Greenhouse gas intensity of oil sands production

Today and in the future

September 2018

Canadian Oil Sands Dialogue | **Strategic Report**

Contents

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About this report

Purpose. Since 2009, IHS Markit has provided research on issues surrounding the development of the Canadian oil sands. IHS Markit has completed five public studies on the greenhouse gas (GHG) emission intensity of oil sands crude and how the intensity compares with other crudes and the average crude oil refined in the United States. Building on our prior work, IHS Markit constructed a bottom-up model using publicly available data of individual emission sources within oil sands production facilities to estimate historical emissions intensity. Using this model, we established a baseline intensity for each emission source. This allowed us to estimate the impact of specific performance improvements to individual emission sources on aggregate industry emission intensities over time. The results provide a detailed review of the history of upstream oil sands GHG emissions, how they have changed, what factors have influenced these changes, and how emissions could evolve to 2030.

Context. This report is part of a series of reports from the IHS Markit Canadian Oil Sands Dialogue. The dialogue convenes stakeholders in the oil sands to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Stakeholders include representatives from governments, regulators, oil companies, shipping companies, and nongovernmental organizations.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

Methodology. IHS Markit conducted its own extensive research and analysis on this topic, both independently and in consultation with stakeholders. A bottom-up oil sands–specific GHG emission intensity model was purposely built for this analysis. Historical performance was derived using publicly available regulatory data. Future estimates relied on historical baselines, individual data requests from select oil sands operations, and IHS Markit expertise. Detailed appendices are included. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

Structure. This report has five sections and two appendixes.

- Introduction
- The IHS Markit method
- The history of oil sands GHG emission intensity
- Mapping the future course of oil sands GHG emission intensity to 2030
- Concluding remarks and comparisons
- Appendix A
- Appendix B

Key implications

In the wake of expanding and increasingly stringent climate policy, as well as greater questions about energy transition, interest in the greenhouse gas (GHG) emission intensity of oil sands extraction has never been greater. Unlike prior IHS Markit studies that focused on emissions over the entire life cycle (from well to wheels), this study presents a detailed bottom-up analysis of historical upstream GHG emission intensity and provides a view to 2030.

- **Different system boundaries (which define which emissions are counted) result in differences among GHG estimates.** Consistent with prior IHS Markit life-cycle analysis, in addition to direct emissions, upstream emissions associated with the production of imported fuels are included, while emissions associated with power exported to the grid are deducted from GHG intensity estimates.

- **The average intensity of oil sands extraction has fallen 21% since 2009—a story dominated by mined oil sands.** From 2009 to 2017, the GHG intensity of mined oil sands fell by more than 25%, principally from the ramp-up of less GHG-intensive operations. In situ operations remained relatively flat as reductions in natural gas intensity were offset by nearly equivalent reductions in the intensity of exports of surplus electrical power to the grid.

- **New modes of oil sands production are less carbon intensive and already contributing to intensity reductions.** Newer mined diluted bitumen operations are different—coming in at roughly half the upstream GHG intensity of legacy mining operations, which convert bitumen into lighter synthetic crude oil. Two proposed thermal in situ projects aim to use solvent to aid in production, lowering the GHG intensity of extraction.

- **By 2030, the GHG intensity of oil sands extraction could be 16–23% below 2017 levels—more than one-third less than in 2009.** The deployment of commercial and near-commercial technologies and efficiencies could result in a 17–27% reduction in the GHG intensity of steam-assisted gravity drainage operations (which accounted for 45% of oil sands supply in 2017) by 2030 and a 15–20% reduction in the GHG intensity of mined oil sands. On a full life-cycle basis (inclusive of emissions from production to combustion), these upstream intensities would place these sources within 2–4% and 5–7% of the average crude oil refined in the United States, respectively.

- **Among oil sands developments, the range of upstream GHG emissions intensities are diverse, a factor that a focus solely on the averages will miss.** The use of averages in GHG estimation can be informative, but distribution matters as well. In 2017, the upstream GHG emissions intensity range of oil sands facilities spanned 88 kilograms (kg) of carbon dioxide equivalent (CO_2e) per bbl (from 39 to 127 kgCO_2e/bbl), and as a result, any one facility may not be well represented by the average. On a full life-cycle GHG emission intensity basis (wells-to-wheels), the range of oil sands intensities in 2017 goes from approximately 1% below to 16% above the average crude oil refined in the United States.

- **The potential for more transformational changes in oil sands extraction technology exists, and with them a more radical impact on emissions.** With few exceptions, the IHS Markit oil sands GHG emission outlook does not include these transformational changes in extraction technology. Yet, many such technologies are advancing, and with them greater reductions in GHG intensity should be expected.

Greenhouse gas intensity of oil sands production

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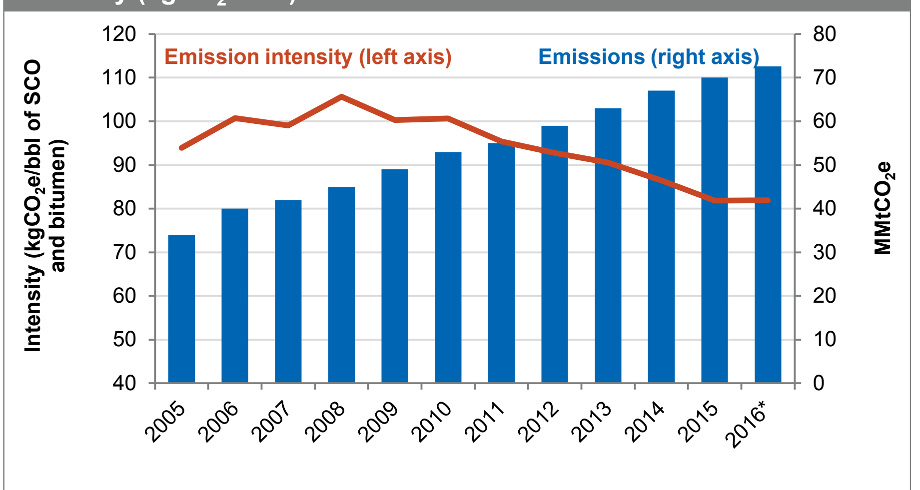
Kevin Birn, Vice President[1]

Introduction

Over the more than 50 years since commercial oil sands extraction began, production has almost always increased. Along with rising production, absolute GHG emissions have also increased, but at a declining rate per barrel. According to Canada's National Inventory Report (NIR), which captures direct emissions, between 2005 and 2016 annual oil sands emissions increased 39 million metric tons of carbon dioxide equivalent (MMtCO$_2$e), to 73 MMtCO$_2$e. Meanwhile, oil sands production expanded 1.4 MMb/d, to 2.4 MMb/d, making Canada the sixth-largest producer of crude oil globally (Canada, in 2017, subsequently overtook China and became the fifth largest).[2] This change equates to a direct emission intensity reduction of 13% per barrel over the same period (see Figure 1).[3]

Figure 1



*The 2016 Fort McMurray wildfire led to significant upstream oil sands disruption.
Source: IHS Markit, Alberta Energy Regulator (AER), Canada's NIR 2018 © 2018 IHS Markit

Growth in oil sands emissions, within the context of a relatively small population (in 2017, Canada was the 38th-most-populous nation globally) and a fairly low GHG-intensive power sector (four-fifths of power generation is nonemitting), has contributed to oil sands accounting for a greater share of overall national emissions.[4] Environment and Climate Change Canada estimates that oil sands accounted for about 10% of national emissions in 2016.[5]

Numerous policies have advanced in recent years to try to limit and reverse oil sands emission growth while minimizing the economic impacts. These include an intensity-based carbon pricing mechanism intended to protect trade-exposed sectors and limit carbon leakage; an absolute cap on oil sands GHG emissions at 100 MMtCO$_2$e per year; and a national pricing policy that aims to ensure the price of emissions in Canada will rise to $50 per metric

1. Special thank you to former IHS Markit colleague Hossein Safaei, the original architect of IHS Markit upstream oil sands greenhouse gas (GHG) intensity models.

2. The latest data available at time of completion of this report were for 2016. Source: Environment and Climate Change Canada, *National Inventory Report 1990–2016: Greenhouse Gas Sources and Sinks in Canada,* April 2018, https://unfccc.int/documents/65715, retrieved 16 July 2018.

3. GHG intensity is estimated by dividing total direct oil sands emissions derived from Canada's NIR 2018 by IHS Markit oil sands production (upgraded bitumen, such as synthetic crude oil [SCO], and unupgraded bitumen).

4. Population data sourced from the United Nations, Department of Economic and Social Affairs, Population Division, "World Population Prospects 2017," https://esa.un.org/unpd/wpp/, retrieved 17 August 2018. For more information on Canadian national emissions and power grid intensity, see the IHS Markit Strategic Report *The State of Canadian and US Climate Policy.*

5. Canada's NIR reports direct oil sands emissions at 73 MMtCO$_2$e in 2016 and total Canadian emissions at 704 MMtCO$_2$e. Source: Environment and Climate Change Canada, *National Inventory Report 1990–2016: Greenhouse Gas Sources and Sinks in Canada,* April 2018, https://unfccc.int/documents/65715, retrieved 16 July 2018.

ton of CO_2e by 2022.[6] Governments and industry are also investing in research and technology to lower emission intensity.

This report explores the past and future GHG intensity of upstream oil sands extraction. The report begins with a review of the study purpose, method, and uncertainties in estimating oil sands emission intensity. This discussion is followed by the results of the assessment of historical upstream oil sands emission intensity from 2008 or 2009 to 2017 and then the outlook for future emission trends from 2018 to 2030. The report concludes with a discussion of the implications and comparison on a full life-cycle basis.

The report includes two appendixes: Appendix A provides additional detail on the results and Appendix B provides a detailed description of our methodology.

Throughout this report, numerous oil sands terms are referenced. For more information, please refer to the box "Oil sands GHG primer."

Oil sands GHG primer

Accounting for approximately 3.8% of global supply in 2017, the oil sands are perhaps the most scrutinized source of crude oil in the world.* This attention is due, at least in part, to the sheer scale of the resource potential and concerns about environmental impacts. Current estimates place the amount of remaining economically recoverable reserves in the oil sands at 164 billion bbl, making oil sands the world's third-largest proven oil reserve (after Saudi Arabia and Venezuela).**

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands is bitumen, an extra-heavy crude oil with high viscosity. Accessing, separating, and marketing bitumen from the oil sands require energy, resulting in GHG emissions. The intensity of upstream production emissions depends on the reservoir characteristics, the extraction method, and each facility's unique configuration (performance and energy sources). Two forms of extraction dominate: mining and in situ.

Mining. About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface mining process, the overburden (vegetation, soil, clay, and gravel) is removed and used in associated infrastructure, such as roads and embankments, or stockpiled for later use in reclamation. The layer of oil sands ore is excavated using large shovels that scoop the material, which is then transported by truck to a processing facility. The ore is crushed or sized and then mixed with warm water and agitated, which causes the bitumen to separate. The energy used to power the vehicles involved in the mining process comes from fossil fuels, as does the heat used in the separation plant. In 2017, just less than two-fifths of oil sands supply (which can include diluent) came from mining; but, by 2030, as other forms of production are expected to outpace mining growth, mining's share of output will fall to less than one-third. There are two forms of mining extraction:

- **Integrated mines or mined SCO.** Legacy mining operations invested in and constructed heavy oil processing units upstream in the oil sands, which are often found integrated downstream into complex heavy oil refineries. Known as upgraders, these specialized processing units convert bitumen into a lighter SCO. As a result, upgraders add to upstream "mined SCO" emissions, which otherwise would occur downstream.

*The estimate is based on total oil sands supply, inclusive of diluents imported into and used in the creation of bitumen blends in 2017, compared with total global crude production as marketed from the IHS Markit Annual Strategic Workbook 2018. On a production basis (without diluent), oil sands accounted for approximately 3.4% of the global crude oil system. Both estimates do not include NGLs, biofuels, or other liquids.

**AER, ST98: 2018: *Alberta's Energy Reserves & Supply/Demand Outlook: Executive Summary*, p. 7, https://www.aer.ca/documents/sts/ST98/ST98-2018_Executive_Summary.pdf, retrieved 30 May 2018.

6. For more information on the oil sands GHG emission cap, see "Bill 25: Oil Sands Emissions Limit Act," www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_29/session_2/20160308_bill-025.pdf, retrieved 20 July 2018; and for more information on the Pan-Canadian Framework, see "Pan-Canadian Framework on Clean Growth and Climate Change," Canada.ca, www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework.html, retrieved 30 July 2018.

Oil sands GHG primer (continued)

- **Unintegrated mines or mined dilbit (PFT).** In more recent years, two new mining operations have been completed that do not feature an integrated upgrader. Through a process known as paraffinic froth treatment (PFT), some of the heaviest components found in bitumen are precipitated out. The recovered bitumen is then diluted with lighter hydrocarbons (typically a natural gas condensate) and shipped to market as a bitumen blend or specifically a diluted bitumen (dilbit). This process avoids the energy associated with upgrading, reducing upstream GHG production emissions. However, the marketed dilbit is thereby more GHG intensive to refine, increasing downstream refining emissions. Still, on a net or full life-cycle basis, mined dilbit is lower than mined SCO (see “Concluding remarks and comparisons” section). The PFT process has also been found to produce a modestly higher-quality bitumen and results in a dilbit product with a ratio of approximately four-fifths bitumen to one-fifth condensate.

In situ. About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling. These deposits are the largest-growing source of oil sands production. In 2017, more than three-fifths of oil sands supply came from in situ operations, and, by 2030, this amount could exceed two-thirds. Both primary and thermal extraction methods are deployed in situ. The primary extraction method is much more akin to conventional oil production and in 2017 accounted for about 6% of supply (including diluent). However, as growth of other sources of supply continues to outpace primary extraction, its share of supply is expected to fall, reaching about 4% by 2030. Thermal production accounts for more than half of oil sands supply today (and nearly 90% of in situ supply). Thermal methods inject steam into the reservoir to lower the viscosity of the bitumen and allow it to flow to the surface. Natural gas is used to generate the steam, which results in GHG emissions. Bitumen produced from in situ operations is also too viscous to permit transport by pipeline and must be diluted with lighter hydrocarbons, making a bitumen blend. The most common blend is dilbit with a ratio of 70% bitumen to 30% condensate. There are two dominant forms of thermal in situ extraction.

- **Steam-assisted gravity drainage (SAGD)** is the fastest-growing method, accounting for more than 45% of supply in 2017, and is expected to dominate growth, accounting for 56% of supply by 2030.

- **Cyclic steam stimulation (CSS)** was the first thermal process used to commercially recover oil sands in situ. CSS currently makes up 10% of total supply, and growth in other sources of supply is expected to outpace CSS, and its share of total output could fall to 7% by 2030.

The IHS Markit method

This section discusses the scope of the study, our estimation method, and comparability and uncertainty associated with our results.

Study scope

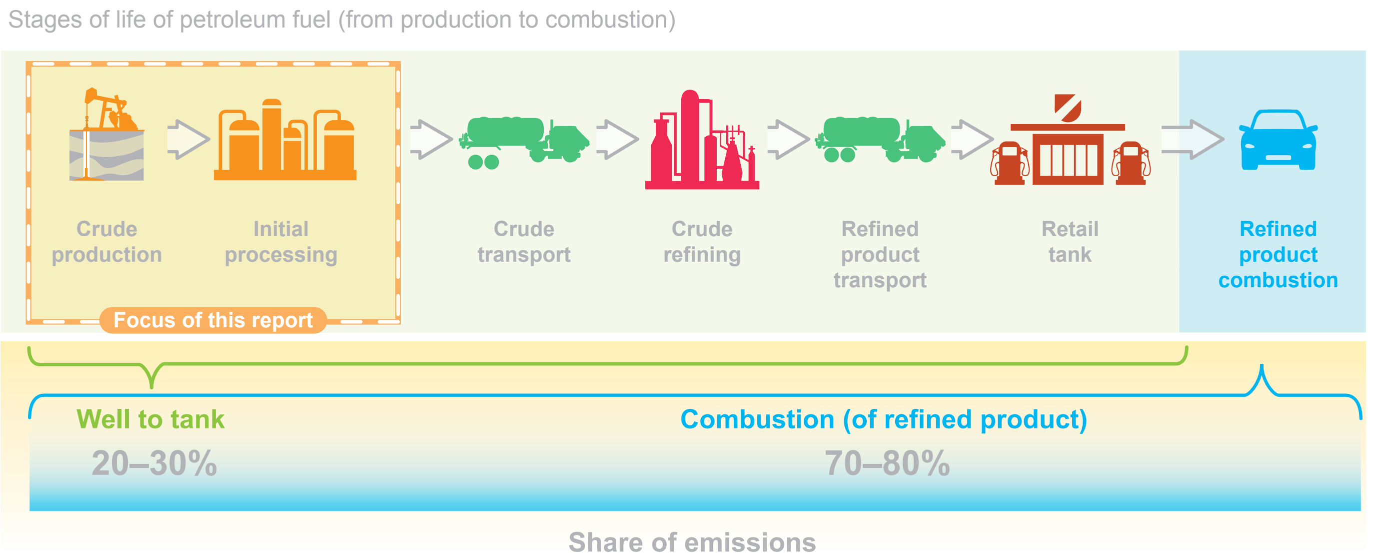
GHG emissions occur over the entire life of liquid hydrocarbon fuel, from production, refining, transport to markets, and finally combustion (see Figure 2). The production, refining, and marketing phases make up a relatively small share of overall emissions. Most emissions—70–80%—occur at combustion.

IHS Markit has performed extensive life-cycle analysis of the GHG intensity of oil sands crude and how the intensity compares with other crudes and the average crude oil refined in the United States (“the US average”). IHS Markit has consistently found the GHG intensity of oil sands–derived crude oil to be above the US average, but we have also found it to be within the range of other crude oils. In our last study, released in 2014, we found oil sands crude ranged from 1% to 19% higher than the US average, with more than 45% of the crude oil processed in the United States fitting within that range.[7] We also have found that sensitivity to assumptions and data limitations lead to uncertainty associated with estimating GHG emissions.

The focus of this study is oil sands extraction and initial processing—upstream emissions (as highlighted in Figure 2). The results may also be viewed as the Canadian-centric component, because most oil sands production is exported. The analysis includes a historical bottom-up analysis of energy and fuel use derived from publicly available data and data requests from governments and regulators. Furthermore, because our approach allowed us to establish a historical GHG emission intensity by fuel or emission source, such as natural gas or diesel, we could measure the aggregate impact of efficiency improvements over time on individual fuel or emission sources as well as fluctuations in production. Our outlook was complemented with additional publicly available government data and data requests of specific facilities in production ramp-up. The result is a very detailed analysis of a possible future trajectory of upstream oil sands GHG emission intensity to 2030.

Figure 2

Life-cycle GHG emissions of petroleum fuels



Source: IHS Markit

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Estimating historical oil sands emission intensities

We estimated historical oil sands emission intensities for mining and in situ thermal operations. Estimates of primary, experimental, or enhanced oil recovery (EOR) techniques used in the oil sands region were included in the total oil sands industry average (shown in the final section of the report) using estimates from prior IHS Markit reports and other analysis, but are not modeled in this study.

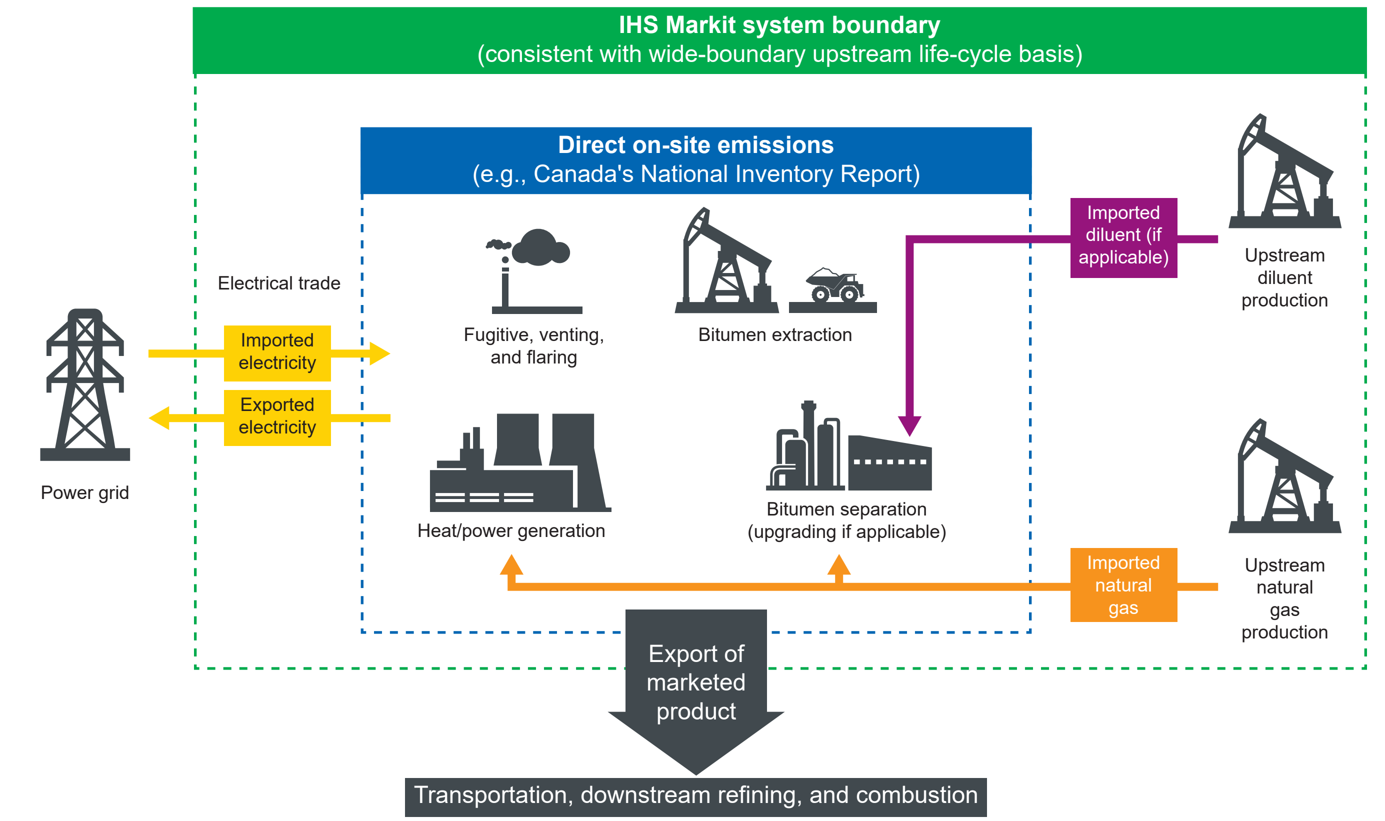
Differences in data and production processes necessitate distinct modeling approaches for mining and in situ operations. Data limitations affect the period for which we could make historical estimates: 2008–17 for mining operations and 2009–17 for in situ operations. IHS Markit chose system boundaries (the scope of emissions captured/included) consistent with prior research to allow for results to be compared and integrated with prior IHS Markit life-cycle assessments. As a result, in addition to direct emissions, emissions associated with upstream production of fuel, such as natural gas or diluent used in the creation of diluted bitumen, as well

7. IHS Markit estimated that on a full life-cycle basis, from wells to wheels, oil sands ranged from 506 kg of carbon dioxide equivalent (CO_2e) per bbl to 598 $kgCO_2e$/bbl of refined product, while the average GHG intensity of crude oil refined in the United States was estimated to be 502 $kgCO_2e$/bbl of refined product in 2012. Source: IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil.*

as the import and export of electricity that can arise from the use of cogeneration, were included. See Figure 3 for a depiction of IHS Markit system boundaries.

Figure 3

System boundaries



Source: IHS Markit

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We estimated historical emissions by converting energy use reported to regulators and environmental departments in Alberta to GHG emissions. To this, we added indirect emissions from upstream production of natural gas used to generate heat and electricity and from diluent (which we assumed to be condensate) used in operations that market dilbit. Electrical imports and exports were credited or debited against oil sands GHG emissions at a rate equivalent to combined-cycle natural gas combustion. Electrical credits or surplus electricity exported to the grid can result from an oil sands facility use of cogeneration. Estimating the impact of cogeneration can complicate oil sands emission intensity estimating. For more information on cogeneration, see the box "Allocating cogeneration emissions."

Allocating cogeneration emissions

Electricity imports and exports complicate emission calculations. Since electricity crosses the system boundary, energy and thus emissions can enter and leave the system. GHG emission estimates can vary depending on the method used to treat electricity trade—including the value or credit of electricity-associated emissions.

Oil sands plants need both heat (steam) and electricity. Although there is nothing inherent in their processes, mining has historically been fairly energy balanced (with neither large imports nor exports of electricity), while in situ operations have been large electrical exporters (on an intensity basis).

Allocating cogeneration emissions (continued)

IHS Markit chose to allocate GHG emissions associated with electrical trade according to energy balance—only energy consumed within the plant. Deducting net power exports against facility emissions (assigning a credit for exported power against facility emissions) is an accepted methodology in GHG estimation (although the value of the credit is an area of difference of opinions).[1]

For this study, the value of the electrical trade was 440 kgCO_2e/MWh, which aligns with the combined value of a combined-cycle natural gas generation unit (370 kgCO_2e/MWh) plus the associated upstream GHG emissions from the natural gas needed to fire the unit.[2] This rate was chosen because a combined-cycle natural gas generation unit was viewed as the most likely marginal source of power in Alberta. Using the Alberta grid average would have been another method but would have nearly doubled the credit value because of Alberta's current reliance on coal-fired generation. However, this value would be expected to fall as Alberta decarbonizes its grid, adding an additional layer of complexity and debate to our modeling.

1. This choice is also consistent with Alberta's Carbon Competitiveness Incentive Regulation GHG accounting rules: https://www.alberta.ca/carbon-competitiveness-incentive-regulation.aspx.

2. Upstream natural gas emissions are discussed in Appendix B.

Results are presented as the average of the marketed product by extractive technology to best represent the GHG intensity of production that is sold and processed by downstream refineries. Our results included mined SCO average, mined dilbit (PFT), total mining average, SAGD dilbit, and CSS dilbit.

A summary of the IHS Markit historical emission estimation method is included in the box "Historical oil sands mining emissions" and the box "Historical oil sands in situ emissions." A detailed methodology is included in Appendix B.

Estimating historical oil sands mining emissions

The AER has provided data on energy consumption, production, and electrical balance for each mining facility since 2008. These data include use of natural gas, produced gas, petroleum coke, and electrical imports/exports as well as flaring.*

In addition to these data, information on mobile mine fleet diesel consumption and estimates of fugitive emissions were obtained from the Alberta Environment and Parks Specified Gas Emitters Regulation (SGER) database up to 2015. Diesel consumption was further refined with data requests from individual operations.**

Emission factors were used to convert energy use to GHG emission estimates and then divided by production to arrive at emission and/or energy intensities. We made adjustments to the natural gas conversion factor to incorporate upstream natural gas production. Upstream diluent production emissions were included based on a simplified blending assumption per barrel of bitumen output. For more information, see Appendix B.

Electrical imports and exports were credited or debited against oil sands operations at a rate equivalent to combined-cycle natural gas combustion, as discussed in the box "Allocating cogeneration emissions."

*"ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement," AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39, retrieved 4 April 2018.

**Alberta Environment and Parks, SGER database, obtained upon request, accessed 2016.

Estimating historical oil sands mining emissions (continued)

We estimated emission intensity for each mining project individually and summed them to develop an industry weighted average for mined SCO, mined dilbit (PFT), and total mined production.

Special cases were incorporated into our estimate and model, such as the impact of one mine that operates an integrated carbon capture unit. More information is available in Appendix B.

Estimating historical oil sands in situ emissions

The AER provides data on in situ steam demand and efficiency as recorded in steam-to-oil ratios (SOR).* The SOR measures the equivalent volume of steam required to produce 1 barrel of oil. Because natural gas is used exclusively to meet steam demand, the SOR is a good measure of efficiency and GHG emission intensity.

Although the SOR can act as a good estimate for steam and thus natural gas consumption, some electricity is required. Electrical intensity of production was obtained from the Alberta Environment and Parks SGER database, which provides historical estimates of the share of cogeneration to heat and electricity as well as efficiency. We used these values to estimate electrical demand per barrel. A survey of installed cogeneration capacity resulted in an estimate of total generation capacity. A surplus of electricity resulted in a credit, while a deficit was debited against facility emissions. The value of the credit was based on the equivalent to the best available natural gas power generation unit, plus the emissions associated with the upstream production of natural gas consumed—consistent with mining assumptions.

Like mines, indirect emissions from the import and use of natural gas for heat and electricity and diluents were included and converted to emissions at the same rate as mines.

Please note that we needed to estimate heat from cogeneration and heat from boilers separately for later use in estimating future emissions. We estimated this using data on heat from cogeneration obtained from the SGER database. Any difference between total steam demand and steam from cogeneration was assumed to come from natural gas–fired boilers.

All the sources were summed and then converted into an industry weighted average intensity estimate. More information is available in Appendix B.

*"ST53: Alberta In Situ Oil Sands Production Summary," AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53, retrieved 30 May 2018.

Estimating future oil sands emission intensities

IHS Markit sought to understand the impact of additional efficiency improvements and the deployment of commercial or near-commercial technologies on oil sands GHG emission intensity over time. Critical factors included not only the potential technologies and efficiencies but also the pace of adoption and future growth.

The first part of the report establishes historical baselines of emission intensity by fuel and/or emission source for oil sands operations based on government data. Using these baselines, IHS Markit was able to estimate the impact on future emission intensities of efficiency improvements on individual fuel and/or emission streams in the IHS Markit production outlook to 2030. This impacted oil sands mining and in situ projects differently.

Mining operations baselines by fuel or emission source were carried forward based on the last year of operation. Project operators that have recently completed mining projects or are about to undertake work expected to impact operations were consulted regarding their expected operational energy supply and demand following completion of their work and/or normalization of operations. IHS Markit currently does not have any entirely new mining projects commencing operations prior to 2030.

The key indicator for in situ performance is steam intensity, or the SOR. The average of the past three years of operation was used to establish the baseline SOR of existing facilities in our outlook to 2030.[8] Regulatory applications were used to establish baselines for new facilities, while a combination of regulatory applications and past performance was used for expansion projects.

After establishing a baseline of operations for each facility (mining and in situ), we layered new technologies and efficiencies onto specific fuel, energy, and/or emission streams. Considerable detail was put into modeling the potential pace of deployment. For example, in situ technologies in which steam could be displaced were not universally applied, with the potential benefit limited to new wells. Projects that proposed to incorporate similar technologies in their application to what IHS Markit was modeling were not allowed to benefit from IHS Markit assumptions. A discussion of modeled improvements is included later in the report and in Appendix B.

To be certain, each facility is unique, and there is an array of advancing technologies that could materially alter future oil sands extraction and emissions. It was not feasible for this analysis to model the full array of technologies (many of which are bespoke), and we made some simplifying assumptions. With few exceptions, we did not include transformational technology changes. Our forecast is best viewed as the outcome of a reasonable pace of commercial and near-commercial technology deployment (existing technologies) and efficiency gains on oil sands GHG intensity. As a result, our outlook may be conservative, since some transformational changes will more than likely occur prior to 2030, including the deployment of a broader array of technologies than we considered that would result in a more dramatic reduction in GHG emission intensity.

The future intensity of CSS dilbit was not included in our outlook simply because of additional scope and because production remains relatively flat in the IHS Markit outlook to 2030.

Additional details are included in Appendix B.

Uncertainty and comparability

Considerable data are required to estimate oil sands emissions by source. Alberta is unique in the quality of data available. However, some gaps still exist and some data may still be subject to improvements. For example, data for diesel fuel consumption were not universally available, and estimates of fugitive emissions appeared to be based on a limited sample.

Comparisons across various GHG intensity estimates are also challenging. Differences in key assumptions, such as emission conversion factors (the rate of carbon dioxide [CO_2] emitted per unit consumed or used) and system boundaries (such as whether and how indirect emissions associated with upstream or off-site production of energy use are included or not [IHS Markit included both]), can result in differences among estimates.

In this regard, Canada's NIR, prepared by Environment and Climate Change Canada, is often regarded as the gold standard for absolute Canadian and oil sands sector emissions. The NIR measures direct emissions. For comparison, the IHS Markit method adjusts for energy that crosses in and out of the facility or system boundary (see Figure 3).

8. When setting mining and SAGD baselines for facilities impacted by the Fort McMurray wildfire, we omitted data for 2016.

These differences do not mean that the IHS Markit results are inconsistent with the Government of Canada or that one is better than the other; IHS Markit and the NIR simply measure things differently. As a result, some variation in results should be expected. However, as shown in Table 1, adjusting the IHS Markit system boundary to align with the NIR (capturing only direct emissions and converting intensity estimates into total emissions) shows a high degree of correlation between IHS Markit and the NIR.

Table 1

IHS Markit and Canada's NIR estimates of direct oil sands emissions ($MMtCO_2e$)

	2010	2011	2012	2013	2014	2015	2016**
NIR							
Mining and upgrading	33	33	34	35	37	36	35
In situ	20	22	25	28	30	34	38
Total	**53**	**55**	**59**	**63**	**67**	**70**	**73**
IHS Markit							
Mining and upgrading*	35	32	35	36	36	36	29
In situ	21	22	26	29	32	36	39
Total	**56**	**54**	**62**	**66**	**69**	**72**	**67**
Difference	**6%**	**-1%**	**5%**	**4%**	**2%**	**3%**	**-7%**

*IHS Markit model does not allow differentiation between mining and mining upgrading emissions. China National Offshore Oil Corporation (CNOOC)/Nexen integrated in situ operations upgrading emissions are included in mining and upgrading until 2015, when the upgrader ceased operation. Their SAGD extraction emissions were included for in situ.
**In 2016, there was a large forest fire, and numerous operations were affected, which impacted emission estimates.

Source: IHS Markit, Environment and Climate Change Canada's NIR 2018 © 2018 IHS Markit

The history of oil sands GHG emission intensity

This section presents the IHS Markit results of historical oil sands emissions, broken down by mining (mined SCO and mined dilbit [PFT]) and in situ (SAGD dilbit and CSS dilbit). Oil sands mining and thermal in situ (SAGD and CSS) accounted for more than 90% of all oil sands production in 2017 and account for nearly all of the oil sands growth in the IHS Markit outlook to 2030.[9]

Sources of historical oil sands mining emissions, 2008–17

Nearly three-quarters of oil sands mining emissions result from the combustion of fossil fuels. These fuels include natural gas, process gas, and petroleum coke used in the generation of heat and electricity as well as diesel to power truck and shovel operations (the mobile mine fleet). Just over 5% of emissions stem from fugitives and flaring. Other emissions are indirect, resulting from some operations' import and use of electrical power and the diluent used in dilbit. Emissions are also associated with the upstream production of natural gas used to generate heat and power.

Note that each operation is unique. Some operations may have older vehicles, use shorter or longer mine trains (mine fleet needs to drive further), or use a different fuel mix for heat and power generation. For example, three of the six operating mines produce petroleum coke, only two combust it, and one facility operates a carbon capture unit. In recent years, two new mines have entered operation that use a PFT process that permits the marketing of dilbit as opposed to upgraded bitumen (SCO). This process negates the up-front cost and operating emissions associated with upgrading and results in a different emission profile (see Figures 4 and 5).

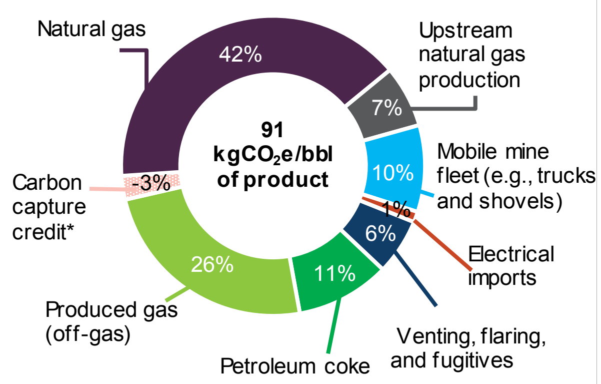
The evolution of oil sands mining (and emissions)

Oil sands mining has undergone several transformational changes over its 50-year history, which have influenced the industry's current emission profile. Some major changes included

9. Other forms of production include primary, experimental, and EOR techniques.

Figure 4

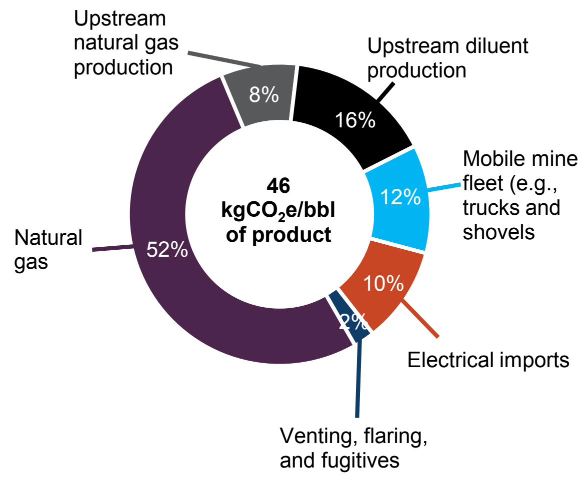
Sources of oil sands mined SCO GHG emissions in 2017 (91 $kgCO_2e$/bbl of SCO)



*In 2015, the Quest project commenced operations, capturing and sequestering CO_2 emissions from an oil sands upgrader. This results in a credit against SCO emissions using IHS Markit system boundary conditions. This credit is applied to natural gas for purposes of this figure.
Source: IHS Markit © 2018 IHS Markit

Figure 5

Sources of oil sands mined dilbit (PFT) GHG emissions in 2017 (46 $kgCO_2e$/bbl of dilbit)



Source: IHS Markit © 2018 IHS Markit

- **Bucket-wheel.** In the early 1990s, oil sands mining operations phased out bucket-wheel excavators in favor of trucks and shovels. The intention was to improve the efficiency of operations by transitioning from one critical point of failure—the bucket-wheel—toward the more redundant and flexible truck and shovel. Less downtime meant greater throughput on average and less energy and emissions per barrel produced.

- **Hydrotransport.** Also in the 1990s, warm water oil sands ore slurry pipe systems (known as hydrotransport) were introduced over legacy conveyor belt systems. Hydrotransport aids in the bitumen separation from the ore and has allowed operations to lower process temperature and thus energy and emissions per barrel.

- **PFT.** PFT removes impurities and precipitates out some of the heaviest parts of bitumen. This process eliminates the need for on-site upgrading and the associated emissions, with dilbit marketed instead of SCO. Note, however, that although the absence of upstream upgrading reduces the intensity of mined dilbit production, mined dilbit is more GHG intensive to refine than mined SCO.[10] As a result, the GHG intensity of the *upstream emissions*, including imported diluent, is roughly half that of the average mined SCO. However, on a well-to-tank basis (including upstream production and downstream refining up to the point of combustion), the GHG intensity of mined dilbit is about 25% lower than of mined SCO.[11] The first nonintegrated mine was completed in 2015 and the second in 2017.

Oil sands mining emissions, 2008–17

Although mined SCO and mined dilbit (PFT) are both mining operations, they are distinct processes. For the most part, IHS Markit presents them both as part of the mining sector, but we also present them individually. What follows are the results of our historical mining estimates.

Mining average. The average intensity of oil sands mining operations fell 26%, or 29 $kgCO_2e$/bbl of marketed product (SCO and dilbit), over the past decade—from 112 $kgCO_2e$/bbl in 2008 to 83 $kgCO_2e$/bbl in 2017 (see

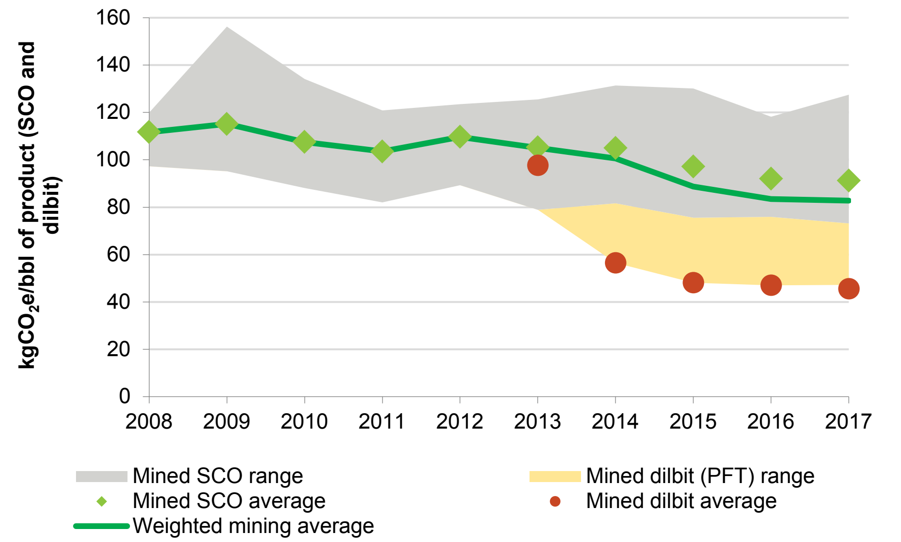
10. SCO is known as a bottomless crude because the heavy components have been converted to lighter molecules. Mined dilbit requires higher temperature and/or pressure than SCO to be converted into higher-value refined product.

11. Source: IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil.*

Figure 6). The main contributor was a reduction in the intensity of petroleum coke use, followed by the introduction of mined dilbit (diluting the overall mining emission average) and improvements and ramp-up of more efficient mined SCO operations (see Figure 7). Meanwhile, a reduction in the net trade of electricity offset some of the intensity reductions.

Figure 6

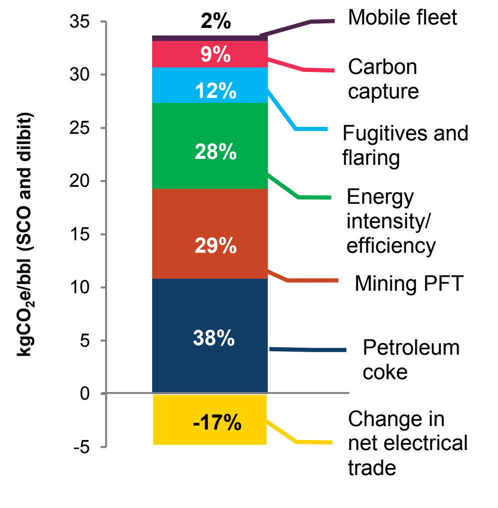
Historical GHG intensity of mined oil sands by marketed product (SCO and dilbit)



Source: IHS Markit © 2018 IHS Markit

Figure 7

Source of oil sands mining GHG intensity improvement, 2008–17 (29 $kgCO_2e$/bbl of product)



Source: IHS Markit © 2018 IHS Markit

In 2017, oil sands mining spanned from 46 $kgCO_2e$/bbl to 127 $kgCO_2e$/bbl of marketed product.

Mined SCO. Mined SCO emissions declined 18% over the same period (per barrel of SCO), to 91 $kgCO_2e$/bbl in 2017. The largest driver was the reduction in the intensity of petroleum coke use (which includes an increase of production not using petroleum coke). For more information on petroleum coke combustion, see the box "Petroleum coke: A by-product of mined SCO production."

Petroleum coke: A by-product of mined SCO production

The combustion of petroleum coke has a similar GHG intensity as coal combustion—approximately two times more carbon intensive than natural gas.* Petroleum coke is a by-product of heavy oil processing in which high temperature and pressure are used to convert complex heavier molecules into lighter fractions. Although not all heavy oil processes generate petroleum coke, the most common process, known as thermal cracking or coking, does. Petroleum coke is not a unique result of oil sands crude but a common by-product of heavy crude oil processing globally.

In the oil sands, petroleum coke results from the upgrading process (upgraders are essentially freestanding heavy oil processing units). Petroleum coke is low value and was considered low-cost feedstock for heat and power in early oil sands mines. Three of the four mined SCO operations produce petroleum coke, and two combust it.

Over the past decade, petroleum coke use has declined as the price of natural gas has fallen and public interest in GHG emissions has increased. In 2008, approximately 1.76 million metric tons (MMt) of petroleum coke was

*See Table B-1 in Appendix B.

Petroleum coke: A by-product of mined SCO production (continued)

combusted and/or exported from the oil sands—30% of the volume produced. In 2017, this amount had fallen to about 1 MMt and none was exported—this result was just over 10% of the volume produced.** Most of the petroleum coke produced in the oil sands is permanently stored.

Producers have made announcements that are expected to lead to further reductions in petroleum coke use. However, design limitations may also limit a total petroleum coke phaseout.***

**“ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement,” AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39, retrieved 4 April 2018.

***See Appendix B for additional details.

Mined dilbit (PFT). The first operation to market mined dilbit (PFT) began in 2013, followed by another operation in late 2017 (effectively 2018). As these new facilities have ramped up production (which is continuing), the GHG intensity of mined dilbit has fallen. In 2017, we estimate the GHG intensity of mined dilbit (PFT) production was 46 $kgCO_2e/bbl$.

Sources of historical oil sands thermal emissions, 2009-17

Over the past decade, in situ, led by SAGD, has become the dominant source of oil sands production growth. SAGD accounted for two-fifths of oil sands production in 2017 and accounts for three-quarters of the oil sands growth in the IHS Markit outlook to 2030 (the remainder coming from the ramp-up and productivity improvements of mining operations, including debottlenecking projects). CSS was captured in our historical intensity estimates but was not a focus of the report because it is not expected to materially grow to 2030.

In situ operations are fundamentally different from mining because they rely on subsurface injection of steam (thermal energy) into the reservoir to mobilize and extract bitumen.

Nearly all on-site GHG emissions result from the combustion of natural gas for the generation of steam. Like mining operations, there are upstream emissions associated with the production of natural gas consumed on site and diluent imports. In 2017, SAGD operations exported more electrical power to the grid than they imported, which helped offset or lower their emission intensity (using our system boundaries) (see Figure 8).

No oil sands in situ operations currently operate an upgrader and thus produce or combust petroleum coke. In situ operations are generally more carbon intensive than mining without an upgrader (but not with an upgrader).

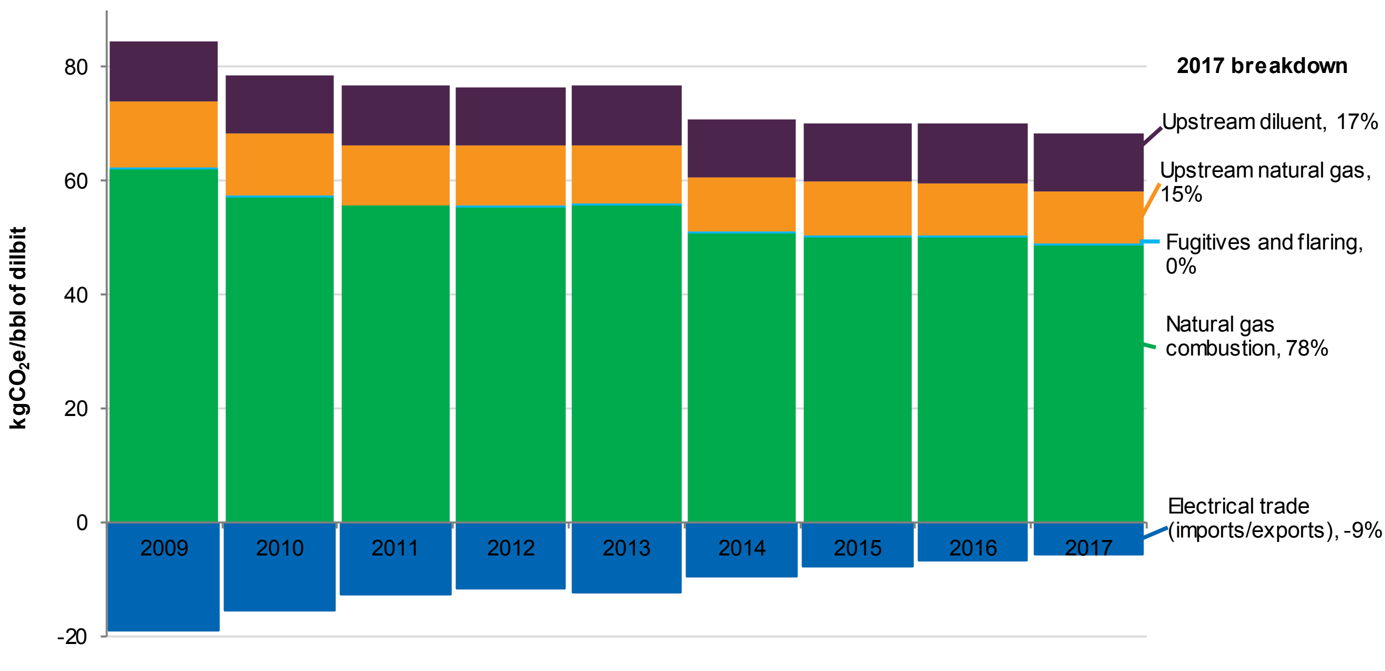
The evolution of oil sands SAGD (and emissions)

At about 17 years old, SAGD has yet to undergo any of the transformational changes that occurred in mining. Most emission intensity reductions have come from incremental improvements and learning by doing. Examples include greater accuracy in well placement, improvements in downhole monitoring, and better steam control (directing steam where it needs to go along the injection well and in the reservoir). More durable parts and predictive maintenance have helped reduce unplanned outages and downtime, improving reliability, utilization, cost, and emissions in the process.

The results have shown up in the industry average SOR, which declined 8% over 2009–17, from 2.95 to 2.71.

Figure 8

Composition of historical SAGD dilbit GHG intensity, 2009–17



Source: IHS Markit © 2018 IHS Markit

Well productivity, which is measured by the daily volume of oil recovered per well, has also improved. From 2008 to 2015, the average productivity per SAGD recovery well in the oil sands increased more than 120%.[12]

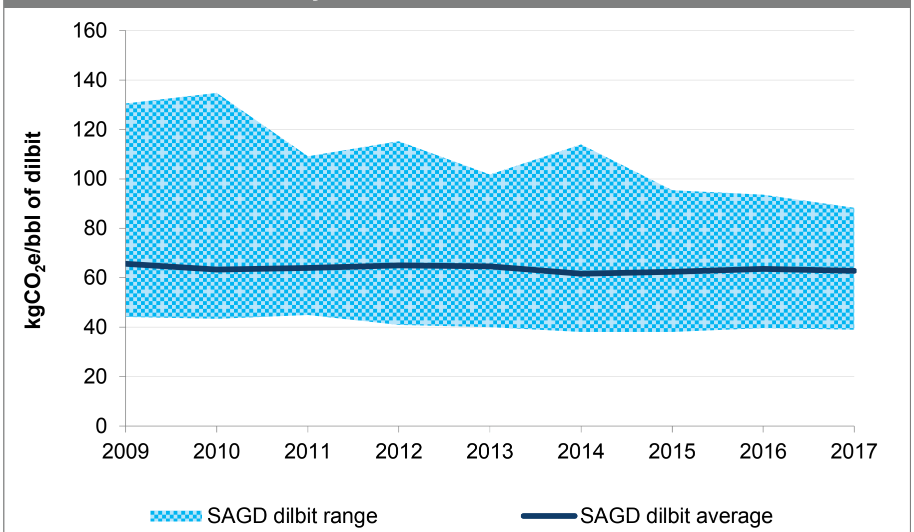
Oil sands SAGD emissions, 2009–17

Although operations have become more efficient (demonstrated by the falling SOR), the average emission intensity of SAGD dilbit has remained relatively constant—down 4% since 2009. Figure 9 shows the full range and average intensity of SAGD dilbit from 2009 to 2017. In 2017, the average intensity was estimated at 63 kgCO_2e/bbl of dilbit, while the industry ranged from 39 kgCO_2e/bbl to 88 kgCO_2e/bbl of dilbit.

This seemingly contradictory finding is a product of the IHS Markit system boundary conditions coupled with the industry's historical relationship with

Figure 9

Historical GHG intensity of SAGD dilbit, 2009–17



Source: IHS Markit © 2018 IHS Markit

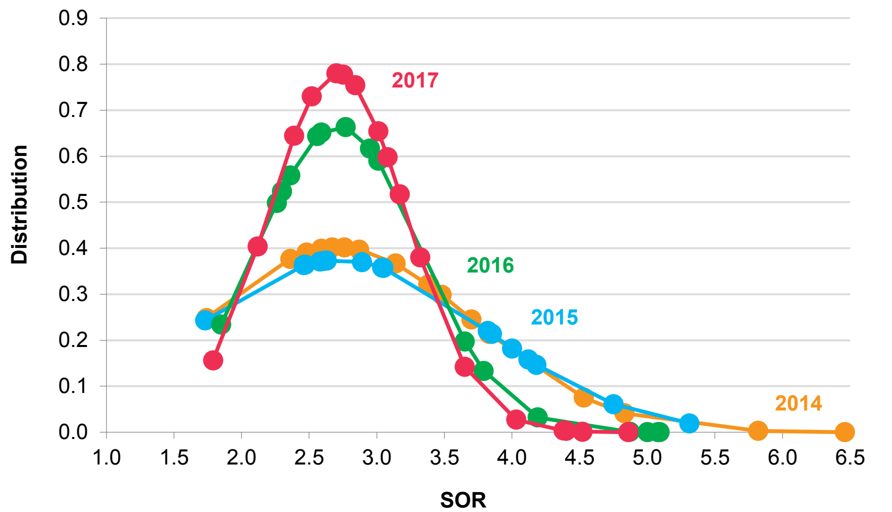
12. Source: AccuMapTM by IHS Markit.

cogeneration and electrical exports. Several facilities operate cogeneration units, which generate both steam and electricity. These operations can result in surplus electricity exported to the power grid. Although the use of cogeneration in SAGD is not ubiquitous, on average, the sector is a net energy exporter. Using the IHS Markit method (and life-cycle method), these emissions are deducted from the emission intensity. Over time, the ratio of cogeneration electrical generation capacity to production capacity has fallen as newer operations have more closely tailored cogeneration capacity to steam demand. Moreover, a reduction in investment since the price collapse arguably helped dampen the rate of cogeneration expansion, further tightening cogeneration capacity to production. This tightening has reduced electrical export intensity, all while operations have become more efficient, demanding less steam per barrel of oil (the SOR declined). Taken together, the reduction of electrical power export intensity has offset reductions in natural gas intensity, keeping overall emission intensity relatively flat. This relationship is visible in Figure 8, which shows that emissions from natural gas per barrel fell by about 13 kgCO_2e/bbl from 2009 to 2017 while the electrical export intensity credit declined by nearly the equivalent amount. This is an example of how system boundaries can impact results. For example, using direct emission system boundaries (shown in Figure 3), SAGD intensity fell 24% between 2009 and 2017.[13]

Meanwhile, the range of SAGD dilbit GHG intensity has tightened as outliers or more carbon-intensive operations have improved and facilities closer to the mean increased output. This result is visible in Figure 9 but more apparent in Figure 10, which plots the distribution of SOR of SAGD operations over the past four years (since the oil price collapse began).

Figure 10

Distribution of SAGD SOR by year



Source: AER, IHS Markit

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An aside on CSS emissions, 2009–17

We included the history of CSS emission intensity, but not the outlook to 2030.

The use of CSS is limited to specific geological regions in the oil sands, and production is highly consolidated. In 2017, there were only three operating CSS projects, with 60% of output coming from one operation alone. In 2017, CSS accounted for 10% of total oil sands supply (inclusive of diluents).

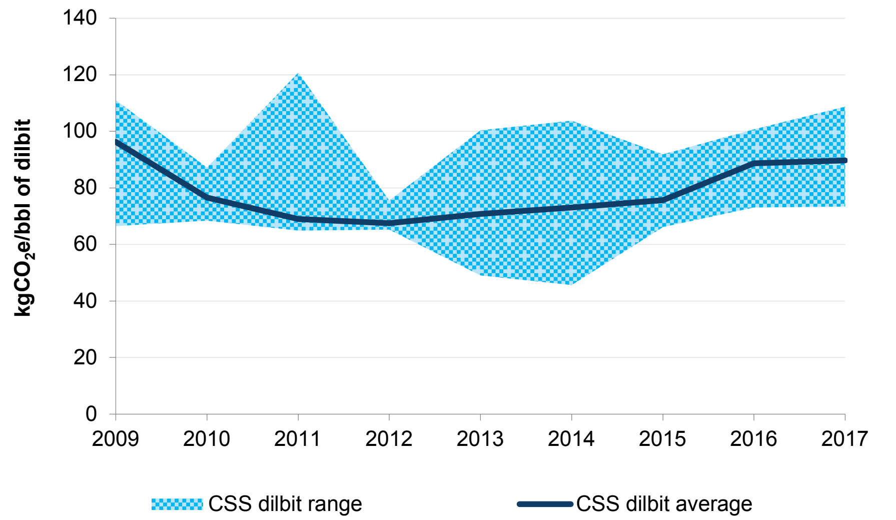
Although the emission intensity of CSS dilbit has been trending up in more recent years, the average intensity in 2017 (90 kgCO_2e/bbl of dilbit) was still 7% lower than in 2009 (see Figure 11). The overall reduction from 2009 to 2017 is linked to an increase in electrical exports to the grid, which has more than offset an increase in steam intensity (the SOR rose from 4.35 to 4.61 from 2009 to 2017). IHS Markit believes lower oil prices in recent years may have played a role in the increase, which could once again be influenced by higher oil prices.

13. Note that this differs from the summary table in Appendix A because this estimate is based on a bitumen barrel basis, which can be estimated using the same data.

Mapping the future course of oil sands GHG emission intensity to 2030

Figure 11

Historical GHG intensity of CSS dilbit, 2009–17



Source: IHS Markit

Looking to the future, questions abound about the trajectory of oil sands growth, the intensity of production, and, ultimately, absolute emissions. The promise of technology is often invoked as the reason emissions will fall. It is true that technology has the potential to lead to transformational changes in oil sands extraction and thus emissions. Yet, technology deployment can take time, it may never be applied universally, and, from a modeling perspective, a focus solely on new technology can overlook efficiency improvements and learning by doing—major drivers of historical emission improvements.

To be sure, this is a forecast, and modeling future oil sands is predicated on a wide range of assumptions—investment, production, and technology. Using a bottom-up approach, we sought to capture the impact of a reasonable pace of deployment of commercial and near-commercial technologies and potential efficiency improvements on the GHG intensity of production. With few exceptions, transformational technologies were not modeled. As a result, we view our outlook as conservative, or a projection of current trends.

We discuss the potential technologies and improvements first. This discussion is followed by the results and projections for future emissions. IHS Markit results are presented as a range to capture some of the uncertainty regarding the pace of deployment and potential benefits. For simplicity, the upper-bound contains more conservative assumptions, whereas the lower-bound considers a more aggressive deployment of current technology and know-how. In both cases, IHS Markit used the same production outlook and project composition to 2030.

The question of reservoir quality

In addition to the advancement of new extractive technologies and further efficiency improvements, IHS Markit considered two additional factors influencing the future trajectory of oil sands emissions: reservoir or resource quality and production growth.

- **Production growth influences both absolute and industry emission intensity.** The greater the level of growth, the higher absolute emissions are likely to be, but likely at lower intensity. This is because newer projects tend to benefit more from the latest technology. The greater the share of new production, the greater the impact on the average industry performance. An example of this dilution effect is clearly visible from the impact of the introduction of mined dilbit (PFT) on mining emissions. This example also highlights how composition—which projects advance—influences average emission intensity.

IHS Markit expects growth in the Canadian oil sands to continue to 2030, but at a slower pace.[14] By 2030, production (SCO and bitumen) could approach 4 MMb/d, roughly one-quarter million barrels lower than our pre–oil price collapse forecast from 2014. The composition of projects in the IHS Markit outlook has also tilted toward SAGD projects because they are lower cost and quicker to first oil. This change implies that the future of mining emissions may rely more on existing facilities, whereas the future of SAGD emissions has the added complexity of being influenced by the projects that could advance in the future.

- **Oil sands reservoir quality is not yet expected to materially limit GHG emission improvements to 2030.** Within any reservoir or play, the geology will vary, influencing the quality and ease of extraction. Terms such as "sweet spots" have been given much visibility by the rise of US tight oil. However, the varying quality holds true in most reservoirs. Reservoir quality can influence the type of oil sands operations differently. For mines, it can influence the degree of ore handling. For in situ operations, steam intensity can be affected. Both can influence the GHG intensity of extraction.

  Over the coming decade, based on the current IHS Markit understanding and production outlook, while some outliers may occur, on average, we do not expect our results to be materially impacted by the quality of oil sands reservoirs under active development. There were a couple reasons for this:

  In the case of the oil sands, there is a lot of oil still out there. Of the estimated 177 billion bbl of recoverable resources, only 7.5% has been exploited to date.[15] Certainly, the quality of the reservoirs varies, and there is nothing to prevent anyone from building in a more challenging area. However, many attractive areas remain. Lower prices have also slowed the pace of future growth, slowing the rate at which industry will move through the resource. Meanwhile, Alberta and Canada's planned escalation of carbon pricing and industry consolidation will likely discourage investments in lesser-known regions and drive capital preferentially toward areas that are better understood, with more attractive reservoirs.

  For our study, estimates of the performance of new projects were informed by regulatory submissions, which provide guidance on the expected operating profile for the majority of our outlook period. For existing projects, as they move through their leases, future performance could be impacted late in our outlook period. However, we believe that the use of conservative technology assumptions, particularly in the upper-bound case, provide a further hedge against the possible impact should some projects gradually move into lower-quality reservoirs.

A possible future of oil sands mining emissions to 2030

IHS Markit expects oil sands mining production growth to be outpaced by SAGD extraction following the ramp-up of recently completed mining operations and recently sanctioned debottlenecking projects.[16] Any meaningful change in emission intensity may be more reliant on existing operations. Barring a transformational change in extraction technology (as per IHS Markit study assumptions, these were not included), there may be a limited set of levers currently available to oil sands mining operations to lower emissions. These levers are also not evenly distributed across operations. For example, in 2017, petroleum coke combustion, which occurred at only two mining operations, still accounted for about 9% of the emission intensity of oil sands mining (mined SCO and mined dilbit combined).

14. For more information, see "Uncertainties continue to weigh on the oil sands growth story," IHS Markit, https://ihsmarkit.com/research-analysis/uncertainties-continue-to-weigh-on-the-oil-sands-growth-story.html.

15. "ST98: Alberta's Energy Reserves and Supply/Demand Outlook," Table R3.2: Reserve and production change highlights (106 m3), AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98, retrieved 30 May 2018.

16. In 2017, both the Fort Hills mined dilbit (PFT) and the Horizon mined SCO expansions commenced operations, while the Kearl mined dilbit (PFT) facility announced it would be undertaking a debottlenecking project during 2018 and 2019. Horizon has also announced additional work it could undertake to expand output.

IHS Markit identified five key areas where commercial or near-commercial technology or efficiency improvements could drive GHG emission intensity improvements. These included fuel switching from petroleum coke to gas; cogeneration capacity expansion; fuel switching and efficiency gains in the mobile mining fleets; separation process improvements, such as a reduction in process temperature; and carbon capture and storage (CCS). Further background on each potential improvement area is discussed in the box "Oil sands mining assumptions," with detail on what was modeled included in Table 2.

Oil sands mining assumptions

Fuel switching. Two mining operations currently combust petroleum coke: Suncor base mine and Syncrude. The Suncor plant uses specially designed boilers to combust petroleum coke, while at Syncrude combustion occurs as part of the plant's upgrading process. There may be opportunities to convert existing coke-fired boilers to natural gas or introduce cogeneration capacity, which could reduce coke combustion. In fact, Suncor Energy has announced the phaseout of coke boilers on its site, in favor of two new cogeneration units.* However, because Syncrude combusts petroleum coke as part of its upgrading process, options may be more limited without a more involved redesign.

Cogeneration. For the most part, oil sands mining operations are electrically balanced—neither major importers nor exporters of electricity from the grid. To meet demand, they use a combination of boilers and cogeneration units. An expansion of mining cogeneration capacity could alter the industry energy balance and energy export intensity.

Mobile mining fleet. Oil sands mining operations have large fleets of heavy equipment haulers, shovels, and earthen works equipment, which run on diesel. These fleets can be extensive; for example, one mine has well over 150 trucks and shovels of various sizes (all of the vehicles are not in operation at any given time, but this number gives a sense of scale). LNG for heavy equipment is a proven technology and has been tested in the field. Autonomous mining vehicles are not more combustion efficient but can reduce vehicle downtime and improve utilization—reducing emission intensity. One operator has announced its intention to phase in autonomous vehicles at scale.** Both technologies can lower emission intensity but will also take time to deploy and turn over the existing fleet.

CCS. CCS involves the capture and geological storage of CO_2 emissions from the combustion of fossil fuels. Currently, there is one oil sands mine with an integrated capture unit.*** Although IHS Markit considered further deployment of CCS, this was not modeled in our outlook because the core oil sands mining region is remote from likely geological storage options. The only operating facility is unique in that the installed capture facility is integrated into an upgrader located in Edmonton, Alberta—far from oil sands operations. Since 2009, CO_2 has also been injected into tailing material at the Horizon mined SCO project. Although some CO_2 is most likely being sequestered, there was uncertainty to the degree or volumes, and they were not included in our estimate.****

*"Coke Boiler Replacement Project," Suncor, http://www.suncor.com/about-us/oil-sands/process/coke-boiler-replacement-project, retrieved 2 February 2018.

**"Suncor Energy Implements First Commercial Fleet of Autonomous Haul Trucks in the Oil Sands," Suncor, 30 January 2018, http://www.suncor.com/newsroom/news-releases/2173961, retrieved 30 May 2018.

***For more information on the Shell Quest CCS project, see "Quest Carbon Capture and Storage," Shell, https://www.shell.ca/en_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html, retrieved 18 July 2018.

****For more information, see "Managing Tailings," Canadian Natural Resources, https://www.cnrl.com/corporate-responsibility/advancements-in-technology/managing-tailings.html, retrieved 30 July 2018.

Oil sands mining assumptions (continued)

Process efficiency. The separation of bitumen from sand, clay, and water in mining operations requires large volumes of warm water. This requires energy. Over time, as operations have become more efficient, this temperature has generally fallen and/or greater waste heat integration has reduced energy demand to maintain process temperature. Further efficiency gains are likely to drive greater efficiency and thus emission improvements. The application of solvents in the mining separation process is under development, which could dramatically improve process temperature or allow greater output from existing heat use.

Table 2

IHS Markit GHG intensity mining outlook assumptions

Pathway	Description	Upper-bound case (more conservative)	Lower-bound case (more aggressive)
Fuel switching	Two mining operations combust petroleum coke. There are economic and technical limitations to fuel switching. In 2017, petroleum coke combustion accounted for 9% of the intensity of oil sands mining, or about 8 $kgCO_2e/bbl$ of product.	At one of the two mines combusting petroleum coke, Suncor, we assumed that the existing coke boilers would be phased out in 2022. Both units were assumed to be replaced with cogeneration units, which ties this assumption to the cogeneration assumption. IHS Markit estimates that this would half industry petroleum coke use/ combustion.	
Cogeneration expansion	Building cogeneration facilities can reduce the net GHG emission intensity of oil sands facilities owing to simultaneous production of steam and electricity.	IHS Markit modeled the addition of two 350 MW additions to the Suncor base mine in 2022 as announced by Suncor Energy.	In addition to the upper-bound case assumptions, three additional 100 MW units were phased in at a rate of one per year between 2023 and 2025. The dates chosen were arbitrary, but facilities were chosen to make current net electrical importers and net exporters to the grid (or more accurately, roughly balance them).
Mobile mine fleet operations	The mobile mine fleet accounts for about 11% of emissions today. Advancements in engine technology, deployment of commercial LNG engines, and greater fleet optimization through autonomous vehicles could drive improvements.	The introduction of LNG engines was modeled starting in 2021 at 1% of the fleet, increasing to 5% by 2025. Adoption of an autonomous mine fleet was assumed at one operation beginning in 2019 with a 1% improvement in efficiency, ramping up to a maximum of 10%; then adoption was assumed to expand to all other mines in 2024, ramping up at 1% per year and reaching a maximum of 7% in 2030.	The introduction of LNG engines was modeled starting in 2021 at 1% of the fleet, increasing to 10% of the fleet by 2030. The adoption of an autonomous mobile mine fleet was assumed to begin at one operation in 2019, resulting in a 2% improvement per year in fleet intensity to a maximum of 14%. Autonomous trucks were assumed to expand to all other mines beginning in 2022 at an accelerated rate of 2% per year to a maximum fleet penetration of 14%.
Efficiency improvements (e.g., process temperature/waste heat integration)	Oil sands mines are large consumers of heat to extract bitumen and produce SCO. There is room for improvement through methods such as heat integration, optimization, and use of solvents.	To capture improvements or reductions in process energy demand, IHS Markit modeled the equivalent to a 0.5 degree Celsius (°C) reduction per year in process temperature, starting in 2020 for legacy mining operations producers and 2024 for newer facilities at half the rate (0.25°C) per year because newer facilities were assumed to operate at cooler rates. By 2030, older operations reach an equivalent reduction of 5.5°C, while newer operations get to 3.5°C.*	The equivalent of a 0.5°C per year reduction in process temperature was modeled starting in 2018 for legacy mining operations and 2020 for newer facilities.* Solvent-aided separation technology was included, being adopted starting in 2026 for mined SCO operations and 2028 for mined dilbit (PFT) facilities, resulting in an immediate 5°C temperature reduction, increasing by 0.5°C per year (resulting in a 1°C temperature improvement per year thereafter). By 2030, older operations reach an equivalent reduction of 11.5°C, while newer operations get to 10.5°C.*
CCS	CCS has the potential to sequester CO_2 emissions directly at the source.	An absence of quality disposable sites in core oil sands regions results in limited sequester opportunities currently, and we did not model beyond what is already established.	

*Legacy operations include Suncor base mine, Syncrude, and Albian Sands.

Source: IHS Markit

IHS Markit expects that more transformational technologies will come forward, which will lead to far more radical emission reductions than considered in this study. Indeed, industry and governments are investing in new technologies, and many are in advanced pilots. An exhaustive list of these technologies and their state of commerciality would easily necessitate its own report. Moreover, the subsequent modeling effort would be even more complex. Instead, we sought to understand the trajectory of the GHG emission intensity of oil sands extraction as a result of ongoing efficiency improvements and a reasonable pace of deployment of commercial and near-commercial technologies today. For these reasons, we view our output as conservative. However, equally true is the role that a more optimistic oil price or investment outlook could play in influencing future emissions.

Results: Carbon intensity of future mining operations

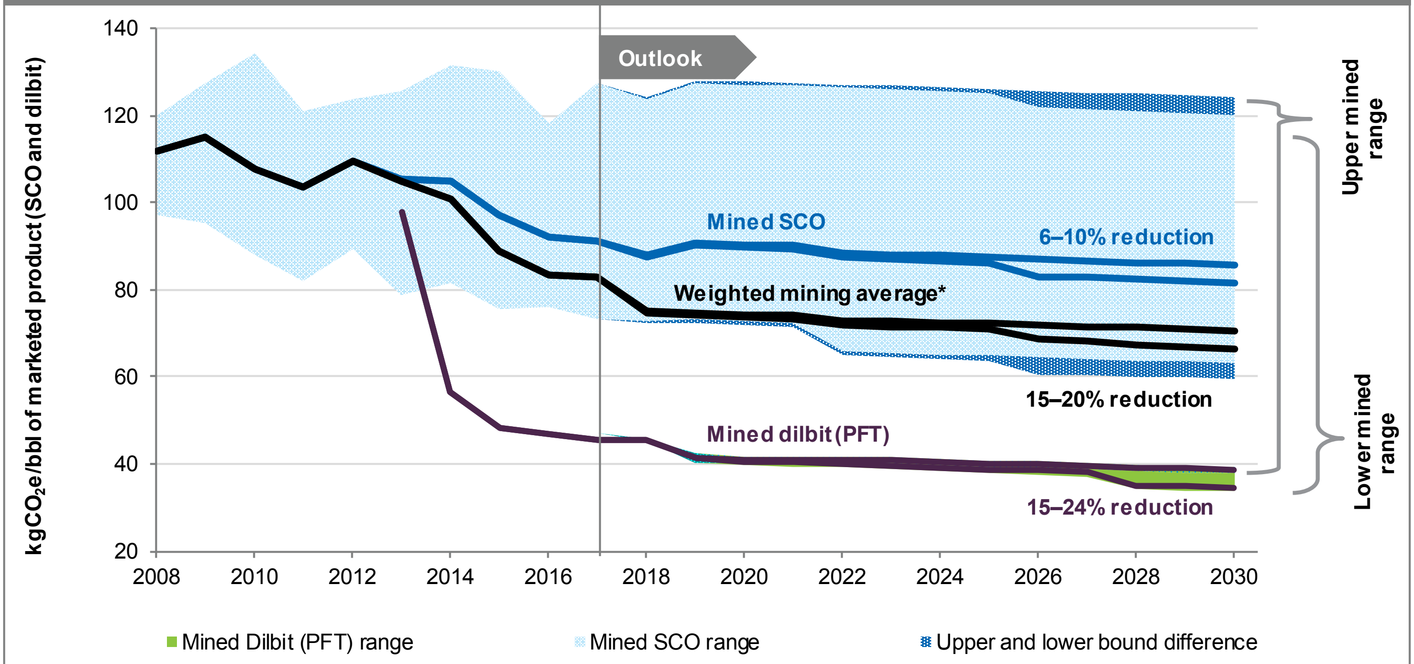
Like historical oil sands mining emissions, results are presented as a mining average, as well as separately for mined SCO and mined dilbit (PFT).

Mining average. The average GHG intensity of upstream oil sands mining on a marketed product basis (SCO and dilbit) falls by 12–16 kgCO_2e/bbl from 2017 to 2030 in the IHS Markit outlook—a 15–20% reduction (see Figure 12). Average mined oil sands production emissions in 2030 range from 67–71 kgCO_2e/bbl. This is less than the historical drop of 2–3% per year during 2008–17. Figures 13 and 14 break down the key contributors behind the reduction in our outlook to 2030. Many of the key drivers, such as the ramp-up of newer mined dilbit (PFT) processes—diluting more GHG-intensive legacy integrated mined SCO operations—and a reduction in petroleum coke use, are arguably already under way.

Mined SCO. The GHG intensity of mined SCO falls by 6–10 kgCO_2e/bbl from 2017 to 2030—a reduction of 6–10%. Average mined SCO production emissions range from 82–86 kgCO_2e/bbl in 2030. Improvements in process temperature/efficiency are the largest contributor, followed by reductions in the use of petroleum coke.

Figure 12

GHG intensity of oil sands mining by marketed product (SCO and dilbit), 2008–30

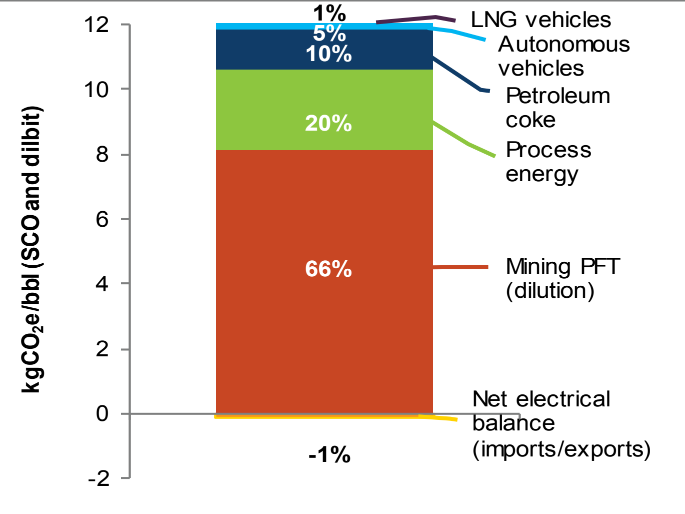


*Estimate of total oil sands average includes mined SCO and mined dilbit.
Source: IHS Markit

© 2018 IHS Markit

Figure 13

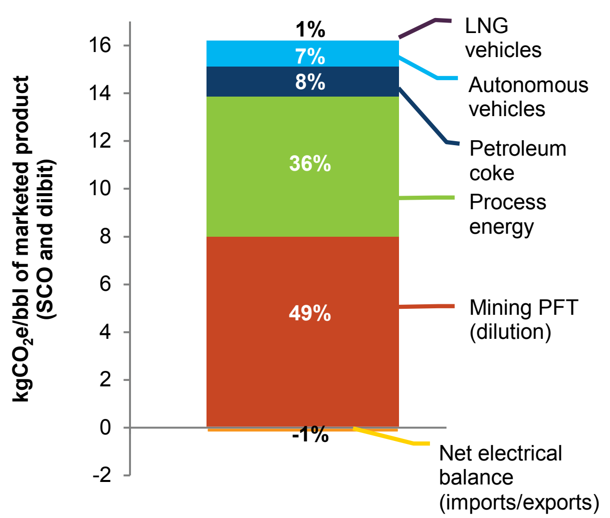
Source of oil sands mining GHG intensity improvement, 2017–30 (12 $kgCO_2e$/bbl of product)



Source: IHS Markit © 2018 IHS Markit

Figure 14

Source of oil sands mining GHG intensity improvement, 2017–30 (16 $kgCO_2e$/bbl of product)



Source: IHS Markit © 2018 IHS Markit

Mined dilbit (PFT). Mined dilbit (PFT) emissions continue to fall as facilities ramp up production, complete debottlenecking work, and normalize operations. Improvements in process temperature/efficiency help lower emission intensity over time. Mined dilbit (PFT) emissions decline by 7–11 $kgCO_2e$/bbl—a 15–24% reduction—bringing emissions in 2030 to 34–39 $kgCO_2e$/bbl.

For more details, see the box "Oil sands mined SCO and mined dilbit (PFT) cases in detail." Detailed results can be found in Appendix A.

A possible future of oil sands SAGD emissions to 2030

SAGD has become the dominant source of oil sands growth. Between 2017 and 2030, roughly half of the anticipated 1.2 MMb/d rise in the IHS Markit oil sands outlook is expected to come from new SAGD projects, which include entirely new greenfield operations and expansions of existing facilities. As a result, what happens to SAGD will weigh not only on production but also on GHG emission intensity.

IHS Markit explored four key areas as having the potential to drive emission improvements in SAGD operations. These included well productivity, boiler/steam generation efficiency, steam displacement technologies (such as solvents), and cogeneration. The type and volume of future or yet-to-be-sanctioned SAGD projects also influence future emission intensity. Similar to mines, transformational technologies were not included.[17]

Detailed improvements are outlined in Table 3 following the box "Oil sands mined SCO and mined dilbit (PFT) cases in detail", with additional background in the box "Oil sands SAGD assumptions."

17. It is an arguable point whether steam displacement technologies are transformational. They were included since we deemed them to be commercial or near commercial.

Oil sands mined SCO and mined dilbit (PFT) cases in detail

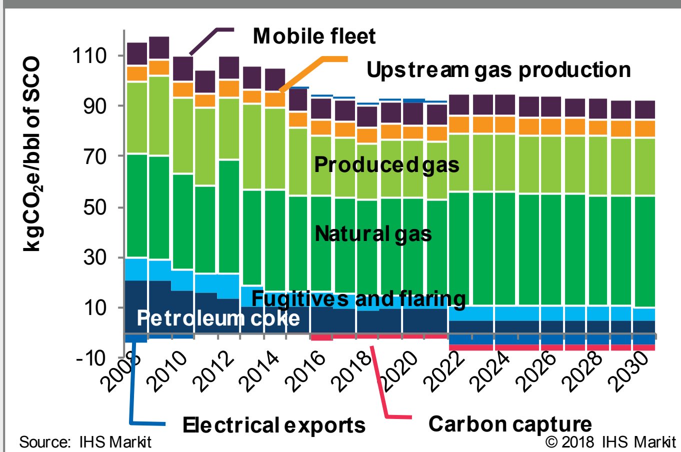
IHS Markit explored four key levers—and two sets of assumptions affecting the intensity of these levers—impacting the future carbon intensity of mining operations. This text box presents the results of the individual cases by mined SCO and mined dilbit (PFT) for the two cases or sets of assumptions modeled.

Oil sands mined SCO

In the IHS Markit upper-bound (more conservative) case, oil sands mined SCO emissions decline from 91 kgCO_2e/bbl in 2017 to 86 kgCO_2e/bbl in 2030—a 6% reduction. The introduction of 700 MW of cogeneration in conjunction with a reduction in petroluem coke combustion is noticeable in the mined SCO emission profile in 2022 in Figure 15 as the rise in associated natural gas combustion emissions is more than offset by the combined reductions from less petroleum coke use and greater electrical export intensity. Figure 16 shows the drivers of the roughly 6 kgCO_2e/bbl decline from 2017 to 2030. The major contributors are process temperature and efficiency and a reduction in petroleum coke intensity (which includes not only reductions in use but also an increase in output from facilities not using petroleum coke). The ramp-up of newer lower-emission mined SCO operations and the deployment of autonomous vehicles also contribute.

Figure 15

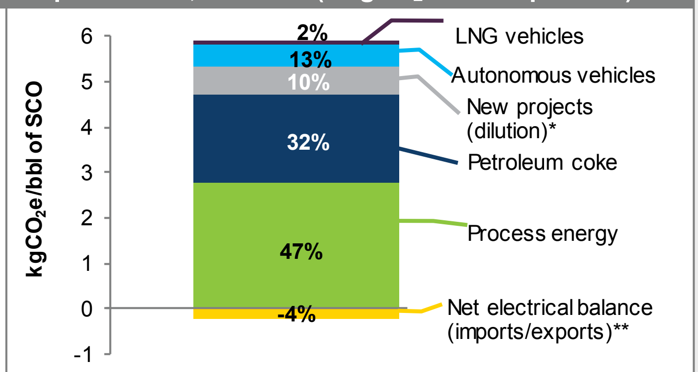
Composition of upper-bound mined SCO intensity, 2008–30



Source: IHS Markit © 2018 IHS Markit

Figure 16

Source of upper-bound mined SCO GHG intensity improvement, 2017–30 (6 kgCO_2e/bbl of product)



*New projects represent changes in intensity due to ramp-up of operation and performance of legacy operations. **Inclusive of increase in natural gas demand to meet cogeneration less heat from cogeneration and surplus power export to the grid.

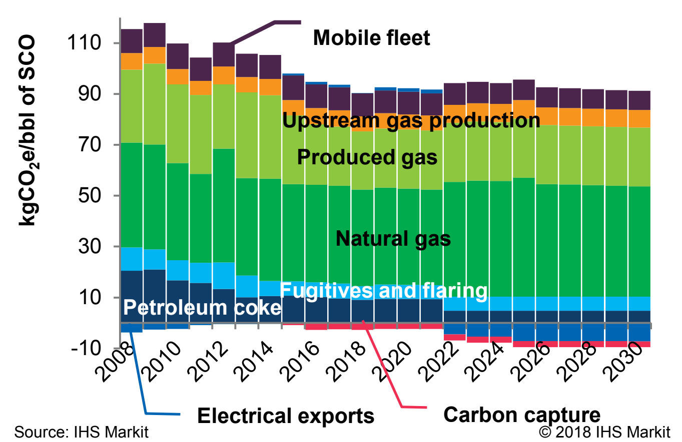
Source: IHS Markit © 2018 IHS Markit

In the IHS Markit lower-bound (more aggressive) case, oil sands mined SCO emissions decline from 91 kgCO_2e/bbl in 2017 to 82 kgCO_2e/bbl in 2030—a 10% reduction. A petroleum coke reduction and project performance have a fixed or equivalent impact on both the upper- and lower-bound cases and thus account for a smaller percentage of the greater reduction in the lower-bound case. Stronger process temperature improvements make larger contributions to intensity improvements (see Figures 17 and 18).

Oil sands mined SCO and mined dilbit (PFT) cases in detail (continued)

Figure 17

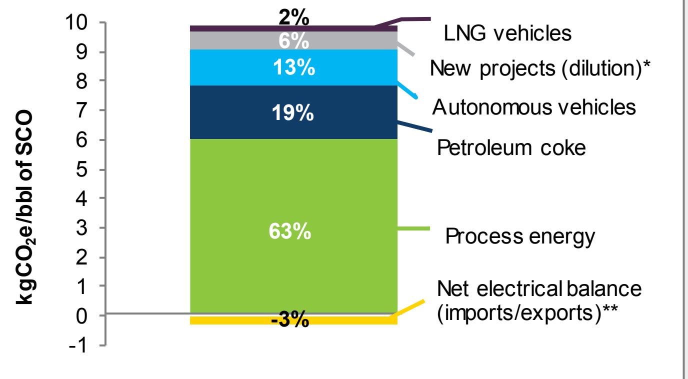
Composition of lower-bound mined SCO intensity, 2008–30



Source: IHS Markit © 2018 IHS Markit

Figure 18

Source of lower-bound mined SCO GHG intensity improvement, 2017–30 (10 $kgCO_2e$/bbl of product)



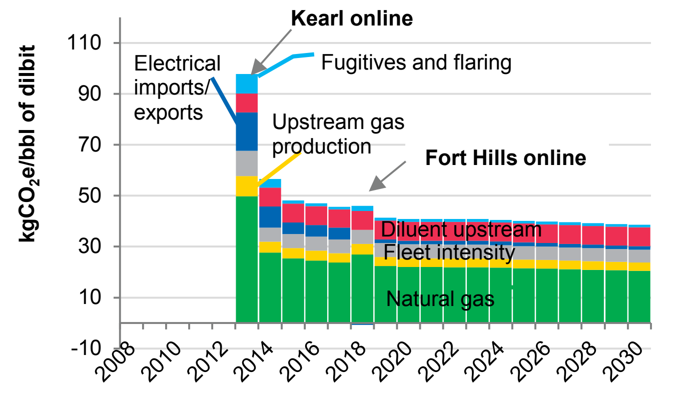
*New projects represent changes in intensity due to ramp-up of operation and performance of legacy operations. **Inclusive of increase in natural gas demand to meet cogeneration less heat from cogeneration and surplus power export to the grid.
Source: IHS Markit © 2018 IHS Markit

Oil sands mined dilbit (PFT)

In the IHS Markit upper-bound (more conservative) case, oil sands mined dilbit (PFT) emissions decline from 46 $kgCO_2e$/bbl in 2017 to 39 $kgCO_2e$/bbl in 2030—a 15% reduction. Project performance is by far the largest contributor, driven by improvements in reliability at the two mined dilbit (PFT) operations: the ramp-up of the Fort Hills project during 2018 and the undertaking of a debottlenecking project at the Kearl facility into 2019 will improve plant reliability and lower emission intensity as a result. To a lesser extent, process temperature and the rollout of an autonomous fleet also contribute (see Figures 19 and 20).

Figure 19

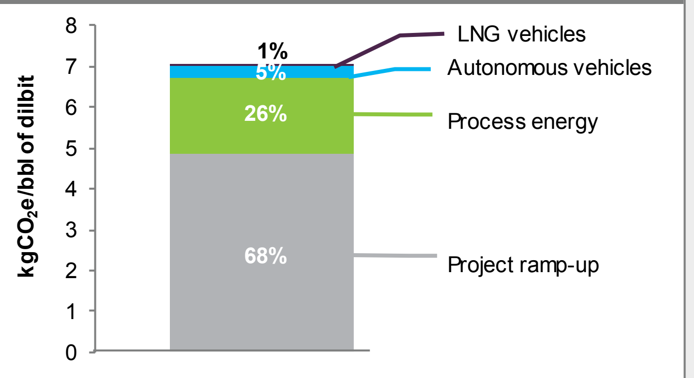
Composition of upper-bound mined dilbit (PFT) intensity, 2008–30



Source: IHS Markit © 2018 IHS Markit

Figure 20

Source of upper-bound mined dilbit (PFT) GHG intensity improvement, 2017–30 (7 $kgCO_2e$/bbl of dilbit)



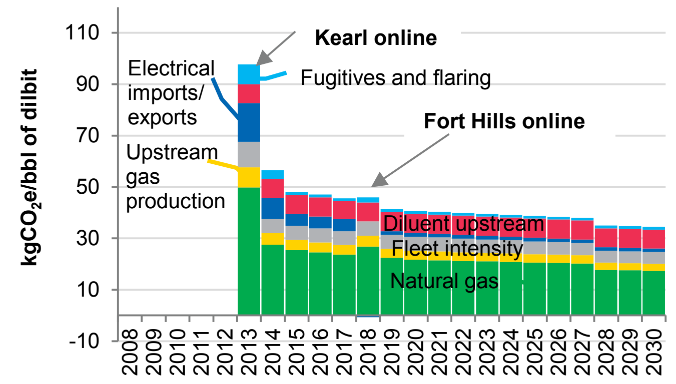
Source: IHS Markit © 2018 IHS Markit

Oil sands mined SCO and mined dilbit (PFT) cases in detail (continued)

In the IHS Markit lower-bound (more aggressive) case, oil sands mined dilbit (PFT) emissions decline from 46 $kgCO_2e$/bbl in 2017 to 34 $kgCO_2e$/bbl in 2030—a 24% reduction. The process temperature edges out project ramp-ups, with the lockstep change in process temperature modeled clearly visible in 2028. Improvements in the reliability of the two mined dilbit (PFT) operations contribute to the same absolute improvement but are a smaller share of the total reduction (see Figures 21 and 22).

Figure 21

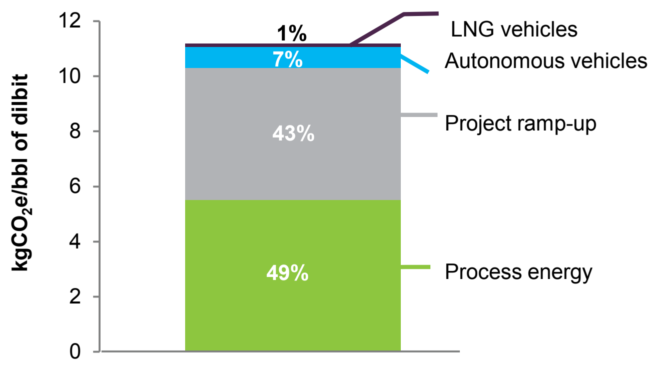
Composition of lower-bound mined dilbit (PFT) intensity, 2008–30



Source: IHS Markit © 2018 IHS Markit

Figure 22

Source of lower-bound mined dilbit (PFT) GHG intensity improvement, 2017–30 (11 $kgCO_2e$/bbl of dilbit)



Source: IHS Markit © 2018 IHS Markit

Detailed data tables can be found in Appendix A.

Table 3

IHS Markit GHG intensity SAGD outlook assumptions

Pathway	Description	Upper-bound case (more conservative)	Lower-bound case (more aggressive)
Well productivity	More durable submersible pumps, advanced seismic, greater drilling precision, and infill wells can increase the volume of oil produced with little increase in heat/steam/energy required. Over the past decade, well productivity for oil sands thermal projects has improved about 10% per year on average; however, this does not directly correlate to emission intensity improvement.	A 1% annual improvement was modeled starting in 2018. New wells were credited with the cumulative improvement the year the well is completed, with that benefit fixed (no additional gain) for the life of that well. For a well drilled in 2030, the cumulative productivity gain would reach 12%, but because the benefit was limited to new wells and fixed for the life of the well, the weighted average impact across the industry is just over 5%.	A 2% annual improvement was modeled starting in 2018. New wells were credited with the cumulative improvement the year the well is completed, with that benefit fixed (no additional gain) for the life of that well. For a well drilled in 2030, the cumulative productivity gain would reach 24%, but because the benefit was limited to new wells and fixed for the life of the well, the weighted average impact across the industry is nearly 11%.
Boiler/steam generation efficiency	The quality of water affects the efficiency of steam production. Lower water quality means less steam is produced for a similar level of fuel consumption. Improvements in water treatment and boiler technology can improve the transfer of natural gas combustion to steam production and reduce the energy intensity of steam generation.	A 1% annual improvement in boiler/ steam efficiency was modeled between 2021 and 2024. Improvements were stepped down in 2025 to 0.25% per year to reflect the likelihood that further improvements would require new technology. By 2030, the total efficiency gain is 5.5%.	A 2% annual improvement in boiler/ steam efficiency was modeled between 2019 and 2023 as new technologies and better water treatment capabilities. Improvements were stepped down in 2024 to 0.5% per year to reflect the likelihood that further improvements would require new technology. By 2030, the total benefit reaches 8.5%.

Table 3

IHS Markit GHG intensity SAGD outlook assumptions (continued)

Pathway	Description	Upper-bound case (more conservative)	Lower-bound case (more aggressive)
Steam displacement technologies	Steam displacement technologies, including natural gas coinjection and solvents, are increasingly being piloted in the field. These technologies physically reduce the volume of steam required to produce a barrel of oil. Solvents have the added benefit of increasing the mobility of bitumen and increasing the well productivity as a result. Often, solvents may also lead to the recovery of a slightly higher-quality oil.	Associated with coinjection technologies, beginning in 2020, a 4% improvement in the SOR was modeled, increasing at a rate of 0.5% per year. A further 2% improvement in the SOR was modeled associated with the deployment of solvent technology beginning in 2024 for new wells and wells drilled in the prior three years (back to 2021) with the benefit escalating at 0.5% per year (1% in combination with displacement technologies). The net gain was estimated improvement of 14% by 2030. Similar to well productivity, the benefit of these technologies was restricted to new wells but, unlike well productivity, allowed to escalate. The weighted impact exceeds 9% in 2030.	IHS Markit assumed much faster learning curves. Associated with coinjection technologies, beginning in 2019, a 4% improvement in the SOR was modeled, increasing at 0.5% per year until 2022. A further 3% improvement in the SOR was modeled associated with the deployment of solvent technology beginning in 2022 for new wells and wells drilled in the prior three years (back to 2020) with the benefit escalating at 0.5% per year until a maximum of 6% improvement is attained in 2028. The net gain for affected wells was a steam intensity reduction of 20% by 2030. However, because benefits were restricted to new wells, the weighted average impact is just over 13% in 2030.
Cogeneration expansion and net electrical balance	Building cogeneration facilities can reduce net GHG emission intensity of oil sands facilities owing to simultaneous production of steam and electricity and subsequent export of electricity. SAGD facilities are currently net exporters of electricity owing to their higher steam demand compared with electricity use.	In addition to existing installation cogeneration capacity, IHS Markit assumed that a cogeneration unit (85 MW) could be deployed as facilities achieve 60,000 b/d thresholds between 2020 and 2030.	In addition to existing installation cogeneration capacity, IHS Markit assumed that a cogeneration unit (85 MW) could be deployed as facilities achieve 45,000 b/d thresholds between 2020 and 2030.

Source: IHS Markit

The importance of deployment

Across the board, technology improvement assumptions may not work for estimating future oil sands GHG emission intensities. Thermal in situ extraction processes use wells to access subsurface oil sands deposits. These wells have limited lifespans. As areas of the reservoir under active production deplete, new wells, known as sustaining wells, must be drilled and brought online to replace the declining productivity of mature wells. This changeover of wells can impact the deployment of new technologies that rely on the life or placement of new wells. For example, steam displacement technologies make more economic sense if they are deployed earlier in well life when there is a greater volume of recoverable resources left. For this reason, IHS Markit limited the availability of new technologies to new wells after 2018. Projects proposed to incorporate displacement technologies were restricted from benefiting from IHS Markit modeled displacement improvements. The net impact of the IHS Markit attention to deployment is that by 2030 only 66% of active production is directly impacted by the IHS Markit estimated benefits of displacement technologies. Similarly, well productivity was fixed for the life of that well based on the year it was completed. The weighted average impact is reported in Table 3.

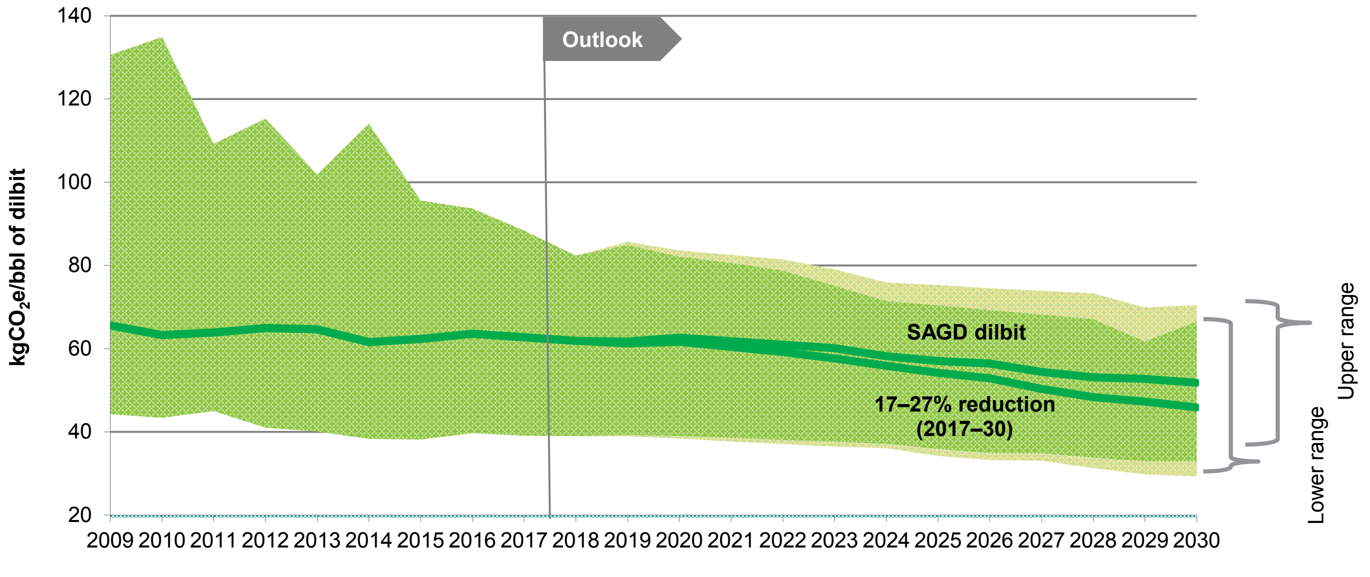
Results: Carbon intensity of future SAGD operations

Based on IHS Markit assumptions and attention to deployment, the GHG intensity of oil sands SAGD dilbit declines from 63 $kgCO_2e$/bbl in 2017 to 46–52 $kgCO_2e$/bbl by 2030—a 17–27% reduction (see Figure 23).

The reductions relate to lower steam intensity arising from steam displacement technologies, as well as better use of natural gas from improvements in well productivity and steam generation (see Figures 24 and 25). The composition of growth (what will be developed) also contributed. This composition was arguably influenced

Figure 23

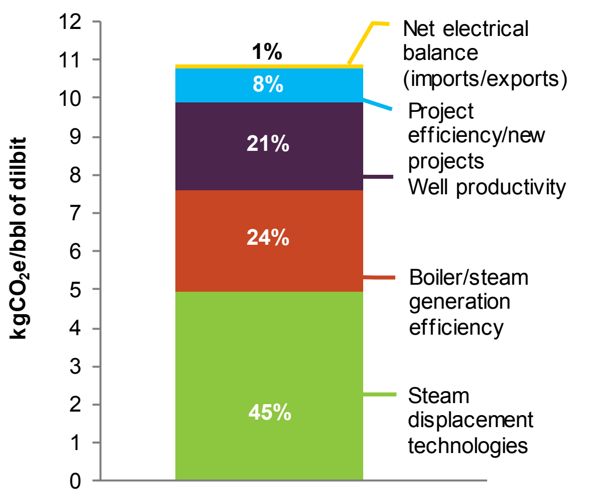
GHG intensity of oil sands SAGD dilbit, 2009–30



Note: CNOOC/Nexen Long Lake was not included in our estimate of SAGD GHG emission intensity. Had the facility been included, it would have increased early SAGD emission intensity because of its associated upgrader. In recent years, the facility has operated at reduced rates and without an upgrader. It would not have significantly affected current industrywide emission estimates as a result. Production is increasing in 2018, but there is currently no associated upgrader operating. Because of variability in emissions and production, the facility was not included in the SAGD estimate.
Source: IHS Markit

Figure 24

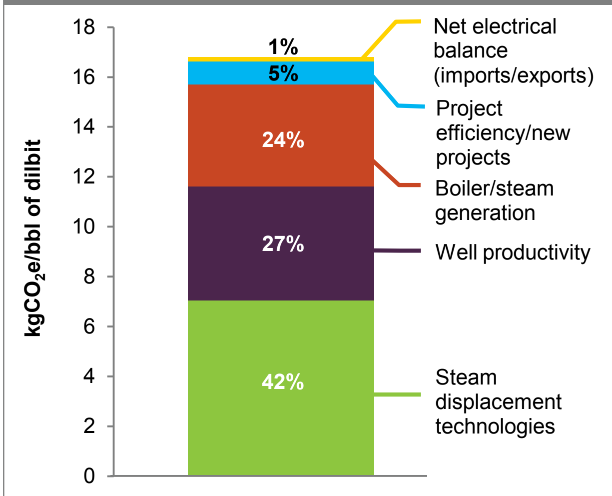
Source of upper-bound oil sands SAGD GHG intensity improvement, 2017–30 (11 $kgCO_2e$/bbl of dilbit)



Source: IHS Markit

Figure 25

Source of lower-bound oil sands SAGD GHG intensity improvement, 2017–30 (17 $kgCO_2e$/bbl of dilbit)



Source: IHS Markit

Oil sands SAGD assumptions

Well productivity. Better understanding and drilling techniques have improved the placement of wells, while new technologies have allowed for better steam control (using steam more efficiently), expanded access to the reservoir (better conformance), and longer laterals (more oil from the same well). Innovations such as the use of infill wells have aided recovery with no net new steam requirement. Other technologies such as more durable submersible pumps, which aid in recovery, combined with predictive maintenance have reduced downtime and thus increased output. Although well productivity contributes to more efficient extraction, these improvements do not necessarily equate one-to-one with emissions. Moreover, in the absence of transformational technology, productivity gains are not inexhaustible and would slow.

Boiler/steam generation. Boiler efficiency is the rate of energy transfer from natural gas to steam. Over time, boilers have become more efficient. Technologies are under development that could dramatically improve this relationship. The efficiency of steam generation is affected by water quality or impurities (energy wasted on material that cannot be converted to steam). Advancements in water treatment that can improve the quality of water that moves into boilers would allow for more efficient use of natural gas.*

Steam displacement technologies. SAGD operates on two fundamental principles: energy (to warm and mobilize the bitumen) and pressure (to assist gravity in recovery). The steam plays both these functions. Over time, oil sands reservoirs have been found to be more insulated than once believed, and once a reservoir is at sufficient temperature, less energy may be required to maintain the reservoir temperature. SAGD producers are experimenting in the field with replacing steam with noncondensable gases and solvents. These alternative materials physically reduce steam and thus natural gas demand per barrel produced while maintaining the "gravity assist" or pressure. Solvents have the additional benefit of improving the mobility of bitumen (lowering the energy required to improve mobility). Both technologies have great potential, with the former being deployed at scale on select fields and the latter involved in advanced pilots and incorporated in two proposed projects. Methane has been the principal displacement gas used to date, but some may be experimenting with other gases. Although these technologies reduce the natural gas combustion intensity of extraction, upstream emissions are associated with the production of the coinjected material. These emissions were captured in the IHS Markit model and counted against steam displacement intensity improvements. Note that some solvent processes aspire to be 100% solvent (e.g., nsolv). These were not modeled by IHS Markit.

Cogeneration. SAGD operations use both boilers and cogeneration to meet steam demand. In 2017, IHS Markit estimated that installed cogeneration capacity at SAGD operations contributed to an offset credit (using the IHS Markit method) of approximately 6 $kgCO_2e$/bbl of dilbit. In recent years, the rate of installed cogeneration capacity expansion versus production growth has slowed. SAGD operations averaged about one 85 MW cogeneration unit per 56,000 b/d over the past decade and a half (2003–17), compared with one 85 MW unit per 70,000 b/d over just the past decade (2008–17). This change has tightened or eroded the benefit of electrical power exports on the GHG intensity of production. Depending on the future level of cogeneration, this trend could continue or be reversed.

*Impurities can build up in the recycled water used in oil sands extraction. These impurities cannot be converted to steam, which reduces the efficiency of steam generation.

** The comparison is based on the weighted average in 2030 of projects in the IHS Markit outlook not in operation in 2017 without any technology or efficiency improvements applied to the base operating efficiencies compared with the weighted industry average in 2017. The historical SOR is based on "ST53: Alberta In Situ Oil Sands Production Summary," AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53, retrieved 30 May 2018. The estimate of the future SAGD weighted SOR is based on the IHS Markit *North American Crude Oil Markets Canadian Fundamentals Data: First quarter 2018* and AER regulatory applications, company announcements, and websites.

Oil sands SAGD assumptions (continued)

Composition of growth. The composition of new developments—which projects, how big they are, and their design efficiency—will influence the future average carbon intensity. All things being equal, new operations should be more efficient than legacy ones because they benefit the most from the latest technologies. However, reservoir quality will also influence how these facilities operate. IHS Markit assumed operations for existing SAGD expansions would be similar to the average operations of the main facility over the past three years (2015–17, adjusting for operations impacted by the 2016 Fort McMurray wildfire). For entirely new operations, IHS Markit used regulatory filings and investor relation releases to establish base efficiencies onto which new technologies or efficiencies could be modeled. In general, the weighted average SOR of new developments (before any additional assumptions were allowed to impact efficiency) was 8% lower than the industry average of 2.71 in 2017.** This would reduce overall industry intensity should the growth occur as IHS Markit envisions. In this way, the greater the potential growth, the greater the potential for GHG emission intensity reductions.

by lower prices, resulting in more focused development of more efficient projects in the IHS Markit outlook. Examples include projects designed to incorporate solvent extraction technologies from the start. The stronger technology assumptions in the lower-bound case diminished the relative significance of the impact of new projects, which do not change between our cases (see Table 3).

An interesting result, however, was that our assumption about future expansion of cogeneration capacity was not sufficient to materially contribute to lower GHG emission intensity. This was related to the value of the electrical exports we chose. A higher value would generate different results. For more details, see Appendix A.

Concluding remarks and comparisons

This section discusses some of the implications, including presenting the results on an upstream or production industry average basis and a full-cycle basis by drawing upon prior IHS Markit research.

An industry average

Rolling up our results, we created overall oil sands average intensity. Over the past (near) decade (2009–17), the average upstream GHG intensity of oil sands extraction (using system boundaries consistent with a life-cycle basis) fell 21%—led by oil sands mining. This trend is expected to continue, with many improvements already in motion. Examples included the planned expansion of mining cogeneration capacity that could further reduce petroleum coke use, the ongoing ramp-up and expansion of newer mining operations with lower GHG emission intensities, and the deployment of steam displacement technologies among in situ operations. These factors, when coupled with a reasonable pace of technology development and efficiency deployment, could further reduce the oil sands GHG emission intensity by 16–23% by 2030 (see Figure 26). Certainly, this is a forecast, and the reality will differ from our projections. Yet, the lack of transformational technologies in our outlook, many of which are in advanced pilots and demonstrations, such as in-pit mine face extraction, could lead to much more dramatic results.[18]

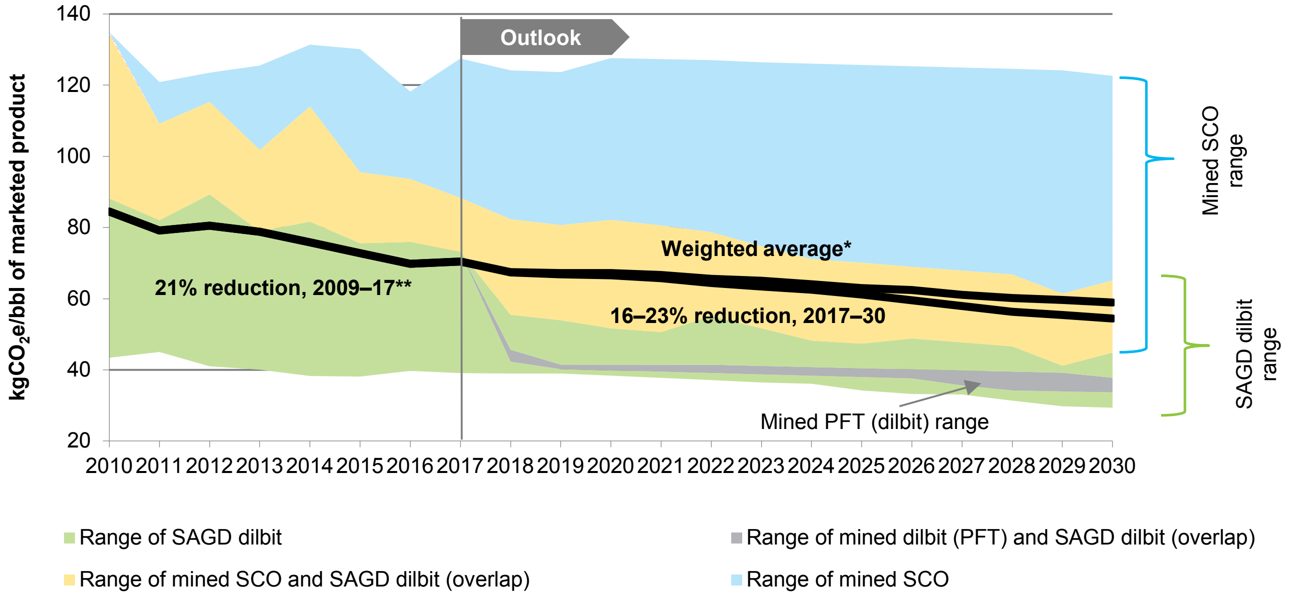
Variability in the oil sands

This report has focused on estimating the average upstream GHG intensity of the oil sands by extraction process and marketed product (CSS dilbit, SAGD dilbit, mined SCO, and mined dilbit). Yet, within any region or play there is considerable variability in operations and performance. This is equally true in the Canadian oil

18. For more information on in-pit mine face extraction, see "In-Pit Extraction Process," Emissions Reduction Alberta, http://eralberta.ca/projects/details/in-pit-extraction-process, retrieved 3 August 2018.

Figure 26

Average and full range of oil sands GHG emission intensity by year, 2010–30 ($kgCO_2e$/bbl of marketed product)



*Estimate of total oil sands average includes oil sands CSS dilbit, SAGD dilbit, mined SCO, mined dilbit, primary, experimental, and EOR. Historical estimates for CSS were included with no intensity improvement after 2017. Estimates for primary were taken from a prior IHS Markit report (cited at the end of this note) with the same values being applied to experimental and EOR. Primary, experimental, and EOR accounted for about 7% of oil sands production in 2017 (18% including CSS), declining to 5% by 2030 (11% including CSS). Ranges shown for mined dilbit (PFT), SAGD dilbit, and mined SCO range from lower-bound minimum to upper-bound maximum. Note that prior to 2018, there was only one operating mined dilbit (PFT) facility and thus no range. Source of prior estimates IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*, www.ihsmarkit.com/oilsandsdialogue.
**Note that 2009 is not shown in this figure but is in Appendix A.

Source: IHS Markit

sands and is clearly visible in Figure 26. In 2017, IHS Markit estimates the full range of upstream GHG intensity of oil sands production (on a marketed product basis) spanned 88 $kgCO_2e$/bbl—from 39 $kgCO_2e$/bbl to 127 $kgCO_2e$/bbl. This range highlights that the average is not the reality for many operations and that caution should be exercised when considering averages.

The oil sands on a full life-cycle basis

Given the scope and complexity of this report, we could not include an update to the downstream components of a full life-cycle basis or update our estimate of the average crude oil refined in the United States (the US average). However, by sourcing downstream estimates of transportation and refining emissions from our prior study, we could include an estimate of the full life-cycle GHG intensity for mined SCO, mined dilbit (PFT), and SAGD dilbit, as well as a range from the minimum to maximum intensity (see Figure 27).[19]

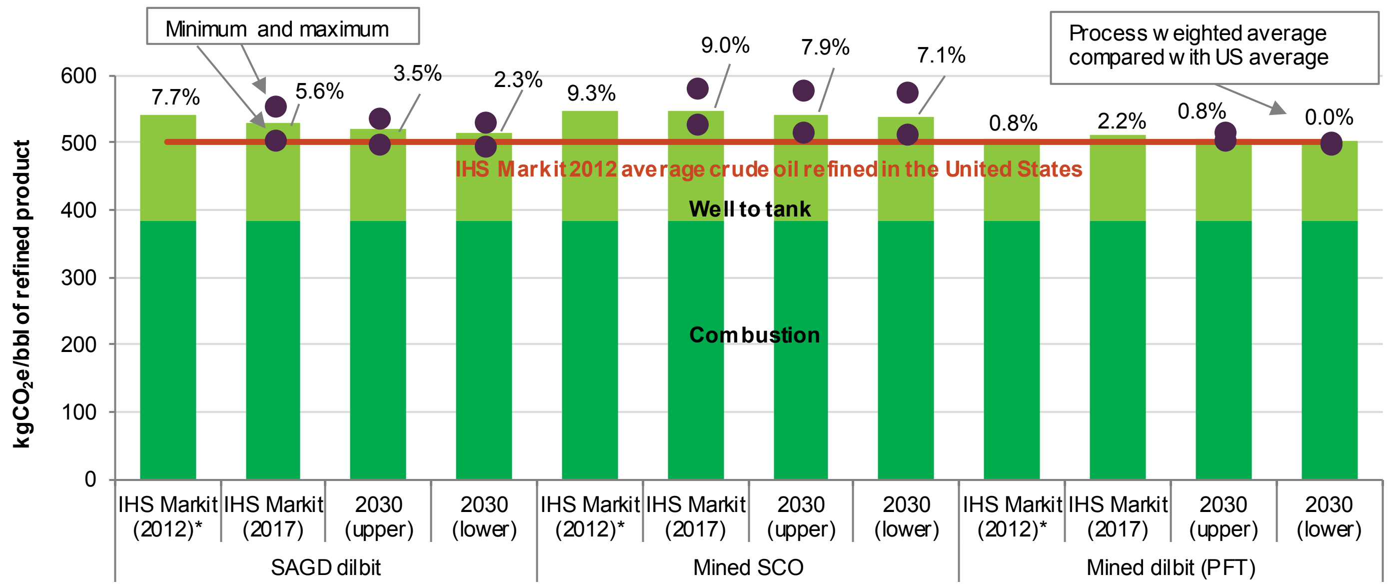
Interestingly, the lower end of the IHS Markit estimate of oil sands GHG emission intensity indicates that some facilities, when placed on a full life-cycle basis, are already (in 2017) comparable to the US average. Discussion of each stream is included below:

- **SAGD dilbit.** Compared with our prior 2012 estimate, our SAGD dilbit emission intensity is lower. Assuming the US average remains relatively static, the SAGD dilbit average emission intensity would decline to within 2–4% of the US average.

19. Source of prior estimates: IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*.

Figure 27

Oil sands life-cycle GHG emission cases compared



*The completion of the full life-cycle assessment for "IHS Markit (2017)," "2030 (upper)," and "2030 (lower)" incorporated crude transport, crude refining, and refined product transport sourced from the prior IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*, www.ihsmarkit.com/oilsandsdialogue. "IHS Markit (2012)" and "IHS Markit 2012 average crude oil refined in the United States" were also sourced from the same study. The US average is based on the year 2012. IHS Markit acknowledges that it could evolve over time. There was no feasible way to account for this variance in this study. However, one of the conclusions of the prior IHS Markit study cited here already was that although US production changed considerably between 2005 and 2012, the US average remained relatively constant as refinery runs continued to process similar crudes, albeit from different supply sources.

Source: IHS Markit

- **Mined SCO.** The mined SCO emission intensity was nearly identical between our current estimate and prior estimate. On a full life-cycle basis, mined SCO emission intensity declines 1–2% against the US average. This arguably reflects the limited assumptions we modeled for mined SCO and the relative share of upstream emissions over total life-cycle emissions.

- **Mined dilbit**. Production of mined dilbit (PFT) did not start until 2013, and our prior estimate was of a fully ramped-up facility. However, normalization of output does not appear to have yet been achieved with mined dilbit (PFT), as evidenced in the higher estimate of GHG emission intensity than our 2012 estimate. Over time, the mined dilbit (PFT) emission intensity will fall to be on a par with the US average.[20]

Concluding thoughts

This study reviewed the historical GHG emission intensity of upstream oil sands extraction and the factors that could shape its future. Prior IHS Markit analysis has shown the oil sands to be within the range of other crude oils refined in North America. This study shows that upstream oil sands GHG intensity has been declining. On average, upstream emissions are one-fifth lower than a decade ago and could fall another approximately 20% over the coming decade. On a full life-cycle basis, this would bring the industry closer to the US average. However, averages do not capture the entire picture, with some facilities already at or near the US average today. Still, this is a forecast. Challenges remain, and work still needs to be done. However, the absence, with few exceptions, of transformational technologies in this study—even though many are advancing—may indicate a greater potential for reductions than shown in our results.

20. Depending on the severity of the PFT process, bitumen quality can be impacted. This can affect downstream refining emissions. The IHS Markit use of prior downstream mined dilbit (PFT) emissions did not consider this potential, and a lower total life cycle could result than our estimate.

IHS Markit team[21]

Kevin Birn, vice president, IHS Markit, is part of the IHS Markit North American Crude Oil Markets team and leads the IHS Markit Oil Sands Dialogue. Mr. Birn is responsible for a team of oil market analysts focused on western Canada. He has authored numerous reports associated with the development of the Canadian oil sands. His expertise includes Canadian oil sands development, oil sands cost and competitiveness, crude oil markets, crude oil transportation logistics, GHG intensity of crude oil, and Canadian energy and climate policy. Mr. Birn has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US secretary of energy. Prior to joining IHS Markit, Mr. Birn was a senior economist with the Government of Canada and a partner in a software firm. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta.

21. Special thank you to former IHS Markit colleague Hossein Safaei, the original architect of IHS Markit upstream oil sands greenhouse gas (GHG) intensity models.

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