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The Canadian Oil Transport Conundrum

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with an Introduction by Kenneth P. Green

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An Overview of Oil Transportation in Canada

By Kenneth P. Green

Introduction

Recent events have elevated the importance of how we transport energy—specifically oil—to high profile status. The long-stalled approval of the Keystone XL pipeline is probably the highest profile political event that has caused oil transport to surge to the fore in energy policy discussions today, but more prosaic economic issues also have played a role. Most importantly, because of limitations in the ability to ship oil to coastal refiners and overseas markets, Canada is forced to sell crude oil into the US market at a considerable discount relative to world oil price markers such as Brent.¹ This is costing Canadians at least \$15 billion each year (Beltrame, 2003, Apr. 13). Among other things, this shortfall has been blamed (wrongly, we believe) for problems with the balance sheet of Alberta’s government, bringing the issue to still greater prominence (Milke, 2013). Economic research has shown that eliminating bottlenecks (whether physical or political) can reduce oil price discounting similar to that which Canada currently endures (Bausell Jr. et al., 2001). Aside from price, in a recent Fraser Alert, we also observe that securing additional transport infrastructure is important to Canada’s energy security (Green and Eule, 2013). Most recently, US President Barack Obama has turned up the heat on the discussion, dismissing the importance of the Keystone XL pipeline to the US in terms of job creation, and repeating his requirement that the pipeline may not exacerbate anthropogenic climate change (New York Times, 2013, Jul. 27).

To understand the many challenges Canada faces in fixing its oil-transport problems, we have first to understand the basics of oil transport: how much we produce, where it goes, and how it gets there. Next, we have to consider the different environment, health, and safety considerations attendant on different modes of oil transport. Third, we need to know where the key bottlenecks are in North America’s integrated oil transport networks. We also need to know

1. Geographical crude oil price differentials are affected by a variety of factors in addition to the availability of transport infrastructure. Changes in production and bottlenecks caused by other factors can also play a role, and price differentials fluctuate significantly over time.

how Canada might resolve issues pertaining to First Nations' acceptance of needed infrastructure. In this series of essays, the Fraser Institute will explore each of these issues, with the goal of advancing the oil transport discussion in Canada. This first essay is intended to simply provide an overview of the important public policy issues pertaining to transportation of these important energy commodities. Later essays will discuss bottlenecks in the transport system, compare the safety of rail vs. pipeline transport, and discuss Aboriginal affairs that relate to oil and gas transport.

Overview

How big are Canada's oil reserves?

Crude oil: According to BP's *Statistical Review of World Energy 2013* (2013), Canada's remaining total established (proved) oil reserves (including oil sands) are the third largest in the world, at 173.9 billion barrels, which would sustain current levels of production for about 128 years. Canada's conventional oil reserves are estimated at 4.3 billion barrels, most of which are located in Western Canada (BP, 2013; and calculation by author).

Canada's conventional oil reserves are really only the tip of the iceberg. Canada's total "in-place" oil-sands bitumen resources are estimated at 1.8 trillion barrels, an amount that exceeds the total volume of oil produced to date worldwide. Approximately 10% of those oil-sands resources are considered proved or 'remaining established' oil reserves (168.7 billion barrels). As a consequence, Canada's total proved reserves of oil are only less than those of Venezuela (297.6 billion barrels), and Saudi Arabia (265.9 billion barrels) (BP, 2013). Because all of Canada's proved oil-sands reserves are so far found in Alberta, 99% of Canada's total oil reserves are located in that province, followed by Saskatchewan with 0.3%. But Western Canada's oil production potential is considerably greater than indicated by the estimated size of the oil sands and conventional resources and proved reserves because those estimates do not reflect the immense quantity of oil that is now believed to be recoverable from shale formations. In fact, the application of horizontal drilling and hydraulic fracturing technologies to oil shale has been boosting oil production in Saskatchewan and North Dakota considerably for several years now. A recent study by the U.S. Energy Information Administration estimates that Alberta has 7.2 billion barrels of technically recoverable oil and condensate in oil shale formations (including 4 billion barrels in the Duvernay formation alone), while the Saskatchewan portion of the Williston Basin Bakken Play holds more than 1.6 billion barrels (U.S. Energy Information Administration, 2013).

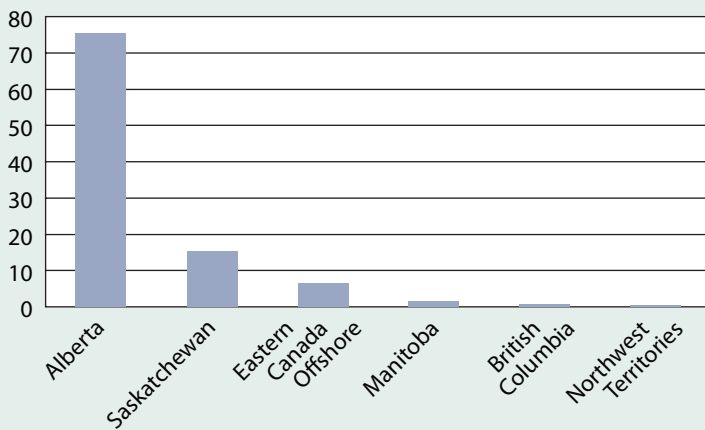
How much oil do we actually produce each year? How is that expected to change over time?

According to the Canadian Association of Petroleum Producers (CAPP, 2013a), Canada's 2012 oil production rate was 3.2 million barrels per day, including both conventional oil and oil from the Alberta oil sands (CAPP, 2013a). Only 6.5%

was produced in Eastern Canada (offshore Newfoundland & Labrador except for a very small amount in Ontario). About 43% of Western Canada’s 2012 oil production came from conventional sources, and 57% from the oil sands.

CAPP is projecting a significant increase in oil production from 2012 to 2030 in its most recent (2013) forecast, with the total production rate expected to more than double, to 6.7 million barrels per day (CAPP, 2013b). Most of that increase, 3.4 million barrels per day (to reach 5.2 million barrels per day), is projected to come from the oil sands. Consequently, the share of total oil production attributed to oil sands would rise considerably by 2030, exceeding 80%.

Figure 1: Percentage shares of Canadian oil production in 2012



Source: CAPP (2013a), Statistical Handbook.

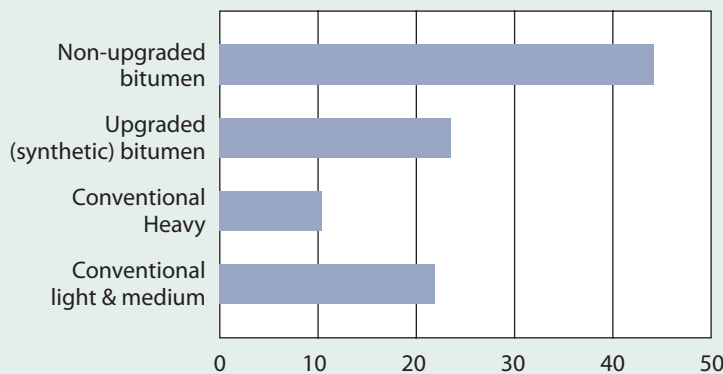
Where is Canadian oil produced?

As already noted, the vast majority of Canada’s oil production is in Western Canada. Alberta and Saskatchewan production alone are responsible for almost 91% of total Canadian oil production. And a growing proportion of Canada’s oil production is coming from non-conventional sources – i.e., Alberta oil-sands bitumen.

Figure 1 shows how Canada’s 2012 oil production of about 1.1 billion barrels per day breaks down according to the respective provincial and territorial shares.

Figure 2 shows the composition of the Western Canadian production by type that was available for shipment on trunk or transmission pipelines during 2012 on average. Nearly all of the crude oil produced in Eastern Canada was conventional light/medium crude from offshore Newfoundland & Labrador that was transported to refineries by tanker.²

Figure 2: Western Canadian crude oil available to trunk pipelines



Source: CAPP (2013b), Crude Oil Forecast, Markets and Transportation.

2. The exception was the very small amount of crude oil that was produced in Ontario.

Where does Canadian oil go?

About 1/3 of Canadian oil production is consumed domestically (Natural Resources Canada, 2013). Nearly all of the oil that was not consumed in Canada was exported to the United States. According to the National Energy Board, Canada exported 2.3 million barrels of oil per day during 2012 (Natural Resources Canada, 2011), mostly to refineries in the US Midwest (National Energy Board, 2013).

Canada's oil exports are shipped to regions in the United States known as PADDs³. Seventy percent of the crude oil exports to the US went to PADD II (US Midwest region), 10% to PADD IV (US Rocky Mountain area), 7% to PADD I (US Eastern region), and 8% to locations on the West Coast of the US (PADD V). Only 5% was sent to refineries in the US Gulf Coast region (calculations by author from National Energy Board, 2013).

Oil and gas delivery by pipeline

Existing oil pipelines:

Four major pipelines move oil produced in Alberta that is not required for consumption in that province to markets in British Columbia, Eastern Canada, and the United States from pipeline terminals that are located at Edmonton and Hardisty: they are the Enbridge Mainline, the Kinder Morgan Trans Mountain Pipeline, the Spectra Express Pipeline, and the TransCanada Keystone Pipeline (CAPP, 2012). The existing pipeline network provides access to markets for Alberta and other western Canadian crude oil, including Western Canada's own refineries; plants in Ontario; the US Midwest; PADD IV; and the West Coast including refineries on Puget Sound in PADD V. There is at the moment very limited access for Alberta oil to the US Gulf Coast. The Enbridge mainline also handles some refined oil products and transports mixed natural gas liquids from the Edmonton area to Sarnia. Similarly, the Kinder Morgan Trans Mountain pipeline delivers finished oil products to the Kamloops area and to the BC lower mainland (CAPP, 2012).

Figure 3 provides an overview of where Canadian oil exported by pipeline flows, and in what quantities.

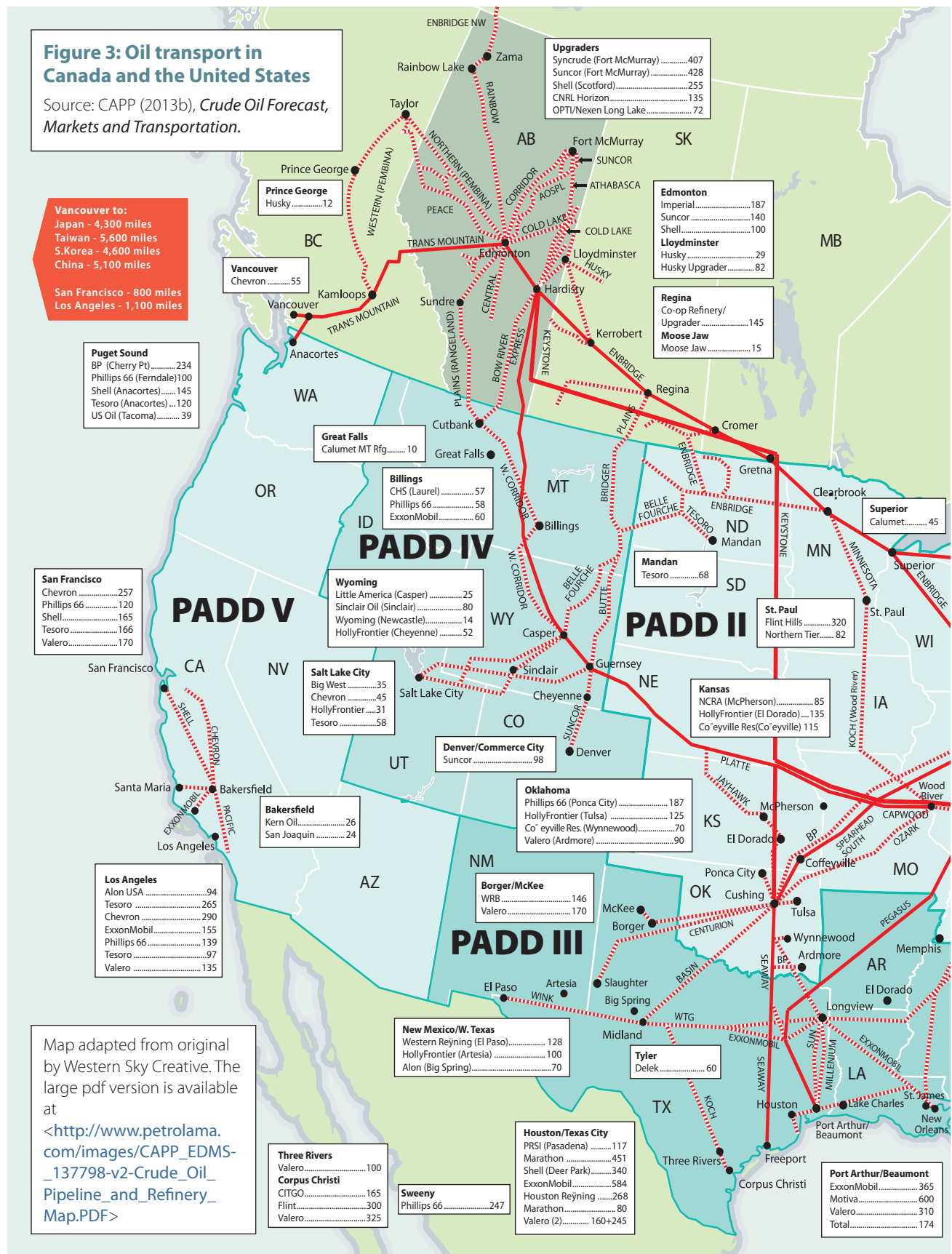
Planned oil pipeline expansions:

Several expansions are planned to crude oil pipelines in the Western Canadian Sedimentary Basin (WCSB). Table 1 from CAPP's 2013 market

-
3. PADD stands for Petroleum Administration for Defense Districts. These regions were defined during WWII to help organize the flow of oil and diesel fuel. There are 5 PADDs, with lower numbered PADDs being in the east, and rising to the west.

Figure 3: Oil transport in Canada and the United States

Source: CAPP (2013b), *Crude Oil Forecast, Markets and Transportation.*



Map adapted from original by Western Sky Creative. The large pdf version is available at
http://www.petrolama.com/images/CAPP_EDMS-137798-v2-Crude_Oil_Pipeline_and_Refinery_Map.PDF



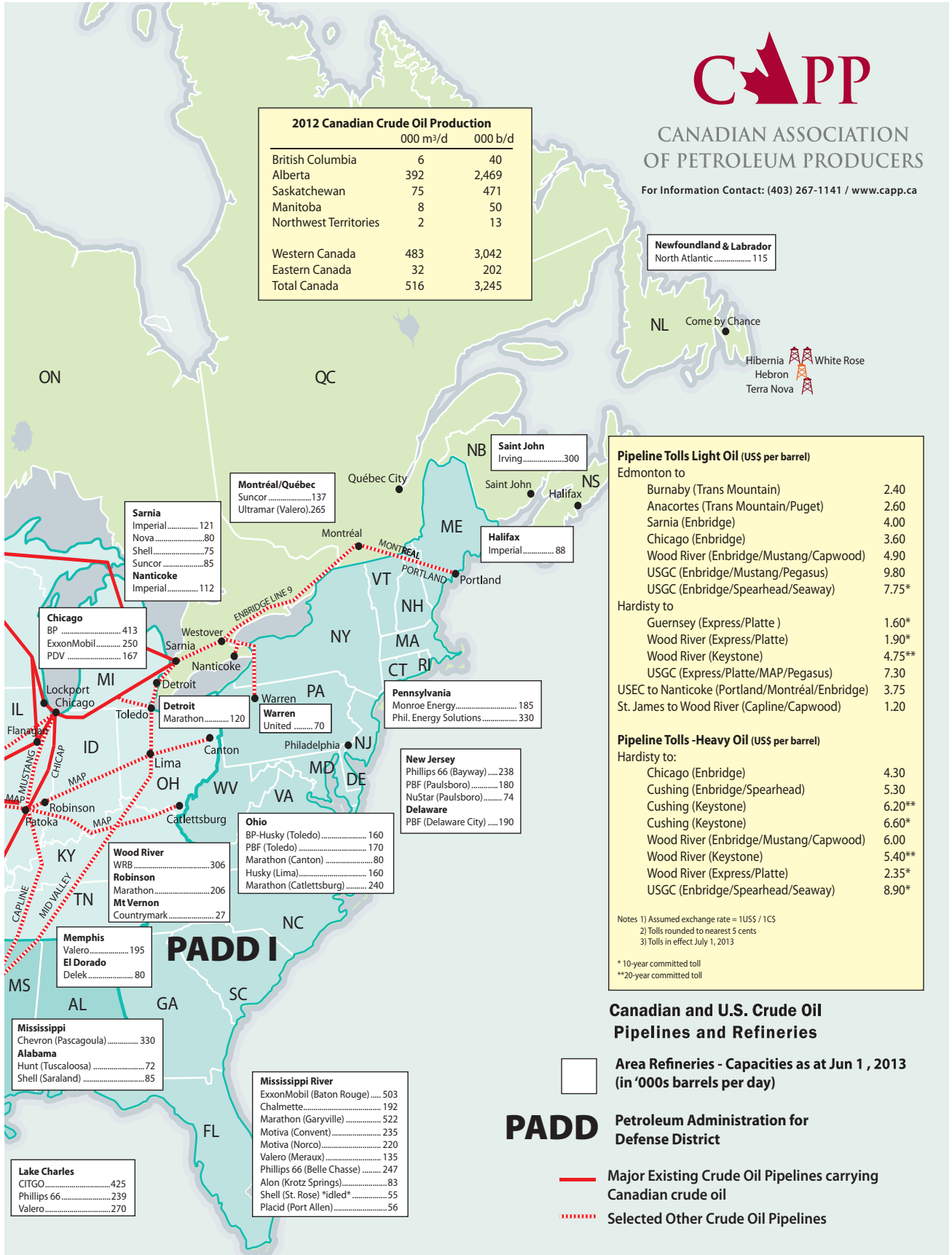
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2012 Canadian Crude Oil Production		
	000 m ³ /d	000 b/d
British Columbia	6	40
Alberta	392	2,469
Saskatchewan	75	471
Manitoba	8	50
Northwest Territories	2	13
Western Canada	483	3,042
Eastern Canada	32	202
Total Canada	516	3,245

Newfoundland & Labrador	
North Atlantic	115

NL Come by Chance
 Hibernia
 Hebron
 Terra Nova
 White Rose



Pipeline Tolls Light Oil (US\$ per barrel)	
Edmonton to	
Burnaby (Trans Mountain)	2.40
Anacortes (Trans Mountain/Puget)	2.60
Sarnia (Enbridge)	4.00
Chicago (Enbridge)	3.60
Wood River (Enbridge/Mustang/Capwood)	4.90
USGC (Enbridge/Mustang/Pegasus)	9.80
USGC (Enbridge/Spearhead/Seaway)	7.75*
Hardisty to	
Guernsey (Express/Platte)	1.60*
Wood River (Express/Platte)	1.90*
Wood River (Keystone)	4.75**
USGC (Express/Platte/MAP/Pegasus)	7.30
USEC to Nanticoke (Portland/Montréal/Enbridge)	3.75
St. James to Wood River (Capline/Capwood)	1.20
Pipeline Tolls -Heavy Oil (US\$ per barrel)	
Hardisty to:	
Chicago (Enbridge)	4.30
Cushing (Enbridge/Spearhead)	5.30
Cushing (Keystone)	6.20**
Cushing (Keystone)	6.60*
Wood River (Enbridge/Mustang/Capwood)	6.00
Wood River (Keystone)	5.40**
Wood River (Express/Platte)	2.35*
USGC (Enbridge/Spearhead/Seaway)	8.90*

Notes 1) Assumed exchange rate = 1US\$ / 1CS
 2) Tolls rounded to nearest 5 cents
 3) Tolls in effect July 1, 2013
 * 10-year committed toll
 **20-year committed toll

Canadian and U.S. Crude Oil Pipelines and Refineries

- Area Refineries - Capacities as at Jun 1, 2013 (in '000s barrels per day)
- PADD** Petroleum Administration for Defense District
- Major Existing Crude Oil Pipelines carrying Canadian crude oil
- Selected Other Crude Oil Pipelines

forecast lists the four existing pipelines noted above, planned oil pipeline expansions (Enbridge Alberta Clipper and Trans Mountain), and the proposed Enbridge Northern Gateway, Keystone XL, and TransCanada East pipelines (CAPP, 2013b). Keystone XL would provide direct access to the US Gulf Coast region from Alberta. Northern Gateway would transport Alberta crude oil to Kitimat, BC, for shipment to markets in Asia and, possibly, refineries on the US West Coast. The proposed TransCanada Energy East Pipeline would ship oil to Montreal and, possibly, as far as Saint John, New Brunswick.

The existing pipelines have a total capacity of 3,671 thousand barrels per day. The proposed expansions would bring from 2,820 to 3,145 thousand barrels per day of additional capacity.

Table 1: Major existing crude oil pipelines and proposals exiting the Western Canadian Sedimentary Basin

Pipeline	Capacity 000 Bbls/day	Target In-service Date
Enbridge Mainline	2,500	Operating since 1950
Enbridge Alberta Clipper Expansion	+120	Q3 2014
Enbridge Alberta Clipper Expansion	+230	Q1 2016
Kinder Morgan Trans Mountain	300	Operating since 1953
Trans Mountain Expansion	+590	Q4 2017
Spectra Express	280	Operating since 1997*
TransCanada Keystone	591	Operating since 2010
TransCanada Keystone XL	+830	2015
Enbridge Northern Gateway	+525	Q4 2017
TransCanada Energy East	+525 to 850	Q4 2017

*downstream Platte operating since 1952.

See: <<http://www.capp.ca/getdoc.aspx?DocId=227308&DT=NTV table 4.1>>.

Source: CAPP (2013b), *Crude Oil Forecast, Markets and Transportation*.

Only a single pipeline moves oil out of the WCSB to the Pacific coast, the Kinder Morgan Trans Mountain Pipeline. There are currently proposals to nearly triple the capacity of the Trans Mountain pipeline, as well as construction of the proposed Enbridge Northern Gateway pipeline from Alberta to Kitimat, BC, mentioned above (Kinder Morgan, 2013).

There is currently very little movement of oil from the WCSB to the Atlantic region. Two proposals have been made to address that limitation. One proposal would involve reversing and upgrading the flow of an existing pipeline, Enbridge's Line 9, which flows east-to-west from Sarnia, Ontario, to Montreal, Quebec (Enbridge, 2013). The purpose of reversing the flow would be to allow oil from the WCSB to reach refineries in Quebec, which had been the original function of the pipeline when it was constructed in the mid-1970s. A second proposal by TransCanada is to convert existing pipeline (and build new pipeline) that could move up to 850,000 barrels per day from Western Canada to Montreal, Quebec, and potentially build additional pipeline capacity to Saint John, New Brunswick (TransCanada, 2013).

Pipelines to Quebec and New Brunswick would allow western oil to reach refineries located at tidewater sites, and allow crude oil or refined petroleum products to be exported to US PADD I, Europe, or Asia. As with the Alberta-

to-BC pipelines mentioned above, environmentalists and some other interest groups have expressed strong opposition to the construction of new pipelines (or the reversal of existing lines), so the prospects for the proposed Atlantic pathways are also uncertain at this stage.

As indicated in Table 2, seven pipelines currently transport Western Canadian crude oil to destinations in the Midwestern United States: the Minnesota Pipeline, the Enbridge Mainline, the Enbridge Spearhead North and

Table 2: Summary of Crude Oil Pipelines to U.S. Midwest

Pipeline	Origin	Destination	Status	Capacity 000's of Bbls/day
Minnesota	Clearbrook MN	MN refineries	Operating	465
Enbridge Mainline	Superior WI	Various WI & IL	Operating	1,551
Southern Access Exp.	Superior WI	Flanagan IL	Proposed - Q3 2014	70
Southern Access Exp.	Superior WI	Flanagan IL	Proposed - Q1 2015	260
Enbridge Spearhead North	Flanagan IL	Chicago	Operating	130
Expansion	Flanagan IL	Chicago	Proposed - Q4 2013	105
Enbridge Spearhead North Twin	Flanagan IL	Chicago	Proposed - Q4 2015	570
Enbridge Spearhead South	Flanagan IL	Cushing OK	Operating	193
Enbridge Flanagan South	Flanagan IL	Cushing OK	Proposed - Q3 2014	585
Enbridge Mustang	Lockport IL	Patoka IL	Operating	100
Spectra express	Guernsey WY	Wood River IL	Operating	145
TransCanada Keystone	Hardisty AB	Cushing OK	Operating	591

Source: National Energy Board as updated by correspondence in April 2013

South pipelines, the Enbridge Mustang Pipeline, the Spectra Express-Platte Pipeline, and the Trans Canada Keystone pipeline. As with the pipelines moving oil out of Western Canada, there are plans to expand and add to the current pipeline systems carrying Canadian oil into the US Midwest. Table 2 summarizes both existing and planned oil transport capacity to markets in this region.

The seven pipelines currently transporting Canadian crude oil

into the US Midwest region have a combined capacity of about 3.2 million barrels per day. However, the proposed Enbridge Southern Access, Spearhead North, and Flanagan South expansions would, if they proceed as planned, add 1.6 million barrels per day or 50% by the fourth quarter of 2015 at which time the total capacity would reach 4.8 million barrels per day (CAPP, 2013b).

At present only two pipelines are available to transport Canadian and US crude oil to refineries in the US Gulf Coast region. These are the ExxonMobil line, with a capacity of only 96,000 barrels per day, that connects Patoka, IL to Netherlands, TX, and the 400,000-barrel-per-day Seaway pipeline, which runs from Cushing, OK, to Freeport, TX. However, from 1,700 to

1,940 thousand barrels per day of additional capacity is planned to be in place by 2015, if the required permits are obtained. This includes the Keystone XL Pipeline, with a capacity of 830,000 barrels per day, twinning the Seaway line to add 450,000 barrels per day, and the Enbridge/Energy Transfer Eastern Gulf Coast Access project that would allow shipment of between 420,000 and 660,000 barrels per day from Patoka, IL, to St. James, LA (CAPP, 2013b).

Oil by rail

Not all of the steadily growing volumes of WCSB oil production is being transported by pipeline. There has been a substantial increase in the amount of oil that is being shipped by rail. For example, Canadian monthly railcar oil loadings in early 2013 (at about 13,000 car loads per month) were more than double what they were during the 2000 to 2010 period (CAPP, 2013b). As indicated by the increased loading capacity currently underway or planned (Table 3) this upward trend appears destined to continue, at least for a while.

There are a number of reasons for this quite apart from the lack of

immediately available pipeline capacity. First, the railroad network throughout Canada and the US is extensive, with rail lines running to, or close to, most oil refinery and shipping terminal destinations. Second, even where railroad system loading and unloading infrastructure is not already in place it can generally be built more quickly than pipeline capacity even to handle unit trains (70 to 100 cars), which are generally more economical than shorter trains. Thirdly, there is less financial

risk as the shippers do not have to enter into long-term take-or-pay pipeline capacity or invest in pipelines of their own. Finally, oil-sands bitumen can be shipped by rail without the need to reduce its viscosity by adding diluent where insulated railway cars equipped with heating coils are available (Angevine and Oviedo, 2012).

The desire to access refineries in the US Gulf Coast and other coastal refineries and terminals, where the Canadian oil can obtain the full international price, is causing an increasing number of western Canadian oil producers to turn to railroads to transport their oil. Even oil pipeline giant Enbridge Inc. is investing in railroad infrastructure, including oil loading and unloading

Table 3: Major new railway oil-loading terminals in Western Canada

Operator	Location	Capacity Thous. Bbl/d	Planned Startup
Tundra	Cromer MB	Phase 1 - 30	Q3 2013
		Phase 2 - 30	Q1 2014
Keyera	Cheecham AB	30	Q3 2013
Canexus	Bruderheim AB	70	Q3 2013
Gibson	Hardisty AB	60	2014
Ceres Global	Northgate SK	70	Q4 2014
Total		292	

Source: CAPP 2013b

facilities in North Dakota and Philadelphia, respectively, as a stop-gap measure, until required expansions to the pipeline infrastructure can be built (Enbridge Energy Management, L.L.C., 2013 and Hussain, 2013, Nov. 26).

RBC Capital Markets estimates rail shipments at 5% of western Canadian production, though it observes that there is no official tracking data available for crude oil shipments by rail (RBC, 2013). RBC estimates that currently, 115,000 barrels of oil per day are shipped by rail to the US, with a trend toward 300,000 barrels per day by 2015. For perspective, the Keystone XL pipeline, if approved, would carry 830,000 barrels per day.

RBC (2013) suggests that the future growth of oil by rail depends heavily on whether or not large pipelines are built:

Continued growth in crude oil shipments by rail will absorb some of the planned growth envisioned by select companies in Canada's oil sands sector, but we expect some large projects are likely candidates to be deferred with overall industry growth being constrained if the 830,000 bbl/d Keystone XL pipeline is not approved. In the event that Keystone XL is declined by President Obama, our analysis suggests that approximately 450,000 bbl/d, or one third, of Canada's oil sands growth could be temporarily deferred in the 2015–16 timeframe, with production remaining nearly 300,000 bbl/d (6%) lower than our base outlook by 2020. As a base case, we expect crude oil shipments by rail from Canada to peak at just above 300,000 bbl/d by 2015 (approximately 8% of estimated Western Canadian production at that time). However, in the event that Keystone XL is declined, we would expect crude oil shipments by rail from Canada to increase to 425,000 bbl/d by 2017 (approximately 16% of estimated Western Canadian production at that time) [Page 4].

Baytex Energy (an oil/gas producer in Alberta) and other companies are turning to rail in order “to reach higher value markets on tidewater” or in the US northeast with the volume of crude oil being shipped from Western Canada in this manner reportedly now totaling as much as 300,000 barrels per day transporting. Baytex Energy, for example, is trucking some of its heavy crude to a rail terminal for shipments to higher-value markets rather than selling at the western select price and absorbing a large discount (Els, 2013, Jan. 29).

Railway transportation is therefore providing short-term relief for some of the incremental production from Alberta's oil sands and from Saskatchewan's portion of the Bakken formation which would otherwise be shut-in at great cost to both the producer and the royalty owner. Rail may have a cost advantage for relatively low volume shipments, but for large volumes pipeline transportation appears to be less costly (Campbell, 2011, Aug. 31).

In fact, Enbridge Inc. has indicated that at volumes greater than 150,000 bpd, cost comparisons with rail are clearly in favour of pipelines (Vanderklippe, 2011, February 7). For example, CN estimates the cost of shipping bitumen from Fort McMurray to Vancouver to be around \$3,978 per rail car or \$7.23 per barrel of crude oil⁴ compared with \$2.05 per barrel on the TransMountain pipeline system (Angevine and Oviedo, 2012). Recent estimates published by Enbridge Inc. indicate that oil by rail transport from Alberta to US West Coast refineries costs about \$US 13/barrel and that the cost of rail shipment to Cushing, OK, St. James, LA, and the US East Coast is approximately \$9/barrel, \$12/barrel, and \$14 to \$17/barrel, respectively (Varsanyi, 2013).

It should be noted that the amount of oil moving to Gulf Coast refineries is still quite small. The Alaska Business Monthly reports that:

Small amounts of Canadian crude are also starting to move by rail to US refineries, with 2011 marking the first time in 10 years that foreign-sourced rail shipments were reported. At nearly 1,000 barrels per day (bbl/d), this was the highest volume of foreign oil-by-rail recorded since EIA started publishing these data in 1981. In 2012 that number set a new record of more than 11,000 bbl/d (Alaska Business Monthly, 2013, July 11).

Oil by barge

Another possible pathway for Canadian oil to move into the US market is by integrated railway-barge systems. As Kelly Cryderman writing for the *Globe and Mail* reports:

America's Big River could be a new passage for Canadian heavy oil in the race to bypass pipeline jams and get Alberta bitumen to refineries on the Gulf Coast.

MEG Energy Corp. said Thursday it has a new plan to transport Canadian crude by inland waterway, barging the bitumen down the Mississippi River beginning later this year.

The diluted bitumen, the company said, will travel by rail from northern Alberta to Bruderheim, near Edmonton, then be transported by rail or pipeline to Chicago canals, and finally move onward to the Mississippi River system—where it will be loaded onto the barges to be shipped to refineries in the Gulf of Mexico area where crude prices are higher (2013, Jan. 31).

4. A rail tank car can typically hold 500–525 barrels of heavy oil or 600–700 barrels of light oil.

The Globe report suggests that MEG Energy Corp (a mid-sized oil sand developer) could eventually move 40,000 barrels of oil per day by rail and barge to refineries in the US Gulf Coast region, at costs comparable to a pipeline. “MEG spokesman Brad Bellows said the per-barrel shipping cost is in the teens of dollars, and barging is even a few dollars cheaper per barrel than transporting by rail alone” (Cryderman, 2013, Jan. 31).

According to a report in the *Edmonton Journal* in early February, later this year unit trains with up to 118 tank cars of bitumen from the oil sands and heavy oil will leave Bruderheim (near Edmonton) every day for Chicago. There, the oil will be delivered for onward transportation by pipelines or river barges. The rail/barge system could also continue to the US Gulf Coast so as to deliver the bitumen to several large refineries with equipment that can process heavy crude (Cooper, 2013, Feb. 1).

Calgary-based chemical company Canexus is expanding its existing terminal operation just east of Bruderheim that is currently being used to move chemicals, to ship up to 70,000 barrels of oil per day when it opens this summer (Cooper, 2013, Feb. 1). Similarly, Southern Pacific Resources is looking to trucks, rail, and Mississippi River barges to ship its oil production from northern Alberta, and Devon Canada is reportedly now moving about 10% of its heavy oil production by rail (Healing, 2013, Feb. 1).

Oil by truck

Still another way that Canadian oil moves to markets is by truck. Trucks not only carry oil from production facilities to nearby pipeline and railway loading facilities, but some trucking firms are beginning to take significant quantities of Canadian oil directly to markets in the US.

According to an article in *Alberta Oil Magazine*,

Gibson Energy Inc. hauls roughly 250,000 barrels of energy products per day. With access to a fleet of about 3,130 trucks, the Calgary-based company is one of the largest truck haulers of oil, natural gas liquids, propane, butane, condensate, and refined products in North America.

All of that product gets shifted through one of Gibson’s two major storage hubs in Alberta—Edmonton and Hardisty—or to third-party terminals and pipeline or rail loading facilities in other locations in Canada and the United States (Ricciotti, 2013).

Conclusion

Canada is a prodigious producer of oil with world-class resources that, with the exception of the East Coast offshore, are disadvantageously landlocked. Previously, its pipeline infrastructure expanded historically to keep pace with development of these resources, which heretofore was never significantly impaired by the lack of such facilities. But now enormous challenges loom for the expansion of the energy transport capacity needed to meet the growth of production of oil-sands bitumen from prolific but distant unconventional sources which can make a critically important contribution to economic development and wealth creation regionally and nationally for the next half century. The technical and commercial challenges that have been successfully met in the past have been compounded in recent years by increasing opposition by environmental groups and Aboriginal interests that to a significant degree aim to thwart upstream petroleum development, specifically oil sands (and shale gas fracking) through their aggressive interventions in the public hearings involved in the creation of large new linear projects. In consequence, extremely long and costly regulatory processes intended to respond to the right of interest groups to be heard have been added to already-stringent regulatory regimes. As a result, the lead times for the development of pipeline projects have been enormously extended.

The plans to expand the capacity to ship crude oil from Western Canada to refineries and port facilities on the east and west coasts of Canada and the United States, as well as the plans to increase railcar oil-loading and unloading facilities, will help to reduce the severe transportation bottleneck that has been penalizing western Canadian oil producers. However, in light of the large increase in oil-sands bitumen production that is forecast to occur by 2030, and the growth in production from oil shale that is unfolding in Alberta and Saskatchewan, much more transportation capacity than that which has so far been identified will need to be added in order to gain access to tidewater and thereby secure access to world oil prices. The potential cost to Canadians and the Canadian economy from failure to achieve this objective will be addressed in another essay in this series.

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Kenneth P. Green is Senior Director, Energy and Natural Resource Studies at the Fraser Institute. He has studied environmental, energy, and natural resource policy for more than 20 years at think-tanks across North America including the Reason Foundation in Los Angeles; the American Enterprise Institute in Washington, DC; and previously at the Fraser Institute, where he ran the Centre for Risk, Regulation, and the Environment.

A frequent commentator in North American print and broadcast media, Dr. Green has testified before several state and federal legislative bodies in the United States including committees and subcommittees of the House of Representatives and Senate. He twice reviewed reports for the United Nations Intergovernmental Panel on Climate Change and is also the author of two textbooks: *Global Warming: Understanding the Debate*, for middle-school students studying climate change, and *Abundant Energy: The Fuel of Human Flourishing*, for post-secondary studies in energy policy.

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Challenges Posed by Pipeline Infrastructure Bottlenecks

By Gerry Angevine

Introduction

Bottlenecks in the transportation systems that move Canadian crude oil to markets in Eastern Canada, the United States, and overseas are inflicting economic and financial losses not only on petroleum companies and their shareholders, but also on governments of oil-producing provinces and territories, where growth in royalty and other revenues from petroleum production that would otherwise occur is being constrained by slower development related to transportation infrastructure uncertainties and, for extended periods of time, by discounting of the price of oil produced in the Western Canadian Sedimentary Basin (WCSB)¹ relative to the world market. This means that the governments of the western provinces and territories, but especially Alberta, which is the largest oil producer, are having to rely more on other revenue sources such tax increases and/or increased borrowing to fund capital projects and the day-to-day delivery of essential public services such as health and education. Moreover, these bottlenecks are inflicting losses on Canadians in general because of the negative impacts on employment, labor income, and the rate of economic growth. Consequently, there are fewer opportunities for the average person to benefit from improved living standards and socio-economic conditions.

This essay describes the nature of existing bottlenecks, explains the impacts that they are having on the oil prices being realized by Canada's oil producers, and examines the economic consequences of delays being experienced in putting the required infrastructure in place. As Canadian natural gas transport is generally not being impacted by insufficient infrastructure, this essay focusses on oil transport.²

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1. Often referred to as the "WCSB", it extends from southwestern Manitoba through much of Saskatchewan and Alberta to northeastern British Columbia, the southeast part of the Yukon, and the southwest corner of the Northwest Territories.
 2. In coming years LNG export development in BC will require the construction of considerable natural gas transmission capacity from northeast BC to the coast.

Transportation bottlenecks faced by Canada's oil producers

The outlook for WCSB oil production:

With Canada from BC to Ontario being much more than self-sufficient with respect to oil refinery feedstock, continuing investment in production from Alberta's oil sands and light oil from shale formations in Saskatchewan and Alberta means that the volume of western Canadian crude oil available for shipment to refiners in other parts of Canada and the US, including refineries not presently linked to the WCSB and (potentially) overseas, is poised to increase substantially.

According to the National Energy Board, Canadian oil production is projected to increase from an estimated 3 million barrels per day in 2010 to as much as 5.7 million barrels per day by 2030, with most of that increase occurring in Alberta (2011). And that estimate could be on the low side, as it did not take into account the surge in oil production from oil shale that is now underway.

A more recent forecast, by the Canadian Association of Oil Producers (CAPP) suggests that the total supply of crude oil from Western Canada to trunk pipelines and markets could increase by as much as 4.6 million barrels per day from 2012 to 2030—from 3.2 million barrels per day to 7.8 million barrels per day—a 254% increase.³ All but about 5% of that increase is projected to come from production of oil-sands bitumen and related materials. The remainder of the increase is attributable to greater production of conventional light and medium crudes as production from oil shale more than offsets declines in output from maturing basins (CAPP, 2013).⁴

The 2013 CAPP projection is clearly much more aggressive than the NEB's 2011 forecast. But the message is clear: in either case WCSB oil production is poised for very considerable growth, most of which will come from Alberta's oil sands.

Given that oil transportation infrastructure is already constrained, with shippers now regularly being allocated less pipeline capacity than requested for transportation service from Alberta on both the Enbridge

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3. To put these numbers into perspective, the Irving Oil refinery in Saint John, New Brunswick (Canada's largest oil refinery) has a capacity of about 300,000 barrels per day.
 4. See Appendix B, Supply Sheet.

Corporation and Kinder Morgan Trans Mountain Pipeline systems, it is abundantly clear that expanded and new pipelines will need to be built to meet the capacity implied by the expected growth in western Canadian oil production and exports.⁵

The economic effects of pipeline bottlenecks:

Western Canadian crude oil producers have for extended periods been suffering substantial revenue losses. Essentially, this is because most of the oil that they are exporting, as well as oil sales to domestic refineries, are being discounted severely compared with the prices being realized by the production from the Newfoundland and Labrador offshore fields, for example, which is being sold at world prices in coastal refining centres which source their feedstock from overseas.

True, approximately 300,000 barrels per day of WCSB crude oil are being shipped to the west coast via the Trans Mountain Pipeline (National Energy Board, 2013).⁶ However, WCSB producers selling conventional heavy and synthetic crude oil to BC and Pacific Northwest refineries, despite their exposure to the international market, generally receive prices related to that of the Western Canada Select (WCS) benchmark price. WCS is a blend of Canadian heavy conventional and bitumen crude oils, synthetic oils (i.e., upgraded bitumen), and condensates that are used as diluents to reduce the viscosity of the blend. WCS is heavier (20.5 degrees API) and more acidic than conventional light/medium crudes (Cenovus Energy, 2013).

The price of WCS is determined largely by its opportunity price relative to the West Texas Intermediate (WTI) light/medium sweet crude oil price marker that is determined at Cushing, Oklahoma. WCS trades at a discount

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5. The Enbridge Mainline transports crude oil and some natural gas liquids and refined petroleum products from terminals at Edmonton and Hardisty, Alberta to southern Manitoba and then continues eastward through parts of the northern US. The Mainline re-enters Canada at Sarnia, Ontario from where it supplies several western Ontario customers and connects with the company's Line 9 which terminates in Montreal. The Trans Mountain Pipeline begins at a terminal in Sherwood Park just east of Edmonton and terminates in Burnaby, BC.

Kinder Morgan announced on May 21, 2013 that shippers on the Trans Mountain Pipeline would be limited to just 37% of hoped-for volumes during June. This resulted from capacity on the line being over-nominated by 63%. Nominations have exceeded capacity since late 2010 (Reuters, 2013, May 21). Various sections of the Enbridge oil pipeline system have also frequently been under apportionment, as in January 2013 when apportionment became necessary in mid-month. The startup of production at Imperial Oil's Kearl Lake oil sands production facility this year is increasing the demand for capacity on the Enbridge oil pipeline transportation system.

6. This volume includes refined petroleum products being transported from Alberta to the BC interior and lower mainland.

to WTI because of the higher cost of refining WCS crude into refined products, such as gasoline, jet fuel, kerosene, and diesel.

The price of WTI has for long periods been discounted relative to world oil prices such as that of UK North Sea Brent crude oil, a widely cited reference for the price of internationally traded crude oil (Energy & Capital, 2013). The principal cause of this disconnect (with world pricing) is that supplies of oil to inland Canadian and American refineries from both Canadian and US production have been growing beyond those refineries' needs. The pipeline industry has been unable for a variety of reasons to provide the full amount of capacity required to move this oil further afield and relieve the downward pressure reflected in the price of WTI.

There is little capacity available on the Trans Mountain Pipeline that would allow producers to sell into Asian Pacific markets where prices are generally at world market levels.⁷ This is the main reason why the owners are planning to more than double the existing capacity of the pipeline and the Westridge Marine Terminal in Vancouver (Kinder Morgan Canada, 2013). Further, there is no pipeline infrastructure available to provide western Canadian producers access to refineries and shipping terminals in Quebec and New Brunswick where they could likely realize higher prices than the often discounted prices available in the midcontinent region because of less competition and potential access to overseas markets.

While some pipeline capacity is available to transport crude oil southwards from Cushing, Oklahoma to the lucrative US Gulf of Mexico oil refinery and petrochemicals markets, it is not nearly sufficient relative to the space required to allow much Canadian oil to compete there at world prices. In fact, even if substantial additional capacity was available to move more crude oil to the US Gulf, as with TransCanada Corporation's proposed 825,000 barrel per day Keystone XL pipeline, Canadian oil would still have to compete for capacity with surging production from oil shale formations in North Dakota and a number of other states, mostly in the north, which is expected to continue for some time. The current focus on Keystone XL is far too myopic: not only must pipeline capacity to refineries in the US Gulf and the northeast (e.g., Pennsylvania and New Jersey) be increased substantially, but capacity must be put in place to allow western Canadian crude oil to reach tidewater on Canada's western and eastern coasts—if Canada is to get its oil to markets where higher prices can be realized.⁸

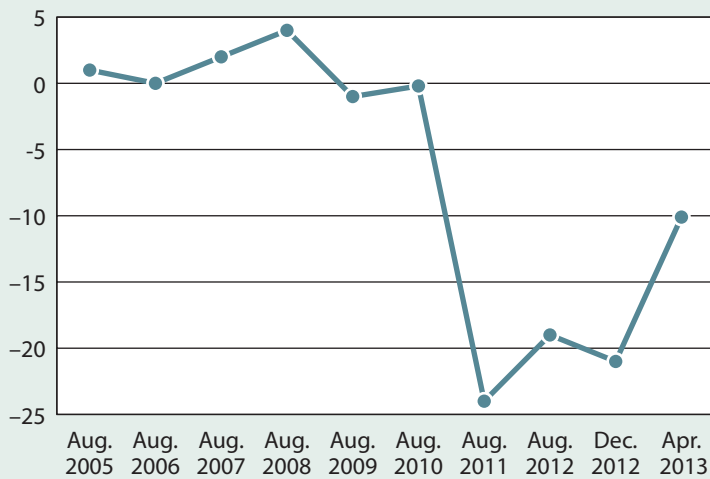
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7. Small shipments are being made on a continuing basis from Trans Mountain Pipeline's Westridge marine terminal.
 8. As indicated later in the paper, some Canadian crude oil is being shipped to US tidewater facilities on the east coast via rail and barge delivery systems. Although the volumes are relatively small, the high shipping cost is more than offset by the higher prices that producers can realize.

The consequences for netbacks and revenues

Bottlenecks within the US market:

The lack of sufficient infrastructure to ship increasing supplies of western Canadian crude oil to coastal refineries in Eastern and Western Canada (where it could compete with imported supplies, and thereby secure world market prices) means that WCSB oil producers must seek US markets. But the increase in US oil production from shale formations and bottlenecks constraining ship-

Figure 1: WTI – Brent Price Differential



Note: The figure shows the per barrel price of WTI crude oil minus the price of Brent crude.

Source: U.S. Department of Energy (2013).

ments southwards from Cushing, Oklahoma—where the WTI oil price marker is established—to the US Gulf meant that WTI was trading at a substantial (more than 20%) discount to the Brent (North Sea) oil price marker most of the time from 2010 until late in the spring of 2013 as illustrated by Figure 1.⁹

Price discounting—light sweet Canadian crudes:

The WTI price marker only applies to those light, sweet crudes that are most readily accepted by US refiners. However, on average, western Canadian light blends traded about US \$8/barrel less than WTI during 2012 as reflected

by the differential between the WTI price and the so-called Edmonton Par price (TD Economics, 2013, Mar. 14).

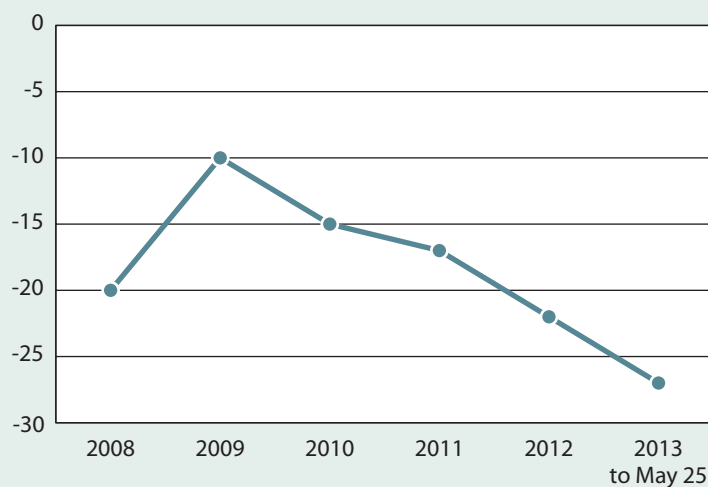
Canadian heavy crudes and bitumen, which account for about two-thirds of Canada's crude oil exports (although they currently represent about

9. Brent blend is a light crude oil, though not quite as light as WTI. WTI has also been trading at a significant discount to other key oil price markers such as Dubai and Tapis (Angevine, G. and V. Oviedo, 2012).

By July 2013 the Brent-WTI price spread had narrowed to just over US \$3 per barrel due to a number of factors: (1) The coming on line of new transportation infrastructure around Cushing, Oklahoma relieved the bottlenecks there and prompted increases in the WTI price; (2) US refinery feedstock demand increased the demand for domestic crude oil; and (3) with access to domestic crudes some refineries were able to replace higher cost Brent and similar crudes, reducing pressure on the price of Brent. More recently, though, the Brent-WTI differential has begun to widen, exceeding US \$13 per barrel on August 6, 2013. (U.S. Dept. of Energy, 2013).

half of overall production), are subject to a much greater discount than lighter crude oil blends in US markets. In fact, as illustrated by Figure 2, the price of the Western Canada Select heavy crude blend traded about \$US 27/barrel below WTI, on average during the first five months of 2013.¹⁰

Figure 2: West Texas Intermediate-Western Canada Select Price Differential



Sources: U.S. Department of Energy (2013) and FirstEnergy Capital Corp. and Petroleum Services Association of Canada (2013, May 27).

Figure 3: Brent-Western Canada Select Price Differential



Sources: U.S. Department of Energy (2013) and First Energy Capital Corp. and Petroleum Services Association of Canada (2013, May 27).

Price discounting— Canadian heavies:

Compared to the much higher price of North Sea crudes, as captured by the Brent price marker, WCS was being discounted by about \$US 36/barrel, on average, since 2010 until late May 2013 compared with only \$US 14/barrel during the 2008–2010 period (Figure 3). The reason for the increased differential, and the large 30% plus discount relative to Brent, is that the WCS price has not increased as much as the Brent price. This reflects the growing supplies of crude oil from both Canadian and US domestic sources competing in the US midcontinent region. From the Canadian perspective, the solution requires expanded and new pipeline infrastructure to enable Canadian oil to reach markets where prices much closer to the world price can be realized.

Of course, the discount that Canadian oil faces is not entirely due to the glut in the US Midwest: heavier crudes would normally be expected to fetch slightly lower prices than lighter crudes because of additional

10. There has been some narrowing more recently, with the WTI-WCS price differential closing at US \$23.24 per barrel on August 6, 2013 (FirstEnergy Capital Corp. and Petroleum Services Association of Canada, 2013, Aug. 7).

processing that is required at refineries. But that discount need not be large; in fact, Mexican Maya heavy crude oil (which is of similar quality to the Canadian WCS blend) has been trading in the US Gulf above the WTI price, subject only to a modest discount relative to the higher Brent price marker (Els, 2013, Jan. 29). This is further evidence of the need to market Canadian crude oil to tidewater markets in Canada and the US as well as to offshore markets as in the Asian Pacific.

WCSB producers' revenue losses:

The discounts that Canadian crude oils are subject to in US midcontinent markets, and most especially heavy crudes, are resulting in a huge ongoing and increasing loss of revenue. In the fourth quarter of 2012, for example, exports of conventional heavy crude oil and bitumen blends (excluding upgraded bitumen or so-called synthetic crudes) reached a combined production rate of 1,278,089 barrels per day (National Energy Board, 2013). At that rate, and if all of that oil were being discounted by \$37/barrel compared to Brent (the actual differential registered during the first 5 months of 2013), this translates to a loss of \$47 million per day or about \$17 billion per year. Granted, some of the heavy crudes and blends would likely reach tidewater via the very limited pipeline capacity that is available to refineries in the US Gulf of Mexico, and via rail transportation (combined with barge connections in some instances). However, the overall loss is almost certainly greater than \$17 billion/year because that estimate ignores the fact that Canadian light/medium and synthetic crude oil exports to the US are averaging 365 million barrels or more per year, and these too are generally being marketed at a discount.

Although the light crudes are being sold at a smaller discount to WTI than the heavy blends, their discount relative to Brent is still considerable (e.g., \$26/barrel or 23% in 2012). Depending on the size of the Brent/WTI differential and the discounts occurring in the WCS price relative to that of WTI, the annual losses being incurred on total Canadian oil exports could reach \$25 billion per year.

The outlook for revenue losses:

Looking ahead, these losses could grow sharply as more raw (non-upgraded) bitumen becomes available as new and expanded oil sands production capacity is added. For example, Imperial Oil's Kearl Lake Oil sands project commenced production in April of this year (Imperial Oil Limited, 2013, Apr. 27). Bitumen production from Kearl Lake is expected to reach 110,000 barrels per day by the end of the year and 600,000 barrels per day by 2020. As already noted, the Canadian Association of Petroleum Producers is projecting production of oil-sands bitumen to continue to grow as more new projects come on stream. If all of the incremental production is marketed in the US midcontinent, and the current severe discounting practices continue because of bottlenecks, the annual loss incurred from not being able to market Canadian

oil at the world price will continue to mount, conceivably reaching \$35 billion or more by 2030.

These losses are having and continue to have widespread economic consequences in Canada.

The Economic Consequences of Price Discounting

Factors preventing Canadian oil production from realizing world oil prices include: the lack of sufficient pipeline infrastructure to allow much of Canada's oil exports to reach refineries in the US Gulf; the complete absence of pipeline transportation capacity to allow this country's oil to access oil refineries and potential export terminals in Eastern Canada and the United States; and severely limited access to the west coasts.¹¹ The huge revenue losses that have been incurred have been very costly not only to the producers, but also to their shareholders, pensioners, governments, and the economy as a whole.

Impacts on oil companies and their shareholders

Foregone revenue on account of discounted crude oil export prices has a direct impact on oil producers' bottom lines. For the oil producing companies affected, to the extent that the reduction in revenue is unexpected or greater than expected, the lower cash flow will likely prevent targeted rates of return from being realized. This could lead to significant changes in financial plans, including increased borrowing requirements and greater than anticipated interest costs. Asset acquisition and growth plans may need to be cut back, slowed or postponed and, in some cases, divestiture of assets may be required because of price uncertainty and reduced access to capital. Slower than expected asset growth, in turn, will impact the cost of capital because potential investors will find the companies less attractive if the potential for appreciation of their share prices is dampened.

One indication of the impact that discounts in oil export prices are having is that corporate profits in Canada's oil and gas extraction sector fell more than 50% in 2012 to \$7.1 billion—the lowest amount since 1999 (TD Economics, 2013, Mar. 14).¹² If much of the exported oil could have been sold at or close to world market prices the profit performance would obviously have been much different. And, of course, lower profits are reducing the companies' capacity to grow dividend payments to their shareholders, or to pay a dividend at all.

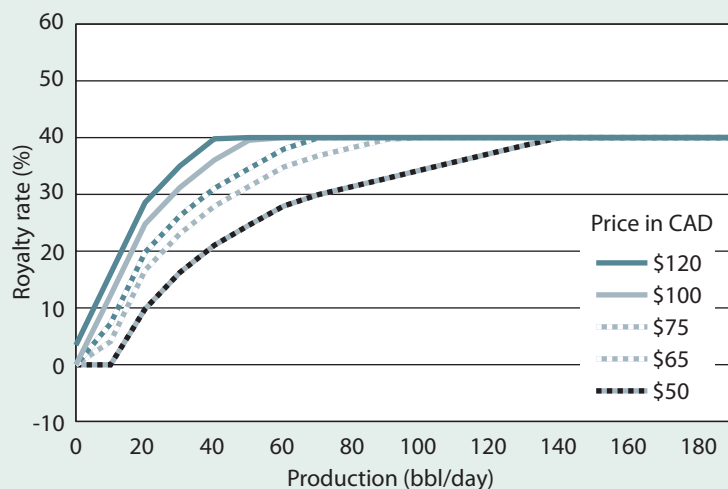
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11. Exceptions are the oil being produced from the east coast offshore region and the small amounts that are reaching tidewater refineries via alternative means of transportation (e.g., rail, barge, and/or truck).
 12. Part of the decline in profits is undoubtedly attributable to the fact that natural gas prices were substantially lower in 2012 than previously as a consequence of surging production from shale formations.

Impacts on pensioners

Pensioners also suffer from reduced revenues on account of oil exports being discounted relative to the world oil price. This is because the Canada Pension Plan Investment Board, the Ontario Teachers Pension Plan, and other public pension plans have invested significant portions of their holdings in shares of companies involved in oil sands production. For example, the Canada Pension Plan Investment Board holds publicly traded shares valued in the vicinity of \$2.8 billion of companies with major oil-sands activities (Canada Pension Plan Investment Board, 2013). Also, the Ontario Teachers Pension Plan has invested over \$1 billion in companies engaged in oil-sands activities (Ontario Teachers Pension Plan, 2013). Many private pension plan funds can also be assumed to hold shares in such companies. In time, of course, astute fund managers would be expected to reduce their holdings in the petroleum production sector, thereby limiting the impact on pensioners. In turn, however, the sell off of shares of oil-producing companies would further reduce the ability of the sector to finance capital expenditures.

Many individuals manage their own retirement investment plans. Other things equal, the value of their portfolios will fall if the net asset value of oil companies whose shares they hold decreases as a consequence of reduced earnings. If they are not sufficiently astute and quick enough to recognize what is occurring, and make appropriate adjustments to their holdings, their investment income is likely to be reduced.

Figure 4: Oil royalty rate comparison, 2011



Source: Alberta Department of Energy (2013a).

Impacts on government revenues

Government revenues are also impacted by discounts in the price of oil relative to the world price.

Oil prices and royalty revenues

Royalties are price sensitive: royalties on all of the oil produced are reduced by a reduction in wellhead or plant gate (oil sands) prices. The greatest impacts of this kind are felt in Alberta, which has the lion's share of Canadian oil production.

Alberta's revenues from the royalties on conventional heavy crude oil are directly impacted

by lower oil prices because of the role that prices play in the royalty formula. As the oil price falls, the royalty rate follows suit, depending on the production rate. This is illustrated by Figure 4.

This means that the lower the price of WCS relative to WTI—i.e., the greater the discount—the lower the conventional heavy crude oil royalty rate applicable to a given rate of production.

As illustrated in Table 1, the province’s royalties on oil-sands bitumen are directly linked to the WTI price. Excess supply in the WTI pricing region

Table 1: Oil sands royalty rates

Price WTI C\$/bbl	Royalty rate on gross revenue	Royalty rate on net revenue
Below C\$55	1.00%	25.00%
C\$55	1.00%	25.00%
C\$60	1.62%	26.15%
C\$65	2.23%	27.31%
C\$70	2.85%	28.46%
C\$75	3.46%	29.62%
C\$80	4.08%	30.77%
C\$85	4.69%	31.92%
C\$90	5.31%	33.08%
C\$95	5.92%	34.23%
C\$100	6.54%	35.38%
C\$105	7.15%	36.54%
C\$110	7.77%	37.69%
C\$115	8.38%	38.85%
C\$120	9.00%	40.00%
Above C\$125	9.00%	40.00%

Source: Alberta Department of Energy (2013b).

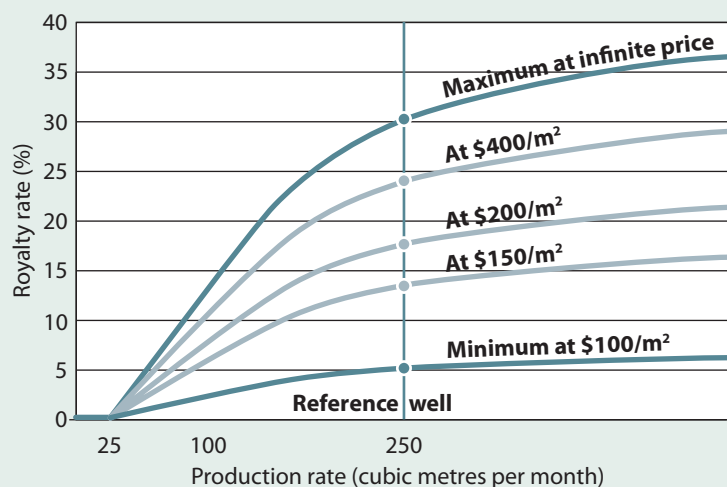
that results in a lower WTI price, therefore, pulls the royalty rate down. This is true regardless of whether or not a project has been “paid out” (i.e., that capital spending has been recovered). As Table 1 indicates, oil-sands royalties vary from 1% to 9% of gross revenue in the case of projects that have not been paid out, and from 25% to 40% of net revenue in the case of paid out projects, as the WTI price (in Canadian dollar terms) increases from \$55/barrel to \$120/barrel.

Lower-than-forecast prices of WCS and WTI contributed to shortfalls in Alberta crude oil and bitumen royalties in fiscal year 2012–13 compared to the estimates contained in the provincial budget for that period. The forecasts for these items with respect to fiscal 2012–13 that were contained in the province’s budget for 2013–14 (released in March 2013) indicate that crude oil royalties were expected to come in \$230 million below the original estimate, and bitumen royalties as much as \$2.2 billion lower. The expected total reduction from the original budget with respect to these items combined was close to \$2.4 billion (Alberta, Dept. of Finance, 2013).¹³

In Saskatchewan, the second largest Canadian producer of conventional heavy crude oil, royalty revenues are also flagging because of their price sensitivity. At or below the low \$100/cubic meter base price in the heavy oil royalty formula, the monthly royalty at a given level of production is essentially a function of the production volume. But at higher prices, in the range where heavy oil prices normally fluctuate, the royalty share of production for the month is calculated by applying the “base” royalty rate to the “base” price and a “marginal” royalty rate to the portion of the average heavy oil price for the month (as calculated by the government) that is above the base price. That “marginal” royalty rate, which applies to all so-called “Fourth Tier” wells (i.e., wells that were drilled by or after October 1, 2002) is 30% (Government of Saskatchewan, 2010).

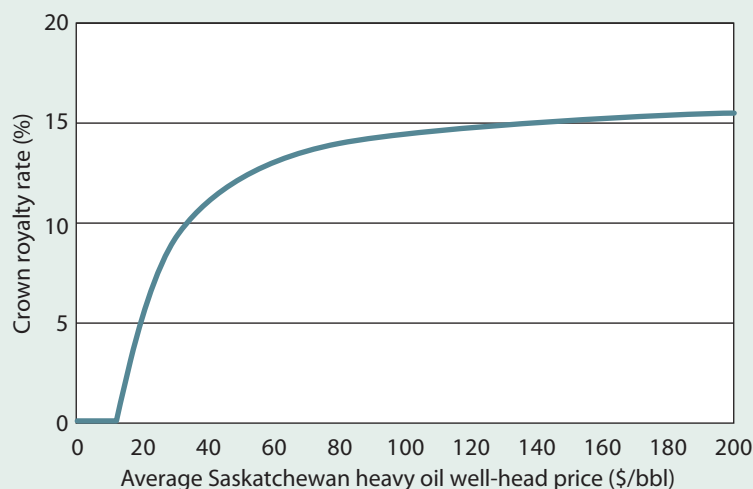
13. See Revenue Estimates on p. 130.

Figure 5: Saskatchewan conventional oil royalty curve price sensitivity (Fourth Tier Oil)



Source: Saskatchewan Government, Ministry of Economy (2013).

Figure 6: Saskatchewan Fourth Tier royalty curve at constant production (25 bbl/day)



Source: Government of Saskatchewan Ministry of Economy (2013)

Figure 5 illustrates how the Saskatchewan Crown royalty on Fourth Tier oil production varies with the price of oil at various rates of production.¹⁴

Figure 6 shows how the Crown royalty rate on conventional heavy oil production at the rate of 25 barrels per day varies with the price.

Given the manner in which the price of oil impacts the Saskatchewan royalty rate, a hefty discount in the heavy oil price relative to WTI because of excess supplies in the US midcontinent region will pull the province's oil royalty revenues down. In fact, a wider than expected gap between realized heavy oil prices and the WTI price (i.e., a deeper discount) helps to explain why, in spite of continued buoyant oil production levels, Saskatchewan's revenues from oil production royalties during fiscal year 2012–2013 were forecast to be \$278 million lower when the 2013–2014 budget was recently brought down than originally estimated (in the 2012–2013 budget) (Government of Saskatchewan, 2013).¹⁵

Contrary to the situation with respect to Alberta and Saskatchewan oil, where shipments from the region are generally

unable to access world oil prices, Newfoundland and Labrador's royalty

14. Note that one cubic meter of oil is equivalent to approximately 6.3 barrels. Consequently prices in terms of \$/cubic metre are easily converted to prices per barrel by dividing by 6.3.

15. This estimate excludes revenues from the province's resource surcharge and Crown land sales. See Revenue Schedule.

revenues are not suffering from discounted prices since its production has access to markets where the oil price is linked to Brent. Although royalty revenues there were projected to come in substantially lower than estimated in the 2012–13 budget, the shortfall is mostly the result of declining production from Hibernia and Terra Nova fields, as well as maintenance issues (TD Economics, 2013, Mar. 14).

Oil prices and income taxes:

In addition to royalties, federal and provincial corporate income taxes are also impacted by reduced corporate revenues from oil producers as a result of price discounts. Most affected in this regard are Alberta, Saskatchewan, and the federal government. Those jurisdictions, as well as others, will also experience reductions in corporate income taxes payable by businesses providing equipment and services to the oil industry and personal income taxes from the levels that might otherwise have been achieved as a result of the consequences of lower oil prices for employment and labor income.

Economic impacts

To the extent that part of their cash flow is being allocated to expansion of existing operations, or investment in other Canadian projects, reduced corporate revenues are bound to be reflected in slower Canadian employment and labor income growth. In the aggregate, this means that gains in Canada's Gross Domestic Product (GDP) will be smaller than they might otherwise be, not only because of the direct impacts, but also because the so-called ripple or multiplier impacts throughout the economy will be smaller as a result of reduced indirect and induced impacts on employment, income, and consumer spending.

In its January 2013 *Monetary Policy Report*, the Bank of Canada estimated that the underperforming oil sector knocked approximately half a percentage point off the annualized rate of growth of the Canadian real GDP in 2012 (Carney et al., 2013). As explained above, this reflects not only the direct effects of the revenue losses being incurred, but also the impacts on “engineering” investment (including oil-sands projects) and oil production growth. Combined with deterioration in the terms of energy-related oil trade because of the decline in oil export prices and the increased cost of imported crude oil and refined petroleum products, this had a negative impact on employment growth and consumer spending which resulted in slower overall growth. If the revenue losses are allowed to increase through a combination of expanded oil-sands bitumen production and continued discounting from the world oil price, the economy will inevitably continue to suffer as a consequence.

From a regional perspective Alberta, where most of the country's heavy oil production and all of the oil-sands bitumen output occur, is most affected by the revenue losses, followed by Saskatchewan. Yet, although the

slowing in overall economic growth from reduced oil export revenues is concentrated in those provinces, it is not confined to them because much of the indirect and induced economic impacts from oil production in Western Canada fall in central Canada. This means that there will be fewer employment opportunities than otherwise in many parts of Canada. Consequently, for some households the likelihood of any meaningful improvement in living standards resulting from better socio-economic conditions will, at best, be postponed.

Essentially, the constraints on the transportation of Canadian crude oil that are preventing it from reaching markets where it would realize greater value is costly not only to the oil producers, but also to governments and individuals. Removing these constraints would allow both the companies and the governments to capture more revenue, with positive economic benefits for the country and Canadians.

Conclusion

Oil production from Alberta's oil sands and also now from oil shale resources in Saskatchewan and Alberta (as well as in the United States) is outpacing the capacity of the available pipeline infrastructure and the necessary expansion of that infrastructure is being impeded by a variety of factors—of which the most important are regulatory and political.

The short-term response of some producers and even pipelines is to turn to the railways and river barge system. However, rail/barge transportation does not appear capable of competing with pipelines on a large-volume long-haul basis, carries obvious environmental costs and is more accident-prone. For more information on the expansion of rail and barge usage in oil transportation, see the first essay in this study, *Oil Transport Overview* by Kenneth Green.

Clearly, a proactive policy approach is needed to facilitate and accelerate investment in new and expanded oil pipelines in order that western Canadian oil producers can realize world market prices for their production similar to those being achieved by crude oil being produced from offshore Newfoundland and Labrador. However, addressing the scope and details of the strategic policy framework that Canada needs to meet this objective was beyond the scope of this analysis.¹⁶

Supportive policies such as regulatory streamlining and federal efforts to gain acceptance from Aboriginal groups could accelerate the process of building new oil pipeline capacity. The sooner that significant and growing volumes of western Canadian crude oil can be dispatched to tidewater destinations, whether for refining or export overseas, the sooner the economic losses from the revenues being foregone will be reduced and ultimately reversed. Because this would be of considerable benefit to all Canadians, it is in the interests of governments at all levels, throughout Canada and the US, to work together to remove the existing bottlenecks.

16. Policy changes are also required in the United States with regard to pipeline infrastructure issues in that country, particularly issues that are inhibiting and delaying investment in new infrastructure that would allow Canadian oil to flow more readily to refinery and export terminal facilities on the US east and west coasts.

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