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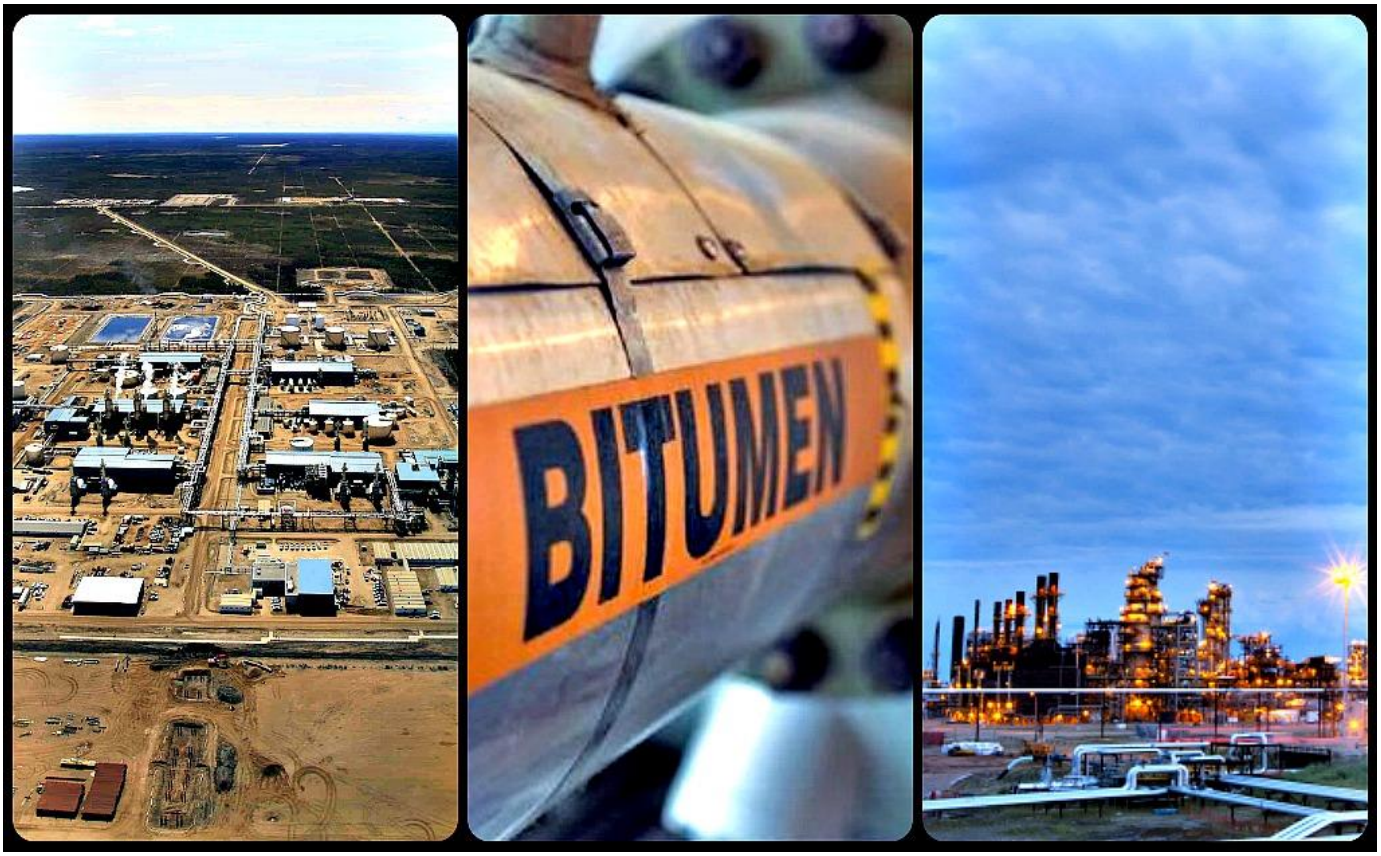
Canadian Oil Sands Supply Costs and Development Projects (2015-2035)



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CANADIAN OIL SANDS SUPPLY COSTS AND DEVELOPMENT PROJECTS (2015-2035)

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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 tenth 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 12.5 percent (nominal) based on the assumed inflation rate of 2.5 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$58.65/bbl for a SAGD project and C$70.18/bbl, for a standalone mine. A comparison[1] of field gate costs from the July 2014 update[2] with this year's supply costs indicates that, after adjusting for inflation, the supply cost for a SAGD producer has risen by 10.3 percent, and fell 6.5 percent for a standalone mine.

After adjusting for blending and transportation, the WTI equivalent supply costs at Cushing for SAGD projects is US$80.06/bbl, and US$89.71/bbl for a standalone mine. In comparison to last year's update, the WTI equivalent costs for a greenfield SAGD project are 9.9 percent lower and 18.7 percent lower for a standalone mine based on lower light-heavy differential, a lower US/CDN exchange rate assumption and a lack of premium on diluent costs.[3] A summary of costs are presented in Chapter 3. At current WTI prices of just above US$50/bbl,[4] 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 has not suffered that much, nor is this the most difficult period for oil sands pricing in recent history.[5]

[1] Direct cost comparison is not recommended and only shown to illustrate the direction of change. Because some changes were made in the project assumptions regarding carbon policy as well as project economics, such as a change in corporate taxes 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] Macleans, "Just How Much Is The Oil Price Drop Hurting Oil Sands Projects?". November 2014.
[4] At the time of writing, WTI prices traded at just above US$50/bbl.
[5] ARC Financial Corp. "The Fiscal Pulse of Canada's Oil and Gas Industry, First Quarter 2015", April 2015.

A few noteworthy changes that affected the supply costs were: the new corporate tax rate increase from 10 to 12 percent provincially; the elimination of accelerated capital cost allowance (CCA); and doubling of the carbon tax from $15 to $30 per tonne of CO2 eq. The resulting impact on the overall cost of an oil sands project is shown in Figure 2.8; the percentage shares of income taxes and carbon taxes increased from last year's results by 6.5 percent and 150 percent, respectively, for a SAGD project. Similar increases are present for a mining project – the share of income taxes is expected to increase by 9.7 percent and the share of emission compliance costs are expected to double.

While capital costs and the return on investment account for a substantial portion of the total supply cost, the province stands to gain $10.41 to $12.80 in royalty revenues for each barrel of oil produced on average, over the life of an oil sands project. On a percentage basis, these range from a 17.8 to 18.3 percent share of total supply cost, a decrease of 2.8 percent for a SAGD project and 4.2 percent for a mining project as a result of income taxes and compliance costs increase.

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

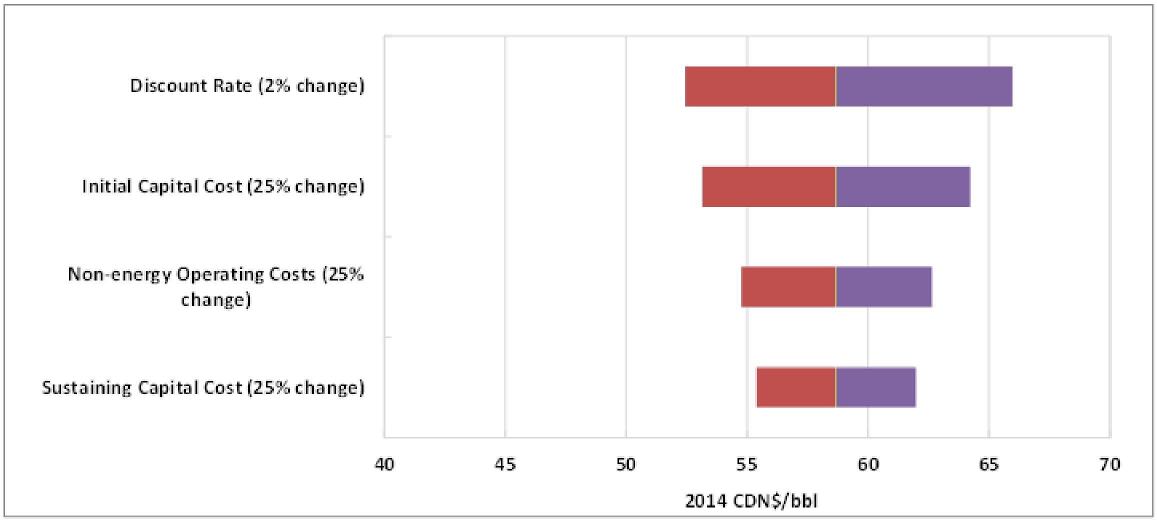
	SAGD 10% ROR (a)	Mining 10% ROR (a)
Fixed Capital (Initial & Sustaining)	$22.91	$32.12
Operating Working Capital	$0.53	$0.70
Fuel (Natural Gas)	$6.90	$3.07
Other Operating Costs (incl. Elec.)	$13.74	$16.57
Royalties	$10.41	$12.80
Income Taxes	$3.80	$4.74
Emissions Compliance Costs	$0.31	$0.13
Abandonment Costs	$0.04	$0.05

Source: CERI

Supply Cost Sensitivities

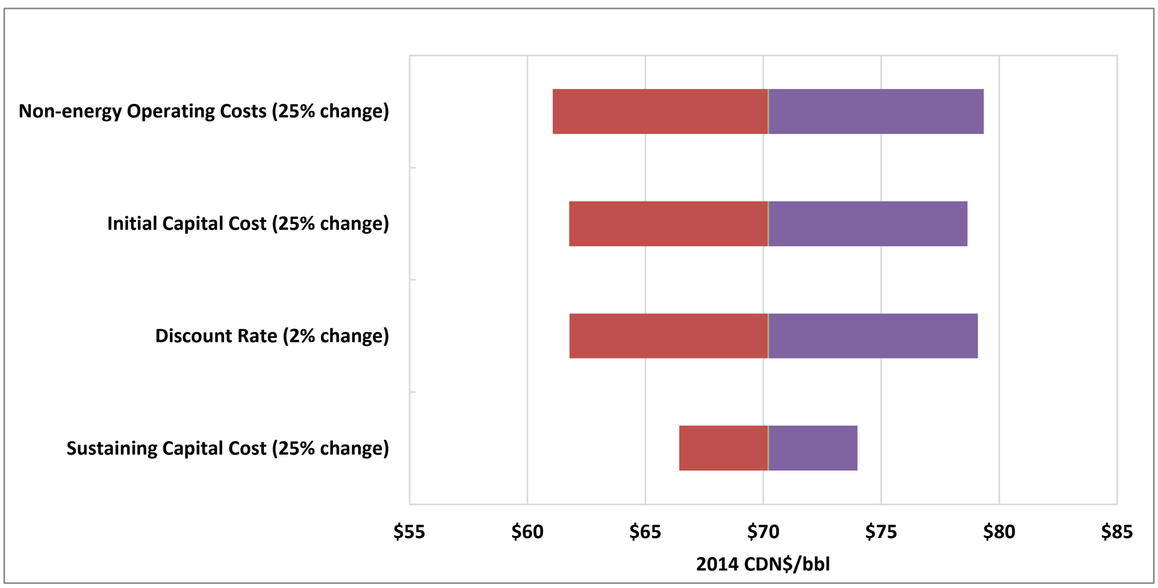
The presented costs for oil sands projects also need to be analyzed in terms of how sensitive costs are to changes to some of the variables. Bitumen supply cost sensitivities for a hypothetical SAGD and standalone mine projects are represented graphically in Figures E.2-E.3.

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



Source: CERI

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



Source: CERI

The results indicate that SAGD supply costs are subject to change the most under two sensitivities for the assumed discount rate. If the discount rate is raised to 12 percent real, the supply cost is estimated to increase by $7.28/bbl, and when it is decreased to 8 percent real, the cost will decrease by $6.23/bbl from its base of $58.65/bbl. The changes in capital and operating costs are also influential in changes to the supply costs.

For a standalone mining project the operating cost, capital cost and discount rate changes are almost equally significant on the changes of the base mining cost. The supply cost for a mining project will increase by C$9.12/bbl if the non-energy related operating costs increase by 25 percent. A discount rate increase to 12 percent will increase the supply cost by $8.87/bbl and a decrease to 8 percent will result in an $8.40/bbl drop in the base supply cost of a mine.

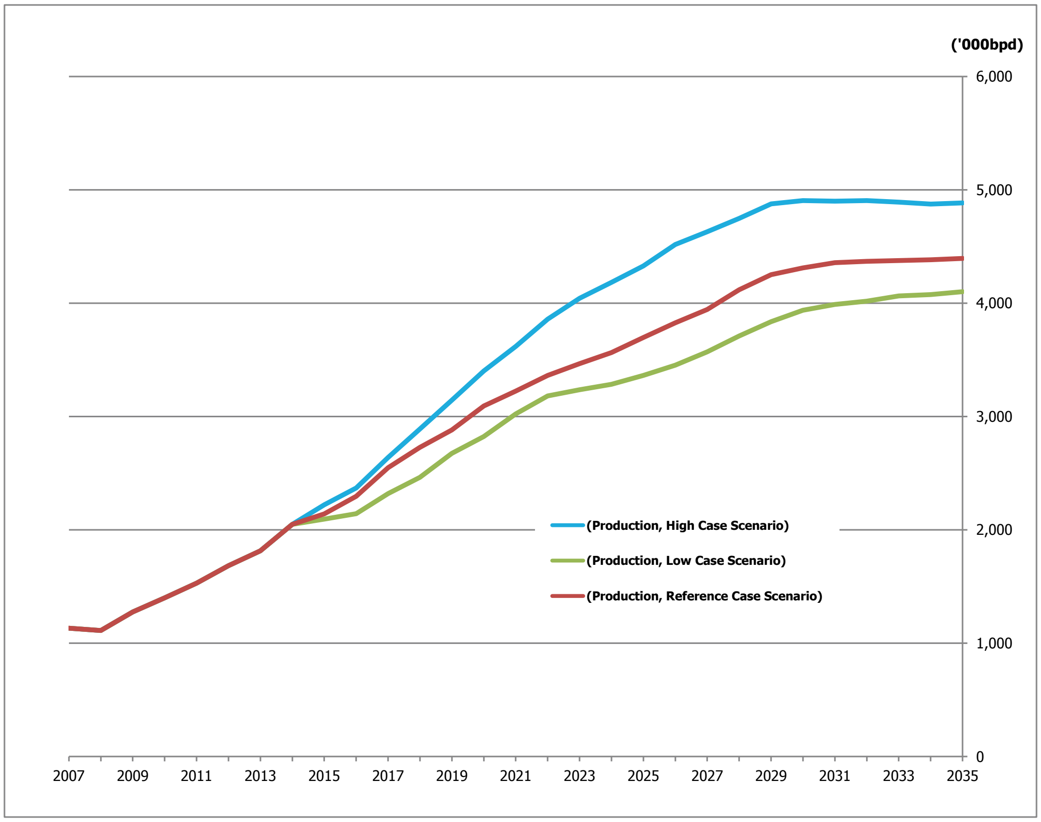
Production Forecast – Three Scenarios

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 2.34 MMBPD in 2014, comprised of in situ and mining production of 2.05 MMBPD and 0.29 MMBPD of primary and enhanced oil recovery (EOR) production within the boundaries of oil sands areas. Total production in 2013 was 2.08 MMBPD, meaning the oil sands production grew 11 percent year-over-year. Production from oil sands includes an increasing share of Alberta's and Canada's crude oil production. In 2014, non-upgraded bitumen and SCO production made up 58 percent of total Canadian crude production and 74 percent of Alberta's total production.

In the **High Case Scenario**, production from mining and in situ thermal and solvent extraction (excluding primary recovery) is set to grow from 2.05 MMBPD in 2014 to 3.4 MMBPD by 2020 and 4.9 MMBPD by 2035. In the **Low Case Scenario** production rises to 3.9 MMBPD by 2030 and 4.1 MMBPD by the end of the forecast period. CERI's **Reference Case Scenario** provides a more plausible view of oil sands production. Projected production volume will increase to 3.1 MMBPD by 2020 and 4.4 MMBPD in 2035 (see Figure 3.2 and Table 3.1). Cold bitumen production from primary and EOR wells is forecasted to increase from 0.29 MMBPD in 2014 to its peak of 0.41 MMBPD by 2020 and then growing at a flat rate to 0.49 by the end of the forecast period.

Figure E.4: Bitumen Production Projections



Note: Since the primary and EOR production forecast is estimated using CERI's crude oil forecasting model, this Figure does not illustrate that forecast.

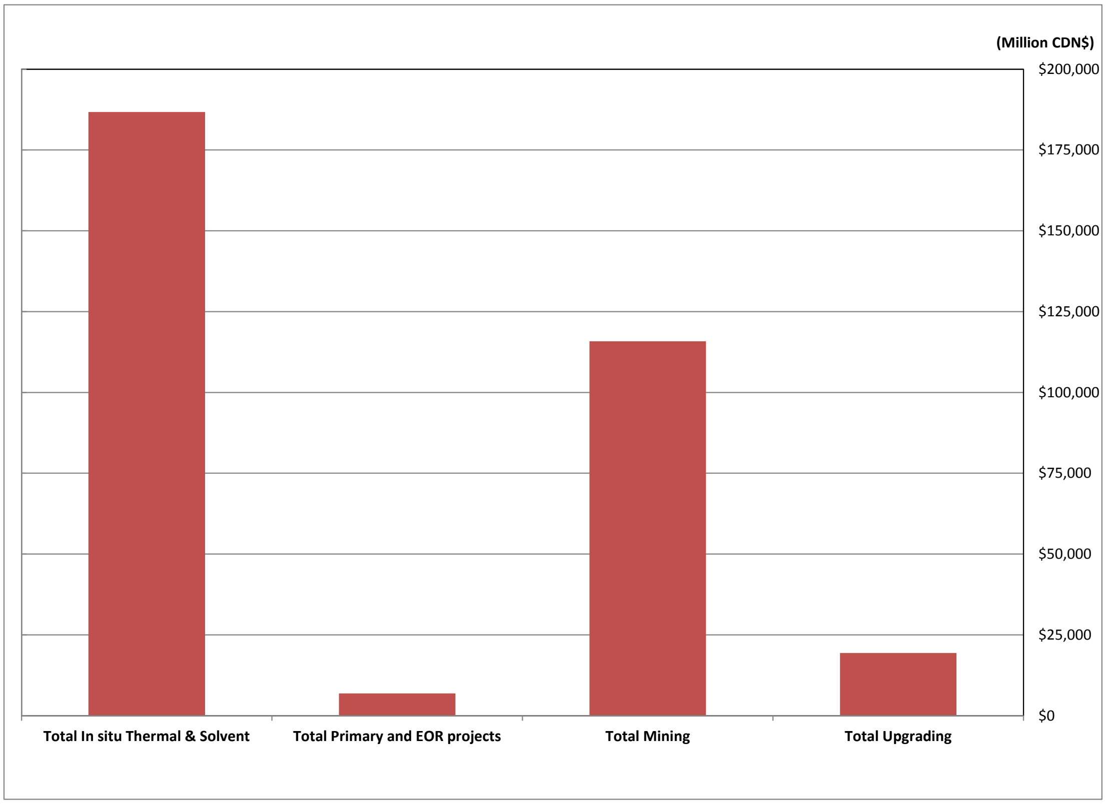
Source: CERI, CanOils

Other Requirements

Capital Investment and Operating Costs

Total capital spending requirements are broken down by project type and are illustrated in Figures E.5. Over the 20-year projection period from 2015 to 2035 inclusive, the total initial and sustaining capital required for all projects is projected to be C$329 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 2015 to 2035, it is projected that C$116 billion (initial and sustaining) will be invested into mining projects and C$194 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$19 billion.

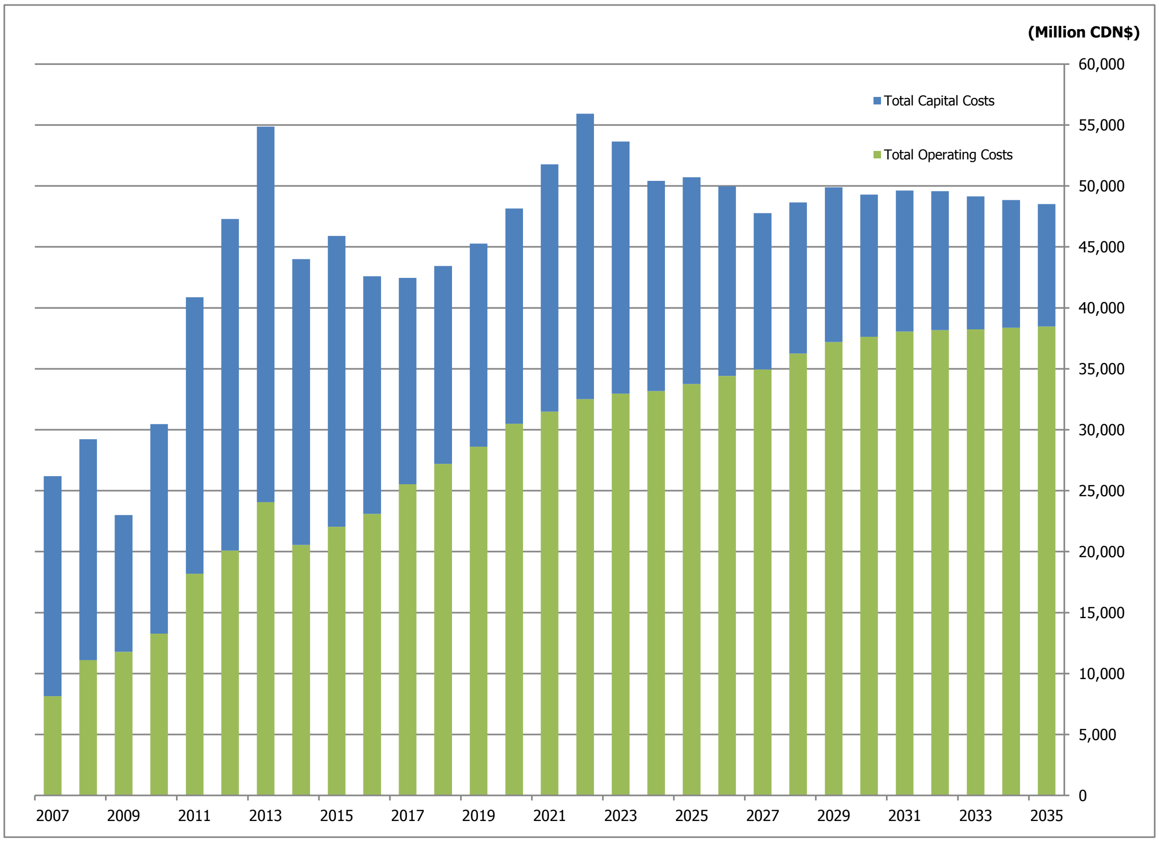
Figure E.5: Total Capital Invested by Project Type



Source: CERI, CanOils

Total cost requirements for the oil sands industry 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 2013, reaching an all-time high of C$55 billion in 2013. Investment then starts to fall with declining oil prices in the near term, and slowly recovering to a forecast's peak of C$56 billion in 2022, at which point it flattens out, averaging C$50 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. The total operating costs average C$33 billion a year, and over the forecast period cumulatively add up to C$693 billion.

Figure E.6: Total Cost Requirements



Source: CERI, CanOils

Alberta Oil Sands Royalty Revenues

Figure E.7 displays the breakdown of royalties collected by project type under the reference case over the 2015 to 2035 timeframe (on an annual and cumulative basis, in 2014 dollars) and compares the results to the last published version of this study.[6] Annual royalty revenues amount to C$33 billion by 2035 and cumulatively C$353 billion will be collected over the 20-year window.

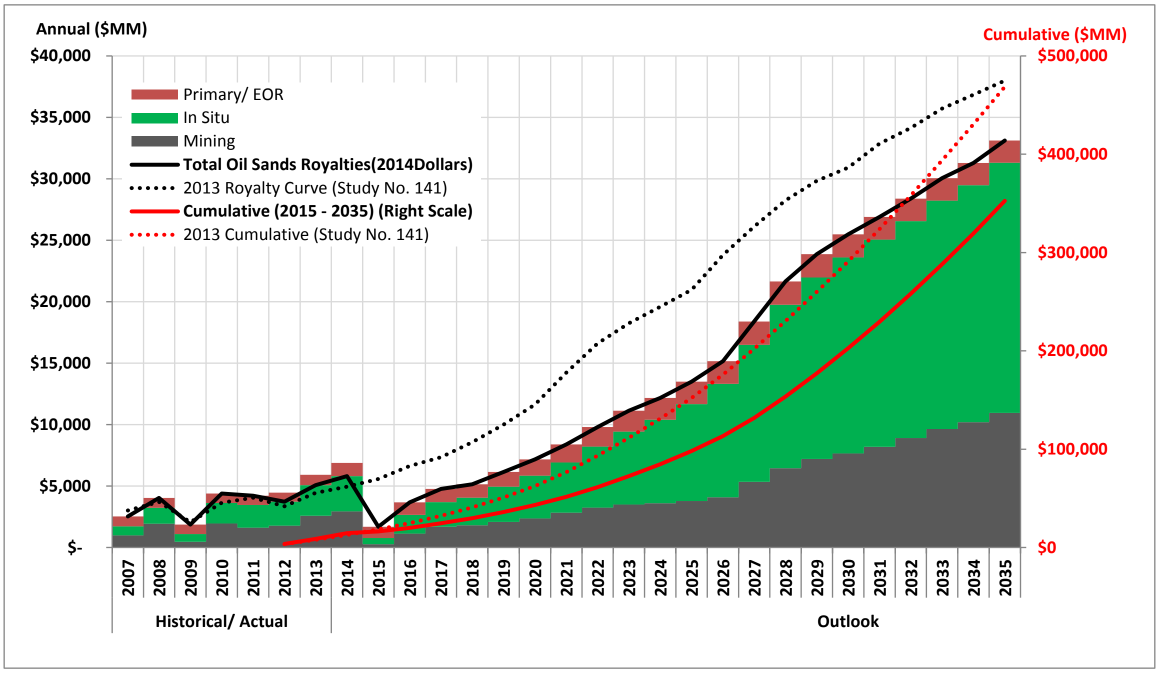
As a result of capital spending cuts and low prices, royalties will decrease in 2015 to 2009 levels, barely reaching C$2 billion. Over the next five years from 2015 to 2020, royalty revenues will add up to just under $32 billion, all other things being equal.

On a cumulative basis, bitumen royalties collected are 29 percent lower compared to last's years study for a number of reasons. Let's recall that changes in royalties are related to changes in project cash flows implying changes on the costs and revenues side of the ledger. On the cost side, capital costs are higher compared to last year's report; on the revenue side, not only are overall production levels lower, but so are forecasted prices. Thus a combination of lower

[6] CERI Study No. 141,"Canadian Oil Sands Supply Costs and Development Projects (2014-2048)", July 2014.

production levels, lower revenues, and higher project costs lead to overall lower royalty payments.

Figure E.7: Bitumen Royalties Collected by Project Type



Source: CanOils, CERI

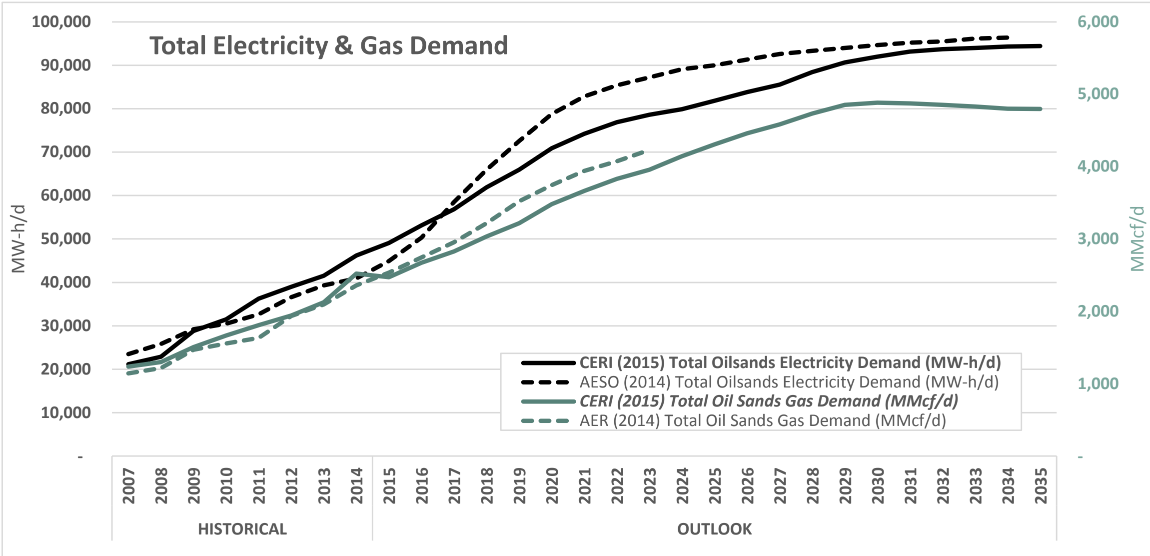
Natural Gas, Electricity and Diesel Demand

Total natural gas demand for the oil sands industry is expected to increase from 2.5 billion cubic feet per day (bcf/d) in 2014 to 4.8 bcf/d by 2035, and grow at a compound annual growth rate of over 3 percent (Figure E.8).

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 primary/EOR projects, and mining 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.

Total electricity demand from the oil sands is expected to increase by 48.2 GWh/d (or by 104 percent) from an estimate of 46.2 GWh/d in 2014, to 94.4 GWh/d by 2035. Demand for electricity from the oil sands is expected to increase the most across in-situ projects, followed by mining projects, and upgrading projects.

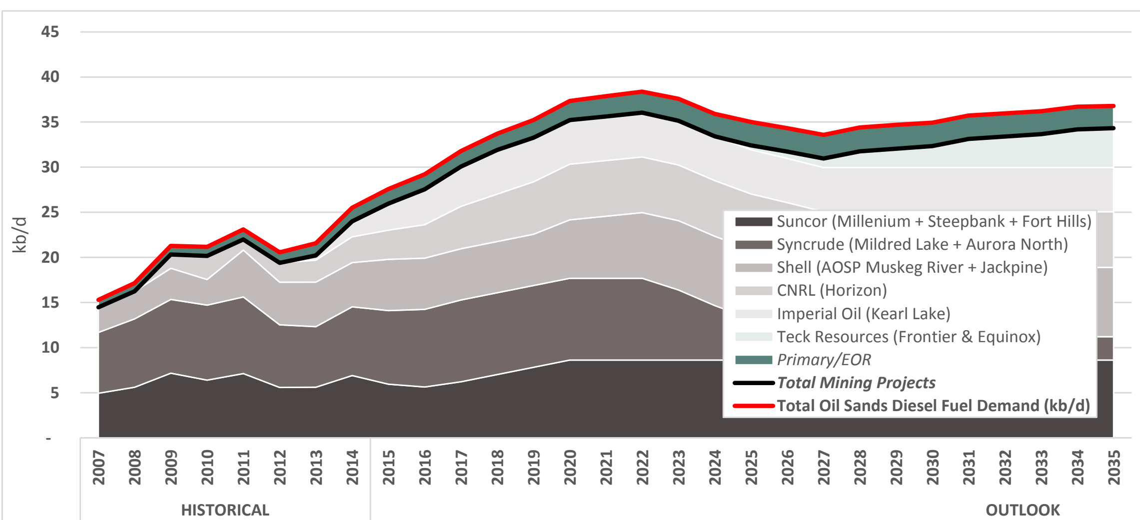
Figure E.8: Oil Sands Industry Electricity (MWh/d) and Gas Demand (MMcf/d)



Source: Data from AER, AESO, and CERI

Figure E.9 shows demand for diesel fuel for oil sands operations is estimated to increase from 26 kb/d in 2014 to 37 kb/d by 2035 (or by 42 percent). CERI estimates that diesel fuel demand from oil sands projects accounted for 19 percent of total diesel demand in Alberta in 2014 (of 134 kb/d), but that the percentage is expected to decrease to 15 percent of the total diesel demand in the province (of 242 kb/d) by 2035.

Figure E.9: Oil Sands Industry Diesel Fuel Demand



Source: CERI

Economic Benefits

GDP

Table E.1 presents the total impacts associated with both investment and operation of projects in the Alberta oil sands and direct staging and assembling facilities in Edmonton, Leduc and other Alberta communities for the period 2015 to 2035. The total Canadian GDP impacts amount to $4,058 billion (2014 Canadian dollars) and employment (direct, indirect, induced) is projected to double from the current level of 520,404 jobs to 1,240,277 (see Figure 5.2). Approximately 88 percent of the GDP impacts and 80 percent of the employment impacts occur in Alberta. Ontario and Quebec account for 7.2 percent of the GDP impacts and 11.5 percent of the employment impacts. The other provincial impacts are detailed in Table E.1.

Table E.1: Economic Impacts of Oil Sands Development (2015-2035)

Investment and Operations	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alberta	3,600,779	1,584,496	16,034
British Columbia	105,212	64,364	947
Manitoba	17,764	10,199	177
New Brunswick	5,289	2,956	54
Newfoundland/Labrador	2,473	1,123	18
Nova Scotia	4,214	2,613	43
Nunavut	366	261	4
Northwest Territories	837	517	8
Ontario	221,208	133,936	1,640
Prince Edward Island	363	210	4
Quebec	69,928	39,591	661
Saskatchewan	28,938	12,686	209
Yukon Territory	382	237	3
Total Canada	**4,057,754**	**1,853,189**	**19,802**

Source: CERI

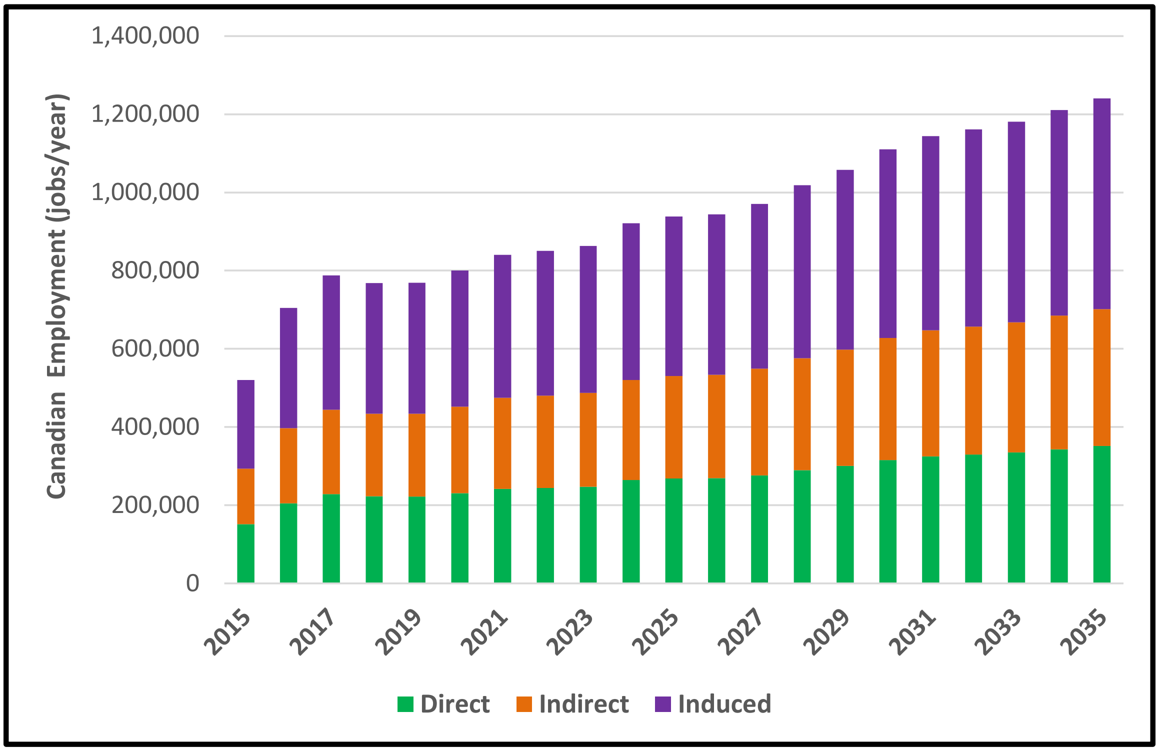
Employment

Figure E.10 illustrates the total employment impacts broken down into direct, indirect and induced categories.

Direct employment effects are considered jobs created or preserved in the Province of Alberta and are considered as construction or operation jobs in the oil sands projects, manufacturing jobs in the oil sands staging areas (Edmonton, Leduc, etc.) and drilling related jobs in the cold bitumen production (CBP) area. Oil sands direct employment is projected to grow from the current level of 151,000 jobs to a peak of 351,000 jobs by 2035.

Indirect job effects account for the potential of jobs created in the many industries across Canada that service the oil sands industry including manufacturing in Ontario, pipeline mills in Saskatchewan and Alberta, and electronic components in British Columbia, Ontario and Quebec, to name a few. Induced job effects account for workers in the oil sands sector spending their additional income on consumer goods and services. This additional income is stimulated by direct and indirect impacts.

Figure E.10: Oil Sands Direct, Indirect and Induced Employment Forecast



Source: CERI

Tax Perspective

Generally speaking, taxes on income are considered direct taxes, while taxes on expenditures (GST, PST, HST, etc.) and all taxes deductible by corporations for income tax purposes (such as property taxes) are considered indirect taxes. The tax impact on a corporation includes taxes generated by economic activity within a province payable to federal, provincial and municipal governments.

Over the forecast period, oil sands related taxes (indirect, personal and corporate) directed to all levels of government will total $750 billion (2014$Cdn). The Canadian Federal government will receive $464 billion with 89 percent (or $417 billion) sourced from Alberta-based companies. Canadian provincial governments will receive $286 billion with 85 percent (or $245 billion) attributable to the Alberta government.

Table E.2: Tax Receipts as a Result of Alberta Oil Sands Investment and Operation Federal and Provincial: Corporate, Indirect and Personal

Investment and Operations	Federal Corporate $CAD Million	Federal Indirect $CAD Million	Federal Personal $CAD Million	Provincial Corporate $CAD Million	Provincial Indirect $CAD Million	Provincial Personal $CAD Million
Alberta	127,781	43,573	245,678	64,717	47,625	132,539
British Columbia	2,075	1,804	7,082	763	3,810	3,072
Manitoba	277	308	1,042	96	722	834
New Brunswick	79	75	312	36	176	239
Newfoundland/Labrador	48	29	124	68	62	88
Nova Scotia	74	69	271	40	131	227
Nunavut	4	5	19	1	3	6
Northwest Territories	18	19	36	11	21	15
Ontario	4,033	4,107	15,681	2,121	8,050	9,396
Prince Edward Island	5	7	21	3	18	18
Quebec	1,273	1,231	4,590	892	3,240	4,255
Saskatchewan	647	416	1,425	437	1,009	860
Yukon Territory	4	9	19	1	7	9
Total Canada	**136,319**	**51,650**	**276,302**	**69,184**	**64,874**	**151,559**

Source: CERI

Chapter 1: Introduction

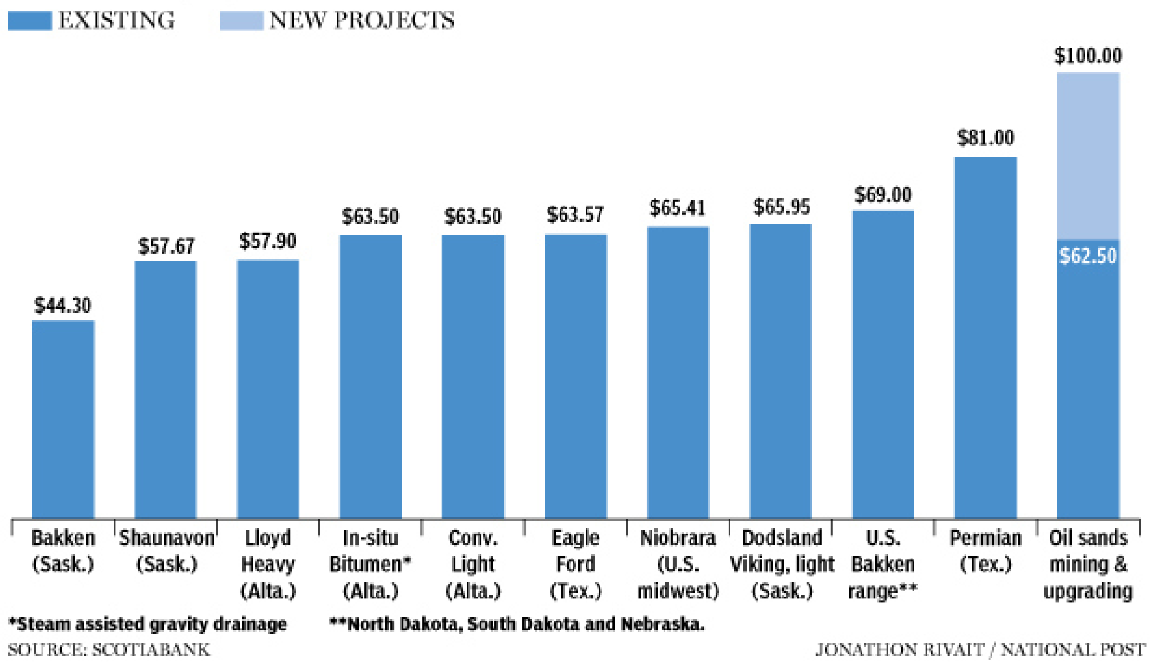
Background

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 a more manageable phased in situ growth.

Notwithstanding the uncertainties around market access and lower crude oil prices due to excess supply globally as a result of increased US tight oil production, oil sands production is expected to reach three million barrels per day (MMBPD) by 2020. This means the industry is expected to add approximately 1 MMBPD of production in five years, from both mining and in situ operations. In addition to several in situ projects/phases currently underway or expected to get the necessary approval in the near term, at least three mining projects are considered for major growth. This includes the Kearl project, the staged integrated mining/upgrading expansion at Horizon, and the long-awaited 190,000 barrel per day greenfield installation at Fort Hills.

One of the main differences between the oil sands market of today and the oil sands market of 10 years ago is the emergence of tight oil development, primarily in the United States. Although the two plays have vastly different profiles, they are being compared against each other; with many assuming that oil sands project supply costs are prohibitive by comparison, which might not necessarily be the case. According to a study by Scotiabank of more than 50 plays across Canada and the US, Western Canadian plays — including those in the oil sands — cost less to produce on average than plays in the US such as the Bakken in North Dakota, and the Eagle Ford and the Permian Basin, both in Texas (Figure 1.1).

Figure 1.1: Full Cycle Supply Costs (US$ per barrel)



The Saskatchewan Bakken offers one of North America's best deals with a break-even cost of US$44.30 a barrel — including a 9 percent after-tax return.

Oil from existing in situ oil sands projects in Alberta is produced at a break-even cost of US$63.50 on average, and oil from existing integrated oil sands mining projects has a break-even cost of US$60 to US$65, also including a 9 percent after-tax return. However, according to CERI's research and analysis of greenfield oil sands projects, the break-even supply costs for in situ and mining projects are significantly higher, making them riskier if oil prices weaken significantly. Chapter 3 of this report discusses the supply costs for greenfield oil sands projects. The technology development and implementation when it comes to in situ extraction holds a large potential for cost reduction.

According to BMO's research study on oil and gas global costs "…a shift in focus from integrated mining projects to smaller in situ developments has helped reduce the overall weighted average to $70 per barrel, with several projects economic at prices as low as $40 per barrel."[1] This is exactly what the industry is witnessing – a move towards more in situ projects as their smaller scale allows for more efficient management of capital and scheduling to match the availability of key inputs such as skilled labour. Moreover, the smaller-scale in situ processing facilities are more easily modularized and can be outsourced to equipment fabrication shops.

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

[1] BMO Capital Markets, "Oil and Gas Global Costs", August 2013.

production decline), then the advantage in the oil sands goes to far-sighted companies that effectively deliberate over the risks of multi-decade operations. Heavy oil differentials, pipeline capacity limitations and speculative oil price loadings all play a role in these considerations, but they invariably take a back seat to larger and more global oil supply and demand fundamentals.

Delays in the approval 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 – have 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. The Seaway line that used to flow north to Cushing has been reversed with current capacity of 600,000 BPD. Since the original Keystone XL was rejected, the project has been split into two parts: a southern leg from Cushing to the Gulf that received all necessary permissions to proceed started operation in late 2013. A Seaway reversal and expansion, with the Keystone XL southern leg, adds over 1.65 MMBPD of capacity out of Cushing to the Gulf. This substantially alleviated the 'Cushing congestion' – storage volumes in PADD II are back from all-time highs of over 40 million barrels of crude to seasonal norms and the differential between West Texas Intermediate (WTI) and Brent has returned to historical values. 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.

As for light-heavy oil differentials, which widened early in 2013 (Canadian benchmark heavy pricing traded at a discount to Brent as high as a US$60 per barrel in the first quarter), by summer, they had narrowed to about $20. Much of that wide spread was connected to pipeline constraints. Going forward, in CERI's analysis, the light-heavy differential of US$15.00/bbl between light WTI and Western Canadian Select (WCS) was assumed.

Another factor that plays a role in the pace of oil sands development after global and regional supply and demand fundamentals is the federal government's new rules on foreign ownership. In handing down its decision on the US$15.1 billion takeover of Canadian oil and gas company Nexen Inc. by Chinese state-owned entity CNOOC Limited, Industry Canada ruled out majority stakes in the oil sands by foreign national oil companies. Tougher rules combined with market access issues left the mergers and acquisitions shelf empty, but most analysts see more money coming from Asia in the future. Despite the new challenges, majors and national oil companies will find it difficult to ignore the scale of production and resource found in the oil sands.

If Warren Buffett's recent disclosure that he increased Berkshire Hathoway Inc.'s stake in the oil sands to more than US$500 million and celebrity billionaire T. Boone Pickens' similar move that saw BP Capital Management's shares in Suncor increase to over US$160 million are visible signs of confidence in Alberta's oil sands, then many on the ground closer to the action can share that optimism.

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 producers to maintain their social license to operate,
iii) appropriately managing project cost inflation by addressing skilled labour shortages and operational efficiencies, 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, electricity and diluent requirements.
- Understand the natural gas and electricity requirements of the industry.
- Estimate the supply cost, including costs associated with carbon emissions, for greenfield projects consistent with in situ and mining.
- Provide the economic benefits of the oil sands industry development.

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 March 16, 2015), 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., standalone 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, scope and the methodology.

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, royalties, and emissions.

Chapter 4 discusses future energy requirements of the oil sands industry with respect to natural gas, electricity and diesel consumption.

Chapter 5 covers the economic impacts of oil sands development in the province of Alberta as well as nationally.

Chapter 2: Oil Sands Supply Costs

Introduction

Sheer determination by pioneer oil sands developers and dedicated research and development (R&D) have stimulated the employment of innovative technologies to recover crude bitumen from Alberta's vast 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 upon 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 standalone 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 2014 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 Studies 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.

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 identified some of these opportunities in a recently released study, titled "Process Efficiencies of Unconventional Oil and Gas".[3]

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, 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. Currently, in situ and mining projects do not generate any excess electricity, in fact in situ projects purchase electricity from the provincial grid.

[3] CERI Study No. 147, "Process Efficiencies of Unconventional Oil and Gas", June 2015

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
Average Capacity Factor (over production life)	percent	75.00%	89.00%
Capital Expenditures (2014 CDN Dollars)			
Initial	Millions of dollars	1,090.8	7,051.7
Initial	Dollars per bbl of capacity	36,360.8	70,517.4
Sustaining (Annual Average)	Millions of dollars	54.8	237.3
Operating Working Capital	Days payment	45	45
Operating Costs (2014 CDN Dollars)			
Fixed (Annual Average)	Millions of dollars	97.7	530.0
	Dollars per bbl of capacity	8.9	14.5
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 all have contributed to cost overruns. Capital costs increased which ultimately eroded returns for producers. Operators have learned from the most recent boom and are intently focused on controlling cost inflation; however, if oil prices strengthen further, CERI expects the pace of development to increase in response.

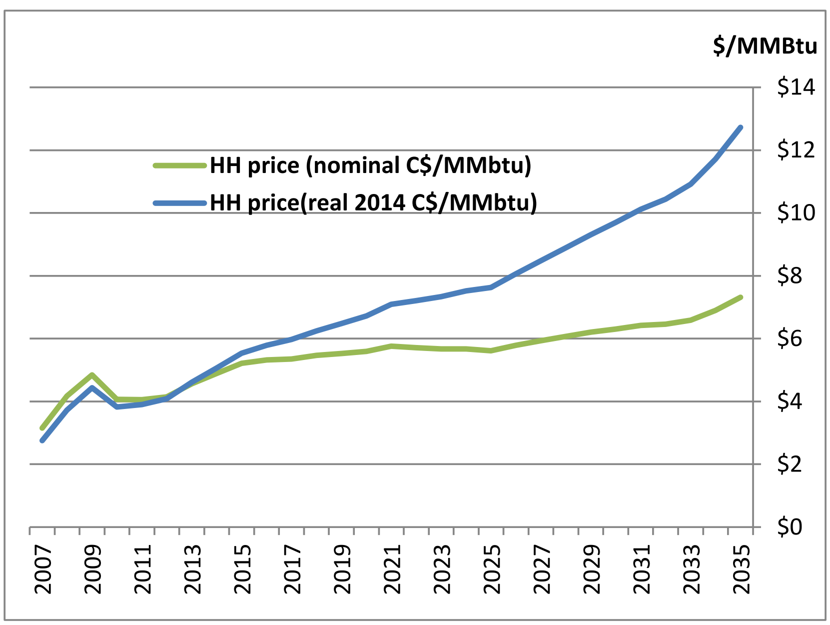
Adjusting the capital cost estimates from 2013 dollars to 2014 dollars, the real initial capital costs in 2014 have increased by 2.4 percent for SAGD producers and decreased by 16 percent for mining projects. The sustaining capital costs have been adjusted upward to reflect sustaining capital requirements that are consistent with the industry estimates: sustaining capital costs are $5.0/bbl per day of capacity for a SAGD project and $6.50/bbl per day of capacity for a standalone 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 6 percent on average and for mining producers – by 21 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) 2015 for the period 2015 to 2040.[4] Prices were then transformed to 2014 dollars, as seen in Figure 2.1. The Henry Hub prices were then 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$1.25/MMBTU, and a field premium of C$0.27/GJ.

Figure 2.1: Henry Hub Natural Gas Price Forecast



Source: EIA, CERI

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

Since 2011 prices of natural gas have been recovering, the year-on-year change from 2013 to 2014 indicates an increase in prices of 15 percent, from $4.87/MMBTU to $5.60/MMBTU. The increase in prices contributed to a year-on-year increase in gas related operating costs for oil sands producers. The prices will remain flat (in real terms) until 2017-18 and then gradually start to increase, approaching an $8/MMBTU mark later in the forecast period.

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 anticipated that most in situ projects will move towards cogeneration, with units sized to match a projects' steam and electricity load. 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) forecast for 2015 was sourced from Alberta Electric System Operator (AESO) 2014 Annual Market Statistics, 2014.[5] The 2015 price estimate is $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 the 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.

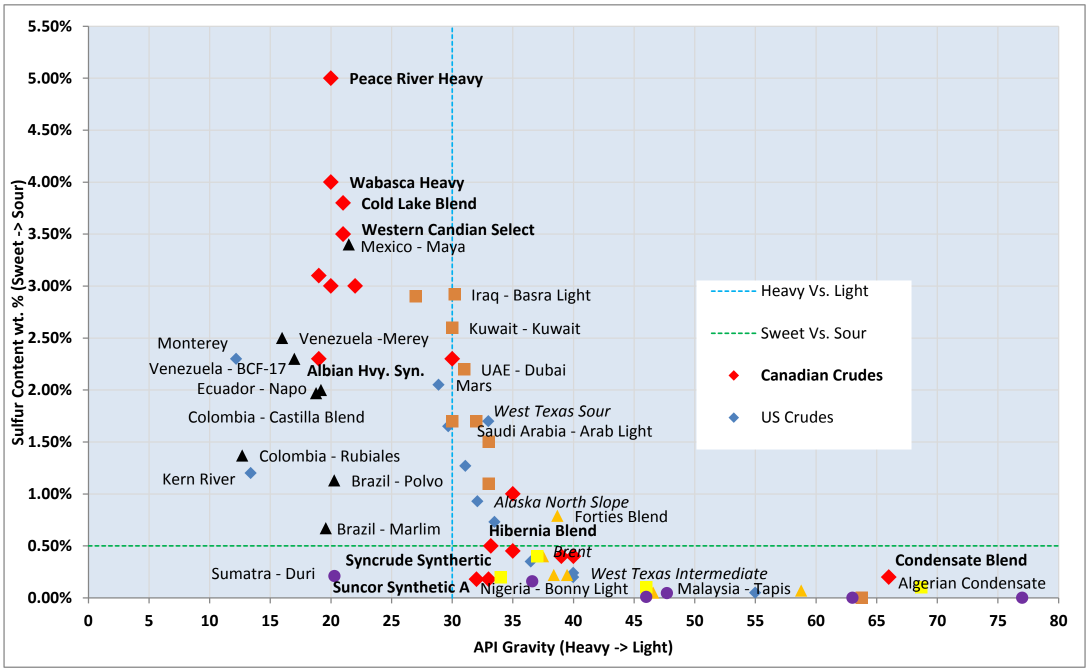
All crude oil is not valued equally. Light oil that is low in sulphur content (i.e., sweet) is more valuable to refiners than heavy oil with higher sulphur content (i.e., sour), because it is less energy-intensive to refine light sweet crude, and the resulting petroleum products are of higher quality. 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

[5] Technical Meeting. AESO's 2015 Forecasts, Own Costs Budget Stakeholder Meeting October 6 and 8, 2014.

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.

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.[6] Table 2.2 compares the characteristics of the WCS blend with two other heavy crude oils.[7] 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.

[6] 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)

[7] 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.[8] Since the reversal of Seaway pipeline and construction of the southern leg of the Keystone XL in 2013 to connect Cushing to the Gulf of Mexico, the 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,[9] 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

[8] 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.

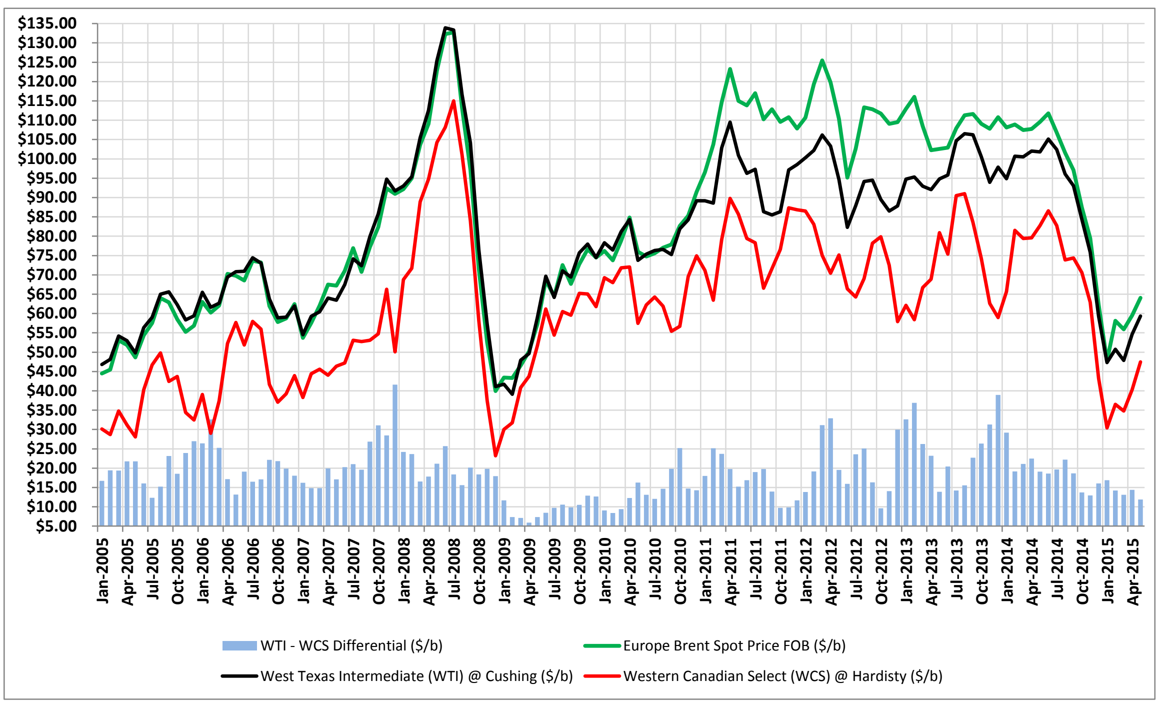
[9] Maya has in turn historically traded at a US$7-9/bbl discount to WTI reflecting mainly quality differences. On the other hand Maya has historically traded at a $10/bbl discount to LLS, which further reflects the light-heavy differential in the coastal area (more reflective of a global light-heavy 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,[10] 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, which is US$3/bbl lower than the differential used in last year's report. 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

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

(Edmonton and Hardisty), and to an equivalent market price of WTI crude oil at Cushing, Oklahoma. For non-integrated projects, blending costs are estimated through accounting for the volume of diluent required per barrel to bring the bitumen blend to a density that meets pipeline specifications, the cost of diluent, and the cost of transporting diluent to the field. Based 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 Cushing, Oklahoma is assumed to be C$1.01 per barrel from the field to Hardisty. Transportation costs from Hardisty to Cushing have been adjusted upward to US$5.45 per barrel.[11] Per barrel transportation costs from the field to Hardisty, and Edmonton to Cushing, Oklahoma, are assumed to rise at an annual inflation rate of 2.5 percent.

Economic and Taxation Assumptions

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 12.5 percent (nominal) based on the assumed average inflation rate of 2.5 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[12] and 12 percent,[13] respectively.

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.[14] 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

[11] CAPP, "Crude Oil Forecast, Markets & Transportation", June 2015.
[12] Effective January 1, 2012, the federal rate dropped to 15 percent from 16.5 percent.
[13] Effective July 1, 2015, the provincial corporate rate increased from 10 to 12 percent. Source: http://www.finance.alberta.ca/publications/tax_rebates/corporate/overview.html
[14] 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.

cost of the eligible assets, not exceeding the taxpayer's income for the year (calculated after 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 strategic 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.[15] 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 will be 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 from 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.

[15] 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, 2014, and begin operating on January 1, 2017. The projects will continue to operate until end of year 2046, based on a 30-year project life.

In June 2015 the new Alberta Government enacted changes to the carbon policy. The new regulations state that by 2017 large emitters will have to reduce the intensity of their greenhouse gases by 20 percent (15 percent by 2016) and carbon levies will double from $15/T of CO2eq. to $30/T of CO2eq. ($20/T of CO2eq. by 2016). Complying with the policy can be facilitated in four ways:

1. Make facility changes to improve performance and lower emissions.
2. Purchase Alberta-based carbon offsets.
3. Pay $30-a-tonne into the Climate Change and Emissions Management Fund.
4. Purchase/use emission performance credits generated in previous years or at other facilities.

CERI's supply cost model incorporates this $30.00/tonne tax for emissions over the 100,000 limit, increasing at an annual average inflation rate of 2.5 percent.[16]

Royalty Assumptions

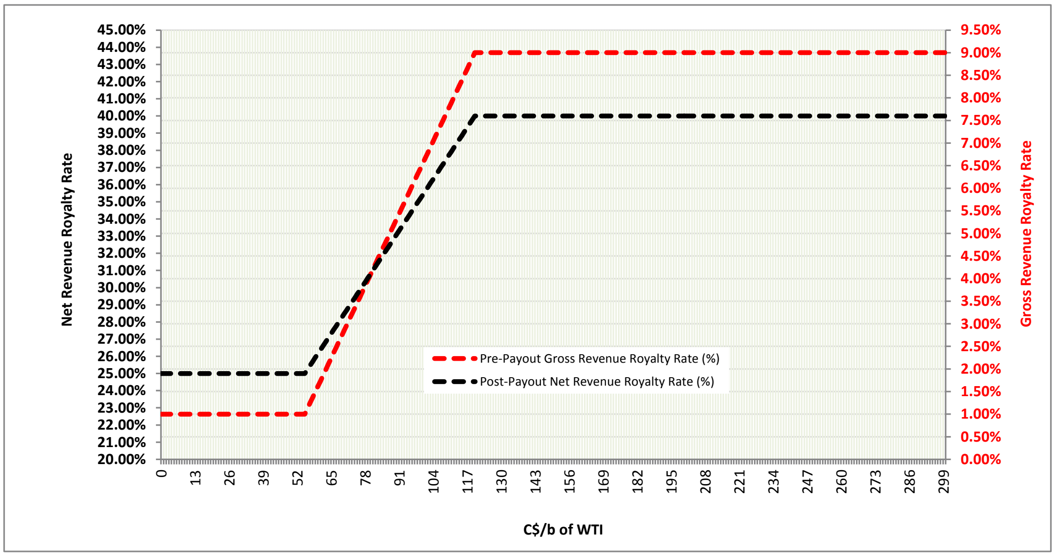
The Alberta oil sands royalty regime is based on the net revenue system whereby the oil sands producer pays a lower royalty rate based on gross revenues until the point at which the producer has recovered all the allowed project costs (those incurred up to three, and in some cases up to five, years prior to the approved effective date) plus a return allowance based on current Long Term Government Bond Rates (LTBR) issued by the Government of Canada (floor risk).[17] 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 seen 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,

[16] CERI assumes that the reduction in carbon intensity and/or purchase of carbon offset credits more or less equates to carbon tax.
[17] Assumed to be 5.5 percent.

as well as the costs of compliance with environmental regulations and with termination of a project, abandonment and reclamation of a project site.[18]

Figure 2.4: Alberta Bitumen Royalty Rates

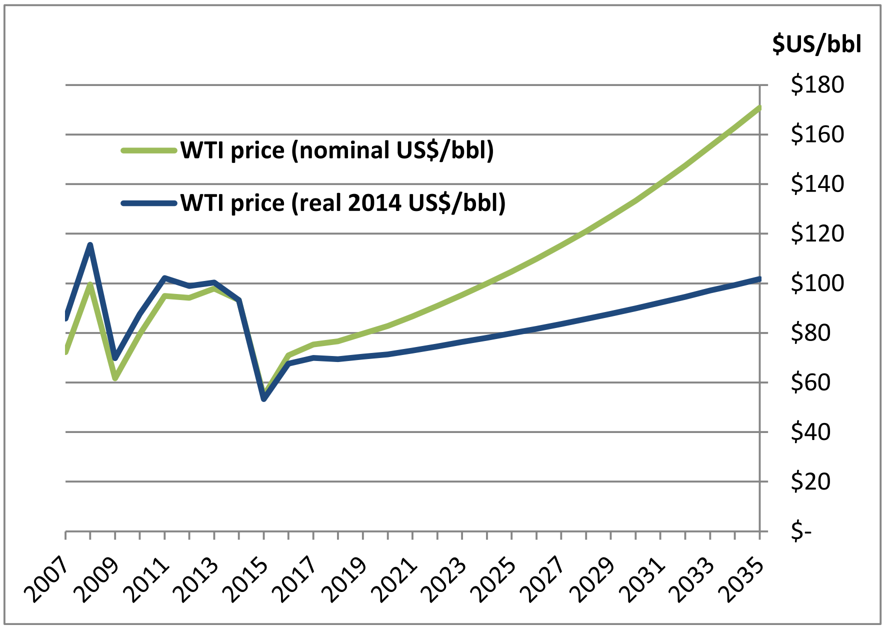


Source: CERI

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 2015, for the period 2015 to 2040.[19] Prices were then transformed to 2014 dollars as seen in Figure 2.5. Since the summer of 2014, global and North 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. Hence, the WTI forecast has been revised and the overall price level was reduced since the last edition of the AEO in 2014. Oil prices will remain flat for the rest of this decade, gradually recovering to triple digits by 2035.

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

Figure 2.5: WTI Price Forecast



Source: EIA, CERI

US-Canadian Exchange Rate

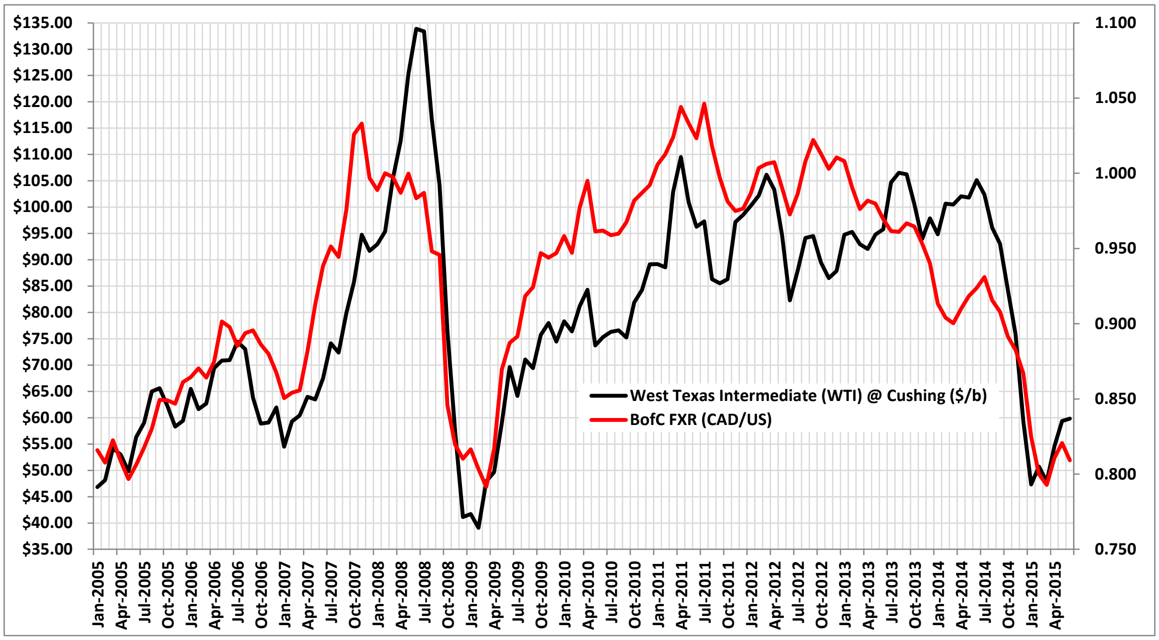
Since the summer of 2014, the price of oil has plummeted to its lowest point in years – and so has the Canadian dollar, continuing an ongoing debate on how closely the two are related. Canada's dollar is often viewed as a petrocurrency because its movements often track oil prices (see Figure 2.6). In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

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[20,21,] an exchange rate of US/CDN$0.85 will be assumed in the supply cost calculation. This represents a 15 percent drop since last year's assumption of parity between the two currencies.

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

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

Figure 2.6: CDN/US Exchange Rate



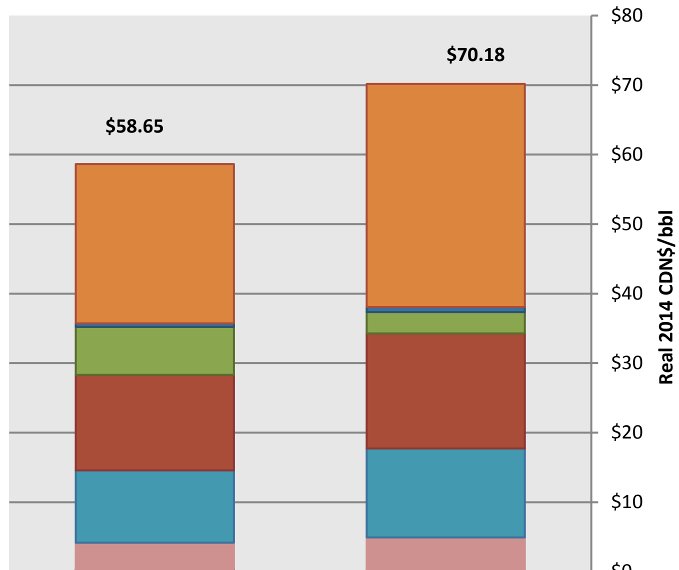
Source: EIA, Bank of Canada

Supply Cost Results

Based on these assumptions, the supply costs of crude bitumen 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$58.65/bbl for a SAGD project and C$70.18/bbl for a standalone mine. A comparison[22] of field gate costs from the July 2014 update with this year's supply costs indicates that, after adjusting for inflation, the supply cost for a SAGD producer has risen by 10.3 percent, and fell 6.5 percent for a standalone mine.

[22] 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, such as a change in corporate taxes 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)	$22.91	$32.12
Operating Working Capital	$0.53	$0.70
Fuel (Natural Gas)	$6.90	$3.07
Other Operating Costs (incl. Elec.)	$13.74	$16.57
Royalties	$10.41	$12.80
Income Taxes	$3.80	$4.74
Emissions Compliance Costs	$0.31	$0.13
Abandonment Costs	$0.04	$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$80.06/bbl and US$89.71/bbl for a standalone mine. In comparison to last year's update, the WTI equivalent costs for a greenfield SAGD project are 9.9 percent lower and 18.7 percent lower for a standalone mine based on lower light-heavy differential, lower US/CDN exchange rate assumption and a lack of premium on diluent costs.[23] A summary of costs are presented in Table 2.4. At current WTI prices of just above US$50/bbl,[24] one can assume that these greenfield projects are not economic or have to accept a lower rate of return. However, as

[23] Macleans, "Just How Much Is The Oil Price Drop Hurting Oil Sands Projects?". November 2014.
[24] At the time of writing, WTI prices traded at just above US$50/bbl.

observed in the industry, the relative position of oil sands projects has not suffered that much, nor is this the most difficult period for oil sands pricing in recent history.[25]

Table 2.4: Supply Costs Summary

Project	SC at Field Gate (C$2014/bbl)	WTI Equivalent SC (US$2014/bbl)
SAGD	58.65	80.06
Standalone Mine	70.18	89.96

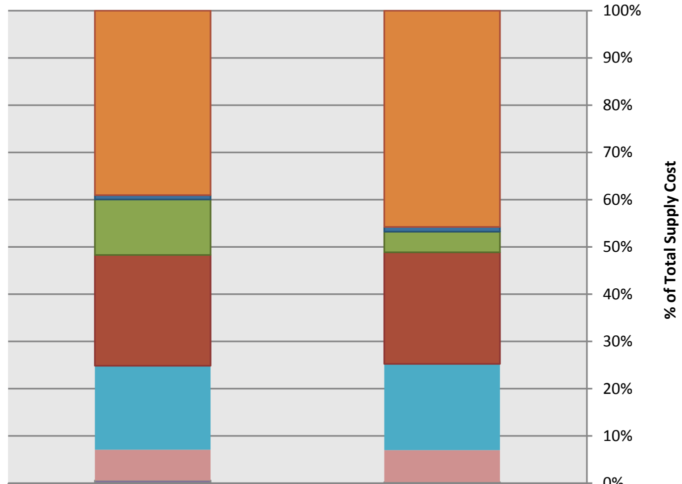
Source: CERI

A few noteworthy changes that affected the supply costs were: the new corporate tax rate increase from 10 to 12 percent provincially, the elimination of accelerated CCA, and doubling of the carbon tax from $15 to $30 per tonne of CO2 eq. The resulting impact on the overall cost of an oil sands project is shown in Figure 2.8; the percentage shares of income taxes and carbon taxes increased from last year's results by 6.5 percent and 150 percent, respectively, for a SAGD project. Similar increases are present for a mining project – the share of income taxes is expected to increase by 9.7 percent and the share of emission compliance costs is expected to double. It is assumed that compliance costs are royalty deductible, as is currently the case. When compliance costs are royalty deductible, collected by the province, and spent entirely within the province, a transfer of money outside of Alberta does not take place. Under a harmonized system, emission compliance costs would be collected by the federal government, and represent a monetary transfer from Alberta to federal coffers.

While capital costs and the return on investment account for a substantial portion of the total supply cost, the province stands to gain $10.41 to $12.80 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 17.8 to 18.3 percent share of total supply cost, a decrease of 2.8 percent for a SAGD project and 4.2 percent for a mining project as a result of income taxes and compliance cost increases (see Figure 2.8).

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

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



	SAGD 10% ROR (a)	Mining 10% ROR (a)
Fixed Capital (Initial & Sustaining)	39.1%	46.0%
Operating Working Capital	0.9%	1.0%
Fuel (Natural Gas)	11.8%	4.4%
Other Operating Costs (incl. Elec.)	23.4%	23.7%
Royalties	17.8%	18.3%
Income Taxes	6.5%	6.8%
Emissions Compliance Costs	0.5%	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 with a lower discount rate than CERI's estimates) are presented in Table 2.5. CERI's estimates are within the AER's range: SAGD costs are at the higher end of the range and mining costs are in the lower end of the range.

Table 2.5: Supply Costs Comparison – WTI Equivalent Supply Costs

Project	CERI (2014 US$/bbl)	AER (2014 US$/bbl)[26]
SAGD	**80.06**	50-80
Standalone Mine	**89.96**	90-105

Source: CERI, AER.

[26] AER, ST-98-2015. "Alberta's Energy Reserves 2014 and Supply/Demand outlook 2015-2024", June 2015. A nominal 10 percent discount rate is used.

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.

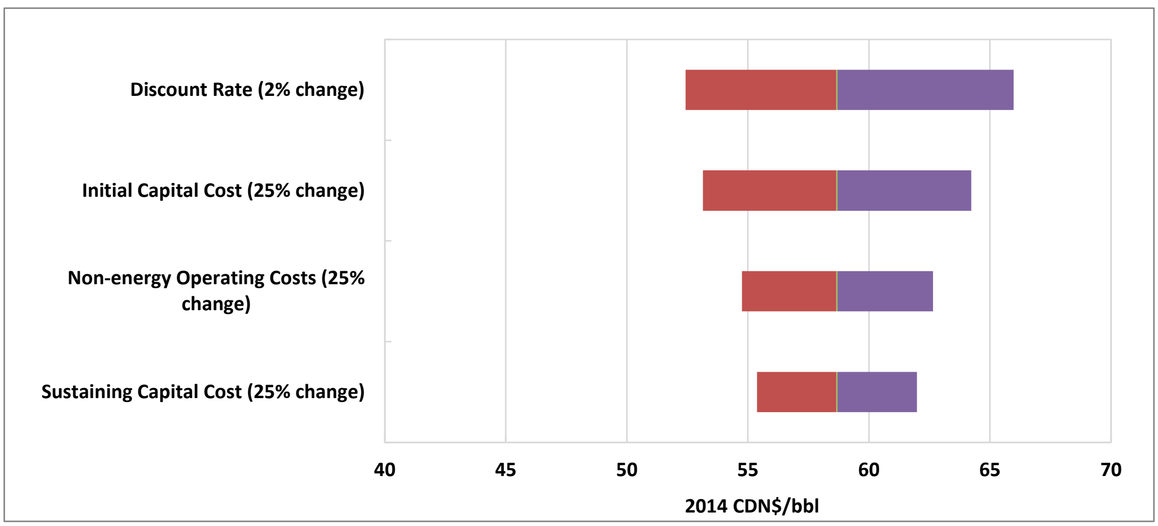
Table 2.6: Assumptions for Sensitivity Analysis

Parameter	Sensitivity
Initial Capital Cost	+/-25%
Sustaining Capital Cost	+/-25%
Non-Energy Operating Costs	+/-25%
Discount Rate	+/-2%
Carbon Tax	+CDN$10/tonne CO_2

Source: CERI

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

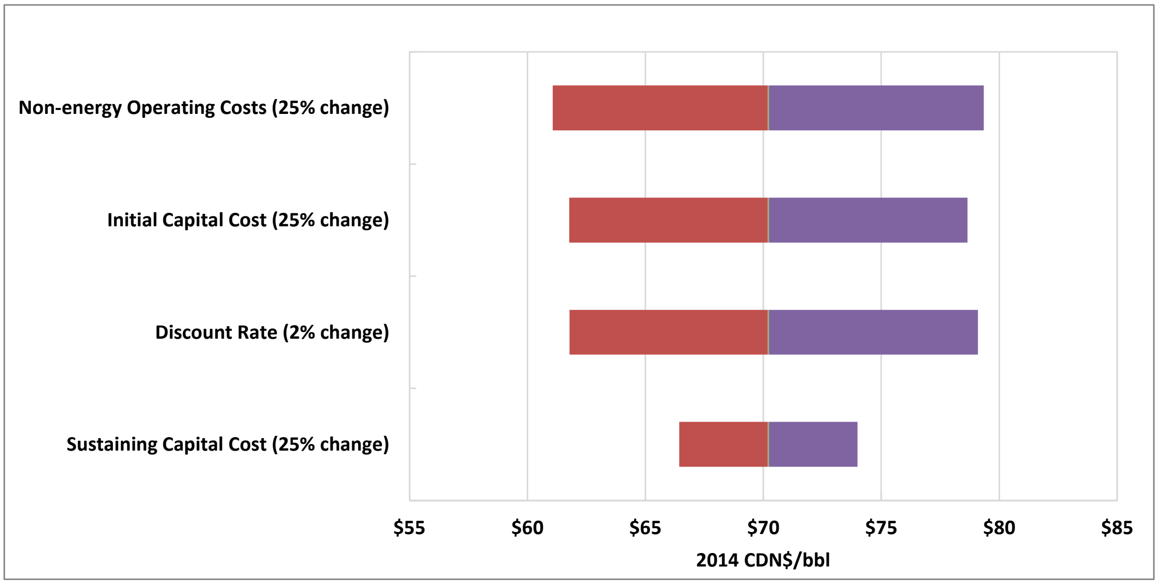
Figure 2.9: Supply Cost Sensitivity – 30 MBPD SAGD Project



Source: CERI

The results indicate that SAGD supply cost is subject to change the most under two sensitivities for the assumed discount rate. If the discount rate is raised to 12 percent real, the supply cost is estimated to increase by $7.28/bbl, and when it is decreased to 8 percent real, the cost will decrease by $6.23/bbl from its base of $58.65/bbl. The changes in capital and operating costs are also influential in changes to the supply costs.

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



Source: CERI

For a standalone mining project the operating cost, capital cost and discount rate changes are almost equally significant on the changes of the base mining cost. The supply cost for a mining project will increase by C$9.12/bbl if the non-energy related operating costs increase by 25 percent. The discount rate increase to 12 percent will increase the supply cost by $8.87/bbl and a decrease to 8 percent will result in a $8.40/bbl drop in the base supply cost of a mine.

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. Low oil prices have caused companies to announce capital spending cuts, the exchange rate to drop, light-heavy differentials to narrow and some 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 that is worth nurturing. 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.

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. A special focus is paid 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 not part of the overall forecast.

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. The projects that fall into the announced category have not been added in the production forecast. Another factor that is contributing to this increase in delays and capacity curtailments is 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 there are proposals to expand the export pipeline capacity, many projects are facing challenges in moving ahead. Producers have responded to this by starting to ship oil by rail, which in itself is remarkable, given how quickly the rail industry was able to respond, and today there are outbound terminals being built in Northern Alberta with producers committing future volumes to be shipped on rail cars. The outbound terminal capacity is set to grow anywhere from 0.75 to 1.4 MMBPD by 2015-2017.[27] Nevertheless, in the long run, pipelines will still be a preferred option to ship crude for cost and safety reasons.

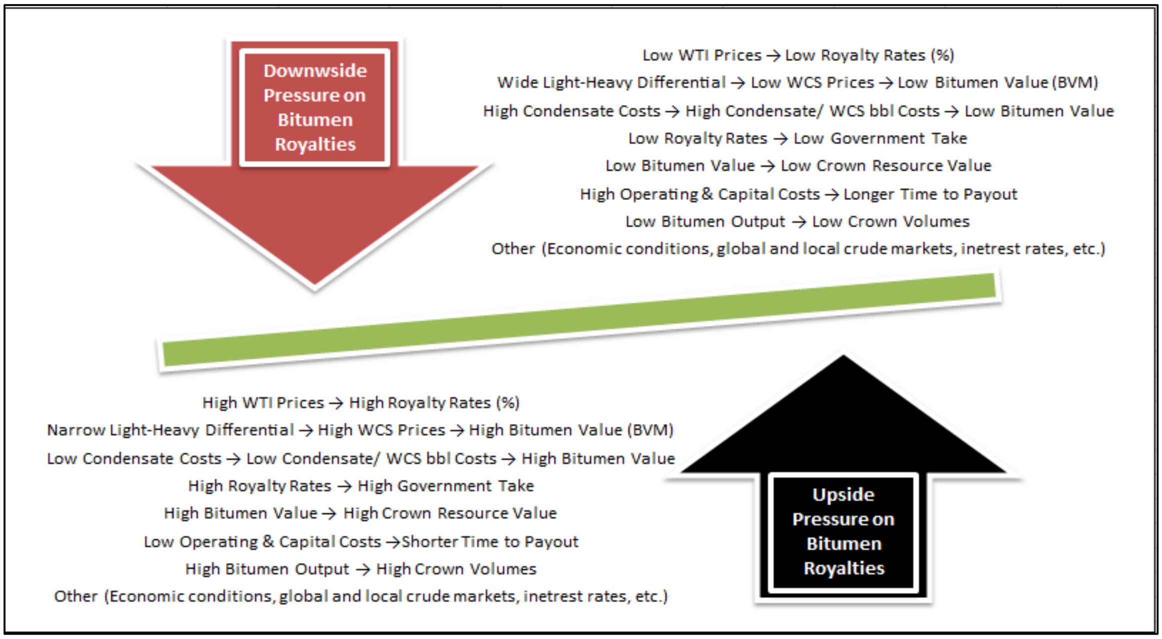
Estimating Royalty Revenues and Blending Requirements

Due to their importance to the provincial 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 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.[28] 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).[29] 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.

[27] CERI Study 146. "Ribbons of Steel: Linking Canada's Economic Future". May 2015.
[28] ARC Financial Corp. "The Fiscal Pulse of Canada's Oil and Gas Industry, First Quarter 2015", April 2015.
[29] The newly elected

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.[30]

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, and awaiting approval. Announced projects are not included in this year's forecast due to uncertainties regarding timing and economic conditions. This year the projection period is from 2015 to 2035, inclusive.[31]

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

[30] CERI Study No. 133, "Canadian Oil Sands Supply Costs and Development Projects (2012-2046)", May 2013.
[31] The projection time period was shortened from 35 to 20 years.

market price for blended bitumen and SCO (demand). Despite the current outlook for the light-heavy differential, escalating construction costs, probability of construction and regulatory delays, and availability of suitable and accessible refinery capacity, 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 2.34 MMBPD in 2014, comprised of in situ and mining production of 2.05 MMBPD and 0.29 MMBPD of primary and enhanced oil recovery (EOR) production within the boundaries of oil sands areas. Total production in 2013 was 2.08 MMBPD, meaning the oil sands production grew 11 percent year-over-year. Production from oil sands includes an increasing share of Alberta's and Canada's crude oil production. In 2014, non-upgraded bitumen and SCO production made up 58 percent of total Canadian crude production and 74 percent of Alberta's total production.

In the **High Case Scenario**, production from mining and in situ thermal and solvent extraction (excluding primary recovery) is set to grow from 2.05 MMBPD in 2014 to 3.4 MMBPD by 2020 and 4.9 MMBPD by 2035. In the **Low Case Scenario** production rises to 3.9 MMBPD by 2030 and 4.1 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 3.1 MMBPD by 2020 and 4.4 MMBPD in 2035 (see Figure 3.2 and Table 3.1). Cold bitumen production from primary and EOR wells is forecasted to increase from 0.29 MMBPD in 2014 to its peak of 0.41 MMBPD by 2020 and then growing at a flat rate to 0.49 by the end of forecast period.

Table 3.1: Oil Sands Production Forecast*

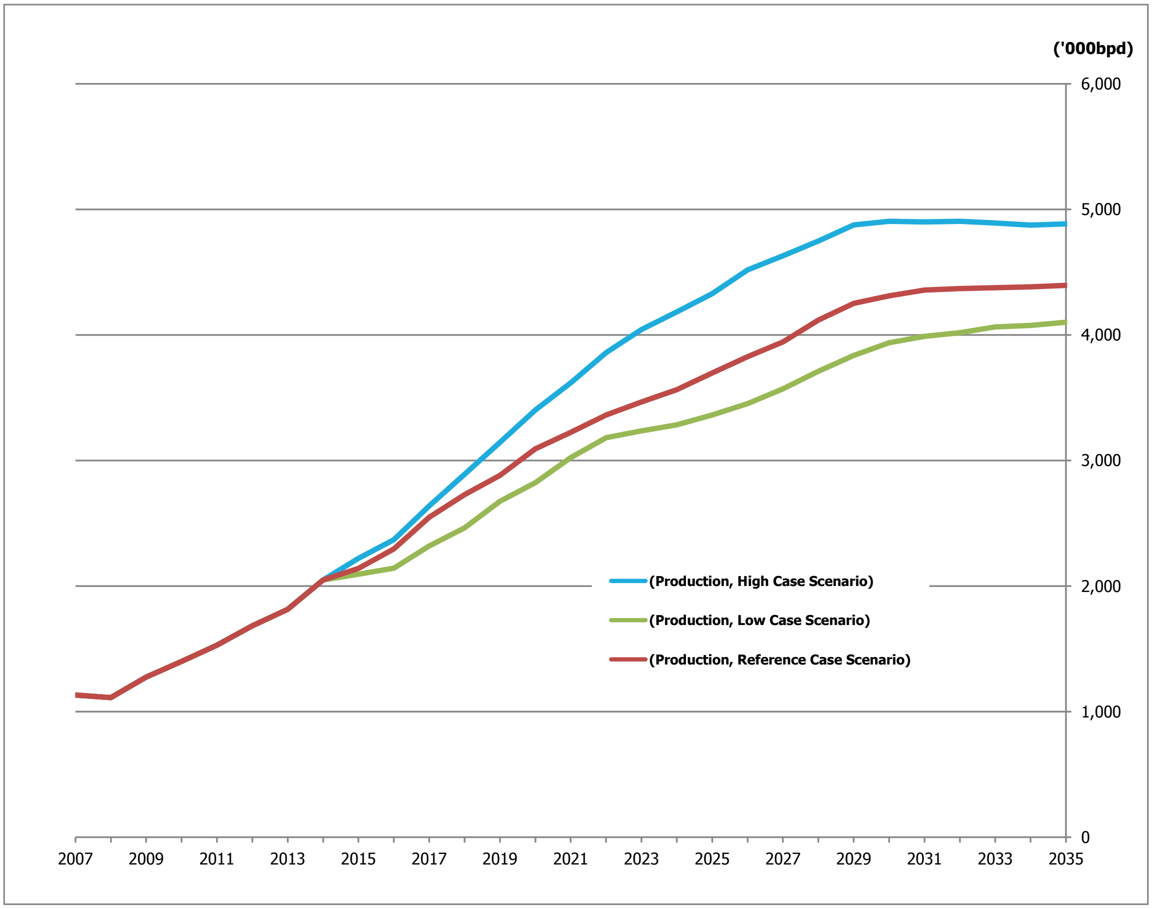
	2014	2020	2030	2035
	MMBPD			
High Case	2.05	3.40	4.91	4.89
Reference Case	2.05	3.09	4.31	4.39
Low Case	2.05	2.82	3.94	4.10

*Excludes primary bitumen production.

Source: CERI

Peak production volume of 5.8 MMBPD in the **High Case Scenario** is reached in 2037. Peak production volumes for the other two cases are lower and reach their peak later in the projection period. Under the **Low Case Scenario**, the highest production of 4.4 MMBPD is reached in 2041. Production under the **Reference Case Scenario** peaks at 5.0 MMBPD in 2039. 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.

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.

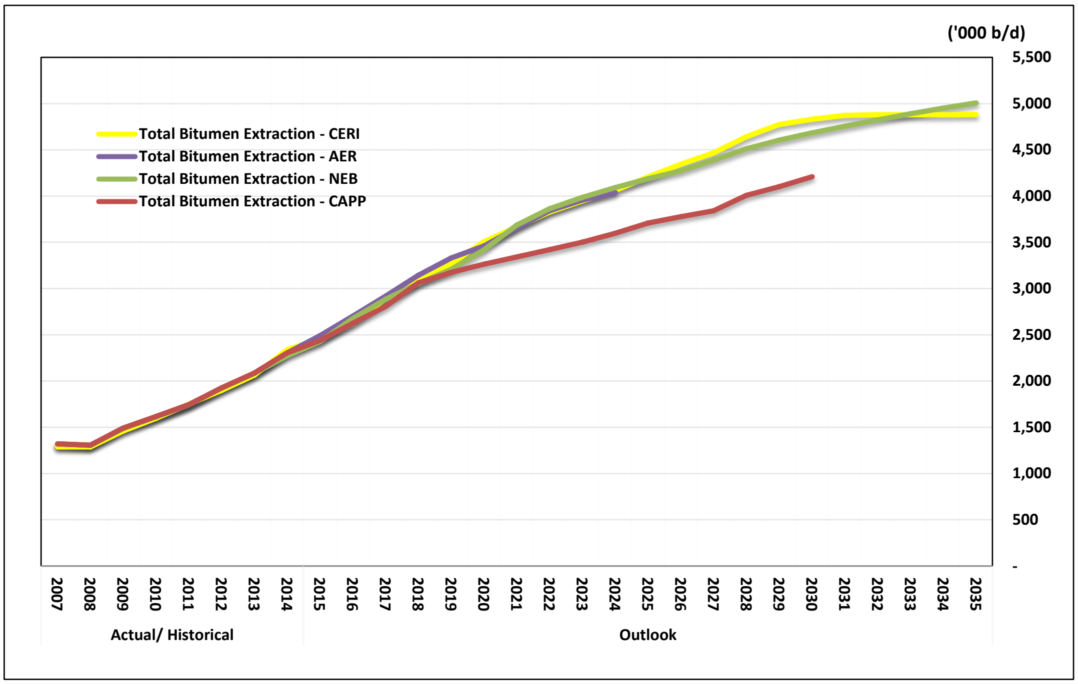
Reference Case Scenario

This section will focus on the results of CERI's **Reference Case Scenario**. Projections of production, capital and operating costs, diluent and royalties are included in the discussion. Chapter 4 will discuss the energy requirements such as natural gas, electricity and diesel needed to sustain the production forecast in the **Reference Case Scenario.**

Oil Sands Production – Historic and Forecast

A comparison is presented between CERI's **Reference Case Scenario** production and other agencies' forecasts, such as CAPP,[32] the AER,[33] and the NEB[34] 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 2024, CAPP's to 2030 and the NEB's to 2035. CERI's total production projection from oil sands areas (including primary and EOR projects) is consistent with all the forecasts up to 2020. After that, the CAPP forecast diverges lower for the remainder of the forecast period, whereas the three other forecasts (CERI, the AER and the NEB) are consistent with each other.

Figure 3.3: Bitumen Production Forecast – Comparison



Source: CERI, AER, CAPP, NEB.

Currently, most mined bitumen and a portion of in situ production are upgraded to SCO. According to the AER, in 2014, 10.5 percent of in situ production was upgraded to SCO. The 2014 production of SCO amounted to 1.0 MMBPD and is expected to increase to 1.2 MMBPD in 2020, and then decline to 0.98 MMBPD by 2035.

Illustrated in Figure 3.4 are the production projections by extraction type. Total mined bitumen production is expected to increase from 1.1 MMBPD in 2014 to its peak of just over 1.6 MMBPD by 2022, at which point the production dips until it reaches 1.5 by 2035. The decrease in mining

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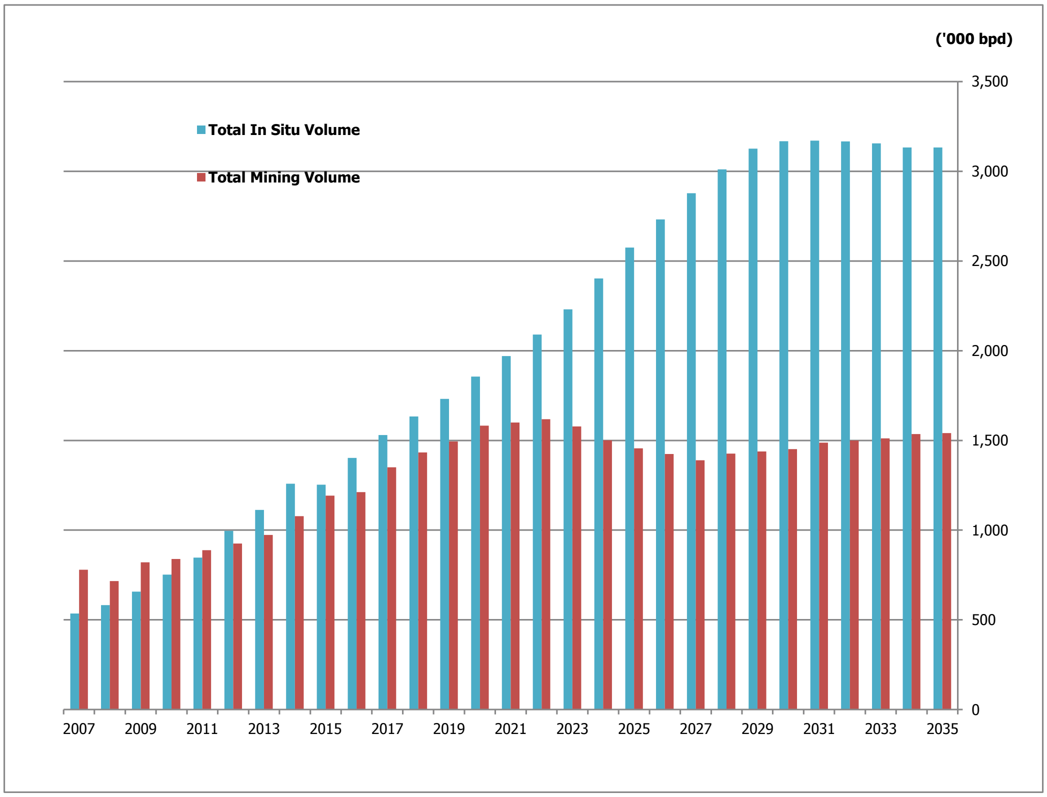
[32] CAPP, "Canadian Crude Oil Forecast and Market Outlook", June 2015

[33] AER ST98, "Alberta's Energy Reserves 2013 and Supply/ Demand Outlook (2015-2024)", June 2015.

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

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 from 1.3 MMBPD[35] in 2014, peak in 2031 at 3.2 MMBPD and reach 3.1 MMBPD in 2035 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 2014 to 33 percent in 2035. By the end of the projection period in 2035, in situ bitumen accounts for 67 percent of total bitumen production volumes.

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

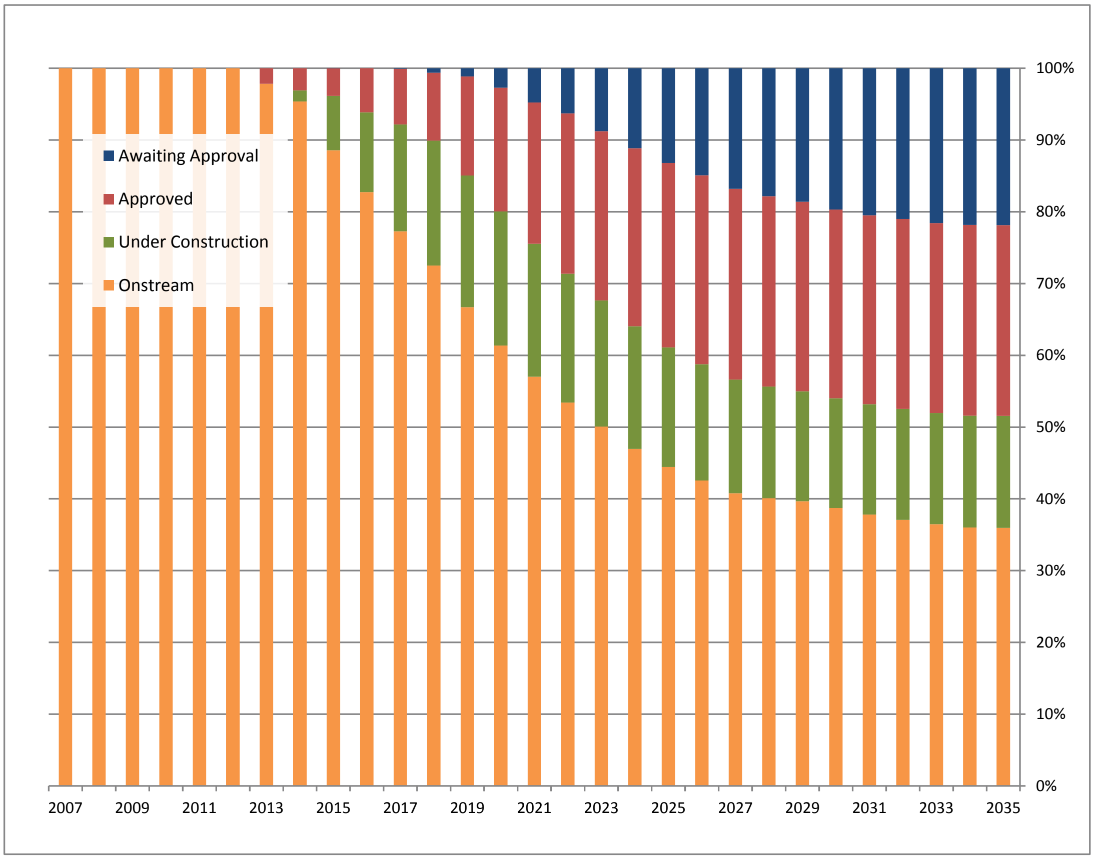


Source: CERI, CanOils

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 are made up of on-stream and approved projects. The portion attributable to the announced category has been taken out of the forecast as a result of a near-term lower oil price forecast and lack of clearness on what will happen to all the proposed pipeline projects. The risk of these projects not proceeding is high. As the proportion of on-stream projects starts to decline from 100 percent in 2012 to just a third in 2035, the total proportion of under construction, approved, and awaiting approval projects takes up the share of total production.

[35] Including Primary and EOR projects. Totals may not add up due to rounding.

Figure 3.5: Bitumen Production by Project Status[36]



Source: CERI, CanOils

Diluent Demand, Supply, and Transportation

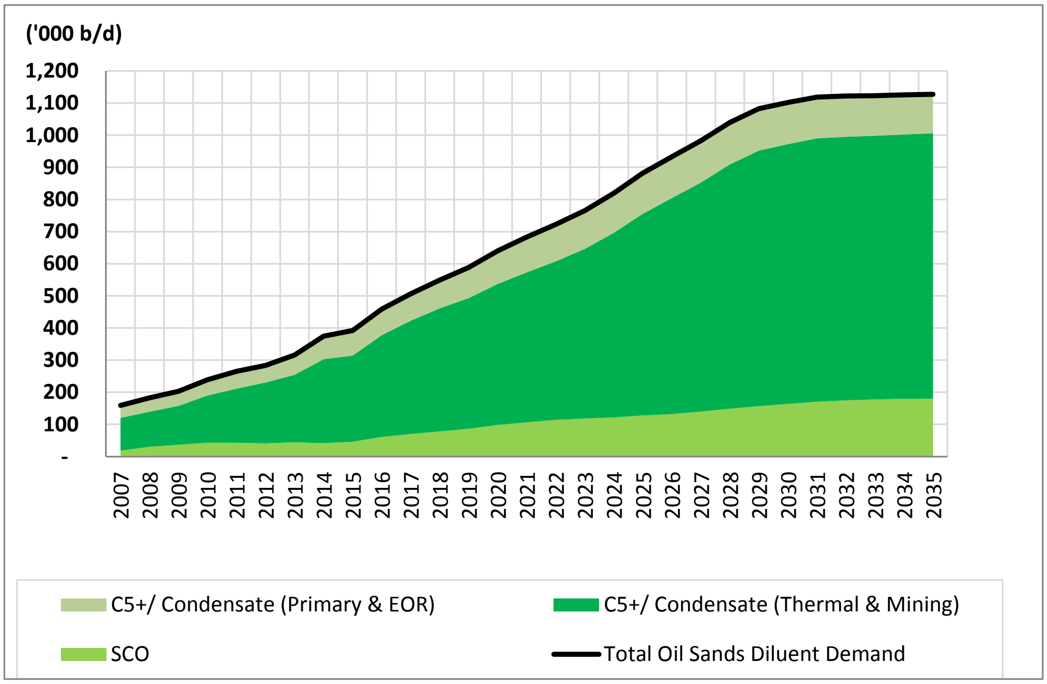
Diluent is an important component of oil sands operations for transportation purposes. Adding diluent brings that barrel of bitumen to the pipeline specifications and allows it to flow; otherwise, non-upgraded bitumen is too viscous to flow.

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. While the choice of diluent used by different project operators is based on economic and technical

[36] This graph does not include the forecast of primary and EOR projects.

considerations,[37] pentanes plus remains the diluent of choice for oil sands operators. Figure 3.6 displays the estimated demand for diluent by project type and by diluent type to 2035.[38]

Figure 3.6: Oil Sands Diluent Demand by Type of Diluent



Source: AER, CERI

Total demand for diluent in Western Canada for 2013 is estimated at 375 thousand barrels per day (MBPD) including 72 MBPD of pentanes plus and condensate for primary/EOR bitumen projects, 261 MBPD for SAGD/CSS/Mining projects, 41 MBPD of SCO for synbit and dilsynbit blends, and 19 MBPD of butanes used as a diluent. The diluent demand is expected to rise in tandem with bitumen production, as more in situ projects come online, requiring diluent for transportation. Total demand will rise from the current level to over 1,100 MBPD by 2035.

While import levels for diluent are expected to remain high, the overall estimated levels of required imports are lower when compared to previous reports' estimates, primarily due to changes in the local production profile. CERI believes that the domestically produced volumes of pentanes plus and condensate will continue to be sold in Western Canada given a prevailing price premium compared to other markets. Meanwhile, production of pentanes plus and condensate are estimated to be higher during the forecast period given a combination of factors including

[37] See CERI Study 133.

[38] The 2030 timeline is used here as the supply side projections are derived from a different CERI model (NGLs model) whose timeframe does not reach beyond 2030. However, it is important to note that total oil sands production, the main driver for diluent demand, peaks in 2030 and thus demand for diluent will flatten and decrease beyond that point (according to the current modeling assumptions), and thus the maximum peak demand levels for diluent, the focus of this section, is reached within the timeframe displayed.

the continued focus of gas producers on liquids-rich and “oily” gas plays like the Duvernay, but also overall increasing levels of gas production due to the commissioning of liquefied natural gas projects (LNG) in British Columbia.

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.

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,[39] 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 (for which capacity is expected to be expanded over the coming years), the Cochin pipeline which was reversed and switched over from propane to diluent service, and the proposed Northern Gateway diluent line. 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.

Up until 2024, the import infrastructure seems to be sufficient to accommodate the needed import volumes. Beyond that, a combination of factors could help ease any infrastructure shortage including any further expansion of existing pipelines or the building of new pipelines, but also the use of rail. The increased use of rail can play different roles in fulfilling the increased diluent import needs. For one, as discussed above, it has the potential to reduce diluent demand depending on how the bitumen is transported. Additionally, increasingly available rail tank cars can also be used for diluent haul-backs; that is, once the shipped crude reaches its destination, rather than sending an empty car back to Alberta, that same tank car could be sent back with diluent available for the market.

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

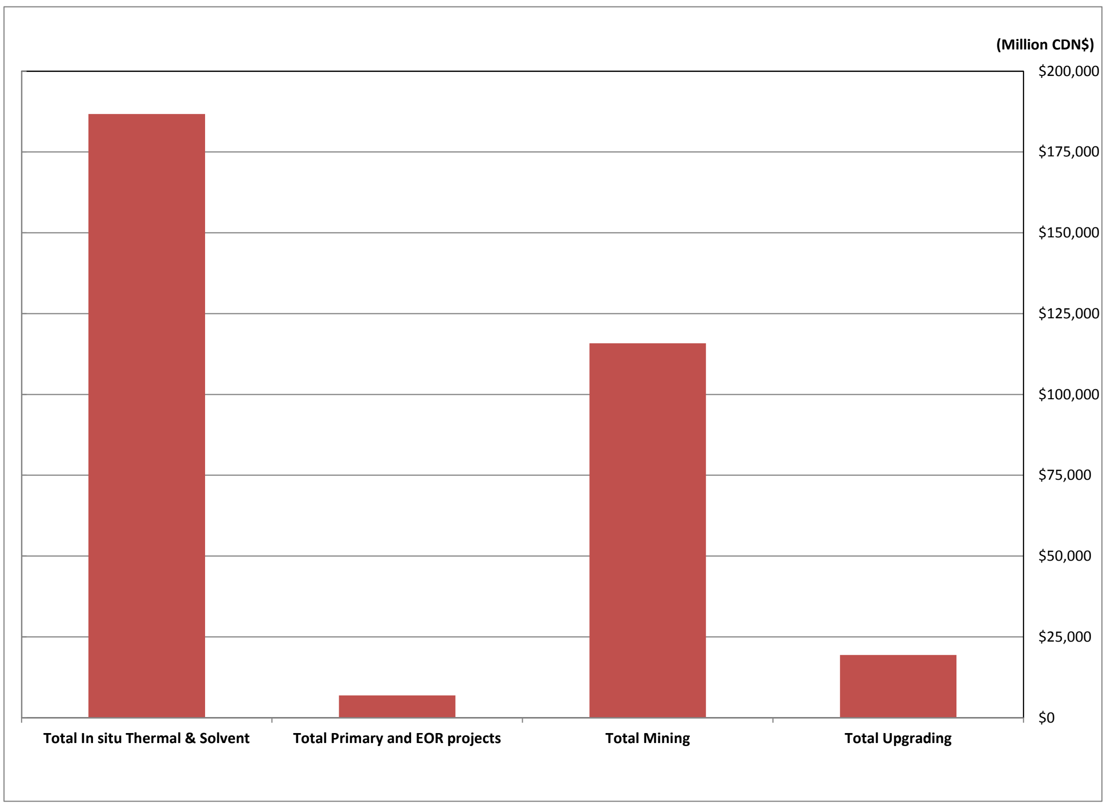
[39] Dilbit via rail would use the same amount of diluent as dilbit in pipelines or around 30%. Railbit will require about 17% diluent and cleanbit would require no diluent at all. Railbit and cleanbit would require coil and insulated (C&I) rail cars for transportation purposes.

haul-backs. Last but not least, given the high level of import requirements. It is important to survey the required infrastructure, which appears to be sufficient at the present moment.

Capital Investment and Operating Costs

Total capital spending requirements are broken down by project type and are illustrated in Figure 3.7. Over the 20-year projection period from 2015 to 2035 inclusive, the total initial and sustaining capital required for all projects is projected to be C$329 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 2015 to 2035, it is projected that C$116 billion (initial and sustaining) will be invested into mining projects and C$194 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$19 billion.

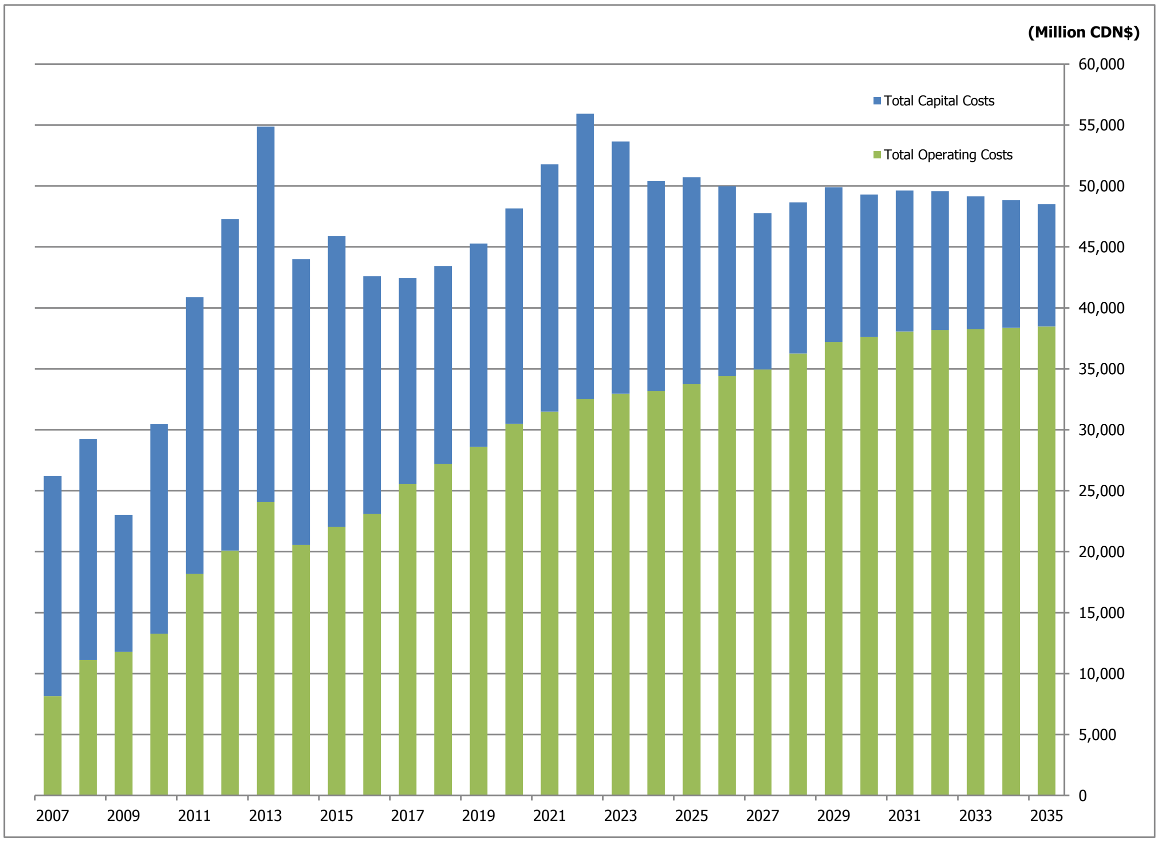
Figure 3.7: Total Capital Invested by Project Type



Source: CERI, CanOils

Total cost requirements for the oil sands industry are presented in Figure 3.8. These include the initial and sustaining capital and operating costs for all types of projects. Total spending increases from 2007 to 2013, reaching an all-time high of C$55 billion in 2013. With falling oil prices in the near term, the investment starts to fall, slowly recovering to a forecast peak of C$56 billion in 2022, at which point it flattens out, averaging C$50 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. The total operating costs average C$33 billion a year and over the forecast period cumulatively add up to C$693 billion.

Figure 3.8: Total Cost Requirements



Source: CERI, CanOils

Alberta Oil Sands Royalty Revenues

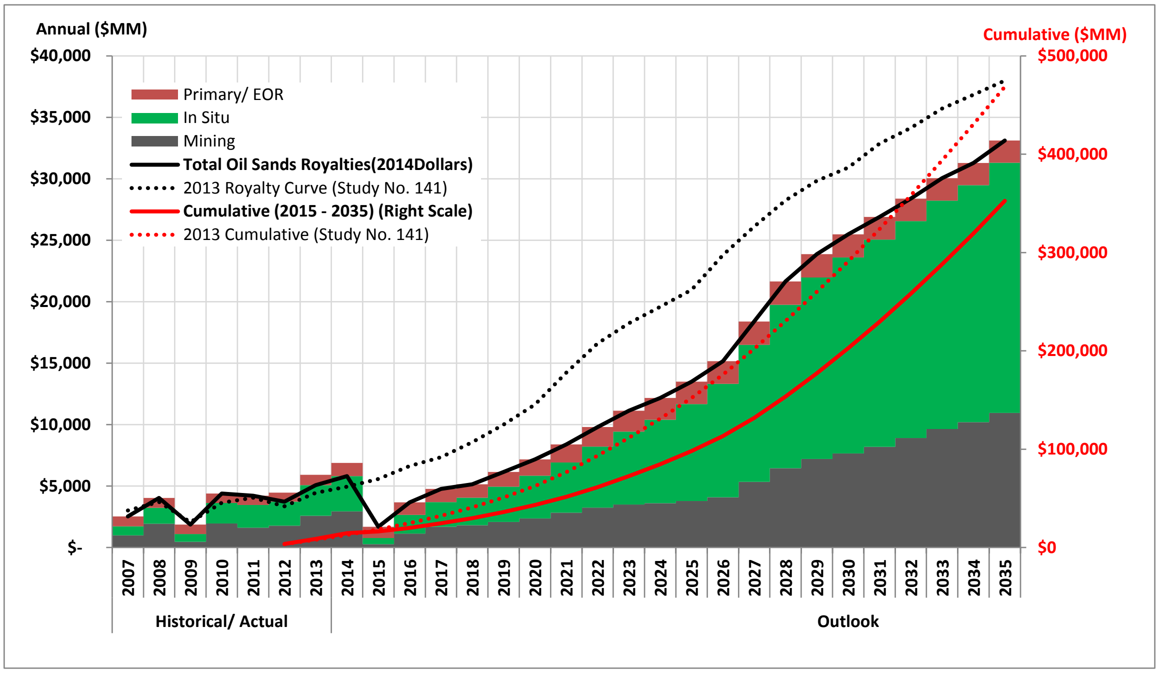
Figure 3.9 displays the breakdown of royalties collected by project type under the reference case over the 2015 to 2035 timeframe (on an annual and cumulative basis, in 2014 dollars) and compares the results to the last published version of this study.[40] Annual royalty revenues amount to C$33 billion by 2035, and cumulatively C$344 billion will be collected over the 20-year window.

As a result of capital spending cuts and low prices, royalties will decrease in 2015 to 2009 levels, barely reaching C$2 billion. Over the next five years from 2015 to 2020, royalty revenues will add up to just under $32 billion, all other things being equal.

[40] CERI Study No. 141,"Canadian Oil Sands Supply Costs and Development Projects (2014-2048)", July 2014.

On a cumulative basis, bitumen royalties collected are 29 percent lower compared to last's years study for a number of reasons. Let's recall that changes in royalties are related to changes in project cash flows implying changes on the costs and revenues side of the ledger. On the cost side, capital costs are higher compared to last year's report; on the revenues side, not only are overall production levels lower, but so are forecasted prices. Thus a combination of lower production levels, lower revenues, and higher project costs lead to overall lower royalty payments.

Figure 3.9: Bitumen Royalties Collected by Project Type



Source: CanOils, CERI

Chapter 4: Energy Requirements

Types of Energy Feedstock

Oil sands projects are energy-intensive operations. In general, demand for energy inputs for oil sands projects can be divided into four main categories: thermal energy demand; electricity demand; hydrogen demand for upgrading;[1] and demand for transportation fuels (primarily diesel).

Thermal Energy

Thermal energy for oil sands operations is primarily used in the form of steam, hot process water (HPW), and heating requirements for the different processes. Natural gas is the main fuel used for this purpose, while upgrader fuel gas, synthetic gas, associated gas, and even in some instances, petroleum coke, are also used as fuels for thermal energy production across the oil sands industry.

Steam is used at in-situ thermal operations[2] in order to mobilize the bitumen from the reservoir to the wellhead; it is also used in the separation process at mining and extraction operations. In upgrading projects, steam is used across various process units.[3]

Hot process water (HPW) is used in mining projects at the different extraction and separation stages.

Heating fuel is used in various primary upgrading units (via furnaces) in order to drive the fractionation, distillation, and cracking processes, as well as to provide heat for other units including the hydrogen production plant and the various hydro-treating units in secondary upgrading.[4]

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[1] While hydrogen (H_2) is not used for its energy content in the upgrading process per se, natural gas is the primary feedstock for H_2 production, and natural gas' alternative use is predominantly for fuel (power generation) and thermal energy (heat) purposes.

[2] Including steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) projects.

[3] Main steam users: amine regeneration unit in sulfur recovery plant (SRP), hydro-treating (or secondary upgrading) units, and steam turbine power generators. Main steam producers: cogeneration plant via heat-recovery steam generators (HRSGs) or process steam boilers such as once-through steam generators (OTSGs) (in the absence of a cogeneration unit), sulfur plant, and steam methane reforming (SMR) plant (hydrogen (H_2) production facility). Note that the main fuel source for steam generation within the upgrading facility is normally natural gas followed by fuel gas.

[4] *Primary upgrading* units in the context of this report refer to distillation and upgrading units including the crude distillation and diluent recovery units (CDU/DRU), vacuum distillation unit (VDU), coking or hydro-cracking units, and gas recovery (GRU) units. *Secondary upgrading* in turn includes utilities such as the sulfur recovery plant (SRP), the steam methane reforming plant (SMR), in addition to the various hydro-treating (HT) units such as naphtha, distillate, and gasoil units (NHT, DHT, and GOHT, respectively).

In-situ projects generally produce associated gas in conjunction with the extracted crude bitumen.[5] This associated gas is normally used within the operation (after being treated and processed) in order to provide a portion of the gas requirements for steam and power generation (where applicable); it is also used for natural gas powered pumps (gas lift) and compressors. In general, produced associated gas supplies need to be supplemented with external gas purchases. Depending on the project's gas demand levels, proximity to processing and marketing infrastructure, and economic viability, a portion of the in-situ associated gas production may be flared and vented.

Upgraders produce fuel gas and syngas,[6] the composition and heating value[7] of which depends on the upgrading process used. This fuel gas is produced mainly at the primary upgrading units (via distillation, thermal cracking, and gasification processes). Fuel gas and syngas are internally used for meeting thermal energy needs (heating and steam), some level of direct hydrogen and hydrogen feedstock requirements, and in some instances, as fuel for power generation.

In general, fuel gas production from upgraders is enough to meet the upgrader's thermal energy needs. Where fuel gas production exceeds the upgraders' thermal energy needs and the composition/heat content of the fuel gas might not be suitable for use as a power generation fuel or hydrogen feedstock, excess thermal energy from the fuel gas may be transferred to nearby extraction facilities in the form of steam or hot water, while some level of fuel gas flaring and venting will also occur.

Mining projects generally meet their thermal energy needs through heat integration with nearby upgrading and/or cogeneration operations, but can alternatively purchase natural gas from the local distribution system to meet their demands.

Electricity

Electricity is used at in-situ operations primarily for powering pumps, compressors, mixers, heaters, and injectors both at the well pads and at central processing facilities (CPFs). Some in-situ projects use natural gas instead of electricity at the reservoir level, depending on the lift method being employed (i.e., natural gas in gas lift, versus electricity in down-hole electric submersible pumps (ESPs) for mechanical lift).

[5] The amount, composition, and heating value of the produced associated gas varies by deposit.

[6] Fuel gas is generally produced from the primary upgrading processes such as distillation and cracking, while syngas might be produced from the gasification of petroleum residue (such as coke or ashphaltenes). Fuel gas will generally be a mix of hydrogen and light hydrocarbons, while syngas is primarily composed of hydrogen and carbon monoxide. Fuel and syngas will generally contain sulfur in the form of hydrogen sulfide (H_2S), which is removed as elemental sulfur at gas treating and sulfur removal facilities at upgrading complexes.

[7] Fuel gas produced at coking upgraders tends to have a large content of light paraffinic and olefinic hydrocarbons, which in turn produces a fuel gas of high heating content. Fuel gas from hydrocracking and gasifying process tends to be high in hydrogen and carbon monoxide content, respectively, producing a fuel gas with lower heating content.

The amount of electricity used by in-situ operations will also be determined by the type of water treatment used at the CPF for the production of boiler feed water (i.e., lime softening and ion exchange, versus evaporators).

In mining operations, electricity can be used to power electric shovels, but generally, it is used to power feeders and crushers at the mine site, as well as conveyor belts, pumps, valves, compressors, and other equipment such as separators, centrifuges, cyclones, and mixers in the extraction process (which transforms the mined oil sands ore from a slurry, to a froth, and eventually to cleaned bitumen ready to be marketed).

In upgrading operations, electricity is used to power pumps and valves that move bitumen and its derivatives through different process units and also to power different process units. The amount of electricity used in upgrading operations will largely depend on the upgrader's configuration (such as coking[8] versus hydro-conversion[9]) and complexity (or level of hydro-treating, such as that required for the production of sweet versus sour products[10]).

Electricity is also used across all types of oil sands operations to provide general power and lighting needs for the facilities.

Electricity for oil sands operations can be produced at on-site cogeneration facilities, which produce both electricity and thermal energy (mainly in the form of steam but also hot water), or purchased directly from the provincial grid by oil sands project operators.

Cogeneration facilities at standalone (or satellite) in-situ and mining operations generally rely on natural gas purchases from the market to meet their fuel requirements, with the primary objective of providing a reliable source of steam and power for their operations. Some satellite projects have pipeline and/or electric transmission line connections to the project operator's main facilities which generally have a cogeneration facility.

Cogeneration facilities at integrated extraction and upgrading projects will use internally produced fuels such as associated gas from the reservoir, fuel gas and syngas from the upgrading process, and in some instances petroleum coke to supplement natural gas purchases for supplying fuel needs to their facilities. Generally, cogeneration facilities produce surplus

[8] Coking refers to the primary upgrading *thermal* cracking process which takes place at high temperatures, in the absence of catalysts, and which purpose is to upgrade heavy residues such as vacuum residue to lighter fractions and solid petroleum coke.
[9] The terms *hydro-cracking* and *hydro-conversion* are used interchangeably within the context of this report. These terms refer to the primary upgrading *catalytic* cracking process, which consists of adding hydrogen, under pressure, in the presence of catalysts, to upgrade heavy residues (which generally originate from the vacuum distillation units) to lighter hydrocarbon fractions. These terms are not be confused with *hydro-treating*, which refers to the secondary upgrading process of adding hydrogen to the primary upgraded fractions such as naphtha, diesel, and gas oil, in order to remove impurities such as sulfur and nitrogen, for the production of sweet synthetic crude oil (SCO).
[10] Primary versus secondary upgrading.

electricity (above their internal needs), which is then sold to provincial markets at prevailing prices, providing an additional revenue stream for oil sands project operators.

Electricity purchased from the grid for oil sands operations is generated off-site at large-scale commercial generators and can be assumed to have been generated using a fuel mix which reflects the provincial average, which is in turn largely dominated by coal and natural gas.

Hydrogen

Hydrogen is used in primary upgrading processes such as hydro-cracking upgraders, and in secondary upgrading processes for the purpose of hydro-treating, which allows for the production of low-sulfur content (or sweet) clean SCO (or fractions thereof such as naphtha and diesel fuel).

Hydrogen is mainly produced from natural gas via steam methane reforming, yet some upgraders will use internally produced fuel gas to produce hydrogen, while in some areas where industrial integration exists (such as in the Alberta Industrial Heartland), upgrading operations might have the option of purchasing pure hydrogen streams from nearby industrial facilities.[11]

Diesel

Diesel fuel is mainly used to power trucks and shovels in mining and extraction operations. Some integrated mining and upgrading operations produce diesel on-site to meet their project's needs, while others will simply purchase diesel in the open market.

Diesel fuel may also be used (depending on access to natural gas/electricity distribution infrastructure and economies of scale) at non-thermal in-situ operations[12] for powering pumps and compressors.[13]

Oil Sands Energy Feedstock Forecast

With an understanding of the different energy requirements for oil sands operations, this section presents historical and forecasted energy demand across different types of oil sands operations. CERI forecasts are compared to other publicly available forecasts, and are discussed in further detail below.

The main energy demand components of oil sands projects discussed in this section include electricity, gas (for thermal energy and hydrogen production requirements) and diesel fuel. Fuel

[11] As an example, upgrading projects can purchase hydrogen streams from nearby refineries and petrochemical facilities.

[12] Bitumen production via primary production and enhanced oil recovery (EOR) are also known as "cold" bitumen production methods. The term cold heavy oil production with sand (CHOPS) is also used to refer to these types of projects.

[13] Energy demand for CHOPS operations is for the purposes of water re-injection, gas treatment, crude lifting, water treatment, and gas re-injection. Depending on access to different energy sources, these processes might be powered by using electricity, natural gas, or diesel fuel. CHOPS operations are more likely to resemble conventional crude oil operations.

requirements for power generation are outside the scope of this analysis, but are briefly discussed herein.

Generally speaking, demand for the different types of energy in the oil sands industry will be a function of oil sands production volumes and energy intensity factors.

Production volumes will be driven by macroeconomic and global market conditions that will determine the economic viability of new projects going forward. Intensity factors for energy use in oil sands projects will vary depending on subsurface factors such as reservoir characteristics (or reservoir quality), as well as aboveground factors related to employed processes and technology (such as energy efficiency, and potentially, the commercial development and deployment of new production technologies).[14]

In order to compare CERI's energy demand estimates with other forecasts, it is imperative to compare both oil sands production volumes and intensity factors.

While intensity factors are not generally given in the external forecasts, they can be derived as implied estimates by dividing the energy demand of a given type of project by its output. However, the data necessary for such calculations is not always readily available on an individual project, project type, or geographical area basis.

Figure 4.1 displays total bitumen extraction (mining + in-situ projects) and SCO production volume estimates from CERI's **Reference Case Scenario**, as well as data from equivalent forecasts sourced from the Alberta Electric System Operator's (AESO) long-term outlook (LTO)[15] (2014), and the Alberta Energy Regulator's (AER) ST-98 report (2014).[16] While CERI's forecast extends to 2035 (in the context of this report), the AESO's forecast stops at 2034,[17] while the AER's forecast's final year is 2023.

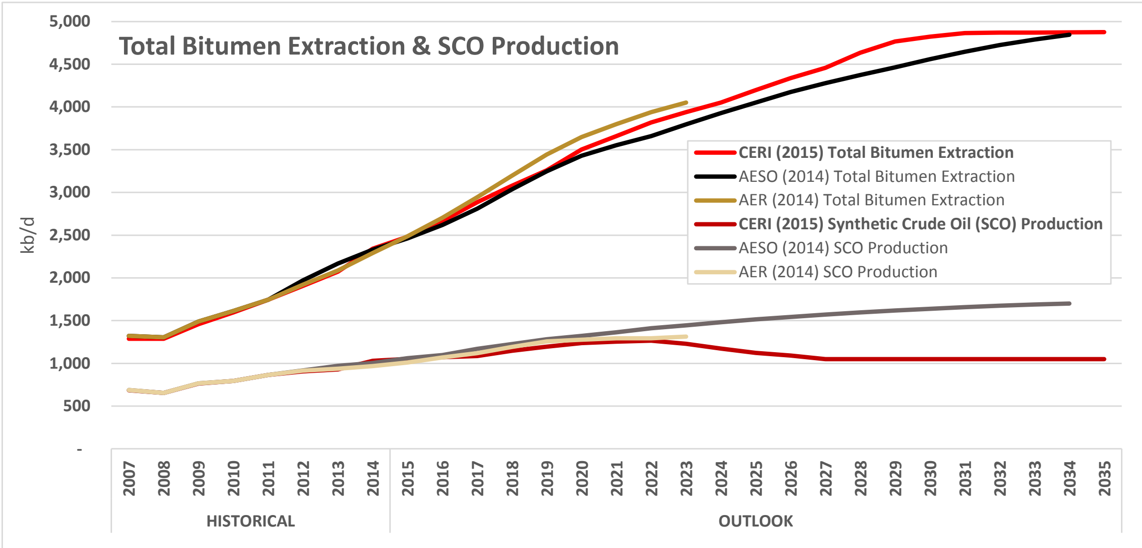
[14] Energy intensity factors, the type of energy required, and the fuel-mix sourced to satisfy the oil sands industry energy needs, will in turn determine greenhouse gas (GHG) emissions intensity per unit of output from the industry. Overall GHG emissions from the industry will then be a function of the availability of different energy sources and the technology required to meet those needs, evolving energy intensity factors, and overall production volumes from the industry. While a detailed discussion of GHG emissions from the industry is outside the scope of this section of the report, it is important to understand that there are implications on such emissions levels as a result of different levels of energy requirements for the industry.

[15] Available at: http://www.aeso.ca/downloads/AESO_2014_Long-term_Outlook.pdf
Note that oil sands production numbers in the AESO's LTO are sourced from the Conference Board of Canada's (CBoC) long-term provincial economic forecast.

[16] Available at: https://www.aer.ca/documents/sts/ST98/ST98-2014.pdf.

[17] Where necessary and applicable, CERI has extended the AESO's estimates from 2034 to 2035 by using an annual long-term compound annual growth rate (CAGR) calculated for the period from 2015 to 2034 (based on the source's original data).

Figure 4.1: Bitumen Extraction and SCO Production Forecast Comparison



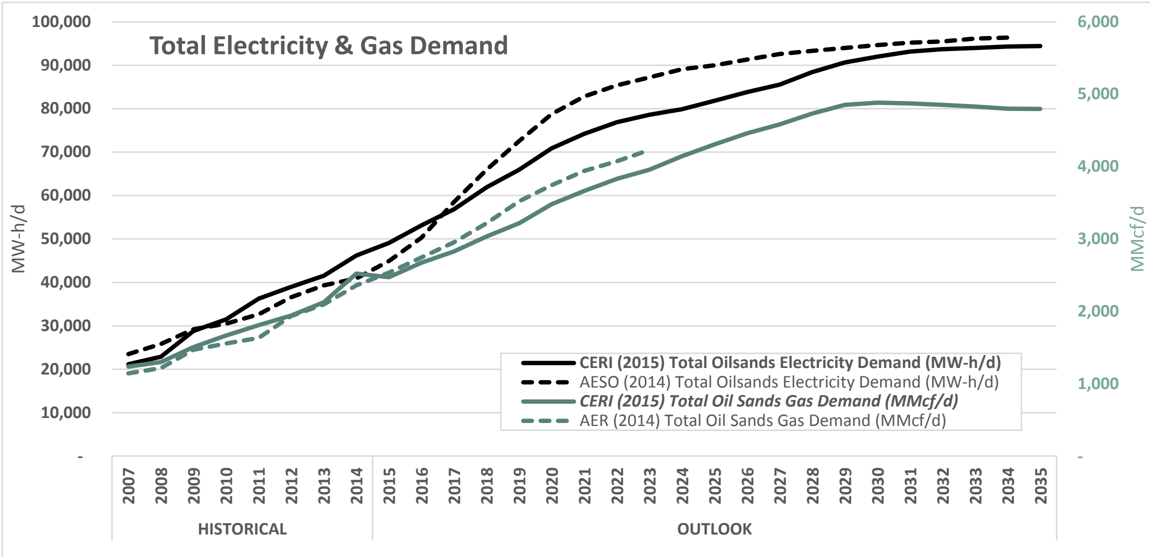
Source: Data from AER, AESO, and CERI

As can be observed, both the total bitumen extraction and SCO production volumes, across CERI's estimates, when compared with those from the AESO and the AER, are very similar. The exception to this finding is the SCO production forecast presented by the AESO, which exhibits a continued upwards trajectory past the early 2020s, compared to the trends observed in CERI's and the AER's projections of peaking (AER) and declining (CERI) past that point.

AESO's 2014 LTO provides estimates for future electricity demand (to 2034) for the oil sands industry, while the AER's 2014 ST-98 provides gas demand[18] estimates (to 2023). These estimates are compared with CERI's own in Figure 4.2.

[18] Unless otherwise specified "gas demand" refers to total gas demand including demand for natural gas, fuel gas, syngas, and associated gas. The term "natural gas" is used in the context of this section to refer to *marketable natural gas* as purchased from the local distribution system

Figure 4.2: Oil Sands Industry Electricity (MWh/d) and Gas Demand (MMcf/d)



Source: Data from AER, AESO, and CERI

As can be observed, CERI's energy demand estimates for the oil sands industry are in line with those from the AESO (for electricity) and the AER (for gas). These results are discussed in more detail below.

Gas Demand Outlook

Through extensive research, three energy use datasets were created by extracting detailed information from:

1) a large empirical/historical project-by-project dataset built using various statistical forms and documents sourced from the AER (in some instances dating back to 1970);
2) a comprehensive literature review of 23 publicly available government and consultant reports as well as published academic journal articles on oil sands energy use and emissions issues, and;
3) information provided in energy balances for newly completed and recently approved oil sands projects (submitted through the environmental impact assessment (EIA) process in Volume I under the projects' descriptions).[19]

These datasets were then used by CERI to develop a comprehensive statistical set of ranges for energy intensity factors across different types of oil sands projects.[20]

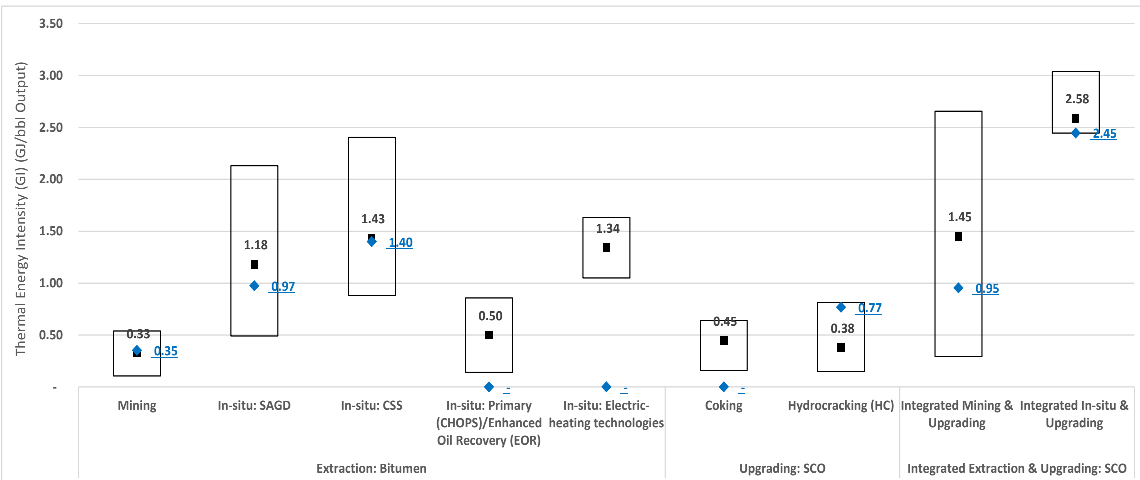
[19] These three broadly defined groups of data sources are meant to be as comprehensive as possible in collecting data on energy intensity factors for the oil sands industry as they are meant to provide (1) CERI's own analysis of the existing data; (2) an aggregation of similar analysis across the academic, government, and consulting spectrum, and (3) estimates of energy use for the latest project designs.

[20] These include steam to oil ratios (SOR) (bbl STEAM/bbl of output (SCO or BIT)) for thermal in-situ projects (SAGD and CSS); electricity intensity (ELI) for all project types (kW-h/bbl); thermal energy/gas intensity (GI) for all project

These ranges are meant to capture a large degree of variability and uncertainty across several estimates developed for oil sands energy use metrics. Meanwhile, they can also be used to generate scenarios for energy demand.[21]

Figure 4.3 displays the range for thermal energy/gas intensity factors developed by CERI 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 4.4 displays (natural gas equivalent) hydrogen intensity factors for upgrading projects.

Figure 4.3: Oil Sands Industry Thermal Energy Intensity Factors by Project Type (GJ/Bbl of Output)

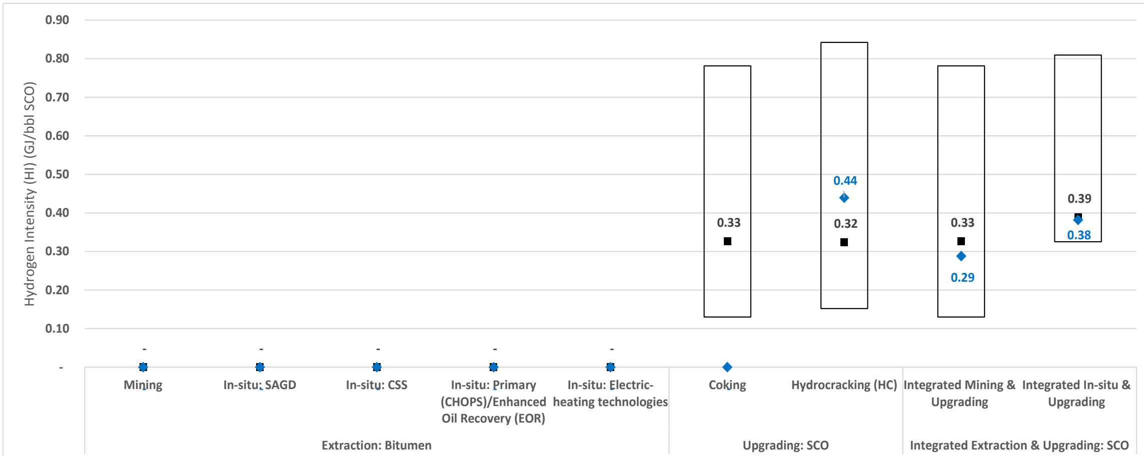


Source: CERI

types (GJ/bbl); hydrogen intensity (HI) for upgrading projects (GJ/bbl); diesel intensity (DI) for mining projects (GJ/bbl), as well as; associated (AGY) and fuel/syngas (FGY) yield factors for in-situ and upgrading projects, respectively (GJ/bbl). Thermal energy, hydrogen, and diesel intensity factors, as well as associated and fuel/syngas yield factors, are also expressed on a volumetric basis (such as mcf/bbl or bbl/bbl). Associated and fuel gas yield factors are net of gas flared and vented, based on historical data. Intensity factors for in-situ thermal projects are also calculated on a bbl of STEAM basis.

[21] For discussion of other scenarios, see forthcoming CERI study “Oil Sands industry Energy Requirements and Greenhouse Gas Emissions Outlook (2015-2050)”.

Figure 4.4: 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 from the three aforementioned datasets (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 oil sands industry by project type. Figure 4.5 displays the results of such analysis.

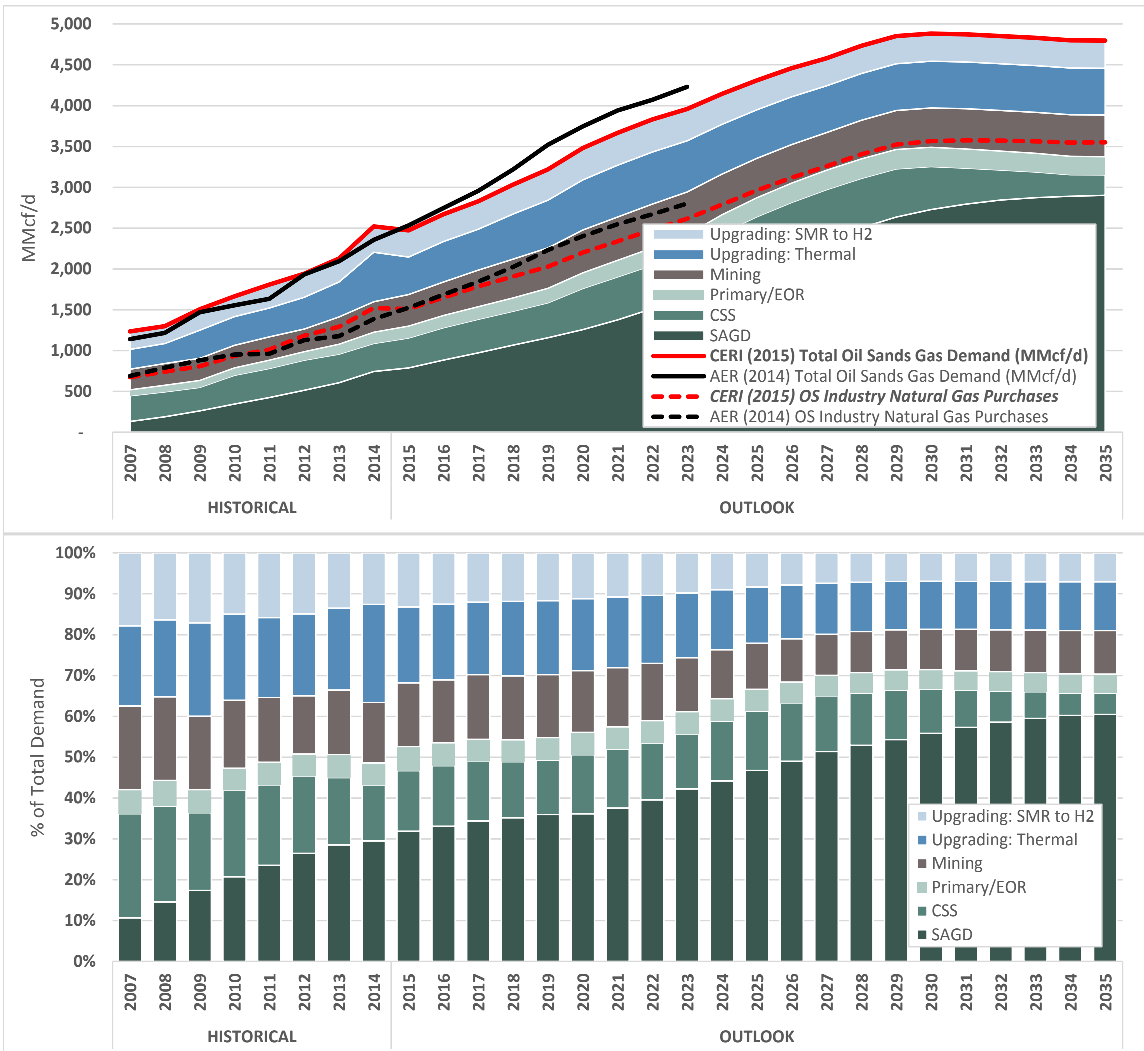
Figure 4.5 illustrates the total oil sands demand for gas (including natural gas, fuel gas, syngas, and associated gas) for the purpose of meeting thermal energy requirements and feedstock for hydrogen production. These estimates *do not* include gas requirements for power generation.[22] Oil sands industry natural gas purchases in Figure 4.5 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.

As can be observed in Figure 4.5, CERI's estimates for total gas demand for the oil sands industry (solid line) as well as estimates for required marketable natural gas purchases (dashed line) are consistent with those from the AER. Total gas demand for the oil sands industry is expected to increase from 2.5 billion cubic feet per day (bcf/d) in 2014 to 4.8 bcf/d by 2035 and grow at a compound annual growth rate of over 3 percent.

[22] See forthcoming CERI study "Oil Sands industry Energy Requirements and Greenhouse Gas Emissions Outlook (2015-2050)".

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 primary/EOR projects, and mining 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 4.5: Oil Sands Industry Gas Demand for Thermal Energy and Hydrogen Production by Project Type



Source: Data from AER and CERI

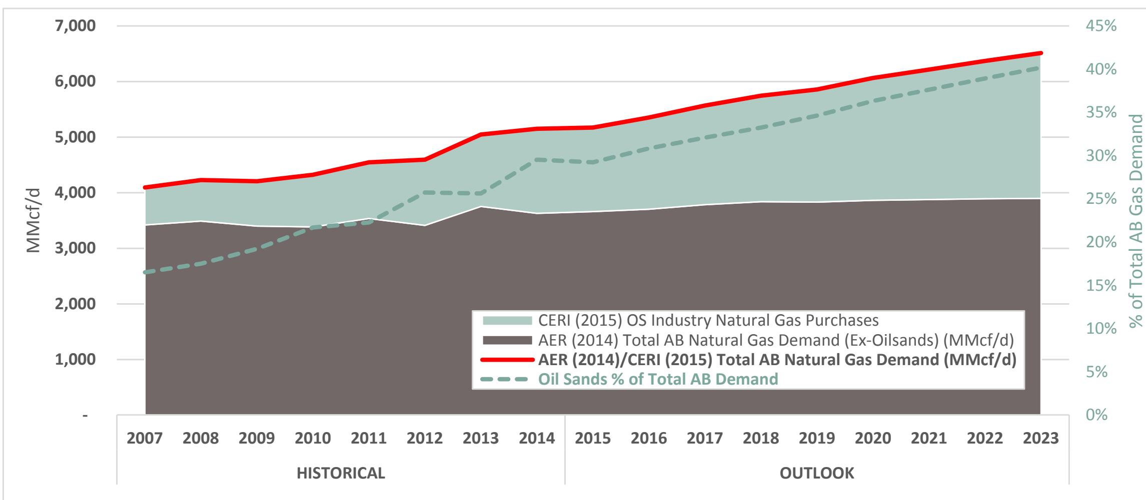
It is also important to put into context the level of natural gas demand from the oil sands industry compared to other demand sources in Alberta. This is the case because the oil sands industry's demand levels will increasingly have an impact on local energy markets, regional energy systems and infrastructure, and other end-users in the province.

Figure 4.6 displays the AER's demand forecast for natural gas in Alberta and the breakdown between oil sands and all other sectors. CERI's estimates for oil sands natural gas purchases are replaced with those provided by the AER, yet it is important to note that this should not affect the validity of the analysis as CERI's and the AER's oil sands natural gas demand estimates are very similar (as per dashed lines on Figure 4.5).

As can be observed in Figure 4.6, natural gas demand growth in the province over the coming decade is expected to come primarily from the oil sands sector. While the combined AER/CERI estimates indicate that total gas demand in the province is estimated to increase to 6.6 bcf/d by 2023 (from 5.1 bcf/d in 2014), an estimated 80 percent (or 1.2 bcf/d) of that total increase corresponds to increased demand from the oil sands industry (for thermal energy and hydrogen production).

This then leads to the oil sands industry to increasingly account for a larger portion of the provincial gas market in Alberta, as illustrated by the green dashed line.

Figure 4.6: Oil Sands Industry Natural Gas Purchases and Total Alberta Provincial Natural Gas Demand[23]



Source: Data from AER and CERI

While the *other demand excluding oil sands* category (grey area in Figure 45.6) remains relatively flat over the forecast period, there are some interesting trends behind this level of aggregation. Decreases in gas demand within the reprocessing and gas shrinkage category over the outlook period are consistent with an expected continued decrease in export flows from Alberta to other markets. Slightly decreasing, flat, and slightly increasing demand trends are displayed across the transportation, commercial and petrochemical, and residential end-use categories (respectively). Meanwhile, rapid growth is observed across the power generation and other industrial

[23] The 2023 end year is used here instead of 2035 in order to be able to use the AER's in a relevant and consistent manner

categories. Within the power generation portion, AER data indicates that gas use for power generation for oil sands projects will be a primary driver of gas demand for power generation in the province.

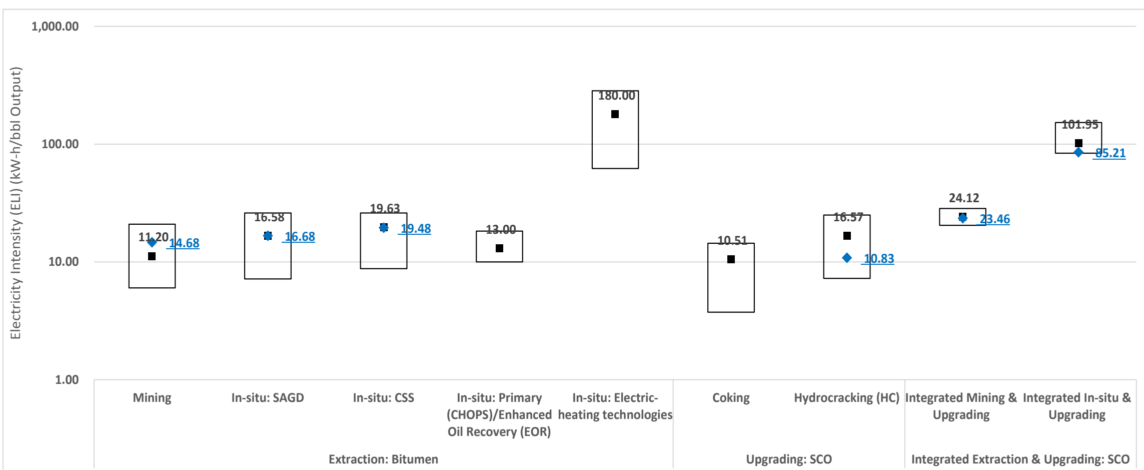
Taking into account the AER's estimates for natural gas demand for power generation for oil sands facilities, combined with CERI's estimated natural gas requirements for thermal energy and hydrogen production, total gas use from the oil sands will account for 56 percent of the total natural gas demand in the province by 2023.

Without a doubt, such a large share of total domestic demand within the province will have an effect on natural gas markets and end-users. This is the case particularly as gas production volumes in Western Canada are driven more and more by increasing domestic demand needs rather than export opportunities. This will also have implications across total energy use in the province, and subsequently, GHG levels emissions.

Electricity Demand Outlook

Figure 4.7 displays the electricity intensity factor ranges for different types of oil sands projects.

Figure 4.7: Oil Sands Industry Electricity Intensity Factors by Project Type (kWh/Bbl of Output)[24]



Source: CERI

As can be observed, electricity intensity values exhibit a significant spread with values as small as 4 and 6 kilowatt hours per barrel of output (for coking and mining projects, respectively), to as high as 300 and 150 kWh/bbl (for electric-heating technologies and integrated in-situ and upgrading projects, respectively).

Consistent with the methodology used for estimating the oil sands industry gas requirements, historical electricity intensity values are used to estimate historical energy demand, while the

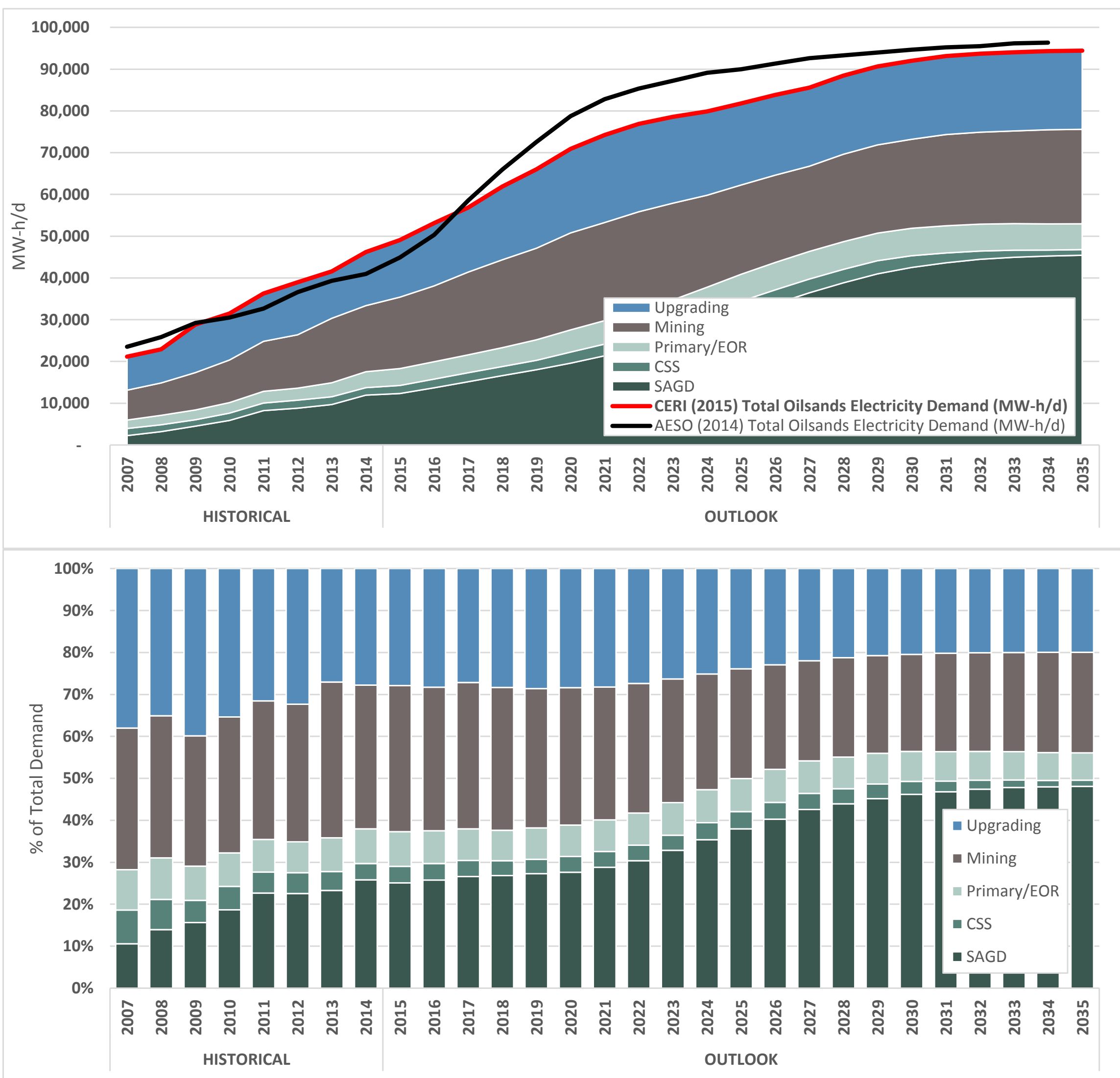
[24] Note that the *y* or vertical axis in this figure is given in a logarithmic scale.

latest year's empirical value is used on a constant basis over the outlook period to forecast future energy requirements. If the latest empirical value is an outlier, the median value or the previous year's empirical value (whichever is most consistent with recently observed values) is used over the forecast period in order to better represent future energy intensities for a type of project.

Figure 4.8 displays CERI's electricity demand estimates for the oil sands industry by project type, and compares the total with the AESO's most recent numbers.

Total electricity demand from the oil sands is expected to increase by 48.2 GWh/d (or by 104 percent) from an estimate of 46.2 GWh/d in 2014 to 94.4 GWh/d by 2035. Demand for electricity from the oil sands is expected to increase the most across in-situ projects, followed by mining projects, and upgrading projects.

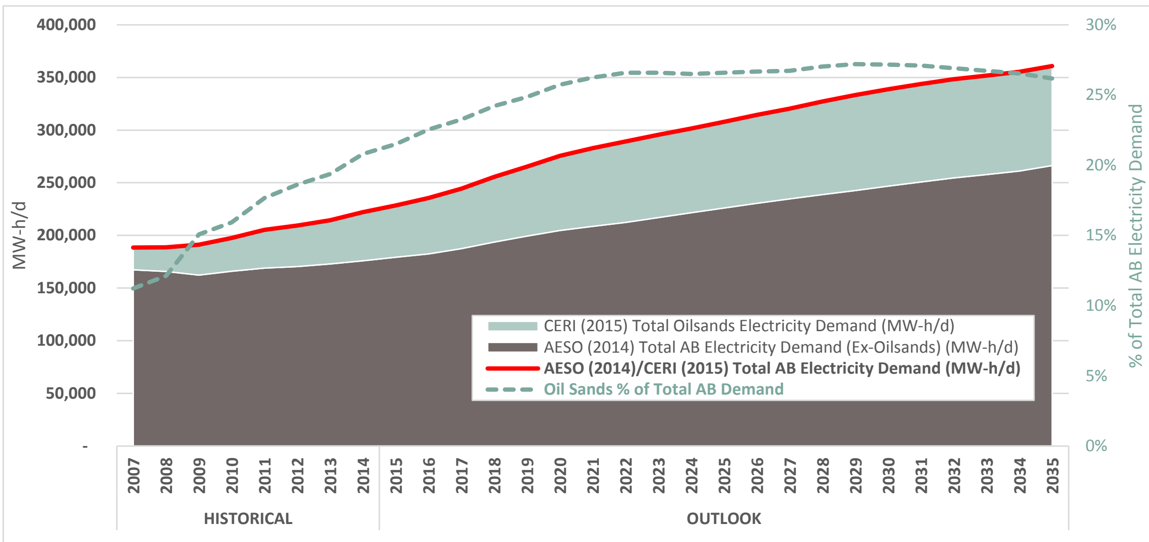
Figure 4.8: Oil Sands Industry Electricity Demand by Project Type (MWh/d)



Source: Data from AESO and CERI. Figures by CERI

Figure 4.9 displays the oil sands electricity demand in the provincial context. As a percentage of total provincial demand, oil sands electricity demand will increase its share and will account for about a quarter of total electricity demand in Alberta by 2035. Within the balance of electricity end-users in the province, AESO's numbers indicate moderate and steady demand growth across the farm, residential, and commercial categories.

Figure 4.9: Oil Sands Industry Electricity Demand and Total Alberta Provincial Electricity Demand (MWh/d)



Source: Data from AESO and CERI. Figures by CERI

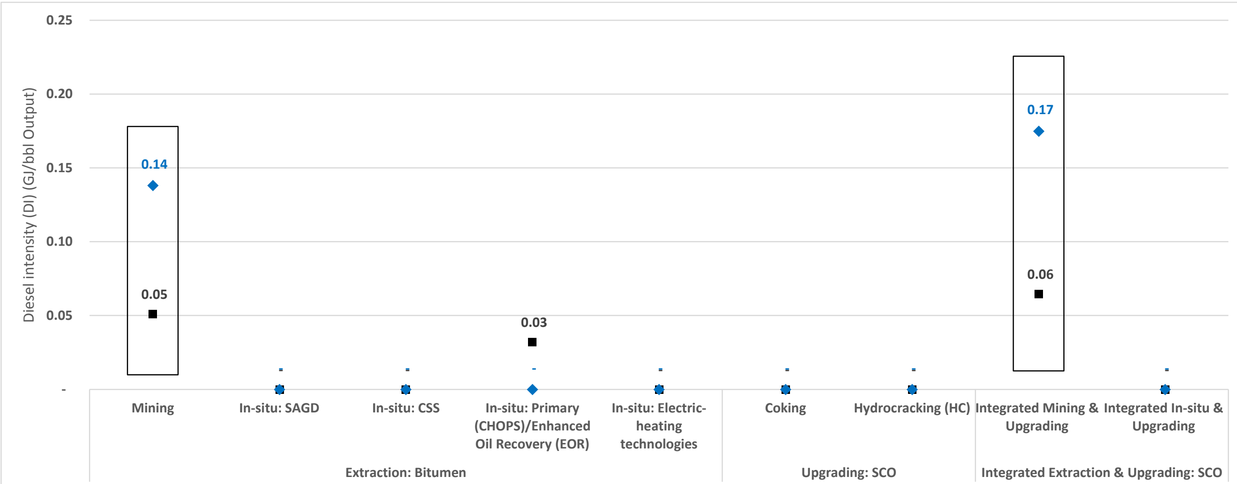
Rapid and significant growth in electricity demand is estimated by the AESO for the industrial demand category (excluding oil sands projects), under the premise that electricity demand in industries that serve oil sands projects, such as pipelines and manufacturing, will be driven by a strong oil sands production outlook.

Once again, this indicates that when considering the indirect or spill-over effects of oil sands electricity demand across other industries, the share of oil sands electricity requirements in the province can be anticipated to be greater than just a quarter of the total by 2035. The fuel-mix used to generate the required power for the oil sands industry is also expected to have an impact on the resulting GHG emissions in the power sector in the province.

Diesel Fuel Demand Outlook

Figure 4.10 displays the diesel fuel intensity ranges for oil sands operations, while Figure 4.11 displays the demand outlook for the mining category on a project-by-project basis including the primary/EOR category.

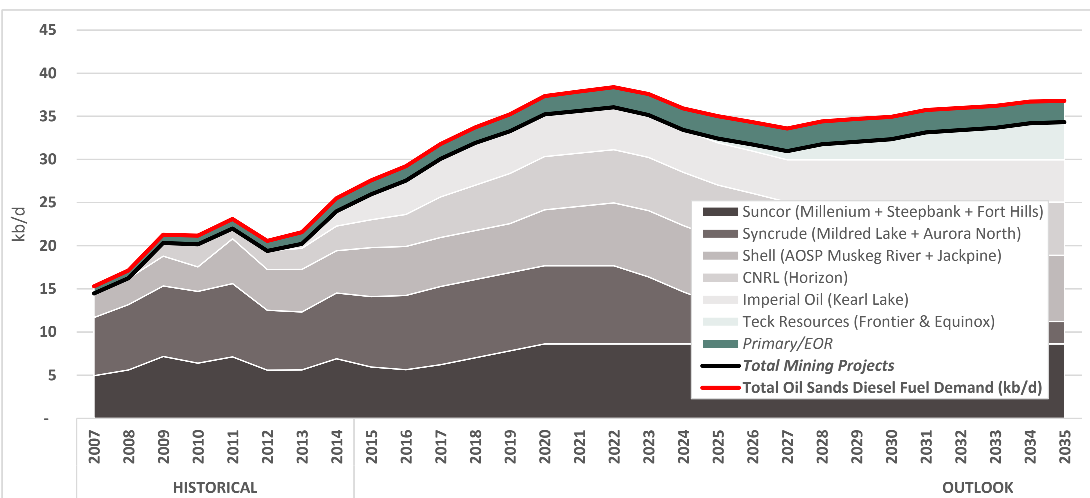
Figure 4.10: Oil Sands Industry Diesel Fuel Intensity Factors by Project Type (bbl diesel/bbl bitumen)



Source: CERI

Demand for diesel fuel for oil sands operations is estimated to increase from 26 kb/d in 2014 to 37 kb/d by 2035 (or by 42 percent). In Figure 4.12, using data from Statistics Canada[25] and the National Energy Board's (NEB) latest version of their Energy Futures Report[26,27,] CERI estimates that diesel fuel demand from oil sands projects accounted for 19 percent of total diesel demand in Alberta in 2014 (of 134 kb/d), but that the percentage is expected to decrease to 15 percent of the total diesel demand in the province (of 242 kb/d) by 2035.

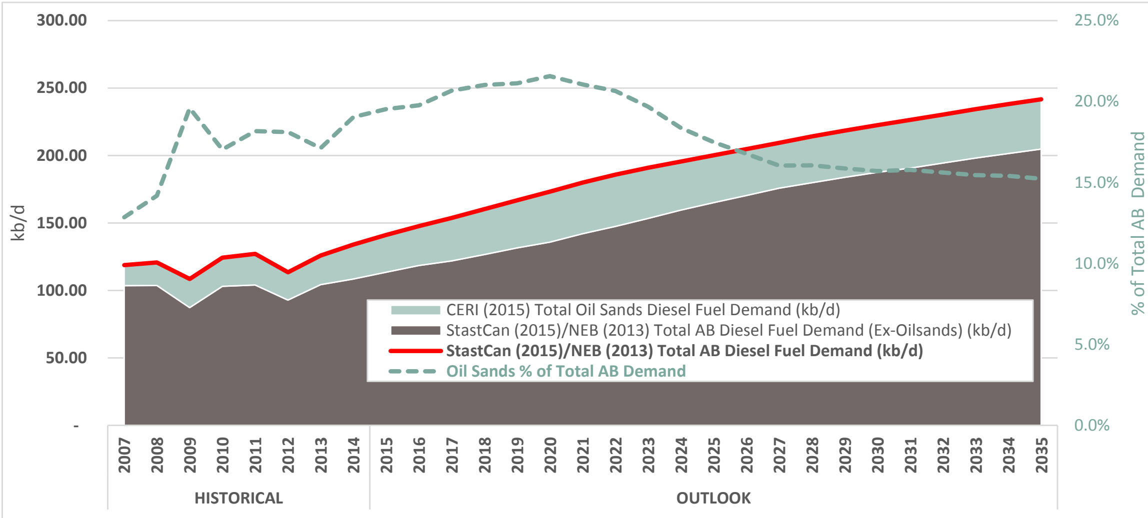
Figure 4.11: Oil Sands Industry Diesel Fuel Demand



Source: CERI

[25] Statistics Canada, Table 134-0004.
[26] Report available at: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/index-eng.html.
[27] Appendix data tables: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/ppndcs/pxndsdmnd-eng.html.

Figure 4.12: Oil Sands Industry Diesel Fuel Demand and Total Alberta Provincial Demand



Source: Data from AESO and CERI. Figures by CERI

Different production outlooks for oil sands crude as well as the evolution of intensity factors going forward will result in different levels of energy demand across the industry. These forecasts of energy requirements for the oil sands industry indicate a significant growth in feedstock demand such as natural gas and electricity over the coming decades. Also, results indicate that oil sands' share of total provincial demand for those commodities (in the context of the local markets) is increasing, which in turn might impact other sectors in the economy.

How these energy requirements will be met in the future will have implications in terms of total energy use, environmental impacts (such as GHG emissions) and costs associated with using one energy source over another, under present and anticipated technology constraints. This is another set of parameters that allows us to model energy supply choices for the oil sands industry, and the corresponding implications for the industry in the context of energy, environment, and economics.

Chapter 5: Economic Impacts of Oil Sands Development

This chapter presents the results of CERI's Input/Output (I/O) model;[1] specifically the economic impacts on major macroeconomic variables such as GDP and employment from oil sands development. The results are presented on provincial and national levels.

GDP

Table 5.1 presents the total impacts associated with both investment and operation of projects in the Alberta oil sands and direct staging and assembling facilities in Edmonton, Leduc and other Alberta communities for the period 2015 to 2035. The total Canadian GDP impacts amount to $4,058 billion (2014 Canadian dollars) and employment (direct, indirect, induced) is projected to double from the current level of 520,404 jobs to 1,240,277 (see Figure 5.2). Approximately 88 percent of the GDP impacts and 80 percent of the employment impacts occur in Alberta. Ontario and Quebec account for 7.2 percent of the GDP impacts and 11.5 percent of the employment impacts. The other provincial impacts are detailed in Table 5.1.

Table 5.1: Economic Impacts of Oil Sands Development (2015-2035)

Investment and Operations	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alberta	3,600,779	1,584,496	16,034
British Columbia	105,212	64,364	947
Manitoba	17,764	10,199	177
New Brunswick	5,289	2,956	54
Newfoundland/Labrador	2,473	1,123	18
Nova Scotia	4,214	2,613	43
Nunavut	366	261	4
Northwest Territories	837	517	8
Ontario	221,208	133,936	1,640
Prince Edward Island	363	210	4
Quebec	69,928	39,591	661
Saskatchewan	28,938	12,686	209
Yukon Territory	382	237	3
Total Canada	**4,057,754**	**1,853,189**	**19,802**

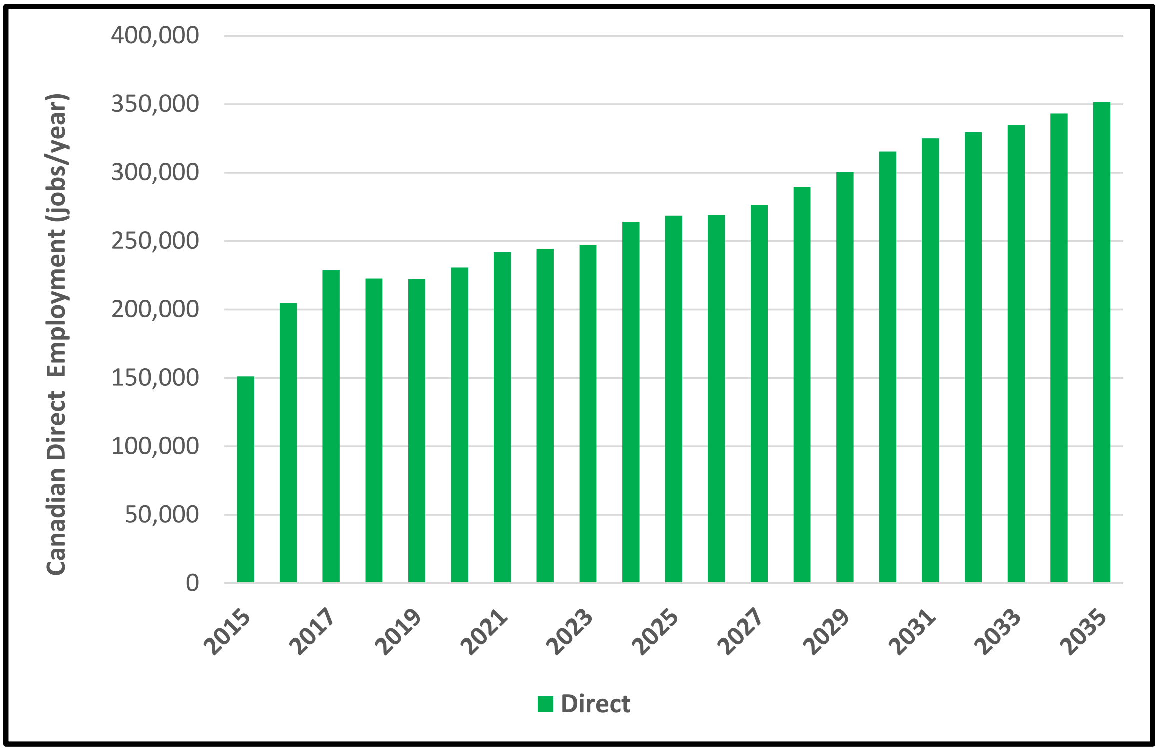
Source: CERI

[1] The methodology and assumptions of CERI's I/O model are presented in detail in CERI Study 124.

Employment

Direct employment effects are considered jobs created or preserved in the province of Alberta and are considered as construction or operation jobs in the oil sands projects, manufacturing jobs in the oil sands staging areas (Edmonton, Leduc, etc.) and drilling related jobs in the cold bitumen production (CBP) area. Oil sands direct employment is projected to grow from the current level of 151,000 jobs to a peak of 351,000 jobs by 2035 (see Figure 5.1).

Figure 5.1: Oil Sands Direct Employment Forecast

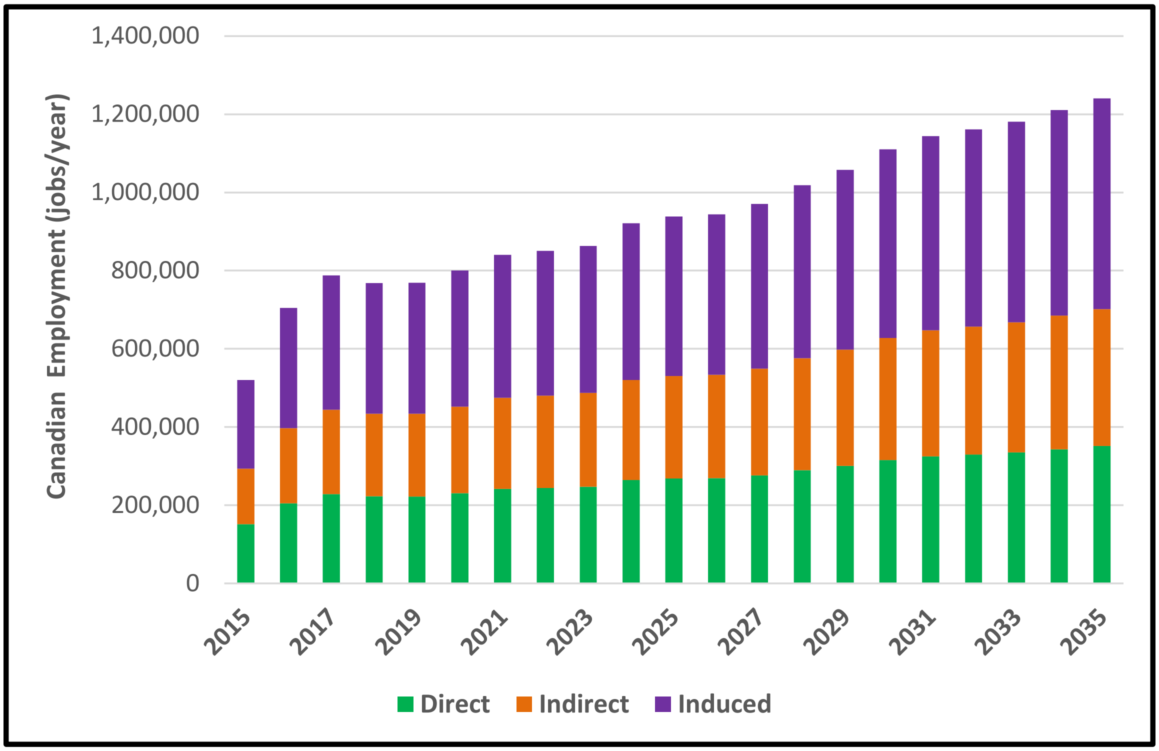


Source: CERI

Indirect job effects account for the potential of jobs created in the many industries across Canada that service the oil sands industry including manufacturing in Ontario, pipeline mills in Saskatchewan and Alberta, and electronic components in British Columbia, Ontario and Quebec, to name a few. Induced job effects account for workers in the oil sands sector spending their additional income on consumer goods and services. This additional income is stimulated by direct and indirect impacts.

Figure 5.2 illustrates the total employment impacts broken into direct, indirect and induced categories.

Figure 5.2: Oil Sands Direct, Indirect and Induced Employment Forecast



Source: CERI

Tax Perspective

Generally speaking, taxes on income are considered direct taxes, while taxes on expenditures (GST, PST, HST, etc.) and all taxes deductible by corporations for income tax purposes (such as property taxes) are considered indirect taxes. The tax impact on a corporation includes taxes generated by economic activity within a province payable to federal, provincial and municipal governments.

Over the forecast period, oil sands related taxes (indirect, personal and corporate) directed to all levels of government will total $750 billion (2014$Cdn). The Canadian Federal government will receive $464 billion with 89 percent or $417 billion sourced from Alberta-based companies. Canadian provincial governments will receive $286 billion with 85 percent or $245 billion attributable to the Alberta government (see Figure 5.3).

Table 5.2: Tax Receipts as a Result of Alberta Oil Sands Investment and Operation Federal and Provincial: Corporate, Indirect and Personal

Investment and Operations	Federal Corporate $CAD Million	Federal Indirect $CAD Million	Federal Personal $CAD Million	Provincial Corporate $CAD Million	Provincial Indirect $CAD Million	Provincial Personal $CAD Million
Alberta	127,781	43,573	245,678	64,717	47,625	132,539
British Columbia	2,075	1,804	7,082	763	3,810	3,072
Manitoba	277	308	1,042	96	722	834
New Brunswick	79	75	312	36	176	239
Newfoundland/Labrador	48	29	124	68	62	88
Nova Scotia	74	69	271	40	131	227
Nunavut	4	5	19	1	3	6
Northwest Territories	18	19	36	11	21	15
Ontario	4,033	4,107	15,681	2,121	8,050	9,396
Prince Edward Island	5	7	21	3	18	18
Quebec	1,273	1,231	4,590	892	3,240	4,255
Saskatchewan	647	416	1,425	437	1,009	860
Yukon Territory	4	9	19	1	7	9
Total Canada	**136,319**	**51,650**	**276,302**	**69,184**	**64,874**	**151,559**

Source: CERI

Table 5.3: Tax Receipts as a Result of Alberta Oil Sands Investment and Operation Federal and Provincial

Investment and Operations	Federal $CAD Million	Provincial $CAD Million
Alberta	417,032	244,881
British Columbia	10,962	7,644
Manitoba	1,627	1,652
New Brunswick	467	451
Newfoundland/Labrador	201	218
Nova Scotia	414	398
Nunavut	28	11
Northwest Territories	74	48
Ontario	23,821	19,566
Prince Edward Island	33	39
Quebec	7,094	8,387
Saskatchewan	2,487	2,306
Yukon Territory	31	17
Total Canada	464,271	285,618

Source: CERI