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Can Canada Expand Oil and Gas Production, Build Pipelines and Keep Its Climate Change Commitments?

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Cover photo by Garth Lenz

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David Hughes is an earth scientist who has studied the energy resources of Canada and the US for more than four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager, where he headed unconventional gas and coal research. His research focus has been on unconventional fuels, primarily shale gas and tight oil, but also coal, coalbed methane and other unconventional sources, including oil sands, coal gasification and gas hydrates. Hughes is currently President of Global Sustainability Research Inc, a consultancy dedicated to research on energy and sustainability issues.

Hughes has published widely in the scientific literature and his work has been featured in *Nature, The Economist, LA Times, Bloomberg, USA Today* and *Canadian Business,* as well as other press, radio, and television. Most recently he authored *A Clear Look at BC LNG: Energy security, environmental implications and economic potential,* published by the Canadian Centre for Policy Alternatives' BC Office.

He also published *Drilling Deeper: A Reality Check on US Government Forecasts of a Lasting Shale Gas and Tight Oil Boom,* which is an in-depth review of major US shale gas and tight oil plays, including forecasts of future production. This was preceded by *Drilling California: A Reality Check on the Monterey Shale,* which critically examined the US Energy Information Administration's (EIA) estimates of technically recoverable tight oil in the Monterey Shale, and predicted the subsequent 96% downgrade of tight oil resources. In early 2013, Hughes authored *Drill, Baby, Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?*, which took a far-ranging look at the prospects for various unconventional fuels to provide energy abundance for the United States in the 21st century.

Over the past decade, Hughes has researched and lectured widely on global energy and sustainability issues in North America and internationally.

Summary

IN DECEMBER 2015, Canada joined 176 other countries to sign the Paris Agreement. By doing so, Canada has pledged to reduce its greenhouse gas emissions to 30 per cent below 2005 levels by 2030 (a minimum reduction that must be revisited according to the terms of the agreement). Environment Canada's latest projections show that under existing energy and climate policies, emissions will be 55 per cent above the Paris Agreement target in 2030, which means that Canada has some serious work to do to fulfill its commitment.

Yet plans are afoot to expand the oil and gas sector, which constituted 26 per cent of emissions in 2014, by growing oil sands production in Alberta and establishing a liquefied natural gas (LNG) export industry in BC. The oil and gas industry is also pushing hard for new pipelines to export its growing production. Political leaders in Western Canada and the Prime Minister, meanwhile, assure citizens it is possible to meet our climate commitments while at the same time significantly expanding oil and gas production and infrastructure.

This study assesses the consequences of several scenarios of such expansion in the oil and gas sector in terms of the amount that the non–oil and gas sectors of the economy would need to reduce emissions to meet Canada's commitments under the Paris Agreement. It also reviews existing pipeline and rail capacity for oil exports under the cap on oil sands emissions announced last year by the Alberta government (set at 100 million tonnes (Mt) per year).

Key Findings

Projected growth in oil and gas production under several scenarios means that non–oil and gas sectors of the economy would need to reduce their emissions by between 47 and 59 per cent below 2014 levels by 2030 to meet the Paris Agreement commitment. This level of reduction is near-impossible without severe economic consequences.

Canada's Energy Future 2016, published by the National Energy Board (NEB) earlier this year, outlines several possible scenarios for oil and gas production through 2040. The NEB's "reference case" represents its view of the most likely scenario. It projects a substantial increase in oil and gas production, driven mainly by a near-doubling of oil sands bitumen production.

- In the NEB reference case, oil and gas sector emissions would account for 50 per cent of allowable emissions under the Paris Agreement by 2030. The rest of the economy's emissions would have to shrink by 52 per cent below 2014 levels.
- The NEB reference case accounts for the development of only one large LNG export facility in BC. However, if the BC government's plans for five LNG terminals exporting 82 million tonnes of LNG per year materialize, the oil and gas sector would take up 58 per cent of allowable emissions by 2030. This scenario would force a reduction in the rest of the economy of 59 per cent.
- The near-doubling of bitumen production forecast in the NEB reference case is larger than can be accommodated under Alberta's 100 Mt/year oil sands emissions cap (which would see only a 45 per cent increase in oil sands production over 2014 levels). Adjusting the NEB reference case to comply with Alberta's cap, and assuming the BC government's LNG export plans materialize, means the oil and gas sector would take up 53 per cent of allowable emissions by 2030, requiring a 55 per cent reduction in the rest of the economy.
- A "best-case" scenario without further policy changes would be the NEB's reference case of only one large LNG export facility, coupled with the Alberta oil sands emissions cap, which would still see the oil and gas sector take up 45 per cent of allowable emissions by 2030, compared to 26 per cent at present, requiring a 47 per cent reduction in the rest of the economy.

It would be very difficult to reduce emissions outside the oil and gas sector by between 47 and 59 per cent below 2014 levels by 2030. Short of an economic collapse, it is difficult to see how Canada could realistically meet its Paris commitments without rethinking its plans for oil and gas development.

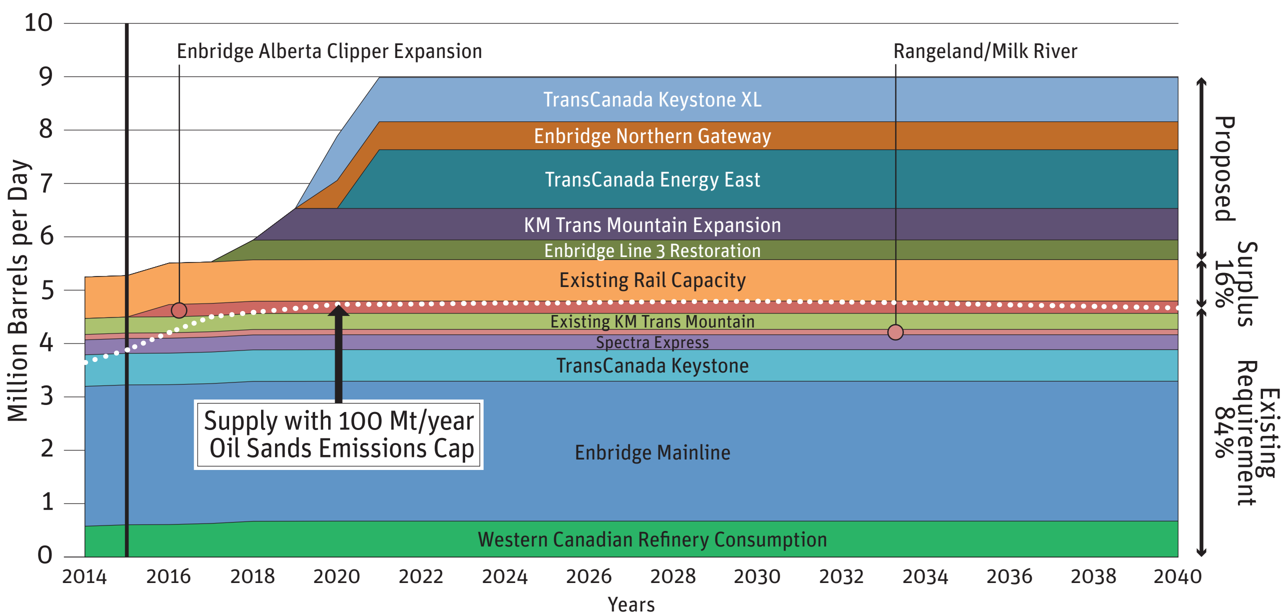
New pipelines are not needed under Alberta's cap on oil sands emissions.

Although current pipeline and rail capacity is not sufficient to transport the near-doubling in bitumen production forecast in the NEB reference case, it is sufficient under the Alberta government's announced cap on oil sands emissions at 100 Mt per year.

Under Alberta's emissions cap, growth in oil sands production would be limited to 45 per cent over 2014 levels. Although there is insufficient pipeline capacity alone to move a 45 per cent ramp up in the oil sands, there is enough existing rail and pipeline capacity to handle it (including a 15 per cent surplus to allow for maintenance and outages).

The additional pipelines being lobbied for by industry and governments are therefore not necessary (see *Figure A*).

FIGURE A Existing pipeline export capacity from Western Canada and Western Canadian refinery consumption with projected supply, given Alberta's cap on oil sands emissions. Also shown are proposed new pipeline projects.



Source Pipeline and rail capacity from CAPP, *Crude Oil Forecasts, Markets and Transportation* (2015): 24. Rangeland–Milk River pipeline capacity is from NEB, *Canada's Energy Future 2016*. Projected supply through 2040 under a scenario where oil sands emissions are capped at 100 Mt/year is also shown.

New pipelines with tidewater access will not significantly increase the price Canada receives for its oil.

Although oil is a globally priced commodity, between 2011 and 2014 the international price of oil ("Brent") was significantly higher than the North American price ("West Texas Intermediate" or WTI), which caused the enthusiasm for "tidewater" access to allow overseas exports. This premium, which was primarily a result of the rapid increase of US tight oil production and a lack of pipeline capacity to move it to the Gulf Coast, has largely disappeared as a result of new pipelines coming online to relieve congestion, coupled with an end to the US ban on oil exports.

Canada's primary oil export, "Western Canada Select," is a lower quality grade of oil that requires more effort to refine and comes with higher transportation costs than the WTI benchmark, and therefore commands a lower price. This discount will occur regardless of whether the oil is sold in the US, or to international markets in Europe or Asia.

The assertion by politicians that tidewater access enabling overseas exports will somehow confer a significant price premium for Canadian oil is therefore not supported by the facts.

The widely recited rhetoric that Canada must continue its de facto energy strategy of liquidating its remaining non-renewable energy resources as fast as possible to maintain the economy is not credible on economic or environmental grounds.

The only prospect for significant growth in oil production in Canada is bitumen. But new bitumen projects require oil prices between $68 and $100 per barrel to be viable (price depends on the method of extraction and level of upgrading). Given the current state of global oil prices, significant expansion of oil sands production, beyond projects currently under construction, is unlikely regardless of what the NEB forecasts, or what industry and political leaders wish for.

Even if the price of oil wasn't a barrier, the argument that Canada can build new pipelines to meet expanded oil production while also reaching its targets under the Paris Agreement is a "have your cake and eat it too" argument. Canada must rethink its dependence on the oil and gas sector. Canada has never produced more oil, yet the economy is sluggish, caught in the downdraft of low oil prices which Canadian politicians can do absolutely nothing about. If Canada is to have any hope of meeting its Paris commitment, the aggressive oil and gas growth ambitions of the Alberta and BC governments will have to be reconsidered and reduced, as there simply isn't the capacity in the rest of the economy to provide the emission reductions committed to by 2030.

Governments would serve the public much better — especially the workers and communities whose economic hopes currently hinge on a substantially expanded oil and gas sector — by planning for the shifts in energy development that are necessary to meet their climate change commitments.

1. Introduction

AT THE 2015 United Nations Climate Change Conference meeting in Paris (COP21), Canada committed to reduce its greenhouse gas emissions (GHG) to 30 per cent below 2005 levels by 2030 (a target that many consider insufficient). Yet, the latest *National Inventory Report,*[1] which contains Canada's annual GHG emissions estimates, indicates that emissions in 2014 were significantly above the level required by the COP21 trend line. Environment Canada also recently projected that "with current measures,"[2] emissions in 2030 will be 55 per cent *above* the Paris Agreement target. Clearly, Canada has some serious work to do.

At the same time, the National Energy Board's (NEB) recently released report on Canada's energy future[3] projects substantial growth in the oil sands, which is one of Canada's major sources of emissions. The BC government also aspires to rapidly grow natural gas production in order to supply a nascent liquefied natural gas (LNG) export industry. Notwithstanding the Alberta government's commitment to cap oil sands emissions at 100 megatonnes (Mt) per year, 47 per cent above 2014 levels, the rest of the economy will have to contract its emissions by nearly impossible amounts to achieve the Paris Agreement target.

A related issue is the lobbying by the oil and gas sector and politicians in Alberta and Saskatchewan for more pipelines and "tidewater access," as if this will somehow cure the revenue shortfalls they are experiencing. The capacity to transport oil to markets outside of the Western Canadian Sedimentary Basin (WCSB) using existing pipeline and rail infrastructure is not constrained now, nor will it be under the Alberta government's 100 Mt per year cap on oil sands emissions. That would certainly change should the growth in production projected by the NEB's reference case occur, but that growth would also push Canada even farther away from its COP21 emissions target and above the Alberta government's emissions cap.

Canada has never produced more oil, yet the political rhetoric insists that the oil and gas industry must continue to expand, or Canada's economy will be severely impacted. The fact is that oil is a globally priced commodity and its price is beyond the control of provincial or federal politicians. Bitumen remains the only source of oil in Canada with potential for significant growth, and it sells at a substantial discount because its heavy, highly viscous nature, and high sulphur content make it more costly to refine. This reality will not change even if large volumes reach tidewater for export, as the difference in price that existed over the past few years between the international benchmark — Brent Crude — and North America's benchmark — West Texas Intermediate (WTI) — which did provide a premium for tidewater access over the past few years, has now been reduced to almost nothing.

This report reviews the realities of Canadian oil production, emissions and pipelines in the light of Canada's commitment to combat climate change under the Paris Agreement negotiated at COP21.

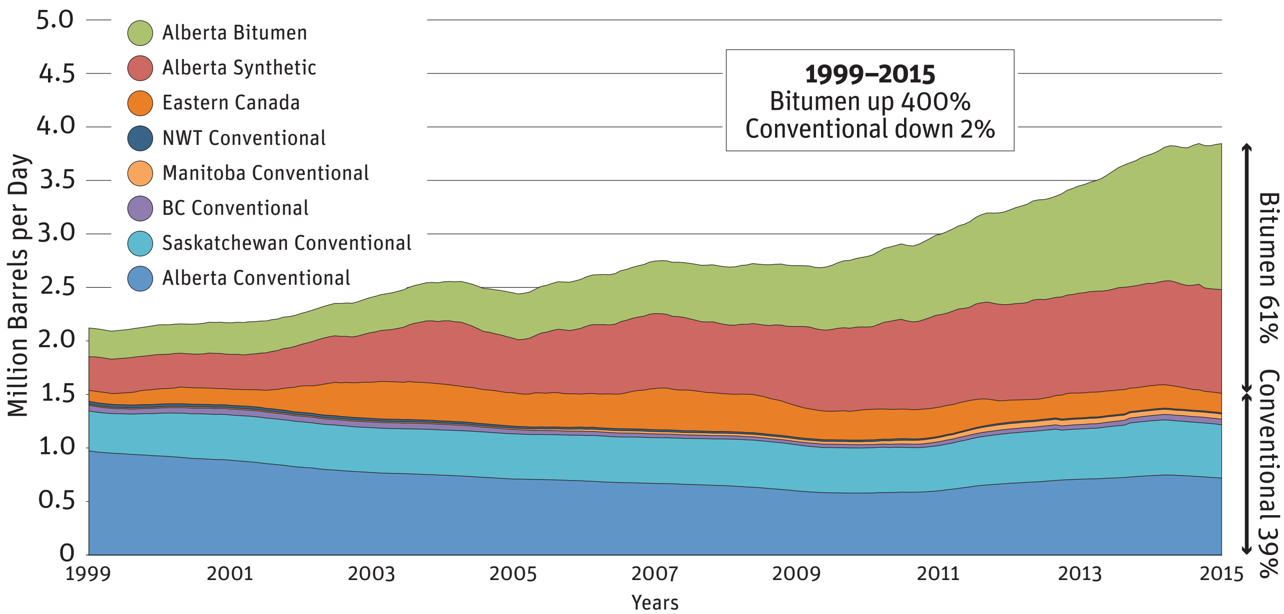
2. Canadian oil production and NEB projections

CANADIAN OIL PRODUCTION is at an all-time high. Production is up 83 per cent since 1999. *Figure 1* illustrates production by province and type of oil. Conventional oil production has been flat over the period, but bitumen from the oil sands has increased by 400 per cent, such that, in 2015, 61 per cent of Canadian production was bitumen versus 39 per cent conventional oil.[4] Offshore production from the East Coast peaked in 2007 and has declined since, although conventional production from the Western provinces has increased slightly since 2011 thanks to the large-scale application of horizontal drilling and hydraulic fracturing. Conventional oil production in Canada in fact peaked in 1973 at nearly two million barrels per day.[5]

Bitumen is produced both by surface mining and by in situ methods. In the past, most of the bitumen recovered from surface mining operations has been upgraded to synthetic crude oil (SCO), whereas the in situ bitumen has mainly been diluted with condensate and sold in a raw form as “dilbit.” In situ methods, which are more energy- and emissions-intensive than mining, account for nearly 60 per cent of current bitumen production and are expected to provide most of future production growth.

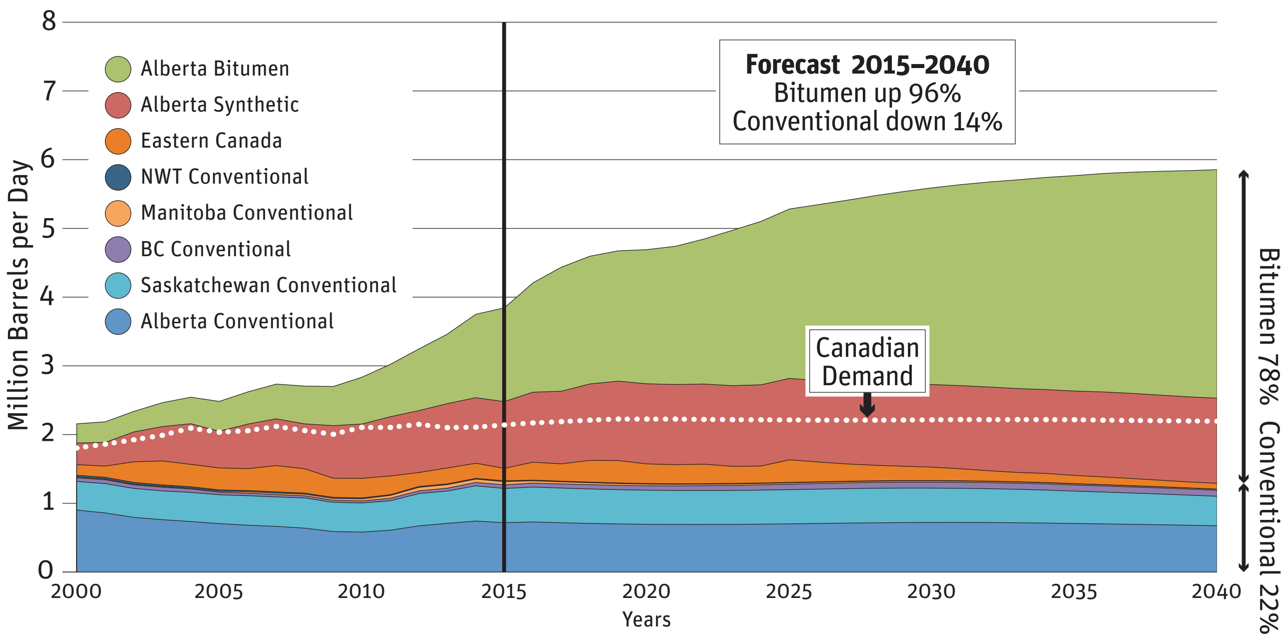
The NEB’s *Canada’s Energy Future 2016* report projects crude oil and natural gas production through 2040.[7] *Figure 2* illustrates the NEB’s reference

FIGURE 1 Oil production (including natural gas liquids) by province in Canada from 1999 to 2015



Source National Energy Board, Annual (1999–2015) Estimated Production of Canadian Crude Oil and Equivalent.[6]

FIGURE 2 National Energy Board reference case projection of Canadian crude oil production through 2040 by province and type

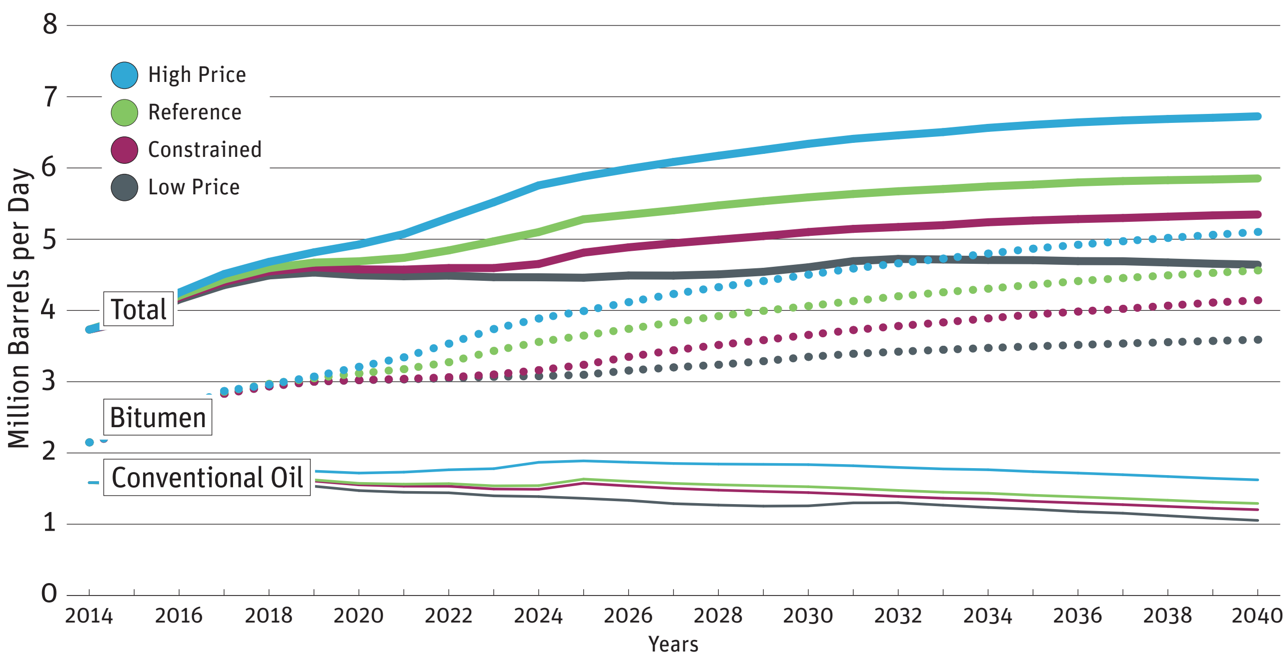


Source National Energy Board, *Canada's Energy Future 2016*.[8] Historical production from National Energy Board *Annual (1999–2015) Estimated Production of Canadian Crude Oil and Equivalent.*[9] The reference case Canadian domestic demand projection is also shown.

case projection for crude oil. Conventional oil production is forecast to fall by 14 per cent through 2040. In contrast, bitumen production, both upgraded and raw, is projected to nearly double, to 78 per cent of 2040 production, with non-upgraded bitumen making up most of that growth. More than 90 per cent of production comes from the Western provinces at present, and this proportion will rise as production on the East Coast declines.

The NEB's *Energy Future* report offers a range of cases for its crude oil projections based on assumed prices, as well as a "constrained" case, which assumes that none of the four proposed major export pipelines (Keystone XL, Energy East, Trans Mountain expansion, Northern Gateway) are built. It also offers "no LNG" and "high LNG" cases, which are not considered as they are essentially the same as the reference case projection for oil. *Figure 3* illustrates these cases for conventional oil, bitumen and total production. The spread between the low- and high-price cases is more than two million barrels per day in 2040. In all cases, the only growth occurs in bitumen production, with conventional production projected to be flat or to fall through 2040.

FIGURE 3 National Energy Board projections of bitumen, conventional and total Canadian crude oil production in four cases from 2014 to 2040



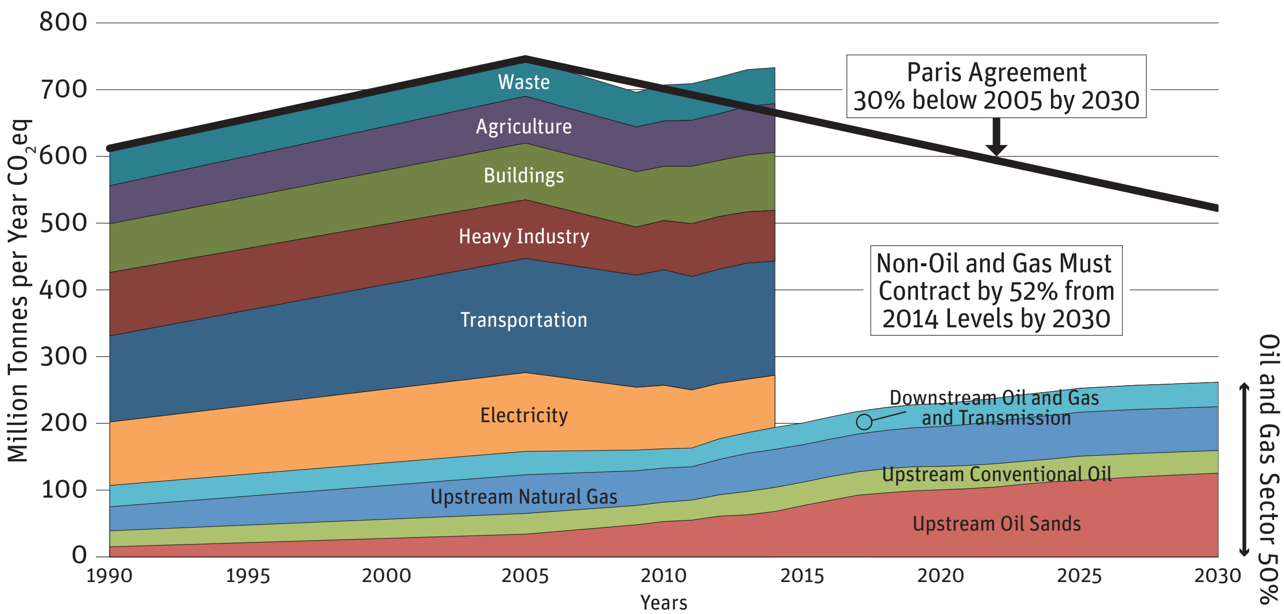
Source National Energy Board, *Canada's Energy Future 2016*.[10]

3. Greenhouse gas emissions and implications under COP21

CANADA'S MOST RECENT data on its greenhouse gas emissions are available in the *National Inventory Report*, which it submits annually to the United Nations.[11] This report subdivides emissions by sector and is the official benchmark for the reductions Canada committed to under the Paris Agreement that was negotiated at COP21. The oil and gas sector is further subdivided into upstream oil sands and upstream conventional oil and natural gas, as well as downstream emissions from transmission and refining. The most recent data are from 2014.

Figure 4 illustrates emissions by economic sector from 1990 to 2014 as outlined in the report. Emissions from components of the oil and gas sector are projected to 2030 based on the NEB's reference case scenario. Emissions per unit of production are held constant at the average level from 2010 to 2014 for the projection. This assumption is conservative, as emissions per unit of natural gas production are likely to grow in the future as production from shale- and tight-gas reservoirs using horizontal drilling and hydraulic fracturing technology increases.[12] Emissions per unit of bitumen produc-

FIGURE 4 Canada's greenhouse gas emissions by sector from 1990 to 2014, with oil and gas sector projections through 2030, based on the National Energy Board (2016) reference case



Source Environment Canada *National Inventory Report*,[14] National Energy Board *Canada's Energy Future 2016*.[15] Also shown is the greenhouse gas reduction committed to under the Paris Agreement.

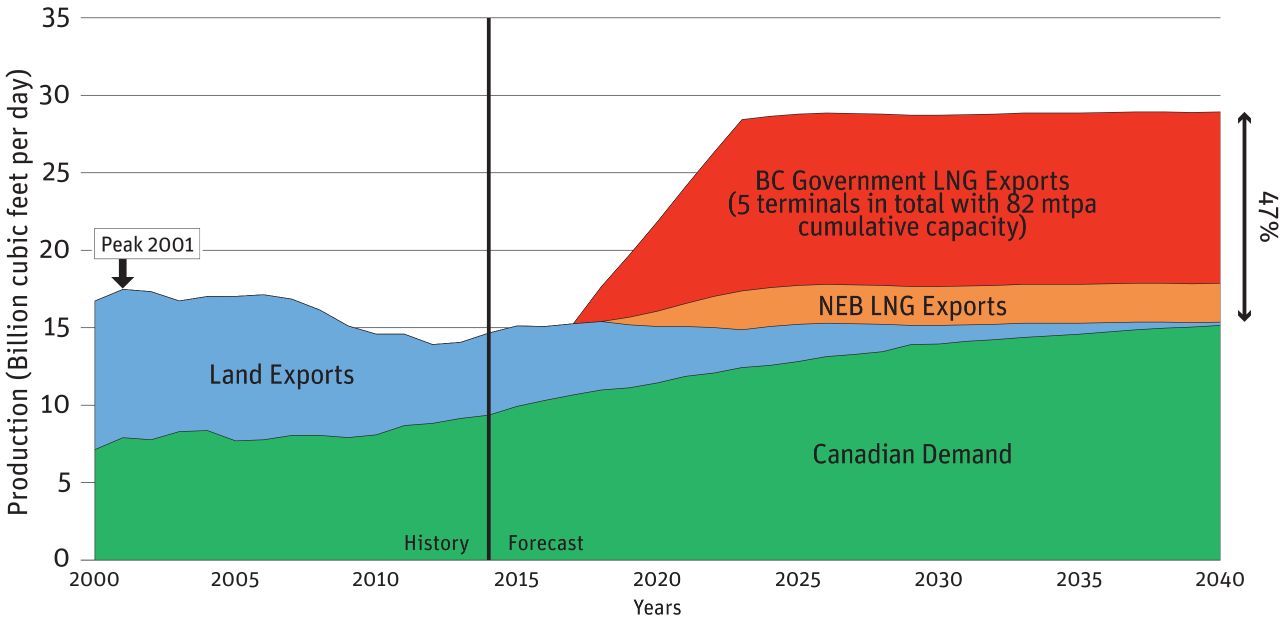
tion will also grow, as bitumen is increasingly being recovered using in situ methods that produce more greenhouse gases than surface mining.[13]

Also shown is the greenhouse gas reduction that Canada has committed to under the Paris Agreement. If the country is to meet its commitment by 2030, the non-oil and gas sectors of the Canadian economy will have to reduce emissions by 52 per cent from 2014 levels. The oil and gas sector would then account for 50 per cent of Canada's emissions, up from 26 per cent in 2014.

Lowering emissions by so much in the non-oil and gas sectors will be extremely difficult to do. Canada's electricity sector, for example, is already one of the lowest carbon emitters in the world thanks to its large hydro component and the recent elimination of coal in Ontario.

To make matters worse, the BC government aspires to develop an LNG industry that will put out 82 million tonnes of LNG per year (mtpa) and require five large export terminals.[16] The NEB reference case allows for only 2.5 billion cubic feet/day (bcf/d) of LNG exports, which is enough for just one large terminal. If BC's ambitions come to fruition, Canada's gas production will have to grow considerably more than in the NEB projection.

FIGURE 5 Canadian natural gas production, demand and exports in the National Energy Board's reference case from 2000 to 2040, and projected production needed to meet an 82 mtpa BC LNG export scenario



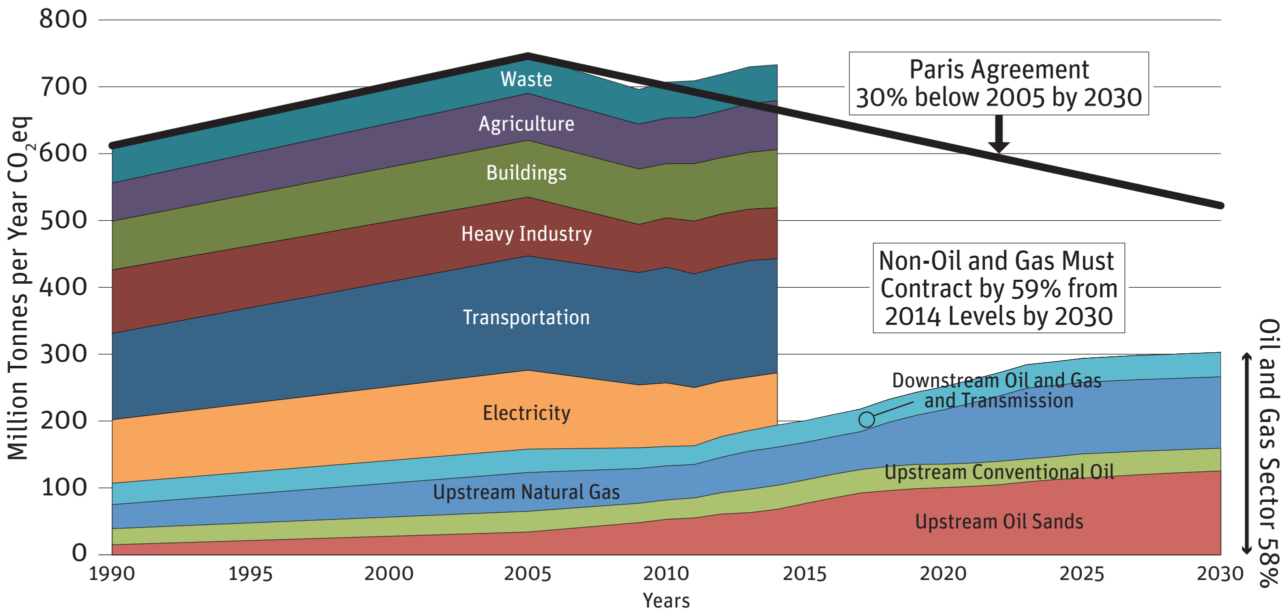
Source National Energy Board *Canada's Energy Future 2016.*[17] 2000–2005 production from National Energy Board *Canada's Energy Future 2013.* Gas production for 5 LNG export terminals (82 mtpa) from Hughes *A Clear Look at BC LNG.*[18]

Figure 5 illustrates Canadian gas production in this scenario, which would see 47 per cent of vastly expanded gas production exported as LNG in 2040.

Figure 6 illustrates the growth in oil and gas sector emissions if the BC government's LNG exports come to fruition. Note that this figure includes only the upstream emissions of producing the gas, not the emissions from gas burned to power the liquefaction process (which would be counted in the industrial sector). If Canada is to meet its COP21 target by 2030, non-oil and gas sector emissions will have to contract by 59 per cent from 2014 levels. The oil and gas sector would then account for 58 per cent of Canadian emissions, up from 26 per cent in 2014.

The Alberta government recently announced a climate change initiative with a cap on oil sands growth at 100 million tonnes (Mt) per year of emissions,[22] which would allow emissions to grow 47 per cent from the 2014 level of 68 Mt.[23] This cap would allow projects currently under construction to be completed and existing projects to continue but would limit the development of new projects that would be needed to meet NEB's reference case. Although this initiative claims that it will reduce emissions per barrel, it be-

FIGURE 6 Canada's greenhouse gas emissions by sector from 1990 to 2014
with upstream oil and gas sector projections through 2030 based on the National Energy Board (2016) reference case and the development of a liquefied natural gas export industry in BC exporting 82 mtpa (does not include emissions from burning gas used to power the liquefaction process)



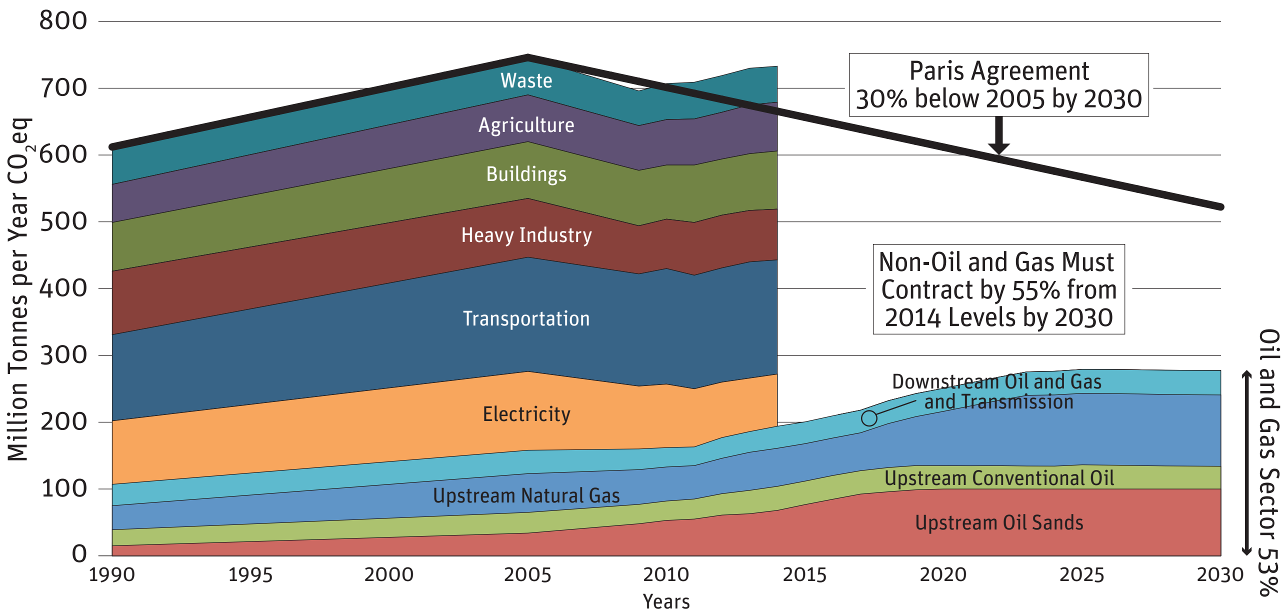
Source Environment Canada *National Inventory Report*,[19] National Energy Board *Canada's Energy Future 2016*.[20] Emissions determined from gas production for 5 LNG export terminals (82 mtpa) from Hughes *A Clear Look at BC LNG*.[21] Also shown is the greenhouse gas reduction committed to under the Paris Agreement.

lies the fact that an increasing proportion of the oil sands production will be done by more energy-intensive in situ methods that will increase, not decrease, average emissions per barrel. (Applying better technology, however, could reduce emissions from what they would otherwise be.)

Figure 7 illustrates the growth in emissions if both the Alberta government's 100 Mt per year oil sands cap and the BC government's LNG export plans come to fruition. The cap doesn't help much, though oil sector emissions will flatten starting in 2020. The non–oil and gas sector of the economy would have to contract by 55 per cent from 2014 levels. The oil and gas sector would then account for 53 per cent of Canada's emissions by 2030.

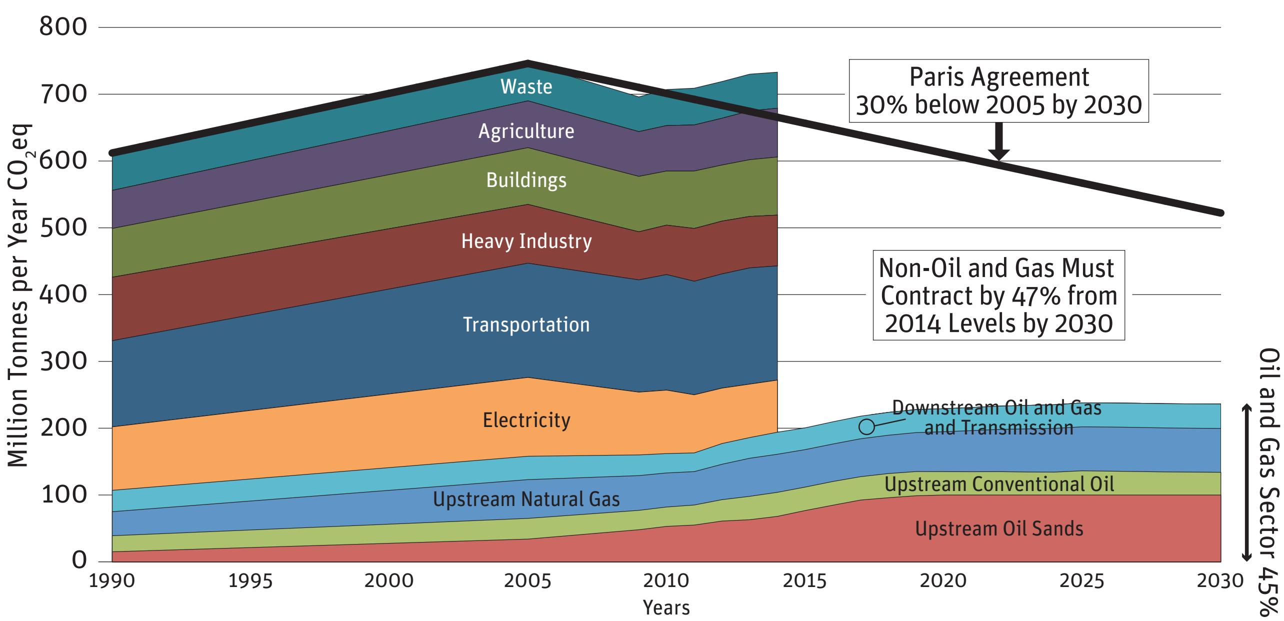
The best-case scenario, assuming the announced oil sands emissions cap, would be that the BC government develops only one large LNG export terminal, which is essentially the NEB reference case. *Figure 8* illustrates this scenario. Non-oil and gas sector emissions would have to contract by 47 per cent from 2014 levels by 2030. The oil and gas sector would then account for 45 per cent of Canada's emissions, up from from 26 per cent in 2014.

FIGURE 7 Canada's greenhouse gas emissions by sector from 1990 to 2014, with oil and gas sector projections through 2030 based on the National Energy Board (2016) reference case, a 100 Mt/year emissions cap on the oil sands and a liquefied natural gas export industry in BC exporting 82 mtpa



Source Environment Canada *National Inventory Report*,[24] National Energy Board *Canada's Energy Future 2016*.[25] Emissions determined from gas production for 5 LNG export terminals (82 mtpa) from Hughes *A Clear Look at BC LNG*.[26] Also shown is the greenhouse gas reduction committed to under the Paris Agreement.

FIGURE 8 Canada's greenhouse gas emissions by sector from 1990 to 2014, with oil and gas sector projections through 2030 based on the National Energy Board (2016) reference case, a 100 Mt/year emissions cap on the oil sands and only one (of five proposed) liquefied natural gas terminals in BC (the NEB reference case)

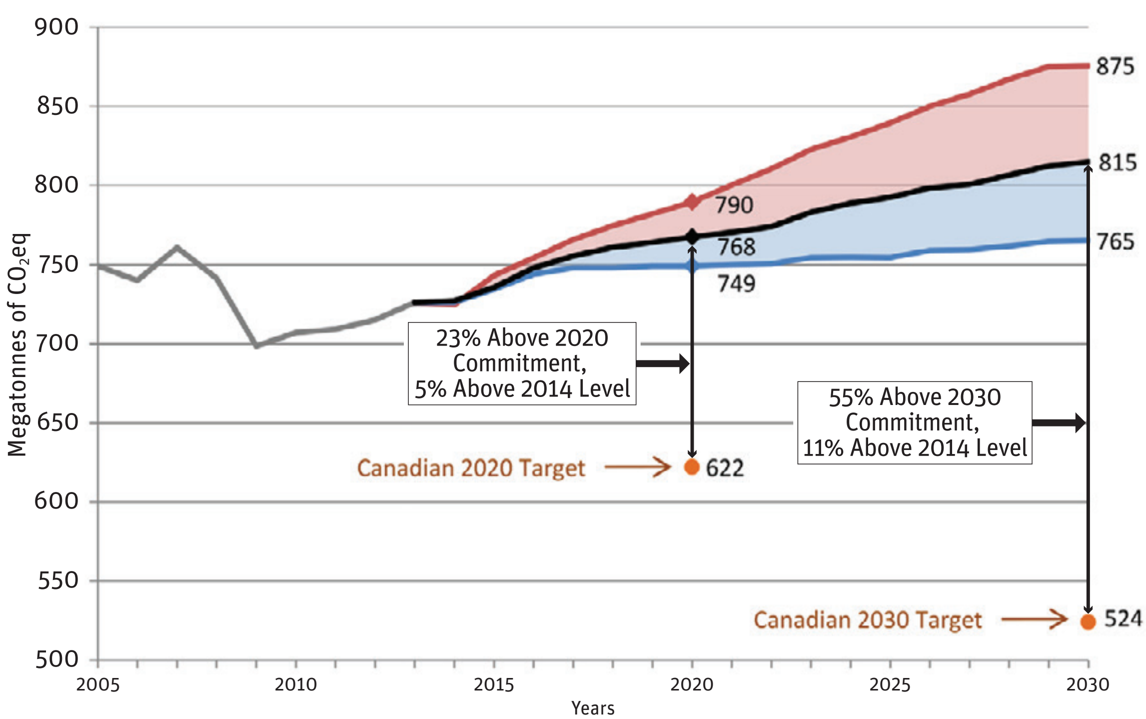


Source Environment Canada *National Inventory Report*,[27] National Energy Board *Canada's Energy Future 2016*.[28] Also shown is the greenhouse gas reduction committed to under the Paris Agreement.

It is hard to imagine even this best-case scenario allowing Canada to meet the targets it has committed to in the Paris Agreement, given the level of reductions that would be needed outside of the oil and gas sector. As mentioned, there is some room to reduce emissions in Canada's electricity sector (the Alberta government has vowed to phase out coal in that province, for example), but that sector is already 78 per cent carbon-free thanks to large hydro, nuclear and other renewable power projects.[29] Cutting emissions by 47 per cent or more in the transportation and buildings sectors, which have a large stock of vehicles and buildings that take considerable time to turnover/retrofit, would be extremely difficult by 2030. These sectors, along with heavy industry and agriculture, are linked to economic activity. Barring an economic collapse, therefore, *Canada will have to reconsider its planned oil and gas production growth and demand real emissions reductions from the oil and gas sector in order to have any hope of meeting its COP21 commitment*.

Environment Canada has recognized the untenable trajectory that the country's emissions are on. In January 2016 it released the chart in *Figure 9*,

FIGURE 9 Environment Canada projections of Canadian emissions "with current measures" compared to the Paris Agreement targets through 2030



Source Environment Canada, "Canada's Emission Projections in 2020 and 2030 (Mt CO_2 eq)." The ranges illustrated are "the expected range of the same projections under different economic and energy price and production scenarios."[32] The percentage calculations have been added to the original chart.

which suggests that Canada's emissions under a "with current measures" scenario will be 5 per cent above 2014 levels in 2020 and 11 per cent above 2014 levels in 2030. In other words, in 2030 Canada's emission levels will be 55 per cent above those agreed to in the COP21 commitment.[30] Note that this chart assumes that natural gas production remains flat through 2030, implying that an LNG industry on the scale envisioned by the BC government is not developed.[31] Clearly drastic action will be needed to meet Canada's commitments, and the oil and gas sector, because of its large proportion of total emissions, will have to provide some of those reductions.

4. Pipeline infrastructure and requirements under COP21

ENVIRONMENTALISTS AND INDUSTRY have battled incessantly for the past few years over new pipelines to export Western Canadian crude oil. This standoff culminated in the US government rejecting the Keystone XL pipeline project in 2015 and the Northern Gateway pipeline project will likely be cancelled due to the federal government's announced tanker ban. The question remains: exactly how much new pipeline capacity does Canada need if it is to meet its obligations under the Paris Agreement?

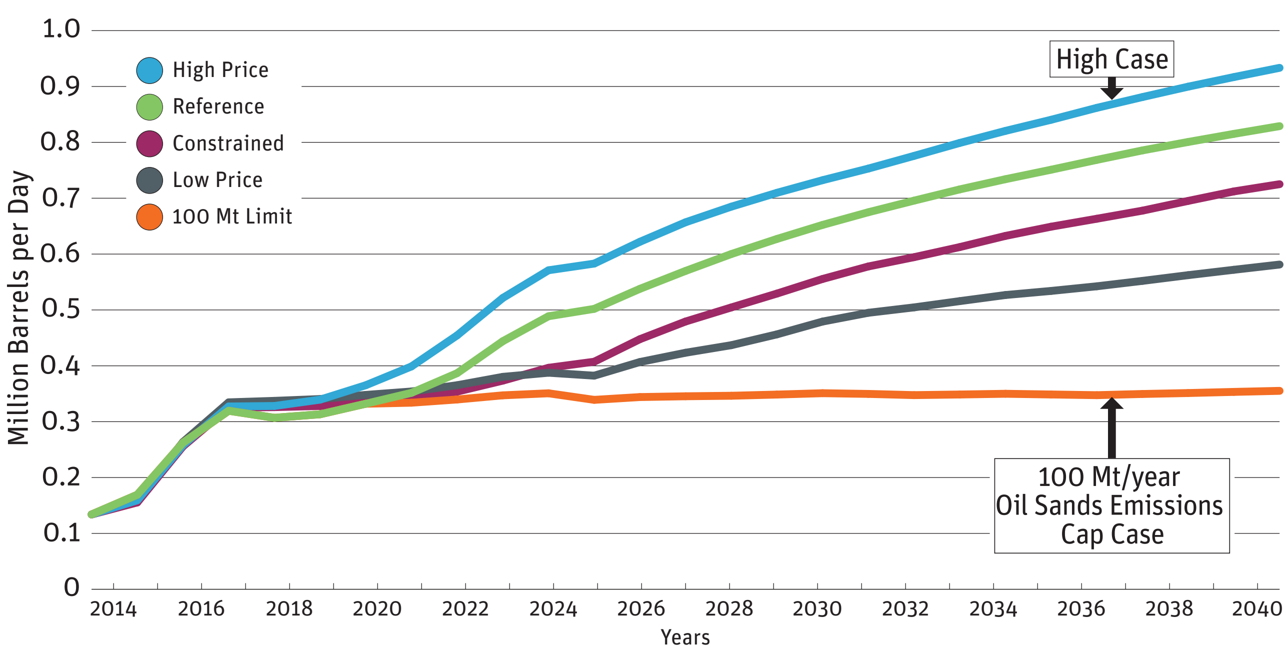
Bitumen must be blended with a diluent in order to reduce its viscosity enough to be moved via pipeline. The preferred diluent is condensate, a light hydrocarbon, which is added to bitumen to create about a 30 per cent blend by volume. (Bitumen which has been upgraded to synthetic crude oil (SCO) does not need diluting and, in fact, can be used as a diluent at a higher blend ratio than condensate.) Until recently Canada produced enough of its own diluent from gas processing plants, refineries and field condensate, but it now has to import increasing amounts to blend with the growing production of raw bitumen for export. Thus, pipelines have to be sized to accommodate both the added volume of imported diluent as well as the actual bitumen production.

Figure 10 illustrates the projected amounts of diluent imports required under the different NEB oil production cases as well as a case in which oil sands emissions are capped under Alberta's announced climate initiative.[33] Under NEB's reference case, Canada will be importing just over 0.8 million barrels per day of diluent by 2040. Even under a 100 Mt/year emissions cap, Canada will need to import 330,000 barrels/day of diluent by 2020, which would remain relatively constant thereafter.[34]

Rail transport has some advantages compared to pipelines for bitumen transport, though it is more expensive than pipelines. The Canadian Association of Petroleum Producers (CAPP) notes several advantages,[36] the most important of which are as follows.

- Bitumen transported by rail requires the use of little or no diluent, which reduces the volume of material to be moved and decreases or eliminates the cost of diluent. Furthermore, bitumen without diluent is a semi-solid with low volatility, and is unlikely to result in con-

FIGURE 10 Imported diluent requirements for four National Energy Board cases and a case limiting oil sands emissions to 100 Mt/year through 2040



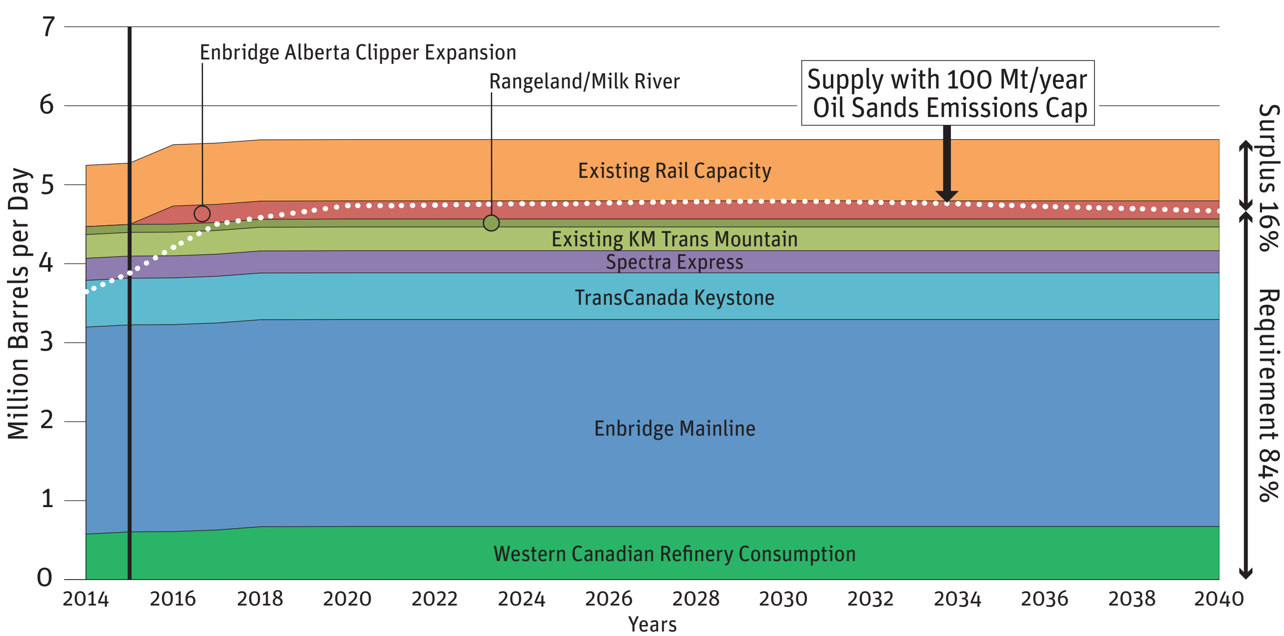
Source National Energy Board *Canada's Energy Future 2016*.[35]

flagrations in the event of accident such as the Lac-Mégantic rail disaster. (The Lac-Mégantic disaster involved highly volatile light oil from North Dakota.) Safety standards for rail cars have also been improved following that disaster.

- Rail transport provides more flexibility than pipelines, as railroads already exist to most destinations.
- Rail transport is scalable at lower-capital cost. In other words, it can be easily and quickly ramped up compared to pipelines.

Although some of Western Canada's oil production is used as feedstock for its refineries, most must be exported from the Western Canadian Sedimentary Basin (eastern BC, Alberta, Saskatchewan, Manitoba and the southern Northwest Territories) to other markets. *Figure 11* illustrates existing pipeline and rail capacity out of the WCSB along with consumption by Western Canadian refineries and total supply, including imported diluent, in a scenario where oil sands emissions are capped at 100 Mt/year.

FIGURE 11 Existing export capacity and supply from the Western Canadian Sedimentary Basin, including pipelines, rail and refinery consumption, under the National Energy Board reference case with a 100 Mt per year cap on the oil sands

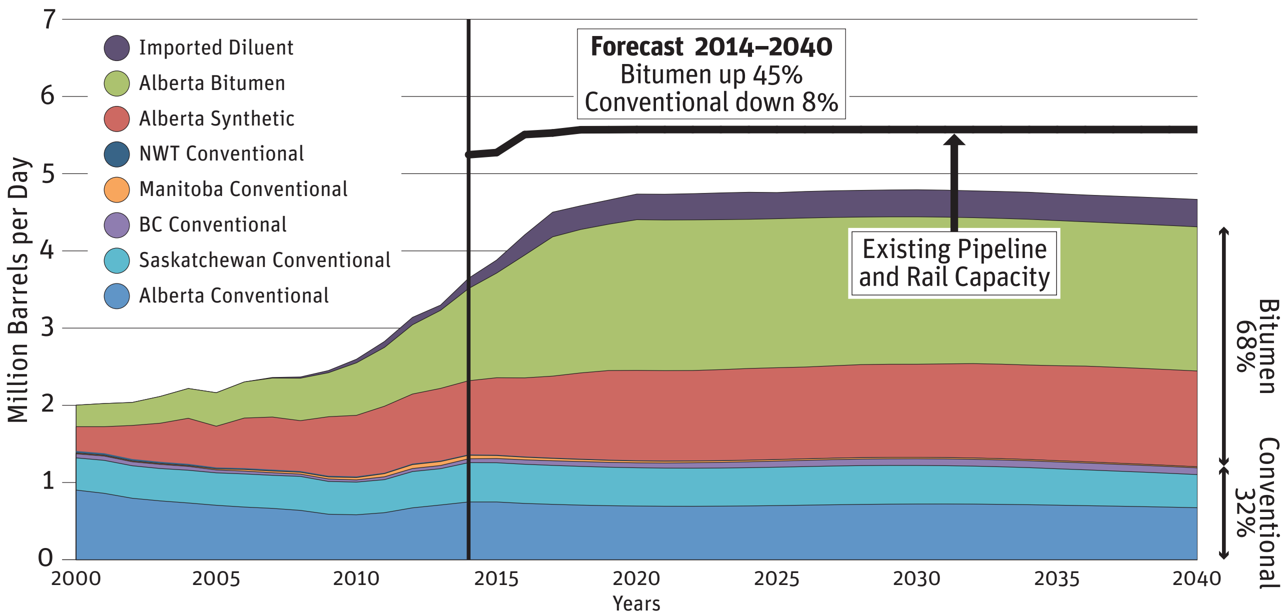


Source Pipeline and rail capacity from Canadian Association of Petroleum Producers, *Crude Oil Forecasts, Markets and Transportation* (2015): 24. Rangeland–Milk River pipeline capacity is from National Energy Board, *Canada's Energy Future 2016*. Projected supply through 2040 under a scenario where oil sands emissions are capped at 100 Mt/year and other production meets the National Energy Board's reference case in *Canada's Energy Future 2016* is also shown. If no new pipelines and rail capacity are built, and no new refinery capacity is added, a 14–16 per cent surplus over requirements will exist over the 2020–2040 period to provide a buffer for pipeline maintenance and outages.

Existing pipeline and rail capacity are sufficient under a scenario where oil sands emissions are capped, with a 14–16 per cent buffer over the 2020–2040 period allowing for maintenance and outages on pipelines and rail.[37] *Figure 12* illustrates WCSB supply sources and oil type compared to maximum existing export capacity under a 100 Mt/year cap on oil sands emissions. WCSB production and supply grow until 2030 and decline gradually thereafter due to the drop in conventional oil production, not bitumen. (*Figure 12* uses the NEB reference case for conventional oil and upgraded bitumen production.) Bitumen production grows by 45 per cent from 2014 levels by 2020 whereas conventional oil production from Western Canada declines by 11 per cent by 2040. Under this scenario, bitumen would make up 68 per cent of Canada's production in 2040.

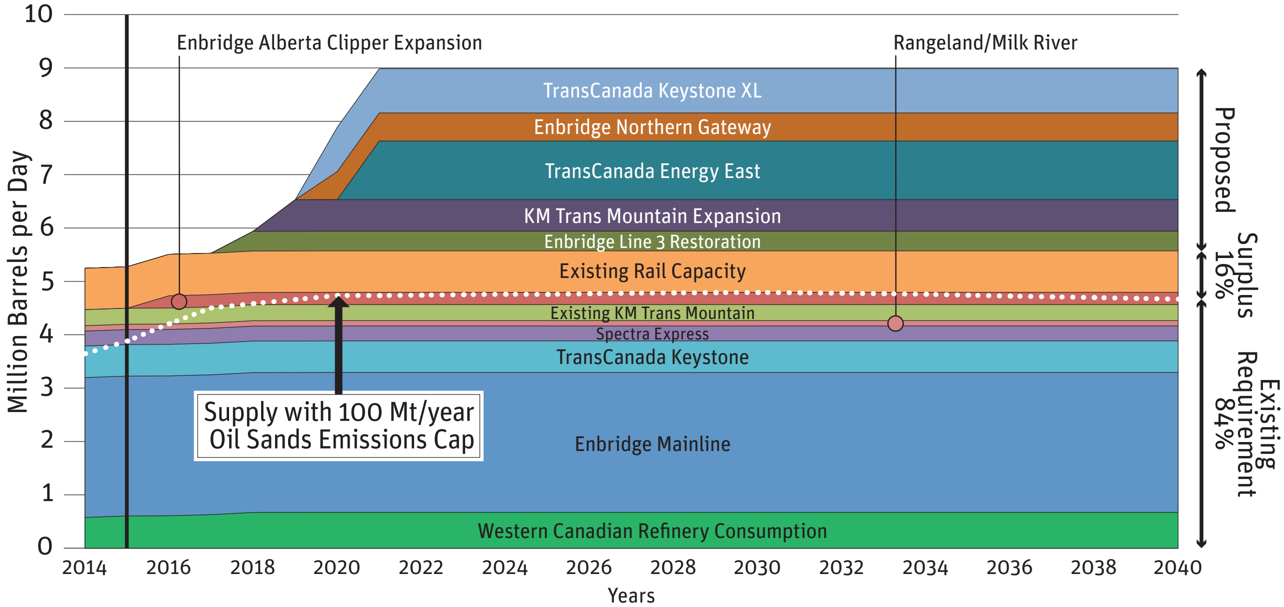
Notwithstanding the fact that the existing pipeline and rail infrastructure could handle a 45 per cent growth in bitumen production over 2014 levels under the 100 Mt/year emissions cap scenario, governments and industry are pushing for more export pipelines. *Figure 13* illustrates the various proposals compared to the actual requirement if oil sands emissions were to be capped.

FIGURE 12 Western Canadian Sedimentary Basin supply by province and oil type under a 100 Mt/year oil sands emissions cap through 2040 compared to existing pipeline and rail capacity



Source National Energy Board *Canada's Energy Future 2016* for conventional oil and refined bitumen production.[38] Unrefined bitumen and diluent calculated from the NEB reference case given a 100 Mt per year cap on oil sands emissions.

FIGURE 13 Existing and proposed export capacity from the Western Canadian Sedimentary Basin, including pipelines, rail and refinery consumption compared to supply under a 100 Mt per year emissions cap



Source Pipeline and rail capacity from CAPP, *Crude Oil Forecasts, Markets and Transportation* (2015): 24. Rangeland–Milk River pipeline capacity is from NEB, *Canada's Energy Future 2016*. Projected supply through 2040 under a scenario where oil sands emissions are capped at 100 Mt/year is also shown.

New pipelines are not needed if the Alberta government's announced cap on emissions is observed, though the Line 3 Replacement Program, which proposes to restore an Enbridge pipeline between Hardisty, Alberta, and Superior, Wisconsin, would provide an additional buffer for pipeline maintenance and outages.

Three of these pipeline proposals are designed to provide direct "tidewater" access. A fourth, Keystone XL, would have connected with the newly constructed southern leg of Keystone XL at Cushing, Oklahoma, to increase throughput to the Gulf Coast; however, the US government rejected the proposal in 2015. Perhaps the project that makes the most sense is the Line 3 restoration, which would replace an aging pipeline, increase its capacity to its original design specification and thereby provide an additional buffer for maintenance and outages on other pipelines under a capped oil sands scenario.

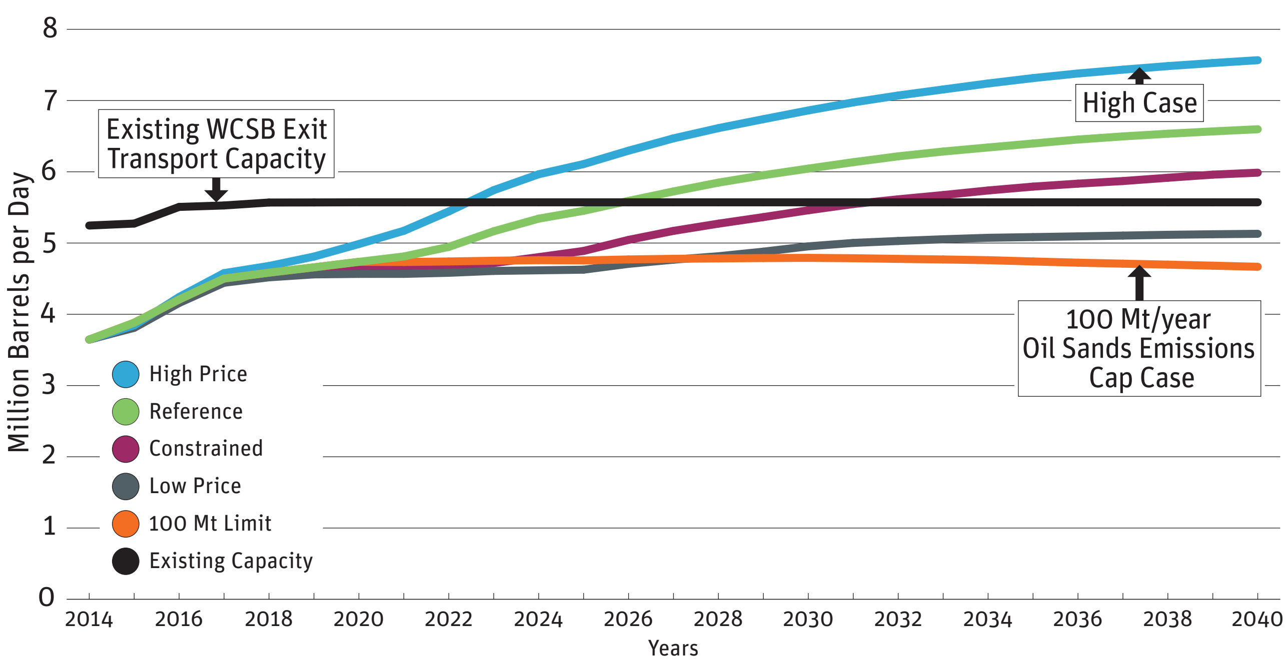
The Energy East pipeline has been heralded as a way to get Canadian oil to Eastern Canadian refineries, but in fact Enbridge's Line 9,[39] a section of pipeline from Sarnia, Ontario, to Montreal, Quebec, whose flow was recently reversed, is now providing refineries in Quebec with Western Canadian oil (as well as some US oil imports). Refineries in the Maritimes are currently served by imports, mainly from the US[40], as well as by some East Coast production. Much of the Energy East capacity would therefore go to foreign exports.

The Northern Gateway pipeline is unlikely to be developed owing to extreme opposition coupled with the tanker ban announced by the federal government. The same could be said for the expansion of the Kinder Morgan Trans Mountain pipeline — although it has recently been approved by NEB it still has other hurdles including Cabinet approval.

In any event, these pipelines are not needed if Canada is serious about meeting its emissions commitment under the Paris Agreement.

Figure 14 illustrates existing WCSB export transport capacity compared to the different NEB supply cases. Three of the four cases would hit transport capacity limits in the next few years. Only the low-price NEB case, which is similar to the 100 Mt/year emissions limit case, would require no new infrastructure. Most of the NEB scenarios call for oil sands growth that is incompatible with Canada's commitment at COP21 in Paris and the Alberta government's 100 Mt/year oil sands emissions cap.

FIGURE 14 Western Canadian Sedimentary Basin supply in four National Energy Board oil production cases and a case in which oil sands emissions are limited at 100 Mt/year through 2040



Source National Energy Board, *Canada's Energy Future 2016.* See Figure 11 of this paper for transport capacity sources.

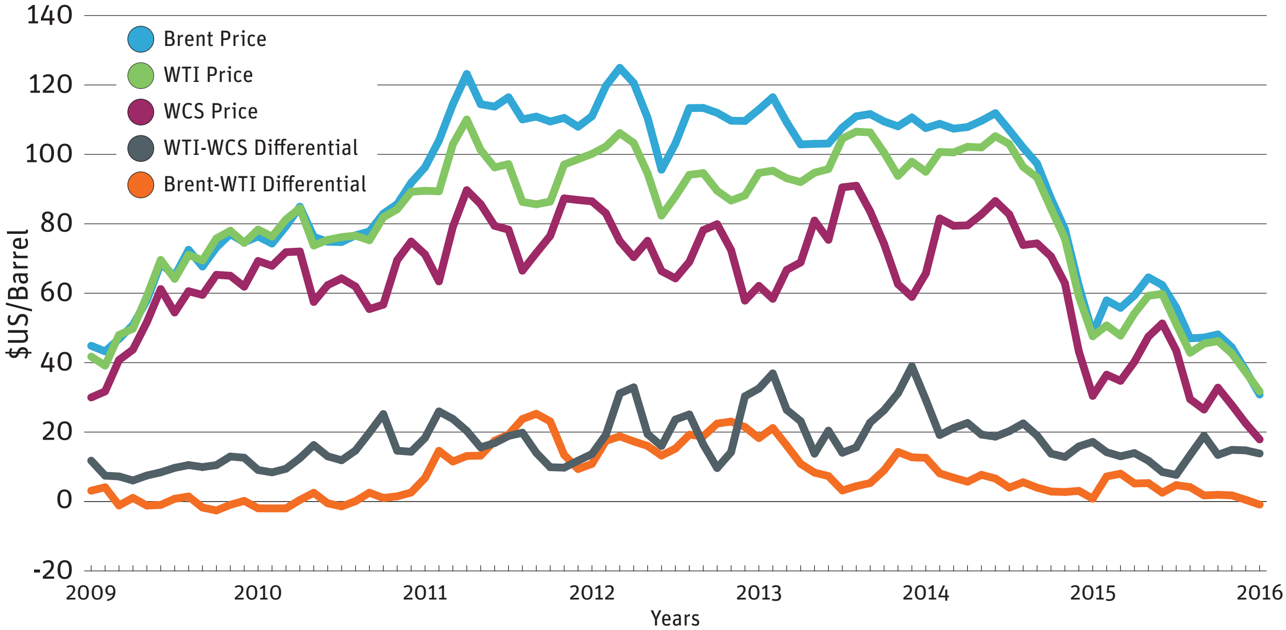
5. Realities of tidewater access pricing

Oil is a globally priced commodity, yet politicians and industry insist that "tidewater access" is somehow the elixir that will save Canada's oil industry from low prices while simultaneously bemoaning the fact that Canada has only one customer. This belief is derived from the large premium that existed for a few years between the international (Brent) and North American (West Texas Intermediate or "WTI") prices of oil as a result of rapidly increasing tight oil production in the US and a lack of pipeline capacity from the central hub in Cushing, Oklahoma, to the Gulf Coast. Completion of the Seaway and Keystone XL (south) pipelines has eliminated this lack of pipeline capacity — and the US has recently resumed crude oil exports after a 40-year ban, with the result that the differential between WTI and Brent prices is now nearly zero.

Canadian oil, as exemplified by the Western Canada Select (WCS) benchmark, is a lower quality grade (due to its heavy, highly viscous nature and high sulphur content) that requires more effort to refine. It also comes with higher transportation costs and therefore commands a lower price than the WTI benchmark. This discount will occur regardless of where the oil is sold.

Figure 15 illustrates the price of WTI, Brent and WCS oil since 2009 along with the differential between Brent and WTI, and WTI and WCS. Brent and WTI were essentially the same up until 2011, diverged when the aforementioned problems resulted in a significant premium for exports outside

FIGURE 15 Brent, WTI and WCS prices and differentials from 2009 to 2016



Source Brent and WTI prices from http://www.indexmundi.com/commodities/?commodity=crude-oil-brent and WCS price from http://economicdashboard.albertacanada.com/EnergyPrice.

North America and have now returned to near zero. (The Brent-WTI differential averaged just $1.53/barrel over the six months ending January 2016, and Brent was $0.90/barrel below WTI in January.)

Thus, there is nothing any politician can do to change the price of a globally traded commodity such as oil, no matter how many pipelines are built. Barring a resurrection in the price differential between Brent and WTI, Canadian oil sold in North America will command essentially the same netbacks — the revenues, less all costs associated with getting the oil to market — as Canadian oil sold overseas.

The only prospect for significant growth in oil production in Canada is bitumen, and this is a very high-cost source. *Table 1* illustrates supply costs for new bitumen projects from three agencies. Taking the mean of these estimates, new in situ projects need $68/barrel and likely as high as $85, standalone mining needs $96/barrel and mining with upgrading needs $100. Thus, there is little chance of beginning new projects unless prices go much higher, and the NEB's low-price scenario may be the most likely future production projection. Since this scenario is even lower than the emissions cap scenario out to 2027 (*Figure 14*), building new pipelines is even less necessary.

TABLE 1 Supply costs for new oil sands projects, in US dollars per barrel

	SAGD in situ bitumen	Stand-alone mined bitumen	Mining and upgrading
PTAC 2015	85	105.5	109.5
AER 2015	50–80	90–105	
NEB 2016	50–60	80–90	80–100

Source Petroleum Technology Alliance Canada (PTAC), *Needs Assessment for Partial and Field Upgrading* (2015); Alberta Energy Regulator (AER), ST98-2015 (*Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015–2024)*; National Energy Board (NEB), *Canada's Energy Future 2016*. SAGD is an acronym for steam-assisted gravity drainage.

The widely recited rhetoric that Canada must continue its de facto energy strategy of liquidating its remaining nonrenewable resources as fast as possible to maintain the economy has no credibility. Canada has never produced more oil, yet government revenues from the industry have collapsed. Yes, prices are low and that is affecting the industry, but nothing can be done about that given that prices are set globally. Maintaining the notion that only ever-expanded exports can rescue the Canadian economy ignores fundamental price realities as well as eliminates any chance that Canada will meet its emission-reduction targets under COP21.

6. Summary and implications

THE CURRENT POLITICAL discourse that Canada needs new pipelines to meet expanded oil production and will also reach its targets under the Paris Agreement is a "have your cake and eat it too" argument. The reality is that Canada has very little chance of meeting its emissions-reduction commitment, given provincial aspirations for LNG exports and oil sands growth.

The NEB reference case, which includes enough gas production for one large LNG export terminal, coupled with Alberta's announced emissions cap on the oil sands, would see the oil and gas sector increase its emissions from 26 per cent of Canada's total in 2014 to 45 per cent in 2030, while the rest of the economy's emissions would have to contract by 47 per cent.

The Alberta government's cap on oil sands emissions at 100 Mt/year, which is 47 per cent above 2014 levels, is designed to allow projects currently under construction to be completed as well as a limited number of new developments. Even given this production cap, Alberta and Saskatchewan premiers insist that new pipeline capacity such as Energy East is needed. This assertion is not supported by the facts. Others have noted that the business case for Energy East has disappeared, even without considering the greenhouse gas emission implications, as well as the myth that tidewater access will command a significantly higher price.[41,42] Quebec refineries already have access to Western Canadian oil thanks to the recent reversal of Enbridge's Line 9 between Sarnia and Montreal. Foreign imports, mostly from the US,[43] as well as some East Coast production serve refineries in the Maritimes.

The electricity sector offers limited opportunities for reduction, as it comprised only 11 per cent of 2014 emissions. Canada's electricity sector is already 78 per cent carbon free (based on current generation), thanks to large hydro, nuclear and other renewables. Drastically reducing coal while ramping up natural gas could cut emissions from this sector by 32 per cent from 2013 levels by 2030, according to Environment Canada;[44] however, its projected COP21 overrun (shown in *Figure 9*) already includes this assumption. Further reductions are certainly possible by adding renewables, eliminating coal in Alberta, introducing greater efficiency etc., but these strategies are limited in how much they can achieve compared to the overall reductions required.

Transportation, at 23 per cent of 2014 emissions, can be reduced. Cutting these by 47 per cent or more by 2030 would be extremely difficult, however, given the time needed to turn over the vehicle fleet and ramp up the scale of low- or zero-carbon electric or fuel-cell vehicles from a very small base. In its projection in *Figure 9*, Environment Canada estimates emissions from transportation will fall just 3 per cent from 2013 levels by 2030.[45] Investments in mass transit, and incentives for hybrid and electric vehicles, rather than pipelines, would certainly be the way to prioritize capital expenditures.

Buildings, which amounted to 12 per cent of 2014 emissions, would also be extremely difficult to reduce by 47 per cent or more by 2030. In its projection in *Figure 9*, Environment Canada forecasts emissions from buildings will grow by 27 per cent from 2013 levels by 2030.[46] Applying zero-emission building codes will be critical, along with providing incentives for retrofits, but these strategies are unlikely to achieve the required emission reductions by 2030, given the large legacy of existing building stock.

Heavy industry and agriculture, which amounted to 20 per cent of 2014 emissions, are closely linked to economic activity. While reductions are certainly possible, 47 per cent or more by 2030 would require a heroic effort, if they are not to disrupt the economy. Assuming the greenhouse gas reduction policies in place as of September 2015, Environment Canada projects heavy industry emissions will grow by 41 per cent and agriculture emissions will grow by 1 per cent (for a collective total of 21 per cent) from 2013 levels by 2030.[47] (LNG exports using natural gas for the liquefaction process would further increase industrial emissions beyond this estimate).

In short, oil and gas sector emissions cannot expect to grow substantially in any scenario in which Canada's emission reduction commitments are met. It is wishful thinking to assert that it is possible to develop a "climate plan" that would allow Canada to meet its commitments while at the same time substantially increasing oil and gas production. Given its size, the oil and gas sector will have to contribute a significant share of the emissions reductions. New pipelines are not needed if Canada is serious about meeting its COP21 commitment, and Canadians would be well served if politicians focused on the realities of the very difficult path forward, rather than on "have your cake and eat it too" fantasies.

Notes

1 Environment Canada, *National Inventory Report* (April 2016), http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2016-nir-14apr16.zip.

2 Environment Canada, “Canada’s Greenhouse Gas Emissions Projections in 2020 and 2030” (2016), https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=8BAAFCC5-1.

3 National Energy Board, *Canada’s Energy Future 2016: Energy Supply and Demand Projections to 2040 — An Energy Market Assessment* (January 2016), https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html.

4 In this report, “conventional oil” means “non-bitumen oil” and includes heavy, intermediate and light oil, even though it may be recovered by unconventional methods, such as hydraulic fracturing in combination with horizontal drilling, which are defined as “unconventional” in many other jurisdictions.

5 Canadian Association of Petroleum Producers, *Statistical Handbook Table 03-16 updated April 21, 2015* http://statshbnew.capp.ca/SHB/Sheet.asp?SectionID=3&SheetID=233

6 See https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/stmtdprdctn-eng.html. These numbers represent yearly marketable production statistics from 1999 to 2015, including natural gas liquids (NGLs), as a 12-month centred moving average. Overall production has increased by 83 per cent over the period, with oil sands bitumen responsible for all of this growth.

7 National Energy Board, *Canada’s Energy Future 2016*. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html

8 See https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html, Crude Oil Production Appendix. The NEB reports raw bitumen only in its totals in the *Energy Future* projections, with separate estimates of upgraded bitumen, whereas in its marketable production statistics it reports marketed volumes of non-upgraded bitumen. The “unrefined bitumen” production in Figure 2 has been calculated using a shrinkage factor of 14 per cent from raw bitumen to upgraded bitumen, so that the actual volume of non-upgraded bitumen available to the market is displayed.

9 See https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/stmtdprdctn-eng.html. These numbers represent yearly marketable production statistics from 2000 to 2015, including natural gas liquids (NGLs).

10 Ibid.

11 Environment Canada, *National Inventory Report*, released April, 2016. See Table 2-12 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2016-nir-14apr16.zip. Note that there is an error with labelling years in table 2-12 compared to table 2-3 in this report (year 2009 is mistakenly labelled as year 2005), and it is assumed that the labels in table 2-3 are correct, as emissions levels by year in table 2-3 are consistent with the emissions levels in the 2015 *National Inventory Report*.

12 R.W. Howarth, "Methane emissions and climatic warming risk from hydraulic fracturing and shale gas development: implications for policy," *Energy and Emission Control Technologies*, vol. 3 (2015): 45–54, doi: http://dx.doi.org/10.2147/EECT.S61539.

13 The Alberta Energy Regulator (2015) reports purchased gas used for in situ bitumen is 1–2 mcf/barrel versus 0.4–0.6 mcf/barrel for mining operations (see Table S3.3 in report ST98-2015, *Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015–2024*). Furthermore, the Energy Resources Conservation Board (2011) reports that even if bitumen is upgraded to synthetic crude oil, it consumes just 0.7 mcf/barrel of purchased gas in total (see Table 3.10 in report ST98-2011, *Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011–2020*).

14 Environment Canada, *National Inventory Report*, released April, 2016. See Table 2-12 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2016-nir-14apr16.zip.

15 National Energy Board, *Canada's Energy Future 2016*. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html.

16 BC Oil and Gas Commission, *LNG Forecast Scenario*, http://www.bcogc.ca/node/11277/download, accessed March 1, 2016.

17 National Energy Board, *Canada's Energy Future 2016*. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html.

18 For details on the volumes of gas required, see J. David Hughes, *A Clear Look at BC LNG: Energy security, environmental implications and economic potential* (Vancouver: Canadian Centre for Policy Alternatives, 2015). These numbers include marketable gas produced for exports and needed for fuel in the liquefaction and shipping process, https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2015/05/CCPA-BC-Clear-Look-LNG-final_0_0.pdf.

19 Environment Canada, *National Inventory Report*, released April, 2016. See Table 2-12 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2016-nir-14apr16.zip.

20 National Energy Board, *Canada's Energy Future 2016*. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html.

21 For details on the volumes of gas required, see J. David Hughes, *A Clear Look at BC LNG: Energy security, environmental implications and economic potential* (Vancouver: Canadian Centre for Policy Alternatives, 2015), https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2015/05/CCPA-BC-Clear-Look-LNG-final_0_0.pdf.

22 Alberta Government, "Climate Leadership Plan: A summary of Alberta's new policy response to climate change" (2015), http://www.alberta.ca/climate-oilsands-emissions.cfm.

23 Emissions would grow by 47% but bitumen production would grow by only 45% given the increasing proportion of production forecast from higher emitting in situ technologies.

24 Environment Canada, *National Inventory Report*, released April, 2016. See Table 2-12 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2016-nir-14apr16.zip.

25 National Energy Board, *Canada's Energy Future 2016*. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html.

26 For details on the volumes of gas required, see J. David Hughes, *A Clear Look at BC LNG: Energy security, environmental implications and economic potential* (Vancouver: Canadian Centre for Policy Alternatives, 2015), https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2015/05/CCPA-BC-Clear-Look-LNG-final_0_0.pdf.

27 Environment Canada, *National Inventory Report*, released April, 2016. See Table 2-12 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2016-nir-14apr16.zip.

28 National Energy Board, *Canada's Energy Future 2016*. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html.

29 This number refers only to emissions from current generation, not the embodied carbon emissions from the energy it took to build the hydro, nuclear and renewables infrastructure.

30 Environment Canada, "Canada's Emission Projections in 2020 and 2030 (Mt CO_2 eq)" (January 2016), https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=8BAAFCC5-1.

31 Environment Canada, "Canada's Second Biennial Report on Climate Change," Annex 3 (2016). "With current measures" assumes greenhouse gas reduction policies in place as of September 2015, https://www.ec.gc.ca/GES-GHG/02D095CB-BAB0-40D6-B7F0-828145249AF5/3001%20UNFCCC%202nd%20Biennial%20Report_e_v7_lowRes.pdf.

32 Environment Canada, "Canada's Emission Projections in 2020 and 2030 (Mt CO_2 eq)." https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=8BAAFCC5-1

33 National Energy Board, *Canada's Energy Future 2016*. See reference case data for Figure 7.5. The other cases were calculated based on the actual amount of raw bitumen available for export, assuming all domestic diluent production would be used first before importing. The blending ratio for the other cases assumed the blending ratio for the reference case, which varies between 27 and 32 per cent.

34 Note that the amount of synthetic crude oil produced in the NEB's reference case was assumed in the 100 Mt/year emissions cap scenario. This assumption reduced the need for imported diluents even compared to the NEB "low-price" case, which had higher levels of unrefined bitumen and lower levels of upgraded bitumen.

35 National Energy Board, *Canada's Energy Future 2016*. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html. See reference case data for Figure 7.5. The other cases were calculated based on the actual amount of raw bitumen available for export, assuming all domestic diluent production would be used first before importing. The blending ratio for the other cases assumed the blending ratio for the reference case, which varies between 27 and 32 per cent.

36 Canadian Association of Petroleum Producers, *Crude Oil Forecasts, Markets and Transportation* (2015): 32. Note that shipping bitumen with lower diluent volumes ("railbit") or no diluent requires rail cars with heater coils and insulation so that the bitumen can be heated to facilitate unloading.

37 Pipelines rarely operate at maximum capacity given the need for maintenance, nor does rail given operational requirements.

38 National Energy Board, *Canada's Energy Future 2016*. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html.

39 Line 9 will have a final capacity of 300,000 barrels/day to Montreal, "Line 9B Reversal and Line 9 Capacity Expansion Project," http://www.enbridge.com/ECRAI.aspx.

40 National Energy Board, "Market Snapshot: Record high crude oil imports from the U.S. push Canadian oil imports to a three year high" (March 2016), http://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2016/03-01hghcrdlmprt-eng.html.

41 Ross Belot, "The business case for Energy East just fell apart," *iPolitics*, March 1, 2016, https://ipolitics.ca/2016/03/01/the-business-case-for-energy-east-just-fell-apart/.

42 Hannah McKinnon, "Tar sands and the myth of tidewater access," *Oil Change International*, March 17, 2016, http://priceofoil.org/2016/03/17/tar-sands-and-the-myth-of-tidewater-access/.

43 National Energy Board, "Market Snapshot: Record high crude oil imports from the U.S. push Canadian oil imports to a three year high," (March 2016), http://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2016/03-01hghcrdlmprt-eng.html.

44 Environment Canada, "Canada's Second Biennial Report on Climate Change," Annex 3.

45 Ibid.

46 Ibid.

47 Ibid.