STUDY NO. 183
JULY 2019

CANADIAN OIL SANDS SUPPLY COSTS AND DEVELOPMENT PROJECTS (2019-2039)

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ISBN 1-927037-68-3

July 2019
Printed in Canada

Front cover photo courtesy of Google images

Acknowledgements:
The author of this report would like to extend her thanks and sincere gratitude to all CERI staff that provided insightful comments and essential data inputs required for the completion of this report, as well as those involved in the production, reviewing and editing of the material, including but not limited to Hamid Rahmanifard, Hossein Hosseini, Andrei Romaniuk, Allan Fogwill and Megan Murphy.

ABOUT THE CANADIAN ENERGY RESEARCH INSTITUTE

Founded in 1975, the Canadian Energy Research Institute (CERI) is an independent, registered charitable organization specializing in the analysis of energy economics and related environmental issues in the energy production, transportation, and consumption sectors. Our mission is to provide relevant, independent, and objective research to benefit business, government, academia, and the public.

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Abbreviations

AECO-C price	Natural gas price benchmark in Western Canada
AEO	Annual Energy Outlook
AER	Alberta Energy Regulator
API	American Petroleum Institute
BCFPD	billion cubic feet per day
BPD	barrels per day
CAPP	Canadian Association of Petroleum Producers
CCA	Capital Cost Allowance
CCI	Carbon Competitiveness Incentive
CERI	Canadian Energy Research Institute
CO2eq.	Carbon dioxide equivalent
CSS	Cyclic Steam Stimulation
E&P	Exploration and Production
EOR	Enhanced Oil Recovery
GDP	Gross Domestic Product
GHG	greenhouse gas
GJ/d	gigajoules per day
GSP	Gross State Product
I/O	Input-Output
IMO	International Maritime Organization
LNG	Liquified Natural Gas
LTBR	Long-term Bond Rate
MMBPD	million barrels per day
MMBTU	million British Thermal Units
MMCFPD	million cubic feet per day
MT or Mt	mega-tonne
MWh	megawatt-hour
NEB	National Energy Board
NGL	Natural Gas Liquid
NPV	Net Present Value
OPEC	Organization of the Petroleum Exporting Countries
R&D	Research and Development
SAGD	Steam-Assisted Gravity Drainage

SCO	Synthetic Crude Oil
SGER	Specific Gas Emitters Regulation
SOR	Steam to Oil Ratio
US	United States
US EIA	United States Energy Information Administration
US PADD	United States Petroleum Administration for Defense Districts
USGC	United States Gulf Coast
WCS	Western Canadian Select
WTI	West Texas Intermediate

Executive Summary

Each year the Canadian Energy Research Institute (CERI) publishes its long-term outlook for Canadian oil sands production and supply in conjunction with an examination of oil sands supply costs. This is the thirteenth edition of CERI's oil sands supply cost and development projects update report. Similar to past editions of the report, several scenarios for oil sands development are explored. In addition, given the assumptions for the current cost structure, an outlook for future supply costs is provided.

Supply Cost Results

Supply cost is the constant dollar price needed to recover all capital expenditures, operating costs, royalties and taxes and earn a specified return on investment. Supply costs in this study are calculated using an annual discount rate of 10 percent (real), which is equivalent to an annual return on investment of 12.0 percent (nominal) based on the assumed inflation rate of 2.0 percent per annum.

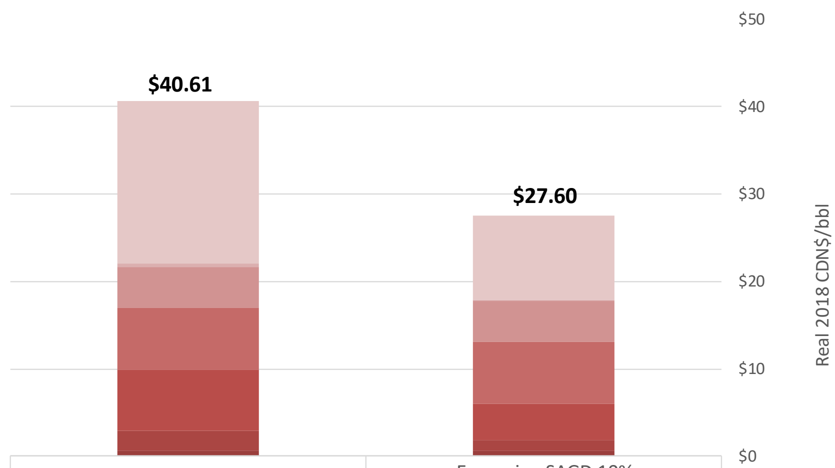
Based on the assumptions presented in Chapter 2, the supply costs of crude bitumen for a greenfield steam-assisted gravity drainage (SAGD) project and an expansion phase SAGD project are presented in Figure E.1. The plant gate supply costs, which exclude transportation and blending costs, are C$40.61/bbl for a SAGD project and C$27.60/bbl for an expansion phase SAGD project. A comparison[1] of field gate costs from the 2018 update with this year's supply costs indicates that, after adjusting for inflation, the supply cost for a greenfield SAGD producer has decreased by 11 percent, and by 6 percent for an expansion SAGD.

After adjusting for blending and transportation, the WTI equivalent supply costs at Cushing are US$52.84/bbl and US$45.88/bbl for a greenfield and expansion SAGD, respectively. At current WTI prices of around US$60/bbl,[2] these projects are decidedly economic. The relative position of oil sands projects against other crude oils is comparatively competitive, and as oil prices are expected to increase, so will the profitability of oil sands projects. There are risk factors that might affect project economics, such as market access, exchange rate, future oil prices, project costs, etc. Some of these impacts were evaluated through a sensitivity analysis in Chapter 2.

[1] Direct cost comparison is not recommended and only shown to illustrate the direction of change. Because some changes were made in the project assumptions regarding carbon policy as well as project economics, a direct comparison of costs is not favoured.

[2] At the time of writing, WTI prices traded at US$60.83/bbl

Figure E.1: Total Field Gate Bitumen Supply Costs



	SAGD 10% ROR (a)	Expansion SAGD 10% ROR (a)
Fixed Capital (Initial & Sustaining)	$18.59	$9.67
Operating Working Capital	$0.38	$0.20
Fuel (Natural Gas)	$4.63	$4.63
Other Operating Costs (incl. Elec.)	$7.07	$7.07
Royalties	$7.04	$4.18
Income Taxes	$2.21	$1.17
Emissions Compliance Costs	$0.67	$0.67
Abandonment Costs	$0.03	$0.01

[a]Return on capital included. Source: CERI

Production Forecast – Three Scenarios

Figure E.2 illustrates the possible paths for production under the three scenarios. For an oil sands producer, a project's viability relies on many factors such as, but not limited to, the demand-supply relationship between production, operating and transportation costs (supply side) and the market price for blended bitumen and SCO (demand).

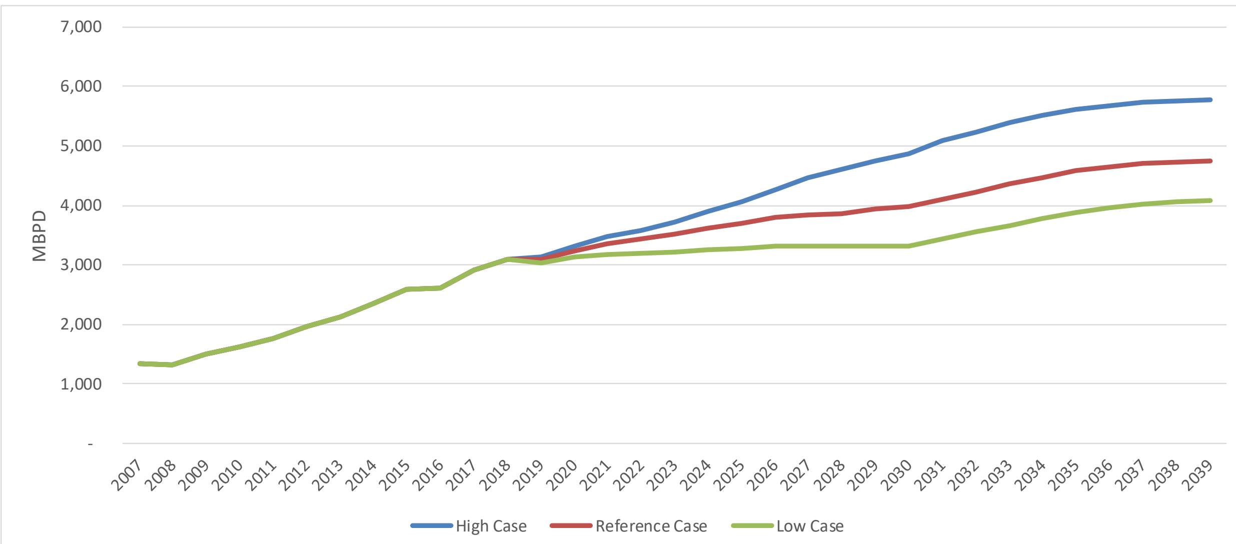
Total production from oil sands areas reached a significant milestone of a 3 million-barrel-per-day (MMBPD) level in 2018, surpassing 2017 production by 210 thousand barrels per day (MBPD). Oil sands bitumen production is comprised of in-situ (thermal and cold bitumen) production of 1.6 MMBPD and mining production of 1.5 MMBPD within the boundaries of oil sands areas.[3] Total production in 2017 was 2.84 MMBPD, meaning oil sands production grew 7 percent year-over-year. Production from oil sands includes an increasing share of Alberta's and Canada's crude oil

[3] Totals may not add up due to rounding. Historical production is sourced from the Alberta provincial regulator.

production. In 2018, non-upgraded bitumen and SCO production made up two-thirds of total Canadian crude production and 87 percent of Alberta's total production.

In the future, under the **High Case Scenario**, production from mining and in-situ projects (thermal and cold bitumen) is set to grow to 3.3 MMBPD by the end of the decade and reach 4.9 MMBPD in 2030, peaking at an all-time high of 5.8 MMBPD by 2039. In the **Low Case Scenario** production grows at a slower rate, rising to 3.1 MMBPD in 2020, 3.3 MMBPD by 2030 and to 4.1 MMBPD by the end of the forecast period. CERI's **Reference Case Scenario** provides a base case of oil sands production. Projected production volume will increase to 3.2 MMBPD by 2020 and 4 MMBPD in 2030, peaking at 4.7 MMBPD by 2039 (see Chapter 3 for more details).

Figure E.2: Bitumen Production Scenarios



Source: CERI, CanOils

Bitumen production in CERI's Reference Case grows by an annual average of approximately 80 MBPD or just over 2 percent per year. This growth rate is downgraded from last year's estimate of 3 percent. The slight decline in 2016 is the result of wildfires in northern Alberta that happened mid-2016 affecting oil sands projects. The 2019 estimated drop is due to mandated production curtailment implemented by the Alberta government and enforced in January 2019 to counteract the increasing price differential between WTI and WCS.

Capital Investment

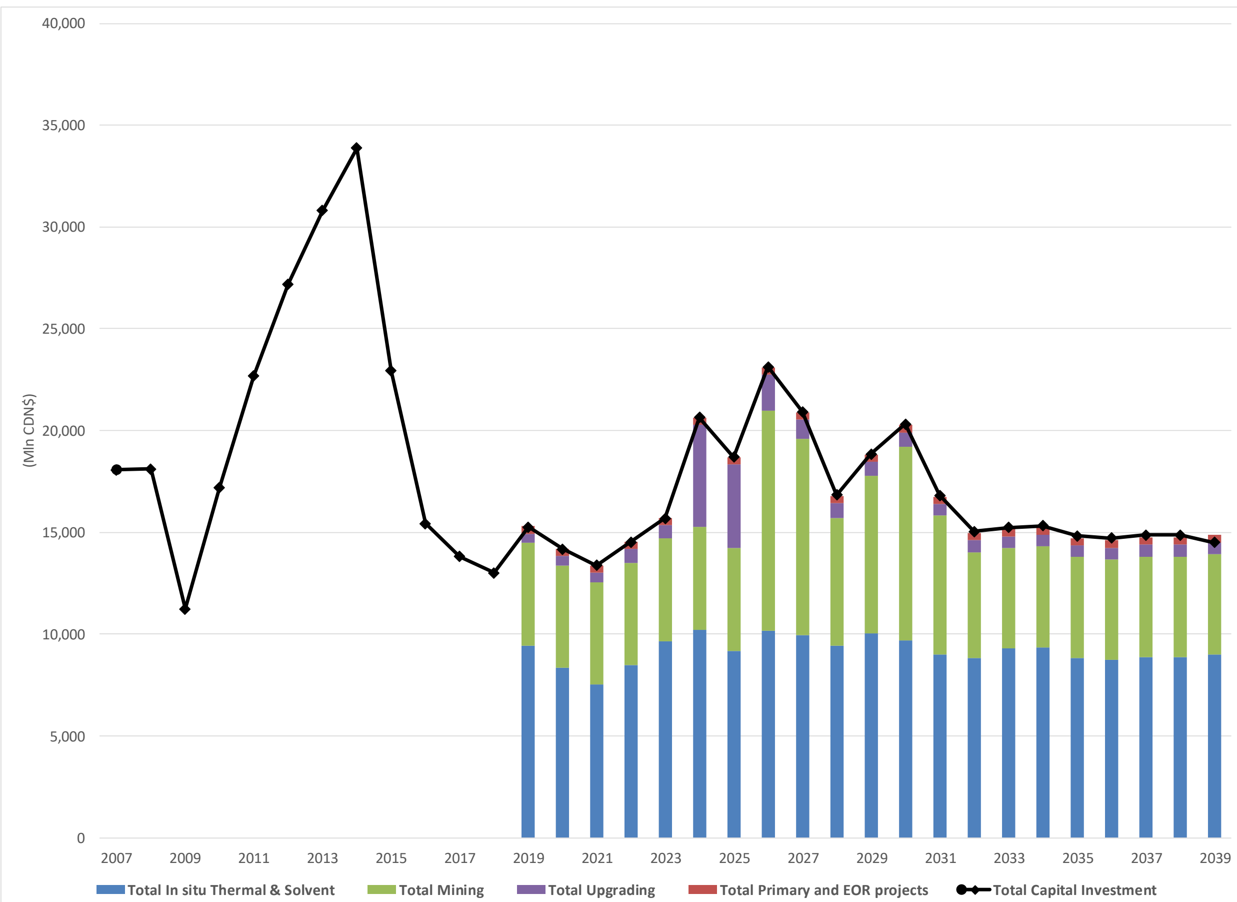
Oil sands capital spending is expected to stay weak in the near term of the forecast, continuing a downward trend. A majority of oil sands companies keeps deferring new projects in the short term, focusing instead on sustaining existing facilities and lowering costs of production.

From 2019 to 2039, it is projected that almost C$126 billion (initial and sustaining) will be invested into mining projects and C$200 billion into in-situ thermal and solvent as well as primary and EOR cold bitumen projects. Upgrading projects see the least amount of capital spent, amounting to C$22 billion.

Historical and forecast capital expenditures from 2007 to 2039 are shown in Figure E.3. As evidenced in the industry, capital expenditures on oil sands projects have been on the decline since 2014, coinciding with a decrease in oil prices. Investment fell by 10 percent to C$13.8 billion in 2017 as compared to 2016 levels and a further estimated 6 percent in 2018. The 2014 peak spending of almost $34 billion is not projected. For the next 5 years, the investment will remain less than C$15 billion.

Going forward, overall capital expenditures average $16.5 billion per year in the 2019-2039 forecast period and decline at one-tenth of a percent per year on average. There are lingering risk factors that could impact the capital outlay outlook – further deferral of projects; successful deployment of cost-reduction strategies; uncertainty on a 100 MT cap on oil sands emissions; and uncertainty over export pipeline development projects. Expenditures in the oil sands are expected to be invested in new thermal projects or primarily aimed at sustaining capital and expanding existing projects.

Figure E.3: Total Oil Sands Capital Expenditures by Project Type



Source: CERI, CAPP, CanOils

Oil Sands Economic Contribution

Canadian Impacts

The industry is projected to contribute $1.01 trillion to the Canadian GDP over the next 11 years (Table E.1). Most of the impacts will be felt in Alberta, but Saskatchewan is a growing contributor as oil sands projects from that province are coming online. Governments will collect tax revenues in the form of corporate taxes and royalties. Those are estimated to be $16.7 billion in overall tax revenues for Canada; of that, $11 billion will be collected in Alberta.

Table E.1: Total Economic Impacts of Oil Sands Development, 2019-2029

Economic Impact	Region	2019-2029
GDP (million $CAD)	Alberta	886,667
	Canada	1,012,502
Employment (person-years)	Alberta	3,468,300
	Canada	4,688,261
Tax (million $CAD)	Alberta	11,003
	Canada	16,675

Source: CERI

The annual GDP growth for Canada will average approximately C$92 billion, growing from C$71.3 billion in 2019 to C$117 billion in 2029. Alberta will account for 88 percent of the total impact, averaging C$80 billion per year.

Total employment (direct and indirect) in Canada will amount to 4,688 thousand-person years, translating to growth from 332,847 jobs in 2018 to 532,673 jobs in 2029. Direct and indirect employment in Alberta grows from 247,144 jobs in 2019 to 391,187 jobs by 2029. Over 70 percent of jobs are filled in Alberta.

Total tax revenues generated from oil sands development to the government will amount to almost C$17 billion over the 2019-2029 period (Table E.1). On average, annual tax revenues (federal and provincial) will be C$1.5 billion, increasing from C$1.2 billion in 2019 to C$1.9 billion in 2029. Given that the majority of oil sands projects are located in Alberta, the province will generate the highest shares of both federal and provincial tax revenues at 66 percent.

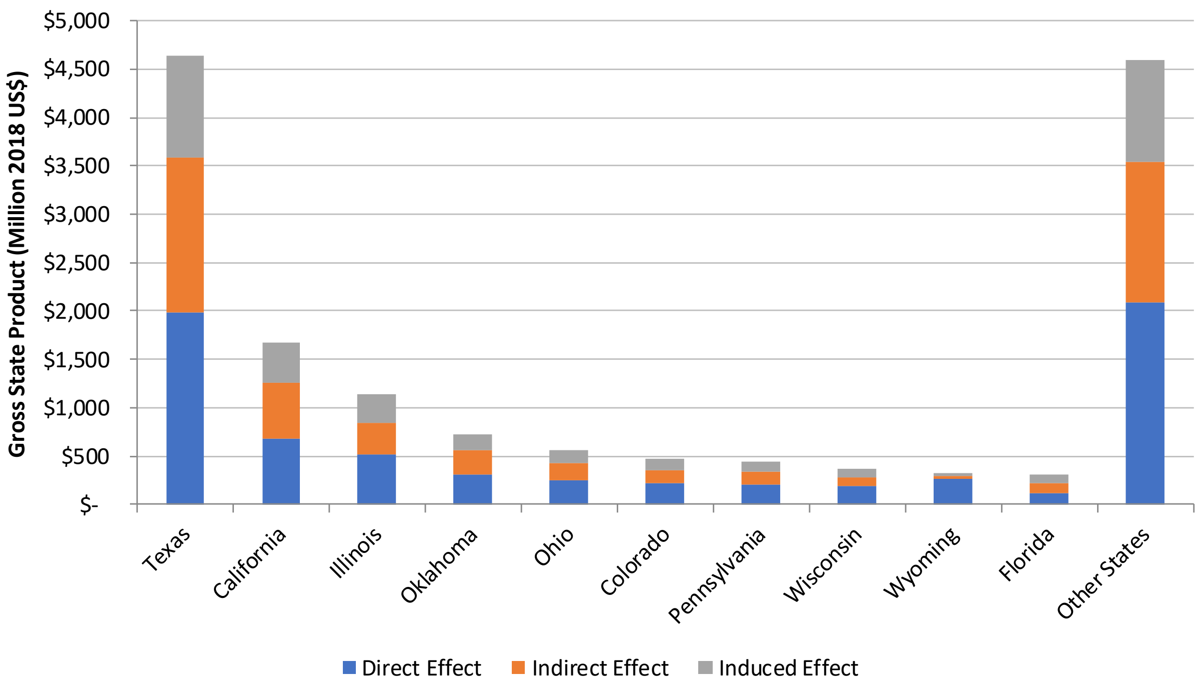
US Impacts

Investments and operations of Canadian oil and gas projects make important contributions to the United States economy as well. The US benefits not only from importing oil and gas from Canada but also from supplying goods and services used by the Canadian oil and gas industry. Prior to the 2014 oil price collapse, the Canadian oil and gas production sector imported C$6.5 billion worth of products and services from the US in 2013. Supply of those products and services spur economic activity and create or preserve jobs in respective US states.

For the forecast period of 2019-2029, it is estimated that the total impact on the US gross state product (GSP)[4] will amount to almost US$15 billion or C$20.3 billion (using the exchange rate of US$0.75 per CAD$1). The total employment impact is measured in creating or sustaining around 133,000 full-time equivalent jobs over the 11-year period.

The top ten states that benefit the most from Canadian oil sands development are, in descending order, Texas, California, Illinois, Oklahoma, Ohio, Colorado, Pennsylvania, Wisconsin, and Florida (Figure E.4). Together, the top ten states make up 70 percent of the total GSP impact and 67 percent of total employment impact. Texas, by far, the largest beneficiary in terms of gross state product (GSP) and employment, totalling almost US$5 billion over the 11-year forecast or 30 percent of total GSP impact. Growing employment in Texas that is created or sustained will more than double, totalling 36,698 jobs over the 11-year period.

Figure E.4: Oil Sands GSP Impacts for Top US States

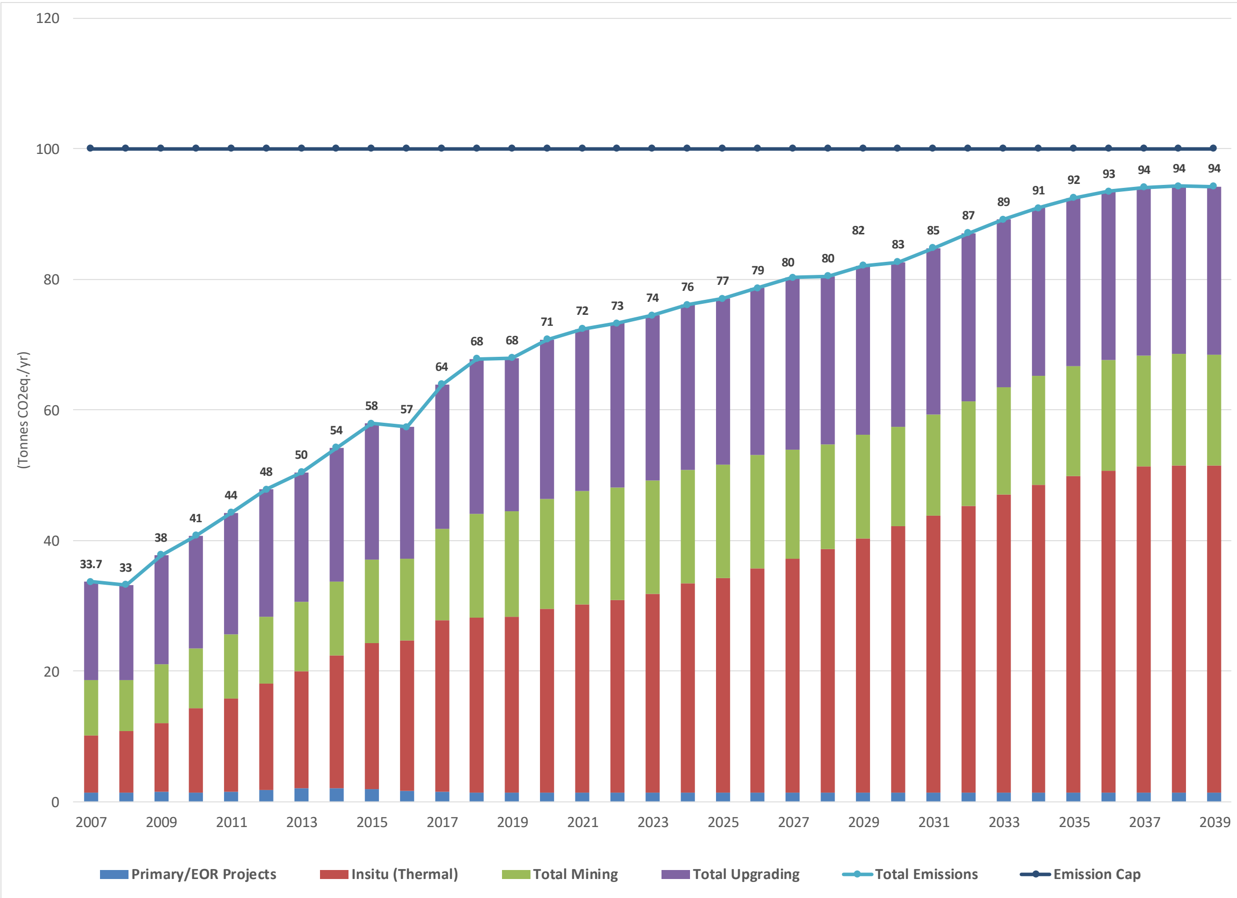


Emissions

Figure E.5 illustrates total emissions projection for the **Reference Case** production forecast. The on-site emissions projection includes emissions from existing upgrading, electricity or fugitive emissions and flaring. Current on-site emissions are projected to grow from 68 MT/year in 2018 to 94 MT/year in 2039, not reaching the emissions cap of 100 MT. In comparison to last year's update, the 100 MT level was reached in 2030. The difference is explained by a lower production forecast and is not reflective of technological changes to reduce emissions.

[4] In the US, the definition of the gross state product (GSP) is similar to the provincial gross domestic product in Canada.

Figure E.5: Oil Sands Emissions by Project Type



Source: CERI, CanOils

Chapter 1: Introduction

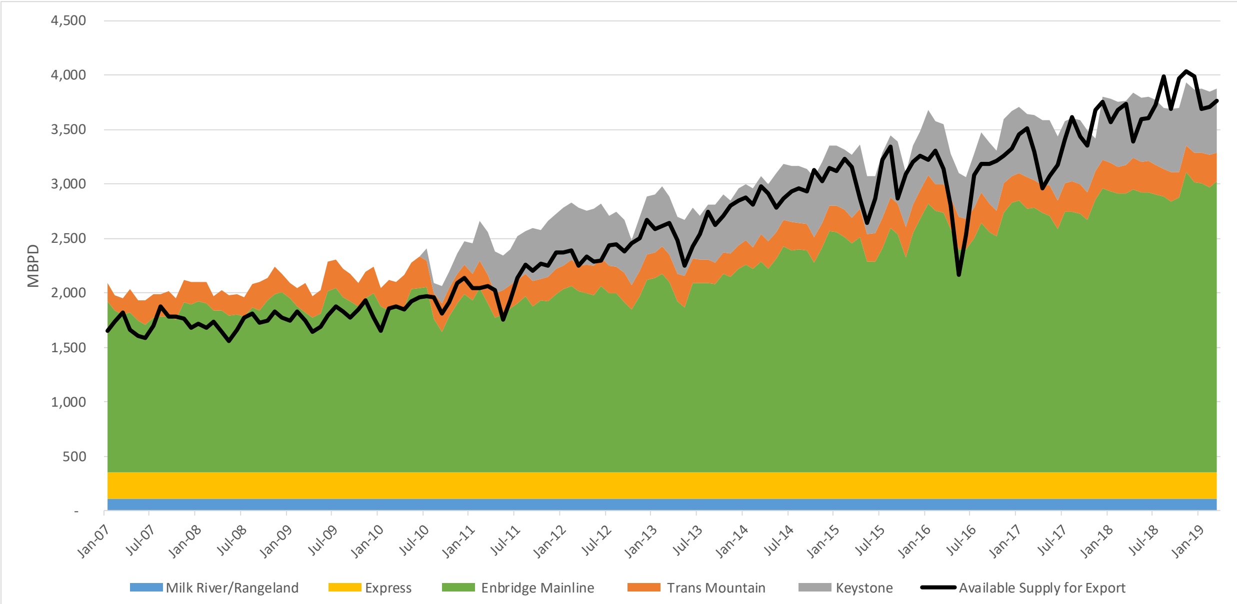
Background

The collapse in oil prices worldwide has affected the industry and slowed the pace of upstream investment around the world – including in heavy crude oil development in Canada. Although the global market remains volatile, there is a sentiment that the low oil prices witnessed in 2014-2015 are behind us. Indeed, prices have recovered. In 2018, the Brent oil price averaged US$71/bbl and WTI – US$65/bbl, a much-needed relief for oil producers.

The level of prices allowed oil companies worldwide, especially in the US, to begin to rebuild production capacity, resulting in an increase in new investments in oil production. Canada's oil sands, however, are still suffering from low investment and the trend is likely to continue for the near term. Canada is still among the top five global crude oil producers, and synthetic crude oil (SCO) and bitumen production is expected to grow, albeit at a slower pace, and the need for expansion in existing oil pipeline capacity comes at the forefront of challenges that the oil sands industry is facing today, in addition to oil prices. As Western Canadian crude oil production continues to grow, the leverage of these resources for economic benefits to the nation will depend on the ability to connect this growing supply with downstream demand.

It is also important to stress how some excess capacity is crucial to be able to manage pipeline maintenance times and to provide flexibility for new market development. Not to mention that constraints in pipeline capacity and the lack of access to existing and new demand centres have deepened the discount between WTI and Western Canadian crudes and hence have had a severe impact on the netbacks realized by Canadian producers. As a result of limited egress out of Western Canada, in the fall of 2018 the discount deepened to new record levels, intraday trading saw the differential widen to as much as US$65/bbl; the 2018 annual average for WTI-WCS differential grew to US$26.5/bbl from US$12/bbl in 2017. As crude oil and bitumen production surpassed what could be exported by rail or pipeline in the latter half of 2018 (Figure 1.1), the Government of Alberta put a temporary production curtailment in place to address excess supply and export capacity in effect from January 1 to December 31, 2019.

Figure 1.1: Pipeline Throughput and Crude Available for Export



Source: NEB, CERI

The Alberta Energy Regulator (AER) administers the production limit on behalf of the government. Under the amended formula that determines how space is allocated under the production limit, each company's baseline production level is based on its highest level during their best single month from November 2017 to October 2018:

- production limits will apply to both oil sands and conventional oil;
- the first 10,000 barrels produced by each operator are exempt;
- as there will still be significant oil available, refining operations will be able to access the oil supply required to meet their refining needs.

An AER panel will review company-specific concerns and make policy recommendations back to the Government of Alberta.

With the ongoing opposition of the federally-approved and owned Trans Mountain pipeline expansion and Enbridge's Line 3, doubts are mounting as to whether export pipeline capacity will increase by approximately 1 million barrels per day, alleviating some existing constraints in the mid-term. Also, crude-by-rail still serves markets where pipeline capacity is non-existent or constrained.

More recently, pipeline companies have made several announcements on their plans to add additional pipeline capacity to alleviate some egress issues. Enbridge announced how it proposes to add 450,000 BPD to its existing pipeline system without building new pipelines.[1] The work would entail several adjustments. First, Bakken light shale oil that currently ties into the Enbridge mainline at Cromer, Manitoba, could be cut back or even reduced to zero, allowing for an additional 100,000 BPD of Canadian crude to be delivered into the US. The company is also looking at upgrading its Line 4, adding drag-reducing agents and optimizing its crude slate to free up another 100,000 BPD of capacity. Those changes are expected to be phased in over the next two years, with another 100,000 BPD of system upgrades expected to be completed by 2022.

Another major change is the reversal of its Southern Lights Pipeline, which currently delivers condensate from the Midwest region into Edmonton, for use as diluent for heavy oil transport. Reversing the line is subject to regulatory approval but could be completed by 2023. If approved, that's another 150,000 BPD of light oil export capacity out of Western Canada.

Aside from its Mainline volumes, Enbridge also says it can boost capacity on its Express Line into the Rocky Mountains region by up to 60,000 BPD through the addition of chemicals and upgrades to pump stations. Those could potentially be completed by the end of next year.

Another Canadian company, Plains Midstream Canada, announced an expansion on its Rangeland pipeline for additional delivery capacity both north to Edmonton, Alberta and south to the border at Carway, Alberta. This expansion is subject to receiving sufficient commitments from shippers and receipt of necessary permits and regulatory approvals and will provide incremental takeaway capacity for the East Duvernay and other Rangeland-area production, as well as south egress access out of the Edmonton market hub. Combined, the expansion will increase Rangeland's current light crude oil capacity to approximately 200,000 BPD. Service between Edmonton and Sundre will be expanded from 50,000 to approximately 100,000 BPD and, additionally, will be capable of bi-directional service. Sundre, south to the border, will be expanded from its current 20,000 to 100,000 BPD. The expansions will be staged into service during the last half of 2019 with full capacity realized in 2021.[2]

On the supply side, as a consequence of the rapid growth in American oil production, inland refining markets in the US Midwest (current recipients of most of the Canadian heavy imports) have been flooded with cheap, high quality tight crude oil, which leaves Canadian heavy sour crude oil subject to price markdowns (due to lower quality and bottlenecks in their delivery infrastructure). This situation provides Canadian producers with a financial incentive to expand market access in the United States, Canada, and beyond. It also highlights the risk of over-reliance on limited markets and the need for options.

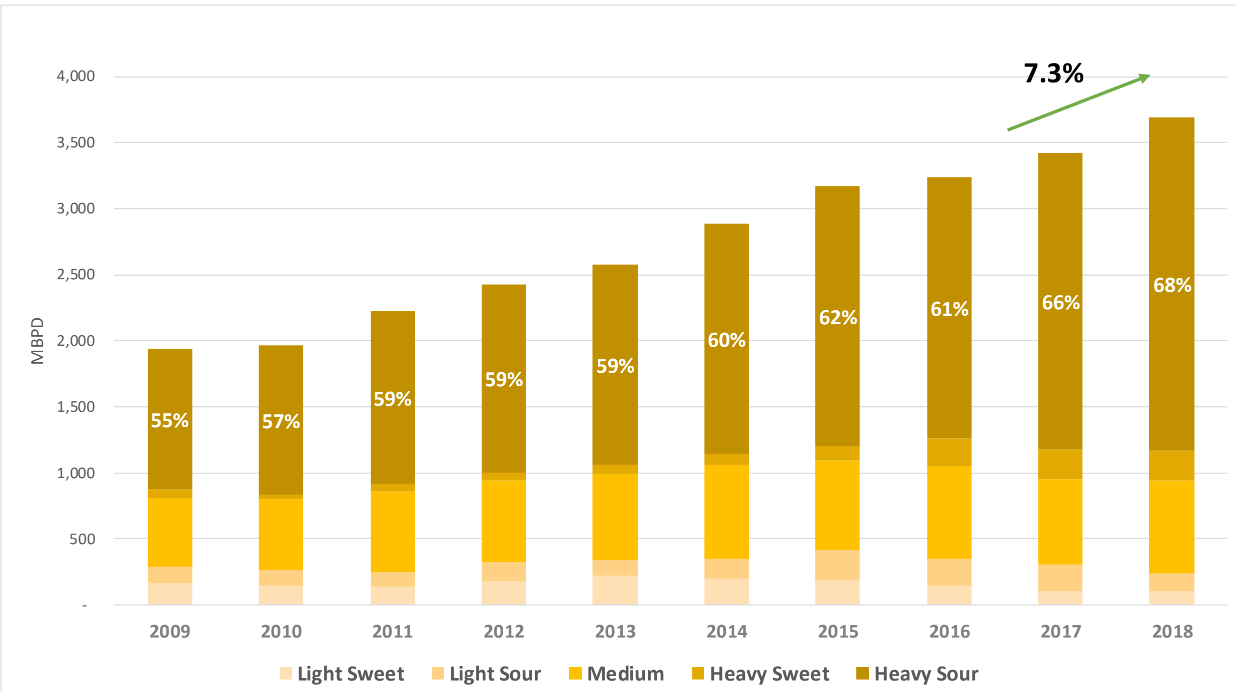
The US Gulf Coast (USGC) is one of the world's largest refining centres, and its considerable heavy oil processing capacity presents the largest opportunity for Western Canadian heavy crude oil

[1] Oilsands Magazine. "Enbridge hatches a plan to export more Canadian barrels, without building new pipelines". https://www.oilsandsmagazine.com/news/2018/12/12/enbridge-hatches-a-plan-to-export-more-barrels-without-building-new-pipelines

[2] Plains Midstream Canada. https://www.newswire.ca/news-releases/plains-midstream-canada-announces-rangeland-pipeline-expansion-889088998.html

supply, making it Canadian heavy producers' first target for market access. Canadian heavy crude oil competes for market share in the US Gulf Coast with heavy crude oil from Latin American producers, mainly Mexico, Venezuela, Brazil and Ecuador. Mexico and Venezuela are the main heavy crude oil exporters to the US Gulf Coast, accounting for over 45 percent of total crude oil imports to the US Gulf Coast. More recently, crude exports from Mexico and Venezuela have been declining due to domestic social and economic reasons, providing a further opportunity for Canadian heavy crude to replace some of the lost volumes and expand their market share in the US Gulf. Total Canadian crude exports to the US increased 7.3 percent in 2018, with growth coming from heavy sour crude exports, its share increased to 68 percent in 2018 (Figure 1.2).

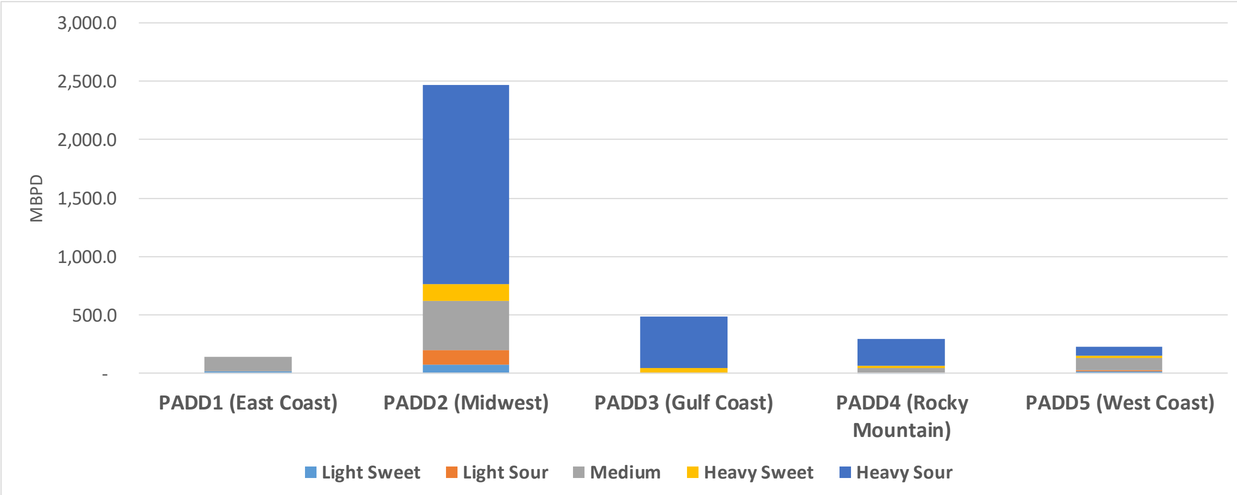
Figure 1.2: Canadian Crude Exports to the US



Source: EIA, CERI

The US Midwest region (or PADD 2) is still the dominant market for Canadian crude, capturing almost 70 percent of all Canadian imports, however, PADD 3 (or the US Gulf Coast) increased its Canadian exports by 30 percent in 2018 as compared to 2017, amounting to almost 500 MBPD, all of which is heavy crude supply (Figure 1.3).

Figure 1.3: Canadian Crude Exports by US PADD Region



Source: EIA, CERI

Expansion of pipeline infrastructure and shipping routes to international markets and the US would not only create many opportunities for Canadian oil producers but benefit the Canadian economy as well. Through increasing market access for our products, Canada will compete in global markets, capture higher tax revenues from producers, increase employment in energy and non-energy sectors, and continue to fund the important social structure of this country, not to mention a potential to invest in further research and development and innovation in our energy systems. Allocating exports to other markets such as Asia and Europe also reduces dependence on the US markets.

Although the need to expand and reach new markets for oil sands is pressing, production and pipeline projects associated with oil sands have come under increased scrutiny, contributing to delays and uncertainty. Although not every factor will influence future markets for oil sands, some of the most prominent ones include regulatory processes, local concerns, greenhouse gas emissions and climate change policies, as well as Indigenous People's rights in Canada.

If the advantage in tight oil plays goes to companies who move quickly to secure acreage and climb steep learning curves to economic oil production (and the steep downward curve of production decline), then the advantage in the oil sands goes to companies that effectively deliberate over the risks of multi-decade operations. Heavy oil differentials, pipeline capacity limitations and a volatile oil price all play a role in these considerations, but they invariably take a back seat to larger and more global oil supply and demand fundamentals.

For oil sands opponents, sustained decline in investment provides a point of view that the industry is too costly to compete. What this view ignores, however, are continuing capital and operating cost reductions captured by project operators through project efficiency initiatives such as debottlenecking. Continuing efforts at reducing costs through technological improvements and other operational measures, while remaining conscious of the environment, should ensure a robust future.

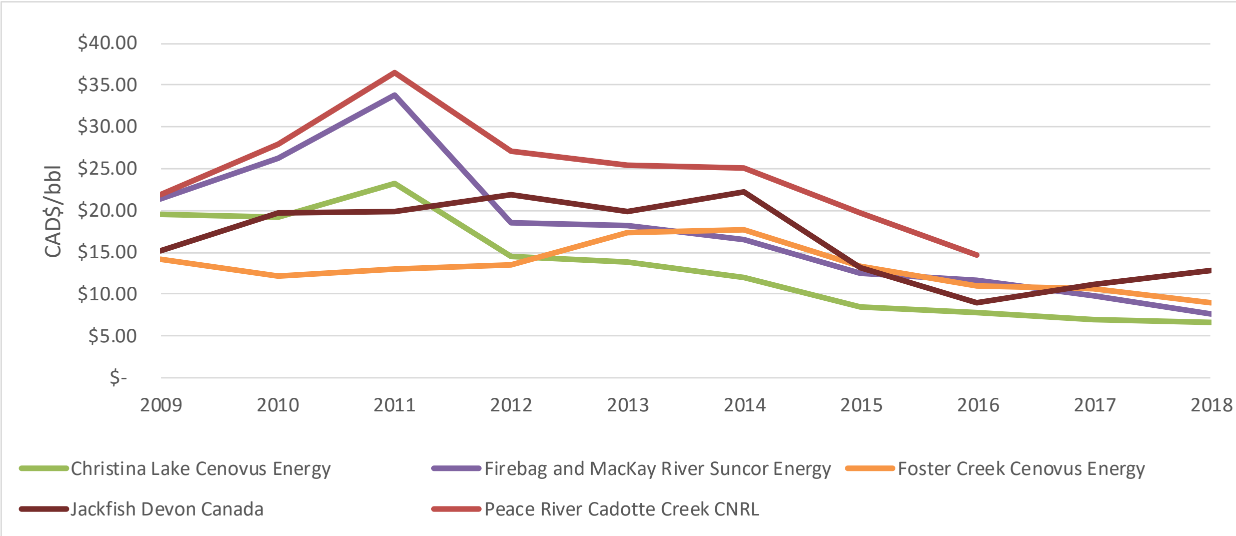
Historically, oil sands projects have experienced significant inflationary pressures as projects progressed towards completion. Labour shortages, material scarcity, administrative and engineering delays have all contributed to cost overruns. Capital cost increases ultimately eroded returns for producers. With the downturn in the oil prices globally – 2014-2016 – capital spending in new projects has experienced a decline, as more projects were being postponed and even cancelled. In spite of a global price recovery in 2017 and 2018, the oil sands industry is still facing many hurdles. One of the factors sited to limit the growth of the industry is a lack of incremental market access.

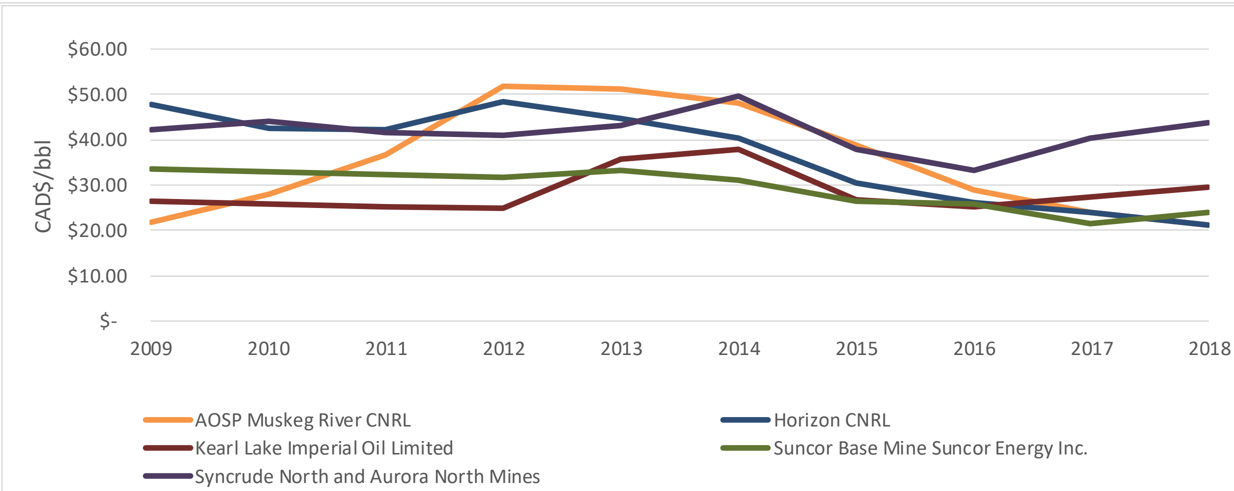
Nevertheless, a handful of producers are building new projects or expanding existing facilities with expansion phases as relatively higher oil prices in 2018 encouraged some projects to move forward. Project operators managed to gain new capital efficiency through improvements in reliability and output initiatives such as debottlenecking projects.

The total operating costs have been decreasing year-on-year for most existing projects, in-situ and integrated and stand-alone mining. Historical total operating costs for selected projects are shown in Figure 1.4. The sampled operating costs for in-situ producers, who are mostly SAGD facility operators, are shown in the top part of Figure 1.4. For integrated and stand-alone mining producers, the sampled operating costs are shown in the bottom part of Figure 1.4.

From 2014, when oil prices crashed, to 2018, total operating costs for both oil sands mining and in-situ producers fell on average by 40 percent, and in some cases, operators slashed costs in half. SAGD producers achieved a 48 percent cost reduction between 2014 and 2018, and a year-on-year reduction of 7 percent in 2018 as compared to 2017. Integrated and stand-alone mining projects' operating costs on average declined by 32 percent in 2018 versus 2014.

Figure 1.4: Total Operating Costs for In-situ and Mining Projects (2018 C$/bbl)



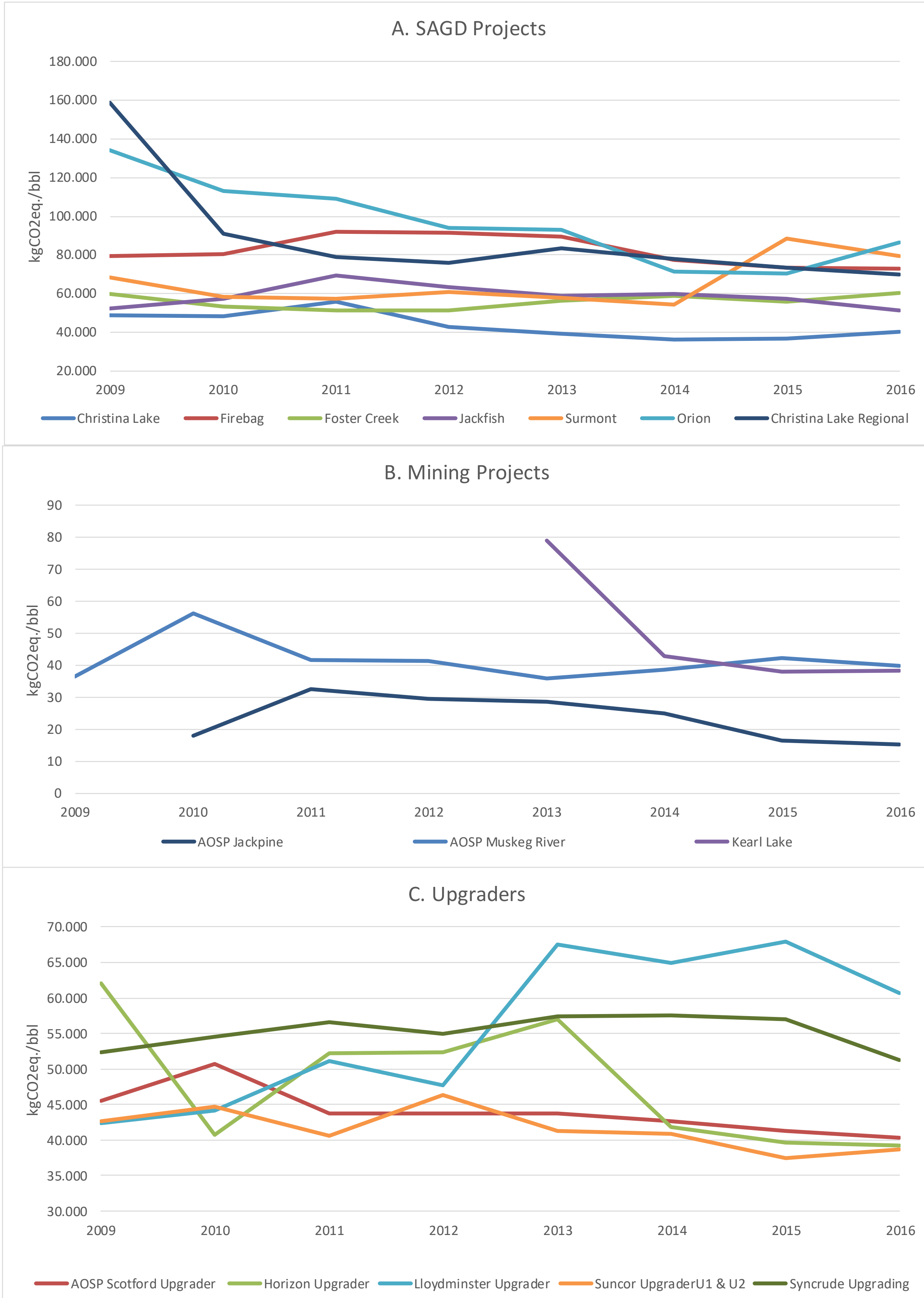


Source: CanOils, CERI

Growth in commercial oil sands production has also caused absolute GHG emissions related to oil sands development to increase but at a declining rate per barrel. Figure 1.5 illustrates the historic emission intensities for selected projects from 2009 to 2016. It is observed that between 2009 and 2016, average emission intensity levels of onstream projects have decreased by 11, 15 and 10 percent for SAGD, mining, and upgrading, respectively.

Numerous policies and regulations have been adopted in recent years with an aim to limit and reverse oil sands emissions growth while sustaining production levels and minimizing economy-wide impacts. Some of the mechanisms include intensity-based carbon pricing to protect trade-exposed sectors and limit carbon leakage, an absolute emissions cap on oil sands, and a federally-mandated carbon tax that will rise to C$50 per metric tonne of CO2eq. by 2022.

Figure 1.5: Emission Intensities by Project (kgCO2eq./bbl bitumen)



Source: Canoils, CERI

CERI's oil sands production forecast calls for growth of bitumen production over the next 20 years. The plans to expand oil sands production, increase pipeline takeaway capacity and gain access to other markets are still, however, dependent on key elements that must align for the industry. CERI believes these elements are:

i) favourable oil prices at levels where oil sands projects can be economic,
ii) timely regulatory environment,
iii) implementing cost-cutting measures through the adoption of improved processes and technologies,
iv) continuous improvement in an environmental performance among oil sands producers,
v) appropriately managing project planning with a realistic timeline and budget, and
vi) the ability to collaborate effectively in a competitive environment.

Approach

Similar to past editions of this report, three scenarios for oil sands developments are explored. In addition, given the assumptions for the current cost structure, an outlook for future supply costs will be provided.

The purpose of this report is to:

- Provide the reader with a better understanding of the current status of Canadian oil sands projects, both existing and planned. The status assessment covers the full spectrum of activities and technologies, such as in-situ, mining, and integrated production; and facilities for upgrading crude bitumen to synthetic crude oil (SCO).
- Explore the future direction of oil sands development, including projections of production, investments, operating costs, natural gas, emissions and diluent requirements.
- Estimate the supply costs, including costs associated with carbon emissions, for greenfield projects as well as expansion phases.
- Provide an update on the economic impacts of oil sands development.

CERI's oil sands projections and supply cost analysis is used by industry, governments, and other stakeholders as part of their market analysis. This report relies upon up-to-date information available on project announcements (updated to the end of 2018), and market intelligence gathered by CERI's oil sands team.

This year's report presents project vintages and production capacities of existing and planned projects. Within CERI's oil sands database, the projects are identified by type (e.g., mining and extraction, in-situ, upgrading), location, and extraction technologies (including pilot projects). Similarly, upgrading facilities are characterized by technology, and by type (i.e., stand-alone or integrated with crude bitumen extraction facilities).

All of the above information for both existing and future projects is presented at the aggregate industry level (i.e., the oil sands industry as a whole) throughout this report. The oil sands projects are classified according to their stage of development.

Organization of the Report

Chapter 1 highlights the background of the study and presents the objective and the scope.

Chapter 2 presents the assumptions and methodology used in the supply cost assessment, followed by results for supply costs and sensitivities.

Chapter 3 highlights the assumptions and methodology used in the oil sands forecasting model and presents scenario-based production projections, followed by projections of capital investment, operating costs, natural gas and diluent demand, and emissions projection.

Chapter 4 presents the economic impacts of oil sands development on the Canadian and US economies.

Chapter 2: Oil Sands Supply Costs

This chapter presents oil sands supply cost results along with CERI's supply cost methodology and assumptions used.

Methodology and Assumptions

Supply cost, sometimes referred to as break-even price, is the constant dollar price needed to recover all capital expenditures, operating costs, royalties and taxes, and earn a realistic return on investment. For this study, supply costs are calculated in constant 2018 dollars. CERI has used imperial units of measurement for production volumes and reserves. Oil supply costs and prices are stated in imperial units, either in Canadian dollars per barrel (C$/bbl) or US dollars per barrel (US$/bbl).

CERI's model solves for a break-even oil price – that is, the oil price that gives a net present value (NPV) of zero – with a real discount rate of 10 percent. The model also has the flexibility to vary inputs, thus allowing for estimation of the supply cost by extraction method required to bring forth new oil sands projects.

Supply costs have been calculated for the raw bitumen at the source field location. To place these values in a market context, supply costs have been calculated in terms of equivalent prices for marketable crude oil (e.g., blended bitumen) at key Alberta market centers (i.e., Hardisty and Edmonton), and in terms of the corresponding equivalent market price of West Texas Intermediate (WTI) crude oil at Cushing, Oklahoma. This required that CERI make a number of assumptions about market pricing relationships – described later in this chapter.

Although each project is different in its geographical location, quality of reserves and financial structure, this analysis that relies heavily on capital and operating cost estimates is prepared for a more generic project. Here, CERI evaluates a typical stand-alone greenfield steam-assisted gravity drainage (SAGD) project, and an expansion of an existing SAGD project, or in other words, a new production phase of an existing project, reflecting the changes in the oil sands industry.

While significant production comes from integrated mining projects, no new mining projects are under construction; hence the supply cost analysis does not extend to a mining project. The majority of new proposed and announced in-situ projects will use SAGD technology and/or a variation of it, like a hybrid steam/solvent technology. More innovative in-situ technologies were evaluated in CERI's report addressing costs and environmental performances of new processes and technologies.[1]

[1] CERI Study 164. "Economic Potentials and Efficiencies of Oil Sands Operations: Processes and Technologies". April 2017.

Project Design and Economic Assumptions

The assumptions that underpin each project are presented in Table 2.1. The data for capital and operating costs are collected from the CanOils database, as well as public sources, such as company annual reports, investor presentations, company announcements, etc., and is averaged across projects according to the extraction method. These costs reflect today's economy and are representative of costs for typical greenfield investment; they do not reflect opportunities for reduced supply costs that are available to industry. Oil sands operations are assumed to commence construction on January 1, 2019 and begin operating on January 1, 2021. The projects will continue to operate until the end of the 2050 year, based on 30-year project life.

The project design parameters for two hypothetical projects are shown in Table 2.1 with a SAGD project being a typical stand-alone greenfield SAGD project with a production flow rate of 30,000 BPD. The SAGD expansion is defined as an expansion of an existing SAGD project, or in other words, a new production phase of an existing project, reflecting the changes in the oil sands industry – moving away from mega-scale projects such as open-pit mines to in-situ expansion and new projects that are more manageable in size and cost. The production capacity for the expansion SAGD is assumed to be the same as for a greenfield SAGD project. It can be argued that the capacity of a phased SAGD project should be closer to 10,000 BPD given the current volatile market prices and limited egress out of Western Canada, however, CERI evaluates the same production capacities for both examples.

The energy requirements have been estimated according to the design parameters and reflect today's use of natural gas and electricity feedstock. The natural gas required for a SAGD plant is 35,910 GJ/d (~2.8 steam to oil ratio or SOR). Currently, the SOR among SAGD operators varies between 1.5 to 7 barrels of steam per barrel of bitumen, with a bulk of projects operating in the SOR range of 2.5-3 bbl/bbl. It is assumed that in-situ projects do not generate any excess electricity and that in-situ projects purchase electricity from the provincial grid.[2]

[2] In-situ with co-generation capability is not evaluated.

Table 2.1: Design Assumptions

	Measurement Units	SAGD	SAGD Expansion
Project Design Parameters			
Stream day capacity	bbl of bitumen per day	30,000	30,000
Production Life	years	30	30
Capacity Factor (Annual Average)	%	90%	90%
Capital Expenditures (2018 CAD Dollars)			
Initial	Millions of dollars	$1,140.0	$600.0
	Dollars per bbl of capacity	$38,000.0	$20,000.0
Sustaining (Annual Average)	Millions of dollars/year	$43.8	$21.9
Operating Working Capital	Days payment	45	45
Operating Costs (2018 CAD Dollars)			
Total Operating Costs	Millions of dollars/year	$92.0	$92.0
Non-Energy Operating Costs	Millions of dollars/year	$64.4	$64.4
Energy Requirements			
Natural Gas	GJ per day	35,910	35,910
Electricity Purchased	MWh/d	300	300
Electricity Sold	MWh/d	0	0
Other Project Assumptions			
Abandonment and Reclamation	percent of total capital	2%	2%

Source: CanOils, CERI

The capital cost estimates used in the supply cost calculations are estimates for the projects that are or will be under construction during the 2019-2022 timeframe. The capital requirements range from a SAGD expansion phase estimate of $17,000/b/d to a new-build of $65,000/b/d of flowing capacity. In this context, two estimates were taken for supply costs calculations – a greenfield project with $38,000/b/d of flowing capacity and an expansion phase with $20,000/b/d of flowing capacity.

The sustaining capital costs reflect sustaining capital requirements that are consistent with the industry estimates: sustaining capital costs are $4.00/bbl of capacity for a greenfield SAGD project and $2/bbl of capacity for an expansion phase. The lower sustaining capital estimate for an expansion SAGD captures economies of scale and efficiency gains.

The operating cost estimates for supply cost calculations are 2018 costs of existing in-situ projects and are assumed to represent operating costs for new projects going forward. The total operating costs and non-energy portion of costs are shown in Table 2.1. The non-energy related portion is about 70 percent of total operating costs.

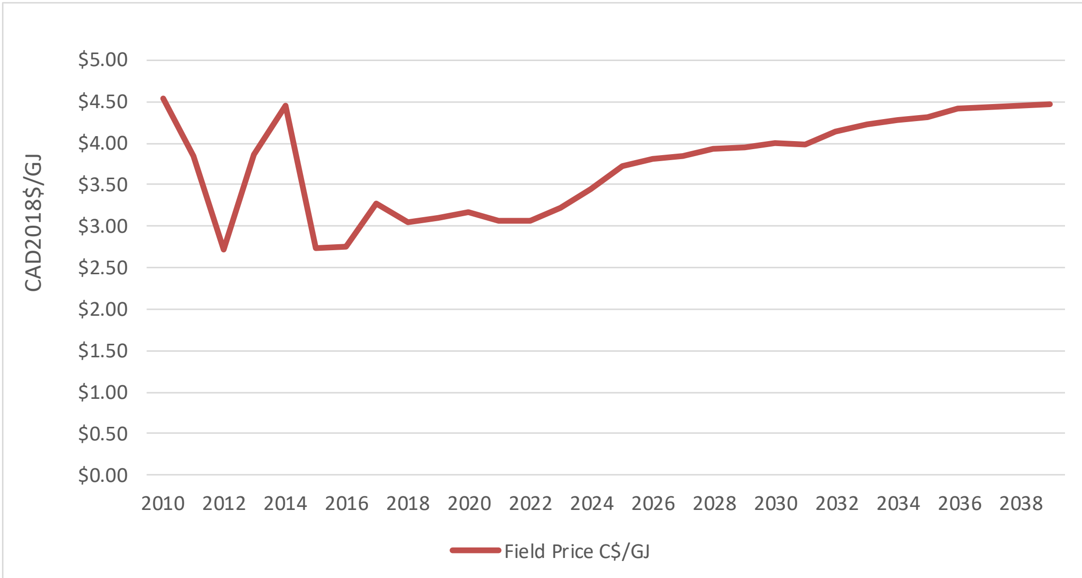
Commodity Prices

Oil sands projects are very energy-intensive, consuming large quantities of natural gas, electricity, diesel and chemicals, which are often purchased on the market and hence the energy-related portion of operating costs is very dependent on the prices of natural gas, electricity and other products used as an energy feedstock. To approximate the energy-related portion of operating costs for an in-situ producer, natural gas and electricity prices are used together with their consumption.

While research continues on finding ways to use less natural gas, it is still the primary fuel source for the oil sands industry. Hence, the cost of gas is important and has become a significant component of the total supply cost framework. To approximate the cost of natural gas purchases, a forecast of Henry Hub natural gas prices was obtained from the US EIA's Annual Energy Outlook (AEO) 2019 for the period 2016 to 2050. Prices were then transformed to 2018 dollars and converted to AECO-C basis gas prices to better reflect the actual cost paid by producers for natural gas. CERI used an AECO-C/Henry Hub differential of US$0.75/MMBTU, and a field premium of C$0.27/GJ. In reality, in-situ producers would utilize the associated natural gas that is produced (not all in-situ projects have an associated gas production), and might not be purchasing the full volume that is required, and hence the overall cost for natural gas might be lower. For supply cost purposes, however, it is assumed that producers purchase natural gas from the market.

Figure 2.1 displays field prices paid by oil sands producers. Since 2010, natural gas prices have been fluctuating between $2.50 and $4.50/GJ. Since 2014, with the oil price decline, gas prices followed suit. Over the medium term, prices are estimated to be around the $3.00-$3.50/GJ mark in real 2018 dollars, growing at 2 percent between 2019 and 2039 to reach $4.50/GJ by the end of the forecast period.

Figure 2.1: Natural Gas Price Forecast (2018C$/GJ)



Source: EIA, CERI

Another significant input to oil sands operations is electricity. Prices play a key role in determining the cost of electricity as feedstock to oil sands projects. The 2018 Alberta average hourly pool price, that was sourced from the Alberta Electric System Operator (AESO) was $50.39/MWh,[3] more than double the 2017 annual average of $22.63/MWh. The unusually low electricity price in the province was experienced due to low natural gas prices in Alberta. Natural gas prices are still low, however, the price of electricity increased. It is further expected that, in the future, electricity rates will be higher if the province transitions to a cleaner grid by retiring its coal power plants and adding 30 percent or more of renewable generation options as directed by the previous Alberta Climate Leadership Plan.[4] The main challenge for Alberta's electricity sector is ensuring sufficient reliable capacity is available to satisfy the electricity demand upon the retirement of coal-fired generating units by 2030.[5]

To estimate the cost of electricity for supply cost calculations, the 2018 Alberta average hourly pool price (C$/MWh) was used and inflated at an annual inflation rate (i.e., in real terms, price is forecast to remain flat). This forecast is not reflective of Alberta pool prices and considers the possibility of increased use of cogeneration for in-situ projects, which would lower the overall energy-related portion of the operating costs. Over the next decade, it is probable that in-situ projects will move towards cogeneration, with units sized to match a projects' steam and electricity load or potentially even sell the excess electricity to the provincial grid.

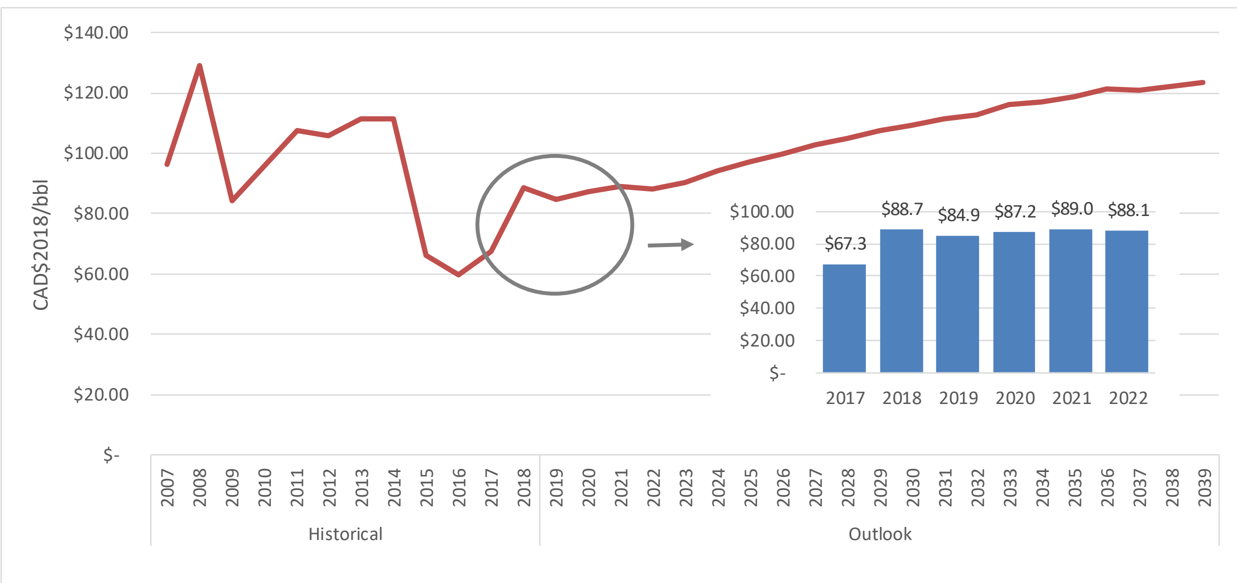
[3] Alberta Electric System Operator 2018 Annual Market Statistics, March 2019. https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/
[4] With the newly elected provincial government this may change. At the time of writing, there was no indication as to what the new plan will look like when it comes to coal facilities and renewable energy integration.
[5] CERI Study 168. "A Comprehensive Guide to Electricity Generation Options in Canada". February 2018.

Oil Prices

Turning to oil price projection, a distinct set of drivers will determine futures prices in the medium and long terms. Short- to medium-term prices are primarily dependent on expectations of supply and demand balances (measured by the global stock changes). They are also impacted by other factors such as geopolitics, speculation and overall market sentiment. Contrary to this, in the long-term, prices are mostly driven by the cost factors of producing a marginal barrel. In this case, a rising marginal barrel cost is expected as a result of increasingly complex supply developments, such as oil sands projects, tight oil plays in more complex geological structures, deep-water and potentially Arctic fields. On the other hand, the drive for more efficiencies and innovative technology will partially limit the rise in exploration and production (E&P) costs.

To better understand this year's supply cost results, an oil price projection was required. The forecast of the WTI price was obtained from the EIA's AEO 2019, for the period 2016 to 2050. Prices were adjusted to constant 2018 dollars and converted to Canadian dollars as shown in Figure 2.2. Prices in the near term (inset graph in Figure 2.2) will average C$84/bbl. Over the forecast period of 2019 to 2039, real prices will grow at 2.5 percent, reaching almost C$120/bbl.

Figure 2.2: WTI Price Forecast (CDN$2018/bbl)



Source: EIA, CERI

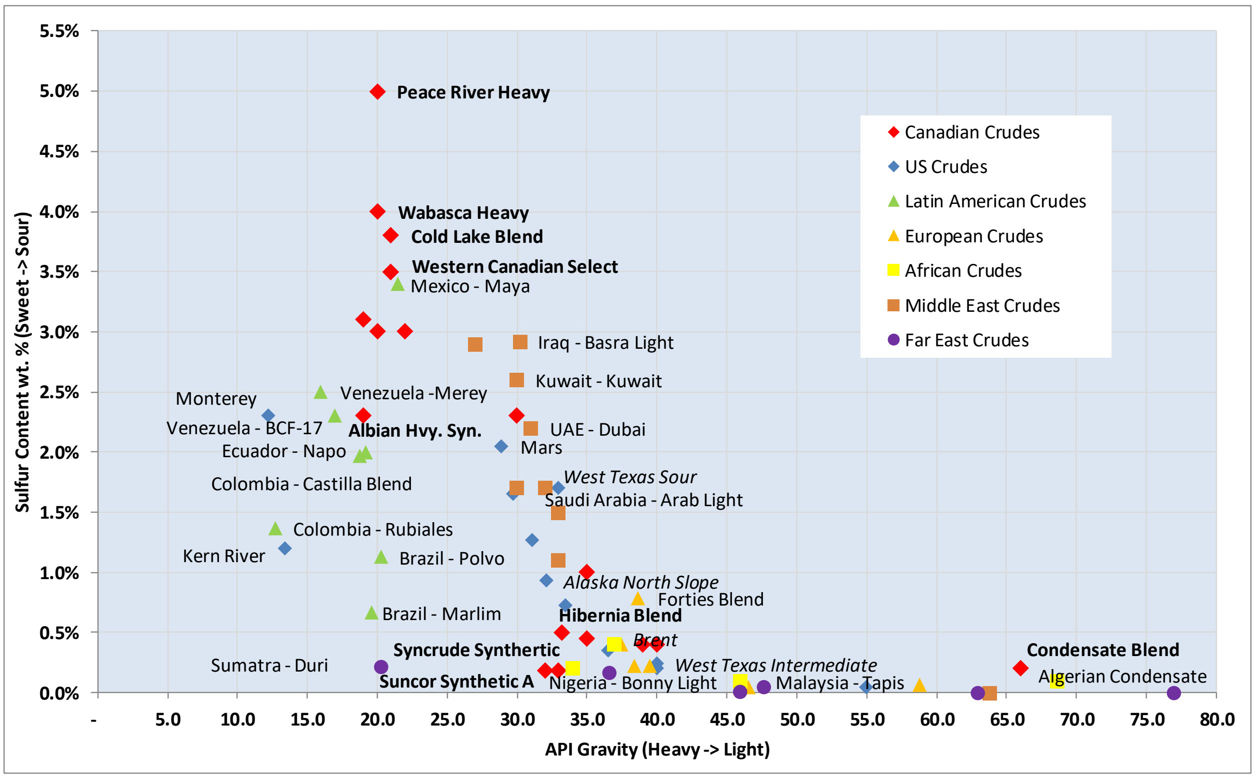
Light-Heavy Differential

To place oil sands supply costs of a barrel of bitumen in a market context, they have been calculated in terms of equivalent prices for marketable crude oil (e.g., blended) at key Alberta market centers (i.e., Hardisty and Edmonton), and in terms of the corresponding equivalent market price of WTI crude oil at Cushing, Oklahoma. This required CERI to make a number of assumptions about market pricing relationships. Of particular importance is the light-heavy differential, specifically the differential between light WTI and heavy WCS.

All crude oil is not created or valued equally. A light oil that is low in sulphur content (i.e., sweet) is more valuable to refiners than heavy oil with higher sulphur content (i.e., sour) because it is less energy-intensive to refine light sweet crude, and the resulting petroleum products are of higher quality. Thus, refining of heavy sour grades requires more complex refining operations. The market value of each crude stream, therefore, reflects the crude characteristics as well as the yield of the refined product from such crude. The price difference between a barrel of light sweet oil and a barrel of heavy sour oil represents the light-heavy or quality price differential.

Two of the most important physical crude qualities are density (as measured by API gravity) and sulphur content. Figure 2.3 illustrates those characteristics for various crudes from around the world (including various pricing benchmarks) and places Canadian crudes in the context of crude oil quality. It becomes very clear that bitumen-derived crudes measure high in sulphur content and low on gravity as compared to some other crudes.

Figure 2.3: Densities and Sulphur Content of Crude Oils



Source: BP, EIA, Genesis Capital, Oil & Gas Journal, Pemex, Statoil

Almost all of the Canadian crude oil exports are transported to refineries in Canada and the US with the largest share originating in Alberta. The two main distribution hubs in Alberta are located near Edmonton and Hardisty – the price point for WCS as a heavy crude benchmark. Launched in 2004 by Encana Corporation (now Cenovus Energy), Canadian Natural Resources Limited, Talisman, and Petro-Canada (now Suncor), the WCS is a blend of conventional Western Canadian heavy oil and crude bitumen that has been blended with sweet SCO and diluents.[6]

WCS crude is sold at a discount to WTI because it is a lower quality crude, producing a positive light-heavy differential. The differential between WTI and WCS has fluctuated from a low of just under US$6/bbl in April 2009 to a high of US$46/bbl as recently as November 2018, with an average annual differential for 2018 at about US$26/bbl. In the first three months of 2019, it shrank to US$12.21/bbl.

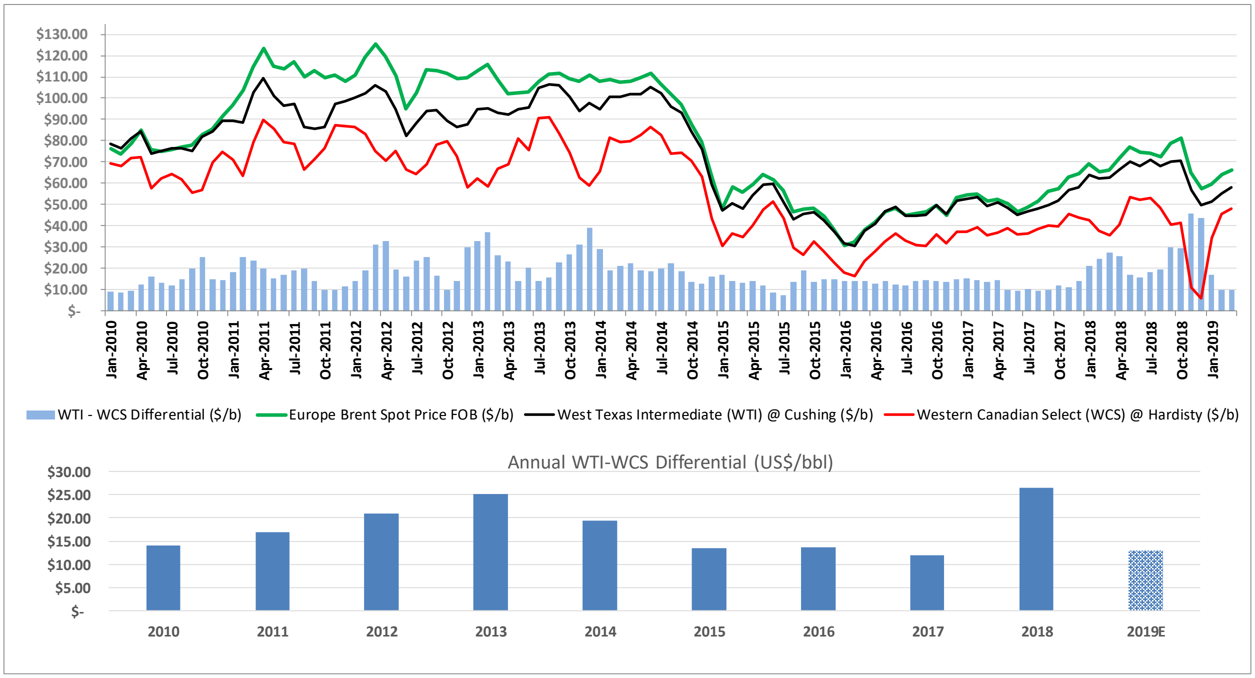
While the WTI-WCS differential has been much discussed and pondered upon by media, industry and government, empirical evidence shows that the differential fluctuates over time, that is, it narrows and widens based on market conditions. While this fluctuation is hard to estimate in the long-term, the data support an assumption of a long-term average WTI-WCS differential of US$13/bbl. Therefore, based on the historical data, the light-heavy differential (including transportation costs) is assumed to be constant at US$13/bbl. Over time, as more blended bitumen and SCO continue to penetrate existing as well as new markets such as the US Gulf Coast and markets outside of North America, the light-heavy differential might narrow in the future to just quality-based. On the other hand, the differential may widen with the upcoming International Maritime Organization (IMO) regulation of reducing sulphur content in marine bunker fuel from the existing 3.5 percent to 0.5 percent starting in January 2020.

The data series for WCS prices comes from the Baytex Energy website,[7] while Brent and WTI prices are sourced from the US EIA from January 2010 to April 2019. Figure 2.4 illustrates the selected historical benchmark price series and WTI-WCS differential.

[6] While WCS or dilbit is a blend of bitumen, conventional and synthetic crudes, its main crude quality parameters (both API gravity and sulphur content) are very similar to those of other western Canadian conventional heavy sour blends such as Lloyd Blend, Bow River, and other heavy sour conventional blends produced in Alberta and Saskatchewan. Cold Lake Blend is another dilbit blend that trades in large volumes. Other dilbits include Access Western Blend, Borealis Heavy Blend, Christina Dilbit Blend, Peace River Heavy, Seal Heavy, Statoil Cheecham Blend, and Wabasca Heavy (see: http://crudemonitor.ca/home.php)

[7] http://www.baytexenergy.com/operations/marketing/benchmark-heavy-oil-prices.cfm

Figure 2.4: Light-Heavy Differential (US$/bbl)



Source: EIA, Baytex Energy, CERI

Crude Oil Transportation Costs

The supply cost is calculated for raw crude bitumen produced in the field. This bitumen supply cost is converted to prices of marketable blended bitumen at key Alberta market centres (Edmonton and Hardisty), and to an equivalent market price of WTI crude oil at Cushing, Oklahoma. For non-integrated projects, blending costs are estimated through accounting for the volume of diluent required per barrel to bring the bitumen blend to a density that meets pipeline specifications, the cost of diluent, and the cost of transporting diluent to the field. Based on recent industry data, a 5 percent premium for a diluent cost above WTI price has been removed, given the increased supply of condensate from domestic sources and pipeline imports from the US. Transporting the blend from the field to Hardisty is assumed to be C$1.00 per barrel. Transportation costs from Hardisty to Cushing have been adjusted upward to US$5.35 per barrel.[8] Per barrel transportation costs from the field to Hardisty, and Edmonton to Cushing, Oklahoma, are assumed to rise at an annual inflation rate of 2.0 percent.

Rate of Return

The supply cost estimates presented in this study have been calculated using cash flow models similar to those used by industry and governments. The costs have been calculated using an annual discount rate of 10 percent (real). This is equivalent to an annual return on investment of 12.0 percent (nominal) based on the assumed average inflation rate of 2.0 percent per annum.

[8] CAPP, “Crude Oil Forecast, Markets & Transportation”, June 2018.

Companies may evaluate individual investments using higher discount rates; these would translate to higher supply costs than those presented here.

Within the supply cost model, federal and provincial corporate income taxes have been assumed constant at 15 percent and 12 percent,[9] respectively.

Capital Depreciation

Currently, most machinery, equipment and structures used to produce income from an oil sands project, including buildings and community infrastructure related to worker accommodations, are eligible for a capital cost allowance (CCA) rate of 25 percent under the Class 41 of Schedule II to the Income Tax Regulations.[10] In addition, the Government of Canada in late 2018 proposed an Accelerated Investment Incentive, which provides an enhanced first-year allowance for certain eligible property that is subject to the Capital Cost Allowance (CCA) rules.[11]

You must acquire the eligible property after November 20, 2018, and it must be available for use before 2028 in order to qualify for the incentive or the full expensing measure. A phase-out will begin for property that becomes available for use after 2023.

The Accelerated Investment Incentive will generally apply to additional allowances permitted under the Income Tax Regulations such as an enhanced first-year allowance in respect of Canadian development expense and Canadian oil and gas property expense. An enhanced deduction will generally apply to eligible Canadian development expenses (CDE) or Canadian oil and gas property expenses (COGPE) incurred after November 20, 2018, and before 2028. These expenses are not subject to a half-year rule and, thus, will qualify for a first-year deduction equal to one-and-a-half times the deduction that would otherwise be available.

This accelerated CCA provides a financial benefit by effectively deferring taxation until the cost of capital assets has been recovered from project earnings. This incentive helps to offset some of the risk associated with early investments in the oil sands and contributed to the development of this resource.

Carbon Tax

With a new provincial government elected in spring 2019, a new climate change regime is likely to occur eliminating the Climate Change Leadership plan implemented by the previous

[9] At the time of writing, the new provincial government has not changed the provincial corporate rate as indicated during the election platform.
[10] Property acquired by a taxpayer for the purpose of gaining or producing income from a bituminous oil sands project in Canada will generally be included in Class 41. http://www.cra-arc.gc.ca/E/pub/tp/it476r/it476r-e.html#Bituminoussandsprojects. Accessed on February 28, 2012.
[11] Government of Canada. Accelerated Investment Incentive. https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/accelerated-investment-incentive.html#CDECOPGE

government. The plan was a strategy to reduce emissions while diversifying the provincial economy. Several key aspects included:

- implementing an economy-wide carbon price on greenhouse gas emissions;
- retiring coal-generated electricity by 2030;
- developing more renewable energy;
- capping oil sands emissions to 100 megatonnes per year
- reducing methane emissions by 45 percent by 2025.

Alberta will implement a \$30/tonne carbon price for oil sands facilities to drive towards reduced emissions. A legislated maximum emissions limit of 100 Mt per year, with provisions for cogeneration and new upgrading capacity, will help drive technological progress. The carbon price started at \$20/tonne of CO2eq. on January 1, 2017, and increased to \$30/tonne on January 1, 2018. Post-2018, the federal carbon tax assumption is adopted.[12] The federal carbon tax will be \$40/tonneCO2eq. in 2021 and increase to \$50/tonne in 2022 and subsequent years.

On January 1, 2018, the Carbon Competitiveness Incentive (CCI) regulation replaced the Specific Gas Emitters Regulation (SGER).[13] Similar to the SGER, the CCI regulation applies to facilities that emitted 100,000 tonnes or more of greenhouse gases in 2003, or a subsequent year. Facilities that emit less than 100,000 tonnes have a choice to opt-in according to guidelines provided in the Regulation document. The policy prescribes product-specific emission performance standards or benchmarks that replace the past uniform intensity-based reduction approach. This replaces the existing intensity targets, which are based on GHG reductions per unit of production regardless of the type of product. Access to flexibility mechanisms (such as the ability to purchase Alberta-based offsets or pay into the existing technology fund in lieu of reducing operational emissions) is expected to continue to be a compliance option for large emitters.

Since there is no new policy at the time of this report, CERI's supply cost model incorporates the established benchmarks for oil sands production. While there are options that a producer can exercise to comply with the policy, the model assumes that a producer pays carbon tax on emissions above the established benchmarks. The benchmarks are shown in Table 2.2.

[12] Federal Government. https://www.canada.ca/en/services/environment/weather/climatechange/technical-paper-federal-carbon-pricing-backstop.html
[13] For more information on the Regulation: https://www.alberta.ca/carbon-competitiveness-incentive-regulation.aspx.

Table 2.2: Established Benchmarks for Oil Sands Production

	In Situ Bitumen		Mining Bitumen	
Unit	tonnesCO2eq./m3	kgCO2eq./bbl	tonnesCO2eq./m3	kgCO2eq./bbl
2018	0.3504	55.7075	0.1954	31.0652
2019	0.3504	55.7075	0.1954	31.0652
2020	0.3469	55.1510	0.1934	30.7472
2021	0.3434	54.5946	0.1914	30.4293
2022	0.3399	54.0382	0.1894	30.1113
2023+	BE=BEY-1 - 0.0035	BE=BEY-1 - 0.5564	BE=BEY-1 - 0.0020	BE=BEY-1 - 0.3180

Note: The values in the rows for 2020, 2021 and 2022 reflect the application of an annual 1% tightening rate. BE is an established benchmark for the year. BE_{Y-1} is an established benchmark for the previous year.

Source: Alberta Government. "Carbon Competitiveness Incentive Regulation". CERI converted the unit from tonnes CO2eq./m3 of bitumen to kgCO2eq./bbl of bitumen.

The benchmarks are based on existing best performers' emission profiles, i.e., benchmarks equal the lowest facility production-weighted emission intensity in the sector. For example, the established benchmark for in-situ bitumen of 0.3504 tonnes CO2eq./m3 (or 55.71 kgCO2eq./bbl) of bitumen for the 2018-2019 period translates to a project with a SOR of approximately 2-2.3.

Royalty Assumptions

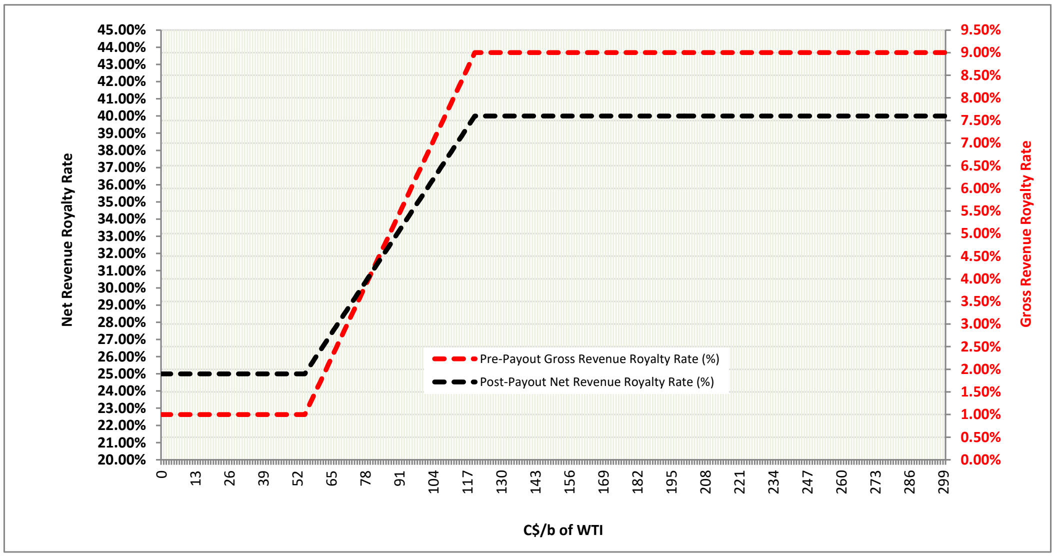
The Alberta oil sands royalty regime is based on the net revenue system whereby the oil sands producer pays a lower royalty rate based on gross revenues until the point at which the producer has recovered all the allowed project costs (those incurred up to five years prior to the approved effective date) plus a return allowance based on current Long-Term Government Bond Rates (LTBR) issued by the Government of Canada (floor risk).[14] After payout has been achieved, the project proponent pays the higher of gross revenue royalties based on a gross revenue royalty rate or net revenue royalties based on a higher net revenue royalty rate. Prior to 2009, the rates were fixed at 1 percent of gross revenues (pre-payout) and 25 percent of net revenues (post-payout). After 2009, royalty rates are calculated based on the Canadian dollar price of a barrel of WTI and are fixed at a floor of 1 percent (gross) and 25 percent (net) when the price is below C$55/bbl, increasing linearly to a ceiling of 9 percent (gross) and 40 percent (net) when the price of WTI is above C$120/bbl as shown in Figure 2.5.

The gross revenue of the project is defined as the revenue collected from the sale of oil sands products (or the equivalent fair market value) less the costs of any diluents contained in any blended bitumen sold. Allowed costs are those incurred by the project operator to carry out operations, and to recover, obtain, process, transport, or market oil sands products recovered,

[14] Assumed to be 2.4 percent.

as well as the costs of compliance with environmental regulations and with the termination of a project, abandonment and reclamation of a project site.[15]

Figure 2.5: Alberta Bitumen Royalty Rates



Source: CERI

US-Canada Exchange Rate

Since the summer of 2014, the price of oil has plummeted to its lowest point in years – and so has the Canadian dollar, continuing an ongoing debate on how closely the two are related. Canada's dollar is often viewed as a petrocurrency because its movements often track oil prices (see Figure 2.6). In simple terms, a petrocurrency is a currency of an oil-producing country — such as Canada — whose oil exports as a share of total exports are sufficiently large enough that the currency's value rises and falls along with the price of oil. In other words, a petrocurrency appreciates when oil prices rise and depreciates when oil prices fall.

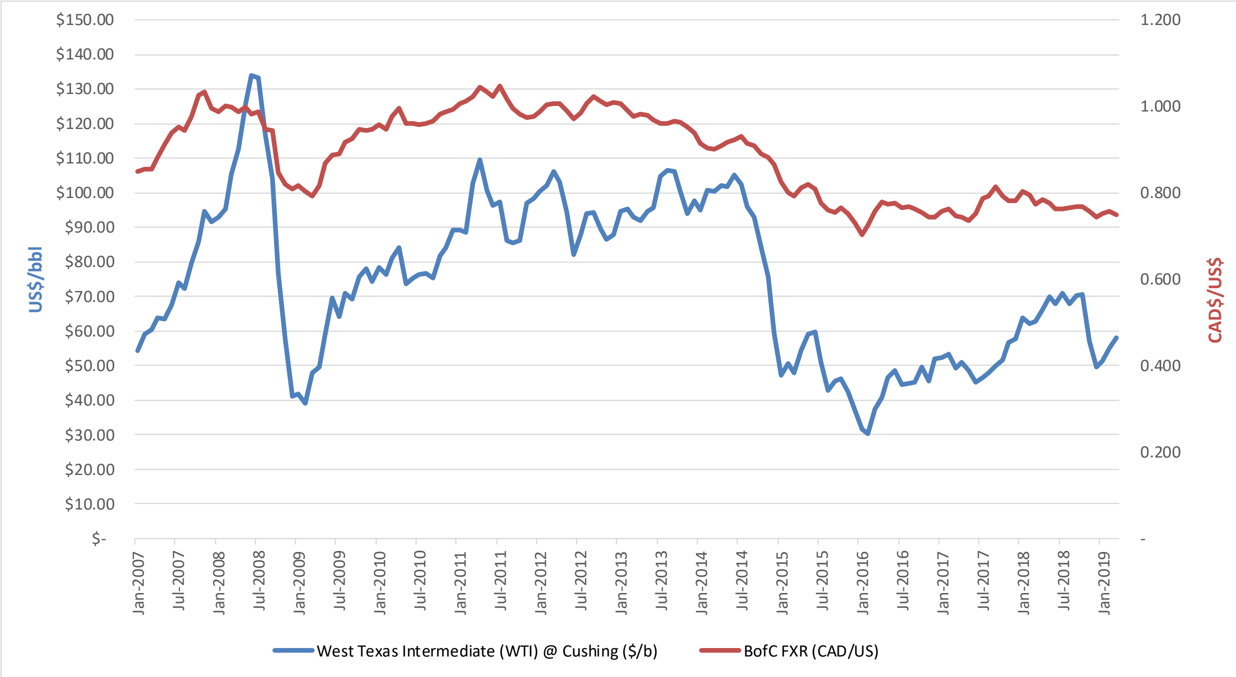
The most recent 50 percent decline in oil prices in summer 2014 coincides with the depreciation of the Canadian dollar. Given the oil price forecast and high correlation factor between the exchange rate and oil prices,[16,17] an exchange rate of US/CDN$0.80 will be assumed in the supply cost calculation. This represents a 20 percent drop from previous assumptions of parity between the two currencies.

[15] Government of Alberta, 2012. Service Alberta, Queen's Printer, Laws Online/Catalogue, Legislation, Mines and Minerals Act, Oil Sands Royalty Regulation, 2009 (http://www.qp.alberta.ca/574.cfm?page=2008_223.cfm&leg_type=Regs&isbncln=9780779732272), accessed on January 26, 2012.

[16] http://news.ubc.ca/2015/04/16/is-the-canadian-dollar-a-petrocurrency/

[17] http://www.bankofcanada.ca/wp-content/uploads/2012/02/workshop-exchange-rates-june2011-Ferraro-Rogoff-Rossi-presentation.pdf

Figure 2.6: CDN/US Exchange Rate



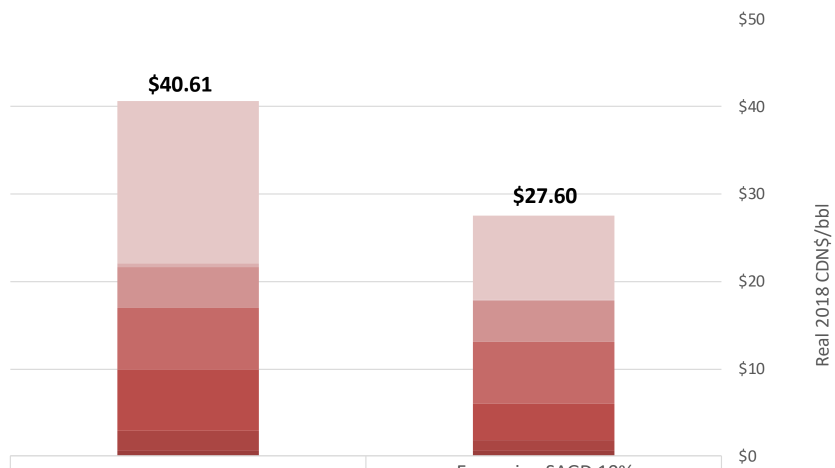
Source: EIA, Bank of Canada

Supply Cost Results

Based on these assumptions, the supply costs of crude bitumen for a greenfield SAGD and an expansion phase SAGD have been calculated. Figure 2.7 illustrates the supply costs for these projects. The plant gate supply costs, which exclude transportation and blending costs, are C$40.61/bbl for a SAGD project and C$27.60/bbl for an expansion phase of SAGD. A comparison[18] of field gate costs from the 2018 update with this year's supply costs indicates that, after adjusting for inflation, the supply cost for a greenfield SAGD producer has decreased by 11 percent, and by 6 percent for an expansion SAGD.

[18] Direct cost comparison is not recommended and only shown to illustrate the direction of change. Because some changes were made in the project assumptions regarding carbon policy as well as project economics, a direct comparison of costs is not favoured.

Figure 2.7: Total Field Gate Bitumen Supply Costs



	SAGD 10% ROR (a)	Expansion SAGD 10% ROR (a)
Fixed Capital (Initial & Sustaining)	$18.59	$9.67
Operating Working Capital	$0.38	$0.20
Fuel (Natural Gas)	$4.63	$4.63
Other Operating Costs (incl. Elec.)	$7.07	$7.07
Royalties	$7.04	$4.18
Income Taxes	$2.21	$1.17
Emissions Compliance Costs	$0.67	$0.67
Abandonment Costs	$0.03	$0.01

[a]Return on capital included.

Source: CERI

After adjusting for blending and transportation, the WTI equivalent supply costs at Cushing are US$52.84/bbl and US$45.88/bbl for a greenfield and expansion SAGD, respectively. A summary of costs is presented in Table 2.3. At current WTI prices of around US$60/bbl,[19] these projects are decidedly economic. The relative position of oil sands projects against other crude oils is comparatively competitive, and as oil prices are expected to increase, so will the profitability of oil sands projects. There are risk factors that might affect project economics, such as market access, exchange rate, future oil prices, project costs, etc. Some of these impacts were evaluated through a sensitivity analysis in the next section.

[19] At the time of writing, WTI prices traded at US$60.83/bbl

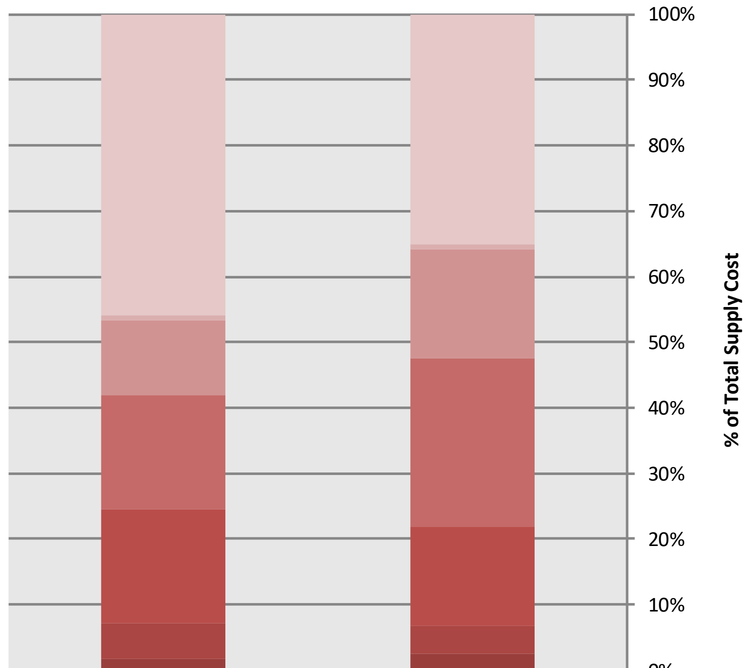
Table 2.3: Supply Costs Summary

Supply Cost	SAGD 10% ROR (a)	Expansion SAGD 10% ROR (a)
Net Present Value (C$ Millions)	$0	$0
Discount Rate	10%	10%
Base Year	2017	2017
	Discounted	Discounted
Costs (C$/b)		
Return on Investment	Included	Included
Fixed Capital (Initial & Sustaining)	$18.59	$9.67
Operating Working Capital	$0.38	$0.20
Fuel (Natural Gas)	$4.63	$4.63
Other Operating Costs (incl. Elec.)	$7.07	$7.07
Abandonment Costs	$0.03	$0.01
Royalties	$7.04	$4.18
Income Taxes	$2.21	$1.17
Emissions Compliance Costs	$0.67	$0.67
Subtotal	$40.61	$27.60
Electricity Sales	0.0	0.0
Subtotal	0.0	0.0
Total Supply Cost (C$/b)	**$40.61**	**$27.60**
Blend Product @ Hardisty in C$/b	$49.36	$40.66
Blend Product @ Hardisty in US$/b	$39.49	$32.53
Blend Product's WTI Equivalent @ Edmonton in US$/b	$47.49	$40.53
WTI Equivalent (US$/b)	**$52.84**	**$45.88**

Source: CERI

The resulting impact on the overall cost of an oil sands project broken down by percentage share is shown in Figure 2.8. While capital costs and the return on investment account for a substantial portion of the total supply cost, the province stands to gain $4.18 to $7.04 in royalty revenues for each barrel of oil produced on average, over the life of an oil sands project. On a percentage basis, these range from a 15.1 to 17.3 percent share of total supply cost (see Figure 2.8).

Figure 2.8: Oil Sands Supply Costs – % Contribution



	SAGD 10% ROR (a)	Expansion SAGD 10% ROR (a)
Fixed Capital (Initial & Sustaining)	45.8%	35.0%
Operating Working Capital	0.9%	0.7%
Fuel (Natural Gas)	11.4%	16.8%
Other Operating Costs (incl. Elec.)	17.4%	25.6%
Royalties	17.3%	15.1%
Income Taxes	5.4%	4.2%
Emissions Compliance Costs	1.6%	2.4%
Abandonment Costs	0.1%	0.1%

Source: CERI

Supply Cost Sensitivities

The presented costs for oil sands projects also need to be analyzed in terms of how sensitive costs are to changes to some of the input variables. The ranges used for sensitivities are summarized in Table 2.4.

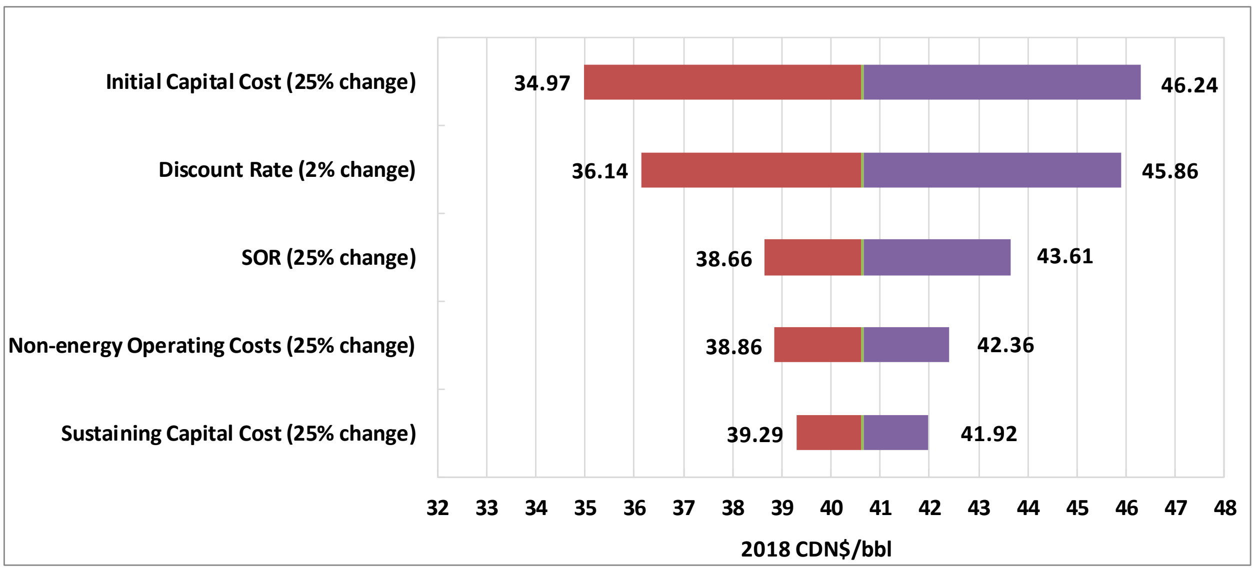
Table 2.4: Assumptions for Sensitivity Analysis

Parameter	Sensitivity
Initial Capital Cost	+/-25%
Sustaining Capital Cost	+/-25%
Non-Energy Operating Costs	+/-25%
Discount Rate	+/-2%
SOR	+/-25%

Source: CERI

Bitumen supply cost sensitivities for a greenfield SAGD and an expansion phase SAGD are represented graphically in Figures 2.9 and 2.10.

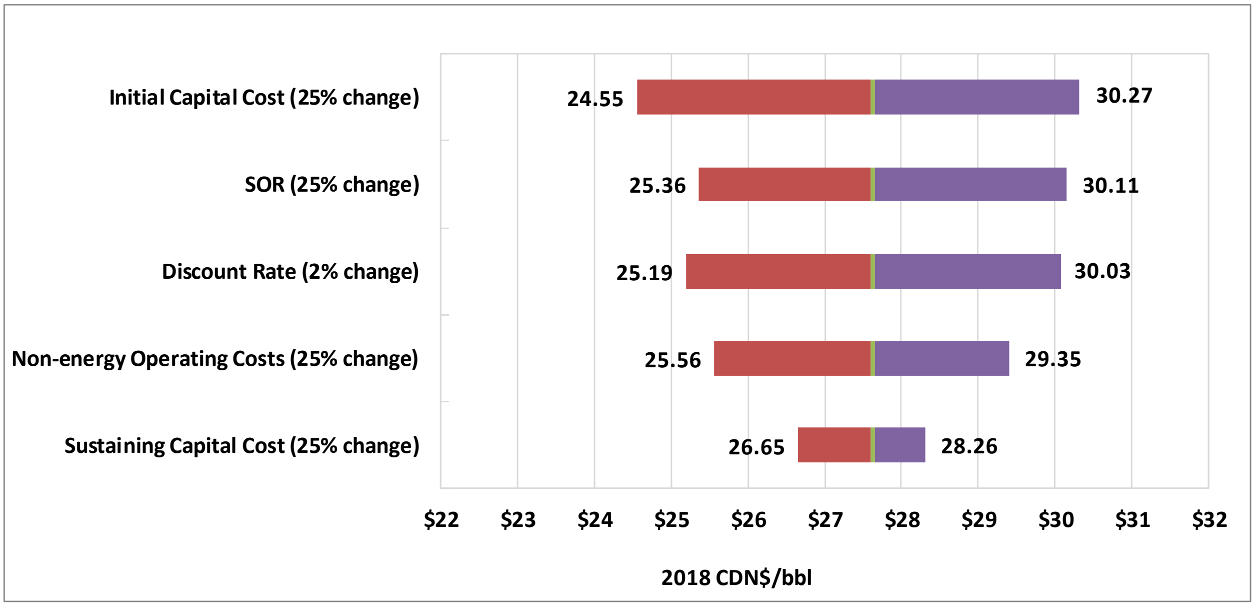
Figure 2.9: Supply Cost Sensitivity – 30 MBPD SAGD Project



Source: CERI

The results indicate that SAGD supply cost is the most sensitive to changes in the initial capital expenditures and the assumed discount rate, SOR is another factor that impacts the supply costs. If initial capital is 25 percent higher than the original estimate, the field gate supply cost rises to $46.24/bbl from $40.61/bbl, in contrast, supply cost decreases to $34.97/bbl if initial capital is 25 percent lower. If the discount rate is raised to 12 percent real, the supply cost is estimated to increase by $5.25/bbl and when it is decreased to 8 percent real, the cost will decrease by $4.47/bbl from its base of $40.61/bbl.

Figure 2.10: Supply Cost Sensitivity – 30 MBPD Expansion SAGD Project



Source: CERI

For an expansion phase SAGD, the supply cost will increase to $30.27/bbl and decrease to $24.55/bbl if the initial capital cost increases or decreases by 25 percent, respectively. The discount rate increase to 12 percent will increase the supply cost by $2.43/bbl and a decrease to 8 percent will result in a $2.41/bbl drop in the base supply cost of $27.60/bbl.

Chapter 3: Oil Sands Production Scenarios

The past mega-large projects like open-pit mines are no longer the trend forward, development of additional phases to existing brownfield facilities cost less than greenfield development and are seen as a way to future growth. Low oil prices have caused companies to announce capital spending cuts, the exchange rate to drop and capital and operating costs to fall. However, an improvement in oil prices in the latter part of this decade indicates that oil sands projects present a profitable long-term investment. This does not imply that every oil sands project will move from concept to reality. Nor does it imply that every oil sands project should go forward. Inevitably, some projects will experience delays for a variety of reasons, including but not limited to those related to financing and transportation and environmental performance.

This chapter presents CERI's three oil sands production scenarios. Together with production projections for bitumen and SCO, this chapter also presents natural gas and diluent requirements, capital investment, operating costs, and emissions. Special focus is given to the **Reference Case Scenario** and discussed in more detail.

Methodology and Assumptions

CERI's methodology for projecting bitumen and SCO production remains unchanged from past reports. Projections are based on the summation of existing and new projects, with a variety of assumptions pertaining to the project schedule and delays, technology, and state of development. The method by which projects are delayed, or the rate at which production comes on-stream, is based upon CERI's long-running observations of oil sands market dynamics and specific characteristics of oil sands projects.

The extraction of oil sands is currently based on two methods: in-situ and mining. In-situ recovery consists of primary recovery, thermal recovery, solvent-based recovery, and hybrid thermal/solvent processes. Surface mining and extraction[1] could be either a stand-alone mine or integrated with an upgrader. Within in-situ and mining methods, various technologies to extract valuable bitumen from the oil sands are utilized.[2] Future research and development (R&D) will focus on increasing recoverable reserves, reducing costs, improving product quality and enhancing environmental performance. Industry, government and community stakeholders will continue to carry out R&D as long as there is a perceived commercial incentive to do so. For more information on what technologies and processes are being developed, refer to CERI Study 164.[3]

[1]Within mining and extraction, various technologies are used to support the extraction process and transportation of oil sands. While each technology has some advantages and disadvantages, they have all been categorized as mining and extraction for this report and are treated as one technology type.

[2]The reader is assumed to have some familiarity with each extraction method. Detailed descriptions of the extraction technologies are available from CERI Studies 122 and 126.

[3] CERI Study 164. "Economic Potentials and Efficiencies of Oil Sands Operations: Processes and Technologies". April 2017.

The three scenarios are the **Reference Case**, **High Case**, and **Low Case**. The **Reference Case** incorporates existing and future oil sands project developments subject to two constraints: project startup delays and capacity curtailments.

Delay Assumptions

Onstream projects are assumed to be producing bitumen until the end of the project (unless new phases were added); projects that are under construction will proceed with minimal delays and reach their nameplate capacity. Projects further along the regulatory process are given shorter delays and have higher probabilities of proceeding to their announced production capacity. Given the current economic downturn, projects that have been announced, but have not yet entered the regulatory process with a disclosure document are given the longest delays. Table 3.1 presents these factors according to project status.

Table 3.1: Project Delay Factors

	High Case		Reference Case		Low Case	
Project Status	**Capacity Fraction**	**Delay Years**	**Capacity Fraction**	**Delay Years**	**Capacity Fraction**	**Delay Years**
Onstream	1.00	0	1.00	0	1.00	0
Under Construction	1.00	0	1.00	0	0.80	2
Approved	0.90	0	0.65	0	0.50	6
Awaiting Approval	0.80	4	0.65	6	0.45	8
Announced	0.75	5	0.50	7	0.35	10
Suspended	1.00	0	0.00	0	0.00	0
Prospect	0.00	0	0.00	0	0.00	0
Cancelled	0.00	0	0.00	0	0.00	0
Concluded	0.00	0	0.00	0	0.00	0

Delays and probabilities, as measured by a probability fraction, for each phase of the regulatory approval process, are based upon reasonable estimates of the length of time each phase could take. As compared to delay years and capacity curtailments of last year's update, this year sees an increase in the number of delay years for some categories and a decrease in probabilities of reaching full capacity. Another factor that is contributing to this increase in delays and capacity curtailments is that existing export pipeline capacity is not sufficient to transport the incremental volumes of future produced bitumen and SCO and has an impact on the project announcements and construction. Although the federal government had approved the expansion of the Trans Mountain pipeline[4] and Line 3 refurbishment and expansion, both projects are facing rising

[4] John Paul Tasker. "Trudeau cabinet approves Trans Mountain expansion project". https://www.cbc.ca/news/politics/tasker-trans-mountain-trudeau-cabinet-decision-1.5180269. Accessed on June 18, 2019.

opposition and hence incremental growth in oil sands production post-2018 will face market access challenges, unless there is a significant increase in rail transport, additional export pipeline capacity or a reduction in the amount of diluent used to transport non-upgraded bitumen.

Oil Sands Production – Three Scenarios

The projection of crude bitumen and SCO production is dependent on information provided by oil sands producers. This includes data on production capacity provided to the Alberta regulator, in addition to other publicly available documents, such as annual reports, investor presentations and press releases as well as CanOils database. The projections include production from existing projects as well as new projects that are under construction, approved, awaiting approval, and announced.[5] This year, the projection period is from 2019 to 2039, inclusive.

Figure 3.1 illustrates the possible paths for production under the three scenarios. For an oil sands producer, a project's viability relies on many factors, such as but not limited to the demand-supply relationship between production, operating and transportation costs (supply side) and the market price for blended bitumen and SCO (demand). Oil prices, market access, construction and regulatory delays, availability of suitable and accessible refinery capacity, and environmental performance metrics and other risk factors have and might cause significant delays for projects.

Total production from oil sands areas reached a significant milestone of a 3 million-barrel-per-day (MMBPD) level in 2018, surpassing 2017 production by 210 thousand barrels per day (MBPD). Oil sands bitumen production is comprised of in-situ (thermal and cold bitumen) production of 1.6 MMBPD and mining production of 1.5 MMBPD within the boundaries of oil sands areas.[6] Total production in 2017 was 2.84 MMBPD, meaning oil sands production grew 7 percent year-over-year. Production from oil sands includes an increasing share of Alberta's and Canada's crude oil production. In 2018, non-upgraded bitumen and SCO production made up two-thirds of total Canadian crude production and 87 percent of Alberta's total production.

In the **High Case**, production from mining and in-situ projects (thermal and cold bitumen) is set to grow to 3.3 MMBPD by the end of the decade and reach 4.9 MMBPD in 2030, peaking at an all-time high of 5.8 MMBPD by 2039. In the **Low Case,** production grows at a slower rate, rising to 3.1 MMBPD in 2020, 3.3 MMBPD by 2030 and to 4.1 MMBPD by the end of the forecast period. CERI's **Reference Case** provides a base case of oil sands production. Projected production volumes will increase to 3.2 MMBPD by 2020 and 4 MMBPD in 2030, peaking at 4.7 MMBPD by 2039 (see Table 3.2 and Figure 3.1).

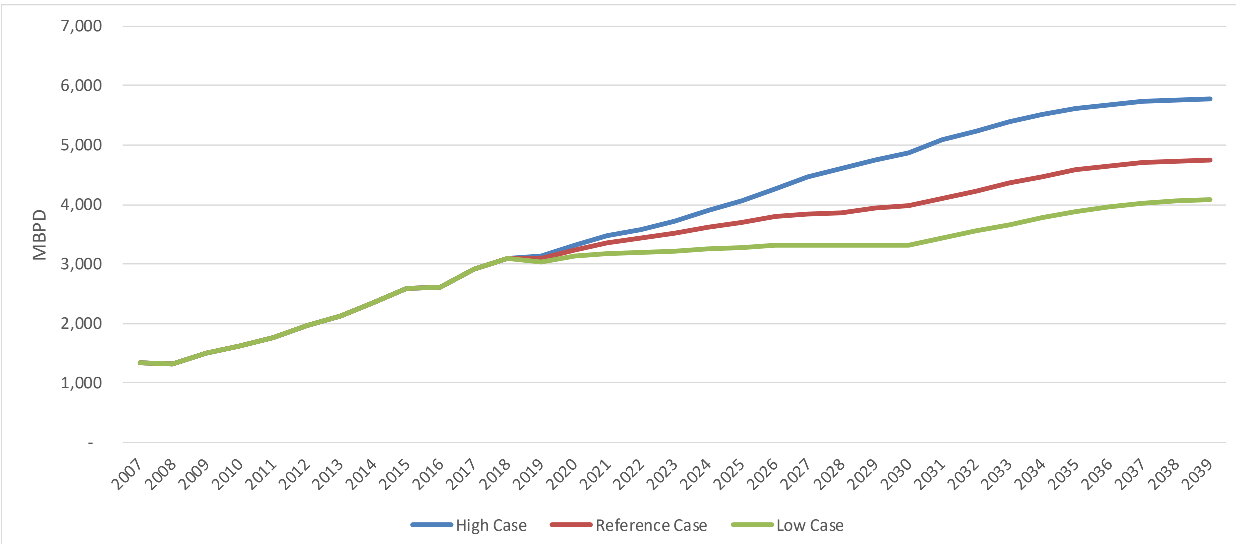
[5] Announced projects are assigned with high uncertainties regarding timing and project production capacities.
[6] Totals may not add up due to rounding. Historical production is sourced from the Alberta provincial regulator.

Table 3.2: Oil Sands Production Forecast (MBPD)

Scenario	2020	2025	2030	2035	2039
High Case	3,319	4,062	4,870	5,620	5,782
Reference Case	3,243	3,699	3,977	4,579	4,745
Low Case	3,129	3,264	3,320	3,875	4,081

Source: CERI

Figure 3.1: Bitumen Production Scenarios



Source: CERI, CanOils

Achieving any of the levels of production outlined in the three scenarios requires a substantial number of inputs, of which capital (both strategic and sustaining) and natural gas are critical. Without the required capital, an oil sands project cannot be constructed. The project, with current technologies, cannot operate without an abundant and affordable supply of natural gas. Lastly, once the facility is operating there is an ongoing need for sustaining capital to ensure that production volumes stay at their design capacities. These and other requirements are discussed in the next section.

Reference Case Scenario

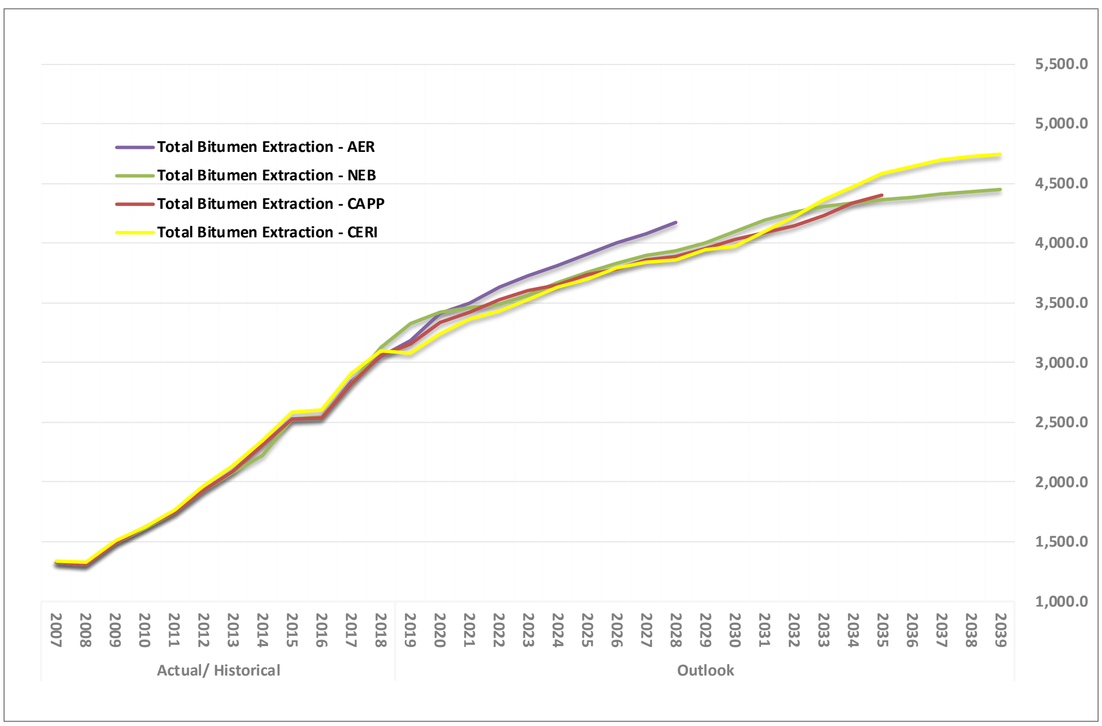
This section will focus on the results of CERI's **Reference Case**. Projections of bitumen and SCO production, capital and operating costs, natural gas and diluent demand and emissions are included in the discussion.

Oil Sands Production – Historic and Forecast

A comparison is presented between CERI's **Reference Case** production and other agencies' forecasts, such as CAPP,[7] the AER,[8] and the NEB[9] that report oil sands forecasts. Figure 3.2 illustrates the comparison of bitumen production between CERI and the three agencies. CERI's total production projection from oil sands areas spans from 2019 to 2039, inclusive. All four outlooks are relevantly similar, with slightly lower production under CERI's Reference Case in the short to medium term, supported by continued egress constraints. CERI's Reference Case production in the latter part of the forecast period is projected to grow faster than the NEB's. This is supported by an assumption of increasing oil prices in the longer term which would attract more greenfield development.

Bitumen production in CERI's Reference Case grows by an average annual of approximately 80 MBPD or just over 2 percent per year. This growth rate is downgraded from last year's estimate of 3 percent. The slight decline in 2016 is the result of wildfires in northern Alberta that happened mid-2016 affecting oil sands projects. The 2019 estimated drop is due to mandated production curtailment implemented by the Alberta government and enforced in January 2019 to counteract the increasing price differential between WTI and WCS.

Figure 3.2: Bitumen Production Forecast

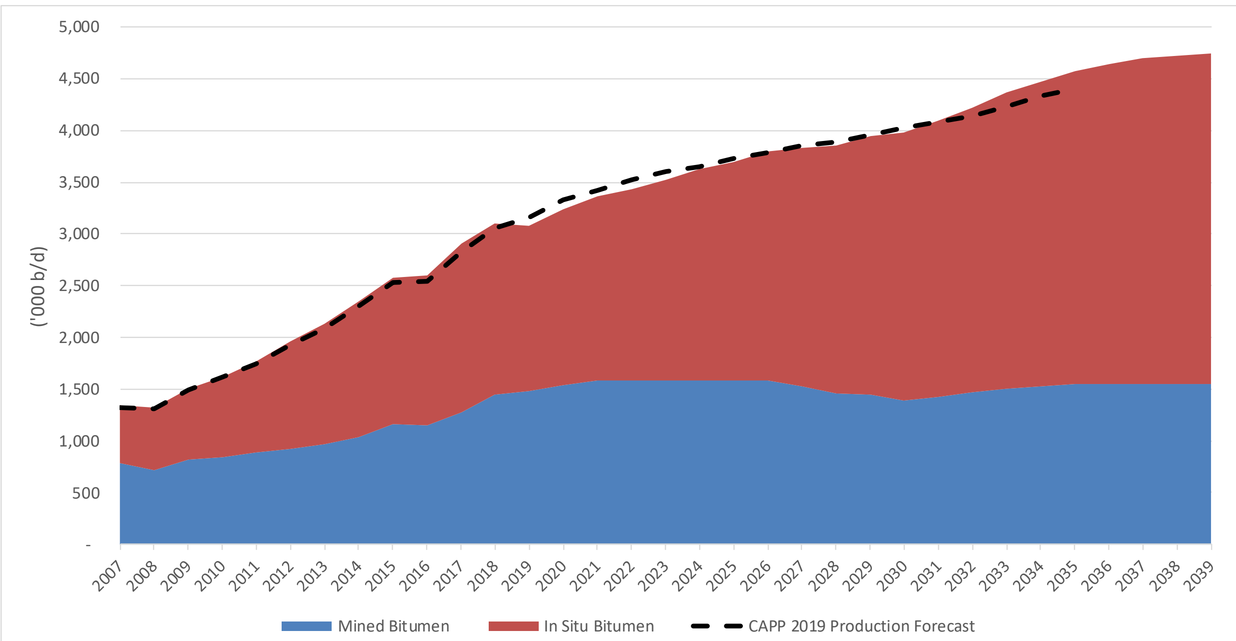


Source: CERI, AER, CAPP, NEB.

[7] CAPP, "Canadian Crude Oil Forecast and Market Outlook", June 2019.
[8] AER ST-98, 2019.
[9] NEB Energy Futures Report, updated November 2018.

Illustrated in Figure 3.3 are the production projections by extraction type. Total mined bitumen production is expected to remain flat at the million and a half barrels per day level, growing at less than half a percent annually. The decrease in mining production in 2028 is due to one of the phases of a legacy mine coming offline before another phase starts operations. Since 2012, in-situ production continues to be higher than mining. Production is expected to increase continuously from 1.5 MMBPD in 2017 to a peak of 3.2 MMBPD in 2039, growing at an average annual rate of 3.3 percent, because of the addition of new proposed projects, the expansion of existing and construction of approved projects. The share of bitumen production from mining will continue to decrease – from 45 percent in 2017 to 30 percent in 2039. By the end of the projection period, in-situ bitumen accounts for the majority of incremental bitumen barrels produced.

Figure 3.3: Bitumen Production by Extraction Type – Reference Case

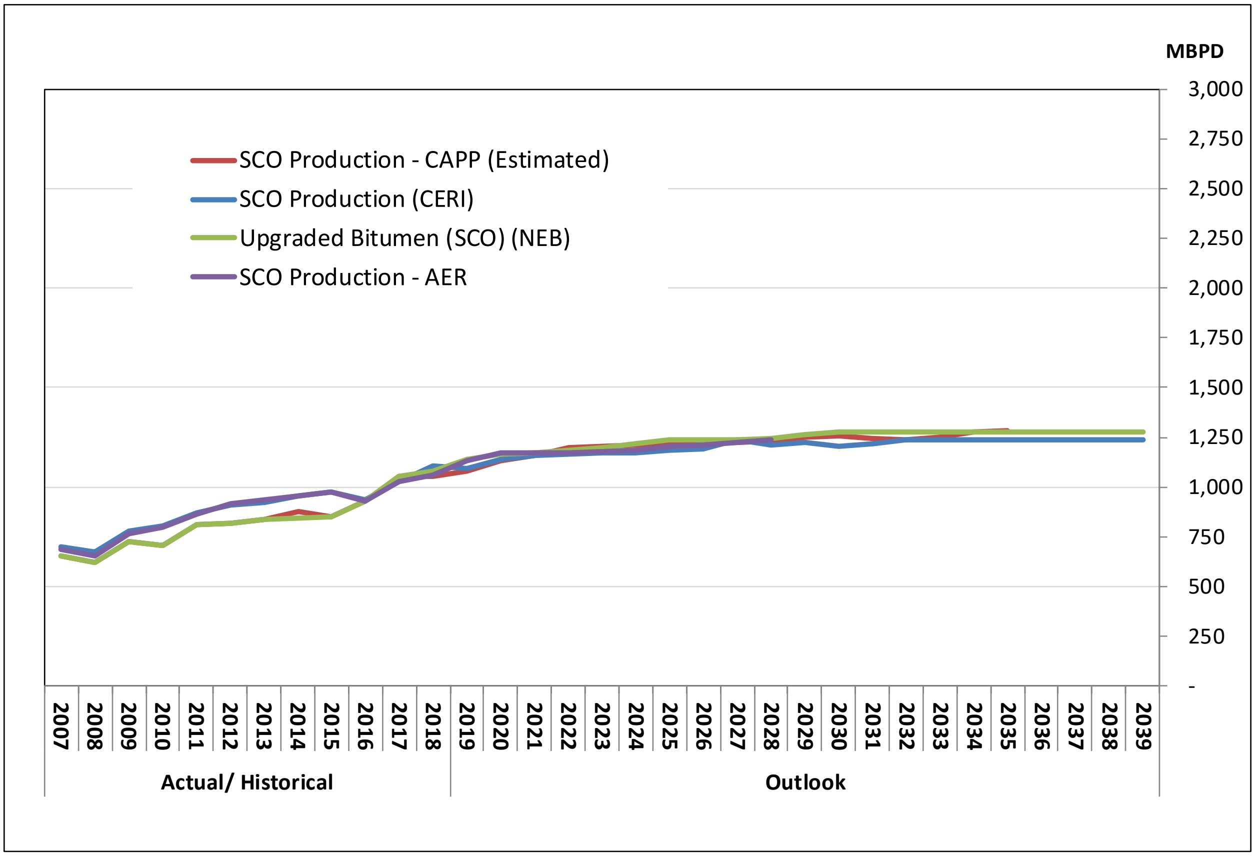


Source: CERI, CanOils

The majority of the oil sands mines are integrated with an upgrader that converts raw bitumen to synthetic crude oil, similar to WTI quality. On average, about 15 percent of raw bitumen used as feedstock for upgrading is lost in the conversion process. The growth in production of non-upgraded bitumen is expected to outpace that of upgraded bitumen, mainly because new mines (Fort Hills and Kearl) will not have upgrading capabilities.

Total average daily production of SCO averaged 1.1 MMBPD in 2018 and was up by an estimated 3 percent as compared to 2017. Upgraded bitumen production is forecast to grow in the medium term to reach a level of approximately 1.3 MMPBD and remain flat afterwards, given there are no additional upgraders currently under construction and the ones that were planned have been cancelled. Figure 3.4 illustrates CERI's Reference Case SCO production together with forecasts from CAPP, the NEB and the AER.

Figure 3.4: SCO Production Forecast



Source: AER, CAPP, CERI, NEB

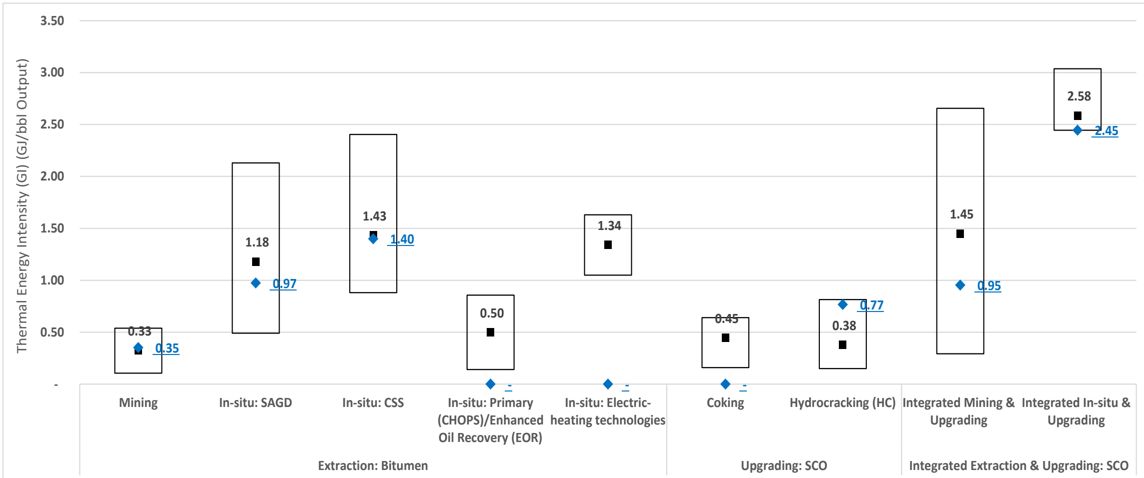
Natural Gas Demand

The oil sands industry increasingly accounts for a larger portion of the provincial gas market in Alberta. Overall, natural gas demand growth in the province of Alberta over the coming decade is expected to come primarily from the industrial sector including oil sands, power generation and petrochemical sectors. The oil sands industry increasingly accounts for a larger portion of the provincial gas market in Alberta.

Figure 3.5 displays the range for thermal energy/gas intensity factors developed by CERI[10] for the different project types including extraction processes such as mining, in-situ (SAGD, CSS, primary/EOR, and electric-heating technologies), upgrading projects such as coking and hydrocracking, as well as integrated extraction (mining or SAGD) and upgrading projects. Figure 3.6 displays (natural gas equivalent) hydrogen intensity factors for upgrading projects.

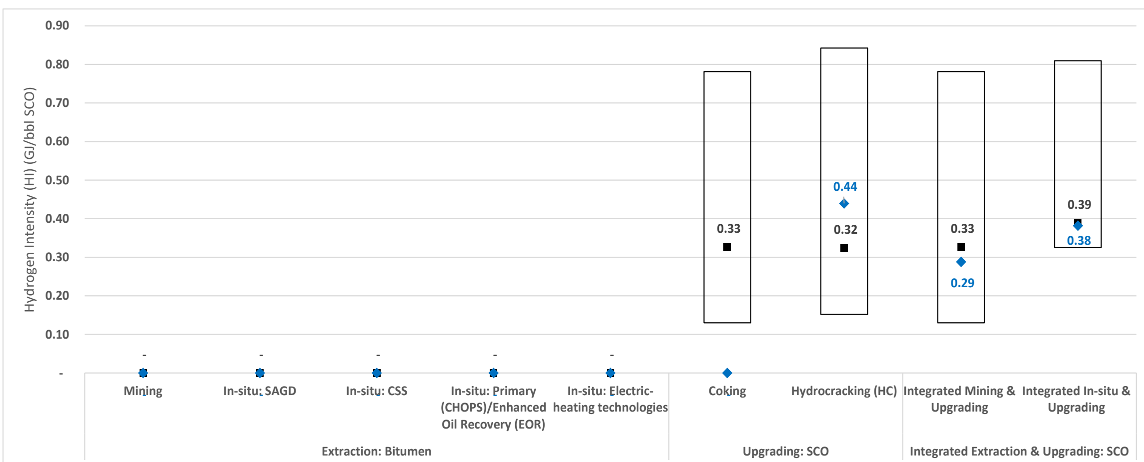
[10] For more information on how these factors were developed, see CERI Study 151.

Figure 3.5: Oil Sands Industry Thermal Energy Intensity Factors by Project Type (GJ/bbl of Output)



Source: CERI

Figure 3.6: Oil Sands Industry Hydrogen Energy Intensity Factors by Project Type (GJ/bbl of Output)



Source: CERI

The ranges were calculated based on statistical methods which are meant to capture most of the collected data values (excluding large outliers), with a median value illustrated by the black square-shaped marker, while the blue diamond-shaped marker displays the latest empirical value collected for a given project type (where applicable), which is generally an average for 2014 (or 2013, depending on data availability).

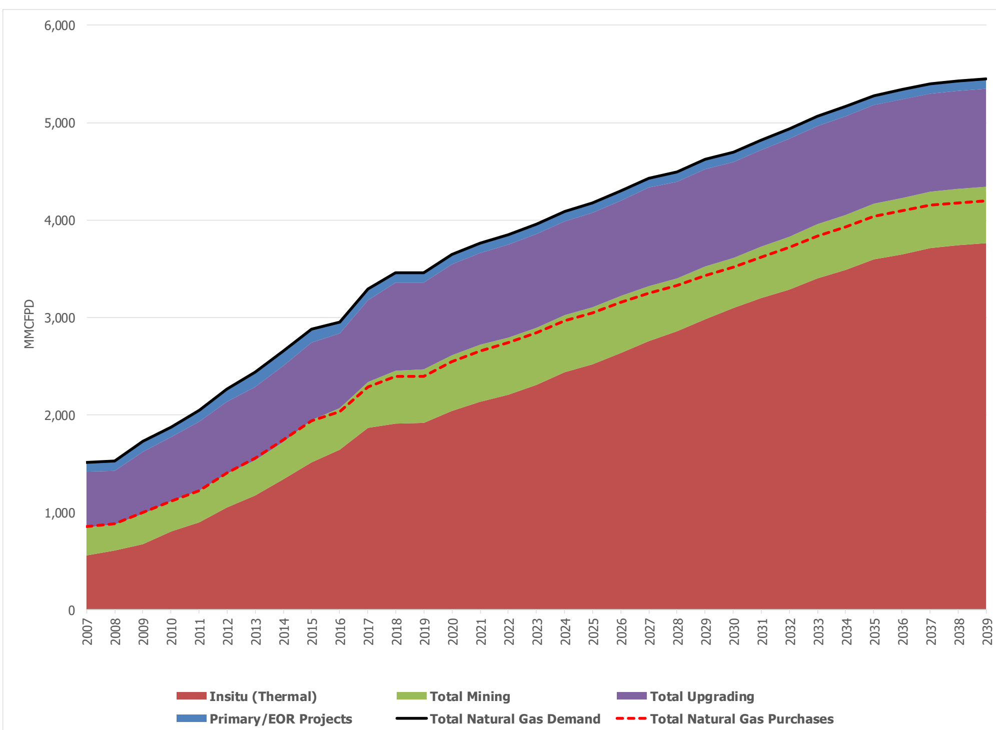
Thermal energy and hydrogen intensity factors are converted to a volumetric basis in order to come up with an estimate for gas demand for the oil sands industry by project type. Figure 3.6 displays the results of such analysis.

Figure 3.7 also illustrates the total oil sands demand for gas (including natural gas, fuel gas, syngas, and associated gas) for the purpose of meeting thermal energy requirements and feedstock for hydrogen production. The oil sands industry's natural gas purchases refer to marketable natural gas purchased from the market, for meeting thermal energy and hydrogen requirements, after accounting for internally produced and utilized gas sources. Gas purchases make up 70 percent of total demand on average, signifying a continuing reliance on the natural gas industry to produce natural gas required for the oil sands industry.

Total gas demand for the oil sands industry is expected to increase by 2 billion cubic feet per day (BCFPD) from 3.5 BCFPD in 2018 to 5.5 BCFPD by 2039. Most of the growth in gas demand from the industry is expected to come in the form of thermal energy demand requirements for SAGD and CSS projects, followed by mining and upgrading projects. Under the assumption of constant energy intensity factors in the Reference Case, this trend is primarily the result of an evolving product mix on a project-type basis rather than technological changes.

This is a limiting assumption because the oil sands reservoirs are not uniform and hence various projects will face different steam requirements and hence natural gas demand. Technological improvements in steam generation, or moving towards solvent-type extraction technologies, will impact natural gas demand for in-situ projects. On the other hand, as oil sands continue to be produced, the remaining reservoirs are becoming more mature and energy requirements might be higher to extract bitumen because the current "low-hanging" and uniform bitumen in-situ leases are produced and depleted.

Figure 3.7: Natural Gas Demand and Purchases for Thermal Energy and Hydrogen Production



Source: AER, CERI

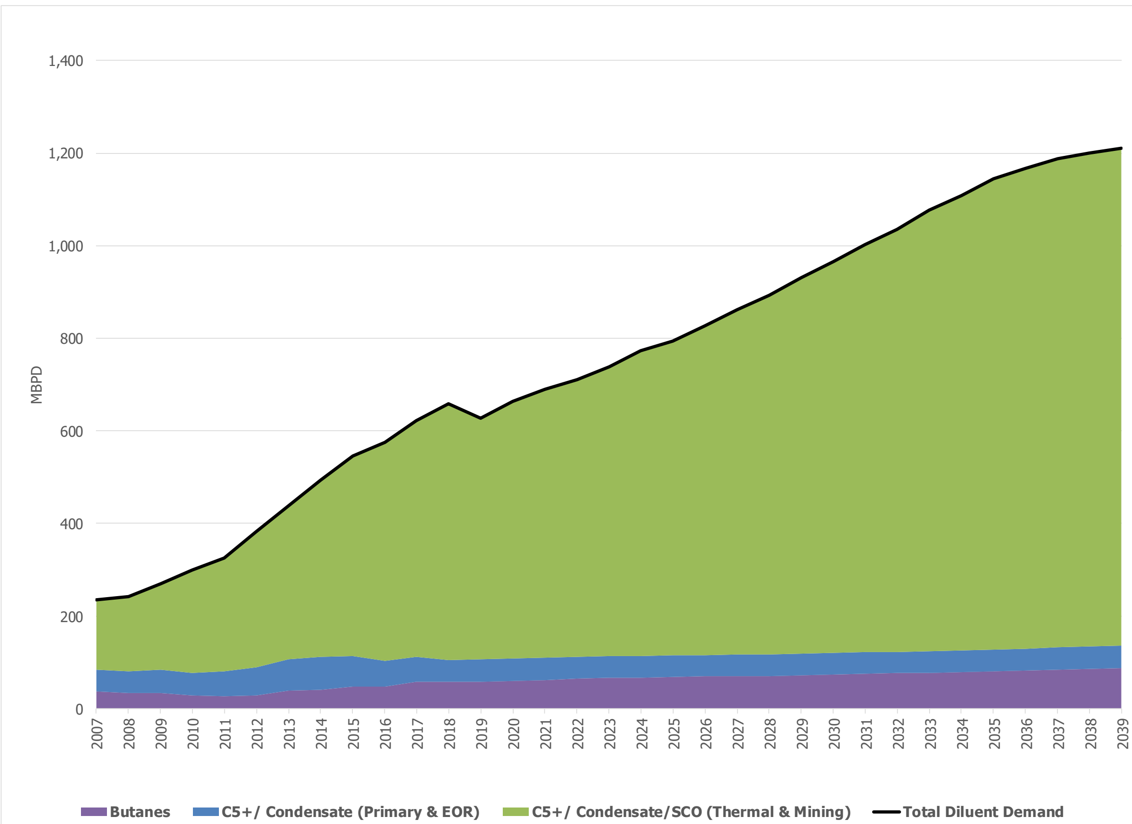
Diluent Demand

Diluent is an important component of oil sands operations for transportation purposes. Adding diluent brings bitumen to pipeline specifications and allows it to flow safely. Currently, domestic sources and imports of condensate satisfy the diluent demand for bitumen production.

In oil sands operations, demand for diluent is driven by non-integrated projects whose primary output is a crude bitumen blend such as WCS. The diluent pool, in turn, is made up of various components including light crudes such as SCO and condensates (ultra-light crude), but also natural gas liquids (NGLs) such as butanes, but most importantly, pentanes plus. More recently, butanes and propane are being used to pilot solvent-aided in-situ projects, where a combination of steam and solvent aids in the extraction of bitumen, thus reducing the need for natural gas to create steam and reducing overall GHG emissions from the production process.

While the choice of diluent used by different project operators is based on economic and technical considerations,[11] pentanes plus remains the diluent of choice for oil sands operators. Figure 3.8 displays the estimated demand for diluent by project type and by diluent type.

Figure 3.8: Diluent Demand by Type of Diluent



Source: AER, CERI

[11] See CERI Study 133, "Canadian Oil Sands Supply Costs and Development Projects (2012-2046)", May 2013.

Total demand for diluent for 2018 was almost 659 MBPD including pentanes plus and condensate, SCO, and butanes. The diluent demand is expected to rise in tandem with bitumen production, as more in-situ projects come online, requiring diluent for transportation, assuming no technological breakthroughs.[12] Total demand will rise from the current level to over 1,2010 MBPD by 2039.

The demand for diluent is met through domestic supply and imports from the US. Based on CERI's conventional oil forecast, Western Canadian production of pentanes plus and condensate will continue to grow, driven primarily by liquids-rich natural gas wells for LNG purposes in British Columbia. Total domestic production for the forecasted period will grow from 452.5 MBPD in 2019 to 604.5 MBPD in 2039.[13] The remaining demand will be met by condensate imports from the US.

Meanwhile, it is important to consider that diluent import requirements are not only a function of local production volumes but of overall demand levels as well. CERI's diluent demand projection is based on the premise that crude bitumen would be blended, that is, no field upgrading will occur, in which case diluent demand for blending purposes could decrease. Partial upgrading, among other technologies, could impact how bitumen is processed and transported (i.e., without minimal or no addition of diluent).

Alternatively, crude bitumen could be moved by rail, and this will increasingly be the case under continued market access and pipeline logistics constraints. This is not to say that crude-by-rail is not experiencing its own issues like non-availability of rail cars, required train personnel, capacity and back-logs on transporting other commodities. Regardless, rail can move bitumen with little to no diluent required.[14]

Last but not least, in the context of diluent import requirements it is important to consider the infrastructure required to move such volumes to the Alberta diluent market. Diluent import infrastructure includes pipelines such as the Southern Lights pipeline and Cochin pipeline which was reversed and switched over from propane to diluent service. Other infrastructure includes rail terminals dedicated to diluent service in the Edmonton/Fort Saskatchewan area, as well as a terminal on the Kitimat coast that moves diluent via rail to Alberta.

Overall, diluent demand levels will be driven by the production of crude bitumen blends rather than synthetic crude from oil sands operations. Rail transportation of bitumen has the potential to reduce diluent demand depending on the type of blend/product transported but also to add to the diluent pool supply by making use of diluent haul-backs. Technologies, such as partial

[12] CERI Study 164.
[13] CERI Study 182, "Canadian Crude Oil and Natural Gas Production, Supply Costs, Economic Impacts and Emissions Outlook (2019-2039)", July 2019.
[14] Dilbit via rail would use the same amount of diluent as dilbit in pipelines or around 30%. Railbit will require about 17% diluent and cleanbit would require no diluent at all. Railbit and cleanbit would require coil and insulated (C&I) rail cars for transportation purposes.

upgrading, could also create products that meet pipeline specifications without additional diluent.

Emissions

Greenhouse gas (GHG) emissions are a major area of environmental concern in the oil sands sector. Increasing concentrations of anthropogenic (i.e., human-produced) GHGs in the atmosphere are a major driver of climate change attributed to human activity. GHGs influence climate by trapping radiation from the earth's surface, resulting in an overall warming effect on the planet. This can lead to a number of potentially adverse outcomes such as changing climate patterns (for example, increased or decreased precipitation) and rising sea levels.

Total Canadian emissions of CO_2eq were 732 Mt or 1.6 percent of global emissions;[15] of these emissions, 9.3 percent came from the oil sands sector.[16] The effects of the sector on Canada's total emissions and the ability to meet international commitments to GHG abatement are substantial. Canada has committed under the Paris Agreement of 2015 to decrease emissions by 30 percent below 2005 levels by the year 2030. Canada's 2050 reduction targets are set at 80 percent below 2005.

Besides the international commitment, Alberta's Climate Change Leadership Plan includes an emissions cap on the oil sands industry in the order of 100 Mt of CO_2eq. With a new provincial government elected in spring of 2019, it is still unknown if the emissions cap will be in place.

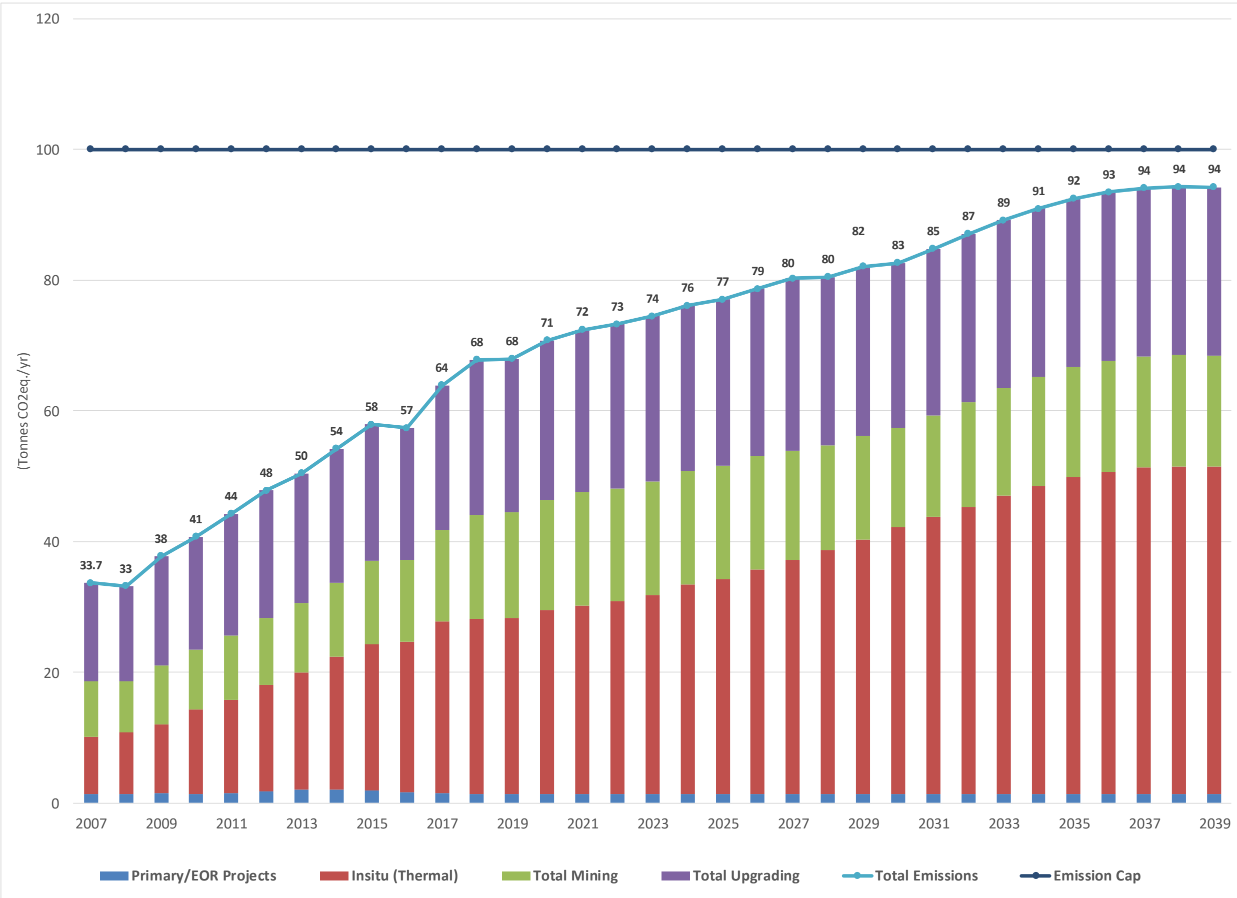
There are two methods to consider when looking at emissions performance. The first is GHG emissions intensity, which is the emissions in CO_2 equivalents per barrel of bitumen or synthetic crude oil produced. Emissions intensity is valuable for examining whether changes in operating conditions at a project level have been effective considering changing production volumes. The second is bulk emissions for a project. A project can make significant efforts to reduce GHG emissions, but total emissions can still rise if bitumen production has risen at a faster rate than emissions have fallen. Looking at bulk emissions can obscure progress made to curb GHGs, but this metric is important to examine as the climate response of emissions will not depend on how many resources were extracted during the emission of these gases.

Figure 3.9 illustrates the total emissions projection for the **Reference Case** production forecast. The on-site emissions projection includes emissions from existing upgrading, electricity or fugitive emissions and flaring. Current on-site emissions are projected to grow from 68 MT/year in 2018 to 94 MT/year in 2039, not reaching the emissions cap of 100 MT. In comparison to last year's update, the 100 MT level was reached in 2030. The difference is explained by a lower production forecast and is not reflective of technological changes to reduce emissions. In CERI

[15] Environment and Climate Change Canada. "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada".
[16] Environment and Climate Change Canada.

Study 164, the Institute outlined several techno-economic paths on how to grow oil sands production while reducing overall emissions.

Figure 3.9: Oil Sands Emissions by Project Type



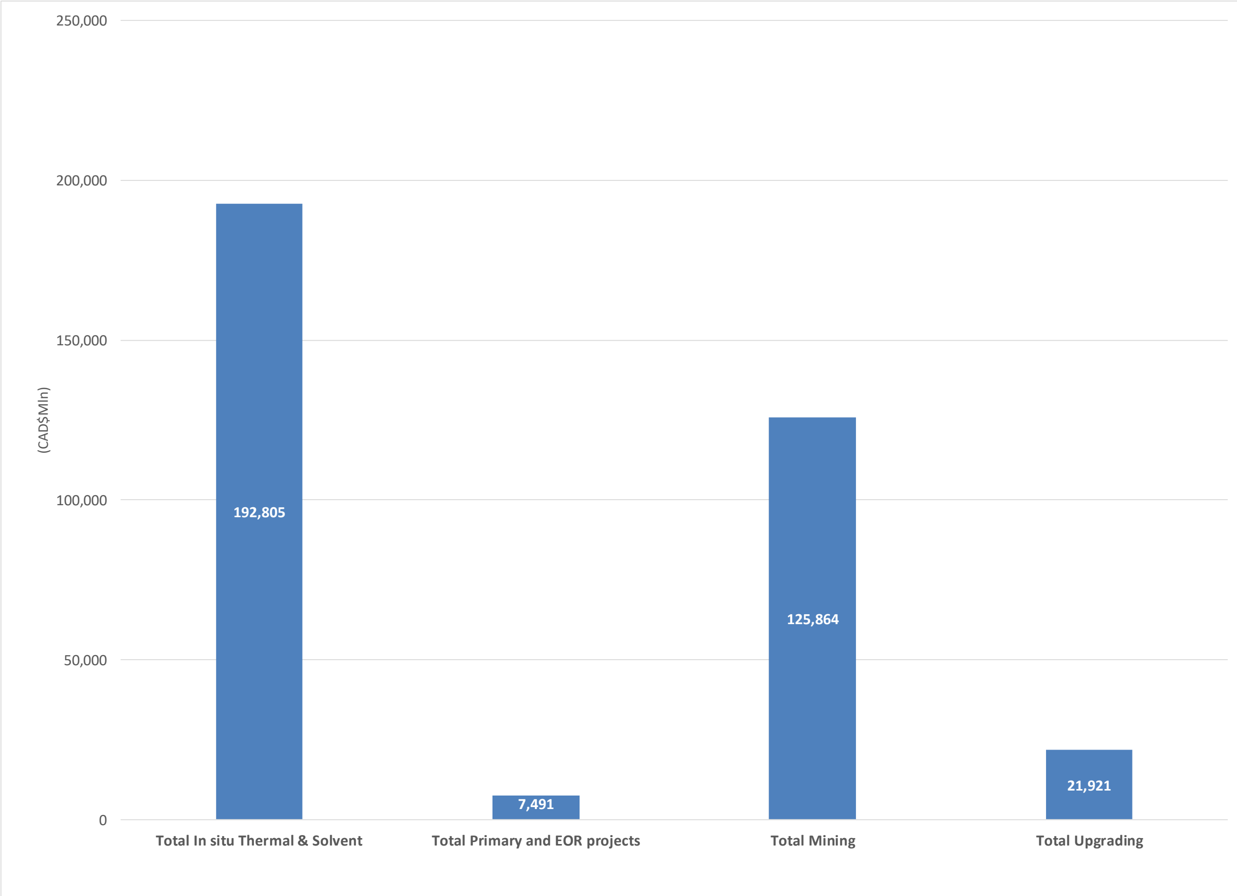
Source: CERI, CanOils

Capital Investment and Operating Costs

Oil sands capital spending is expected to stay weak in the near term of the forecast, continuing a downward trend. A majority of oil sands companies keep deferring new projects in the short term, focusing instead on sustaining existing facilities and lowering production costs.

Total capital spending requirements are broken down by project type and are illustrated in Figure 3.10. Over the 21-year projection period from 2019 to 2039 inclusive, the total initial and sustaining capital required for all projects is projected to be C$348.6 billion under the **Reference Case Scenario**, almost 60 billion lower than last year's projection**.** Capital investment in in-situ projects surpasses the capital spent on mining projects, which is consistent with the ongoing trend. From 2019 to 2039, it is projected that almost C$126 billion (initial and sustaining) will be invested into mining projects and C$200 billion into in-situ thermal and solvent as well as primary and EOR cold bitumen projects. Upgrading projects see the least amount of capital spent, amounting to C$22 billion.

Figure 3.10: Total Capital Invested by Project Type



Source: CERI, CanOils

Historical and forecast capital expenditures from 2007 to 2039 are shown in Figure 3.11. As evidenced in the industry, capital expenditures on oil sands projects have been on the decline since 2014, coinciding with a decrease in oil prices. Investment fell by 10 percent to C$13.8 billion in 2017 as compared to 2016 levels and a further estimated 6 percent in 2018. The 2014 peak spending of almost $34 billion is not projected. For the next 5 years, the investment will remain at the sub C$15 billion mark.

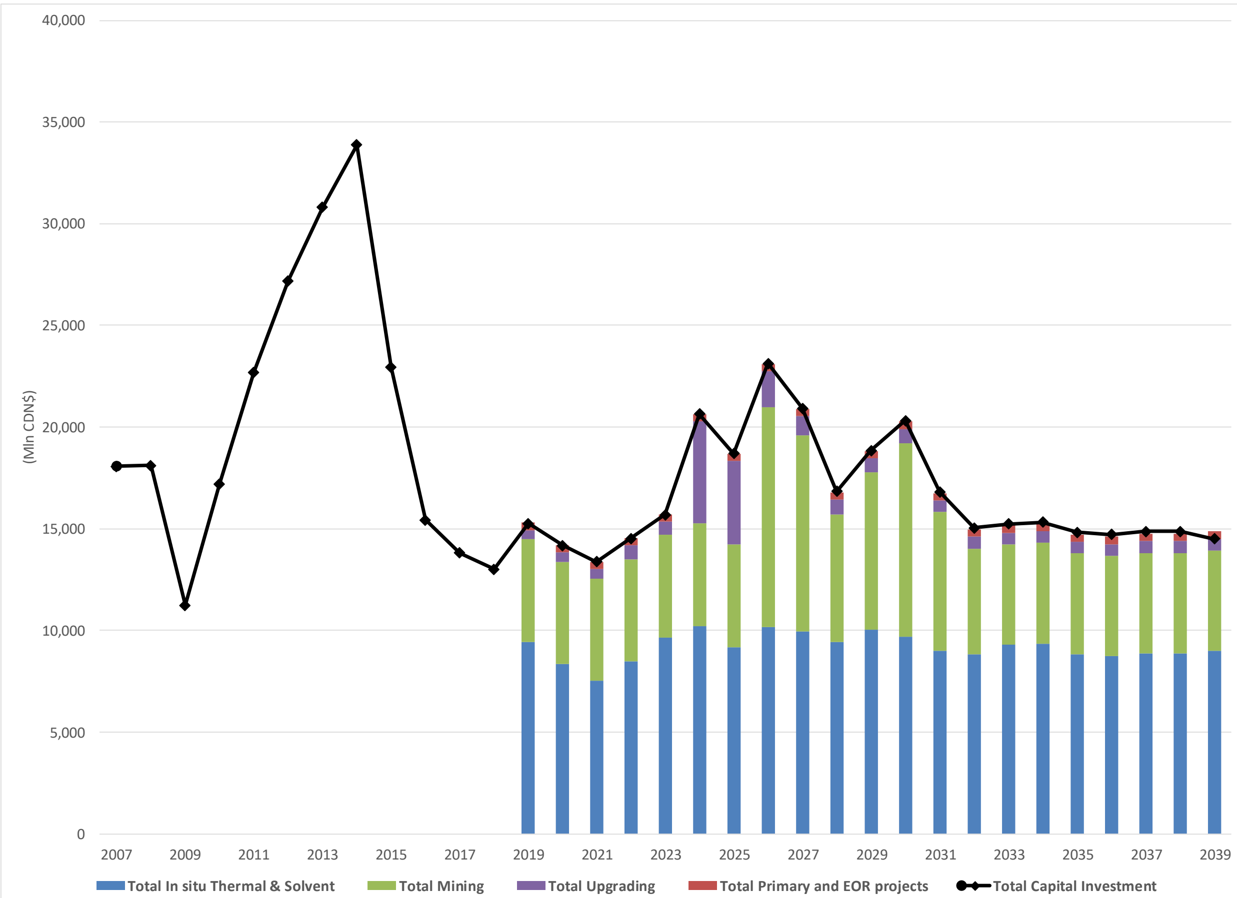
Going forward, overall capital expenditures average $16.5 billion per year in the 2019-2039 forecast period and decline at one-tenth of a percent per year on average. There are lingering risk factors that could impact the capital outlay outlook:

- further deferral of projects;
- successful deployment of cost-reduction strategies;
- uncertainty on a 100 MT cap on oil sands emissions; and
- uncertainty over export pipeline development projects.

Expenditures in the oil sands are expected to be invested in new thermal projects or primarily aimed at sustaining capital and expanding existing projects.

The methodology related to estimating capital investment is related to project capacity additions in the form of expansions of existing projects and greenfield development.

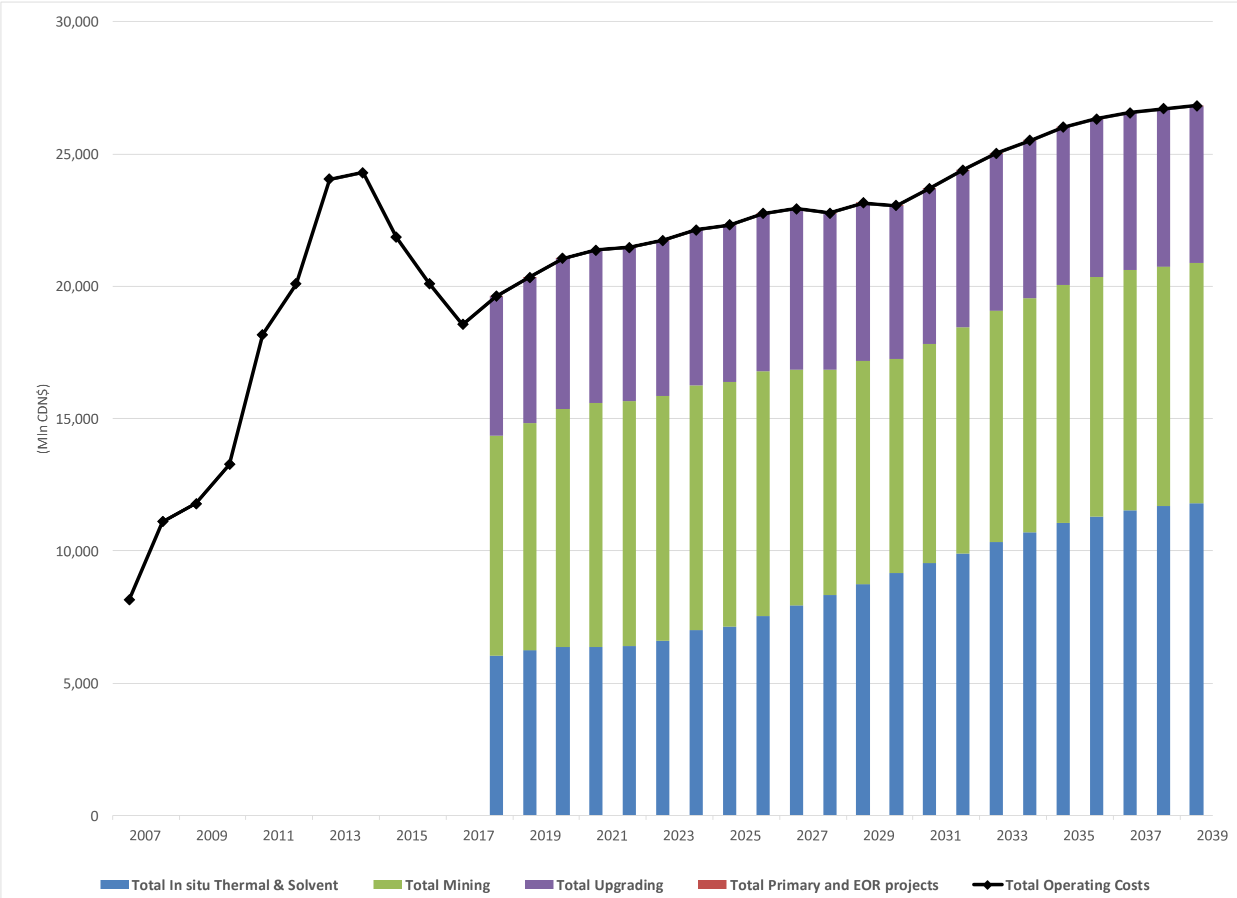
Figure 3.11: Total Oil Sands Capital Expenditures by Project Type



Source: CERI, CAPP, CanOils

Historical and forecast operating costs by project type are presented in Figure 3.12. As can be seen, total operating costs have been declining since 2014 with a year-on-year decrease of 8 percent in 2017. This is the result of not only declining oil prices, but oil sands project operators have also managed to reduce their overall operating cost per barrel of bitumen or SCO produced. Over the forecast period, total operating costs are expected to increase in line with increased production levels, averaging $23.6 billion per year.

Figure 3.12: Total Oil Sands Operating Costs



Source: CERI, CAPP, CanOils

Chapter 4: Canadian Oil Sands Economic Impacts

Input-Output

Input-Output (I/O) analysis in general addresses the way economic circumstances in one part of an economy can ripple through the rest. It deals with inter-industry relationships, notably the use of the output from one industrial process as an input into another. CERI's model is used to determine an approximate impact on the macroeconomic variables with the introduction of investments (or 'shocks'). In the case of resource or infrastructure developments, the expenditures include those for the investment and operation phases of a project. Any activity that leads to increased production capacity in an economy has two components: a) the construction or development of the capacity, and b) the operation of the capacity to generate outputs.

The first component is referred to as the investment phase, while the second is the operation phase. Both activities affect the economy through purchases of goods, services, and labour. The construction phase represents short-term activity and hence leads to short-term temporary impacts; whereas operations and management of a facility are typically continuous. The first step is to estimate and forecast the value of the investment (i.e., construction or development expenditure) and operations. CERI has done this for the various activities. The second step is to estimate and forecast the value of total operations from those processes.

The forecasted values of investment and operations are then used to estimate the demand for the various goods and services and labour used in both phases. These demands are met through two sources: domestic goods production and goods imports. Domestic contents of the goods and services are calculated using Statistics Canada data. Impacts are calculated for Canada, broken down by province. They are presented as Gross Domestic Product (GDP), employment and tax revenues. For employment, jobs are direct, or indirect. Direct jobs are those tied directly to the activity. Indirect jobs would be those where economic sectors play a support role in the activity such as financial or legal services. Induced jobs are a third category that CERI has determined that, as an indicator of economic impact, these effects are too diverse to meaningfully be attributed to any one activity.

There are two main assumptions underpinning the construction of an I/O model. The first assumption is that the economy is in equilibrium. Equilibrium means that the existing relationship between economic activities is constant and there are no surplus or deficits of production or need between sectors. This is a realistic assumption in the long run, as economies move to use up surplus or create additional production to meet a need. A second important assumption in the I/O analysis is the linear relationship between inputs and outputs in the economy. Each sector uses a variety of inputs linearly to produce various final products under the assumption of fixed proportions. A very interesting aspect of this assumption is the constant return to scale. Though the linearity of the production relationship function gives a constant average and marginal products, these are justified if the analysis focuses on the medium term. Long-run changes in the economy (beyond 20 years) may affect the fixed relationship between sectors. CERI employs a 10-year horizon to limit the challenges of changing economic relationships between sectors.

Canadian Oil Sands Economic Impacts

The oil sands industry is a significant contributor to the provincial and Canadian economies in the form of royalty and land payments and taxes. It also employs thousands of people. The sector has experienced sustained cost-cutting, restructuring and deeper than anticipated job losses since the oil price collapse in 2014.

To determine the economic impacts of the Canadian oil sands development, this study uses the **Reference Case Scenario** production forecast, estimated capital expenditures and revenues for bitumen and synthetic crude oil presented in Chapter 3. This section presents the economic impacts of oil sands development, including both existing and future drilling activity within the active oil sands areas of the province of Alberta and western Saskatchewan over the period of 2019 to 2029. The analysis covers the production of bitumen and synthetic crude oil (SCO).

The industry is projected to contribute $1.01 trillion to the Canadian GDP over the next 11 years. Most of the impact will be felt in Alberta, but Saskatchewan is a growing contributor as oil sands projects from that province are coming online. Governments will collect tax revenues in the form of corporate taxes and royalties. Those are estimated to be $16.7 billion in overall tax revenues for Canada; of that total, $11 billion will be collected in Alberta.

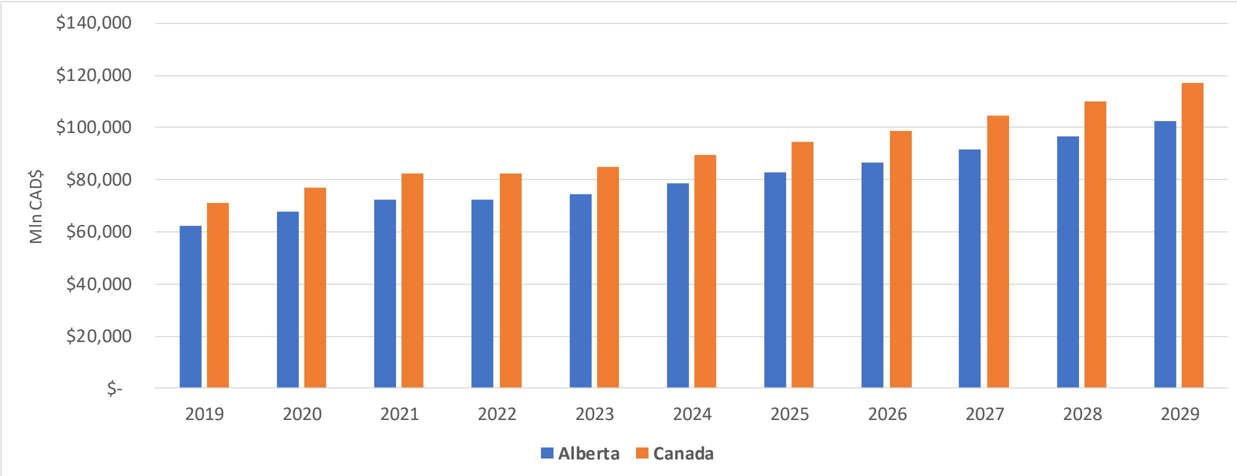
Table 4.1: Total Economic Impacts of Oil Sands Development, 2019-2029

Economic Impact	Region	2019-2029
GDP (million $CAD)	Alberta	886,667
	Canada	1,012,502
Employment (person-years)	Alberta	3,468,300
	Canada	4,688,261
Tax (million $CAD)	Alberta	11,003
	Canada	16,675

Source: CERI

The annual GDP growth for Canada will average approximately C$92 billion, growing from C$71.3 billion in 2019 to C$117 billion in 2029 (Figure 4.1). Alberta will account for 88 percent of the total impact, averaging C$80 billion per year.

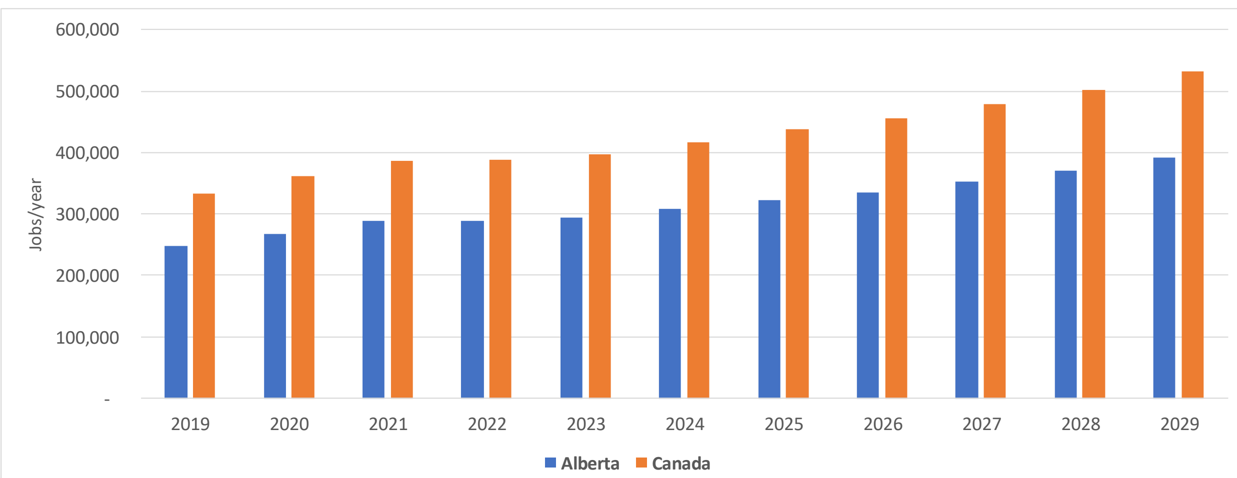
Figure 4.1: Annual GDP Impacts of Oil Sands Development



Source: CERI

Total employment (direct and indirect) in Canada will amount to 4,688 thousand-person years, translating to growth from 332,847 jobs in 2018 to 532,673 jobs in 2029 (Figure 4.2). Direct and indirect employment in Alberta (i.e., created, or preserved construction or operation jobs in the oil sands projects, manufacturing jobs in the oil sands staging areas (Edmonton, Leduc, etc.) and drilling-related jobs in the cold bitumen production area) grows from 247,144 jobs in 2019 to 391,187 jobs by 2029. Over 70 percent of jobs are filled in Alberta.

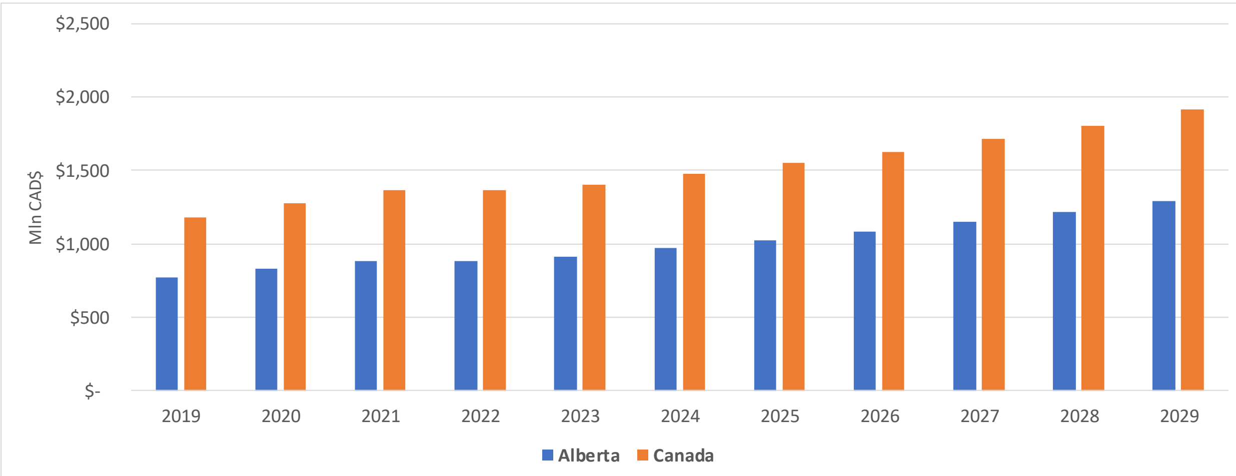
Figure 4.2: Annual Employment Impacts of Oil Sands Development



Source: CERI

Total tax revenues generated from oil sands development to the government will amount to almost C$17 billion over the 2019-2029 period (Table 4.1). On average, annual tax revenues (federal and provincial) will be C$1.5 billion, increasing from C$1.2 billion in 2019 to C$1.9 billion in 2029 (Figure 4.3). Given that the majority of oil sands projects are located in Alberta, the province will generate the highest shares of both federal and provincial tax revenues at 66 percent.

Figure 4.3: Annual Tax Receipts from Oil Sands Development



Source: CERI

US Oil Sands Economic Impacts

Investments and operations of Canadian oil and gas projects make important contributions to the United States economy as well. The US benefits not only from importing oil and gas from Canada but also from supplying goods and services used by the Canadian oil and gas industry. In 2017, CERI published a comprehensive study on US economic impacts from Canadian conventional oil and gas and oil sands production.[1] This section will update upstream oil sands-related impacts.

Prior to the 2014 oil price collapse, the Canadian oil and gas production sector imported C$6.5 billion worth of products and services from the US in 2013. Supply of those products and services spur economic activity and create or preserve jobs in respective US states. This section presents those economic impacts accruing in the US states because of Canadian oil sands development. The US impacts of conventional oil and gas are presented separately in the most recent 2019 production update of conventional oil and gas (CERI Study 182).

For the forecast period of 2019-2029, it is estimated that the total impact on the US gross state products (GSP)[2] will amount to almost US$15 billion or C$20.3 billion (using the exchange rate of C$0.75 per US$1). The total employment impact is measured in creating or sustaining around 133 thousand full-time equivalent jobs in the 11-year period (Table 4.2).

[1] CERI Study 166, "Economic Impacts of Canadian Oil and Gas Supply in Canada and the US (2017-2027)". August 2017.

[2] In the US, the definition of the gross state product (GSP) is similar to the provincial gross domestic product in Canada.

Table 4.2: Oil Sands Economic Impacts in the US by State and by Type of Impact (2019-2029)

State	Employment Impact (# of Jobs created or sustained)				Contribution to gross state product (million 2018 USD)			
	Direct Effect	Indirect Effect	Induced Effect	Total Effect	Direct Effect	Indirect Effect	Induced Effect	Total Effect
Texas	11,921	12,447	12,329	36,698	$ 1,982	$ 1,596	$ 1,063	$ 4,641
California	4,568	4,750	4,181	13,499	$ 677	$ 577	$ 411	$ 1,666
Illinois	5,395	2,604	3,331	11,331	$ 515	$ 320	$ 308	$ 1,143
Oklahoma	2,885	2,450	1,979	7,313	$ 306	$ 257	$ 152	$ 716
Ohio	1,655	1,609	1,665	4,929	$ 250	$ 179	$ 138	$ 567
Colorado	1,120	1,177	1,280	3,578	$ 220	$ 139	$ 111	$ 470
Pennsylvania	1,362	1,124	1,278	3,764	$ 198	$ 138	$ 112	$ 448
Wisconsin	1,453	978	1,063	3,494	$ 184	$ 97	$ 86	$ 367
Wyoming	333	358	231	922	$ 261	$ 39	$ 18	$ 318
Florida	916	1,093	1,021	3,030	$ 108	$ 111	$ 82	$ 301
Indiana	902	779	729	2,410	$ 148	$ 74	$ 57	$ 279
Michigan	2,357	1,275	1,352	4,984	$ 38	$ 130	$ 107	$ 275
Arizona	862	888	844	2,594	$ 118	$ 78	$ 69	$ 265
Montana	942	818	692	2,453	$ 133	$ 74	$ 46	$ 253
Utah	948	927	811	2,686	$ 101	$ 89	$ 63	$ 252
Minnesota	751	578	669	1,998	$ 109	$ 65	$ 59	$ 233
Oregon	630	741	592	1,962	$ 86	$ 75	$ 45	$ 206
Washington	737	621	482	1,839	$ 73	$ 75	$ 45	$ 193
Iowa	611	542	477	1,630	$ 93	$ 54	$ 36	$ 184
Georgia	536	436	456	1,428	$ 75	$ 47	$ 38	$ 159
Kentucky	603	420	543	1,566	$ 75	$ 40	$ 40	$ 156
New York	525	343	320	1,188	$ 69	$ 48	$ 34	$ 152
North Carolina	424	401	377	1,202	$ 80	$ 40	$ 30	$ 151
New Jersey	353	364	368	1,085	$ 55	$ 50	$ 37	$ 143
Louisiana	497	388	386	1,271	$ 71	$ 37	$ 29	$ 138
Kansas	618	552	422	1,593	$ 47	$ 55	$ 32	$ 134
Alabama	357	396	298	1,050	$ 58	$ 40	$ 23	$ 121
North Dakota	166	251	136	553	$ 80	$ 30	$ 11	$ 120
Connecticut	375	239	274	888	$ 55	$ 36	$ 29	$ 119
Missouri	351	341	349	1,041	$ 50	$ 34	$ 28	$ 111
Mississipi	405	402	286	1,094	$ 54	$ 37	$ 20	$ 111
Nevada	462	313	256	1,031	$ 46	$ 33	$ 23	$ 101
Tennessee	344	294	280	918	$ 48	$ 30	$ 23	$ 100
Virginia	332	210	201	743	$ 53	$ 24	$ 18	$ 95
South Carolina	382	254	278	914	$ 51	$ 22	$ 21	$ 94
Nebraska	323	288	216	827	$ 44	$ 30	$ 17	$ 92
Idaho	404	319	242	965	$ 40	$ 25	$ 16	$ 80
Massachusetts	219	153	198	570	$ 38	$ 20	$ 19	$ 77
Arkansas	256	230	179	664	$ 35	$ 23	$ 13	$ 72
Maryland	142	119	109	370	$ 19	$ 14	$ 10	$ 42
New Mexico	121	94	61	277	$ 14	$ 8	$ 5	$ 27
New Hampshir	105	64	86	255	$ 12	$ 7	$ 7	$ 26
West Virginia	37	24	19	80	$ 8	$ 2	$ 1	$ 11
Delaware	29	12	18	60	$ 5	$ 2	$ 2	$ 8
South Dakota	31	21	22	75	$ 4	$ 2	$ 2	$ 8
Maine	22	10	8	40	$ 1	$ 1	$ 1	$ 3
Rhode Island	10	5	6	21	$ 1	$ 1	$ 1	$ 2
Vermont	6	3	3	12	$ 0	$ 0	$ 0	$ 1
Alaska	4	2	2	7	$ 0	$ 0	$ 0	$ 1
Total	**48,787**	**42,707**	**41,405**	**132,900**	**$ 6,787**	**$ 4,906**	**$ 3,538**	**$ 15,232**

The top ten states that benefit the most from Canadian oil sands development are, in descending order, Texas, California, Illinois, Oklahoma, Ohio, Colorado, Pennsylvania, Wisconsin, and Florida (Figure 4.4). Together, the top ten states make up 70 percent of the total GSP impact and 67 percent of total employment impact. Texas, by far, is the largest beneficiary in terms of gross state product (GSP) and employment, totalling almost US$5 billion over the 11-year forecast or 30 percent of total GSP impact. Growing employment in Texas that is created or sustained will more than double, totalling 36,698 jobs over the 11-year period.

Figure 4.4: Oil Sands GSP Impacts for Top US States