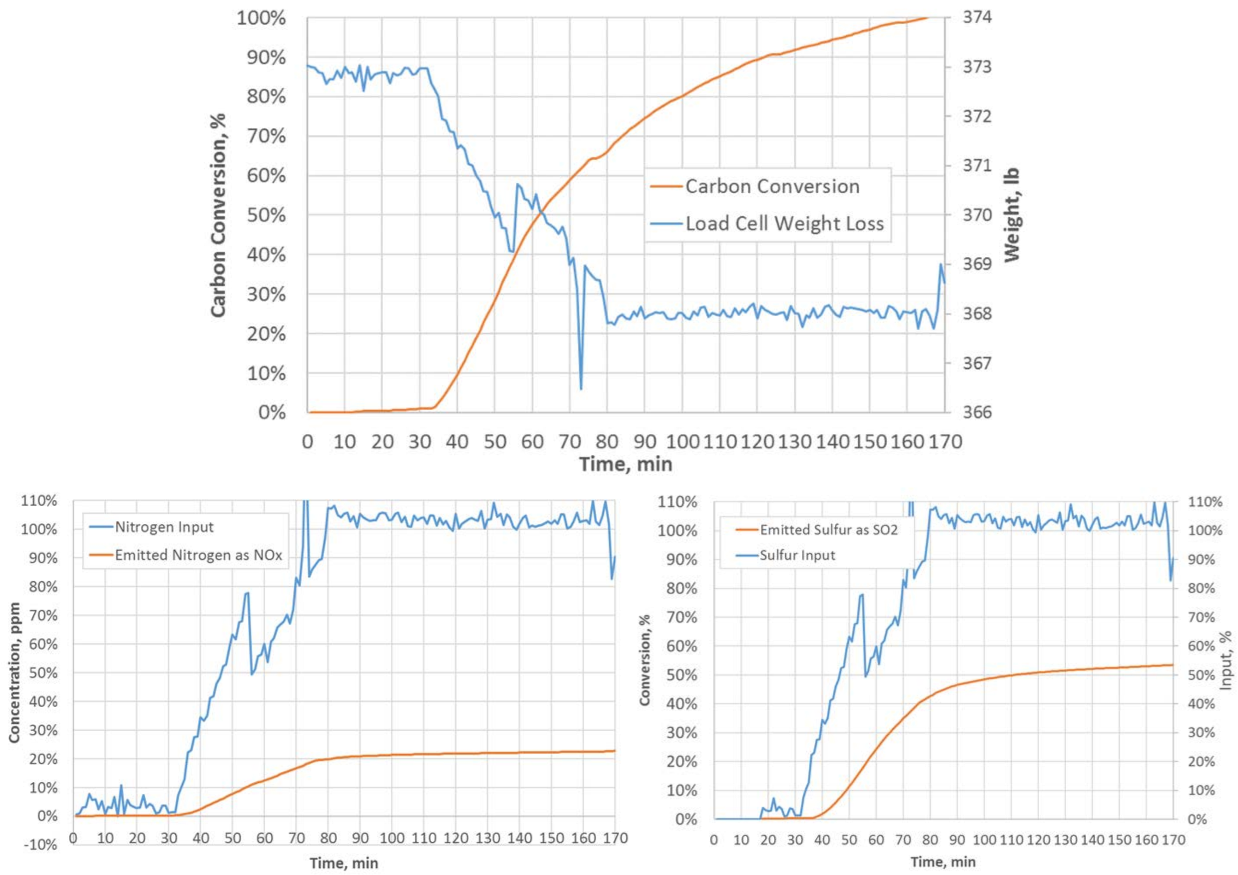


Figure 19. Carbon, Nitrogen, and Sulfur balance for the third coal injection.

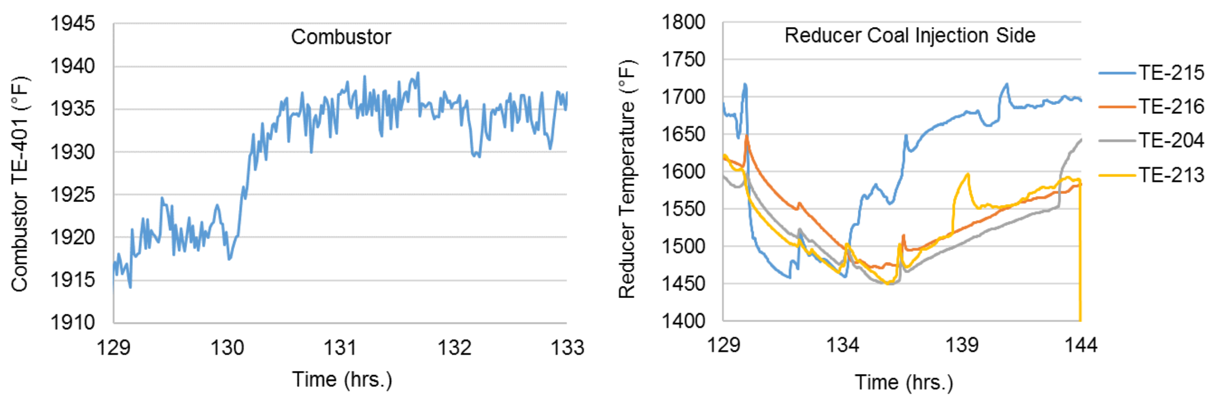


Figure 20. Temperature change in Combustor and Reducer after the third coal injection.

6) Particle Attrition

The fines entrained from the reactor were collected by the baghouse and weighed throughout the operation. The attrition rate was calculated by the equation below. **Figure 21** shows that the attrition rate in the second test campaign is in the range of 0.01 %/hr to 0.04 %/hr. This low attrition rate significantly reduces the operation cost of the CDCL technology.

$$Attrition\ rate = \frac{weight\ of\ collected\ fines}{time\ \times total\ inventory}$$

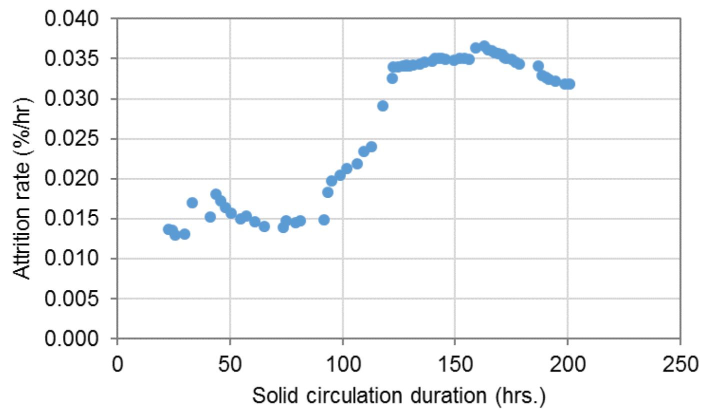


Figure 21. Attrition rate of particles.

Based on the test result, the milestones for the second test campaign had mostly been achieved. The successes of this test campaign from both aspects of operation and testing are listed in **Table 4.** However, a long-term coal injection test would still be needed. B&W and OSU are worked with DOE to plan for a third test campaign.

Table 4. Successful achievement from the second test campaign.

Operation	Testing
a) Fast heat up by preheating the reducer b) Reduced heat loss in the reducer with insulation c) Maintained 110 hours continuous solid circulation at 1950 °F d) Prevented air infiltration by operating at slightly positive pressure e) Better control of the flame temperature of the startup burner f) Evenly distributed coal with the assistance of N_2 injection	a) Successful intermittent coal injection for seven times b) High coal volatile conversion, CO_2 purity > 90 % c) Obtained particle attrition data; attrition rate very low, 0.01 %/hr to 0.04 %/hr d) Obtained CO, NO_x and SO_2 emission data during short-term coal injection

In the seventh quarter (**FY3Q1**), after the second test campaign, B&W and OSU performed a post-run inspection on the 250 kWth reactor. Approximately ten drums of particles were drained from the bottom of standpipe and re-sieved. Agglomerates and refractory pieces were collected and analyzed by Inductively Coupled Plasma (ICP), Scanning Electron Microscope (SEM), TGA, and fixed-bed studies to identify the potential causes. A hypothesis was that the reducer agglomerates formed due to ash softening. However, it was found later after ICP analysis that there was no ash composition in the agglomerates. Furthermore, the initial ash deformation temperature was found to be 2200 °F, indicating that the agglomeration was not induced by ash softening or melting. Similarly, it was hypothesized that particles were fusing forming agglomerates. Based on the particle fusibility analysis, the initial particle deformation temperature was 2685 °F under oxidizing atmosphere, and 2565 °F under reducing atmosphere. The reactor was operated at 1750 °F for the reducer and 1950 °F for the combustor, much lower than the initial particle deformation temperature. This indicates that particles can withstand the operation temperature.

After extensive testing on the oxygen carrier and coal/ash particles, the team concluded that the very likely cause leading to the formation of the agglomerates in the reducer reactor was due to the presence of localized hot spots. the formation of these hot spots is only possible under the presence of oxygen. Hence, it was hypothesized that air leaked through the standpipe which in turn reacted with the coal leading to the formation of local hot spots and hence to the agglomerates. During the second test campaign, the zone seal was unreliable due to obstructions caused by pieces of refractory. The compromised zone seal was ineffective to prevent air infiltration to the reducer reactor from the combustor. B&W and OSU are implementing the addition of steam into the reducer which will enhance sealing of reducer reactor from air leakage. O_2 level across the BMB reducer will be monitored during operation.

According to the lessons learned from the second test campaign, the following modifications would be implemented on the CDCL pilot unit.

1) Implement stringent testing protocols:
    a. Additional seal gas to prevent pressure imbalances
    b. Continuous oxygen mapping before and during coal injection at selected locations
2) Pre-coal injection testing of zone seal gas and injection system
3) Additional steam injection ports in the reducer reactor to assist coal flow & gasification
4) Replace nitrogen with CO_2 as zone seal gas
5) Improve temperature mapping on the reducer reactor
6) Modify air quench system to increase capacity
7) Incorporate Gas Chromatograph (GC) system for H_2S analysis and monitoring
8) Improve reducer gas extraction system including rebuild of sampling probes
9) High-alloy ram rods and metal insert to break agglomerates at the bottom of the reducer
10) Update data controls and logging system

The steam injection ports and ram rod ports were fabricated. High alloy material for steam lances, thermowells, and ram rod was purchased and received. The SBSII booster fan was connected to the quench system to increase the cooling capacity. Sampling probes were designed, and fabrication started. Metal insert for protecting refractory when breaking agglomerates was designed, fabricated, and installed. The flange on the combustor was reinstalled after combustor inspection. Steam delivery system was evaluated, built and ready for testing. An electrical heated CO_2 regulator was purchased to prevent the freezing issue of CO_2 delivery pipeline in winter. MKS instrument and Mass Flow Controllers (MFCs) were calibrated by manufactures. The GC system for H_2S analysis was setup and calibrated. Dräger tubes in various ranges were purchased as the backup for H_2S analysis. O_2 analysis system for continuous oxygen mapping was identified and will be installed before the third pilot testing.

Third Pilot Test Campaign (January 2019)

The third pilot test campaign was performed during the eighth quarter (**FY3Q2**), from January 28th to February 10th, 2019, after implementing all the proposed modifications listed above. The detailed experimental results are discussed below.

1) Temperature Profile and Operation Sequence

Figure 22 shows the temperature profile of the main CDCL loop and the operation sequence of the January 2019 test campaign. The system was operated steadily for 288 hours with smooth particle circulation.

The system was first heated up with preheated air for 24 hours. After the reducer reached 550 °F, the preheated air to the reducer was shut off due to the temperature limitation of carbon steel and the reducer temperature started to drop slightly. The temperature of the preheated air to the combustor was gradually increased up to 987 °F. To further heat up the system, the start-up burner was turned on. As the temperature increased, the required air flow to circulate particles decreased when solid circulation was established. From this point on the reducer was heated up to the target temperature with hot circulated particles. As the combustor temperature reached the auto-ignition temperature of natural gas (1100 °F), natural gas was gradually switched from the burner to the injection lance in the bottom of the combustor. The system was continuously heated with natural gas injection with less demand on the burner. In this way, the particles can be protected from the direct firing of the burner and less likely to form agglomerates. System target temperature was reached after heating up for 75 hours. This is much faster than the previous testing.

During the the reducer. The steam and coal feeding systems were tested first. Then, a 5-hour coal test at a low load (10 lb/hr) was accomplished. The system was steady operation, the temperature was maintained at 1750 °F to 1900 °F for the combustor and 1400 °F to 1700 °F for able to maintain steady performance after the 5-hour coal injection during a follow-up system flushing period. The practice of using a flushing period was employed to verify that accumulated ash in the reducer did not induce agglomeration. Therefore, a long-term coal injection (35-hour) at 10 lb/hr was conducted. Parametric testing of the operation temperature and the coal load capacity was conducted afterwards. Full design capacity up to 40 lb/hr was reached during the parametric testing. Towards the end of the campaign, a momentary power outage for approximately 1 min occurred. The entire system shutdown upon loss of power. It took about 1 hour to turn everything back on. The system temperature dropped slightly during this period. However, it was quickly recovered after all the heating sources were back on. Parametric testing at full design capacity was continued and accomplished after the system was recovered. The facility was proven to be robust and resilient to electrical outage. The system brought itself down safely without operator intervention. All valves and dampers failed in their proper position and all energy sources isolated from the system. At the end of the testing, the system was shut down as scheduled.

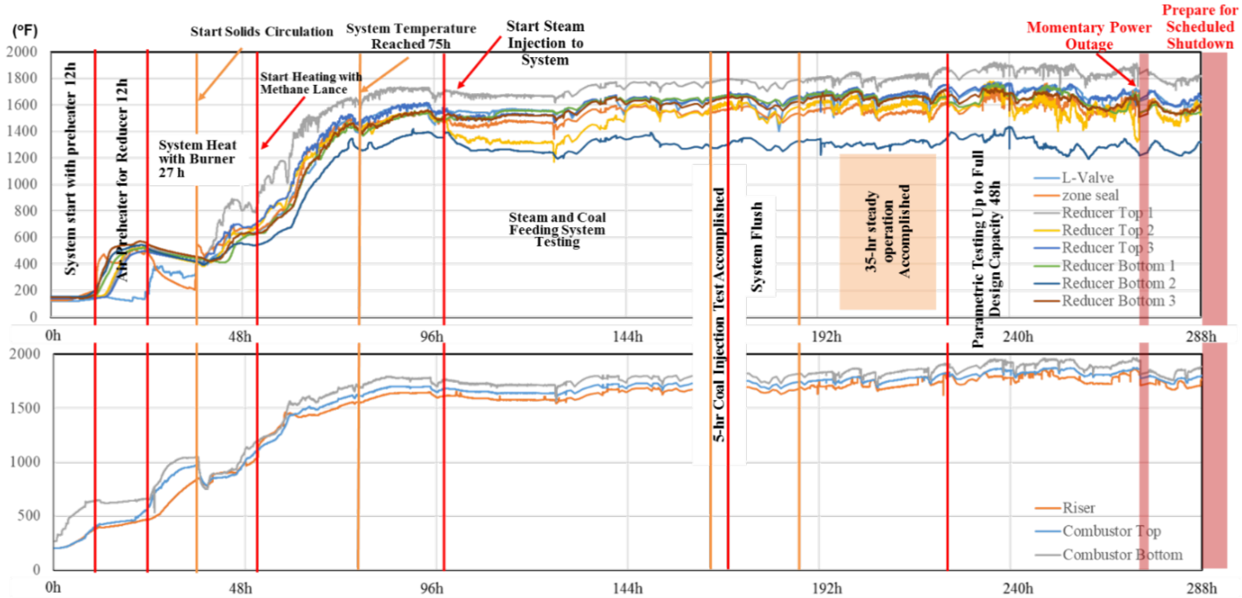


Figure 22. Temperature profile and system operation sequence.

2) Burner Operation

The start-up burner was turned on after preheating the system with air for approximately 24 hours. The stoichiometric ratio of the burner was mostly maintained above 2, corresponding to a flame temperature lower than 2000 °F (**Figure 23**). The purpose of maintaining a relatively lower flame temperature was to protect particles from agglomeration, as was the practice during the previous test campaigns.

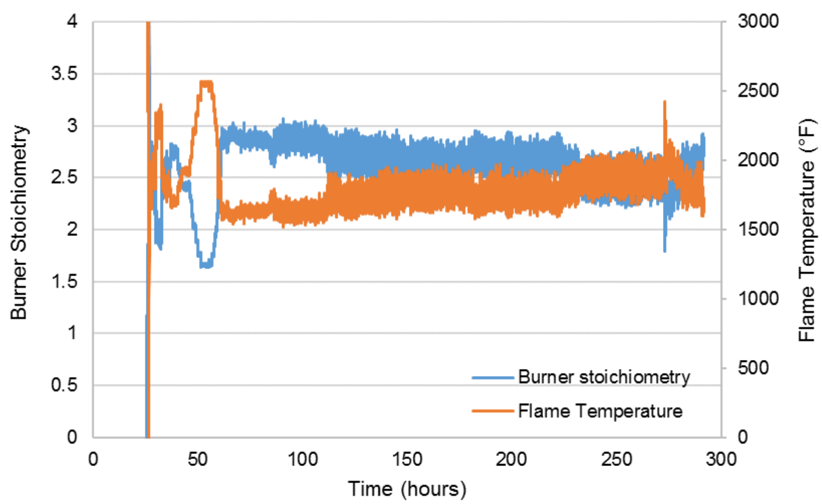


Figure 23. Burner stoichiometry and flame temperature.

3) Pressure Balance

Figure 24 shows the pressure balance during steady operation at 200 hrs. The system was operated under slightly positive pressure of 0.9 inH_2O, to prevent any potential air infiltration. The main difference from the previous test campaign was that the reducer was operated at a higher pressure than the combustor due to the high enhancer gas flow. This inhibited any air back flow from the combustor to the reducer. In fact, O_2 was not detected at the bottom of the reducer throughout this test campaign.

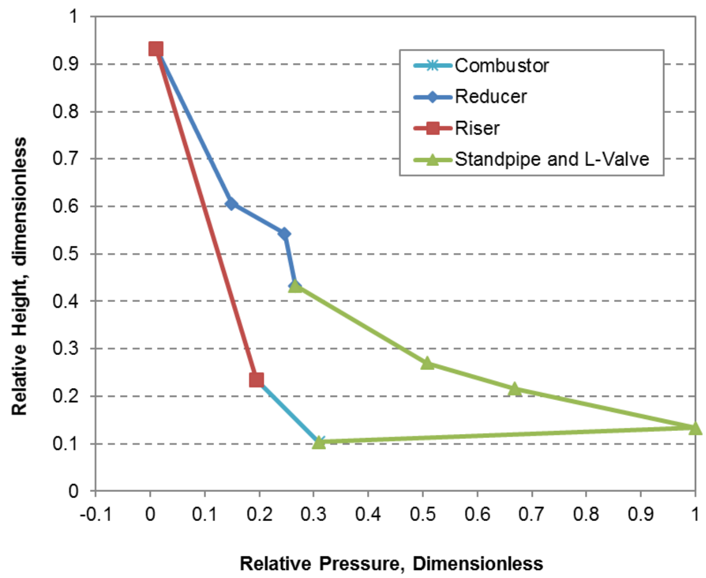


Figure 24. Pressure balance at 200 hours.

4) Solid Circulation and Residence Time

Figure 25 shows the solid circulation and particle residence time during the third test campaign. The solid circulation rate was controlled in the range of 1000 lb/hr to 6000 lb/hr by the aeration flow to the L-valve. During the period of coal testing, the circulation rate was in a high range, 5000 lb/hr to 6000 lb/hr. The particle residence time during coal testing period was 10 min for the combustor, 20 min for the TMB reducer and 60 min for the BMB reducer. These residence times are consistent with the design values.

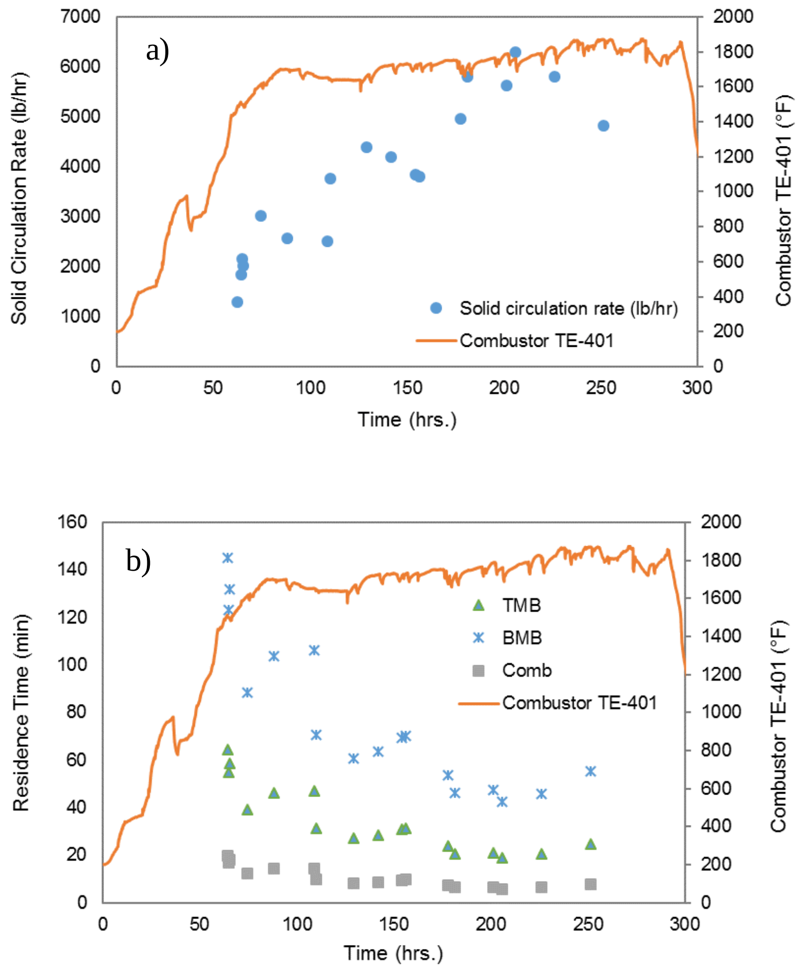


Figure 25. a) Solid circulation and b) Residence time.

5) Coal Testing

The third test campaign resulted in nine periods of coal injection, as summarized in **Table 5** with a total accumulated coal test duration of nearly 62 hours. Steady operation was maintained after each coal injection. A 35-hour coal test at a lower load of 6 lb/hr to 10 lb/hr was accomplished. Parametric testing at higher loads of 20 lb/hr to 40 lb/hr was also completed on February 7, 2019 and February 8, 2019. Performance data of three of the coal tests highlighted in yellow in Table 5 is further detailed below.

Table 5. Coal injection summary.

Date	Time	Duration	Amount of Coal
02/03/2019	05:19-05:55	36 min	3 lb
02/03/2019	19:20-02/04 0:35	5 hr 14 min	38 lb
02/04/2019	19:55-02/06 7:10	35 hr 13 min	213 lb
02/06/2019	16:00-18:43	2 hr 43 min	11 lb
02/06/2019	19:06-21:30	2 hr 24 min	33 lb
02/07/2019	04:40-14:12	9 hr 32 min	176 lb

02/07/2019	16:53-18:25	1 hr 32 min	15 lb
02/08/2019	03:45-07:37	3 hr 52 min	106 lb
02/08/2019	23:30-02/09 0:24	54 min	12 lb
Total accumulated coal test duration: 61 hr 54 min			

35-hour coal testing:

Figure 26 and **Figure 27** show performance results of both the reducer and the combustor during the 35-hour long-term coal injection test period. The figures below portray a representative 60-minute segment. As seen in the figures, the coal conversion reached 95 % and the CO_2 purity (N_2 free) was maintained at around 97 %. The ability of the counter-current moving bed design to obtain high purities of CO_2 was thereby validated at the 250 kW_{th} pilot scale. Emissions of SO_2 and NO_x from the reducer reached levels of 3000 ppm and 5000 ppm, respectively. The corresponding S and N balance were 75 % and 55 %, respectively. H_2S was not detected. The remaining S and N likely reported to the ash. Since the fly ash collected by the baghouse was mixed with particle fines and cannot be separated, the residual S and N in the ash and its corresponding flow rate could not be determined. On the combustor side, carbon carryover was not observed. A temperature increase of 10 °F in one hour was observed during periods of coal testing, which is expected to result in an exothermic particle oxidation reaction. In order to compensate for the exothermic reaction and maintain steady operating temperatures in the combustor, the amount of natural-gas injected into the combustor was simultaneously decreased.

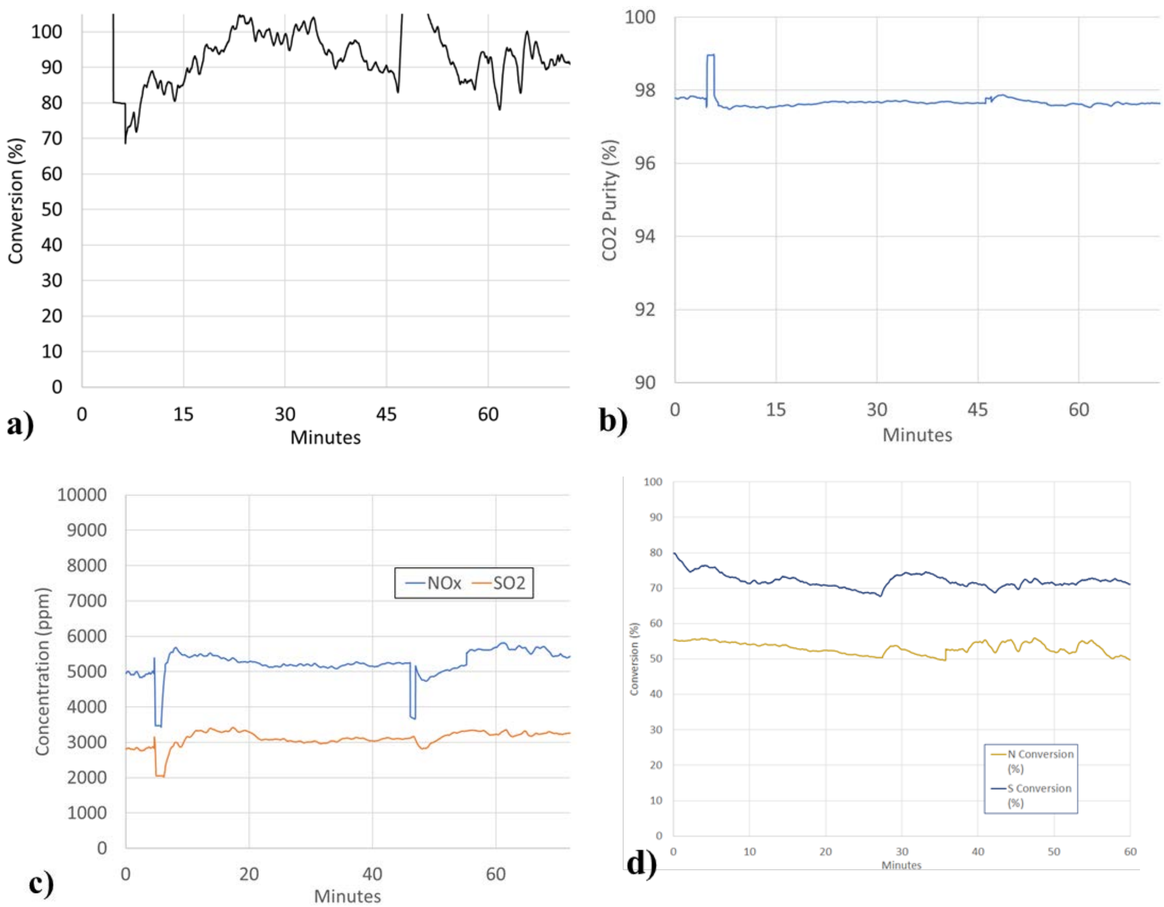


Figure 26. Reducer performance during 35-hour coal testing: a) coal conversion; b) CO_2 purity (N_2 Free); c) SO_2 and NO_x emissions. d) N and S balance reporting from Reducer measurements (*A representative 60-minute segment is shown).*

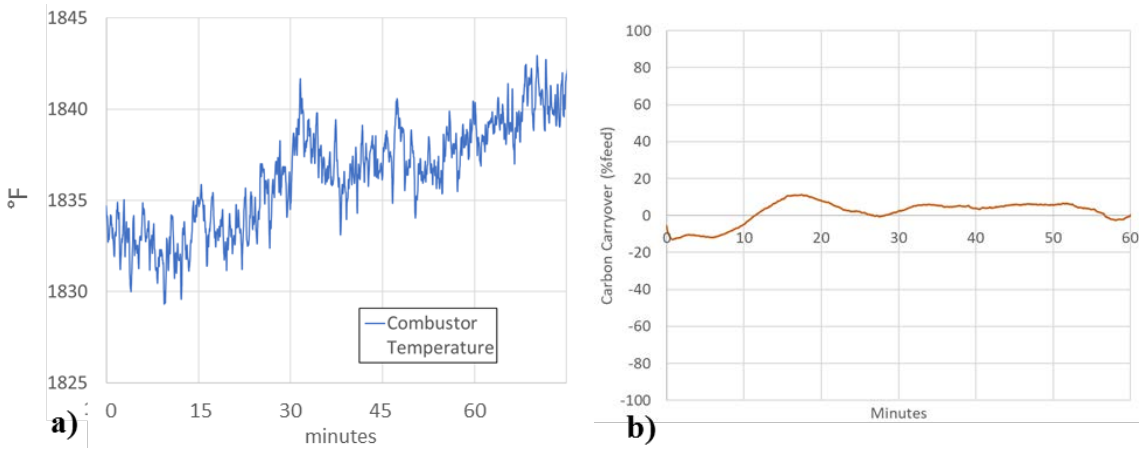
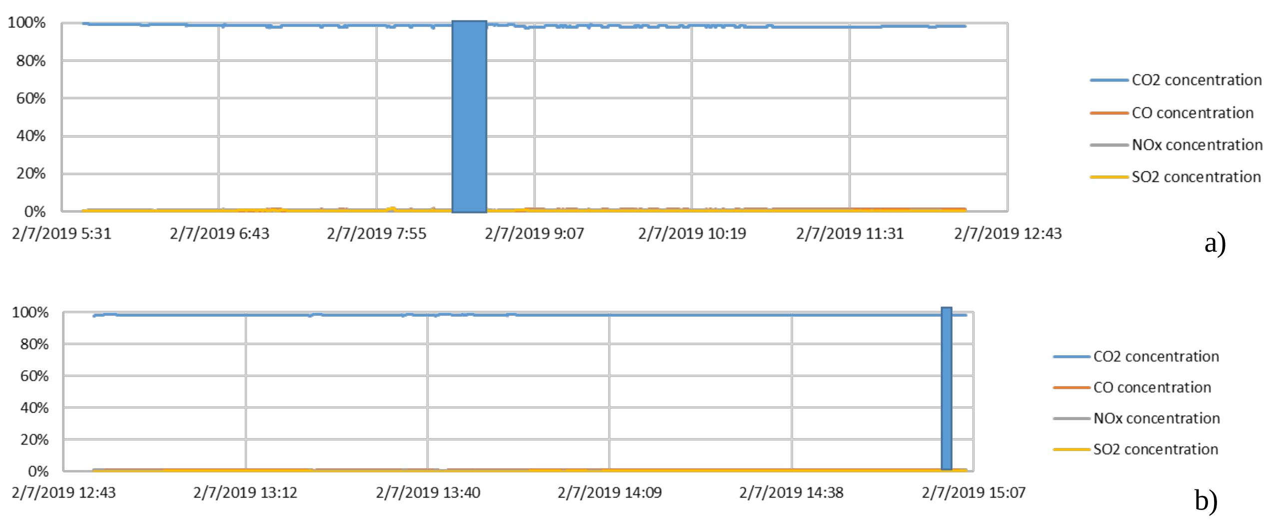


Figure 27. Combustor performance during 35-hour coal testing: a) combustor temperature; b) carbon carryover (*A representative 60-minute segment is shown).*

Parametric testing at high coal loading rate:

Figure 28 shows the N_2-free concentration of CO_2, CO, NO_x and SO_2 at the reducer top at higher coal injection loads of 20 lb/hr to 40 lb/hr. The CO_2 purity at high load reached 95 % to 99 %. The facility was successfully operated at the nominal design capacity of 40 lb/hr. In the figures below, the periods highlighted in blue represent the time where the analyzers were offline.



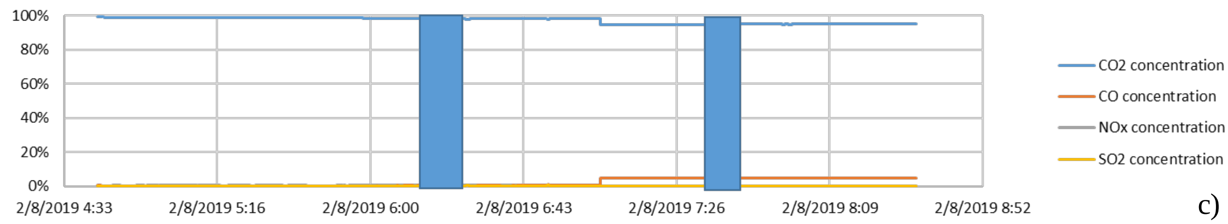


Figure 28. Reducer top gas concentration (N_2 free) at various loads: a) 20 lb/hr; b) 30 lb/hr; c) 40 lb/hr. Sampling offline period is blocked in blue.

6) Particle Attrition

Particles entrained from the reactor loop were collected at the baghouse throughout the operation. The fines less than 700 µm were then separated by further sieving and weighing in order to determine attrition rates. **Figure 29** shows the attrition rate of the third test campaign. The attrition rate is in the range of 0.02 %/hr to 0.03 %/hr, which is consistent with the attrition rate measured during the second test campaign.

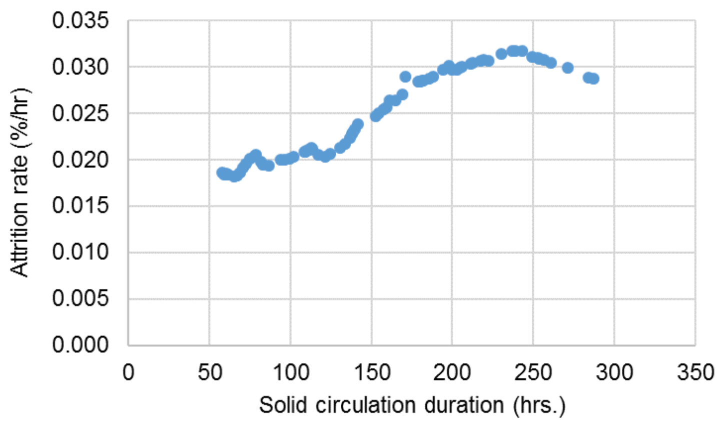


Figure 29. Particle attrition from the Third Test Campaign.

<u>Subtask 2.2. Design, Construction and Testing of Modular Cold Flow Model</u>

(FY2Q2) OSU and PSRI held a kick-off meeting on March 23, 2018. The studies on coal distribution and combustor Cold Flow Model (CFM) were discussed briefly. PSRI suggested to design the CFM based on their existing facility (**Figure 30**). A follow-up conference call was held on March 29, 2018. In the follow up conference call, OSU and B&W provided some general guidelines on the test objectives and the CFM suggested dimensions and expected operating parameters.

Figure 30. PSRI 2D facility for CFM study.

There was no reported activity during quarters (**FY2Q3**), (**FY2Q4**), (**FY3Q1**), and (**FY3Q2**).

During the ninth quarter (**FY3Q3**), OSU developed a constructed a cold flow model of the moving bed reducer to study the path of pulverized coal particles in a moving bed of glass beads at various inlet gas flows. Details on the flow model were provided in the following quarter.

(**FY3Q4**) A cold flow model, of which a schematic diagram is shown in **Figure 31**, was built and testing was performed to characterize the fluidization of coal particles in a packed moving bed of oxygen carrier particles. The experimental system of the CFM consists of a test zone of cylindrical column with an ID of 3 inches and a height of 20 inches. Another cylindrical column with a height of 6 inch is connected to the test zone through flanges and serves as the windbox section to provide fluidization gas to the test zone. A wire mesh with a mesh number 325 (0.044 mm by 0.044 mm) is placed between the test zone and the windbox for the purpose of gas distribution. The outlet of the CFM is connected to baghouse to capture the fines which might be entrained by the fluidization gas. Compressed air from a compressor is used as the fluidization gas through the bed and is introduced into the system from the side of the windbox. ALICAT MFC with a range of 0-50 slpm is used to precisely control the mass flow rate of the air to the test system. Three pressure transducers (OMEGA, PX-419005DWU5V), DP1, DP2 and DP3, were installed to measure pressure drop at different locations of the fluidized bed. Copper wire was twined around the column and connected to ground to remove the static charge during the operation of the experiment. Coarse glass beads with a diameter between 1.5 mm and 2 mm were used to represent oxygen carrier particles and silica sand was used to represent fine coal particles for the experiments. The glass beads have a particle density of 2,500 kg/m^3 and a bulk density of 1,300 kg/m^3. The silica sand has a particle density of 2,650 kg/m^3 and a bulk density of 1370 kg/m^3. The physical properties of the glass beads and silica sand particles are similar to coal and oxygen carriers, respectively.

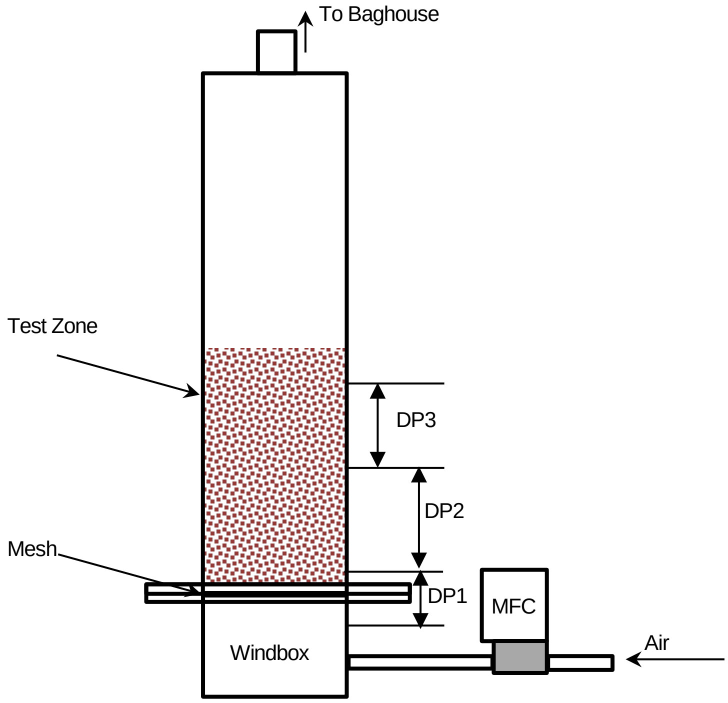


Figure 31 Schematic diagram of the experimental setup

At the bottom section of the test zone, a mixture of glass beads and silica sand was introduced together up to the level of the top leg of DP2. Another layer of particles which consist of only coarse glass beads is then filled to the top section of the bed. In the test, the mixture of glass beads and silica sand are mixed with different concentrations (vol %) of fines based on the volume of the bottom section of the bed. The concentration of fines used correspond to 5 vol%,10 vol% and 15 vol%.

During the test, different gas flow rates through the bed between 0 slpm to 60 slpm were used. At each gas flow rate, the pressure readings of DP1, DP2, and DP3 were recorded. DP2 was then used to calculate the pressure drop of the fines. To determine the pressure drop exclusively due to fines in the coarse-fine particle mixture, the pressure drop due to coarse particles was subtracted from the overall pressure drop.

As can be seen from **Figure 32**, the pressure drop increases almost linearly with gas flow rate up to 40 slpm (0.15 m/s) for all the cases. Beyond the gas flow rate, the pressure drop fluctuates around a certain value. This indicates that the minimum fluidization gas flow rate is around 0.15 m/s. The minimum fluidization velocity of fine particles in the bed of coarse particles is significantly higher than that of fines without any coarse particles (0.015 m/s).

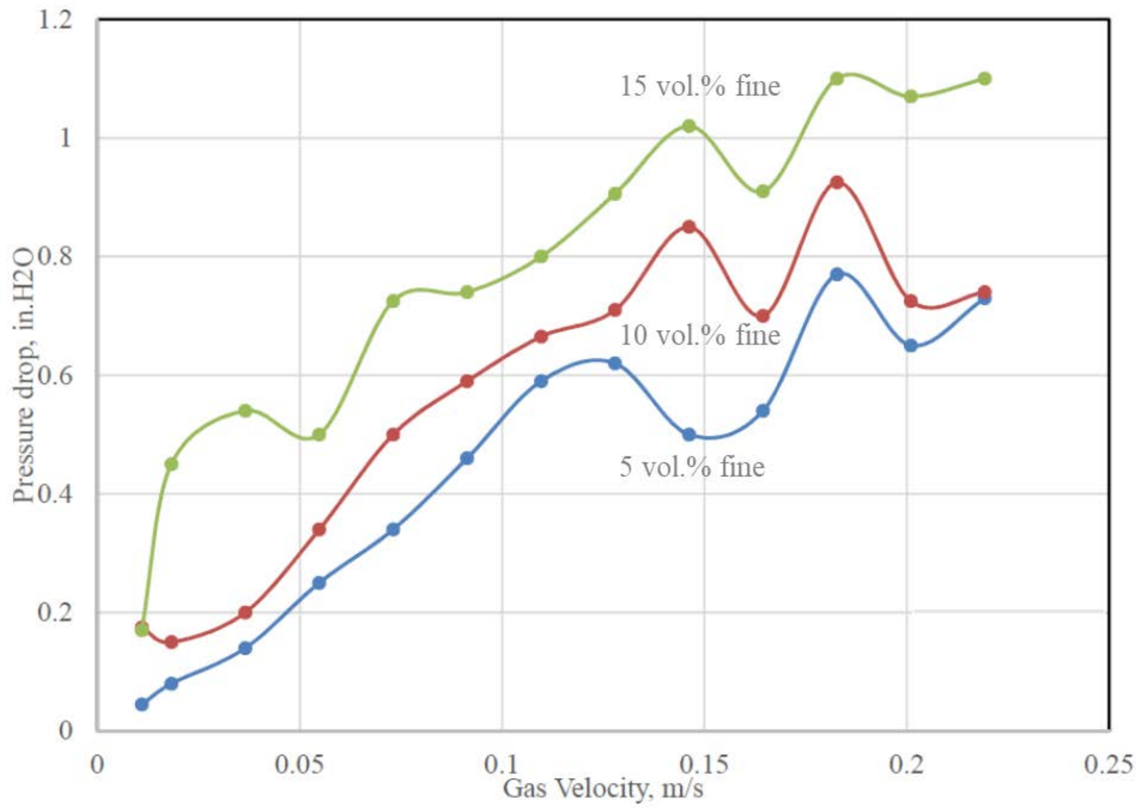


Figure 32. Pressure drop of fines at different fine concentrations

There was no reported activity during quarters (**FY4Q1**) and (**FY4Q2**).

Subtask 2.3. Emissions Performance and Environmental Control Report

General

The study consists of installing a 10 MWe coal direct chemical looping (CDCL) large pilot demonstration unit at the Dover Light & Power (DL&P) site in Dover, Ohio. The pilot unit will consist of four 2.5 MWe chemical looping modules providing heat for steam generation in a common convection pass and steam supply header. This project will serve as a significant step forward to demonstration carbon-friendly power generation technology by producing pipeline quality CO2 suitable for utilization or sequestration, though transportation and utilization or sequestration will not be demonstrated as part of the project.

The study is limited to produce pipeline quality carbon dioxide and does not include the piping of the carbon dioxide to an end user or sequestration site nor its environmental effects. This is considered beyond the scope and budget for the current project but could be a topic of a future project.

Since this is a first-of-a-kind demonstration at this scale, the team has developed an approach to mitigate technical and operational risks associated with performance or operability. The first 2.5 MWe module will be built along with the entire balance of plant system. The first 2.5 MWe module will be tested and operated for an extended period of time to identify performance or operational issues not identified in the previous 250 kWt smaller scale test facility. The design will be modified or enhanced to address the issues. The improvements will then be incorporated into the design of the remaining three modules prior to their fabrication and installation. Finally, the full system will be operated to confirm full system functional performance and operability.

It is assumed that Dover Light & Power will continue to operate the facility after the completion of the DOE project as part of its full suite of steam generation equipment at the site, thereby increasing its power generation capacity.

Environmental Impact of the CDCL pilot unit

1) Land Use, Geologic and Soil Conditions

The existing Dover Light and Power Municipal Plant is located on approximately 4 acres of land in North-Central Tuscarawas County. The land in the immediate vicinity of the Dover Plant is a mix of residential and industrial. The predominant land use in the vicinity of the property is developed for other human use, though there are forest and woodland areas located northeast of the plant.

The unit will be installed within the confines of the existing plant; no additional land will be acquired. There may be changes to on-site structures to accommodate equipment, but no onsite land use changes will result from installation of the CDLC unit. Additionally, no changes to vicinity land use or land use designations will occur. Lay down area is available across the street for construction phase.

Since all the construction will be occurring within the existing plant boundaries, no impact to geological or soil conditions is expected due to construction.

2) Air Quality

Air pollution comes from wide variety of both anthropogenic and biogenic sources. Air quality is affected in many ways by the pollution emitted from these sources. The Clean Air Act (CAA) provides the principal framework for national, state, and local efforts to protect air quality in the U.S. Under the CAA, the United States Environmental Protection Agency (USEPA) is responsible for setting standards known as the National Ambient Air Quality Standards (NAAQS) for pollutants which are considered harmful to public health. These pollutants, known as ‘criteria pollutants’, are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), particulate matter (PM), and lead (Pb).

An air quality control region is a federally designated area that is required to meet and maintain the NAAQS. Regions may include nearby locations in the same state or nearby states that share common air pollution problems. The Dover Plant is located in Tuscarawas County, which is included entirely within the Zanesville-Cambridge Intrastate Air Quality Control Region promulgated in 40 CFR 81.205.

Air quality in Ohio is regulated by the Ohio Environmental Protection Agency (Ohio EPA) and Region 5 of USEPA. USEPA has established two (2) sets of NAAQS for pollutants considered harmful to public health and the environment. Primary standards provide public health protection, including protecting the health of sensitive populations such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. **Table 6** below identifies the primary and secondary NAAQS established by USEPA.

Table 6 Primary and Secondary NAAQS

Pollutant	Averaging Period	Primary Standard ($\mu g/m^3$)	Secondary Standard ($\mu g/m^3$)
CO	1-hr[a]	35 ppm	--
	8-hr[a]	9 ppm	--
Pb	Rolling 3mo average[b]	0.15 $\mu g/m^3$	0.15 $\mu g/m^3$
NO_2	1-hr[c]	100 ppb	--
	Annual[d]	53 ppb	53 ppb
Ozone	8-hr[e]	70 ppb	70 ppb
PM_{10}	24-hr[f]	150 $\mu g/m^3$	150 $\mu g/m^3$
$PM_{2.5}$	24-hr[g]	35 $\mu g/m^3$	35 $\mu g/m^3$
	Annual[h]	12.0 $\mu g/m^3$	15.0 $\mu g/m^3$
SO_2	1-hr[i]	75 ppb	--
	3-hr[a]	--	0.5 ppm

a. Not to be exceeded more than once per year.
b. Not to be exceeded.
c. 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
d. Annual mean, not to be exceeded
e. Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years
f. Not to be exceeded more than once per year on average over 3 years
g. 98th percentile, averaged over 3 years
h. Annual mean, averaged over 3 years
i. 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years

Tuscarawas County is designated as attainment or unclassifiable for all criteria pollutants.

The CDCL plant will generate controlled emissions during construction and operation. The study includes projections on such emissions. Two sets of controlled emissions targets listed below: 1) targeted emission limits for air permitting and 2) targeted emission limit for pipeline quality CO_2 transport. The emissions are summarized in **Table 7**

Table 7 Predicted Controlled Emissions from CDCL

Emission Rates	Max Potential Emission		Uncontrolled Emission		Assumed Removal Efficiency	Controlled Emission	Pipeline Limits	Permitted Limits
	lb/hr	ton/year	lb/MBtu	ton/year		ton/year		
Sulfur dioxide	267.16	903	2-2.5	824-1030	99%	8-10	100 ppmv	TBD
Hydrogen sulfide (H_2S)	0	0	Not detectable	Not detectable		Not detectable	0.01 vol%	
Nitrogen oxides	63.45	214	2.5-3	1030-1236	75%	258-309	100 ppmv	TBD
Carbon monoxide	0	0	4.4-5.1	1813-2101		1813-2101	35 ppmv	TBD
HCl	9.8	33	Not measured	Not measured	75%	8	Unavailable	TBD
Hg	0.0021	0.0071	Not measured	Not measured	75%	0.0018	Unavailable	TBD
VOC	0	0	Not measured	Not measured		0	Unavailable	TBD
Particulate	918.61	3105	Not measured	Not measured	99.99%	0.31	1 ppmv	0.013 lbs/MBtu
Carbon dioxide (CO_2)	31783.65	107444	400-520	164781-214216	96.50%	5767-7498	95 vol% (minimum)	
Nitrogen (N_2)	153.29	518	450-520	185379-214216		185379-214216	4 vol%	
Oxygen (O_2)	0	0	0.5	206		206	4 vol %	
Sources	Heat and mass balance		250 kWt Pilot data		Estimated		DOE study	Ohio EPA

a. The total permitted limits assume 85 % capacity factor (7446 hours/year) and the following removal rates.
b. The uncontrolled emissions are based on test results obtained with an oxygenated Ohio bituminous coal on B&W's 250 kWt coal direct chemical looping pilot facility. The added oxygen in the treated coal tends to increase NOx emissions relative to unoxygenated coal.
c. Assumed removal efficiencies that are used to calculate controlled emissions levels are based on typical industry performance.
d. Pipeline CO2 purity levels are based on review of DOE guidelines influenced by observations from PetraNova operating pipeline.

Construction:

The predicted emissions from construction activities are summarized in **Table 8**.

Table 8 Predicted Emissions from Construction Activities

Predicted Controlled Emission	Emission Rates (lbs/hr)	Duration (hours)	Frequency Once/day? Once/week? Once/project?	Permitted Limits Total (tons/year)
Land Disturbance Dust	None anticipated. Construction will proceed within and existing building and on a small apron area outside of the building.			
Construction Equipment				
- Dsl. Crane	0.183 VOC/2.48 NOx	640	Total project	TBD
- Dsl. Forklift	0.092 VOC/.367 NOx	1600	Total project	TBD
- Dsl. Excavator	7.53 VOC /106.5 NOx	480	Total project	TBD
- Truck/Hauling	0.283CO/0.85 NOx / 0.006 PM / 0.063CO2	200	Total project	TBD

a. Construction equipment includes backhoe, crane, front end loader, dump trucks combusting diesel fuel

Solid Waste Disposal Operations:

Containers for solid waste disposal during construction – agreement with plant for trash services. Nearby Kimble Dover Sanitary Landfill (3596 State Route 39 NW, Dover, Ohio 44622, 330-343-1226) is an EPA approved landfill and can accept construction and demolition debris.

Coal Handling:

The existing coal receiving and storage equipment will be used without modification. A new chute will be installed to transfer coal from the existing storage hopper to the pulverizer feeder for the chemical looping coal preparation system.

The existing coal handling system is gas tight so it does not generate coal particulate emissions from the coal silo. The fugitive emissions from the coal pile are de minimis because only a small amount of coal is stored on site and the coal is stored under cover.

Based on current rates of consumption together with anticipated rates of consumption for the new CDCL system, Dover Light & Power has a reliable supply of 1.5 % low-sulfur coal from the West Moreland Coal Company. Tuscarawas County produces 1 million tons of coal a year. The nearby AEP Conesville Station uses high-sulfur coal and will be closing in 2020, so this will not be a draw on the low-sulfur coal supply.

Ash Handling:

The existing ash handling silo with the associated pneumatic ash transport system is equipped with a particulate filter (99.9 % efficient). The ash handling system emits less than 50 lbs per year of particulates.

Water Quality:

The Dover Plant is located along the Tuscarawas River, which is the principal source of cooling water for the plant. Located in northeastern Ohio, the Tuscarawas River is a principal tributary of the Muskingum River. The plant withdraws water from the Tuscarawas River via the facility's intake structure. The intake structure is equipped with three pumps. Under current operations, either one or two pumps are typically operated. The discharge from all three pumps are connected to a common header which supplies one 20-inch and one 12-inch supply line to the facility's surface condenser. Water withdrawn from the intake structure is passed through the condenser for use as non-contact cooling water. In summary, low-pressure steam leaving the facility's turbine is directed to the condenser where it is cooled and condensed by the non-contact cooling water withdrawn from the river flowing through the condenser tubes (i.e., heat exchanger tubes). The non-contact cooling water used to condense the steam is discharged back to the river. The condensed steam (condensate) is returned to the boiler where it is again converted to steam.

Well water is also used for cooling purposes at the facility. Well water is used for cooling at the condenser in addition to the water withdrawn via the intake structure. The facility maintains the three (3) river water pumps mentioned above and three (3) well water pumps which feed the condenser cooling water system. Operation of different combinations of these pumps is used to satisfy various operational conditions. Pre-startup and unit shutdown operations usually requires two (2) well pumps only to maintain adequate condenser operation. During turbine warm-up and very low load operation, a combination of two (2) well pumps and one (1) river water pump is a standard arrangement. With reasonable weather conditions, normal turbine load range requires two (2) river pumps only. During warmer weather conditions two (2) river pumps and one (1) well pump are typically operated. All cooling water is once-through with no recirculation to a cooling tower or other water cooling structure.

City water is used to cool the facility's generator air system and is also used to cool the intake pump bearings. The generator air cooling system and cooling of the pump bearings are not associated with the intake structure. City water is used for steam generation. The Dover Plant facility does not operate any "contact cooling water" systems.

The CDCL facility does not require changes in groundwater water and the three wells currently available on the plant are expected to provide sufficient cooling water for the chemical looping system. The chemical looping components and flue enclosures will be cooled with feedwater as part of the steam cycle circuitry.

The chemical looping system will not need a settling pond for wet scrubber sludge. Dewatered sludge will be discharged directly into a lined roll-off and transported to wall board manufacturer or approved land fill. Nearby Kimble Dover Sanitary Landfill (3596 State Route 39 NW, Dover, Ohio 44622, 330-343-1226) is an EPA approved landfill with clay liner for ash and sludge disposal.

Increase in the wastewater discharge due to the new chemical looping equipment is indicated below and will be sent to sanitary sewer as required. The existing NPDES permit will be modified to accommodate the change in wastewater discharge rate as projected in **Table 9**.

Table 9 Wastewater Treatment and Discharges.

Wastewater Stream	Discharge Rate	Discharge Frequency	Duration
Boiler blowdown Sanitary Sewer	3,048 lbs/hr	Continuous when operating	7446 hrs
Wet scrubber waste water Sanitary Sewer	2 gpm @1.15 wt % solids	Continuous when operating	7446 hours
Wet scrubber evaporation	38 gpm		
Washdown waste water Sanitary Sewer	6. gpm / 7.481ga/ft3 *60 min/hr*62.4 lbs/ft3 = 3000 lbs/hr	Once/day 310 days/year	1 hour
Cooling water discharge Non-contact cooling river water - returned to river @62% of Turbine MCR from Chemical Looping system	3,880,000 lbs/hr Inlet Temp 59° Outlet Temp 77°	Continuous when operating	7446
Total New Fresh Water Make-up, lb/hr	22,000	Continuous when operating	

Vegetation and Wildlife Resources:

Within the vicinity of the plant and the anticipated construction area no impacts are expected. The most likely impact would be to the species and habitats in the nearby Tuscarawas River, but none are anticipated. The changes in Dover operations regarding vegetation and wildlife resources will remain consistent with current operations after the development of the CDCL pilot facility.

Solid and Hazardous Wastes:

Nearby Kimble Dover Sanitary Landfill (3596 State Route 39 NW, Dover, Ohio 44622, 330-343-1226) is an EPA approved landfill with clay liner for ash and sludge disposal. The landfill can also accept construction and demolition waste.

Task 3. 10 MWe Pilot Facility Design and Costing

Subtask 3.1. Host Site Selection and Agreement

During the second quarter (**FY1Q4**) Dover Light & Power (DL&P) expressed strong interest to be considered as the host site for the 10 MWe CDCL large pilot unit. DL&P is committed to providing environmentally friendly, economic and reliable power to almost 1000 commercial customers and more than 14000 residents. DL&P would therefore serve as an ideal primary host site for the demonstration of the CDCL technology as they have plans to further expand current capacity and are committed to the continued and responsible use of Ohio coal for power production. DL&P plan to use the CDCL 10 MWe plant and a natural gas package boiler to power a recently acquired 20 MWe subcritical steam turbine. DL&P provided B&W with the manufacturer's information on the steam turbine components to help support the design efforts of the pre-feed study.

For design and costing purposes it would be assumed that the host site would be the Dover Light & Power Municipal Plant and the power produced would be provided as additional power to the host site. According to the proposed changes to the scope of work, Subtask 3.1 would no longer be performed under this program. The host site selection and agreement would be performed under the program DE-FE0031582. A justification for the host site selected will be provided.

Subtask 3.2. Modular CDCL Reactor Integration Design

In the fifth quarter (**FY2Q3**), the mass and energy balance of the primary loop of the 2.5 MWe module was calculated and summarized in **Table 10**. A preliminary design of one module was developed based on the mass and energy balance and the existing data from the 250 kWth pilot testing. The main components in the primary loop are Combustor, Riser, Disengagement Zone, Particle Hopper, TMB Reducer, BMB Reducer, Standpipe, and L-Valve.

Initial assumptions used for the design were as follow:

1. Oxygen carrier particle loading between 20% to 40 % Fe_2O_3.
2. Maximum particle residence time of 10 mins in combustor, 20 mins in TMB Reducer, and 40 mins in BMB Reducer.
3. Particle to coal ratio ranging from 50:1 to 100:1.

Further design information of the modular reactor can be found in the mechanical functional specification document, which has been released to the DOE as part of the deliverables and milestones set for this project. The CDCL design continued to be updated through the duration of the project as more information became available from the design activities and the pilot testing in Task 2.

Table 10. Summary of the mass and heat balance for the 2.5 MWe module.

Power Output	kWe	2500
Estimated Efficiency	%	28
Thermal Input	kWth	8929
Coal Input	lb/hr	2423
Air Input	lb/hr	28150
Particle Size	mm	1.5
Particle Density	kg/m^3	3807
Particle Inventory	ton	128
Particle: Coal		100: 1
Reducer Reaction Heat	kW	1640
Reducer Inlet Temperature	°F	2012
Reducer Outlet Temperature	°F	1868
Reducer Flue Gas	lb/hr	9374
Reducer Outlet CO_2	wt.	85%
Reducer Outlet H_2O	wt.	12%
Reducer Outlet SO_2	wt.	1%
Reducer Outlet N_2	wt.	2%
Combustor Reaction Heat	kW	-10748
Combustor Inlet Temperature	°F	1864
Combustor Outlet Temperature	°F	2271
Combustor Flue Gas	lb/hr	22615

A preliminary arrangement of the heat transfer surfaces for the 10 MWe pilot plant was developed incorporating features such as in-bed heat exchangers, membrane walls, and convection-pass heat exchangers. **Figure 33** shows a schematic of the initial heat integration scheme developed. In this initial heat integration arrangement, the boiler feedwater passes through an economizer on the reducer (CO_2) exhaust line, an economizer in the combustor exhaust line and then through the combustor generation bank. The mixture of water and steam then goes to a vertical separator where steam is separated and sent to the primary super-heater, the secondary super-heater followed by the final super-heater imbedded in the combustor reactor. Finally, the super-heated steam is sent from the final super-heater to the steam turbine.

The inlet air gas is preheated by an air heater located after the convection pass to recover as much waste heat from the combustor exhaust gas. Similarly, the CO_2 recycle stream is preheated with a heat exchanger (to be determined) to recover waste heat from the reducer exhaust gas.

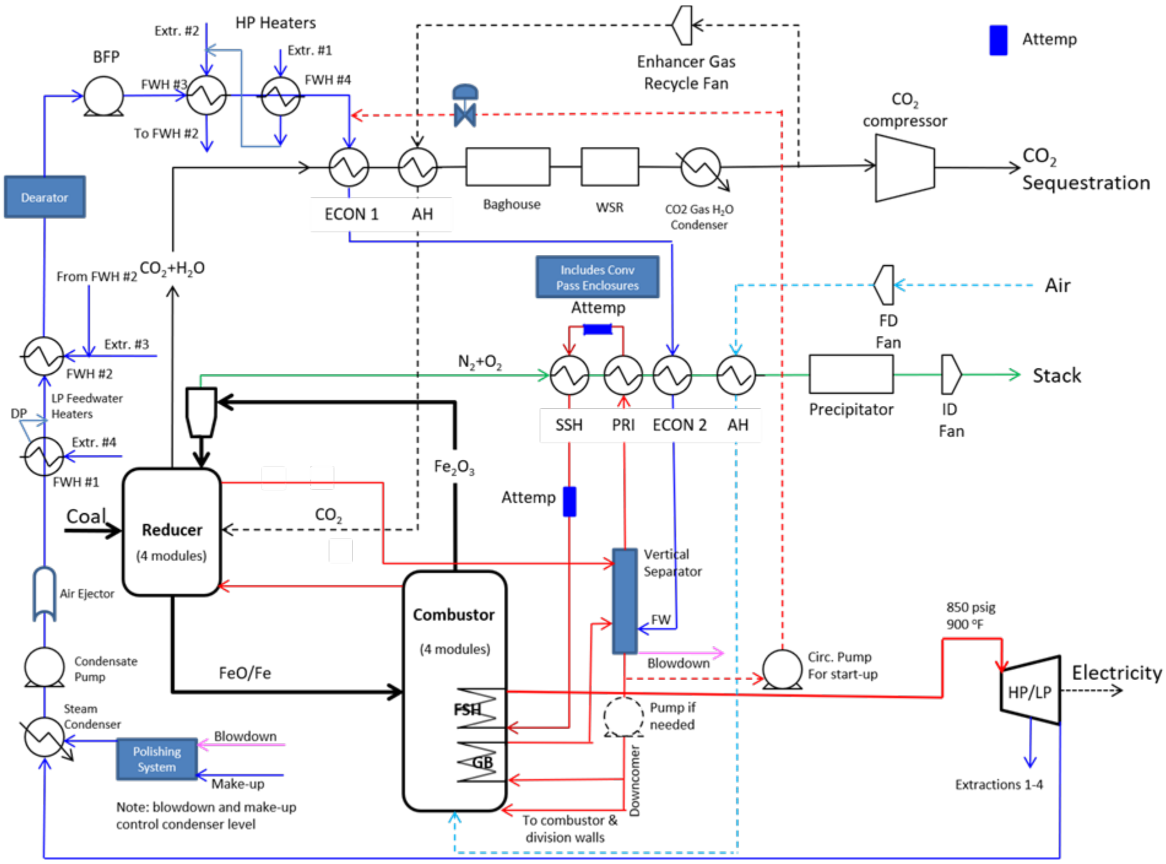


Figure 33. Heat integration of the 10 MWe CDCL pilot plant.

In the sixth quarter (**FY2Q4**), The preliminary heat integration scheme was evaluated. The Aspen model was updated accordingly, as shown in **Figure 34**. Superheaters were added in the reducer convection pass to extract more heat from the flue gas. To maintain the required water temperature after economizers, which is at least 30 °F below the saturation temperature, the economizers located in both reducer and combustor convection passes were changed to be in parallel, instead of being in series. The flue gas temperature was controlled to be lower than 1150 °F after the primary superheater, so the superheater exchanger can be constructed with lower cost alloy materials. The heat integration scheme was refined and the Aspen model updated as the project progressed. A first attempt to integrate the steam cycle and the primary loop has been completed. However, the overall plant heat integration is still undergoing. Additional iterations may be required and would be discussed in more detail once further details are incorporated.

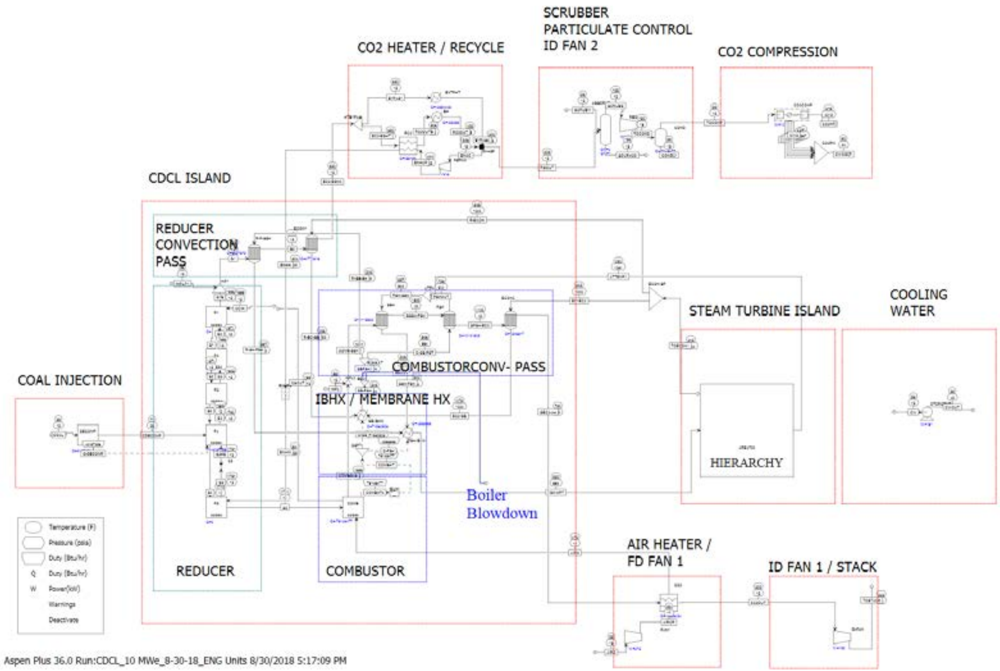
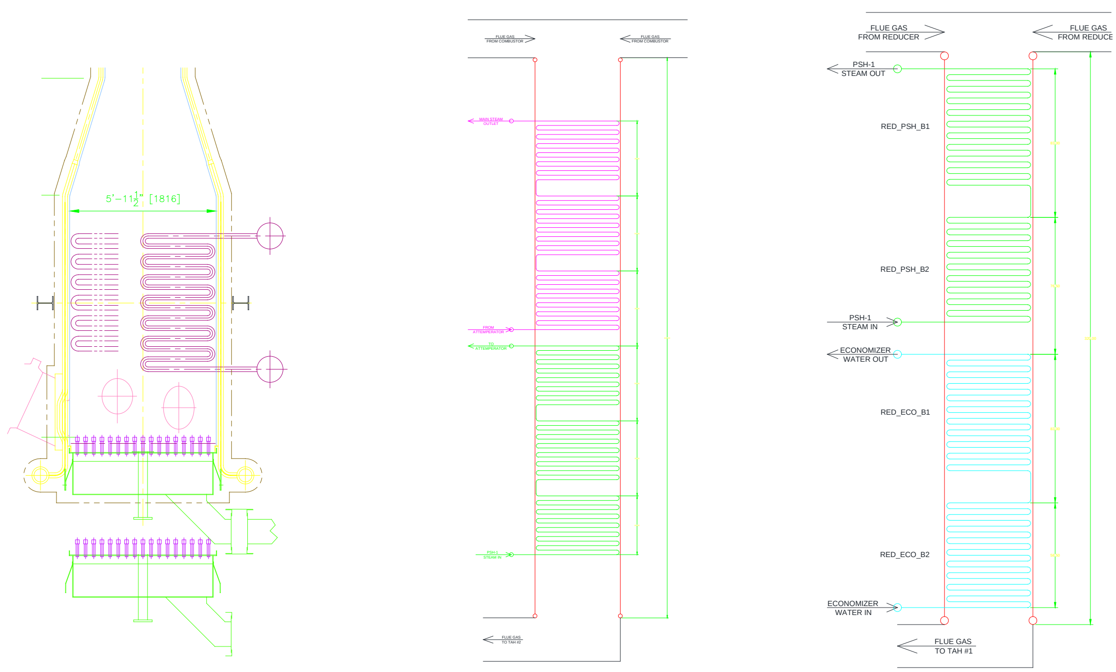


Figure 34. 10 MWe CDCL pilot plant process flow diagram from Aspen.

In the seventh quarter (**FY3Q1**), the heat exchanger surfaces were designed, sized and incorporated in the convection pass and the reactor vessel, as shown in **Figure 35**. Cold startup procedure of each module was discussed and documented.



Combustor In-Bed Heat Exchanger (IBHX) Combustor Convection Pass Reducer Convection Pass

Figure 35. Heat exchanger design.

(**FY3Q2**) There was no reported activity during the eighth quarter.

During the ninth quarter (**FY3Q3**), the modular CDCL reactor design was modified. The updated design of the CDCL primary loop components made use of novel/innovative approaches in the incorporation of steam generation surfaces, structural and other design features that are partially driven by anticipated commercial needs. A patent application was prepared by B&W.

There was no reported activity during quarters (**FY3Q4**), (**FY4Q1**), and (**FY4Q1**).

Subtask 3.3. Technology Engineering Design Specifications

(**FY2Q3**) The Mechanical functional specifications document of the 10 MWe plant was created to include the design standards, design basis, design assumptions, functional descriptions, intrinsic design data, extrinsic design data, and mechanical design for all the equipment that pertain to the 10 MWe pilot facility. The functional specification document is organized into the CDCL primary loop equipment as well as the auxiliary or balance of plant equipment. The design of the primary loop equipment is based on the preliminary design of each module and would be updated as further information becomes available. Similarly, the balance of plant (BOP) equipment design specifications or requirements would be updated as more information becomes available. Non-proprietary sections of the functional specifications document may be shared with subcontractors or third-party entities that need to know design specifications in order to develop equipment specifications or quotes. Further, the mechanical functional specifications document would be used to capture issues and resolution to issues that might arise during the 10 MWe CDCL design phase.

(**FY2Q4** and **FY3Q1**) The mechanical functional specifications were updated as the project progressed.

There was no reported activity during this quarter, (**FY3Q2**).

(**FY3Q3**) Updates were made to the mechanical functional specifications.

(**FY3Q4**) A comprehensive review and update of the mechanical functional specifications document was performed by Ntre Tech and B&W. The Design Basis and Design Functional Specifications Report was prepared and submitted to the DOE.

There was no reported activity during quarters (**FY4Q1**) and (**FY4Q2**).

Subtask 3.4. Technology Readiness and Risk Assessment

(**FY2Q3**) B&W and EPRI held a teleconference meeting on June 15th, 2018. EPRI would perform the evaluation on the Technology Readiness Level (TRL) of the CDCL technology. B&W would provide EPRI needed information for the TRL evaluation.

(**FY2Q4**) B&W, OSU and EPRI held a face-to-face meeting on September 20, 2018 at B&W's Research Center. The meeting served to provide guidance to EPRI in better defining and detailing out the scope of work around this task. EPRI will provide a draft of the risk assessment on the project as well as perspectives on the CO_2 and fossil power market.

(**FY3Q1**) EPRI and B&W drafted a list of questionnaires and sent it out to utility representatives, to obtain their perspectives on fossil power market, development of chemical looping technology, and carbon capture. Industry feedback will be compiled, and a summary of their input will be provided in the next quarter.

(**FY3Q2**) EPRI received the feedback from their utility industry survey during this quarter. Three utilities showed interest in the CDCL technology for carbon capture in power plants, including American Electric Power (AEP), Southern Company and Tri-State. Southern Company and AEP provided letters of support for the renewal application of a sister project (10 MWe CDCL Large Pilot Plant Test – Phase II Engineering).

EPRI completed the TRL assessment of the CDCL technology based on the work that had been done, see **Table 11**. It is concluded that the current TRL of the iron-based CDCL is TRL 5, approaching TRL 6, which requires a pilot unit that is 1 % to 5 % the size of a commercial unit with prototype components whose design and function are essentially the same as expected for full-scale deployment. EPRI made this assessment based on its review of the technology and progress made.

Table 11. TRL assessment for the CDCL technology.

<table>
<tr><th>TRL</th><th>Description</th><th>Summary of Work Done</th><th>Comments</th></tr>
<tr><td>1</td><td>Basic principles observed and reported</td><td rowspan="2">Several patents have been filed starting in 2004 around CDCL and the basic elements it is composed of and early documents have been published discussing its underpinnings:

“Combustion Looping Using Composite Oxygen Carriers,” T. Thomas, L.-S. Fan, et al., U.S. Patent 11,010,648, 2004.

“Hydrogen Production from Combustion Looping (Solids-Coal),” P. Gupta, L. G. Velazquez-Vargas, et al., Proceedings of the Clearwater Coal Conference, 2004.

“Systems and Methods of Converting Fuels,” L.-S. Fan, P. Gupta, et al., PCT International Applications WO 2007082089, 2007.</td><td rowspan="2">These documents and their statements have been reviewed by EPRI and the original work has been discussed with B&W and OSU. These documents provide evidence of achieving TRL-1 and TRL-2.</td></tr>
<tr><td>2</td><td>Technology concept and/or application formulated</td></tr>
<tr><td>3</td><td>Analytical and experimental critical function and/or characteristic proof-of-concept validated</td><td>Development of the CDCL concept was largely led by OSU with the development of a flow sheet and computer model and bench-scale, proof-of-concept cold-flow models. Significant oxygen carrier work was also performed. Numerous reports and papers have been published on the topic including:

“Chemical Looping Technology and Its Fossil Energy Applications,” L.-S Fan and F. Li, I&EC Research, 49, 2010.</td><td>Documents and their statements have been reviewed by EPRI and the original work has been discussed with B&W and OSU. These provide evidence of achieving TRL-3.</td></tr>
</table>

TRL	Description	Summary of Work Done	Comments
		"Chemical Looping Processes for Clean Coal Conversion," S. Bayham and L-S. Fan, Eastern Coal Council, May 2013.	
4	Basic technology components integrated and validated in a laboratory environment	A 25 kWt sub-scale pilot was built at OSU in the 2010 timeframe to perform testing on core components of the CDCL system. Significant testing has occurred over the last decade as the facility has achieved nearly 1000 hours of operational experience and over 200 hours of continuous operation. Numerous reports and papers have been published on the topic including this summary: "Coal Direct Chemical Looping (CDCL) Retrofit to Pulverized Coal Power Plants for In-Situ CO2 Capture," DE-NT0005289, 2012.	EPRI has reviewed the work for this stage of the TRL having visited the 25 kWt facility, been involved in sessions detailing testing and test results, and read associated technical reports. Based on this review, the technology has achieved TRL-4.
5	Basic technology components integrated and validated in a relevant environment	Both the construction and long-term testing of the 25 kWt and 250 kWt CDCL pilots provide evidence that the basic components of the system (especially the moving-bed and fluidized-bed reactors) have been validated in a relevant environment. Multiple reports have been published on these pilots including this summary: "Commercialization of the Iron Base Coal Direct Chemical Looping Process for Power Production with in situ Carbon Dioxide Capture," FE0009761, 2012.	EPRI has reviewed the work for this stage of the TRL. Note that TRL-5 was largely accomplished in conjunction with the advancement of TRL-6.
6	Pilot unit of ~1–5% of full scale in size with prototype components whose design and function are essentially the same as expected for full-scale deployment has been deployed	A 250 kWt CDCL unit has been constructed in Barberton, OH and has undergone significant testing to show key characteristics of chemical looping operation can be achieved over representative run times (hundreds of hours) including reactor temperatures of nearly 1000^{o}C, near complete carbon conversion, and appropriate carrier flow and behavior in the system. However, the pilot is not complete. It lacks a power generation island and some of the backend environmental equipment and requires heating to operate. The power island and environmental controls are considered unnecessary for validation of the novel components of the system, but require a larger-scale design. Requiring heat to operate is endemic of the scale of the 250 kWt pilot and should not be required at larger sizes.	EPRI has reviewed the work for this stage of the TRL having visited the 250 kWt facility, been involved in sessions detailing testing and test results, and read associated technical reports. Based on this review, EPRI has deemed the technology as approaching TRL-6.

There was no reported activity during quarters (**FY3Q3**), (**FY3Q4**), (**FY4Q1**), and (**FY4Q2**).

Subtask 3.5. Oxygen Carrier Commercial Manufacturing Development

During the first quarter (**FY1Q4**), The Ohio State University (OSU) and Johnson Matthey (JM) developed a three-phase approach to evaluate the commercial manufacturing of oxygen carrier particles.

In Phase 1, OSU would transfer the formulation and knowledge of particle manufacturing at laboratory scale to Johnson Matthey. Johnson Matthey would develop a series of samples based on their proprietary manufacturing processes that would produce similar particles as those produced by OSU. These samples will be shipped to OSU for verification of reactivity in TGA and strength and attrition analysis in a Jet-Cup setup.

Once Johnson Matthey is able to replicate OSU's reactivity and attrition specifications, Johnson Matthey and OSU would move to Phase 2, where they would explore the use of materials that are more economic and optimize particle manufacturing in terms of shape factor, reactivity, attrition resistance and cost.

In Phase 3, Johnson Matthey would use the results from Phase 2 and input the materials, methods and expected commercial quantities into their proprietary cost-models to obtain a fair cost estimate of the commercial manufacturing of the oxygen carrier.

A graphic representation of the three-phase approach can be seen in **Figure 36** below.

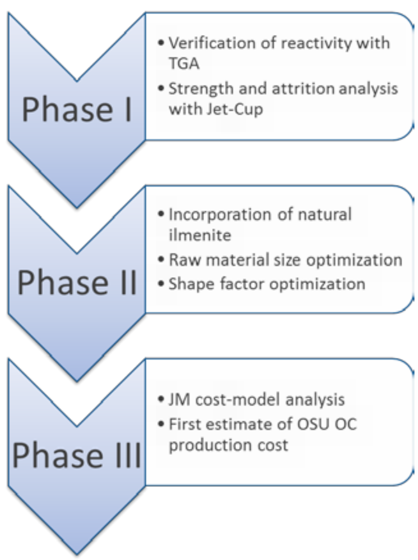
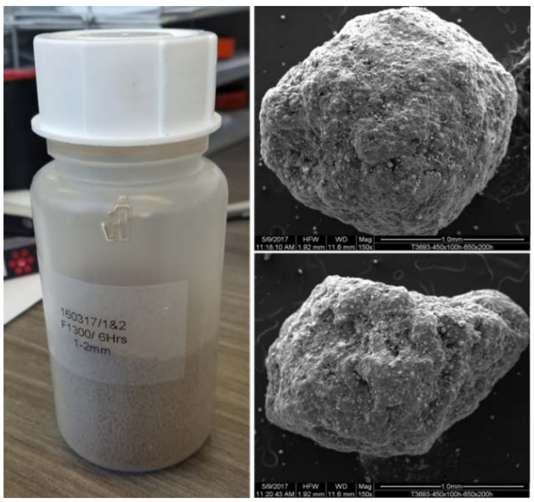


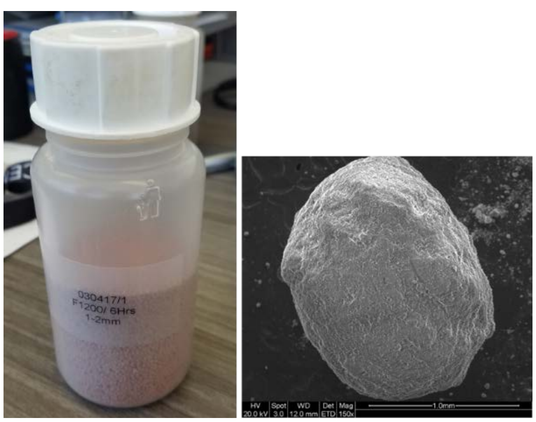
Figure 36. Oxygen carrier commercial manufacturing development plan.

OSU transferred their particle formulation and manufacturing knowledge to Johnson Matthey. JM used this information to produce several samples of OSU's particles in their facilities. Below are photographs of these samples with their respective particle SEM picture. These particles were received by OSU quartering the order to allow for further reactivity and attrition testing.

Sample 1



Sample 2



Sample 3

Figure 37. Oxygen carrier samples and their SEM pictures produced by JM and tested at OSU.

OSU then determined that sample #2 had the closest reactivity and mechanical stability of the particles produced by OSU with in-lab testing. The result was discussed over conference call with JM in late May 2017 with a follow up in-person meeting between OSU and JM in June at JM's technology Centre in the UK. The meeting resulted in the developmental plan shown in **Figure 36**. The next batch of samples were then expected to be manufactured in September using locally sourced natural ilmenite.

During the second quarter (**FY1Q4**), OSU continued testing the JM samples in their laboratory. JM's sample #2 again showed satisfactory reactivity and strength. During this phase, sphericity and size were not priorities but they will have to be addressed in Phase II.

Johnson Matthey started sourcing different raw materials for the manufacture of the oxygen carrier particles as cheaper materials would help make the oxygen carrier more economic. In Phase 2, JM will continue to optimize particle manufacturing in terms of shape factor, reactivity, attrition resistance and cost.

During the third quarter (**FY2Q1**) and fourth quarter (**FY2Q2**), JM continued to source materials for the preparation of new particle samples. No further testing has been conducted at OSU.

In the fifth quarter (**FY2Q3**), JM prepared new particle samples and sent them to OSU for further evaluation and testing.

There was no reported activity in quarters (**FY2Q4**), (**FY3Q1**), and (**FY3Q2**).

During the ninth quarter (**FY3Q3**), additional formulations were sent through processing steps which include granulation and granulation followed by spheronization to improve the density and the shape of particles. Six different samples were tested for reactivity and mechanical strength. As seen in **Figure 37** and **Figure 38**, investigations on these samples showed that one of the samples met the desired particle performance metrics. The particles from this batch were spherical, with average diameter of particles being closer to the target size of 1.5 mm. Particles showed a solid conversion of 25.28 % after 100 redox cycles and achieved the target mechanical strength. However, it was observed that oxidation of particles was incomplete in 5 min, which would need to be addressed in future formulations. **Figure 38** shows the SEM image of the oxygen carrier particle after the 100 redox cycles. **Figure 39** depicts the normalized weight data for 100 redox cycles where the reactivity of particles increases gradually over cycles before it becomes steady, and the particles achieve desirable steady state solid conversion. The spheronization technique was validated as being able to achieve the appropriate particle shape. These particles will be further optimized for further testing and may serve as the basis for the updated cost models.

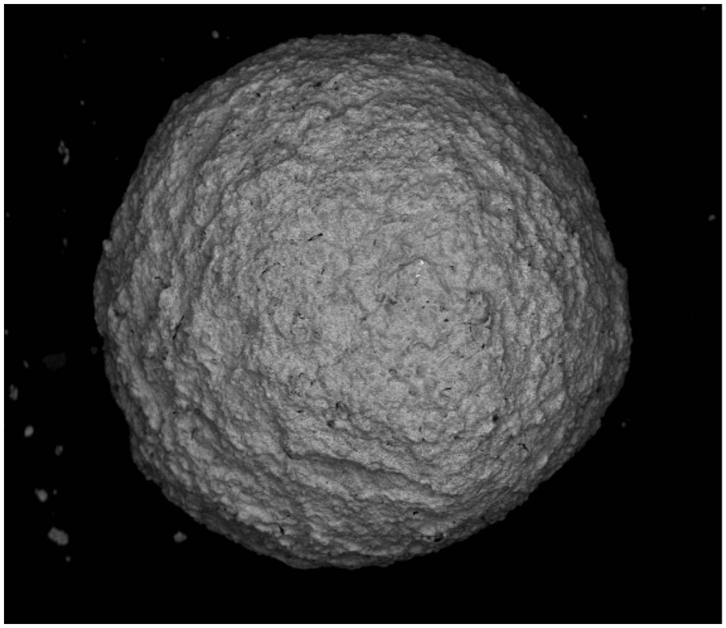


Figure 38. SEM image of 221118/5 OC.

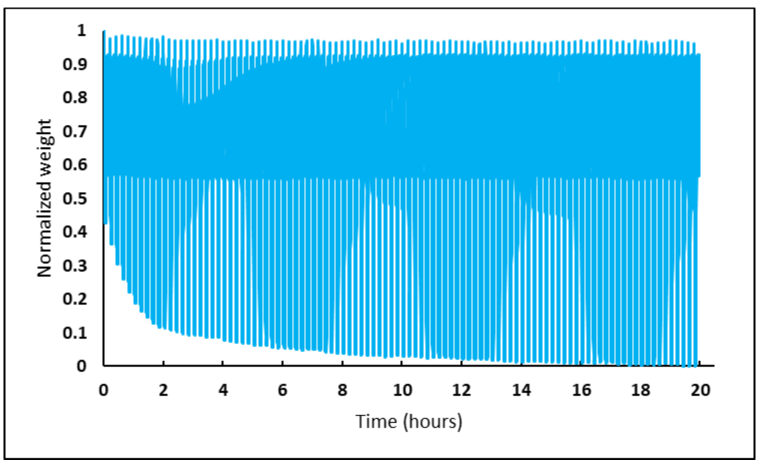


Figure 39. Isothermal redox cycles at 1000 °C, 1 atm.

During the tenth quarter (**FY3Q4**), JM completed the cost estimation of oxygen carrier particles produced using the wet granulation route employed by JM. A detailed report was delivered to B&W and OSU. In summary, the estimated price ranges from \$16.35 USD/kg to \$22.64 USD/kg to manufacture and supply at a commercial scale of 1000 ton per year with a UK location. The estimated manufacturing cost includes fixed cost (labor) and variable cost (raw material, utilities, maintenance, packaging). The assessment shows that the cost of raw material is the main contributor comprising nearly 50 % of the total manufacturing cost. The utility cost is also a significant cost component (~30%). Scaling up the production capacity will reduce the manufacturing cost. For a larger scale commercial operation at 10,000 ton per year capacity, the price would be reduced by a third to \$10.90 USD/kg to \$15.09 USD/kg.

There was no reported activity during quarters (**FY4Q1**) and (**FY4Q2**).

Subtask 3.6. CDCL Large Pilot Facility Design

In the fifth quarter (**FY2Q3**), a Work Breakdown Structure (WBS) and division of work (DOW) were developed for this portion of the project. Special consideration was given to clearly define work to be performed under this award and the sister project DE-FE-0031582 to prevent duplication of effort. The WBS and DOW developed were based on B&W's project management system used in our commercial projects.

B&W performed a site visit to the selected host site on June 27, 2018. Terminal points for the 10 MWe pilot facility were identified during the host site visit.

Feasibility and applicability of B&W's PCI /distribution bottle system was assessed for use as the CDCL plant's coal feeding system. According to the information gathered and calculations performed, the PCI system was shown to be suitable for coal injection into the CDCL.

DOE provided a guidance document that specifies the CO_2 purity requirements for transporting to different end users.

A technical designer was assigned to the CDCL project to generate 3D general arrangement drawings of the 10 MWe pilot plant.

In the sixth quarter (**FY2Q4**), general arrangement drawings of the 10 MWe pilot plant has been preliminarily developed in 3D. The 3D design has included four 2.5 MWe CDCL modules, inlet and outlet piping, the coal preparation and feeding system, downstream environmental equipment (e.g. baghouse and wet scrubber), and stack as well as the associated support structure. **Figure 40** shows the 3D and top view of the 10 MWe plant layout. The general arrangement drawings will be updated while additional components are incorporated.

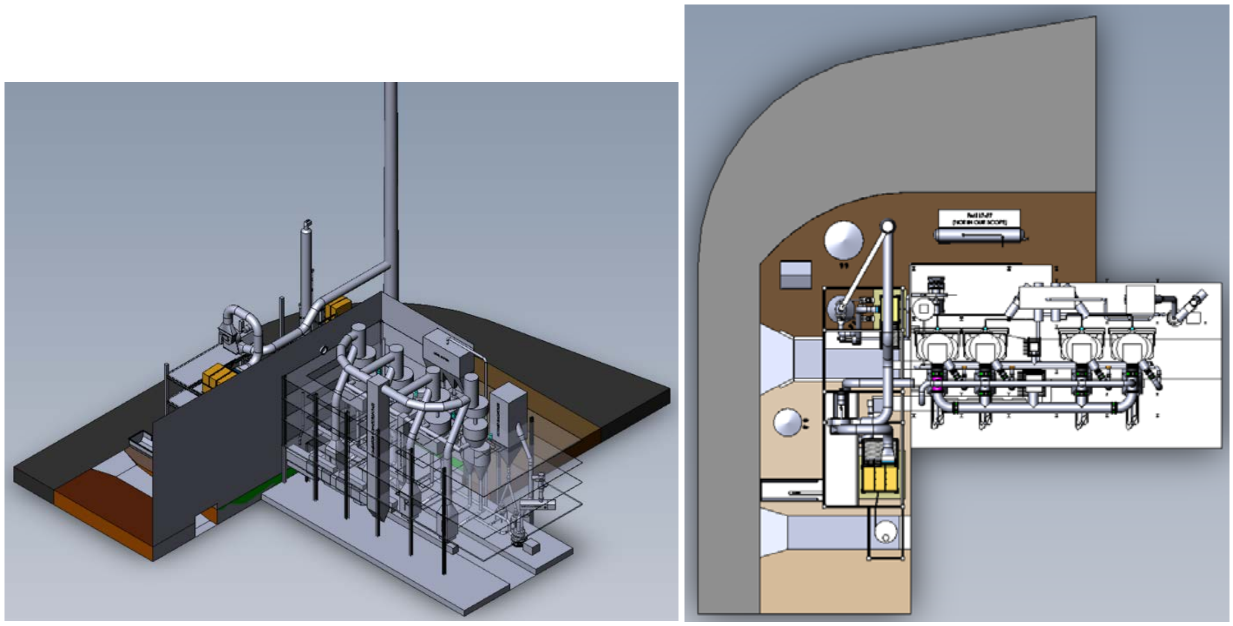


Figure 40. 3D and top view of the 10 MWe plant layout.

The technical designer for piping and instrument diagrams (P&IDs) was also identified during this quarter.

The development of P&IDs was started.

(**FY2Q4**) On September 20, 2018, EPRI, OSU and B&W held a face-to-face meeting. B&W provided an update on the design of the pilot facility to EPRI and OSU. EPRI would participate in design review meetings to further guide the team. EPRI would also use the design information to develop figures of merit for the pilot facility.

In the seventh quarter (**FY3Q1**), heat exchangers were added in the 3D general arrangement drawing. The particle makeup system was sized and incorporated in the 3D drawing as well. P&IDs for the main CDCL loop were developed. P&IDs for the wet scrubber island and the steam cycle were initiated.

In the eighth quarter (**FY3Q2**), design of the 10 MWe CDCL large pilot plant continued. Most efforts were focused on estimating the engineering, construction and operating costs of the plant.

During the ninth quarter (**FY3Q3**), pulverized coal injection (PCI) into the reducer of the 2.5 MWe modular reactor was preliminarily evaluated by CFD modeling, in order to optimize the distribution of coal. **Figure 41** shows the injection system geometry. **Figure 42** shows the applied CFD model domain. Different coal particle sizes and gas velocities were investigated, as shown in **Figure 43**. For a constant coal size, the higher gas flow velocity of 15 ft/s results in the better distribution over the lower gas velocity. When the coal size is larger than 122 microns, the round nozzle used for simulation does not achieve the desired even distribution. These larger coal particles drop near the feed point even when the gas velocity is at the higher velocity of 15 ft/s. Considering the various design variables, the shape of the coal injection nozzle is one that appears to play an important role on the coal distribution. The next steps will therefore focus on optimizing the design of the coal injection nozzle. Location and spacing of feed points, with the use of horizontal nozzles, end nozzles, “slanted” nozzles, as well as the shape of the nozzle will be studied further with CFD modeling.

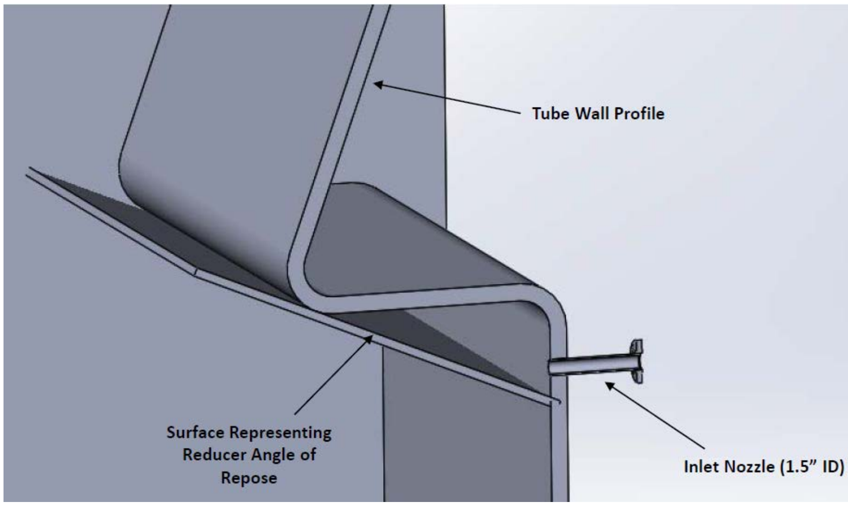


Figure 41. Coal feeding system geometry.

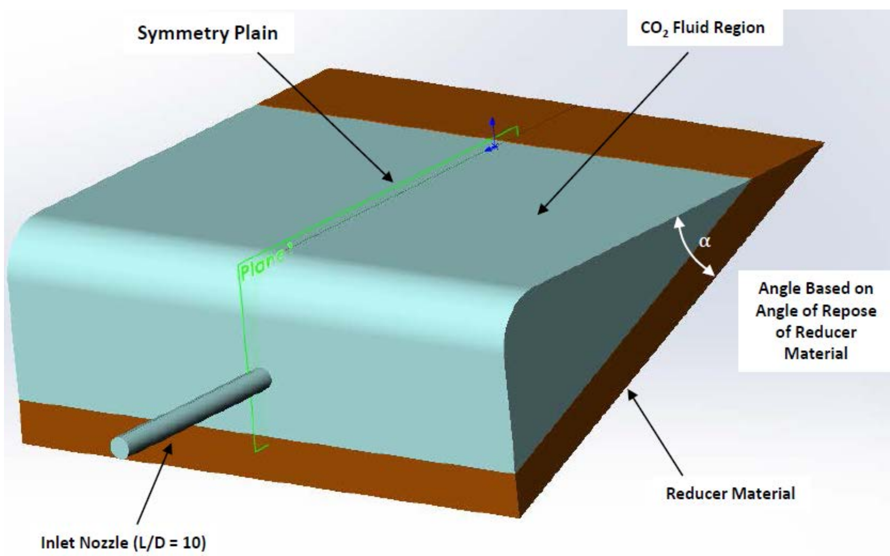


Figure 42. CFD model applied domain.

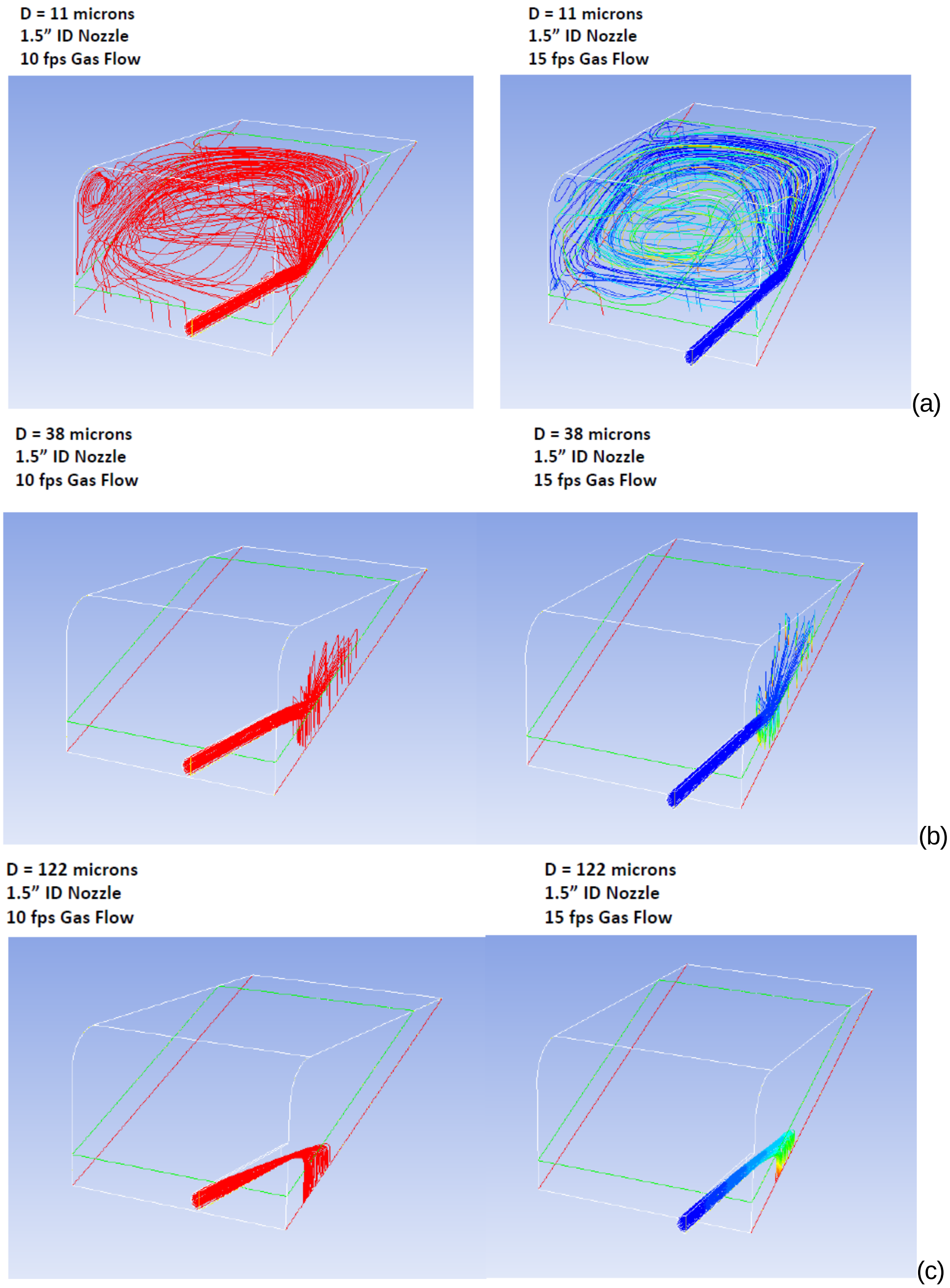


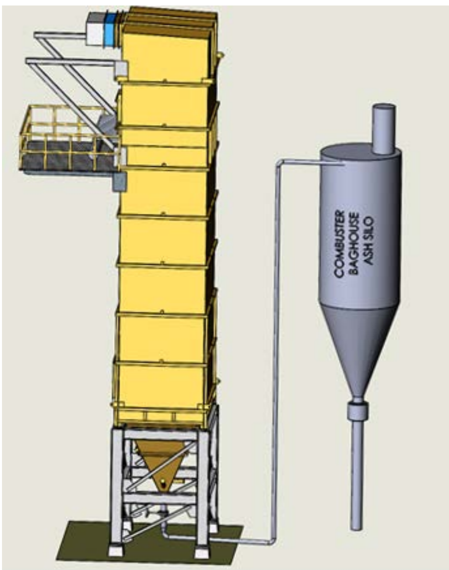
Figure 43. Coal distribution in the 2.5 MWe CDCL reducer.

Risks pertaining to scale-up to the larger scale pilot system were itemized based on the current HAZOP analysis and information from the 250 kWth pilot facility. The risk analysis document was sent to OSU for further review and update.

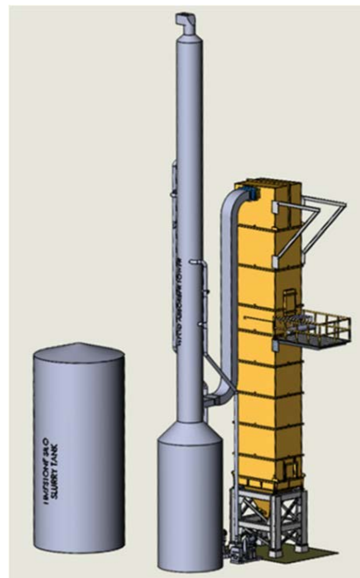
There was no reported activity during quarters (**FY3Q4**), (**FY4Q1**), and (**FY4Q2**).

Subtask 3.7. Building and Utilities

In the seventh quarter (**FY3Q1**), utility requirements for the 10 MWe plant were specified and captured in the mechanical functional specification document. Existing capacity to supply necessary utilities to the 10MWe plant at the DL&P host site will be further checked to determine whether it would meet requirements. Design efforts addressed various systems including startup burners, air supply blowers, air heaters, coal storage, offloading & transfer, particle makeup hopper & transfer, and ash silo & discharge systems. Design of downstream environmental equipment (**Figure 44**), wet scrubber, baghouse, and activated carbon injection, was completed as well. Detailed information can be found in the mechanical functional specification document.



Combustor Baghouse



Reducer Wet Scrubber and Baghouse

Figure 44. Environmental equipment for the 10 MWe CDCL plant

Potential users of the captured CO_2 near the host site, such as Airgas, Dover Chemical, Kraton, and Artex Oil Company were contacted. Positive feedback was received from them. Requirements of pipeline CO_2 quality was discussed and will be further looked into in conjunction with ClearSkies consulting. Due to the limited funding and high cost of a CO_2 pipeline, at this point, the system will be designed to produce pipeline quality CO_2, but not incorporate CO_2 compression and sequestration.

(**FY3Q4**) In the tenth quarter, utility requirements for the 10 MWe plant were updated in the mechanical functional specification document based on the most recent design and simulation data.

There was no reported activity during quarters (**FY4Q1**) and (**FY4Q2**).

Subtask 3.8. Construction and Operation Cost Estimate

(**FY2Q4**) On September 20, 2018, EPRI, OSU and B&W held a face-to-face meeting. During the meeting, EPRI proposed to subcontract Nexant to assist in the development of the cost for a greenfield 10 MWe pilot facility. This greenfield plant estimate will also help in the evaluation of the selected host site and serve as a comparison in determining the advantages and disadvantages. DOE agreed for EPRI to subcontract part of their scope of work.

(**FY3Q1**) Detailed information of the existing main equipment, building, infrastructure, space, and utilities at DL&P was provided to Nexant for the purpose of estimating the additional cost at a greenfield site. B&W Construction Co. (BWCC) visited the host site on November 18, 2018, to identify construction sequence and evaluate the anticipated cost for construction.

(**FY3Q2**) The cost estimate of the additional scope at a greenfield site was provided by EPRI's subcontractor, Nexant, as shown in **Table 12**. The total cost for the added scope at a greenfield site was estimated to be $38.4 million, which could be eliminated by using the Dover host site. The advantage of installing the 10 MWe unit at the Dover site is substantial from the capital cost point of view. A preliminary cost estimate of construction and operation was developed, as shown in **Table 13**. The total cost of the supply, construction, commissioning and testing rolled up at $64 million. This cost bears uncertainty around the design and testing of a first-of-a-kind chemical looping system. As the design matures and other costs such as the overall project management, environmental permitting, and testing are better defined, the total cost is expected to come down.

Table 12. Cost breakdown for 10 MWe greenfield CDCL plant BOP (performed by EPRI).

10 MWe Greenfield CDCL Plant Balance of Plant Total Plant Cost Details (Jun 2018 Basis)

Cost Basis: 2018 ($x1000)
Plant Size: 10 MWe, net

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O & Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST, $1,000
1	COAL & SORBENT HANDLING										
1.1	Coal Receive & Unload	$378	$0	$170	$0	$0	$548	$55	$0	$90	$693
1.2	Coal Stack out & Reclaim	$488	$0	$109	$0	$0	$597	$60	$0	$98	$755
1.3	Coal Conveyors & Yard Crushing	$454	$0	$108	$0	$0	$561	$56	$0	$93	$710
1.4	Other Coal Handling	$119	$0	$25	$0	$0	$144	$14	$0	$24	$182
1.9	Coal & Sorbent Handling Foundations	$0	$437	$577	$0	$0	$1,014	$101	$0	$167	$1,283
	SUBTOTAL 1.	**$1,438**	**$437**	**$989**	**$0**	**$0**	**$2,864**	**$286**	**$0**	**$472**	**$3,623**
3	FEEDWATER & MISC BOP SYSTEMS										
3.1	Feedwater System	$596	$0	$192	$0	$0	$788	$79	$0	$130	$997
3.2	Water Makeup & Pretreating	$726	$0	$230	$0	$0	$956	$96	$0	$210	$1,262
3.3	Other Feedwater Systems	$187	$0	$77	$0	$0	$264	$26	$0	$44	$334
3.4	Service Water Systems	$426	$0	$223	$0	$0	$649	$65	$0	$143	$857
3.6	Natural Gas Supply	$24	$0	$28	$0	$0	$52	$5	$0	$9	$65
3.7	Waste Treatment Equipment	$229	$0	$132	$0	$0	$361	$36	$0	$79	$477
3.8	Misc Power Plant Equipment	$1,260	$0	$390	$0	$0	$1,650	$165	$0	$363	$2,178
	SUBTOTAL 3.	**$3,449**	**$0**	**$1,272**	**$0**	**$0**	**$4,721**	**$472**	**$0**	**$978**	**$6,171**
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	$4,847	$0	$529	$0	$0	$5,376	$538	$0	$591	$6,504
8.2	Turbine Plant Auxiliaries	$27	$0	$57	$0	$0	$84	$8	$0	$9	$102
8.3	Condenser & Auxiliaries	$842	$0	$294	$0	$0	$1,137	$114	$0	$125	$1,375
8.4	Steam Piping	$191	$0	$78	$0	$0	$269	$27	$0	$44	$340
8.9	TG Foundations	$0	$77	$127	$0	$0	$205	$20	$0	$45	$270
	SUBTOTAL 8.	**$5,907**	**$77**	**$1,085**	**$0**	**$0**	**$7,070**	**$707**	**$0**	**$815**	**$8,591**
9	COOLING WATER SYSTEM										
9.1	Cooling Towers	$445	$0	$138	$0	$0	$582	$58	$0	$64	$705
9.2	Circulating Water Pumps	$105	$0	$7	$0	$0	$112	$11	$0	$12	$136
9.3	Circ. Water System Auxiliaries	$26	$0	$3	$0	$0	$30	$3	$0	$3	$36
9.4	Circ. Water Piping	$0	$213	$193	$0	$0	$406	$41	$0	$67	$514
9.5	Make-up Water System	$60	$0	$77	$0	$0	$136	$14	$0	$22	$172
9.6	Component Cooling Water System	$195	$0	$150	$0	$0	$344	$34	$0	$57	$435
9.9	Circ. Water System Foundations	$0	$113	$188	$0	$0	$301	$30	$0	$66	$397
	SUBTOTAL 9.	**$831**	**$326**	**$755**	**$0**	**$0**	**$1,912**	**$191**	**$0**	**$292**	**$2,395**
10	ASH/SPENT SORBENT HANDLING SYS										
10.6	Ash Storage Silos	$129	$0	$396	$0	$0	$526	$53	$0	$58	$636
10.7	Ash Transport & Feed Equipment	$860	$0	$853	$0	$0	$1,713	$171	$0	$188	$2,073
10.9	Ash/Spent Sorbent Foundation	$0	$29	$36	$0	$0	$65	$7	$0	$14	$86
	SUBTOTAL 10.	**$990**	**$29**	**$1,285**	**$0**	**$0**	**$2,304**	**$230**	**$0**	**$261**	**$2,795**
11	ACCESSORY ELECTRIC PLANT										
	SUBTOTAL 11.	**$1,049**	**$400**	**$1,089**	**$0**	**$0**	**$2,538**	**$254**	**$0**	**$346**	**$3,138**
12A	INSTRUMENTATION & CONTROL (NO	$0	$1,227	$736	$0	$0	$1,964	$196	$0	$267	$2,427
12B	INSTRUMENTATION & CONTROL (CDCL)		TBD from B&W				TBD			TBD	
	SUBTOTAL 12.	**$0**	**$1,227**	**$736**	**$0**	**$0**	**$1,964**	**$196**	**$0**	**$267**	**$2,427**
13	IMPROVEMENTS TO SITE										
13.1	Site Preparation	$0	$20	$436	$0	$0	$456	$46	$0	$100	$602
13.2	Site Improvements	$0	$681	$899	$0	$0	$1,580	$158	$0	$348	$2,085
13.3	Site Facilities	$1,220	$0	$1,279	$0	$0	$2,499	$250	$0	$550	$3,299
	SUBTOTAL 13.	**$1,220**	**$701**	**$2,614**	**$0**	**$0**	**$4,535**	**$453**	**$0**	**$998**	**$5,986**
14	BUILDINGS & STRUCTURES										
14.1	CDCL Building		TBD from B&W				TBD			TBD	
14.2	Turbine Building	$0	$585	$545	$0	$0	$1,130	$113	$0	$186	$1,429
14.3	Administration Building	$0	$283	$299	$0	$0	$582	$58	$0	$96	$737
14.4	Circulating Water Pumphouse	$0	$27	$21	$0	$0	$48	$5	$0	$8	$60
14.5	Water Treatment Buildings	$0	$37	$34	$0	$0	$71	$7	$0	$12	$90
14.6	Machine Shop	$0	$162	$108	$0	$0	$270	$27	$0	$45	$342
14.7	Warehouse	$0	$109	$110	$0	$0	$219	$22	$0	$36	$277
14.8	Other Buildings & Structures	$0	$89	$76	$0	$0	$165	$17	$0	$27	$209
14.9	Waste Treating Building & Structures	$0	$33	$101	$0	$0	$134	$13	$0	$22	$169
	SUBTOTAL 14.	**$0**	**$1,326**	**$1,294**	**$0**	**$0**	**$2,620**	**$262**	**$0**	**$432**	**$3,314**
	CALCULATED TOTAL COST	**$14,883**	**$4,524**	**$11,120**	**$0**	**$0**	**$30,527**	**$3,053**	**$0**	**$4,860**	**$38,440**

Table 13. Preliminary cost estimate for the supply, construction, erection and commissioning.

Description	Total
Coal, Sorbent, Metal Oxide Handling	$ 5,463,174
Coal, Sorbent, Metal Oxide Preparation & Feed	$ 6,828,415
Feedwater & Miscellaneous BOP Systems	$ 2,905,962
Chemical Looping Primary Loop & Accessories	$ 22,129,062
Flue Gas Cleanup	$ 2,032,744
Combustion Turbine/Accessories (Not Applicable)	$ -
Ducts, Flues, Stack (HRSG in DOE Tab)	$ 3,287,589
Steam Trubine Generator	$ 1,193,708
Cooling Water System	$ -
Ash/Spent Sorbent/Spent Metal Oxide Handling Systems	$ 449,514
Accessory Electric Plant	$ 956,327
Instrumentation & Controls	$ 8,413,048
Improvements to Site	$ 798,776
Building & Structures	$ 6,121,968
Pilot Plant Fuctional Specifications Documents	$ 221,704
Transportation, Storage & Monitoring	$ 354,000
Engineering Project Management - Phase III	$ 3,286,924
TOTAL	**$ 64,442,915**

There was no reported activity during quarters (**FY3Q4**), (**FY4Q1**), and (**FY4Q2**).

Task 4. Commercial Design & Economic Evaluation

Subtask 4.1. Update Commercial Plant Design and Evaluation

(**FY2Q4**) EPRI agreed to provide a list of questions to B&W and OSU regarding the environmental performance of the pilot facility. EPRI would evaluate the pilot facility's expected performance and provide recommendations.

(**FY3Q1**) B&W's cost estimate and economic analysis for a 550 MWe CDCL commercial plant were passed to EPRI for review and update.

(**FY3Q2**) EPRI reviewed B&W's economic analysis of the 550 MWe CDCL commercial plant. Discussions were under way during this quarter for recommended updates on scope and strategy.

(**FY3Q3**) OSU's subcontractor, Ntre Tech, and EPRI started to work together to update the economic analysis of the 550 MWe CDCL commercial plant.

(**FY3Q4**) The 10 MWe CDCL Aspen process simulation was updated by Ntre Tech to reflect the current approach on the design and operation of a 10MWe system. Model additions and enhancements were made on the Wet FGD, pulverizer air preheater and indirect pulverized coal injection (PCI) system, enhancer gas recycle and particulate control as well as in the overall arrangement of heat exchangers. Parametric evaluation was performed to assess and compare various enhancer gas recycle scenarios, including cold recycle (after FGD), warm recycle (before FGD), and mixed recycle at different recycle ratios. **Table 14** shows evaluation results of different recycle schemes. Warm recycle has the advantage of higher temperature (300 °F) and higher moisture; however, the warm recycled gas also contains a higher percent of SO_2 and other acid gas species because it recycles gas before the FGD system. Cold recycle which extracts gas after the FGD has much lower levels of SO_2, but it contains less moisture and has a lower temperature (135 °F). The mixed cold & warm recycle is in blend of gases from cold recycle and warm recycle. The recycle ratio is determined by the required amount of enhancer gas. Based on the recent update on the mechanical functional specification, a higher recycle ratio of around 35 % may be needed.

The first module of the 10 MWe CDCL large plant is envisioned to be built with the flexibility to operate in both warm and cold recycle modes. Different recycle approaches can then be tested on the first module and allow for the optimal recycle approach to be applied to the three remaining modules. The preferred approach would need to weigh the benefits against impact on equipment size & cost, operating costs as well as risks including corrosion. B&W and Ntre Tech have documented these risks and benefits. Recycle CO_2 gas is used for the following purposes: Coal feed, Enhancer gas, Zone seal top and bottom, L-valve aeration (use steam or CO_2 or Nitrogen), Purge on pressure ports (use steam or CO_2 or Nitrogen), Pulsing gas. The mechanical specifications document has been updated to reflect the desired quality and amount of CO_2 at each of these points.

Ntre Tech would continue to update the process model of the 550 MWe commercial CDCL plant to be reported in subsequent quarters.

Table 14. Process evaluation with different recycle schemes

		MIXED RECYCLE		WARM RECYCLE			COLD RECYCLE		
		WR22% - CR 25%	WR22% - CR 15%	WR22% - CR 0%	WR30% - CR 0%	WR38% - CR 0%	WR0% - CR 25%	WR0% - CR 35%	WR0% - CR 43.5%
Raw Coal Flow	lb/hr	9752	9752	9752	9752	9752	9752	9752	9751
Raw Coal Temp	F	59	59	59	59	59	59	59	59
Dry Coal Flow	lb/hr	9752	9752	9752	9752	9752	9752	9752	9751
Dry Coal Temp	F	139	139	139	139	139	139	139	139
Reducer Gas Outlet	lb/hr	51743	46157	39870	44314	49906	40582	46282	52710
Reducer Gas Outlet	F	1862	1861	1860	1861	1862	1860	1861	1862
Recycle Gas Flow	lb/hr	20452	14862	8568	13017	18613	9282	14987	21423
Enhancer Gas Flow	lb/hr	15470	9880	3586	8035	13631	4300	10005	16441
Enhancer Gas Temp	F	430	430	430	430	430	430	430	430
Enhancer Gas Composition									
O2	ppm	1391.19	1527.44	1661.57	1495.72	1330.10	1903.73	1656.44	1446.18
N2	%	1.59	1.54	1.43	1.43	1.43	1.71	1.71	1.71
H2	ppm	3.61	3.76	3.84	3.80	3.76	3.97	3.69	3.44
CO	ppm	16.70	16.43	15.42	15.29	15.12	18.37	18.19	17.95
CO2_Enh Gas	%	74.77	72.63	67.21	67.22	67.23	80.65	80.67	80.70
H2O_Enh Gas	%	23.28	25.37	30.70	30.70	30.70	17.45	17.45	17.45
COS	ppm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H2S	ppm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NH3	ppm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2_Enh Gas	ppm	2184.27	2964.23	4957.75	4958.81	4959.22	1.85	1.17	0.84
SO3	ppm	2.72	3.04	3.64	3.67	3.72	2.40	2.18	1.96
NO	ppm	0.67	0.62	0.55	0.57	0.60	0.65	0.68	0.71
NO2	ppm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

(**FY4Q1**) The 550 MWe plant process model has been updated by NtreTech to reflect the current approach and design considerations. The process flow diagram, which is shown in **Figure 45** and **Table 15**, provides the stream information for the corresponding mass balance. The commercial embodiment of CDCL produces 550 MWe with a steam output of 1,904,458 kg/hr (4,198,611 lb/hr) at 24.23 MPa (3514.7 psia) / 593 C (1100 °F), and 1,583,363 kg/hr (3,490,717 lb/hr) reheat steam at 4.73 MPa (685.8 psia) / 593 C (1100 °F). The steam generator is arranged in the combustor which is performing the oxidation of the metal oxide carrier, along with two convection pass heating surface components cooling the reducer CO_2 off-gas stream and the combustor off-gas stream. The process flow diagram shows the major environmental back-end equipment which include particulate control devices (Baghouse) on both convection passes and a wet FGD unit and an Activated Carbon Injection (ACI) system after the reducer convection pass. A recycle heater system is included to provided heated recycled CO_2/H_2O stream to various locations within the chemical looping reactor system. In the 550 MWe model, the cold recycle system has been adopted as the default baseline configuration. Unlike the 10 MWe model, the Bituminous coal used in the 550 MWe has high sulfur content therefore, the recycle gas stream would have high concentrations of SO_2 and other corrosive constituents. While warm recycle and mixed recycle scenarios may be evaluated in the future, especially if low-sulfur coals are used in the plant, the baseline configuration that will be used for the TEA will be based on the cold recycle configuration. The Process Flow Diagram (PFD) shows some of the major components of the Coal Preparation System which uses a coal pulverizer / dryer to provide the desired coal properties (particle size distribution / moisture content). A bin storage system is used to store the pulverized coal. A Pulverized Coal Injection System (PCI) carries the coal into the reducer. This allows the system to operate by supplying heated air into the pulverizer and recycle CO_2 to carry the coal into the reducer. The CO_2 compression system is modeled based on systems depicted in NETL reports: “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity”.

From **Table 16**, the 550 MWe plant auxiliary power consumption has been estimated to be 15.8 % of gross power with 6.5 % of gross used by the CO_2 compressor. This compares to an atmospheric oxygen combustion plant requiring about 27.5 % auxiliary power.

NETL’s update on the cost and performance baseline of bituminous coal to electricity that was recently released by DOE[1] incorporates additional process design considerations which are being looked at currently and will be referenced in the update of the TEA of the commercial CDCL plant. The commercial plant layout is also undergoing review for further update.

[1] Robert James, Alexander Zoelle, Dale Keairns, Marc Turner, Mark Woods, Norma Kuehn “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity”, NETL-PUB-22638, 2019.

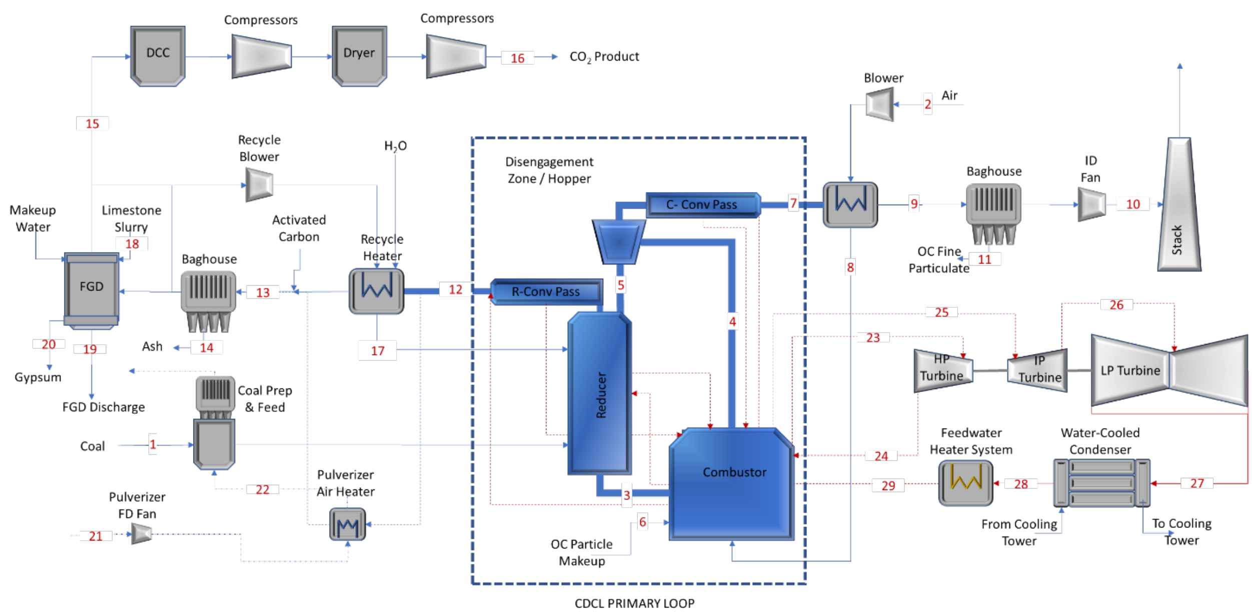


Figure 45. Process flow diagram – 550 MWe CDCL plant.

Table 15. 550 MWe CDCL plant mass balance.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V_L Mole Fraction															
Ar	0.0000	0.0092	0.0000	0.0112	0.0000	0.0000	0.0112	0.0092	0.0112	0.0112	0.0000	0.0001	0.0001	0.0000	0.0006
CO2	0.0000	0.0003	0.0000	0.0004	0.0000	0.0000	0.0004	0.0003	0.0004	0.0004	0.0000	0.6488	0.6505	0.0000	0.8174
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0000	0.0099	0.0000	0.0121	0.0000	0.0000	0.0121	0.0099	0.0121	0.0121	0.0000	0.3369	0.3352	0.0000	0.1740
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0008	0.0000	0.0000
N2	0.0000	0.7732	0.0000	0.9451	0.0000	0.0000	0.9451	0.7732	0.9451	0.9451	0.0000	0.0058	0.0058	0.0000	0.0075
O2	0.0000	0.2074	0.0000	0.0310	0.0000	0.0000	0.0310	0.2074	0.0310	0.0310	0.0000	0.0002	0.0002	0.0000	0.0003
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0075	0.0075	0.0000	0.0000
SO3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
V-L Flowrate (kgmol/hr)	0	68596	0	56113	0	0	56128	68596	56128	56128	0	13532	20927	0	12935
V-L Flowrate (kg/hr)	0	1979393	0	1579931	0	0	1580361	1979393	1580361	1580361	0	477718	739671	0	509103
Solids Flowrate (kg/hr)	200303	0	9615762	10016978	10015225	1753	1753	0	1753	0	1753	12625	19468	20745	0
Temperature (oC)	15	15	921	1049	1049	15	1049	403	111	123	111	343	149	27	57
Pressure (Mpa, abs)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.15	0.10	0.11	0.10	0.10	0.10	0.10	0.101352932
Density (kg/m3)		1.2	4729.2		4527.4	5020.1	0.3	0.8	0.9	0.9	4527.4	0.7	1.0	2285.3	1.5
V-L Molecular Weight	0	29	0	28	0	0	28	29	28	28	0	35	35	0	39
V-L Flowrate (lbmol/hr)	0	151229	0	123707	0	0	123740	151229	123740	123740	0	29832	46136	0	28517
V-L Flowrate (lb/hr)	0	4363814	0	3483151	0	0	3484099	4363814	3484099	3484099	0	1053188	1630695	0	1122380
Solids Flowrate (lb/hr)	441592	0	21199127	22083655	22079791	3865	3865	0	3865	0	3865	27833	42919	45734	0
Temperature (oF)	59	59	1690	1920	1920	59	1920	758	232	253	232	650	300	80	135
Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	21.9	14.7	15.8	14.6	14.7	14.6	14.5	14.7
AspenPlus Enthalpy (Btu/lb)	-902.3	-41.9	-3738.7		-3781.2	-3546.3	440.1	131.2	-12.9	-3.1	-4141.2	-4000.0	-4094.4	-4590.6	-3963.3
Density (lb/ft3)		0.0762	295.2321		282.6380	313.3920	0.0162	0.0484	0.0558	0.0580	282.6380	0.0447	0.0652	142.6671	0.0911

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V_L Mole Fraction														
Ar	0.0008	0.0005	0.0000	0.0000	0.0000	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.9874	0.6400	0.0000	0.0000	0.0000	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0022	0.3533	1.0000	1.0000	1.0000	0.0099	0.0099	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N2	0.0091	0.0059	0.0000	0.0000	0.0000	0.7732	0.7732	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0004	0.0003	0.0000	0.0000	0.0000	0.2074	0.2074	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
V-L Flowrate (kgmol/hr)	10601	4660	4472	7856	8	12497	12497	105713	87890	87890	73919	60231	79966	105713
V-L Flowrate (kg/hr)	464285	161810	80558	141540	142	360606	360606	1904458	1583363	1583363	1331676	1085071	1440612	1904458
Solids Flowrate (kg/hr)	0	0	20140	673	24110	0	0	0	0	0	0	0	0	0
Temperature (oC)	30	316	15	57	57	15	149	593	354	594	362	39	37	290
Pressure (Mpa, abs)	15.27	0.07	0.20	0.10	0.10	0.10	0.12	24.23	4.90	4.73	0.95	0.01	0.01	27.65
Density (kg/m3)	739.1	0.5	1147.2	991.4	4098.3	1.2	1.0	69.2	18.6	12.1	3.3	0.1	993.2	765.0
V-L Molecular Weight	44	35	22	18	116	29	29	18	18	18	18	18	18	18
V-L Flowrate (lbmol/hr)	23371	10272	9858	17320	17	27551	27551	233058	193764	193764	162964	132786	176295	233058
V-L Flowrate (lb/hr)	1023573	356730	177600	312041	312	795000	795000	4198611	3490717	3490717	2935843	2392172	3176005	4198611
Solids Flowrate (lb/hr)	0	0	44400	1484	53152	0	0	0	0	0	0	0	0	0
Temperature (oF)	86.0	600.0	59.0	135.0	135.0	59.0	300.0	1100.0	669.9	1100.5	682.8	101.7	99.2	553.4
Pressure (psia)	2214.5	10.0	29.7	14.7	14.7	14.7	17.4	3514.7	710.8	685.8	137.7	1.0	0.9	4010.0
AspenPlus Enthalpy (Btu/lb)	-3926.4	-4035.7	-6547.7	-6746.1	-4658.8	-41.9	16.6	-5375.0	-5545.4	-5299.5	-5501.9	-5834.5	-6803.1	-6321.3
Density (lb/ft3)	46.141	0.031	71.615	61.891	255.846	0.076	0.062	4.319	1.163	0.755	0.206	0.003	62.001	47.760

Table 16. 550 MWe Supercritical CDCL performance summary.

PERFORMANCE SUMMARY		
	Phase II	PreFeed -Update
Coal Feed Rate, kg/h (lb/h)	203,803 (449,308)	200,303 (441,592)
Total HHV Heat Input, kWt (MMBTU/h)[a]	1,536,165(5,242)	1,508,558 (5,152)
Gross Electric Power Output, kWe	**657,000**	**656,782**
Auxiliary Load, kWe		
Coal Handling and Conveying	483	481
Sorbent Handling & Reagent Preparation	976	959
Pulverizers	1,390	3,007
Coal Injection System		2,931
Carrier Particle Handling		500
Ash Handling	581	693
Primary Air Fans		0
Forced Draft Fans/blower	38,975	26,249
Induced Draft Fans	3,400	6,436
SCR, ACI, DSI		165
Baghouse	24	101
Wet FGD	1,006	2,651
Enhancer Gas Recycle Compressors	4,142	2,056
HCl Scrubber Pump		
CO_2 Compressor	42,835	42,664
Miscellaneous Balance of Plant[b,c]	2,000	2,000
Steam Turbine Auxiliaries	400	400
Condensate Pumps	906	805
Circulating Water Pumps	4,730	5,804
Ground Water Pumps	543	591
Cooling Tower Fans	2,440	3,005
Transformer Losses	1,820	2,061
Total Auxiliaries, kWe	**106,651**	**103,560**
Net Electric Power Output, kWe	**550,349**	**553,222**
Net Plant HHV Heat Rate, kJ/kWh (Btu/kWh)	10,049(9,525)	9,817 (9,312)
Net Plant HHV Efficiency, %	35.8%	36.7%
CO_2 Capture Efficiency, %[e]	96.5%	98.9%
Net CO_2 Emissions, kg/MWhnet (lb/MWhnet)	30.7 (67.7)	9.8 (21.5)
Raw Water Withdrawal, m^3/min (gpm)	22.8 (6,023.0)	23.0 (6,082.0)
Cooling Tower Load, GJ/h (MMBTU/h)		2,951 (2,797)
Solid Waste Disposal, kg/h (lb/h)[f]		20,745 (45,734)

a HHV of as-received Illinois coal is 27,113 kJ/kg (11,666 Btu/lb)
b Boiler feed pumps are turbine drive
c Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads
d Computed relative to base plant on a net HHV efficiency basis
e CO_2 capture efficiency = (carbon in CO_2 product for geologic storage) ÷ (carbon in fuel + carbon in FGD sorbent – carbon in ash – carbon in FGD byproduct)

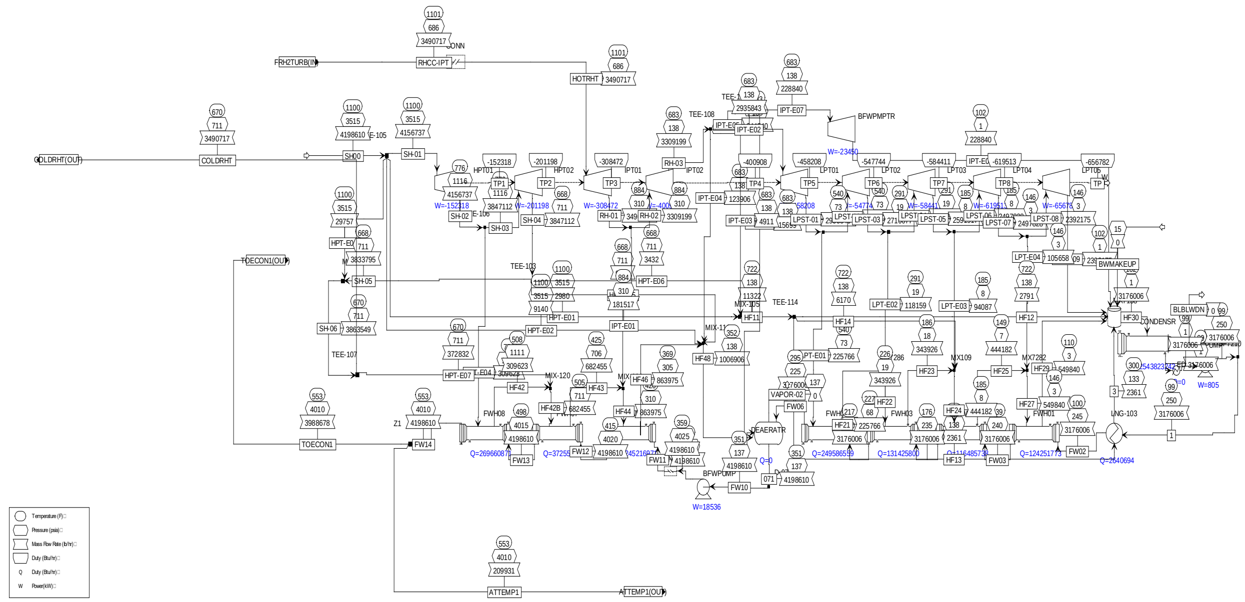


Figure 46. Supercritical steam cycle – Aspen flowsheet.

(**FY4Q2**) B&W and NtreTech reviewed the commercial plant layout and updated the process flow diagram and mass & energy Aspen balance. NETLs update on the cost and performance baseline of bituminous coal to electricity which was released in 2019 by DOE was used as the basis for the update.

The updated plant is a 650 MWe net generation plant as opposed to the 550 MWe reference plant size that was used in previous B&W and NETL studies. The plant size was updated to allow the B&W's cost and performance analysis to be in-line and consistent with the DOE-NETL studies. The current study also incorporates process changes. The updated process flow diagram is shown in Figure 47. Table 17 provides the stream information for the corresponding mass balance. A Spray Dry Evaporator (SDE) has been incorporated to get rid of the WFGD wastewater. The process conditions have been assessed and it was determined that the SDE would be incorporated on the combustor exhaust stream rather than the reducer outlet. The high moisture content of the reducer gas was one of the key underlying reasons that made it difficult to incorporate the SDE on the reducer outlet. As the process is further matured and depending on other process considerations the placement of the SDE may be a subject of further study in the future. The WFGD operating temperature has also been changed in order to provide the higher moisture content desired in the recycle stream. The modified operating conditions are within B&W's operating experience and hence do not pose additional risks.

The updated commercial embodiment of the CDCL produces 650 MWe with a steam output of 2,248,859 kg/hr (4,957,884 lb/hr) at 24.23 MPa (3,514.7 psia) / 593 C (1,100 °F), and 1,869,697 kg/hr (4,121,975 lb/hr) reheat steam at 4.73 MPa (685.8 psia) / 593 C (1,100 °F). The steam generator is arranged in the combustor which is performing the oxidation of the metal oxide carrier, along with two convection pass heating surface components cooling the reducer CO_2 off-gas stream and the combustor off-gas stream. The process flow diagram shows the major environmental back-end equipment which include particulate control devices (Baghouse) on both convection passes and a wet FGD unit after the reducer convection pass as well as the added SDE on the combustor exhaust line to get rid of WFGD wastewater stream. A recycle heater system is included to provided heated recycled CO_2/H_2O stream to various locations within the reduced. Similar to the 550 MWe case, the 650 MWe case would also use recycle CO_2 after the WFGD as its default baseline configuration largely due to the high sulfur content of the fuel and hence the reducer exit gas stream. The PFD shows some of the major components of the Coal Preparation system which uses a coal pulverizer / dryer to provide the desired coal properties (particle size distribution / moisture content). A bin storage system is used to store the pulverized coal. A PCI system then carries the coal into the reducer. This allows the system to operate by supplying heated air into the pulverizer and recycle CO_2 to carry the coal into the reducer. The CO_2 compression system is modeled after systems depicted in NETL reports: "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity".

Table 17, provides a summary of plant auxiliary power consumption, and provides the plant auxiliary for the 650MWe NETL baseline case B12A. Auxiliary power demand is 15.8% of gross power with 6.5% of gross used by the CO_2 compressor. The plant model balance results in a gross power generation of 775.7 MWe, with a total parasitic energy consumption of 118.7 MWe which results in the Net power production of 657MWe. The plant is estimated to have a net plant efficiency of 36 % compared to the baseline supercritical PC case B12A of 40.3 % with a heat rate of 9,992 kJ/kWh (9,479 Btu/kWh). The process flow balance is based on a CO_2 capture efficiency of 95.9 % as opposed to the baseline case that is based on 90 % capture of CO_2. Carbon carryover into the combustor has been factored in as a potential loss of CO2. Other area where losses can occur include the FGD oxidation tank, compression train and minor leaks from compressors and line losses.

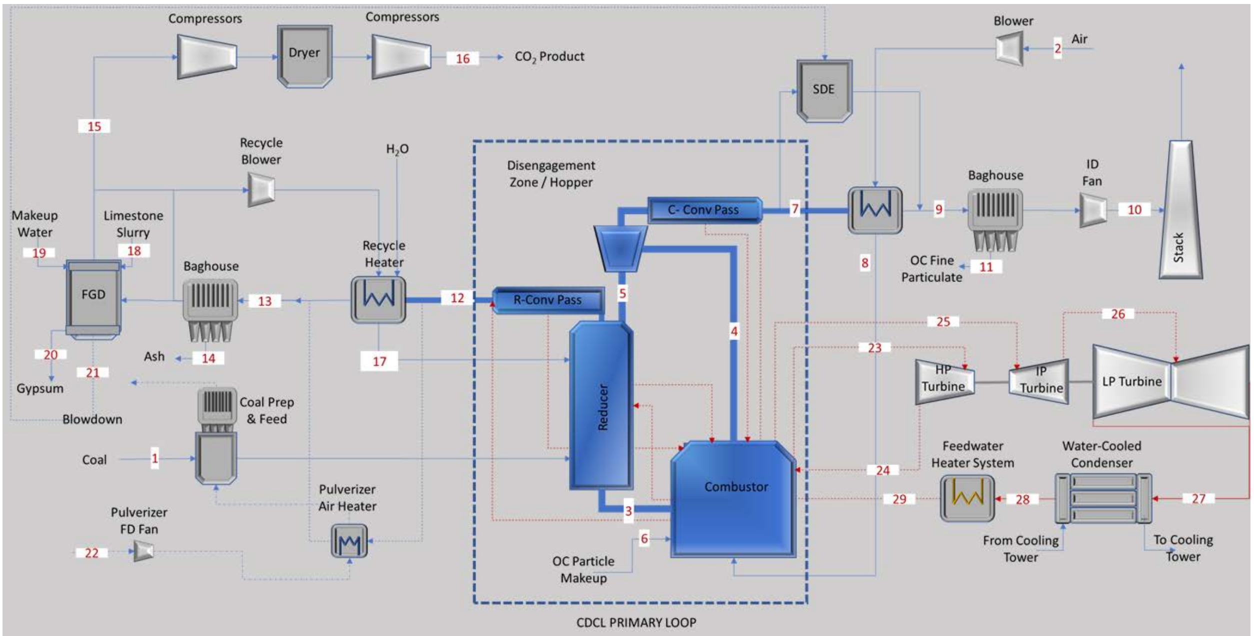


Figure 47 Process flow diagram – 650 MWe CDCL plant.

Table 17 Supercritical CDCL 650 MWe stream table.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V_L Mole Fraction															
Ar	0.0000	0.0092	0.0000	0.0111	0.0000	0.0000	0.0111	0.0092	0.0111	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0000	0.0003	0.0000	0.0079	0.0000	0.0000	0.0079	0.0003	0.0079	0.0077	0.0000	0.6452	0.6469	0.0000	0.6719
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0000	0.0099	0.0000	0.0157	0.0000	0.0000	0.0157	0.0099	0.0157	0.0404	0.0000	0.3403	0.3386	0.0000	0.3220
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0008	0.0000	0.0000
N2	0.0000	0.7732	0.0000	0.9315	0.0000	0.0000	0.9315	0.7732	0.9315	0.9077	0.0000	0.0057	0.0058	0.0000	0.0059
O2	0.0000	0.2074	0.0000	0.0335	0.0000	0.0000	0.0336	0.2074	0.0336	0.0327	0.0000	0.0001	0.0001	0.0000	0.0002
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0078	0.0077	0.0000	0.0000
SO3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
V-L Flowrate (kgmol/hr)	0	83240	0	69088	0	0	69103	83240	62192	70911	0	15685	24258	0	18446
V-L Flowrate (kg/hr)	0	2401957	0	1951657	0	0	1952087	2401957	1756878	1985262	0	552407	855383	0	655603
Solids Flowrate (kg/hr)	239724	0	11504584	11988380	11986282	2098	2098	0	1888	0	2098	15110	23246	24774	0
Temperature (oC)	15	15	898	1049	1049	15	1049	376	111	116	104	316	149	27	74
Pressure (bar, abs)	1.01	1.01	0.69	1.01	1.01	1.01	1.01	1.51	1.01	1.09	1.00	0.69	0.68	0.67	1.01
Density (kg/m3)		1.2	4729.2		4527.4	5020.1	0.3	0.8	0.9	0.9	4527.4	0.5	0.7	2285.3	1.3
V-L Molecular Weight	0	29	30	28	0	0	28	29	28	28	0	35	35	0	36
V-L Flowrate (lbmol/hr)	0	183514	0	152312	0	0	152345	183514	137111	156333	0	34579	53479	0	40665
V-L Flowrate (lb/hr)	0	5295409	0	4302666	0	0	4303614	5295409	3873254	4376753	0	1217848	1885796	0	1445357
Solids Flowrate (lb/hr)	528500	0	25363267	26429854	26425228	4625	4625	0	4163	0	4625	33311	51248	54617	0
Temperature (oF)	59	59	1648	1920	1920	59	1920	709	232	241	220	600	300	80	166
Pressure (psia)	14.7	14.7	10.0	14.7	14.7	14.7	14.7	21.9	14.7	15.8	14.6	10.0	9.9	9.8	14.7
AspenPlus Enthalpy (Btu/lb)	-902.3	-41.9	-3738.6		-3781.2	-3546.3	383.0	118.6	-71.2	-152.5	-4143.3	-4018.6	-4098.8	-4600.5	-4122.9
Density (lb/ft3)		0.0762	295.2322		282.6380	313.3920	0.0163	0.0504	0.0560	0.0587	282.6380	0.0318	0.0442	142.6696	0.0784

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V_L Mole Fraction														
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.9827	0.6264	0.0000	0.0002	0.0000	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0084	0.3679	1.0000	0.9998	1.0000	0.0099	0.0099	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N2	0.0086	0.0055	0.0000	0.0000	0.0000	0.7732	0.7732	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0002	0.0001	0.0000	0.0000	0.0000	0.2074	0.2074	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
V-L Flowrate (kgmol/hr)	12486	5580	2291	4452	17	14857	14857	124831	103784	103784	87287	71123	94427	124831
V-L Flowrate (kg/hr)	544994	191719	41277	80231	300	428715	428715	2248859	1869697	1869697	1572495	1281294	1701131	2248859
Solids Flowrate (kg/hr)	0	0	23133	2839	28613	0	0	0	0	0	0	0	0	0
Temperature (oC)	30	293	15	71	64	15	149	593	354	594	362	39	37	290
Pressure (bar, abs)	152.68	0.69	2.05	1.01	1.01	1.01	1.20	242.33	49.01	47.28	9.49	0.07	0.06	276.48
Density (kg/m3)	828.9	0.5	1298.2	930.7	2938.6	1.2	1.0	69.2	18.6	12.1	3.3	0.1	993.2	765.0
V-L Molecular Weight	44	34	26	18	123	29	29	18	18	18	18	18	18	18
V-L Flowrate (lbmol/hr)	27526	12302	5051	9816	37	32755	32755	275204	228804	228804	192434	156799	208176	275204
V-L Flowrate (lb/hr)	1201506	422668	91000	176880	662	945154	945154	4957884	4121975	4121975	3466758	2824771	3750352	4957884
Solids Flowrate (lb/hr)	0	0	51000	6258	63081	0	0	0	0	0	0	0	0	0
Temperature (oF)	86.0	560.0	59.0	160.0	146.6	59.0	300.0	1100.0	669.9	1101.0	683.1	101.7	99.2	553.4
Pressure (psia)	2214.5	10.0	29.7	14.7	14.7	14.7	17.4	3514.7	710.8	685.8	137.7	1.0	0.9	4010.0
AspenPlus Enthalpy (Btu/lb)	-3937.6	-4068.7	-6306.3	-6628.5	-4741.5	-41.9	16.6	-5375.0	-5545.4	-5299.3	-5501.7	-5834.4	-6803.1	-6321.3
Density (lb/ft3)	51.744	0.031	81.047	58.101	183.452	0.076	0.062	4.319	1.163	0.755	0.206	0.003	62.001	47.758

Table 18 Supercritical PC (NETL Case B12A) & supercritical CDCL 650 MWe performance summary.

PERFORMANCE SUMMARY	Case B12A 650MWe	CDCL 650MWe
Coal Feed Rate, kg/h (lb/h)	214113	239,724 (528,500)
Total HHV Heat Input, kWt (MMBTU/h)[a]	1613874	1,805,451 (6,165)
Gross Electric Power Output, kWe	**685,070**	**775,699**
Auxiliary Load, kWe		
ACI	30	0
Ash Handling	690	829
Baghouse	90	101
Carrier Particle Handling		591
Circulating Water Pumps	5,300	7,661
CO_2 Compressor	0	49,347
Coal Handling and Conveying	470	526
Coal Injection System		3,296
Condensate Pumps	660	951
Cooling Tower Fans	2,740	3,966
DSI	60	0
Enhancer Gas Recycle Compressors		4,182
Forced Draft Fans/blower	2,010	25,299
Ground Water Pumps	550	780
Induced Draft Fans	8,210	8,259
Miscellaneous Balance of Plant[b,c]	2,250	2,250
Primary Air Fans	1,570	0
Pulverizers	3,210	3,594
SCR	30	0
Sorbent Handling & Reagent Preparation	1,000	1,120
Spray Dryer Evaporator	240	269
Steam Turbine Auxiliaries	500	500
Transformer Losses	2,150	2,434
Wet FGD	3,310	2,722
Total Auxiliaries, kWe	**35,070**	**118,677**
Net Electric Power Output, kWe	**650,000**	**657,022**
Net Plant HHV Heat Rate, kJ/kWh (Btu/kWh)	8,938	9,893 (9,384)
Net Plant HHV Efficiency, %	40.3%	36.0%
CO_2 Capture Efficiency, %[e]		95.9%
Net CO_2 Emissions, kg/MWhnet (lb/MWhnet)		35.0 (77.2)
Raw Water Withdrawal, m^3/min (gpm)	22.9(6054)	34.5 (9,107.4)
Cooling Tower Load, GJ/h (MMBTU/h)	2589(2454)	3,895 (3,692)
Solid Waste Disposal, kg/h (lb/h)[f]		24,774 (54,617)

a HHV of as-received Illinois coal is 27,113 kJ/kg (11,666 Btu/lb)
b Boiler feed pumps are turbine drive
c Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads
d Computed relative to base plant on a net HHV efficiency basis
e CO_2 capture efficiency = (carbon in CO_2 product for geologic storage) ÷ (carbon in fuel + carbon in FGD sorbent – carbon in ash – carbon in FGD byproduct)

Subtask 4.2. Update Commercial Cost Analysis and Comparison

Due to the surplus of natural gas and the decrease in coal demand for power generation, the coal price has dropped significantly in the last few years. According to the US Energy Information Administration, current coal prices are estimated at about $1.30 per MMBTU. **Figure 48** shows the historical coal prices for various coal types. Fuel cost is an important assumption in the CDCL economic analysis. Hence, the CDCL commercial plant economic analysis was adjusted using a coal price of $1.30 per MMBTU.

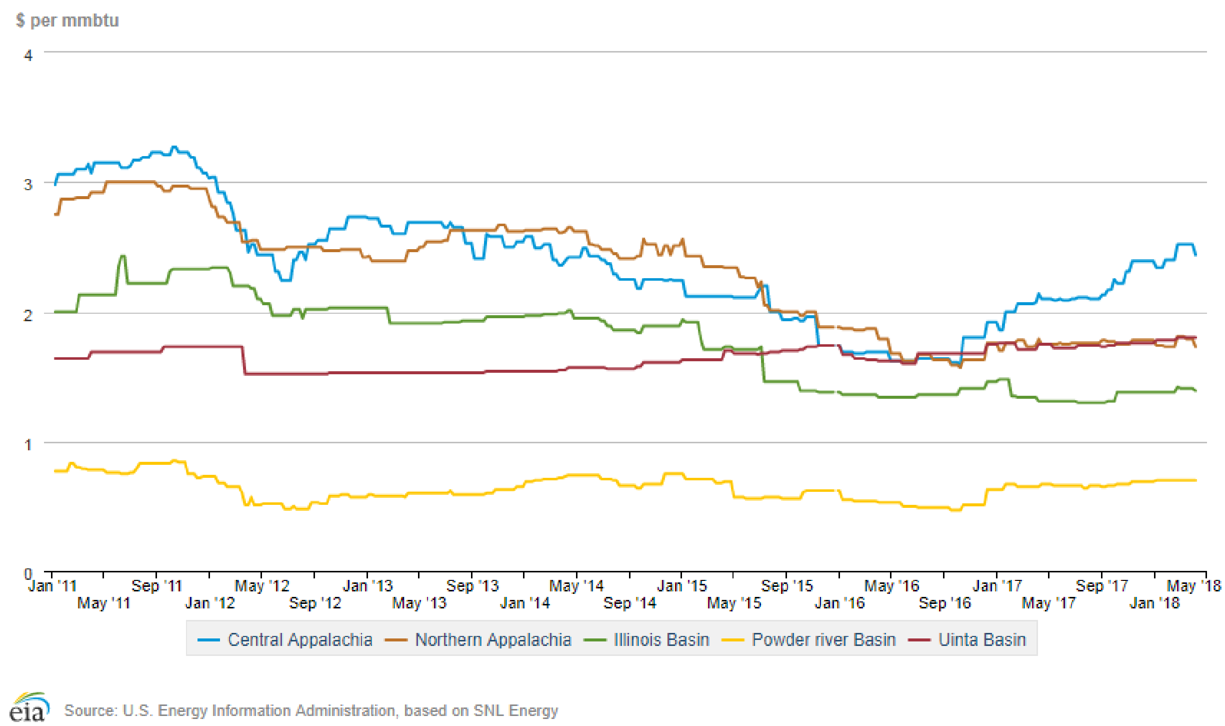


Figure 48. Historical coal prices.

The CDCL technology has been demonstrated at a 25 kWth scale to have low NOX emissions. Economic analysis was adjusted to discount the capital equipment for the SCR system. The capital cost of SCR systems for a commercial plant is about $100/kWe (B&W's estimated value). For a 550 MWe plant, the cost of an SCR system would be about $55 Million. Since the DOE plant cost estimate has no breakdown on the cost of the SCR system, a direct adjustment could not be made. The adjustment of the SCR cost system was then applied to the total capital cost.

Mercury emissions in the CDCL are expected to report to the CO_2 stream. Since Mercury limits have not been specified for sequestrable CO_2, the mercury removal system is not required in the CDCL system. Costs associated with Mercury removal were also eliminated from the capital cost of the CDCL plant.

The CDCL plant requires less coal preparation equipment, since in the CDCL plant, the coal size is larger than the size of a PC plant. Furthermore, the CDCL plant is less sensitive to coal moisture content. Hence, the CDCL plant requires substantially less coal crushing and drying equipment. A discount of 50 % on the cost of coal crushing equipment was taken on the CDCL capital equipment compared to the PC plant.

Based on these savings, the total capital cost for the commercial CDCL plant was revised. **Table 19** shows the adjusted CDCL plant capital cost. The new capital cost for the CDCL plant is close to $1,283 million.

Table 19. 550 MWe Commercial CDCL total plant costs.

	Account	Units	TOTAL COST
Gross electrical production		kW	657,000.00
Net electrical production		kW	550,349.00
1.0 COAL & SORBENT HANDLING		k$	$ 33,121.31
2.0 COAL & SORBENT PREP & FEED (Adjusted Coal Crushin		k$	$ 13,052.65
3.0 FEEDWATER & MISC BOP SYSTEMS		k$	$ 89,175.18
4.0 CDCL EQUIPMENT		k$	$ 525,998.81
5.0 FLUE GAS CLEANUP (NO Hg REMOVAL)		k$	$ 172,106.90
5.0B CO2 REMOVAL & COMPRESSION		k$	$ -
6.0 COMBUSTION TURBINE/ACCESSORIES		k$	$ -
7.0 HR, DUCTING & STACK		k$	$ 46,328.59
8.0 STEAM TURBINE GENERATOR		k$	$ 169,473.69
9.0 COOLING WATER SYSTEM		k$	$ 49,291.39
10.0 ASH/SPENT SORBENT HANDLING SYS		k$	$ 18,021.07
11.0 ACCESSORY ELECTRIC PLANT		k$	$ 99,570.37
12.0 INSTRUMENTATION & CONTROLS		k$	$ 32,373.59
13.0 IMPROVEMENTS TO SITE		k$	$ 18,061.88
14.0 BUILDINGS & STRUCTURES		k$	$ 71,528.93
16.0 TRANSPORTATION, STORAGE & MONITORING		k$	$ -
17.0 ADJUSTMENTS (SCR EQUIPMENT)			$ (55,000.00)
Total Plant Cost (TPC) wo/T,S&M		k$	$ 1,283,104.35
Capital Cost wo/T,S&M		$/kWn	2,331.44

Based on the modifications listed above, a new cost of electricity was estimated for the CDCL plant. **Table 20** shows a summary of the economic analysis performed to estimate the cost of electricity for various plant configuration. **Table 20** compares the CDCL cost of electricity reported for Phase I and Phase II of project DE-FE-0009761 (commercialization of an atmospheric iron-based CDCL process for power production). Based on the adjustments discussed above, the CDCL plant has an estimated cost of electricity of $83.32 per MW-hr. This estimated cost of electricity is competitive against the estimated cost of electricity for a NGCC system with CO_2 capture.

Table 20. Economic analysis for various plants (Phase I and Phase II DE-FE-0009761)

	Dated July 6 2015 160 2011$ Sup PC w/CO2 CAP Case B12B	Dated July 6 2015 Page 192 2011$ NGCC Case B31A	Dated July 6 2015 Page 208 2011$ NGCC W/CO2 CAP Case B31B	Phase I 2011$ Supercritical CDCL	Phase II 2011$ Supercritical CDCL	10 Mwe Project 2011$ Supercritical CDCL
Capacity Factor	85%	85%	85%	85%	85%	85%
Net Power (kWe)	550,000.00	630,000	559,000	550,349.00	550,349.00	550,349.00
Coal Cost ($/MMBtu)	**2.937**					**1.300**
Coal Cost ($/ton) 2000 lb = ton	$68.54			$68.60	$68.60	$30.33
Natural Gas Costs, $/MMBTU	$6.13	$6.13	$6.13	$0.00	$0.00	$0.00
Net Plant Heat Rate (Btu/kWh)	10,512.22	6,624.03	7,465.37	9,524.69	9,524.69	9,933.30
Capital						
Total Plant Cost (TPC), $k	$ 1,939,143	$ 430,933	$ 827,903	$ 1,380,401	$ 1,384,130	$ 1,283,104
Total Overnight Cost (TOC), $k	$ 2,384,353	$ 527,638	$ 1,008,369	$ 1,722,059	$ 1,727,930	$ 1,591,393
Capital Factor Assumption	High Risk 5 Years	Low Risk 3 Years	High Risk 3 Years	High Risk 5 Years	High Risk 5 Years	High Risk 5 Years
Capital Factor (Page 62, Nov-2010 Report)	0.124	0.105	0.111	0.124	0.124	0.124
Fixed and Variable Costs						
Fixed Operating & Maintenance Costs, k$/year	$63,094.57	$ 15,883	$ 27,368	$48,811.96	$48,564.68	$44,025.85
Variable Operating & Maintenance Costs k$/year	$60,366.96	$ 7,800	$ 16,500	$27,645.84	$32,656.13	$31,540.73
Fuel Cost, k$/year	$126,458.92	$ 190,479	$ 190,479	$114,748.17	$114,748.17	$52,917.35
Oxygen Carrier Cost, k$/year @ $1199.50/ton				$15,580.96	$15,596.24	$15,596.24
CO2 TS&M Costs						
CO2 Removal at 85% CF (ton/year)	3,934,091.75		1,709,119.19	3,824,380.58	3,824,380.58	3,988,446.50
CO2 TS&M Costs ($/ton)	$10.00		$0.00	$10.00	$10.00	$10.00
CO2 TS&M Costs, ($k)	$39,340.92		$0.00	$38,243.81	$38,243.81	$39,884.47
CO2 Credits						
CO2 Credit $20/Ton (CO2)						
Contributions to COE, $/MWh						
Capital	$72.19	$11.81	$26.89	$52.11	$52.29	$48.15
Fixed O&M	$15.41	$3.39	$6.58	$11.91	$11.85	$10.74
Variable O&M	$14.74	$1.66	$3.96	$6.75	$7.97	$7.70
Fuel	$30.88	$40.61	$45.76	$28.00	$28.00	$12.91
Oxygen Carrier	$0.00	$0.00	$0.00	$3.80	$3.81	$3.81
COE ($/MWh)	**$133.22**	**$57.46**	**$83.19**	**$102.57**	**$103.92**	**$83.32**

(**FY2Q2**) The economic analysis and cost estimation for CDCL commercial plant will be passed to EPRI for reviewing.

(**FY3Q4**) The cost and performance baseline of bituminous coal to electricity was released by DOE and will be referenced in the update of the TEA of the commercial 550 MWe CDCL plant.

(**FY4Q1**) B&W, NtreTech and OSU reviewed results from the heat integration and optimization studies and reported potential cost savings on the 550 MWe commercial plants due to a shift in heat duty from the convection banks to in-bed heat exchanger sections of the combustor. The potential cost savings have been reported in the quarterly report for the *Heat Integration Optimization and Dynamic Modeling Investigation for Advancing the Coal Direct Chemical Looping Process* project (DE-FE0029093) that was focused on the heat integration studies. These findings, additional savings and cost adders that have been identified will be further evaluated and incorporated as part of the update on the TEA of the commercial 550 MWe plant.

(**FY4Q2**) B&W and NtreTech reviewed and updated the commercial plant layout, process flow diagram and Aspen mass & energy balance. In conjunction with the plant balance update, the economic analysis of the commercial plant was updated in order to be consistent with the latest NETL update on the cost and performance baseline of bituminous coal to electricity which was released in 2019.

The updated plant, as previously discussed, is a 650 MWe net generation plant as opposed to the 550 MWe reference plant size that was used in previous B&W and NETL studies. While the current update incorporates process changes, it also updates the economic assumptions that form the basis of the calculation. Again, the economic assumptions are consistent and in-line with the latest NETL update. **Table 21** provides the site characteristics and ambient conditions for the 650MWe plant which are consistent with the corresponding NETL cases B12A and B12B. As mentioned earlier, the updated NETL study uses new economic assumptions such as a change in the tax rates, financing structure, depreciation period, debt to equity ratio and debt term to list a few. **Table 22** provides the assumptions that have been used in the updated economic model in order to provide a basis for comparison with the NETL supercritical PC without and with CO_2 capture (cases B12A and B12B). While most of the parameters are included in the referenced NETL Publications 22580 and 22697, there are specific numbers that are pertinent to the CDCL case related to the Oxygen Carrier cost and CDCL island capital cost. **Table 23** provides the update COE estimates for the supercritical CDCL plant and a comparison with the NETL cases. The COE for the CDCL plant is estimated to be $83.3/MWh which is 20.9 % below the COE for the corresponding NETL Case B12B which uses an amine based solvent to capture and separate the CO_2 from a PC Boiler. The CDCL case results in an increase in COE of 29.4 % over the baseline Supercritical Case B12A with no CO_2 capture.

Table 21 Site Characteristics and Ambient Conditions.

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water
Elevation, m (ft)	0 (0)
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[A]	15.6 (60)
Air composition based on published psychrometric data, mass %	
N_2	75.055
O_2	22.998
Ar	1.28
H_2O	0.616
CO_2	0.05
Total	100

[A] *The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 4.8°C (8.5°F) above ambient wet bulb conditions in ISO cases.*

Table 22 650 MWe cost model assumptions and basis.

Parameter	Value
Nominal Plant Size, MWe	650
Capacity Factor, %	85
Estimate in Year, $	2018
Capital Cost Estimation / Scaling	Consistent with NETL 2019 Quality Guidelines for Energy System Studies (QGESS)[A]
Operating Life, years	30
Capital Expenditure Period, years	5
Economic Analysis Period	35 years (capital expenditure period plus operational period)
Income Tax Rates	21% federal, 6% state (Effective tax rate [ETR} 25.74%)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0
Tax Holiday	0 years
Contracting Strategy	Engineering Procurement Construction (EPC) Management
Capital Cost Escalation During Capital Expenditure Period	0% real (3% nominal)
Debt/Equity Split	Commercial IOU = 55/45 TOC
Debt Term	30 years (Equals operating period)
Debt Interest Rate	Commercial IOU = 2.94% real
Fixed Charge Rate (FCR Real)	0.0707
Capital Recovery Factor	0.0630
TASC/TOC $_{Real}$	1.154
Escalation (CDCL Capital Equipment Cost), %/yr	1.89
Operating Labor Rate, Midwest, $/hr	38.5
Coal Cost, $/MMBtu delivered	2.227
Coal Cost, $/ton delivered	51.96
Limestone CaCO3, %	80.4
Oxygen Carrier Cost, $/ton	4918.33
CO2 Capture, %	95.9
Engineering Construction Management, Home Office and Fee, %	17.5
Technology Status - Small Pilot Plant Data	
Process Contingency, %	20 on novel equipment
Process Contingency - Instrumentation and Controls, %	5
Project Contingency, %	15-20 (consistent with NETL Cases B12A and B12B)
Other Owner's Cost (% of TPC)	15
Financing Cost (% of TPC)	2.7
Maintenance Factor out of TPC, %	0.96
Property Tax and Insurance, % of Capital Cost	2
Labor	50hr/wk, 10 hr day
Operating Labor Requirements per Shift	15
Operating Labor Rate, $/hour	38.5
Operating Labor Burden, % of Base	30
Operating Labor O-H Charge Rate, % of Labor	25
Performance Factors	
WFGD Sulfur Removal, %	>98
Oxygen Carrier Loading, lbs/lbs Coal Feed	50:1
Oxygen Carrier Attrition Rate, %/cycle	0.0175

[A]NETL-PUB-22697 "QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES Capital Cost Scaling Methodology : Revision 4" and NETL-PUB-22580 "Cost Estimation Methodology for NETL Assessments of Power Plant Performance"

Table 23 COE summary and comparison with NETL cases.

Report Type Case	Dated Sep 24 2019 Subcritical PC Case B11A	Dated Sep 24 2019 Sub PC w/CO2 CAP Case B11B	Dated Sep 24 2019 Supercritical PC CASE B12A	Dated Sep 24 2019 Sup PC w/CO2 CAP Case B12B	PreFEED Supercritical CDCL
<u>**Contributions to COE, $/MWh**</u>					
Capital	$27.2	$50.4	$28.3	$51.0	$31.9
Fixed O&M	$9.1	$16.0	$9.5	$16.1	$10.4
Variable O&M	$7.9	$14.5	$7.7	$14.0	$7.1
Fuel	$19.7	$25.4	$18.9	$24.1	$20.9
Oxygen Carrier	$0.0	$0.0	$0.0	$0.0	$13.0
COE ($/MWh)	**$63.8**	**$106.2**	**$64.4**	**$105.2**	**$83.3**
Increase in COE			0.0%	63.5%	29.4%
Reduction from PC with CO2 capture			-38.8%	0.0%	-20.9%

(**FY4Q2**) In addition to the effort of updating the CDCL cost performance in order to be consistent with the latest NETL study, released in 2019, EPRI in collaboration with NtreTech, performed an evaluation of the cost of the CDCL for a mine-mouth operation. In this case, the cost of fuel would be lower since it does not incur any shipping costs. The case for operations in Japan, Eastern Europe and Japan were also evaluated. The objective to evaluate the CDCL cost for these locations was that the cost differential between natural gas and coal is much higher than the differential in the USA. This cost differential may provide the potential to offer the CDCL technology in these markets against competing Natural Gas Combined Cycle or other advanced power generation technologies. The results from this study are summarized in **Figure 49** and **Figure 50.**

Figure 49 Comparison of NETL and CDCL levelized cost of electricity (Part 1).

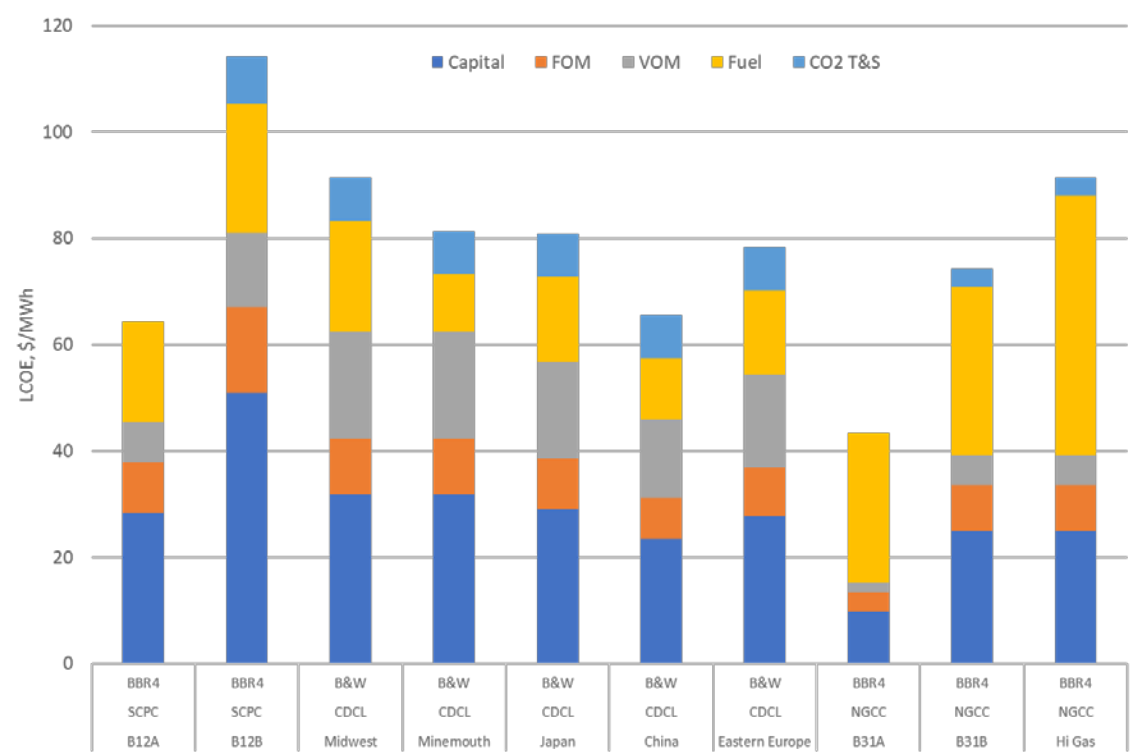
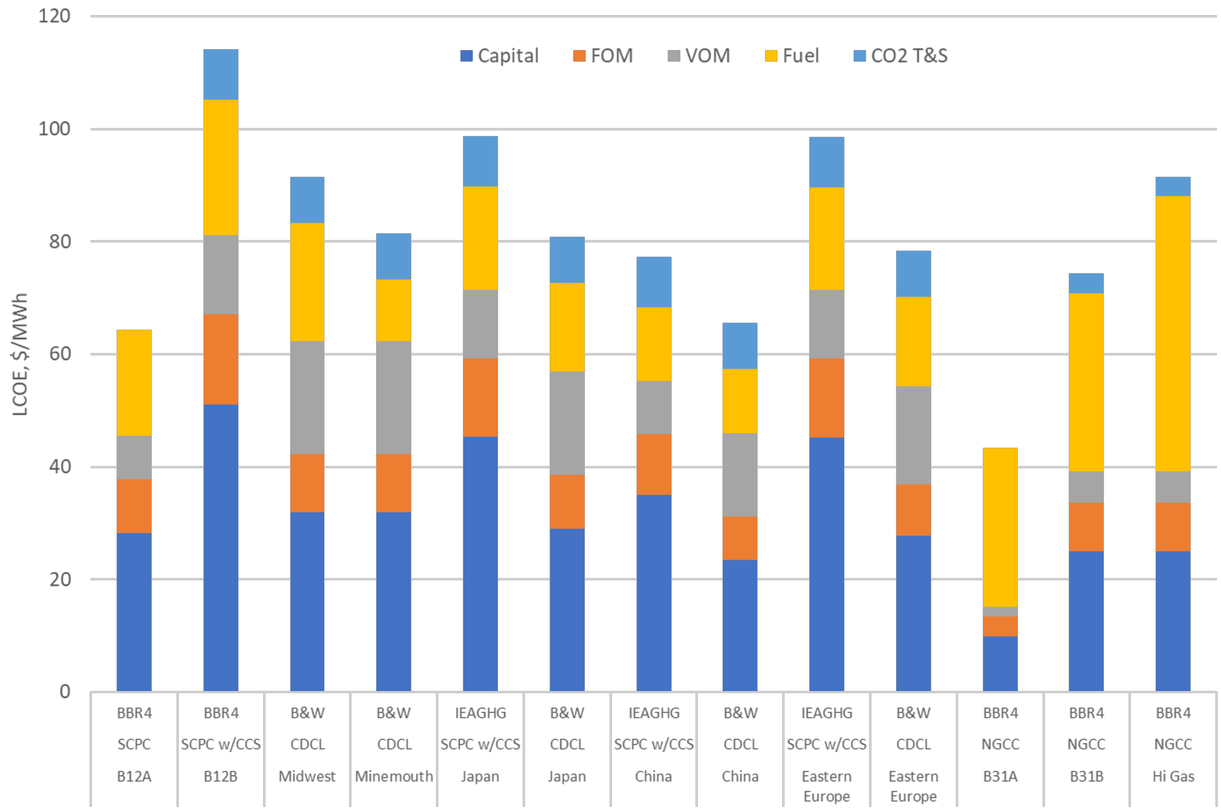


Figure 50 Comparison of NETL and CDCL levelized cost of electricity (Part 2).



The factors used to adjust for the Total Plant Cost are listed in **Table 24**. The fuel prices for Coal and Natural gas are as follows:

- PRB Coal: $2.23/MMBtu (Midwest USA)
- PRB Coal: $1.16/MMBtu (Minemouth USA)
- Natural Gas: $4.42/MMBtu
- High gas price set at $6.82/MMBtu to match the COE for Midwest CDCL

The cost of CO_2 transportation and storage was kept to $10/tonne CO_2 for all cases, which is consistent with the given plant location based on April 2018 IEAGHG report titled "Effects of Plant Location on the Costs of CO_2 Capture"

This study shows that the CDCL process cost of electricity are low, and the process may be competitive in those locations where the natural gas prices per million BTU is much higher than coal. Those locations are usually countries that import natural gas and where they have easy access to coal, such as China.

Table 24 Relative total plant costs factors.

	Relative Total Plant Cost	Relative Coal Cost
Midwest USA	1.0	1.0
Japan	0.912	0.758
China	0.737	0.564
Eastern Europe	0.871	0.758

Subtask 4.3. CDCL Commercialization Roadmap and Risk Assessment

(**FY2Q4**) During the EPRI, OSU and B&W meeting, EPRI agreed to provide conclusions on the outlook and feasibility of the CDCL commercialization plan in view of the present and future power markets.

No activity to report in these quarters (**FY3Q1**), (**FY3Q2**), and (**FY3Q3**).

(**FY3Q4**) EPRI provided a draft of the CDCL commercialization roadmap to B&W for review. The roadmap will be finalized and reported during the next quarter.

(**FY4Q1**) B&W and OSU reviewed the CDCL commercialization roadmap from EPRI. The CDCL technology status, performance and economics, remaining technology gaps, and commercialization path were summarized and provided to EPRI.

(**FY4Q2**) EPRI completed his analysis and provided a comprehensive analysis on the CDCL technology. EPRI's final commercialization perspective is provided in the additional subtask 4.4.

Subtask 4.4. Utility Perspective on the CDCL Business Plan

NOTE: The content of this subtask is an extract from EPRI's CDCL Business Plan assessment, which reads as follows:

This document outlines how the development timeline for achieving commercial deployment for the coal direct chemical looping (CDCL) system. The document also discusses next steps and the potential market for the technology, providing a high-level business plan for its potential viability.

Overview

The Babcock and Wilcox Company (B&W) and The Ohio State University (OSU) are working together in developing CDCL, a process where fluidization and transport of a metal-oxide oxygen carrier is circulated in the process loop permitting a reduction / oxidation reaction producing a high-percentage CO2 stream readily suitable for capture. An air separation is hence not required, which is a major advantage of chemical looping systems in general, reducing the inherent energy penalty of cryogenic air separation. Repowering with CDCL would reuse the steam cycle, fuel preparation, and balance-of-plant facilities. The successful pilot plant trials undertaken at OSU and B&W demonstrated the potential for the technology. The characteristics of the metal-oxide oxygen carrier are a key factor of the technology and selection of satisfactory properties must be obtained for the long-term success of CDCL[2].

Process Description

In the CDCL system, an iron-based oxygen carrier, hematite, Fe_2O_3, and wüstite, FeO, are circulated around a reduction / oxidation process loop. The loop consists of a moving-bed reducer, a non-mechanical valve and standpipe, a bubbling fluidized-bed / entrained-flow combustor (oxidizer), a solid transport riser, and a gas-solid separation cyclone. The iron-based oxygen carrier provides the oxygen to the coal, avoiding the direct contact of fuel with air as is present in conventional fuel combustion. The coal is injected to the reducer with the Fe_2O_3 and the FeO from the reducer goes to the combustor. Air is provided to the combustor to re-oxidize the FeO, releasing high-temperature heat, which is captured with in-bed heat exchangers in the combustor as well as in the convection pass on the spent air and product CO_2 streams to produce steam for a conventional steam-Rankine power plant (or a supercritical CO_2 power cycle). Heat is also recovered for air pre-heating before entering the combustor as well as for heating recycled CO_2 enhancer gas used in the reducer and transport gas for pulverized coal (PC) injection. The CDCL process produces a concentrated CO_2 off-gas stream, with little nitrogen or other trace species from the reducer and a spent air stream from the gas-solid separation cyclone.

A cycle flow diagram for a proposed 10-MWe pilot plant demonstration project at Dover Light and Power (DL&P) is shown in **Figure 51**. There are four modules of the reducer / combustor. The modular system provides for turndown and addresses the scale-up limitations. A module is a single loop of components as used in the B&W / OSU technology instead of two solids interchanging component loops, such as two circulating fluidized bed (CFB) reactors as proposed in systems by others.
The circulation and storage of solids is controlled by a non-mechanical “L” valve between the reducer and the combustor. Transport air flow controls the combustor solids removal to the separating cyclone. Heat removal from the combustor by an integral steam generator maintains solids temperature.

[2] E. Chung, S. Bayham, M. Kathe, A. Tong, L. Zeng, L.-S. Fan. Chemical Looping Combustion and Gasification in Handbook of Clean Energy Systems. 2015. Wiley.

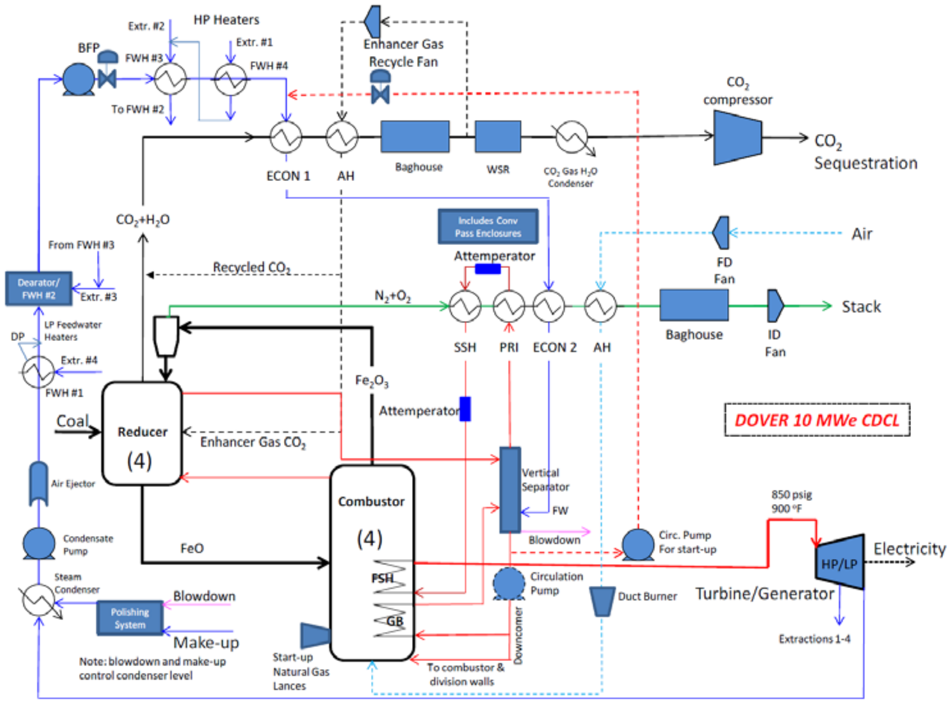


Figure 51 B&W's CDCL process flow diagram for the DL&P 10 MWe pilot plant.

Technology Status

In early 2017, the Ohio Development Service Agency awarded OSU, and the U.S. Department of Energy (DOE) awarded B&W, to perform, in collaboration, a pre-front-end engineering and design (pre-FEED) study for a 10-MWe pilot unit.[3] B&W has selected a potential host plant, DL&P, located in Ohio that could house the CDCL pilot unit. The unit will produce steam that could be incorporated into the existing plant for power generation. B&W is proposing to build a 4 x 2.5-MWe module system that will operate in a similar fashion as larger commercial plants. One module would be built first, and the remaining modules would be built using lessons learned from the first module. Assuming success with the 10-MWe process development unit (PDU) plant, the next step would be to build a single, commercial module 70-MWe demonstration plant. This is considered the largest module required to support the installation of a commercial-scale 550-MWe plant, which would use eight 70-MWe modules, as shown in **Figure 52**. The system's capability allows steam conditions for either ultra-supercritical (USC) or advanced USC steam turbines.

[3] "10 MWe CDCL Large Pilot Plant Demonstration Phase I Feasibility," U.S. DOE Project DE-FE0031582, 2018.

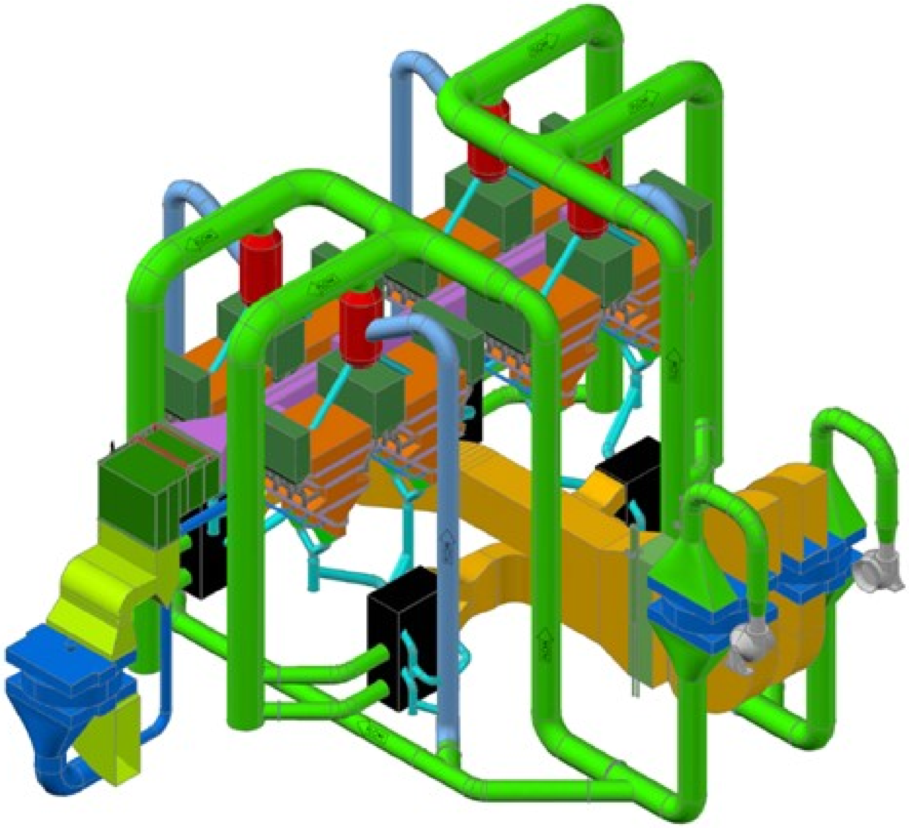


Figure 52 SolidWorks model for a 550-MWe commercial plant.

The DL&P pilot demonstration project, which performed pre-FEED work through a DOE-funded project, proposes to build the first module and start commissioning / testing. The three additional modules would be built later and reap the benefit of the lessons learned with the first module. The pilot facility concept is shown in **Figure 53**.

The OSU laboratory-scale unit sized at 2.5 kWth commenced operations in 2012. The next scale up test was at OSU's 25-kWth facility, which was operational for several years, achieving nearly 700 hours of operational experience and over 200 hours of continuous operation. Construction of a 250-kWth CDCL unit, which is located at B&W's Research Center facilities in Barberton, OH, began in July 2016 and concluded in January 2017. A schematic of the B&W 250-kWth unit is shown in **Figure 54.**[4]

[4] "Assessment of Chemical Looping," EPRI, Palo Alto, CA: 2014. 3002003620.

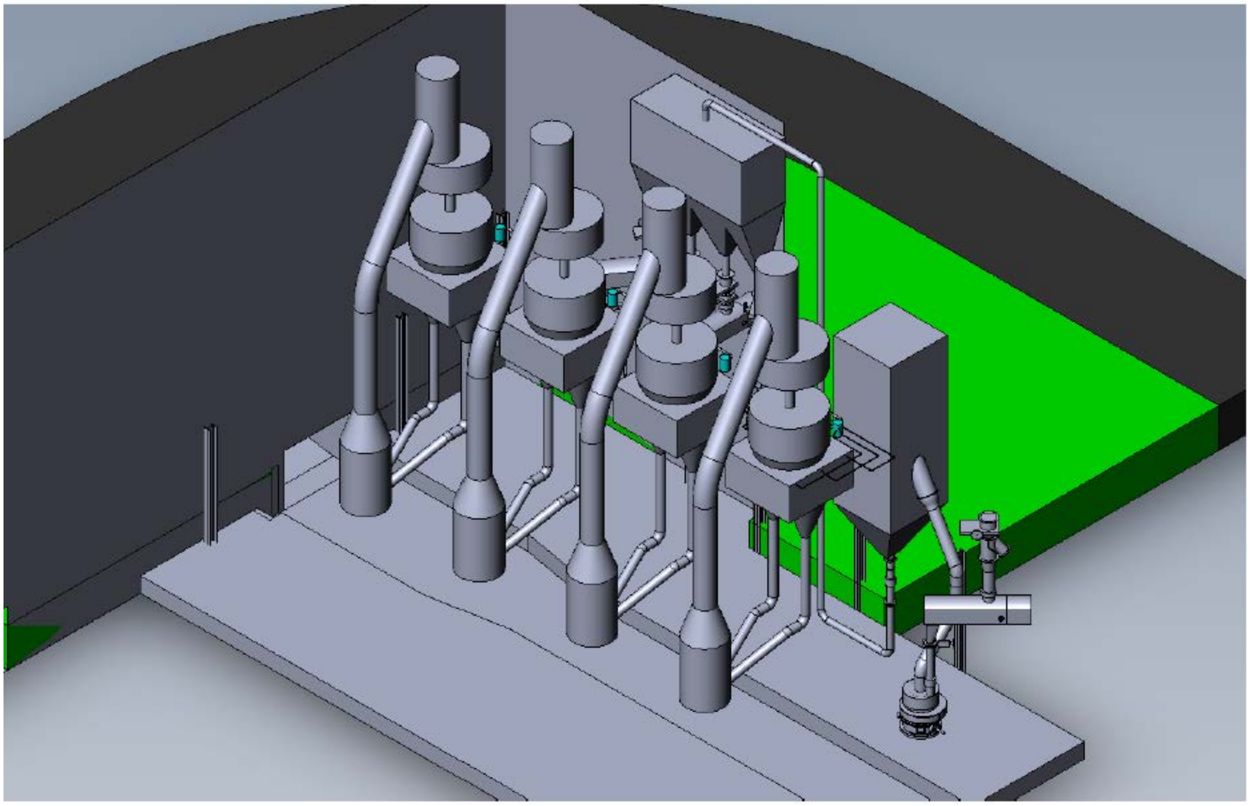


Figure 53 Schematic for the DL&P 10 MWe plant.

Operating results from the 250-kWth unit were derived from five test campaigns. Two test campaigns were performed in 2017. Initial shakedown and facility limitations were observed, and the data were used to improve the facility design and features. Full temperature of 1800°F (982°C) in the combustor was attained in the second test. After these lessons and subsequent modifications, a 35-hour long-term test campaign with coal injection was completed in 2019.[5]

Data from the 250-kWth unit shows that a 50-hour startup period is possible. Therefore, the estimated start time to achieve first fire on coal is 24 hrs to 48 hours, which could be reduced to 12 hours. A dynamic model of the system is being developed that will be used to optimize the startup procedure and address questions regarding transient operation.

Inherently, CDCL is not a fast load-changing technology. The time required to take modules in and out of service, like what is done on a cyclone furnace boiler, would be a key factor in the load rate of change. The inventory of solids is large and therefore takes a long time to heat up or cool down. Once the large inventory of solids is heated up, hot restarts can be achieved quickly much like slumping portions of the bed overnight in a CFB boiler. Turndown is primarily achieved through the modular design.

[5] "250 kWt Pilot Testing in Support of a 10 MWe Coal-Direct Chemical Looping Demonstration Feasibility Study," T. Flynn, et al., 2019 Clean Energy Conference, 2019.

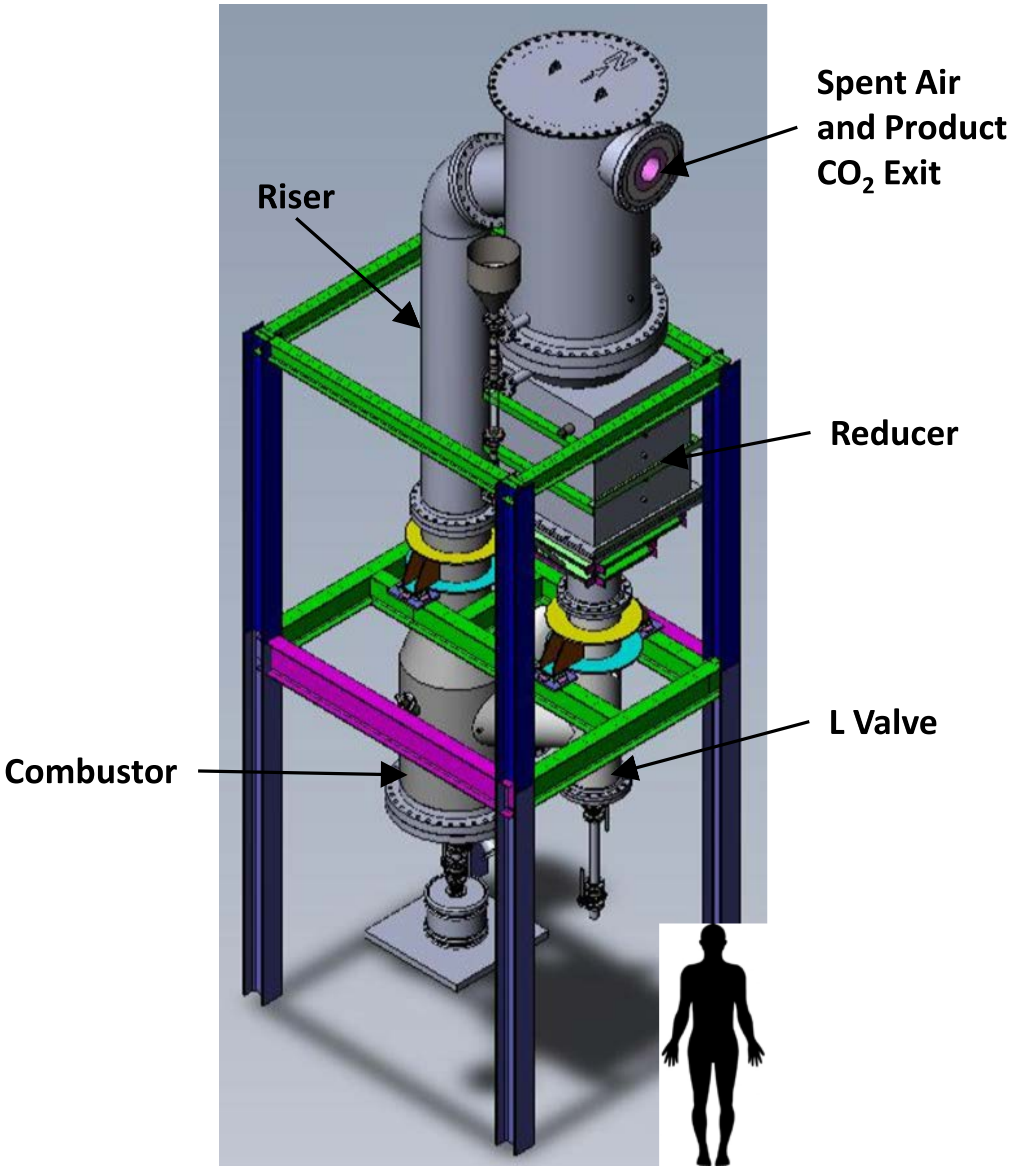


Figure 54 Schematic of the 250 kWth CDCL unit.

Performance and Economics

The primary benefit of chemical looping combustion technology in general is that the positives of oxy-combustion with CO_2 capture (which also includes near-zero emissions and water generation) can be realized without employing cryogenic air separation. This results in a significant capital cost benefit and reduction in auxiliary power use compared to atmospheric-pressure oxy-combustion.

The commercial embodiment of CDCL produces 550 MWe by the steam output of 4,198,611 lb/hr (1,904,458 kg/hr) at 3515 psia (24.2 MPa) and 1100°F (593°C) and 3,490,717 lb/hr (1,583,363 kg/hr) reheat steam at 686 psia (4.7 MPa) and 1100°F (593°C).

From **Table 25**, the 550-MWe plant auxiliary power consumption is 15.8 % of the gross power. This compares to an atmospheric-pressure oxy-combustion plant requiring about 27.5 % auxiliary power.[6] The efficiency is 3.3 % points higher than a PC plant with amine-based carbon capture and storage (CCS) with a larger percentage of CO_2 captured.

Based on a recent update done as part of a DOE project utilizing a bituminous coal,[7] the estimated cost of electricity (COE) for the 550-MWe commercial CDCL plant is $96.8/MWh as shown in **Table 25**. The COE cost impact of the metal oxide oxygen carrier is $11.70/MWh or 12 % for the total COE. As shown in **Table 25**, the COE and efficiency for CDCL is significantly better than a PC plant with CCS provided by conventional amine-based post-combustion capture (PCC). Capital and operations and maintenance (O&M) costs are also significantly lower for CDCL.

The corresponding overnight capital cost for the 550-MWe commercial unit is $1.72B ($3131/kW). These costs reflect lessons learned from the design and testing efforts done as part of several DOE-funded projects. The Electric Power Research Institute, Inc. (EPRI) participated in and independently vetted the performance and economics calculations in this study.

Table 25 Techno-economic analysis for CDCL compared to PC cases with and without CCS.

Item	Base Plant*	Base Plant with CCS**	CDCL
Gross Power, MWe	580	663	657
Auxiliary Power, MWe	30	113	107
Net Power, MWe	550	550	550
Net Efficiency, % HHV	40.7	32.5	35.8
Carbon Capture, %	0	90	96.5
Capital, $/MWh	39.1	72.2	47.2
Fixed O&M, $/MWh	9.6	15.4	10.6
Variable O&M, $/MWh	9.1	14.7	6.2
Fuel, $/MWh	18.7	23.4	21.1
Oxygen Carrier, $/MWh	---		11.7
COE, $/MWh	76.4	125.8	96.8
Increase in COE, %	---	64.7	26.8
Reduction in COE from Base Plant with CCS, %	---	---	23.0

** NETL Case B12A, PC without CCS and 3515 psia / 1100°F / 1100°F (242 bar / 593°C / 593°C) steam conditions, adjusted for current coal prices*

*** NETL Case B12B, PC with CCS and 3515 psia / 1100°F / 1100°F (242 bar / 593°C / 593°C) steam conditions adjusted, for current coal prices*

Review of Technology Gaps

Planners considering adoption of B&W's CDCL technology in a future power plant will want to follow and evaluate testing results that address the potential technology gaps from a next-step

[6] "Oxy-Coal Combustion for Low Carbon Electric Power Generation," K. McCauley, S. Moorman, and D. McDonald, Fifth International Conference on Clean Coal Technologies, May 2011.

[7] "10 MWe CDCL Large Pilot Plant Demonstration Phase I Feasibility," U.S. DOE Project DE FE0031582, 2018.

commercial-scale demonstration. The apparent technology gaps that are important for the acceptance of the CDCL technology include:

- Factors potentially affecting the useful lifetime and make-up rate of the metal-oxide oxygen carriers:
  - **Attrition and Abrasion:** Proper design of components to reduce the damage to carrier particles.
  - **Agglomeration:** Operational and environmental parameters need to be set to avoid problems such as eutectic melting and clumping of the fuel alkali and bed material.[8]
  - **High Reactivity with the Fuel:** Operating parameters must be properly set to achieve high carbon conversion
  - **Sensitivity to Chemical Degradation:** Exposure that reduces the effectiveness of the carrier reactivity should be avoided.
- Adequacy of component and hardware design parameters and standards must be validated in practice, including:
  - Combustor
    - Bed fluidization parameters through the load range
    - In-bed steam generator surface
  - Reducer
    - Ash separation
    - Char residence time
    - Coal feed injection point spacing
    - Enhancer gas requirements
- System operating procedures, including startup and shut down must be developed and demonstrated. Required warm-up time for the system in particular must be reduced. During startup, it is desirable to heat up the particles in the system, while at the same time protecting the heat transfer surface from overheating. Cooling the heat transfer surface takes heat away from the particles, which slows particle heat up that in turn could increase startup times.
- It is imperative that the larger CDCL systems focus on achieving longer-term auto-thermal operation, meaning they can operate continually without the aid of external heating, to improve reliability and prove the technology's viability.

Roadmap to Commercialization

EPRI has assessed the CDCL technology in terms of its maturity and has designated it at Technology Readiness Level (TRL) of 6.[9] The basis for TRL-6, which is in accordance with

[8] "CO_2 Acceptor Gasification Process," Curran, G.P., Fink, C.E., Gorin, E.T., American Chemical Society ISBN13: 9780841200708, June 1967.

[9] "Novel Cycles Database Report: 2019," EPRI, Palo Alto, CA: 2019. 3002014390.

performing testing of prototype components in a relevant environment, whose design and function are essentially the same as expected for full-scale deployment, was largely accomplished through the building and operation at B&W of the 250-kWth unit. The next-step roadmap milestone is to conduct a demonstration of the CDCL technology at PDU scale (10 MWe), which would achieve TRL-7. The intended first commercial CDCL plant is sized at 550 MWe.

B&W has developed an aggressive strategy whereby they are seeking to shorten the time to full-scale deployment of their CDCL technology, by skipping directly to a PDU-scale demonstration. **Figure 55** shows the procession in demonstration scales proposed by B&W. With the implementation of multiple feed points, the CDCL technology can be scaled disproportionately to larger scales based on the results of testing at smaller scales. Based on this strategy, with the pre-FEED already in place for the 4 x 2.5-MWe unit at DL&P and with the assumption that the demonstration begins in 2020, the next step would be to build a single, commercial module 70-MWe demonstration plant in the 2020–2025 timeframe with operation commencing thereafter. This is considered the largest module required to support the installation of a commercial-scale 550-MWe plant using eight 70-MWe modules, which would then be scheduled to be built and commence operations by 2030.

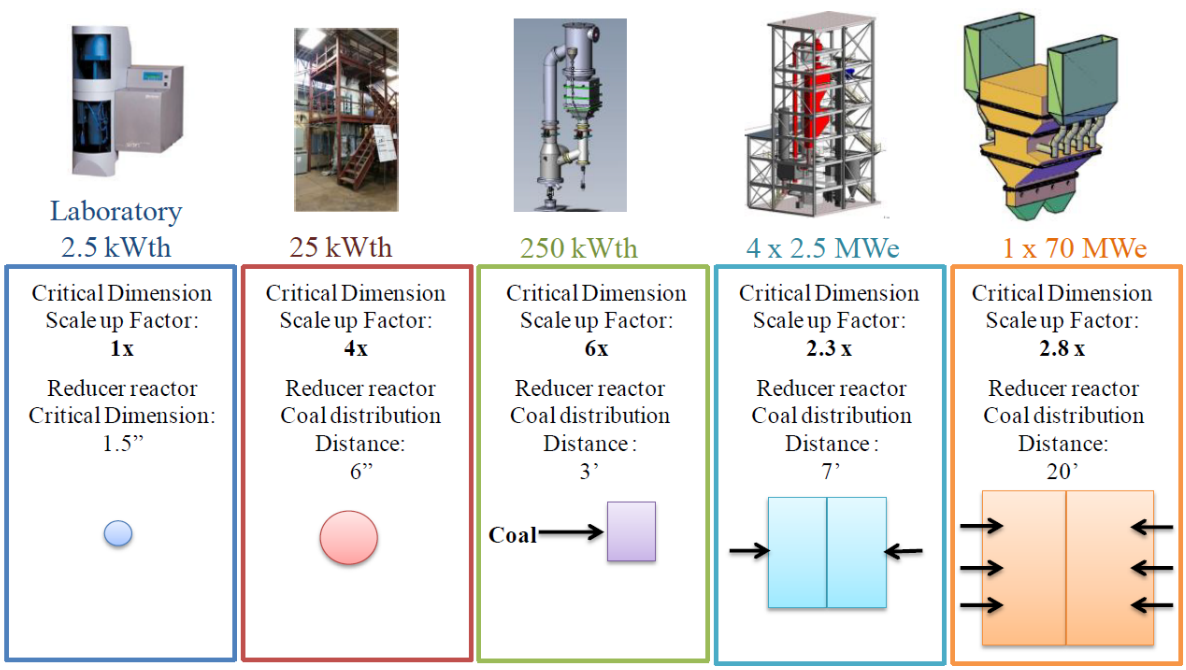


Figure 55 CDCL proposed demonstration sizes.

Table 26 shows the timing of each step for B&W’s timeline with standard assumptions for the length of each step in the chain.

Note that if the timing of the 4 x 2.5-MWe PDU demonstration is delayed by N years, this will simply add to the overall schedule by N years. Hence, as an example, if the 4 x 2.5-MWe unit’s FEED starts in January 2022 instead of January 2020, the year that the commercial-scale, 550 MWe plant would commence operations would be pushed back by two years to 2032.

Table 26 Commercial timeline for B&W's CDCL technology.

Development Stage	Size, MWe	TRL	Planning	FEED	Construction	Commissioning	Operations
PDU	10	7	Complete	Jan 2020 – Jun 2020	Jul 2020 – Jun 2021	Jul 2021 – Sep 2021	Oct 2022 – Dec 2022
Commercial Pilot Plant	70	8	Oct 2021 – Sep 2022	Oct 2022 – Jun 2023	Jul 2023 – Jun 2025	Jul 2025 – Dec 2025	Jan 2026 – Dec 2026
First Commercial Deployment	550	9	Jan 2024 – Jun 2025	Jul 2025 – Jun 2027	Jul 2027 – Jun 2029	Jul 2029 – Dec 2029	N / A

Market Assessment

The current marketplace for coal power varies widely on a regional basis, but in all cases, one or more of the following drivers impact its future viability:

- **Competition against other power sources:** In some regions, coal remains a low-cost generator, while in others, NG-based power is typically more economical due to the availability of low-cost NG (e.g., in the U.S., NG is about half the cost of elsewhere).
- **Drive towards low carbon:** 179 countries have signed the Paris Agreement, whose goal is to reduce greenhouse gas emissions (typically, countries have pledged to reduce CO_2 emissions on the order of 20 % to 40 % from 2012 levels). While the U.S. has not signed the accord, multiple states have enacted low-carbon initiatives including several that have committed to 80 % reductions by 2040. Coal, as a fossil fuel, and one that produces double the CO_2 per MWh that NG does, is therefore a bigger target related towards reducing CO_2.
- **Energy security:** In some regions, coal is an abundant natural resource, representing energy security and reducing the need for reliance on fuels or energy from foreign countries. Finding ways to use it more effectively can be critical for these regions.
- **Environmental regulations:** Coal emission regulations—CO, NO_X, hazardous air pollutants, mercury, particulate matter, and SO_X—vary globally, but coal universally remains a tougher permitting challenge than NG.
- **Financing:** Financing is becoming more challenging for larger plants as the future power market has significant uncertainties, especially around carbon. Coal power plants are a particular challenge (30 banks have stopped financing coal). Smaller plants are thought to be lower risk since they require less capital, and hence have a better opportunity for financing.
- **Meeting a changing market:** The energy market is changing, largely due to the growth of variable renewable energy. Intermittency requires grid protection provided by dispatchable

sources, which largely comes from fossil-based units. In the U.S., some coal power plants are providing such grid support, requiring them to operate more flexibly than they were designed for, which is deleterious to performance. Such operating behavior will likely also occur in other regions as renewables grow, reducing the need for base-load fossil power, while putting extra importance on their ability to provide grid resilience.

The characteristics of CDCL which aid in its being able to satisfy these market drivers include:

- This system can be made smaller than conventional coal-fired units (as small as 70 MWe net) and still maintain high efficiency and flexibility. Smaller units can minimize the financing hurdle needed for investment.
- CDCL is one of the highest-efficiency and least-cost technologies for CO_2 capture. The net efficiency for the CDCL system, using a bituminous coal at 550 MWe, is 35.8 % HHV. The improvement in efficiency, compared to atmospheric oxy-combustion or PCC, is on the order of 3.3 % to 5 % points. On a total plant cost (TPC) basis, CDCL will be significantly cheaper than these options.
- CDCL's environmental performance is superior to any existing PC power plant and can capture higher percentages of CO_2 (95 %) than a PCC plant can. CDCL also is a net water producer, while PCC systems require a significant amount of water to operate.
- As the CDCL system will be modular in nature, it has substantial flexibility characteristics with the ability to provide significant turndown, which could be key in the future marketplace.

DOE performed a techno-economic analysis for coal power plants using Powder River Basin coal with and without CCS, as shown in **Table 27**, with TPC, levelized cost of electricity (LCOE), and CO_2 captured cost adjusted to 2019 $ by EPRI.

Table 27 Cost for coal power plants with and without CCS.

Technology	Case	Size, MWe	Efficiency, % HHV	TPC, $/kW	LCOE, $/MWh	CO_2 Captured Cost, $/tonne
Oxy-combustion (atmospheric, supercritical)	S12F	650	31.0	4084	169.0	51
PC without CCS (supercritical)	S12A	650	38.8	2406	94.2	---
PC with CCS (supercritical)	S12B	650	27.0	4243	181.4	52

Based on these data from DOE, EPRI determined:

- TPC for CDCL to equal the LCOE of coal with CCS is $3914/kW
- TPC for CDCL to get the cost of CO_2 captured to $40/tonne is $2926/kW

Based on this high-level review, for CDCL to be competitive, beyond achieving its design performance characteristics, **Table 28** provides cost targets for the technology in various regions and scenarios.

Table 28 Cost targets for CDCL to be competitive.

Region	Scenario	Competition	Cost Targets
U.S.	NG < \$4.4/MBtu (coal \$2.2/MBtu) and Enhanced Oil Recovery (EOR) / 45Q available	Coal or NG with CCS	TPC < \$3200/kW; CO_2 cost < \$40/tonne
Africa, Asia, Eastern Europe	NG > \$11.6/MBtu (coal \$2.2/MBtu)	Coal with CCS	LCOE < \$160/MWh; TPC < \$3900/kW
Anywhere	CO_2 value of \$50/tonne	Any CCS	CO_2 cost < \$50/tonne

The cases in **Table 28** assume a base-load unit with 85 % capacity factor and ~5.5 M tonnes of CO_2 captured annually. The \$40/tonne value for CO_2 is roughly a summation of Enhanced Oil Recovery (EOR) value with 45Q tax credits (or 45Q tax credits for storage only). <u>So, the cost targets for the technology are TPC = \$3900/kW, LCOE = \$160/MWh, and CO_2 cost = \$50/tonne</u>. Based on the economics studies performed for CDCL, which estimated the TPC at \$3131/kW, the costs for CDCL meet these targets.

Several additional comments:

- The short-term market for CDCL will be in regions where there is an EOR play, e.g., Texas and Wyoming. Generally, EOR projects must provide >1 M tonnes of CO_2 annually to be considered, and the nominal 550 MWe size for the CDCL commercial system, which produces about 5.5 M tonnes of CO_2 annually if base loaded satisfies this requirement.
- In regions where NG is more expensive (e.g., Africa, Asia, and Eastern Europe), or if NG prices should rise in North America, the technology will be competing directly with more established PCC systems for coal. In these cases, CDCL must have capital costs and LCOE that are comparable, and preferably superior (given it might be perceived to be higher risk), to this option. On paper, this is the case.
- Another factor is if the value of CO_2 is increased (either by a CO_2 price or value) in comparison to the cost of CO_2 captured, then the CDCL technology will have more opportunities.

Next Steps

While there are numerous CCS technologies that have been or are being developed, CCS has not been readily applied at commercial scales because there has been little value for CO_2 to help overcome the cost of capture, either in the form of tax or regulatory incentives designed to drive CO_2 reductions, or markets that can use it. Chemical looping, similar to other oxy-combustion type technologies, has been a challenge because it in general requires a new build (or significant retrofit), making demonstration at scale more expensive than PCC, which can be tested on an existing unit on a slipstream. Several planned large-scale oxy-combustion demonstrations, including FutureGen 2.0 (with B&W's PC-boiler-based atmospheric-pressure oxy-combustion technology), have not gone to fruition largely due to costs.

However, first-generation, atmospheric-pressure, oxy-combustion processes suffered from lower efficiency and higher costs than will be the case with CDCL. CDCL's potential for modular construction also has benefits that prior first-generation oxy-combustion related systems could not capitalize on, further reducing costs and project risk.

Recently, dozens of U.S. states have set future low-carbon targets and multiple major U.S. utilities have also committed to being low carbon, joining countries worldwide who are bound to reducing carbon emissions through their signature of the Paris Agreement. In this coming new reality, firm, synchronous-based generation will become a premium to counteract the grid instability created by increasing amounts of variable renewable energy. As a result, EPRI has seen a significant increase in interest in doing CCS projects within the U.S., particularly with the advent of 45Q and the ability of EOR to provide value for CO_2 capture. Similar interest has been seen abroad. CDCL plays into this interest and has an opportunity to have a viable market.

To advance to the commercial finish line, funding will be needed to perform the two CDCL demonstrations that would precede the first commercial deployment. The PDU demonstration at 10 MWe, which likely would have no more than a small portion of its operational costs (fuel, labor, maintenance, etc.) recovered by sales and little or no expectation that capital costs will be recovered, will require tens of millions of dollars in funding, either from private or public sources, or some combination.

While the 70-MWe commercial pilot plant should recover all operating expenses by power and CO_2 sales, recovery of all capital costs is not expected. Hence, this demonstration will also require funding, probably in the low hundreds of million dollars range.

In conclusion, given funding and the growing marketplace for technologies that can provide low-cost CCS, CDCL has an opportunity to be a viability technology in the 2030 timeframe.

Task 5. Final Report and Close Out Documents

Subtask 5.1. Phase II Final Report and Close Out Documents

(**FY4Q2**) During the last quarter of the project, the final report was assembled along with required close-out documents. Close-out documents that were generated and submitted were the following:

a) Invention Certification.

b) SF-428 & 428B Final Property Report

c) SF-428 Tangible Personal Property Report Forms Family

d) Annual Incurred Cost Proposal

e) Audit of For-Profit Recipients

f) Subject Invention Reporting

g) Invention Utilization Report

These reports, forms and documents were submitted to the Program Manager as well as the indicated location according to the U.S. Department of Energy Federal Assistance Reporting Checklist and Instructions.

Subtask 5.2 Pilot Demonstration Decision Point Go/No-Go

Recommendation

The project team recommends that the project move to demonstrate the technology at a larger scale. Based on the 25 kWth sub-pilot unit and 250 kWth small pilot facility test results, the current state of CDCL technology is progressing towards TRL-6. Data obtained from this operation is sufficient to support the planning and design of the next-generation 10 MWe large pilot (4 x 2.5 MWe CDCL system integrated with a subcritical steam cycle), which is designed to further elevate the technology to TRL-7.

Current status of the technology

During the most recent operation on the 250 kWt CDCL pilot unit in early 2019, 288 hours of continuous operation were achieved with no issues related to oxygen carrier circulation. During the test campaign, 62 hours of cumulative coal injection was demonstrated with a 35-hour continuous injection as the longest coal injection operation. A coal conversion of 95 % and CO_2 purity (N_2 free) of 95 % to 99 % was sustained during the 35 hours of extended testing. Additionally, H_2S was not detected in the gas sample from CDCL gas outlet, indicating complete sulfur conversion to SO_2 where nearly all of the sulfur species were observed reporting to the reducer gas outlet. The attrition rate of oxygen carrier was measured to be 0.02 wt%/hr, which is consistent with previous operations.

Below is a summary of the technology gaps identified by the project team and industrial review committee that have been investigated and addressed through lab-scale, bench-scale, sub-pilot, and small pilot-scale research.

1. Char residence time in the reducer

Gasification of char with CO_2 and H_2O progresses as the char moves downward in the reducer. Gasification reactions continue to reduce the char size in the moving bed of oxygen-carrier particles. As the char size is reduced, the char and coal ash particles entrain into a stream of CO_2 and H_2O enhancer gas and other gasification byproducts and are carried upward and out of the reducer. Cold flow model studies have confirmed that coal/ash particles follow the gas flow path in the reducer reactor. Another important assumption of longer residence times for coal than oxygen-carrier particles in the reducer was also verified in these tests. Negligible carry-under of unconverted carbon from reducer into the combustor was detected based on the results of gas analysis in the operation of 25 kWth sub-pilot and 250 kWth small pilot CDCL units. Those experiments suggest that the current L-valve and zone seal designs are effective to maintain sufficient residence time of char in reducer and prevent the char from transporting to the combustor.

2. Enhancer gas

The amount of H_2O/CO_2 enhancer gas depends on the reducer reactor design, coal particle flow patterns and the char gasification and particle oxidation rates. Blending a small amount of steam with the enhancer gas can increase the rate of coal gasification and meet the required carbon conversion (> 95 %) and CO_2 concentration (> 90 %) at the reducer gas outlet. The usage of steam and CO_2 as enhancer gas was tested during the operation of the 250 kWth CDCL unit in early 2019. The results of gas analysis show a coal conversion of 95 % and CO_2 concentration (N_2 free) at 95 % to 99 %, both achieving the required design target. The operation of 10 MWe pilot plant will further evaluate the usage of recycled reducer gas product as enhancer gas compared to current setting of mixing steam and CO_2 as the enhancer gas.

3. Coal preparation and particle size

Prior to injection into the reducer, the coal is processed to a desired fineness depending on practical factors including coal type, de-volatilization rate, char gasification rate, the oxygen-carrier particle size or minimum particle fluidization velocity. Coal de-volatilization and char gasification results indicate that full conversion of pulverized coal in the reducer can be achieved at temperatures above 900 °C and residence times from 0.5 hr to 2 hr. Pulverized coal was successfully tested at the 250 kWth pilot plant with conversions of 95 % or higher.

4. Fate of alkali metals

Alkali elements can coat the oxygen-carrier particles causing agglomeration and/or deactivation. Previous laboratory experiments have shown that bed agglomeration occurs only at > 9 % by weight alkali concentrations, a condition which is not expected to occur during normal operation due to the continuous removal of small alkaline compounds inherent to the hydrodynamic design of the system. In addition, the presence of alkaline species was reversible and removed during the regeneration of spent oxygen-carrying particles with air. Agglomeration-free operation is expected to be maintained on a commercial unit as long as coal distribution across the moving bed is properly distributed.

5. Coal conversion studies

Laboratory studies on coal gasification indicate that full conversion of coal in the CDCL reducer can be achieved at temperatures above 900 °C and residence times from 0.5 hr to 2 hr. Therefore, the reaction prerequisites for full coal conversion in the reactor have been identified for achieving the desired performance. This technology gap is considered closed.

6. Oxygen carrier particle development, testing, and characterization

Oxygen-carrier particles are the core of the chemical looping process and are critical to its commercial success. Bench-scale experiments have revealed that the OSU iron-based oxygen-carrier particles can be reduced and oxidized at 1000 °C for more than 3000 redox cycles, the longest ever to be reported in chemical looping research, and equivalent to 6 months to 8 months of continuous commercial operation. Particles showed no signs of decreasing activity and mechanical strength during numerous redox cycles within the studied temperature range. An attrition rate of 0.02 wt% per hour of oxygen carriers of similar design was obtained in the 250 kWth Syngas Chemical Looping pilot unit (DE-FE0023915), which is close to the commercial target. Besides, the same attrition rate has been obtained under continuous coal injection conditions in the 250 kWth CDCL small pilot unit from the most recent 288 hours of continuous operation. It is also crucial to demonstrate that the attrition rate for particles made under high-volume manufacturing processes is comparable to samples produced at small quantities.

7. Large-scale particle manufacturing

Under DE-FE0027654, OSU and B&W contracted with Johnson Matthey, a commercial catalyst manufacturer, for high-volume production of oxygen-carrier particles. The production method of oxygen carriers has been optimized with respect to various parameters as the cost of particle production adds to the overall economics of the technology. Different techniques of particle manufacturing have been tested to produce particles. These techniques have been investigated against the redox performance of the oxygen carrier, mechanical strength, scalability of the technique and other considerations. Currently, the process for particle production has been established and the economic analysis was conducted in collaboration with Johnson Matthey.

8. Fluidized-bed combustor

A good understanding of the particle oxidation reaction from operation of the 25 kWth and the 250 kWth units has been obtained. B&W has considerable experience with heat transfer characterization in conventional coal-fired fluidized-bed boilers, heat extraction from fluidized bed combustor though its commercial In-bed heat exchanger. B&W's current circulating fluidized-bed boiler has an in-bed heat exchanger whose design can be adopted for the design of the in-bed heat exchanger in the CDCL combustor. Basic design parameters, such as the heat transfer coefficient have been obtained from the lab-scale experiment of heat transfer characterization of gas-solids fluidized bed using CDCL oxygen carrier particles. The current DOE-sponsored heat integration project (DE-FE-0029093) is investigating the value of the heat transfer coefficient for a specific combustor tube bundle geometry based on B&W's patented In-Bed Heat Exchanger design. Combustor design and operation will benefit from the integration of the in-bed heat exchange surfaces at a larger scale demonstration.

9. Particle riser

The riser transports fully regenerated particles from the combustor reactor back to the reducer reactor to reinitiate the redox loop. The riser uses air as the transport medium. The spent air from the combustor can be major or sole part of the transportation air for the riser. Minimum performance solids loading target for particle transport is 1 % for smooth continuous operation and low attrition. From the five test campaigns on the 250 kWth CDCL pilot facility, control of the solid loading in the riser has already been established and particle transportation by riser to reducer reactor with only spent air from combustor used has been successfully demonstrated.

Table 29 shows a summary of the technology gaps that have been addressed through previous and current project. As can be seen, the technology will benefit substantially from a larger pilot test, since most of the remaining technology gaps are scale dependent.

Table 29 Technology gap analysis summary.

Design/Technology Issues	Past Mitigation	Current Mitigation Under this Award	Future Mitigation
Particles			
Manufacturing Cost	OSU's Analysis	JM Studies	Manufacturing
Attrition	Testing at NCCC	250 kW_t Pilot Studies	
High Temperature Resistance	High Temperature TGA Studies	250 kW_t Pilot Studies	
Alkaline Agglomeration	2" BFB (Preliminary)		
Reducer Design			
Ash Separation	Cold Flow Model Studies		2.5 MWe Pilot Scale
Pressure Drop & Temperature Profile	Phase I (Calculation)	250 kW_t Pilot Studies	
CO_2 Purity	OSU's Sub-Pilot Tests	250 kW_t Pilot Studies	
Sulfur, NOx, Hg Emissions*	OSU's Sub-Pilot Tests	250 kW_t Pilot Studies	2.5 MWe Pilot Scale
Coal Distribution*	OSU's Sub-Pilot Tests	250 kW_t Pilot Studies	2.5 MWe Pilot Scale
Char Conversion & Residence Time	OSU's Sub-Pilot Tests	250 kW_t Pilot Studies	
Combustor Design			
Heat Exchanger surface	B&W's CFB Technology	CFD Model	2.5 MWe Pilot Scale
Combustor Operation	Phase I (Calculation)	250 kW_t Pilot Studies	
System			
Long-Term Operation	OSU's Sub-Pilot Test	250 kW_t Pilot Studies	2.5 MWe Pilot Scale
Start up/Shut down/Turn down/up	Testing at NCCC	250 kW_t Pilot Studies	2.5 MWe Pilot Scale

B&W's most recent techno-economic analysis provides key metrics regarding CDCL process viability. Based on B&W's commercial plant design, including current assumptions and contingencies, a 650 MWe supercritical CDCL plant is projected to achieve greater than 96.5 % CO_2 capture with a cost of electricity (COE) of $83.3 per MWh. The CDCL process is the most cost-effective coal power generation process with carbon capture to date. Further, by combining the criteria air pollutants in a single stream, the CDCL process is able to lower the capital cost of the coal-fired power plant compared to a pulverized-coal-fired boiler by eliminating the wet flue gas desulfurization; selective catalytic reduction/hydrated lime injection; and carbon injection control processes for sulfur dioxide, nitrogen oxides, and mercury capture, resulting in substantial capital cost savings.

Next Scale Demonstration

The team is proposing a 10 MWe modular plant, which is a natural progression following the 250 kWth CDCL pilot facility. The plant will be constructed as four (4) modules of 2.5 MWe each. The modular designed approach will substantially reduce the technical and financial risks associated with demonstrating this first-of-a-kind technology at the full 10 MWe scale. The modular design will address key operational aspects in the commercialization of the technology, such as evaluation of the module interaction and integration with the steam generation and plant operation. B&W plans to further reduce risk by constructing and testing a single module prior to constructing the remaining three modules.

Our commercialization roadmap envisions a step-wise scale-up from a 250 kWth to a 10 MWe pilot plant. Under the current project (DE-FE0027654), functional specifications of the 10 MWe modular plant were developed while additional tests at the 250 kWth CDCL pilot facility were conducted to verify the moving bed reducer performance. The project team recommends the project to move to a larger scale project to complete detailed design of the large pilot unit, provide equipment specifications, identify vendors and develop a full construction and testing schedule and budget. A larger demonstration of the unit will result in advancing the CDCL technology that shows to be a viable and a cost-effective carbon friendly process for power generation.

OPPORTUNITIES FOR TRAINING AND PROFESSIONAL DEVELOPMENT

No training activities to report.

DISTRIBUTION OF RESULTS

Project data and communications has been exchanged via secure email among project participants.

FUTURE ACTIVITIES AND PROJECT SCHEDULE

The project schedule is provided in **Figure 56**.

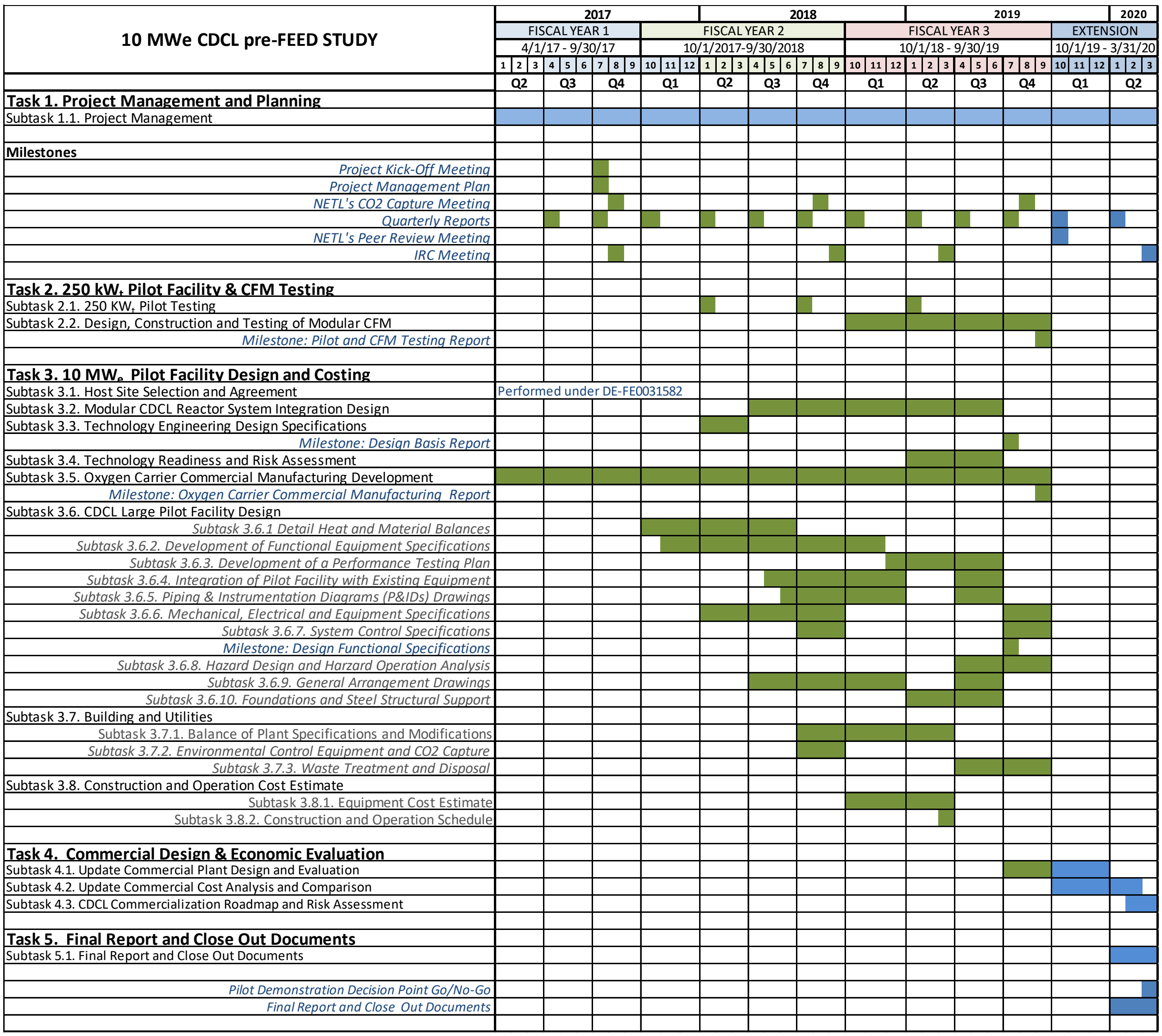


Figure 56. Project schedule.

PRODUCTS

PUBLICATIONS, CONFERENCE PAPERS AND PRESENTATIONS

“Update on the Design of the 10 MWe Iron-Based Coal Direct Chemical Looping Demonstration Plant” was presented at the 43rd International Technical Conference on Clean Energy in Clearwater, FL during June 3-7 of 2018.

“Scale-up of Chemical Looping Reactors: Practical Considerations and Design of Industrial Systems” was presented at the 5th International Chemical Looping Conference in Park City, UT during September 24-27 of 2018.

“Summary of the results from the recent pilot tests and update on the design of the 10 MWe pilot plant” was presented at IRC meeting held through webinar on November 16, 2018.

“Summary of the results from the recent pilot tests and update on the design of the 10 MWe pilot plant” was presented at an IRC meeting held via a webinar on March 18, 2019.

(**FY3Q2**) An abstract for a technical paper was submitted to the 44th International Technical Conference on Clean Energy, June 16 to 21, 2019 in Clearwater, FL. The title of the paper (#94 for the conference) is 250 kWth Pilot Testing in Support of a 10 MWe Coal-Direct Chemical Looping Demonstration Feasibility Study.”

(**FY3Q3**) A technical paper on the “250 kWth Pilot Testing in Support of a 10 MWe Coal-Direct Chemical Looping Demonstration Feasibility Study” was presented at the 44th International Technical Conference on Clean Energy during June 16 to 21, 2019 in Clearwater, FL.

(**FY3Q4**) “Direct Chemical Looping Technology” was presented to IDAES visitors during a meeting held at BWRC on August 22, 2019.

(**FY4Q1**) “10 Megawatts Electric Coal Direct Chemical Looping Large Pilot Plant - Pre-Front End Engineering and Design Study” was presented at the DOE/NETL peer review meeting held at the Pittsburg NETL Field Office on October 24, 2019.

(**FY4Q2**) Submitted an abstract to 2020 Clearwater Clean Energy Conference: “Recent Updates on the Iron-Based Coal-Direct Chemical Looping Process Demonstration”.

JOURNAL PUBLICATIONS.

BOOKS OR OTHER NON-PERIODICAL, ONE-TIME PUBLICATIONS

No activity.

OTHER PUBLICATIONS

No activity.

WEBSITE(S) OR OTHER INTERNET SITES(S)

No activity.

TECHNOLOGIES OR TECHNIQUES

No activity.

INVENTIONS, PATENT APPLICATIONS, AND/OR LICENSES

(**FY3Q3**) A patent applications has been prepared for the updated design of the 2.5 MWe CDCL reactor system. The application process is in progress.

(**FY3Q4**) The drafted patent application referenced during the previous quarter is under review.

(**FY4Q2**) The drafted patent application referenced during the previous quarter is still under review.

OTHER PRODUCTS

No activity.

PARTICIPANTS AND OTHER COLLABORATING ORGANIZATIONS (OPTIONAL)

PARTICIPANTS

Table 30. Individuals from B&W.

Name:	Dr. Luis Velazquez-Vargas
Project Role:	Principal Investigator
Nearest Person month worked:	3 / per quarter
Contribution to Project:	Project management and technology lead. Oversees collaboration between B&W and other participants. Assists contractual negotiations, oversees B&W's safety policies and protocols, and intellectual property management. Prepares and presents work at meetings/conferences. Prepares quarterly reports and reporting requirements. Reviews technical work and directs work.
Collaborated with individual in foreign country:	Yes. Coordinates research efforts with Johnson Matthey.
Country(ies) of foreign collaborator:	United Kingdom
If traveled to foreign country(ies), duration of stay:	N/A

Name:	Thomas J. Flynn
Project Role:	Technical Consultant
Nearest Person month worked:	3 / per quarter
Contribution to Project:	Tom will assist the project PI manage the project, provide technical input, organize the team, direct the scope of work, and oversee all the project activities.
Collaborated with individual in foreign country:	N/A
Country(ies) of foreign collaborator:	N/A
If traveled to foreign country(ies), duration of stay:	N/A

Table 31. Individuals from other organizations.

Name:	Prof. Liang-Shih Fan
Project Role:	Co-Principal Investigator
Nearest Person month worked:	0.5 / per quarter
Contribution to Project:	Oversees project from OSU's side. Provides engineering support from years of research in particle technology.
Collaborated with individual in foreign country:	N/A
Country(ies) of foreign collaborator:	N/A
If traveled to foreign country(ies), duration of stay:	N/A

Name:	Prof. Andrew Tong
Project Role:	Assistant Professor
Nearest person month worked:	3 / per quarter
Contribution to Project:	Coordinates and oversees CDCL activities from OSU's side. Provides engineering support on CDCL reaction and system hydrodynamics. Oversees OSU's subcontracts and directs OSU's personnel and research activities.
Collaborated with individual in foreign country:	Andrew Tong coordinates research efforts assigned to Johnson Matthey in the UK.
Country(ies) of foreign collaborator:	United Kingdom
If traveled to foreign country(ies), duration of stay:	N/A

Name:	Gareth Williams
Nearest Person month worked:	1 / per quarter
Contribution to Project:	Coordinates research activities on JM's side. Provides research, schedule and budget updates to OSU and B&W. Oversees oxygen carrier manufacturing processes and methods. Oversees commercial manufacturing cost estimates.
Collaborated with individual in foreign country:	N/A
Country(ies) of foreign collaborator:	N/A
If traveled to foreign country(ies), duration of stay:	N/A

Name:	Bartev Sakadjian
Nearest Person month worked:	10 Total
Contribution to Project:	Subcontractor to OSU provides expertise and support on system/ equipment design, process modeling and cost estimating.
Collaborated with individual in foreign country:	N/A
Country(ies) of foreign collaborator:	N/A
If traveled to foreign country(ies), duration of stay:	N/A

OTHER PARTNERS

No additional partner organizations outside of the previously identified project participants were involved.

OTHER COLLABORATORS

No additional collaborators outside of the previously identified project collaborators were involved.

IMPACT (OPTIONAL)

CDCL is considered a near-term technology with the potential to simplify carbon dioxide (CO_2) capture both efficiently and economically in power plant applications. Rather than oxy-combustion which requires an expensive and energy intensive oxygen separation plant or post-combustion CO_2 capture technologies which require 25 % to 30 % of the plant's energy to regenerate the solvent, CDCL directly produces a CO_2-rich stream. However, several critical technology gaps have to be addressed before the CDCL technology is ready for commercial demonstration. The use of CFD modeling and process simulation tools for industrial applications is accelerating due to advancements in computational hardware and their transformational ability to validate process designs with minimal costs and time.

For more than 20 years, OSU has been one of the world leading developers of chemical looping combustion (CLC) technologies with significant laboratory-, bench- and sub-pilot scale testing data showing the high potential for commercialization of the processes [(1) (2) (3)]. The research efforts in developing the CDCL technology has culminated into the development of an optimized oxygen carrier, a total of > 680 hours of sub-pilot scale (25 kWth) demonstration with one test-run lasting more than 200 hours continuous operation – the world's first known longest continuous demonstration of a CLC system, the design and construction of a 250 kWth small pilot unit, and the initiation of a 10 MWe large pilot test unit design for integration with a steam cycle provided by the test site host for electricity production [(4) (5)]. Majority of the work to date in CLC technologies has been focused on the development of an oxygen carrier particle with high reactivity, strength/attrition resistance, and recyclability, a reducer design capable of achieving high fuel and oxygen carrier conversions, and process devices for solids transport, gas sealing, and ash removal. Limited research has been performed on the combustor in the CDCL process as well as on the integration of the modular CDCL reactor design with a steam cycle.

As part of a previous NETL project (DE-FE0009761), B&W performed a comprehensive techno-economic analysis of the CDCL process at a 550 MWe commercial plant scale with carbon capture. Based on the results of this project, the CDCL plant is projected to achieve a first-year cost of electricity (COE) of $102.67 per MWh, corresponding to only a 26.82 % increase in COE over a base pulverized coal (PC)-fired supercritical plant without CO_2 emissions control. Thus, the CDCL technology has the potential to exceed USDOE's goal of 90 % CO_2 capture with less than 35 % increase in COE.

The proposed project is relevant to enabling the CDCL technology, an advanced combustion system for CO_2 capture, by addressing key technology gaps in the design and operation of a modular CDCL process. Specifically, the proposed work will perform a pre-FEED design of a modular 10 MWe large-pilot unit (DOE DE-FE0027654, B&W RCD-1500). 250 kWth pilot scale test will be performed with the goal to support the specific design efforts of the 10 MW_e facility based on the host site fuel specifications and steam requirements. Pilot-scale testing will take advantage of a 250 th unit at the Recipient's facilities. Operational, fuel and particle handling, and emissions performance characterizations tests will be conducted using host site's coal or similar. The results from this project will result in the design of the modular 10 MWe large-pilot plant and improve the process efficiency and economic feasibility of the commercial scale CDCL process, thereby, reducing the risks associated with scaling up the CDCL technology along its commercialization roadmap.

PRINCIPAL DISCIPLINE(S)

The project team's efforts to perform a pre-FEED study of a 10 MWth CDCL technology under this project fits well into the overall vision and suite of projects to advance the chemical looping technology closer to commercialization. The Team has been methodically addressing the technical challenges previously identified under a previous DOE program (DE-FE0009761). The Team has been prudent in its proposed next steps to avoid overreach in the development process. Significant challenges have been efficiently overcome at each step of development.

The principal disciplines that will be impacted in this project are process and reactor design and manufacturing. Designs of first-of-a-kind equipment are being developed for scale up of the CDCL technology and its subsequent integration into an existing plant. Multiple academic disciplines are involved in the project, which includes reactor design of a moving bed system, solid transport, fluidization, material science, and environmental and pollution control.

Under DOE Award DE-FE0009761 entitled "Commercialization of an Atmospheric Iron-Based CDCL Process for Power Production the team is evaluating the commercial viability of coal-direct chemical looping technology. The specific objectives included developing a commercial plant concept, performing a techno-economic analysis and estimating the commercial plant cost of electricity (COE). The COE came in measurably under the 30 % increase in price above the DOE base plant without CO_2 capture, so the commercial viability was promising and the Team decided to continue. Under a Phase II of the same project the Team has built and is commissioning a 250 kWth coal-direct chemical looping (CDCL) pilot facility at the B&W Research Center in Barberton, Ohio. The goal of testing on this facility is to address technology gaps identified during the techno-economic analysis.

Under DOE Award DE-FE0029093 entitled "Heat Integration Optimization and Dynamic Modeling Investigation for Advancing the Coal-Direct Chemical Looping Process" OSU and B&W are refining the thermal integration to optimize heat recovery and steam generation using pinch analysis and B&W steam generation design tools.

Under DOE Award DE-FE0026334, entitled "Advanced Control Architecture and Sensor Information Development for Process Automation, Optimization and Imaging of Chemical Looping Systems", OSU and B&W will develop advanced process automation control architecture, imaging and optimization sensor information of the chemical looping process. A high-level controller (HLC) consisting of decision-making and controller-selection logic integrated with sliding mode controllers (SMCs) will be used to develop a distributed intelligence automation scheme for the chemical looping process startup and shutdown.

OTHER DISCIPLINES

For mature industries like power generation, opportunities for incremental improvement in performance from equipment and hardware improvements become increasingly difficult to achieve. Over the years equipment and hardware have been optimized for the individual unit operation. What then becomes the challenge is to maintain the operation at near optimum over the load range or with time as components experience wear and tear and deteriorating performance. The route to maintaining optimum performance is through enhanced controls and automation. This occurs in two ways. First, the operation of each unit operation can be continuously optimized and monitored for deterioration with advanced controls systems. Second, the overall system performance can be optimized with advanced control strategies that may lead to individual unit operations not being operated at optimum in favor of better overall performance. “The best overall performance may not be achieved with each individual unit operation operating at its optimum!” Advanced control schemes and optimizers that are possible with advanced tools such as FocalPoint provide the means to achieve overall system optimization. The modular design proposed in this project may open the field for developing new algorithms that could result in higher efficiencies for the overall process.

DEVELOPMENT OF HUMAN RESOURCES

OSU students will benefit directly from the guidance provided by the senior engineers at the Babcock and Wilcox Company

PHYSICAL, INSTITUTIONAL, AND INFORMATION RESOURCES THAT FORM INFRASTRUCTURE

The project had significant impact on the development of information resources. Work in this project used traditional resources to complete its scope of work and no new developments were required.

TECHNOLOGY TRANSFER

As the technology progresses from laboratory to commercial, the chemical looping technology is being transferred to the industry as the case for particle manufacturing at Johnson Matthey and equipment manufacturing to The Babcock & Wilcox Company. Other aspects of the technology, such as indirect applications may be eventually being licensed to allow commercial use.

SOCIETY BEYOND SCIENCE AND TECHNOLOGY

Chemical looping technology has the potential to be a game-changer in environmentally-friendly energy conversion. Efficiencies and carbon management of chemical looping-based technologies are superior to traditional energy conversion processes. As a result, it could provide electricity (or chemicals) with less impact to the environment than traditional technology options. If implemented from the start in developing countries, it could allow the developing countries to advance technologically without the negative impact on the environment that has been experienced in the past.

EXPENDITURES IN FOREIGN COUNTRY(IES)

Johnson Matthey, located in the United Kingdom, is performing work under subtask 3.6. The total approved scope for JM is less than 5.25 % of the total project budget.

CHANGES/PROBLEMS

CHANGES IN APPROACH AND REASONS FOR CHANGE

No changes in approach identified or anticipated.

ACTUAL OR ANTICIPATED PROBLEMS OR DELAYS AND CORRECTIVE ACTION(S)

(**FY1Q4**) Due to a 6-month delay associated with finalizing awards and subcontract negotiations, B&W anticipated a delay in B&W's scope of work. However, B&W is adjusting resources and the task schedule to meet the deliverables of the project.

(**FY2Q1**) Agglomerates formed in the combustor during the 250 kWth pilot test may have caused solid circulation issues that had contributed to the premature shutdown of the test. These agglomerates may have formed due to the high temperatures in the burner. Particle agglomerates caused a delay in acquiring design information expected from subtask 2.1 (250kWth pilot testing). B&W would like to request a scope and budget change to allocate resources to subtask 2.1 for an additional test run. Several modifications to the unit are necessary to correct the problems found during coal injection. The corrective actions are to 1) fire the startup burner leaner to moderate peak flame temperatures and avoid the formation of particle agglomerates, 2) replace the diesel compressor with a cheaper and more reliable electrical compressor, and 3) operate the unit under slightly positive pressure to avoid air infiltration in the reducer. Additional modifications may be required to address other operating issues.

(**FY3Q2**) Due to the additional effort required on Task 2 – 250 kWth pilot testing, the remaining tasks of the project were delayed. After discussing with DOE, the project was extended to September 30, 2019.

(**FY3Q3**) B&W's project financial analyst, Chad Gill, transitioned to another company and no longer works at B&W. B&W has assigned an accountant to assist temporarily with the project's accounting needs while a new accountant is assigned to the project. The project should not be impacted by this change.

(**FY4Q2**) The project deliverables and scope of work was not impacted by the COVID-19 pandemic.

CHANGES THAT HAVE A SIGNFICANT IMPACT ON EXPENDITURES

For the fourth quarter (**FY2Q2**), no changes to the work scope have been made. However, some minor changes to the work scope are anticipated for next quarter to allocate additional funding to Subtask 2.1. These changes will be submitted to the DOE for approval.

(**FY2Q3 & FY2Q4**) B&W is proposing modifications to the 250 kWth pilot facility to resolve findings from the previous pilot test campaign. Furthermore, B&W is proposing to perform additional tests on the 250 kWth pilot facility to gather data for the design of the 10 MWe pilot unit. These modifications will result in additional expenses to Task 2. To allocate funding for completing Task 2, the scope of other tasks has been modified, as described in the updated statement of project objective (SOPO).

SIGNIFICANT CHANGES IN USE OR CARE OF HUMAN SUBJECTS, VERTEBRATE ANIMALS OR BIOHAZARDS

Not applicable.

CHANGE OF PRIMARY PERFORMANCE SITE LOCATION FROM THAT ORIGINALLY PROPOSED

No changes to site location.

SPECIAL REPORTING REQUIREMENTS

No developments that have a significant favorable impact on the project.

No problems, delays, or adverse conditions which materially impair the recipient's ability to meet the objectives of the award or which may require DOE to respond to questions relating to such events from the public.

No event to report that would require the need to issue a written or verbal statement to the local media.

BUDGETARY INFORMATION

Table 32. Cost plans/status.

Baseline Reporting Quarter	FY1							
	Q1		Q2		Q3		Q4	
	10/1/16 - 12/31/16		1/1/2017 - 3/31/2017		4/1/2017 - 6/30/2017		7/1/2017- 9/31/2017	
	Q1	Cumulative Total	Q2	Cumulative Total	Q3	Cumulative Total	Q4	Cumulative Total
Baseline Cost Plan								
Total Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ 88,397	$ 88,397
Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,947	$ 62,947
Non-Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,450	$ 25,450
Actual Incurred Cost								
Total Incurred Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 88,397	$ 88,397
Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,947	$ 62,947
Non-Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,450	$ 25,450
Variances								
Total Variance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Baseline Reporting Quarter	FY2							
	Q1		Q2		Q3		Q4	
	10/1/17 - 12/31/17		1/1/2018 - 3/31/2018		4/1/2018 - 6/30/2018		7/1/2018 - 9/31/2018	
	Q1	Cumulative Total	Q2	Cumulative Total	Q3	Cumulative Total	Q4	Cumulative Total
Baseline Cost Plan								
Total Planned	$ 177,437	$ 265,834	$ 695,393	$ 961,227	$ 411,439	$ 1,372,666	$ 719,672	$ 2,092,338
Federal Share	$ 116,323	$ 179,270	$ 513,043	$ 692,314	$ 284,673	$ 976,986	$ 479,948	$ 1,456,935
Non-Federal Share	$ 61,113	$ 86,564	$ 182,350	$ 268,913	$ 126,766	$ 395,680	$ 239,724	$ 635,404
Actual Incurred Cost								
Total Incurred Costs	$ 177,437	$ 265,834	$ 695,393	$ 961,227	$ 411,439	$ 1,372,666	$ 719,672	$ 2,092,338
Federal Share	$ 116,323	$ 179,270	$ 513,043	$ 692,314	$ 284,673	$ 976,986	$ 479,948	$ 1,456,935
Non-Federal Share	$ 61,113	$ 86,564	$ 182,350	$ 268,913	$ 126,766	$ 395,680	$ 239,724	$ 635,404
Variances								
Total Variance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Baseline Reporting Quarter	FY3							
	Q1		Q2		Q3		Q4	
	10/1/18 - 12/31/18		1/1/2019- 3/31/2019		4/1/2019 - 6/30/2019		7/1/2019 - 9/31/2019	
	Q1	Cumulative Total	Q2	Cumulative Total	Q3	Cumulative Total	Q4	Cumulative Total
Baseline Cost Plan								
Total Planned	$ 854,020	$ 2,946,358	$ 638,110	$ 3,584,469	$ 271,435	$ 3,855,903	$ 107,212	$ 3,963,116
Federal Share	$ 475,402	$ 1,932,336	$ 389,072	$ 2,321,408	$ 147,381	$ 2,468,789	$ 107,212	$ 2,576,001
Non-Federal Share	$ 378,618	$ 1,014,022	$ 249,039	$ 1,263,061	$ 124,054	$ 1,387,115	$ -	$ 1,387,115
Actual Incurred Cost								
Total Incurred Costs	$ 854,020	$ 2,946,358	$ 638,110	$ 3,584,469	$ 271,435	$ 3,855,903	$ 107,212	$ 3,963,116
Federal Share	$ 475,402	$ 1,932,336	$ 389,072	$ 2,321,408	$ 147,381	$ 2,468,789	$ 107,212	$ 2,576,001
Non-Federal Share	$ 378,618	$ 1,014,022	$ 249,039	$ 1,263,061	$ 124,054	$ 1,387,115	$ -	$ 1,387,115
Variances								
Total Variance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Federal Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Baseline Reporting Quarter	FY3							
	Q1		Q2		Q3			
	10/1/19 - 12/31/19		1/1/2020- 3/31/2020		4/1/2020- 7/30/2020			
	Q1	Cumulative Total	Q2	Cumulative Total	Q3	Cumulative Total		
Baseline Cost Plan								
Total Planned	$ 783,613	$ 4,746,728	$ 102,337	$ 4,849,066	$ 262,047	$ 5,111,113		
Federal Share	$ 406,201	$ 2,982,202	$ 91,252	$ 3,073,454	$ 216,471	$ 3,289,925		
Non-Federal Share	$ 377,411	$ 1,764,526	$ 11,085	$ 1,775,611	$ 45,577	$ 1,821,188		
Actual Incurred Cost								
Total Incurred Costs	$ 783,613	$ 4,746,728	$ 102,337	$ 4,849,066	$ 293,796	$ 5,142,862		
Federal Share	$ 406,201	$ 2,982,202	$ 91,252	$ 3,073,454	$ 216,471	$ 3,289,925		
Non-Federal Share	$ 377,411	$ 1,764,526	$ 11,085	$ 1,775,611	$ 77,325	$ 1,852,937		
Variances								
Total Variance	$ -	$ -	$ -	$ -	$ (31,749)	$ (31,749)		
Federal Share	$ -	$ -	$ -	$ -	$ -	$ -		
Non-Federal Share	$ -	$ -	$ -	$ -	$ (31,749)	$ (31,749)		

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REFERENCES

National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity", September 24, 2019. NETL-PUB-22638

APPENDIX: PROJECT INSTRUMENT LIST

INSTRUMENT LIST

- CDCL 250 kw Pilot Facility
- TGA Setaram Setsys Evolution