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Evaluating long-term greenhouse gas mitigation opportunities through carbon capture, utilization, and storage in the oil sands

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ABSTRACT

Carbon capture, utilization, and storage (CCUS) has been identified as the only option for substantially reducing greenhouse gas (GHG) emissions from fossil fuel-based processes. There has been limited research into the long-term GHG reduction potential of integrating CCUS into unconventional oil extraction processes. We developed a CCUS-oil sands market penetration model and integrated it with a bottom-up energy model (LEAP-Canada) to conduct a cost-benefit case study for the Canadian oil sands. Scenarios were developed considering currently available CCUS technologies and were investigated under different carbon pricing policies. Cumulative GHG emission mitigation potential from the CCUS applications ranged from 3 to 232 million tonnes (Mt) with marginal costs of \$-28–42/tCO_2e. Carbon pricing led to an average 3% increase in 2050 market shares of the technologies, resulting in additional GHG abatement of 4.9% (172 Mt). CCUS was found to be the costliest GHG emission mitigation option compared to increased integration of cogeneration and energy efficiency measures. The maximum cumulative oil sands GHG emission mitigation achieved in this study was 7%. This research ultimately provides insights into applications of CCUS technologies into the oil sands industry that might be useful to industry planners and policymakers and support the sustainable development of oil sands resources.

1. Introduction

The quantity of oil produced from geological reservoirs around the globe has been increasing over the last 20 years, with 2017 oil production 17% higher than it was in 2000 [1,2]. This trend is expected to continue with forecasts suggesting global oil demand will rise until at least 2030 [1,2]. Many countries around the world have agreed that carbon based emissions from the consumption of fossil fuels are causing detrimental effects to the planet and have agreed to reduce their emissions [3]. Emission data suggests that at least 65% of global carbon emissions are a result of producing and consuming fossil fuels such as crude oil [4]. Canada is home to the third largest proven oil reserves in the world known as the oil sands [5], but they are currently among the most energy intensive oil sources to produce [6]. In 2015 the Alberta (one of the provinces in Canada) oil sands contributed the largest share of greenhouse gas (GHG) emissions to Canada's oil and gas sector, 37%, and 10% to Canadian-wide GHG emissions [7]. The sector is thus one in which GHG emission intensity reductions would have a major impact on national GHG emission levels. The oil sands industry contributed 5% to the Canadian GDP in 2016 [8] and is expected to grow by over 50% from 2018 levels by 2050 in terms of barrels of oil produced [9].Thus the oil sands industry is a key aspect of the Canadian economy. Because of the economic importance and high GHG emissions of oil sands production, finding cost-effective GHG emission reduction strategies is an area of focus for industry and government, so much so that a firm GHG emissions cap of 100 million tonnes (Mt) annually has been imposed on the sector [10]. These competing pressures have led to an urgency to lower the GHG emission intensities of oil sands processes, where fossil fuels are currently used for heat and power needs, while permitting industry growth and economic contribution. Furthermore, in order to meet the targets of the Paris Agreement, immediate action must be taken to reduce GHG emissions [3].

Carbon capture, utilization, and storage (CCUS) technologies have been identified as the only option for substantially reducing

Abbreviations: CCUS, Carbon capture, utilization, and storage; EOR, Enhanced oil recovery; IPCC, Intergovernmental Panel on Climate Change; IRR, Internal rate of return; kbpd, thousand barrels per day; PCF, Pan-Canadian Framework on Clean Growth and Climate Change; SAGD, Steam assisted gravity drainage; SCO, Synthetic crude oil; SMR, Steam methane reforming; UCG, Underground coal gasification.

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GHG emission intensities while using fossil-fuel based processes [11]. The three stages involved in CCUS processes are capturing the CO_2, transporting it from the source to a suitable geological formation, and storing it in the formation. In some instances, it is possible to utilize the captured carbon during the storage process by injecting it into nearly depleted oil production wells for enhanced oil recovery (EOR). Studies on the applicability of CCUS technologies in the Alberta oil sands that consider all three stages have not analyzed the associated long-term GHG emission abatement potential, despite the high potential for EOR in the oil extraction sector [12]. Ordorica-Garcia et al. conducted a study to identify the optimal carbon capture technology for each major oil sands process [13]. This study identified post-combustion capture for surface mines, oxyfuel boilers for in situ mines, and gasified bitumen (pre-combustion capture) for upgrading; however, the study lacked quantitative analysis of performance or cost of any of these options. Olateju and Kumar conducted techno-economic assessments of hydrogen production from underground coal gasification (UCG) with pre-combustion capture and of steam methane reforming (SMR) with post-combustion capture in Alberta [14]. This study estimated the costs of using CCS with SMR to be \$2.11-\$2.70/kg H_2 and CCS with UCG to be \$2.41/kg H_2 but did not determine the cost of mitigated GHG emissions or the GHG abatement potential. Verma and Kumar [15] conducted a life cycle assessment of the carbon emissions from UCG with carbon capture in Alberta but did not perform economic analysis. Verma et al. [16] developed the marginal cost of GHG abatement for carbon capture applied to UCG and SMR in the two studies above and found that cost savings for reduced emissions were possible if the captured CO_2 could be sold to EOR operators and that UCG was the lowest cost mitigation option. The long-term GHG abatement potential of each technology was not discussed in these studies. Bolea et al. [17] developed the costs of using oxyfuel boilers with both natural gas and bitumen as fuel and found that bitumen-fueled oxyfuel boilers can be competitive with currently used once-through natural gas boilers. However, this study only considered carbon capture costs, not transportation and storage, and did not determine the GHG emission abatement potential of the options considered. Key limitations in all of these studies are that year-to-year changes in operation costs based on expected changes in fuel prices are not accounted for and that a single value for the marginal cost of abatement is given. This is useful for determining the basic competitiveness of these technologies with what is currently used but does not allow cumulative abatement potential to be calculated over a long-term evaluation period. This is critical for long term decision making and policy formation.

Moreover, in studies of CCUS technologies, minimal consideration has been given to market penetration modeling. None of the studies discussed above considered the rate at which the CCUS technology being evaluated could enter the market. Ordorica-Garcia et al. conducted an optimization study by setting emission reduction targets and using linear optimization with several CCUS options to determine the lowest cost of achieving the targets [18,19]. This study found that GHG emissions could be reduced by 39% by implementing CCS with a 20% increase in production cost. Later, these same authors considered the costs of CCUS options based on the CO_2 concentration of the flue gas streams, again using linear optimization to determine the technology combination that offers the lowest capture cost at a particular concentration [20]. This study found that CCS costs almost tripled from high purity (>15% CO_2 concentration in flue stream) to low purity (<10% CO_2 concentration in flue stream) and that oil sands emissions are dominated by low purity sources. Also, this study identified gasification for hydrogen production in upgrading operations as the most promising technology. A key issue with linear optimization studies, however, is that they do not account for non-cost related reasons that affect the rates at which technologies can feasibly enter markets. Rather, they assume that the lowest cost options are what is chosen (subject to constraints) during the period evaluated. While this is a useful approach to take, it does not always accurately reflect how decisions are made in industry due to the different information available to private companies making investments, unique factors that impact site-by-site costs, and strategic plans unique to each organization [21]. Thus, using additional technology adoption models that consider different approaches to analyze an issue is valuable. Additionally, these studies do not consider any carbon utilization options, such as selling captured carbon to EOR operations and the impacts on market adoption. It would be helpful to compare the results from these studies to a study using market penetration modeling and incorporate other technology options.

There is also no analysis in the literature of the long-term (to 2050) GHG emission abatement potential of using CCUS technologies in oil sands processes. This research gap, along with the other above-discussed knowledge gaps, is confirmed in the reviewed literature, which has focused on research and development of specific carbon capture technologies or components, or has been policy-focused [22]. This study performs an assessment of long-term GHG emission abatement from the use of CCUS in the oil sands and ranks the options in terms of marginal cost of GHG emission abatement. The study's novelty includes using a diffusion-based market penetration model to determine the penetration of each CCUS technology then evaluating the GHG emission impacts related to the use of those technologies in a bottom-up energy accounting model. The bottom-up energy accounting model in this study was developed as a continuation of the LEAP-Canada model developed previously [23]. The oil sands subsector of that model was further developed for CCUS technologies and integrated with the market penetration model to give an analysis of the market viability and GHG abatement potential of these technology options.

In summary, the gap that the present work addresses is long-term assessment and ranking of carbon capture, utilization, and storage options for GHG mitigation in the oil sands in different policy contexts. The existing literature has focused largely on individual technologies without considering the long-term dynamics of market penetration or comparisons across multiple technologies. In this context, this paper makes the following 5 contributions:

- A novel application of an integrated market adoption and bottom-up energy environmental modelling framework for the evaluation of long-term carbon capture, utilization, and storage options. This approach considers technology competition through life cycle costing that yields technology adoption rates closer to what is typically observed in industry compared to the approaches used in published studies.
- The long-term marginal GHG abatement costs are determined and compared across multiple carbon capture, utilization, and storage scenarios. Long-term changes in operation costs based on expected changes in fuel prices are accounted for.
- CO_2 utilization and carbon pricing are also investigated for the first time in terms of how they affect the adoption and, in turn, the GHG emission abatement potential and marginal cost of each technology.
- The feasible potential for CCUS integration into the oil sands is evaluated along with the impacts CCUS could have on long-term emission reduction targets.
- Results from the scenario analysis will provide industry and government decision makers with an outlook for the expected GHG emission reduction potential of CCUS technologies, associated costs, and impacts of different climate policies from the present day to 2050.

The overall purpose of this research is to investigate CCUS technologies for GHG emission abatement potential and marginal GHG abatement costs when used in oil sands processes. The results will be achieved by the following study objectives:

- Create feasible technology scenarios under different carbon pricing policies for the implementation of CCUS technologies into oil sands processes in Alberta.
- Develop market penetration models to determine the rate CCUS technologies could enter the market.
- Use bottom-up energy modeling with integration of the market penetration model results to determine each technology's long-term GHG abatement potential and associated marginal costs over a planning horizon of 2020–2050.
- Assess 24 different GHG mitigation scenarios through penetration of CCUS technologies in oil sands.
- Conduct a case study for Alberta, an oil-producing province in Canada

2. Methods

2.1. Study framework

This study evaluates CCUS technologies for use in the oil sands from 2019 to 2050. Fig. 1 shows the study overview, providing the flow of data from inputs through modeling to the final output data. Scenario development, discussed in detail in Section 2.2, involves developing a reference scenario that reflects current practices and potential CCS and CCUS technology options that can replace technologies in specific processes in the reference scenario. Modeling work involves two key components. The market penetration model determines how quickly new technologies could gain market shares based on their projected costs and published market forecast data. The LEAP-Oil Sands model calculates energy use and subsequent GHG emissions in each scenario, using results from the market penetration model and published forecasts. These models and their respective inputs and outputs are discussed in Section 2.3. Results are provided in terms of a cost-benefit analysis, detailed in Section 2.4. Here, the GHG abatement potential and marginal costs of each scenario compared to the reference scenario are determined and the relative performances of CCS and CCUS technology options are compared.

2.2. Scenario development

A reference scenario was developed to represent business-as-usual practices and serve as a baseline against which to compare alternative technology scenarios. The reference scenario considers currently used technologies in the oil sands, their energy and emission intensities, and their costs. An assumption is made in the reference scenario that currently used technologies and their respective energy intensities will be consistent through the evaluation period.

CCS and CCUS scenarios were developed by considering the feasible CCS technologies available to oil sands producers. Fig. 2 shows the general pathways for producing bitumen from the oil sands including the three main subsectors of surface mining, in situ mining, and upgrading. Further background on the oil sands is provided in the supplementary file in the Appendix). Surface mining involves mobile mining equipment, for which current CCUS technologies cannot be used, and process heat for bitumen extraction. In situ production involves steam production through natural gas boilers. Current technologies used for process heat and steam generation have relatively low carbon concentrations. Upgrading consumes energy primarily through hydrogen production using steam methane reforming and hydrogen production processes have substantially higher concentrations of carbon in their flue streams. All of these subsectors also consume electricity to power various equipment and facilities; this electricity comes from either site cogeneration facilities or the Alberta grid.

A literature review on available CCS technologies was conducted for these processes, and where techno-economic data on those technologies was available to allow for long-term modeling of the process, it was developed into a scenario for this study. Further background on the CCS technologies considered is provided in the supplementary information file in the Appendix. There was insufficient data found on pre-combustion carbon capture options for use in oil sands to develop any scenarios. A pre-combustion carbon capture study investigated options for decarbonizing natural gas feedstocks in Alberta and provided some supply cost estimates [24]. However, the cost of implementing these technologies was not provided in detail; more techno-economic data applied to oil sand's context is still needed in order to develop practical scenarios from these options. 2 post-combustion and 2 oxyfuel technology options were found to have sufficient data to allow for feasible scenario development in the oil sands in situ and upgrading sectors; these

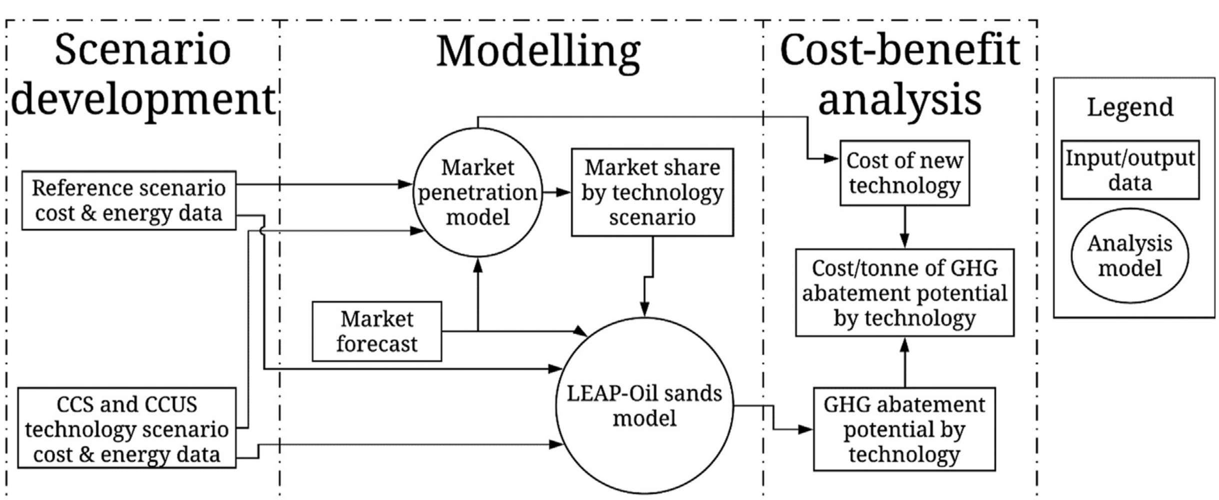


Fig. 1. Study framework.

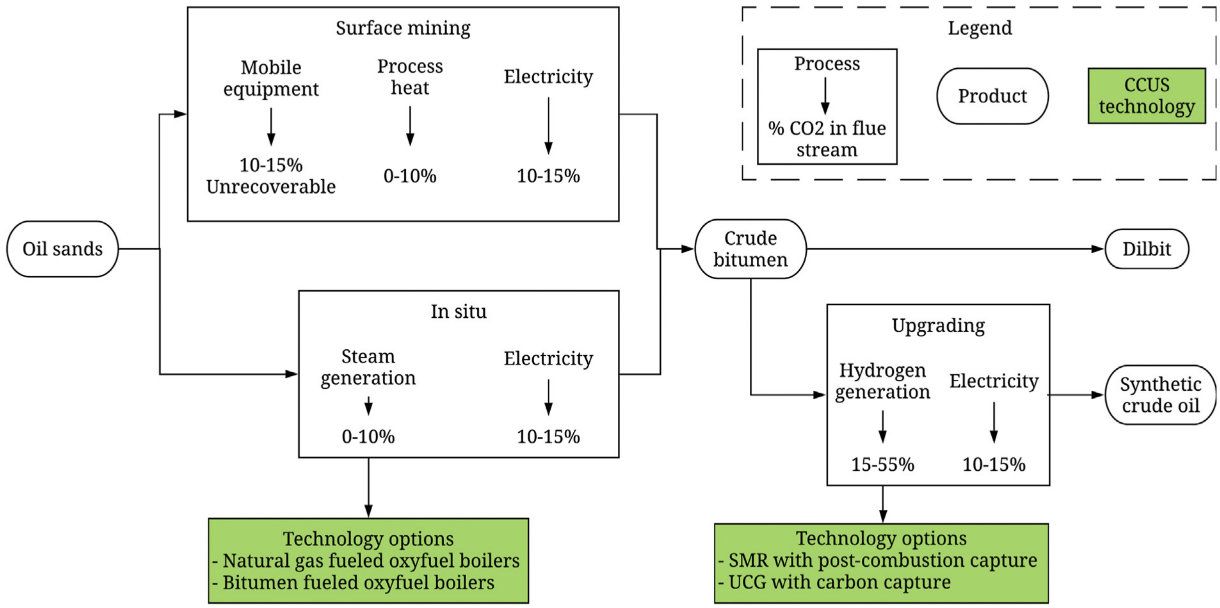


Fig. 2. Overview of CO_2 emission sources in oil sands processing and potential CCS technology applications.

are shown in Fig. 2. There was insufficient techno-economic data for CCS integration into the surface mining subsector; thus, this subsector was not considered. This subsector likely has not been the focus for CCS due to the lower expected growth compared to in situ options and the higher difficulty of capturing GHG emissions from flue streams due to low and unrecoverable CO_2 concentrations, as shown in Fig. 2.

The 2 in situ technologies compete with current natural gas boiler steam generation and are both oxyfuel boilers in the SAGD subsector, one fueled by natural gas and the other by bitumen. The 2 upgrading technologies incorporate carbon capture into hydrogen generation for upgrading through post-combustion capture with SMR and through UCG with carbon capture. CO_2 concentration in flue streams were taken from Ordorica-Garcia et al. [20]. As Fig. 2 shows, the SMR process has substantially higher CO_2 concentrations than other processes, making post-combustion capture possible [20]. The UCG plant involves gasifying underground coal to produce syngas. The syngas is processed to separate hydrogen, which is compressed and transported to upgraders, and CO_2, which is captured [14].

Each scenario's key metrics are outlined in Table 1. Costs for the upgrading and SAGD reference cases were calculated from overnight construction costs and estimated operating costs for facilities of average size for the industry [48]. In the evaluation of each technology, two options were considered for the disposition of captured CO_2: 1 − captured CO_2 is transported into saline aquifers and stored (CCS); 2 − captured CO_2 is transported and sold to EOR operators where it is used for oil recovery operations and permanently stored in the depleted oil reservoir (US).

Costs for carbon capture scenarios are based on the use of the technology for producing the required product and the lifetime costs associated with capturing, transporting, and storing (or utilizing and then storing) the emissions. The oxyfuel boiler scenarios (SAGD-OFNG-CCS, SAGD-OFBIT-CCS, SAGD-OFNG-CCUS, SAGD-OFBIT-CCUS) include the cost of an air separation unit for oxygen production, extra equipment for capturing and compressing the flue gas, and any heating value differences in the case of the bitumen fuel option [17]. Oxyfuel boiler costs associated with the operation of the boilers and the capture and compression of CO_2 at the site were based on techno-economic data taken from literature [17]. In order to account for the transportation and storage costs, the transportation and storage models developed in Verma et al. [16] were adapted to the flow rates and transportation distances required in the oxyfuel boiler scenarios developed in this study. The SMR plant with CCS scenario (H2-SMR-CCS) considers the additional cost of energy and equipment for incorporating post-combustion capture to currently used SMR processes for hydrogen production [16]. The UCG with CCS scenario (H2-UCG-CCS) considers the cost of producing and transporting hydrogen to upgrading sites as well as capturing and transporting GHG emissions [16]. For carbon utilization scenarios, the revenue from the sale of captured CO_2 was assumed to be 47 CAD/tonne in 2020, which was previously identified as an acceptable market value in the oil sands [16] and falls within North American ranges from an other study; 30−60 USD/tonne [26].

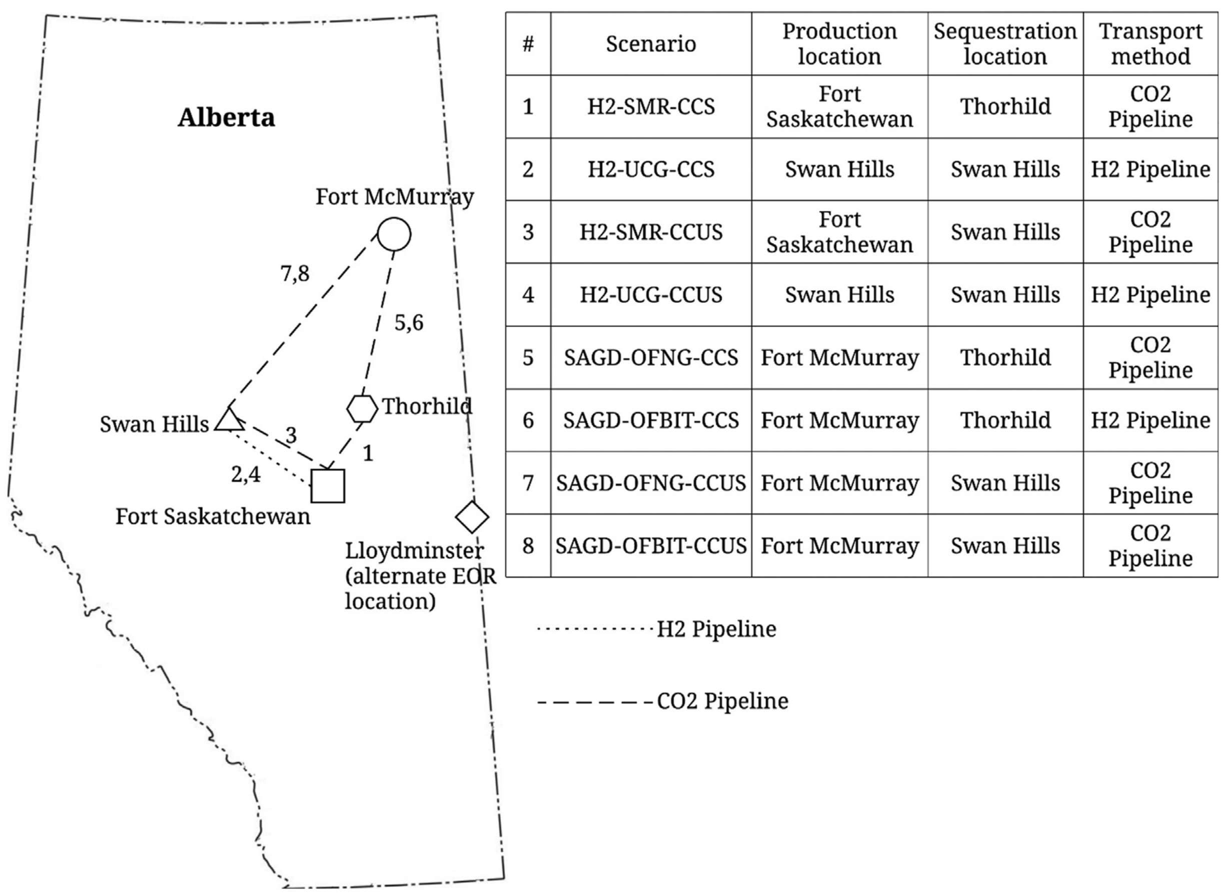
GHG emission factors for the reference case technologies are from the LEAP Technology and Environment Database that includes emission factors for major fuels [27]. GHG emission factors for CCUS technologies are based on the expected GHG emission intensity and capture efficiency of each process. They consider the parasitic energy required to operate the additional equipment needed and the energy needed for transportation and injection. GHG emission factors for the CCUS technologies considered in this study are based on the rate of capture presented in the techno-economic literature used to develop new technology scenarios and cited throughout this work.

The geographical location of commodity production, use, and storage is an important factor in the costs and practicalility of each scenario. Fig. 3 shows this information for each scenario, highlighting the location of the carbon source, sequestration site, and required major pipelines. The associated costs of the required pipelines are considered in each scenario. Current scenario costs are based on carbon utilization scenarios selling captured CO_2 to EOR operators in the Swan Hills area; however, recent reports have suggested that Lloydminster, Alberta may also be an optimal area for these operations [29]. Differences in transportation distances

Table 1
Key scenario information.

Subsector	Scenario name	Description	Carbon transport location	Annualized cost[a] ($/kg H_2)	Emission factor (kg CO_2/kg H2)
Upgrading (hydrogen production)	Reference	Steam methane reforming (SMR)	Emitted to atmosphere	$1.41 + 0.15 \times P_{NG}$	8.47
	H2-SMR-CCS	Steam methane reforming with CO_2 storage	Aquifer storage	$1.69 + 0.15 \times P_{NG}$	2.98 [16]
	H2-UCG-CCS	Underground coal gasification with CO_2 storage	Aquifer storage	$2.63 + 0.40 \times P_{Coal}$	1.52 [16]
	H2-SMR-CCUS	Steam methane reforming with CO_2 enhanced oil recovery	Depleted oil wells	$1.55 + 0.15 \times P_{NG}$	2.98 [16]
	H2-UCG-CCUS	Underground coal gasification with CO_2 enhanced oil recovery	Depleted oil wells	$2.37 + 0.40 \times P_{Coal}$	1.52 [16]
SAGD (steam production)	Reference	Natural gas boilers	Emitted to atmosphere	$21.67 + 1.12 \times P_{NG}$	60.4
	SAGD-OFNG-CCS	Natural gas oxyfuel boilers with CO_2 storage	Aquifer storage	$24.75 + 1.13 \times P_{NG} + 4.7$ x P_{ELEC}	6.0 [17]
	SAGD-OFBIT-CCS	Bitumen oxyfuel boilers with CO_2 storage	Aquifer storage	$25.12 + 1.54 \times P_{BIT} + 4.7$ x P_{ELEC}	12.1 [17]
	SAGD-OFNG-CCUS	Natural gas oxyfuel boilers with CO_2 enhanced oil recovery	Depleted oil wells	$21.59 + 1.13 \times P_{NG} + 4.7$ x P_{ELEC}	6.0 [17]
	SAGD-OFBIT-CCUS	Bitumen oxyfuel boilers with CO_2 enhanced oil recovery	Depleted oil wells	$22.24 + 1.54 \times P_{BIT} + 4.7$ x P_{ELEC}	12.1 [17]

[a] Detailed information about the development of these values is provided in Table 3. P_{NG} = price of natural gas ($/GJ); P_{COAL} = price of coal ($/tonne); P_{BIT} = price of bitumen ($/GJ); P_{ELEC} = price of electricity ($/kWh).



#	Scenario	Production location	Sequestration location	Transport method
1	H2-SMR-CCS	Fort Saskatchewan	Thorhild	CO2 Pipeline
2	H2-UCG-CCS	Swan Hills	Swan Hills	H2 Pipeline
3	H2-SMR-CCUS	Fort Saskatchewan	Swan Hills	CO2 Pipeline
4	H2-UCG-CCUS	Swan Hills	Swan Hills	H2 Pipeline
5	SAGD-OFNG-CCS	Fort McMurray	Thorhild	CO2 Pipeline
6	SAGD-OFBIT-CCS	Fort McMurray	Thorhild	H2 Pipeline
7	SAGD-OFNG-CCUS	Fort McMurray	Swan Hills	CO2 Pipeline
8	SAGD-OFBIT-CCUS	Fort McMurray	Swan Hills	CO2 Pipeline

Fig. 3. Overview of scenario locations and captured carbon or produced hydrogen transportation methods (map taken from NRCan and used in accordance with the Canadian Open Government License [28]).

from Fort Saskatchewan or Fort McMurray to either location were analyzed and considered negligible. The cost to implement the scenarios in both locations would be similar.

Each scenario is also considered under three different carbon taxation or carbon pricing policies. Carbon taxation or carbon pricing refers to the act of taxing GHG emissions directly associated with specified activities. First, scenarios are considered in the absence of any carbon pricing to allow for a clear comparison of cost performance without regard to emissions. Second, a price of $30/$tCO_2$ is applied [30]. Third, a price of $30/$tCO_2$ is applied until 2020, is increased to $40/$tCO_2$ in 2021, to $50/$tCO_2$ in 2022, and remains static for the remainder of the evaluation period. This final option follows the Pan-Canadian Framework proposed by the federal government [31]. Emissions above the given benchmark are taxable and GHG emissions below the given benchmarks are subject to credits equivalent to the taxation rate. Table 2 below provides the emission benchmarks for industries considered in this study.

Scenario names are used to differentiate the carbon pricing options being evaluated. The zero carbon price scheme is indicated by "CP0" added to the scenario name, "CP30" is added for the scheme reaching $30/tCO$_2$, and "CP50" indicates the scheme reaching $50/tCO$_2$.

2.3. Modeling

2.3.1. Market penetration

The rate at which a prospective technology can feasibly enter the market is determined through market penetration modeling using the costs of the prospective technology and the currently used technology. Several methods exist to assess technology market penetration. For technologies that have been demonstrated but have little existing market penetration, cost and diffusion modeling are useful approaches [34]. Technology diffusion involves assigning market share based on a logistic curve that represents the assumption that technology uptake is slow both early on and when the technology has become saturated but is quick in the intervening period. An earlier study presents an equation for calculating annual market share of technologies based on technology lifetime cost shown in Equation (1) [35]:

$$\mathrm{MS_j} = \frac{\mathrm{LCC_j^{-v}}}{\sum_{j=1}^{k} \mathrm{LCC_j^{-v}}} \tag{1}$$

where MS_j is the market share of technology j in the examined year, LCC_j is the annualized lifetime cost of technology j in the examined year, ν is the cost variance parameter discussed in more detail below, and k is the number of competing technologies in the subsector being examined. The cost variance parameter is included to represent market research showing that decision makers do not always choose the cheapest technology but may select a more expensive technology for a variety of reasons such as long-term outlook of the technology. For the energy industry, a range of 6–10 is considered appropriate [21]. In this study a value of 8 is used and sensitivity analysis is conducted over the entire range consider appropriate in the literature [21].

The annualized lifetime cost is developed so that a year-by-year cost per unit of production for each technology is determined using all the major cost components of that technology. This value is calculated by adapting equation proposed in literature [35] to oil sands costs:

$$\mathrm{LCC_j} = \left(\mathrm{CC_j} \times \frac{\mathrm{i}}{1-(1+\mathrm{i})^{-\mathrm{n}}}\right) + \mathrm{OC_j} + \mathrm{ECC_j} + \mathrm{EC_j} \tag{2}$$

In our Equation (2), CC_j is the overnight capital cost of technology j, i is the interest rate, n is the technology lifetime, OC_j is the annual operating and maintenance costs of technology j, ECC_j is the annual cost of emitted carbon for technology j calculated using the emission benchmarks in Table 2 and the carbon price, and EC_j is the annual energy cost for technology j. Technology costs are evaluated using an internal rate of return (IRR) of 10% for the interest rate and converting all dollars to 2020 $CAD. IRR selections are variable and based on the perceived risk of the technology; we used 10%, as found in earlier studies for new technologies [36,37]. Sensitivity analysis was also conducted on the value.

Annual market share results from Equation (1) are multiplied by the forecasted new production in the considered subsector to calculate the new production each year from every considered technology, based on the production forecasts shown in Fig. 4. The production forecasts up to 2040 are taken directly from LEAP-Canada model and are in line with the Canadian National Energy Board (NEB) [9]. Production beyond 2040 was determined by extrapolation using each subsector's growth between 2030 and 2040 using the LEAP-Canada model. New production available for CCUS technologies is the difference between the forecasted production in the evaluation year and the forecasted production from the previous year. The calculated market share for each technology is used to determine what share of the production increase in each year is assigned to each technology. If there is no production increase in that year, then there is no change in market share for the technologies.

In situ scenario costs are based on earlier studies for facilities from production rates of 30–100 thousand barrels per day (kbpd). Currently active commercial SAGD facilities range from 1.5 to 180 kbpd with an average of 48 kbpd in 2019 [38]. Expected production growth in the SAGD subsector is 20 million barrels/year from 2020 to 2040 [9], suggesting ample room for new technologies to penetrate the market. Due to the relatively small average facility size compared to the expected growth, no minimum facility size constraints were required in the model and the calculated market share from Equation (1) was used to calculate expected production levels directly.

The upgrading subsector has a lower rate of expected growth of 196 kbpd from 2020 to 2040 [9], an 18% capacity increase. The additional hydrogen required to meet the increased production would be approximately 670 tonnes H_2/day. Since the CCUS technology facility sizes considered in this study are 607 and 660 tonnes H_2/day for SMR and UCG plants [16], respectively, the forecasted growth allows for upgrading with CCUS to be considered in this study. There is also the potential for bitumen upgrading to grow beyond the NEB forecasts as there are currently interest and financial incentives for alternative upgrading options in Alberta that would require additional hydrogen if successful [32,33,39]. Therefore, despite the lower forecasted growth of the upgrading subsector, there is value in investigating technology options in it. The potential to implement CCUS technologies at existing facilities was not considered due to the lack of available economic data and the range of facility sizes currently operating. New growth offers the most cost-effective implementation pathway for new technologies (because the additional capital costs can be somewhat absorbed into the construction activities of the new facility) and is the focus of the present work. Input costs for Equation (2) developed from earlier studies for each scenario are shown in Table 3.

2.3.2. LEAP-oil sands model

Long-range Energy Alternatives Planning (LEAP) model [27] was

Table 2
Taxable GHG emissions benchmark values [32,33] (BE_y: Established benchmark for year y [tCO$_2$e per product unit]).

Product	2018	2019	2020	2021	2022	Subsequent years	Product unit
Hydrogen	7.97	7.97	7.89	7.81	7.73	$BE = BE_{y-1}$ - 0.08	Tonne
Oil sands in situ bitumen	0.3504	0.3504	0.3469	0.3434	0.3399	$BE = BE_{y-1}$ - 0.0035	m^3 bitumen

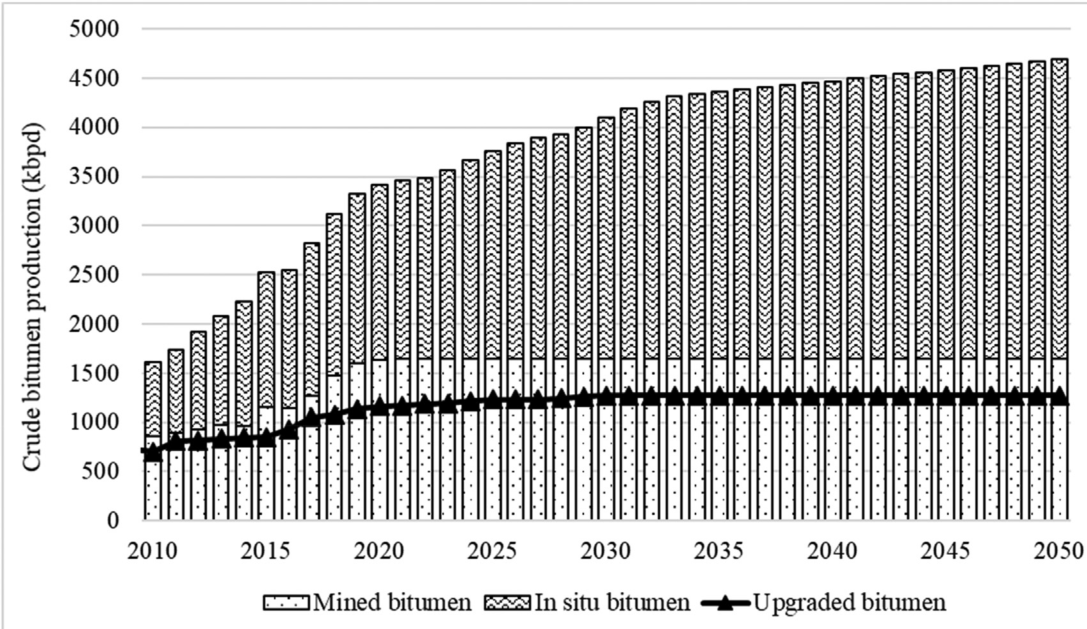


Fig. 4. Relevant subsector production forecasts entered into the LEAP-Oil sands model.

Table 3
Key input data for Equation (2) by technology.

Technology	CC	OC	ECC	EC[a]	Units	Lifetime (years)	Source
Reference – Bitumen upgrading	1.14	0.27	0.008	$0.15\times P_{NG}$	\$/kg H_2	20	[16]
H2-SMR-CCS	1.37	0.32	0.003	$0.15\times P_{NG}$	\$/kg H_2	20	[16]
H2-UCG-CCS	2.25	0.38	0.002	$0.40\times P_{Coal}$	\$/kg H_2	20	[16]
H2-SMR-CCUS	1.26	0.3	0.003	$0.15\times P_{NG}$	\$/kg H_2	20	[16]
H2-UCG-CCUS	2.01	0.36	0.002	$0.40\times P_{Coal}$	\$/kg H_2	20	[16]
Reference - SAGD	13.02	8.64	0.056	$1.12\times P_{NG}$	\$/bbl	20	[48]
SAGD-OFNG-CCS	16.11	8.64	0.006	$1.13\times P_{NG}$	\$/bbl	20	[17]
SAGD-OFBIT-CCS	16.47	8.64	0.012	$1.54\times P_{BIT}$	\$/bbl	20	[17]
SAGD-OFNG-CCUS	15.5	6.09	0.006	$1.13\times P_{NG}$	\$/bbl	20	[17]
SAGD-OFBIT-CCUS	15.87	6.37	0.012	$1.54\times P_{BIT}$	\$/bbl	20	[17]

[a] P_{NG} = price of natural gas; P_{BIT} = price of fuels derived from produced bitumen (approximated as 1/3 of natural gas price [17]).

used to develop an energy and GHG emission accounting model for the oil sands (LEAP-Oil sands) and to determine the emission reduction potential of the technology scenarios. The LEAP-Oil sands model was developed and validated as part of previous research [43,46]. Validation included comparing the LEAP-Oil sands model results to publicly available historical energy consumption values provided by the Canadian Energy Research Institute [41], which were within 1% of reported values, and GHG emissions values from Environment and Climate Change Canada [42], which were within 2% of reported values. The model is structured into demand and transformation modules. The demand module includes the energy-consuming technologies used for oil sands production, with their energy intensities (energy required per barrel of production activity) and fuel types defined. The energy requirements calculated in the demand module are met from the transformation module, where energy sources and conversion processes are defined in the model. The model is driven by production forecasts with the latest production forecasts published by the NEB [9]; the relevant subsector data, shown in Fig. 4, gives total production from the surface mining and in situ subsectors (the two combined gives total oil sands production) and the portion of product upgraded. Intergovernmental Panel on Climate Change (IPCC) and user-defined GHG emission factors are used for the specific fuels consumed in the oil sands to calculate GHG emissions. Emission factors for existing technologies are based on the values provided in LEAP's Technology and Environmental Database, which applies IPCC emission factors from the Fifth Assessment Report [4]. For a more detailed breakdown of the model structure, assumptions, and function see Katta et al. [43].

The structure of the LEAP-Oil sands model described in Katta et al. [43] is shown below in Fig. 5. This model was updated in this study to include the 8 technology scenarios that consider the replacement of current SAGD and upgrading subsector technologies with CCS and CCUS options. In the SAGD branch of the model, oxyfuel boilers fueled by bitumen and natural gas are added, along with their emission factors from Table 1, to compete with non-CCUS steam generation. In the upgrading branch of the model, as shown in Fig. 5, SMR hydrogen generation equipped with carbon capture and UCG with carbon capture are added along with their emission factors from Table 1, to compete with non-CCUS SMR operations. The energy intensity values of the new branches were derived from Ref. [16,17]. The activity levels of the competing technologies were determined by the market share model results and were input to the LEAP-Oil sands model.

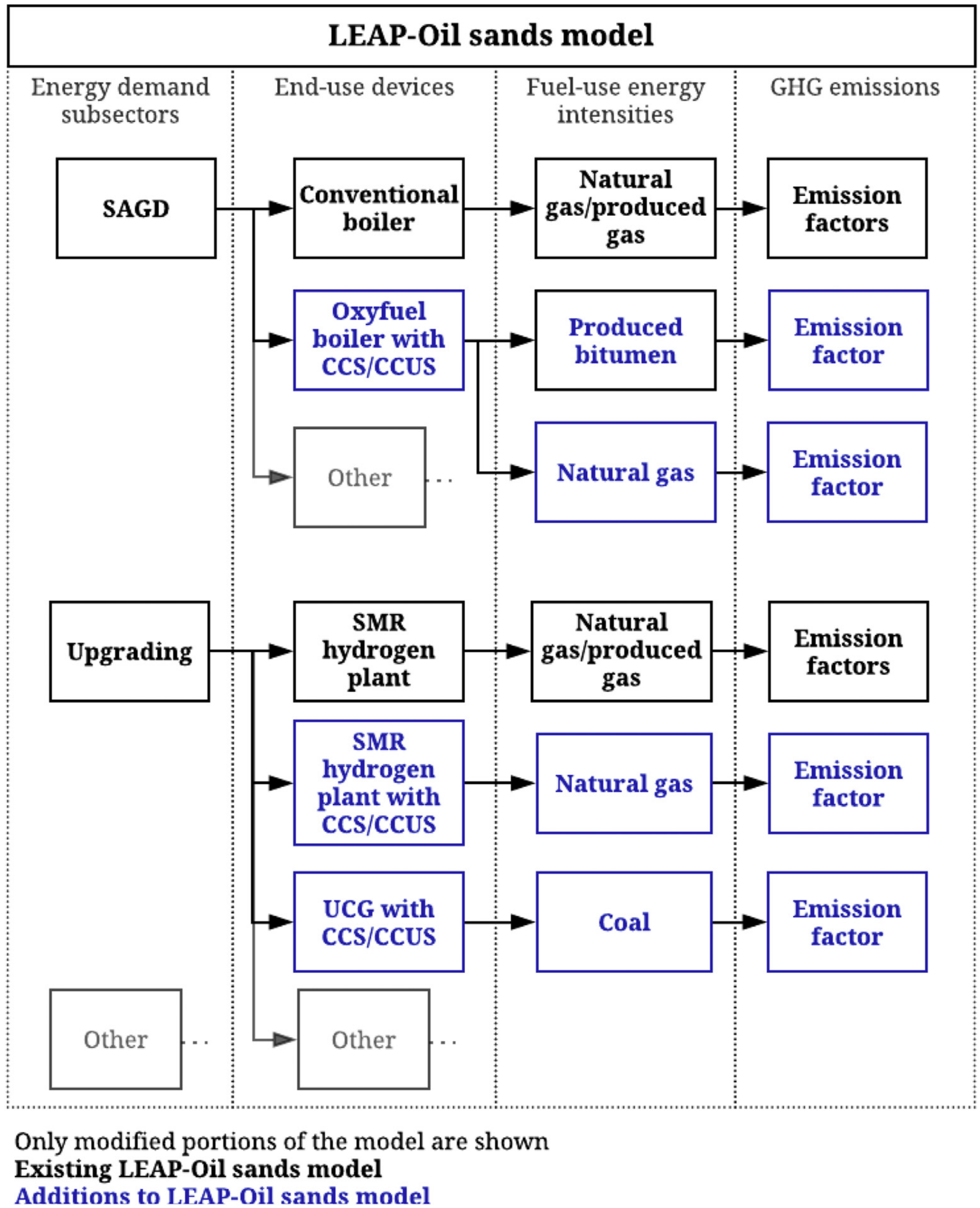


Fig. 5. LEAP-Oil sands model overview with CCUS technologies.

2.4. Cost-benefit analysis

The results from the LEAP-Oil sands model and the market penetration model are combined to develop marginal GHG abatement cost curves for each scenario, which provide the GHG emission abatement potential and marginal cost of GHG abatement for each scenario.

Equation (3) is used to calculate the cost of mitigation in each scenario using the GHG emission quantities from LEAP-Oil sands and the costs calculated in the market penetration model.

$$Scenario_x\ marginal\ cost\ [\$ / tonne] = \sum_{n=i}^{n} \frac{SC_{xn} - SC_{BAUn}}{SE_{BAUn} - SE_{xn}} \tag{3}$$

In the equation, *Scenario$_x$ marginal cost* is the cost per tonne of CO_2 equivalent for scenario x, SC_{xn} is the annualized cost of using technology x per unit produced in year n, SC_{BAUn} is the annualized cost of using the business-as-usual technology per unit produced in year n, SE_{BAUn} is the GHG emissions from using the business-as-usual technology in year n, and SE_{xn} is the GHG emissions from using the technology x in year n. The results are summed for the entire evaluation period (2020–2050) for a cumulative cost of mitigation for each scenario. Future scenario costs are discounted at a rate of 5% to 2020 Canadian dollars, based on earlier studies for GHG mitigation [37].

2.5. Sensitivity analysis

Sensitivity analysis was conducted on key variables that are subject to variation and influence results in order to examine the factors that most impact the results of this work. While no specific error range in the model was calculated because the source data does not provide these values, the sensitivity analysis effectively shows the variability possible in the results if key input data changes. The cost variance parameter used in Equation (1) was changed over the range applicable to the energy industry (6–10) and the resulting changes in technology market shares were recorded. Carbon credits change with availability and demand. Average values of how much less credits are typically traded for are not publicly available. For that reason, the assumed market value of 85% of the taxation rate is changed by ± 10% to determine the effect on results. Natural gas prices have historically varied considerably in North America and have a significant impact on the costs of operating the business-as-usual technologies; therefore, technology penetration and cost of GHG mitigation results were tested for prices ± 20% of forecasted values, roughly matching the ranges in the "high price"/"low price" scenarios provided by the Alberta Energy Regulator [44]. Forecasted market growth depends on many factors, including the global price of oil, infrastructure for shipping product, and government policy for new project approvals; therefore, the results were tested for changes of ± 20% in growth projections, roughly matching the "low growth" and "high growth" scenarios provided by the NEB [9]. Finally, the results were recorded with IRRs of ± 5% to cover general IRR values used for low- and high-risk technologies and determine the impact of internal policies and perceived risk of new technologies on their market potential. Results for the sensitivity analysis are in the supplementary file in the Appendix.

3. Results and discussion

3.1. Market penetration

The 2050 market share results from the market penetration model are shown for carbon storage scenarios in the upper portion of Fig. 6. Technologies consistently achieve higher market shares with increased carbon pricing; however, the increase from no carbon pricing to CP30 is more significant than the difference between CP30 and CP50. The highest performing scenario was oxyfuel bitumen boilers (SAGD-OFBIT-CCS); the technology achieved market shares of 17.6% with CP0, 21.1% with CP30, and 23.1% with CP50. The high penetration resulted from two factors; the improved operating costs from lower-cost fuel as the natural gas price increased over time and the relatively similar capital costs compared to the reference scenario. Oxyfuel natural gas boilers (SAGD-OFNG-CCS) achieved significant market share, though lower than the bitumen-fueled option. Market shares were 9.4% with CP0, 11.6% with CP30, and 12.8% with CP50. The highest potential penetration in the SAGD subsector was 58%, with the top performing scenario capturing 40% of the available growth. The lower market shares are due to the higher forecasted cost of oxyfuel boilers fueled by natural gas as natural gas prices increase.

Hydrogen-producing scenarios generally achieved lower market shares than technologies in the SAGD sector because of lower expected growth in the upgrading sector, where the highest potential penetration in the upgrading subsector was 18% (because of the lower growth expected in the subsector). SMR with CCS (H2-SMR-CCS) gained 4.3%, 6.2%, and 6.8% market shares for CP0, CP30, and CP50 scenarios, respectively, while UCG with CCS (H2-UCG-CCS) gained 1.3%, 1.9%, and 2.3% market shares for CP0, CP30, and CP50 scenarios, respectively. The top performing scenario in the upgrading sector (H2-SMR-CCS-CP50) captured 38% of the available market growth. In these scenarios, the additional cost of UCG facilities and the additional transportation distance of captured CO_2 to the sequestration site contributed to the lower cost competitiveness of UCG options. The expected increases to natural gas prices were not significant enough to make UCG cheaper than SMR in these scenarios. Additionally, the limited forecasted growth of the upgrading subsector restricted the market share available to be gained by both UCG and SMR technologies, and the large size of a new SMR or UCG plant may restrict the feasibility of implementing these scenarios unless similar costs can be achieved with scaled-down facilities.

Scenarios considering the utilization of captured CO_2 for EOR operations offered a revenue stream for captured carbon, thereby reducing costs. Reduced costs from the sale of captured CO_2

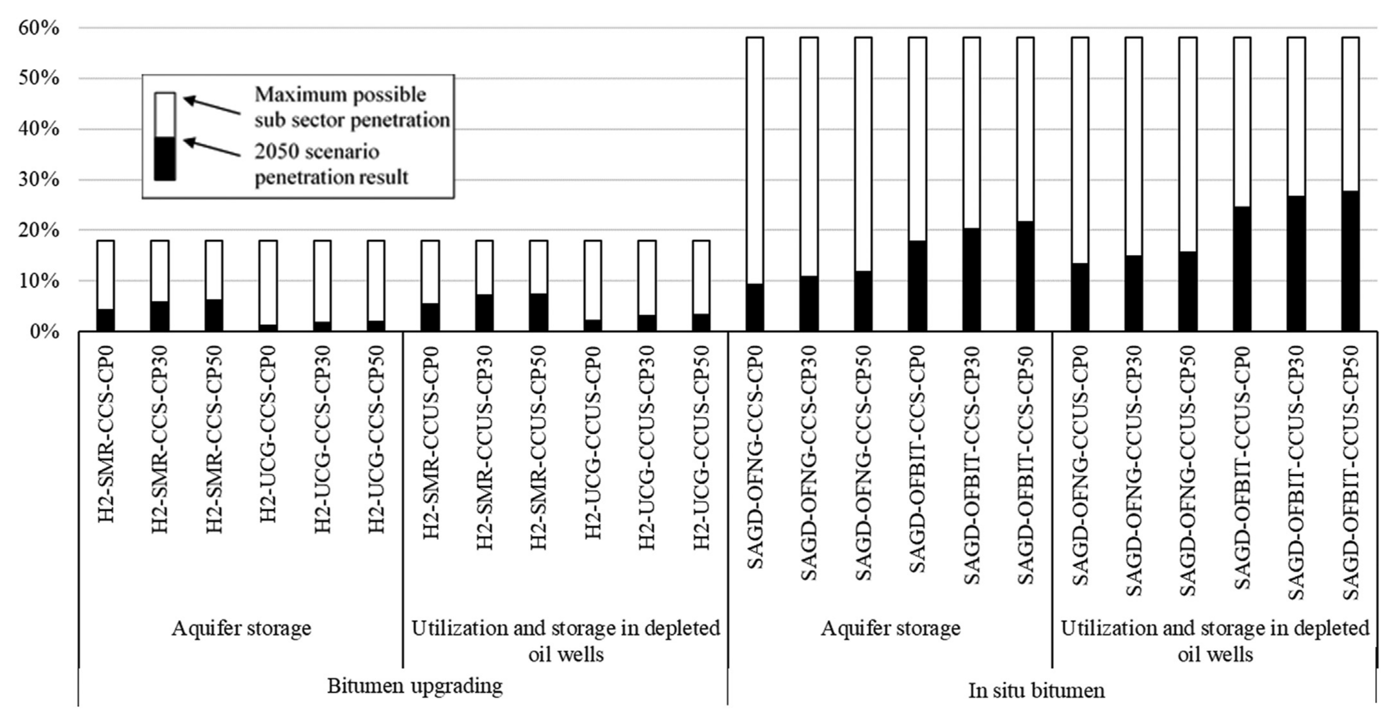


Fig. 6. 2050 market share results for scenarios with respect to maximum subsector penetration.

resulted in increased 2050 market shares for every scenario, as shown in Fig. 6. Again, the top performing technology was the bitumen-fueled oxyfuel boiler used for SAGD steam, represented by the SAGD-OFBIT-CCUS scenarios. Market share results for this technology were 25% for CP0, 27% for CP30, and 30% for CP50. For these options, the top performing scenario captured 52% of the available growth.

For hydrogen options, SMR again outperformed UCG options, gaining 5.5%, 7.3%, and 8.5% market shares under no carbon cost, CP30, and CP50, respectively. Here, H2-SMR-CP50-CCUS gained 47% of the available market growth. These were more than double the market shares achieved by UCG. Although it is the highest performing scenario in the upgrading subsector, it represents a facility of only 315 tonnes H_2/day, while the optimal facility size, based on earlier studies, is a 607 tonnes H_2/day [16]. Because of the large facility size, limited forecasted growth in the upgrading subsector, and the resulting lower market shares, the feasible implementation of the upgrading subsector scenarios may be limited. In all the carbon utilization scenarios, carbon pricing had a smaller impact on market share results than when carbon was captured for storage.

3.2. GHG emission abatement potential

Combining the top aquifer storage (CCS) scenarios from both sub sectors resulted in 157 Mt, 183 Mt, and 196 Mt of GHG abatement potential by 2050 for the CP0, CP30, and CP50 carbon pricing, respectively. These results translate to maximum reductions of 4.5%, 5.2%, and 5.6% of industry-wide GHG emissions during the evaluation period, respectively, depending on the carbon price. Carbon pricing resulted in an additional 26 Mt of abatement potential for CP30 and 39 Mt for CP50. If the results are similarly added for the top carbon utilization scenarios (CCUS scenarios), the results are 215 Mt, 236 Mt, and 245 Mt of GHG abatement potential by 2050, or 6.1%, 6.7%, and 7.0% reductions for CP0, CP30, and CP50 scenarios, respectively. These results show that the option to gain revenue from captured CO_2 increases the viability of these technology options significantly, providing a 1.5% increase in abatement potential on average. Carbon pricing resulted in an additional 21 Mt of abatement potential for CP30 and 30 Mt for CP50.

Annual GHG abatement potential from each scenario was calculated, and results from the CP30 scenarios are shown in Fig. 7. The top performing technology was bitumen-fueled oxyfuel boiler for SAGD steam (SAGD-OFBIT), providing 170 Mt and 225 Mt of abatement potential in the carbon storage and carbon utilization scenarios, respectively. The highest performing upgrading technology was steam methane reforming with carbon capture, which provided 11 Mt and 13 Mt of abatement potential in the carbon storage and carbon utilization scenarios, respectively.

CP30 scenario results were adjusted to consider only the sources applicable to the legislated 100 Mt GHG emissions cap and are shown in Fig. 7, to allow for comparison to the cap. Scenarios incorporating upgrading technologies are not considered here because upgraders constructed or expanded after 2015 are excluded from the cap. The reference case is expected to exceed the GHG emission cap in 2041, and all four scenarios incorporating carbon capture into SAGD are expected to provide GHG emission abatement significant enough to keep the industry below the emission cap. SAGD-OFBIT-CCUS performed the best, with 2050 emissions reaching only 93.7 Mt. SAGD-OFNG-CCS provided the lowest abatement potential, and 2050 emission levels are projected to be 99.7 Mt in 2050 and expected to exceed the emission cap if the industry continues to grow.

Comparing these results with those of other studies on long-term GHG abatement in the oil sands indicates that CCUS options do offer comparable mitigation potential, even considering that the high costs resulted in less marked adoption compared to previously evaluated measures of cogeneration [47] and energy efficiency [43] as GHG mitigation strategies. In the previous studies, the integration of higher amounts of cogeneration into the oil sands resulted in 2% GHG mitigation and energy efficiency measures resulted in 7% GHG mitigation. The present study has shown that CCUS has the potential to mitigate 6.7% of oil sands emissions under similar policy conditions, nearly equivalent to the maximum potential estimated through energy efficiency and higher than the amount associated with increasing the use of cogeneration.

3.3. Cost-benefit analysis

The marginal cost of GHG emission mitigation for each scenario is presented in the cost curve in Fig. 8. The marginal costs are discounted at a rate of 5% to give a net present value (NPV) of the scenario in the first year of evaluation (2020). For each scenario in the cost curve there is a rectangle whose width represents the potential GHG abatement available in the scenario and whose height represents the cost of mitigation. The scenarios are organized by cost from left (lowest) to right (highest), and scenarios that show negative costs indicate that selecting that scenario would result in cost savings over the evaluation period. The table on the right-hand side of the figure provides the total mitigation by scenario and the percent of all the GHG mitigation available for each scenario.

The three top performing scenarios were SAGD-OFBIT-CCUS-CP50, SAGD-OFBIT-CCUS-CP30, and SAGD-OFBIT-CCUS-CP0 with 253 Mt of abatement potential at -\$30/tCO_2e, 225 Mt of abatement potential at -\$24/tCO_2e, and 205 Mt of abatement potential at -\$15/tCO_2e, respectively. Negative abatement costs indicate that cost savings are forecasted in the associated technology scenario. The results show that the strongest financial performance came from the same technology, oxyfuel boilers using bitumen fuel for SAGD steam, and also that, regardless of the carbon tax policy, all scenarios resulted in cost savings. For comparison, SAGD-OFBIT-CCS-CP30 resulted in 170 Mt abatement potential at -\$4/tCO_2e, a \$20/tCO_2e cost increase, and a 55 Mt decrease in GHG abatement potential. This difference represents the effect of the ability to sell captured CO_2 rather than simply storing it. In the upgrading subsector, H2-SMR-CCUS-CP50 was the top performing scenario and resulted in 15 Mt of GHG abatement potential at -\$7/tCO_2e. Scenarios in the upgrading subsector where captured carbon was stored and no carbon price was applied performed the most poorly in both abatement potential and marginal GHG abatement cost. H2-UCG-CCS and H2-SMR-CCS were limited to 3 Mt at \$42/tCO_2e and 8 Mt at \$32/tCO_2e, respectively, because of the low expected growth in the subsector and the lack of financial benefit (either through the sale of captured carbon or carbon pricing policies). SAGD-OFNG-CCS suffered similarly high costs at \$30/tCO_2e, but still had relatively strong abatement potential at 94 Mt due to the high expected growth in the in situ subsector.

Research by Katta et al. [43] into other GHG abatement opportunities for the oil sands gives insight into where CCUS options stand in terms of cost-effectiveness and abatement potential. Energy efficiency options from the Katta et al. study evaluated under policy conditions similar to CP50 scenarios in our study show that the in situ sector could provide an abatement potential of 165 Mt at -\$70/tCO_2e by 2050 [43]. In the same study, the upgrading sector was found to have 49 Mt at -\$145/tCO_2e by 2050. These results show that the cost-effectiveness of energy efficiency options may be superior to CCUS options, and if used in conjunction with each other could provide substantially more abatement potential for the oil sands industry. Comparisons can also be made to a previous study by the authors that used a similar framework to evaluate the

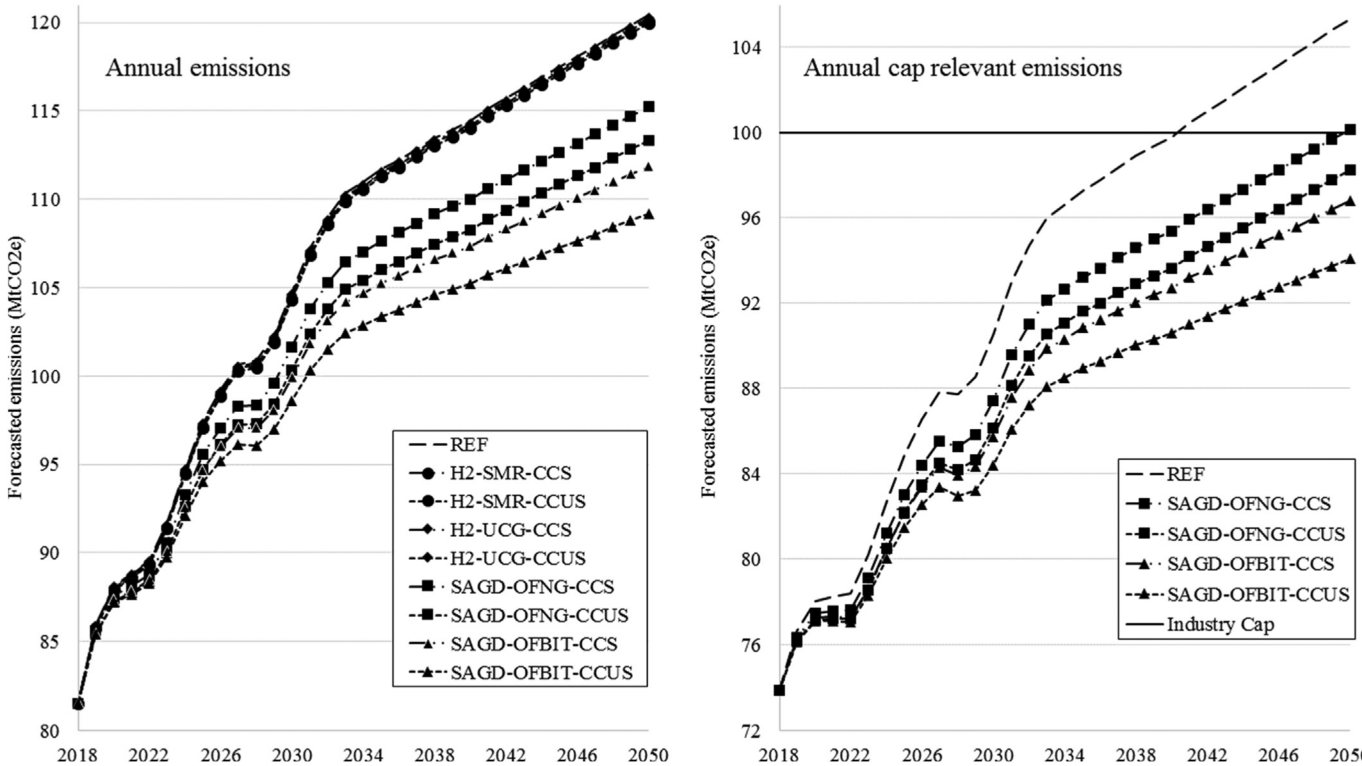
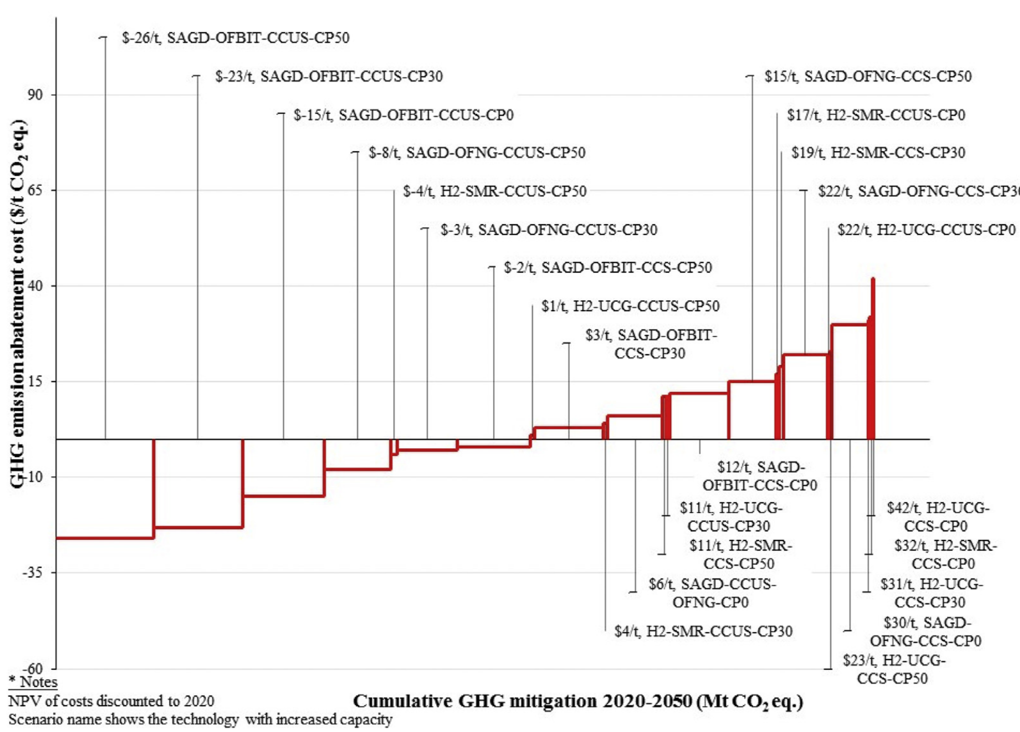


Fig. 7. Annual emission results for CP30 scenarios.



Scenario	Mitigation (Mt)	%
SAGD-OFBIT-CCUS-CP50	246	11.9
SAGD-OFBIT-CCUS-CP30	223	10.8
SAGD-OFBIT-CCUS-CP0	205	10
SAGD-OFNG-CCUS-CP50	169	8.2
H2-SMR-CCUS-CP50	15	0.7
SAGD-OFBIT-CCS-CP50	185	9
SAGD-OFNG-CCUS-CP30	152	7.4
H2-UCG-CCUS-CP50	9	0.4
SAGD-OFBIT-CCS-CP30	173	8.4
H2-SMR-CCUS-CP30	13	0.6
SAGD-OFNG-CCUS-CP0	136	6.6
H2-SMR-CCS-CP50	11	0.5
H2-UCG-CCUS-CP30	8	0.4
SAGD-OFBIT-CCS-CP0	150	7.3
SAGD-OFNG-CCS-CP50	117	5.7
H2-SMR-CCS-CP30	11	0.5
H2-SMR-CCUS-CP0	10	0.5
SAGD-OFNG-CCS-CP30	109	5.3
H2-UCG-CCS-CP50	5	0.2
H2-UCG-CCUS-CP0	6	0.3
H2-UCG-CCS-CP30	4	0.2
SAGD-OFNG-CCS-CP0	92	4.5
H2-SMR-CCS-CP0	8	0.4
H2-UCG-CCS-CP0	3	0.1

Fig. 8. GHG mitigation cost curve to 2050.

integration of higher amounts of cogeneration into the oil sands [47]. Scenarios using cogeneration as a GHG mitigation strategy in the upgrading sector resulted in less total GHG abatement by 2050, 0.6 Mt CO_2e, compared to the CCUS-CP30 options, which ranged from 4 to 8 Mt. The GHG abatement cost associated with cogeneration integration was shown to be much more favorable than CCUS options, indicating that CCUS is not cost effective compared to other available options to mitigate GHG emissions in the long term.

3.4. Limitations and recommendations

The number of carbon capture and storage technologies considered in this study was limited due to the lack of research focused on the cost and performance of incorporating CCUS into oil sands processes. There are a growing number of technologies and processes available to conduct CCUS, and many show promise for reducing energy and costs [45]. Further research into these technologies applied to oil sands processes expand the present work to consider more options and other subsectors of the oil sands industry.

The methods used to evaluate technologies in this study also have limitations that are important to understand. The market penetration model uses diffusion principles for technologies gaining market share that assume a technology acceptance rate fits onto a symmetrical logistic curve based on the cost of the incoming technology compared to what is currently used. While this approach is appropriate for estimating penetration with currently available information, a penetration rate is not necessarily symmetrical and is based on many factors besides costs. Unexpected technological improvements or limitations, social acceptance of one technology over another, and many other factors also impact the success of these technologies. Additionally, this study uses economic forecasts for industries and commodities that have fluctuated significantly throughout history. While the forecasts represent the best available knowledge currently, oil and gas markets are determined globally and are impacted by many factors that cannot be accounted for in the forecasts used. The reference case assumed the technologies currently being used in the oil sands will continue with their relative market shares until the end of the evaluation period. This was done so that a consistent base case could be developed that any technology could be compared to, but it does not accurately reflect changes such as technology and energy efficiency improvements and the need to develop reservoirs for continued growth. In addition, market shares gained by the evaluated technologies are based on forecasted growth in the industry and do not consider the potential to retrofit existing facilities with these technologies, which is feasible. The cost data used in the study is not valid for this type of use and no studies exist that considered the cost difference.

A final limitation is in the carbon pricing evaluation. Currently, carbon credits from technologies operating under the emission benchmarks are traded at some value below the taxation rate depending on their availability in the industry. No data is available on the average value of these credits, so this study assumed they were traded at 85% of the market value and conducted sensitivity analysis to understand the impact of that assumption on the results.

A key recommendation is to conduct further research using the framework of this study to include other types of GHG mitigation measures available to the oil sands. CCUS, cogeneration, renewable energy technologies, energy efficiency, and other measures could be assessed on a single platform using the same model parameters to comparatively assess their market penetration potential, GHG abatement potential, and marginal costs. Since different GHG mitigation technology types could compete in such a model, a more complete and accurate picture of long-term GHG mitigation performance for the oil sands could be obtained.

4. Conclusions

Carbon capture, utilization, and storage technology in the Canadian oil sands could play a key role in GHG abatement, helping Canada meet its emission reduction commitments and industry meet the oil sands emission cap. A novel oil sands CCUS model was developed that integrates market penetration and long-term bottom-up energy accounting, providing a data-intensive and transparent method for the evaluation of different CCUS technologies. Twenty-four scenarios were evaluated for market adoption, GHG abatement potential, and marginal GHG abatement costs covering a range of technologies, policy scenarios, and market conditions to identify optimal pathways for CCUS technologies to gain market share.

The results show that of the two subsectors analyzed (upgrading and in situ), in situ offers significantly greater potential for CCUS technologies. Market penetration modeling results show in situ scenarios ranging from 9.3 to 27.7% of 2050 market share, whereas upgrading subsector scenario results range from 1.3 to 7.5% of the 2050 market share. Subsequent 2050 GHG abatement potential ranges from 92 Mt to 232 Mt for in situ scenarios and 3 Mt to 14 Mt in upgrading scenarios, with a maximum combined abatement potential of 246 Mt for scenarios that can be implemented simultaneously. The expected growth of the in situ subsector compared to the upgrading subsector and the cost competitiveness of CCUS technologies in the in situ subsector are the key reasons for these results. Carbon pricing at $50/tonne and the sale of captured carbon both had a significant impact on making CCUS technologies in the oil sands viable. Oxyfuel boilers using bitumen for fuel was the top performing technology of the options considered. In 4 cases, long-term cost savings were shown, making these scenarios of special interest to industry planners, policymakers, and stakeholders.

The results from this study are of value to government policymakers and industry stakeholders for identifying and promoting the best CCUS technology options for cost-effective emission reductions and even possible areas for profit. The bottom-up model developed is transparent, simple to modify as new technologies emerge or forecasts change, and comprehensive in that it incorporates the latest policies, market projections, and technology options for CCUS in the oil sands industry. The results summarize the key subsectors where emissions can be reduced with CCUS technologies, show the impact of policies that provide incentives for reducing emissions, and help quantify what levels of emission reduction can feasibly be achieved at different costs. This information can be used to optimize investment in specific technologies, structure policies effectively, and set attainable targets. The modeling structure can also be expanded to other technology types, providing a consistent framework and reference scenario to compare any technology with GHG emissions abatement potential in the oil sands industry.

CRediT authorship contribution statement

Ryan Janzen: Conceptualization, Methodology, Validation, Writing - original draft. **Matthew Davis:** Methodology, Investigation, Supervision, Writing - review & editing. **Amit Kumar:** Supervision, Investigation, Resources, Visualization, Writing - review & editing.

Declaration of competing interest

None.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.energy.2020.118364.

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