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Historical trends in greenhouse gas emissions of the Alberta oil sands (1970–2010)

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Abstract
There has been increased scrutiny of the Alberta oil sands due to their high carbon intensity (CI) relative to conventional crude oil. Relying entirely on public and peer-reviewed data sources, we examine historical trends in the CI of oil sands extraction, upgrading, and refining. Monthly data were collected and interpolated from 1970 to 2010 (inclusive) for each oil sands project. Results show a reduction in oil sands CI over time, with industry-average full-fuel cycle (well-to-wheels, WTW) CI declining from 165 $gCO_2e\ MJ^{-1}$ higher heating value (HHV) of reformulated gasoline (RFG) to 105 (−12, +9) $gCO_2e\ MJ^{-1}$ HHV RFG. 2010 averages by production pathways are 102 $gCO_2e\ MJ^{-1}$ for Mining and 111 $gCO_2e\ MJ^{-1}$ for *in situ*. The CI of mining-based projects has declined due to upgrader efficiency improvements and a shift away from coke to natural gas as a process fuel. *In situ* projects have benefitted from substantial reductions in fugitive emissions from bitumen batteries. Both mining and *in situ* projects have benefitted from improved refining efficiencies. However, despite these improvements, the CI of oil sands production (on a pathway-average basis) ranges from 12 to 24% higher than CI values from conventional oil production. Due to growing output, total emissions from the oil sands continue to increase despite improved efficiency: total upstream emissions were roughly 65 $MtCO_2e$ in 2010, or 9% of Canada's emissions.

Keywords: transportation fuels, Alberta oil sands, unconventional oil, life-cycle assessment, LCA, climate change

S Online supplementary data available from stacks.iop.org/ERL/8/044036/mmedia

1. Introduction

The Alberta oil sands have become a prominent source of liquid fuels. Production of crude bitumen from the oil sands reached 9.6×10^6 GJ d^{-1} (1.43 Mbbl d^{-1}) in 2010, or ≈2% of world oil production. The Canadian Association of Petroleum Producers forecast bitumen production of 3.6×10^7 GJ d^{-1} (5.33 Mbbl d^{-1}) by 2030 (O&GJ 2012).

A challenge for oil-sands-derived fuels is that the full-fuel cycle (otherwise known as well-to-wheels, WTW) carbon intensity (CI) of oil-sands-derived fuels is higher than fuels derived from conventional crude feedstocks. Increased emissions are due to the carbon-rich, hydrogen-deficient nature of the bitumen feedstock, which requires more energy to extract, separate, and process than conventional crude oil (Brandt *et al* 2013). In addition, oil sands extraction results in secondary emissions sources such as fugitive emissions, land-use impacts, and methane emissions from tailings ponds. Regulations such as the California Low Carbon Fuel Standard (LCFS) and the European Union Fuel Quality Directive

(FQD) have focused attention on high CI fuels like the oil sands (CARB 2011, Brandt 2011). In addition, public concern over the development of the oil sands has been heightened by the debate over the Keystone XL pipeline.

Recent research on life-cycle GHG emissions from oil sands operations suggests significant variation between processes, depending on their energy efficiency and the fuel mix consumed ((S&T)^2 2011, Wang *et al* 2012, Forrest *et al* 2012, TIAX 2009, Keesom *et al* 2012). Some have argued that extraction of liquid fuels from the oil sands has become more efficient over time. For example, IHS-CERA found that emissions from the largest mining and upgrading projects declined 37% since 1990 (Hobbs *et al* 2011). In this letter, we aim to test this assertion more generally, and over a longer time period, by examining long-term public datasets acquired from the Alberta Energy Regulator (AER, formerly Energy Resources Conservation Board). Our analysis includes flaring and fugitive emissions from operations, indirect emissions from upstream energy sources, and land-use change associated emissions.

This letter proceeds as follows: first, we provide an overview of oil sands production practices. We discuss previous life-cycle analysis (LCA) studies of the oil sands and describe how this work differs. We define our system boundary and outline the methods and data used to reconstruct historical CI. Next, we illustrate trends in oil sands CI over time, given the uncertainty and limitations of our methods. Lastly, we examine the implications of our results for future emissions from oil sands production.

1.1. Historical development of oil sands operations

Pre-commercial oil sands development started in the 1930s and 1940s. Commercial-scale extraction began in 1967 with the Great Canadian Oil Sands integrated mine and upgrader project, later renamed Suncor (Ferguson and Adkins 1952, Chastko 2004). In 1978, the Syncrude project became operational. It has since overtaken Suncor as the largest oil sands producer. These mining-based projects upgrade raw bitumen to synthetic crude oil (SCO).

The first *in situ* project was developed by Imperial Oil in 1974 at Cold Lake, but was not scaled to industrial production until 1984. Cold Lake uses cyclic steam stimulation, a technology similar to that used in other heavy oil resources (e.g. California). In the 1980s and 1990s, steam assisted gravity drainage (SAGD) technology was developed through public–private research partnerships (Deutsch and McLennan 2005). SAGD allows for extraction of the heavier bitumen and provides access to deeper reservoirs. SAGD uses two horizontal wells; steam is injected into the top well to warm the bitumen, reducing the viscosity, and allowing it to flow by gravity to the lower horizontal well, where it is drawn to the surface.

1.2. Oil sands production practices and extraction pathways

Bitumen can be extracted from oil sands by surface mining, *in situ* production, and primary production. This study examines surface mining and *in situ* processes, which account for 85–90% of current oil sands production. Primary production is not included in this study, as data on energy consumption in primary production are not provided in the regulatory data reported to the ERCB. Resources produced via primary production are generally of a higher quality (e.g., higher API gravity) than bitumen produced via mining or thermal *in situ* methods (Energy Resources Conservation Board 1993–2010).

Though the bitumen production can be categorized by the extraction method (mining or *in situ*), there are multiple pathways from which bitumen is refined into products. A first-order approximation is to categorize the pathways as 'mining plus upgrading' and '*in situ* plus refining', as these are the most prevalent pathways ((S&T)^2 2011, Wang *et al* 2012, Forrest *et al* 2012, Yeh *et al* 2010). However, as refineries have become better able to accept oil sands bitumen as either dilbit (bitumen thinned by an added diluent, typically natural gas condensate or naphtha produced at an upgrader) or synbit (bitumen mixed with SCO), this first-order approximation breaks down. In 2010, 7% of products are sent from upgraders as dilbit or synbit, and there are *in situ* projects which send their products to upgraders (e.g. Suncor Firebag).

1.3. Previous LCA treatment of oil sands CI

There are a number of notable LCA models of oil sands emissions. Models such as GREET and GHGenius compare broad fuel pathways, for example comparing oil sands pathways to corn ethanol production (Wang *et al* 2012, (S&T)^2 2012). In contrast, engineering-based process models perform more detailed modeling of oil sands processes (TIAX 2009, Keesom *et al* 2012, Bergerson *et al* 2012). Meta-analyses synthesize other model results and provide a framework for understanding the industry-wide LCA (Forrest *et al* 2012, Charpentier *et al* 2009, Brandt 2011). Though some of these examinations include many sources of fugitive emissions (particularly ((S&T) ^{2} 2012, Bergerson *et al* 2012, Keesom *et al* 2012, Forrest *et al* 2012)), they do not include venting from crude bitumen batteries and all but GHGenius lack a representation of the Alberta grid.

One study by Hobbs *et al* examined historical trends in CI from 1990 to 2009 (Hobbs *et al* 2011). This study was limited to 1990–2009 and it focused on specific pathways, rather than the industry as a whole. For example, the energy intensity and CI values that they report apply either to specific mining projects (i.e. Suncor) or to specific SAGD configurations. This study therefore does not provide insight into the industry-average CI. This study also does not include emissions sources such as tailings ponds and flaring. They do not explore sources of uncertainty and do not provide documentation of their sources.

2. Materials and methods

We use historical data from 1970 to 2010 to conduct an LCA of the CI of fuels produced from the Alberta oil sands on a well-to-wheel basis. Our dataset contains energy consumption and production quantities reported monthly to the AER in

statistical reports (see supplementary information available at stacks.iop.org/ERL/8/044036/mmedia for a more detailed description of data and methods). Where needed, additional data from emissions models and the scientific literature are used. These include tailings pond emissions for which measured time series data are unavailable.

Our system boundary includes direct consumption of all primary fuels and electricity at production sites as well as processing of gas for H_2 generation. We also include emissions associated with direct land-use change, flaring from upgraders, emissions from tailings ponds (for mining), upstream emissions from natural gas production, and emissions from crude bitumen batteries from *in situ* production. Our system boundary does not include emissions from embodied capital such as well pads, trucks, upgraders, etc (see supplementary information available at stacks.iop.org/ERL/8/044036/mmedia for a schematic). Our functional unit is one megajoule (MJ) on a higher heating value (HHV) basis of reformulated gasoline consumed in an automobile. Our carbon intensity (CI) values are presented as grams of CO_2 equivalent ($gCO_2e\ MJ^{-1}$ (RFG) HHV).

This analysis examines the oil sands industry as a whole, with aggregated results reported by extraction method (either mining or *in situ*) on a production-weighted-average basis. Pathways are categorized by extraction technology: mining includes pathways where mined bitumen is sent directly to refineries (as a synbit or dilbit) and *in situ* includes pathways where *in situ* produced bitumen is sent to upgraders.

Our system boundary includes emissions from directly producing the fuels in both mining and *in situ* production. Equations (1) and (2) illustrate how these individual project and pathway CIs were calculated. To calculate each project CI ($CI_p(t)$ e.g. Suncor), the energy intensity (EI) for each fuel (e.g. natural gas, fuel gas, etc) was calculated. This EI ($\frac{F_{pf}(t)}{P_p(t)}$) has units of MJ of fuel consumed per MJ of output. The EIs were multiplied by the specific fuel CI ($CI_f(t)$). Fuel CIs for imported fuels such as natural gas and electricity include upstream emissions associated in the production of that fuel. Next, all other WTW emissions sources were added ($CI_{po}(t)$). Project CIs were smoothed with a twelve-month moving average. The production-weighted average for a pathway was calculated from all of these individual project CIs weighted by the bitumen output from each project ($P_p^{bit}(t)$, see equation (2)).

$$CI_p(t) = \sum_f \underbrace{\frac{F_{pf}(t)}{P_p(t)}}_{EI} CI_f(t) + \sum_o CI_{po}(t) \quad (1)$$

$$CI_{mining}(t) = \sum_p \frac{P_p^{bit}(t)}{\sum_p P_p^{bit}(t)} CI_p(t) \quad (2)$$

$CI_p(t)$ ($gCO_2e\ MJ^{-1}$ RFG)
$F_f(t)$ (MJ fuel)
$P(t)$ (MJ refinery input (SCO/Bitumen))
$P_p^{bit}(t)$ (MJ Bitumen)
$CI_f(t)$ ($gCO_2e\ MJ^{-1}$ fuel)
$CI_{po}(t)$ ($gCO_2\ MJ^{-1}$ RFG)

Data gaps are interpolated using EI of production. EIs (GJ of fuel consumed per GJ of SCO produced, or $\frac{F_{fp}(t)}{P_p(t)}$) are less variable than absolute measures of energy consumption, which change with often sporadic monthly product output. Secondary emissions sources $CI_{po}(t)$ such as tailings pond emissions are taken from the literature due to the lack of reported data. The result of these calculations is a time series of the production-weighted average of the WTW CI from the oil sands. Though some sources are reported on a lower heating value (LHV) basis, all CI values in this analysis are converted to a HHV basis (see supplementary information available at stacks.iop.org/ERL/8/044036/mmedia for LHV values).

3. Results

Our results show a significant decrease in the CI of oil sands produced fuels from 1970 to 2010. Figure 1 shows yearly average CI for mining and upgrading pathways at ten-year increments. Over these periods, the CI has decreased for the mining projects from 165 $gCO_2e\ MJ^{-1}$ RFG in 1970 to 102 $gCO_2e\ MJ^{-1}$ RFG in 2010, while the *in situ* weighted pathway has decreased from 140 $gCO_2e\ MJ^{-1}$ RFG in 1980 to 111 $gCO_2e\ MJ^{-1}$ RFG in 2010 (all HHV basis). On a production-weighted-average basis, the CI of oil-sands-derived RFG has declined from 165 $gCO_2e\ MJ^{-1}$ RFG (−4, +11) to 105 $gCO_2e\ MJ^{-1}$ (−12, +8). On a lower heating value (LHV) basis, the central emissions estimates for 2010 are 109, 119, and 113 $gCO_2e\ MJ^{-1}$ for the mining, *in situ*, and industry-wide basis, respectively (see SI available at stacks.iop.org/ERL/8/044036/mmedia).

Figure 1 also demonstrates that most of the reductions in mining emissions occurred due to efficiencies in mining and upgrading, while for *in situ* production, reductions are primarily due to refining efficiencies and reductions in fugitive emissions from *in situ* crude bitumen batteries (the system of storage tanks used to receive bitumen).

This trend can also be shown on a more detailed, month-by-month basis (see figure 2). Figure 2 (left) shows well-to-refinery entrance (WTR) CIs that exclude changes in refining technology. Therefore, emissions improvements of the oil sands industry can be isolated. WTR emissions for mining have decreased from 78 $gCO_2e\ MJ^{-1}$ refinery input in 1970 to 22 $gCO_2e\ MJ^{-1}$ refinery input in 2010. *In situ* efficiency increases have been more modest: WTR CI has decreased from 30 $gCO_2e\ MJ^{-1}$ refinery input in 1980 to 20 $gCO_2e\ MJ^{-1}$ refinery input. Most of this decrease is attributable to reduction of emissions from crude bitumen batteries, which dropped by 11 $gCO_2e\ MJ^{-1}$ from 1980 to 2010. This drop has been offset by *in situ* production sent to upgraders, which have higher CI than the average *in situ* produced bitumen. Figure 2 (right) shows the time trend in WTW emissions, including improvements in refining as modeled in the GHGenius model (see SI available at stacks.iop.org/ERL/8/044036/mmedia). Our computed uncertainty is plotted around the production-weighted average in gray. The main sources of uncertainty are variations in refining, fuel energy content, and tailings pond emissions (see below).

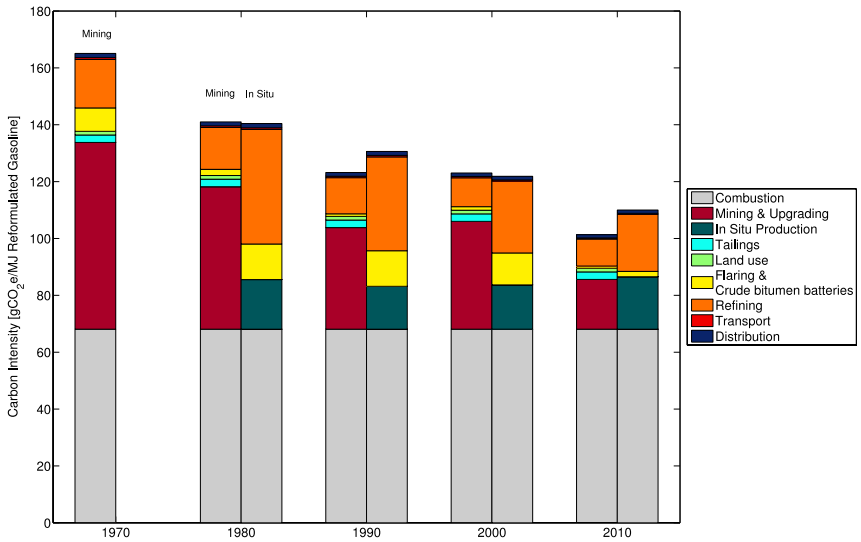

Figure 1. Trends in well-to-wheel pathway-specific CI. *In situ* production began in 1974, so no value is computable for 1970.

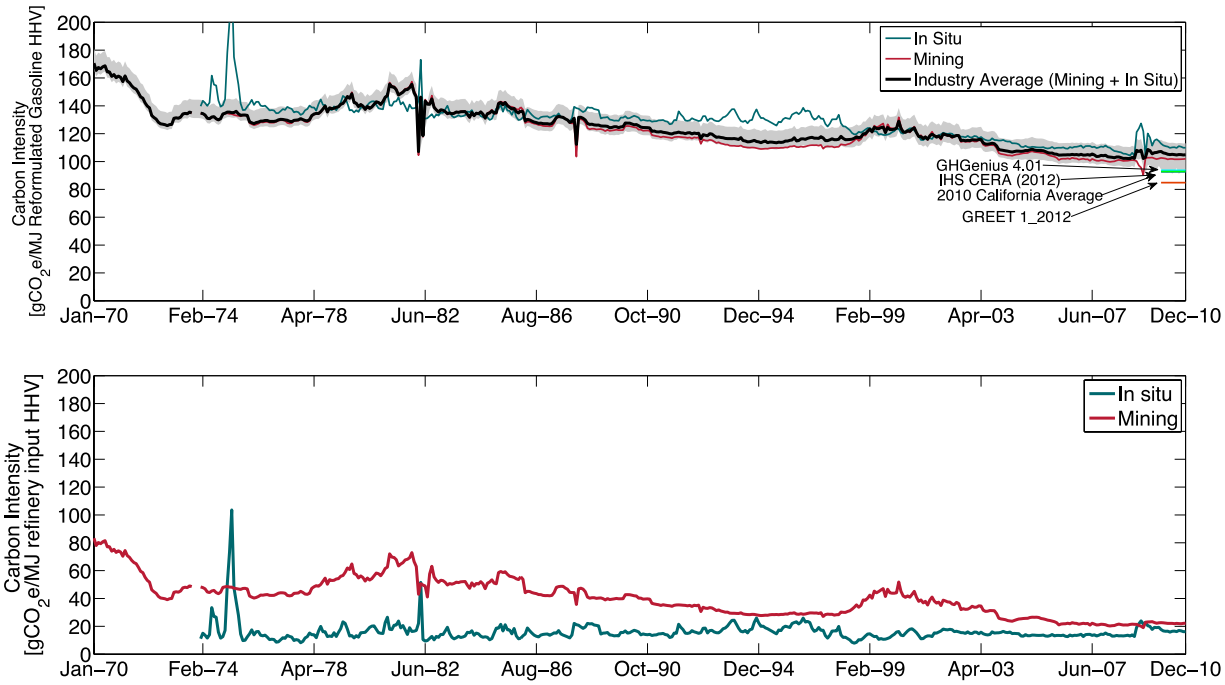

Figure 2. Historical trend in oil sands CI. Left: well-to-refinery entrance (WTR) emissions for mining and *in situ* pathways. Right: well-to-wheels emissions for mining, *in situ* and industry average. The black line represents the production-weighted industry average with gray uncertainty range. The bars on the right-hand side represent literature values for conventional crude for 2010.

Although there has been a decrease in the CI of extracting oil from the oil sands as shown by these data, the CI of oil-sands-derived products is higher than conventional crude and this is likely to remain the case in the medium term. When comparing oil sands CI to conventional oil pathways, the differences are more distinct. Figure 2 (right) highlights that oil-sands-derived fuels have a CI that are demonstrably higher than baseline figures for industry-wide or conventional crude intensities. For example, the GREET and GHGenius default CIs are 85 and 93 $gCO_2e\ MJ^{-1}$, respectively, while the California baseline CI for the low carbon fuel standard (LCFS) is 93 $gCO_2e\ MJ^{-1}$ after converting to a HHV basis. As shown in figure 2, oil-sands-derived fuels are 12–24% more carbon intensive than models present for the average US crude (Wang *et al* 2012, Forrest *et al* 2012, (S&T)^2 2012, CARB 2012). Though these numbers are taken from average or 'typical' crude oil, it is important to note that the emissions from conventional crude oil can vary with factors like flaring rate, water–oil ratio, or production practices (Energy-Redefined LLC 2010, El-Houjeiri *et al* 2013). Further examination into the variations in conventional crude oil production is necessary however it has been noted that particularly for fields with high flaring rates, which is known to occur in Nigeria and Russia, the CI for this conventional production is comparable to oil sands production (El-Houjeiri *et al* 2013).

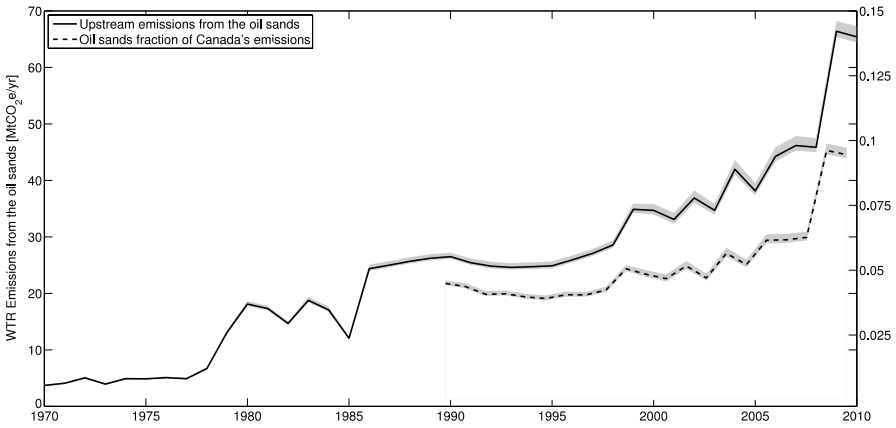

Figure 3. Total upstream emissions from oil sands industry along with the relative fraction of the oil sands in Canada's overall emissions with uncertainty.

Though the CI of oil-sands-derived fuels has decreased, absolute emissions from oil sands production have increased. As illustrated in figure 3, the emissions from oil sands production and upgrading has increased from 3.9 Mt CO_2e in 1970 to 70 Mt CO_2 in 2010. As a proportion of Canada's total emissions, the contribution of emissions from the oil sands has increased from 4% in 1990 to 9% in 2010 of Canada's total emissions (Environment Canada 2012).

4. Sources of uncertainty

There are a number of sources of uncertainty in calculating the CI from the oil sands. The most significant source of uncertainty in this WTW CI is in refining (Abella and Bergerson 2012). Abella and Bergerson concluded that there is more variation in the refining CI for all crude inputs than was previously modeled (on the order of ± 10 gCO_2e MJ^{-1}), especially for lower API inputs most similar to the bitumen fraction of dilbit. The CI values for refining were derived from GHGenius version 4.01 and the historical trends were extrapolated (see supplementary information available at stacks.iop.org/ERL/8/044036/mmedia for more detail).

Some emissions sources were not included in this analysis. These include embodied emissions in capital equipment (e.g., steel for SAGD wells, upgraders, pipelines etc). There were no data available for these emissions, and further study of these embodied emissions is necessary.

The fuel CI for electricity is another source of uncertainty. Our baseline assumption is that electricity debits or credits are calculated using the average CI of the Alberta grid. Since oil sands facilities run constantly (barring upsets), the electricity imported would be a relatively even mixture of power sources on the grid (see supplementary information available at stacks.iop.org/ERL/8/044036/mmedia for the trends in the Alberta grid) (AEUB 1972–2000). However, if the electricity displaced an Alberta natural gas generator instead of the grid average, the mining CI for 2010 increases by roughly 0.5 gCO_2e MJ^{-1}. If instead we assume that coal-fired power is displaced, the overall CI decreases from 105 to 104 gCO_2e MJ^{-1} RFG.

Data extrapolation and interpolation introduce uncertainty into the results (see supplementary information available at stacks.iop.org/ERL/8/044036/mmedia). Trends in mining and upgrading energy intensities, upon which these extrapolations are made, are generally stable over the history of a project (with coke use being a notable exception). Given the capital intensities of these projects, short-term gaps in data availability are not likely to conceal major shifts in process energy intensity or fuel mix. The most consequential of these data gaps are the availability of coke data and the limited availability of natural gas and electricity consumption data for *in situ* projects in early producing years (ERCB 1970–2002, 2008–2010).

Also, emissions from land cover change, methane emissions from the mine face, and methanogenic production from tailings ponds for the mining projects are uncertain ((S&T)^2 2011, Yeh *et al* 2010, Siddique *et al* 2008). The combined estimated emissions associated with these sources range between ≈3–6 gCO_2e MJ^{-1} RFG. Also emissions from crude transport are assumed to be ≈0.5 gCO_2e MJ^{-1} RFG for 400 km to the refinery. If transport to the US gulf coast is assumed, emissions could rise by ≈1 gCO_2e MJ^{-1} RFG.

Lastly, the energy and carbon content of the fuels consumed (coke, natural gas, fuel gas, etc) varies by fuel composition, which differs by project (and possibly over time). Project-specific compositions were obtained where possible.

Though the methodologies we use are different, our CI values are similar to those reported LCA literature (see figure 4). We compared our CI values for 2010 to previous studies ((S&T)^2 2012, Keesom *et al* 2012, Forrest *et al* 2012, Bergerson *et al* 2012). Slight modifications of the other analyses were necessary to make the comparison more applicable. For example, Bergerson *et al* provide CI values for specific technology pathways (e.g. for mining pathways this included mining + upgrading versus mining + synbit). To make this analysis more consistent with our methodology, we took a production-weighted average of the CI values such that the fraction of mining production upgraded to SCO was given the mining + upgrading CI while the un-upgraded mined bitumen sent directly to the refinery was given the mining + synbit CI value (see supplementary information available at stacks.iop.org/ERL/8/044036/mmedia).

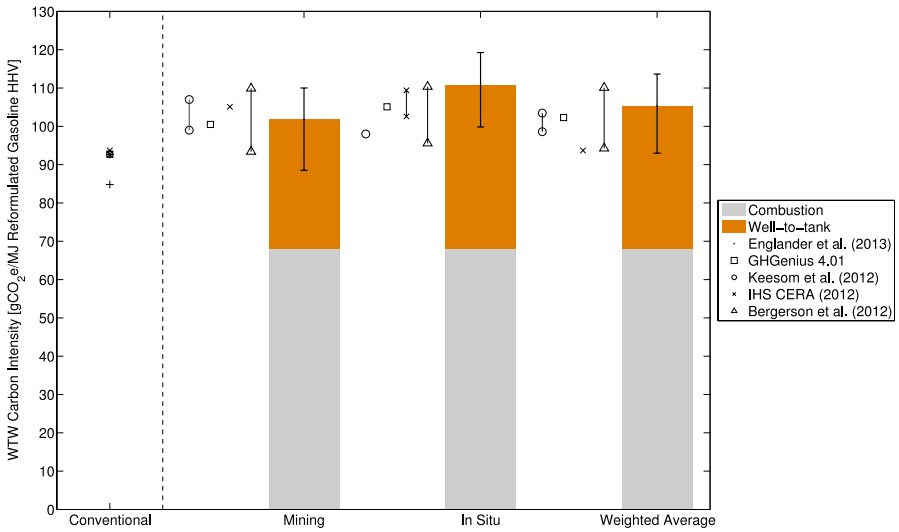

Figure 4. Comparison of this analysis to literature values for CI from the oil sands. The literature values were modified to fit the pathway definition used in this analysis.

Table 1. Underlying causes for the decreased CI of oil sands production on a well-to-refinery basis.

	Energy intensity				Carbon intensity of input fuels			
	(MJ consumed/MJ refinery input)				(gCO_2e MJ^{-1} consumed)			
Year	(GJ GJ^{-1})	Mining (%)	*In situ* (%)	Overall (%)	(gCO_2 MJ^{-1})	Mining (%)	*In situ* (%)	Overall (%)
1970–1975	0.59	—	—	—	82.3	—	—	—
1975–1980	0.50	−13	2	−16	84.4	0	5	3
1980–1985	0.63	27	−12	25	78.0	−8	−3	−8
1985–1990	0.48	−17	0	−24	81.3	−1	−2	−6
1990–1995	0.38	−26	3	−21	78.7	−3	−2	−3
1995–2000	0.37	0	−4	−2	77.8	−5	4	−1
2000–2005	0.40	10	0	9	69.3	−5	−21	−11
2005–2010	0.30	−34	2	−27	62.8	−8	−15	−9

Note that our *in situ* CI value is slightly higher than the LCA literature. This is due to the inefficient Nexen Long Lake upgrader, which was not included in previous work. In addition, the literature values do not take into account methane emissions associated with bitumen batteries as well as consumption of produced gas.

A decrease in well-to-refinery CI for oil-sands-derived fuels can have two potential drivers: either a decrease in energy intensity (GJ fuel consumed/GJ refinery input), or a decrease in the CI of the input fuels (gCO_2 GJ^{-1} fuel consumed) (e.g. coke compared to natural gas). We tabulate these upstream changes for the entire industry and for pathways in table 1.

Over the long term, there have been decreases in both EI and the CI of the input fuels. However, significant changes have occurred more prominently for mining in comparison to *in situ*, where efficiency improvements have been more modest. In comparing these disaggregated intensities to the overall CI, the overall upstream CI is more closely correlated to the energy ratio than the fuel CI (see supplementary information available at stacks.iop.org/ERL/8/044036/mmedia).

5. Discussion and conclusion

A variety of technological developments over the last 40 years have driven the decline in CI of oil sands operations. The most substantial efficiency gains occurred in separation and upgrading. Hobbs *et al* point to the fluidizing of raw oil sands before separation, which preconditions the ore and allows for lower separation water temperatures (Hobbs *et al* 2011). Process optimization and heat-recovery improvements within the upgrading process are other possible sources for increased efficiencies, however detailed accounts of such changes are not publicly available. Additional significant efficiency increases were achieved in refining, as shown in GHGenius datasets that form the basis for our refinery emissions modeling ((S&T)^2 2012).

It is probable that the general trends observed here from 1970 to 2010 will not continue as observed historically. Also, since the largest efficiency improvement in the oil sands operations has occurred in the processing and upgrading processes, the shift toward increased capabilities of refineries to handle oil sands bitumen, as well as the increasing share of *in situ* production, suggest that upgrading will be less relevant to future emissions profiles.

For *in situ* pathways, industry-wide steam to oil ratios (SOR)—which are a key driver for efficiency in *in situ* production—have been generally stable over the last 20 years. Potential technologies on the horizon to reduce SORs include solvent co-injection with steam (Buchanan *et al* 2009, Hobbs *et al* 2011). Steam generation technology is relatively mature, with less room for improvement then technology such as upgrading. This can be seen in table 1 where the energy intensity trends are slightly increasing and not falling. Reducing stack losses (such as through adoption of air preheat or condensing economizers), or reducing the pressure of steam required for SAGD (through use of downhole pumps enabling low-pressure-SAGD) have both been proposed as means to improve SAGD efficiency. Energy efficiency improvements of perhaps 20% have been suggested (Buchanan *et al* 2009). The incentive for adoption of these technologies is uncertain when natural gas prices are low.

On the whole, these trends suggest that near-term oil sands CI is not likely to be significantly lower than today's production on an industry-wide basis. In the longer term, technologies on the horizon could potentially allow for significant reductions in emissions from oil sands operations. Carbon capture and storage at large upgrading and refining facilities (e.g., the Shell Quest project) could result in significant reductions in oil sands CI (Ordorica-Garcia *et al* 2007, Bergerson and Keith 2010). Advanced *in situ* technologies also may hold promise for longer term reductions (e.g., thermal recovery with low carbon electric resistive heating) (Keesom *et al* 2012).

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