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Heat integration analysis and optimization for a post combustion CO_2 capture retrofit study of SaskPower's Shand Power Station

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ABSTRACT

Post-combustion CO_2 capture processes require thermal energy (from steam) for amine regeneration. In coal-fired power stations, steam can be extracted from within the steam cycle – resulting in a power production penalty. Heat integration is the study of minimizing energy consumption while maximizing heat recovery; required for successful CCS retrofits. In October 2014, the world's first fully integrated carbon capture facility, SaskPower's Boundary Dam Unit 3 (BD3), went on line. Various modifications to the turbine and feed heating system at BD3 contributed greatly to overall project costs. Novel heat integration strategies can reduce these costs. SaskPower's Shand Power Station (Shand) is a 305 MW, single unit, subcritical, lignite coal-fired power plant producing approximately 1100 kg of CO_2/MWh. Shand's capacity is twice that of BD3's - an ideal candidate for a CCS scale-up project. Using the design of the BD3 facility as a basis, heat integration analysis of the existing steam cycle at Shand was conducted using GateCycle™ with aims to minimize costly modifications to the feed heating system. A baseline model was built using Shand's heat balance and served as the design case. Configurations of steam extractions to the deaerator (DEA), extractions to the reboiler, and utilization of a flue gas cooler (FGC) working in conjunction with a condensate pre-heater (CPH) train were investigated. Optimization of steam extraction to the reboiler and a novel configuration of the condensate preheating train integrated within the LP feed heating system were also accomplished.

1. Introduction

1.1. Shand Power Station and the CCS feasibility study

SaskPower's Shand Power Station was commissioned in 1992. It is a single unit, coal fired power generating station with a gross capacity of 305 MW. Shand has various advanced environmental design considerations including: 1) a finely-tuned burner temperature and enhanced air quantity which reduces nitrogen oxide formations by up to 50 per cent, 2) a closed-loop, zero-discharge water management system that ensures no facility water is discharged into the environment, except through evaporation, and 3) a high efficiency electro-static precipitator (ESP), which acts as a giant dust collector to remove over 99 per cent of the fly ash before it leaves the power station's stack. Shand is SaskPower's newest 300 MW unit. SaskPower's other "sister units" in the 300 MW range include Boundary Dam Power Station Unit 6 and Poplar River Power Station Units 1 and 2. The assumptions for Shand's current operating performance are summarized in Table 1.

The CCS retrofit of SaskPower's Boundary Dam Unit 3 (BD3), located outside of Estevan Canada, was the world's first fully integrated, utility scale carbon capture facility on a coal fired power station. Shand Power Station, located 14 km away from Boundary Dam Power Station, utilizes the same fuel source, and is approximately double the size of BD3. Shand is an ideal candidate for an upscale CCS retrofit project based on the original design of the BD3 CCS retrofit design. Various design details from the BD3 CCS integration were used as the basis for the design of the Shand CCS feasibility study and greatly influenced the optimizations presented in this paper. The feasibility study was carried out by Mitsubishi Heavy Industries (MHI), Mitsubishi Hitachi Power Systems (MHPS) and the International CCS Knowledge Centre. The study evaluated retrofitting Shand Power Station with MHI's KM CDR™ process. This paper presents some of the heat integration studies

Abbreviations: CCS, carbon capture and storage; CEP, condensate extraction pump; CO_2, carbon dioxide; CPH, condensate preheater; DEA, deaerator; FG, flue gas; FGC, flue gas cooler; FGD, flue gas desulphurization unit; FPT, flow pressure temperature modifier; FWH, feed water heater; HP, high pressure; IP, intermediate pressure; KM CDR, Kansai Mitsubishi carbon dioxide recovery process; LMTD, log mean temperature difference; LP, low pressure; MCR, maximum continuous rating; MDF, maximum design flow; MHI, Mitsubishi Heavy Industries; MHPS, Mitsubishi Hitachi Power Systems; NPV, net present value

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Table 1
Shand Power Station current operating performance.

Operating Parameter	Value
Gross output (MW)	305
Auxiliary load (MW)	26.5
Net output (MW)	278.5
Fuel input (MJ/hr)	3230
Gross unit heat rate (kJ/kWh)	10590
Net unit heat rate (kJ/kWh)	11598

undertaken over the duration of the study.

1.2. The steam cycle

Thermal power plants produce electricity by manipulating the behavior of steam. The main components of a thermal power plant include a boiler, a series of turbines (high-pressure, intermediate-pressure and low-pressure), a condenser, low-pressure feed water heaters (LP FWH), a Deaerator (DEA), and high-pressure feed water heaters (HP FWH). A fuel source is combusted in the boiler to provide thermal energy to incoming feedwater which creates steam. In the case of coal fired power plants, this energy is derived from the combustion of coal. The coal is burned in the boiler's furnace then the hot flue gas generated exchanges thermal energy to the feed water to generate superheated steam. The superheated steam is fed to a series of turbines. Once the steam enters the turbines, it expands. The high pressure and kinetic energy of the steam act on the turbine blades and turn the turbine shaft allowing the turbine to generate work which will be converted to electricity in the generator. The exhaust steam exiting the LP turbine flows to a condenser where the low-pressure steam is condensed. The condensed steam is removed from the condenser by condensate extraction pumps (CEP) and pumped through low pressure feed water heaters before entering the deaerator. The CEPs develop sufficient head to deliver the condensate to the DEA which is located at an elevated location within the plant in order to provide adequate suction head for the Boiler Feed Pump (BFP), which pushes the feedwater through the HP FWHs and back to the boiler. FWHs function to preheat the condensate (or boiler feed water) prior to it reentering the boiler. FWHs extract steam from the turbines to accomplish this. The DEA is located between the LP and HP FWHs, and as its name implies, its purpose is to remove dissolved gases from boiler feed water (Sanders, 2004). The combined arrangement of the LP FWHs, the DEA and the HP FWHs are often referred to as the feed heating train. The condensate's enthalpy is progressively increased as it passes through the feed heating train. Optimization of the feed heating train is essential in increasing the efficiency of the thermal cycle.

1.3. Modifications to the steam cycle for CCS integration

In a solvent based, post combustion, fully-integrated commercial scale CCS coal fired powered plant, steam is extracted from within the

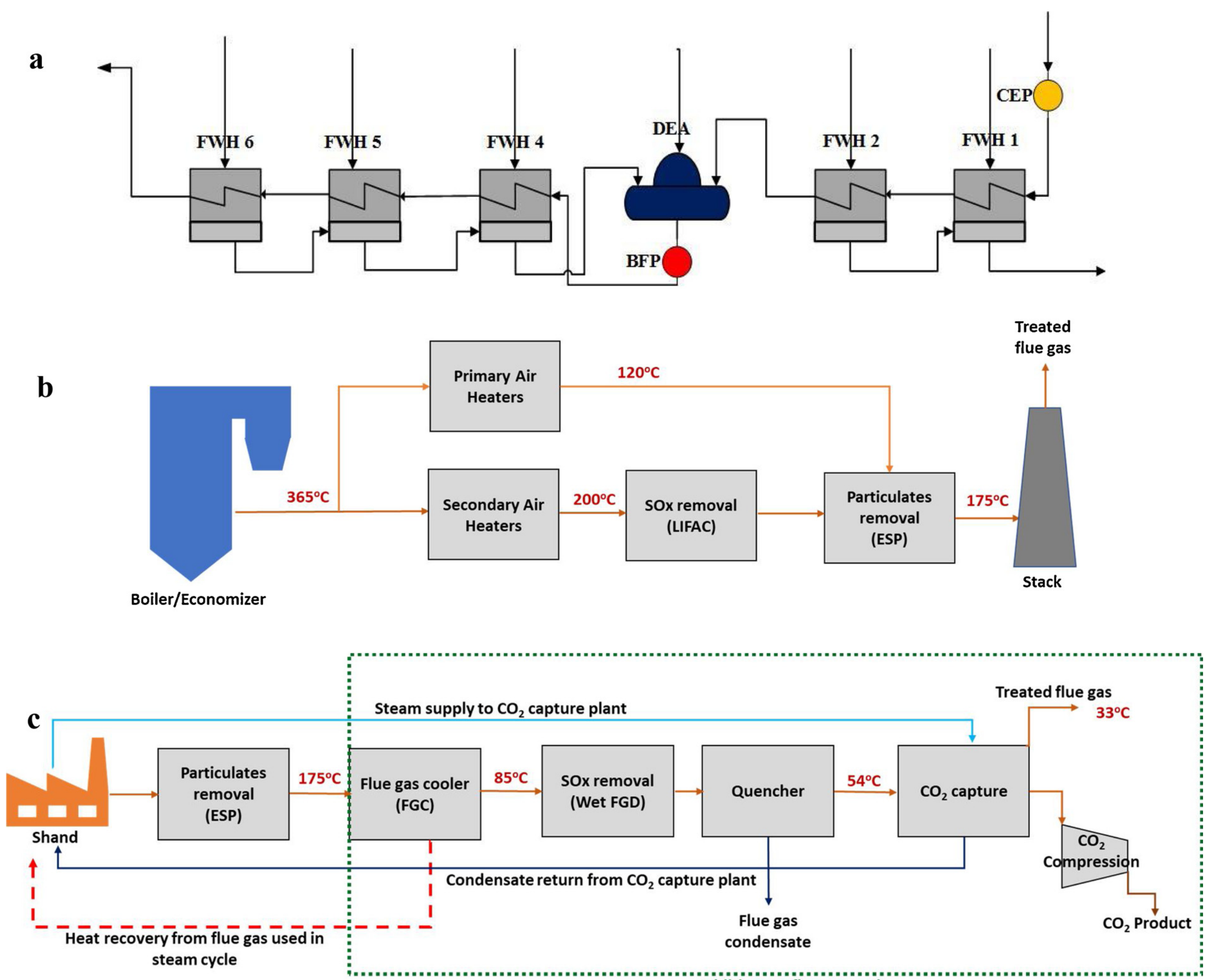

Fig. 1. (A) Feed heating train. (B) Current flue gas path at Shand power station. (C) Proposed additions to flue gas path clean up with CCS retrofit at Shand power station highlighted within the box.

steam cycle for use in the reboiler of the capture facility. Additional intermittent steam extractions from either the hot or cold reheat lines can also be required for use in a reclaimer (provided that the process configurations includes one). These extractions impose a cost to the net output of the power plant often referred to as the power production penalty or parasitic load (Lucquiaud and Gibbins, 2011). The extracted steam returns to the steam cycle from the capture island as condensate and is often referred to as condensate return. This returning condensate is tied back into the power plant's condensate system. The condensate return has a higher enthalpy than the condensate in the power plant. Considerations for the tie in location must be made. In the case for Shand CCS, the capture island condensate is tied back at the inlet of the DEA and mixes with the power plant condensate as it emerges from the LP FWH train.

Prior to entering the capture facility Flue Gas (FG) must be cooled to a desired temperature for favorable reaction kinetics and to avoid thermal degradation of amine (Gouedard et al., 2012; Rinker et al., 1996). This rejected heat can be repurposed for power plant condensate preheating through heat integration methods. Reducing the power output penalty associated with carbon capture is the main motivation behind heat integration strategies. Various approaches have been investigated in the literature pertaining to heat integration strategies for improved energy efficiency and reduced energy cost (Soundararajan et al., 2014; Garlapalli et al., 2018; Lucquiaud and Gibbins, 2011; Oh et al., 2018).

The rejected heat from the FG is low grade and available in excess; applications to utilize the full amount of this heat are limited. The focus of this study was to maximize the utilization of this low-grade heat. A decision was made to utilize FGC technology as it provided other benefits such as mitigation of aerosols. Other FG temperature reduction techniques such as direct quenching can facilitate formation of aerosols (Mertens et al., 2015). A FGC was also utilized at BD3. The current flue as path at Shand is depicted in Fig. 1B while the proposed additions to the flue gas path with a CCS installation is depicted in Fig. 1C.

2. Model development

The steam cycle of Shand Power Station was modelled using GateCycle™ software, which uses a component approach to model various systems pertaining to combined-cycle and fossil boiler power plants. Two modes are available with the GateCycle™ software; "design" and "off-design". The on-design mode allows users to build processes according to desired design specifications. The built-in off-design correlations enable users to quickly and accurately predict component and system performance at various operating points. Equipment additions cannot be made to the off-design case models. All intended equipment components for heat integration purposes must be built into the design model and placed on by-pass. Input to these pieces of equipment can then be assigned and altered in the various off-design case models.

In power plant design, MCR is the maximum output that a power station can continuously generate under normal conditions over a year while MDF indicates the maximum output the power station is designed to deliver. For this work an initial design model was built by referencing Shand's MDF heat balance in design mode. The plant normally runs at MDF load, therefore MDF was also used for overall performance evaluation and optimization. Various off-design "case" models were generated by setting certain components in "off-design" mode. In specific the HP, IP, and LP steam turbines were set to "off-design" mode in all the heat integration models. This ensured that all steam turbine parameters are held constant and prevented GateCycle™ from altering their input design parameters. This enabled proper modeling of the turbines allowing the user to observe performance changes within the steam cycle when implementing various heat integration techniques. Heat integration techniques involved modifications to the feed heating train; to this extent the low-pressure and high-pressure feed water heaters along with the deaerator were left on "design" mode for heat integration modelling. A reduced load case based off the 75% MCR heat balance was also modelled using the off-design mode.

3. Optimizing the steam extraction to the capture facility

3.1. Modelling the steam extraction to the reboiler

This study evaluated the use of MHI's KM CDR Process™ for a CCS retrofit of Shand Power Station. As such a model of the capture facility was not required; all necessary capture facility inputs were based off an industrial scale post combustion capture facility and were provided by MHI. Power plant performance while providing the necessary energy requirements for the capture process became the focus of this investigation. The effects of the steam extraction to the capture facility on the steam cycle were investigated using a model component in GateCycle™ known as a flow pressure temperature modifier (FPT). This tool is a single equipment icon that allows changes in pressure, temperature and flow rate to be specified. The FPT can model pressure loss or increase, energy loss or energy gain and even flow rate decrease or increase. The important operating parameters therefore include the pressure change of the stream passing through the FPT equipment icon and the specified changes in energy and flow rate. Differences in energy between the inlet and outlet flows of the FPT are reported as a duty, and this duty can be specified which is easier than adjusting the mass flow until the required duty is achieved. As such energy requirements were input rather than steam mass flows when modeling the capture process using the FPT. A splitter was orientated within the IP-LP crossover and upstream of the FPT. Inputs included "down stream flow control" allowing for steam to be directed towards the FPT based on the energy inputs of the FPT. The FPT was designed using the "desired duty" input method. The required reboiler duty was used as the input to the FPT. The quality of the steam exiting the FPT was set to 0; indicating a saturated water stream of condensate exiting the capture facility. This condensate was tied back into the steam cycle's condensate stream between CPH 3 and the DEA as illustrated in Fig. 2. Essentially the FPT removes the required energy from the steam cycle required by the capture process using a single piece of equipment.

3.2. Addition of a butterfly valve in the IP-LP crossover

The performance of a commercial scale capture facility fully-integrated with a coal fired power plant is dependent on the power plant's ability to supply the required steam for solvent regeneration. The point of extraction should be easily accessible as the volume of steam required is large. Steam should be extracted from a point within the steam cycle as to minimize the output penalty; that is, steam should be extracted at the point where the energy density of the steam meets but does not exceed the reboiler temperature and pressure requirements. With this consideration the steam at the IP-LP becomes the preferred extraction source as it has already produced power in the HP and IP sections of the turbine, resulting in the lowest thermal energy density. To this extent, sourcing the steam for the capture facility from the IP-LP crossover was selected for this study.

At reduced loads the pressure in the IP-LP crossover drops and eventually the steam extraction to the capture facility cannot be maintained. This limiting factor prevents continued capture operations at reduced loads. However, increased flexibility of the capture plant can be facilitated by designing the thermal cycle for planned curtailment. The Shand CCS facility would be designed for continued capture operations at full capacity during decreased power plant output; as dictated by a reduction in grid load demand. This is accomplished by inserting a butterfly valve in the IP-LP crossover in between the steam extraction point and the inlet to the LP turbine. Traditionally, butterfly valves are often employed to maintain the pressure at the back end of the IP turbine, thus avoiding costly modifications to the turbine itself, albeit at the cost of reduced efficiency. In the intended design of

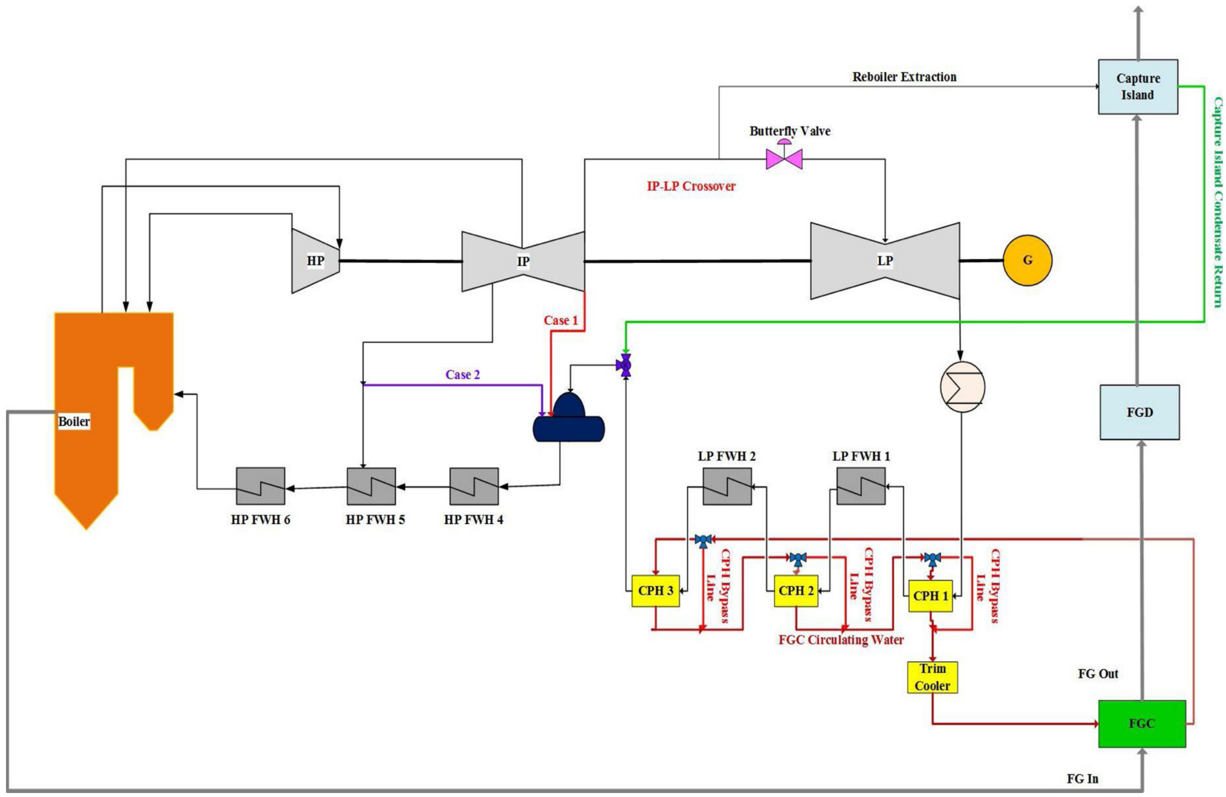

Fig. 2. (A) Steam cycle configurations for reboiler and DEA extractions, and CPH loop.

Shand's steam cycle, the butterfly valve remains fully open at full load to maximize efficiency. At reduced loads, however, the butterfly valve functions to control supply steam at a high enough pressure to continue capture operations by throttling the flow of steam. These modifications were investigated using the GateCycle™ model.

As the power plant load decreases, the quantity of main steam also decreases. The pressure of the steam at the IP-LP crossover also decreases resulting in decreased energy density of the steam to the reboiler. Ultimately the extent of load decrease results in a steam saturation temperature which creates low temperature approach conditions within the reboiler which hinders solvent regeneration. Throttling the steam at reduced loads via the butterfly valve, maintains sufficient energy flow to the reboiler for continued capture operations. Furthermore, reduced power plant load also reduces the overall quantity of steam available within the steam cycle. However, the drop in the desired duty to the reboiler is disproportional, resulting in a greater percentage of the steam consumed for capture operations. The butterfly valve also enables over capture (beyond the 90% capture design parameter) at reduced loads by steam throttling. 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 indicates that CCS equipped coal-fired power plants can be made responsive to variable renewable generation and emits less CO_2 per MWh when doing so, effectively increasing the emission reduction contribution of the renewables.

4. DEA and HP feedwater train modifications

4.1. Modelling the DEA

Deaerators prevent corrosion of steam cycle components by removing dissolved gases from boiler feedwater. A DEA consists of a deaeration section, a storage tank, and a vent. A DEA acts much like a FWH as it also draws steam from the turbine to heat boiler feed water. Steam is drawn to heat the condensate to the full saturation temperature corresponding to the steam pressure in the deaerator to scrub out and carry away dissolved gasses. Depending on manufacturer specifications, steam flow may be parallel, cross, or counter to the water flow (U.S. Department of Energy, 2012). A prescribed minimum temperature rise across the DEA is also included by the manufacturer. For the modeling presented in this paper this temperature rise was set at 15 °C.

Currently Shand's DEA draws its steam extraction from the LP turbine. Integrating Shand with CCS produces a stream of condensate return from the capture facility that ties into the feedwater condensate stream between the LP FWH 2 and DEA. The enthalpy of this return condensate stream is higher than the current feedwater saturation condition. Furthermore, using rejected flue gas heat for condensate preheating increases the enthalpy of the feedwater condensate during capture mode. The combined effects of these two factors produce a hotter condensate stream entering the DEA. The current steam extraction does not have sufficient energy to provide adequate deaeration and temperature rise to the condensate as it passes through the DEA. The steam for the DEA being sourced from the LP turbine limits the quantity of condensate preheating possible and hinders performance. To adjust for this the temperature and pressure of the DEA must be increased by changing its steam extraction source to a higher energy steam. Two sources were evaluated for a new steam extraction to the DEA; the IP exhaust (Case 1), and the extraction line from the IP to FWH5 (Case 2). Each case was evaluated at 100% and 75% loads.

Case 1 involved sourcing the new steam extraction to the DEA from the IP exhaust. This location was chosen as it provides additional heating for the DEA without exceeding the pressure limitations of the current DEA. This configuration allows continued use of the current LP feed heating system equipment to avoid the associated replacement costs. Modelling was completed to determine the maximum amount of condensate preheating that could be accommodated with this new arrangement. The DEA pressure was set to its current design values for the 100% and 75% cases. The DEA extraction was switched to the IP

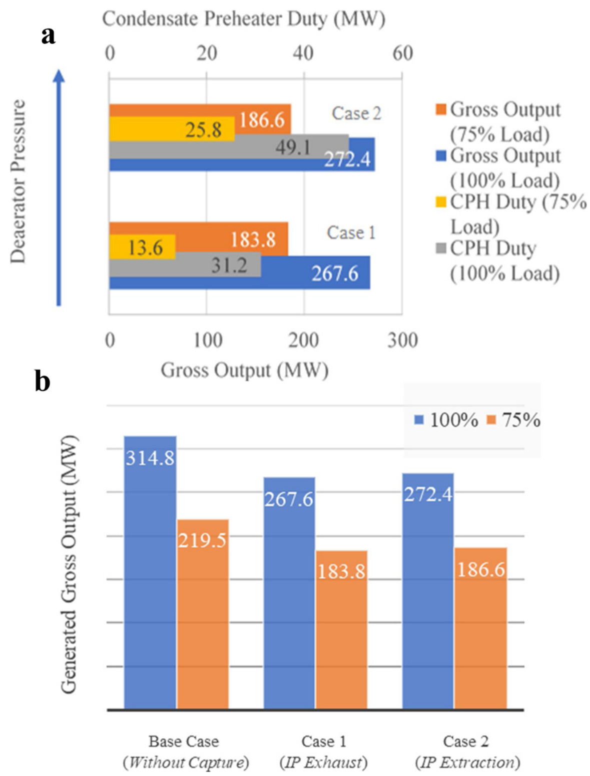

Fig. 3. (A) Effects on the available CPH duty and gross output with increasing deaerator pressure (B) Comparing gross output and CPH duty of cases 1 and 2 with the base case.

exhaust. The duty in the condensate preheating loop was incrementally increased while ensuring the minimum 15-degree temperature rise between the inlet and outlet condensate streams passing through the DEA. This iterative process resulted in a maximum CPH duty of 31.2 MW and 13.6 MW at 100% and 75% power plant loads respectively (Fig. 3)

Case 2 involved sourcing the new steam extraction to the DEA from the IP to FWH5 extraction line. This arrangement greatly increases the temperature and pressure of the DEA allowing for a higher extent of condensate preheating. Using the same iterative process as Case 1, the maximum amount of condensate preheating that can be facilitated from this configuration was determined at 49.1 MW and 25.8 MW at 100% and 75% power plant loads respectively (Fig. 3A).

Sourcing the steam extraction to the DEA from the IP extraction for the FWH 5 yields a 70% increase in pressure and a 14% increase in temperature from current DEA operating conditions. Moving the DEA extraction line from the IP exhaust to an IP extraction increases condensate preheating duty by 57.4% at 100% load and by 89.7% at 75% load. Furthermore, sourcing the steam extraction to the DEA from the IP extraction allows additional recovery of the power production penalty during CCS operations. These changes facilitate a greater extent of condensate preheating, better utilization of "waste" flue gas heat, and an overall decrease in the output penalty to the plant (Fig. 3B).

The configuration described in Case 2 was chosen for the Shand CCS feasibility study. However, sourcing the steam extraction to the DEA from the IP extraction increases the pressure of the DEA beyond its design limits. As such, DEA replacement would be required to accommodate this change. In addition, the increased extent of condensate preheating by increasing the temperature and pressure of the DEA eliminates the need for FWH 4. As such, FWH 4 would be placed out of service during capture operations. Modifications to the HP feed heating system for these accommodations would include bypass lines and additional bypass drain lines around FWH 4. These modifications are estimated at $3.5 million (CAD), which is easily justified by the resulting 4.8 MW increase in net output. Pumps and interconnecting pipework were also evaluated by MHPS. Preliminary investigations verified that the pressure/temperature limitations of the existing pipework were sufficient to accommodate the increased DEA pressure. Replacement of piping would not be needed. Preliminary investigations of the pump capacity indicated that the existing pumps would also be sufficient for the new DEA pressure. Results of these initial finding would need to be confirmed in the FEED phase of this project. If necessary, the cost to increase pump capacity would not jeopardize the economics of this project.

5. Flue gas cooling and condensate preheating integration

5.1. Design theory and considerations

Prior to entering the capture facility, FG must be cooled to a desired temperature for favorable reaction kinetics and to avoid thermal degradation of amine (Gouedard et al., 2012). FGCs are useful heat recovery units that accommodate this removal of heat (Garlapalli et al., 2018; Brück, 2009). Heat is removed (or rejected) from the FG via a FGC and transferred into a closed loop of hot circulating water. A FGC facilitates the transfer of heat from a gas to liquid; due to the nature of this transfer phenomena (between gas and liquid) the size of a FGC needed to service a power plant's flue gas stream is large and will result in significant capital costs. Due to this, it is necessary to perform proper modeling confirming that the use of FGC and condensate preheating reduces the energy penalty by recovering lost MWs. An economic evaluation regarding the NPV associated with the recovery in gross output is also necessary to justify the large capital expenditure of a FGC.

Modelling entailed configuring a closed loop of circulating water between the FGC and the CPH loop. Cool circulating water enters the FGC and cools the flue gas via a gas to liquid thermal energy exchange process resulting in a stream of hot circulation water. Heating of the circulating water provides reasonable approach between the circulating water and the cold condensate. This rejected heat is integrated back into the steam cycle via a CPH loop. Due to the quality of heat recovered from the FG it is optimal to design the CPH loop to meet the requirements of the LP feed heating system. The integration of the CPH loop within the LP feed heating train essentially eliminates the need for LP feed water heaters while the FGC is in service. At BD3, the intention was for LP FWHs 1 and 2 to remain fully out of service and accomplish equivalent feed water heating using the flue gas waste heat while CCS was on line. However, based on operational experience an alternate condensate preheating strategy was investigated for Shand.

The current configuration of the condensate preheating loop at BD3 involves complete bypass of LP FWH 1 and 2 while the FGC is in service. If, however, the FGC comes off line, flue gas is diverted back to the stack (via diverter dampers), the capture island shuts down, but the power plant maintains operations while the LP FWH 1 and 2 remain out of service. There exists a lag in time before LP FWHs can be placed back in service. This creates a scenario where the temperature of the condensate entering the DEA drops. The DEA registers this sudden change and must compensate for this loss in condensate preheating which was previously only supplied by the CPH loop. To do this, the DEA begins to extract additional steam. This creates a differential pressure between the DEA and the turbine extraction which generates extreme flow velocity within the steam extraction line; creating unacceptable conditions for continuous operation. In addition, BD3 was optimized for full load on the capture plant and the power plant, and as the plant runs at partial capture, with a percentage of the flue gas exiting the existing stack, BD3 often runs with condensate heating duty split between the CPH and the LP FWHs. To avoid this for Shand, complete bypass of LP FWH 1 and 2 was avoided. Instead, three smaller CPHs were configured in series with LP FWHs 1 and 2. The "cool" condensate was configured to flow from CPH 1 to CPH 3 while the "hot" circulating water coming from the FGC was configured to flow from CPH 3 to CPH 1; enabling

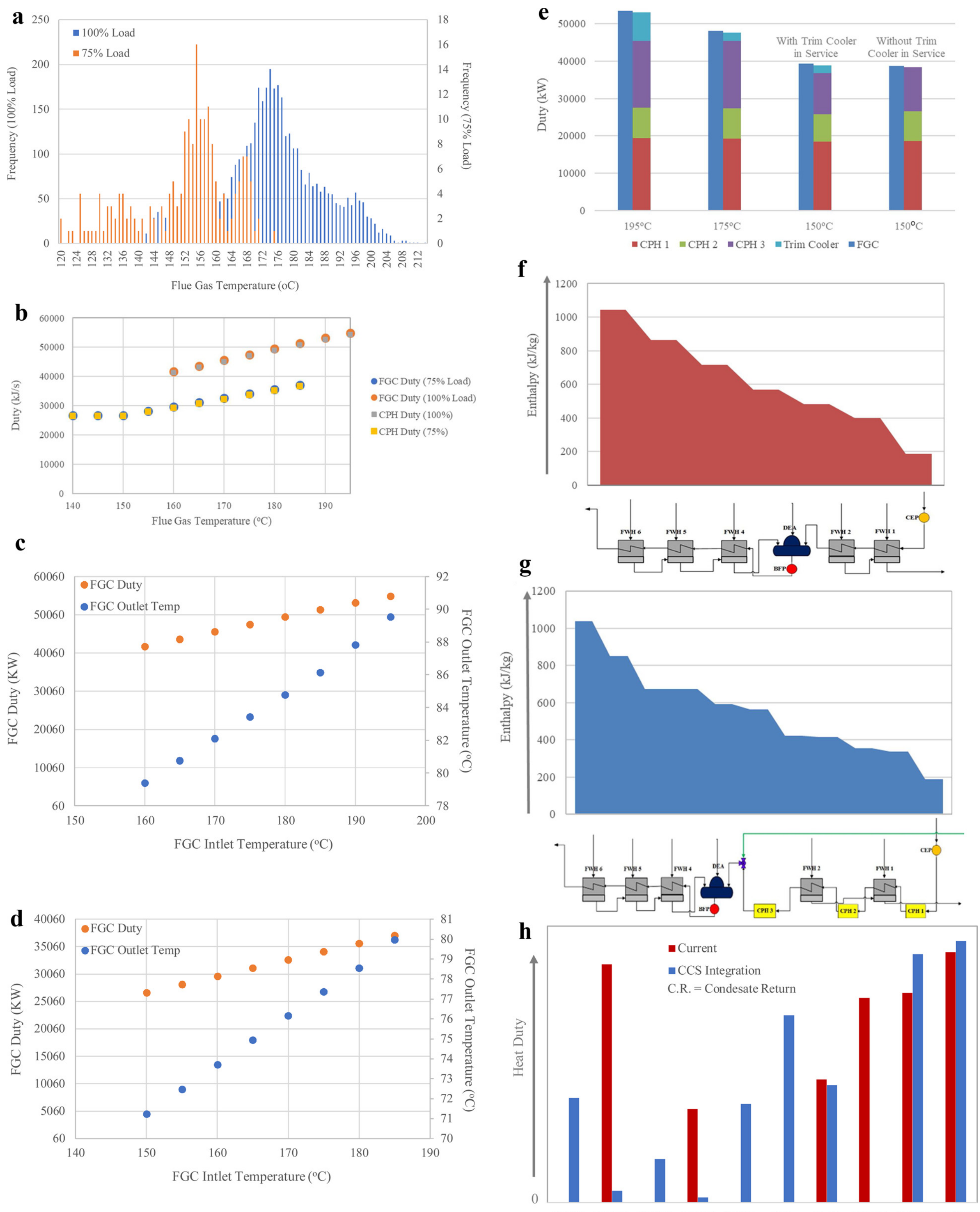

Fig. 4. (A) Stack FG temperature range at 100% and 75% load. (B) Summary of FGC and CPH duty with varying flue gas temperatures at 100% and 75% loads (C) Resulting FGC duty and FGC outlet temperatures with varying FGC inlet temperature at 100% load (D) Resulting FGC duty and FGC outlet temperatures with varying FGC inlet temperature at 75% load (E) Summary of FGC and CPH loop duties at varying FG temperatures (F) Boiler feedwater enthalpy profile of the current steam cycle (G) Boiler feedwater enthalpy profile of the steam cycle with CCS integration (H) Comparing the associated duty for each component in the feed heating train between the current and proposed CCS integrated cases.

countercurrent flow.

A trim cooler was also incorporated for removal of excess heat in the case of higher than usual flue gas temperatures. The CPH train loop was optimized by keeping a 5% duty (based on values from the MDF model) on FWH 1 and 2 while ensuring the 15 °C temperature rise across the DEA. FGC temperatures were input at 150 °C, 175 °C to optimize the sizing of the three CPHs and at and 195 °C to optimize the sizing of the trim cooler.

5.2. Modelling the flue gas cooler and condensate preheaters

The purpose of the FGC and CPHs is to repurpose rejected flue gas heat for preheating of the power plant condensate. Flue gas temperatures dictate the extent of condensate preheating available. A range of flue gas temperatures based on historical FG stack temperatures at Shand observed over a 5-year period (between January 1, 2012 and January 1, 2017) was extracted from the PI Historian Software that SaskPower utilizes to log performance of their fleet. The histogram depicted in Fig. 4A and B summarized the range of available flue gas temperatures and the frequency of their occurrence at 100% and 75% load respectively. The shape of Fig. 4 indicated that the design FG temperature for the inlet of the FGC should be set at 175 °C for the 100% load case while the shape of Fig. 4 suggested a FG temperature of 155 °C for the 75% load case. A lower limit of 150 °C and a higher limit of 195 °C were also selected and subsequently used in optimizing the condensate preheating loop and trim cooler. It is also important to note that Shand is operated as a base load unit and has a capacity factor of 85%. This implies that Shand runs at 100% load most of the time; the data resulting from the full load investigated should be the basis of optimization.

The FGC and condensate preheating train were modelled using a series of heat exchangers. Three main equipment types were modelled; the FGC, the CPHs, and the trim cooler. Although all three types of equipment were modelled using heat exchangers, the design inputs were varied to reflect the variations in performance of each type of equipment. Inputs for the FGC, CPH and trim cooler are summarized in Table 2.

The FGC inputs were based on double the capacity of the FGC in service at the BD3 capture facility. To model this a surface area input double that of BD3's FGC was used. A gas stream was used as one of the two process streams; the other being the circulation water common to both the FGC and CPHs. Shand's FG composition was used as input for the gas stream. Condensate preheating modelling was based on the LP feed heating system design parameters. High pressure condensate preheating (although a valid option) was not investigated in detail due to higher pressure requirements in the feed heating system, increased heat quality needs, and overall increased complexity. Initially, the CPH and trim cooler surface areas were also estimated by doubling the BD3 design values. A single condensate preheater aligned parallel to LP FWH 1 and 2 facilitating complete bypass of LP FWH 1 and 2 during capture operations was modelled in GateCycle™ based on the BD3 condensate preheating loop configuration. This configuration was used to determine the maximum amount of condensate preheating available based on the desired FGC outlet temperature.

Initially, a range of flue gas temperatures were input into the FGC model component; (160–195)°C at 100% load and (150–185)°C at 75% load. The surface area of the FGC was held constant at double that of the FGC at BD3. The size of the flue gas cooler was validated through the initial modeling of the FGC and the condensate preheater. A FGC twice the size of BD3 produced a flue gas outlet temperature of 85 °C when operating with the average flue gas inlet temperature for the 100% load case of 175 °C. The lowest flue gas temperature that could economically be achieved in optimization work for BD3 was 85 °C. FG exiting the FGC enters first into the flue gas desulphurization unit (FGD) and then into a quencher before entering the capture process. Further cooling and final conditioning of the FG is accomplished by the quencher. This ensures FG enters the capture process at the proper temperature. Considering a range of incoming FG temperatures when design the quencher ensures sufficient quencher capacity. For this study this range was (75–95)°C. This allows for increased operational flexibility.

The LMTD and performance of the FGC and CPH within these ranges was calculated. The FG outlet temperatures were evaluated. Resulting heat duties of the FGC and CPH were also extracted from the model. The results of this evaluation are summarized in Fig. 4A–C. Based on this, the FG temperatures of 175 °C and 100% load and 150 °C at 75% load were finalized as the design case values. The corresponding condensate preheating duty available was determined to be 47,240 kW and 31,600 kW at 100% load and 75% load respectively. These values were then used as input for condensate preheating loop configuration and turbine design optimization.

5.3. Minimizing the energy penalty by optimizing the condensate preheating loop configuration

The configuration of the CPH loop as described in Section 5.1 involves positioning CPH 1, 2 and 3 in series with LP FWHs 1 and 2. This enables the full volume of condensate to continue flowing through LP FWHs 1 and 2 but keeps the condensate pre-heating through them at a minimum, while maintaining a minimum amount of extraction steam flow. Keeping the full volume of condensate flowing through LP FHW 1 and 2 allows them to easily resume operations if the incoming condensate temperature drops as a result of a FGC trip, or other scenarios when heat is no longer being supplied to CPHs 1, 2, and 3.

Design criteria considered in CPH loop modelling included 100% load for the power plant, steam extraction to the reboiler at the required duty (as per MHI specifications), and a design FGC inlet and outlet temperatures of 175 °C and 85 °C respectively. The flow and pressure of the circulating water within the CPH loop was adjusted to match that of the power plant's condensate stream. Pressure in the circulating loop should be high enough to prevent boiling within it. However, the pressure should not be too high as it impacts wall thickness, thermal performance, and cost of the FGC plastic tubes.

CPH 1, 2 and 3 were sized by indicating a suitable "cold side outlet temperature" which would allow a duty of 5% to remain LP FWH's 1 and 2. Using an iterative process, the "cold side temperature" value was adjusted until a 5% duty was achieved across LP FHWs 1 and 2. Once the 5% duty on LP FWHs 1 and 2 was established the input method on CPHs 1, 2 and 3 was switched to "surface area". No further changes were made to the inputs of CPHs 1, 2 and 3 and LP FWHs 1 and 2. The trim cooler was then placed in service. The trim cooler's circulating water was designed to tie into the power plant's heat rejection system.

Table 2
Design Inputs for FGC-CPH train modelling.

Equipment	Design Method	Overall Heat Transfer Coefficient (kJ/sec·m^2·K)	Configuration Method
FGC	Surface Area	0.0532	Cross Counter Configuration
CPH	Surface Area (Initially) Cold Side Outlet Temperature	5.5577	Pure Counter Flow
Trim Cooler	Cold Side Outlet Temperature	6.2791	Pure Counter Flow

As such, the circulating water exiting the trim cooler must be held constant at 44.5 °C. The flow of cooling water to the trim cooler was adjusted until a flue gas outlet temperature of 85 °C was reached. Furthermore, adjustments to trim cooler's circulating water flow were required to ensure the minimum 15-degree temperature rise across the DEA.

Once the design case had been optimized the temperature of the flue gas was increased to 195 °C. This was done to ensure adequate sizing of the trim cooler. Using a flue gas inlet temperature of 195 °C satisfies the upper range limit of possible flue gas temperatures and effectively sizes the trim cooler to accommodate excess heat in the case of outlier flue gas temperatures. The trim cooler is orientated before the FGC; its purpose is to reject excess heat from the circulating water prior to it re-entering the FGC. Main reasons for installing a trim cooler include ensuring that the temperature in circulating loop does not exceed economic design temperatures for FGC tubing, as plastic tubes lose significant strength at high temperatures, and to limit the maximum flue gas temperature at the FGC outlet. Recall that once the FG exits the FGC it passes through the FGD and then the quencher before entering the CO_2 capture process. Excess heat in the FG could also be mitigated in the design capacity of quencher. However, the cost of trim coolers is minimal when compared to that of the FGC and FGD. Trim coolers provide an economical solution in preventing thermal related damage to the FGC and lower costs by avoiding excess capacity in the quencher.

To properly size the trim cooler, the surface areas of CPHs 1, 2 and 3 (now optimized) were kept constant while sizing of the trim cooler was adjusted to meet the requirement of a "Cold Side Outlet Temperature" of 44.5 °C. The temperature of the FG was then lowered to 150 °C. The model was run with and without the trim cooler in service at this temperature, results were summarized in Table 3. This was done to evaluate the need of a trim cooler at lower than design case FG temperatures. As indicated in Fig. 4E. at higher FG temperatures more of the heat duty extracted by the FGC is disposed of through the trim cooler. This is due to certain design considerations of the integration to the feed heating system that must be realized. At FG temperatures lower than the design case, condensate preheating availability is decreased. In this case the DEA draws additional steam to make up for this lack in condensate heating resulting in a larger temperature rise across the DEA. This comes at a cost to the power plants gross output as indicated in Table 3. Keeping the trim cooler in service at reduced FG temperatures is detrimental to power plant performance as also indicated in the results summarized in Table 3.

Ideally the design case (FGC inlet temperature of 175 °C) would have no duty on the trim cooler. Duty on the trim cooler during average conditions is not ideal; this indicates that a portion of the recovered heat is simply rejected into the trim cooler. This phenomenon can be attributed to the 5% duty that is kept on LP FHWs 1 and 2. The concept to allow this minimal duty on LP FWHs 1 and 2 was incorporated later in the study. To adjust for this, the surface area of the FGC should be reduced by accounting for the duty provided by LP FWHs 1 and 2 in further optimization steps. Subsequently the trim cooler will also require resizing. Recall that these two components were originally sized by doubling the dimensions of the equivalent BD3 components. These modeling results indicate Shand's FGC should be sized to slightly less than double the BD3 FGC. Sizing of the FGC and trim cooler should only be optimized to maximize heat utilization at average conditions.

Table 3
Summary of CPH train FG temperature optimization.

Flue Gas Temperature (°C)	Total CPH Duty (MW)	Trim Cooler in Service	Temperature Rise Across DEA (°C)	Gross Output (MW)
195	53.04	Yes	14.92	274.62
175	47.64	Yes	14.76	274.65
150	38.78	Yes	22.42	272.49
150	38.30	No	21.46	272.73

5.4. Comparing enthalpy profiles of the feed heating trains with and without CCS

Any modifications to the feed heating train must ensure that the enthalpy of the boiler feed water is maintained to conserve cycle performance and overall efficiency of the power plant. The steam cycle is optimized to ensure that boiler feed water reenters the boiler with enough thermal energy as to not hinder the steam output of the boiler. A decrease in boiler feed water enthalpy requires more work from the boiler and additional fuel input. This reduces the efficiency of the steam cycle and increases the heat rate of the power plant – an undesirable scenario. The boiler feed water enthalpy profiles of the current steam cycle and the steam cycle integrated with CCS are summarized in Fig. 4F and G respectively. The duty comparisons for each component in the feed heating train between the two cases is summarized in Fig. 4H.

Comparisons can be drawn between the two enthalpy profiles. The resulting final enthalpies of the boiler feed water are similar between the two cases. HP FWH 6 and the DEA also experiences similar duties in both cases. Taking HP FWH 4 out of service during CSS operations forces HP FWH 5 to increase the volume of its steam extraction to compensate for the duty make up requirements. The LP feed heating requirements are compensated for by CPH 1, 2 and 3, however the total duty of the LP feed heating system resulting from the LP feed heating equipment is lower for the CCS integrated case; this is compensated for by the large extent of duty supplied by the stream of condensate returning from the capture facility (condensate return). The condensate return has a higher energy density than the power plant condensate stream that it ties into. As such, this higher energy condensate return greatly contributes to boiler feed water warming. The GateCylce™ model of Shand's current steam cycle indicated boiler feed water reentering the boiler at 1041.7 kJ/kg. The model resulting from CCS integration produced a reentering boiler feed water enthalpy of 1036.8 kJ/kg. The models also indicate that the CCS integrated model experiences a 3.7% decrease in overall duty within the entire feed heating train. This can be attributed to operational changes in the LP feed heading train when CCS is on line. During CCS operations the DEA experiences an 87% increase in pressure and a 17% increase in temperature. Changes in the DEA operating parameters combined with the preheating effects of the condensate return changes the feed heating profile of the LP feed heating train.

5.5. Limitations in condensate preheating

When applying heat integration techniques to pre-exiting facilities, such as a power plant, various limitations arise from the design parameters of the power plant. The maximum amount of condensate preheating is dictated by the following factors:

Design pressure of the DEA

- The design pressure of the DEA limits the extent of low pressure condensate preheating. Although DEA replacement is possible, challenges could be encountered in the requirement for more costly materials, or alternate designs, to manufacture a DEA with increased pressure and temperature design limits.

% Duty on LP FWH 1 and 2

- Maintaining the 5% duty on LP FWHs 1 and 2 can also limit the extent of CPH. Exceeding the designed amount of condensate preheating produces a hotter stream of condensate. When entering LP FWHs 1 and 2 this hotter condensate stream can essentially shut off the steam extraction to LP FWHs 1 and 2 and eliminate the 5%

minimum duty. This would cause the FWHs to run dry. Installing bypass temperature control valves to adjust the amount of heat transfer through each of the CPH can ensure that the LP FHWs continue to consume a small amount of steam.

Minimum Temperature Rise Across the DEA

- The minimum 15 °C temperature rise across the DEA is needed for maintaining the steam draw into the DEA for adequate deaeration. This requirement limits the quantity of the rejected heat that can be incorporated into LP condensate preheating. Exceeding the designed amount of condensate preheating produces a hotter inlet stream of condensate which results in decreased steam draw to the DEA. To avoid this, as was done with the LP FWHs, a CPH bypass will limit the amount of preheating. In order to reject enough heat for the FGC to work as intended, the trim cooler must be adequately sized to reject the heat not used in the CPHs.

Capital Costs

- Capital costs of LP and HP feed heating modifications, and installation of new CPHs, trim coolers and a FGC are significant. Increased capital costs must be considered and weighed against potential increases in revenue realized by decreasing the output penalty through condensate preheating.

5.6. Considerations for alternative heat integration strategies

This paper presents a case for the integration of flue gas waste heat for low pressure condensate preheating using a FGC. The decision to utilize this particular source of lower grade waste heat was based on maximizing the efficiency through heat integration strategies for a Shand CCS retrofit. The implementation of a FGC for low pressure condensate preheating was chosen for two primary reasons: 1) flue gas cooling offers the greatest quantity of higher quality waste heat available for integration and 2) condensate preheating utilizes a greater quantity of this flue gas waste heat.

Other integration strategies could be available. Some evaluation on alternate heat integration strategies was investigated. Discussions are presented below:

1) Utilizing recovered flue gas heat in the stripper

Recovered heat from the flue gas cooler could alternatively be used within the capture process by supplying some heat to stripper. However, only the higher quality portion of this recovered waste heat would be available to be used in the stripper given the operating pressure and temperature of the given stripper design used in the KM CDR™ process. Comparatively, the restrictions associated with steam quality apply to a lesser extent on condensate preheating therefore allowing a higher quantity of this waste heat to be used. Other stripper designs and/or configurations requiring lower regeneration energy could make better use of a larger quantity of this waste heat (Rezazadeh et al., 2016).

Both methods reduce the overall quantity of steam extracted from the turbine. The ability to utilize this waste heat for the CO_2 stripper reduces the amount of steam extracted from the IP-LP crossover whereas utilizing this heat for condensate preheating minimizes the low-pressure steam bleeds to the LP FWHs. However, in the case of condensate preheating the lower quality steam extraction to the LP FWHs is completely replaced with the waste heat (save for the required 5% minimum duty) that would otherwise be too low in quality/pressure to completely off set the stripper duty requirements.

1) *Utilizing recovered flue gas heat from within the capture process*

Many sources of low quality waste heat exist within the capture facility, for example the stripper overhead condenser. However, there are few uses or sinks for this very low-quality heat. Condensate preheating is one such sink for waste heat but can only absorb a limited quantity of low-quality waste heat (primarily in the LP condensate preheating section) before needing progressively higher quality heat inputs (as indicated in Fig. 4H).

1) *Utilizing compression heat*

Heat can also be recovered from the CO_2 compressor and used for condensate preheating. This option was considered in the preliminary stages of this study. However, a smaller quantity of usable heat would be recovered from the compression system and in order to maximize efficiency additional heat from the flue gas would need to supplement the CPH. Rather than using two systems to supply condensate preheating the economics favored maximizing the size of the FGC and using a single system. Furthermore, the belief that flue gas cooling mitigates aerosols, which contribute to emission issues, was also considered in the selection of a FGC. At the cost of efficiency, maximizing the use of only compression heat could be investigated further. A cost comparison between the sources of heat for CPH could present a case in favor of compression heat integration.

1) *Flue gas reheating*

Recovered flue gas heat could also be employed for flue gas reheating using a gas to gas heat exchanger. This is commonly done in areas where plume mitigation is required. In the case of Shand this is not a regulatory requirement; although the use of a gas to gas heat exchanger could be utilized for heat rejection purposes in place of the FGC, effectively reducing the duty on the other heat rejection systems. Waste heat that is not integrated into the process and converted to electricity must be rejected. Additional capacity for heat rejection may not be available at some facilities. At Shand the heat rejection system operates at capacity. Furthermore, additional water draw from the local dam that sources Shand's cooling water is limited.

However, it is important to note that gas to gas heat exchangers often suffer from leakage which could potentially lead to higher maintenance costs and even impair CO_2 capture rates by allowing CO_2 or flue gas to bypass the capture process. Further process, cost, and risk evaluations on the use of a gas to gas heat exchanger in place of a FGC could be done. If the economics are favorable the costs savings associated with using a gas to gas heat exchanger in place of the FGC could justify reducing the efficiency requirement.

As a producer of electricity, a main deliverable of a CCS retrofit for Shand was to limit the parasitic load. Overall, flue gas waste heat was the highest quality heat available and allowed for the greatest quantity of heat integration which maximized efficiency. Low pressure condensate preheating was selected as it offered the greatest gains in electrical output generation which are more than justified by the capital costs required to implement the required modifications. Other strategies could be explored further. If significant cost savings could be realized by foregoing the use of a FGC and using only a smaller quantity of heat from other low grade heat sources for condensate preheating, the requirement to maximize efficiency may be reduced.

6. Conclusions and future work

Heat integration is the study of minimizing energy consumption while maximizing heat recovery; required for successful CCS retrofits. When retrofitting an existing power plant with a fully integrated carbon capture facility the steam extraction for amine regeneration imposed on the power plant results in an output penalty. Flue gas must also be cooled prior to entering the capture process. This rejected waste heat, however, provides an opportunity for heat integration practices within the power plant which minimize the loss in net output while increasing the efficiency of CCS. A heat integration strategy for SaskPower's Shand Power Station was investigated in this work. The performance of the steam cycle was investigated using GateCycle™. The extent of condensate preheating was determined to be 47,240 kW and 31,600 kW at 100% and 75% loads respectively. A novel configuration for condensate preheating integration to the LP feed heating system was also evaluated. Configuring three smaller CPHs in series with LP FWHs 1 and 2 instead of completely bypassing LP FWHs 1 and 2 during capture operations facilitates easier transition between capture and non-capture operations, allows for partial flue gas capture mode, and reduces stresses on equipment downstream of the condensate preheating loop.

The need to provide integration with intermittent renewable energy sources requires designing units to adjust their load to maintain the supply-demand balance in the electricity grid and is key in the future operations of large coal fire power stations. Continued capture operations at reduced loads is essential. The insertion of a butterfly valve in the IP-LP crossover downstream of the steam extraction point enables steam throttling at reduced loads which provides steam with enough energy to continue capture operations at full capacity. This increases the operational flexibility of the power plant by allowing it to respond to load demand changes.

The next phase of this study should include further optimization of the CPH loop. Specifically, FGC and trim cooler sizing should be adjusted to eliminate the duty on the trim cooler during design conditions (FGC inlet temperature of 175 °C). This will result in a higher FGC outlet temperature which will also require an increase to the capacity of the quencher.

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