Supplementary Information: Historical trends in greenhouse gas emissions of the Alberta oil sands (1970-2010)

Jacob G. Englander, Adam R. Brandt,* and Sharad Bharadwaj

Department of Energy Resources Engineering, Stanford University

E-mail: abrandt@stanford.edu

This supplemental document presents the system boundaries, methods, data handling and interpolations, as well as background calculations which underly this analysis.

System boundary and functional unit

The fundamental framework of an LCA is the system boundary, which delineates which impacts are or are not accounted for in the analysis. This is described explicitly in the main text, but a schematic of the mining pathway system boundary can be found in Figure 1. 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 (RFG) HHV).

*To whom correspondence should be addressed

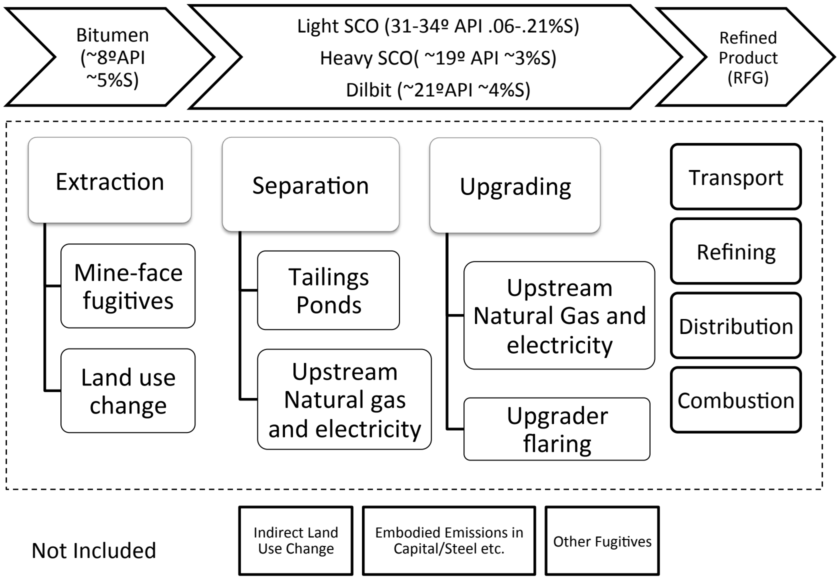

Figure 1: System boundary for mining & upgrading pathway

Data Sets

The foundation of this analysis are the historical data provided by the Alberta Energy Regulator (AER, formerly Energy Resources Conservation Board or ERCB). The raw data used for both mining and *in situ* projects are available to download alongside this paper. Proper attribution to the specific AER datasets are required for use. See below for further detail as to the references for all sources and emissions categories referenced.

Mining

Data for oil sands mining and upgrading operations were gathered primarily from AER data sets. Key datasets include ST-39 and ST-43 (*1*, *2*), which record monthly quantities of energy sources consumed and produced. Energy streams tracked include: Synthetic Crude Oil (SCO) [1000 m^3], bitumen [1000 m^3], coke [tonnes], purchased natural gas [1000 m^3], produced fuel gas [1000 m^3], intermediate hydrocarbons [1000 m^3], and electricity [MWh]. ST-39 data were collected in

Excel files from 1967-1998 and 2008-2010. ST-43 data and ST-39 data between 1999 and 2007 were extracted from PDF files using *ABBYY PDF Transformer 2.0*. These statistical reports are available for download for years 2008-2012 on the AER website while data from 1968-2007 can be purchased.

Because some oil sands production facilities are integrated between the mine and upgrader, not all of the energy use recorded in these datasets can be disaggregated between the process of mining and separating of bitumen from ore versus the upgrading of the bitumen to SCO. Additionally, some projects in the ST-39 and ST-43 data are upgraders for *in situ* projects (such as the Nexen Long Lake upgrader), while others are stand-alone, non-integrated upgraders (Shell Scotford).

Some projects are not included in the overall mining calculations as they are not directly tied to mining projects (e.g., Williams Energy diluent plant). Additionally, the Imperial Kearl Lake project was not included in this study as there was insufficient data available to determine its energy intensity (EI). This is because Imperial Kearl Lake is not fully operational.

Where data are missing or unavailable, data were interpolated using the EI ratios for each energy source. Energy input though interpolation was only necessary for the Suncor and Syncrude Mildred Lake projects. We use the EI ratios (GJ Fuel/ GJ Product) as the basis for our interpolations. While the raw amount of a fuel consumed may change dramatically from month to month, the ratio of fuel used per unit of output product is much more stable. EI ratios were smoothed using a 12-month moving average. Figure 2 shows moving averages of EIs as thicker lines.

Drivers of CI reductions can be examined by showing the fuel use at a given facility over time. For example, Figure 2 shows the overall energy intensity of the Syncrude operation, as well as the fuel-specific CI (GJ of energy consumed per GJ of SCO produced). The overall energy intensity of the Syncrude operation dropped from 0.72 GJ/GJ SCO in 1978 to 0.32 GJ/GJ SCO in 2010. Also, the use of coke declined from 0.27 GJ/GJ in 1978 to 0.03 GJ/GJ SCO. In contrast, fuel gas consumption stayed relatively constant. Purchased natural gas use declined significantly over the study period as well. In total, the fuel-weighted average CI of input fuels changed from 77 gCO_2e/MJ in 1978 to 60 gCO_2e/MJ in 2010.

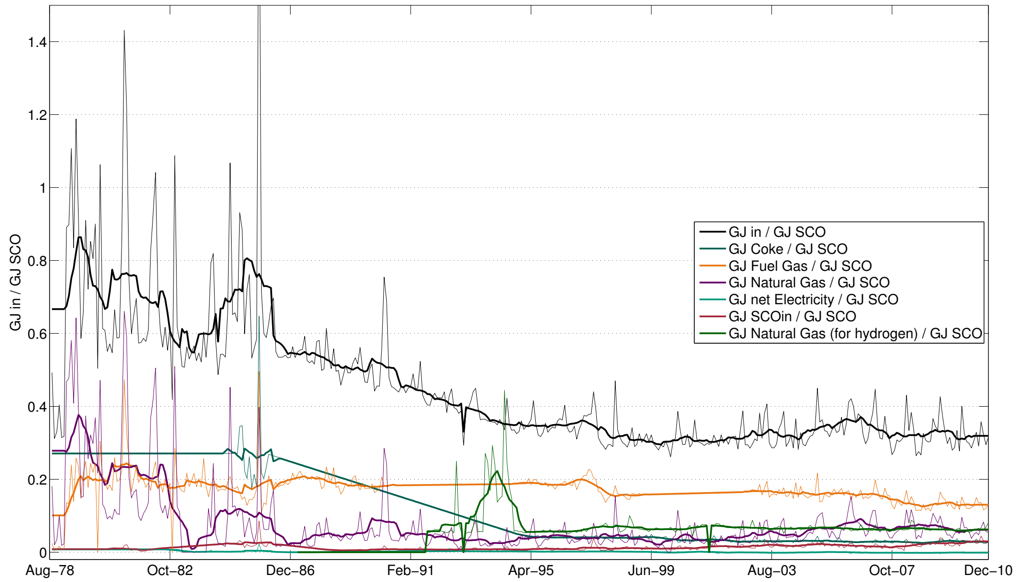

Figure 2: Energy intensity of the Syncrude operation, in GJ consumed per GJ of synthetic crude oil (SCO) produced.

Conversion factors used to translate natural units into energy units can be found in Table 1. These energy and carbon intensity factors are applicable for all energy sources relating to mining and upgrading projects.

A key driver of emissions differences is the difference in fuel mix consumed at each facility. Figure 3 shows the fuel mix at each mine/upgrader or stand-alone upgrader for 2010. There are considerable differences between projects, with important implications for CI. Projects with higher coke and imported electricity usage have higher carbon intensities. There is debate in the literature over how net emissions from electricity imports and exports are best calculated (as discussed in main text).

Synthetic Crude Oil Production and Consumption

The primary output from oil sands upgraders is SCO (although in recent years upgraders have begun to export bitumen as well). SCO is also utilized as an input for some of the heavy machinery in mines (e.g., trucks). As an input SCO was only used by Suncor, Syncrude Mildred Lake and CNRL Horizon. SCO accounted for $<10\%$ of the total energy inputs.

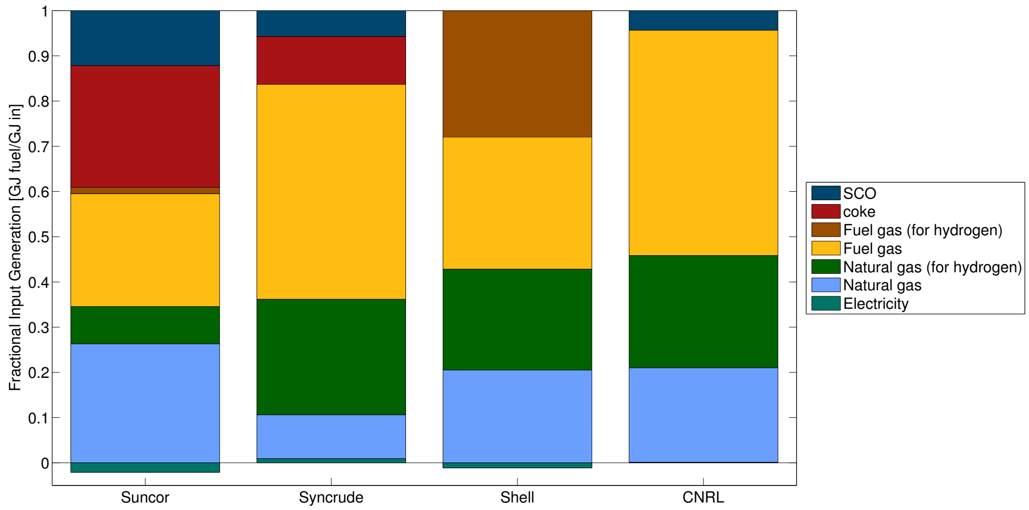

Figure 3: Upgrader energy consumption fuel mix for years 2009-2010. The electricity reported here is primary (thermal) energy used to generate electricity.

In energy and carbon intensity calculations, SCO delivery data are not smoothed with a moving average. There were three months of Suncor data for which there were no SCO output data provided. In these months, inputs were also taken out of the dataset as well so as to prevent skewing of the EI. The sources for SCO data can be seen in Table 3 and the references for converting the natural units of SCO to energy units can be found in Table 1.

Coke production and consumption

Coke is reported in AER datasets as a produced, consumed and stockpiled quantity. It is a byproduct of the upgrading process for the Suncor, Syncrude Mildred Lake, and CNRL Horizon upgraders. Coke is consumed at Suncor and Syncrude. Coke consumption data are less regular than other energy sources, thus requiring interpolation. For Syncrude, coke consumption data were not available between 1978-1984 and 1986-1994. As shown in Figure 2, we assume that the ratio of coke consumption to SCO output was unchanged between the yearly average of 1985 and the beginning of commercial operations in 1978 and was linearly changing between 1986 and 1995. Suncor datasets had smaller gaps, and similar techniques were applied (see Table 3).

Since coke composition is not given alongside consumption, multiple data sources for the composition and energy content of coke were utilized in order to estimate the calorific and carbon content. Average, low and high figures for energy content were derived from these sources (see Table 3).

Fuel gas consumption

Similar to coke, fuel gas is an intermediate product of the upgrading process. Its composition is more diverse than natural gas. Composition of fuel gas ranges from H_2 to butanes, with higher fractions non-methane species than purchased natural gas. Unlike coke it is produced at all upgraders and is consumed at all of the upgrading facilities. At some upgrading facilities, fuel gas is also used as a process fuel for H_2 generation. For months in which data were not reported in datasets, we interpolated data between the yearly average before and after the gap (larger gaps), or between the average of the previous and subsequent month (gaps of one month). A complete list of the data sources for fuel gas consumption can be found in Table 3.

As shown in Table 1, fuel gas composition data are not readily available and is likely a source of uncertainty in these calculations. A discussion of this uncertainty can be found in the primary document.

Purchased natural gas consumption

Natural gas is purchased for all mining and upgrading projects and are reported as monthly quantities in 1000m^3. There are very few instances of missing natural gas data where interpolations were necessary (an example of this can also be seen in purple in Figure 2). Additionally, natural gas is used as the primary input for H_2 generation for the upgraders (as can be seen in green in Figure 2). A summary table of the sources for natural gas consumption can be found in Table 3. In addition to the direct emissions from natural gas consumption, the emissions from the upstream fuel-cycle in production and transmission of natural gas to the facilities were incorporated. These values were taken from GHGenius version 4.01 Sheet “Elec_Emissions" cell E22 (*3*).

Electricity

Though most mining operations generate sufficient electricity onsite and even sell electricity back to the grid, many projects have historically purchased electricity from the grid. To account for the associated GHG emissions, the CI of the grid was calculated in a time-series using data taken from AER ST-28 (for years 1970-1998), Statistics Canada 57-202-x (for years 1999-2007), and AESO Annual Market Statistics Report (for years 2008-2010). The datasets provide the natural units consumed (Mg Coal, m^3 Gas, etc.), their associated heat rates, and aggregate electricity generated (*4–7*). Figure 4 shows the average grid mix for the Alberta grid along with the the CI for electricity. A summary of these data sources can be found in Table 3. Some of the datasets provide monthly data while the majority are annual data. In order to regularize the data across all of the time intervals, an annual average was calculated where monthly data were provided. Because the carbon content of the fuels were not provided in the data, the carbon content of coal was determined from (*8*), while the natural gas properties were estimated from the EIA Voluntary Reporting of Greenhouse gas Program (*9*). A weighted average value for the CI (gCO_2/MWh) was calculated for each year.

Each month's net electricity usage (purchased electricity less electricity sold back to the grid) is used to estimate the emissions credit or debit. This net usage quantity was used to account for the electricity sold to the grid (or purchased). In the baseline case, we assume that the electricity imports and exports displace power with the same thermal and carbon content of the average Alberta grid. For the uncertainty analysis, we estimate high and low electricity CI as a natural gas combined cycle turbine or as a baseload coal-fired power plant. The values and efficiencies are taken from the operating power plants on the Alberta grid. Discussion regarding the effect of changing the source of the electricity CI value can be found in the primary document.

Flaring emissions

Though data availability is sparse, flaring from the upgraders is reported alongside consumption in ST-39 and ST-43. In the statistical documents these quantities are called "Flared/Wasted." Flaring

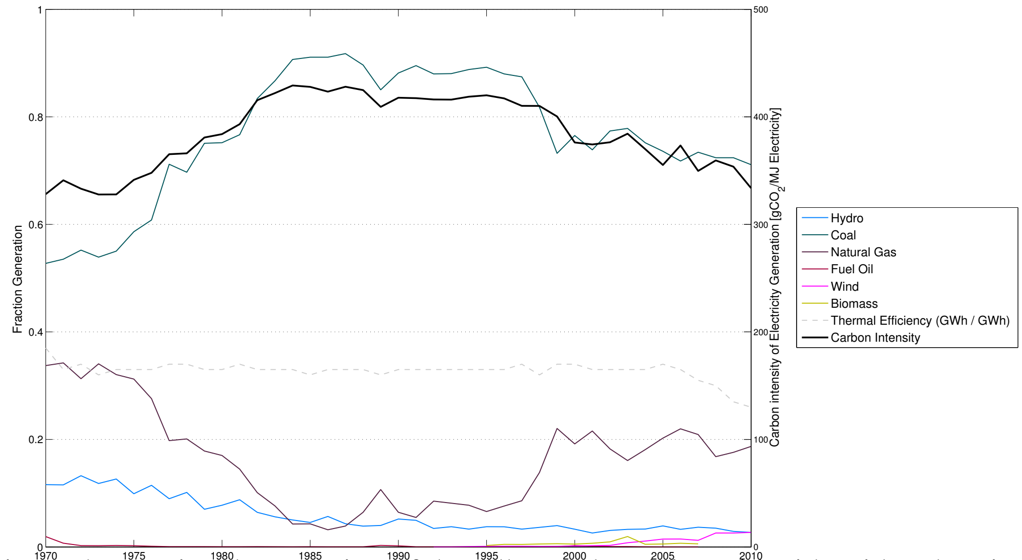

Figure 4: Fractional generation of the Alberta electricity grid with grid carbon intensity

emissions are reported for natural gas, diluent, and bitumen while some projects also report flaring of fuel gas. The flaring rates for fuel gas, natural gas, and diluent is treated at a rate of 100% combustion and depending on the project can add >1 gCO_2e/MJ refinery input.

The quantities reported for bitumen flared/wasted vary significantly between projects. According to AER personnel, the natural gas, diluent, and fuel gas reported as Flared/Wasted are flared. Conversely, bitumen reported as Flared/Wasted is instead wasted (e.g., sent to tailings pond or disposed of in mines).

Wasted bitumen occurs as a result of separation processes. These waste products are different for each project. For example, the Albian Sands mine reported bitumen in the flared/wasted category is two orders of magnitude higher than that of Suncor or Syncrude. This is the case because the bitumen ore at the Albian Sands mine is of a higher quality and in the initial separations process a pipeline quality bitumen is produced (which is subsequently sent to the Scotford upgraded). In this process, some of the higher carbon asphaltenes are extracted from the bitumen and disposed. This does not occur at the Suncor and Syncrude projects.

Table 1: Sources for energy conversions for mining & upgrading energy consumption

Energy type	Data units	Specification	Energy density	Sources for energy density
SCO	$1000 m^3$	Elem. comp. (CHOS)	GJ/m^3	(*10*, *11*)
Coke	Tonnes	Elem. comp. (CHOS)	GJ/tonne	(*12–15*)
Fuel gas	$1000 m^3$	Chem. comp.	GJ/m^3	(*14*, *16*)
Natural gas	$1000 m^3$	Chem. comp.	GJ/m^3	(*9*, *16*)
Electricity:	MWh	Alberta Grid Mix	GJ/MWh	(*5–7*)

In situ projects

Data gathering and handling

Data on *in situ* production emissions are collected from a variety of sources. Some data are available from the onset of production at a project to the current day. Other data are interpolated from more recent reported data.

Tabulated data were collected directly from original AER datasets. Graphical data were extracted from graphs using *GraphClick* software. Images were exported as PDFs at large scale (1000% magnification) and modified if necessary in *Adobe Illustrator* to remove extraneous curves that might interfere with data extraction. Automatic line detection in *GraphClick* was used where applicable to extract data. Otherwise, hand placement of data points was performed.

In order to test the accuracy of the graphical data extraction, data were gathered graphically for months in which tabulated data are available. Divergence between graphically extracted and tabular data is $<1\%$ in most cases.

An *in situ* project is considered operational from the first month of either steam injection or bitumen production. Commonly, steam injection occurs before bitumen production, or injection and production begin in the same month.

A small number of *in situ* projects are not included in the dataset due to lack of data: PennWest Petroleum - Seal; Cenovus - Pelican Lake; Baytex - Harmon Pilot. These projects are newly operational did not report sufficient data for analysis before the end of 2010.

Bitumen production and steam injection

Historical bitumen production from *in situ* operations is collected from AER datasets. The primary data source is ST-53 *Alberta In Situ Oil Sands Summary*, which is available on a monthly basis from 1992 to the present. Data from 2002 forward are available in spreadsheet form, while data prior to 2002 were extracted from PDF tables (*17*).

For projects producing prior to 1992 (Shell Peace River, Imperial Cold Lake, CNRL Primrose and Wolf Lake) data were collected from various sources. Shell Peace River production data for all years was derived from the 2007 Yearly Progress Report (YPR) p. 55 using graphical extraction. CNRL Primrose and Wolf Lake data were extracted similarly from 2011 YPR p. 63 (*18*).

Imperial Cold Lake extraction data before 1992 were modeled from AER ST-16 datasets. Data from Clearwater Formation production were gathered to 1975 from the ST-16 dataset. In years with no corroborating data (1975-1985), we assume that all Clearwater formation production is from Imperial Cold Lake. In years with corroborating yearly production data from graphical plots (1985-1991), yearly data are used to apportion the fraction of monthly Clearwater formation production to the Cold Lake project (*19*).

Steam injection data are gathered from identical data sources. Imperial Cold Lake data on steam injection for 1975-1985 were estimated from bitumen production rates.

A complete listing of data sources for bitumen production and steam injection is given in Table 3.

Natural gas, produced gas, and electricity consumption

While bitumen production and steam injection data are available as above for materially all operating months for each project (baring a small number of exceptions) data on energy use are much less available.

Data on natural gas consumption, produced gas consumption and electricity generation, consumption, imports and exports began to be reported by producers in yearly progress reports (YPRs) in 2009. Thus, 24 months of data are available (at most) for each project. A minority of projects have less than 24 months of data, generally because they are very new or because they appear to be non-operational (e.g., Total Joslyn Creek).

Because oil producing and steam generating capital equipment is long-lived, we extrapolate from 2009-2010 data to estimate energy use in previous years. We first calculate the fuel intensity per unit of steam generated for each project (m^3 of natural and produced gas consumed per m^3 of steam generated). We also compute the electricity consumed per unit of fluid handled (MWh/m^3 of fluid handled). These ratios are then used to extrapolate to previous months with no consumption data, based on the production of steam and bitumen in those months.

Essentially, the SOR of a project is used as a proxy for efficiency, and is multiplied by the project-specific EI of steam generation and fluid handling (including both fuel and electricity) (*20*). Both the gas (natural gas + produced gas) intensity and electricity intensity per m^3 of bitumen produced vary significantly for the same project from month to month. Therefore, the average over available months for each project is taken as the expected value, while high and low values provide the range.

For projects with no reported fuel gas or electricity use, the industry-average fuel and electricity intensities are used.

Flaring and fugitive emissions

Flaring and fugitive emissions are reported in detail in AER ST-60B dataset. Facility-level emissions for thousands of facilities across Alberta are reported. However, it is difficult to assign these facilities (often crude gathering batteries) to individual *in situ* production projects (*21*).

Because of the challenge of associating these emissions with individual projects, we instead use aggregated statistics from report ST-60B. ST-60B reports quantities of gas flared and vented from crude bitumen batteries for the entire industry in Tables 4 and 7 of the report (*21*). Data are reported from 2000-2010. Using these estimates of gas vented (reported as m^3), we generate venting and flaring per unit output of bitumen (m^3 vented/m^3 bitumen). Using literature values for gas composition, we converted these values to gCO_2e/MJ Bitumen (*9*, *17*, *22*). Data on flaring and fugitives from batteries were not gathered prior to 2000, so earlier flaring and fugitive emissions intensities (gCO_2e/MJ) are assumed equal to those from 2000 (per unit of output). Because reductions in flaring and venting likely occurred as a result of regulation, assuming constant prior emissions intensity is a conservative assumption. Flaring and fugitive emissions are a significant source of emissions from *in situ* production in the pre-2005 time period.

Other Emissions Sources

Land use & mine-face fugitives

Land use emissions occur as a result of the disturbance of carbon-rich soil in the removal of overburden and the extraction. Quantifying GHG emissions from the disturbance of land for oil sands production is challenging, and many LCAs neglect such emissions. Yeh et al. (*23*) provide estimates of emissions as a result of direct land cover change due to oil sands and report emissions on an emissions intensity basis.

Alternatively, Rooney et al. (*24*) attempt to measure the extent of peatland destruction as a result of oil sands mining operations outside of the context of LCA. In their results, land use emissions are given as tones of stored carbon oxidized. We use the intensity numbers provided by Yeh et al. (*23*) for this analysis. It should be noted that the CI values for land use are changed slightly from Yeh et al. to be consistent with the OPGEE model temporal basis (*25*). In addition, emissions also occur at the mine face when the oil sands are exposed in the shoveling processes. Though the actual emissions associated with the mine face are highly variable, estimates for these fugitive emissions (assumed to be methane) are collected in the literature. In our analysis we use values documented in the GHGenius 2011 oil production and refining update (*26*).

Tailings ponds

Tailings ponds result from the accumulation of the process water used in the separation process of an oil sands mine. Though bitumen extraction has become more efficient over time and there has been a greater use of process water recycling, historical accumulations of process water are stored in open tailings ponds and the volumes of water stored continue to increase. Tailings ponds have low concentrations of separating agents as well as bitumen in suspension with the sand particles which take decades to settle. It has been observed that microbes break down these hydrocarbons and release methane to the atmosphere (*27*). Due to these complex biological conditions and chemistry, estimating the emissions associated with tailings ponds is challenging and uncertain. In this analysis, we use the estimates for tailings emissions provided in the GHGenius 2011 oil production and refining update (*26*). Emissions associated from tailings ponds are not well understood and have high degrees of uncertainty, which is discussed in the primary document.

Downstream emissions sources

Emissions from transportation, refining, distribution and combustion of products are also included in this analysis. We used GHGenius version 4.01 to generate transportation, refining, and distribution emissions.

Transportation emissions (specifically pipeline transport) are a function of distance. We assumed that the transport distance was roughly the average distance by pipeline to Alberta refineries, which is given at 400 km (*3*). Including transport to distant regions (e.g. Gulf Coast refineries) would increase emissions by ≈ 1 gCO_2/MJ RFG.

Refining emissions are presented as a function of input stream, because refining SCO results in lower emissions than refining bitumen (SCO is, in a sense, pre-refined). According to GHGenius underlying datasets, there have also been efficiency improvements in refining as a function of time. GHGenius provides results for 1995-2010, so refining emissions factors for the remainder of our analysis time period (1970-1994) were extrapolated linearly, using the same relationship as GHGenius. The trends in refining emissions can be found in Figure 5. This results in refining intensity of 17.2 gCO_2e/MJ RFG in 1970 for SCO, an 81% increase from 2010 emissions.

Refining emissions are uncertain due to significant variation from processing the same feedstock at different refineries. This is because different refineries have different operating efficiencies, installed equipment, and product slate outputs (e.g., fraction of gasoline and diesel produced). Recent LCA models deal explicitly with refining emissions, specifically the PRELIM model of Abella and Bergerson(*28*). Their work illustrates the variance in refining emissions as a function of API gravity and compare this variation to other estimates. Because the ranges in refining CI for dilbit can be as significant as 10-15 gCO_2e/MJ RFG, we attempt to account for this variance in the range of uncertainty around the industry-wide emissions. From Abella et al. Fig. 3 we extract

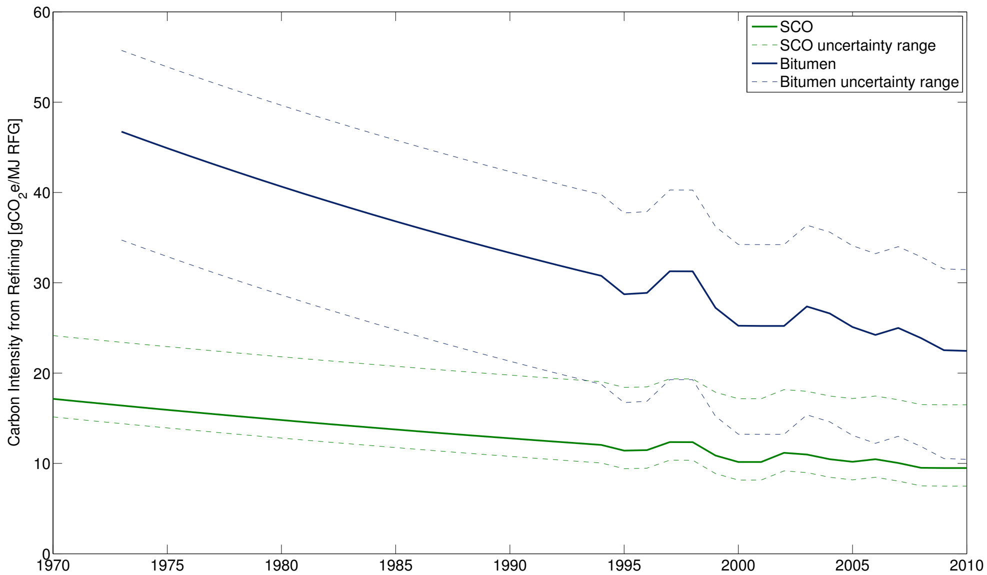

Figure 5: Extrapolated trends in refining CI using the output from GHGenius. Values from 1995-2010 are output values from GHGenius, while values from 1970-1994 are extrapolated linearly.

uncertainty ranges of +7 and -2 g for SCO refining and +9 and -12 gCO_2e/MJ for bitumen refining (*28*).

Lastly, end user combustion emissions are assumed to be constant over the entirety of the study and are derived from the California Air Resources Board CI for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) (*29*). It should be noted that the formulations of gasoline have shifted considerably from 1970 and as such there has likely been some variation in the CI of combustion. In this study RFG was assumed to have constant CI.

Combining mining & *in situ* production

Outputs from the mining and *in situ* AER data sets are in different units, which does not allow for direct combination of production volumes into a weighted average for upstream emissions. The primary output from the upgraders is given as SCO, while the *in situ* projects report delivered bitumen. We weight the relative contribution of each product by primary bitumen production. For example, each mining project has a different contribution to the total bitumen production and thus has a different share of production from the mining pathway. For projects that both produce and import bitumen, it is necessary to distinguish between the bitumen processed by the upgrader and that produced on site. For the case of Suncor, this is done by using the raw bitumen production numbers on site for the Suncor integrated mine and upgraded project, but not including bitumen imports (which match closely to the production of Firebag and MacKay River 2007-2010). In addition we attribute the emissions from the Scotford Upgrader as a combination of the bitumen production at the Albian Sands and Jackpine mines.

Comparing to average crude pathways

Figure 2 of the main text compares the calculated numbers from the oil sands with representations of the CI of the average crude input. The sources we used include: GREET (version 1.2012) (*30*), GHGenius (version 4.01) (*3*), IHS-CERA (*31*), and California Air Resources Board for the Low Carbon Fuel Standard (*29*). Each study has a different basis for determining CI. Values were adjusted to match the calculated CI. GREET and CARB provided CI on a lower heating-value (LHV) basis and required conversion to the HHV basis used in these calculations. A correction factor of 0.932 was incorporated (taken from GREET 1.2012 “Fuel Specs" sheet cell I10). GHGenius provided CI on both a HHV and LHV basis and the HHV numbers were used for the comparison. The IHS-CERA report provides CI in appendix table A1-18 on a WTW basis for gCO_2e/MJ gasoline (wide boundary case is used). In this case, we use the combustion factor from CARB (68.1 gCO_2e/MJ RFG HHV). This is because different formulations of combustion emissions have significant implications for the WTW CI of fuels (they account for between 60-80% of the WTW CI). Table 2 provides both the LHV and HHV for each of the models used.

Comparing to oil sands pathways

In Figure 4 of the main text, we provided a comparison between the calculated CI values from the oil sands for 2010 with literature values for the oil sands. The sources we used: GHGenius (version 4.01), IHS-CERA, Jacobs, and Bergerson 2012 (*3*, *31–33*). Similar to the comparison to the conventional crude pathways, the combustion emissions were normalized to be 68.1 gCO_2e/MJ

RFG HHV. However, because many of these values were for pathways of specific production processes (e.g. mining + upgrading or *in situ* + refining), slight manipulations to these values were used in order to create a comparison most similar to the pathways used in our historical analysis. Because each source uses slightly different definitions for their oil sands results, a summary of the values and the manipulations can be found in Table 2.

For Keesom et al. (2012), combustion emissions required adjustment to CARB standard values (as noted above) and a combined oil sands number is generated using the fraction of mining and *in situ* production from our analysis. For $(S\&T)^2$ (2012), the upstream HHV values for the Synthetic and Bitumen pathways (assumed to be for mining and *in situ* production respectively) were calculated for 2010 and then allocated by the fractional production for each pathway. For the case of Forrest et al. (2012), the mining pathway was taken from the “Canadian Oil Sands: Mining SCO" pathway from table A1-18 in the Appendix, while the *in situ* values for the “Canadian Oil Sands: CSS Dilbit" and “Canadian Oil Sands: SAGD Dilbit" pathways. However for the combined value, the CI used was the value for “Average Oil Sands Refined in the United States (2011)" which is lower than the pathway values due to the inclusion of non-thermal production (CHOPS).

For the comparison to Bergerson et al. (2012), some adjustment was required. Bergerson et al. reported results for for mining + upgrading, mining + refining, as well as *in situ* + upgrading, and *in situ* + refining pathways. For example roughly 20% of *in situ* production was upgraded to SCO (this includes Suncor projects Firebag and MacKay River as well as Nexen Long Lake). So, for the *in situ* weighted average, 80% of the CI came from the *in situ* + bitumen pathway while the 20% came from the *in situ* + SCO pathway.

Table 2: Calculating values for Oil Sands Comparison Graph (Figure 4 of the main text). Units of gCO_2e/MJ RFG, various heating value basis.

	Mining			*In situ*			Weighted OS		Conv.	
	Original	HHV	LHV	Original	HHV	LHV	HHV	LHV	HHV	LHV
Englander et al. 2013	-	102	109	-	111	119	105	113	-	-
Keesom et al.	(105-113)	99-107	106-115	(104)	98	105	99-103	106-111	-	-
$(S\&T)^2$ 2012	-	101		-	105	113	102	109	93	100
Wang et al. 2012	-	-	-	-	-	-	-	-	85	91
CARB 2012	-	-	-	-	-	-	-	-	93	99
Forrest et al. 2012	(107)	105	113	(111-116)	103-109	111-117	107	114	94	101
Bergerson et al. 2012	(SCO: 94-111 Bit: 88-100)	93-110	100-118	(SCO: 102-120 Bit: 94-108)	96-110	103-118	94-110	101-118	-	-

Table 3: Aggregated Data Sources For Emissions and Production

Emissions Source	Units	Data Sources	Frequency	Years (gaps)	Interpolations
Mining					
SCO	m^3	AER ST-39, ST-43	Monthly	1970-2010 (three months in 1974)	none
Bitumen	m^3	AER ST-39, ST-43	Monthly	1970-2010 (three months in 1974)	none
Flared bitumen	m^3	AER ST-39, ST-43	Monthly	1970-2010 (Suncor 1970-May1997, 2000-Jan2003, Apr2003-Jun2003, Aug2003-Oct2003, 2005-2006; Syncrude 1978-Oct2000, Mar-Dec2001)	Suncor and Syncurde average flaring rate, interpolated linearly between smaller gaps
Coke	m^3	AER ST-39, ST-43	Monthly	1970-2010 (Syncrude 1978-1984, 1986-1994)	1978-1984: directly from 1985 average 1986-1994: linearly from 1985 average to 1995 average
Fuel gas	m^3	AER ST-39, ST-43	Monthly	1970-2010 (Suncor 1972, Suncor and Syncrude 1990-1994, 1999-2003) (corrected units from 1973-1979)	Linearly between respective yearly averages
Flared fuel gas	m^3	AER ST-39, ST-43	Monthly	1970-2010 (Suncor 1971, Oct-Dec1972, 1989-1993, 1998-2001, 2010, Syncrude 1978-1984,1986-2010, CNRL Mar-May2009)	Suncor, CNRL interpolated linearly, Syncrude interpolated from 1985 data
Natural gas	m^3	AER ST-39, ST-43	Monthly	(Suncor 1970-1975) 1976-2010	Directly from 1976 average ratio
Flared natural gas	m^3	AER ST-39, ST-43	Monthly	(Suncor 1970-1975) 1976-2010	Directly from 1976 average ratio
Electricity	MWh	AER ST-39, ST-43	Monthly	1983-2010 (1970-1982) (corrected units 1983-1994)	Directly from 1983 average
In situ					
Bitumen	m^3	AER ST-16, ST-53, Yearly progress reports (YPR)	Monthly	1974-2010	Modeled for Imperial Cold Lake: 1974-1991
Steam injection	m^3	AER ST-16, ST-53, YPR	Monthly	1974-2010	Modeled for Imperial Cold Lake: 1974-2008
Natural gas	m^3	ST-43, YPR	Monthly	2009-2010	Extrapolated from SOR 1974-2008

Notes on Table 1 of the main text

In some instances the overall energy intensity change is larger than that of changes in either mining or in situ. This is due to the fact that in situ production is a growing share of total oil sands production. Since in situ production is not upgraded, it has a lower energy intensity value than mining and thus when there is an increase in in situ production, even with no change in EI, the overall EI decreases. For example from 1980-1985 in situ production grew from 4 to 25% of all oil sands production.

For in situ production the CI of input fuels is relatively constant until the past decade. This has occurred as a direct result of the introduction of SAGD as a production technology. Compared to the older CSS technology, SAGD requires as inputs far more natural gas relative to electricity. Grid connected electricity has a CI of over 300 gCO2e/MJ as compared to natural gas which has a WTW CI between 57-60 gCO2e/MJ.

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