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

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

Supply Cost Results

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

Based on these assumptions, the supply costs of crude bitumen using steam-assisted gravity drainage (SAGD) and surface mining and extraction have been calculated for a hypothetical project. Figure E.1 illustrates the supply costs for these projects. The plant gate supply costs, which exclude transportation and blending costs, are C$43.31/bbl for a SAGD project and C$70.08/bbl for a stand-alone mine. A comparison¹ of field gate costs from the August 2015 update² with this year’s supply costs indicates that, after adjusting for inflation, the supply cost for a SAGD producer has fallen by 27 percent, and 6 percent for a stand-alone mine.

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

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

¹ Direct cost comparison is not recommended and is only shown to illustrate the direction of change. Because some changes were made in the project assumptions regarding carbon policy as well as project economics, a direct comparison of costs is not favoured.
³ At the time of writing, WTI prices traded at just above US$50/bbl.
average, over the life of an oil sands project. On a percentage basis, these range from a 16.5 to 18.6 percent share of total supply cost, a decrease of 7.3 percent for a SAGD project and unchanged for a mining project.

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

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

Source: CERI
The results indicate that SAGD supply cost is the most sensitive to changes in the initial capital expenditures and the assumed discount rate. If the discount rate is raised to 12 percent real, the supply cost is estimated to increase by $5.57/bbl (or 13 percent); when it is decreased to 8 percent real, the cost will decrease by $5.10/bbl (or 12 percent) from its base of $43.31/bbl.

Source: CERI
For a stand-alone mining project, the supply cost will increase by C$9.68/bbl (or 14 percent) and decrease by $10.01/bbl (or 14 percent) if the initial capital cost increases or decreases by 25 percent, respectively. The discount rate increase to 12 percent will increase the supply cost by $9.61/bbl (or 14 percent) and a decrease to 8 percent will result in a $9.08/bbl (or 13 percent) drop in the base supply cost of $70.08/bbl.

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

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

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

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Totals may not add up due to rounding. Historical production from the provincial regulator.
Other Requirements

Capital Investment and Operating Costs

Total capital spending requirements are broken down by project type and are illustrated in Figure E.5. Over the 20-year projection period from 2016 to 2036 inclusive, the total initial and sustaining capital required for all projects is projected to be C$502.5 billion under the Reference Case Scenario. Capital investment in in situ projects surpasses the capital spent for mining projects, which is consistent with the ongoing trend to invest more into in situ projects rather than mining. From 2016 to 2036, it is projected that almost C$160 billion (initial and sustaining) will be invested into mining projects and C$304 billion in in situ thermal and solvent as well as primary and EOR cold bitumen projects. Upgrading projects see the least amount of capital spent, amounting to C$39 billion.
Total cost requirements for the oil sands industry year over year are presented in Figure E.6. These include the initial and sustaining capital and operating costs for all types of projects. Total spending increases from 2007 to 2014, reaching an all-time high of C$58 billion in 2014. With falling oil prices in the near term, the investment starts to fall, slowly recovering to a forecast peak of C$58.5 billion in 2021, at which point it flattens out, averaging C$55 billion per year. As mentioned earlier, initial capital starts to decline by the end of the projection period. This does not reflect a slowdown in the oil sands, merely a lack of new capacity coming on-stream, and relates back to CERI’s assumptions for project start dates and announcements from the oil sands proponents. Over the forecast period, total operating costs are expected to increase in line with increasing production levels, averaging $28 billion per year.
Alberta Oil Sands Royalty Revenues

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

As a result of capital spending cuts and low prices, royalties will continue to decrease (after an all-time high in 2014) throughout 2015 and 2016. Over the next five years, from 2016 to 2021, as oil prices are expected to recover, royalty revenues will add up to $55 billion (cumulatively), all other things being equal.
The forecast of oil sands royalties might change significantly as it depends on many moving factors such as production level, oil prices, capital and operating costs. The royalty review advisory panel has issued a report\(^5\) where they make a number of recommendations to the government. The government already implemented changes to the conventional oil and gas royalty formula. Among the recommendations, the panel suggested to retain the current structure and royalty rates for oil sands, but increase the transparency of allowable costs. Through their engagement process with many Albertans, they found that people do not have confidence in the validity of allowable costs. This low level of trust is driven in large part by the lack of transparency in respect of these costs to researchers, analysts and the general public. The panel believes that the success of the oil sands royalty structure critically depends on the validity of allowable costs. To this end, the panel proposed a suite of measures aimed at ensuring allowable costs in the oil sands are transparent, reasonable, up-to-date and valid.

\(^5\) Royalty Review Advisory panel. “Alberta at a crossroads”. 
Emissions

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

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

![Figure E.8: Oil Sands Emissions by Project Type](source: CERI)

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