



FLAWED FUNDAMENTALS

SHELL'S AND BP'S STALLED TAR SANDS AMBITIONS



EXECUTIVE SUMMARY

In the context of shrinking access to conventional oil resources, Alberta's tar sands were presented in the late 2000s by the oil industry as a glittering prize. The Canadian tar sands represent about half of the world's total oil reserves that are available to international oil companies (IOCs). They are the third-largest known reserves in the world, after Saudi Arabia and Venezuela.¹ Combined with a politically favourable operating environment – until 2015 both federal and provincial governments gave unqualified support – the tar sands were presented as a long-term growth opportunity for the industry.

However, since 2014, 42 tar sands projects have been put on-hold, delayed, or cancelled (see Appendix 1). These projects include the cancellation of Shell's Carmon Creek project after the final investment decision, and the postponement of Phases 2A and 2B of the BP/Husky joint venture Sunrise project.

These cancellations and delays are not, despite mainstream industry commentary,² due solely to the fall in global oil prices but instead to a combination of factors including lack of market access infrastructure, the gathering momentum to implement measures to reduce carbon emissions at a regional, national, and global level, and mounting public opposition on climate change grounds. In other words, the reasons for stalled growth in the tar sands suggests structural rather than cyclical challenges for the industry.

In 2010 BP and Shell dismissed shareholder concerns about the assumptions underpinning their Canadian tar sands operations about fundamental issues such as long term oil price stability, Indigenous groups' and local community opposition, and increasing regulation on GHG emissions. Fast forward 6 years and such shareholder concerns have been vindicated. Shell's plans for expanding its tar sands operations have moved into the realm of mere "ideas" according to CEO Ben van Beurden speaking at this year's AGM.³ Despite BP claiming as recently as December 2014 that Sunrise Phase 2 and Pike would also be producing by 2020 and that all three of its projects were growth opportunities to 2020 and beyond,⁴ Bob Dudley stated in April 2016

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that "[BP] have one oil sands project. It is very questionable whether we'll have any more".⁵

This report examines the combination of factors that have led to this reappraisal of once priority projects at BP and Shell. In doing so, we encourage investors to scrutinise what those factors mean more widely for the high-cost growth model of the IOCs. The report also examines the potential economic viability of Shell and BP's planned – but not yet under construction – tar sands projects. We suggest questions for investors to ask Shell and BP in order to understand their plans for their tar sands assets. We also suggest questions to assess the companies' understanding of and preparedness for the wider impacts of shifting conditions in the oil industry.

BUSINESS MODEL UNDER THREAT (SECTION 1)

While the industry might wish to paint the oil price plunge since 2014 as a cyclical storm to be waited out, the reality is that there are fundamental structural problems with the IOC business model, which predated the price crash, and which the crash simply put into stark relief.

Increasing national resource sovereignty has forced IOCs to pursue ever more financially, technically, and geographically extreme forms of oil and gas extraction including the Canadian tar sands. IOCs are therefore forced to compete for market share against more accessible, cheaper oil under the control of national oil companies. This high-cost strategy depends on continuing growth in oil demand and sustained high oil prices.

From 2000 to 2014 exploration expenditure increased fourfold, while discoveries followed a steady downward trend.⁶ As noted by one commentator, "this inherent flaw in the oil companies' business model was disguised for the past 40 years by the fact that oil prices rose even faster than the costs of exploration and production".⁷ However, high prices were not enough to completely offset the decline in returns: analysis of 80 oil and gas companies by IHS Energy found that return on average capital employed (ROACE) fell from above 20% in 2006 to just 9% in 2013, while the oil price rose from about \$70 to over \$100.⁸

All of this comes on top of the existential threat posed to the industry by climate risk whether in the form of transition, regulatory, and/or liability risk. A significant source of uncertainty for the oil industry is the potential for disruptive technologies – such as electric vehicles – to transform the oil market.⁹ The dependence of IOC's business models on continuing high oil demand represents a gamble on the world's policy-makers failing to tackle climate change. This is an increasingly high-risk bet in light of the momentum created by the Paris Agreement and the rejection of Keystone XL specifically on climate grounds. Tar sands are uniquely exposed to such risks, given the long timescales of projects. Relying on these types of oil plays means betting that there will be no serious climate policy or disruptive technology, not just in the next 10 years, but for decades to come.

2 Commentators are now discussing “concern about the demise of the IOCs¹⁰ and questioning whether their business model is “fundamentally flawed”.¹¹ A recent FT leader noted, “the message is one that is always hard for investors and management teams to hear: room for growth is tightly constrained, and in the long term output will have to fall rather than rise”.¹² This has led to calls from commentators and investors for oil majors including Exxon and Chevron to reweight corporate capital allocations towards increased dividends and share buybacks. Some have gone as far as suggesting that they largely give up on growth altogether.¹³

BP AND SHELL’S TAR SANDS OPERATIONS (SECTION 2)

Each of BP and Shell have operating tar sands assets. However, both companies also have planned projects which are currently stalled (Section 2). While Phase 1 of BP’s joint venture Sunrise project is producing, subsequent phases have not proceeded. The company describes its Pike project, operated by Devon Energy, as being at the design stage while Terre de Grace, which is planned to be BP-operated, is currently under appraisal for future development. As recently as December 2014, the company had hoped to see Sunrise Phase 2 and Pike producing by 2020 and was describing all three of its projects as growth opportunities to 2020 and beyond.¹⁴ In addition to its cancellation of Carmon Creek,¹⁵ Shell has placed its Pierre River project on indefinite suspension. The company also confirmed that it has no plans at this time to proceed with its intended Muskeg River expansion and Jackpine Mine extension projects.¹⁶

CANCELLED AND POSTPONED PROJECTS (SECTION 3)

Since 2014, 42 tar sands projects have been put on-hold, delayed, or cancelled (Appendix 1). These include BP’s Sunrise project phases 2A and 2B and Shell’s Pierre River and Carmon Creek projects. The narrative in the media and among industry commentators is that this is due solely to the fall in oil prices, and that once prices recover the sector will bounce back. While oil prices are an important factor in capital expenditure decision-making, the current price environment has exposed more structural weaknesses within the tar sands industry, including the reality that pipeline access to new markets is critical for industry profitability.

In this report we use economic analysis to model the companies’ decisions, in order to consider the extent to which other factors including market access restrictions played a role in those decisions.

Our analysis (Section 3) shows the mainstream narrative, asserting that low oil prices are the only cause of tar sands project delays and cancellations, is inaccurate. More than half of the projects analysed could still have been viable under post-crash price expectations: it was lack of pipeline access that pushed them over the edge, as the additional cost of rail rendered these projects uneconomic.

Of the 42 cancelled, delayed or suspended projects, we analyse 27 (data is unavailable for the remaining 15). We assume that companies will decide to proceed with projects where Internal Rate of Return (IRR) exceeds 10% and reject those with an IRR below 10% (in real

terms). While in reality the threshold is not a precise cut-off in that way, like in any model the process is simplified. In reality, companies will consider several oil price scenarios, assigning a likelihood to each to assess upside and downside risk in a project – and the precise approach will vary from company to company. To simplify, we use a single, “most-likely” price forecast, for which we simulate company expectations using the Energy Information Administration’s price forecasts.

The question we are using the model to answer is:

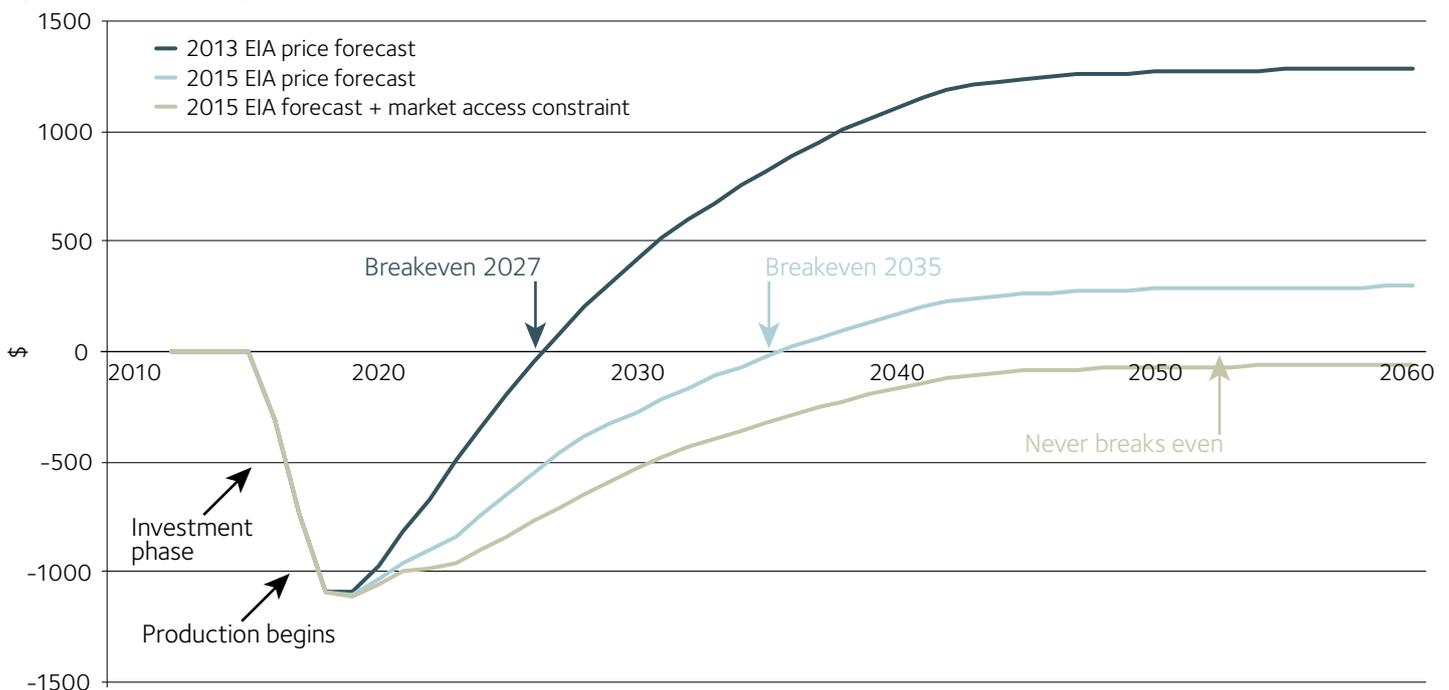
“Under a most-likely price forecast, does the price drop alone move a project from being commercial to uncommercial, or only in combination with lack of pipeline access to markets?”

This assessment is based on three scenarios:

1. a higher oil price forecast from before the crash (EIA 2013) (“2013 Price Scenario”)
2. post-crash price expectations but pipeline availability (EIA 2015), (“2015 Pipe Scenario”)
3. with post-crash price expectations and no new pipelines; (“2015 No Pipe Scenario”).

For scenario 1, we use the EIA’s price forecast published in its 2013 Annual Energy Outlook, which had prices rising steadily throughout the period, reaching \$133 per barrel by 2030. For scenarios 2 and 3, we use its forecast published in 2015, which accounts for the recent price crash and sees the price taking until 2028 to climb back to \$100 per barrel.¹⁷ We also factor in the price differentials at which tar sands crudes sell.

Figure 1: Sunrise 2A project cumulative discounted cash flow (real, discount rate 10%) Source: Rystad UCube, Oil Change International model



All 27 projects we analysed are commercial in the 2013 Price Scenario. We interpret the causes of delays as follows:

- ☒ Project is uncommercial in 2015 Pipe Scenario: price drop alone was sufficient cause for delay.
- ☒ Commercial in 2015 Pipe Scenario but uncommercial in 2015 No Pipe Scenario: it was market access that tipped the project over the edge.
- ☒ Commercial in all 3 scenarios: other reasons were at play.

The project-by-project results are shown in Appendix 1. Of the 27 projects we assessed, we found that 14 – including BP’s Sunrise and Shell’s Carmon Creek – are rendered uneconomic by the combination of 2015 oil prices and the additional cost of rail. These projects are associated with over 60% of the reserves held in all 27 projects.

An additional eight projects are uneconomic under the current oil price scenario with or without additional pipeline capacity. In other words, these projects fit within the mainstream view that it is low oil prices alone affecting tar sands production growth rather than market access.

Finally, five of the projects were delayed for other reasons (the combination of lower prices and lack of pipelines did not push them into being uncommercial). For example, these might include a shortage of company cash flow, or a desire to prioritise other projects. See Appendix 1 for further details of each project’s status.

INDUSTRY PROJECTIONS – DECLINING BUT CONTINUED GROWTH (SECTION 4)

As both limited market access and lower oil prices have taken hold, forecasts for future tar sands production have shifted. The Canadian Association of Petroleum Producers has reduced its projection for tar sands production in 2030 in its annual flagship publication for four years running.

The downgrade for future growth has shaved over 1.6 million barrels per day (Mbpd) off the forecast, with the 2030 number shifting from 5.3 Mbpd in the 2013 report to 3.7 Mbpd in 2016 (see Figure 7).¹⁸ Nevertheless, the 2030 number is nearly 65 percent higher than today’s production level and would clearly require many new projects to be sanctioned by companies as well as additional pipeline capacity far beyond that which exists or is in construction today.

While forecasts for existing and in-construction projects represent reasonable expectations for production in the future, growth forecasts are speculative. The most recent industry forecasts for long-term growth are based on three questionable assumptions:

- ☒ **Market Access:** At least one of the major pipeline proposals receive approval and are built providing additional capacity within the next three to five years: the Kinder Morgan Trans Mountain expansion and/or Energy East pipeline.
- ☒ **Price Recovery:** It is generally assumed that after remaining low for the next one to three years, oil prices will see a gradual and continuous rise for the remainder of the forecast period.
- ☒ **Modest Regulatory Changes:** While it is recognized that the Albertan government is seeking tighter environmental regulations, it is generally assumed that neither it nor the new Federal government will impose measures that would substantively impact production growth.

MARKET ACCESS CONSTRAINTS (SECTION 5)

The tar sands in Northern Alberta are located a long distance from major crude oil markets. In order to proceed with a new project, companies need to feel confident that they will have affordable access to these markets. Until 2010, pipeline expansions and refinery conversions had marched in lockstep with tar sands production growth. However, no new pipelines have been built out of Alberta since 2010.

As well as Keystone XL, three other major new tar sands pipelines were proposed: Kinder Morgan’s Trans Mountain Expansion and Enbridge’s Northern Gateway, both running west to the British Columbia (BC) coast, and TransCanada’s Energy East to New Brunswick on the east coast.

Public efforts to delay and stop pipeline expansion have been successful, in that affordable market access required to stimulate future production growth is simply not in place.

With Prime Minister Trudeau’s opposition to Northern Gateway, just two major pipeline proposals (Kinder Morgan’s Trans Mountain Expansion and Energy East) remain, and both are also facing significant political, legal and public obstacles (see Figure 10). These proposed pipelines, which were originally designed to come after Keystone XL and deliver future production growth, now also

hang in the balance. In parallel with these efforts to build new pipelines, Enbridge has pursued incremental expansions to its existing Mainline system. While some expansions have occurred in recent years, new incremental additions too are now facing growing public opposition, especially in the U.S. Midwest. Much of this opposition is driven by concern for the climate and environmental impacts of tar sands expansion, as well as concern for the direct impacts on communities on the frontlines of development. It appears to have taken the industry by surprise. This successful opposition to fossil fuel projects and supporting infrastructure is being replicated globally.¹⁹

This report uses Oil Change International’s Integrated North American Pipeline model (INAP) to assess the surplus pipeline capacity for tar sands production (See Appendix 2). According to INAP, the system is about 89% full, at 4,000 kbd. We find that if no new pipelines are built there will be no pipeline space available for tar sands production growth beyond that which arises from the projects already under construction.

Tar sands production is set to grow for a few years even if no new projects are approved due to projects that are already under construction coming on stream. The reason for this is that building a tar sands project commonly takes five years or more, so extraction is currently growing due to projects that were approved on the assumption that market access constraints would be quickly resolved and pipeline capacity would become available.

Due to this locked-in growth, without any new pipelines, the export system could reach its limit as soon as 2018 (Figure 8). If proposed expansions of the Enbridge system (in Figure 10 below) are completed, this would add up to 300 kbd to the system, accommodating the committed growth but leaving no significant room for further growth beyond that.

When pipeline capacity becomes tight, sending tar sands crude by rail is an option. But it is not an option that producers can depend on enough to justify multi-billion dollar investments in new tar sands production. While the transport of tar sands by rail has grown in recent years, its potential is severely hampered by high costs and unreliable logistics.²⁰

The question is whether producers will invest in new production if rail is the only available transportation option, i.e. if pipeline capacity

4 is full and no new pipelines are being built. While there may be a few exceptions, where project costs are very low, and/ or where an integrated company can play upstream margins against refining, generally the additional cost of rail eats too far into already tight netbacks. Lack of pipeline capacity, and the resulting prospect of having to rely on rail, was a key factor behind at many of the delayed and cancelled tar sands projects (Section 3).

IMPACT SPECIFICALLY ON BP'S AND SHELL'S FUTURE TAR SANDS PROJECTS (SECTION 6).

If no new pipelines are built, there will be no pipeline export capacity for tar sands projects that have yet to break ground. We again use cash flow analysis to examine whether BP's and Shell's potential future projects might be able to proceed if rail is the only option available. We calculate the breakeven oil price – the flat West Texas Intermediate (WTI) price at which a project would achieve 10% IRR – for each of BP and Shell's projects, in two

scenarios: with the Kinder Morgan pipeline and with no pipelines built.

Even with a pipeline, breakeven prices are so high that while it is not implausible that oil prices could reach such a range in the coming years the projects would carry high risks of making losses if those prices do not persist. Over the long timeframes of tar sands projects, this leaves investors very exposed. In the event that no more pipelines are built, it is hard to imagine circumstances in which these BP and Shell projects could proceed.

Aside from the outliers of the cheaper Pike 1 and Terre de Grace pilot and the expensive Jackpine projects, BP and Shell's future projects generally have breakeven prices in the range of \$75-85, even if the Kinder Morgan pipeline is built. This is significantly higher than the vast majority of the world's proven oil reserves.

If forced to rely on rail, the projects' economics become even more stark. Apart from Pike 1

and Terre de Grace pilot, the breakeven price range increases to \$95-110 – around the levels reached during the high price years of 2008-14.

REGULATORY CHALLENGES (SECTION 7)

While higher global oil prices could offset increased transport costs or reduced local prices, stronger regulations could shift the economic balance back. Furthermore, they create additional time for legal efforts by First Nations and directly impacted communities in Northern Alberta to object to infrastructure projects in order to protect their traditional lands and treaty rights.

Improving project performance to reduce air pollution, water pollution, water use, land and habitat disturbance and greenhouse gas emissions intensity are all expected to increase marginal costs for producers, while pressure to cut costs from shareholders and investors continues to build.

Figure 2: Breakeven WTI price for future potential BP and Shell tar sands projects, with and without pipeline availability

Sources: Oil Change International model, Rystad UCube

	Product	With Kinder Morgan pipeline	No pipelines
BP			
Terre de Grace pilot	bitumen	\$67	\$88
Terre de Grace 1	bitumen	\$75	\$95
Terre de Grace 2	bitumen	\$73	\$93
Sunrise 2A	bitumen	\$74	\$93
Sunrise 2B	bitumen	\$75	\$95
Pike 1	bitumen	\$62	\$81
Pike 2	bitumen	\$78	\$98
Shell			
Carmon Creek 1	bitumen	\$80	\$100
Carmon Creek 2	bitumen	\$84	\$103
Muskeg River Expansion & Debottlenecking	SCO	\$87	\$98
Jackpine 1B	SCO	\$94	\$106
Jackpine Extension	SCO	\$98	\$109



No tar sands producer to date has been successful in meeting stated goals for managing tailings waste.^{21,22} In 2014, Shell admitted it had not made significant progress towards its targets and in 2015, the Alberta government suspended the target to allow producers more time to develop 'dry tailings' technology.²³ Shell Canada's then president Lorraine Mitchelmore implied that the cost of meeting the targets was a problem, noting that business units like Shell Canada were under pressure to cut costs to compete for capital investment.²⁴ Pressure to reduce costs continues, as new regulations have been put in place requiring companies to shrink their tailings ponds, reduce wastewater, and to clean up and restore mined land within ten years.

On 22 November 2015, the Alberta Government announced a new climate plan.²⁵ The plan includes a 100 megatonne per

year (Mt/y) cap on tar sands emissions, over the period 2020–30. Assuming constant emissions intensity, a 100 Mt cap would allow a further increase in tar sands extraction of 250 thousand barrels per day (kbd) – the equivalent of a large mine – beyond what is already under construction.²⁶ However, if industry is able to get halfway to achieving already stated goals for emissions intensity (respectively to existing/under-construction and to new projects),²⁷ the 100Mt/y cap could allow for more than 720 kbd of new production beyond what is already under construction.²⁸ If it achieved these targets completely (applying a 20% intensity-reduction target to all existing and under-construction projects, not just the largest ones), it would allow over 1.7 mbd of further growth.²⁹ It appears then that the cap will place a limit on further expansion; as for how much of a limit, it remains to be seen what changes occur in emissions intensity.

However, significant tar sands production growth beyond what is already under construction would require the adoption of new transformative technologies to reduce the current emissions intensity. There is little evidence to date that emissions reductions on the required scale will be possible. There have not been meaningful improvements made in average emissions intensity since 2005. The industry often repeats a misleading statistic: "Emissions per barrel have been reduced by 26 per cent between 1990 and 2011." However, all notable reductions happened before 2005 and average emissions intensity has stayed flat.^{30,31}

Questions for investors to ask Shell and BP on these issues are suggested at the end of each relevant section and brought together in the conclusion.

INTRODUCTION

While the circumstances for rapid expansion of the tar sands were favourable for the industry over the past two decades, there are clear signs that pro-expansion conditions such as unfettered market access, stable high oil prices, political and public support, growing U.S. demand and minimal regulatory constraints have shifted.

As a result of this combination of changing factors, all tar sands projects that have not yet broken ground should be considered economically uncertain at best. Therefore, beyond the projects that were already under construction by 2014, there is a de facto moratorium on tar sands production growth.

This shift represents a remarkable turnaround and a significant setback not only to those oil companies betting heavily on the continued expansion of Canadian tar sands, but also to the IOCs' high-cost, frontier driven growth model. IOCs and their investors face the prospect of the current fate of the tar sands becoming the template for the industry.

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It is crucial for investors to understand the matrix of risks that have stalled the predicted unchecked growth of the tar sands as they combine to suggest structural rather than cyclical changes in the oil industry.

This report:

- ☒ Outlines the factors other than the current oil price that have led to stalled growth in the tar sands.
- ☒ Focuses on BP's and Royal Dutch Shell's intended expansions of their tar sands operations in Canada and assesses their future commercial viability.
- ☒ Proposes questions that shareholders should ask of Shell and BP to understand their plans for their tar sands assets and to assess the companies' understanding of and preparedness for the wider impacts of shifting oil industry conditions illustrated by the fate of the tar sands.





1. BUSINESS MODEL UNDER THREAT

The plunge in oil prices since June 2014 – driven by US tight oil expansion, and reinforced by OPEC’s decision (led by Saudi Arabia) to maintain supply in order to protect current and future market share – has had significant impacts on the oil industry. In addition to the loss of approximately 250,000 jobs globally,³² in January Wood Mackenzie estimated £380 billion of delayed investments on 68 major upstream projects.³³

While the industry might wish to paint oil price volatility as a cyclical storm to be waited out, the reality is that there are fundamental structural problems with the IOC business model, which predated the price crash, and which the crash simply put into more stark relief.

Increasing national resource sovereignty in Latin America, the Middle East, and Russia has forced IOCs to pursue ever more financially,

technically, and geographically extreme forms of oil and gas extraction including the Canadian tar sands. IOCs are therefore forced to compete for market share against more accessible, cheaper oil under the control of national oil companies. This high-cost strategy depends on continuing growth in oil demand and sustained high oil prices.

From 2000 to 2014 exploration expenditure increased fourfold, while discoveries followed a steady downward trend.³⁴ Based on this big increase in expenditure, the majors for the most part sustained 100% RRRs during the period, largely by adding projects of ever lower value, propped up by high prices.³⁵ As noted by one commentator, “this inherent flaw in the oil companies’ business model was disguised for the past 40 years by the fact that oil prices rose even faster than the costs of exploration and production”.³⁶

However, the high prices were not enough to completely offset the decline in returns: analysis of 80 oil and gas companies by IHS Energy found that return on average capital employed (ROACE) fell from above 20% in 2006 to just 9% in 2013, while the oil price rose from about \$70 to over \$100.³⁷

The fall in prices pulled the plug on this high-spending model, and exposed the diminishing returns companies were delivering. 2015 saw the lowest level of exploration finds for more than 60 years.³⁸

Meanwhile, the shale revolution changed the dynamic of the oil market to one that might never again favour the high-cost mega-projects of the majors: when prices start to recover, the highly-responsive shale drillers are likely to up production, and thereby could put a ceiling on price.

Figure 3: Brent oil price, 1990 to date (nominal, monthly ave) Source: Bloomberg



All of this comes on top of the existential threat posed to the industry by climate risk whether in the form of transition, regulatory, and/or liability risk.

Commentators are now discussing “concern about the demise of the IOCs”³⁹ and questioning whether the IOC business model is “fundamentally flawed”.⁴⁰ A recent FT leader entitled ‘The long twilight of the big oil companies’ noted, “the message is one that is always hard for investors and management teams to hear: room for growth is tightly constrained, and in the long term output will have to fall rather than rise”.⁴¹ This has led to calls from commentators and investors for oil majors including Exxon and Chevron to reweight corporate capital allocations towards increased dividends and share buybacks. Some have gone as far as suggesting not only that companies emphasise returns to investors over growth, but that they largely give up on growth altogether. As Paul Sankey of Wolfe Research put it, “really the essence of the opportunity for oil is to be dividend stocks to pay out. Not to attempt to grow, but actually to orderly liquidate.”⁴²

QUESTIONS FOR BP AND SHELL

- ☒ What proportion of the company’s oil and gas reserves and resources require a break-even price in excess of \$60 bbl?
- ☒ In making final investment decisions for long-life projects what are your projections regarding long-term oil price?
- ☒ What assumptions underpin your projected oil price? e.g. level of electric vehicle and renewable energy penetration; climate policy; level of oil demand.
- ☒ Does the company stress-test the resilience of such projects against a range of demand and price scenarios including scenarios compatible with the goals of the Paris Agreement to keep global temperature increases to well below 2C with an ambition for 1.5C?

The dependence of the IOC business model on continuing high oil demand represents a gamble on the world’s policy makers failing to tackle climate change. This is an increasingly high-risk bet in light of the momentum created by the Paris Agreement and the rejection of Keystone XL specifically on climate grounds. A further significant source of uncertainty for the oil industry is the potential for disruptive technologies – such as electric vehicles – to transform the oil market.⁴³

Tar sands are uniquely exposed to such risks, given the long timescales of projects. Relying on these types of oil plays means betting that there will be no serious climate policy or disruptive technology, not just in the next 10 years, but for decades to come.

Investors must assess whether in this industry and regulatory environment expanding tar sands production is an appropriate allocation of shareholder capital or even a realistic prospect.



2. BP AND SHELL'S TAR SANDS OPERATIONS

BP

BP has an interest in three tar sands lease areas in Alberta: Sunrise, Pike and Terre de Grace, all of which are in-situ recovery projects. BP does not have any surface mining tar sands projects.

- ☒ Sunrise is a 50% joint venture with Husky Energy who is the operator. Phase 1 began production in 2015 and according to BP is currently producing approximately 20,000 barrels per day of bitumen. Four phases were originally planned and all four were originally intended to be in production by 2018.
- ☒ BP has a 50% non-operated interest in the Pike leases with Devon intended to be the operator. Pike Phase 1 was granted regulatory approval in November 2014. Engineering activities are under way to design and plan the construction of the first phase of development. Appraisal activities are ongoing to evaluate the remainder of the lease.
- ☒ BP operates and has a 75% interest in the Terre de Grace leases with Value Creation Inc. as partner. BP has conducted several summer and winter work programmes, consisting of environmental field studies, seismic exploration, delineation drilling and reclamation work. Terre de Grace is under appraisal for future development.⁴⁴

Despite BP claiming as recently as December 2014 that Sunrise Phase 2 and Pike would also be producing by 2020 and that all three of its projects were growth opportunities to 2020 and beyond,⁴⁵ Bob Dudley stated in April 2016 that "[BP] have one oil sands project. It is very questionable whether we'll have any more".⁴⁶

SHELL

Shell first started exploring for tar sands in the Athabasca region in the 1940s. It brought on stream the first in situ production at Peace River in 1979. Today it produces just 12 kbd there.

However, serious investment began in 1999 when Shell started to develop the Athabasca Oil Sands Project (AOSP) integrating the Muskeg River Mine and the Scotford Upgrader, and subsequently the Jackpine Mine. On a third mine within the project, Pierre River, Shell has withdrawn its application for regulatory approval of development, but maintains the lease. The AOSP is a joint venture operated by Shell and owned by Shell (60%), Chevron Canada Corporation (20%) and Marathon Oil Sands LP (20%), and currently produces 200 kbd of synthetic crude oil. It also includes the the Quest carbon capture and storage project, located at the Scotford facility.⁴⁷

Shell has confirmed that it has no plans at this time to proceed with its intended Muskeg River expansion and Jackpine Mine extension projects.⁴⁸

In 2014 Shell began construction of Carmon Creek, an in-situ project in the Peace River area. However in October 2015, Shell stopped construction, stating that "the project does not rank in its portfolio at this time".⁴⁹ Since the project had appeared as an asset on Shell's balance sheet following the final investment decision in 2013, Shell took a \$2 billion impairment with the decision to stop.

Figure 4: BP and Shell's interests in future potential tar sands projects

Asset	Total capital cost ⁱ	Peak production / kbd ⁱⁱ	Companies (operator listed first)	Status (none as yet proceeding)
Pike 1	\$2.8 bn	30	Devon 50% / BP 50%	Approved (original planned start year 2019).
Pike 2	\$3.3 bn	24	Devon 50% / BP 50%	Approved (original planned start year 2020).
Terre de Grace Phase 1	\$3.1 bn	20	BP 75% / Value Creation 25%	Announced
Terre de Grace Phase 2	\$0.9 bn	5	BP 75% / Value Creation 25%	Announced
Terre de Grace Pilot	\$1.2 bn	7	BP 75% / Value Creation 25%	Approved
Sunrise Phase 2A	\$4.7 bn	32	Husky 50% / BP 50%	On hold
Sunrise Phase 2B	\$4.9 bn	32	Husky 50% / BP 50%	On hold
Jackpine Extension	\$19.7 bn	70	Shell 60% / Chevron 20% / Marathon 20%	Approved
Jackpine Phase 1B	\$13.8 bn	70	Shell 60% / Chevron 20% / Marathon 20%	Approved
Muskeg River Mine Expansion and debottlenecking	\$15.2 bn	81	Shell 60% / Chevron 20% / Marathon 20%	Approved
Pierre River Phase 1		60	Shell 60% / Chevron 20% / Marathon 20%	Postponed indefinitely in 2014. Shell withdrew its application for development approval but maintained its leases, stating that it may re-apply in the future.
Pierre River Phase 2		60	Shell 60% / Chevron 20% / Marathon 20%	As per Phase 1
Carmon Creek Phase 1	\$4.9 bn	32	Shell 100%	Suspended construction, indefinitely removed from Shell project portfolio, but leases and some equipment maintained
Carmon Creek Phase 2	\$4.8 bn	28	Shell 100%	As per Phase 1

i Estimate of total capital expenditure over full life of project. Source: Rystad UCube

ii The figure here relates to total project production, not just BP's or Shell's share. Source: Rystad UCube

3. CANCELLED AND POSTPONED TAR SANDS PROJECTS

Since 2014, 42 tar sands projects have been put on-hold, delayed, or cancelled (See Appendix 1). These include BP's Sunrise project phases 2A and 2B and Shell's Pierre River and Carmon Creek projects. The mainstream narrative in the media and among industry commentators is that this is due solely to the fall in oil prices, and that once prices recover the sector will bounce back.

In this report we use economic analysis to model the companies' decisions, in order to consider the extent to which other factors including market access restrictions played a role in those decisions.

While oil prices are an important factor in capital expenditure decision-making, the current price environment has exposed more structural weaknesses within the tar sands industry, including the reality that pipeline access to new markets is critical for industry profitability. Even prior to the precipitous drop in global oil prices, three major tar sands projects had already been shelved without a profitable path forward. These projects – Total's Joslyn North,⁵⁰ Shell's Pierre River⁵¹ and Statoil's Corner – had a combined capacity of 400,000 bpd and were cancelled while oil prices were above \$80 per barrel.

These cancellations came at a time of growing concern related to market access. In particular, in announcing the cancellation of the Corner Project, a Statoil spokesperson noted that "Costs for labour and materials have continued to rise in recent years and are working against the economics of new projects. Market access

issues also play a role – including limited pipeline access which weighs on prices for Alberta oil, squeezing margins and making it difficult to sustain financial returns."⁵²

Our analysis shows the mainstream narrative, asserting that low oil prices are the only cause of tar sands project delays and cancellations^{53,54}, is inaccurate. More than half of the projects analysed could still have been viable under post-crash price expectations: it was lack of pipeline access that pushed them over the edge, as the additional cost of rail renders these projects uneconomic.

PIPELINES: FROM INEVITABILITY TO CANCELLATIONS

Until recently, tar sands operators assumed that new pipelines were inevitable: there may have been delays in the regulatory process, but they would get built in the end. Given massive public opposition both locally and nationally – based on growing concerns over oil spill risks, land rights and climate concerns – that assumption has proved incorrect.

The last major tar sands export pipeline to be built was in 2010: the 590-kbd Keystone 1.

TransCanada's second proposed tar sands pipeline into the USA, Keystone XL, was originally planned to be completed in 2012. However, the project faced extensive local and national opposition which steadily grew over time, leading to six years of regulatory delays until the project was finally rejected by President Obama in late 2015.

In Canada, Enbridge's Northern Gateway proposal to pipe oil to Kitimat, BC for export via tanker faced similar levels of public opposition. The project was first proposed in 2006, but was repeatedly delayed. After a lengthy regulatory review, the project was eventually approved by the Canadian government in 2014, but remained blocked by First Nations legal challenges and overwhelming public opposition in BC⁵⁵. The project approval was finally overturned by Canadian courts in Spring 2016 due to the failure of the Canadian government to respect First Nations legal rights.⁵⁶ A permanent crude-oil tanker ban for the entire north coast of BC has also been promised by the Canadian government under Prime Minister Trudeau. The ban is expected to end all future pipeline and rail project proposals to export oil from Alberta through Northern BC^{57,58}.

The two other remaining major export pipeline proposals face similar opposition. Kinder Morgan's Trans Mountain Expansion proposal to export crude oil to southern BC has been opposed by numerous First Nations, the BC provincial government, and the cities of Burnaby and Vancouver among others.⁵⁹ TransCanada's Energy East proposal, an attempt to ship more than 1.1 Million barrels per day east across six provinces to Saint John, New Brunswick has run into similar opposition from First Nations, municipal governments and the Province of Quebec.⁶⁰

More than half of the projects analysed could still have been viable under post-crash price expectations: it was lack of pipeline access that pushed them over the edge, as the additional cost of rail renders these projects uneconomic



KEYSTONE XL

ON 6TH NOVEMBER 2015, SEVEN YEARS AFTER THE ORIGINAL APPLICATION, PRESIDENT OBAMA, CITING CLIMATE IMPACTS, REJECTED THE PROPOSED 1,179-MILE PIPELINE, WHICH WOULD HAVE CARRIED 830,000 BARRELS A DAY FROM THE CANADIAN TAR SANDS TO THE GULF COAST.⁶¹ THE PIPELINE HAD BECOME THE “SINGLE MOST CONTROVERSIAL PIECE OF INFRASTRUCTURE IN NORTH AMERICA”⁶² AND WAS THE SUBJECT OF CO-ORDINATED AND SUSTAINED CIVIL SOCIETY, INDIGENOUS AND LOCAL COMMUNITY OPPOSITION.



14 Canada's regulatory system for reviewing pipeline proposals has faced increasing criticism.⁶³ As a result, the Canadian government has announced an overhaul of Canada's energy and environmental review processes over the next two years.⁶⁴ The two remaining pipelines are still being reviewed under the old system, potentially undermining the legitimacy of any regulatory approvals granted. This could increase their vulnerability to further procedural delays and legal challenges.

With only two of the four major proposed pipelines still being considered, and both facing major legal and political obstacles, there is a very real possibility that no more pipelines will be built.

ASSESSING THE REASONS FOR DELAYED PROJECTS

Methodology: Modelling the Internal Rate of Return

A characteristic of the tar sands sector is that each project relies heavily on a single investment decision,⁶⁵ which will set the course for the coming decades. Due to the high upfront sunk costs (Capex) and long production plateaus typical of most tar sands projects, it becomes very costly for a producer to change the plan once construction has started. For projects already producing oil, as long as the netback price received exceeds the marginal operating costs, the economic incentives are to continue even if that means a long-term loss on the capital invested – as stopping production would lead to an even greater loss.

To simulate the investment decisions, we conduct cash flow analysis of the projects, using projections of expenditure and production from Rystad Energy's UCube upstream database. Such cash flow forecasting is the method (in simplified form) that the industry uses to judge the profitability of projects for investment decisions.

We use a project's internal rate of return (IRR) as the key decision-making metric. Companies generally set a hurdle rate (threshold) for project investment decisions of around 10% IRR in real terms, which reflects the cost of capital and the opportunity cost of investing elsewhere. In practice, the threshold will vary from case to case, reflecting a company's appetite for risk, and strategic advantages such as getting established in a market.

In this analysis, we assume that companies will decide to proceed with projects where IRR exceeds 10% and reject those with an IRR below 10% (in real terms). While in reality the

threshold is not a precise cut-off in that way, like in any model the process is simplified. We assume that while some projects may proceed with projected IRR of 9.7%, say, and some be rejected with 10.3%, these variations will average out. In reality, companies will consider several oil price scenarios, assigning a likelihood to each to assess upside and downside risk in a project – and the precise approach will vary from company to company. To simplify, we use a single, "most-likely" price forecast, for which we simulate company expectations using the Energy Information Administration's price forecasts.

The question we are using the model to answer is:

☒ Under a most-likely price forecast, does the price drop alone move a project from being commercial to uncommercial, or only in combination with lack of pipeline access to markets?

PRICES VS. MARKET ACCESS

Of the 42 cancelled, delayed or suspended projects, we analyse 27 (data is unavailable for the remaining 15). We use the IRR analysis described above to understand why companies decided to put a hold on those 27 projects. This assessment is based on three scenarios:

1. a higher oil price forecast from before the crash (EIA 2013), ("2013 Price Scenario")
2. post-crash price expectations but pipeline availability (EIA 2015), ("2015 Pipe Scenario")
3. with post-crash price expectations and no new pipelines (2015 No Pipe Scenario").

For scenario 1, we use the EIA's price forecast published in its 2013 Annual Energy Outlook, which had prices rising steadily throughout the period, reaching \$133 per barrel by 2030. For scenarios 2 and 3, we use its forecast published in 2015, which accounts for the recent price crash and sees the price taking until 2028 to climb back to \$100 per barrel. We also factor in the price differentials at which tar sands crudes sell.

In scenarios 1 and 2, we assume that oil was to be transported to the Gulf Coast (the highest-netback market with excess demand) in the Keystone XL pipeline, at a cost of \$10 per barrel for dilbit or \$9 per barrel for synthetic (these are rates estimated for a 10-year shipping commitment).⁶⁶ In scenario 3, with no new pipelines built, we assume that producers instead transport by rail to the Gulf Coast, at a cost of \$19.05 for dilbit or \$16.80 for synthetic crude.⁶⁷ As described in Section 5, there is not sufficient space in the pipeline system to accommodate oil from new

tar sands projects that are not already either producing or under construction.

All 27 projects we analysed are commercial in the 2013 Price Scenario. We interpret the causes of delays as follows:

- ☒ Project is uncommercial in 2015 Pipe Scenario: price drop alone was sufficient cause for delay.
- ☒ Commercial in 2015 Scenario Pipe but uncommercial in 2015 No Pipe Scenario: it was market access that tipped the project over the edge.
- ☒ Commercial in all 3 scenarios: other reasons were at play.

RESULTS: WHY WERE PROJECTS DELAYED?

The project-by-project results are shown in Appendix 1. Of the 27 projects we assessed, we found that 14 – including BP's Sunrise and Shell's Carmon Creek – are rendered uneconomic by the combination of 2015 oil prices and the additional cost of rail. These projects are associated with over 60 percent of the reserves held in all 27 projects.

We can see this impact illustrated in Figure 6 for the example of Sunrise 2A. The chart shows discounted (at a 10% rate) real cumulative cash flow, which builds in the hurdle rate: in order for the project to be commercially viable, the curve needs to get above zero at some point. We see that with the pre-crash price forecast and an expectation of pipeline access to the Gulf Coast, the project would comfortably break into the commercial zone by 2027. With reduced price forecasts but still an expectation of pipelines, it still gets there, though not until 2035 (extending the period at which capital is at risk of making a loss, for example if prices fall). Once the prospect of pipelines is taken away, the project never gets there, and remains in uncommercial territory.

An additional eight projects are uneconomic under the current oil price scenario with or without additional pipeline capacity. In other words, these projects fit within the mainstream view that it is low oil prices alone affecting tar sands production growth rather than market access.

Finally, five of the projects were delayed for other reasons (the combination of lower prices and lack of pipelines did not push them into being uncommercial). For example, these might include a shortage of company cash flow, or a desire to prioritise other projects. See Appendix 1 for further details of each project's status.

Figure 5: Energy Information Administration Brent price forecasts (real, 2014 prices), Annual Energy Outlook 2013 and 2015

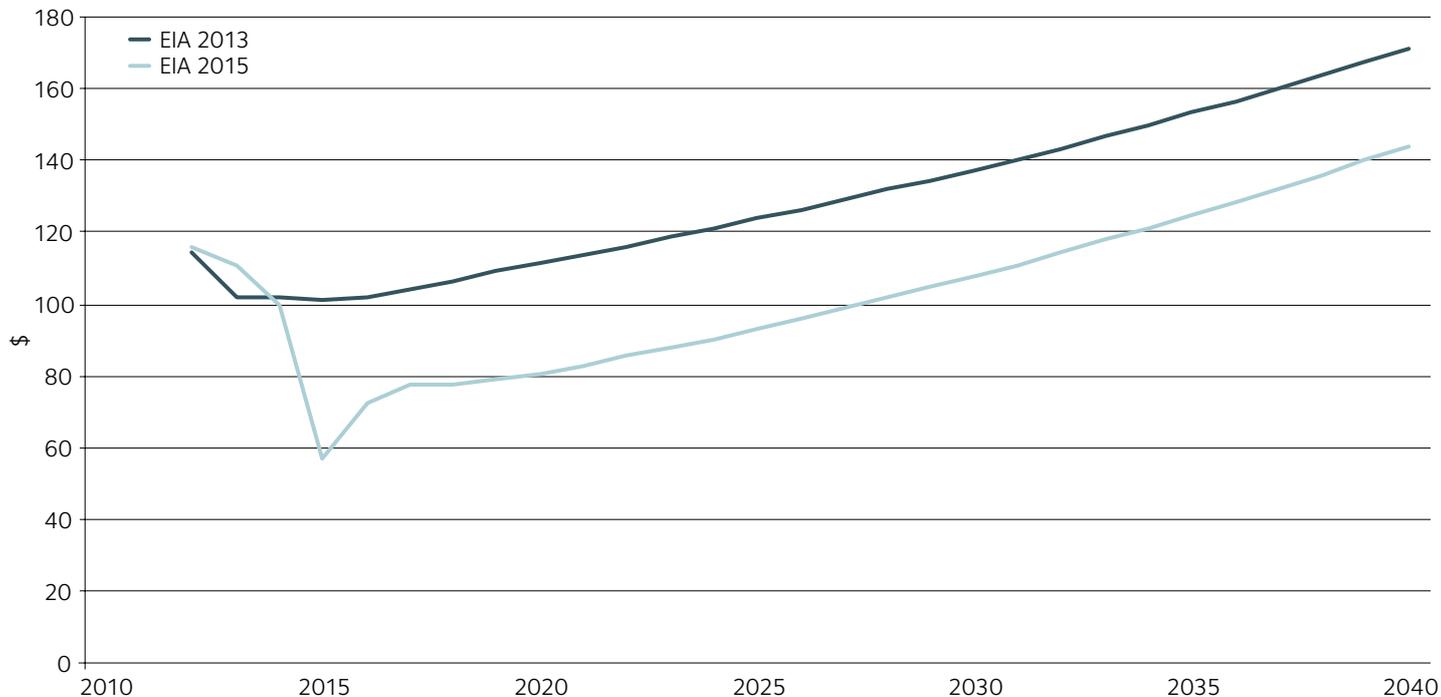
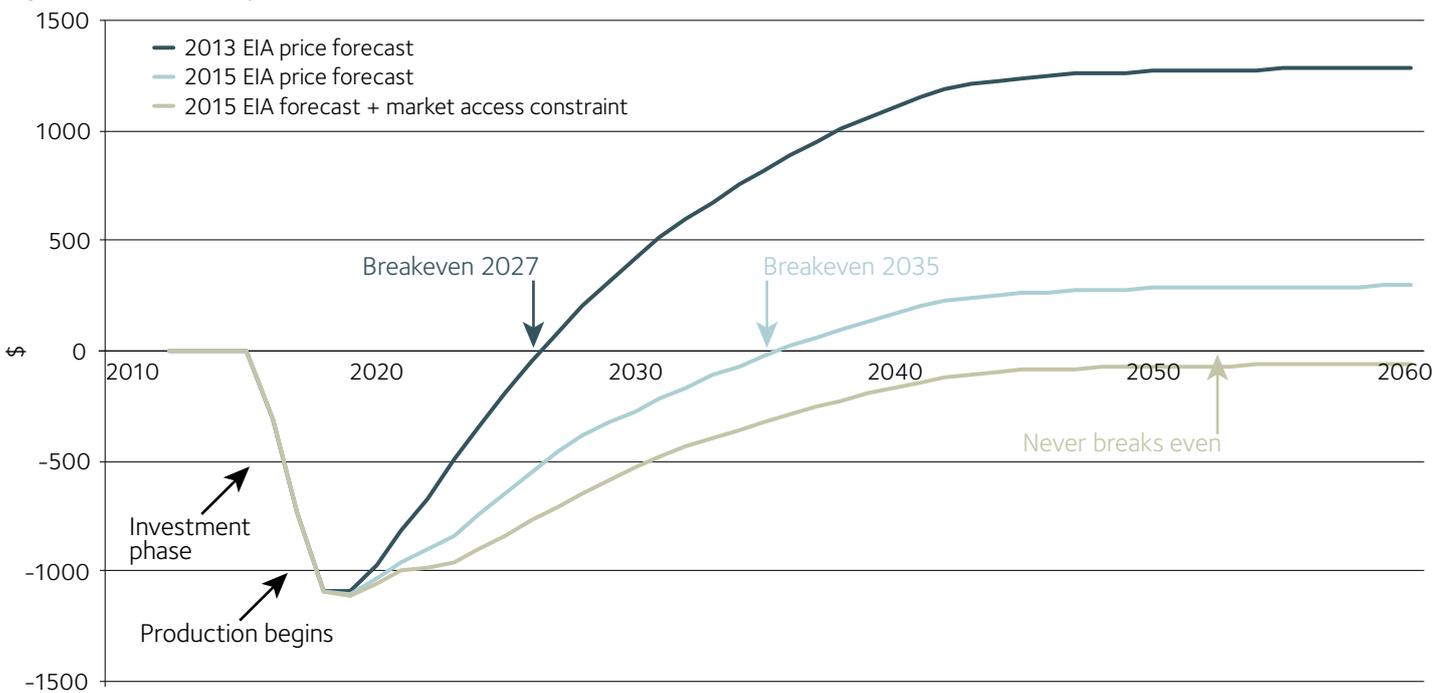


Figure 6: Sunrise 2A project cumulative discounted cash flow (real, discount rate 10%) Source: Rystad UCube, Oil Change International model



4: MAINSTREAM FORECASTS: SHIFTING EXPECTATIONS FOR TAR SANDS PRODUCTION

While the industry forecasts for tar sands production discussed below have been reduced every year for the past four years, they still project growth beyond operating and in-construction projects.

As both limited market access and lower oil prices have taken hold, forecasts for future tar sands production have shifted. The Canadian Association of Petroleum Producers (CAPP) has reduced its expectation for tar sands production in 2030 in its annual flagship publication for four years running.

The downgrade for future growth has shaved over 1.6 million barrels per day (Mbpd) off the forecast, with the 2030 number shifting from 5.3 Mbpd in the 2013 report to 3.7

Mbpd in 2016 (see Figure 7).⁶⁸ Nevertheless, the 2030 number is nearly 65 percent higher than today's production level and would clearly require many new projects to be sanctioned by companies as well as additional pipeline capacity far beyond that which exists or is in construction today.⁶⁹

While forecasts for existing and in-construction projects represent reasonable expectations for production in the future, growth forecasts are speculative. The most recent industry forecasts for long-term growth are based on three questionable assumptions:

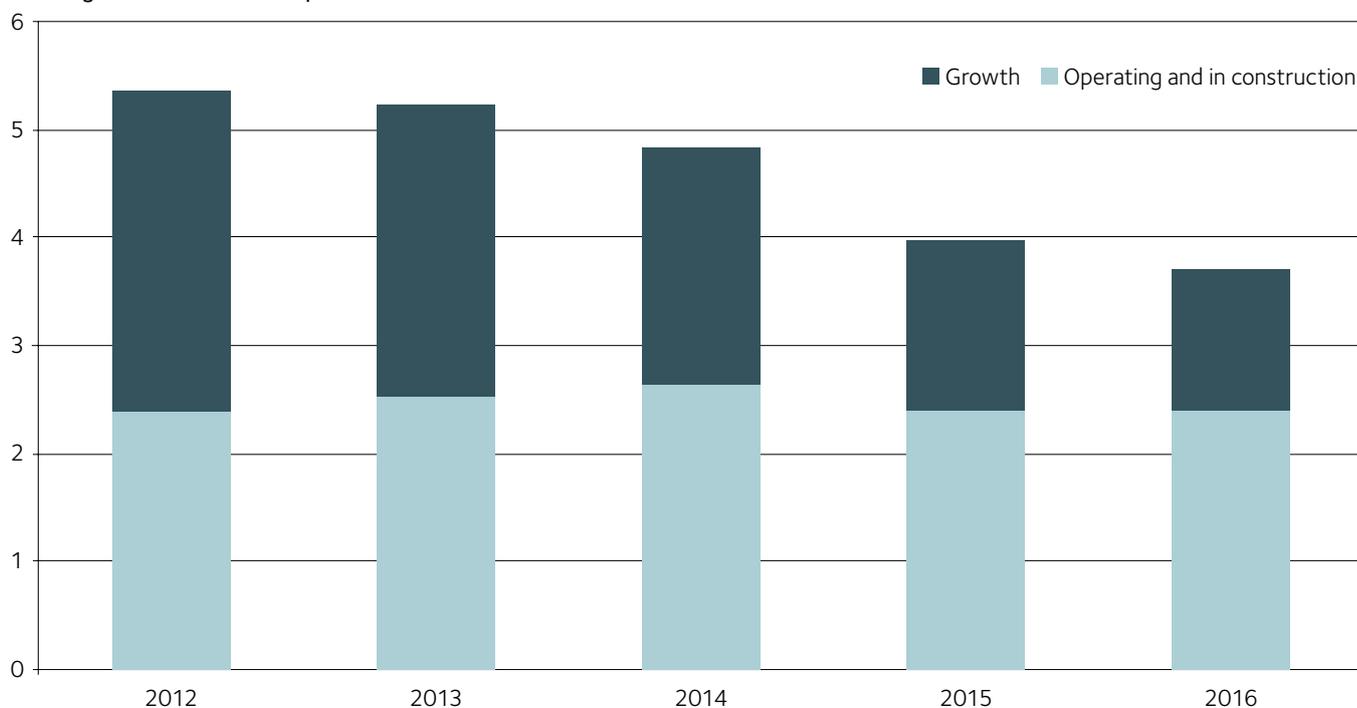
☐ **Market Access:** At least one of the major pipeline proposals goes ahead providing additional capacity within the next three to

five years: either the Kinder Morgan Trans Mountain expansion and/or Energy East.

☐ **Price Recovery:** It is generally assumed that after remaining low for the next one to three years, oil prices will see a gradual and continuous rise for the remainder of the forecast period.

☐ **Modest Regulatory Changes:** While it is recognized that the new Albertan government is seeking tighter environmental regulations, it is generally assumed that neither it nor the new Federal government will impose measures that would substantively impact production growth.

Figure 7: Changes in CAPP tar sands production forecasts for 2030



*CAPP ceased reporting on the split between in construction/operating & growth in 2016. 2016 estimate assumes operating/in construction production peaks in 2020



5. MARKET ACCESS CONSTRAINTS

The tar sands in Northern Alberta are located a long distance from major crude oil markets. In order to proceed with a new project, companies need to feel confident that they will have affordable access to these markets. Until 2010, pipeline expansions and refinery conversions had marched in lockstep with tar sands production growth. The Alberta Clipper and first Keystone pipeline (Keystone 1) were built in that year to deliver tar sands crude to newly converted refinery capacity in the U.S. Midwest.

Having met the capacity of the Midwest refineries, the tar sands sector planned to redirect production to the U.S. Gulf Coast, the location of the largest concentration of refining capacity in the world, which Keystone XL was originally designed to reach (via Cushing, OK) by 2012. If this had been achieved, no pipeline-related impediments to growth would exist for the bulk of this decade.

As well as Keystone XL, three other major new tar sands pipelines were proposed: Kinder Morgan's Trans Mountain Expansion and Enbridge's Northern Gateway, both running west to the BC coast, and TransCanada's Energy East to New Brunswick on the east coast.

However, no new pipelines have been built out of Alberta since 2010. The Keystone XL pipeline was repeatedly delayed due

to opposition from environmentalists, landowners, Indigenous groups and municipalities, and ultimately rejected by President Obama in November 2015. During those five years, opposition also grew against the other proposed pipelines.

Just two weeks after Obama's rejection, new Canadian Prime Minister Justin Trudeau announced a plan to ban tanker traffic in northern BC,⁷⁰ effectively ending the prospects of Northern Gateway, which had been looking unlikely in spite of receiving federal approval from the Harper government, especially due to First Nations concerns about damage to the economy, culture and rights. The project's demise was confirmed in June 2016 when the Federal Court of Appeal overturned the original approval.⁷¹ While in principle the court refers the project back to the Canadian government for a new decision, approval seems highly unlikely given the new Prime Minister's strong opposition to it.

Now just two major pipeline proposals remain, and both are also facing significant political, legal and public obstacles. These proposed pipelines, which were originally designed to come after Keystone XL and deliver future production growth, now also hang in the balance.





20 In parallel with these efforts to build new pipelines, Enbridge has pursued incremental expansions to its existing Mainline system. In the longer term, expansions are also being considered on Spectra's Express-Platte system. While some expansions have occurred in recent years, new incremental additions too are now facing growing public opposition, especially in the U.S. Midwest. Much of this opposition is driven by concern for the climate and environmental impacts of tar sands expansion, as well as concern for the direct impacts on communities on the frontlines of development. It appears to have taken the industry by surprise. This successful opposition to fossil fuel projects and supporting infrastructure is being replicated globally.⁷²

Figure 10 describes the status of remaining pipeline proposals.

NO PIPELINE CAPACITY FOR NEW TAR SANDS PROJECTS

This report uses Oil Change International's Integrated North American Pipeline model (INAP)⁷³ to assess the surplus pipeline capacity for tar sands production.

We find that if no new pipelines are built there will be no pipeline space available for tar sands production growth beyond that which arises from the projects already under construction.

INAP assesses the available capacity to export and refine Canadian crude. Unlike some other analyses, it looks not only at the pipelines directly leaving Alberta and Saskatchewan, but at the whole system of export infrastructure, and the pipelines and refineries connected to it. It assesses effective capacity by evaluating bottlenecks, from western Canada to the ultimate refinery or export tanker.

The detailed methodology is described in Appendix 2.

According to INAP, the takeaway capacity that Canadian tar sands crude has access to is 4,500 kbd.⁷⁴ Current tar sands production is about 2,200 kbd, which requires a further 500 kbd of diluent to make the bitumen flow. Western Canadian conventional crude production is about 1,300 kbd.⁷⁵ Hence the system is about 89% full at 4,000 kbd.

Tar sands production is set to grow for a few years even if no new projects are approved due to projects that are already under construction coming on stream. The reason for this is that building a tar sands project commonly takes five years or more, so extraction is currently growing due to projects that were approved on the assumption that market access constraints would be quickly resolved and pipeline capacity would become available.

Figure 8: Available Export Capacity is Filled in 2018 Unless New Pipeline Infrastructure is Completed Source: Oil Change International INAP model

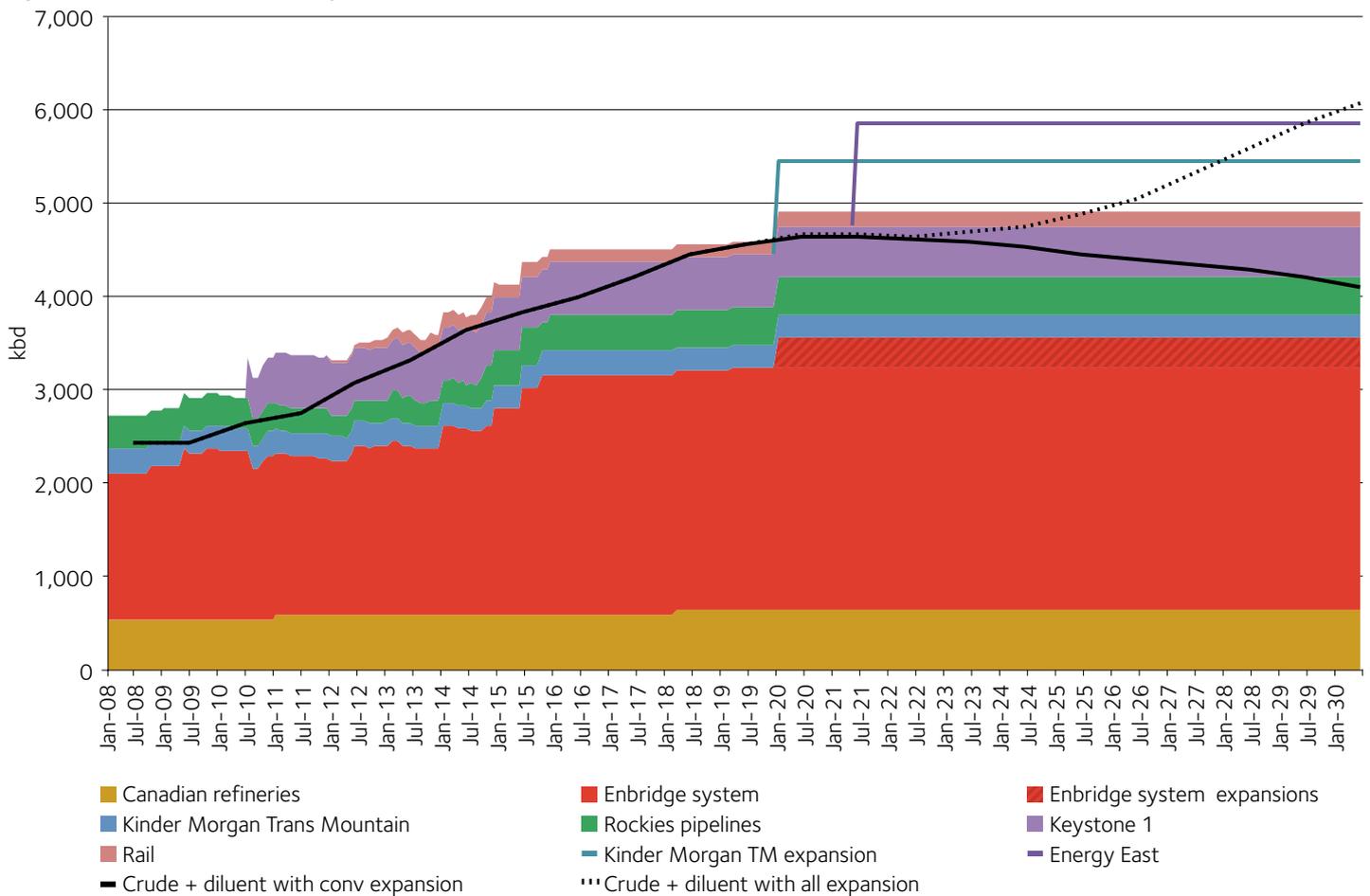




Figure 9: The Tar Sands Export System

- Proposed pipelines
- Existing pipelines
-  Refineries
-  Oil Storage

22 While several tar sands projects have been postponed due to the oil price and/or due to lack of market access, these are almost all projects that have yet to break ground. Due to this locked-in growth, without any new pipelines, the export system could reach its limit as soon as 2018 (Figure 8). If proposed expansions of the Enbridge system (in Figure 10 below) are completed, this would add up to 300 kbd to the system, accommodating the committed growth but leaving no significant room for further growth beyond that.

EXISTING PIPELINE SYSTEMS

The industry currently depends primarily on four major pipeline systems, described below and shown in Figure 9:

Trans Mountain: Kinder Morgan's 300 thousand barrel per day (kbpd) westward pipeline to BC, with a branch also going to Anacortes, Washington.

Rockies pipelines (three southward pipelines): Spectra Energy's 280 kbpd Express to Casper, Wyoming; Plains' 83 kbpd Rangeland and Interpipeline's 118 kbpd Milk River, both to Cut Bank, Montana, where they connect with Phillips 66's Glacier and Cenex's Front Range; deliveries are distributed throughout Montana, Wyoming, Colorado and Utah, and surplus carried on to Patoka, Illinois, and Cushing, Oklahoma.

Keystone 1: TransCanada's 590 kbpd southeastward pipeline to Patoka and Cushing.

Enbridge System: 2.5 million barrel per day (mbpd) of southeastward pipelines, crossing into Minnesota, then splitting essentially into two branches: one to Midwest refineries and on to Ontario, the other to Cushing.

Public efforts to delay and stop pipeline expansion have been successful, in that affordable market access required to stimulate future production growth is simply not in place.

Rail

When pipeline capacity becomes tight, sending tar sands crude by rail is an option. But it is not an option that producers can depend on enough to justify multi-billion dollar investments in new tar sands production. While the transport of tar sands by rail has grown in recent years, its potential is severely hampered by high costs, increasing pressure for regulation, and unreliable logistics.⁷⁶

While the physical infrastructure of rail loading/unloading terminals is quicker and cheaper to build than pipelines, the per-barrel transport cost is nearly double that of pipelines (see Section 3).

Even those in the business of transporting tar sands crude by rail admit that rail cannot substitute for pipelines, but instead acts as a stop-gap solution for insufficient pipeline capacity. "Crude by rail is not a panacea," says Stewart Hanlon, President and CEO, Gibson Energy Inc, a tar sands rail terminal operator. "It's not going to replace pipe."⁷⁷ Part of the reason is that rail is less reliable than pipe. Trains are often stopped or delayed when the weather is bad, for example. Crude oil also has to compete with many other commodities for capacity on the rail system; a challenge it does not face with a dedicated pipeline. New safety regulations aimed at addressing the explosive result of crude oil train derailments are also posing new challenges to the trade. The logistical and market challenges of crude by rail are only likely to lead to volatility and rising costs.

Crude by rail loading capacity in Alberta and Saskatchewan was largely built from 2012 onwards. So when Canadian crude production actually exceeded the available pipeline and refinery capacity on several occasions in 2013 and 2014, the excess was carried by rail.

The question is whether producers will invest in new production if rail is the only available transportation option, i.e. if pipeline capacity is full and no new pipelines are being built. While there may be a few exceptions, where project costs are very low, and/or where an integrated company can play upstream margins against refining, generally the additional cost of rail eats too far into already tight netbacks. Lack of pipeline capacity, and the resulting prospect of having to rely on rail, was a key factor behind at many of the delayed and cancelled tar sands projects (Section 3). We shall explore the impact specifically on potential future BP and Shell tar sands projects in Section 6.

Figure 10: Status of pipeline proposals

	Pipeline	Status	Role in North American system
Enbridge Expansions	Line 61 expansion phase 2 and Line 66	Tied up in a permitting dispute: a county permit for the expansion was made conditional on Enbridge holding sufficient insurance against spill risks; but a State budget provision subsequently denied counties the right to apply such conditions. Enbridge has filed suit against the conditionality of the permit; landowners have counter-sued, arguing that the budget provision cannot be applied retroactively. Facing growing public opposition along with all mid-west pipeline expansions.	Expansion of Line 61 from Superior, WI, to Flanagan IL from 950 kbpd to 1,200 kbpd. Enbridge is in an early stage of planning to “twin” Line 61 with a new Line 66, which would add an additional 1.2mbd. Together, Line 61 and 66 would be a total of 2.4mbd
	Alberta Clipper (Line 67)	The federal permit for the expansion is pending; however Enbridge is pumping up to 800k bpd even though their current permit is for 450k. They achieved this through a “Double Cross” in which crude is switched into a new section of Line 3 north of the border and switched back into Line 67 on the U.S. side. The White Earth Nation and green groups challenge to this arrangement was dismissed by the a federal judge, and the higher volume may be pumped until the US Presidential Permit process is completed. Canadian permits are secured.	Expansion of the Hardisty-Superior line from 450 to 800 kbpd. In the absence of the US Presidential Permit, the cross-border section is being rerouted through Line 3, the permit for which is vague on volume restrictions.
	Line 3 replacement and expansion	The 18-mile cross border section is complete but currently in use for the Clipper expansion; the rest of the line’s permits are being reviewed by the Minnesota Public Utilities Commission and the federal government. Opposition centres around the sensitivity of the new route, plans for abandonment of the old Line 3, and the lack of application of climate criteria as per Keystone XL. The National Energy Board approved the replacement/expansion on the Canadian side in April, 2016. The project continues to face opposition from First Nations communities and environmentalists.	Built in the 1960s, Line 3 is unsafe and inefficient. Enbridge’s intention is to exploit the vagueness of the decades-old permit to replace the 390 kbpd pipeline with a 760-800 kbpd one. The new Line 3 would also make room on Line 4, allowing expanded use of that line for cross border tar sands shipments. Total Enbridge expansions, if completed, would equal some 1.1mbd of cross border tar sands capacity.
Enbridge Northern Gateway		Widely considered ‘unbuildable’. Originally granted approval from the Canadian Government with 209 conditions, but approval was revoked by federal courts in 2016, due to failure to adequately consult First Nations. Other First Nations legal challenges are ongoing. In late 2015, new Prime Minister Trudeau promised to legislate a permanent ban on tanker traffic on BC’s North coast, which would render the project, or any amended route, useless.	Proposed 525 kbpd new pipeline from tar sands to Kitimat BC for access to the Pacific coast and subsequent tankers for international markets.
Kinder Morgan Trans Mountain Expansion		Facing increasing opposition and legal challenges from First Nations, the public and large municipalities (including the city of Vancouver). Additional opposition driven by concerns related to tanker traffic. Formally opposed by the BC government in early 2016. The National Energy Board recommended approval to the Federal Cabinet in May 2016. A final decision from federal cabinet is expected by December 2016. Multiple First Nations legal challenges could block the project even if formally approved.	A twin pipeline that would add 590 kbpd between the tar sands and the Southern BC coast for Pacific access to international markets.
TransCanada Energy East		Delayed for two years due to environmental concerns over beluga whale habitat and new changes to improve the credibility of the Federal review process. Facing mounting opposition from the public, significant municipal opposition (including the city of Montreal and the Montreal Metropolitan Community), official opposition from the Quebec Assembly of First Nations, and growing political hesitancy in support from provincial governments including an injunction from the province calling for a provincial environmental assessment of the project. National Energy Board hearings officially started in June 2016, with recommendations to federal cabinet expected in March 2018.	A proposed 1.1 mbpd new eastward pipeline from the tar sands to refineries in Eastern Canada and an export terminal in St John, NB for Atlantic access to international markets.

6: SHELL AND BP PROJECTS – VIABILITY AND ROLE OF PIPELINES

Preceding sections of this report indicate that if no new pipelines are built, there will be no pipeline export capacity for tar sands projects that have yet to break ground. In this section, we examine whether BP's and Shell's potential future projects might be able to proceed if rail is the only option available.

As in Section 3, we use cash flow forecasting of the projects to model the final investment decision on each project, assuming a real 10% hurdle rate. Again we use modelled data for expenditure and production from Rystad Energy's UCube database. However rather than trying to explain historical yes/no decisions, in this section we want to know how feasible the projects are, so instead we use breakeven price as the metric.

We define break-even price as the flat WTI price at which a project has a zero net present value, at a discount rate of 10%, in real terms. Or put differently, the flat price at which a project delivers a 10% real IRR. While prices obviously go up and down, the flat price gives an easier-to-grasp sense of what price is needed.ⁱⁱⁱ

We consider two scenarios:

- ☑ The Kinder Morgan pipeline is built, and oil from the projects is piped to the port of Vancouver, then carried by vessel to refinery in northern California;
- ☑ No pipelines are built, and the oil is carried by rail to a refinery on the Gulf Coast.

In each case, the destination market is taken to be the one with marginal demand (i.e. not fully supplied by dedicated inland supplies) that delivers the highest netback to the producer in Alberta.

We do not include the Pierre River Mine in the analysis, because having withdrawn the application for development approval there is no longer data available on which to base cost and production estimates. We include the other projects listed in Section 1, including Carmon Creek.

We see from Figure 11 that – aside from the outliers of the cheaper Pike 1 and Terre de Grace pilot and the expensive Jackpine projects – the projects generally have breakeven prices in the range of \$75–85 if the Kinder Morgan pipeline is built. This is significantly higher than the vast majority of the world's proven oil reserves.

If forced to rely on rail, the projects' economics become even more stark. Apart from Pike 1 and Terre de Grace pilot, the breakeven price range increases to \$95–110 – around the levels reached during the high price years of 2008–14.

One interesting finding here is that whereas rail adds a little more than \$10 per barrel to transportation cost, it increases the breakeven price of the non-upgraded projects by about \$20 per barrel. This is for three reasons:

- (i) since dilbit (diluted bitumen) is of low quality, a \$10 increase in dilbit costs translates proportionally to more than \$10 in higher-quality WTI, the crude that is used in the breakeven price metric;
- (ii) the bitumen is diluted with diluent (generally condensate or light oil), which has to be purchased by the producer – so a higher price not only compensates the higher dilbit transportation costs but also conversely increases the blending costs before transportation;
- (iii) the Alberta fiscal system includes variable royalty rates that depend on the WTI price: so as breakeven price goes up, more of the increased revenue gets absorbed in government take.

For synthetic crude oil, a light oil closer in quality to WTI, a \$10 increase in transportation costs translates to a roughly \$10 increase in breakeven prices, as intuitively expected.

Even with a pipeline, breakeven prices are so high that – while it is not implausible that oil prices could reach such a range in the coming years – the projects would carry high risks of making losses if those prices do not persist. Over the long timeframes of tar sands projects, this leaves investors very exposed. In the event that no more pipelines are built, it is hard to imagine circumstances in which these projects could proceed.

iii. In theory, a company investment decision will be based on a detailed analysis of profitability under a range of price scenarios. But given the notorious difficulty of forecasting oil prices, especially beyond a few months into the future, current price at the time of decision plays a significant psychological role. The breakeven price metric speaks helpfully to this.

Figure 11: Breakeven WTI price for future potential BP and Shell tar sands projects, with and without pipeline availability

Sources: Oil Change International model, Rystad UCube

	Product	With Kinder Morgan pipeline	No pipelines
BP			
Terre de Grace pilot	bitumen	\$67	\$88
Terre de Grace 1	bitumen	\$75	\$95
Terre de Grace 2	bitumen	\$73	\$93
Sunrise 2A	bitumen	\$74	\$93
Sunrise 2B	bitumen	\$75	\$95
Pike 1	bitumen	\$62	\$81
Pike 2	bitumen	\$78	\$98
Shell			
Carmon Creek 1	bitumen	\$80	\$100
Carmon Creek 2	bitumen	\$84	\$103
Muskeg River Expansion & Debottlenecking	SCO	\$87	\$98
Jackpine 1B	SCO	\$94	\$106
Jackpine Extension	SCO	\$98	\$109

QUESTIONS FOR BP AND SHELL

- What is the company's assessment of the breakeven price of its, as yet unconstructed, tar sands projects with and without pipeline access?
- On which pipelines has the company contracted volumes?
- Does the company consider pipeline access as a prerequisite to the projects proceeding?
- What is the company's hurdle rate for approving these projects?
- Does the company anticipate making final investment decisions on any or all of these projects in the foreseeable future? If not, does the company anticipate relinquishing the relevant leases and equipment or will it continue to incur some costs?

7: PRICE RECOVERY AND REGULATORY CHALLENGES

PRICE RECOVERY

According to a recent report from Chatham House, "...the IOCs cannot assume that, as in the past, all they need to survive is to wait for crude prices to resume an upward direction. The oil market is going through fundamental structural changes driven by a technological revolution and geopolitical shifts. The old cycle of lower prices followed by higher prices is no longer applicable."⁷⁸

Rystad data comparing the breakeven oil price for various unsanctioned projects indicates that tar sands will be at a disadvantage against other projects such as shale. See Figure 12. According to Rystad data from April 2016 "[t]he average Brent breakeven price for shale projects is approximately 71 \$/bbl.

For offshore projects, only the offshore shelf has a lower breakeven price than shale. Oil sands have the highest breakeven price of around 98 \$/bbl."⁷⁹

REGULATORY CHALLENGES

Project and pipeline delays increase the risk exposure for new projects to growing regulatory stringency and shifts in the political climate, such as the recent dramatic shift in provincial politics in Alberta from a party sympathetic to the oil industry to one committed to economic and energy system diversification. While higher oil prices could offset increased transport costs or reduced local prices, stronger regulations could shift the economic balance back. Furthermore, they create additional time for legal efforts by First

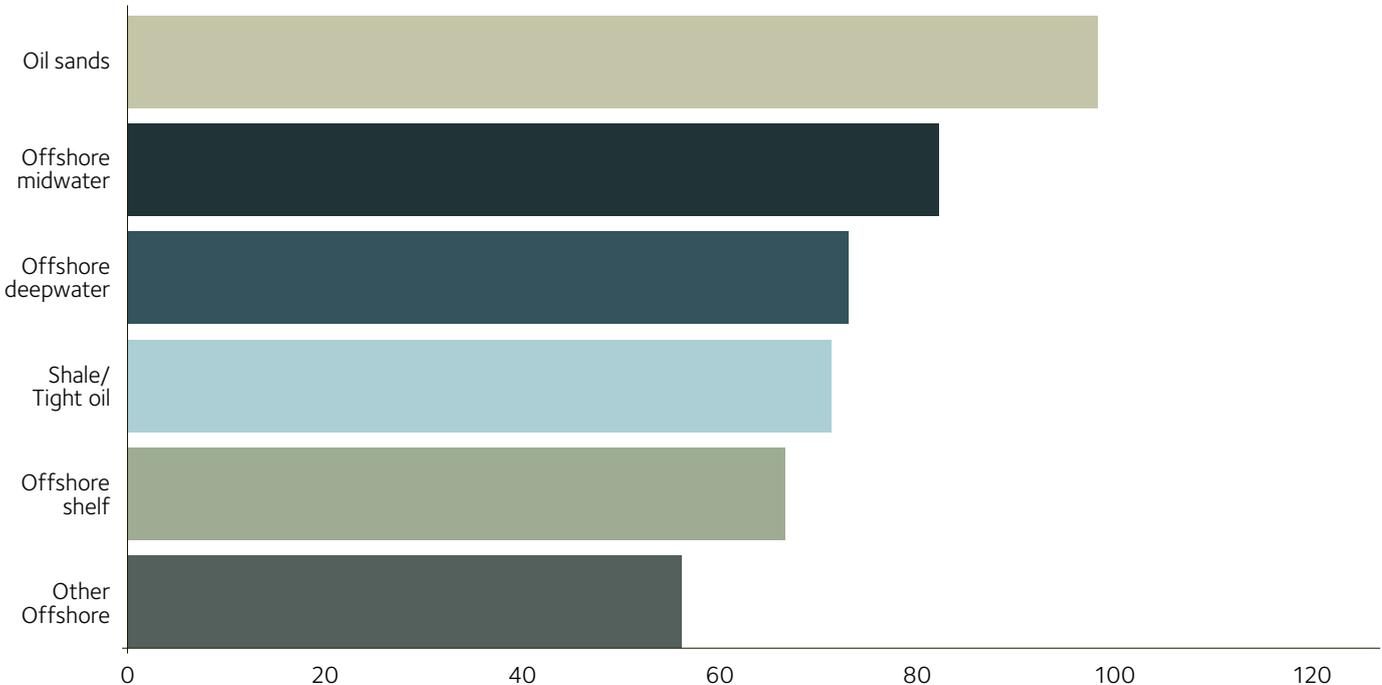
Nations and directly impacted communities in Northern Alberta to object to infrastructure project in order to protect their traditional lands and treaty rights.

ECONOMIC IMPACT OF ENVIRONMENTAL POLICIES

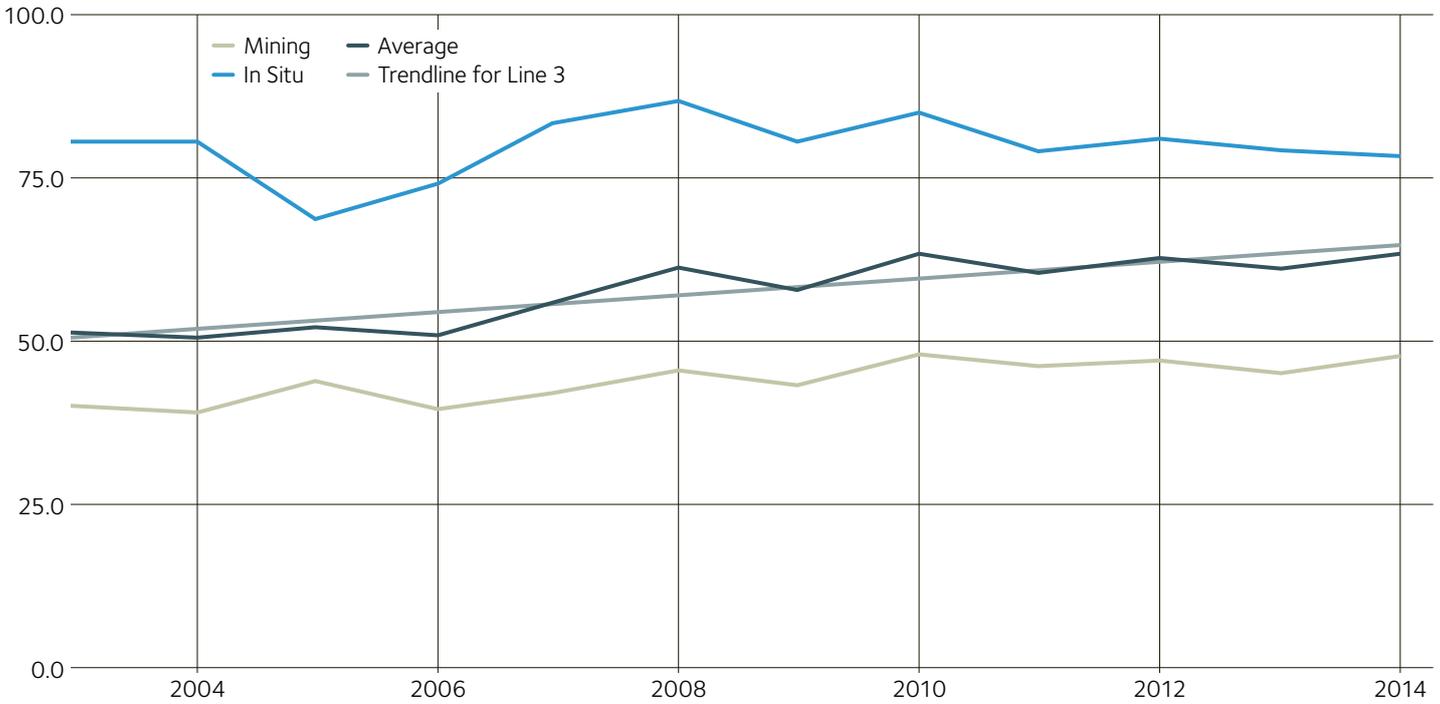
Improving project performance to reduce air pollution, water pollution, water use, land and habitat disturbance and greenhouse gas emissions intensity are all expected to increase marginal costs for producers, while pressure to cut costs from shareholders and investors continues to build.

No tar sands producer to date has been successful in meeting stated goals for managing tailings waste. Finding solutions to remove

Figure 12: Average Brent Breakeven Oil Price for Unsanctioned Projects per Supply Group - \$/bbl Source: Rystad 2016







water from tailings (which do not arise in in-situ projects) is a major challenge. In 2009, Shell and other companies negotiated a company specific target for capturing fine particulates in tailings with the Alberta government. Shell's target to cut fine particulates by 50%, along with similar targets for other producers was captured in Directive 74, a provincial regulation intended to cut tailings significantly by 2015. In 2014, Shell admitted it had not made significant progress towards their targets and in 2015, the Alberta government suspended the directive to allow producers more time to develop 'dry tailings' technology.⁸⁰ Shell Canada's then president Lorraine Mitchelmore implied that the cost of meeting the targets was a problem, noting that business units like Shell Canada were under pressure to cut costs to compete for capital investment.⁸¹ Pressure to reduce costs continues, as new regulations have been put in place requiring companies to shrink their tailings ponds, reduce wastewater, and to clean up and restore mined land within ten years.

Public pressure to improve the environmental performance of the tar sands continues to

increase.⁸² This is compounded by limitations on their capacity to invest, due to pressure to reduce expenditure, to overcome the technical challenges to reduce pollution.⁸³

EMISSIONS CAP

On 22 November 2015, the Alberta Government announced a new climate plan.⁸⁴ While representing a significant move forwards in Alberta's approach to climate, the plan does not align with the ambition to limit global warming to less than 2 degrees, let alone Canada's new ambitious commitment to a 1.5 degree target, so there is significant room for further regulatory tightening in the future.

Nonetheless, the plan includes a 100 megatonne per year (Mt/y) cap on tar sands emissions, over the period 2020-30. Current emissions from the tar sands are 70 Mt/y, according to the Alberta government.

Thus, the 100Mt/y cap would allow for for some 43% growth in emissions from today's levels. On a simple assumption that average

emissions intensity is the same for under-construction projects as for those already operating, a 32% production increase, from 2.2 to 2.9 mbd, would lead to a 32% emissions increase, from 70 Mt to 92 Mt. Again assuming constant emissions intensity, a 100 Mt cap would allow a further increase in tar sands extraction of 250 thousand barrels per day (kbd) - the equivalent of a large mine - beyond what is already under construction.⁸⁵

The plan provides no information on how the cap will be implemented, enforced, and on what the penalties would be for non-compliance.

EFFICIENCY GAINS REQUIRED

The Alberta government has been clear that the objective is to fit as much growth under the cap as possible through efficiency gains.

Existing Alberta regulations have a target of improving (i.e. reducing) emissions intensity in the largest projects of production by 20% by 2017 (compared to 2005, or to the start of the project if later).⁸⁶

QUESTIONS FOR BP AND SHELL

- ⊗ In light of Shell's track record of failing to meet specific targets for capturing fine particulates in tailings, can the company provide an update on its current compliance with requirements to manage tailings waste? Does Shell Canada still consider the costs of compliance in current industry conditions to be an obstacle to meeting the requirements?
- ⊗ What specific measures are the companies taking to reduce GHG emissions in their operations? –
- ⊗ What emissions intensity do you project for the company's proposed projects, and what is the basis for this estimate?
- ⊗ How do you foresee the company's projects fitting within the 100 Mt emissions cap, given the small amount of space for all new projects?
- ⊗ The cap applies until 2030, and after that will need to be rapidly decreased to meet global climate targets. If the company's projects go ahead, can their emissions be significantly reduced after they have been built?
- ⊗ Given the failure to improve emissions intensity significantly in the last 10 years, how confident is the company that emissions reduction can now be accelerated to meet the newly introduced requirements and indeed any future strengthening of them?

The Alberta Climate Leadership report focuses on industry's aspirational goal of reducing emissions intensity to the level of conventional production. It recommends a reduction of 50 – 75% within 10 years, to bring tar sands production emissions “in line with much of the world's conventional resource.”⁸⁷

If industry is able to get halfway to achieving these goals for emissions intensity (respectively to existing/under-construction and to new projects), the 100Mt/y cap could allow for more than 720 kbd of new production beyond what is already under construction.⁸⁸ If it achieved these targets completely (applying a 20% intensity-reduction target to all existing and under-construction projects, not just the largest ones), it would allow over 1.7 mbd of further growth.⁸⁹ It appears then that the cap will place a limit on further expansion; as for

how much of a limit, it remains to be seen what changes can and do occur in emissions intensity. However, significant tar sands production growth beyond what is already under construction would require the adoption of new transformative technologies to reduce the current emissions intensity.

There is little evidence to date that reductions on the required scale will be possible.

FAILURE TO ACHIEVE EFFICIENCY GAINS

There have not been meaningful improvements made in average emissions intensity since 2005. As is shown in Figure 13, emissions intensity has been nearly flat for more than a decade, in spite of 80% growth in oil production over that period. The industry often repeats a misleading statistic: “Emissions per barrel have been reduced by 26 per

cent between 1990 and 2011.” However, all notable reductions happened before 2005 and average emissions intensity has stayed flat. While some improvements have been made in technical and operational efficiency since that time, more high-intensity in-situ projects have been added to the total mix of projects. The result is that average emissions intensity has stayed flat. In the future, this trend is expected continue with all but one planned new project is an in-situ operation, and new projects trending towards lower reservoir quality.⁹¹

CONCLUSION

It would be easy to disregard BP's and Shell's stunted tar sands ambitions as the temporary and not too serious consequence of a volatile oil price. But to do so would be to miss the worrying signposts this reversal of fortune provides for the oil industry's future. That the Canadian tar sands are dependent on sustained high oil prices; are vulnerable to First Nations and local community opposition; are regarded as a front-line battle in the fight against climate change, and therefore are commercially vulnerable has been long-argued.

Institutional shareholders, worried about the impact those very issues would have on the economic viability of Shell's and BP's tar sands plans, filed resolutions for the 2010 shareholder meetings calling for greater

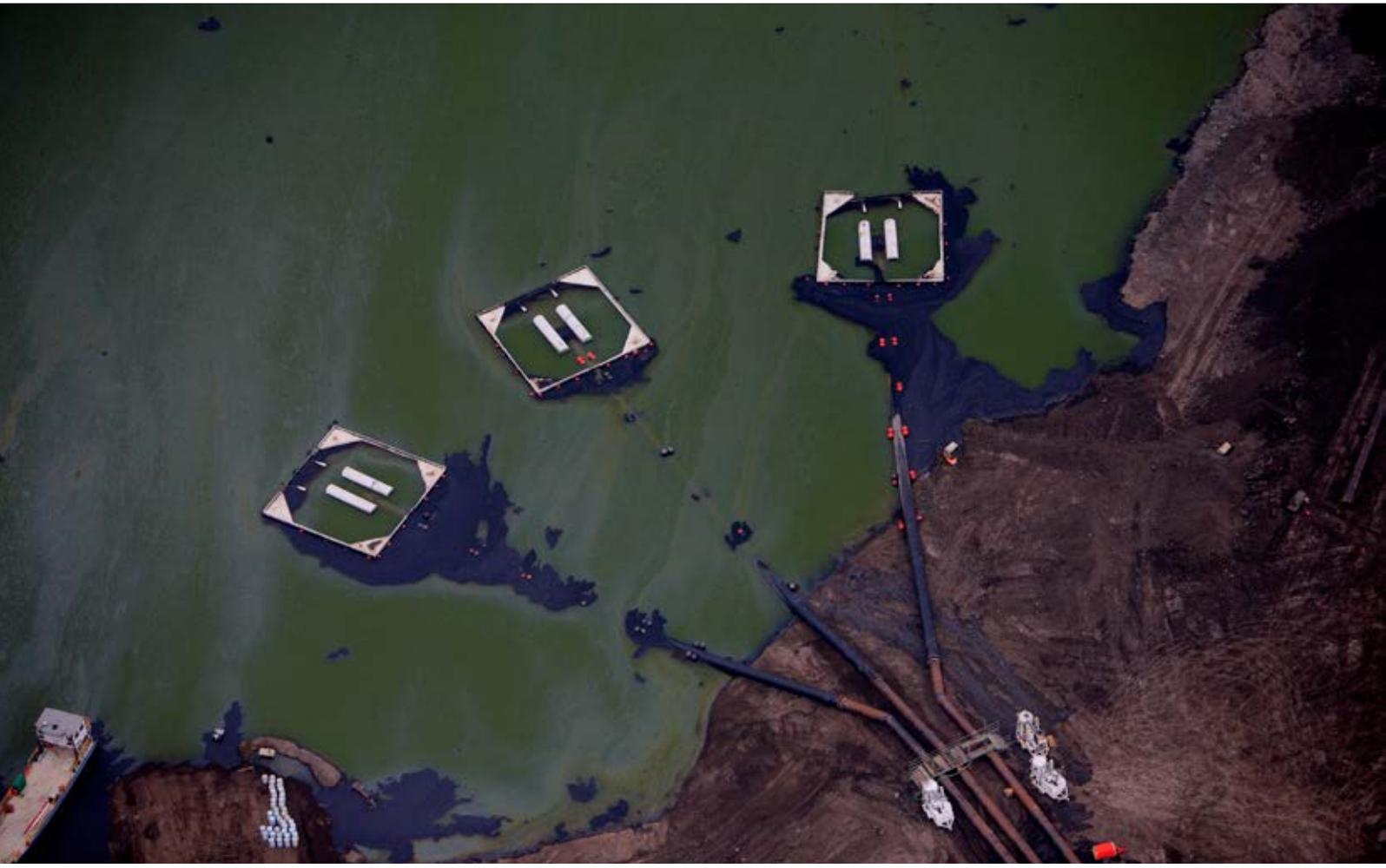
disclosures on the companies' planning assumptions. They were rebuffed by over-confident boards of directors. Shareholder concerns have been vindicated. It's vital that the correct lessons are learned by the companies and investors.

Those lessons extend beyond tar sands projects to the centre of the IOC business model.

Industry conditions - including the US shale boom and Saudi Arabia's assertive moves to protect market share - highlight the vulnerability of projects such as Canadian tar sands which sit at the wrong end of the cost curve. The rejection of essential market access infrastructure for tar sands specifically on climate grounds highlight industry

vulnerability to increasingly ambitious climate policy, and the coordinated grassroots opposition which demanded that decision highlights the growing opposition facing oil projects across the world.

This report provides investors with an analysis of the factors that have led to this shelving of BP's and Shell's tar sands expansion plans. It examines the economic viability of those projects with and without additional pipelines. We suggest questions for investors to ask Shell and BP in order to understand their plans for their tar sands assets. We also suggest questions to assess the companies' understanding of and preparedness for the wider impacts of shifting oil industry conditions illustrated by the fate of the tar sands



QUESTIONS FOR BP AND SHELL

- ⊗ What proportion of the company's oil and gas reserves and resources require a break-even price in excess of \$60 bbl?
- ⊗ In making final investment decisions for long-life projects what are your projections regarding long-term oil price?
- ⊗ What assumptions underpin your projected oil price? e.g. level of electric vehicle and renewable energy penetration; climate policy; level of oil demand.
- ⊗ Does the company stress-test the resilience of such projects against a range of demand and price scenarios compatible with the goals of the Paris Agreement to keep global temperature increases to well below 2C with an ambition for 1.5C?
- ⊗ What is the company's assessment of the breakeven price of its, as yet unconstructed, tar sands projects with and without pipeline access?
- ⊗ On which pipelines has the company contracted volumes?
- ⊗ Does the company consider pipeline access as a prerequisite to the projects proceeding?
- ⊗ What is the company's hurdle rate for approving these projects?
- ⊗ Does the company anticipate making final investment decisions on any or all of these projects in the foreseeable future? If not, does the company anticipate relinquishing the relevant leases and equipment or will it continue to incur some costs?
- ⊗ In light of Shell's track record of failing to meet specific targets for capturing fine particulates in tailings, can the company provide an update on its current compliance with requirements to manage tailings waste? Does Shell Canada still consider the costs of compliance in current industry conditions to be an obstacle to meeting the requirements?
- ⊗ What specific measures are the companies taking to reduce GHG emissions in their operations?
- ⊗ What emissions intensity do you project for the company's proposed projects, and what is the basis for this estimate?
- ⊗ How do you foresee the company's projects fitting within the 100 Mt emissions cap, given the small amount of space for all new projects?
- ⊗ The cap applies until 2030, and after that will need to be rapidly decreased to meet global climate targets. If the company's projects go ahead, can their emissions be significantly reduced after they have been built?
- ⊗ Given the failure to improve emissions intensity significantly in the last 10 years, how confident is the company that emissions reduction can now be accelerated to meet the newly introduced requirements and indeed any future strengthening of them?

APPENDIX 1: ECONOMIC ANALYSIS OF DELAYED AND ON-HOLD PROJECTS

Figure 14: Delayed Project Causal Analysis⁹²

Project	Dependent projects	All phases combined		IRR (scenarios)		
		Resources / m bbl	Peak production / kbd	Pipe 2013 prices	Pipe 2015 prices	Rail 2015 prices
Delayed due to lack of pipelines						
Carmon Creek Phase 1	Phase 2	595	64	15.2%	10.0%	8.1%
Christina Lake Cenovus Phase G (North)	Phase H	914	70	17.5%	11.6%	9.4%
Kearl Phase 3 (Debottleneck)	-	875	56	15.4%	10.3%	8.5%
Kirby North CNR Phase 1	Phase 2	923	68	14.1%	10.2%	8.7%
Mackay River PetroChina phase 2	Phases 3, 4	697	82	14.9%	11.2%	9.7%
Sunrise Phase 2A	Phase 2B	894	98	18.4%	12.1%	9.5%
Telephone Lake Phase A	Phase B	518	54	16.1%	11.2%	9.0%
SUB-TOTAL		5,416	492	(14 projects)		
Delayed due to price fall alone						
Black Gold Phase 1	Phase 2	260	20	15.2%	9.4%	7.5%
Frontier Phase 1	Phases 2, 3	1422	143	12.5%	7.2%	4.9%
Kai Kos Dehseh Corner	Corner Expansion	669	52	13.4%	9.3%	7.8%
Walleye Phase 1	-	60	5	13.3%	7.3%	4.4%
SUB-TOTAL		2,411	220	(8 projects)		
Delayed for other reasons						
Foster Creek Phase H	Phase J	633	54	22.2%	14.8%	11.9%
Kai Kos Dehseh South Leismer	-	191	12	18.8%	13.4%	11.4%
Lindbergh Phase 2	-	100	9	28.5%	18.6%	14.9%
Mackay River Suncor phase 2	-	166	15	17.3%	12.0%	10.6%
SUB-TOTAL		999	90	(5 projects)		
TOTAL		8,826	220	(27 projects)		

The Gulf Coast is the number one destination for tar sands crude in North America after the already saturated U.S. Midwest due to its high volume of capacity to refine heavy sour crude. The infrastructure to unload significant quantities of tar sands crude by rail in the Gulf Coast exists but is being substantially underutilized because of poor returns. Recent research by Oil Change International (Tracking

Emissions: The Climate Impact of the Proposed Crude-by-Rail Terminals in the Pacific Northwest, October 2015, available at www.priceofoil.org) has found that rail to the Pacific Northwest region would be viable, due to the shorter distance and hence lower costs. Over 700,000 kbpd of new rail unloading capacity is proposed for that region, but this faces massive public opposition (see Eric de Place,

'The Thin Green Line Is Stopping Coal and Oil in Their Tracks', August 13 2015, <http://daily.sightline.org/2015/08/13/the-thin-green-line-is-stopping-coal-and-oil-in-their-tracks/>). Since these terminals therefore have the same status as the blocked pipelines in this report, we focus rail economics on the Gulf Coast, where capacity already exists.

APPENDIX 2: BASICS OF THE INTEGRATED NORTH AMERICAN PIPELINE MODEL (INAP)

The INAP model aims to assess the surplus capacity for tar sands exports. Unlike some other analyses, it does not look only at the pipelines directly leaving Alberta (to BC or to the United States). Instead, it estimates the effective capacity by also considering bottlenecks throughout the entire system, from extraction in Western Canada to the ultimate refinery (or export tanker). INAP thus compares actual and forecast crude production in Alberta/Saskatchewan/Manitoba/NWT (combining tar sands, conventional crude oil and light tight oil) with the capacity of pipeline systems and refineries.

Where U.S. sources of crude (such as from the Bakken and Permian fields) enter the same export/distribution system (especially at Patoka and Cushing, but also Rockies, Clearbrook, Chicago area, and Sarnia/Westover), their actual or forecast flows are deducted from the pipeline capacity available for Western Canadian oil. The model treats all export infrastructure, and pipelines and refineries connected to it, as a single super-system, collectively optimising the individual pipeline systems that comprise it. There are several key pipelines connecting the nodes in different parts of the system: Pony Express, White Cliffs, later Saddlehorn and Grand Mesa from Rockies to Cushing; Ozark from Cushing to Patoka; BP1 from Cushing to Chicago; and Chicap and Mustang between Patoka and Chicago. The model first finds what would happen in the absence of these pipelines, then rebalances any gluts between the nodes, to the extent those pipes allow. Spearhead North from Flanagan to Chicago is handled similarly in the Enbridge system model. In contrast, Platte is treated as a straightforward part of the Canadian oil export system (even though it connects Rockies and Patoka). Rail exports from Canada are considered separately, as their economics are different.

Fundamental Approximations and Assumptions

Light and heavy oil are not differentiated in INAP. One reason for doing this is that synthetic crude (accounting for around half of current tar sands production) is a light oil, whereas diluted bitumen is heavy – hence tar sands include both light and heavy portions. Secondly, there is a degree of fungibility: pipelines can be switched between transporting light and heavy oil (sometimes with a relatively small investment in pump stations); and while heavy oil can only be refined in suitably equipped refineries, heavy-capable refineries can take light oil if necessary (though they

prefer not to, due to economics). The non-differentiation is an approximation because a pipeline's capacity to pump heavy will be lower than its capacity to pump light, due to higher viscosity: hence a barrel of one is not neatly exchangeable for a barrel of the other. It was judged that separating the streams would be an equally great, or greater, approximation, due to the degree of fungibility. Similar approximations are made in other estimates of pipeline capacity (e.g. CAPP, CERI), and our model shows strong correlation of surplus pipeline capacity with price differentials, which indicates the approximation is reasonable.

It is assumed that published capacities of pipelines are on the basis of the balance of grades they are considered likely to carry. Some nodes of the system are single terminals (e.g. Flanagan), while others represent several refineries/terminals in a town or city area (Chicago area, Sarnia, Cushing) and others larger regions combined into a single unit (Western Canada ex-BC, Rockies states (MT, WY, CO and UT), Gulf Coast). Patoka and Wood River are also treated as single node. Montreal, BC and the U.S. Gulf Coast are treated as having no constraints on capacity to receive oil due to potential export of any excess. In the case of Montreal, there are indeed loading constraints, but in reality they are unlikely to significantly restrict capacity in the coming years: in fact most Western Canadian oil via Enbridge Line 9 (post-reversal) will go to refineries in Montreal and Quebec City. The biggest approximation here is that the Gulf is treated as a single point location, on the assumption that pipelines will be built along the coast to connect supply gluts with refinery demand. Refineries (and most pipes) are treated as having steady capacity throughout the year, with maintenance times etc. changing annual averages but not monthly rates.

Bitumen is combined with diluent in a 72-28 ratio. The model assumes all Albertan (lease) condensate and 20% of NGLs are used as diluent, and a further 10% of NGLs are exported through the crude system; the rest of the 72-28 requirement is imported from the USA on Enbridge's Southern Lights pipeline, or brought from BC on Pembina's Peace or Northern pipeline systems.

In the U.S. Rockies (MT, WY, CO and UT), all crude and condensate production are assumed to enter the pipeline/refinery system, but none of the produced NGL does. Rail has been increasingly used to transport crude out of

the Rockies, to the U.S. west and east coasts, averaging 125 kbd in 2014. Road trucking from pipe system to refineries is neglected: i.e. it is assumed that the system can only deliver to a refinery if a pipeline goes right there.

Past and Future

For past years, INAP uses actual production data, annualized pipeline capacities, seasonally-adjusted refinery capacities and actual flows from competing inbound pipelines. For the tar sands export system itself (as opposed to connecting lines), future pipelines that are already fully approved and under construction are assumed to be completed on schedule. Those requiring approvals or subject to legal challenge are assumed not to proceed in the base case, with separate scenarios to show their impact. For competing lines from U.S. plays, approved and under-construction pipelines are assumed to be completed according to their current schedule. Proposed new U.S. pipelines (where permitting and land acquisition are needed) are assumed to start 6 months behind schedule. Expansions of existing lines are assumed to be completed on schedule.

Principal Data Sources

- ☑ Western Canadian production: annual production figures, historic and forecast, are taken from Rystad's UCube database.
- ☑ Pipeline capacities: Pipeline capacities are assumed to operate at up to 95% of nameplate capacity. They are generally taken from reports of the operator companies, with industry sources (e.g. Genscape), EIA or NEB data and media reports occasionally used e.g. for capacity additions.
- ☑ Refinery capacities: Annual capacities (i.e. allowing for maintenance/ downtime) are taken from the annual CAPP Statistical Handbook (Canada) and NPRA/AFPM Refinery Capacity Report (USA).
- ☑ Competing crude inputs: Competing crude volumes are taken from FERC Form 6 data (except small lines less than 60k bpd, which are approximated to run at 80% capacity). For future years, the utilization is assumed the same as in 2014, but adjusted according to growth/decline prospects in the oil play from which their crude is sourced.

Future Pipeline Construction and Expansions

The base case also assumes construction and expansion of the following U.S. pipelines: White Cliffs, Pony Express, Saddlehorn/Grand Mesa, Dakota Access, and Diamond.

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Design: paul@hellowpaul.com

GREENPEACE

CANONBURY VILLAS
LONDON
N1 2PN
+44 (0)20 7865 8100
greenpeace.org.uk

OILCHANGE
INTERNATIONAL

OIL CHANGE INTERNATIONAL
714 G ST. SE
WASHINGTON DC, 20003
+1-2-2-518-9029
priceofoil.org

