CANADIAN ENERGY RESEARCH INSTITUTE

Study No. 157
May 2016

CANADIAN ENERGY RESEARCH INSTITUTE

HEAVY BARREL COMPETITION IN THE US GULF COAST: CAN CANADIAN BARRELS COMPETE?

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HEAVY BARREL COMPETITION IN THE US GULF COAST: CAN CANADIAN HEAVY BARRELS COMPETE?

Heavy Barrel Competition in the US Gulf Coast:
Can Canadian Heavy Barrels Compete?

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ISBN 1-927037-41-6

May 2016
Printed in Canada

Front photos courtesy of:

- http://business.financialpost.com/news/energy/the-coming-showdown-between-canadian-and-saudi-oil-producers-on-the-u-s-gulf-coast?__lsa=219e-2266
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Acknowledgements:
The authors of this report would like to extend their thanks and sincere gratitude to all CERI staff involved in the production and editing of the material, including but not limited to Allan Fogwill and Megan Murphy.

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Executive Summary

The collapse in oil prices worldwide is affecting the industry widely and is expected to slow the pace of upstream investment around the world – including in heavy crude oil development in Canada. Still, growth in Canadian heavy crude oil production is already largely locked in until 2020, due to new projects in construction coming on-stream. As Western Canadian crude oil production continues to grow, the leverage of these resources for economic benefits to the nation will depend on the ability to connect this growing supply with downstream demand.

As a consequence of the rapid growth in American oil production, inland refining markets in the US Midwest (current recipients of most of the Canadian heavy imports) have been flooded with cheap, high quality tight crude oil, which leaves Canadian heavy crude oil subject to price markdowns (due to lower quality and bottlenecks in their delivery infrastructure). This situation provides Canadian producers a financial incentive to expand market access in the United States, Canada, and beyond. It also highlights the risk of overreliance on limited markets and the need for options.

The US Gulf Coast (USGC) is one of the world's largest refining centers, and its considerable heavy oil processing capacity presents the largest opportunity for Western Canadian heavy crude oil supply, making it Canadian heavy producers' first target for market access. This study evaluates how much Canadian heavy crude oil could be potentially exported to the US Gulf Coast. The study also reveals the dynamics of the US Gulf Coast refining sector and what would be the netbacks for Canadian producers in the short and long term.

Canadian heavy crude oil competes for market share in the US Gulf Coast with heavy crude oil from Latin American producers, mainly Mexico, Venezuela, Brazil and Ecuador. Mexico and Venezuela are the main heavy crude oil exporters to the US Gulf Coast, accounting for over 45 percent of total crude oil imports to the US Gulf Coast (an average of 1.5 million barrels per day [MMbpd] out of the total 3.2 MMbpd imported to Gulf Coast refineries in 2015).

Over the last 10 years, heavy crude imports from Mexico and Venezuela have decreased by over 1 MMbpd as a consequence of declining reservoirs as well as insufficient upstream investment. This leaves a considerable gap for Canadian producers to establish a new market share in the Gulf. If oil sands could displace most of the Mexican and Venezuelan imports, the opportunity for bitumen blends and conventional heavy oil could be approximately 1.5 MMbpd. In the latest years heavy Canadian barrels are starting to reach the Gulf in increasing volumes, both by rail and the existing Enbridge system. However, current transportation infrastructure is not enough and market access would depend on the development of more pipeline projects that integrate Western Canada with the US Gulf Coast.

Western Canadian production has always had limited access to the US Gulf Coast market, especially because of the lack of infrastructure connecting Cushing, Oklahoma (the primary US hub for Western Canadian crude oil) to refineries in Texas. To support market access to the Gulf

Coast, more than 1.2 MMbpd of pipeline capacity from the US Midwest to the Texas Gulf Coast has been installed. Enbridge decided to reverse the direction of flow of their Seaway Pipeline, adding 400,000 barrels per day (bpd) of capacity from Cushing to Freeport, Texas. The TransCanada Gulf Coast Pipeline (the first stage of the now rejected Keystone XL pipeline) transports another 520,000 bpd from Oklahoma to Texas. Additional lines that improve crude oil delivery from Illinois to Cushing, Oklahoma have also been built, such as Enbridge's Flanagan South and the Southern Access pipeline.

Additionally, rail shipments from Western Canada to the US Gulf Coast will likely continue to increase. Future rail shipping capacity is expected to increase by up to 250,000 bpd in 2016 and 600,000 bpd in 2018. Crude-by-rail shipments to the US Gulf Coast averaged 56,000 bpd in 2015. Crude-by-barge has become a frequently used transport mode for producers looking for alternative transportation alternatives from Cushing to the Gulf Coast. Depending on distances travelled, it can cost between \$12/bbl to \$20/bbl[1] to move oil by rail or barge, compared to a total cost of \$5/bbl to \$13/bbl for pipeline transportation. Rail costs are significantly higher than pipeline, which favours pipeline transportation among Western Canadian producers wanting to get their product to the US Gulf market in a profitable way.

Overall, Western Canadian heavy crude oil production is expected to grow from 2.6 MMbpd in 2015 to 4.7 MMbpd in 2035, more than 2 MMbpd over the next twenty years. Domestic demand for heavy crude oil from Canada has been continuously growing over the last few years, as Canadian refineries continue to transition from offshore imports to Western Canadian feedstocks. Domestic demand for heavy crude oil is expected to increase by approximately 50 percent and reach over 800,000 bpd by 2035. Net heavy Canadian available exports are the result of subtracting domestic demand from heavy (including bitumen) crude oil production, and is expected to grow to volumes larger than 3.5 MMbpd over the next five years, and then slow down to about 1 MMbpd of growth from 2020 to 2035.

Shipments to the east and west coast of Canada, where heavy crude could reach offshore markets, are also being proposed as a way to reach attractive offshore markets, such as Asia and Europe. These projects, expected to come online potentially by 2020, will create new export outlets for Western Canadian crude oil to Asian and European markets. Politics (both local and international) as well as prices are expected to play a role in shaping future trade flows of Canadian heavy crude oil.

Access to new markets is expected to have a positive effect on the prices received by Canadian producers in the US, Europe and Asia. TransCanada's Energy East pipeline, anticipated to be in service by 2020, will carry 1.1 MMbpd of Western Canadian crude from Alberta and Saskatchewan to marine terminals in Quebec and New Brunswick (shipping to European and other markets), as well as refineries in Eastern Canada. Kinder Morgan's Trans Mountain Expansion (TMX) is expected to add 590,000 bpd of shipping capacity from Alberta to the West Coast by 2019, increasing potential volumes exported to Asian markets. Enbridge's Northern

[1] All amounts are US dollars

Gateway project, with a capacity of 525,000 bpd from Alberta to the West Coast would increase Canada's export capacity to Asian markets by 2020.

Although these major pipeline projects have faced delays in their approvals and opposition from some stakeholder groups, it is anticipated they will come online over the next five years. By transporting Western Canadian crude volumes to markets outside North America, these projects will decrease the available heavy crude exports to the US. The rate at which these projects will decrease net available heavy crude exports to the US will depend on the amount of Western Canadian heavy crude oil (excluding high API synthetic crude oil) to be transported using these pipelines to international shipping terminals.

Figure E.1 displays the forecasted potential heavy crude exports to the US, after discounting for heavy crude volumes transported to other international markets through Energy East (EE), the Trans Mountain Expansion (TMX) and Northern Gateway (NG). In order to account for the uncertainty surrounding these transportation projects and the volumes of heavy crude oil they will take, three different scenarios with different transportation quotas are considered. The first and more conservative scenario predicts that no major coast pipeline is built and all available exports are destined to the US. The second scenario projects that only the Energy East and the Trans Mountain Expansion pipelines are carried forward2. Within this approach, two different transportation quotas are considered: one where 50 percent of the pipeline capacity is used to transport heavy crude oil, and the second one where 75 percent of the pipeline capacity is used to transport Western Canadian crude oil to other international markets.

The third scenario predicts that all three pipeline projects (EE, TMX and NG) will come online and transport heavy crude to international markets. Both transportation quotas are considered for this scenario as well. Lines in Figure E.1 display the potential heavy crude oil exports to the US after the different scenarios and transportation quotas are considered. Volumes being transported to Asia, Europe and other international markets are subtracted from the net available heavy crude exports out of Western Canada (if applicable) and the lines represent the potential heavy crude exports to the US.

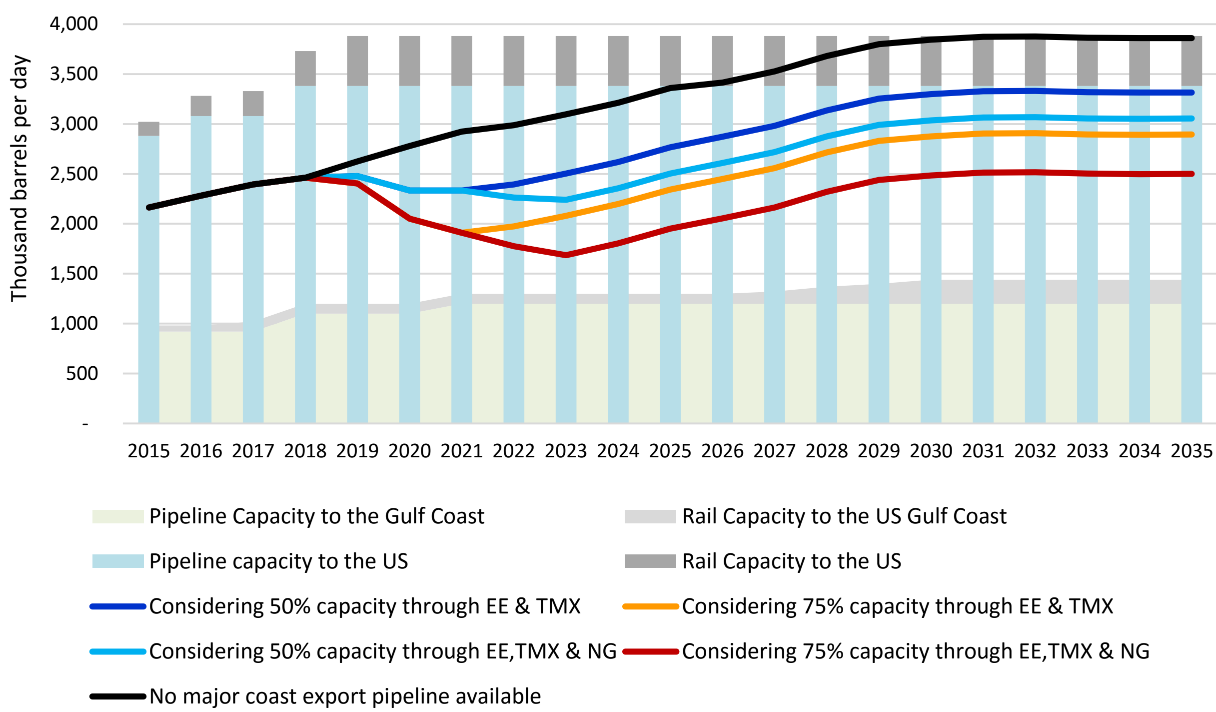
Overall, the potential heavy crude exports from Western Canada to the US vary between 2.5 MMbpd and 3.9 MMbpd by 2035. The red line (75 percent capacity, all three pipelines operating), displays the lower end of the range, while the black line (all exports to the US, no coast pipeline capacity) displays the upper end of the forecasted range of potential heavy crude exports to the US.

The bars in Figure E.1 display the total export transportation capacity from Alberta to the US. Light blue columns represent the existing pipeline capacity (from both Hardisty and Edmonton) to the US, while grey columns display the crude-by-rail capacity. It is clear that under the current

[2] Although Northern Gateway has been approved by the Governor Council (in June 2014), the 209 conditions and further discussions with indigenous communities are still pending and need to be resolved in order to move forward.

production growth forecast, transportation infrastructure from Western Canada to the US seems to be sufficient to transport the predicted potential heavy exports.3 However, if none of the major export pipelines proposed (Energy East, Trans Mountain Expansion or Northern Gateway) come online and all heavy exports are directed to the US, transportation capacity could be heavily constrained and dependent on expansions of the railway system.

Figure E.1: Potential Heavy Crude Exports to the US



Source: CERI

The area in light green represents the pipeline transportation capacity to the US Gulf Coast, followed by the crude-by-rail capacity, displayed in light grey. The creation of pipeline infrastructure to the east and west coast of Canada, and subsequent new export outlets for Western Canadian heavy crude oil, will have a positive effect on the current transportation constraints to the US Gulf Coast. With these projects coming forward, it is expected that almost half of the total available heavy exports to the US could be directed to the US Gulf Coast Market.

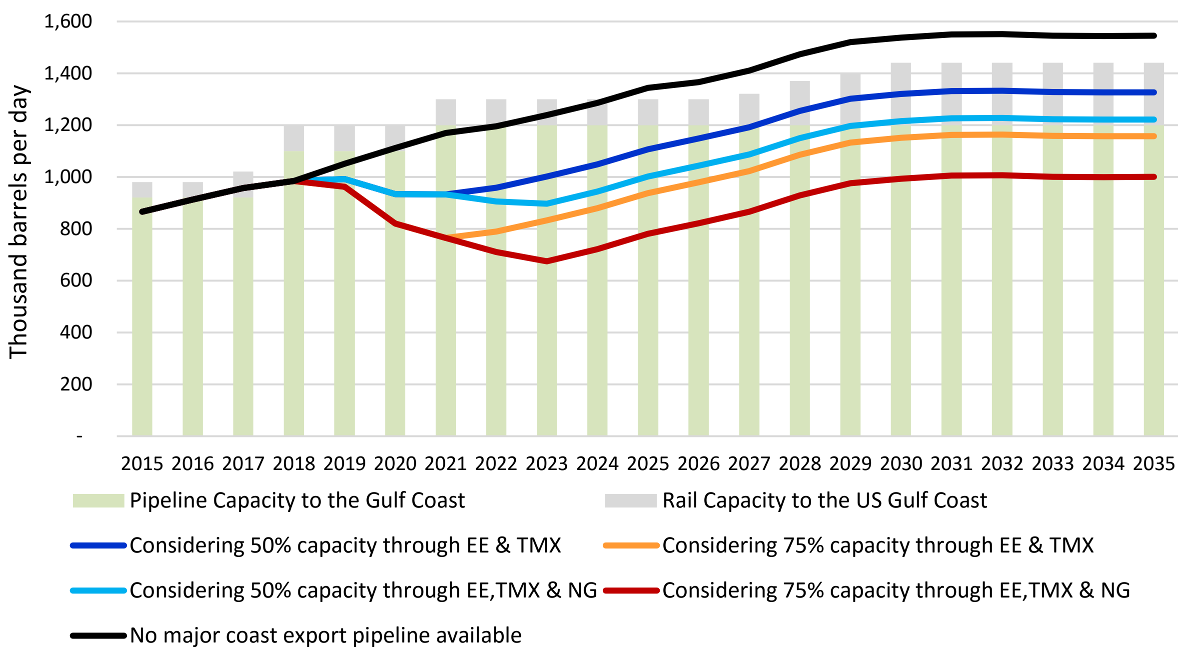
The US Midwest (PADD 2) will continue to absorb most of the Canadian heavy exports to the US. Besides having prime infrastructure connecting this area with Alberta, there are agreements in place between Canadian producers and US Midwest fuel refiners (i.e., Cenovus, Husky, and

[3] Western Canadian light volumes (high quality synthetic crude oil, or SCO) are expected to be exported to international markets where it would receive more competitive prices than in the US market, which is oversupplied with domestic light tight oil. It will also supply Eastern Canadian refineries, which are configured for light feedstocks. Taking these into consideration, it is not expected to see large volumes of SCO being shipped to the US in the future.

Imperial, among others who depend on supply agreements with integrated refineries) that will continue to be active for the next decades. According to Hart Energy report,4 contracts with integrated refineries in the US Midwest account for approximately 1.3 MMbpd of crude oil imported to PADD 2, approximately 60 percent of the total heavy exports to the US. This leaves 40 percent of the potential exports to the US to be redirected to the US Gulf Coast.

Figure E.2 displays the potential heavy crude exports to the US Gulf Coast (estimated as 40 percent of the total exports to the US). Lines represent the different scenarios and transportation quotas also considered for Figure E.1. The green columns show the forecasted pipeline transportation capacity to the US Gulf Coast, while the grey columns represent the predicted crude-by-rail capacity to the Gulf Coast from either Canadian or US Midwest terminals.

Figure E.2: Potential Heavy Crude Exports to the US Gulf Coast



Source: CERI

It is clear that the creation of pipeline infrastructure and shipping routes to international markets other than the US would favour market access of Western Canadian heavy crude oil into the US Gulf Coast. By allocating heavy production to other markets such as Asia and Europe, Canadian producers are able to reduce their overland dependence on the US market, reduce their supply to that market and overcome pipeline constraint issues to the US Gulf Coast.

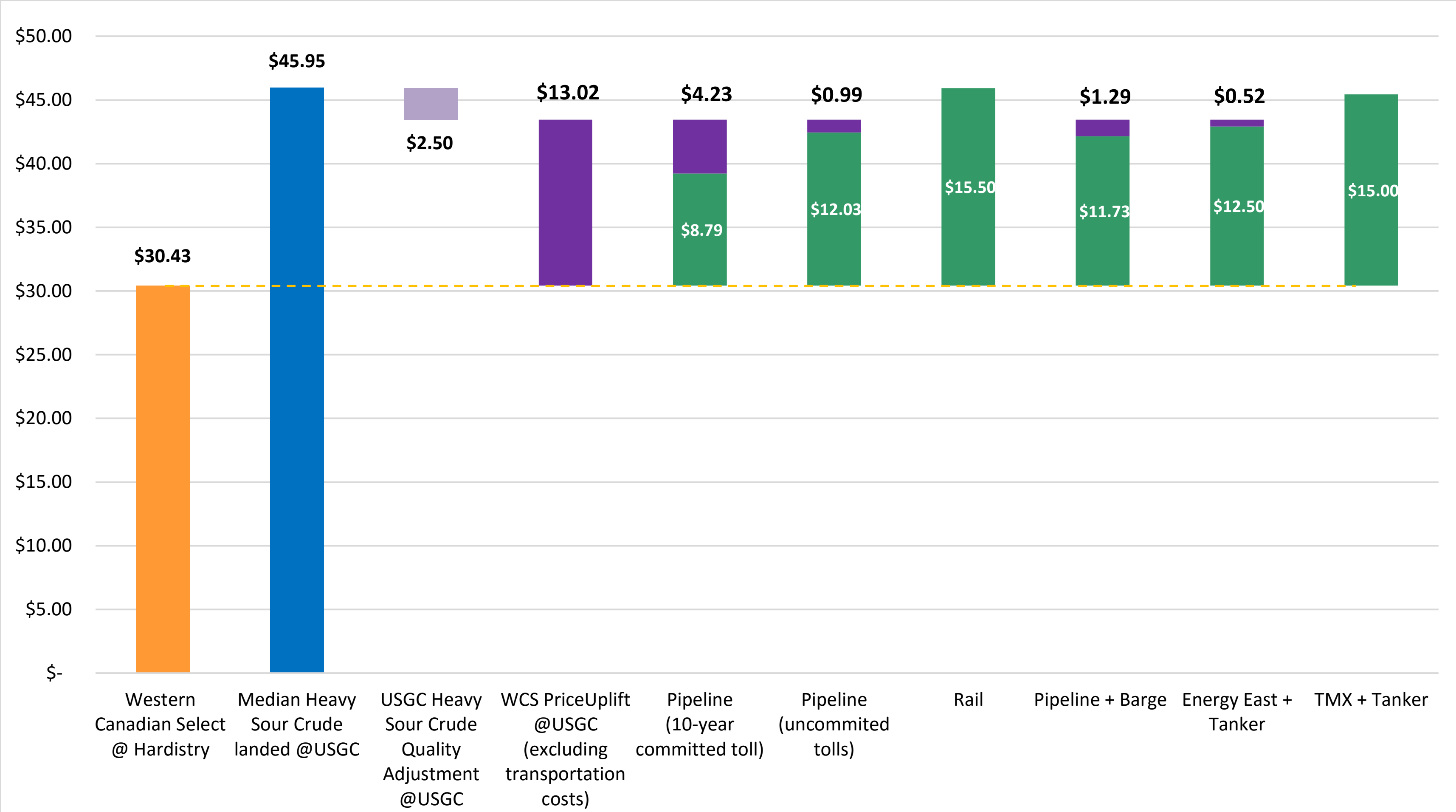
Although the need to expand and reach new markets for oil sands is pressing, production and pipeline projects associated with oil sands have come under increased scrutiny, contributing to delays and uncertainty. Project economics are not alone in shaping future markets for oil sands.

[4] Hart Energy, Refining Unconventional Oil, 2012.

Although not every factor will influence future markets for oil sands, some of the most prominent ones include regulatory processes, local concerns, greenhouse gas emissions (GHG) and climate change policies, as well as indigenous people's rights in Canada.

Figure E.3 displays the overall analysis of the netbacks (in Canadian dollars) Canadian producers could receive for a Western Canadian Select (WCS) equivalent Heavy Crude Barrel, under 2015 average market conditions. The first component of the analysis is the orange bar, which represents the average WCS price at Hardisty in 2015 ($30.43/bbl). This is in effect reflective of the price Western Canadian heavy producers are currently receiving at Alberta.

Figure E.3: US Gulf Coast Netback Analysis for Canadian Heavy Crude Oil Producers



Source: CERI

The blue column shows the average price heavy sour crude imports (mostly Mexican and Venezuelan) receive at the US Gulf Coast. A quality adjustment (displayed in the third column) is applied in order to better reflect the potential prices of Canadian heavy crude oil. This is, for the most part, diluted bitumen, which is assessed against Latin America imports, which are less acidic and easier to refine.

The difference between WCS at Hardisty and the estimated WCS price at the USGC (after applying the quality adjustment) is the gross possible price uplift Canadian producers could receive at the Gulf Coast. Simultaneously, this $13.02/bbl figure is the maximum amount producers would be willing to pay for transportation costs in order to receive positive netbacks at said target market.

Netbacks to Canadian producers, after taking into account transportation costs, are shown in purple in columns five to ten for the different modes of crude transportation analyzed. Shipping using existing pipeline routes proves to be the most profitable way for Canadian heavy crude oil to reach the US Gulf Coast market.

Canadian producers' willingness to spend more on alternate transportation and ship their product using rail, barge or tanker seems to have shifted after crude oil prices started to fall dramatically. Most Western Canadian heavy crude oil production comes from very expensive oil sands mining or in situ steam heating operations, which are designed to produce consistently for decades and are costly to shutter in a downturn. Under the current price market, crude netbacks for heavy crude oil production in Western Canada are dramatically low, further justifying investment in shipping to the US Gulf Coast.

Chapter 1: Introduction

Competition for market share is increasing between Canadian and other heavy crude oil suppliers for access to the United States Gulf Coast (USGC)[5] refinery market. This report explores how much of Canadian heavy crude oil is exported to the USGC, current Canadian export capacity, the USGC refining sector, and the competition among its various players.

The USGC is one of the world's largest refining centres, with a refining capacity of 9.4 million barrels per day (MMbpd) (over 45 percent of the US total).[6] The USGC has a significant heavy oil[7] processing capacity, with most refineries having the capacity to process heavy, high sulphur crude oil. This makes the USGC an ideal target market for Western Canadian heavy crude oil supplies outside of traditional markets for Canadian exports such as the US Midwest, which currently refines more than 70 percent of total Canadian exports to the US.

The Gulf region's refineries can consume about 2.4 million barrels of heavy crude per day. Currently, the majority of the heavy supply comes from Mexico (0.7 MMbpd) and Venezuela (0.8 MMbpd), with smaller contributions from Colombia (0.2 MMbpd), Brazil (0.2 MMbpd) and Ecuador (0.1 MMbpd).[8]

In 2015, almost 383,000 barrels per day (bpd) of Canadian heavy crude made its way to the USGC by pipeline and rail, a 200,000 bpd increase from 2014 and more than tripling the 100,000 barrels exported in 2011.[9] These volumes are expected to increase with more than 1.2 MMbpd of new pipeline capacity planned to connect western Canada to the Gulf Coast in upcoming years.

Current US Gulf demand for heavy crude is not expected to rise since the surge of American light tight oil production created a surplus of light crude in the region that will discourage refiners from investing in capacity for heavier feedstocks.

Refinery conversions have historically been a major source of new demand for Canadian bitumen in the United States.[10] With no future demand growth expected for heavy crude oil in the Gulf Coast, opportunities for bitumen blends will primarily come from replacing imports from South American suppliers.

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[5] The USGC/PADD 3 region includes the six states of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas.

[6] US Energy Information Agency (EIA), Refinery Utilization and Capacity, 2015 https://www.eia.gov/dnav/pet/pet_pnp_unc_a_(na)_YRL_mbblpd_m.htm.

[7] For the purpose of this study, heavy oil has been defined as liquid petroleum with an API gravity of less than 25°.

[8] EIA 2014 PADD 3 imports.

[9] National Energy Board, "Estimated Canadian Crude Oil Exports by Type and Destination", http://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/ttlcrdlxprtdstntn-eng.html.

[10] For example, conversions in the US Midwest at Marathon Detroit and BP Whiting will increase US Midwest heavy oil refining capacity by 340,000 b/d. These two projects were geared toward heavy Canadian bitumen blends. These projects were approved prior to the light tight oil American boom.

In later years, Mexican heavy imports to the Gulf declined from over 1 MMbpd in 2010 to 0.6 MMbpd in 2015.[11] This decline is associated with falling reservoir pressure in offshore fields, after reaching peak levels.[12] Venezuelan heavy crude supply to the Gulf has also decreased in later years, while political uncertainty and difficulty of access keep escalating.[13] From a US Gulf Coast refiner perspective, Canada is considered a preferred supplier since it offers a more certain alternative to the current ones.

There is a considerable space for Canadian producers to establish a new market share in the Gulf. If oil sands could displace most of the Mexican and Venezuelan imports, the opportunity for bitumen blends would be approximately 1.5 MMbpd. In the latest years heavy Canadian barrels are starting to reach the Gulf in increasing volumes, both by rail and the existing Enbridge system. However, current transportation infrastructure is not enough and market access would depend on the development of more pipeline projects that integrate Western Canada with the US Gulf Coast.

Overall, the US Gulf Coast is a huge crude oil market, nearly equivalent to all of China's today. As so, it is considered a critical part of the future for oil sands, particularly heavy bitumen blends. This study evaluates how much Canadian heavy crude oil could be exported to the US Gulf Coast and what would be the netbacks for Canadian producers in the short and long term.

[11] EIA Crude oil imports to PADD 3 historical data.
[12] EIA Mexico Country Analysis – Petroleum and other liquids https://www.eia.gov/beta/international/analysis.cfm?iso=MEX .
[13] EIA Venezuela Country Analysis – Petroleum and other liquids https://www.eia.gov/beta/international/analysis.cfm?iso=VEN .

Chapter 2: Canadian Exports to the US

Current Canadian Exports of Heavy Barrels

Canada has been the top foreign supplier of crude oil to the US since 2004 and it is likely to remain as such for the foreseeable future. According to the latest data from the US Energy Information Administration (EIA), Canada's total exports to the US increased by 287,000 bpd in 2015; a 9 percent increase from 2014 despite no growth in total US imports.[1] Canada produced 3.9 MMbpd in 2015 and exported just above 3 MMbpd, with the majority of these volumes being exported to the US.[2] The remaining volumes were destined to domestic refineries in Western and Eastern Canada.

Canada's market access is limited by a lack of infrastructure to send liquids anywhere but the US. The current rise in US domestic production, driven by horizontal hydraulic fracturing of tight oil plays in Texas and the Dakota's,[3] has displaced oil imports. In 2014, US production of crude oil exceeded the level of US imports for the first time in 20 years. This light tight oil has flooded refineries on the East and Gulf Coast. However, since the projected growth of western Canadian crude oil supplies are predominately heavy crude oil, the US Gulf Coast and Midwest refineries – with their substantial heavy oil processing capacities – remain a key target market. Canada represents a reliable source of good quality crude for the US, transported straight to the refinery gate via pipeline, a preferable option to waterborne crude oil.

In 2015, 63 percent of total Canadian exports to the US (1.9 MMbpd) went to the US Midwest (PADD 2[4]). The US Gulf Coast (PADD 3) imported 0.4 MMbpd of crude oil from Canada in 2015, which translates to 13 percent of Canada's total imports, an increase of 6 percent from 2014.[5] Although the Gulf Coast refineries are best suited to handle Western Canadian heavy crudes, the existing pipeline infrastructure is not sufficient to effectively access the market and compete with Latin-American heavy crude volumes.

Nearly all of Canada's crude oil exports to the US come from the western provinces of Alberta and Saskatchewan,[6] primarily heavy crude oil producers. The vast majority of Canada's crude oil reserves reside in the oil sands so it is natural for these bituminous resources to be the primary

[1] EIA Imports by country of origin http://www.eia.gov/dnav/pet/pet_move_impcp_a1_NCA_epc0_ip0_mbblpd_a.htm.

[2] According to the NEB 2015 Canadian crude oil exports, in 2015, less than 1% of total Canadian exports end up in markets other than the US.

[3] In Texas, Eagle Ford light tight oil production averaged 1.5 mbd in October 2015. In the Dakotas, the Bakken formation produced an average of 1.2 mbd of light tight oil http://www.pennenergy.com/articles/pennenergy/2015/11/shale-oil-production-in-bakken-eagle-ford-remained-flat-in-october.html .

[4] The Petroleum Administration for Defense District (PADD) are geographic aggregations of the 50 States used as their official delineation to describe their oil market regions. There are five different PADDS: East Coast (1), Midwest (2), Gulf Coast (3), Rocky Mountain (4) and West Coast (5).

[5] National Energy Board - Estimated Canadian Crude Oil Exports by Type and Destination, 2015

[6] Canada Association of Petroleum Producers, "Crude Oil: Forecast, Markets, and Transportation", June 2015

driver of Canadian production.[7] Conventional oil reservoirs are also dominated by resources in the Western Canadian Sedimentary Basin (WCSB), with a large percentage of its production being heavy crude oil.

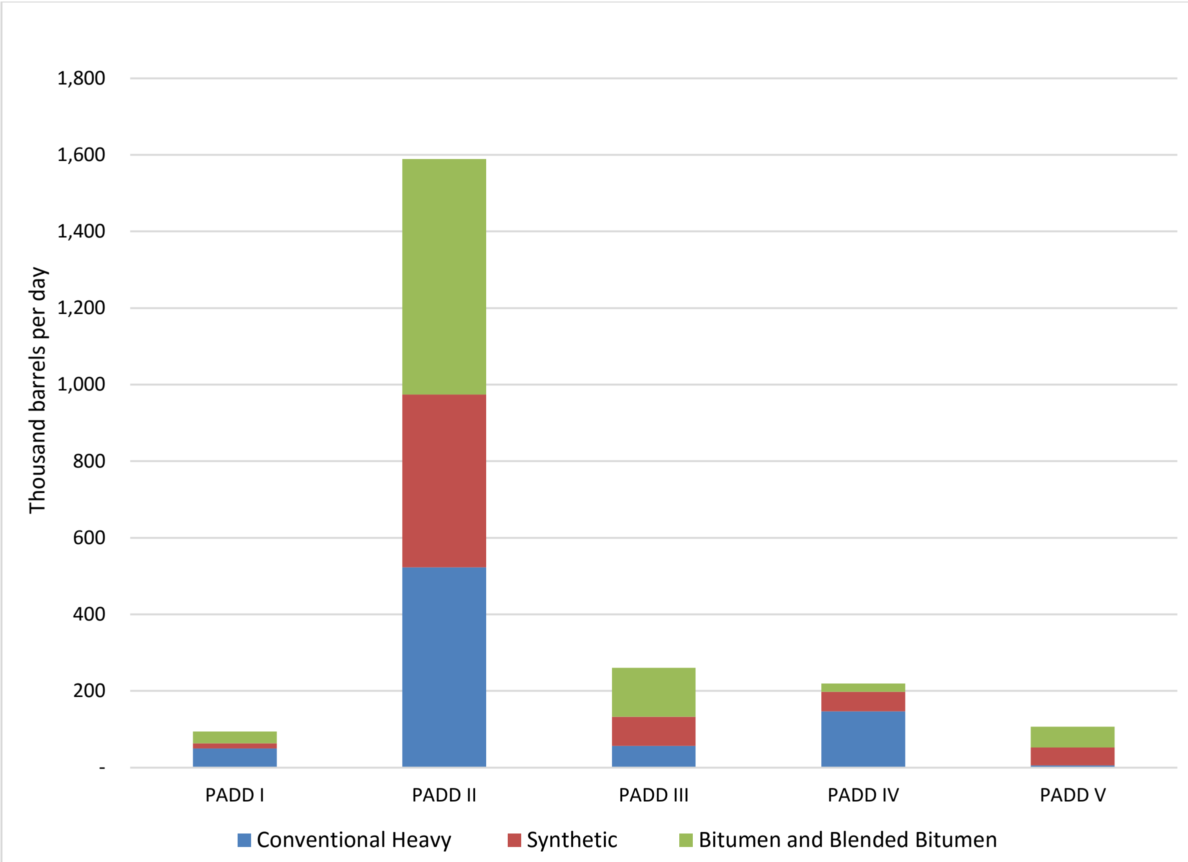
Overall, heavy crude oil exports accounts for over 72 percent of total Canadian exports (2.2 MMbpd out of 3 MMbpd total).[8] Bitumen (diluted to facilitate pipeline transportation) represents almost 40 percent of the heavy oil supply to the US, followed by conventional heavy volumes (32 percent) and synthetic crude oil (SCO),[9] with over 25 percent of the total.

Figure 2.1 displays Canadian heavy crude oil exports by type and destination, as reported quarterly by the National Energy Board (NEB) for the 2014-2015 period.[10] About 70 percent of total exports (1.6 MMbpd) are directed to the US Midwest (PADD 2). Approximately 260,000 bpd were destined to the US Gulf Coast (PADD 3), 220,000 bpd to the Rocky Mountain region (PADD 4) and 105,000 bpd to the West Coast (PADD 5). All of these volumes constitute a blend of diluted bitumen, SCO and conventional heavy crude oil.

Before the US export ban was lifted, the only country allowed to import US crude oil was Canada. US imports to Canada averaged 331,000 bpd in 2014.[11] These crude export volumes actually include Canadian-produced barrels that are moved through the US and then re-exported mostly to Canada, and more recently to other countries such as Switzerland, Spain, Italy and Singapore[12] (since mid-2014). In 2014, approximately 80,000 bpd of Canadian crude oil were exported to Europe and Asia through the US Gulf Coast. Almost 6,000 bpd were diluted bitumen from Western Canada. The NEB reports this volume, but it is too small to be displayed in Figure 2.1.

[7] Alberta's Oil Sands established reserves account for 97% of Canada's total (166.3 billion barrels out of 170.8).
[8] National Energy Board - Estimated Canadian Crude Oil Exports by Type and Destination, 2015.
[9] Upgraded oil sands bitumen.
[10] National Energy Board - Estimated Canadian Crude Oil Exports by Type and Destination, 2014-2015.
[11] EIA Exports by destination https://www.eia.gov/dnav/pet/pet_move_expc_a_EPC0_EEX_mbblpd_a.htm
[12] https://www.eia.gov/todayinenergy/detail.cfm?id=18631 .

Figure 2.1: Canadian Exports of Heavy Barrels to the US by PADD Region and Type of Crude (2014-2015)



Source: National Energy Board, 2014

Canadian Export Pipeline Network

Western Canada production centers are connected to domestic and US refining and export centers mainly through pipelines. Members of the Canadian Energy Pipeline Association (CEPA) reportedly transport 3.4 MMbpd of crude oil and other liquids over approximately 40,000 km of pipeline in 2014.[13] Although pipelines are the transportation method of choice, an increasing volume of crude is now transported by rail because of infrastructure constraints.

Four companies operate the majority of these export pipelines: Enbridge, Kinder Morgan, Spectra, and TransCanada. Both the Enbridge Mainline pipeline and the Kinder Morgan Trans Mountain pipeline originate at Edmonton, Alberta; while the Spectra Express pipeline and the TransCanada Keystone pipeline originate at Hardisty, Alberta. Together, these four pipelines provide about 3.8 MMbpd of capacity out of Western Canada.

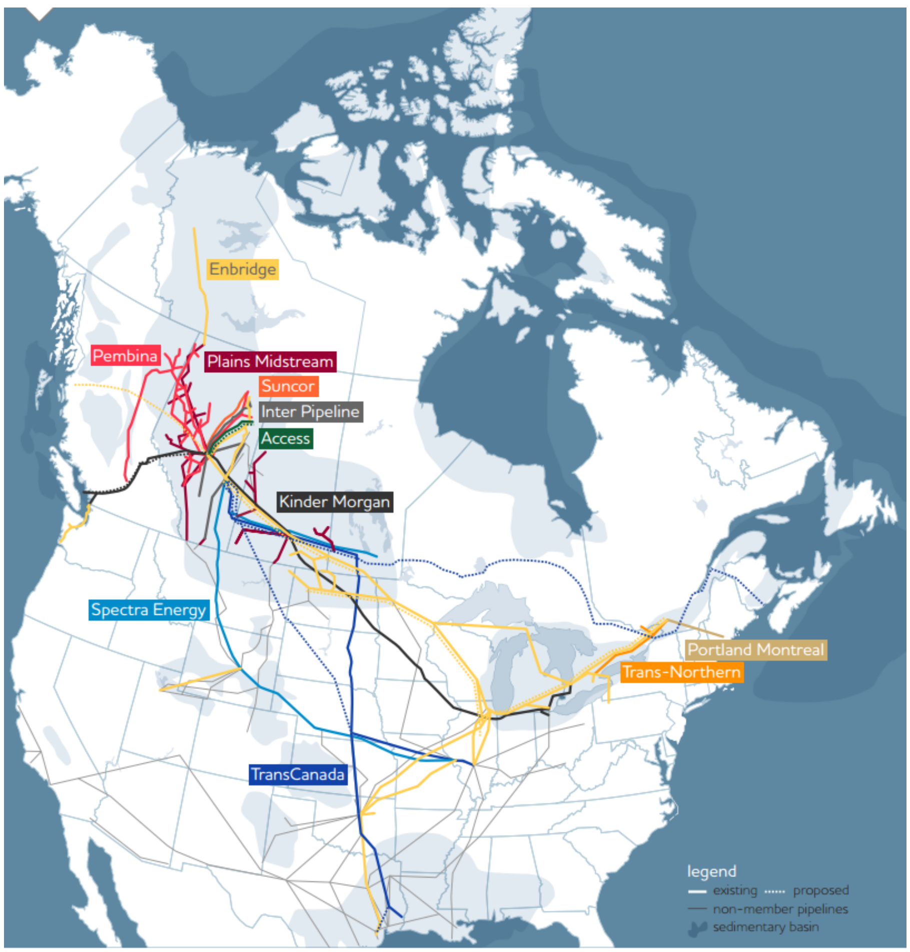
Figure 2.2 shows Canada's current pipeline network, as well as proposed pipeline projects as reported by CEPA. Enbridge's pipelines are displayed in yellow. The Enbridge Mainline system (all

[13] http://www.cepa.com/library/cepa-member-statistics

yellow pipelines going south of Edmonton) consists of numerous lines that transport crude oil from Western Canada, Montana and North Dakota to the US Midwest and Ontario. According to the Canadian Association of Petroleum Producers (CAPP), the current capacity of the system between Edmonton, Alberta and Superior, Wisconsin is approximately 2.6 MMbpd.[14] Enbridge's Mainline is the largest export pipeline system and transports more than half of the Canadian crude exported to the US.

The Kinder Morgan Trans Mountain system is displayed in black. This is the only pipeline serving the West Coast. It originates at Edmonton and delivers crude oil to British Columbia, Washington and the Westridge marine terminal (located in Burnaby, BC). From this terminal, crude oil is loaded onto vessels for offshore exports, destined almost exclusively for California and the US Gulf Coast (PADD 5 and 3, respectively). Its capacity is rated at 300,000 bpd. According to CAPP, approximately 220,000 bpd are allocated to refineries in British Columbia and Washington, while 80,000 bpd are exported via vessel.

Figure 2.2: Canadian Crude Oil Pipeline Network



Source: Canadian Energy Pipeline Association

[14] CAPP's Crude Oil Forecast, Markets and Transportation, June 2015

TransCanada's Keystone pipeline system originates at Hardisty, Alberta and has a junction at Steele City, Nebraska. From here, crude oil can be directed east to Illinois terminals in Wood River or south to Cushing, Oklahoma. Keystone can deliver up to 590,000 bpd. CAPP reported that about 530,000 bpd of capacity is already contracted for an average of 18 years.

The Spectra Express pipeline (displayed in blue), with a designed capacity of 280,000 bpd, originates at Hardisty, Alberta and terminates at Casper, Wyoming. From there, it connects with the Platte Pipeline, which transports crude oil to Wood River, Illinois (PADD 2). The ability to move crude on the Express pipeline is limited due to insufficient capacity of the Platte Pipeline, with 165,000 bpd. In recent years, rail connections from Casper, Wyoming have helped to increase throughput capacity of the Spectra Express system by approximately 15,000 bpd.

Proposed Export Pipelines

Pipeline capacity is considered to be a bottleneck for the Western Canadian crude oil production growth forecast. A number of pipeline projects that could increase crude transportation capacity out of Canada have been proposed to take place over the next five years.

Enbridge recently completed a number of pipeline expansions and is planning on further expansion projects. A pipeline from Line 3 of the Mainline system is being replaced, which would increase the line capacity by 370,000 bpd. The Alberta Clipper, which goes from Hardisty, Alberta to Superior, Wisconsin completed phase 1 of the expansion by adding 120,000 bpd of capacity in late 2014. Phase 2 was completed in 2015 and added an additional 230,000 bpd.[15] In total the Alberta Clipper pipeline increased its capacity from 450,000 bpd to 800,000 bpd.

Additionally, Enbridge has invested in the Southern Access pipeline, which starts operating in 2016 and would transport 300,000 bpd from Flanagan to Patoka, Illinois.[16] This line directs Western Canadian crude to reach the US Gulf Coast market.

Enbridge's proposed Northern Gateway pipeline would transport an initial capacity of 525,000 bpd from Edmonton, Alberta to Kitimat, British Columbia. The Governor in Council approved the project subject to 209 conditions and further discussions with aboriginal communities. The target in-service date for the project is 2019. This pipeline would provide access to international markets via maritime terminal.

Kinder Morgan also planned for expansion of its existing Trans Mountain pipeline. A second pipeline, within the same right-of-way has been proposed. This new line and revamped

[15] Enbridge Website, Mainline Enhancement Program. Accessed February 2016 http://www.enbridge.com/MainlineEnhancementProgram/Canada/Alberta-Clipper-Capacity-Expansion-Phase-II.aspx.

[16] Enbridge Website, Southern Access pipeline Route Map. Accessed February 2016 http://www.enbridge.com/MediaCentre/News/lomap.aspx .

configuration would add 590,000 bpd in capacity to the existing system for a total capacity of 890,000 bpd. The new line is expected to be in operation by 2019.[17]

TransCanada proposed Keystone XL as an addition to the Keystone system in 2005. With a capacity of 830,000 bpd, the pipeline was supposed to run parallel to the existing line, directly from Hardisty, Alberta to Steele City, Nebraska. TransCanada applied for a Presidential Permit with the US Department of State in 2008, which was denied because of environmental concerns. TransCanada reapplied in 2012, proposing alternative routes through Nebraska, but was ultimately rejected in November 2015.

A shorter section of the line that is entirely within the United States was pursued as a separate project and completed in 2014. This portion, now known as TransCanada's Gulf Coast pipeline, transports 520,000 bpd of crude from Cushing, Oklahoma to Texas refineries. It has been key in solving some of the infrastructure constraints that led to an oversupply of oil at the Cushing storage hub. TransCanada plans to expand its capacity to 700,000 bpd now that Keystone XL has been rejected.

Western Canadian production has always had limited access to the US Gulf Coast market, especially because of the lack of infrastructure connecting Cushing, Oklahoma (the primary US hub for Western Canadian crude oil) to refineries in Texas. Besides TransCanada's efforts, Enbridge decided to reverse the direction of flow of their Seaway Pipeline (jointly owned with Enterprise Product Partners L.P.). Since 2012, Seaway delivers Western Canadian crude oil from the Mainline system delivery point at Cushing, Oklahoma to Freeport, Texas. The original capacity of the reversed pipeline was only 150,000 bpd but was increased to 400,000 bpd through pump station modifications and additions in 2013. In 2014, Seaway transported 290,000 bpd on average from Cushing to refineries in the Gulf Coast.

To support Western Canadian market access to the Gulf Coast through Seaway, Enbridge also built a new line between Pontiac, Illinois and Cushing, Oklahoma (called Flanagan South) with 585,000 bpd of capacity. Enbridge shippers that contract capacity on Flanagan South are able to nominate Western Canadian crude volumes for delivery to the US Gulf Coast through this pipeline, which connects to the downstream Seaway line. In total, more than 1.2 MMbpd of pipeline capacity has been installed in the US to support market access for Western Canadian crude oil to the Gulf Coast refining hub.

The most recent pipeline proposal is TransCanada's Energy East project, which would transport Western Canadian crude oil from Hardisty, Alberta and Moosomin, Saskatchewan to delivery points in Quebec and New Brunswick. This is the only export pipeline proposal to the east coast, which would open the market for delivery to refineries in Eastern Canada and exports to Europe and other markets. This pipeline would have a 1.1 MMbpd capacity and includes the conversion of a natural gas pipeline to oil service, as well as constructing new pipeline segments throughout.

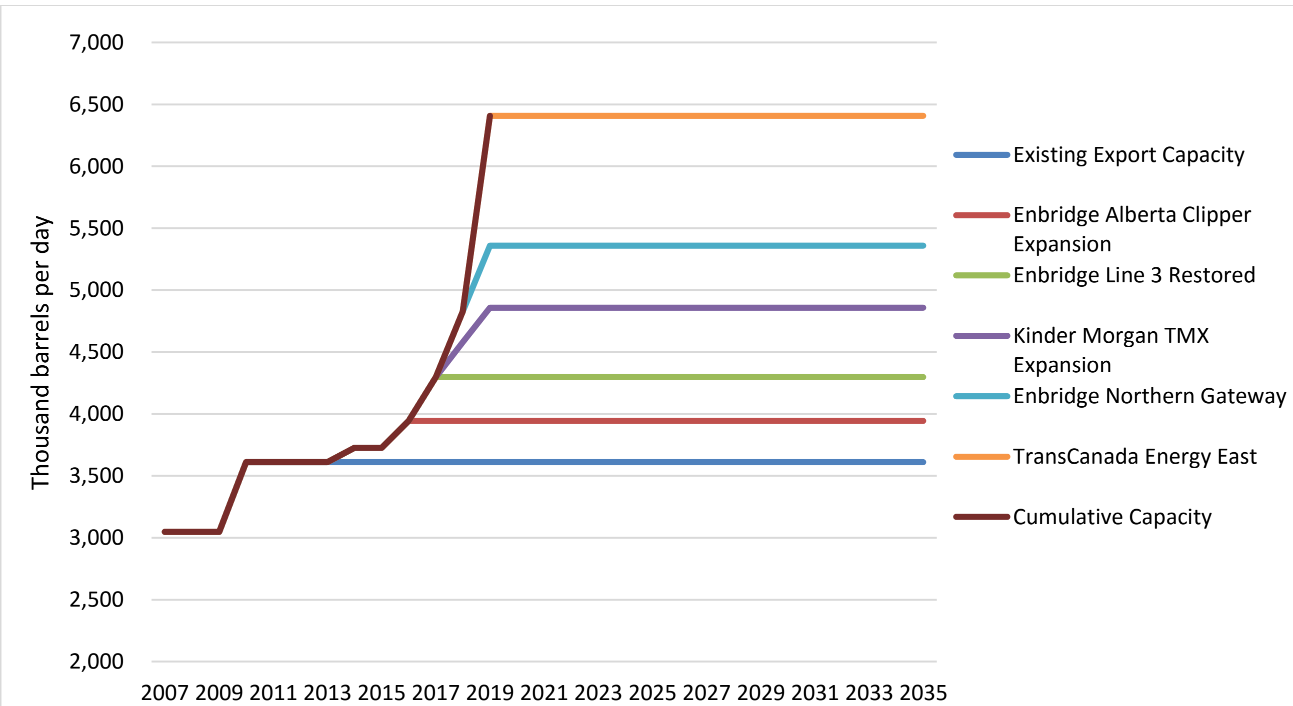
[17] Trans Mountain Expansion Website, Accessed February 2016 http://www.transmountain.com/proposed-expansion.

About 900,000 bpd are already underpinned by firm contracts. Applications have been submitted and the in-service date for the project is 2020.

The creation of pipeline infrastructure to the West coast (Trans Mountain expansion and Northern Gateway) and East coast (Energy East), will create new export outlets for Western Canadian crude oil. This new access to Asian and European markets could reduce Canada's overland dependence on the US market, and positively affect the prices received by Canadian crude oil producers.

Figure 2.3 displays the existing and forecasted pipeline export capacity from Western Alberta. As of 2015, existing export capacity is 3.79 MMbpd, provided by four main pipeline systems: Enbridge Mainline, Kinder Morgan Trans Mountain, Spectra Express and TransCanada Keystone. Total proposed additional capacity is 2.82 MMbpd, provided by the projects listed in Figure 2.3. By 2020, the total pipeline export capacity from the Western Canadian Sedimentary Basin is anticipated to increase to almost 6.5 MMbpd.

Figure 2.3: Existing and Future Western Canadian Pipeline Export Capacity



Source: Canadian Association of Petroleum Producers

Pipeline transportation costs for Western Canadian oil producers vary depending on the pipeline operator, routes, contract agreement and crude oil quality. Using Hardisty, Alberta as the common departure point for western Canadian heavy crude oil, the tolls to ship to the US Midwest (Chicago, Illinois) are about \$4 to \$5 per barrel.[18] Shipping to Cushing, Oklahoma costs

[18] All monetary amounts are reported in Canadian Dollars.

approximately $6 to $7 per barrel, depending on the operator and operating contract. Pipeline transportation costs from Hardisty to the US Gulf Coast are highly dependent on contract nature and range between $7 and $13.[19] Most of the shipments to the US Gulf Coast require operators to sign long-term contracts.

Crude Oil Exports by Rail

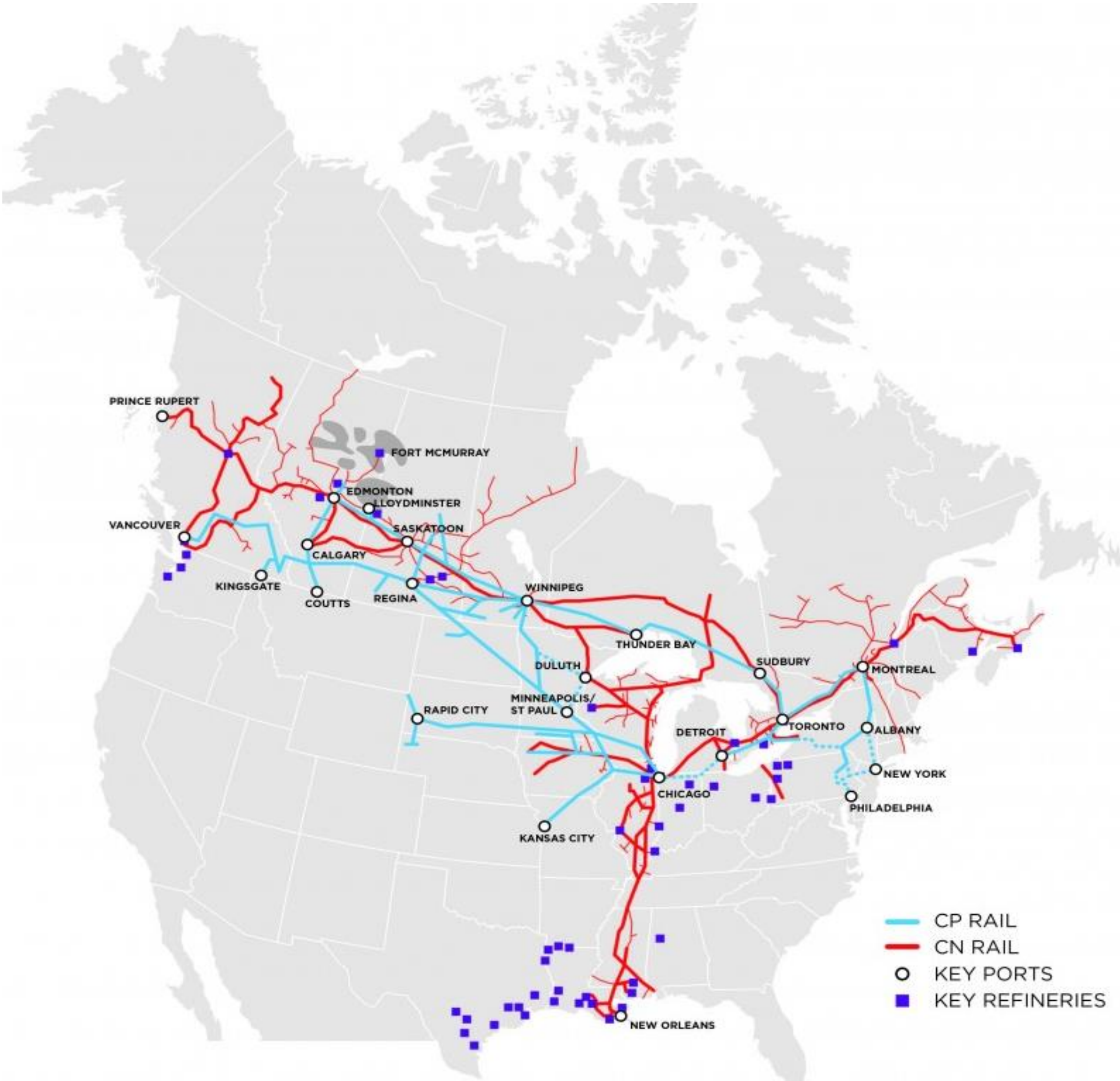
Rapid growth in Western Canadian crude oil production (especially from oil sands operations) has outpaced pipeline capacity and pipeline companies' expansion efforts. In recent years, rail transport of crude oil has surged as an alternative mode of transport to accommodate new supply volumes that exceed pipeline capacity.

Rail transport is expected to continue to rise due to the strict and lengthy pipeline approval process. In 2014, Western Canadian crude oil transported by rail reached 185,000 bpd, of which 140,000 bpd were transported to the US.[20] Compared to the previous year, exports of crude oil by rail increased 172 percent.

In 2014, 51 percent of crude oil exports by rail (71,000 bpd) were destined to the East Coast (PADD 1), 40 percent (56,000 bpd) to the US Gulf Coast (PADD 3) and 7 percent (10,000 bpd) to the West Coast (PADD 5). CAPP predicts that exports by rail will continue to increase, by up to 250,000 bpd of crude oil in 2016 and 600,000 bpd in 2018. Most of this growth is in response to the rejection of the Keystone XL pipeline, which encourages crude-by-rail transportation as a time-sensitive alternative. An added value of crude-by-rail is that it provides crude oil producers with the flexibility to move to different markets in response to demand, which is valuable in the current economic climate. Figure 2.4 shows the current Canadian railway network for crude oil transport, and outlines the key shipping terminals and main refining centers receiving the product.

[19] CAPP 2015 Statistics.
[20] CAPP's Crude Oil Forecast, Markets and Transportation, June 2015.

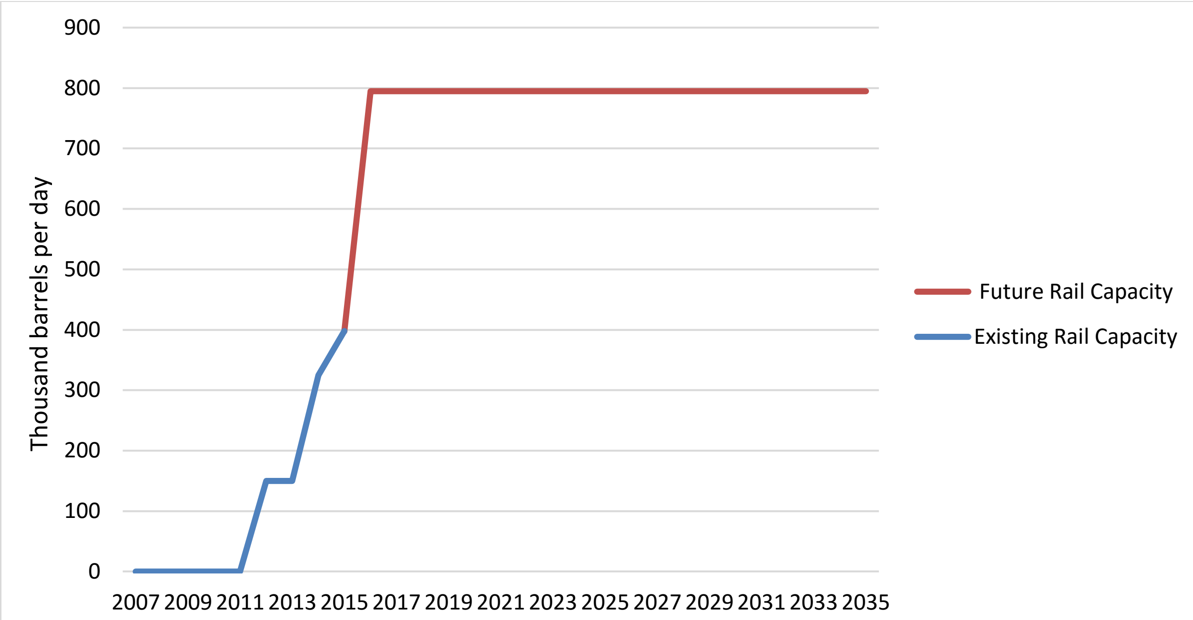
Figure 2.4: Canadian Railway Network for Crude Oil Transportation



Source: CAPP

CAPP estimates current rail loading capacity originating in Western Canada at 776,000 bpd. Most of this capacity has come online in recent years. New facilities and expansion projects were originally proposed to be in service by the end of 2015 but have been deferred with unknown timing. Figure 2.5 displays the existing and future rail capacity from Western Canada for the next 20 years. Deferred projects were not included.

Figure 2.5: Current and Proposed Rail Loading Capacity Out of Western Canada



Source: Canadian Association of Petroleum Producers

The economics of transport by rail improves with unit trains.[21] Moving oil by rail can cost between $12 and $20 per barrel, depending on distances travelled. Pipeline transportation is a lower cost alternative ranging from $5 to $13.[22] Higher rail costs favour pipeline transportation among Western Canadian producers wanting to move their products to the US Gulf Market in the least costly way.

Pipeline transportation offers higher producer netbacks, and more predictable planning compared to rail. Refiners (the final client), also favour the reliability of pipelines over rail, which can be impeded by weather and other external factors, such as competition for space with non-petroleum products. For these reasons, as new pipeline infrastructure becomes available, the crude volumes transported by rail could be reduced.

[21] According to CAPP, unit trains are a group of rail cars (typically between 70 and 120 railcars) that move as a solid train from one location directly to another and carry only crude oil. By contrast, manifest cars are individual cars or small groups of cars, and need to wait for additional cars to gather together before being shipped to a destination. When refineries consider crude by rail projects, Unit Train capability is a top priority. Not only does a refiner achieve economies of scale for project design, but cycle time efficiency is the highest with unit trains. Refineries can still have economically viable projects with manifest car designs; however, at the expense of higher operating costs or lower throughputs. Not only will cycle times increase with manifest car operations, but demurrage and non-ratable receipts will occur as cars bunch and get delayed.

[22] CAPP's Transporting Crude Oil by Rail in Canada, March 2014.

Chapter 3: Refining Sector in the US Gulf Coast

About 45 percent of the US refining sector is concentrated along the US Gulf Coast. The PADD 3 region, which includes the six states of Texas, Louisiana, Mississippi, Alabama, Arkansas and New Mexico, is the largest fuel producing region in the world, with 56 refineries and a combined atmospheric crude distillation capacity of 9.3 MMbpd.[1] Texas has the largest capacity along the Gulf Coast, with 27 operating refineries and a combined atmospheric crude distillation capacity of approximately 5.2 MMbpd, followed by Louisiana with 3.3 MMbpd of atmospheric crude distillation capacity distributed among 19 refineries. Alabama, Mississippi, New Mexico and Arkansas have a little over 0.6 MMbpd of combined refining capacity, distributed between 10 refining plants.[2]

Figure 3.1 displays the regional refinery capacity distribution in the US Petroleum Administration for Defense Districts. As of January 2014, there were 133 operating refineries with atmospheric crude oil distillation units in the US, totalling a capacity of 18.9 million barrels per stream day. Heavy capacity denotes refineries with coking capacity; light capacity denotes refineries without coking capacity.

The US Gulf Coast region, displayed in red, contains 56 operating refineries with atmospheric crude distillation units, with a total capacity of 9.7 million barrels per stream day. Around 81 percent of the US Gulf Coast refining capacity is allocated at facilities with coking capacity, representing the largest coking capacity share among PADD regions.

Coking units can upgrade heavy crude oil into higher-valued lighter products, such as distillate and gasoline. Heavy crude oil feedstocks are ideal for refineries with coking units, making the US Gulf Coast an ideal market for Canadian heavy crude oil and diluted bitumen. In order to accommodate the recent increase in US light crude oil production from shale plays, recent expansions in the US Gulf Coast have increased atmospheric crude distillation capacity by 625,000 barrels per stream day since 2010, while coking capacity has only increased 160,000 barrels per stream day over the last five years.[3]

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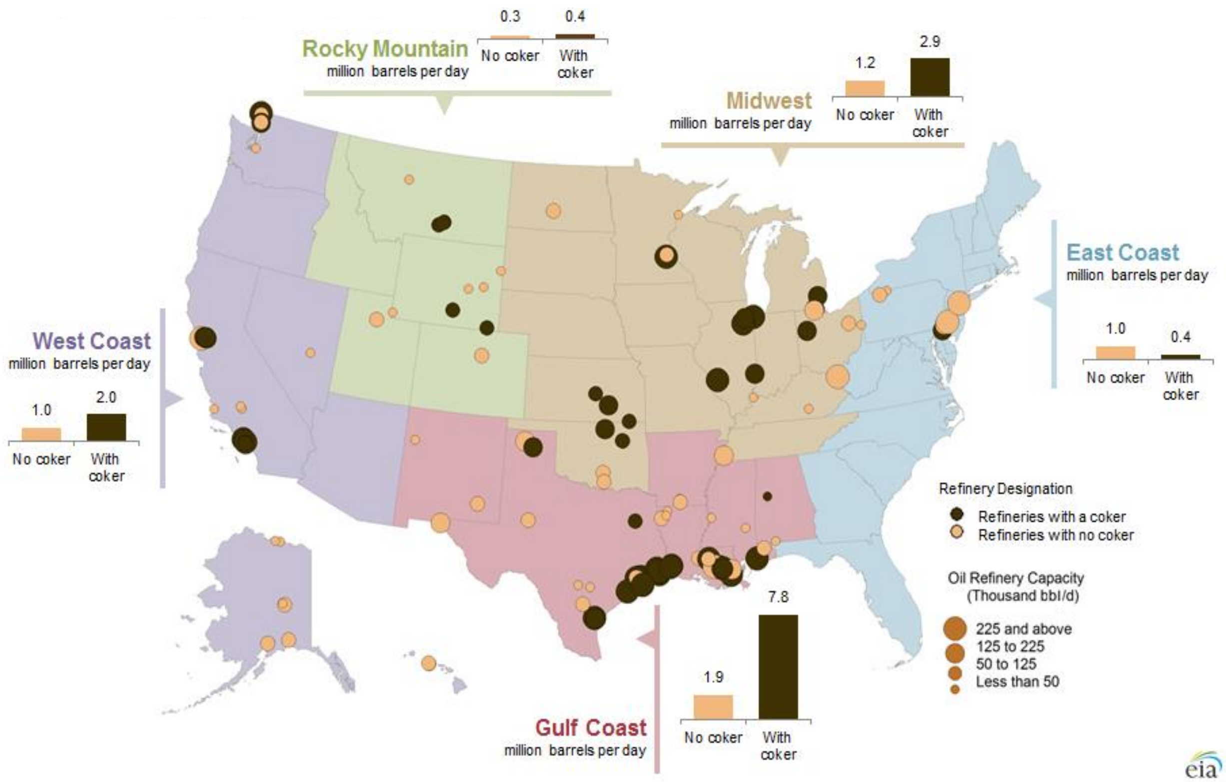
[1] EIA PADD 3 Number and Capacity of Petroleum Refineries, 2015 https://www.eia.gov/dnav/pet/pet_pnp_cap1_dcu_R30_a.htm .

[2] EIA State specific number and capacity of petroleum refineries, 2015 http://www.eia.gov/dnav/pet/pet_pnp_cap1_dcu_STX_a.htm .

[3] EIA News Release, Regional refinery trends evolve to accommodate increased domestic crude oil production, 2015 http://www.eia.gov/todayinenergy/detail.cfm?id=19591.

Figure 3.1: US Regional Refinery Capacity (With or Without Coking Units)



Source: US Energy Information Administration

Over the years, refineries in the US Gulf Coast have grown in capacity. In 1982, EIA data shows that there were 97 refineries operating with 7.3 MMbpd of operating crude distillation capacity. Over the decades, the average capacity of operating refineries in the PADD 3 region has more than doubled while the aggregate capacity has grown only 20 percent. With an average capacity of approximately 200,000 bpd in 2014, refineries in the US Gulf Coast are the largest in the US.

Integrated major oil companies and international operators comprise about 51 percent of the total refining capacity in PADD 3, while the remaining 49 percent is made up of independent refiners. Usually integrated companies and international firms operate the largest refineries.[4] Table 3.1 provides a list of refineries and their capacities in Texas and the Louisiana Gulf Coast, as of 2015. All Canadian exports to the US Gulf Coast are transported to these regions specifically.

Some of these Gulf Coast refineries retain heavy crude supply arrangements or joint ventures with various companies or countries. For example, the Port Arthur refinery in Texas operated by Motiva with a capacity of 610,000 bpd is partnered with Shell/Saudi Aramco in a joint venture agreement.[5]

[4] Hart Energy's Refining Unconventional Oil, 2012.
[5] IHS Energy, Future Markets for Canadian Oil Sands, 2013.

Table 3.1: US Gulf Coast Operable Refinery Capacity, 2015 (barrels per calendar day)

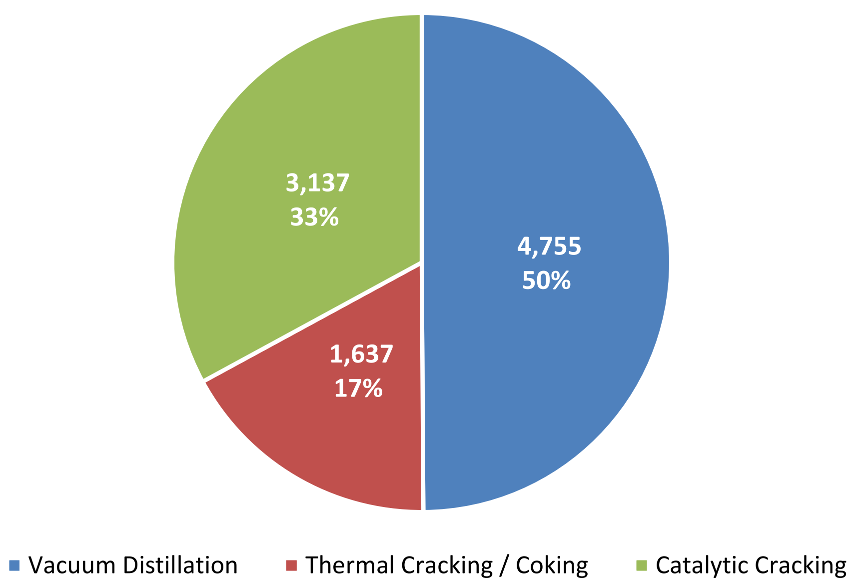
Refiner	Refinery	State	Capacity
Louisiana Gulf Coast Refining District			
Alon Refining Krotz Springs Inc	Krotz Springs	LA	80,000
Calcasieu Refining Co	Lake Charles	LA	80,000
Chalmette Refining LLC	Chalmette	LA	192,500
Chevron USA Inc	Pascagoula	MS	330,000
Citgo Petroleum Corp	Lake Charles	LA	427,800
ExxonMobil Refining & Supply Co	Baton Rouge	LA	502,500
Marathon Petroleum Company LLC	Garyville	LA	522,000
Motiva Enterprises LLC	Convent	LA	235,000
Motiva Enterprises LLC	Norco	LA	238,000
Phillips 66 Company	Belle Chasse	LA	247,000
Phillips 66 Company	Westlake	LA	260,000
Placid Refining Co	Port Allen	LA	75,000
Shell Chemical LP	Saraland	AL	80,000
Shell Oil Products US	St. Rose	LA	45,000
Valero Refining New Orleans LLC	Norco	LA	215,000
Valero Energy Corp	Meraux	LA	125,000
Subtotal			3,654,800
Texas Gulf Coast Refining District			
Citgo Refining & Chemical Inc	Corpus Christi	TX	157,500
Deer Park Refining LTD Partnership	Deer Park	TX	316,600
ExxonMobil Refining & Supply Co	Baytown	TX	560,500
ExxonMobil Refining & Supply Co	Beaumont	TX	344,600
Flint Hills Resources LP	Corpus Christi	TX	290,000
Houston Refining LP	Houston	TX	263,776
Kinder Morgan Crude & Condensate	Galena Park	TX	42,000
Marathon Petroleum Company LLC	Galveston Bay	TX	451,000
Marathon Petroleum Company LLC	Texas City	TX	84,000
Motiva Enterprises LLC	Port Arthur	TX	603,000
Pasadena Refining Systems Inc	Pasadena	TX	100,000
Phillips 66 Company	Sweeny	TX	247,000
Premcor Refining Group Inc	Port Arthur	TX	335,000
Total Petrochemicals Inc	Port Arthur	TX	225,500
Valero Refining Co Texas LP	Corpus Christi	TX	205,000
Valero Refining Co Texas LP	Houston	TX	100,000
Valero Refining Co Texas LP	Texas City	TX	225,000
Subtotal			4,550,476
Total US Gulf Coast Capacity (Texas and Louisiana regions)			**8,205,276**
Total US Capacity			17,967,088
Gulf Coast Share of US Refinery Capacity			46 percent

Source: EIA, 2014 Annual Refinery Report, Table 3

Figure 3.2 shows the US Gulf Coast refining capacity distribution, depending on the refinery configuration. About 50 percent of the total capacity is provided by Vacuum Distillation Refineries, while approximately 33 percent uses catalytic cracking as the main conversion process of the plant. Roughly 17 percent of the total US Gulf Coast refining capacity comes from thermal cracking conversion units, catered towards heavy crude oil, such as Western Canadian.

With a significant capacity to process heavy, high sulphur crude oil and new transportation infrastructure including pipelines and railway, Gulf Coast refineries have become a favored destination for Canadian production. Supplies of Western Canadian heavy crude oil to the US Gulf Coast are expected to increase, since heavy crude oil refining capacity in the US Midwest is not expected to significantly increase.

Figure 3.2: 2015 PADD 3 Refining Capacity – Conversion Technologies (thousand barrels per day)



Source: EIA, 2015 statistics

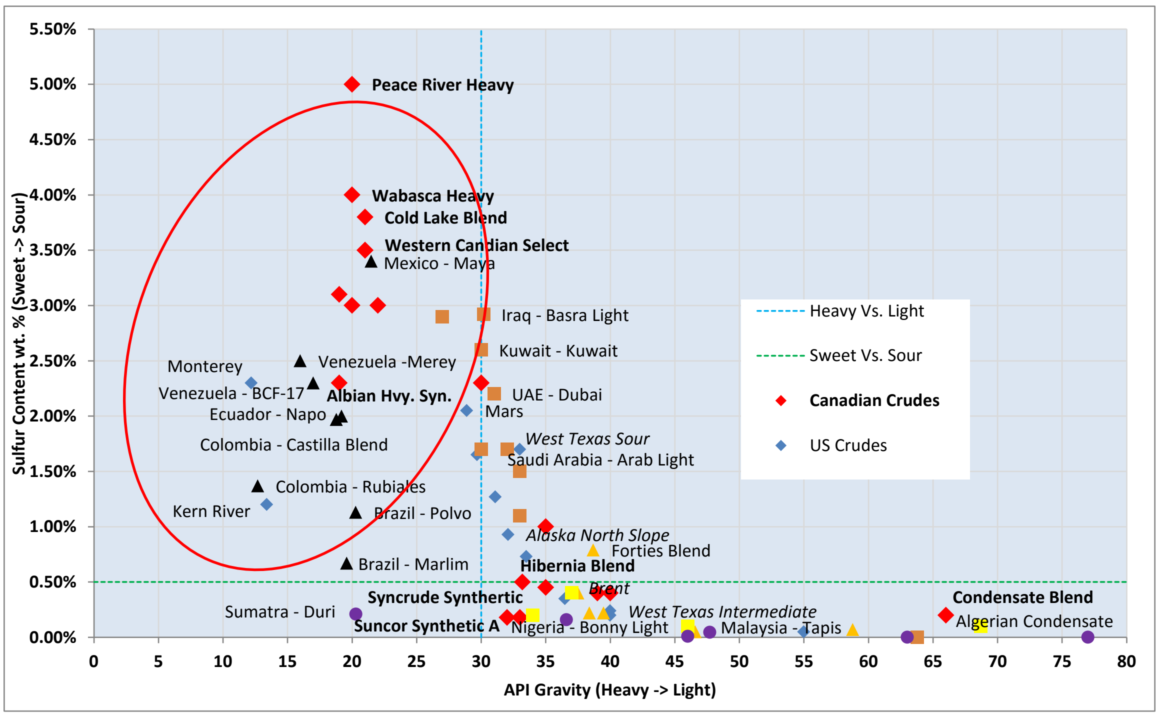
Heavy Crude Refining Capacity in the US Gulf Coast

Most of the US heavy crude processing is located in the Gulf Coast. Refining capacity in PADD 3 has large secondary conversion capacity including hydrocrackers, coking units, and desulfurization units. These units enable the processing of heavy, high sulphur (sour) crude oils like Mexican Maya, Venezuelan Merey and Western Canadian Heavy, which typically sell at a discount to light, low sulphur (sweet) crudes like Brent and Louisiana Light Sweet. Contrary to the West Coast, East Coast refineries have less secondary conversion capacity, and in general they process crude oil with lower sulphur content and a lighter density. This lighter, lower sulphur crude oil commands a premium price on world markets.

The price difference between a barrel of light sweet oil and a barrel of heavy sour oil is referred as the light-heavy price discount. Refining heavy sour grades requires more complex refining operations, such as the large secondary conversion units in the Gulf.

Two of the most important physical crude qualities of crude oil streams are density (as measured by API gravity) and sulphur content. Figure 3.3 illustrates those characteristics for various crudes from around the world (including various pricing benchmarks) and places Canadian crudes in the context of crude oil quality. It becomes very clear that Western Canadian crudes measure high in sulphur content and low on gravity, and have similar characteristics than Mexican, Venezuelan, Colombian and Brazilian crude streams used as pricing benchmarks. All of these crudes, including Western Canadian Select, are usually traded with a quality discount.

Figure 3.3: Densities and Sulphur Content of Crude Oils



Source: BP, EIA, Genesis Capital, Oil & Gas Journal, Pemex, Statoil

The average barrel input to the US Gulf Coast refinery ran at 31.8˚ API and had a sulphur content of 1.54 percent.[6] Historic data shows the input has grown heavier and sourer compared with 1985 data, when sulphur was at 0.85 percent and gravity at 34˚ API. This shift is due to the discounted sour and heavy crudes that increasingly became available in this region after the rise in production from Mexico and Venezuela in the 1980s and 1990s, which incentivized investment in heavy crude oil processing capacity. Investment decisions during that time have subsequently led to a pronounced increase in coking capacity in the Gulf in the past few years. These investments included several joint ventures and supply agreements between refiners and

[6] EIA PADD 3 Crude Input Quality, 2015 http://www.eia.gov/dnav/pet/pet_pnp_crq_a_EPC0_YCS_pct_a.htm.

Mexican and Venezuelan producers.[7] New and reconfigured refineries that run on the cheap heavy and sour crude oil from Mexico and Venezuela have led to a considerable market for heavy crude oil in the US Gulf Coast region. However, future growth in heavy crude oil refineries is not expected in the near future, as the area becomes flush with lower-cost light sweet crude from domestic sources.

The abundance of light crude oil from domestic sources has shifted the previous logic that imported heavy crude oil would be at a wide enough discount to light, sweet crude to fund the capital expenses and profitably operate with heavy crude oil. As a result of the shale oil revolution, light, sweet crude oil, especially those barrels priced with WTI, are at substantial discount to the millions of imported barrels of Mexican and Venezuelan crude oil.

Although the supply picture has changed dramatically over the past years, the demand side has not. The US Gulf Coast market still has a significant need for heavy, sour barrels because of its large contingent of deep conversion refineries that were built specifically to process heavy crude oil.

US Gulf Coast Heavy Crude Imports

Canadian heavy crude oil competes for market share in the US Gulf Coast with heavy crude oil from Latin American producers, mainly Mexico, Venezuela, Brazil and Ecuador. Mexico and Venezuela are the main heavy crude oil exporters into the US Gulf Coast, accounting for over 45 percent of total crude oil imports to the US Gulf Coast (an average of 1.5 MMbpd out of the total 3.2 MMbpd imported to Gulf Coast refineries in 2015).

Figure 3.4 displays US Gulf Coast historical heavy crude oil imports. Mexican heavy imports, which accounted for 54 percent of total heavy crude imports with approximately 1.5 MMbpd, have decreased significantly over the last 10 years, to about 0.6 MMbpd in 2015 (29 percent of the heavy imports). Similarly, Venezuelan heavy crude oil imports have decreased from about 1 MMbpd in 2005 to 0.8 MMbpd in 2015.

According to EIA statistics,[8] Mexican total crude oil production has fallen by nearly 1 MMbpd since 2004, with most of this drop due to declining heavy crude production. Venezuelan total oil production is down over 700,000 bpd from its peak in the 1990s. In both cases this is due to insufficient upstream investment. In the case of Venezuela, exports have also moved away from the US market to Asia as a result of a set of Chinese government loans that carry with them a commitment of Venezuelan heavy oil supply.

To fight production declines, Mexico has recently started a reform of its oil industry, opening the Mexican oil market to foreign investment for the first time since the industry was nationalized in 1938. However, this reform is unlikely to reverse the country's output decline for several years.

[7] IHS CERA. North America's Heavy crude future essay, 2015.
[8] EIA Mexico's Key Energy Statistics, 2015 https://www.eia.gov/beta/international/country.cfm?iso=MEX.

Additionally, Mexico's exports of heavy crude oil to Asia are also increasing.[9] In Venezuela, investment is lapsing and there are no signs of reform.

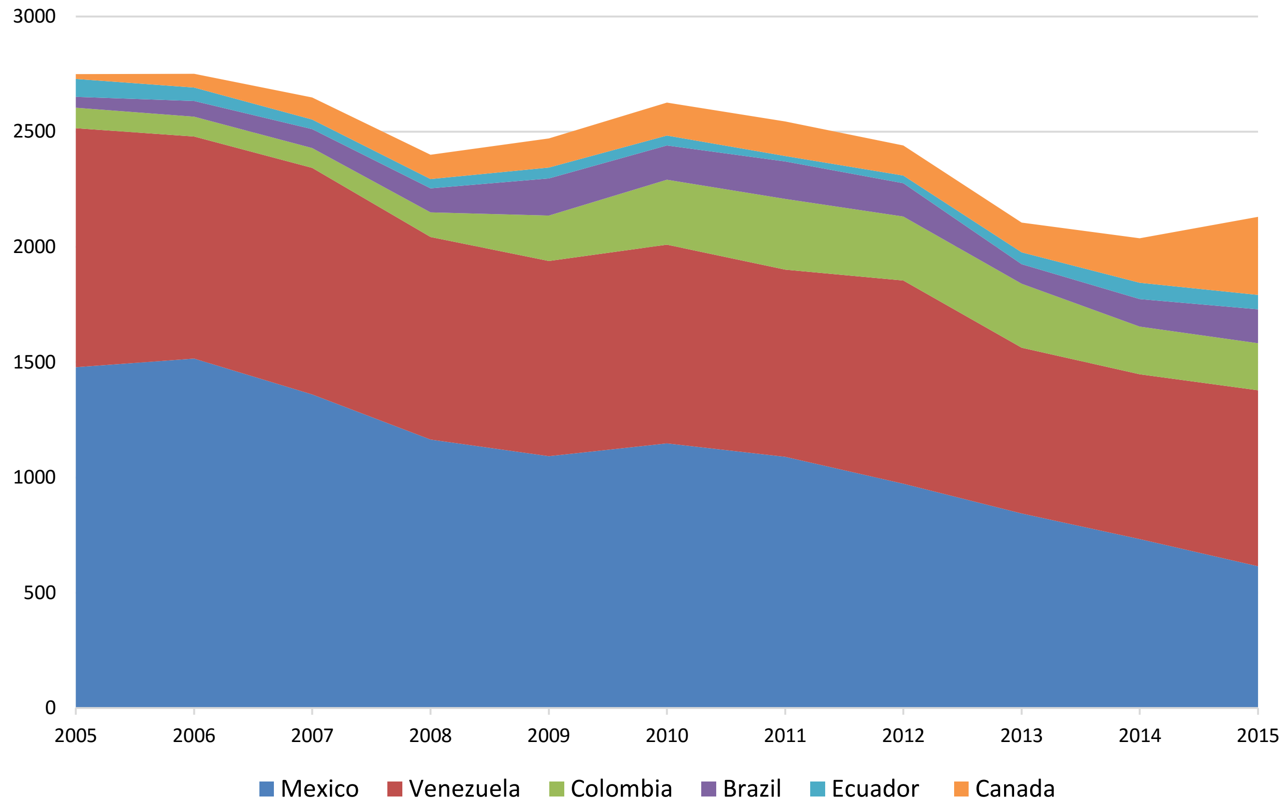
Colombia, Brazil and Ecuador's heavy crude oil production has increased over the last 10 years, as well as their exports to the US Gulf Coast. Although their export volumes to the US Gulf Coast are not as significant (averaging approximately 200,000 bpd for Colombia, 150,000 bpd for Brazil and 65,000 bpd for Ecuador in 2015), they have become reliable and steady exporters to the US Gulf Coast. However, production growth in Latin America is expected to be surpassed by their main competitor: Canada.

Since Canadian oil sands-derived bitumen blends have a similar quality to heavy Venezuelan and Mexican Maya blends, they are a natural fit for the US Gulf Coast heavy crude refineries. Both Western Canadian heavy crude producers and Gulf Coast refiners find a mutual benefit in securing an efficient supply infrastructure between the neighboring countries, especially as Latin American heavy crude becomes less available.

In the last couple of years heavy Canadian imports to the Gulf have increased from about 130,000 bpd in 2013 to 340,000 bpd in 2015[10]. This is a result of the Seaway pipeline reversal and the completion of the TransCanada Gulf Coast pipeline in 2014, which has permitted Canadian heavy barrels to reach Gulf refiners by pipeline as an alternative to rail, reducing transportation costs.

[9] IEA News Release, Mexican crude oil shipments to Europe and Asia are rising as U.S. imports fall, 2015 http://www.eia.gov/todayinenergy/detail.cfm?id=24112.
[10] IEA PADD 3 Imports by Country of Origin, 2015 https://www.eia.gov/dnav/pet/pet_move_impcp_a2_r30_epc0_ip0_mbblpd_a.htm.

Figure 3.4: US Gulf Coast Heavy Crude Imports (thousand barrels per day)



Source: EIA PADD 3 imports by country of origin, 2015

The decline in Latin American heavy crude availability and the increase in coking capacity in the US Gulf Coast creates an opportunity for Canadian producers to establish new market share without having to push out Latin American barrels.

Latin American heavy imports are expected to continue its flow to the Gulf, as many contractual agreements are and will be in place for the foreseeable future. The CITGO heavy crude refineries in Corpus Christi, Texas and Lake Charles, Louisiana, are subsidiaries of Petróleos de Venezuela S.A. (PDVSA) and are likely to continue to import Venezuelan crude. The Petróleos Mexicanos (PEMEX)/Shell joint venture refinery in Deer Park, Texas, will also continue to import Mayan heavy crude.[11] The one change in this prediction would come if PDVSA sold its CITGO refineries. This could alter the landscape for Venezuelan imports and open the market for additional Canadian supply.

In recent years, higher domestic production of light, tight crude oil has led to a reduction in crude oil imports all around the US. This has affected mostly light imports coming from Africa (light-sweet) and the Middle East. Also, Gulf Coast imports of medium crude oil have also fallen because

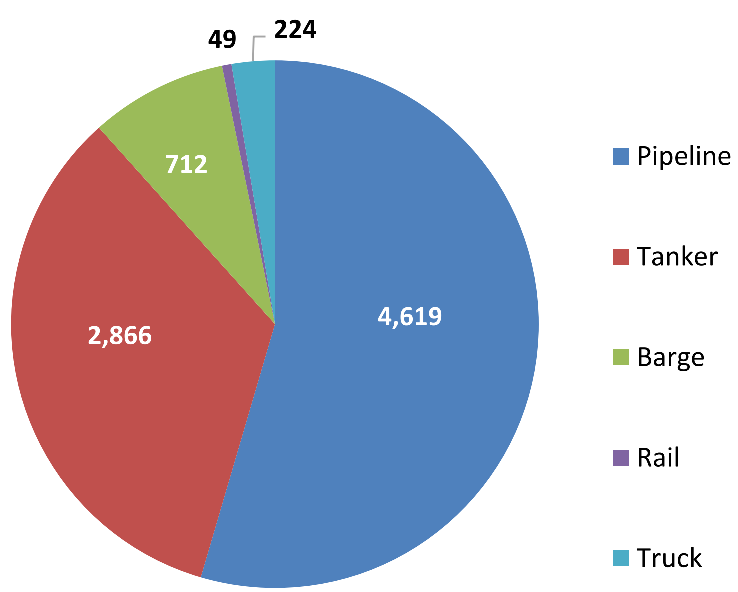
[11] IHS Energy, North America's Heavy Crude Future, 2015.

of increased production from the Eagle Ford, Bakken and Permian regions. From 2010 to 2014, net imports into the US Gulf Coast have fallen by 2.3 MMbpd, according to the EIA.[12]

US Gulf Coast Inbound and Outbound Pipeline and Rail Capacity

PADD 3 crude supplied to refineries comes from the production of local onshore and offshore sources, waterborne imports from producing nations around the globe and transfers from other PADD regions. About 55 percent of refinery receipts in the US Gulf Coast are transported by pipeline from domestic production, other PADD regions or Canadian imports. A little less than 43 percent comes from waterborne imports (34 percent from tanker and 8 percent from barge). Around 3 percent of total refinery receipts in the US Gulf Coast are delivered by truck and 1 percent by rail. Figure 3.5 displays the crude oil volumes delivered to US Gulf Coast refiners, distributed according to their transportation method.

Figure 3.5: 2014 US Gulf Coast Refinery Receipts by Method of Transportation (thousand barrels per day)



Source: EIA, 2014

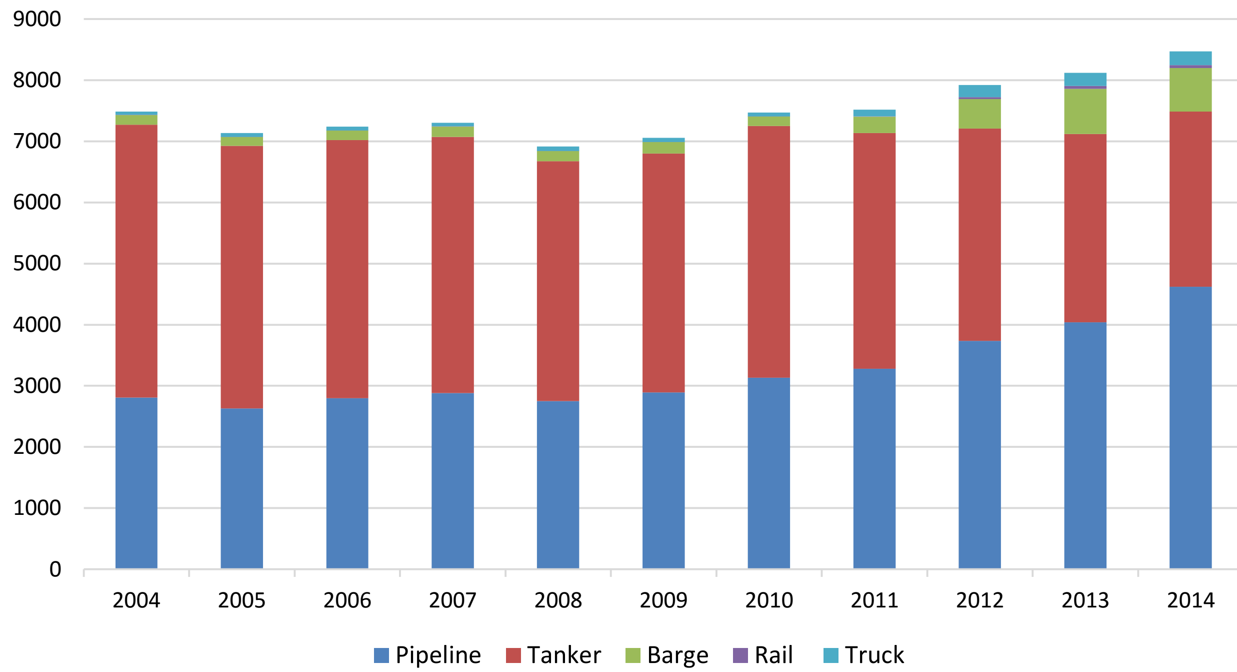
Figure 3.6 shows the historical US Gulf Coast refinery receipts by method of transportation over the past 10 years. Pipeline transportation to PADD 3 has increased considerably over the last five years, mostly due to the increase in domestic production, but also as a consequence of the implementation of pipeline projects to transport Canadian crude from Alberta to the Gulf. Waterborne imports ("tanker" in Figure 3.6) have decreased after the US shale revolution that has flooded the market with light, sweet oil from tight formations. As tanker receipts decrease,

[12] EIA News Release, Regional refinery trends evolve to accommodate increased domestic crude oil production, 2015 http://www.eia.gov/todayinenergy/detail.cfm?id=19591.

barge receipts rise considerably. It is assumed that barge-transported volumes come from domestic light, tight production.

Despite growth over the last couple of years in North America, oil-by-rail is not a significant mode of transportation to the US Gulf Coast. Volumes of crude oil receipts transported by truck account for four times more volume than rail transported crude oil.

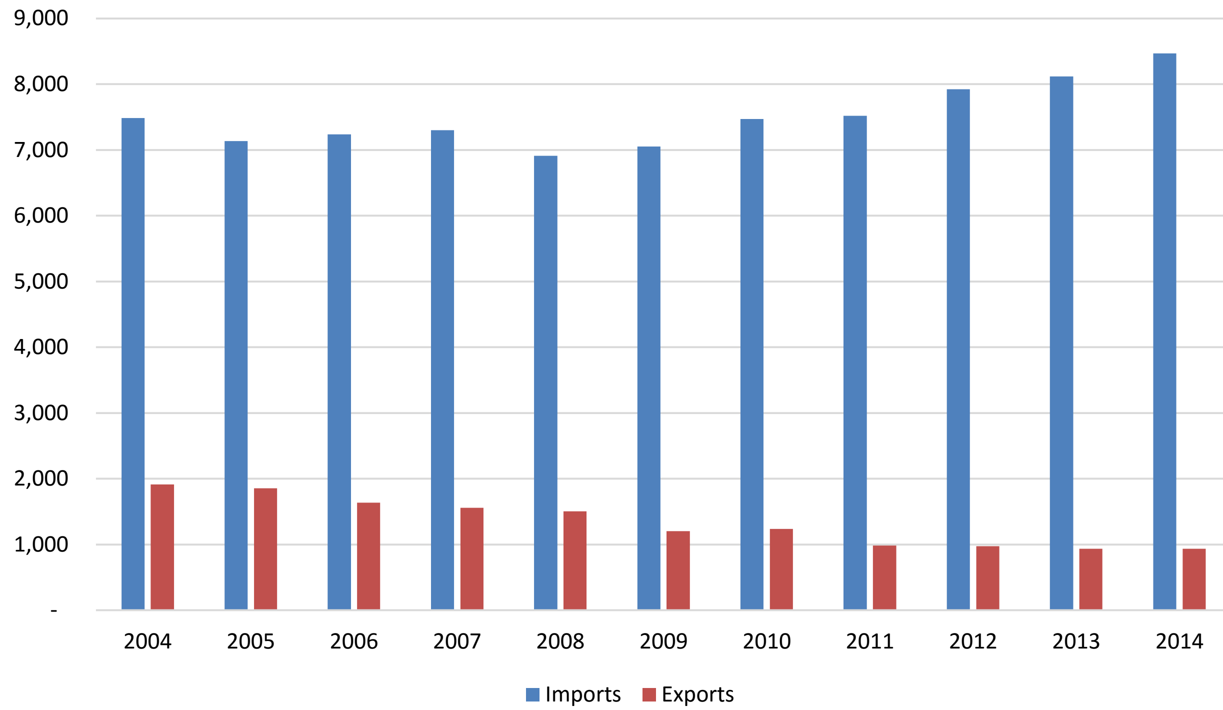
Figure 3.6: US Gulf Coast Historical Refinery Receipts by Transportation Method (thousand barrels per day)



Source: EIA, 2014

The disposition of crude within and from PADD 3 includes refinery runs and transfers to other PADD regions. PADD 3 historical in and out transportation is displayed in Figure 3.7. Imports to PADD 3 (domestic or international) are considerably larger than exports from the US Gulf Coast region (to other PADD regions, since the export ban was still active). Over the last few years, inputs to the region have increased, while outputs from PADD 3 have decreases. This might change in the future as a result of lifting the US export ban.

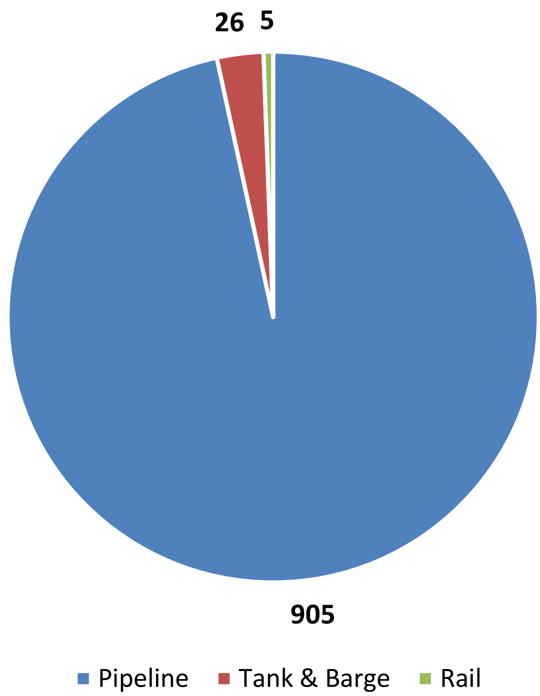
Figure 3.7: PADD 3 Historical In and Out Movements of Crude Oil (thousand barrels per day)



Source: EIA, 2014

Crude oil movements from the US Gulf Coast to other PADD regions are performed mostly by pipeline, as shown in Figure 3.8 (905,000 bpd average in 2014). The primary recipient of these crude oil volumes is PADD 2, in the Midwest. US Midwest refineries have a considerable light crude oil demand for blending with Canadian bitumen. This demand seems to be covered using light, tight oil from Texan reservoirs that have been flooding the US Gulf Coast market. About 26,000 bpd of crude oil output from the Gulf is transported by tanker or barge and only 5,000 bpd leave the US Gulf coast by rail.

Figure 3.8: Crude Oil Movements from PADD 3 to Other PADDs by Transportation Method, 2014 (thousand barrels per day)



Source: EIA, 2014

Roughly 1 MMbpd of crude oil moves from PADD 3 to PADD 2, which holds approximately 21 percent of the total US refining capacity. In comparison, crude oil movements from PADD 3 to PADD 2 averaged 1.8 MMbpd by 2005. Over the last 10 years, crude oil movement from the US Gulf Coast has decreased considerably. This trend goes conjointly with the US shale revolution that increased domestic light crude oil production drastically in both PADD 2 and 3.

Chapter 4: Forecast of Canadian Exports to the US Gulf Coast

Forecast of Net Available Crude Exports Out of Western Canada

Canadian oil reserves are abundant, with an estimated remaining oil reserve of 171 billion barrels as of early 2016. Approximately 90 percent of these are bitumen resources located in the Alberta oil sands. The remaining 10 percent is attributed to conventional oil reservoirs, located across Canada, but dominated by reservoirs in the Western Canadian Sedimentary Basin (WCSB) and the East Coast offshore.

Current Canadian oil production is approximately 3.9 MMbpd.[1] About 63 percent of the total production (2.4 MMbpd) is Alberta bitumen from the oil sands (upgraded or diluted), while heavy crude oil produced using conventional methods accounts for more than 10 percent of the total (0.4 MMbpd). The remaining 1.1 MMbpd is light conventional crude oil and condensate produced across Canada. About 94 percent of total Canadian crude oil is produced in Alberta and shipped to the US.[2]

Canada is the world's fifth largest crude oil producer and prime crude oil exporter to the US. In 2014, Canadian crude oil accounted for almost 40 percent of US imports (2.9 MMbpd out of 7.3 MMbpd total).[3] Even today, where increasing levels of US domestic crude oil production have decreased US foreign imports by almost 2.8 MMbpd in the last 10 years, Canadian exports to the US still continue to increase.

Canadian crude oil production is expected to continue growing over the next 20 years, but at a slower pace than previously anticipated. In the uncertain global price environment, companies are continuously evaluating their development plans and have adjusted their growth projections to more conservative numbers.

Most operating and under construction projects in the oil sands, whose development stages widen after 2020, will continue to operate. However, future projects and additional growth are surrounded by uncertainty. In contrast, conventional crude oil production has proved more sensitive to fluctuations in oil market prices. In its latest forecast, shown in Figure 4.1, CAPP reports operating and in construction volumes and predicted growth volumes. Total production is expected to grow from 3.9 MMbpd in 2015 to 5.3 MMbpd in 2030, almost 1.1 MMbpd less than CAPP's 2014 forecast.[4] Growth in oil sands production is consistent until 2020, the year when all projects in construction come online. Additional growth after 2020 will depend on global

[1] As of December 2015, according to the National Energy Board.

[2] NEB, Estimated Production of Canadian Crude Oil and Equivalent, 2015 https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/stmtdprdctn-eng.html.

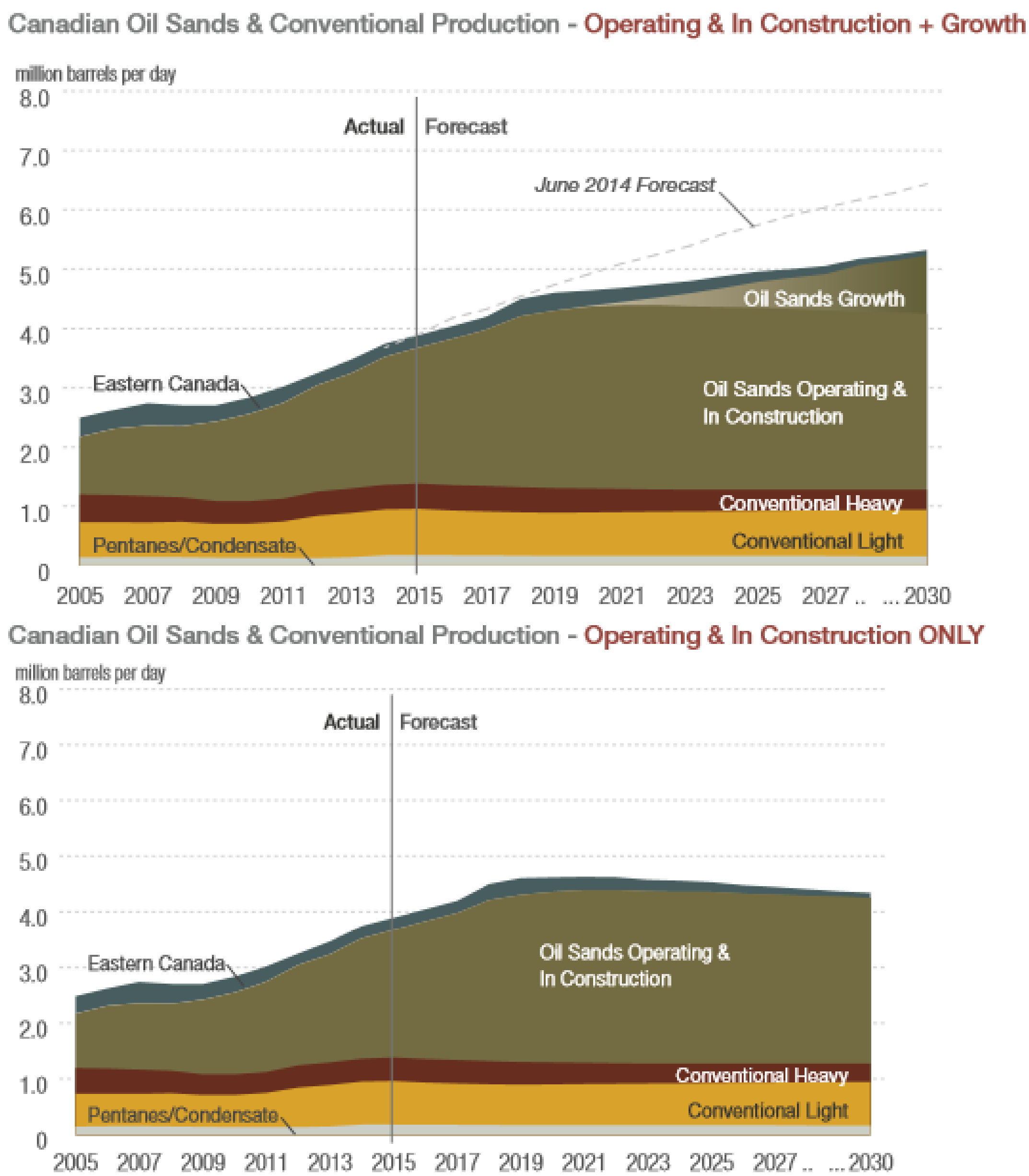
[3] EIA, US Imports by Country of Origin, 2015 https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbblpd_a.htm.

[4] CAPP's Crude Oil Forecast, Markets & Transportation, June 2015

oil market dynamics as well as timely development of infrastructure to obtain access to attractive markets.

Conventional production in Western Canada (conventional heavy and condensates) is expected to decline slightly throughout the next 15 years, falling from about 1.4 MMbpd in 2015 to 1.2 MMbpd in 2030. CAPP also forecasts oil sands production to grow from 2.2 MMbpd produced in 2014 to approximately 4 MMbpd in 2030.

Figure 4.1: Canadian Total Crude Oil Production Forecast Considering a) Operating and Under Construction Volumes + Growth, and b) Operating and Under Construction Volumes Exclusively



Source: CAPP Crude Oil Forecast, Markets and Transportation, 2015

Canadian crude exports to the US Gulf Coast consist mostly of heavy crude oil –including diluted bitumen – produced in Western Canada and shipped from Hardisty, Alberta. In order to forecast the net available volumes of heavy crude oil produced in Western Canada and available for export, CERI separately assessed the conventional heavy crude oil production in the provinces of Saskatchewan and Alberta, and the oil sands bitumen production located in the Alberta oil sands regions. Additionally, domestic demand for heavy crude oil has to be assessed and taken into account in order to estimate the final available volumes more accurately.

Conventional crude oil production in Western Canada comes exclusively from Saskatchewan and Alberta. Over 40 percent of production from these provinces is heavy crude oil, an average of 420,000 bpd. Saskatchewan is the most prolific heavy producer, with a 70 percent share, while Alberta accounts for 30 percent of that total. Although heavy crude oil production has experienced continuous growth over the last five years in both provinces, a slow decline is expected to start in 2016 as a consequence of depleting reservoirs and declining investment as a result of fallen oil prices. Overall conventional heavy oil production is expected to decrease from 320,000 bpd in 2015 to about 200,000 bpd by 2035.[5]

Oil sands are extracted using two main recovery methods: surface mining and in situ techniques, such as Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD). About 54 percent of the current oil sands production is produced using in situ techniques (1.2 MMbpd out of the 2.3 MMbpd of bitumen produced in 2015). Most of the mined bitumen produced in the oil sands is upgraded and converted to synthetic crude oil,[6] while most of the in situ produced bitumen is diluted in order to meet pipeline specifications before shipping it to a refinery.[7]

The forecasted growth in oil sands production is comprised of further development from phases of the oil sands projects that are either already operating or in construction as well as new projects. Oil sands mining and in situ production is expected to continue its growth over the next five years. After 2020, mining and in situ trends are expected to experience a shift. In situ production will continue to grow, while mining production is expected to decline slightly due to the life cycle of operating mines.

CERI’s methodology for projecting bitumen and SCO production volumes remains unchanged from past reports. Projections are based on the summation of existing and new projects, with a variety of assumptions pertaining to the project schedule and delays, technology, and state of development. The method by which projects are delayed, or the rate at which production comes on-stream, is based on CERI’s understanding of oil market dynamics and specific characteristics of oil sands projects.

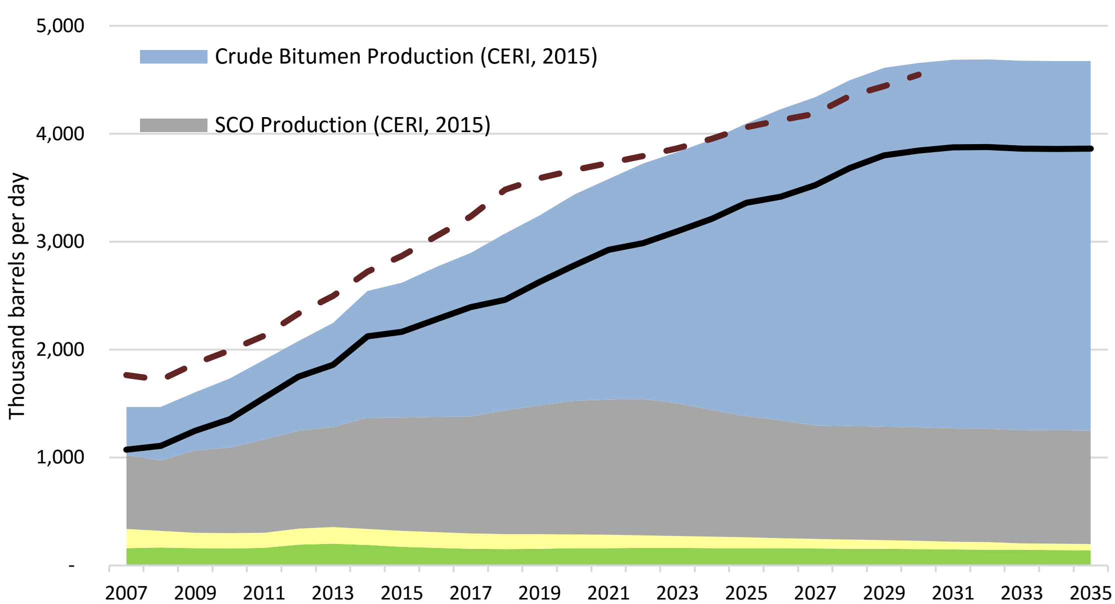
[5] CERI model calculations, 2015.
[6] With the exception of Imperial’s Kearl Mining project, which does not have an affiliated upgrader to transform bitumen into synthetic crude oil.
[7] With the exception of Nexen’s Long Lake project, the only in situ operation coupled with upgrading facilities.

Figure 4.2 displays CERI's 2015[8] production forecast for heavy conventional crude oil from Saskatchewan and Alberta in green and yellow, respectively. Oil sands upgraded crude oil production is displayed in grey. Since most mined bitumen is upgraded, the grey area offers a good proxy to the growth in surface mining production. Along with mined production, synthetic crude oil volumes are expected to start declining after 2020, from around 1.3 MMbpd in 2021 to approximately 1 MMbpd in 2035.

In situ production, as previously mentioned, is mostly diluted and commercialized as such. Figure 4.2 shows the forecasted diluted bitumen production in blue. Most of the growth in heavy crude oil production in Western Canada comes from in situ bitumen production. Diluted bitumen volumes are expected to increase to 3.4 MMbpd in 2035, from 1.2 MMbpd in 2015. This is due to the fact that the economics of mining and upgrading are less attractive compared to in situ over the projection period.

Overall, Western Canadian heavy crude oil production is expected to grow from 2.6 MMbpd in 2015 to 4.7 MMbpd in 2035, more than a 2 MMbpd increase over the next twenty years. Recent low crude oil prices have affected long-term projections, but its effect on near-term projections has been limited. Oil sands producers are unlikely to lower production from currently producing projects or delay projects that are already in construction. CERI's forecast predicts production growth post-2020, but at a slower pace than CAPP's forecast, displayed in Figure 4.2 as the dashed line.

Figure 4.2: Western Canadian Heavy Crude Oil Production and Net Available Exports Forecast



Source: CERI, 2015

[8] For more details on how production forecasts were generated, see CERI Study No. 150 for conventional oil and CERI Study No. 152 for oil sands.

The black line in Figure 4.2 displays the net available heavy crude oil imports, after discounting for the domestic refinery demand for heavy Canadian crude oil from Western Canada. Canadian refineries use oil from domestic and foreign sources, depending on their location. Western Canada refineries rely mostly on domestically sourced heavy crude oil, while refineries in Eastern Canada historically receive foreign crude oil.

In recent years, some Canadian refineries have transitioned from offshore imports to Western Canadian feedstocks, increasing the domestic demand for Western Canadian crude oil. According to Statistics Canada, between 2013 and 2014 domestic crude oil received by Canadian refineries increased by 10 percent, while imported crude oil fell 15 percent.[9] Domestic crude oil has become more attractive to refiners due to discounted prices compared to foreign crude oil.

The displacement of crude imports by Western Canadian oil occurred mostly in Ontario and Quebec refineries, thanks to the development of rail offloading facilities in these eastern refineries. This trend is expected to continue as potential pipeline projects that connect Canada from coast to coast are being proposed. Additionally, refining capacity in Western Canada is expected to increase by 150,000 bpd with the North West Redwater Partnership refinery in Alberta, whose phase 1 (at 50,000 bpd) is expected to start producing diesel by 2018.

There are some key uncertainties associated with the net available heavy crude oil exports from Western Canada. Regulations regarding oil sands development continue to evolve and create uncertainty around the viability of future projects. Crude oil prices are expected to display a volatile behavior over the next decades, with possible price spikes in either direction that will affect production and market value in Western Canada. Technological breakthroughs could significantly affect production volume and price, as has happened in the past. All of these factors could change the Western Canadian crude oil output, as well as the oil market in general.

Canadian Heavy Exports to US PADD Regions and Other Markets

Nearly all of Canada's exports have historically been directed to the United States. As previously mentioned, Canada is the largest exporter of crude oil to the US, accounting for about 39 percent in 2014 (2.9 MMbpd of the 7.3 MMbpd of crude oil imported to the US in 2014).[10] Saudi Arabia, the second largest exporter to the US, accounted for a little more than one third of Canadian volumes (about 15 percent of the total).

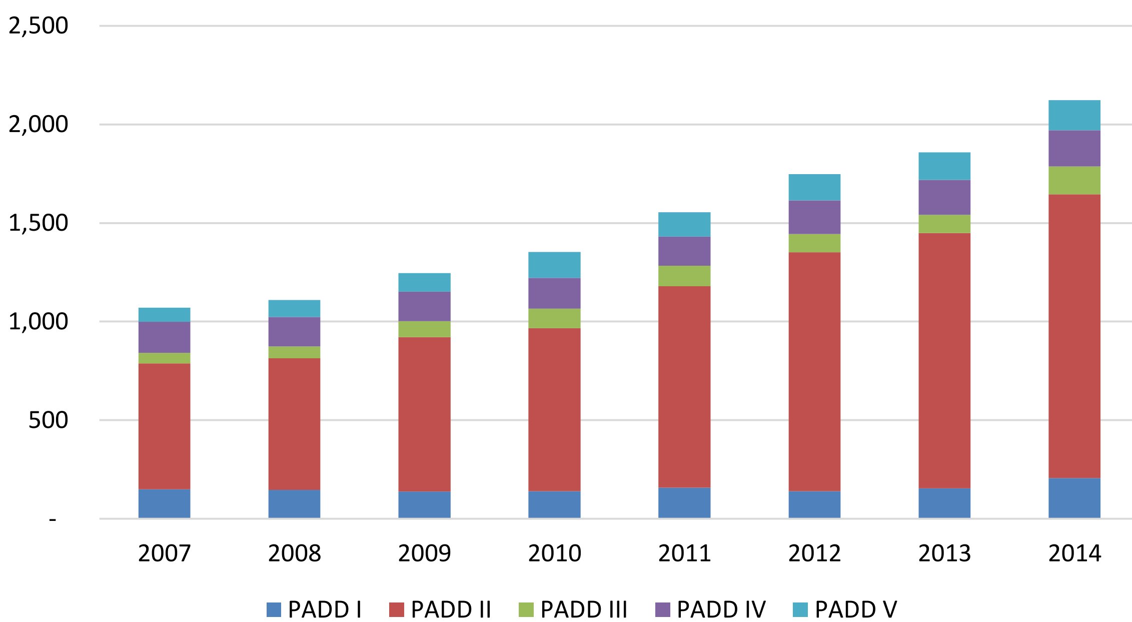
While overall US imports of crude oil have been declining since 2010, Canada is one of the few countries from which US crude oil imports are increasing. Over the past decade, US imports of Canadian crude oil have increased considerably (by 44 percent), while oil imports from the other major suppliers have decreased, displaced largely by increased domestic production.

[9] Statistics Canada Table 134-0001, Refinery Supply of Crude Oil and Equivalent http://www5.statcan.gc.ca/cansim/pick-choisir?lang=eng&p2=33&id=1340001.
[10] EIA, US Imports by Country of Origin, 2015 https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbblpd_a.htm.

Almost all of Canada's crude oil exports come from Alberta and Saskatchewan, and it is considered to be heavy crude oil. By 2014, almost 75 percent of total US imports were classified as heavy crude oil from the western provinces, with the remaining 25 percent classified as light crude oil produced in the Bakken tight reservoir in southern Saskatchewan, as well as conventional reservoirs in southern Alberta. Heavy crude oil exports have continuously increased its share as oil sands production has become the predominant growing supply in Canada.

Figure 4.3 displays the historical Western Canadian heavy crude oil exports to the US over the last eight years, including their destination. Heavy exports have grown by over 1 MMbpd in the 2007-2014 period. Most of the heavy crude exports are sent to refineries in the US Midwest (PADD 2), which have also absorbed the growth in shipments to the US. In 2015, the US Midwest imported about 1.5 MMbpd of Western Canadian heavy crude oil, accounting for over 67 percent of total Canadian heavy imports to the US (see Figure 4.4).

Figure 4.3: Canadian Heavy Crude Exports to US PADD Regions (thousand barrels per day)

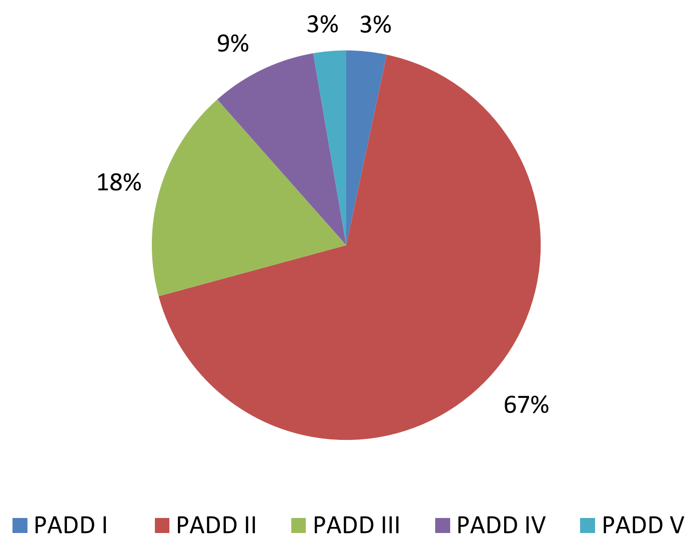


Source: EIA, CERI

Figure 4.4 displays the share of Canadian heavy crude oil imported to each US PADD region in 2015. East Coast refineries, located in PADD 1, imported a little more than 72,000 bpd of heavy crude oil, accounting for 3 percent of the total. On the US West Coast, the Rocky Mountain region (PADD 4) and the California West Coast (PADD 5) imported about 12 percent of the total Canadian heavy crude oil imports to the US. Imports to the US Gulf Coast represent 18 percent of the total, with about 383,000 bpd of western Canadian heavy crude oil reaching US Gulf refineries in 2015. Heavy crude oil imports have experienced continuous growth for each PADD region, but this growth has been steeper in the US Midwest, due to the available pipeline infrastructure between Alberta and the US Midwest.

Although the Gulf Coast refineries are best suited to handle the heavier crudes coming from western Canada, the current pipeline infrastructure allows the Gulf Coast to import less than a tenth of the crude oil that is sent to the Midwest.

Figure 4.4: 2015 Canadian Heavy Crude Exports Share between US PADD Regions



Source: NEB, CERI

Canadian crude exports to markets other than the US are not large enough to be considered in Figures 4.3 and 4.4. According to the National Energy Board, total exports to markets outside of North America accounted for about 26,000 bpd in 2015 (down from 80,000 bpd in 2014). The Board does not track which specific countries receive the shipments, but reports suggest destinations in Asia, Latin America and Europe.[11] Out of the 26,000 bpd of Canadian crude exported to other markets in 2015, 5,146 bpd was Western Canadian heavy crude oil. This represents less than half a percent of total heavy crude oil exports.

Canadian heavy crude oil producers have started taking action to diversify their market in order to support the expected production growth of oil sands. The Energy East pipeline project and the Trans Mountain pipeline expansion are expected to open access to European and Asian markets, respectively.

Although market prices and economics are key to shaping future markets for oil sands, a number of other factors can also influence western Canadian heavy oil market access. Delays on western Canadian crude oil transportation projects have started to affect market access (i.e., Keystone XL

[11] Financial Post News Release, Cenovus secures U.S. export license, as more Canadian crude heads to non-U.S. markets, 2015 http://business.financialpost.com/news/energy/cenovus-secures-u-s-export-licence-as-more-canadian-crude-heads-to-non-u-s-markets?__lsa=31b9-90e9.

project rejection). Regulatory views, local concerns, indigenous people's rights in Canada, climate change and GHG emissions management, as well as employment and economic incentives are expected to affect decision making around market access for Western Canadian heavy oil production.

Canadian Crude Oil Re-Exports off the Gulf Coast

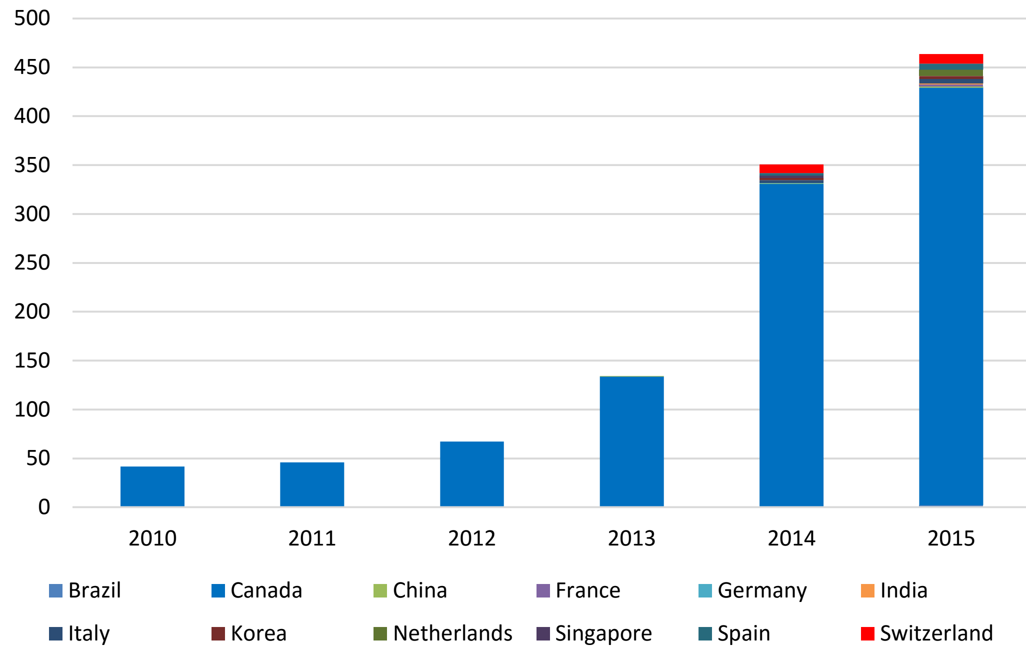
Due to legal restrictions, lifted in December 2015,[12] Canada was the only country the US was allowed to export their crude oil. As a result, most US crude exports were and still are sourced domestically and sent only to Canada. However, over the last two years, American crude exports have included modest amounts of Canadian produced barrels that are moved through the United States and then re-exported from Gulf Coast terminals to Switzerland, Spain, Italy, and Singapore.

Figure 4.5 displays US crude oil exports over the last five years, by country of destination. US crude oil exports to Canada, the only country American producers are allowed to ship, averaged 331,000 bpd in 2014, more than doubling 2013's volumes. In 2015, US exports to Canada continue increasing, achieving an average of 427,000 bpd. These barrels are mostly shipped to Canadian east coast refineries, which have an appetite for the light crude oil that has been boosting US domestic production. Most of these shipments depart from crude oil terminals on the US Gulf Coast.

Shipments of Canadian crude oil through the US Gulf Coast to other markets in Asia, Latin America and Europe only started in 2013. These recent shipments are part of the effort Canadian oil and gas companies have been making to seek new markets and reduce their dependence on US refineries, following years of growth in US crude oil production. Companies such as Suncor, BP Canada and Cenovus have secured export licenses from the US as well as shipping crude oil from Canadian coasts to European and Asian Markets.[13]

[12] Wall Street Journal, Congressional Leaders Agree to Lift 40-Year Ban on Oil Exports, 2015 http://www.wsj.com/articles/congressional-leaders-agree-to-lift-40-year-ban-on-oil-exports-1450242995.
[13] Globe and Mail, Canadian crude shipments from U.S. Gulf hitting global markets, 2015 http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/canadian-crude-shipments-from-us-gulf-hitting-global-markets/article24037483/.

**Figure 4.5: US Crude Oil Exports by Destination
(thousand barrels per day)**



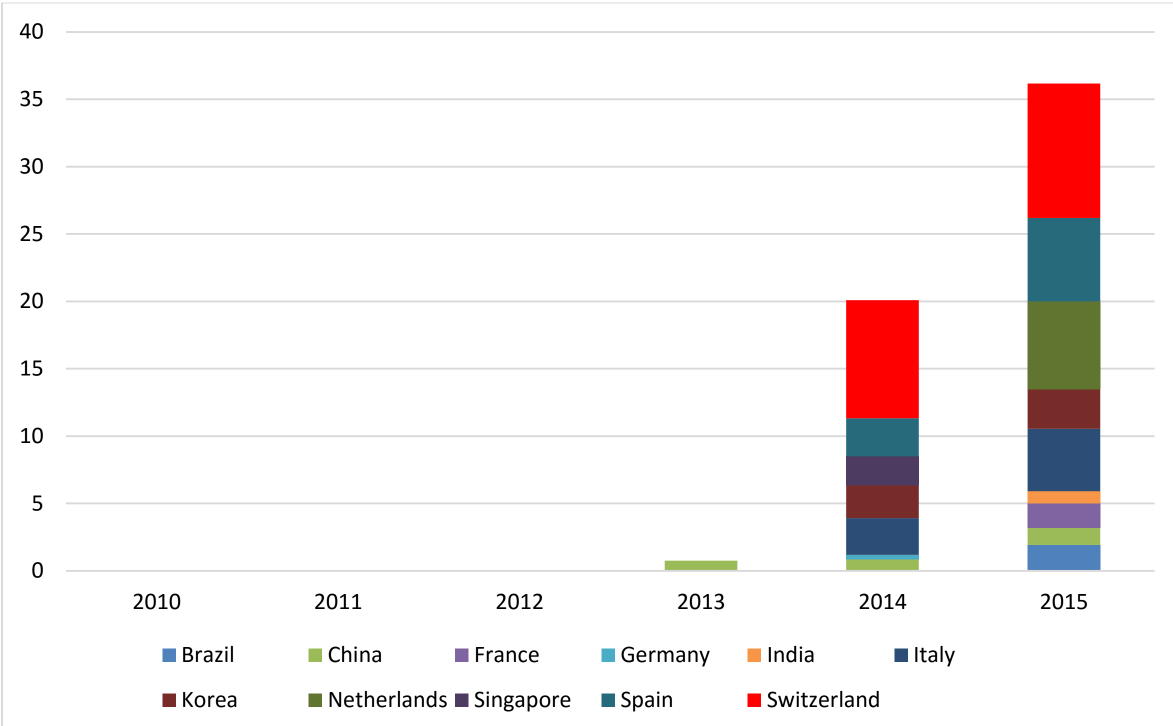
Source: EIA, 2015[14]

Current Canadian re-exports shipped through the US Gulf Coast are mostly Western Canadian heavy crude oil quantities that were not committed in the US refining market and not commingled with US produced barrels. Figure 4.6 offers a more detailed snapshot of the recipients of Canadian crude oil in Asia, Latin America and Europe and the volumes shipped. In 2015, over 36,000 bpd were shipped to refineries outside North America. Around 10,000 bpd of these were shipped to Switzerland, turning it into the largest recipient of Canadian produced crude oil after the US.

It is unclear if this recent trend of Canadian re-exports from the Gulf Coast will continue, and if so, for how long. Several proposed Canadian pipeline projects may provide producers with alternative routes for delivering crude to markets beyond North America, but the timing of this is still uncertain. The recent lift in the US export ban is also expected to affect Canadian re-exports.

[14] EIA, US Crude Oil Exports by Destination, 2015
https://www.eia.gov/dnav/pet/pet_move_expc_a_EPC0_EEX_mbblpd_m.htm.

Figure 4.6: Canadian Crude Oil Re-Exports by Destination (thousand barrels per day)



Source: EIA, 2015[15]

CERI predicts that as Canadian crude oil barrels become more available in the US Gulf Coast, global exports will continue to increase over time. If international pricing of Western Canadian heavy crude is competitive against the US discounted rate for Western Canadian Select, producers will continue to make the effort to send their product out of North America.

Forecast of Heavy Crude Exports to the US Gulf Coast

Proposed export pipeline projects to come online in 2020 will create new export outlets for Western Canadian crude oil to Asian and European markets. This would have a positive effect on the prices received by Canadian producers in the US and new markets in Europe and Asia. TransCanada's Energy East pipeline, scheduled to come online by 2020, will carry 1.1 MMbpd of Western Canadian crude from Alberta and Saskatchewan to marine terminals in Quebec and New Brunswick (shipping to European and other markets), as well as refineries in eastern Canada. Kinder Morgan's Trans Mountain Expansion (TMX) is expected to add 590,000 bpd of shipping capacity from Alberta to the West Coast by 2019, increasing potential volumes exported to Asian markets. Enbridge's Northern Gateway project, with a capacity of 525,000 bpd from Alberta to the west coast will increase Canada's export capacity to Asian markets by 2020.

[15] EIA, US Crude Oil Exports by Destination, 2015
https://www.eia.gov/dnav/pet/pet_move_expc_a_EPC0_EEX_mbblpd_m.htm

Although these major pipeline projects have faced delays in their approvals and opposition from some stakeholder groups, it is expected they will come online over the next five years. By transporting Western Canadian crude volumes to markets outside North America, these projects will decrease the available heavy crude exports to the US. The rate at which these projects will decrease net available heavy crude exports to the US will depend on the amount of heavy crude oil (excluding high API SCO) to be transported using these pipelines to international shipping terminals.

Figure 4.7 displays the forecasted potential heavy crude exports to the US, after discounting for heavy crude volumes transported to other international markets through Energy East, the Trans Mountain Expansion and Northern Gateway. In order to account for the uncertainty surrounding these transportation projects and the volumes of heavy crude oil they will take, three different scenarios with different transportation quotas are considered. The first and more conservative scenario predicts that no major coast pipeline is built and all available exports are destined to the US. The second scenario projects that only the Energy East and the Trans Mountain Expansion pipelines are carried forward.[16] Within this approach, two different transportation quotas are considered: one where 50 percent of the pipeline capacity is used to transport heavy crude oil, and the second one where 75 percent of the pipeline capacity is used to transport Western Canadian crude oil to other international markets.

The third scenario predicts that all three pipeline projects (Energy East, Trans Mountain Expansion and Northern Gateway) will come online and transport heavy crude to international markets. Both transportation quotas are considered for this scenario as well. Lines in Figure 4.7 display the potential heavy crude oil exports to the US after the different scenarios and transportation quotas are considered. Volumes being transported to Asia, Europe and other international markets are subtracted from the net available heavy crude exports out of Western Canada (if applicable) and the lines represent the potential heavy crude exports to the US.

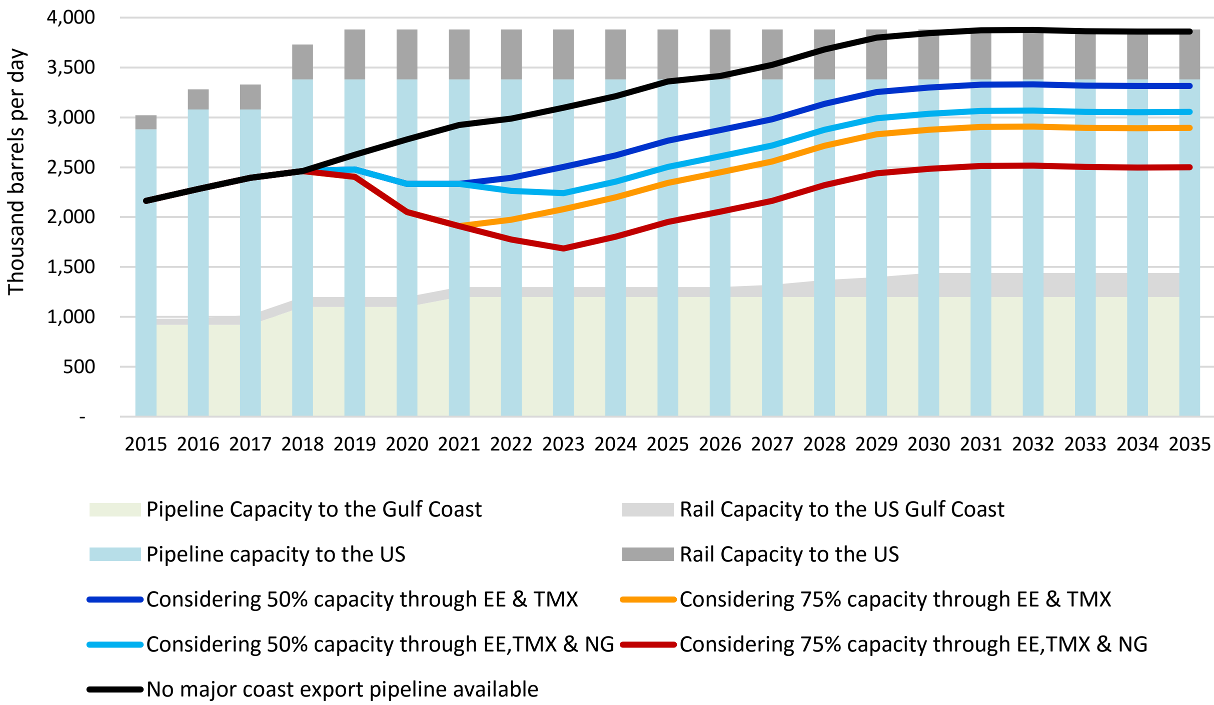
Overall, the potential heavy crude exports from Western Canada to the US vary between 2.5 MMbpd and 3.9 MMbpd by 2035. The red line (75 percent capacity, all three pipelines operating), displays the lower end of the range, while the black line (all exports to the US, no coast pipeline capacity) displays the upper end of the forecasted range of potential heavy crude exports to the US.

Columns in Figure 4.7 display the total export transportation capacity from Alberta to the US. The light blue columns represent the pipeline capacity (from both Hardisty and Edmonton) to the US, while the grey columns display the crude-by-rail capacity. It is clear that under the current production growth forecast, transportation infrastructure from Western Canada to the US seems

[16] Although Northern Gateway has been approved by the Governor Council (in June 2014), the 209 conditions and further discussions with indigenous communities are still pending and need to be resolved in order to move forward.

to be sufficient to transport the predicted potential heavy exports.[17] However, if none of the major export pipelines proposed (Energy East, Trans Mountain Expansion or Northern Gateway) come online and all heavy exports are directed to the US, transportation capacity could be heavily constrained and dependent on expansions of the railway system.

Figure 4.7: Potential Heavy Crude Exports to the US



Source: CERI

The area in green represents the pipeline transportation capacity to the US Gulf Coast, followed by the crude-by-rail capacity, displayed in light grey. The creation of pipeline infrastructure to the east and west coast of Canada, and subsequent new export outlets for Western Canadian heavy crude oil, will have a positive effect on the current transportation constraints to the US Gulf Coast. With these projects coming forward, it is expected that almost half of the total available heavy exports to the US could be directed to the US Gulf Coast Market.

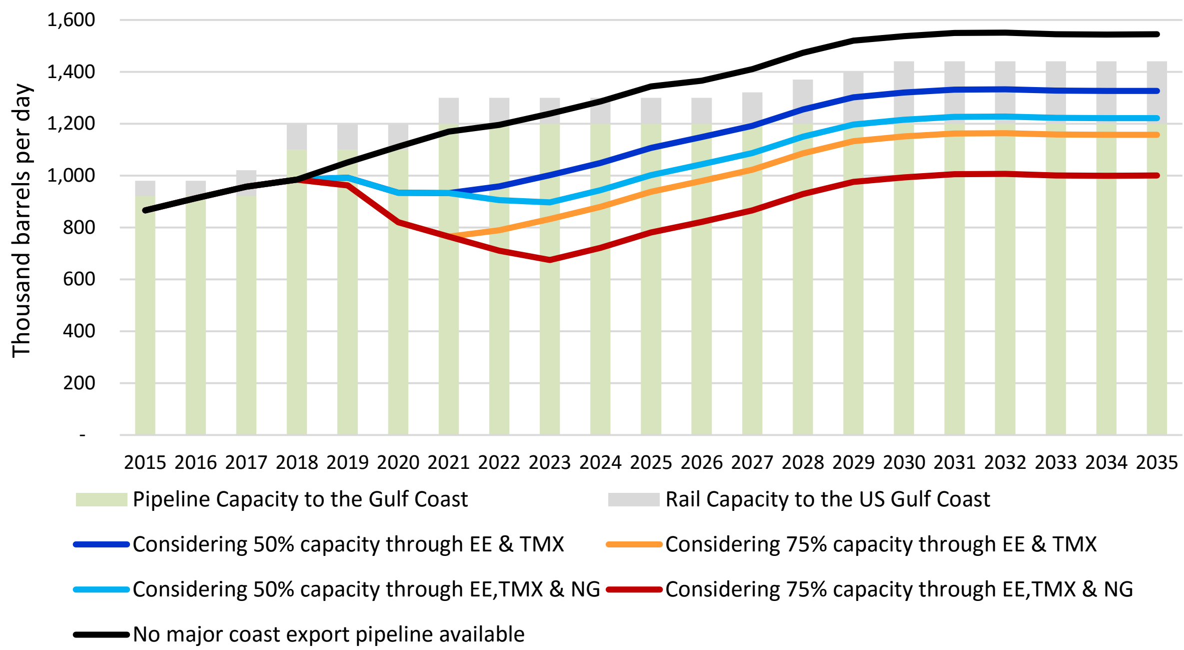
The US Midwest (PADD 2) will continue to absorb most of the Canadian heavy exports to the US. Besides having prime infrastructure connecting this area with Alberta, there are agreements in place between Canadian producers and US Midwest fuel refiners (i.e., Cenovus, Husky, and Imperial, among others, who depend on supply agreements with integrated refineries) that will

[17] Western Canadian light volumes (high quality synthetic crude oil, or SCO) are expected to be exported to international markets where it would receive more competitive prices than in the US market, which is oversupplied with domestic light tight oil. It will also supply Eastern Canadian refineries, which are configured for light feedstocks. Taking these into consideration, it is not expected to see large volumes of SCO being shipped to the US in the future.

continue to be active for the next decades. According to Hart Energy,[18] contracts with integrated refineries in the US Midwest account for approximately 1.3 MMbpd of crude oil imported to PADD 2, approximately 60 percent of the total heavy exports to the US. This leaves 40 percent of the potential exports to the US to be redirected to the US Gulf Coast.

Figure 4.8 displays the potential heavy crude exports to the US Gulf Coast (estimated as 40 percent of the total exports to the US). Lines represent the different scenarios and transportation quotas also considered for Figure 4.7. The green columns show the forecasted pipeline transportation capacity to the US Gulf Coast, while the grey columns represent the predicted crude-by-rail capacity to the Gulf Coast from either Canadian or US Midwest terminals.

Figure 4.8: Potential Heavy Crude Exports to the US Gulf Coast



Source: CERI

It is clear that the creation of pipeline infrastructure and shipping routes to international markets other than the US would favour market access of Western Canadian heavy crude oil into the US Gulf Coast. By allocating heavy production to other markets such as Asia and Europe, Canadian producers are able to reduce their overland dependence on the US market, reduce their supply to that market and overcome pipeline constraint issues to the US Gulf Coast.

[18] Hart Energy, Refining Unconventional Oil, 2012.

Chapter 5: Netbacks to Canadian Producers

In North America, Western Canadian heavy crude prices are generally attached to the price of benchmark Western Canadian Select (WCS), a blended crude oil composed mostly of bitumen blended with sweet synthetic and condensate diluents and 25 existing streams of both conventional and unconventional crude. These different crude oils are blended at the Husky terminal in Hardisty, Alberta and then diluted with sweet synthetic crude oil (upgraded bitumen) and gas condensates or naphtha in order to reduce viscosity and facilitate transport.

WCS has grown to become a benchmark crude due to its tightly controlled stream with stringent specifications, supervised by its producers (Suncor, Cenovus, Canadian Natural Resources and the former Talisman Energy). This ensure refiners receive stable, reliable and consistent heavy crude oil streams with minimal variability; important crude oil characteristics for refinery operations. WCS is a sour heavy crude oil with an API between 20.5 and 21.5, sulphur content of approximately 3.5 percent w/w and a TAN value of less than 1.

Since lighter crude is easier to process than heavy crude, WCS has traditionally been priced at a discount to US light, sweet benchmark West Texas Intermediate (WTI) at Cushing, Oklahoma. The difference between WTI and WCS is called the Heavy Oil Discount and historically has varied from $10 to $40 per barrel. The differential between heavy WCS and light WTI historically has been around $10-$15 per barrel to account for the quality difference between the two streams, but lately in the last few years, the differential grew substantially as a response to infrastructure bottlenecks.

Western Canadian Select crude oil quality is very similar to the Mayan crude oil produced in Mexico in terms of API gravity and composition. However, WCS normally trades at a discount to Maya crude due to transportation bottlenecks. This makes WCS an attractive feedstock for refineries in the US Gulf Coast, which are built to process heavy, sour crude oil such as Mayan and Venezuelan.

Given that most of the WCS supply is destined to PADD 2, the main price for Western Canadian heavy crude oil is then dictated by the refiner's value of the crude in the US Midwest. This is, in turn, dictated by a series of factors including the crude gross product worth, an indicator of the value of refined products estimated by its percentage share in the yield of the total barrel of crude, as well as the processing costs, transportation costs, refinery margins, and the availability and price of competing crudes.[1] Since the majority of heavy crude oil processed in the US Midwest is Canadian heavy crudes, the price of Canadian heavy crudes is therefore dictated by the availability of required refining capacity in the area for such crudes.

[1] Hart Energy, Refining Unconventional Oil, 2012

In recent years, Canadian heavy crude volumes have exhausted the refining capacity in this market. According to the EIA, US Midwest refineries ran at 94 percent capacity in 2015, and have become saturated, as evidenced by the high level of inventories from growing domestic production and imports of heavy crude oil from Western Canada.[2] If this persists, Canadian heavy crudes will need to be sold at steeper discounts in order to remain competitive in the US Midwest market. Potential Canadian heavy crude discounts due to saturation supports the current debate of opening new markets.

Over the past two years, which includes the slide in global crude oil prices, the price differential between West Texas Intermediate and Western Canadian Select has dropped as a consequence of new pipeline capacity from Hardisty to the US opening up. In 2014, the discount averaged about $18.50/bbl; by the end of 2015 it had decreased to US$13.25/bbl.[3]

In order to assess the possible netbacks that Western Canadian producers could receive for their heavy crude oil in the US Gulf Coast, 2015 market prices and differentials are used. Transportation costs through existing pipeline and rail routes are considered, as well as proposed alternative routes, such as pipeline and barge combinations and tanker shipments involving the Energy East project and the Trans Mountain pipeline expansion in the West Coast.

Although key for this analysis, it is important to note the WCS price per barrel at Hardisty, Alberta is not reflective of all heavy crude oil produced in Western Canada for two reasons. First, various oil sands producers have upgrading operations which turn crude bitumen to synthetic crude oil (SCO). The average price in 2015 was $45.31/bbl,[4] more competitive when compared to a WTI price of $47.33/bbl.[5] Second, various oil sands producers have downstream refining assets which means that their equity produced bitumen crudes are transferred to their refining facilities and refined into petroleum products. Therefore, not all heavy crude oil production in Western Canada should be assumed to receive WCS prices, although the majority of the production does receive it.

The primary focus of this analysis is to determine the competitive advantage that Canadian producers could receive from transporting and commercializing WCS in the US Gulf Coast, instead of current destination markets in the US Midwest, guided by the price per barrel received at Hardisty, Alberta. In order to determine this, the WCS average 2015 price per barrel of $30.43 is used, as reported by the Government of Alberta.[6]

Another part of the analysis is the prices of crude, which are of similar quality to WCS crude in the US Gulf Coast, the target market in question. For the US Gulf Coast, most heavy crudes are

[2] EIA PADD 2 Refinery Utilization and Capacity, 2015 https://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r20_m.htm.
[3] All figures presented in the report are in US dollars.
[4] EIA, F.O.B. Costs of Imported Crude Oil for Selected Crude Streams, 2015 https://www.eia.gov/dnav/pet/pet_move_imc2_k_m.htm .
[5] Government of Alberta, Energy Prices 2015 http://economicdashboard.albertacanada.com/EnergyPrice .
[6] Ibid.

waterborne imported heavy sour crudes from Mexico (Mayan, with 21.5 API and 3.4 percent sulphur) and Venezuela (Merey, with 16 API and 2.5 percent sulphur – see Figure 3.3). An average median landed cost of $45.95/bbl in 2015 is used, as reported by the US Energy Information Agency.[7] A quality adjustment of $2.50/bbl was estimated for WCS crude oil when compared to US Gulf Coast heavy imports.[8]

The difference between WCS at Hardisty and the estimated WCS equivalent price at the US Gulf Coast (after a quality adjustment) is defined as the gross possible price uplift to oil sands producers. According to CERI's analysis, the WCS price uplift at the US Gulf Coast market is approximately $13.02/bbl on average in 2015. This value represents Western Canadian heavy crude oil prices at Hardisty versus their potential price at the US Gulf Coast. This, in turn, is the maximum possible uplift to WCS prices but also the maximum transportation cost that a Canadian heavy producer will be willing to pay in order to be indifferent between selling to the US Midwest or the US Gulf Coast refiners.

Netting crude transportation costs (given for the different transportation options analyzed) from the maximum price uplift yields the estimated netback price Western Canadian producers receive in Alberta for selling its heavy crude oil at the US Gulf Coast. These netbacks are quantified for existing pipeline, rail and future pipeline/tanker combinations.

Netbacks for Canadian Producers Using Existing Pipeline Routes

The best case scenario for Canadian producers is to transport its crude oil through pipeline directly from Hardisty, Alberta to the US Gulf Coast. CERI used the Houston refinery hub as the assumed destination within the Gulf Coast, in order to offer a consistent analysis. Relevant costs and assumptions are laid out in Table 5.1.

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[7] EIA, F.O.B. Costs of Imported Crude Oil for Selected Crude Streams, 2015
https://www.eia.gov/dnav/pet/pet_move_imc2_k_m.htm

[8] Quality adjustment was estimated comparing Mexican Mayan and WCS Total Acid Number (TAN) and Sulphur parameters.

Table 5.1: Netbacks for WCS Transported by Existing Pipeline (Committed Tolls) from Hardisty, AB to the US Gulf Coast

Pipeline toll Hardisty to Texas Gulf Coast (10-year committed toll) US$/bbl	$7.79
Pipeline load terminal fee US$/bbl	$1.00
Total Pipeline Transportation Cost – Hardisty to Houston / bbl	**$8.79**
Western Canadian Select @ Hardisty	$30.43
Median USGC Heavy Sour Crude landed	$45.95
USGC Heavy Sour Crude - Dilbit Quality Adjustment	$2.5
Estimated WCS Price Uplift @USGC	**$13.02**
Netback for Canadian producers at the USGC	**$4.23**

*All values are 2015 averages
Source: CERI

Pipeline transportation costs from Hardisty, Alberta to US Gulf Coast refiners in the Houston, Texas area in 2015 are reported by the Canadian Association of Petroleum Producers.[9] For this analysis, CERI used an average price point between Enbridge and Keystone fees for 10-year and 20-year committed tolls. Also, CERI estimates that there would be a $1/bbl terminal fee for loading crude into the pipeline at Hardisty.

Overall, if a producer has access to pipeline capacity to the USGC under a 10-year or 20-year toll commitment at a cost of $7.79/bbl and a loading fee of $1.00/bbl, then $13.02/bbl (gross possible price uplift at the US Gulf Coast) – ($7.79/bbl +$1.00/bbl) (transportation costs) = $4.23/bbl (netback @USGC) + $30.43/bbl (WCS @ Hardisty) = $34.66/bbl, which is the price the producer receives for selling its crude in the USGC (versus $30.43/bbl at Hardisty, Alberta).

Table 5.2 displays netbacks for Western Canadian producers who do not have a committed toll with the pipeline operator. Overall, producers with committed tolls signed with pipeline operators receive a competitive advantage and price per barrel when transporting their product to the US Gulf Coast Market.

[9] CAPP Crude Oil forecast, markets and transportation, June 2015

Table 5.2: Netbacks for WCS Transported by Existing Pipeline (Uncommitted Tolls) from Hardisty, AB to the US Gulf Coast

Pipeline fee Hardisty to Texas Gulf Coast (uncommitted toll) US$/bbl	$11.03
Pipeline load terminal fee US$/bbl	$1.00
Total Pipeline Transportation Cost – Hardisty to Houston / bbl (uncommitted tolls)	**$12.03**
Western Canadian Select @ Hardisty	$30.43
Median USGC Heavy Sour Crude landed	$45.95
USGC Heavy Sour Crude - Dilbit Quality Adjustment	$2.5
Estimated WCS Price Uplift @USGC	**$13.02**
Netback for Canadian producers at the USGC	**$0.99**

*All values are 2015 averages
Source: CERI

As long as the price at the US Gulf Coast minus the transportation cost exceeds the market price at Hardisty, Western Canadian producers will continue to make efforts to open market access to Gulf Coast refiners. As an example of the potential profit improvement from pipeline infrastructure to the US Gulf Coast, a project producing 100,000 bpd could improve daily profit margins by $423,000 per day, or approximately $155 million per year.

Netbacks for Canadian Producers Using Existing Rail Routes

The Western Canadian Select denomination is a given to a pipeline blend in Hardisty, Alberta. As such, it is unlikely to be moved by rail. Western Canadian heavy crude grades moving by rail are likely to be heavier than WCS and attract a discount to WCS at the Gulf Coast. In order to make the analysis consistent, CERI has not applied any discount and a WCS price is assumed at the Gulf Coast.

The various cost elements for crude-by-rail transportation from Hardisty, Alberta to refineries in the US Gulf Coast are shown in Table 5.3. CERI assumes that the rail journey from Hardisty, Alberta to Houston, Texas will be on a unit train dedicated to shipping crude with 600 barrels of crude in each rail tank car. The rail freight cost from Hardisty to Houston is estimated at $12.00/bbl. The rail tank car lease would add another $0.50/bbl at $600/month (two round trip turns/month = $300/trip divided by 600 bbl = $0.50/bbl). The rail load and unload terminal feels account for $1.50/bbl at each end of the trip. The total rail freight cost is therefore $15.50/bbl.[10]

By subtracting the rail freight from the WCS price uplift at the Gulf Coast, we obtain a netback of $(-2.48)/bbl. By transporting their heavy crude oil from Alberta to the US Gulf Coast by rail, Canadian producers could lose approximately $2.48 per barrel.

[10] RBN Energy, Canadian heavy crude oil producers can't make it up on volume. February 2016.

Table 5.3: Netbacks for WCS Transported by Rail from Hardisty, AB to the US Gulf Coast

Rail Tank Car (bbl)	600
Rail Freight Hardisty to Texas Gulf Coast (Heavy Crude) US$/bbl Unit Train	$12.00
Rail Tank Car Lease / bbl ($600/month, 2 turns)	$0.50
Rail Car Load and Unload Terminal Fee / bbl ($1.50 each)	$3.00
Total Rail Transportation Cost – Hardisty to Houston / bbl	**$15.50**
Western Canadian Select @ Hardisty	$30.43
Median USGC Heavy Sour Crude landed	$45.95
USGC Heavy Sour Crude - Dilbit Quality Adjustment	$2.5
Estimated WCS Price Uplift @USGC	**$13.02**
Netback for Canadian producers at the USGC	**$(-2.48)**

*All values are 2015 averages
Source: CERI

Netbacks for Canadian Producers Using Existing Pipeline and Barge Combined Routes

In recent years, Western Canadian heavy crude oil has been arriving to the US Gulf Coast in barges from Cushing, Oklahoma. This transportation method has offered Canadian producers an alternative to break the logistical bottlenecks associated with pipeline transportation from Cushing to the Gulf Coast. Table 5.4 displays a netback calculation for this transportation combination.

Table 5.4: Netbacks for WCS Transported by Combined Pipeline and Barge from Hardisty, AB to the US Gulf Coast

Pipeline fee Hardisty to Cushing, Oklahoma (10-year committed toll) US$/bbl	$5.73
Barge transportation from Cushing to Louisiana refineries. Heavy crude oil US$/bbl	$6.00
Total Pipeline + Barge Transportation Cost – Hardisty to Houston / bbl	**$11.73**
Western Canadian Select @ Hardisty	$30.43
Median USGC Heavy Sour Crude landed	$45.95
USGC Heavy Sour Crude - Dilbit Quality Adjustment	$2.5
Estimated WCS Price Uplift @USGC	**$13.02**
Netback for Canadian producers at the USGC	**$1.29**

*All values are 2015 averages
Source: CERI

Pipeline transportation costs from Hardisty, Alberta to Cushing, Oklahoma are reported by CAPP for the two main operators: Enbridge and TransCanada (Keystone).[11] According to Reuters,[12] shipping costs for barge transportation are about $5.00/bbl and $7.00/bbl. A median of $6.00/bbl is applied for the calculations. Adding both transportations fees, total pipeline and barge combined transportation from Hardisty to the Gulf Coast costs about $11.73/bbl.

Overall, netbacks for WCS producers shipping their product from Cushing, Oklahoma to refineries in the US Gulf Coast using inland barges is about $1.29/bbl. Although the crude-by-barge movement down the Mississippi River to the US Gulf Coast has been influenced and mirrors the crude-by-rail movement, its numbers prove to be better under current market prices for heavy crude oil. However, the rapid crude price decline has caused long-term inland crude-by-barge contract prices to rise, which could affect this transportation mode in the near future.

Netbacks for Canadian Producers Using Proposed Pipeline and Tanker Combined Routes

Proposed pipeline projects to the East and West coast offer Canadian producers the possibility to ship their product to foreign markets out of North America, such as Europe and India, but also allow for waterborne shipments to the US Gulf Coast via tanker.

Table 5.5 displays the netbacks Canadian producers could receive when shipping their product through Energy East and then tanker to the US Gulf Coast. Shipping Western Canadian heavy crude oil from Hardisty, Alberta to the Canadian east coast is expected to cost $7/bbl, about $5/bbl less than it costs to ship by rail.[13] Tanker transportation from Montreal terminals to the US Gulf Coast could cost approximately $5.50/bbl.[14] Overall, transportation costs using this route would be about $3/bbl less than crude-by-rail transportation.

[11] CAPP Crude Oil forecast, markets and transportation, June 2015

[12] Reuters News Release, Oil moving by barge as Midwest discount deepens, 2013 http://www.reuters.com/article/us-midwest-cushing-barges-idUSTRE75D6FP20110614 .

[13] Platts Energy News, TransCanada says to build Energy East cross-Canada crude pipeline, 2009 http://www.platts.com/latest-news/oil/newyork/transcanada-says-to-build-energy-east-cross-canada-21365710.

[14] U.S. Rail Transportation of Crude Oil: Background and Issues for Congress, 2014 https://www.fas.org/sgp/crs/misc/R43390.pdf .

Table 5.5: Netbacks for WCS Transported Using Proposed Energy East Pipeline and Tanker Configuration from Hardisty, AB to the US Gulf Coast

Pipeline fee Hardisty to Montreal (15-year committed toll) US$/bbl	$7.00
Tanker transportation Montreal-USGC, Heavy crude oil US$/bbl	$5.50
Total Pipeline + Tanker Transportation Cost – Hardisty to Houston / bbl	**$12.50**
Western Canadian Select @ Hardisty	$30.43
Median USGC Heavy Sour Crude landed	$45.95
USGC Heavy Sour Crude - Dilbit Quality Adjustment	$2.5
Estimated WCS Price Uplift @USGC	**$13.02**
Netback for Canadian producers at the USGC	**$0.52**

*All values are 2015 averages
Source: CERI

Table 5.6 looks at the estimated netbacks for Canadian producers aiming to ship their product to the US Gulf Coast using the proposed expansion to Kinder Morgan's Trans Mountain pipeline, TMX. Although the pipeline transportation cost from Hardisty to the Canadian West Coast is cheaper than any other pipeline route that reaches a water terminal, the costs associated with supertanker transportation from the Pacific coast to the US Gulf Coast are about $4.5/bbl more expensive than shipping from the Atlantic coast, due to the costs associated with using the Panama Canal.

Under current market conditions, the latter alternative does not hold to existing pipeline infrastructure through the US, which seems to be the most profitable route for Western Canadian producers trying to get their barrels to the US Gulf Coast. The Energy East alternative seems to produce some positive netbacks when compared to the WCS price at Hardisty. However, these proposed projects face delays in their construction and uncertainty around their completion due to public concern about environmental and social impacts.

Table 5.6: Netbacks for WCS Transported Using Trans Mountain Pipeline Expansion and Tanker Configuration from Edmonton, AB to the US Gulf Coast

Pipeline fee Edmonton to Vancouver (15-year committed toll) US$/bbl	$5.00
Tanker transportation Vancouver-USGC, Heavy crude oil US$/bbl (using the Panama Canal)	$10.00
Total Pipeline + Tanker Transportation Cost – Edmonton to Houston / bbl	**$15.00**
Western Canadian Select @ Hardisty	$30.43
Median USGC Heavy Sour Crude landed	$45.95
USGC Heavy Sour Crude - Dilbit Quality Adjustment	$2.5
Estimated WCS Price Uplift @USGC	**$13.02**
Netback for Canadian producers at the USGC	**$(-1.98)**

*All values are 2015 averages
Source: CERI

Canadian producers are left to choose between transportation alternatives to reach the US Gulf Coast market (current pipeline, rail, combined pipeline and barge, etc.). These netbacks are not only the price improvement Canadian producers could receive if they continue to expand their reach to the Gulf Coast market, but also reflect the refiner's willingness to pay for Canadian heavy crude oil versus current Latin American heavy imports.

Chapter 6: Conclusion

The collapse in oil prices worldwide is affecting the industry widely and is expected to slow the pace of upstream investment around the world – including in heavy crude oil development in Canada. Still, growth in Canadian heavy crude oil production is already largely locked in until 2020, due to new projects in construction coming on-stream. As Western Canadian crude oil production continues to grow, the leverage of these resources for economic benefits to the nation will depend on the ability to connect this growing supply with demand.

As a consequence of the rapid growth in American oil production, inland refining markets in the US Midwest (current recipients of most of the Canadian heavy imports) have been flooded with cheap, high quality tight crude oil, which leaves Canadian heavy crude oil subject to price markdowns (due to lower quality and bottlenecks in their delivery infrastructure). This situation provides Canadian producers a financial incentive to expand market access in the United States, Canada, and beyond. It also highlights the risk of overreliance on limited markets and the need for options. Overall, the potential heavy crude exports from Western Canada to the US could vary between 2.5 MMbpd and 3.9 MMbpd by 2035.

The US Gulf Coast is one of the world's most significant refining centers, and its considerable heavy oil processing capacity presents the largest opportunity for Western Canadian heavy crude oil supply, making it Canadian heavy producers' first target for market access. Shipments to the east and west coast of Canada, where heavy crude could reach offshore markets, are also being proposed as a way to reach attractive offshore markets, such as Asia and Europe. Politics (both local and international) as well as prices are expected to play a role in shaping future trade flows of Canadian heavy crude oil.

Canadian heavy crude oil competes for market share in the US Gulf Coast with heavy crude oil from Latin American producers, mainly Mexico, Venezuela, Brazil and Ecuador. Mexico and Venezuela are the main heavy crude oil importers in the US Gulf Coast, accounting for over 45 percent of total crude oil imports to the US Gulf Coast (an average of 1.5 MMbpd of the total 3.2 MMbpd imported to Gulf Coast refineries in 2015).

Over the past 10 years, heavy crude imports from Mexico and Venezuela have decreased by over 1 MMbpd as a consequence of declining reservoirs as well as insufficient upstream investment. This leaves a considerable space for Canadian producers to establish a new market share in the Gulf. If oil sands could displace most of the Mexican and Venezuelan imports, the opportunity for bitumen blends and heavy oil would be about 1.5 MMbpd. Overall, the potential heavy crude exports from Western Canada to the US Gulf Coast could vary between 1 MMbpd and 1.5 MMbpd by 2035. Lately, heavy Canadian barrels are starting to reach the Gulf in increasing volumes, both by rail and the existing Enbridge system. However, current transportation infrastructure is not enough and market access would depend on the development of more pipeline projects that integrate Western Canada with the US Gulf Coast.

Western Canadian production has always had limited access to the US Gulf Coast market, especially because the lack of infrastructure connecting Cushing, Oklahoma (the primary US hub for Western Canadian crude oil) to refineries in Texas. To support market access to the Gulf Coast, more than 1.2 MMbpd of pipeline capacity from the US Midwest to the Texas Gulf Coast has been installed. Enbridge decided to reverse the direction of flow of their Seaway Pipeline, adding 400,000 bpd of capacity from Cushing to Freeport, Texas. The TransCanada Gulf Coast Pipeline (the first stage of the now rejected Keystone XL pipeline) transports another 520,000 bpd from Oklahoma to Texas. Additional lines that improve crude oil delivery from Illinois to Cushing, Oklahoma have also been built, such as Enbridge's Flanagan South and the Southern Access pipeline.

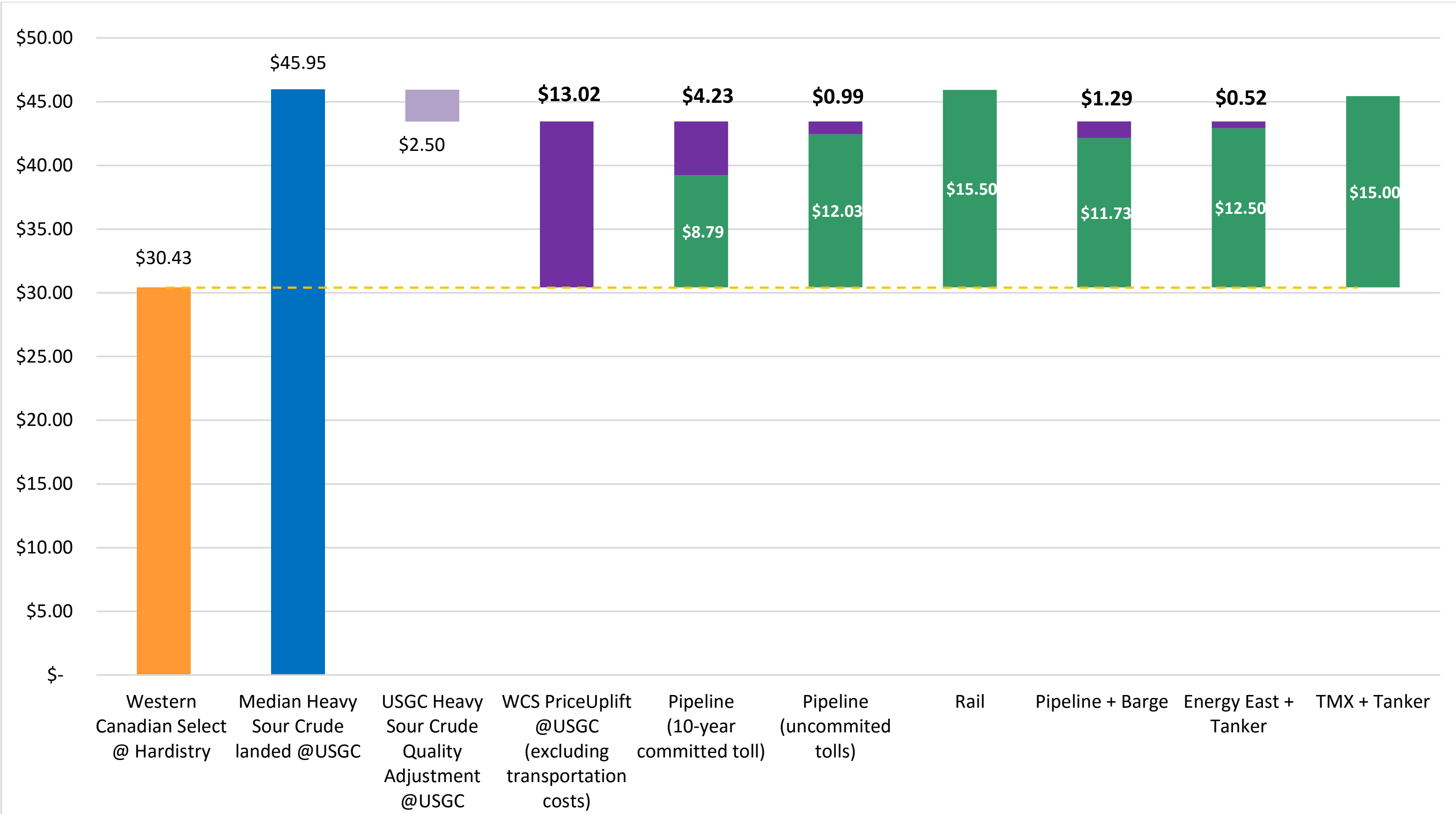
Additionally, rail shipments from Western Canada to the US Gulf Coast will continue to increase. Future rail shipping capacity is expected to increase by up to 250,000 bpd in 2016 and 600,000 bpd in 2018. Crude-by-rail shipments to the US Gulf Coast averaged 56,000 bpd in 2015. Crude-by-barge has become a frequently used transport method for producers looking for transportation alternatives from Cushing to the Gulf Coast. Depending on distances travelled, it can cost between \$12/bbl to \$20/bbl to move oil by rail or barge, compared to a total cost of \$5/bbl to \$13/bbl for pipeline transportation. Rail costs are significantly higher than pipeline, which favours pipeline transportation among Western Canadian producers wanting to get their product to the US Gulf market in a profitable way.

Overall, Western Canadian heavy crude oil production is expected to grow from 2.6 MMbpd in 2015 to 4.7 MMbpd in 2035, more than a 2 MMbpd increase over the next twenty years. Domestic demand for heavy crude oil has been continuously growing over the last few years, as Canadian refineries have transitioned from offshore imports to Western Canadian feedstocks. Domestic demand for heavy crude oil is expected to increase by approximately 50 percent and reach over 800,000 bpd by 2035. Net heavy Canadian available exports are the result of subtracting domestic demand from heavy crude oil production, and is expected to grow to volumes larger than 3.5 MMbpd over the next five years, and then slow down to about 1 MMbpd of growth from 2020 to 2035.

Although the need to expand and reach new markets for oil sands is pressing, production and pipeline projects associated with oil sands have come under increased scrutiny, contributing to delays and uncertainty. Project economics are not alone in shaping future markets for oil sands. Although not every factor will influence future markets for oil sands, some of the most prominent ones include regulatory processes, local concerns, greenhouse gas emissions (GHG) and climate change policies, as well as indigenous people's rights in Canada.

Figure 6.1 displays the overall analysis of the netbacks Canadian producers could receive for a WCS equivalent heavy crude barrel, under 2015 average market conditions. The first component of the analysis is the orange bar, which represents the average WCS price at Hardisty in 2015 (\$30.43/bbl). This is in effect reflective of the price Western Canadian heavy producers are currently receiving at Alberta.

Figure 6.1: US Gulf Coast Netback Analysis for Canadian Heavy Crude Oil Producers



Source: CERI

The blue column shows the average price heavy sour crude imports (mostly Mexican and Venezuelan) receive at the US Gulf Coast. A quality adjustment (displayed in the third column) is applied in order to better reflect the potential prices of Canadian heavy crude oil. This is, for the most part, diluted bitumen, which is assessed against Latin America imports, which are less acidic and easier to refine.

The difference between WCS at Hardisty and the estimated WCS price at the USGC (after applying the quality adjustment) is the gross possible price uplift Canadian producers could receive at the Gulf Coast. Simultaneously, this $13.02/bbl figure is the maximum amount producers would be willing to pay for transportation costs in order to receive positive netbacks at said target market.

Netbacks to Canadian producers after taking into account transportation costs are shown in purple in columns five to ten for the different modes of crude transportation analyzed. Shipping using existing pipeline routes proves to be the most profitable way for Canadian heavy crude oil to reach the US Gulf Coast market.

Producers willingness to spend more on alternate transportation and ship their product using rail, barge or tanker seems to have shifted after crude oil prices started to fall dramatically. Most Western Canadian heavy crude oil production comes from very expensive oil sands mining or in situ steam heating operations, which are designed to produce consistently for decades and are costly to shutter in a downturn. Under the current price market, crude netbacks for Heavy crude oil production sold in Western Canada are low, further justifying investment in shipping to the US Gulf Coast.