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

Jacob G Englander, Sharad Bharadwaj and Adam R Brandt

Department of Energy Resources Engineering, Stanford University, Green Earth Sciences Building 065, 367 Panama Street, Stanford, CA 94305-2220, USA

E-mail: abrandt@stanford.edu

Received 8 July 2013
Accepted for publication 28 October 2013
Published 18 November 2013
Online at stacks.iop.org/ERL/8/044036

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$_2$e MJ$^{-1}$ higher heating value (HHV) of reformulated gasoline (RFG) to 105 ($-12, +9$) gCO$_2$e MJ$^{-1}$ HHV RFG. 2010 averages by production pathways are 102 gCO$_2$e MJ$^{-1}$ for Mining and 111 gCO$_2$e 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$_2$e in 2010, or 9% of Canada’s emissions.

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

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 $\times$ 10$^6$ GJ d$^{-1}$ (1.43 Mbbd d$^{-1}$) in 2010, or $\approx$2% of world oil production. The Canadian Association of Petroleum Producers forecast bitumen production of 3.6 $\times$ 10$^7$ GJ d$^{-1}$ (5.33 Mbbd 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., Canada). 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$_2$e 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 syncrude 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 ($EIP(t)$) has units of MJ of fuel consumed per MJ of output. The EIs are 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 ($\Sigma f_p CI(t)$, see equation (2)).

$$CI_p(t) = \sum f_p CI(t) + \sum CI_{po(t)}$$

$$CI_{mining}(t) = \sum \frac{p(t)}{p(t)} CI_p(t)$$

$CI_p(t)$ (gCO$_2$e MJ$^{-1}$ RFG), $EIP(t)$ (MJ fuel), $P(t)$ (MJ refinery input (SCO/Bitumen)), $p(t)$ (MJ Bitumen), $CI_f(t)$ (gCO$_2$e MJ$^{-1}$ fuel), $CI_{po(t)}$ (gCO$_2$e MJ$^{-1}$ RFG)

Data gaps are interpolated using EI of production. EIs (GJ of fuel consumed per GJ of SCO produced, or $\frac{F_p(t)}{P(t)}$) 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$_2$e MJ$^{-1}$ RFG in 1970 to 102 gCO$_2$e MJ$^{-1}$ RFG in 2010, while the in situ weighted pathway has decreased from 140 gCO$_2$e MJ$^{-1}$ RFG in 1980 to 111 gCO$_2$e 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$_2$e MJ$^{-1}$ RFG (−4, +11) to 105 gCO$_2$e MJ$^{-1}$ (−12, +8). On a lower heating value (LHV) basis, the central emissions estimates for 2010 are 109, 119, and 113 gCO$_2$e 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$_2$e MJ$^{-1}$ refinery input in 1970 to 22 gCO$_2$e MJ$^{-1}$ refinery input in 2010. In situ efficiency increases have been more modest: WTR CI has decreased from 30 gCO$_2$e MJ$^{-1}$ refinery input in 1980 to 20 gCO$_2$e MJ$^{-1}$ refinery input. Most of this decrease is attributable to reduction of emissions from crude bitumen batteries, which dropped by 11 gCO$_2$e 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 gCO₂e MJ⁻¹, respectively, while the California baseline CI for the low carbon fuel standard (LCFS) is 93 gCO₂e 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 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).
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 CO₂e in 1970 to 70 Mt CO₂ 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 gCO₂e 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 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.

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 gCO₂e MJ⁻¹ RFG. Also emissions from crude transport are assumed to be ≈0.5 gCO₂e MJ⁻¹ RFG for 400 km to the refinery. If transport to the US gulf coast is assumed, emissions could rise by ≈1 gCO₂e 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 3. Total upstream emissions from oil sands industry along with the relative fraction of the oil sands in Canada’s overall emissions with uncertainty.](https://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.

| Year       | Energy intensity (MJ consumed/MJ refinery input) | Carbon intensity of input fuels (gCO₂ MJ⁻¹ consumed) |
|------------|-------------------------------------------------|-----------------------------------------------------|
|            | (GJ GJ⁻¹)                                       | (gCO₂ 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   | 81.3 | −1 | −2 | −6 | — |
| 1985–1990  | 0.48                                            | −17                                                 | 0           | −24  | 78.0 | −3 | −2 | −3 | — |
| 1990–1995  | 0.38                                            | −26                                                 | 3           | −21  | 77.8 | −5 | 4  | −1 | — |
| 1995–2000  | 0.37                                            | 0                                                   | −4          | −2   | 69.3 | −5 | −21 | −11 | — |
| 2000–2005  | 0.40                                            | 10                                                  | 0           | 9    | 62.8 | −8 | −15 | −9 | — |
| 2005–2010  | 0.30                                            | −34                                                 | 2           | −27  | —    | —  | —  | —  | —  |

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 (gCO₂ 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 \textit{in situ} pathways, industry-wide steam to oil ratios (SOR)—have been a key driver for efficiency in \textit{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 than 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 \textit{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).

Acknowledgments

The authors would like to thank Sarah M Jordaan for her helpful input, as well conversations with Don O’Connor, Joule Bergerson, and Michael Wang.

Fellowship support for JGE was provided by The Stanford Fund, Chevron Corporation, and the Stanford School of Earth Sciences. Support for SB was provided by the Stanford School of Earth Sciences Undergraduate Summer Research program. Chevron Corporation had no input on research topic, methods or results.

References

Abella J P and Bergerson J A 2012 \textit{Environ. Sci. Technol.} 46 13037–47

AEUB 1972–2000 ST27: \textit{Alberta Electric Industry Monthly Statistics}

Bergerson J A and Keith D W 2010 \textit{Environ. Sci. Technol.} 44 6010–5

Bergerson J A, Kofoworola O, Charpentier A D, Sleep S and Maclean H L 2012 \textit{Environ. Sci. Technol.} 46 7865–74

Brandt A R 2011 \textit{Environ. Sci. Technol.} 46 1253–61

Brandt A R, Englander J and Bharadwaj S 2013 The energy efficiency of oil sands extraction: energy return ratios from 1970 to 2010 \textit{Energy} 55 693–702

Buchanan I, Westphalen D, Daives S, Chawla N and Gieseman J 2009 SAGD energy efficiency study \textit{Technical Report} (Chicago, IL: Jacobs Consultancy)

CARB 2011 \textit{Low Carbon Fuel Standard Question and Answer Guidance Document} (Version 1.0) www.arb.ca.gov/fuels/lcfs/LCFS_Guidance_Final_v1.0.pdf

CARB (California Air Resource Board) 2012 Detailed California-modified GREET pathway for California reformulated gasoline blendstock for oxygenate blending (CARBOB) from average crude refined in California \textit{Technical Report} Supplement Version 2.0 to: Stationary Source Division, Air Resources Board (27 February 2009, v2.1) (Sacramento, CA: California Environmental Protection Agency) www.arb.ca.gov/regact/2011/lcfs2011/carbob.pdf

Charpentier A D, Bergerson J and MacLean H L 2009 \textit{Environ. Res. Lett.} 4 014005

Chastko P 2004 Developing Alberta’s Oil Sands, \textit{From Karl Clark to Kyoto} (Calgary: University of Calgary Press)

Deutsch C and McLennan J 2005 Guide to SAGD (steam assisted gravity drainage) reservoir characterization using geostatistics \textit{Technical Report} Centre for Computational Geostatistics, www.uofaweb.uAlberta.ca/ccg/pdfs/vol3-introsagd.pdf

El-Houjeiri H M, Brandt A R and Duffy J E 2013 \textit{Environ. Sci. Technol.} 47 5998–6006

Energy-Refined LLC 2010 Carbon intensity of crude oil in Europe crude \textit{Technical Report} International Council for Clean Transportation, www.theicct.org/sites/default/files/ICCT_crudefuelEurope_Dec2010.pdf

Energy Resources Conservation Board 1993–2010 ST53: Alberta \textit{Crude Bitumen Production—Monthly Statistics}

Environment Canada 2012 National inventory report: greenhouse gas sources and sinks in Canada \textit{Technical Report} Statistics Canada Ottawa, Ontario www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=68EE200C-1&offset=1&toc=show

ERCB 1970–2002, 2006–2010 ST39: Alberta Movable Oil Sands Plant Statistics Monthly Supplement

Ferguson J and Adkins W 1952 Apparatus for the recovery of tar sands Canadian patent number CA 488928 http://patents.ic.gc.ca/opic-cipo/cdp/eng/patent/488928/summary.html

Forrest J, Gross S and Meyer J 2010 Oil sands, greenhouse gases, and US oil supply: getting the numbers right-2012 update \textit{Technical Report} (Cambridge, MA: IHS-CERA) www.api.org/~media/Files/Oil-and-Natural-Gas/OilSands/CERA_Oil_Sands_GHGs_US_OilSupply.pdf

Hobbs D, Burkhard J, Forrest J, Goodman R J and Jacobs J 2011 Oil sands technology: past, present, and future \textit{Technical Report} IHS CERA http://a1024.g.akamai.net/1/1024/1/13859/1d/ihsgroup.download.akami.com/13859/ihsg/cera/Oil-Sands-Technology-Past-Present-and-Future.pdf

Keesom B, Bliesener J and Unnasch S 2012 EU pathway study: life cycle assessment of crude oils in a European context \textit{Technical Report} Alberta Petroleum Marketing Commission Calgary, Alberta, www.energy.alberta.ca/Oil/pdfs/OSPathwayStudyEUjacobsRept2012.pdf

O&G2 2012 \textit{Oil Sands, Conventional Growth will Double Canada’s Oil Output} by 2030e www.ogi.com/articles/print/vol/110/issue-07/exploration-development/oil-sands-conventional-growth.html

Ordorica-Garcia J G, Croiset E, Douglas P, Elkamal A and Gupta M 2007 \textit{Energy Fuels} 4 2098–111

Siddique T, Gupta R, Fedorak P M, MacKinnon M D and Foght J M 2012 \textit{Transportation Fuels} 4 2098–111

S&T\textsuperscript{y} 2011 GHGenius 3.20 A Model for Lifecycle Assessment of Transportation Fuels www.ghgenius.ca

S&T\textsuperscript{y} 2012 GHGenius 4.01 A Model for Lifecycle Assessment of Transportation Fuels www.ghgenius.ca

TIAx 2009 Comparison of North American and imported crude oil lifecycle GHG emissions \textit{Technical Report} TIAX LLC and MathPro Inc. for Alberta Energy Research Institute Calgary, Alberta, http://eipa.alberta.ca/media/39643/life_cycle_analysis_tiax_final_report.pdf

Wang M et al 2012 \textit{GREET: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model} http://greet.es.anl.gov/

Yeh S, Jordan S M, Brandt A R, Turetsky M R, Spatari S and Keith D W 2010 \textit{Environ. Sci. Technol.} 44 8766–72