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Environmental Performance of Hypothetical Canadian Pre-Combustion Carbon Dioxide Capture Processes Using Life-Cycle Techniques

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Abstract: The methodology of life-cycle assessment was applied in order to evaluate the environmental performance of a hypothetical Saskatchewan lignite-fueled Integrated Gasification Combined Cycle (IGCC) electricity generation, with and without pre-combustion carbon dioxide (CO₂) capture from a full life-cycle perspective. The emphasis here is placed on environmental performance associated with air contaminants of the comparison between IGCC systems (with and without CO₂ capture) and a competing lignite pulverized coal-fired electricity generating station in order to reveal which technology offers the most positive environmental effects. Moreover, ambient air pollutant modeling was also conducted by using American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) air dispersion modeling to determine the ground-level concentration of pollutants emitted from four different electricity generating stations. This study assumes that all stations are located close to Estevan. The results showed a significant reduction in greenhouse gas (GHG) emissions and acidification potential by applying both post-combustion and pre-combustion CO₂ capture processes. The GHG emissions were found to have reduced by 27%–86%, and IGCC systems were found to compare favorably to pulverized coal systems. However, in other environmental impact categories, there are multiple environmental trade-offs depending on the capture technology used. In the case of post-combustion capture, it was observed that the environmental impact category of eutrophication potential, summer smog, and ozone depletion increased due to the application of the CO₂ capture process and the surface mining coal operation. IGCC systems, on the other hand, showed the same tendency as the conventional coal-fired electricity generation systems, but to a lesser degree. This is because the IGCC system is a cleaner technology that produces lower pollutant emission levels than the electricity generating station; thus, the benefits of capture are reduced on a comparative basis. The results from air dispersion analysis showed that the maximum ground-level concentrations of pollutants from all electricity generating stations are in compliance with all air quality standards, except for Co, Pb and Ni. The IGCC with capture revealed the lowest nitrogen dioxide (NO₂) ground-level concentration compared to all other scenarios. Moreover, IGCC systems both with and without pre-combustion CO₂ capture revealed no ground-level concentration of trace elements. This is because the IGCC system operates with an acid gas cleaning process that removes most of the trace contaminants from the syngas.

Keywords: IGCC; life-cycle assessment (LCA); AERMOD; Saskatchewan lignite; coal; pre-combustion CO₂ capture processes

1. Introduction

Currently, CO₂ emissions are the primary concern in the electrical generation industry, as carbon dioxide emissions from electrical generation accounted for 12% of the total Canadian emissions in 2013, Figure 1 [1]. Coal-fired electrical generation is the predominant source of electricity, accounting for 47% of generation in Saskatchewan, while natural gas accounts for 28%, hydropower 19%, and renewable and others 6% [2]. Efforts are being made by engineers and scientists to overcome anthropogenically induced climate change by researching and developing electrical generation systems, including clean coal technology, which produces lower CO₂ emissions than conventional plants. One promising approach to reduce the emission of CO₂ into the atmosphere is carbon capture and storage (CCS).

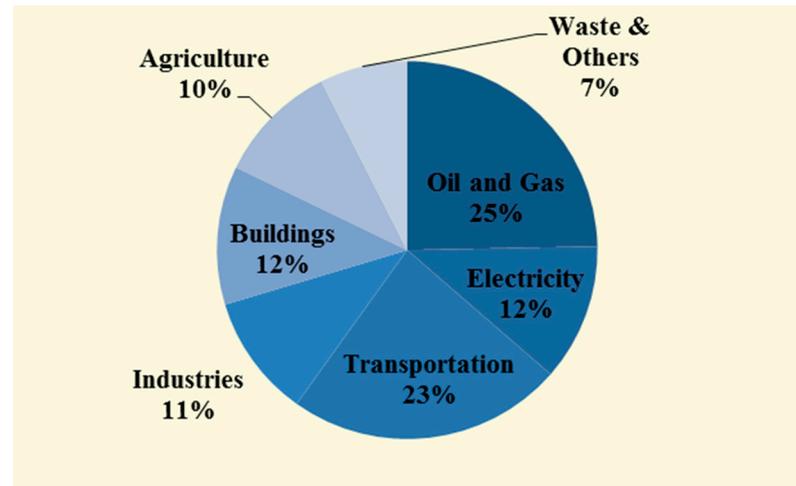


Figure 1. Canada carbon dioxide emissions by source in 2013 [1].

Coal gasification is a proven technology that is being adopted in commercial Integrated Gasification Combined Cycle (IGCC) electricity generation. The IGCC is an advanced generation concept that combines modern coal gasification technology with gas turbines (Brayton cycle) and steam turbines (Rankine cycle). IGCC technology has proven to be one of the cleanest coal-based electrical generation technologies, emitting the least of several key pollutants of NO_x, SO_x, CO_x and PM₁₀ compared to any other coal-based technology [3–5]. The IGCC can be combined with the pre-combustion CO₂ capture technology for further gas purification, which enables efficient separation of the CO₂ by means of pressure-swing absorption or physical solvents such as chilled methanol (Rectisol[®], Munich, Germany) or a mixture of dimethyl ethers of polyethylene glycol (Selexol[®], Des Plaines, IL, USA) [6,7]. With CO₂ concentration of 15%–60% by volume in a pre-combustion process and only 15% by volume in a post-combustion process, the CO₂ partial pressure can be significantly higher in the pre-combustion CO₂ capture process. These factors help to improve the driving force for the separation process. As a consequence, the required equipment for the pre-combustion CO₂ capture process can be smaller than that for the post-combustion CO₂ capture process [8].

Although there are many environmental and performance-enhancing advantages associated with CO₂ capture with IGCC technology, it must be recognized that CO₂ capture is an energy-intensive process which significantly decreases the overall efficiency of the electrical generation station; hence, a larger amount of coal is needed to compensate for the efficiency loss. This will lead to further emissions associated with the additional coal. Moreover, the upstream emissions from fuel/material acquisition and the downstream emissions from waste disposal cannot be readily captured. The conversion of uncontrolled emissions release from the generating station itself to the atmosphere to a solid or liquid stream offers the potential for well-designed landfills to store waste safely. The CO₂ emissions produced at the plant can be captured for underground storage. In a traditional plant, the emissions from upstream and downstream processes are small when compared to the emissions from the

combustion process [9]. However, the upstream and downstream emissions become more relevant when the CO₂ capture process is applied with the reduction in the “mid-stream” emissions. Therefore, it is very important to conduct a life-cycle assessment of an electricity generation station with CO₂ capture and evaluate its environmental performance. Given the current lack of commercial experience in IGCC, it is necessary to predict its environmental performance from a full life-cycle perspective to comprehensively understand its environmental impacts. It is also important to understand the full ramifications of the process when comparisons are made to other alternative technologies for greenhouse gas emissions reduction. Moreover, air dispersion modeling was used to evaluate the ground-level concentration of sixteen air contaminant components including sulfur dioxide (SO₂), nitrous oxide (N₂O), particulate matter (PM_{2.5}), arsenic (As), cadmium (Cd), chromium (Cr), mercury (Hg), manganese (Mn), lead (Pb), antimony (Sb), cobalt (Co), copper (Cu), molybdenum (Mo), selenium (Se), vanadium (V), and nickel (Ni).

At present, there are only fourteen IGCC plants operating worldwide with a capacity size ranging from 40 MWe to 582 MWe, most of them are in the United States and Europe [10]. None of these plants currently capture CO₂. However, the Kemper County IGCC is nearing commercial operations and will be operating in 2016. This plant will capture 65% of the CO₂ and send it to oil companies for enhanced oil recovery. According to [11], there are ten IGCC plants (exclude Nuon IGCC, Buggenum, which was closed down in April 2013) in operation or advanced construction in Europe. Four of them use coal (accounts for over 1500 MWe or over 47% of total electricity generated from the IGCC in Europe). The other six plants are fueled by using gasified refinery by products. In the United States there are currently four IGCC coal-based plants in operation including Tampa Electric, Polk County (250 MWe), Wabash, West Terre Haute (265 MWe), Edwardsport IGCC Station, Indiana (618 MWe) and Kemper County IGCC, Mississippi (582 MWe). In addition, there are about eighteen plants that are being planned, six plants that are in the initial stage will be located in Europe, twelve plants will be located in North America; ten plants will be located in the United States and two in Canada [12–14].

Based on the database of operating plants, the IGCC electrical generating station is still in the early phase which makes for a significant limitation on actual technical data and experiences. The life-cycle assessment evaluation of electrical generation had never been applied and studied in detail, in Saskatchewan, until the year 2006 when Suebsiri conducted the CO₂ emission accounting study of the Weyburn project in Saskatchewan. So far, there have only been two studies on LCA-CCS electrical generating stations based in Saskatchewan [15] and [16]. Suebsiri [15] conducted the study of an environmental model of carbon capture and storage for SaskPower’s Boundary Dam. In 2011, the full life-cycle assessment of SaskPower’s Boundary Dam power generation station was studied in detail. Both of the studies focused on the post-combustion technology coupled with the existing electrical generating station in Saskatchewan. Up to this point, there has been no research on LCA-IGCC coal-based generation coupled with pre-combustion technology in Saskatchewan. This research is the starting point for the evaluation of LCA of IGCC systems when fueled by Saskatchewan’s unique lignite coal. This research also focuses on air dispersion modeling associated with an IGCC electrical generating station. The database resulting from this research will benefit future LCA-IGCC Saskatchewan lignite-based projects.

This study applies life-cycle assessment (LCA) methodology to evaluate the environmental performance associated with air contaminants from the IGCC, with and without pre-combustion CO₂ capture from a full life-cycle perspective. Moreover, the air dispersion modeling method is also conducted to predict the impact of atmospheric emissions associated with electrical generating operations in the SaskPower Boundary Dam (Estevan) area. The results from both LCA methodology and the air dispersion modeling of IGCC electricity generation, with and without pre-combustion CO₂ capture, are compared to conventional lignite coal-fired electricity generation, with and without post-combustion CO₂ capture.

The paper is organized as follows. Section 2 describes the methodology for life-cycle assessment and air dispersion modeling. Section 3 provides a detailed description and inventories of IGCC and conventional lignite coal-fired electricity generation. Section 4 presents the results and discussion of the life-cycle impact assessment and air dispersion modeling of both technologies. Section 5 presents a conclusion and recommendation for the future work.

2. Methodology

2.1. Environmental Life-Cycle Assessment Methodology

2.1.1. Goal and Scope Definition

The goal of this LCA study is to evaluate the environmental performance of Saskatchewan lignite-fueled IGCC electrical generation, with and without CO₂ capture. This research was intended to provide results specific to Western Canadian lignite used in an IGCC facility. The emphasis was thereby put on the comparison between IGCC systems (with and without CO₂ capture) and the competing lignite-pulverized coal electrical generation stations (with and without CO₂ capture) in order to reveal which technology offers the most positive environmental effects. The composition of Saskatchewan lignite coal used in all case scenarios is listed in Table 1, and the heating value of lignite coal was 15,119 kJ/kg.

Table 1. Composition of Saskatchewan lignite coal [16].

Parameter	Unit	Value
Moisture	%	35.00
Carbon	%	41.70
Hydrogen	%	2.61
Nitrogen	%	0.79
Sulfur	%	0.54
Ash	%	9.47
Oxygen	%	9.90
Mercury	ppb	79.00
Chlorine	ppm	10.20

The assessment of environmental impacts performance from IGCC and PC systems was conducted using the “cradle-to-gate” approach, where the activities stop at transport entry point to the field. Four system options were analyzed and compared:

1. conventional lignite coal-fired electricity generation without a post-combustion CO₂ capture process;
2. conventional lignite coal-fired electricity generation with an amine post-combustion CO₂ capture process;
3. integrated Gasification Combined Cycle (IGCC) without a pre-combustion CO₂ capture process;
4. integrated Gasification Combined Cycle (IGCC) with Selexol[®] as the chosen pre-combustion CO₂ capture process.

Functional Unit

The functional unit provides a standard reference metric for all input and output variables (*i.e.*, energy, materials, emissions, and wastes). The functional unit for this study was selected as 1 MWh of electricity generated, considering that this is a product of the electrical generation by any means.

System Boundaries

In this LCA study, the full life cycle of electricity generating stations was considered.

The “cradle-to-gate” approach is one in which the environmental effects associated with all life-cycle activities, from resource extraction (e.g., coal, limestone and iron) and the production of materials (e.g., steel, concrete and monoethanolamine (MEA)) to the generation of electrical energy at the generating station, as well as the CO₂ capture process and all transportation stages, are taken into account; however, no accounting is made for the utilization of any oil produced under enhanced oil recovery (EOR) nor for underground CO₂ sequestration, for example. The material and energy inputs needed for equipment manufacture are not included in this study. Exclusion of these activities is common practice where it is expected that these processes have far smaller environmental implications than the operations of the facilities [17]. MEA solvent consumption and production for the post-combustion process is included; this is the amine with abundant information in the literature. For pre-combustion, the Selexol[®] solvent production was not included because of a lack of data. It was thought to have no relevant effects on the environmental impacts since the Selexol[®] consumption is two orders of magnitude less than amine consumption [18]. For downstream processes, waste transport and disposal in a nearby landfill were considered. The system boundary for lignite-IGCC electrical generating stations with pre-combustion capture is presented in Figure 2.

Temporal and geographical boundaries: The temporal boundary was defined as 34 years, and it was assumed for the purpose of this study that plant construction (IGCC and PC) would be completed by 2015. This duration included the time needed for coal mine development, plant construction, commissioning, and operation. The construction and commissioning phase was assumed to be four years before the operation starts. This number was based on the report from the Polk Electricity Generating Station [19]. Although the system boundary of this research does not include downstream processes after CO₂ is captured, it is assumed that the CO₂ will eventually be used for enhanced oil recovery. Therefore, the lifespan of the electrical generating station was assumed to be 34 years to accommodate CO₂-EOR projects, with an expected requirement for new CO₂ purchase of 15 years, where the first four years is the plant construction phase and the rest (30 years) is the operational phase.

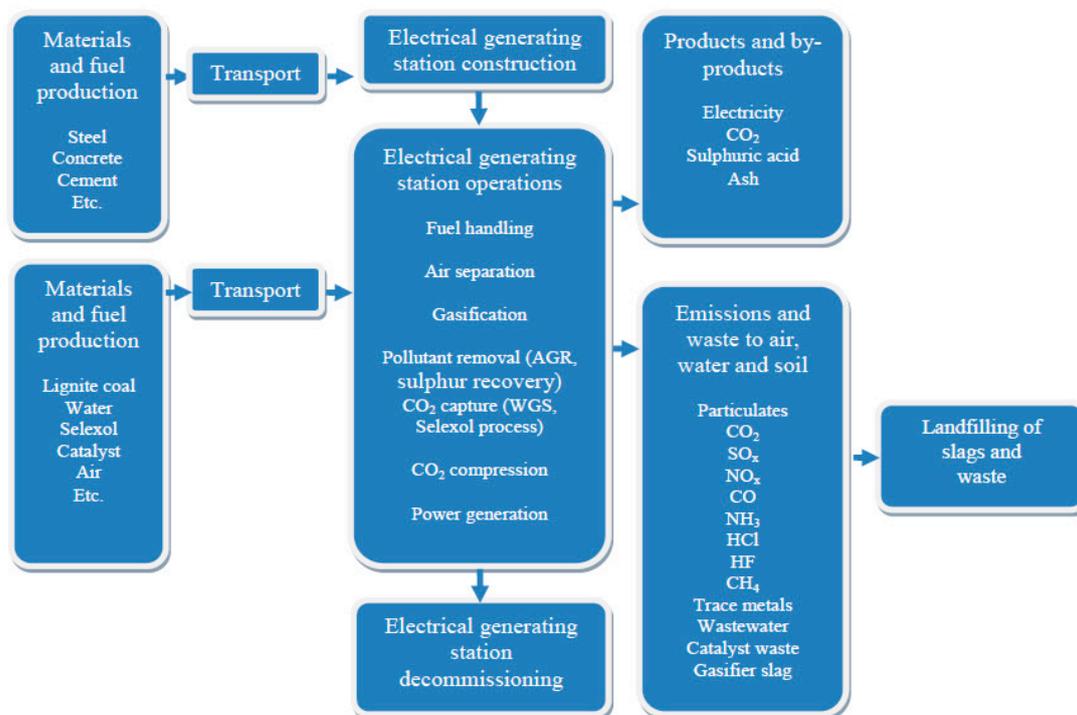


Figure 2. System boundaries for lignite-IGCC electrical generating station with pre-combustion capture.

2.1.2. Life-Cycle Inventory Data Quality, Sources and Assumptions

The majority of the data used in this study is specific to Western Canada. In the absence of Western Canadian data, information was drawn from other Canadian sources, followed by North American and European sources and, finally, from pre-existing life-cycle databases, most notably Ecoinvent v2.1.

The majority of operational data for IGCC plants came from the technical documentation of the IGCC with carbon dioxide capture and storage (CCS), [20]. Other sources of data came from US Department of Energy (DOE) reports.

In the case of post-combustion CO₂ capture, refer to [21] and [16], since the conventional lignite coal-fired electricity generation (PC) in both cases, with and without CO₂ capture, were adopted from the previous work of [16].

2.1.3. Life-Cycle Assessment Modeling

All unit processes at the electrical generating plant were modeled so that emissions associated with each unit process could be tracked. The IGCC model was created using an Excel™ (2010) spreadsheet and AspenPlus® (Version 2004.1) simulation software. The modeling results were transferred to the LCA software GaBi™ (Version 5.0), which is a software product of PE International, Germany.

2.1.4. Life-Cycle Impact Assessment

The life-cycle impact assessment was carried out in order to identify environmental impacts that arise from this LCA study. In this study, the TRACI life-cycle impact assessment (LCIA) method was adopted for the analysis. Since this study is specific to Saskatchewan/Canada, it was thought that the selected impact assessment methodology should represent Canadian or US environmental conditions for accurate impacts evaluation. LUCAS, the Canadian LCIA method, is still in the development stage and so was not usable for this purpose at this time. Therefore, TRACI impact assessment methodology was applied in this study. The environmental impacts were categorized into five categories. Brief descriptions of each environmental impact category are summarized in Table 2.

Table 2. TRACI impact categories considered in the study.

Impact Category	Abbreviation	Short Description	Relevant LCI Data	Characterization Factor
Global warming potential	GWP	Radiative forcing of atmosphere, causing a temperature rise	CO ₂ , N ₂ O, CH ₄ , SF ₆ , CHCl ₃ , CF ₄ , CFCs, HCFCs, CH ₃ Br	kg CO ₂ -equivalent
Acidification potential	AP	Emission of acid-forming substances	SO ₂ , NO _x , NH ₃ , HCL, HF, H ₂ S	kg SO ₂ -equivalent
Eutrophication potential	EP	Excessive supply of nutrients	NO _x , NH ₃ , PO ₄ ³⁻	kg N-equivalent
Ozone depletion potential	ODP	The relative amount of degradation to the ozone layer	R 11, R 114, R12, and R13	kg CFC 11-Equivalent
Photochemical oxidation potential (Summer smog)	POCP	The complex reactions during the formation of reactive chemical compounds by action of sunlight on primary pollutants	NO _x , PAH, NMVOC, CH ₄	kg ethylene-equivalent

2.2. Air Dispersion Modeling Methodology.

Air dispersion modeling assessment was conducted for the purpose of predicting the impact of air contaminant emissions to the atmosphere associated with electrical generation operations in the SaskPower Boundary Dam area. The assessment was conducted to evaluate and compare the atmospheric emissions of an IGCC-based electricity generating plant, with and without pre-combustion CO₂ capture, with a competing pulverized lignite coal-fired electricity generating stations (with and without CO₂ capture). The atmospheric emissions associated with a pulverized coal-fired electricity generating station without CO₂ capture process was used for the base case scenario, and the rest, the atmospheric emissions of pulverized lignite coal-fired electricity generating station with CO₂ capture and the IGCC, with and without CO₂ capture, are compared to the base case scenario. The location of all plants was assumed to be the same site as SaskPower's Boundary Dam, approximately 5 kilometers southwest of the city of Estevan, Saskatchewan.

In this study, the U.S. EPA AERMOD dispersion modeling (Version 13350) was selected to predict the maximum ground-level air concentrations of SO₂, nitrogen dioxide (NO₂), PM_{2.5}, Hg, Cd as well as other heavy metals that could have an impact on human health resulting from the operation of electricity from both pulverized and IGCC plants. The dispersion modeling was performed based on Saskatchewan Air Quality Modeling Guidelines [22]. The primary input to AERMOD was the "run stream setup file" and contains source location, parameter data, receptor location, pre-processor meteorological data file (American Meteorological Society/Environmental Protection Agency Regulatory Meteorological (AERMET)), and output options. The background concentration values and ambient air quality standard values for air contaminants were adopted from available regional ambient air quality monitoring data provided by the Saskatchewan Ministry of Environment [22–25]. The cumulative assessment of each air contaminant was addressed by the inclusion of ambient background concentrations of an air contaminant to the predicted value from AERMOD to obtain total concentrations before making a comparison to Saskatchewan ambient air quality standards. In the case that Saskatchewan air quality standards were not available, the comparison was made to Ontario.

2.2.1. Facility Regional Setting and Study Area

In this paper, the study area of 20 kilometers by 20 kilometers centered on the SaskPower Boundary Dam electricity generating station was selected to conduct the air quality modeling assessment. As the plant is located approximately 5 kilometers southwest of the city of Estevan, it was thought that a 20 km × 20 km area was a reasonable size for covering Estevan and the surrounding area, as most pollution concentration occurs within this range based on the reports from [25] and [26]. Figure 2 presents the location of air dispersion quality study area. The City of Estevan is the major population concentration in the region.

2.2.2. Meteorology, Receptors and Terrain

In order to assess air quality impacts, meteorology data are necessary for air dispersion modeling, as the contaminants being studied migrate through the environment. AERMOD uses hour-by-hour meteorological data that is processed through AERMET, where the meteorology data is organized into a suitable format for the AERMOD dispersion model. To run the air dispersion model, five consecutive years of representative meteorology data should be used to adequately predict the pollutant concentrations at ground level [25]. AERMET requires at least one surface meteorological station and one station where the data of wind speed, wind direction and temperature are collected at standard heights [22]. The surface parameters include albedo (the percentage of radiation returning from a surface compared to that which strikes it [27]), Bowen ratio (to determine the surface moisture), and surface roughness (the measure of how efficiently momentum can be transferred to the ground at a given wind speed [28]). Preparing AERMET input files is time-consuming; therefore,

to accommodate the air quality modeling, the Saskatchewan Ministry of Environment has developed regional meteorological data sets, and these are available on the ministry's website. Saskatchewan's meteorological data sets have been developed based on geographical area and are categorized into five zones; Northern, North Central, Central, Southwestern and Southeastern. Each regional meteorological data set provided by the Ministry contains five years of hourly meteorological data for the years 2003 to 2007, as this AERMET input file is the most recent data available and is representative of the area under the study. In the AERMET file, the standard height used in the sampling at the meteorological station is set as 9 meters.

In this study, the flat terrain option was chosen to model the effects of terrain above stack base in the rural setting as the geography of Estevan and the surrounding area in the southwest of Saskatchewan is relatively flat. The origin receptor grid defined the locations where the model would predict ground-level concentration or where the stack was located. The distances along each directional radial at which the receptor was located were defined as 2000 meters, 4000 meters, 6000 meters and 10,000 meters for all case scenarios. The model also generated direction radials for the receptor network; in this case, there were 36 directions, beginning with the 10 degree flow vector and incrementing every 10 degrees clockwise. The receptor network is shown in Figure 3.

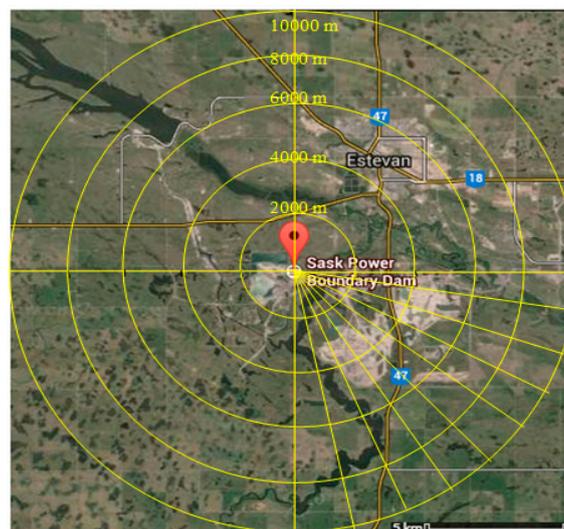


Figure 3. Location of air dispersion study area and receptor network specification.

2.2.3. Emission Source Characterization

In this study, a prediction of maximum ground-level air concentrations of emissions from a Saskatchewan lignite IGCC-based electricity generating plant, with and without the pre-combustion CO₂ capture process, and from the competing pulverized lignite coal-fired electricity generating stations, with and without CO₂ capture process, was made. The specific air contaminants released into the atmosphere associated with the operation of all electricity generating stations include NO₂, SO₂, PM_{2.5}, As, Cd, Cr, Hg, Mn, Sb, Co, Cu, Pb, Mo, Se, V, and Ni.

The emission data related to the operation of a pulverized coal-fired electricity generating station were adopted from the previous work of [16]. The emissions data of IGCC systems were conducted with the engineering simulation software AspenPlus[®], Excel[™] spreadsheets and life-cycle assessment simulation software GaBi5[™]. The emission rates are based on each MWh net electricity produced. Physical dimensions of the emission source (stack height and stack diameter) as well as emission parameters characterizing of the exit conditions (exit velocity and exit temperature) were taken from [1] and [29] for Pulverized coal-fired and IGCC systems, respectively. It has to be noted that, due to the limitation and confidentiality of the data, the stack height and stack diameter of pulverized coal-fired

with post-combustion CO₂ capture process are assumed based on [30]. Table 3 shows the emission rate and stack parameters used for air dispersion modeling.

Table 3. Emission rates and stack parameters for AERMOD.

Parameters	PC	PC with Capture	IGCC	IGCC with Capture
Net Electricity Output (MW)	820	552	342	261
Stack Height (m)	92	55	99.06	99.06
Stack Diameter (m)	5.18	3	7.3	7.3
Stack Exit Velocity (m/s)	24.4	24.4	14.02	14.02
Exit Gas Temperature (K)	436.15	340	373.7	373.7
Emission rate (g/s) per MWh				
NO ₂	3.1×10^{-2}	3.7×10^{-2}	2.2×10^{-2}	1.9×10^{-2}
SO ₂	1.8×10^{-2}	1.42×10^{-3}	2.6×10^{-2}	2.9×10^{-2}
PM _{2.5}	2.4×10^{-2}	1.9×10^{-2}	2.3×10^{-2}	1.4×10^{-2}
As	1.2×10^{-2}	2.09×10^{-4}	8.33×10^{-7}	1.43×10^{-8}
Cd	1.1×10^{-3}	2.42×10^{-4}	5.94×10^{-8}	7.0×10^{-9}
Cr	1.6×10^{-2}	7.06×10^{-5}	1.44×10^{-8}	6.11×10^{-12}
Hg	1.3×10^{-3}	1.29×10^{-6}	1.39×10^{-7}	1.39×10^{-11}
Mn	1.2×10^{-3}	1.42×10^{-6}	1.83×10^{-7}	3.11×10^{-9}
Sb	1.1×10^{-3}	2.28×10^{-7}	7.22×10^{-8}	1.44×10^{-9}
Co	1.9×10^{-3}	1.92×10^{-6}	4.03×10^{-8}	4.03×10^{-9}
Cu	6.4×10^{-4}	3.89×10^{-6}	1.53×10^{-7}	3.06×10^{-9}
Pb	8.3×10^{-3}	1.25×10^{-5}	1.08×10^{-6}	1.62×10^{-8}
Mo	1.1×10^{-2}	2.11×10^{-5}	8.89×10^{-9}	1.78×10^{-10}
Se	1.1×10^{-1}	2.4×10^{-2}	2.0×10^{-6}	9.89×10^{-7}
V	2.4×10^{-2}	4.06×10^{-5}	3.14×10^{-6}	6.28×10^{-8}
Ni	1.6×10^{-1}	5.64×10^{-4}	2.94×10^{-7}	7.36×10^{-9}

3. Data Inventory Modeling and Systems Descriptions

3.1. Integrated Gasification Combined Cycle (IGCC) with Pre—Combustion CO₂ Capture Process

The IGCC system equipped with a CO₂ capture process includes the following: an Air Separation Unit (ASU), a Gasification Unit, a Gas Cleaning/Acid Gas Removal unit, a Sulfur Recovery Unit, a Water Gas Shift Unit (WGS), a CO₂ Removal Unit, and a Combined Cycle Electrical Generation Unit (Gas turbine, Steam turbine, and Heat Recovery Steam Generator). The simplified flow diagram of the IGCC with a pre-combustion CO₂ capture process is shown in Figure 4.

The processes mentioned above (ASU, Gasifier, Gas cleaning and WGS) were simulated with AspenPlus[®], while the CO₂ removal and combined cycle electrical generation unit were simulated using a spreadsheet. The specific design and detailed description of the process unit in this study are given below.

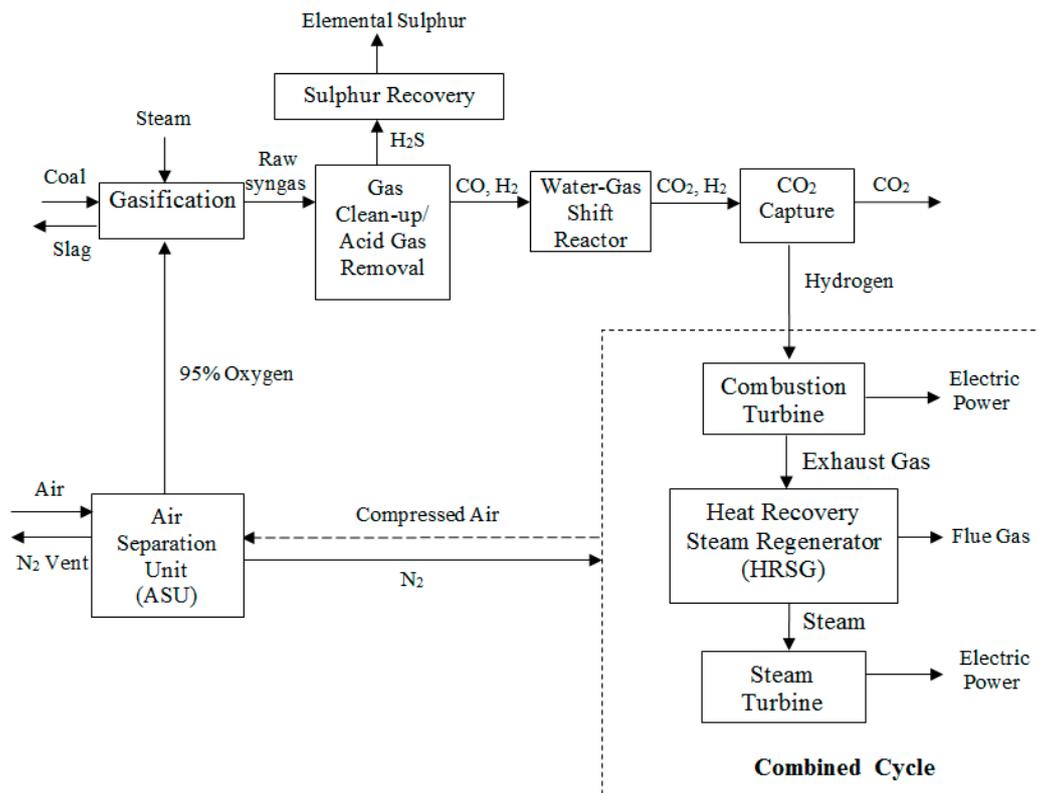


Figure 4. Simplified flow diagram of IGCC with CO₂ capture process.

3.1.1. Air Separation Unit (ASU)

In this study, cryogenic separation was applied since it is the most common method and widely used for medium and large scale oxygen production with high purity requirements. Ambient air is first sent to a multistage air compressor unit. The air is compressed to approximately 6.3 bar (630 kPa). The compressed air is then cooled in the main heat exchangers. The cooled air is then fed into the cryogenic separation unit. As a result, the air stream is liquefied and split into three streams: a nitrogen stream, a 95% oxygen stream, and a water stream. In this study, 70% of nitrogen was sent to gas turbines to moderate combustion conditions and minimize or reduce NO_x formation. In the meantime, the 95% oxygen was compressed and sent to the gasifier to further the fuel reaction process.

3.1.2. Gasification

The feed coal slurry was pumped into the gasifier (reactor) together with a high purity oxidant (95% O₂) to partially oxidize the fuel, by controlling the amount of oxygen and steam. The reaction of coal slurry and oxygen took place at a high temperature of between 1250 °C and 1427 °C.

In the simulation, an entrained flow gasifier (GE) was modeled at a pressure of 580 psia (4 MPa) and operated on a 35 kg/s coal mass flow. The entrained-flow gasifier was a plug type reactor. This reactor is suitable for fine feedstock fuel, which, in this case, had a particle diameter less than 0.1 mm. The fuel flows co-current and reacts with oxygen and with or without steam (depending on whether the coal was added as dry feed or water-based slurry). The highly pure oxygen (95% O₂) at an ambient temperature of 25 °C and slurry coal were introduced at the top of the gasifier. The mass ratio between injected water and coal was set at 0.54 and the oxygen-fuel ratio was set at 0.85, based on the report from [31] for the optimum steam-fuel ratio and oxygen-fuel ratio, respectively. The fuel (slurry-coal) flows co-currently and reacts with the oxygen. The fuel selected in this study was Saskatchewan lignite coal.

3.1.3. Acid Gas Removal and Sulfur Recovery Process

The raw syngas from the gasification process mainly consisted of carbon monoxide (CO) and hydrogen (H₂), and a small quantity of contaminant compounds such as hydrogen-sulfide (H₂S) and carbonyl sulfide (COS), oxides of carbon and sulfur such as carbon dioxide (CO₂) and sulfur dioxide (SO₂), nitrogen compounds such as ammonia (NH₃), hydrogen cyanide (HCN), Hg, and particulates from the mineral fraction of the coal such as unconverted carbon and ash [32]. Some of the corrosive components such as sulfide, nitride, and dust were removed in this cleaning section.

The H₂S rich gas from the Acid Gas Removal (AGR) process was then fed into the two-step Claus Plant Process (sulfur recovery) to produce sulfur [33]. In this process, 96% of H₂S in the acid gas feed stream was converted into elemental sulfur [33]. Sulfur is a valuable product, which can be used for manufacturing sulfuric acid and fertilizer, *etc.* It has to be noted that SaskPower converts the captured SO_x to sulfuric acid (H₂SO₄). The alternative of IGCC would be to take the H₂S gas stream and re-inject it with the captured CO₂ stream, as there is no impact of H₂S on EOR (Weyburn receives a CO₂ stream at 1% H₂S) or to inject it separately into a disposal well (Alberta has over 40 acid gas disposal wells).

3.1.4. Water Gas Shift and CO₂ Removal Unit

After the H₂S scrubbing process, the syngas stream containing mainly CO and H₂ was fed to the shift reactors. In order to meet the steam-to-carbon ratio requirement, steam was added to the clean syngas before passing through the shift reactor.

In the first shift reactor, the steam reacted with syngas at high temperature. The reaction took place with the ratio of 1.0 mole of water per mole of carbon monoxide. The water gas shift reaction was an exothermic reaction that produced sensible heat, and the syngas from the high temperature reactor had to be cooled before being fed into the low temperature reactor. The shift reaction was repeated in the second reactor with a lower temperature than the first reactor. The syngas that left the WGS reactor had a much higher H₂ composition than the raw syngas with the CO conversion of 90% [32,33].

The CO₂ and H₂ rich syngas from water-gas-shift process was then fed to a Selexol[®] process, licensed by UOP LLC, to remove CO₂. The Selexol[®] solvent was a mixture of Dimethylethers and Polyethylene glycol with the formulation of CH₃(CH₂O)_nCH₃, where n is between 3 and 9. The Selexol[®] solvent absorbed 95% of the CO₂ from the feed syngas when at the relatively high pressure of between 300 and 2000 psia (2.068 and 13.8 MPa) [34]. The rich solvent containing acid gas (CO₂) was then sent to a regenerator to strip off the solvent and recover the CO₂. The resulting gases, containing 95% by mass CO₂, was then sent to a dehydrator and compressor and compressed to 80 bar (8 MPa) in an intercooled staged compressor and liquefied. The CO₂ was then ready to be transported and used for enhanced oil recovery. One of the advantages of Selexol[®] process over an amine absorption process is that Selexol[®] requires less energy than amine-based processes. This is because there is no chemical reaction involved between the solvent and the acid gas. However, the solvent capacity is reduced when the feed syngas pressure is less than 300 psia (2.068 MPa). With high pressure syngas, the physical absorption using Selexol[®] has proven to be favorable for CO₂ removal [20].

3.1.5. Electrical Generation Unit

After the CO₂ removal process, the hydrogen rich syngas was then introduced to the combined cycle electricity generation unit to produce electricity. The combined cycle electricity generation consists of a gas turbine system and steam turbine system. The inventory modeling of combined cycle was conducted based on the Excel[™] spreadsheet of mass and energy balance model of a gas turbine combined cycle from [35,36] and are described in detail in the following section. The main inputs and assumptions of the combined cycle are also presented in Table 4.

Table 4. Input assumptions for combined cycle system [36].

Parameter	Value
Ambient Pressure (psia)	14.7 (101.35 kPa)
Ambient Temperature (K)	288
Compressor Pressure Ratio	15.7
Combustor Pressure Drop (psia)	4 (27.5 kPa)
Turbine Backpressure (psia)	2 (13.8 kPa)
Turbine Inlet Temperature (K)	1600
Turbine Inlet Reference Mass flow (kg/s)	455
Cooling Air Extraction Fraction (%)	12
Nitrogen Injection (%)	70
Nitrogen/Syngas molar ratio	0.6–0.8
Adiabatic Compressor Efficiency	0.77
Adiabatic Turbine Efficiency	0.87
Shaft/generator Efficiency	0.98
Steam Cycle Heat Rate (10^6 J/kWh, LHV)	9.653
HRSG Outlet Temperature (K)	386

3.1.6. Combined Cycle Electricity Generation

After the CO₂ scrubbing process, the hydrogen rich syngas was fed into a combined cycle generator to produce electricity. The combined cycle generation consists of two main components; gas turbine system and steam turbine system.

A gas turbine system consists of three main components; the compressor, the combustor, and the turbine. Air at ambient conditions enters the compressor. The compressed air then enters the combustion chamber, where the air is mixed with the high pressure fuel (clean syngas). In the combustion unit, the air and fuel are burned at a constant pressure [35]. The high pressure gases from combustor are sent to the turbine (expander) where the pressure and temperature of the gas is reduced. The difference between the work output of the expander and the work input to the compressor is the net electricity produced from the generator. The high temperature exhaust gas is then passed to the steam turbine cycle process.

The steam turbine cycle consists of a heat recovery steam generator (HRSG), a steam turbine and other auxiliary parts. The gas turbine exhaust flows through the heat recovery steam regenerator to provide superheated steam, saturated steam and boiler feed water [36]. The steam is then sent to the high pressure steam turbine and low pressure steam turbine. Then, the generator converts shaft work into electricity. The cooled flue gas from the HRSG is exhausted from a flue stack.

3.2. Integrated Gasification Combined Cycle (IGCC) Without Pre-Combustion CO₂ Capture

A typical IGCC system without CO₂ capture is similar to an IGCC system with CO₂ capture except that there is no water gas shift (WGS) or Selexol[®] unit installed in the system. Thus, the turbine is powered by syngas not a relatively pure stream of H₂. In the gasification process, slurry-coal is first reacted with steam and high purity oxygen to produce syngas. The high purity oxygen (95% O₂) is produced in an ASU. After the gasification process, the syngas, which contains a high content of CO and H₂, is cooled and cleaned in the gas cleaning/acid gas removal unit and Sulfur recovery unit. Then, the clean syngas is combusted with excess N₂ (to keep NO_x level down) in the gas turbine combined cycle system. In the combined cycle, the clean syngas (fuel) is first reacted with the compressed air in the combustor. The product gas from the combustor then enters the expander inside the turbine, and the shaft work is produced. The heat from the gas turbine exhaust flows through the HRSG to make steam. The steam is then expanded in the steam turbine. Finally, the electricity is generated by gas turbine and steam turbine. The simplify flow diagram of IGCC without pre-combustion is shown in Figure 5. The process-specific parameters of both IGCC, with and without pre-combustion CO₂ capture, are shown in Table 5, and the results composition of syngas for both IGCC, with and without CO₂ capture along with energy consumptions for each process, are shown in Table 6.

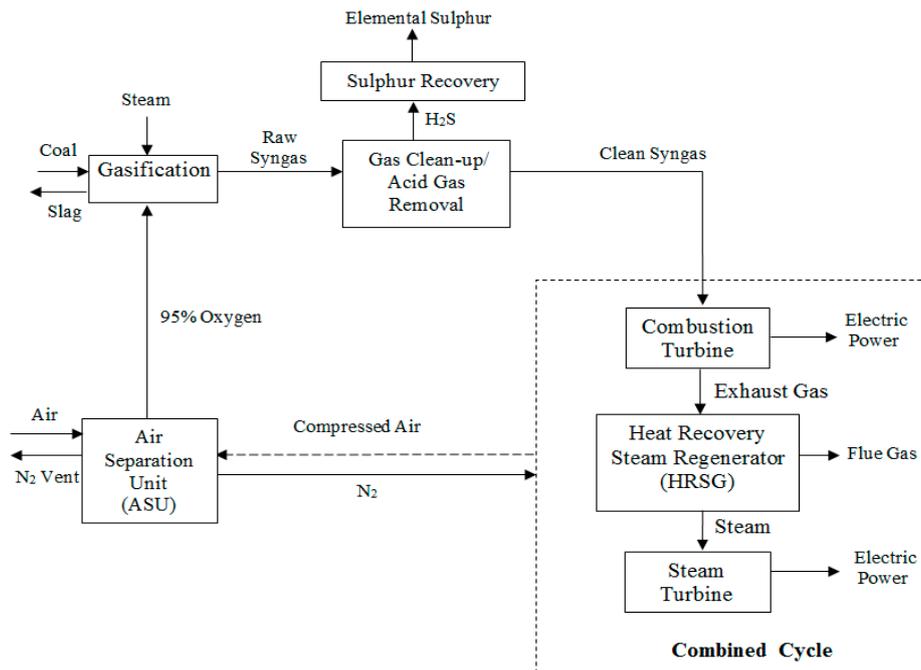


Figure 5. Flow diagram of IGCC without pre-combustion CO₂ capture process.

Table 5. Main model parameters for IGCC electrical generating station including CO₂ capture process (Selexol®).

Process	Parameter	Value
ASU	Type and number of ASU	One cryogenic separation train
	O ₂ purity	95%
	Excess Nitrogen Injection	70%
Gasification	Type and number of Gasifier	One oxygen-blow GE gasifier
	Gasifier temperature, °C	1250
	Gasifier pressure, Mpa	6
	Steam input to gasifier, mol H ₂ O/mol C	0.54
	Oxidant pressure (at outlet of ASU), MPa	4
	Particulate removal efficiency from syngas, %	50
AGR	COS to H ₂ S conversion efficiency, %	96
	H ₂ S removal sufficiency, %	98
	COS removal efficiency, %	40
	Sulfur recovery system	Claus plant and Bravon-Stretford tail gas unit
	Sulfur recovery efficiency, %	95
CO ₂ capture	Steam added to shift reactor, mol H ₂ O/mol CO converted	1
	CO ₂ removal efficiency, %	95
Combined cycle electricity output	Combined cycle electricity output, MW net	342.41 (without CO ₂ capture),
		261.22 (with CO ₂ capture)

Table 6. Model results of IGCC with and without capture.

Syngas Compositions (% by Volume)	IGCC without Pre-Combustion CO ₂ Capture	IGCC with Pre-Combustion CO ₂ Capture (95% CO ₂ Removal)
AR+N ₂	5.53	6.55
O ₂	0.36	0.75
CH ₄	0.4	0.45
CO ₂	53.63	7.66
H ₂ S	0.02	0.02
H ₂	12.62	68.05
CO	27.62	13.07
H ₂ O	1.73	3.03
Total	100	100
H ₂ /CO	0.45	5.22
Fuel heating value (HHV) (J/g)	47,915.4	53,665.3
Gas turbine power output	202.45	184.60
Steam turbine power output (MWh)	252.34	241.1
Combined cycle power output (MW _{gross})	454.79	425.7
Misc. Power Block Use (MW)	11.35	9.60
Air Separation Unit Use (MW)	77.09	76.77
Gasifier Use (MW)	14.24	14.39
Sulfur Capture Use (MW)	5.90	6.47
Claus Plant Use (MW)	0.49	0.51
Beavon-Stretford Use (MW)	1.49	1.55
WGS and Selexol Use (MW)	-	49.5
Net electricity output (MW _{net})	342	261
Plant Efficiency (%)	64.63	49.3

3.3. The Conventional Lignite Coal-Fired Electricity Generation With and Without Post Combustion CO₂ Capture Process

As mentioned earlier in this paper, the conventional lignite coal-fired electricity generation was adopted from the previous work of [16]. The process description and input data of post-combustion is therefore not explained in extensive detail. For this study, Saskpower's Boundary Dam Power Station (BDPS), a conventional lignite coal-fired power station in Estevan, Saskatchewan was chosen as a case study. Operations of the BDPS were modeled. The plant generates a gross electricity capacity of 882 MW for the purposes of Manuilova's work (part of the station has subsequently been closed).

The amount of lignite coal needed to produce the gross electric capacity of 882 MW was calculated based on the gross cycle heat rate and higher heating value of coal. The amount of oxygen needed for stoichiometric combustion of fuel is the sum of oxygen needed to convert carbon to carbon dioxide, hydrogen to water, and sulfur to sulfur dioxide, minus any oxygen in fuel. The combustion products were calculated using emissions factors for pulverized coal tangentially-fired dry bottom boilers [21]. More detailed information can be found in [16].

In the capture scenario, the flue gas desulfurization (FGDs) and CO₂ capture units were installed for gas cleaning process. The wet flue gas desulfurization unit was installed to remove 99% of SO₂ before the flue gas entered the CO₂ capture unit, in which the post-combustion amine-based absorption of CO₂ from flue gases and CO₂ compression was modeled. 30 wt% monoethanolamine (MEA) was used as the sorbent for removing 90% of CO₂ from the flue gas. The modeling assumptions are presented in Table 7.

Table 7. Model assumptions of the conventional lignite coal-fire electricity generation with and without post-combustion CO₂ capture process [21].

Parameter	Value		
MEA concentration in sorbent, %	30		
Lean sorbent CO ₂ loading, mole CO ₂ /mole MEA	0.2		
Temperature of the flue gas entering the CO ₂ absorber, °C	50		
Desired CO ₂ product pressure, psig	2000 (13.8 MPa)		
MEA losses, kg MEA/tonne CO ₂	1.3607		
Reclaimer waste, kg/tonne CO ₂ captured	3.2		
Activated carbon consumption, kg C/tonne CO ₂ captured	0.075		
Caustic consumption, kg NaOH/tonne CO ₂ captured	0.13		
Ammonia formation, kg NH ₃ /tonne CO ₂	0.136		
Water consumption, tonne/MWh	1.1		
Sorbent regeneration heat requirement, kJ/kg	3600		
Enthalpy of steam, kJ/kg steam	2000		
Reboiler efficiency, %	85		
Steam requirement, kg/MWh	2045		
Parameter	ESP *	FGD **	CO ₂ Capture and Compression
Particulates removal efficiency, %	99	70	50
CO ₂ removal efficiency, %	-	-	90
SO ₂ removal efficiency, %	-	99	99.5
SO ₃ removal efficiency, %	25	50	99.5
HCl removal efficiency, %	-	90	95
NO ₂ removal efficiency, %	-	-	25
Hg ²⁺ removal efficiency, %	7.5	25	80
Auxiliary power requirements, % MW _{gross}	6.9 ***	3.8	34.6

* ESP is installed on both capture and non-capture scenario; **FGD is install on only capture scenario;
 *** Auxiliary power requirements for the boiler and ESP operations.

4. Results and Discussions

4.1. LCA Results

The electricity outputs for four different scenarios are presented in Figure 6. The net electricity output of pulverized coal without post-combustion CO₂ capture process is 820 MWh and 552 MWh for pulverized coal with post-combustion CO₂ capture process. For the IGCC system, the net electricity outputs are 342 MWh and 261 MWh for the IGCC and the IGCC with pre-combustion CO₂ capture process, respectively. In the case of the IGCC system, there is a 24% reduction in electricity output in the “IGCC with capture” scenario compared to the “IGCC” scenario. For the conventional pulverized coal system, there is a 33% electricity reduction in the “PC with capture” scenario compared to the “PC” scenario. These reductions in electricity output were due to the additional electricity and steam requirements of the CO₂ capture process system. In order to compensate for this loss in electricity output, additional coal needs to be burned. As shown in Figure 7, 36% extra coal is needed for the “IGCC with capture” scenario and 48% extra coal is needed for the “PC with capture” scenario, compared to the “IGCC” and “PC” scenarios, respectively.

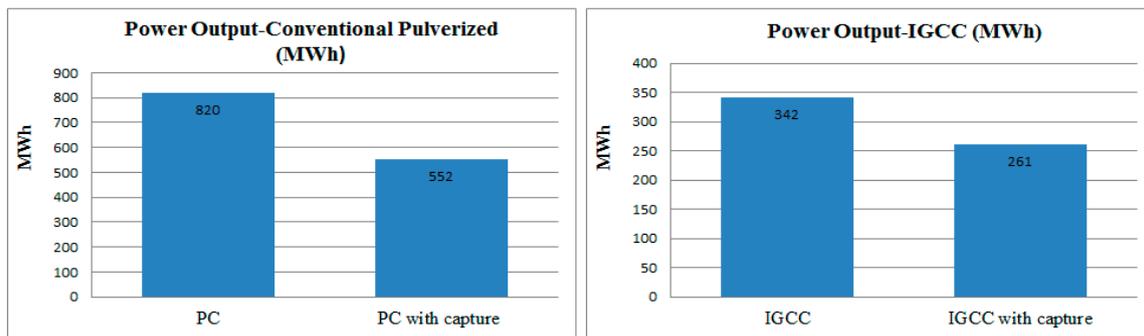


Figure 6. Net power output for four scenarios.

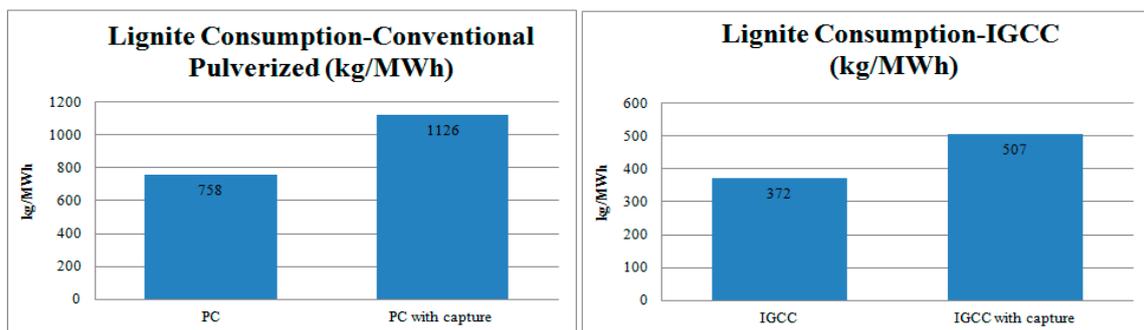


Figure 7. Lignite consumption for four scenarios.

The results for different impact categories per 1 MWh of electricity output as well as the environmental contributions of each process toward the impact categories are shown in Figure 8. The analysis of the environmental impacts for each impact category is presented as follows. The analysis adopts the “conventional pulverized coal-fired electricity generation system without CO₂ capture” or the “PC” scenario as the baseline, and the differences between the “PC” scenario *versus* the “PC with capture,” “IGCC” and “IGCC with capture” scenarios are shown as percentage changes. As mentioned earlier, the system boundary of this research does not include the utilization of any oil produced under EOR as well as the CO₂ sequestration underground process. See [16] for the life-cycle assessment of the power generation associated with a CO₂-EOR process.

4.1.1. Global Warming Potential

The results showed a reduction in global warming potential in terms of CO₂ equivalents, achieved through the application of the post-combustion and pre-combustion CO₂ capture and IGCC technologies. Among them, the IGCC with capture performed the best, followed by PC with capture and IGCC without capture. The category of CO₂ emissions from the PC with capture scenario was found to be 233 kg CO₂ equivalent per MWh of electricity produced. For the IGCC with capture scenario, the CO₂ emissions category was found to be 77 kg CO₂ equivalent per MWh of electricity produced. The PC with post-combustion showed a reduction in global warming potential of 80% compared to PC. Compared to PC, the IGCC system, with and without the pre-combustion technology, showed a reduction in global warming potential by 93% and 75%, respectively. Due to the higher CO₂ concentration in the syngas after the WGS in the IGCC process, the removal of CO₂ from the combustion gas stream was more efficient than the pulverized coal-fired electricity generation technology. Additionally, the integrated gasification combined cycle (IGCC) gasifier was operated under higher pressure, which made it easier to remove CO₂ from the gas stream than to capture it from the flue gas at atmospheric pressure.

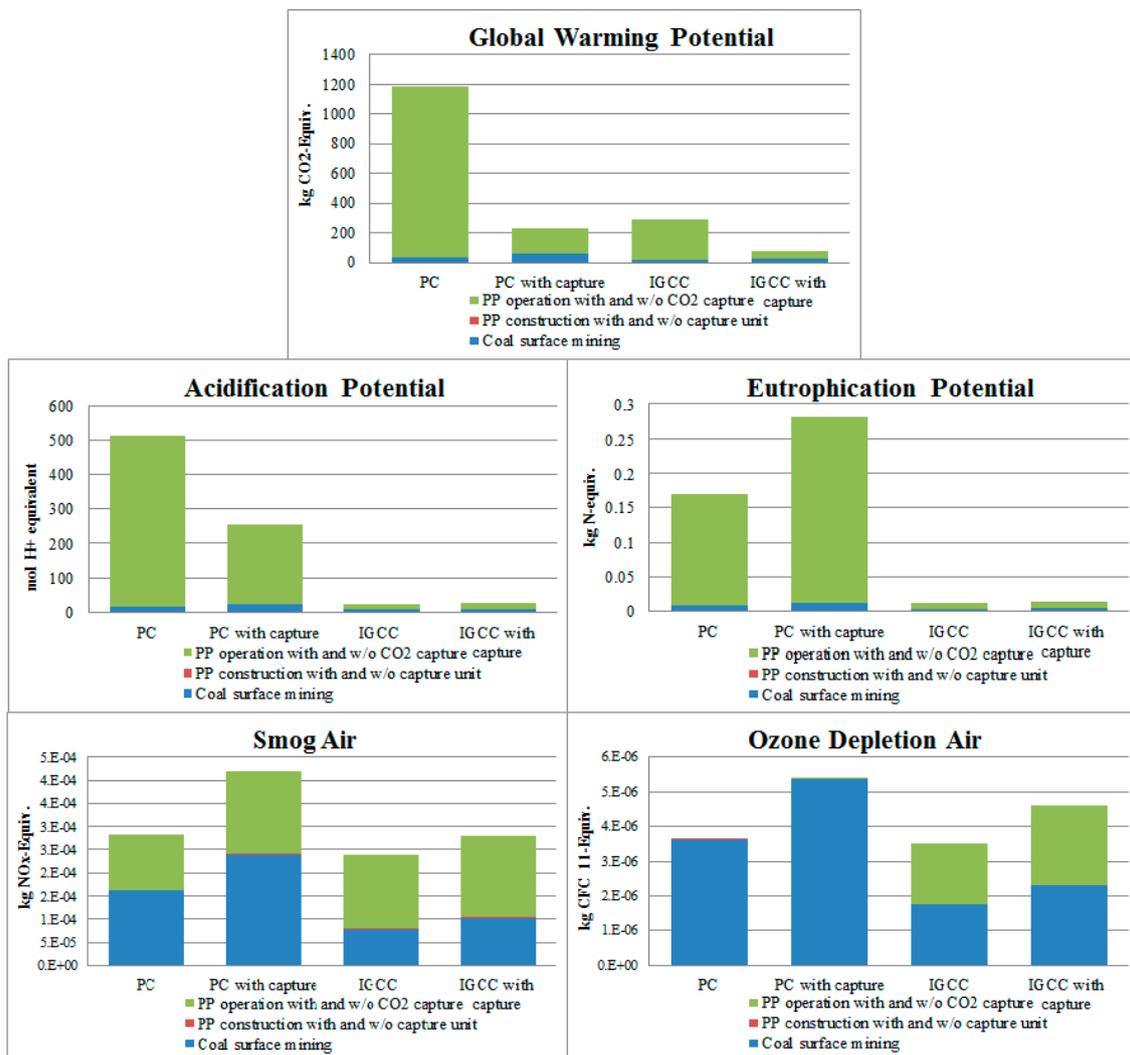


Figure 8. Life-cycle impact assessment.

4.1.2. Acidification

The pollutants that contribute to acidification include: sulfur oxides (SO_x), nitrous oxides (NO_x), hydrochloric acid (HCl), and hydrofluoric acid (HF). These acids can be deposited dry (e.g., dust) or wet (e.g., acid rain). In the acidification category, the impacts are relatively low for the “PC with capture,” “IGCC,” and “IGCC with capture” scenarios compared to the baseline case of PC.

In the case of the “PC with capture” scenario, the reduction of acidification potential was found to be 50%. This is mainly due to the removal of SO_x in the FGD. The IGCC system performed distinctly better than the conventional electricity generation station. The result showed a reduction in the acidification impact category of 95% and 96% for the IGCC technology, with and without pre-combustion capture, respectively, compared to the baseline case of the coal-fired electricity generation station without CO_2 capture. This was due to the gas cleaning process in the IGCC, which removed most of the pollutants. Only small amounts of sulfur and nitrogen oxides remained in the syngas, and these were converted to SO_2 and NO_x in the combustion turbine and released into the atmosphere. The process of electricity generation was the main contributor to the acidification impact category in all the scenarios.

4.1.3. Eutrophication

The eutrophication category included the impact of nutrients and degradable organic pollution, which led to oxygen consumption in the ecosystem. The release of nutrient and the nitrogen compounds of nitrogen oxide (NO), N₂O, nitrogen dioxide (NO₂) and NH₃ cause eutrophication. In this category, the impacts are relatively high for PC with CO₂ capture compared to the baseline scenario. The observed increase in eutrophication potential impact category is 66% in post-combustion scenarios. This is due to the loss of plant capacity, and NO_x emissions increased with the addition of a capture unit. In addition, the emissions of NH₃, MEA, and ethylene from the production of MEA also contributed to an increase in the eutrophication potential.

Compared to a conventional electricity generating station, the eutrophication potential of the IGCC electricity system, with and without CO₂ capture, showed a significant reduction of 91% and 93%, respectively, compared to the conventional coal-fired electricity generation system without CO₂ capture. The operation of the IGCC system was the primary contributor to the eutrophication impact category. The electricity generation process produced inorganic solid waste, which was collected and landfilled, and with time leached into the soil and ground water. This accounted for 90% of the impact in this category.

4.1.4. Ozone Depletion

The electricity generation systems contribute to ozone depletion because of their production of halogenated organic, volatile organic compounds (VOC), trichlorofluoromethane (R11), and dichlorotetrafluoroethane (R114), which are released into the air. The results show that the ozone depletion air impact category was increased by 48% in the "PC with capture" scenario and by 27% in the "IGCC with capture scenario", compared to the "PC" scenario. There was also an observed reduction by 4% in the "IGCC without capture" scenario. Coal mining and electricity operation are mainly responsible for the ozone depletion. Since the results are presented in the form of percentages and not in absolute numbers, small absolute increases can be exaggerated when viewed as percentage increases.

4.1.5. Smog Air

Coal surface mining and the electrical operation processes produce NO_x, which contributes directly to smog air or summer smog. The results from the "PC with capture" scenario showed an increase of 48.6% on the impact category of smog air compared to the baseline scenario. This increase was mainly due to NO_x from coal mining and NO₂ from the operation of the electrical generating station. In the case of the IGCC systems, the results also showed the reduction in the smog air impact category. The results showed a reduction of 15.8% and 1.1% on the "IGCC" and "IGCC with capture" scenarios, respectively, compared to the baseline scenario. The reduction was due to less NO_x content in the flue gas from syngas combustion. The main contributions to the category of smog air of IGCC are the operation of the electrical generating station and coal surface mining.

4.2. Air Dispersion Modeling Results

The results of air dispersion assessment from electricity generating stations are presented in Tables 8–11. The assessment considers air emissions of NO₂, SO₂, PM_{2.5}, As, Cd, Cr, Hg, Mn, Sb, Co, Cu, Pb, Mo, Se, V, and Ni. These air emission substances have an impact on human health, which will be further analyzed in the next section of this paper. The maximum air pollution concentrations of each substance are compared to Saskatchewan air quality standards unless otherwise noted.

The total maximum concentration results are reported with the inclusion of ambient background concentrations to air contaminant predicted values as per the methodology outline in Saskatchewan Air Dispersion Modeling guideline. The maximum predicted ground-level concentrations per MWh of net electricity produced on both not including and including the ambient ground-level concentration are summarized in Tables 8 and 9 respectively. The location of predicted ground-level concentration

of each element for each averaging time is shown in Table 10. The maximum predicted ground-level concentration with the inclusion of ambient ground-level concentrations on total electricity produced are summarized in Table 11.

Table 8. AERMOD results: maximum predicted ground-level concentration per MWe produced.

Substance	Averaging Period	Ambient Background Concentration ($\mu\text{g}/\text{m}^3$)	Limited Ambient Air Quality Standard ($\mu\text{g}/\text{m}^3$)	AERMOD Results of Maximum Predicted Ground Level Concentration ($\mu\text{g}/\text{m}^3$) per MW Net Electricity			
				PC	PC with Capture	IGCC	IGCC with Capture
NO ₂	One-hour	2.2×10^{-2}	400	3.1×10^{-2}	1.3×10^{-1}	2.3×10^{-2}	2.1×10^{-2}
	Daily	2.0×10^{-2}	200	2.9×10^{-3}	1.4×10^{-2}	2.5×10^{-3}	2.2×10^{-3}
	Annual	1.0×10^{-2}	100	6.1×10^{-4}	9.6×10^{-4}	1.7×10^{-4}	1.6×10^{-4}
SO ₂	One-hour	3.0×10^{-3}	450	1.8×10^{-2}	4.9×10^{-3}	2.8×10^{-2}	3.0×10^{-2}
	Daily	2.0×10^{-3}	150	1.7×10^{-3}	5.5×10^{-4}	2.9×10^{-3}	3.2×10^{-3}
	Annual	0	30	3.5×10^{-4}	4.0×10^{-5}	2.1×10^{-4}	2.2×10^{-4}
PM _{2.5}	Daily	8.3	30	2.3×10^{-4}	7.5×10^{-3}	2.6×10^{-3}	1.6×10^{-3}
	Annual	3.7	15	2.0×10^{-5}	5.0×10^{-4}	1.8×10^{-4}	1.1×10^{-4}
As	Daily	-	0.3	1.6×10^{-4}	8.0×10^{-5}	0	0
Cd	Daily	-	2	1.1×10^{-4}	9.0×10^{-5}	0	0
Cr	Daily	-	1.5	1.5×10^{-3}	3.0×10^{-5}	0	0
Hg	Daily	-	2	1.3×10^{-3}	0	0	0
Mn	Daily	-	0.15	1.1×10^{-4}	0	0	0
Sb	Daily	-	25	1.1×10^{-4}	0	0	0
Co	Daily	-	0.1	1.8×10^{-4}	0	0	0
Cu	Daily	-	50	6.0×10^{-5}	0	0	0
Pb	Daily	-	0.5	7.8×10^{-4}	0	0	0
Mo	Daily	-	120	9.9×10^{-5}	1.0×10^{-4}	0	0
Se	Daily	-	10	1.1×10^{-2}	9.1×10^{-3}	0	0
V	Daily	-	2	2.3×10^{-3}	0	0	0
Ni	Daily	-	0.2	1.5×10^{-3}	2.2×10^{-4}	0	0

0 means the concentration is very small (less than 6 digits).

Table 9. AERMOD results: maximum predicted ground-level concentration including background concentrations per MWe produced.

Substance	Averaging Period	Ambient Background Concentration ($\mu\text{g}/\text{m}^3$)	Limited Ambient Air Quality Standard ($\mu\text{g}/\text{m}^3$)	AERMOD Results of Maximum Predicted Ground Level Concentration Including Ambient Background Concentration ($\mu\text{g}/\text{m}^3$) Per MW Net Electricity			
				PC	PC with Capture	IGCC	IGCC with Capture
NO ₂	One-hour	2.2×10^{-2}	400	5.3×10^{-2}	1.5×10^{-1}	4.5×10^{-2}	4.3×10^{-2}
	Daily	2.0×10^{-2}	200	2.3×10^{-2}	3.4×10^{-2}	2.2×10^{-2}	2.2×10^{-2}
	Annual	1.0×10^{-2}	100	1.1×10^{-2}	1.1×10^{-2}	1.0×10^{-2}	1.0×10^{-2}
SO ₂	One-hour	3.0×10^{-3}	450	2.0×10^{-2}	7.9×10^{-3}	3.1×10^{-2}	3.3×10^{-2}
	Daily	2.0×10^{-3}	150	3.7×10^{-3}	2.6×10^{-3}	4.9×10^{-3}	5.2×10^{-3}
	Annual	0	30	3.5×10^{-4}	4.0×10^{-5}	2.1×10^{-4}	2.2×10^{-4}
PM _{2.5}	Daily	8.3	30	8.30023	8.30752	8.30259	8.30158
	Annual	3.7	15	3.70002	3.70050	3.70018	3.70011
As	Daily	-	0.3	1.15×10^{-4}	8.0×10^{-4}	0	0
Cd	Daily	-	2	1.1×10^{-4}	9.0×10^{-5}	0	0
Cr	Daily	-	1.5	1.54×10^{-3}	3.0×10^{-5}	0	0
Hg	Daily	-	2	1.3×10^{-3}	0	0	0
Mn	Daily	-	0.15	1.1×10^{-4}	0	0	0
Sb	Daily	-	25	1.1×10^{-4}	0	0	0
Co	Daily	-	0.1	1.8×10^{-4}	0	0	0
Cu	Daily	-	50	6.0×10^{-5}	0	0	0
Pb	Daily	-	0.5	7.8×10^{-4}	0	0	0
Mo	Daily	-	120	9.9×10^{-4}	1.0×10^{-5}	0	0
Se	Daily	-	10	1.1×10^{-2}	9.1×10^{-3}	0	0
V	Daily	-	2	2.3×10^{-3}	0	0	0
Ni	Daily	-	2	1.5×10^{-3}	2.2×10^{-4}	0	0

Table 10. AERMOD results: location of maximum predicted ground-level concentration including background concentrations Per MWe produced.

Substance	Averaging Period	AERMOD Results of Maximum Predicted Ground Level Concentration Including Ambient Background Concentration ($\mu\text{g}/\text{m}^3$) Per MW Net Electricity				Maximum Prediction Location
		PC	PC with Capture	IGCC	IGCC with Capture	
NO ₂	One-hour	5.3×10^{-2}	1.5×10^{-1}	4.5×10^{-2}	4.3×10^{-2}	2000 meters, 140 degrees, SW of the facility
	Daily	2.3×10^{-2}	3.5×10^{-2}	2.2×10^{-2}	2.2×10^{-2}	2000 meters, West of the facility
	Annual	1.1×10^{-2}	1.1×10^{-2}	1.0×10^{-2}	1.0×10^{-2}	2000 meters, 140 degrees, SE of the facility
SO ₂	One-hour	2.0×10^{-2}	7.9×10^{-3}	3.1×10^{-2}	3.3×10^{-2}	2000 meters, 130 degrees, SW of the facility
	Daily	3.7×10^{-3}	2.6×10^{-2}	4.9×10^{-3}	5.2×10^{-3}	2000 meters, West of the facility
	Annual	3.5×10^{-4}	4.0×10^{-5}	2.1×10^{-4}	2.2×10^{-4}	2000 meters, 140 degrees, SE of the facility
PM _{2.5}	Daily	8.30023	8.30752	8.30259	8.30158	2000 meters, West of the facility
	Annual	3.70002	3.70050	3.70018	3.70011	2000 meters, 140 degrees, SE of the facility
As	Daily	1.2×10^{-4}	8.0×10^{-5}	0	0	2000 meters, West of the facility
Cd	Daily	1.1×10^{-4}	9.0×10^{-5}	0	0	2000 meters, West of the facility
Cr	Daily	1.5×10^{-3}	3.0×10^{-5}	0	0	2000 meters, West of the facility
Hg	Daily	1.3×10^{-3}	0	0	0	2000 meters, West of the facility
Mn	Daily	1.1×10^{-4}	0	0	0	2000 meters, West of the facility
Sb	Daily	1.1×10^{-4}	0	0	0	2000 meters, West of the facility
Co	Daily	1.8×10^{-4}	0	0	0	2000 meters, West of the facility
Cu	Daily	6.0×10^{-5}	0	0	0	2000 meters, West of the facility
Pb	Daily	7.8×10^{-4}	0	0	0	2000 meters, West of the facility
Mo	Daily	9.9×10^{-4}	1.0×10^{-5}	0	0	2000 meters, West of the facility
Se	Daily	1.1×10^{-2}	9.1×10^{-3}	0	0	2000 meters, West of the facility
V	Daily	2.3×10^{-3}	0	0	0	2000 meters, West of the facility
Ni	Daily	1.5×10^{-3}	2.2×10^{-4}	0	0	2000 meters, West of the facility

Table 11. AERMOD results: maximum predicted ground-level concentration including background concentrations.

Substance	Averaging Period	Ambient Background Concentration ($\mu\text{g}/\text{m}^3$)	Limited Ambient Air Quality Standard ($\mu\text{g}/\text{m}^3$)	AERMOD Results of Maximum Predicted Ground Level Concentration Including Ambient Background Concentration ($\mu\text{g}/\text{m}^3$)							
				PC	% of Criteria	PC with Capture	% of Criteria	IGCC	% of Criteria	IGCC With Capture	% of Criteria
NO ₂	One-hour	2.2×10^{-2}	400	25.0400	6.3%	70.0320	17.5%	8.0110	2.0%	5.5108	1.4%
	Daily	2.0×10^{-2}	200	2.3898	1.2%	7.9522	4.0%	0.8610	0.4%	0.5994	0.3%
	Annual	1.0×10^{-2}	100	0.5102	0.5%	0.5399	0.5%	6.8×10^{-2}	0.1%	5.2×10^{-2}	0.1%
SO ₂	One-hour	3.0×10^{-3}	450	14.5330	3.2%	2.7022	0.6%	9.4830	2.1%	7.8878	1.8%
	Daily	2.0×10^{-3}	150	1.3796	0.9%	0.3056	0.2%	1.0000	0.7%	0.8345	0.6%
	Annual	0	30	0.2870	1.0%	2.2×10^{-2}	0.1%	7.1×10^{-2}	0.2%	5.7×10^{-2}	0.2%
PM _{2.5}	Daily	8.3	30	8.4886	28.3%	12.4510	41.5%	9.1850	30.6%	8.7123	29.0%
	Annual	3.7	15	3.7164	24.8%	3.9760	26.5%	3.7610	25.1%	3.7287	24.9%
As	Daily	-	0.3	9.4×10^{-2}	31.4%	4.4×10^{-2}	14.7%	0	0.0%	0	0.0%
Cd	Daily	-	2	9.0×10^{-2}	4.51%	4.9×10^{-2}	2.48%	0	0.0%	0	0.0%
Cr	Daily	-	1.5	1.2628	84.2%	1.7×10^{-2}	1.1%	0	0.0%	0	0.0%
Hg	Daily	-	2	1.0438	52.2%	0	0.0%	0	0.0%	0	0.0%
Mn	Daily	-	0.15	9.0×10^{-2}	60.1%	0	0.0%	0	0.0%	0	0.0%
Sb	Daily	-	25	9.0×10^{-2}	0.36%	0	0.0%	0	0.0%	0	0.0%
Co	Daily	-	0.1	0.1476	147.6%	0	0.0%	0	0.0%	0	0.0%
Cu	Daily	-	50	4.9×10^{-2}	0.098%	0	0.0%	0	0.0%	0	0.0%
Pb	Daily	-	0.5	0.6396	127.9%	0	0.0%	0	0.0%	0	0.0%
Mo	Daily	-	120	0.8118	0.6%	5.0×10^{-3}	0.004%	0	0.0%	0	0.0%
Se	Daily	-	10	8.7658	87.66%	5.0450	50.45%	0	0.0%	0	0.0%
V	Daily	-	2	1.8778	93.9%	0	0.0%	0	0.0%	0	0.0%
Ni	Daily	-	0.2	1.2400	620%	0.1214	60.7%	0	0.0%	0	0.0%

4.2.1. NO₂ Predictions

The maximum predicted one-hour average ground-level NO₂ concentrations associated with “PC,” “PC with capture,” “IGCC” and “IGCC with capture” scenarios are 25, 70, 8 and 5.5 µg/m³, respectively. The maximum predicted 24-hour average ground-level concentration for NO₂ concentration associated with “PC,” “PC with capture,” “IGCC” and “IGCC with capture” scenarios are 2.4, 7.9, 0.8 and 0.6 µg/m³, respectively. For the annual average ground level, the results show NO₂ concentration associated with “PC,” “PC with capture,” “IGCC” and “IGCC with capture” scenarios are 0.51, 0.54, 0.068 and 0.0517 µg/m³, respectively. The maximum predicted ground-level concentration of a one-hour averaging period shows the highest NO₂ ground-level concentration of all scenarios.

IGCC with capture scenario shows the lowest NO₂ ground-level concentration compared to all other scenarios. Meanwhile, the “PC with capture” scenario shows the highest ground-level concentration for all averaging periods compared to all case scenarios. The high ground-level concentration of the “PC” scenario is due to the highest NO₂ emission rate that was produced from the post-combustion CO₂ capture process. All maximum predicted NO₂ concentrations associated with all scenarios are lower than the Saskatchewan ambient air quality standard. The maximum predicted 1-hour, 24-hour and annual average ground-level NO₂ concentrations are predicted to occur southwest, west and southeast of the facility, roughly 2 km away.

4.2.2. SO₂ Predictions

The maximum predicted one-hour average ground-level SO₂ concentrations associated with “PC,” “PC with capture,” “IGCC” and “IGCC with capture” scenarios are 14, 2.7, 9.4 and 7.8 µg/m³, respectively. The maximum predicted 24-hour average ground-level concentrations for SO₂ concentrations associated with “PC,” “PC with capture,” “IGCC” and “IGCC with capture” scenarios are 1.4, 0.3, 1 and 0.8 µg/m³, respectively. For the annual average ground level, the results show SO₂ concentration associated with “PC,” “PC with capture,” “IGCC” and “IGCC with capture” scenarios to be 0.29, 0.022, 0.071 and 0.0574 µg/m³, respectively. The maximum predicted ground-level concentration of a one-hour averaging period shows the highest SO₂ ground-level concentration of all scenarios.

The “PC with capture” scenario shows the lowest SO₂ ground-level concentration compared to all other scenarios. Meanwhile, the “PC” scenario shows the highest ground-level concentration for all averaging periods compared to all case scenarios. The high ground-level concentration of the “PC” scenario is due to the highest SO₂ emission rate that was produced from post-combustion CO₂ capture process. All maximum predicted SO₂ concentrations associated with all scenarios are lower than the Saskatchewan ambient air quality standard. The maximum predicted 1-hour, 24-hour and annual average ground-level SO₂ concentrations are predicted to occur southwest, west and southeast of the facility, roughly 2 km away.

4.2.3. PM_{2.5} Predictions

The maximum predicted 24-hour average ground-level PM_{2.5} concentration associated with “PC,” “PC with capture,” “IGCC” and “IGCC with capture” scenarios are 8.5, 12.5, 9.2 and 8.7 µg/m³, respectively. For the annual average ground level, the results show PM_{2.5} concentrations associated with “PC,” “PC with capture,” “IGCC” and “IGCC with capture” scenarios are 3.7, 4.0, 3.76 and 3.72 µg/m³, respectively. The maximum predicted ground-level concentration of a 24-hour averaging period shows the highest PM_{2.5} ground-level concentration of all scenarios.

The “PC” scenario shows the lowest PM_{2.5} ground-level concentration compared to all other scenarios. Meanwhile, the “PC with capture” scenario shows the highest ground-level concentration for all averaging periods compared to all case scenarios. All maximum predicted PM_{2.5} concentrations associated with all scenarios are lower than the Saskatchewan ambient air quality standard.

The maximum predicted PM_{2.5} concentration is predicted to occur west and southeast (24-hour and annual average) of the facility, roughly 2 km away.

4.2.4. Arsenic (As) Predictions

The maximum predicted 24-hour average ground-level Arsenic concentration associated with the "PC" and "PC with capture" scenarios are 0.0943 and 0.0441 µg/m³, respectively. The predicted results show no ground-level concentration in either the "IGCC" or "IGCC with capture" scenarios. This is because the IGCC system generates very minimal amounts of trace elements and heavy metals due to the cleaning process that removes most of the trace element emissions from the syngas.

The maximum predicted 24-hour average As concentrations associated with "PC" and "PC with capture" scenarios are lower than the Ontario air quality standard. The maximum ground-level concentrations are predicted to occur west of the facility.

4.2.5. Cadmium (Cd) Predictions

The maximum predicted 24-hour average ground-level Cd concentration associated with the "PC" and "PC with capture" scenarios are 0.0902 and 0.0496 µg/m³, respectively. The predicted results show no ground-level concentration in either the "IGCC" or "IGCC with capture" scenarios due to the cleaning process that removes most of the trace element emissions from the syngas.

The maximum predicted 24-hour average Cd concentrations associated with "PC" and "PC with capture" scenarios are lower than the Saskatchewan standard. The maximum ground-level concentrations are predicted to occur on the west side of the facility.

4.2.6. Chromium (Cr) Predictions

The maximum predicted 24-hour average ground-level Cr concentration associated with the "PC" and "PC with capture" scenarios are 1.2628 and 0.0165 µg/m³, respectively. The predicted results also show no ground-level concentration in either the "IGCC" or "IGCC with capture" scenarios. The maximum predicted 24-hour average Cr concentrations associated with "PC" and "PC with capture" scenarios are both lower than Ontario air quality standard. The maximum ground-level concentrations are predicted to occur on the west side of the facility.

4.2.7. Elemental Mercury (Hg) Predictions

The maximum predicted 24-hour average ground-level Hg concentration associated with the "PC" scenario is 1.0438 µg/m³. The predicted results show no ground-level concentration in the "PC with capture", "IGCC" and "IGCC with capture" scenario due to acid gas cleaning process on IGCC systems and FGD and ESP process on PC with capture scenario. The maximum predicted 24-hour average Hg concentration associated with the "PC" scenario is lower than the Ontario air quality standard. The maximum ground-level concentrations are predicted to occur on the west side of the facility, roughly 2 km away.

4.2.8. Manganese (Mn) Predictions

The maximum predicted 24-hour average ground-level Mn concentration associated with the "PC" scenario is 0.0902 µg/m³. The predicted results show no ground-level concentration in the "PC with capture", "IGCC" and "IGCC with capture" scenarios due to the acid gas cleaning process of IGCC systems and FGD and ESP processes on PC with the capture scenario. The maximum predicted 24-hour average Hg concentration associated with the "PC" scenario is lower than the relevant Ontario air quality standard. The maximum ground-level concentrations are predicted to occur on the west side of the facility, roughly 2 km away.

4.2.9. Lead (Pb) Predictions

The maximum predicted 24-hour average ground-level Pb concentration associated with the “PC” scenario is $0.6396 \mu\text{g}/\text{m}^3$. Compared to the Limited Ambient Air Quality Standard, the maximum predicted Pb concentration associated with the “PC” scenario is greater than the limited ambient air quality standard. The maximum ground-level concentrations are predicted to occur on the west side of the facility, roughly 2 km away. The predicted results show no ground-level concentration in the “PC with capture”, “IGCC” or “IGCC with capture” scenarios.

4.2.10. Other Trace Elements

The maximum predicted ground-level concentrations of other trace elements are lower than the Limited Ambient Air Quality Standard level except for Co and Ni. The maximum predicted 24-hour average ground-level of Co and Ni concentration associated with the “PC” scenario are $0.1476 \mu\text{g}/\text{m}^3$ and $1.240 \mu\text{g}/\text{m}^3$, respectively. The exceeding ground-level concentration of Co and Ni indicate that further evaluation may be necessary to determine the possibility of risk associated with human health. The predicted results show no ground-level concentration in the “PC with capture,” “IGCC” and “IGCC with capture” scenarios due to the acid gas in the cleaning process on IGCC systems and FGD and ESP process on PC with capture scenario. The maximum ground-level concentrations of other trace elements are predicted to occur on the west side of the facility, roughly 2 km away.

4.3. Discussions

Compared to the amount of lignite coal from an electrical generating station without CO₂ capture, there is an increase in coal used in the “PC with capture” and “IGCC with capture” scenarios due to additional units for CO₂ capture process, which consumed additional auxiliary power. Percentages are used rather than absolute quantities in this study; as a result, the impact categories, particularly under eutrophication potential, appear as significant increases. The results of using percentages as the absolute changes are quite small. Global warming is the most significant, and this impact category demonstrated a major environmental benefit.

The LCA results of this study correlates with the results found on [9,18,37]. Post-combustion CO₂ capture at a conventional pulverized lignite coal-fired electricity generation station resulted in increased impacts in the eutrophication potential, ozone depletion air, and smog air due to the CO₂ capture process, *i.e.*, the production and use of a solvent, as well as coal surface mining operation, in which reductions in the acidification air and global warming impact categories were observed.

IGCC systems in both the capture and non-capture scenarios showed the same tendency of increased impacts in some specific categories as the conventional coal-fired electricity generation system, but to a lesser degree. This is because the IGCC system is a cleaner technology which produces fewer pollutant emissions from the electricity generation station. The environmental impacts of IGCC generally increased only slightly when the IGCC system with CO₂ capture was introduced. On the other hand, the observed increase in the specific impact categories of eutrophication potential was generally small and remained rather low compared to the global warming potential and acidification potential. Ultimately, the IGCC technology was recognized as the cleaner technology, compared to the conventional coal-fired generation process.

The air dispersion analysis in this study involves the assessment of compliance of the predicted ambient air pollution concentrations emitted from four electrical generating stations with a limited ambient air quality standard. The analysis was conducted by following the outline of Saskatchewan air quality modeling guideline. In this study, AERMOD air dispersion modeling was used to predict the ground-level concentration of pollutants in the 20 km × 20 km modeling domain. The maximum ground-level concentrations of pollutants from all electricity generating stations were found to be in compliance with all limited air quality standards except for Co, Pb and Ni. The predicted maximum

ground-level concentration is believed to be occurring 2 km southwest of the facility for a 1-hour averaging time, and west and southeast of the facility for the 24-hour and annual times, respectively.

IGCC with the capture scenario shows the lowest NO₂ ground-level concentration compared to all other scenarios. Meanwhile, the "PC with capture" scenario shows the highest ground-level concentration for all averaging periods on NO₂ substance. For SO₂ ground-level concentration, the "PC with capture" scenario shows the lowest maximum ground-level concentration and the "PC" scenario shows the highest maximum ground-level concentration compared to all other case scenarios. However, in terms of PM_{2.5}, "PC" has the lowest maximum ground-level concentration, but the "PC with capture" scenario shows the highest maximum ground-level concentration, compared to all other scenarios. This is because the stack height of the "PC with capture" scenario was the lowest compared to other scenarios, as stack height has an impact on air concentration modeling. The assumption of the "PC with capture" scenario's stack height was made using the best estimation based on SaskPower's available public information. In addition, the maximum ground-level concentrations of most trace elements are also lower than the limited ambient air quality standard. The "PC" scenario shows the highest trace element ground-level concentrations compared to the other scenarios. Nevertheless, IGCC systems in either scenario, with and without the pre-combustion CO₂ capture process, shows no ground-level concentration of the trace elements. This is because the IGCC system operates with an acid gas cleaning process that removes most of the trace contaminants from the syngas.

5. Conclusions and Recommendations for Future Work

5.1. Conclusion

A life-cycle assessment was carried out to evaluate the environmental performance as well as the adverse potential health impact of the hypothetical Saskatchewan lignite-fueled IGCC electricity generation station, with and without a CO₂ capture process. However, the comparison between the capture system and non-capture system might not be completely fair, as the non-capture plant will result in more air pollutants if equipment such as desulfurization and dust filters are not installed. This does not apply when it comes to European electricity generation stations because they do have the desulfurization and dust filters installed. Saskatchewan electricity generation stations operate on low-sulfur coal and are not equipped with NO_x and SO_x capture which is the baseline scenario. Since this study considered a typical Saskatchewan electricity generation station, the comparison was made to a plant equipped only with PM capture. The goal is to compare a typical Western Canadian electricity generation station with and without CO₂ capture.

The results of the study revealed that, by applying both post-combustion and pre-combustion CO₂ capture, a significant reduction in greenhouse gas emissions can be achieved. The greenhouse gas emissions were found to be reduced by 75% and 93% in the "IGCC" and "IGCC with capture" scenarios, respectively. The conventional coal-fired electricity generation plant with post-combustion CO₂ capture resulted in an 80% reduction in greenhouse gas emissions. However, similar improvements in other environmental impact categories are not guaranteed, and the impacts depend on the CO₂ capture technology employed. Additionally, one of the challenges associated with implementing a CO₂ capture process is the decrease in electricity generation efficiency, because additional fuel is needed to compensate for the loss in electricity production. Therefore, implementing a CO₂ capture process will cause a substantial decrease in electricity output or an increase in coal consumption, which has an impact on environmental performance.

In case of air dispersion modeling, the maximum predicted ground-level concentrations are found to be in compliance with all air quality standards except for Co, Pb and Ni. IGCC systems on both with and without the pre-combustion CO₂ capture process show no ground-level concentration on all heavy metals. This is because IGCC systems operate with an acid gas removal unit that works to remove most of the heavy metals from the syngas.

5.2. Future Perspective

The IGCC process is understood to be a clean coal-fired electricity production technology that is cleaner and offers higher efficiency compared to most electricity generation technologies. It provides many advantages in terms of environmental impacts and performance. The results obtained from this LCA study of the IGCC system were consistent with this general perception. However, two weaknesses observed in the current investigation can be addressed in future studies. Firstly, the technology is still in the initial stage of development. Since the IGCC plants are not yet economically feasible, there is a lack of actual technical data about, and experience with, these plants. As a consequence, the technical data used in this study were adopted from the available literature. In the future, data from an actual industrial plant, or at least from a pilot plant, will be used so that the analysis can be more accurate (*i.e.*, once the Kemper County IGCC starts its operation). Secondly, the data on the trace elements emissions used in this study were not obtained via direct measurement because of the lack of available data on Saskatchewan lignite coal and the coal-fired gasification process. The data on the trace elements and heavy metal emissions were taken from a coal-fired power plant in the US. Therefore, it is possible that the environmental performance on some impact categories related to heavy metal and trace elements may be slightly higher than has been evaluated in this study. Therefore, it would improve the accuracy of the LCA analysis in the future if real and directly measured data from an industrial plant can be obtained.

As mentioned earlier, IGCC technology is still in the initial stage of development, and the IGCC plants are not yet economically feasible; therefore, additional research and development is required to identify and evaluate the means by which the technology can be improved to make it economic viable and cost-competitive in comparison with the existing coal-based electrical generating stations. Moreover, future work may include an analysis from the full life-cycle perspective (*i.e.*, a cradle-to-grave approach that includes CO₂-EOR and CO₂-storage).

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