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SaskPower's Boundary Dam Unit 3 Carbon Capture Facility - The Journey to Achieving Reliability

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Abstract

SaskPower's Integrated Carbon Capture and Storage Project on Boundary Dam's Unit 3 (BD3 ICCS) began operations in October of 2014. By early October 2020, the facility had captured its 3.5 millionth metric tonne of carbon dioxide (CO_2). The road to 3.5 million tonnes of CO_2 abated was not without difficulties. As a "first of kind" project, the capture facility at BD3 has been a platform for in-depth learning and optimization. The capture facility experienced unforeseen operational challenges and design oversights which hindered overall performance and significantly reduced its reliability and availability in the early days of operation. Availability of the capture facility did not exceed 70% during the first year and a half of operations while the average daily capture rate in the first 12 months of operation was merely 1240 tonnes/day. Based on experience, reduced capture performance can be attributed to difficulties in three broad categories of process flows: limitations in flue gas flow, limitations in amine flow, and limitations in heat transfer. Equipment responsible for facilitating these flows was identified. Major issues included fly ash accumulation, fouling of key heat exchangers and amine foaming. Corrections and additions to the capture facility were made to increase the facility's reliability and availability. Corrections and additions to the capture facility including the installation of redundancy and isolations to key pieces of equipment was instrumental in correcting the performance of the facility, increasing its reliability and availability. By the summer of 2019 (May to July) the daily average capture rate was 2580 tonnes/day while availability in the 2018 to 2019 period had improved to over 90%. This paper documents the challenges and measures taken over the first five years of operations to improve the performance of the BD3 ICCS facility.

Keywords: Industrial Scale CCS; CCS Retrofit; Coal Fired Power Stations; Process Redundancy; Perfomance Reliability; Heat Exchanger Performance; Amine Foaming Mitigation.

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Nomenclature

BD3	Boundary Dam Power Station Unit 3
CCS	Carbon Capture & Storage
EOR	Enhanced Oil Recovery
EPC	Engineering Procurement Construction
ESP	Electrostatic Precipitator
FGC	Flue Gas Cooler
ICCS	Integrated Carbon Capture & Storage
IP-LP	Intermediate Pressure – Low Pressure
LCOE	Levelized Cost of Electricity
NGCC	Natural Gas Combined Cycle

1. Introduction

SaskPower's Integrated Carbon Capture and Storage Facility on Unit 3 of the Boundary Dam power station (BD3 ICCS) is the world's first fully integrated and full-chain carbon capture and storage (CCS) facility on a coal-fired power plant. Captured CO_2 is used for Enhanced Oil Recovery (EOR) in a nearby oilfield and for injection into a deep saline reservoir at a research project called Aquistore. The full chain cluster of facilities is within proximity to the BD3 facility, providing for a full demonstration and operation of proven and safe CCS.

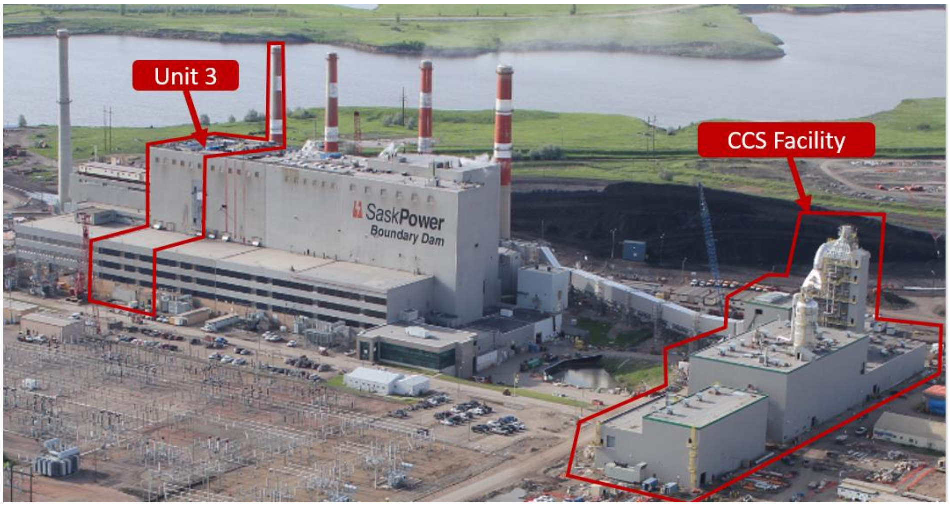


Fig. 1 Boundary Dam Power Station and the ICCS Facility

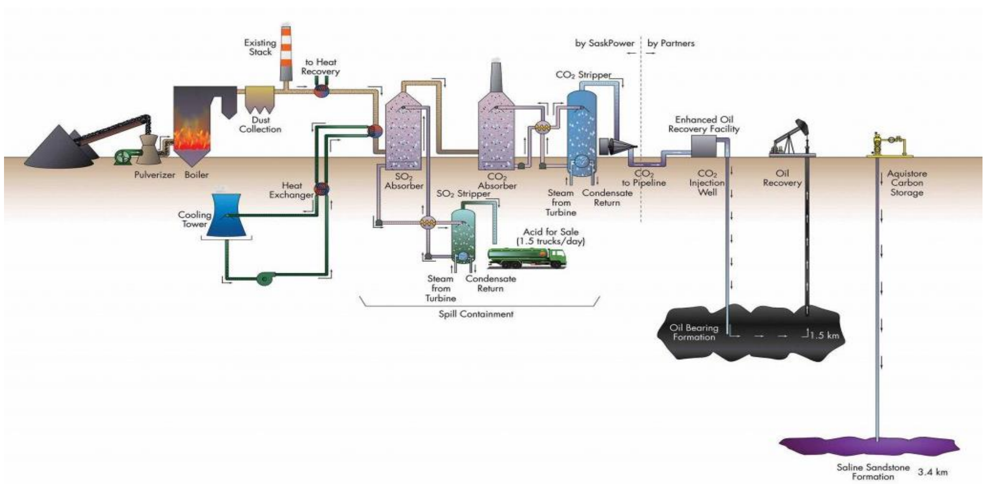


Fig. 2 Full chain carbon capture process

SaskPower's history with carbon capture and storage stems back to the 1980s. A cumulation of events spanning decades ultimately lead to the implementation of the carbon capture facility at BD3. Development began in 2007. After numerous studies the decision to proceed with the project was made in 2010. At the time of approval, economics favoured the project. Furthermore, the BD3 project was aided by a one-time CDN$240 million grant from the Government of Canada. This grant, coupled with an assumed sale of the CO_2 for EOR, and extensive re-use of an end-of-life coal plant combined to create a project which evaluated to a Levelized Cost of Electricity (LCOE) which was competitive with building a new Natural Gas Combined Cycle (NGCC) plant at that time. The total initial investment in the power unit's retrofit and carbon capture plant was approximately $1.5 billion CAD, 50% of this cost was attributed to the capture facility itself, 30% to the power plant refurbishment and 20% for emissions controls and efficiency upgrades. The project required two distinct parts: 1) upgrades and modifications to unit 3 of the power station and 2) construction and integration of the CO_2 capture facility. When completed, the integrated carbon capture plant's original design aspired to capture 1 million tonnes per year, reflecting a 90 percent capture rate and extending the life of the power plant by 30 years. Construction began in the Spring of 2011 and was completed in 2014. Commissioning occurred between 2013 and 2014 with the grand launch of the facility to full operations on October 2, 2014. It is important to recognize the proactivity of the decision to proceed with the installation of CCS on BD3 as the federal CO_2 emission regulations, although anticipated, had not yet materialized. With the enforcement of the federal emissions standards and a carbon tax expected to reach $170 CAD/tonne by 2030, capturing the CO_2 emissions from the BD3 power station have proven to be favourable for SaskPower.

1.1 Capture process selection, capture island construction and integration

The CANSOLV process, an amine solvent system, was chosen as the CO_2 capture technology for the BD3 ICCS project. This process, depicted in Fig. 3, consists of two distinct processes working in series: The sulphur dioxide (SO_2) Capture Train and the CO_2 Capture Train. The SO_2 Capture Train is a Cansolv amine-based desulphurization process which removes 99% of the SO_2 from the flue gas. The captured SO_2 is sent to a Sulphuric Acid Plant where it is converted into sulphuric acid. The desulphurized flue gas then passes through the CO_2 Capture Train were up to 90% of the CO_2 is removed. Steam, extracted from the Intermediate Pressure – Lower Pressure (IP-LP) crossover on the BD3 turbine, is required to regenerate the amine in both processes. The CO_2 product is compressed to 2500 psi and is transported approximately 70 km by pipeline on a continuous basis for utilization in the CO_2-enhanced oil recovery (CO_2-EOR) operation at the Weyburn oilfield during which it is injected 1.7 km underground into the oil-bearing Midale geological formation – and – on an intermittent basis, CO_2 is transported by a 2 km pipeline to the Aquistore site for injection and long-term geological storage in the Deadwood deep saline aquifer at a depth of approximately 3.4 km.

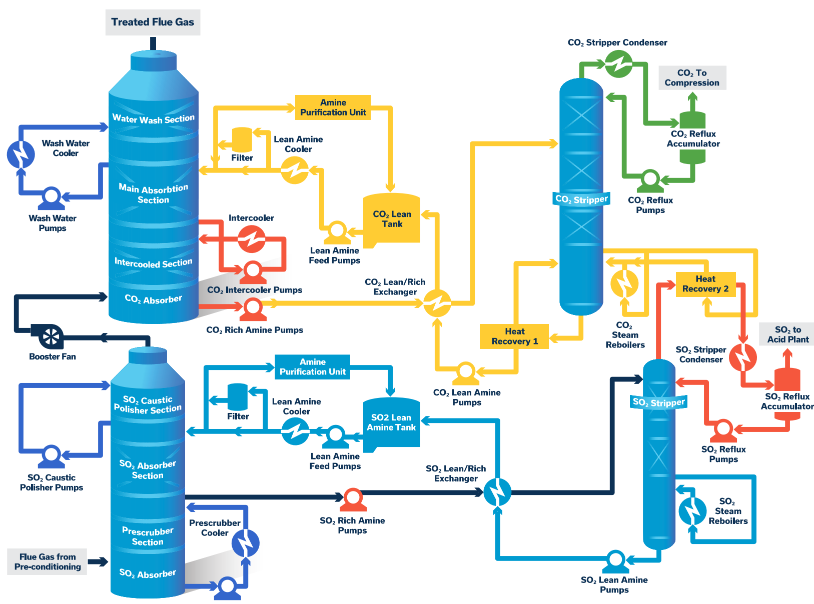


Fig. 3 Cansolv's SO_2 and CO_2 Amine Capture System as Deployed at SaskPower's BD3 Power Unit

2. Capture plant performance history

The startup of the BD3 ICCS facility was the culmination of a decade's worth of work by SaskPower focused on continued operation of coal-fired power-generating stations which provide fuel diversity for its fleet, while mitigating the climate change impact of associated air emissions. As is commonly experienced with "first of a kind" projects, the capture facility at BD3 experienced unforeseen operational challenges which hindered its overall performance and significantly reduced its reliability in the initial years of operation. The investment in BD3 and the journey to optimize its performance had been under public scrutiny. While the global and national response to the project has mainly been highly supportive of the accomplishment SaskPower made by installing the first commercially-viable CCS installation in conjunction with coal-fired power generation, provincial (local) reaction had been critical. This negative publicity was most pronounced following the first year of operation when there was a generally poor understanding of the challenges that typically face a new technology at a newly constructed and operational facility. Facilities of this type, particularly those based on chemical processes, require a tuning and refining period to reach optimum performance. Solutions to these challenges are crucial not only for improving the reliability of the individual facility but for establishing and strengthening global perception and confidence in CCS as a CO_2 mitigation solution. The challenges facing the facility were further complicated by excessive design and construction deficiencies. During its first year of operation, BD3 captured approximately 50% of its designed volume of CO_2 and its operational reliability was lower than expected. Continued efforts to identify and rectify these deficiencies have steadily improved operations since initial startup. The facility has addressed safety issues and now achieves a level of reliability that is consistent with a thermal-generating facility, although still below design CO_2 production levels. Achieving stable operations of the facility is necessary to allow the plant operations and support staff to focus on improving the efficiency and cost effectiveness of the operation.

2.1 Performance history and capture milestones

The BD3 capture facility captured 3.6 million tonnes of CO_2 from the October 2014 to the October 2020 period. The capture facility reached a milestone of 1 million tonnes of CO_2 captured in July of 2016. The 2 million tonnes and 3 million tonnes of cumulative CO_2 captured milestones would be achieved in March 2018 and November 2019 respectively; comparatively quicker than the initial 1 million tonnes. Operational data of the BD3 capture facility is monitored and logged on a continuous basis. Evaluating the first six years of this historical operational data highlights improvements in capture performance. A major planned outage in the summer of 2017 would rectify many of the design deficiencies which hindered the capture performance of the facility in the initial years of operations. A summary of the capture rate including the average daily capture rate for specified periods as well as the cumulative capture rate is depicted in Fig. 4. Furthermore, the facility's annual availability is shown in Fig. 5. It is evident that the performance of the BD3 capture facility has improved. The facility continues to maintain this improved level of performance indicating that the corrections made in addressing the design deficiencies of the capture facility were both needed and beneficial.

Most of the captured CO_2 is supplied to a CO_2 off-taker, Whitecap Resources (previously Cenovus), to be utilized for CO_2 EOR operations. Any volume of CO_2 in excess of the off-taker's demand is injected into the Aquistore well – a deep saline CO_2 storage injection well. There exists a disconnect between the installed capacity (design capacity) and achieved capacity of the capture plant. The disconnect is partly the result of the limited economic incentives to capture beyond the delivery demands of the CO_2 off-taker. However, it should be noted that increases in the Canadian federal carbon pricing (which is currently \$40/tonne but is expected to rise to \$170/tonne of CO_2 by 2030) will incentivize meeting the design capture capacity of the plant.

Table 1. Breakdown Summary of Average Daily Capture Rates October 2014 – October 2020

Period	Average Daily Capture Rate (tonnes/day)
First 12 months of operation	1238
November 2015 to August 2017	2041
September 2017 to December 2017	2342
January 2018 to June 2018	2245
September 2018 to March 2019	2198
May to November 2019	2269
December 2019 to March 2020	2056
April to June 2020	2264
July to October 2020	2343

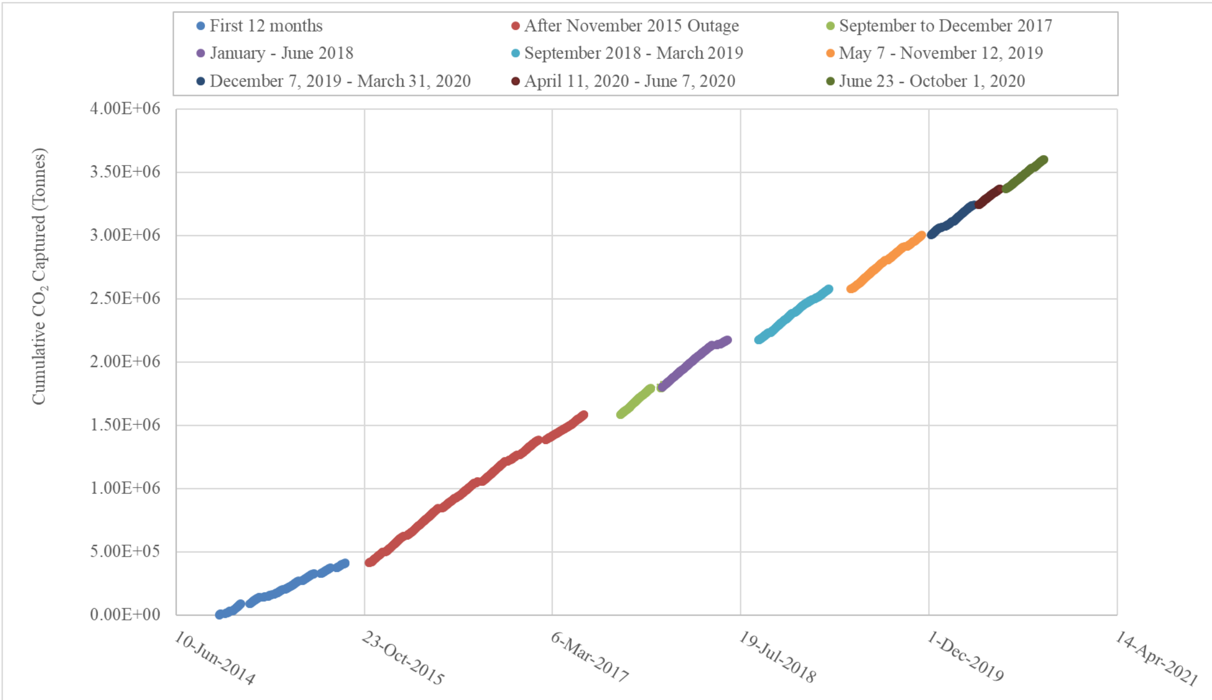


Fig. 4 Summary of the cumulative CO_2 capture (October 2014 – October 2020)

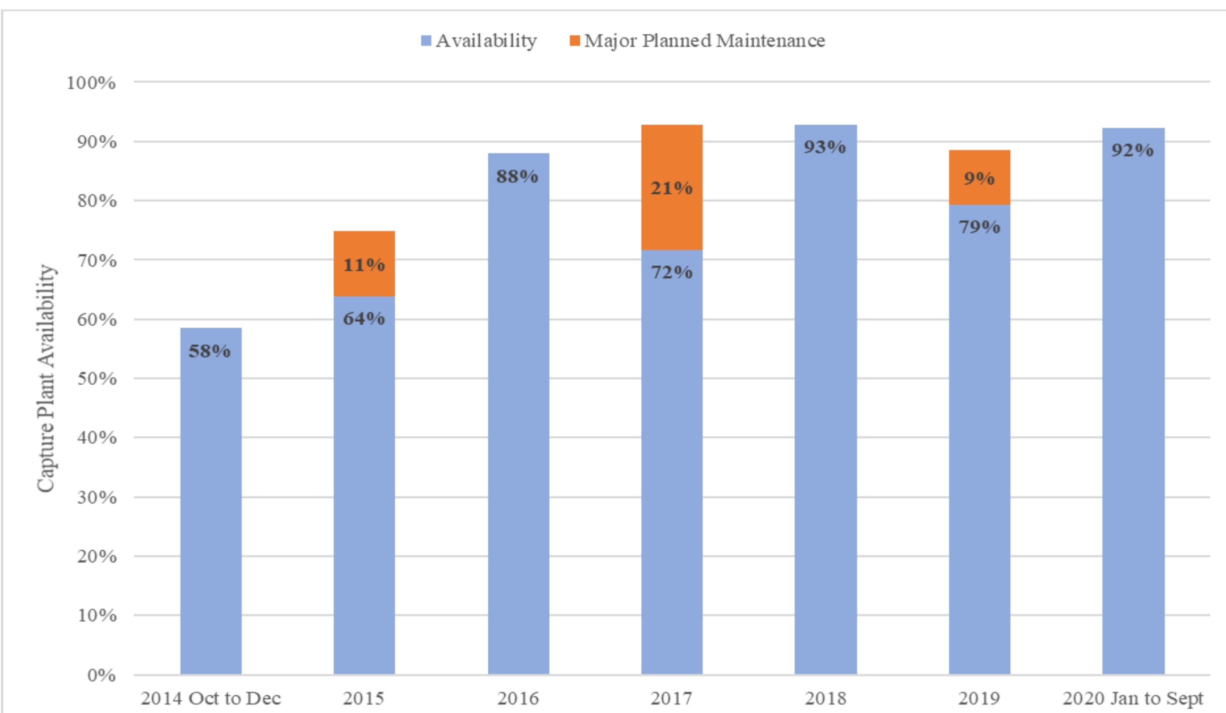
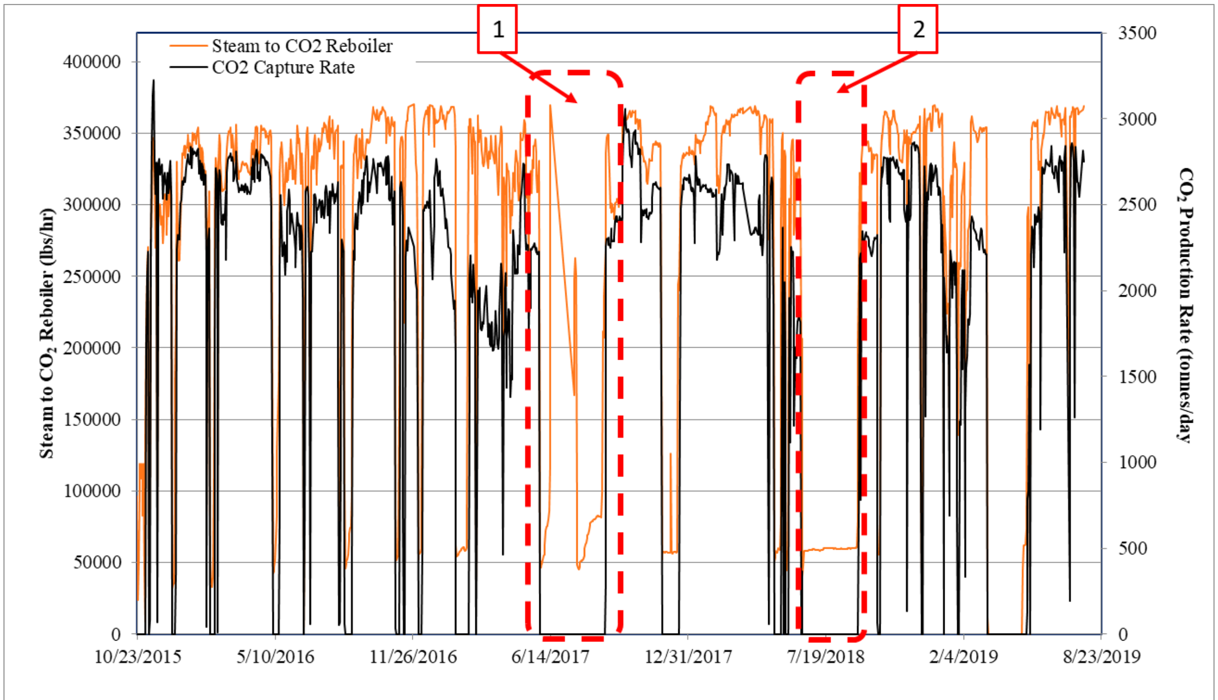


Fig. 5 Annual availability of the capture facility

3. Overcoming challenges by addressing design deficiencies

3.1. Identifying sources of operational difficulties

The BD3 CCS project comprised of two distinct sub projects: 1) modifications to the existing power plant to enable the turbine steam extraction which would supply the regeneration energy and 2) building the capture plant. The fully integrated design between power plant and capture plant has worked well. The steam extraction from the turbine has been reliable, as illustrated in Fig. 6, and has not shown to be a main contributor to decreased CO_2 capture.



1. Planned Outage, Summer 2017
2. Adverse weather resulting in power plant turbine trip, Summer 2018

Fig. 6 Comparing steam supply to the CO_2 reboiler and CO_2 capture rate

This same reliability cannot be stated for the capture island. Design oversights of the capture facility hindered achieving performance specifications during the initial years of operation. The design of the capture facility for BD3 was based on a contractual specification which stated a design availability for the capture island. This metric was used by the EPC contractors to design the plant accordingly. Subsequently, responsibility for the inclusion or lack of redundancy on various pieces of equipment, also fell on the EPC contractors. Lack of redundancy on various key pieces of equipment, particularly key heat exchangers, resulted in numerous unplanned outages early on. It is important to note that the effects of trace contaminants in the flue gas, which have been identified as fouling precursors, were not expected. As is typical with a first of a kind project, this unforeseen issue manifested early.

Evaluating the performance of the BD3 capture facility prompted initiatives to improve the capture facility's reliability. This formal process evaluated all the first contingency process equipment in the facility to assess operational history, process impact, potential upgrades, and the cost and benefits of the potential upgrades, in order to assemble the scope of work for the upgrade work. The engineering efforts and operational impact of corrections that were applied to the facility to improve its reliability are summarized in this paper.

Two major efforts were made in bettering the performance of the facility while also correcting the identified deficiencies. The first was made during the planned outage in the fall of 2015 while the second occurred during the planned outage in the summer of 2017. A summary of the work scope undertaken during the 2015 fall and 2017 summer outages are presented in Tables 2 and 3 respectively.

Table 2. Summary highlights of deficiency corrections completed in the 2015 fall outage

Issue	Corrective Action Taken
Low placed vents for process venting.	Vents relocated to locations such as atop the CO_2 absorber and CO_2 stripper
Poor CO_2 mechanical vapor recompressor performance due to design and installation deficiencies.	Piping modifications at CO_2 mechanical vapor recompressors.
Frequent fly ash induced fouling of demisters. Due to a combination of process and facility design issues the capture facility was not able to operate as designed at this high level of fly ash.	Upgrade to the power plant ESPs to capture more fly ash. Added spray curtain and pre-scrubber at capture facility intake to reduce infiltration of fly ash. Added top sprays to demisters in the SO_2 absorber pre-scrubber to reduce fouling frequency.
Leaking CO_2 amine tank.	After multiple attempts to repair the leaks a double-walled stainless steel tank was installed to replace original concrete tank.
Underperforming thermal reclaimer unit due to plugging.	The unit's fouled piping was replaced to meet as-new specifications.
CO_2 amine degradation higher than expected. The CO_2 reclaimer too small and underperforming.	Contractor brought on site to perform large-scale amine regeneration to meet < 1% degradation specification.
High pressure CO_2 leak into cooling water caused corrosion and fouling of all process coolers.	Heat exchangers cleaned to reinstate steel surfaces to as-new specification Added monitor to measure cooling water pH to allow for early detection of CO_2 leakage.
Temperature of steam to the reboiler was too high due to design and construction deficiency of the attemperator inside of the capture facility.	Continued to operate CO_2 reboiler inside capture facility as insufficient time to rectify Prepared to make modifications at later date. Attemperator changes were made through iterative process during power plant outage to meet design specifications for steam temperature (300°F vs. 480-500°F).
Underperforming power plant governor valve. A high wear issue resulted in un-stable operation of the turbine at specific loads.	Power plant was operated outside of the range that resulted in unstable operation. Issue patched in Fall 2015, and final fix installed in mid-2017 outage.
Issues with incorrect seal material selection, gasket selection, packing, resulted in multiple leaking valves.	Repaired, realigned or replaced throughout capture and power plant facilities.

Table 3. Summary highlights of deficiency corrections completed in the 2017 summer outage

Issue	Corrective Action Taken
Fly ash induced fouling in the absorber towers.	Cleaning the demisters of the prescrubber. Cleaning the chimney trays of the SO_2 absorber.
CO_2 compressor piping.	CO_2 compressor piping required alignment which was completed.
Various shortcomings in heat exchanger performance	Scaling caused frequent fouling in key heat exchangers within the plant which reduced performance. Redundant heat exchangers were added to the SO_2 lean/rich amine heat exchanger, to the SO_2 reboiler, and to the CO_2 absorber's wash water section cooler.

3.2. Managing Particulates

Fly ash carryover and build up in the CCS facility has played a role in reduced capture performance. The local lignite used by the Boundary Dam facility produces a fine fly ash which is very difficult to manage. Currently, fly ash is managed at Boundary Dam using electrostatic precipitators (ESPs) although the smallest of these particles bypass these systems. The issues surrounding fly ash manifested a mere two months after the facility began operations. The build up of fly ash on certain pieces of equipment impaired flue gas flow at the front end of the CCS process, particularly hindering operations of the SO_2 removal system, which subsequently impeded the overall CO_2 capture rate. Two major issues are attributed to fly ash carry over: 1) SO_2 reboiler fouling and 2) SO_2 absorber demister fouling.

3.2.1 Frequent fouling of the SO_2 reboiler.

Fouling of the SO_2 reboiler was frequent; a scale was found to build up on the plates of heat exchangers. A compositional analysis of a sample taken from this scale indicated the presence of calcium sulphates. It has been postulated that calcium present in the fly ash leaches out into the SO_2 amine and subsequently plates out onto the hot surface of the SO_2 reboiler. The degree of fouling was significant and prevented adequate regeneration of the SO_2 amine (i.e. stripping out the SO_2) as the build up of scale would create large differential pressures across the exchangers hence limiting amine flow. The build-up of scale would also create an insulating layer between the plates, inhibiting the transfer of energy between the LP steam and the amine flowing through, limiting the generation of steam in the amine that is used to regenerate the rich amine entering the SO2 stripper. Since the SO_2 reboilers lacked redundancy, correcting this issue would require taking an outage to remove the scale build up from the SO_2 reboilers via chemical cleaning with an EDTA solution. This reduced the availability of the capture facility and subsequently reduced the overall CO_2 capture rate.

3.2.2 Mitigating fly ash carryover

The SO_2 absorber is comprised of three sections. The first section is the prescrubber section, the second is the amine section and the third is a caustic wash section. Significant increase in the pressure differential readings manifested across the demisters in the prescrubber section due to fly ash build up. This in turn restricted flue gas flow rate through the SO_2 absorber ultimately leading to reduced volumes of processed flue gas and an overall reduction of CO_2 capture rates. To manage the fly ash build up various wash systems were added. This included additional demister wash systems, a pre-scrubber flue gas inlet curtain spray wash system, flue gas cooler throat sprays, and a booster fan wash system.

Demister sprays

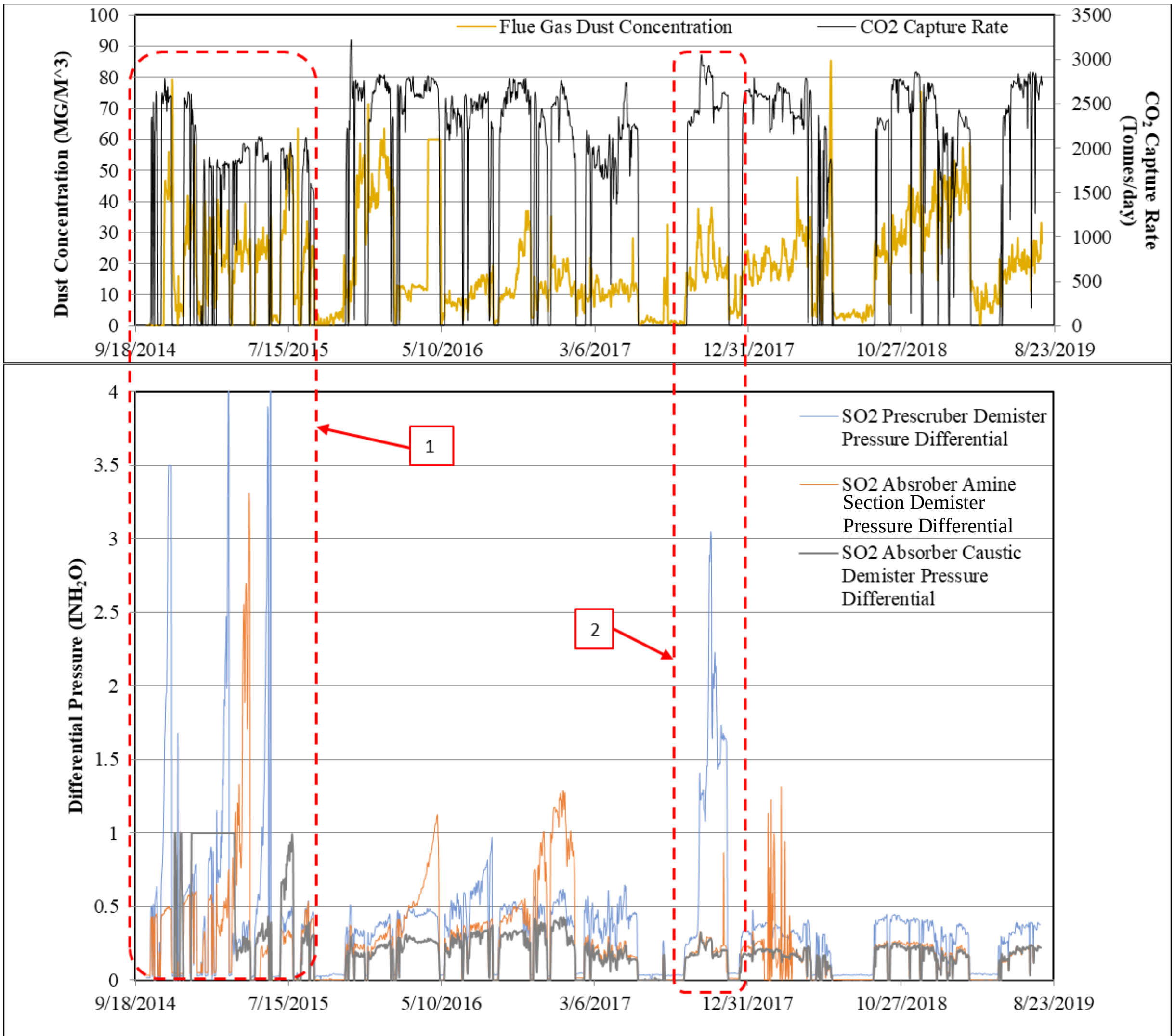
Demisters are used to prevent carryover and contamination between different liquid sections and are designed to prevent liquid from penetrating through them. The SO_2 absorber has three sections of demisters. The prescrubber demister is a section just above the prescrubber section of the SO_2 absorber that is designed to prevent carryover contamination of any liquid droplets from the prescrubber section into the SO_2 amine section. The amine section is also equipped with a demister system to prevent amine losses through liquid entrainment to the caustic section. A third set of demisters in the caustic section prevents the carryover of caustic wash solution to the CO_2 absorber. Fly ash would plug off the prescrubber demisters approximately every six to eight weeks. This would lead to significant increases in differential pressures across the prescrubber demisters to the point that the booster fan could no longer physically overcome the pressure drop while the induced draft fans at Unit 3 would begin to max out. This would inhibit the amount of flue gas passing through the SO_2 absorber (and subsequently the CO_2 absorber) resulting in overall reduced CO_2 capture rates (as demonstrated in scenario 1 of Fig. 7). The other two sets of demisters fouled, although less frequently, with the amine section demisters fouling every six months while the caustic wash section demisters fouled approximately every 12 to 18 months. The original design included bottom sprays for the demister systems which would spray intermittently every 15 minutes. These would prove to be inadequate. Top sprays were added to the prescubber demisters in 2015 to combat fly ash plugging issues. Top sprays were then also added to the amine and caustic section demisters in 2017. The occurrence of increased differential pressures across the SO_2 absorber demisters has been reduced (as demonstrated in Fig. 7).

Prescrubber spray curtain

Carry over of fly ash into the CCS facility was anticipated. The prescrubber section was designed to remove about 30% of the fly ash that enters it. The remaining fly ash was found to partially dissolve in the amine solutions over time making it difficult to remove the remaining fly ash particles from the amine solutions.To combat this, a spray header was set up across the inlet of the prescrubber creating a curtain of water that the flue gas has to pass through before entering the SO_2 absorber. This dense curtain of water works in two ways: 1) it changes the velocity of the flue gas such that the fly ash is knocked out, and 2) it forces the fly ash particles to be ensnared on the curtain itself which then drop into the prescrubber sump below. This spray curtain was put into service in 2015, shortly after the facility began operations. Significant improvements in ash loading have been observed after its installation.

FGC throat sprays

A throat spray system, comprised of a series of nozzles that are orientated to spray with the flow of the flue gas, was installed at the flue gas cooler outlet to the prescrubber. The spray works by generating a water fog that ensnares the particles of fly ash creating larger particles that are then more easily knocked out of the flue gas by the spray curtain at the entrance of the prescrubber.



1. Prior to implementing flue gas dust management procedure, demister fouling occurred more frequently during initial operations.
2. Example scenario: An increase in fly ash concentration in flue gas elicits an increase in pre-scrubber demister differential, the system responds by increasing wash water cycle frequency. Capture operations are not affected.

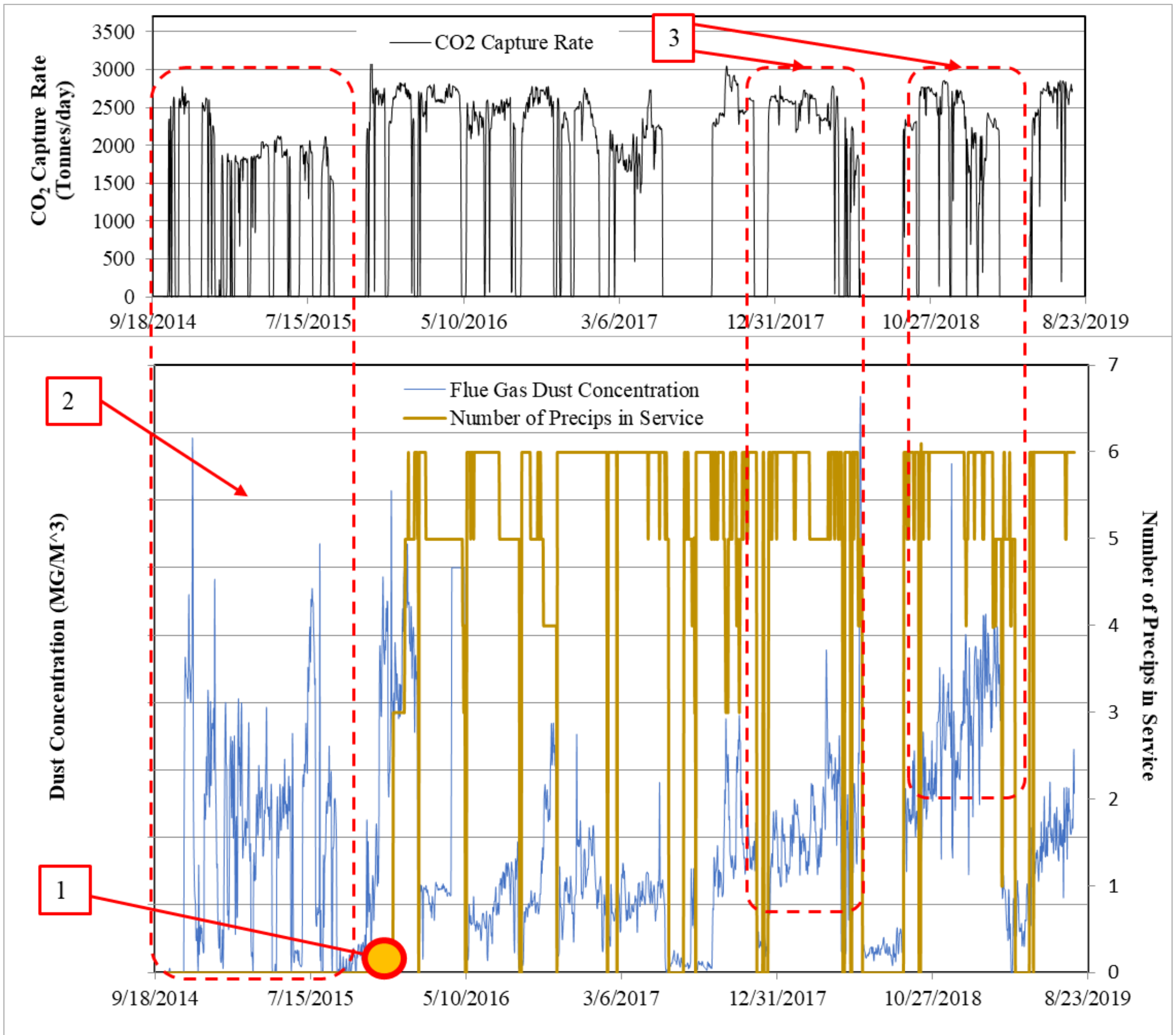
Fig. 7 Example of how demister wash systems mitigate losses in CO_2 capture rates

Booster fan spray system

Fly ash was also observed to build up onto the impellor of the booster fan and solidify into a concrete like material (requiring high pressure washing for removal). This would impede fan operations and cause undesired vibrations. To combat this, a set of spray nozzles were installed on either side of the impeller. These nozzles spray demineralized water at regular intervals onto the inside edges of the fan blades. By keeping the blades constantly wetted, fly ash is unable to adhere and solidify into concrete and is instead flung off and settles out at the bottom of the booster fan casing or is entrained with the flue gas and sent into the CO_2 absorber. These spray systems have mitigated capacity limitations associated with fly ash build up that is associated with the booster fan.

Electrostatic precipitator upgrades

Fly ash is managed at the Boundary Dam power station using electrostatic precipitators (ESPs) although the smallest of particles bypass these systems. Fly ash was identified as a main contributor to reduced CO_2 capture rates (as demonstrated in scenario 2 in Fig. 8). This prompted upgrades to be made to the ESPs. Switch Integrated Rectifiers (SIRs) were added in late 2015/early 2016. These upgrades aided in managing flue gas dust concentration. Although dust concentration increases from time to time (as dust concentration is highly dependent upon the ash content of the coal, among other things), the combination of these upgrades with the addition of the various wash spray systems limits the severity of reduced CO_2 capture performance resulting from fly ash ingress (as demonstrated in scenario 3 in Fig. 8).



1. Upgrades to the electrostatic precipitators (ESP).
2. High dust loading in flue gas resulted in reduced capture rates.
3. Capture rates not as adversely affected with high dust loading following upgrades to ESPs.

Fig. 8 Affects of dust loading in flue gas on capture rates

3.3 Redundancy and Isolations

Redundancy within an industrial facility entails the inclusion of spare capacity in various pieces of equipment. This can be implemented using trains of equipment such as designing for pump requirements to be met by three identical 50% capacity pumps; this allows for a spare third pump that can be swapped into service in the event that one of the two pumps in operation requires maintenance. Redundancy should be considered for and installed on equipment whose functionality is vital in achieving continuous process operations. Implementing redundancy is also favorable for equipment susceptible to frequent fouling. Fouling inhibits the performance of equipment - for example, scale build up in heat exchangers not only adversely affects the coefficient of heat transfer but also bottlenecks the overall volumetric flow of the amine which reduces overall capture rate. Often equipment is required to be taken out of service for rectification of the fouling. If spare capacity is not present in the form of redundancy the entire process must be halted. Lack of redundancy on equipment prone to frequent fouling results in annual capture rate losses.

Isolations, such as double block and bleed valves allow positive isolation and de-energizing of equipment while redirecting process fluids to facilitate online maintenance. Isolations allow for seamless utilization of redundancy by re-directing process fluids away from a fouled piece of equipment and towards a redundant one. This allows for continued operations of the capture facility eliminating the need for an outage to chemically or mechanically clean the fouled equipment. Economics favor the installation of redundancy during construction as it is significantly cheaper when compared to retrofit installations. Identifying equipment within the capture facility requiring redundancy and isolations is essential in increasing the reliability of future CCS installations.

The BD3 ICCS facility was designed to meet a specified availability as was determined by SaskPower at the time of project development. This determined value reflected:

1) Intentions to continue operating Unit 3 of the Boundary Dam Power Station with a baseload operating profile (note that the coal units in Saskatchewan are operated at high capacity loadings to meet the consistent electricity demands of large industrial consumers in the province).
2) Intentions to maximize the revenue from CO_2 sales (for EOR purposes) therefore increasing the attractiveness of the business case. It is important to note, however, then project approval for the BD3 ICCS facility was granted prior to securing a CO_2 sale contract. At the time development and implementation of EOR in the area was high as was the demand for additional CO_2. Securing a CO_2 sale was assumed and eventually materialized.

The determined availability metric dictated the extent to which redundancy and isolations were included in the design of the capture facility by the EPC contractors. Inclusion of and the extent of redundancy and isolations on various pieces of equipment was the sole responsibility of the EPC contractors and unfortunately proved to be inadequate in various areas of the capture facility.

3.3.1 Redundancy and isolations regarding heat exchanger performance

The importance of redundancy and isolations is magnified when evaluating the correlation between heat exchanger performance and capture plant availability. Three major groups of heat exchangers exhibited unexpected fouling in the first two years of operations; the SO_2 reboiler, the SO_2 lean/rich heat exchanger and the CO_2 lean/rich heat exchangers. The onset of fouling for the SO_2 reboiler occurred in 2014, while both the SO_2 and CO_2 lean/rich heat exchangers began to exhibit fouling in 2015. Consequences of this fouling included plugging (which reduced overall amine flow through the process and restricted capture performance), undesirable pressure drops within the heat exchangers, and declining coefficient of heat transfer. The lack of adequate isolations and redundancy restricted maintenance and cleaning of these heat exchangers to offline servicing as on-line maintenance could not be performed. This necessitated outages for remediation occurred approximately every 10 weeks during the 2015 year. Difficulties with other heat exchanger systems (i.e. various amine and wash water coolers) were also encountered. These difficulties were cited as contributing to the overall reduction in capture rate experienced by the facility in the initial years of operations.

Various options were considered for addressing the performance deficiencies of the heat exchangers. Options included: scheduling reoccurring maintenance for cleaning and service of the heat exchangers, increasing the number of plates of the heat exchangers to add extra capacity, adding isolations for on-line maintenance with partial capacity loss, and installing redundant heat exchanger sets to allow on-line maintenance with no capacity loss. Challenges with installing these modifications factored significantly in the economics and heavily influenced the modifications chosen. The chosen corrections would be completed as retrofit installations. This provided an additional level of difficulty as there is limited space within the original building footprint where the additional/redundant equipment was to be installed. Incorporation of redundancy and increasing the presence of isolations on selected pieces of equipment were pursued in hopes of increasing annual run time and subsequently the overall annual CO_2 capture rate. Heat exchanger deficiencies were corrected during the summer 2017 overhaul. A summary of the corrective actions completed is presented in Table 4.

Table 4. Summary of heat exchanger deficiencies corrective actions

Heat Exchanger System	Corrective Action
SO_2 Lean/rich	Added redundant exchanger and double block and bleed isolations
SO_2 Lean Amine Cooler	Modified the valve in the bypass line
SO_2 Reboiler	Added redundant exchanger and double block and bleed isolations
CO_2 Lean/rich	Added double block and bleed isolations
CO_2 Lean Amine Cooler	Added redundant exchanger and double block and bleed isolations
CO_2 Reboiler	Added double block and bleed isolations
CO_2 Wash Water Cooler	Added redundant exchanger and double block and bleed isolations
Closed Loop Cooling Water Supply	Added capacity (additional plates) which enabled online cleaning of the heat exchanger pairs and double block and bleed isolations

The SO_2 reboiler experienced scale build up which was attributed to particulate matter (fly ash) that had entered the SO_2 capture system. This scale acted as an insulator and prevented heat transfer between the steam and the amine which subsequently hindered the regeneration of the rich SO_2 amine and reduced the efficiency of the SO_2 removal system. Although the addition of wash spray systems did reduce the incidence of fly ash carryover, fouling of the SO_2 reboiler continued to persist, requiring an outage every three to four months of the entire capture facility in order to chemically clean the reboiler. A second redundant reboiler with double block and bleed valves was installed in June of 2017 to mitigate this issue by allowing online maintenance and continued operations by swapping between the two heat exchangers as required. The SO_2 lean/rich heat exchanger also experienced fouling which was detected by monitoring increased pressure differentials across both the rich and lean sides. The lean side however exhibited far greater pressure differentials. Sulphate formation was discovered to occur during the amine regeneration process demonstrating that sulphate plugging uniquely affects only the lean side of the lean/rich heat exchanger. To counter this, a second, identical, redundant SO_2 lean/rich heat exchanger was installed. Fig. 9 illustrates which heat exchangers received corrections within the SO_2 capture processes.

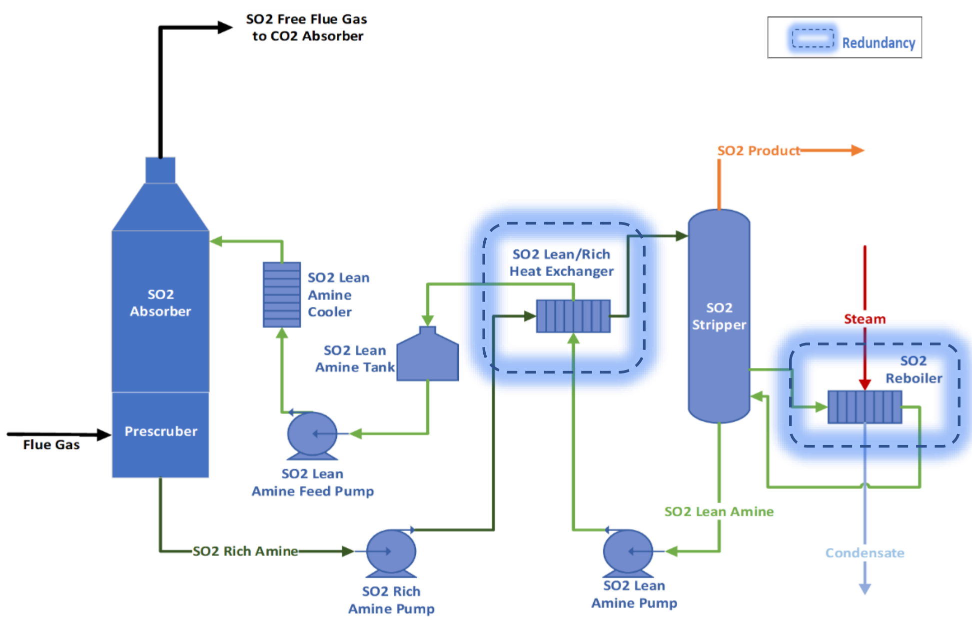


Fig. 9. Locations of added redundancy to key heat exchanger system in the SO_2 capture system

Other specific process examples on the benefits of redundancy and isolations can be drawn from the CO_2 capture train. The top of the CO_2 absorber includes a wash water section which is used to remove amine entrained in the flue gas before the processed flue gas exists to the atmosphere. Effectiveness of this wash water system is dependent on keeping the temperature of the wash water cool. The original design of this system included a single cooler. Fouling of this cooler hindered its ability to deliver consistent and adequate cooling; struggles were encountered in maintaining wash water temperatures. The CO_2 capture process cannot operate without a wash water cooler as this would result in amine emissions out the top of the absorber which is not permissible. To rectify this, a second wash water cooler was added in parallel to the original cooler. This provided better control over cooling and also compensated for any fouling issues. Double-block and bleed valves were also installed to allow isolation of each cooler for on-line maintenance as necessary.

Difficulties in cooling were also encountered with the CO_2 lean amine cooler. Once again, the original design included a single heat exchanger for this purpose. Adequate cooling of the lean amine prior to its re-entry to the absorber tower was not being provided. This meant that the lean amine was entering the absorber tower at higher than anticipated temperatures. This interfered with the water balance of the system and required the addition of demineralized water to maintain the desired concentration of the amine. The high temperatures also reduced the CO_2 amine's ability to adsorb CO_2 from the flue gas, resulting in a slight decrease in CO_2 capture performance. Hydraulics modeling was completed which suggested that the lean amine cooler was not receiving sufficient flow and that additional cooling capacity would help achieve the desired amine temperatures. A second lean amine cooler was installed in February of 2017. Isolations were included with this second cooler and were also added to the existing cooler. Once the second lean amine cooler was placed into service the original cooler was isolated for on-line servicing. Scaling was discovered on the amine side of the original lean amine cooler which is thought to have contributed to the issues in performance. Fig. 10 illustrates which heat exchangers received corrections within the CO_2 capture processes.

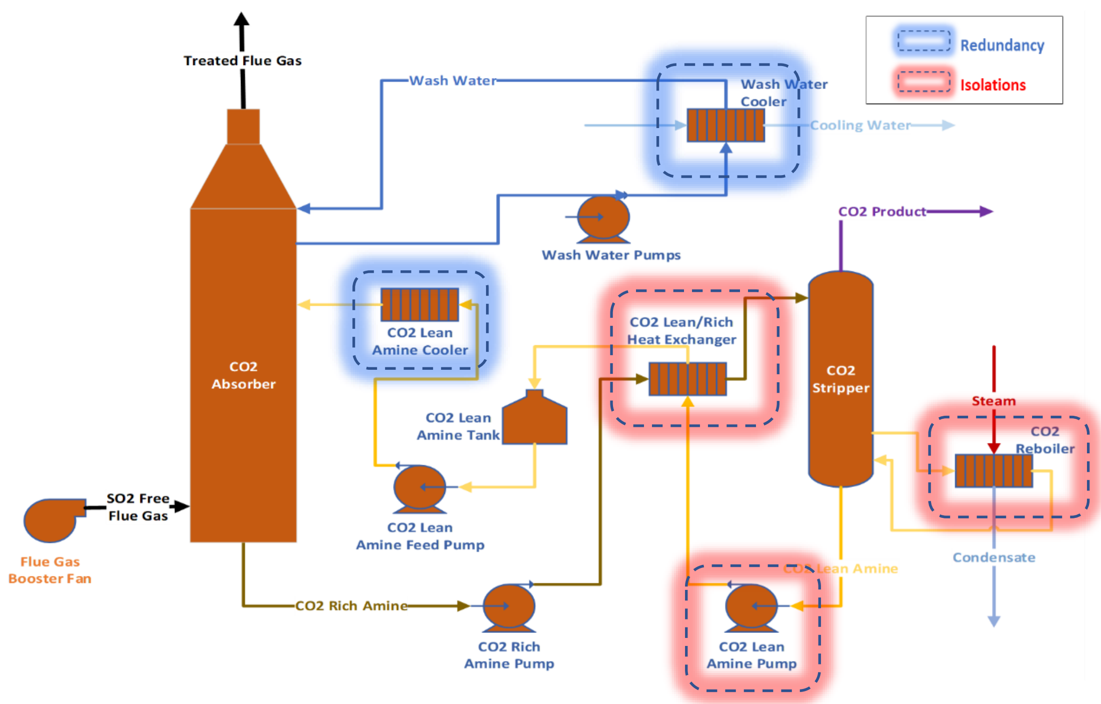


Fig. 10. Locations of added redundancy and isolation to key heat exchanger system in the CO_2 capture system

As expected, correcting the difficulties associated with the various heat exchanger systems, and the other upgrades that were implemented, improved the performance and reliability of the capture facility. Comparisons of capture facility performance prior to and following the modifications confirmed this; availability of the capture plant improved to 94% in 2018.

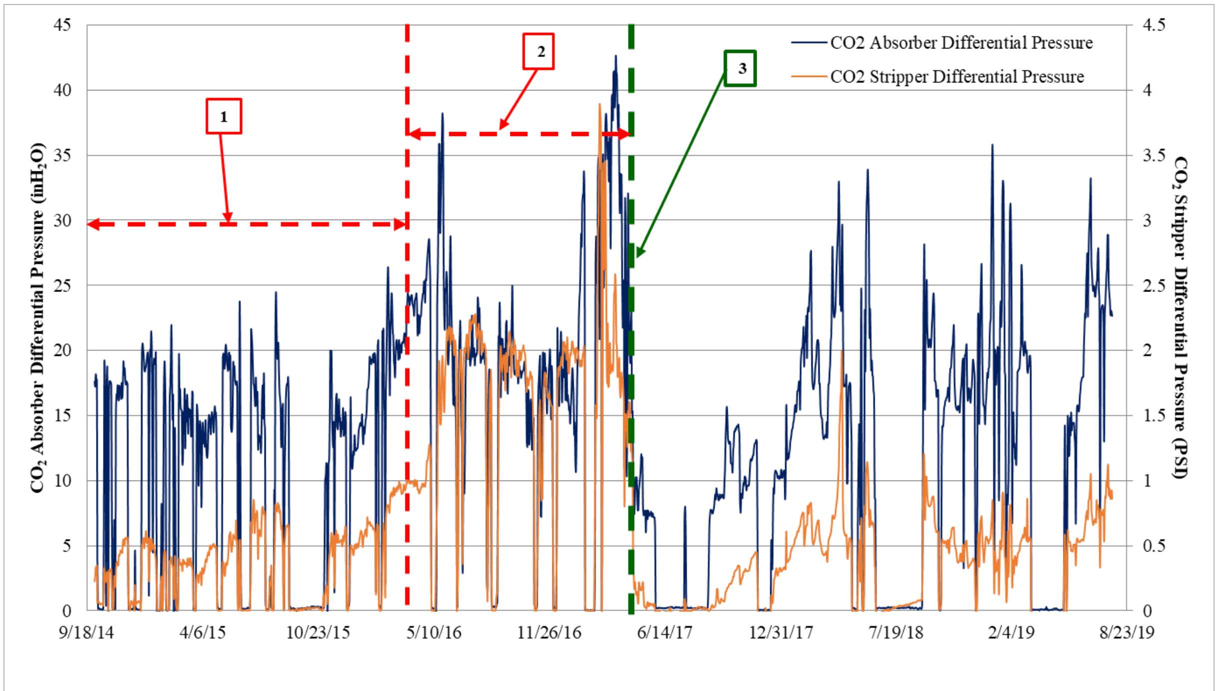
3.4 Amine health and the foaming issue

Maintaining amine health is vital for achieving expected capture rates. One of the challenges regarding amine health manifested in foaming. The presence of foaming has been a common but poorly understood problem in the industrial world. Foaming is a significant problem at large-scale post-combustion carbon capture plants using liquid amine solutions and it's directly related to the degradation products which limits both the flue gas flow rate and mass transfer. In carbon capture systems using aqueous amine solutions, degradation and associated foaming can be an ongoing issue, resulting from contact of the solvent with wide range of impurities during its operational lifetime. The main sources of impurities in the system are the gas itself, the metal infrastructure and the cyclical heating process - which also contributes to some degree of solvent degradation. Foam formation results in solvent loss and changes the composition of the solution thereby increasing the costs of operation and reducing the efficiency of the system.

The initial onset of foaming at the CCS facility at BD3 was after the 2015 fall outage. Foaming was experienced in both the CO_2 absorber and CO_2 stripper columns. Foaming was detected through increased pressure drops across the structured packing in the stripper and absorber towers. In the absorber column, foam interferes with the mass transfer and thus limits the amount of CO_2 the amine can absorb. In the stripper column, foaming limits the ability for the steam to transfer its energy to the rich amine in order to effectively strip off the captured CO_2. During and following the fall outage, it was determined that thermal reclamation would be conducted on the amine to remove an assumed build-up of degradation products. This reclamation was conducted onsite using a contracted reclaimer system on a period basis in the Fall 2015. With continuous system cleaning, reduction of foaming was observed although the issue persisted.

Antifoam was then sought after to manage foaming; continuous antifoam injection began in April 2016. Bigger volumes of antifoam were periodically dosed into the CO_2 amine which lowered the foaming tendencies of the solvent. The cost of the antifoaming agent, however, was great. Signs of instability of the system operation due to the antifoam were also observed. Another issue was related to determining the amount of antifoam in the system as excessive antifoam can potentially cause foaming. In February 2017, CO_2 stripper packing damage caused by the instability of the system from antifoam was discovered on a small section of bed 1. During the June 2017 outage, damage was also observed in the packing further up the column. Damaged packing in the affected beds was replaced in July of 2017. Antifoam use was put on hold and was not used again until December 2020.

An activated carbon filtration system was then trialed to mitigate foaming. Activated carbon filters have been used for removal of dissolved organic contaminants in amines utilizing an adsorption unit or "filter" utilizing granular activated carbon. Activated carbon filters operate more effectively at lower temperatures. In April 2017 a smaller pilot scale of this system would be implemented on the lean side of the CO_2 amine, upstream of the CO_2 absorber. The pilot proved to be successful in its effectiveness at relatively low cost. An added benefit of activated carbon is to remove excess antifoaming agents from the amine. During the Spring 2017 outage, the system was appropriately sized to be a full-scale pilot size processing roughly 2% of the CO_2 amine stream. Replacing the defoaming agent with an activated carbon unit worked well from the May 2017 to October 2017 (as illustrated in Fig. 11) however levels of foaming gradually increased over time. Today foaming continues to persist. It is not currently clear whether the root cause is related to fouling and exhaustion of the activated carbon, inadequacy of the volume of the slip stream being processed through the activated carbon or other process changes. Investigations into this matter continue.



1. Prior to installing activated carbon system, periodic dosing of antifoam was being used to manage foaming issues.
2. Continuous injection of antifoaming was used during this period to manage foaming.
3. Activated carbon system put into service in April 2017, significant improvements in foaming management.

Fig. 11 Example of foaming indicative differential pressures in the absorber and stripper towers

4. Conclusion

The BD3 CCS facility is a first of its kind implementation. Early operations of the facility saw difficulties in achieving desired CO_2 capture rates. Many of the operational complications can be attributed to design deficiencies of the plant itself. Main factors contributing to reduced capture performance stem from higher than anticipated flue gas particulate carryover into the capture facility. Efforts have been made (and continue to be made) to rectify deficiencies while also managing particulates and improving the overall performance and availability of the plant. These efforts have included additional washing systems to limit particulate carry over and adding redundancy and isolations to allow for online cleaning and maintenance of equipment. The lessons learned from operating the BD3 CCS facility are informing other CCS projects and will greatly benefit future implementations of this technology.