# Scenarios of Future Growth

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Canadian Oil Sands Dialogue | **Strategic Report**

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# Scenarios of Future Growth

## About this report

**Purpose.** Since 2009, IHS Markit has made public research on issues surrounding the development of the Canadian oil sands. Since the turn of the last century, the oil sands have been a pillar of global oil supply growth. Yet, since 2014 a lower oil price has reduced investment and expectations of future growth. The ultimate arbiter of the oil sands' role in future supply is the long-term trajectory of the price of oil, which has also come into question. This report explores the outlook for oil sands growth under three IHS Markit energy scenarios.

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

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

**Methodology.** IHS Markit conducted our own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a focus group meeting held in Ottawa, Ontario, on 7 June 2016, as well as participant feedback on a draft version of the report. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for a list of participants and the IHS Markit team).

**Structure.** This report has five parts.

- Part 1: Introduction—An uncertain future for the oil sands
- Part 2: Lower prices have reduced investment in the oil sands
- Part 3: Oil prices, costs, and investor confidence
- Part 4: Price will conquer all—Scenarios of oil sands growth
- Part 5: Conclusion

Unless otherwise stated, values are in US dollars. All investment projections are normalized to 2016 constant/real dollars.

# Scenarios of Future Growth

## Key implications

Since the turn of the last century, the oil sands have been a pillar of global oil supply growth. Yet, since 2014 a lower oil price has reduced investment and expectations of future growth. The ultimate arbiter of the oil sands' role in future supply is the long-term trajectory of the price of oil, which has also come into question. This report explores the future of the Canadian oil sands under IHS Markit scenarios.

- **Lower prices have reduced investment in the oil sands.** Since the onset of the price collapse, upstream investment in new oil sands production capacity has fallen by two-thirds—from over $30 billion in 2014 to just over $10 billion estimated for 2017. Estimates for 2018 indicate that the level of investment may yet fall further.

- **Despite ongoing cost reductions, a number of uncertainties weigh on investments in new oil sands projects.** In 2017, the lowest-cost oil sands projects—cost to construct and bring online—require a WTI price under $50/bbl to break even. Yet, a constrained pipeline takeaway system, the prospect of increasingly stringent carbon policy, and shifting global marine fuel quality specifications—all of which have the potential to add cost or reduce the value of oil sands crude—complicate investment decisions in new oil sands projects.

- **The oil price holds more sway over the future of the Canadian oil sands than any other variable.** A notable and sustained improvement in the price of oil has the potential to offset uncertainties in the industry and lead to increased levels in investment. However, should prices linger in the mid-$50s/bbl WTI, the outlook for oil sands growth based on existing technology may remain more muted.

- **The long-flat production profile of oil sands assets makes a future without growth in the coming decade difficult to see—and a future with less output than today even more remote.** Oil sands facilities, once operational, are largely unresponsive to the oil price—with production neither ramping up nor ramping down materially. Oil sands production is more akin to base-load power generation, but for the oil market. Since the oil sands do not have to overcome production declines, growth can be more readily achieved.

- **The level and pace of future investment and growth is lower in all scenarios.** Regardless of the scenario, the rate of investment and growth in the oil sands will likely be lower and slower compared with the decade preceding the oil price collapse (the takeoff phase of Canadian oil sands development amid rising and historically high oil prices).

## Part 1: Introduction—An uncertain future for the oil sands

In 2014, upstream investment in new Canadian oil sands projects topped $30 billion. About 1 MMb/d of new production capacity was under construction.[1] Oil sands producers were focused on reining in capital cost inflation, which, if left unchecked, risked suffocating future growth.[2] However, in second half 2014, as US tight oil production continued to rise swiftly, a global supply glut began to emerge. By the end of the year, global oil benchmark prices had been halved from well over $100/bbl WTI to less than $50/bbl. The worst of it was in early 2016, when at times, WTI slipped below $30/bbl.

The impact of the 2014–15 price crash on cash flow from oil sands projects was immediate and dramatic. At the worst of it in early 2016, many operators found themselves producing at a loss. However, with few exceptions, oil sands projects continued to produce, and projects that were already under construction continued to completion. This ongoing activity served as a shock absorber for the Canadian economy and enabled Canada's oil industry to continue to grow production volumes.

1. Unless otherwise stated, all values are in 2016 US dollars. Source: Canadian Association of Petroleum Producers (CAPP), Statistical Handbook for Canada's Upstream Petroleum Industry, Oil Sands Expenditures, http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook, historical investment derived by Statistics Canada as provided to CAPP, retrieved 11 September 2017.

2. For more information on historical cost pressure in Canadian oil sands, see the IHS Markit Strategic Report *Oil Sands Cost and Competitiveness*.

Indeed, since the oil price collapse began, Canada's crude oil production has grown by almost 500,000 b/d, and it may rise by an additional 700,000 b/d by 2020.[3] Although most production growth has come from the completion of new oil sands projects sanctioned before mid-2014, production has also been buttressed by efficiency gains that have allowed more oil to come from existing facilities.

Despite the outlook for rising oil sands production through the end of this decade, the longer-term trajectory for the oil sands is arguably more uncertain than it has been in many years. Each year since 2014, investment and activity in the oil sands has declined. In 2017, investment in new and sustaining oil sands projects is estimated to be roughly one-third of 2014 levels—just over $10 billion in nearly 380,000 b/d of capacity under construction.

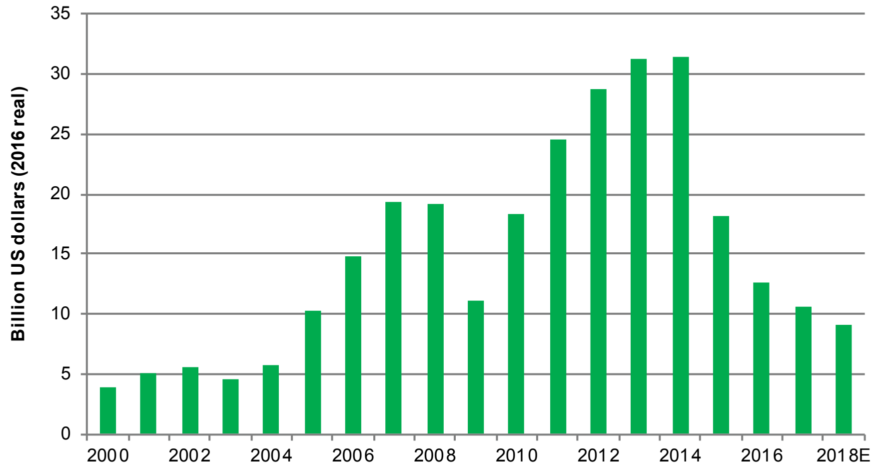
The long-term outlook for the oil sands depends in large part on the pace and scale of the oil price recovery. Compelling cases can be made for a world in which prices gradually recover in the coming years and remain modestly higher than in recent years; in which prices stay low for a protracted period; and in which prices are more volatile, reaching highs well above recent price levels and lows well below them as well. These cases are roughly the oil price trajectories of the three IHS Markit global energy scenarios: Rivalry (our base case), Autonomy, and Vertigo. Although IHS Markit scenarios cover the entire global energy landscape, this report explores the outlook for oil sands investment and production growth in each.

## Part 2: Lower prices have reduced investment in the oil sands

In 2014, the Canadian oil sands were firing on all cylinders—more than $30 billion was invested in the construction of over 1 MMb/d of production capacity. If operating costs and royalties are considered, the investment figure for 2014 nearly doubles, approaching $60 billion.[4] However, when the oil price began to collapse in second half 2014, the cash flow of the oil sands industry began to dry up, and during the price nadir in first quarter 2016 many operators produced oil at a loss. Yet, very few operations shuttered. Most facilities counterintuitively found ways to increase output to reduce per-unit production costs. Moreover, most new projects sanctioned before the price crash continued toward completion.

Figure 1

Oil sands capital investment




Note: E = estimated.
Source: CAPP, IHS Markit

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Each year since 2014, investment in the oil sands has fallen as projects have been completed and brought online and few new projects have been sanctioned (see Figure 1). Indeed, this is part of a trend that has led to a 45% reduction in spending on new oil projects globally from 2014 to 2017.[5] In the oil sands, the last of the projects sanctioned prior to the price collapse—two large mines—will be completed in 2017. Three in situ steam-assisted gravity drainage (SAGD) projects—ones that were sanctioned prior to the oil price collapse and delayed owing to it—moved back into construction in 2017. However, the scale of the projects wrapping up in 2017—with combined capacity of nearly 290,000 b/d—is greater than the scale of the projects expected in construction in 2018—110,000 b/d. This suggests that oil sands investment activity is set to fall further.

3. Based on annual averages of synthetic crude oil (SCO) and bitumen from 2014 to 2017 and 2017 to 2020, respectively.

4. CAPP, Statistical Handbook for Canada's Upstream Petroleum Industry, Oil Sands Expenditures, http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook, historical investment derived by Statistics Canada as provided to CAPP, retrieved 11 September 2017.

5. IHS Markit Upstream Costs & Expenditures, https://www.ihs.com/products/upstream-costs-expenditures.html.

## Part 3: Oil prices, costs, and investor confidence

Despite the resilience shown by oil sands projects in operation or under construction, the outlook for future development activity and associated economic benefits remain a source of uncertainty for Canada.[6] With 165 billion bbl of established reserves, great potential remains in Canada's oil sands.[7]

The projected oil price and estimated cost of a project are the two most important variables a company weighs in deciding whether to invest in a new development. This section discusses the factors that will influence future oil sands project economics, and the next section explores different oil price futures and the possible implications for future oil sands investment and production.

### Oil sands costs have fallen—and may fall further

The cost to build and produce oil from an oil sands project can be a source of confusion. There are two distinct types of oil sands production—in situ and mining. Besides both producing oil from the oil sands, they otherwise have little in common. The difference in the cost to maintain production from existing facilities and the cost to construct a new project can be another source of confusion. These differences can result in very different cost estimates.

The cost to operate and sustain an existing oil sands facility is far less than the full-cycle cost or the cost to build, operate, and sustain a new one. This distinction is arguably more important for the oil sands than for many other sources of global supply. This is because, while production from most global oil projects will decline over time, output from an oil sands facility, if properly maintained, does not in the medium to long term. In 2017, IHS Markit estimates that most oil sands (both mining and in situ) operations required a WTI oil price of $30–40/bbl to cover the cost of operating and sustaining operations and marketing the bitumen produced.[8] Most operations in 2017 would have been on the lower end of this range.[9]

If the cost to build an oil sands facility is taken into account (and assuming a 10% return on capital), in addition to the operating, sustaining, and marketing costs, the full-cycle cost of a new project is higher. A new mining operation would be more expensive, requiring greater than $70/bbl in 2017 to break even. New in situ operations, specifically SAGD projects, require just over $50/bbl WTI. However, because existing in situ facilities can leverage established infrastructure, in situ expansions can have the lowest breakevens. IHS Markit estimates that in situ expansions, specifically of a SAGD operation, could break even around $48/bbl WTI in 2017.

As projects are redesigned, standardized, and descaled to be more efficient, reductions in labor, steel, and construction time could further reduce up-front capital outlay and/or increase productivity and accelerate payback—improving project economics. New technologies that displace steam used for in situ extraction with noncondensable gases and solvents are moving from pilot to deployment and could increase production from both existing and new operations alike, lowering capital intensity and improving project economics.

### Expectations—and confidence—are key to future investment decisions

Decisions to advance projects in the oil sands—and elsewhere—in theory are based on confidence that the oil price will be high enough over the life of the asset to generate a positive return for investors. For oil sands projects, the expectation of the future trajectory of oil prices two to three years in the future may be more relevant given the lead time to construct and bring online new production capacity. However, the reality is that the current oil market sentiment exercises much influence over expectations of future oil prices. Despite ongoing cost reductions, producers likely need a price and future price expectation well in excess of current breakevens. Should WTI linger in the mid-$50s or below, companies may still struggle to justify sanctioning a new oil sands project, based on existing

6. For more information on the historical scale of associated economic benefits, see the IHS Markit Strategic Report *Oil Sands Economic Benefits: Today and in the future*.

7. For more information, see Alberta Energy Regulator, ST98, Table 1: Resources, reserves, and production summary, 2016, http://aer.ca/data-and-publications/statistical-reports/executive-summary, retrieved 4 July 2017.

8. Marketing of bitumen requires either the purchase of diluents to dilute bitumen to meet pipeline specification or the upgrading of bitumen to lighter SCO. Both processes add cost. The resulting crude oil product in either scenario also then must be transported to market and adjusted for quality to obtain a WTI equivalent.

9. However, some operations do require higher prices, above $40/bbl WTI, but these are fewer in number and typically smaller in output.

technologies.[10] A brightening of the oil sands investment outlook will likely require further declines in project costs and greater confidence that oil prices will be higher, on average, in the future than they are today. Unfortunately, in addition to a volatile oil price, a number of other uncertainties—some transitory and some particular to western Canada—currently complicate the oil sands investment case.

## Uncertainties facing the oil sands

In addition to the oil price, the oil sands face several other challenges that create uncertainty for investors. A brief description of these challenges follows, but fundamentally they all have the potential to add cost to oil sands operations and/or reduce the price that producers obtain for their crude oil.

Some of the challenges are unique to the industry and are, in part, the result of poor public perception of the industry and an organized environmental opposition to further development; others are more global in nature and are not unique to the oil sands. Three key challenges are

- **A constrained pipeline takeaway system.** The timing of new pipeline capacity and corresponding impact on western Canadian heavy oil benchmarks add uncertainty to future returns for oil sands producers. As western Canadian heavy oil production has grown, the pipeline system has struggled to keep pace. Late in 2017, transportation bottlenecks reemerged, causing price discounts for western Canadian heavy oil, compared with what could be obtained had crude oil been able to clear the market more efficiently.[11]

  A number of pipelines have been proposed to resolve this situation and have been met with opposition. Opposition has contributed to delays in the construction and streaming of these pipelines—creating uncertainty for the future price of western Canadian heavy crude oil. With new western Canadian pipeline capacity unlikely to come online before late 2019 at the earliest, and heavy oil sands production set to rise further between now and then, more crude oil from the oil sands is expected to move by rail. The movement of crude by rail is anticipated to come at a greater cost, reducing the value of western Canadian heavy oil. The longer the pipeline system remains constrained, the greater the volume of oil that will move by rail—and the more it may cost to ship western Canadian crude oil to market as railroads seek to cover the incremental cost of building new rail capacity to support greater movements.[12]

- **Increasingly stringent carbon policies.** In recent years, governments in Canada have moved to increase both the coverage and stringency of greenhouse gas (GHG) reduction policies. Putting a price on carbon is not new to the oil sands industry. In 2007, Alberta became the first jurisdiction in North America to establish a carbon price. More recently, the province moved to strengthen its carbon pricing policy and placed an absolute cap on oil sands GHG emissions. At the federal level, a minimum national carbon price will ensure the price in Alberta will escalate from C$30 per metric ton to C$50 per metric ton by 2022. IHS Markit believes that carbon levies to 2022 have not materially altered the economics for most oil sands production.[13] However, current policies are designed so the cost of compliance increases for more carbon-intensive operations. The impact in a lower price scenario could be material if those facilities are unable to reduce emissions intensity. IHS Markit believes that current policies will encourage greater investment in GHG reduction measures while reducing the incentive to invest in more challenging reservoirs (which could result in more GHG-intensive production). At the same time, the oil sands are one of the few sources of global oil supply that currently face an increasing cost of carbon. For potential investors in the oil sands, this adds an additional layer of complexity and risk that is not yet present in most other oil-producing jurisdictions. (For more details of carbon policies relevant to the oil sands, please see the text box "Carbon policies and the Canadian oil sands.")

- **Shifting global marine fuel specifications.** In 2016, the International Maritime Organization (IMO) agreed to reduce sulfur dioxide ($SO_2$) emissions from the global shipping fleet starting in 2020.[14] If enforced, these rules could negatively

10. Oil sands operations typically receive a price below WTI subject to transportation and quality adjustments, which can change over time.

11. From January to December 2017, Western Canadian Select, a heavy crude oil price benchmark in Canada, averaged about $11/bbl beneath WTI, an inland US light, sweet crude oil benchmark. However, beginning in late November the difference in price began to grow, reaching as much as $26/bbl at times in December and averaging over $23/bbl that month.

12. For more information on western Canadian crude-by-rail dynamics, please see the IHS Markit Strategic Report *Pipelines, Prices, and Promises—The story of western Canadian market access*.

13. On 6 December 2017, Alberta finalized the rules for how carbon pricing will be levied on the oil sands. For more information, see "Carbon Competitiveness Incentives protect jobs," Alberta government, 6 December 2017, www.alberta.ca/release.cfm?xID=51121C0A77352-9809-750B-7CC8BD5ED81774AD, retrieved 6 December 2017.

14. For details of the IMO fuel specifications, see *Sulphur oxides ($SO_x$) and Particulate Matter (PM) – Regulation 14*, IMO, retrieved 27 November 2017.

## Carbon policies and the Canadian oil sands

Alberta and Canada have put a price on carbon for the oil sands. Alberta has had a price on carbon in place since 2007 for all large emitters. More recently, it has taken measures that would expand coverage to fossil fuel combustion and increase the carbon price to $30 per metric ton for large emitters and $30 per metric ton in 2018 for the rest of the economy.[1] The federal government is backstopping provincial measures with a national price, which will apply in regions that have not advanced their own equivalent policy and ensure that the price in Canadian regions will rise to $50 per metric ton by 2022.[2]

Oil sands production is considered an emission-intensive, trade-exposed sector. Emission intensive means that the level of emissions per unit of output is relatively high. Trade exposed means that the oil sands export most of their output, which competes with producers from around the world. For these industries, which are not limited to oil sands, carbon pricing can create a cost disadvantage that their global peers may not face. In this circumstance, firms that compete globally may physically relocate or lose out to their competitors. Along with this, the investment, employment, and emissions could end up being redistributed to jurisdictions with less stringent policies. If countermeasures are not taken, the local economy with more advanced climate policies may be negatively impacted with little impact on global GHG emissions.

To protect against this outcome, Alberta and Canada have opted to provide emission credits to these sectors. The value of the credits are set by the sector-level emission intensity benchmark (emissions per unit of output) and are allocated to facilities based on output. These are known as output-based allocations. The higher the production level, the more credits are allotted, but at a set emission intensity value. Under this credit system, higher emission-intensive facilities will have insufficient credits to cover their total emissions and will have to pay on the remainder, while more efficient operations may be able to bank or vend surplus credits. In this way, the price acts to encourage GHG reductions while minimizing the incremental cost that could result in a shift of investment, economic benefits, and emissions to other jurisdictions. For the oil sands, the credit value will be based on top the quartile of performers for each major oil sands segment, in situ extraction, mining extraction, and upgrading. Alberta has dubbed the policy the Carbon Competitiveness Incentives and will be phasing it in over 2018 and 2019. It will be coming into full force in 2020.[3]

Assuming compliance is met solely through payment of the carbon price, based on the performance of in situ operations (both SAGD and cyclic steam stimulation [CSS]) in 2017, the estimated average cost of compliance for in situ projects could remain below C$0.80/bbl in 2022 when the national price of carbon is expected to reach C$50 per metric ton.[4] However, more carbon-intensive operations will face a greater cost of compliance. If these facilities are unable to reduce their emissions intensity, they could face a potential cost of carbon between C$3 and C$4/bbl in 2022 (based on the upper range of in situ projects in 2017).[5]

The oil sands also face an absolute cap on emissions as part of provincial policies. In each of the three IHS Markit scenarios discussed later, the cap is not expected to restrict oil sands production to 2030. This being said, our assessment is sensitive to assumptions about the degree of future investment, and thus production, and future carbon intensity of extraction. To be sure, a number of details of the oil sands emission cap policy have yet to be finalized.

When investors are deciding today whether to invest in an oil sands project that may operate over 30 years, and the potential exists—however remote—that that operation could face restrictions at a later date that may affect its ability to produce, the investors will factor in at least some of that risk today. Although technology may exist to drive significant reductions, until it is commercially deployed on a large scale, investors may view oil sands GHG policy as an additional investment risk that other regions do not face.

1. For more information, see “Climate change,” Alberta government, https://www.alberta.ca/climate-change.aspx, retrieved 6 December 2017.

2. The Pan-Canadian Framework allows for quantity-based benchmarks for regions that adopt cap-and-trade systems, and, as a result, the price in these regions can vary from the national level.

3. For more information, see “Climate change,” Alberta government, https://www.alberta.ca/climate-change.aspx, retrieved 6 December 2017.

4. The IHS Markit estimate of the cost of compliance in 2022 is based on the weighted industry average emission intensity over the first nine months of 2017. The top quartile of in situ operations was used as the benchmark in 2022 as provided by established benchmarks in Schedule 2 of the Carbon Competitiveness Incentive Legislation. See http://www.qp.alberta.ca/1266.cfm?page=2017_255.cfm&leg_type=Regs&isbncln=9780779800193, retrieved 11 January 2018.

5. Based on the first nine months of data in 2017, the production weighted average efficiency of in situ operations (including SAGD and CSS) as measured by the steam-to-oil ratio (SOR) was 3.06. For this estimate, operations with SOR between 5 and 6 were used to represent more carbon-intensive operations. Based on the first nine months of operations in 2017, and after adjusting for facilities in ramp-up that had temporarily high SOR, there was one operation near 5 and three operations between 5 and 6. Historical in situ SOR data was derived from Alberta Energy Regulator, “Alberta In Situ Oil Sands Production Summary,” ST-53 https://www.aer.ca/data-and-publications/statistical-reports, retrieved December 2017. IHS Markit analysis is preliminary as some details on the application of Alberta’s new policy are still forthcoming.

impact the value of higher-sulfur crude oil, such as from the oil sands, for a period beginning in 2020. $SO_2$ emissions result from the combustion of high-sulfur fuels. Although multiple compliance options are available to shipowners, such as installation of shipboard scrubbers, which can remove $SO_2$ from the exhaust gases, the primary means of compliance in the immediate term will likely come from the consumption of lower-sulfur marine fuels. Heavier crude oils, including from the oil sands, typically contain higher levels of sulfur. Increased investment will be required to remove additional sulfur or address $SO_2$ emissions from exhaust gases. In either case, the value of high-sulfur crude oil would be expected to temporarily weaken relative to lower-sulfur crudes. This, in turn, creates incentives to invest in the infrastructure necessary to address sulfur content and allow the price to gradually recover. Key to the degree of the IMO impact on light-heavy differentials will be the level of compliance. Should compliance be gradual, the impact on heavy oil prices could be less pronounced. If compliance is strong at the onset, the price impact could be greater but would likely span a shorter period. Regardless, the pending IMO rule creates uncertainty about the future price of heavy, sour crude oil at the onset of the next decade.[15]

## Part 4: Price above all—Scenarios of oil sands growth

The oil sands are a business of big investments, long lead times, and enduring asset life. Depending on scale, oil sands projects can cost between $1 billion and well over $10 billion and require between two and five years to be brought online.[16] Expansions of existing thermal projects are at the lower end of both these ranges, and new mining operations are at the upper end. In short, oil sands investors need to wait at least a few years before their large capital outlays begin to generate returns. In return for a large up-front investment and lag in cash generation, investors get a very long life asset. If properly maintained, oil sands facilities can produce a relatively stable volume of oil for 30 years or more. This long production life is a unique aspect of oil sands operations, and it allows production growth to be more readily achieved than in most other global oil plays where output declines more rapidly.[17] Oil sands production is arguably similar to base-load power generation, but for the oil market. The absence of meaningful declines makes a future without oil sands growth difficult to see.

As a result of long project lead times, oil sands production growth to the close of this decade is essentially locked in with investment decisions having to have been made by now. Indeed, although investment decisions in the oil sands (and elsewhere) can have an almost immediate impact on jobs and the economy, the impact of such decisions on output is delayed—in the case of the oil sands by two years or more.[18]

The production profile in the coming decade (after 2020), by contrast, is much less clear. Currently, the investment case for the oil sands is challenged as outlined above. The prospect of further project cost reductions could provide a counterbalance but remains unproven.

Ultimately, though, the pace of oil sands investment and production growth depends more than anything else on oil prices. An increase in the price of oil will make oil sands investments unambiguously more attractive, all else being equal. To be sure, there is much nuance in projecting oil investment and production in different price environments. For example, a protracted period of lower prices may result in less investment but greater cost reductions and efficiency gains; and a period of rising prices may lead to more investment and production growth, but also more rapid cost inflation and fewer efficiency gains.

In our base case, IHS Markit believes that oil prices will gradually recover over the next several years and then stay at higher levels on average through 2030. However, credible cases exist that could lead oil prices to traverse very different paths, including those in the two alternative IHS Markit scenarios. Below, we outline the three IHS Markit energy scenarios as they pertain to oil and explain how oil sands investment and production fare in each.

15. For more information on IHS Markit views on the IMO impact, see the IHS Markit News Release *New Low-Sulfur Requirements for Marine Bunker Fuels Causing Scramble for Refiners and Shippers, IHS Markit Says,* retrieved 7 September 2017.

16. This estimate is based on a representative range of new or greenfield historical oil sands projects. Expansions of in situ facilities are typically lower cost, and smaller-scale projects do exist that would reduce capital cost. However, historically project scales have been larger, from 30,000 b/d for thermal in situ development to even greater for large mining operations. For more information on historical oil sands capital cost, see the IHS Markit Strategic Report *Oil Sands Costs and Competitiveness*.

17. With proper maintenance, central processing plants for mining and in situ operations access massive reservoirs sufficient to produce a steady volume of oil for decades.

18. Notably, because of the lag between the sanctioning of a project and first oil, oil sands production growth is a relatively poor indicator of health of the industry.

## Overview of the IHS Markit energy scenarios

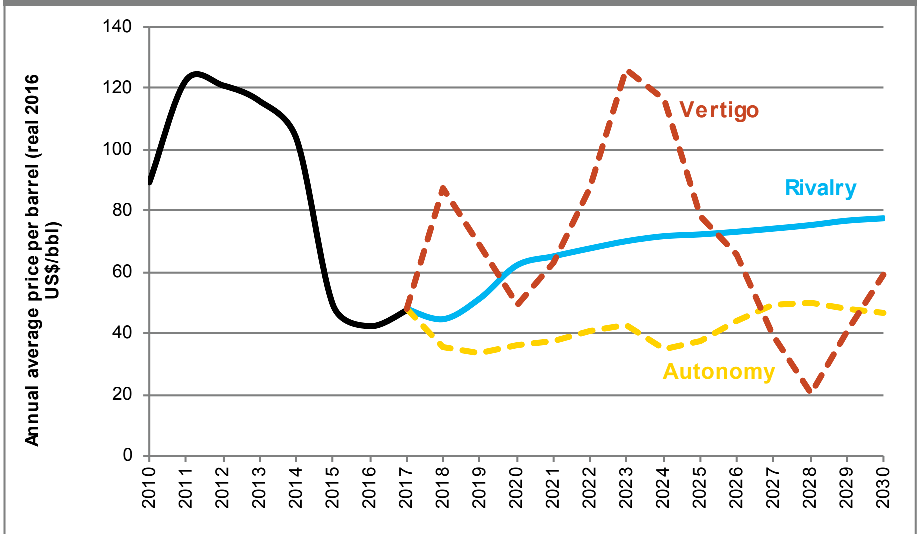
IHS Markit uses scenarios to challenge conventional thinking in an uncertain world. To this end, we offer three views of the future of oil to 2030:

- **Rivalry (the IHS Markit base case).** Rivalry is a world where global oil demand rises gradually over the next decade, although greater interfuel rivalry, efficiency gains, and government policy decelerate the pace of growth. Meanwhile, price and cost continue to regulate world oil supply as OPEC has little success in managing output. Gulf-5 and North American tight oil are the two key sources of supply growth over the next decade.[19] But supply from these two areas is not enough to offset declines from producing fields and meet demand growth. Oil prices gradually rise in the coming years as world oil demand growth remains robust and the impact of lower upstream spending reduces supply growth. Higher prices are needed to incentivize investment in higher-cost projects that are necessary to satisfy demand. But the annual average prices do not return to anywhere near the $100 plus levels between 2011 and 2014. By 2030, the Dated Brent price approaches $80/bbl in real terms. Overall, Dated Brent averages about $68/bbl in 2017–30.

- **Autonomy.** Autonomy is a world where low upstream costs and the expansion of tight oil production outside of North America allow more oil to be produced at much lower prices than once thought possible. World oil demand peaks in the mid-2020s owing in large part to the combined impact of rising fuel economy standards, driverless technology, mobility service companies, and electric vehicles (which include pure battery electric vehicles and plug-in hybrid electric vehicles). Policy supports these disruptors of oil demand because they lower the cost of mobility via the car and are seen as addressing urban congestion and air pollution. Low upstream costs and weaker oil demand keep oil prices low through the next decade. Dated Brent averages about $42/bbl in real terms in 2017–30.

Figure 2

Crude oil price outlook to 2030 by scenario




Source: IHS Markit



- **Vertigo.** Vertigo is a world where a volatile global economy leads to frequent mismatches between supply and demand. Global oil producers chronically misjudge demand cycles. This leads to extreme oil price swings. Rising prices lead to rising upstream costs, but costs do not fall as quickly as prices during downturns, straining producer profit margins. To 2030, in real terms, the annual average Dated Brent price rises to $90/bbl, falls to $50/bbl, rises to $130/bbl, and falls below $20/bbl, before recovering again. All in all, Dated Brent averages about $70/bbl in 2017–30.

See Figure 2 for the oil price tracks in the three scenarios and Figure 3 for an overview of the three scenarios.[20]

## Scenarios of oil sands growth

How do oil sands investment and production fare in these three scenarios?

In **Rivalry**, oil demand is robust enough to support a gradual recovery in oil prices. This incentivizes an increase in upstream production investment. Carried forward by projects sanctioned prior to the 2014–15 price crash, oil sands

19. The Gulf-5 is a group of low-cost producers in the Middle East comprising Saudi Arabia, Iran, Iraq, Kuwait, and the United Arab Emirates.

20. For more information on the IHS Markit energy scenarios, please see Long-Term Planning and Energy Scenarios, https://www.ihs.com/products/long-term-energy-planning-scenarios.html.

Figure 3

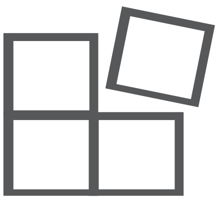
## IHS Markit scenarios

**Rivalry**

IHS Markit planning scenario

**Most intense competition in history among energy sources for market share amid evolutionary social and technological change**

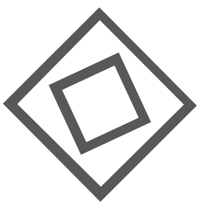
- The energy rivalry is driven by four factors: price differentials, environmental concerns, technology improvements, and energy security.
- Gas and electricity loosen oil's grip on transport demand; renewables become increasingly competitive with gas, coal, and nuclear in power generation.



**Autonomy**

**Transition of energy mix from fossil fuels at a much faster pace than expected**

- Market, technology, and social forces decentralize the global energy mix.
- A mobility revolution radically alters how cars are sold, used, and powered.
- Generational change and urbanization pressures alter energy demand dynamics—demand for coal and oil falls.
- Breakthrough occurs in electricity storage and solar photovoltaics.
- Development of unconventional oil and gas is more widespread than anticipated.



**Vertigo**

**World economy like weather on a mountaintop—sunny and pleasant one moment, then engulfed in fog and rocked by hurricane-force winds the next**

- Economic instability undermines confidence and exacerbates risk aversion.
- Volatile economic growth creates mismatches between demand and supply.
- Conservative capital investment spending slows the move to a less carbon-intensive economy.

Source: IHS Markit

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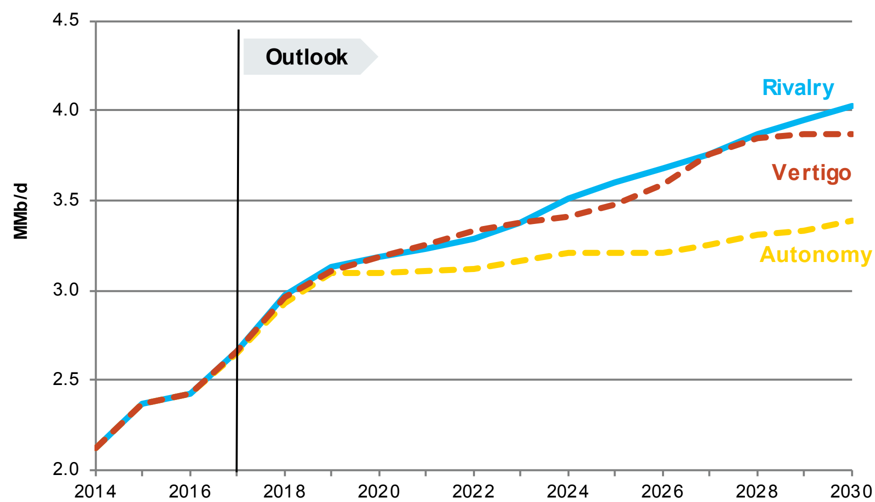
production maintains strong growth to 2019, as shown in Figure 4. Yet investment in the oil sands continues to decline, bottoming out in 2018 above $9 billion—less than one-third of the level in 2014 (see Figure 5). Investment gradually recovers but remains well below early 2010 levels. For the remainder of this decade (to 2020), investments are focused primarily on furthering efficiency gains at existing facilities, with only a handful of in situ expansions proceeding and no greenfield projects. In the early 2020s, oil prices continue to gradually recover and investors slowly become more comfortable as uncertainties facing the oil sands (including transportation constraints and the rising carbon price) are better understood. This leads to a gradual rise in investment as efforts to bring down project costs bear fruit and, together with a higher oil price, give companies confidence to commit more

Figure 4

## Oil sands production outlook (SCO and bitumen)




Source: IHS Markit

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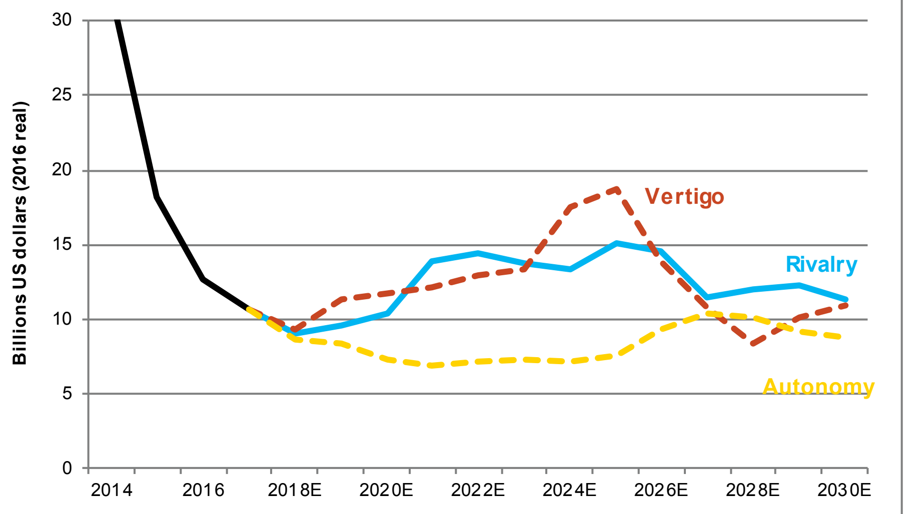
capital to building new facilities. Yet, while investment levels recover, they remain well below the heights of 2014 for the remainder of our outlook. This reduces the trajectory of production growth in the 2020s from that of the 2010s. All told, oil sands output expands nearly 1.4 MMb/d in 2017–30—with 26% of this growth from projects already in ramp-up or under construction today, 13% from efficiency gains, and the remainder from projects yet to be sanctioned (the vast majority of those being expansions).

Figure 5

Oil sands capital investment




Note: E = estimated.
Source: CAPP, IHS Markit

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**Autonomy** is characterized by a period of sustained lower prices. Global oil demand falls short of expectations, setting the stage for a protracted period of lower prices through the mid-2020s. Lower prices shrink upstream investment in the oil sands (and elsewhere) more than in the other IHS Markit scenarios. Investments that are made aim to increase the operational efficiency of existing facilities, and in only the most attractive projects. Just like in Rivalry, the oil sands move into a period of reduced investment as uncertainties such as market access by pipeline and the stringency of carbon policies weigh on investment. However, the impact is particularly acute and sustained with prices remaining entrenched around $40/bbl WTI into the early part of the next decade. Oil sands projects that are near completion today are brought online, but new investments are put on hold. Through the worst of the price trough (from 2018 to 2022), a handful of less efficient, smaller-scale oil sands operations eventually succumb to the protracted price environment and shutter. Yet, most oil sands production continues as producers manage to continue to deliver efficiency gains. Upstream costs continue to deflate, and more oil is produced from existing operations offsetting what shut-ins do occur. When prices do finally begin to strengthen in the mid-2020s, the upshot of nearly a decade of focus on operational efficiency allows projects to advance for less. Beginning in the mid-2020s, oil sands investment begins to increase—first in efforts to further enhance the efficiency of existing operations and then later to expand existing facilities. This allows production growth to slowly reemerge nearly a decade after the price collapse began.

Oil sands investment levels in Autonomy are the lowest of the three scenarios. Investment remains just above the low point in Rivalry until the mid-2020s and below $10 billion per year for nearly a decade from 2018 to 2027. This is partly because of reduced cash flows of oil sands producers but also because when investments in new projects are made, they come at lower costs than other scenarios. Production growth is correspondingly the lowest in Autonomy. From 2017 to 2030, oil sands production rises over 700,000 b/d. About 70% of this growth comes from existing projects and projects under construction or recently completed, including productivity gains, which account for one-quarter of overall production gains. The remaining growth comes from project expansions that begin to gradually emerge around 2026. If oil sands production declined at the global aggregate rate for conventional fields—an annual average of roughly 2.5% in 2016—total oil sands production in 2030 would be the same as in 2017.[21] These numbers underline the importance of the "no decline" characteristic of oil sands projects.

**Vertigo** exemplifies an uncertain world, where risk and economic volatility weigh on investment decisions globally. The oil price cycle is collapsed, and price swings are dramatic but short lived. A surge in demand growth helps drive oil prices near $90/bbl in real terms in 2018. Yet oil sands companies are hesitant to respond, facing short-term market uncertainties such as crude by rail, and are eager to rebuild their balance sheets. Nonetheless, improved cash flow from

21. Based on 2016 stock of global conventional fields as estimated in the 2017 IHS Markit Annual Strategic Workshop.

higher prices eventually encourages some producers to accelerate projects planned for a more distant date. But almost as soon as these projects are sanctioned, they are caught in the rapidly falling price cycle that emerges almost as quickly as prices rose. To be sure, the magnitude of the 2019–20 price decline is not severe enough to jeopardize projects under construction, and projects continue to completion, but it causes some hesitation in additional project sanctions. As prices begin to recover again in 2021–22, balance sheets of oil sands producers begin to heal, and, again, higher prices stimulate greater investment. But the price collapse toward the end of the decade is debilitating, with many producers having to produce at a loss for the better part of 2028 (when the oil price falls below $20/bbl WTI in real terms on an annual average basis). A number of smaller oil sands projects are caught out, given the severity of this price drop. Investment is cut and many projects under construction are indefinitely deferred; some are outright canceled, and a number of operations, some nearing the end of their natural life, are shuttered early.

In total, oil sands output expands over 1.2 MMb/d from 2017 to 2030. This is less than in Rivalry, with volatility slowing investment decisions and reducing the number of projects in operation at the end of 2030. Overall investment levels between 2017 and 2030 are similar to Rivalry, with price volatility contributing to periods of more rapid cost inflation and thus higher required investment levels. New capital and sustained investment average just over $12 billion per year from 2017 to 2030—almost identical to Rivalry but with more wild movements (as shown in Figure 5), from lows just over $8 billion to highs of almost $19 billion. Notably, even in Vertigo, investment levels never exceed the highs of 2014. In this scenario, the drivers of growth are relatively balanced, with new projects fueling about half of overall growth. The remaining 650,000 b/d of anticipated production comes from recently completed projects and projects in construction today, with nearly half of this gain influenced by productivity improvements particularly related to the 2028 price collapse.

## Part 5: Conclusion

Oil sands projects require investors to make large out-of-pocket, up-front investments for two years or more. In exchange, they receive an incredibly long, relatively stable oil-producing asset that can generate annuity-style cash flow. The up-front, out-of-pocket investment required to bring a new oil sands project creates a hurdle that has challenged investors since the onset of the price collapse.

All signs point to the ongoing slowdown in the oil sands continuing to play out, at least to the end of this decade. Every year since 2014, investment has declined. The long lead time associated with bringing a new oil sands project online has allowed the oil sands to continue to grow since the price collapse. However, with less than a handful of projects sanctioned since the downturn, these same lead times point to a period of reduced supply additions.

Since the oil price crash, oil sands producers have renewed their focus on improving their competitiveness by improving operational efficiency—and thus driving production higher from existing projects and at lower cost. However, so too have producers globally, and though oil prices have improved, future investments in the oil sands remain clouded, not only by the future trajectory of global oil prices but also by a number of unique uncertainties the oil sands face.

The future of the oil sands is inextricably linked to the course of the future oil price. In all three IHS Markit energy scenarios, a few commonalities are true. Oil sands facilities, once operational, are largely unresponsive to the oil price—with production neither ramping up nor ramping down materially. Oil sands production is more akin to base-load power generation, but for the oil market. The long-flat production profile of oil sands assets makes a future without growth difficult to see—and a future with less output than today even more remote. Even in the IHS Markit scenario with the lowest annual average oil price, oil sands production does rise, albeit more modestly, and is more reliant on further efficiency gains from existing projects. Yet, in each of the three scenarios considered in this report, including the two that depict higher annual average oil prices than today, oil sands investment and growth remain lower and slower than in recent history.

## Report participants and reviewers

IHS Markit hosted a focus group meeting in Ottawa, Ontario, Canada, on 7 June 2017 to provide an opportunity for stakeholders to come together and discuss the future of transportation fuels. A number of participants also reviewed a draft version of this report. Participation in the focus group or review of the draft report does not reflect endorsement of the content of this report. IHS Markit is exclusively responsible for the content of this report.

- Alberta Innovates
- Alberta Department of Energy
- Alberta School of Business, University of Alberta
- Cenovus Energy
- Ecofiscal Commission
- Imperial
- Natural Resources Canada
- The International Emissions Trading Association (IETA)
- Suncor Energy
- Environment and Climate Change Canada
- TransCanada Corporation

## IHS Markit team

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