OILCHANGE INTERNATIONAL

LOCKDOWN: THE END OF GROWTH IN THE TAR SANDS

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Oil Change International (OCI) exposes the true costs of fossil fuels and identifies and overcomes barriers to the coming transition towards clean energy. OCI works to achieve its mission by producing strategic research and hard-hitting, campaign-relevant investigations; engaging in domestic and international policy and media spaces; and providing leadership in, and support for, resistance to the political influence of the fossil fuel industry, particularly in North America.

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LOCKDOWN:
THE END OF GROWTH IN THE TAR SANDS

The Alberta tar sands are among the most carbon intensive sources of oil in the world.

The oil industry has set expansion goals that, if reached, would see production soar from about 2.1 million barrels per day (mbpd) today to 4.7 mbpd by 2030, and to as much as 5.8 mbpd by 2035.[i,ii,1]

The tar sands are the third largest oil reserve in the world, and the vast majority of it cannot be burned if we are to avoid the worst impacts of climate change.[iii] If industry expansion plans are realized, carbon emissions from the tar sands would see Canada's emissions rise, rather than fall at a time when the country has promised to reduce emissions in line with limiting global warming to two degrees Celsius or less.

However, the industry is facing increasingly strong headwinds that show that this rapid expansion is far from inevitable. At the forefront is a groundswell of public opposition to tar sands export infrastructure and expansion due to their incompatibility with addressing the threat of global climate change and addressing local environmental, social and health risks. This is in addition to the recent steep drop in oil prices and the permanent high cost of extracting tar sands oil.

Citizen opposition from across North America has successfully stopped and/or delayed tar sands pipeline infrastructure, benefiting our shared climate. This citizen opposition is growing stronger as evidenced by massive public protests such as last year's People's Climate March in New York and this past summer's Jobs Justice and Climate March in Toronto.

This report illustrates that oil industry expansion plans are no longer inevitable. Public support for climate action, and therefore opposition to export pipelines for the tar sands, has directly impacted the viability of expansion plans in the land-locked tar sands. *The report also shows how building new tar sands pipelines would result in a direct and significant increase in carbon pollution.*

While rail will be used as a high cost backup for existing production, our cash-flow models show that the additional cost of shipping tar sands by rail can turn a typical tar sands project from a money maker to a loser (based on EIA forecasts of oil price.)

In almost all cases, development of new projects is therefore highly unlikely to be considered without secure pipeline capacity. Expanded rail transport cannot be considered a given either given growing public and political opposition.

Growing public opposition has put this high-carbon, high-cost sector in a position in which it could run out of pipeline export capacity once it reaches a production level of 2.5 mbpd, a level likely to be reached as soon as 2017. Currently, the tar sands pipeline system is 89 per cent full.

To conduct this analysis, OCI has constructed an **Integrated North American Pipeline model (INAP)**. The INAP model enables a comprehensive view of how pipeline capacity – or lack thereof – affects the development of the tar sands. It considers the two broad strategies which the industry is using for pipeline expansion: incremental and ongoing additions to existing systems and stand-alone new large pipeline proposals.

The analysis concludes that without new pipelines significant amounts (some 34.6 billion metric tons) of carbon will stay in the ground. *This would mean a better chance to maintain a safer climate future.*

In other words, tar sands producers have run out of room to grow. And public efforts to slow and stop tar sands expansion by challenging expansion of the North American tar sands pipeline system will continue to have a meaningful impact on keeping carbon in the ground.

The recent crash in global oil prices is a clear reminder of the sector's tight profit margins. The steep decline in prices has driven companies to slash spending, cut jobs and shelve projects. But many projects would have remained commercially viable with lower prices if sufficient pipeline capacity were available. For those projects, it is the market access constraints that have tipped projects into being unviable. Public opposition has and will continue to limit the pace and scale of tar sands expansion and that will mean the carbon stays in the ground, which is in line with what science confirms we need for a safe climate.

1 Views on the impact of the fall in oil prices vary among industry sources. The Canadian Association of Petroleum Producers has revised its 2030 tar sands production forecast to 4 mbpd (CAPP, Crude Oil Forecast, Markets & Transportation, June 2015, p.ii) whereas the Canadian Energy Research Institute forecasts 4.9 mpbd by 2035(Oil sands supply cost update, 2015-2035), August 2015, http://www.ceri.ca/images/stories/Study_152_-_Oil_Sands_Supply_Cost_Update_2015-2035_-_August_2015.pdf

SUMMARY OF KEY FINDINGS

Thanks to growing public opposition, tar sands expansion projects have been delayed or stopped, keeping carbon in the ground and benefiting our climate.

Currently, tar sands pipelines are nearly full, and leave no room for further growth in production:

- Current tar sands production is on the brink of running out of export capacity. If public opposition continues to block pipelines, the tar sands will lose the ability to expand, benefiting our shared climate.
- Without new pipelines and expansions, the tar sands will run out of pipeline capacity as soon as 2017, when tar sands production is projected to hit 2.5 mbpd (current production is 2.1 mbpd).
- The pipeline system is currently 89% full. This is because while the refinery and pipeline system have 4.5 mbpd of capacity, this is shared between 2.1 mbpd of tar sands, 0.4 mbpd of diluent and 1.5 mbpd of conventional production - totalling 4.0 mbpd.[2]
- In order to develop new projects, the tar sands sector will need to overcome massive public opposition to at least one of the following new major pipelines: Keystone XL, Energy East, Northern Gateway, or Trans Mountain Expansion, in the near-term. Without them, there is simply no spare export capacity. **But public opposition for each of these projects continues to grow**.
- In parallel with the fight for those mega-projects, Enbridge Inc. is driving a creeping expansion of existing lines, trying to keep up with production by a less-visible process. However, the stealth approach is not working: these expansions are also facing growing public and legal opposition.
- Recent expansions of the pipeline system on the U.S. side of the border mean that (after Line 61 expansion) bottlenecks in the Enbridge system would be at the border, where they are likely to require a Presidential permit - the hurdle that has delayed the Keystone XL pipeline for over six years.[3]
- If these incremental Enbridge system expansions overcome growing opposition, the tar sands would then run out of pipeline capacity in 2019 at 2.8 mbpd.

Rail can't solve the market access problem:

- Rail provides a stopgap solution for existing production that does not have access to pipelines; however, our analysis shows that the additional cost of shipping tar sands by rail can turn a typical tar sands project from commercial to uncommercial. In most cases, investment in new projects based on rail as the only transport option is therefore unlikely to go ahead.

Few, if any, new tar sands projects are viable, leading to significant carbon savings:

- Public opposition and market access constraints have created a *de facto* '**no new growth**' scenario in the tar sands where most new projects are unlikely to be greenlighted by producers without major new pipeline infrastructure. This is relative to industry expansion projections that aim at more than doubling production between 2012 and 2030.
- Our analysis shows that up to 46.6 billion barrels of proposed tar sands crude could be stranded if the four major new proposed pipelines do not get built. The emissions from producing and consuming the tar sands bitumen that could be left in the ground are 34.6 billion metric tons of CO_2 equivalent. This is equivalent to the emissions of 227 coal plants over 40 years.

2 While the capacities we have used are operating rather than peak capacities (ie taking into account the time required for maintenance or batching etc), it is still not possible to achieve 100% usage, as this would imply a perfectly efficient system; the likely maximum is 90-95%.

3 Proposals "for the construction, connection, operation, or maintenance," of pipelines that cross into the United States from a neighboring country require a Presidential permit under Executive Order 13337's. Modifications or expansions of existing pipeline systems must be approved through E.O. 13337's National Interest Determination process and subject to NEPA review. An expansion of Enbridge's existing cross border pipeline network will be subject to this process, providing the public with an opportunity to raise environmental concerns associated with tar sands infrastructure. Enbridge's initial proposal to expand its Line 65 is in the preliminary stages of the Presidential permit process and NEPA environmental review, while the company's attempt to modify its Line 3 are currently the subject of pending litigation (see White Earth Band of Chippewa Indians et al v. Kerry et.

Proposed expansions of the North American tar sands pipeline system: an overview

	Pipeline	Role in North American system	Status
Enbridge Expansions	Line 61 expansion phase 2	Expansion of Line 61 from Superior, WI, to Flanagan IL from 800 kbpd to 1,200 kbpd.	Tied up in a permitting dispute with a local authority relating to Enbridge's refusal to sufficiently insure spill risks. Facing growing public opposition along with all mid-west pipeline expansions.
	Alberta Clipper (Line 67)	Expansion of the Hardisty-Superior line from 450 to 800 kbpd. In the absence of a presidential permit, the cross-border section is being rerouted through Line 3, the permit for which is vague on volume restrictions.	Currently awaiting a cross-border Presidential permit for expansion. First Nations and environmental organizations are challenging Enbridge's move to use Line 3 as an interim solution to skirt the Presidential Permit hurdle in court.
	Line 3 replacement	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 kbpd one.	Currently facing opposition given Enbridge's intention to use a 50 year old permit to rebuild. Also facing legal and public opposition for its use in skirting the cross border permit required for Line 67.
TransCanada Keystone XL		Proposed 830 kbpd new pipeline to Cushing OK for access to the Gulf Coast and international markets.	Delayed for over 6 years by a failure to obtain the necessary cross-border presidential permit. Opposition driven by grassroots organizing across North America. The pipeline is now widely seen as an indicator of President Obama's commitment on climate change.
Enbridge Northern Gateway		Proposed 525 kbpd new pipeline from tar sands to Kitimat B.C. for access to the Pacific coast and subsequent tankers for international markets.	Granted approval from the Canadian government with 209 conditions, but widely considered 'unbuildable'. Facing unprecedented legal challenges from First Nations across British Columbia. Further concerns related to terminal construction and tanker traffic in high-risk waters.
Kinder Morgan TransMountain twinning		A twin pipeline that would add 590 kbpd between the tar sands and the Southern BC coast for Pacific access to international markets.	Facing increasing opposition and legal challenges from First Nations, the public and large municipalities. Additional opposition driven by concerns related to tanker traffic.
TransCanada Energy East		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.	Delayed for two years due to environmental concerns over beluga whale habitat. Facing mounting opposition from the public, 125 municipal resolutions along the route, 75 in opposition and 55 with serious concerns, as well as growing political hesitancy in support from provincial governments.

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LIST OF ABBREVIATIONS

AFPM	American Fuel and Petrochemical Manufacturers
API	American Petroleum Institute
Bbl	Barrel
Bn bbl	billion barrels
CAPP	Canadian Association of Petroleum Producers
CERI	Canadian Energy Research Institute
$C0_2e$	Carbon dioxide equivalent
Dilbit	Diluted Bitumen
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
INAP	Integrated North American Pipeline model
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal Rate of Return
kbpd	thousand barrels per day
mbpd	million barrels per day
NEPA	National Environmental Policy Act
NPV	Net Present Value
OCI	Oil Change International
SCO	Synthetic Crude Oil
WCS	Western Canada Select
WTI	West Texas Intermediate

INTRODUCTION

While the circumstances for rapid expansion of the tar sands have been favorable for the industry over the past two decades, there are clear signs that this perfect storm of unfettered market access, political support, growing U.S. demand and minimal regulatory constraints is shifting.

This report looks specifically at market access constraints and bottlenecks. Pipeline delays impede the ability of tar sands producers to get their product to market. This affects the price that they are able to receive – which is particularly impactful in a high-cost sector such as the tar sands, where profit margins can be tight. This lack of export infrastructure is among the biggest long-term threats for the land-locked tar sands. The industry knows this and has therefore placed a high priority on building new export infrastructure – but thus far, it has not succeeded.

The report considers the two broad strategies used by industry to increase pipeline capacity: major new pipeline infrastructure proposals and incremental expansion to existing systems. It also addresses the role of crude by rail as well as the climate implications of our conclusions.

Our analysis concludes that industry will run out of pipeline capacity as early as 2017 when tar sands production reaches 2.5 mbpd. This is a *de facto* 'no new growth' scenario, driven by the success of public opposition to increasing climate pollution.

Public opposition to tar sands extraction and major new export infrastructure that would link it to market now constitutes a formidable barrier to pipeline expansion in both the United States and Canada. Incremental expansions to existing pipelines needed to temporarily ease bottlenecks are also facing growing opposition.

Much of this opposition is driven by concern for climate and the environmental impacts of tar sands expansion, as well as concern for the direct impacts on communities on the front lines of development. The Alberta tar sands are among the highest-carbon oils on the planet, and a growing number of analyses have indicated that the vast majority of the remaining resource is so-called "unburnable carbon" in scenarios that work to limit dangerous global warming to 2 degrees C.[iv,v,vi] In June 2015, over 100 prominent North American scientists called for a moratorium on tar sands development and related infrastructure given its impact on greenhouse gas emissions and climate change.[vii]

The Intergovernmental Panel on Climate Change – among many others – has confirmed that the majority of fossil fuel reserves that we already have access to must stay in the ground.[viii] As such, expansion of tar sands production effectively ignores the best available science on how to avoid catastrophic global warming.

In the absence of political leadership on the need to slow and stop exploration and expansion of new fossil fuels, civil society efforts have stepped in to fill the vacuum by using other levers. In this case, by opposing, delaying and stopping the transportation infrastructure needed to affordably move the product to global markets, project economics have changed to make tar sands expansion increasingly unlikely.

TAR SANDS AND PIPELINES: HAND-IN-HAND GROWTH

The location of the tar sands in Northern Alberta is 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 the delay of Keystone XL, 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 specifically to deliver tar sands crude to newly converted refinery capacity in the U.S. Midwest.

Having inundated the Midwest refineries, the tar sands sector set its sights on the U.S. Gulf Coast, home to the world's largest concentration of refining capacity, 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.

However, the groundswell of local, national and international opposition to the tar sands industry, which has become a poster child of a high-carbon future incompatible with a safe global climate, was not predicted by industry. This opposition threatens not only Keystone XL but also Canadian pipelines such as Northern Gateway and Trans-Mountain Expansion to the Canadian west coast, Energy East aimed at the Canadian east, as well as expansions to existing pipeline systems such as the Enbridge Mainline.[ix] These proposed pipes, which were originally designed to come after Keystone XL and deliver future production growth to international markets in Asia and beyond, now hang in the balance.

Public efforts to delay and stop pipeline expansion have been successful, in that a supply glut in Alberta is rapidly approaching with production that is already online and under construction and the assured, affordable market access required to stimulate future production growth is simply not in place.

COLLATERAL IMPACTS

Uncertainty around market access for the tar sands is contributing to an unprecedented number of project delays following the crash in global oil prices.

For every 1,000 bpd of approved and in construction production capacity, over 500 bpd are trapped in delayed or on hold projects.[x] While oil prices are an important factor in capital expenditure decision-making, the current price environment has exposed more structural weakness within the tar sands industry, including the reality that affordable access to new markets is exceedingly critical for industry profitability.

Even prior to last year's 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, Shell's Pierre River and Total's Corner - had a combined capacity of 400,000 bpd and were cancelled while oil prices were above $90 per barrel.[xi]

These cancellations came at a time of growing concern related to market access.[xii] 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."[xiii]

Project and pipeline delays also 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 an industry-friendly conservative dynasty, to a left-leaning social democratic party committed to economic and energy diversification. Furthermore, they create additional time for critical legal efforts by First Nations and directly impacted communities in Northern Alberta to protect their traditional lands and treaty rights.

THE TAR SANDS EXPORT SYSTEM

There are four main pipeline routes out of Alberta and four additional major pipelines currently being proposed. These are described below and can be seen in Figure 1.

EXISTING PIPELINE SYSTEMS

The industry currently depends primarily on four major pipeline systems (broadly defined), described below:

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

'Rockies System' (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, competing with production from these states, and surplus carried on to Patoka, Illinois, and Cushing, Oklahoma. For the purposes of the model, these pipelines are collectively referred to as the "Rockies System", though in reality it is not considered a system, as it does not have a single operator.

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.

MAJOR PROPOSED PIPELINES

Industry's most recognized export infrastructure expansion strategy is the construction of major new pipelines. There are currently four such proposals:

Trans-Mountain Expansion: a twin pipeline that would add 690 kbpd capacity to the existing Trans-Mountain system. Kinder Morgan has applied for federal government approval from the Canadian Government, but faces massive opposition in British Columbia, especially from First Nations. It has faced a forced delay from the federal energy regulator driven in large part by public concern and protests from local communities, accompanied by a series of legal challenges from municipal governments.

Northern Gateway: Enbridge's proposed 525 kbpd westward pipeline to Kitimat, British Columbia. While the Canadian federal government approved the project in June 2014 with 209 conditions, this project faces profound obstacles. First Nations are challenging the approval in court, and opposition by many First Nations could make land acquisition and local permits impossible. The legal permissibility of ocean tanker shipments is also uncertain. Some believe Enbridge may be quietly shelving the project, both because of the legal and political challenges and because the 209 conditions may make the pipeline too expensive to be viable.[xiv]

Keystone XL: TransCanada's proposed 830 kbpd pipeline to Cushing. The pipeline has faced unprecedented levels of public opposition and is now seen as an issue that will either build or erode President Obama's environmental record. Having been held up for more than six years, it now awaits his decision, which is expected in the coming months.

Energy East: TransCanada's 1.1 mbpd eastward pipeline to refineries in eastern Canada and an export terminal in St. John,

Figure 1: Main Pipeline and Proposed Pipeline Routes Leading Out of the Alberta Tar Sands Source: Oil Change International

New Brunswick. Though at an earlier stage of regulatory review than the pipelines discussed above, public opposition to the project is growing. TransCanada formally filed for regulatory approval in October 2014 following months of delay given concerns over routing driven by the public. The pipeline already faces formal concerns from the provinces of Ontario and Quebec, 125 resolutions along the route (75 in opposition, 55 with serious concerns), as well as growing public opposition.[xv] The project was recently delayed by two years, following cancellation of a planned marine terminal at Cacouna, Quebec, due to impact on beluga whales.

PROPOSED PIPELINE SYSTEM EXPANSIONS

Another strategy central to industry's export capacity is incremental expansions to existing pipeline systems, in particular the Enbridge system. These expansions increase capacity on a step-by-step basis, shifting the bottleneck of the system to the next tightest point.

These too are facing growing public opposition, especially in the U.S. Midwest. Most recently, in August of 2015, dozens of students were arrested protesting the project, "Clippergate" or the "Switcheroo" - the re-routing of Enbridge's Line 67 through Line 3 to circumvent permitting requirements in front of Secretary of State, John Kerry's residence. In June 2015, thousands of demonstrators took to the streets of St Paul, Minnesota, to protest against the multiple pipeline expansions. The most important planned Enbridge expansions are:

- **Line 61 expansion, phase 2:** further expanding the line from Superior, Wisconsin, to Flanagan, Illinois, from 800 kbpd to 1,200 kbpd. The project is currently stuck in a standoff between Enbridge and a local authority. The zoning committee of Dane County, Wisconsin, made its permit approval conditional on Enbridge taking out sufficient insurance to cover the costs of an oil spill. The company has balked at the additional cost.

- **Alberta Clipper (Line 67) expansion:** increasing capacity of the Hardisty-Superior line, from 450 to 800 kbpd. Enbridge has applied for a cross-border permit, which is currently being considered by the State Department. While waiting for that permit, Enbridge decided to re-route the cross-border section through Line 3, whose permit is vague on volume restrictions. This move is currently being challenged in court by environmental and First Nations groups.

- **Line 3 replacement:** built in the 1960s, Line 3 is due for replacement. Enbridge looks poised to to exploit the vagueness of the permit to replace the 390 kbpd line with a larger one of 760 kbpd.

In the longer term, expansions are also being considered on Spectra's Express-Platte system.

Rail transport is used to meet shortfalls in pipeline capacity (see rail section below, page 19) but has generally proven to be an uneconomic alternative to pipelines for the tar sands industry.


Gas and Oil Pipeline Construction in the Lower Mainland, BC, Canada.

THE INTEGRATED NORTH AMERICAN PIPELINE MODEL (INAP)

In this report, we present a new and comprehensive market access model, examining the real capacity constraints that lead to widened oil price differentials and reduce the income received by tar sands producers. Earlier analysis done in collaboration with the Institute for Energy Economics and Financial Analysis estimated that these differentials cost the industry $31 billion between 2010 and 2013.[xvi]

INAP allows a thorough analysis of existing tar sands pipeline capacity, current bottlenecks and likely future bottlenecks. It demonstrates that market access was the central cause of this loss, and that continuing market access constraints will lead to further losses in the future as well as limiting profitable opportunities for expansion.

The model aims to assess the surplus capacity for tar sands exports. Unlike some other analyses, it looks not only at the pipelines directly leaving Alberta and Saskatchewan, but also at the entire continent-wide system for oil exports from western Canada (which includes tar sands).

INAP treats all export infrastructure, and the pipelines and refineries connected to it, as a single super-system, optimizing among the individual pipeline systems that comprise it. The entire system of connected pipelines is shown schematically in Figure 2.

The model assesses effective capacity by also considering bottlenecks, from western Canada to the ultimate refinery or export tanker. That capacity is reduced when taken up by competing U.S. crude production, especially light tight oil from shale fields.

Our detailed methodology is described in an Appendix 1.

In the analysis that follows, we compare two key quantities:

(a) Extracted Canadian crude oil that needs to reach a market (as modelled in Rystad Energy's UCube database);
(b) Pipeline system and refinery capacity available for Canadian crude.

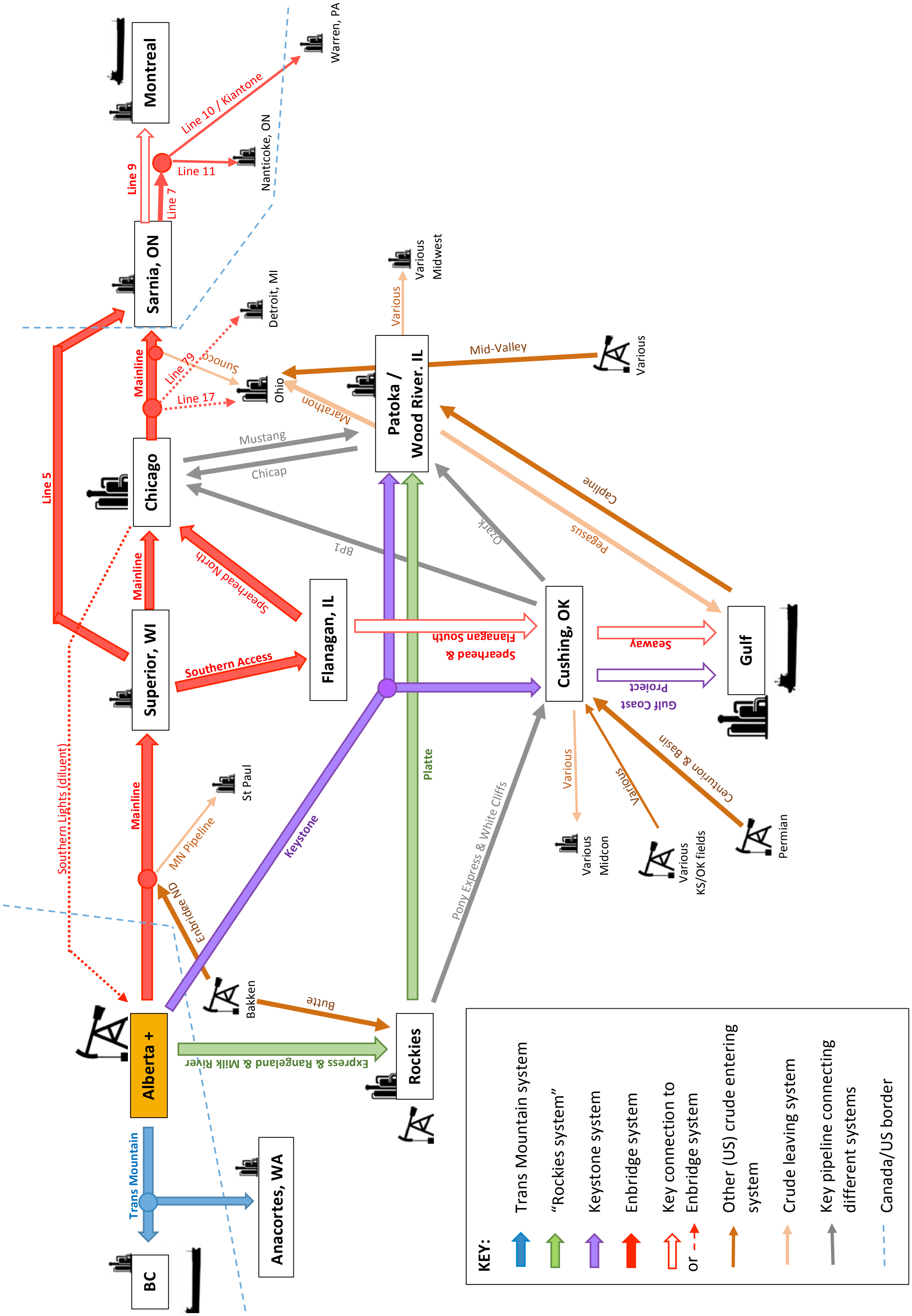
To further explain these two:

(a) Canadian crude volumes consist of three elements:
- a. Tar sands production, comprising bitumen and (upgraded) synthetic crude;
- b. Diluent, used to dilute the bitumen in order to allow it to flow down pipelines;
- c. Conventional crude oil, which largely uses the same export system.

These volumes, historical and forecast, are shown in Figure 3. The growth in production from 2015 to 2020 is a result of tar sands extraction projects that are already under construction, for which producers are unlikely to write off the capital already invested.

Figure 2: A Schematic Model of the North American Pipeline System Used to Export Canadian Crude (including tar sands)

Source: Oil Change International



In subsequent charts, we show only the combined, total Canadian crude production. Charts to 2020 show only the production from existing and under-development projects. Figure 9, which extends to 2030, shows also the additional production that would be generated by new, as yet unsanctioned projects.

(b) Available capacity also consists of three elements:

a. Canadian refinery capacity in Alberta and Saskatchewan;

b. Pipeline capacity to the USA or to Canadian coasts;

c. Crude transported by rail (actual volumes).

These three are shown separately in subsequent charts.

We show actual historical volumes rather than capacity of rail exports, because the economics are different from those of pipelines. Rail loading capacity substantially exceeds actual usage, which is limited due to high transport costs.

U.S. crude oil enters the same pipeline system in several places. For instance, light, tight oil from the Bakken shales enters at Clearbrook, Minnesota, and various crudes from Texas and elsewhere enter at Cushing, Oklahoma. The reduction in available pipeline capacity is shown in Figure 4.

Due to the nature of the system, these U.S. crude oil inputs have different impacts on available capacity, depending on where they enter the system. They have a larger impact if they enter at an existing bottleneck, for example.

Figure 3: Canadian Crude Production, Historical and Forecast (kbpd)

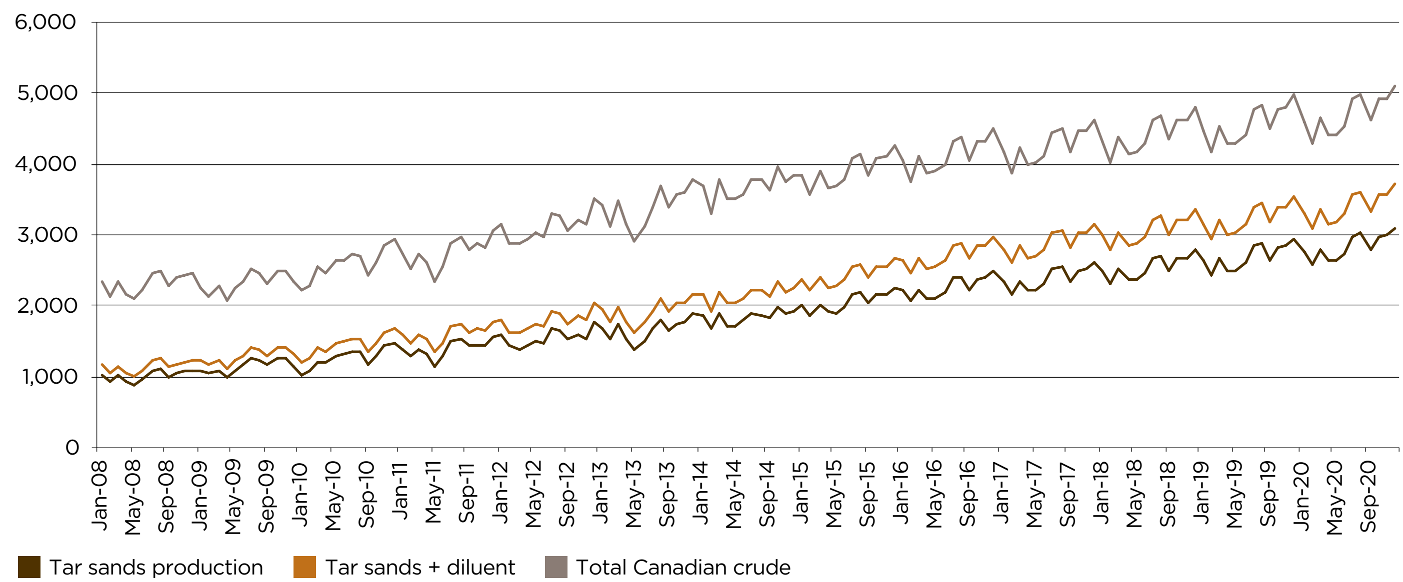
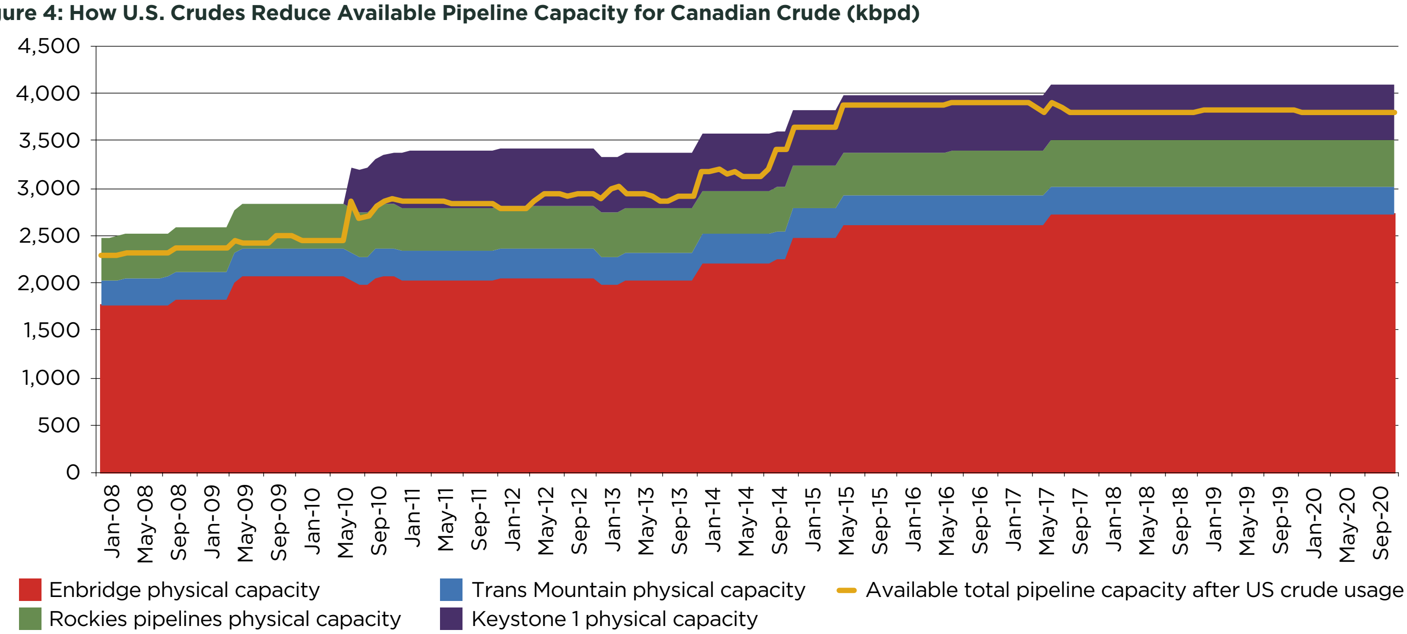


Figure 4: How U.S. Crudes Reduce Available Pipeline Capacity for Canadian Crude (kbpd)



For that reason, subsequent charts show the available capacity after deducting the actual (historical and forecast) volumes of these U.S. crudes. Where U.S. crudes' demand for pipelines increases, the available capacity for Canadian crude sometimes declines over time.

PAST CAPACITY AND THE CURRENT SYSTEM

In order to examine the future, it is helpful first to understand the system as it exists currently, and how it got to this point. An examination of past capacity and utilization (2008-14) was also used to test the model against actual export data and price spreads.

Figure 5 shows how the export system has been expanded since 2008. **Since the opening of the Keystone 1 pipeline in July 2010, surplus export system capacity has shrunk. It has grown especially tight from 2012 onward, reducing the price producers receive for tar sands oil in Alberta.**

The price of Western Canada Select (a benchmark for diluted bitumen) has traded at a discount of up to $38 per barrel, relative to West Texas Intermediate, which is the standard North American oil price benchmark.[4]

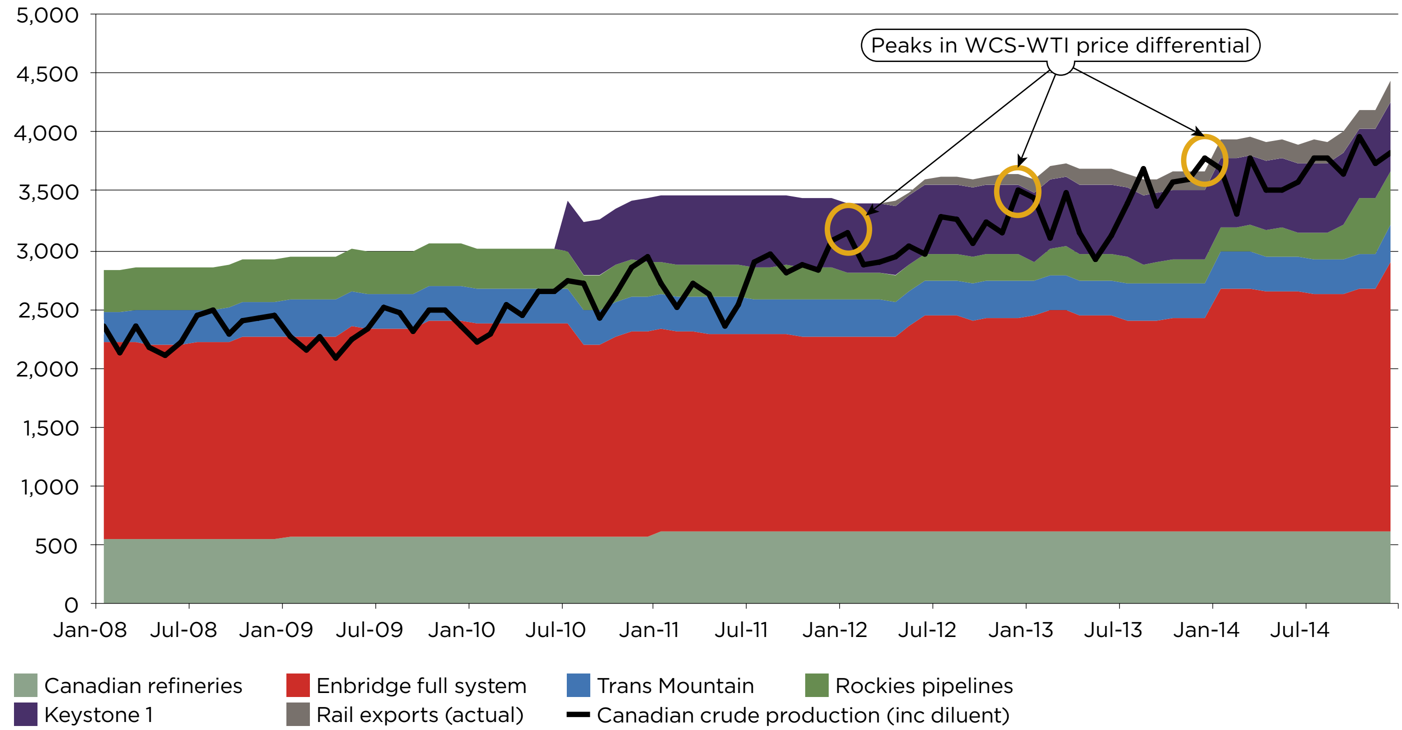
This discount peaked precisely at the times when pipeline capacity was tightest, as shown by our model. (See Box: Understanding Crude Oil Benchmarks, page 22.)

Additionally, Figure 5 shows:

- The biggest addition to the entire system was Keystone 1 in July 2010;

- The capacity of the Enbridge system grew in January 2014, with the completion of upgrades on BP's Whiting refinery, and the TransCanada Gulf Coast (Keystone South) pipeline that increased flows south from Cushing to the Gulf Coast. It grew again in December 2014, with the Seaway Twin and Flanagan South pipelines. The addition of Clipper in October 2010 increased cross border capacity but

Figure 5: Expansion of Canadian Crude Export System 2008 – 2014 Source: Oil Change International



4 Oil price data from Bloomberg Professional. The monthly-average spot WTI-WCS price spread peaked at $37.5 in October 2013.

the Enbridge system remained limited until these south-of-the-border constraints were eased;

- In 2013 and 2014 spare capacity remained tight, but increasing use of rail provided short-term relief.

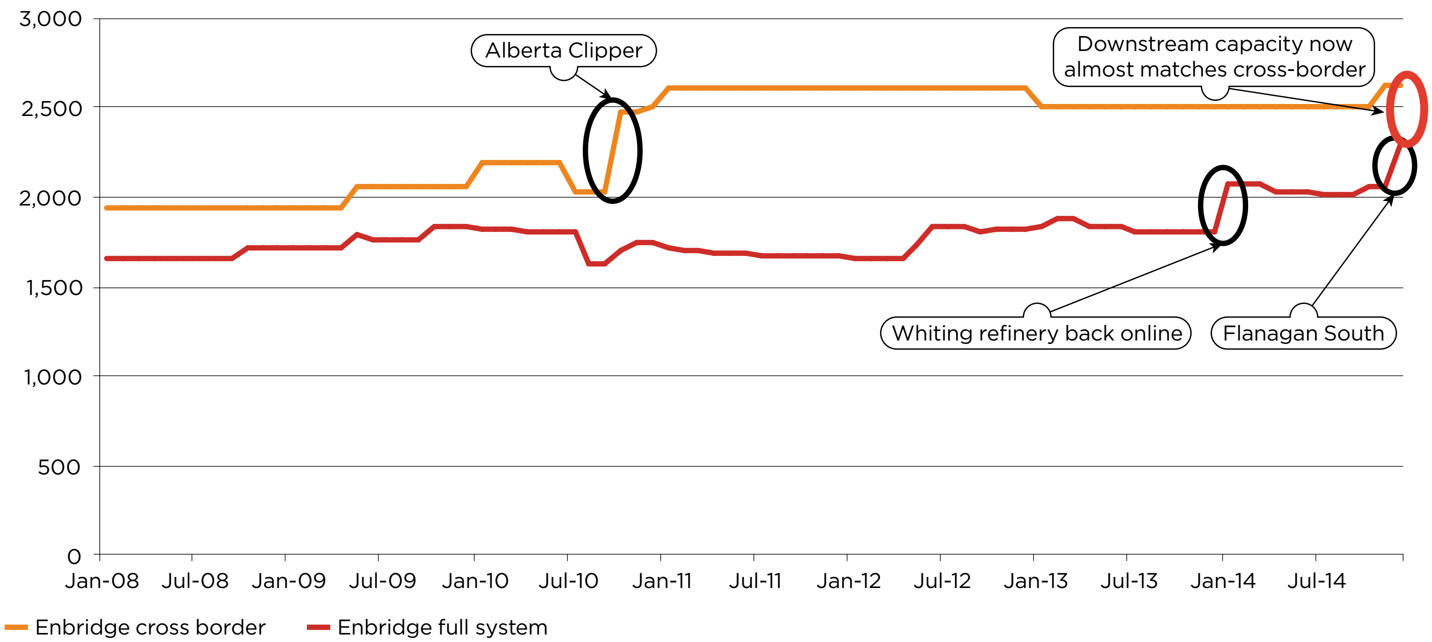
Our model looks at the complex network of connected pipelines and refineries. It shows that in the Enbridge system, cross-border capacity has consistently exceeded downstream capacity, as shown in Figure 6. The cross-border pipelines have therefore not been used at full capacity, because they run into bottlenecks downstream.

For that reason, Enbridge has focused recent expansions on the U.S. side of the border, particularly Flanagan South (to Cushing, Oklahoma) and Seaway (from Cushing, Oklahoma) to the Gulf Coast.

With these expansions, **capacity south of the border has nearly caught up with cross-border capacity. This means that significant further expansion is likely to require a Presidential permit.**[5]

The last major cross-border increase was the construction of the Alberta Clipper in October 2010.

Figure 6: Illustration of Bottlenecks in the Enbridge System 2008 – 2014 Source: Oil Change International



5 Proposals "for the construction, connection, operation, or maintenance," of pipelines that cross into the United States from a neighboring country require a Presidential permit under Executive Order 13337's. Modifications or expansions of existing pipeline systems must be approved through E.O. 13337's National Interest Determination process and subject to NEPA review. An expansion of Enbridge's existing cross border pipeline network will be subject to this process, providing the public with an opportunity to raise environmental concerns associated with tar sands infrastructure. Enbridge's initial proposal to expand its Line 65 is in the preliminary stages of the Presidential permit process and NEPA environmental review, while the company's attempt to modify its Line 3 are currently the subject of pending litigation (see White Earth Band of Chippewa Indians et al v. Kerry et.

KEY FINDINGS AND ANALYSIS: FUTURE PIPELINE CONSTRAINTS

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PIPELINES NEARLY FULL

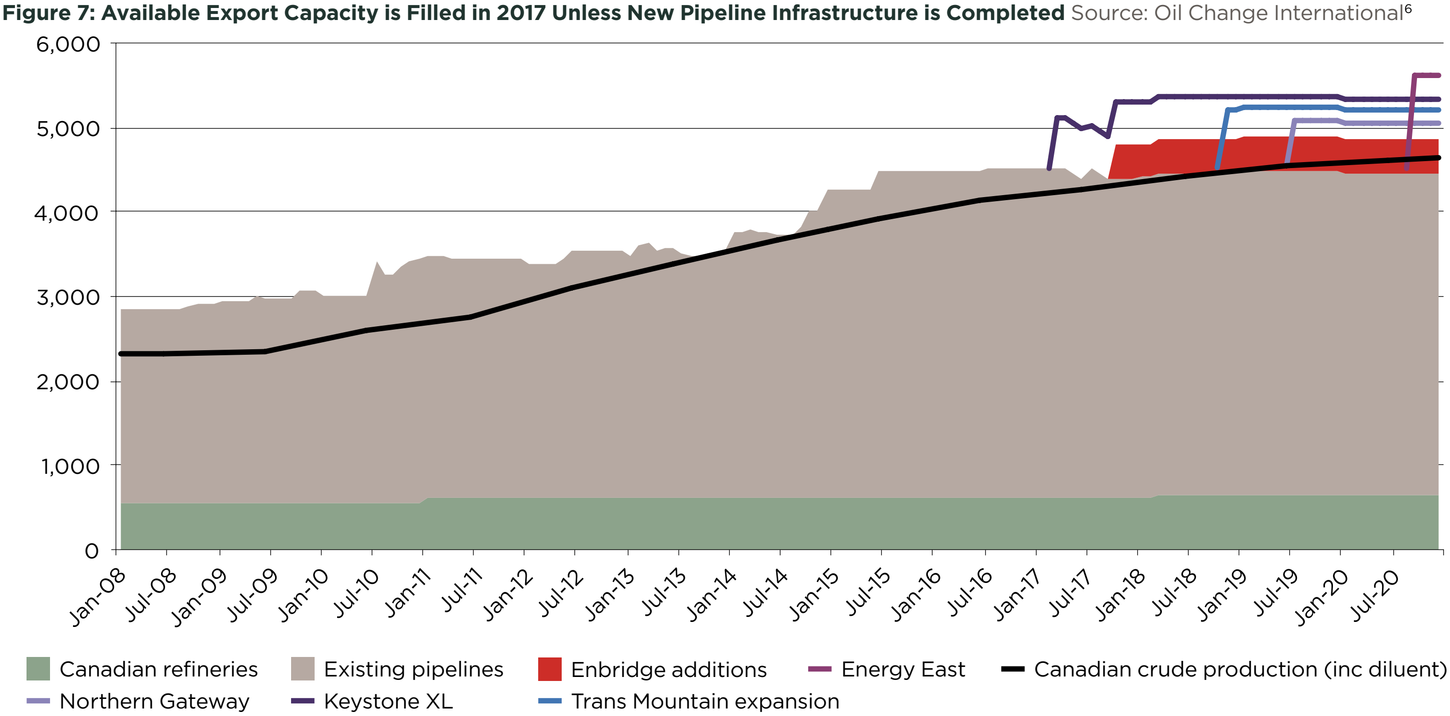
Tar sands production is set to grow for a few years even if no new projects are approved, due to projects coming on stream that are already under construction. The reason for this is that building a tar sands project commonly takes five years or more, so extraction is currently growing due to projects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

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. [xvii]

Due to this locked-in growth, without any new pipelines, the export system will likely be completely full by mid-2017 (Figure 7). The system is currently 89% full.

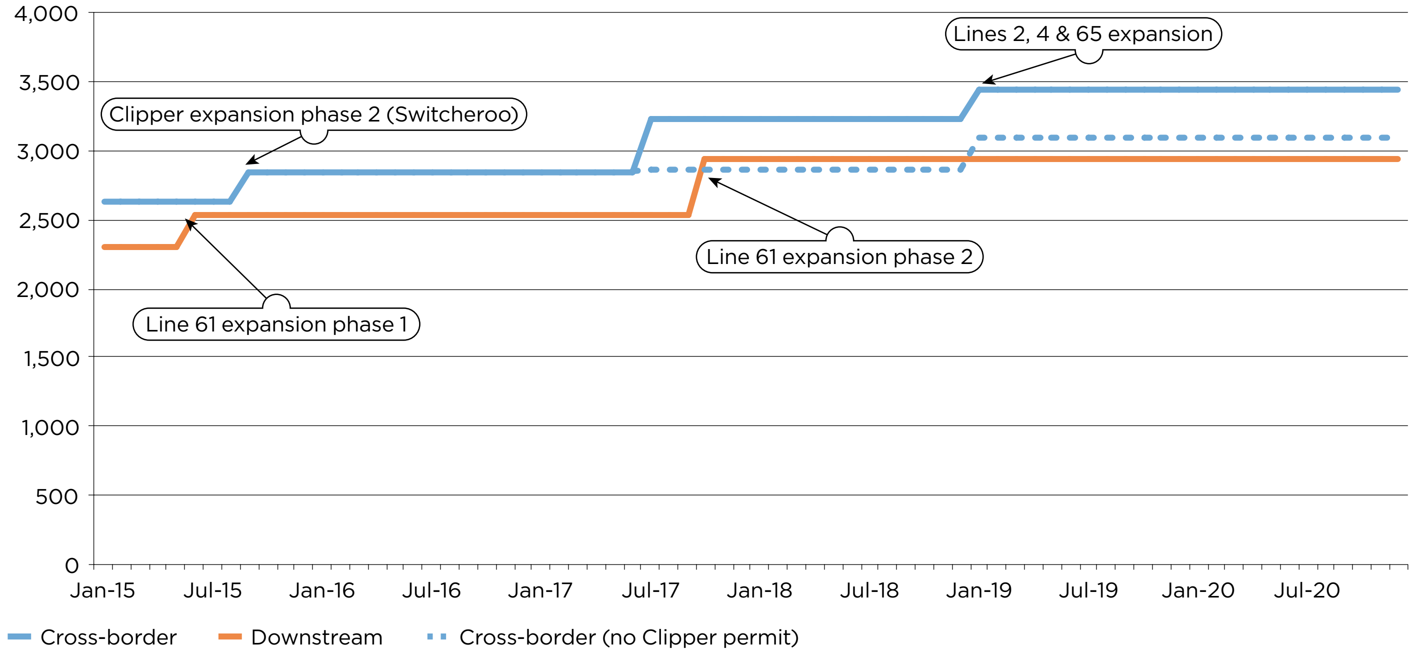
On the other hand, any one of the major new pipelines - Keystone XL, Energy East, Northern Gateway, or Trans Mountain Expansion- together with planned additions to the Enbridge system, would create spare capacity out to 2020 and beyond. Without the Enbridge additions, two of these major pipelines would be needed to keep up with current tar sands production growth.

Figure 7: Available Export Capacity is Filled in 2017 Unless New Pipeline Infrastructure is Completed Source: Oil Change International[6]



6 Whereas previous charts in this report have included a seasonal variation in production rates, for the longer term we focus just on the underlying trend. In the Enbridge additions scenario, when seasonal variations are imposed the peak production results in capacity constraints in 2019.

Figure 8: Enbridge System Bottlenecks (historical and forecast) Source: Oil Change International



Even with Enbridge expansions, the capacity crunch is pushed out by just over two years, to 2019, in the absence of the major new pipelines i.e. if all of the planned additions to the Enbridge system overcome the opposition and are completed.

As for the Enbridge System, the largest among the short-term expansion projects is Line 61 from Superior, WI, to Flanagan IL. This pipeline is currently delayed by the Zoning Committee of Dane County, WI. The committee requires that Enbridge take sufficient insurance to cover a potential spill on the Line 61 expansion, which the company refuses to do.

As mentioned above, the model shows how the Enbridge system bottleneck would move to the border if Line 61 is built. The priority for Enbridge would then be the permanent expansion of the Alberta Clipper, allowing Line 3 to expand in its own right in mid-2017. The Clipper expansion, however, requires a U.S. Presidential permit, like Keystone XL, and like any other cross-border pipeline (Figure 8). The inability to obtain this permit has delayed Keystone XL for over six years.

The Enbridge system cross-border bottleneck would gain temporary reprieve with the 'Switcheroo' – which would shuffle oil between Line 67 and Line 3 for a short stretch across the Manitoba/North Dakota border in order to increase cross-border capacity. This switch would enable around 350 kbpd of additional cross-border capacity while Enbridge seeks permanent expansions that require a new Presidential permit.

These 'stealth' efforts by Enbridge to expand pipeline capacity through incremental expansions and exploiting regulatory loopholes are also facing significant and growing public and legal opposition. While historically these expansions have been less visible than larger scale and new pipeline projects, this is increasingly no longer the case. Grassroots, municipal, and national opposition to these projects is growing – putting further unexpected pressure on the industry for what were long-considered quick fixes to address bottlenecks.

RAIL WILL NOT SUPPORT NEW TAR SANDS PROJECTS

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.[xviii]

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. Railing crude from Alberta to the U.S. Gulf Coast has proved uneconomic, as tar sands crude competes there with heavy crudes from Mexico and elsewhere that have much lower transport cost.

Even those in the business of transporting tar sands crude by rail admit that rail cannot substitute for pipelines, but instead acts as a band-aid for insufficient pipeline capacity. “Crude by rail is not a panacea,” says Stewart Hanlon, President & CEO, Gibson Energy Inc, a tar sands rail terminal operator. “It’s not going to replace pipe.”[xix] 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.

The cost of rail is already eating into profit margins to the extent that many producers have given up on railing to the most important refining market for tar sands crude, the U.S. Gulf Coast.[xx] Industry consultant IHS Energy estimates that transporting heavy oil from Alberta to the Gulf Coast by rail costs $10.50 per barrel of bitumen more compared with pipelines.[xxi] IHS assessments of tar sands by rail have been consistently over-optimistic and we believe this to be a conservative estimate at best.[xxii]

Producers will turn (and have turned) to rail when they have no choice, when there is no pipeline available. In 2014, Canadian crude oil shipments by rail to the Gulf Coast averaged a mere 36,500 bpd.[7] If we assume that all Canadian shipments to the Midwest went onto the Gulf Coast via barge the total is still less than 50,000 bpd.[8] This is just six percent of the capacity of the proposed Keystone XL pipeline.

The stopgap role of rail can be seen in Figure 5. 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.

7 EIA Crude by rail data http://www.eia.gov/dnav/pet/PET_MOVE_RAILNA_A_EPC0_RAIL_MBBL_M.htm Conversion from monthly total barrels to barrels per day by Oil Change International
8 Ibid.

Understanding Crude Oil Benchmarks

Crude oil sales use a number of 'benchmark' indexes as reference points for pricing. A benchmark is of a specified composition (of light and heavy hydrocarbon compounds, and impurities), and delivered at a specified geographical location. Any sale can then determine a price, based on how the traded crude's composition differs from the benchmark, plus a transport cost associated with its location.

The most well-known international benchmarks are Brent, a light, sweet (low-sulphur) blend delivered to Sullom Voe, Scotland; and West Texas Intermediate (WTI), which is also light and sweet, delivered to Cushing, Oklahoma. When people talk about 'the oil price', they are usually referring to the market price of one of these two benchmarks.

WTI is sometimes used in Canadian trades, as much Canadian crude ends up in the refineries of the U.S. Midwest. The most important Canadian benchmark is Western Canadian Select (WCS), a blend of bitumen, conventional heavy crude oil and diluent (dilbit), delivered to Hardisty, Alberta. Syncrude is also traded: a synthetic medium/light crude (upgraded bitumen), delivered to Edmonton.

The benchmark prices vary according to market conditions. If a delivery point receives more crude than it has pipeline capacity to pump out, the excess supply over demand depresses the price of the relevant benchmark. This was the case in Cushing before the Seaway and TransCanada Gulf Coast (Keystone South) pipelines were built and as a result WTI traded at a wide discount to Brent. During 2011-13, WTI prices were generally around $15-20/barrel lower than Brent, whereas previously they had been about the same (within $2-3).

An oil producer in Alberta has essentially two options for how to sell their oil. Either they can sell to a trader in the local market in Hardisty or Edmonton, based on the WCS or syncrude price, or they can pay to transport the oil to another market (such as the U.S. Midwest or Gulf Coast), based on the WTI price. In the former case, the traders either sell to a local refinery or pay themselves to transport it elsewhere.

Through many transactions, the two options should reach equilibrium. Thus the WCS price gives an estimate of the price a new tar sands producer obtains for a barrel of dilbit, and the syncrude price an estimate of what a tar sands upgrader would obtain for synthetic crude. The price a producer actually obtains is called the netback price.*

As pipeline capacity is constrained, netbacks will fall relative to other crude benchmarks, to reflect the excess supply in Alberta relative to export capacity. For example, in early 2012, as spare capacity fell below 100 kbpd, the price differential between WCS and WTI spiked at nearly $38 (i.e. a barrel of WCS in Hardisty would sell for $38 less than a barrel of WTI in Cushing).

**Producers may obtain higher netbacks than WCS or the syncrude price, if they have contracts for committed pipeline capacity at a fixed price.*

And whereas on earlier occasions pipeline constraints had pushed the Western Canada Select (WCS) price to a record spread of $38 below West Texas Intermediate (WTI) (see Box: Understanding Crude Oil Benchmarks), in 2014 the differential peaked at around $20 per barrel. While rail can buffer differentials to a degree, the differential can remain substantial even with some rail infrastructure.

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.[9]

9 This analysis is primarily based on the economics of rail to the U.S. Gulf Coast. The Gulf Coast is the number one destination for tar sands crude in North America after the already saturated U.S. Midwest. The capacity to unload significant quantities of tar sands crude by rail in the Gulf Coast exists but is being substantially underutilized because of the poor economics. 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 railing instead 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 terminals are proposed for that region, but are facing massive public opposition (see Eric de Place, 'The Thin Green Line Is Stopping Coal and Oil in Their Tracks', 13 August 2015, http://daily.sightline.org/2015/08/13/the-thin-green-line-is-stopping-coal-and-oil-in-their-tracks/). Since they therefore have the same status as the blocked pipelines in this report, we focus rail economics on the Gulf, where capacity already exists.

CASE STUDIES: RAIL ECONOMICS AND STOPPING TAR SANDS EXPANSION

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 these proposed projects might be able to proceed if rail is the only option available.

The economic impact of relying on rail would be to reduce the netbacks received by producers. Ultimately, a decision on whether to proceed with a new project investment will depend on a company's expectations of future oil prices and its appetite for risk; however looking at the economics for various project profiles, we can assess likely outcomes.

Table 1, below, groups tar sands projects that have not yet broken ground according to the breakeven price band. This gives a rough indicator of project economics.[10] The projects are all listed in Appendix 2.

- 8 projects have breakeven prices below $70. This may be low enough – and hence potential profits high enough – to justify the risk of developing a project even without a secure export route. However, other factors including mounting First Nation opposition, shifting taxation policies, new climate policies and stronger environmental regulations may pose additional challenges.
- 78 projects have breakeven prices between $70 and $100. These are likely to be in the borderline area, where market access may become a serious threat – so we examine these further below.
- 65 projects have breakeven prices above $100. Even if prices do rise, this would push the projects into the marginal zone, in which market access becomes a significant factor.

Table 1: Undeveloped Tar Sands Projects by Phase 1 Breakeven Price Band Source: Rystad UCube

Breakeven oil price	Number of projects	2035 production[xxiii] (kbd)	Reserves (bn bbl)
<$70	8	88	1.0
$70-100	78	1,244	20.5
>$100	65	1,121	26.0

10 Defined as the constant real oil price at which project NPV would be positive, at a 10% discount rate.

For the projects in the middle range, we look at the economics of reduced market access using a cashflow model to assess the profitability for four typical projects, with different breakeven prices in that middle range. The results are shown in Table 2, using the U.S. Energy Information Administration's (EIA) current price forecast.[xxiv] The EIA's forecast has been revised downwards to reflect the price drop of the last year, but grows steadily, reaching $100 again around 2030.

We model the impact of market access constraints by reducing the netbacks received by producers by $10.50 per barrel. This is the additional cost of carrying crude by rail from Alberta to the Gulf Coast, the principal growth market for tar sands, as estimated by industry consultant IHS.[11]

While the threshold Internal Rate of Return (IRR) required for approving a project will vary from company to company, it is generally around 10% (in real terms). Below this level, companies would not consider projects to be viable, due to not meeting the cost of capital, or being unattractive compared to other opportunities worldwide.

The results below show that while these typical projects remained profitable in spite of the current low price expectations, the reduced netbacks due to market access constraints could tip a project from commercial to marginal, or marginal to uncommercial.

Given the impact on project economics that rail is likely to assert we can conclude that the vast majority of tar sands expansion is unlikely to be viable without affordable, secure new pipeline infrastructure.

This is a conclusion that is supported by industry bodies. The Canadian Association of Petroleum Producers (CAPP) has confirmed that additional pipelines are imperative to make new expansion commercial.[xxv]

Table 2: Profitability of Illustrative Undeveloped Projects – Impact of Market Access Constraints[12] Source: Oil Change International

Project	Rystad breakeven price	IRR (EIA price forecast)	
		No constraint	market access constraint
Christina Lake Phase 3B (MEG)	74-75	11.8%	9.2%
Foster Creek Phase J (Cenovus/Conoco)	76-77	12.1%	9.7%
Sunrise Phase 2A (BP/Husky)	88-89	10.6%	8.5%
Christina Lake Phase H (Cenovus/Conoco)	91-92	10.1%	8.7%

11 IHS Energy, Crude by rail: The new logistics of tight oil and oil sands growth, December 2014, p.15. Table 2 gives total median cost of transporting bitumen by pipeline as $16 per barrel, and by rail (as dilbit) as $26.50. Prices for Canadian dilbit at the Gulf Coast are modeled relative to Maya, using EIA's Brent forecast adjusted by (i) 3-year averages of Maya price differentials to Brent, (ii) the 3-year average cost of shipping Maya from Cayo Arcas to the Gulf, and (iii) the formula that each degree of API gravity raises the price 0.7%, while each additional one percentage point of sulphur lowers the price 5.6%, as developed by in Robert Bacon & Silvana Tordo, 2005 paper. Crude Oil Price Differentials and Differences in Oil Qualities: A Statistical Analysis, World Bank ESMAP Technical Paper 081,https://www.esmap.org/sites/esmap.org/files/08105.Technical%20Paper_Crude%20Oil%20Price%20Differentials%20and%20Differences%20in%20Oil%20Qualities%20A%20Statistical%20Analysis.pdf The table also gives lower rail costs for transporting railbit or rawbit, which both have lower diluent content than dilbit; however the reality is that the vast majority of tar sands crude that travels by rail does so as diluted bitumen (dilbit), so we do not include these largely hypothetical costs in our model. The reason is that the large unit train terminals in Alberta are located in Edmonton and Hardisty, hundreds of miles from the tar sands fields. Bitumen is transported to these two locations exclusively by pipeline, for which it is necessary to dilute it to dilbit. While diluent recovery is an option in theory, to date only one experimental diluent recovery unit is under construction and the economics are as yet unproven. The shippers that are railing undiluted bitumen are doing so at small terminals close to production using trucks to ferry bitumen from production sites to the loading terminals. They save on diluent but generally pay more expensive 'manifest rail' shipping rates as they cannot achieve the economies of scale that unit train shipping affords. Therefore, nobody is actually achieving the 'holy grail' of unit train raw bitumen shipping that is costed in IHS's table.

12 The cashflow model uses production, capex and opex forecasts from Rystad UCube. Government take is calculated by the model, according to Alberta tar sands fiscal terms. Oil price forecasts are from the US Energy Information Administration's annual energy outlook, 2015. The 'no constraint' cases assume netback prices obtained for the oil to be equal to average price differentials in the absence of market access constraints, namely WCS (at Hardisty) = WTI (at Cushing) minus $12. The 'constrained' case deducts $10.50 from the netback price received, due to reliance on rail.

KEEPING CARBON IN THE GROUND: A CEILING ON TAR SANDS PRODUCTION

According to our model, refinery and pipeline capacity for Canadian tar sands crude is 4.5 mbpd.[13] Roughly 1.5 mbpd of this is taken up by conventional Canadian crude. There is thus available capacity for around 2.5 mbpd of tar sands production, plus 0.5 mbpd of diluent to make the bitumen flow. If expansions to the Enbridge system overcame the opposition, this could increase to 2.7-2.8 mbpd of tar sands production.

Projects already under construction would take tar sands production to 2.9 mbpd. So there is no further space in pipelines to export tar sands from any new projects.

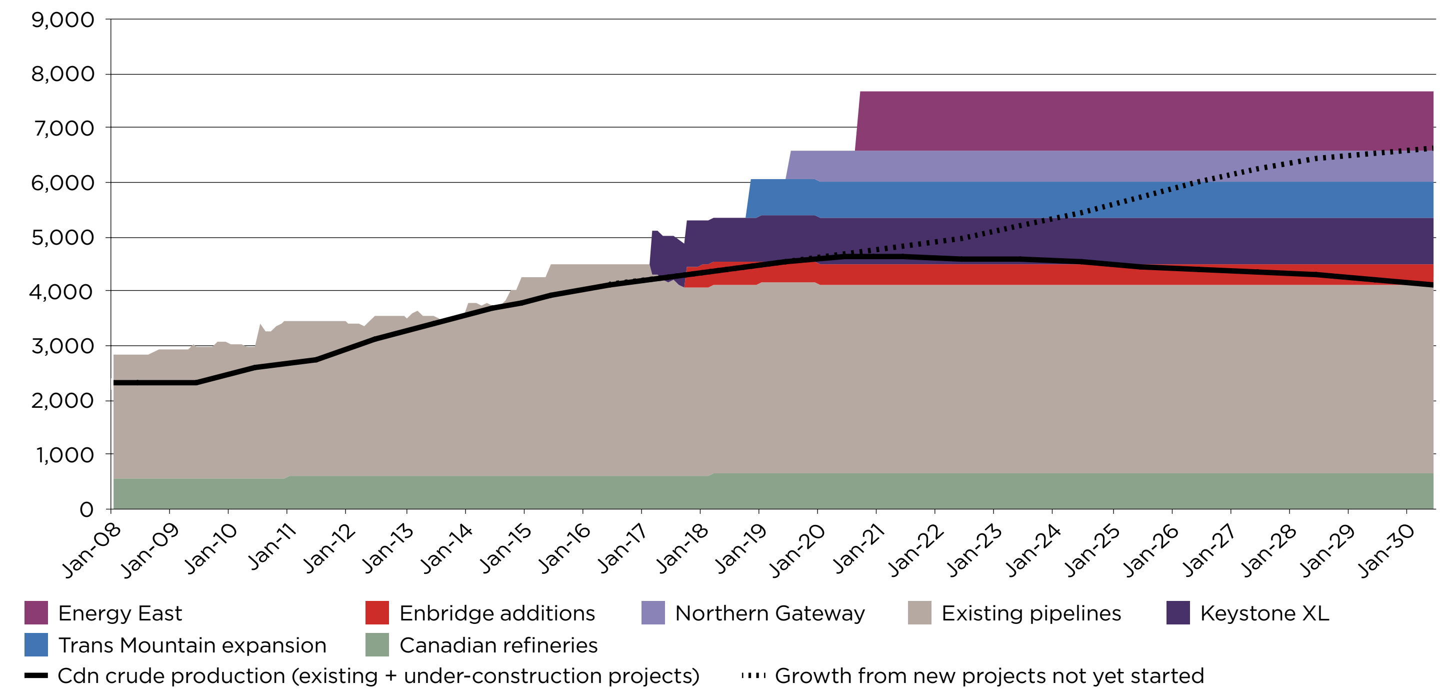
We can thus estimate the ceiling for tar sands production, in the absence of major new export infrastructure, as being approximately 2.9 mbpd. This is a significantly different pathway than industry's stated plans to more than double production levels between 2012 and 2030 (to around 4.7 mbpd according to Rystad).

Figure 9 below shows the capacity increases of both expansions to the Enbridge system, as well as the 4 major new pipeline proposals and compares them with both the locked-in production growth from tar sands projects already under construction, and that from new projects not yet started. Importantly, it shows that without the new major pipelines there is no room in pipelines for further growth in tar sands production and that the addition of projects already under construction will exceed export capacity.

In a scenario in which no tar sands projects that are yet to break ground go ahead - with the possibly exception of the eight projects with breakeven price below $70 - up to 46.6 billion barrels of tar sands crude in all the other currently proposed projects and project phases will be left in the ground. The emissions from producing, processing and consuming this bitumen are estimated at nearly 34.6 billion metric tons.[15] This is equivalent to the emissions from 227 average U.S. coal-fired power plants over 40 years.[16]

Figure 9: Forecast Western Canadian Crude Oil (including tar sands) Production and Existing and Proposed Pipeline Capacity

Source: Oil Change International[14]



13 4.5 mbpd includes total capacity to absorb Canadian crude, combining capacity of refineries in Alberta and Saskatchewan and the capacity of downstream pipelines (beyond Alberta) and the refineries they serve.

14 Note that Western Canadian crude production is forecast to fall from 4.6 mbpd in 2020 to 4.1 mbpd in 2030 (including diluent) if no new tar sands products are developed, due to depletion of Canada's conventional oilfields.

15 We used Rystad UCube to divide proposed projects into those that would produce bitumen and those that would produce synthetic crude oil (SCO). This is important as SCO production is generally more emissions intensive than bitumen production. We then used the Carnegie Endowment for International Peace Oil Climate Index (http://oci.carnegieendowment.org/) to derive average per barrel GHG emissions from the production, processing and consumption of bitumen and SCO. The Oil Climate Index assessed three streams of SCO and we averaged these to attain a figure of 0.775 metric tons of carbon dioxide equivalent (CO_2e) per barrel of SCO. For bitumen we took the figure for a barrel of diluted bitumen (dilbit) and replaced the diluent portion with the equivalent figure for raw bitumen to derive a barrel of bitumen. This resulted in a figure of 0.73 metric tons of CO_2e per barrel of bitumen. These figures are appropriate for assessing the true carbon content embedded in tar sands resources. They encompass the full range of emissions involved in extracting, processing and consuming all the products derived from the bitumen. Other studies looking at the life cycle emissions of tar sands bitumen have examined the emissions intensity of the most common products derived from crude oil, i.e. gasoline and diesel. These studies may not give a complete picture of the emissions from consuming the complete barrel and also present issues in extrapolating back to the original barrel. (See for example: http://pubs.acs.org/doi/abs/10.1021/acs.est.5b01255)

16 We took the total emissions embedded in the projects calculated as described in Footnote 16 and divided by 40. We then entered this number into the EPA's Greenhouse Gas Equivalents Calculator http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results to derive the U.S. coal plant equivalent.

CONCLUSION

Tar sands producers have run out of room to grow. Without major new export infrastructure, few - if any - new tar sands projects will be viable. This is a *de facto* no new growth scenario and would result in some 34.6 billion tons of CO_2 left in the ground.

Currently, the industry's pipeline system is 89% full and growing opposition delaying and stopping major new export infrastructure, combined with resistance to incremental expansions to temporarily ease bottlenecks, could lead to export constraints as early as 2017. If industry overcomes growing opposition to incremental expansions, major constraints will then be reached in 2019 without major new pipelines.

In order for significant new tar sands expansion to be sanctioned by companies, the INAP model confirms that major new pipeline capacity (i.e. one or more of the four new major proposals) would have to be built in the near-term. But all of these major pipelines – Keystone XL, Northern Gateway, Energy East and TransMountain - are currently in limbo, facing substantial public, legal, and political opposition.

Rail will continue to be used as a high cost backup for existing production, but our cashflow models confirm that the additional cost of shipping tar sands by rail can turn a typical tar sands project from commercial to uncommercial (based on EIA forecasts of oil price). In almost all cases, development of new projects is therefore highly unlikely to be considered viable without secured pipeline capacity. Existing and proposed rail expansion is also facing growing public and political opposition, which could further drive up costs.

The projects we examined would have still looked viable under reduced price expectations following the price drop of the last year, if they could export by pipeline. Subsequently, these market access constraints are a critical factor in the viability of expansion under current expectations of oil price recovery.

Without major new export infrastructure, pipeline capacity will be exhausted between 2.5 and 2.8 mbpd of tar sands production: a no new growth scenario. This is relative to around 2.1 mbpd of current production and significantly lower than industry's expansion goals of more than doubling production by 2030.

Public concern and efforts to slow and stop tar sands expansion by challenging expansion of the North American tar sands pipeline system are poised to have a meaningful impact on keeping carbon in the ground – close to 34.6 billion tons of CO_2 – if existing hurdles to pipeline expansion are maintained. This is equivalent to the emissions of 227 coal plants over 40 years.

The analysis and model presented in this report confirm that public opposition and efforts to restrict market access have effectively limited the pace and scale of tar sands expansion, and will keep carbon in the ground in line with what science confirms is necessary for a safe climate future.


PEOPLES CLIMATE MARCH
FRONTLINES OF CRISIS
FOREFRONT OF CHANGE
POWER TO THE PEOPLE!
FIRE
WATER
BIKE LANE
CLIMATE JUSTICE NOW NOW NOW
green love
ROCKAWAY YOUTH TASK FORCE
PEOPLE POWER in full bloom
STOP TRANSCANADA PIPELINE

APPENDICES

APPENDIX 1: METHODOLOGY

Basics of the Integrated North American Pipeline model (INAP)

The INAP model aims to assess the surplus capacity for tar sands exports, from 2008 to 2020. 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 Alberta (and SK, MB & NWT) 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 optimizing the individual pipeline systems that comprise it. There are several key pipelines connecting the nodes in different parts of the system (dark grey in the full system schematic on page 13): 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. For future projections, we assume this increases to 200 kbd in 2015, 250 in 2016, 300 in 2017, 400 in 2018 and 500 in 2019-20.

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. In the scenario where Keystone XL is built, it is assumed that – due to the resulting glut at Cushing – pipeline flows from the Permian to Cushing are reduced by 80%, and instead travel to the West coast (by rail) or to the Gulf (by rail or pipeline). This is because the Permian has significant surplus rail loading and pipeline capacity, and because Permian producers will have less long-term transport contracts with pipeline owners.

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 (e.g. Line 9B reversal and expansion to 300 kbpd) 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: For past years, annual production figures are taken from Rystad's UCube database, shared between months for past in proportion to Statistics Canada's production data.[17] For future years, Rystad forecasts (base case) are used, with seasonal variation in proportion to the average variation of 2008-14.
- Pipeline capacities: Pipeline capacities are annual capacities (i.e. allowing for maintenance and batching) rather than peak/daily. They are generally taken from reports of the operator companies,[18] 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)[19] and NPRA/AFPM Refinery Capacity Report (USA).[20]
- Competing crude inputs: Competing crude volumes are taken from FERC Form 6 data (except small lines less than 60kbpd, 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.

17 Statistics Canada, CANSIM Table 126-0001, Supply and disposition of crude oil and equivalent
18 For example: http://www.enbridge.com/~/media/www/Site%20Documents/Delivering%20Energy/LiquidsPipelines/Pipeline%20Configuration%20Map_%20Q1%202014.pdf
19 http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook
20 For example, latest can be found at: https://www.afpm.org/uploadedFiles/Content/Publications/Statistics/2014%20Refining%20Capacity%20Report.pdf

APPENDIX 2: UNDEVELOPED TAR SANDS PROJECTS

Asset	Companies	Resources Barrels (2015)	Estimated Potential Production BPD (2030)	Product (Bitumen)	CO_2e/Bbl (Tonnes)	Total CO_2e (Tonnes)
Aspen	ExxonMobil/Imperial	299,780,300	27,014	Bitumen	0.73	218,839,619
Birch AOSC phase 1	Kuwait Petroleum / Athabasca	109,907,700	7,205	Bitumen	0.73	80,232,621
Birch Mountain Phase 1	CNRL	299,806,400	30,000	Bitumen	0.73	218,858,672
Birch Mountain Phase 2	CNRL	284,796,800	9,608	Bitumen	0.73	207,901,664
Birchwood demonstration	Marathon	131,150,300	7,200	Bitumen	0.73	95,739,719
Birchwood Phase 2	Marathon	191,763,100	10,512	Bitumen	0.73	139,987,063
Black Gold Phase 2	KNOC (South Korea)	123,910,100	12,000	Bitumen	0.73	90,454,373
Blackrod Phase 1	Black Pearl Resources	330,679,600	12,000	Bitumen	0.73	241,396,108
Blackrod Phase 2	Black Pearl Resources	1,791,855,000	18,000	Bitumen	0.73	1,308,054,150
Blackrod Phase 3	Black Pearl Resources	628,965,500	6,798	Bitumen	0.73	459,144,815
Burnt Lakes	Laricina Energy	56,852,910	-	Bitumen	0.73	41,502,624
Caribou Lake Demonstration Project	Husky Energy	109,386,800	7,000	Bitumen	0.73	79,852,364
Carmon Creek Phase 2	Shell	275,659,900	28,000	Bitumen	0.73	201,231,727
Christina Lake Phase H	Cenovus/Conoco	462,929,000	30,000	Bitumen	0.73	337,938,170
Christina Lake MEG Phase 3A	MEG Energy	465,515,600	40,000	Bitumen	0.73	339,826,388
Christina Lake MEG Phase 3B	MEG Energy	267,478,100	35,000	Bitumen	0.73	195,259,013
Christina Lake MEG Phase 3C	MEG Energy	170,434,700	35,000	Bitumen	0.73	124,417,331
Conn Creek	Laricina Energy	130,413,400	-	Bitumen	0.73	95,201,782
Dawson Phase 2	Touchstone Exploration	72,923,550	5,000	Bitumen	0.73	53,234,192
Dover North Phase 1	PetroChina	519,590,700	35,000	Bitumen	0.73	379,301,211
Dover North Phase 2	PetroChina	364,634,400	35,000	Bitumen	0.73	266,183,112
Dover South Phase 3	PetroChina	364,646,100	35,000	Bitumen	0.73	266,191,653
Dover South Phase 4	PetroChina	546,657,800	9,186	Bitumen	0.73	399,060,194
Dover South Phase 5	PetroChina	364,646,100	-	Bitumen	0.73	266,191,653
Dover West Sands Phase 1	Athabasca Oil Corp.	87,916,720	7,200	Bitumen	0.73	64,179,206
Dover West Sands Phase 2	Athabasca Oil Corp.	255,738,500	17,500	Bitumen	0.73	186,689,105
Dover West Sands Phase 3	Athabasca Oil Corp.	255,698,100	13,168	Bitumen	0.73	186,659,613

Asset	Companies	Resources Barrels (2015)	Estimated Potential Production BPD (2030)	Product (Bitumen)	CO_2e/Bbl (Tonnes)	Total CO_2e (Tonnes)
Dover West Sands Phase 4	Athabasca Oil Corp.	255,659,400	173	Bitumen	0.73	186,631,362
Dover West Sands Phase 5	Athabasca Oil Corp.	255,567,000	-	Bitumen	0.73	186,563,910
Equinox	Teck Resources	409,596,800	-	Bitumen	0.73	299,005,664
Foster Creek Phase J	Cenovus/Conoco	333,071,200	30,000	Bitumen	0.73	243,141,976
Frontier Phase 1	Teck Resources	409,656,900	36,131	Bitumen	0.73	299,049,537
Frontier Phase 2	Teck Resources	578,448,900	-	Bitumen	0.73	422,267,697
Frontier Phase 3	Teck Resources	434,473,500	-	Bitumen	0.73	317,165,655
Frontier Phase 4 Equinox	Teck Resources	429,710,800	-	Bitumen	0.73	313,688,884
Gemini commercial_Baytex Energy	Baytex Energy	29,980,390	3,562	Bitumen	0.73	21,885,685
Germain Phase 2	Laricina Energy	205,868,800	18,000	Bitumen	0.73	150,284,224
Germain Phase 3	Laricina Energy	337,783,000	36,000	Bitumen	0.73	246,581,590
Germain Phase 4	Laricina Energy	339,770,100	3,373	Bitumen	0.73	248,032,173
Grand Rapids Phase 1	Cenovus Energy	74,948,430	8,000	Bitumen	0.73	54,712,354
Great divide expansion 1A	Connacher	87,906,310	8,400	Bitumen	0.73	64,171,606
Great divide expansion 1B	Connacher	87,918,160	8,400	Bitumen	0.73	64,180,257
Gregoire Lake Phase 1	CNRL	315,789,000	30,000	Bitumen	0.73	230,525,970
Gregoire Lake Phase 2	CNRL	289,790,000	296	Bitumen	0.73	211,546,700
Grosmont AOSC	Bounty & Athabasca	105,332,700	-	Bitumen	0.73	76,892,871
Grouse	CNRL	495,537,800	30,000	Bitumen	0.73	361,742,594
Hangingstone AOSC Phase 2A Debottleneck	Athabasca Oil Corp.	362,716,800	24,000	Bitumen	0.73	264,783,264
Hangingstone AOSC Phase 3	Athabasca Oil Corp.	308,466,700	18,000	Bitumen	0.73	225,180,691
Hoole Phase 1_Cavalier Energy	Paramount Resources	54,955,150	6,000	Bitumen	0.73	40,117,260
Hoole Phase 2_Cavalier Energy	Paramount Resources	255,764,900	17,500	Bitumen	0.73	186,708,377
Hoole Phase 3_Cavalier Energy	Paramount Resources	255,790,800	17,500	Bitumen	0.73	186,727,284
Jackfish East	Devon Energy	145,858,000	10,000	Bitumen	0.73	106,476,340
Joslyn (Deer Creek) SAGD Phase 2	Total/Others	41,208,610	3,763	Bitumen	0.73	30,082,285
Joslyn (Deer Creek) SAGD Phase 3A	Total/Others	53,953,760	-	Bitumen	0.73	39,386,245

Asset	Companies	Resources Barrels (2015)	Estimated Potential Production BPD (2030)	Product (Bitumen)	CO_2e/Bbl (Tonnes)	Total CO_2e (Tonnes)
Joslyn (Deer Creek) SAGD Phase 3B	Total/Others	45,965,650	-	Bitumen	0.73	33,554,925
Kai Kos Dehseh Corner Expansion	Statoil	292,616,700	18,562	Bitumen	0.73	213,610,191
Kai Kos Dehseh Corner	Statoil	375,622,800	28,000	Bitumen	0.73	274,204,644
Kai Kos Dehseh Leismer Expansion	Statoil	129,909,000	14,000	Bitumen	0.73	94,833,570
Kai Kos Dehseh North Hangingstone	PTTEP	190,757,500	-	Bitumen	0.73	139,252,975
Kai Kos Dehseh NW Leismer	Statoil	170,824,600	-	Bitumen	0.73	124,701,958
Kai Kos Dehseh South Hangingstone	PTTEP	177,818,200	-	Bitumen	0.73	129,807,286
Kai Kos Dehseh South Leismer	Statoil	190,696,300	6,559	Bitumen	0.73	139,208,299
Kai Kos Dehseh Thornbury	PTTEP	203,845,300	24,000	Bitumen	0.73	148,807,069
Kai Kos Dehseh West Thornbury	PTTEP	225,840,000	16,986	Bitumen	0.73	164,863,200
Kearl Phase 3 (Debottleneck)	Imperial	875,257,400	56,000	Bitumen	0.73	638,937,902
Kirby North CNR Phase 2	CNRL	437,551,900	36,000	Bitumen	0.73	319,412,887
Kirby South CNR Phase 2	CNRL	89,910,450	7,205	Bitumen	0.73	65,634,629
Legend Lake Phase A1	Sunshine Oil Sands	72,944,320	6,000	Bitumen	0.73	53,249,354
Legend Lake Phase A2	Sunshine Oil Sands	219,707,400	15,000	Bitumen	0.73	160,386,402
Legend Lake Phase B	Sunshine Oil Sands	326,177,200	4,804	Bitumen	0.73	238,109,356
Liege	OSUM	420,672,300	-	Bitumen	0.73	307,090,779
Lindbergh phase 2_Pengrowth	Pengrowth Energy	99,881,400	8,750	Bitumen	0.73	72,913,422
Lindbergh phase 3_Pengrowth	Pengrowth Energy	99,883,460	10,000	Bitumen	0.73	72,914,926
MacKay River Phase 2_Petrochina	PetroChina	419,686,500	28,000	Bitumen	0.73	306,371,145
MacKay River Phase 3_Petrochina	PetroChina	148,325,700	29,031	Bitumen	0.73	108,277,761
MacKay River Phase 4_Petrochina	PetroChina	129,724,100	24,788	Bitumen	0.73	94,698,593
May River Phase 1 & 2	Gulfport Energy & others	131,230,900	7,123	Bitumen	0.73	95,798,557
May River Phase 3-4-5	Gulfport Energy & others	248,814,200	18,027	Bitumen	0.73	181,634,366
McKay Phase 2	Suncor	130,706,300	7,200	Bitumen	0.73	95,415,599
McMurray East Phase 1	Cenovus	303,392,900	15,000	Bitumen	0.73	221,476,817
Namur Pilot	Marathon & others	19,980,200	1,826	Bitumen	0.73	14,585,546

Asset	Companies	Resources Barrels (2015)	Estimated Potential Production BPD (2030)	Product (Bitumen)	CO_2e/Bbl (Tonnes)	Total CO_2e (Tonnes)
Narrows Lake Phase B	Cenovus/Conoco	317,773,000	31,500	Bitumen	0.73	231,974,290
Narrows Lake Phase C	Cenovus/Conoco	342,776,900	-	Bitumen	0.73	250,227,137
Northern Lights Phase 1	Total/Sinopec	200,243,600	-	Bitumen	0.73	146,177,828
Orion (Hilda Lake) Phase 2	OSUM	97,742,340	7,000	Bitumen	0.73	71,351,908
Pierre River Phase 1	Shell/Chevron/Marathon	744,410,500	49,063	Bitumen	0.73	543,419,665
Pierre River Phase 2	Shell/Chevron/Marathon	1,093,024,000	5,315	Bitumen	0.73	797,907,520
Pike 1	BP	199,878,300	21,000	Bitumen	0.73	145,911,159
Pike 2	BP	199,752,900	-	Bitumen	0.73	145,819,617
Pike 3	BP	199,322,900	-	Bitumen	0.73	145,505,717
Red Earth commercial	Southern Pacific Resources	23,985,070	5,000	Bitumen	0.73	17,509,101
Red Earth pilot expansion	Southern Pacific Resources	29,953,040	1,500	Bitumen	0.73	21,865,719
Saleski Laricina Phase 1	Laricina Energy	117,040,900	7,490	Bitumen	0.73	85,439,857
Saleski Laricina Phase 2	Laricina Energy	306,434,400	15,000	Bitumen	0.73	223,697,112
Saleski Laricina Phase 3	Laricina Energy	662,243,100	18,099	Bitumen	0.73	483,437,463
Saleski Laricina Phase 4	Laricina Energy	654,969,900	-	Bitumen	0.73	478,128,027
Saleski Laricina Phase 5	Laricina Energy	420,587,900	-	Bitumen	0.73	307,029,167
Saleski West OSUM	OSUM	344,644,000	-	Bitumen	0.73	251,590,120
Sepiko Kesik Phase 1	OSUM	219,787,300	18,000	Bitumen	0.73	160,444,729
Sepiko Kesik Phase 2	OSUM	219,783,200	13,922	Bitumen	0.73	160,441,736
Sunrise Phase 2A	Husky/BP	446,617,800	49,000	Bitumen	0.73	326,030,994
Sunrise phase 2B	Husky/BP	446,631,900	48,767	Bitumen	0.73	326,041,287
Sunshine Thickwood Phase A1	Sunshine Oil Sands	167,593,100	7,000	Bitumen	0.73	122,342,963
Sunshine Thickwood Phase A2	Sunshine Oil Sands	219,836,600	15,000	Bitumen	0.73	160,480,718
Sunshine Thickwood Phase B	Sunshine Oil Sands	219,815,400	15,000	Bitumen	0.73	160,465,242
Surmont MEG Energy	MEG Energy	636,410,800	73,808	Bitumen	0.73	464,579,884
Surmont Phase 3 - Tranche 1	Conoco/Total/MEG	491,676,500	22,500	Bitumen	0.73	358,923,845
Surmont Phase 4	Conoco/Total/MEG	109,913,000	-	Bitumen	0.73	80,236,490

Asset	Companies	Resources Barrels (2015)	Estimated Potential Production BPD (2030)	Product (Bitumen)	CO_2e/Bbl (Tonnes)	Total CO_2e (Tonnes)
Taiga/Marie Lake (Cold Lake OSUM) Phase 1	OSUM	467,262,600	16,100	Bitumen	0.73	341,101,698
Taiga/Marie Lake (Cold Lake OSUM) Phase 2	OSUM	149,883,900	15,400	Bitumen	0.73	109,415,247
Telephone Lake Phase A	Cenovus Energy	225,825,400	27,000	Bitumen	0.73	164,852,542
Telephone Lake Phase B	Cenovus Energy	491,561,100	17,112	Bitumen	0.73	358,839,603
Walleye Phase 1	Devon Energy	59,942,750	5,400	Bitumen	0.73	43,758,208
West Ells Phase A2	Sunshine Oil Sands	75,729,230	3,500	Bitumen	0.73	55,282,338
West Ells Phase A3	Sunshine Oil Sands	219,823,000	15,000	Bitumen	0.73	160,470,790
West Ells Phase B	Sunshine Oil Sands	145,874,300	7,959	Bitumen	0.73	106,488,239
West Ells Phase C	Sunshine Oil Sands	327,205,400	3,008	Bitumen	0.73	238,859,942
West Kirby Phase 1	Cenovus Energy	219,767,900	8,643	Bitumen	0.73	160,430,567
Winefred Lake Phase 1	Cenovus Energy	219,767,800	14,750	Bitumen	0.73	160,430,494
Asset	**Companies**	**Resources Barrels (2015)**	**Estimated Potential Production BPD (2030)**	**Product (SCO)**	**CO_2e/Bbl (Tonnes)**	**Total CO_2e (Tonnes)**
ATS-1	Value Creation	109,891,600	9,000	SCO	0.775	85,165,990
ATS-2	Value Creation	219,783,200	1,687	SCO	0.775	170,331,980
ATS-3	Value Creation	219,783,200	-	SCO	0.775	170,331,980
Chard Phase 1	Exxon/Suncor/others	434,292,200	-	SCO	0.775	336,576,455
Firebag Phase 5	Suncor	799,977,500	43,750	SCO	0.775	619,982,563
Firebag Phase 6	Suncor	799,848,900	43,750	SCO	0.775	619,882,898
Firebag Stages 3-6 Debottleneck	Suncor	167,897,100	13,800	SCO	0.775	130,120,253
Fort Hills Debottlenecking	Suncor/Total/Teck	220,694,800	14,000	SCO	0.775	171,038,470
Horizon Phase 4	CNRL	999,198,100	72,603	SCO	0.775	774,378,528
Horizon Phase 5	CNRL	899,367,500	21,260	SCO	0.775	697,009,813
Jackpine Extension	Shell/Chevron/Marathon	800,421,900	70,000	SCO	0.775	620,326,973
Jackpine Phase 1B	Shell/Chevron/Marathon	655,623,700	70,000	SCO	0.775	508,108,368
Joslyn (Deer Creek) Mine Phase 1 (North)	Total/Others	523,892,800	56,115	SCO	0.775	406,016,920
Joslyn (Deer Creek) Mine Phase 2 (North)	Total/Others	349,251,400	-	SCO	0.775	270,669,835

Asset	Companies	Resources Barrels (2015)	Estimated Potential Production BPD (2030)	Product (SCO)	CO_2e/Bbl (Tonnes)	Total CO_2e (Tonnes)
Joslyn (Deer Creek) Mine Phase 3 (South)	Total/Others	218,828,800	-	SCO	0.775	169,592,320
Joslyn (Deer Creek) Mine Phase 4 (South)	Total/Others	218,828,800	-	SCO	0.775	169,592,320
Lewis Creek Phase 1	Suncor	282,727,700	20,000	SCO	0.775	219,113,968
Lewis Creek Phase 2	Suncor	235,772,900	-	SCO	0.775	182,723,998
Long Lake Phase 2 (Kinosis 2)	CNOOC	200,760,900	28,000	SCO	0.775	155,589,698
MacKay River Phase 2	Suncor	165,781,200	15,068	SCO	0.775	128,480,430
Meadow Creek Phase 1	Suncor / CNOOC	350,498,200	28,000	SCO	0.775	271,636,105
Meadow Creek Phase 2	Suncor / CNOOC	325,505,500	-	SCO	0.775	252,266,763
Muskeg River Mine Expansion and Debottlenecking	Shell/Chevron/Marathon	875,179,300	80,500	SCO	0.775	678,263,958
Suncor Voyageur South Phase 1	Suncor	1,555,660,000	-	SCO	0.775	1,205,636,500
Syncrude Mildred Lake and Aurora Stage 3 Debottlenecking	Canadian Oil Sands/ Suncor/Exxon/others	590,365,700	37,500	SCO	0.775	457,533,418
Syncrude Stage 4 (Aurora South)	Canadian Oil Sands/ Suncor/Exxon/others	1,093,656,000	57,093	SCO	0.775	847,583,400
Tamarack Phase 1	Ivanhoe Energy	510,000	12,000	SCO	0.775	395,250
Tamarack Phase 2	Ivanhoe Energy	510,002	8,466	SCO	0.775	395,252
Terre de Grace Phase 1	BP / Value Creation	218,849,200	20,000	SCO	0.775	169,608,130
Terre de Grace Phase 2	BP / Value Creation	56,965,120	-	SCO	0.775	44,147,968
Terre de Grace Pilot	BP / Value Creation	91,907,020	7,000	SCO	0.775	71,227,941
Tristar Pilot	Value Creation	7,290,786	600	SCO	0.775	5,650,359
Totals		47,522,016,528	2,452,379			35,307,100,512

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