

# 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 kbbl/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 aim to 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 and greenhouse gas emissions. Next, it compares a variety of recent LCA estimates of GHG emissions from oil sands, and outlines reasons for variation between estimates. Lastly, it chooses representative results from existing LCA models to outline low, high and “most likely” estimates of GHG emissions from oil sands. The representative “most likely” result is meant to provide an estimate of industry-average emissions for the crude oil sands-derived product assumed to be supplied to EU refineries. Using these results from previous LCA studies, comparison is made between these emissions to those of conventional fuels currently being supplied to the EU.

Methodologically, this report makes no changes or modifications to existing model assumptions, but simply compares their fitness for use in generating industry-average most likely emissions estimates. Recommended areas for future research and model improvement are suggested in the conclusion to the report, given what was learned in reviewing current models. This report focuses on the European context, and therefore uses standard EU-specific emissions factors across all models for transport refining, and distribution of fuels. These standardized factors are used across pathways and were developed with as a result of stakeholder consultation conducted by the European Commission. Also, this report focuses near-term (1-4 years) operations, with only an occasional discussion of emissions from future operations. This is because future operations and technologies are uncertain and their assessment is currently speculative.

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 consumed during oil sands extraction and upgrading between studies.
4. Significant differences in the operational parameters between projects of a given type (e.g., variation in steam injection rates in steam-assisted gravity drainage in situ projects).
5. Other operational differences between projects.
6. Treatment of non-combustion emissions sources, such as venting, flaring and fugitive emissions.

7. Treatment of ecological emissions sources, such as land-use change (LUC) associated emissions.

The importance of these differences in quantifying emissions variation is discussed in some detail, although without access to original model calculations it is difficult to determine all reasons for divergence in emissions estimates.

Resulting low, high and most likely emissions estimates for Canadian oil sands derived fuels are shown in Figure 1. Low emissions estimate is from natural-gas fired integrated mining & upgrading processes, while high emissions estimate is 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 the 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 default emissions factors that distinguish between oil sands and conventional oil processes.

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

1. Treatment of electricity cogeneration is variable across studies, and is uncertain due to a lack of data on amounts of co-produced power in in-situ production operations, and uncertainty in allocating emissions given co-production of electricity exports.
2. Detailed treatment of refining is lacking in public domain models, due to lack of access to proprietary refining models.
3. Market considerations are lacking, which may have important effects on co-product and by-product disposition, including the fate of produced coke.

In addition, there is significant sensitivity to the treatment of oil sands as a “separate” crude oil resource in fuel quality regulations. The results of this report (and other work ongoing in the service of fuel carbon intensity regulations) suggest that subsequent, more

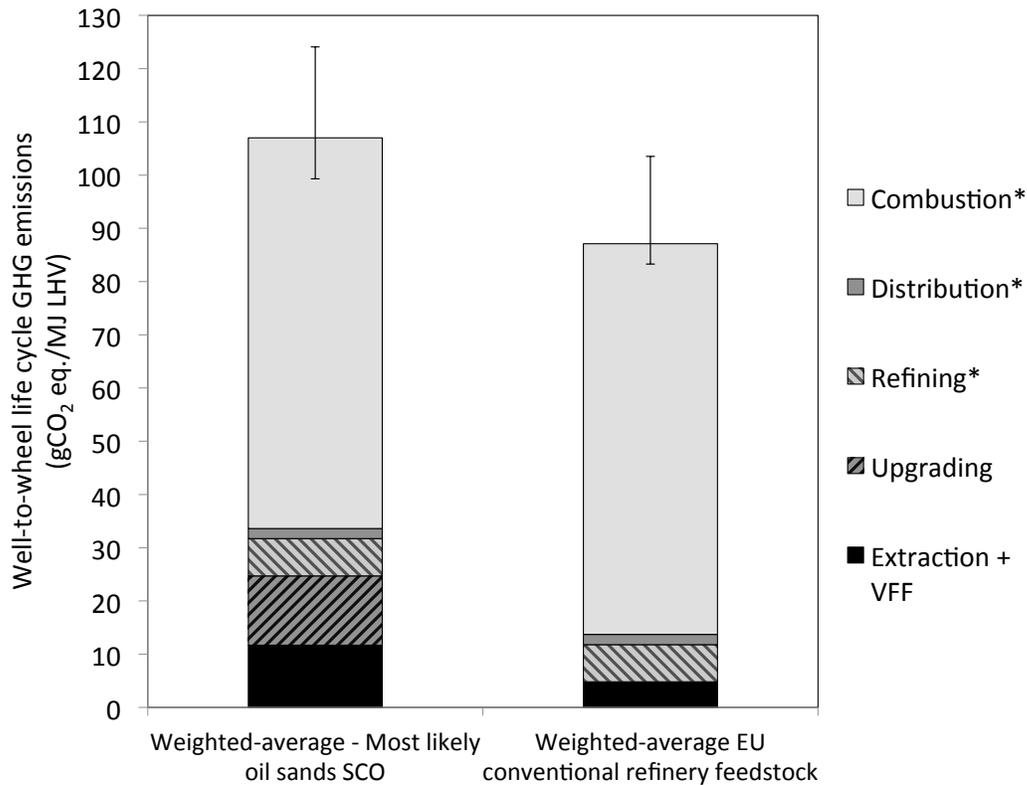


Figure 1: Oil sands emissions compared to conventional EU refinery feedstock emissions. Most likely estimates are base values of bars, low and high ranges are represented by error bars. See report text for calculation details.

detailed process-specific modeling of fuel GHG emissions may be of use in future regulations. Nevertheless, the “most likely” values generated in this report yield default values that represent best-available current scientific knowledge of the impacts of oil sands derived fuels.

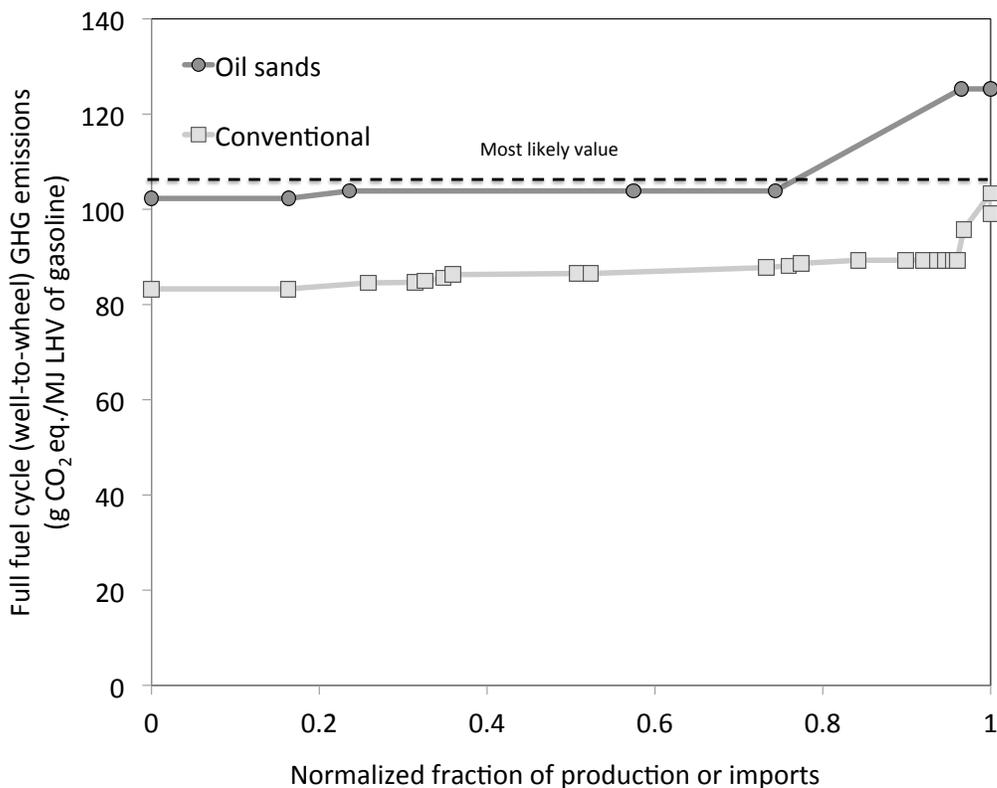


Figure 2: Emissions as a function of cumulative normalized output, for oil sands projects (low and high estimates) and conventional oil imports to the EU. Only oil sands projects that produce refinery ready SCO are included as these full-fuel-cycle estimates utilize pre-calculated emissions estimates for EU refineries processing approximately 30 °API oil. Bounds on oil sands emissions are provided by (low) Jacobs model of mining & cracking pathway, (high) TIAX model of OPTI-Nexen, Long Lake SAGD + Residue gasification to SCO. The middle cases are given by GHGenius mining & upgrading pathway. 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.

This report was reviewed by a panel of technical experts in life cycle assessment:

- W. Keesom, Jacobs Consultancy;
- S. Unnasch, Life Cycle Associates LLC.;
- D. O'Connor, S&T<sup>2</sup> Consultants Inc.;
- J. Bergerson and Life Cycle Assessment of Oil Sands research team, University of Calgary and University of Toronto;
- R. Plevin, Transportation Sustainability Research Center, University of California Berkeley;
- G. Howarth, Energy-Redefined LLC.;
- W. Weindorf and Z. Mátra, Ludwig-Bolkow-Systemtechnik GmbH.

Reviewer comments were addressed comprehensively to the extent that they were within the study scope.

## 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 aim to 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 CO<sub>2</sub> injection) [1]. Global EOR production is less certain due to poor data availability, but exceeds 1200 kbbbl/d [1]. Thermal production of oil occurs globally, and is not limited to Canadian heavy oil resources, with production centers occurring in California, Indonesia, Oman, Canada, China, and other oil producing regions.

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  $\approx 600$  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 operation, 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.

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**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  $\approx 5$ -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 feedstock 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 wellbore 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 slurring 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].<sup>1</sup>

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].

<sup>1</sup>Given 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.

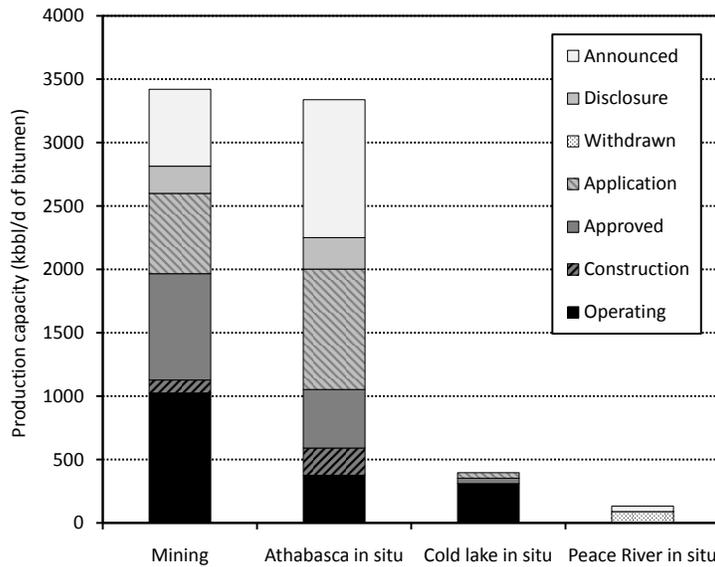


Figure 3: Oil sands production capacity, operational and proposed projects, by stage of completion (current as of January, 2010) [3].

### 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 (year-long average of instantaneous SOR, 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

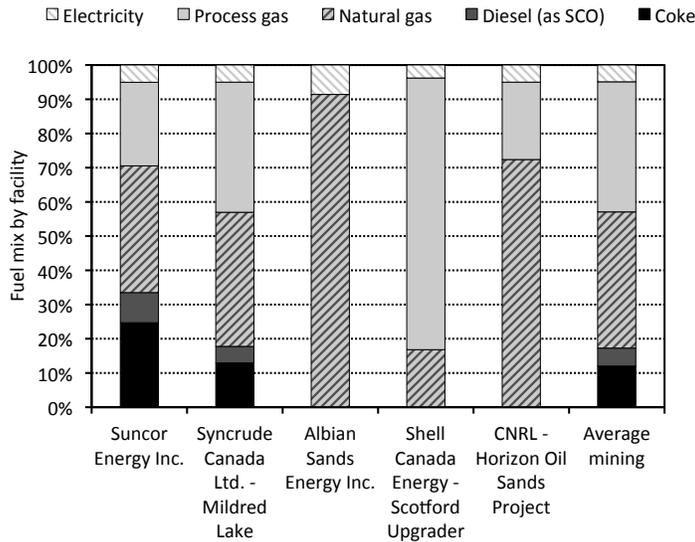


Figure 4: Mining and upgrading fuel mixes for integrated (Suncor and Syncrude) and stand-alone mining and upgrading operations. Compiled from volumetric [ $\text{m}^3$ ] and mass [tonne] consumption rates by project as reported by ERCB [11]. ERCB does not report direct diesel consumption for haul trucks, but self-consumed SCO is included as assumed haul-truck fuel diesel. Avg. mine & upgrade represents summed consumption across all projects in ERCB ST-39 dataset except Opti-Nexen, which is an integrated in situ operation.

partially offset by declining resource quality over time).

A significant portion of the variability in emissions between in situ production operations will be due to variation in the steam-oil ratio. For example, a doubling of the steam oil ratio from 2.5 to 5 would approximately double upstream (extraction) GHG emissions due to a doubling of steam requirements and an approximate doubling of pumping energy requirements (if all else is held equal). Thus, variability in emissions between different in situ projects is likely to be larger than the average variability between in situ and mining-based project emissions. Also, given the SOR variability across project life, the incremental emissions per  $\text{m}^3$  of bitumen produced are largest at the initial production stage (during heat buildup) and lower in later time periods. For this reason, using the cumulative SOR over the project life (cSOR) will provide the best metric of the emissions over the entire project life (although such analysis can only be performed retrospectively). Also, for this reason, the choice of projects for analysis will result in significantly different results depending on whether the project is in the early stages of its life cycle or the late stages. Nevertheless, the current industry-average SOR serves as a useful overall assessment because many of these factors are evened-out between different projects.

Accounting for the above uncertainties, steam generation energy consumption for an SOR range of 2.5 to 5 ranges from  $\approx 950$  to  $2100$  MJ/bbl of bitumen produced, assuming

steam generation equipment similar to California thermal EOR projects.<sup>2</sup> 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  $\approx 540$  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, 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].

Because the emissions from thermal production projects are so closely tied to SORs, future analyses should pay close attention to operating SORs for projects, and regulatory frameworks should account for variation in project emissions with varying SOR (variation occurs in a predictable manner and therefore can be modeled with reasonable complexity).

### 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.

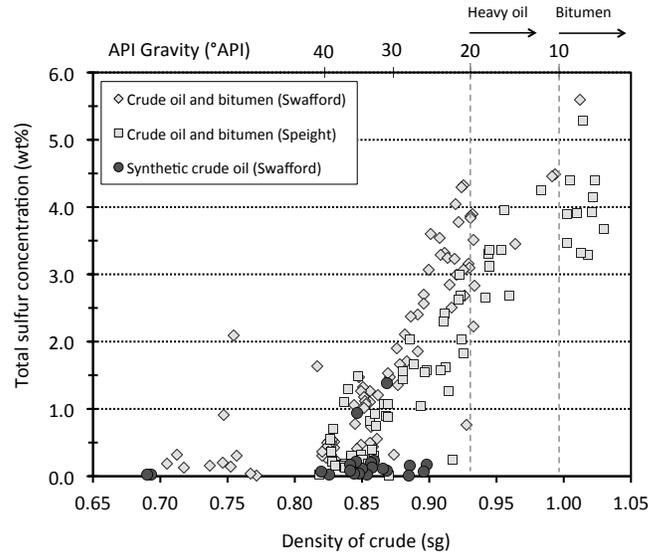
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<sup>2</sup>Calculation method follows that of Brandt and Unnasch [7]. This low and high range assumes enthalpy of steam of 325 and 337.5 MJ/bbl, once-through steam generator with 85% and 80% efficient steam generation, LHV basis, and SORs of 2.5 and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

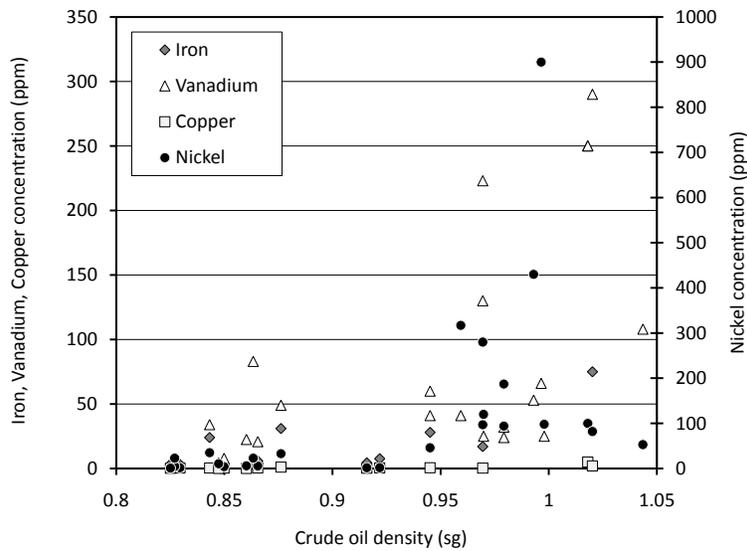
Table 1: Steam oil ratios (SORs) for thermal in situ bitumen production (ERCB 2010 data). All data are yearly averages of monthly data [20].

Operator	Project	Bitumen prod. m <sup>3</sup> /d	Water inject. m <sup>3</sup> /d	SOR m <sup>3</sup> water/m <sup>3</sup> oil
North Peace Energy Corp.	Red Earth	11.8	142.9	12.08
Shell Canada Ltd.	Peace River	982.0	4165.9	4.24
Imperial Oil Resources	Cold Lake	22471.6	78538.6	3.49
Canadian Natural Resources Ltd.	Primrose and Wolf Lake	9827.3	58889.0	5.99
Devon Canada Corporation	Jackfish 1	3547.1	8593.8	2.42
Shell Canada Energy	Orion	433.0	2782.0	6.42
Meg Energy Corp.	Christina Lake	402.5	1176.6	2.92
Great Divide Oil Corporation	Great Divide	1006.7	3735.5	3.7
Meg Energy Corp.	Christina Lake	437.2	2300.9	5.26
Cenovus FCCL Ltd.	Christina Lake	2115.0	4460.3	2.10
EnCana Corporation	Foster Creek	12049.4	30058.3	2.49
Suncor Energy Inc.	Mackay River	4665.9	11765.4	2.52
Japan Canada Oil Sands Ltd.	Hangingstone	1170.5	4728.2	4.03
Suncor Energy Inc.	Firebag	7755.7	24300.8	3.13
Cenovus FCCL Ltd.		3.0	45.5	15.27
Total E&P Joslyn Ltd.	Joslyn Creek	359.4	690.6	1.92
ConocoPhillips Canada Resources Corp.	Surmont	2323.4	6532.9	2.81
ConocoPhillips Canada Ltd.	Surmont Pilot	93.9	319.9	3.40
Nexen Inc.	Long Lake	1976.0	10550.0	5.33
Husky Oil Operations Ltd.	Tucker Lake	615.0	4470.3	7.26
<b>Total thermal in situ</b>		<b>72246.3</b>	<b>258247.1</b>	<b>3.57</b>

*a* - Total values include summed bitumen production and steam injection for all projects in ERCB databases labeled "Commercial-CSS", "Commercial-SAGD" Pilot and experimental projects excluded, as are projects labeled "Primary" are not included due to the fact that these represent non-thermal primary production of heavy crude oils (i.e., cold production).



(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 for conventional crude oil and raw bitumen. Data plotted from Speight.

Figure 5: Crude oil contaminants increase as a function of crude density, necessitating intensive refining. Data sources include [21, Ch. 8, tables 3, 4] [21, Ch. 7, tables 2, 3, and 19] [22].

Table 2: Bitumen and conventional oil properties [23, table 1], [24].

	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

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 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 [25]. 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,

Table 3: Characteristics of bitumen-derived SCO products. Source: Batch Quality Reports, [www.crudemonitor.ca](http://www.crudemonitor.ca) [28]. Most recent assay is used for each crude stream, long-term averages used for metals content.

	API	Density	Sulfur	Metals
	°API	kg/m <sup>3</sup>	wt%	(Fe+Ni+V+Mo) mg/l
Premium Albian 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

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 H<sub>2</sub>, 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 contain the majority of the contaminants—are hydrotreated (i.e., treated through the addition of H<sub>2</sub> 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 [26]. 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.

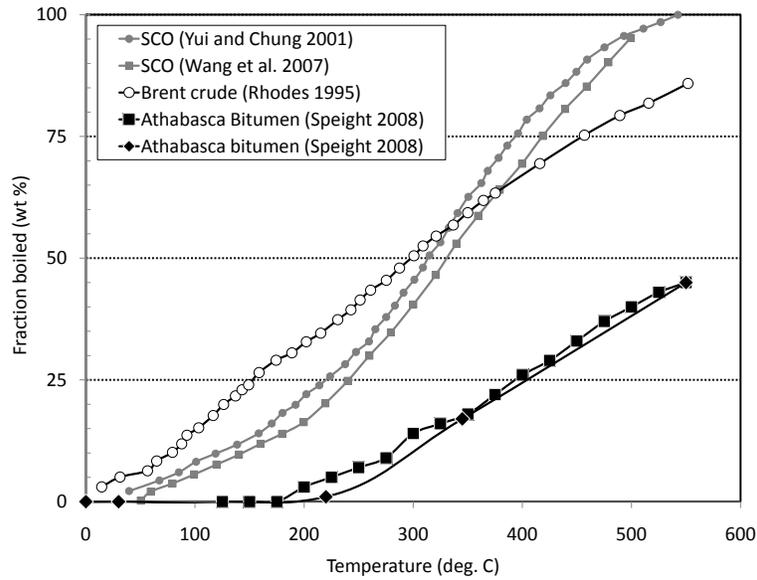
Hydrogen consumption by hydrotreaters is significantly often in excess of 3 times the stoichiometric requirement for heteroatom removal, due to simultaneous hydrogenation of unsaturated hydrocarbons [26, p. 295]. Hydrogen consumed in secondary upgrading is generally produced via steam methane reformation 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 H<sub>2</sub> production. Consumption of H<sub>2</sub> in upgrading processes ranges from 200-500 MJ/bbl of bitumen upgraded [27, 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].

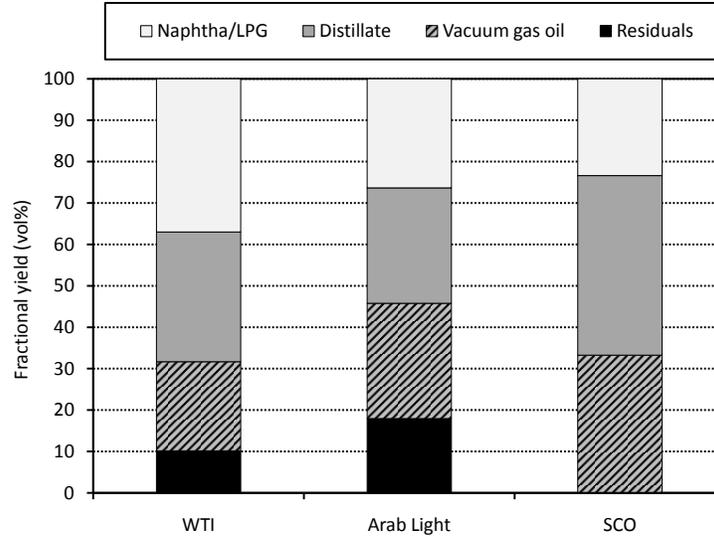
### 3.3 SCO and bitumen refining

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 asphaltenes content.

Many SCOs produced are high-value, low-density, low-contaminant products, although some heavy synthetic streams are also produced (see Table 3). Figure 5(a) shows that for a given density, SCOs (dark markers) have low sulfur content compared to conventional crude oils of similar density. High-quality 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 a high-quality SCO [29].



(a) Distillation curves for Athabasca bitumen, Brent crude marker, and Athabasca bitumen SCO. Two Athabasca bitumen curves are due to different reported data from the same source.



(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] [30] [31] [24].

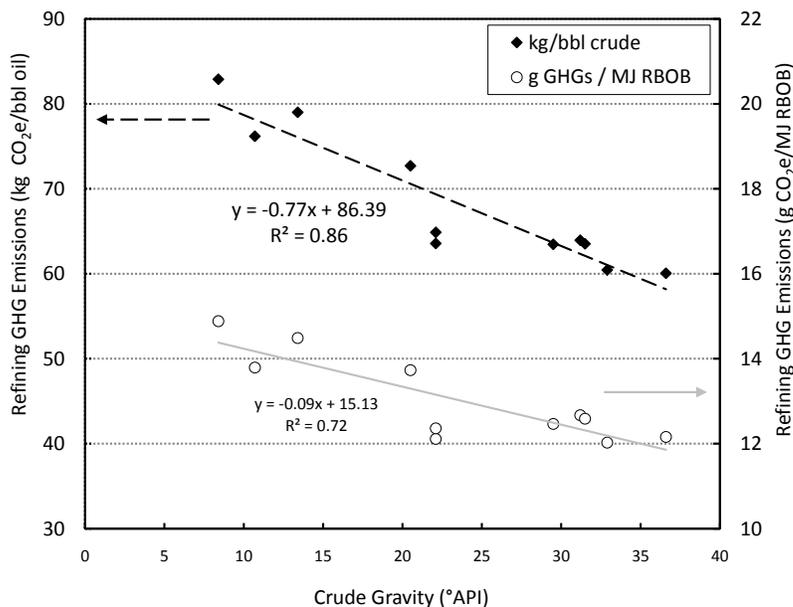


Figure 7: Fit of modeled GHG emissions to API gravity, from 11 crude streams modeled by Keesom *et al.* [7, 27]. Emissions on right axis per unit of reformulated blendstock for oxygenate blending (RBOB, i.e., raw gasoline before final blending).

Most LCA studies to date treat the refining of crude inputs (SCO and bitumen) in a very simple fashion [32, 33]. This is partly due to the absence of publicly-available models of refinery operations, and due to the fact that numerous 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 of refining 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 [27]. Similar work was undertaken by Rosenfeld *et al.* [19]. The most detailed macro-scale statistical assessment of refining emissions was recently published by Karras [34]. The work of Karras allows a broad understanding of the role of hydrocarbon density and sulfur on GHG emissions, and is adopted in modified form by the current version of GHGenius [35].

Emissions from refining of oil sands products (e.g. different SCO streams) 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 gCO<sub>2</sub> 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 H<sub>2</sub>S stream removed from the feedstock crude, due to saturation of unsatu-

rated hydrocarbons (e.g., olefins, aromatics) [36, 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 H<sub>2</sub> are consumed for every mole of H<sub>2</sub>S formed, and H<sub>2</sub> is produced in a steam methane reformer, CO<sub>2</sub> emissions will increase by  $\approx 1.4$  kg CO<sub>2</sub> per kg S removed [37].

It should be noted that this linear relationship between crude density and emissions seen in Figure 7 is only approximate and will vary with crude quality, sulfur content, refinery configuration, refinery product slate, and regional differences in refinery regulation and fuel specifications. Accurate process-specific refinery emissions modeling for a given crude oil stream requires detailed refinery models with proprietary refinery configuration data.

Also, allocating emissions from refining to the individual refinery products produced in the refinery is a problem with a necessarily subjective element: allocations of impacts to products by mass, energy content, and economic value have been explored, and it is generally considered a matter of analyst judgement as to which result is most appropriate [38]. The resulting emissions differences between allocation methods are small to moderate in size (generally on order 10-20% of overall refining emissions) [38, Fig. 3].

For the purposes of this study, one refining GHG intensity was used, representing the industry average European refining intensity of refining the current slate of crude oils. The above factors affecting refining intensity will therefore not affect this standard value (which was adopted as a policy choice by regulators and stakeholders who favored a single refining value for regulatory simplicity).

### 3.4 Secondary process emissions

Other process emissions include emissions from venting, flaring, and fugitive emissions (hereafter VFF), 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.* [40] 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 gCO<sub>2</sub>/MJ and a representative value of 2.3 g CO<sub>2</sub>/MJ.<sup>3</sup>

Global venting and flaring emissions are of some significant uncertainty [41]. This is due to a number of reasons, including lack of monitoring of venting and flaring emissions and uncertainty about the completeness of combustion in flaring systems. Alberta has comprehensive flaring and venting regulations, which provide insight not provided into operations in other regions.

### 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 [40]. These emissions are somewhat smaller than venting and fugitive emissions, with values ranging from 1.0-2.3 g CO<sub>2</sub>/MJ of bitumen produced (representative value 1.4 g CO<sub>2</sub>/MJ) for mining operations. In a case

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

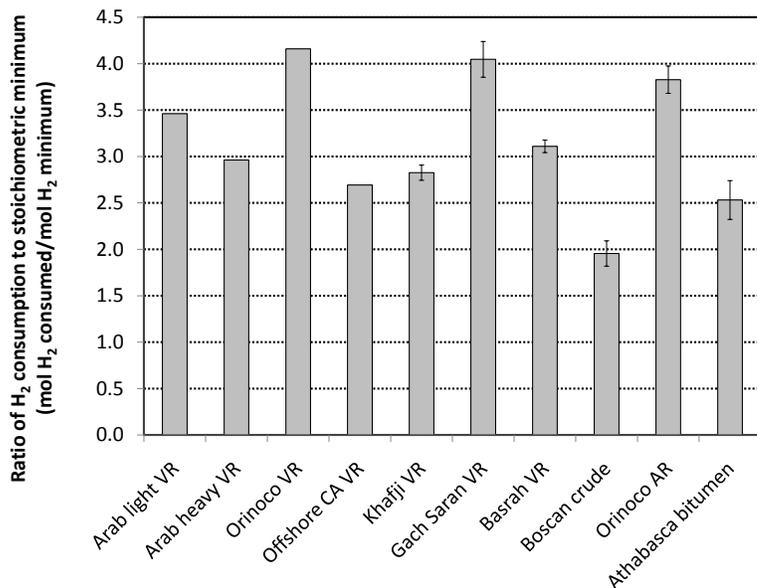


Figure 8: Observed hydrogen consumption compared to minimum hydrogen consumption for sulfur removal for a variety of crude residues and heavy crude oils. VR = vacuum residue, or residue from distillation under vacuum, AR = atmospheric residue, or residue from distillation at atmospheric pressure. Data from Speight [39, Tables 6-18, 6-19, 6-20, 6-21].

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 [40]. In situ operations were found to have negligible land use emissions,  $\approx 0.1$  gCO<sub>2</sub> 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 [43, 44, 27]. Over time, LCA studies have improved in quality and quantity of documen-

Table 4: Venting, flaring, and fugitive (VFF) emissions from mining and in situ production. Units: gCO<sub>2</sub> eq./MJ bitumen production, LHV basis. Data are industry averages from [42].

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

tation, although gaps remain in the realm of publicly-available models (see discussion below). No European-specific LCA studies of oil sands have been generated, due to historical lack of oil sands imports to the EU. This results in our review focusing on North American LCA studies, augmented with EU-specific refinery figures, as noted 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 [45]. Most recently documented in *Summary of Expansions and Revisions in GREET1.8d Version* [33], and also documented in [24, 46, 47, 48].

**GHGenius** The GHGenius model v. 3.18. (S&T)<sup>2</sup> Consultants for Natural Resources Canada [49]. 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 [27].

**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 [50]. 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 [37].

**CERA** IHS-CERA (2010). *Oil sands, greenhouse gases, and US oil supply: Getting the numbers right*. Cambridge, MA, Cambridge Energy Research Associates [51].

A comprehensive comparison of oil sands GHG studies (including references [52, 9, 49, 45, 53, 25]) was produced by Charpentier *et al.* [15]. Other useful reviews are provided by Mui *et al.* [54, 55]. 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 [56].

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.<sup>4</sup>

<sup>4</sup>Small divergence between studies in TTW emissions does occur. For example, GHGenius TTW emissions

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 kgCO<sub>2</sub> per bbl of refined product produced, and are therefore not comparable with other studies without making significant assumptions.<sup>5</sup>

Figure 9 shows emissions estimates for mining-based processes with upgrading to SCO. There is significant divergence between reviewed estimates. 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.

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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 CO<sub>2</sub> by calculating the mass-equivalent conversion of CO to CO<sub>2</sub>. 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.

<sup>5</sup>See Appendix A for further discussion of this issue.

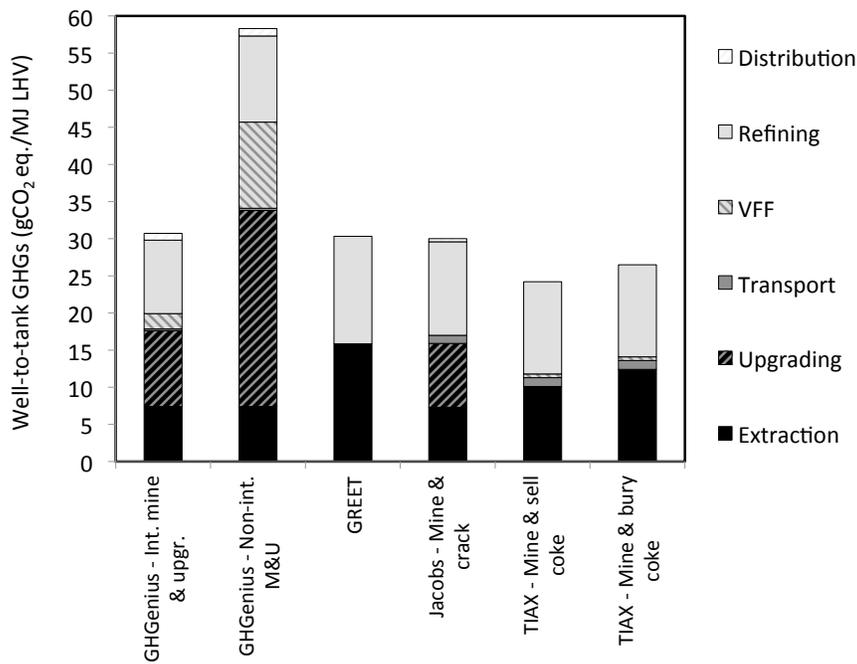


Figure 9: Mining & upgrading emissions estimates. Emissions estimates from included studies [45, 35, 19, 27, 50]. All results converted to units of gCO<sub>2</sub> eq./MJ of refined fuel produced, reformulated gasoline, LHV basis.

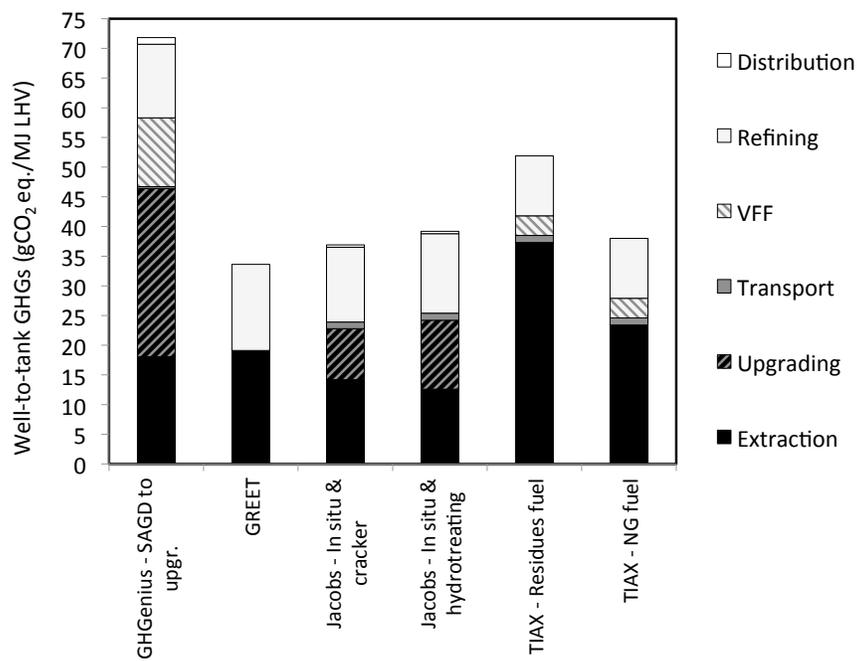


Figure 10: In situ & upgrading emissions estimates. Emissions estimates from included studies [45, 19, 27, 50]. All results converted to units of  $\text{gCO}_2 \text{ eq./MJ}$  of refined fuel produced, reformulated gasoline, LHV basis.

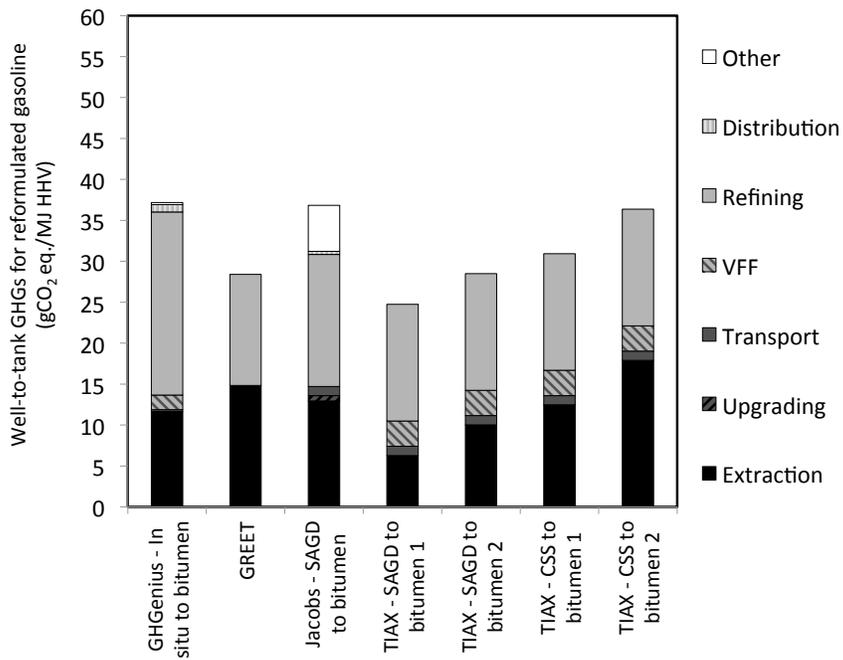


Figure 11: In situ & production of diluted bitumen emissions estimates. Emissions estimates from included studies [45, 35, 19, 27, 50]. All results converted to units of  $\text{gCO}_2 \text{ eq./MJ}$  of refined fuel produced, reformulated gasoline, LHV basis. These results are not included in our most-likely estimate as diluted bitumen is not included in our study.

## 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 [56, p. 232]. This low diesel use (compare with range noted above of  $\approx 50$ -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, 25]. Additionally, despite the fact that GREET figures are based on ACR fuel use data, GREET emissions are 15.9 gCO<sub>2</sub>/MJ refined fuel delivered, while ACR emissions results range from  $\approx 19$ -22 gCO<sub>2</sub>/MJ.<sup>6</sup> This is likely due to the omission of coke combustion in the GREET model.<sup>7</sup> 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** A variety of fuel sources are assumed in the integrated mining and upgrading case for GHGenius version 3.20, as shown in Sheet “S”. Somewhat less than 15%

<sup>6</sup>These figures are only approximate comparisons, because ACR data are measured in kgCO<sub>2</sub>/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.

<sup>7</sup>One 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.

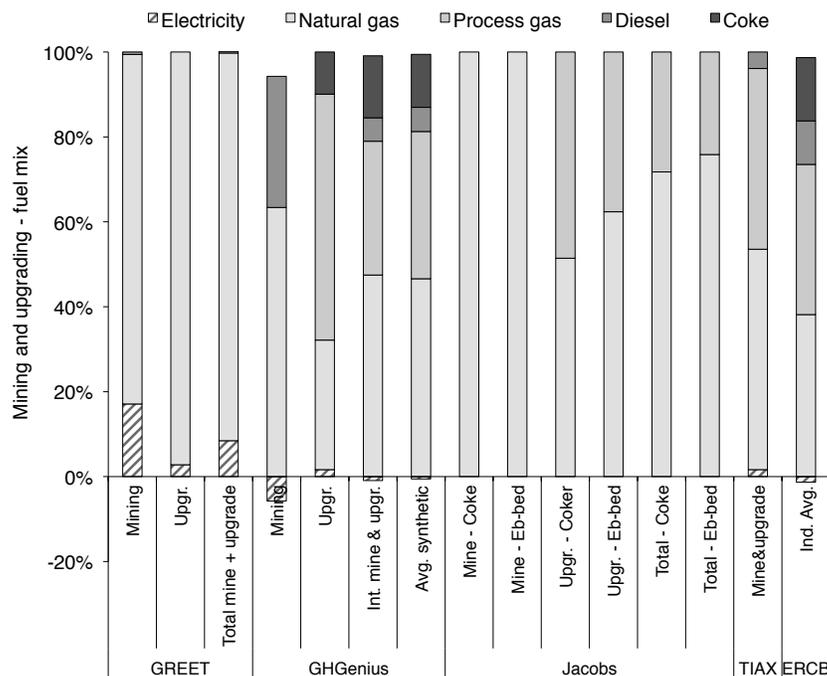


Figure 12: Fuel mix for mining and upgrading assumed by different models and industry average fuel mix. Fuel mix assumptions calculated from model inputs as described in text. Industry average fuel mix calculated from fuel consumption rates reported by ERCB for 2010 all mining and upgrading operations [20].

of the primary energy for integrated mining/upgrading operations being provided by coke, while less is assumed for non-integrated mining and upgrading [35, Sheet “S”]. The overall weighted fuel mix in GHGenius for mining and upgrading to SCO assumes 13% of energy content from coke. Of the studied models, the GHGenius fuel mix 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 [27, 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 consumes 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 [37, p. 12], as reported in Environment Canada facilities emission database [57]. 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, 25]. 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 [25]. Others believe that unconventional gas resources (such as shale gas) 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. This topic is discussed further below.

## 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 [56, 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, 58]. 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.<sup>8</sup>

<sup>8</sup>Source: 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).

**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) [27, 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 [27, 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 [27, 59], 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 [37, p. 12], as reported in Environment Canada facilities emission database [57]. 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.

### 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  $\approx 520$  MJ natural gas/bbl SCO produced [56, 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  $\approx 990$  MJ/bbl SCO [49, 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 [58, Table 6-5]

**Jacobs** Consumption is  $\approx 820$  MJ/bbl SCO for coking, and 1050 MJ/bbl SCO for Eb-bed. Fuel mix includes both natural gas and process gas<sup>9</sup>, 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 [50, 37]. 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

Because only one refining GHG intensity is used to represent the notional EU refinery, the drivers of GHG emissions from refining do not affect the results below. However, it is useful to discuss these emissions drivers from an informational perspective.

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).

**GREET** Model calculates refinery emissions from processing oil-sands-derived streams as equivalent to processing conventional crude oil streams [56, p. 231] [45, sheet "Petroleum", column O]. This assumption will not result in significant errors, because GREET assumes mined and in situ bitumen are upgraded to SCO [45, 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** GHGenius refining emissions estimates were updated in April 2011 with a significant modification [35, 60]. This update removed an older quadratic formulation<sup>10</sup> and has replaced it with a linear relationship between crude specific gravity

<sup>9</sup>Fuel 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 [27].

<sup>10</sup>In this older formulation the emissions depended on the square of specific gravity and sulfur content, based on data from MAPLE-C, a Canadian energy modeling effort with a petroleum market module [58].

Table 5: Bitumen and synthetic crude oil properties by study<sup>a</sup>

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

*a* - No information is given on SCO quality in GREET or in Larson *et al.* [56]. Information on SCO and bitumen qualities is lacking in the NETL study, which cites API gravity of “20-33 °API” [50, 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  $\approx 8$  for raw bitumen).

and sulfur content and refining emissions. This relationship is derived from recently published work by Karras [34] and Keesom *et al.* [27], with coefficients largely determined using results from Karras’ statistical study of refinery emissions from US refineries as a function of quality of crude oil inputs. Possible shortcomings with this model include the relatively small range of crude quality variation present in the study (due to results generated at the PADD region level, with many refinery streams aggregated) [35].

**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 [27, e.g., Table 5-3, 5-4]. Detailed utilities consumption is presented for Arab Medium crude, but not for oil-sands-derived streams [27, 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 gCO<sub>2</sub> eq./MJ for diluted bitumen vs. 10.1-12.4 gCO<sub>2</sub> 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.* [50] is outlined in detail in Skone *et al.* [37]. 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.* [32], 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 [37]. 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 [50, 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.

One 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 CO<sub>2</sub> 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 more below, although they are not addressed in the study results because they are beyond the scope of this analysis.

## 5.5 Venting, flaring, and fugitive emissions

Emissions from venting, fugitive emissions and flaring (VFF) are unevenly addressed in the above studies. This is an area requiring significant additional research.

**GREET** GREET does not include non-combustion (e.g., VFF) emissions from bitumen extraction or upgrading [45, sheet "Petroleum", columns G,J]. GHGenius does include venting and flaring emissions [61].

**GHGenius** GHGenius version 3.20 contains significant updates to venting, flaring, and fugitive emissions, which significantly increases fugitive emissions for in situ production (CSS, SGAD, primary) compared to earlier versions of the model (as seen above in Figures 9 and 10. The model adopts reported emissions from oil sands operations as collected by ERCB datasets (ERCB dataset ST-60). These emissions amount in baseline year (2000) to some 37 m<sup>3</sup> per m<sup>3</sup> of bitumen produced, which are controlled over time to significantly lower values using control factors.

**Jacobs** Jacobs does not include VFF emissions from oil sands production (all oil sands and thermal EOR pathways assigned VFF emissions of 0) [27, Table 8.7]. It is not known if these emissions sources are included in aggregate extraction emissions.

**TIAX** TIAX includes VFF emissions, of 0.5 to 3.3 gCO<sub>2</sub>eq./MJ [19, Table 6.3]. These emissions are from regulatory documents related to the Horizon oil sands mine.

**NETL** NETL does include venting and flaring generally [50, 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.

**CERA** CERA does not explicitly report VFF emissions [51, Table A-8] and it is unclear if VFF emissions are included in extraction or processing stages.

## 5.6 Land-use change associated emissions

Land use emissions are only explicitly considered in the GHGenius model (as near as the author could ascertain) GHGenius 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) [49, 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 [45].

**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 [49, 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 [51, 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 of 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) [27, 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) [37, 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) [51, 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 [51, 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 [62, 63]. For our below calculated values, estimated values for the following process stages are replaced with EU-specific default values:

- Refining and processing: 7.0 gCO<sub>2</sub> eq./MJ
- Transport and distribution: 1.91 gCO<sub>2</sub> eq./MJ
- Combustion: 73.38 gCO<sub>2</sub> 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.

It should be noted that JEC study results for refining are marginal rather than average GHG emissions values for producing an additional unit of transportation fuel [64, p. 59]. They represent an average of EU simple and complex refinery responses to changes in product demand due to regulatory compliance.

#### 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 gCO<sub>2</sub>/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 (≈ 4 gCO<sub>2</sub>/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 gCO<sub>2</sub>/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 [40].

Because of the requirement to produce refinery-ready crude streams most similar to current EU refinery inputs, our most likely case includes only SCO pathways. We utilize the GHGenius default SCO pathway, as of version 3.20, which contains a mix of production processes as follows:

- Approx. 5% in-situ
- Approx. 95% Mined

In the default SCO setting for GHGenius version 3.20, 80% of oil sands-derived SCO comes from integrated mining and upgrading operations. Of the remaining 20% of SCO, nearly all of this (82%) comes from non-integrated mining and upgrading, and only 18% comes from SAGD to upgrading projects (e.g., Opti-Nexen SAGD to SCO project) [35, Sheet "S" cells AD6-AG6]

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

Table 6: Results for specified refinery mix [gCO<sub>2</sub>/MJ LHV]. Results derived from detailed results in Table 8 with JEC standard factors used for lifecycle stages marked with \*.

	Extraction	Upgrading	VFF	Refining*	Transport and Distribution*	Combustion*	Total
Oil sands emissions estimates							
Low <sup>a</sup>	7.3	8.6	0.0	7.0	1.9	73.4	98.2
High <sup>a</sup>	37.3	0.0	3.3	7.0	1.9	73.4	122.9
Most likely <sup>a</sup>	7.7	13.0	4.0	7.0	1.9	73.4	107.0
EU conventional oil emissions estimates							
Low <sup>b</sup>	1.0	-	w/ extract	7.0	1.9	73.4	83.3
High <sup>b</sup>	21.1	-	w/ extract	7.0	1.9	73.4	103.4
Most likely <sup>b</sup>	4.8	-	w/ extract	7.0	1.9	73.4	87.1

<sup>a</sup> - 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 default GHGenius SCO case. All of these results are derived from Table 8, with JEC standard factors used for life cycle stages marked with \*.

<sup>b</sup> - 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 [62, 63]. 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 gCO<sub>2</sub>/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” [37], 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 [37] and converted to MJ of crude oil equivalent using a density-based conversion factor.<sup>11</sup> 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).

Note that there is some uncertainty with respect to these values for conventional fuels. GHGenus calculations of a similar crude slate result in weighted-average emissions of 6.4 g CO<sub>2</sub> eq./MJ, as compared to 4.8 g CO<sub>2</sub> eq./MJ calculated here.<sup>12</sup> This variability is worth exploring in further work but is not likely to change the general conclusions of a comparison between conventional oil and oil sands operations.

<sup>11</sup>Crude oil energy densities taken from Gerdes and Skone [50, Table 2-6] and converted to energy density using data from Schmidt [65]. For crudes without listed density, EIA average of 6.1 GJ/bbl is used.

<sup>12</sup>Communication in peer review, D. O'Connor (S&T)<sup>2</sup> Consultants.

Table 7: Conventional crude oil mix to nominal EU refinery and resulting weighted-average GHG emissions<sup>a</sup> from upstream (well-to-refinery) GHGs measured in gCO<sub>2</sub>/MJ of crude oil produced. Crude oil mix is the average mix over 10 year period (1998-2007).

Region or country	Fraction of EU crude input	Upstream GHGs	Case	Notes
Unspecified EU production	0.1484	4.2		a
Russian federation	0.209	5.5		
Norway	0.163	1.0	Low	
Saudi Arabia	0.095	2.2		
Libya	0.068	6.9		b
Iran	0.056	6.9		b
United Kingdom	0.056	2.4		
Nigeria	0.032	21.2	High	
Algeria	0.027	5.8		
Kazakhstan	0.022	6.9		b
Iraq	0.022	3.3		
Denmark	0.016	4.2		a
Syria	0.016	6.9		b
Mexico	0.015	6.0		
Kuwait	0.012	2.6		
Venezuela	0.011	3.8		
Azerbaijan	0.01	6.9		b
Angola	0.008	13.4		
Cameroon	0.0086	6.9		b
Egypt	0.005	6.9		b
<b>Weighted average</b>		<b>4.81</b>	<b>Most likely</b>	

*a* - Used "EU-25" value from Skone and Gerdes [37].

*b* - Used "Foreign average" value from Skone and Gerdes [37].

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 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.<sup>13</sup> 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 gCO<sub>2</sub>/MJ RBOB (see Jacobs Table 8.7). NETL estimates are used as the upper bound, at 21.1 gCO<sub>2</sub>/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.

Similar results in aggregate were previously found by Howarth in an earlier study of crude oil inputs to the EU [66]. These result in generally equivalent GHG emissions figures for oil sands emissions, as well as generally similar results for conventional crude oil streams. Because the *Energy-Redefined* database used by Howarth contains 6000-7000 fields, the shape of the emissions by cumulative production curve is somewhat different than results shown in Figure 14.<sup>14</sup>

<sup>13</sup>Projects included are: Shell Albian 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 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.

<sup>14</sup>The variation in field-specific data in the Energy-Redefined study is likely to be “evened out” in any real

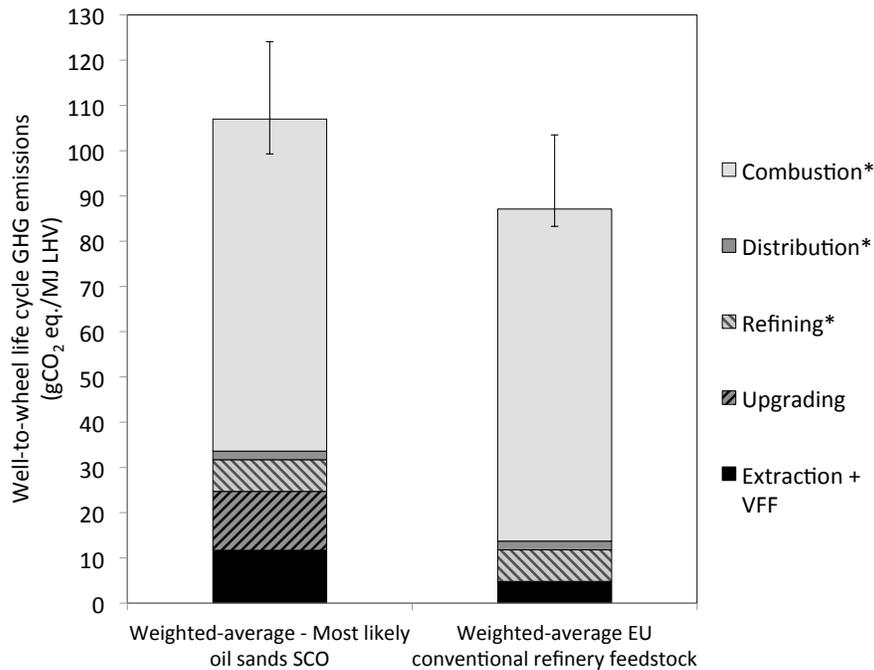


Figure 13: Weighted-average most likely oil sands emissions compared to weighted average conventional EU refinery feedstock. Range of values for oil sands provided by low-high range shown above in Table 6. Range of values for conventional oil shown above in Table 7, for Norway (low) and Nigeria (high).

crude import scenario, as imports are generally crude blends from a given region, representing one or more specific crudes blended to match the specifications of the crude blend offered. This would result in some high and low emissions crude being blended to result in a smoothed emissions curve.

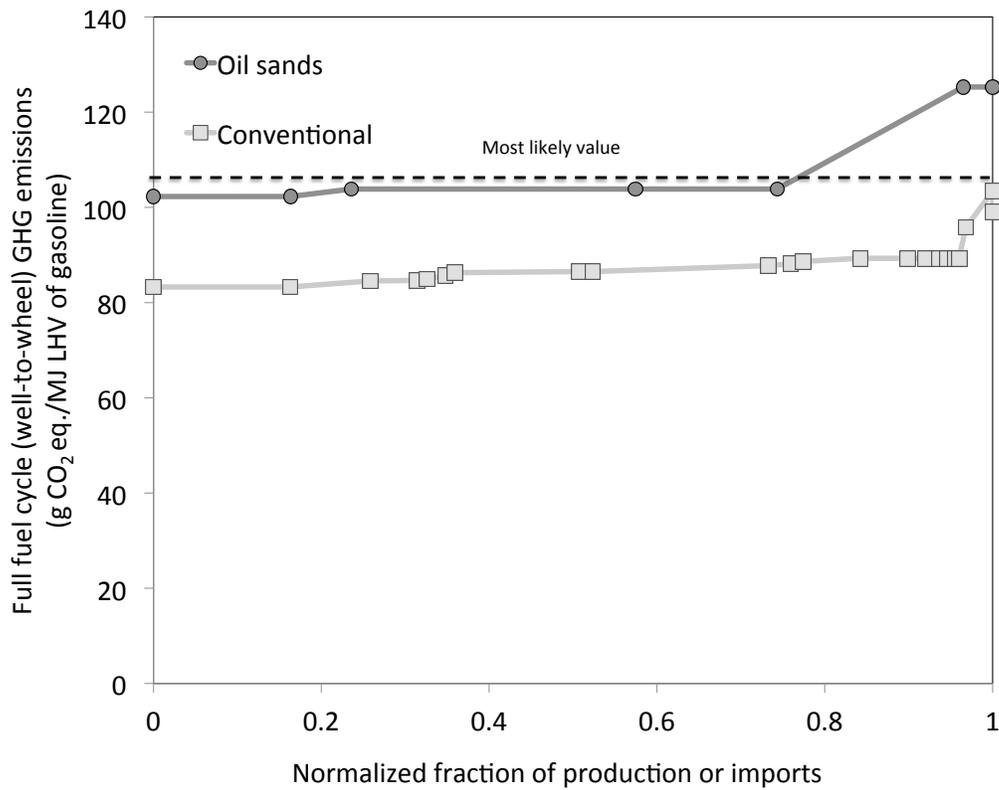


Figure 14: Emissions as a function of cumulative normalized output, for oil sands projects (low and high estimates) and conventional oil imports to the EU. While there is some overlap at the tails (highest conventional oil is higher than lowest oil sands) the production- or import-weighted average emissions 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 and needs for further research

Uncertainties remain in calculating life cycle GHG emissions from oil sands operations, as well as uncertainties regarding the importing of oil sands products into the EU.

These uncertainties can be classified as 1) uncertainties associated with an engineering-based attributional LCA approach (as generally practiced in the reviewed studies) and 2) uncertainties associated with broader market contexts and the interaction with production systems with the larger economy.

Uncertainties of type 1 have been addressed throughout the report, and further research needs to address them are discussed below. Uncertainties of type 2 are considered beyond the scope of this analysis, but are discussed in the associated document outlining responses to reviewers.

### 8.1 Uncertainty effects on “most likely” value

There is some unavoidable ambiguity about the “true” value of the industry-average SCO production emissions. This uncertainty will never be completely removed in the future (either for conventional oil streams or oil sands derived crude oils) given the complexity of performing an LCA on real-world systems (e.g., difficulty of collecting measured data, uncertainty in measurements, uneven compliance, variability over time, and other challenges). Such unavoidable uncertainty is not unique to the oil sands problem (nor LCA in general), and it therefore is important to keep the magnitude of potential uncertainty in perspective.

In fact, this uncertainty is most important from a policy perspective if it might contribute to policy failure. Such a failure might include the favoring of a fuel pathway as a low-GHG pathway when it is actually a high-GHG pathway. This might occur in a case where conventional oil is favored over oil-sands-derived fuels when in fact oil-sands-derived fuels have lower emissions. Given the difference between the central tendencies of the conventional oil and oil sands emissions estimates shown in Figures 13 and 14, it is very unlikely that such policy failure would occur with the default values recommended above.

In order to reduce this uncertainty, further research should be conducted so that default values can be more accurately characterized.

### 8.2 Needs for further research

This review of oil sands LCA studies above has suggested areas for more research in order to improve future LCAs. Some areas noted throughout the study above include:

1. The proper treatment of diluted bitumen mixtures in EU refineries should be examined in detail, give the possibility that diluted bitumen streams could be imported to the EU in the future. This will require updating JRC refining modeling to allow for modeling the refining of heavy bitumen mixtures, with proper attention paid to co-production credits for any light hydrocarbons generated from diluent.
2. The treatment of refining in all LCA studies of oil emissions could be improved in all LCA models. In particular, the discrepancies between publicly available refining

figures and the results of proprietary refining models need additional investigation. Also, significant effort should be paid to distinguish differences in the output slate of products from refining conventional crude oil, SCO, and bitumen. Given the different compositions of these fuels, a very different slate of products can be produced (e.g., more low-value products from bitumen production, less low-value product from SCO).

3. The treatment of conventional oil emissions is lacking in most publicly available models, with additional research needed into the effects of water oil ratios, steam oil ratios for thermal recovery processes, gas oil ratios and venting leaks, flare efficiency and flaring rates, etc. Many of these issues will be addressed in future work funded by the California Air Resources Board as part of their Low Carbon Fuel Standard effort.
4. The treatment of co-production of power needs additional investigation, with greater data availability from in situ operations and more investigation of the uncertainties associated with displacement effects on the electricity grid.
5. Additional work could be performed in disaggregating emissions further and generating more comprehensive assessments of the differences between study assumptions. This work is difficult and would likely require collaboration between study authors on a comprehensive model of oil sands emissions.

Additional work in these areas would increase the accuracy of the emissions estimates from oil sands production.

## 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 gCO<sub>2</sub> 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.

	Extraction	Upgrading	Transport	VFF	Refining	Distribution	Case
<b>Mining and upgrading</b>							
GHGenius - Integrated mine & upgrade	7.4	10.2	0.3	2.1	9.9	0.9	-
GHGenius - Non-int. mine & upgrade	7.4	26.4	0.3	11.6	11.6	1.0	-
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	-
<b>In situ and upgrading</b>							
	Extraction	Upgrading	Transport	VFF	Refining	Distribution	Case
GHGenius - SAGD to upgrader	18.1	28.31	0.3	11.6	12.4	1.1	-
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	-
<b>In situ without upgrading</b>							
	Extraction	Upgrading	Transport	VFF	Refining	Distribution	Case
GHGenius - SAGD to bitumen	13.4	0.0	0.25	1.89	24.01	1.0	-
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	-
<b>Mixed</b>							
	Extraction	Upgrading	Transport	VFF	Refining	Distribution	Case
GHGenius - Default SCO	7.7	13.0	0.3	4.0	10.2	1.0	M
GHGenius - Default Bitumen	11.4	0	0.3	1.7	23.7	1.0	-
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	GHGenius version 3.20, May 2011	GHGenius version 3.20 is used instead of version 3.13 due to significant changes in model v3.20 that affect refining and oil sands pathways. See Table 11 for outline of settings that generated tabular results, and Table 12 for the resulting GHGenius LHV upstream results.
GREET	Charpentier <i>et al.</i> [15, Supporting information, Table S2]	Converted from gCO <sub>2</sub> eq. per km to gCO <sub>2</sub> 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> [27]	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 [51]	Because figures are reported in kgCO <sub>2</sub> 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> [50] and Skone <i>et al.</i> [37]	Data from Gerdes <i>et al.</i> [50] are derived from earlier, more comprehensive report by Skone <i>et al.</i> [37]. Value for oil sands is taken from data on Imperial Oil - Cold Lake project (crude bitumen) and for SCO from Syncrude [37, 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 <sup>e</sup>
	GREET <sup>a</sup>			GHGenius <sup>b</sup>			Jacobs <sup>c</sup>		TIAX <sup>d</sup>		
	Mine	Upgr.	Mine	Upgr.	Int. mine & upgr.	Industry ave. SCO	Upgr.-Coker	Upgr.-Eb-bed	Int. mine & upgr.		
Diesel fuel	0.01	0.00	0.35	0.00	0.06	0.06	0.00	0.00	0.05	0.11	
Natural gas	0.82	0.97	0.72	0.30	0.48	0.47	0.51	0.62	0.42	0.39	
Electricity	0.17	0.03	-0.06	0.02	-0.01	-0.01	0.00	0.00	0.02	-0.01	
Pet. coke	0.00	0.00	0.00	0.10	0.15	0.13	0.00	0.00	0.0	0.15	
Refinery still gas	0.00	0.00	0.00	0.58	0.32	0.35	0.49	0.38	0.51	0.36	

*a* - Values from GREET model 1.8d, worksheet "Petroleum", Columns F,H 40-51.

*b* - Values from GHGenius model 3.20, worksheet "S". Values for mining, SAGD, etc.

*c* - Values from Jacobs report, Table 4-6 [27]. 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 [27].

*e* - Values from ERCB, reported by project [20]. 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.

## 10 Appendix B: Generation of GHGenius results

GHGenius results are generated using the most recent GHGenius model, version 3.20, released May 2011. This model was chosen over version 3.13 used in a previous version of this analysis because it contains significant changes to the modeling of refining and minor changes to oil sands pathways fuel intensities and fuel mixes. Version 3.20 is noted by GHGenius author Don O'Connor to be improved for modeling oil sands pathways, so is therefore used in this report.

Six cases are generated using GHGenius version 3.20. These cases include:

1. Synthetic crude oil produced using default GHGenius settings
2. Synthetic crude oil produced using only integrated mining & upgrading projects
3. Synthetic crude oil produced using only non-integrated mining & upgrading projects
4. Synthetic crude oil produced using only SAGD to upgrading projects
5. Diluted bitumen produced using default GHGenius settings
6. Diluted bitumen produced using only SAGD operations

These cases are generated using the steps noted in Table 11, after consultation with GHGenius author Don O'Connor regarding methods to model oil sands pathways using GHGenius.

Table 11: Changes made to GHGenius version 3.20 to generate results for figures and “most likely” estimates.

Model change	Change location
<b>Default SCO</b>	
Change region to Western Canada	“Input” sheet
Change crude split option to “Input”	“Input” sheet B62
Change crude type to 100% SCO	“Input” sheet row 65 to fractional synthetic = 1
Generate upstream results	Upstream results LHV, values for low sulfur gasoline, D7-D20
<b>Integrated mining &amp; upgrading</b>	
Change region to Western Canada	“Input” sheet
Change crude split dialog to “Input”	“Input” sheet B62
Change crude type to 100% synthetic	“Input” sheet row 65 to fractional synthetic = 1
Change SCO split to all integrated	Sheet “S” AM6-AN6 changed to [0, 1] to generate SCO from 100% integrated operations
Generate upstream results	Upstream results LHV, values for low sulfur gasoline, D7-D20
<b>Non-integrated mining &amp; upgrading</b>	
Change region to Western Canada	“Input” sheet
Change crude split dialog to “Input”	“Input” sheet B62
Change crude type to 100% synthetic	“Input” sheet row 65 to fractional synthetic = 1
Change SCO split to all integrated	Sheet “S” AM6-AN6 changed to [1, 0] to generate SCO from 100% non-integrated operations
Change bitumen split to all mining	Sheet “S” cells AD4-AG4 to [0, 0, 0, 1] to change to all mining for non-integrated SCO
Generate upstream results	Upstream results LHV, values for low sulfur gasoline, D7-D20
<b>Non-integrated SCO from SAGD</b>	
Change region to Western Canada	“Input” sheet
Change crude split dialog to “Input”	“Input” sheet B62
Change crude type to 100% synthetic	“Input” sheet row 65 to fractional synthetic = 1
Change SCO split to all integrated	Sheet “S” AM6-AN6 changed to [1, 0] to generate SCO from 100% non-integrated operations
Change bitumen split to all mining	Sheet “S” cells AD4-AG4 to [0, 1, 0, 0] to change to all SGAD for non-integrated SCO
Generate upstream results	Upstream results LHV, values for low sulfur gasoline, D7-D20
<b>Default Bitumen</b>	
Change region to Western Canada	“Input” sheet
Change crude split option to “Input”	“Input” sheet B62
Change crude type to 100% bitumen	“Input” sheet row 65 to fractional bitumen = 1
Generate upstream results	Upstream results LHV, values for low sulfur gasoline, D7-D20
<b>SAGD to bitumen</b>	
Change region to Western Canada	“Input” sheet
Change crude split option to “Input”	“Input” sheet B62
Change crude type to all bitumen	“Input” sheet row 65 to fractional bitumen = 1
Change bitumen input split to 100% SAGD	Sheet “S” cells AD6-AG6 to [0, 1, 0, 0] to generate bitumen from 100% SAGD operations
Generate upstream results	Upstream results LHV, values for low sulfur gasoline, D7-D20

Table 12: Results from GHGenius v3.20 from sheet "Upstream results LHV" for low-sulfur gasoline. Settings that generated results shown in Table 11.

	Default SCO	Integrated SCO	Non- integrated SCO	SAGD to SCO	Default Bitumen	SAGD to bitumen	Notes
Extraction	7.74	7.42	7.35	18.12	11.41	13.38	Includes "Feedstock recovery"
Upgrading	12.97	10.19	26.38	28.31	0.00	0.00	Includes "Feedstock upgrading"
Transport	0.25	0.25	0.26	0.27	0.25	0.25	Includes "Feedstock transmission"
VFF	3.97	2.06	11.61	11.61	1.65	1.89	Includes "Gas leaks and flares"
Refining	10.22	9.89	11.59	12.41	23.67	24.01	Includes "Fuel production"
Distribution	0.95	0.92	1.03	1.08	0.95	0.96	Includes "Fuel dispensing" and "Fuel distribution and storage"
Other	0.16	0.18	0.13	-0.17	0.30	0.26	Includes "Land-use changes, cultivation" and "Emissions displaced"
<b>Total upstream</b>	<b>36.26</b>	<b>30.92</b>	<b>58.35</b>	<b>71.62</b>	<b>38.23</b>	<b>40.76</b>	

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