



National Energy Board

Office national de l'énergie

AN ENERGY MARKET ASSESSMENT



Canada's Energy Future **2017** Supplement

OIL SANDS

Canada

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Background

The National Energy Board's (NEB) *Energy Futures* (EF) series explores how possible energy futures might unfold for Canadians over the long term. EF analysis considers a range of impacts across the entire Canadian energy system. In order to cover all aspects of Canadian energy in one supply and demand outlook, crude oil and natural gas production analysis can only be addressed at a relatively high level. Supplemental crude oil and natural gas production analyses address impacts specific to the supply sector, creating an opportunity to provide additional detail and to expand the number of cases to cover greater volatility in crude oil and natural gas prices and in supply-side technology assessment.

Future oil prices are a key driver of future oil production and a key uncertainty to the projections in the [Canada's Energy Future 2017: Energy Supply and Demand Projections to 2040](#) (EF2017). Crude oil prices could be higher or lower depending on demand, technology, geopolitical events, and the pace at which nations enact policies to reduce GHG emissions.

EF analysis assumes that over the long term all energy produced, given the pricing conditions of the case, will find markets and infrastructure will be built as needed to move that energy to markets. The timing and extent to which particular markets emerge, whether demand growth over/undershoots local production, whether export/import opportunities arise, and whether new infrastructure for crude oil is built, are difficult to predict. This is why simplifying assumptions are made. The analysis in this supplemental report continues the EF tradition of assuming these short-term disconnects are resolved over the longer term.

EF series Natural Gas and Crude Oil Production Supplemental Reports include six cases: the three EF2017 cases, and three additional cases that further analyze oil and gas production in Canada.

T A B L E 1 . 1

EF2017 Natural Gas and Crude Oil Production Supplements Assumptions/Cases etc.

Variables	EF2017			Additional Cases		
	Reference	Higher Carbon Price	Higher Carbon Price + Technology	Reference + Technology	High Price	Low Price
Oil Price	Moderate	Moderate	Moderate	Moderate	High	Low
Gas Price	Moderate	Moderate	Moderate	Moderate	High	Low
Carbon Price	Fixed nominal C\$50/t	Increasing CO ₂ cost reaching nominal C\$140/t in 2040	Increasing CO ₂ cost reaching nominal C\$140/t in 2040	Fixed nominal C\$50/t	Fixed nominal C\$50/t	Fixed nominal C\$50/t
Technology Advances	Reference assumption	Reference assumption	Accelerated	Accelerated	Reference assumption	Reference assumption
Notes	Based on a current economic outlook and a moderate view of energy prices	Considers the impact on the Canadian energy system of higher carbon pricing	Considers the impact of greater adoption of select emerging energy technologies on the Canadian energy system, including technological advances in oil sands production		Since price is one of the most influential factors in oil and gas production, and does vary over time, these two cases look at the effects of significant price differences on production	

Alberta's oil sands will be responsible for the majority of crude oil production growth in Canada through 2040 in all six cases, with nearly all of that growth because of increasing in situ¹ production. This supplemental report provides additional analysis of the Reference Case as well as data and results from all six cases. Differences in the production forecasts between the cases are attributable to differences in oil price assumptions and the application of new technologies related to in situ development.

The Appendix includes a description of the methods and assumptions used to derive the production projections, and numerous detailed data sets for all cases. These include; average annual [steam to oil ratios \(SOR\)](#), natural gas usage, solvent requirements, monthly production by oil sands region, method of extraction and whether the production is from existing, expansion or new projects. The [Appendix](#), data from the [Appendix](#), and [Chart data](#) are available.

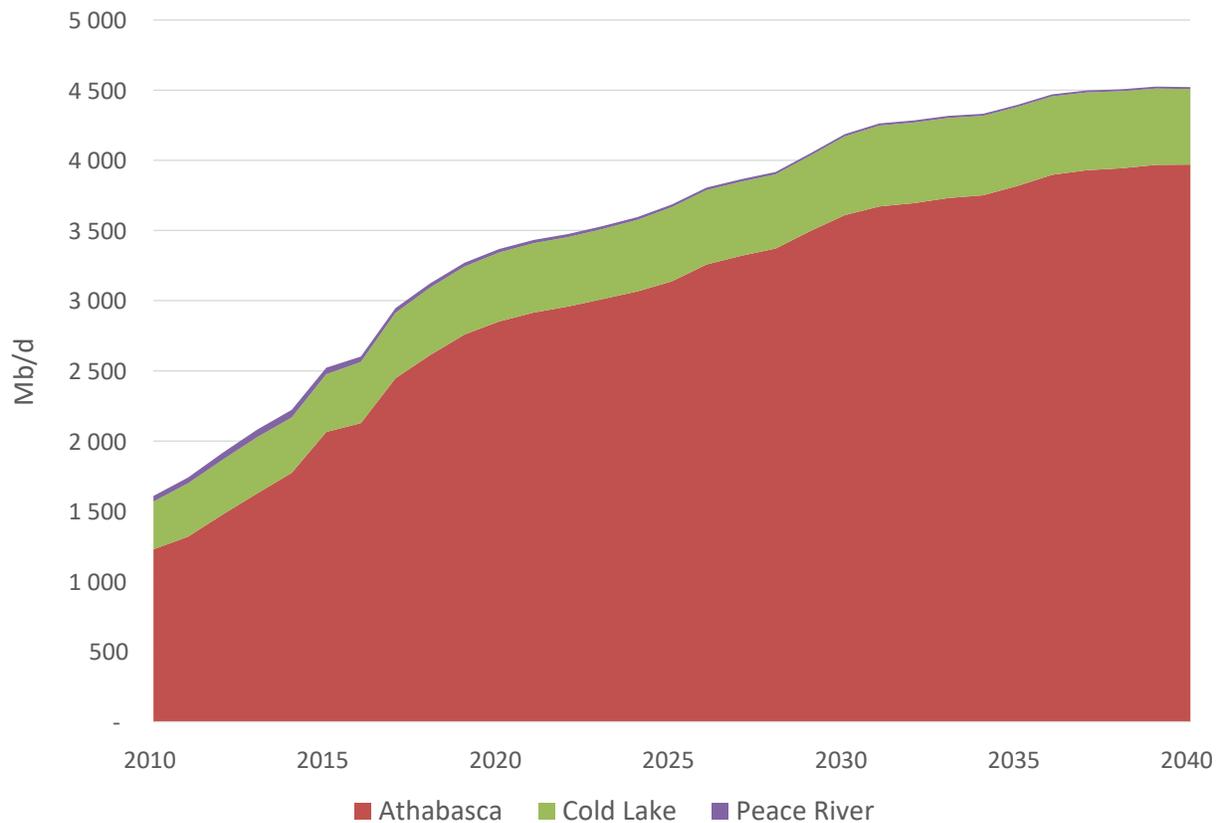
1 When bitumen is recovered through wells, generally because the reservoir is too deep to permit surface mining. In situ typically uses steam or solvents such as propane or butane to reduce the bitumen's viscosity so that it can be recovered.

Results – Reference Case

Production by Oil Sands Region

FIGURE 2.1

Raw Bitumen Production by Region



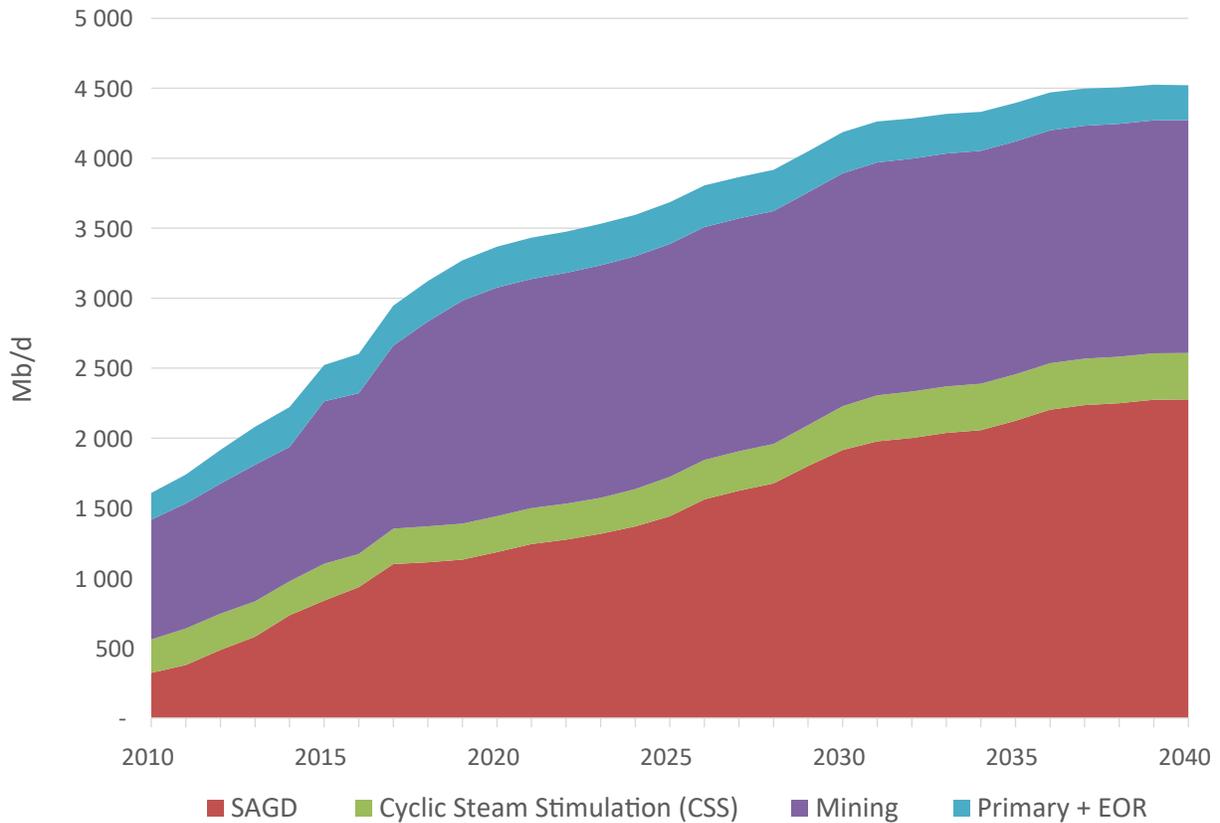
- Despite persistently low oil prices, production has continued to increase in recent years largely because of projects coming online that were under construction prior to the start of the mid-2014 crude oil price collapse. This trend will continue into the early 2020s after which time production growth will be somewhat slower. In 2017, [Brent](#) oil prices are assumed to average US \$53.10 per barrel which, when netted back to western Canada is a price level sufficient to cover ongoing costs of operations and in some cases spur investment in new projects. As Brent prices begin to rise, reaching US \$80.00 per barrel by 2027, additional investment in oil sands projects occurs leading to higher growth rates in the second half of the next decade. Production in 2016 was just under 2.6 million barrels per day (MMb/d) and reaches just over 4.5 MMb/d in 2040, a 73% increase.

- The Athabasca region is responsible for the majority of oil sands production, both historically and throughout the projections as seen in Figure 2.1. Averaging 2.1 MMB/d in 2016 the Athabasca region accounted for 82% of all raw bitumen production, with Cold Lake and Peace River responsible for 16% per cent and 2% respectively.
- Most of the mined bitumen as well as some in situ production is upgraded in Alberta into synthetic crude oil. There are exceptions however. Fort Hills which comes online later this year, and Kearl both produce diluted bitumen which is transported to end-use markets by pipeline or rail.
- The [May 2016 wildfires near Fort McMurray](#) were responsible for taking over 1 MMB/d of oil sands production offline, with some of that production taking months to regain full capacity.

Production by Extraction Method

FIGURE 2.2

Raw Bitumen Production by Extraction Method



-
- Bitumen is produced in Alberta in one of three ways:
 - o Surface mining using trucks and excavators (referred to as “truck and shovel”).
 - o In situ which primarily uses steam to heat the reservoir allowing the bitumen to be pumped to the surface through horizontal wells. This can be either Steam Assisted Gravity Drainage (SAGD)² or Cyclic Steam Stimulation (CSS).³
 - o Primary production and enhanced oil production (EOR) which produces the bitumen in a method most similar to conventional oil wells and requires no steam.
 - Mining is currently used to develop oil sands deposits up to a depth of about 70 meters. For much of the history of oil sands development in Alberta, mining was the largest form of extraction. However, only about 20% of oil sands deposits can be accessed this way.
 - The remaining 80% of oil sands deposits are only accessible using in situ methods. In 2012 in situ production surpassed mining as the dominant extraction method and this trend is expected to continue, with in situ accounting for 62% of all raw bitumen production by 2040.
 - Figure 2.2 shows that production from mining is expected to plateau after the current slate of projects are completed and ramped up to their full expected production capacity which is typically 85% of nameplate capacity. Mined production reaches 1.7 MMb/d in 2022 and remains relatively stable for the remainder of the projection period. Typically producers access the best parts of their project areas first, stepping out into portions of their land-base with lower quality reservoir as the operation ages. This is the case with oil sands mines as well. It is assumed that companies will continue to improve processes and technologies that will offset declines in bitumen production related to poorer quality reservoir over the projection period, keeping overall mined production levels relatively stable.
 - Continued improvements in the cost to operate or expand existing facilities and also to build new ones leads to growth of in situ operations. In situ production from both SAGD and CSS methods reaches 2.6 MMb/d by 2040.
 - Primary and EOR production remains relatively stable throughout the forecast, peaking in 2025 at 0.30 MMb/d before declining to 0.25 MMb/d by 2040.

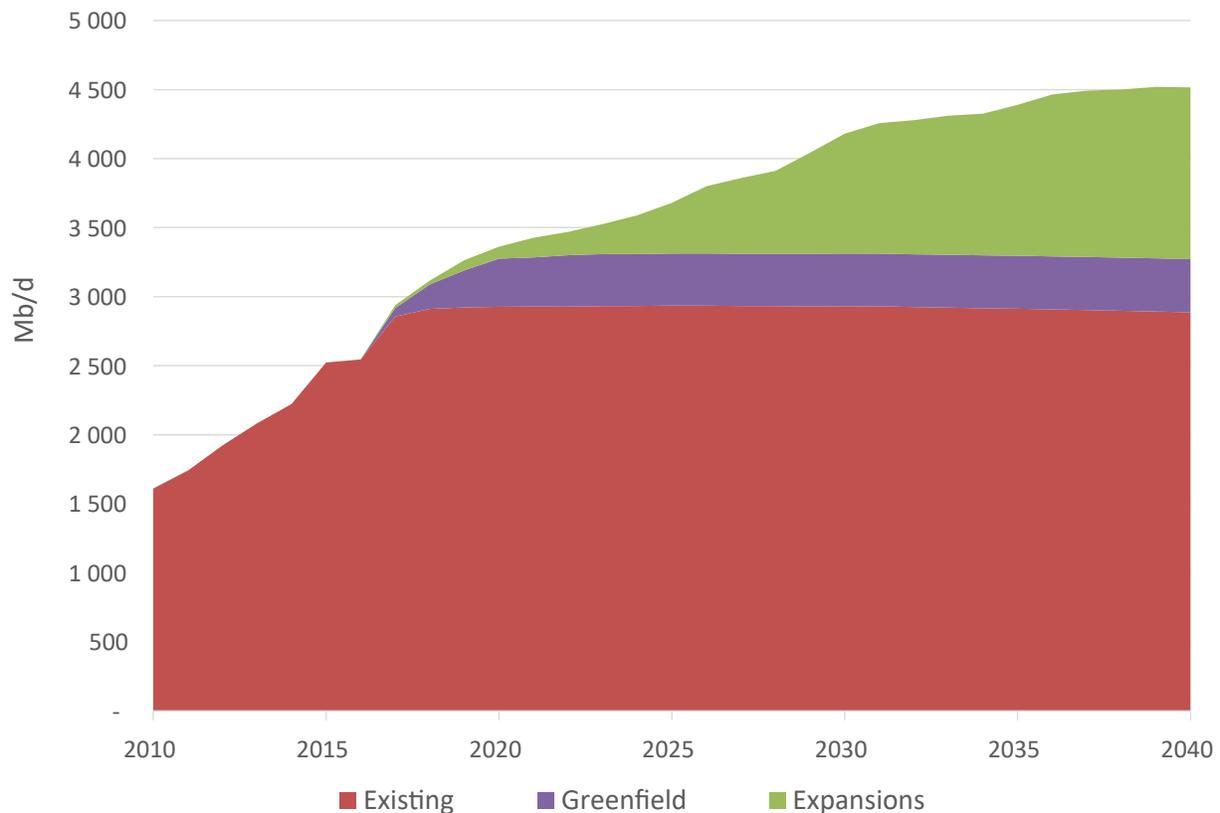
2 SAGD uses pairs of horizontal wells to produce bitumen in the oil sands. Steam is injected into an upper well to heat the bitumen, which then drains by gravity into a lower well and is pumped to the surface.

3 A thermal process to produce in-situ bitumen. Steam is injected into the reservoir through a well over a period of several months, decreasing the bitumen's viscosity. Later, the steam is turned off and the emulsion of water and bitumen flows back into the well over a period of several months. The process is repeated for the economic life of the well.

New and Legacy Bitumen Production

FIGURE 2.3

New and Legacy Production

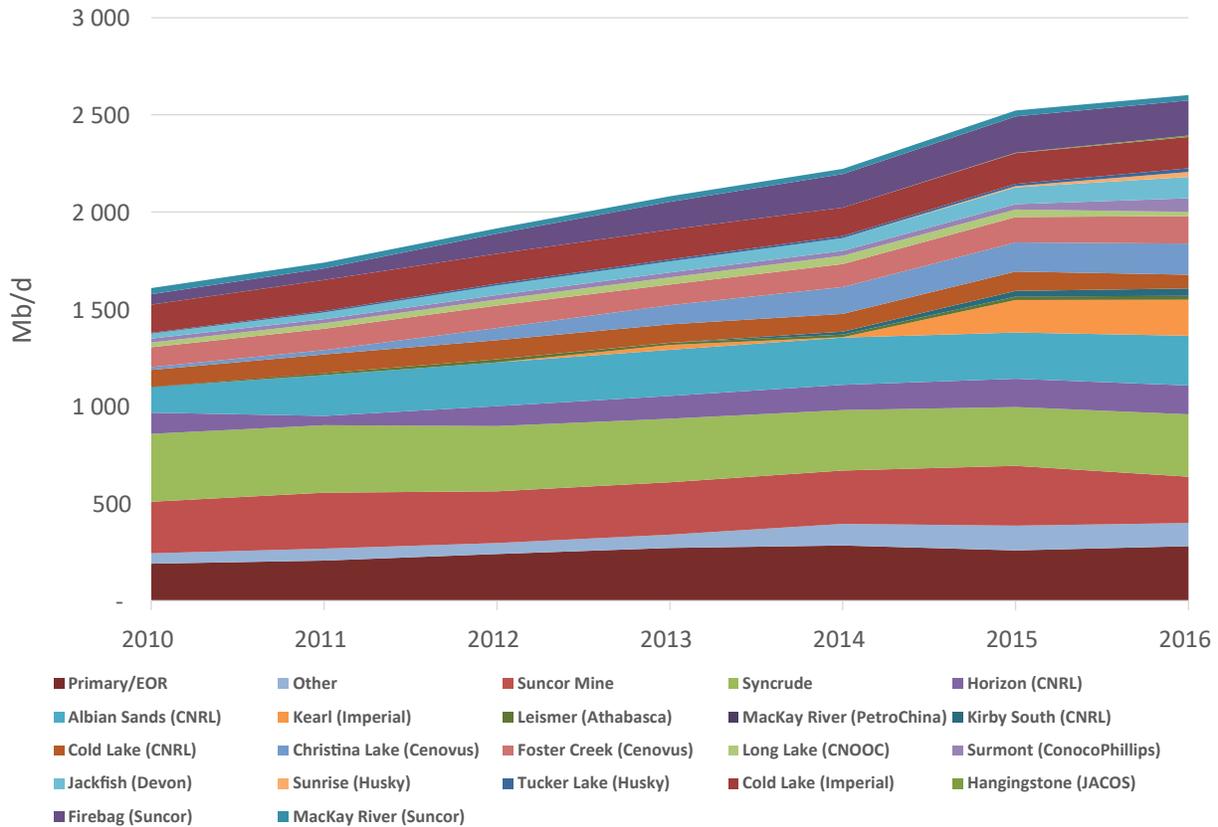


- Due to its near-zero decline rate, nearly all of the bitumen production that is currently online, whether mined or in situ, will remain so for the majority of the forecast period.
- Production in 2016 averaged just under 2.6 MMb/d from mining, in situ and primary/EOR. Figure 2.3 shows that the volume from current projects increases slightly over the projection period because of process and technology improvements and the ramp-up in production from projects that have yet to reach full capacity, reaching 2.9 MMb/d by 2040.
- The largest contributor to growth in the oil sands will be expansions to existing in situ facilities. At 1.2 MMb/d, expansions will account for 28% of all oil sands production by 2040.
- Entirely new projects (greenfield projects) will also contribute to growth, although they are more costly to construct than expansions and as such are expected to account for a much smaller share of the growth, reaching only 0.4 MMb/d or 9% of all production by 2040.

Production by Project

FIGURE 2.4

Raw Bitumen Production by Project

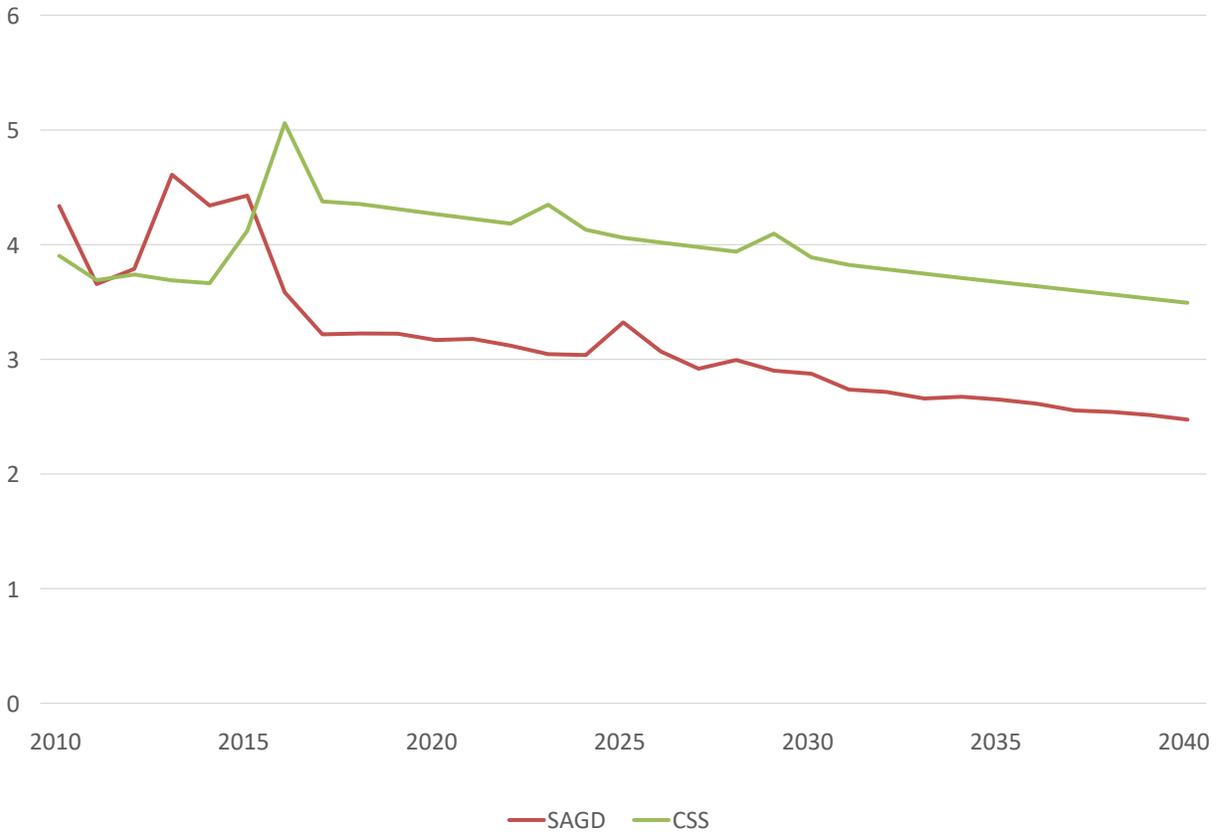


- Projects individually shown in Figure 2.4 are those that have a capacity exceeding 20 000 barrels per day. All other projects are grouped into “Other”.
- Average annual production rose from 1.6 MMb/d in 2010 to over 2.6 MMb/d in 2016.
- Mining accounted for over 51% of all production in 2010 falling to 42% in 2016 with the remaining production coming from in situ and primary/EOR methods.

Steam to Oil Ratios

FIGURE 2.5

Steam to Oil Ratios

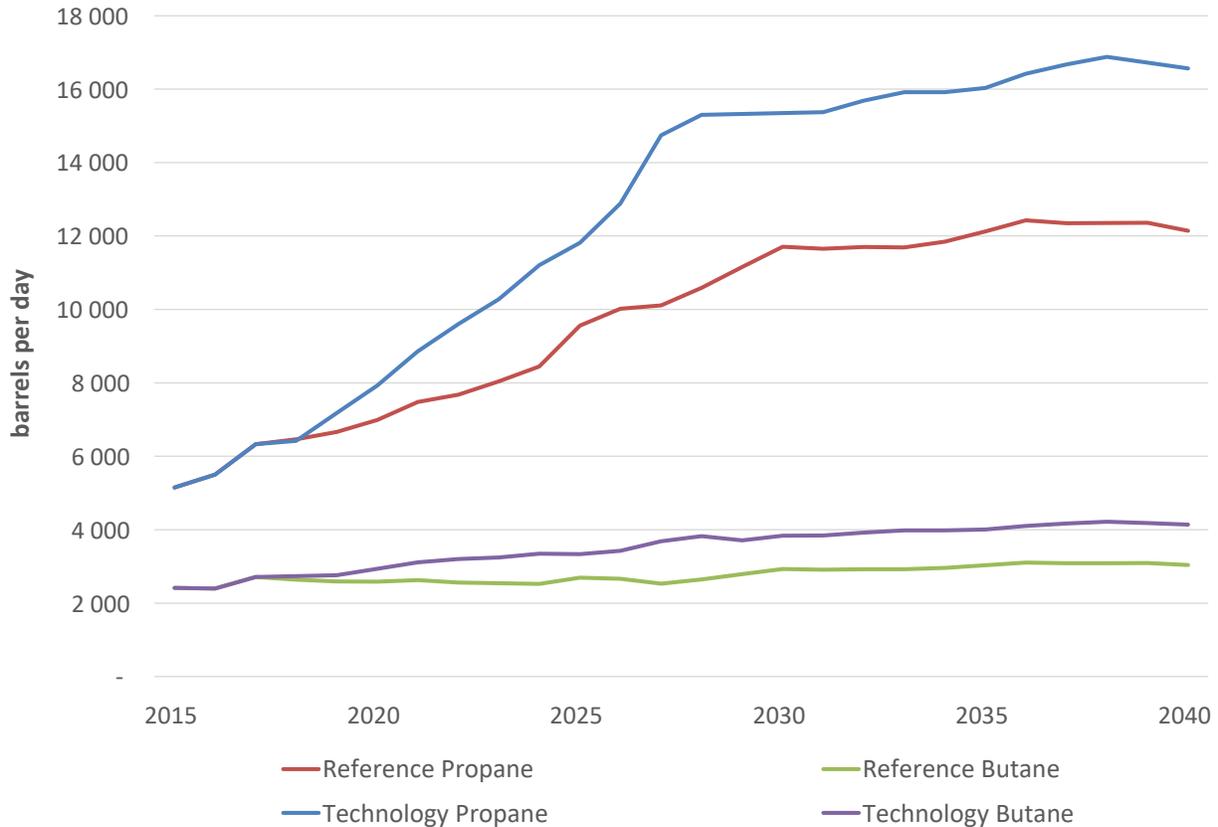


- Figure 2.5 shows that SORs for both SAGD and CSS are expected to trend lower over the projection period as new technologies are developed and improvements to existing ones continue to advance. In the Reference Case, this includes the adoption of steam solvents by a small number of producers. In the High Technology Case, steam solvents are used more extensively and have a noticeable effect on SORs and also on bitumen production (Appendix A). SORs in the Athabasca region are roughly 20% lower as a result of solvent adoption in the High Technology Case.
- Figure 2.3 shows average SORs which were 3.58 for SAGD and 5.06 for CSS projects in 2016. This drops to 2.47 and 3.49 for SAGD and CSS respectively by 2040. Companies tend to develop their best assets first and as production expands to lower quality reservoirs there can be a tendency for SORs to increase. The development and adoption of new technologies is more than adequate to make up for reservoir quality declines in the Reference Case.
- Increases in SORs in a particular year are due to new projects or expansions to existing ones coming online. SORs tend to be higher during the initial stages of bitumen production due to the increased production of steam to continue heating the reservoir with only a gradual increase in bitumen production.

Steam Solvents and Solvent Demand

FIGURE 2.6

Solvent Demand

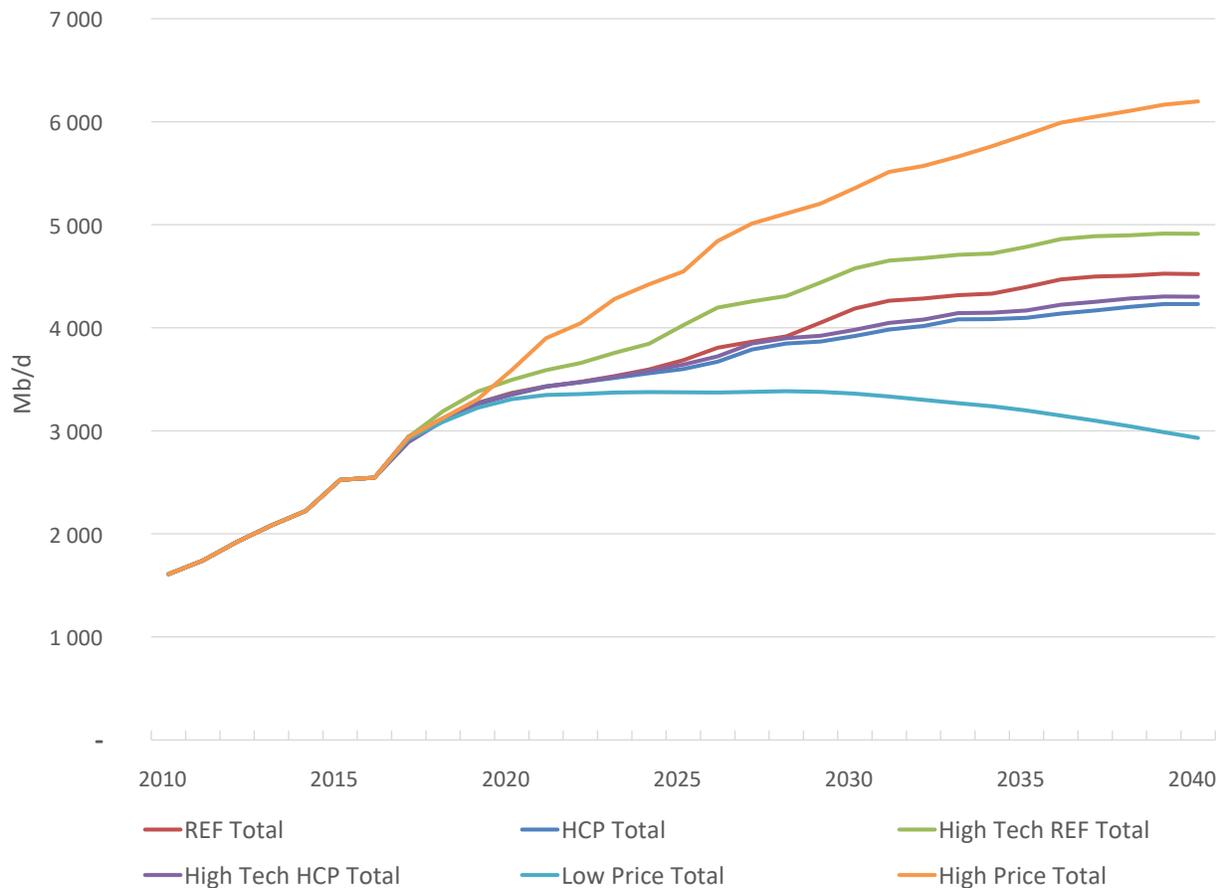


- Companies have increasingly experimented with the addition of solvents to the steam injected into their in situ wells. This has a number of effects, notably; it decreases the amount of steam needed to produce a barrel of bitumen, and also lowers the carbon footprint of that same barrel of oil by requiring less natural gas to produce the steam.
- Though the technology is not widely used yet, demand for propane and butane, the two natural gas liquids primarily used as solvents in pilot projects, has potential to significantly increase as shown in Figure 2.6.
- In the Reference Case the use of steam solvents is modest. It is assumed that the production technique is not widespread and, when it is used, applies primarily to new or expansion projects. In the Technology Case steam solvents have a much higher implementation rate with a noticeable effect on SORs and also bitumen production (Appendices A,B).
- Propane demand for solvent use is expected to more than double in the Reference Case from an average of 5 thousand barrels per day (Mb/d) in 2016 to over 12 Mb/d in 2040. In the High Technology Case demand for propane for solvent use increases to over 16 Mb/d.

All Cases

FIGURE 3.1

Raw Bitumen Production from all six EF2017 Cases



- To capture the uncertainty inherent in the projections a wide range in future pricing assumptions was employed. Brent prices reach C\$120 in the High Price Case and decline to C\$40 in the Low Price Case. Figure 3.1 shows the corresponding bitumen production levels which in 2040 are 6.2 MMb/d and 2.9 MMb/d respectively.
- Price assumptions between the other four cases are more subtle with much of the difference in production outcomes being driven by differing technological innovation and carbon pricing assumptions between the cases. For instance, technologies like flow control devices, wedge wells and steam solvents lead to increased production in the technology cases relative to the Reference and High Carbon Price cases.

-
- Similarly, higher carbon prices in the High Carbon Price and High Technology Carbon Price Case lead to forecasts of lower production relative to the cases where lower carbon prices are assumed.
 - The Reference and High Technology Reference Price cases reach 4.5 MMb/d and 4.9 MMb/d respectively. In both cases, growth is a result of increasing to in situ production with mining staying relatively similar between the cases. Owing to greater application of new technologies, the growth rate in the Technology Case is higher early in the forecast before slowing near the end of the next decade due to lower price assumptions.
 - The application of technology is also the main driver of differences between the High Carbon Price and High Carbon Price Technology cases. The High Carbon Price reaches 4.19 MMb/d while the High Carbon Price Technology Case reaches 4.23 MMb/d by the end of the projection period.

Final Thoughts

- Future oil prices are a key driver of future oil production and a key uncertainty to the projections in EF2017. Crude oil prices could be higher or lower depending on demand trends, technological developments, geopolitical events, and the pace at which nations enact policies to reduce GHG emissions.
- This analysis assumes that over the long term, all energy production will find markets and infrastructure will be built as needed. However, availability of pipeline infrastructure will impact pricing of Canadian crude oil and the economics of production.
- The higher carbon price cases assume that global crude oil prices are lower than in the Reference Case. This price impact is uncertain and depends on the robustness of concerted global climate action, the responsiveness of oil demand to higher carbon costs, and the availability of alternatives to existing technologies.
- Efforts to increase efficiency and decrease costs and environmental footprints in the oil sands are another key uncertainty in our projections. Should technologies advance at a different pace than currently assumed in our models then projections of bitumen production would change accordingly.

Appendix A

Projecting Oil Sands Production: Methods

Oil sands production is projected by applying utilization rates to the capacities of 1) existing oil sands projects, and 2) a timeline of new projects and expansion phases expected to be built in the future. Projections do not consider changes to production from weather, equipment failure, or other potential interruptions. Raw bitumen production and synthetic crude oil production are projected for each case.

The main differences between the cases are oil prices, carbon taxes, and technology assumptions. Varying oil prices affect industry revenues, and the reinvestment of a portion of the revenue as capital expenditures. Varying carbon taxes affect the net revenue available: the higher the carbon taxes, the higher the cost of production and the lower the net revenue. Technological advancements affect both bitumen production as well as the steam to oil ratio (SOR). These variations do not affect all oil sands projects uniformly. For instance, the better a project's SOR, the less impact rising carbon taxes have. This results in an emissions credit for some projects in some years. More details about how emissions are calculated are provided in Section A4.4.

Mining and in situ production are estimated using the same method. Projects are assessed based on their announced capacities and start dates and then risked in terms of start time. Production from all projects of each type (i.e. mining, in situ) is then aggregated. Production from projects that are currently operating is held relatively constant for the majority of the projection. In some cases, depending on the age of the facility, production is decreased towards the end of the projection period. Increases in production for any given project are largely the result of new phases coming online and, to a lesser extent, process improvements in the early years of that project or phase. These methods significantly differ from conventional oil projections, which are well-based and use decline-curve analysis.

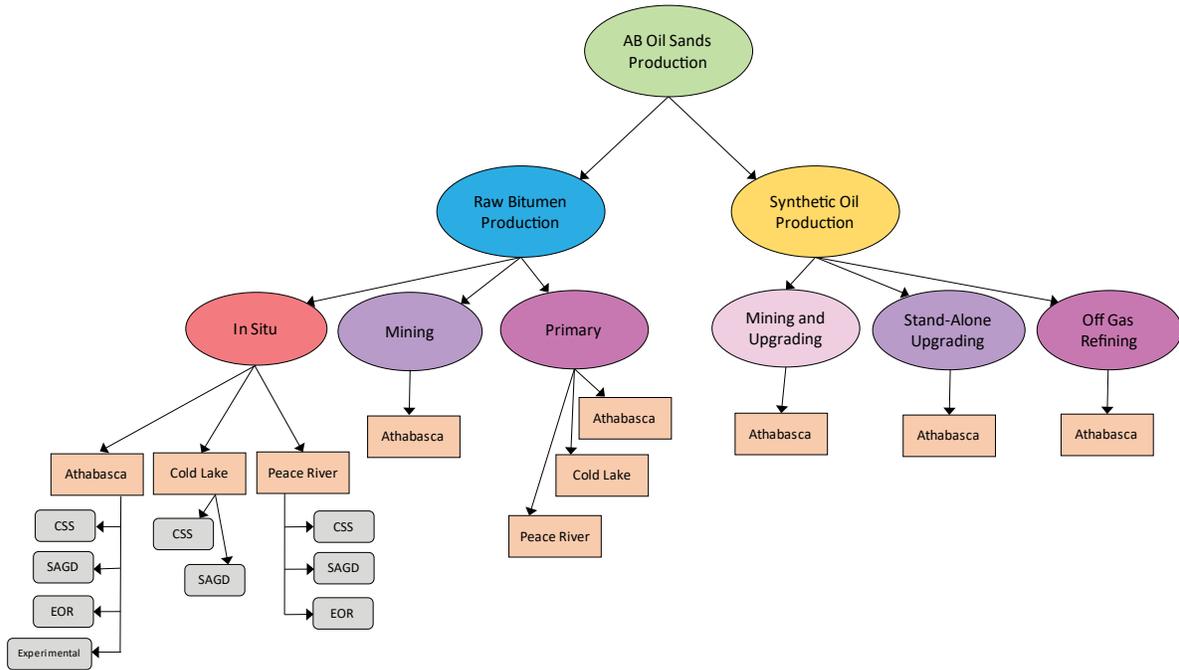
Details on oil sands producing areas are in Appendix A1.1. How production is determined is discussed in Appendix A1.2. Projection results can be found in [Appendix B](#).

A.1 Oil Sands Production Categories

For this analysis, oil sands production is categorized by type of production, type of recovery, geography, and recovery method. Figure A.1 shows the breakdown.

FIGURE A.1.1

Oil Sands Production Categories

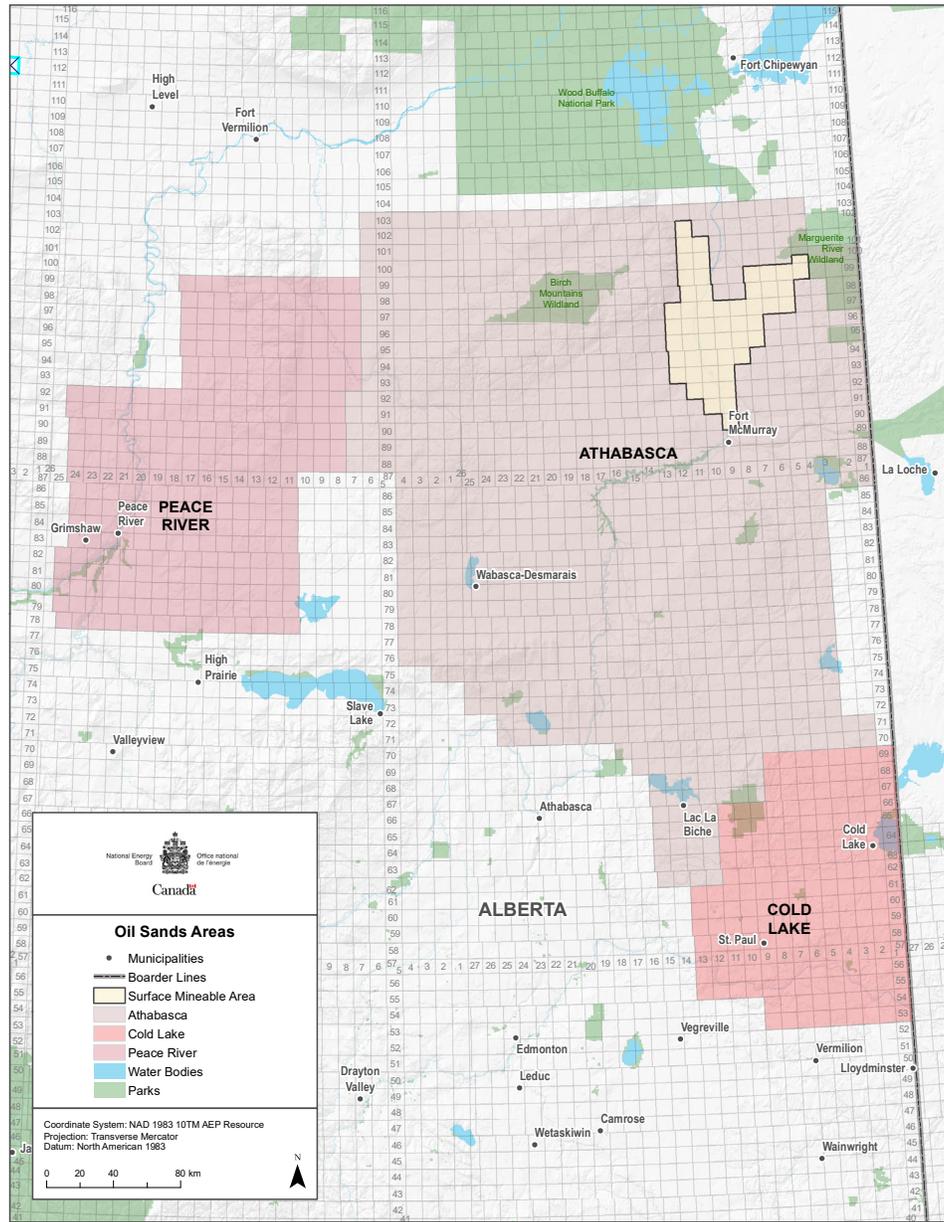


A.1.1 Oil Sands Areas

Oil sands production occurs in three areas in Alberta: Athabasca, Cold Lake, and Peace River. Athabasca has the majority of activity and production, including SAGD, CSS, and EOR in situ projects. Athabasca also has mining projects, upgrading, off gas refinery projects, and primary projects. Cold Lake has SAGD and CSS in situ projects as well as primary projects. Peace River has SAGD, CSS, and EOR in situ projects and primary projects.

FIGURE A1.2

Oil Sands Areas Map



A.1.2 Type of Production – Raw Bitumen and Synthetic Crude Oil

Both raw bitumen production and synthetic crude oil production are projected as part of the analysis. The majority of mined bitumen is upgraded within Alberta with some notable exceptions. In addition, production from two in situ facilities, Suncor’s Firebag and MacKay River projects, is partially upgraded to synthetic crude oil. The remaining volumes of in situ production, as well as production from Imperial’s Kearl Mine Suncor’s Fort Hills Mine (once it is completed), are marketed as diluted bitumen.

A.1.3 Type of Recovery – In Situ, Mining, Primary, EOR

Bitumen is produced in one of four ways. Roughly 90 per cent is either mined or extracted using in situ methods. Remaining production comes from Primary and Enhanced Oil Recovery (EOR). Primary bitumen production is slightly less viscous than in situ bitumen and can flow to the surface without applying heat or solvents. However, these projects are of a smaller scale than in situ developments. EOR uses reservoir flooding similar to the technology used for conventional oil. These too are a smaller scale than either mining or in situ projects. Combined, there were over 150 Primary and EOR projects operating within Alberta in 2016.

A.1.4 In Situ Recovery Method – SAGD, CSS, EOR

There are three types of in situ recovery technologies included in this report: SAGD, CSS, and EOR.

SAGD typically uses pairs of horizontal wells to produce bitumen. Steam is injected into an upper well to heat the bitumen, which then drains by gravity into a lower well and is pumped to the surface.

CSS also uses steam to produce bitumen. The steam is injected into a reservoir through a well over a period of several months, heating and decreasing the bitumen's viscosity. Later, the steam is turned off and the emulsion of water and bitumen flows back into the well over a period of several months. The process is repeated for the economic life of the well.

EOR extracts oil from reservoirs once pressures have fallen to a point where natural production is no longer economically viable, even with artificial lifts like pump jacks. This includes pressure maintenance, cycling, water flooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids.

A.2 Methods to Project Bitumen Production

For this report, historical production data, plans announced by producers, and industry and government consultations were used to derive projections. Monthly projections out to the end of 2040 are made for existing projects, for future (new) projects, and for expansions of both existing and new projects.

A.2.1 Method for Existing Projects

Projects that are, or have, produced are categorized as existing projects and their historical monthly production trend is used to project future production. For the most part, existing projects' production is held constant out to 2040. Projections for projects whose production is currently declining maintain that decline. Projects whose production is currently zero but produced in the past will either have zero production over the projections (retired projects) or return to the expected levels at a given time based on publicly available information (i.e., projects that have been temporarily shut down).

A.2.2 Method for Expansions

Expansions are additions to existing projects. Given the oil price assumptions, most future increases in bitumen production will come from expansions of existing projects rather than new projects. Publically available information is used to determine the size and timing of expansions.

A.2.3 Method for Future Projects

Given a projected oil price and other assumptions, it may be warranted to include one or more new projects in the projection. New in situ projects are expected to be built as well though the timing, size and number of projects differs between the cases.

A.3 Synthetic Crude Oil Production Projection Methods

Synthetic crude oil is raw bitumen that is processed into a lighter crude oil. Most mined bitumen is currently upgraded and it is assumed this trend will continue throughout the projection period. In addition to mining, some in situ and heavy oil production is upgraded.

A.4 Other Assumptions and Analysis

A.4.1 Capital Expenditures

Capital expenditures are made up of two things: sustaining and construction.

Sustaining capital expenditure is the investment needed to maintain existing projects, and is generally closely linked to production levels. If production is expected to trend upwards over the projection, so too will the sustaining capital expenditures. In this analysis sustaining capital is set at:

- \$1 500 / b/d of gross bitumen produced per year for primary production
- \$9 000 / b/d of gross bitumen produced per year for mining production
- \$5 000 / b/d of synthetic oil produced per year for upgraded production
- \$6 300 / b/d of gross bitumen produced per year for in situ production

Construction capital expenditure is the cost for new projects or expansions. The cost is assumed to start in the first month of construction, and is spread evenly over the construction months. Most projects or expansions' construction periods are assumed to take 18 to 24 months. New projects and expansions also have ramp-up times for production, since production generally does not start at the maximum amount in the first month of operation. Construction costs are based on available information and consultation. Costs differ between producers and projects, but generally range from:

- \$30 000 - 60 000 per b/d of capacity for in situ
- \$80 000 - 95 000 per b/d of capacity for mining
- \$50 000 - 70 000 per b/d of capacity for upgrading

The wide range reflects the highly variable nature of the quality of reservoirs available to each producer as well as technology assumptions.

A.4.2 SOR and Natural Gas Use Assumptions

A steam-oil-ratio (SOR) is the number of barrels of steam used to produce a barrel of oil used for the thermal (SAGD, CSS) in situ projects. The lower the SOR, the more efficient the project is, and generally has a lower supply cost than a project with a higher SOR. For most projects, the steam is generated by burning natural or synthetic gas. If the SOR is available, the ratios assumed to estimate gas use are:

- Dry SOR * 0.41 Mcf/b of steam = Mcf/b of bitumen production for SAGD
- Wet SOR * 0.32 Mcf/b of steam = Mcf/b of bitumen production for CSS

For some projects, the historical SOR is unknown, and so the general ratios used would be:

- 0.187 Mcf/b of bitumen produced for EOR
- 2.0 Mcf/b of bitumen produced for SAGD and CSS

Projected monthly SORs for a project are based on historical trends, technology and efficiency projections, and schedule of expansions (which will generally temporarily increase the SOR, because new projects or expansions commence steaming in preparation for production startup). Given the projected SOR or general ratios, monthly gas use in the oil sands industry is also projected.

Mining, upgrading, and primary projects do not use steam, but may use natural gas for operations. The historical ratios for each project are carried forward in the projection to calculate future gas use from these projects.

A.4.3 Electricity Assumptions

Historical electricity use for mining and upgrading projects is available for most projects. The ratios of electricity use per unit of production are carried forward over the projection to calculate electricity use. For other projects, the electricity use assumptions are:

- 18.9 kW.h/b of bitumen production for primary and EOR
- 15.0 kW.h/b of bitumen production for SAGD and CSS

A.4.4 CO₂ Assumptions

The cost of carbon dioxide emissions are included in the analysis. The cost of emissions decreases industry revenue and cash flow available for future capital expenditures. However, on a project by project basis, the cost of carbon may or may not affect the production projection. More efficient projects with lower SORs won't have their economics affected as much as less efficient projects. Thus, for most projects, given current and projected SORs, the production projection is the same^{A1} for varying carbon prices. Less efficient, usually smaller, projects are assumed to be affected with some production taken out of the projection given the carbon and oil price assumptions.

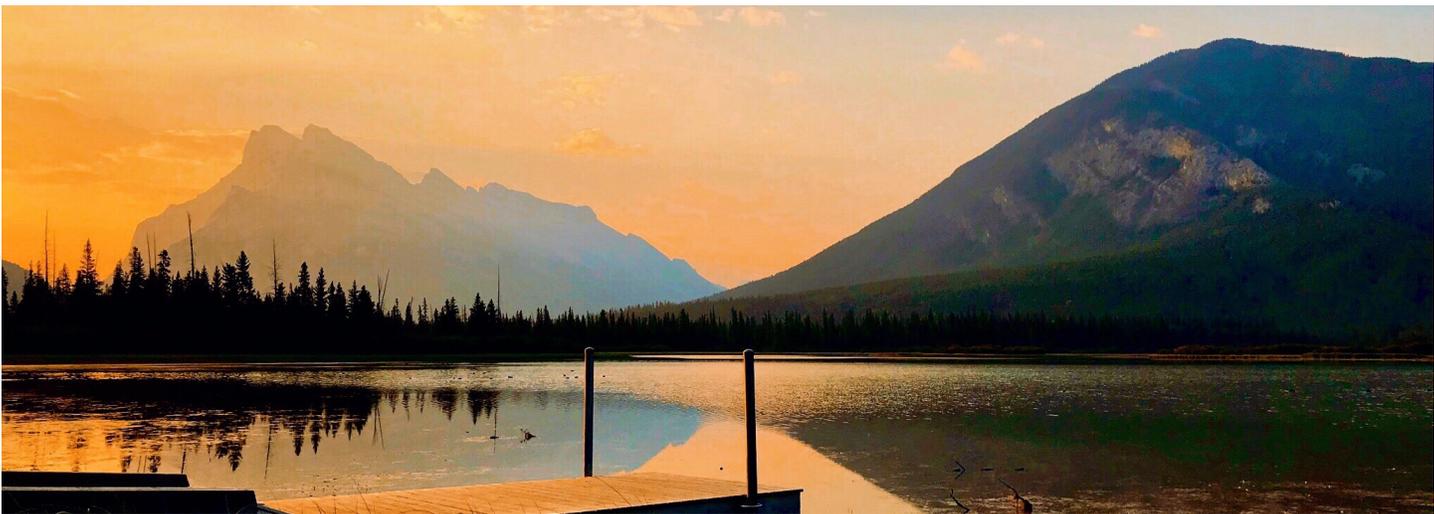
The amount of gas consumed, and CO₂ emitted, can be calculated using the gas use per barrel of bitumen or synthetic oil discussed in section A.4.2. The assumed ratio is:

0.0019 tonnes of CO₂ / m³ of natural gas use

An output-based adjustment, as based on Alberta's climate plan, was then applied to the actual cost of CO₂, for each project by year. For a given year, the projects are ranked from lowest SOR to highest SOR. The 25th percentile lowest SOR is a threshold level. The carbon cost associated with that SOR is the output-based adjustment and all projects' carbon costs are adjusted by that amount. Thus, the projects with lower SORs than the threshold end up with a carbon cost less than zero (revenue is adjusted up) and the rest of the projects have lower, but still positive carbon costs (revenue is adjusted lower). More information on carbon calculations and provincial policies can be found in the [Energy Futures 2017](#) report.

Data for the figures in Appendices A and B [are available](#).

A1 Nameplate production capacity of a project does not change with changing carbon prices.



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