14th International Conference on Greenhouse Gas Control Technologies, GHGT-14

21st -25th October 2018, Melbourne, Australia

Post combustion CO_2 capture retrofit of SaskPower's Shand Power Station: Capital and operating cost reduction of a 2nd generation capture facility

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Abstract

SaskPower's Integrated Carbon Capture and Storage Demonstration Project on Boundary Dam's Unit 3 pioneered the way for full-scale carbon capture facilities around the world. With such an undertaking, many lessons were learned through the design, construction and operations of the facility. These lessons have resulted in novel optimizations, operating methods and overall learnings for the facility and its role as a power generator in the power utility. Saskatchewan and its provincial utility, SaskPower, again find themselves on the cusp of an important decision. The utility has a need to provide base-load power which regionally is only available from coal or natural gas. Regulations in Canada are closing the window on coal-fired power generation without carbon capture, and while there is a significant revenue opportunity to utilize and sequester CO_2 for Enhanced Oil Recovery (EOR) operations, low oil prices have softened the demand for the CO_2. The economics of retrofitting coal with Carbon Capture and Storage (CCS) are further challenged by locally all-time low natural gas prices. The International CCS Knowledge Centre (Knowledge Centre) is currently executing a feasibility study with SaskPower to determine if a business case can be made for a post combustion carbon capture retrofit of the 305MW Shand Power Station. The study included the addition of a 90% carbon capture facility that will have a nominal annual capacity of 2 million tonnes per year. This paper includes interpretation of the public and non-confidential portion of this study to highlight both the overall impact on the cost of CO_2 capture, as well as contrasting the impact of the major design modifications with the Boundary Dam Unit 3 system (BD3).

Keywords:Carbon Capture and Storage; Industrial Scale CCS; CCS Scale Up; CCS Feasibility Study; CCS Economics

1. Introduction

In October 2014, SaskPower's Integrated Carbon Capture and Storage Demonstration Project on BD3, using the CANSOLV® Carbon Dioxide (CO_2) Capture System came online. This project, approved before regulations on CO_2 emissions from coal plants were defined in Canada, provided an option for reducing the CO_2 emissions of the lignite coal-fired power plants that provide a large portion of the base generating capacity in the province, and as a first in the world, BD3 pioneered the way for full-scale carbon capture facilities around the world. On July 1, 2015, new Canadian Federal Government performance standards were put into force mandating that new coal-fired electricity generating units must limit their CO_2 emissions to 420 tonnes/GWh. Units which have reached their end of life (nominally 50 years) are also subject to this new CO_2 emissions standards for continued operation [1]. CCS is the only method by which coal-fired power generation can achieve these emission targets. Therefore, in Canada, a facility past its retirement date must be retrofitted with carbon capture technology or closed.

Nomenclature

BD3	SaskPower's Boundary Dam Power Station Unit 3
LCOC	Levelized cost of capture
MHI	Mitsubishi Heavy Industries
MHPS	Mitsubishi Hitachi Power Systems
NGCC	Natural gas combined cycle
NPV	Net present value
OEM	Original equipment manufacturer

Conventional lignite coal-fired power generation (used in Saskatchewan, Canada) emits roughly 1,100 tonnes of CO_2/GWh (t/GWh). Traditional natural gas-fired power facilities emit in excess of 500 t/GWh. Newer combined-cycle facilities can operate at 375 t/GWh, and when used as a backup to intermittent non-emitting renewable energy can contribute to an effective emission intensity as low as the 200-250 t/GWh range. In contrast, BD3 was designed to capture up to 90% of the CO_2 in the flue gas and operate as low as 120-140 t/GWh. The greatest gains in CO_2 emissions reductions, in an electrical system without the ability to add hydro or nuclear facilities, are realized with CCS.

Regulations in Canada are closing the window on coal-fired power generation without carbon capture, and while there is a significant revenue opportunity to utilize and sequester CO_2 for enhanced oil recovery operations, low oil prices have softened the demand for the CO_2. The economics of retrofitting coal with CCS are further challenged by an abundant supply of natural gas which is available at all-time low prices that have persisted long enough that the price level is perceived to have found a new norm in North America. Can the experience gained in building and operating BD3, the world's first commercial coal-fired power plant fully integrated with CCS, and the technical advancements that have taken place in the 10 years since the BD3 project was originally conceived combine to allow CCS on coal to be competitive with a modern natural gas combined cycle power plant in North America?

The BD3 project was aided by a one-time $240CAD million grant from the Government of Canada, and 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 was evaluated to be equivalent to a new build Natural Gas Combined Cycle (NGCC) plant at that time, with both options evaluating to a common Levelized Cost Of Electricity (LCOE). Since that time, the current forecasts for future natural gas prices, which are the largest single contributor to the price of electricity from a NGCC plant, have persistently declined.

In order to evaluate whether CCS would be feasible in this market, and in light of studies which showed that a business case for a CCS retrofit of BD3's sister units, Boundary Dam Unit 4 and 5 was unlikely to be feasible, (and in fact SaskPower publicly announced in the summer of 2018 that these units will not be retrofitted with CCS[2]), a feasibility study was undertaken to determine what would be the best possible business case and configuration for a coal-fired power plant retrofit to CCS in Saskatchewan. This paper highlights some of the important globally applicable learnings from this exercise, which are described in more detail in the full public report.

2. The Shand CCS retrofit feasibility study drivers

Shand Power Station, a single unit plant with approximately twice the capacity of BD3, was commissioned in 1992. It was originally designed with provisions for a second unit that was never built, it is SaskPower's newest coal-fired power plant, and is thought to be the best candidate for SaskPower's next CCS Project. A feasibility study evaluating the business case for a post-combustion carbon capture retrofit of the 300MW Shand Power Station (located 12 km from Boundary Dam) resulting in the addition of a 90% carbon capture facility with a nominal annual capacity of 2 million tonnes per year was completed. Mitsubishi Heavy Industries' (MHI's) KM CDR Process^{TM}, currently used at Petra Nova (the world's largest CCS plant), was evaluated during this study in order to allow the project team to assess the relative merits of the two technology providers who have built systems at commercial scale, Cansolv and MHI. The study was managed by the International CCS Knowledge Centre (Knowledge Centre) and was a collaborative effort between SaskPower, MHI, and the Knowledge Centre.

The factors that lead to the selection of Shand as the site for the study, and the parameters of the project that would increase the probability of the project being viable are explored. It is felt that the majority of these factors are globally relevant and will be general common characteristics of successful CCS implementations throughout the world. In depth analysis of the impact of these factors is beyond the scope of this paper and additional information can be found in the full public report.

2.1 Capture plant size

A fundamental driver in the utility industry has always been the economies of scale. In general, facilities that are larger are more economic. Previous studies had been completed on combining two 150MW units with a single carbon capture plant in order to increase the scale of the capture plant. While this decreased the capital cost of the facility on a full nameplate capacity basis, the realities of interaction of the maintenance of the three plants resulted in a lower utilization factor which muted the improvements on capital cost. The operational experience with BD3 makes it seem doubtful that a next generation capture plant could be more reliable and require less maintenance downtime than the two accompanying coal-fired power units.

In Saskatchewan, the largest coal units are in the 300MW class, with effectively double the total emissions of BD3, which would result in a 90% capture plant that would have an annual nameplate size of 2,000,000 tonnes / year. The four units at SaskPower that are in the 300MW class, are Boundary Dam Unit 6, Poplar River Units 1 & 2, and Shand Unit 1. Boundary Dam and Shand are located near Estevan Saskatchewan, while the Poplar River Power Station is located 200 km west of Estevan. Preliminary review indicated that most components for the capture facility will still be at a reasonable size, with the exception of the CO_2 compressor which would be larger than is currently commercially available, and the CO_2 desorber, which may become too large in diameter to be fabricated as a single pressure vessel.

2.2 Power plant reliability / capture plant partial capacity

The ability for the power plant to be able to continue running uninterrupted in the event of issues with the capture facility was one of the main risk mitigation strategies built into the original design of BD3, this feature is generally referred to as dual mode. It worked, and was needed often, especially in the early days of operation. The key to this was provisions that allowed steam consumption to be varied somewhat independently of capture plant demand, and diverter dampers that allowed the flue gas to be sent to either the original stack or the capture facility or a combination of the two. While the dual modes provide reliability for the power plant, it is the ability to partially bypass the capture plant that is a key to flexibility in the capture plant. For the Shand study, the systems will be the same, and partial bypass of the capture facility will be designed to be the normal means of dealing with lack of capacity in the capture facility for any number of reasons. This allows design margins in the capture facility to be tighter.

2.3 Thermal integration and host selection

For this study, the regeneration energy source was known to be an integration with the steam turbine. In addition to the benefits for dispatch flexibility, the subject of a separate paper by our technical staff, although available with the addition of pipeline infrastructure, none of the coal-fired power plants in SaskPower's fleet has adequate natural gas infrastructure to support the addition of a large combined cycle facility to be used as the regeneration energy source.

Units 4 and 5 at Boundary Dam have a similar turbine thermal design to the original BD3 turbine which was replaced as part of the conversion to CCS. In order to modify BD4 and BD5, the turbine would have to be replaced in its entirety. As well, if the plant was optimized for CCS steam delivery, it would not be able to reach full load in non-CCS mode without the replacement of the entire feed-heating plant as was done for BD3. The cost and complexity of this modification is not trivial.

All of the 300MW units at SaskPower have relatively similar turbine thermal designs. Rather conveniently, the pressure at the cross-over is much more amenable to a conversion to be used for carbon capture. Preliminary modeling indicated that there was the probability that the regeneration energy could be sourced from the turbine relatively efficiently with very few changes to the feed-heating plant, and bolt in modifications to the steam turbine. Further it was determined that the modifications would not preclude the unit from running at full load when the CO_2 capture facility was not drawing steam from the turbine. The design of the modifications to allow heat integration are described in separate papers.

The thermal modifications suggested were reviewed, analyzed and refined by the turbine OEM, Mitsubishi Hitachi Power System (MHPS), and a budget proposal which incorporated the main concept was found to be an economic and workable solution.

2.4 Grid support and ancillary services

Large thermal power stations play an important role in the electricity system as it relates to system response to frequency disruptions and power factor correction. In addition, these units are required to adjust their load to maintain the supply-demand balance in the electricity grid. The goal to provide an option which would see all of the existing coal thermal plants at SaskPower converted to CCS represents as much as 40% of the annual energy supply. Had these units been designed like BD3, with very limited capacity to adjust load, the load adjustment range of the balance of the fleet would have been un-workable. If CCS were to be viable for a large build-out, it would have to maintain the flexible operating range of the existing unit, and it would spend enough time at these loads, that CO_2 capture rate would need to be maintained.

Considerations for planned curtailment were made in designing the capture system for Shand. At partial load, the CCS facilities are essentially over-sized for the amount of CO_2 that needs to be captured. The only limitation is the amount of steam that is available from the steam turbine. The decision was made to design the thermal cycle so that it could meet full load with the turbine as optimized, and then to add a butterfly valve in the IP-LP cross-over which would be fully opened except when the unit was at partial load, or when off performance design margin was required. This valve would allow throttling of the steam flow at reduced loads which enables continued capture operations at full capacity while the power plant reduces load. The result was a plant operating profile that could maintain, and potentially increase its capture rate across its normal dispatch range.

2.5 Over-capture at reduced load

Based on experience from BD3 (which uses partial flue gas diversion to limit the amount of CO_2 that is captured and is often run at capture rates exceeding 90% on a partial stream of flue gas, and the configuration of the steam source as described above), it was apparent that exceeding 90% capture at lower loads would be possible. A sensitivity analysis was performed by MHI that showed probable capture rates reaching in excess of 96% at 75% load on the power station.

From a CO_2 supply point of view, this means more consistent volumes of CO_2 delivered while allowing the plant to vary its load. From an emissions mitigation point of view, it means that the CCS equipped coal-fired power plant could be made responsive to variable renewable generation, and when it does, it emits less CO_2 per MWh, effectively increasing the emission reduction of the renewables. In contrast, a natural gas plant without CCS that is dispatched down in load to support variable renewable generation increases its emission intensity, somewhat muting the impact of the environmental benefit of the renewable generation.

2.6 CO_2 market

Key to the approval of the BD3 project was the prospect of a sale of the CO_2 for use in an Enhanced Oil Recovery (EOR) operations. In fact, the revenue from the sale of CO_2 was a required component of the business case in order for the project to be competitive with Natural Gas Combined Cycle (NGCC). While not in place at the time of project approval for BD3, it was clear that an opportunity existed, and in fact a sale agreement was entered into with an oil operator for their nearby Weyburn oil field, a field that had already been injecting CO_2 from another source for many years.

There are potential additional opportunities for use of CO_2 in EOR within 100 km of Estevan, Saskatchewan [3]. However, it is uncertain whether these opportunities can be economically developed. The opportunity depends on oil prices that can support the associated higher production costs, and an ability to attract companies to develop and co-ordinate new CO_2 EOR projects, as well as improvements in knowledge for using CO_2 EOR in the Bakken. While there are no nearby EOR opportunities in the area of the Poplar River Power Station, a long-distance pipeline to transport CO_2 to oil producing regions might be economically feasible if the amount of CO_2 transported is large. The larger the pipeline the lower the cost per tonne of CO_2 transported.

When CO_2 is used in an EOR operation, the needs of the oil field are somewhat inconsistent with the capability of a single carbon capture plant. The EOR facility requires a reliable supply of CO_2, as interruptions in availability of CO_2 has impacts on the oil operation. As well, the quantities of CO_2 that can be injected into a new field will gradually increase over the first three to five years of operation. By contrast, a single capture facility is prone to interruptions and trips from either the capture process, or the associated power facility, and once on-line, the economics and the facility work best at full output. The Aquistore CO_2 storage facility, has similar characteristics to the EOR oilfields, taking significant periods of time to get to full capability after any interruption. Although the agreement between SaskPower and their EOR off-taker is confidential, there is significant public information on the shortfall payments that SaskPower has paid due to the lack of reliability of the CO_2 supply [4]. Not all of the CO_2 from the BD3 facility has been sold.

The opportunity exists to join the Shand CO_2 pipeline to the BD3 pipeline. This would benefit the reliability, as the two power units and associated capture units would not be scheduled to do planned maintenance concurrently, and the probability of simultaneous unplanned outages would be low. It is anticipated that the combined reliability of the two facilities would exceed 98% in comparison to the single facility reliability which was originally targeted at 85%. If the pipeline between the new EOR off-taker and Shand, and the connection to the BD3 pipeline was completed in advance of the carbon capture plant completion, the excess un-sold CO_2 from BD3, could be delivered to the new fields so that the fields could develop capacity to accept the higher volumes of CO_2 that would be available when the new capture facility comes on-line. This would also improve the economics of the BD3 facility by increasing the number of off-takers and potential volumes of CO_2 to be sold.

2.7 Site layout and modularization

The availability of space for the CCS plant footprint is a factor in determining a suitable location. The distance between the power facility and the capture facility on BD3 resulted in significant capital expenditures for interconnections between the two plants, that amounted to almost 8% of the overall capital costs for BD3. In addition, the physical distance between the plants makes integration of the operations more difficult and less likely.

In contrast to the Boundary Dam site, the Shand site with its single unit is un-congested and open. The original project concept of locating the CCS plant parallel to the existing power unit, with the CO_2 absorber tower aligned with the boiler house, the CO_2 desorber aligned with the boiler house / turbine house wall, and the CO_2 compressor aligned with the power generator, minimized the length of interconnections for flue gas, steam, and electricity. The concept of sharing common steel and adjoining the two plants was abandoned in favor of construction access and to support modular construction, although there may be merit of re-using elevators and access in locations where modularity is not a significant benefit.

Modular construction for major infrastructure projects in western Canada, specifically the Alberta oil sands, has been embraced as a means of controlling costs. Routes exist in Saskatchewan and Alberta that can support the road delivery of modules and vessels that can be 30 feet (9m) high, 24 feet (8m) wide, and 120 feet (40m) long. This shop assembly of structural steel, equipment, piping, electrical and instrumentation dramatically increases productivity, reduces travel costs and results in shorter on-site construction time.

2.8 Fuel pricing, and common services

A consideration when determining where best to site the next potential CCS facility, especially when considering the economics and environmental policies that are making the future of coal-fired power plants uncertain, is to ensure that critical mass of the industry is maintained.

Coal mining is a capital-intensive undertaking, and there is significant investment in being able to deliver the coal at peak demand. As has been seen in West Virginia and other locations in the USA, scaling back on coal deliveries does not decrease the fixed costs of coal mining, and the price of the delivered fuel rises on a per ton basis as the demand is decreased. This negative feedback loop results in ever increasing costs for coal as the demand is decreased, and ever decreasing demand for coal as the price of the electricity from the coal-fired power plant increases.

In the case of Shand, it is fed from a common mine with Boundary Dam, and with BD3 already being converted to CCS, it is the coal fuel source with the best long-term viability. CCS plants, especially those fed by mine mouth operations are likely to be concentrated for this reason.

2.9 Matching capture capacity to regulatory requirement

With current regulations known in Canada as of 2012, and the focus on reducing capital cost, there is obvious logic in building the CCS plant only as big as it needs to be to capture the required amount of CO_2. Studies were undertaken to determine the amount of capital cost reduction that could be realized, as well as determining the relative benefit of treating all of the flue gas to capture 70% of the CO_2 or capturing 90% of the CO_2 from 80% of the flue gas. Due to the economies of scale, the 80% sized capture plant had capital costs on a per tonne basis that increased by 7%, and the plant that processed all of the flue gas at a lower capture rate was even worse. It is clear that building the plant smaller or designing the plant to capture less than 90% of the flue gas will ultimately increase the per ton cost of CO_2 capture.

The regulations in Canada contain language that encourages the provinces to draft their own equivalent legislation that best fits their region and achieves the same CO_2 reduction [1]. For a staged reduction in the emissions from coal, a plan where the biggest units are completed first, and they are built to capture at least 90% of the CO_2 produced is the most cost-efficient way of reducing the emissions from coal while maintaining it as a fuel source. The Federal and Provincial government have reported that they are working on an equivalency agreement, but the details are not public.

From a global perspective, in addition to the increased cost for lower capture rates, future regulatory tightening makes building a plant that is less than best available technology a risk that is difficult to quantify, and will be a barrier to any investment decision. Building too small could in fact undermine the value of the entire endeavor. To reduce the long-term risk of costs from tightening CO_2 policy, it is likely that only projects exceeding rates of 90% CO_2 capture will be planned and approved.

2.10 Increasing capture capacity from 90% to 95%

As a sensitivity case, the effects of capture efficiency were also investigated by evaluating the cost increase from a 90% capture rate to a 95% capture rate. An estimate for the increase in overall capital costs and steam requirements were provided by MHI and MHPS. The increased volume of CO_2 captured at a 95% capture efficiency was also calculated. These values were used to determine the changes in capital costs and energy penalty per tonne of CO_2 captured.

The overall increase in capital costs required to facilitate the increase in capture produces a lower overall cost per tonne. The steam requirements however are increased when moving to higher capture capacity. Further investigation reflecting overall changes in the NPV of the cost of capture must be done although preliminary analysis results indicate a potentially lower cost of CO_2 capture at the higher capture rate. Investigating potential increase in CO_2 revenue from the added volume of captured CO_2 must also be considered to determine the point of diminished returns for capture efficiency.

The selection of a higher capture rate would appear to have merit in situations where the unit is sufficiently base-loaded so as not to benefit from the inherent increased capture rate at lower load as described in section 2.5.

2.11 Flue gas pre-treatment

The coal-fired power plants in Saskatchewan, with the exception of BD3, are similar in pollution control equipment, with generally low NOx burners and separated over-fire air for NO_x reduction, and electrostatic precipitators. A portion of the units are fitted with activated carbon injection for mercury abatement. The Shand unit was the only unit fitted with SO_2 abatement, using a furnace based limestone injection system. This system has been challenging to operate and not overly effective. In addition, the configuration of the system makes the fly ash from the unit un-saleable for use in concrete. A new contemporary wet-limestone FGD would improve the utilization efficiency of the limestone, and reduce the amount of SO_2 that would have to be removed in the SO_2 polishing step. More importantly, the 140,000 tonnes per year of fly ash that would now be saleable for the concrete market would create a valuable revenue stream.

In addition, although not universally recognized, the sale of fly ash for concrete use is itself a carbon offset when compared to the emissions associated with producing cement. While numbers vary on the impact, if an effective rate of 0.9 tons of CO_2 reduction per ton of fly ash is used, this translates into a carbon reduction offset of 78 t/GWh [5]. Interestingly, the combination of these fly ash sales emission offsets to cement production with a plant designed for 95% capture as described above could result in a coal-fired power plant that is carbon negative. The ability to sell the fly ash, as an addition to the fly ash that is sold from Boundary Dam, and to take advantage of the common infrastructure to ship the product would be a benefit to the project. As it has transpired, SaskPower has received approval to discontinue the SO_2 abatement on Shand based on the SO_2 that is now captured at BD3. The fly ash sale benefits are being realized and can no longer be attributed to this project, and as such are not included in the financial benefit that would be realized from the project.

2.12 Plant maintainability

The coal-fired power plants to which CCS facilities are attached are the product of multiple generations of revision. The economics, equipment and process characteristics has led to designs that balance costs and reliability which have been proven over and over again. In a sub-critical coal-fired power plant, you anticipate at least one additional burner group or pulverizer than what is required for full load, typically the large fans are 2 x 50% capacity, the feedwater heater number changes, but there are groups of heat exchangers that can be bypassed to allow the process to continue to run with one or more out of service.

This same level of refinement has not yet been achieved for amine based CCS plants. The BD3 facility has undergone complex and difficult renovation projects to add redundancy, isolation, and other modifications. In the short term, where the cost of adding equipment after the original construction is an order of magnitude more expensive than installing as part of the original design, it is believed that there is value in including additional process isolations and redundancy at selected locations in the process. To this end, the capital cost estimate includes additional funds to cover this enhanced functionality.

2.13 Heat rejection design considerations

Experience has shown that the addition of CCS to a coal-fired power plant results in a 50% increase in the heat rejection requirement. Since the availability of cooling is generally one of the first design concerns for siting a new facility, and quite often ends up being the limiting factor for further expansion at a given site, it is anticipated that the availability of cooling capacity will quite often be a major project impediment for a new CCS facility.

For the Shand facility, there is limited water in the area, and an additional water use permit is not probable. In addition, the plants operating license is based on a Zero Liquid Discharge original plant design and maintaining this designation would be an important consideration for the plant.

A major challenge in western Canada where the ambient temperature can range from +40deg C to -40deg C, is the selection of the design temperature for the cooling system. De-rates of the CCS facility are viewed as being acceptable at high ambient temperatures, especially when the impact is slightly lower CO_2 capture with increased power output during times of excessive temperatures, and more CO_2 can be captured at low ambient temperatures. To this end, the heat rejection system was designed for the 85^{th} percentile. This became the basis for the design case and provided reduced margins in favor of cost savings.

The only new water used in the system is the water that is condensed out of the unit's flue gas. The use of a hybrid cooling system with dry coolers and wet surface air coolers provides a double layer of protections for the leakage of process fluids to the evaporation side of the cooling tower, allows the amount of water evaporated to be controlled by biasing heat rejection duty between the two coolers, and results in an air cooler system with high approaches, and an evaporative system which provides the lower approach final cooling of the circuit.

The design of the heat rejection system and maintenance of the water balance at Shand is the subject of its own paper. This type of cooling system has the potential to be a reasonable first approach to cooling at any coal-fired power plant and is especially effective with high moisture low rank coals.

3. The Shand CCS retrofit feasibility study execution

The project consisted of a series of deliverables. The responsibility of each deliverable is outlined in Table 3.1. SaskPower was also consulted for various work items under the responsibility of the Knowledge Centre. The study evaluated the use of MHPS's wet limestone flue gas desulfurization unit (FGD) to capture essentially all the SO_2 emissions and MHI's KM CDR Process^{TM} to capture up to 90% of the CO_2 from the existing power station. MHI was responsible for work associated with turbine modifications, the flue gas desulfurization unit (FGD), the capture facility, and all associated engineering, procurement and construction costs. The Knowledge Centre was accountable for modifications to the heat cycle and heat rejection system, design of the draft system and flue gas cooler, electricity supply to new facilities and the overall balance of plant. Associated owner's costs were also determined by the Knowledge Centre.

Table 3.1 Responsibility chart for Shand CCS study deliverables

MHI/MHPS	Knowledge Centre
• SO_2 Capture System	• Feed Heating System Modifications
• CO_2 Capture System	• Steam Extraction to the BL
• CO_2 Compression	• Plant Interconnects

- Turbine Modification
- Additional Heat Rejection Capacity
- Flue Gas Tie-In (Diverter and Ducting)
- Flue Gas Cooler
- Additional Water Treatment Capacity
- Site Modifications and Construction Preparation

4. Determining the cost of capture

In Canada there is a performance standard for coal-fired electrical generators which is unachievable without the integration of CCS, the continued operation of the facility, is an outcome of an investment in CCS. As such the value products of the facility can include electricity, CO_2, and other byproducts such as sulfuric acid, fly ash, gypsum and so on. As an electrical utility, it would be common to evaluate the cost of electricity from the facility over the course of its lifetime by looking at capital and ongoing costs such as fuel and maintenance, offset by anticipated revenue streams from byproducts to determine the Levelized Cost Of Electricity (LCOE), or other related methods which attempt to determine the minimum cost of providing the electricity. The LCOE of coal with CCS (after adjustment for revenue from by-product sales) would be compared to the LCOE of the best available alternative.

In the majority of the world where individual power unit emission intensity is not regulated, it is more appropriate to evaluate the cost of capturing CO_2 and the value of selling CO_2 and other by-products relative to not installing CO_2 capture. This number in $/ tonne of CO_2 abated, can be readily used to compare the economics of the facility to other emission mitigation options, such as fuel switching, or to a carbon tax, or emission credit. This metric is also appropriate for potential CO_2 off-takers as it allows them to determine the economics of supplying CO_2 to their enhanced oil recovery operation or other beneficial uses for CO_2.

In order to be most usable for a global audience, the key performance metric used is Levelized Cost Of CO_2 Capture (LCOC), and the results are converted and presented in $US / metric tonne. This method assumes that the existing power facility continues to run and be maintained at a reasonable level of reliability. Plant reliability is assumed to be consistent with an 85% capacity factor, and both units are evaluated at 90% capture, which would correspond to an emission intensity of 120-140 tonnes / GWh.

4.1 The energy costs of CCS

The overall annual capture rate for a Shand CCS Retrofit was determined as part of the study. A CCS retrofit of Shand, which produces double the electricity output, achieves a capture rate of 6540 metric tonnes per day (tpd); a value slightly more than double the capture rate of the BD3 facility (3240 tpd).

Table 4.1 Capture rate of BD3 and Shand

	Gross Output (MW)	Capture Rate (tpd)
BD3	161.1	3240
Shand	305.0* (317.0)	6540

** Current value*
( ) Corrected for turbine degradation

BD3 incurred extensive turbine upgrades for CCS compatibility and efficiency, including increasing the steam temperature which resulted in a gross output increase from 150 MW to 161.1 MW. CCS on Shand will require only minor modifications to the turbine. These modifications will also correct any turbine degradation that is currently being experienced, as a result a 3% increase in gross output is expected from turbine degradation correction. The costs in terms of energy were calculated using Equation 4.1.

$$KWh/CO2\ Captured = \frac{KWh\ (Loss)}{CO_2\ Captured} \tag{4.1}$$

The energy costs in kWh per tonne of CO_2 captured were evaluated for three parameters: gross output increase due to modifications done concurrently with the CCS retrofit, regeneration steam requirements and capture island auxiliary loads. Comparisons between BD3 and Shand CCS are summarized in Fig. 4.1 These outcomes can be explained as follows:

- BD3 was at the end of its life, and as such, more extensive modifications were done concurrently with the CCS retrofit, enabling a greater increase in the existing facility's gross output. This can be generally attributed to improved performance of equipment that was replaced due to its age,

- The capture system applied to the Shand facility has a simpler flow sheet which results in lower auxiliary loads at the cost of additional steam consumption by the CO_2 system
- The amine based SO_2 removal system on BD3 (as opposed to the limestone system on Shand) increases the auxiliary load requirements for BD3. However, overall steam requirements are decreased on BD3, even though additional steam is required for SO_2 amine regeneration. Although not portrayed in Fig. 4.1, this increase in energy consumption is offset by the benefit of lower consumables requirements due to the regenerable nature of amine.

In aggregate, the net change in energy consumption for the Shand facility is greater than BD3 by approximately 5%.

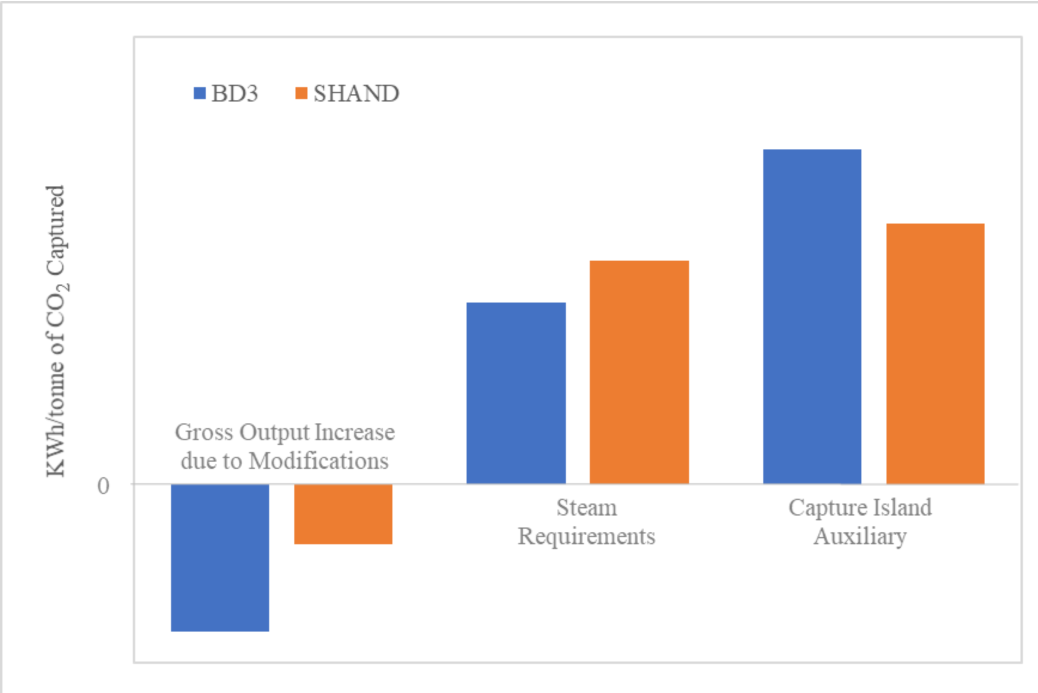

Figure 4.1 Comparing efficiency penalty of CO_2 capture between BD3 and Shand CCS

4.2 Comparing capital costs per tonne of CO_2 captured between BD3 and Shand

Capital costs of the Shand CCS retrofit were determined based on the cost estimate methodology that was in place at the time of the original approval for the BD3 project and includes interest during construction, contingency, owner-controlled insurance program, project and site management as well as transition to operations activities. Costs related to dealing with life management of the existing Shand unit, although relatively minor due to its age, are excluded for consistency with the calculation method.

Capital costs for the CCS portion of the BD3 project had to be determined independently of the life extension work on the power plant. For the power plant, the modification costs necessary to support the capture facility for BD3 as opposed to the life extension costs were estimated based on a review of the line items in the final project budget, and determined to represent approximately 40% of the capital expended in the power island. The cost reduction related to the federal government contributions to the BD3 project, are not included in order to represent a non-subsidized project.

Local taxes and permits have been removed from both project cost estimates for global applicability. The capital cost differential was adjusted to account for 10 years of 2%/year escalation.

Due to the nature of the estimates provided and the system design, both projects contain an SO_2 abatement system, that is difficult to separate from the overall projects. It is worthy of note that the BD3 system produces a sulfuric acid byproduct which is saleable, while the wet limestone FGD in the Shand case will require the purchase of limestone as a consumable.

In order to account for the less efficient heat integration that is proposed for the Shand facility, which was part of the efforts to greatly reduce capital costs, the loss in power generated, or power production penalty, due to capture operations was accounted and converted to a cost value by requiring the project to "purchase" this loss in power based on a non-escalated estimate of the LCOE from a NGCC plant. This methodology would be consistent with a system that is experiencing an expanding electrical demand as is the case locally.

The capital cost for the Shand facility is projected to be 67% less than the BD3 facility on a dollar per tonne of CO_2 basis. This value compensates for the lost energy penalty difference between the two projects. It is worthy of note that factors such as scale, modularization, simplifications and other lessons learned as a result of building and operating the BD3 facility contributed directly to these reductions.

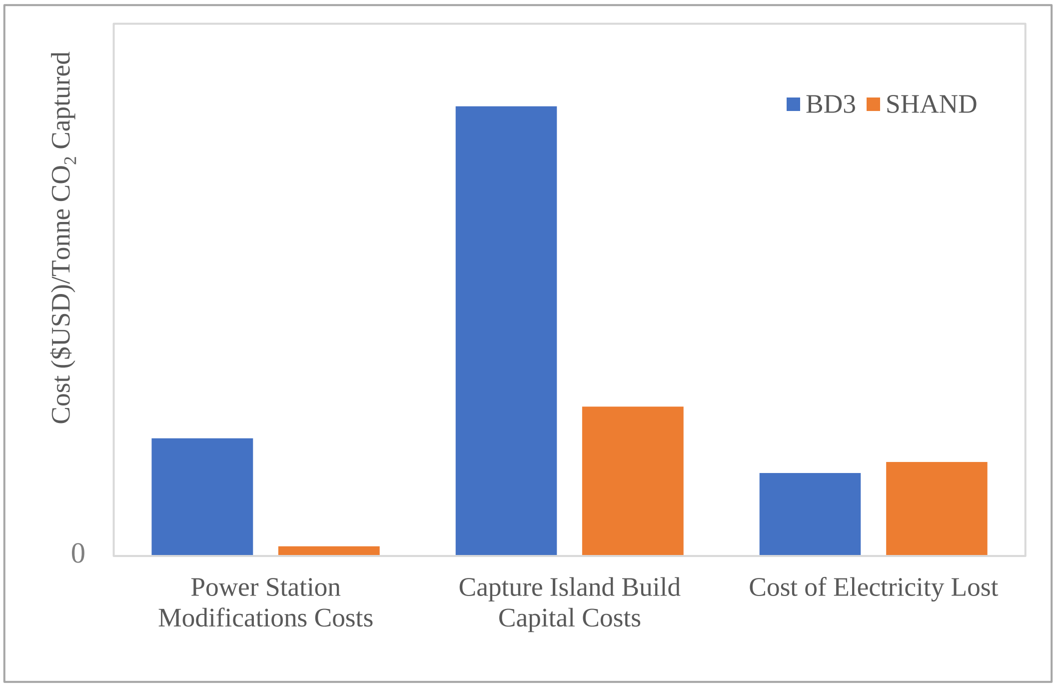

Figure 4.2 Cost reduction of the Shand 2nd Generation CCS facility as compared to the BD3 project

4.3 Determining the levelized cost of capture

Factors considered when calculating the levelized cost of capture included: capture island capital costs, capture island OM&A and consumables costs, the cost of modifications to the power island, and the cost of the power production penalty. Construction of the capture island was set to begin at the start of 2020 and finish with commissioning complete by the end of 2023. CO_2 capture operations were set to commence at the beginning of 2024. A 30-year life span was assumed for this project; values were projected up until the end of 2054.

The levelized cost per tonne of CO_2 captured was calculated using the net present value (NPV) methodology using Equation 4.2.

$$Levelized\ Cost\ of\ Capture = \frac{PV\ Costs}{PV\ CO2\ Captured} \tag{4.2}$$

Where the present value (PV) is calculated using:

$$PV = \frac{Cash\ Flow_{period}}{(1 + Rate\ of\ Return)^{number\ of\ periods}} \tag{4.3}$$

Table 4.2 includes the inputs to the equations.

Table 4.2 Inputs for the levelized cost of capture calculation

Parameter	Value
Discount Rate	5.50%
Escalation Rate	2.00%
Replacement electricity ($/MWh)	65

Net Output prior to CCS (MW)	278.5
Net Output with CCS (MW)	216.75
CO_2 Produced (tonnes per day)	6540

The overall cost for Shand CCS is approximately $45 USD/tonne of CO_2, and by necessity includes the costs related to SO_2 abatement. Costs are attributed to four major divisions (Figure 4.3).

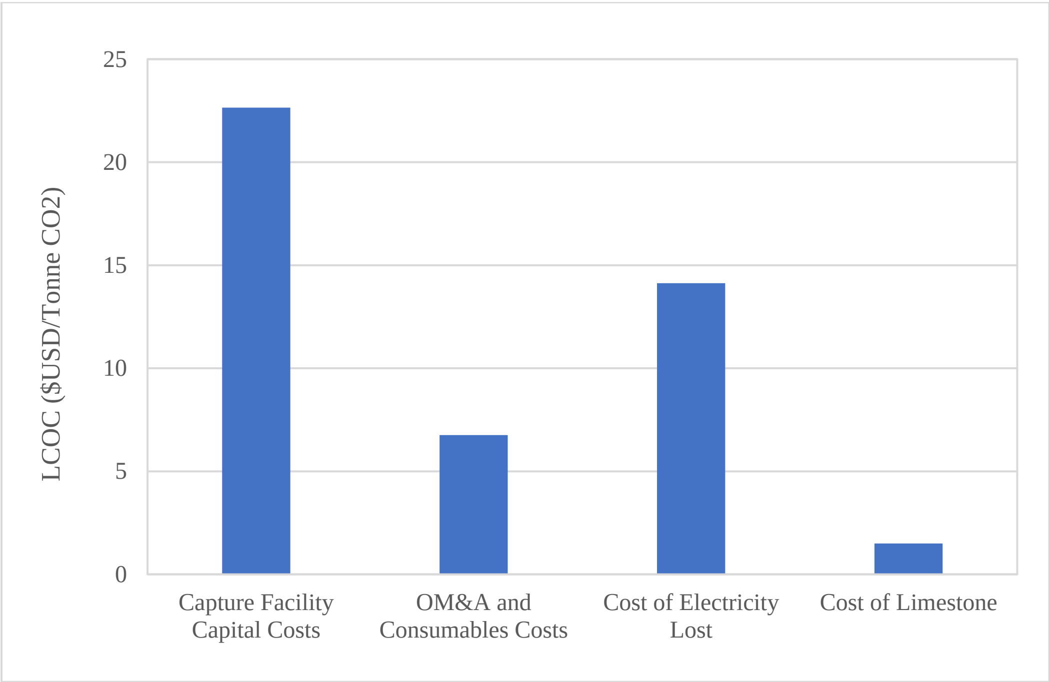

Figure 4.3 Break down of LCOC for Shand CCS

5. Conclusions and future work

Shand Power Station provides an excellent opportunity for an industrial scale CCS facility. Learnings from SaskPower's BD3 CCS project have been utilized to dramatically lower the capital costs of this project. The study has successfully demonstrated favorable economics of size and other factors to reduce the cost of CO_2 capture. The differential between the cost basis of the existing coal station and other viable alternatives, will determine whether the establishment of a CO_2 off-taker market can effectively reduce the cost of capture. Further economic analysis and a CO_2 EOR potential evaluation is required.

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