Pipelines, Trains and Trucks

Moving Rising North American Oil Production to Market

Trisha Curtis
Director of Research, Upstream and Midstream

Coauthors:

Matt Calderon
Research Analyst

Ben Montalbano
Director of Research and Operations

Lucian Pugliaresi
President

ENERGY POLICY RESEARCH FOUNDATION INC.

EPRINC Est. 1944

1031 31st Street, NW
Washington, DC 20007
202.944.3339
eprinc.org

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Pipelines, Trains and Trucks: Moving Rising North American Oil Production to Market

The North American petroleum renaissance is a remarkable achievement of technological innovation and risk taking. Improvements identifying oil and gas reserves paired with advances in drilling and production technology, such as horizontal drilling, hydraulic fracturing, and steam assisted gravity drainage (SAGD) have resulted in rapid North American oil and natural gas production growth. These primary technological advancements were first applied to natural gas plays in Texas and Pennsylvania during the mid-2000s. This spurred a surge in shale gas production that reversed long-held expectations that the U.S. would become a major importer of natural gas. The U.S. is now the world's largest producer of natural gas and on track to become a net exporter of natural gas before the end of this decade.

Continued improvements in drilling and production technology are also providing access to unconventional oil formations. Oil production in Texas and North Dakota has increased dramatically with the application of horizontal drilling and hydraulic fracturing. Advances in heavy oil production technology have helped enable steady production growth in Canada's Athabasca oil sands. Canada, which is experiencing little growth in petroleum consumption and has limited outlets for waterborne exports, continues to export rising oil sands production into the U.S. market via pipeline (and to a lesser extent by rail).

U.S. and Canadian oil production has grown by over three million barrels per day (mbd) since 2008 (figure 1). This represents the single largest contribution to global oil production growth over the past five years. These new supplies came online at the very time oil production centers abroad faced turmoil. As a result, rising North American production has limited the growth in world oil prices. Oil prices remain high by historical standards, but would likely be higher without advances made in U.S. and Canadian oil production. Incremental North American production has helped to offset production disruptions in the Middle East and Africa as well as U.S. sanctions on Iran which targeted crude oil exports.

Together, the U.S. and Canada are producing nearly 11 million barrels of oil each day. This dramatic rise in U.S. and Canadian production presents a range of logistical challenges. Historically, large volumes of domestic oil production were sourced from offshore and onshore petroleum provinces in the Gulf of Mexico region (Texas and Louisiana). Since the 1950s, the U.S. petroleum complex has been constructed around a network in which most, but not all, major refining centers were located on the coasts. The petroleum transportation network evolved into an integrated system which moved large volumes of crude oil and petroleum product into the mid-continent and northern tier from the Gulf States. Refineries on the East and West Coasts relied heavily on foreign crude oil imports (additionally supplemented by

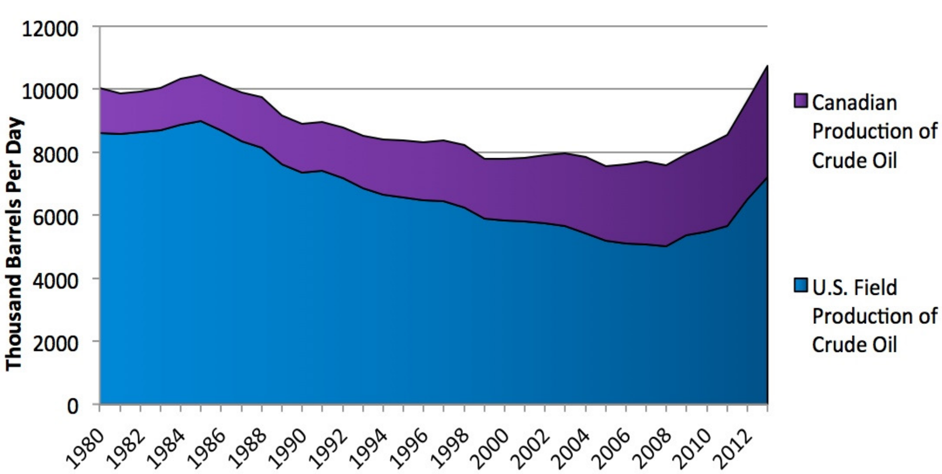
imports of refined products). As U.S. field production declined, the Gulf States became a major hub for moving larger volumes of waterborne petroleum imports (crude oil as well as petroleum products) northwards into the mid-continent and northern tier of North America. The transportation network for crude oil (as well as petroleum products) was largely a system that moved supplies from the south to the north.

Oil production growth from Canada and North Dakota combined with rapidly rising output from the Eagle Ford and Permian Basin is placing considerable stress on the North American transportation network. Major network modifications are required to move crude oil from Canada and North Dakota to processing centers on the Gulf Coast as well as the East and West Coasts. The turnaround in North American crude oil production has been so extensive that all refineries in the mid-continent (central U.S. and Canada) have backed out nearly all non-Canadian imports and are processing only U.S. and Canadian crude.

The crude oil transportation network is responding to the emergence of new oil production primarily through expanded rail connections, pipeline construction and reversals, and extensive barge traffic. Trucking is also playing an important role in moving oil to rail and pipeline terminals from the wellhead. Rail, however, has emerged as an important near and likely long-term transportation solution (for certain crude oils to certain markets, namely Bakken crude to the East and West Coasts). Rail facilities for loading and unloading crude oil can be constructed quickly and connected to an extensive rail network which reaches all major processing centers. Rail has enabled many producers to obtain flexibility in moving their production to alternative markets without requiring commitment to long-term contracts (often the case for pipelines).

Precisely how the new North American oil transportation network will evolve remains unclear. Some combination of pipeline and rail will ultimately be used to move crude oil to major processing centers. Extensive pipeline build out, identified within this report, will play a major role in moving large volumes of new crude oil supplies from the U.S. and Canada to major coastal refineries throughout North America. However, the lack of large scale greenfield pipeline development will likely limit sizeable volumes of Bakken crude oil from moving via pipeline to refineries on the West Coast and East Coast – natural markets for this oil. These supplies will utilize rail

Figure 1. U.S. and Canadian Oil Production



Source: EIA

as a major long-term transportation solution.

Pipeline bottlenecks have created discounts in the Canadian and Bakken regions. Crude oil production has risen in these regions without matching pipeline capacity to major refining centers. This has had the effect of reducing market competition and thus the pricing power of certain crude oils. These discounts are reflected in lower wellhead values which may eventually lead to production growth constraints, reduce revenues to royalty owners and limit revenues to local, state, and federal governments should they persist. Canadian crude oil discounts are currently $33 per barrel below West Texas Intermediate (WTI) prices, the benchmark for most crude oil sold at U.S. processing centers, currently at $103 per barrel. This discount reached over $40 below WTI in December of 2012 when WTI prices were at just $88 per barrel. Heavy Canadian crude oil, Western Canadian Select (WCS), was priced below $50 per barrel.

These discounts have reduced Canadian oil sands royalties by millions of dollars. EPRINC estimates that discounts on Canadian crude oil reduce royalties by nearly $1 million per day[1]. These price discounts are more sensitive in a lower oil price environment. At a crude oil price of $100 WTI, production throughout the U.S. and much of Canada is sustainable, even with sizeable discounts. In an environment of $80 WTI, however, a Canadian crude oil discount of $20 drops the price of Canadian crude oil to $60 per barrel – a cut sizeable enough to constrain production if sustained for a long period of time.

A $1 discount on North Dakota crude oil reduces state revenues by nearly $3 million per month[2]. Should these high discounts persist, project development may be delayed or impaired as reduced wellhead values (i.e. producer revenue) reduce the potential for further investment. Discounts on oil in North Dakota and throughout the U.S. have also reduced tax revenues to local, state, and federal governments.

This EPRINC report examines the scale and the scope of the task before policy makers and the U.S. petroleum industry in building out a new crude oil transportation network in response to the North American petroleum renaissance. Production growth is expanding quickly and constraints in moving crude oil to refining centers remains a challenge in both the near and long-term. While the success and sustainability of the North American petroleum renaissance rests largely on a combination of technology and geology, it will also require the capacity to overcome political and regulatory limitations. If crude oil cannot be moved to refining centers efficiently, the higher transportation costs will ultimately be reflected in lower wellhead values, potentially lost production, and ultimately lost economic opportunity to the United States and Canada. It is also worth considering whether or not actions to inhibit soundly regulated infrastructure projects, when they are primarily an objection to a resource rather than a specific project, are counterproductive to their original intent to improve environmental quality and reduce GHG emissions.

1 EPRINC estimate using calculations of pre and post payout for oil sand projects, Alberta government royalty rates, and average light heavy differentials.

2 May 2013 production with an effective tax rate of 10.8 percent

Summary of Findings

- The WTI Brent differential (a proxy measure of the difference between U.S. and world oil prices) is no longer strictly tied to the level of petroleum stocks in Cushing, OK. Producing regions north of the Cushing trading center, primarily oil produced in North Dakota, Wyoming, and Canada often face large discounts to world prices even when the WTI Brent differential is narrow. This has encouraged producers to utilize other modes of transportation, primarily rail, to move crude oil to coastal markets where they can realize higher (world) oil prices for their production.
- Much of the growth in Canadian oil production is in the form of heavy oil, with an API gravity around 22 degrees, while rising U.S. production is very light, with API gravities often higher than 40 degrees. Blending of heavy and light crude oils at coastal refining centers will be increasingly important for absorption of larger volumes of domestic and Canadian production.
- Discounts of crude oil throughout major producing centers in North America have encouraged the use of alternative modes of transportation. Despite being more costly than pipeline, crude by rail shipments have increased as producers seek to avoid saturated pipeline connection hubs in the mid-continent. Roughly 870,000 b/d of crude oil is moving via rail in the U.S. and Canada. The majority of rail activity is focused on the Bakken formation in North Dakota. Approximately 650,000 b/d of Bakken crude is exported out of the Williston Basin via rail. Barge movements along inland and coastal waterways have also increased, although future barge utilization growth may be constrained due to Jones Act limitations.
- Construction of new crude oil transportation infrastructure is constrained by both commercial and regulatory risk. Financing of pipelines require stable reserves and confidence that destination markets are profitable. Uncertainty regarding the size of the reserves of some unconventional plays, a slow and unpredictable regulatory approval process, and changing oil prices in destination markets are delaying the build out of additional pipeline infrastructure. Rail shipments offer a near term solution (loading facilities can be constructed quickly) and longer-term "optionality." Rail reaches all major U.S. refining markets and permits producers to alter destination markets quickly in response to changing crude values.
- Current pipeline projects are largely occurring through modifications and expansions of the existing pipeline network. However, the existing pipeline network does not connect the mid-continent to either East or West Coast refining centers, where the need for new pipeline capacity is most apparent.
- Wellhead values throughout North American will improve substantially if the industry addresses the entire range of network challenges, including efficient movement of crude oil to refining centers by matching crude oil quality characteristics with appropriate refining technology. For North America, the oil transportation system can generate improved value and production growth by moving Canadian oil sands to Gulf Coast refineries well equipped to process heavier crude oil, and by moving domestic light sweet crude oil to East and West Coast refining centers.
- Inhibiting the Keystone XL pipeline and other well-regulated transportation projects, in an attempt to either reduce GHG emissions or transition to alternative forms of energy, will have discernible economic, political and environmental consequences without making progress toward desired goals. The proposed pipeline provides a low cost distribution solution matching Canadian oil sands with Gulf Coast refiners who are well equipped to process heavy crude oil.

Recent Trends in U.S. and Canadian Oil Production

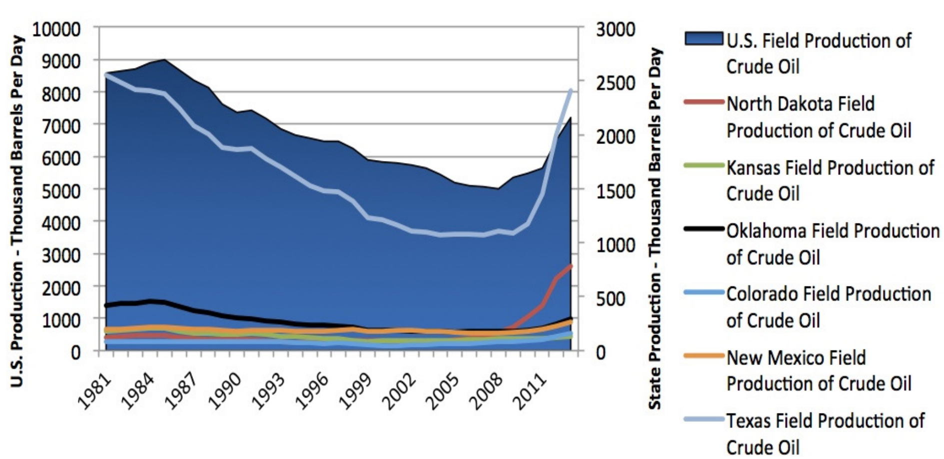
U.S. Production

After decades of decline, U.S. oil production has risen by 2 mbd since 2008, an increase of approximately 40 percent in five years. Almost all of this production growth is attributable to the application of horizontal drilling and hydraulic fracturing in the Bakken and Eagle Ford plays. The majority of this new production is light sweet crude oil. EPRINC considers this new growth to represent the beginning of the U.S. petroleum renaissance.

The most prolific shale oil plays of the petroleum renaissance are the Bakken in North Dakota (and eastern Montana) and the Eagle Ford in west Texas. Oil production from North Dakota's Bakken shale has risen by more than 700,000 b/d in five years, from 172,000 b/d in 2008 to 874,000 b/d today. The state of Texas currently produces 2.6 mbd, over one third of U.S. production. Along with the Permian Basin, the five-year-old Eagle Ford play has helped to add over 1 mbd to Texas' production since 2008. Today, Eagle Ford production is roughly 1 mbd.

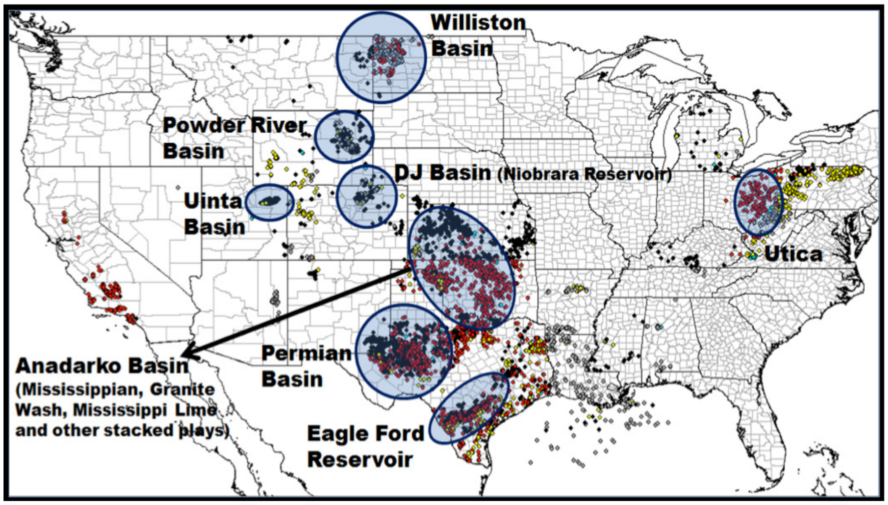
Shale oil plays in North Dakota and Texas have been among the most prominent success stories, but smaller plays in other states are beginning to contribute meaningful production volumes. Colorado's Niobrara shale, primarily located in Weld County, has lifted the state's oil production from 80,000 b/d in 2008 to 161,000 b/d today. The Mississippi Lime and Granite Wash stacked plays have boosted production in Oklahoma (and to a lesser extent in Kansas). Production in Oklahoma rose nearly 140,000 b/d (183,000 b/d to 321,000 b/d) between 2008 and June 2013. Production in New Mexico has also risen 100,000 b/d since 2008, largely stemming from recent advances in understanding the geology of the Permian Basin. The Permian Basin, which straddles the border of southern New Mexico and western Texas, is one of the most explored oil plays in the world. However, companies have only recently begun exploiting the potential of its stacked layers with both vertical and horizontal drilling.

Figure 2. U.S. Production of Crude Oil



Source: EIA

Figure 3. Major U.S. Oil Plays and Permit Activity



Source: HPDI, permit activity in past 90 days, September 2013

The first wave of modern lateral drilling and multi-stage fracking carried over from shale gas plays unlocked these reservoirs, but ongoing advances in technology will play an integral role in extracting more barrels out of tight source rock. To date, only a small fraction[3] of the reserves are being extracted from within these reservoirs, but technology is continually improving. Oil companies are investing heavily in reservoir testing to better understand the geology of these reservoirs. Drillers can now take a sample of reservoir rock and conduct full diagnostics in days (before the shale oil boom companies would send their rock samples to a lab for testing with week long delays before results were made available). This information tells companies the mineralogy make-up of the rock and can give them a full 3-D image of the sample, which shows pore spacing in addition to other qualities, providing a full picture of the rock composition.

Additional advances are being made to measure the size of the fractures (such as where the proppant[4] ends up in a fracture) and understand which fractured zones are producing. Producers are realizing that there is far less oil drainage from the reservoir than they originally expected. As a result, companies have begun to downsize their acreage spacing between wells and place more horizontal wells both next to each other and on top of one another in stacked formations, as seen with multi-well pad drilling. Such advances have enabled higher extraction rates from

[3] The percentage of reserve extraction depends on the original reserve calculation. For example, production of 820,000 b/d with total reserves of 4 billion barrels in place would be much smaller than the percentage of extraction assuming 11 billion barrels of oil in place.

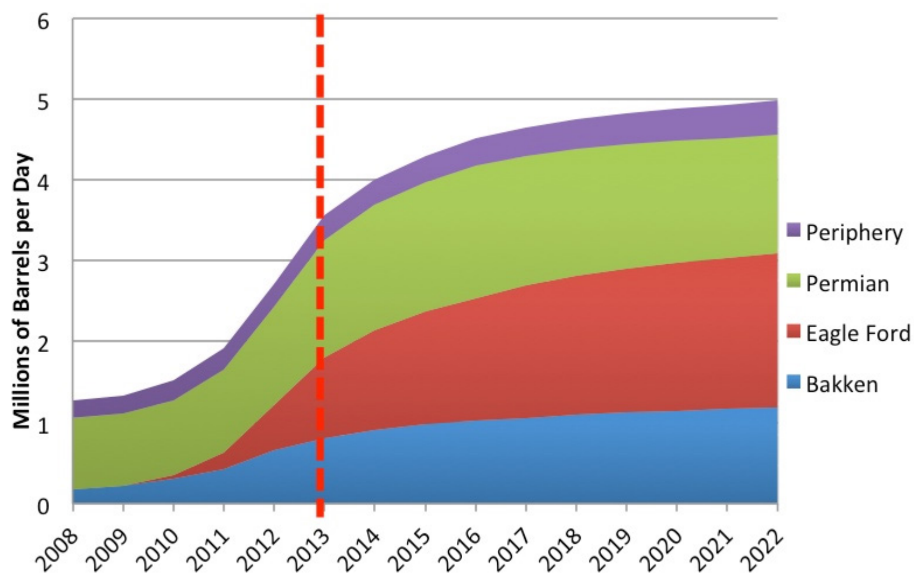
[4] Proppant is used in the hydraulic fracturing process. Proppant, either in the form of ceramic, sand, or resin coated sand is pumped down the wellbore along with water and a fraction of chemicals at high pressure. The hydraulic fracturing fluid is pushed through the cracks in the rock to make a fracture. The proppant help keeps the fractures open to allow oil to flow through and into the wellbore after the fracturing fluid had been flown back up the wellbore.

the reservoir[5] in addition to drilling efficiencies.

To determine future production growth potential, EPRINC has evaluated three major shale plays in the United States: the Bakken, the Permian Basin, and the Eagle Ford. A "periphery" play category has also been added to designate other plays contributing to U.S. production, such as the Niobrara in Colorado and the many stacked plays in Oklahoma. While there are justifiable reservations with regard to this forecast should oil prices fall, EPRINC's assessment, developed from detailed well analysis, current technology development, and the pace of completions, is a relatively conservative forecast.

EPRINC's forecast model utilizes a calculation for average annual production growth which incorporates the pace of average well completion, decline rates for each play/formation, and a set of analytical assumptions based on EPRINC's assessment of the reservoirs and their economics. EPRINC places a high level of confidence on the growth rate from 2013 to 2015. EPRINC estimates that these shale/tight oil formations will yield an additional 1.5 mbd by 2022 over current levels. As the forecast indicates, 2022 may be the point at which some of these plays begin to plateau (in terms of production). Considerable uncertainty exists with regards to long-term growth potential. There is little agreement among geologists (and others in the industry) as to when these plays and

Figure 4. EPRINC'S Shale Oil Play Forecast



Source: EPRINC. Well data from HDPI and NDPA. [6]

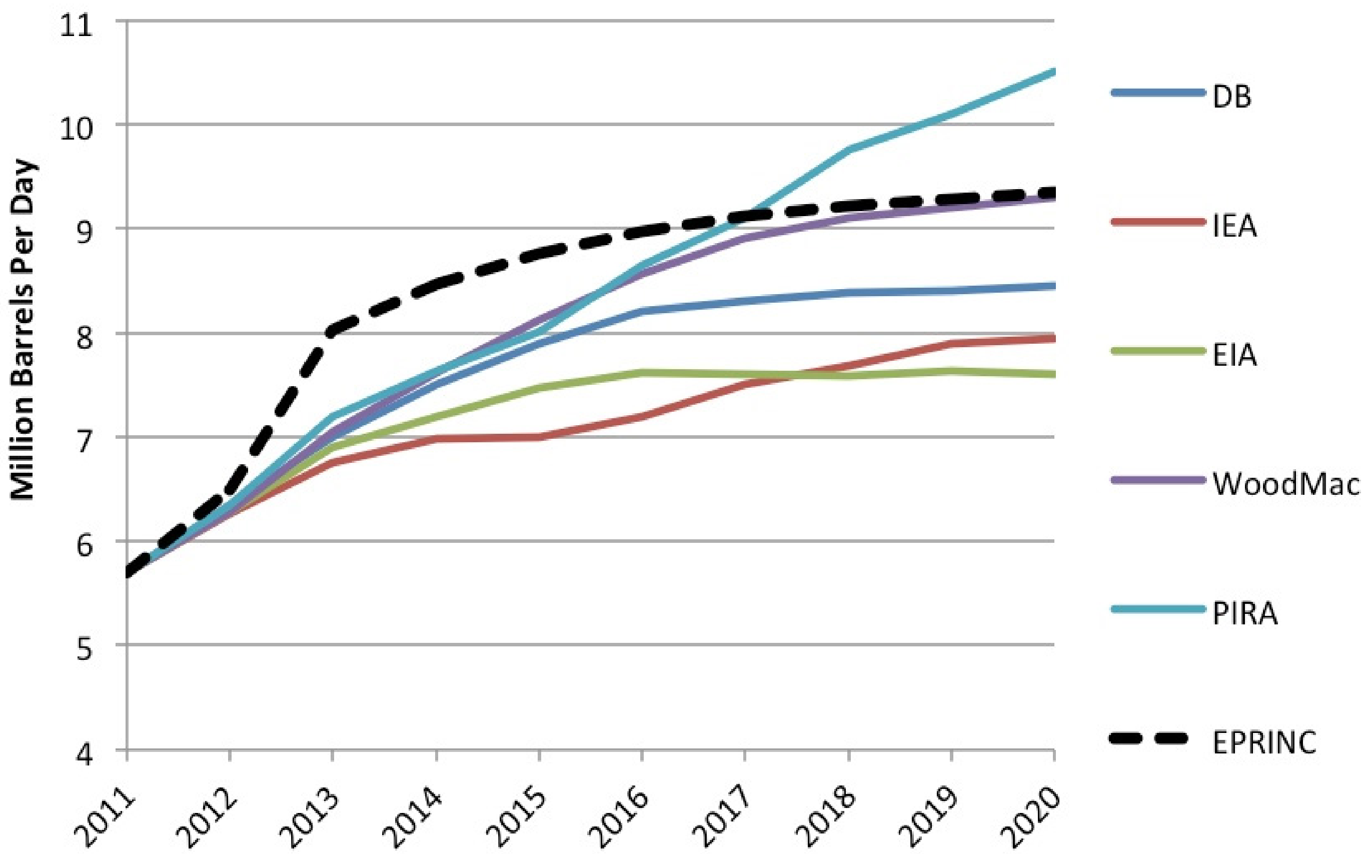
5 Note that production from shale formations to date only constitutes a fraction of the resource in place. Small improvements in extraction techniques can provide large increases in new supplies. The future of U.S. oil production will be determined largely by technology.

6 The "Bakken" forecast is a North Dakota forecast and does not include eastern Montana or South Dakota. The "Eagle Ford" forecast does include condensate. The percentage of what is condensate and what is crude oil in Eagle Ford production is an issue of debate right now, but estimates range from 40 to 60 percent of production. All other forecasted reservoirs and plays do include other liquids in addition to crude oil; however, the Bakken is almost strictly crude oil. The Permian Basin is largely crude oil, but does include some condensates (probably no more than 30 percent).

reservoirs will plateau and subsequently decline. Technology, oil prices, and other factors can play a significant role in the extent to which these light sweet shale plays are developed. The Permian Basin contains multiple stacked formations which offer several extraction possibilities for the industry over the coming years. Even if the Permian, Bakken, and Eagle Ford reservoirs plateau or decline in the coming years, other plays such as those within the Anadarko Basin, including the Granite Wash and Mississippi Lime, may offer future production growth with the application of improved extraction technologies. Although uncertainty remains on future production levels, given advances in technology, access to markets, and a stable price environment, considerable upside potential remains.

Figure 5 presents EPRINC's forecast along with estimates from other analysts.

Figure 5. EPRINC vs. Major Industry Forecasts for U.S. Oil Production



Source: EPRINC Forecast and Estimates compiled from Deutsche Bank Report Dec 2012 "Future of US Oil"

Canadian Production

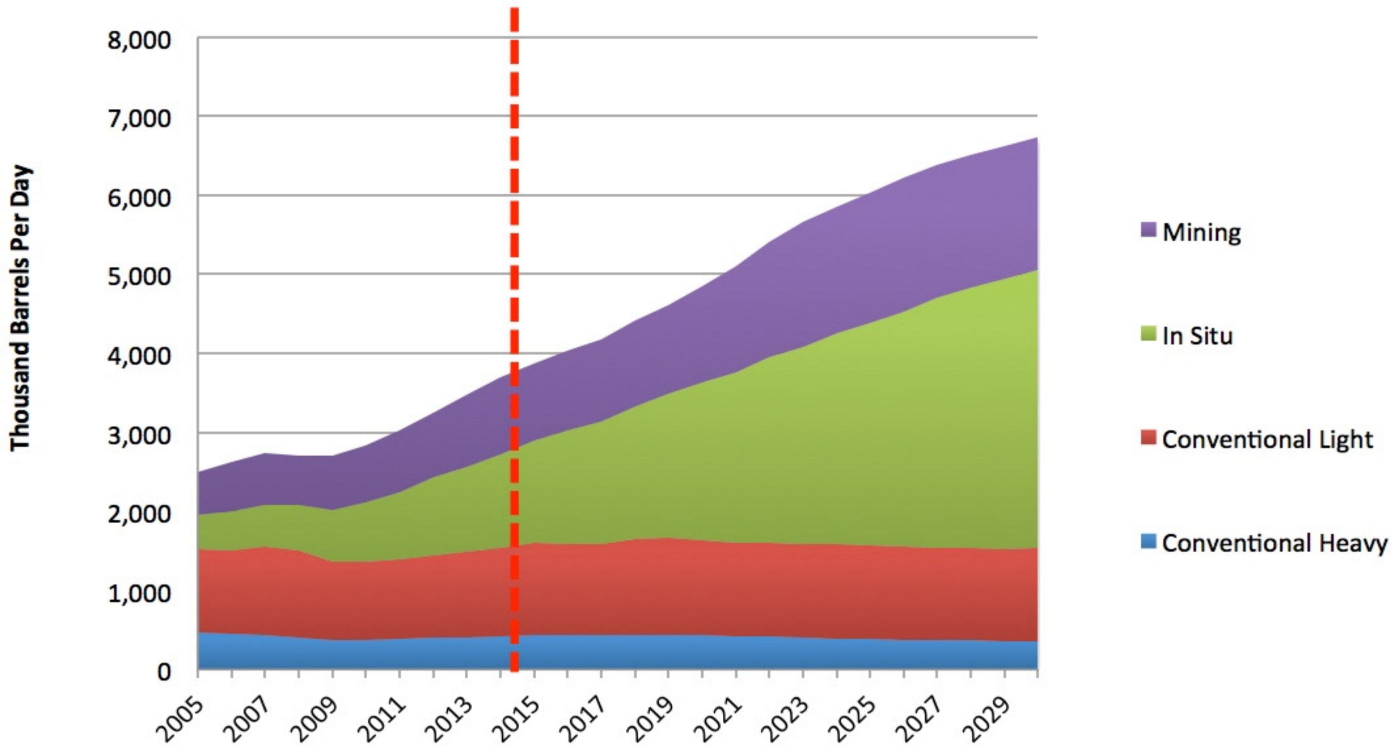
Canada currently produces 3.5 mbd, up nearly 1 mbd from 2008. Oil sands output continues to account for the largest share of past and future production growth. While production via mining will remain a substantial portion of total production, in situ production, largely in the form of SAGD (Steam Assisted Gravity Drainage)[7], will account for the majority of Canadian crude oil growth. Canadian oil production (shown in figure 6) is expected to increase over 3 mbd by 2030 according to estimates from the Canadian Association of Petroleum Producers (CAPP).

Historically, almost all Canadian crude oil and petroleum product exports have been marketed to the United States. Given that projected petroleum consumption in both the U.S. and Canada is expected to remain relatively flat over the coming years, incremental Canadian production growth will primarily be exported to the United States. These incremental barrels from Canada to the U.S. will replace non-North American waterborne imports. However, this can only take place if large-scale transportation options (new pipelines) are made available to move heavy Canadian oil sands to major U.S. refining centers.

Given the promise for robust production growth in both the U.S. and Canada, the pace at which oil transportation infrastructure can be put into place will play a significant role in determining the potential of the North American petroleum renaissance.

7 Please see EPRINC's primer on the Canadian oil sands. http://eprinc.org/pdf/oilsandsprimer.pdf

Figure 6. Canadian Oil Production Forecast

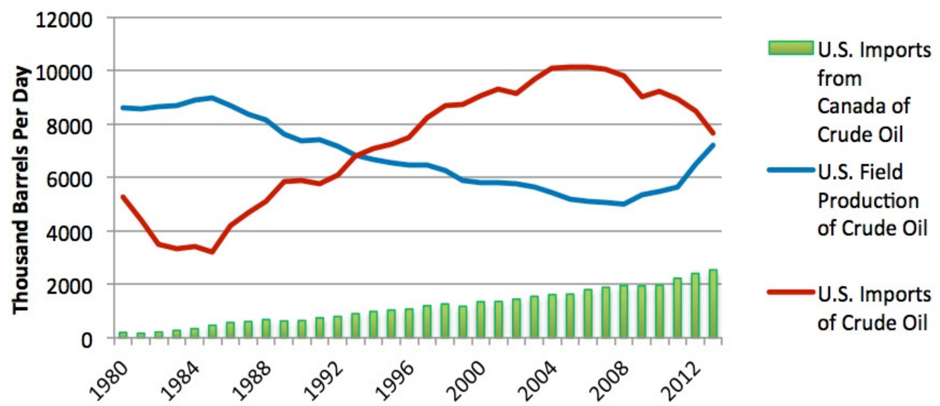


Source: CAPP 2013 "Crude Oil Forecast, Markets, and Transportation" data

Shifting Crude Oil Imports and Altering Domestic Flows

The rapid growth of North American oil production is actively changing the U.S. import portfolio and shifting oil flows around the globe. A major shift away from waterborne imports is taking place as light sweet domestic production rises, imports are backed out, and heavy Canadian imports rise. North America stands to capture considerable economic value and growth from this petroleum renaissance, but moving these new supplies efficiently to high value markets is essential for sustaining production growth, particularly if production costs rise sharply or oil prices and wellhead values decline significantly.[8] Transportation inefficiencies ultimately raise the cost of production. Higher costs reduce potential economic activity as well as producer, landowner, and government royalties. Reduced domestic production will be offset by increased crude oil imports (until cost competitive alternative forms of energy arrive at scale) and contribute to higher global oil prices.

Figure 7. U.S. Imports, U.S. Production, and U.S. Imports from Canada



Source: EIA

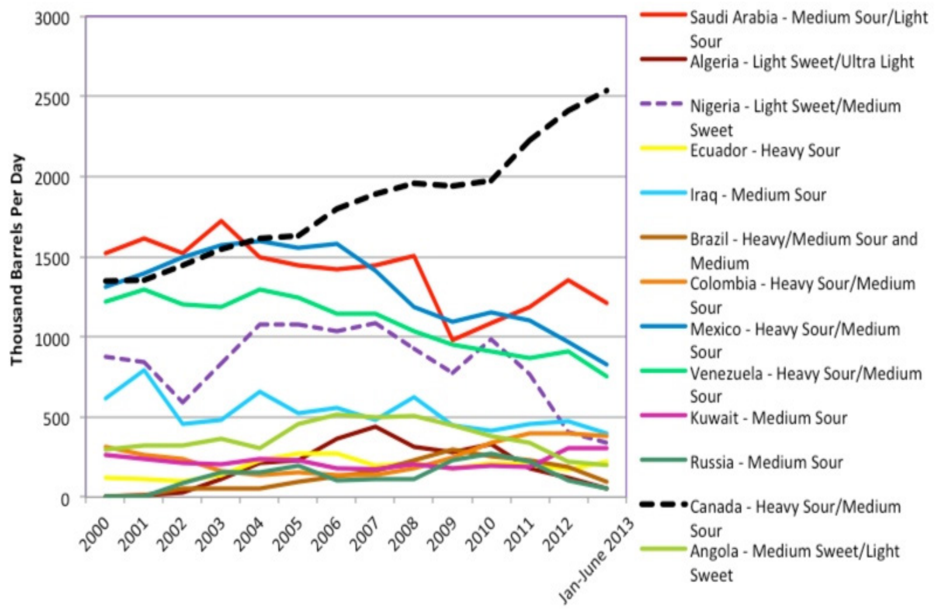
For the first time since 1993, U.S. oil production has nearly eclipsed crude oil imports. The U.S. will soon import less than half of its crude oil needs. If U.S. exports of refined products are included in this calculation, the U.S. already imports less than 50 percent of its domestic petroleum consumption. As figure 7 indicates, of the remaining 7.6 mbd of imports, Canada accounts for 2.5 mbd, or 33 percent of total foreign imports. This brings total non-Canadian foreign imports to 5 mbd. As the production forecasts above suggest, this number could drop to under 3 mbd by 2022 given flat consumption trends (this assumes the U.S would be importing an additional 1 mbd from Canada by 2022). EPRINC's forecast adds another 1.5 mbd to U.S. production by 2022 and CAPP's forecast adds another 1.8 mbd to Canadian production. Further improvements in import reductions could also come from increasingly stringent automotive fuel efficiency

8 Oil production requires long-term commitments of capital and these commitments are less constrained in an economic environment in which the distribution of supplies to markets is both stable and efficient.

standards (CAFE) and the renewable fuels standard (RFS).[9]

Figure 8 illustrates the dramatic changes in the source and characteristics of oil imports into the United States. Rising domestic production has reduced demand for light sweet crude from North Africa. At the same time, heavy crude oil imports from Canada are increasing. As both U.S. and Canadian production rise, waterborne imports into the U.S. are rapidly declining. In order to further replace waterborne imports with domestic production, the crude oil distribution network must be able to move large volumes of supplies to coastal refineries currently relying upon foreign waterborne imports. Note that imports from Saudi Arabia and Nigeria, formerly top importers to the U.S., are on decline as light sweet crude oil from the Bakken, Permian Basin, Eagle Ford, and other shale plays make their way to major U.S. refining centers.

Figure 8. Top U.S. Imports by Country of Origin and Crude Oil Type



Source: EIA Data, Oil types from ENI World Oil Book

As the U.S. import portfolio continues to shift, displacing light sweet imports from countries such as Nigeria, Algeria, and Angola, more blending will occur; that is, more light sweet oil will be blended with heavier oil from Canada (and elsewhere) to make medium grade crude oils. This will help refining centers adapt to increasing volumes of light sweet crude and in turn push out medium grade barrels.[10] U.S. and Canadian coastal refining centers are the only destinations left for additional volumes of both U.S. and Canadian crude oil. As rising volumes of both light sweet crude oil from the U.S. and heavy crude oil from Canada make their way to the coasts, foreign waterborne imports will continue to decline.

The Canadian Association of Petroleum Producers' most recent map of oil disposition by processing region illustrates where domestic U.S. crude oil, Canadian crude oil, and foreign non-Canadian crude oil are being processed. Processing centers in central U.S. and Canada are completely saturated by Canadian and domestic crude oil. Very little non-North American crude oil is processed in central U.S. and Canada, as indicated in figure 9, which shows the destinations of North American crude oil and waterborne crude oil

9 Further gains in reducing imports could come from fuel efficiencies. U.S. consumption for fuel is expected to remain relatively flat in the coming years (AEO reference case 2013).

10 Please see appendix for further information on crude oil quality and grades.

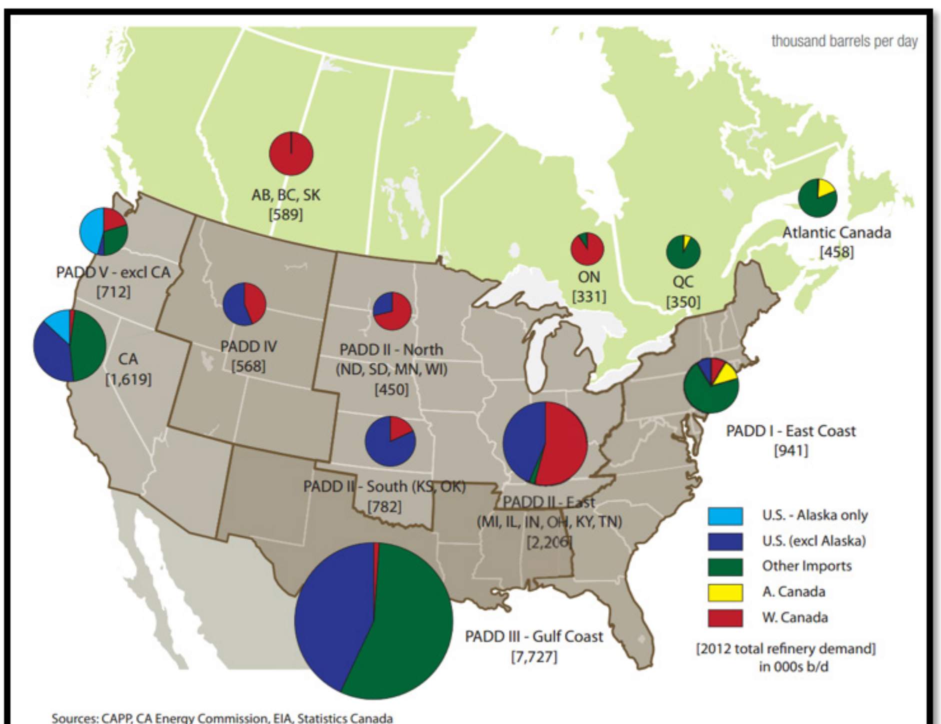
imports. The green portions of the pie charts below indicate where foreign non-Canadian crude is processed. Rising Bakken and Canadian production should be moved to refining centers along the U.S. and Canadian coasts (the Canadian East Coast). Current export options for additional Canadian production are limited to areas already saturated with domestic and Canadian crude oil, the Rockies and the Midwest.

Given the abundance of light sweet crude oil in the U.S., questions regarding crude oil exports have arisen. While discussion on this subject will likely increase over the coming months and years, major exports of crude oil from the U.S. are unlikely to take place in the foreseeable future. Crude oil production is rising in the U.S. for the first time since the 1990s; however, the U.S. still imports over 7 mbd and consumes roughly 15 mbd of crude oil. This topic is both complex and highly politicized.

The movement of crude oil is heavily regulated for strategic purposes. Crude oil can be exported, but producers need a permit to do so. The Department of Commerce has the authority to grant exemption permits. Shipments to Canada are the only exports routinely approved (It is likely that Mexico would be treated in the same manner as Canada). The boom in shale oil production has increased the flow of U.S. crude oil to Canada; exports to Canada eclipsed the 100,000 b/d mark in February of 2013, its highest level since the late 1990s. The abundance of light sweet crude in the U.S. makes eastern Canadian refineries, which largely run a light crude oil slate, a natural market for U.S. production.

The U.S. implemented its export control system in the post-WWII era. Although legislation regulating the export of domestically produced crude oil has changed over the years, U.S. policy has consistently restricted exports of crude oil. The basis for restrictions on oil exports is rooted in the Cold War and is implemented through the short supply control program administered by the U.S. Department of Commerce. Short supply controls restrict the exports of scarce goods.

Figure 9. Crude Oil Disposition by Origin



Source: CAPP

The Bottlenecks: Understanding Their Development

North America's crude oil pipeline network has been unable to keep pace with the 3 mbd of production added over the past five years. Large volumes of light sweet and heavy crude oil are moving to U.S. refining centers through a highly constrained transportation network, now requiring the use of rail. Much of the U.S. crude oil pipeline network was constructed when waterborne oil shipments into the Gulf began to supplant declining onshore production. The pipeline network was built to move crude oil northwards from the Gulf Coast. The West Coast received its crude oil from domestic (California and Alaska) sources and the East Coast imported the bulk of its oil from North Africa and the Middle East. There was no need to have abundant pipeline connectivity from the center of the country to the East and West Coasts.

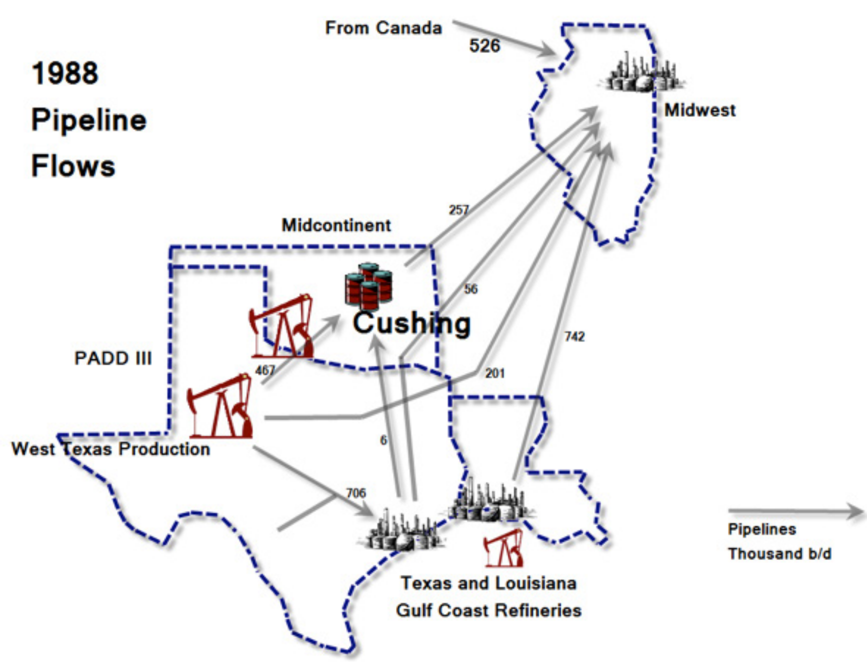
Figure 10 illustrates the historic shifts in crude oil flows from 1988 to 2008. Between 1988 and 2008, imports into the Midwest from Canada more than doubled, pipeline flows from west Texas to Gulf were reversed, and flows from the Gulf to Cushing and the Midwest grew.

Midstream companies have quickly adapted to the changing production geography by investing in new crude oil transportation projects. These projects seek to move crude oil along new routes, whether by pipeline, rail or barge. The build out of new infrastructure has been extensive, but the system still possesses inefficiencies and limitations. As the infrastructure system has worked to adapt, debate concerning the overlap of energy and the environment has led to serious regulatory delays.

Bottleneck Timeline

In 2006, U.S. shale gas production began to rise

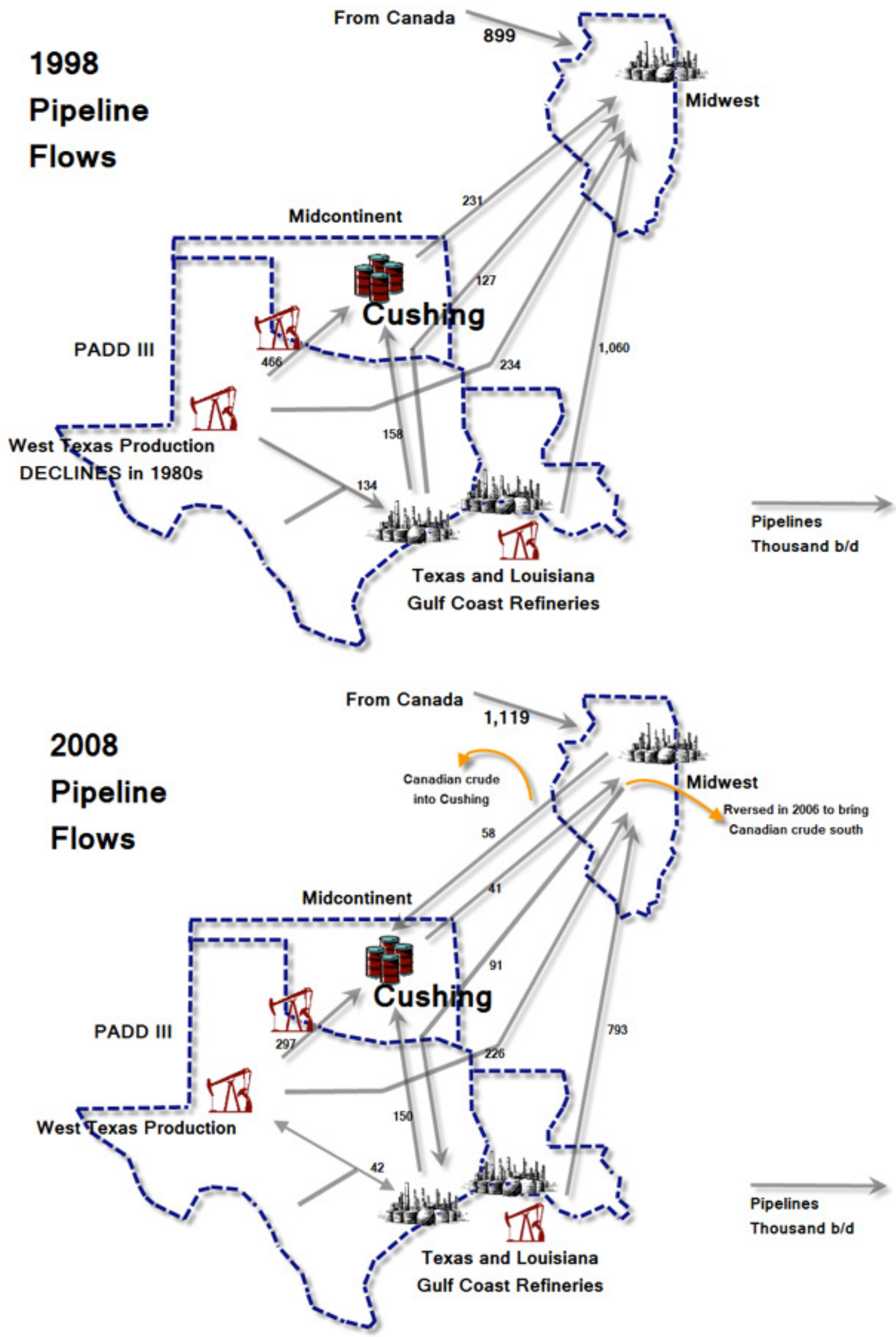
Figure 10. Historic Pipeline Flows Between PADD II and PADD III



dramatically, sparked by the application of horizontal drilling and multistage hydraulic fracturing in a high natural gas price environment. Within a few years these technologies were being widely applied to oil rich shale/tight formations, such as the Bakken formation. Oil production in North Dakota rapidly increased following the recovery of oil prices after the 2008 price collapse. As production in the Bakken surged, upstream companies extended their search for new supplies in similar shale/tight oil formations, applying and improving these technologies.

In 2008, TransCanada submitted its application for the Keystone XL pipeline. What was at the time considered a relatively straightforward, albeit thorough, approval process quickly evolved into one of the most controversial infrastructure projects in North America. Because the proposed pipeline would cross an international border, it

Figure 10. Continued. Historic Pipeline Flows Between PADD II and PADD III



Source: EPRINC Maps. Data from CME Group and Purvin and Gertz "The Role of WTI as a Benchmark"

required Presidential approval.[11] Several existing pipelines which carry Canadian oil sands to U.S. refineries have been approved, including TransCanada's own 590,000 b/d Keystone phase 1 pipeline which was completed and launched in 2010 (the original Keystone pipeline which runs from Hardisty, Alberta to Patoka, Illinois). TransCanada is still awaiting approval for the northern leg of Keystone XL which would originate in Hardisty, Alberta and move crude oil to Steele City, Nebraska. The southern leg from Cushing, Oklahoma to the Gulf Coast has been approved and is nearly completed. The extension from Steele City, Nebraska to Cushing, Oklahoma was finished in 2011.[12]

Opposition to Keystone XL, primarily from environmental groups, has been extensive. Initial opposition formed over the pipeline's route, which crossed the Ogallala aquifer, and later from the pipeline's planned route in Nebraska which crossed the environmentally sensitive Sand Hills region.[13] The decision was officially delayed and a second Environmental Impact Statement was ordered. Beyond these land issues lurked a wider range of concerns that the Keystone XL project would effectively increase greenhouse gas emissions by enabling oil sands production growth. The concerns surrounding Keystone XL grew in tandem with the need for additional pipeline capacity, specifically pipeline capacity that would bypass the congested Midwest and move heavy oil to the Gulf.

Combined growth in Canadian and North Dakota production severely constrained pipeline capacity to move rising production volumes to coastal refining centers. Prior to the surge in North American output, Canadian operators had enjoyed flexibility in the pipeline system with ample room to allocate varying production flows each month. As rising volumes of Bakken crude oil from North Dakota began to make its way into Enbridge's mainline (from Alberta, Canada into the Midwest), capacity for Canadian oil shipments into the Midwest became constrained.[14] The discount between Western Canadian Select (WCS), the benchmark for heavy oil sands crude, and West Texas Intermediate (WTI), the benchmark for U.S. crude oil, began to widen, reflecting the constraints in pipeline capacity.[15] The constraints in transportation capacity were reflected in pricing discounts for Bakken crude oil at Clearbrook, Minnesota, a major

11 Presidential permits are required for construction of pipelines and facilities across the borders of Canada and Mexico. Originally under the President's authority, Presidential permits for oil pipelines were officially delegated to the Department of State in 1968. In 2004 President George W. Bush passed an executive order enacting a review process for Presidential Permits of oil pipelines.

12 See appendix for Keystone XL map.

13 The Ogallala aquifer crosses a total of eight U.S. states. The Sand Hills region is a combination of grass prairie and sand dunes stabilized by grass. It covers over one quarter of Nebraska.

14 See appendix for map of major Canadian pipelines to the U.S.

15 WTI is much lighter and sweeter (less sulfur) than heavy Canadian crude oil. See appendix for more information on benchmarks and crude oil quality.

settling point for crude oil along Enbridge's mainline route through the Midwest. This resulted in lower wellhead values for producers in Canada and North Dakota.

Further down the pipeline, stocks of crude oil in Cushing, Oklahoma, a major storage hub for crude oil and settling point for paper contracts on the NYMEX (New York Mercantile Exchange), continued to rise with increasing flows of light sweet crude oil production from the Niobrara and Permian Basin.[16] By 2011, Eagle Ford production was expanding and the Gulf Coast saw localized light sweet oil growth. Meanwhile, Canadian crude oil imports into the U.S. continued to climb, saturating the Midwest. There was little opportunity to move the crude oil to the Gulf Coast or elsewhere. Discounts on WCS and Bakken crude oil persisted and demand for alternative oil transportation grew. Rail transportation became an attractive alternative for producers, often in combination with pipeline and barge. Crude oil by rail was more costly than pipeline, but it provided a flexible solution that offered shippers the ability to move their crude oil to coastal markets and earn a higher price for their product. This allowed producers the opportunity to capture higher coastal prices, more closely linked to global oil prices or Brent, the international benchmark for crude oil.[17]

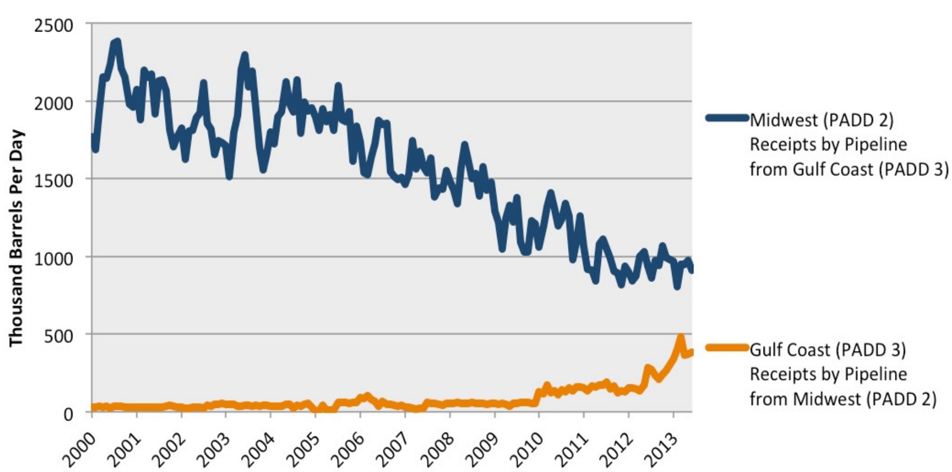
16 Cushing is the delivery point for crude oil bought and sold on the NYMEX.

17 See appendix for explanation on crude quality and benchmarks.

Shifts in Pipeline Flows

As crude oil from Canada and the Bakken pressed its way into the Midwest (PADD 2) , shipments via pipeline from the Gulf to the Midwest reversed. Crude oil shipments from the south (Gulf Coast) to the north (Midwest) have declined substantially while shipments from the north (Midwest) to the south (Gulf Coast) have risen. The following figure shows the dramatic shift in oil transportation via pipeline from the Gulf Coast (PADD 3) to the Midwest

Figure 11. Changes in Pipeline Flows from the Midwest to the Gulf Coast



Source: EIA

(PADD 2).[18] Shipments from the Gulf into the Midwest have dropped 500,000 b/d from 1.5 mbd in 2008 to under 1 mbd in 2013. Pipeline shipments from the Midwest to the Gulf Coast have risen from only 50,000 b/d in 2008 to over 380,000 b/d in 2013.

These large shifts in pipeline flows from the Gulf to the Midwest, along with the rise of rail and other alternative modes of transportation, demonstrate both the constrained pipeline capacity and market saturation of traditional pipeline destinations for Bakken and Canadian crude oil. Pipelines out of North Dakota have two options, north or east, both of which flow into Enbridge's mainline bringing crude into the Midwest, specifically Clearbrook, Minnesota (a chokepoint indicated on the maps at the end of this section in figure 12). The other option is to go south into True Companies' system bringing crude oil into the Rockies, specifically Guernsey, Wyoming (another chokepoint indicated on the following maps in figure 12). Both of these markets are now saturated with domestic and Canadian crude oil.

Limited Canadian Export Options and Planned Expansions

Canadian oil movements are similarly constrained; however, unlike Bakken crude oil, Canadian crude oil has yet to take full advantage of rail opportunities. Rail loading facilities in Canada are rapidly coming online but limitations exist. There is a lack of heavy oil destination facilities which can offload viscous bitumen (which must be transported in heated rail cars).[19] The existing transportation infrastructure to move Canadian crude oil to U.S. markets via pipeline is now at capacity. Kinder Morgan's Trans Mountain pipeline, which runs from Alberta to the British Colombia Coast, has a capacity of 300,000 b/d and is currently full. Spectra's Platte line to Wood River, Illinois is also full at 280,000 b/d of capacity. TransCanada's original Keystone system from Alberta to Patoka, Illinois is at capacity at 580,000 b/d. Enbridge's mainline system, which transports the majority of Canadian imports into the U.S., specifically the Midwest, has a nameplate capacity of 2.5 mbd, but currently runs tightly at around 2 mbd.[20]

Out of these four pipeline systems, three have planned expansions: the northern leg of Keystone XL, which would add an additional 780,000 b/d of capacity and move heavy Canadian oil directly to the Gulf, avoiding the congested Midwest; the Trans Mountain expansion, which would add an additional 500,000 b/d to the British Colombia Coast; and Enbridge's

[18] PADD or Petroleum Administration Defense District references refining regions further explained in the refining section of this report.

[19] Railing oil sands crude oil/bitumen can be done in multiple ways, but one of the most economic ways would be to rail unit trains (over 100 cars) of straight bitumen (meaning there is little or no diluent required, thus cutting costs). This requires a tank car that can be heated. In addition, the destination's offloading facility must have the ability to heat the bitumen in order to extract the crude from the tank cars.

[20] Since the onset of the shale oil boom in 2008, throughputs in many pipelines have risen, depleting spare pipeline capacity.

mainline system, currently undergoing multiple expansion projects to bring additional crude oil to eastern Canada and heavy barrels to the Gulf Coast.

Enbridge's planned Northern Gateway project, if approved, would move 525,000 b/d of crude oil from Alberta to the coast of British Colombia for export. TransCanada's recently proposed Energy East project, a partial gas line conversion, could move over 1 mbd of crude oil to refineries in eastern Canada. Should approval of Energy East be granted there would be potential to export crude oil from the coast of eastern Canada.

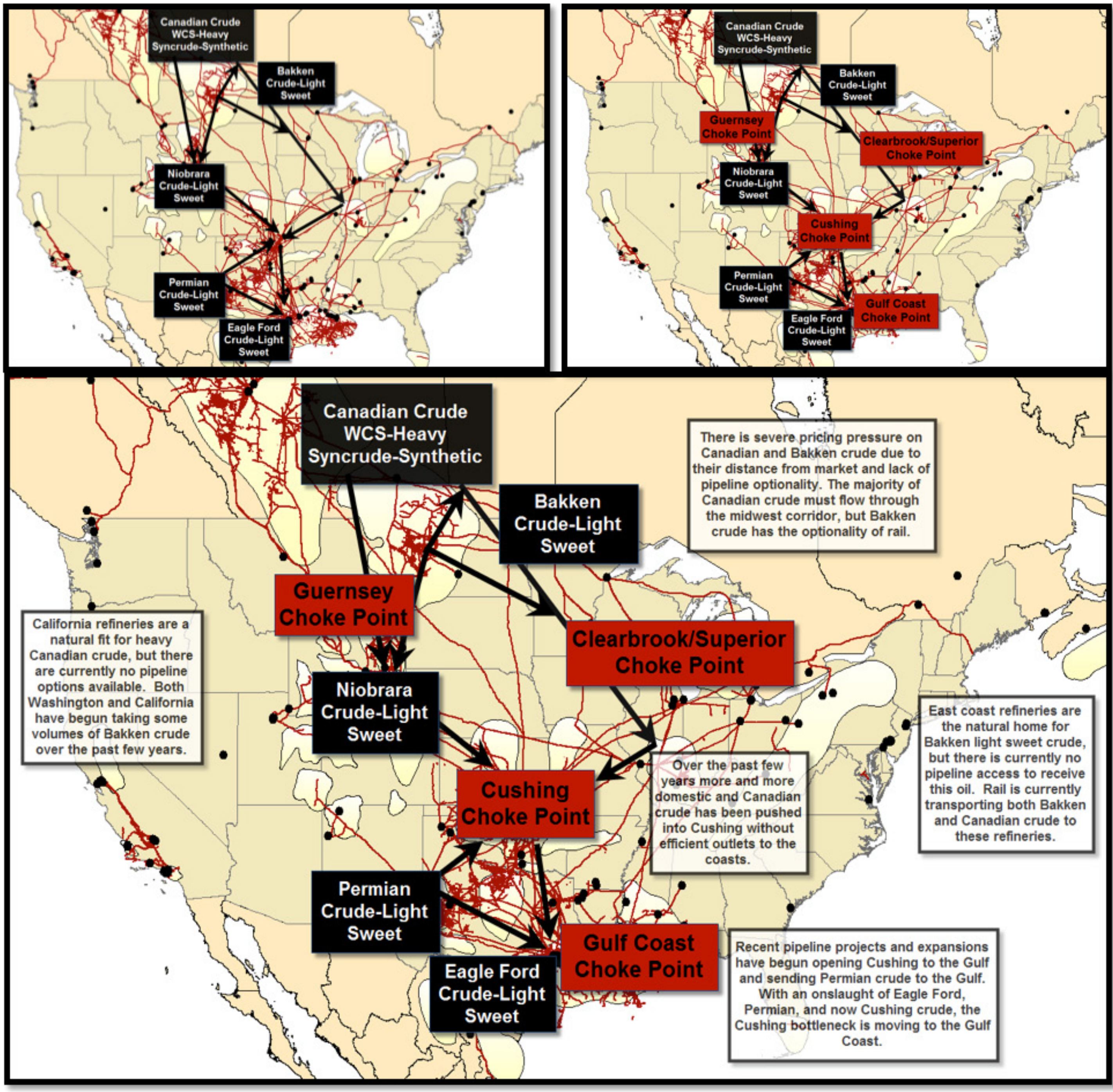
The necessity of these pipeline projects and expansions have become increasingly clear given sustained growth in Canadian production, constrained export options to the coasts, and the subsequent impact on prices.

Illustrating the Bottlenecks

The maps below demonstrate how the dramatic shifts in the flow of U.S. and Canadian crude oil have created multiple pipeline bottlenecks and chokepoints across the United States. These choke points developed largely as a result of increased throughput in existing pipelines and resulting storage build-ups. They are the quintessential bottleneck: multiple avenues of crude oil flowing into a central point with a congested outlet. A system once designed to move oil north has been trying to send it south. The Williston Basin (comprised of western North Dakota, eastern Montana, and northern South Dakota), home of the Bakken formation, has never been a significant producing center or refining hub so major pipelines never existed to export or import crude oil to the region. As Bakken production rose, new pipeline capacity had to be built to get the oil out of North Dakota and Montana. However, this new capacity simply fed into a larger system of existing, outdated capacity. Along with rising Canadian imports, the surge in Bakken production contributed to the development of chokepoints in Guernsey, Wyoming and Clearbrook, Minnesota.

Oil from Wyoming and Minnesota subsequently flowed into Cushing, Oklahoma along with crude oil from the Niobrara in Colorado and the Permian Basin in western Texas and southern New Mexico. Stocks built up in Cushing with limited outbound capacity. Today, new pipelines are coming online to debottleneck Cushing, sending millions of barrels each day to the Gulf Coast. While this helps to alleviate the buildup in Cushing, the Gulf Coast is experiencing an influx of light sweet crude oil via pipeline in addition to surging Eagle Ford production.

Figure 12. EPRINC Choke Point Maps



Price Dislocations

Pricing dislocations are indicative of the regional imbalances in crude oil markets. When a storage hub, such as Cushing, becomes crowded and inventories rise above historical norms, it is a signal that supply at that hub is stronger than demand. Regional imbalances create regional pricing discrepancies, in turn affecting supplier and consumer behavior.

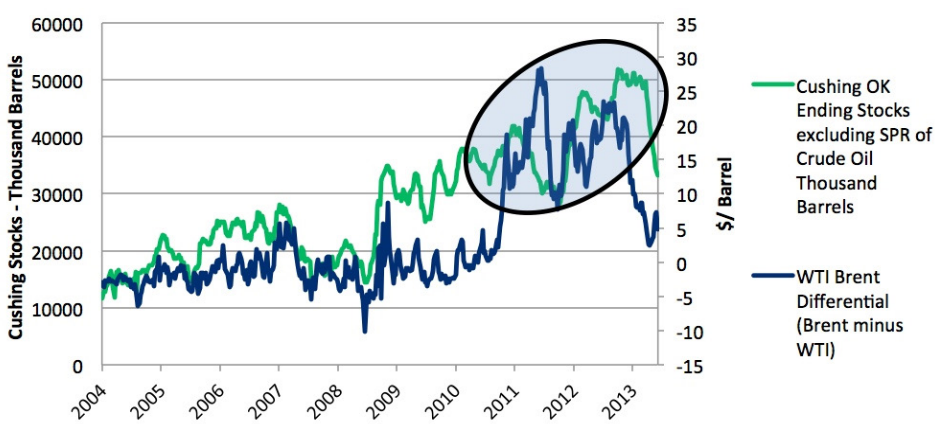
The relative oversupply of crude oil in Cushing, Clearbrook, and other clearing points drove prices down in those markets relative to prices on the coasts where markets were more balanced. Local refineries with pipeline access to these discounted crude oils quickly adapted to the new pricing structure, purchasing as much discounted Bakken and Canadian crude oil as their capacity allowed. As production rose, local refining capacity became fully saturated and stockpiles continued to build, putting further downward pressure on mid-continent crude oil prices. These discounts did not go unnoticed. They were large enough to justify the higher costs associated with crude by rail shipments from North Dakota to the East, West, and Gulf Coasts, where prices were set by the more costly Brent benchmark, allowing producers and shippers to share the remaining arbitrage.

Despite the recent narrowing of the WTI Brent spread, mid-continent discounts have remained sufficient enough to justify most crude by rail shipments. Crude by rail shipments would have become uneconomic had mid-continent discounts narrowed too far. But a halt to rail shipments would have caused inventories to rebuild and spreads to reopen, incentivizing a return to rail shipments.

Cushing, Oklahoma

Rising U.S. and Canadian production faced limited outlets to market. Stocks in Cushing, Oklahoma rose as new crude oil supplies made their way through existing pipeline systems, many of which settled in Cushing. Because few pipelines systems existed to move crude oil out of Cushing and into major refining centers, WTI prices began to discount from global Brent prices. Up until the end of 2010, the WTI Brent differential rose and fell with Cushing stocks, historically

Figure 13. WTI Brent Differential and Cushing Stocks (excluding Strategic Petroleum Reserve)



Source: EIA

a proxy for measuring the degree of congestion. This congestion occurred because Cushing did not have the outbound infrastructure capacity required to move these new oil supplies to market, nor adequate storage facilities. In recent years new storage facilities have been constructed, but this largely kept an already congested chokepoint from getting worse as production continued to increase, Canadian imports rose, and light sweet barrels made their way to Cushing.

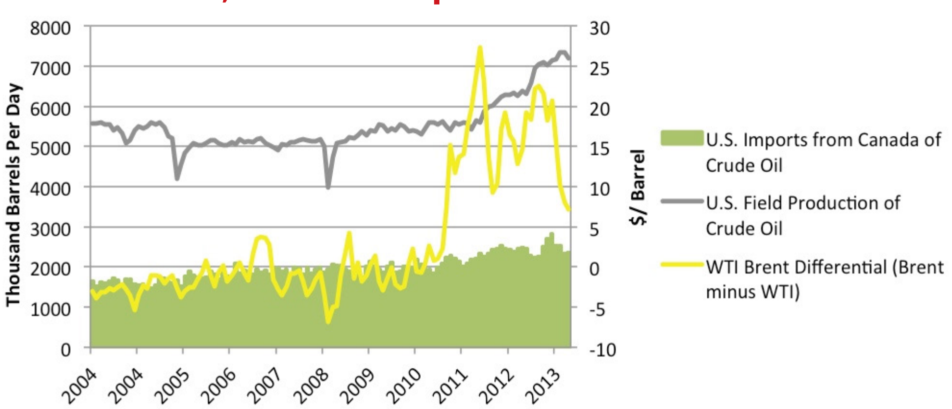
In 2011 stocks of crude oil in Cushing began to decrease, but the WTI Brent differential continued to widen. Rail transportation played a direct role in decreasing crude oil stocks in Cushing. Shipping crude by rail allowed production, otherwise destined for Cushing, to be sent directly to the West, Gulf, and East Coasts. However, rail alone could not solve the rise of the WTI Brent differential stemming from Cushing. New pipeline capacity needed to be built to either move inbound Cushing supplies to the Gulf or avert inbound volumes directly to another market. The recent narrowing of the WTI Brent differential is partially reflective of new pipeline capacity coming online. In the second quarter of 2013 over 300,000 b/d of pipeline capacity was made available to move Permian Basin crude oil directly to the Gulf, volumes which had been previously destined for Cushing, Oklahoma.

As shown in figure 14, a combination of domestic supply growth, rising Canadian imports, and constraints in existing pipeline capacity were largely responsible for the WTI Brent differential's peak of $28 in September of 2011.

As U.S. production and Canadian imports rose, the differential opened up; as more capacity came online to move crude oil to processing centers and reduce congestion, the differential narrowed. Other factors can also affect the WTI Brent spread, for example a production curtailment in Canada can act to ease congestion and narrow the WTI Brent differential as seen in recent months. Floods in Alberta over the summer took large volumes of production offline and as a result U.S. processing centers drew down domestic stocks to supplant Canadian imports.

Figure 15 shows the relationship between the rise in Canadian imports and the opening of the WTI Brent differential. As pipeline infrastructure in the Midwest became constrained and refineries in the Midwest became awash with crude oil, the WTI Brent differential rose.

Figure 14. WTI Brent Differential, U.S. Crude Oil Production, and U.S. Imports of Canadian Crude Oil



Source: EIA

Discounts Across North America

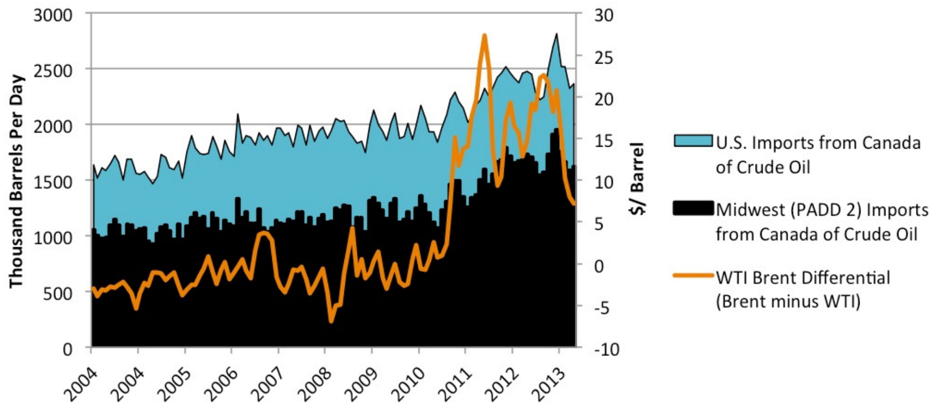
Local discounts in producing regions opened up

as the WTI Brent spread grew. Canadian and Bakken crude oil received substantial discounts off WTI as rising volumes of oil flowed into Clearbrook, Minnesota. In February of 2012, the Bakken discount from WTI at Clearbrook hit $20 and surpassed $10 again the following June. Discounts in Clearbrook were not only caused by increasing Bakken production and rising Canadian imports, but also refinery outages in the Midwest and pipeline maintenance. These issues help point towards the larger constraint: an extremely tight and limited pipeline system unable to adjust to significant production increases.

Deterioration in wellhead values (discounts from Brent and WTI) is common throughout many of the new producing regions, not only Canada and North Dakota. These discounts have incentivized producers to seek alternative methods for shipping crude oil, allowing their production to reach markets with higher prices. In some cases pipeline capacity was available, but was not adequate to move crude oil to the highest value markets. Sending crude oil via pipeline to Clearbrook meant receiving a large discount off WTI (and Brent). Sending crude oil toward Cushing meant getting prices closer to WTI, but still at a significant discount. Transporting crude oil to the coasts via rail and barge to earn Brent (the international benchmark and price of waterborne imports into the U.S.) prices generated the highest returns. The cost to ship crude by rail from North Dakota to the East and West Coasts vary, but are estimated between $10 and $15 (including base rail costs, tank car leasing, and loading and unloading fees). The current differentials, while narrow, still support most rail movements. Shippers are willing to pay more for the transportation of crude oil if it means getting it to a higher value market, thus ensuring a higher netback.[21] Producers may also be willing to pay more in a narrower discount environment to ensure market flexibility.

Figure 16 shows the difference in prices between Brent, WTI, North Dakota Light Sweet (Bakken), and Western Canadian Select. Figure 17 illustrates recent regional price differences across North America. Notice the large differentials

Figure 15. WTI Brent Differential, Midwest Imports from Canada, and U.S. Imports from Canada



Source: EIA

21 A netback is the net profit received from the sale of crude oil. It is the receiving price of the crude oil and associated products minus the total costs of moving the crude oil to market.

Figure 16. Price Differentials between WTI, Brent, Bakken, and WCS

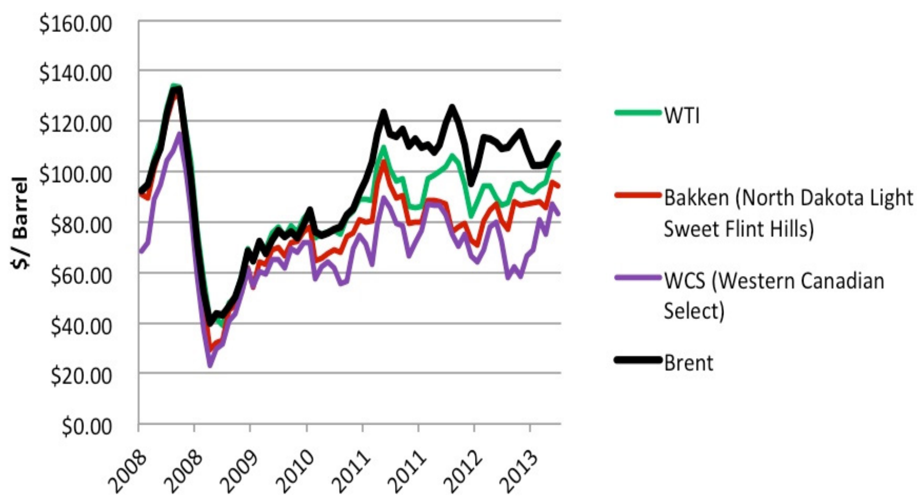


Figure 17. Geographic Pricing Disparities

Source: AFPM Map; Bloomberg Brent and WTI prices; Midland, Clearbrook, LLS (estimates); North Dakota, Wyoming, DJ from Flint Hills and estimates, Canadian assumptions and estimates (Bloomberg)

between Bakken and Brent prices as well as WCS and Brent prices. While the differential between WTI and Brent has narrowed, the price spreads between the producing regions and Brent still warrant more expensive rail shipments.

Canadian Crude Oil Discounts

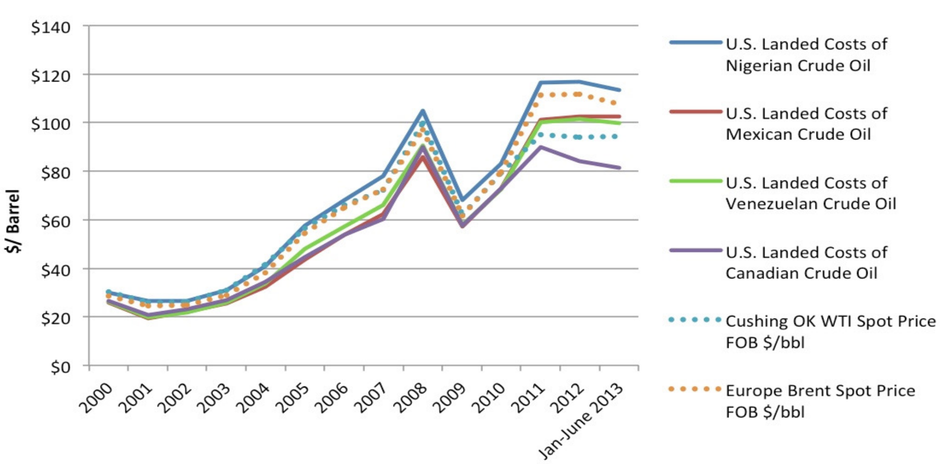
Canadian oil production has also been subject to steep discounts due to market limiting transportation constraints. However, Canadian producers do not have access to the same level of transportation flexibility U.S. producers have utilized to circumvent price discounts. For the most part, the only available destination for growing Canadian crude oil production is the saturated Midwestern United States. Of the current 2.5 mbd being exported to the U.S., only 551,000 b/d (one fifth) reach the U.S. Gulf, West, or East Coasts. This means 2 mbd must be sent through the existing pipeline network into the Midwest and the Rockies; leaving Canadian producers with no alternatives to a $30 discount to WTI (and an even greater discount compared to global crude oil

prices).[22]

About 1 mbd of the crude oil sent to the U.S. from Canada is blended bitumen, similar to heavy crude oil. Assuming no transportation bottlenecks, like grades of crude oil should be valued similarly. Recent data from the Energy Information Administration (EIA) for 2013 shows that the average landed cost of Canadian crude is $81.26 while the average landed cost of Venezuelan crude is $99.89, a difference of $18.63. Most of this difference is attributable to transportation bottlenecks and market saturation in the Midwest (PADD 2) and Rockies (PADD IV). As figure 18 indicates, this discount has widened substantially in the past three years.

In 2007, just before the onset of the shale boom, Canadian producers enjoyed pipeline redundancy and optionality (exports to the U.S. were only 1.9 mbd); the difference in landed costs for Venezuelan and Canadian crude oil was only $5.75. Most Venezuelan and Mexican crude oil purchased in the U.S is in the form of heavy crude oil imported into the Gulf via tanker, therefore the price difference of $18 does not represent the discount of heavy crude oil compared to higher quality light sweet oil, but rather substantial transportation and market saturation discounts.[23] For example, the average landed cost for Nigerian crude oil, a premium light sweet crude oil, is $113.42 compared to $99.89 for Venezuelan crude oil, a $13.53 price difference. This difference in price reflects the light heavy differential. Canadian crude oil is discounted by over $30 per barrel compared to light sweet Nigerian crude oil. Transportation constraints are responsible for two thirds of this discount.

Figure 18. U.S. Landed Costs of Crude Oil by Country[24]



Source: EIA

[22] Western Canadian Select (WCS) was -$25 to WTI as of September 12th 2013. (WSC $83, WTI $108, Brent $112). WCS is the benchmark for heavy Canadian crude from the oil sands (typically produced by in situ methods and sent to the U.S. via pipeline with condensate).

[23] The average API gravity of Venezuelan heavy crude oil is 24. The average API gravity of the heavy crude oil from the Canadian oil sands is 22 (blended bitumen). See Appendix for further discussion on crude oil quality and benchmarks

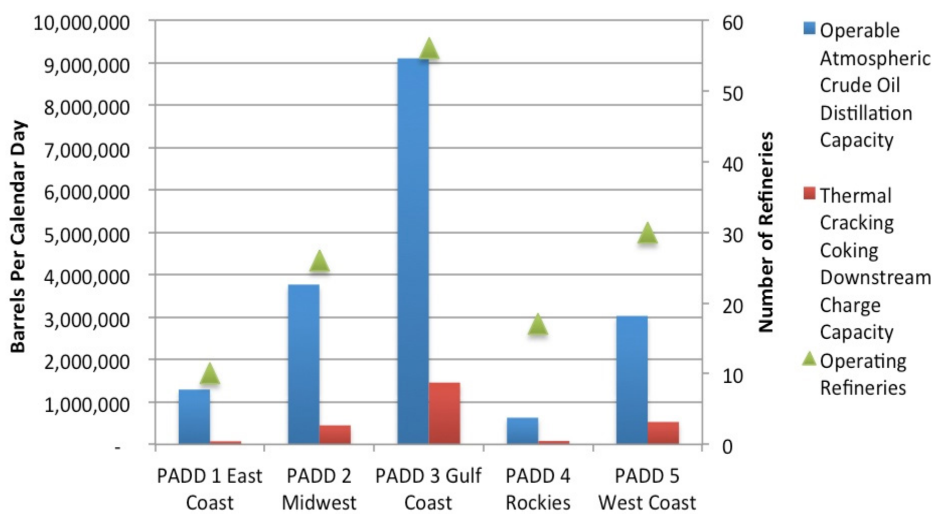
[24] "The dollar per barrel price of crude oil at the port of discharge. Includes all charges associated with the purchase, transportation, and insuring of a cargo from the purchase point to the port of discharge. Does not include charges incurred at the discharge port (e.g., import tariffs or fees, wharfage charges, and demurrage)." EIA

Refineries: Understanding Crude Oil Types and Destinations

Rising volumes of crude oil from the U.S. and Canada have changed North America's crude oil disposition. Refineries in central U.S. and Canada are now processing only Canadian and domestic crude oil. These processing centers have reached saturation and cannot process additional volumes of Canadian or domestic crude oil. Moderate upgrades and expansions can be made, but would do little to solve the larger market saturation issue. Infrastructure must be built to move these light sweet and heavy oil barrels out of the producing centers and to the refining centers with spare capacity to process those respective types of crude oil. Refineries in the Rockies and the Midwest have been the prime beneficiaries of discounted crude oils, but economic benefits must be widespread for the long-term sustainability of the petroleum renaissance.

Refineries on the West Coast and the East Coast have begun purchasing discounted domestic (and to a lesser extent Canadian) crude oil, shipping it to their facilities by rail. Rail has enabled light sweet Bakken crude oil to get to its natural market along the East Coast, but additional infrastructure needs to be built to allow for further production growth in both the U.S. and Canada. North American production growth can be improved if new crude oil supplies have access to transportation infrastructure that permits production to reach refining centers well matched to crude oil supplies. Specific grades of crude oil must move efficiently to major refinery markets that are geared to process those types of crude oil. Major pipeline projects such as Keystone XL would move heavy Canadian crude oil to the Gulf Coast, a refinery district built to process heavy crude oil. Several expansion projects by Enbridge are planning to move light sweet Bakken crude oil to eastern Canadian refineries, geared to process a lighter crude oil slate.

Figure 19. Coking Capacity, Refining Capacity, and Operating Refineries by PADD



Source: EIA

Which Refinery Districts Want the Heavy Crude Oil and Which Want the Light Crude Oil?

Not all oil is created alike and different refineries have different appetites for crude oil. While refining is an extremely complicated process, put simply, refineries with coking capacity have the ability to process heavy crude oil. A coker allows a refinery to process and upgrade the heavier, bottom of the barrel, components in heavy crude oil into more valuable light products. Figure 19 indicates refining capacity in blue (operable atmospheric crude distillation capacity) and the coking or heavy processing capability in red (thermal cracking coking capacity) for each refining region in the U.S.[25]

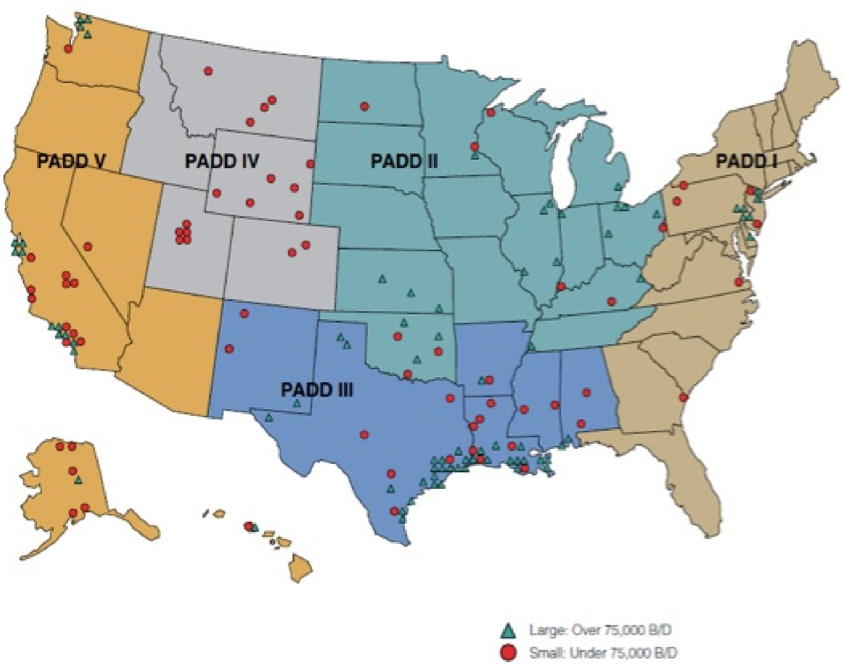
Figure 20 organizes refining regions into PADDs (Petroleum Administration Defense Districts)[26] and shows where each refinery is located.

PADD 1 – East Coast Refineries

The East Coast (PADD 1) historically imported light sweet crude oil from Africa and the Middle East. These refineries, for the most part, are less complex and designed to process largely light and medium crude oils with few inherent "bottom of the barrel" components. Only one refinery on the East Coast has a coker and it is currently receiving heavy Canadian crude oil via rail.

East Coast refineries have historically been characterized by low margins and high oil acquisition costs. They also face competition from European gasoline exports (European dieselization policies have left the continent with a gasoline surplus). Over the past decade, several refineries on the East Coast have either been closed or put up for sale. Several of these refineries have been acquired by new owners

Figure 20. Petroleum Administration Defense Districts (PADDs)



Source: AFPM

[25] Coking capacity is not direct representation of heavy crude oil processing capacity, rather an indication of the region's ability to process heavy crude oil.

[26] PADD or Petroleum Administration Defense District is a carryover term from WWII used to designate and organize areas for fuel usage.

and have avoided closure by supplanting expensive foreign imports with discounted Bakken crude oil via rail and barge. Bakken crude oil is well suited for East Coast refineries because it is light and sweet and similar in quality to imports from North Africa and the Middle East. The East Coast will remain a prime market for Bakken crude oil along with the West Coast, due to inland and Gulf Coast light sweet crude oil market saturation.

PADD 2 – Midwest Refineries

Since 2008, the Midwest (PADD 2) has been the primary destination for rising output from the Canadian oil sands as well as Bakken crude oil. Almost all foreign imports into the Midwest are from Canada.[27] These supplies have been heavily discounted, reflecting limited opportunities to move the crude oil to higher value destinations (thereby increasing demand and competition for these crude oils). Many of these refineries have invested heavily in upgrades in order to process additional volumes of heavy Canadian crude oil. PADD 2 has a significant amount of coking capacity and refines both heavy blended bitumen from Canada as well as upgraded bitumen in the form of synthetic crude oil.[28] Additional refinery upgrades set to come online in the next three years will add to PADD 2's coking capacity. These upgrades will enable refiners to process additional volumes of heavy crude oil, but will displace up to 500,000 b/d of current light sweet processing, further incentivizing light sweet Bakken crude oil to move to the East Coast and West Coast, most likely via rail.

PADD 3 – Gulf Coast Refineries

The Gulf Coast has one of the most sophisticated and complex refining centers in the world, capable of processing heavy, viscous crude oils such as Canadian bitumen, Mexican Maya, and Venezuelan heavy crude oil. The Gulf Coast has the majority of the United States' cokers (and over 8 mbd of total refining capacity), yet receives only 118,000 b/d of Canadian crude oil. Projects such as Keystone XL and Enbridge's Seaway expansion are vital to bringing heavy Canadian oil directly to the Gulf, helping to alleviate steep discounts on Canadian crude oil by debottlenecking the Midwest and replacing declining volumes of Venezuelan and Mexican imports, the primary heavy crude oils imported into the Gulf, both of which are suffering from production declines.

In 2008, before the resurgence of the Permian Basin and the discovery of the Eagle Ford, Bakken producers began railing oil to St. James, Louisiana to seek relief from rising price discounts in North Dakota. As rail activity out of the Bakken proliferated, more crude oil was sent to St. James where the necessary offloading capacity and infrastructure quickly developed. Today the Gulf Coast is almost entirely saturated with light sweet crude oil. It is expected that before the end of 2013 all light sweet imports into the Gulf Coast will cease, notwithstanding

27 Only 30,000 b/d are from Saudi Arabia.

28 Synthetic crude oil (often referred to as SCO or Syncrude) is mined oil sands crude that is upgraded into lighter crude. It typically trades at a $1 to $3 premium to WTI. It is similar in quality to light or medium crude oil and it is very flexible in a refinery. It also has high distillate yields. Please see EPRINC's primer of the Canadian oil sands

contractual obligations. Some refineries in the Gulf have retooled to take in more light sweet crude oil than originally designed, but the limit has nearly been reached. Demand will no longer exist for additional light sweet Bakken barrels as production from the Eagle Ford continues to increase and pipeline flows from west Texas (Permian Basin barrels) continue to rise.

PADD 4 – Rockies Refineries

Similar to the Midwest, the Rockies (PADD 4) have been the destination market for large volumes of light sweet domestic production and surging Canadian imports (both heavy as well as synthetic crude oil). These refineries have enjoyed higher margins from discounted Canadian and domestic crude oil. Much like the Midwest, refineries in the Rockies are fully supplied with North American crude oil. Unless these refineries undergo significant upgrades and expansions, no additional volumes of either domestic or Canadian crude oil can be processed in PADD 4.[29] Because Guernsey, Wyoming is a major destination for Bakken crude oil as well as Canadian crude oil, several rail projects near this destination hub have been announced over the course of the year. These projects may offer an outlet for domestic and Canadian crude oil to the West and Gulf Coasts via rail.

PADD 5 – West Coast Refineries

California refineries have historically processed heavy crude oil from local production and Alaskan crude oil shipped by pipeline (Trans-Alaska Pipeline throughput has been on a steady decline). As both sources decline, waterborne imports into California from Colombia, Saudi Arabia, and Russia have increased. Washington, unlike California, is connected by pipeline to Canada and its refineries receive heavy and synthetic crude oil from Canada. Washington's proximity to North Dakota has also enabled it to access Bakken crude oil at competitive prices through rail shipments.

The technical configuration of California refineries is well suited for processing heavy Canadian barrels; however, there is considerable uncertainty on whether regulatory initiatives in California will permit the processing of additional Canadian heavy crude oil volumes. California's Low Carbon Fuel Standard (LCFS) may prohibit (or make too costly) the processing of higher volumes of heavy Canadian oil given regulatory constraints on lifecycle emissions from Canadian oil sands production. Furthermore, infrastructure to move large volumes of Canadian oil to California refining centers is lacking. Some refiners in California are looking to receive Bakken oil via rail, but have yet to obtain the necessary permits to build rail facilities to receive the crude oil. Some refineries are currently receiving volumes via rail. Waterborne shipments remain a potential cost-effective option for moving additional Canadian supplies to California. However, Canadian production from Alberta must first reach a deep-water port. Transportation solutions for moving Albertan production

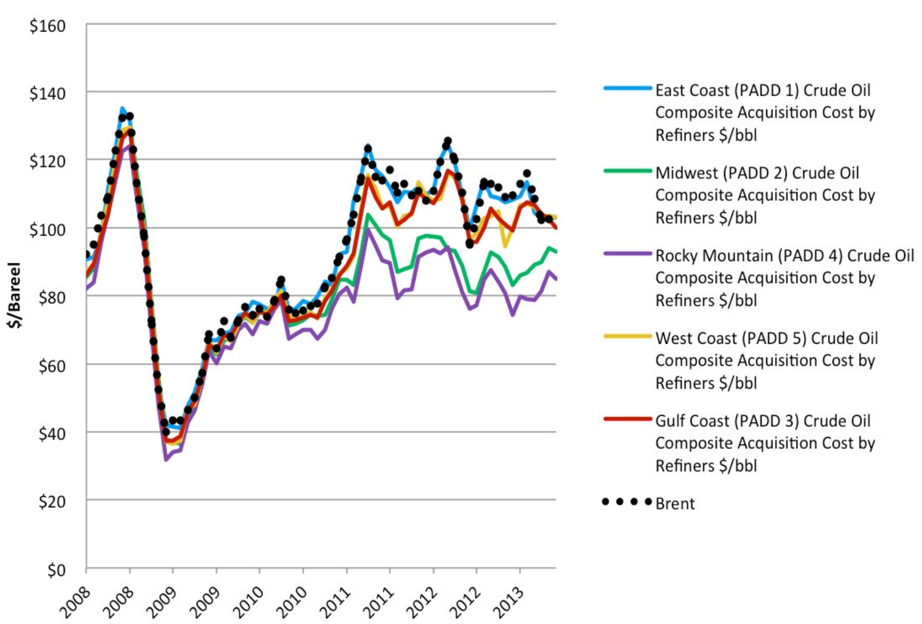
29 Only domestic and Canadian crude oil are processed in PADD 4. See Appendix for total imports vs. Canadian imports by PADD.

to deep-water ports on the West Coast of Canada also face opposition. Although several proposals are underway to move crude oil production from Alberta to West Coast ports, British Columbia has resisted pipeline construction and additional tanker traffic along the coast. Another alternative would be to transport rail shipments from Washington to refineries along the West Coast via barge (for both Bakken and Canadian crude oil to refineries in California).

Costs Per Barrel by Refinery District

Refinery Acquisition Costs (RAC) by PADD show the per barrel acquisition cost of crude oil feedstock in each region. In recent months, RACs in PADDs 1, 3, and 5 have converged. This has benefitted refineries in PADD I which have historically had the highest RAC among U.S. refining centers, importing almost all of their crude oil from North Africa and the Middle East. The composite RAC shown below is the average RAC for both domestic and foreign barrels. The coasts are seeing slightly lower RACs than in the past as more refineries gain access to domestic oil production, but their purchasing discounts are far less than their inland peers. The price discounts for both domestic and Canadian oil are evident in the RACs for both the Rockies (PADD 4) and the Midwest (PADD 2).

Figure 21. Composite Refinery Acquisition Cost by PADD



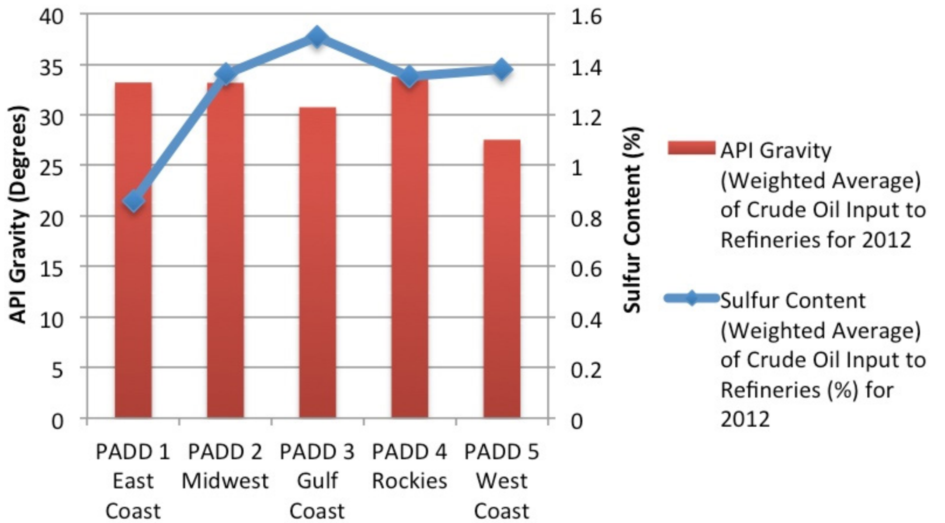
Source: EIA

Medium Crude Oil Grades and the Need for Blending

Figure 22 shows the average oil quality consumed by each refining region in 2012.[30] The Gulf Coast and the West Coast both refine heavier and more sour crudes than the other three refining districts. However, the Gulf Coast's average API gravity for 2012 was significantly higher than the West Coast. These differences in crude oil gravity illustrate the influx of light sweet oil being refined in the Gulf Coast. PADD 4 (the Rockies) is refining both light sweet crude oil produced domestically as well as heavier and more sour crude oils from Canada. This is reflected in the higher API gravity (indicating lighter oils) and the higher sulfur content (indicating more sour oils). It is also important to note that on average, the U.S. crude oil refining slate is not overly heavy or overly light,

30 A higher API gravity number indicates a lighter crude oil whereas a lower API gravity number indicates a heavier crude oil. The higher the sulfur percentage the more sour the crude oil and the lower the sulfur percentage the sweeter the crude oil.

Figure 22. API Gravity and Sulfur Content by PADD for 2012



Source: EIA

it is medium sour. The average API gravity for the U.S. in 2012 was 31 degrees with a 1.41 percentage of sulfur. The average API gravity on the East Coast for 2012 was 33 degrees; in comparison, light sweet Bakken crude oil has an API gravity of around 46 degrees. While 33 degrees is a relatively light-medium crude oil, Bakken crude oil at 46 degrees is extremely light.

A significant amount of medium and medium sour crude is refined in the United States. Not every refinery runs just heavy crude oil or just light crude oil; rather refineries are configured to process different and blended crude slates. Sending heavy Canadian crude oil to the West and Gulf Coasts and sending light sweet Bakken crude oil the East Coast will help match refineries to their desired crude types, but it will not solve the problem entirely.

Given the current rise in production of both domestic and Canadian crude oil, refinery feedstock composition is diverging into a bifurcated slate of extremely light sweet crude oil and heavy sour crude oil.[31] Surging production from both ends of the crude oil spectrum has created a "dumbbell" effect for refineries. Because many refineries are tooled to run an overall medium grade oil, blending must occur to displace medium and medium sour imports on the coasts. This will enable these regions to process additional volumes of both light and heavy crude oil. Blending is not new to the industry, but it is becoming more widespread and can be done by a third party or by the refineries themselves (with the necessary infrastructure). As this dumbbell effect becomes exacerbated, blending will become more important.

Since 2010, U.S. refineries have enjoyed higher operating margins by gaining access to discounted domestic crude oil barrels and increasing utilization rates by expanding exports of middle distillates (diesel) and other refined products.[32] To meet the desired production levels of middle distillates, refiners will have to adjust their crude oil slate and their refinery operations to produce a product slate that properly balances declining demand for gasoline and rising demand for distillate. Heavy crude oil has the

31 See appendix for figures explaining light and heavy crude oil

32 The U.S. now exports over 1 mbd of distillate. Please see appendix for more information.

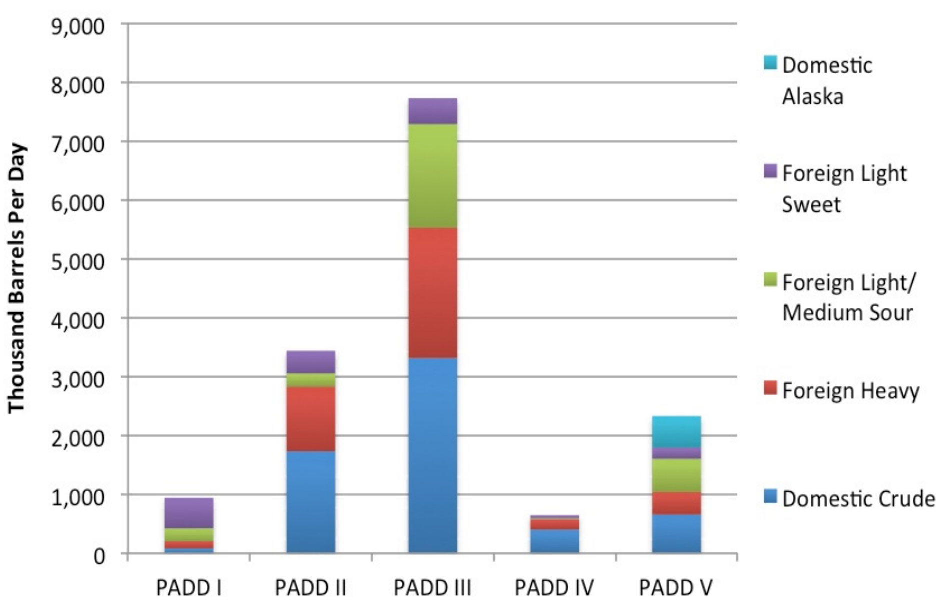
added benefit of larger distillate yields than a lighter barrel. Synthetic crude oil may play an important role due to its flexibility in refineries and its large distillate yield.

Import Displacement Potential

The current crude oil slate, when examined by refining district, illustrates both the refining region's oil appetite as well as the need and opportunity for infrastructure to bring light sweet and heavy crude oil to higher value refining centers. Figure 23 shows the distribution of crude oil by characteristic and origin processed in each PADD. The "foreign light sweet" portion is roughly equivalent to the existing potential for light sweet domestic production can to directly displace foreign imports (should the necessary infrastructure be built to bring this oil from producing regions to refineries on the coasts). At the time of this survey, conducted by CAPP, the amount of foreign light sweet crude oil refined in the U.S. was 1.6 mbd. As indicated by figure 23, only a small fraction of each refining district's crude oil slate consists of "foreign light sweet" crude oil. The majority of light sweet imports remain on the East Coast in PADD 1, the natural home for light sweet Bakken crude oil.

The amount of foreign heavy crude oil refined in the U.S. is 4 mbd. The non-Canadian portion of this foreign heavy crude oil is 2.3 mbd.

Figure 23. Crude Oil Composition by Refining District



Source: CAPP 2013 Refinery Survey

Heavy Canadian crude oil from the oil sands could directly displace 2.3 mbd of heavy crude oil imports, largely imports from Mexico and Venezuela into the Gulf Coast. This will require the development of planned pipeline expansions from Cushing to the Gulf Coast as well as Keystone XL and possibly rail shipments.

Beyond displacing current imports of light and heavy crude oil, blending must occur in order to absorb larger volumes of both light and heavy oil. The amount of non-Canadian light and medium sour imports in the U.S. is roughly 2.3 mbd. The Gulf Coast and the West Coast currently run the largest volumes of light and medium sour crude oils. In addition to blending both domestic light sweet crude oil with heavy Canadian crude oil to supplant these imports, these refining regions could also accept larger volumes of synthetic crude oil (SCO), upgraded bitumen from the oil sands, similar in quality to a light or medium oil.

Available refining capacity for processing heavier gravity crude oil may be available on the West Coast as Californian and Alaskan production declines, offering additional heavy and medium sour capacity for domestic and Canadian crude oil.

Capturing the Arbitrage: Alternative Modes of Transportation

While crude by rail has proved to be a flexible and relatively cost effective option to move oil to market, the continued reliance and expanded use of rail is also the result of limited pipeline infrastructure and changing market dynamics. The original incentive to move crude by rail originated in North Dakota at the beginning of the Bakken oil boom when the region was short on pipeline capacity and experiencing rapid production growth. Upstream producer EOG spearheaded the Stanley rail project to move their oil directly to St. James, Louisiana, in order to avoid steep pricing discounts and gain some control over the transportation of their oil production. This rail facility provided the company flexibility and diversification in getting their crude oil to market. In a high discount environment companies could move their crude oil to a more favorable coastal market where they could receive Brent pricing instead of discounted Clearbrook or Cushing prices. While rail shipments are more costly than pipeline, there is room to pay for rail transportation when the WTI Brent discount ranges from $10 to $20.

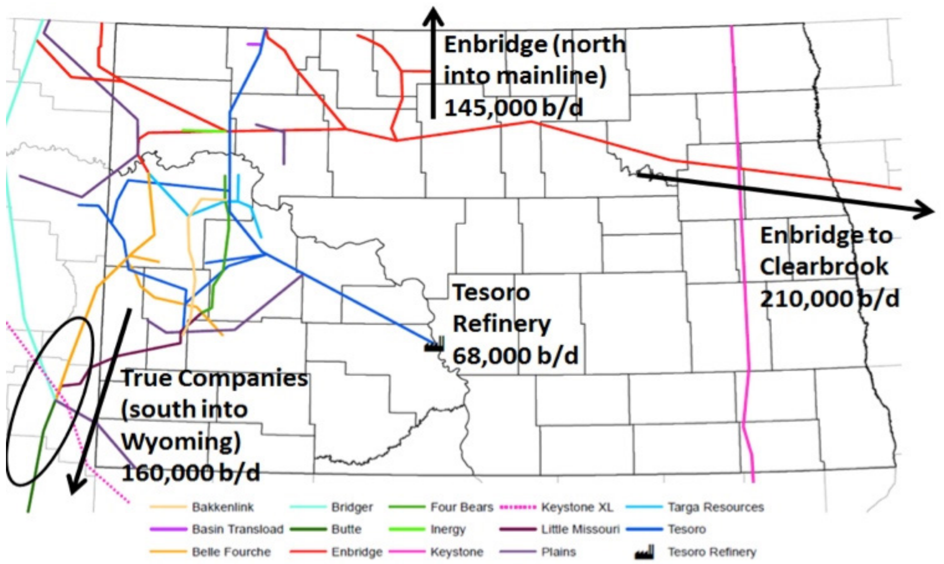
Today, a large amount of spare pipeline capacity exists to move Bakken crude oil from North Dakota. This is due to the growth in rail terminal capacity and rail's wide footprint, which connects the Midwest to the East and West Coasts. New pipeline capacity has come online, but it has been largely built along existing routes and to existing markets. Some producers may wish to allocate some, but not all, of their production to these existing markets while maintaining the flexibility to move a portion of their production via rail to different markets where they can achieve higher netbacks.

Over 650,000 b/d, or 67 percent of Williston Basin production, is moving by rail out of North Dakota. This number has dipped slightly in recent months as the WTI Brent spread has narrowed, but the spread between North Dakota light sweet and Brent is still wide enough to warrant prudent crude by rail shipments. The cost to ship crude by rail varies from railroad to railroad, shipper to shipper, and deal to deal. However, EPRINC estimates that the cost to move crude oil from North Dakota to the East Coast and West Coast is between $10 and $15. Crude oil shipment via rail is relatively costly, and the narrowing price spreads along with an overbuild of origin terminals has helped cool the market. However, crude by rail shipments are likely to stay at elevated levels, between 500,000 b/d and 800,000 b/d over the coming months, because of the necessity to move crude oil efficiently in a tight pipeline capacity environment and the desire for diversification and flexibility by shippers. Regardless of price spreads, spare pipeline capacity out of North Dakota is likely to remain. As described in previous sections, the middle of the U.S is saturated with light sweet crude oil and the Gulf Coast is quickly becoming saturated as well. Producers are choosing to put large volumes of crude into tank cars rather than use existing pipelines which serve saturated markets.

The only available homes in the U.S. for Bakken crude oil are the East Coast and West

Coast, both of which are inconveniently disconnected from the crude oil pipeline system. The pipeline systems out of North Dakota offer producers little incentive to commit barrels to their pipelines. Enbridge's system can send Bakken crude oil north and east into the Enbridge mainline. Both options settle in Clearbrook, Minnesota, a market that typically discounts Bakken crude oil and is sensitive to regional refinery maintenance, pipeline maintenance, and Canadian supply disruptions. True Companies' system sends crude oil south into Wyoming, another saturated market. Both of these pipeline systems have been severely underutilized in the last several months as producers moved their barrels to rail seeking higher priced markets through diversification and flexibility in where they could send their crude oil. Rail will remain a major mode of transportation for North Dakota simply because the current pipeline network cannot move Bakken crude oil to the East or West Coasts where both the refining capacity and demand exist.

Figure 24. Pipeline Capacity Out of North Dakota



Source: NDPA with EPRINC Additions

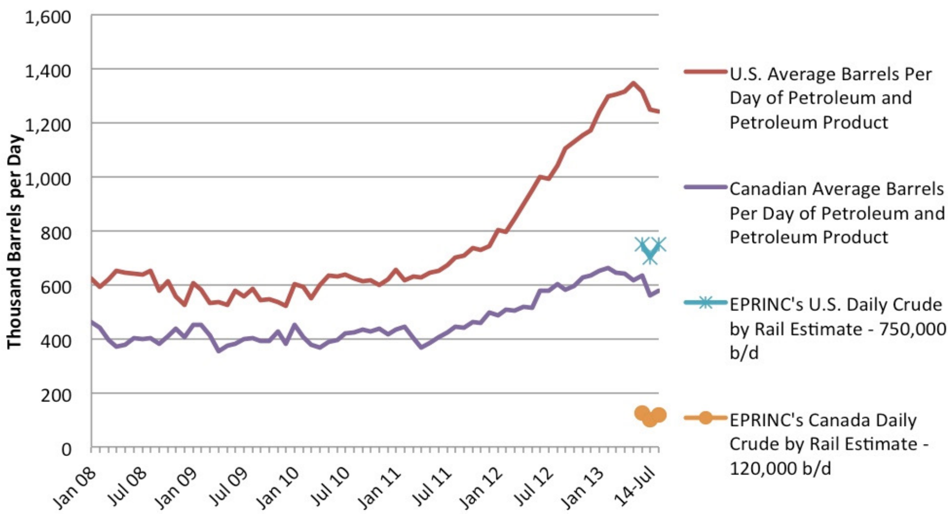
The majority of crude oil moving by rail within the U.S. and Canada is from the Bakken. EPRINC estimates that of the 1.2 mbd of crude oil and petroleum product moving via rail in the U.S. alone, roughly 750,000 b/d are crude oil. Of the 580,000 b/d of crude oil and petroleum product moving via rail in Canada, approximately 120,000 b/d are only crude oil. Together, 870,000 b/d of oil are moving via rail in the U.S. and Canada, of which 650,000 b/d are Bakken crude. An additional 100,000 b/d are likely moving from plays within the U.S. (likely from the Niobrara and the Anadarko Basin). Roughly 120,000 b/d are moving out of Canada to refineries within Canada and along the U.S. East Coast.[33] Roughly 600,000 b/d of ethanol bound for the gasoline supply are also moved via rail.

Canadian railroads have not moved as quickly as U.S. railroads to accommodate growing, discounted production in their backyard. This is partially attributable to the lack of destination facilities available to accept Canadian crude oil, particularly in the form of heavy bitumen. Origin terminals are being planned and rapidly built in Canada, but only a handful of facilities are currently available to unload and dispatch heavy bitumen via rail.[34] To take advantage of economies of scale, unit trains, which use over 100 tank cars, will be required (manifest shipments will take

33 All "crude only" numbers are EPRINC estimates.

34 The most likely method for shipping bitumen via rail would be in the form of heated cars to avoid the use of diluent or condensate which adds significant costs. Without the diluent however, rail cars must be heated to be properly unloaded and this requires the necessary infrastructure at the unloading facility.

Figure 25. Daily Rail Movements of Crude Oil and Petroleum Product



Source: Association of American Railroads[35]

place but they will be more costly as they lack economies of scale). Realizing the efficiencies of unit trains will require destination facilities to have the necessary infrastructure and capacity to unload hundreds of railcars at a time. Some efforts to build destination facilities are now underway. Crude by rail will become an increasingly important asset for Canadian producers going forward. But given the lag in infrastructure build out for heavy oil unloading, blended bitumen via unit train may be adapted in the near term. Rail will be an essential, rather than an additional, mode of crude oil shipment should neither Keystone XL, Northern Gateway, nor TransCanada's Energy East projects be approved.

Until recently, the regulatory environment for the transportation of crude oil via rail has been relatively modest. Unlike oil pipelines in which the tariff structures are regulated by FERC (Federal Energy Regulatory Commission), moving crude by rail requires no regulatory pricing approvals. Companies and third parties negotiate prices with the railroad for either short or long-term rates. Individual states have discretion in how they regulate terminal build out. This regulatory flexibility is partially responsible the quick adaptation by the oil industry to move their crude by rail.

While there have been spills from crude by rail shipments, data from the past three years suggest the volumes have been relatively minor. However, the recent tragedy in Lac Magentic, Quebec has changed the perception of the safety of moving crude oil by rail. While investigations are still taking place, Canadian regulators have already made changes to safety requirements. Immediate regulatory changes which require trains to be manned at all times, staffed with at least two crew members, and require more brakes to be engaged along the course of the train when stopped have been implemented. The American Association of Railroads (AAR) has recently responded to the requests by the Federal Railroad Administration (FRA) to implement similar measures. The containment integrity (strength) of the railcars moving the crude oil has also come into question; however, industry responses suggest that the fleet of railcars today will be quickly updated to approved DOT standard tank cars with thicker tanks and more robust safety bumpers. Further issues

35 Crude and petroleum product includes liquefied gases, asphalt, fuel oil, lubricating oil, jet fuel, etc. U.S. operations exclude U.S. operations of CN and CP. Canadian operations include CN and CP and their U.S. operations. One carload holds 30,000 gallons (or 714.3 barrels).

remain for the role of short line railroads regarding the movement of crude oil and other hazardous chemicals in light of recent difficulties obtaining adequate insurance coverage.

Barges

Producers have turned to barging in recent years as partial solution to infrastructure challenges. They are utilizing both inland waterways and rail-to-barge routes. The lack of pipelines and discounted prices have led Bakken producers to embrace rail-to-barge methods to send crude oil to coastal refineries. Eastbound crude oil is railed to Albany, NY then loaded onto barges and shipped down the Hudson River to East Coast refineries. Westbound crude oil is currently railed to Washington refineries. The potential exists to barge crude oil along the West Coast to refineries in California (but the Jones Act may make the cost of doing so prohibitive). In addition, rail-to-barge facilities have been developed along inland waterways on the Upper Mississippi River and Illinois River, connecting Minneapolis and Chicago to the Gulf Coast. These rail-to-barge facilities primarily transport Bakken crude oil, but also move Canadian crude oil railed into PADD II.

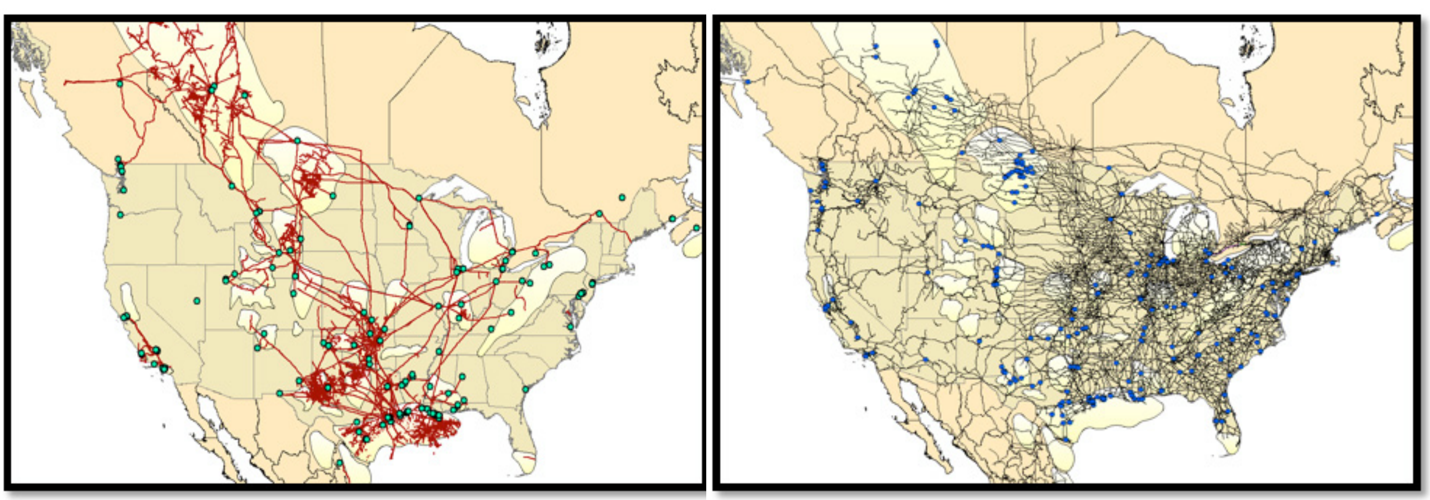
Figure 27 shows the substantial increase in barge shipments from the Midwest to the Gulf Coast since 2005, currently at 100,000 b/d, up nearly 90,000 b/d since 2010.

Given the large volumes of crude oil flowing into the Gulf, barge movements are playing an important role in moving production to refineries along the Gulf Coast. Barge shipments of crude oil from Corpus Christi rose from almost zero in early 2012 to 300,000 b/d by year end.[36] Barging volumes may decrease when pipelines such as the Ho-Ho start taking crude oil from Houston to refineries in St. James, Louisiana. As such infrastructure is built within the Gulf, less barging may be needed for short coastal movements. Nevertheless, barging will remain an integral mode of transportation as demand grows to move crude oil along the East and West Coasts, but the Jones Act will ultimately limit its potential.

The Merchant Marine Act of 1920, better known as the Jones Act, requires the use

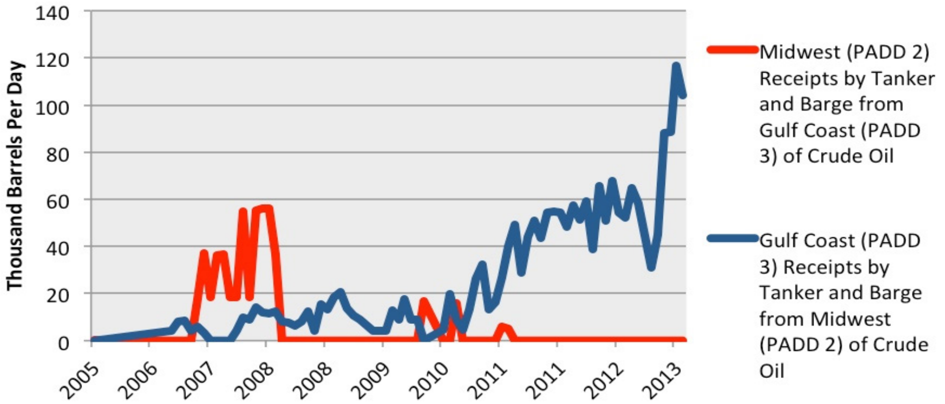
36 Fielden, Sandy. "We're Jammin' – But Can All Dat' Crude Get Through? - Corpus Christi Terminals." RBN Energy. N.p., 13 2 2013. Web. 31 Jul. 2013. http://www.rbnenergy.com/were-jammin-but-can-all-dat-crude-get-through

Figure 26. Crude Oil Pipelines and Refineries vs. Railroads and Terminals



Source: EPRINC Maps using Hart Energy data via ArcGIS

Figure 27. Barge Shipments from Midwest (PADD 2) to the Gulf Coast (PADD 3) Petroleum Product



Source: EIA

of U.S. flagged and owned vessels to transport goods between U.S. ports. Jones Act vessels must be owned by an American company, manned by an American crew, and constructed in America.[37] Jones Act requirements apply to both tankers and barges. These requirements increase the cost of shipping between U.S. ports. The exact premium imposed by the Jones Act is unclear, but it will likely become an issue of discussion as light sweet crude oil continues to make its way to the Gulf Coast and Eagle Ford production breaches 1 mbd.[38] The requirement to move larger crude oil volumes throughout the North American continent raises the issue of whether exemptions to the Jones Act are needed or whether the Jones Act can be adapted more efficiently so ships can play a larger role in moving domestic crude oil to refining centers (for example, shipments of domestic light sweet crude oil from the Gulf Coast to the East Coast).

In Conclusion…

Pipeline capacity did not adapt quickly enough to move rising crude oil volumes sufficiently to market. Constraints, both commercial and regulatory, in building out new pipeline infrastructure and expanding existing infrastructure contributed to steep price discounts for Canadian, Bakken, and other domestic crude oil. Rail now offers producers the ability to select which markets they will sell their crude oil without requiring a long-term destination commitment. Production uncertainty in these new shale/tight oil formations may have played a role in large scale pipeline development early on. Pipelines typically require a high degree of confidence that shipping volumes can be sustained long enough to amortize a pipeline over 20 years. Because the scale and speed of this tight/shale oil development in combination with growth from the Canadian oil sands was so fast, many companies were unable to adapt.

Regardless, new pipeline projects face uncertainty in obtaining construction permits. Not only is the regulatory structure and approval process for greenfield pipeline projects cumbersome and uncertain, producers (shippers) are now hesitant to commit large volumes into a single market for a long period of time. In addition, refineries may be less willing to commit to pipeline volumes as they work to adapt to new crude oil slates with varying discounts.

37 The Jones Act requires the crew must be 75 percent American and that vessels limit the amount of foreign materials used in repairs. Only 10 percent by weight may be used.

38 It costs about $4 a barrel to ship crude oil from the Gulf Coast to the Northeast on a Jones Act vessel. Bussey, John. "Oil and the Ghost of 1920." Wall Street Journal. 28 Aug. 2013. Shipping crude oil from the Gulf Coast to the Northeast on Jones Act barge costs about 15 cents per gallon, or $6.30 per barrel. EIA

Pipeline Development

The resurgence in rail (and to a lesser extent barge) reflects the desire of producers to maintain flexibility (production volumes not committed to a pipeline for 20 years) and achieve improved netbacks by shipping to the East Coast, West Coast, or Gulf Coast. It also reflects the lack of pipeline development needed to reach those desired markets and the market saturation that developed due to the slow pace of pipeline build out. As production rose, pipelines adapted to move new crude oil volumes from the producing regions into the larger existing pipeline network. The delay in major projects such as Keystone XL created market uncertainty regarding the construction of large-scale greenfield projects and inhibited rapid debottlenecking of Canadian and Bakken crude oil in the Midwest. As bottlenecks and chokepoints developed, prices discounted, incentivizing crude by rail shipments. The potential for rail to compete with certain pipeline projects puts the commercial viability of those projects into question.

For pipelines, obtaining the necessary long-term commitments from shippers to develop a pipeline is difficult now that producers have the optionality of both market diversification and short-term contracts via rail. Producers can shift their production volumes to alternative destinations as market conditions change. Pipeline development has largely been limited to move oil to existing markets. Greenfield projects to a new market, for example a pipeline from North Dakota to the East Coast or North Dakota to the West Coast, might attract higher desirability by shippers, but the regulatory uncertainty is too great.[39] Expanding, retrofitting, reversing, or twinning along existing routes seems to be the preference among midstream companies. These options also carry financial risks because most projects feed into existing markets. Oneok's pipeline project to move Bakken crude oil from the Williston Basin to Cushing, Oklahoma was canceled because it could not attract the interest of shippers and the willingness to commit sizeable volumes for the long-term.

Despite recent cancelations, the vast amount of crude oil on the market has created a need for both pipelines and alternative modes of shipping. Today a plethora of pipelines are in the process of coming online, under construction, or in the first stages of development. The majority of this new pipeline capacity, roughly 7.7 mbd as estimated by EPRINC, is composed of pipeline reversals, expansions, twinning, repurposing, and retrofitting, further confirming the dilemmas and dynamic market the midstream sector now faces. Utilizing existing assets and existing rights of way saves midstream companies considerable capital and time.

39 These regulatory risks could include political opposition and NIMBYism

Figure 28. Major Pipeline Projects by Name, Capacity, and Type

Pipeline Name	Company Name	Capacity (thousand barrels per day)	Type
Mainline	Enbridge	0-800	Expansion
Line 9	Enbridge	300	Reversal
Southern Access	Enbridge	1,200	Twinned/Reversal
Line 6B	Enbridge	500	Expansion
Flanagan South	Enbridge	600	Twinned
Toledo	Enbridge	100	Expansion
Sandpiper	Enbridge	225	Expansion
Eastern Gulf Crude Access/ Trunkline	Enbridge/ Energy Transfer	420-660	Conversion (gas to oil)
Trans Mountain	Kinder Morgan	590	New
Cochin	Kinder Morgan	95	Reversal
KMCC	Kinder Morgan	300	Conversion
Dakota Express	Koch Pipeline Company	250	New
Pettus to Corpus Christi Line	Koch Pipeline Company	250	New
Longhorn	Magellan Midstream Partners	225	Reversal
BridgeTex	Magellan Midstream Partners	300	Conversion
Niobrara Falls	NuStar	125	New
Basin Pipeline	Plains All American	450	Expansion
Cactus Pipeline	Plains All American	200	New
Mississippian Lime	Plains All American	175	Expansion
Western Oklahoma	Plains All American	75	Expansion
Southern Trails	Questar	120	Reversal
Seaway	Seaway	450	Expansions/Twinned
White Cliffs	SemCrude (joint)	150	Expansion
Glass Mountain	SemGroup	140	New
Ho-Ho	Shell	250	Reversal
Westward Ho	Shell	900	New
Permian Express	Sunoco	150	Expansion
West Texas - Houston Access	Sunoco	44	New
West Texas - Longview Access	Sunoco	30	New
West Texas - Nederland	Sunoco	40	New
Pony Express	Tallgrass Energy (formerly KM)	210	Reversal/Expansion
Keystone	TransCanada	508	New
Keystone XL (extension to Keystone)	TransCanada	830 (original Keystone 508)	New
Keystone Gulf Coast	TransCanada	700	New
White Plains Pipeline expansion	White Plains	150	Expansion
Total		**12,092**	

Source: EPRINC Table

Regulatory procedures still exist, but the timeframe from idea to construction is usually shortened when existing assets and rights of way are already in place.

Figure 28 lists major pipeline projects since 2012 and highlights the capacity of each project along with the type i.e.: expansion, conversion, twin, etc.

As the pipeline project table suggests, significant investments are being made in the midstream space. Companies are actively working to move new crude oil volumes to market, but a new normal for pipeline permitting, development, and construction, coupled with production increases in remote regions, means that alleviating many of these new-found bottlenecks and chokepoints will take time. As the midstream space works to relieve congestion in Cushing, new constraints in the Gulf arise. Without the ability to export crude oil from the Gulf, either abroad or to the East Coast (via water shipments), new inbound pipeline capacity together with rising Permian and Eagle Ford production will cause logistical challenges within the Gulf Coast. Figure 29 breaks down inbound pipeline capacity additions to Cushing and the Gulf. Over the next three years Cushing, Oklahoma and the Gulf Coast will see an influx of inbound pipeline capacity.

Over 3.5 mbd of new inbound transportation capacity into Gulf Coast is set to come online between now and 2015. In recent months multiple pipeline projects have begun flowing oil from the Permian Basin to the Gulf Coast, altering the traditional flow of Permian Basin crude oil into Cushing.[40] In 2012, only small volumes of Permian Basin crude oil moved to the Gulf Coast, roughly 500,000 b/d were sent into Cushing via pipeline. By year end, 400,000 b/d of available pipeline capacity from west Texas to the Gulf Coast will be constructed and made available. By the end of 2014, pipeline capacity will rise to approximately 700,000 b/d.

This redirection of oil flow is critical to alleviating the bottleneck in Cushing, Oklahoma; however, coupled with rising Eagle Ford production, over 1 mbd, another 700,000 b/d of light sweet crude oil into the Gulf will not only finish backing out all light sweet imports, it will also fundamentally change the flow of crude oil within the Gulf Coast. Major pipeline flows into the Houston area are rising from minimal volumes to a projected 3+ mbd by the end of 2014. Like Cushing, Houston is becoming a storage hub and terminal center for the Gulf Coast. Rail shipments of Bakken crude oil into St. James, Louisiana will undoubtedly come to a stop in the coming months (depending on contractual arrangements).

The planned Trunkline, a pipeline from Patoka, Illinois to St. James, Louisiana will bring an additional 660,000 b/d of light sweet crude oil into the Gulf Coast. Because many of these refineries have already reached capacity for processing light sweet

40 This has helped with the recent narrowing of the WTI Brent spread by moving hundreds of thousands of barrels out of Cushing. The recent narrowing of the WTI Brent spread also reflects severe disruptions in Canadian production caused by flooding in June and subsequent draw downs in Cushing from Midwest refiners who could not get Canadian crude.

Figure 29. Inbound Cushing and Gulf Pipeline Projects

Inbound and Outbound Pipelines				
Pipeline	**Company**	**Origins**	**Capacity**	**Startup**
Inbound: Cushing, Ok				
Flanagan South	Enbridge	Flanagan, IL	600	mid-2014
Basin Pipeline	Plains All American	Colorado City, TX	450	In service
Mississippian Lime	Plains All American	Coldwater, KS	175	mid-2013
Western Oklahoma	Plains All American	Reydon, OK	75	Q1 2014
Glass Mountain	SemGroup	Alva, OK. Arnett, OK	140	Q4 2013
White Cliffs	SemCrude	Platteville, CO	150	1H 2014
Pony Express	Tallgrass Energy (formerly owned by Kinder Morgan)	Baker, MT/Guernsey, WY	230	Q4 2013
White Plains Pipeline expansion	White Plains	Platteville, CO	150	Q1 2014
			Total: 1.97	
Outbound: Cushing, OK		**Destinations**		
Keystone Gulf Coast	TransCanada	Nederland, TX	700	2H 2013
Seaway Pipeline	Seaway	Freeport, TX	400	In service: Q1 2013
Expansion			450	Q2 2014
			Total: 1.55	
Inbound: Gulf Coast		**Origins**		
Keystone Gulf Coast	TransCanada	Cushing, OK to Nederland, TX	700	2H 2013
Seaway Pipeline	Seaway	Cushing, OK to Freeport, TX	400	In service: Q1 2013
Expansion			450	Q2 2014
Trunkline	Enbridge/ Energy Transfer	Patoka, IL to St. James	660	2015
Longhorn	Magellan Midstream Partners	Crane, TX to Houston, TX	225	In service: 2013
BridgeTex	Magellan Midstream Partners	Colorado City, TX to Houston	300	2Q 2014
Niobrara Falls	NuStar	Platteville, CO to Borger, TX	125	Q2 2013
Permian Express	Sunoco	Wichita Falls, TX/ Colorado City, TX to Port Arthur, TX	150	In service: 2Q 2013 (90)/Phase II 2014 (60)
Permian Express II			200	Q3 2014
West Texas - Houston Access	Sunoco	Midland, TX to Houston	40	In service: Q2 2012
West Texas - Longview Access	Sunoco	Midland, TX to Longview	30	Planned Q1 2013
West Texas - Nederland	Sunoco	Midland, TX to Nederland	40	Q2 2013
Cactus Pipeline	Plains All American	McCamery, TX to Gardendale, TX	200	Q1 2015
			Total: 3.52	
Within Gulf		**Origins**		
Ho-Ho	Shell	Houston, TX to St. James, LA	250	1H 2014
Westward Ho	Shell	St. James, LA to Houston	900	1H 2015
			Total: 1.15	

Source: EPRINC

crude oil from the Eagle Ford and elsewhere, refineries will either have to blend this crude oil to make a medium barrel or adjust their refineries to run a lighter crude oil slate. Regardless, such high volumes of additional light sweet crude oil moving into the Gulf coupled with rising Eagle Ford production will create bottlenecks and dislocations. The Gulf Coast market will have to adapt to the influx of these light sweet crude oil barrels. To absorb rising volumes of light sweet crude oil, the Gulf Coast will need to import additional heavy oil barrels to blend accordingly. (The market could discount light sweet barrels substantially, incentivizing refineries to run a lighter crude slate. Or, refineries and midstream operators may work to construct large scale blending capacity to utilize multiple crude slates more efficiently at the refinery.)

Planned pipeline capacity and development represent a significant amount of infrastructure investment. They are helping to alleviate many of the bottlenecks and inefficiencies throughout the existing pipeline network. However, even with all of these scheduled projects, congestion and inefficiencies will likely remain. First, some of these projects may not be developed; secondly, none of them solve the Bakken dilemma. In fact they exacerbate it. As infrastructure develops to move Permian Basin crude oil to the Gulf Coast, Bakken crude oil will no longer have a home in St. James, Louisiana. Production increases from the Eagle Ford will supplant any residual capacity available from refineries. The Trunkline project, which plans to move light sweet crude oil out of the Midwest, may not come to fruition because of these factors.[41] Bakken crude oil will be left without a home accessible by pipeline and will subsequently continue to move by rail to the East and West Coasts.

41 In order to continually support such high volumes of light sweet crude oil imports, the Gulf Coast would need to add several hundred thousand barrels a day of heavy oil imports to be blended with the light sweet crude oil in order to create a medium barrel crude oil. Infrastructure to blend such high volumes will need to be developed in tandem with these pipeline projects. Or, blending could take place in the Midwest and the Trunkline could transport a medium crude oil to the Gulf.

Risks, Uncertainty, and Regulatory Challenges

There are two primary constraints impeding the construction of new crude oil transportation infrastructure in North America: commercial and regulatory risk. Perhaps the most frequently encountered constraint is the commercial risk associated with new pipeline construction. Most pipeline projects are only economically viable when they secure long-term supply commitments from upstream producers. Without such commitments, a pipeline operator cannot be certain that their project will generate the revenues necessary to justify the costs and the time involved to plan, permit, construct, and operate.

The North American petroleum renaissance emerged at a pace that surprised many industry participants, and did so in parts of the United States where the petroleum sector had either been left for dead (PADD 1 refineries), in decline (the Permian Basin and west Texas) or barely existed at all (North Dakota). The renaissance's rapid emergence and continued growth has created uncertainty, even within the industry, regarding its ultimate size and scope. With this uncertainty in mind, many upstream producers find it risky to commit to a pipeline project that requires a 20 year contract. Such a commitment locks a portion of their production into a single market along a fixed route. If market conditions change, for example a shift in a refining center's appetite for a given crude oil, producers with fixed commitments will not be able to fully adjust to the new market dynamics and could be forced to absorb significant economic costs. Given the ongoing evolution of the petroleum renaissance, and in particular crude oil demand among refineries in coastal regions combined with still fledgling shale plays, producers remain hesitant to commit to long-term pipeline projects.

Kinder Morgan's $2 billion Freedom pipeline conversion from west Texas to California was canceled because it lacked both the commitment of shippers and the commitment of purchasers. Potential shippers found the short-term flexibility of rail to be more attractive given uncertainty in the market and the changing price spreads. Refineries on the purchasing end cited concerns over the potential receipt of Bakken crude oil via rail from North Dakota. Both parties were not willing to commit to long-term contracts and risk potential upside of other more flexible options.

Rail shipments of crude oil have emerged to fill the transportation vacuum created by the lack of new pipeline projects in certain regions. In one sense, it can be argued that the proliferation of rail, particularly in the Bakken, has prevented the construction of some new pipelines. However, one must consider whether Bakken production would have reached its current extent without access to coastal refinery regions via rail shipments. Rail has provided flexibility and optionality that pipeline projects cannot offer. It has done so in a short time period. Without

rail optionality in the Bakken, producers would still be faced with the risk of locking themselves into a market that becomes undesirable in the future (i.e., a market which offers them a lower wellhead value). For example, commitments to send Bakken crude oil south by pipeline would have likely exacerbated exiting bottlenecks in Cushing and nearby regions, thereby lowering wellhead values and investment in the Bakken. It would have also reduced the availability of light sweet crude oil to refiners in PADD 1, preventing PADD 1's second lease on life.

Not all pipeline projects are hindered by commercial risk. Demand for the proposed Keystone XL pipeline was clear to oil sands producers and Gulf Coast refiners. Canadian oil sands are well matched to the refining complexity of many Gulf Coast refineries (some of which were modified specifically to process Canadian bitumen). With the expected steady increase in Canadian oil sands production, more capacity was going to be needed to send oil from Alberta to the Gulf Coast. With this in mind, Keystone XL was proposed and received commercial backing from producers. The risk to Keystone XL, and several other projects, is regulatory.

The $5.3 billion[42] project has faced numerous obstacles in its quest for a Presidential Permit over the past four years, including a second application, a re-route, and two Environmental Impact Statements (EIS). President Obama has stated that the pipeline will only be approved if the project "does not significantly exacerbate the problem of carbon pollution."[43] Environmental studies as well as a review of over 1.2 million public comments are coming to a close. The final decision on Keystone XL is scheduled for late 2013, but there have already been rumors of a push-back until early 2014. A major concern with Keystone XL is whether the U.S. is setting a precedent for an uncooperative energy policy agenda.

Similarly, Enbridge's 731 mile long Northern Gateway pipeline is still in the process of receiving final approval from Canada's National Energy Board (NEB). The Joint Review Panel, an independent panel appointed by the NEB, recently wrapped up its public hearing process in June of 2013. The $6 Billion project faces opposition from environmental groups and First Nations.[44] The pipeline is planned to transport crude oil to the coast of Kitmat, British Columbia from Edmonton, Alberta for export to Asia and the U.S West Coast.[45] It will also send condensate in the reverse direction from the West Coast. First Nations argue against an increase in crude oil tanker traffic along the coast, currently at an estimated level of 79,000 b/d.[46] Enbridge has already spent $500 million on environmental studies and legal fees defending the project.

These two major pipeline

42 Anticipated costs by TransCanada

43 President Obama remarks on climate change at Georgetown University, June 25, 2013

44 First Nations refers to one of the Aboriginal groups in Canada. There are 617 First Nations communities, which represent 4 percent of the Canadian population.

45 Condensate is used as a diluent for heavy crude oil. Canada needs condensate so it can export crude oil to the U.S. via pipeline.

46 Kinder Morgan's Trans Mountain system is the only Canadian crude oil pipeline to Canada's west coast. Trans Mountain has a capacity of 300,000 b/d, 221,000 b/d is allocated to refineries, while 79,000 b/d is allocated for marine exports.

projects offer Canadian producers viable outlets to move their crude oil to markets where ample demand exists. The delay in both of these projects, particularly Keystone XL, has created extensive uncertainty around the ability to build a large-scale greenfield pipeline in the future and the role environmental opposition will play in future infrastructure development. Current opposition to Keystone XL is unique in that rather than targeting the pipeline itself, it is primarily focused on the oil sands that would flow through the pipeline.

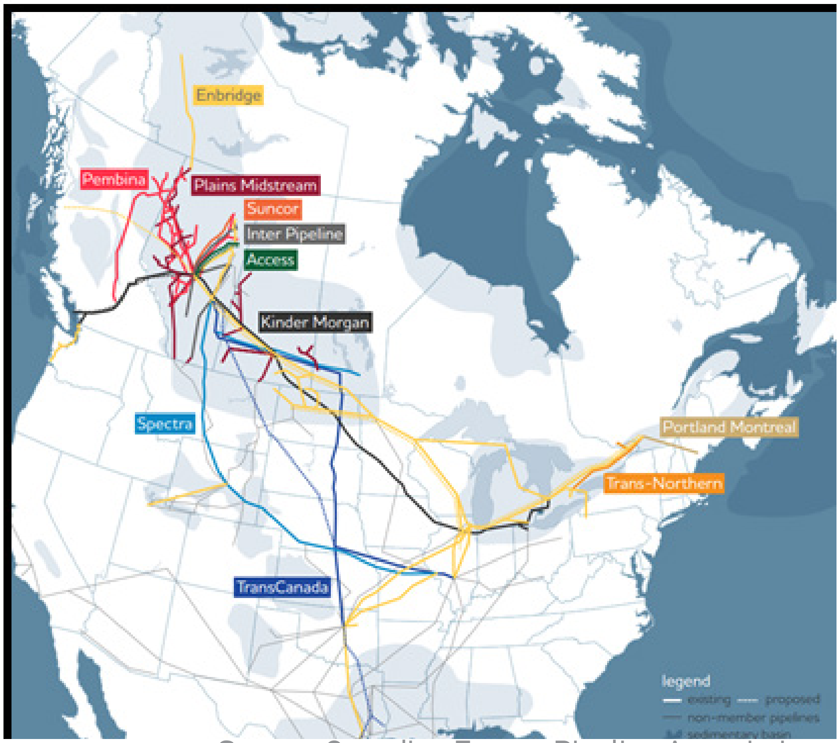
Beyond these highly politicized projects, a major question is whether regulatory concerns are impacting smaller scale pipeline projects. As noted in this report, millions of barrels of capacity are planned and under construction to move these new crude oil supplies to market, but significant limitations in the pipeline network will remain. Smaller midstream companies have noted a substantial increase in the time it takes to receive infrastructure permits and complete a project. There are a number of factors contributing to delays. First, obtaining the necessary rights of way (ROW) can be difficult in regions which are new to high volume oil production, such as the Bakken. Landowners experiencing increased oilfield activity on their land and in their communities are becoming less willing to quickly accommodate upstream and midstream companies seeking to lay pipelines on their land. Second, the number of applications for pipeline projects has increased since the onset of this shale/tight oil boom. Regulators simply have more projects to evaluate than they did before. Lastly, the permitting process is quite complex and often requires coordinating with multiple agencies simultaneously. This process, which varies from state to state, is often unclear and has been exacerbated by the recent rush of planned pipeline projects.

While the regulatory climate can be cumbersome, new and existing infrastructure projects must be closely regulated in order minimize local safety hazards and environmental risks. Pipeline spills and rail accidents that have occurred in 2013 suggest that there is room to improve both regulatory statutes and enforcement of said statutes. However, when actions are taken to impede infrastructure development and used as a proxy in a campaign against a given energy supply, the results of those actions might ultimately be both economically and environmentally counterproductive. The economic impact of prohibiting the Keystone XL pipeline, for example, will have economic costs to the U.S. economy, the refining sector, and the consumer. It will also impact the Canadian economy and federal, provincial, and local governments.

Without shipments of oil sands to the Gulf, the U.S. will have to replace potential Canadian imports with waterborne tanker imports from countries with fewer shared economic ties (and probably increased volatility). In addition, rail shipments of Canadian oil sands will increase. Canadian producers will continue to pursue alternate transportation routes. Inhibiting the Keystone XL pipeline and other well-regulated transportation projects, in an attempt to either reduce GHG emissions or transition to alternative forms of energy, will have discernible economic, political, and environmental consequences without making progress toward the said desired goals.

APPENDIX

Figure 1. Canadian Pipeline Map



Source: Canadian Energy Pipeline Association

Figure 2. Keystone XL Map

Source: TransCanada

Figure 3. U.S. Product Exports

Source: EIA

Crude Quality and Benchmarks

Crude oil is valued within the market according to its quality and in turn the product slate it produces. Benchmarks have been created in markets so that crude oils of varying quality and value can be transparently and easily traded. Because WTI and Brent, the two primary global crude oil benchmarks, are considered high quality crude oils, oils of lower quality generally sell at a discount to WTI and Brent.

Refiners face highly competitive markets for the sale of petroleum products processed at their facilities and are constantly improving their operations to improve what is called the "crack spread." A crack spread is the difference between the acquisition cost of the crude oil and the value of the refined products produced. Some oils are more costly to fully process than others. This cost difference is largely, but not entirely, based on two characteristics of crude oil: the API gravity and the sulfur content. In general, crude oil with lower API gravity and higher sulfur content are more costly to refine into a standard product slate than crude oil with higher API gravity and lower sulfur content.

Both Brent and WTI crude oil are of very high quality and yield high volumes of gasoline and distillates. WTI has an API gravity of 39.6 degrees (making it a "light" crude oil) and contains only 0.24 percent sulfur (making it a "sweet" crude oil). Brent is a combination of crude oil from 15 different oil fields in the Brent and Ninian systems located in the North Sea. Its API gravity is 38.3 degrees (making it a "light" crude oil, but not quite as "light" as WTI), and it contains about 0.37 percent sulfur (making it a "sweet" crude oil, but slightly less "sweet" than WTI).

WTI and Brent are the world's crude oil benchmarks because of both their quality and also their countries' respective financial hubs (New York and London). This allows the physical crude to be traded in paper contracts in a stable legal environment with sound institutions granting transparency and predictability.

Figure 4. API Gravity by Crude Oil Class

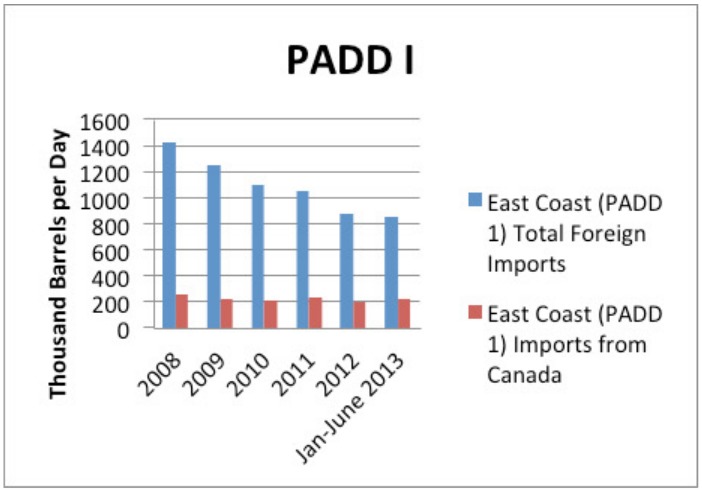
	Property	Range
Crude Oil Class	Gravity	Sulfur
	(°API)	(wt. %)
Light Sweet	35-60	0-0.5
Light Sour	35-60	> 0.5
Medium Medium Sour	26-35	0-1.1
Medium Sour	26-35	>1.1
Heavy Sweet	10-26	0-1.1
Heavy Sour	10-26	>1.1

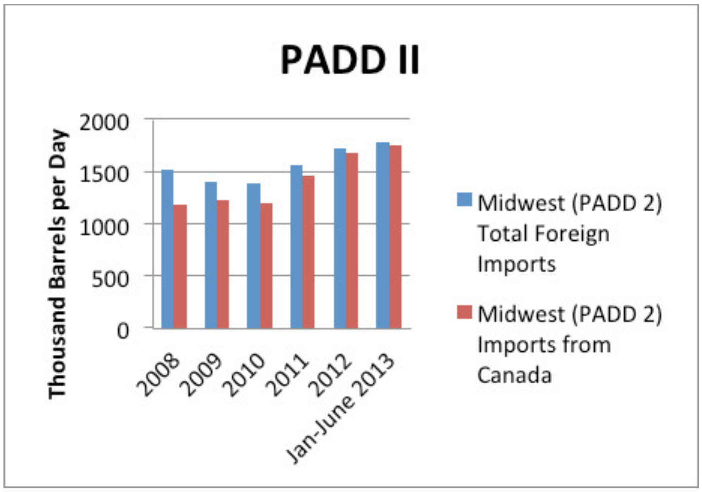
Figure 5. API Gravity by Benchmark

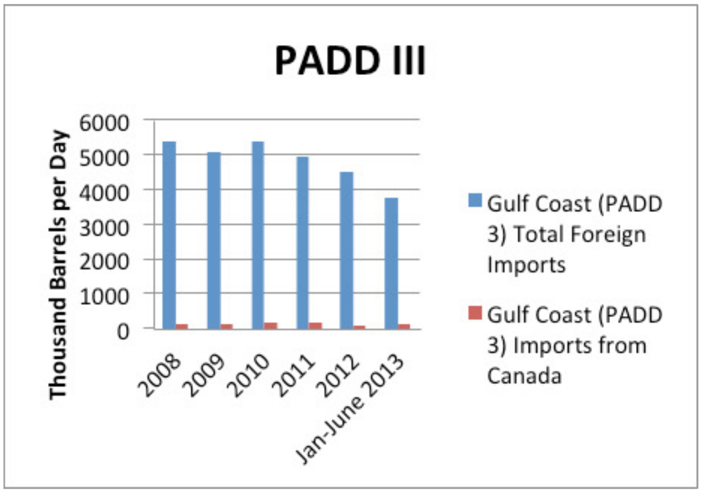
Crude Oil	Country of Origin	Crude Oil Class	Gravity	Sulfur
			(°API)	(wt. %)
Brent	U.K.	Light Sweet	40.0	0.5
West Texas Intermediate	U.S.A.	Light Sweet	39.8	0.3
Arabian Extra Lt. Export	Saudi Arabia	Light Sour	38.1	1.1
Daqing	China	Medium Medium Sour	33.0	0.1
Forcados Export	Nigeria	Medium Medium Sour	29.5	0.2
Arabian Light Export	Saudi Arabia	Medium Sour	34.0	1.9
Kuwait Export Blend	Kuwait	Medium Sour	30.9	2.5
Marlim Export	Brazil	Heavy Sweet	20.1	0.7
Cano Limon	Colombia	Heavy Sweet	25.2	0.9
Oriente Export	Ecuador	Heavy Sour	25.0	1.4
Maya Heavy Export	Mexico	Heavy Sour	21.3	3.4

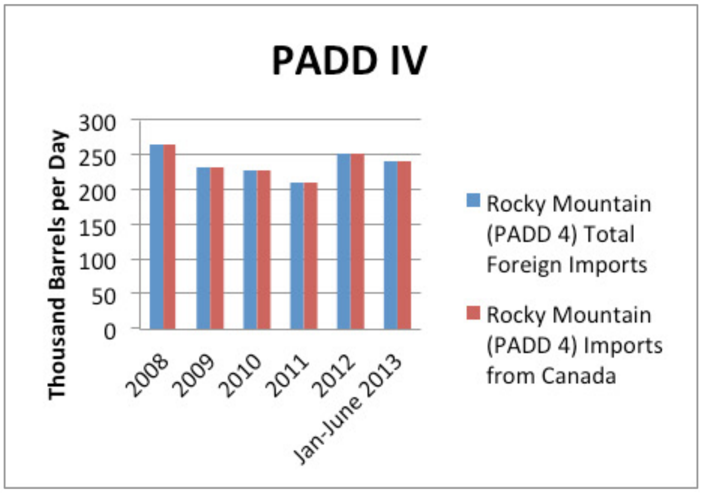
Source: http://www.theicct.org/sites/default/files/publications/ICCT05_Refining_Tutorial_FINAL_R1.pdf

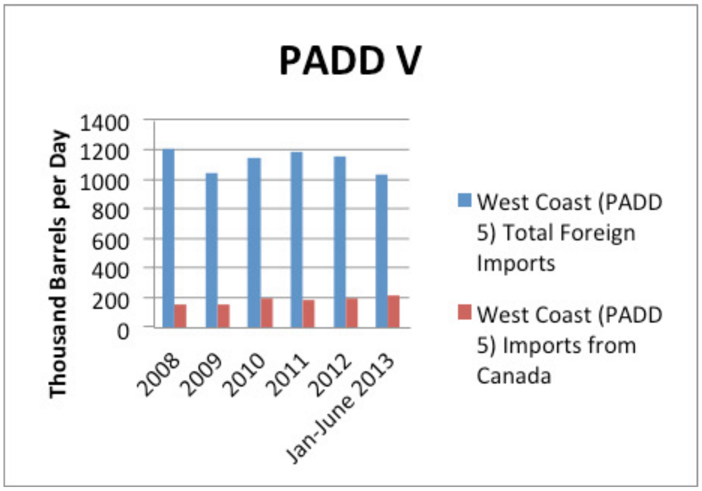
Figure 6. Total Imports vs. Canadian Imports by PADD











Source: EIA, light, heavy, synthetic, and blended bitumen