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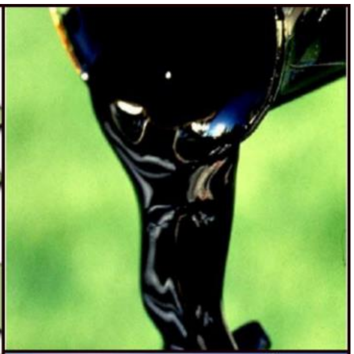
CANADIAN OIL SANDS SUPPLY COSTS AND DEVELOPMENT PROJECTS (2016-2036)



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CANADIAN OIL SANDS SUPPLY COSTS AND DEVELOPMENT PROJECTS (2016-2036)

Canadian Oil Sands Supply Costs and Development Projects (2016-2036)

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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 eleventh annual 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 developments are explored. In addition, given the assumptions for the current cost structure, an outlook for future supply costs will be 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 these assumptions, the supply costs of crude bitumen using steam-assisted gravity drainage (SAGD) and surface mining and extraction have been calculated for a hypothetical project. Figure E.1 illustrates the supply costs for these projects. The plant gate supply costs, which exclude transportation and blending costs, are C$43.31/bbl for a SAGD project and C$70.08/bbl for a stand-alone mine. A comparison[1] of field gate costs from the August 2015 update[2] with this year's supply costs indicates that, after adjusting for inflation, the supply cost for a SAGD producer has fallen by 27 percent, and 6 percent for a stand-alone mine.

After adjusting for blending and transportation, the WTI equivalent supply costs at Cushing for SAGD projects is US$60.52/bbl, and US$75.73/bbl for a stand-alone mine. In comparison to last year's update, the WTI equivalent costs for a greenfield SAGD project are 25 percent lower and 16 percent lower for a stand-alone mine based on lower operating costs, changes in US/CDN exchange rate assumption and a lack of premium on diluent costs. At current WTI prices of just above US$50/bbl,[3] one can assume that these greenfield projects are not economic or have to accept a lower rate of return. However, as observed in the industry, the relative position of oil sands projects against other crude oils is comparatively competitive, and as oil prices are expected to recover, so will the profitability of oil sands projects.

The resulting impact on the overall cost of an oil sands project is shown in Chapter 2. While capital costs and the return on investment account for a substantial portion of the total supply cost, Alberta stands to gain $7.14 to $13.5 in royalty revenues for each barrel of oil produced on

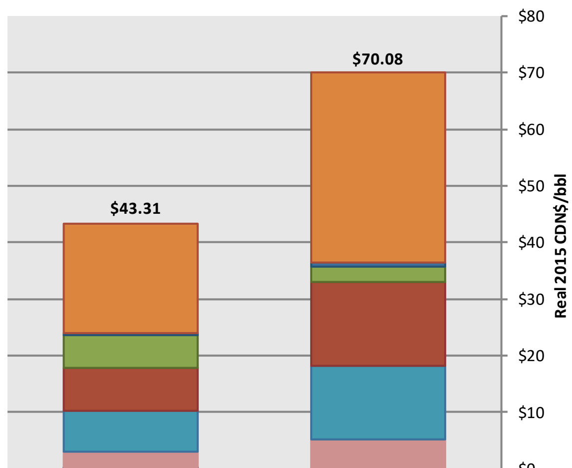
[1] Direct cost comparison is not recommended and is only shown to illustrate the direction of change. Because some changes were made in the project assumptions regarding carbon policy as well as project economics, a direct comparison of costs is not favoured.

[2] CERI Study No. 141, "Canadian Oil Sands Supply Costs and Development Projects (2014-20148), July 2014.

[3] At the time of writing, WTI prices traded at just above US$50/bbl.

average, over the life of an oil sands project. On a percentage basis, these range from a 16.5 to 18.6 percent share of total supply cost, a decrease of 7.3 percent for a SAGD project and unchanged for a mining project.

Figure E.1: Total Field Gate Bitumen/SCO Supply Costs



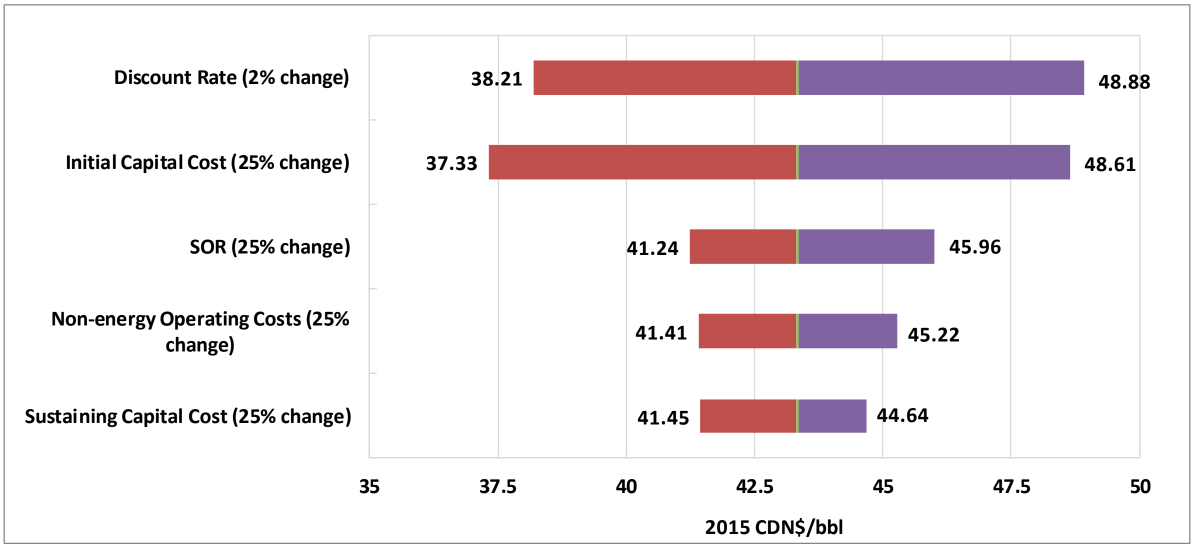
	SAGD 10% ROR (a)	Mining 10% ROR (a)
Fixed Capital (Initial & Sustaining)	$19.25	$33.68
Operating Working Capital	$0.40	$0.70
Fuel (Natural Gas)	$5.87	$2.68
Other Operating Costs (incl. Elec.)	$7.53	$14.84
Royalties	$7.14	$13.05
Income Taxes	$2.82	$4.94
Emissions Compliance Costs	$0.27	$0.13
Abandonment Costs	$0.03	$0.05

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 variables. Bitumen supply cost sensitivities for a hypothetical SAGD and stand-alone mine project are represented graphically in Figures E.2 and E.3.

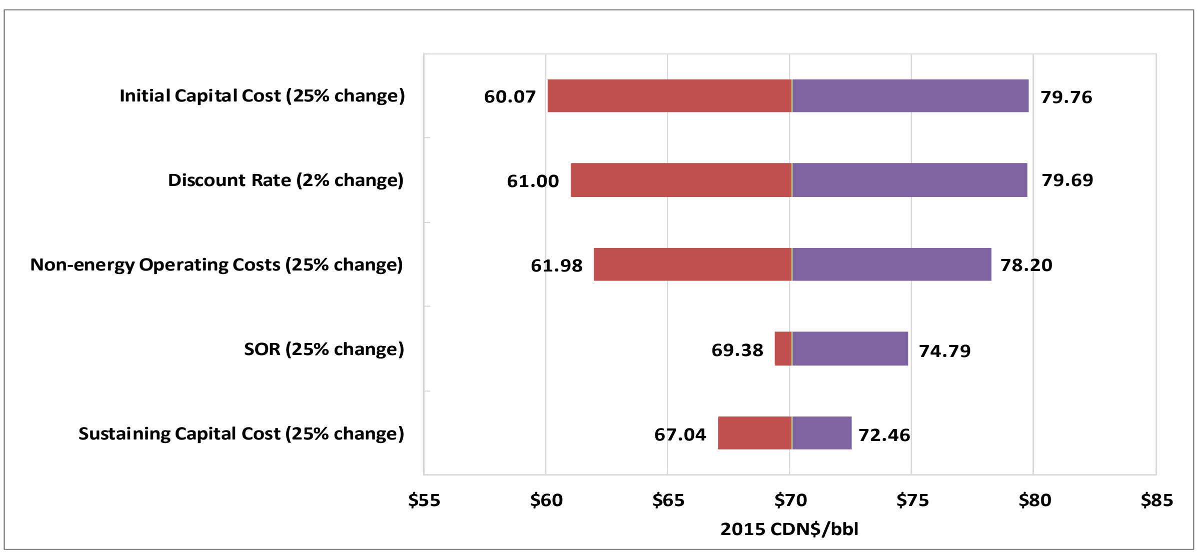
Figure E.2: Supply Cost Sensitivity – 30 MBPD SAGD Project



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. If the discount rate is raised to 12 percent real, the supply cost is estimated to increase by $5.57/bbl (or 13 percent); when it is decreased to 8 percent real, the cost will decrease by $5.10/bbl (or 12 percent) from its base of $43.31/bbl.

Figure E.3: Supply Cost Sensitivity – 100 MBPD Mining and Extraction Project



Source: CERI

For a stand-alone mining project, the supply cost will increase by C$9.68/bbl (or 14 percent) and decrease by $10.01/bbl (or 14 percent) 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 $9.61/bbl (or 14 percent) and a decrease to 8 percent will result in a $9.08/bbl (or 13 percent) drop in the base supply cost of $70.08/bbl.

Production Forecast – Three Scenarios

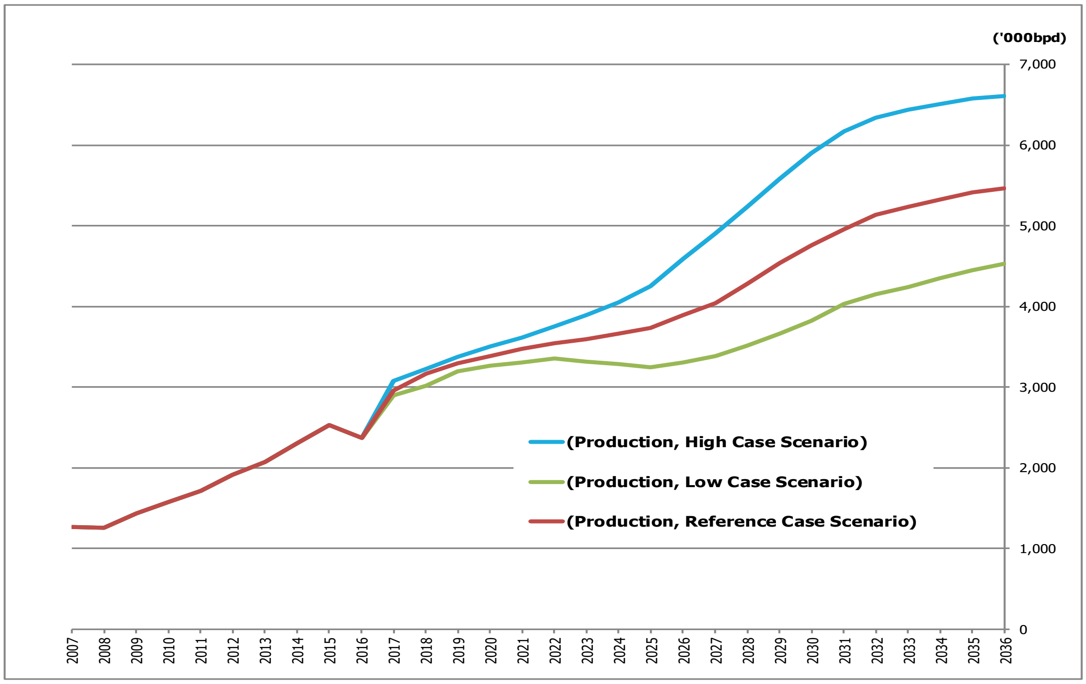
Figure E.4 illustrates the possible paths for production under the three scenarios. For an oil sands producer, a project's viability relies on many factors such as, but not limited to, the demand-supply relationship between production, operating and transportation costs (supply side) and the market price for blended bitumen and SCO (demand). All three scenarios show a significant growth in oil sands production for the 20-year projection period.

Total production from oil sands areas totaled 2.53 MMBPD in 2015, comprised of in situ (thermal and cold bitumen) production of 1.36 MMBPD and mining production of 1.16 MMBPD within the boundaries of oil sands areas.[4] Total production in 2014 was 2.31 MMBPD, meaning the oil sands production grew 9.6 percent year-over-year. Production from oil sands includes an increasing share of Alberta's and Canada's crude oil production. In 2015, non-upgraded bitumen and SCO production made up 62 percent of total Canadian crude production and 78 percent of Alberta's total production.

In the **High Case Scenario**, production from mining and in situ projects (thermal and cold bitumen) is set to grow to 3.5 MMBPD by 2020 and 5.9 MMBPD in 2030, peaking at an all-time high of 6.6 MMBPD by 2036. In the **Low Case Scenario** production rises to 3.3 MMBPD in 2020, 3.8 MMBPD by 2030 and 4.5 MMBPD by the end of the forecast period. CERI's **Reference Case Scenario** provides a more plausible view of the oil sands production. Projected production volume will increase to 3.4 MMBPD by 2020 and 4.8 MMBPD in 2030, peaking at 5.5 MMBPD by 2036 (see Figure E.4). The dip from 2015 to 2016 is the result of wildfires that happened earlier in 2016 affecting oil sands projects.

[4] Totals may not add up due to rounding. Historical production from the provincial regulator.

Figure E.4: Bitumen Production Projections



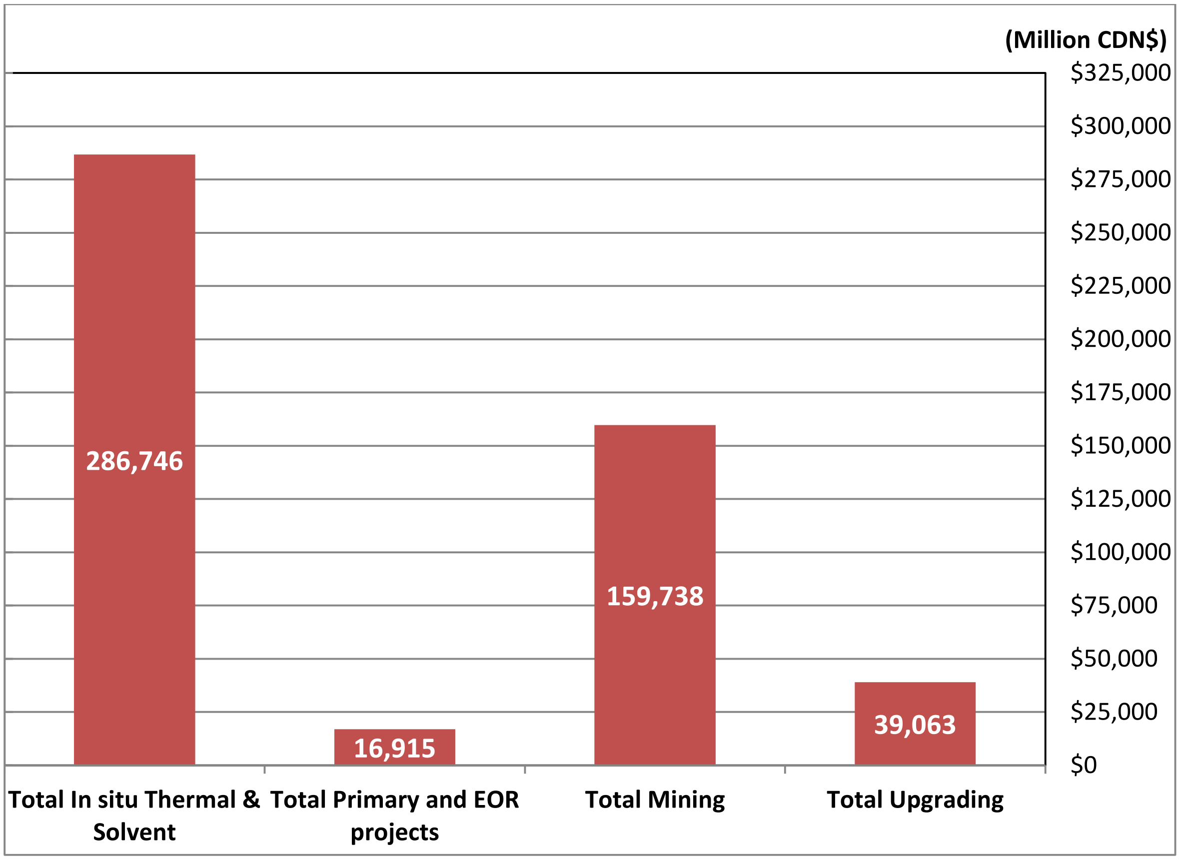
Source: CERI, CanOils

Other Requirements

Capital Investment and Operating Costs

Total capital spending requirements are broken down by project type and are illustrated in Figure E.5. Over the 20-year projection period from 2016 to 2036 inclusive, the total initial and sustaining capital required for all projects is projected to be C$502.5 billion under the **Reference Case Scenario.** Capital investment in in situ projects surpasses the capital spent for mining projects, which is consistent with the ongoing trend to invest more into in situ projects rather than mining. From 2016 to 2036, it is projected that almost C$160 billion (initial and sustaining) will be invested into mining projects and C$304 billion in 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$39 billion.

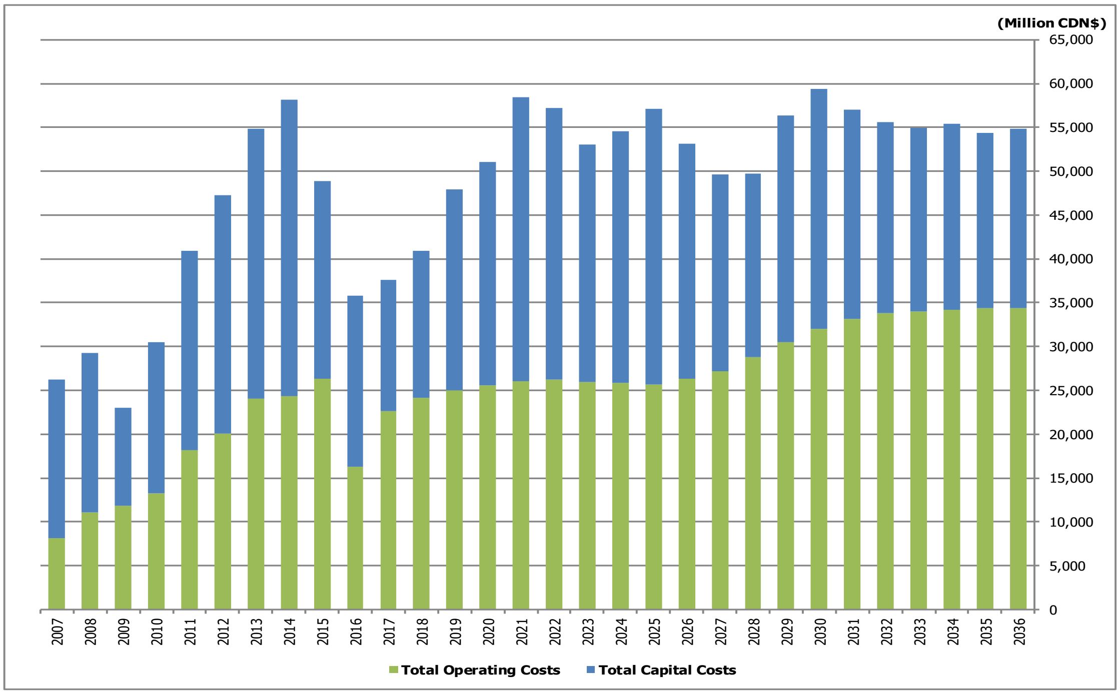
Figure E.5: Total Capital Invested by Project Type



Source: CERI, CanOils

Total cost requirements for the oil sands industry year over year are presented in Figure E.6. These include the initial and sustaining capital and operating costs for all types of projects. Total spending increases from 2007 to 2014, reaching an all-time high of C$58 billion in 2014. With falling oil prices in the near term, the investment starts to fall, slowly recovering to a forecast peak of C$58.5 billion in 2021, at which point it flattens out, averaging C$55 billion per year. As mentioned earlier, initial capital starts to decline by the end of the projection period. This does not reflect a slowdown in the oil sands, merely a lack of new capacity coming on-stream, and relates back to CERI's assumptions for project start dates and announcements from the oil sands proponents. Over the forecast period, total operating costs are expected to increase in line with increasing production levels, averaging $28 billion per year.

Figure E.6: Total Cost Requirements



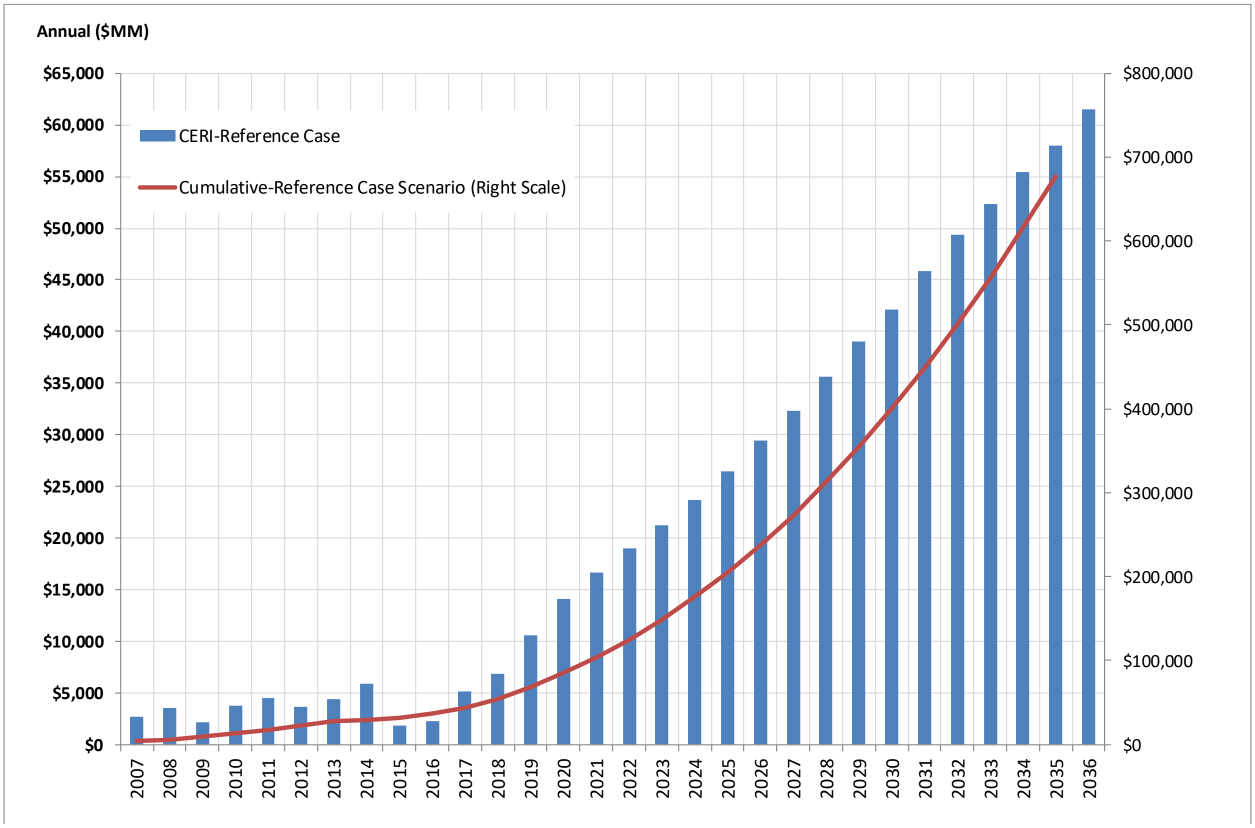
Source: CERI, CanOils

Alberta Oil Sands Royalty Revenues

Figure E.7 displays historical and forecast (2016 to 2036) oil sands royalties on an annual and cumulative basis, in 2015 dollars. Annual royalty revenues amount to C$61.5 billion by 2036, and cumulatively C$676 billion will be collected over the 20-year window.

As a result of capital spending cuts and low prices, royalties will continue to decrease (after an all-time high in 2014) throughout 2015 and 2016. Over the next five years, from 2016 to 2021, as oil prices are expected to recover, royalty revenues will add up to $55 billion (cumulatively), all other things being equal.

Figure E.7: Bitumen Royalties Collected by Project Type



Source: CanOils, CERI

The forecast of oil sands royalties might change significantly as it depends on many moving factors such as production level, oil prices, capital and operating costs. The royalty review advisory panel has issued a report[5] where they make a number of recommendations to the government. The government already implemented changes to the conventional oil and gas royalty formula. Among the recommendations, the panel suggested to retain the current structure and royalty rates for oil sands, but increase the transparency of allowable costs. Through their engagement process with many Albertans, they found that people do not have confidence in the validity of allowable costs. This low level of trust is driven in large part by the lack of transparency in respect of these costs to researchers, analysts and the general public. The panel believes that the success of the oil sands royalty structure critically depends on the validity of allowable costs. To this end, the panel proposed a suite of measures aimed at ensuring allowable costs in the oil sands are transparent, reasonable, up-to-date and valid.

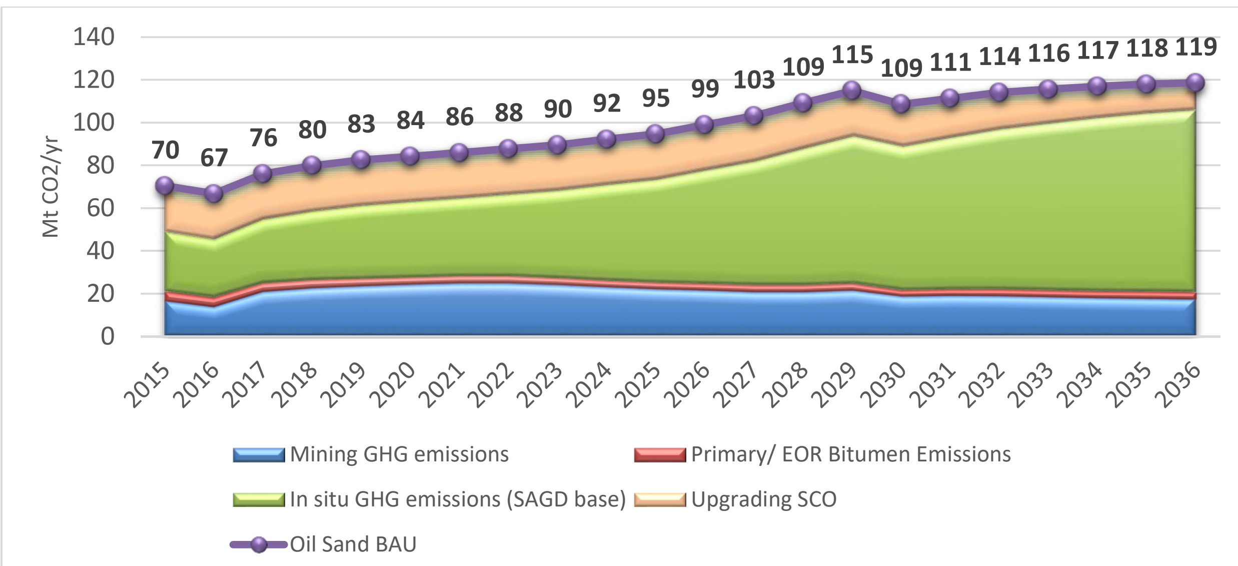
[5] Royalty Review Advisory panel. "Alberta at a crossroads". http://www.energy.alberta.ca/Org/pdfs/RoyaltyReportJan2016.pdf

Emissions

Figure E.8 illustrates the emissions projection for the **Reference Case** production forecast. The on-site emissions projection includes emissions from existing upgrading, electricity or fugitive emissions and flaring. Emissions associated with upgrading capacity that was added after 2015 are not included in the forecast as set by the provincial policy.

Current on-site emissions will grow from 70 MT/year in 2015 to 95 MT in 2025 and total share of the oil sands sector to Canadian emissions are projected to increase from 4.6 percent in 2005 to 12.8 percent.[6] Given the production projection, the oil sands industry will reach the 100 Mt emissions cap by 2026. Increasing production in this sector makes the meeting of international commitments increasingly difficult to meet, and thus there is interest in reducing the amount of GHGs emitted to extract bitumen from the oil sands and generate synthetic crude oil. In CERI's forthcoming study, the Institute outlines the technological path on how to grow oil sands production but reduce overall emissions.

Figure E.8: Oil Sands Emissions by Project Type



Source: CERI

[6] Using Environment and Climate Change Canada's projection of Canadian emissions in 2030 of 742 Mt.

Chapter 1: Introduction

Background

It has been almost two and a half years since the oil price plummeted bringing changes and enormous attention to the industry and its future. After the crash in 2014, the market has been continuously waiting to reach a new equilibrium. Rebalancing was expected in 2015 and 2016, and now has been moved further to 2017. Some may suggest that there is some sort of balance in the market already: since April 2016, the WTI price stabilized around $45 per barrel, and has not gone lower than $40/bbl, except for one day in August.

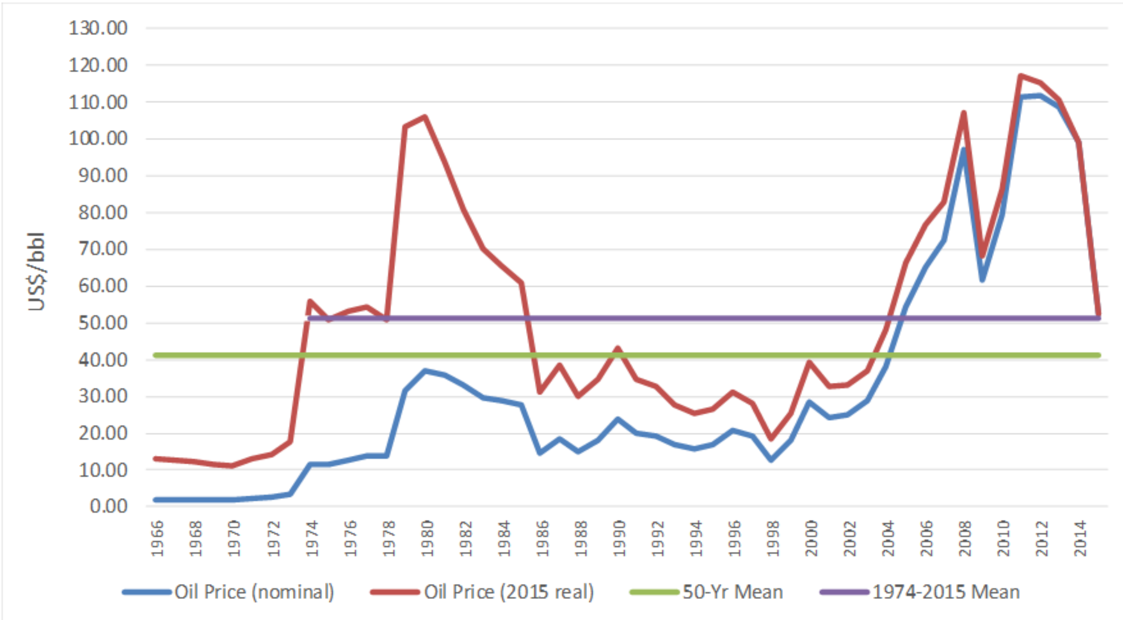
It is now time that the world stops talking about the oil price crash and starts talking about a recovery. Recovery might imply that oil prices should be higher than today's level, but that might not be the case. An oil price at US$45-50 a barrel, the level it's been at for most of 2016, is neither high or low. What we are seeing is what economists call the reversal to the mean, or in other words, the price is returning to its long-term mean value. For the last fifty years, from 1966 to 2015, the mean price of crude oil was US$41.30/bbl, after adjusting for inflation, and between 1974, the year OPEC declared an oil embargo, to 2015 the mean of real price (in 2015 dollars) averaged US$51.40/bbl. This historical range of US$41-51 per barrel might be a return of crude prices to its old range (Figure 1.1).

The International Energy Agency (IEA) does not forecast prices[1] but in its latest Oil Market Report, the Agency points out sluggish demand growth and continuous build of oil stocks and rising supply, signaling that the price surge is not happening, not in the short term.

The Organization of Petroleum Exporting Countries (OPEC) is in the position to cut or freeze production to inflate the price. Back in 2008 the cartel took 2 million barrels per day (MMPBD) of crude supply off market thus increasing prices. Almost eight years later, it agreed to do it again. In September "OPEC agreed to reduce its oil output to 32.5 to 33 MMPBD from the current production levels of around 33.24 MMPBD".[2] This has not happened since the oil prices started to fall in 2014 because OPEC refused to take on their traditional role of protecting the price and instead concentrated on protecting and expanding their global market share. In December, the market saw the first proposed output cut by OPEC since 2008 – and the first deal including non-OPEC producers since 2001 – which marks a major departure from the market share policy followed for the past two years. OPEC's cut to crude production of 1.2 MMBPD almost matches its deliberate production increase of 1.3 MMBPD in the twelve months leading to October 2016 (the month on which the OPEC cuts are based), while the non-OPEC group has seen its crude output fall in the same period by about 0.9 MMBPD.

[1] IEA produces scenarios in their World Energy Outlooks rather than forecasting.
[2] IEA. Oil Market Report, October 2016

Figure 1.1: Crude Oil Price (US$/bbl)



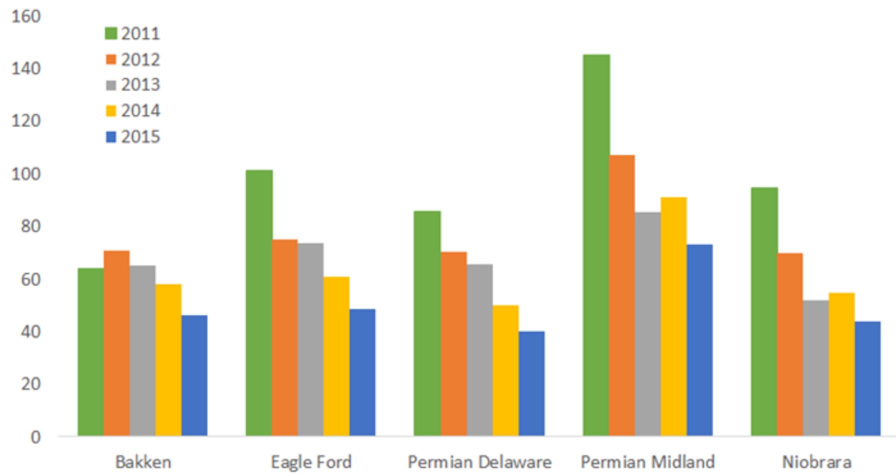
Source: BP Statistical Review of World Energy June 2016

If OPEC promptly and fully sticks to its production target, assessed at 32.7 MMBPD, and non-OPEC producers deliver the agreed cuts of 558 MBPD outlined on December 10, 2016, then the market is likely to move into deficit in the first half of 2017. After the first half of 2017, the analysis is complicated by the fact that the proposed cut is for six months, and will be reviewed at the next OPEC ministerial meeting at the end of May 2017. This can be seen as prudent given the underlying uncertainties in the oil market and the global economy but also a warning that production restraint might not be extended. OPEC also appears to be signaling that high-cost producers should not take for granted that they will receive a free ride to higher production.

Clearly, the next few weeks will be crucial in determining if the production cuts are being implemented and whether the recent increase in oil prices will last. The big question is will the short-term increase in prices sustain itself in the medium-term with more upstream producers tempted to resume production, specifically US tight oil producers? In the US, upstream activity has already picked up. Rig counts are up, increasing by 33 percent from May to October this year.[3] The tight oil well economics are remarkably robust. In 2015, the main plays had an average supply cost of less than US$50 per barrel, with the exception of Permian Midland.[4] New wells in parts of the Permian, Bakken and Eagle Ford areas are now profitable at $40 a barrel[5] (see Figure 1.2).

[3] Baker Hughes North American Rig Count
[4] OPEC World Oil Outlook, 2015, p. 156
[5] http://www.bloomberg.com/news/articles/2016-10-18/oil-seen-stuck-in-50-to-60-range-as-shale-blunts-opec-action

Figure 1.2: WTI Breakeven Prices for US Shale Oil Plays



Source: OPEC, "World Oil Outlook 2015"

Demand outlook for crude oil is somewhat mixed. In the recently published World Energy Outlook 2016 report, the IEA builds scenarios on their view of oil demand. In a scenario where countries will adhere to what they pledged to do at the recent Paris climate summit, which calls for sharp reductions in greenhouse gas emissions, the IEA foresees some major changes in how much oil the world will use for transportation purposes. While industrial, petrochemical and other uses still mean the world will consume more oil in the coming decades (projected demand grows from 92 MMBPD in 2015 to 103.5 MMBPD in 2040), the IEA foresees a future where we use much less oil to get around, with electric vehicle ownership increasing from 1.3 million cars worldwide today to 30 million in 2025 and 150 million by 2040.

Turning to the future oil price assumption, 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), but they're 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.

Production and capital investment forecasts for the oil sands industry are estimated to continue to increase well into the future, albeit with some reduction on capital spending in the near term (2015-2017) as a result of low crude prices and an overall global economic downturn. The nature of new project development in the oil sands has changed. Ten years ago the industry was dominated by megaproject mines and upgraders each built by several thousand people, since then the sector has transformed into smaller, more manageable in situ projects. Notwithstanding the uncertainties around market access and lower crude oil prices due to excess supply globally, oil sands production is expected to grow.

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.

Rejection of TransCanada Corporation's Keystone XL project – originally regarded as the essential link between Canadian bitumen and the US Gulf Coast's untapped refining capacity – has already prompted the industry to look for other solutions. Given current constraints and opposition to expansion of existing pipeline capacity and new pipeline developments, companies have been proactive at exploring other transport options such as rail.

Some pipelines have caught traction though. Until recently, most heavy barrels from Alberta and Saskatchewan moved to refineries in the US Midwest. But pipeline construction and reversals (Seaway twin, TCPL's Gulf Coast extension and Flanagan) have opened more than 1.2 MMBPD of transport capacity from the Midwest – especially Cushing – and the Gulf Coast to support market access for Western Canadian crude oil to the Gulf Coast refining hub. This substantially alleviated the 'Cushing congestion' and the differential between West Texas Intermediate (WTI) and Western Canadian Select (WCS), a benchmark for Canadian heavy output has returned to historical values (the WTI/WCS differential has dropped from an all-time high of $40/bbl to around $15/bbl which historically represents the crude quality difference). A recent Canaccord Genuity report points out that the combination of developments in transportation of crude oil by rail, pipeline project progress in key areas, and new refining capacity should "at the minimum mean heavy oil producers are no longer victimized by transportation bottlenecks." Canaccord goes so far as to say that the Keystone XL pipeline isn't even needed anymore.

Furthermore, in November 2016 the federal government of Canada approved two pipeline project proposals and rejected Northern Gateway pipeline. The two approved projects are the expansion of Kinder Morgan's Trans Mountain pipeline by an additional 590 MBPD and Enbridge's Line 3 replacement enhancing its capacity by 370 MBPD. Both lines are planned to be online with new capacity by 2019. More importantly, with two of the projects Canadian producers will be able to reach markets outside of the traditional US downstream hubs.

Another factor that plays a role in the pace of oil sands development after global and regional supply and demand fundamentals is the provincial and federal governments' climate change policies – an increased carbon tax and absolute emissions cap in Alberta, potential introduction of a federal carbon pricing, and changes to the environmental assessment of major infrastructure projects.

CERI's oil sands production forecast calls for relatively strong growth in both mining and in situ over the next 20 years. The plans to expand oil sands production, increase pipeline take-away 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) favorable oil prices at levels where oil sands projects can be economic,
ii) continuous improvement in an environmental performance among oil sand producers,
iii) appropriately managing project planning with a realistic timeline and budget, and
iv) 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, royalties, natural gas, and diluent requirements.
- Estimate the supply cost, including costs associated with carbon emissions, for greenfield projects consistent with in situ and mining.
- Provide an update to the availability of export capacity with a growing supply.

CERI has established itself as a leader in oil sands related market intelligence. CERI's oil sands projections and supply cost analysis are 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 August 2016), 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., oil sands industry as a whole) throughout this report. The oil sands projects are classified according to their stage of development.

This report also presents greenfield supply costs by project type.

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, emissions and royalties for the Reference Case Scenario.

Chapter 4 discusses the availability of export capacity.

Chapter 2: Oil Sands Supply Costs

Introduction

Oil sands developers and dedicated research and development (R&D) have stimulated the employment of innovative technologies to recover crude bitumen from Alberta's oil sands resources. The result is a dynamic and commercially viable industry that effectively competes on the world scale with conventional and other energy sources. Continuing efforts at reducing costs through technological improvements and other operational measures, while remaining conscious of the environment, should ensure a robust future.

The extraction of Alberta's 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 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. The end result will be an oil sands industry that is better equipped to withstand adverse changes of market forces.

This chapter discusses CERI's supply cost methodology and assumptions and presents supply cost results.

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 2015 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 flexibility to vary inputs, thus allowing for estimation of the supply cost by extraction method required to bring forth new oil sands projects.

[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 Study 122 and 126.

Supply costs have been calculated for the raw bitumen produced (at either an in situ or a mining and extraction operation) 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 or SCO) 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. The generic project specification is based on production method. Here, CERI evaluates a typical steam-assisted gravity drainage (SAGD) project, and a mining project. While significant production comes from integrated mining projects, no new projects have been announced; hence the supply cost analysis does not extend to an integrated 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 are evaluated in CERI's upcoming report addressing costs and environmental performances of new processes and technologies.

Design Assumptions

The Canadian Oil Sands industry is facing several cost-related and market issues that have affected the economic viability of some oil sands projects. Capital and operating costs play the most important role in determining the supply costs. In view of the cost pressures being faced by the industry, CERI decided it was necessary to update its existing cost assumptions. The assumptions that underpin each production method are presented in Table 2.1. The data for capital and operating costs is collected from CanOils database, as well as public sources, such as company annual reports, investor presentations, company announcements, etc., and is averaged across projects according to 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. CERI will identify some of these opportunities in our forthcoming study mentioned above.

The project design parameters are typical of the industry's projects that are being built today; a production flow rate of 30,000 BPD is assumed for a SAGD project and a rate of 100,000 BPD for a mine. 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 requirement for a SAGD plant is 35,910 GJ/d (~2.8 steam to oil ratio or SOR) to reflect recent history – 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 and mining projects do not generate any excess electricity, and that in situ projects purchase electricity from the provincial grid.[3]

Table 2.1: Design Assumptions by Extraction Method

	Measurement Units	SAGD	Mining and Extraction
Project Design Parameters			
Stream day capacity	bbl of bitumen per day	30,000	100,000
Production Life	years	30	30
Capital Expenditures (2015 CDN Dollars)			
Initial	Millions of dollars	1,192.8	7,965.0
Initial	Dollars per bbl of capacity	39,760.0	79,650.3
Sustaining (Annual Average)	Millions of dollars	43.8	386.2
Operating Working Capital	Days payment	45	45
Operating Costs (2015 CDN Dollars)			
Non-energy (Annual Average)	Millions of dollars	70.6	474.7
	Dollars per bbl of capacity	6.4	13.0
Energy Requirements			
Natural Gas			
Royalty Applicable	GJ per day	35,910	54,000
Non-Royalty Applicable	GJ per day		
Electricity Purchased			
Royalty Applicable	MWh/d	300	0
Non-Royalty Applicable	MWh/d		
Electricity Sold	MWh/d	0	0
Other Project Assumptions			
Abandonment and Reclamation	percent of total capital	2%	2%

Source: CanOils, CERI

With oil prices determined in the context of the global market, capital costs are one of only a few parameters operators directly control that have an impact on project economics. 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 – 2015-2016 and even into 2017 – capital spending in the oil sands industry has experienced some decline, as more projects were being postponed. Nevertheless, a handful of producers are building new projects or expanding existing facilities.

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

The capital cost estimates used in the supply cost calculations are averaged over the projects' capital costs that will come online over the 2016-2019 timeframe.

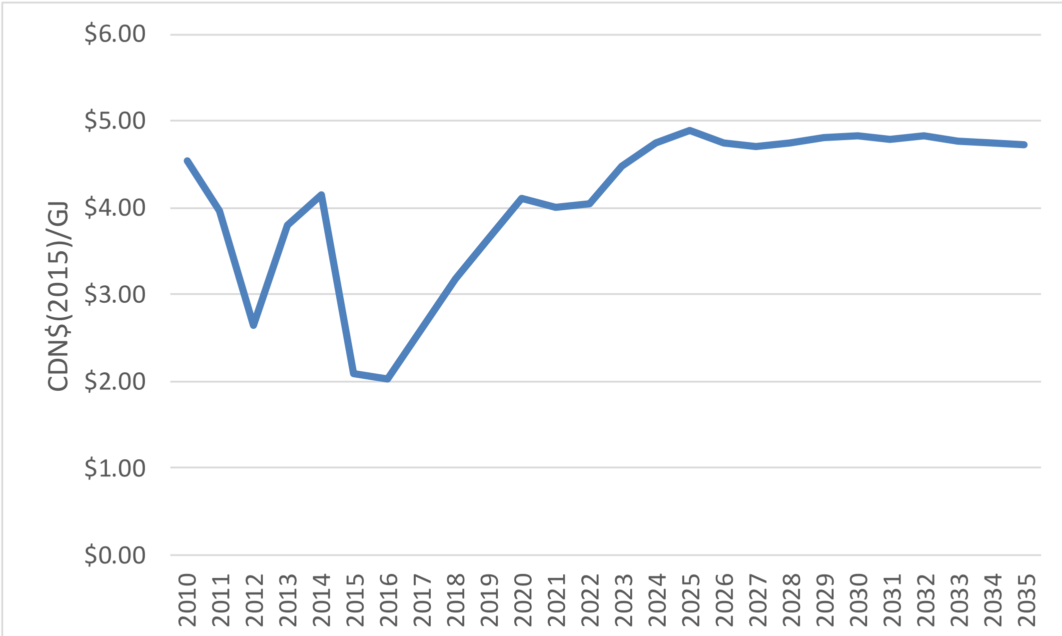
The initial capital costs in 2016 were $39,760 per barrel per day of flowing capacity for a SAGD project and $79,650 per barrel per day of flowing capacity for a stand-alone mine project. These estimates represent an increase from last year's estimates for initial capital of 9.6 percent for SAGD producers and 13.2 percent for mining projects. The sustaining capital costs reflect sustaining capital requirements that are consistent with the industry estimates: sustaining capital costs are $4.00/bbl per day of capacity for a SAGD project and $10.58/bbl per day of capacity for a stand-alone mine.

The average non-energy operating costs have decreased year-on-year for both SAGD and mining projects. The non-energy operating costs for SAGD producers have declined by 25 percent on average year on year; for mining producers – by 22 percent.

The other portion that makes up the total operating cost is the energy-related portion. Oil sands projects are very energy-intensive, consuming large quantities of natural gas, electricity, and chemicals, which are purchased on the market and hence energy-related operating costs are very dependent on the prices of natural gas, electricity and others used as energy feedstock. To approximate energy related costs, natural gas and electricity prices are used.

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) 2016 for the period 2016 to 2040. Prices were then transformed to 2015 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$1.00/MMBTU, and a field premium of C$0.27/GJ (Figure 2.1 displays field prices paid by oil sands producers).

Figure 2.1: Natural Gas Price Forecast



Source: EIA, CERI

Gone are the days when natural gas prices were in double digits, when gas production in Western Canada was at record levels. More recently, prices have been bouncing in the range from just under $2/GJ to almost $5/GJ. With the oil price collapse that started in the summer of 2014, gas prices followed suit. Prices hit a new low, where daily prices for Henry Hub and AECO-C traded below the $2 mark. Over the long horizon, prices are estimated to increase to a sub $5/GJ mark in real 2015 dollars.

Another significant input to oil sands operations is electricity. It has been assumed that on-site cogeneration is in place for mining and upgrading projects as all existing mining operations have co-gen capabilities. The assumption that any excess electricity is sold into the Alberta system holds true, however over the last few years mines and integrated mines have been net importers of electricity. Hence in the design parameters, it is assumed that there is no excess electricity for a mine project.

Over the next decade, it is highly 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. However, for the purposes of calculating supply costs, in situ projects are assumed to purchase electricity from the Alberta grid.

Electricity prices will play a key role in determining the cost of electricity as feedstock to oil sands projects. To approximate the cost of electricity, the Alberta average hourly pool price (CDN$/MWh) was sourced from Alberta Electric System Operator (AESO) 2015 Annual Market

Statistics, 2016.[4] The 2015 price is $33.34, which is 20 percent lower than the 2014 estimate of 41.49/MWh; post-2015, prices are inflated at an annual inflation rate (i.e., in real terms prices are forecast to remain flat).

Light-Heavy Differential

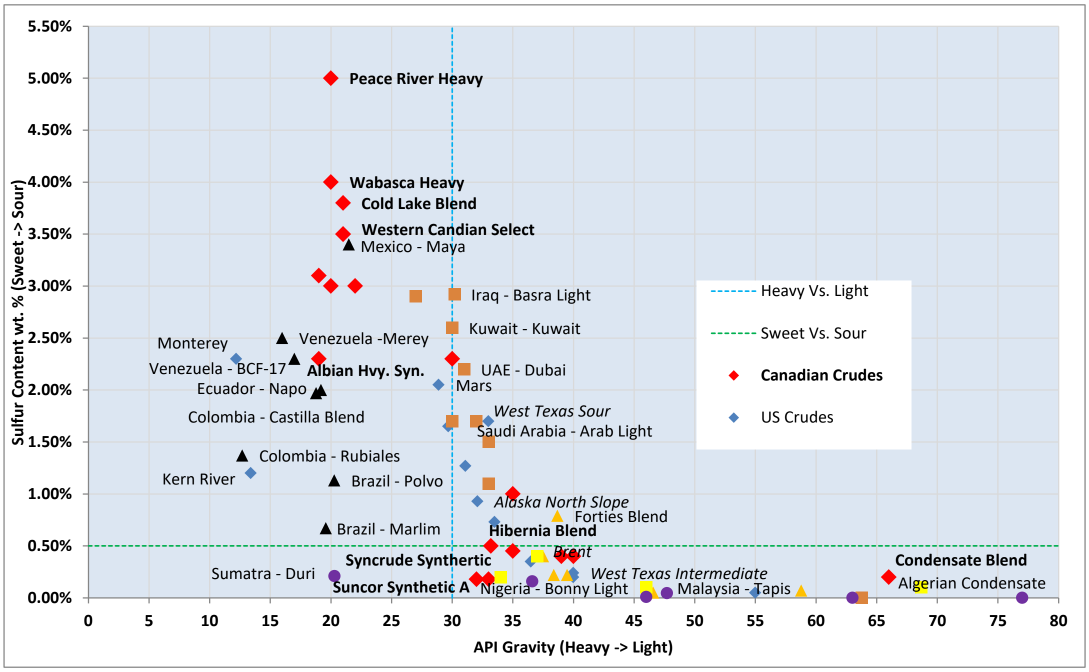
To place oil sands supply costs of a barrel of bitumen in a market context, they have been calculated in terms of equivalent prices for marketable crude oil (e.g., blended bitumen or SCO) at key Alberta market centers (i.e., Hardisty and Edmonton), and in terms of the corresponding equivalent market 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 valued equally. 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 heavy sour grades requires more complex refining operations. The market value of each crude stream therefore reflects the crude characteristics as well as the refined products yield 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 sulfur content. Figure 2.2 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 sulfur content and low on gravity as compared to some other crudes.

[4] Alberta Electric System Operator 2015 Annual Market Statistics, March 2016. https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/

Figure 2.2: Densities and Sulfur Content of Crude Oils



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

Almost all of 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.[5] Table 2.2 compares the characteristics of the WCS blend with two other heavy crude oils.[6] Currently, WCS prices are closely linked to WTI because the majority of WCS crude is shipped to the US Midwest market, for which the historical benchmark has been WTI. WCS crude is sold at a discount to WTI because it is a lower quality crude, producing a positive light-heavy differential.

[5] While WCS or dilbit is a blend of bitumen, conventional and synthetic crudes, its main crude quality parameters (both API gravity and sulfur 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)

[6] Paterson, Shaun, "Restructuring the Canadian Heavy Oil Markets: The Case for a Large Heavy Oil Stream", Encana Corporation presentation to the Canadian Heavy Oil Association, February 3, 2005, http://www.choa.ab.ca/documents/Feb0305.pdf. Accessed on January 11, 2011.

Table 2.2: Crude Oil Characteristics

	WCS Target	Maya	Mars
Gravity (API^0)	19-22	21.8	30.4
Carbon Residue (Wt %)	7.0-9.0	13	5.5
Sulphur (Wt %)	2.8-3.2	3.5	1.9
TAN[a] (mo KOH/g)	0.7-1.0	0.3	0.68

[a]TAN – Total Acid Number, measured in mg of potassium hydroxide needed to neutralize one gram of oil.

Source: Paterson, Shaun, "Restructuring the Canadian Heavy Oil Markets: The Case for a Large Heavy Oil Stream", Encana Corporation presentation to the Canadian Heavy Oil Association, February 3, 2005, http://www.choa.ab.ca/documents/Feb0305.pdf.

As the US tight oil production rose, flooding the US with extra crude supply and squeezing the outflow pipeline capacity in the Cushing, Oklahoma hub, the price for WTI at the hub, which had historically run in close parity with an international benchmark, North Sea Brent, became depressed and started to disconnect from the global benchmark. Discounts deepened, affecting essentially all inland lower-48 crude grades, as well as WCS (since it is priced off WTI). Since January 2011, these discounts have been steep and have been considered 'structural' as seen in Figure 2.3.[7] Since the reversal of the Seaway pipeline and construction of the southern leg of the Keystone XL in 2013 to connect Cushing to the Gulf of Mexico, WTI prices have increased, narrowing the differential between Brent and WTI, but not near its historical norm of US$2-5/bbl, potentially indicating two things: either the two markets are no longer correlated and prices are representative of regional markets only or the market to market connectivity is not sufficient to increase WTI prices to Brent levels (sans transportation costs) or a combination of both.

Besides the lack of appropriate pipeline capacity between the US markets, the problem is further exacerbated by the lack of much needed export pipeline capacity from Western Canada to the US, thus depressing WCS prices against WTI and other crudes, like Mexican Maya. Maya is considered close in quality to WCS, yet Maya is a waterborne crude with readily available access to US Gulf Coast refiners and represents the potential price/market WCS producers could realize/access. Historically, WCS has tended to trade at a discount to Maya,[8] averaging an annual discount of US$6.50/bbl between 2005 and 2010, but the differential started to widen and reached as much as US$48/bbl in February 2013. Recently, with rail bringing in more crude from Canada to the Gulf, that differential narrowed again.

Since the launch of WCS, the price has been tracking the movements of WTI fairly closely with periodic fluctuations. In turn, 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$37/bbl in February 2013, with average and

[7] Another example is WTI versus Light Louisiana Sweet (LLS), a coastal crude, which prior to 2011 traded at $1/bbl discount to WTI but has recently traded at $24/bbl premium to WTI.

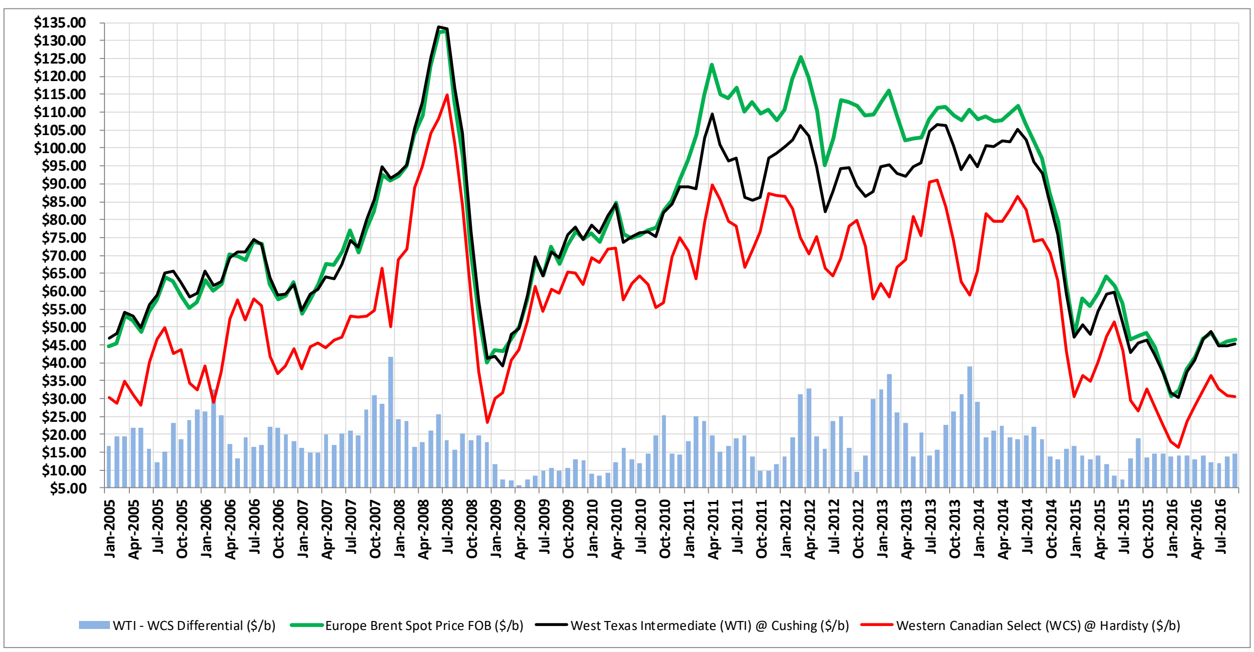
[8] Maya has in turn historically traded at a US$7-9/bbl discount to WTI reflecting mainly quality differences. On the other hand, Maya has historically traded at a $10/bbl discount to Light Louisiana Sweet (LLS), which further reflects the light-heavy differential in the coastal area (more reflective of a global light-heavy differential).

median differentials at about US$18/bbl. The average differential in 2014 stood at US$19.40/bbl, and in the first six months of 2015 it shrank to US$13.16/bbl.

The data series for WCS prices comes from the Baytex Energy website,[9] while Brent and WTI prices are sourced from the US EIA from January 2005 to May 2015. Figure 2.3 illustrates the selected historical benchmark price series and WTI-WCS differential.

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 supports an assumption of a long-term average WTI-WCS differential of US$15/bbl. Therefore, based on the historical data, the light-heavy differential (not including transportation costs) is assumed to be constant at US$15/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.

Figure 2.3: Light-Heavy Differentials (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 centers (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

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

specifications, the cost of diluent, and the cost of transporting diluent to the field. Based upon 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$1.01 per barrel. Transportation costs from Hardisty to Cushing have been adjusted upward to US$5.15 per barrel.[10] 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.

Economic and Taxation Assumptions

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. 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[11] and 12 percent,[12] 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.[13] In addition to the regular CCA deduction, an accelerated CCA has been provided since 1972 for assets acquired for use in new mines, including oil sands mines, as well as assets acquired for major mine expansions (i.e., those that increase the capacity of a mine by at least 25 percent). In 1996, this accelerated CCA was extended to in situ oil sands projects. This change ensured that both types of oil sands projects are accorded the same CCA treatment.

The accelerated CCA takes the form of an additional allowance that supplements the regular CCA claim. Once an asset is available for use, the taxpayer is entitled to deduct CCA at the regular rate. The additional allowance allows the taxpayer to deduct up to 100 percent of the remaining cost of the eligible assets, not exceeding the taxpayer's income for the year (calculated after

[10] CAPP, “Crude Oil Forecast, Markets & Transportation”, June 2016.
[11] Effective January 1, 2012, the federal rate dropped to 15 percent from 16.5 percent.
[12] Effective July 1, 2015, the provincial corporate rate increased from 10 to 12 percent. http://www.finance.alberta.ca/publications/tax_rebates/corporate/overview.html
[13] Property acquired by a taxpayer for the purpose of gaining or producing income from a bituminous 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.

deducting the regular CCA). 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 helped to offset some of the risk associated with early investments in the oil sands and contributed to the development of this resource. Over time, however, technological developments and changing economic conditions have led to major investments that have moved the sector to a point where the majority of Canada's oil production will soon come from oil sands. As a result, this preferential treatment is no longer required. Budget 2007 phased out the accelerated CCA for oil sands projects – both mining and in situ.[14] The regular 25 percent CCA rate will remain in place. To provide stability, and in recognition of the long lead time involved in some oil sands projects, the following transitional relief was provided:

- the accelerated CCA will continue to be available in full for:
  - assets acquired before March 19, 2007, and
  - assets acquired before 2012 that are part of a project phase on which major construction began before March 19, 2007
- for other assets, the additional accelerated allowance will be gradually phased down over the period 2011 to 2015 (when it will be eliminated), according to the schedule set out below.

The percentage allowed will decline each calendar year, as shown in Table 2.3 (prorated for off-calendar taxation years).

Table 2.3: Phase-Out Schedule

Year	Allowable % of Additional Allowance
2010	100
2011	90
2012	80
2013	60
2014	30
2015	0

Source: Budget Plan 2007, Annex 5.

For the purposes of this report, it is assumed that the transitional relief is not applicable for the supply cost calculation of our greenfield projects and hence the phase out schedule is applied as set in Table 2.3.

[14] To the extent that the accelerated CCA for oil sands projects induces incremental oil sands development that could contribute to environmental impacts such as greenhouse gas emissions, air and water contaminants, water usage, and disturbance of natural habitats and wildlife, these changes could help reduce such incremental impacts.

Oil sands operations are assumed to commence construction on January 1, 2016, and begin operating on January 1, 2018. The projects will continue to operate until end of year 2047, based on a 30-year project life.

Carbon Tax

In 2016, Alberta Government enacted changes to its carbon policy. The new Climate Leadership Plan is a strategy to reduce emissions while diversifying the provincial economy. Several key aspects include:

- 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% 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, moving to $30/tonne on January 1, 2018, and increasing in nominal terms each year thereafter. SGER (Specific Gas Emitters) systems covering large emitters will transition to the new approach, in which product-specific emission performance standards will replace the current uniform intensity-based reduction approach. This will replace the existing intensity targets, which are based on GHG reductions per unit of production regardless of type of product. SGER expects to remain in place (aligned at $30/tonne in 2018) in the near term, while the transition plan is being developed. 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.

At the time of writing, the new product-based approach for reducing emissions intensity was not announced and hence CERI's supply cost model assumes existing SGER systems for emission intensity reduction, and that producers exercise the option of paying the $30.00/tonne tax, which increased at an annual average inflation rate of 2.0 percent.[15]

Royalty Assumptions

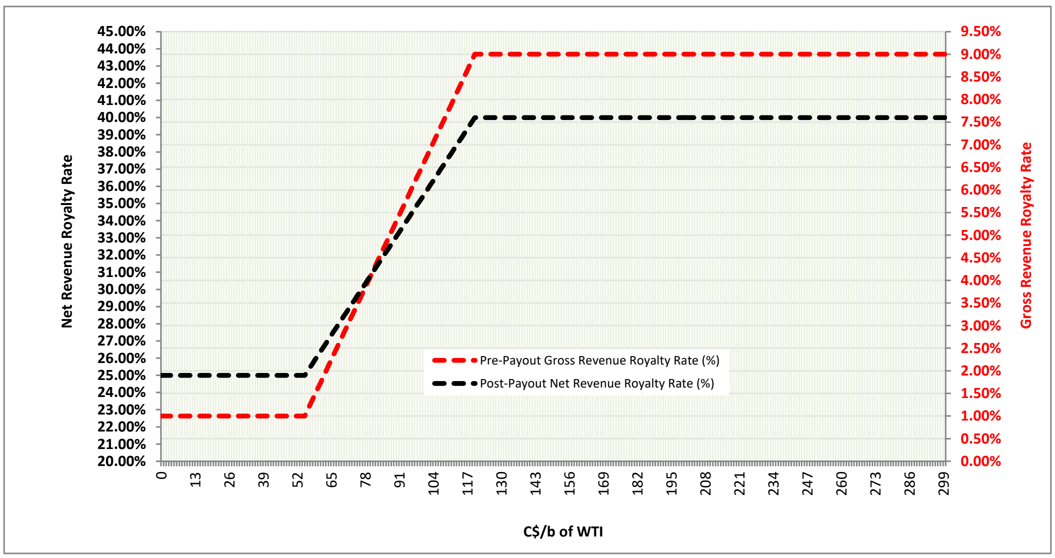
The Alberta oil sands royalty regime is based on the net revenue system whereby the oil sands producer pays a lower royalty rate based on gross revenues until the point at which the producer has recovered all the allowed project costs (those incurred up to three, and in some cases up to five, years prior to the approved effective date) plus a return allowance based on current Long

[15] CERI assumes that the reduction in carbon intensity and/or purchase of carbon offset credits more or less equates to carbon tax.

Term Government Bond Rates (LTBR) issued by the Government of Canada (floor risk).[16] 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 2.4.

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, as well as the costs of compliance with environmental regulations and with termination of a project, abandonment and reclamation of a project site.[17]

Figure 2.4: Alberta Bitumen Royalty Rates



Source: CERI

To better understand this year's supply cost results, an oil price projection was required in order to accurately estimate the royalties. The forecast of the WTI price was obtained from the EIA's AEO 2016, for the period 2015 to 2040.[18] Prices were then transformed to 2015 dollars and converted to Canadian dollars as shown in Figure 2.5. Since the summer of 2014, global and North

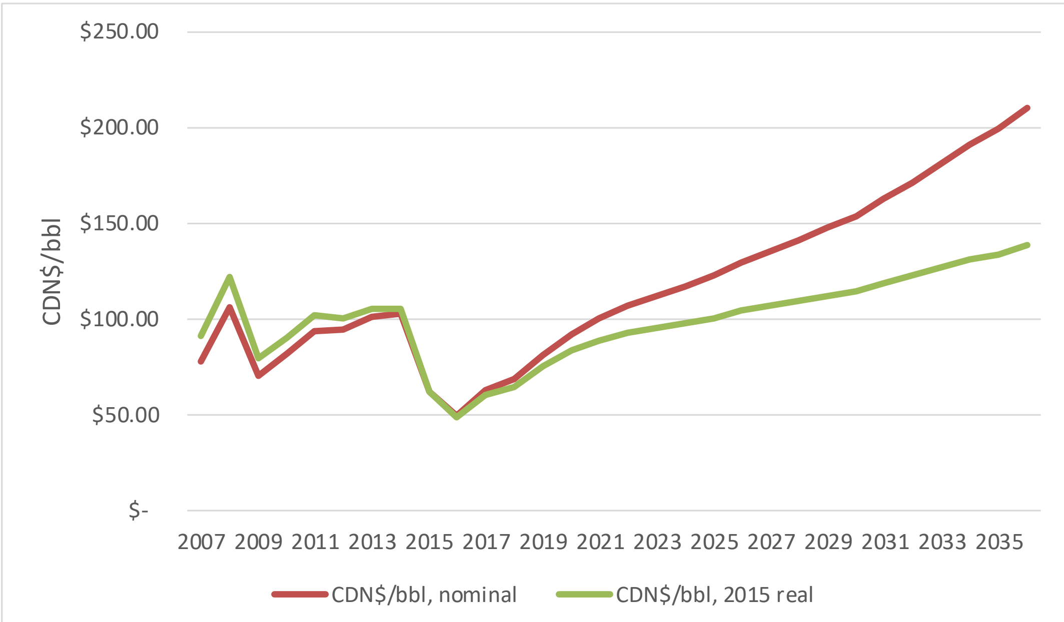
[16] Assumed to be 5.5 percent.

[17] 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.

[18] Beyond 2040, prices were simply inflated at 2.5 inflation rate.

American crude prices decreased by around 50 percent from US$100+/bbl to US$50/bbl due to an overall global crude oil excess supply driven by high US production levels. Oil prices have started to increase as the market fundamentals are coming into balance as crude inventories have started to get depleted. The market signals for a higher price as OPEC members and some non-OPEC countries have promised to cut production.

Figure 2.5: WTI Price Forecast (CDN$/bbl)



Source: EIA, CERI

US-Canadian Exchange Rate

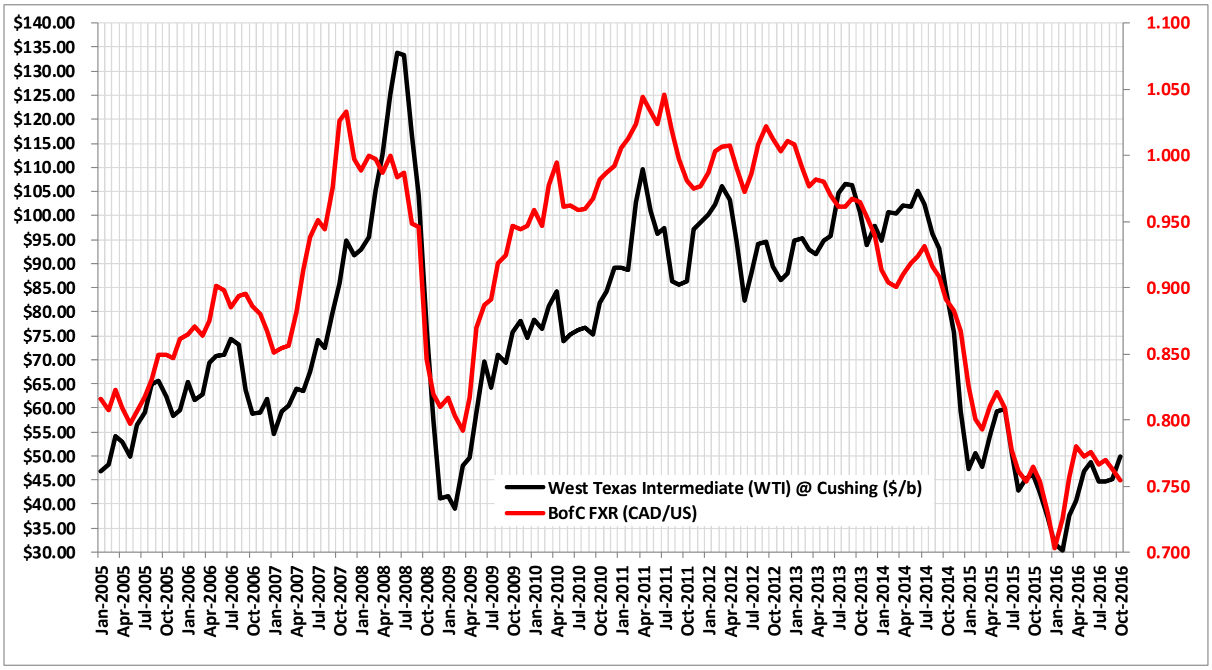
Since the summer of 2014, the price of oil has plummeted to its lowest point in years – and so has the Canadian dollar, continuing an ongoing debate on how closely the two are related. Canada's dollar is often viewed as a petrocurrency because its movements often track oil prices (see Figure 2.6). In 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.

Since 2008, when the WTI price closed for the first time at over US$100/bbl and the Canadian dollar was trading at parity with the US dollar, price and exchange rate have undergone several cycles. The most recent 50 percent decline in oil prices in the summer 2014 coincides with the depreciation of the Canadian dollar. Given the flat oil price forecast and high correlation factor between the exchange rate and oil prices,[19,20] an exchange rate of US/CDN$0.85 will be assumed

[19] http://news.ubc.ca/2015/04/16/is-the-canadian-dollar-a-petrocurrency/
[20] http://www.bankofcanada.ca/wp-content/uploads/2012/02/workshop-exchange-rates-june2011-Ferraro-Rogoff-Rossi-presentation.pdf

in the supply cost calculation. This represents a 15 percent drop from previous assumptions of parity between the two currencies.

Figure 2.6: CDN/US Exchange Rate



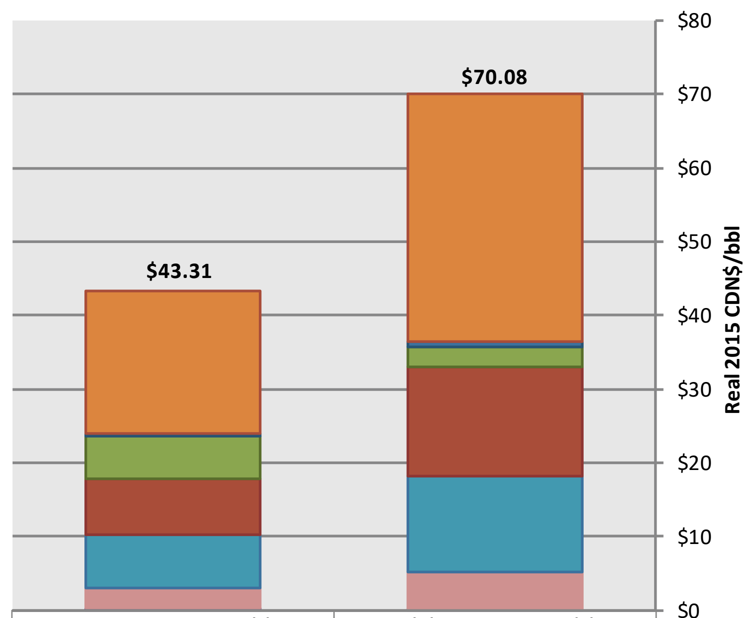
Source: EIA, Bank of Canada

Supply Cost Results

Based on these assumptions, the supply costs of crude bitumen using SAGD and surface mining and extraction have been calculated for a hypothetical project. Figure 2.7 illustrates the supply costs for these projects. The plant gate supply costs, which exclude transportation and blending costs, are C$43.31/bbl for a SAGD project and C$70.08/bbl for a stand-alone mine. A comparison[21] of field gate costs from the August 2015 update with this year's supply costs indicates that, after adjusting for inflation, the supply cost for a SAGD producer has fallen by 27 percent, and 6 percent for a stand-alone mine.

[21] 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/SCO Supply Costs



	SAGD 10% ROR (a)	Mining 10% ROR (a)
Fixed Capital (Initial & Sustaining)	$19.25	$33.68
Operating Working Capital	$0.40	$0.70
Fuel (Natural Gas)	$5.87	$2.68
Other Operating Costs (incl. Elec.)	$7.53	$14.84
Royalties	$7.14	$13.05
Income Taxes	$2.82	$4.94
Emissions Compliance Costs	$0.27	$0.13
Abandonment Costs	$0.03	$0.05

[a]Return on capital included.

Source: CERI

After adjusting for blending and transportation, the WTI equivalent supply costs at Cushing for SAGD projects is US$60.52/bbl and US$75.73/bbl for a stand-alone mine. In comparison to last year's update, the WTI equivalent costs for a greenfield SAGD project are 25.3 percent lower and 16.5 percent lower for a stand-alone mine. This year's lower supply costs for SAGD and mining projects are primarily due to lower operating costs – namely, prices for natural gas and electricity – and recent changes in the US/Canadian dollar exchange rate. A summary of costs are presented in Table 2.4. At current WTI prices of just above US$50/bbl,[22] one can assume that these greenfield projects are not economic or have to accept a lower rate of return. However, as observed in the industry, the relative position of oil sands projects against other crude oils is

[22] At the time of writing, WTI prices traded at just above US$50/bbl.

comparatively competitive, and as oil prices are expected to increase, so will the profitability of oil sands projects.

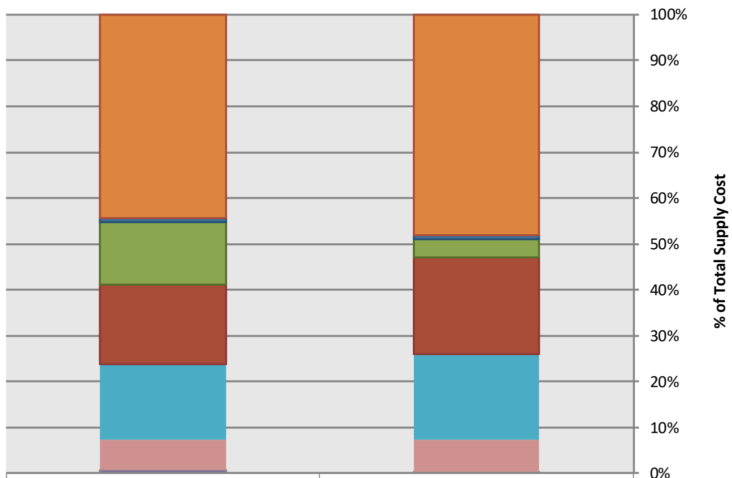
Table 2.4: Supply Costs Summary

Supply Cost	SAGD 10% ROR (a)	Mining 10% ROR (a)
Net Present Value (C$ Millions)	$0	$0
Discount Rate	$0	$0
Base Year	2015	2015
	Discounted	Discounted
Costs (C$/b)		
Return on Investment	Included	Included
Fixed Capital (Initial & Sustaining)	$19.25	$33.68
Operating Working Capital	$0.40	$0.70
Fuel (Natural Gas)	$5.87	$2.68
Other Operating Costs (incl. Elec.)	$7.53	$14.84
Abandonment Costs	$0.03	$0.05
Royalties	$7.14	$13.05
Income Taxes	$2.82	$4.94
Emissions Compliance Costs	$0.27	$0.13
Subtotal	$43.31	$70.08
Electricity Sales	0.0	0.0
Subtotal	0.0	0.0
Total Supply Cost (C$/b)	43.31	70.08
WTI Equivalent (US$/b)	60.52	75.73

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. It is assumed that emission compliance costs are royalty deductible, as is currently the case. While capital costs and the return on investment account for a substantial portion of the total supply cost, the province stands to gain $7.14 to $13.05 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 16.5 to 18.6 percent share of total supply cost, a decrease of 7.3 percent for a SAGD project and unchanged for a mining project (see Figure 2.8).

Figure 2.8: Oil Sands Supply Costs – Reference Case Scenario (% Contribution)



	SAGD 10% ROR (a)	Mining 10% ROR (a)
Fixed Capital (Initial & Sustaining)	44.4%	48.1%
Operating Working Capital	0.9%	1.0%
Fuel (Natural Gas)	13.6%	3.8%
Other Operating Costs (incl. Elec.)	17.4%	21.2%
Royalties	16.5%	18.6%
Income Taxes	6.5%	7.1%
Emissions Compliance Costs	0.6%	0.2%
Abandonment Costs	0.1%	0.1%

Source: CERI

CERI's estimates of supply costs compared to the Alberta Energy Regulator's (AER) calculated costs (AER's costs are calculated using a nominal discount rate of 10 percent)[23] are presented in Table 2.5. AER's range for a SAGD project between $45/bbl for brownfield projects to $60/bbl for higher-cost greenfield operations are comparable to CERI's findings of $60.52/bbl for greenfield SAGD. AER's supply costs for greenfield mining range between $75 and $85/bbl are also in line with CERI's results.

[23] For other supply cost assumptions, see AER ST-98-2016. "Alberta's Energy Reserves 2015 and Supply/Demand Outlook 2016-2025". June 2016.

Table 2.5: Supply Costs Comparison – WTI Equivalent Supply Costs

Project	CERI (2015 US$/bbl)	AER (2015 US$/bbl)[24]
SAGD	**60.52**	45-60
Stand-alone Mine	**75.73**	75-85

Source: CERI, AER.

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 2.6.

Table 2.6: Assumptions for Sensitivity Analysis

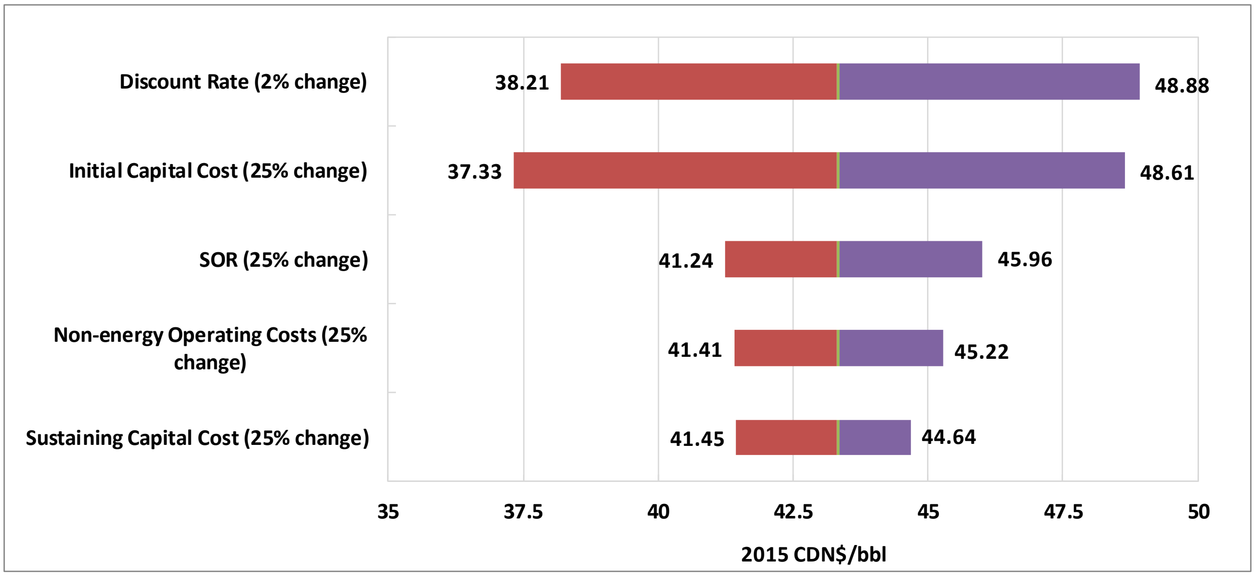
Parameter	Sensitivity
Initial Capital Cost	+/-25%
Sustaining Capital Cost	+/-25%
Non-Energy Operating Costs	+/-25%
Discount Rate	+/-2%
SOR	+/-25%

Source: CERI

Bitumen supply cost sensitivities for a hypothetical SAGD and a stand-alone mine are represented graphically in Figures 2.9 and 2.10.

[24] Ibid.

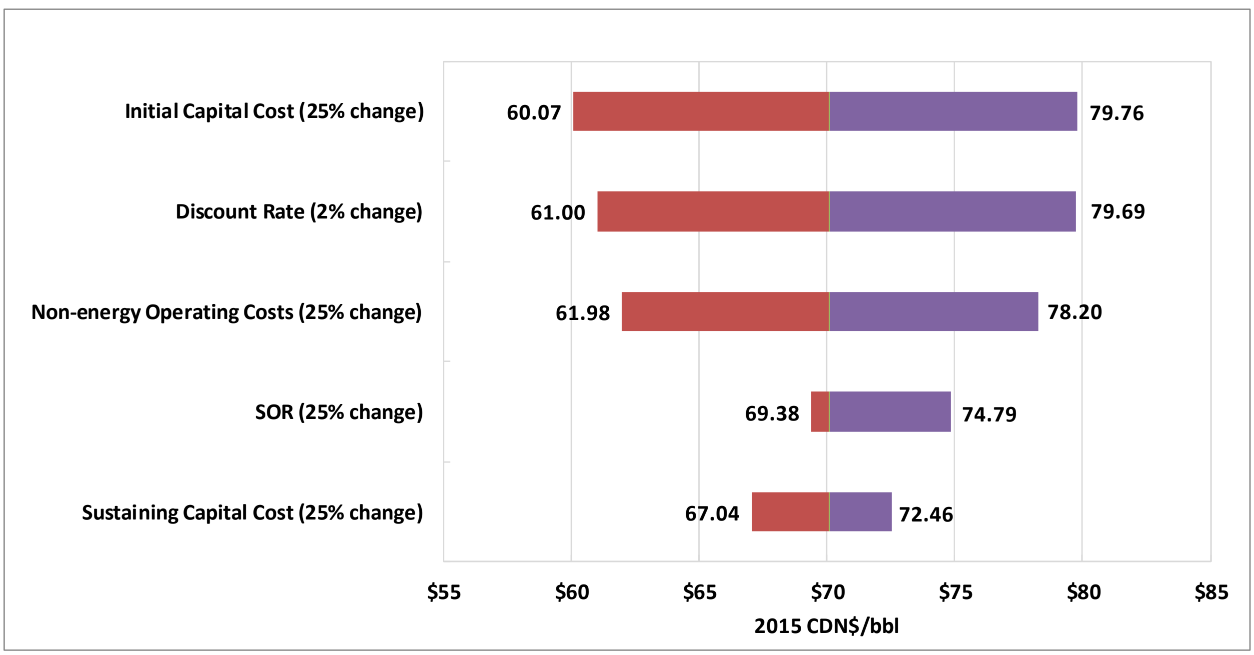
Figure 2.9: Supply Cost Sensitivity – 30 MBPD SAGD Project



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. If the discount rate is raised to 12 percent real, the supply cost is estimated to increase by $5.57/bbl (or 13 percent), and when it is decreased to 8 percent real, the cost will decrease by $5.10/bbl (or 12 percent) from its base of $43.31/bbl.

Figure 2.10: Supply Cost Sensitivity – 100 MBPD Mining and Extraction Project



Source: CERI

For a stand-alone mining project, the supply cost will increase by C$9.68/bbl (or 14 percent) and decrease by $10.01/bbl (or 14 percent) 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 $9.61/bbl (or 14 percent) and a decrease to 8 percent will result in a $9.08/bbl (or 13 percent) drop in the base supply cost of $70.08/bbl.

Chapter 3: Oil Sands Projections

Based upon the supply cost results and given the oil price forecast, the last chapter concluded that greenfield oil sands projects might be challenged, however, a comparison of costs with last year's results indicates some relief to producers – development of additional phases to existing brownfield facilities can cost less than greenfield development. Low oil prices have caused companies to announce capital spending cuts, the exchange rate to drop, light-heavy differentials to narrow and operating costs to fall. However, an improvement in oil prices in the latter part of this decade still 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 view of where oil sands production might be heading. A discussion of the methodology used to develop the projections is followed by the assumptions used to delay, and/or cancel oil sands projects. CERI's oil sands projections for bitumen, SCO, natural gas requirements, strategic and sustaining capital, operating costs, and provincial royalty revenues are then provided. Special focus is given to the **Reference Case Scenario** and discussed in more detail at the end of the chapter.

Methodology and Assumptions

CERI's methodology for projecting bitumen and SCO production volumes 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 understanding of oil market dynamics and specific characteristics of oil sands projects.

The scenarios are the **Reference Case**, **High Case**, and **Low Case**. Each scenario contains its own assumptions as to delays in the on-stream date and the rates of capacity/production additions.

The impact that these scenarios could have on oil sands developments was translated into two constraints: project startup delays, and capacity curtailments. These constraints were a function of the scenarios and their impact on a project's ability to move through the regulatory and internal corporate approval processes.

Delay Assumptions

On-stream projects are assumed to be producing 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.

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. The delays and probabilities are different for each scenario to represent the economic environment of each individual scenario. 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 and Line 3 refurbishment and expansion,[25] 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.

Royalty Revenues and Blending Requirements

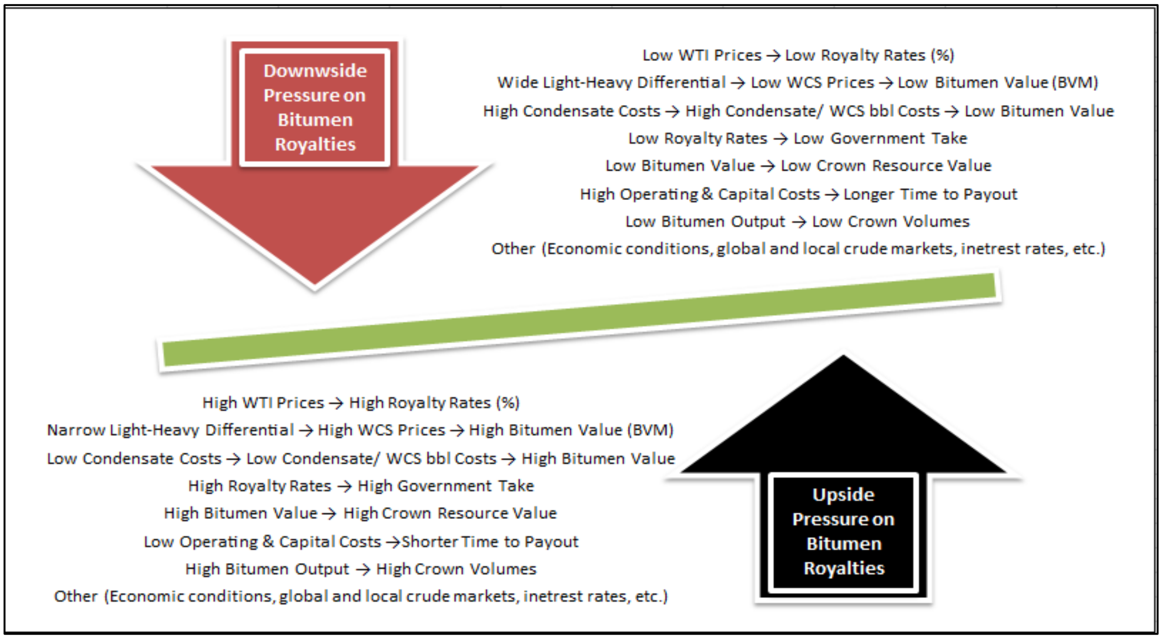
Due to their importance to Alberta's economy as well as the complexity of their calculation, it is important to develop accurate estimates of royalty revenues in the context of this report. Further, while various organizations such as the Canadian Association of Petroleum Producers (CAPP), the Alberta Energy Regulator (AER), and the National Energy Board (NEB) develop estimates for production, supply, and associated costs, none of them provide estimates for royalties. Two reports provide oil sands royalty estimates over the short term, including a report by ARC Financial Corp.[26] and Alberta Finance in its latest budget revenue outlook. The results of these projections are compared with CERI's own projection in the Results section of this chapter.

Generally speaking, bitumen royalties are a function of royalty rates and producers' revenues (either gross or net revenues, depending on project payout status). However, while that seems simple enough, there are various channels through which both upside and downside pressures are exerted on total bitumen royalties collected, as illustrated in Figure 3.1.

[25] John Pail Tasker. "Trudeau cabinet approves Trans Mountain, Line 3 pipelines, rejects Northern Gateway". http://www.cbc.ca/news/politics/federal-cabinet-trudeau-pipeline-decisions-1.3872828. Accessed on November 29, 2016.

[26] ARC Financial Corp. "The Fiscal Pulse of Canada's Oil and Gas Industry, First Quarter 2015", April 2015.

Figure 3.1: Bitumen Royalty Drivers



Source: CERI

CERI developed a cash flow methodology on a project phase by project phase basis in order to calculate royalties from oil sands projects. CERI has been publishing long-term oil sands royalty forecasts for a number of years. More information on the cash flow methodology is provided in Appendix A of CERI Study 133.[27]

Blending requirements are determined through the bitumen valuation methodology together with evaluation of each individual crude slate from various oil sands projects. Further details are described in Appendix A of CERI Study 133.

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. The projections include production from existing projects as well as new projects that are under construction, approved, awaiting approval, and announced[28]. This year the projection period is from 2016 to 2036, inclusive.

Figure 3.2 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). Despite the short-term outlook for flat oil

[27] CERI Study No. 133, "Canadian Oil Sands Supply Costs and Development Projects (2012-2046)", May 2013.
[28] Announced projects are assigned with high uncertainties regarding timing and project production capacities.

prices, high construction costs, probability of construction and regulatory delays, availability of suitable and accessible refinery capacity, and environmental performance metrics, the prevailing view in the industry appears to be cautiously optimistic. All three scenarios show a growth in oil sands production for the 20-year projection period.

Total production from oil sands areas totaled 2.53 MMBPD in 2015, comprised of in situ (thermal and cold bitumen) production of 1.36 MMBPD and mining production of 1.16 MMBPD within the boundaries of oil sands areas.[29] Total production in 2014 was 2.31 MMBPD, meaning the oil sands production grew 9.6 percent year-over-year. Production from oil sands includes an increasing share of Alberta's and Canada's crude oil production. In 2015, non-upgraded bitumen and SCO production made up 62 percent of total Canadian crude production and 78 percent of Alberta's total production.

In the **High Case Scenario**, production from mining and in situ projects (thermal and cold bitumen) is set to grow to 3.5 MMBPD by 2020 and 5.9 MMBPD in 2030, peaking at an all-time high of 6.6 MMBPD by 2036. In the **Low Case Scenario** production rises to 3.3 MMBPD in 2020, 3.8 MMBPD by 2030 and 4.5 MMBPD by the end of the forecast period. CERI's **Reference Case Scenario** provides a more plausible view of the oil sands production. Projected production volume will increase to 3.4 MMBPD by 2020 and 4.8 MMBPD in 2030, peaking at 5.5 MMBPD by 2036 (see Figure 3.2 and Table 3.1).

Table 3.1: Oil Sands Production Forecast (MMBPD)

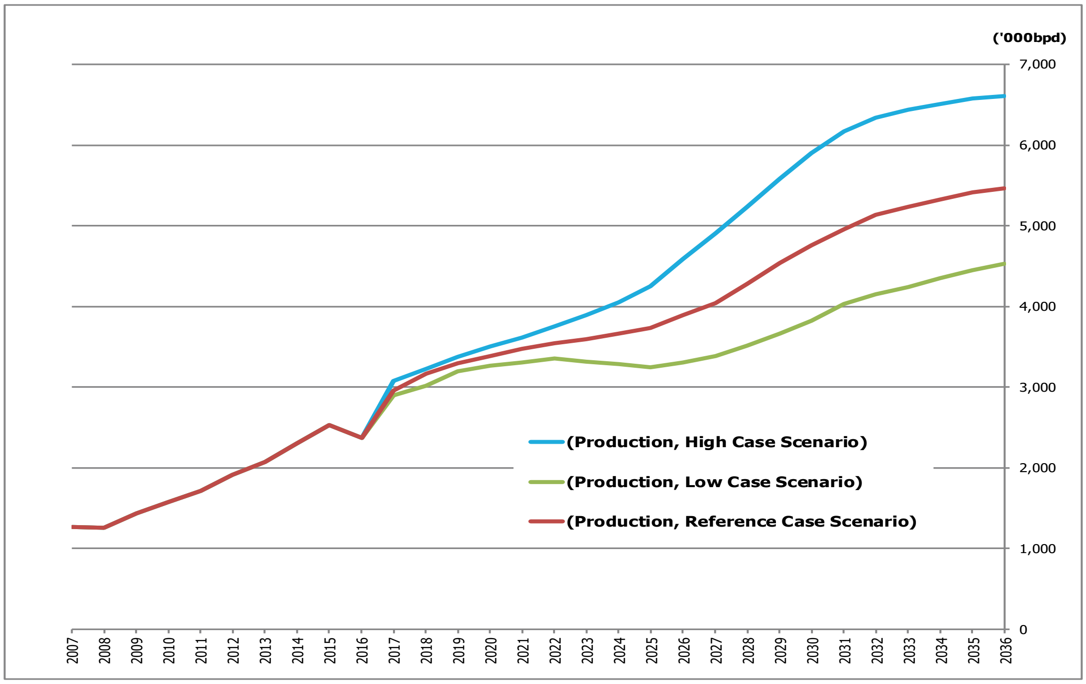
	2015	2020	2030	2036
High Case	2.53	3.51	5.90	6.61
Reference Case	2.53	3.38	4.76	5.47
Low Case	2.53	3.26	3.82	4.53

Source: CERI

The differences in magnitude of production growth among the three scenarios can be explained by a combination of the acceleration/deceleration of the startup of projects and capacity curtailments. This year's forecast includes projects that were announced due to a higher oil price forecast.

[29] Totals may not add up due to rounding. Historical production from the provincial regulator.

Figure 3.2: Bitumen Production Projections



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 Scenario**. Projections of production, capital and operating costs, diluent, natural gas and royalties are included in the discussion. Chapter 4 will discuss the transportation logistics to export markets**.**

Oil Sands Production – Historic and Forecast

A comparison is presented between CERI's **Reference Case Scenario** production and other agencies' forecasts, such as CAPP,[30] the AER,[31] and the NEB[32] that report oil sands forecasts. Figure 3.3 illustrates the comparison of bitumen production between CERI and the three agencies. The AER's forecast goes out to 2025, CAPP's to 2030 and the NEB's to 2040. CERI's total

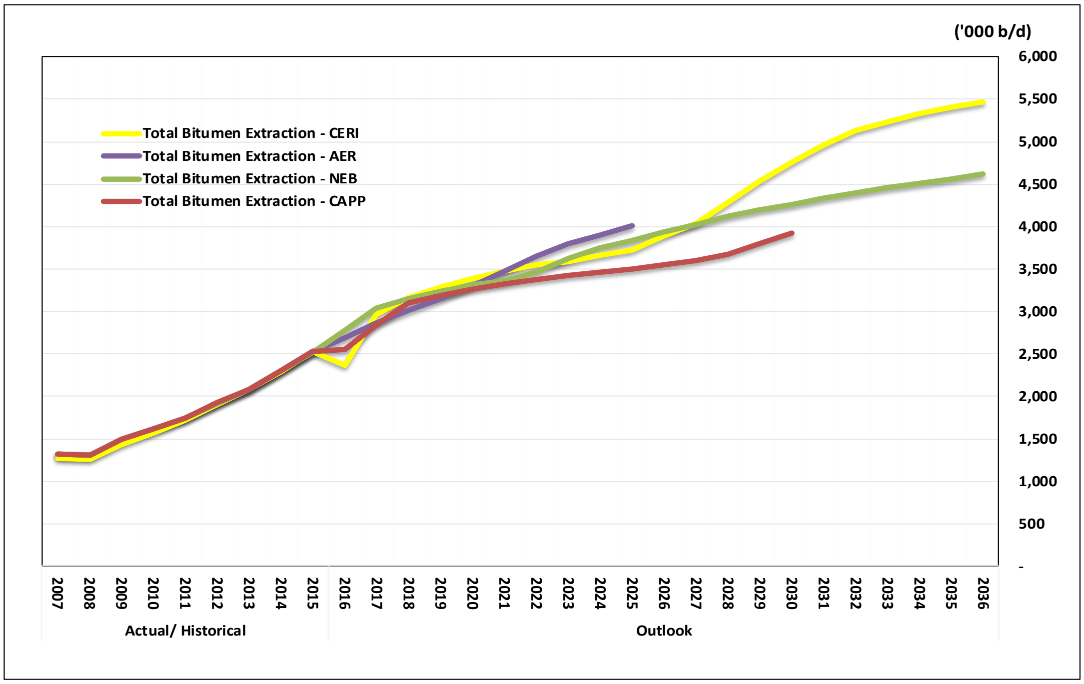
[30] CAPP, "Canadian Crude Oil Forecast and Market Outlook", June 2015

[31] AER ST-98, "Alberta's Energy Reserves 2013 and Supply/Demand Outlook (2015-2024)", June 2015.

[32] NEB, "Canada's Energy Future: Energy Supply and Demand Projections to 2035 – Energy Market Assessment 2013", November 2013.

production projection from oil sands areas (including primary and EOR projects) spans from 2016 to 2036, inclusive. CERI's Reference Case production projection is similar to other forecasts for the short and medium term, while later in the time period production is expected to grow faster as oil prices improve and more greenfield development will occur (announced projects are included in the projection, however due to uncertainties on timing and project capacities, they are heavily discounted). The dip from 2015 to 2016 is the result of wildfires that happened mid-2016 affecting oil sands projects.

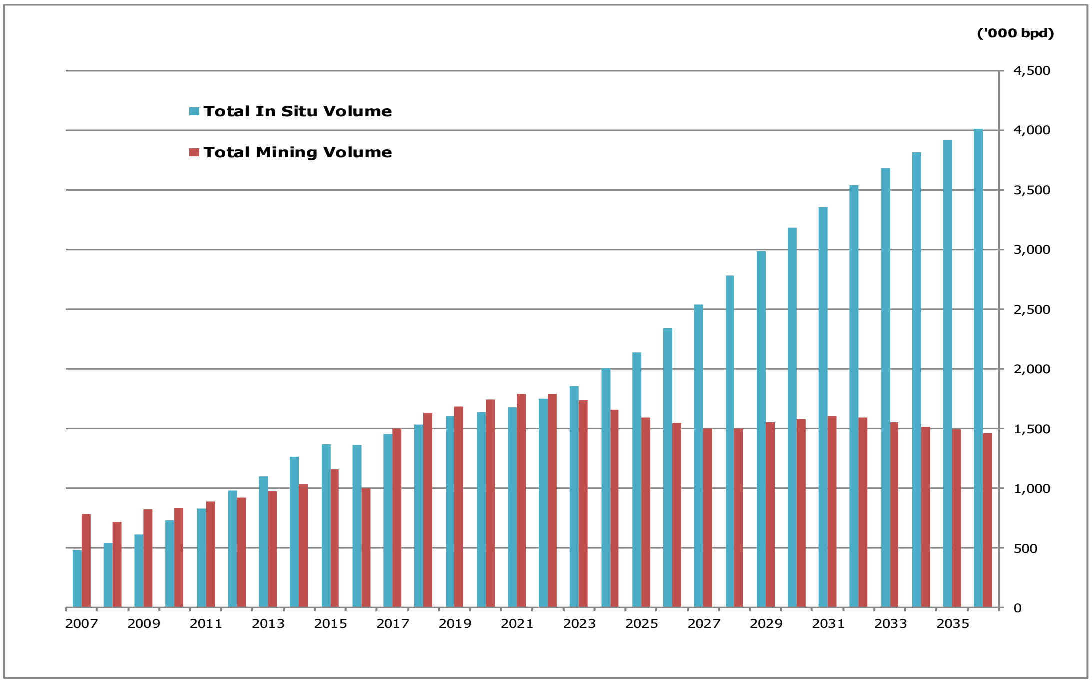
Figure 3.3: Bitumen Production Forecast – Comparison



Source: CERI, AER, CAPP, NEB.

Illustrated in Figure 3.4 are the production projections by extraction type. Total mined bitumen production is expected to increase from 1.2 MMBPD in 2015 to its peak of almost 1.8 MMBPD by 2022, at which point the production dips to 1.5 MMBPD by 2036. The decrease in mining production is explained by some of the legacy mines coming offline. The remainder of the projection period remains flat. Since 2012, in situ production continues to be higher than mining. Production is expected to increase continuously from 1.4 MMBPD in 2015, to an all-time peak of 4 MMBPD in 2036 as a result 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 46 percent in 2016 to 27 percent in 2036. By the end of the projection period in 2036, in situ bitumen accounts for the majority of incremental bitumen barrels.

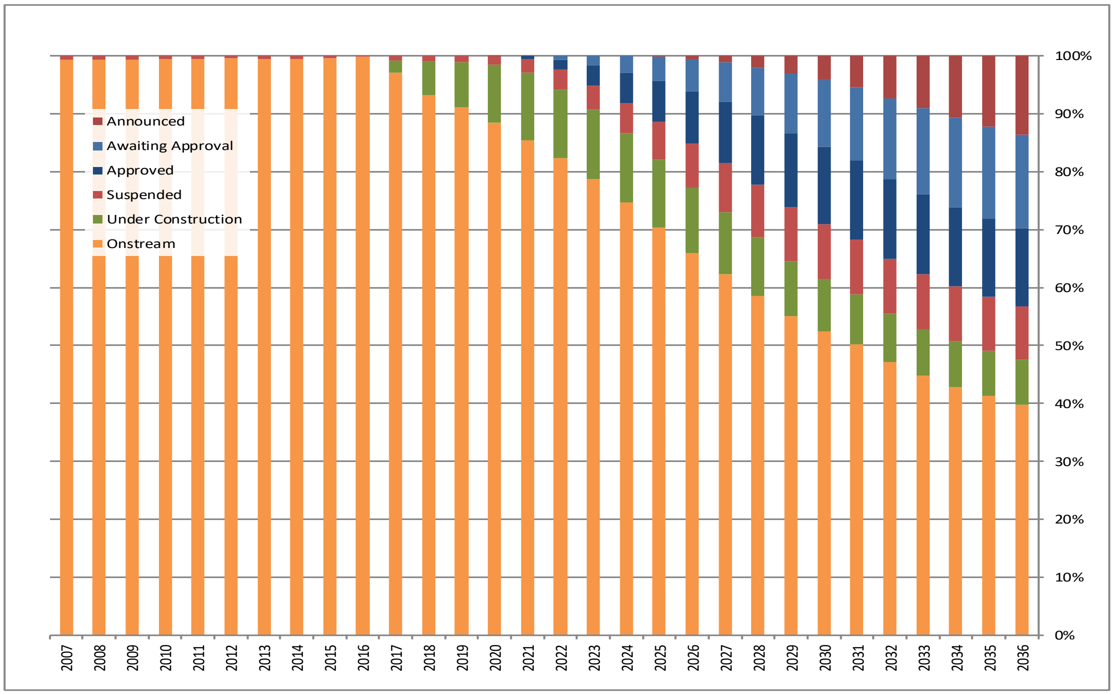
Figure 3.4: Bitumen Production by Extraction Type – Reference Case Scenario



Source: CERI, CanOils

Given the production projection, bitumen production is shown by project category in Figure 3.5. The figure illustrates that a large share of total projects is made up of on-stream projects. As the proportion of on-stream projects starts to decline, the total proportion of under construction, approved, and awaiting approval projects takes up the share of total production.

Figure 3.5: Bitumen Production by Project Status[33]



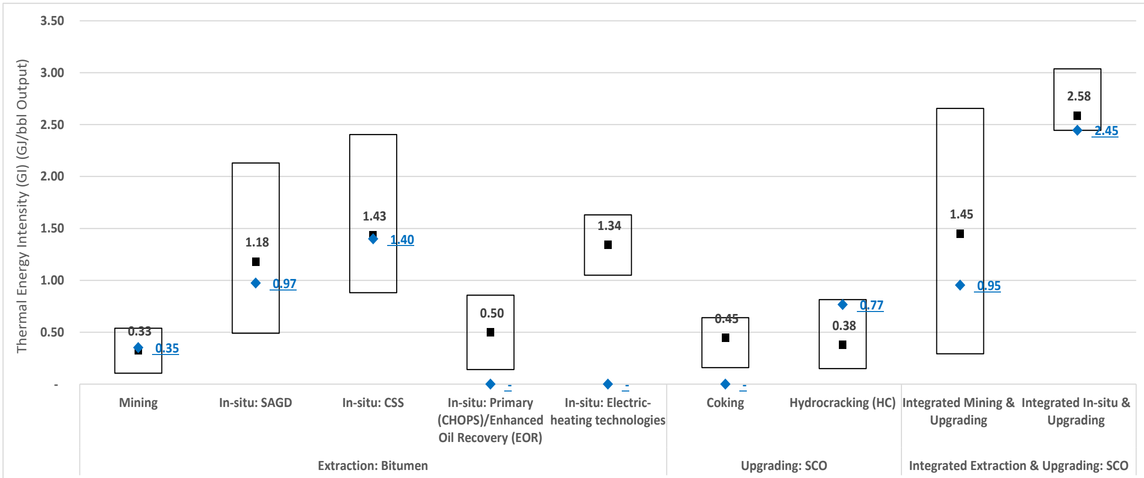
Source: CERI, CanOils

Natural Gas Demand

Figure 3.6 displays the range for thermal energy/gas intensity factors developed by CERI[34] 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 3.7 displays (natural gas equivalent) hydrogen intensity factors for upgrading projects.

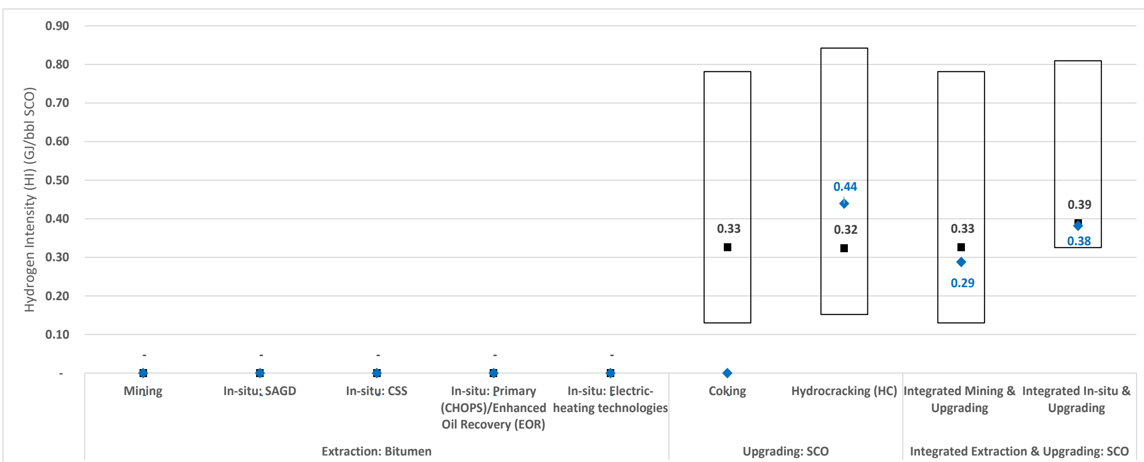
[33] This graph does not include the forecast of primary and EOR projects.
[34] For more information on how these factors were developed, see CERI Study 151.

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



Source: CERI

Figure 3.7: 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).

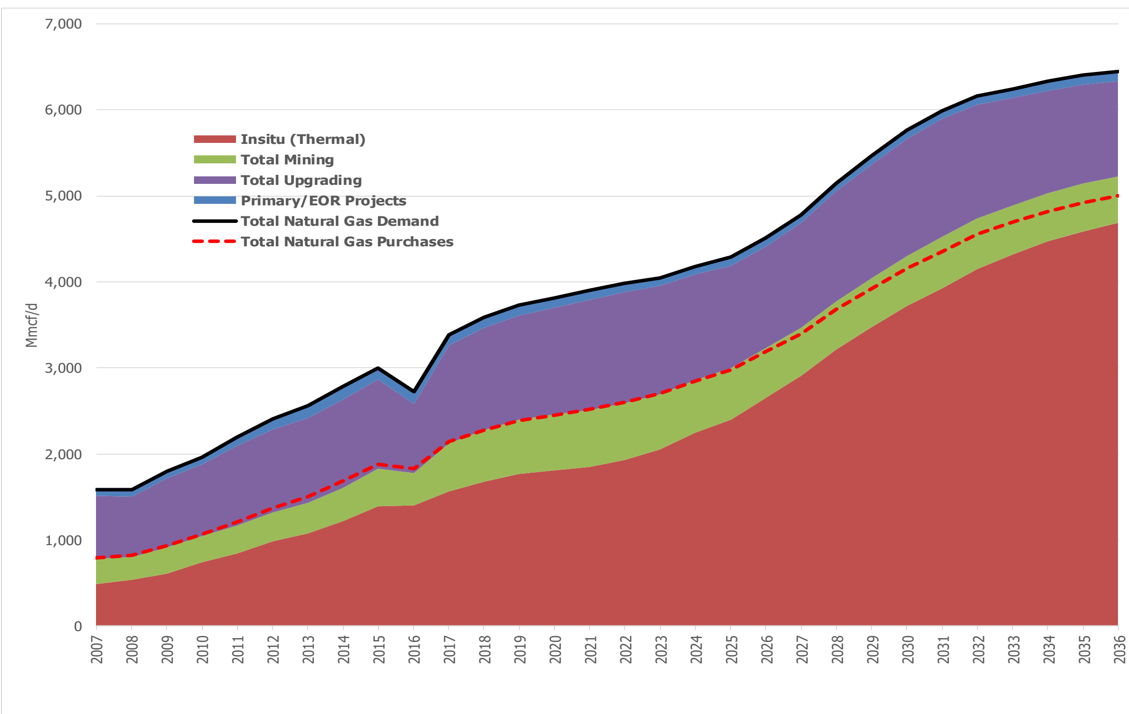
Thermal energy and hydrogen intensity factors are converted to a volumetric basis in order to come up with an estimate for gas demand for the oil sands industry by project type. Figure 3.8 displays the results of such analysis.

Figure 3.8 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 in Figure 3.8 refers to marketable natural gas purchased from the market, for meeting thermal energy and hydrogen requirements, after accounting for internally produced and utilized gas sources.

Total gas demand for the oil sands industry is expected to increase from almost 3 billion cubic feet per day (BCFPD) in 2015 to almost 6.5 BCFPD by 2036. Total gas purchases, which made up 63 percent of total gas demand in 2015, will increase to almost 80 percent by the end of forecast period, assuming no major technological breakthroughs are made to reduce the use of natural gas in the industry.

The majority of the growth in gas demand from the industry is expected to come in the form of thermal energy demand requirements for SAGD 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 production mix on a project-type basis rather than technological changes.

Figure 3.8: Natural Gas Demand and Purchases for Thermal Energy and Hydrogen Production



Source: AER, CERI

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

Diluent Demand

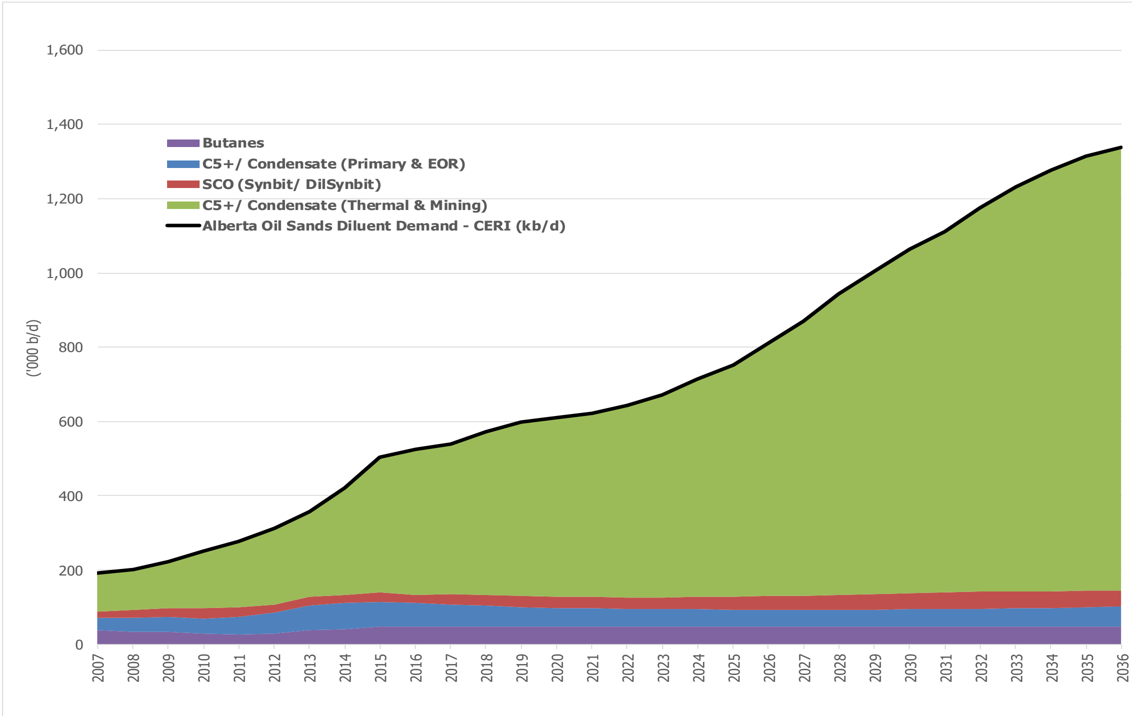
Diluent is an important component of oil sands operations for transportation purposes. Adding diluent brings that barrel of bitumen to the pipeline specifications and allows it to flow; otherwise, non-upgraded bitumen is too viscous to flow.

In addition to oil sands production, diluent demand is also driven (although to a much lesser extent) by conventional heavy crude oil production both in Saskatchewan and Alberta. In oil sands operations, demand for diluent is driven by non-integrated projects whose primary output is a crude bitumen blend such as WCS rather than SCO. 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 propanes 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 to burn 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,[35] pentanes plus remains the diluent of choice for oil sands operators. Figure 3.9 displays the estimated demand for diluent by project type and by diluent type to 2036.

[35] See CERI Study 133.

Figure 3.9: Diluent Demand by Type of Diluent



Source: AER, CERI

Total demand for diluent for 2015 was 504 thousand barrels per day (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.[36] Total demand will rise from the current level to over 1,339 MBPD by 2036.

The demand for diluent is met through domestic supply and imports. Production of pentanes plus and condensate, a predominant fuel used as diluent, is estimated by the AER to remain flat for the foreseeable future at just under 200 MBPD. A combination of factors including continued focus of gas producers on liquids-rich and "oily" gas plays like the Duvernay, and the potential commissioning of liquefied natural gas projects (LNG) in British Columbia could change the production forecast in the upward direction.

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. In previous reports, we have discussed the fact that CERI's demand projections are based on the premise that crude bitumen would be blended primarily as dilbit, that is, no field upgrading will occur, but also that it will be moved primarily via pipeline.

[36] See forthcoming CERI Study on new partial upgrading technologies that might reduce and/or eliminate the need to transport bitumen with diluent.

Alternatively, crude bitumen could be moved by rail (and this will increasingly be the case under continued market access and pipeline logistics constraints), and depending on how the bitumen would be moved,[37] there is a potential for diluent demand to decrease.

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 existing Southern Lights pipeline, the Cochin pipeline which was reversed and switched over from propane to diluent service, and up until recently, the proposed Northern Gateway diluent line.[38] 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 increasing production of crude bitumen blends rather than synthetic crude from oil sands operations. Given that demand is well above and beyond local production levels, diluent will continue to be imported in large volumes. 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 upgrading, could also create products that meet pipeline specifications without additional diluent.

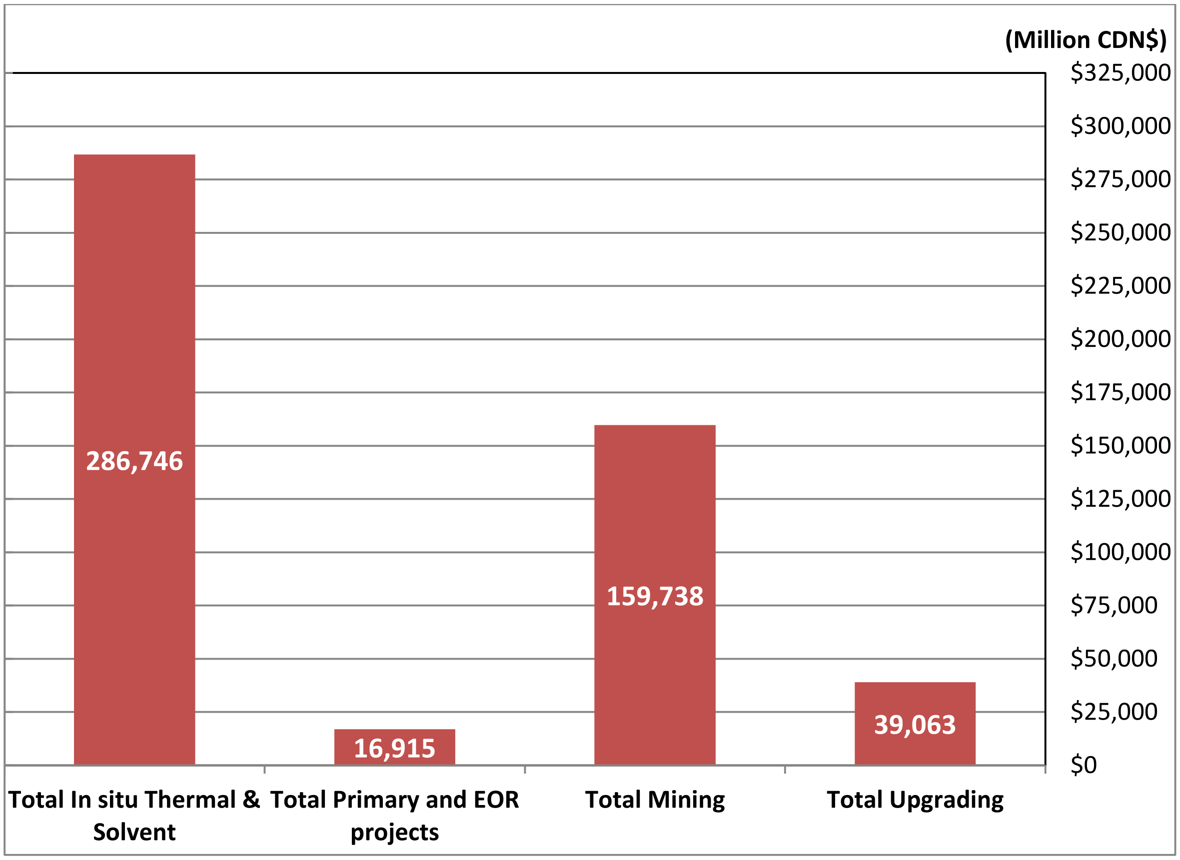
Capital Investment and Operating Costs

Total capital spending requirements are broken down by project type and are illustrated in Figure 3.10. Over the 20-year projection period from 2016 to 2036 inclusive, the total initial and sustaining capital required for all projects is projected to be C$502.5 billion under the **Reference Case Scenario.** Capital investment in in situ projects surpasses the capital spent for mining projects, which is consistent with the ongoing trend to invest more into in situ projects rather than mining. From 2016 to 2036, it is projected that almost C$160 billion (initial and sustaining) will be invested into mining projects and C$304 billion in 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$39 billion.

[37] 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.

[38] The Northern Gateway project was rejected by the federal government in late November 2016.

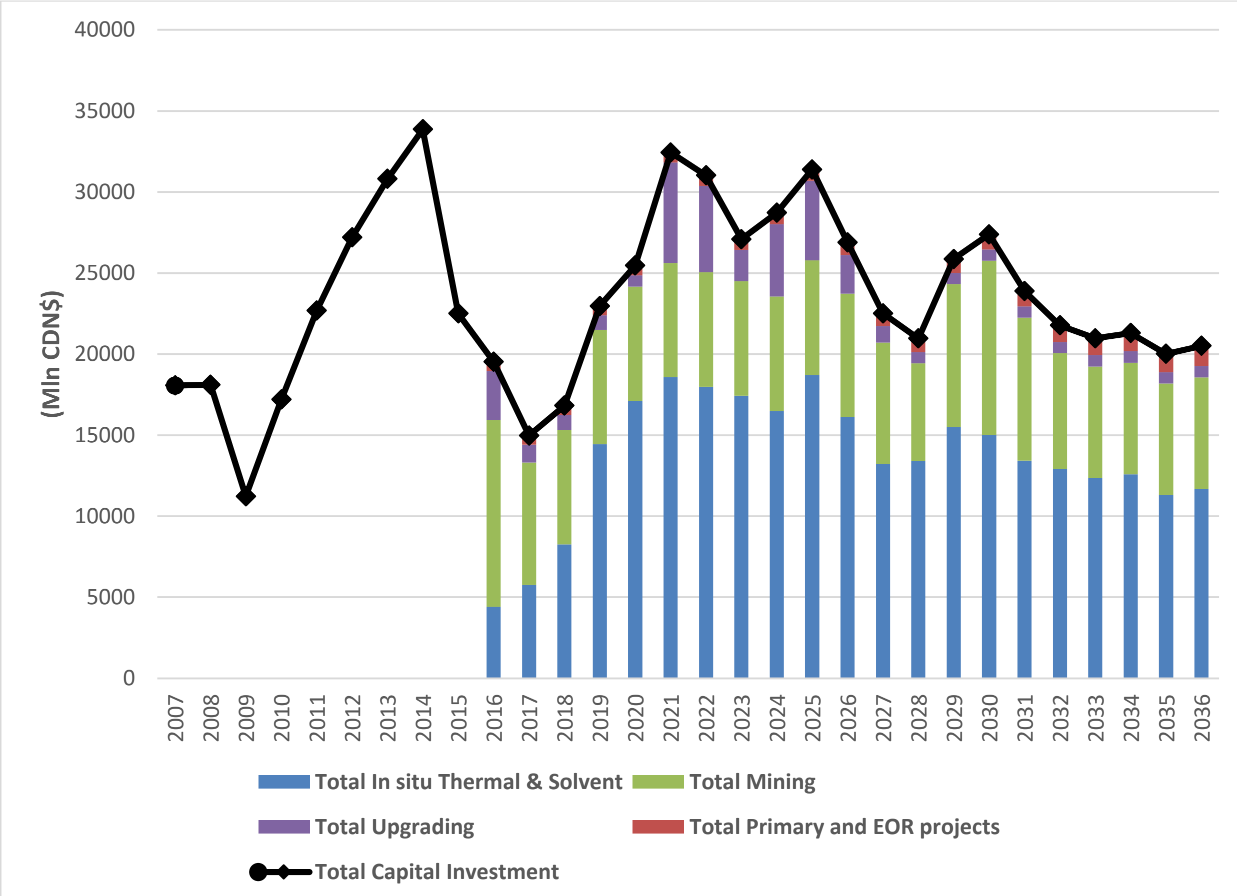
Figure 3.10: Total Capital Invested by Project Type



Source: CERI, CanOils

Historical and forecast capital expenditures from 2007 to 2036 are shown in Figure 3.11. As evidenced in the industry, capital expenditures on oil sands projects have been on decline since 2014, coinciding with the drop in oil prices. The peak spending of almost $34 billion happened in 2014, just before oil prices started their decline. Going forward, overall capital expenditures are not expected to reach this peak, averaging $24 billion per year in the forecast period. The investment starts to increase again post-2017, reaching $31.4 billion in 2025. The capital investment is related to project capacity additions in the form of expansions of existing projects and greenfield development.

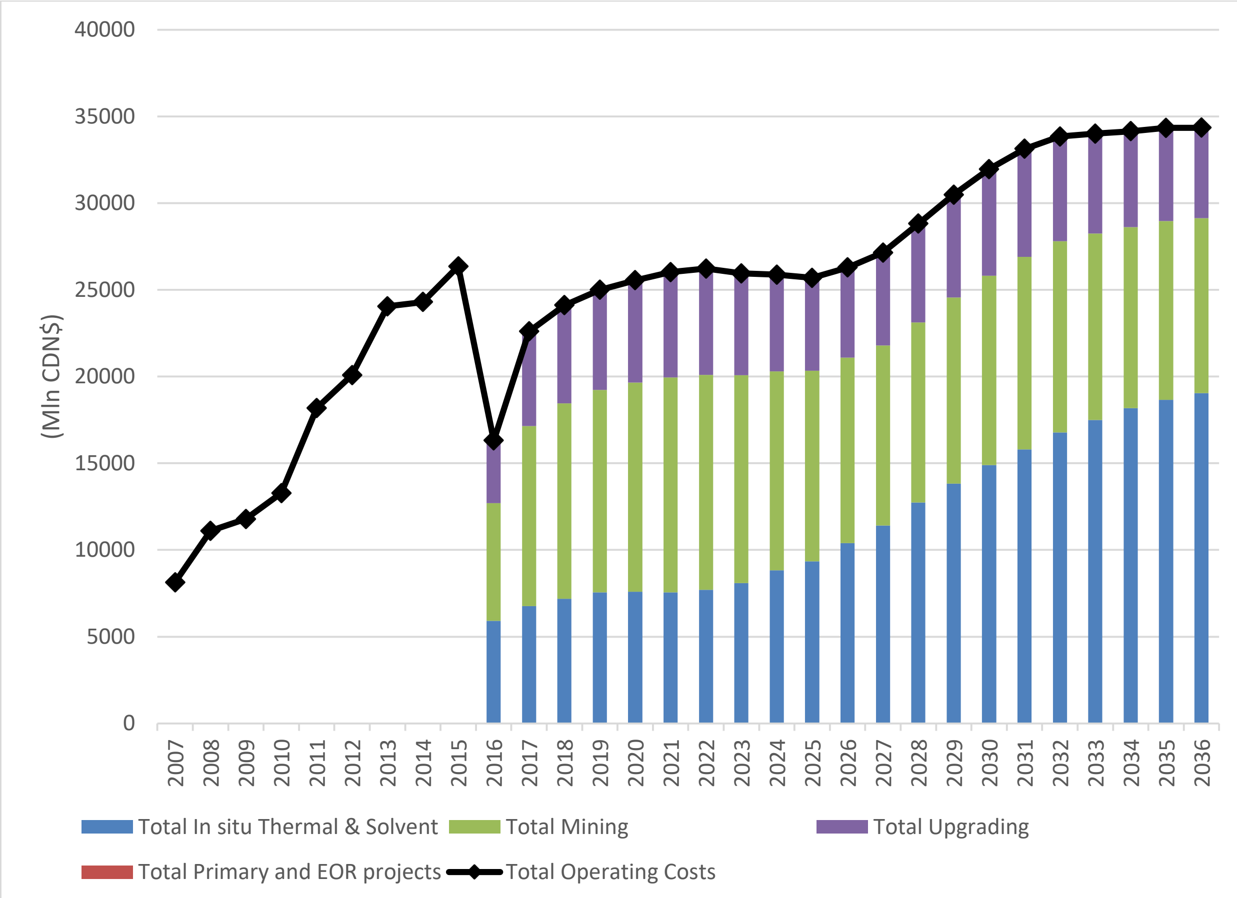
Figure 3.11: Total Capital Expenditures by Project Type



Source: CERI, CAPP, CanOils

Historical and forecast operating costs by project type are presented in Figure 3.12. As can be seen, costs have been increasing over the last 10 years, coinciding with rapid development of oil sands projects and increasing oil prices. Since 2014, operating costs have seen a significant decline. This is the result of not only declining oil prices, but oil sands project operators have managed to reduce their overall operating cost per barrel of bitumen or SCO produced. Over the forecast period, total operating costs are excepted to increase in line with increasing production levels, averaging $28 billion per year.

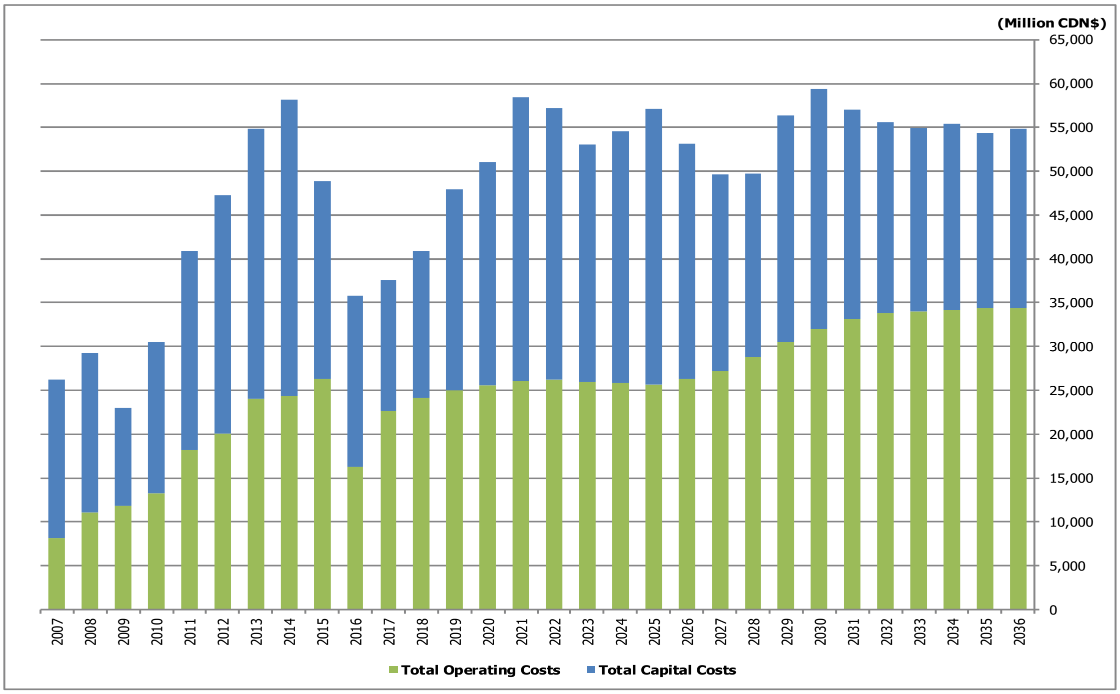
Figure 3.12: Total Operating Costs



Source: CERI, CAPP, CanOils

Total cost requirements for the oil sands industry year over year are presented in Figure 3.13. These include the initial and sustaining capital and operating costs for all types of projects. Total spending increases from 2007 to 2014, reaching an all-time high of C$58 billion in 2014. With falling oil prices in the near term, the investment starts to fall, slowly recovering to a forecast peak of C$58.5 billion in 2021, at which point it flattens out, averaging C$55 billion per year. As mentioned earlier, initial capital starts to decline by the end of the projection period. This does not reflect a slowdown in the oil sands, merely a lack of new capacity coming on-stream, and relates back to CERI's assumptions for project start dates and announcements from the oil sands proponents.

Figure 3.13: Total Cost Requirements



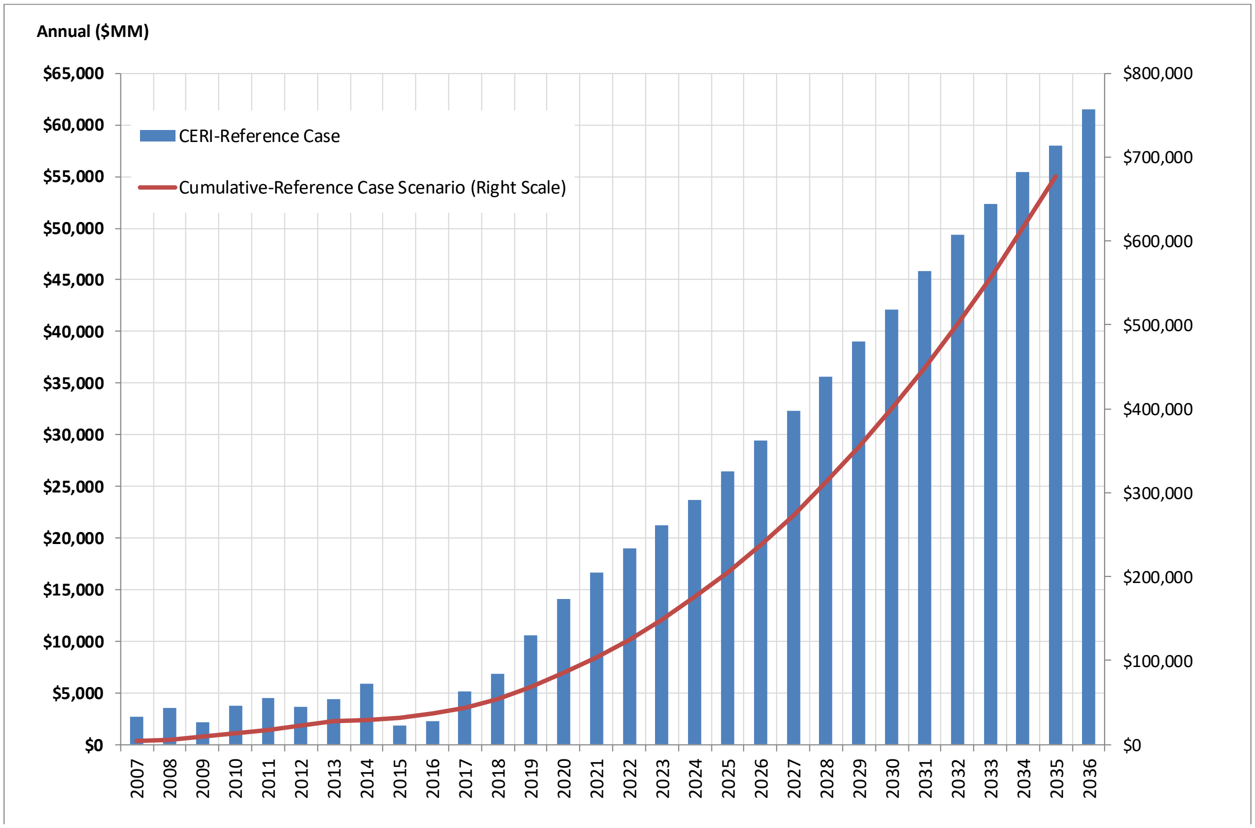
Source: CERI, CAPP, CanOils

Alberta Oil Sands Royalty Revenues and Economic Contribution

Figure 3.14 displays historical and forecast (2016 to 2036) oil sands royalties on an annual and cumulative basis, in 2015 dollars. Annual royalty revenues amount to C$61.5 billion by 2036, and cumulatively C$676 billion will be collected over the 20-year window.

As a result of capital spending cuts and low prices, royalties will continue to decrease from the all-time high in 2014 throughout 2015 and 2016. Over the next five years from 2016 to 2021, as oil prices are expected to recover, royalty revenues will add up to $55 billion (cumulatively), all other things being equal.

Figure 3.14: Bitumen Royalties Collected by Project Type



Source: CanOils, CERI

The forecast of oil sands royalties might change significantly as it depends on many factors such as change in production level, oil prices, capital and operating costs. The royalty review advisory panel has issued a report[39] where they make a number of recommendations to the government. The government has already implemented changes to the conventional oil and gas royalty formula. Among the recommendations, the panel suggested retaining the current structure and royalty rates for oil sands, but increase the transparency of allowable costs. Through their engagement process with many Albertans, they found that people do not have confidence in the validity of allowable costs. This low level of trust is driven in large part by the lack of transparency in respect of these costs to researchers, analysts and the general public. The panel believes that the success of the oil sands royalty structure critically depends on the validity of allowable costs. To this end, the panel proposed a suite of measures aimed at ensuring allowable costs in the oil sands are transparent, reasonable, up-to-date and valid.

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 cuts in

[39] Royalty Review Advisory panel. "Alberta at a crossroads". http://www.energy.alberta.ca/Org/pdfs/RoyaltyReportJan2016.pdf

2016, but a modest recovery of about 3,400 net jobs is projected over the next four years as companies shift their spending from expansion to maintenance, and repair and optimization of their operations, according to the "Oil Sands Labour Demand Outlook to 2020 Update report", released by PetroLMI, a Division of Enform.

Employment is forecast to grow by approximately 6 percent, or about 3,400 jobs, from an estimated 63,800 in 2016 to 67,200 in 2020. Jobs in on-site construction and module fabrication will decline by 6,500 but will be offset by an increased requirement for 9,900 workers to support ongoing operations, maintenance and turnaround activities.

Overall contribution of the Canadian oil and gas industry to the Canadian GDP amounted to $135 billion in 2015 (or nearly 10 percent share of total Canadian GDP), which is down by 3.4 percent from 2014.[40] Oil sands represents a significant portion of the sector, and it is projected it will contribute over $4 trillion to the Canadian economy over the next twenty years.[41]

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 in 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,[42] and of these emissions, 9.3 percent came from the oil sands sector.[43] The effects of the sector on Canada's total emissions and 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 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. Not exceeding the absolute cap is of importance to government and industry.

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 in light of changing production volumes. The

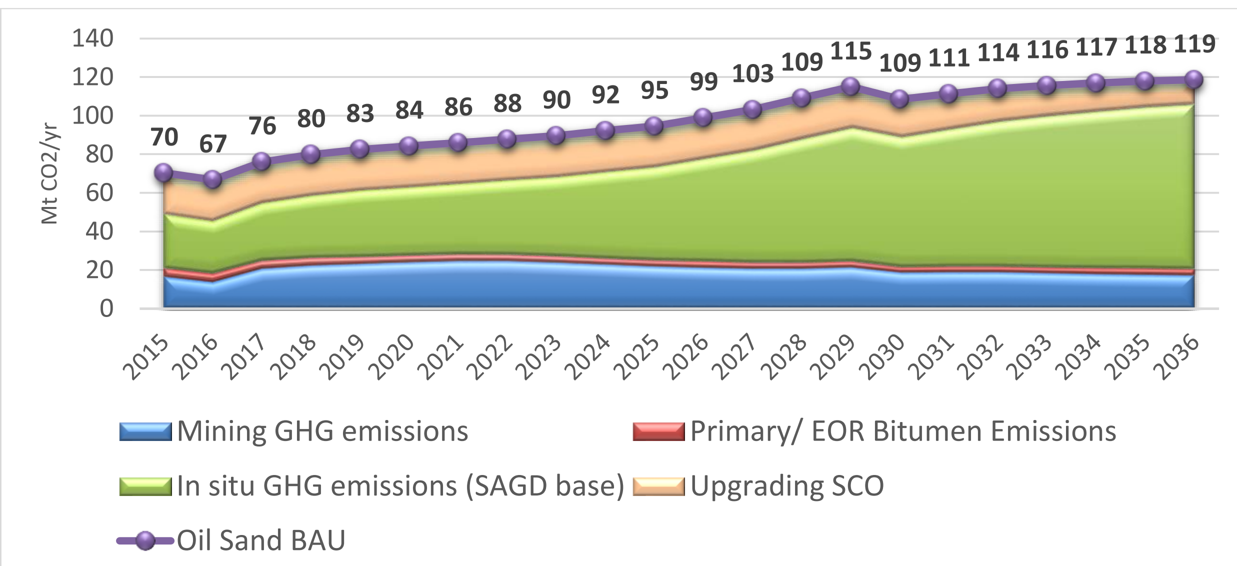
[40] Statistics Canada, CANSIM, table 379-0031.
[41] CERI Study 152.
[42] Environment and Climate Change Canada. "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada".
[43] Environment and Climate Change Canada.

second is the 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 much resource was extracted during the emission of these gases.

Figure 3.15 illustrates emissions projection for the **Reference Case** production forecast. The on-site emissions projection includes emissions from existing upgrading, electricity or fugitive emissions and flaring. Emissions associated with upgrading capacity that was added after 2015 are not included in the forecast as set by the provincial policy.

Current on-site emissions will grow from 70 MT/year in 2015 to 95 MT in 2025, and the total share of the oil sands sector to Canadian emissions are projected to increase from 4.6 percent in 2005 to 12.8 percent.[44] Given the production projection, the oil sands industry will reach the 100 Mt emissions cap by 2026. Increasing production in this sector makes the meeting of international commitments increasingly difficult to meet, and thus there is interest in reducing the amount of GHGs emitted to extract bitumen from the oil sands and generate synthetic crude oil. In CERI's forthcoming study, the Institute outlines the techno-economic path on how to grow oil sands production but reduce overall emissions.

Figure 3.15: Oil Sands Emissions by Project Type



Source: CERI, CanOils

[44] Taking Environment and Climate Change Canada's projection of Canadian emissions in 2030 of 742 Mt.

Chapter 4: Transportation and Market Access

This chapter focuses on the proposed development of export pipeline infrastructure relating to Alberta's oil sands. The collapse in oil prices worldwide is affecting the industry widely and is expected to slow the pace of upstream investment around the world in the near future – including in heavy crude oil development in Canada. In the long run, however, SCO and bitumen production is expected to grow, 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 centers have deepened the discount between WTI and Western Canadian crudes and hence have had a severe impact on the netbacks realized by Canadian producers. With the recent announcement by the federal government approving the expansion of Kinder Morgan's Trans Mountain pipeline and Enbridge's Line 3, 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.

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 crude oil subject to price markdowns (due to lower quality and bottlenecks in their delivery infrastructure). This situation provides Canadian producers a financial incentive to expand market access in the United States, Canada, and beyond. It also highlights the risk of overreliance on limited markets and the need for options.

The US Gulf Coast (USGC) is one of the world's largest refining centers, and its considerable heavy oil processing capacity presents the largest opportunity for Western Canadian heavy crude oil 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 (an average of 1.5 MMBPD out of the total 3.2 MMBPD imported to Gulf Coast refineries in 2015).

Over the last 10 years, heavy crude imports from Mexico and Venezuela have decreased by over 1 MMBPD as a consequence of declining reservoirs as well as insufficient upstream investment. This leaves a considerable gap for Canadian producers to establish a new market share in the Gulf. If oil sands could displace most of the Mexican and Venezuelan imports, the opportunity for bitumen blends and conventional heavy oil could be approximately 1.5 MMBPD.

Western Canadian production has always had limited access to the US Gulf Coast market, especially because of the lack of infrastructure connecting Cushing, Oklahoma (the primary US hub for Western Canadian crude oil) to refineries in Texas. To support market access to the Gulf Coast, more than 1.2 MMBPD of pipeline capacity from the US Midwest to the Texas Gulf Coast has been installed. Enbridge decided to reverse the direction of flow of their Seaway Pipeline, adding 400,000 BPD of capacity from Cushing to Freeport, Texas. The TransCanada Gulf Coast Pipeline transports another 520,000 BPD from Oklahoma to Texas. Additional lines that improve crude oil delivery from Illinois to Cushing, Oklahoma have also been built, such as Enbridge's Flanagan South and the Southern Access pipeline.

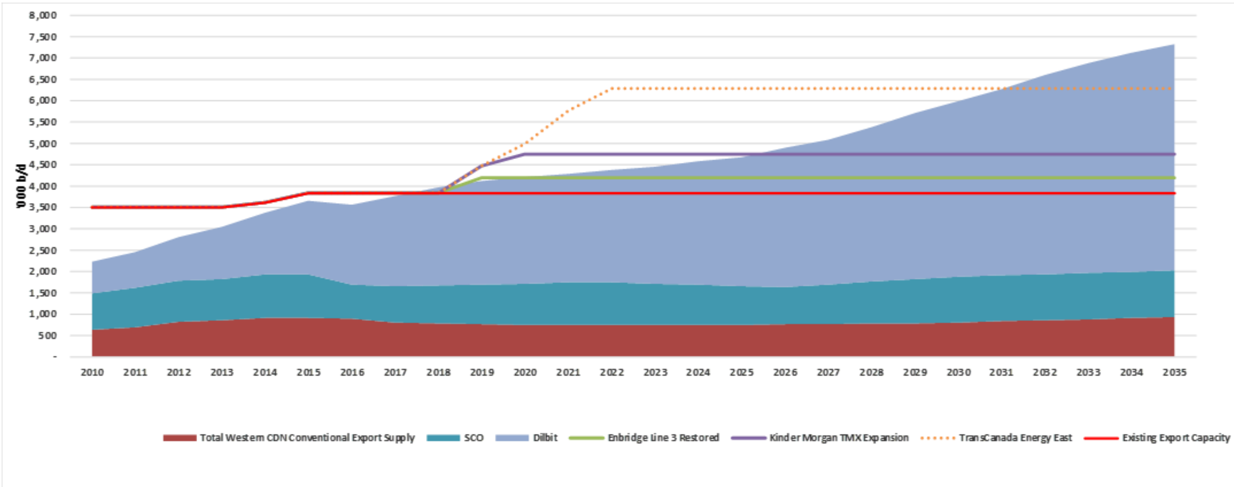
Shipments to the east and west coast of Canada, where heavy crude could reach offshore markets, are also being proposed as a way to reach attractive offshore markets, such as Asia and Europe. These projects, expected to come online potentially by 2020, will create new export outlets for Western Canadian crude oil to Asian and European markets. Politics (both local and international) as well as prices are expected to play a role in shaping future trade flows of Canadian heavy crude oil.

Access to new markets is expected to have a positive effect on the prices received by Canadian producers in the US, Europe and Asia. TransCanada's Energy East pipeline will carry 1.1 MMBPD of Western Canadian crude from Alberta and Saskatchewan to marine terminals in Quebec and New Brunswick (shipping to European and other markets), as well as refineries in Eastern Canada. Kinder Morgan's Trans Mountain Expansion (TMX) is expected to add 590,000 BPD of shipping capacity from Alberta to the West Coast by 2019, increasing potential volumes exported to Asian markets.

Although these major pipeline projects have faced delays in their approvals and opposition from some stakeholder groups, it is assumed that they will come online over the next five years. By transporting Western Canadian crude volumes to markets outside North America, these projects will decrease the available crude exports to the US. The rate at which these projects will decrease net available heavy crude exports to the US will depend on the amount of Western Canadian crude oil to be transported using these pipelines to international shipping terminals.

Figure 4.1 displays the forecasted potential crude exports out of Western Canada, net of domestic refining against the existing and proposed pipeline infrastructure.

Figure 4.1: Western Canadian Net Exports and Pipeline Infrastructure



Source: CERI

The red area in the graph refers to conventional crude oil supply out of Alberta, British Columbia, Saskatchewan, and Manitoba (net of domestic refining); the green-blue area is synthetic crude oil supply from upgraded and mined bitumen, and the light-blue area refers to non-upgraded bitumen supply that requires diluent to flow in the pipeline – on average diluent makes up 30 percent of a dilbit barrel. The lines refer to existing and proposed pipelines.

Currently the existing pipelines are able to accommodate all the export volumes available out of Western Canada, this is also evident in the narrowing of price differentials between Canadian crudes and WTI and decreased shipments of crude by rail. However, starting in 2018-2019, without additional pipeline capacity, the crude exports will be locked in and will have no market access. With recently approved expansions and restorations of Trans Mountain and Line 3, the total export capacity will increase by 960,000 barrels per day, thus providing access to markets in the US and potentially to Asia (via Trans Mountain and an oil tanker from the West Coast). In the middle of the next decade, by 2025, export volumes might be limited again by the lack of available export capacity.

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, be able to 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 market, which used to be Canada's number 1 customer. Until it became our number 1 competitor.

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. Project economics are not alone in shaping future markets for oil sands. 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.