INTEGRATING MOLTEN CARBONATE FUEL CELLS INTO STEAM ASSISTED GRAVITY DRAINAGE

A Study on Low GHG Bitumen and Power for Alberta

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Final Report

Fall 2015 SCIE 529

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December 11th, 2015

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Abstract

This project investigates the potential for molten carbonate fuel cells (MCFCs) to be deployed across Alberta's SAGD operations in order to reduce the greenhouse gas intensity of *in situ* oil sands operations and potentially that of Alberta's electricity grid. Scenario modeling was applied to investigate the risks and opportunities associated with MCFC integration in SAGD operations and impacts on the electrical grid. **The following conclusions were made based on the findings:**

1. Introduction of MCFC technology within SAGD operations for 900,000 bbl/day bitumen production will result in a reduction of 865 MT CO_2e by 2060, equivalent to 25 MT CO_2e/year from 2037 onwards.
2. Implementing MCFCs within SAGD has the potential to be profitable under the new $30/tonne carbon tax in Alberta.
3. The overall emissions intensity of oil sands bitumen in Alberta would drop to 35 kg CO_2e/ bbl by 2037, compared to the current intensity of 76.3 kg CO_2e/ bbl.
4. MCFC-integrated SAGD technology has the potential to phase out 1336 MW of coal power by 2037.

The report proposes policy recommendations to support the deployment of MCFC technology within SAGD projects in order to achieve substantive emissions reductions in Alberta’s oil sands and electrical grid systems.

1.0 Introduction

Alberta's oil sands are the third largest oil reserves in the world [1]. Approximately 80% of these reserves are buried too deep for access by surface mining and are too heavy to flow by conventional drilling. An advanced technology, Steam Assisted Gravity Drainage (SAGD), recovers bitumen by injecting steam into the reservoir [1]. The heated bitumen flows by gravity into a well and is subsequently pumped to the surface [2]. One major challenge with SAGD is the large quantity of Greenhouse Gases (GHGs) released when burning natural gas to produce steam, thereby contributing to climate change [4]. SAGD required 408 PJ/yr of heat energy to produce steam and released 24 million tonnes of carbon dioxide equivalent (CO_2e) emissions in 2014, equivalent to 76.3 kg CO_2e/bbl [1], [2].

A consequence of these high emissions for Alberta's oil sands is the undermining of public support for future development and market access [3]. Recently, the NDP government in Alberta announced a new carbon tax policy that will be implemented such that a $20 per tonne CO_2e tax will take effect in 2017 and be increased to $30 per tonne CO_2e in 2018 [4]. The policy includes a total emissions cap of 100 Mt CO_2e/yr over the entire oil sands industry [4]. Additional measures include phasing out Alberta's coal power plants by 2030, which carry a high emissions intensity of 1020 kgCO_2e/ MWh [4].

Consequently, there is a critical need for a transformative technology which can be incorporated into SAGD facilities that will lower the greenhouse gas intensity of oil sands and economically compete with the new carbon tax. The Canadian Oil Sands Innovation Alliance (COSIA) identified the integration of Molten Carbonate Fuel Cells (MCFCs) within SAGD facilities as a promising technology for significantly reducing emissions from in situ operations. The combustion of natural gas to produce steam and electricity accounts for 74-83% of SAGD emissions [2]. MCFCs offer the potential to significantly reduce SAGD emissions by capturing up to 90% of these CO_2 emissions [5]. MFCFCs operate by feeding flue gas from a SAGD boiler and natural gas to an electrochemical unit which produces electricity and simultaneously separates CO_2 for capture (See Alternative Scenario: SAGD-MCFC Integration for a detailed process description). The captured CO_2 is sequestered and stored underground in deep saline aquifers. A portion of the electricity MCFCs generate is used to power the SAGD facility with the excess being sold to Alberta's electrical grid to offset more carbon-intensive electricity generation, such as coal power [5]. MCFC technology could transform

Alberta's energy system by lowering the cumulative emissions of Alberta's oil sands, competitively meeting new regulatory constraints and facilitating the phase out of coal power.

2.0 Methodology

A Low Oil Sands Growth (LOSG) model was adopted for the analysis in this report based on a projection by a model from Canadian Energy Systems Simulator (CanESS) [1]. Under the LOSG model, there will be no new SAGD facility implementation after the year 2020. This is in accordance with the current low price of oil which makes new SAGD operations unviable. The model was also built on the retirement of coal by the year 2045 as opposed to 2030 as is the objective under new government policy. The model reflects a steady increase in the use of MCFC technology which offsets coal until 2037. At this point, the deployment scenario intersects and completely offsets coal demand. It was assumed that at this point, MCFC technology would have reached full market saturation. This is due to competition with natural gas combined cycle plants, which would be much more costly to force offline. Thus, it was assumed no MCFC deployment would occur after 2037.

The factors for various unit conversions and emissions are summarized in the electronic Microsoft Excel file accompanying the report. The scenario model was built upon a SAGD and electricity grid model provided by CanESS. The main assumptions of this investigation were the reference SAGD facility output, the SAGD steam to oil ratio, and the standard size of MCFC integration within the reference facility. These parameters are summarized in Table 1 along with the emissions parameters used in calculation. The reference SAGD facility output was taken as a standard COSIA reference [6].

Table 1: Assumed parameters for scenario modelling

Parameter	Value	Parameter	Value
Reference Facility Output	33,000 (bbl/day) [1]	Coal Emission Factor	1020 (kg CO_2e / MWh)
SAGD Steam Oil Ratio	3 (bbl H_2O / bbl bitumen)	NG-SC Emission Factor	500 (kg CO_2e / MWh)
Interest Rate	8%	NG-CC Emission Factor	380 (kg CO_2e / MWh)
MCFC Installation Size	76 MW [1]	SAGD Emission Factor	76.3 (kg CO_2e / bbl)

An analysis was conducted to compare the results of a Business as Usual Scenario (BAU), where no technology was implemented to limit emissions, and an Alternative Scenario where MCFCs were integrated into SAGD. The cumulative emissions from both scenarios were determined in addition to the total energy flows. For the Alternative Scenario, an aggressive deployment rate was developed based on the opportunity to retire coal early and the need to build generation capacity as coal comes offline. This ensured that market share would be available for MCFCs and the electricity generated would fill grid demand. The economics for the Alternative Scenario were presented as an avoidance cost on CO_2 emissions, thus allowing the cost of MCFC to be directly compared with the carbon tax policy being put into effect.

3.0 Scenario Modeling

The complete results of the analysis for the scenario modelling of the BAU and Alternative Scenario can be seen in the Microsoft Excel File accompanying this report. These models include analyses of production values, energy and material balances, and culminate in forecasts of GHG emissions for both cases as well as MCFC deployment rate and economics for the Alternative Scenario. The model also states the emissivity of oil sands bitumen resulting from MCFC deployment at the rate given by the model.

The BAU and SAGD-MCFC scenarios were compared based on the avoidance cost of capture and the effective reduction in bitumen emissivity. The avoidance cost for capture from the BAU Scenario is simply the carbon tax imposed under the NDP carbon policy. The BAU and MCFC-SAGD cases will be described separately.

3.1 Business as Usual Scenario: SAGD Operations

The BAU Scenario represents normal SAGD operation without carbon capture or enhanced efficiency systems. It is assumed that natural gas is burned to generate steam in a once-through steam generator (OTSG) and then injected into a reservoir facilitating bitumen production. The once through steam generator was taken to have a 92% efficiency [7]. A large number of SAGD sites operate in the oil sands rich area of Alberta surrounding Fort McMurray, Peace River, and Cold Lake; overall, there are 21 SAGD sites currently in operation within Alberta [8].

The life cycle assessment (LCA) of total emissions for the reference scenario was based on the COSIA Challenge Report on “Natural Gas Decarbonization” [9]. The system boundaries of this reference include the energy and emissions from the production of bitumen from the well pad, the oil and water treating processes, chemicals, utilities, diluent use, dilbit (diluted bitumen) transportation, imported natural gas and operation of the OTSGs. This study incorporates all these elements in order to accurately compare the BAU Scenario with the 'SAGD-MCFC' option. The process includes integrated flows of heat and electricity.

The reference SAGD facility was taken to produce 33,000 barrels per day (bbl/day) of bitumen using a steam to oil ratio of 3 volume units steam to one volume unit of bitumen [9]. The COSIA report assumes a basis of six steam boilers requiring 1600 GJ/h (lower heating value) of natural gas, operating at 92% efficiency and releasing flue gas with a CO_2 concentration of 8% [9]. These assumptions were incorporated for the purposes of this report. This report accounts for emissions from associated produced and imported gas, radiation losses and stack losses from the OTSG. These were used to calculate the direct GHG emissions for SAGD steam generation as 66.4 kg CO_2e/bbl.

The indirect GHG emissions were also accounted for in calculating the electrical power loads in the system. In the steam generation and injection process, electricity is required for associated facility equipment, glycol heating and utilities. The electricity demand for the overall process was estimated at 13.0 kWh/bbl [11]. The steam generation and injection process mentioned previously also has a significant demand for thermal energy, with the overall requirement being estimated at 296.6 kWh/bbl [11]. The combined heat and electrical demands for the facility were used to obtain GHG emissions for the overall process, amounting to 76.33kg CO_2e/bbl [11].

Using the reference 33,000 bbl/day facility in combination with modeled future SAGD oil sands production, the total heat and electricity demands for the entire SAGD industry of Alberta were evaluated up to 2060, as illustrated in **Figure 1** of the Appendix. The total production from SAGD operations is shown in **Figure 2a** of the Appendix. The analysis was completed for a period starting in 2001 at the beginning of SAGD production in Alberta and ending with forecasted values up to 2060. The LOSG model assumes project development of future SAGD facilities will cease in 2020, based on the current low commodity prices. The LOSG model does not take into account facility life or production declines due to decreasing reservoir quality, as production within Alberta remains constant after 2020. This is based on the assumption that process improvements would compensate for rising heat requirements due to declining reservoir quality. The trends illustrated were calculated for total SAGD oil sands production in bbl/day while projected heat and electricity demands were calculated in petajoules per year (PJ/yr). CO_2 emission projections for the entire SAGD industry were calculated in MtCO_2e/yr.

The low growth projection demonstrates a roughly linear growth in facility construction and therefore production between 2015 and 2020 (**Figure 2a**) resulting in similar increases in each of 'Heat Demand (PJ/year)' (**Figure 1**, left ordinate scale), 'Electricity Demand (PJ/year)' (**Figure 1**, right ordinate scale), and total cumulative electricity and SAGD GHG emissions, 'Emissions (MtCO_2e/year)' (**Figure 3a**). In these projections, electricity and heat demand increase by over 70% compared to current values and peak in 2020; furthermore, production and emissions are expected to rise by approximately 80% by 2020. After 2020, production, heat demand, electricity demand, and emissions are all expected to remain steady through the life of the existing SAGD facilities into 2060 (**Figure 1, 2 & 3**). This low growth assumption provides not only a reasonable model for the growth of SAGD in the long term future given continued low commodity prices, but also provides a conservative 'low end' estimate for the subsequent impact of MCFCs on emissions and levelized costs. Increases in commodity prices may result in greater *in situ* production, increasing the potential MCFC install base, resulting in further reductions in the intensity of the electrical grid and decreasing costs compared to the BAU results.

3.2 Business as Usual Scenario: Alberta Electrical Grid

The BAU model for Alberta's electrical grid represents known annual generation and carbon intensity from 2010 to 2015 and projects values from 2015 to 2060. The scenario model is based on electricity demand (TWhe/yr) and GHG emissions (MtCO_2e/yr) between 2010 and 2015 derived from the Alberta Utility Commission. The projected demand and intensity from 2016 to 2060 was based on the gradual retirement of coal plants in Alberta after reaching 50 years of plant operation (**Figure 4a** – dark blue area) and their replacement by combined cycle natural gas (NGCC) plants (**Figure 4a -** light blue area). As mentioned earlier, this model deviates slightly from the newly proposed government scenario where coal is phased out by 2030 as opposed to 2045. This change was out of scope for this report.

Electrical generation on the Alberta grid (**Figure 4a**) comes from both dedicated base load and peaking plants, and is supplemented by additional power supplied in part by cogeneration plants integrated into SAGD central processing facilities. These are expected to grow modestly, but as their continued contribution is unknown in the medium to long term, their absolute contribution to the Alberta grid is held constant at the value estimated for 2020. On the other hand, additional generation demand is expected to be met by a two to three fold expansion of renewable electricity sources by 2060, particularly wind-based generation (**Figure 4a**).

Shifts in electricity generation based on sources which are less carbon intense will result in declines in GHG emissions directly attributable to Alberta's power generation. Power generation based on solar, wind, and hydroelectric sources emit no GHGs and therefore do not contribute to increasing emissions with increasing power demand. Conversely, the shift from coal-based generation to NGCC-based generation by 2060 could result in a nearly two fold reduction in electrical grid GHG emissions in Alberta (**Figure 3a**). Specifically, as high GHG intensity coal-fired plants (1020 kg CO_2e/MWh) are gradually replaced by lower intensity NGCC plants (380 kgCO_2e/MWh), the intensity of the electrical grid is expected to gradually decline from over 50 MtCO_2/year to approximately 30 MtCO_2e/yr (**Figure 3a**) even given increased electrical generation capacity (**Figure 4a**).

3.3 Alternative Scenario: SAGD – MCFC Integration

The SAGD-MCFC Alternative Scenario models the implementation of MCFCs into SAGD facilities in Alberta allowing for the capture of CO_2 from a flue gas stream exiting an OTSG as illustrated by **Figure 5**. As opposed to being released into the atmosphere, flue gas generated from the combustion of natural gas to generate steam can be used as a feedstock to operate an MCFC as suggested by COSIA. MCFCs function through an electrochemical process which consumes fuel, water, oxygen, and carbon dioxide, and returns power along with a high concentration stream of carbon dioxide which can be captured [10]. Residual fuel and water can be separated from this stream and reused. The heat generated from the reaction is used to preheat the fuel and water being sent into the reaction for increased efficiency. A standard COSIA facility at 33,000 bbl/day production requires a 76 MW MCFC installation to adequately handle the volume of flue gas generated [7]. A portion of the electricity generated (24.6 MW) is used to power the SAGD facility with the balance (51.4 MW) being sold to the electricity grid.

Molten carbonate fuel cells are high temperature fuel cells that operate at over 600°C. They consist of an anode and cathode catalyst, functioning as an electrochemical unit which generates electricity. Natural gas is supplied to an internal reformer on the anode side of the MCFC where it reacts with steam over a catalyst to produce CO_2 and H_2 (syngas). Flue gas from the OSTG is a second source of CO_2 in addition to the natural gas, and is fed to the cathode side of the MCFC. The purpose of the secondary source of CO_2 is to increase the ion transport across the catalyst membrane. Air and CO_2 from the anode are recycled to the cathode along with excess flue gas from the OTSG [11].

On the cathode side, CO_2 is separated and converted to carbonate ions. These carbonate ions flow through a molten carbonate electrolyte to the anode. At the anode, hydrogen in the syngas reacts with the carbonate ions and produces CO_2, H_2O and electrons. Electricity is generated by the flow of charged ions through the electrolyte and CO_2 is concentrated at the anode for capture. The potential gradient in electrons between the anode and cathode reactions drives an electrical circuit, and generates an electrical current [11]. The process of electricity generation and the utilization of the CO_2 stream for sequestration and the electricity generated for export to SAGD and the electricity grid is shown in detail in **Figure 5**.

MCFC technology is very different from traditional CCS technologies like amine scrubbing which uses a solvent based approach to remove carbon. Amine scrubbing is energy intensive and expensive compared to the benefits of MCFCs. Amine scrubbing is typically used for flue gas cleaning of various plant effluent streams to meet emission regulations. MCFC has the inherent benefit of not only cleaning the flue gas stream, but also generating electricity in the process. Amine scrubbing is an energy intensive process while MCFC is an energy extensive process.

Through the implementation of the Alternative Scenario, it is assumed that 90% of CO_2 volumes exiting the OTSG systems of the facilities can be captured and removed from the entering flue gas stream. Through either sequestration or industrial application of this highly concentrated CO_2 process stream, corresponding GHG emissions released from the generation of steam can be reduced from 66.4 $kgCO_2e$/bbl of bitumen produced to 6.64 $kgCO_2e$/bbl, dropping total SAGD crude intensity from 76.3 to 6.64 kgCO2e/bbl where MCFCs are applied (**Figure 6)**.

The analysis assumes an aggressive deployment rate for MCFC technology. It was assumed that the modular and stackable nature of the fuel cells would allow the installation of equivalent capacity for sites which have production rates differing from the reference facility. To account for the introduction of MCFCs into industry, the deployment scenario begins with a 2 MW pilot installation operating for two years beginning in 2016. The small pilot is followed by a larger proof of concept installation at 20 MW. Following the successful proof of MCFC technology, the deployment scenario involves the installation of 152 MW of generation each year, until 2037. At this point, MCFCs will be installed in 26 equivalent facilities, accounting for 891,000 bbl/day of production (**Figure 2b)**. This deployment rate assumes an increase in the manufacturing capacity of Fuel Cell Energy (FCE) to meet the demand for MCFCs. The only retailer of MCFC technology is FCE which, at the time of this report, is limited to an annual production of 100 MW of production capacity for MCFCs [12].

The US National Renewable Energy Laboratory conducted a technical and cost gap analysis on the technical advancements and volume production required to achieve significant cost reductions in MCFC technology [12]. The current installed price of MCFC technology is approximately $4200/kW [12]. This includes $2400/kW for the fuel cell itself, $1100/kW for balance of plant integration, and $700/kW for installation labour and commissioning [12]. The gap analysis, conducted by Remick and Wheeler, forecasts the reduction of capital cost for MCFC technology due to research and development and the increase of electrode life [12]. The overhead costs of MCFC technology are currently $840/ installed kW, but could be reduced by $440/kW due to increased efficiency with increased volume production [12]. In addition, the expansion of FCE's manufacturing capacity beyond 100MW would allow for more efficient production of MCFC technology, resulting in a further decrease in overhead cost by $200/kW. The materials cost for MCFCs is currently at $1400/kW [12]. Increases in the energy density of the fuel cell (an improvement from the current 120 mW/cm^2 to 150 mW/cm^2) would result in savings of $330/kW [12]. The current lifetime of electrodes for MCFCs is 6-7 years [12]. With further research, it is projected that the lifetime of the electrodes will increase to 10 years by 2030, reducing the operating cost of the installation [12].

Overall, the cost of MCFC technology could be reduced from $4200/kW to approximately $2830/kW in 2020 and $2000/kW by 2030 [12]. These values were considered when conducting an economic assessment of MCFC technology. Reported as a cost of avoidance per tonne of CO_2e, the cost of MCFC utilization compared to the BAU Scenario is shown in **Figure 7** in the Appendix. The analysis assumes an 8% industry standard interest rate for financing the deployment and a 30 year loan, based on the life of a SAGD project.

The costs shown in **Figure 7** decrease due to the forecasted price reductions as discussed above. In addition, the trend accounts for sale of the generated electricity to the Alberta electricity grid at a pool price of $50/MWh. Although the time-averaged pool price over the past five years was somewhat higher at roughly $65/MWh according to the Alberta Electrical Systems Operator, the lowest annual average pool price of $50/MWh was used in order to provide a conservative but reasonable estimate of the expected revenue

Due to the low emissivity of the bitumen produced (**Figure 6**), it is likely that a premium value for bitumen produced using MCFC technology could be garnered. The premium amount was not forecasted in this report. It is understood that this could be a potential source of secondary revenue as corporations would be interested in low emission fuel to decrease their own GHG emissions. As part of the study, the emissivity of bitumen produced with MCFC technology was compared with crudes from a variety of producers (**Figure 8**). As can be seen, using MCFC technology reduces the emissivity to put SAGD at among the cleanest crude in North America.

3.4 Alternative Scenario: CO_2 End Use

MCFCs produce a purified stream of CO_2 that could be sequestered or used in a secondary process such as enhanced oil recovery (EOR). As assumed, MCFCs capture 90% of the CO_2 present in the flue gas fed into the fuel cell, but this can be increased or decreased based on the desired performance [5]. From a preliminary economic and environmental assessment, the pure stream of CO_2 generated by a MCFC SAGD site would most likely be sequestered in geological formations, potentially as part of the Alberta Saline Aquifer Project (ASAP) [13]. The alternative is to transport the CO_2 large distances for EOR projects. 'Phase 1' of ASAP, completed in 2009, mapped saline aquifer candidate regions for CO_2 injection and assessed their feasibility [13]. In 'Phase 2' a representative pilot plant would be studied and was scheduled to be operational by the end of 2015 [16].

Use of the produced CO_2 in EOR tertiary oil recovery is potentially lucrative (at a sale price of $30/tonne CO_2), but the sale of CO_2 for EOR is unlikely. EOR sales would require a CO_2 trunkline to market and the introduction of SAGD CO_2 would flood the market in Alberta for the commodity. There is currently not enough economic incentive to install a trunkline for transport to central Albertan markets. Thus, the CO_2 would be compressed and injected into deep saline aquifers. The assessment of CO_2 sequestration was out of scope for this project, although it is known that Alberta contains approximately 20% of global saline aquifer resources [13]. It is therefore assumed that a large enough volume in the aquifer system would be available for sequestration of all generated CO_2. Compression costs are included in the overall facility cost for MCFC integration.

3.4 Comparison of BAU and SAGD-MCFC Energy Flows

A comparison of the energy flows for the BAU and Alternative Scenario was conducted, the results of which can be seen in the two Sankey diagrams in **Figure 9**. **Figure 9a** represents the BAU Scenario, showing an overall input of 18.8 PJ/year including 14 PJ/year of natural gas and 4.8 PJ/year of coal-based electricity generation. The losses incurred are 4.1 PJ/year, SGAD operations take a resulting 13.3 PJ/year and 1.4 PJ/year of electricity is exported to the grid. The electricity export to the grid is considered as part of the standard COSIA model [6]. In the Alternative Scenario (**Figure 9b**), the total input decreases by 2 PJ/year to 16.8 PJ/year. At the same time, the natural gas input increases to account for MCFC consumption, while the MCFC itself consumes 2.8 PJ/year of energy. The overall result is 13.8 PJ/year to SAGD, an increase due to compression requirements for the CO_2, a loss reduction to 1.6 PJ/year, and the same amount of electricity export to the grid (1.4 PJ/year). The losses and total energy input for the MCFC scenario are shown to be 2 PJ/year less than for the BAU Scenario.

4.0 Results and Discussion

4.1 Results

The model for MCFC deployment consisted of two stages. First, the pilot study stage consisted of the implementation of an initial 2 MW facility in 2016 followed by a 20 MW facility three years later. For both pilot projects, engineering, procurement, construction and commissioning (EPC) was assumed to take 2 years in total, such that by the beginning of the third year the facility was capable of producing power with a 50% utilization. Full utilization was assumed in the following year. The second stage was assumed to begin in 2022 following regulatory approval based on at least one full year of operation of both pilot projects. This second stage consisted of two installations (152 MW) integrated with COSIA standard SAGD facilities deployed each year to a total of 26 facilities by 2037. These facilities would generate a total of 1976 MW and export a net amount of 1336.4 MW to the grid. The difference was due to balance-of-plant usage, on-site CO_2 compression and transmission losses. Stated otherwise, MCFC-based SAGD bitumen recovery would account for nearly 900,000 barrels of crude recovered of the predicted 1,800,000 total daily production by 2037 (**Figure 2b**). Additionally, the energy demand of SAGD facilities remained constant regardless of whether MCFCs were deployed to SAGD facilities or not (**Figure 1**). Half of the total energy demand of SAGD facilities would be met directly by effectively emissions free MCFC power in the Alternative

Scenario. This resulted in a 50% decrease in SAGD energy-demand-based emissions by 2037 regardless of the specific GHG intensity of the grid in any given year.

Just as with SAGD energy demand between the BAU and SAGD-MCFC scenario, the electricity demand of Alberta is predicted to remain constant. Only the relative proportions of electricity generated were forecasted to change (**Figure 4**). The deployment of MCFCs was initially constrained by regulatory approval which was followed by a rapid a deployment of annual power (152 MW total MCFC power annually at maximum). The scenario was deemed aggressive but reasonable. The final amount of deployment by 2037 of 1976 MW total power was defined by a motivation to retire coal power as quickly as possible. The deployment of MCFCs ceased once coal had been offset so as not to compete directly with natural gas combined cycle power generation for the grid (**Figure 4b**). Therefore, when net exported MCFC power reaches its peak in 2037 at 1336 MW (51.4 MW net exported power for each 76 MW of total MCFC power installed – power required for the balance of plant, CO2 compression and transmission losses account for the difference), there is no longer coal power on the Alberta grid. At this point there is also less natural gas combined cycle power than there would be based on the BAU Scenario (**Figures 4a & 4b**).

The goal of this study was to generate a scenario hypothesis of the total avoided emissions in both the Alberta oil sands and the electricity grid based on the deployment of MCFCs to SAGD facilities as proposed by COSIA [9]. The emissions avoided on SAGD sites results from a shift in SAGD emissions of roughly 76.3 kg CO_2e/bbl of bitumen to approximately 6.64 kgCO_2e/bbl at the 26 sites where MCFCs are integrated (nearly half of all SAGD sites by 2037). Although gradual replacement of coal power with natural gas in the BAU Scenario would result in expected emissions reductions, the replacement of demand met by high GHG emitters such as coal and natural gas with effectively 'emissions-free' electricity from SAGD-MCFCs would reduce emissions even further. Therefore, by 2037, SAGD emissions are expected to decrease from 35.5 MtCO_2e/year to 23.5 MtCO_2e/year, and electricity grid emissions from 38.0 MtCO_2e/year to 25.0 MtCO_2e/year, for a total emissions reduction of roughly 25 MtCO_2e/year across both industries (**Figure 3a & b**).

Reducing Alberta's total emissions by targeting emissions from SAGD sites in the oil sands has the added benefit of reducing the GHG intensity of SAGD bitumen. Specifically, the GHG intensity of SAGD bitumen is reduced from 76.3 $kgCO_2e/bbl$ to 35.0 $kgCO_2e/bbl$ (**Figure 6a**). This compares favourably with the GHG intensity of other globally-sourced crudes (**Figure 8**), and reaches among the lowest emissivity crudes in North America.

In order to gain insight into the economic feasibility of MCFC deployment, the 'avoidance cost' of GHGs (the net cost of avoiding CO_2 emissions by deploying a relevant technology – MCFCs) was compared to the 'compliance cost' (the cost to an industry of paying the current carbon tax for emissions; **Figure 7**). Avoidance costs are the sum of the capital costs, operating costs and costs of borrowing at an industry standard annual interest rate (8%) minus the revenue expected by sale of electricity to the grid at the five year, time-weighted average pool price provided by the AESO ($64.21/MWh; [14]). Natural gas costs were incorporated into operating costs and were projected based on forecasts provided by the International Monetary Fund [15]. As of 2016, the avoidance costs ($29.87/$tCO_2e$) exceed the compliance cost ($20/$tCO_2e$). However, declining production costs, increased stack life and economies of scale for MCFCs [12], and an increased carbon tax by the Government of Alberta is expected to result in equality of the avoidance and compliance costs at $30/$tCO_2e$ in 2020. While compliance costs remain at $30/$tCO_2e$ for the foreseeable future, production costs are expected to continue to decrease reaching a low in 2031 at $6.08/$tCO_2e$ (**Figure 7**).

4.2 Discussion

The goal for the study was to assess the potential for greenhouse gas emissions reductions in both the SAGD portion of the Oil Sands bitumen recovery industry, and in the electricity generation industry through the MCFC-mediated capture and compression of CO_2, and the export of MCFC-generated 'emissions-free' electricity to the grid, respectively. An aggressive and successful deployment of MCFCs to SAGD facilities accounting for nearly 900,000 bbl/day of bitumen production could collectively capture up to 25 Mt CO_2e/year by 2037.

This result clearly depends on an infrastructure and policy which promotes the industrial and political integration of the oil sands with the electricity generation industries in Alberta. Given the potential impact to Alberta electricity generation GHG intensity and to that of the crude produced by the oil sands, an emphasis on providing support to transmissions infrastructure from the oil sands to the grid would be a requirement. In addition, promotion of regulatory oversight which is streamlined between the Alberta Energy Regulator (AER) and the Alberta Electrical

Systems Operator (AESO) would be necessary. Without these, there would be independent and possibly conflicting regulatory constraints on the deployment and exploitation of MCFC technology in the oil sands. Streamlining these regulatory and political bottlenecks would be permissive of the overall emissions reduction target of 25 Mt CO_2e/year by 2037.

Another potential hazard to investment in MCFC technologies for deployment in SAGD facilities is the ambiguity with respect to CO_2 custody transfer, particular with respect to costs. This study assessed the total and net costs associated with MCFC deployment in any given year, including capital costs, operating costs, costs of borrowing, costs of compressed CO_2 transport and storage, and potential revenue from electricity sales through the AESO at the current pool price (assumed to be $64.21/MWh based on a 5 year average pool price from the AESO). However, the cost associated with continuous ownership of the CO_2 produced by the MCFC, and its associated liability for environmental externalities is unknown. This constitutes another regulatory ambiguity which must be considered prior to the large scale deployment of this technology predicted by our model to occur in 2020. Indeed, the infrastructure required to transport 25 million tonnes of compressed CO_2 does not yet exist in Alberta. Although pilot projects exist which are validating the economics and engineering behind a 'carbon trunkline' in Alberta, a large capacity trunkline would be required in order to handle the compressed CO_2 produced by this technology. Fortunately, Alberta contains roughly 20% of the saline aquifers in the world, which would provide sufficient storage space for the produced CO_2 into 2060.

Although storage of the compressed CO_2 produced by MCFCs in saline aquifers remains the most likely solution to the compressed CO_2 storage problem, other potential solutions exist as well. Broadly, CO_2 could constitute an additional commodity produced by the MCFCs rather than simply being a waste product. The sale of CO_2 for use in 'enhanced oil recovery' in tertiary production methods could generate additional revenue. As well, the use of compressed and purified CO_2 for artificial photosynthesis systems could also be of economic benefit.

An additional source of revenue generated by the integration of MCFCs within SAGD facilities could be access to premium crude oil pricing through green credits or through buyers and markets seeking low emissions bitumen. Such markets and buyers have not traditionally accessed Alberta's oil due to its relative intensity, therefore immediate access to such buyers would be limited and difficult to quantify. However, as MCFCs capture purified CO_2

from the SAGD facilities, Alberta's SAGD crude intensity (35 $kgCO_2e/bbl$) would begin to compare much more favourably with other crudes (**Figure 8**), and could qualify for sale to California even given the current 'Low Carbon Fuel Standard' policy which limits purchase of crude oil with a high GHG intensity due to production.

However, all these considerations depend on the timely and efficient deployment of MCFCs to SAGD facilities according the model outlined in this report. The model has several key strengths and weaknesses. Although constrained by regulatory requirements, particularly in its early stages, the model is not constrained in any means by the ability of North America's sole MCFC manufacturer to meet required demand. FCE Inc. is currently seeking markets with the potential for sales on the order of the annual demand described in this study to generate sufficient revenue. This highlights the central limitation to the near term deployment of MCFCs to SAGD facilities other than costs: regulatory approval. Additionally, in the medium term, transmission infrastructure must continue to be able to deliver the electricity from the supply source to the location of demand. This will likely require additional investments in transmission infrastructure in Alberta, but is likely to be no more difficult to implement than infrastructure designed to deliver electricity from SAGD cogeneration facilities to the grid.

Early deployment of MCFCs is critical in order to compete with natural gas combined cycle power in offsetting coal power according to the BAU model. Although the model does not require MCFC power to displace NGCC-based power generation, it is intended to be deployed aggressively in order to help offset coal power demand quickly (**Figure 4b**). It would be economically and politically difficult to justify the early retirement of NGCC power facilities (which have at least a 25 year lifespan) in favour of MCFCs unless MCFCs were significantly more fiscally competitive in order to account for the stranded capital in NGCC projects. Although the exact competitiveness of MCFCs with NGCC facilities was beyond the scope of the current study, it could begin to favour MCFCs with a sufficiently high carbon tax, such as those being implemented by the Government of Alberta in the next two years.

4.3 Additional Considerations

According to an 'Alberta Innovates – Energy and Environment' (AIEES)-commissioned report, a SAGD facility with integrated MCFC technology for carbon capture and compression could potentially reduce emissions by 88%, reduce operating costs by 6%, but increase capital costs by roughly 50% [5]. The application of MCFCs to SAGD facilities may cost roughly 30% that of standard carbon capture methods and, by offsetting Alberta grid electricity, could result in bitumen production with a reduced carbon footprint [10]. The present study expands on these previous reports to investigate the effect on costs and GHG emissions of deploying MCFCs at a large scale in the Alberta oil sands at the energy systems level of analysis.

Based on the results presented by the gap analysis, this study projects FCE's manufacturing capability to reach 700 MW per year by 2030 [12]. This study proposes an initial 2 MW pilot installation for two years, followed by a larger 20 MW proof of concept. Subsequent to the proof of concept, the study presents a rate of deployment of 76 MW per year of generation capacity for MCFCs in SAGD facilities until 2037. Consequently, the deployment rate falls well within Fuel Cells' current and future manufacturing capabilities. This is based on projections for the cost reduction and technological improvements in extending electrode stack life to 10 years, increasing power density by 20% and capturing efficiencies in volume production.

5.0 Conclusion

The introduction of MCFC technology within the SAGD industry would result in a cumulative emissions reduction of 865 million tonnes of CO_2e to 2060 over the business as usual scenario. This represents an emissions reduction of approximately 25 million tonnes of CO_2e per year after 2037. MCFC technology therefore has a high potential to meet the climate change targets under regulations by the Government of Alberta and thus transform the energy industry within Alberta. The deployment scenario used in this report allows the offset of carbon-intensive coal powered generation and could effectively be used to retire coal plants within the province to meet increasingly shorter deadlines by displacing up to 1336 MW by 2060.

MCFC implementation could be profitable for companies under the newly proposed $30/tonne CO_2e carbon tax. Taking into account the barriers to implementation, MCFCs represent a potentially viable technology solution. The introduced capacity could be used to increase the rate of oils sands production while still meeting the 100 million tonne/year carbon cap proposed by the new government. In total, the use of MCFC technology could reduce the emissivity of oils sand bitumen to 35 kg/bbl in 2037 as opposed to the 76.3 kg/bbl seen currently. This would reduce oil sands crude to among the lowest emissivity crudes in North America.

6.0 Policy Recommendations

To move forward with the projected scenario, several policy recommendations are being recommended to incentivize the early deployment of MCFCs to realize the environmental and economic benefits:

- Fast-track and streamline the regulatory approval process of MCFCs to be tested on a 2 MW pilot scale followed by the construction of a proof of concept 20 MW facility
- Encourage MCFC research and development through industry groups such as COSIA and CCEM funding to achieve cost reductions and improve technical feasibility
- Incentivize the early adoption of MCFCs through industry tax incentives, subsidies or other financing aids
- Implement a carbon accounting system that allows for the transfer of emissions from oil sands facilities to exported electrical power for ultra-low emissivity bitumen production

Additional policy actions that would help to achieve the full potential of MCFC integration in SAGD include:

- Providing regulatory oversight on the transportation and operation of CO_2 via pipelines and storage underground in saline aquifers
- Providing support for the negotiation of surface rights access for CO_2 pipeline construction and operation
- Providing incentives for the transmission and generation of electricity for oil sands operators
- Studying the opportunity to credit bitumen with a “green bitumen premium” from crown lands and offer favorable royalty treatment

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Expert Advisor References

1. Meetings and correspondences with Dr. Song Sit, Cenovus Energy
    a. Assumptions for Alternative Scenario including comparisons for well to tank GHG emissions and regulatory scenarios
    b. Assumptions on rate of deployment and feasibility of implementing for new technology
2. Meetings and correspondences with Dr. Viola Birss, U of C Chemistry Professor
    a. Capital and operating costs and economies of scale for MCFCs
    b. Technical assumptions on MCFC performance and engineering for scale up options

Appendix – Figures

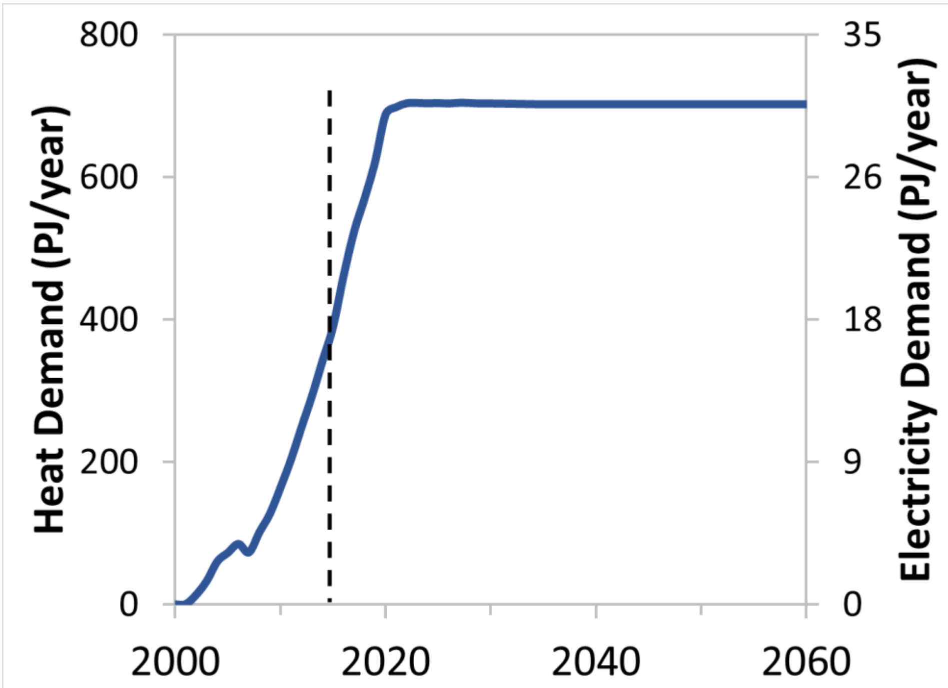

Figure 1. A comparison of heat (left ordinate scale) and electricity (right ordinate scale) demands of all SAGD facilities in Alberta calculated by extrapolating heat and electricity demand data from a COSIA standard 33,000 bbl/day facility.

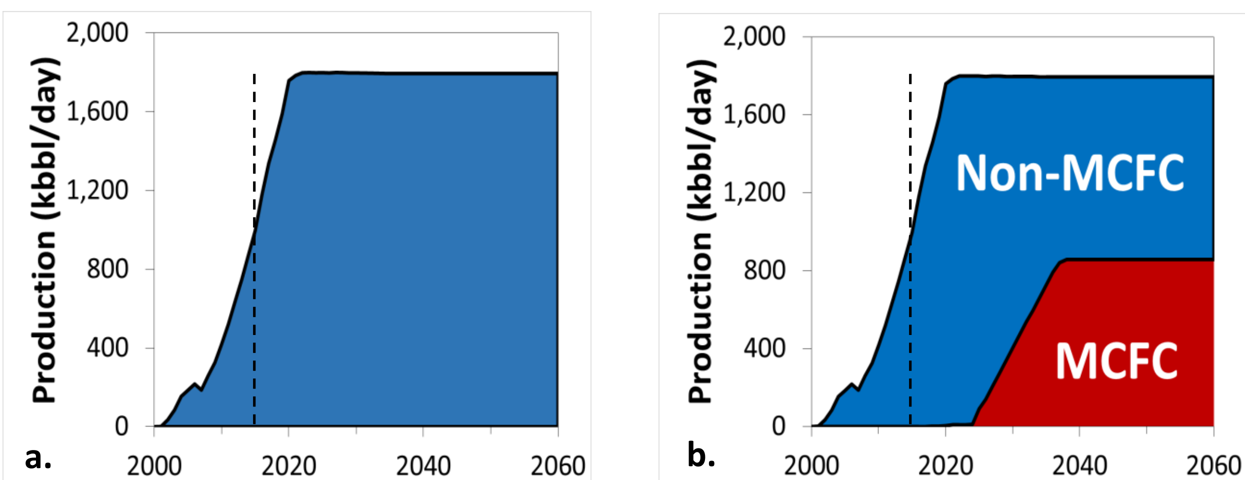

Figure 2. A comparison of total SAGD production in Alberta for the BAU model (**a.**) and the MCFC Alternative Scenario model (**b.**) generated under a low oil sands growth scenario.

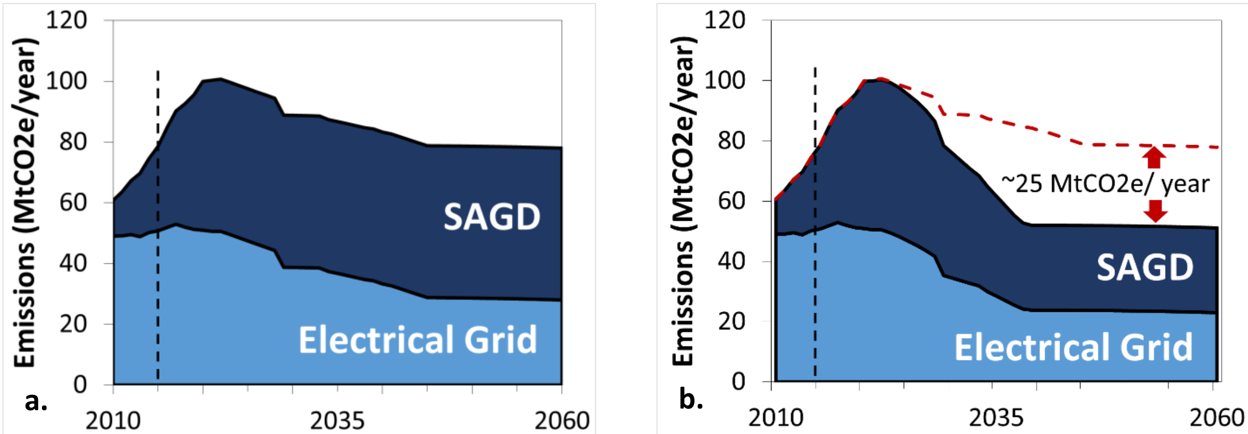

Figure 3. A comparison of GHG emissions released by both the SAGD industry in Alberta and the electricity grid in Alberta for the BAU model (**a.**) and the SAGD-MCFC Alternative Scenario model (**b.**) that illustrates the potential GHG emission savings from the implementation of MCFCs into SAGD facilities based on an aggressive deployment model.

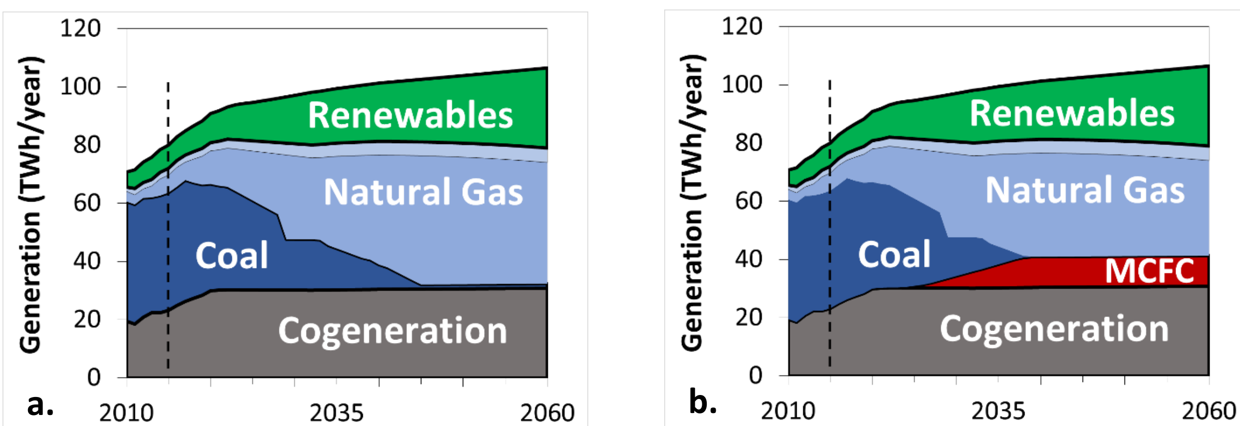

Figure 4. Electricity generation in Alberta for the BAU model (**a.**) and the SAGD-MCFC Alternative Scenario model (**b.**) generated under the assumption that coal fired power plants would be replaced with alternative sources of electricity generation after a 50 year plant life.

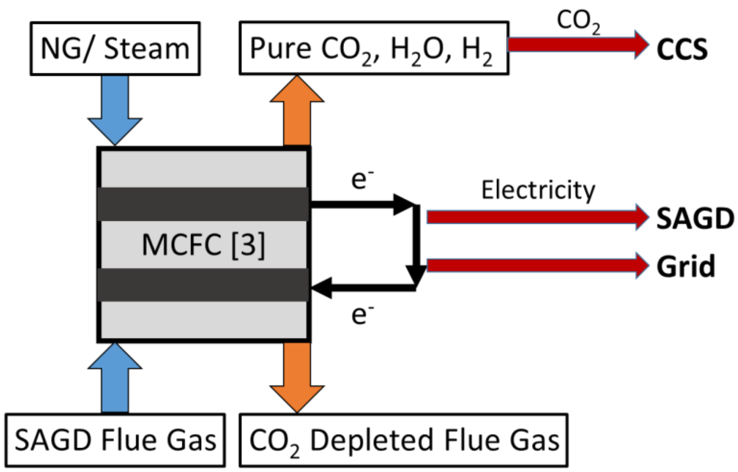

Figure 5. Integration of an molten carbonate fuel cell (MCFC) into a SAGD facility such that once-through steam generator (OTSG) flue gas is fed into the anode of the fuel cell and, CO_2 is capture and compressed for storage, excess electricity is generated and exported for sale to the electrical grid and CO_2 depleted flue gas is emitted to the atmosphere (modified from Jacobs Consultancy 2015).

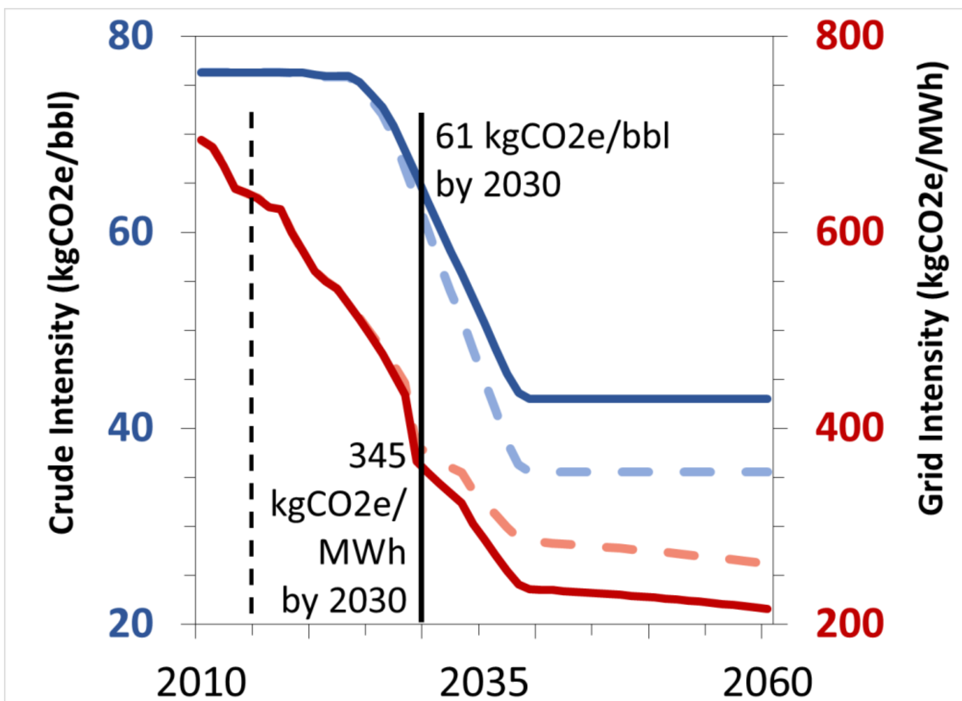

Figure 6. A comparison of the average SAGD produced bitumen CO_2 intensity (left ordinate scale) and the average electrical grid CO_2 intensity in Alberta (right ordinate scale) under a SAGD-MCFC Alternative Scenario. Dotted lines represent average CO_2 intensities for SAGD production and the electricity grid within Alberta under the assumption that electricity generated by MCFCs would enter the grid at 418 $kgCO_2e/MWh$ (maximum allowable intensity for new electricity generation projects) with equivalent intensity reductions applied to bitumen production to market low intensity SAGD crude.

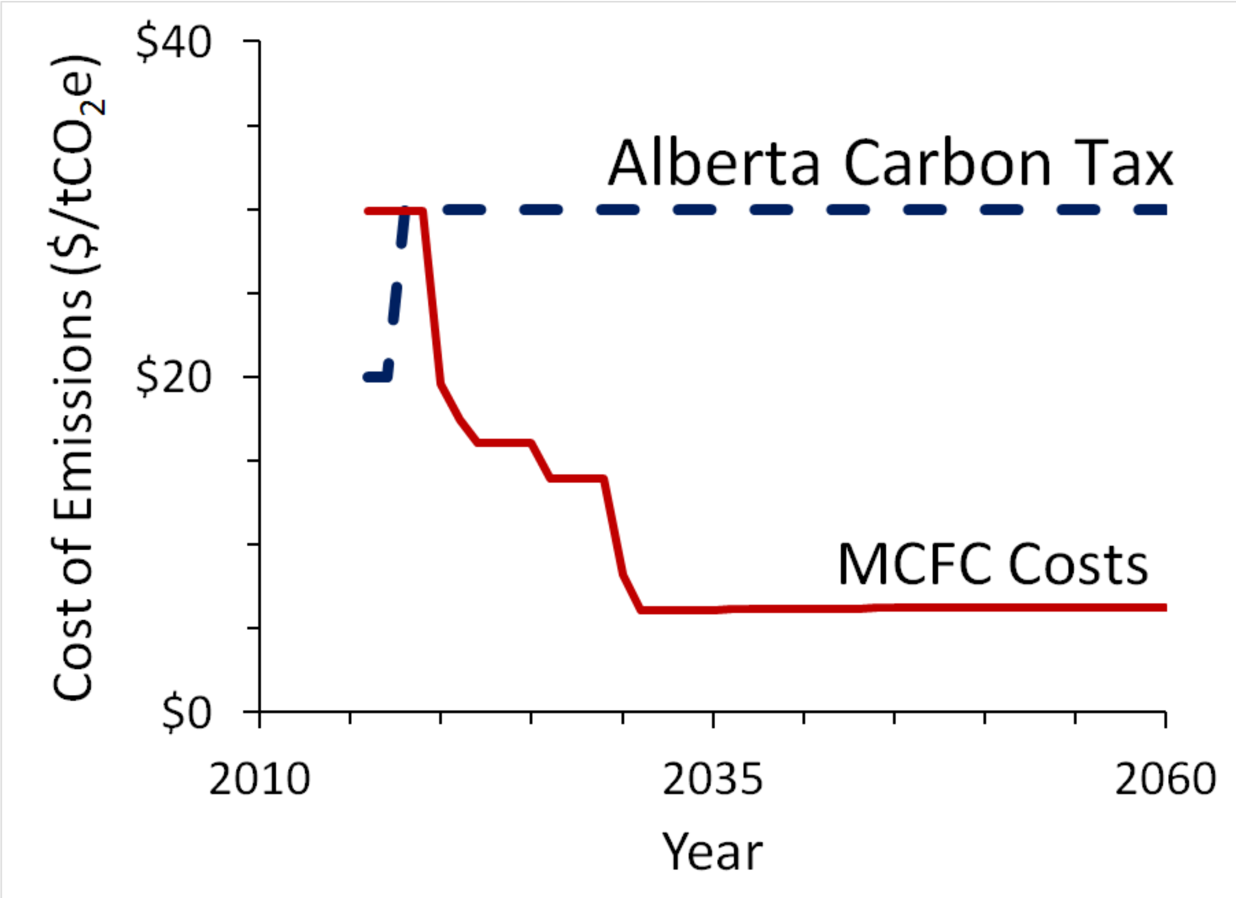

Figure 7. A comparison of MCFC avoidance and compliance costs based on a newly implemented climate change policy by the Government of Alberta. Avoidance costs are calculated based on assumptions in technological advancement and increased manufacturing capacity projected by Fuel Cell Energy.

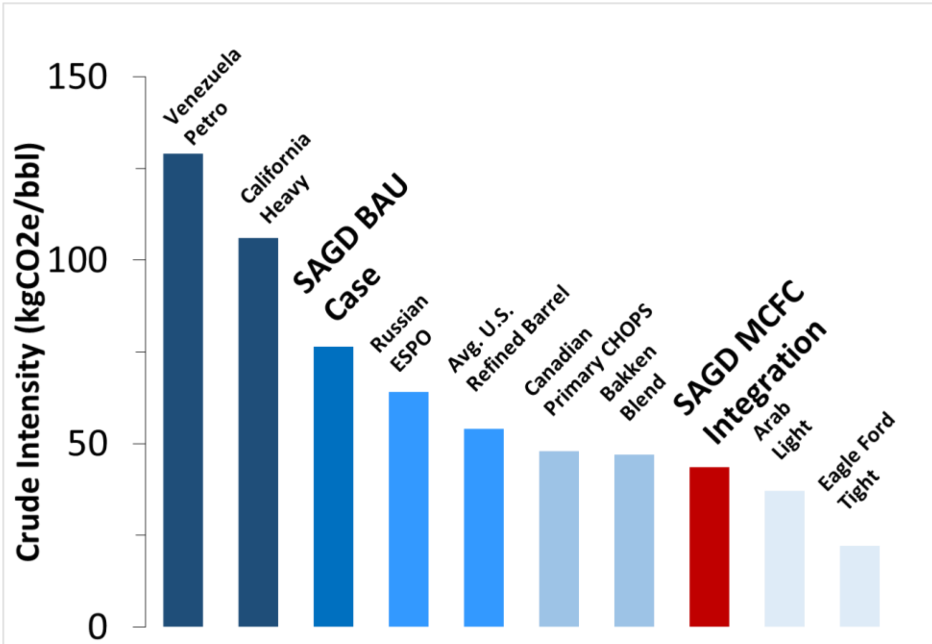

Figure 8. A comparison of various produced crude oils and the average CO_2 intensity associated with their production. Both the BAU model average CO_2 intensity and the SAGD-MCFC Alternative Scenario model average CO_2 intensity (2037-2060) are represented in this figure.

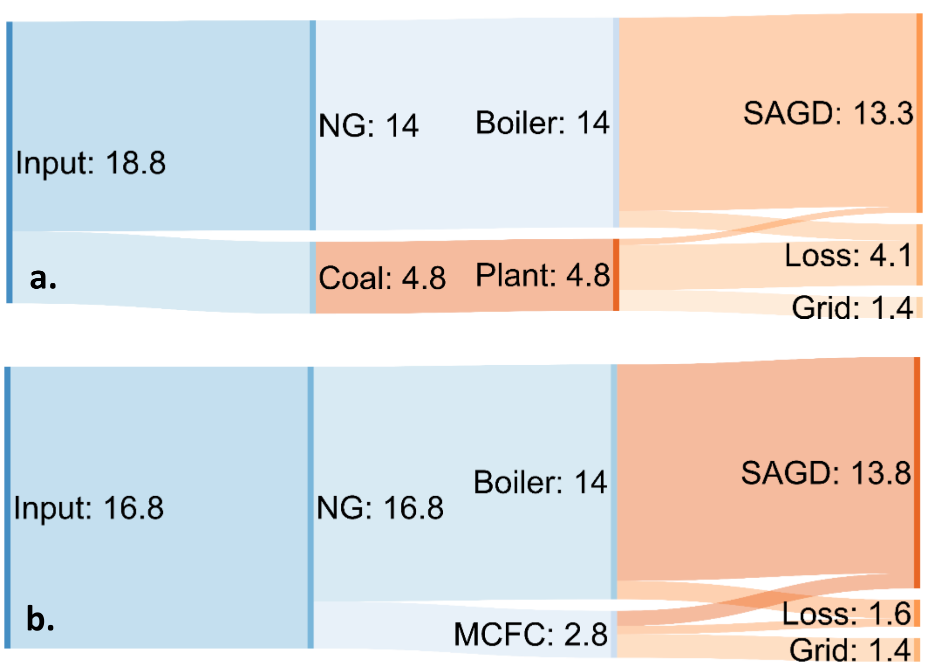

Figure 9. A comparison of the energy budget (PJ/year) of a 'business-as-usual' SAGD facility (**a.**) compared to a SAGD facility with an integrated MCFC (as detailed in Figure 1) based on a 33,000bbl/day COSIA standard SAGD facility (**b.**).