U.S. Crude Oil Pricing Analysis

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I. Introduction and Summary of Findings

After the oil crisis of 1973, the United States (U.S.) government in 1975 prohibited crude oil exports from the U.S., with only a few exceptions. Today, with the rapid increase in domestic crude production, historical pricing relationships have changed. Stancil & Co. (Stancil) has been retained by Monroe Energy, LLC (Monroe) and Consumers and Refiners United for Domestic Energy (The CRUDE Coalition) to study potential effects of lifting the crude oil export ban.

In exploring this question, Stancil has examined whether and to what extent crude oil export restrictions historically have had an effect upon U.S. crude oil production, pricing, and imports, and whether and to what extent other factors have affected pricing relationships. We have analyzed extensive historical data from the Department of Energy (DOE), the Energy Information Administration (EIA), along with published petroleum pricing information. Our primary findings are as follows:

- Allowing the export of crude would cause domestic gasoline, jet fuel, diesel, and heating oil prices to increase
- Lower fuel prices in recent months have created material benefits for American consumers
- Domestic refining capacity and utilization is at an all-time high
- Allowing exports of domestic crude would have a negative impact on the U.S. trade balance
- The Organization of Petroleum Exporting Countries (OPEC) cartel continues to control crude oil prices indirectly through its regulation of production volumes

About this report: The findings and conclusions expressed herein are those of the authors of the report.

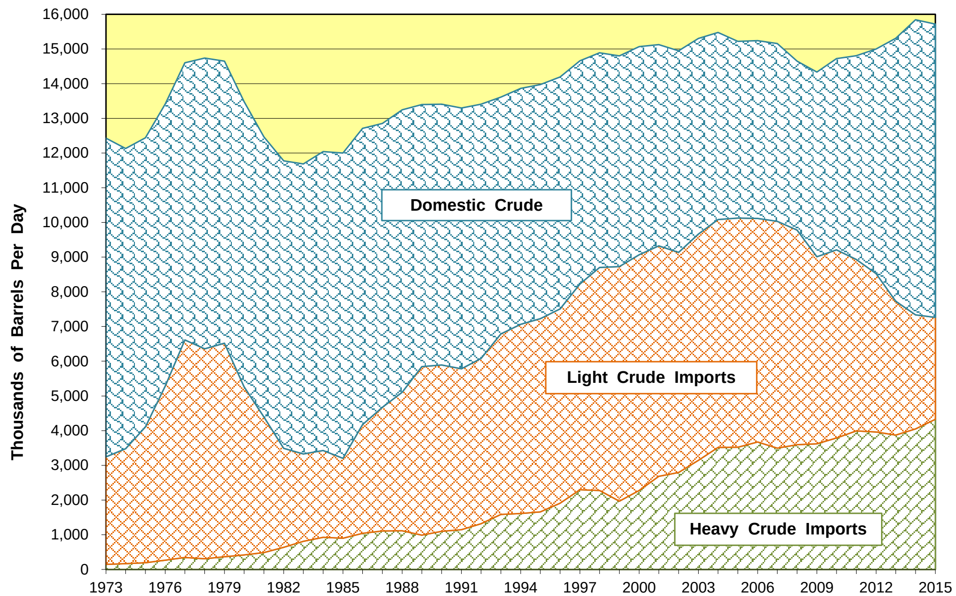
In addition to the above, lifting the crude export ban would result in a domestic crude price increase of approximately $3.00 per barrel, thereby eliminating the incentive to export products. This would have significant implications on the U.S. refining industry, including:

- Lower refinery utilization and/or possible refinery closures
  - Manpower reductions, both at affected refineries themselves and at service providers supporting these refineries
  - Roll down effect on remainder of economy (due to multiplier effect of refinery jobs on the wider economy)
- Increased imports of crude and refined products
  - National security implications resulting from increased reliance on less secure foreign energy sources
- The impact of increased petroleum product costs would impact all consumers of gasoline, jet fuel, diesel, and heating oil. These consumers are not only the driving public, but also airlines, trucking companies, railroads, etc., which would increase their cost of services to cover the increased fuel costs

Historical Context

- U.S. crude oil production peaked in 1970 at 9.6 million barrels per day (B/D) but declined to 5.0 million B/D in 2008
- U.S. crude production rose again with the advent of shale exploration, reaching a new high of 9.7 million B/D in April 2015
- Crude imports in 1973 totaled 3.2 million B/D, peaking at 10.1 million B/D in 2006
- The U.S. imported 7.3 million B/D in 2014. In April 2015, the U.S. imported 7.2 million B/D

U.S. Refinery Crude Input Summary



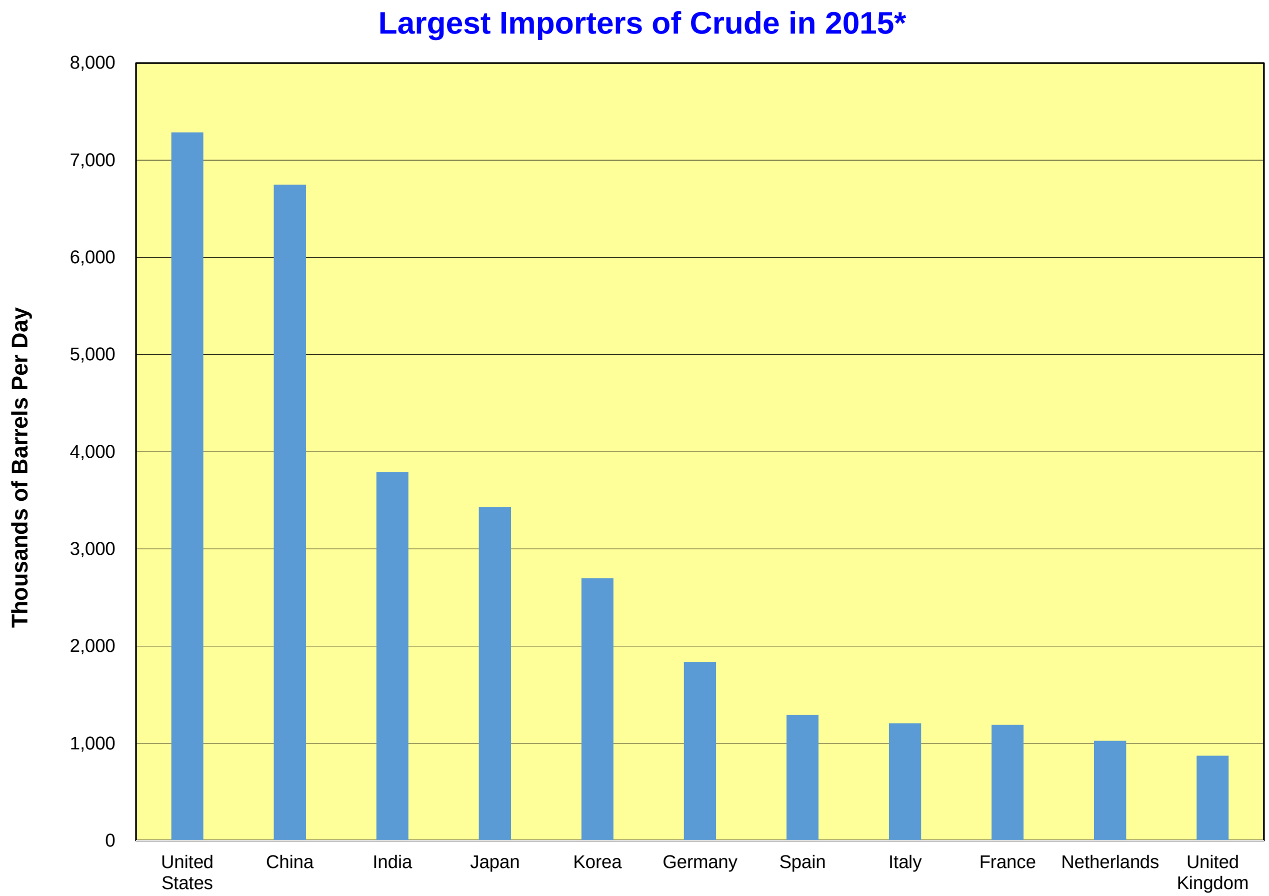
NOTE: Data for 2015 is based on monthly data through April.

SOURCE: Energy Information Administration.

Because the U.S. is still importing over 7 million B/D of crude, any volume of crude exports will result in a corresponding increase in crude imports. Exports of U.S. domestic crude will therefore have no net effect on the world crude balance.

Allowing the Export of Crude Would Cause American Gasoline Prices to Increase

Even though the U.S. has reduced crude imports by almost 3 million B/D, current imports of 7 million B/D still places the U.S. as the country with the highest volume of crude imports, followed by China with imports of 6.7 million B/D. Historical crude imports for the 11 largest crude oil importing countries are shown on the following graph.



*January through April.

SOURCE: JODI.

Any exports of crude oil would require a higher level of imports to satisfy refinery crude requirements. Exports of crude from the U.S. would be light crudes shipped out of the U.S. Gulf Coast, the area importing 3.4 million B/D of crude to supply refinery requirements. Even with the crude oil export ban, the U.S. still imports 650,000 B/D of light crudes.

For comparative purposes, pricing of fuels, such as gasoline, must be made at the major manufacturing centers. Other price points such as the U.S. East Coast (New York Harbor) are consumer market areas, and those prices are based on U.S. Gulf Coast pricing plus transportation or other alternate supply points. For the U.S., the major pricing location is the U.S. Gulf Coast pricing center at Houston.

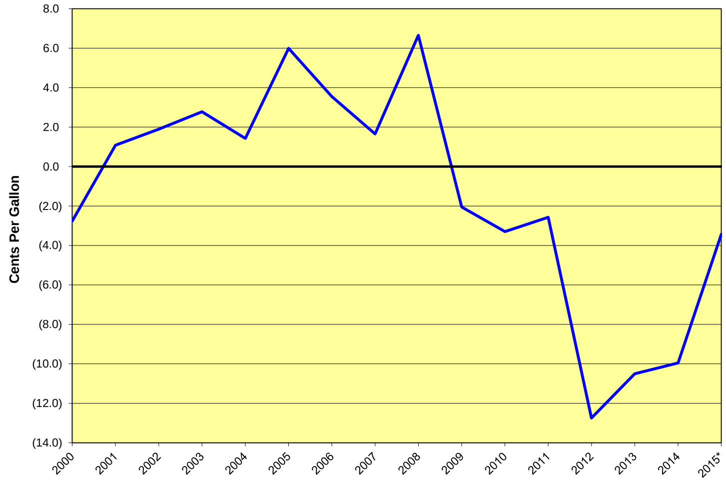
From 2002 through 2008, European gasoline prices averaged $0.034 per gallon less than U.S. Gulf Coast prices. With the surplus of gasoline on the U.S. Gulf Coast and cheaper crude prices, U.S. Gulf Coast gasoline prices declined against European gasoline prices as the U.S. Gulf Coast refiners exported more finished products to Latin American countries.

For 2012, 2013, and 2014, U.S. Gulf Coast prices for gasoline have been discounted versus European prices an average of $0.111 per gallon. Over the same period of time, U.S. jet fuel, diesel, and heating oil prices have been $0.038, $0.044, and $0.054 per gallon, respectively, below European prices. Even with the collapse in world crude prices at the end of 2014, U.S. Gulf Coast gasoline prices have continued to be $0.034 per gallon below European gasoline prices during the first six months of 2015. For the first six months of 2015, U.S. jet fuel, diesel, and heating oil prices have averaged $0.052, $0.012, and $0.045 per gallon, respectively, below European prices.

Allowing exports of crude would escalate U.S. crude prices to parity with world prices, with U.S. Gulf Coast gasoline prices returning to their historical premium of $0.034 per gallon versus European gasoline prices. The gasoline price to the U.S. consumer would rise $0.084 to $0.145 per gallon from today's price level. The U.S. consumer has the lowest free market base price for gasoline of any nation, due to a combination of two main factors: 1) lower crude oil prices compared to world crude prices, and 2) low natural gas prices which reduce operating costs for refineries.

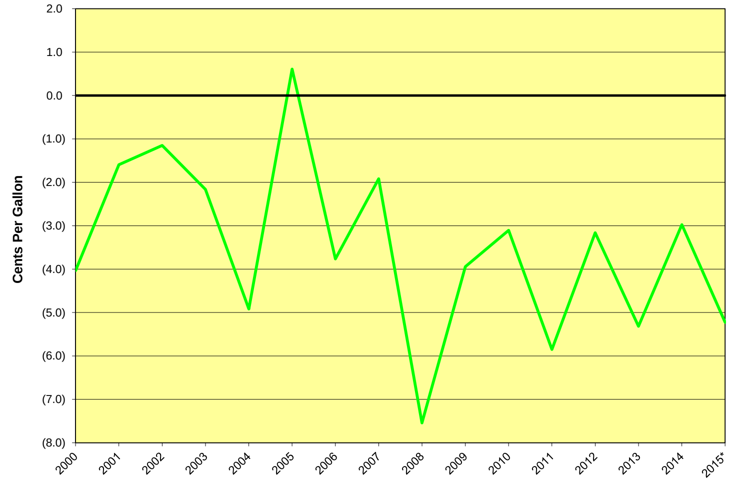
Prices at the key Houston market setting location for the four major products have declined to below other world market prices as shown on the graphs on the following page.

Annual Average Gasoline Price Differentials
(U.S. Gulf Coast Waterborne Unleaded 87/CBOB 87 Minus Cargoes CIF NW Europe Premium Unleaded/Gasoline 10 ppm)



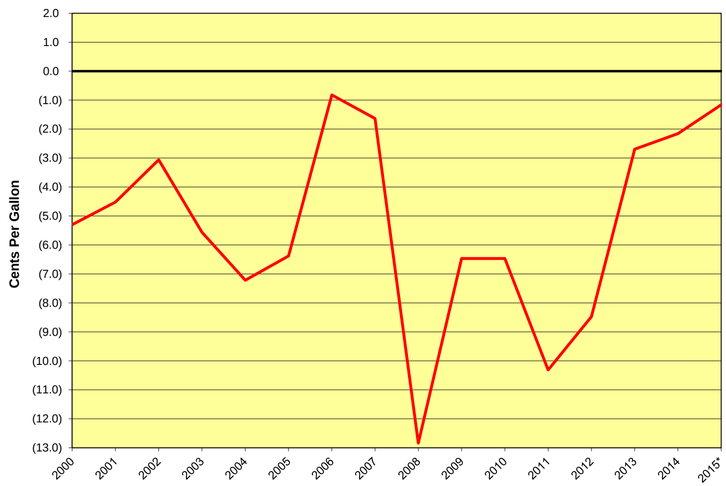
*January through June.

Annual Average Jet/Kerosense Price Differentials
(U.S. Gulf Coast Waterborne Jet/Kerosene 54 Minus Cargoes CIF NW Europe Jet/Kerosene)



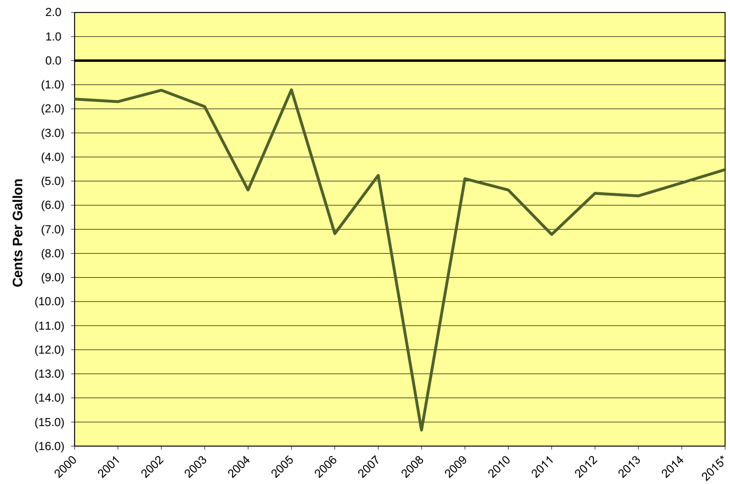
*January through June.

Annual Average Diesel Price Differentials
(U.S. Gulf Coast Waterborne Low Sulfur/Ultra Low Sulfur Diesel Minus Cargoes CIF NW Europe Gasoil EN 590/Gasoil 10 ppm/Ultra Low Sulfur Diesel 10 ppm)



*January through June.

Annual Average Heating Oil Price Differentials
(U.S. Gulf Coast Waterborne No. 2 Heating Oil Minus Cargoes CIF NW Europe Gasoil 0.2% Sulfur/Gasoil 0.1% Sulfur)



*January through June.

SOURCE: *Platts Oilgram Price Report.*

Increased Cost to Consumers Resulting From Exports of Domestic Crude Oil

						Net Penalty	
				MBbl/D	***MM$/Yr***	***$/Driver***	***$/Family***
Assumptions:							
Exports Allowed							
Gasoline Price Increase ($/Gal)	0.084	to	0.145				
Crude Price Increase ($/Bbl)	3.23						
Gasoline	Low Penalty			8,922	11,490	59	120
	High Penalty			8,922	19,833	101	207
Distillate				4,010	4,728	24	49
Total Low Penalty					16,218	83	170
Total High Penalty					24,561	125	257

The above table summarizes the total penalty to consumers that would result from allowing exports of domestic crude oil.

The consumer penalty will partially offset the large benefit the consumer has enjoyed as a result of the 50% decline in world crude prices. The decline in world crude prices was driven by the rapid increase in U.S. crude production, exports of products, and reduction in imports; tilting the world crude supply to a surplus position.

Consumer Benefit – Transportation Fuels

		Average Prices		***2014***	***Net Benefit***		
		Jan-Sep 2014	***Jan-Jun 2015***	***MBbl/D***	***MM$/Yr***	***$/Driver***	***$/Family***
WTI	$/Bbl	99.60	53.29				
Brent	$/Bbl	106.99	57.74				
Gasoline (1)	$/Gal	2.76	1.74	8,922	139,651	713	1,461
Distillate (1)	$/Gal	2.88	1.76	4,010	68,960	352	721
Total Benefit					208,611	1,064	2,182

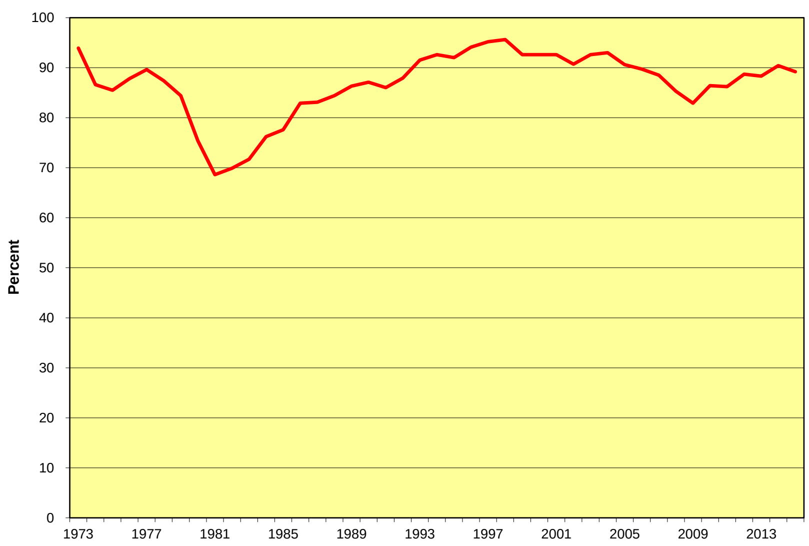
NOTE: (1) U.S. Gulf Coast prices.

The above table shows the total benefit to consumers by maintaining the ban on exports of domestic crude.

Domestic Refining and Utilization is at an All-Time High

The record-high throughputs and utilizations of U.S. refineries are driven by lower U.S. crude prices and the economic incentive to export products. Refinery utilization is a reflection of refining economics at the time. During economic downturns, refinery economics are poorer as product demand declines and higher cost, less efficient refineries cannot be competitive at lower refinery margins. Utilization also reflects the competitiveness of U.S. refining versus world refining. Natural gas is a large component of refinery operating expenses. From 2008 to 2009, natural gas prices in the U.S. dropped $5.00 per million British thermal units (MMBtu), and since that time has dropped another $1.00 per MMBtu. The lower price of natural gas compared to other world refining centers gave the U.S. refiners a $1.00 to $3.00 per barrel operating cost advantage, providing an incentive to run incremental crudes to export products. Beginning in late 2010, West Texas Intermediate (WTI) crude began to be priced under Brent, providing Midcontinent refiners with economic incentive to increase crude processing. As the price differential grew, affecting U.S. Gulf Coast crude prices, U.S. Gulf Coast refining utilization (and capacity) increased, allowing large volumes of products to be exported.

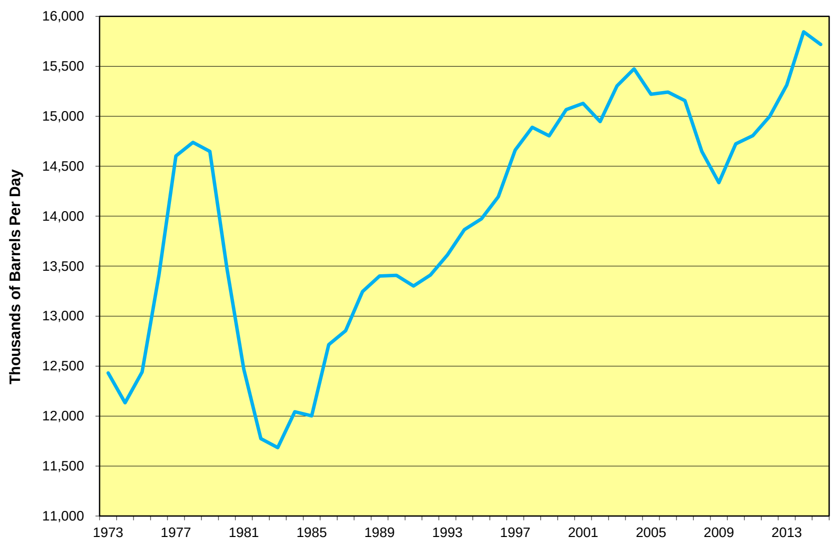
U.S. Refinery Utilization



NOTE: Data for 2015 is based on monthly data through April.

SOURCE: Energy Information Administration.

U.S. Refinery Crude Inputs



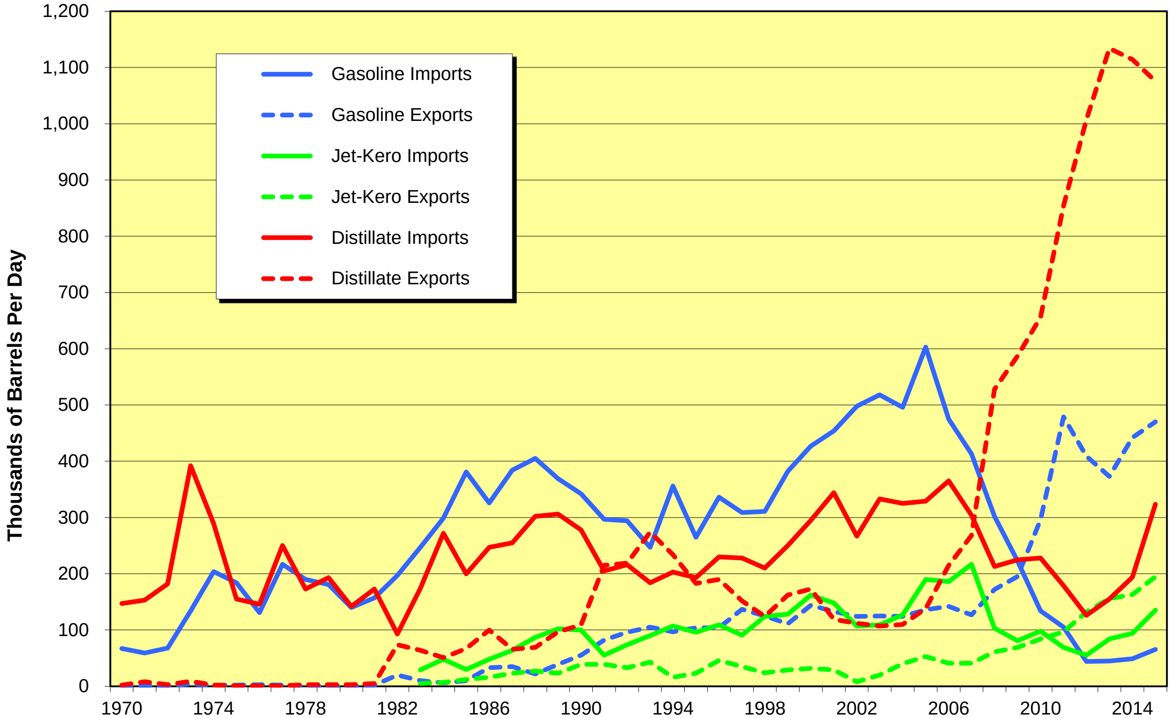
NOTE: Data for 2015 is based on monthly data through April.

SOURCE: Energy Information Administration.

Allowing Exports of Domestic Crude Would Have a Negative Impact on the U.S. Trade Balance

The dramatic increase in U.S. product exports and decrease in product imports is shown on the following graph for gasoline, jet fuel, and diesel.

U.S. Annual Product Imports and Exports



NOTE: Data for 2015 is based on monthly imports and exports through April.

SOURCE: Energy Information Administration.

Allowing crude exports would reverse this virtuous trend. Imports of foreign crude and foreign refined products would increase, and exports of refined products would decrease.

Since 2008, the total positive impact to the U.S. balance of trade has been $221 billion per year. Lifting of the crude export ban would result in a dramatic reduction - or even elimination - of the surplus in trade created by the petroleum industry.

Change in U.S. Trade Balance - 2008 to 2014 (1)

	Annual Trade Balance Improvement/(Deficit)	
	(MB/D)	***(Billion $/Yr)***
Reduction in U.S. Crude Oil Imports	2,303	106.5
Reduction in Gasoline, Jet, and Distillate Imports	568	24.2
Reduction in Other Petroleum Product Imports	733	27.2
Increase in Gasoline, Jet, and Distillate Exports	1,121	38.0
Increase in Other Petroleum Product Exports	1,092	13.3
Increase in Crude Exports	381	12.2
Total	6,197	221.2

NOTE: (1) July through December 2014 average versus 2008.

The OPEC Cartel Continues to Control Prices Indirectly Through Regulations of Production Volumes

The production of crude in OPEC nations has increased from 25 million B/D in 1995 to 32 million B/D in 2014, as shown in the table below. As a percentage of world crude production, it has averaged 42% over the past 20 years, varying in a narrow range from a low of 39.3% in 2002 to a high of 44.2% in 2008. In 2014, OPEC's production averaged 41.7% of world production.

World Crude Production
(Thousands of Barrels Per Day)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total World Production	62,434	63,818	65,806	67,032	65,967	68,527	68,132	67,290	69,460	72,595	73,866	73,478	73,164	74,062	72,871	74,653	74,734	76,160	76,254	77,687
OPEC Production	25,500	26,003	27,274	28,346	27,199	28,944	28,129	26,465	27,977	30,432	31,897	31,607	31,354	32,718	31,035	31,993	32,219	33,392	32,488	32,388
OPEC as Percent of World	40.8%	40.7%	41.4%	42.3%	41.2%	42.2%	41.3%	39.3%	40.3%	41.9%	43.2%	43.0%	42.9%	44.2%	42.6%	42.9%	43.1%	43.8%	42.6%	41.7%

NOTE: Production for 2014 is the average of January through November 2014.

SOURCE: Energy Information Administration.

OPEC cannot control prices directly, only indirectly through production volumes. In times that world crude supplies exceed demand, OPEC has two options:

1) Drop OPEC production and maintain static world crude prices
2) Maintain OPEC production, increasing world surplus supply to the point that crude oil prices drop. Maintaining world crude prices at elevated levels continues to provide the economic incentive to develop non-OPEC crude production. Allowing crude prices to drop reduces the incentive for development.

Saudi Arabia-led OPEC is currently imposing its will on the international crude oil market by maintaining current production levels. Its strategy is to slow or stop other world crude reserve developments. This strategy may take several years before definitive reductions in world crude production is visible, but there are already concrete signs of slowing production in the United States – particularly in the Bakken Formation. Low crude prices will encourage more demand, and at some point in time, crude production and demand will again balance and prices can rise. Saudi Arabia has crude reserves that could be used to increase production to moderate any increases in prices driven by increasing demand, further dampening other world crude reserve developments. Other world events could rapidly change the supply/demand picture, such as disruptions in Libya, Iran, Iraq, etc. At that point, crude prices could escalate over a short period of time, but OPEC retains a firm grip on the international crude market.

II. Summary and Conclusions

The studies examining the export of United States (U.S.) crudes have forecast that it would result in U.S. crude oil prices increasing. It is assumed that the crude price increase would translate into corresponding increases in gasoline prices by $0.084 to $0.145 per gallon and jet, heating oil, and diesel prices by $3.23 per barrel. The penalty for the consumer as a result of lifting the export ban would be up to $25 billion per year, or $125.00 per driver and $257.00 per family. The calculations are shown in the table below.

Increased Cost to Consumers Resulting From Exports of Domestic Crude Oil

						Net Penalty	
					MBbl/D	***MM$/Yr***	***$/Driver***	***$/Family***
Assumptions:								
Exports Allowed								
Gasoline Price Increase ($/Gal)		0.084	to	0.145				
Crude Price Increase ($/Bbl)		3.23						
Gasoline	Low Penalty				8,922	11,490	59	120
	High Penalty				8,922	19,833	101	207
Distillate					4,010	4,728	24	49
Total Low Penalty						16,218	83	170
Total High Penalty						24,561	125	257

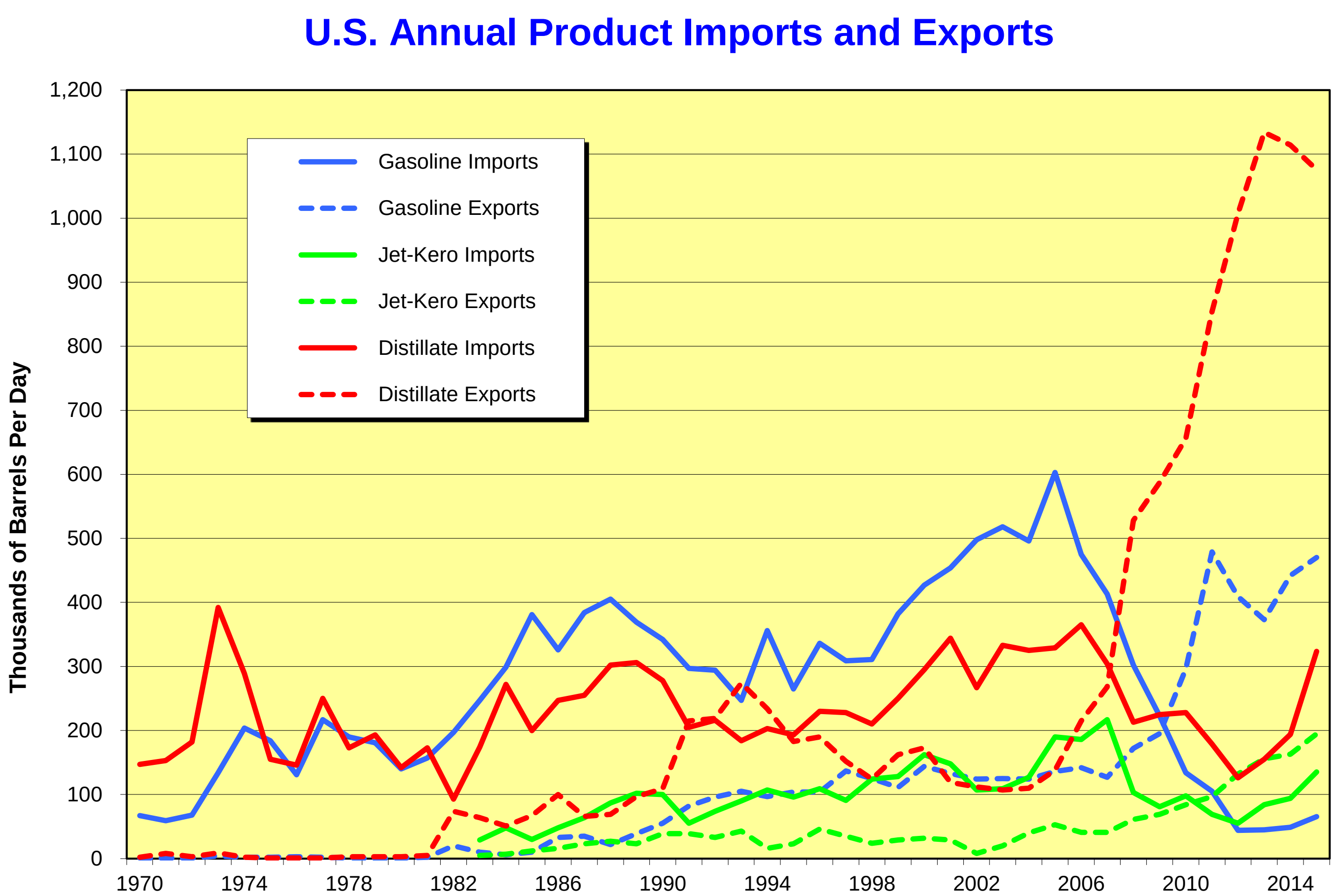
The U.S. consumer has experienced a large savings due to the drop in transportation fuels prices as a result of increased world supply driven by U.S. production. Comparing the prices of gasoline and diesel from the first nine months of 2014 to the first six months of 2015, the decline has been $43.00 per barrel and $47.00 per barrel, respectively. The dramatic decline in prices has resulted in a U.S. consumer benefit of $209 billion per year. This translates to $1,064 per driver and $2,182 per family. The calculations are shown in the table below.

Consumer Benefit – Transportation Fuels

		Average Prices		***2014***	***Net Benefit***		
		Jan-Sep 2014	***Jan-Jun 2015***	***MBbl/D***	***MM$/Yr***	***$/Driver***	***$/Family***
WTI	$/Bbl	99.60	53.29				
Brent	$/Bbl	106.99	57.74				
Gasoline	$/Gal	2.76	1.74	8,922	139,651	713	1,461
Distillate	$/Gal	2.88	1.76	4,010	68,960	352	721
Total Benefit					208,611	1,064	2,182

Petroleum Administration for Defense District (PADD) 1 refinery utilization in 2007 was 86%, but as a result of the economic recession, utilization dropped to 68% in 2011, accompanied by the closure of refining capacity. Since 2011, crude throughputs have remained mostly constant at 1.1 million barrels per day (B/D) and utilizations in the 79% to 84% range. Supplies of domestic crude to PADD 1 refiners has increased to 44% in 2015, but the supplies are generally priced at parity with Brent crude, due to the high logistics costs incurred for delivery. Refinery capacity has stabilized, but the higher delivered crude prices compared to the U.S. Gulf Coast has precluded the economic incentive for expansions.

Because of the changes in domestic crude availability and higher refinery utilization, the U.S. refined product import/export pattern has changed significantly.



NOTE: Data for 2015 is based on monthly imports and exports through April.

SOURCE: Energy Information Administration.

The net import/export balance for gasoline, jet, and total distillates shifted from 627,000 B/D net imports in 2008 to net exports of 946,000 B/D in 2014. This swing of over 1.6 million B/D of products had a large impact on refinery utilization (and crude consumption) for non-U.S. refiners. Based on International Energy Agency (IEA) data, the gasoline, jet, and distillate yield for an average world refinery is 65% to 70%. To produce the 1.6 million B/D of gasoline, jet, and other distillates would require 2.3 million B/D of crude. With the swing in the U.S. from a net importer to a net exporter due to increased U.S. refinery runs, the shift in non-U.S. world crude requirements was reduced by 3 million+ B/D, effectively increasing non-U.S. crude supply by that quantity.

In addition to exports of gasoline, jet, and distillate, the U.S. is exporting greater quantities of other petroleum products and natural gas liquids (NGLs). Shale crude oil and natural gas production generally contains higher percentages of NGLs such as ethane, propane, butanes, and natural gasoline. A significant portion of the production of NGLs is exported. These products in foreign markets are displacing other petroleum products on a British thermal unit (Btu) basis, further reducing world crude oil requirements. Other petroleum intermediates are also being exported, also reducing foreign crude requirements.

The total volume of other exports is currently 2.1 million B/D, an increase of 1.1 million B/D compared to 2008. Because of the lower Btu of the NGLs component, the equivalent crude oil volume that is being displaced is estimated to be 1.0 million B/D higher than 2008.

The direct impact of reduced crude imports since 2008 is 2.3 million B/D of incremental crude on the world market. The export of 463,000 B/D of crude (October 2014 through April 2015) mainly to Canada is also a direct impact on incremental world crude requirements. However, the reduced imports of products and increased exports of products and intermediates effectively adds another 4.1 million B/D of crude on the world market by reducing crude processing requirements in other areas of the world. In total, the increases in U.S. domestic production (crude and natural gas) have added over 6.8 million B/D of crude equivalent to the world energy markets.

The total effect of world crude supply as a result of the increases in U.S. domestic energy supply and U.S. refinery throughputs can be summarized below.

Change in U.S. Crude Supply Since 2008 [(1)]

(Thousands of Barrels Per Day)

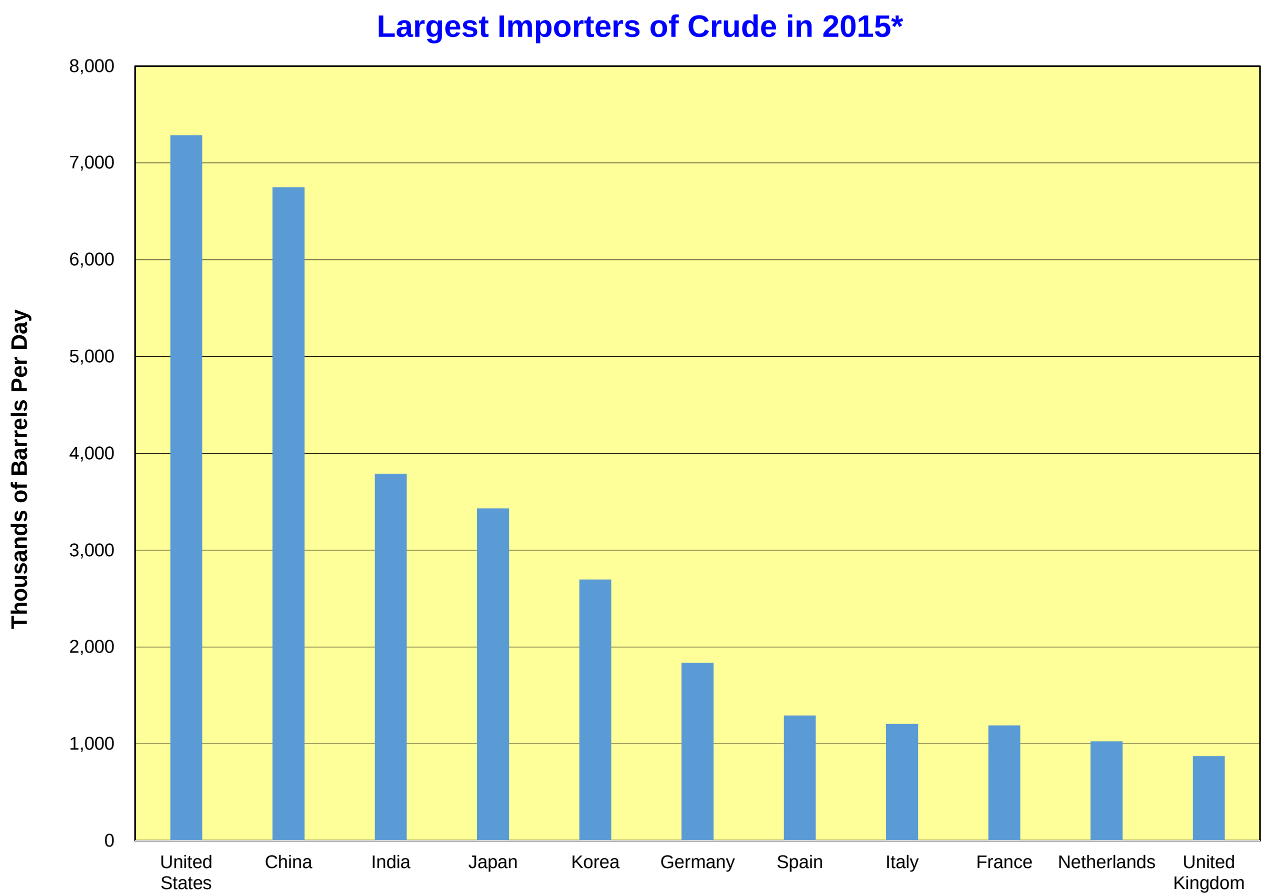
	Change in Volume	***Equivalent Crude Volume***
Reduction in U.S. Crude Oil Imports	2,303.3	2,303.3
Reduction in Gasoline, Jet, and Distillate Imports	567.5	810.7
Reduction in Other Petroleum Product Imports	574.6	574.6
Reduction in NGL Product Imports	158.4	126.7
Increase in Gasoline, Jet, and Distillate Exports	1,121.5	1,602.1
Increase in Other Petroleum Product Exports	423.6	423.6
Increase in NGL Product Exports	668.0	534.4
Increase in Crude Exports	380.8	380.8
Total	6,197.7	6,756.3

NOTE: (1) July through December 2014 average versus 2008.

From 2007 through 2013, world petroleum demand increased from 86.7 million B/D to 91.2 million B/D, an increase of 4.5 million B/D. The increase in U.S. crude production, product exports, and reduced crude and product imports over this same period is 6.8 million B/D, helping create the current world crude surplus position.

The U.S. is currently importing 7.2 million B/D of foreign crudes to supplement the 9.7 million B/D of domestic crudes.

Even though the U.S. has reduced crude imports by almost 3 million B/D, current imports of 7 million B/D still places the U.S. as the country with the highest volume of crude imports, followed by China with imports of 6.7 million B/D. Historical crude imports for the 11 largest crude oil importing countries are shown on the following graph.



*January through April.

SOURCE: JODI.

There are no forecasts that predict the U.S. will produce enough domestic crude to totally eliminate foreign crude imports. Future domestic crude production increases will displace an equal volume of foreign crude, creating further surpluses on the world market. Exports of U.S. domestic crude, primarily to Canada or other permitted countries, will result in the importation of an equal volume of foreign crude to supply the U.S. refining system, having no net effect on the world crude balance. With the current high level of exports of finished products, NGLs, and other petroleum products, the U.S. is effectively supplying 6.8 million B/D of equivalent crude oil barrels to the world markets.

U.S. crudes in coastal locations are being priced at world prices. Inland crude production is discounted by the cost to deliver those barrels to the coastal market setting locations. When pipeline capacity is available, the inland producer receives a price closer to world marker prices. When incremental logistics require rail or other higher cost transportation alternatives, then the producer receives a lower netback price.

Using Brent as the world marker crude price, crudes such as West Texas Intermediate (WTI) appear to be selling at a discount. WTI is priced at Cushing, Oklahoma, in an area where crude supplies exceed local demand. The excess must be transported to the U.S. Gulf Coast for consumption. The cost of pipeline transportation is approximately $4.00 per barrel. On the U.S. Gulf Coast, WTI must be priced at a delivered foreign barrel equivalent (adjusted for quality) in order to displace the foreign barrel.

A similar analysis can be made for Bakken crude in North Dakota. Bakken crude is priced in Clearbrook, Minnesota. A producer incurs $2.90 per barrel pipeline tariff to Clearbrook. The Bakken discount to Brent in the last half of 2014 was in the range of $10.00 per barrel, driven solely by rail logistics. Rail costs to the U.S. East Coast are $15.00 to $16.00 per barrel. Brent delivery cost to the U.S. East Coast for 2015 was $2.29 per barrel. The netback price to the producer is Brent plus $2.29 transportation less $15.50 for a net of Brent less $13.21. Selling at Clearbrook results in a producer discount of Brent less $10.00, less $2.90 pipeline cost, or a net of Brent less $12.90. This is an example showing how the logistics issues determine the prices quoted in the producing areas.

The benefit in U.S. balance of trade due to increasing crude production and associated downstream activities has been $221 billion per year, comparing 2014 versus 2008. The largest component has been the reduction in crude oil imports, accounting for $106 billion per year of the improvement. Imports of gasoline, jet, and diesel have also dropped, accounting for $24 billion per year improvement, and exports of these three products have increased substantially, providing another $38 billion per year in benefits. A complete outline of each category is shown in the table below.

Change in U.S. Trade Balance - 2008 to 2014 (1)

	Annual Trade Balance Improvement/(Deficit)	
	(MB/D)	***(Billion $/Yr)***
Reduction in U.S. Crude Oil Imports	2,303	106.5
Reduction in Gasoline, Jet, and Distillate Imports	568	24.2
Reduction in Other Petroleum Product Imports	733	27.2
Increase in Gasoline, Jet, and Distillate Exports	1,121	38.0
Increase in Other Petroleum Product Exports	1,092	13.3
Increase in Crude Exports	381	12.2
Total	6,197	221.2

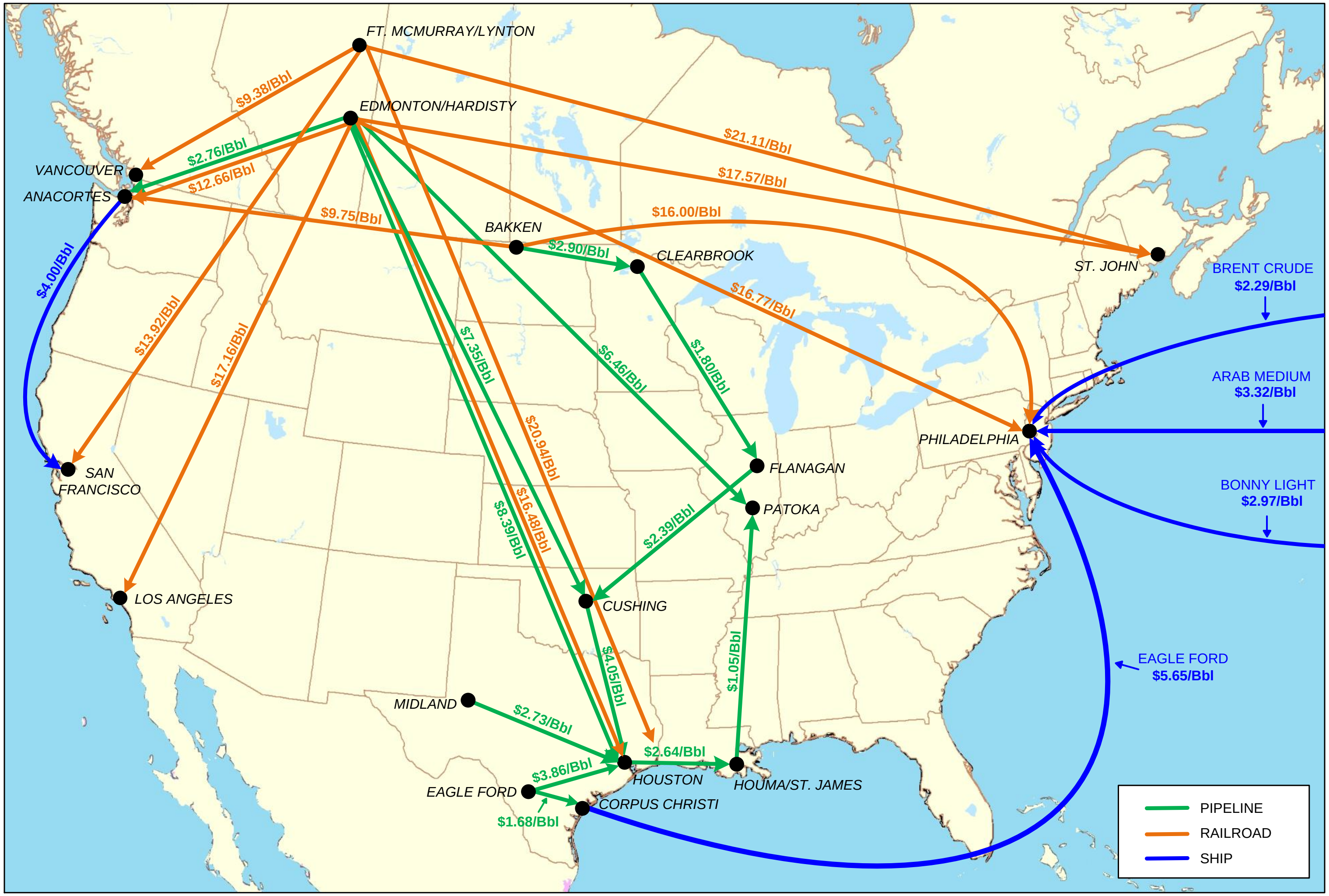
NOTE: (1) July through December 2014 average versus 2008.

From a peak production rate of 9.6 million B/D in 1970, U.S. crude production had declined to 5.0 million B/D in 2008. Rapidly escalating crude prices provided the economic incentive to increase exploration activity. New drilling techniques developed for natural gas drilling in shale formations was converted for development of oil reserves. In April 2015, U.S. crude production had increased to 9.7 million B/D.

The first area of crude production increases occurred in North Dakota and quickly exceeded the capacity of local refineries and pipelines that could transport the excess to other refining centers. Pipeline companies began planning new pipelines to transport the increasing crude production. The new pipeline projects require planning, permits, financing, etc. The time frame for this process can take several years.

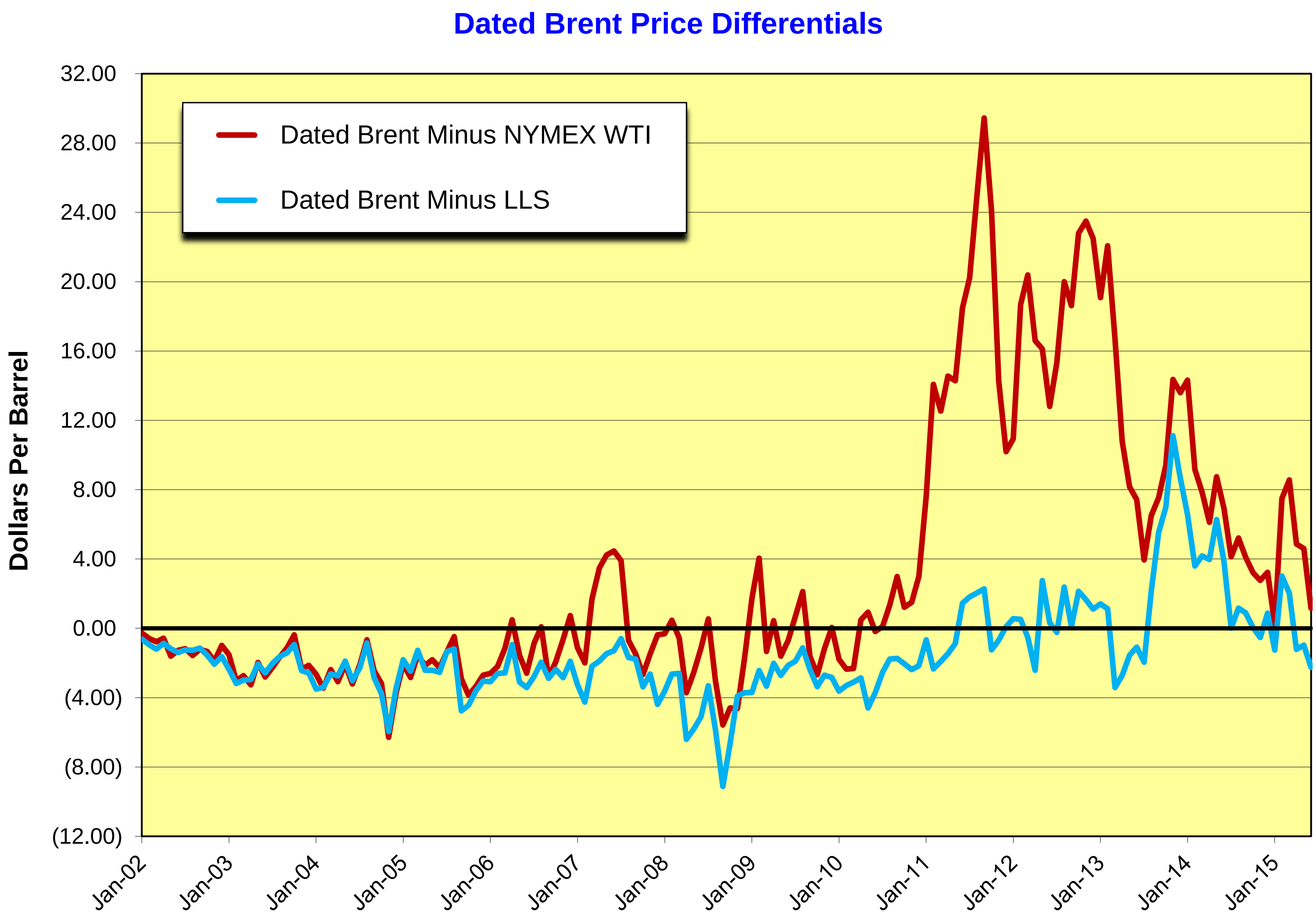
In the interim, crude producers have production coming online and developed alternate rail delivery projects. The netback price to producers is higher when crude is shipped by pipeline due to the lower delivery costs. However, when faced with very limited pipeline capacity, producers accept lower netbacks (due to higher delivery costs by rail) versus shutting in wells and reducing or stopping drilling operations. The economic decision for producers is weighing the cost of production (drilling and operating costs) and lower netback prices, and then calculating a rate-of-return that is deemed acceptable.

2015 Crude Pipeline, Rail, and Ship Freight Costs



As more domestic crude production was available in the Midcontinent area (from the Bakken and Permian Basin), refiners purchased local crude production, reducing imports of U.S. Gulf Coast barrels (offshore domestic crude or foreign imports). Additional volumes of shale crude were developed in other regions – Eagle Ford in South Texas, Permian Basin in West Texas, Niobrara in Colorado, and Uinta in Utah. Each of these areas had very limited pipeline systems requiring rail or truck facilities to transport the crude to refining or market centers.

The logistics constraints and much higher alternate delivery costs resulted in significant discounts for the producers compared to world marker crude prices. WTI was the common marker crude for Midcontinent refineries for decades and Light Louisiana Sweet (LLS) was the common marker for the U.S. Gulf Coast. The region was short of crude and relied on imports of Canadian crudes and U.S. Gulf Coast and foreign crudes to supply incremental crude requirements. The imported foreign crudes were all priced on a Brent basis. The primary worldwide marker price is Brent crude oil. In the U.S., WTI and LLS closely tracked Brent price. The graph on the following page shows the Brent/WTI/LLS differentials from 2002 through current.



SOURCES: *Argus Crude* and *Platts Oilgram Price Report.*

Increasing Bakken production was providing upper Midcontinent refiners with incremental supplies of light sweet crude oils, displacing historical deliveries of WTI from Cushing. With limited pipeline capacity to move Cushing barrels south to the U.S. Gulf Coast refining complex, inventories began to reach the upper limits of storage capacity at Cushing. Once the pipeline capacity constraints were reached, rail, and to a lesser extent barging, were the only viable alternatives. The production field value of crude dropped until the discounted price covered the added transportation costs to the major market areas on the U.S. East Coast and U.S. Gulf Coast.

During this time frame, the relationship of crude oil prices on the U.S. Gulf Coast remained relatively constant (LLS versus Brent). Further development of shale crudes in the Eagle Ford and Permian Basin areas added supplies in areas without adequate pipeline capacity to the major refining centers on the Texas/Louisiana/Mississippi Gulf Coast. Pipelines were and are being currently developed to increase pipeline capacity in these areas.

Barge and shiploading facilities were developed in Corpus Christi, Texas to transport the increasing crude supplies to U.S. Gulf Coast and U.S. East Coast refiners. Between any two ports in the U.S., ship deliveries must be made on ships that meet the requirements of the Merchant Marine Act of 1920, also known as the Jones Act. The law requires that all goods transported by water between U.S. ports be carried on U.S. flagged ships, constructed in the U.S., owned by U.S. citizens, and crewed by U.S. citizens and U.S. permanent residents.

The cost of shipping products between U.S. ports is substantially higher than shipping costs for equivalent distances in other parts of the world. Depending upon the size of the ship, the cost of transporting crude can be 200% to 300% higher. As an example, the cost of shipping crude from the North Sea to the U.S. East Coast (6,354 nautical miles) is approximately $2.29 per barrel. The cost of shipping Eagle Ford crude from Corpus Christi to the U.S. East Coast (3,995 nautical miles) is $5.65 per barrel. All mileage numbers quoted are for round-trips.

The Energy Policy and Conservation Act (EPCA) of 1975 prohibited the export of crude oil from the U.S. Exemptions from the EPCA allow crude oil to be shipped to Canada under specifically granted permits. These shipments can be made in non-Jones Act ships. The cost of shipping Eagle Ford crude to refineries in Eastern Canada from Corpus Christi, Texas (4,853 nautical miles) is $2.86 per barrel. Export shipments (mainly to Canada) have increased from 29,000 B/D in 2008 to a peak of 586,000 B/D in April 2015.

By mid-2011, the price of LLS had declined to parity with Brent rather than the historical premium of $2.00 to $3.00 per barrel as a result of increasing pipeline capacity from the Permian Basin and Cushing to the U.S. Gulf Coast. The PADD 3 refinery throughputs increased from 7.1 million B/D (84.5% utilization) in 2009 to 8.4 million B/D (91.5% utilization) in 2014. The increased throughputs were the result of not only higher utilization, but increased refining capacity as a result of expansion projects.

With access to less expensive natural gas, resulting in lower operating costs compared to other world refining centers, the U.S. Gulf Coast refiners began to export increasing quantities of gasoline and distillates to Latin America, while continuing to export distillates to Europe.

As Eagle Ford and Permian Basin crude production increased, LLS price further declined versus Brent. U.S. Gulf Coast refiners displaced foreign light sweet crude, plus other heavier crudes. Processing configurations led to early constraints on the absolute quantity of light crudes that could be processed, and refiners began programs to remove the constraints. As the U.S. Gulf Coast refiners developed larger foreign markets, refinery throughputs increased to sustained levels at historical highs.

The production of crude in the Organization of Petroleum Exporting Countries (OPEC) nations has increased from 25 million B/D in 1995 to 32 million B/D in 2014, as shown in the table below. As a percentage of world crude production, it has averaged 42% over the past 20 years, varying in a narrow range from a low of 39.3% in 2002 to a high of 44.2% in 2008.

World Crude Production

(Thousands of Barrels Per Day)

	1995	*1996*	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
Total World Production	62,434	63,818	65,806	67,032	65,967	68,527	68,132	67,290	69,460	72,595	73,866	73,478	73,164	74,062	72,871	74,653	74,734	76,160	76,254	77,687
OPEC Production	25,500	26,003	27,274	28,346	27,199	28,944	28,129	26,465	27,977	30,432	31,897	31,607	31,354	32,718	31,035	31,993	32,219	33,392	32,488	32,388
OPEC as Percent of World	40.8%	40.7%	41.4%	42.3%	41.2%	42.2%	41.3%	39.3%	40.3%	41.9%	43.2%	43.0%	42.9%	44.2%	42.6%	42.9%	43.1%	43.8%	42.6%	41.7%

NOTE: Production for 2014 is the average of January through November 2014.

SOURCE: Energy Information Administration.

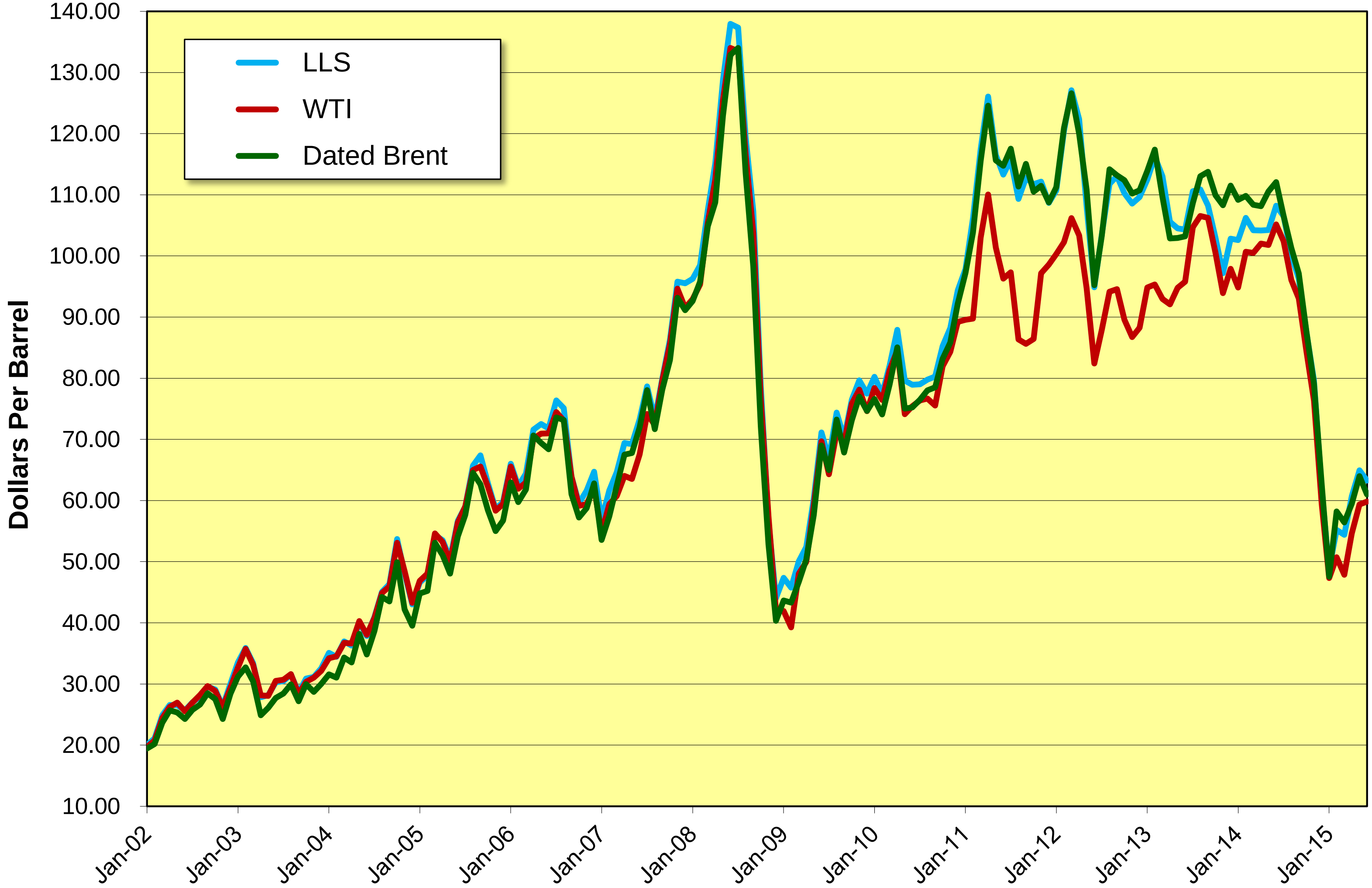
OPEC cannot control prices directly, only indirectly through production volumes. In times that world crude supplies exceed demand, OPEC has two options:

1) Drop OPEC production and maintain static world crude prices
2) Maintain OPEC production, increasing world surplus supply to the point that crude oil prices drop.

Maintaining world crude prices at elevated levels continues to provide the economic incentive to develop non-OPEC crude production. Allowing crude prices to drop reduces the incentive for development.

World crude oil demand growth in 2014 was below previous years, and crude production growth exceeded demand growth. The result was a slow decline in Brent crude prices, from $112.07 per barrel in June 2014 to $55.31 per barrel for the first four months of 2015. The November 2014 OPEC meeting resulted in a steady volume quota for the OPEC members. The world commodity trading community interpreted the announcement as OPEC's method of maintaining market share, realizing that crude prices would drop to the point of discouraging new developments.

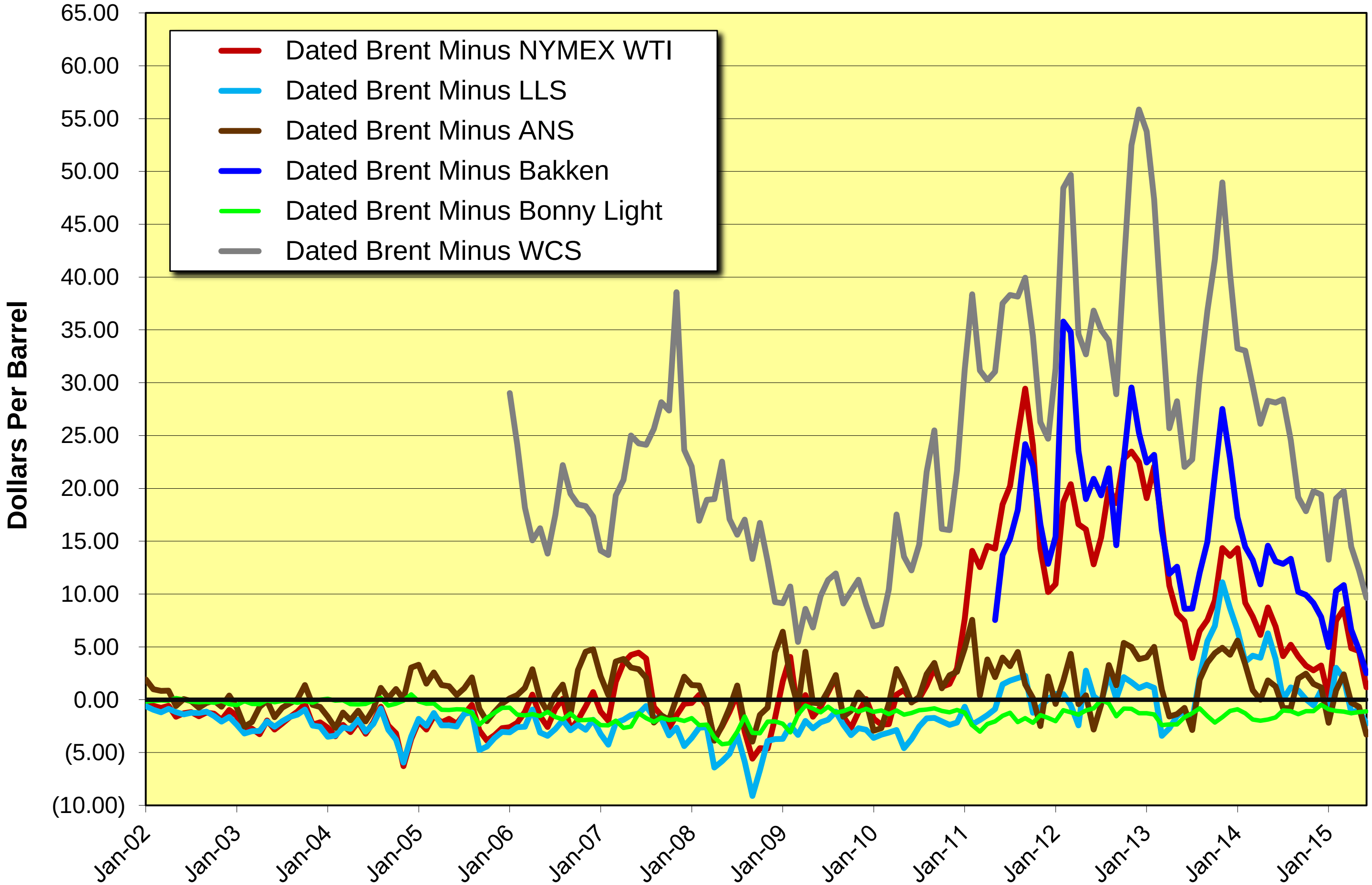
Historical Monthly Average Crude Prices



SOURCES: *Argus Crude* and *Platts Oilgram Price Report.*

The differential between LLS, WTI, and Brent has collapsed, along with the decline in Brent price.

Historical Monthly Dated Brent Price Differentials



SOURCES: *Argus Crude* and *Platts Oilgram Price Report.*

The precipitous drop in crude prices will have a worldwide effect on crude development projects. The revenue impact on OPEC and non-OPEC producers will be substantial. OPEC producers with large currency reserves, such as Saudi Arabia, can meet internal financial obligations for many years during a period of budget deficits. Other large producers such as Iran, Venezuela, and Russia will suffer immediate financial issues. Saudi Arabia is currently imposing its will over the remaining OPEC members by maintaining current production levels. Its strategy is to slow or stop other world crude reserve developments. Low crude prices will encourage more demand, and at some point in time, crude production and demand will again balance and prices can rise. Saudi Arabia has crude reserves that could be used to increase production to moderate any increases in prices driven by increasing demand, further dampening reserve developments. Other world events could rapidly change the supply/demand picture, such as disruptions in Libya, Iran, Iraq, etc. At that point, crude prices could escalate over a short period of time.

To look at the effects of lifting the crude oil export ban, potential end use markets for U.S. crudes must be evaluated. For comparison purposes, Stancil has calculated the delivered cost of Brent and Eagle Ford crudes to each of these locations for the past three years to determine the incentive to import Eagle Ford over Brent.

Economic Incentive to Import Eagle Ford Over Brent

(Dollars Per Barrel)

Port of Discharge	***2012*** [(1)]	***2013***	***2014***
Philadelphia, Pennsylvania	(0.92)	(0.14)	0.39
St. John, Canada	1.99	3.09	3.04
Buenos Aires, Argentina	2.08	3.11	3.06
Rotterdam, Netherlands	1.28	2.67	2.55
Augusta, Italy	2.06	3.18	3.07
Singapore	1.31	2.59	2.84
Cilacap, Indonesia	1.27	2.56	2.80
Onsan, South Korea	1.52	2.81	3.13
Kawasaki, Japan	1.57	2.87	3.18
Shanghai, China	1.51	2.80	3.10

NOTE: (1) Eagle Ford prices in 2012 are based on a correlation to LLS prices.

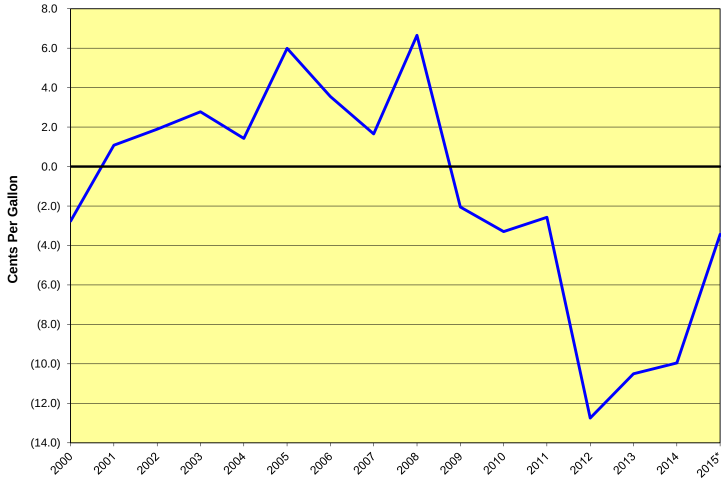
SOURCES: *Worldscale, Platts Oilgram Price Report,* and *Argus Crude.*

Using historical prices, it would have been economic for refiners in the Atlantic Basin and the Far East to purchase Eagle Ford crude versus Brent in the period 2012 through February 2015. The incentive was approximately $3.00 per barrel for the 2013 to 2014 period. If the world was in a crude short position, then the argument could be made that if exports had been allowed, U.S. crude prices would have risen by approximately $3.00 per barrel. For the first six months of 2015, Stancil has calculated that crude prices to Texas Gulf Coast refiners would have increased by $3.23 per barrel. This calculation was based on the refining value of Gulf Coast crudes that could be exported to other world refining centers. The European refining centers currently run crudes similar to Eagle Ford and WTI. Using the first six months of 2015 pricing for Gulf Coast crudes, Stancil has used a linear programming model of European refining to calculate the price European refiners would pay for U.S. crudes. The FOB price on the Gulf Coast was then compared to actual prices for the same time period to determine the price increase if the export ban was lifted.

The U.S. would have imported an equal quantity of higher cost foreign crude to offset the loss of exported U.S. crude; however, U.S. refiners would have a reduced incentive to run incremental barrels and export product to foreign countries. It is likely that foreign refinery utilization would have increased and U.S. refinery utilization would have decreased. The overall world crude supply/demand balance would not have changed, but shifts would be noted in refinery capacity utilization in the different refining regions.

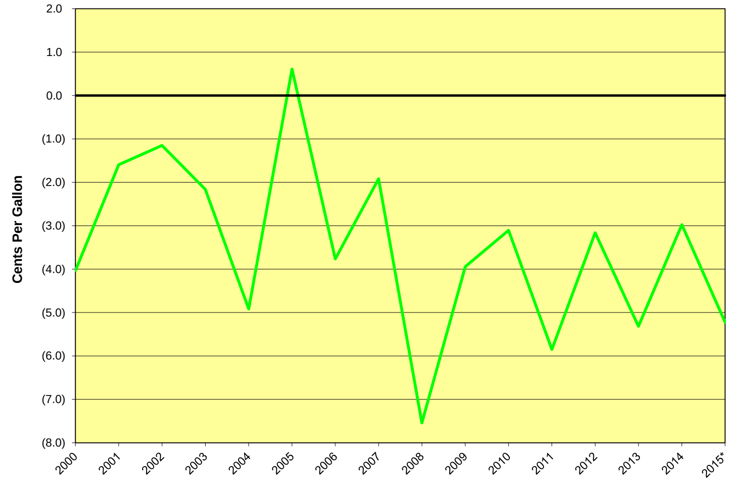
Gasoline, jet, diesel, and heating oil prices at the key Houston market setting location have declined to below other world market prices.

Annual Average Gasoline Price Differentials
(U.S. Gulf Coast Waterborne Unleaded 87/CBOB 87 Minus Cargoes CIF NW Europe Premium Unleaded/Gasoline 10 ppm)



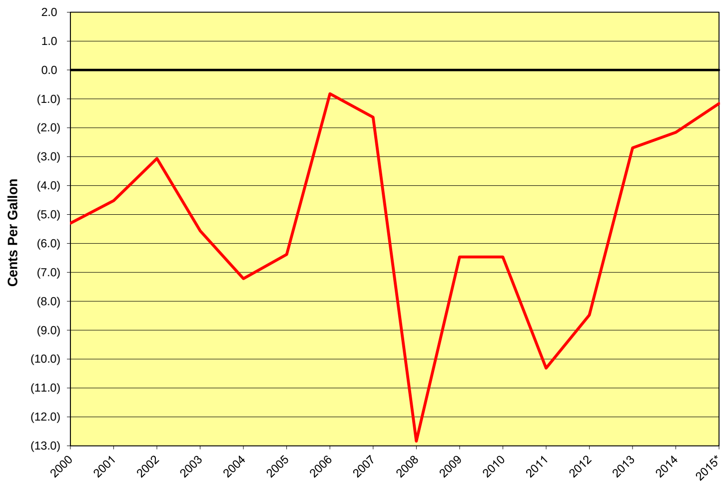
*January through June.

Annual Average Jet/Kerosense Price Differentials
(U.S. Gulf Coast Waterborne Jet/Kerosene 54 Minus Cargoes CIF NW Europe Jet/Kerosene)



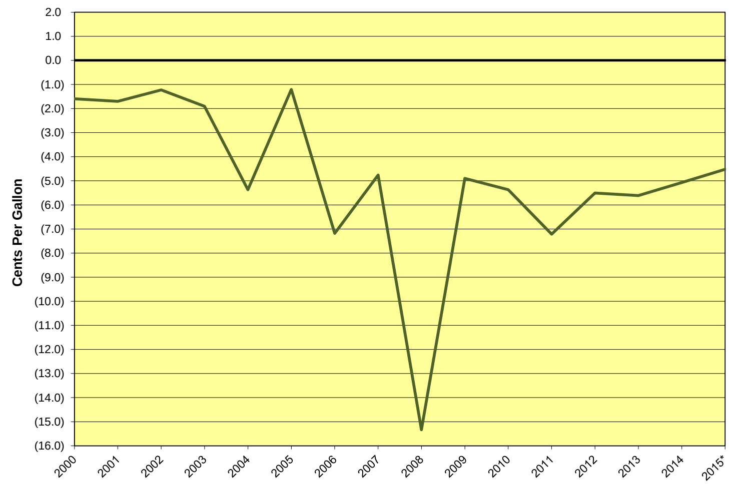
*January through June.

Annual Average Diesel Price Differentials
(U.S. Gulf Coast Waterborne Low Sulfur/Ultra Low Sulfur Diesel Minus Cargoes CIF NW Europe Gasoil EN 590/Gasoil 10 ppm/Ultra Low Sulfur Diesel 10 ppm)



*January through June.

Annual Average Heating Oil Price Differentials
(U.S. Gulf Coast Waterborne No. 2 Heating Oil Minus Cargoes CIF NW Europe Gasoil 0.2% Sulfur/Gasoil 0.1% Sulfur)



*January through June.

SOURCE: *Platts Oilgram Price Report.*

The lower prices are a result of lower crude prices on the U.S. Gulf Coast and increased crude oil processing. Gasoline and diesel production on the U.S. Gulf Coast exceed local demands and pipeline capacity to deliver to other parts of the country. Exported products are priced to be delivered to foreign locations at a cheaper price than supplies from other world refiners.

Prior to 2009, European gasoline prices averaged $0.034 per gallon above U.S. Gulf Coast prices. With the surplus of gasoline on the U.S. Gulf Coast and cheaper crude prices, U.S. Gulf Coast prices declined against European prices as the U.S. Gulf Coast refiners exported more barrels to Latin American countries. For 2012, 2013, and 2014, U.S. Gulf Coast prices for gasoline were discounted versus European prices, an average of $0.111 per gallon. Even with the collapse in world crude prices at the end of 2014, U.S. Gulf Coast prices are still $0.034 per gallon below European prices for the first six months of 2015. Allowing exports of crude would escalate U.S. crude prices to parity with world prices, and U.S. Gulf Coast gasoline prices would return to its historical premium of $0.034 versus European prices. The gasoline price to the U.S. consumer would rise a minimum of $0.084 per gallon to a maximum of $0.145 per gallon.

Without the economic incentive to run incremental barrels for export, the U.S. would have remained a net importer of products, impacting foreign trade balances. Over the 2008 through 2014 period, the U.S. swing from net imports to net exports was 1.6 million B/D. This would translate to approximately 2.3 million B/D of crude runs. There would not have been significant investment in the refining industry without the economic incentive to run incremental crude to export products. Increasing netback prices to U.S. crude producers by $3.00 per barrel would not have impacted their investment decisions for exploration and production as market prices were already far above production costs. It would have increased producers' overall earnings by $3.00 per barrel.

Beginning in late 2014, along with the 50+% decline in crude prices, the differential between U.S. Gulf Coast crude and Brent price also collapsed. The calculated difference in incentives for foreign refiners in Canada or Northwest Europe to import Eagle Ford crude is less than $0.50 per barrel.

Another factor apparent in the data is the economic penalty incurred by the U.S. East Coast and U.S. West Coast refiners due to the Jones Act. Domestic crude must be delivered to these refineries by rail, ship, or barge. The high cost of Jones Act transport of crude from the U.S. Gulf Coast to the U.S. East Coast or West Coast refiners results in a $2.50 to $3.00 disadvantage compared to shipment of the same crude to foreign refineries. For 2013 to 2014, the price of Eagle Ford delivered to the U.S. East Coast was at parity with Brent deliveries. At the present time, there is a $2.01 per barrel disincentive to transport Eagle Ford to the U.S. East Coast, versus importing Brent.

Every crude oil is unique and exhibits different properties. Some crude oils have naturally occurring higher percentages of premium products such as jet and diesel, others have low percentages. Some crudes have very low levels of sulfur compounds and others have high levels. Refineries are generally configured to process one general type of crude – light sweet, medium sour, heavy sour, etc., although the individual refining configurations have evolved over the years based on the long-term outlook relative to pricing and availability of each type. Refiners are constantly evaluating economics relating to crude availability and pricing, versus processing unit constraints. Some changes can be made in a relatively short period of time to relieve process bottlenecks, while other projects may take more planning, engineering, and implementation. The recent spike in refinery projects is evidence of the economic driving forces of the new crude supplies.

Marker light sweet crudes such as Brent, WTI, Bonny, and LLS have different refining values to each individual refinery. Stancil has a proprietary linear programming (LP) modelling system that is used for refinery crude purchasing and optimization. The LP system can be tailored to a specific refinery, or can be configured to represent a major refining center. For the Monroe and The CRUDE Coalition assignment, Stancil has built LP models that represent the U.S. Gulf Coast and U.S. East Coast refining centers. The LP model was used to evaluate the relative refining value of foreign and domestic crudes on the
U.S. Gulf Coast and U.S. East Coast. Other refining centers may have different values. Using 2014 average costs and 2015 average costs (January and February), refining values for the average U.S. Gulf Coast and U.S. East Coast refinery are shown below, in reference to a base Brent price.

Refining Value Versus Brent

(Dollars Per Barrel)

	U.S. Gulf Coast		*U.S. East Coast*	
Crude	***2014 Avg Prices***	***Jan-Feb 2015 Avg Prices***	***2014 Avg Prices***	***Jan-Feb 2015 Avg Prices***
West Texas Intermediate	0.33	0.25	0.83	0.23
Light Louisiana Sweet	2.00	1.11	--	--
Bakken	0.64	0.61	0.92	0.61
Eagle Ford Light	0.72	1.07	1.62	1.01
Eagle Ford Heavy	1.88	1.05	1.79	1.86
Bonny	2.95	1.94	3.76	2.29
Arab Light	(2.38)	(2.04)	(2.76)	(3.30)
Maya	(14.95)	(9.73)	(16.46)	(12.92)
Western Canadian Select	(10.10)	(6.83)	(12.35)	(10.78)

Stancil's conclusions on the factors that affected price relationships and distribution patterns since 2007 are as follows:

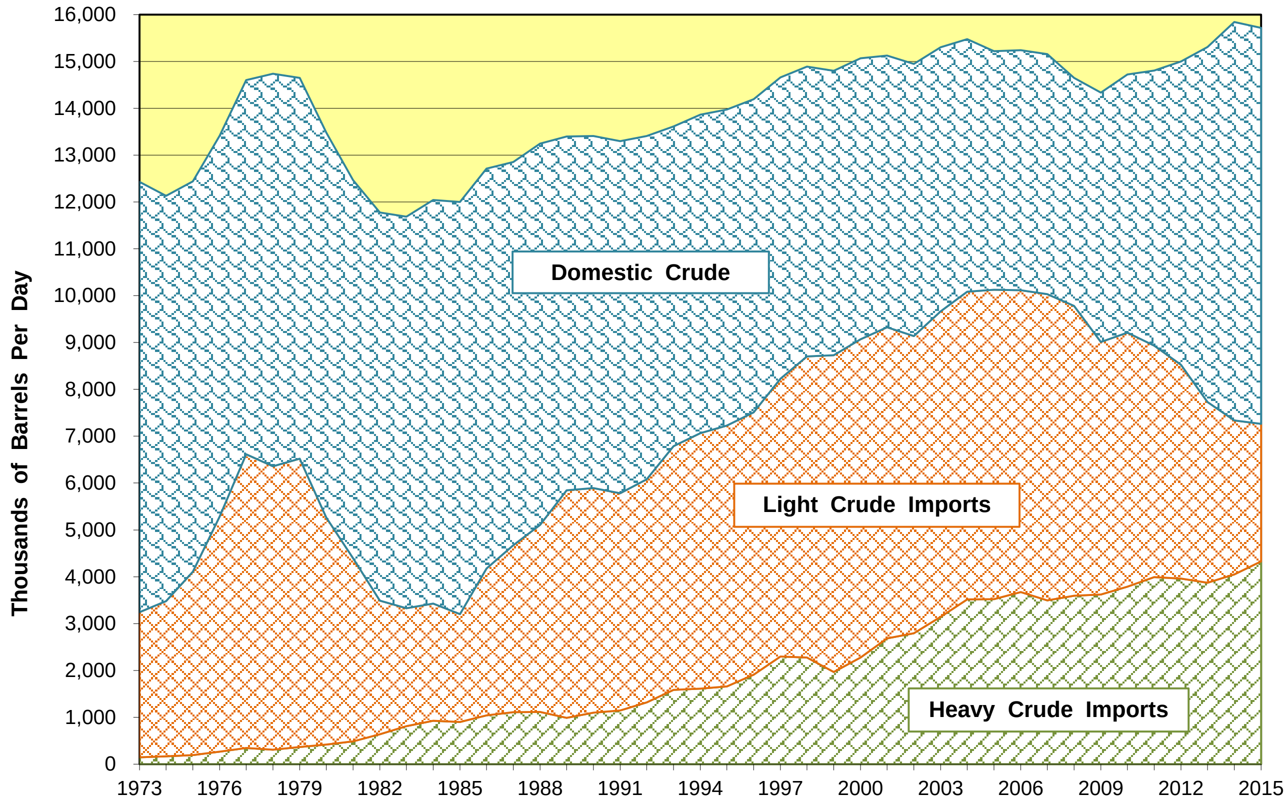
- The Midcontinent area crude supply changed from an area of a deficit compared to local refinery demand to a surplus of supply
- The South Texas and West Texas incremental production provided additional surplus light crude
- Logistics severely limited the ability to move surplus crude out of the producing areas
- Historical inland crude prices were based on Brent marker prices **plus** transportation to the U.S. Gulf Coast/Midcontinent areas. When the area shifted to a surplus supply, the pricing basis became U.S. Gulf Coast prices (based on world marker prices) **less** transportation costs. With limited pipeline capacity to the U.S. Gulf Coast and no pipeline capacity to the U.S. East Coast or U.S. West Coast, incremental volumes were transported by rail, resulting in larger discounts in the inland areas and to some extent on the U.S. Gulf Coast
- With access to less expensive domestic crudes and natural gas, U.S. Gulf Coast refiners were able to increase exports of finished and unfinished products, increasing crude runs. Instead of exporting crude oil, which was prohibited, refiners were able to export higher value refined products. These exported volumes reduced the demand on foreign refineries' crude demand, effectively increasing world crude surpluses
- A by-product of increased U.S. natural gas production was large incremental volumes of NGLs. The excess NGL production exceeded U.S. demand and is being exported. The exported NGL volumes further reduce hydrocarbon requirements in foreign locations, providing additional surplus hydrocarbon volumes on world markets
- Nominal crude exports, primarily to Canada, occurred until early 2013 when volumes increased from 110,000 B/D to 463,000 B/D for October 2014 through April 2015. Export volumes to Canada reached a peak of 586,000 B/D in April 2015. The U.S. Gulf Coast light sweet barrels are being preferentially shipped to Canada versus the U.S. East Coast due to the difference in shipping rates - $5.65 per barrel to the U.S. East Coast in Jones Act ships, versus $2.86 per barrel to Eastern Canada in non-Jones Act ships

- With a total reduction of imports, plus an increase in exports (over 6.8 million B/D of crude oil equivalent barrels), the U.S. energy industry has not been limited by the crude export ban. Short- and intermediate-term disruptions caused by logistics limitations should not be viewed as the long-term final outcome. Price relationships are returning to a more historical basis, considering the U.S. Gulf Coast and Midcontinent areas are no longer an importer of light sweet crudes
- Crude production increases occurred faster than logistics facilities could be built. Historical pricing relationships become distorted as a result of the high incremental delivery costs. The large WTI discounts starting in 2011 were strictly a result of logistics limitations and higher delivery costs. The lower prices quoted for inland barrels (WTI, Bakken, etc.) were the result of high logistics costs to deliver the crude to coastal areas where crudes were priced on a world marker basis
- For specific light crude grades, the U.S. is now more self-sufficient in the U.S. Gulf Coast area. Imports of light sweet crudes still occur on the U.S. East Coast, and there are still volumes imported into the Midcontinent from Canada
- U.S. refiners' crude selection is driven by economics, evaluating a wide basket of available foreign and domestic crudes on a delivered basis. Purchases are made to obtain the highest economical return. Higher U.S. Gulf Coast refinery utilizations depend upon sufficient economics on price netbacks for exported products
- The increased production of crude oil and NGLs has affected a number of petroleum balances and resulting U.S. balance of trade
  - Reduced foreign crude oil imports
  - Increased U.S. refinery throughput
  - Increased gasoline, jet, and distillate exports
  - Reduced imports of gasoline, jet, and distillate
- Increase in other petroleum product exports
  - NGLs
  - Gasoline, jet, and distillate blendstocks
  - Naphthas and petrochemical feedstocks
  - Heavy petroleum products

III. Crude Production

In 1970, U.S. crude production peaked at 9.6 million B/D, and then began a slow decline with a bottom in 2008 of 5.0 million B/D. With the advent of innovative drilling techniques first developed for recovery of natural gas from shale formations, new opportunities were explored and crude production began to increase.

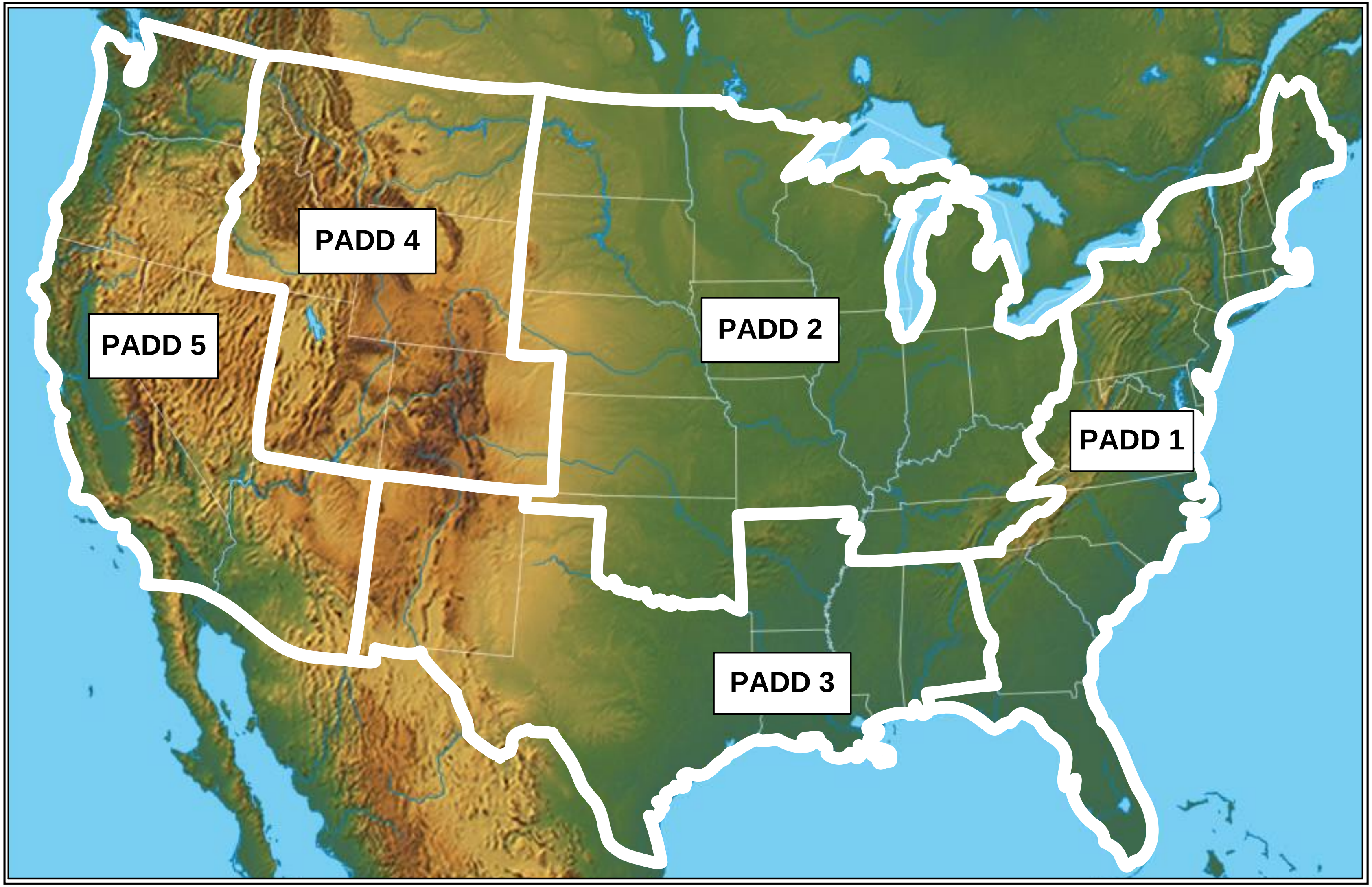
U.S. Refinery Crude Input Summary



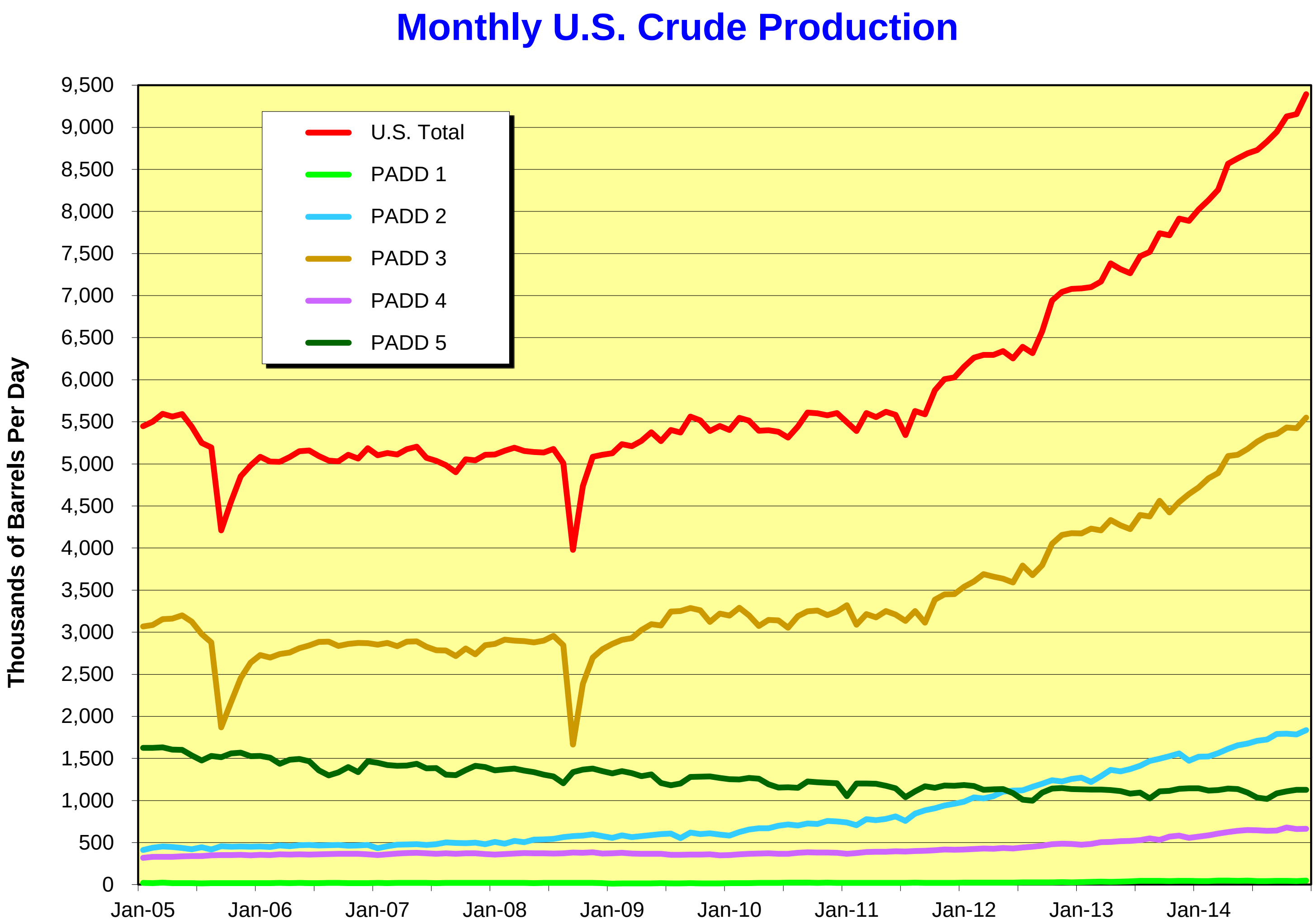
NOTE: Data for 2015 is based on monthly data through April.

SOURCE: Energy Information Administration.

A map detailing the Petroleum Administration for Defense Districts (PADDs) is shown below.



Monthly crude production since 2005 is shown below and in Appendix A, *Crude Production*.



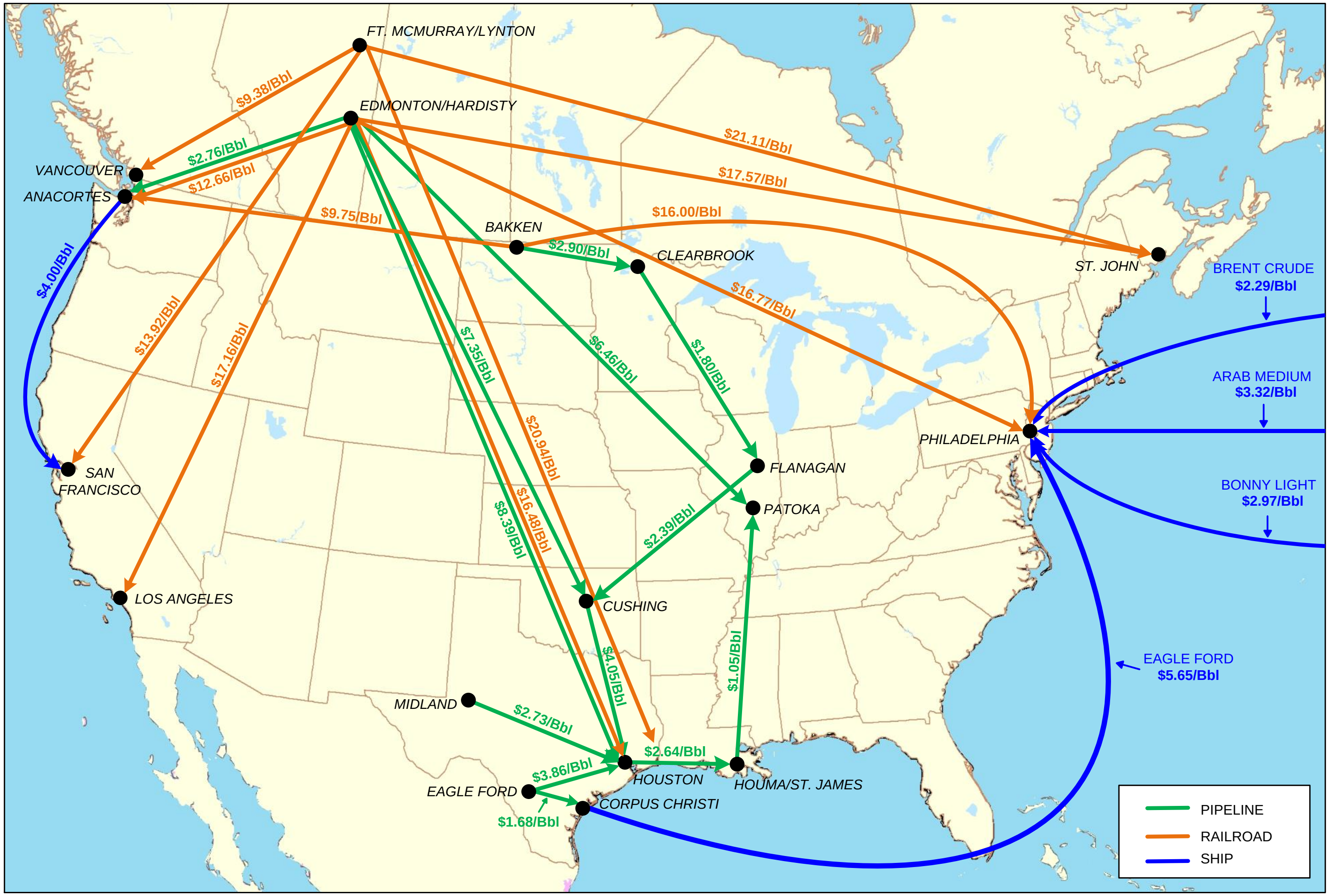
SOURCE: Energy Information Administration.

Prior to 2005, peak monthly crude oil production in North Dakota had occurred in 1984 at a level of 148,000 B/D. The single refinery in North Dakota consumed 58,000 B/D, leaving 90,000 B/D to be transported out of the state. By 2003, North Dakota crude production had declined to 81,000 B/D, with the remaining 23,000 B/D exported out of the state. There was a single small crude pipeline that delivered excess crude oil to refineries in Minnesota.

When crude oil production began to increase, available pipeline capacity to transport crude out of the state was rapidly filled. Pipeline projects were initiated, but new pipelines can take two to three years from the time of inception to operational. Trucking could be an alternative for short distances (under a few hundred miles), but in the case of Bakken production, no viable refining centers or large pipeline receipt points were available within trucking distance. Rail shipments were the only other viable option. The advantage of rail is that specific end users could be targeted, allowing the producers to optimize crude oil netback prices.

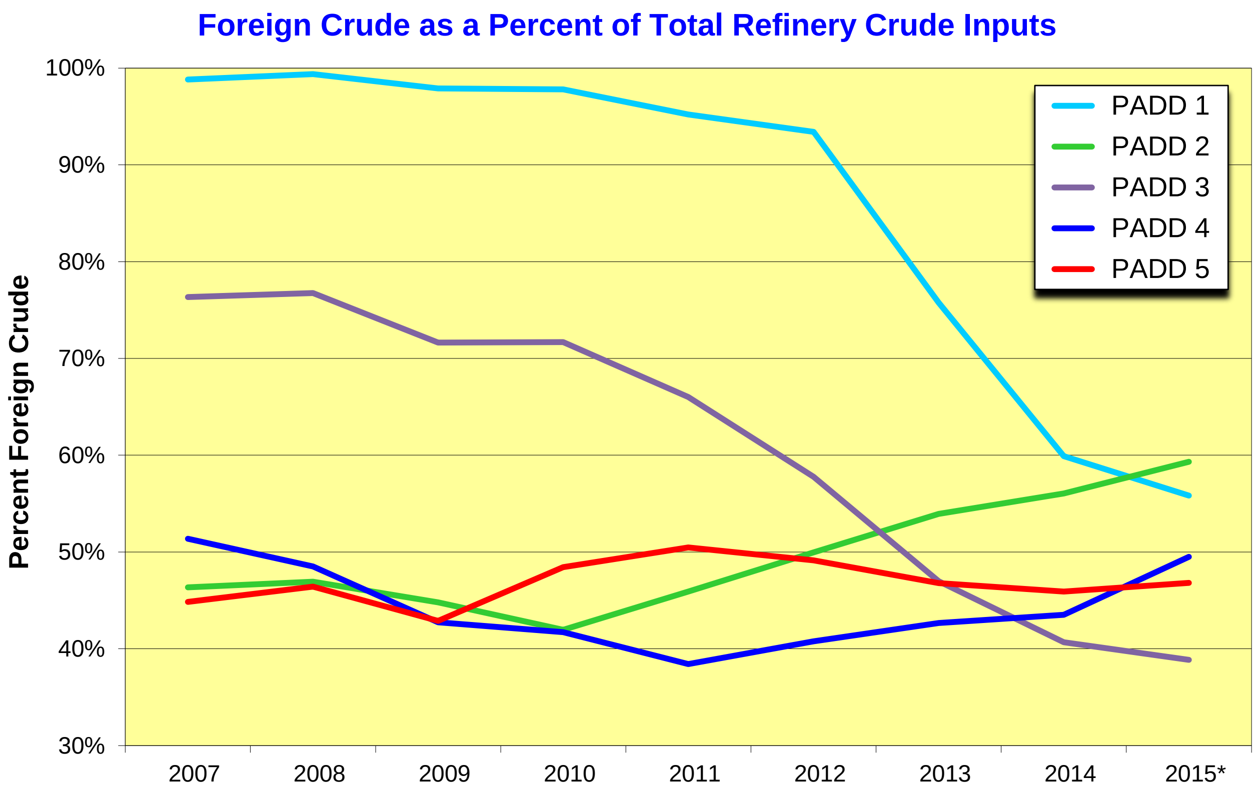
The following map shows the approximate cost of crude oil delivery to various points in the U.S. via pipeline, rail, and ship.

2015 Crude Pipeline, Rail, and Ship Freight Costs



Cushing, Oklahoma, the trading point for West Texas Intermediate (WTI), soon became the focal point of increasing crude oil inventories and accompanying discounts to Brent and Light Louisiana Sweet (LLS) prices. Shipping crude south by rail from North Dakota to Cushing would result in low netback prices to the producers. Better Bakken netbacks resulted from shipping the crude to the U.S. Gulf Coast refining centers, where refiners were purchasing foreign sweet crudes. The best netback prices were derived from railing crude to the U.S. East Coast or U.S. West Coast refiners.

Rail costs became the price setting mechanism for Bakken crude oils. The large coastal refining centers in the U.S. (U.S. Gulf Coast, U.S. East Coast, and U.S. West Coast) process a high percentage of foreign crude. These purchases of foreign crude are priced on the world marker crude price (Brent).



*January through April.

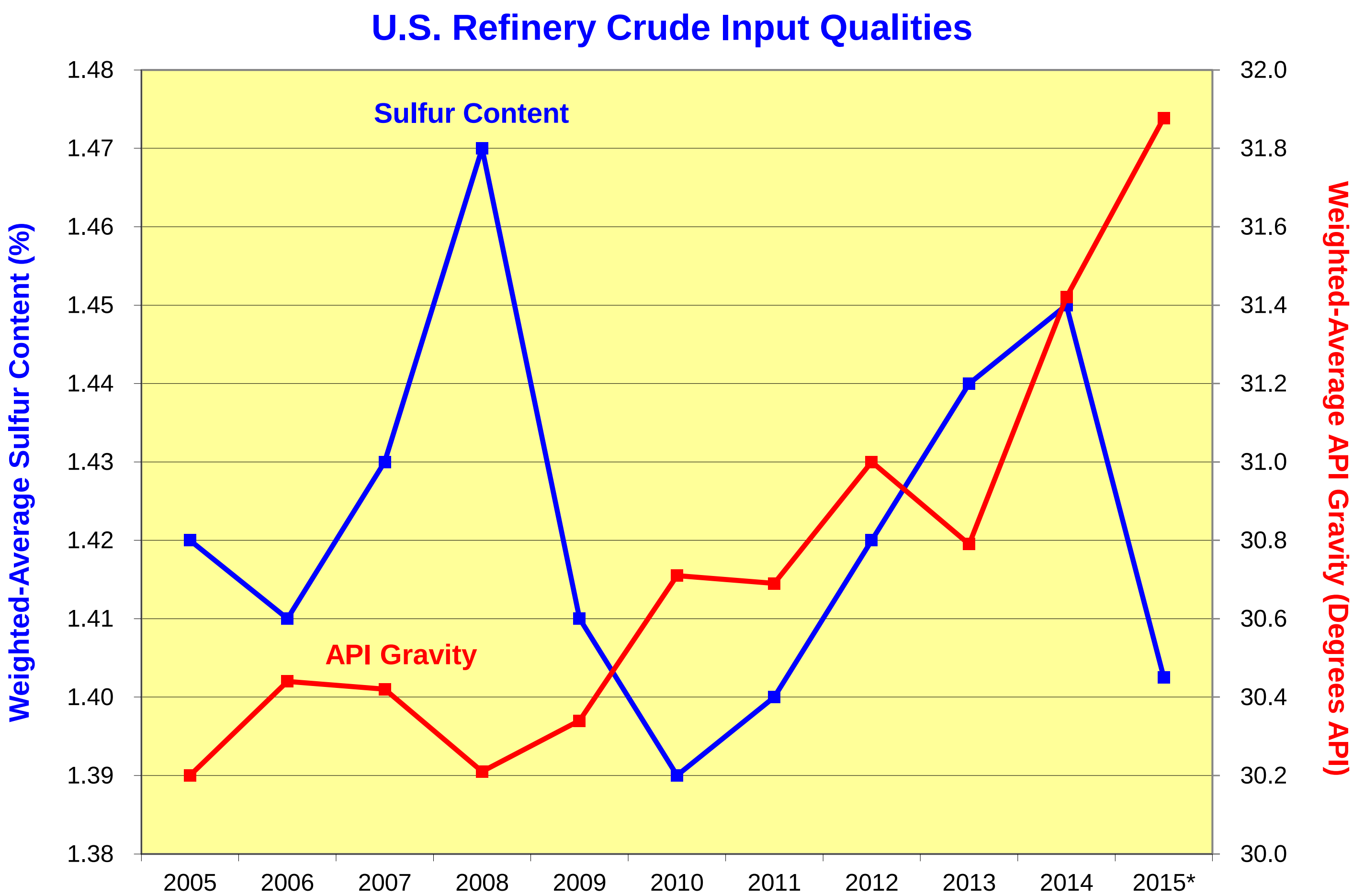
SOURCE: Energy Information Administration.

For U.S. domestic crude producers, the highest price they can receive is at the competitive consumption point where world crude oils are processed. The crude price at the refining center is based on the delivered marker crude prices, adjusted for quality differentials. The price received by the crude producer is the world marker crude price, adjusted for the producer's specific crude quality differentials, less transportation costs from the producing field to the refining center.

World crude prices are referenced to Brent crude. For U.S. refiners on the U.S. Gulf Coast and U.S. East Coast, historically, a high percentage of the crudes processed are imported, and therefore are priced on a delivered Brent basis. U.S. domestic crudes processed in these refining centers are priced based on delivered Brent, as adjusted for quality differences. The price the producer receives is the price at the consumption point (refinery) less the cost of transporting the crude to the refinery. The producer must compare his netback price with the total cost of production (exploration and completion costs, plus operating costs, etc.) to determine if his operations produce an acceptable rate-of-return on his investment.

In 2007 and 2008, the U.S. East Coast refiners (PADD 1) ran 99% foreign crudes. The earliest deliveries of domestic crude slowly started in 2009 to 2011, but by April 2015, domestic crudes were 44% of the crude slate. In 2007, PADD 3 refiners only processed 24% domestic crude, but by April 2015 this percentage had grown to 61%. The displacement of foreign crudes at these coastal refining centers has resulted from competitive pricing at the refining centers, with U.S. producers receiving world prices, as adjusted by quality differentials and logistics costs. The producers evaluate the netback price versus exploration and production costs to determine acceptable rates-of-return.

The EIA maintains a database of overall crude oil qualities for refineries in the U.S. This data is summarized by PADD and total U.S. For the U.S., API gravity has increased overall since 2010. The lighter gravity trend is apparent in all five PADDs. The graph of sulfur content and API gravity for the U.S. is shown below. Individual PADD data is shown in Appendix A.



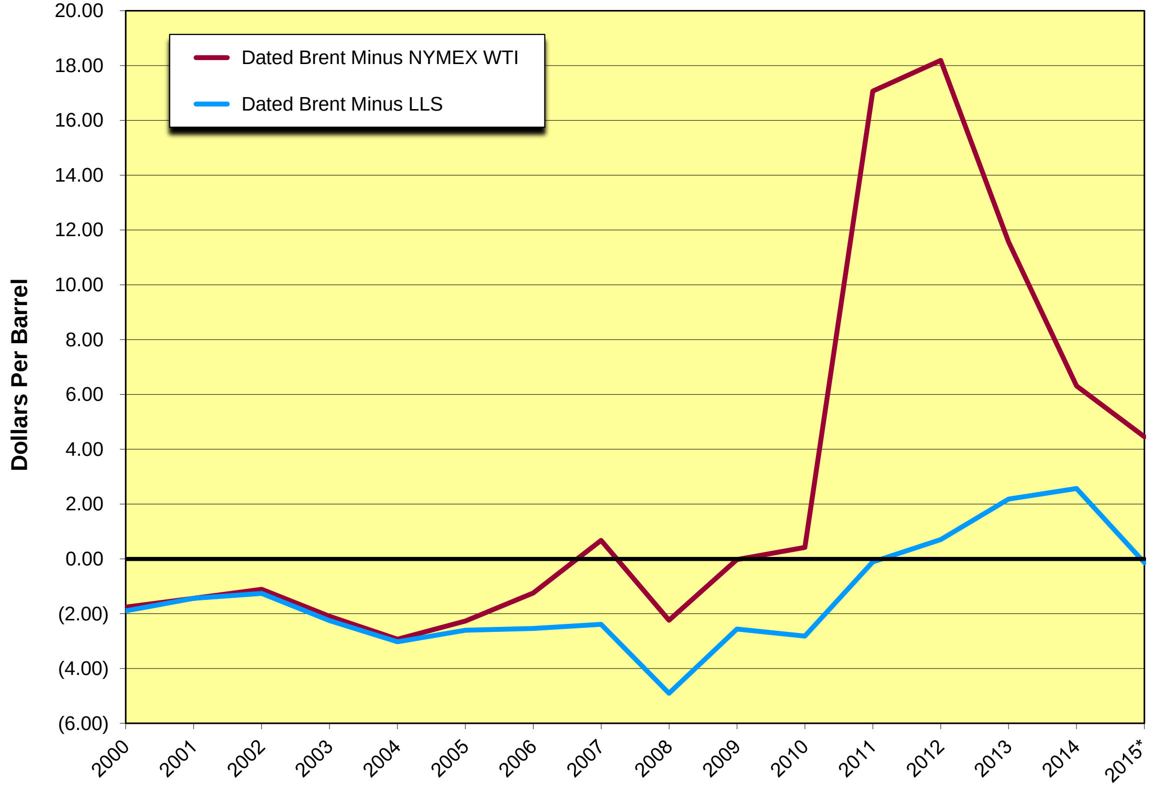
*January through April.

SOURCE: Energy Information Administration.

IV. Lifting the Crude Export Ban

Due to the surplus of domestic crude on the Texas Gulf Coast, crude prices have declined versus world prices. The discount of WTI and other inland crudes since 2010 has been driven not by the crude export ban, but by the lack of infrastructure to move production from producing areas that are inland to the coastal refining centers.

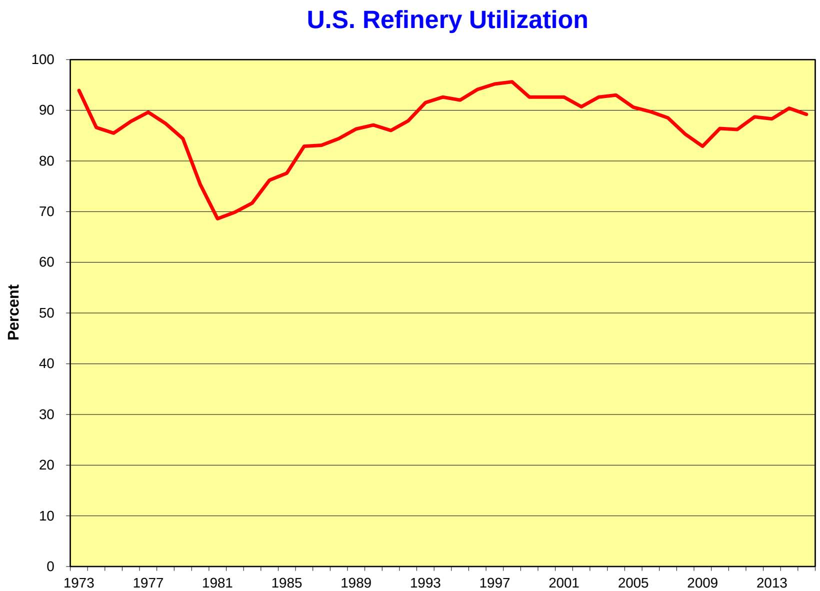
Annual Average Dated Brent Price Differentials



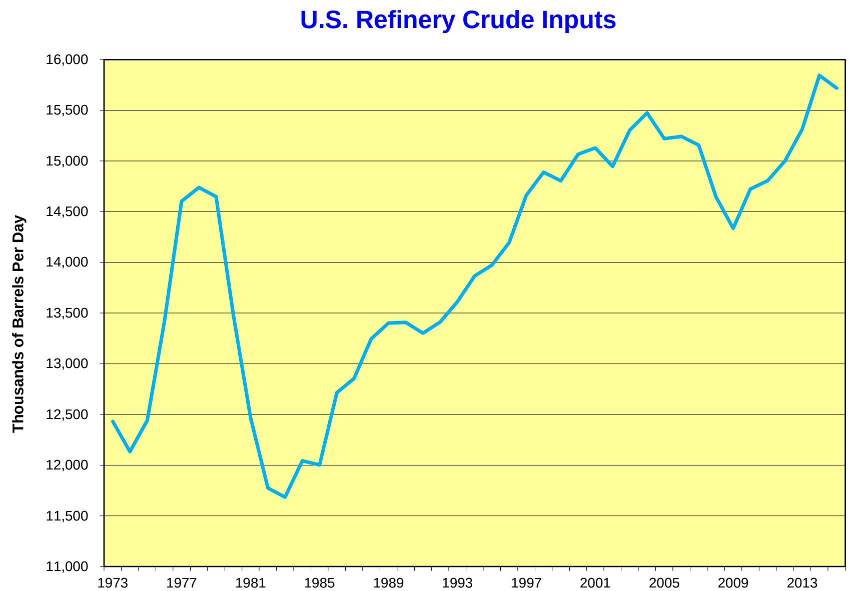
*January through June.

SOURCES: *Platts Oilgram Price Report* and *Argus Crude.*

Refining capacity and utilization in the U.S. is at an all-time high, driven by cheaper crudes prices and advantageous pricing for exports.



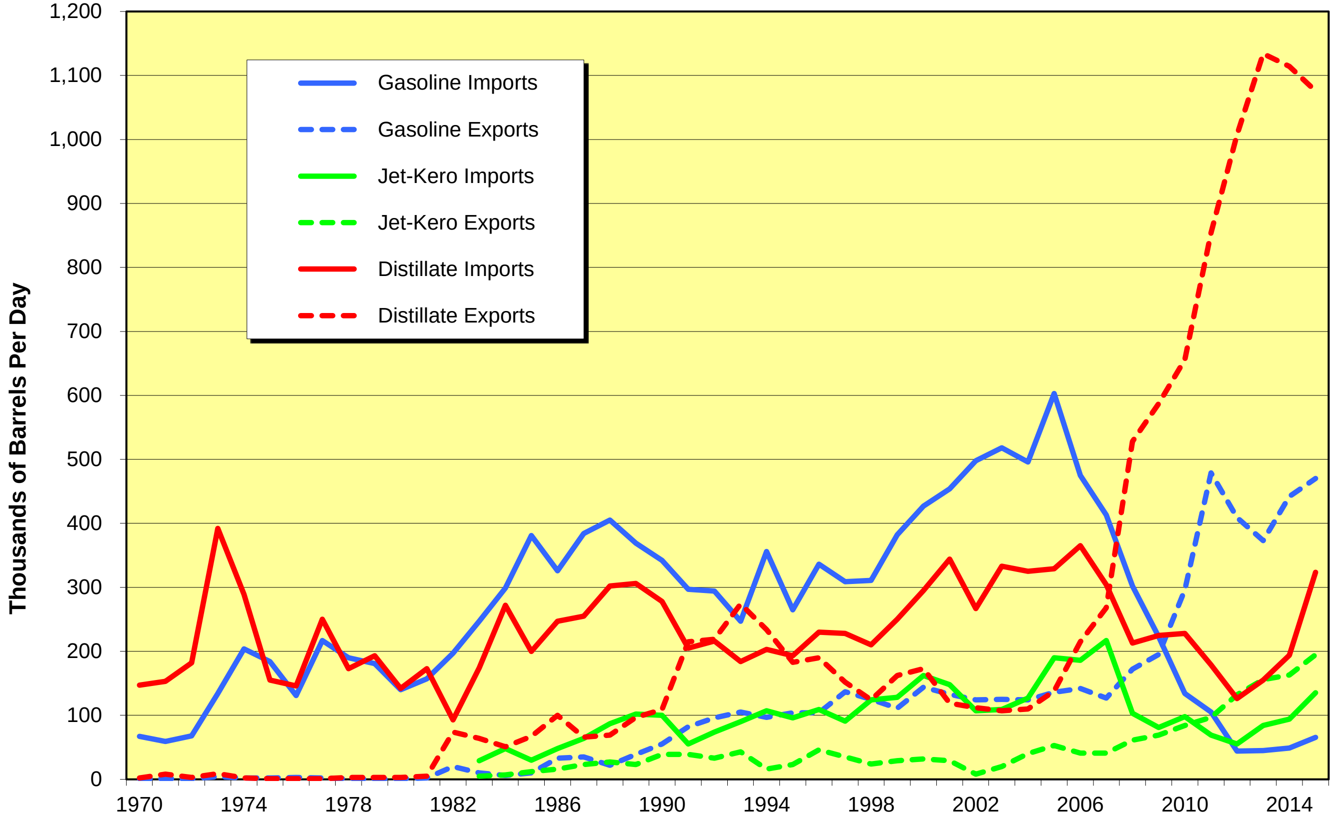
NOTE: Data for 2015 is based on monthly data through April.
SOURCE: Energy Information Administration.



NOTE: Data for 2015 is based on monthly data through April.
SOURCE: Energy Information Administration.

The high throughputs and utilizations are driven by lower U.S. crude prices and the economic incentive to export products. The dramatic increase in U.S. product exports and decrease in product imports is shown on the following graph for gasoline, jet, and diesel.

U.S. Annual Product Imports and Exports

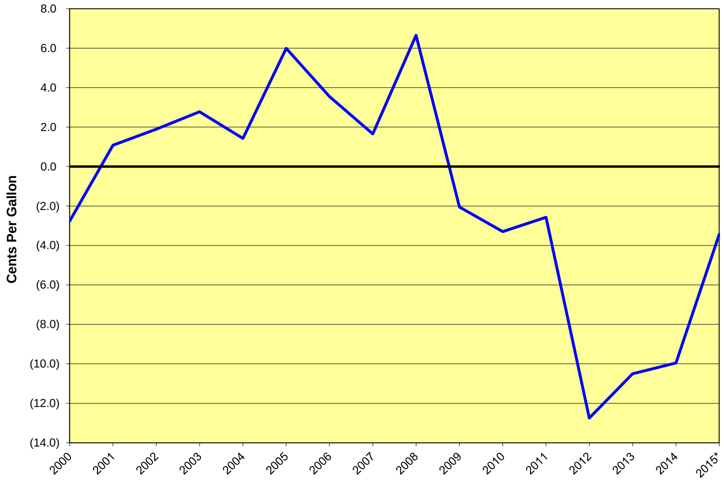


NOTE: Data for 2015 is based on monthly imports and exports through April.

SOURCE: Energy Information Administration.

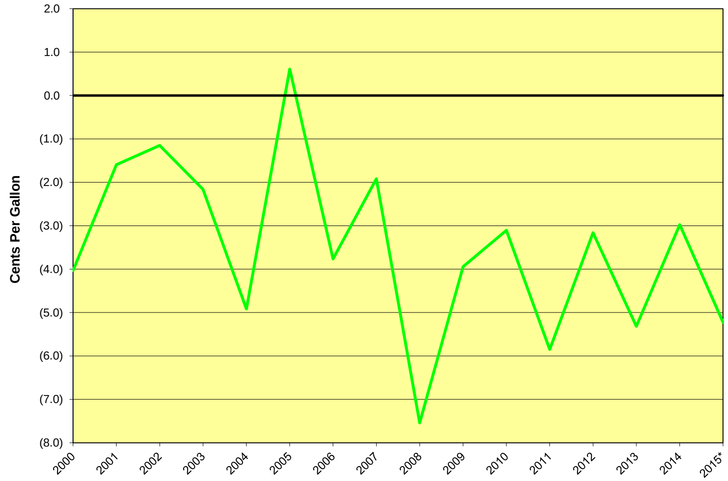
The U.S. has displaced a large majority of product imports and has become the world's largest exporter of products. Since the world prices are competitive, the only way the U.S. can export large quantities is by pricing under alternate suppliers. The pricing shifts are clearly reflected in the prices of U.S. Gulf Coast product prices versus world product prices.

Annual Average Gasoline Price Differentials
(U.S. Gulf Coast Waterborne Unleaded 87/CBOB 87 Minus Cargoes CIF NW Europe Premium Unleaded/Gasoline 10 ppm)



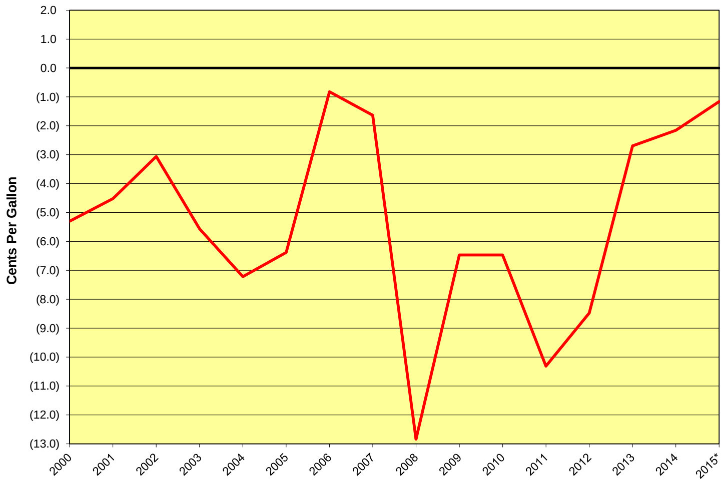
*January through June.

Annual Average Jet/Kerosense Price Differentials
(U.S. Gulf Coast Waterborne Jet/Kerosene 54 Minus Cargoes CIF NW Europe Jet/Kerosene)



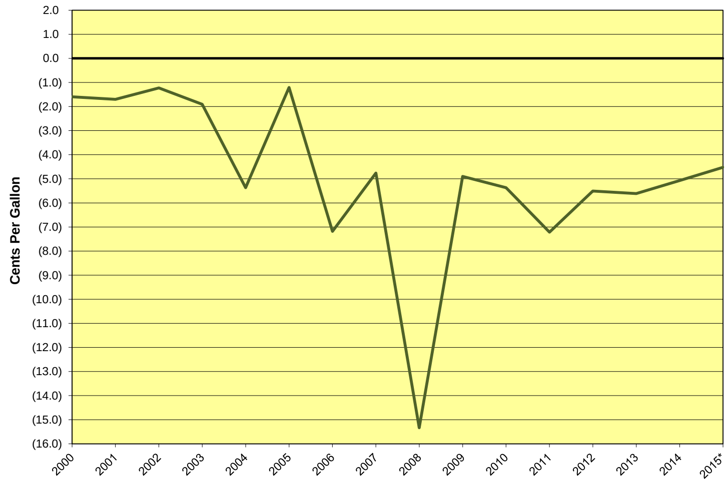
*January through June.

Annual Average Diesel Price Differentials
(U.S. Gulf Coast Waterborne Low Sulfur/Ultra Low Sulfur Diesel Minus Cargoes CIF NW Europe Gasoil EN 590/Gasoil 10 ppm/Ultra Low Sulfur Diesel 10 ppm)



*January through June.

Annual Average Heating Oil Price Differentials
(U.S. Gulf Coast Waterborne No. 2 Heating Oil Minus Cargoes CIF NW Europe Gasoil 0.2% Sulfur/Gasoil 0.1% Sulfur)



*January through June.

SOURCE: *Platts Oilgram Price Report.*

Lifting the crude export ban would reverse all of the major shifts in reductions in imports, dramatic increases in exports, and large increases in refinery throughputs. Crude prices on the Gulf Coast would rise to world parity ($3.23 per barrel for the first six months of 2015) making the U.S. refiners much less competitive in the world markets. In turn, world refiner's product would become more competitive as imports into the U.S., resulting in lower U.S. refinery throughputs.

To evaluate the potential for crude exports, Stancil has evaluated world crude markets, logistics costs, and refinery locations to determine the competitive position.

To look at the effects of a potential lifting of the crude oil export ban, potential end use markets for U.S. crudes must be evaluated. Crude is currently being exported to Canada under specific export licenses. Further exports could be routed to Atlantic Basin refining centers that currently import light sweet crudes, or to Far East refining centers. The Atlantic Basin centers would include Northwest Europe, Italy, West Africa, and Latin America. The Far East would include Japan, Korea, Singapore, and Indonesia.

For comparison purposes, Stancil has calculated the delivered cost of Brent and Eagle Ford crudes to each of these locations for the past three years.

Economic Incentive to Import Eagle Ford Over Brent
(Dollars Per Barrel)

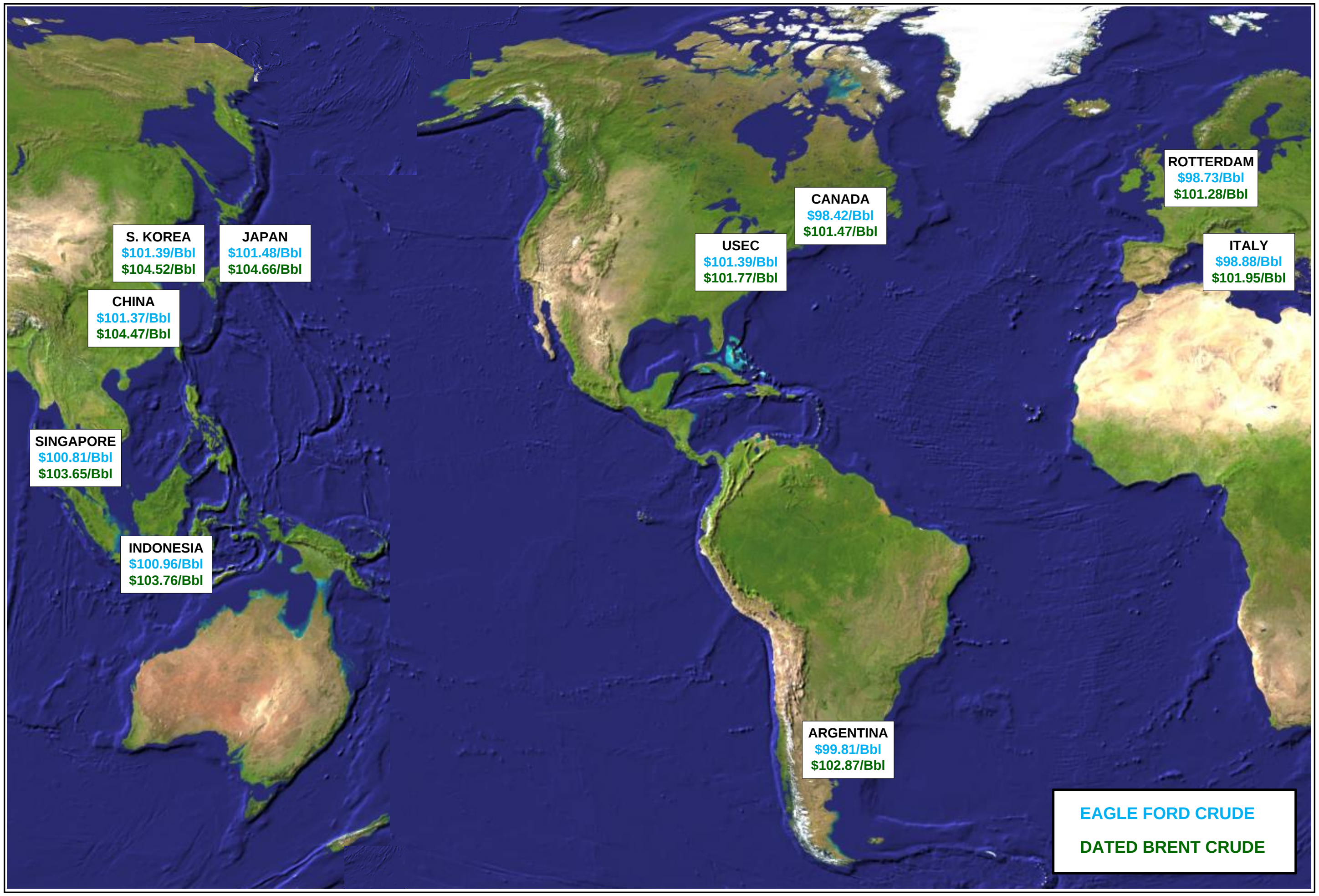
Port of Discharge	*2012* [(1)]	*2013*	*2014*
Philadelphia, Pennsylvania	(0.92)	(0.14)	0.39
St. John, Canada	1.99	3.09	3.04
Buenos Aires, Argentina	2.08	3.11	3.06
Rotterdam, Netherlands	1.28	2.67	2.55
Augusta, Italy	2.06	3.18	3.07
Singapore	1.31	2.59	2.84
Cilacap, Indonesia	1.27	2.56	2.80
Onsan, South Korea	1.52	2.81	3.13
Kawasaki, Japan	1.57	2.87	3.18
Shanghai, China	1.51	2.80	3.10

NOTE: (1) Eagle Ford prices in 2012 are based on a correlation to LLS prices.

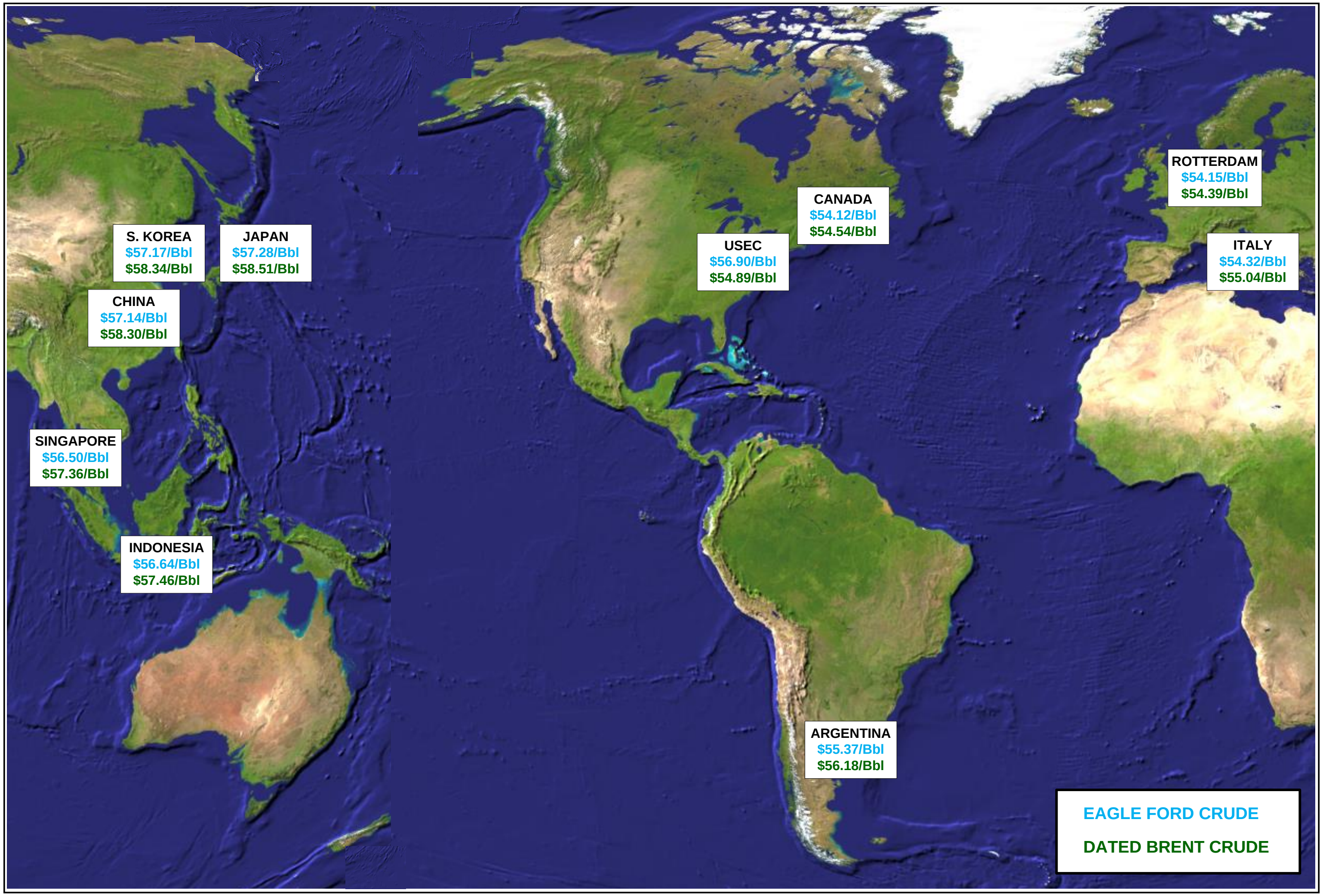
SOURCES: *Worldscale, Platts Oilgram Price Report,* and *Argus Crude.*

The following maps show the historical freight rates and delivered costs of Brent and Eagle Ford to world refining centers. More detailed information is included in Appendix B, *Lifting the Crude Export Ban*.

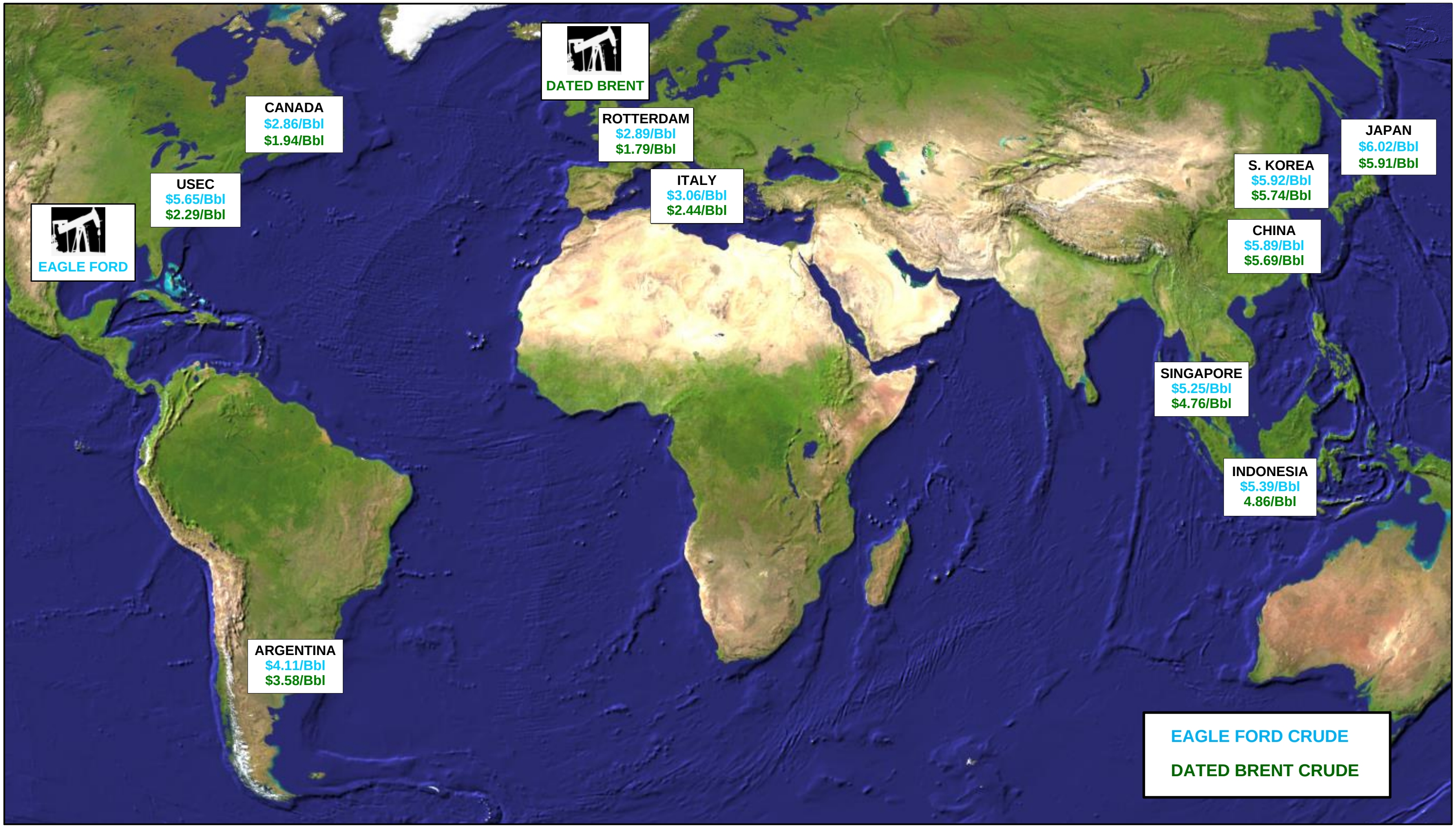
2014 Average Eagle Ford and Dated Brent Laid-In Costs to Various Refining Centers



2015 Average (January-February) Eagle Ford and Dated Brent Laid-In Costs to Various Refining Centers



2015 Average (January-February) Eagle Ford and Dated Brent Freight Costs to Various Refining Centers



Using historical prices, it would have been economic for refiners in the Atlantic Basin (Canada, Europe, and Latin America) and the Far East to purchase Eagle Ford crude versus Brent in the period 2012 through 2014. The incentive was in a narrow range for all three years and was approximately $3.00 per barrel. If the world was in a crude short position, then the argument could be made that if exports had been allowed, U.S. crude prices would have risen by $3.00 per barrel. For the first six months of 2015, Stancil has calculated that Gulf Coast crude oil prices would have increased by $3.23 per barrel if the crude export ban had been lifted. This calculation was based on the refining value of Gulf Coast crudes that could be exported to other world refining centers. The European refining centers currently run crudes similar to Eagle Ford and WTI. Using the first six months of 2015 pricing for Gulf Coast crudes, Stancil has used a linear programming model of European refining to calculate the price European refiners would pay for U.S. crudes. The FOB price on the Gulf Coast was then compared to actual prices for the same time period to determine the price increase if the export ban was lifted.

The U.S. would have imported an equal quantity of higher cost foreign crude to offset the loss of exported U.S. crude; however, U.S. refiners would have a reduced incentive to run incremental barrels and export product to foreign countries. It is likely that foreign refinery utilization would have increased, and U.S. refinery utilization would have decreased. The overall world crude supply/demand balance would not have changed, but shifts would be noted in refinery capacity utilization in the different refining regions.

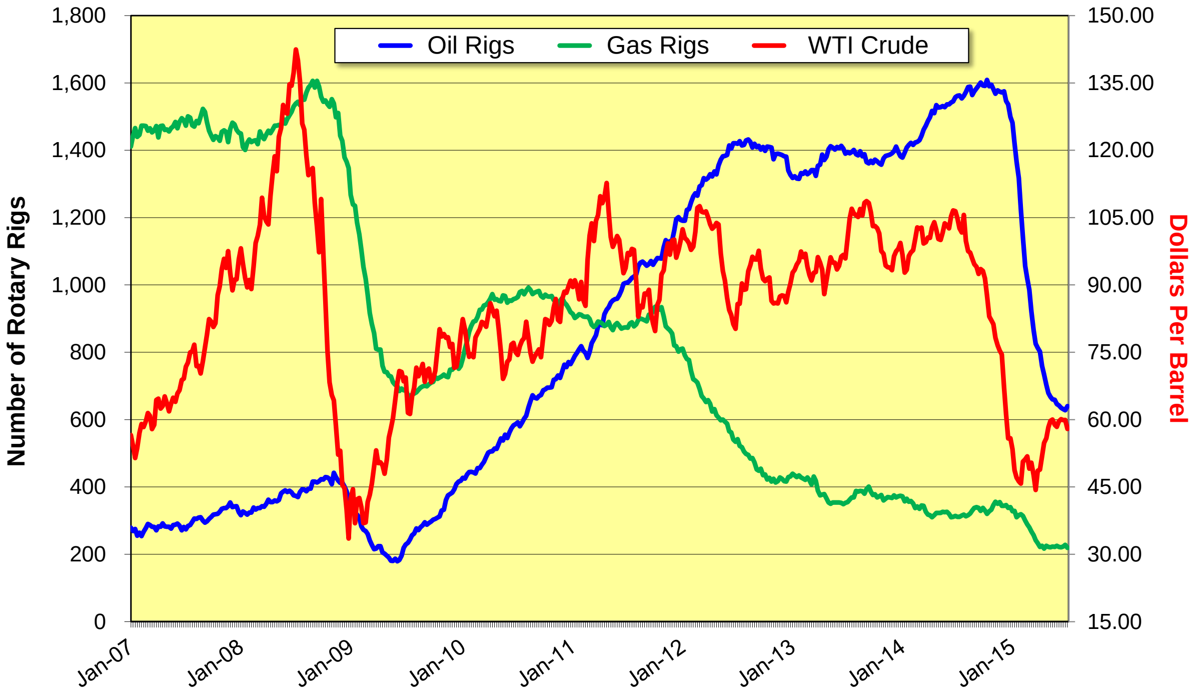
Allowing exports of crude which would have raised U.S. crude prices by $3.23 per barrel, U.S. gasoline prices would increase by $0.084 to $0.145 per gallon, and distillate prices by $3.23 per barrel. Without the economic incentive to run incremental barrels for export, the U.S. would have remained a net importer of products, impacting foreign trade balances. Over the 2008 through 2014 period, the U.S. swing from net imports to net exports was 1.6 million B/D. This would translate to approximately 2.3 million B/D of crude runs. There would not have been significant investment in the refining industry without the economic incentive to run incremental crude to export products. Increasing netback prices to U.S. crude producers by $3.23 per barrel would not have impacted their investment decisions for exploration and production as market prices were already far above production costs. It would have increased producers' overall earnings by $3.23 per barrel.

Beginning in late 2014, along with the 50+% decline in crude prices, the differential between U.S. Gulf Coast crude and Brent price also collapsed.

The world refining system will now began to rebalance, driven by the shift in crude oil prices and the fluctuations in refining margins. The U.S. Gulf Coast refining industry has lost some of its crude price advantage versus other world refining centers, although it maintains an operating cost advantage due to the decline in natural gas prices. U.S. Gulf Coast refiners may lose foreign market share to other export refining centers and could see reduced utilizations. The lower utilizations would back out more imports of foreign crude. This foreign crude would be processed in other areas of the world.

The drop in crude prices will negatively impact both the producing and refining sectors of the oil industry. With WTI crude prices at or below $50.00 per barrel, exploration and production companies rapidly curtailed drilling activities. The U.S. rig count for oil reached a peak of 1,609 in October 2014, but has declined to a low of 628 in June 2015. An accompanying decline in U.S. crude production is expected to occur by mid-2015. A graph of oil and gas drilling rig activity is shown below.

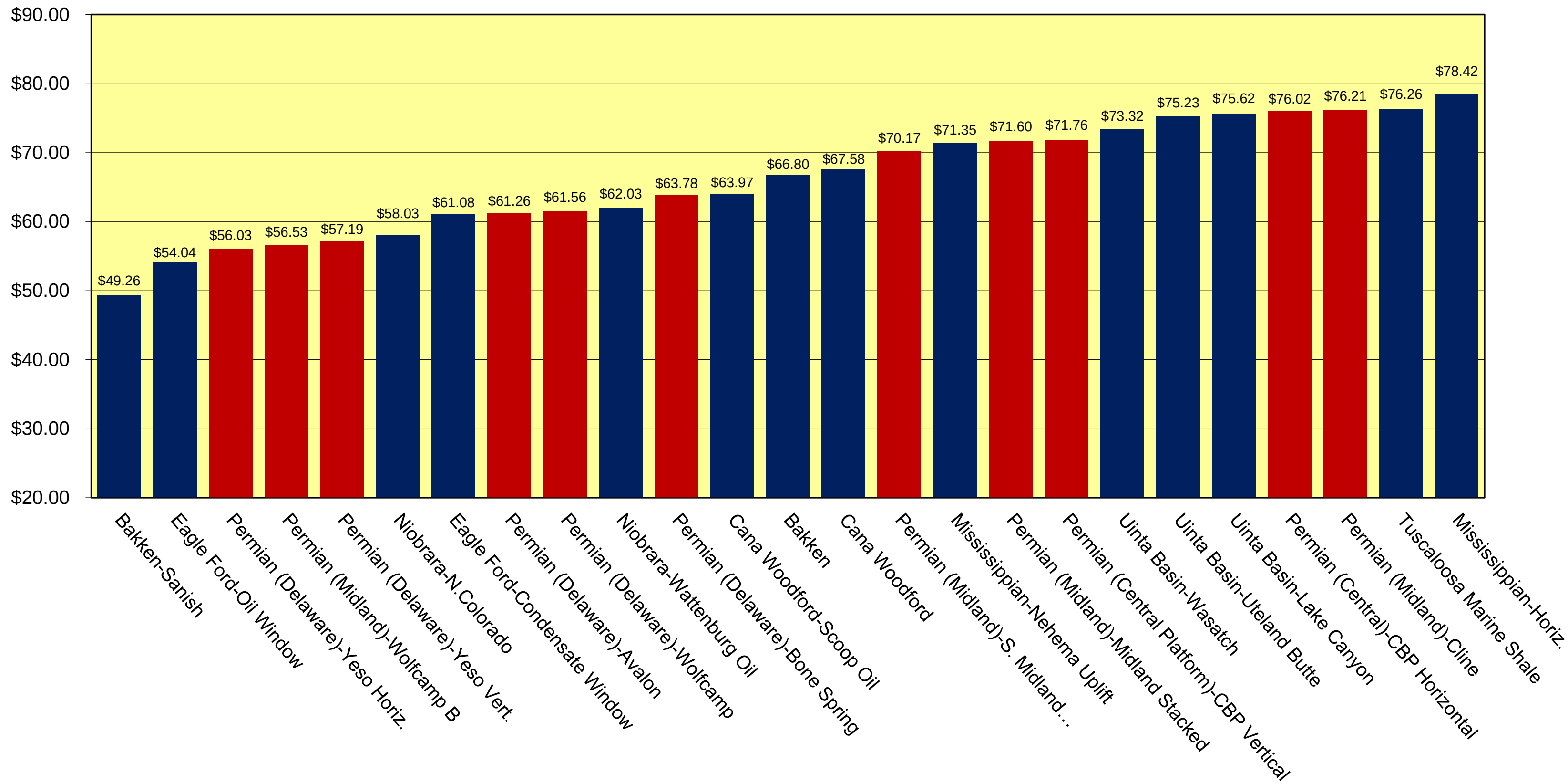
Weekly Count of U.S. Rotary Rigs by Type vs Argus WTI Cushing



SOURCES: *Baker Hughes* and *Argus Crude.*

Crude prices are now at or below the economic breakeven point of some of the shale oil areas (see the graph below of threshold pricing prepared by Simmons & Company International). Since the preparation of the graph below, drilling and fracking costs have declined due to the large drop in active drilling rigs. In addition, well productivity has continued to improve, further reducing the crude oil price breakeven point for producers.

Overview of Average Threshold Pricing By Plays (1)



NOTE: (1) Assumes 15% average total rate-of-return.

SOURCE: Simmons & Company International.

In late 2014, the U.S. refining margins dropped to a level last seen in the recession of 2008 and 2009, but began to recover in early 2015. It will take some time before the world refining sector rebalances regional supply and demand. It is expected that the U.S. refining sector could lose some of its export markets and utilization will drop. New project developments will be re-evaluated pending analysis and projection of future crude prices, availability, and differentials.

Another factor apparent in the data is the economic penalty incurred by the U.S. East Coast and U.S. West Coast refiners due to the Jones Act. There are no pipelines from the Midcontinent area that deliver crude to the U.S. East Coast or U.S. West Coast refiners. Domestic crude must be delivered to these refineries by rail, ship, or barge. The high cost of Jones Act transport of crude from the U.S. Gulf Coast to the U.S. East Coast or U.S. West Coast refiners results in a $2.50 to $3.00 disadvantage compared to shipment of the same crude to foreign refineries. For 2013 to 2014, the price of Eagle Ford delivered to the U.S. East Coast was at parity with Brent deliveries. At the present time, there is a $2.01 per barrel disincentive to transport Eagle Ford to the U.S. East Coast, versus importing Brent.

V. Consumer Impact

Potential Consumer Penalty

The studies examining the export of U.S. crudes have forecast that it would result in U.S. crude oil prices increases of approximately $3.00 per barrel. Stancil's analysis has calculated that average crude prices to Texas Gulf Coast refiners would have increased by $3.23 per barrel for the first six months of 2015 if crude oil exports had been allowed. This calculation was based on the refining value of Gulf Coast crudes that could be exported to other world refining centers. The European refining centers currently run crudes similar to Eagle Ford and WTI. Using the first six months of 2015 pricing for Gulf Coast crudes, Stancil has used a linear programming model of European refining to calculate the price European refiners would pay for U.S. crudes. The FOB price on the Gulf Coast was then compared to actual prices for the same time period to determine the price increase if the export ban was lifted.

It is assumed that the crude price increase would translate into corresponding increases in gasoline prices by $0.084 to $0.145 per gallon and distillate prices by $3.23 per barrel. The penalty for the consumer as a result of lifting the export ban would be up to $25 billion per year, or $125.00 per driver and $257.00 per family. The calculations are shown in the table below.

Increased Cost to Consumers Resulting From Exports of Domestic Crude Oil

							Net Penalty		
						MBbl/D	***MM$/Yr***	***$/Driver***	***$/Family***
Assumptions:									
	Exports Allowed								
	Gasoline Price Increase ($/Gal)		0.084	to	0.145				
	Crude Price Increase ($/Bbl)		3.23						
Gasoline		Low Penalty				8,922	11,490	59	120
		High Penalty				8,922	19,833	101	207
Distillate						4,010	4,728	24	49
Total Low Penalty							16,218	83	170
Total High Penalty							24,561	125	257

Consumer Benefit

The U.S. consumer has experienced a large savings due to the drop in transportation fuels prices as a result of increased world supply driven by U.S. production. In 2014, average daily U.S. consumption of gasoline was 8.92 million B/D and diesel was 4.01 million B/D. Comparing the prices of gasoline and diesel from the first nine months of 2014 to the first six months of 2015, the decline has been $43.00 per barrel and $47.00 per barrel, respectively.

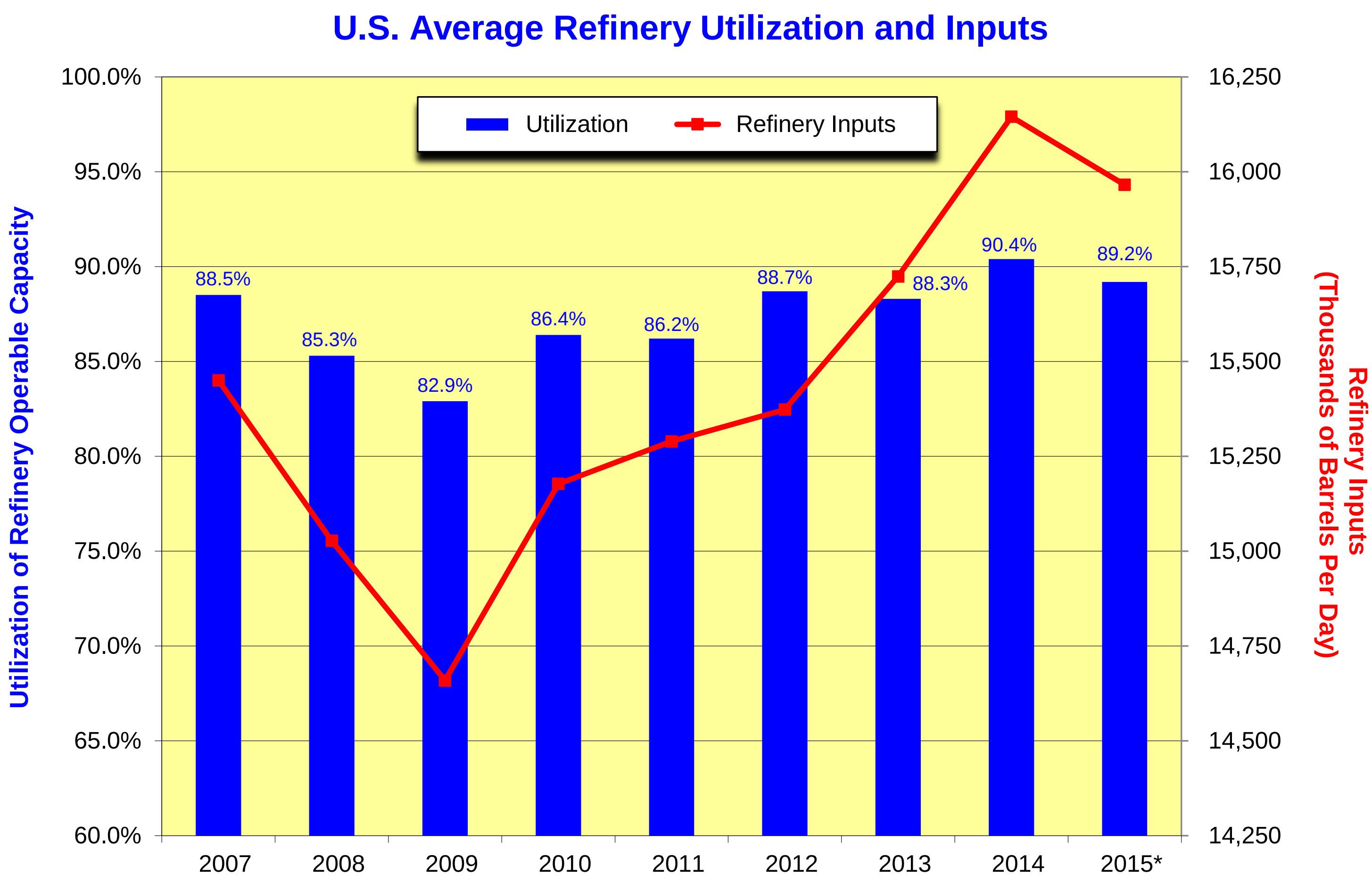
The dramatic decline in prices has resulted in a U.S. consumer benefit of $209 billion per year. This translates to $1,064 per driver and $2,182 per family. The calculations are shown in the table below:

Consumer Benefit – Transportation Fuels

		Average Prices		***2014***	***Net Benefit***		
		Jan-Sep 2014	***Jan-Jun 2015***	***MBbl/D***	***MM$/Yr***	***$/Driver***	***$/Family***
WTI	$/Bbl	99.60	53.29				
Brent	$/Bbl	106.99	57.74				
Gasoline	$/Gal	2.76	1.74	8,922	139,651	713	1,461
Distillate	$/Gal	2.88	1.76	4,010	68,960	352	721
Total Benefit					208,611	1,064	2,182

VI. Refinery Utilization and Production

In 2007, total U.S. refinery throughputs were 15.4 million B/D at a utilization rate of 88.5%. With the economic recession, throughputs dropped to 14.7 million B/D in 2009 at a utilization rate of 82.9%.



*January through April.

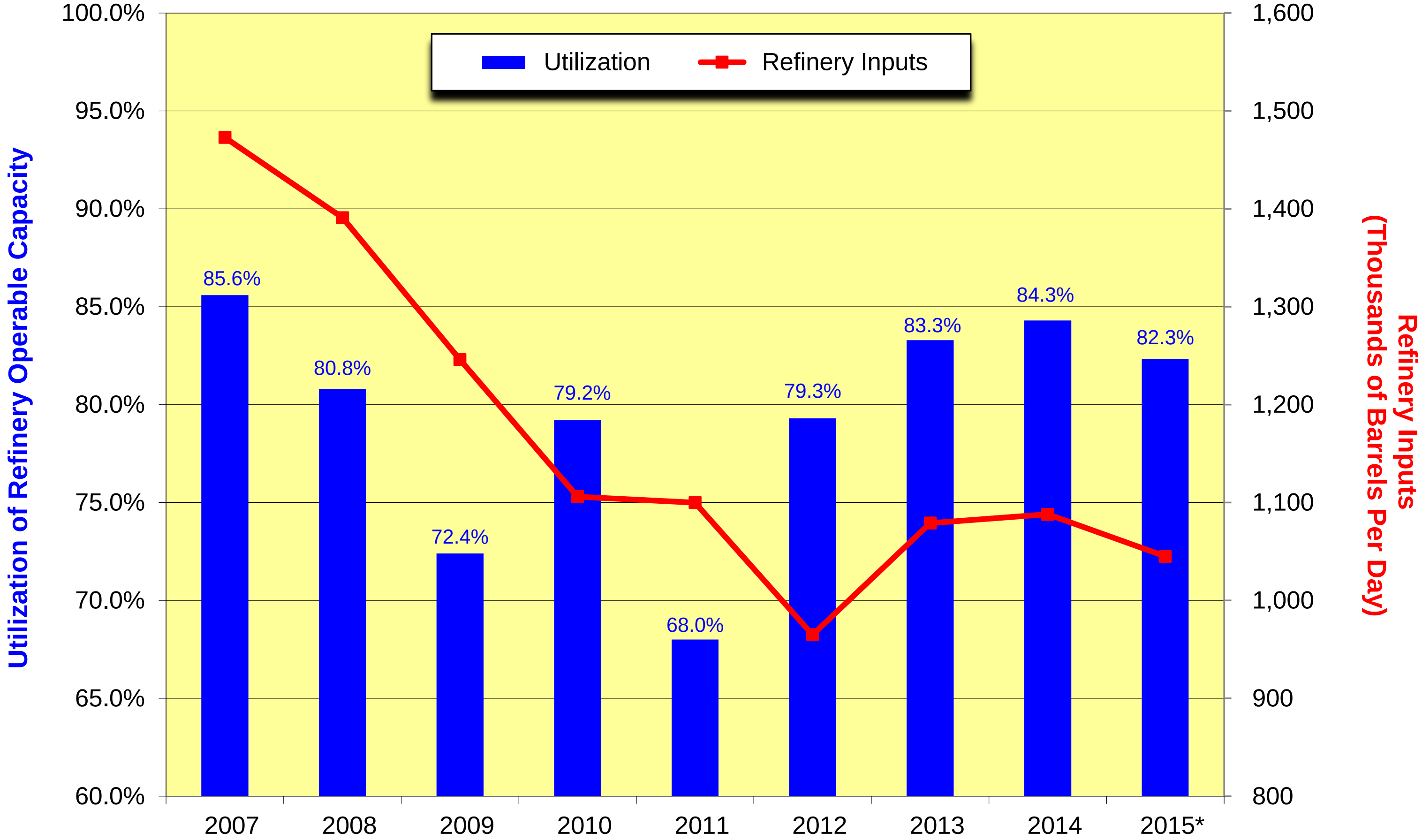
SOURCE: Energy Information Administration.

PADD 1 refinery utilization in 2007 was 86%, but as a result of the economic recession, utilization dropped to 68%, accompanied by the closure of refining capacity. Since 2011, crude throughputs have remained mostly constant at 1.1 million B/D and utilizations in the 79% to 84% range.

PADD 1 refiners have not benefited from increased domestic production of crude. Domestic crude throughputs have increased substantial in PADD 1, but high transportation costs have greatly reduced the financial benefit compared to U.S. Gulf Coast or Midcontinent refiners. The result has been a halt in the decline in refining capacity, but expansions or higher throughputs have not occurred, in part due to the current uncertainty on crude export policy.

Detailed information on refinery throughput by PADDs is shown in Appendix C, *Refinery Utilization and Production*.

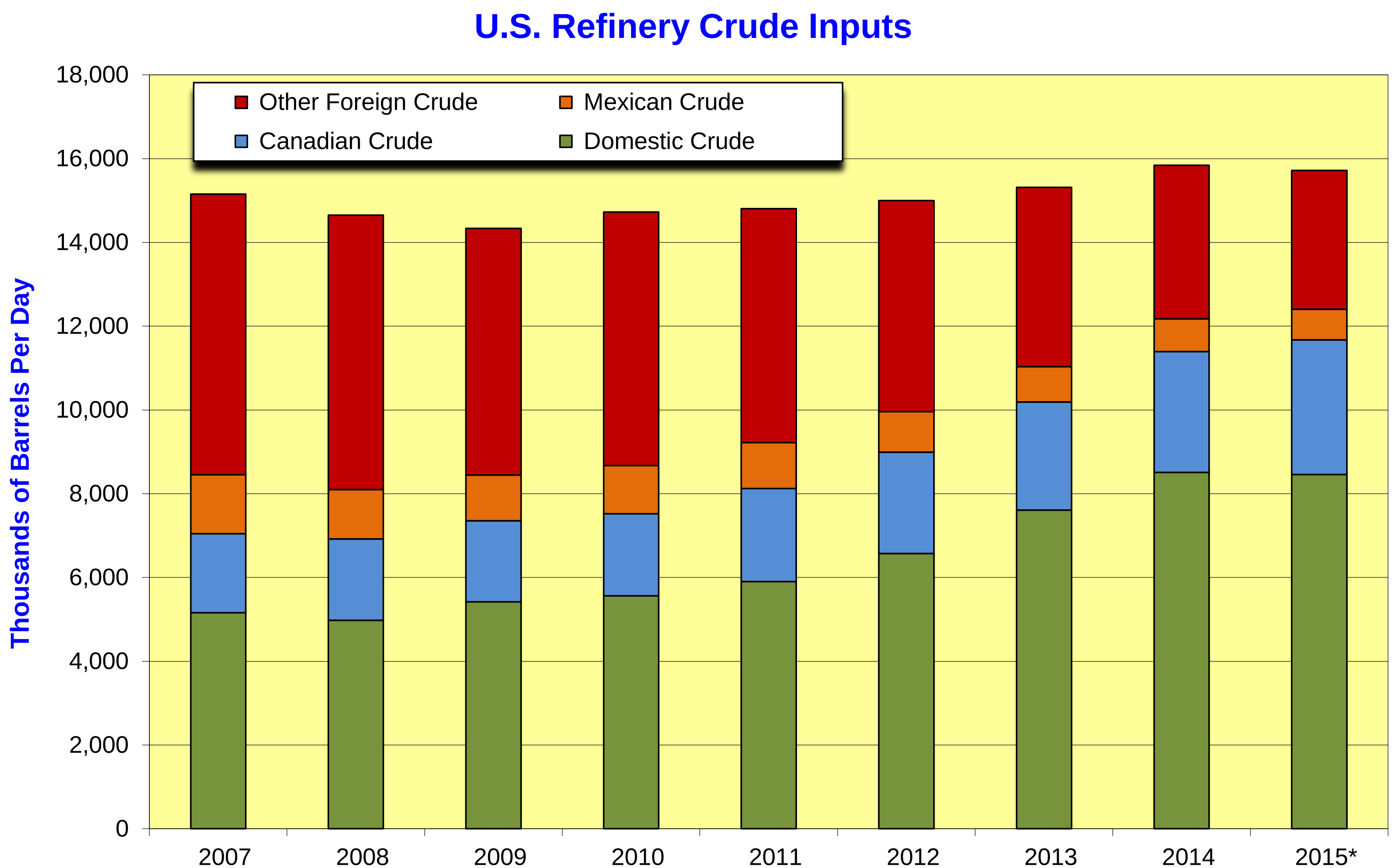
PADD 1 Average Refinery Utilization and Inputs



*January through April.

SOURCE: Energy Information Administration.

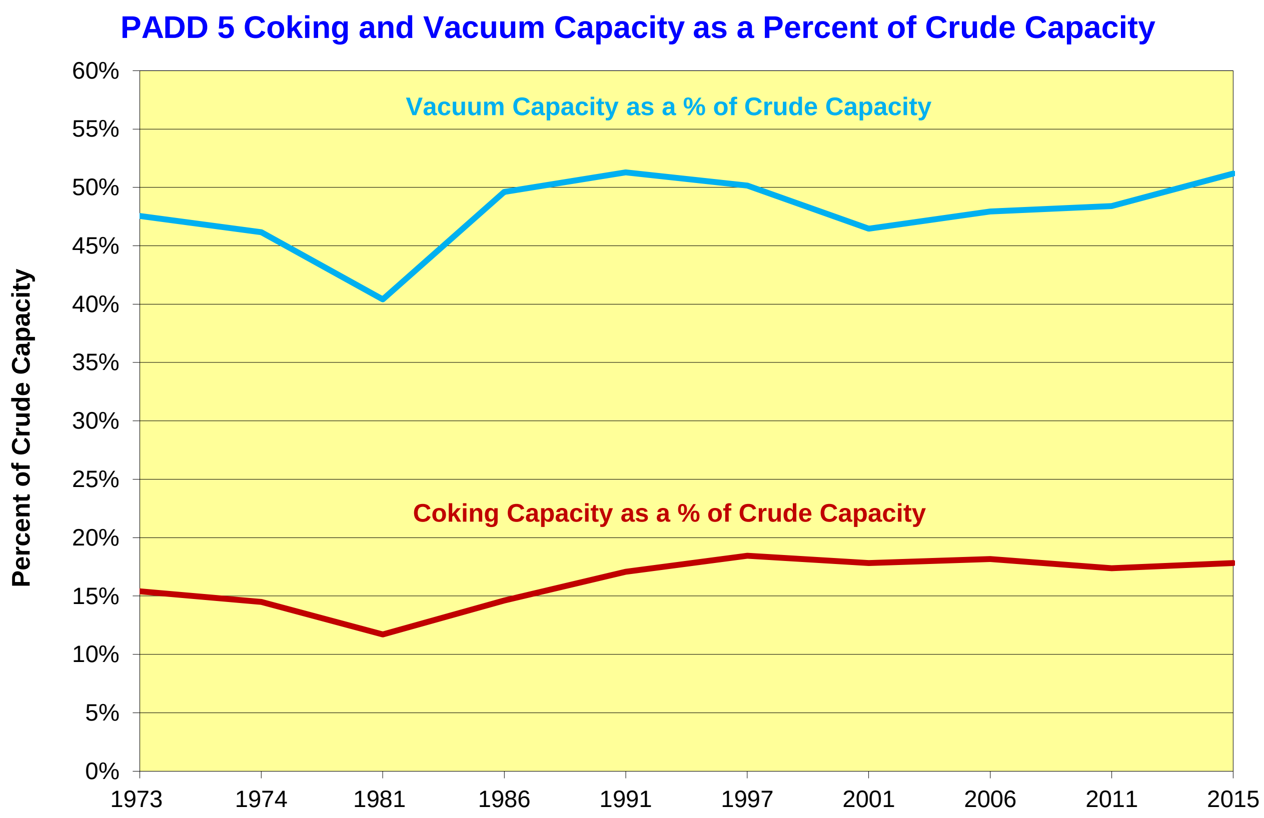
Total U.S. refinery crude throughputs have grown from 15.16 million B/D in 2007 to 15.84 million B/D in 2014, (700,000 B/D increase) at a time when foreign crude imports have dropped by 2.7 million B/D. This implies that the increased absorption of domestic crudes has increased by 3.4 million B/D.



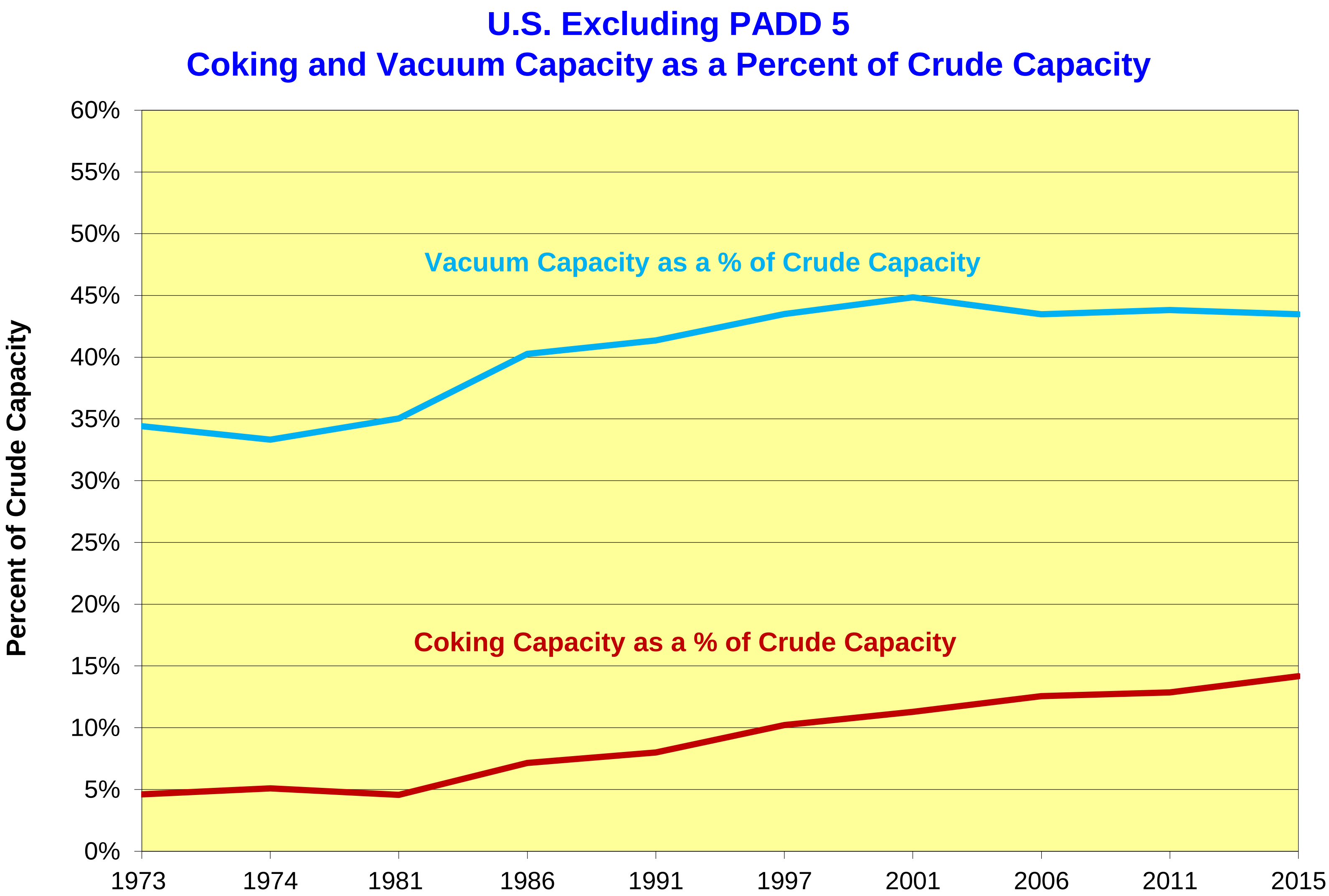
*January through April.

SOURCE: Energy Information Administration.

As shown on the graph on page III-1, imported heavy crude inputs to U.S. refineries has increased steadily since 1973 (147,000 B/D) to an average of 4.33 million B/D for January through April 2015. The driving force for the increase in heavy crudes was the price discount versus light crudes. With declining demand in the U.S. for residual products (asphalt, fuel oil, bunker fuel, etc.), refiners installed coking units to convert the residual portion of the heavy barrel into light products. The history of vacuum distillation and coking capacity is shown on the following graphs. These are divided into two areas – PADD 5 (U.S. West Coast) and PADDs 1 through 4 (remainder of the U.S.). Historically, California had a higher percentage of coking capacity due to the large amount of heavy local crudes. The increase in vacuum distillation and coking capacity is more pronounced in PADDs 1 through 4 as heavy crudes were imported.

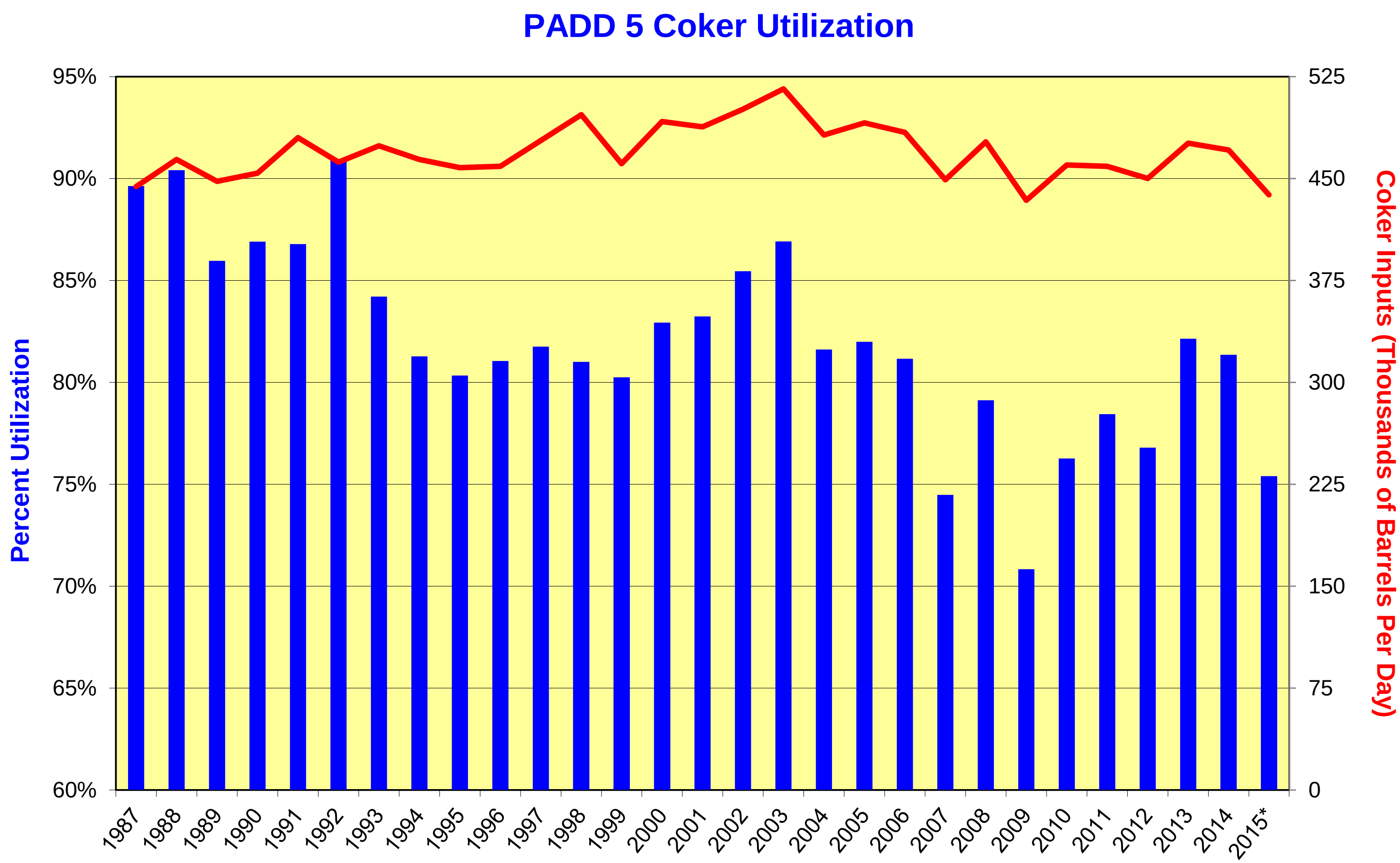


SOURCE: *Oil & Gas Journal Worldwide Refining Survey.*



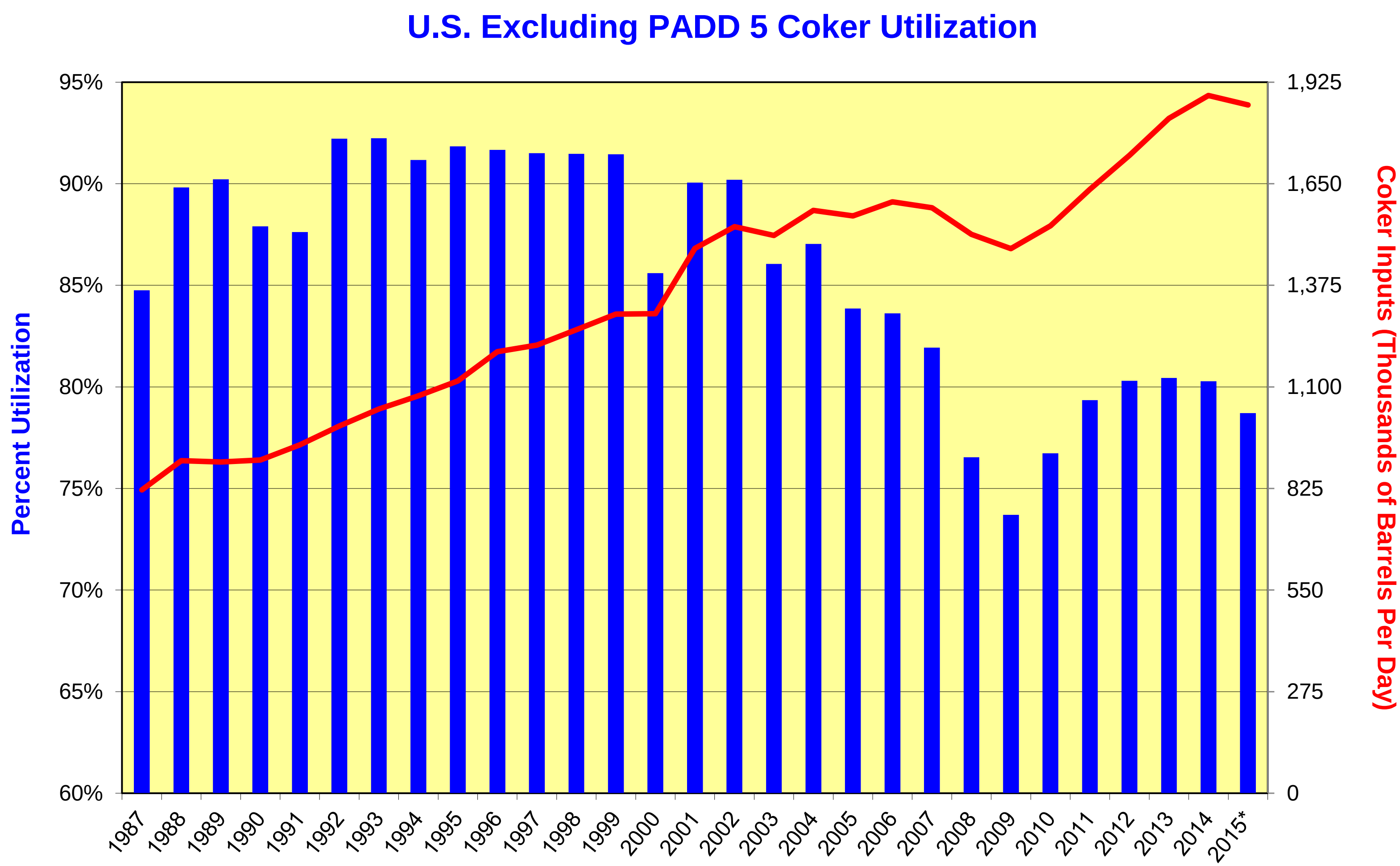
SOURCE: *Oil & Gas Journal Worldwide Refining Survey.*

As shale crude has continued to displace foreign light crudes, and to some extent medium crudes, refiners have sought to blend heavy crudes with light shale crude to create a synthetic medium crude. The shale crudes contain less residuum compared to imported foreign light crudes. The impact on refiners has been a reduction in coker utilization, driven by the economics of lower priced light domestic crude. The impact on coker throughputs and utilization is shown on the following graphs.



*January through April.

SOURCE: Energy Information Administration.



*January through April.

SOURCE: Energy Information Administration.

Lifting the crude export ban would result in a crude price increase of $3.23 per barrel and would eliminate the incentive to export products. This would have significant implications on the U.S. refining industry:

- Lower refinery utilization to pre-2008 levels and/or possible refinery closures
  - Manpower reductions
  - Reduction of service providers
  - Elimination of capital projects
    - Construction jobs
    - Equipment manufacturers
  - Roll down effect on remainder of economy
- Increased imports of crude and products
  - National security implications
- Negative impact on U.S. economy

VII. U.S. Balance of Trade

The U.S. balance of trade is significantly affected by the importation of foreign crude. In 2008, the U.S. was importing 9.7 million B/D of crude at an average price of approximately $100.00 per barrel. The total outflow of cash from the U.S. was approximately $350 billion per year for crude imports alone. The increased production of crude oil and NGLs product has affected a number of petroleum balances:

- Reduced foreign crude oil imports
- Increased U.S. refinery throughput
  - Increased gasoline, jet, and distillate exports
  - Reduced imports of gasoline, jet, and distillate
- Increase in other petroleum product exports
  - NGLs
  - Gasoline, jet, and distillate blendstocks
  - Naphthas and petrochemical feedstocks
  - Heavy petroleum products

The U. S. balance of trade benefited from positive changes in every category listed on the previous page. A comparison has been made showing the net trade balance in 2008 versus net balance in 2014. The benefit in U.S. balance of trade due to increasing crude production and associated downstream activities has been $221 billion per year, comparing 2014 versus 2008. The largest component has been the reduction in crude oil imports, accounting for $106 billion per year of the improvement. Imports of gasoline, jet, and diesel have also dropped, accounting for $24 billion per year improvement, and exports of these three products have increased substantially, providing another $38 billion per year in benefits. A complete outline of each category is shown in the table below.

Change in U.S. Trade Balance - 2008 to 2014 [(1)]

	Annual Trade Balance Improvement/(Deficit)	
	(MB/D)	***(Billion $/Yr)***
Reduction in U.S. Crude Oil Imports	2,303	106.5
Reduction in Gasoline, Jet, and Distillate Imports	568	24.2
Reduction in Other Petroleum Product Imports	733	27.2
Increase in Gasoline, Jet, and Distillate Exports	1,121	38.0
Increase in Other Petroleum Product Exports	1,092	13.3
Increase in Crude Exports	381	12.2
Total	6,197	221.2

NOTE: (1) July through December 2014 average versus 2008.

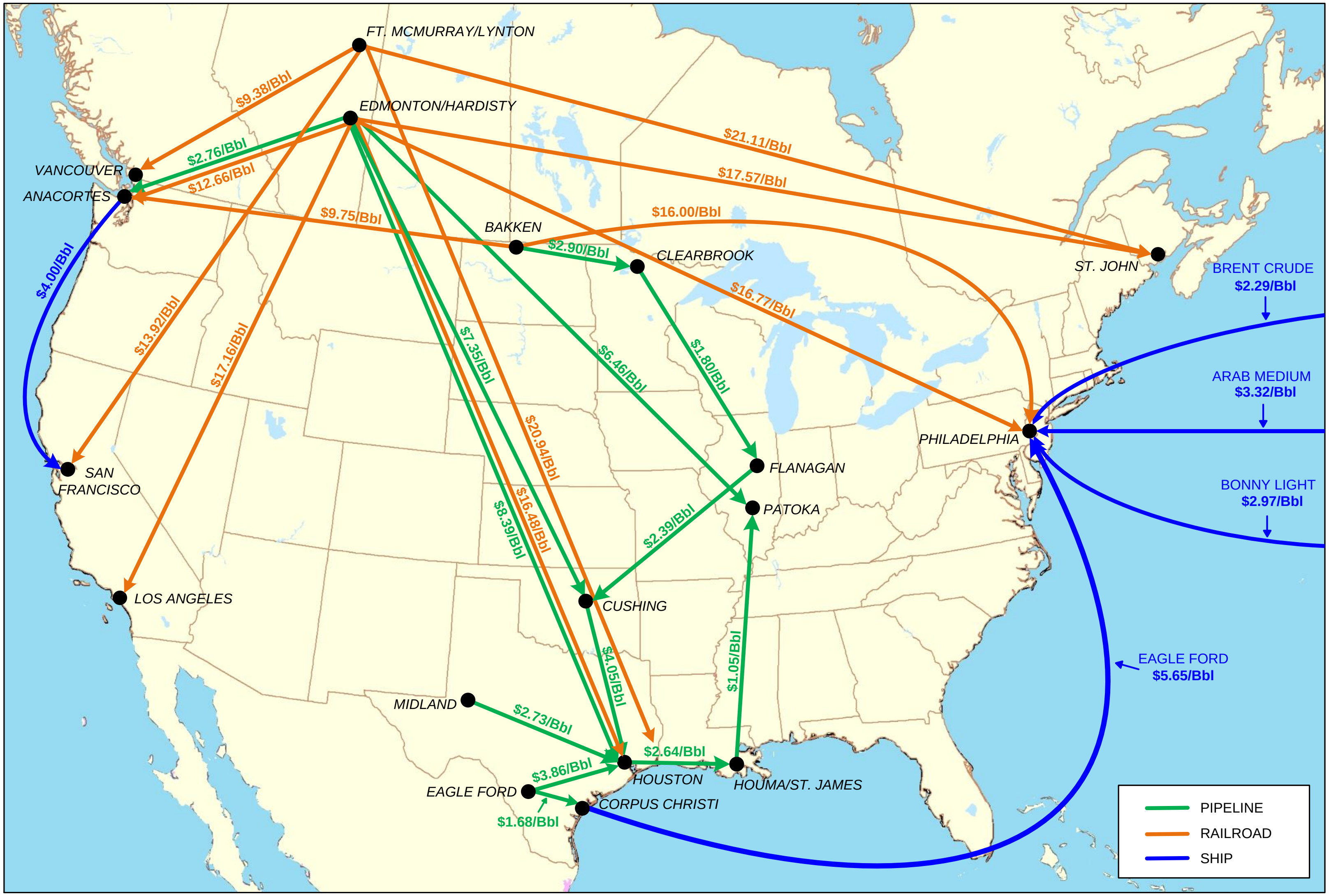
VIII. Logistics

Pipeline companies reacted to the rapidly increasing volumes of crude beginning in 2007 and began many projects to deliver crude oils from the new producing areas to regional refining centers. The projects included the following:

- New pipelines
- Reversing existing pipelines
- Conversion of service to crude oil

The new pipeline projects require planning, permits, financing, etc. The time frame for this process can take several years. In the interim, crude producers have production coming online and they must develop alternate methods of delivering crude. The primary method of delivery was rail. Rail costs are significantly higher than pipeline costs. Representative rail, pipeline, and ship delivery costs are illustrated on the following page.

2015 Crude Pipeline, Rail, and Ship Freight Costs



There are multiple advantages to shipping crude by rail:

- Allows for multiple destinations
  - Shifts in delivery point to maximize crude oil price netbacks
- Short time frame for construction of rail loading/unloading facilities
- Capacity can be changed by varying loading cycles
- No long-term contracts

The disadvantages include the following:

- Higher delivery costs compared to pipelines
- Securing large numbers of railcars (lease or purchase)
- Land area to build unloading facilities near refining or storage centers

The netback price to producers is higher when crude is shipped by pipeline due to the lower delivery costs. However, when faced with very limited pipeline capacity, producers accept lower netbacks (due to higher delivery costs by rail) versus shutting in wells and reducing or stopping drilling operations. The economic decision for producers is weighing the cost of production (drilling and operating costs) and lower netback prices and then calculating a rate-of-return that is deemed acceptable.

As more domestic crude production was available in the Midcontinent area (from the Bakken and Permian Basin areas), refiners purchased local crude production reducing imports of U.S. Gulf Coast barrels, either offshore domestic crude or foreign imports.

A complete history of foreign crude imports is shown in Section XI and Appendix F, *Crude Imports*.

As local crude production exceeded local refining capacity demand, incremental barrels were transported to more distant markets. The reduction, and finally elimination of foreign and U.S. Gulf Coast offshore crude deliveries into the Midcontinent area, resulted in additional supplies available to U.S. Gulf Coast refiners, and produced further reductions in foreign crude imports.

Producers in the Permian Basin and Bakken areas had filled available pipeline capacity, and incremental markets were required that could be supplied by rail. Initially, incremental crude was supplied to the U.S. Gulf Coast by rail, but the larger markets were the U.S. East Coast and Washington state markets. These markets were purchasing foreign crudes delivered by very large crude carriers (VLCCs). To displace the foreign crude, the domestic delivered crude price had to be below the delivered cost of the foreign crudes as adjusted for quality differentials (quality differentials are discussed in Section XIV, *Quality Differentials*).

To be economically viable for the U.S. East Coast and U.S. West Coast refiners, the purchased price of Bakken, Permian Basin, and Eagle Ford crudes had to be below the equivalent foreign barrels on a delivered basis. Since pipelines to deliver crude to the U.S. East Coast or U.S. West Coast did not exist, the only viable delivery method was rail. As shown on the map on page VIII-2, Bakken rail delivery costs to the U.S. East Coast are in the range of $15.00 to $16.00 per barrel. The refiner evaluates the Bakken delivered crude versus foreign marker crudes such as Brent. The refiner will only purchase the Bakken crude if it provides an economic incentive over the marker crude. The price the crude producer receives is roughly calculated by the following formula:

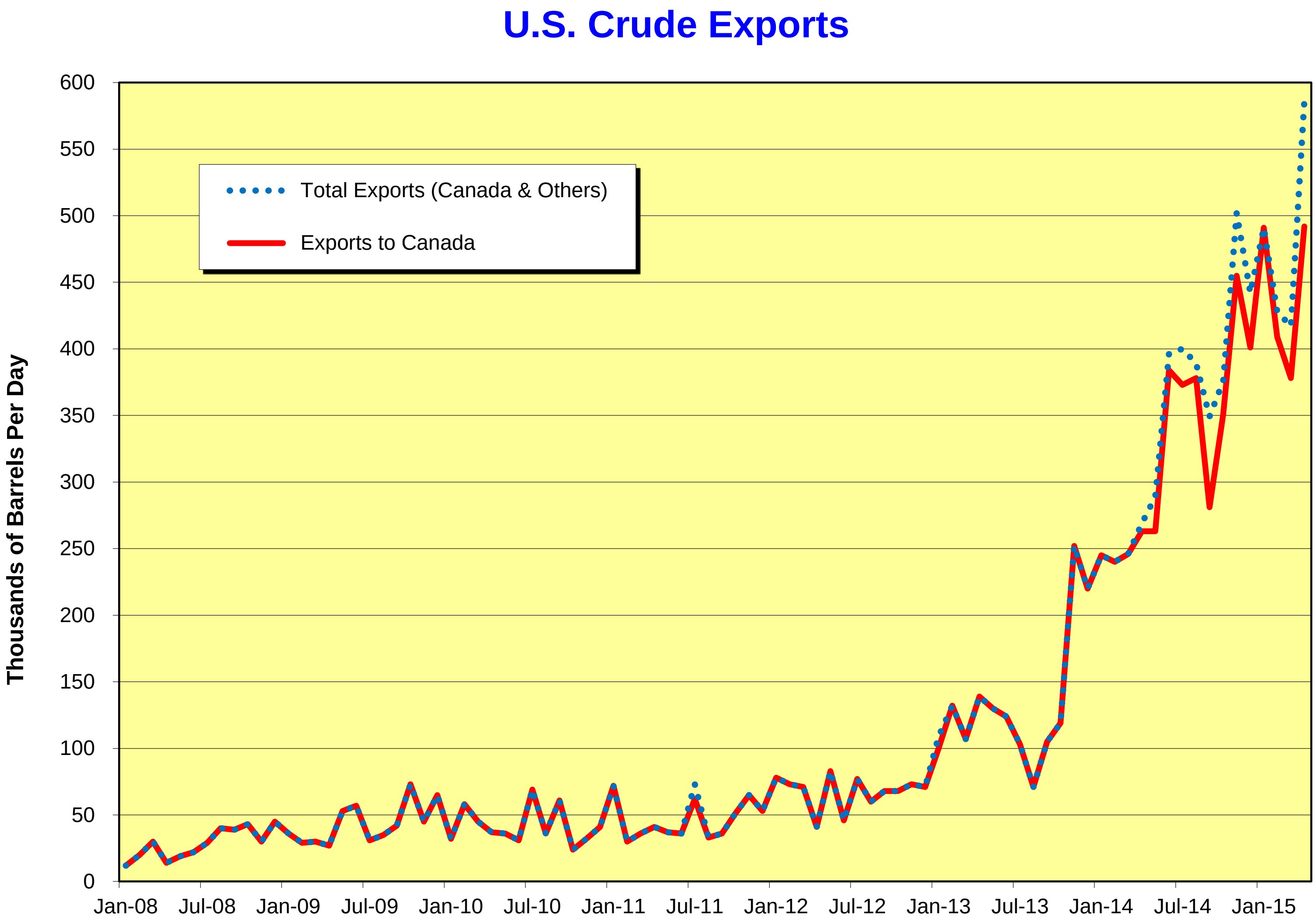
Bakken Netback Price = Brent Plus Transportation to the U.S. East Coast
Less Rail Delivery Cost of Bakken, Adjusted for Quality Differentials

The second largest new production area in the U.S. was the Eagle Ford region in South Texas. Pipeline systems were developed to deliver the crude to Corpus Christi, Texas and to Houston, Texas. Rail and truck transportation was also required to move the increased production. The capacity of the refineries to process lighter crudes in Corpus Christi, Texas was quickly exceeded. With limited pipeline capacity to Houston, Texas, producers began loading ships and barges to deliver crude to the refining centers in Texas, Louisiana, and the U.S. East Coast.

Between any two ports in the U.S., ship deliveries must be made on ships that meet the requirements of the Merchant Marine Act of 1920, also known as the Jones Act. The Jones Act is a U.S. federal statute that provides for the promotion and maintenance of the American merchant marine. Among other purposes, the law regulates maritime commerce in U.S. waters and between U.S. ports. Section 27 of the Jones Act deals with cabotage (i.e., coastal shipping) and requires that all goods transported by water between U.S. ports be carried on U.S. flagged ships, constructed in the U.S., owned by U.S. citizens, and crewed by U.S. citizens and U.S. permanent residents.

The cost of shipping products between U.S. ports is substantially higher than shipping costs for equivalent distances in other parts of the world. Depending upon the size of the ship, the cost of transporting crude can be 200% to 300% higher. As an example, the cost of shipping crude from the North Sea to the U.S. East Coast (6,354 nautical miles) is approximately $2.29 per barrel. The cost of shipping Eagle Ford crude from Corpus Christi to the U.S. East Coast (3,995 nautical miles) is $5.65 per barrel. All mileage numbers are quoted for round-trips.

The Energy Policy and Conservation Act (EPCA) of 1975 prohibited the export of crude oil from the U.S. Exemptions from the EPCA allowed crude oil to be shipped to Canada under specifically granted permits. These shipments can be made in non-Jones Act ships. The cost of shipping Eagle Ford crude to refineries in Eastern Canada from Corpus Christi, Texas is $2.86 per barrel, at a corresponding distance of 4,853 nautical miles. Exports, mainly to Canada, have increased dramatically from 29,000 B/D in 2008 to 463,000 B/D from October 2014 through April 2015.



SOURCE: Energy Information Administration.

To be competitive versus foreign light sweet crudes delivered to the U.S. East Coast, most deliveries of domestic crudes are via rail service from North Dakota or Canada. Bakken producers have few logistical options for delivering crude by pipeline, and the majority of production is shipped by rail.

Stancil has compiled a list of crude pipeline tariffs from the major producing areas in the U.S. and Canada to the U.S. refining centers. These tariffs are shown in Appendix D, *Logistics*. One of the large components in determining the economics of importing foreign crudes and exporting refined products is international shipping rates. Stancil has completed an analysis of shipping rates on crude deliveries to the major world refining centers, which are presented in Appendix D. Also included are shipping rates for refined products from the major refining centers to areas that are importers of products as shown in Appendix D. The maps include shipping rates for crudes transported within the U.S. on Jones Act ships. The freight rates presented are January through February 2015 average costs.

IX. OPEC

The production of crude in OPEC nations has increased from 25 million B/D in 1995 to 32 million B/D in 2014, as shown in the table below. As a percentage of world crude production, it has averaged 42% over the past 20 years, varying in a narrow range from a low of 39.3% in 2002 to a high of 44.2% in 2008. In 2014, OPEC's production averaged 41.7% of world production.

World Crude Production

(Thousands of Barrels Per Day)

	1995	*1996*	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
Total World Production	62,434	63,818	65,806	67,032	65,967	68,527	68,132	67,290	69,460	72,595	73,866	73,478	73,164	74,062	72,871	74,653	74,734	76,160	76,254	77,687
OPEC Production	25,500	26,003	27,274	28,346	27,199	28,944	28,129	26,465	27,977	30,432	31,897	31,607	31,354	32,718	31,035	31,993	32,219	33,392	32,488	32,388
OPEC as Percent of World	40.8%	40.7%	41.4%	42.3%	41.2%	42.2%	41.3%	39.3%	40.3%	41.9%	43.2%	43.0%	42.9%	44.2%	42.6%	42.9%	43.1%	43.8%	42.6%	41.7%

NOTE: Production for 2014 is the average of January through November 2014.

SOURCE: Energy Information Administration.

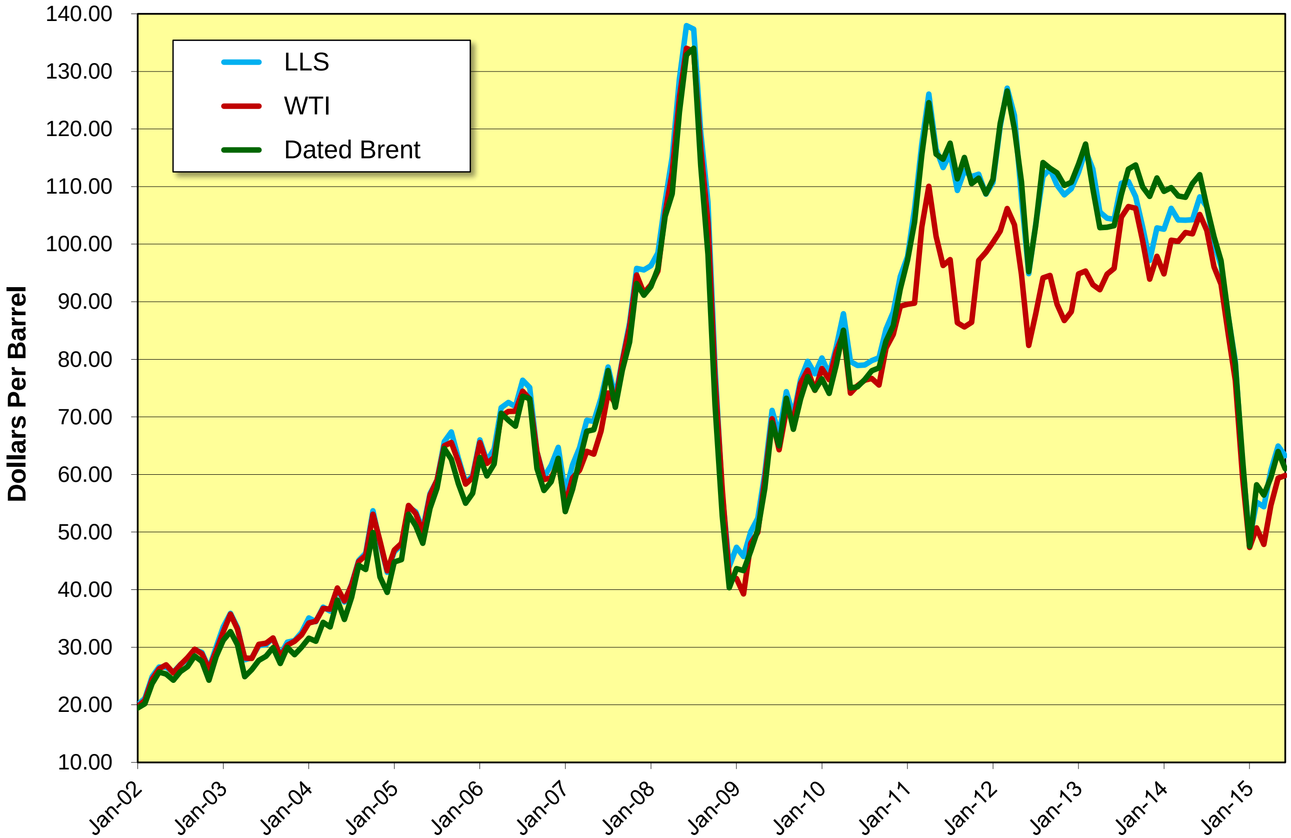
OPEC cannot control prices directly, only indirectly through production volumes. In times that world crude supplies exceed demand, OPEC has two options:

1) Drop OPEC production and maintain static world crude prices
2) Maintain OPEC production, increasing world surplus supply to the point that crude oil prices drop.

Maintaining world crude prices at elevated levels continues to provide the economic incentive to develop non-OPEC crude production. Allowing crude prices to drop reduces the incentive for development.

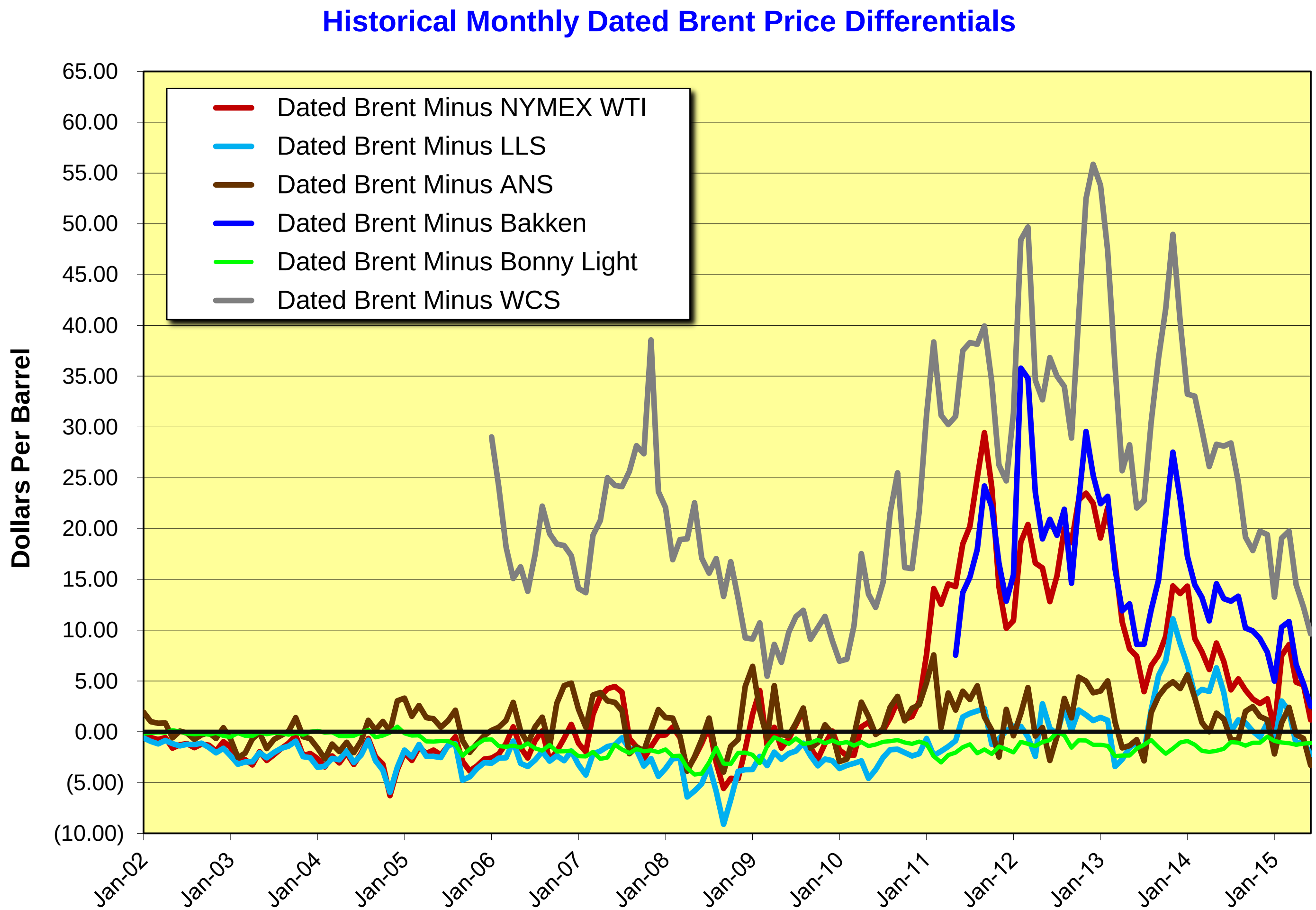
World crude oil demand growth in 2014 was below previous years and crude production growth exceeded demand growth, resulting in increasing world inventories of crude. The result was a slow decline in Brent crude prices, from $112.07 per barrel in June 2014 to $87.55 per barrel in October 2014. The late November 2014 OPEC meeting resulted in a steady continuing volume quota for the OPEC members. The world commodity trading community interpreted the announcement as OPEC's method of maintaining market share, realizing that crude prices would drop to the point of discouraging new developments. The November average price dropped to $79.12 per barrel, then $62.74 per barrel in December. For the first six months of 2015, average Brent prices have dropped to $57.74 per barrel (see graph below).

Historical Monthly Average Crude Prices



SOURCES: *Argus Crude* and *Platts Oilgram Price Report.*

The differential between LLS, WTI, and Brent has collapsed, along with the decline in Brent price. In May 2014, the Brent LLS differential was $6.28 per barrel versus $0.88 per barrel in December 2014. The corresponding differentials for Brent WTI were $8.74 and $3.24 per barrel, respectively. For the period January through June 2015, the Brent LLS differential has been a negative ($0.14) per barrel and the Brent WTI differential has been $4.45. Various crude differentials to Brent are shown in the graph below.



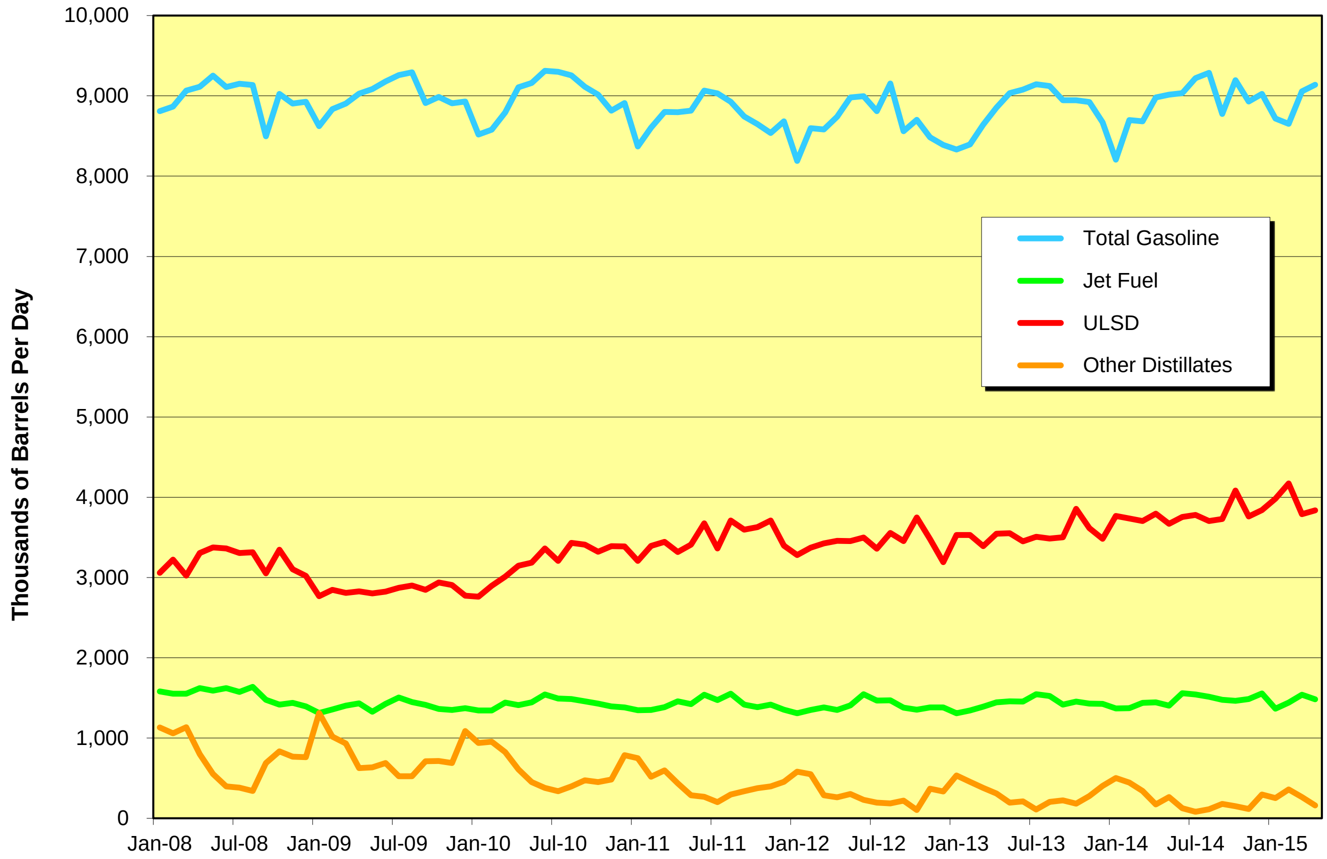
SOURCES: *Argus Crude* and *Platts Oilgram Price Report.*

The precipitous drop in crude prices will have a worldwide effect on crude development projects. The revenue impact on OPEC and non-OPEC producers will be substantial. OPEC producers with large currency reserves, such as Saudi Arabia, can meet internal financial obligations for many years during a period of budget deficits. Other large producers such as Iran, Venezuela, and Russia will suffer immediate financial issues. Saudi Arabia is currently imposing its will over the remaining OPEC members by maintaining current production levels. Its strategy is to slow or stop other world crude reserve developments. This strategy may take several years before definitive reductions in world crude production is visible. Low crude prices will encourage more demand, and at some point in time, crude production and demand will again balance and prices can rise. Saudi Arabia has crude reserves that could be used to increase production to moderate any increases in prices driven by increasing demand, further dampening reserve developments. Other world events could rapidly change the supply/demand picture, such as disruptions in Libya, Iran, Iraq, etc. At that point, crude prices could escalate over a short period of time.

X. Supply/Demand and Imports/Exports

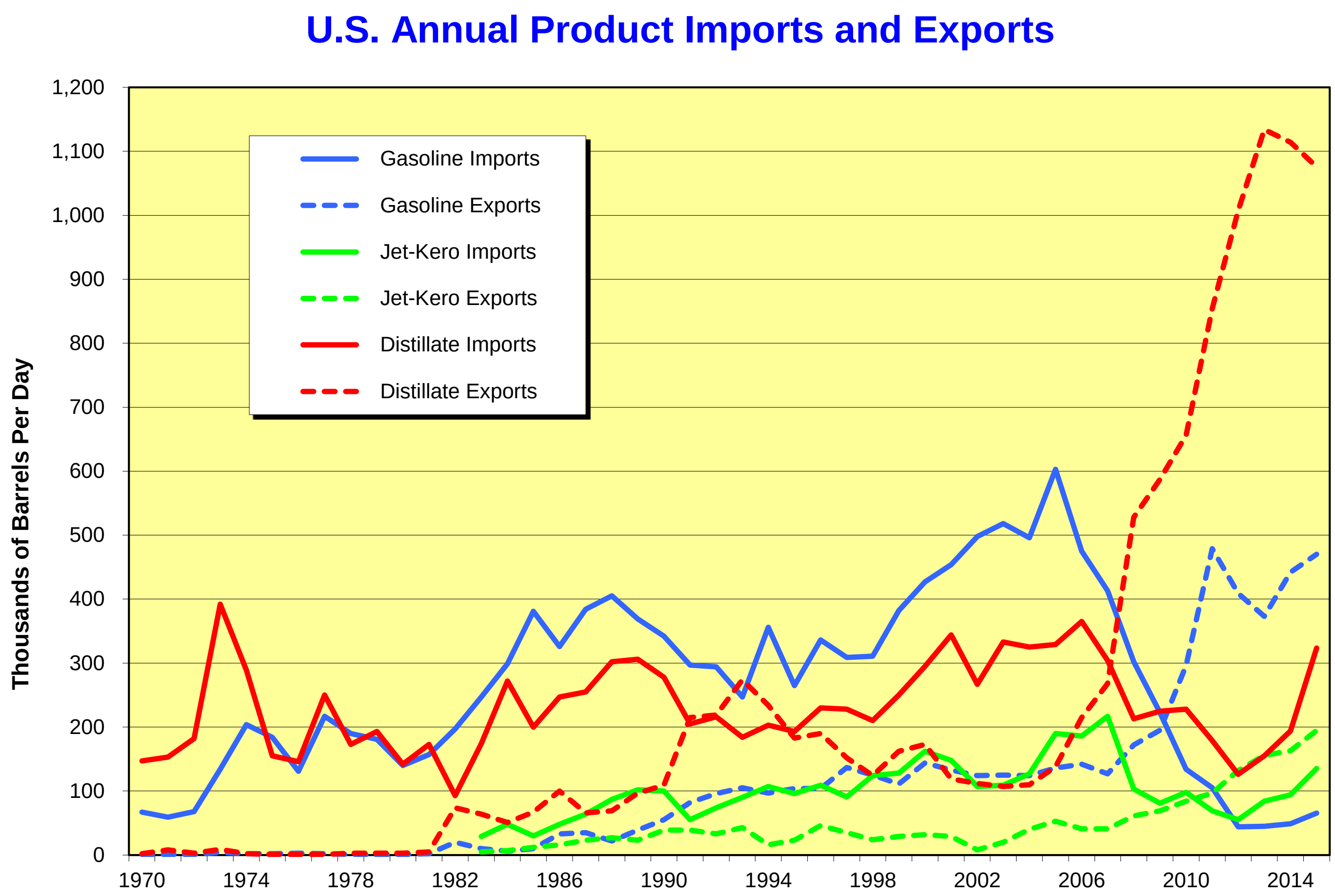
U.S. refined product demand for the three major products – gasoline, jet, and other distillates – has remained very flat since 2008. The only exception has been the growth of ultra low sulfur diesel (ULSD), and recently, motor gasoline.

U.S. Product Demand



SOURCE: Energy Information Administration.

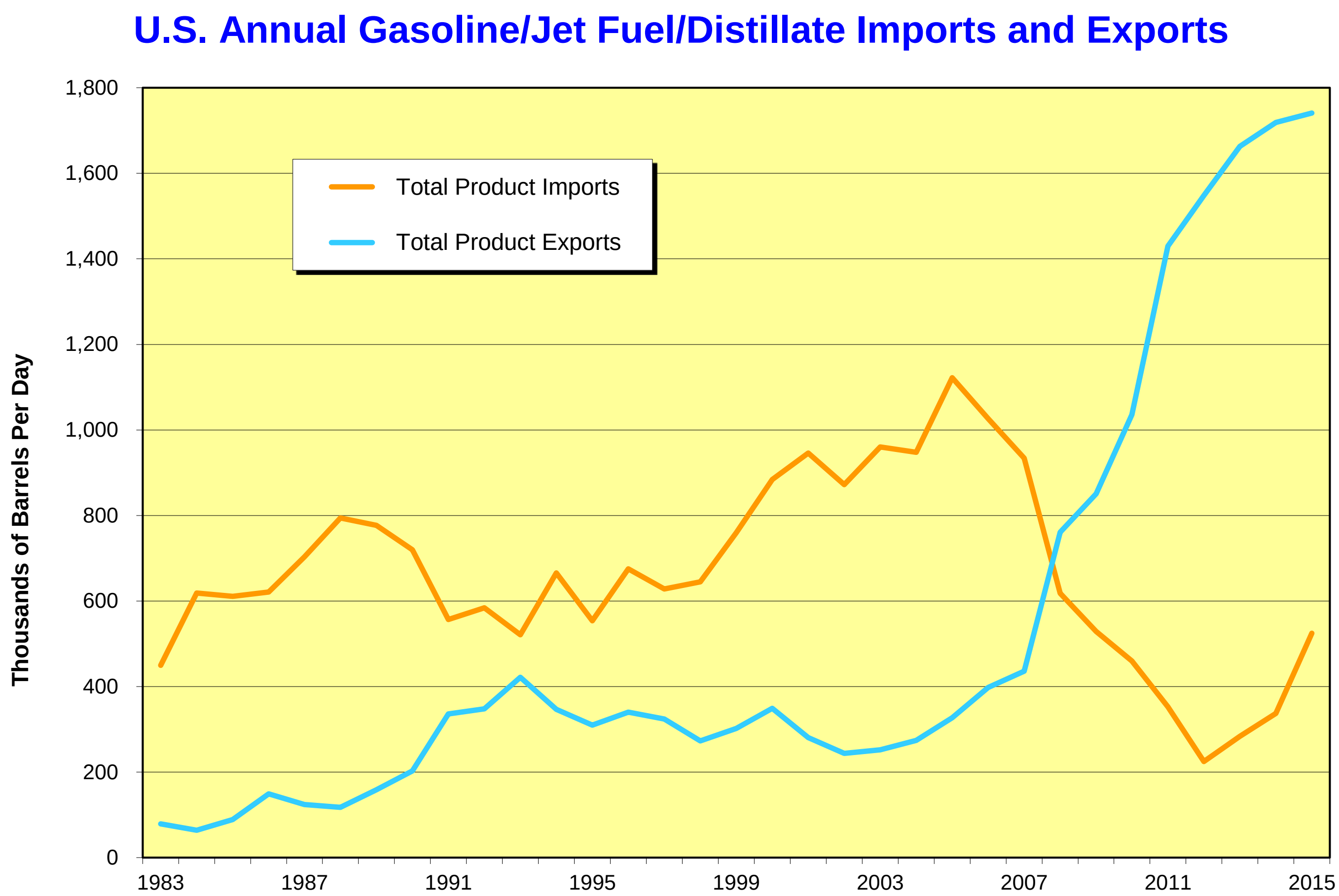
Because of the changes in domestic crude availability and higher refinery utilization, the refined product import/export pattern has changed significantly.



NOTE: Data for 2015 is based on monthly imports and exports through April.

SOURCE: Energy Information Administration.

The combined impact of increased exports and reduced imports of the three major products (gasoline, jet, and distillate) is illustrated in the graph below.



NOTE: Data for 2015 is based on monthly imports and exports through April.

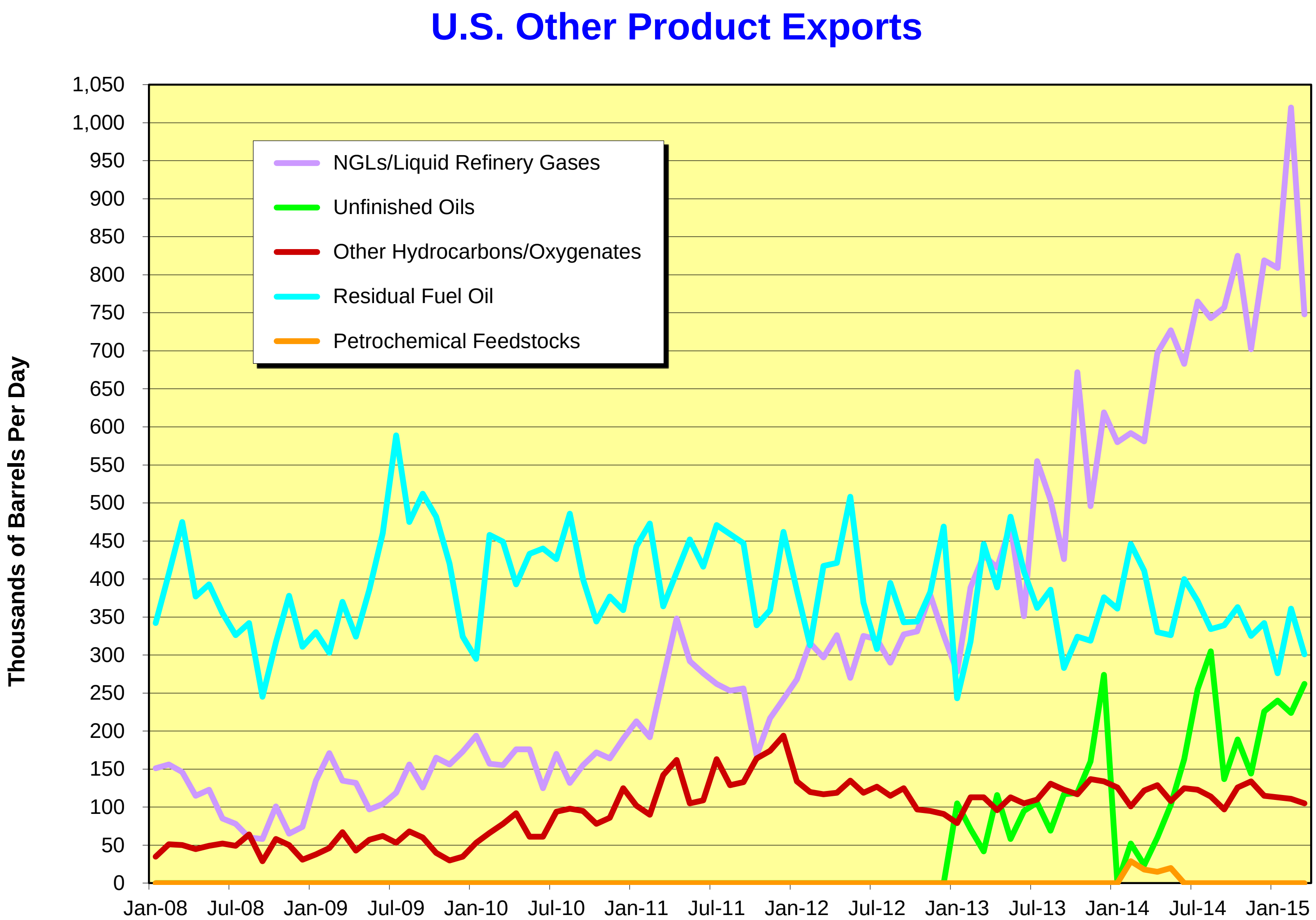
SOURCE: Energy Information Administration.

More information detailing imports and exports to and from Canada and Mexico is shown in Appendix E, *Supply/Demand and Imports/Exports* There has been slight growth of exports to Canada and Mexico, but the large part of the export growth has been to other areas of the world.

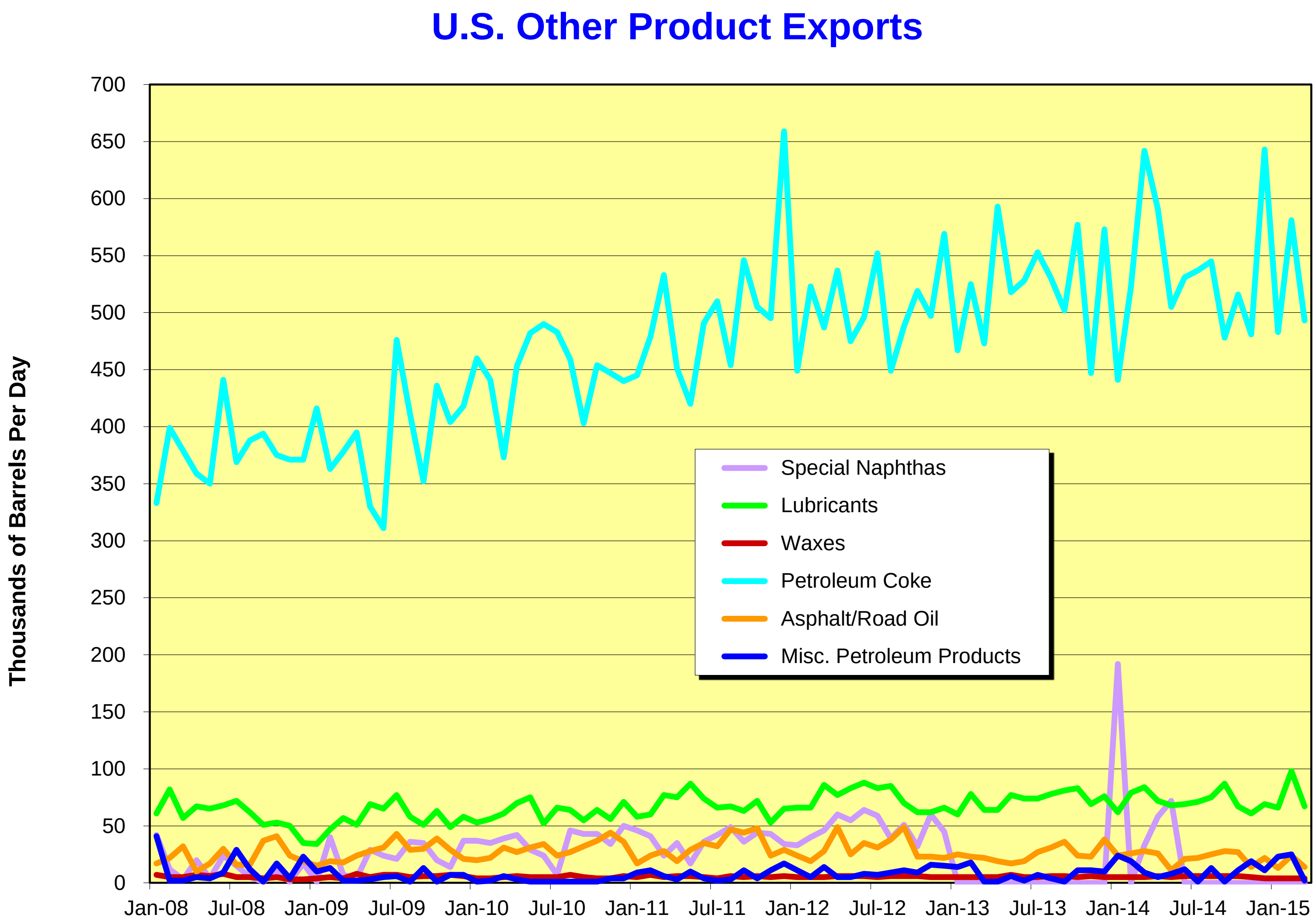
Imports of gasoline into the U.S. have dropped from 1.1 million B/D to 590,000 B/D. The majority of these imports are into PADD 1. Exports of gasoline have increased from under 200,000 B/D to 546,000 B/D (from PADDs 3 and 5). Jet fuel imports have dropped from 103,000 B/D to 95,000 B/D (mostly into PADDs 1 and 5), and exports have increased from 61,000 B/D to 163,000 B/D (from PADD 3). Total distillate exports have increased from 528,000 B/D to over 1.1 million B/D (PADDs 3 and 5). Overall, total exports have increased by over 1.0 million B/D and imports have decreased by 528,000 B/D. A complete analysis of product demand, imports, and exports by PADD is shown in Appendix E.

The net import/export balance for gasoline, jet, and total distillates shifted from 627,000 B/D net imports in 2008 to net exports of 946,000 B/D in 2014. This swing of over 1.6 million B/D of products had a large impact on refinery utilization (and crude consumption) for non-U.S. refiners. The gasoline, jet, and distillate yield for an average world refinery is 65% to 70%. To produce the 1.6 million B/D of gasoline, jet, and other distillates would require 2.3 million B/D of crude. With the swing in the U.S. from a net importer to a net exporter due to increased U.S. refinery runs, the shift in non-U.S. world crude requirements was reduced by 3 million+ B/D, effectively increasing non-U.S. crude supply by that quantity.

In addition to exports of gasoline, jet, and distillate, the U.S. is exporting greater quantities of other petroleum products and NGLs. Shale crude oil and natural gas production generally contains higher percentages of NGLs such as ethane, propane, butanes, and natural gasoline. A significant portion of the production of NGLs is exported. These products in foreign markets are displacing other petroleum products on a British thermal unit (Btu) basis, further reducing world crude oil requirements. Other petroleum intermediates are being exported, also reducing foreign crude requirements.



SOURCE: Energy Information Administration.



SOURCE: Energy Information Administration.

The total volume of other exports is currently 2.1 million B/D, an increase of 1.1 million B/D compared to 2008. Because of the lower Btu of the NGLs component, the equivalent crude oil volume that is being displaced is estimated to be 1.0 million B/D higher than 2008.

U.S. Annual - Other Product Exports
(Thousands of Barrels Per Day)

	2008	***2009***	***2010***	***2011***	***2012***	***2013***	***2014***	***Jan-Mar 2015***
Natural Gas Liquids/Liquid Refinery Gases	101	139	164	249	314	468	707	854
Unfinished Oils	-	-	-	-	-	111	139	243
Other Hydrocarbons/Oxygenates	47	50	82	139	116	114	118	110
Residual Fuel Oil	356	415	405	424	388	362	362	311
Petrochemical Feedstocks	-	-	-	-	-	-	7	-
Special Naphthas	13	22	36	37	49	-	30	-
Lubricants	60	57	62	68	75	73	72	76
Waxes	5	6	5	5	6	5	5	4
Petroleum Coke	377	391	449	499	503	524	536	517
Asphalt/Road Oil	23	27	30	31	30	25	23	17
Miscellaneous Petroleum Products	13	6	2	8	10	7	11	16
Total	995	1,113	1,235	1,462	1,491	1,691	2,010	2,147

SOURCE: Energy Information Administration.

The direct impact of reduced crude imports since 2008 is 2.3 million B/D of incremental crude on the world market. The export of 463,000 B/D of crude primarily to Canada is also a direct impact on incremental world crude requirements. However, the reduced imports of products and increased exports of products and intermediates adds another 4.1 million B/D of crude on the world market. In total, the increases in U.S. domestic production (crude and natural gas) have added over 6.8 million B/D of crude equivalent to the world energy markets. The total effect of world crude supply as a result of the increases in U.S. domestic crude supply and U.S. refinery throughputs can be summarized below.

Change in U.S. Crude Supply Since 2008 (1)

(Thousands of Barrels Per Day)

	Change in Volume	*Equivalent Crude Volume*
Reduction in U.S. Crude Oil Imports	2,303.3	2,303.3
Reduction in Gasoline, Jet, and Distillate Imports	567.5	810.7
Reduction in Other Petroleum Product Imports	574.6	574.6
Reduction in NGL Product Imports	158.4	126.7
Increase in Gasoline, Jet, and Distillate Exports	1,121.5	1,602.1
Increase in Other Petroleum Product Exports	423.6	423.6
Increase in NGL Product Exports	668.0	534.4
Increase in Crude Exports	380.8	380.8
Total	6,197.7	6,756.3

NOTE: (1) July through December 2014 average versus 2008.

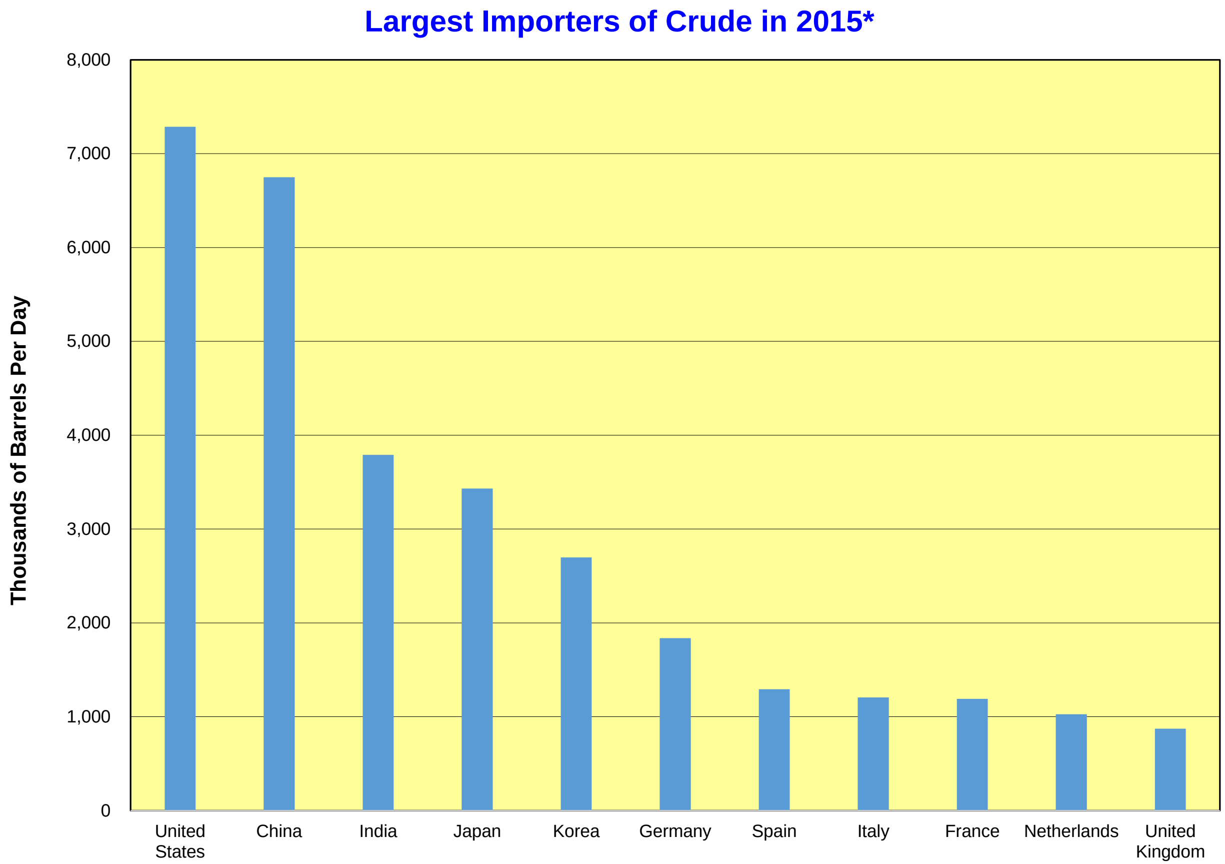
From 2007 through 2013, world petroleum demand has increased from 86.7 million B/D to 91.2 million B/D, an increase of 4.5 million B/D. The increase in U.S. crude production, product exports, and reduced crude and product imports over this same period is 6.8 million B/D, helping create the current world crude surplus position.

The changes in crude oil supply and pricing differences has also caused a shift in the crude and product movements in the different regions of the U.S. (PADDs). Instead of imported crude flowing from the U.S. Gulf Coast into the Midcontinent area, local supply plus imported Canadian crude now provides 100% of the Midcontinent requirements. The Midcontinent refiners are operating at a high utilization rate, backing out shipments of product from the U.S. Gulf Coast. The changes in movements between PADDs are illustrated on the graphs in Appendix E.

XI. Crude Imports

Crude oil imports into the U.S. in 2007 were 10.0 million B/D. Increases in domestic crude production have reduced imports to 7.3 million B/D in January through April 2015.

Even though the U.S. has reduced crude imports by almost 3 million B/D, current imports of 7 million B/D still places the U.S. as the country with the highest volume of crude imports, followed by China with imports of 6.7 million B/D. Historical crude imports for the 11 largest crude oil importing countries are shown on the following graph.



*January through April.

SOURCE: JODI.

For this study, the grades of crude oil were divided into the following subgroups – less than 0.5 weight percent (Wt.%) sulfur (sweet crude) and greater than 0.5 Wt.% sulfur, light crude oil (greater than 35˚API), medium crude oil (26˚API to 35˚API), and heavy crude oil (less than 26˚API). The following table and graph show the changes in each grade between 2007 and 2014.

Change in U.S. Crude Imports - 2014 Versus 2007

(Barrels Per Calendar Day Unless Noted)

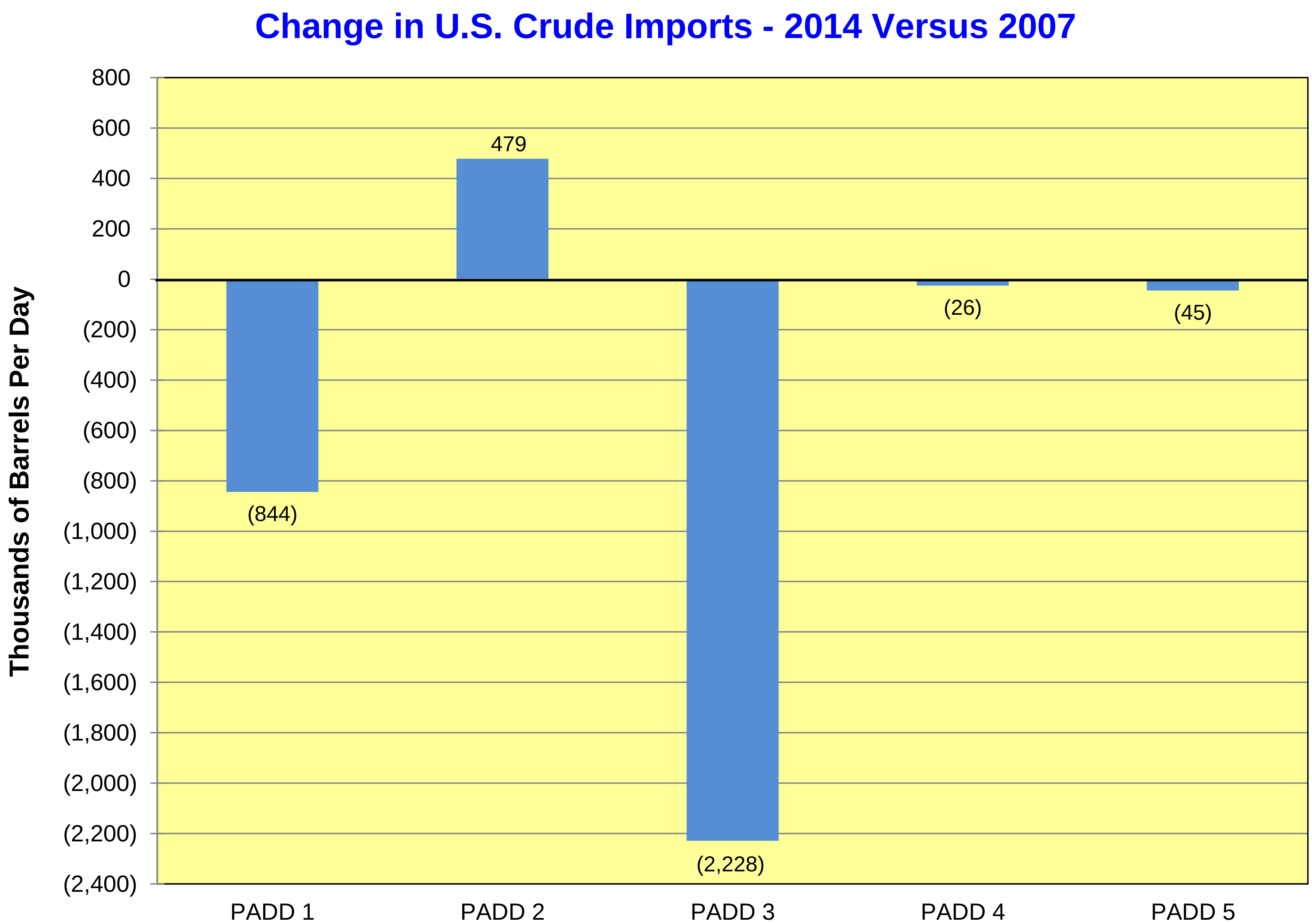
	2007	*2014*	*Delta (2014 Minus 2007)*
PADD 1			
Light Sweet	565,600	141,934	(423,666)
Light Sour	2,537	16,296	13,759
Medium Sweet	345,682	122,211	(223,471)
Medium Sour	261,762	237,784	(23,978)
Heavy Sweet	74,803	43,679	(31,123)
Heavy Sour	244,849	89,268	(155,581)
Total PADD 1	1,495,233	651,173	(844,060)
PADD 2			
Light Sweet	145,792	145,395	(397)
Light Sour	47,542	74,545	27,003
Medium Sweet	220,605	176,740	(43,866)
Medium Sour	202,367	299,052	96,685
Heavy Sweet	3,677	61,332	57,655
Heavy Sour	875,299	1,216,737	341,438
Total PADD 2	1,495,282	1,973,800	478,518
PADD 3			
Light Sweet	898,490	10,463	(888,027)
Light Sour	285,923	46,658	(239,266)
Medium Sweet	491,474	28,866	(462,608)
Medium Sour	1,500,712	1,244,156	(256,556)
Heavy Sweet	74,992	63,532	(11,460)
Heavy Sour	2,332,342	1,961,951	(370,392)
Total PADD 3	5,583,934	3,355,625	(2,228,310)

Change in U.S. Crude Imports - 2014 Versus 2007 (Continued)

(Barrels Per Calendar Day Unless Noted)

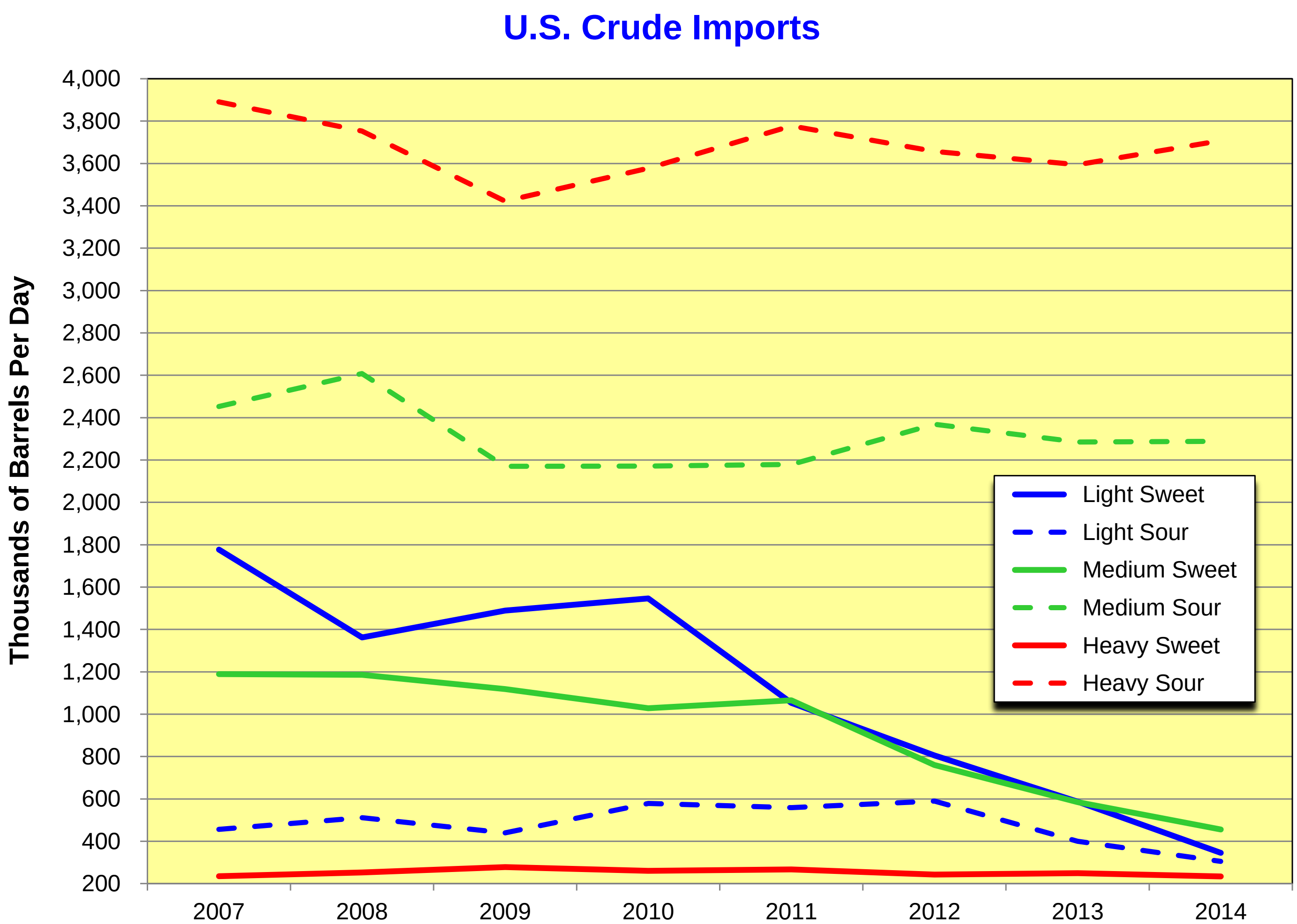
	2007	*2014*	*Delta (2014 Minus 2007)*
PADD 4			
Light Sweet	8,677	7,353	(1,323)
Light Sour	26,671	13,175	(13,496)
Medium Sweet	43,932	39,055	(4,877)
Medium Sour	28,022	10,022	(18,000)
Heavy Sweet	28,063	15,597	(12,466)
Heavy Sour	143,049	167,521	24,471
Total PADD 4	278,414	252,723	(25,690)
PADD 5			
Light Sweet	158,630	40,342	(118,288)
Light Sour	93,049	153,852	60,803
Medium Sweet	87,778	88,849	1,071
Medium Sour	460,099	497,573	37,474
Heavy Sweet	53,148	49,301	(3,847)
Heavy Sour	295,014	272,682	(22,332)
Total PADD 5	1,147,718	1,102,600	(45,118)
Total U.S.			
Light Sweet	1,777,189	345,488	(1,431,701)
Light Sour	455,723	304,526	(151,197)
Medium Sweet	1,189,471	455,721	(733,751)
Medium Sour	2,452,962	2,288,586	(164,375)
Heavy Sweet	234,682	233,441	(1,241)
Heavy Sour	3,890,553	3,708,159	(182,395)
Total U.S.	10,000,581	7,335,921	(2,664,660)

SOURCE: Energy Information Administration.



SOURCE: Energy Information Administration.

The six grades of total U.S. imported crude from 2007 through 2014 are shown in Appendix F, *Crude Imports*.



SOURCE: Energy Information Administration.

The most significant drop in volumes is in the light sweet crudes (1.43 million B/D) followed by the medium sweet crudes (734,000 B/D). This clearly indicates the displacement of foreign light and medium sweet crudes by light sweet shale crudes. The breakdown by regions is shown below.

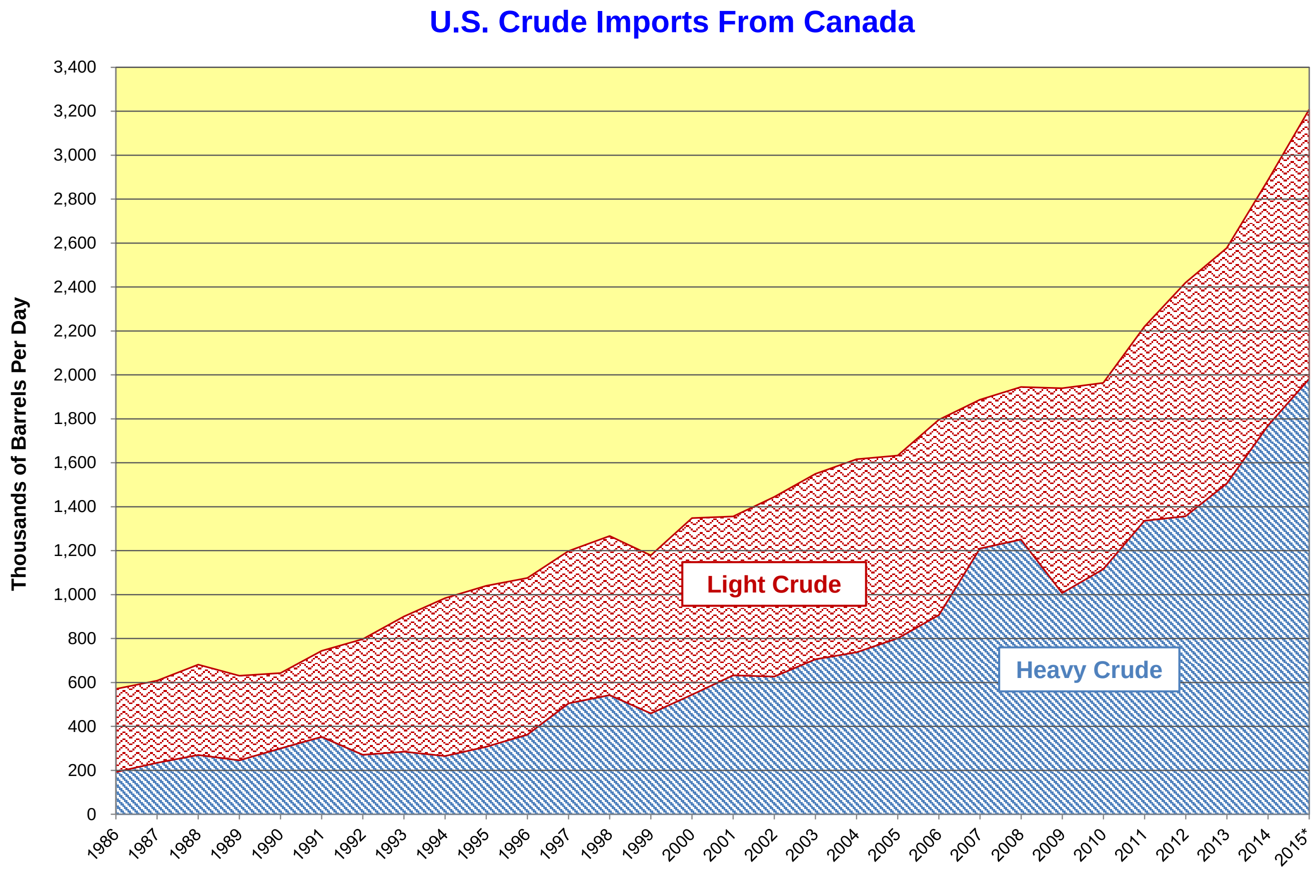
Change in Light Sweet and Medium Sweet Crude Imports
2014 Versus 2007
(Barrels Per Calendar Day Unless Noted)

	2007	*2014*	*Delta (2014 Minus 2007)*
PADD 1			
Light Sweet	565,600	141,934	(423,666)
Medium Sweet	345,682	122,211	(223,471)
Total PADD 1	911,282	264,145	(647,137)
PADD 2			
Light Sweet	145,792	145,395	(397)
Medium Sweet	220,605	176,740	(43,866)
Total PADD 2	366,397	322,134	(44,263)
PADD 3			
Light Sweet	898,490	10,463	(888,027)
Medium Sweet	491,474	28,866	(462,608)
Total PADD 3	1,389,964	39,329	(1,350,636)
PADD 4			
Light Sweet	8,677	7,353	(1,323)
Medium Sweet	43,932	39,055	(4,877)
Total PADD 4	52,608	46,408	(6,200)
PADD 5			
Light Sweet	158,630	40,342	(118,288)
Medium Sweet	87,778	88,849	1,071
Total PADD 5	246,408	129,192	(117,216)
Total U.S.			
Light Sweet	1,777,189	345,488	(1,431,701)
Medium Sweet	1,189,471	455,721	(733,751)
Total U.S.	2,966,660	801,208	(2,165,452)

SOURCE: Energy Information Administration.

Detailed information for each PADD is shown in Appendix F.

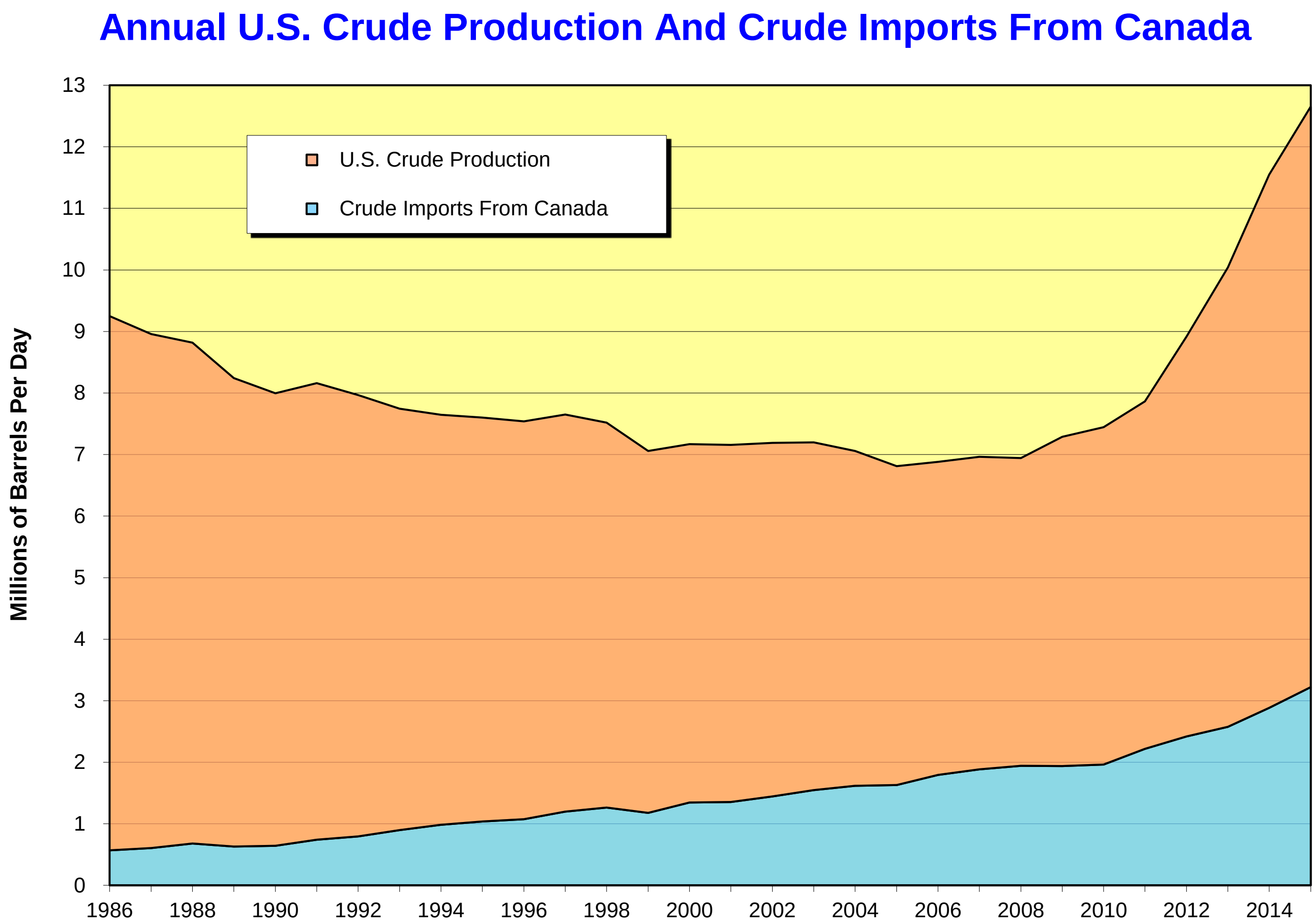
The only increases in crude oil imports into the U.S. are from Canada. Canadian crudes, particularly heavy grades of crude, have been discounted due to logistics constraints out of the producing areas in Western Canada. Rail movements have provided the only incremental outlet, and have set the producer price based on rail economics. A summary of the increases in Canadian crude imports is shown on the graph below.   A detailed table is shown in Appendix F.



*January through February.

SOURCE: Energy Information Administration.

Total U.S. production and Canadian imports are shown below.



SOURCE: Energy Information Administration.

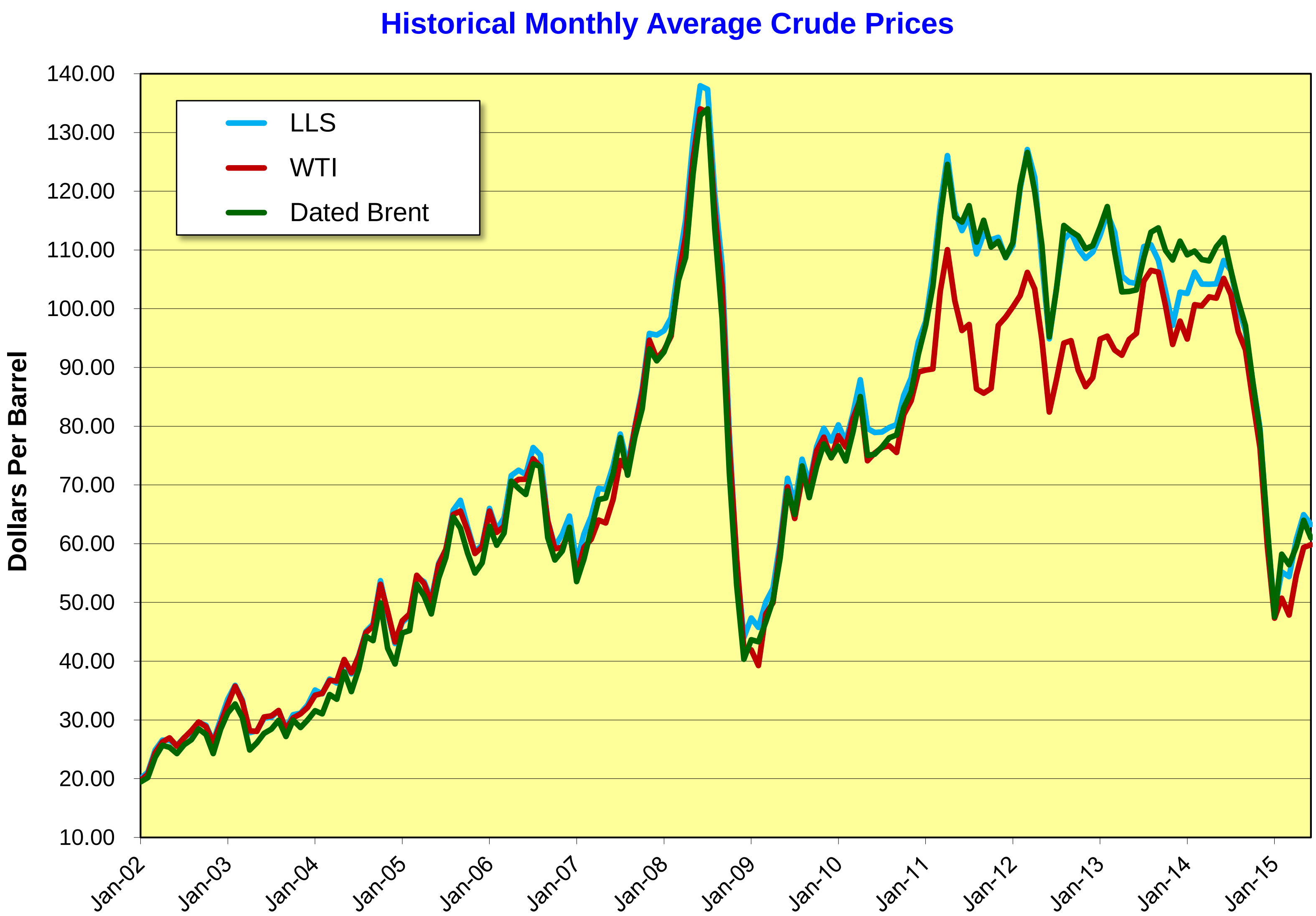
XII. Pricing

Petroleum prices are driven by a number of factors:

- Supply/Demand
  - Crude Oil
    - Type
    - Location
  - Products
    - Grades
      - Gasoline
      - Distillates
      - Residual Products
    - Specifications
- Crude Oil Quality
- Refinery
  - Capacity
  - Configuration
- Logistics
- Alternate Energy Sources
- Regional Political Concerns
  - Threats of War
  - Terrorism

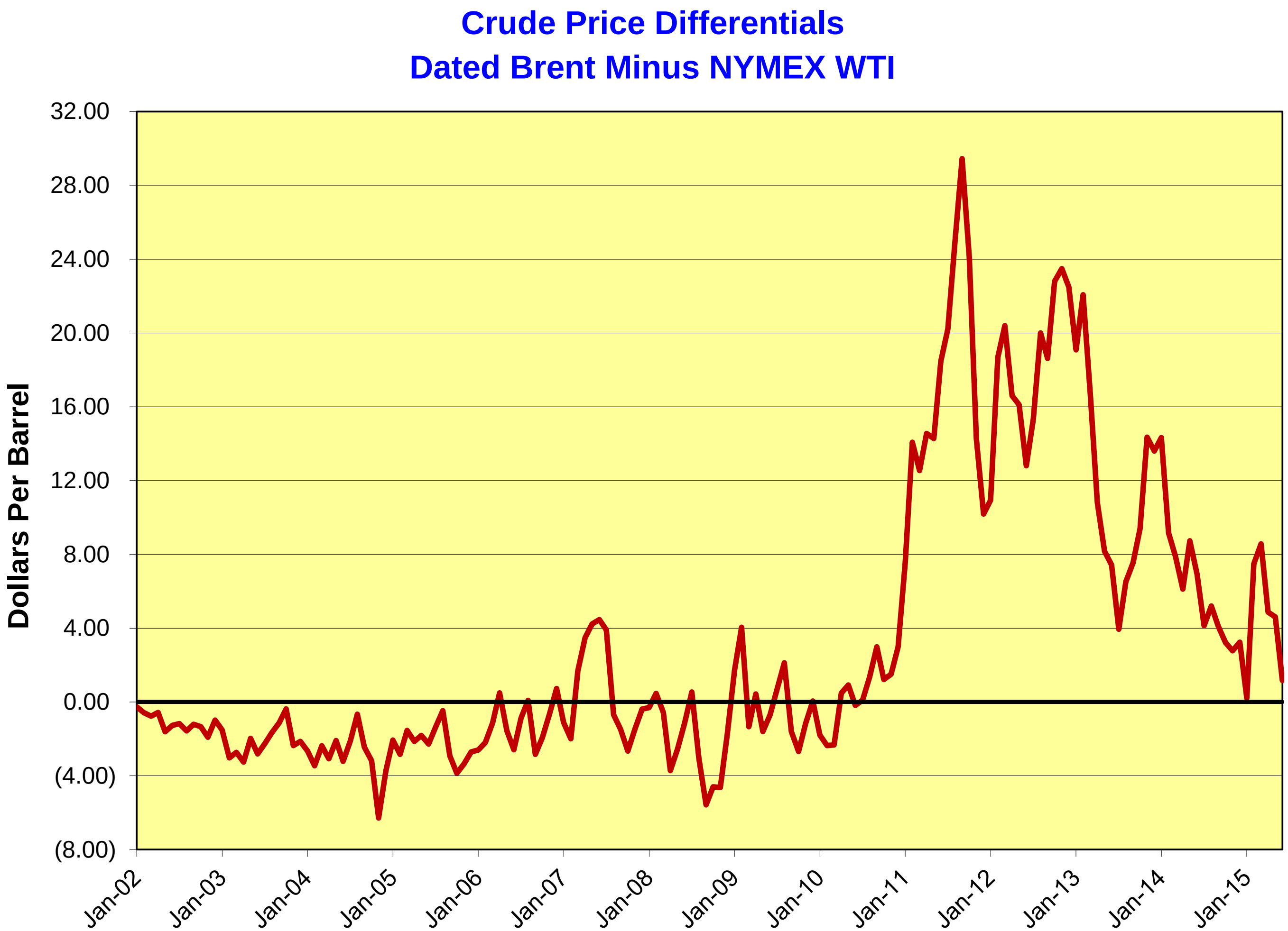
- Market Perceptions
  - Futures Markets
  - Economic Conditions
    - Current
    - Future
- Regulatory

Historical crude oil marker prices are shown on the following graphs.



SOURCES: *Argus Crude* and *Platts Oilgram Price Report.*

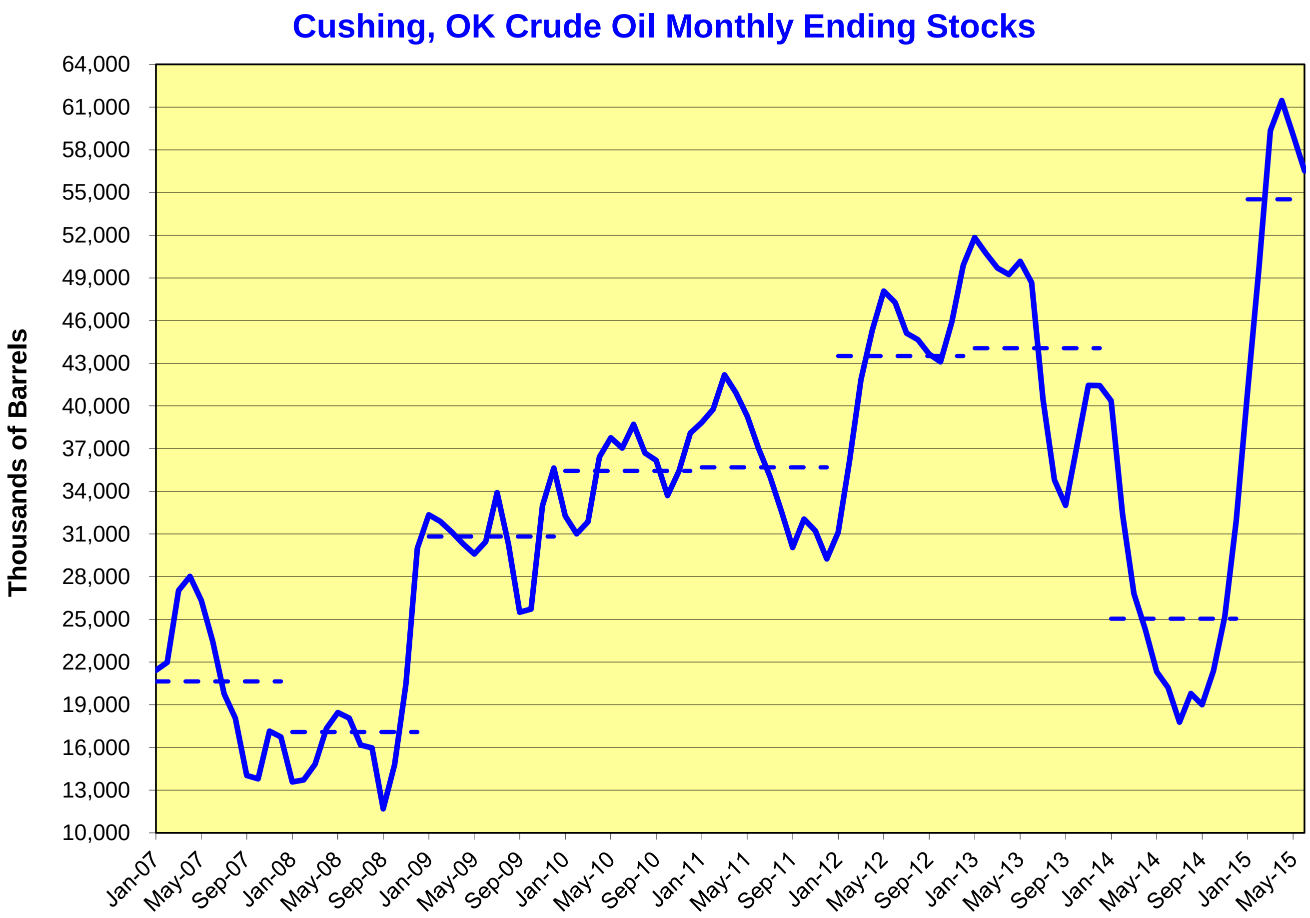
WTI was the common marker crude for Midcontinent refineries for decades. The region was short of crude and relied on imports of Canadian crudes and U.S. Gulf Coast and foreign crudes to supply incremental crude requirements. The imported foreign crudes were all priced on a Brent basis. The primary worldwide marker price is Brent crude oil. In the U.S., WTI closely tracked Brent price. The graph below shows the Brent/WTI differential from 2002 through current.



SOURCES: *Argus Crude* and *Platts Oilgram Price Report.*

In the early years represented in the graph, the Midcontinent and the U.S. Gulf Coast was short of domestic crude and relied on imports. WTI traded consistently at a $2.00 to $3.00 per barrel premium to Brent. The premium reflected the alternate supply cost of Brent type crude to the U.S. Gulf Coast/Midcontinent markets.

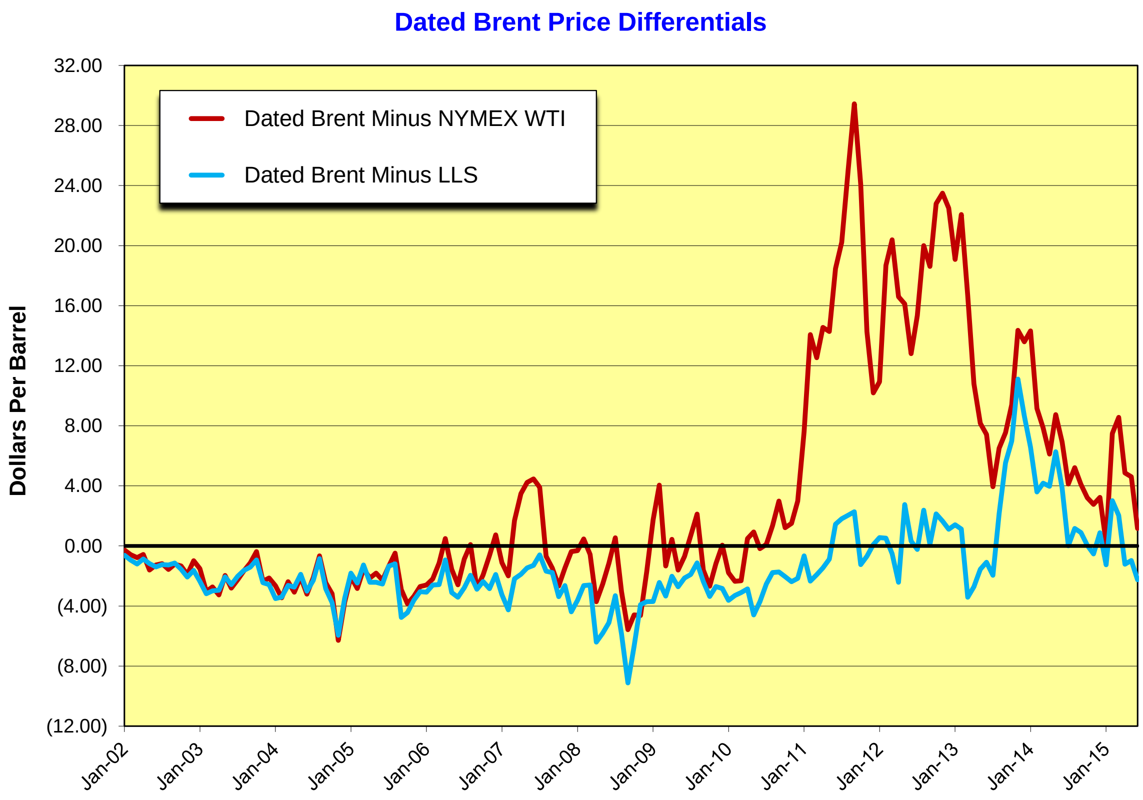
In late 2010, WTI began to sell at discounted prices relative to Brent. The discount followed almost a year of increasing crude oil inventories at Cushing, Oklahoma, the trading point for WTI.



SOURCE: Energy Information Administration.

Increasing Bakken production was providing upper Midcontinent refiners with incremental supplies of light sweet crude oils, displacing historical deliveries of WTI from Cushing. With limited pipeline capacity to move Cushing barrels south to the U.S. Gulf Coast refining complex, inventories began to reach the upper limits of storage capacity at Cushing. Once the pipeline capacity constraints were reached, producers were forced to evaluate alternate methods of delivering crude to potential markets. Trucking more than a few hundred miles is prohibitively expensive. Rail, and to a lesser extent barging, were the only viable alternatives. The production field value of crude dropped until the discounted price covered the added transportation costs to the major market areas on the U.S. East Coast and U.S. Gulf Coast.

During this time frame, the relationship of crude oil prices on the U.S. Gulf Coast remained relatively constant (LLS versus Brent).



SOURCES: *Argus Crude* and *Platts Oilgram Price Report.*

As Eagle Ford production began to increase in South Texas in 2011, Houston/Corpus Christi refineries began running Eagle Ford, backing out deliveries of Louisiana Offshore crudes resulting in a discount of LLS versus Brent.

The discounts of WTI, Bakken, and Eagle Ford were driven by logistics limitations. With declining Lower 48 U.S. crude production from the 1970s through 2009, very few new onshore crude pipelines were built and many existing pipelines were abandoned or converted to other services (refined product, liquefied petroleum gas (LPGs), or natural gas). With rapidly increasing crude production beginning in 2009, existing pipeline capacity was exceeded. Pipeline companies began many projects to deliver crude oils from the new producing areas to regional refining centers. The projects included the following:

- New pipelines
- Reversing existing pipelines
- Conversion of service to crude oil

A list of new or repurposed crude oil pipelines is shown in the tables on the following pages.

Texas Gulf Coast Crude Pipelines
New Construction and Expansion

Project	Company	Route: Origin	Route: Destination	Service Date	Capacity (MB/D)
Eagle Ford					
Eagle Ford Enterprise Pipeline	Enterprise/Plains All American	Lyssy, TX	Houston, TX	Jun/2012	350
KM Crude/Condensate	Kinder Morgan	East Eagle Ford, TX	Houston, TX	Jun/2012	300
Double Eagle Pipeline	Kinder Morgan/Magellan	West Eagle Ford, TX	Corpus Christi, TX	2Q/2013	100
Eaglebine Express	Sunoco	Hearne, TX	Nederland, TX	4Q/2014	60
Cushing					
Seaway	Enterprise/Enbridge	Cushing, OK	Freeport, TX	Jan/2013	400
Seaway - Twin	Enterprise/Enbridge	Cushing, OK	Freeport, TX	2Q/2014	450
Seaway - Extension	Enterprise/Enbridge	Freeport, TX	Port Arthur, TX	3Q/2014	--
Keystone Gulf Extension	TransCanada	Cushing, OK	Port Arthur/Houston, TX	Jan/2014	700
Keystone Houston Lateral	TransCanada	Port Arthur/Houston, TX	Houston Area Refineries, TX	2H/2015	--
Permian Basin					
Longhorn Reversal	Magellan	Crane, TX	Houston, TX	4Q/2013	275
Granite Walsh Extension	Sunoco	Wheeler County, TX	Ringold, TX	4Q/2014	70
West Texas - Houston	Sunoco	Colorado City, TX	Houston, TX	2Q/2012	40
West Texas - Longview	Sunoco	Colorado City, TX	Longview, TX	2Q/2013	30
West Texas - Nederland	Sunoco	Colorado City, TX	Nederland, TX	3Q/2014	40
Sunvit Pipeline	Sunoco/Vitol	Midland, TX	Gardendale, TX	2H/2015	200
Pecos River System	Blueknight/Advantage	Grand Falls, TX	Crane, TX	Sep/2013	150
Pecos River System	Blueknight/Advantage	Pecos, TX	Loving, NM	3Q/2014	--
BridgeTex	Oxy/Magellan	Colorado City, TX	Houston, TX	Sep/2014	300
Cactus	Plains All American	McCamey, TX	Corpus Christi, TX	2Q/2015	250
Cactus	Plains All American	McCamey, TX	Corpus Christi, TX	4Q/2015	80
Sunrise	Plains All American	Midland, TX	Colorado City, TX	4Q/2014	250
Permian Express - Phase 1	Sunoco	Wichita Falls, TX	Nederland/Beaumont, TX	1Q/2014	150
Permian Express - Phase 2	Sunoco	Midland/Colorado City, TX	Nederland, TX	2H/2015	200
Permian Express - Longview Ext.	Sunoco	Midland, TX	Longview, TX	3Q/2014	100
Delaware Basin Extension	Sunoco	Delaware Basin, NM	Midland, TX	1H/2016	100
Gulf Coast Region					
Ho-Ho	Shell	Houston, TX	Houma, LA	Dec/2013	250/375
Westward Ho	Shell	St. James, LA	Nederland, TX	4Q/2017	400

SOURCE: Public data.

Other Crude Pipelines - Excluding Texas Gulf Coast
New Construction and Expansion

Project	Company	Route: Origin	Route: Destination	Service Year	Capacity (MB/D)
Bakken Shale					
Bakken Expansion Program	Enbridge	Berthold, ND	Cromer, Manitoba	Mar/2013	145
Sandpiper Project	Enbridge	Beaver Lodge, ND	Clearbrook, MN	2017	225
Sandpiper Project	Enbridge	Clearbrook, MN	Superior, WI	2017	375
Cushing					
Line 5 Expansion	Enbridge	Superior, WI	Sarnia, ON	2013/2014	540
Line 9 Reversal and Expansion	Enbridge	Griffith, IN	Montreal, QC	Oct/2014	300
Line 9B Reversal	Enbridge	Westover, ON	Montreal, QC	TBD	240
Toledo Pipeline Partial Twin	Enbridge	Stockbridge, Michigan	Toledo, OH	2013	180
Line 61 Expansion	Enbridge	Superior, WI	Flanagan, IL	Sep/2014	560
Express Pipeline	Spectra Energy	Hardisty, AB	Casper, WY	Oct/2013	280
Platte Pipeline	Spectra Energy	Casper, WY	Wood River, IL	Oct/2013	164-145
Grand Rapids	TransCanada/Phoenix Energy	Fort McMurray, AB	Heartland, AB	2H/2015	900
Grand Rapids - Diluent	TransCanada/Phoenix Energy	Fort McMurray, AB	Heartland, AB	2017	330
Line 6B Replacement	Enbridge	Griffith, IN	Marysville, MI	Oct/2014	500
Line 6B Expansion	Enbridge	Griffith, IN	Stockbridge, MI	1Q/2016	570
Spearhead North (Line 62)	Enbridge	Flanagan, IL	Griffith, IN	2013	235
Spearhead North (Line 62) - Twin	Enbridge	Flanagan, IL	Griffith, IN	3Q/2015	570
Flanagan South Project	Enbridge	Flanagan, IL	Cushing, OK	4Q/2014	600
Alberta Clipper (Line 67) - Phase 2	Enbridge	Hardisty, AB	Superior, WI	3Q/2015	800
Northern Gateway West	Enbridge	Bruderheim, Alberta	Kitimat, BC	2018	525
Northern Gateway East - Diluent	Enbridge	Kitimat, BC	Bruderheim, Alberta	2018	193
Trunkline	Enbridge/Energy Transfer	Patoka, IL	Nederland, TX	4Q/2016	320
Keystone XL	TransCanada	Hardisty, AB	Steele City, NB	2017	830
Keystone XL Northern Leg	TransCanada	Steele City, NB	Cushing, OK	Feb/2011	591
Trans Mountain Expansion	Kinder Morgan	Edmonton, AB	Vancouver, BC/Puget Sound, WA	4Q/2017	300/590
Energy East Pipeline	TransCanada	Hardisty, AB	St. John, NB	4Q/2018	1,100
Niobrara					
White Cliffs	Rose Rock	Platteville, CO	Cushing, OK	Aug/2014	150
Niobrara Falls Project - Phase 1	NuStar	Platteville, CO	McKee,TX	1Q/2014	75
Niobrara Falls Project - Phase 2	NuStar	McKee,TX	Wichita Falls, TX	TBD	75
Pony Express Conversion	Tall Grass Pipeline	Guernsey, WY	Cushing, OK	Oct/2014	230-320
Spectra Express Pipeline	Spectra Energy	Guernsey, WY	Patoka, IL	2017	400
California					
Inland California Express (ICE) Pipeline	Questar/Spectra Energy	Whitewater, CA	Long Beach, CA	3Q/2016	140

SOURCE: Public data.

A further description of the pipeline logistics limitations is discussed in Section VIII, *Logistics*.

An exemption to the crude oil export ban allowed U.S. domestic crude to be exported to Canada and other specifically permitted countries. Historically, nominal amounts of crude (25,000 B/D to 50,000 B/D) were exported to Canada. In 2012, larger amounts were exported following the price of Eagle Ford crude trading at a larger discount to Brent. Because of the Jones Act, Eagle Ford crude could be transported in 2015 to U.S. Gulf Coast refineries at a cost of over $3.00 per barrel or to the U.S. East Coast for $5.65 per barrel. Using non-Jones Act ships, Eagle Ford could be transported to Eastern Canadian refineries for $2.86 per barrel (see map in Section VIII, *Logistics*, page VIII-2). To be competitive at either U.S. East Coast or Eastern Canada refineries, Eagle Ford or a similar domestic crude delivered cost must be priced at or below world crude prices, such as Brent on a delivered basis, adjusted for quality differentials.

Because of the difference in 2015 shipping costs, the netback price for Eagle Ford crude producers is $2.79 per barrel higher for sales to Eastern Canada. The calculation of this difference is as follows:

> The delivery cost of Brent to Eastern Canada is $1.94 per barrel. Assuming Brent and Eagle Ford are equivalent on a quality basis, the breakeven price for Eagle Ford would be Brent plus freight to Canada of $1.94 per barrel minus $2.86 per barrel freight from Corpus Christi, or Brent less $0.92 per barrel. The netback price for ship delivered barrels of Eagle Ford to the U.S. East Coast would be Brent plus $2.29 freight less $5.65 freight from Corpus Christi for a net of negative $3.36 per barrel. Actual netback prices would be adjusted for quality differences. Freight costs change frequently and affect the relative netback prices.

For the U.S. East Coast refiners, the best option on domestic crude deliveries is Bakken. Bakken producers were limited by available pipeline capacity to move their crude production to the Midcontinent or U.S. Gulf Coast refineries. Rail was the only viable option. Rail deliveries do offer many options on destination points. The map on page VIII-2 of the *Logistics* section, shows rail delivery costs from the Bakken producing area to various refining centers. Rail costs for Bakken crude are lowest to the Anacortes area in Washington ($9.75 per barrel). Deliveries to the U.S. East Coast are approximately $16.00 per barrel. The rail loading points for Bakken are in the producing areas, and the pricing point for Bakken crude is Clearbrook, Minnesota. Gathering and pipeline fees from the Bakken producing area to Clearbrook is $2.90 per barrel. Rail shipments do not incur the transportation costs to Clearbrook; therefore, for pipeline shipments, the producer would receive on average the Clearbrook price less $2.90 per barrel. The typical rail netback calculation for the producer, assuming Brent and Eagle Ford are equal quality, would be as follows:

Producer Netback for Bakken Sales to the U.S. East Coast = Brent Plus $2.29 Per Barrel Freight
Less $15.50 Per Barrel Rail Cost (Brent Less $13.21)

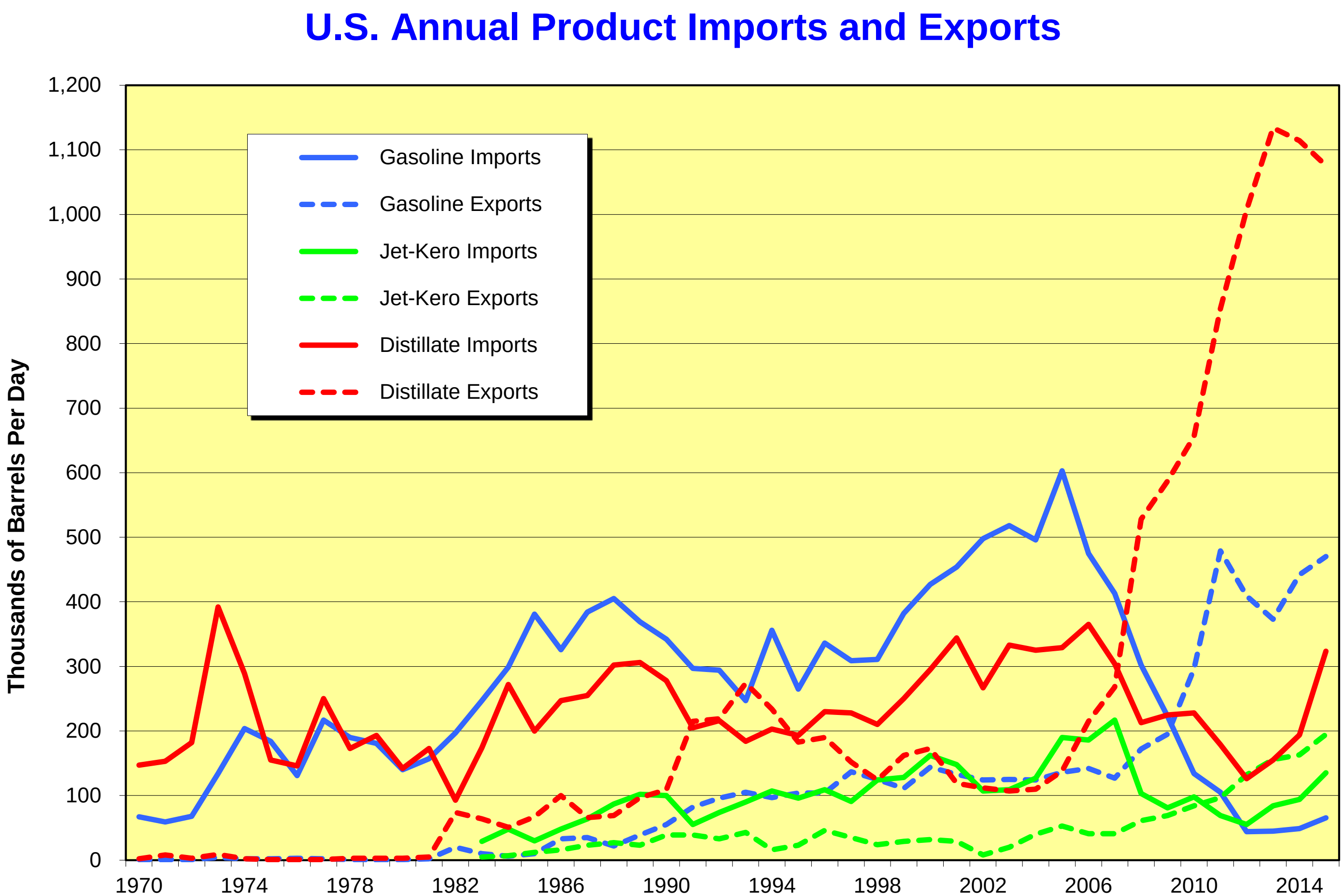
Bakken rail cost to the U.S. Gulf Coast is $12.50 per barrel. The producer netback would be LLS less $12.50 per barrel. If pipeline space is available to the U.S. Gulf Coast, the pipeline tariff would be $11.15 per barrel.

XIII. Atlantic Basin

The capability of the U.S. domestic refiners to export gasoline, jet, and distillates is primarily affected by the product demand patterns in the Atlantic Basin. Up until 2008, the U.S. had imported almost 1.4 million B/D of this major product group.

The forerunner of oil shale developments was natural gas exploration using new drilling techniques. With rapidly increasing volumes of natural gas available, natural gas prices declined. A major operating cost component of refineries is natural gas. It is used directly as fuel, generates electricity and steam, and is used to produce hydrogen (used for removal of sulfur, and in many processing units, for catalytic reactions). With low cost natural gas, U.S. refiners had an operating cost advantage over non-U.S. refiners. The refiners began to increase crude throughput rates, reducing imports of products and increasing exports.

Beginning in 2010, WTI was beginning to be priced at a discount to LLS and Brent due to the increasing volumes and logistics constraints. With lower crude costs than U.S. Gulf Coast refiners, the Midcontinent refiners increased crude throughputs, backing out products being shipped into the Midcontinent from the U.S. Gulf Coast. The additional product from the U.S. Gulf Coast was then exported. As U.S. Gulf Coast crude prices began to shift from a premium to Brent, then to parity, and finally at a discount, the U.S. Gulf Coast refiners had the economic incentive to export products to further destinations. In importing areas such as Latin America, Africa, and Europe, the U.S. refiners were able to displace imports from other world regional refining centers. The increasing exports, coupled with decreasing imports, are graphically shown on the following pages.



NOTE: Data for 2015 is based on monthly imports and exports through April.

SOURCE: Energy Information Administration.

At the same time as availability of products from the U.S. increased, countries in the Atlantic Basin had increasing petroleum requirements that could not be met internally. The import/export balances for Latin America, Africa, and Europe are shown in Appendix G, *Atlantic Basin*.

XIV. Quality Differentials

Every crude oil is unique and exhibits different properties. Some crude oils have naturally occurring higher percentages of premium products such as jet and diesel, others have low percentages. Some crudes have very low levels of sulfur compounds and others have high levels. Refineries are generally configured to process one general type of crude – light sweet, medium sour, heavy sour, etc., although the individual refining configurations have evolved over the years based on the long-term outlook relative to pricing and availability of each type. Refiners are constantly evaluating economics relating to crude availability and pricing, versus processing unit constraints. Some changes can be made in a relatively short period of time to relieve process bottlenecks, while other projects may take more planning, engineering, and implementation. The recent spike in refinery projects is evidence of the economic driving forces of the new crude supplies.

The definition of marker crude is a crude oil that serves as a benchmark or reference price for other crudes to be measured against. Crude prices are generally quoted based on a free on board (FOB) price at the production point. There are world marker crudes and regional marker crudes. The predominate world crude marker price is Brent. Most of the contracts for purchases of world crudes are based on a Brent price. WTI has historically been the marker price in the U.S. As shown in Section XII, *Pricing,* prior to 2011, WTI had traded at a premium to Brent, driven by logistics. The U.S. was a large importer of light sweet crudes, and WTI was priced at an equivalent Brent delivered price to the U.S. Until 2011, LLS price was equal to a Brent price plus $2.00 to $3.00 per barrel, which was equivalent to freight from the United Kingdom (UK) to the U.S. Gulf Coast.

Brent and WTI are similar crudes, but have slightly different properties. A comparison of the natural qualities of four similar light sweet crudes is shown below.

Light Crude Quality Comparison

			Distillation Range, °F					
Crude	**Gravity (°API)**	**Sulfur (Wt.%)**	**Light Ends (IBP-210)**	**Naphtha (210-300)**	**Kerosene (300-450)**	**Diesel (450-680)**	**Gas Oil (680-1020)**	**Residual (1020-FBP)**
Brent	37.6	0.40	14.3%	10.9%	14.8%	23.5%	26.1%	10.2%
Bonny Light	35.3	0.15	12.5%	13.3%	15.4%	30.9%	23.2%	4.7%
LLS	36.5	0.41	11.4%	8.9%	17.7%	28.2%	25.2%	8.6%
WTI	39.7	0.40	15.8%	13.8%	16.6%	20.1%	23.9%	9.9%

Because of the natural differences in properties of each crude, a refiner must evaluate each crude separately for his specific refinery to determine the most economical mix of crude oil that produces the maximum net margin, as limited by the refinery processing constraints. Market areas in the world require different mixtures of refinery products – LPG, gasoline, jet, diesel, residual products, specialty products, etc. The market differences result in different refining values for each crude. For example, Brent crude will have a different refining value for a U.S. Gulf Coast, U.S. East Coast, Europe, or Asian refinery.

When comparing crude prices delivered to the refinery and calculating refining values, one obvious difference is the logistics price to deliver the crude from the producing area to the refinery. The second major factor is the difference in refining value.

Refiners build sophisticated linear programs (LPs) to evaluate crudes and to plan operations. The LPs provide a tool for crude selection that evaluates each crude versus a universe of crudes with different qualities and different laid-in prices. In a particular major market area, a particular crude will have a specific refining area, as the refined market area is defined and individual refiners are competing for crude that will offer the optimum crude slate to produce the highest net margin.

Stancil has a proprietary LP modelling system that is used for refinery crude purchasing and optimization. The LP system can be tailored to a specific refinery, or can be configured to represent a major refining center. For the Monroe and The CRUDE Coalition assignment, Stancil has built LP models that represent the U.S. Gulf Coast and the U.S. East Coast refining centers.

Stancil prepared a database of world crude prices and world refined product prices. Logistics costs were included for crude oil and product deliveries using posted pipeline tariffs and shipping costs (representative Worldscale rates for specific routes and monthly estimates of percentages of Worldscale for various sizes of ships). Cases can be run using daily, monthly, or annual prices. For presentation purposes, Stancil has run annual price cases. These cases were then analyzed to determine the relative value of major world crude prices at the different major refining centers.

Maps showing the major refining centers, routes for crude and product deliveries, and representative January through February 2015 delivery costs are included in Section VIII and Appendix D, *Logistics.*

Using 2014 average costs (and January through February 2015), Stancil has calculated the relative refining value of marker crudes on the U.S. Gulf Coast and U.S. East Coast. The differences in refining value for various grades are summarized in the table below.

Refining Value Versus Brent

(Dollars Per Barrel)

	U.S. Gulf Coast		*U.S. East Coast*	
Crude	***2014 Avg Prices***	***Jan-Feb 2015 Avg Prices***	***2014 Avg Prices***	***Jan-Feb 2015 Avg Prices***
West Texas Intermediate	0.33	0.25	0.83	0.23
Light Louisiana Sweet	2.00	1.11	--	--
Bakken	0.64	0.61	0.92	0.61
Eagle Ford Light	0.72	1.07	1.62	1.01
Eagle Ford Heavy	1.88	1.05	1.79	1.86
Bonny	2.95	1.94	3.76	2.29
Arab Light	(2.38)	(2.04)	(2.76)	(3.30)
Maya	(14.95)	(9.73)	(16.46)	(12.92)
Western Canadian Select	(10.10)	(6.83)	(12.35)	(10.78)