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A restrained optimism in Canada's oil sands:

Is the improved efficiency, pipeline outlook, and technology bolstering the world's largest petroleum resource enough to make it competitive?

Headwinds and resilience

Starting a few years ago, Canada's oil sands producers faced a growing set of challenges clouding their growth prospects. The steady increase in costs, followed by a collapse in oil prices in 2014 — roughly 70% for oil sands synthetic crude and 80% for bitumen blend — brought new project proposals to a halt.[1] Meanwhile, growing environmental opposition to pipelines needed to access new markets and new governments at the federal and provincial levels that are both committed to strong climate policies, added uncertainty, weakening investor interest. To compound the gloom, in the spring of 2016, a calamitous wildfire hit the city of Fort McMurray. It became the costliest natural disaster in Canadian history, and more than 1 mb/d was forced offline for several weeks.[2] Perhaps the only saving grace for producers at the time was a roughly 30% decline in the value of the Canadian dollar, which boosted US dollar earnings.

Since the late nineteenth century, portents around Canada's oil sands have swung erratically between exuberance and disregard.[3] The oil sands was the darling of global investors, supermajors, and national oil companies just a decade ago — roughly 2 mb/d of production was added to the basin during the 2000–2015 boom (current production is about 2.7 mb/d and once legacy projects are completed by 2020, production will exceed 3.1 mb/d).[4] A few early movers, who invested before the oil price began to spike in 2004–05, reaped handsome returns well above any market index.[5] Feverish expansion soon stifled growth however, creating egress bottlenecks, environmental opposition, and often exorbitant rent seeking throughout the supply value chain. These problems are summarised in detail in an OIES paper written during the price nadir of early 2016 when some

[1] See Alberta Government Economic dashboard for WTI and Western Canadian Select (WCS) historical prices from the peak in June 2014 to the trough in February 2016: http://economicdashboard.alberta.ca/OilPrice.

[2] Wallis Snowdon, "Fort Mcmurray Wildfire Costs To Reach Almost $9B, New Report Says", *CBC News*, 2017, http://www.cbc.ca/news/canada/edmonton/fort-mcmurray-wildfire-costs-to-reach-almost-9b-new-report-says-1.3939953.

[3] After assessing the resource endowment of a recently confederated nation in 1888, the Geological Survey of Canada declared: "The evidence…points to the existence in the Athabasca…of the most extensive petroleum field in America, if not in the world. The uses of petroleum and consequently the demand for it by all nations are increasing at such a rapid ratio, that it is probable this great petroleum field will assume an enormous value in the near future and will rank among the chief assets…of the Dominion." *Journals of the Senate of Canada: Being the second Session of the Sixth Parliament,* 1888, Queen's Printer, p163.

[4] Oil sands supply is significantly higher than production (currently around 3.3 mb/d and estimated to grow to 3.9 mb/d in 2020 according to Canadian Association of Petroleum Producers). This is due to the blending of produced condensate from outside the oil sands, with produced oil sands bitumen.

[5] As indicative examples, CNRL and Suncor share prices each appreciated more than 400% from 2001–2006

J. Peter Findlay

pronounced long-term oil sands growth to be all but dead.[6] It is important to note that although many of these headwinds started around 2008, production growth continued inexorably from 2007 to 2015. And despite a recent slowdown in project additions, some remarkable trends are happening on the ground in Canada's western province of Alberta that point to continued, if subdued, growth.

Resilient oil sands employees have shown resolve while confronting rounds of layoffs and a wildfire that razed the majority of Fort McMurray (including almost CAD$4 billion in property damage), not to mention the perennial frigid winters. This manifests in increasing competitiveness — operating, sustaining, and new-build capital costs are falling faster than most analysts foresaw. SAGD projects that in 2014 required a WTI price of $80–90 per barrel to be profitable are being revamped, and now might need only $55–65. With hues of renewed optimism around some sort of oil price recovery, brownfield expansion projects are being restarted, and reinvigorated with more cost-efficient designs. Some shelved greenfield projects are even getting a fresh look, and could be approved within the next year or two, though final investment decisions are not assured given price uncertainty.

On the regulatory front, progressive environmental regulations are earning oil sands producers an improved public reputation, at least notionally.[7] Alberta's 'Climate Leadership Plan' is arguably the most potent climate policy directed at the hydrocarbon sector anywhere in the world. Some feel this shift helped embolden Canadian Prime Minister Justin Trudeau to confront environmental activism and approve Kinder Morgan's Trans Mountain Expansion project, adding 0.59 mb/d of egress capacity by 2019. Meanwhile, the surprise election of US president Donald Trump has given a hitherto unthinkable optimism to the high-profile 0.83 mb/d Keystone XL pipeline. Both pipelines could propel future growth, yet still face formidable hurdles to actually being built.

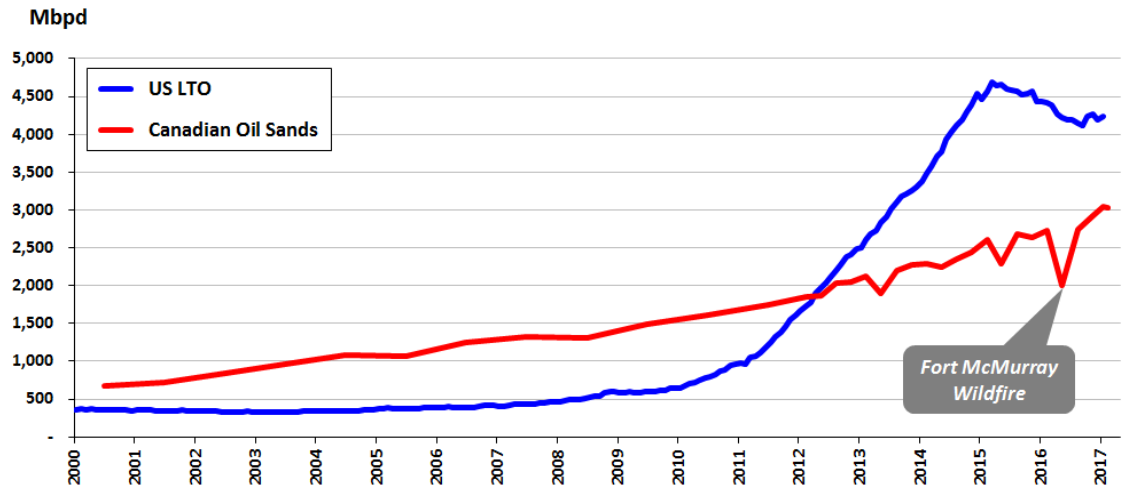
Foreign investor sentiment remains somewhat gloomy, despite some positive signs. Major integrated oil companies are shrinking their footprint in the oil sands and directing capital to other global opportunities. Shell and ConocoPhillips have followed Total and Statoil in selling much of their oil sands assets; BP and Chevron are rumoured to have their interests on the auction block.[8] In reality, the majors are leaving more to tweak their balance sheets, debt levels, capital allocation, and environmental perception, than as a complete shunning of the oil sands. Even those that have sold major assets have retained some material foothold. The more telling story is the consolidation of production, which is being gobbled up by the largest Canadian producers aiming to drive down costs through scale and focus.

[6] A more detailed overview of the oil sands, including a primer on its unique geological and production characteristics, can be found in J. Peter Findlay, *The Future Of Canadian Oil Sands: Growth Potential Of A Unique Resource Amidst Regulation, Egress, Cost, And Price Uncertainty* (Oxford Institute for Energy Studies, 2017).

[7] Many environmental groups still consider oil sands production anathema, despite considerable progress and technologies aimed at lowering emission intensity and local pollution impact.

[8] Matt Zborowski, "Shell To Divest Nearly All Of Its Canadian Oil Sands Interests For $7.25 Billion", *Oil And Gas Journal*, 2017.

Figure 1: Canadian oil sands vs. US LTO production



Sources: EIA, Canoils

The inertia of oil sands development is a salient, underappreciated driver of the growth outlook. Despite the price rout, oil sands production is forecast to grow by 45% between 2014–2020, having already increased by 25% through 2017. Price elasticity is only relevant over the long term. Whether mined at the surface or produced from the subsurface (called 'in-situ'), oil sands production is deemed to be *manufacturing.* Most of the effort and cost focuses on the energy intensive process of reversing geology: transforming bituminous sand to lighter, sweeter, more marketable crude. And because operating a manufacturing plant below 100% utilisation hampers economics, producers are unlikely to shut-in output even at a WTI price of $20 as they need to offset their high fixed costs. Save for improbable and short-lived events like the 2016 wildfire, overall oil sands production effectively does not decline, and although substantial sustaining capital is needed, capacity tends to grow. Historically, capacity is added in boom times, and manufacturing efficiency is restored in gloomy times, like today.[9] Figure 1 contrasts the responsiveness of oil sands production versus that of its doughty and nimble, if high-declining counterpart south of the border: US light tight oil (LTO). Inexorable ongoing production and long construction lead-times for new production, means the oil sands will neither curtail production to contribute to a global rebalancing (like OPEC and LTO), nor rapidly surge production to keep an oil price spike in check (like LTO). Nevertheless, this sluggish response does not necessarily put the oil sands at a disadvantage in competing for new growth against other global basins over the next decade.

Has LTO and bearish demand growth obviated 'energy security'?

Arguably more than any other global basin, Canada's oil sands offer investors the notion of 'energy security'. The oil sands' nearly 2 trillion barrels of original-oil-in-place reserves (200 billion barrels are considered economically recoverable today) attracted fervent global interest from 2000–2014 in a seemingly supply-constrained world. Almost suddenly in 2014, it seemed the world was no longer supply constrained, at least for the foreseeable future. The previously coveted asset of energy security (measured in reserves) was reassessed and impaired on balance sheets.

Impressive advancements in cost reduction and productivity bode well for LTO's future. This is especially true in the Permian basin, which has clearly emerged as an investor favourite, and is now

[9] Though production efficiency improvements for both mining and in-situ have been impressive, mine upgrader utilization has confronted persistent issues, beyond the 2016 wildfire.

the most prolific producer in the US.[10,11,12] The astounding growth and resiliency story of US LTO production is emblematic of the dynamism of American capitalism. Its ascension has come through a combination of privately-owned mineral rights, advances in technology and equipment, oil-friendly regulations, a financial industry with few investment alternatives, historically low interest rates, and investors voraciously chasing growth rather than capital efficiency. The 2014 price crash only seemed to bolster the sector. Thanks to a Darwinian rejigging of leases, producing assets, and capital towards the most efficient and profitable producers, the LTO production outlook is stronger than before.

The North American natural gas market offers a useful analogy. During the 2012 shale-gas supply glut and $2 per mcf price nadir, many predicted a return to 'balance' at $6–7 per mcf. Producer bankruptcies soared and the market consensus was that producers would curtail drilling new wells, and price would recover. In fact, producer resiliency caused gas production to increase almost 10% since 2012, and prices have stayed relatively flat, and not returned to pre-shale levels. Many producers are now profitable with prices above $2.

With the doubling down on crude investment in the Permian basin, LTO may be following a similar storyline. As efficient, dynamic producers bolster LTO production, the near-term oil price looks to be somewhat capped and Canada's oil sands seem less relevant on the global stage.[13] However, the near term is of little interest to oil sands executives looking at the multi-year lead times required to develop new capacity. It is the medium term (roughly 3–6 years out) and beyond that is more germane to their project decisions.

In that timeframe, there is some consensus that the oil price will not be capped by LTO, as there are geological and other limits to LTO growth. More importantly, growing global demand and declining supply of conventional oil outside North America could also outstrip LTO's ability to balance the markets. The International Energy Agency (IEA), among others, note that unless major new production projects are undertaken, the world will struggle to keep pace with continued growth in demand, with a supply crunch possible as early as 2019 and sharp price escalations cresting in 2022.[14] A supply-constrained medium-term global oil outlook with concomitant higher prices bodes well for oil sands growth, though there is uncertainty of that outlook materialising.

This uncertainty is holding back new projects. Given the balance sheet scars taken in recent years, executives want a more solid price signal before rolling the dice on decades-long projects that takes three years or more from sanctioning until first oil. In the meantime, producers are doing what the international oil industry did in the 1998–2001 period after 12–15 years of depressed prices: consolidating and cutting costs. Beyond legacy construction, production will grow in small incremental additions where the economics are sensible. In the background, industrious producers are preparing for a potential price rebound by rethinking and redesigning how more cost-efficient capacity could be added, rapidly.

The last oil sands mine?

Oil sands production has historically (and visually in the public perception) come via mining, using the bitumen separation techniques pioneered in the 1920s.[15] Just recently, with the commercial advent of the Steam Assisted Gravity Drainage (SAGD) technique in 2001, has in-situ production began to

[10] Trisha Curtis, *Unravelling The US Shale Productivity Gains* (Oxford Institute for Energy Studies, 2016).

[11] Evelina Pagkalou, *Why Has Light Tight Oil Production Proven So Resilient In The Permian?* (McKinsey Energy Insights, 2016).

[12] As of early 2017, the Permian basin is producing roughly 2 mb/d, more than the Eagle Ford and Bakken combined.

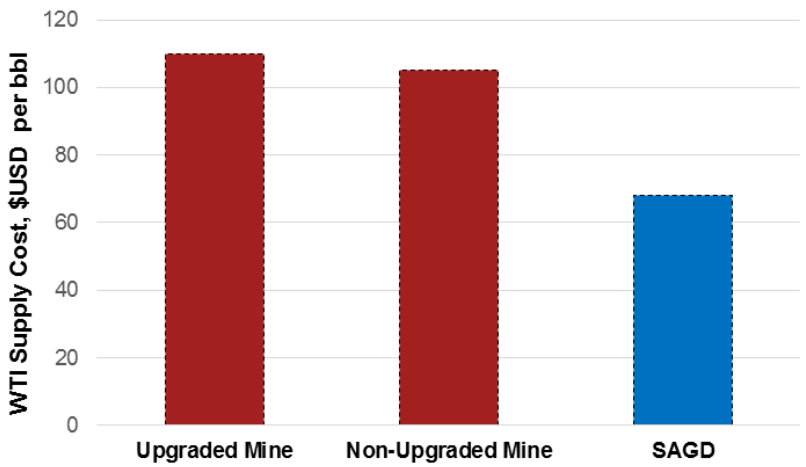
[13] LTO production is likely to become less burdened with regulations given the current Republican control of the US presidency, House of Representatives, and Senate, and an energy production friendly head of the Environmental Protection Agency.

[14] International Energy Agency, *Oil 2017*, Market Report Series (Paris, 2017).

[15] More detail can be found in the oil sands primer in *The Future Of Canadian Oil Sands: Growth Potential Of A Unique Resource Amidst Regulation, Egress, Cost, And Price Uncertainty* (Oxford Institute for Energy Studies, 2017).

eclipse mining. Decreasing relative costs, modular projects, less environmental disruption at the surface, and access to more than ten times the reserves, favours subsurface production for future growth. Reclaiming tailing ponds that contain toxic residue from the bitumen separation process can take decades and their long-term regulatory requirements are not certain, adding potential liabilities to balance sheets for producers.[16] Furthermore, potentially disruptive production technologies like the use of solvents, microwaves, or microbes, are all aimed at producing deeper bitumen resources. Canadian investment bank CIBC contrasts WTI-equivalent supply costs between greenfield mining and SAGD projects in Figure 2, starkly highlighting the infeasibility of new mines.

Figure 2: Break-even costs for greenfield projects at 15% IRR



Source: CIBC World Markets[17]

CIBC continues to analyse and quantify sizeable cost reductions that have materialised since the 2014 price crash for potential SAGD greenfield projects, while disregarding some of that potential for mining.[17] With little appetite for new mines, companies are not investing resources in redesigning long-shelved project plans. Accordingly, industry insiders are pondering whether Suncor's Fort Hills mine, a 0.2 mb/d mega project aiming for first production near the end of 2017, will be the oil sands' last new mine project.[18] Suncor CEO Steve Williams corroborates the bearish view on new mines:

> Mining investments are coming to an end, not just for Suncor but for the industry, I believe, for a considerable period, probably in excess of 10 years. So whilst we look at the go-forward economics of Fort Hills, when we look at the absolute economics of Fort Hills those are not projects we will be repeating in the foreseeable future. Some substantial things in the cycle would need to change.[19]

However, with project lives of 50 years or more (Suncor's vanguard 1967 mine and upgrader celebrates a half century of operation this summer), production from mines will not decline anytime soon. Producers champion their mines as cash generators they can use to enable growth in SAGD projects or beyond the oil sands. This was Shell's view before they sold their mine-weighted assets to Canadian Natural Resources (CNRL). Moreover, mining producers have shown impressive operating

[16] Very little (~1 per cent) of the disturbed land from mining to-date is considered 'certified reclaimed'; mining producers face myriad challenges in satisfying regulators for long-term reclamation: Deborah Jaremko, "Suncor Tailings Application Denied On Insufficient Assessment Of Risks For Water-Capping And Its Alternative", *JWN Energy*, 2017.

[17] CIBC World Markets, *Visibility for Economic Oil Sands Growth in a US$50/Bbl World*, Oil Sands Technology Update, 2017.

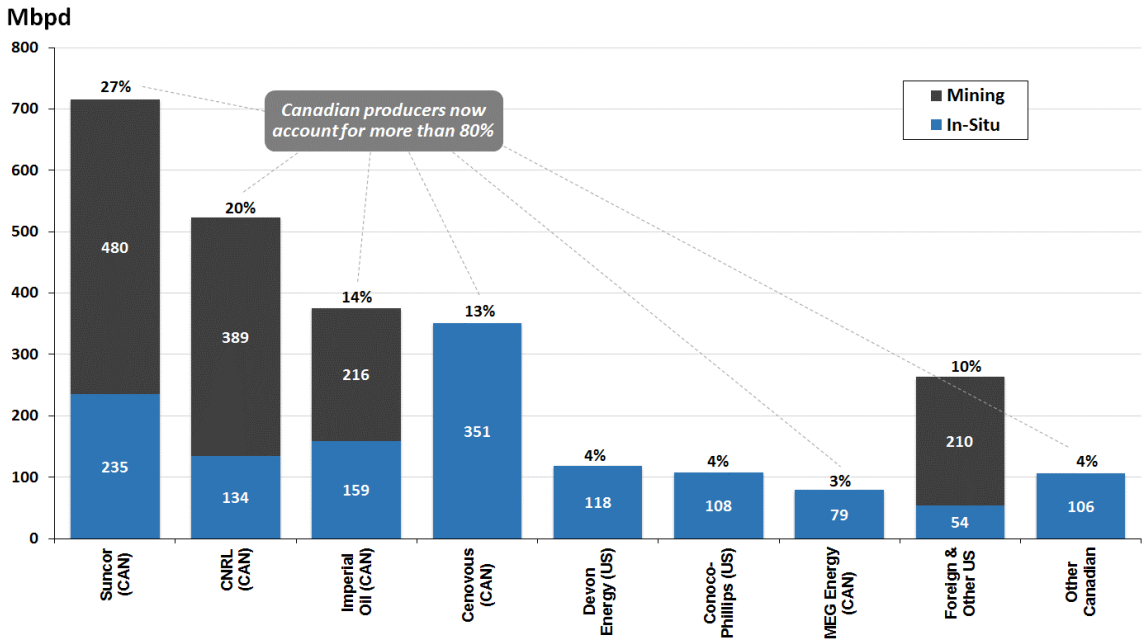
[18] As of July 2017, Suncor's joint venture partner Total, who controls 29.2% of the Fort Hills project, is protesting cost escalations for the $15 billion project (now estimated at up to $17 billion) and has cut off funding as a result.

[19] Suncor Energy, *Fourth Quarter 2016 Financial Results Conference Call & Webcast*

cost cuts of 30% or more through the downturn, approaching $20 per barrel (WTI equivalent). Then there is the cost associated with shutting in current production and leaving plants idle. Due to the manufacturing complexity of the large-scale operation, the costs of shuttering a mine and upgrader could exceed a billion dollars; the cost of starting-up again would approach another billion.[20] Shutting-in is just not a viable option for any oil sands producer, like it may be in other global basins.

Global sellers meet Canadian consolidators

Figure 3: Ownership Interest in Oil Sands ProductioN



Source: JWN and AER Production Data for December 2016 (recent transaction impact is included)

Only three mining operators remain following Shell's divestiture, all with deep-seated Canadian roots: CNRL (whose stock appreciated with the Shell asset acquisition), Suncor, and Imperial Oil (ExxonMobil).[21] On the in-situ side, which is expected to be the engine of growth, these same three operators, along with Canadian SAGD pioneer Cenovus, dominate production. Devon Energy, Meg Energy and Nexen (CNOOC) are important middle-tier operators. Cenovus went 'all-in' on oil sands in-situ production in a CAD$17.7 billion ($13.3 billion) mega-deal, buying out its partner ConocoPhillips, essentially doubling its enterprise value through higher leverage (though paying a severe share price penalty).[22] Current production data summarised in Figure 3 indicates that roughly 75% of oil sands production is now concentrated between these four Canadian producers, with less than 20% being foreign owned.[23]

[20] Substantial costs are required to protect and idle operating units, trucks, shovels, and other mechanical equipment, as well as purge all the lines and vessels, keeping some on warm shut down.

[21] Syncrude, a sizeable consortium, now majority owned by Suncor and producing now more than 0.4 mb/d of bitumen, has historically been operated by Imperial Oil with support from parent ExxonMobil, though Suncor is likely looking to leverage its ownership stake and drive efficiencies.

[22] Alex Nussbaum, Kevin Orland and Robert Tuttle, "Cenovus Drops Most Ever As $13.3 Billion Deal Ramps Up Risks", *Bloomberg*, 2017.

[23] Assumes that Imperial Oil is a Canadian company, even though the majority of public shares are owned by ExxonMobil

Speculation abounds that following the sizeable foreign divestments of Shell, ConocoPhillips, Marathon, Total, and Statoil from the oil sands, others will follow. The potential foreign deals that remain, however, are likely smaller in scale (below $5 billion in value at going market rates). Examples include the joint venture SAGD footholds of Devon Energy, ConocoPhillips, and BP. Chevron has reportedly considered selling their interest in the formerly Shell-operated mine. To be sure, a few foreign-owned entities (primarily from Asia) are making countercyclical SAGD investments. Brion Energy (a PetroChina subsidiary) and Japan's JAPEX are both looking to blossom into profitable and somewhat sizeable SAGD producers. The sluggish price recovery, though, has of course curtailed their ambitions when compared to growth plans before the price crash.

Most players are retaining at least a toehold in the basin in the chance that a boom returns. However, the trend of asset migration from foreign ownership to home-grown oil sands anchor producers is driven by an overarching investor directive: divest from the oil sands if you do not have scale and cannot reduce costs, have more attractive opportunities to deploy capital elsewhere, or are feeling governance and shareholder pressure to divert capital from oil to lower emission energy sources like wind or solar (falling in line with promulgated climate change rationale).

Low crude prices engender transformation and competitiveness

Ironically, the remaining producers may not yearn for a crude price rebound back to a heady $80–90 per barrel in the near term. Oil sands investors with long-term investment outlooks (not to mention executives with stock option compensation packages that skew to longer-term performance), realise that down cycles are where growth project plans can be reformulated, operations optimised, and rent-seeking in the value chain can be methodically curtailed, at least to some extent.[24] Escalating oil prices bring frenzied growth, and producers are notoriously cost insensitive during these periods — efforts to stay lean or commercialise technology can stifle production growth and create a 'fear of missing out' on the revenue bonanza coveted by insatiable investors.

Oil producers hoping for a 'lower for longer' price scenario may seem paradoxical, but it highlights the manufacturing ethos that underpins oil sands production: continuous improvement is imperative for long-term survival. What then are 'manufactures' doing during these price doldrums?

Producers have historically prioritised engineering and subsurface expertise, astute land and deal brokering, and risk management, rather than efficiency. Surface mining mainstays Suncor, Syncrude, Imperial Oil / ExxonMobil, and CNRL have lived the manufacturing mantra for years, at least in their mining operations. Driven by process standardisation and efficiency, these mining operators were historically able to approve and build greenfield projects at inflation-adjusted crude prices that were lower than today's.[25]

Conversely, in-situ producers were slow to embrace a manufacturing ethos, focusing on proving out their production concept while they develop what are still somewhat nascent production methods. Rapidly escalating crude prices from 2003–2008, followed by the robustly high prices of 2010–2014, diverted their focus from demonstrating economic efficiency of this new SAGD technology to growing as quickly as they could. The 2014 price rout, however, disruptively redirected their focus towards better designed projects, technology, and operating efficiency.

Producers imposed little restraint on the purchase of advanced equipment and bespoke design of SAGD projects during the first 10–15 years of commercial production. They were concerned with understanding how the reservoir produced bitumen, rather than driving cost out of projects. Today,

[24] The predominant and most stubborn operations cost item is labour, and oil sands employees and contractors are accustomed to the highest wages and most perks in Canada. Reeling in this remuneration to be in line with other manufacturing sector employees takes time and can cause uproar.

[25] The addition of 0.4–0.5 mb/d of mining capacity between 2000 and 2007 was approved before the crude price began to significantly spike in 2004, to above an inflation adjusted price of $45–50 per barrel, WTI.

the prodding of cost pressures and the cumulative insights gained from a decade or more of production enables SAGD operators to impressively improve, standardise, and simplify their project designs. Multiple measures from Suncor and Cenovus (among others) are being deployed to chisel capital costs off greenfield projects, as detailed in Table 1. In aggregate, analysts estimate that such design improvements, what Suncor calls 'replication,' can deliver a reduction of an estimated $11 per barrel savings of WTI supply cost, lowering the required WTI price of a new SAGD project to $57 (assuming a required 15% rate of return).[26]

Table 1: SAGD DESIGN: Cost-SAVING Levers

Cost Element	Design Change
Reservoir	• Major SAGD players are able to identify contiguous or nearby reservoirs that demonstrate geology and petrophysics similar to their producing reservoirs. • Similar reservoir characteristics allow for repeatability and design standardisation — growth projects of 40,000 b/d increments can be built for decreasing cost.
Well Pads	• Facilities, especially well-pad facilities, drive roughly one-half of the upfront capital cost of SAGD. • Repeatability leads to economies of scale savings for Suncor of roughly 90% less engineering hours, 60% less field construction hours, and 80% less manual valves. • Cenovus notes they are seeing 40–60% reduction in material requirements. • By standardising their pad designs, producers are looking to save up to 50% versus historical builds.
Control Facilities	• Suncor is looking to implement an 'Integrated Operating Centre' system that they piloted in 2016, whereby the producer leverages a much more automated, centralised control system that reduces costs per well and human error. • Advanced software leverages a 'big data' approach to better understand operating decision trade-offs and optimise production.
Processing Facilities	• Suncor will use a more efficient, less complex central processing facility (CPF) than they have used in the past. • The newly proposed CPF is 45% smaller than recent industry builds.
Cycle Time	• Cenovus is delivering an up to 30% decrease in drilling times. • Standardisation and repeatability, enables the overarching concept of **modularisation** of projects, resulting in much shorter construction cycles. • Shifting the project development time to 12–18 months (versus the historical three years or more) improves project economics and enables producers to better make decisions on expansion.
Well Performance	• Though not as prodigious as the productivity increases in LTO drilling in the Permian basin, oil sands SAGD producers have made impressive improvements in well design. • Cenovus is demonstrating much higher, faster recovery in its most recent wells due to increases in lateral length, better drilling, better control, and different start-up techniques.

Sources: CIBC Oil Sands Technology Update (January 2017); Cenovus Corporate Update (April 2017)

Exogenous cost relief

Exchange rate

Because crude is Canada's largest export, the Canadian dollar is directly correlated with the price of oil, and acts as a buffer for producers in times of low oil prices. The value of the Canadian dollar has recovered somewhat so far in 2017, but has still lost almost 20% against the US dollar since June of

[26] Estimate for Suncor from CIBC's 2017 Oil Sands Technology Update, based on two phases of 'replication' design improvements

2014; this effective cost decrease for producers helps to offset some of the more than 55% fall in the price of bitumen-blend heavy oil since that time.[27]

Labour costs

The inherent inertia of human resources policies means that Albertan oil and gas wages remain much higher relative to other Canadian manufacturing sectors, despite record layoffs at producers, engineering contractors, and service providers, who have all been hit especially hard. As of April 2017, oil and gas wages in Canada were 63% higher than the average of the utilities, logging, construction, and other manufacturing sectors. (Oil and gas wages were only 33% higher in 2001, before the crude price escalation.) [28] The shift in unemployment in the Albertan oil and gas sector from 3.5% in 2014 to 9.9% in 2016 surely grants companies negotiating leverage on new hires, and overall remuneration should decrease if managers show determination in lowering costs. Executives and managers have shown a predilection for mass layoffs, rather than cutting wages and other emoluments — likely an untenable strategy for further cost savings.

Supplier power erosion

Analogous to the labour surplus, energy service companies as well as engineering, procurement and construction firms, find themselves trying to stay afloat in a lower margin and depressed volume industry. Beset by cash crunches and perilous balance sheets, these suppliers and contractors no longer hold the same negotiating power they enjoyed during the near 15-year boom ending in 2014. Oil sands producers are beginning to benefit from this shift in the balance of power — though with an oil price recovery, service company shareholders will once again expect more rent.[29]

Natural gas prices

Producing bitumen from stubbornly viscous oil sands with today's proven commercial techniques requires a substantial amount of energy, which is delivered through steam derived from natural gas combustion. The natural gas fuel input cost is thus a concern for producers, especially in-situ producers. As of early 2017, the Canadian Energy Research Institute estimates gas input costs at CAD$5.87 (roughly $4.50) per barrel over the lifetime of a new SAGD project. Fortunately for producers, thanks to the abundance of US, and increasingly Canadian, shale gas, natural gas markets in Alberta remain relatively depressed, currently below $2 per mcf, with an ongoing discount from the US Henry Hub price of around $1 per mcf.[30] An additional benefit of lower gas prices is that it lowers Alberta electricity prices, driving down operating costs.

There is a general consensus that gas producers are becoming increasingly efficient and Alberta will not see drastic shortages of natural gas in the near to medium term. Producer trepidation relating to future natural gas prices has subsided dramatically since the days before the North American shale gas renaissance, when natural gas prices would routinely spike above $10 per mcf and calls for nuclear power plants in the oil sands region were bandied about.

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[27] The Canadian Dollar is less of a 'petro-currency' than Russia's Rouble, whose 40% devaluation since 2014 has enabled Russian producers to better combat the crude price rout.

[28] Statistics Canada: Table 281-0063.

[29] Leverage is applied both with a cudgel, where producers simply demand drastic price cuts, and more collaborative approaches with suppliers to reduce waste. Producers are also looking to leaner industries outside oil and gas, such as automotive, chemicals and consumer goods, for supply chain insights and talent that can engender a competitive advantage.

[30] Indeed, there are myriad future scenarios for Western Canadian gas markets that are predicated on uncertainty around the final investment decision status of major LNG proposals, power generation demand (including cogeneration for oil sands), NGL markets, and egress developments.

Technology: Clearing the commercial hurdle

First addressed by the Oxford Institute for Energy Studies in 2011, promising oil sands technologies continue to grapple with real-world business challenges to becoming commercial.[31] SAGD technology revolutionised oil sands production but required persistent development and shepherding from oil sands pioneer Robert Butler at Imperial Oil. Decades passed from Butler's original technical concept in 1969, to the granting of the commercial patent in 1982, to government-supported pilot testing throughout the 1980s, to an appropriate fiscal regime and the first (small-scale) commercial operation in 1996.[32] Unfortunately for producers, that type of relatively small, but highly impactful provincial and federal support for the SAGD pilot (named the 'Underground Test Facility' or UTF), is inaccessible to promising technologies today.

Novel oil sands technologies need to be deployed at scale to deliver economic benefit, versus say a new technology for LTO extraction that can be gradually expanded from a few individual wells to hundreds, and tinkered with according to how the technology performs. They have to run for several years to get them past ramp-up and plateau, before they begin their natural decline. They require a great deal of expensive monitoring and observation wells. Technologies for in-situ production therefore struggle to make the formidable leap from the pilot stage to the first large commercial investment. That said, there has been a major shift in recent years, accelerated by the low oil price impetus, where a few long-promised production technologies are nearing commercial viability.

The bulk of in-situ oil sands technologies fall into the following categories:[33,34]

- **Production:** Methods of producing bitumen, in-situ, from oil sands
- **Upgrading:** Methods of increasing heavy bitumen API to approach pipeline specification
- **Steam generation:** Methods of producing steam and managing the heat cycle
- **Environmental impact alleviation:** Water and wastewater treatment, land impact, etc.

Production technology (1): Solvent-steam

Potentially the most commercially ready oil sands production technology that has not yet been deployed at scale, the addition of hydrocarbon solvents (a natural gas liquid such as propane, butane, or a mixture) to the steam in SAGD operations has such appeal that at least nine different producing operations have been testing it.[35,36,37] Once added, the natural gas liquid is vaporised and releases heat much like the steam in SAGD. In addition, the solvent acts as a thinner through a chemical effect — diluting and mobilising the bitumen so that it can travel more quickly and at lower temperatures than SAGD.

The advantages of adding solvent have been touted for roughly two decades and are difficult to disregard. Because of the enhanced production, substantially less steam is needed per barrel of production, reducing upfront and sustaining capital costs of steam plants by perhaps 25–40%. The

[31] 'Robert Skinner Assesses The Technological Challenge Of Producing Heavy Oil', *The Oxford Energy Forum*, no. 86 (2011): Pages 20–23.

[32] Wayne Patton et al., *Steam Assisted Gravity Drainage (SAGD): A Unique Alberta Success Story With Implications For Future Investment In Energy Innovation* (University of Calgary: Institute for Sustainable Energy, Environment and Economy, 2006).

[33] Business process technology such as the improved use of big data and information technology is omitted here, though was incorporated in the *Transforming into a true 'manufacturer'* section.

[34] For a broader discussion and summary of oil sands technologies, see J. Peter Findlay, *The Future Of Canadian Oil Sands* (Oxford Institute for Energy Studies, 2017), and the Canadian Energy Research Institute paper in the below footnote, which provides a more detailed technical summary of current technologies.

[35] Wedge Wells™ (Cenovus, others) and injecting non-condensable gases (MEG Energy) have already been deployed with some success, though do not likely have as wide an application.

[36] Canadian Energy Research Institute, *Economic Potentials And Efficiencies Of Oil Sands Operations: Processes And Technologies*, Study No. 164, 2017.

[37] Producers use different names for their proprietary solvent-steam technologies such as SA-SAGD (Imperial), SAP (Cenovus), eMVAPEX (MEG Energy), and E-SAGD (ConocoPhillips).

solvent also works to partially upgrade the bitumen in-situ, even shaking off some heavy asphaltenes, such that less bulky and costly diluent is needed in order to meet pipeline specific gravity and viscosity specification. There is a sizeable reduction in GHG emissions as the solvents are not derived from natural gas combustion, like steam. Furthermore, it is believed that in the long-term, overall recovery per well will increase as operators can produce for longer at lower steam-to-oil (SOR) ratios.[38]

The major drawback of injecting solvents is that they are costly and not all easily recovered from the reservoir, a problem known as 'solvent hold-up.' As the technology develops, however, hold-up is being addressed, and thanks to the shale gas boom and glut of natural gas liquids in the Western Canadian Sedimentary basin, solvent looks to be rather affordable for the foreseeable future. As an indicative example, investment bank CIBC estimates that Imperial Oil's SA-SAGD process can reduce the WTI supply cost by $11 per barrel (at a 15% rate of return), and projects could be online within 2-3 years.

Production technology (2): Pure solvent

The pure hot solvent production method pioneered by technology firm NSOLV has less promise for commercialisation at a large scale within the next couple of years, but has demonstrated enticing benefits and holds more potential to be a truly disruptive in-situ technology.[39] A promising pilot was recently completed a Suncor property, producing more than 125,000 barrels of oil while generating very little greenhouse gas emissions and using no water.[40] The technology obviates the need for water, natural gas, and complex steam generation facilities, while reducing GHG emissions by over 80% and upgrading bitumen from an API of 8–9 to 14–15 degrees (lessening the need for diluent by roughly half). In addition, the lower pressure and temperature operating conditions of pure solvent production, allows access to a much wider array of reserves than traditional SAGD, and could foreseeably unlock billions of barrels of additional reserves for exploitation in the 'donut' of resource too deep to mine and too shallow for steam injection technologies.

Though there is concern over the solvent hold-up issue, and the successful pilot has not yet been tested at longer, commercial SAGD well lateral lengths, the more daunting challenge facing the viability of this technology is the reluctance of major producers to build a project of sufficient scale without more costly piloting. Nevertheless, the production economics seem to favour a pure-solvent process (CIBC estimated a $19 per barrel WTI supply cost reduction to $49 at a 15% rate of return without even accounting for the value of reduced GHG emissions). These economics are more compelling than just adding a 'booster' to the standard SAGD approach, and could very well be a step-change for the economic and environmental character of the oil sands. Calls abound for a government assisted, large-scale commercial pilot similar to the one that actuated the commercialisation of SAGD, back in the 1980s, to spur further commercial investments.

Other production technologies

Proposals leveraging electromagnetic heating (Suncor) and the use of surfactants (Cenovus) are being piloted with decent results, though are generally considered as less attractive than adding solvents, in the near term anyway.

In the academic realm, the University of Calgary received a sizeable grant in the fall of 2016 to research ways to more efficiently develop Canada's oil sands. The research will focus on technologies relating to well design that use cloud data mining to optimise well configuration, design, and placement in the reservoir by reservoir type, and better understand reservoir geometry. They are

[38] CIBC World Markets, *Visibility For Economic Oil Sands Growth In A US$50/Bbl World*, Oil Sands Technology Update, 2017.

[39] Imperial oil is also experimenting with a solvent-only production process, though it is more similar to the cyclic-steam-stimulation (CSS) than SAGD

[40] CBC News, "'Shifting The Paradigm': Calgary Company Touts Pilot Project That Yields Heavy Oil With Low Emissions", 2017, http://www.cbc.ca/news/canada/calgary/nsolv-pilot-project-success-1.4012709.

also looking at various technologies to control steam distribution along a well pair to optimise steam chamber start-up and growth. More audaciously, they are researching the use of nanoparticles and alternative methods of mobilising the bitumen from the reservoir.[41]

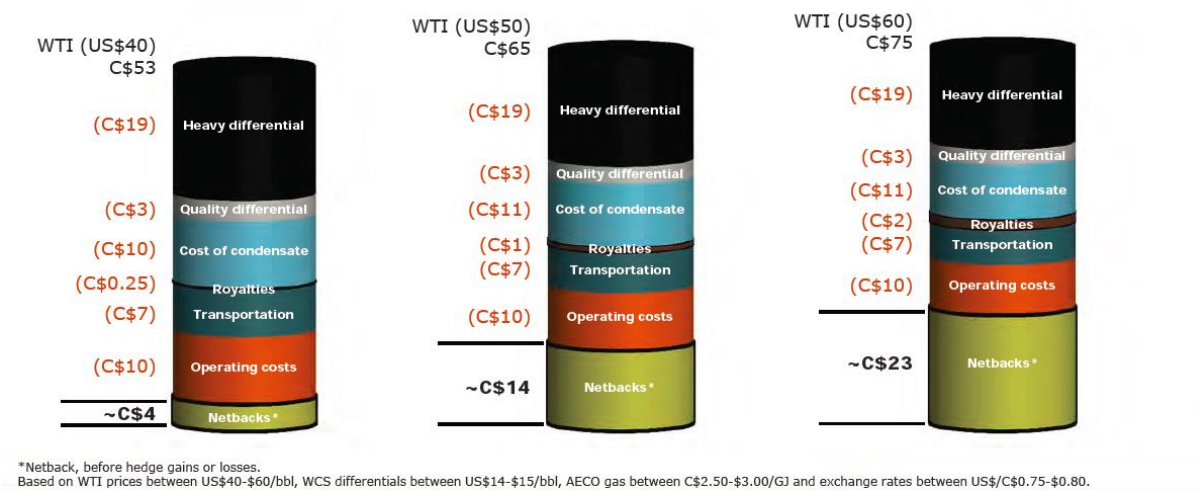
Steam generation technologies

New steam generation technologies show promise in lowering energy costs, water usage, and GHG emissions for the SAGD process, something that could prove critical as the use of SAGD grows, and Canada's oil sands producers as an aggregate are charged with keeping emissions under 100 Megatonnes (Mt) of GHG per annum (current emissions are roughly 70 Mt).[42] Direct Contact Steam Generation (DCSG) is one of the more promising ideas and looks to be 4–5 years away from commercialisation. Rather than using traditional heat-exchange mechanisms, DCSG involves direct contact of the combusting flame with the feedstock water, such that the resulting steam contains the carbon dioxide by-product, which is injected into the subsurface. The benefit is that the carbon dioxide enhances bitumen production, and stays either sequestered in the reservoir, or can be separated out at the surface — essentially eliminating greenhouse gas emissions from the SAGD process, certainly a disruptive technology enabling oil sands growth. Further development is needed to lower costs, but the outlook is encouraging.

(Partial) upgrading technologies

Any technology that can economically upgrade bitumen, even partially by 5–10 degrees API or more, is a 'holy grail' for producers — it would act to offset the netback-destroying Canadian heavy oil discount. **Figure 4** demonstrates the heavy price differential and condensate cost headwind that Cenovus, by far the largest SAGD producer, confronts. (Note that the 'Netbacks' shown are expected to cover capital and corporate costs, then generate full-cycle profits to distribute to impatient shareholders.)

Figure 4: Cenovus SAGD Netbacks (Illustrative)



Source: Cenovus Corporate Update, April 2017

Because the economic viability for new traditional, full upgraders is not currently propitious, adding value to low-API bitumen within Canada requires substantially improved upgrading technology,

[41] Robert Skinner, Advisor Energy Research, Office of VP Research, University of Calgary

[42] Government of Alberta (http://oilsands.alberta.ca/FactSheets/Reclamation_FSht_Sep_2013_Online.pdf, 2013).

especially that which can be deployed on smaller scales.[43] A number of promising technologies, featuring a mix of thermal, mechanical, and chemical processes, are in the development stage, with growing indications of commercial viability. The challenge is that these technologies must demonstrate highly compelling economics, at a scale small enough that producers are willing to risk scarce capital. Moreover, with newly enacted carbon-tax laws in Alberta that will see greenhouse gas emissions taxed at a rate as high as CAD$30 per tonne, and oil sands overall emissions limits capped at 100 MT per year, these technologies' concomitant GHG emissions do not help their chances of being adopted. That said, some of the proposed technologies only add marginal amounts of additional GHG emissions considering the value increase of the upgrade. Furthermore, subsurface production processes are becoming less emissive with solvents and other technologies, and the 100 MT annual cap will be difficult to enforce (if it is not abrogated by a more industry-friendly government). Ergo, it is unlikely that the GHG emissions of promising partial upgrading technologies will be the factor that stymies their commercialisation.

The stubborn discount on Canadian bitumen

The production of bitumen alone seems economically attractive enough. The Canadian Energy Research Institute estimates in its 2017 report that, after recent reductions, the full-cycle supply cost of producing bitumen from a new SAGD project is roughly $32 (CAD$43) per barrel of bitumen, including an economic return and without the full benefit of new design standardisations.[44] Alas, the costly burden of 'getting to WTI' is what continues to ail producers. This involves blending the sulphur-laden, 8–9 degree API produced bitumen with costly diluent to reach pipeline heavy oil specification at roughly 21 degrees API, then having to transport the blend, where the diluent volume is along for a costly ride, either along bottlenecked pipelines or by economically inefficient rail, only to receive a further discount to WTI at the faraway refinery. This refinery gate discount is due to the low API, high-sulphur content, and total acid number (TAN) of WCS, not to mention the loss in value of the diluent at the US refinery where condensate sells for less than in Northern Alberta, due to the US LTO boom.[45,46]

In aggregate, this blending and transporting of bitumen from the oil sands to the refinery gate currently accounts for around $30–35 per barrel of production, approximately half of the total supply cost of a greenfield SAGD project, estimated between $55-70 (depending on the performance improvements and cost efficiency assumptions).[47] Indeed, this high cost of blending and the ongoing WCS-WTI differential impedes oil sands producers.

Blending costs: Increasing the API

Condensate was trading at a price well above WTI in Alberta during the growth boom, though that differential has recently evaporated due to increased, low-cost LTO production in Alberta and improved pipeline access to US LTO. There is little promise of a further decrease, however, and notwithstanding the promising, if unproven upgrading technologies referred to in the last section, there

[43] Even before the oil price crash, Suncor and others have shelved plans for new upgrader builds. The most recent, and soon-to-be operational North West Partnership's Sturgeon Refinery / Upgrader required substantial Alberta government subsidies, derided by some taxpayer groups as a boondoggle.

[44] Canadian Energy Research Institute, *Canadian Oil Sands Supply Costs And Development Projects (2016-2036)*, Study 163 (Calgary, 2017).

[45] One standard for the blend of diluent and oil sands bitumen is the Western Canadian Select (WCS) benchmark, a heavy, sour blend with an average API gravity of 20.8 and sulphur content of 3.5%. (Compare this with Mexico's Maya crude with 21.8 average API and 3.3% sulphur.)

[46] Bitumen can be mixed with condensate at a roughly 70-30 product to diluent split to create 'dilbit' (of which WCS is a type), or mixed with Synthetic Crude Oil (SCO) that emanates from oil sands upgraders, in a roughly 50-50 product to diluent split to create 'synbit', which has a similar API to dilbit, but contains less sulphur.

[47] The supply cost for a new SAGD project is estimated by CERI at $61 per barrel (at 12% return), CIBC at $68 per barrel (at 15% per barrel), and by IHS at between $55–65.

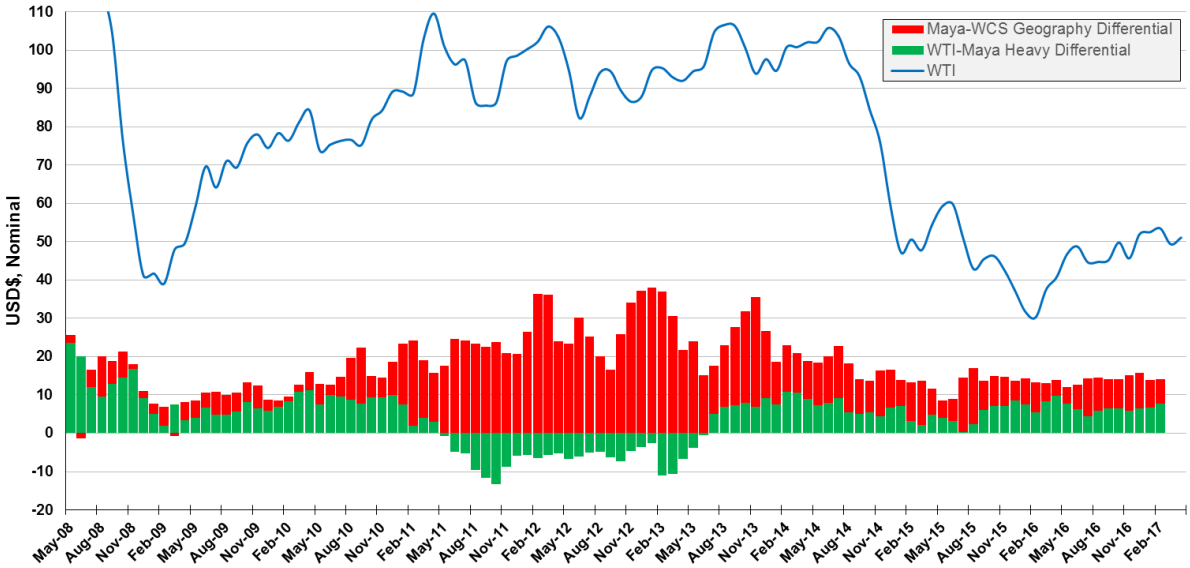
is only so much producers can do to reduce the price of blending to a pipeline specification of 20 degrees API.

Transport costs: WCS-WTI differential and pipeline politics

Oil sands producers have faced a WCS discount to WTI of around $11–14 per barrel over the past couple years, and even more to Brent thanks to that benchmark's premium over WTI due to burgeoning US LTO supply and OPEC cuts (though recently assuaged by new US pipeline capacity and a lifting of the US ban on exporting oil). This is driven by the heavy and sour nature of WCS and its landlocked origin, which is periodically constrained by inadequate pipeline capacity. **Figure 5** highlights the combined effects of the heavy discount (represented by the differential between WTI and Maya, a heavy oil produced in Mexico of similar quality as WCS), and the geography discount (represented by the differential between Maya and WCS).[48]

Starting in 2011, the US found itself in an oil value-chain predicament that midstream traders revelled in; they had an overabundance of newly refurbished heavy oil refining capability (based on the consensus in the 2000s that North American oil production would become increasingly heavy). This was coupled with an unexpected supply glut of very light oil from shale plays. From **Figure 5**, we see that this led to an atypical premium (rather than discount) on nearby Mayan heavy oil for several years when compared with WTI, which did not abate until 2013, when the heavy discount regressed to a $5–7 average from 2013–17 — reflective of the extra cost of processing heavy, sour oil.

Figure 5 WTI vs. WCS and Maya Differentials



Source: Bloomberg

While Mexico (and Venezuela) reaped the rewards of this imbalance, Canadian oil sands producers watched wistfully as their profits were eroded by the massive WCS discounts from Maya (and WTI), caused by a bottleneck from Alberta to US refineries. For the three-year period between 2011 and 2014, the Maya-WCS geography discount averaged $24 per barrel, peaking at over $40 per barrel in January 2013. Thanks to the advent of large-scale transport by rail, a decline in Alberta conventional production, and some incremental, though not transformational, capacity addition downstream in the

[48] Maya is marginally lighter and sweeter than WCS at 21.8 degrees API and 3.3% sulphur, versus 20.9 and 3.5%, respectively, though has a substantially lower TAN of roughly 0.4 vs WCS, which is approximately 1.0.

US pipeline network, the geographical discount for the oil sands (from Maya) has decreased to an average of $8 per barrel, over the past two years.

The WTI-WCS differential will likely continue to fluctuate around its recent average range of $11-14 per barrel at these crude prices, though industry analysts foresee an increasing discount in the coming years — higher oil prices tend to exacerbate the discount, which averaged 20–30% of WTI since 2011. The oil sands alone are slated to add over 0.4 mb/d of production by 2020, while even a mild price upswing would spur conventional and LTO production in Western Canada to bounce back from its 0.3 mb/d decline since the price crash and even push higher.[49] Fortunately, the capability of the rail network to handle large quantities of crude oil is more developed today than in 2011, which will act to cap escalating discounts, likely below $25 per barrel.

Cognisant of this history and the future production outlook, it is clear that without new pipeline capacity, oil sands producers, not to mention Albertan and Canadian governments, will continue to forgo billions of dollars of lost revenue every year because of asphyxiated market access.[50] This clash of ideals — economic growth and efficient distribution of energy versus environmental impact reduction and adhering to expectations for climate change progressivism — is at the root of *pipeline politics*.

Pipeline politics pervades Canadian, and to a lesser extent US, political discourse. Much of the Canadian public are familiar with proposed pipeline names like Keystone XL, Trans Mountain, Energy East, and Dakota Access — a phenomenon that is essentially unique to North America and our current times. Canadian Prime Minister Justin Trudeau, during the election in the fall of 2015, touted his ability to bridge the gap between oil sands proponents and detractors, by reassuring Canadians and the world alike, that environmental progress would not be compromised as Canada strives to transport its hydrocarbon products to global markets. As first noted by this institute in early 2016, Trudeau faces a challenging task: no major egress pipelines, either to the United States or to tidewater for tanker shipment, have been built in recent years and the average review process for new pipelines is more than 5 years.[51] (Meanwhile, more than 10,000km of hydrocarbon pipelines have been laid in the US.) Legal challenges, indigenous community appeasement requirements, and environmental protection conditions imposed on midstream companies like Enbridge, Kinder Morgan, and TransCanada, err towards being prohibitively onerous, to appease myriad vocal opposition groups.

The recent federal approval of Kinder Morgan's Trans Mountain pipeline, which adds 0.59 mb/d to the current pipe that transports 0.3 mb/d, and Donald Trump's presidential approval of the Keystone XL pipeline, slated to add 0.83 mb/d, is promising news, though each pipeline still faces stout opposition and regulatory hurdles.[52] The oil sands are unlikely to have significant takeaway capacity increases until 2020 or beyond with the Trans Mountain Expansion now aiming for a December 2019 in-service date, as a best-case scenario. Despite this pipeline capacity shortage, it is important to remember that there is roughly 1 mb/d of rail capacity available, and although the transportation costs are higher, economics demand that oil sands production *will* go to market one way or another, even at lower prices.

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[49] "CAPP Crude Oil Forecast, Markets & Transportation - Production & Supply Data", 2017, http://www.capp.ca/publications-and-statistics/publications/302698.

[50] US President Barack Obama vetoed the Keystone XL pipeline in 2015, an act that appears to violate their North American Free Trade agreement with Canada, with questionable claims that 'moving forward with this project would significantly undermine our ability to continue leading the world in combatting climate change.' This statement discounts that the US State Department had concluded that the pipeline would be unlikely to alter greenhouse gas emissions.

[51] An excellent summary of obstacles to approval and construction that midstream companies face, as well as the current timeline of pipeline proposals is given by Kevin Birn, *Pipelines, Prices, And Promises: The Story Of Western Canadian Market Access*, Canadian Oil Sands Dialogue (IHS Markit, 2017).

[52] Despite Canada already having some of the most onerous regulatory conditions in the world for energy infrastructure, the Trudeau government is planning to increase, rather than streamline, the regulatory burden on these and future projects, though proclaims his ardent support of them.

If several of these pipeline projects are approved and constructed (say the Trans Mountain Expansion and Keystone XL), and more than ample capacity becomes available, oil sands producers could see a decrease in the roughly $8 discount to Maya heavy, to maybe $3–4. More importantly, investors and executives would stop pinpointing market access as a prohibitive risk when deciding whether to fund new projects. Only then, can sizeable new growth projects return to the oil sands.

Bullish or bearish?

Since the 2014 price collapse, financial media have leaned towards a pessimistic view on future attractiveness and growth prospects in the oil sands. The cooling off of integrated oil company enthusiasm for the oil sands (Shell, Total, ConocoPhillips, and Statoil have redirected substantial capital) provides easy fodder for analysts and journalists trying to extrapolate an underlying industry trend. Though CNRL stock saw an increase in value after purchasing Shell's assets, markets rebuked Cenovus' $13.3 billion buyout of its SAGD joint venture partner ConocoPhillips, with an immediate 14% decrease in share value; CEO Brian Ferguson soon thereafter announced his resignation.[53] Detractors argue that the oil sands are the world's most expensive marginal barrel and a unique environmental pariah.

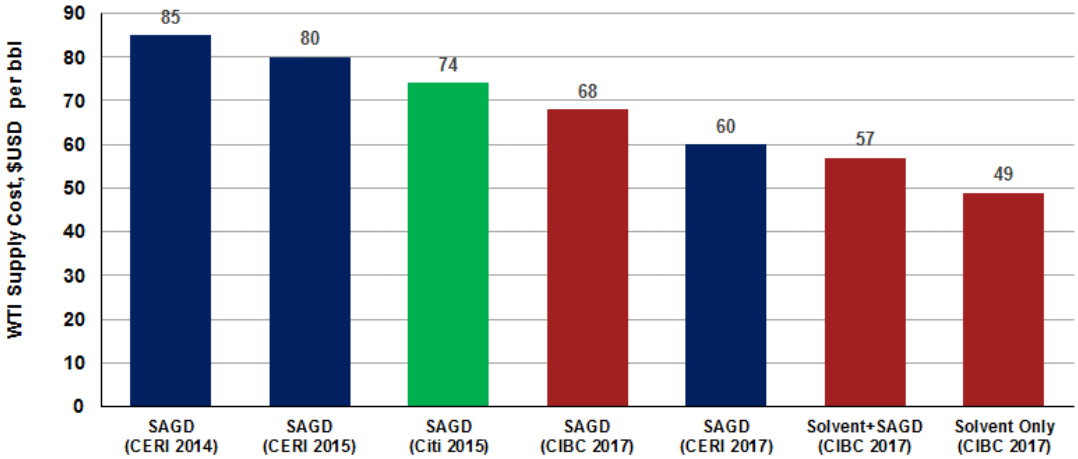
Even so, these notions are really oversimplifications of a more nuanced and complex story. Certainly, oil sands costs escalated relentlessly from the ramp-up in the early 2000s through 2014. Yet recent cost reductions are impressive, due to (in decreasing order of magnitude): decreasing differentials, a lower Canadian dollar, lower operating costs, lower capital costs, lower natural gas costs, and lower condensate costs for diluent. **Figure 6** highlights this trend, hinting at the likelihood in coming years of sub-$50 per barrel WTI supply costs, at least for the higher quality reservoirs[54]. With their backs against the wall and shareholders clamouring, producers are consolidating and adapting as they have in previous downturns to become lean manufacturers. Suppliers and the labour market are starting to follow suit, further driving down costs with more competition and less rent-seeking than during the boom years. And though oil sands production is far from being environmentally innocuous, the visually unappealing open face mines are being reclaimed and greenfield projects have halted, while the lower-land impact, but higher-emitting SAGD operations are becoming less carbon intensive — stimulated by carbon pricing incentives to improve energy efficiency, and the use of solvents and new steam generating technologies. These advances could eventually even help oil sands production become one of the world's lower emitting sources of crude oil production. Currently emitting roughly 70 MT of GHG per year, the oil sands comprises roughly 0.13% of global emissions, and when considering this with the recently announced government imposed cap of 100 MT, the basin has never been, is not, and never will be itself a material contributor to global emissions.[55]

[53] Investors simultaneously rewarded the larger ConocoPhillips by an increase in their share price of roughly 8.5% for diverting capital from the oil sands.

[54] Not all oil sands leases were created equal. The highest quality reservoir tends to occur in the area amenable to mining and in a 'corridor' along the eastern edge of the Athabasca oil sands royalty region. See map on AER's website.

[55] Environment Canada, 2016

Figure 6: Estimates of Breakeven Costs including 12-15% return (2015-17)



Source: Citi Research, CIBC World Markets, CERI

Whether one is bearish or bullish on oil sands growth then, is a matter of perspective. The international energy community, including the major IOCs and foreign national oil companies, exhibit bearish behaviour as North America continues to drown in light tight oil, restraining regional and global prices. (Remember that these IOCs and NOCs are not completely pessimistic — many retain a foothold of some kind.) Such large players tend to follow production trends rather than start them. Canadian-based oil sands bedrock producers like Suncor, Cenovus, CNRL, and Imperial Oil are, at least to some extent, doubling-down on their oil sands investments, betting that their cumulative years of experience pioneering and developing oil sands manufacturing, as well as their recently acquired increased scale, will help them compete with other global plays. This approach proved successful in the 1990s and early 2000s, when they developed production technologies and expanded production rather impressively amid low oil prices, before the rest of the world rushed in. Such countercyclical investments, though difficult to stomach at the time, have historically proven fruitful, especially since oil sands projects show little to no decline (unlike their short-cycle LTO capital competitor and equally capital-intensive, long-cycle deep water plays). Some executives and Canadian industry insiders are more bullish, proclaiming that the oil sands are primed to deliver the scale of technical improvements seen in the Permian basin and other US LTO plays, citing the innovation and cost-cutting efforts among the remaining four major Canadian producers. In reality, however, though oil sands producers are indeed becoming more efficient, the direct comparison to LTO players is misguided. These two sources are for the most part dichotomous, with fundamentally different operations and lifecycles. They produce grades of crude at opposite ends of the API spectrum and do not compete with each other at the refinery gate. They are also governed by antithetical investor types — a rapid growth focus versus a preference for long-term cash flows and dividends.

To summarise, oil sands producers and investors have a number of reasons to feel sanguine. Western Canadian producers operate under the highest environmental standards of any major oil basin in the world, with extensive carbon taxes, levies, carbon emissions caps, methane emissions rules, water use restrictions, and wildlife protection regulations. Capital supply is reliable — Canada offers stability to investors concerned with geopolitical risk.[56] Rapidly falling costs, streamlined designs and operations, labour and supplier availability, technological improvements, environmental impact reduction, and (eventually) new exit pipeline capacity, all point toward some level of continued

[56] Eurasia Group's Robert Johnson noted in May 2017: "Number one, and this probably reflects my bias as a political scientist, I think capital will go to politically-stable climates. We can talk about what countries those are, but I would argue Canada is very high on that list."

growth in the oil sands: research groups are estimating roughly 3.1–3.3 mb/d by 2020, with a projected increment of 1–2 mb/d from 2020 to 2030. Some more bullish scenarios forecast as much as 3 mb/d of incremental growth. Suncor alone has announced projects totalling 0.4 mb/d of new output over the next decade, while Cenovus is signalling it plans to restart several of its more defined, previously shelved projects, to be completed even sooner.[57] That said, what is most vital for prosperous oil sands growth, is that the cornerstone Canadian-based producers demonstrate success in driving down full-cycle production costs, even beyond what has been already accomplished and that the global oil price remains relatively robust.

[57] Nia Williams, "Cenovus May Restart Another Two Deferred Oil Sands Projects", 2017, http://ca.reuters.com/article/businessNews/idCAKBN15V1E0.

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