

Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries

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1 Executive summary

Production of hydrocarbons from the Canadian oil sands reached approximately 1500 kbbbl/d in 2009, or almost 2% of global crude petroleum production. Due to the energy intensity of oil sands extraction and refining, fuel greenhouse gas (GHG) regulations must assess the GHG emissions from oil-sands-derived fuels in comparison to emissions from conventional oil production.

This report outlines the nature of oil sands extraction and upgrading processes, with an emphasis on factors affecting energy consumption. Next, it compares a variety of recent estimates of GHG emissions from oil sands, and outlines reasons for variation between estimates. Lastly, it outlines low, high and “most likely” estimates of GHG emissions from oil sands, given results from previously produced estimates, and compare these emissions to those of conventional fuels. This report focuses on the European context, and therefore uses EU-specific emissions factors for transport and refining of fuels.

There is significant variation between current estimates of GHG emissions from oil-sands-derived fuels. This variation has a number of causes, including:

1. Differences in scope and methods of estimates: some studies model emissions from specific projects, while others generate average industry-wide emissions estimates.
2. Differences in assumed efficiencies of extraction and upgrading, especially with respect to the energy efficiency of steam-assisted gravity drainage (SAGD).
3. Differences in the fuel mix assumed to be consumed during oil sands extraction and upgrading.
4. Treatment of secondary non-combustion emissions sources, such as venting, flaring and fugitive emissions.
5. Treatment of ecological emissions sources, such as land-use change (LUC) associated emissions.

These differences are discussed in some detail, although without access to original model calculations it is difficult to determine all reasons for divergence in emissions estimates.

Low, high and most likely emissions estimates for Canadian oil sands derived fuels are shown in Figure 1. Low emissions are likely for natural-gas fired mining and upgrading processes, while high emissions are likely from SAGD processes fueled with bitumen residues. Figure 1 also shows the range of estimates for current conventional fuel streams in the EU. For conventional crude streams, low and high ranges are supplied by the least and most GHG-intensive petroleum streams consumed in the EU (i.e., Norway and Nigeria, respectively).

Figure 1 shows that the lowest intensity oil sands process is less GHG intensive than the most intensive conventional fuel (as noted in recent reports by IHS-CERA, Jacobs Consultancy and others). Importantly though, the most likely industry-average GHG emissions from oil sands are significantly higher than most likely industry-average emissions from conventional fuels. The significant range between low and high estimates in both oil sands

and conventional fuel streams is primarily due to variation in modeled process parameters, not due to fundamental uncertainty about the technologies.

Figure 2 shows the relative importance of upstream emissions from oil sands projects by plotting output by oil sands project, cumulated and placed in order of low to high emissions. It also displays cumulated conventional oil consumption in the EU in order of emissions intensity (see text for construction details). The key result is that while the highest emissions conventional oil has higher upstream emissions than the lowest emissions oil sands estimate, the production-weighted emissions profiles are significantly different. Despite uncertainty in these figures, GHG emissions from oil sands production are significantly different enough from conventional oil emissions that regulatory frameworks should address this discrepancy with pathway-specific emissions factors that distinguish between oil sands and conventional oil processes.

The uncertainties that still remain with respect to modeling GHG emissions from the Canadian oil sands suggest the need for additional research. The most important uncertainties include:

1. Treatment of electricity cogeneration is variable across studies, and is uncertain because of a lack of data on amounts of co-produced power, and difficulty in determining the correct co-production credit for electricity exports.
2. Detailed treatment of refining is lacking in publicly available models, due to lack of access to proprietary refining models.
3. Market considerations are lacking, which have important effects on co-product and by-product disposition, including the fate of produced coke.

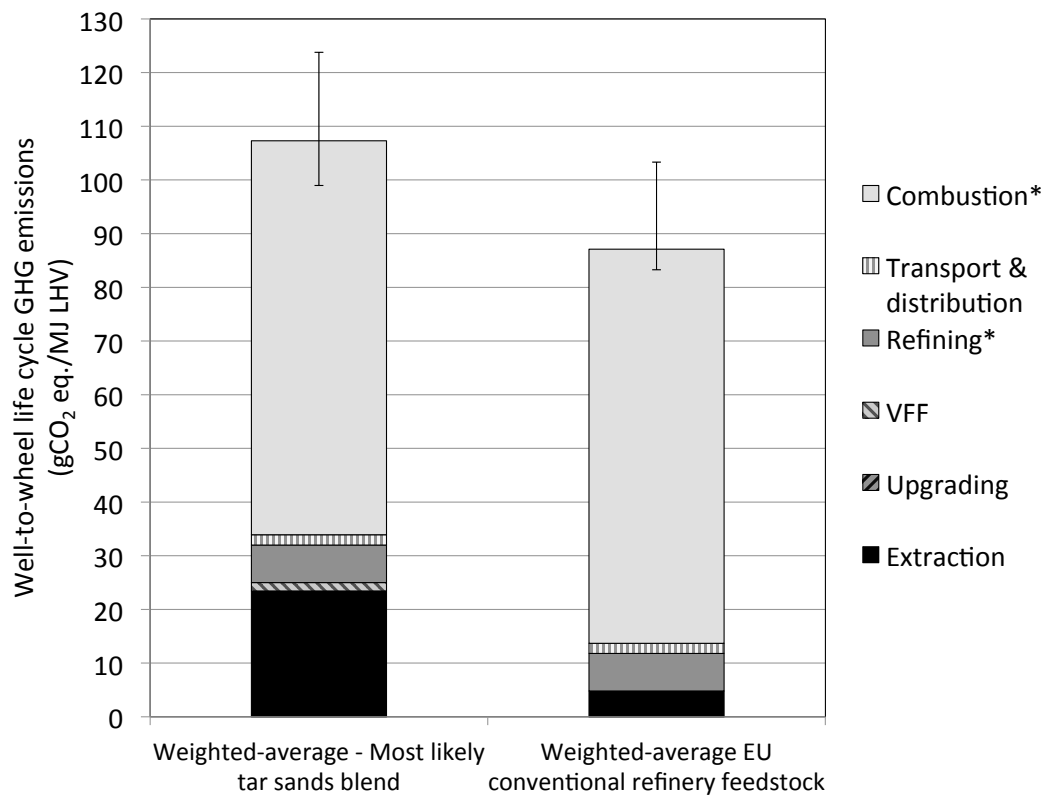


Figure 1: Oil sands emissions compared to conventional EU refinery feedstock emissions. Most likely estimates are base values of bars, low and high ranges are represented by error bars. See report text for calculation details.

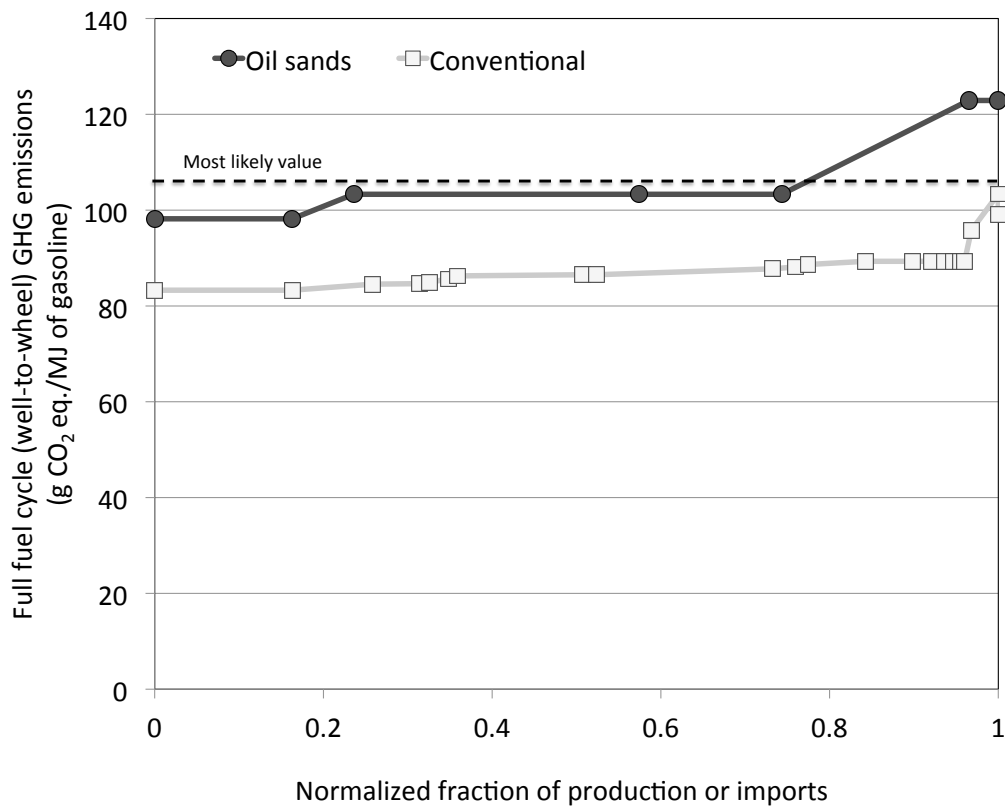


Figure 2: Emissions as a function of cumulative normalized output, for oil sands projects (low and high estimates) and conventional oil imports to the EU. Only oil sands projects that produce refinery ready SCO are included as these full-fuel-cycle estimates utilize pre-calculated emissions estimates for EU refineries processing approximately 30 °API oil. Bounds on oil sands emissions are provided by (low) CNRL Horizon, (high) OPTI-Nexen, Long Lake SAGD + Residue gasification to SCO. The bounds on conventional oil emissions are provided by (low) Norway, (high) Nigeria. Due to uncertainty in Nigerian crude oil emissions, two values are reported for Nigerian crude. See report text for calculation details.

2 Introduction

As conventional oil production becomes increasingly constrained, transportation fuels are being produced from low-quality hydrocarbon resources (e.g. bitumen deposits) as well as from non-petroleum fossil fuel feedstocks (e.g. gas-to-liquid synthetic fuels). Greenhouse gas (GHG) regulations such as the California Low Carbon Fuel Standard (CA LCFS) and European Union Fuel Quality Directive must properly account for the GHG intensities of these new fuel sources.

Significant volumes of transport fuels are already produced using unconventional technologies and from unconventional resources. These include enhanced oil recovery, oil sands, coal-to-liquids and gas-to-liquids synthetic fuels, and oil shale. US enhanced oil recovery (EOR) projects produced 663 kbbbl/d in 2010 [1]. About 40% of US EOR production is from steam-induced heavy oil production in California and 60% is from gas injection (largely CO₂ injection) [1]. Global EOR production is less certain due to poor data availability, but exceeds 1200 kbbbl/d [1].

Production of crude bitumen from the oil sands reached 1490 kbbbl/d in 2009 [2, 3]. Production of liquid products from oil sands, including raw bitumen and synthetic crude oil (SCO), reached 1350 kbbbl/d in 2009, due to volume loss upon upgrading of bitumen to SCO. This amount represents an increase from ≈ 600 kbbbl/d in 2000 [4]. Current plans for expansion of production capacity are significant, with over 7000 kbbbl/d of capacity in all stages of construction and planning, as shown in Figure 3 [3].

This report studies upstream GHG emissions from Alberta oil sands production. The goal of this report is to comment on the comparability of previously published estimates of GHGs from oil-sands-derived fuels, and to compile a range of emissions factors for oil-sands-derived fuel streams as inputs to a notional EU refinery.

First, this report provides an overview of the Alberta oil sands, with a focus on determinants of energy use and emissions from oil sands production. Next, previous estimates of GHG emissions from oil sands production are reviewed and compared. Lastly, this report uses published model results to estimate emissions from oil-sands-derived fuels processed in a notional European refinery.

Technical note: All units and prefixes used in this report are in SI units, with the exception of volumes of crude oil produced and steam injected, which will be reported in barrels (bbl). Crude oil density is generally reported in specific gravity (sg) rather than API gravity. Emissions per unit of energy will generally be reported per megajoule (MJ) on a lower heating value (LHV) basis, except where the original source is unclear about the basis. For most fuels of interest in this report, the potential error in GHG emissions estimates due to unspecified fuel heating value basis is ≈ 5 -7%.

3 Overview of oil sands production methods

Oil sands (also called tar sands) are more accurately called bituminous sands, as they contain natural bitumen [5]. Resource estimates for Canadian bitumen in place are between 1.17 Tbbbl [5] and 2.5 Tbbbl [6]. Oil sands are a mixture of sand and other mineral matter (80-85%) water (5-10%) and bitumen (1-18%) [5]. Bitumen is a dense, viscous mixture of high-molecular weight hydrocarbon molecules. Bitumen is either sold as a refinery feed-stock or upgraded to SCO and shipped to refineries.

3.1 Oil sands extraction

Bitumen can be produced through surface mining or in situ production methods. Surface mining techniques require removal of vegetation and topsoil, removal of overburden (inert, non-hydrocarbon bearing mineral matter that lies above bitumen) and mining of the bitumen/sand mixture. The bitumen/sand mixture is transported to processing facilities where it is mixed with hot water, screened and separated into bitumen and tailings (a water/sand mixture) [5]. A variety of in situ techniques exist, the most commonly applied being steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). These in situ processes are similar in concept to thermal EOR processes for heavy oil extraction: heat from injected steam reduces the viscosity of bitumen, allowing it to flow to the well-bore under existing pressure gradients or by gravity drainage [7].

3.1.1 Mining-based bitumen production

Overburden removal is typically performed with a truck-and-shovel operation [8]. Bitumen ore is mined with diesel or electric hydraulic shovels. Large haul trucks (diesel powered) move the ore to central crushing and slurrying centers for hydrotransport via pipeline to extraction centers. Some mining and processing equipment is powered with electricity co-produced on site from natural gas, upgrading process gas, or coke, with the generating fuel dependent on the operation [9]. In 2002, Syncrude reported consuming 1 Mbbbl of diesel fuel for the production of 250,000 bbl/day of SCO, or about 62 MJ of diesel per bbl of SCO produced [9]. Estimates presented in the literature of mining energy consumption vary across an order of magnitude from 50-580 MJ/bbl of SCO [6, 10].¹

At the extraction facilities, bitumen froth (60%+ bitumen, remainder water) is separated from sand. This has been called an “expensive...and inflexible” process, requiring warm water and consuming 40% of the energy used to produce a barrel of SCO [8]. In integrated operations, upgrader by-products, including process gas and coke, provide heat and power for the separation process [9]. Consumption data from integrated operations are shown in Figure 4, illustrating the variety of fuels consumed by projects [11].

After primary separation, the bitumen froth is treated to remove water and solids, using naphtha or paraffinic solvents. This produces a bitumen ready for either dilution and sale or for upgrading to synthetic crude oil. Energy costs for separation of the bitumen are estimated at 150 MJ/bbl [10, 12].

¹Given that the high end of this range (580 MJ/bbl SCO) represents some 10% of the energy content of the SCO, this is likely an overestimate of mining energy inputs.

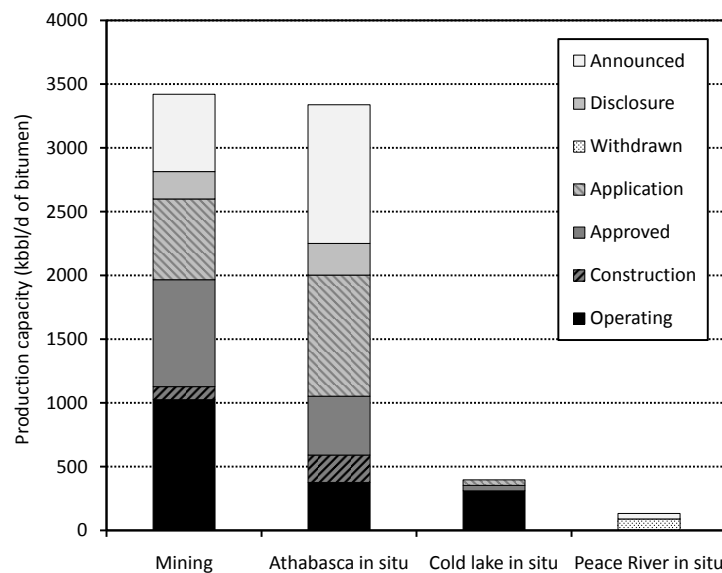


Figure 3: Oil sands production capacity, operational and proposed projects, by stage of completion (current as of January, 2010) [3].

3.1.2 In-situ bitumen production

Oil sands are currently produced in situ using three techniques: cold production (generally suitable for resources above $\approx 12^\circ$ API and so not considered further), cyclic steam stimulation (CSS), and steam assisted gravity drainage (SAGD) [8]. Thermal in situ production via CSS or SAGD is more energy intensive than mining-based production.

Thermal in situ recovery is made possible by the reduction in hydrocarbon viscosity with increases in temperature. After heating with steam, bitumen reaches a state where it will flow to the well for production. SAGD and CSS differ primarily in the well configuration used for steam injection and bitumen extraction.

GHG emissions from in situ production result primarily from fuels combusted for steam generation. The amount of energy required to convert water to steam for injection depends on the steam pressure and steam quality, with cited values for 80% quality steam ranging from 320-380 MJ/bbl of cold water equivalent (CWE) turned to steam [7]. A key indicator is the steam oil ratio (SOR), measured as volume of CWE steam injected per volume of oil produced. Higher SORs, if all else is held equal, will result in larger GHG emissions from in situ production. Common SORs for in situ recovery projects range from 2 to 5, with the production-weighted industry average being 3.2 in 2009 (see Table 1). SORs as high as 9.6 were reported in 2009, but these may represent transient effects due to required initial buildup of reservoir temperature at the start of SAGD operations [13]. SORs have tended to improve over time with the maturation of SAGD technology. This can be expected to continue, given the strong financial incentives (as well as regulatory requirements) to reduce natural gas consumption. Such trends will likely have beneficial impacts on GHG emissions from SAGD (which may be partially offset by declining resource qual-

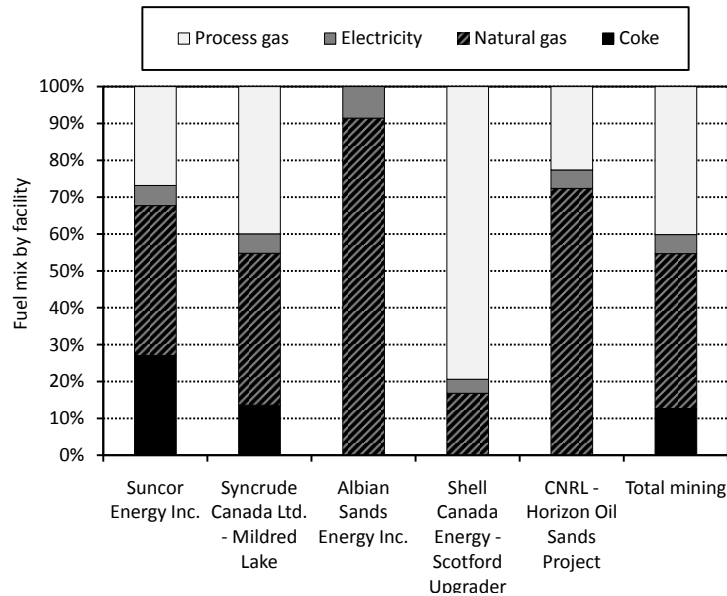


Figure 4: Approximate mining and upgrading fuel mixes for integrated (Suncor and Syncrude) and stand-alone operations. Compiled from volumetric [m^3] and mass [tonne] consumption rates by project as reported by ERCB [11]. ERCB does not report diesel consumption for haul trucks, allowing only an approximate fuel mix determination.

ity over time).

Accounting for the above uncertainties, steam generation energy consumption for an SOR range of 2.5 to 5 ranges from ≈ 950 to 2100 MJ/bbl of bitumen produced, assuming steam generation equipment similar to California thermal EOR projects.² This range is conservative, and is based on producing 80% quality steam for California thermal EOR via steamflooding [7]. Energy consumption in SAGD projects is likely to be somewhat higher, due to the requirement for 100% quality steam [14], although this will be partially offset by the newer age of the equipment in SAGD operations. To produce 100% quality steam, 80% quality steam is first produced in once-through steam generators, and vapor-liquid separators are used to reject solute-laden liquid phase water (“blowdown” water). Due to the heat of vaporization of water and imperfect heat recovery from blowdown water, energy consumption is higher for 100% quality steam. Charpentier cites up to 450 MJ/bbl of steam, while Butler cites ≈ 540 MJ/bbl for 100% quality steam generation [15, p. 7] [16]. Electricity consumption for in situ production has been estimated as 30 MJ/bbl bitumen (8.25 kWh/bbl bitumen), but will vary with SOR due to dependence on pumping loads [8].

Steam generation for in situ production is generally fueled with natural gas. An exception is the OPTI-Nexen Long Lake project, which consumes gasified bitumen residues [17, 18]. This converts a low-quality upgrading residue to fuel for the extraction process,

²Calculation method follows that of Brandt and Unnasch [7]. This low and high range assumes enthalpy of steam of 325 and 337.5 MJ/bbl, once-through steam generator with 85% and 80% efficient steam generation, LHV basis, and SORs of 2.5 and 5 , respectively. Energy consumed per bbl of steam is 380 – 420 MJ/bbl steam.

Table 1: Steam oil ratios (SORs) for in situ bitumen production (2009). A sample of large in situ projects is included, along with the average for all thermal in situ production [13].

Operator - Project	Bitumen production $10^3 \text{ m}^3/\text{d}$	Water injection $10^3 \text{ m}^3/\text{d}$	SOR $\text{m}^3 \text{ water}/\text{m}^3 \text{ oil}$
Imperial - Cold lake	22.4	78.5	3.50
CNRL - Primrose	9.8	58.9	5.99
EnCana - Foster creek	12.0	30.1	2.49
Suncor - Firebag	7.8	24.3	3.13
Total thermal in situ^a	81.4	256.3	3.18

a - Total values include summed bitumen production and steam injection for all projects in ERCB databases labeled "Commercial", "Commercial-CSS", "Commercial-SAGD", "Enhanced Recovery", and "Experimental" [13]. Projects labeled "Primary" are not included due to likelihood that these represent primary production of heavy crude oils (i.e., cold production).

avoiding purchases of natural gas and the associated operating expense volatility. However, this configuration also significantly increases GHG emissions compared to natural-gas-fueled SAGD [18, 19].

3.2 Bitumen upgrading

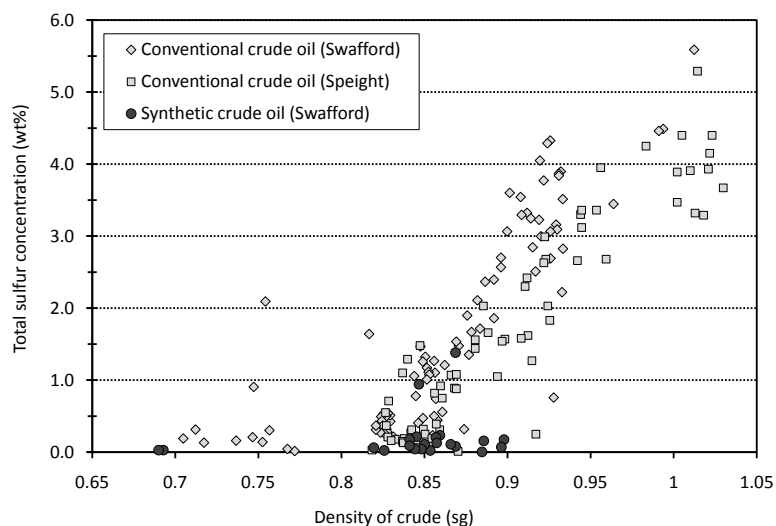
Because contaminants are concentrated in heavy hydrocarbon fractions, bitumen has significant sulfur and metals content, as shown in Table 2 and Figure 5. In addition, bitumen is carbon-rich, hydrogen-deficient, and contains a larger fraction of asphaltenes compared to conventional crude oils (Table 2). Thus, bitumen requires more intensive upgrading and refining than conventional crude oil.

Raw bitumen will not reliably flow through a pipeline at ambient temperatures. Therefore it must be modified before delivery. Bitumen can be transported after dilution with a lighter hydrocarbon diluent (creating "dilbit," or "synbit" if synthetic crude oil is used as the diluent). Diluent can either be returned to the processing site or included with bitumen to the refinery stream. If bitumen is not diluted, it must be upgraded into a synthetic crude oil (SCO) before shipment.

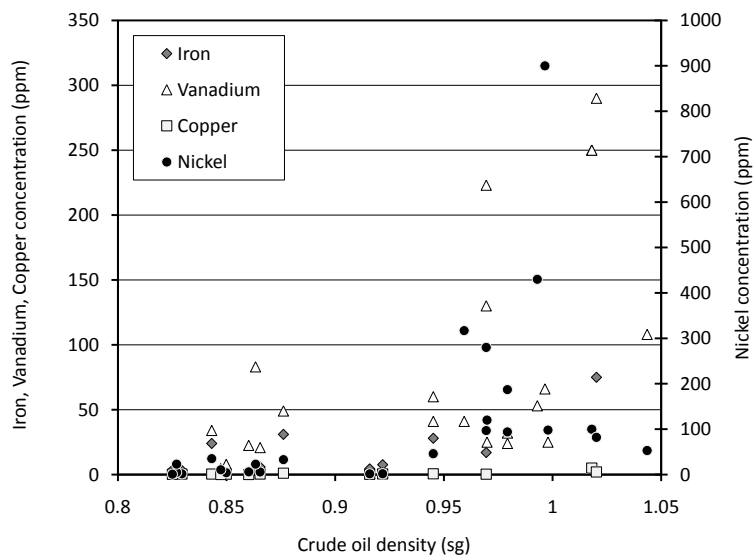
Greenhouse gas emissions from upgrading have three causes:

1. Combustion of fuels for process heat, including process gas, natural gas or petroleum coke.
2. Hydrogen production using steam reformation of natural gas, or less commonly from gassification of petroleum coke or bitumen residues.
3. Combustion for electricity generation (whether on-site as part of a cogeneration scheme or off-site for production of purchased electricity).

Upgrading bitumen to SCO is performed in two stages. Primary upgrading separates the bitumen into fractions and reduces the density of the resulting SCO by increasing the



(a) Sulfur concentration as a function of crude oil density. Bitumen has $sg \geq 1$. Data plotted from Speight and Swafford.



(b) Metals concentration as a function of crude oil density. Data plotted from Speight.

Figure 5: Crude oil contaminants increase as a function of crude density, necessitating intensive refining. Data sources include [20, Ch. 8, tables 3, 4] [20, Ch. 7, tables 2, 3, and 19] [21].

Table 2: Bitumen and conventional oil properties [22, table 1], [23].

	Property	Conv. oil	Athabasca Bitumen	Athabasca SCO
Density [sg]		0.82-0.93	0.99-1.02	0.877
Elemental comp. [wt %]	Carbon	86	83.1	87.53
	Hydrogen	13.5	10.6	12.32
	Sulfur	0.1-2	4.8	0.136
	Nitrogen	0.2	0.4	0.079
	Oxygen	—	1.1	—
Metals [ppm]	Vanadium	≤100 total	2500	≤0.1
	Nickel		100	≤0.1
	Iron		75	≤0.1
	Copper		5	0.1
HC type [wt.%]	Oils	95	49	98+
	Resins	—	32	0.96
	Asphaltenes	≤ 5	19	0.06

hydrogen-to-carbon (H/C) ratio of the heavy fractions. Secondary upgrading treats resulting SCO fractions to remove impurities such as sulfur, nitrogen and metals.

Primary upgrading changes the H/C ratio by adding hydrogen or rejecting carbon from the heavy fraction of the bitumen feedstock. The most common upgrading processes rely on coking to reject carbon [24]. Carbon is rejected from heavy bitumen fractions using fluid or delayed coking processes [5]. Of the major integrated operations, Syncrude utilizes fluid coking, while Suncor uses delayed coking. Coking generates upgraded SCO as well as byproducts of coke and process gas [8]. For example, Suncor's delayed coking upgrading resulted in 85% by energy content produced as SCO, 9% as process gas, and 6% as coke [11]. Natural gas or co-produced process gas is often used to drive coking, but in a fluid coker a portion of the coke can be combusted to fuel the coking process.

In existing operations, coke disposition varies. In 2009, Suncor consumed 26% of produced coke and exported another 7% for offsite use, while the rest was stockpiled or land-filled. In contrast, the CNRL Horizon project stockpiled all produced coke. Syncrude operations were intermediate in coke consumption levels [11]. The OPTI-Nexen project avoids this need for coke disposal by gassifying upgrading residues (as asphaltenes) and generating no net coke output.

A competing upgrading approach relies on hydrogen addition for primary upgrading, as used by Shell at their Scotford upgrader [13], which uses an ebullating-bed catalytic hydrotreating process. Treating the bitumen with hydrogen addition results in larger volumes of SCO produced from a given bitumen stream, and a high quality product. It also requires larger volumes of H₂, with associated natural gas consumption and GHG emissions. The Scotford upgrader produced 82% of process outputs as SCO, 18% as process gas, and no coke (on an energy content basis) [11].

In secondary upgrading the heavier fractions of primary upgrading processes—which

Table 3: Characteristics of bitumen-derived SCO products. Source: Batch Quality Reports, www.crudemonitor.ca [27]. Most recent assay is used for each crude stream, long-term averages used for metals content.

	API	Density	Sulfur	Metals
	°API	kg/m ³	wt%	(Fe+Ni+V+Mo) mg/l
Premium Albion Synthetic	34	854	0.05	6
Suncor Synthetic A	32.2	864	0.2	7
CNRL Light Sweet Synthetic	34.4	852	0.05	-
Syncrude Synthetic	31.8	866	0.21	-
Albian Heavy Synthetic	19.1	939	2.9	163
Suncor Synthetic H	19.5	937	3.07	15
Cold Lake Dilbit	21.3	925	3.76	224

contain the majority of the contaminants—are hydrotreated (i.e., treated through the addition of H₂ in the presence of heat, pressure, and a catalyst). This reduces sulfur concentrations and improves the quality of the product. Blending of resulting streams produces light refinery-ready SCO of 30-34 °API, 0.1 wt% sulfur and 500 ppm nitrogen [25]. Heavy SCO streams, such as Suncor Synthetic H, are also produced, but in smaller quantities. Suncor Synthetic H has an API gravity of ≈ 20 and sulfur content of ≈ 3 wt.%. In chemical composition, dilbit looks similar to heavy synthetic blends. Characteristics of some marketed SCO products are listed in Table 3.

Hydrogen consumption by hydrotreaters is significantly often in excess of 3 times the stoichiometric requirement for heteroatom removal, due to simultaneous hydrogenation of unsaturated hydrocarbons [25, p. 295]. Hydrogen consumed in secondary upgrading is generally produced via steam methane reformation of natural gas, regardless of primary upgrading process [9]. Current expectations include the OPTI-Nexen integrated SAGD to SCO project, which uses bitumen residues for H₂ production. Consumption of H₂ in upgrading processes ranges from 200-500 MJ/bbl of bitumen upgraded [26, p. 4-6].

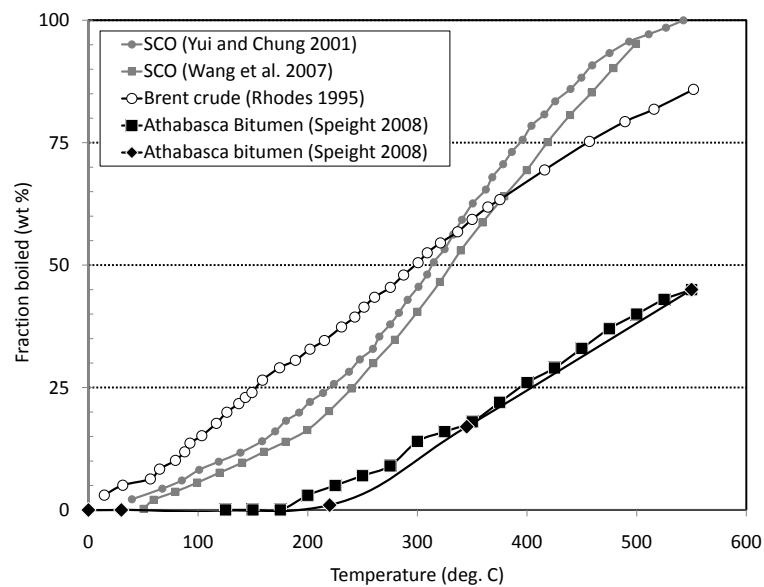
Nearly all of the bitumen produced from mining is upgraded, while most of the in-situ-based production is shipped as a bitumen/diluent mixture to refineries in the PADD II region [8]. There is no fundamental physical or chemical reason that in situ produced bitumen cannot be upgraded [18].

3.3 SCO and bitumen refining

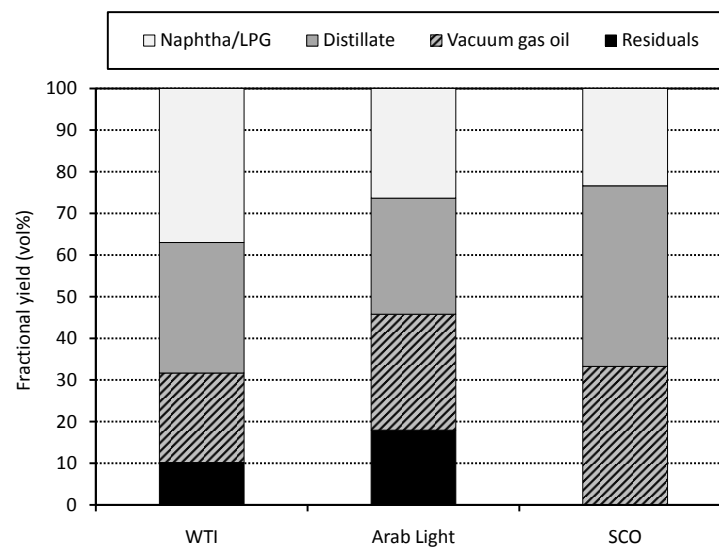
Non-upgraded bitumen supplied to refineries requires intensive refining, due to quality deficiencies cited above (Table 2). Refining of bitumen also produces a less desirable slate of outputs without extensive processing, due to high asphaltene content.

Synthetic crude oil is a high-value product. Figure 5(a) shows that for a given density, SCOs (dark markers) have low sulfur content compared to conventional crude oils of similar density. Also, SCOs lack the typical “bottom” of a conventional crude oil (i.e., residual products from distillation), because the components that would form the bottom

of the SCO barrel are destroyed during upgrading. Figure 6(a) shows distillation curves for Athabasca bitumens, SCOs and Brent conventional crude. As the temperature increases, increasingly heavier fractions boil. As can be seen, over half of the mass of bitumen has not boiled by 550°C, while all of SCO boils at temperatures $\leq 550^\circ\text{C}$. Note that SCOs have less heavy fraction than the conventional Brent crude marker (for this reason they are sometimes called “bottomless”). Figure 6(b) shows the breakdown of products obtained under vacuum distillation, indicating the lack of residual bottom fraction in SCO [28].



(a) Distillation curves for Athabasca bitumen, Brent crude marker, and Athabasca bitumen SCO.



(b) Yields of product from crude separation/distillation. SCO yields lack low-quality residual oils.

Figure 6: Qualities of SCO as compared to conventional crudes. Data sources include [5, tables 4.2, 4.4] [29] [30] [23].

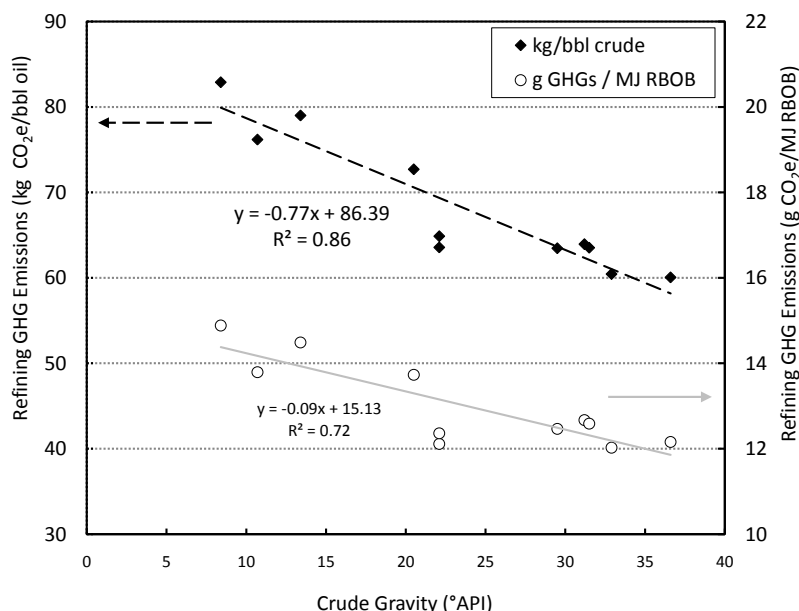


Figure 7: Fit of modeled GHG emissions to API gravity, from 11 crude streams modeled by Keesom *et al.* [7, 26]. Emissions on right axis per unit of reformulated blendstock for oxygenate blending (RBOB, i.e., raw gasoline before final blending).

Most LCA studies to date treat the refining of crude inputs (SCO and bitumen) in a very simple fashion [31, 32]. This is partly due to the absence of publicly-available models of refinery operations, and due to the fact that historical models (e.g., GREET have sought to produce a national average result, without attention to refining differences between individual crude blends). The most detailed study to date is the work of Keesom *et al.*, who model the refining of SCO, bitumen, and diluent-bitumen mixtures using a commercial refinery model [26]. Similar work was undertaken by Rosenfeld *et al.* [19].

Emissions can be approximately adjusted for crudes of differing density using the linear fit from Brandt and Unnasch, which is based on the output from Keesom *et al.* model, shown in Figure 7 [7]. By the line of best fit, each API gravity decrease of 1° will increase refining emissions by 0.09 gCO₂ per MJ of gasoline blendstock produced.

Also, streams that have different sulfur content than the nominal refinery feedstock can be given a credit or debit based on the hydrogen consumption for desulfurization, assuming the hydrogen is generated from steam methane reforming. Observed hydrogen consumption is generally in excess of that which would be expected based on the hydrogen contained in H₂S stream removed from the feedstock crude, due to saturation of unsaturated hydrocarbons (e.g., olefins, aromatics) [33, p. 294]. Data from a variety of heavy crudes and residue are plotted in Figure 8, showing a similar relationship. Assuming that 3 moles of H₂ are consumed for every mole of H₂S formed, and H₂ is produced in a steam methane reformer, CO₂ emissions will increase by ≈ 1.4 kg CO₂ per kg S removed [34].

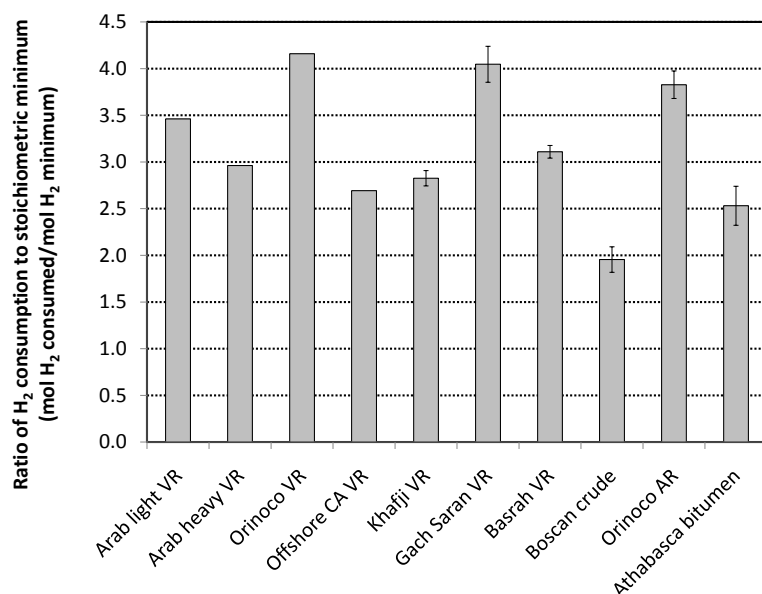


Figure 8: Observed hydrogen consumption compared to minimum hydrogen consumption for sulfur removal for a variety of crude residues and heavy crude oils. VR = vacuum residue, or residue from distillation under vacuum, AR = atmospheric residue, or residue from distillation at atmospheric pressure. Data from Speight [35, Tables 6-18, 6-19, 6-20, 6-21].

3.4 Non-combustion process emissions

Other process emissions include emissions from venting, flaring, and fugitive emissions (hereafter VFF emissions), as well as biogenic emissions from land use change associated with extraction operations.

Table 4 shows venting and flaring emissions by project type as estimated by Environment Canada as part of the *National Inventory Report 1990-2008: Greenhouse gas sources and sinks in Canada*. Yeh *et al.* [36] found for mining operations that tailings ponds fugitive emissions had a wider range than fugitive emissions reported by Environment Canada, with a range of 0-8.7 gCO₂/MJ and a representative value of 2.3 g CO₂/MJ.³

3.5 Land use change associated emissions

Land use change emissions are associated with biomass disturbance and oxidation due to land clearing, soil disturbance, and peat disturbance [36]. These emissions are somewhat smaller than venting and fugitive emissions, with values ranging from 1.0-2.3 g CO₂/MJ of bitumen produced (representative value 1.4 g CO₂/MJ) for mining operations. In a case where development was 100% on peatlands, land use emissions would increase by a factor of 3, suggesting that peat disturbance is a key driver of oil sands land use GHG emissions

³It is not clear whether Environment Canada incorporates tailings pond emissions in these figures.

Table 4: Venting, flaring, and fugitive (VFF) emissions from mining and in situ production. Units: gCO₂ eq./MJ bitumen production, LHV basis. Data are industry averages from [37].

	Venting	Flaring	Fugitive
Mining	1.5	0.5	0.9
In situ	0.5	0.3	0

[36]. In situ operations were found to have negligible land use emissions, ≈ 0.1 gCO₂ eq./MJ of crude produced.

4 Previous oil sands LCA results

A number of LCAs of oil sands production have been performed, although none are comprehensive across all production stages with coverage of all oil sands production processes [38, 39, 26]. Over time, LCA studies have improved in quality and quantity of documentation, although gaps remain in the realm of publicly-available models (see discussion below).

The studies reviewed in this report are listed below. Descriptors in bold will hereafter be used to refer to studies:

GREET The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model, Argonne National Laboratory, Version 1.8d [40]. Most recently documented in *Summary of Expansions and Revisions in GREET1.8d Version* [32], and also documented in [23, 41, 42, 43].

GHGenius The GHGenius model v. 3.18. (S&T)² Consultants for Natural Resources Canada [44]. Available with multiple volumes of documentation from <http://www.ghgenius.ca/>.

Jacobs Keesom, W., S. Unnasch, *et al.* (2009). *Life cycle assessment comparison of North American and imported crudes*. Chicago, IL, Jacobs Consultancy and Life Cycle Associates for Alberta Energy Resources Institute [26].

TIAX Rosenfeld, J., J. Pont, *et al.* (2009). *Comparison of North American and imported crude oil life cycle GHG emissions*. Cupertino, CA, TIAX LLC. and MathPro Inc. for Alberta Energy Research Institute. [19].

NETL Gerdes, K. J. and T. J. Skone (2009). *An evaluation of the extraction, transport and refining of imported crude oils and the impact on life cycle greenhouse gas emissions*. Pittsburgh, PA, Office of Systems, Analysis and Planning, National Energy Technology Laboratory [45]. A companion report is also reviewed: Skone, T. J. and K. J. Gerdes (2008). *Development of baseline data and analysis of life cycle greenhouse gas emissions of petroleum-based fuels*, Office of Systems, Analyses and Planning, National Energy Technology Laboratory [34].

CERA IHS-CERA (2010). *Oil sands, greenhouse gases, and US oil supply: Getting the numbers right*. Cambridge, MA, Cambridge Energy Research Associates [46].

A comprehensive comparison of oil sands GHG studies (including references [47, 9, 44, 40, 48, 24]) was produced by Charpentier *et al.* [15]. Other useful reviews are provided by Mui *et al.* [49, 50]. We will not attempt to recreate the analysis of Charpentier *et al.* or Mui *et al.* but instead present their results to allow comparison with a broader set of studies. One study reviewed but not included above is the *Oil sands technology roadmap* [8], which is of particular importance because it is the source for GREET energy inputs to oil sands production [51].

Upstream (well-to-tank) GHG emissions results from the above studies are put on a consistent basis and plotted in Figures 9, 10, and 11. See Appendix A and Table 8 for calculation and comparison methods. Because tank-to-wheels (TTW) emissions are approximately constant across studies, we will not address them further here.⁴

NETL and CERA results are not plotted in Figures 9, 10, and 11. NETL results are for a representative mixture of SCO and dilbit, produced using a combination of techniques, and therefore cannot be plotted on these plots, which are organized by production technology. CERA results are not plotted because they are reported in kgCO₂ per bbl of refined product produced, and are therefore not comparable with other studies without making significant assumptions.⁵

Figure 9 shows emissions estimates for mining-based processes with upgrading to SCO. In addition, the range of results compiled by Charpentier are plotted along with our main study results for comparison (see arrows) [15]. There is significant divergence between reviewed estimates, although there is less divergence between the studied estimates and the estimates reviewed by Charpentier *et al.* [15].⁶ In Section 5 we describe reasons for these differences.

Figure 10 shows emissions estimates for in situ processes with upgrading to SCO. Again note that there is significant divergence between estimates. These estimates diverge primarily due to different assumptions about fuel mixes consumed in production and upgrading of bitumen (see Section 5), as well as due to different treatment of cogeneration.

Figure 11 shows emissions estimates for pathways involving direct refining of bitumen with no upgrading. Note the relatively higher refining emissions compared to SCO refining in most cases, but the lower overall emissions compared to the in situ & upgrading cases.

⁴Small divergence between studies in TTW emissions does occur. For example, GHGenius TTW emissions differ from GREET TTW emissions because GHGenius does not include carbon monoxide emissions in GHG totals, while GREET assumes relatively rapid oxidation of CO to CO₂ by calculating the mass-equivalent conversion of CO to CO₂. Other similarly small changes, such as treatment of combusted engine lubricant, result in slightly different values between different models and different versions of the same model.

⁵See Appendix A for further discussion of this problem.

⁶Charpentier's review included assessments from Furimsky [9], which included future scenarios with very low emissions - e.g., as low or lower than conventional oil production, which accounts for the wide spread indicated by the arrow.

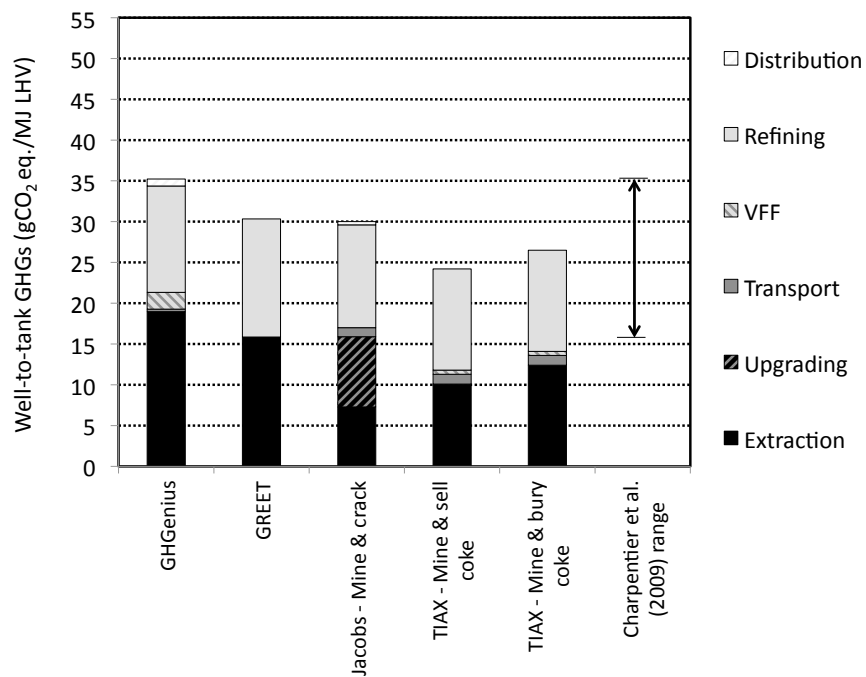


Figure 9: Mining & upgrading emissions estimates. Emissions estimates from included studies [40, 44, 19, 26, 45] and other results compiled by Charpentier *et al.* [15]. All results converted to units of gCO₂ eq./MJ of refined fuel produced, reformulated gasoline, LHV basis.

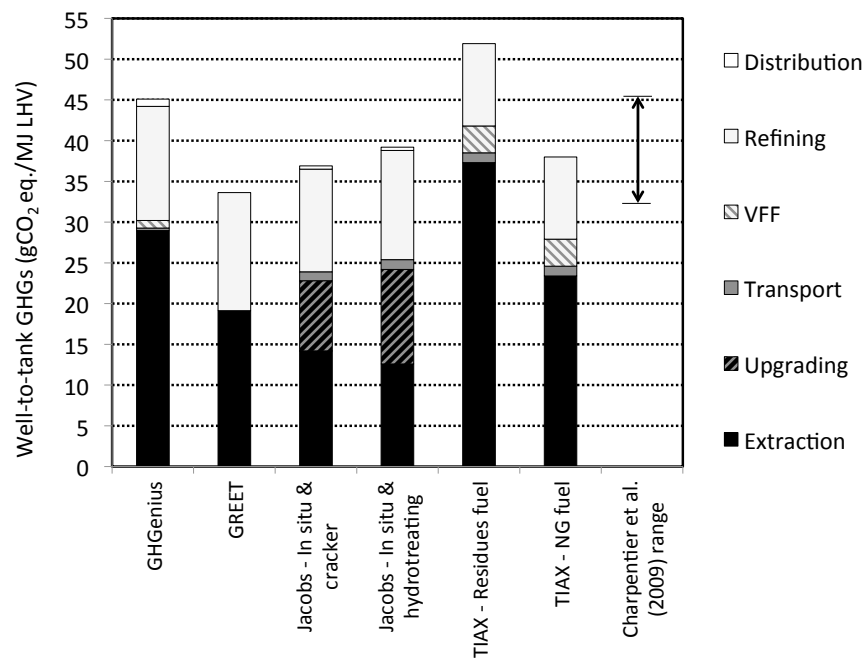


Figure 10: In situ & upgrading emissions estimates. Emissions estimates from included studies [40, 44, 19, 26, 45] and other results compiled by Charpentier *et al.* [15]. All results converted to units of gCO₂ eq./MJ of refined fuel produced, reformulated gasoline, LHV basis.

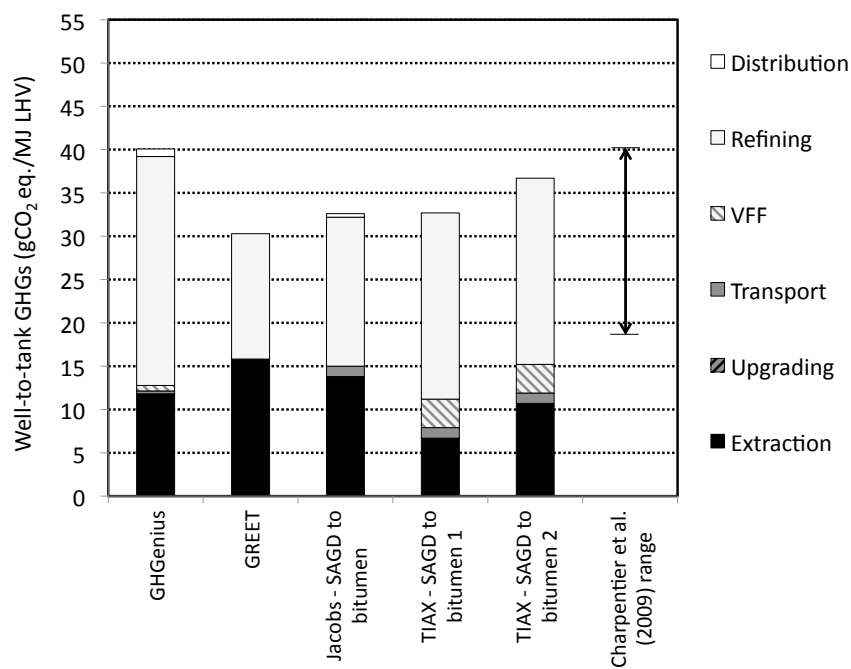


Figure 11: In situ & production of diluted bitumen emissions estimates. Emissions estimates from included studies [40, 44, 19, 26, 45]. All results converted to units of gCO₂ eq./MJ of refined fuel produced, reformulated gasoline, LHV basis.

5 Differences in model treatment of oil sands processes

Fully determining the causes of the differences between the above results is beyond the scope of this report (and likely impossible without access to original model calculations) [15]. However, differences between modeling approaches, data sources, and assumptions are noted in this section so as to provide justification for calculation of low, high and “most likely” emissions from a notional EU refinery.

Many differences are due to the fact that some models attempt to assess emissions for the “average” oil-sands-derived fuel stream (GREET, GHGenius, NETL), while others model specific project emissions (TIAX and Jacobs). As Charpentier *et al.* note, “the nature of the data used for the analysis varies significantly from theoretical literature values to project-specific material and energy balances” [15, p. 7].

5.1 Surface mining

The primary determinants of emissions from mining are the fuel consumed per bbl of raw bitumen produced and upgraded and the fuel mix consumed during upgrading. The fuel mixes assumed by models and the observed industry average fuel mix for mining operations are shown in Figure 12. Details for calculating these fuel mixes are shown in Appendix B, Table 10. These fuel mixes differ largely due to differences in process configuration assumed by each model.

GREET Estimates for diesel use are derived from Alberta Chamber of Resources data, which includes 54 MJ of electricity (15 kWh), 250 MJ of natural gas and 1.5 MJ diesel used per bbl of bitumen mined [51, p. 232]. This low diesel use (compare with range noted above of ≈ 50 -500 MJ/bbl bitumen) is a possible difference between GREET results and those of other oil sands LCAs.

GREET assumes no coke consumption, which is at odds with empirical fuel mixes presented in Figure 12, and other reports [9, 24]. Additionally, despite the fact that GREET figures are based on ACR fuel use data, GREET emissions are 15.9 gCO₂/MJ refined fuel delivered, while ACR emissions results range from ≈ 19 -22 gCO₂/MJ.⁷ This is likely due to the omission of coke combustion in the GREET model.⁸ Charpentier previously noted these discrepancies, stating that “the energy balance in GREET appears to omit the diesel fuel used in mining and the coke used in upgrading” [15, p. 7].

GHGenius GHGenius data are derived from CIEEDAC sources, and include emissions

⁷These figures are only approximate comparisons, because ACR data are measured in kgCO₂/bbl of SCO produced and conversion factors to energetic units are not provided in ACR [8]. SCO density and energy density were set to values for 31 °API oil to allow comparison.

⁸One possible explanation for the discrepancy is that the GREET energy inputs may have been derived from Figure 7.2 in the ACR report [8], which is titled “Energy elements in the cost chain.” This figure includes natural gas and electricity, but because coke is a byproduct fuel from upgrading in integrated operations, it does not show up in this cost figure. Calculated fuel mixes using the data from Figure 7.2 in align well with GREET fuel mixes, suggesting that this is possibly the error.

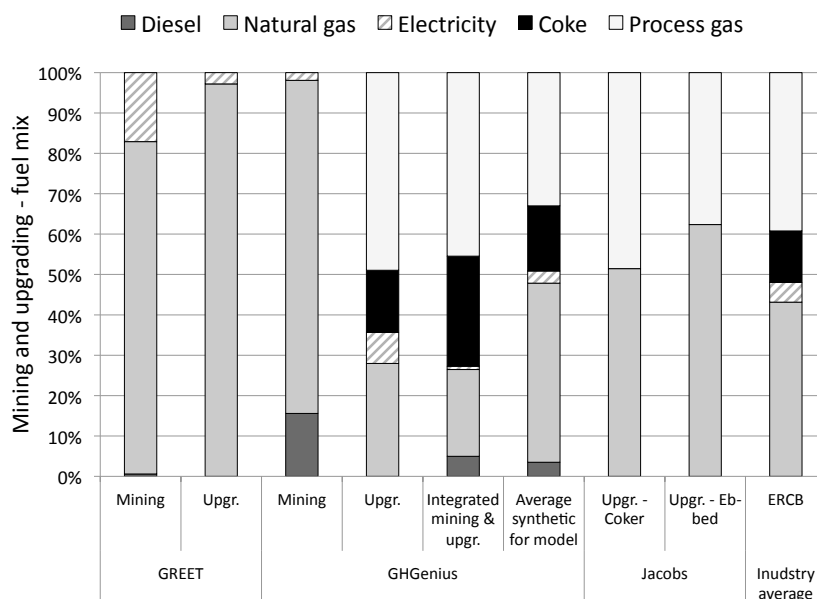


Figure 12: Fuel mix for mining and upgrading assumed by different models and industry average fuel mix. Fuel mix assumptions calculated from model inputs as described in text. Industry average fuel mix calculated from fuel consumption rates reported by ERCB for 2009 mining and upgrading operations [11].

from off-site power and hydrogen production [52].⁹ A variety of fuel sources are assumed in the integrated case. Approximately 25% of the primary energy for integrated mining/upgrading operations being provided by coke, while less is assumed for non-integrated mining and upgrading [44, worksheet “S”, cell AI14]. The overall weighted fuel mix in GHGenius for mining and upgrading to synthetic crude assumes 16% of energy content from coke. Of the studied models, this figure is most closely in line with observed industry average mining fuel mix shown in Figure 12.

Jacobs Surface mining process model is not described in detail. Mining operation does not include coke combustion [26, Figure 3.8]. Process model represents an integrated operation fueled with natural gas, therefore similar to the CNRL Horizon oil sands project (Figure 4) rather than an industry-wide average mining and upgrading fuel mix. This causes the Jacobs mining and upgrading emissions estimate to be lower than the GHGenius estimate.

TIAX Model represents the CNRL Horizon mining and upgrading project, which com-

⁹The source document for these estimates appears to have been removed from the CIEEDAC website, preventing a detailed review of the original sources for GHGenius mining figures. GHGenius technical documentation provides ample documentation [52, 53].

sumes natural gas and stockpiles coke generated during upgrading [19, Figure 3-12]. This assessment therefore does not represent an industry-wide average estimate. The fuel mix shows a lack of coke combustion (Table 10).

NETL Model uses emissions reported by Syncrude for integrated mining and upgrading operation [34, p. 12], as reported in Environment Canada facilities emission database [54]. As noted by Charpentier *et al.* there are difficulties in relying solely on data reported by companies because of completeness and system boundary considerations (for example, upstream emissions from production of purchased electricity or hydrogen are generally not reported).

CERA Estimate is based on meta-analysis of above studies and other studies also reviewed by Charpentier *et al.* [15]. Methods of meta-analysis are not described in detail.

Much of the difference between mining GHG emissions estimates are therefore due to differing fuel mix assumptions. This dependence has implications for future emissions, as future fuel mixes in mining operations are uncertain. Some argue that future projects will rely on coke as much as or more than current operations, due to decreasing availability of low-cost natural gas [18, 24]. For example, Flint argues that natural-gas based expansion to very large volumes of bitumen production is unlikely, and would lead to “unacceptable” aggregate natural gas consumption [24]. Others believe that unconventional gas resources will cause low natural gas prices to continue in the long term.

A shortcoming of existing studies is uneven attention to cogeneration of electric power. This is in part due to the complexity and ambiguity of accounting for emissions offsets from cogenerated electric power. Jacobs is the only study to explicitly include cogeneration of electric power. GHGenius included co-generated power in an earlier version, but has since removed it [53, p. 26]. GHGenius removed cogenerated electric power from integrated mining and upgrading operations, based on lack of information in Syncrude and Suncor publications about power sales [53, p. 26]. ERCB data suggest that Suncor and Syncrude do export some electric power, with Syncrude Mildred lake facility exporting some 10% of generated power, and Suncor exporting some 33% of generated power [11]. This is a shortcoming of the GHGenius model, but will not result in extreme differences in emissions estimates. For example, Suncor exported some 4.1 PJ of electric power in 2009, compared to electricity consumption of 7.5 PJ and total energy consumption of 137.1 PJ [11]. This cogeneration credit should be included in future emissions estimates, but will likely be small due to small magnitudes of electricity export.

5.2 In situ production

Because of relatively homogenous fuel mix consumed during in situ production, the primary determinants of emissions from in situ production are the SOR and the energy consumed to produce each bbl of steam CWE. In some cases, the product of these two terms, or the energy consumed per bbl of crude bitumen produced is reported.

GREET In situ production emissions are on the low end of the range in Figure 10. Natural gas consumption is approximately 1085 MJ/bbl [51, Table 1], or 70% of that

estimated in GHGenius. This figure is at the lower bound of the range for in situ production listed above (950 MJ/bbl - 2100 MJ/bbl bitumen).

GHGenius SORs of 3.2 and 3.4 assumed for SAGD and CSS, respectively [15, 53]. These figures are in line with industry averages presented in Table 1. Natural gas consumption is 1325-1475 MJ/bbl of bitumen produced, for CSS and SAGD, respectively. These consumption rates are higher than those from Jacobs *et al.* for example, but within the range of potential natural gas consumption rates for in situ production listed above. Net export of cogenerated power is not included in the current version of GHGenius, although it can be modeled by inputting a negative electricity demand into extraction demand.¹⁰

Jacobs Emissions are lower than GHGenius results, partially due to lower SOR assumption and partially due to cogeneration. Jacobs assumes SORs of 3 (compare to observed range in Table 1) [26, Table 3-10]. Energy content of steam is 325 MJ/bbl CWE steam, while efficiency is 85% (LHV basis). This figure is at the low bound of the energy intensity range cited above. Consideration of higher energy consumption from 100% quality steam is not accounted for. Cogeneration of electric power provides an emissions offset [26, Table 3-10, Figure 3-8]. Because SAGD net cogeneration exports are not reported in ERCB datasets, this figure is cannot be verified [13].

TIAX Natural gas consumption rates are at the low end of the above cited range, roughly 700-1150 MJ/bbl bitumen for cases Christina Lake (SAGD) and Cold Lake (CSS) [19, Figures 3-14, 3-15]. The SAGD case has a low SOR of 2.5, and a low implied energy consumption of 275 MJ/bbl CWE of steam. These values are significantly lower than empirical values cited above [26, 55], driving the low emissions from the TIAX natural gas case. TIAX is the only report to consider integrated in situ production with bitumen residue or coke firing. The TIAX case with coke consumption for steam generation (analogous to OPTI-Nexen Long Lake project) results in higher emissions, as should be expect from carbon intensity of asphaltene residue gasification [19, Figure 3-13].

NETL Emissions calculated for Imperial Oil Cold Lake project using CSS [34, p. 12], as reported in Environment Canada facilities emission database [54]. In 2009, Cold Lake had an SOR of 3.5 (see Table 1). As noted by Charpentier *et al.*, there are difficulties in relying on data reported by companies because of completeness and system boundary considerations (for example, upstream emissions from production of purchased electricity or hydrogen are generally not reported).

CERA Estimate is based on meta-analysis of above studies and other studies also reviewed by Charpentier *et al.* [15]. SORs of 3-3.35 are used, which are in line with industry average SORs. No other information is provided.

¹⁰Source: Personal communication, Don O'Connor. This method would assign the Alberta grid electricity GHG intensity to the emissions avoidance credit (due to power exports offsetting power demand on the Alberta grid).

5.3 Upgrading emissions

Upgrading emissions are driven by the energy consumed per bbl of SCO produced, plus the fuel mix used in upgrading. As with other emissions estimates above, the studies vary in their assumed energy intensity and the assumed fuel mix that provides this energy.

GREET Upgrading consumption values are low compared to other estimates (e.g., Jacobs). Consumption of natural gas equals ≈ 520 MJ natural gas/bbl SCO produced [51, Table 1]. No consumption of coke or process gas is recorded, which differs from observed fuel mixes shown in Figure 4.

GHGenius Consumption in upgrader is ≈ 990 MJ/bbl SCO [44, sheet “S”, column AG], with a mixture of fuels consumed (28% natural gas, 49% still gas, 15% coke, and remainder electricity). Detailed information on upgrading emissions and energy intensity is given in GHGenius documentation [53, Table 6-5]

Jacobs Consumption is ≈ 820 MJ/bbl SCO for coking, and 1050 MJ/bbl SCO for Eb-bed. Fuel mix includes both natural gas and process gas¹¹, with no consumption of coke. This fuel mix therefore does not represent an industry average.

TIAX Study does not report upgrading consumption separately from mining or SAGD consumption. This is because integrated operations are modeled and therefore process flows are not delineated by mining and upgrading stages [19, e.g., Figure 3-12].

NETL Additional description of upgrading is not provided in NETL studies [45, 34]. Upgrading emissions are included in emissions from Syncrude integrating mining and upgrading operation, as described above.

CERA Estimate is based on meta-analysis of above studies and other studies also reviewed in Charpentier *et al.* [15]. Methods of meta-analysis are not described in detail.

Differences between Jacobs and GHGenius estimates are likely due to fuel mix differences, due to the similar energy consumption values. GREET energy consumption is significantly lower than other studies with documentation for reasons for low energy use. Given observed consumption of coke in fluid coking operations, GHGenius estimates are likely more representative of industry-wide upgrading intensity. GHG-intensive upgrading using bitumen residues at OPTI-Nexen Long Lake is neglected in all models except TIAX.

5.4 Refining emissions

Refinery feedstock qualities differ by study, as shown in Table 5. Some studies do not state explicitly the quality of refinery feedstock. Note that these SCO characteristics align well with reported characteristics of SCO products (Table 3).

¹¹Fuel mix is $\approx 50\%$ each natural gas and process gas for the coking unit, 60% natural gas and 40% process gas in Eb-bed reactor [26].

Table 5: Bitumen and synthetic crude oil properties by study^a

		API grav. °API	Spec. grav. tonne/m ³	Sulfur wt. %	Case
GHGenius ^b	Synthetic crude oil	31	0.871	0.2	Most likely
GHGenius ^b	Bitumen	8	1.014	4.7	
Jacobs ^c	SCO - Eb. bed	23.12	-	0.13	Low
Jacobs ^c	SCO - Delayed coker	29.01	-	0.4	
Jacobs ^c	Bitumen	8.44	-	4.81	
TIAX ^d	SCO - mining	32.2	-	0.16	High
TIAX ^d	SCO - in situ	39.4	-	0.001	
TIAX ^d	Dilbit	21.2	-	0.69	

a - No information is given on SCO quality in GREET or in Larson *et al.* [51]. Information on SCO and bitumen qualities is lacking in the NETL study, which cites API gravity of “20-33 °API” [45, p. 5]. The CERA study does not specify the quality of SCO used in calculations.

b - Values from GHGenius, sheet “S”, row 95

c - Values from Keesom *et al.*, Table 5.2

d - Values from Rosenfeld *et al.*, Appendix D, Exhibit 3.1. No case of raw bitumen refining is considered, in that diluent is considered refined along with delivered bitumen (hence API gravity of 21.1, rather than ≈ 8 for raw bitumen).

GREET Model calculates refinery emissions from processing oil-sands-derived streams as equivalent to processing conventional crude oil streams [51, p. 231] [40, sheet “Petroleum”, column O]. This assumption will not result in significant errors, because GREET assumes mined and in situ bitumen are upgraded to SCO [40, sheet “Petroleum”]. As noted above, SCO refinery emissions are likely to be equivalent to or below conventional oil refining emissions, due to lack of “bottoms” and low impurity concentrations after upgrading (see Figures 5 and 6).

GHGenius Includes crude quality (density and wt.% sulfur) when accounting for refining intensity, as of a 2007 update. This function is derived from MAPLE-C, a Canadian energy modeling effort that contains a petroleum market module (PMM) [52, p. 13]. The PMM contains more than 40 refinery processes. Regression analysis was used to derive a function from the results of MAPLE-C to represent refining energy (MJ/MJ processed) as a quadratic function of crude density and sulfur content. It is unclear what ranges of refinery inputs are included in the inputs to this function. GHGenius results from this refining function for raw bitumen are notably higher than those reported from more detailed refinery modeling.¹² Given that results from more detailed refining modeling (e.g., TIAX, Jacobs) support an approximately linear relationship between crude density and refining intensity, future work should investigate the differences between the GHGenius and other refining approaches.

¹²Charpentier *et al.* values derived from GHGenius for raw bitumen are converted to common baseline in Table 8. This author used the GHGenius model to model refining of raw bitumen of 8 °API and sulfur of 4 wt.%, and found similar, though not identical results. If the model embedded in GHGenius was estimated using data for a narrower range of crude inputs, modeling crudes with high density and sulfur contents could result in overly high emissions estimates, due to quadratic (sulfur² and sg²) terms.

Jacobs Detailed calculation of refinery inputs and outputs is performed using a commercial refining simulation model. Results from the commercial refinery process model are presented in detail, with process throughputs and products breakdown provided for SCO, bitumen, and dilbit [26, e.g., Table 5-3, 5-4]. Detailed utilities consumption is presented for Arab Medium crude, but not for oil-sands-derived streams [26, e.g., Table 5-5]. Aggregate refining results from 11 crude streams modeled are used to generate Figure 7 in this report.

TIAX Model performs detailed calculation of refinery inputs and outputs, with extensive documentation. Model results include differential refining emissions based on the quality of the feedstock [19, Table 6-5]. For example, emissions from diluted bitumen streams (synbit and dilbit) are higher than those from SCO (15.2-16.9 gCO₂ eq./MJ for diluted bitumen vs. 10.1-12.4 gCO₂ eq./MJ for SCO streams). This difference aligns with what is to be expected from refining crudes of different qualities.

NETL Approach used by Gerdes *et al.* [45] is outlined in detail in Skone *et al.* [34]. A novel approach using US nation-wide statistical data on refinery configurations, crude throughputs, crude qualities, and utilization factors for different crude processing stages (e.g., distillation utilized capacity vs. fluid catalytic cracking utilized capacity) is developed. This approach is similar in framework to that taken by Wang *et al.* [31], although Skone *et al.* model process throughputs in more detail. This approach is used to derive a baseline emissions estimate for refining of average US feedstock [34]. It is also used to develop heuristic models for the effect of crude density and sulfur content on refining intensity, which are then used to estimate emissions from a variety of inputs to US refineries, including oil-sands-derived feedstocks [45, e.g., Figures 2.7, 2.8].

CERA This study does not include enough information to evaluate the approach used to model refining of oil-sands-derived products.

In summary, the Jacobs model and TIAX model represent the most thorough efforts to date to model refinery emissions from refining oil-sands-derived feedstocks. The NETL model represents the most thorough treatment of the problem using public data. GHGenius results in somewhat higher refining emissions than other models.

A significant issue in refinery modeling is the different quality of SCO as compared to conventional oil. As shown above, SCO lacks refinery bottoms. This will affect emissions both directly and indirectly from refining. Direct emissions effects would potentially cause a decrease in emissions, due to less need for CO₂ intensive upgrading processes. Indirect emissions effects could arise if significant amounts of SCO were imported to the EU. This would reduce the amount of residual oil available, which could have impacts on the bunker fuels, power generation, and industrial heat markets. This could have a positive impact if residual fuels were replaced with natural gas, and a negative impact if they were replaced with coal. These issues are discussed in more detail below.

5.5 Other process emissions

Emissions from venting, fugitive emissions and flaring (VFF) are unevenly addressed in the above studies. GREET does not include non-combustion (e.g., VFF) emissions from bitumen extraction or upgrading [40, sheet “Petroleum”, columns G,J]. GHGenius does include venting and flaring emissions [52]. Jacobs does not explicitly include VFF emissions from oil sands production; it is not known if these emissions sources are included in aggregate extraction emissions [26, Table 8.7]. TIAX does include VFF emissions, of 0.5 to 3.3 gCO₂eq./MJ [19, Table 6.3]. These emissions are from regulatory documents related to the Horizon oil sands mine. NETL does include venting and flaring generally [45, e.g., Figures 2.1, 2.2], but does not describe method for estimating bitumen VFF emissions. It is unclear if CERA explicitly includes venting and flaring emissions.

Land use emissions are only considered in the GHGenius model, which calculates soil and biomass disturbance per ha and apportions this according to the type of operation (e.g., 100% disturbance on mined lands, no disturbance for SAGD) [44, sheet “S”, columns Z-AB, AG-AI].

6 Comparability of studies

Given the above information, it is useful to summarize the comparability of referenced studies. The comparability of studies with respect to oil sands emissions estimates is discussed, followed by the comparability of studies in their treatment of conventional crude oil. An important factor in the comparability and usefulness of studies is whether or not the study results are indicative of the industry as a whole, or whether they are process-specific emissions estimates.

Process-specific emissions estimates and industry-average emissions estimates are useful in different contexts. For regulatory purposes for determining the potential overall scale of differences in emissions between broad fuel types (e.g., conventional oil and oil sands) industry-wide production-weighted average emissions are more useful than process-specific assessments. For regulating the GHG intensity of a given process or a given import stream, process-specific emissions estimates are required.

6.1 Representativeness of oil sands results to industry-wide averages

The above studies can be compared on how representative their oil sands emissions results are of an industry-wide (e.g., production-weighted) emissions profile for oil sands.

GREET Model includes both mining and in situ production, and generates a consumption-weighted emissions profile for oil sands imported to the US, given differences between in situ and mining processes [40].

GHGenius The model differentiates between the variety of oil sands production processes (e.g., integrated mining and upgrading vs. SAGD), and weights these processes by their relative importance in the oil sands sector [44, Sheet “S”]. This provides an assessment of industry-wide average emissions.

Jacobs Models individual processes in detail, and does not provide an industry-wide emissions assessment. As noted above, Jacobs fuel mix assumptions are for individual projects and are not representative of production-weighted average consumption.

TIAX Models individual processes in detail, and does not provide an industry-wide emissions assessment. Includes a variety of production technologies, including SAGD with residue gasification. These assessments are not used to generate an industry-wide or production-weighted average.

NETL Reported industry values for Syncrude operations are used for mining and upgrading emissions. These values are therefore representative of a single oil sands extraction and upgrading operation, not an industry-wide or production-weighted average.

CERA Includes a production-weighted value for average oil sands imported to the US [46, Figure 3], which allows for an industry-wide assessment of emissions from oil sands. Due to lack of documentation of meta-analysis methodology, it is not certain how this value is computed.

6.2 Representativeness of comparison conventional crude oils

In addition to the comparability of oil sands emissions estimates, it is useful to assess the comparability of emissions estimates for conventional crude oil. A key difficulty is that the emissions from a conventional oil production process will vary with process parameters, such as field depth, water cut, injectant type and volume for EOR, venting and flaring practices, etc. Some of the reviewed studies modeled the emissions from a given crude type or crude blend (i.e., from a given field or group of similar fields), while other studies assess national-level averages.

Due to general methodological uncertainty, it is unclear (in most cases) whether national average crude emissions can be considered indicative of the production-weighted average crude from those regions (e.g., is the NETL value of Mexico a representative production-weighted average value for Mexico, or is it based on limited data from a few projects?) In a similar sense, it is not clear how to scale from crude blend-specific assessments to national averages (e.g., is Maya crude representative of all Mexican crude oils?).

National averages are useful for assessing the overall emissions profile for a given region (given a suite of conventional oil imports) as calculated in the NETL report. However, regulatory processes will require detailed crude-specific emissions estimates: importers generally purchase marketed crude blends (e.g., Maya) or crudes from given fields. They do not purchase a national average crude (e.g., Mexican crude). For this reason, reliance on national averages is problematic for future regulation, and additional detailed analysis by crude oil type is required.

GREET The GREET model includes an assessment of average US crude oil, given typical crude extraction characteristics and the refining profile of the US refining sector. Therefore, conventional crude oil within GREET represents a nation-wide aver-

age. Due to simplicity of modeling, details of crude operations or variation between crude type cannot be readily implemented in GREET.

GHGenius A variety of foreign feedstocks of varying quality, modeled by country of origin, can be included in a model result as weighted inputs to a region of interest (e.g., Eastern US). Therefore, these conventional crude oil emissions effectively represent nation/industry-wide averages, depending on the region selected. It is unclear what weighting was used within country-level estimates, if any.

Jacobs Includes 7 marketed crude oil blends, including Arab Medium (Saudi Arabia), Kirkuk (Iraq), Bonny Light (Nigeria), Maya (Mexico), Bachaquero (Venezuela), Mars (US Gulf offshore), and Kern River (California) [26, p. 6]. These crude streams cover the spectrum of crude oil qualities, from Bonny Light (light, low sulfur) to Kern River (heavy, high-sulfur). These also cover the range of conventional production technologies, including primary, secondary, and tertiary production methods (e.g., including thermal oil recovery of Kern River crude). This detailed treatment allows useful comparison between marketed crude blends. No representative production- or consumption-weighted value is produced for national or industry averages of the constituent regions (e.g., Maya crude is not compared or converted to Mexico average crude oil).

TIAX Includes 9 conventional crude oil streams (Alaska North Slope, Kern County Heavy Oil, West Texas Intermediate, Bow River Heavy Oil (Canada) Saudi Arab Medium, Basrah Medium (Iraq), Escravos (Nigeria), Maya (Mexico) and Bachaquero (Venezuela) [19, Table 3-1]. This treatment of individual crude streams allows for detailed assessment of emissions from each stream, as in the Jacobs study. No production-weighted industry/national average value is produced.

NETL Includes all major crudes imported to the US, aggregated by country of origin (representing 90% of crude oil inputs to US refineries in 2005) [34, p. 9]. Because this assessment treats crude at the country rather than crude product level, there is some uncertainty associated with emissions from each crude basket. For example, results at this level of detail do not allow a crude importer or regulator to understand how Mexican crude oil on average differs from the component crude streams that are imported, such as Maya crude. However, because all major imports to the US are covered, and because they are aggregated in a production-weighted fashion, comparability to industry-wide average values as in GREET are possible.

CERA Assesses average US barrel consumed (2005) [46, Figure 3]. This consumption-weighted value can therefore be readily compared to the production-weighted value of average oil sands imported to the US, but not directly to constituent conventional crude oil streams or project-level oil sands assessments [46, Figure 3].

6.3 Representativeness of refining emissions estimates and their comparability

Crude oil and oil sands refining is treated differently in each study, in some cases with significant methodological differences. The GREET model includes refining in a simple

fashion, and refining energy intensity and emissions do not vary between conventional petroleum and SCO from oil sands. The GHGenius model, as well as studies from Jacobs, TIAX and NETL all incorporate crude quality metrics in their refining emissions assessments. As stated above, GHGenius and NETL use functions relating emissions to key quality factors (i.e., API gravity and % sulfur). TIAX and NETL, on the other hand, rely on detailed petroleum refining models to assess each crude stream separately, as described above. The CERA study does not describe refining methodologies separately from other process stages, although full life cycle figures are generated.

Due to differences in methodologies, refining estimates not be compared directly to each other in a rigorous fashion. More study is required to assess the differences between these refining models and their comparative accuracy.

7 Recommendations for use of previous emissions estimates in EU GHG regulation

Given the above information about GHG estimates from the various models, recommendations can be made regarding the most acceptable models to use for estimating aggregate upstream emissions from oil sands imports into the EU fuels markets.

The two models reviewed above that are in the public domain are GREET and GH-Genius. Of these two public domain models, this report recommends that GHGenius be used to model emissions from oil-sands derived fuels. GREET emissions estimates are not recommended due to the numerous concerns listed above.

The models with non-public models or calculation methods include Jacobs, TIAX, NETL, and CERA. Of these reports, the Jacobs work represents the most thorough and well-documented work. The TIAX report is useful due to its coverage of a wider range of project types. NETL is also a useful reference, especially for its coverage of global crude oils.

7.1 Emissions estimates for oil sands imports to nominal European refinery

This section describes GHG emissions from imports of oil sands to the European fuels markets. We generate low, high and “most likely” results cases. *These estimates assume EU standard life cycle emissions factors for some process stages, which will be different in other regions.* Please see Appendix A, Table 8 for the values as extracted from studies before modification to standard EU downstream values.

Default values from EU well-to-wheels analysis are used for some stages. These EU-specific results are derived from JRC-EUCAR-CONCAWE (JEC) studies as used in EU fuel quality regulations in general [56, 57]. For our below calculated values, estimated values for the following process stages are replaced with EU-specific default values:

- Refining and processing: 7.0 gCO₂ eq./MJ
- Transport and distribution: 1.91 gCO₂ eq./MJ
- Combustion: 73.38 gCO₂ eq./MJ

Using these standard factors allows direct comparison with existing fuel cycle estimates, as produced by the JEC collaborative efforts.

Detailed results by study are presented in Table 8.

7.1.1 Low estimate life cycle emissions

From Table 8, the lower bound estimate of life cycle emissions for EU refinery feedstock would be SCO derived from 100% mining and upgrading to SCO, as modeled by Jacobs. As the process modeled by Jacobs represents a natural-gas fueled operation, it most closely represents the fuel mixes for the CNRL Horizon project, as shown in Figure 4. The total emissions for this pathway are 98.2 gCO₂/MJ LHV after substituting EU-specific estimates for downstream operations as noted above. Life cycle emissions credits from co-generated

electric power are assigned to integrated surface mining with upgrading, as shown in Jacobs, Figure 3.8 ($\approx 4 \text{ gCO}_2/\text{MJ}$). Larger credits are assigned to SAGD projects, due to their larger amounts of power co-generated.

7.1.2 *High estimate life cycle emissions*

From Table 8, the higher bound estimate of life cycle emissions for EU refinery feedstock would be 100% SAGD and integrated upgrading to SCO with bitumen residue gasification, as modeled by TIAx. As noted above, it most closely represents the OPTI-Nexen project. The total emissions for this pathway are $122.9 \text{ gCO}_2/\text{MJ}$ LHV using JEC EU-specific estimates for downstream operations. This figure does not include co-generated electric power, as the OPTI-Nexen project modeled does not include power export to the grid [19, p. 27].

7.1.3 *“Most likely” estimate life cycle emissions with specified feedstock mix*

The above fuel mixes with lowest and highest emissions do not represent realistic import mixes into the EU transport fuel system: it is improbable that imports to the EU would be only from the projects with lowest or highest upstream GHG emissions. Also, in the face of potential GHG regulations, it is unlikely that numerous projects having characteristics similar to the high case will be constructed. We therefore construct a “most likely” mix that represents a blend of product imports. GHGenius does not include co-generated electricity exported to the grid.

For a variety of reasons, we recommend the use of GHGenius for the “most likely” case:

- It is a public model undergoing active and continuous development, with significant attention paid to oil sands modeling. The public nature of the model is particularly important for regulatory processes, which should utilize calculations that are readily accessible by all interested and regulated parties.
- Its model documentation is comprehensive and updated on a continuous basis.
- It includes all pathways, including mining and upgrading, integrated mining operations, and SAGD.
- Its coverage is comprehensive, and its parameters reflect more closely industry average figures, not project-specific figures. For example, its specified fuel mixes and other process parameters conform more closely to industry average values than other models.
- Its treatment of SAGD has an assumed SOR that aligns closely with industry averages as seen in ERCB data [13], and its per-bbl steam energy requirement is realistic given the high-quality steam flows needed for SAGD.
- GHGenius contains VFF emissions, as well as land use change emissions due to mining operations. It is important that these emissions be included in assessments of the GHG intensity of oil sands production [36].

Potential areas for improvement in the GHGenius model (as noted above) include:

- Its treatment of electric power cogeneration should be examined in light of available data on export electricity from mining and upgrading projects. Concerns about cogeneration are a common issue across the models reviewed above.
- Its treatment of refining should be examined in light of recent modeling results (e.g., Jacobs) suggesting linear relationships between crude density and refining emissions intensity.

Because the estimates generated below for importing oil sands to the nominal EU refinery utilize a standardized refining value (not the GHGenius refining value), the second concern listed above will not affect our estimates.

Our most likely case is calculated using the current production split between mining and in situ production:

- Approx. 45% in-situ
- Approx. 55% Mined

The results for the above low, high, and most likely scenarios are shown in Table 6.

Table 6: Results for specified refinery mix [gCO₂/MJ LHV].

	Extraction	Upgrading	VFF	Refining*	Transport and Distribution*	Combustion*	Total
	Oil sands emissions estimates						
Low ^a	7.3	8.6	0.0	7.0	1.9	73.4	98.2
High ^a	37.3	0.0	3.3	7.0	1.9	73.4	122.9
Most likely ^a	23.5	0.0	1.5	7.0	1.9	73.4	107.3
	EU conventional oil emissions estimates						
Low ^b	1.0	0.0	0.0	7.0	1.9	73.4	83.3
High ^b	21.1	0.0	0.0	7.0	1.9	73.4	103.4
Most likely ^b	4.8	0.0	0.0	7.0	1.9	73.4	87.1

^a - Cases defined above. Lower bound represents Jacobs mining & upgrading. High bound represents TIAX integrated SAGD to SCO with residue consumption for steam and hydrogen. Most likely case represents weighted average GHGenius results, 45% in situ to SCO, 55% mining to SCO. All of these results are derived from Table 8, with JEC standard factors used for life cycle stages marked with *.

^b - Conventional EU refinery feedstock, with upstream extraction emissions a weighted average of upstream emissions reported by NETL, as in Table 7. VFF emissions are included in NETL upstream emissions.

* - These process stages are assigned default values from JEC WTW studies for the EU fuel system [56, 57]. See discussion in text above.

7.1.4 Adjustment to EU refinery input stream

Given that our inputs for the most likely case come from the GHGenus model, and given the SCO properties from GHGenus in Table 3, there is no way to meet an average API gravity target of 34 °API, which is the basis for the JEC refinery estimate used in Table 6.

Our modeled SCO streams differ from the nominal EU refinery input by being more dense (e.g., 31 vs. 34 °API for GHGenus case) and having less sulfur (0.2 wt% vs. 1.1 wt.%). There will be some GHG impacts resulting from these differences, and detailed refinery modeled would be required to model the total impacts.

For exploratory purposes, we can use the the simple linear model, developed above in Figure 7 and adjacent text, to calculate a refining “penalty” associated with 3 degrees reduction in API gravity and 0.9 wt% reduction in sulfur content in GHGenus SCO as compared to the nominal EU refinery feedstock. We calculate that the impact on refining emissions of a switch to SCO will be small, on order 0.1 gCO₂/MJ. For this reason, we include no adjustment factor in Table 6. To model this effect in detail, refinery process modeling that accounts for EU refinery configuration and product output slate will be required.

7.2 Comparison to current EU refinery input stream

Our low, high and most likely scenarios above for oil sands emissions can be compared to similar low, high, and “most likely” estimates for the current EU refinery input stream. The results of this analysis are shown in Table 7. These resulting cases for the current EU refinery inputs stream are compared with those from oil sands in Table 6.

Data on global crude oil streams and their upstream GHG emissions are difficult to obtain, and are a topic of significant current research. Here we use results from the NETL report, “Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels” [34], which estimates emissions from a variety of global crude oils. The NETL report uses country-level oil production data from PE International (GaBi database) derive GHG emissions from oil production by source of imported crude oil to the US. Since many of these crudes are also imported to the EU, these data can be used here.

Data are extracted from Figure 2.5 of the NETL report [34] and converted to MJ of crude oil equivalent using a standard conversion factor of 6.1 GJ/bbl of crude oil.¹³ We then apply country- or region-specific upstream emissions factors given 10-year weighted average crude imports to the EU. Where specific country values are not available from NETL, average values are used (see footnotes to Table 7).

The results of comparing the current weighted-average EU refinery feedstock to low, high and most likely oil sands emissions are shown in Figure 13. Note that there is overlap between the most GHG-intensive crude oils (e.g., Nigeria) and the least GHG-intensive oil sands production (e.g., mine and retort using natural gas, from Jacobs). This has been noted by Jacobs, CERA, and other recent sources. Despite this overlap, there is significant deviation between an average EU conventional fuel stream and an average oil sands fuel

¹³Crude oil energy density will vary with API gravity and other crude characteristics. Due to lack of data on crude energy densities, we assume this common figure across all crude oils.

Table 7: Conventional crude oil mix to nominal EU refinery and resulting weighted-average GHG emissions^a from upstream (well-to-refinery) GHGs measured in gCO₂/MJ of crude oil produced.

Region or country	Fraction of EU crude input	Upstream GHGs	Case	Notes
Unspecified EU production	0.148	4.2	Low	<i>a</i>
Russian federation	0.209	5.5		
Norway	0.163	1.0		
Saudi Arabia	0.095	2.3		
Libya	0.068	7.0		<i>b</i>
Iran	0.056	7.0	High	<i>b</i>
United Kingdom	0.056	2.4		
Nigeria	0.032	21.1		
Algeria	0.027	5.8		
Kazakhstan	0.022	7.0		<i>b</i>
Iraq	0.022	3.3		
Denmark	0.016	4.2		<i>a</i>
Syria	0.016	7.0		<i>b</i>
Mexico	0.015	6.4		
Kuwait	0.012	2.7		
Venezuela	0.011	4.0		
Azerbaijan	0.010	7.0		<i>b</i>
Angola	0.008	13.5		
Cameroon	0.009	7.0		<i>b</i>
Egypt	0.005	7.0		<i>b</i>
Weighted average		4.83	Most likely	

a - Used "EU-25" value from Skone and Gerdes [34].

b - Used "Foreign average" value from Skone and Gerdes [34].

stream that is most likely to be imported to the EU.

These results can also be plotted on cumulative-production basis to assess the differences between average and bounding emissions (see Figure 14). This figure plots well-to-wheel emissions for total oil sands production by volume of product generated for projects that produce refinery-ready SCO.¹⁴ Oil sands emissions are generated by assigning each SCO-generating project an emissions value from Table 8 that most closely approximates its production properties. This limited sample of projects that produced SCO amounts to 855 kbbbl/d out of total SCO+bitumen 2009 production of 1284 kbbbl/d in 2009. We also plot total EU conventional oil consumption (as volume of crude oil consumed) [11, 13]. These cumulative volumes are normalized and emissions are arrayed from low to high, as assigned from Table 8 depending on the oil sands project type or the origin of the conventional crude oil from Table 7. For example, the lower bound on the oil sands curves is CNRL Horizon output, assigned a low-intensity emissions factor due to its lack of coke combustion, while the higher bound is OPTI-Nexen SAGD output with residue gasification is assigned a high emissions estimate.

Only projects that generate SCO are included, and all projects (oil sands and conventional) are assigned the EU default refining, distribution, and combustion emissions used in Figure 13. Conventional oil emissions estimates and volumes imported to the EU are plotted from Table 7, and also include default EU refining, transportation & distribution, and combustion emissions. Because of the significant uncertainty regarding venting and flaring emissions from Nigerian crude oil production, two estimates for Nigerian crude are included. Jacobs figures for Bonny Light crude are used as the lower bound estimate, with upstream (production) emissions at 16.8 gCO₂/MJ RBOB (see Jacobs Table 8.7). NETL estimates are used as the upper bound, at 21.1 gCO₂/MJ of refined fuel produced.

As can be seen in Figures 13 and 14, there is some overlap between oil sands emissions and conventional oil emissions. However, Figure 14 there is significant divergence across the majority of the cumulative production profile, suggesting differences between production- or consumption-weighted emissions.

¹⁴Projects included are: Shell Albion Sands, CNRL Horizon, Suncor, Syncrude Mildred Lake and Aurora, and OPTI-Nexen Long Lake, in order of increasing GHG intensity. Each project is assigned an emissions profile from Table 8, with EU standard emissions factors for refining T&D and combustion instead of model-specific results. Projects were assigned emissions according to closest estimate for project type. These include: Shell Albion Sands and CNRL Horizon: Jacobs mining + hydrocracking; Suncor and Syncrude Mildred Lake and Aurora: GHGenius integrated mining and upgrading, OPTI-Nexen SAGD w/ residue gasification: TIAX SAGD to SCO with residue gasification.

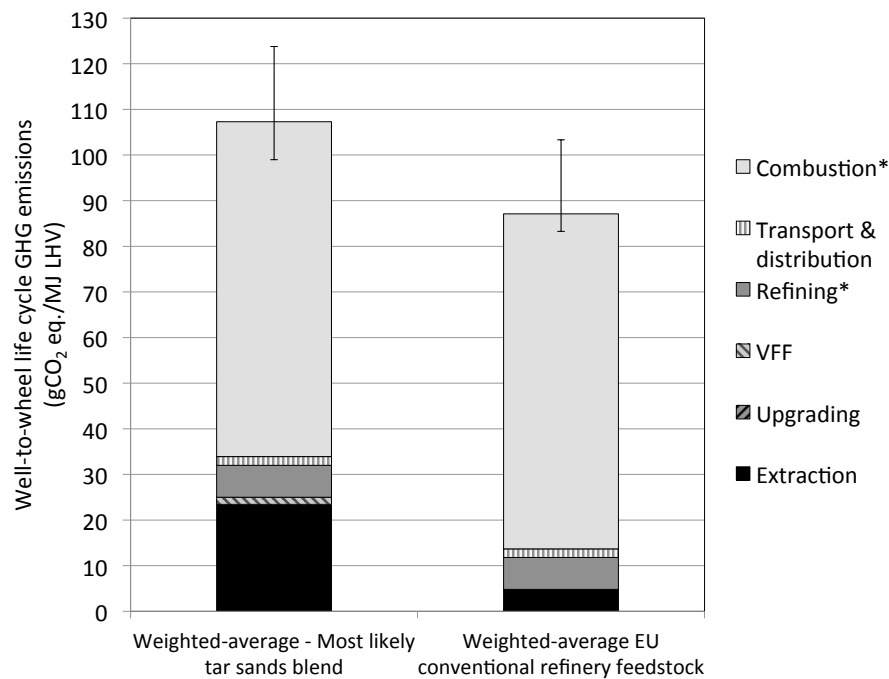


Figure 13: Weighted-average most likely oil sands emissions compared to weighted average conventional EU refinery feedstock. Range of values for oil sands provided by low-high range shown above in Table 6. Range of values for conventional oil shown above in Table 7, for Norway (low) and Nigeria (high).

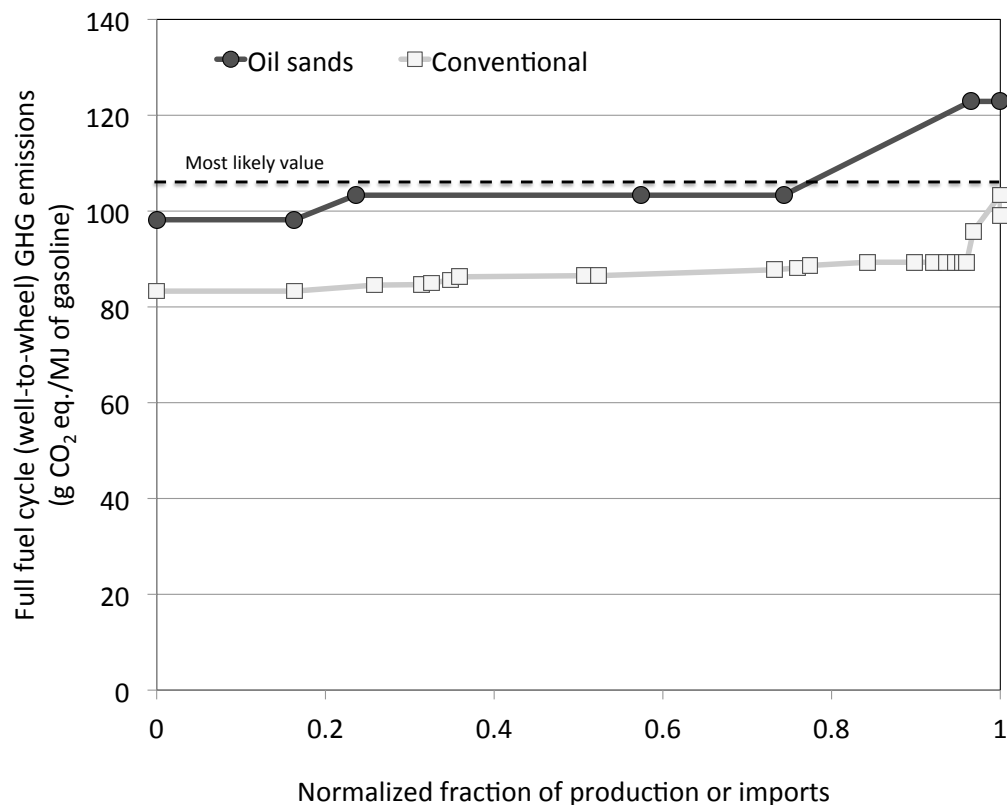


Figure 14: Emissions as a function of cumulative normalized output, for oil sands projects (low and high estimates) and conventional oil imports to the EU. While there is some overlap at the tails (highest conventional oil is higher than lowest oil sands) the production- or import-weighted average emissions are significantly different. The bounds on oil sands emissions are provided by (low) CNRL Horizon, (high) OPTI-Nexen, Long Lake SAGD + Residue gasification. The bounds on conventional oil emissions are provided by (low) Norway, (high) Nigeria. Oil sands estimates are from Table 8, with EU standard emissions factors for refining T&D and combustion instead of model-specific results. Projects were assigned emissions according to closest estimate for project type. These include: Shell Albian Sands and CNRL Horizon: Jacobs mining + hydrocracking; Suncor and Syncrude Mildred Lake and Aurora: GHGenius integrated mining and upgrading, OPTI-Nexen SAGD w/ residue gasification: TIAX SAGD to SCO with residue gasification.

8 Uncertainties

Uncertainties remain in calculating life cycle GHG emissions from oil sands operations and applying these factors to EU refinery inputs. Chief among these uncertainties are:

1. Treatment of cogenerated electric power is a concern in all studies. Given the CO₂ intensity of the Alberta grid, co-production credits from cogenerated power could be important. The Jacobs study addresses these issues, as did previous versions of the GHGenius model. More study of these issues is needed, ideally using observed electric power export data from mining and in situ production projects.
2. Treatment of refining is a difficulty in public-domain studies such as GREET and GHGenius, due to a lack of access to proprietary refinery models. These refinery emissions will be specific to the region of refining and the type of crude oil refined. Addressing the wide range between JEC emissions estimates and other process model emissions estimates for refining should be a priority.
3. The interaction of markets with LCA results (addressed in “consequential” LCA) is not studied in any model results. For example, coking of bitumen at a remote Alberta upgrader and coking of bitumen at a more centrally-located refinery should, in theory, have roughly equivalent emissions profiles. However, because of the lack of nearby markets for residual coke produced at remote Alberta upgraders, the produced carbon is currently stockpiled in large quantities. A shift to shipment of diluted bitumen could cause coke generation to occur at existing refineries. This would result in carbon in coke being produced closer to other markets and infrastructure by which it would be consumed rather than stockpiled (note that refineries currently do not stockpile coke). Thus, the *total* impacts (the full system consequences) from the two systems might differ, even though the engineering processes might be very similar. A similar issue was raised above with regard to the emissions impacts of reducing the amount of residual fuels produced at refineries.

9 Appendix A: Numerical results of comparison of WTW GHG studies

The numerical results used to derive Figures 10 and 9 are shown in Table 8. The source of each reference value is given in Table 9.

For consistency with previous works, results from Charpentier *et al.* are used for GH-Genius and GREET figures.

Table 8: Well-to-tank results from included studies. **These results have not been standardized for EU market conditions.** All results adjusted to gCO₂ eq./MJ of refined fuel delivered, LHV basis. Cases list which pathway is modified for inclusion as “low” (L) “most likely” (M) and “high” (H) in Table 6 above. Methods described in Table 9.

Mining and upgrading		Extraction	Upgrading	Transport	VFF	Refining	Distribution	Case
GHGenius		19.0	0.0	0.3	2.0	13.0	0.9	M
GREET		15.9	0.0	0.0	0.0	14.5	0.0	-
Jacobs - Mine + cracking		7.3	8.6	1.1	0.0	12.6	0.4	L
TIAX - Mine + sell coke		10.1	0.0	1.2	0.5	12.4	0.0	-
TIAX - Mine + bury coke		12.4	0.0	1.2	0.5	12.4	0.0	-
In situ and upgrading		Extraction	Upgrading	Transport	VFF	Refining	Distribution	Case
GHGenius		29.0	0.0	0.3	0.9	14.0	0.9	M
GREET		19.1	0.0	0.0	0.0	14.5	0.0	-
Jacobs - In situ + cracker		14.2	8.6	1.1	0.0	12.6	0.4	-
Jacobs - In situ + hydrotreating		12.6	11.6	1.2	0.0	13.4	0.4	-
TIAX - Residue fuel		37.3	0.0	1.2	3.3	10.1	0.0	H
TIAX - NG fuel		23.4	0.0	1.2	3.3	10.1	0.0	-
In situ without upgrading		Extraction	Upgrading	Transport	VFF	Refining	Distribution	Case
Jacobs - Mine + crack		11.8	0.0	0.3	0.6	26.4	0.9	-
TIAX - Mine + sell coke		15.8	0.0	0.0	0.0	14.5	0.0	-
Jacobs - SAGD to bitumen		13.8	0.0	1.2	0.0	17.2	0.4	-
TIAX - Bitumen SAGD 1		6.7	0.0	1.2	3.3	21.5	0.0	-
TIAX - Bitumen SAGD 2		10.7	0.0	1.2	3.3	21.5	0.0	-
Mixed		Extraction	Upgrading	Transport	VFF	Refining	Distribution	Case
NETL - Mixture of SCO and dilbit		21.5	0.0	1.0	0.0	12.1	1.0	-

Table 9: Notes on included studies conversion to equivalent GHG emissions values.

Report	Source	Notes
GHGenius	Charpentier <i>et al.</i> [15, Supporting information, Table S2]	Converted from gCO ₂ eq. per km to gCO ₂ eq. per MJ using GHGenius vehicle efficiency of 9.556 l/100 km and GHGenius conversion between HHV and LHV (Sheet "E"). This is done to remain consistent with Charpentier methodology, which is based on conversion from MJ to km using GHGenius fuel energy densities and vehicle efficiencies. Charpentier figures are based on GHGenius v. 3.13. The figures for GHGenius in Charpentier paper are calculated as follows (pers. communication, A. Charpentier, October 2010): Total emissions are equal to sheet "Lifecycle Results" C17 less co-product emissions credits (C16). On "Input" sheet the following changes are made: region is changed to Canada West (G3), Input on D5 is changed to 100% Canada West. Crude oil input is changed to 100% SCO (F65). For mining, Charpentier assumed 100% integrated operation, 0% mine to upgrader (sheet "S" AH-AI 6). For SAGD, assumed bitumen to upgrading ("S" AH6), assume 50% SAGD, 50% CCS ("S" Z-AA 4).
GREET	Charpentier <i>et al.</i> [15, Supporting information, Table S2]	Converted from gCO ₂ eq. per km to gCO ₂ eq. per MJ using GHGenius vehicle efficiency of 9.556 l/100 km and GHGenius conversion between HHV and LHV (Sheet "E"). This is done to remain consistent with Charpentier methodology, which is based on conversion from MJ to km using GHGenius fuel energy densities and vehicle efficiencies.
Jacobs	Keesom <i>et al.</i> [26]	Values from Table 8.7 for all oil sands processes.
TIAX	Rosenfeld <i>et al.</i> [19]	Values from Tables 6.3, 6.4, and 6.5. Where applicable, results for delivery to PADD 2 are used.
CERA	CERA [46]	Because figures are reported in kgCO ₂ eq. per barrel of refined product, achieving directly comparable results with other studies is difficult. Refinery yield (e.g., MJ of refinery output per MJ of refinery inputs) is not specified, so data are not plotted.
NETL	Gerdes <i>et al.</i> [45] and Skone <i>et al.</i> [34]	Data from Gerdes <i>et al.</i> [45] are derived from earlier, more comprehensive report by Skone <i>et al.</i> [34]. Value for oil sands is taken from data on Imperial Oil - Cold Lake project (crude bitumen) and for SCO from Syncrude [34, Table 2.5]. The value used is a mixture of these two emissions intensities, and the breakdown in emissions by product stage (extraction, transport, upgrading) is not reported, making comparison difficult. For this reason, values from NETL are not plotted in main results figures
All studies	-	TTW emissions a neglected because they are outside the boundaries of this study. TTW emissions vary slightly between studies.

Table 10: Fuel mix for selected studies (in fraction of total fuel inputs). Not all studies reported fuel mixes.

	Mine and upgrade							Industry average ^e		
	GREET ^a		GHGenius ^b			Jacobs ^c			TIAx ^d	
	Mine	Upgr.	Mine	Upgr.	Int. mine & upgr.	Industry ave. SCO	Upgr.-Coker			Upgr. - Eb-bed
Diesel fuel	0.01	0.00	0.16	0.00	0.05	0.04	0.00	0.00	0.05	0.00
Natural gas	0.82	0.97	0.82	0.28	0.21	0.44	0.51	0.62	0.42	0.44
Electricity	0.17	0.03	0.02	0.08	0.01	0.03	0.00	0.00	0.02	0.05
Pet. coke	0.00	0.00	0.00	0.15	0.27	0.16	0.00	0.00	0.0	0.13
Refinery still gas	0.00	0.00	0.00	0.49	0.45	0.33	0.49	0.38	0.51	0.40

^a - Values from GREET model 1.8d, worksheet "Petroleum", Columns FH 40-51.

^b - Values from GHGenius model 3.18, worksheet "S". Values for mining, SAGD, etc.

^c - Values from Jacobs report, Table 4-6 [26]. Jacobs do not report fuel mix for mining, and therefore lack diesel consumption. Jacobs report assumes electricity needed for process is generated onsite so no net electricity imports.

^d - Values from TIAX report, Figure 3-12, for CNRL Horizon project [26].

^e - Values from ERCB, reported by project [11]. Natural gas is natural gas purchased less that exported. Electricity is "plant use" category. No power export is included. Process gas is process gas used for "further processing" (e.g., hydrogen generation), "fuel/plant use" and "flared/wasted". Coke is "fuel/plant use", with no inclusion coke stockpiled (represented in ERCB figures as differences in opening and closing inventory. ERCB data do not include diesel consumption, so diesel used in haul trucks is not included.

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