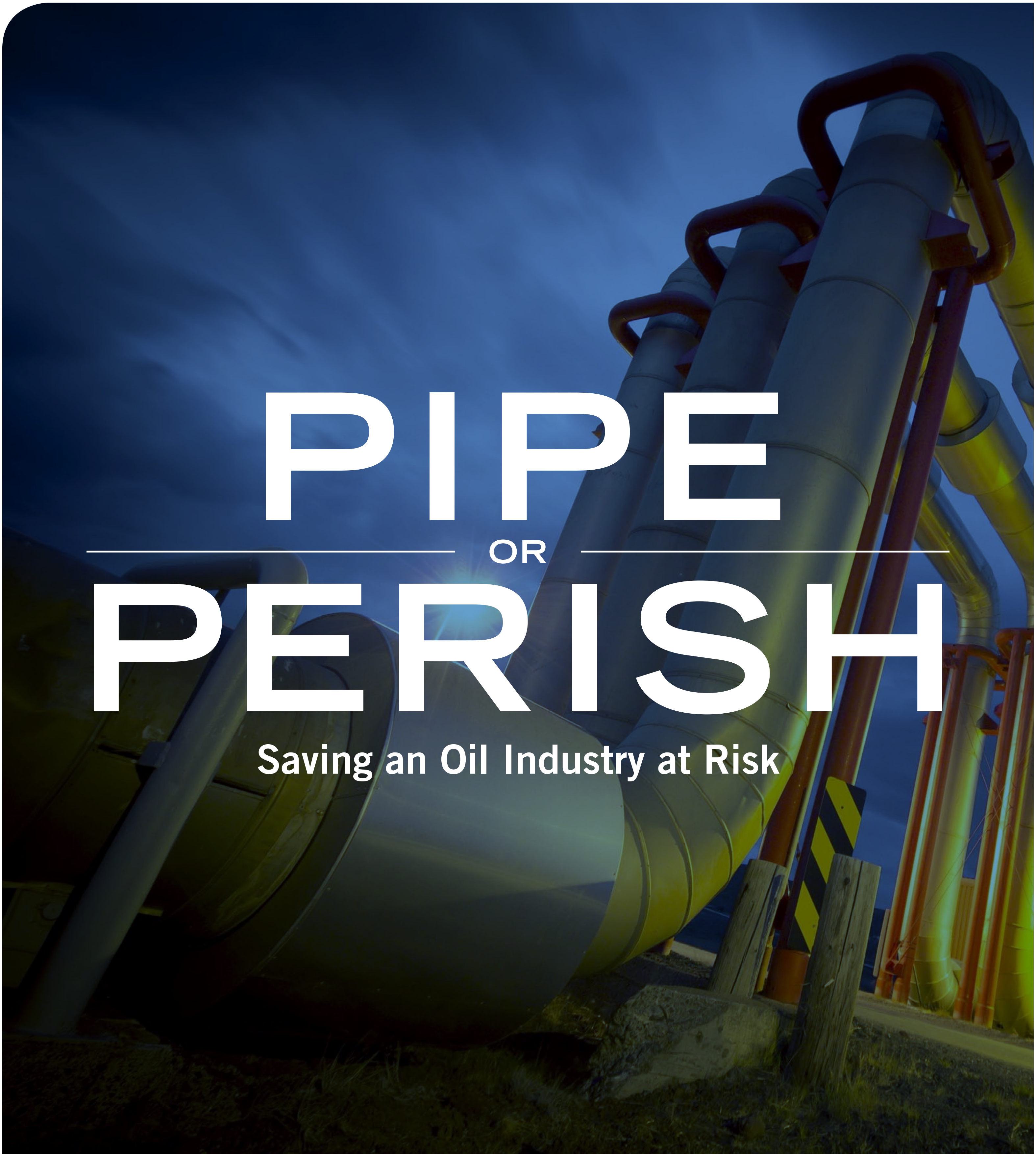

PIPE OR PERISH

Saving an Oil Industry at Risk

FEBRUARY 2013

MICHAEL HOLDEN, SENIOR ECONOMIST

Canada West FOUNDATION

The Canada West Foundation

Our Vision
A dynamic and prosperous West in a strong Canada.

Our Mission
A leading source of strategic insight, conducting and communicating non-partisan economic and public policy research of importance to the four western provinces and all Canadians.

Canada West Foundation is a registered Canadian charitable organization incorporated under federal charter.

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Western Canada's oil transportation network needs to be expanded and repurposed to reflect new realities. Failure to address current shortfalls will put the West's energy sector at risk and undermine the entire Canadian economy.

The North American energy landscape is transforming. Growing output from the oil sands and the transformative effects of hydraulic fracturing of hydrocarbon-rich shale deposits are ushering in an era of abundant oil supply on the interior of the continent. Meanwhile, coastal regions that have been historically reliant on overseas imports are facing high feedstock prices and restricted access to crude oil supplies. On top of all that, demand for oil products in North America is falling.

The continent's oil transportation infrastructure is rapidly becoming ill-suited to this new environment. In essence, some pipes go to where they are needed less, others are inadequate to take away oil from new producing centres, and there is insufficient capacity to deliver product to where demand is the greatest and growing, including overseas markets.

Specifically:

Export opportunities to the United States are shrinking because of booming US oil production and falling domestic demand.

The pipeline system in North America does not reflect current or anticipated needs:

- Transportation bottlenecks in the US Midwest are driving down North American oil prices compared to overseas benchmark rates.
- Western Canada does not have sufficient access to US markets outside the Midwest, driving prices for western Canadian crude lower still.
- Refineries outside the Midwest, especially on the east coast, are forced to scale back or shut down, in part because they do not have access to cheaper domestic oil.

Capacity to export oil to China and other booming markets is almost non-existent.

In short, energy markets are changing and western Canada needs a distribution system that transports oil to where it will be needed. The consequences of inaction are considerable. Already, the deeply discounted price for Canadian oil is resulting in billions of dollars lost to the Canadian economy. The longer-term consequence if this situation endures is under-investment, stranded assets, reduced government revenue and market opportunities foregone to others. Delaying even a single pipeline project that improves market access can cost up to $70 million *per day* in foregone economic activity.

The good news is that it is not yet too late to act. The US will continue to need Canadian oil for some time. Demand in China and other developing Asian markets is only expected to grow.

However, the window of opportunity narrows with every day of delay. Demographic change and more stringent vehicle efficiency standards are driving down gasoline demand in North America. US production will increasingly displace imports. Asia is not waiting for western Canadian oil to arrive at its doorstep and producers in Russia, the Middle East and elsewhere are aggressively moving to secure supply links with the Chinese market.

Preliminary Findings:

With that in mind, urgent action is needed to secure the future of western Canada's oil industry. As a critical first step, the following preliminary findings are offered to inform a strategic discussion and act as a catalyst for debate.

1

Western Canada needs to develop the transportation capacity to reach three critical markets: Asia; the US Gulf Coast; and eastern Canada and the US eastern seaboard.

The need to access Asian markets is obvious. China alone is expected to account for half of all global growth in oil consumption through to 2035. It will need to import more than three times as much crude oil as western Canada currently produces. Moreover, access to overseas markets will allow western Canadian producers to receive higher prices for their oil.

The US Gulf Coast accounts for more than half of all US refining capacity, is well-equipped to handle Canadian heavy crude, and is a major export centre for refined petroleum products. Aided by the nearly-completed Panama Canal expansion, the Gulf Coast also offers western Canadian producers an alternative means of accessing overseas markets.

Eastern refineries in North America have been struggling with lower demand, competitively-priced refined petroleum imports and their reliance on relatively expensive overseas feedstock. Adverse market conditions are causing refinery closures in both Canada and the US. Several facilities, notably those in Quebec, are seeking access to western Canadian crude oil in order to remain competitive.

2

Building new pipelines is the best long-term transportation solution.

Pipelines are the safest and most cost-effective way to get oil to markets. They also can deliver larger volumes and are more energy-efficient than any alternative mode of transportation.

Western Canada needs additional pipelines to absorb expected production growth; to reach US markets outside the US Midwest; and to access overseas markets. As it stands now, oil production in the West could soon outstrip available export capacity. If this happens, investment and expansion will grind to a halt.

Industry has proposed a number of new projects and initiatives that could add between 2.7 and 3.4 million barrels per day of capacity to the existing pipeline network. The challenge is getting these projects approved and completed in a timely manner.

In the meantime, there are opportunities for rail as a transportation solution, especially from new oilfields and to underserved markets. Rail has low up-front capital costs and can quickly adapt to changing market dynamics. However, rail transportation will not be adequate to meet all the West's transportation needs.

3

Current market conditions do not support developing additional refining and upgrading capacity in western Canada.

The economics of refining and upgrading are challenging in the current economic environment. There is already surplus refining capacity in North America and demand for refined petroleum products is falling. The options overseas are limited as well. China, for example, has a stated policy of self-sufficiency in refined petroleum and is building large, new, state-of-the-art refineries that will more than meet its projected future needs. Investment in bitumen upgrading in western Canada is also risky. Up-front capital costs are high and the per-barrel return on that investment is currently low. Exporting diluted bitumen may be a simpler and more secure alternative.

Nevertheless, increasing the amount of refining and upgrading activity that takes place in western Canada is an attractive public policy goal supporting employment and diversification objectives. It remains to be seen if there are solutions that would allow the West to develop a more substantial refining presence.

Western Canada has the potential to become one of the world's major oil producers. However, that potential will go unrealized if we fail to get oil transportation right.

Global Demand Outlook for Crude Oil

OVERVIEW

Crude oil is the world's most important source of energy and will remain so for another generation. However, three significant trends will combine to redraw global crude oil markets:

1 the substitution of less carbon-intensive energy sources;

2 declining consumption in industrialized countries and growing demand in developing nations; and

3 a production boom in the United States which will greatly reduce its dependence on foreign oil.

A number of international organizations and private companies publish global outlook documents that project future expectations in energy supply and demand. While the details may vary from one to the next, every major publication points to the same overarching trend: a long-term decline in oil consumption in North America and Europe, offset by rising demand in developing countries, especially in Asia.

The following analysis draws from the results of the International Energy Agency's (IEAs) *World Energy Outlook 2012* (WEO). The WEO is the most up-to-date outlook document currently available, is reputable, among the most comprehensive, and provides a relatively complete data set for study.[1]

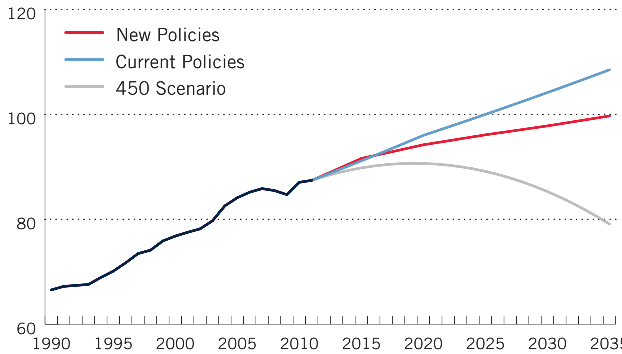
In its outlook, the IEA generates three scenarios that assume varying degrees of government policy intervention in areas like energy conservation, efficiency standards, and greenhouse gas emissions targets. The intent is to generate a range of expectations about where energy supply and demand may be heading, and to provide a basis for discussion and debate.

In two of these three scenarios, global demand for oil is projected to grow for the duration of the outlook period. In the third scenario, oil demand begins to fall in the latter half of the outlook period on the assumption that governments introduce new policies that severely curb oil demand. Even in that relatively dramatic scenario, however, oil remains the single largest source of energy in the world.[2]

Regardless of scenario, the IEA points to three trends that are altering the outlook for western Canadian crude oil producers. First, global oil demand is expected to decelerate in the future as conservation and efficiency measures, and substitution of cleaner-burning fossil fuels, limit consumption needs. Second, petroleum use is projected to fall in industrialized countries while population growth and rising incomes fuel demand in developing and emerging markets. Finally, surging oil production will dramatically reduce the United States' dependence on foreign crude oil.

The effects on global energy flows are dramatic. In the baseline New Policies scenario, oil consumption in industrialized countries falls by 21% over the outlook period, while it rises by 49% in developing nations.

Figure 1.1 World Oil Demand by Scenario (million barrels per day)



Source: Canada West Foundation estimates using data from EIA and IEA *World Energy Outlook 2012.*

THE IEA'S THREE OUTLOOK SCENARIOS

The New Policies Scenario

This is the IEA's reference case scenario. It assumes that governments' existing energy-related policies are maintained and that recently-announced commitments and plans, including those not yet formally adopted, are implemented in a cautious manner. For example, if a country has set a range for a particular policy target, this scenario assumes that it would meet only the less ambitious end of that range.

Oil prices in this scenario are expected to rise from $108 per barrel in 2011 (using inflation-adjusted 2011 dollars) to $120/bbl in 2020 and to $125/bbl in 2035.

The Current Policies Scenario

This is the status-quo scenario. It assumes that government policies that have been enacted or already adopted continue unchanged but that governments take no new policy action and make no effort to meet existing commitments unless they have already done so. No new measures will be added.

Because of anticipated higher demand, crude oil prices are expected to be higher in this scenario – rising to $145/bbl (in 2011 dollars) by the end of the forecast period.

[1] The US Energy Information Administration (EIA) publishes an *Annual Energy Outlook* that provides more detailed data for North America compared to the IEA. However, the EIA did not publish a global outlook in 2012. In December of this year, the EIA released an abridged version of its reference-case outlook for 2013, but its full *Annual Energy Outlook*, which includes its alternative scenarios and more detailed information, will not be released until spring 2013.

[2] IEA data on oil supply and demand include conventional and unconventional crude oil, condensates, natural gas liquids, refinery feedstocks and additives and volume gains from refinery processing.

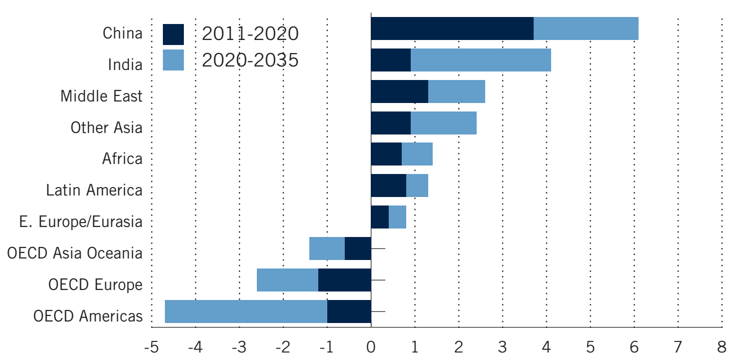
The 450 Scenario

The 450 scenario is one in which vigorous policy action is taken to curb global warming. It assumes aggressive policies are implemented consistent with stabilizing atmospheric greenhouse gas concentration at 450 parts per million and potentially limiting the increase in average global temperature to two degrees Celsius.

For the most part, the policy burden implied by this scenario is expected to be borne by industrialized countries and other major polluters. All countries are assumed to fully meet their Cancun Agreement commitments by 2020, after which point OECD countries and other major economies (such as China, Russia, Brazil and South Africa) are assumed to set hard emissions targets for 2035. Industrialized countries are also assumed to impose escalating carbon prices, reaching $120/tonne (in 2011 dollars) by 2035. The above-mentioned emerging economies introduce a somewhat more modest price on emissions ($95/tonne by 2035).

This scenario results in decreasing energy demand, which is expected to push down oil prices in the second half of the forecast period. In this scenario, oil prices peak at $115/bbl (in 2011 dollars) in 2015 and fall to $100/bbl by 2035.

Figure 1.2 Change in Oil Consumption by Region – 2011 to 2035 (New Policies Scenario) (million barrels per day)



Source: IEA *World Energy Outlook 2012.*

DEMAND BY COUNTRY

China will become the world's largest oil consumer by 2030, regardless of scenario. Conversely, oil demand in the United States falls in every scenario.

Western Canadians have a particular interest in projected oil demand in two countries: the United States, which is effectively the only foreign market for the West's crude oil; and China, which is expected to drive future global oil demand.

United States

Oil consumption in the US has fallen by 8.4% over the past five years, led by lower demand for motor gasoline and other transportation fuels, which account for well over half of current oil consumption. This trend is expected to continue in the future as rising fuel efficiency standards and other measures are put in place to further limit demand.

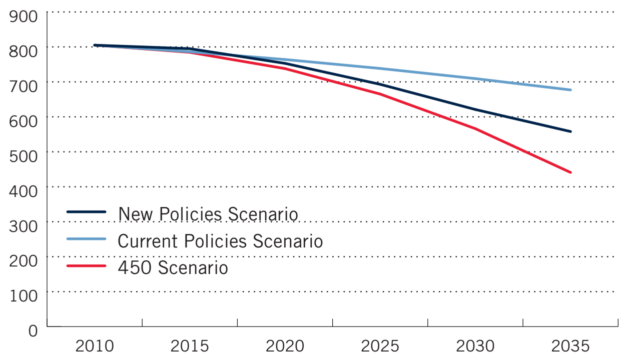
The IEA projects US demand to decline through 2035 regardless of scenario. Initially, there is little to differentiate between the three cases; in all three, current policies (such as tighter regulations on fuel efficiency in motor vehicles) are expected to proceed as planned. In the reference-case scenario, oil demand falls by an additional 6.5% through 2020. The results are comparable in the other two cases.

Beginning in 2020, however, the results begin to diverge. The New Policies scenario projects total demand to fall by 26% from 2020 to 2035 as the US is assumed to implement new policies and conservation measures that reduce greenhouse gas emissions, encourage the use of biofuels, and promote efficiency gains. The Current Policies scenario projects a more modest decrease of 11% through 2035, since it calls for no new policy action to take place. By contrast, the 450 scenario assumes an ambitious policy agenda resulting in a 40% decrease in US oil consumption over that period.

China

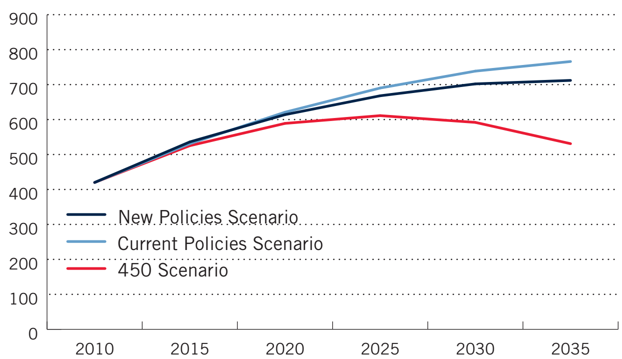
China is expected to become the world's largest oil consumer before 2030. As in other developing Asian markets, the main drivers are population growth and economic expansion. In particular, as incomes rise, demand for motor vehicles and other forms of personal and business transportation is expected to soar, overriding the effects of any gains in fuel efficiency or other conservation measures.

Figure 1.3 Projected US Oil Demand by Scenario (million tonnes of oil equivalent)



Source: IEA *World Energy Outlook 2012*.

Figure 1.4 Projected Chinese Oil Demand by Scenario (million tonnes of oil equivalent)



Source: IEA *World Energy Outlook 2012*.

In the New Policies case, Chinese demand is projected to increase by 46% between now and 2020. Growth slows thereafter; China has adopted fuel efficiency standards that begin to take effect in 2015. From 2020 to 2035, therefore, oil consumption in China is expected to decelerate, growing by a comparatively modest 16%. Nevertheless, China singlehandedly accounts for half of the expected increase in global oil demand through 2035 in this scenario.

While the results of the Current Policies scenario are similar to the New Policies case, the 450 scenario is dramatically different. In the New Policies and Current Policies scenarios, China is not expected to take any major steps towards reducing greenhouse gas emissions. In the 450 scenario, however, China is assumed to implement (and meet) emissions-reduction targets by 2035 and introduce an escalating system of carbon pricing. These actions cause Chinese oil demand to peak around 2025 in this scenario and begin to fall thereafter.

EVALUATING THE SCENARIOS AND CORE ASSUMPTIONS

The IEA presents three outlook scenarios that trace different global energy consumption paths. Are the underlying assumptions reasonable?

The Current Policies scenario and the New Policies scenario both likely underestimate efficiency gains that will be achieved through innovation, market pressure and consumer choice. The scenarios rely on projections from past behaviour and analysis of known government initiatives and international commitments. While many expect little aggressive environmental action by government due to the fragility of the economy, technology and changing consumer expectations are likely to dampen oil demand. They could do so – without significant government intervention – quite dramatically at the outer end of the forecast window. Even without the social considerations, oil is a high cost input and there is a natural market pressure to reduce its use where possible through substitution and technological innovation.

However, the forecast window covers 2-3 business cycles and a resurgence of US manufacturing is very likely in this period driven by rising costs in Asia and natural US advantages of infrastructure, innovation and stable government. Higher-than-expected efficiency gains could be offset by increased economic activity.

Most efficiency technologies rely on higher up-front costs. These are less likely to be adopted by consumers or industry during uncertain economic times. The Canada West Foundation considers it likely that IEA Current Policies and New Policies scenarios in general understate US energy demand in the short-term.[3] The accuracy of the longer term project is difficult to assess given the countervailing factors of efficiency gains and substitution *versus* economic growth, particularly in manufacturing. What is clear is that US demand will be stable but not high growth.

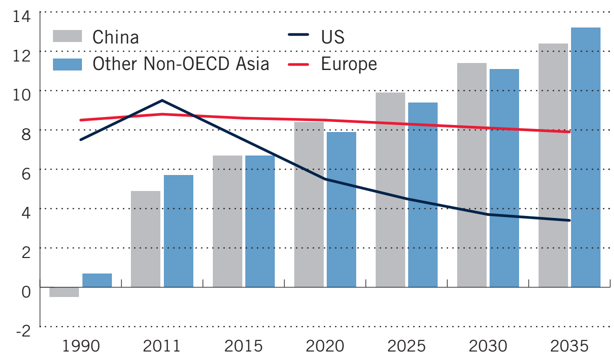
The 450 Scenario is not rooted in analysis of existing behaviour or actual government initiatives. It is outcome-focused. It looks at what steps are needed to limit global warming to 2°C. The challenge with this scenario is the inherent flaw in the Kyoto framework: it makes little sense for industrialized countries to do dramatic damage to their own economies simply to export jobs and carbon emissions to other countries. This approach

[3] It is worth noting that in the early release of its 2013 outlook, the US EIA projects a much smaller decrease in consumer demand in the US.

increases overall global emissions and is an economic disaster. It is hard to imagine North American governments vigorously pursuing the 450 Scenario in the absence of a functional new multilateral treaty arrangement.

One particularly risky assumption underlying all scenarios is that economic growth in China will continue to drive future global energy demand. The Chinese economy has slowed in recent years and while this has been reflected in the outlook scenarios, China remains on shaky ground. A significant downturn could cause simmering political instability to erupt, completely altering the global energy landscape. However, even in this situation, demand in the rest of Asia would likely be very significant.

Figure 1.5 Net Crude Oil Import Requirements (mb/d)



Source: Canada West Foundation calculations using IEA data.

NET IMPORT REQUIREMENTS

US net import requirements for oil are expected to fall by 64% by 2035. Meanwhile, import demand will rise by 153% in China and by 132% in other developing Asian markets.

IEA projections suggest a dramatic shift in global oil trade flows in the years ahead. Regardless of scenario, crude oil demand in the US and Europe is expected to fall over the next 25 years. Meanwhile, consumption in China and other Asian markets is expected to increase considerably.

These trends are only magnified by expectations on the supply side of the equation. Crude oil production in the US is surging, thanks to the development of tight oil resources like the Bakken play in North Dakota, where monthly output has tripled in just three years.

The IEA projects US oil production growth to continue, peaking around 2020 before slowly tapering off. Even though output is expected to decline slowly thereafter, the US is still projected to extract more crude oil in 2035 than it does today.

As a result, US reliance on foreign crude oil is expected to plummet. The IEA's baseline projection suggests that US net import requirements will fall from 9.5 million barrels per day (mb/d) in 2011 to just 3.4 mb/d in 2035 because of the expected combination of lower consumption and higher production.[4]

European net imports are projected to decline as well – from 8.8 mb/d in 2011 to 7.9 mb/d in 2035. Consumption is expected to fall by more than production does, hence the need for less imported crude.

In Asia, by contrast, oil imports are expected to soar as the effects of consumption growth are magnified by declining production. China's net import requirements in 2035 are projected to be 7.5 mb/d higher than they are today. Net imports into other developing Asian markets are expected to rise by another 7.5 mb/d.

IMPLICATIONS FOR CANADIAN CRUDE OIL EXPORTS

By 2035, China will need to import more than three times as much oil as western Canada currently produces, but the West has very little physical access to that market.

The downside of the western Canadian oil industry's dependence on a single market is becoming evident. Reliance on the US has made sense up to now, but structural shifts in the North American oil sector have exposed the costs of a single-customer strategy.

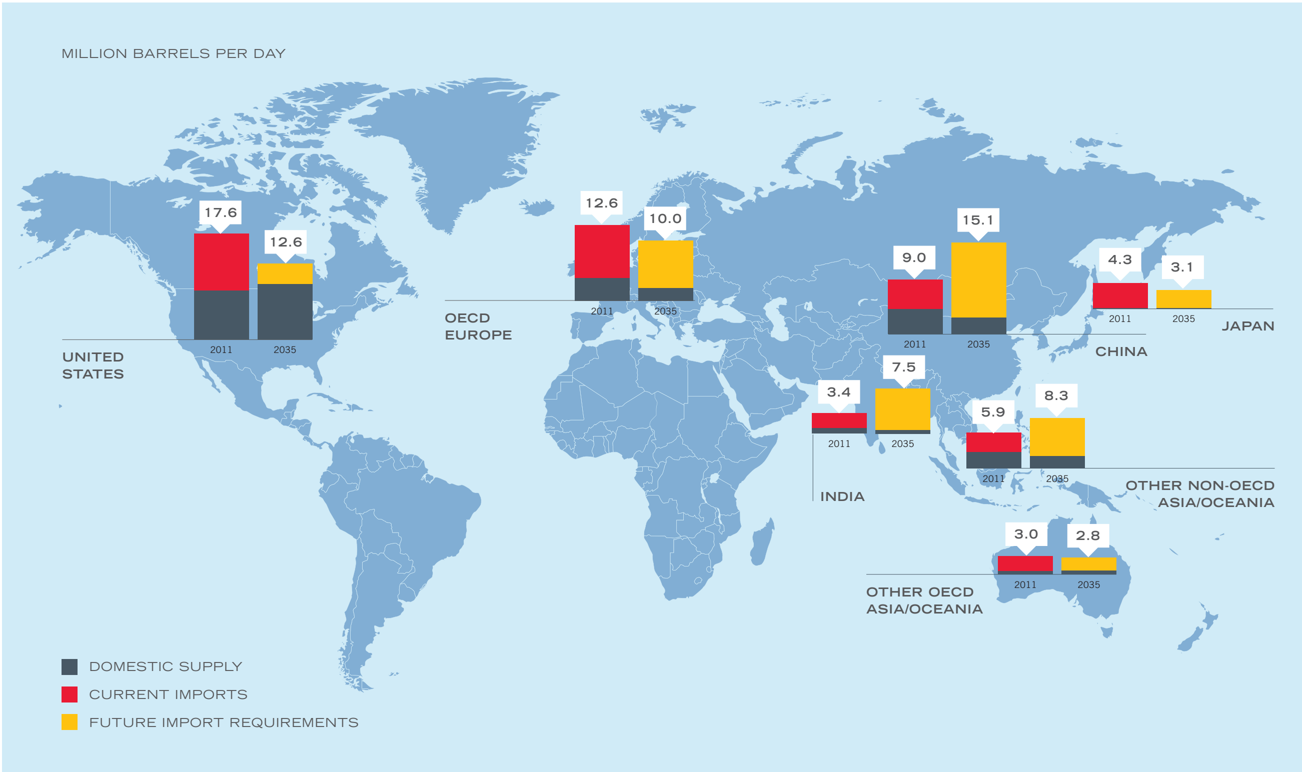
Three quarters of all crude oil produced in western Canada is exported and more than 99% of that goes to the United States. However, the reality is that the US will not need to buy as much Canadian crude in the future. US oil production is booming and consumption is projected to fall by anywhere between 16% and 45% between now and 2035.

This is not to suggest that the US market will completely dry up for Canadian petroleum exporters. Western Canada already has strong pipeline connections to the US Midwest. Moreover, the US is a fragmented energy market and, as will be discussed below, there is untapped potential to export to the Gulf Coast and east coast.

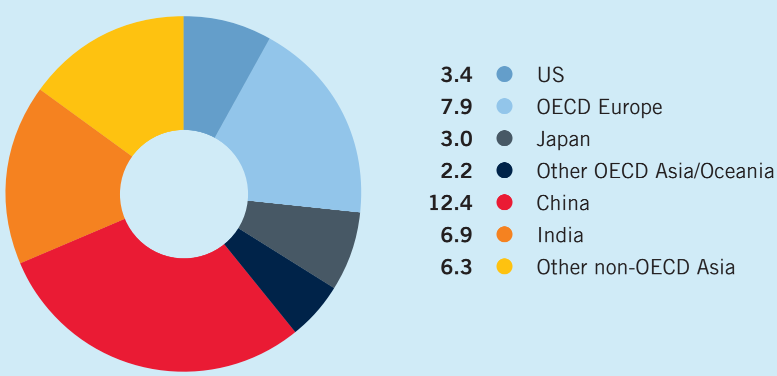
[4] Because it projects a smaller decrease in oil consumption, the EIA's early-release 2013 outlook calls for a much smaller drop in US net import requirements.

Nevertheless, the US will be extracting more oil in the future even as its need for petroleum falls. This trend points to the urgent need for the West to find alternative markets where demand is strong and growing. In particular, securing access to Asia is critical. Chinese demand growth alone is enough to easily outstrip western Canadian production. Giving declining export prospects in the US, failure to expand overseas exports will almost certainly limit future growth in the western Canadian oil patch.

Figure 1.6 Current and Projected Oil Consumption in Major Importing Countries/Regions



Net Import Requirements in 2035 (million barrels per day).



Source: Canada West Foundation calculations using IEA data.

Note: Projections refer to the IEA's baseline "New Policies" scenario.

Western Canadian Production and Supply Outlook

CURRENT PRODUCTION

Western Canada is a major player in global crude oil markets. It holds the third-largest reserves on the planet and, if it was its own country, would be among the ten largest oil-producing nations.

In 2011, western Canada produced about 2.7 mb/d of crude oil, more than Brazil, Kuwait and Iraq. Of that total, about 60% came from Alberta's oil sands. An additional 22% came from other Alberta sources.[5] Nearly 16% of the West's production came from Saskatchewan and the remainder was about evenly split between BC and Manitoba.

Table 2.1 2011 Crude Oil and Liquids Supply

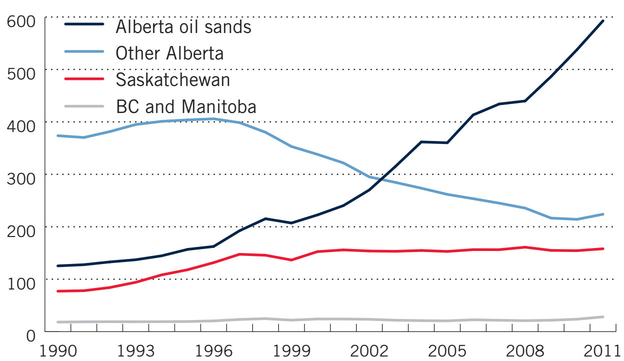
	000 b/d	% of world production	% growth: 2006-2011
Saudi Arabia	11,153	12.8	4.6
Russia	10,229	11.7	5.7
United States	10,142	11.6	21.9
China	4,299	4.9	11.2
Iran	4,234	4.9	2.0
Canada	3,600	4.1	9.4
United Arab Emirates	3,096	3.6	5.0
Mexico	2,959	3.4	-20.2
Brazil	2,687	3.1	24.0
Kuwait	2,682	3.1	0.7

Source: Canada West Foundation calculations using EIA data.

Note: The figures in this table differ from the IEA numbers presented in the previous section because of variations in data collection methodology.

The West's output has expanded rapidly, as growth in the oil sands offsets declining output in conventional deposits. In total, crude oil production in 2011 was 36% higher compared to a decade earlier. Output from the oil sands has increased by 166% while production of conventional crude oil has fallen by 20%.

Figure 2.1 Oil Production in Western Canada (million barrels)



Source: Canada West Foundation calculations using Statistics Canada data.

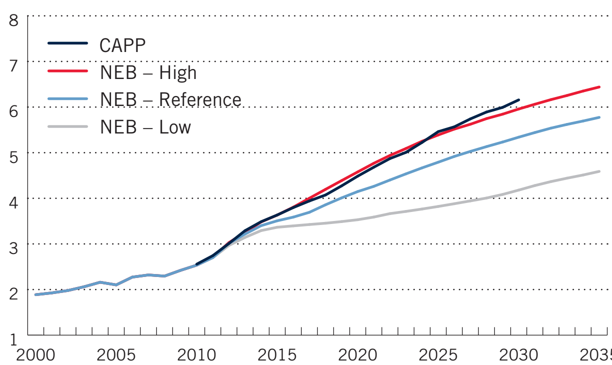
The decline in conventional production has been largely in heavy crude output from Alberta and Saskatchewan. Offsetting that decline, to some extent, has been the development of new sweet crude deposits in Saskatchewan and Manitoba. Light and medium crude output from those two provinces has increased by 76% since 2001.

SUPPLY OUTLOOK

Long-term forecasts call for western Canadian crude oil production to at least double by 2035 – provided that the oil can find its way to market.

Long-term supply forecasts for western Canada have a considerable degree of variation from one to the next, but all point to the same general conclusion: The amount of oil produced in the West is expected to expand even more in the years ahead. Baseline forecasts by the Canadian Association of Petroleum Producers (CAPP), the Canadian Energy Research Institute (CERI) and the National Energy Board (NEB) all anticipate that crude oil output in western Canada will at least double by 2035.[6] In some higher-growth scenarios, total production is more than 130% above current levels.[7]

Figure 2.2 Western Canadian Crude Oil Production Forecasts



Source: National Energy Board (NEB), Canadian Association of Petroleum Producers (CAPP).

[5] These include heavy crude and crude oil equivalents: condensate and pentanes plus.

[6] CAPP forecasts only extend to 2030, but expect western Canadian crude production to rise by 124% in that time.

[7] The IEA's *World Energy Outlook 2012*, discussed in the previous section of this paper, is slightly more conservative, forecasting an 80% increase in Canadian crude production, but a 169% increase in oil sands output from 2011 to 2035.

This growth is expected to come almost completely in the oil sands. Most Canadian analyses expect oil sands production to triple by 2035, by which point it could account for 80-85% of total crude production in the West. Output of conventional crude oil is expected to rise in the near term as new technologies are introduced and production at new deposits accelerates. However, conventional production is projected to resume a downward trajectory thereafter.

Most of the decline in conventional oil production is expected to come in heavy crude output, particularly in Alberta. In Saskatchewan, heavy crude production declines as well, although that drop is largely offset by forecasts of rising light oil extraction in the southeast of the province. For its part, Manitoba is in the midst of a production boom relative to the historical size of the industry. Output has more than tripled since 2000 but is projected to peak in the mid-2010s before falling back to last decade's levels. Oil production in BC is expected to fall throughout the projection period.

ASSUMPTIONS AND UNKNOWNS

A central assumption of Canadian crude oil production forecasts is that all oil will find markets and all necessary transportation infrastructure will be built. These outcomes are far from guaranteed.

As with global outlooks, Canadian oil production projections are not meant to be predictive; rather, they represent an illustration of reasonable expectations based on current information and a series of assumptions about the future.

All projections include basic assumptions about economic performance, population growth, oil prices and many other global and local factors. For example, politics, expansion of light oil plays in Saskatchewan and Manitoba, or the development of Saskatchewan's oil sands could dramatically increase expectations of future output in those provinces. Conversely, low oil prices and high break-even costs could scale back production expectations in Alberta's oil sands.

Most critically, however, Canadian production outlooks make two critical assumptions: that all energy will find markets; and that all necessary transportation infrastructure will be built. In other words, these growth scenarios are only achievable if the right infrastructure is in place to get western Canadian oil to markets.

Transportation Infrastructure in Western Canada

EXISTING EXPORT PIPELINES IN THE WEST

Western Canada's export pipeline capacity has increased by more than 33% since 2009, but it is not aligned to current market realities and will be insufficient to meet our future capacity needs.

The existing pipeline network in western Canada can be divided in two groups. The first is the regional network that delivers raw bitumen and crude oil to refineries, upgraders and distribution terminals within the West. The second transports crude oil and related products out of western Canada to markets and refineries across North America.

Western Canada's existing export pipeline network has undergone considerable expansion in recent years to accommodate growth in oil production. Several expansions to existing lines were completed in 2009 while two new pipelines came online in 2010, adding 33% to the West's oil export capacity: the Alberta Clipper links Hardisty to Enbridge's terminal in Superior, MI; and TransCanada's Keystone Base sends oil sands crude to refineries in Illinois.

There are, at present, seven major pipelines operating in western Canada that transport diluted bitumen, crude oil and refined petroleum products out of the West. Most of this capacity is devoted to serving markets in the US Midwest – Petroleum Administration for Defense District (PADD) II.[8] The US Rocky Mountains (PADD IV) is also an important destination. One pipeline (Kinder Morgan Trans Mountain) links Alberta to ports in Burnaby. Another (Enbridge mainline) connects the West to markets in Ontario, via PADD II.

REQUIREMENT: BETTER ACCESS TO NORTH AMERICAN MARKETS OUTSIDE THE US MIDWEST

Most western Canadian oil exports go to the US Midwest, where transportation bottlenecks are driving domestic oil prices lower. The West needs better access to the US Gulf Coast and eastern North America.

Neither Canada nor the US can lay claim to a pipeline network that allows crude oil or refined petroleum to flow easily from producing regions to major demand centres. In Canada, there is no direct link between western supplies and eastern markets past Ontario. In the US, talk of growing energy independence masks the fact that the country effectively consists of several distinct energy markets. The US west coast and east coast are dependent on overseas oil imports and have very little access to North American crude supplies. The US Gulf Coast is a major net exporter of petroleum products and the US Midwest is contending with a transportation bottleneck large enough to distort continental energy markets.

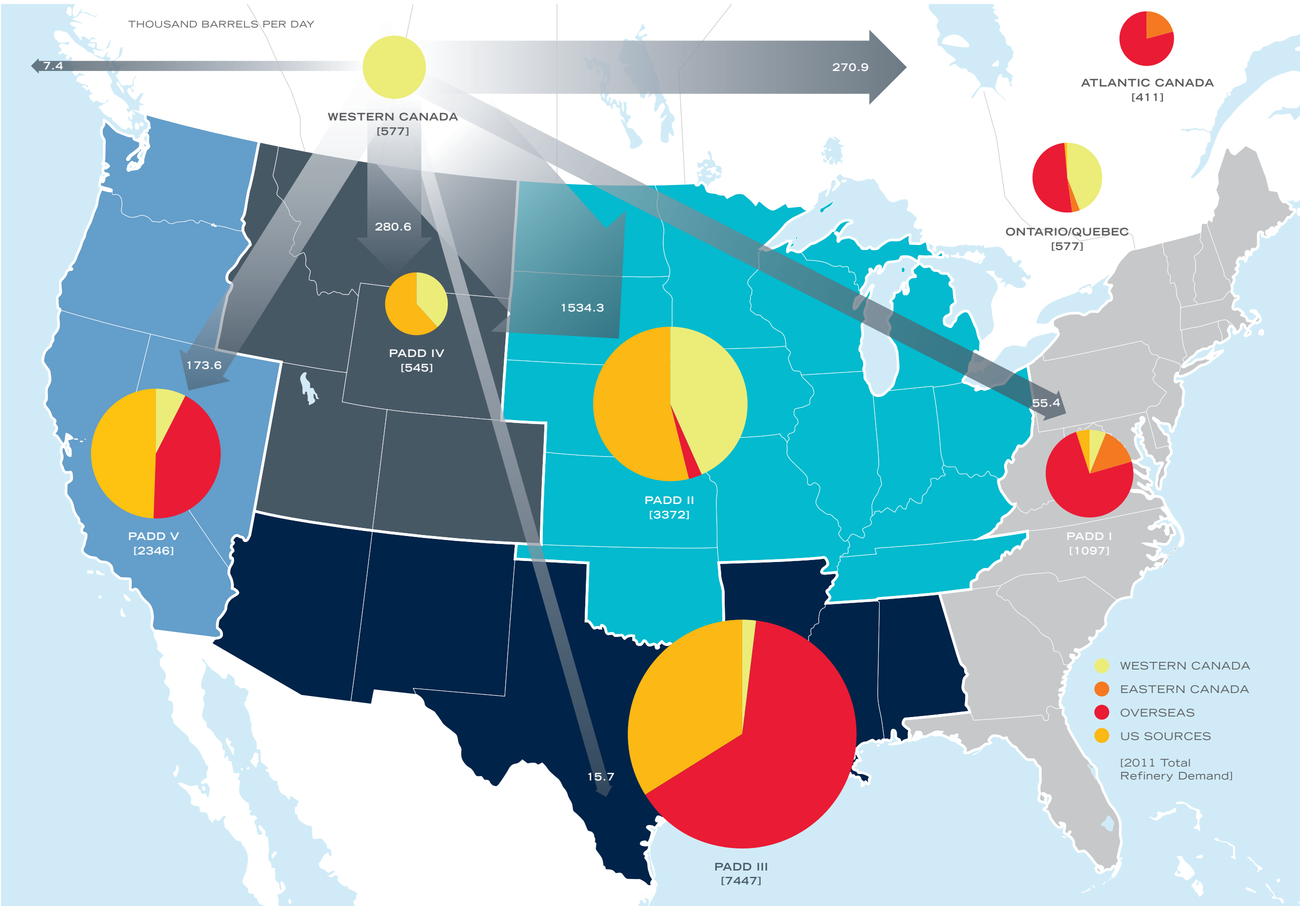
Table 3.1 Existing Export Pipeline Capacity in Western Canada

Name	Type	Destination	Capacity (000 b/d)
Enbridge Pipeline	Crude oil	Eastern Canada US East Coast US Midwest	1,868
Kinder Morgan (Express)	Crude oil	US Rocky Mountains US Midwest	280
Kinder Morgan (Transmountain)	Crude oil and refined products	British Columbia US West Coast Offshore	300
Enbridge Alberta Clipper	Heavy crude	US Midwest	450
TransCanada Keystone	Light/heavy crude	US Midwest	435
Milk River Pipeline	Light oil	US Rocky Mountains	118
Rangeland Pipeline	Cold Lake Blend	US Rocky Mountains	85
Total			**3,536**

Source: Canadian Energy Research Institute.

[8] The United States was divided into five PADDs during World War II to help organize and allocate fuel supply. These regions are still used today.

Figure 3.1 Disposition of Western Canadian Crude Oil and North American Demand in 2011



Sources: CAPP, EIA, Statistics Canada.

The fact that pipelines do not connect every corner of North America with every other corner does not suggest a past economic or public policy failure. The existing oil transportation network, including import and export terminals, evolved in response to the market conditions and policy priorities of the day; for the most part, these investments made economic sense at the time they were made.

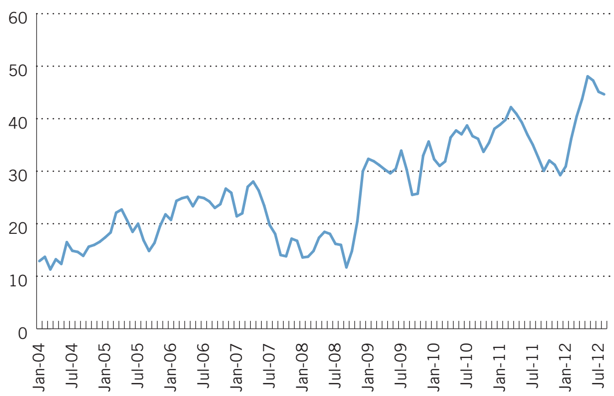
However, conditions have changed. The most pressing issue today in North American crude oil markets is that most new production growth is taking place in areas like western Canada, North Dakota and West Texas, which, with the exception of the latter, are heavily linked by pipeline to the US Midwest – specifically to the PADD II storage and distribution hub in Cushing, Oklahoma. For the most part there is enough space in the current pipeline network to deliver oil to Cushing but insufficient capacity to move products *from* that location to refineries elsewhere.[9]

These capacity constraints have created a transportation bottleneck and a buildup of excess supply in the southern PADD II region. In August 2012, there were 44.7 million barrels of oil stockpiled at Cushing, up from 18.1 million barrels five years earlier. This inventory glut is the primary factor depressing North American crude oil prices compared to overseas benchmark rates.

To get around this problem, a number of Canadian and US pipeline projects have been proposed that would add outgoing capacity from Cushing or would bypass Cushing altogether. Most of these, including the southernmost portion of the Keystone XL project currently under construction, are focused on accessing refineries on the Gulf Coast (PADD III), which account for just over half of all refining capacity in the United States.

[9] At present, relatively little western Canadian crude actually moves to Cushing; most goes to Illinois and other locations in the eastern part of PADD II. However, the impacts of the Cushing bottleneck are still felt in the West.

Figure 3.2 Crude Oil Stockpiles at Cushing, OK (millions of barrels)



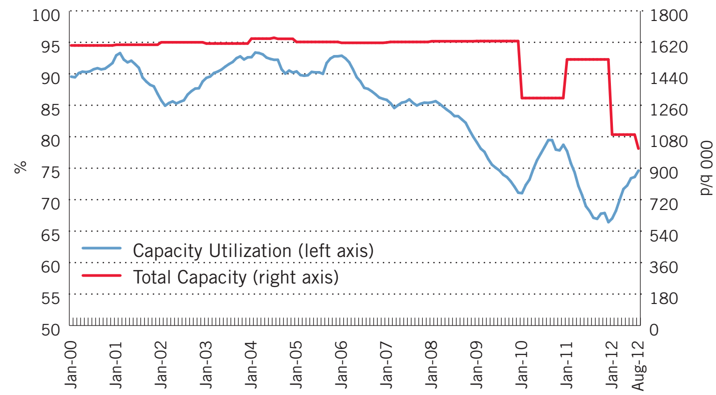
Source: US Energy Information Administration.

The US Gulf Coast has the greatest untapped potential for western Canadian crude oil exports within North America. Unlike most other continental markets, crude oil demand on the Gulf Coast is strong, as the refining industry there has undergone a transformation. In the past, Gulf Coast refineries would process imported oil from Mexico, Venezuela or other foreign sources for domestic use (some would also be re-exported). However, demand in the US for gasoline and other refined petroleum products has been falling. At the same time, foreign oil is expensive and producers are increasingly seeking alternative markets; Mexico is refining more of its own crude oil, while Venezuela is selling oil to China instead.

As a result, the Gulf Coast refineries have focused their output on the export market, with considerable success. Exports of finished petroleum products from PADD III more than tripled from 2006 to 2011, making the US a net exporter of refined petroleum for the first time since 1949. Export opportunities from PADD III will become even more attractive in the near future as the scheduled completion of the Panama Canal expansion will further open new export markets for Gulf Coast refineries. To improve their competitive advantage and ensure access to crude oil feedstock, Gulf Coast facilities are eager to access cheaper North American crude, and most are already capable of processing the heavier grades of oil produced in western Canada.

Eastern Canada and the US eastern seaboard are smaller refining markets than the US Gulf Coast. However, a combination of factors makes east coast access an attractive option for western Canadian oil exporters. For one, refineries in the eastern US and Canada would benefit from improved access to North American crude supplies. The US East Coast (PADD I) has never been well connected to major oil-producing regions in North America; it has historically been reliant on imported crude oil and petroleum products. However, a combination of factors has put the future of east coast refining in doubt.

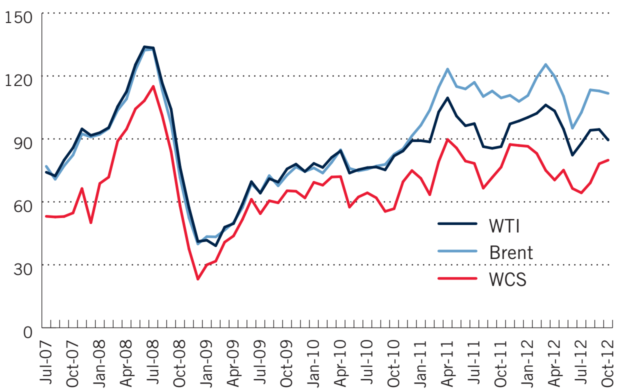
Figure 3.3 US East Coast Refining Capacity and Utilization



Source: US Energy Information Administration, Canada West Foundation.

Note: Capacity utilization rates are smoothed out using a 12-month moving average.

Figure 3.4 Crude Oil Benchmark Prices (US$/b)



Source: US Energy Information Administration.

Not only are PADD I refineries largely dependent on overseas Brent-priced crude which is more expensive than domestic feedstock, but they face softening domestic demand for petroleum products as well. These factors, along with competitive imports of refined petroleum from Europe, have squeezed refiner gross margins, forcing a number of refineries to shut down and others to operate at far below peak capacity. All told, US refining capacity along the east coast has fallen by 38% since 2009 and more closures are on the way. Even with all that capacity taken off the table, those facilities that remain open for business are still not even close to operating at their full potential. From January through August 2012, east coast refineries were, on average, running at just 79% capacity.

The story is similar in Canada, where eastern refineries also depend on higher-priced overseas oil. Tight margins and high input costs have made it difficult for some refiners to remain competitive. Shell closed its Montreal refinery in 2010 and Imperial Oil announced in 2012 that it would shut its facility in Dartmouth, Nova Scotia if a suitable buyer was not found.

In addition to the fact that eastern refineries would benefit from access to the West's oil, there is already infrastructure in place to access those markets. Enbridge is in the process of reversing the flow of its existing Line 9 pipeline, sending western Canadian oil to Montreal refineries. There is also the potential to deliver oil via tanker from Montreal to New Brunswick, as well as to access the US east coast via existing pipelines.

Finally, sending western Canada's oil to eastern Canada offers national economic benefits that could make it easier to gain public acceptance for additional pipeline construction. Unlike the Northern Gateway project which has attracted widespread public opposition, Enbridge's Line 9 reversal has seen comparatively little public resistance and enjoys support from all major federal political parties on the basis that it provides Canadian oil for Canadians. Adding more pipeline capacity connecting the West to eastern Canadian refineries would profit eastern provinces, keep a greater share of the economic benefit of oil production within Canada, and provide eastern Canadians with tangible evidence of the direct benefit they receive from western Canadian oil production.

REQUIREMENT: ACCESS TO ASIAN MARKETS

The existing oil transportation infrastructure in western Canada was built to serve the US market, but the future growth opportunities are in developing Asia.

Western Canada's energy transportation infrastructure has been built almost entirely to export to the US, effectively making the West a captive supplier to that market. Until now, this strategy has served the West well. US demand and direct investment has helped to spur production and export growth, generating thousands of jobs and billions of dollars of government revenues in the process.

However, the future is far less certain. A number of recent developments suggest that long-term demand for Canadian oil in the US is far from certain and have highlighted the risk of overreliance on a single customer. These developments include the following:

- **Flat or declining US demand for crude oil and petroleum products.** As noted earlier, the IEA projects US consumption of crude oil to drop by between 16% and 45%. Other agencies do not foresee such a dramatic decline, but none expect demand to increase.
- **Booming US supply growth.** A growing share of that flat or falling demand will be met with domestic production, reducing US dependence on foreign oil.
- **Resistance to oil sands crude in the US.** The delay of the Keystone XL pipeline proposal not only exposed the risk of overreliance on a single customer, but also illustrated the extent to which opposition to oil sands development has grown, and the extent to which pipeline safety has become a top-of-mind concern in the US.
- **Western Canadian producers selling oil at discount prices.** As noted earlier, transportation bottlenecks mean that western Canadian producers are selling their oil at a steep discount compared to world prices. Effectively, the West is giving away billions of dollars in profits and foregone government revenues because of its inability to access alternative markets.

Meanwhile, the growth opportunities are clearly in developing Asian markets. In total, the IEA projects that developing markets will account for 57% of global crude oil demand by 2035. China will become the world's largest consumer of crude oil by the late 2020s and would need to import 12.4 mb/d of crude oil by 2035 to meet its needs. That total is more than three times current production levels in Canada.

The problem is that there is virtually no capacity in place linking western Canada to these markets. Kinder Morgan's Trans Mountain pipeline is the only direct link to the west coast, but the capacity to use this line to improve access to Asian markets is limited. For one, the pipeline itself is only average in size, with a total capacity of 300,000 barrels per day (b/d). On top of that, nearly all the capacity on that line is already committed to other markets; the Trans Mountain line delivers crude oil and refined products to BC customers, or sends crude oil to Washington State for refining. Only a tiny fraction of oil delivered to the terminal station in Burnaby is shipped overseas.

REQUIREMENT: ADDITIONAL CAPACITY TO ACCOMMODATE GROWTH

Expected growth in western Canadian crude oil production will absorb all available export pipeline capacity by 2016, if not sooner.

For the moment, western Canada has enough export pipeline capacity to meet current needs. Thanks to recent additions to the network, existing pipelines can transport up to 3.5 mb/d of liquids. According to CERI, western Canadian producers needed about 2.5 mb/d of space to transport crude oil, refined products and diluted bitumen out of the West in 2011.

However, production is expanding rapidly and will soon outgrow existing pipeline capacity. CERI estimates that based on expected production growth, the liquids available for export from western Canada will absorb all available pipeline space by 2016, if not sooner.

Further complicating matters, booming oil production in the Bakken will consume some of the pipeline capacity available to western Canadian oil exporters. For example, Enbridge operates a mainline system that sends western Canadian crude to its terminal in Superior, WI, from which point it is distributed to markets in the US Midwest and central Canada. Enbridge is proposing a new Bakken pipeline that would feed North Dakota crude into that mainline system. Connecting Bakken crude to that line would take up some of the capacity currently available to western Canadian producers.

The impact of the proposed Bakken line would be relatively modest – it would take up between 120,000 and 145,000 b/d of available space on the Enbridge mainline – and has already been reflected in CERI's capacity estimates. However, as US oil production continues to expand, it could take up a larger share of existing pipeline capacity and cause western Canadian producers to bump up against transportation constraints even sooner.

In fact, this is already happening. Since CERI published its findings, Enbridge has proposed another new pipeline (the "Sandpiper") that would link oilfields in North Dakota directly to Superior, WI. That pipeline would feed about 225,000 b/d of Bakken crude into the existing Enbridge mainline and would further reduce the capacity available to western Canadian producers beyond Superior.

A lack of sufficient pipeline capacity would dramatically alter the outlook for crude oil production in western Canada. It was noted above that one of the central assumptions in supply forecast exercises is that all energy will find markets and all necessary transportation infrastructure will be built. However, if the necessary infrastructure is not in place, there would be little point in expanding production. Western Canada would see projects delayed or cancelled, investment would dry up and the regional economy would suffer.

FUTURE EXPANSION PLANS

Industry proposals could add between 2.7 and 3.4 mb/d to western Canada's export pipeline network, more than enough to address looming capacity constraints and to accommodate expanded production. The challenge is in getting these projects built before pipeline capacity limits future growth.

Western Canada needs additional pipeline capacity to absorb expected production growth and to reach critical markets: Asia, the US Gulf Coast and eastern North America. Indeed, a number of new projects and initiatives have already been proposed that would address these goals.

Most of these proposals are still in the early developmental stages and subject to changes in design and capacity. However, based on current estimates, they could add between 2.7 and 3.4 mb/d of capacity to the existing export pipeline network – enough to absorb a significant increase in western Canadian production.

If all the proposed initiatives in Table 3.2 were completed, the distribution of western Canadian oil shipments would change considerably. Western Canada would be able to transport nearly 1.0 mb/d of liquids to overseas markets; increase capacity to the Midwest by 630,000 b/d; bypass the Cushing bottleneck; and add between 800,000 and 1.3 million b/d of capacity linking western Canadian crude oil to markets in eastern Canada.

The challenge, of course, is getting these projects approved and completed in a timely manner. The actual process of building a pipeline – from securing a right of way through to land restoration and cleanup – is long and difficult. But on top of that, companies must navigate a complex regulatory approval process and engage in increasingly fractious public consultations before any actual construction can get underway.

Table 3.2 Proposed Export Pipeline Projects

Name	Type	Origin – Destination	Estimated Capacity (000 b/d)
Enbridge Northern Gateway	Diluted bitumen, synthetic crude	Edmonton – Kitimat	530
Enbridge Line 9 Reversal	Light and heavy crude	Edmonton – Montreal	300
TransCanada Mainline Conversion	Light/synthetic crude	Alberta – Eastern Canada	500-1,000
Keystone XL	Light/heavy crude	Hardisty – US Midwest	700-830
Kinder Morgan TransMountain Expansion	Crude oil and refined products	Edmonton – Vancouver	590
Alberta Clipper Expansion	Heavy crude	Hardisty – US Midwest	120
Total			2,740-3,370

Source: CERI, company websites.

For example, Enbridge is currently in the process of applying to reverse the flow within a section of its pipeline that runs from North Westover (65km west of Toronto) to Montreal. This project was announced in May 2012 and requires no new construction. Even so, the line will not deliver western oil to Montreal until the second quarter of 2014; simply changing the direction of the flow within an existing pipeline is a two-year process.

OPPORTUNITIES FOR RAIL

Rail transportation of crude oil is growing rapidly. Is rail a stopgap measure or is it a potential solution to pipeline capacity constraints?

Given the significant obstacles, public resistance and lengthy timelines facing pipeline construction, rail is emerging as a potential solution to looming capacity constraints in the pipeline network and the desire for west coast access.

One of the chief advantages to the rail option is that it will allow the West's oil to reach its desired markets much sooner than waiting for new pipelines to be built. Even if the lengthy regulatory process and public resistance were non-issues and construction could begin today, it would take years before pipelines could be in place linking western Canada to markets in Asia, the Gulf Coast and the east coast. In the meantime, every barrel of western Canadian oil that is sold at less than North American (to say nothing of overseas) benchmark prices represents lost income to the industry, to the West's economy and to government revenues. By providing more immediate access to alternative markets, rail offers a solution to that problem.

Rail also offers several other features that make it an attractive transportation option, including the following:[10]

- the up-front cost is relatively low as much of the required infrastructure is already in place;
- regulatory approval is not required;
- rail can offer immediate benefits by bypassing existing pipeline logjams in the US Midwest;
- expensive diluent is not needed when transporting bitumen in rail cars; and
- rail is more agile, allowing more immediate service from new oil fields and to underserved markets

Currently only a small amount of crude oil in Canada is transported by rail – an estimated 31,600 b/d in 2011. However, volumes are expanding rapidly and Canada's major rail companies have ambitious plans to further increase crude oil shipments. In 2011, CN and CP together moved an estimated 18,000 cars of crude oil (each car holds between 550 and 680 barrels, depending on the product and car type) to various markets in North America. CN expects to move 30,000 carloads in 2012 and CP is targeting 70,000 by 2013.

[10] There is also an ongoing debate about the relative safety merits of rail versus pipeline transportation. Pipelines are generally acknowledged to have a better safety record in terms of accidents and fatalities. However, the rail industry maintains that it has a superior record when it comes to minimizing the likelihood and severity of oil spills.

At the same time, rail has three major disadvantages that limit its potential as a long-term transportation solution. First, it is more expensive; according to CERI, it costs between $5 and $8 to transport one barrel of liquids a thousand miles, compared to $1-$4 for a pipeline. One of the features that make rail feasible in the present environment is that it can transport crude to markets where it can fetch a higher price, thus offsetting higher transportation costs. Crude oil price differentials will likely decrease over time as markets adjust and new pipeline infrastructure comes online.

Second, rail cannot compete with the volume of petroleum liquids that can be transported by pipeline. The entire North American rail network transports an estimated 350,000 to 400,000 b/d of crude oil. While this volume is not insignificant and will rise in the years ahead, it represents the equivalent of adding a single Kinder Morgan Trans Mountain pipeline to the North American pipeline system.

Finally, while much of the necessary rail system is already in place, a shortage of available cars is a major obstacle to expanding rail transportation of crude oil. Investing in new rail cars is expensive and it takes a long time to bring additional capacity on line. Since rail's attractiveness as a liquids transportation option depends in large part on inadequate pipeline capacity, buying more rail cars could be a risky investment if proposed expansions to the pipeline network go ahead.

Nevertheless, for as long as pipeline construction continues to struggle with social acceptance in Canada and the US, there will be an important and growing role for rail to play in oil transportation in North America.

Table 3.3 Costs of Replacing a 1,000-mile long, 150,000 b/d Pipeline

Mode	Approx. cost per 1,000 barrel miles	Capacity Constraints/ Avg. speeds	Average Energy Efficiency (KJ/tonne-km)
Pipeline	$1–$4	3-8 mph	140
Rail – Unit	Light: $5–$6 Bitumen: $7–$8	1 week 90 tank cars	280
Rail – Manifest	$15	Up to 30 tank cars 12 days	280
Truck	$25	500 miles/day	2640
Barge	$5–$7	up to 7 mph	420

Source: Canadian Energy Research Institute.

Note: A manifest train is one with mixture of car types and cargoes.

These make more frequent stops than unit trains which carry only one type of cargo to a single destination.

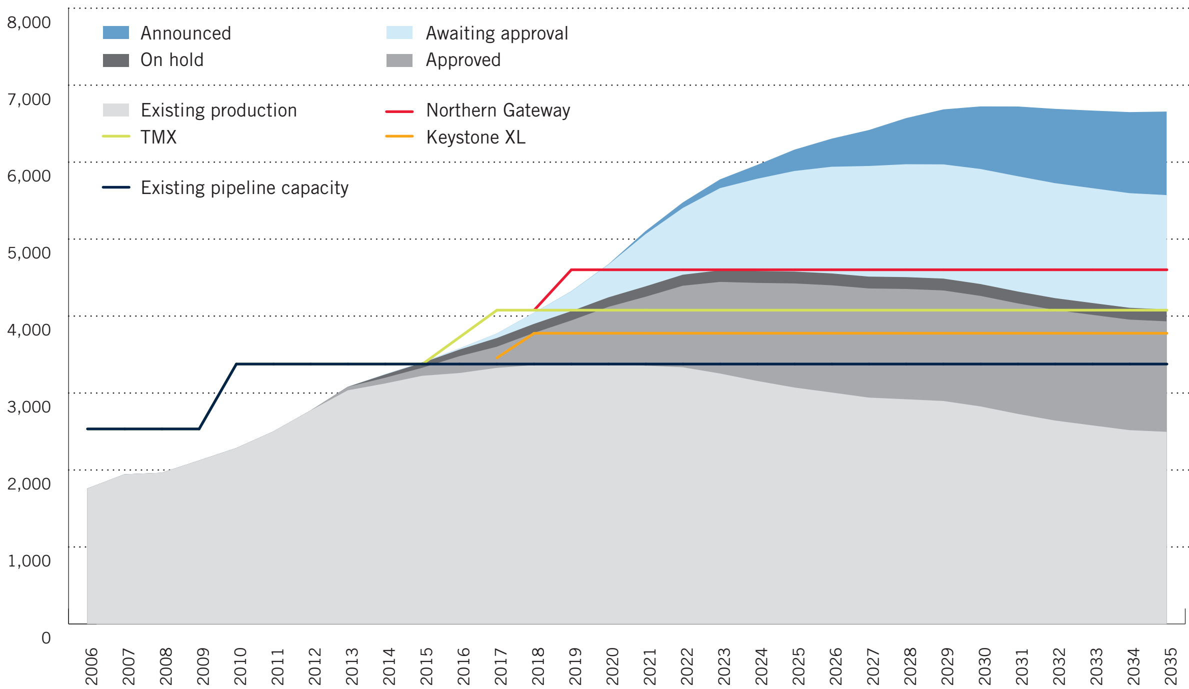
[11] Industry plans to increase the global sourcing of rail cars would help improve the response time for adding new car capacity.

Economic Impact of Adding Export Pipeline Capacity

PIPELINE CAPACITY AS A CONSTRAINT ON OIL PRODUCTION GROWTH

A lack of export pipeline capacity could limit future oil production growth in the West. The result would be billions of dollars in foregone economic activity across Canada.

Figure 4.1 Western Canadian Crude Available for Export with Added Pipeline Capacity (000 b/d)



Source: CERI.

A recent study by CERI illustrates the potential economic benefits of adding export pipeline capacity in western Canada.[12] The study examines the economic impact, through 2035, of adding three new pipelines to the existing network – Keystone XL, the Trans Mountain expansion, and the Northern Gateway pipeline.

A core assumption in this study is that export pipeline capacity imposes an upper limit on oil production in western Canada. Once domestic needs are met, surplus production, whether of diluted bitumen, crude oil or refined petroleum products, is exported. However, if there is no available room in existing pipelines, there would be no point to extracting the oil in the first place. Projects would be scaled back, delayed, or cancelled altogether.

Figure 4.1 shows all existing, planned and proposed crude oil production in western Canada that is available for export; in other words, net of domestic needs. The black line represents status quo capacity in export pipelines. Without any additional capacity, no projects above the black line would be built because there would be no way to transport those volumes out of the West. As such, the primary economic impact of each of these three projects is the additional crude oil that could be produced to consume the newly-available space in the pipeline network.

CERI's analysis is not meant to suggest that the three projects listed above are the only options available, or even the most likely to proceed; there are other proposals on the table and the potential remains to increase capacity in existing lines. However, CERI's study provides a useful illustration of the magnitude of the economic impacts that are associated with adding export pipeline capacity, reaching new markets, and giving the western Canadian crude oil industry room to grow.

Put another way, these economic impacts could be viewed in a negative sense; the cost of *not* addressing pipeline capacity constraints. Considering the challenges that industry and policy-makers face in gaining public acceptance for pipeline projects, these and other projects may never be built. That would effectively place a ceiling on crude oil production in western Canada and prevent any of the benefits discussed here

[12] The findings discussed in this section are taken from CERI Study 129: *Pacific Access: Part I – Linking Oil Sands Supply to New and Existing Markets; and Pacific Access: Part II – Asia-Directed Oil Pathways and their Economic Impacts.* Those papers contain considerably more information about assumptions regarding price differentials, the assumed contents within the pipelines, the potential for alternative means of transportation and many other relevant matters. They are available at http://www.ceri.ca/.

from being realized. The results of this study could be seen as the economic opportunities *foregone* by not acting decisively to secure our energy future today and resolving our looming transportation questions.

ECONOMIC IMPACT OF BUILDING THREE NEW PIPELINES

Expanding the existing Trans Mountain pipeline and building the Keystone XL and Northern Gateway pipelines would unlock more than $1.3 trillion in economic output for Canada; 7.6 million person-years of employment; and $281 billion in tax revenue.[13]

If all three projects were to go ahead as per the CERI study, the cumulative economic impact enabled by the pipelines in the upstream oil industry would be huge. Because most new crude oil production is expected to come in the oil sands, the vast majority of direct, indirect and induced economic benefits would accrue to Alberta; the province would see $1.2 trillion in additional economic activity between now and 2035, as well as the creation of thousands of jobs and billions of dollars in royalty revenues.

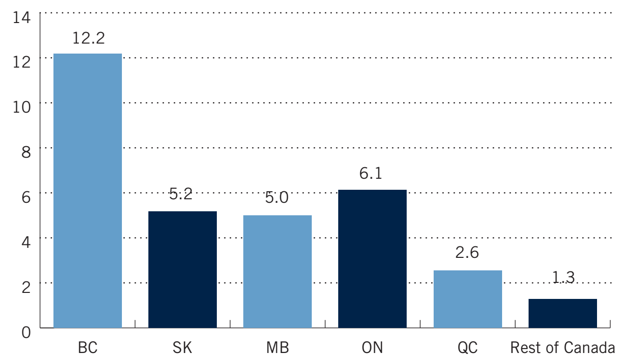
However, the benefits outside Alberta should not be dismissed. The three projects combined would enable an additional $84 billion of economic activity outside Alberta, including $32 billion to the other western provinces. More than 550,000 person-years of employment would be created in BC, Saskatchewan and Manitoba, generating $16.4 billion in wages and salaries.

By far the largest benefit (outside Alberta) would be in BC. The total economic gains over the projection period would be equivalent to 12.2% of provincial economic activity in 2011. Ontario, Saskatchewan and Manitoba would also receive a considerable boost, each equivalent to between 5.0% and 6.1% of last year's provincial GDP.

One reason the economic benefits of these projects skew towards Alberta is because conventional oil production on the Prairies is forecast to decline over most of the study period, to be replaced by surging oil sands output. If this assumption proves to be false – if Bakken production picks up on the Canadian side of the border, or new technologies unlock additional crude reserves – the picture could change considerably, benefitting Saskatchewan and Manitoba in particular.

Finally, it is important to note that the CERI study does not single-out the impact of one critical benefit of pipeline construction – higher *federal* government revenues. CERI's analysis highlights the amount of taxes paid by residents of each province, but does not specify the amount going to the federal government. While a precise figure is not available, the federal government would receive a significant share of the $281 billion in taxes paid, most of which would be collected in Alberta and redistributed across the country through federal spending.

Figure 4.2 Total Economic Impact Outside Alberta (as a % of 2011 GDP)



Source: CWF calculations using data from CERI, Statistics Canada.

Table 4.1 Economic Impact of All Three Projects

	GDP (billion 2010 C$)	Employment (000 person-years)	Compensation (billion 2010 C$)	Taxes Paid (billion 2010 C$)
Canada	1,315.7	7,586	397.9	280.8
AB	1,232.1	6,407	350.9	254.9
ON	40.1	545	23.1	13.1
BC	26.5	394	15.1	7.2
Other provinces	17.0	240	8.7	5.6

Source: Canada West Foundation calculations based on CERI data.

[13] This tax figure does not include resource royalties paid to provincial governments.

Refining and Transportation in Western Canada

REFINING CAPACITY AND TRENDS IN WESTERN CANADA

Western Canada accounts for 90% of Canada's crude oil production and 37% of national refining capacity.

The West has the capacity to refine about 41% of its total conventional and synthetic crude oil production and to meet, on balance, 96.5% of its domestic needs.

Western Canada is home to eight operating refineries: three each in Alberta and Saskatchewan and two in BC,[14] accounting for about 37% of national refining capacity in 2011. As its facilities are generally larger, about 62% of the West's total refining capacity resides in Alberta. Most of Canada's refineries, however, are located outside the West, closer to major markets for petroleum products.

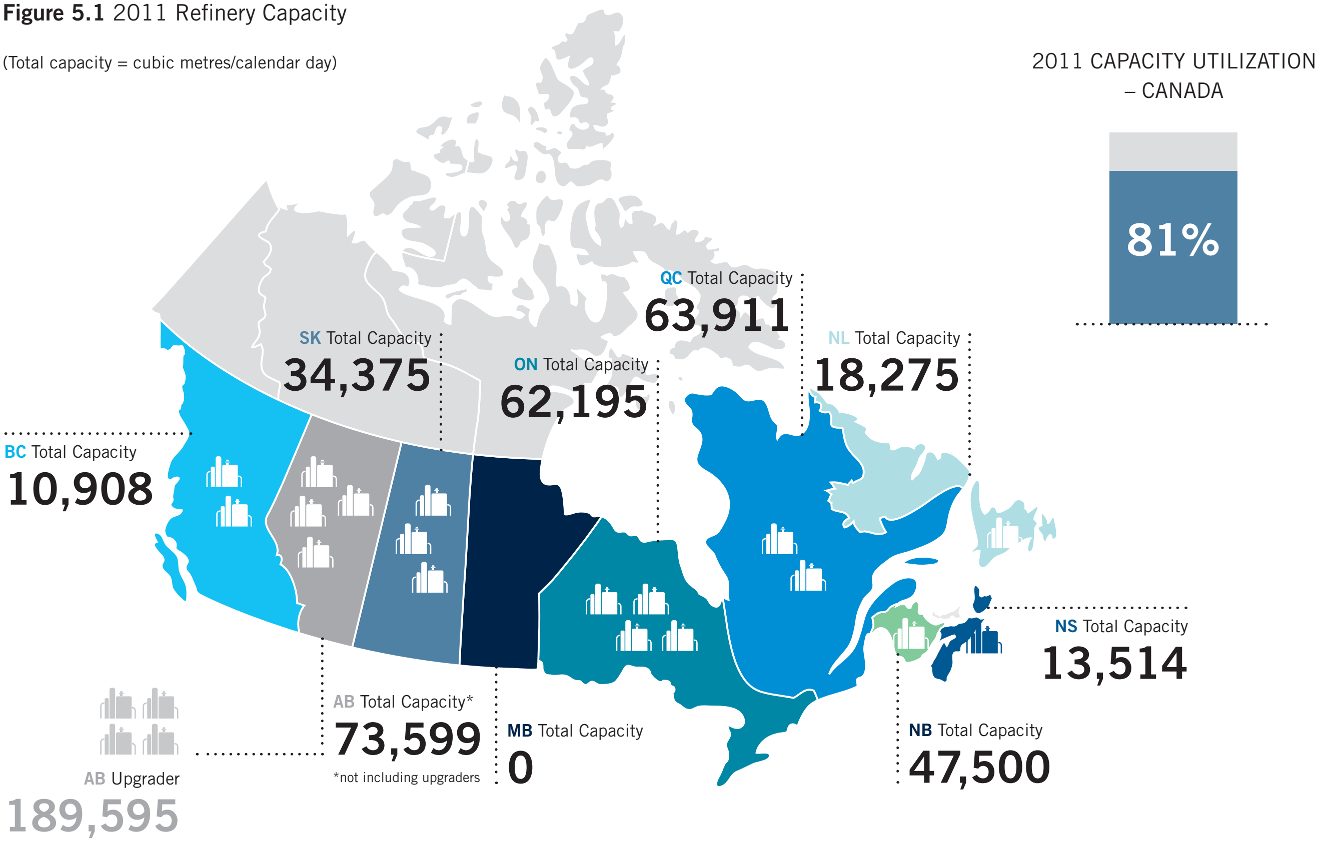
Western Canada is a net exporter of some refined products and a net importer of others. This is a natural result of the fact that not every refinery is capable of producing across the spectrum of refined petroleum products. In aggregate, however, more refined petroleum products move into the West than move out. In 2011, western Canada produced enough refined petroleum to meet 96.5% of its own needs on a volume basis.

Flows vary depending on the product but, generally speaking, western Canada is a net supplier of refined petroleum to other provinces and a net importer from the United States – to the tune of about $4.0 billion in 2011. Several factors contribute to this relatively large trade deficit with the US. One is differences in the value of the specific refined goods the West exports compared to those it imports. Another is the interplay between international and interprovincial trade; for example, Alberta is a net importer of motor gasoline from the US, but it ships a much larger quantity of gasoline to other provinces. The former contributes to Alberta's trade deficit in refined petroleum with the US, but the latter is not counted as an offset in trade statistics.

Reflecting a trend seen across North America, the refining sector in western Canada has been consolidating; there are fewer refineries in the West today compared to the early 1980s, but the average size of each facility is much larger. Overall, total refining capacity in the West increased by 33% from 2001 to 2011.[15]

Figure 5.1 2011 Refinery Capacity

(Total capacity = cubic metres/calendar day)

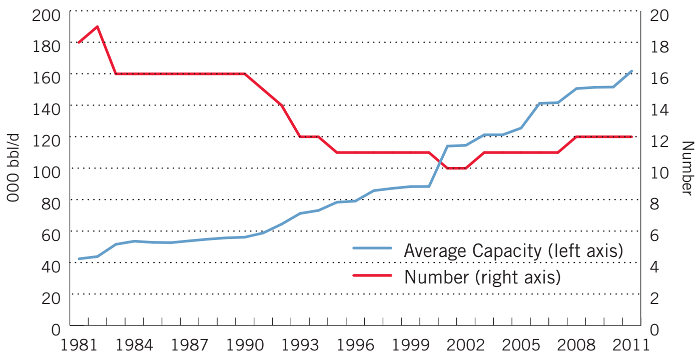


Source: CAPP Statistical Handbook 2011.

[14] Data on refining capacity focus on the volume of crude oil each facility can absorb, not the types of goods each produces. However, refineries are not homogenous units; some are capable of creating a broad range of products, while others have more modest or specialized functions.

[15] These figures do not reflect the recent completion of the $2.7-billion expansion of the Regina Co-op Refinery Complex, which will add 45% to its previous capacity.

Figure 5.2 Number and Size of Operating Refineries in Western Canada



Source: CWF calculations using CAPP data.

Note: Includes both refineries and upgraders.

There are also five upgraders in Alberta, which convert rawbitumen into lighter, synthetic crude oil which is easier to use in many refineries (some upgraders are also able to produce a limited range of petroleum products such as diesel fuel). Those upgraders have enough capacity to handle about 1.3 mb/d of bitumen, equivalent to a little more than half of current oil sands output.

Upgrading capacity in Alberta has more than doubled from 2001 to 2011, not including the impact of Shell's recently-completed expansion of its facility in Scotford. However, upgrading capacity is not expected to keep pace with expanding oil sands development. According to the National Energy Board, the amount of bitumen upgraded within Canada will fall from about 53% presently to about 38% in 2035.

BENEFITS TO ADDING REFINING AND UPGRADING CAPACITY IN WESTERN CANADA

Adding refining and upgrading capacity would increase the amount of value-added economic activity that takes place in the West and reduce dependence on foreign imports.

Increasing the amount of value-added activity that takes place in western Canada has always been an attractive public policy goal, especially in the resources sector. Some of the advantages of building more refining and upgrading capacity in the West include the following:

1

Refining and upgrading captures more of the economic benefit of resource extraction

Selling raw bitumen or crude oil minimizes the benefits of resource extraction to western Canada. While refineries and upgraders are not labour-intensive operations, they do provide economic benefit over and above exporting non-renewable resources at their lowest point on the value chain. Building more such facilities would create jobs, investment and economic growth, allowing the West to capture a greater share of the value of its resources.

2

The West would become self-sufficient in refined petroleum

As noted above, western Canada is a net importer of about $4.0 billion in refined petroleum from the US. Adding refining capacity would allow the West to reduce or eliminate its reliance on the US for certain types of petroleum. For example, Alberta is currently importing large quantities of diluents from the US which are then added to its oil sands output to allow diluted bitumen to be piped out of the province. These imports would not be necessary if local capacity to produce diluents was increased.[16]

3

It broadens the potential customer base

Since crude oil and diluted bitumen require further processing, the only customers for those products are refineries and some industries which use crude oil as a feedstock. Transporting refined products could open up a wider range of potential customers.

[16] It is important to note that eliminating such imports entirely is unlikely and potentially undesirable as, in some cases, bitumen diluents are imported back into western Canada to be re-used.

4

Refining and upgrading in the West is environmentally beneficial

Alberta and Saskatchewan are far and away Canada's largest per capita emitters of greenhouse gasses and increasing the amount of petroleum refining that takes place in the West would only make that situation worse at the local level. However, it could reduce emissions at a global level.

Transporting energy consumes energy. Western Canada is a net exporter of crude oil but a net importer of refined petroleum, implying that more transportation activity is taking place than is strictly necessary.

Economies of scale and specialization of production make it unlikely that western Canada can be competitive enough to be self-sufficient in every type of refined petroleum product. Nevertheless, the more refining that takes place within the West, the less transportation will be required, thus reducing unnecessary energy consumption and environmental impact.

RISKS OF INVESTING IN REFINING AND UPGRADING CAPACITY

There is already surplus refining capacity in North America and petroleum demand is expected to fall. Moreover, there may be more of an export market for unrefined oil than for petroleum products.

Adding refining and upgrading capacity in western Canada is an attractive public policy objective. However, there are a number of challenges that stand in the way.

1

There is already surplus refining capacity in North America

Demand for refined petroleum in North America is falling; refinery receipts of crude oil in the US peaked in 2004 and by 2011 had dropped by 4.3%. Meanwhile, local market pressures brought new refining capacity online in the PADD II and PADD III regions. These divergent trends drove US-wide capacity utilization rates down from 93% in 2004 to 83% in 2009.

Since 2009, capacity utilization rates have recovered a little, but mostly because facilities on the west and east coasts were being left idle. As noted earlier, some of the idle capacity on the US east coast was removed from the system entirely in 2012. Due to these closures, refinery capacity in the US is now at its lowest level since 2005. Even so, there remains excess capacity in the US system.

The story in Canada is even more dramatic. From 2004 to 2011, inputs into Canadian refineries dropped by 14% even as refining capacity increased by 22%. As a result, capacity utilization rates have fallen to 81% from a peak of 95% in 2007. Excess capacity is triggering consolidation in the Canadian refining sector as well, especially in eastern provinces.

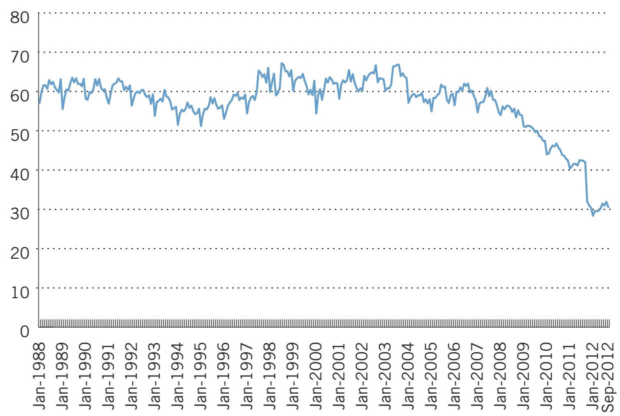
2

The outlook for refined petroleum demand in North America is poor

Every major energy outlook publication expects future crude oil and refined petroleum consumption in North America to remain flat or to fall. Most refined petroleum products are used as transportation fuels and demand for those products in industrialized countries is expected to be especially weak. Higher fuel efficiency standards, increased market penetration of hybrid and electric vehicles, rising use of biofuels, and substitution of natural gas-powered vehicles are all expected to take a bite out of gasoline demand.

As a result, most experts foresee a period of rationalization in the US refining industry in the years ahead. Building new refining capacity in this environment is, to say the least, a high-risk proposition.

Figure 5.3 US Gasoline Retail Sales by Refiners
(millions of gallons per day)



Source: US Energy Information Administration.

3

China has a policy of self-sufficiency in refined petroleum

Given the weak prospects in North America and expectations of robust growth in China and other Asian markets, the latter are clearly a more attractive alternative for refined petroleum exports from western Canada. As noted earlier, Chinese demand for oil is projected to grow by 7.5 mb/d by 2035. Demand in other Asian markets is expected to grow by the same amount.

Complicating matters, however, is that China has a stated policy of self-sufficiency in refined petroleum. There may remain export opportunities elsewhere in Asia for refined products from the West, but export to China appears unlikely. China has been consolidating and modernizing its refining operations, closing down or expanding small "teapot" refineries and building large, new, state-of-the-art facilities. China's installed crude refining capacity is estimated to be over 11.6 mb/d, double 2000 levels and comfortably above existing needs; refinery runs averaged 8.9 mb/d in 2011.

Moreover, refinery capacity is slated to rise even further in anticipation of future demand growth. China's goal is for refining capacity to reach 14 mb/d by 2015. Capacity is expected to increase further – to over 16 mb/d – by 2020. This growth is easily enough to absorb all expected demand growth over that period.

4

Adding refining/upgrading capacity could increase market instability for crude oil exports

Domesticating a high degree of upgrader and refinery export capacity could make it harder for western Canadian crude oil to have secure and stable access to markets. By contrast, locating upgraders in the US could improve stability of demand for Canadian diluted bitumen as companies would be more likely to depend in the long term on oil sands-derived crude, rather than crude of a different quality.

Moreover, differences in government regulations mean that refined petroleum standards, such as the allowable sulfur content or volatility levels (vapour pressure) in motor gasoline, vary across jurisdictions. As such, a refinery in western Canada that wanted to serve the export market would either have to meet the requirements of a specific US or overseas destination, or would have to produce several varieties of each fuel type in order to suit the needs of different markets. Both situations add market stability risk and logistical complexity. It is far simpler to export crude oil or diluted bitumen and allow local operators to refine products tailored to their markets' needs.

5

Price and cost factors do not support adding upgrading capacity

Bitumen upgraders are expensive projects and require significant up-front capital costs. They make money by converting lower-value bitumen and heavy crude into lighter, higher-value grades. However, the price differential between heavier and lighter grades of crude oil has been relatively narrow in recent years and is expected to remain so into the medium term. In other words, the price markup that a company could charge by selling synthetic crude instead of raw bitumen is low.

The combination of high capital costs and a small per-barrel return on that investment makes bitumen upgrading a risky proposition. Rather than expose themselves to that risk, many companies are choosing simply to export diluted bitumen to US refiners.[17]

[17] Recently, Suncor put on hold its plans to build a new 200,000 b/d upgrader in Ft. McMurray; the company has suggested that the $11.6-billion project may not be viable in the present economic environment.

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