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Heat rejection design for zero liquid discharge Shand coal-fired power station integrated with CO_2 capture and storage

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ABSTRACT

The integration of CCS to a coal-fired power plant not only results in the increase in water consumption and cooling duty, but also additional water discharge especially from cooling the flue gas to the much lower temperature required for the CO_2 capture process. This paper presents the design of a heat rejection system for the Shand Power Station that maintains a neutral liquid impact on the existing plant while adding SO_2 and CO_2 capture processes. Moreover, the effect of temperatures throughout the year on heat rejection load and power consumption is investigated. The heat rejection systems were designed and optimized by using Aspen HYSYS and Aspen EDR to accommodate 245 MWth which is the additional heat rejection required for the CO_2 capture process, assuming that flue gas pre-cooling is accomplished from an external source. In the case of this study, the flue gas cooler heat integration, and a quench system serviced by cooling duty which is offset from the existing unit condenser due to the integration steam source provides the required flue gas pre-cooling.

The hybrid heat rejection system, which uses a dry cooler in series with a wet cooler, cools the CO_2 capture plants circulating water loop from 44.5 °C to 25 °C. The wet cooling is by a Wet Surface Air Cooler (WSAC), in order to provide a second layer of protection to ensure that none of the CO_2 capture chemicals will be inadvertently released to the environment. The design dry bulb and wet bulb temperatures are based on the 85 percentiles of the Estevan's weather data for 26 years from 1991 to 2017, and are 18 °C and 13.7 °C respectively. Water produced by the capture process was utilized as the primary source for the wet cooling in order to avoid increasing the overall water draw of the facility. Using the dry cooler for rejecting the higher grade heat, and the WSAC for the lower grade heat improves cooling water temperature, while also maintaining Zero Liquid Discharge (ZLD) status. The heat load on the dry cooling and wet cooling is 156.5 and 81.8 MWth which corresponds to 67 and 33% of the total heat respectively.

The effect of annual variations in dry bulb and wet bulb temperatures on the heat load of the hybrid cooling system was investigated by using Thermoflex. It was noted that the annual average heat rejection load shifted toward wet cooling system due to the lower temperature and the need to evaporate water available from the CO_2 capture process with the percentage of 58% for dry cooling and 42% for wet cooling. This resulted in reduction of fan power requirements. The average fan power consumption throughout a year is 2.58 MW which is only 52% of the design case (4.96 MW).

1. Introduction

The International Energy Agency (IEA) indicates that large-scale carbon dioxide capture and storage (CCS) is one of the technologies capable of significantly reducing carbon dioxide (CO_2) emissions. Capturing the most carbon possible using an affordable technology is key for CCS to be considered a major climate change mitigation option (McCulloch, 2016). However, there exist challenges that must be overcome to improve the economics of this technology. Implementation of technical modifications and process optimizations can decrease the overall costs of capture. For instance, heat integration between the host coal-fired power plant and the capture facility can minimize the power production penalty to the plant. Implementing cost effective management strategies to combat operational issues, such as amine

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Nomenclature

CCS	Carbon dioxide capture and storage
COC	Cycle of concentration for wet cooling tower
FGD	Flue gas desulphurization
FGC	Flue gas cooler
WSAC	Wet surface air cooler
ACHE	Air cooled heat exchanger
ZLD	Zero liquid discharge
LSI	Langelier Saturation Index
TDS	Total dissolved solid
W_{Shand}	Additional water obtained from Shand existing cooling system
W_{WSAC}	Water available for wet cooling system
W_Q	Quencher condensate
W_{FGC}	Water used in flue gas cooler washing
W_{SWP}	Water flow from Soft water pond
η_{VCE}	VCE return efficiency
f_{Evap}	Evaporation factor from blowdown pond
W_{FGD}	Make up water for wet FGD

degradation and foaming, are also required. Significant challenges also arise with the issue of additional water and cooling requirements. Unique challenges can arise as many plants have limited access to water and/or are operating under a Zero Liquid Discharge (ZLD) permit. Although ZLD operations provide unique challenges, this operational practice provides solutions to the environmental challenge of eliminating wastewater while also minimizing water consumption within the plant. ZLD operations hold merit and should be maintained when implementing a CCS retrofit to an existing power plant. A feasibility study between Mitsubishi Heavy Industries (MHI) and the International CCS Knowledge Centre was conducted on retrofitting Shand Power Station (Shand) with MHI's KM CDR™ process. This paper presents the design of a heat rejection system for Shand that maintains the ZLD operation, and requires no additional water, while adding sulphur dioxide (SO_2) and CO_2 abatement technology.

1.1. Heat rejection design theory

Thermal power plants require significant quantities of cooling. The choice of cooling system, and the restrictions from regulations and operating permits vary from site to site. Three main types of cooling systems commonly used in thermal power plant are once through water cooling, evaporative cooling and air cooling (Almås, 2012).

1.1.1. Once through water cooling

Once through water cooling systems draw cool water from open sources, such as rivers, oceans or dams, to circulate for cooling requirements. Cool water is drawn from these open sources and integrated into the cooling loop of the power plant. Heat is then rejected into this water producing a higher temperature water stream. This higher temperature stream is then returned to its original source where the heat it has acquired is dissipated into the environment. This is typically the most economical type of cooling, however, this system is not suitable for power plants in areas with limited water or where increases in the water temperature to the source cannot be tolerated for environmental reasons.

1.1.2. Evaporative cooling

An evaporative cooling tower is used when sufficient water is available to provide the cooling required, but there is no large reservoir, or there is a limitation on the return water temperature to the reservoir for environmental reasons. Evaporative cooling towers rely almost exclusively on latent heat transfer, and as such consume more water than reservoir cooling which can expel heat by sensible heat loss as well as latent heat loss.

In a wet cooling tower, warm water is sprayed into the tower. This water contacts air rising from the bottom of the towers in counter current fashion. Heat transfer takes place between water and air at the water-air surface interface. This occurs at the adiabatic saturation temperature of the ambient air which is referred to as the wet bulb temperature and is theoretically, the lowest temperature that the water can reach. Consequently, the wet bulb temperature sets a lower limit for the cooling water temperature. The evaporation of water to the unsaturated ambient air causes a reduction of water temperature. Water is evaporated until the air is saturated with water vapor and exits at the top of the cooling tower. Cooled water is collected in the bottom of the tower and returned to the power plant for process cooling.

This evaporative process causes the concentration of salts and other impurities to increase in the circulating water (as pure water is evaporated). To avoid buildup of solids and other undesirable components within the cooling tower, water needs to be blown down and replaced with fresh makeup water. The amount of blowdown water depends on the water quality and total Cycles Of Concentration (COC). COC indicates how many cycles or times that a specific volume of water can be used before blowdown from the cooling tower is required (Almås, 2012). The concentrating of salts and impurities in the cooling tower can cause scale formation, blockages and corrosion to the cooling tower and equipment within the water recirculating system. Therefore, when the impurities become concentrated, they need to be removed from the system. To monitor salts and impurities in the cooling water, parameters are used as indications such as pH, hardness by measuring the combination of calcium and magnesium concentrations, Total Dissolved Solid (TDS), and Langelier Saturation Index (LSI) which is an indicator of corrosion and scale forming potential of the water. Once the water quality reaches the limit of indicator parameters, it will be blown down (JEA, 2005). Drift losses due to entrainment of fine water droplets in the discharged air are also a source of water loss, however, for newer cooling towers, the drift losses can be as low as 0.001% of the circulating water. The evaporation, blowdown and drift losses experienced by a wet cooling tower must be compensated through makeup water.

1.1.3. Air cooling

In an air cooling system, heat transfers from cooling water to the cooling airstream by extended surface or fins. The performance of the air cooler is determined by the dry bulb temperature of the air unlike wet cooling systems where performance depends on the wet bulb temperature. Dry bulb temperature is higher than wet bulb temperature and can be drastically effected by seasonal change. The movement of cooling air is usually accomplished through the use of fans. This cooling system does not require makeup water however, its power consumption is high due to the electricity required to operate the fans (Kröger, 2004).

1.2. Heat rejection with a coal fired-power plant integrating CCS

Integrating CCS with an existing coal fired power plant increases the heat rejection load of the overall facility. Almås (2012) evaluated water used in an integrated coal fired power plant equipped with amine based post combustion CO_2 capture. It was found that large amounts of water are required when adding CCS to a coal fired power plant. If the heat rejection system of the plant is operating with mechanical draft wet cooling towers, 87% of the additional water will be consumed in the cooling tower, 11% will be used in FGD make up, 1% will be used for boiler blow down and 1% will be used for amine plant makeup. Large amount of water requirements will not be a challenge if the plant is located near water resources and once through cooling is an option.

However, the design of the heat rejection system in each plant will mainly depend on water availability and the usage permit. This indicates that the solution to increased heat rejection capacity for CCS integration is host power plant dependent and varying solutions are possible.

Ustadi et al. (2017) investigated three options for a cooling system which used sea water as cooling water in a post combustion CO_2 capture process using monoethanolamine solvent. The investigation was focused on the costs of heat exchangers and utilities including water and power consumption. These options included the use of sea water through shell and tube heat exchangers, the use of air coolers, and a hybrid cooling system which combined the use of air coolers and shell and tube heat exchangers. It was discovered that when using shell and tube heat exchangers, the utility cost is higher than the cost of heat exchangers. When replacing the shell and tube heat exchangers by air coolers, the capital cost increased significantly due to the low heat transfer coefficient of air compared to water which results in increasing of surface area to facilitate adequate cooling. This increased the size of the coolers, thereby increasing capital costs. However, in areas with significant water constraints and high utility water costs, the capital costs associated with air coolers and their increased power consumption for the fans can be justified. Another attractive option is a hybrid cooling system which is the combination of air coolers and shell and tube heat exchangers connected in series. Two cooling areas including lean amine cooling and overhead condenser cooling were selected for the investigation of the costs of the hybrid cooling system. In a hybrid cooling system, cooling is facilitated first through the use of air coolers followed by subsequent cooling provided by seawater in shell and tube heat exchangers. This configuration reduces both the capital costs and the electricity consumption. Optimization of the combined use of sea water and air coolers to produce a favorable mix of water usage and electricity consumption is desirable. However, the configuration of such a combination requires additional control equipment, pumps and piping which adds complexity to the overall system. Moreover, the complexity of maintaining the plant's water balance will also increase.

Zhai and Rubin (2010) compared the use of wet and dry cooling methods for the heat rejection system of a post combustion CO_2 capture process integrated to a 550 MW net output coal fired power plant. It was found that ambient air temperatures effect the water requirements for the cooling system makeup. In terms of costs the greatest increase was seen in the cost of water itself (due to increased volume requirements) but overall cost increases to the system as a whole were minimal. The heat rejection requirements of a CCS facility are aggravated by the low process temperatures that are required, this creates a smaller approach temperature which leads to larger cooling systems. The cost of the dry cooling system, which may be required to run with low approach temperature, is dependent on ambient conditions; this results in a large and expensive cooling system. Solely relying on a wet cooling system also adds risk to the plant in the case of limited water availability and increased costs of utility water when needed.

Due to limited availability of water at the proposed Trailblazer Energy Centre in Texas, Tenaska determined air cooling to be the most economical (but highest capital cost) cooling method for the Carbon Capture (CC) Plant. For the CC Plant, Tenaska and Fluor agreed to a design temperature of 82 °F (27.8 °C). The project site ambient temperature exceeds this design temperature for approximately 15 percent of the annual hours. This was done in order to minimize the number of air cooler bays and, thus, the capital cost of the air coolers. At times where the air temperature exceeds 82 °F (27.8 °C), the CO_2 capture recovery rate will degrade slightly (down to approximately 88% at 99.6 °F (37.6 °C) – i.e. the 99th percentile ambient condition). This was deemed to be acceptable since the project goal was to recover between 85 and 90 percent of the incoming CO_2 annually.

To overcome the cooling and water management challenges arising from a CCS retrofit of Shand, a hybrid heat rejection system with neutral water impact to the existing power plant was proposed. This design facilitates Shand's water limitations and also maintains its ZLD status. This design can also be applied to other power stations experiencing similar restrictions. This paper is divided into two parts. Part 1 presents the design of the hybrid heat rejection system based on the proposed design dry bulb and wet bulb temperatures. Part 2 of the paper evaluates the performance of the hybrid cooling system design over the course of a year. Performance variations resulting from local annual weather changes, which affect ambient moisture levels and temperatures, are summarized in this section.

2. Integrating CCS at Shand Power Station

SaskPower's Shand Power Station, located in Estevan, Saskatchewan, Canada was the subject of the CCS retrofit feasibility study which investigated the use of Mitsubishi Heavy Industries (MHI)'s KM CDR™ process. The study was a collaborative effort between MHI, Mitsubishi Hitachi Power Systems (MHPS), and the International CCS Knowledge Centre. Shand is a subcritical lignite-fired power station with a 305 MW gross output. It is a promising candidate for CCS application due to the size of the plant, the location close to oil fields which have the potential for Enhanced Oil Recovery, and its proximity to the Boundary Dam Unit 3 (BD3) CCS facility. Fig. 1 shows the simplified diagram of CCS integrated Shand Power Station. In order to maintain amine health and promote the reaction between CO_2 and amine which favors low temperature, flue gas pretreatments are required to be installed upstream of the CO_2 capture process. The hot flue gas exits the boiler and enters the Electrostatic Precipitator (ESP) for particulate removal and then the first stage of cooling in the flue gas cooler (FGC). The thermal energy from the flue gas is recovered and used for condensate preheating to improve the steam cycle heat rate. The flue gas is then introduced to wet limestone flue gas desulphurization system (wet-FGD) for SOx removal. The flue gas then enters the quencher in order to be cooled down and remove moisture. Finally, the flue gas will be fed to the CO_2 capture process which is a gas absorption process with an amine-based solvent before the remaining flue gas is vented. The CO_2 capture process required thermal energy for solvent

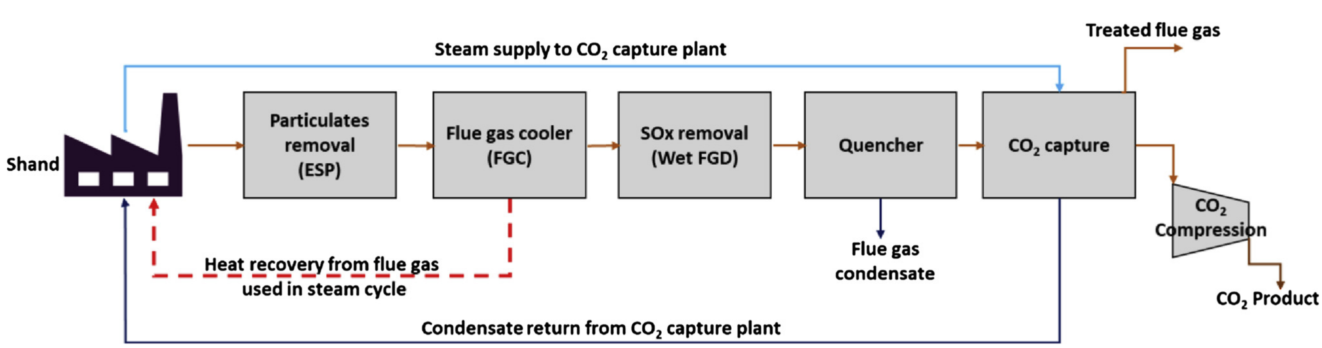

Fig. 1. Simplified diagram for Shand Power Station integrated CCS.

regeneration, and this thermal energy is obtained from steam extracted from the power plant. Shand adheres to a ZLD policy; water supply to the power station is constrained. The addition of a capture facility increases the heat rejection capacity requirement of the plant. Due to water supply constraints, a hybrid Wet Surface Air Cooler (WSAC) combined in series with a dry air cooler heat rejection system was considered to accommodate the increased heat rejection capacity requirement.

2.1. The existing heat rejection system at Shand Power Station

Shand currently rejects 425.7 MWth of heat through wet cooling towers. A simplified flow diagram of Shand's water usage is shown in Fig. 2. The existing power plant currently draws water from three sources: 1) surface water from Rafferty Dam, 2) secondary treated sewage water from the city of Estevan (after passage through a constructed wetland) and 3) snow melt, rain and runoff from a yard drainage collection system. Water drawn from all three sources is pumped to the raw water pond before being sent to the Cooling Tower (CT), where most of the heat rejection is realized by the evaporation of the water. The evaporation process however, results in the concentration of water contaminates within the basin of the cooling towers, requiring blowdown. Blowdown results in two streams of water. The first stream is sent to a softener to be clarified and softened before it is sent to the soft water pond and is subsequently recycled back into the cooling water system. The second stream is sent to the blowdown pond which feeds the Vapor Compressor Evaporators (VCEs), whose product water is forwarded to a demineralizer system in the water treatment plant to produce demineralized water used for boiler make up. Excess distillate water from the VCEs is sent to the soft water pond to be used in the heat rejection system. The residual from the water treatment plant is sent to the decant pond and used in a SO_2 removal process or depending on the quality sent to the blowdown pond, therefore maintaining the ZLD status of the plant (Fig. 2).

2.2. Additional heat rejection load

The integration of a post combustion CO_2 capture process increases the cooling duty by 339 MW_{th}. The additional cooling loads result from the flue gas cooling water cooler, wash water cooler at the top of absorber, CO_2 absorber and stripper cooler, and CO_2 compression and dehydration unit (Fig. 3). However, due to the steam extraction for solvent regeneration the existing condenser experiences duty offloading of approximately 119 MW_{th}.

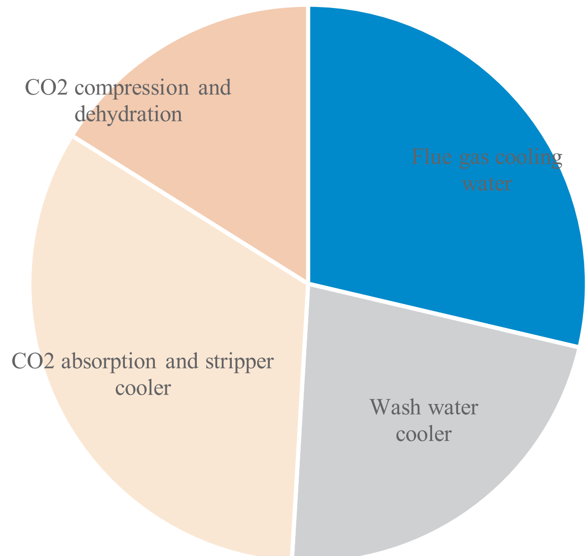

Fig. 3. Break down of the cooling load from the carbon capture process.

When using waste heat from the flue gas for condensate preheating the steam bleed to low pressure feed water heaters (LP FWHs) 1 and 2 is reduced to a minimum, this results in more steam entering the condenser which decreases the extent of duty offloading experienced by the condenser. The net duty offloading frees up heat duty from the existing cooling tower. This allows the flue gas cooling load (97.8 MWth) to be serviced from the existing cooling tower and also frees up some of the makeup water allowance to be used in the new hybrid cooling system.

2.3. Accounting for new liquid water discharge streams

The design of the integrated CCS unit results in the generation of four new liquid water discharge streams: (i) water condensed out of the

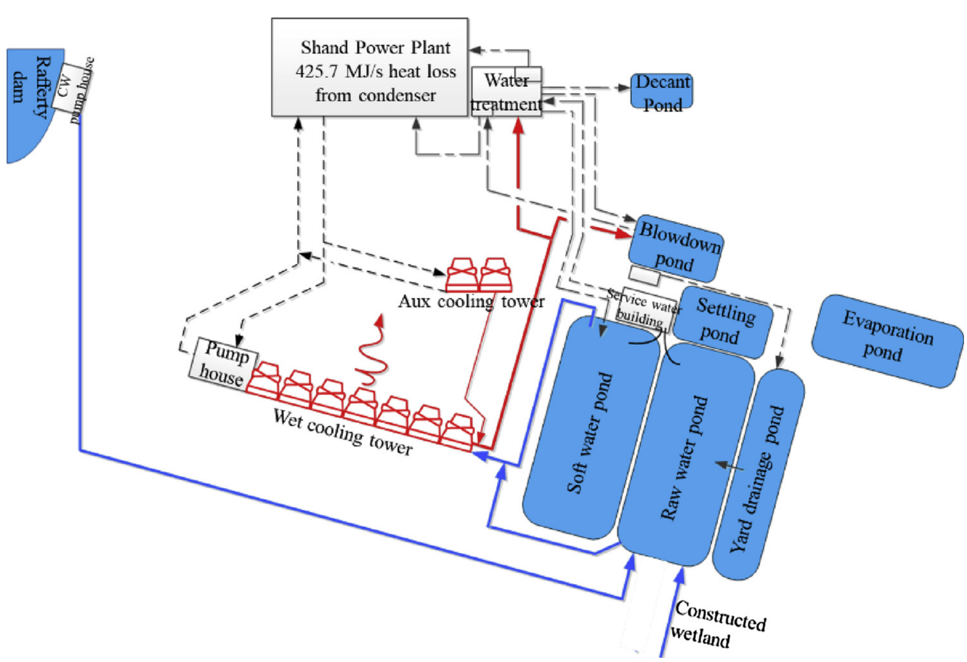

Fig. 2. Schematic of Shand's current water usage configuration.

flue gas from the CCS facility quencher (ii) acidic water from the Flue Gas Cooler (FGC) washing process (iii) water from the wet stages of the CO_2 compressor and (iv) blowdown from the heat rejection system. Management of these streams must result in no liquid discharge from the plant. The management plan for these additional streams was optimized. A simplified diagram of the optimized water usage and waste handling is depicted in Fig. 4.

The designed quenching system will generate 122 t/h of liquid water. Most of this stream will be used for the makeup requirements for the Wet Surface Air Cooler (WSAC) and a portion for FGC wash. After washing the FGC, this water becomes acidic (pH ≈ 4) due to the dissolution of acidic contaminants in the flue gas. The spent wash water will be pH adjusted and used for Flue Gas Desulfurization (FGD) make up, with un-needed surplus being sent to the blowdown pond without requiring pH adjustment. Based on water analysis, the WSAC can be operated with 13 COC. The WSAC blowdown will be mixed with the excess water from FGD make up in the blowdown pond. Some of the water in the blowdown pond is naturally evaporated while some of the water will be drawn to be treated by VCEs which demineralize the water. The demineralized water produced will be used for boiler make up with the excess recycled back into the heat rejection system (Fig. 4 and Fig. 5).

Based on historical data of Shand heat rejection water consumption, the plant rejects heat at a rate of 3070 kJ/kg water. Therefore, the amount of water free up from the existing heat rejection system can be calculated from:

$$W_{Shand} = Avaliable \quad cooling \quad duty\ (MW)*1000/3070 \tag{1}$$

Based on water balance, water available for wet cooling can be calculated from these following equations:

$$W_{WSAC} = W_Q - W_{FGC} + W_{SWP} \tag{2}$$

$$W_{SWP} = \eta_{VCE}*(1 - f_{Evap})*\left(W_{FGC} - W_{FGD} + \frac{W_{WSAC}}{COC}\right) + W_{Shand} \tag{3}$$

Where:

W_{Shand} Additional water obtained from Shand existing cooling system
W_{WSAC} Water available for wet cooling system
W_Q Quencher condensate
W_{FGC} Water used in flue gas cooler washing
W_{SWP} Water flow from Soft water pond
η_{VCE} VCE return efficiency
f_{Evap} Evaporation factor from blowdown pond
W_{FGD} Make up water for wet FGD

3. Hybrid heat rejection system design

The design wet bulb and dry bulb temperatures selected for the design basis of the hybrid heat rejection system are 13.7 °C and 18 °C respectively based on a 26 years survey of Estevan weather data between 1991 and 2017. The temperature is below the design temperature 85 percent of the year. Based on an Aspen Exchanger Design and Rating (EDR) simulation and a verification with a heat exchanger supplier, by changing the design temperature from the 87th percentile (19.5 °C dry bulb, 14.2 °C wet bulb temperature) to the 85th percentile (18 °C dry bulb and 13.7 °C wet bulb) would reduce the WSAC and dry air cooler sizes up to 20% and 17%, respectively. As a result, equipment cost is reduced up to 7% for WSAC and 11% for dry air cooler. An 85th percentile design temperature of the carbon capture system is consistent with the conclusions of the Trailblazer Project in Texas (Tensaka Trailblazer Partners, 2012).

Hysys simulation and information from suppliers was used for the design of the hybrid cooling system. Two cases were evaluated in order to minimize the cost of power consumption (Table 1).

Case 1. *Using a volume of water equivalent to the amount available from the CO_2 capture plant*

Water is produced by the quencher. Some of this water is used for flue gas cooler wash purposes and FGD make up while the remainder (91 t/h) is fed to WSAC.

Case 2. *Divert a volume of water to the hybrid cooling system from the existing plant.*

This utilizes the water available in the existing cooling tower due to condenser offloading and also considers the heat rejection in the flue gas cooling water cooler. The reduction in cooling duty from the existing cooling tower is 21.4 MWth. This makes available approximately 25 t/h of water. By combining this water and the water available from quencher maximized the amount of water available for the WSAC (122.2 t/h).

Table 2 shows the comparison between the two cases. By utilizing

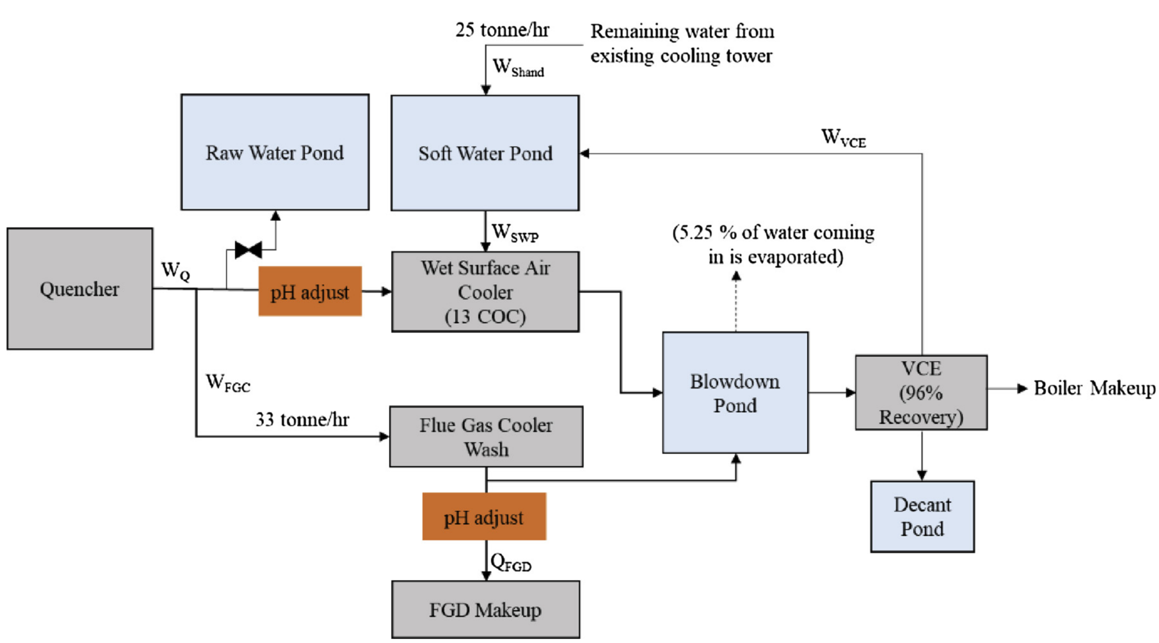

Fig. 4. The water consumption of the CCS plant proposed for integration at Shand.

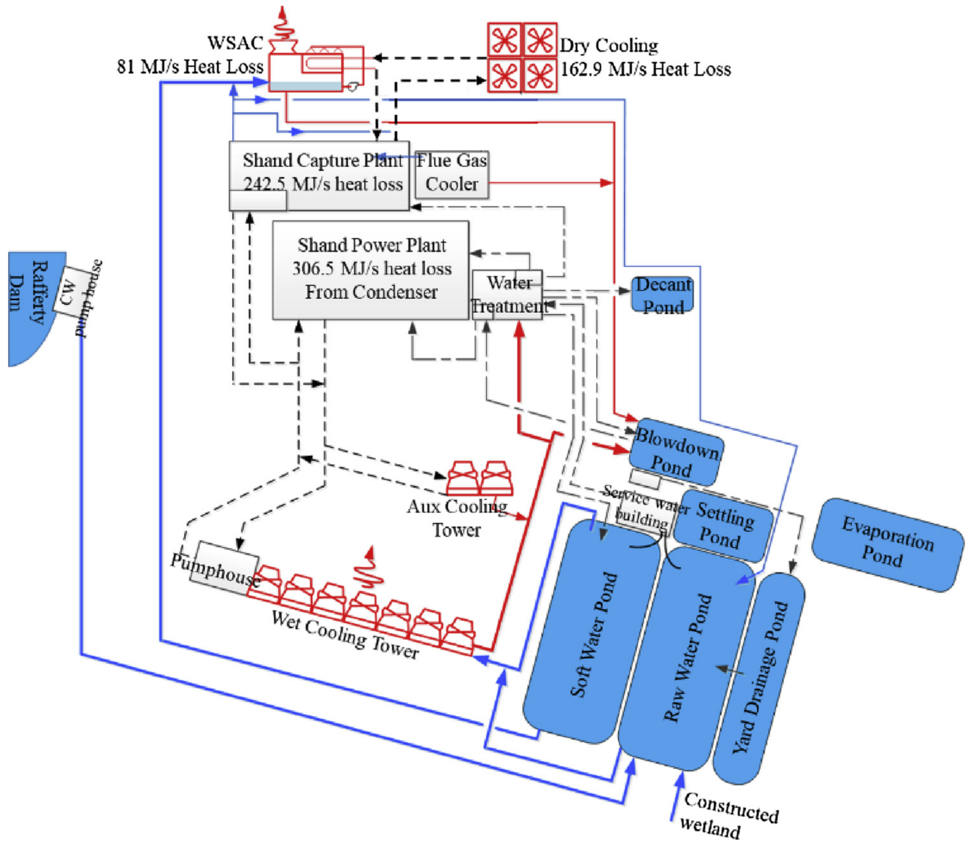

Fig. 5. Schematic of Shand integrated CCS cooling system.

Table 1
Summary of assumptions for design case.

Parameters	Unit	Value
Ambient pressure	kPaa	94
Ambient relative humidity	%	60
Existing Shand Power Plant		
Cooling water temperature	°C	22.4
Cooling water return temperature	°C	36.8
Cooling duty	MWth	425.7
Integrated Shand Power Plant		
Offloading condenser	MWth	119.2
Flue gas cooling water cooler	MWth	97.8
Available cooling duty	MWth	21.4
Hybrid System		
Dry bulb temperature	°C	18
Wet bulb temperature	°C	13.7
Cooling water supply temperature	°C	25
Cooling water return temperature	°C	44.5
Cooling duty	MWth	245

Table 2
The results of heat rejection system design.

Make up water for hybrid cooling system	tonne/hr	Case 1 91	Case 2 122.2
WSAC			
Heat rejection load	MWth	60.5	81.8
Number of Unit	unit	3	4
Design Heat Load	kW	60500	81782
Number of fans per unit		2	2
Fan power	kW	554	739
Spray pump	kW	204.6	272.8
WSAC Aux load	kW	758.6	1011.8
ACHE			
Heat rejection load	MWth	184.2	162.9
Number of Unit		31	26
Design heat load/ unit	kW	5941.78	6265.38
Number of fans per unit		3	3
Fan power/fan	kW	50.1	50.1
Dry cooler Aux load	kW	4659.3	3907.8
Total power consumption	kW	5579	5081
Cost	US$	12,539,520	12,141,700

the water that is freed up from the offloading of the existing cooling system in the WSAC of the new system, the number of WSAC units increases from 3 to 4 while the dry coolers decreased from 31 to 26 units. More importantly this decreases the overall power consumption from 5.6 MW to 5.1 MW.

The second case became the final design of the heat rejection system. Overall, the hybrid heat rejection system consists of air cooled heat exchangers (ACHE) and wet surface air coolers (WSAC) connected in series as shown in Fig. 4. The warm cooling water with the mass flow of 10.8×10^6 kg/hr from the CO_2 capture plant is first treated by ACHE where the process water to be cooled flows through a bundle of finned tubes while forced air passes over the surface of the tubes in a cross-flow direction. The ACHE consists of 26 bays. Each bay is equipped with 3 fans. The cooling water then exits the ACHE at 31 °C and enters the WSAC through bundles of exchanger tubes. WSAC cooling water in the basin beneath the tube bundles is deluged through spray nozzles installed above the exterior surfaces of the tube bundles. Cooling air and the deluge water flows downwards over the tubes in the same direction. Air is drawn over the tubes and a demister before entering the fan where it is released to the atmosphere, while the cooling water flows down to the basin. Blowdown is withdrawn when it meets certain limitations such as conductivity and total dissolved solids (TDS). As water evaporates, is blowdown, and is lost due to drift, make up water enters the WSAC basin to compensate for the loss.

Thermal efficiency and life time of the cooling system depends on the proper management of the cooling water. When water evaporates from the cooling tower, dissolved solids such as calcium, magnesium, chloride and silica remain in the circulating water. As more water is evaporated, the concentration of the dissolved solids increases. If the concentration of the solids is too high, scaling can form in the cooling tower as well as cause corrosion issues. The concentration of dissolved solids is controlled by removing a portion of the highly concentrated water and replacing it with fresh make-up water. Carefully monitoring and controlling the quantity of blowdown provides the most significant opportunity to conserve water in cooling tower operations. A key parameter used to evaluate cooling tower operations is COC. From a water efficiency standpoint, COC should be maximized in order to lower the amount of blowdown water which leads to lower makeup water requirement. However, this depends mainly on water quality. Therefore, the water analysis is required to evaluate the COC of the wet cooling system.

The internal calculation algorithm for water analysis to estimate TDS, activity coefficients, ionic associations and saturation indices at an increase of COC was adopted from DiFilippo (2006)ös methodology. Table 3 below shows a relationship between COC and pH, TDS_{ion}, TDS_{total}, LSI, and scale forming. The LSI is calculated based on pH, calcium carbonate ($CaCO_3$), calcium concentration, total alkalinity concentration, temperature and salt concentration as shown in following equation (DiFilippo, 2006).

$$LSI = pH - pH_s \tag{4}$$

Where, $pH_s = 9.3 + A + B - C - D$

$A = 0.1\ (\log(TDS,\ mg/l) - 1)$

$B = -13.12\ \log(^{o}C + 273) + 34.55$

$C = \log(Ca^{2+},\ mg/l_{caco3}) - 0.4$

$D = \log(M\ alkalinity,\ mg/l_{caco3})$

The pH value of the quench water is iterated until the LSI is close to zero or neutral in order to balance between corrosion and scale forming. It is found that adjusting the pH value to equal 7.5 results in a proper range of LSI values at different cycles of concentration (COC). LSI values between -2.0 and -0.5 indicates serious corrosion, -0.5 to 0 indicates slight corrosion but non-scale forming, 0.0 to 0.5 indicates slight scale forming and corrosion, values ranging between 0.5 and 2.0 indicates scale forming but a non-corrosive environment, and values > 2 indicate high tendency for scale formation. From the analyses, 13 COC is recommended, where the TDS_{ion} is close to the maximum TDS the existing cooling tower can operate. The maximum TDS_{ion} at which the existing cooling tower can operate is 13,098 mg/L.

4. Effect of annual variations in temperature on the hybrid cooling system

In Saskatchewan, Canada, the temperature throughout the year can vary from 40 °C to −40 °C. This temperature not only affects the cooling system but also the quantity of water discharge from the process. Fig. 6 shows the average dry bulb, wet bulb and relative humidity of each month throughout a year. The data was collected from Environmental Canada database from 1991 to 2017 in the Estevan area. Relative humidity is the ratio of the amount of water in the air as a percentage of the amount of water needed for saturation at the same temperature. From Fig. 6, it should be noted that the relative humidity in summer months is lower than those of winter months however, the amount of water in the air in summer months is far higher than in winter months due to the higher moisture capacities at the higher ambient temperatures. The ambient air contains approximately 10 times as much moisture in July as in January.

The ambient temperature and the air humidity affect moisture in the air fed to the boiler which subsequently affects the flue gas moisture composition. The water in the flue gas comes from three sources including moisture in the combustion air, water in the coal, and water produced from combustion of hydrogen in the coal. Moisture in the coal consists of two parts including moisture on coal surface and inherent moisture which is the moisture held within the molecular structure of the coal. The moisture on the coal surface can be removed in atmospheric conditions, while the removal of inherent moisture takes place at temperatures higher than 100 °C. In this study, the flue gas composition in each month throughout the year was calculated based on the assumption that the moisture content in the coal insignificantly changes seasonally. Therefore, the parameter that has an impact on the flue gas moisture content focused in this study is the moisture in the combustion air. The water produced in the boiler due to the moisture in the combustion air, the water produced from the combustion of hydrogen compound, and the water in the fuel are shown in Fig. 7.

The variation in flue gas water content in each month of the year was quantified using a Thermoflex model. Thermoflex is a fully flexible heat and material balance engineering software that is widely used commercially. Prior to CO_2 capture operations, SO_2 must be removed from the flue gas to prevent solvent degradation. Moreover, the flue gas must be cooled down for favorable mass transfer of the CO_2 molecules into the solvent. The cooling process of the flue gas results in water condensation and discharge. The amount of water discharge from FGD and quencher can be quantified through simulation by inputting the data in Table 4. A screen shot of the FGD and quencher modelled in Thermoflex is shown in Fig. 8. The FGD process selected in the model is a wet limestone with forced oxidation process. This process consists of four steps: 1) reagent preparation, 2) SO_2 absorption, 3) slurry dewatering, and 4) final disposal. During the desulphurization process, SO_2 is removed from the flue gas through an irreversible absorption reaction with limestone slurry. Water in the slurry is vaporized into the flue gas. This results in flue gas leaving the absorber that is saturated with water and largely free of SO_2. The treated flue gas then enters the quencher where it is further cooled down or "quenched". Water is condensed and removed from the flue gas. The excess water produced in the quencher will be used in the heat rejection and FGD makeup as explained in the previous section and shown in Fig. 4.

After obtaining the amount of water exiting the quencher through modelling, the water available for the heat rejection system in each month was calculated based on Fig. 4 and Eqs. (1)–(3). The amount of water available for the heat rejection system was used in the model for the hybrid heat rejection system in Thermoflex which can be seen in Fig. 9. The design dry bulb (18 °C)and wet bulb (13.7 °C) temperatures were used in the thermodynamic design. An engineering design model was then developed in Thermoflex based on the data from the thermodynamic model and data (tube and fin dimension) provided from the vendor in the first part of this paper. The developed models were built to duplicate the WSAC and ACHE. However, due to the limitation of the software of not having all the required equipment, a wet cooling tower was used instead of a WSAC to represent the wet cooling system. Both a WSAC and a wet cooling tower are evaporative cooling system which predominantly harness evaporation to cool the water. The information

Table 3
Water analysis under different cycle of concentration.

COC	pH	TDS_{ion} (mg/l)	TDS (mg/l)	Conductivity (mS/cm)	LSI	LSI (with ion association)
4	7.5	3989	4499	4950	0.09	−0.57
5	7.5	4922	5619	6070	0.17	−0.52
6	7.5	5839	6740	7180	0.25	−0.47
7	7.5	6740	7860	8270	0.31	−0.44
8	7.5	7626	8980	9330	0.36	−0.41
9	7.5	8495	10100	10380	0.41	−0.38
10	7.5	9349	11219	11410	0.45	−0.36
11	7.5	10186	12339	12420	0.49	−0.34
12	7.5	11008	13460	13420	0.52	−0.33
13	7.5	11814	14580	14390	0.56	−0.31
14	7.5	12603	15700	15340	0.59	−0.30

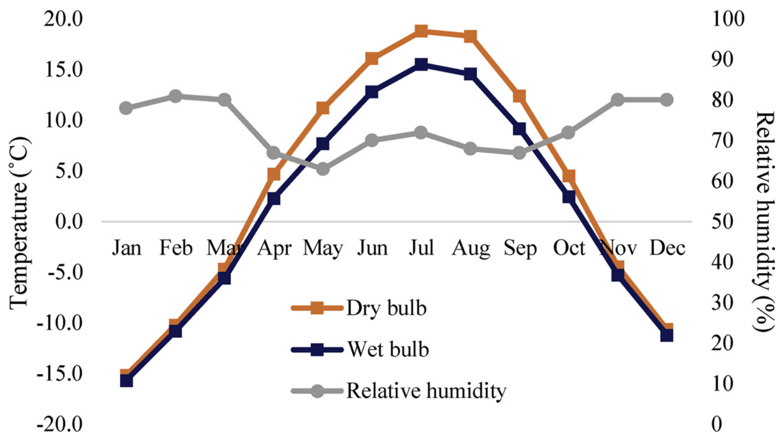

Fig. 6. Monthly average humidity, dry bulb temperature and wet bulb temperature.

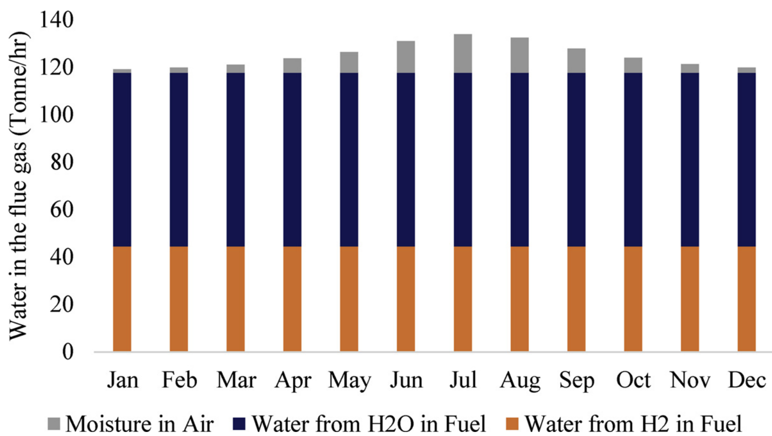

Fig. 7. Sources of moisture in the flue gas.

Table 4
Parameters used in FGD and Quencher simulation design case.

Flue gas flow to FGD (kg/h)	1.7×10^6
Flue gas inlet temperature to FGD (°C)	85
Flue gas outlet temperature from FGD (°C)	53
Flue gas composition (mol%)	
O_2	6.1
CO_2	11.4
H_2O	13
SO_2	0.06
N_2	69.4
Flue gas outlet temperature from Quencher (°C)	30

presented relating to the design of the WSAC and air-cooled heat exchanger in Section 3 were obtained based on vendor information. The comparison of cooling load, water consumption and power consumption of the design case and annual average was made based on the results from Thermoflex software not from the information provided by the vendor. Therefore, the replacement of a WSAC by a wet cooling tower in the simulation does not affect the results on the effect of annual variations in temperatures.

Fig. 9 is a screen shot of the Thermoflex model for the hybrid cooling system at the design condition. Hot water at a temperature of 44.5 C is fed to the forced draft dry cooling system which include 26 modules. Each module is equipped with 3 variable speed fans. The power consumption of each fan at the design mode is 26.81 kW. Following treatment by the dry cooling system, the now warm water is introduced to the wet cooling tower which is a counterflow design consisting of 8 cells representing the 4 units. Each cell is equipped with a variable speed (2 speeds) fan. The power consumption at the design point is 198.3 kW per fan. After the thermodynamic mode and engineering design mode model were built in Thermoflex, an off design model was developed by using the monthly average dry bulb and wet bulb temperatures. The effect of heat rejection load on the designed dry coolers and wet cooling towers were evaluated.

5. Results and discussions

5.1. Effect of ambient temperature on shifting heat rejection load

Changes in ambient temperatures and humidity effect the performance of both the wet and dry cooling systems. The temperature approach on the dry cooling system is affected by the dry bulb temperature. Wet cooling is affected by the wet bulb temperature which is a function of the temperature and humidity. Condensate from the flue gas cooler serves as water makeup to the wet cooling system therefore water availability to the wet cooling system is dependent on flue gas moisture content. The total heat rejection load is comprised of a combination of wet and dry cooling. Changes in weather throughout the year alter the composition of this combination. Variations in total heat rejection composition are summarized in Fig. 10 on a monthly basis. It can be noticed that during the winter months, when the ambient temperature is low, the heat rejection load shifts to favor more wet cooling when compared to the summer months. This can be attributed to the interaction between the cooling water and the ambient air. The cold air draws heat out of the water which in turn decreases the temperature of the cooling water without the need for evaporation. In contrast, during the summer month, when the ambient temperature is higher, increased rates of evaporation are required to sufficiently lower the temperature of the water. The cooling load shifts from wet cooling to dry cooling.

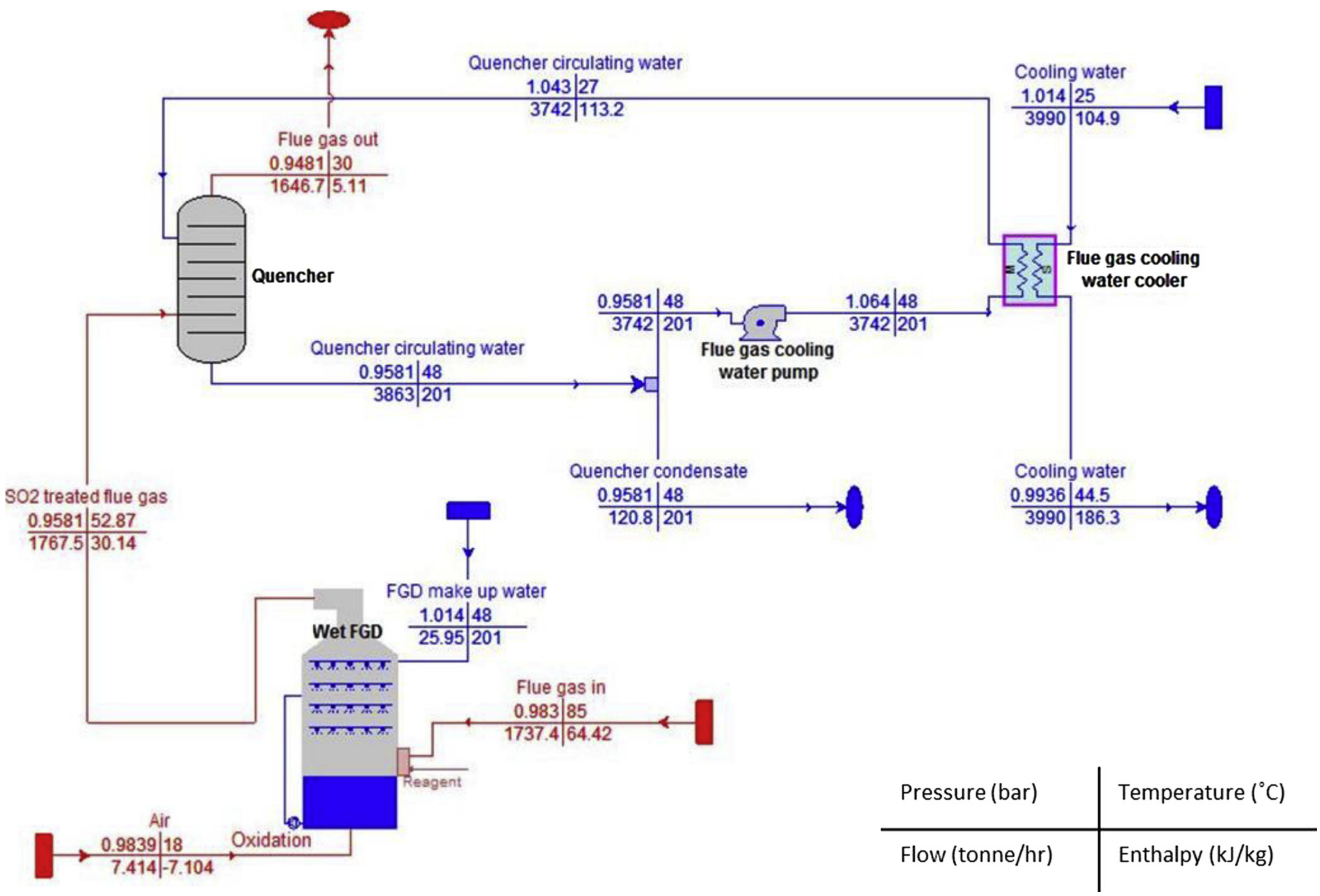

Fig. 8. Screenshot of the FGD and quencher modelling in Thermoflex.

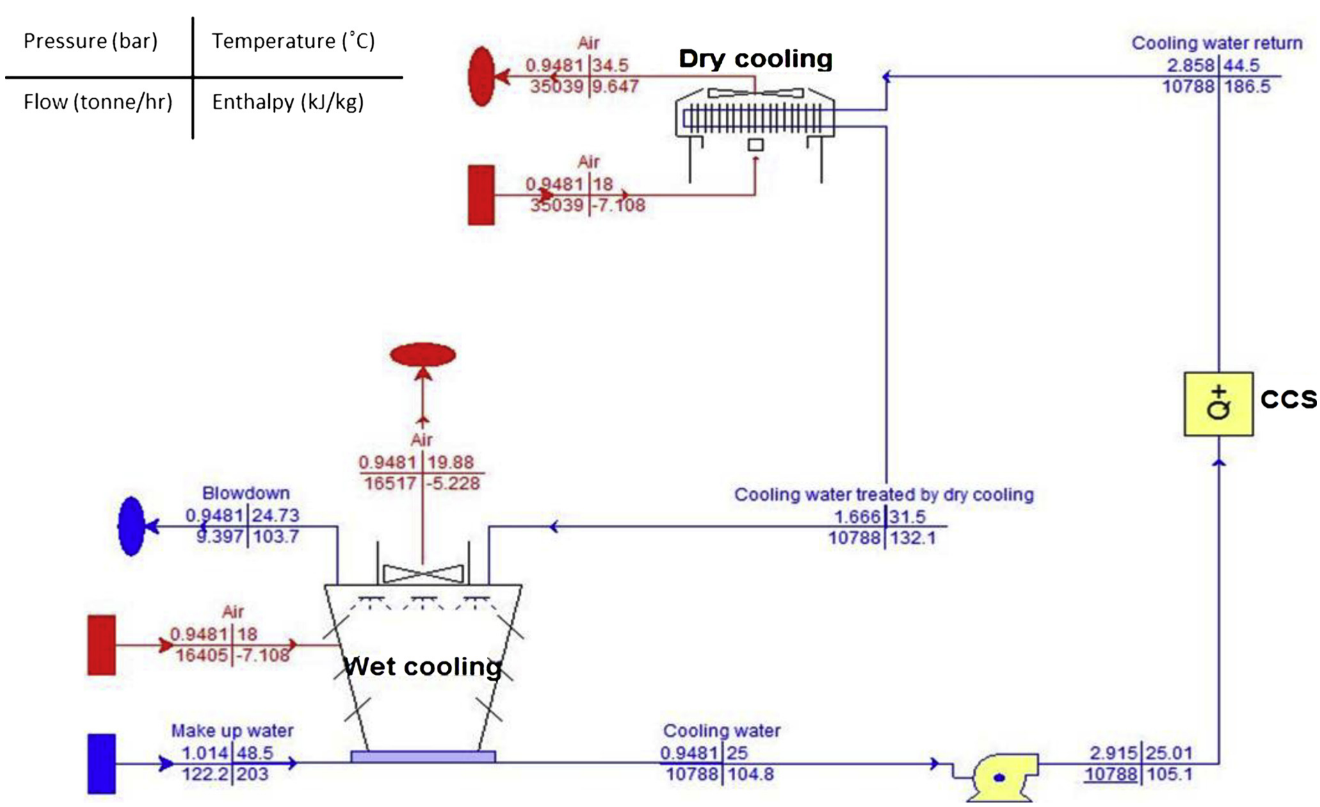

Fig. 9. Screenshot of the hybrid cooling system from Thermoflex.

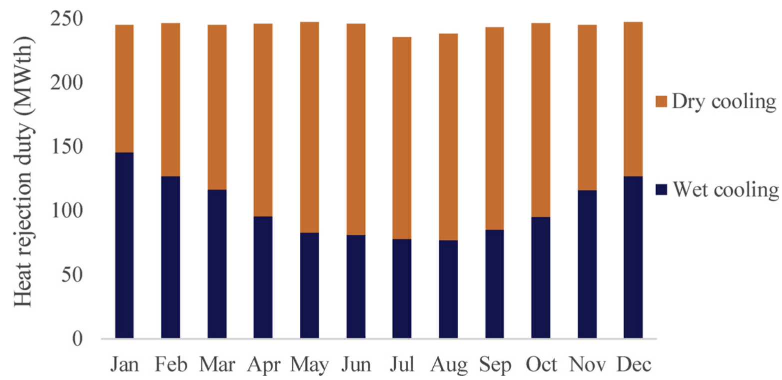

Fig. 10. effect of ambient temperature on heat rejection load in dry and wet cooling.

Fig. 11 shows the comparison of cooling load between the design case and the annual average values. Overall, the total heat rejection load of the hybrid cooling system is 245 MWth. At the design case, the composition of the heat rejection load was 67% dry cooling 33% wet cooling. However, taking into account the annual variations in temperatures, the annual average cooling load becomes 58% dry cooling and 42% wet cooling.

5.2. Effect of ambient temperature on cooling system power consumption

Other than the size of the cooling system, power consumption is of most concern when considering the design of a hybrid heat rejection system. Electricity is required to run fans in wet cooling towers and dry cooling and circulating cooling water pump. The power consumption for the heat rejection system is summarized in Figs. 12 and 13. It should be noted that the circulating cooling water pump consumes almost constant power throughout the year with an average of 0.8 MW. During the summer months power consumption for the dry cooling system increases substantially due to the increased fan usage. Overall power consumption for the design case is 4.96 MW compared to the annual average of 2.58 MW.

5.3. Effect of temperature on water usage

The water balance of the heat rejection system was also accounted for. Fig. 14 summarizes the variations is water availability, cooling tower makeup volumes, blowdown volumes and the amount of water evaporated on a monthly basis. Drift loss from the cooling tower is usually low enough to be considered negligible and is not shown here. During the summer months (June to September) water availability increased; this is due to the increased moisture content in the flue gas experienced at higher ambient temperatures. This is an advantage as in the summer months, more water is required due to the increase in evaporation rate for adequate cooling within the cooling tower. The ideal of hybrid heat rejection design is to consume all the available water in the wet cooling system in order to minimize the heat rejection load and the fan power consumption in the dry cooling system, while evaporating the produced water. The wet cooling tower model in Thermoflex was equipped with a two speed fan that operates at full or half speed, as a variable speed fan is not available in the software. Turning down fan speed from full speed to half speed fan in each cooling unit results in remaining water that is not evaporated in the cooling tower. In practice, variable speed fans can be installed in the cooling towers. This will allow full utilization of all the available water in the wet cooling system.

Integrating Shand with CCS not only increases water consumption but also produces new water discharge streams. To account for these changes all the water discharge from the plant including water from flue gas cooler washing, discharge from the quencher, and the excess water resulting from condenser offloading (approximate $1.169*10^6$ tonne/year) is utilized in the design and integration of the heat rejection system and capture facility. Fig. 15 summarizes the water consumption in the plant throughout the year. Overall, 76% of the discharge water is consumed in heat rejection, 21% is used for FGD makeup, and 3% remains as excess water. The 3% excess water can be used by installing variable speed fans which will allow all the water to be evaporated and shift the cooling load towards the wet cooling system. This will slightly lower the power consumption for the dry coolers. Another option is to use this excess water in the existing cooling system. Shand draws most of the water used in the current heat rejection system from Rafferty Dam and often utilizes the maximum volume of water draw allowed. Using this excess water could lower the volume of water drawn from Rafferty Dam; a favorable result, and potentially valuable in low water years

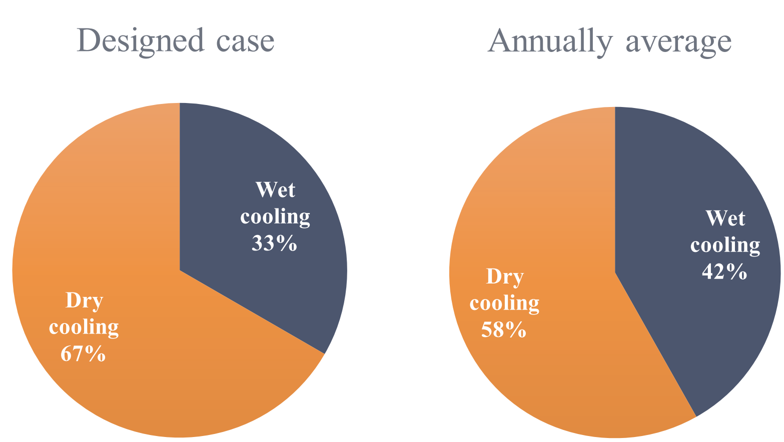

Fig. 11. Comparison of cooling load between design case and annual average.

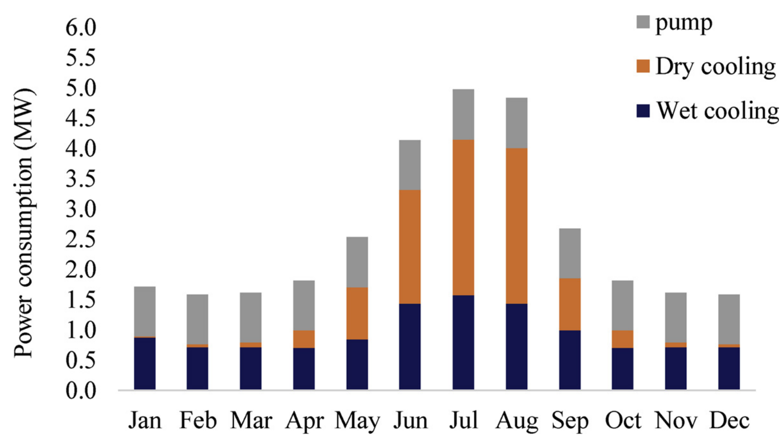

Fig. 12. Monthly power consumption in heat rejection system.

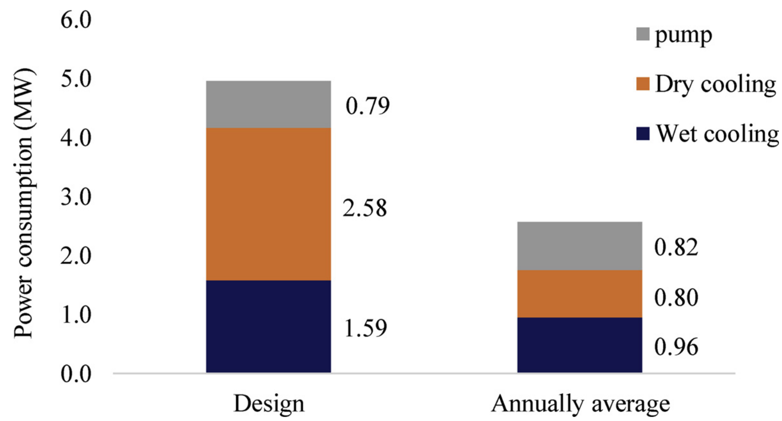

Fig. 13. Comparison between power consumption at design case and annually average.

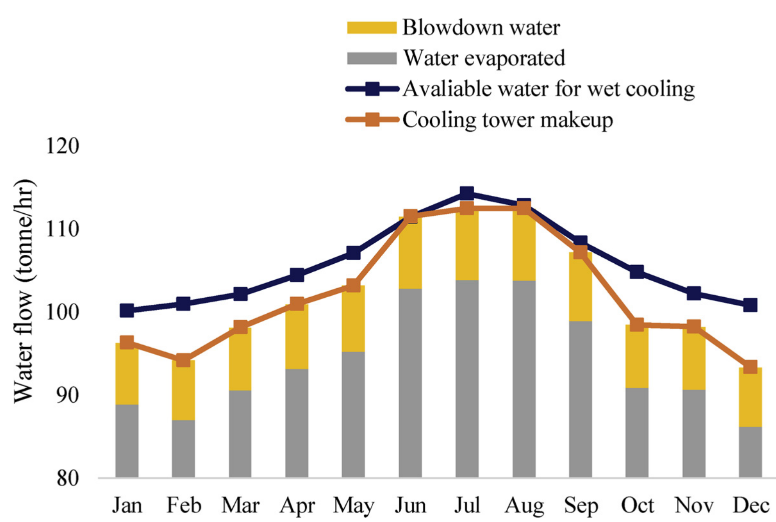

Fig. 14. Water available and water usage for heat rejection system.

5.4. Effect of design temperatures on CO_2 capture plant derate

Designing heat rejection for the hottest day of the year can increase capital costs while this additional cooling capacity will not be utilized for sufficient hours in the year to justify additional the expenditure. Therefore, the heat rejection system in this study is designed on 85th percentile dry bulb and wet bulb temperatures.

Ideally cooling water temperatures should be high enough to minimize the size of the cooling system which reduces capital costs. As design cooling water temperature increases, the capital costs of the capture system increases. Lower design cooling water temperature has the following benefits; lower moisture content in flue gas to absorber and lower specific volume, which means smaller absorber, reduced booster fan power, higher partial pressures of CO_2. Lower lean amine temperatures and flue gas temperatures would improve kinetics, which could improve cyclic loading and reduce required amine flow rates. Lower temperatures would improve compressor power requirements as well.

During periods when temperatures are higher than the design temperature, performance of the heat rejection system will become

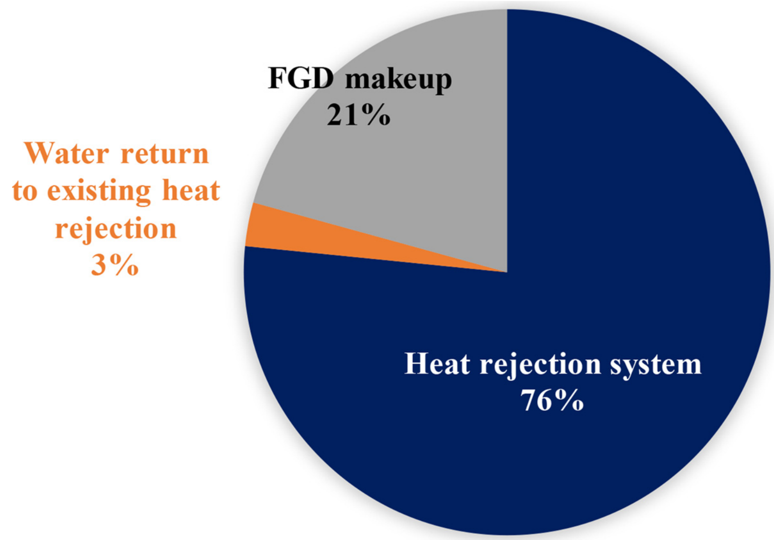

Fig. 15. Annually water consumption.

constrained. This will limit the extent of cooling that can be provided to the capture facility and therefore will also affect the performance of the capture facility. The temperature of supplied cooling water will be higher than the desired temperature (25 °C) and it is unavoidable that the CCS plant will be derated during that period. In this instance, the CO_2 capture rate can be reduced independently of the power plant if that is permissible on a periodic basis based on increased capture at other times that are not constrained, or the output of both the power plant and the capture plant can be reduced in order to maintain an acceptable CO_2 emission intensity.

6. Conclusions

Water constraints and limitations on waste water disposal are becoming more common due to environmental concerns. This can become a limitation not only to the integration of CCS but also to power plant expansion. The concept of a hybrid heat rejection system which is a combination of wet and dry cooling can be a potential solution. This study designed and proposed a hybrid heat rejection system that can solve challenges when integrating CCS to an existing facility that has limited water availability and must abide to a ZLD operating permit. The hybrid heat rejection system was designed for a dry bulb and wet bulb temperatures of 18 °C and 13.7 °C respectively. The hybrid heat rejection system was designed to treat cooling water at the temperature of 44.5 °C returning from the CO_2 capture plant to 25 °C with approximately 245 MWth heat load. The water used in the heat rejection system is the water discharge from the CO_2 capture plant. By comparing two different cases of water usage, it was found that the maximizing water usage in the wet cooling system which led to a higher wet cooling load resulted in 0.5 MW lower power consumption. The optimized heat load on the dry cooling and wet cooling is 156.5 and 81.8 MWth which are 67 and 33% respectively.

The impact of annual variations in dry bulb and wet bulb temperatures on the hybrid cooling system was investigated by using Thermoflex. It was noted that the annual average of heat rejection load shifted toward the wet cooling system due to the lower temperature and water availability from the CO_2 capture process with the percentage of 58% for dry cooling and 42% for wet cooling. This resulted in a reduction of fan power requirements. The average power consumption throughout the year is 2.58 MW which is only 52% of the design case (4.96 MW). Performance of the hybrid heat rejection system may become constrained during the summer months; this can be resolved by derating the capture facility. Increased performance during the winter months can offset this required derate therefore not affecting the overall annual capture rate.

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