Economic Spotlight

Oil Sands Industry Adjusts to Lower Oil Prices

Following the collapse in oil prices in late 2014, oil sands operators were forced to adjust to the lower oil price environment. They did this through optimization, new efficiencies and technological advances. This *Economic Spotlight* looks at how costs have fallen since 2014, based on allowable oil sands cost data submitted by operators to Alberta Energy for royalty calculation purposes.

Unconventional production expects to meet global demand

The cost of producing a barrel of oil can vary widely depending on multiple factors, including: the location and depth of oil reserves, reservoir characteristics, cost of labour, energy and materials and local environmental directives and safety standards. Conventional reserves, which are developed through drilling wells and using either the reservoir pressure or a pump to bring oil to the surface, have some of the lowest production costs. With conventional reservoirs maturing globally, other unconventional reserves, such as oil sands and tight oil, are expected to meet global demand for fossil fuels.

Canada is endowed with 172 billion barrels of proven oil reserves, of which 164 billion are in Alberta's oil sands. Only a small fraction of oil sands reserves, about 15%, has been developed.

Unique characteristics of oil sands

Alberta oil sands deposits are a mixture of sand, clay and water saturated with bitumen, a highly viscous form of petroleum. The physical properties of Alberta's oil sands require a significant amount of water and energy to separate the bitumen from the clay and sand. Depending on the depth of the deposit, there are two methods used to extract oil sands: surface mining and in-situ. Surface mining involves the extraction of near-to-surface deposits, up to about 70 metres deep. These deposits account for about 20% of total oil sands reserves in Alberta. The other 80% are not economical to recover by open pit mining, as they are situated at a depth of 200-700 metres. They require drilling wells and, based on the viscosity of the bitumen, the possible use of steam or solvents to allow the bitumen to be brought to surface. This type of extraction is referred to as in-situ.

Oil sands development requires a high initial capital investment to build a large-scale production facility. When compared with mines, in-situ projects are quicker to construct and can be built in smaller, staged phases, which results in more flexible upfront capital spending. Once in operation, a typical oil sands project (both mining and in-situ) can produce for 40-50 years due to low production decline and high recovery rates. It is the geology and operations of the oil sands that lead to the higher recovery rates: heat promotes continued bitumen flow through the reservoir for in-situ operations, or almost the whole deposit is accessible from the surface and processed in mining operations. The competitive advantage of oil sands is in the long-lived nature of the asset and the relatively constant stream of production, with limited exposure to short-term price volatility (Table 1).

Table 1: Relative ranking of unconventional oil development against conventional

	Initial capital costs	Recovery rate	Production decline rate	Exposure to short-term price volatility
Mining, oil sands	Very high	Very high	Very low	Low
Thermal in-situ, oil sands	High	High	Low	Low
Tight oil	Medium	Low	High	High

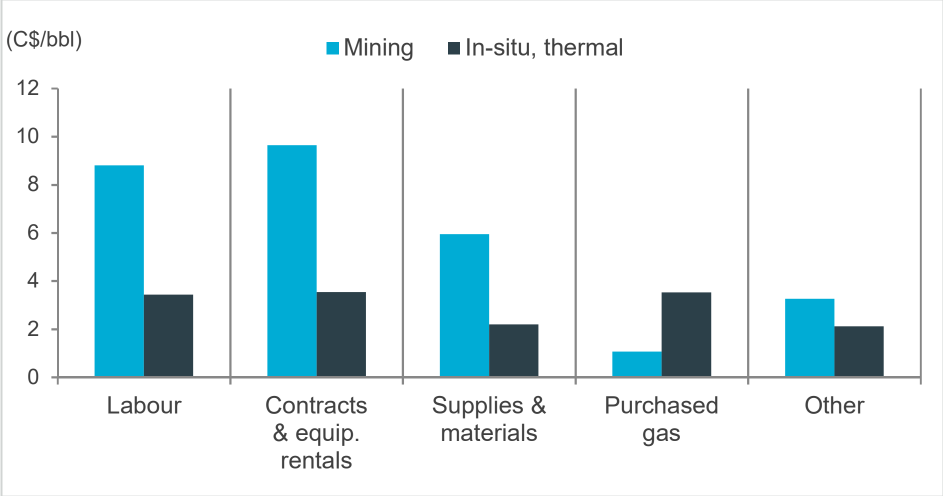
Source: Alberta Treasury Board and Finance

Various definitions

Strategic capital is the cost of constructing a new oil sands project or expanding an existing one. Once a production facility is constructed, any expenditures made to preserve the integrity of the facility and sustain bitumen production levels, including costs for replacement production wells, are called sustaining capital.

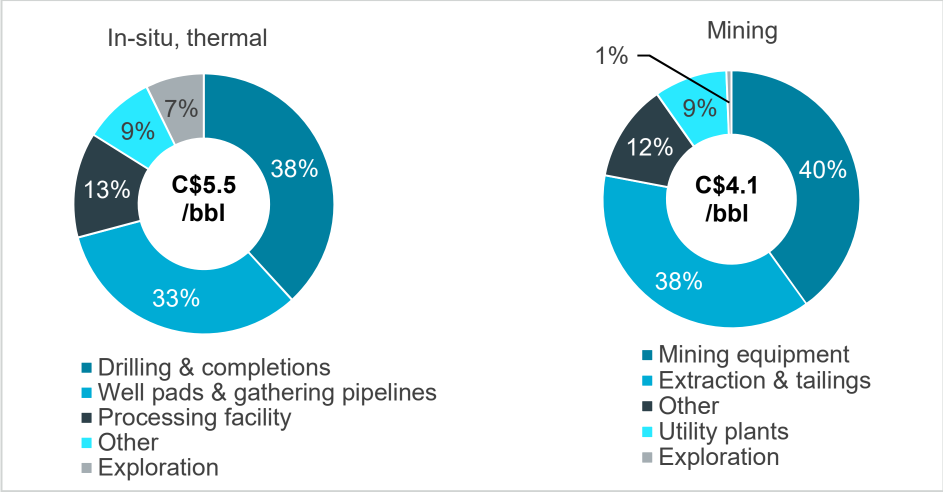
Operating costs are expenses related to running the facility, such as labour, materials and purchased energy. The price level required to recover all oil sands project costs, including a specified return on investment, is called the breakeven price or supply cost. When it is measured in U.S. dollars, it is a West Texas Intermediate (WTI)-equivalent breakeven price that allows for a direct comparison with the North American oil benchmark.

Chart 1: Operating costs for mining and in-situ, by major category
Average per barrel, 2009–2018 (C$/bbl)



Source: Alberta Energy

Chart 2: Sustaining capital for mining and in-situ, by major category
Average per barrel, 2015–2018 (per cent of total)



Source: Alberta Energy

Mining vs. in-situ costs

Differences in the two oil sands extraction processes lead to differences in the cost profiles between the mining and in-situ sectors. Mines typically require more labour, equipment and supplies in all stages of the project than in-situ projects. For in-situ, purchased natural gas, to create steam, is a bigger portion of operating costs compared to mines (Chart 1).

For in-situ operators, the drilling and completion of wells, the well pads and gathering pipelines together account for more than 70% of the sustaining capital costs. On the other hand, mining operators spend about 80% of their sustaining capital to support and maintain mining and extraction equipment and tailing ponds (Chart 2).

Further differences occur after the bitumen is extracted. Currently, most of the bitumen produced by mines goes to onsite upgraders where synthetic crude oil (SCO) is produced. In-situ bitumen, and a growing portion of mined bitumen that is not sent to onsite upgraders, is typically blended with condensate, the most commonly used diluent. The blending is required to meet pipeline specifications to transport blended bitumen to refining facilities.

Cost management as a solution

Despite a decline in oil prices from over US$100/barrel (bbl) in mid-2014 to about US$30/bbl in early 2016, oil sands production kept growing as completed projects continued to ramp up production and other projects with pre-existing capital commitments continued to be developed. Given the capital commitments, operational challenges and costs of shutting in oil sands projects, cost management became a priority during this prolonged period of low oil prices. Oil sands operators decreased their operating and capital expenses by optimizing labour costs, reducing costs of contracts and equipment rentals, shifting to a simplified modular design of facilities, improving drilling practises and focusing on short-term needs. Additionally, the falling price of purchased natural gas supported the decline in oil sands costs.

In-situ breakevens are considerably lower than mining

Based on estimates reported by the Alberta Energy Regulator (AER) and the Canadian Energy Research Institute (CERI), the breakeven price for a new stand-alone mine is currently within the US$75-85/bbl range. Contrary to mining, the breakeven price for new steam-assisted gravity drainage (SAGD) operations, the most commonly used technique for the thermal in-situ recovery, is around US$60/bbl. In contrast, the breakeven of SAGD expansions is about US$52/bbl, which explains in-situ expansions in 2015 and 2016 when WTI was hovering around US$50/bbl (Chart 3).

Operating costs declined

Following the collapse in oil prices in late 2014, oil sands operating costs declined by more than 30% in 2016 from their peak in 2013, according to the Canadian Association of Petroleum Producers.

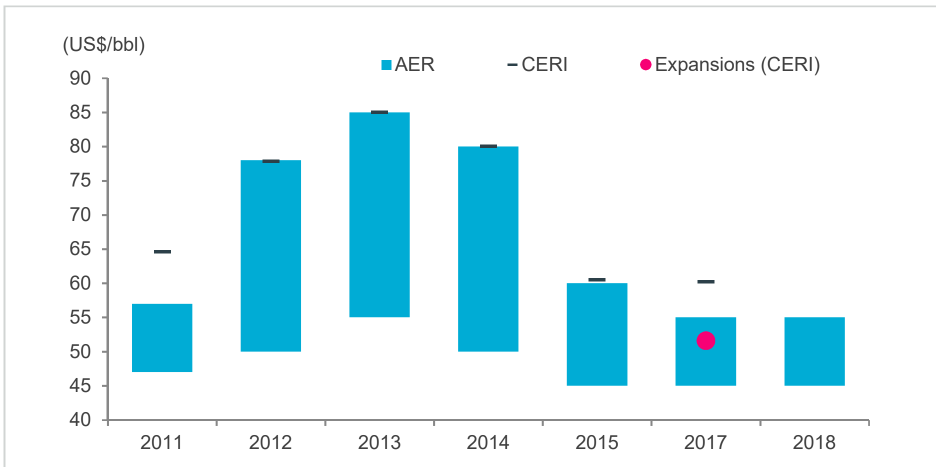
Mining operators saw a larger cost decline than their in-situ counterparts, on a per barrel basis. Based on operator's cost data reported to Alberta Energy, average per barrel operating costs for surface mining had fallen C$7.90 in 2018 from their peak in 2014, to C$27.00/bbl (Chart 4). Over the same period, average per barrel operating costs for in-situ had declined C$7.20, to about C$11.00/bbl (Chart 5).

Labour and rentals drove down mining operating costs

Labour represents about a third of operating costs for mining projects and was the largest source of cost savings between 2014 and 2018. It contributed C$3.30/bbl to the cost decline through both layoffs and improved labour efficiency. Contract services and equipment rentals, along with supplies and materials, were the other large sources of cost savings. Renegotiation of contracts with oilfield service providers and input suppliers, together with an improved focus on procurement, reduced average per barrel operating cost by C$2.10 and C$1.20, respectively. Cost reductions found in other areas further improved operating costs by C$0.50/bbl (Chart 4).

Chart 3: In-situ supply cost declined

Evolution of WTI-equivalent breakeven prices* for a SAGD project



Source: Canadian Energy Research Institute and Alberta Energy Regulator

* Includes blending, transportation and a 10% rate of return. 2016 data were not published.

Chart 4: Labour and rentals led reduction in operating costs for mining

Level change in per barrel operating costs, 2014 vs. 2018 (C$/bbl)

Source: Alberta Energy

Low natural gas prices led a decline in in-situ operating costs

Purchased natural gas used for steam generation is one of the largest operating expenses for in-situ projects. This makes in-situ operating costs more sensitive to fluctuations in natural gas prices compared to mining. Amid declining natural gas prices across North America, average per barrel in-situ operating costs have been on the decline since 2009. During the oil price correction in 2015-16, a further decline in natural gas prices led to falling costs of purchased gas and a C$2.80/bbl reduction in operating costs in 2018 compared with 2014. Through labour optimization, in-situ operators achieved a C$1.70/bbl reduction in operating costs. Renegotiation of contracts and improved procurement, combined, added another C$2.30/bbl to the decline in expenses. Similar to surface mining, reduction in other costs contributed C$0.40/bbl to the operating cost decline (Chart 5).

A reduction in sustaining capital costs

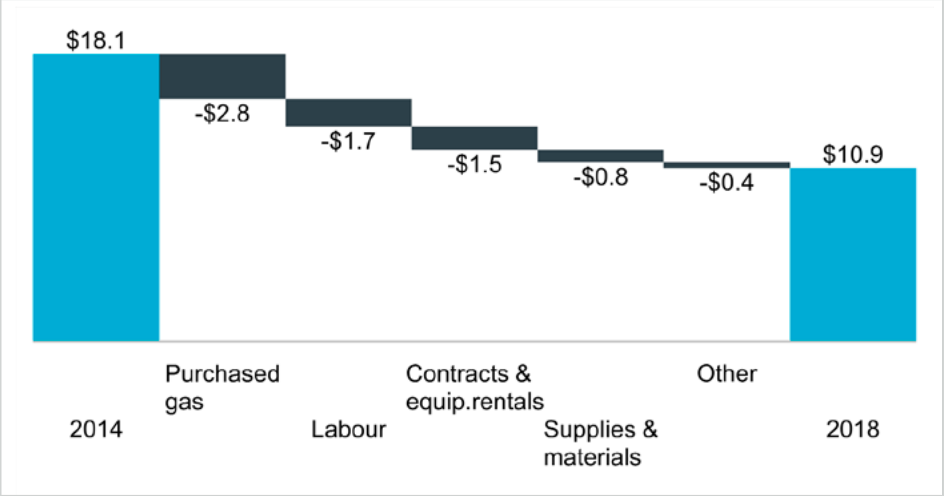
Along with reductions in operating costs, sustaining capital costs have also declined. In-situ operators saw a larger decline than their mining counterparts, on a per barrel basis. Based on operator's cost data reported to Alberta Energy, average per barrel sustaining capital for in-situ had fallen C$4.40 in 2018 compared with 2015 (Chart 6). Over the same period, average per barrel sustaining capital for surface mining had declined C$2.20 (Chart 7).

Improved well design spearheaded decline in in-situ sustaining capital

In the low oil price environment, oil sands operators have shown a shift in business strategy from either greenfield or brownfield project expansions that accelerates production to further development of land leases with existing infrastructure. Using a standard, repeatable well pad design has reduced the amount of structural steel, piping, electrical components and labour needed to construct a well pad, and spearheaded a decline in sustaining capital costs for in-situ operations. A C$1.90/bbl reduction in the well pads and gathering pipelines category led the decline in sustaining capital costs. Improvements to drilling and completion technologies, through reducing the number of wells required to effectively produce the reservoir, further reduced sustaining capital costs by C$1.40/bbl (Chart 6).

Chart 5: Purchased gas led reduction in operating costs for in-situ

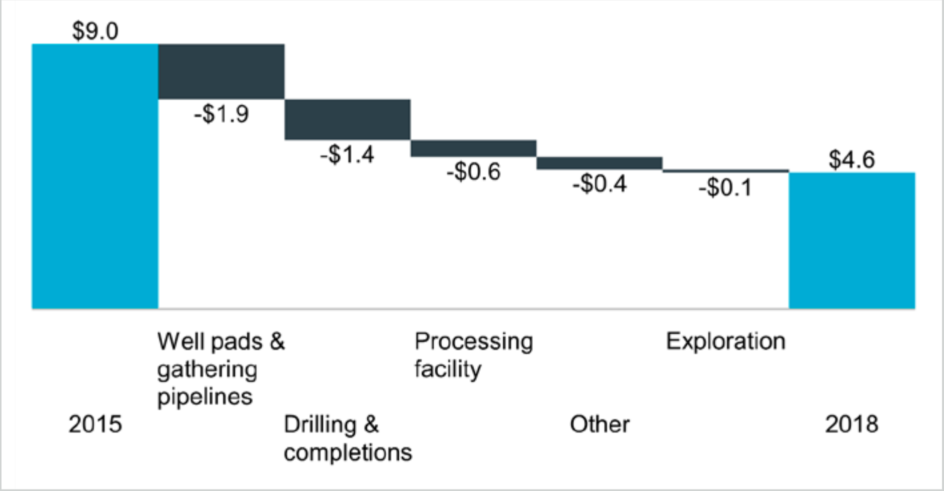
Level change in per barrel operating costs, 2014 vs. 2018 (C$/bbl)



Source: Alberta Energy

Chart 6: Well pads led decline in sustaining capital costs for in-situ

Level change in per barrel sustaining capital, 2015 vs. 2018 (C$/bbl)



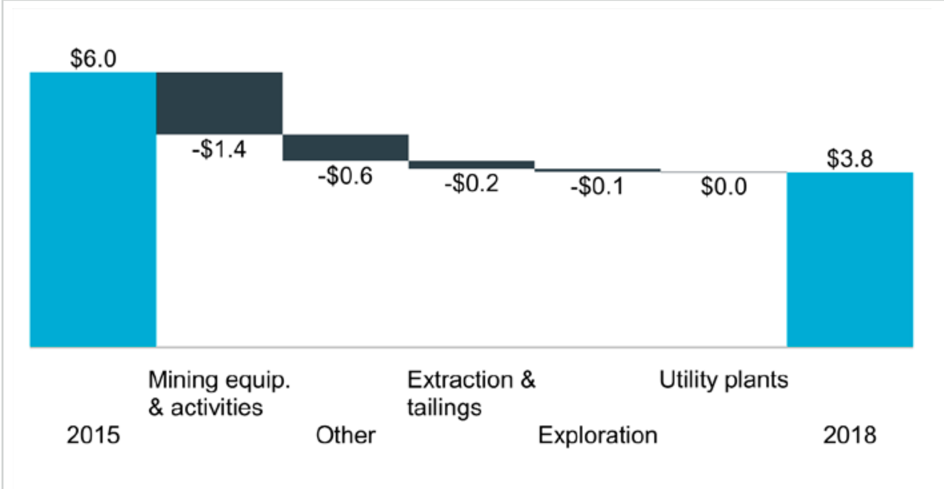
Source: Alberta Energy

Mining equipment led decline in mining sustaining capital costs

A C$1.40/bbl decline in the cost of mining equipment and activities between 2015 and 2018 spearheaded sustaining capital cost declines for surface mining. As new mining projects and expansions came online and increased production capacity over the time period, economies of scale were created. This, combined with an effort by all operators for more efficient and reliable operations, helped push the unit costs down. (Chart 7).

Chart 7: Mining equipment led reduction in sustaining capital costs for mining

Level change in per barrel sustaining capital, 2015 vs. 2018 (C$/bbl)



Source: Alberta Energy

Optimized maintenance

Another recent strategy employed to reduce sustaining capital costs was maintenance optimization. With oil sands ownership becoming more consolidated, operators are able to to minimize turnaround and outage impacts through, among other things, more asset integration and infrastructure sharing.

Reduced stategic capital requirements

Standardization and modularization that assisted in reducing sustaining capital costs of existing oil sands projects also translates into savings for new projects. Instead of the larger, one-off, fit-for-purpose facilities that dominated the industry 10 years ago, industry has shown a trend to move to smaller-scale expansions done at greater frequency. Modular construction, which involves prefabricating equipment and systems offsite with a subsequent delivery to the production site for installation and commissioning, is particularly gaining popularity among in-situ operators. According to the AER, the use of standardization and modularization has allowed in-situ operators to produce ‘first oil’ just three years after the start of construction, which is one to two years earlier than the average project. Combined with improvements to operating and sustaining costs, the ultimate costs of constructing and operating an oil sands project have declined, evidenced in the reduction of breakeven prices.

Industry faces more challenges

By managing costs, oil sands producers have responded to the challenges brought by lower oil prices. However, the industry faces broader issues. The need for more market access has been evident for the last several years. Rising oil sands production is causing long forecasted pipeline bottlenecks. Together with an increasing reliance on rail, rising production raises transportation costs for Alberta heavy oil producers and widens the light-heavy differential, reducing corporate profits. Despite the decline in the cost of oil sands projects, additional pipeline capacity will play a key role in the timing and size of new oil sands investment coming to Alberta.

Contact:
TBF - Tatiana Gubanova at (780) 644.4366
Energy - David Cuglietta at (780) 643.1497