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The trajectory of oil sands GHG emissions: 2009–35

April 2022

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Vice President

Crude Oil Markets | **Strategic Report**

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Key implications

Ambition to accelerate the energy transition is increasing. Governments, industry, and financial institutions are all announcing more aggressive action to combat global warming. This includes in the Canadian oil sands. This study provides a fresh perspective on how the greenhouse gas (GHG) intensity and absolute emissions of the Canadian oil sands could evolve to 2035.

- **Over the past decade, the oil sands GHG intensity declined by 20%, while supply more than doubled, leading to a 60% rise in absolute emissions.** The average upstream GHG intensity of oil sands crude oil fell by 17 kilograms of carbon dioxide equivalent per barrel ($kgCO_2e$/bbl), to 69 $kgCO_2e$/bbl, from 2009 to 2020. Over the same period, supply rose by 1.8 MMb/d, leading to an increase in total emissions of 28 million metric tons of carbon dioxide equivalent ($MMtCO_2e$), to 76 $MMtCO_2e$ in 2020 (80 $MMtCO_2e$ in 2019).

- **Existing trends suggest a further GHG intensity reduction of 20–28% should be expected by 2035 from 2020, or a total reduction over 25 years of 35–42%.** By 2035, the average GHG intensity of oil sands could range from 49 $kgCO_2e$/bbl to 55 $kgCO_2e$/bbl. Although GHG intensity reductions will come from a variety of sources, carbon capture and storage (CCS) and steam displacement technologies are two technologies that could lead to greater reductions.

- **Within the next few years, ongoing GHG intensity reductions are poised to overtake production growth, leading to a peak and then a decline in absolute emissions.** Despite the potential for over 900,000 b/d more output between 2020 and 2035, absolute emissions may begin to decline around the middle of this decade. Thereafter, the rate of decline is linked to the pace and scale of the deployment of key technologies, such as CCS or steam displacements.

- **The IHS Markit outlook is based on existing trends, whereas indications are that GHG reductions could be more dramatic.** Compared with 2020 which was artificially low, existing trends point toward absolute emissions between just over 6 $MMtCO_2e$ higher to 2 $MMtCO_2e$ lower in 2035 (or nearly 8–14 $MMtCO_2e$ lower than peak emissions in the mid-2020s). Announced oil sands ambition could result in an over 19 $MMtCO_2e$ reduction relative to 2020, by 2030—this is 17 $MMtCO_2e$ lower and five years sooner than IHS Markit cases.

- **Although the average delineates the overall trend, it can also significantly diverge from any one facility.** IHS Markit results are presented "on average," but caution is advised because the GHG intensity of any one facility can differ dramatically from the average, and over time as different choices are made.

Note: This report does not directly address implications of existing or announced policies, such as the cap on absolute oil and gas emissions, which could alter these outlooks. This study remains a projection of existing trends.

—April 2022

About this report

Since 2009, IHS Markit has provided research on issues surrounding the development of the Canadian oil sands. To date, IHS Markit has made public seven studies into the greenhouse gas (GHG) emissions intensity of oil sands crude oil. In 2018, we published the comprehensive review of past and future potential GHG intensity of the Canadian oil sands to 2030. The impact of COVID-19 and a rise in global ambition to reduce GHG emissions is driving an acceleration of more ambitious GHG intensity and absolute emissions reduction targets. This study provides a fresh perspective on how oil sands GHG intensity and absolute emissions could evolve to 2035.

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

This report and past Canadian 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. Historical performance was derived using publicly available regulatory data and two purpose-built bottom-up GHG emissions models for oil sands thermal operations and oil sands mining operations, respectively. A description and explanation of IHS Markit historical estimation models and methodology can be found in Appendix B. IHS Markit has full editorial control over this report and is responsible for its content.

Structure. This report has six sections and two appendixes.

- Introduction
- Method: Estimating oil sands GHG emissions
- Part I: GHG intensity of oil sands past: 2009–20
- Part II: GHG intensity of oil sands future: 2021–35
- Part III: Absolute oil sands GHG emissions: 2009–35
- Concluding remarks

- Appendix A: Data tables of results
- Appendix B: Method details

The trajectory of oil sands GHG emissions: 2009–35

Kevin Birn, Vice President

Introduction

Ambition to accelerate the energy transition is growing. At the time of publication, four-fifths of global greenhouse gas (GHG) emissions are covered by some sort of net-zero ambition. Meanwhile, stakeholders are looking to better understand GHG emissions to inform their own policies and targets. Although lowering absolute GHG emissions is what is ultimately required, GHG intensity has emerged as a key competitive metric because it provides a common basis of comparison regardless of the scale of an operation.

These pressures are leading to a reprioritization of capital toward renewables, cleantech, and decarbonization opportunities. Oil and gas companies have been responding to rising pressure to reduce GHG emissions by announcing more ambitious targets. In addition to GHG intensity reduction targets, some companies have begun to make absolute emissions targets. This includes in the Canadian oil sands, where nearly all operations have made net-zero commitments.

In Canada, the oil and gas sector remains a major economic driver, accounting for about 9% of national GDP, and is the country's single-most valuable export.[1] Meanwhile, there has also been a ratcheting up of policy to accelerate the reduction of GHG emissions. Canada has imposed a national price on carbon and set out a trajectory for the price to increase to 2030, when it would reach C$170 per metric ton; the country has implemented a Clean Fuel Standard; and recently Canada announced its intention to cap and set absolute emissions targets for its upstream oil and gas sector (although details on implementation are still forthcoming).[2]

In 2018, IHS Markit published a comprehensive review of the past and potential future GHG intensity of the Canadian oil sands, titled *Greenhouse gas intensity of oil sands production: Today and in the future*.[3] However, much has changed since IHS Markit issued that report. This study provides a fresh perspective of both the future intensity of the Canadian oil sands and the absolute GHG emissions expectations.

This study has six sections:

- Introduction
- Method: Estimating oil sands GHG emissions
- Part I: GHG intensity of oil sands past, 2009–20
- Part II: GHG intensity of oil sands future, 2021–35
- Part III: Absolute oil sands GHG emissions, 2009–35
- Concluding remarks

1. Government of Canada, "Trade Data Online," https://www.ic.gc.ca/eic/site/tdo-dcd.nsf/eng/home, retrieved 4 February 2022; Statistics Canada, Table 36-10-0434-01, "Gross domestic product (GDP) at basic prices, by industry, monthly (x 1,000,000)," January 2021 to November 2021, https://doi.org/10.25318/3610043401-eng, retrieved 4 February 2021.

2. Environment and Climate Change Canada (ECCC), "How carbon pricing works," https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/putting-price-on-carbon-pollution.html, retrieved 2 November 2021; ECCC, "Clean Fuel Standard," https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard.html, retrieved 2 November 2021; CBC News, "Canada will put a cap on oil and gas sector emissions, Trudeau tells COP26 summit," https://www.cbc.ca/news/politics/trudeau-cop26-cao-oil-and-gas-1.6232639, retrieved 2 November 2021.

3. For more information see www.ihsmarkit.com/oilsandsdialogue.

Throughout this report, there are numerous references to oil sands terminology. For additional background on the oil sands, please see the box "Canadian oil sands primer."

Canadian oil sands primer

Accounting for nearly 5% of global supply in 2021, the oil sands are perhaps the most scrutinized source of crude oil in the world.* Current estimates place the amount of remaining economically recoverable reserves in the oil sands at 161 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 requires energy, resulting in GHG emissions. Two forms of extraction dominate: mining and in situ.

Mining. Approximately 20% of 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 2021, over two-fifths of oil sands supply (or marketable product, which can include diluents) came from mining. This ratio is expected to diminish only modestly by 2035. There are two forms of mining extraction:

- **Integrated mines, or mined synthetic crude oil (SCO).** Legacy mining operations invested in and constructed heavy oil processing units upstream in the oil sands, which are typically 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 emissions, which otherwise would occur downstream.

- **Unintegrated mines or mined PFT.** There are two mining operations that do not integrate an upgrader. Through a process known as paraffinic froth treatment (PFT), some of the heaviest components found in bitumen are precipitated out.**** The bitumen produced from these facilities is marketed as a blend of bitumen and lighter hydrocarbons (typically a natural gas condensate), which is known as diluted bitumen (dilbit). This process avoids the energy associated with upgrading, reducing upstream GHG production emissions. However, the marketed dilbit from unintegrated mines is more GHG intensive to refine than SCO, increasing downstream refining emissions. Still, on a net or full life-cycle basis, mined dilbit is lower than mined SCO.

("Canadian oil sands primer" continued on next page.)

*The estimate is based on total oil sands supply, inclusive of diluents imported into and used in the creation of bitumen blends in 2021, compared with total global crude production as marketed from the IHS Markit Annual Strategic Workbook 2021. On a production basis (without diluent), oil sands ac¬counted for just about 4% of the global crude oil system. Global supply and production estimates do not include NGLs, biofuels, or other liquids.

**Alberta Energy Regulator (AER), ST98: 2021: "The ST98: Alberta Energy Outlook 2021, Executive Summary," p. 8, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/executive-summary, retrieved 15 February 2021.

***Despite accounting for one-fifth of the recoverable resource, the total minable area only makes up 3% of the surface area of the oil sands region.

**** Although the Albian sands mining operations use PFT to transport a diluted bitumen (dilbit) from their mining operations near Fort McMurray, Alberta, to the Scotford Upgrader near Edmonton, Alberta, where it then markets SCO. IHS Markit includes this operation as an integrated mine.

Canadian oil sands primer (continued)

In situ. About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling. In 2021, nearly three-fifths of oil sands supply (which includes diluents) came from in situ operations (on a production basis, output is similar to that from mines). The relative share of supply from in situ operations is anticipated to appreciate only modestly by 2035. Both primary and thermal extraction methods are deployed in situ. The primary (which also includes some experimental) extraction methods is much more akin to conventional oil production. In 2021 it accounted for about 5% of total oil sands supply, where it is expected to remain to 2035. Thermal production accounts for more than half (52%) of oil sands supply today (and over 90% of in situ supply). Thermal methods inject steam into the reservoir to lower the viscosity of the bitumen that allow it to flow to the surface. Natural gas is used to generate the steam, which results in GHG emissions. Some operations feature cogeneration units, where natural gas is used to generate both steam and electricity. 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 an average ratio of 72% bitumen to 28% 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 47% of supply in 2021. SAGD is the only form of oil sands extraction where some expansion projects are anticipated, and by 2035 it could account for 51% of oil sands supply.

- **Cyclic steam stimulation (CSS)** was the first thermal process used to commercially recover oil sands in situ. CSS currently makes up about 8% of total supply. CSS output is expected to remain relatively flat to 2035. However, growth from other sources of supply is anticipated to reduce the CSS share of oil sands supply to about 7% by 2035.

Method: Estimating oil sands GHG emissions

This report provides a view of the GHG emissions—past and future—of the two primary sources of oil sands extraction: mining and in situ thermal extraction. Differences in data and production processes necessitate distinct modeling approaches for each. Oil sands mining operations are further subdivided in this report into integrated mines that upgrade bitumen to supply SCO and unintegrated mines (mined PFT) that produce bitumen and market or supply dilbit. Thermal operations are subdivided into SAGD facilities that inject steam to enable bitumen recovery using horizontal well pairs and cyclic steam stimulation (CSS), which principally uses vertical wells to inject and recover bitumen. Both of these facilities produce bitumen but market dilbit. Table 1 provides a list of major crude streams included in this study.[4]

Table 1

Oil sands production techniques modeled in this study

Category	Oil sands extraction type	Name used in study	Period modeled
Mining	Integrated mining (mine with an upgrader)	Mined SCO	Past and outlook
	Unintegrated mining (mine without an upgrader)	Mined PFT	Past and outlook
Thermal in situ	Cyclic steam stimulation	CSS	Past only
	Steam-assisted gravity drainage	SAGD	Past and outlook
Other in situ	Primary, experimental, and enhanced oil recovery	Primary, experimental, and enhanced oil recovery	Not modeled (included as a constant)

Source: IHS Markit

The IHS Markit model and method used in this report builds upon prior oil sands GHG reports. Notably in 2018, the report titled *Greenhouse gas intensity of oil sands production: Today and in the future* introduced and outlined the IHS Markit upstream oil sands emissions model. In 2020, IHS Markit published *The GHG intensity of Canadian oil sands production*, which included some enhancements to the IHS Markit oil sands model.[5]

This section outlines the method and model used in this report. For additional information see Appendix B.

Understanding system boundaries

GHG emissions estimates of the same activity can differ depending on which emissions sources are included. System boundaries or boundary conditions define the parameters for which emissions are counted or included in an estimate and can, for obvious reasons, affect the results.

Different system boundaries are used in this report. Unless otherwise stated (specifically in Part I and Part II), the GHG intensity estimates are aligned with system boundaries consistent with the life-cycle stage of upstream extraction and initial processing (see Figure 1). Absolute oil sands GHG emissions only consider direct on-site GHG emissions, which is consistent with the United Nations Framework Convention on Climate Change (UNFCCC) National Inventory Reporting.[6] This was done to enable comparability with the Environment and Climate Change Canada (ECCC) National Inventory Report (NIR).[7]

4. Other forms of extraction found in the oil sands region—primary, experimental, and enhanced oil recovery (EOR)—were included in the oil sands industry average but not modeled in this study. GHG intensity estimates of primary, experimental, and EOR were held static and sourced from the IHS Markit Strategic Report *Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*.

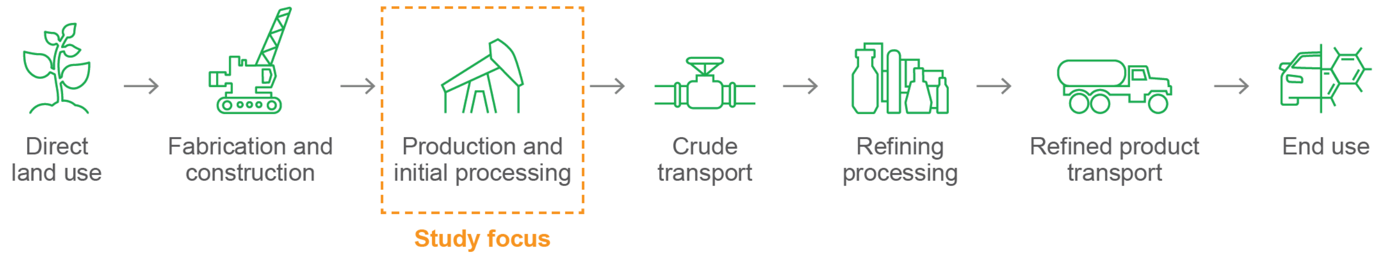
5. Copies of both reports are publicly available and can be accessed from www.ihsmarkit.com/oilsandsdialogue.

6. This is consistent with direct on-site scope 1 emissions.

7. ECCC, "Canada's official greenhouse gas inventory," https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/inventory.html retrieved 27 December 2021.

Figure 1

Illustration of crude oil product life-cycle pathway

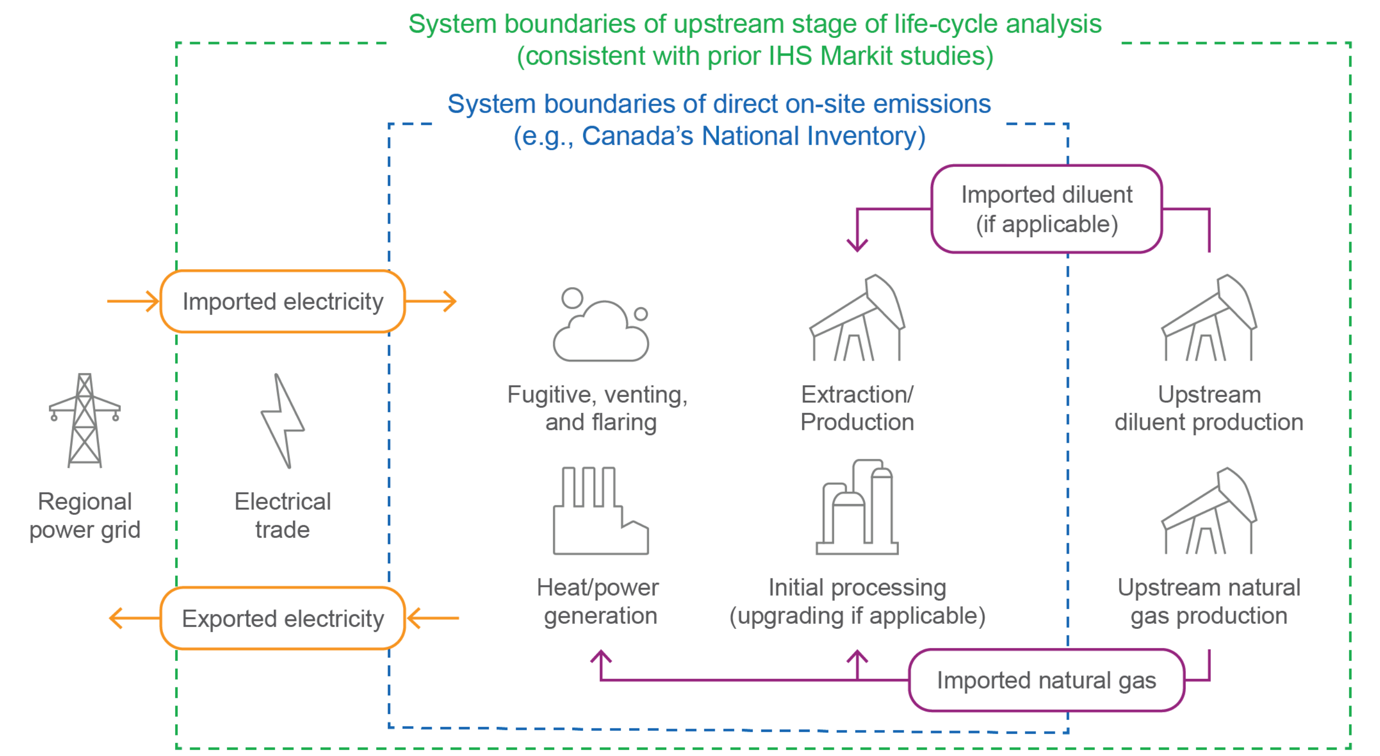


Source: IHS Markit © 2022 IHS Markit: 2005413

Figure 2 illustrates the differences between these two primary system boundaries used in this study. System boundaries consistent with the upstream stage of life-cycle emissions considers a wider set of emissions. In addition to direct on-site GHG emissions, it also includes indirect emissions associated with upstream production of fuel, such as natural gas used in production or diluent used in the creation of dilbit, as well as the import and export of electricity that can arise from facility use or surplus electricity from cogeneration.[8]

Figure 2

Illustration of system boundaries



Source: IHS Markit © 2022 IHS Markit: 2005414

8. Many oil sands facilities incorporate cogeneration units, which results in both electricity and heat. Because of cogeneration, some facilities can be net exporters of electricity to the power grid. This can be a key source of difference between the two system boundaries used in this report.

It should be noted that estimates that have been made to be consistent with life-cycle GHG practices are of marketable oil sands products—this means bitumen processed or upgraded into SCO and bitumen diluted with lighter hydrocarbons to create dilbit. This is consistent with prior IHS Markit GHG intensity studies in the Canadian oil sands. Under direct system boundaries, estimates are of production: SCO and bitumen. These factors were incorporated into the labeling throughout the report. Life-cycle consistent upstream GHG intensity of mining is labeled mined SCO and mined PFT dilbit , and thermal oil sands are labeled as SAGD dilbit and CSS dilbit. This compares with direct GHG intensity estimates being labeled as mined SCO, mined PFT bitumen, SAGD bitumen, and CSS bitumen.

IHS Markit also generated absolute GHG emissions estimates to be consistent with the definition laid out by the Government of Alberta in the Oil Sands Emissions Limit Act, known colloquially as the 100 million metric tons or megatons (MMt) oil sands emission cap (the "100 MMt cap").[9] Under the 100 MMt cap, emissions associated with electricity produced from cogeneration; emissions arising from primary, experimental, and EOR crude oil production (occurring within the oil sands region); and emissions associated with upgraders or upgrader expansions that started after 2015 are excluded.

Where these estimates are shown in the report they are clearly labeled and identified.

Estimating GHG intensity of the oil sands past, future, and absolute emissions

IHS Markit has a well-established GHG emissions model for upstream oil sands extraction. The tool consists of two separate models. One is for upstream oil sands in situ thermal operations, which consist of SAGD and CSS projects. Both thermal extraction methods produce bitumen and market or supply dilbit. The other model covers upstream oil sands mining, which includes integrated mines that upgrade bitumen into SCO and unintegrated mines that market dilbit.

Compared with past analysis, this study incorporates additional operational data up to and including the year 2020, as well as additional cogeneration performance data from the Alberta Environment and Parks (AEP). This study also made changes to IHS Markit estimates of installed cogeneration capacity as well as the treatment of electrical imports, changing their valuation from being consistent with a combined-cycle natural gas generation unit to the Alberta grid average. These changes limit the comparability with past IHS Markit oil sands GHG studies. This report represents our latest and most accurate assessment.

In prior studies, the IHS Markit oil sands emissions model has demonstrated its ability to align with official government estimates. Enhancements made in this report have narrowed the difference between historical IHS Markit oil sands GHG estimates and those reported in Canada's NIR to less than 1%. This section provides an overview of the method and application of the model used in this report.

Estimating historical GHG emissions intensity

The IHS Markit oil sands emissions model makes use of regulatory and government data and, in some instances, data supplied by companies to estimate the intensity of fuel and energy (heat and electricity) use as well as GHG intensity of specific emissions, to estimate emissions of Canadian oil sands facilities. Key sources of information are obtained from the Alberta Energy Regulator (AER) and the AEP. Once fuels, electrical balance, and emissions are sourced, they can be converted to a consistent GHG emissions basis and summed to arrive at historical facility-level estimates.

Establishing future GHG emissions baseline

In making an estimate of past oil sands facilities performance, a historical relationship by fuel and energy use (heat and electricity) and/or GHG intensity is identified by year. These relationships are used to establish a baseline of how a facility or segment may perform under varying production assumptions.

9. "Oil Sands Emissions Limit Act, Province of Alberta," https://www.qp.alberta.ca/documents/Acts/O07p5.pdf, retrieved 1 November 2021.

Once the historical baseline relationships are established, they can be rolled forward against IHS Markit's project-specific production outlook. As facility production shifts over time and/or new facilities come online, individual operations', subsector, and sector GHG intensities will change, as will absolute GHG emissions. The implications of new technologies can also be modeled onto individual fuel, energy, and/or GHG emissions intensity relationships (which were dubbed baselines) to gain insight about how they may influence future emissions.

Because the baseline intensity relationships will change through time, past operations can be less reflective of more recent activity. As a result, the creation of the baseline relationships within each facility relied more on recent history (2017-20). Abnormal annual average fuel, energy, and GHG intensity relationships were removed from the sample period for each facility. These outliers were loosely defined as any unusually high or low fuel, energy, or emissions intensity variation from recent performance. This process was complicated because evidence was found to indicate that western Canadian oil market instabilities had affected facility performance. SAGD well productivity was an area where there was more easily illustrated evidence of market instabilities' impact on operations. For more information, see the box "Review of historical well productivity." The average of the years 2018–19 ended up accounting for over three-quarters of the inputs into the baselines for both mining and thermal in situ oil sands. The impact of market instability is an uncertainty in our analysis.

Review of historical well productivity

As part of this study, IHS Markit undertook a review of historical well productivity of SAGD operations (2005–20). Evidence of recent market instabilities were found to have negatively impacted well productivity, and there was concern that recent operations may not accurately represent actual operating potential.

From 2005 to 2014, SAGD well productivity consistently improved—where well productivity is measured as the average volume of oil recovered per well across the entire system. However, since 2014, except for 2017, well productivity declined every year. IHS Markit upstream teams found little evidence of a pronounced change in well placement, resource quality, or operational infrastructure that would have led to a reversal between 2014 and 2015. Except for 2017, every year since 2015 there were significant market issues that impacted oil sands operations. This included the collapse of oil prices in 2014/15 that lead to temporary reductions in sustaining capital, which can impact well productivity. In 2016, the Fort McMurray wildfire caused large-scale rapid temporary shut-ins in the oil sands. In 2018, western Canadian differentials blew out to over $50/bbl, which caused several facilities to throttle output. Then in 2019, the Government of Alberta imposed a mandatory production curtailment, again impacting normal operations. Finally, in 2020, the COVID-19 demand shock caused the dramatic temporary curtailment and shut-in of several oil sand facilities.

This suggests that well productivity may have been negatively impacted by market conditions and not facility or geological conditions. This indicates that recent well performance across the thermal oil sands system may materially improve in a more stable regional market environment. History may underrepresent that well productivity may benefit from greater regional market stability.

Establishing technology pathways

After establishing a baseline of operations for each facility (mining and in situ thermal operations), the implications of new technologies and efficiencies were incorporated into the fuel, energy, and/or GHG intensity relationships. This only included mining and SAGD operations. Changes to CSS were not modeled in our outlook because of the additional scope of work for a relatively limited share of oil sands output that is not anticipated to materially change to 2035. The CSS historical baseline relationships were held constant in the outlook (2021–35) but still allowed to fluctuate with production. The absence of new technologies and/or efficiencies is a conservative assumption since similar effects to improve SAGD could impact CSS. This decision could contribute to an overestimation of thermal oil sands GHG intensity and absolute emissions.

Several areas for additional efficiency and/or technologies were identified for each form of oil sands extraction with differences in timing, scale of impact, and, to a lesser extent, range of technologies modeled into different cases.

Considerable effort was put into the pace and/or scale of technology deployment. For example, thermal in situ steam displacement technologies (i.e., methane coinjection and/or solvents) were not universally applied and were limited to wells brought online after 2020 (or wells with a minimum of three years of operation). New projects and projects that had strong evidence of use of similar technologies as those being modeled by IHS Markit were exempt from the potential benefits to avoid double counting. The box "Background on oil sands improvements" in Part II includes background descriptions on the various efficiencies and technologies considered in our study. Additional information can be found in Appendix B.

To accommodate the uncertainty around potential evolution of oil sands GHG intensity improvements, two cases based on varying degrees of technology and efficiency assumptions were modeled to obtain a range or trajectory of future GHG intensity and absolute GHG emissions. A third case was developed specifically as a sensitivity to address the potential that historical market instabilities may have negatively influenced the baseline used to project future absolute emissions. The results of the sensitivity case are not included in Part II, which presents the GHG intensity results. This is because it uses principally the same technology assumptions as the other cases and because it is meant as sensitivity to absolute emissions, which are shown in Part III. Detailed data tables are provided on all cases in Appendix A. Assumptions for each case are described in Parts II and III.

To be certain, each facility is unique, and there is an array of advancing technologies that could materially alter future oil sands extraction and GHG emissions. It was not feasible to model all potential technologies or their permutations (many are bespoke), and some simplifications were made. Except for carbon capture and storage (CCS), transformational technologies were not modeled. For these reasons, IHS Markit views its cases as a projection of existing trends and as a potential underestimation of future potential since some level of transformational changes should be expected prior to 2035. This is also why IHS Markit considers a range of outcomes to adjust for the reality that the world will unfold in a more complicated way than a singular pathway. Indeed, the recent formation of the oil sands consortium called "Oil Sands Pathways to Net Zero," with its announced net-zero ambition, suggests that a more aggressive approach to GHG reduction should be expected.[10]

It should also be noted, as it was at the start of this report, that this work was commissioned prior to the recent Government of Canada announcement of its intention to cap oil and gas GHG emissions. It is uncertain at the time of publication how this could impact both future production and emissions of the Canadian oil sands.

Absolute emissions

IHS Markit's estimates of oil sands absolute GHG emissions are attained from each case by multiplying the GHG intensity estimates of each extraction segment by IHS Markit's production outlook.[11] As previously discussed, our absolute oil sands GHG emissions estimates are of direct on-site GHG emissions consistent with the system boundaries of Canada's NIR, as was shown in Figure 2. These results are presented in Part III, with data tables available in Appendix A.

10. "Oil Sands Pathways to Net Zero," https://www.oilsandspathways.ca/, retrieved 20 December 2021.

11. Special treatment is given to the CNOOC/Nexen Long Lake project because of historical upgrader operations. No restart of upgrading was incorporated in this estimate.

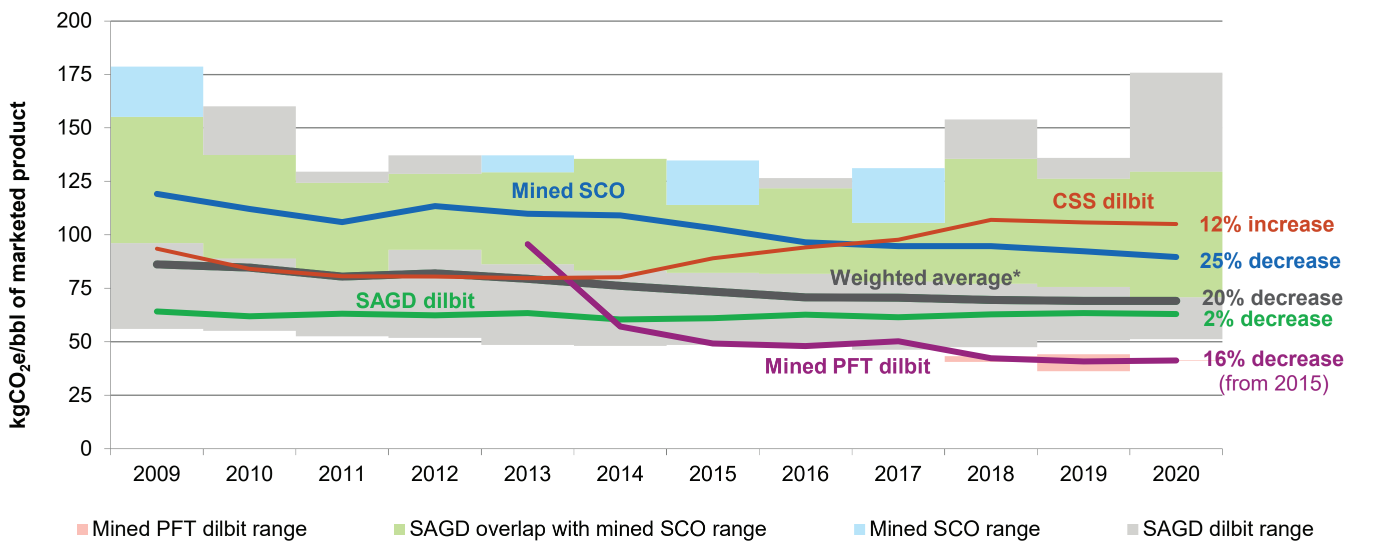
Part I: GHG intensity of oil sands past: 2009–20

This section presents IHS Markit's historical assessment of oil sands GHG intensity estimates from 2009 to 2020.

As shown in Figure 3, the Canadian oil sands have established a trend of GHG intensity reductions.[12] From 2009 to 2020, the overall average GHG intensity of oil sands supply fell by 17 kilograms of carbon dioxide equivalent per barrel (kgCO_2e/bbl), or 20%, to 69 kgCO_2e/bbl in 2020. This is equivalent to an annual average reduction of about 1.5 kgCO_2e/bbl per year over this period. The decline was led by improvements in oil sands mining, which included the ramp-up of newer, less GHG-intensive operations, as well as the growth of comparatively less GHG-intensive thermal operations (specifically SAGD).

Figure 3

Historical GHG intensity of oil sands by extraction process (2009–20, in kgCO_2e/bbl of marketed product)



Note: *Estimate of total oil sands average includes oil sands CSS dilbit; SAGD dilbit; mined SCO; mined PFT dilbit; and primary, experimental and EOR, and adjusts for SAGD SCO. 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. Ranges shown for mined PFT dilbit, SAGD dilbit, and mined SCO range. Source of prior estimates: IHS Markit Strategic Report *Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*, May 2014, www.ihsmarkit.com/oilsandsdialogue.

Source: IHS Markit

Oil sands GHG intensity exists over a wide range. This is an important point, as it means the average should not be assumed to represent any one operation. In 2020, the range expanded considerably compared with 2019 as facilities managed around the global pandemic, with several operations throttling output. In 2020, the GHG intensity of oil sands spanned nearly 135 kgCO_2e/bbl, from 41 kgCO_2e/bbl on the lower end to nearly 176 kgCO_2e/bbl. The upper bound in 2020 was set by a relatively low-volume operation, which experienced a temporary production shut-in that appears to have accentuated the GHG intensity of its marketed products. It is interesting to note that despite the significant market disruption due to the global pandemic, the average GHG intensity of oil sands supply still declined in 2020. IHS Markit also noted reductions from all segments except for mined PFT dilbit . But this was also because of changes in production between different types of extraction. In 2020, the share of the comparatively more GHG-intensive legacy-mined SCO temporarily declined relative to the comparatively lower GHG-intensive SAGD dilbit.

The trend of GHG intensity varies by oil sands production method, and each is discussed next.

12. The average GHG intensity of Canadian oil sands has declined every year from 2009 to 2020, excluding 2012.

GHG intensity of oil sands mining

Under life-cycle consistent system boundaries, mining experienced the largest decline in GHG intensity from 2009 to 2020 (albeit it also started at a higher level than other oil sands segments). From 2009 to 2020, the GHG intensity of mining declined 44 $kgCO_2e/bbl$—a two-fifths reduction. In 2020, the average GHG intensity of oil sands mining was 75 $kgCO_2e/bbl$ and ranged from 41 $kgCO_2e/bbl$ on the low end for mined PFT dilbit to 129 $kgCO_2e/bbl$ on the high end for a mined SCO facility.

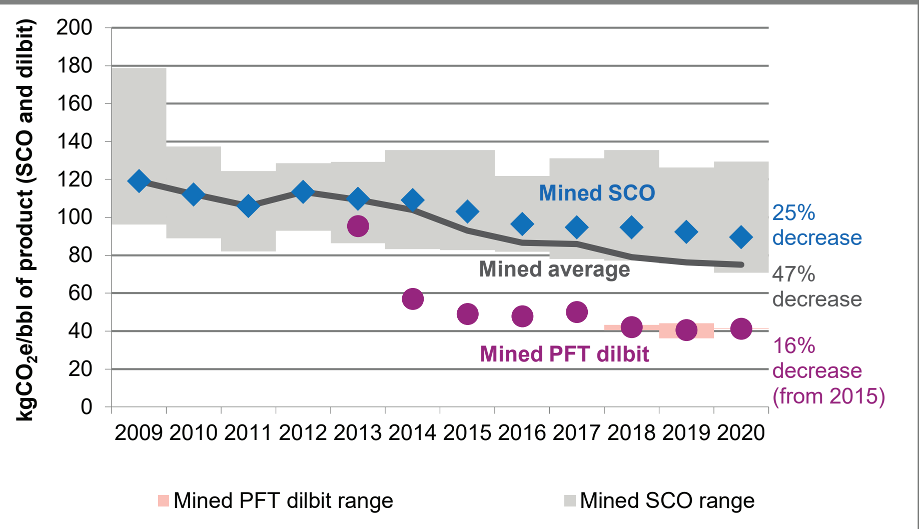
GHG intensity fell for both forms of oil sands mining over the past decade. Legacy mined SCO operations have an established trend of GHG intensity reductions. Meanwhile, the ramp-up of mined PFT dilbit pushed its GHG intensity lower, while greater volumes from these less GHG-intensive operations compared with mined SCO diluted the overall mining average. Figure 4 illustrates the GHG intensity of oil sands mining, by segment and range from 2009 to 2020. Figure 5 provides a breakdown of the factors that contributed to the 44 $kgCO_2e/bbl$ reduction of the mining average. This figure also illustrates the contribution mined PFT dilbit made to reducing the mining average intensity. Efficiency improvements and reductions in the use of more GHG-intensive petroleum coke as a fuel also helped reduce the GHG intensity of mining.

Mined SCO. The GHG intensity of mined SCO declined by nearly 30 $kgCO_2e/bbl$, to under 90 $kgCO_2e/bbl$, from 2009 to 2020. The largest source of GHG intensity reductions in mined SCO came from energy efficiency improvements and a reduction in the use of petroleum coke as a fuel (both from existing facilities and as new facilities have been brought online that do not combust petroleum coke).[13] Smaller, but still notable reductions came from improvements in fugitives and flaring and the deployment of CCS. Figure 6 provides a breakdown of the sources of GHG intensity reductions for mined SCO from 2009 to 2020.

It is important to note that mined SCO is unique among oil sands facilities in that it integrates upgraders that perform the role of heavy processing units that would typically occur in downstream refining. This increases the GHG emissions of mined SCO production, while reducing the refining emissions relative to other oil sands crude oils.

Figure 4

Historical GHG intensity of mined oil sands marketable product (2009–20, in $kgCO_2e/bbl$ of SCO or dilbit)



Source: IHS Markit

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Mined PFT dilbit. Mined PFT is a newer form of oil sands mining. There are two mined PFT facilities that market dilbit using this technology: the Kearl operation, which began in 2013, and Fort Hills, which began in late 2017.[14] IHS Markit believes that most of the GHG intensity reductions recorded by mined PFT dilbit have come from ramp-up and normalization of operations. For this

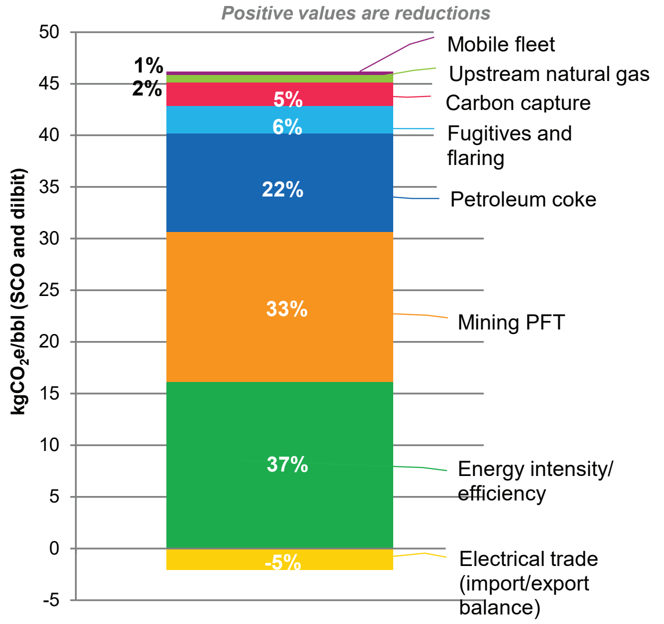
13. Energy efficiency improvements include reductions in the energy required per unit of output. This can occur because of the deployment of specific technologies but also because of higher utilization, which can result in greater output for similar levels of energy use.

14. The Albian sands oil sands mine began operations in 2008 and was the first mine to make use of PFT. However, it does not market dilbit. Instead, the mined PFT dilbit is transported from the mining site near Fort McMurray to an upgrader near Edmonton, Alberta, where is it upgraded. IHS Markit still considers Albian sands an integrated operation, as it incorporates an upgrader and markets SCO.

study, we measured the GHG intensity improvements of mined PFT dilbit beginning in 2015 to avoid the most pronounced ramp-up period, which would accentuate the level of GHG intensity reductions.[15] The GHG intensity of mined PFT dilbit declined by nearly 8 $kgCO_2e/bbl$, to just over 41 $kgCO_2e/bbl$, from 2015 to 2020.[16] The primary drivers are presented in Figure 7, which display the characteristics of facilities undergoing ramp-up and improving energy utilization as that occurs.[17]

Figure 5

Source of oil sands mining GHG intensity improvement (2009–20, 44 $kgCO_2e/bbl$ of product)



Source: IHS Markit

GHG intensity of thermal oil sands

The average GHG intensity of in situ thermal dilbit declined by nearly 9 $kgCO_2e/bbl$, or 11%, from 2009 to 2020. In 2020, IHS Markit estimates that the average in situ thermal oil sands had a GHG intensity of 70 $kgCO_2e/bbl$. As shown in Figure 8, most reductions have come from the ramp-up of comparatively less GHG-intensive SAGD that occurred over the past decade. IHS Markit estimates average in situ thermal GHG intensity ranged from 51 $kgCO_2e/bbl$ to 176 $kgCO_2e/bbl$ in 2020, with the upper end being accentuated due to market disruptions in 2020.

There are differences between the two dominate segments of thermal extraction—SAGD and CSS—which are discussed next.

- **SAGD dilbit.** The GHG intensity of SAGD dilbit has remained relatively constant, declining nearly 2% from 2009 to 2020. In 2020, SAGD dilbit averaged 63 $kgCO_2e/bbl$. As individual SAGD facilities ramped up production, they grew into their cogeneration capacity, which lowered the electricity generated on-site available for export. Under system boundaries consistent with the upstream production stage of life-cycle analysis, emissions resulting from electricity produced on-site and exported to the electrical grid are deducted or removed from GHG estimates (imports are added).[18] As shown in Figure 9, although the efficiency of natural gas use per unit of output improved, higher production from these same operations drew down or reduced electricity exports. This offset efficiency improvements and helped keep the GHG intensity flat. If the system boundaries are changed to direct on-site emissions consistent with Canada's NIR, the results look quite different, with SAGD bitumen GHG intensity declining about 9% over this same period.

15. IHS Markit acknowledges this is an imperfect comparison and that the start of Fort Hills would have put upward pressure on the GHG intensity of mined PFT dilbit in 2017 and 2018. However, the impact of the ramp-up of Fort Hills was muted because of the existing volumes from Kearl.

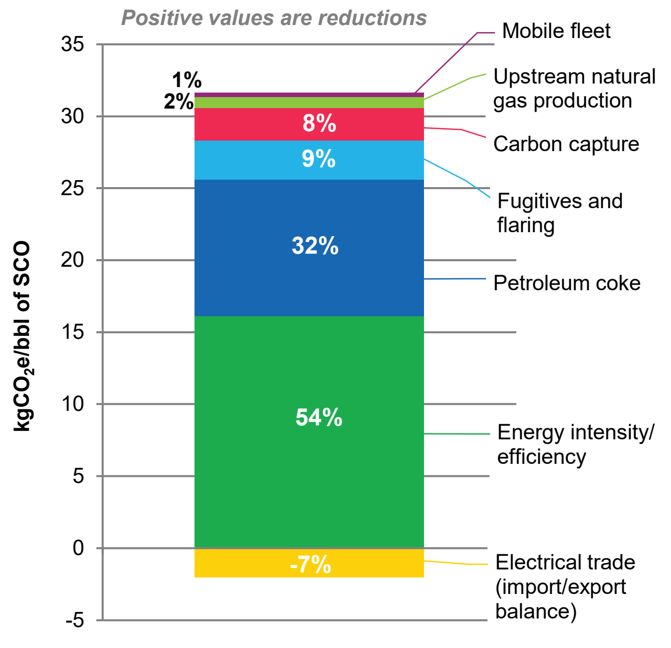
16. From when mined PFT dilbit began operations (in 2013) to 2020, the GHG intensity declined 56%.

17. Electrical trade, or more accurately the change in net electrical balance, shown in Figures 6 and 7, and throughout this report, represents the change in GHG emissions intensity from a change in the electrical power imported or exported from a facility. This may also capture changes in the grid intensity.

18. As the Alberta grid decarbonizes, the valuation of the export credit may change; imports were valued on grid averages, and IHS Markit estimates include changes in intensity of electrical imports.

Figure 6

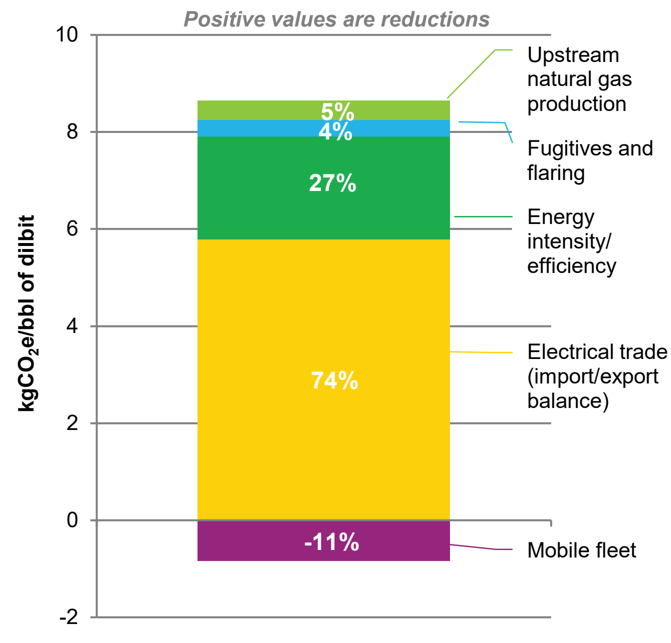
Source of change in mined SCO GHG intensity (2009–20, 30 $kgCO_2e/bbl$ of product)



Source: IHS Markit

Figure 7

Source of oil sands mined dilbit PFT GHG intensity improvement (2015–20, 8 $kgCO_2e/bbl$ of product)

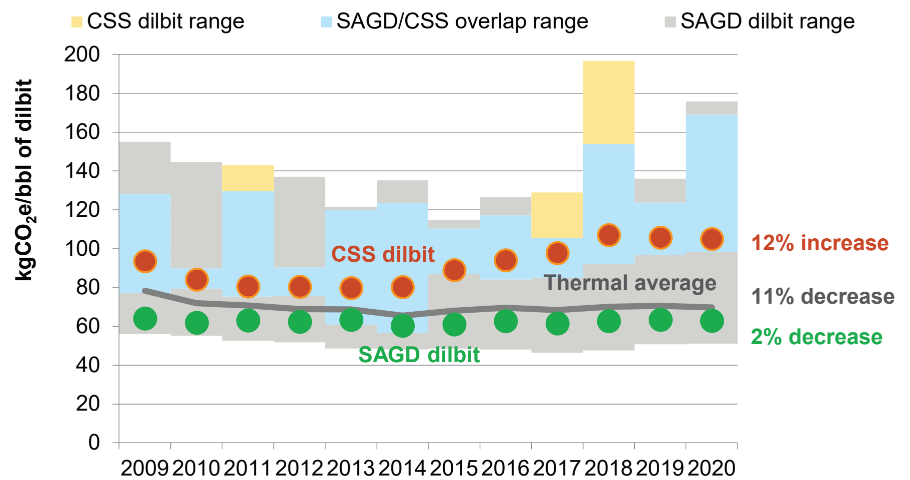


Source: IHS Markit

- **CSS dilbit.** The GHG intensity of CSS dilbit was trending upward until 2018 and has since declined. The smaller volume (CSS dilbit was 14% of thermal supply in 2020) and consolidated nature of CSS dilbit (99% of supply comes from two operations) means there are fewer facilities to spread changes in performance across. IHS Markit believes market volatility may have contributed to delays in the development of newer wells, which would have put upward pressure on GHG intensity. Overall, the GHG intensity of CSS dilbit rose by nearly 12 $kgCO_2e/bbl$, or 12%, from 2009 to 2020 and in 2020 averaged 105 $kgCO_2e/bbl$. Figure 10 provides the composition of changes in CSS dilbit from 2009 to 2020.

Figure 8

Historical GHG intensity of thermal in situ dilbit (2009–20, in $kgCO_2e/bbl$)

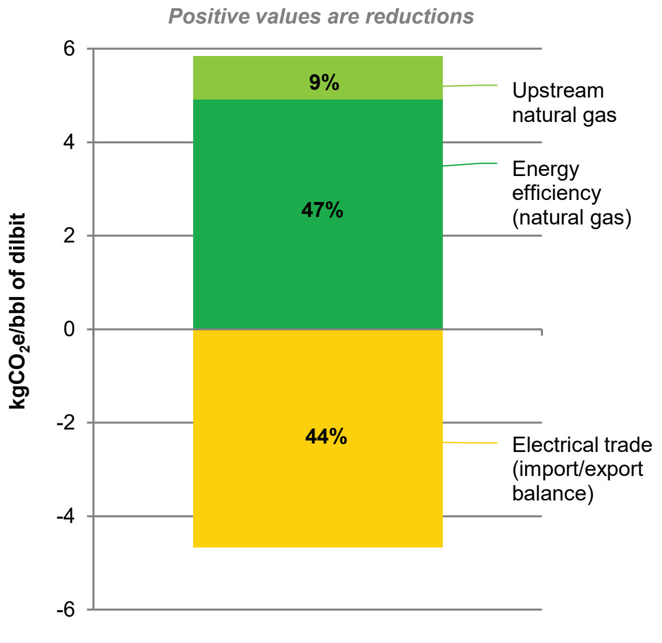


Note: Thermal average includes CSS and SAGD only.

Source: IHS Markit

Figure 9

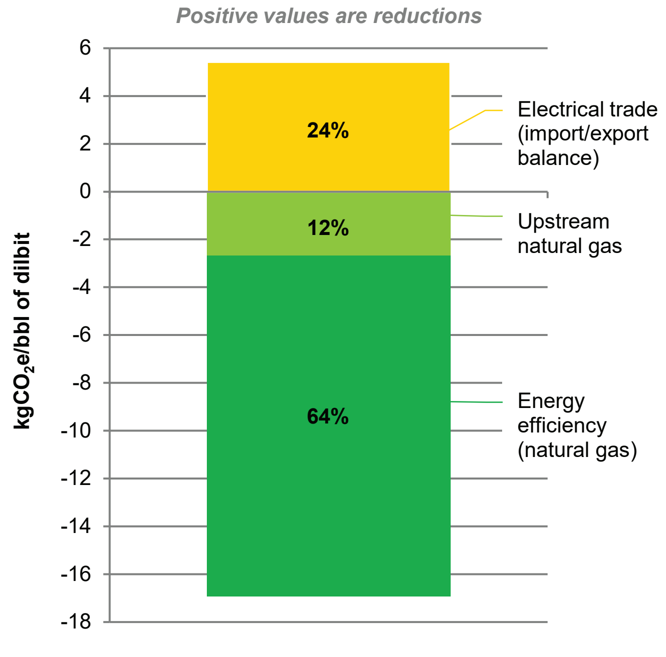
Source of change in SAGD dilbit GHG intensity (2009–20, -1 $kgCO_2e$/bbl of dilbit)



Source: IHS Markit

Figure 10

Source of change in CCS dilbit GHG intensity (2009–20, +12 $kgCO_2e$/bbl of dilbit)



Source: IHS Markit

Part II: GHG intensity of oil sands future: 2021–35

IHS Markit has sought to understand the impact of additional efficiency improvements and the deployment of commercial and near-commercial technologies on oil sands GHG emissions over time. This includes considering not only the effects of new technologies but also the pace and scale of technology deployment. Future production was also a critical consideration.

IHS Markit GHG intensity cases

IHS Markit developed three cases as possible future GHG emissions trajectories for the Canadian oil sands. The first two cases, called “Existing trends,” were designed with the intent to form a range of future GHG emissions trajectories along a pathway consistent with existing trends.

A third case, called “Optimized,” was developed as a sensitivity to explore the potential implications of recent market instability on absolute oil sands GHG emissions to 2035.

This section presents the background and assumptions of each of the three cases. Then the results of the GHG intensities of Existing trends are presented. The results of Optimized are included in Part III as a sensitivity to the absolute emissions trajectory. Detailed results of all three cases are included in Appendix A.

Existing trends

Together, the two Existing trends cases present a fairway, or range, of future oil sands GHG intensity and absolute emissions based on more and less conservative technology assumptions. The case with more conservative assumptions was dubbed Existing trends (higher), and the case with more aggressive assumptions was dubbed Existing trends (lower). The naming was linked to the case outcomes, which would be higher or lower in relation to emissions. Potential efficiency improvements and technologies were modeled against specific fuel/energy intensity baselines and production changes in our outlook. Where applicable, the stringency started low and increased over time to allow for the pace of derisking, development, deployment, and learning by doing. Only near-commercial and/or commercially available technologies were included in the analysis.

Tables 2 and 3 present the stringencies, technologies, and/or improvements included in the two cases for oil sands mining and SAGD, respectively.[19] The box “Background on oil sands improvements” includes a short description and additional background on each technology category modeled. Please refer to Appendix B for additional modeling details.

19. IHS Markit assumptions were meant to represent an extension of historical trends. These were not meant to test or recreate any industry announcement.

Table 2

IHS Markit future efficiency and technology assumptions for mining GHG emissions cases

Pathway	Description	Existing trends (higher)	Existing trends (lower)
Fuel switching	Two mining operations currently combust petroleum coke. Petroleum coke use accounts for about 11% of oil sands mining GHG intensity today (or about 4MMtCO_2e on an absolute basis).	There are economic and technical limitations to fuel switching. It was assumed, consistent with Suncor's announced Coke Boiler Replacement project, that Suncor's boilers would be phased out beginning 2024 and completed in 2025. Both units were assumed to be replaced with cogeneration units, which ties this assumption to the cogeneration assumption. This equates to about half of the industry's petroleum coke use.	
Cogeneration expansion	Cogeneration can reduce the net GHG intensity of oil sands facilities due to simultaneous production of steam and electricity.	IHS Markit modeled 806 MW of capacity associated with Suncor's Coke Boiler Replacement Project beginning late in 2024 and fully online in 2025. An additional 92 MW was assumed to come online in 2025 associated with the Syncrude Mildred Lake Extension and 100 MW that falls within Imperial Kearl's existing permits.	In addition to the higher case, an additional 135 MW of cogeneration capacity was assumed. The 92 MW of Syncrude Mildred Lake capacity starts earlier at the start of third quarter 2024, plus an additional 35 MW of capacity was added to a mined PFT operation in 2026 and 100 MW to a mined SCO operation in 2027.
Efficiency improvements (e.g., lowering process temperature)	Oil sands mines are large consumers of heat, which is required to extract and process bitumen and produce SCO. There is potential 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 a 0.5°C annual reduction in process temperature for mined SCO from 2022 to 2031, and 0.25°C from 2032 to 2035, reaching 6°C by 2035. Because newer mined PFT was assumed to already operate at a lower temperature, a 0.25°C improvement was modeled starting in 2022 and 2024 based on the vintage of the two facilities. By 2035, they obtain a 3°C and 3.5°C reduction, respectively.	An annual reduction in process temperature of 0.5°C was modeled starting in 2022 but staggered across mined SCO operations until a maximum of 5°C was obtained. Mined PFT followed a 0.25°C improvement based on the vintage of operations until a maximum of 3°C is reached. It was assumed solvent aided mining technology, or something similar, would be adopted at a staggered pace in the early 2030s, until all mined SCO facilities reached a 10°C reduction. Based on a staggered ramp-up, mined PFT facilities reach 6°C and 3°C by 2035.
Fleet improvements	The mine fleet accounts for about 11% of mining GHG intensity. Advancements in engine design, greater use of biofuels, and fleet optimization through autonomous vehicles could lead to improvements.	Biodiesel was increased by 0.25% per year in 2023 until 2035, when it reaches 3.5%. The deployment of autonomous vehicles is expected to improve fleet productivity, contributing to GHG intensity savings. However, only a 1% improvement from autonomous vehicles was modeled, as these improvements may be offset by longer mine trains that may emerge over time.	
Carbon capture and storage	Carbon capture and storage has the potential to sequester CO_2. The lowest hanging fruit in the oil sands may be the higher-concentration CO_2 streams from steam methane reformers used in upgrading. In 2019, we estimated that SMR accounted for about 16% of mining emissions.	IHS Markit estimates that SMR produced 7.4 MMtCO_2e in 2019. It was assumed that the highest-purity streams of CO_2 from SMR would be preferentially, but not exclusively, targeted. By 2030, about 4.5 MMtCO_2e CCS was assumed online, inclusive of Shell Quest, for a net capture of about 3.6 MMtCO_2e. This is about 50% of SMR associated emissions.	The same logic was applied as in the higher case, but with more aggressive timing and scale of CCS. Compared with the Existing trends higher, CCS begins to come online more materially in the mid- to late 2020s. By 2030, about 6.5 MMtCO_2e of CCS was assumed online, inclusive of Shell Quest, for a net capture of about 5 MMtCO_2e. This represents about two-thirds of SMR associated emissions.

Source: IHS Markit

Table 3

IHS Markit future efficiency and technology assumptions for SAGD GHG emissions cases

Pathway	Description	Existing trends (higher)	Existing trends (lower)
Well productivity	More durable submersible pumps, advanced seismic, and greater drilling precision can increase the volume of oil produced with little increase in heat/steam/energy required. SAGD has registered both improvements and reductions in well productivity in recent years (which may be market related).	A series of correlations and regressions were done to derive a reasonable pace of change given the uncertainty of past performance. A 0.75% annual improvement starting in 2022 was modeled. New wells were credited with the cumulative improvement that would be attained in the year the well is completed for the life of that well based on the expected well replacement schedule for each operation. By 2035, the cumulative productivity gain reaches 10.5%, but the weighted average impact across the industry is 8.7%.	It was assumed that well productivity would increase 1% annually starting in 2022. New wells were credited with the cumulative improvement that would be attained in the year the well is completed for the life of that well based on the expected well replacement schedule for each oil sands in situ operation. By 2035, the cumulative productivity gain reaches 14%, but the weighted average impact across the industry is 11%.
Boiler/steam efficiency	Water quality affects the efficiency of steam production. Improvements in water treatment and boiler technology can improve the transfer of energy from natural gas combustion to steam and reduce the energy intensity of steam generation. Lower water quality means less steam is produced for similar levels of fuel consumption.	A 0.5% annual improvement in boiler/steam efficiency associated with potential improvements from new technologies and better water treatment was modeled starting in 2024, reaching and remaining at 6% from 2030 and on.	
Steam displacement technologies	Steam displacement technologies are increasingly being tested and deployed to varying degrees (particularly solvents and noncondensible gases). These technologies improve emissions in two ways. First, they physically reduce the volume of steam required to produce a barrel of oil. Second, solvents have the added benefit of increasing the mobility of bitumen and well productivity as a result. The displaced steam may also be deployed elsewhere, which can support greater production.	A SAGD well replacement schedule was developed to estimate well turnover. Steam displacement technologies were made available for new wells beginning in 2023 at 2% per year (or a reduction in the steam-to-oil ratio), rapidly increasing to 10% by 2025 (a minimal viable level according to IHS Markit upstream). The rate increases nonlinearly to 20% in 2030 and 25% in 2035. However, because benefits were restricted to newer wells and certain facilities, the weighted impact is delayed and muted but does reach 22% by 2035. Freed steam was redeployed, resulting in a production increase of about 170,000 b/d by 2035.	A SAGD well replacement schedule was developed to estimate well turnover. Steam displacement technologies were made available for new wells beginning in 2023 at 2% per year (or a reduction in the steam-to-oil ratio), rapidly increasing to 10% by 2025 (a minimal viable level according to IHS Markit upstream). The rate increases nonlinearly to 27.5% in 2030 and 40% in 2035. Because benefits were limited to new wells and certain facilities, the weighted impact is muted and delayed but does reach 35% by 2035. Freed steam was redeployed, resulting in a production increase of about 360,000 b/d by 2035.
Cogeneration expansion	Cogeneration can reduce net GHG intensity of oil sands facilities owing to the simultaneous production of steam and electricity and under certain system boundaries from the electricity exports. SAGD facilities are currently large exporters of electricity owing to their higher steam demand relative to electricity use. The rate of cogeneration build-out in thermal operations has been declining.	Based on historical analysis, IHS Markit assumed one 85 MW cogeneration unit could be deployed as an individual facility reaches incremental capacity additions of 125,000 b/d. At this rate, no new incremental units were assumed in the higher case.	IHS Markit lowered the threshold rate to one 85 MW unit per 80,000 b/d of capacity. At this rate, two 85 MW units were incorporated by 2035.
Blue hydrogen	Hydrogen use can lower the GHG emissions required to meet heat and electrical demand. Although combustion of hydrogen produces only water and oxygen, it takes energy to produce and capture CO_2 that occurs with its production. There may also limitations to the existing infrastructure's ability to transport and combust it.	No hydrogen blending was assumed.	It was assumed that blue hydrogen would be blended into the purchased natural gas stream. Blue hydrogen was introduced at 0.5% in 2027 and increased every two years until reaching 2.5%, when it was held constant. We estimate this would be equivalent about 90,000 metric tons per day unit.
Carbon capture and sequestration	Carbon capture and storage has the potential to sequester CO_2 directly at the source. However, it requires incremental energy to operate.	It was assumed that 0.70 $MMtCO_2$ of capture is deployed by 2029. Considering the capture energy requirements, this results in about 0.6 $MMtCO_2$ of net capture.	It was assumed that capture begins at 0.7 MMtCO2 in 2029 and reaches 1.4 $MMtCO_2$ by 2033. Adjusting for the capture energy requirement, this results in about 1.1 $MMtCO_2$ of net capture.

Source: IHS Markit

Background of oil sands improvements

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. Suncor has announced the phaseout of the coke boilers on its site, in favor of two new cogeneration units by fourth quarter 2024.* The nature of the Syncrude process, however, may require more extensive redesign to reduce its use.

Cogeneration. To meet heat and electrical demand, mining operations use a combination of boilers, cogeneration units, and electrical imports from the power grid. Although each facility is unique, overall the oil sands mining sector is fairly electrically balanced—neither a major importer nor an exporter of electricity from the grid. An expansion of cogeneration capacity could alter the industry energy balance and electrical exports. The implications to GHG emissions differ depending on the system boundaries—under direct on-site emissions boundaries, cogeneration expansion can increase emissions, but under life-cycle emissions boundaries, cogeneration electrical exports are deducted.**

Mobile mining fleet. Oil sands mining operations have large fleets of heavy equipment haulers, shovels, and earthen works equipment, which run on diesel. There are opportunities to reduce GHG emissions associated with these fleets, but over time as mines mature the distances the fleet or ore must travel could increase, offsetting potential improvements.

- Biodiesel is already used in mining operations and could increase to help manage fleet emissions.
- Autonomous mining vehicles are not more combustion efficient but can improve utilization—reducing GHG emissions intensity. Operators are already moving to phase in autonomous vehicles.

Some level of mine fleet electrification is also possible, but it was not incorporated in the analysis at this time.

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, we believe this temperature has generally fallen and/or greater waste heat integration has reduced energy demand to maintain process temperature. Further efficiency improvements, including from new technologies, could support additional reductions, allowing greater output from existing heat use.

("Background of oil sands improvements" continued on next page.)

*Suncor Energy, "Coke Boiler Replacement Project," https://www.suncor.com/en-ca/what-we-do/oil-sands/coke-boiler-replacement-project, retrieved 17 November 2021.

**The IHS Markit method allowed the Alberta grid intensity to decline over time, impacting the GHG intensity of electrical imports. Electrical exports, however, were valued on a constant basis throughout the study period based on a combined-cycle natural gas unit throughout. As Alberta grid intensity declines, the electrical exports from cogeneration could be reassessed at a lower value, and thus the credit value reduced. However, determining when this should occur was uncertain. A change of the electrical export value at some point in the future would reduce the electrical export value to the life-cycle GHG intensity estimate and thus put upward pressure on the IHS Markit long-term projection. Because electrical trade is not included in direct emissions estimates, it would not be expected to impact the absolute GHG emissions projections.

Background of oil sands improvements (continued)

Carbon capture and storage (CCS). CCS involves the capture, transport, potential use, and geological storage of carbon dioxide (CO_2). Oil sands operations are large industrial facilities, with most GHG emissions coming from stationary combustion sources. This makes CCS attractive to deployment in the oil sands, but at varying cost structures associated with the concentration of CO_2 in the flue gas streams and the energy required to capture, transport, and sequester.

CO_2 concentration found in oil sands flue gas can vary. Steam methane reforming (SMR), which is used in the upgrading process found in integrated mines, presents one of the highest CO_2 concentration streams and thus a potentially attractive capture opportunity. IHS Markit estimates that oil sands SMR emits just over 7 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) per year. Of this, roughly three-fifths is assumed to produce fuel gas emissions with CO_2 concentrations near 50%, whereas the remainder is emitted at lower concentration levels associated with heaters used in the process. There is already one oil sands upgrader with an integrated capture unit, known as the Quest project.*** Quest captures about 0.90 $MMtCO_2e$ on a net basis (gross basis is about 1.1 $MMtCO_2e$) from the Scotford upgrader SMR.

Most oil sands operations are remote from storage options, but they are often clustered in relative proximity, posing both advantages and disadvantages to transportation and storage. Shell Quest was potentially unique because the capture facility is integrated into an upgrader located near Edmonton, Alberta—far from oil sands extraction operations but approximate to storage opportunities. The Oil Sands Pathways to Net Zero initiative, which is an alliance of Canada's six largest oil sands producers, has announced its intention to accelerate the deployment of CCS in the oil sands and coordinate on critical infrastructure that would connect capture facilities to storage opportunities.**** Governments in Canada have also announced their intention to provide additional support to the advancement of CCS, including in the oil sands.*****

It is also important to note that since 2009, CO_2 has also been injected into tailings 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.******

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). 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 reductions. Moreover, in the absence of transformational technology, productivity gains are not inexhaustible.

("Background of oil sands improvements" continued on next page.)

***Shell, "Quest Carbon Capture and Storage," https://www.shell.ca/en_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html, retrieved 17 November 2021.

****"Oil Sands Pathways to Net Zero," https://www.oilsandspathways.ca, retrieved 17 November 2021.

*****Government of Canada, Budget 2021, "Tax Incentive for Carbon Capture, Utilization, and Storage," www.budget.gc.ca/2021/report-rapport/p2-en.html#114, retrieved 3 February 2022; Alberta, "Carbon capture, utilization and storage – Overview," www.alberta.ca/carbon-capture-utilization-and-storage-overview.aspx, retrieved 8 February 2022.

******Canadian Natural Resources Limited, "Advancing tailings management technologies," https://www.cnrl.com/corporate-responsibility/advancements-in-technology/managing-tailings.html, retrieved 17 November 2021.

Background of oil sands improvements (continued)

Boiler/steam generation. Boiler efficiency is related to the energy transferred from natural gas combustion to produce steam. Over time, boilers have become more efficient. Technologies are under development that could lead to further improvements. 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 also support the more efficient use of natural gas.

Steam displacement technologies. Thermal oil sands facilities operate on two fundamental principles: energy (to warm and mobilize the bitumen) and pressure (to assist gravity in recovery). Steam has historically provided both 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. Thermal operations have been experimenting with replacing steam with noncondensable gases and solvents. These alternatives physically reduce steam and thus natural gas demand per barrel produced while maintaining the "gravity assist" or pressure. Solvents can also have an additional benefit of improving the mobility of bitumen (lowering the energy required to improve mobility). Both technologies have potential, with the former being deployed at scale on select fields and the latter involved in advanced pilots.

IHS Markit undertook a survey of current well performance as part of this study. A recent decline in the use of solvents, and a significant rise in the injection of methane, was found.

The recent reduction in solvent field trials observed by IHS Markit may be a temporary phenomenon linked to the COVID-19 market shock. Solvents have been shown to have great potential; however, recent and longer-term market factors may complicate their large-scale deployment.*******

IHS Markit is also seeing evidence of a dramatic increase in the use of methane coinjection.******** A review of well data indicates several operators managed to dramatically reduce steam use in some areas by injecting greater quantities of methane earlier in well life. In several examples, IHS Markit found injection levels displacing 100% of steam—so a full displacement of methane for steam—toward the last quarter to third of the anticipated well life (although there were a few examples of much earlier and more dramatic uses).********* IHS Markit ran several sensitivities based on a range of cases and found a potential reduction in the GHG intensity over the entire well life of anywhere from 20% to 45%. Compared with solvent, we believe operators would be attaining higher recycle rates, and the cost of methane would be lower with most facilities already connected to natural gas supply by pipeline.

Although these technologies reduce the natural gas combustion intensity of extraction, upstream emissions are associated with the production of the coinjected material. The upstream GHG emissions associated with the solvent and methane use were captured in the IHS Markit model. However, the high recycle rate muted the overall GHG impact. Note that some solvent processes aspire to be 100% solvent. These were not modeled by IHS Markit.

("Background of oil sands improvements" continued on next page.)

*******Although most solvent is recycled, some losses occur, and a consistent stream of solvent would be required to make up for the loss. Propane and butane are seen as particularly promising solvents. The use of solvents can be sensitive to their price due to the make-up volume requirement. For example, the outlook for the propane market has tightened, and the outlook calls for higher prices going forward and thus higher cost for its use. Thermal operations are distant from Alberta's NGL hub, and absent of a pipeline, trucking would be required.

********Methane has been the principal displacement gas used to date, but some operators may be experimenting with other gases.

*********The number of examples found in IHS Markit's survey was limited but promising, as there was little evidence of a reduction in productivity outside of what would be expected from maturing wells. It was also possible that some wells surveyed may have had their life extended past what would have been economically possible had they continued to inject steam. The implications of this could be significant for thermal GHG intensity, as it implies a negligible level of production emissions at the end of the well life, which can be the most GHG-intensive phase of any well life. For more information on how GHG intensity can change over a well life, see IHS Markit, *From start to finish: Stages of life impact on oil and gas greenhouse gas emission intensity*.

Background of oil sands improvements (continued)

Cogeneration. SAGD operations use both boilers and cogeneration to meet steam demand. On a GHG intensity basis, IHS Markit estimates that installed cogeneration capacity at SAGD operations contributed to an offset credit (using the IHS Markit method) of approximately 3 kgCO_2e/bbl of dilbit on average over the past few years. The rate of installed cogeneration capacity expansion versus production has slowed. SAGD operations averaged about one 85 MW cogeneration unit per 85,000 b/d over the past half-decade (2016–20), compared with one 85 MW unit per 60,000 b/d from 2011 to 2015. This change has been eroding the benefit of electricity exports on the GHG intensity of production (this can be seen in the decline in the GHG credits associated with electrical exports in the Appendix A data tables). Declining electricity exports are expected to decelerate with the slowing growth profile.

Hydrogen blending. Hydrogen can lower the GHG emissions required to meet heat and electrical demand. Although combustion of hydrogen produces only water and oxygen, it takes energy to produce and capture the CO_2 that occurs with its production. There may also be limitations to the existing infrastructure's ability to transport and combust it. For this reason it is more likely hydrogen would be blended with natural gas initially for transport and combustion.

Optimized

IHS Markit projections are sensitive to historical production intensities of fuel, energy (heat and electricity), and GHG emissions with each facility. The review of past production intensities indicated that market instability may have negatively impacted performance over multiple years. Although outliers were removed in establishing the baselines used in the Existing trends cases, the persistence of the disturbances in recent history raised questions about the representativeness of the period in establishing a baseline.

On the assumption that the Existing trends baselines may be unrepresentative, an Optimized case was created. This entailed further scrutinizing past performance for years of both greater consistency and more optimal or more efficient periods of fuel and energy use. This resulted in "optimized" baselines for the fuel/energy relationship within each facility. To be clear, this did not mean that only the best years were included—if a year was unusually efficient it was not necessarily included, but if there were two or more years of greater consistency among the past half-decade, those became the baseline.

Once the Optimized baseline was established, technology assumptions were incorporated consistent with the Existing trends scenarios, with two exceptions:

- Only the more aggressive set of the Existing trends technology assumptions was modeled, since the purpose was to present an alternative, more idealized extension of the other cases (see Tables 2 and 3).

- A more rapid recovery of well productivity was also modeled. Consistent with the Optimized case hypothesis that market instability has impaired recent facility performance, a more rapid recovery of well productivity could be possible. A projection of past performance was modeled that would result in productivity reaching 95% of historical heights but never exceeding that level.[20] Assuming no further regional market disruptions occur (including adequate pipeline capacity is available, and COVID-19 is contained over next few years), productivity begins to dramatically improve in 2022 and reaches 95% of past potential but never exceeds historical highs. This equates to a nearly 20% improvement in well productivity, which is about 6% higher than the more aggressive of the Existing trends cases, with the weighted impact reaching 19% by 2035. The more rapid pace of well productivity recovery results in a much more significant impact across the industry.[21]

20. IHS Markit estimated past peak productivity occured between 2012 and 2014.

21. Well productivity gains are limited to new wells. New wells are credited with the cumulative improvement that would be attained in the year the well is completed for the life of that well based on the expected well replacement schedule for each oil sands in situ operation. As a result, much more rapid recovery in well productivity early in the study period has a more significant impact on overall performance. The assumption to limit gains to new wells is a limiting and conservative assumption.

The future of oil sands growth

Where production grows and the efficiency of that growth will play a role in the future GHG intensity and absolute emissions of the Canadian oil sands.

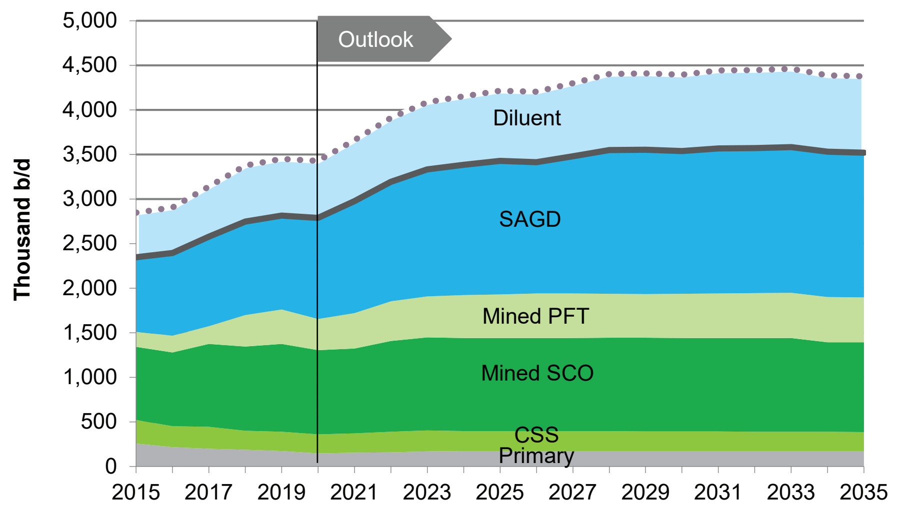
The IHS Markit long-term outlook for the Canadian oil sands has fallen as regional market instability has delayed the timing of future developments while pressures to accelerate the energy transition and prioritize upstream decarbonization have contributed to reductions in our long-term investment expectations.[22] Recent announcements by the Government of Canada to cap oil and gas sector emissions may yet have additional impacts on the IHS Markit oil sands production growth outlook, but at the time of publication there were insufficient details to assess. Moreover, the purpose of this report is to review existing trends, but this is an additional uncertainty in the IHS Markit outlook.

Nevertheless, oil sands output still has significant potential to rise. By 2035, oil sands production could be over 900,000 b/d than 2020 levels (600,000 b/d higher compared with 2021 if recovery from 2020 is considered). Over three-quarters of this growth may be "locked in" because it is underpinned by existing installed infrastructure where there are efficiencies to maximizing output. The ramp-up of this capacity is expected to occur principally between 2021 and 2024. Growth after this period is more reliant on completion of projects that have been on hold and expansion of existing facilities. This growth is less certain, and many developments would have to be sanctioned by the mid-2020s to be online by the late 2020s.[23]

Figure 11 illustrates the IHS Markit oil sands production outlook by extraction type. Over the past decade, SAGD has been the dominant engine of growth in the Canadian oil sands, and this is expected to continue. The IHS Markit outlook is based on our 2021 projections and includes 10 expansion projects (which include optimizations), which account for about a third of oil sands production growth to 2035. Although mining production increases modestly, these volumes come from the ramp-up and optimization of existing facilities. There are no fully greenfield projects in the IHS Markit outlook.

Figure 11

Sources of oil sands supply growth (past 2015–20, and future 2021–35)



Source: IHS Markit © 2022 IHS Markit

The inclusion of new SAGD projects required determining the potential baseline operations of these facilities to be able to estimate their GHG emissions footprint. All things being equal, new operations should be more efficient than legacy ones

22. For more information on the IHS Markit oil sands production outlook, see the IHS Markit 2021 production outlook release, *Canadian oil sands running above pre-pandemic highs, but the lingering impacts of COVID-19 and acceleration of energy transition have lowered the growth prospects*.

23. Cost reductions made in the oil sands since 2014 have allowed them to remain within a competitive range with other key sources of supply globally. The primary challenge associated with new oil sands projects is the large, up-front out-of-pocket cost that must occur over multiple years to bring online a new production facility. This profile disadvantages new oil sands projects compared with the much shorter-term time frame of shale, for example. For more information on the cost of new supply globally, see IHS Markit, *Global crude oil cost curve shows 90% of projects through 2040 breaking even below $50/bbl*.

because they benefit the most from the latest technologies. However, reservoir quality will also influence how these facilities operate. The IHS Markit process involved the review of project regulatory filings, which often provide some indicator of the anticipated steam-to-oil ratio (SOR). The SOR is an important metric in thermal oil sands, as it an excellent proxy for efficiency as it measures the equivalent volume of steam (proxy for energy) required to produce a unit of oil (barrel). For the most part, it was assumed that SAGD expansions would be like those of the base operations they would be expanding, and for most cases the same baseline relationships were used.[24] Still, what grows tended to be more efficient. The average anticipated efficiency of SAGD growth in our outlook as measured by SOR (before any additional assumptions were allowed to impact efficiency) was found to be 7% lower than the industry average of 2.74 in 2020.[25] This implies that although greater production will result in more absolute emissions, these barrels will come from more efficient operations that will contribute to GHG intensity reductions.

There is concern about how remaining reservoir quality may impact future operations. Indeed, as oil sands operations extend themselves into new mine pits or drill into newer areas, some operations may move into lower-quality resource areas. However, it is not necessarily the case that the best is always developed first. For any individual company, it is reasonable to assume the highest-quality areas would be developed first. However, the quality of holdings within any oil and gas play are seldom equitably distributed among operators (e.g., one operator's best may be another's worst). In the case of the oil sands, the shelving of numerous expansion projects as well as the consolidation of the industry suggests that more land may be available to sustain existing operations or support future expansions than previously considered. For some operations, these changes delay the challenges of declining reservoir quality or enable producers to better balance the impact of reservoir quality (this includes across the industry as well). That said, this is an uncertainty that could impact IHS Markit expectations late in our production outlook, but it is not of immediate concern to our projections.

GHG intensity of oil sands future: 2021–35

The conclusion of the application of near-commercial and commercial technologies, as well as CCS, assumptions that make up the Existing trends projection to 2035, are presented in this section. Figure 12 illustrates the Existing trends of GHG intensity by the oil sands average and by extraction segment to 2035. Figure 13 shows the contribution to the overall oil sands average by each segment. What follows is a short description and additional details on mining and SAGD.

Based on Existing trends upper and lower bounds, the GHG intensity of the Canadian oil sands could fall between 14 $kgCO_2e$/bbl and 20 $kgCO_2e$/bbl, or between 20% and 28% between 2020 and 2035. In 2035, the average GHG intensity of the oil sands ranges between 49 $kgCO_2e$/bbl and 55 $kgCO_2e$/bbl, with the upper and lower bounds ranging from 36 $kgCO_2e$/bbl to 117 $kgCO_2e$/bbl.[26] The range remains quite significant, which suggests the average should be used with caution ,because any individual operation could vary significantly from the average.

On a production stream basis, the greatest decline in GHG intensity is experienced by SAGD dilbit, falling 15–23 $kgCO_2e$/bbl, or 24–36% by 2035 relative to 2020. Yet, as can be seen in Figure 13, the largest contributor to the reduction in the overall industry average is mined SCO. Although the Existing trends result in a more

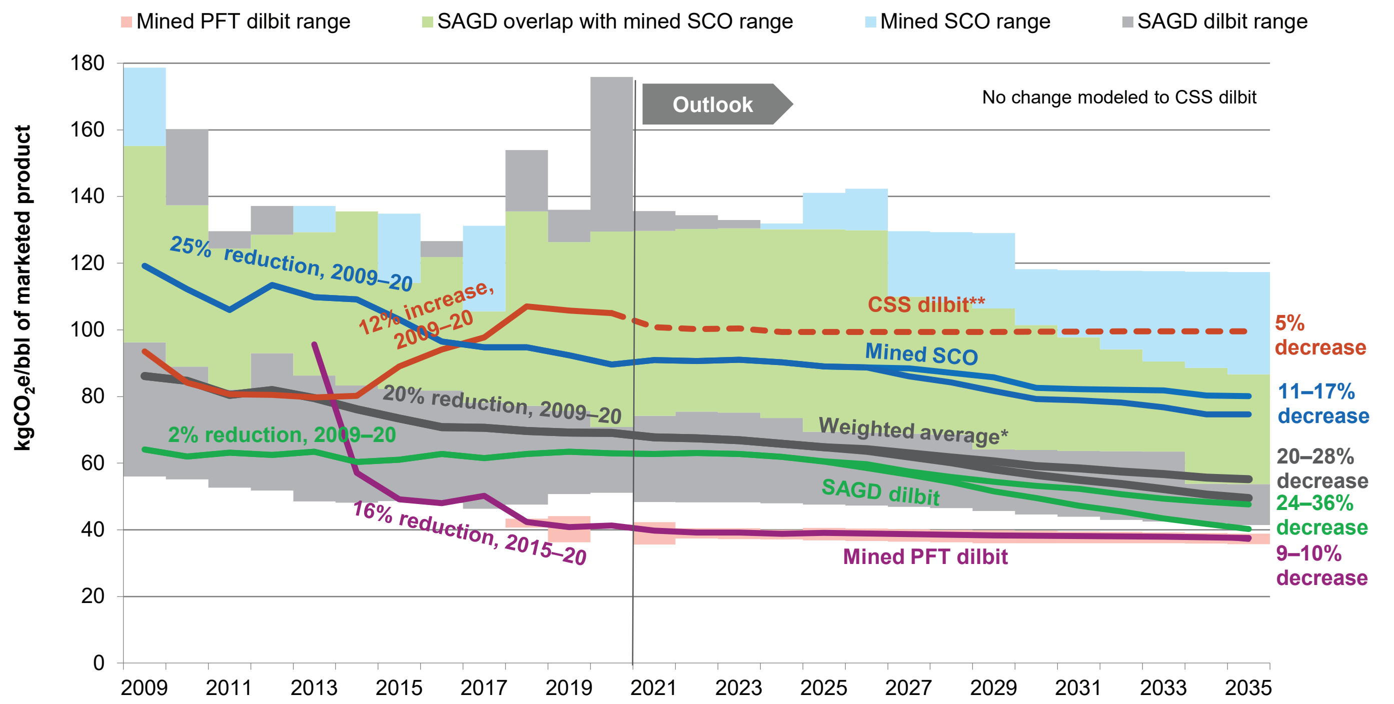
24. Regulatory applications were sourced from the AER database or on request. See https://dds.aer.ca/iar_query/FindApplications.aspx.

25. The comparison is based on the weighted average in 2035 of projects in the IHS Markit outlook not in operation in 2020 without any technology or efficiency improvements applied compared with the industry weighted average in 2020. 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 11 November 2021. The estimate of the future SAGD weighted SOR is based on the production outlook sourced from the IHS Markit *North American Crude Oil Markets Canadian Fundamentals Data: Second quarter 2021* and SOR guidance sourced from AER regulatory applications, company announcements, and websites.

26. CSS is included in the weighted average, but not in the range, as it would be unchanged. Overall, any projected range (minimum/maximum) should be treated with significant caution as the ranges represent individual facilities and could be subject to far more variation than the average.

Figure 12

Average and range of oil sands GHG intensity by year ($kgCO_2e/bbl$ of marketed product)



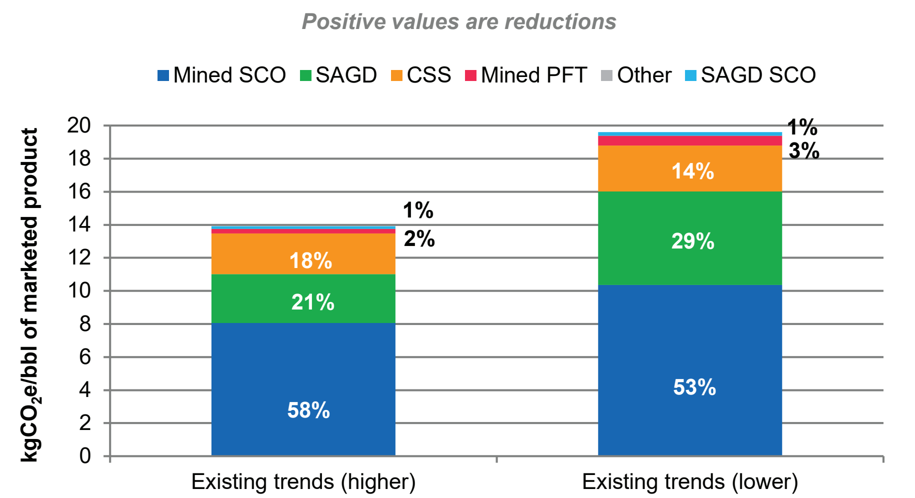
*Estimate of weighted average includes oil sands CSS; SAGD; mined SCO; mined PFT dilbit; and primary, experimental, and EOR. **Historical estimates for CSS were included with no modeled improvement in outlook, which is why the outlook is presented as a dashed line in the figure. Estimates for primary 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 5% of oil sands production in 2021, where it is expected to remain to 2035. Ranges shown for mined PFT dilbit, SAGD dilbit, and mined SCO are from a more conservative existing pathway case. Note that prior to 2018, there was only one operating mined PFT dilbit facility and thus no range. Source of prior estimates: IHS Markit Strategic Report *Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*, www.ihsmarkit.com/oilsandsdialogue.

Source: IHS Markit

modest improvement in mined SCO compared with SAGD dilbit, reductions in the relatively more GHG-intensive mined SCO has a more profound impact on the industry average. It is also worth noting that despite no efficiency or technology changes incorporated into CSS dilbit, the run-up of existing capacity results in reductions early in the outlook. Like mined SCO, the change in the relatively more GHG-intensive nature of CSS dilbit production has a meaningful impact on the average.

Figure 13

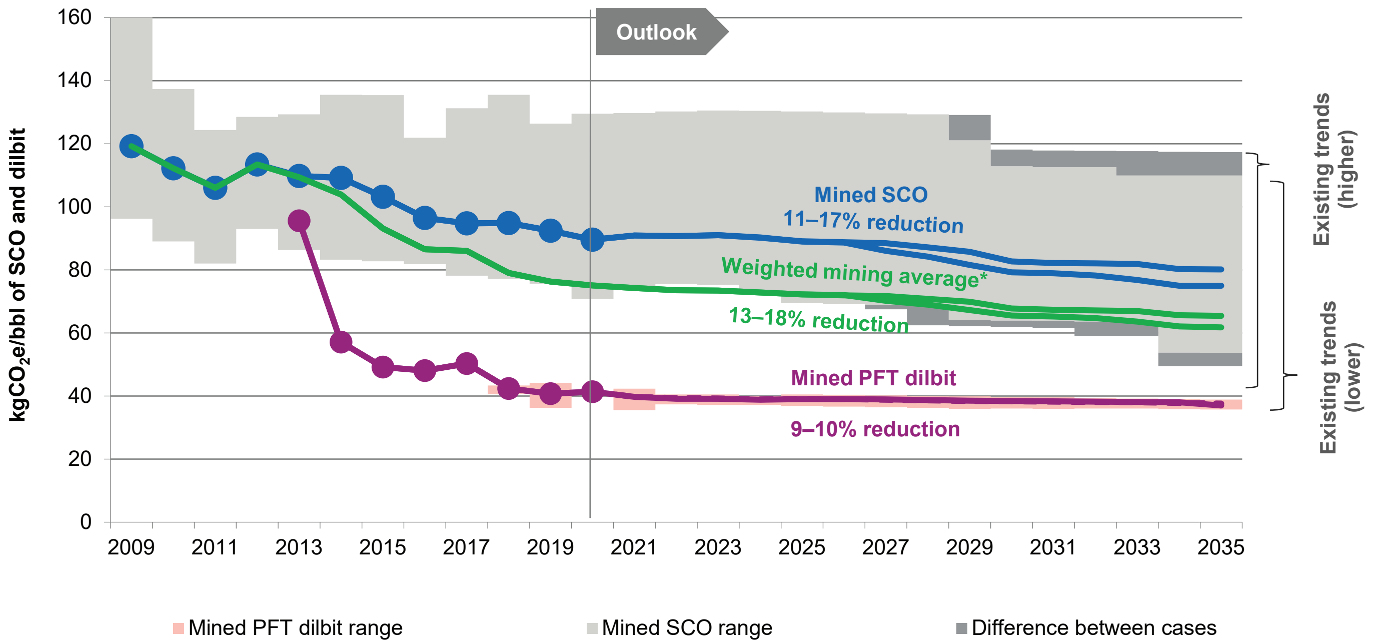
Sources of oil sands GHG intensity change by segment, 2020–35 (14–20 $kgCO_2e/bbl$ of SCO and dilbit)



Note: "Other" includes primary, experimental, and EOR.
Source: IHS Markit

Figure 14

GHG intensity of oil sands mining by year (2009–35, $kgCO_2e$/bbl of marketed product)



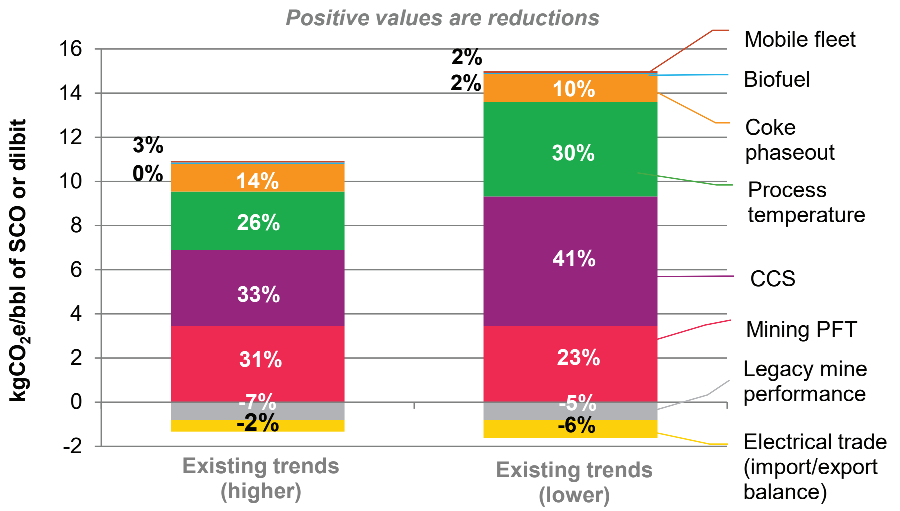
*Estimate of oil sands average includes mined SCO and mined PFT dilbit.
Source: IHS Markit

GHG intensity of oil sands mining

Digging into the individual segments in more detail, the overall mining GHG intensity falls between 10 $kgCO_2e$/bbl and 14 $kgCO_2e$/bbl, or between 13% and 18% from 2020 to 2035. This is shown in Figure 14, with Figure 15 presenting the technology drivers behind changes to the weighted average. The largest drivers of these reductions come from the ramp-up of mined PFT dilbit, deployment of CCS, and energy savings from process temperature improvement assumptions. Although less pronounced, the reduction in the use of petroleum coke from the Suncor base mine is also notable. With respect to deployment of CCS, the assumptions have a direct and indirect impact with the energy requirements of the capture unit, contributing to greater on-site energy use.

Figure 15

Existing trends sources of change in oil sands mining GHG intensity, 2020–35 (10–14 $kgCO_2e$/bbl of SCO or dilbit)



Source: IHS Markit

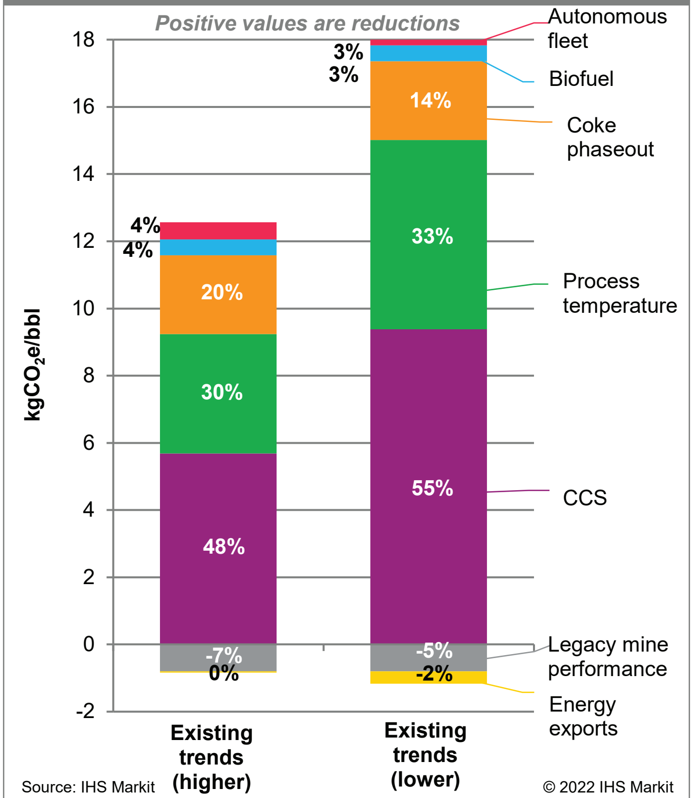
Each mining segment is discussed next.

Mined SCO. Looking at the individual mining extraction technologies shown in Figure 16 and Figure 17, mined SCO experiences a much larger GHG intensity reduction. This is driven by stronger assumptions associated with process temperature and the deployment of CCS. In total, mined SCO GHG intensity declines 10–15 kgCO_2e/bbl, or 11–17%, by 2035. The change in legacy mining performance is influenced by the use of 2020 as the comparison year, which impacted mining operations. The return to normal operations and higher output put some upward pressure on GHG intensity for several mines in the IHS Markit model. Meanwhile, the electricity exports or energy balance captures changes in cogeneration capacity that should be looked at together. In particular, significant cogeneration is associated with Suncor's coke boiler replacement project, which will result in an increase in natural gas combustion. CCS was material in both cases. Deployment of CCS is another critical factor.

Mined PFT dilbit. Mined PFT has fewer technology assumptions because it is a newer form of extraction and as a result experiences a more modest decline of around 4 kgCO_2e/bbl, or 9–11% by 2035. This decline is from a less GHG-intensive level overall.

Figure 16

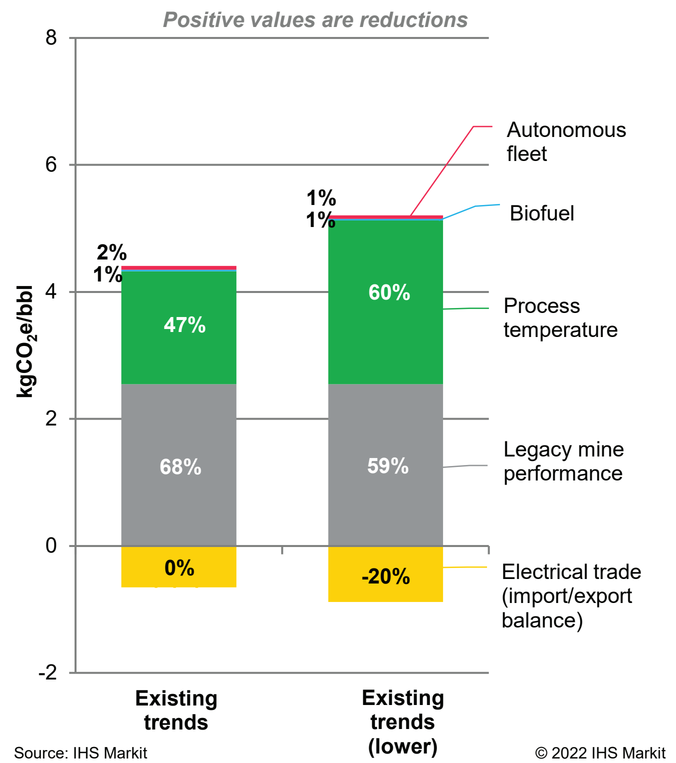
Existing trends sources of change in mined SCO GHG intensity, 2020–35 (10–15 kgCO_2e/bbl of SCO)



Source: IHS Markit © 2022 IHS Markit

Figure 17

Existing trends sources of change in mined PFT dilbit GHG intensity, 2020–35 (~4 kgCO_2e/bbl of dilbit)



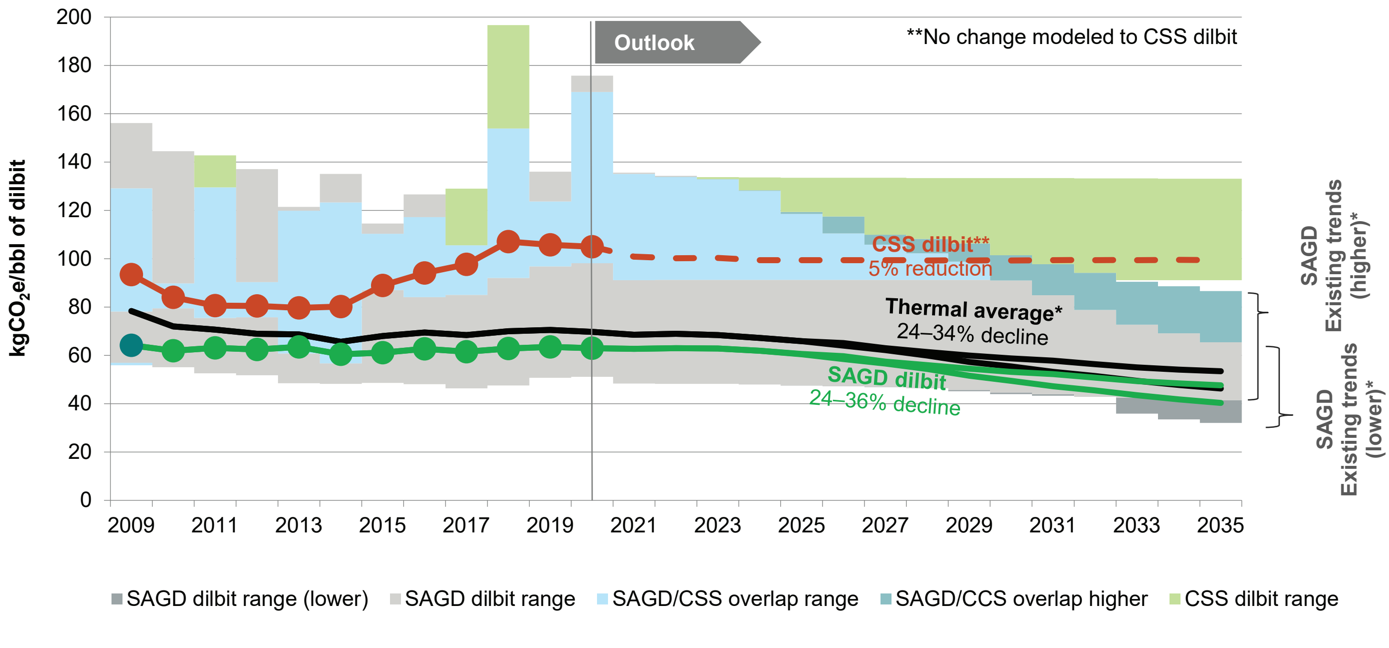
Source: IHS Markit © 2022 IHS Markit

GHG intensity of thermal oil sands

IHS Markit results for thermal oil sands project a reduction in GHG intensity of 16–24 kgCO_2e/bbl, or 24–34%, by 2035. This occurs despite only changes being incorporated into SAGD operations (see Figure 18).

Figure 18

GHG intensity of thermal oil sands dilbit (2009–35, in $kgCO_2e$/bbl of marketed product)



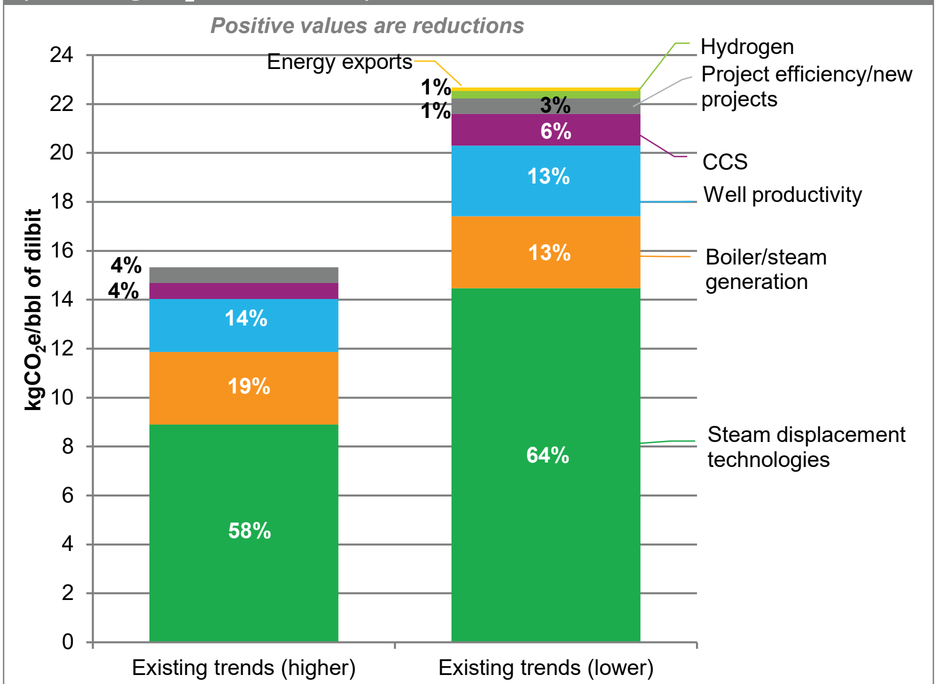
*Thermal average includes CSS and SAGD only. **No changes modeled to CSS dilbit, there is no change in the range of CSS dilbit.
Source: IHS Markit

SAGD dilbit. Existing trends point to a drop in GHG intensity of SAGD dilbit between 15 $kgCO_2e$/bbl and 23 $kgCO_2e$/bbl, or between 24% and 36%, by 2035. This is the greatest decline of any segment. In 2035, the average GHG intensity of SAGD is 40–48 $kgCO_2e$/bbl of dilbit. As shown in Figure 19, steam displacement technologies dominate the reductions. This is followed by boiler and water handling, well productivity, and new projects.

The contributions of steam displacement technologies are significantly larger than was anticipated and may be the source of upside risk to the IHS Markit assessment. However, both cases are best interpreted as forming a range rather than specific pathways.

Figure 19

Existing trends sources of change in SAGD GHG intensity, 2020–35 (15–23 $kgCO_2e$/bbl of dilbit)



Source: IHS Markit

CSS dilbit. CSS is included, but no future efficiencies or technologies were modeled in the outlook. Still, by 2035 CSS dilbit GHG intensity manages to decline by about 5 $kgCO_2e/bbl$, or 5%, from 2020 levels because of a normalization of operations from 2020 market disturbances. This contributes to a 4–6% reduction of thermal in situ intensity by 2035. The lack of equivalent treatment of technologies as SAGD is a limitation of IHS Markit analysis that is visible in Figure 19 and may contribute to overestimation of future oil sands GHG intensity and absolute emissions.

Part III: Absolute oil sands GHG emissions: 2009–35

Although GHG intensity has emerged as a critical metric of oil and gas competitiveness, absolute emissions reductions are key to national and international ambitions. In 2021, Canada's national ambition to reduce absolute GHG emissions increased to 40–45% below 2005 levels by 2030 and to be net zero by 2050.[27] These objectives require a significant change to Canada's emissions, which have remained relatively consistent around 730 MMtCO_2e for over a decade. This has made the future of Canadian oil sands production and emissions a topic of much debate in Canada, particularly when the Government of Canada's most recent projection anticipated a rise of oil sands emissions of around 19 MMt by 2030.[28]

Understanding, estimating, and projecting absolute oil sands GHG emissions is complex. Any projection of future emissions is a function of the performance of existing operations, composition and scale of future production, and the timing and type of new technologies that could be deployed to reduce GHG emissions. This section applies the GHG intensity cases developed earlier, plus the Optimized case, to present possible absolute emissions trajectories. To be clear, these pathways are predicated upon the numerous assumptions, and the future will most certainly evolve differently. To this end, IHS Markit provides several emissions pathways, as well as comparisons to other public sources and estimates based on announced industry ambitions.

Estimating and aligning IHS Markit absolute emissions estimates

Multiplying the IHS Markit production outlook by the estimates of future GHG intensity from the Existing trends and Optimized cases provides a view of the potential trajectory of future absolute oil sands GHG emissions. When it comes to estimates of Canadian GHG emissions, Canada's NIR completed by ECCC is regarded by many as the gold standard. For this reason, it was important to ensure comparability of IHS Markit absolute GHG emissions to the NIR. This required alignment of not only the system boundaries discussed earlier in the report but also of the facilities defined as part of oil sands in the NIR. These changes are discussed below.

Contrasting upstream life-cycle versus direct. To estimate absolute GHG emissions, GHG intensity estimates make use of direct system boundaries, as shown in Figure 2. GHG intensity estimates of direct on-site emissions are an estimate per barrel produced as opposed to barrel marketed or supplied. The change in system boundaries does present a different picture of oil sands GHG intensity. This is because they are measuring a different set of GHG emissions. The box "Comparing GHG intensity of upstream life cycle versus direct system boundaries" provides some additional background.

27. Prime Minister of Canada, "Prime Minister Trudeau announces increased climate ambition," https://pm.gc.ca/en/news/news-releases/2021/04/22/prime-minister-trudeau-announces-increased-climate-ambition, 22 April 2021.

28. ECCC, "Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020," http://publications.gc.ca/collections/collection_2021/eccc/En1-78-2020-eng.pdf, retrieved 29 October 2021.

Comparing GHG intensity of upstream life-cycle versus direct system boundaries

This box provides additional detail on the historical GHG intensity estimates of the Canadian oil sands between direct system boundaries and system boundaries consistent with the upstream stage of the crude oil product life-cycle. As shown in Table 4, on a direct emissions basis, both SAGD bitumen and CSS bitumen are more GHG intensive because all emissions associated with cogeneration fall within oil sands facility boundaries and because diluents which are generally less GHG intensive, have been removed.

A comparison of historical emissions between the two system boundaries, shown in Table 3, also shows the effect of the growth of SAGD dilbit eroding cogeneration credits more clearly. In the wider system boundaries, which are consistent with life-cycle pathways, SAGD dilbit emissions have been relatively flat. However, on a direct on-site basis, SAGD bitumen GHG intensity fell 9% from 2009 to 2020.

Table 4

Historical oil sands GHG emissions intensity by extraction type and emissions boundary

IHS Markit upstream life-cycle boundaries	Unit	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Mined SCO	$kgCO_2e$/bbl of SCO	119	112	106	113	110	109	103	96	95	95	92	90
Mined PFT dilbit	$kgCO_2e$/bbl of dilbit					96	57	49	48	50	42	41	41
SAGD dilbit	$kgCO_2e$/bbl of dilbit	64	62	63	62	63	60	61	63	62	63	63	63
CSS dilbit	$kgCO_2e$/bbl of dilbit	93	84	81	80	80	80	89	94	98	107	106	105
Average*		**86**	**85**	**80**	**82**	**79**	**76**	**73**	**71**	**71**	**70**	**69**	**69**
Direction emissions boundaries													
Mined SCO	$kgCO_2e$/bbl of SCO	111	104	99	102	99	98	90	84	83	84	83	80
Mined PFT bitumen	$kgCO_2e$/bbl of bitumen	0	0	0	0	75	42	37	37	39	37	34	35
SAGD bitumen	$kgCO_2e$/bbl of bitumen	72	68	68	68	71	65	65	67	64	65	66	66
CSS bitumen	$kgCO_2e$/bbl of bitumen	103	91	87	86	86	87	99	109	113	125	124	123
Average*		**93**	**91**	**86**	**87**	**85**	**81**	**76**	**74**	**73**	**72**	**71**	**71**

*The average GHG intensity incorporates primary, experimental and enhanced oil recovery production and adjusts for SAGD SCO production.

Source: IHS Markit

Conversely, mining operations are less GHG intensive because mined SCO has historically, on average, been a net electrical importer, which would not be captured within direct system boundaries.

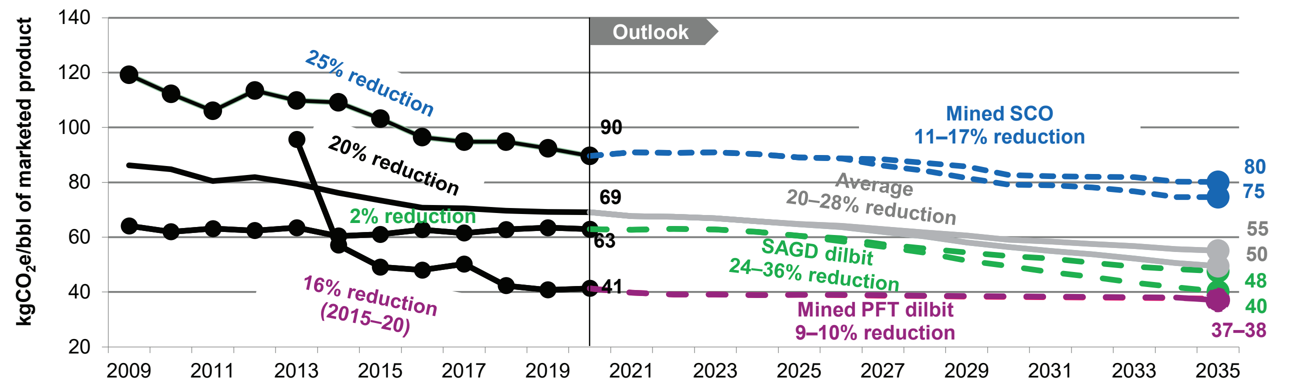
Figures 20 and 21 contrast the differences in the outlook between Existing trends under the two different system boundaries. It is also worth highlighting the increase in mined SCO GHG intensity that occurs around 2025. This is associated with a rise in natural gas use in cogeneration associated with Suncor coke boiler replacement. In Figure 20, the excess electricity is not consumed on-site and is exported, and thus it is deducted from mined SCO emissions. However, under direct on-site emissions, as shown in Figure 21, those emissions count toward mined SCO regardless of their end use and result in a bump in GHG intensity starting around 2025.

("Comparing GHG intensity of upstream life-cycle versus direct system boundaries" continued on next page.)

Comparing GHG intensity of upstream life-cycle versus direct system boundaries (continued)

Figure 20

GHG intensity of oil sands production with system boundaries consistent with upstream stage of life-cycle analysis (kgCO$_2$e/bbl of output SCO or dilbit)



Source: IHS Markit

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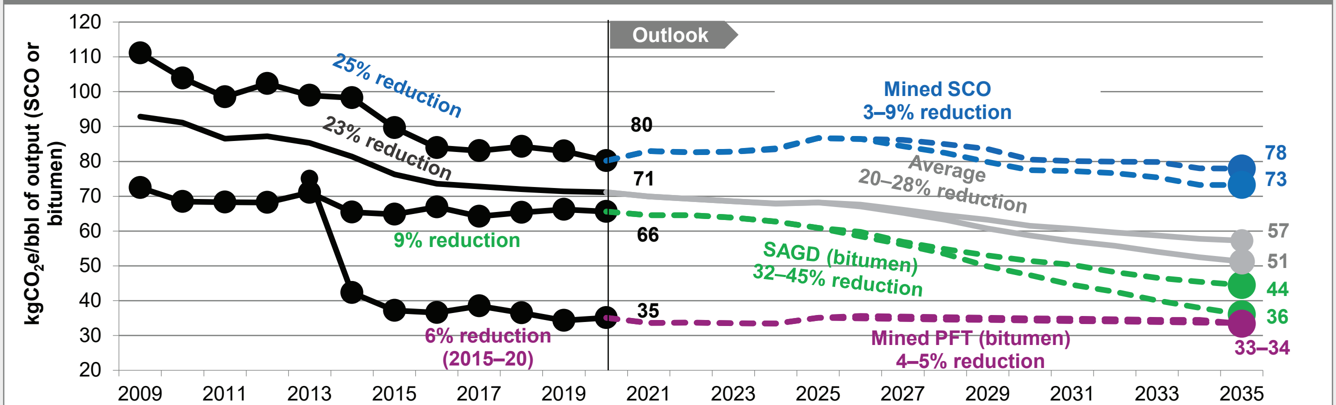
Figure 21

GHG intensity of oil sands production consistent with direct on-site system boundaries (kgCO$_2$e/bbl of output SCO or bitumen)



Source: IHS Markit

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Aligning oil sands facilities between Canada's NIR and IHS Markit. Canada's NIR report considers some additional facilities as part of the oil sands sector that are not included by IHS Markit. Specifically, Canada's NIR includes upgrading in Saskatchewan and the North West Refining (NWR) facility. Both facilities are not included in the IHS Markit estimate. The NIR provides an estimate of Saskatchewan upgrading emissions, which were removed from total oil sands emissions reported in the NIR. GHG emissions associated with the NWR for 2017–19 were also removed from the NIR estimate of the oil sands sector (past and future) using data from Canada's large facilities emitters database.[29]

29. IHS Markit understands that Canada's NIR includes the Husky Energy Bi-Provincial Upgrader (BPU) located in the province of Saskatchewan as part of oil sands upgrader GHG emissions as well as GHG emissions from the NWR facility. The BPU is not included in IHS Markit analysis because it is not dedicated to upgrading oil sands bitumen, and it also processes non–oil sands derived heavy oil. NIR estimates of the Saskatchewan oil sands upgrader were removed from the NIR oil sands totals shown in this report. The NWR facility is also not part of the IHS Markit analysis, as it is designed to market refined product. IHS Markit removed GHG emissions associated with NWR using the ECCC GHG emissions from large facilities database for the years 2017, 2018, and 2019. All forward-looking comparisons between ECCC estimates and IHS Markit absolute estimates were adjusted to remove both the NWR facility and the BPU using the last year of data available. For more information on the Canadian large facilities database, see ECCC, "Greenhouse gas emissions from large facilities," https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/greenhouse-gas-emissions/large-facilities.html, retrieved 20 December 2021.

The trajectory of absolute oil sands GHG emissions: 2021–35

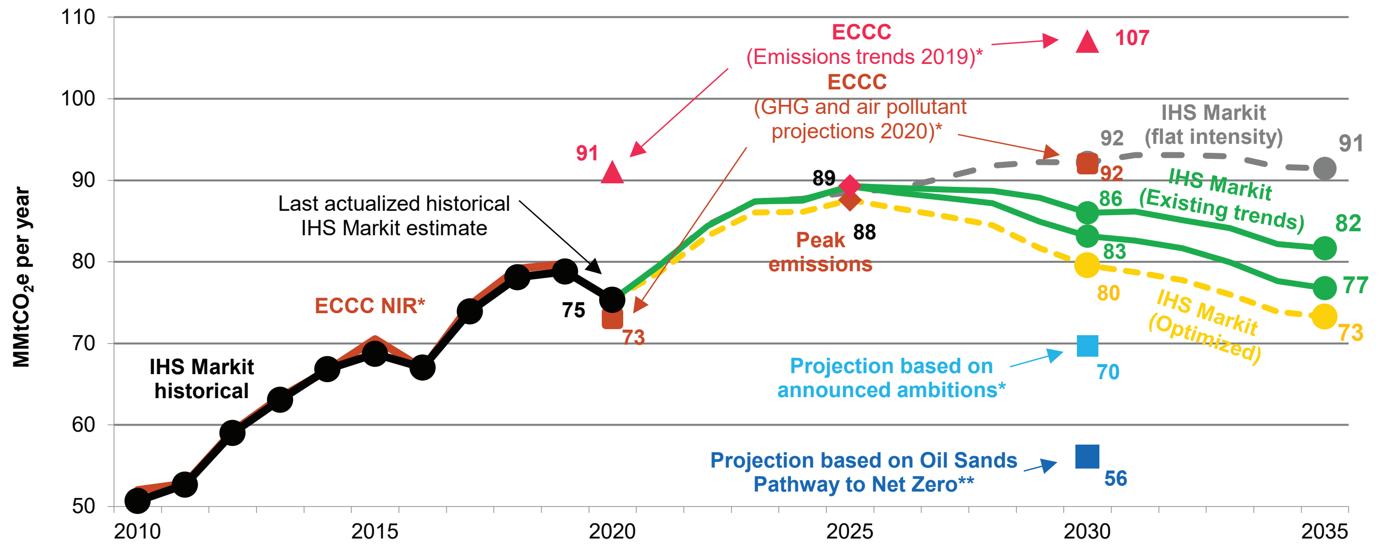
This section presents the results of IHS Markit absolute oil sands GHG emissions under various cases: Existing trends (higher and lower) and Optimized.

As shown in Figure 22, all of IHS Markit's three core cases show that the absolute oil sands GHG emissions continue to rise into the mid-2020s. As operations recover and seek to maximize output from existing capacity, GHG intensity declines while pushing absolute emissions higher in the immediate term. Eventually, however, the pace of GHG intensity reductions begins to outstrip slowing production growth, and absolute emissions begin to decline. This inflection occurs in all cases within the next half-decade, around 2025, between 87 $MMtCO_2e$ and 89 $MMtCO_2e$, while production rises 600,000 b/d over this period.[30] Thereafter, differences in efficiency and technology assumptions shape the trajectory of absolute emission, reductions.

In addition to IHS Markit's three core cases, an estimate of absolute GHG emissions with no incremental GHG intensity improvements was developed using the same base production outlook as the other cases. The "Static (no improvement)" case was made for comparison and is not considered a credible case. In addition to the IHS Markit cases, Figure 22 incorporates several other projections of absolute oil sands emissions to 2030 and 2035. The box "Sources of absolute oil sands GHG emissions projections" provides a description of each of the additional cases.

Figure 22

IHS Markit absolute oil sands GHG emissions projections to 2035 compared against other announcements and outlooks ($MMtCO_2e$ per year)



*ECCC NIR and projections were adjusted to align with same facilities as IHS Markit estimates.**IHS Markit estimated the cumulative impact of the announced ambition of the individual oil sands producers on future GHG emissions as well as the Oil Sands Pathways to Net Zero initiative absolute emissions reduction target by 2030. The IHS Markit projection of announced ambitions only considers announcements made at the time of publication. This is further complicated by companies' use of different target dates, target bases (intensity versus absolute), and scopes (corporate portfolio versus oil sands only). IHS Markit also made use of its own production and intensity expectations to develop this estimate. No analysis was undertaken into the feasibility of achieving the announced ambition or estimates of any other sources cited in this figure. These estimates of future emissions do not consider the potential for the purchase of offsets or credits through initiatives like nature-based solution.

Source: IHS Markit, ECCC NIR 2021, Biennial Report, 2019, GHG and air pollutant projections 2020, various corporate announced ambitions, Oil Sands Pathways to Net Zero © 2022 IHS Markit

30. It should be noted that the IHS Markit model solves for steam required to produce without steam generation limitations. As a result, IHS Markit production assumptions dominate the use of natural gas. However, there are physical limitations associated with steam generation capacity (e.g., there are a fixed number of boilers on a specific oil sands site). If the IHS Markit production outlook is accurate, then this may not present an issue. However, if the IHS Markit outlook is inaccurate or assumes production that would exceed existing steam capacity, this could result in an overestimation of absolute GHG emissions.

Sources of absolute oil sands GHG emissions projections

Several estimates were sourced from ECCC publications. These included the following:

- **NIR 2021.** This reports provides a historical comparison of absolute oil sands emissions from 2010 to 2019. Estimates sourced have been adjusted to remove emissions associated with the BPU in Saskatchewan and the NWR facility to align with IHS Markit emissions boundaries.*

- **Fourth Biennial Report to the UNFCCC (Biennial Report, 2019).** IHS Markit incorporated estimates of future absolute emissions from this report. The report value also had emissions associated with the BPU in Saskatchewan and the NWR facility. They were removed to align with IHS Markit oil sands estimates.**

- **Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020** (GHG and air pollutant projections). IHS Markit incorporated estimates of future absolute emissions from this report. The report value also had emissions associated with the BPU in Saskatchewan and the NWR facility. They were removed to align with IHS Markit oil sands estimates.***

HS Markit also estimated the potential absolute oil sands GHG emissions based on the cumulative announced ambitions of individual oil sands producers, as well as the announced ambitions from the Oil Sands Pathways to Net Zero alliance.

- **Announced ambitions.** IHS Markit developed an estimate of the cumulative effect of the various targets—both intensity and absolute—of major oil sands producers on the absolute oil sands emissions in 2030. The companies whose targets were considered in this estimate included Canadian Natural Resources, Cenovus Energy, Imperial, MEG Energy, and Suncor Energy. Individual targets were modeled to individual facilities to arrive at a cumulative impact in 2030. Where targets were expected to be achieved prior to 2030, only the announced target was considered, and no additional improvements were modeled. This was a significant limiting factor.****

- **The Oil Sands Pathways to Net Zero.** The Oil Sands Pathways to Net Zero alliance includes Canadian Natural Resources, Cenovus Energy, ConocoPhillips, Imperial, MEG Energy, and Suncor Energy. The Oil Sands Pathways to Net Zero has announced an ambition to reduce oil sands absolute emissions by 22 $MMtCO_2e$ from 2018 to 2030.***** The estimate presented in Figure 22 was the IHS Markit estimate of absolute GHG emissions in 2018 less the announced ambition of 22 $MMtCO_2e$, to arrive at 57 $MMtCO_2e$ in 2030.

*ECCC, "National Inventory Report 1990–2019: Greenhouse gas sources and sinks in Canada," https://publications.gc.ca/site/eng/9.506002/publication.html, retrieved 20 December 2021.

**ECCC, "Canada's Fourth Biennial Report on Climate Change," https://unfccc.int/sites/default/files/resource/br4_final_en.pdf, retrieved 29 October 2021.

***ECCC, "Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020," http://publications.gc.ca/collections/collection_2021/eccc/En1-78-2020-eng.pdf, retrieved 29 October 2021.

****MEG Energy has a target for a 30% reduction in GHG intensity from 2013, or a 20% reduction from 2020, by 2030. See MEG Energy Corp., "2021 Environmental, Social & Governance Report," www.megenergy.com/sites/default/files/MEG%20Energy%20ESG%20Report%202021.pdf, retrieved 29 October 2021. Suncor Energy has a target to reduce absolute emissions by 10 MMt by 2030. IHS Markit attributed three-quarters of Suncor's anticipated ambition for oil sands reductions, roughly equivalent to the IHS Markit estimate of the oil sands emissions share for Suncor's total emissions. See Suncor Energy, "2021 Investor Day," sustainability-prd-cdn.suncor.com/-/media/project/suncor/files/investor-centre/investor-day-2021/2021-suncor-energy-investor-day-presentation-en.pdf, retrieved 29 October 2021. Imperial has a target for a 10% reduction by 2023 from 2016 levels. See Imperial, "Energy solutions for a better tomorrow: Corporate sustainability report," www.imperialoil.ca/-/media/Imperial/Files/Publications-and-reports/IMP-0020-Sustainability-Report_final_web_March-29.pdf. Cenovus Energy has target of a 35% reduction in GHG intensity basis by 2035 relative to 2019 (as measured on an equity ownership). See Cenovus Energy, "Cenovus releases 2022 budget, updated strategy and 5-year business plan," https://www.cenovus.com/news/news-releases/2021/12-08-2021-Cenovus-releases-2022-budget-updated-strategy-and-5-year-business-plan.html, retrieved 23 January 2022. Canadian Natural has a target of a 25% reduction in oil sands GHG emissions intensity by 2025 from a 2016 baseline. See Canadian Natural Resources Limited, "2020 Stewardship Report To Stakeholders," https://www.cnrl.com/upload/media_element/1313/04/2020-stewardship-report-to-stakeholders.pdf, retrieved 29 October 2021.

*****Oil Sands Pathways to Net Zero, "Detailed presentation: Pathways plan to achieve net zero emissions," www.oilsandspathways.ca/the-pathways-vision/, retrieved 29 October 2021.

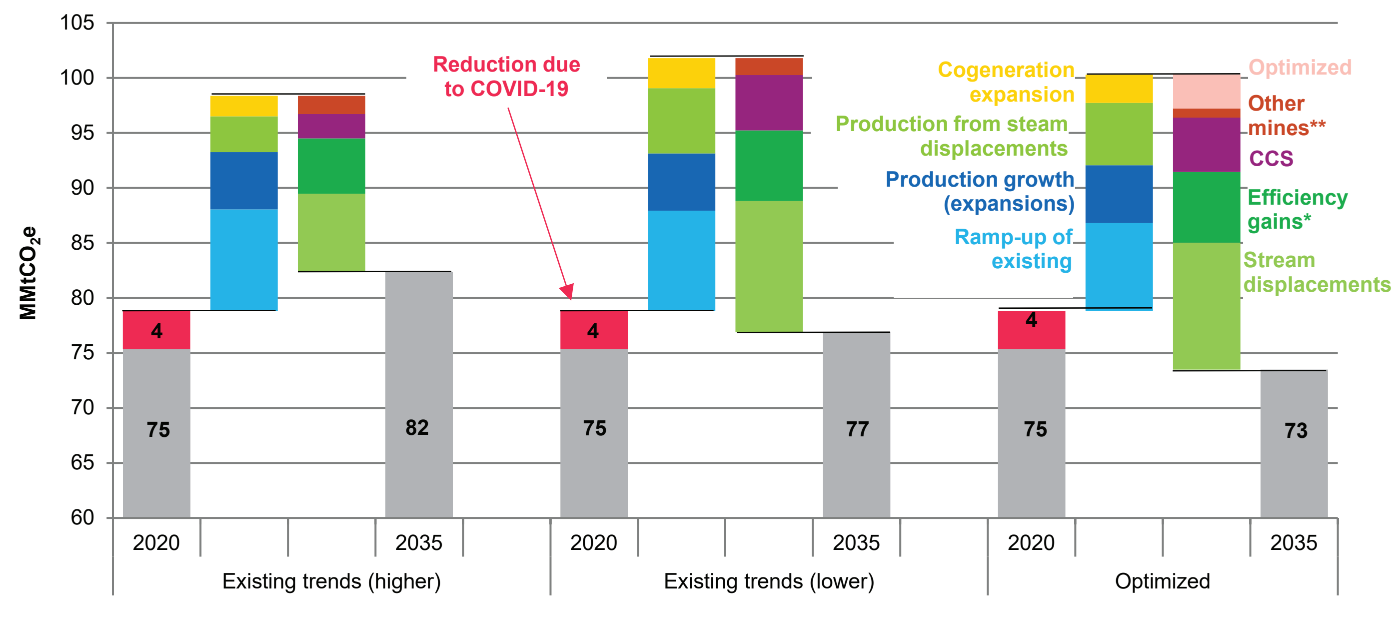
Sources of absolute GHG emissions change in IHS Markit cases

IHS Markit attempted to account for various forces that influence the evolution of oil sands absolute emissions—up and down—in each of the cases. This is presented in Figure 23. Caution is advised in considering each source of change as purely additions or subtractions as the forces interact, and some upward pressures are linked to downward forces. This is particularly relevant for steam displacement technologies that reduce steam intensity and thus GHG intensity but also enable production growth. In interpreting the impact of steam displacements technologies, the net impact should be considered. This complicated the creation of Figure 23.

In all cases, the greatest source of upward pressure on absolute emissions is production (ironically, this also contributes to downward pressure on GHG intensity of output). Most notably, the near-term factors of the recovery of output from COVID-19 and the ramp-up of existing underutilized capacity represented the majority of GHG emissions additions when the net impact of steam displacement technology is considered (shown in pink and light blue in Figure 23).[31] The estimated potential volumes that could come from ramping up existing capacity are significant at over 500,000 b/d from 2020 to early 2023.[32]

Figure 23

Sources of change in IHS Markit cases on absolute oil sands GHG emissions from 2020 to 2035 ($MMtCO_2e$)



Note: Technology improvements modeled do have cross implications. For example, in more aggressive technology assumption cases, production growth would be less GHG intensive, reducing the absolute GHG emissions. *Efficiencies include mining process temperature and thermal well productivity and boiler efficiency. **Other mines include changes in production and mobile mine fleet.
Source: IHS Markit

Cogeneration contributes to absolute emissions increases because any capacity additions add to oil sands emissions regardless of the use of electricity. This is consistent with direct on-site GHG emissions system boundaries.

In the abatement or reduction column, the deployment of CCS, efficiency gains like mining process temperature, well productivity, and boiler efficiency, combined with steam displacement technologies,

31. The upward pressure associated with steam displacement technology should be considered inclusive of the potential reductions, because one does not occur without the other.

32. It should be noted that in general, optimization projects are considered as part of the ramp-up of existing projects, but some optimization volumes are included in the production growth category because they were hard to fully isolate. For more information that IHS Markit used in this report, see IHS Markit, *Canadian oil sands running above pre-pandemic highs, but the lingering impacts of COVID-19 and acceleration of energy transition have lowered the growth prospects*.

collectively manage to match or outstrip production gains to reduce absolute emissions to varying degrees by 2035. The Optimized case benefits from an assumption of more efficient operations and more rapid recovery in well productivity from thermal operations, which contributes to the lowest outcome of the three cases.

CCS remains a wild card capable of more significant reductions, but as modeled by IHS Markit, the single-largest source of reductions was steam displacement technologies.

Steam displacement technologies were unique to the IHS Markit oil sands model in that they influenced not only GHG emissions but also productivity. These technologies physically displace steam required per barrel with solvents, or noncondensable gas like methane. For existing facilities, as steam intensity declines, more oil can be produced using existing infrastructure because less steam is required per barrel. Although these technologies have significant GHG intensity implications, the redeployment of steam in existing facilities mutes the absolute GHG reductions from certain applications of these technologies. This is why both the GHG emissions reductions and the emissions additions associated with production gains are shown separately in Figure 23. However, these two pressures are linked. This linkage between steam intensity and production complicated the modeling and led to some counterintuitive results in which the cases with the lowest absolute emissions had the highest levels of output.[33]

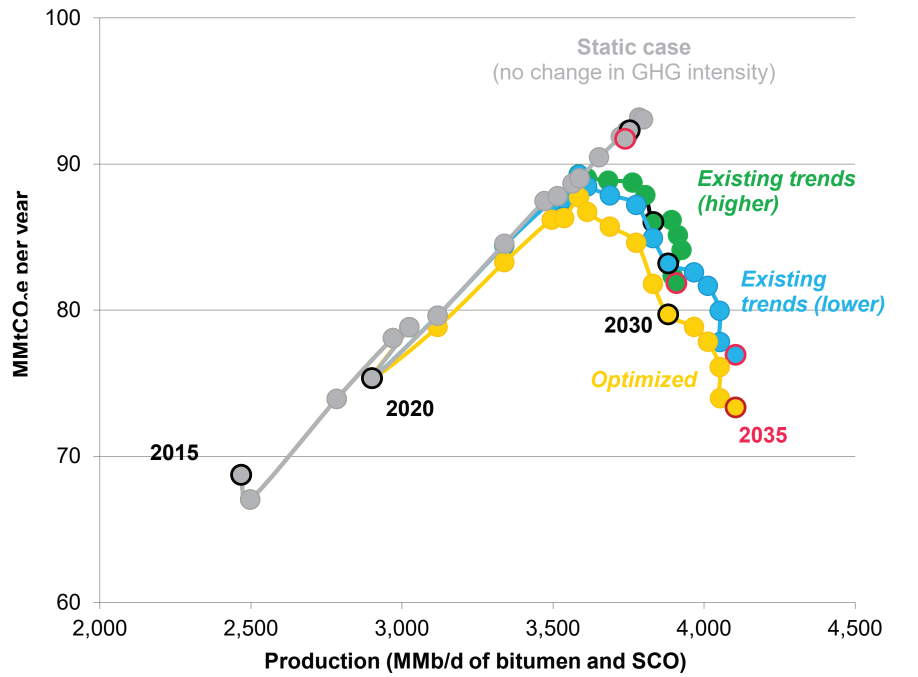
Steam displacement technology complications: Production growth and absolute emissions

Although all the IHS Markit cases start with the same production outlook, the reallocation of steam "freed" from deployment of steam displacement technologies results in different production levels. This drives a seemingly counterintuitive outcome in which the cases with the highest production also have the lowest emissions. This result can be seen in Figure 24, which is a scatterplot of production versus absolute emissions. All things being equal, the cases with the most aggressive technology assumptions would be expected to have the lowest GHG intensity and absolute emissions outcomes. This result makes sense. However, these same cases also have the most dramatic levels of steam displacement technologies, which supports incremental production from existing infrastructure. This is what drives this seemingly counterintuitive result.

As can been seen in Figure 24, the Optimized and the Existing trends (lower) cases achieve the highest level of production while having the lowest absolute emissions. Compared with the Static, no improvement case, steam displacements in Existing trends (higher) contribute to about 170,000 b/d of incremental production (SCO and bitumen) by 2035, whereas Existing trends (lower) and Optimized realize an additional 360,000 b/d.

Figure 24

Cumulative change in oil sands production versus absolute GHG emissions (direct on-site system boundaries)



Source: IHS Markit

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33. There are full solvent processes that continue to be tested that would have significantly lowered GHG emissions.

It should be noted that IHS Markit chose to limit the full redeployment of steam back into production, anticipating that eventually some of the steam intensity improvements could be used to deliver absolute GHG emissions improvements. We also allowed newer facilities—facilities developed after 2025—to be descaled and developed with less steam handling capacity.[34] These assumptions result in more or less absolute emissions from steam displacement technologies.

If IHS Markit assumptions are too conservative, and a greater share of "freed" steam is redeployed to maximize production through 2035 than anticipated, absolute emissions gains could be further offset by higher output. Conversely, however, should steam displacement technologies prove successful at increasing output for little or no emissions gain, then the level and GHG emissions associated with brownfield expansions anticipated in the IHS Markit outlook could be lower, with the logic being that a producer is likely to pursue the least-cost, most efficient means to achieve a similar level of production ambition. This is certainly an area worth further sensitivity analysis and a is source of uncertainty.

Comparing GHG emission projections

Compared to prior projections shown in Figure 22 by ECCC, IHS Markit cases have more volume and lower GHG emissions. The one exception to this is the IHS Markit Static case. A comparison to both the announced ambitions and the Oil Sands Pathways to Net Zero initiative is more difficult because there is no corresponding production associated with the announced ambitions. Still, IHS Markit cases all appear more conservative than the announced ambition of oil sands producers individually, and particularly compared with the Oil Sands Pathways to Net Zero initiative. Oil Sands Pathways to Net Zero achieving absolute emissions being 24 $MMtCO_2e$ below the optimized case in 2030, and 17 $MMtCO_2e$ below the optimized 2035 projection. Table 5 provides a comparison of the production and GHG emissions.

Table 5

Comparison of key absolute oil sands GHG emissions cases and/or reports

		GHG emissions ($MMtCO_2e$)		Production (1,000 b/d of bitumen)	
ECCC publications*	**Publication year**	**2020**	**2030**	**2020**	**2030**
Canada's Fourth Biennial Report on Climate Change	2019	91	107	3,277	4,105
GHG and Air Pollutant Emissions Projections	2021	73	92	2,864	3,935
IHS Markit					
Existing trends (higher)	2021	75	85	2,960	3,915
Existing trends (lower)	2021	75	81	2,960	3,960
Optimized	2021	75	80	2,960	3,960
Static (no improvement)	2021	75	92	2,960	3,830
Other**					
Announced ambitions (estimated)	Various	**N/A**	70	N/A	N/A
Oil Sands Pathways to Net Zero alliance	2021	**N/A**	56	N/A	N/A

Note: These estimates of future emissions do not consider the potential for the purchase of offsets or credits through initiatives like nature-based solutions.
*Consistent with IHS Markit treatment for comparison of ECCC NIR, GHG emissions from the BPU located in Saskatchewan and the NWR facility were removed from both ECCC report projections for greater comparability with IHS Markit estimates. The estimate of 2019 Saskatchewan upgrading emissions were sourced from the NIR, and NWR emissions were sourced from the ECCC larger emitter database for 2019 and deducted. This resulted in a downward revision of just over 2 $MMtCO_2e$.
**Announced ambitions is the IHS Markit estimate of the cumulative impact of individual oil sands producers. The Oil Sands Pathways to Net Zero alliance is the IHS Markit estimate of absolute oil sands emissions in 2030 based on the pathways announced ambitions. The values differ because the announced ambitions only include corporate targets announced at the time of publication as well as because of complications in aligning the different target dates, target bases (intensity versus absolute), and scopes (corporate portfolio versus oil sands only). IHS Markit also made use of its own production and GHG intensity expectations to develop this estimate. No analysis was undertaken into the feasibility of achieving any announced ambitions. For more information on sources, see the box "Sources of absolute oil sands GHG emissions projections.

Source: IHS Markit, ECCC: Canada's Fourth Biennial Report to the UNFCCC, ECCC: Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020, Oil Sands Pathways to Net Zero Alliance, and various corporate sustainability reports, including Cenovus Energy, MEG Energy, Suncor Energy, Imperial, and Canadian Natural Resources

34. IHS Markit assumed that facilities built after 2025 would incorporate the current learnings associated with the use of steam displacement technologies. The facilities were descaled to the level of steam required to achieve a specified output volume based on the level of technology performance at the time the facility is anticipated to be brought online in IHS Markit's model. In this way, steam displacement can not only reduce GHG intensity and increase output but can also contribute to fewer absolute emissions than cases without this technology.

For more information regarding the sources of the cases in Table 5, see the box “Sources of absolute oil sands GHG emissions projections.”

IHS Markit considers its cases—Existing trends to Optimized—as potentially conservative, particularly compared with the ambitions announced by industry. Indeed, compared with historical performance, only in the Optimized case does the rate of change projected by IHS Markit exceed the experience of the past decade but only on a percentage basis. Table 6 provides a comparison of past performance against the IHS Markit cases.

Table 6

Comparison of rate of change between IHS Markit oil sands emission cases (direct emissions)

	Historical		Projection (2020–35)		
	2009–20	2011–20	Existing trends (higher)	Existing trends (lower)	Optimized
Annual average change in GHG intensity (kgCO_2e/bbl)	-1.97	-2.00	-0.93	-1.33	-1.48
Annual average change in GHG intensity (percent)	-2.4%	-2.4%	-1.4%	-2.2%	-2.5%
Implied GHG intensity in 2035			57	51	49
Implied absolute emissions in 2035			82	77	73

Source: IHS Markit © 2022 IHS Markit

The Alberta oil sands emissions limit

In 2016, the Government of Alberta announced the Oil Sands Emissions Limit Act. This rule established an absolute GHG emissions limit of oil sands development of 100 MMtCO_2e. This is not to be confused with the Government of Canada’s announced intention to impose its own cap on oil and gas upstream emissions, which would include more than just the oil sands.

Although Alberta’s cap on oil sands GHG emissions—known as the 100 MMt cap—makes use of different system boundaries than those presented in Figure 22, the results nonetheless indicate that oil sands GHG emissions are unlikely to reach that limit.

The 100 MMtCO_2e cap uses a distinct set of system boundaries. This differs from the definition in Canada’s NIR. Under the 100 MMtCO_2e cap, emissions associated with electricity generation and use; emissions arising from primary, experimental, and EOR crude oil production (occurring within the oil sands region); and emissions associated with upgraders that start up after 2015 are excluded.[35]

As a result of these differences, emissions subject to the cap are lower than those found in the NIR. In 2019, compared with Canada’s NIR, IHS Markit estimates the difference was just over 13 MMtCO_2e (with about 10 MMt associated with electrical power generation and use; about 1 MMt associated with “new upgrading”; and about 2 MMt associated with primary, experimental, and EOR extraction).[36]

A comparison of historical and future GHG emissions of the various IHS Markit cases subject to Alberta’s 100 MMtCO_2e cap is shown in Figure 25. None of the IHS Markit current cases approach Alberta’s 100 MMtCO_2e cap.

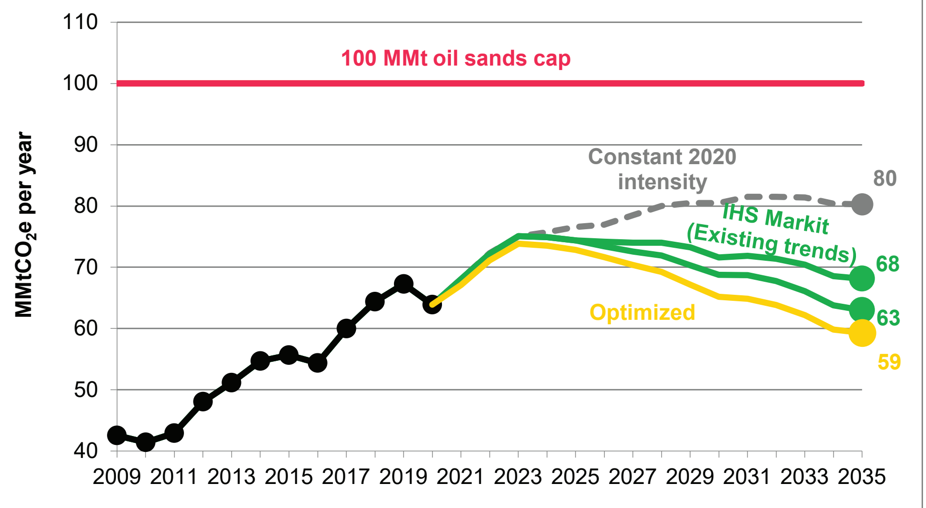
35. IHS Markit made reasonable assumptions based on our interpretation of the Oil Sands Emissions Limit Act to arrive at an estimate of emissions subject to the cap. Should implementation regulations come forward in the future, greater clarity would be expected around the definition of emissions, and the IHS Markit estimate could be affected.

36. The total does not sum owing to rounding.

Concluding remarks

Figure 25

Past and possible future oil sands GHG emissions subject to Alberta's 100 MMtCO$_2$e cap



Source: IHS Markit © 2022 IHS Markit

IHS Markit projections are complex and incorporate numerous assumptions—such as performance of existing facilities, advancement and deployment of critical technology, global supply and demand, future production, and the interactions between all these pieces. The world will undoubtedly unfold differently than these outlooks; however, to better address the GHG reduction challenge, a better understanding is required, particularly because crude oil remains Canada's most valuable export commodity.

IHS Markit presented three distinct cases that result in different outcomes. All things being equal, all the cases point to the fact there is existing underutilized oil sands production capacity that would be expected to ramp up. The ramp-up of this capacity will put downward pressure on GHG intensity and upward pressure on absolute emissions in the immediate term. Or, to put it another way, the ramp-up will generate incremental economic value and improve the global GHG competitiveness of the oil sands while challenging short-term national ambitions. Over the longer term, ongoing GHG intensity reductions are poised to overtake a slowing growth profile, leading to absolute emissions reductions. The degree of reductions will depend on the pace and scale of new efficiencies and technologies, with CCS being a critical wild card.

Looking to the future, indications are that pressure to deliver faster and more material absolute GHG emissions reductions is building. Alberta plans to increase the stringency of its carbon pricing regime, impacting the oil sands over time, and the Government of Canada has announced its intention to cap oil and gas sector emissions at current levels. Meanwhile, core oil sands companies have jointly announced a shared GHG reduction ambition that exceeds the outcomes of all IHS Markit cases. The commissioning of this study predates any discussion of the Government of Canada's oil and gas sector emissions cap as well as the announced Oil Sands Pathways to Net Zero. This study is meant to provide an independent and transparent review of past and potential future oil sands emissions. Detailed appendixes of the results of each case have been made available to allow users to examine and interpret the outcomes for themselves.

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