KIMMERIDGE Energy

Transport Bottlenecks and Arbitrage

The Changing Face of North American Oil

March 2013

A Brief History of Divergent US Oil Prices

Ever since US oil production started to decline in the 1970s, the US has increased its dependence on foreign oil, primarily from seaborne imports. This resulted in weaker economics for inland refiners and a premium accruing to large complex coastal refiners, such as those on the Gulf Coast, which could access a wide variety of seaborne crudes. Indeed, prior to production of crude oil from Canada's oil sands, the majority of crude imports were shipped to the US via the East Coast and Gulf Coast, from areas such as the Middle East, Venezuela, Mexico, the North Sea and West Africa. However, the shift in crude imports towards Canada due to growth in oil sands production prompted a reconfiguration of both the transportation and refining systems in the US over the past decade.

Specifically, the pipeline system was reconfigured through new builds, expansions and reversals, to allow more crude to flow south from Canada into the US Midwest, where a significant amount of refining capacity exists. However, since 2006, limited pipeline capacity to transport growing Canadian crude supplies south to the large Gulf Coast market, has resulted in excess crude supplies in the Rockies and Mid-West. This turned conventional wisdom on its head, with inland refiners enjoying bumper margins due to heavily discounted inland US crude prices.

Additionally, in the last few years the US has undergone a renaissance in inland oil production, which has resulted in lower crude imports, and a changing mix of imported crude types, due to the changing mix of domestic crude produced. Specifically, we have witnessed a marked decrease in overall import volumes, and a change in composition of these imports. The overall quality, as measured by API gravity and sulphur content, has decreased in order to offset increased domestic production of light, sweet crude from onshore tight oil plays. This has meant increased or flat imports from heavy oil producers such as Canada, Mexico and Saudi Arabia, but declining imports from light, sweet producers such as Nigeria, Angola and Algeria. Interestingly, imports from Venezuela are down from their peak, which despite being heavy oil, could be politically motivated as relations between the US and Venezuela have deteriorated, and companies such as ExxonMobil and Chevron have seen their Venezuelan assets expropriated. What is clear is that the US is becoming less dependent on foreign oil, and can be more selective about the source of its imports.

One major issue that has surfaced in the past few years has been discounted domestic crude prices that run counter to intrinsic value based on crude quality. This has given rise to fears that the US oil market is heading in the same direction as the US gas market, with oversupply resulting in lower US oil prices. However, oversupply is not a problem on a national level – rather there are transportation bottlenecks affecting specific regions, and causing price discounts for landlocked crudes as they struggle to find an end market.

Indeed, given the static nature of US refined product demand, and relatively inflexible refinery configurations, producers of both Canadian heavy oil and onshore US tight oil have struggled to get their product to the right end markets. This has been due to inadequate pipeline capacity, as shippers have struggled to reconfigure the pipeline system fast enough to keep pace with the growth in production from Canada's oil sands and inland US tight oil plays.

The result of the above has been supply gluts in the Rockies and Midwest, and heavily discounted oil prices. Midstream operators have been scrambling to expand existing pipelines, build new ones and in some cases reverse the flow of existing pipelines, to accommodate the changes in North American crude supply. However, new pipelines take years to build, and some, such as the Keystone XL project have been held-up by environmental opposition or lack of firm commitments by producers.

Consequently, the large price discounts have presented arbitrage opportunities and forced producers to become more creative, moving an increased amount of oil by rail, and also barge. This is most obvious in the Williston Basin, where a huge amount of oil is shipped by rail, with new routes opening up to the East Coast, where the refineries are perfectly configured to handle Bakken-type crudes. In fact, the heavy discount of Bakken crude has been a lifeline for challenged East Coast refiners, which prior to the growth in tight oil production, struggled to remain economic in a world where the advantage lay with refiners that had upgrading and desulfurization capacity to process cheaper heavy, sour crudes. Additionally, rail companies such as Berkshire Hathaway's Burlington Santa Fe, have benefitted hugely in the past few years from increased crude-by-rail volumes.

However, with the discount of North Dakota oil to WTI narrowing, due to increased transportation options to Cushing (the main crude hub and pricing point in Oklahoma), and new outbound pipeline and rail capacity from both Cushing and the Rockies regions, the question is how will crude prices evolve in these regions going forward?

Crude Quality and the Impact on Pricing

The quality of crude oil directly impacts its value, because of the types of refined products that can be produced from any given crude. In simple terms, higher quality crude oil such as Brent or West Texas Intermediate (WTI) should command a premium to lower quality crude oils such as bitumen or Venezuelan heavy crude, simply because higher quality crudes when refined will produce a higher proportion of high value light products such as gasoline and diesel.

Quality is typically measured by API gravity and sulphur content. API gravity largely reflects the proportion of light to heavy hydrocarbons, with higher API gravity indicating higher content of light hydrocarbons. Higher API crudes therefore produce a greater proportion of gasoline and diesel versus something like bitumen, which produces a high proportion of low-value-heavy-products such as residual fuel oil. Additionally, a low sulphur crude oil will require less de-sulfurization to meet fuel standards, so will command a premium to more sulphurous crudes.

So what determines the quality of crude oil? There are many processes that impact crude quality, including the original type of organic matter that was converted over geologic time to crude oil, the maturation level of the source rock and timing of oil expulsion, and biodegradation. The latter is arguably the most significant when thinking about conventional oil fields and conventional petroleum systems. Biodegradation occurs when oil is expelled from the tight pore spaces within the source rock and into more porous, permeable rocks. During migration from source to trap (field), oil comes into contact with microorganisms (primarily bacteria) which metabolize compounds within the oil, and can result in reduced API gravity, high sulphur content, higher viscosity, higher asphaltene content, higher concentration of certain metals and increased acidity.

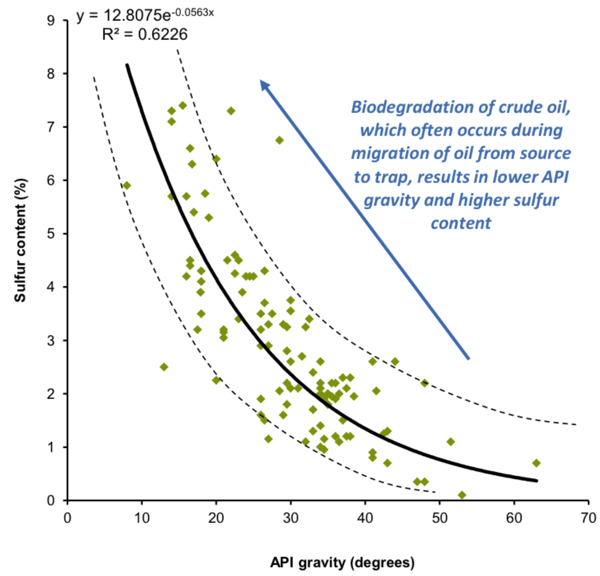


Exhibit 1: API gravity and sulphur content of Iraqi crude oils. Source: Republic of Iraq Ministry of Oil, Geology of Iraq By Saad Z. Jassim, Jeremy C. Goff, Kimmeridge Energy.

Looking at a dataset of crude oils from Iraq (Exhibit 1), there is a reasonably strong correlation between API gravity and sulphur content, which primarily reflects the level of biodegradation of the oil during migration and trapping.

As the world moves towards producing more and more oil from unconventional reservoirs, we should note that one of the biggest differences between conventional and unconventional petroleum systems is the migration distance. Specifically, in unconventional petroleum systems, crude oil is retained in-situ within the source rock (no migration) or trapped in tight carrier beds adjacent or proximal to the source rock (very short distance migration). Oil trapped within low porosity rocks is protected from biodegradation, since pore spaces are too small to allow aerobic metabolism. Additionally, short migration distances allow limited opportunity for the oil to encounter microorganisms that could result in biodegradation. Consequently, oil produced from unconventional reservoirs such as shales or tight carbonates, is almost always light (high API gravity) and sweet (low sulphur).

Notably, the growth in US tight oil production has resulted in a marked increase in the overall quality of domestic crude oil, reversing a steady decades long decline, as crude from the Bakken, Eagle Ford and Permian Basin horizontal plays is typically light and sweet.

Since the US consumes primarily gasoline and diesel, light crude oils should logically command a premium in the US market. Historically this has been the case, but there have been and continue to be periods when oil prices move in a seemingly perverse manner, due to temporal discrepancies between regional supply and disposition.

The most obvious example of this is the persistent discount of West Texas Intermediate (WTI) crude oil prices to Brent or Light Louisiana Sweet (LLS) that emerged in 2006. There are two key factors that have brought about this seemingly perverse situation – the first is the configuration of US refineries; the second is the configuration of the US pipeline/transportation system. In the next section we look at the first factor in more detail.

Probably the Most Complex in the World … the US Refining System

Notably, the US refining system is the most complex in the world and after a decade of major investment in heavy oil upgrading and desulfurization capacity, it is now configured to handle a high proportion of heavy/sour crudes (Exhibit 2). This is because of the historic trend towards heavier/sourer crudes, due to the rapid decline in conventional fields and limited new conventional discoveries. This long term trend resulted in a major CAPEX cycle that saw refiners in the US and globally invest in cokers, crackers, hydrocrackers and desulfurization capacity to deal with lower quality crudes. Additionally, refiners with the most complex configurations should have the highest margins, since they can process low quality, cheap crudes into a high value product slate (i.e. high proportion of gasoline and diesel).

However, the rise of tight oil in the US was not foreseen by refiners (and indeed many people, including major oil companies) – consequently, US refiners are having to rapidly adjust their imports to keep their crude input slates matched to their (relatively fixed) refinery configurations, by offsetting higher quality domestic crude with lower quality imports.

We can see that the renaissance in inland US crude production over the past 3 years, driven by tight oil production in the Bakken, Eagle Ford and Permian Basin, has coincided with a marked improvement in the quality of US crude oil input into US refineries, as measured by API gravity and sulphur content (Exhibit 3). This runs counter to the preceding 3 decades, which saw a steady decrease in API gravity and increase in sulphur content of oils processed by US refineries.

Over the last decade US refiners have invested heavily in upgrading & desulfurization capacity to deal with heavier, more sour crudes such as bitumen.

Taking a more granular look at crude inputs by refinery district, it is clear that areas associated with the boom in tight oil production, such as North

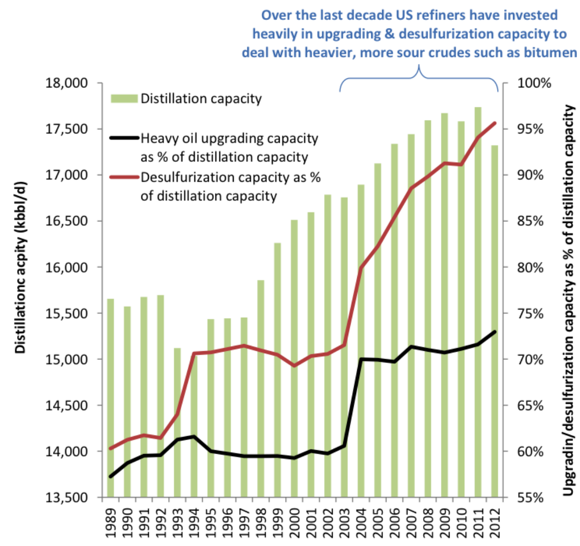


Exhibit 2: Distillation, upgrading and distillation capacity of US refining industry.
Source: OGJ,EIA, Kimmeridge Energy.

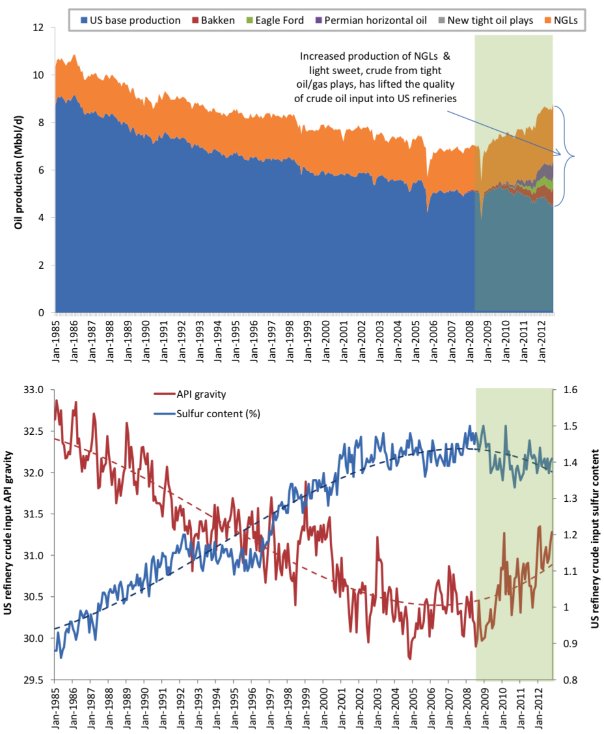
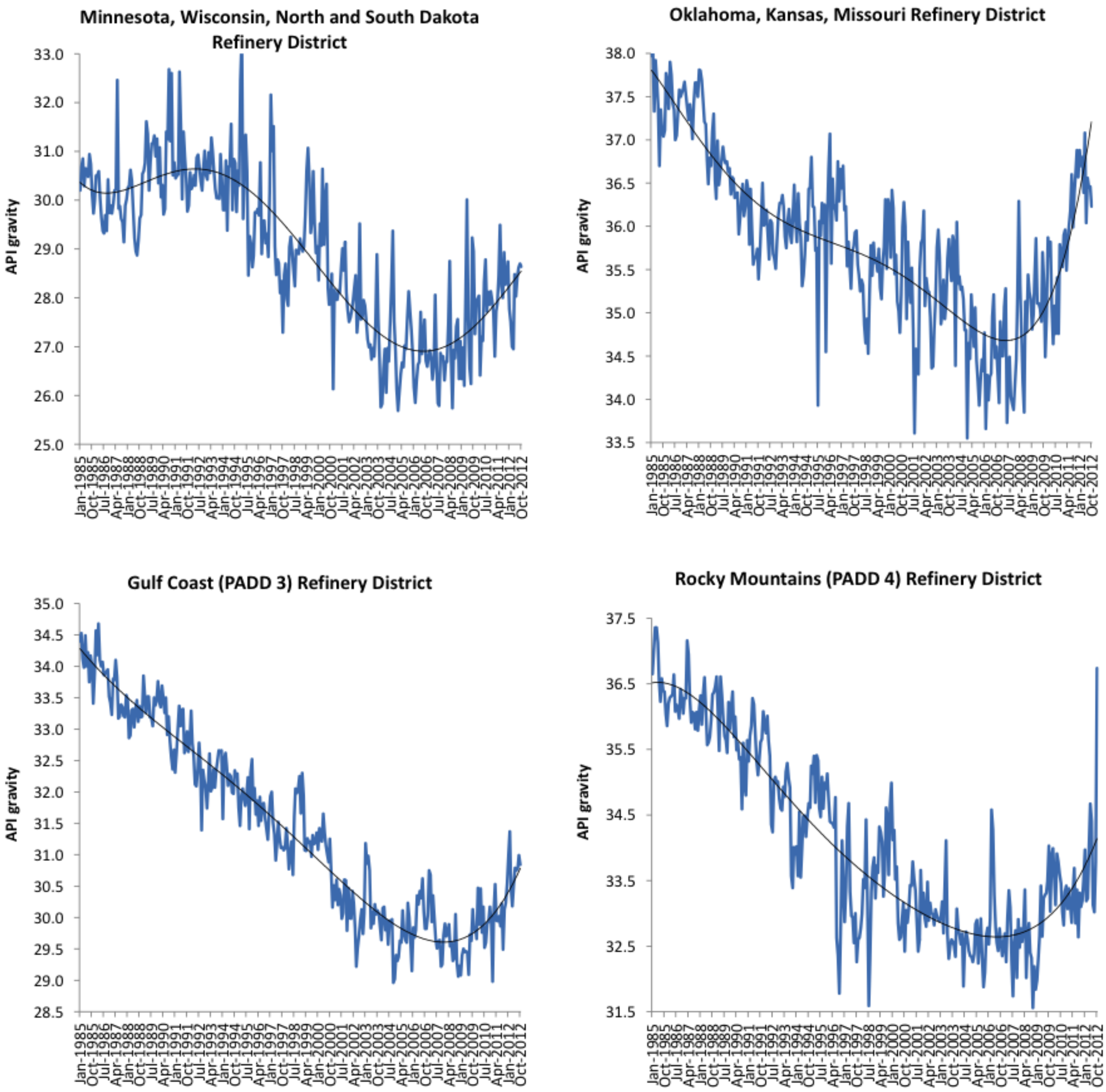


Exhibit 3: US oil production and quality of oil processed by US refineries. Source: EIA and Kimmeridge Energy

Dakota and the Rockies (Bakken), and the Gulf Coast and Oklahoma (Permian Basin and Eagle Ford), have recently seen a significant improvement in crude quality input to their refineries (Exhibits 4-7).



Exhibits 4-7: API gravity of crude imports into US refinery districts. Source: EIA.

The Changing Composition of US Crude Imports

Increased US crude production over the past few years, resulting from the surge in tight oil volumes, has had two notable effects. Firstly it has reduced the overall level of crude imports into the US (Exhibit 8), as US demand has remained broadly flat. And secondly it has meant that US refiners are importing more heavy/sour crudes to balance out the surge in domestic light/sweet crude production from tight oil plays, resulting in a marked decline in the overall quality (API gravity and sulphur content) of crude oils imported into the US (Exhibit 9).

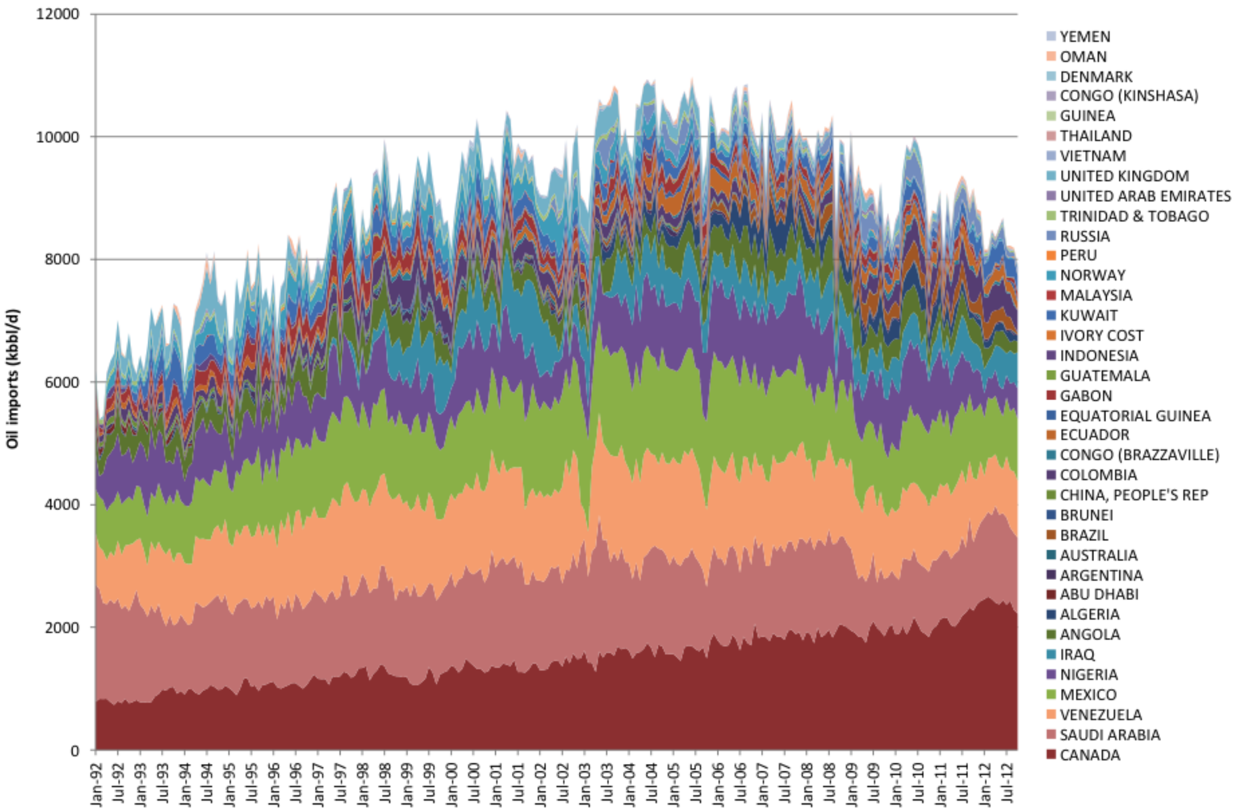


Exhibit 8: US oil imports by country. Source: EIA.

Countries with significant production of lower quality crudes, such as Canada, Saudi Arabia, Kuwait and Colombia, have seen crude exports to the US grow in the past few years. In contrast, countries that primarily produce light/sweet crudes, such as Angola, Nigeria and Algeria have seen a steady decline in exports, as the US has ramped up domestic production of comparable quality crudes. Given the significant investment over the past decade in heavy oil upgrading and desulfurization capacity, US refiners have had to adjust the source of their crude oil, in order to match the input slate for their refineries.

Interestingly, Venezuela has seen a steady and marked decline in crude exports to the US over the past 5-6 years, despite being a producer of heavy/sour crudes, but this could be politically and/or legally driven, following past government asset expropriations from US oil companies. Overall, it is clear that the US is materially adjusting its crude imports, both in terms of amount and quality, in order to account for the surge in domestic production of light/sweet crudes, which runs counter to the prior decade of major investment in heavy oil upgrading and desulfurization capacity in the US refining industry when consensus expectations were for increased processing of heavy, sour crude. Looking ahead, we expect Canada to be the only country to materially increase crude exports to the US, since it is a major producer of heavy/sour crudes, has an integrated pipeline system with the US, and close political ties.

Not only are the composition of crude imports into the US changing as a result of increased domestic production, but flows of crude within the country are also changing significantly, resulting in temporary arbitrage opportunities as the transportation system struggles to keep pace with growing inland production. In the next section we discuss the US crude oil transportation system, which is another major factor affecting US oil prices.

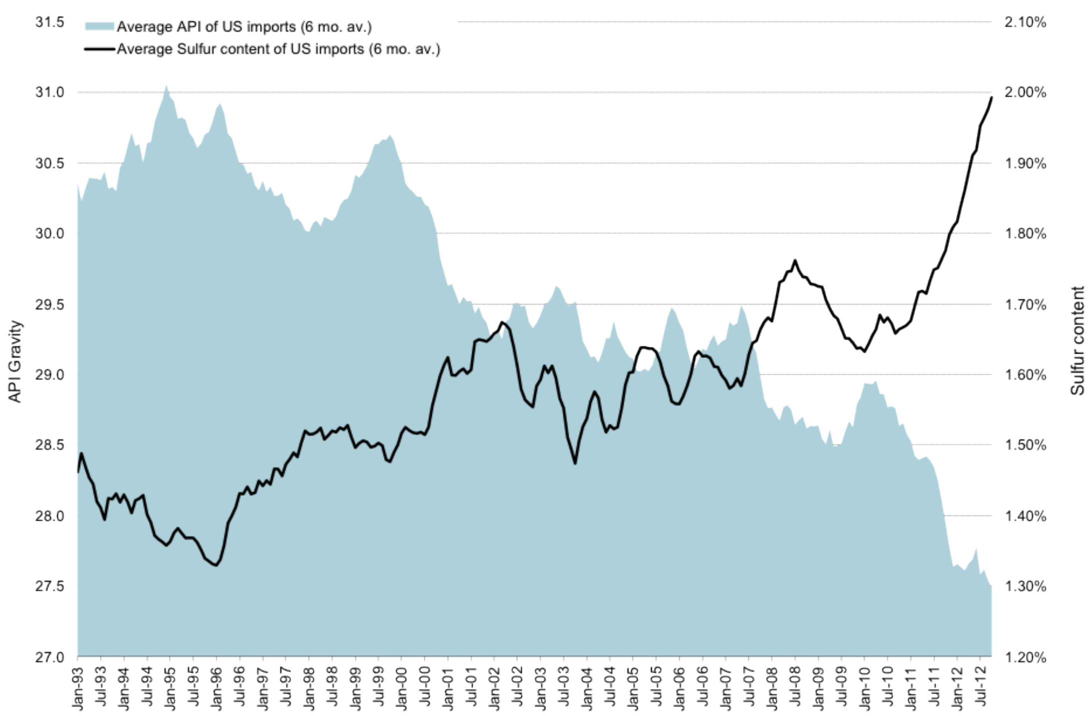


Exhibit 9: API gravity and sulphur content of US oil imports. Source: EIA.

Changing Internal Crude Flows

Prior to the growth in inland crude production from the Bakken and Permian Basin in the last few years, the US pipeline system was reconfigured over time through new builds, expansions and reversals, to allow more crude to flow south from Canada into the US Midwest, where a large chunk of US refining capacity exists. At the same time, US refiners underwent a major capex cycle to upgrade refineries to cope with heavier, sourer crudes such as bitumen, due to both increased crude imports from Canada via pipelines into the Midwest, and increased seaborne imports of heavy, sour crudes into the Gulf Coast region.

Growing crude imports from Canada and slower decline rates in Permian basin production coincided with the reversal of the Spearhead pipeline in 2005, as well as refinery outages, with the result being elevated storage at the Cushing hub, which caused West Texas Intermediate oil prices to move to a discount versus Brent, from a historic premium (Exhibit 10).

At the same time, production from the Bakken had started to increase materially in 2005, and a lack of adequate outbound pipeline capacity and local refinery capacity, caused a discount of North Dakota oil prices versus comparable coastal crudes such as Louisiana Light Sweet. The Cushing and Rockies regions (see Exhibit 11) have continued to experience supply gluts to the present day, resulting in discounted crude prices.

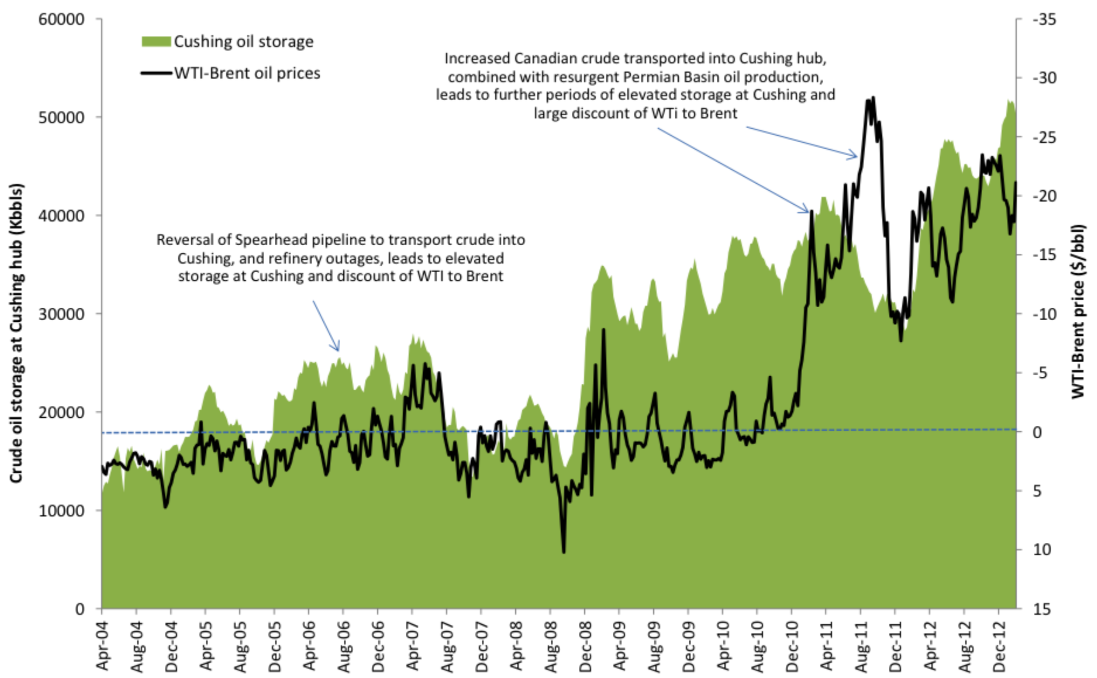


Exhibit 10: Crude oil storage at Cushing and WTI-Brent price differential. Source: EIA.

Notably, the speed and magnitude of Bakken production was almost universally underestimated. While pipeline expansions failed to keep pace with the growth in oil production, rail companies stepped in to transport excess crude out of the region. The first port of choice was to take the crude south to Cushing, where it could travel further on to Gulf Coast refineries. However, this merely exacerbated the existing supply glut at Cushing, and soon oil price differentials between WTI and North Dakota narrowed, making this an unattractive option for producers. Consequently, new rail routes for Bakken oil directly to the Gulf Coast were established, with companies building loading terminals in North Dakota and unloading terminals in places like St. James, Louisiana. However, Gulf Coast refineries are more suited to take heavy, sour crudes, so light, sweet crude from the Bakken has started to flow east to PADD I refineries, which are simple refineries, better configured to process light, sweet crudes such as Brent. These refineries have been largely uneconomic due to high Brent prices, resulting in conversions to storage terminals and Sunoco exiting the refining business. However, more recently, the steep discount of Bakken crude to coastal/seaborne crudes has allowed profitable shipping by rail, despite the high cost ($12-20/bbl). This has been a lifeline to these PADD I refineries, and new rail unloading terminals are being built by companies such as PBF Energy, which purchased both the Delaware and Paulsboro refineries from Valero in 2010, to import more Bakken crude and Canadian bitumen/heavy oil.

In order to determine whether these crude discounts will persist, we have attempted to construct supply/disposition analyses for both the Cushing and Rockies regions. Supply is comprised of local oil production and inbound crude pipeline/rail/barge capacity. Disposition is comprised of local refining capacity and outbound crude pipeline/rail/barge capacity. We have projected the timing of pipeline expansions, newbuilds and reversals, as well as estimating local crude production and refining capacity changes, to model supply and disposition out to 2020.

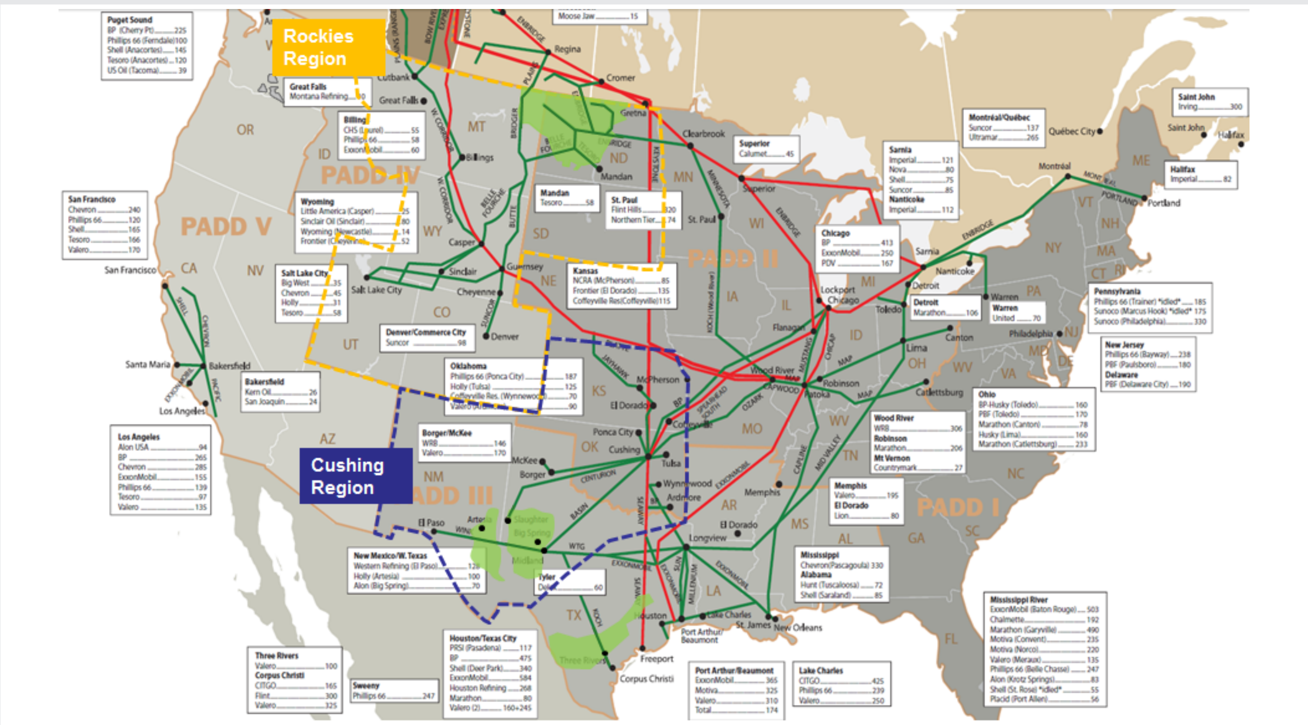


Exhibit 11: North American oil pipelines, refineries and regions with supply bottlenecks.
Source: CAPP, Kimmeridge Enegry.

The Cushing Region Bottleneck

For the Cushing region, we can observe a large amount of new pipeline projects designed to alleviate the oversupply problems that have been apparent since 2005. Consequently, new outbound pipeline capacity significantly exceeds new inbound pipeline capacity (see Exhibits 12 & 13), which should result in a more balanced supply/disposition balance later this year and next, as outbound pipeline projects such as the Seaway reversal and expansion come online (see Exhibit 14). Indeed, we would expect to see smaller discounts of WTI to Brent from later this year onwards, as potential disposition capacity exceeds supply.

Notably, a large increase in volume of crude oil transported by barge from PADD II to PADD III (See Exhibit 15), shows how desperate shippers have become to get crude oil from the discounted Cushing market to higher priced markets such as the Gulf Coast. Indeed, the strong correlation between the WTI-Brent discount and barge volumes indicates a strong sensitivity in volumes to price, which suggests that barge is the most marginal mode of transportation, and should decline just as rapidly when the WTI-Brent differential narrows.

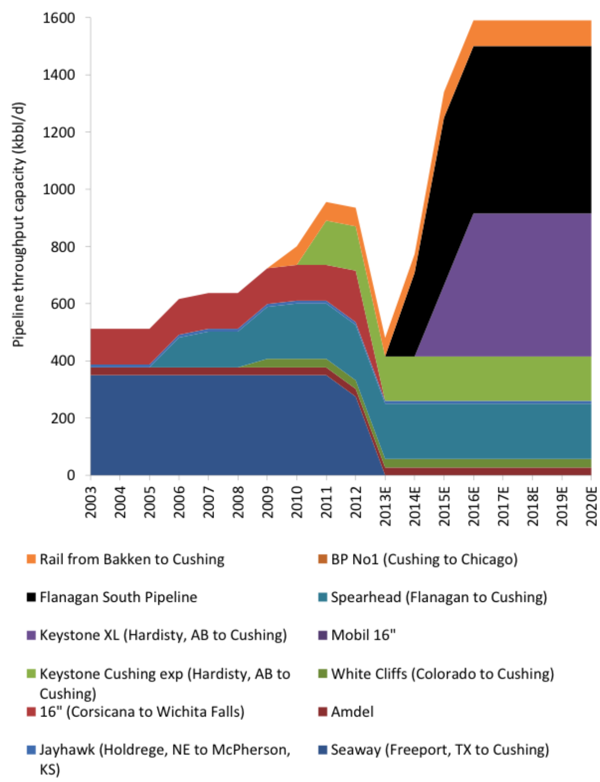


Exhibit 12: Inbound pipeline and rail capacity to Cushing.
Source: Company reports, Media reports, EIA, Kimmeridge Energy.

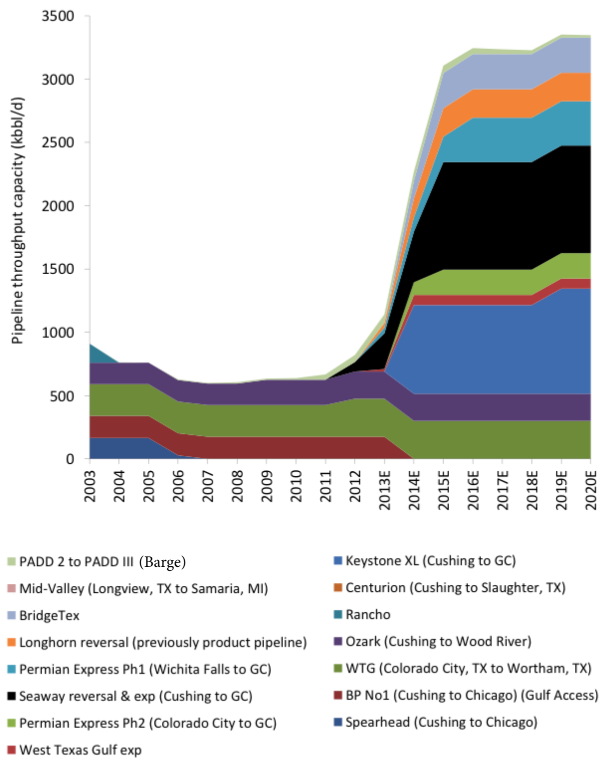


Exhibit 13: Outbound pipeline capacity from Cushing.
Source: Company reports, Media reports, EIA, Kimmeridge Energy.

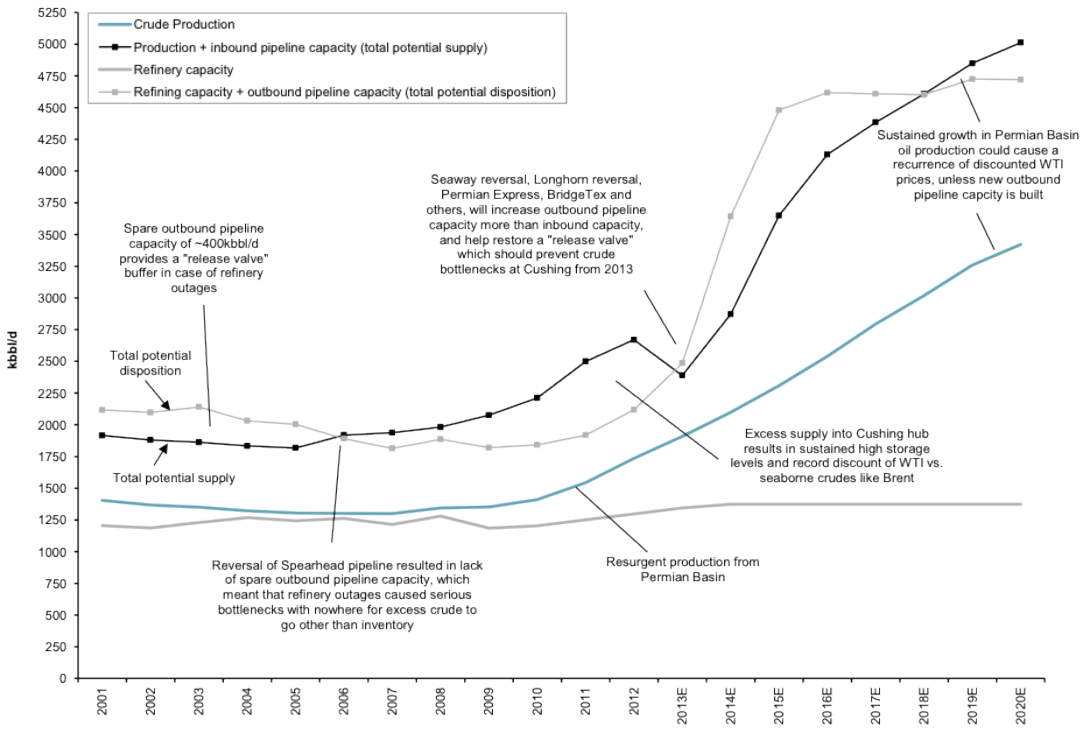


Exhibit 14: Supply and disposition analysis for the Cushing region.
Source: Company reports, Media reports, EIA, Kimmeridge Energy.

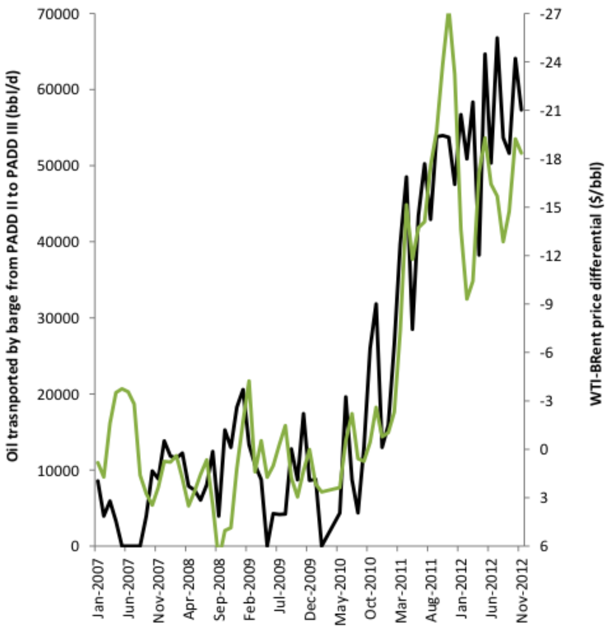


Exhibit 15: Oil by barge volumes from PADD II to PADD III versus WTI-Brent differential. Source: EIA.

Based on our supply/disposition analysis, we expect to see reduced discount of WTI prices to Brent starting later this year, if throughput on the reversed and expanded Seaway pipeline can return to full capacity. Beyond 2013 we believe that potential disposition should comfortably exceed supply until the latter part of this decade, as long as pipeline capacity expansions come online as scheduled.

Notably, the Seaway pipeline reversal and expansion was competed in early January 2013, and should start to materially impact crude stocks at Cushing going forward, as this represents a 750 bbl/ d capacity swing from 350 bbl/d inbound to 400 bbl/d outbound, and indeed has had a noticeable effect already (Exhibit 16). However, the Phillips 66 refinery in Sweeny, Texas with 247 kbbl/d processing capacity went into maintenance at the end of January, forcing a reduction in throughput on the southern section of Seaway to an average of 175 kbbl/d, resulting in a sharp fall in US crude futures, as traders anticipate a build of Cushing inventories. A new oil pipeline connecting Seaway to Houston refineries will only be completed in 2H2013, implying reduced throughput on the Seaway pipeline until later this year. Nevertheless, once the reversed Seaway pipeline ramps back up to full capacity, potentially in 2H2013/early 2014, it should start to materially reduce storage volumes at Cushing.

The biggest risk to pipeline capacity affecting the region appears to be the Harding to Cushing leg of the Keystone XL project, which has been delayed due to lack of a permit. This would reduce inbound oil volumes into the region, which would tighten the supply/disposition balance, and bid up WTI prices versus coastal/ seaborne crudes like Brent/Louisiana Light Sweet.

Additionally, we have modelled in robust growth in Permian Basin oil production – if this fails to materialize, then the Cushing supply/disposition balance would tighten more than expected. Therefore, we expect there to be a greater probability of the discount narrowing due to a tightening of supply/disposition, rather than the discount expanding or persisting at current levels.

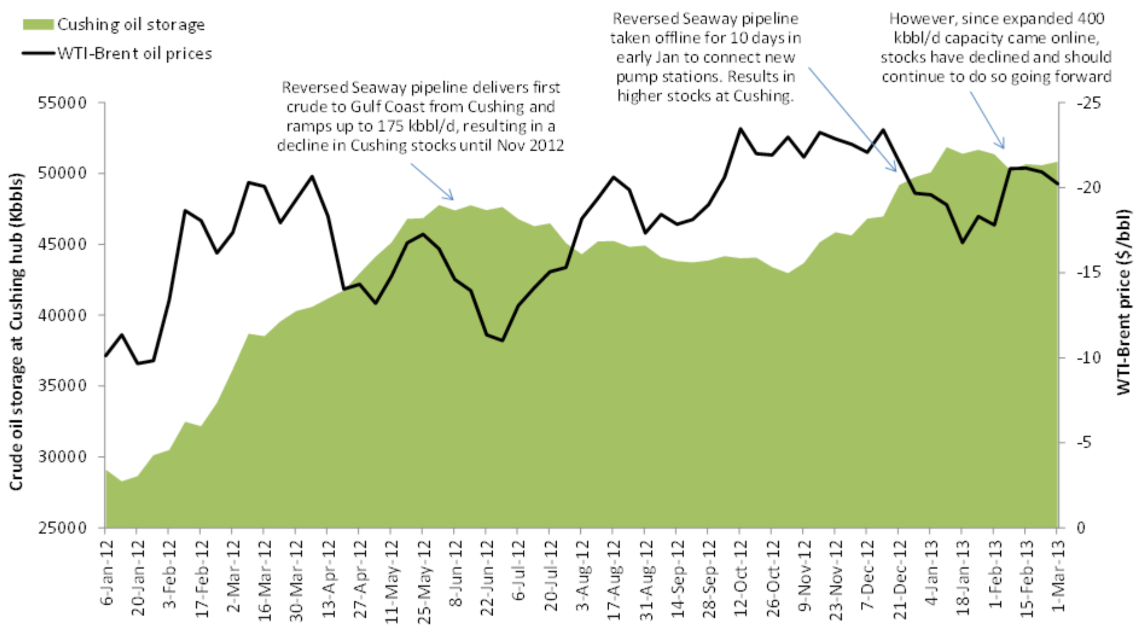


Exhibit 16: Cushing hub oil storage versus WTI-Brent price differential. Source: EIA.

The Rockies Region Bottleneck

For the Rockies region, we don't anticipate any increase in inbound pipeline capacity, but do expect to see a large increase in outbound pipeline and rail takeaway capacity (Exhibit 17). Notably, the surge in Bakken production and severely discounted local oil prices have prompted companies to invest significantly in rail loading capacity (Exhibit 18), with companies such as Berkshire Hathaway's Burlington Santa Fe, benefitting massively from the increased crude-by-rail demand.

Since 2005 when Bakken oil production started to increase materially, there has been a supply glut (Exhibit 19) resulting in heavily discounted crude prices (Exhibit 20). As mentioned previously, this prompted companies to develop new rail export capacity, despite the higher costs of crude-by-rail than pipeline, with the initial destination of choice being Cushing and the Midwest. This exacerbated the oversupply situation at Cushing, but has resulted in a narrowing of North Dakota oil prices versus WTI, making this shipping route less attractive for Bakken producers. Consequently, Bakken producers and shippers have turned to new end markets such as the Gulf Coast, and more recently East and West Coasts, with companies like PBF Energy building new offloading rail terminals at their Delaware refinery in PADD I (see Exhibit 21).

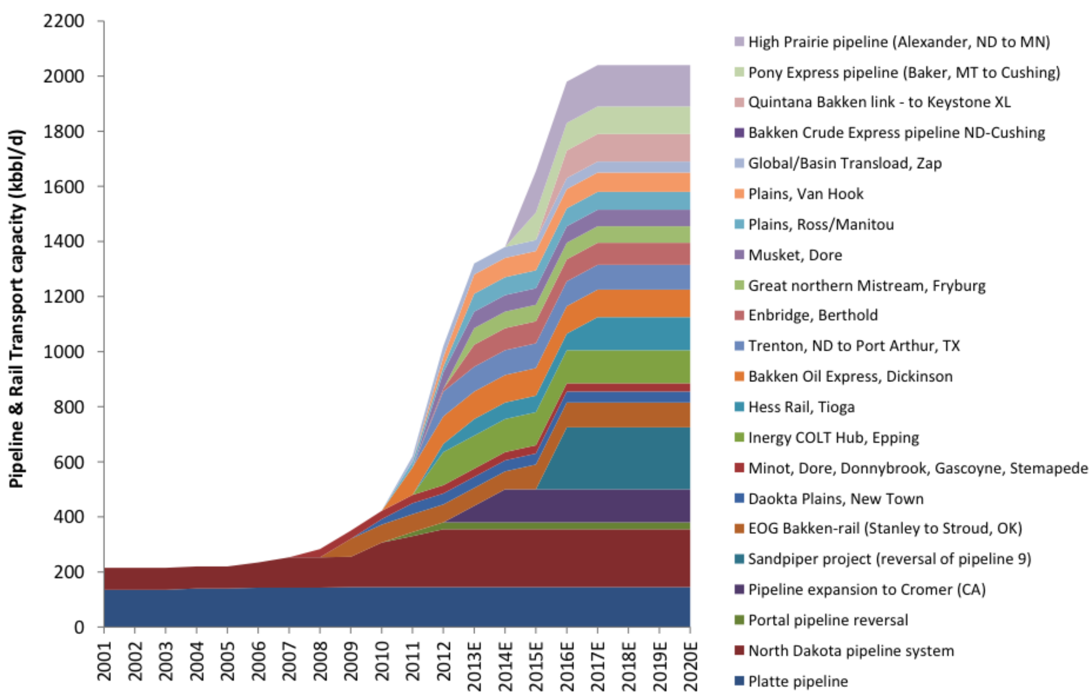


Exhibit 17: Outbound pipeline and rail capacity from the Bakken.
Source: Company reports, Media reports, North Dakota Pipeline Authority, Kimmeridge Energy.

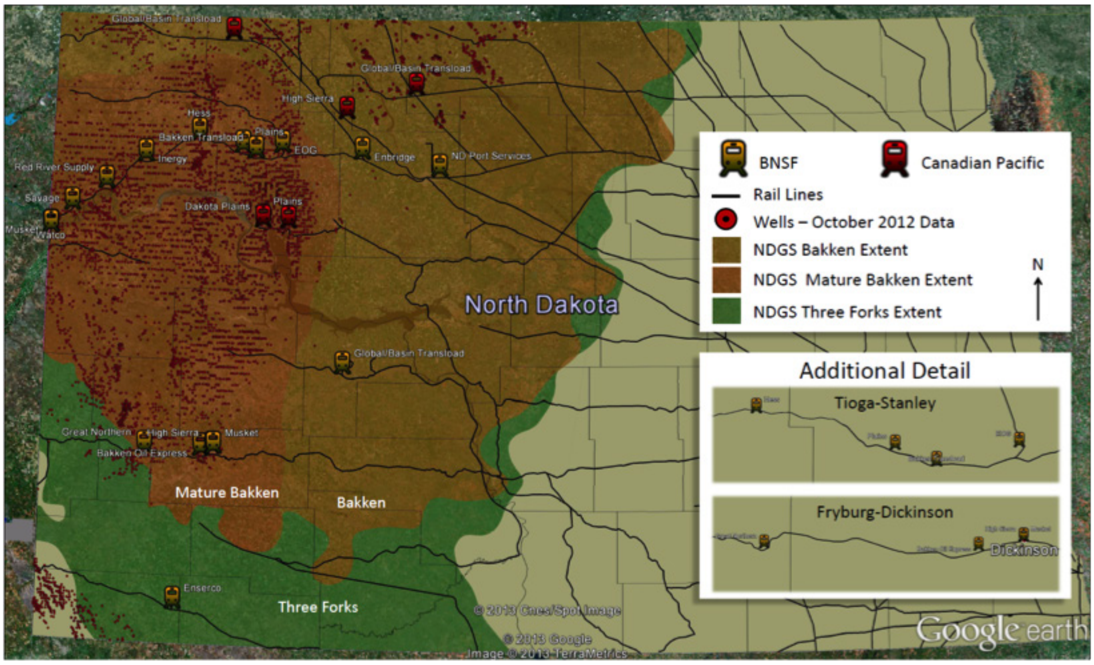


Exhibit 18: Crude rail loading terminals in North Dakota. Source: North Dakota Pipeline Authority.

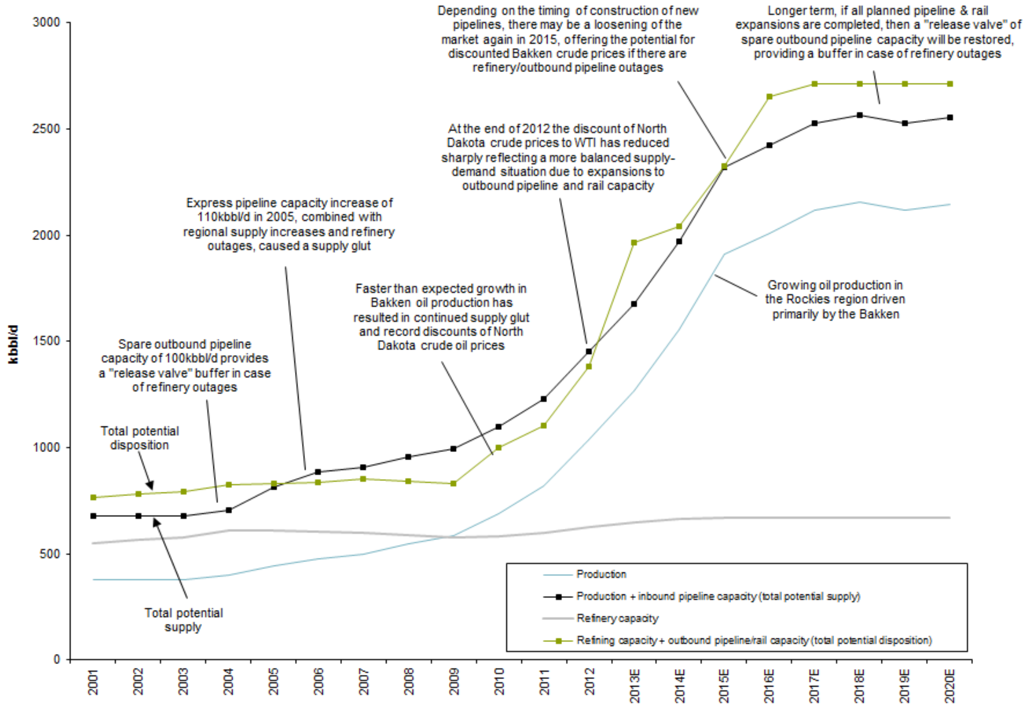


Exhibit 19: Supply and disposition balance for the Rockies region.
Source: Company reports, Media reports, North Dakota Pipeline Authority, Kimmeridge Energy.

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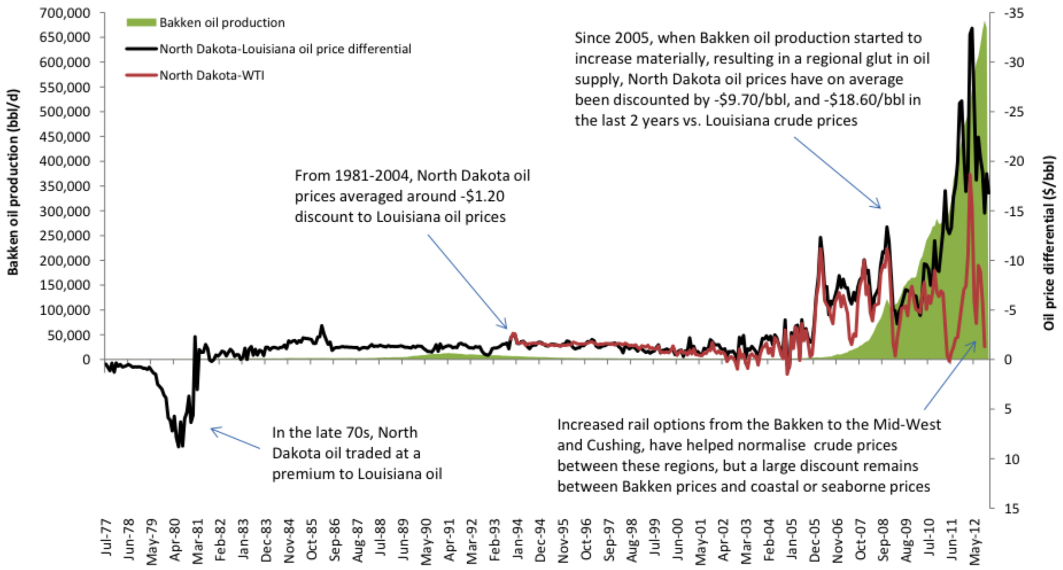

Exhibit 20: Bakken oil production versus North Dakota oil price differentials.
Source: EIA, North Dakota DMR.

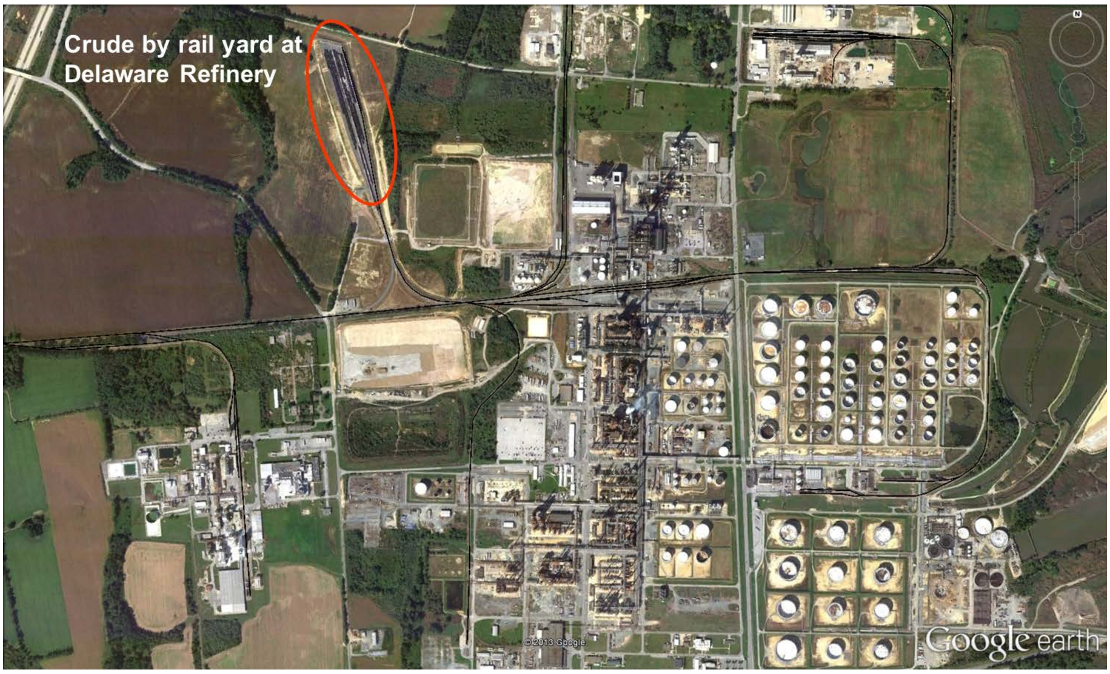

Exhibit 21: Rail offloading terminal at PBF's Delaware refinery. Source: Google Earth, Kimmeridge Energy.

Given that around half of shipping capacity from the Bakken will come from rail this year and going forward, and the flexible nature of this export option, we expect that Bakken crude prices will remain discounted versus coastal/seaborne crudes such as Brent, until cheaper shipping options such as pipeline become available. At the moment it costs around $12-18/bbl to ship oil from the Bakken to the East Coast and around $15-18/bbl to ship it to the West Coast. This compares to pipelines, which have shipping costs of around $1-7/bbl, depending on distance and number of pipelines used. So while the discount to WTI has presently narrowed, we do not expect parity between Bakken and Brent/LLS crude prices, despite the superior quality of Bakken crude.

Additionally, if the discount of WTI to Brent/LLS narrows, then the discount of Bakken to WTI should expand, since rail shipping costs of around $12-20/bbl must be covered to get Bakken crude to end markets.

Furthermore, if the growth in oil production from the Bakken continues as we expect, but new pipeline capacity of 575 Kbbl/d by 2016 is delayed or cancelled, then we could see a loosening of the supply/disposition balance in the Rockies region, which would cause expanded price differentials once again from 2015/16.

Risks to our projections are numerous, but centre around uncertainty over timing of new pipeline/rail capacity and growth projections for oil production. If oil production in either the Permian Basin or Bakken surprise to the upside versus modelled volumes, then local oil price discounts could persist or increase versus current levels. If oil production surprises to the downside, then the supply/ disposition balance should tighten, reducing price discounts.

If outbound pipeline capacity expansions are delayed or cancelled, or local refinery capacity outages occur, this would allow the supply glut to persist or potentially worsen, widening oil price discounts. On the other hand, if inbound pipeline expansions into Cushing (none scheduled for the Rockies region) are delayed or cancelled, or refinery capacity is materially expanded (none scheduled presently), then the supply/ disposition balance would tighten narrowing oil price discounts.

An Overlooked Bottleneck in Illinois

One region where crude prices have been severely discounted, but has largely gone unnoticed, is the Illinois Basin. This is obviously significant for Kimmeridge due to our Fund I investment in the prospective New Albany tight oil play. A look at historic Illinois Basin posted oil prices shows a sustained discount versus WTI, Brent and LLS (Exhibit 22). Illinois basin crude is on average ~36.8 deg API and 0.3% sulphur - this compares to WTI at 39.6 deg API & 0.24% sulfur, and Brent at 38.06 deg API and 0.37% sulphur - so a small price discount is justified. However, discounts versus WTI have risen from around $2/bbl in 2004 to >$5/bbl in 2012; and discounts versus Brent and LLS have peaked at >$30/bbl in 2011, and currently remain >$20/bbl, which is not justified by the small difference in quality alone. Therefore, it is clear that Illinois Basin crude prices are being significantly impacted by transportation issues, similar to the situation at Cushing and in the Rockies.

Notably, there is around 1.6 Mbbl/d of complex refining capacity situated in and around the Illinois Basin, with extensive pipeline connections enabling receipt of both local and imported crudes (Exhibits 23 & 24).

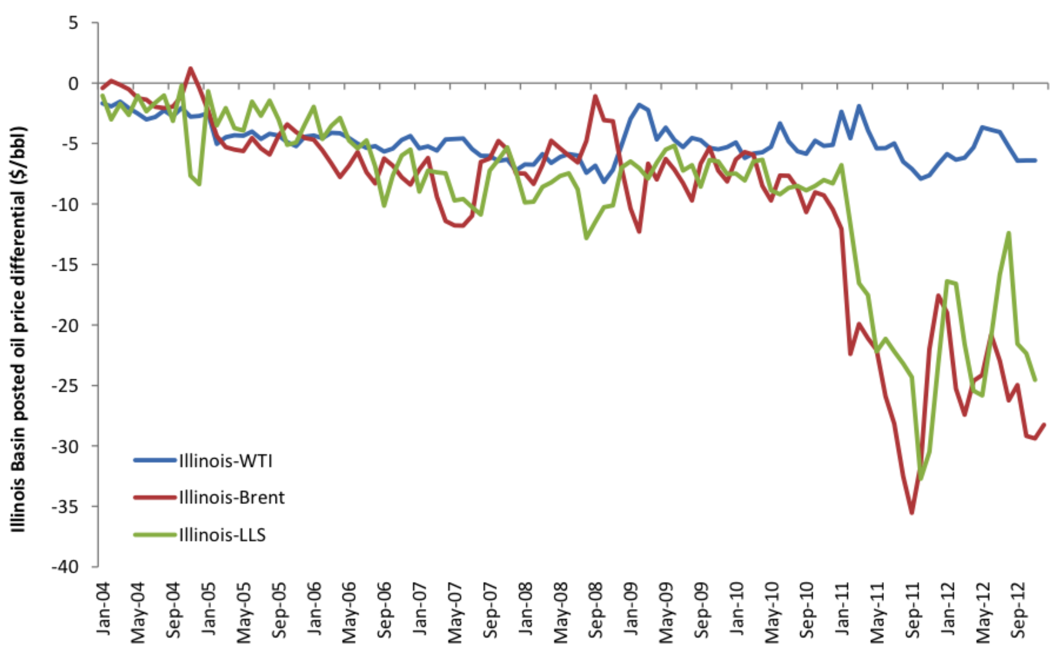

Exhibit 22: Illinois Basin posted oil prices. Source: Illinois Oil & Gas Association, EIA.

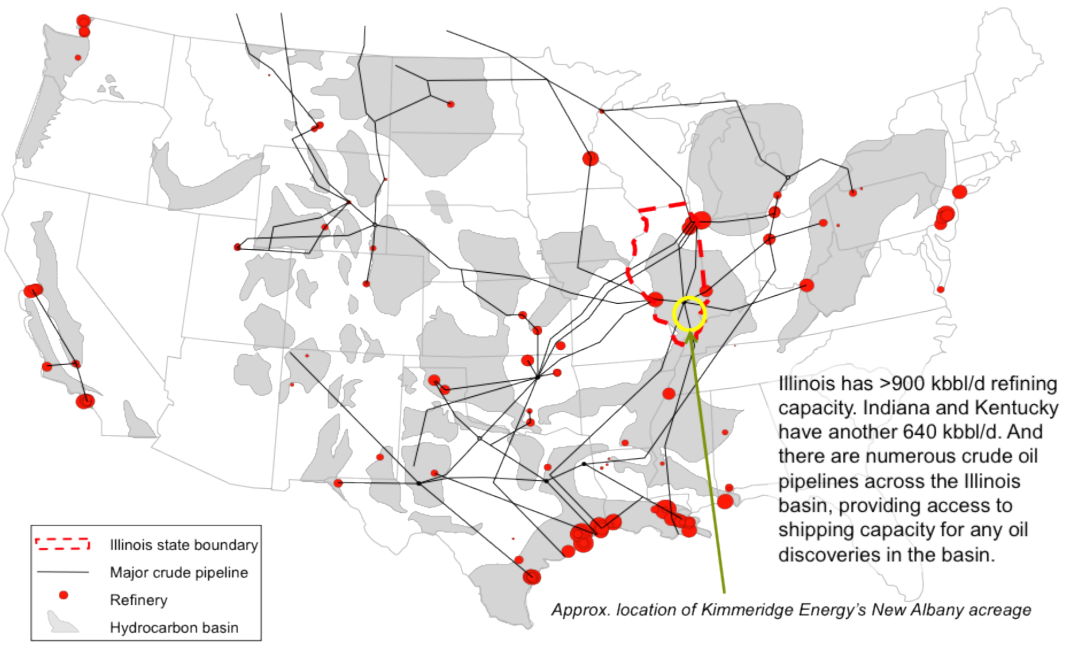

Exhibit 23: Kimmeridge acreage vs. Illinois Basin refineries and crude pipelines Source: OGJ, Kimmeridge Energy.

All capacity in Kbbl/d #	State	Company	Location	CDU	Vac.	Delayed & Fluid Coking	Cat Crack.	Cat. Reform.	Cat. Hydro. Crack.	Cat. Hydro. Refining and treating		Alky. Poly.	Aro. Iso.	H2	Coke	Sulfur	Asphlt.	Nelson Complexity
1	Illinois	Citgo Petroleum Corp.	Lemont	159	71	36	60	28	0	80	23	19	6	5	2	0	0	10.4
2	Illinois	ExxonMobil Refining & Supply Co.	Joliet	238	122	56	95	50	0	108	140	27	0	0	3	1	15	11.4
3	Illinois	Marathon Petroleum Co. LLC	Robinson	204	68	28	48	74	27	138	37	12	14	0	1	0	0	10.5
4	Illinois	WRB Refining LLC	Wood River	356	119	81	91	85	41	170	55	20	4	105	1	0	40	9.5
5	Indiana	BP PLC	Whiting	385	181	101	149	58	0	169	129	23	23	59	2	0	27	9.5
6	Indiana	Countrymark Cooperative Inc.	Mount Vernon	27	11	0	8	7	0	21	0	2	2	0	0	0	3	9.1
7	Kentucky	Marathon Petroleum Co. LLC	Catlettsburg	226	105	0	99	49	0	165	103	20	30	32	0	0	26	12.2
		TOTAL		**1,594**	**677**	**302**	**549**	**350**	**68**	**851**	**486**	**122**	**78**	**201**	**9**	**2**	**110**	**10.4**

Exhibit 24: Capacity and complexity of Illinois Basin refineries.
Source: OGJ, EIA, Company Reports and Kimmeridge Energy.

Based on our analysis of crude imports into specific refineries (from EIA data), we know that the above refineries import crude oil primarily from Canada and Saudi Arabia, with quality ranging from heavy, sour (20 deg API and >4% sulfur) to light, sweet (40 deg API and <0.5% sulphur). This data confirms that Illinois Basin refineries are capable of processing a wide variety of crude oils, including heavy oil from Canada's oil sands, and light, sweet imported or locally produced crudes. Indeed, the local discount for crude oils produced in the Illinois Basin is likely due to competition from imported Canadian crudes.

Wood River and Patoka in Illinois are the other major market hubs in the US Midwest other than Cushing, where oil can be stored and transported. In fact, Wood River and Patoka are connected by pipeline to Western Canada and North Dakota, which are both areas experiencing material growth in oil production. This explains the price discount for local Illinois Basin crude, since local producers are having to compete with Oil Sands and Bakken producers for an end market, namely local refineries. Furthermore, outbound pipeline capacity to take Canadian heavy crude and Bakken oil to the Gulf Coast is limited currently to ExxonMobil's Pegasus pipeline, which only has 96,000 bbl/d capacity.

Consequently, local crude prices in Illinois are likely to remain heavily discounted in the near term due to: (1) continued growth in production from Western Canadian and the Bakken (2) limited local refinery expansions (3) limited outbound pipeline capacity. However, Enbridge and Energy Transfer Partners have proposed the conversion of a gas pipeline to carry between 420,000-660,000 bbl/ d of crude from Patoka, Illinois to the Gulf Coast. The converted pipeline is scheduled to start-up in 2015 and should help to alleviate downward pressure on Canadian heavy crude prices, Bakken crude prices and Illinois Basin crude prices. Expanded outbound pipeline capacity would clearly be a positive medium term factor for any new crude development in the Illinois Basin, such as the New Albany tight oil play, as it should normalise crude prices in the region. Subsequent to a more balanced supply/ disposition situation in Illinois, we believe that light, sweet crudes such as those from the New Albany, should command a local premium, as prices revert to differentials based on quality, and light sweet crudes are also demanded for blending in pipelines with heavy, sour Canadian crudes transiting through Patoka, Illinois to the Gulf Coast.

Tight Oil's Impact on US Refining

US oil product demand has remained fairly consistent over time, with a decline in overall demand since the peak in 2006/7. Heavy product demand (residual fuel oil, petcoke, asphalt, etc) has declined as a percentage of overall demand. Gasoline demand has increased slightly as a percentage of overall demand since 2007, despite being materially lower on an absolute basis, potentially reflecting an increase in gasoline production by refiners due to a lighter crude input slate (i.e. more light, sweet crude which yields higher proportion of light products).

Given the fairly static nature of US oil product demand (Exhibit 25), but the growing proportion of available domestic light, sweet crude, this raises an issue for both refiners and oil producers. Once refineries are configured to process heavy crude, sour they cannot simply switch to processing light, sweet crude. The economics of a complex refiner with significant upgrading capacity is founded on processing low quality, heavy and sour crudes, but still producing a light product slate with high proportion of high value products such as gasoline and diesel.

Consequently, complex refiners will have higher demand for oil types that suit their existing configurations. This means that Gulf Coast (PADD III) and West Coast (PADD V) refiners have higher demand for heavy, sour crudes, since they have the most complex configurations (Exhibit 26). Therefore, it makes more sense to ship Bakken crude to The East Coast or Rockies region, than the Midwest, Gulf Coast or West Coast, since refiners in these regions (East Coast and Rockies) are configured to process light, sweet crudes.

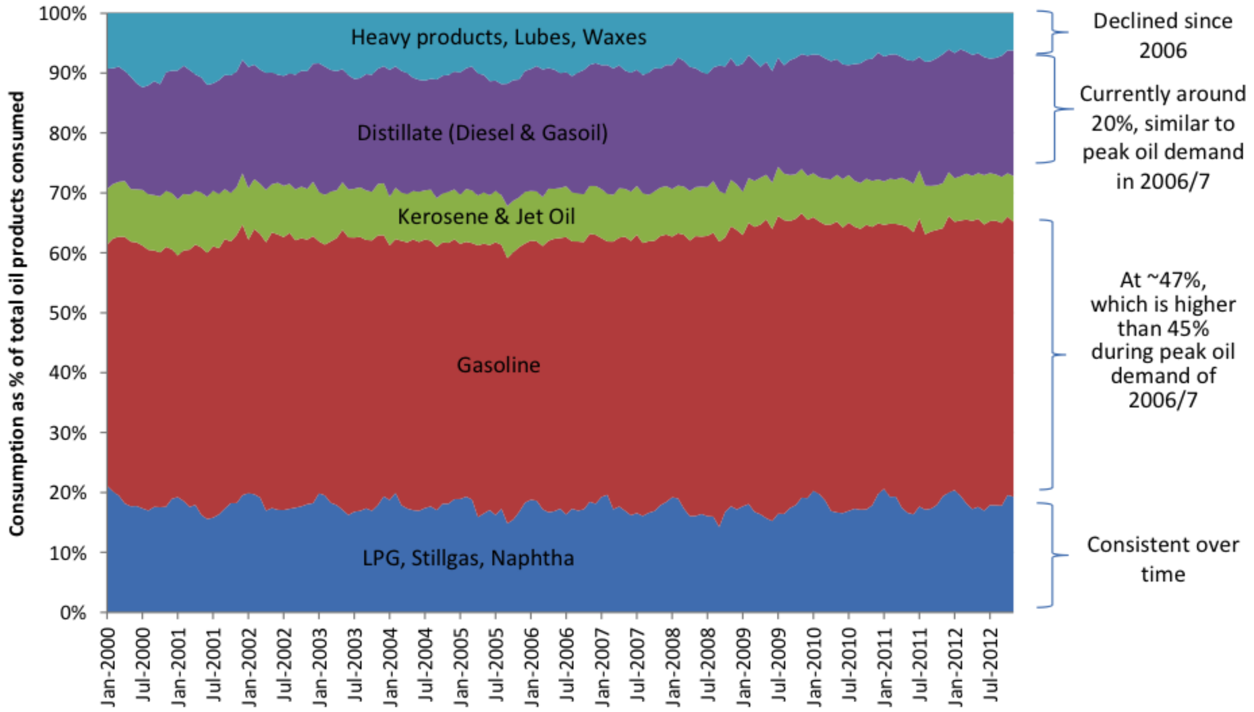

Exhibit 25: Proportional US oil product demand. Source: EIA.

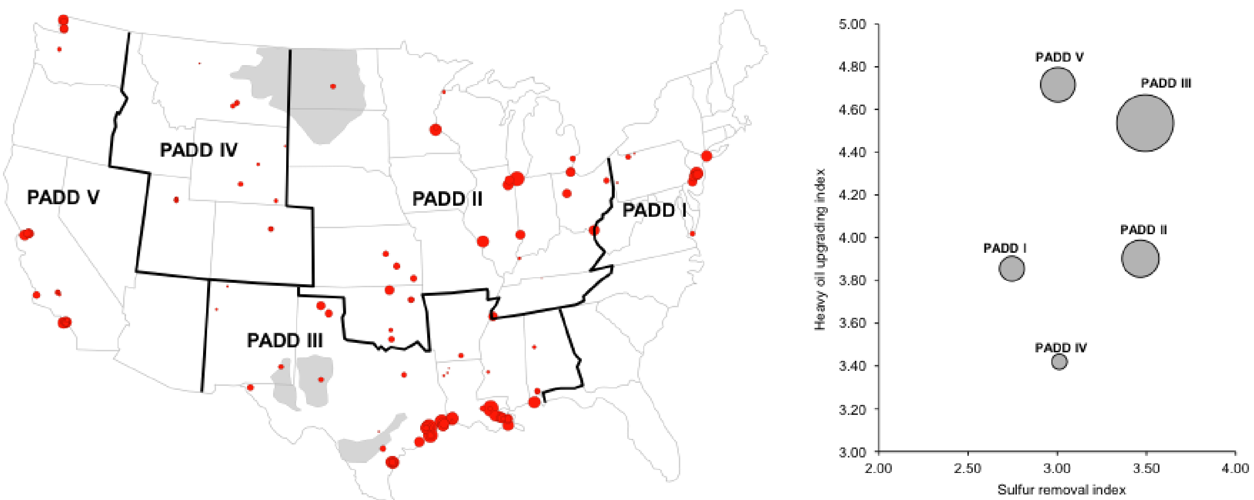

Exhibit 26: Heavy oil upgrading and sulfur removal indices for US refineries. Source: OGJ, Kimmeridge Energy.

Looking at crude assays for global oils, we can see that Bakken crude is lighter and sweeter than WTI, Brent and Louisiana Light Sweet. PADD I refiners process a significant amount of Brent-like crudes, making all of the aforementioned, and particularly Bakken crude, suitable for East Coast refiners. On the other end of the spectrum are Canadian Lloydminster Blend, which is a blend of bitumen (oil sands) and condensate; and Canadian Cold Lake Bitumen (Exhibit 27). These both have very low API and high sulphur content, making them suitable for only the most complex refiners on the Gulf Coast and select refiners in PADD II (Midwest). Indeed, we can see the huge difference in oil product yield from primary cracking from processing different crude types (Exhibit 28). With fairly consistent oil product demand amongst the various US PADD regions, it is clear that the refinery configuration and amount of upgrading/desulfurization capacity will determine the type of crude oil demanded.

Consequently, the "ideal" flow should be Canadian heavy oil to the Gulf Coast, Midwest and West Coast, and Bakken crude to the Rockies and East Coast (Exhibit 29). In the last few years, excess Canadian oil has been ending up at Cushing due to insufficient pipeline capacity to the Gulf Coast and insufficient heavy oil processing capacity in the Rockies and Midwest. Bakken crude has also been ending up at Cushing, due to both insufficient local refining capacity in the Rockies region and insufficient export options to regions such as the East Coast. However, pipeline expansions and reversals will come online this year and next to the Gulf Coast, and East Coast refiners and shippers are building more rail capacity to the East Coast from North Dakota, which should help alleviate regional supply gluts.

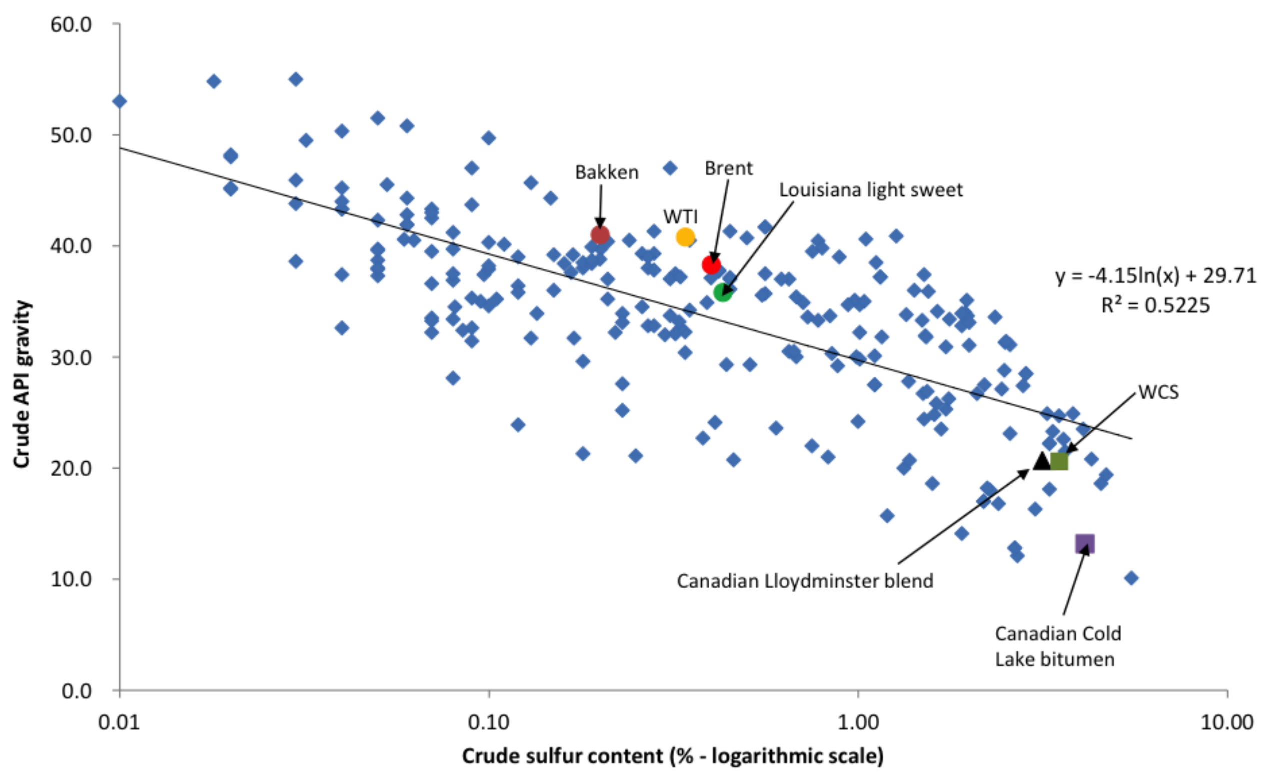

Exhibit 27: API gravity and sulphur content for global crudes.
Source: McKinsey & Company; Turner, Mason & Company; Kimmeridge Energy.

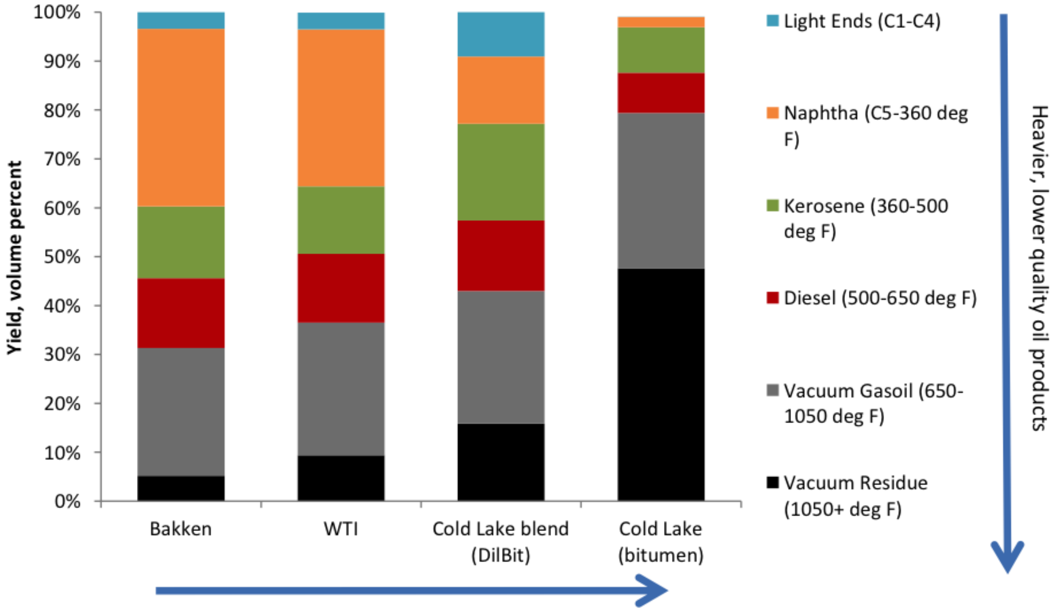

Exhibit 28: Product yield from primary cracking of select crude oils.
Source: McKinsey & Company; Turner, Mason & Company; Kimmeridge Energy.

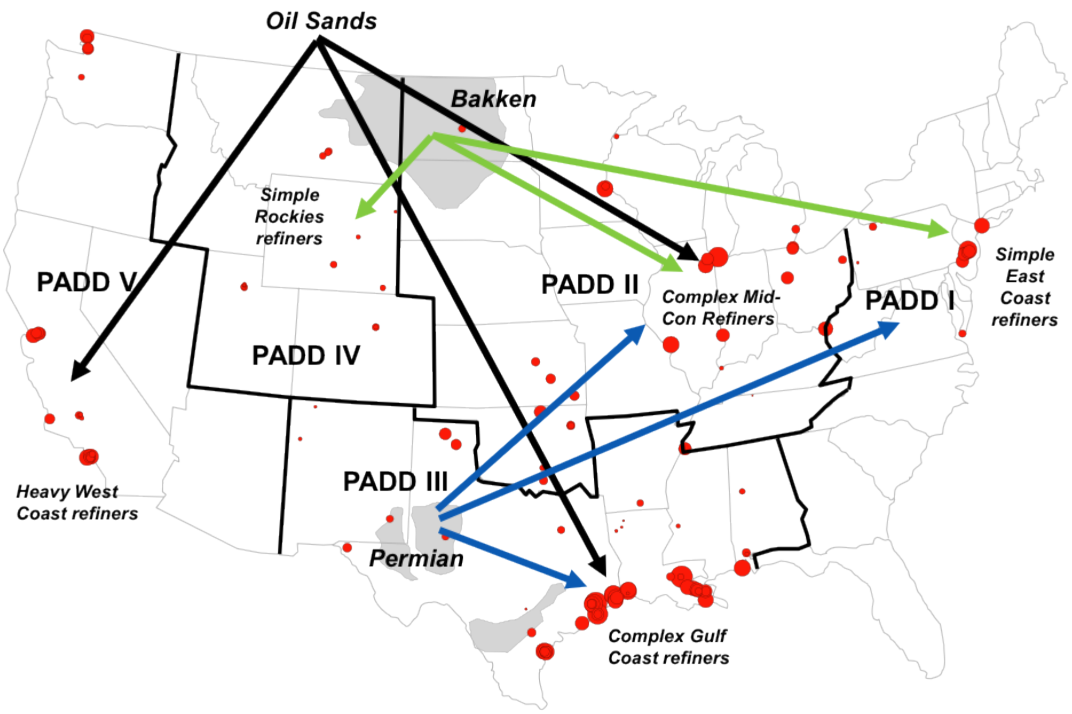

Exhibit 29: "Ideal" crude flows in the US. Source: OGJ, Kimmeridge Energy.

Looking North of the Border – WCS-WTI Differentials Unravelled

Having tracked the WTI to LLS/Brent discount and evolution of the Bakken since 2005, we have seen a much greater awareness amongst investors of the supply/demand dynamics affecting prices for inland US crude oils.

One of the major factors impacting US inland crude prices has been the sustained growth in oil production from Canada's oil sands, and the increased exports to the US. We can see that US imports of Canadian oil have increased materially over the past 3 decades (Exhibit 31). Additionally, the quality of these imports has declined steadily over time, as the mix of oils exported to the US has become increasingly skewed towards bitumen (transported as DilBit, which is approximately 70% bitumen and 30% condensate).

Despite the fact that Maya heavy crude from Mexico is similar in quality to Canadian heavy crudes such as WCS (conventional heavy) and Cold Lake Blend (DilBit), it has traded at a significant premium to WCS since mid-2010, and has even traded at a premium to WTI since mid-2011 (Exhibit 32).

The premium is driven in part by the high demand for heavy, sour crude from Gulf Coast refiners, but also the record discount of WTI to comparable seaborne/coastal light crudes, and the record discount of WCS to WTI. The growth in Canadian heavy oil production has corresponded with the widening WCS-WTI discount (Exhibit 33), as transportation bottlenecks have resulted in regional oversupply.

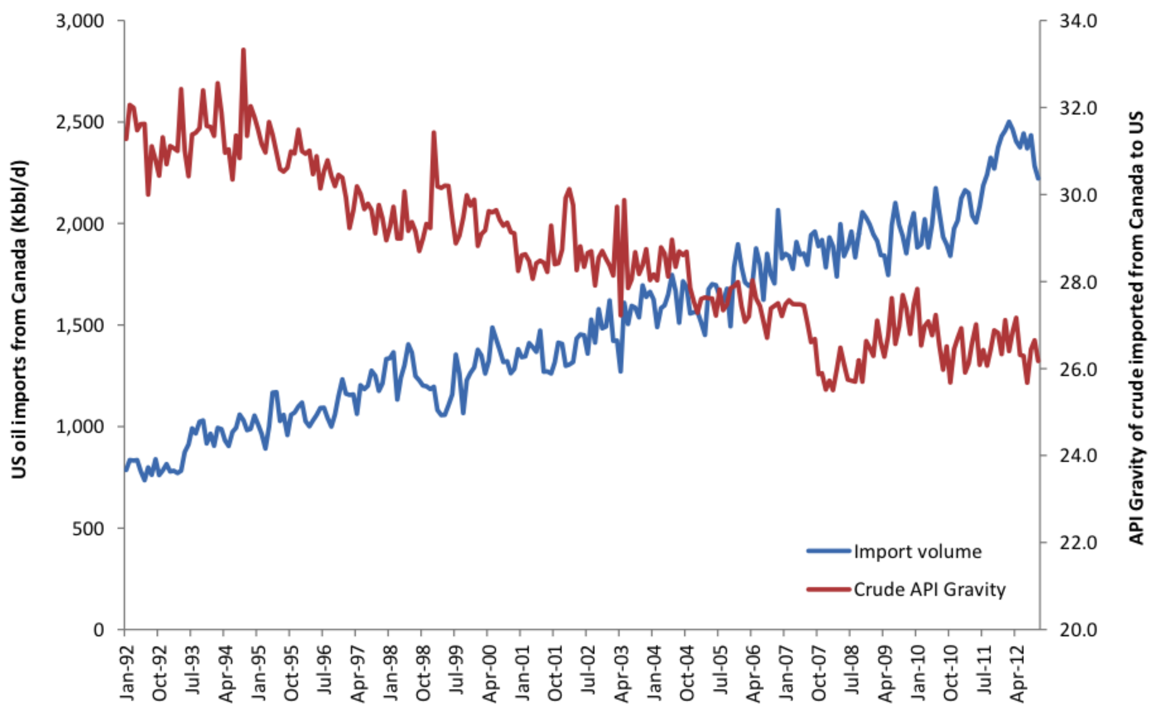

Exhibit 30: Volume and API gravity of US oil imports from Canada. Source: EIA.

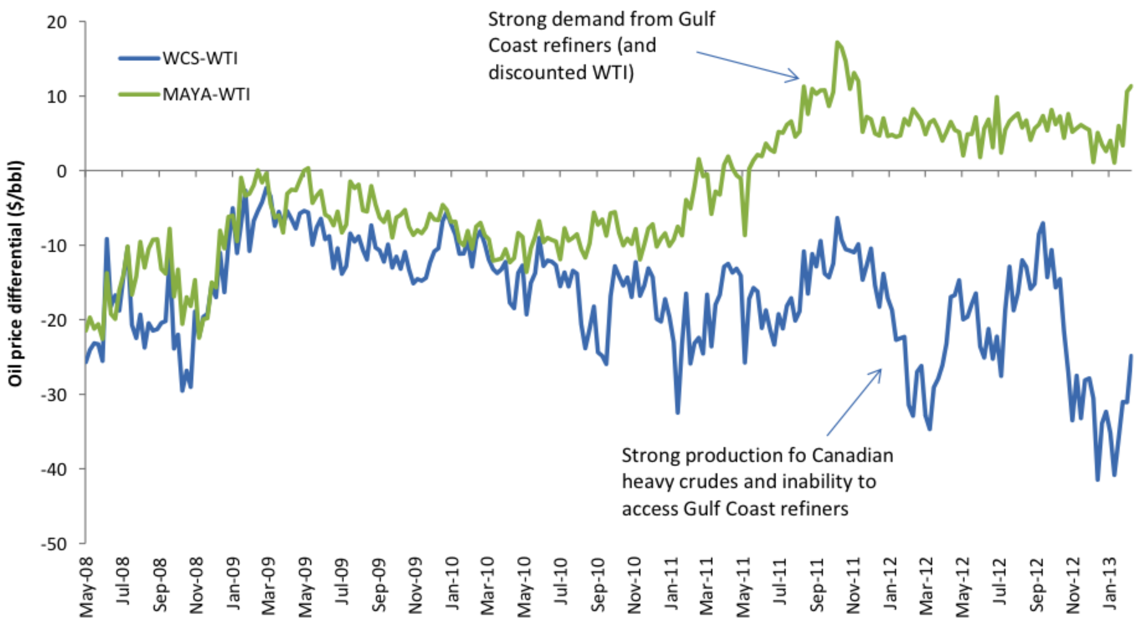

Exhibit 31: WCS-WTI and MAYA-WTI oil price differentials. Source: Bloomberg, EIA.

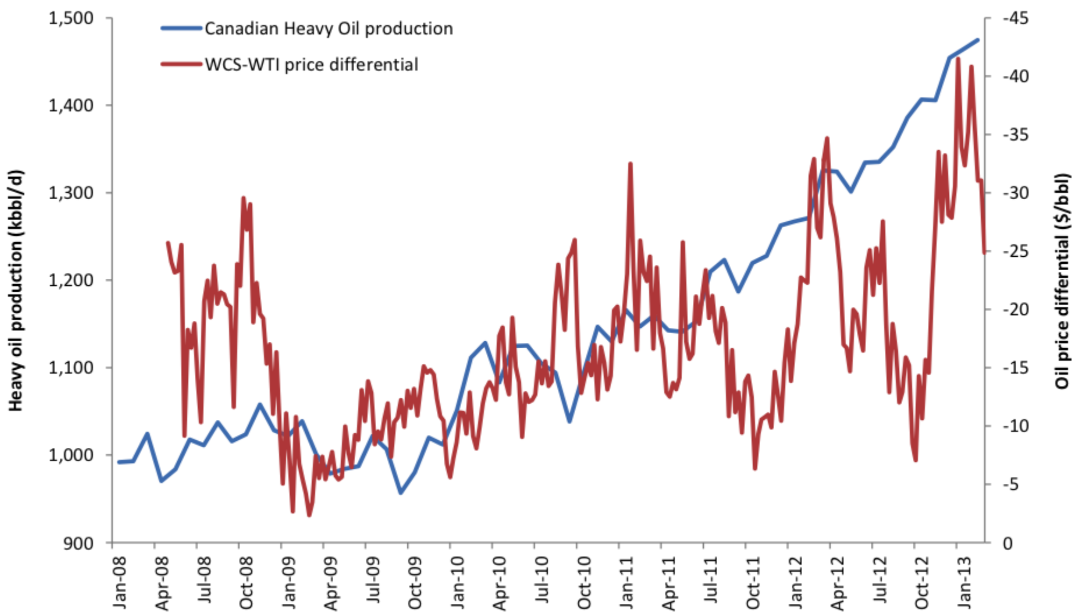

Exhibit 32: Canadian heavy oil production versus WCS-WTI oil price differential. Source: Canadian NEB, EIA.

Since both Canadian conventional heavy oil and DilBit are comparable with Maya crude, prices for Canadian heavy crudes such as WCS would clearly trade closer to Maya if producers could access the Gulf Coast market. We have conducted a supply-disposition analysis to determine whether planned pipeline capacity expansions to increase access for Canadian heavy producers to the Gulf Coast market will be sufficient to reverse the downward pressure on WCS prices.

There are two main constraints for heavy oil producers – (1) heavy oil refining capacity and (2) heavy oil pipeline capacity. We have examined both of these to estimate the amount of accessible heavy oil refining capacity in Canada and the US. This gives a rough estimate for potential demand for Canadian heavy crude. Additionally, we estimated the amount of heavy oil supply by adding production of non-upgraded bitumen converted to DilBit for pipeline transportation at a 70:30 ratio with condensate, and production of conventional heavy oil.

Our analysis shows that from 2008 to 2012 supply of Canadian heavy crude exceeded potential disposition, resulting in transportation bottlenecks at Cushing, where storage of crude oil increased sigificantly. The result was heavily discounted WCS prices. Although potential disposition capacity has increased, with the reversal and expansion of the Seaway pipeline, we don't believe that the supply/demand balance will tighten considerably until at least next year (Exhibit 34).

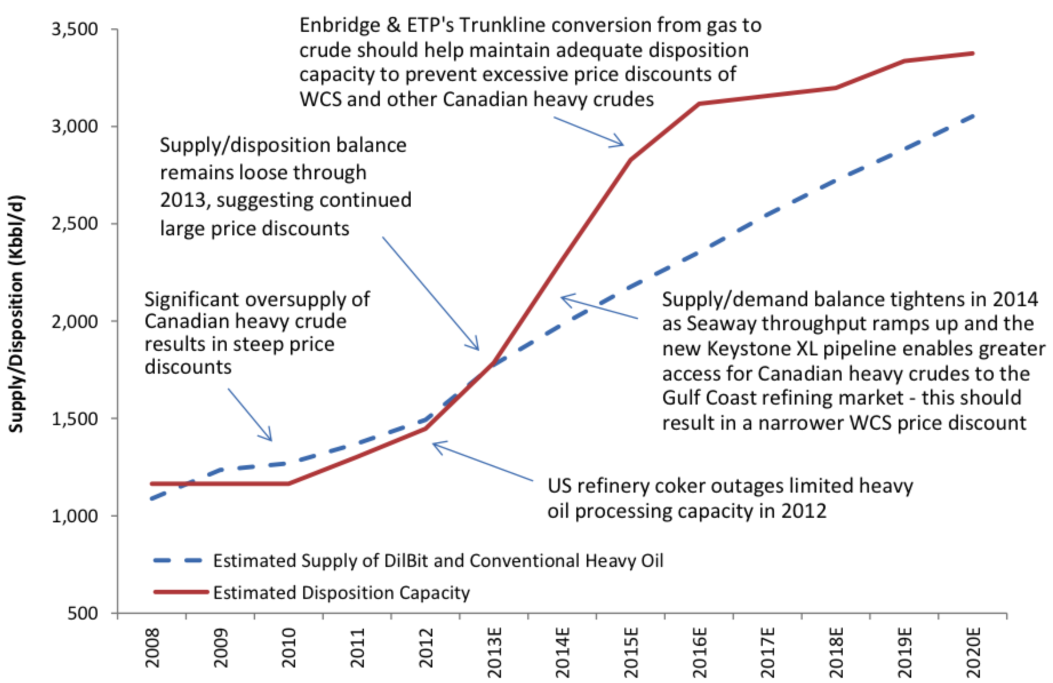

Exhibit 33: Supply and disposition for Canadian heavy crude.
Source: CAPP, NEB, EIA, Company Reports, Media Reports, Kimmeridge Energy.

The TransCanada Gulf Coast pipeline (part of the Keystone pipeline project) is under construction and has an anticipated start-up date of late 2013. This will transport crude from Cushing to the Gulf Coast and allows increased access for Canadian heavy oil producers to the Gulf Coast, although they will have to compete with US oil producers in the Bakken and Permian Basin. However, if we assume that 50% of the pipeline will be used to transport heavy crude from Cushing to the Gulf Coast, this could significantly tighten the supply/disposition balance for Canadian heavy crudes, and thus alleviate downward pressure on WCS oil prices (and other Canadian heavy crudes). Additionally, if the Keystone XL project comes online in 2015 (included in our model), this should allow plenty of excess disposition capacity for Canadian heavy oil, further alleviating downward pressure on WCS prices.

Additionally, the proposed Enbridge-ETP gas trunkline conversion, should add another 420-660,000 bbl/d of pipeline capacity from Patoka, Illinois to St. James Louisiana on the Gulf Coast, which should also contribute incremental disposition capacity to help alleviate downward pressure on Canadian heavy crude prices.

Finally, we can note that crude-by-rail has also been increasingly rapidly, with Canadian National increasing carloads from around 5,000 in 2011, to 30,000 in 2012, and an estimated 60,000 this year. This provides another 100,000 bbl/d of takeaway capacity from Western Canada, and is likely to increase going forward as long as differentials remain wide enough to justify higher shipping costs of crude-by-rail.

Looking further ahead, the sustained growth in oil sands production, which the Canadian Association of Petroleum Producers (CAPP) believes to be skewed towards bitumen rather than syncrude (upgraded bitumen), could result in further supply bottlenecks towards the end of this decade, unless new outbound pipeline capacity can be built to access markets such as the Gulf Coast, which has a large amount of heavy oil refining capacity.

Conclusions

Our analysis of US crude imports shows a marked decline in both volume and quality. Specifically, refiners have been demanding more heavy, sour crude from countries like Canada, Saudi Arabia and Mexico, to offset higher domestic production of light, sweet crude from tight oil plays.

Additionally our analysis of the US refining sector shows that refiners invested heavily in heavy oil upgrading and desulfurization capacity over the past 15 years, based on the premise of a long term trend towards lower quality oil, as conventional oil fields declined. The rise of tight oil in the US runs counter to this assumption and has presented challenges for producers, shippers and refiners. Overall, refiners have adjusted imports to keep their crude input slates broadly the same, since US oil product demand is fairly static, and refinery configurations quite inflexible.

However, transportation systems were also developed over time on the assumption of declining domestic production, increased crude imports from Canada by pipeline and increased seaborne crude imports through the East, West and Gulf Coasts. Our analyses of inland regions in the US shows two regions, Cushing and the Rockies, that are experiencing significant transportation bottlenecks, resulting in discounted crude prices. However, shippers have been investing in pipeline and rail capacity to alleviate these supply gluts.

Indeed, we believe that 2013 will be a pivotal year for WTI oil prices, since pipeline reversals and expansions should come online and start to restore a "release valve" of outbound pipeline capacity that will alleviate the supply glut at Cushing from 2014 onwards and enable WTI prices to trade up towards parity with Brent and LLS.

This year is also significant for Bakken crude prices, as the massive expansion in crude-by-rail capacity has significantly increased export options, enabling greater access to high value markets such as the East Coast and narrowing North Dakota oil price discounts versus WTI and LLS. However, since much of the export capacity is rail, which comes at a much higher cost than pipeline, Bakken crude prices will remain discounted versus coastal/seaborne crudes, until more pipeline capacity is built.

Although there is considerable uncertainty over growth projections in both the Bakken, Permian Basin and other inland regions, the phenomenal rise of Bakken production and major turnaround in Permian Basin production, as well as persistent price discounts for oils produced in these regions, has encouraged companies to invest in new pipeline and rail capacity. Looking ahead, we expect that the US transportation system will start to catch up with the growth in inland oil production, as companies accept the new reality of US tight oil.

Indeed, for exploration companies such as Kimmeridge, being aware of transportation issues and the impact on local crude prices is critical when assessing project economics. Specifically for our New Albany tight oil play in Illinois, we believe that despite current discounted oil prices, future pipeline expansions should help normalise crude prices, and that locally produced light, sweet crudes such as those from the New Albany could command a premium, due to pipeline blending demand as heavy Canadian crude transits through Patoka, Illinois to the Gulf Coast.

Notably, there is likely to be a point when consensus growth expectations for US tight oil production overshoot the realistic level of production, with some observers already expecting US oil self- sufficiency. We do not believe that this is a realistic scenario, based on our detailed analysis of potential new tight oil plays in the US (see our previous research pieces, *"How Will Tight Oil Impact Global Oil Pirces this Decade?"* and *"Brother From the Same Mother? The Relationships Between Unconventional and Conventional Oil and Gas Resources"*). Therefore, at some point in time there could be overinvestment in infrastructure resulting from overoptimistic projections for tight oil production. If this occurs, then inland crude producers will benefit the most as more expensive shipping options such as crude-by-rail will be utilized less in favour of cheaper shipping by pipeline.

Finally, a look at Canadian heavy crude supply/ demand dynamics indicates that severely discounted WCS prices will likely remain a theme throughout this year, but should be alleviated when the Keystone Gulf Coast pipeline comes online in late 2013/early 2014. The combination of the recent Seaway reversal and expansion this year, and Keystone Gulf Coast pipeline next year, will provide much greater access for Canadian heavy oil producers to the large Gulf Coast refining market, which has abundant heavy oil processing capacity. This should reduce storage at Cushing, and alleviate depressed WTI and WCS oil prices. Additionally, inland refiners that previously benefitted from discounted WTI prices may see that advantage diminish, while Gulf Coast refiners who have been paying high prices for Maya heavy crude, should see prices moderate for heavy crude, due to increased supply of Canadian heavy to the Gulf Coast. Western Canadian heavy oil producers will also benefit, as netbacks improve from being able to access higher value coastal markets with high levels of heavy oil demand.

Overall, our analysis shows that the new expansion of North American tight oil production has impacted specific crude prices due to transportation bottlenecks, rather than a general market oversupply of crudes. Going forward, we believe that these transportation bottlenecks and affected crude prices will begin to normalize. However, it is safe to say that future investment in the US refining sector, along the lines witnessed in the past 15 years with the building of upgrading capacity is unlikely to be repeated this decade. Although tight oil production is currently a North American phenomenon, its impact on worldwide crude movements is already being felt.

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