THE ROLE OF WTI AS A CRUDE OIL BENCHMARK

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I. INTRODUCTION

Since 2005 the oil markets have shown more short term volatility and overall price range fluctuation than just about any time in the history of the oil trade. In addition to absolute price volatility, there has also been extreme volatility in the relationships among the crudes, including West Texas Intermediate (WTI) and other benchmarks on the Gulf Coast and around the world. As a result of the intensifying industry concern regarding this market volatility, Purvin & Gertz, Inc was engaged to prepare a report that describes the Midcontinent and U.S. Gulf Coast crude oil market physical infrastructure and flow processes and corresponding commercial taxonomy.

This study will cover the history and evolution of the infrastructure and flow processes from 1970 onward, with concentration on the periods of most relevance for WTI. It will include as a major focus the breakdown of crude flows by source such as U.S. Gulf, Midcontinent U.S. and Canada; the physical interaction of different crude flows; and the resulting economic relationships, including pricing conventions and benchmark pricing, from the interactions of the different crude flows. This study will explain the economic basis for the evolution and development of crude pricing conventions, especially the role of WTI as a crude oil pricing benchmark.

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II. SUMMARY AND CONCLUSIONS

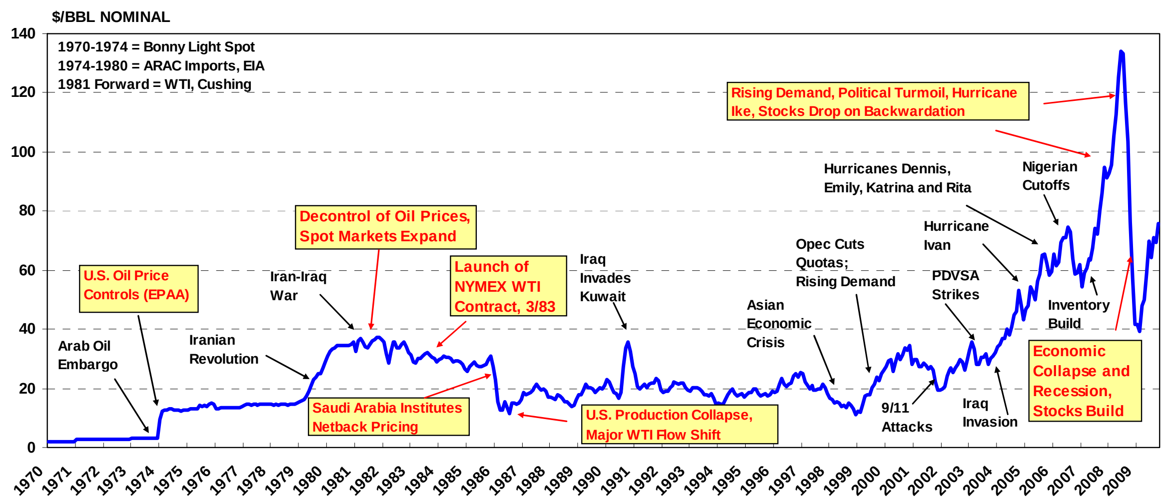
THE ROLE OF WTI AS A CRUDE OIL BENCHMARK

1. **A primary purpose of this study was to develop a fundamental understanding of the evolution of the oil markets, with a focus on West Texas Intermediate (WTI), and how this crude oil stream came to such prominence as a benchmark in global trading.** Another important objective of this analysis was to develop an understanding of how the oil market fundamentals have affected the relationship of WTI prices with other regional and global benchmarks. It is these relationships that have been a main focus of recent concern for participants in this benchmark commodity, with respect to its representation of the oil markets in general and its suitability of use for its intended purpose as a commodity benchmark. **These relationships have been more volatile in recent years than during any other time since the creation of the NYMEX crude oil contract. This volatility has also been characteristic of the absolute levels of prices on a global basis. The relationships among the other internationally recognized benchmarks also have seen similar volatility.**

2. **Some of these observer concerns may be founded on a misunderstanding of the markets and their physical, technical and financial operations. The market dynamics that have lead to these concerns are, indeed, complex.** They can result in confusion and even mistrust, much of which can be resolved by having a clear commercial perspective of how these markets operate, how they have evolved, and how they will likely continue to evolve. Otherwise, these commodities may be applied inappropriately and/or without consideration of the basis risk characteristics of any of these benchmarks.

3. **In the time since 1970, there have been quite a number of significant events that have caused short term volatility in the markets. Figure II-1 summarizes the markets from 1970 to the current time in late 2009, showing many of the most significant events.** Some of these events, however, are more important than others, actually changing the longer term course of trade dynamics and/or pricing relationships among grades, including WTI, which has been subject to its own share of disruptions. Some of the most prominent events are highlighted in red text on the figure.

FIGURE II - 1
CRUDE OIL PRICE HISTORY, 1970 - CURRENT



4. **Through the early 1970s oil prices were very low and relatively stable as compared to what was to follow from that point, though nationalization of oil resources had already begun to destabilize the markets during that time.** The most prominent of the events to follow through the late 1970s to the mid 1980s were the Arab oil embargo in 1973, resulting in U.S. price controls through the Emergency Petroleum and Allocation Act (EPAA), and the Iranian revolution that began in late 1978. Both of these milestone events resulted in major changes in the price of crude oil. Average prices for oil rose from near $3.00/Bbl to over $13.00/Bbl within a few months of the Arab Oil Embargo. Since then, the markets have not seen prices as low as those during the early 1970s and prior. By the early 1980s prices had increased to the mid $30s/Bbl, over 10 times what they were early in the prior decade, and they remained in this range until 2005.

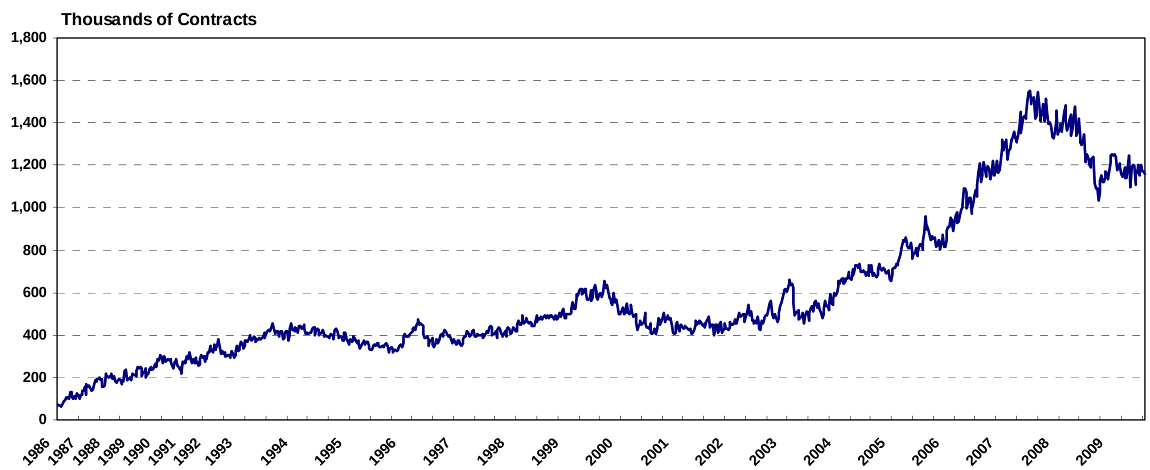
5. **The U.S. Government's decontrol of oil prices, beginning in January 1981, would, once again, change the landscape of the oil markets in the U.S. and globally, particularly influencing the volumes and transparency of the spot markets, including trade in West Texas Intermediate (WTI) and other U.S. grades.** This fostered an immediate convergence of WTI spot trade and prices into a single commodity that prior to the decontrol was split into various price categories under the control mechanics. The transition from "controlled" to "decontrolled" oil prices resulted in a major change in the trade dynamics that ultimately facilitated and grew the commoditization of WTI. This created the circumstances necessary for a successful development and launch of a "paper contract" in domestic light sweet crude at Cushing Oklahoma, typically designated as WTI, by the New York Mercantile Exchange (NYMEX) in March 1983.

6. **The Cushing storage hub became the delivery point of choice for this new "paper" contract as a result of an already well established and liquid "physical" or "wet barrel" trade in this grade.** The Cushing location not only represented a gathering hub for the local crudes for refiners in Oklahoma, Kansas

and Missouri, but it also was the central gathering point for terminus of pipelines originating in Texas and Oklahoma with onward distribution to the main refining centers in the central and eastern Midwest markets in Indiana, Illinois and Ohio. This location was to continue its logistical and infrastructural relevance to this day with continued growth in physical storage and trade liquidity represented by the NYMEX contract. It was to become the world's most liquid forum for crude oil trading, as well as the world's largest-volume futures contract trading on a physical commodity.

7. **Because of its relative liquidity and price transparency, the contract continues to be used as a principal international pricing benchmark.** Figure II-2 shows the trends in the futures contract open interest from the mid 1980s to the current time in late 2009 to make that point. The total open interest has gone from less than 100,000 contracts in 1986 to peaks over the last year of almost 1.6 million contracts, reflecting extensive participation from commodity users around the world. If options trading were included in these figures the open interest peak would approach 8 million contracts. Further detail on the evolution of this trade and its pricing implications are presented below.

FIGURE II - 2
NYMEX CRUDE OIL FUTURES TOTAL OPEN INTEREST

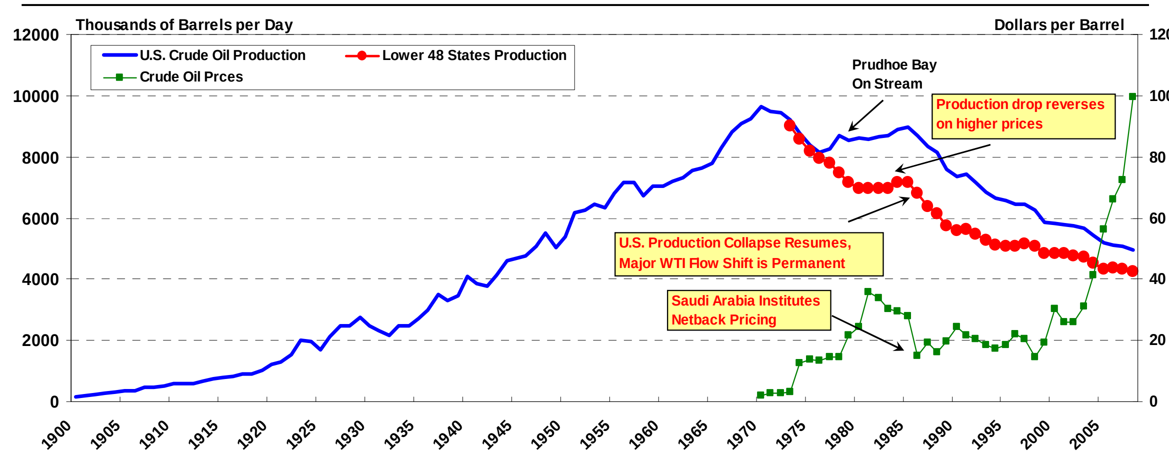


8. **In late 1985, and particularly through 1986, the markets were extremely volatile, with prices collapsing.** The event was brought on by internal OPEC conflicts as the higher prices had driven down demand and raised non-OPEC production to the point of OPEC balancing requirements declining to a total of only 13.5 million barrels per day. Under these circumstances, Saudi Arabia finally began in mid-1985 to price its crude at spot market levels, largely abandoning its official price basis. In late 1985 all of OPEC had made the decision to officially abandon the “administered price system” in favor of a “market share system.” To further its marketing reach, a very critical decision was made by Saudi Arabia in early 1986 to begin pricing its crude competitively into the various major global markets, with “netback pricing” being adopted to ensure competitive parities with the open market crude prices in the

Western Hemisphere. Netback pricing in essence ensured refiner margins that were competitive with the local crudes. Others followed suit. This created a very competitive market and prices responded.

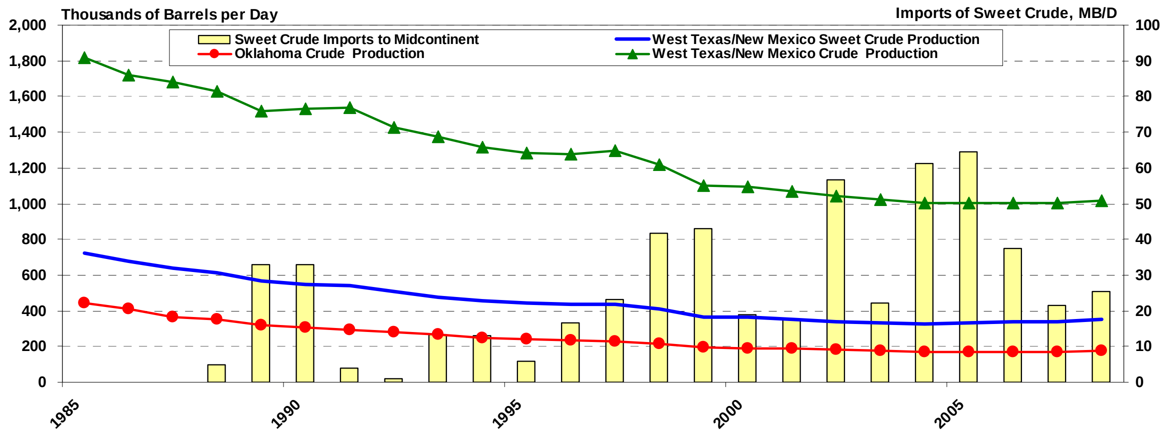
9. **WTI prices peaked at over $30/Bbl in late 1985, but dropped to near $10/Bbl at the lows in mid- 1986, the lowest since the early 1970s. This price drop, in the order of 50% at the time, had a dramatic impact on oil production in the U.S., as noted in Figure II-3.** The low prices resulted in shut-ins of a considerable number of low producing wells (e.g., stripper production classified as such with production of 10 barrels per day or less). Many of these wells were permanently capped, never to be produced again. Data show a loss of nearly 25,000 producing wells in 1986 and by 1990 that drop had approached 45,000 wells versus the peak number in 1985, out of a total of about 625,000 wells nationwide. Production lost during that period was well over 1.5 million barrels per day.

FIGURE II -3
UNITED STATES CRUDE OIL PRODUCTION HISTORY



10. **Of particular importance to the pricing of the WTI market at this time was the collapse of local crude oil supplies to the local Oklahoma regional refiners, as well as the reductions in production from Texas that supplied the Cushing hub and U.S. Gulf Coast refineries.** These events resulted in a drastic change in the trade dynamics in the area and the resultant price relationships among the regional crudes. Figure II-4 shows the results of these price induced changes. As the supplies of crude in the areas feeding the Midcontinent declined, it became necessary to fill the supply gap with offshore imports, changing the price infrastructure.

FIGURE II -4
CRUCIAL CRUDE OIL PRODUCTION PROFILES and IMPORTS INTO THE MIDCONTINENT

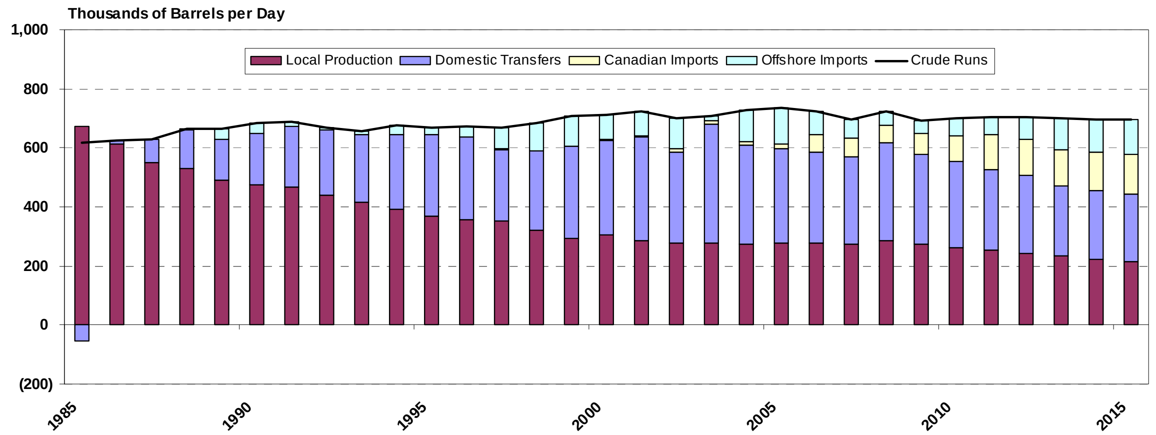


11. **The trade shift resulting from falling Midcontinent production created the physical trade link between the Gulf Coast market, with its supply of imported crudes, and the Cushing, Oklahoma hub through pipeline physical changes. This created the basis for the commoditization of WTI prices at Cushing.** It also set up the eventual need for alternate delivery of foreign crudes into the NYMEX contract.

12. **An important historical fact influencing the WTI trade patterns and price relationships was the excess of supply of crude oil in the Cushing supply region relative to the local refinery demand.** Some of the volume of total crude in the area actually left the area into the Texas Panhandle and Midwest markets, headed for the refining centers there, along with the pass-through of substantial volumes of the West Texas supply with Cushing being the collection and distribution hub for these volumes. This historical balance situation can be seen in the bars for 1985 in Figure II-5.

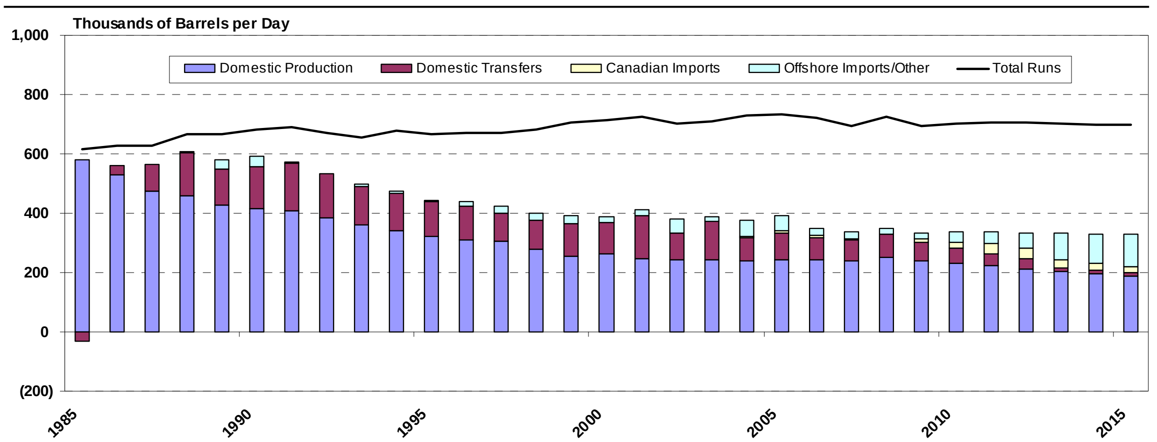
13. **It can also be clearly seen that the trade dynamics for the region designated as the "Midcontinent" (regional refining center in and around the Cushing hub) changed rather dramatically in 1986.** From that point forward the area was destined for a continuing evolution of trade related to the new supply and demand balance in the area resulting from the oil price collapse of 1986. As local production declined, more domestic transfers from West Texas were needed to close the balance. Eventually, that supply would also diminish and offshore imports became required to balance the market. Those total imported supplies (all grades) have continued and they are expected to rise further in the future, supplemented with Canadian supplies which are building rapidly.

FIGURE II - 5
MIDCONTINENT CRUDE SUPPLY



14. **An important dynamic of the WTI trade is that from the early 1990s, the actual demand for sweet crude in that local area began to diminish substantially as refiners upgraded their plants to process more sour and especially heavier crudes.** Beyond the late 1980s and very early 1990s, there was very little sweet offshore crude delivered to the area. This changed from that point forward with seasonally related requirements for these supplies to meet the local demand. And, also important for the outlook, is that imports and/or other supply will be needed in the future to meet those requirements. Canadian sweet synthetics, however, will likely be a part of this supply, potentially in larger quantities than shown and new supplies, though still uncertain, from the Bakken shale in the North Dakota area may help to balance those needs.

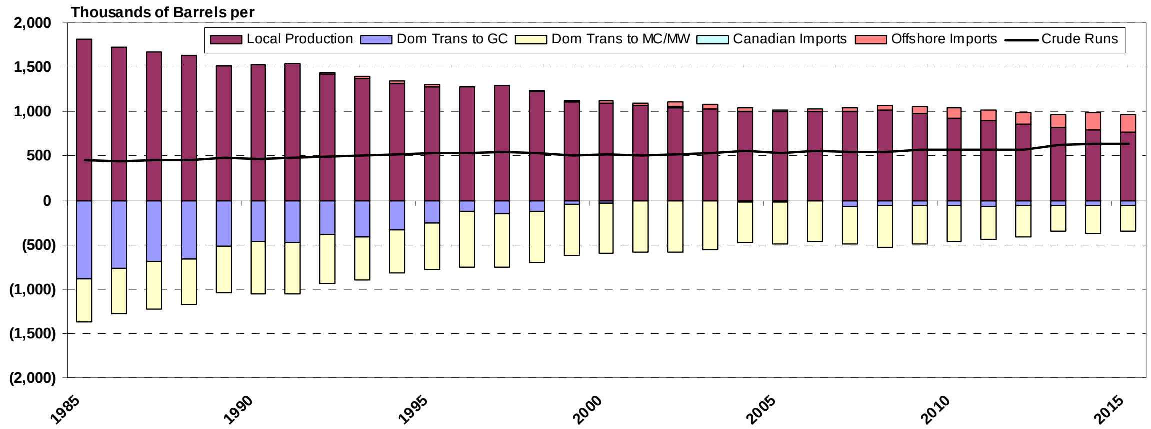
FIGURE II - 6
MIDCONTINENT SWEET CRUDE RUNS



15. **Other dynamics related to the West Texas supply and trade are also important in the understanding of how supply, demand and trade fundamentals affect pricing relationships** Figure II-7 shows the crude oil balance for the West Texas area from 1985 and through the rapid transition period following the price collapse of 1986. A key dynamic is the loss of local production in West Texas with the price

decline, combined with the pull of additional amounts of that supply to the Midcontinent requirements, rapidly depleting the amount of incremental supply available for delivery to the USGC. By the late 1990s the supply to the USGC very nearly disappeared resulting in the pipelines being shut down, reversed or being put into other services. This permanently disconnected the Midland gathering area and its prices from the USGC, changing long established pricing relationships.

FIGURE II - 7
WEST TEXAS CRUDE BALANCE HISTORY AND FORECAST



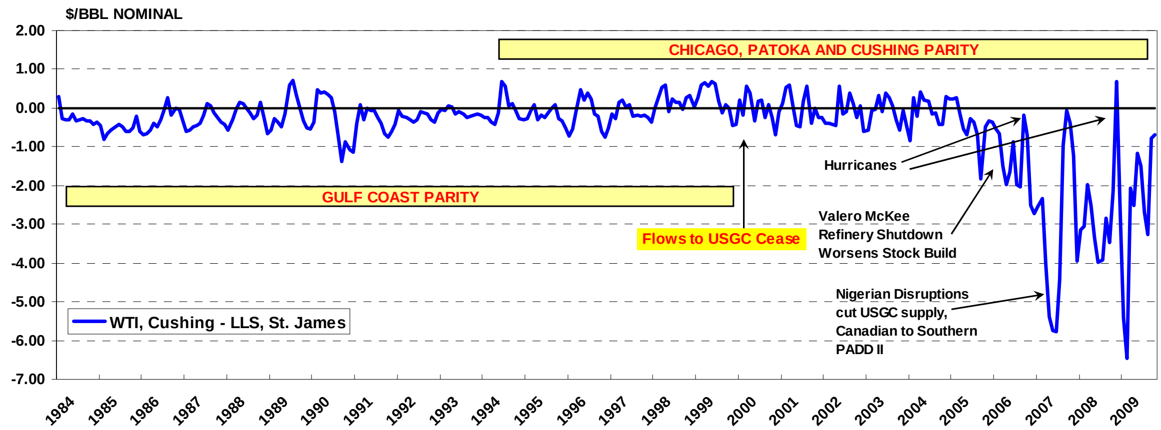
EVOLUTION OF WTI PRICING RELATIONSHIPS

1. **The key to understanding WTI prices and price relationships is calculating the arbitrage relationships by incorporating the flow dynamics and transportation costs to compare the prices at various market locations.** This allows defining the actual physical interface that is setting the market price for the crude being analyzed versus its competition. If there is no competitive "parity" (parity is a condition in which refiners are economically indifferent because the prices of the comparative crudes generate the same margin) for an extra-regional delivery at a market location, it implies a disincentive to move it into that location. Another part of the analysis is being able to identify critical short-term market factors that also may be influencing one or the other of the crudes being compared (e.g., hurricane influence on USGC crudes or the impact of rising stocks in the Midcontinent on prices in that area).

2. **Figure II-8 shows a competitive analysis reflecting relative pricing of the sweet crudes on the USGC versus WTI at Cushing. This chart depicts the transitional dynamics that have occurred as the supply, demand and trade balances have evolved through the fundamental changes since the 1986 price collapse.** Adequate supplies of the West Texas crudes to supply both the Midcontinent and USGC refining regions resulted in a discount on WTI versus the USGC sweet crudes, as characterized by Light Louisiana Sweet (LLS). This was a persistent relationship for years up through 1985 and then it became more volatile and seasonal reflecting the actual trade flow related to the seasonal supply/demand character of the Midcontinent versus the USGC. The relative level of discount or

premium for WTI versus the USGC simply reflects the shifting "parity point" where these crudes physically interface with each other.

FIGURE II - 8
WTI, CUSHING minus LLS, ST. JAMES

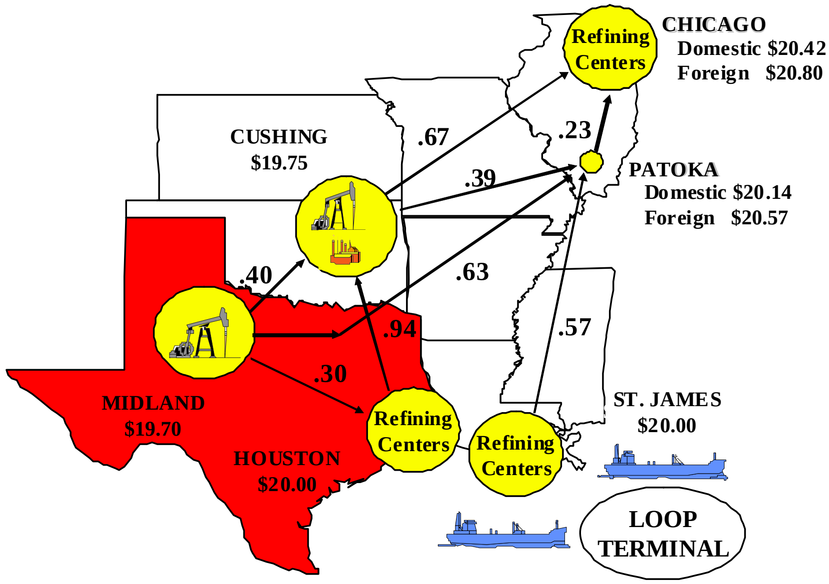


3. **Figure II-9 illustrates the supply costs that drive the relationships in Figure II-8. This scenario is illustrative of the supply costs in the early years before the price collapse in 1986 and the periodic seasonal conditions that existed until the point of cessation of flows to the USGC.** The chart is designated as the **"Gulf Coast Parity"** chart, representing the conditions and prices related to those periods where the USGC competitive interface was the starting basis of the pricing of WTI.

4. **At the USGC the regional sweet crude prices shown in Figure II-9 (assuming similar quality) reflect the interface of offshore supplies coming into the region, setting the prices in Louisiana and Houston area destinations.** An average price of $20/Bbl is the starting scenario assumption, and this was a reasonable average through the late 1980s to 2000. With WTI flowing to the USGC refineries, its price is set at Midland by the netback from USGC delivery. The historical average of actual prices through these periods of Gulf Coast parity indicates that Cushing prices averaged about $0.05/Bbl above Midland, despite the full tariff for that delivery of $0.40/Bbl, indicating more than adequate supply at Cushing and recovery of approximate breakeven delivery costs for equity deliveries. Spot crude traders would not have bought crude at Midland for Cushing delivery if the full tariff had to be paid. Their deliveries would be to the USGC.

FIGURE II- 9

GULF COAST PARITY RELATIONSHIPS



Illustrative Purposes—Prices and Tariffs reflect early 2000s, excluding loss/insurance and credit float. Through tariffs not reflected.

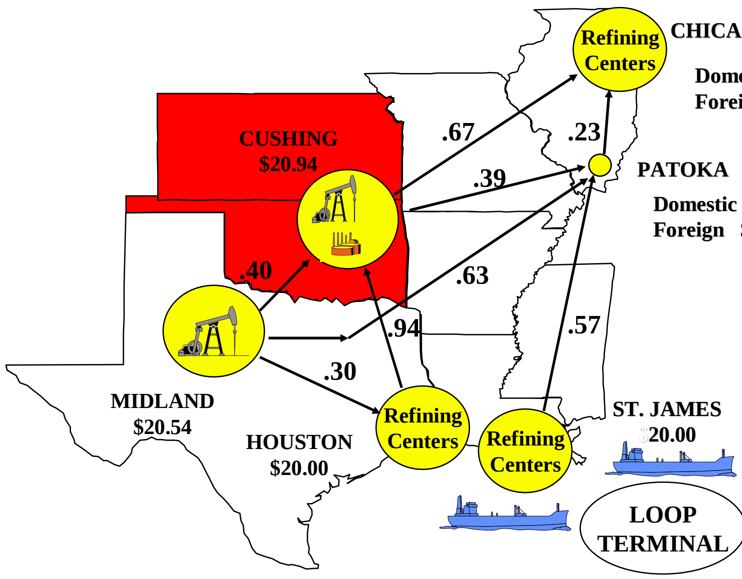
5. **As shown in Figure II-9, the WTI prices at the other main refining centers are based on the Cushing deliveries plus the respective pipeline costs to those centers.** Capline deliveries of LLS or other sweet crudes to those centers, also based on tariffs, show higher costs than the WTI and refiners would be inclined to meet their incremental requirements of refinery feed with the lower cost oil represented by WTI. **Also, note that under these conditions the average price of WTI then is actually $0.25 below the price of LLS and obviously this would preclude spot imports into Cushing from the USGC since the economics do not support those deliveries.** Beyond 1986, the relationship actually oscillates seasonally coincident with the demand for refinery feed in the Midcontinent/Midwest region.

6. **There are several other seasonal parity situations that set prices of WTI, consistent with the seasonal demand fundamentals, directions of flow and the respective pipeline tariffs for the deliveries.** These scenarios are referred to as **"Chicago Parity," "Patoka Parity" and "Cushing Parity."** All of these scenarios are detailed in the body of this report, but the important "Cushing Parity" scenario is illustrated in Figure II-10. This scenario reflects the maximum price for WTI versus the USGC consistent with the Seaway tariff for shipping USGC imports into Cushing. **At that point the WTI would be almost $1.00/Bbl above the LLS, an almost $1.25/Bbl total change in the WTI price from USGC parity conditions, with no change in the base price at the USGC. There is an economic disincentive to deliver incremental supplies into Cushing unless the fundamentals support the full tariff.** Of course, there can still be deliveries during these periods based on settling hedged deals or contractual or equity shipper status. However, the actual

flow trends are certainly reflective of these economics. It is notable that, whichever of the parity conditions is operational, WTI-Cushing is responsive to and reflective of overall market conditions; but its value relative to other crude streams at other locations does change.

FIGURE II- 10

CUSHING PARITY RELATIONSHIPS

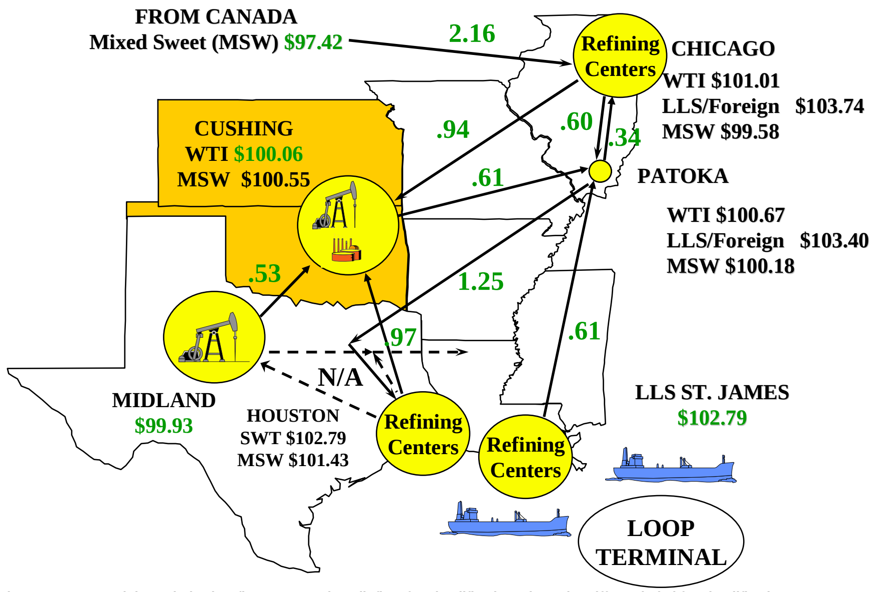


Illustrative Purposes—Prices and Tariffs reflect early 2000s, excluding loss/insurance and credit float. Through tariffs not reflected.

7. **Figure II-11 shows the estimated actual parity conditions using the actual 2008 annual average prices, where available, with estimates for those not quoted by the industry price services. Figure II-11 shows the very unusual price relationships that existed in 2008. Similar conditions existed on average for 2007 and 2009. WTI prices were discounted severely relative to the USGC during this period.** For 2008, the WTI discount to LLS averaged $2.73/Bbl, with the entire inland market seeing much lower prices for the WTI versus USGC sourced sweet domestic or foreign supplies. There were multiple issues related to these unusual trends. The late 2008 discounts for WTI in large part reflected a "contango" related steady inventory build at Cushing leading to all time record levels of excess stocks in early 2009. At that particular point the discount on WTI was in the range of $6.50/Bbl. But, market disparities were also caused in some instances by premiums on the LLS supply, in addition to the excess stocks at Cushing, due to hurricanes and shortages of sweet imports caused by Nigerian political disruptions. However, Canadian crude import increases into the Midwest/Midcontinent markets also added to the supply pressures. Sweet crude flow arbitrage economics from the USGC to Cushing for incremental trade were of course closed through these periods.

FIGURE II- 11

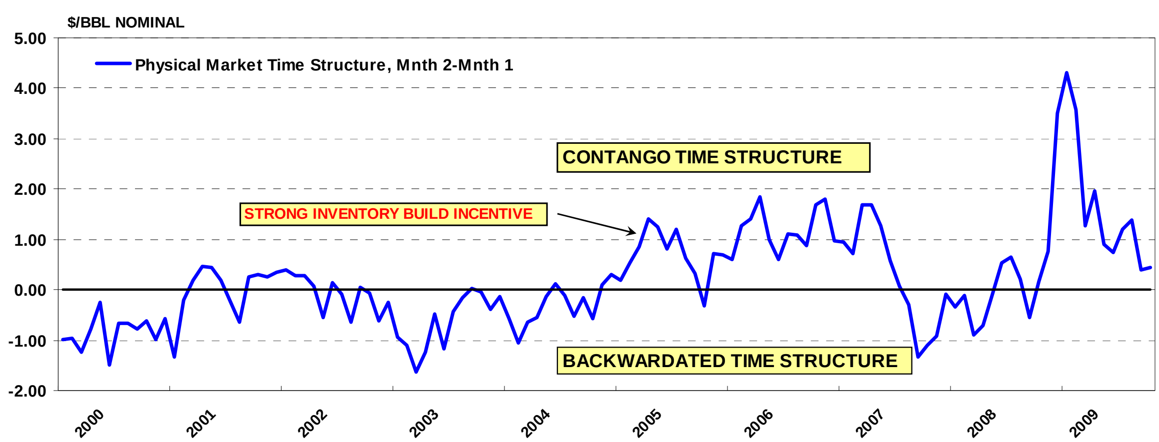
2008 ACTUAL PRICE AND PARITY RELATIONSHIPS



Illustrative purposes—Freight excludes loss/insurance and credit float for simplification. Through tariffs excluded for simplification.

8. **Figure II-12 shows the very extended periods of market "contango" through 2005 to the present time, except for a period of "backwardation" late in 2007 and early 2008.** Contango time structure allows a buyer of any crude to take physical delivery for storage with full price protection by selling forward NYMEX contracts that will be high enough to cover the actual cost of storage, sometimes even high enough to store in tankers. But, these conditions were especially notable with respect to the storage at Cushing, Oklahoma.

FIGURE II - 12
MARKET TIME STRUCTURE HISTORY, WTI (Mnth 2) - WTI (Mnth 1)



9. **Over the years, the robust trade at Cushing, along with these periods of contango, has induced market participants to expand storage at the Cushing terminals quite significantly.** Figure II-13 shows the historical growth of crude storage capacity at Cushing. Storage capacity has more than doubled from the late 1990s to the current time. This additional capacity facilitates expanded NYMEX activity and liquidity as a result of the hedging capability. Figure II-14 shows the expansion of trade activity over these years, especially as related to the time structure and the interrelated changes in the absolute prices of oil.

FIGURE II-13
CUSHING CRUDE STORAGE CAPACITY
(Million Barrels)

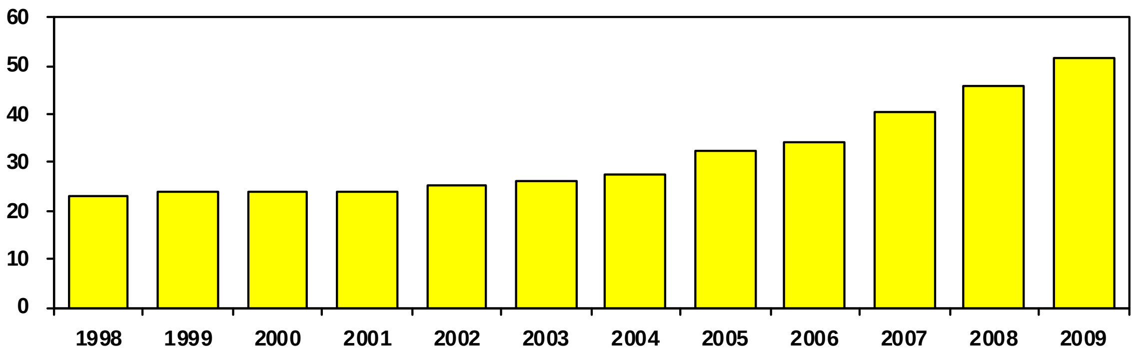
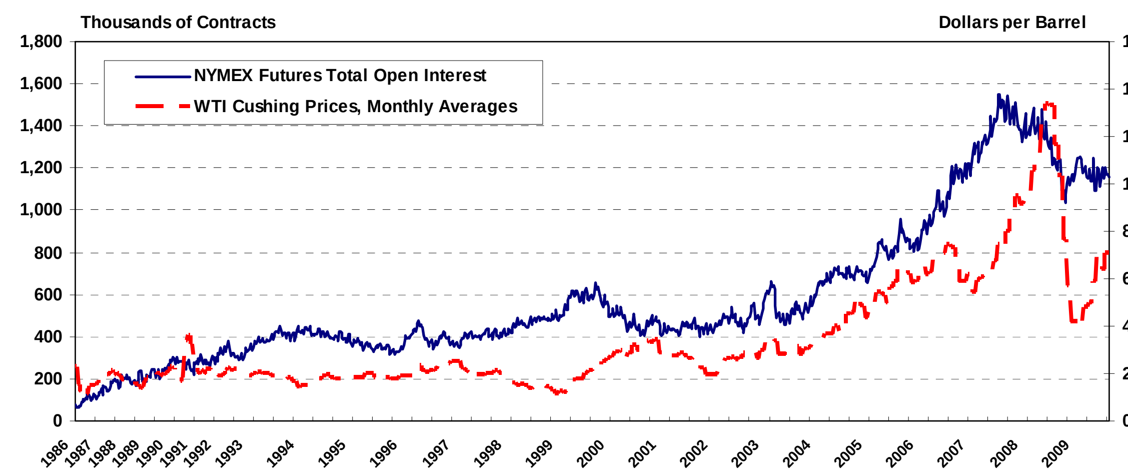


FIGURE II-14
NYMEX CRUDE OIL FUTURES TOTAL OPEN INTEREST vs WTI PRICE TRENDS



10. **The table below is a consolidated pipeline infrastructure chronological summary that gives a good overview of the continuous changes occurring in these markets, especially with regard to the recent expansion activities in pipeline infrastructure related to the Canadian supply penetration into the Midwest and Midcontinent and even the USGC.** A complete analysis of the

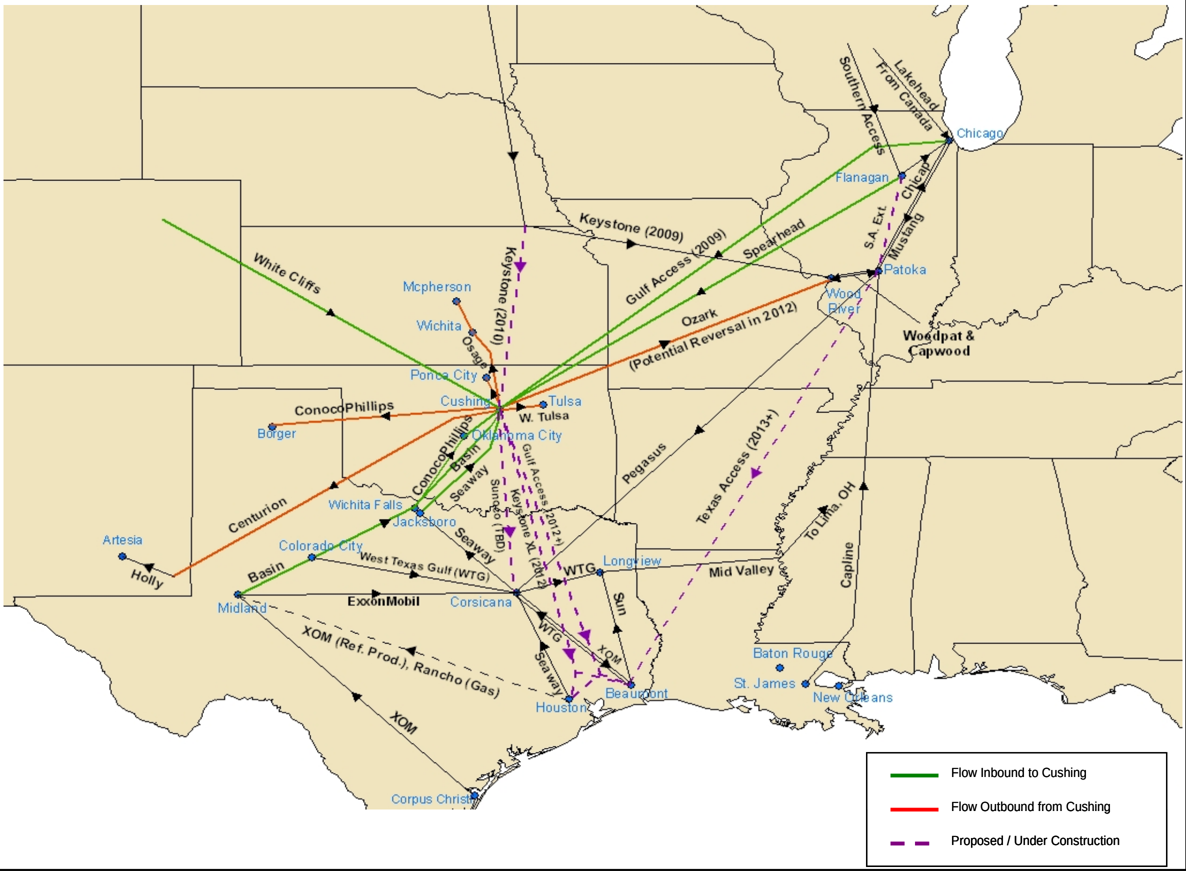
USGC/Midcontinent Infrastructure is presented in Section V of this report. These details review the historical evolution of trends and the outlook for systems storage, pipelines and refinery interconnectivity.

TIMELINE OF PIPELINE SYSTEM CHANGES

Seaway Pipeline	Flow from Freeport to Cushing	**1984** Changed to gas service	**1996** Changed to crude service as part of the Seaway JV; Flow from Freeport to Cushing
ARCO line	Flow from Wichita Falls to Houston	**1988** Reversed, Houston to Cushing via Wichita Falls	**1996** Became part of the Seaway system
Cushing-to-Chicago/ Spearhead Pipeline	Flow from Cushing to Chicago	**2005** Reversed, renamed Spearhead; Flow from Chicago/Flanagan to Cushing	
WTG/Sun	Flow from Corsicana to Beaumont	**1995** Reversed, flow from Beaumont to Corsicana	
BP No. 1/ Gulf Access	Flow from Cushing to Chicago/Whiting, IN	**2009** Reversed, flow from Chicago to Cushing	
Pegasus Pipeline	Flow from Corsicana to Patoka, IL	**2006** Reversed, flow from Patoka to Corsicana	
Mobil line	Flow from Corsicana to Beaumont	**1995** Reversed, flow from Beaumont to Corsicana	**2006** Reversed as part of Pegasus reversal; flow from Corsicana to Beaumont
Centurion Pipeline	Flow from West Texas to Cushing	**2009** Reversed, flow from Cushing to West Texas and Artesia,NM	

11. **Figure II-15 presents a regional schematic of these pipeline systems on a current basis with the specifics of the key pipeline expansions underway and/or being proposed.** This figure highlights the continuing evolution of these regional fundamentals that reveal the related pricing dynamics that will evolve along with those fundamental changes. Understanding these patterns and their impacts is important in order not to misrepresent the pricing trends that result. **The continued importance of the Cushing terminal and pipeline hub is noteworthy. Despite all the changes that have occurred in the systems over the years, the hub has not lost its logistical relevance, nor is this expected to change in the future.** Nevertheless, there are also proposals related to the Canadian supply that will by-pass Cushing for direct delivery to the USGC. Most of this supply, however, is predominately heavy sour crudes and not directly competitive with the sweet USGC or Cushing crudes.

FIGURE II-15
2009 MIDCONTINENT/MIDWEST CRUDE OIL LOGISTICS SYSTEM



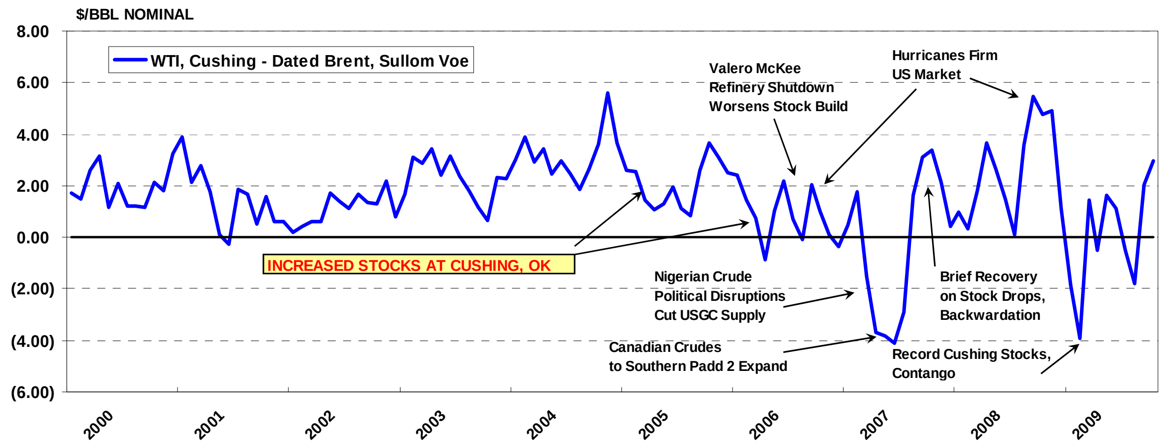
DATED BRENT AS A CRUDE OIL BENCHMARK

1. **A particularly important facet of this study relates to the comparison of the prices of the Dated Brent versus WTI. The Dated Brent/WTI spread is a relationship monitored by many market participants. The volatility of this price relationship over the last few years has become a focus of industry concern. Figure II-16 shows the history of this relationship.** Typical historical spreads have averaged in the $1.50-2.00/Bbl range, but there is considerable volatility in the relationship as a result of the trading dynamics of both of the benchmarks individually.

2. **Dated Brent, in particular, is a volatile benchmark due to its declining volumes and its quality changes over the years. The industry has found it necessary to alter the basis of the Brent benchmark several times over the years in an attempt to stabilize its pricing relationships.** Brent is utilized for the pricing index for many millions of barrels a day of crude from Europe, Africa and other regions. A

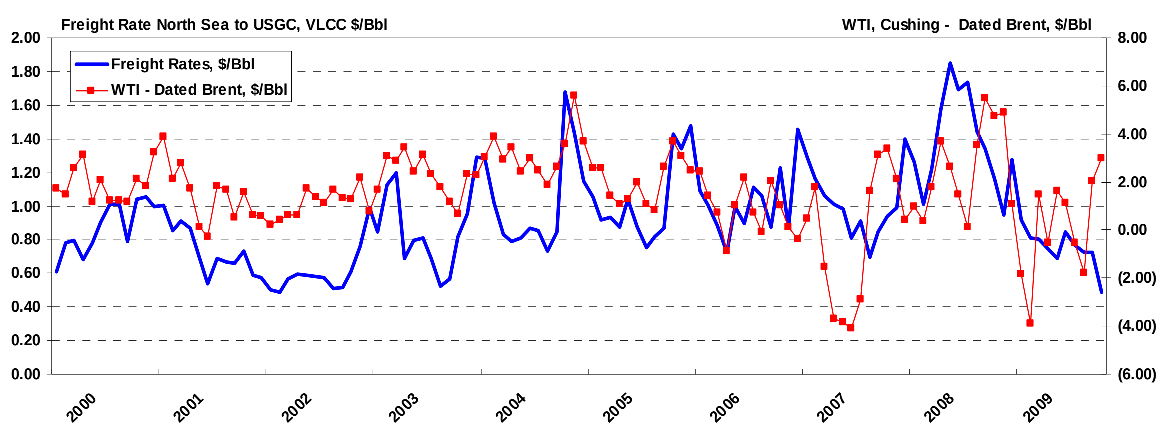
detailed overview of the historical trends and transitions for Brent is presented in Section VI of this report.

FIGURE II-16
WTI, CUSHING minus DATED BRENT, SULLOM VOE



3. **The WTI/Brent spread began to expand over the 2003 to 2005 time frame as a result of several factors, including increases in freight during this period, as shown in Figure II-17.** In fact, the extensive volatility of the relationship through that period and beyond to the most recent periods can at least be partially explained by this freight volatility. Typically, commentary regarding this relationship rarely includes a proper attribution to the freight cost changes that directly impact the netbacks for Brent deliveries into the USGC.

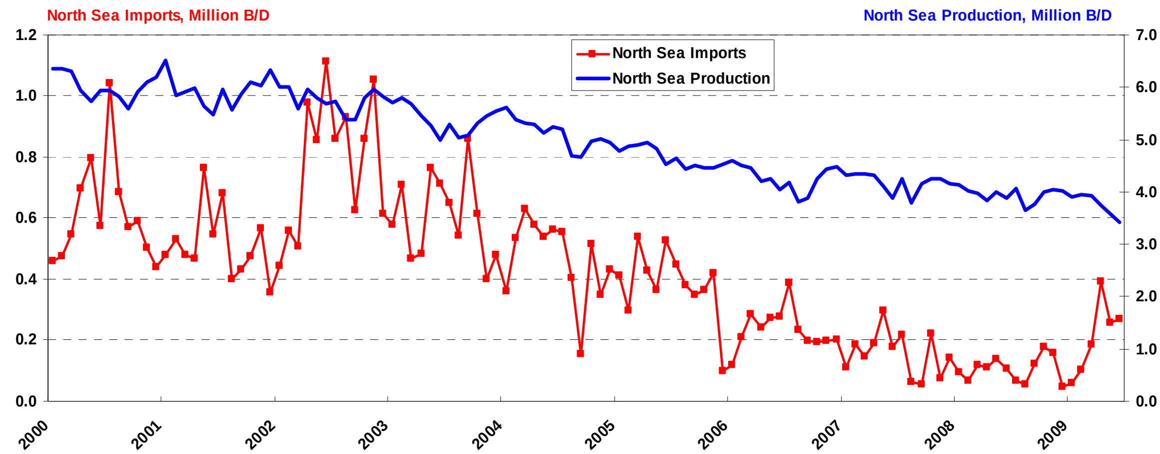
FIGURE II-17
FREIGHT RATES, VLCC NORTH SEA TO USGC versus WTI/BRENT SPREAD, $/Bbl



4. **Another relevant issue with respect to the relationships between Brent and WTI is that Brent has become delinked from the U.S. market entirely for periods of time due to the declining production volumes of Brent and other North Sea crudes. As North Sea production declines, more of the supply is being absorbed locally, and less is available for westbound sales.** Figure II-18 shows the trends in U.S. imports relative to the production of total North Sea crude. Only

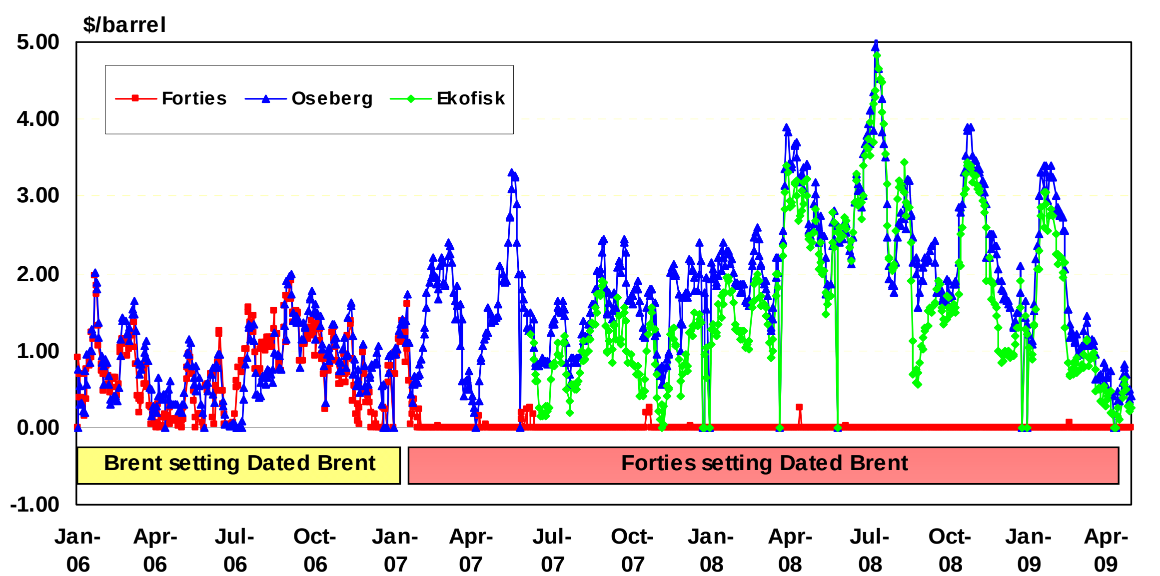
recently has the trend changed temporarily as refining runs in Europe respond to the economic downturn. Spreads have also responded to the collapse of freight rates related to the crude oil price decline.

FIGURE II-18
NORTH SEA PRODUCTION AND U.S. IMPORTS



5. **There have also been significant transitions in the Dated Brent pricing itself over the years. Those changes are related to the decline in the physical production of Brent.** The first changes occurred when the liquidity became so low that the industry adopted a North Sea basket of Brent, Forties and Osberg, with the quote for Dated Brent reflecting the lower of the individual prices. Later, Ekofisk was added to the mix. Then Forties quality changed with the addition of Buzzard to the blend, influencing the final choice of prices. This trend is depicted in Figure II-19.

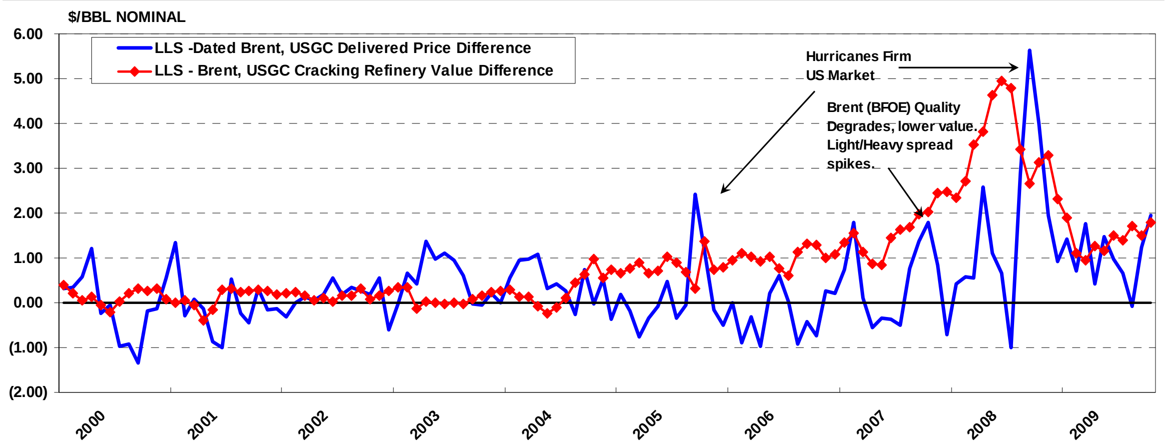
FIGURE II-19
FORTIES, OSEBERG AND EKOFISK PRICE DIFFERENTIALS VERSUS DATED BRENT (PLATTS)



6. **The quality change that has occurred as a result of these transitional issues is also particularly relevant to the price relationships between Brent and the U.S. crudes, including WTI and LLS.** Figure II-20 shows the value and market parity relationship trends for Brent (represented by BFOE quotes) over recent years, reflecting the significant impact of the respective qualities through a period of record setting spreads between light and heavy refined products, which ultimately set the quality differentials among different quality crudes. The figure shows a substantial widening of the competitive differentials between Brent and LLS, largely reflecting the quality issue, but also combined with the volumetric fundamentals discussed earlier.

7. **The Brent and LLS price relationship was relatively stable through the early part of the decade, with Brent and LLS prices at competitive parity on average, with seasonal variations reflecting oscillating market setting locations. But, from mid-decade on, these relationships began to diverge significantly.** The quality differentials began to widen, reflecting the widening price differentials between light products and residual fuel oil. However, the crude price differentials at the USGC did not follow the quality relationships. This reflected the trade dynamics shown earlier in Figure II-18, with prices of Brent being much higher than the USGC value would support, closing off the economic arbitrage for sales of Brent into the USGC. This pricing dynamic also contributed to price volatility and large transitions for the WTI/Brent price relationship, as was depicted in Figure II-17.

FIGURE II-20
LLS - BRENT, USGC Price and Value Differentials

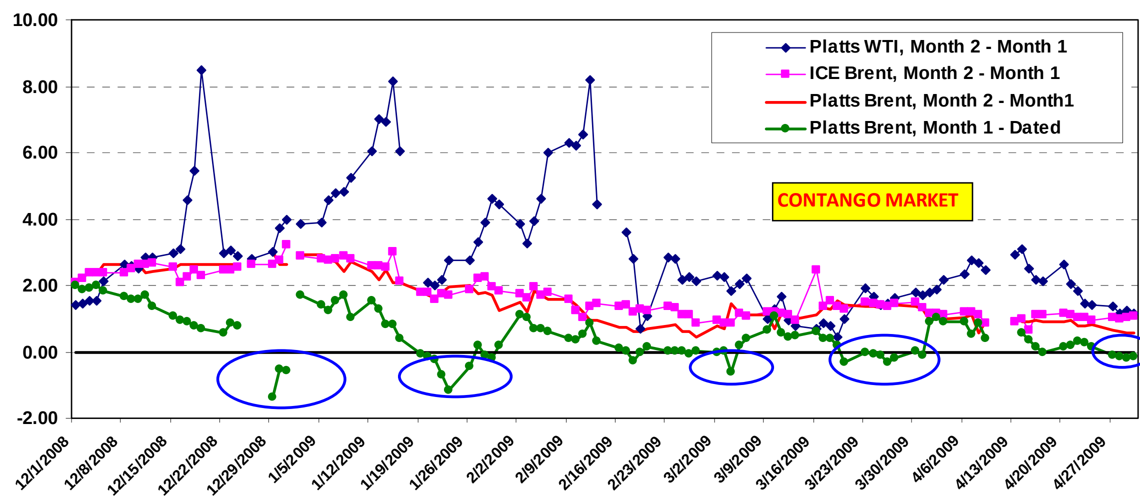


8. **The point of the preceding analysis and discussion is to highlight the volatile history of the Brent benchmark and the influence of this value and fundamental volatility on the relationship between Dated Brent and WTI. The volatility is related to both of the benchmarks and cannot be attributed to only one of them. Both benchmarks have characteristics that are less than perfect with respect to ongoing trade activity and fundamentals. Each can be subjected to valid criticisms.** Brent is frequently criticized for the structure and mechanics of its price determination process especially given its inherent lack of transparency and

illiquidity; it can become unhinged from market fundamentals. Paradoxically, WTI is criticized for reflecting fundamentals, specifically fundamentals in the Midcontinent and Midwest markets when they are temporarily not aligned with parts of the waterborne market

9. **Most recently, in fact, there have been other anomalies of interest related specifically to the Brent pricing activity. As shown in Figure II-21, recent time structure anomalies have shown up in the Brent quotations used for the benchmark formulas.** While, the overall markets were in steep contango, the Dated Brent versus the Month 1 quote showed uncharacteristic backwardation. During these periods, WTI also showed significant trade month volatility. Once again the imperfections in these benchmarks are highlighted, and similar difficulties also exist in the Eastern Hemisphere sour benchmarks Dubai and Oman and the sweet benchmark Tapis. **There are no perfect benchmarks internationally, and users must remain knowledgeable of the actual physical infrastructures in order to properly account for the basis risks that exist with any of these.**

Figure II-21
TIME STRUCTURE, WTI and BRENT, $/BBL



III. THE ROLE OF WTI AS A CRUDE OIL BENCHMARK

INTRODUCTION AND BACKGROUND

A primary purpose of this study was to develop a fundamental understanding of the evolution of the oil markets, with a focus on West Texas Intermediate (WTI), and how this crude oil stream came to such prominence as a benchmark in global trading. Another important objective of this analysis was to develop an understanding of how the oil market fundamentals have affected the relationship of WTI prices with other regional and global benchmarks. It is these relationships that have been a main focus of recent concern for participants in this benchmark commodity, with respect to its representation of the oil markets in general and its suitability of use for its intended purpose as a commodity benchmark. **These relationships have been more volatile in recent years than during any other time since the creation of the NYMEX crude oil contract. This volatility has also been characteristic of the absolute levels of prices on a global basis, and the relationships among the other internationally recognized benchmarks have also seen similar volatility.**

Many of these user concerns are founded on a misunderstanding of the markets and their physical, technical and financial operations. The market dynamics that have lead to these concerns are, indeed, complex. They can result in confusion and even mistrust, much of which can be resolved by having a clear commercial perspective of how these markets have evolved, and how they will likely continue to evolve. **Unlike many other commodities, the dynamics of the oil markets around the world can be subject to permanent physical changes over time, some quite dramatic.** The users of the energy commodity markets must be well educated in the real fundamental factors driving those changes and the resultant influences on relationships among the petroleum benchmarks. Otherwise, these commodities may be applied inappropriately and/or without consideration of the basis risks characteristic of any of these benchmarks.

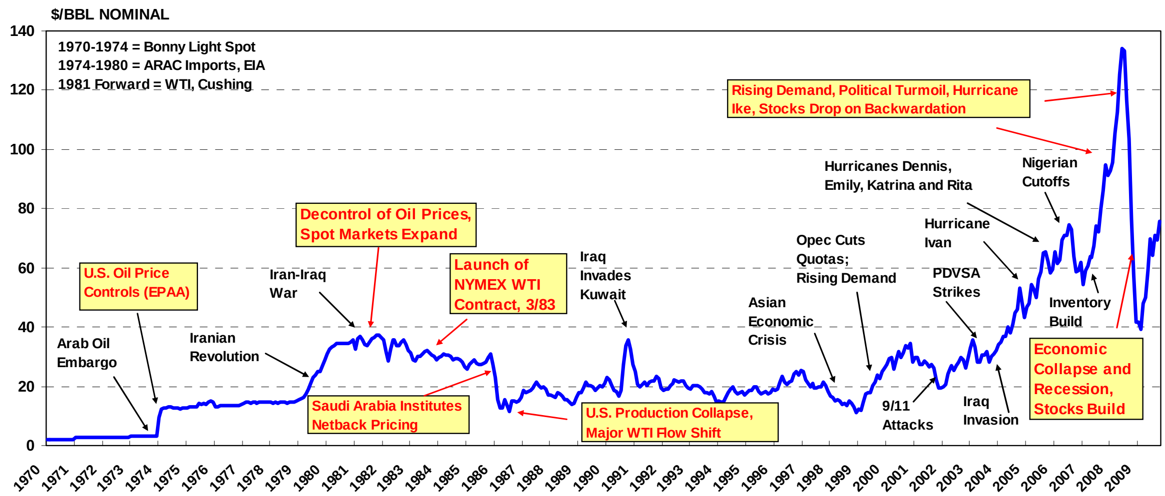
OVERVIEW OF OIL MARKET PRICING CHRONOLOGY

THE EARLY YEARS—1970 TO 1980

To develop this evolutionary fundamental perspective, it is relevant to briefly review the chronology of the oil markets over the years, analyzing the key events that eventually lead to the infrastructure of oil trading we see in the markets today. In particular, the chronology of the evolution of the WTI physical, and eventual paper markets, is of key importance. For the purpose of this study, the time line will begin in 1970, following which, some of the most volatile changes have occurred with respect to absolute price trends, and with respect to the relationships among the regional crude benchmarks, including WTI.

Over the years, there have been quite a number of significant events that have caused short term volatility in the markets. Figure III-1, following, summarizes the markets from 1970 to the current time in mid-2009, showing many of the most significant events. Some of these events, however, are more important than others, actually changing the longer term course of trade dynamics and/or pricing relationships among grades, including WTI, which has been subject to its own share of disruptions. Some of the most prominent events are highlighted in red text on the figure.

FIGURE III - 1
CRUDE OIL PRICE HISTORY, 1970 - CURRENT



Through the 1970's the markets had extended periods of relative stability. However, there were two major events during that period that drastically changed the environment in the oil markets, bringing focus to the potential for extreme oscillations in the energy trade that had not had such relevance for quite a number of years prior. Though OPEC began raising prices early in the decade, resulting in the U.S. instituting price controls (Emergency Petroleum Allocation Act, EPAA) in 1973, it was the politically motivated Arab Oil Embargo in mid to late 1973 that initiated those controls and it had a profound immediate impact on oil prices. **Average prices for oil rose from near $3.00/Bbl to over $13.00/Bbl within a few months, furthering protective controls by the U.S. The markets would never again see prices as low as those during the early 1970s and prior.**

From that point through most of 1978, oil prices remained relatively steady in the $13-$15/Bbl range. But then in January of 1979, Saudi Arabia drastically cut production levels resulting in spot prices eventually spiking to well over $15.00/Bbl (as represented by the average imported price into the U.S. at this point in the curve). Political turmoil during the later part of 1979 lead to prices over $25.00/Bbl, and then eventually to over $30.00/Bbl when Iran took the American hostages and a total embargo of Iranian imports was instituted.

MAJOR TRANSITIONS IN PRICING DYNAMICS AND TRADE—1981-1986

Following the major political events described above, oil prices continued to rise, reaching a peak in early 1981 near $37.00/Bbl in nominal terms responding to the late 1980 beginning of the Iran/Iraq war that was to last for almost eight years. That peak, **now reflecting actual industry quoted physical WTI spot prices in the data series**, was not to be repeated until late 2004 in nominal dollar terms. In constant 2009 dollar terms, though, that peak was near $78.00/Bbl, which was not reached again until early 2008.

A major event occurred in early 1981 that would, once again, change the landscape of the oil markets in the U.S. and globally, particularly influencing the volumes and transparency of the spot markets, including trade in West Texas Intermediate (WTI) and other U.S. grades. That event was the governmental decontrol of oil prices, spearheaded by Ronald Reagan, effective January 28, 1981. This fostered an immediate convergence of WTI spot prices into a single commodity that prior to the decontrol was split into various categories under the control mechanics. There were various tiers of prices that were not able to respond to market dynamics and trading because they were set by specific price and sales margin limits related to the time frame of their origin. It is not of significant relevance for this study to understand all of the intricate details of this complex pricing structure. **However, it is important to have a perspective of how the transition from "controlled" to "decontrolled" oil prices resulted in a major change in the trade dynamics that ultimately facilitated and grew the commoditization of WTI. This created the circumstances necessary for a successful development and launch of a "paper contract" in domestic light sweet crude at Cushing Oklahoma, typically designated as WTI, by the New York Mercantile Exchange (NYMEX) in March 1983.**

Prior to decontrol, U.S. domestic oil prices were fixed at specific levels starting in 1971 and then a more complex pricing structure was created in November 1973 in the **Emergency Petroleum Allocation Act of 1973** (P.L. 93-159) due to the loss of supply from the Arab oil embargo. This law created a two-tiered price control system. Most domestically produced oil was categorized as either "lower tier (old) oil" or "upper tier (new) oil," each having a specific controlled base price. Lower tier oil was generally oil from properties that began production before 1973. Under regulations, the price ceiling on this oil was the highest posted price (buyer commercial offering price) in effect on May 15, 1973 plus $0.35/barrel on all oil produced from wells that produced at less than their 1972 levels. This resulted in a posted price for old oil of about $4.25/barrel. Subsequent regulations increased the ceiling price in 1973 to $5.25/barrel. New oil (oil produced from wells that began production in 1973) was controlled at a different level, and stripper oil (oil produced from wells that produced 10 bpd or less) was eventually completely decontrolled. Imported oil was not price controlled. **These uncontrolled categories could be sold at the market clearing price, which was, nevertheless, still determined by the delivered prices of imported crude inclusive of the customs duties. The result of this control system, therefore, was a financial restriction to the open market trade activities in the domestic crude sales.**

Though there was certainly a widely active domestic crude trading environment prior to decontrol, including the sales activity in West Texas crudes such as WTI, the economic restrictions were not particularly conducive to a real commoditization of these crudes, except to some degree those volumes that were not controlled. Trading activities were in large part focused on the optimization of logistics among the physical sellers and buyers of these crudes. In addition to this, the international markets for the most part volumetrically also had pricing restrictions, primarily as a result of the use of posted prices set by the producing countries. For example, Saudi Arabia set single individual prices for each grade sold, regardless of destination, and many other countries followed these mechanisms. There were spot sales of international crudes such as those from Nigeria, but the major portion of the supply was contracted under the restrictive OPEC price regime. As will be discussed later, these restrictive pricing mechanics would eventually become unworkable and resulted in another major price event that would change the markets again in a major way.

In the years following the decontrol order, however, the open market trade in the domestic crudes developed rapidly. In fact, the industry price service Platts, among others, began to survey the market trades and report the average prices for WTI (both Midland and Cushing terminal prices) and other commonly traded domestic crudes such as West Texas Sour (WTS), Light Louisiana Sweet (LLS), and Wyoming Sweet. The first of these official open market reported prices in the data bases began to appear around May of 1981, depending on the source, though there was active trade in open market decontrolled oil prior to that time.

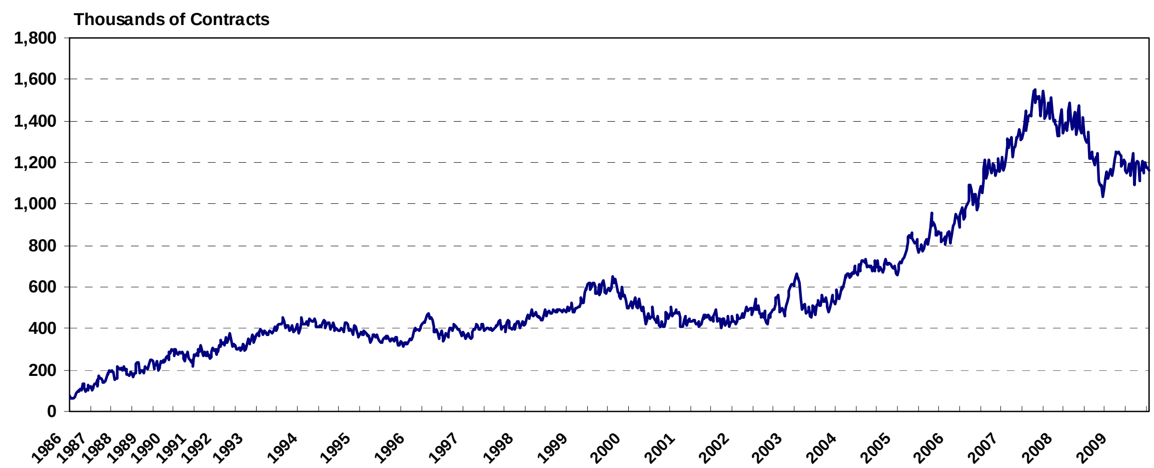
Over the next several years, prices of oil steadily declined from the peaks at the beginning of the decade as the massive increase in prices that occurred from 1980 severely impacted oil demand, resulting in an oversupply internationally. This steady deterioration would eventually lead to the other major oil market event, mentioned above, in 1986 that would permanently change the trading environment for all crudes, but with particular physical impact on the WTI market. This extremely important event and its impacts will be reviewed in detail, following.

But first, it is relevant chronologically to point out, once again, that in March of 1983, due to the changing trade environment, the first trades in the **NYMEX Light Sweet Crude Oil "**paper" commodity contract occurred, joining the already existing contracts for gasoline and heating oil. The NYMEX light, sweet crude oil futures contract was physically deliverable at Cushing, Oklahoma storage for those who wished to deliver or take delivery of the physical commodity there, or exchange it for other crudes at other locations (EFP, or exchange for physicals). The crude is often referred to as WTI, though actually being a composite of other sweet Texas and Oklahoma grades, and later even foreign grades. It often is also referred to as "Domestic Common Sweet". The NYMEX actually specifies domestic grades to include: "Specific domestic crudes with 0.42% sulfur by weight or less, not less than 37° API gravity nor more than 42° API gravity. The following domestic crude streams are deliverable: West Texas Intermediate, Low Sweet Mix, New Mexican Sweet, North Texas Sweet, Oklahoma Sweet, South Texas Sweet".

The Cushing storage hub became the delivery point of choice for this new "paper" contract as a result of an already well established and liquid "physical" or "wet barrel" trade in this grade. The Cushing location not only represented a gathering hub for the local crudes for refiners in Oklahoma, Kansas and Missouri, but it also was the central gathering point for terminus of pipelines originating in Texas and Oklahoma with onward distribution to the main refining centers in the central and eastern Midwest markets in Indiana, Illinois and Ohio. **This location was to continue its logistical and infrastructural relevance to this day with continued growth in physical storage and trade liquidity represented by the NYMEX**

contract. It was to become the world's most liquid forum for crude oil trading, as well as the world's largest volume futures contract trading on a physical commodity. Because of its excellent liquidity and price transparency, the contract is used as a principal international pricing benchmark. Figure III-2, following, shows the trends in the futures contract open interest from the mid 1980s to the current time in mid 2009 to make that point. The total open interest has gone from less than 100,000 contracts in 1986 to peaks over the last year of almost 1.6 million contracts, reflecting extensive participation from commodity users around the world. Further detail on the evolution of this trade and its pricing implications are presented in the following discussions.

FIGURE III - 2
NYMEX CRUDE OIL FUTURES TOTAL OPEN INTEREST



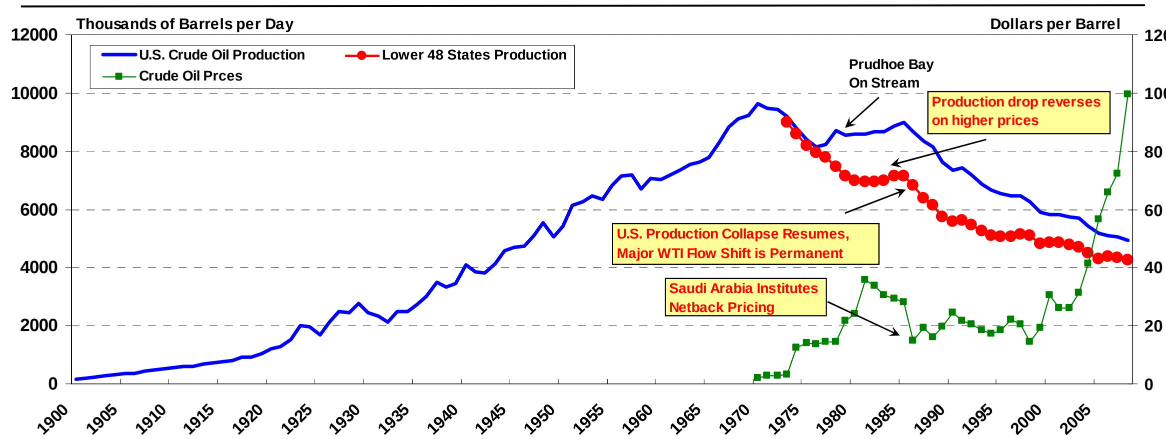
Backtracking now to the historical evolution, the markets in late 1985, and particularly through 1986, were extremely volatile, with prices collapsing. **This resulted in U.S. domestic production dropping dramatically as marginal production was shut in—some permanently. The trade dynamics for WTI changed dramatically at that point and pricing relationships that had been relatively steady in years prior, changed permanently.** The event was brought on by internal OPEC conflict as the higher prices had driven down demand and raised non-OPEC production to the point of OPEC balancing requirements declining to a total of only 13.5 million barrels per day. Saudi Arabian output under the quota systems became so low at that point (about 3.3 million barrels per day) that associated gas production was insufficient to meet internal demand and budgetary needs were not being met. Saudi Arabia at that point had also been taking the role of "swing producer" to balance the market in an attempt to keep prices stable, to their detriment, as other OPEC members were not honoring the production restrictions put in place by those same members.

Under these circumstances, in mid-1985, Saudi Arabia finally began to price its crude at spot market levels, largely abandoning its official price basis. This resulted in increased sales, but the beginning of a sharp decline in prices as OPEC production overall also rose as others adopted more market oriented pricing in a very competitive market environment. In late 1985 all of OPEC made the decision to officially abandon the "administered price system" in favor of a "market share system." To further its marketing reach, a very critical decision was made by

Saudi Arabia in early 1986 to begin pricing its crude competitively into the various major global markets, with "netback pricing" being adopted to ensure competitive parities with the open market crude prices in the Western Hemisphere. Netback pricing in essence ensured refiner margins that were competitive with the local crudes. Others followed suit.

This netback pricing move is often credited as the trigger to the 1986 oil price collapse, though lack of cooperation within OPEC itself to its own market share system at that point was arguably the main driver. WTI prices peaked at over $30/Bbl in late 1985, but dropped to near $10/Bbl at the lows in mid- 1986, the lowest since the early 1970s. This price drop, in the order of 50% at the time, had a dramatic impact on oil production in the U.S., as noted in Figure III-3, following. The low prices resulted in shut-ins of considerable numbers of low producing wells (e.g., stripper production classified as such with production of 10 barrels per day or less). Many of these wells were permanently capped, never to be produced again. Data show a loss of nearly 25,000 producing wells in 1986 and by 1990 that drop had approached 45,000 wells versus the peak number in 1985, out of a total of about 625,000 wells nationwide. Production lost during that period was well over 1.5 million barrels per day. The only thing that kept the overall U.S. decline from being even more severe was that Alaskan Prudhoe Field production had come onstream in 1978 and was approaching its peaks during the collapse of the output from the lower 48 states.

FIGURE III -3
UNITED STATES CRUDE OIL PRODUCTION HISTORY

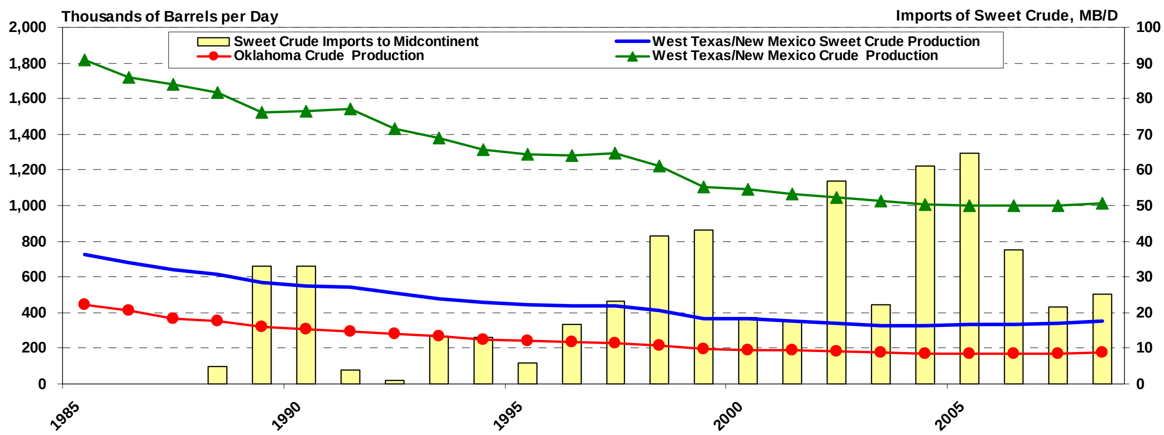


Of particular importance at this point in the timeline, with respect to the pricing of the WTI market, was the volumetric collapse, consistent with the chart above, of the local supply to the Cushing, Oklahoma regional refiners, as well as the reductions in production from Texas that also supplied the Cushing hub as well as the U.S. Gulf Coast refineries. **These events resulted in a drastic change in the trade dynamics in the area and the resultant price relationships among the regional crudes.**

More detail on these pricing relationships, their dynamics and the influence on the NYMEX contract itself will be discussed later, but Figure III-4 below presents an overall summary of this important transition in the trade dynamics related to the WTI market, impacting the pricing relationships among the domestic grades. **This trade shift significantly enhanced the commoditization of the Cushing region at that point, more directly linking the Gulf**

Coast supply of imported crudes to the area through pipeline physical changes. It set up the eventual need for alternate delivery of foreign crudes into the contract. This would not, however, be the only major dynamic shift in these markets from that time to the present. Nor will these changes be the last. These historical and future evolutionary trends are further detailed in the reviews following.

FIGURE III -4
CRUCIAL CRUDE OIL PRODUCTION PROFILES and IMPORTS INTO THE MIDCONTINENT



PERIOD OF RELATIVE STABILITY—1987 TO 2003

Following the crude oil market disruptions in 1986, prices of WTI crude oil experienced quite a period of relative stability through about 2003. This is not to say that there were not periods of extensive volatility on a short term basis a number of times during that span, especially late in the in the millennium during the Asian financial crisis that impacted petroleum demand globally. From a low in 1986 of about $11.50/Bbl for WTI during the bottom of that downturn, prices generally oscillated around the $20/Bbl range for most of this defined period. In fact, OPEC attempted to revive the administered price system again in 1987 due to the severe impacts on the markets of their internal competitive price war, but the basis was not a sustainable and prices of WTI came off peaks in mid 1987 of about $20/Bbl, weakening to below $15/Bbl through the next year or so.

From 1988 to about mid 1990 prices averaged in the $20/Bbl range, and the markets were relatively quiet. But, then in August of 1990 Iraq invaded Kuwait. The natural reaction of the markets at that point was to assume the worst case scenario of major supply disruptions and this resulted in a strong spike in crude oil prices. The initial spike was short-lived as OPEC quickly worked toward increasing production wherever possible within the group to replace the roughly 4 million barrels per day of lost supply. The additional supply was largely heavier grades from Saudi Arabia and Venezuela, which resulted at that time in some quite significant changes in the premiums for sweet crudes globally, including WTI.

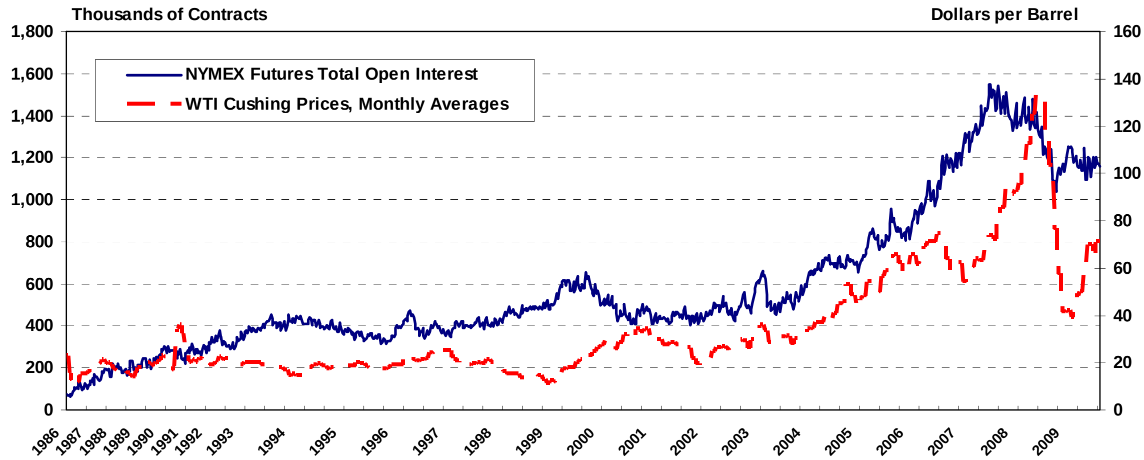
Beyond this point and into the early part of the next year the markets were unsettled as negotiations with Iraq were fruitless. On January 16, 1991 the U.S. began its air attacks on Iraq, very successfully, and with the announcement of a large release of SPR oil by President Bush, prices dropped almost $10/Bbl after having gained about $5/Bbl earlier in the month as the confrontation with Iraq intensified. From this point forward through early 1997, prices were, from an overall perspective, relatively stable, oscillating around the $20/Bbl level. Through this period, there were of course periods of geopolitical turmoil, mostly involving the aftermath of the Iraqi war with the recalcitrant attitude of the Iraqi regime.

The most prominent trend late in this period, though, was the beginning of the Asian financial crisis that would last into 1999. Prices had peaked around $25/Bbl in early 1997, but through the global economic downturn, prices dropped to lows approaching $10/Bbl by early 1999. Through this period, OPEC was actively attempting to cut output to stabilize prices, even bringing in some cooperation of Non-OPEC producers. As the crisis began to wane, however, demand for petroleum began to recover and the oil markets experienced a sustained recovery through 2000 and prices rose to monthly peaks averaging near $35/Bbl late that year. By late in the second quarter, despite OPEC quota increases to keep a lid on prices, prices spiked to over $37/Bbl in reaction to an increase in tensions between Iraq and Kuwait. It was a ten-year high at that point.

Later that year, OPEC oil ministers, meeting in Vienna, announced a decision to put further production increases on hold until their next meeting scheduled for early in the new year. That decision effectively ended OPEC's "price band" mechanism, which had called for automatic increases in production quotas of 500,000 barrels per day when the price of the OPEC Basket of crude oils remained over $28 per barrel for 20 consecutive trading days. Then, weakening oil demand, in part due to the higher oil prices through the prior year, reversed the momentum in the market and prices began to decline. By early 2002 prices had again declined back to the $20/Bbl range, the lowest seen since the Asian financial crises several years before.

In the meantime though, one of the most pervasive events in the history of the country occurred on September 11, 2001. The terrorist attacks on the U.S. World Trade Center and the Pentagon, along with a thwarted attempt of another hijacked airplane likely to target the White House, initiated a very long period of geopolitical turmoil that would, when combined with other factors along the way, lead to the highest oil prices in history. **In addition, it would be a period of extreme uncertainties in the market that would expand the use of the NYMEX crude oil contract dramatically to never before seen levels.**

FIGURE III - 5
NYMEX CRUDE OIL FUTURES TOTAL OPEN INTEREST vs WTI PRICE TRENDS



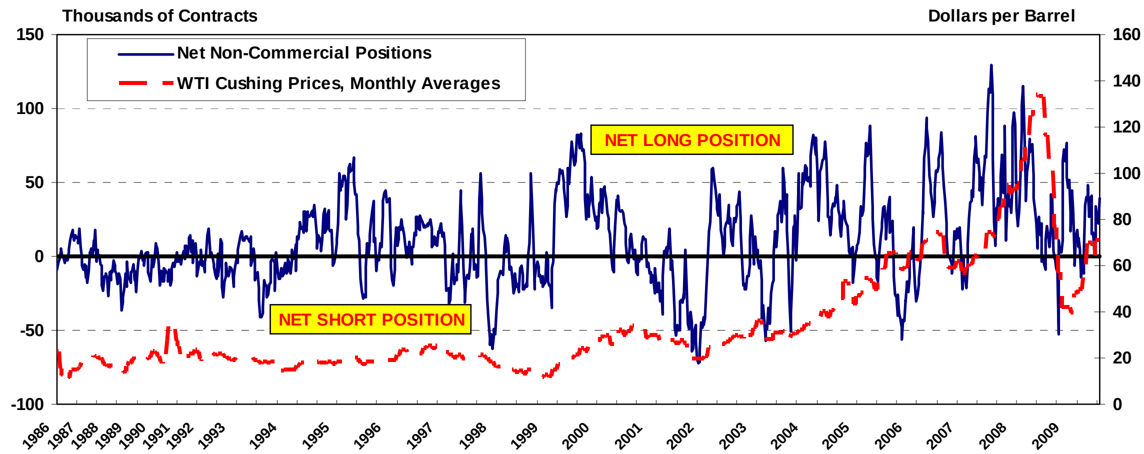
Despite the implications of the 9/11 events and their aftermath, oil prices, as mentioned above, declined from near $35/Bbl down to $20/Bbl through 2002, and then began a move upward again through 2003. This trend was helped along significantly by the political disruptions in Venezuela that resulted in strikes throughout the PDVSA organization. This resulted in crude oil and refinery production outages. At the same time, building concerns about the evolution of the Iraqi situation kept the markets on edge.

Ultimately, on March 19, 2003, military action in Iraq commenced with a bombing raid and missile attack on targets in the Iraqi capitol of Baghdad (March 20 Baghdad time) by Coalition forces, given Saddam Hussein and his regime's rejection of U.S. President George Bush's March 17 ultimatum for compliance with UN resolutions. Oil prices spiked sharply on this action, but the anxieties about potential longer term supply disruptions did not last long as the rapid military success of the invasion was taken positively by the markets. **Prices averaged just over $30/Bbl for the year 2003, but by the end of the year an upward track became persistent, ultimately leading to continuing records in prices and the most significant volatility in prices in the history of the markets.**

UNPRECEDENTED MARKET VOLATILITY—2004 TO 2009

Prices started the year 2004 in the $35/Bbl range. But by October of that year they had peaked near $55/Bbl. Prices had already reached all time records by June of that year, as multiple terrorist attacks on Saudi Arabian government facilities exacerbated the already anxious markets. OPEC attempted to curtail the rises through continuing quota adjustments, but to no avail. Demand for petroleum during the year was also growing significantly, lead by unexpected strength in China, and the tightness in supply and productive capabilities that were starting to appear raised market anxiety further, especially in light of these geopolitical disruptions. **This situation turned out to be a major turning point in market momentum that would last several years, giving the market the necessary fundamental backbone to support steady length in the NYMEX contract as open interest expanded accordingly.**

FIGURE III - 6
NYMEX CRUDE OIL FUTURES NET NON-COMMERCIAL POSITIONS vs WTI PRICE TRENDS



As noted in Figure III-6, preceding, Net Non-Commercial positions were to remain long for the majority of the time for nearly four years, reflecting the market sentiment toward probable directional trends, given the underlying market fundamental and technical factors. Surprisingly, even through the major collapse of early 2009, the sentiment went short for only a brief period, with the obvious expectation that the lows reached early in the year would not be sustainable—and they were correct.

But back to 2004 again, to top off that year, the biggest disruption of the region's output in at least two years occurred. Hurricane Ivan forced Shell Oil Co., ChevronTexaco, ExxonMobil, and Total, to shut some hundreds of thousands of barrels per day of Gulf of Mexico oil production as the companies evacuated more than 3,000 workers from the offshore platforms. Oil tankers from Venezuela also faced a three-day delay on deliveries to the U.S. because of the hurricane. The U.S. Minerals Management Service reported that Ivan had reduced Gulf Coast oil production by 61%. October was the highest price point of the year and, of course a new record high in oil prices. Some permanent damage to offshore facilities was left in the wake of Ivan, but these would not be the worst. More damage was to come in subsequent years. Nevertheless, prices did retreat somewhat as things recovered along the Gulf Coast, before resuming the upward trek that would continue to break all time records by the day.

Price trends, however, have been most volatile recently, especially through the 2005 to 2009 time frame, with never before experienced price range movements and record-setting highs before a major collapse in early 2009. From a proportional perspective, the markets had not seen these levels of volatility since the 1986 price crash, and prior to that, the Iranian revolution of 1979 and the Arab Embargo of 1973.

WTI prices hovered in the mid-$30s/Bbl in the early part of 2004, but beyond this point prices began an almost uninterrupted upward track to all time highs well over $130/Bbl on a monthly average basis in late 2008, with peaks approaching $150/Bbl on a daily basis. This trend was perpetuated by an environment of strong demand early in this period, and supported by tight productive capacity availability, leaving the markets extremely vulnerable to upsets in a politically charged global geopolitical atmosphere.

Through this period, the capacity capability of OPEC, particularly that of Saudi Arabia, became less and less able to counter any major disruptions in supply that could easily have resulted on a number of fronts in a politically charged environment. For example, periodic losses of significant production in Nigeria resulted in political turmoil there. Then, beginning in the summer of 2005, the Gulf Coast was hit by a record number of hurricanes, seriously impacting crude and gas production and knocking out a large amount of refining capacity in the area. Hurricane Katrina was the worst and Rita also damaged facilities again that were still trying to recover from the serious damage from Katrina. These impacts lasted well into 2006. **All these events induced heavy trade and hedging activity targeted against the potential impact of potential further market disruptions caused by the unstable geopolitical environment.**

Except for a brief correction into early 2007, when prices dropped from mid 2006 peaks near $75/Bbl to about $55/Bbl, prices rose sharply through 2008. The economy was relatively weak in 2007, but that did not stop the upward trek from those early year lows in an unexpected and unabated spike toward the highest level ever in the oil markets. By mid 2008, monthly average peaks rose to about $133/Bbl, with daily peaks approaching $150/Bbl.

Then, as geopolitical tensions began to ease somewhat internationally, the world was shocked by an almost unprecedented collapse of the financial markets. With the already noticeable impact of the severe price escalation on demand, this financial shock had an immediate further negative impact on the demand, rapidly expanding spare capacity in global oil productive capabilities and refinery capacity around the world. Refinery operating rates dropped sharply into 2009 and refinery profits dropped precipitously. By mid 2009 there were even shutdowns of complex refinery capacity in the U.S. and elsewhere. **During the early year drop in refinery runs, stocks of crude also built dramatically, resulting in historically significant volatility in the price relationships for WTI versus other regional benchmarks. More detail on these events and the pricing impact will be presented in the next subsection.**

The economic downturn resulted in a rapid price collapse from the $130s/Bbl in mid 2008 to a low of $40/Bbl by January 2009. Actual daily lows were in the mid $30s/Bbl for a brief period before some stabilization lead to a return to the $50/Bbl range by mid year and then back to the $70/Bbl range by the third quarter. At this writing, volatility is expected to continue, particularly in the short to medium term given the economic environment and its affect on demand, refinery runs and trade flows. **In addition, longer term dynamic shifts in the trade into the Cushing region could be enhancing ties to the USGC. This will be also be discussed in the section following, which now will cover the physical trade in WTI and its price relationships with other local and regional benchmarks.**

EVOLUTION OF WTI TRADE AND PRICING RELATIONSHIPS

INTRODUCTION

In addition to the periodic, and sometimes extraordinary volatility in absolute price levels over the years, especially in recent years, the relationships among the regional and international grades and benchmarks have shown extensive volatility, as well. There have, of course, been a number of short term market events along the way that have disrupted the normal dynamics of trade. But, the trade and pricing relationships related to WTI have also gone through a number of more persistent transitions that have resulted in significant changes in the relationships of WTI to other regional and international benchmarks. Many of these transitions have been specifically related to the changes in trade dynamics, brought about by the impacts of price changes in a number of cases, or changing availability of resources to supply the regional markets in others.

In particular, volatility between the NYMEX WTI contract and Gulf Coast crude streams, including LLS, Mars and others has increased as a result of a number of factors, including temporary disruptions of the markets due to such events as refinery outages and hurricanes. But, as described in the previous discussion of the absolute price trends over the years, there have been several key instances where market disruptions have resulted in permanent or at least very long lasting impacts. In addition, relationships of WTI with some other benchmarks such as UK Brent crude have, at times, moved well outside the bounds of historical traditional ranges, not all related to the basic fundamentals of the WTI but rather to the other benchmark.

A key initiating factor for this study of the WTI market, including the evolution of its trading dynamics, relates to the above described changes in the relationships between WTI and the other benchmarks. Some public comments have challenged the performance of the NYMEX sweet contract as a benchmark due to these relationship changes. In many cases, these concerns are derived from a lack of understanding of the underlying factors for this volatility. Simply put, one must have a solid grasp on the real fundamental drivers in the market at any point in time, in order to decipher the changes that are occurring. Of course, understanding these fundamentals enhances ones ability to utilize the benchmark most effectively and to be cognizant of the basis risk that is inherent in this or any other commodity or benchmark.

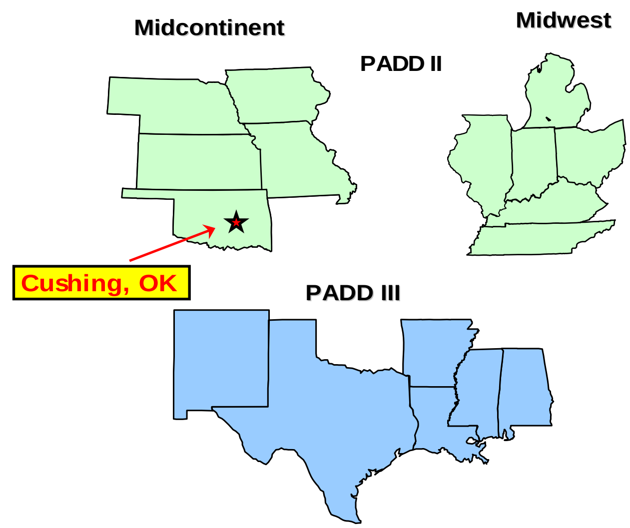
Therefore, it is the purpose of this section of the analysis to draw on the underlying price background of the preceding discussions to carry the analysis toward an understanding of the physical reasons for the relationships between WTI and the other key regional crudes that are being viewed in the market’s perception of WTI’s benchmark validity. The first discussion needed here is a background on the basic fundamentals that have driven the relationships over the years and will continue to drive them in the future. This analysis will then tie the trade dynamics to the market events defined and the resultant price relationships, both short term temporary events, and those that have shifted the relationships for longer periods of time.

ANALYSIS OF HISTORICAL AND FORECAST WTI TRADE DYNAMICS

Before starting this discussion, it is first appropriate to define the specific regions of the market that will be focused upon with respect to the logistics, trade and pricing relationships. First, there are the standard regional definitions for “Petroleum Allocation for Defense Districts” (PADD). We will be dealing primarily with the U.S. Gulf Coast (USGC) and West Texas linkages that are within PADD III. Then PADD II is broken down into Midcontinent and Midwest by Purvin & Gertz, Inc definitions, but consistent with the U.S. Department of Energy refining regions.

Cushing, Oklahoma, the physical delivery point of the NYMEX Sweet Crude contract, is located in the Midcontinent region, with crude flows in from Texas and surrounding Oklahoma and Kansas areas and flows out to local refineries in the Midcontinent and toward the refineries in the Midwest. Detailed historical and forecast flows, with respective chronological maps, are presented and discussed in the logistics analysis in the next section of this report. The discussions in this section will concentrate on the macro trade dynamics that put perspective on the pricing issues and relationships. This is intended to apply a fundamental basis to the volatility in the relationships among the benchmarks that has been a cause of concern for market participants, especially in recent times.

FIGURE III-7 MIDCONTINENT, MIDWEST, AND PADD III REGIONS



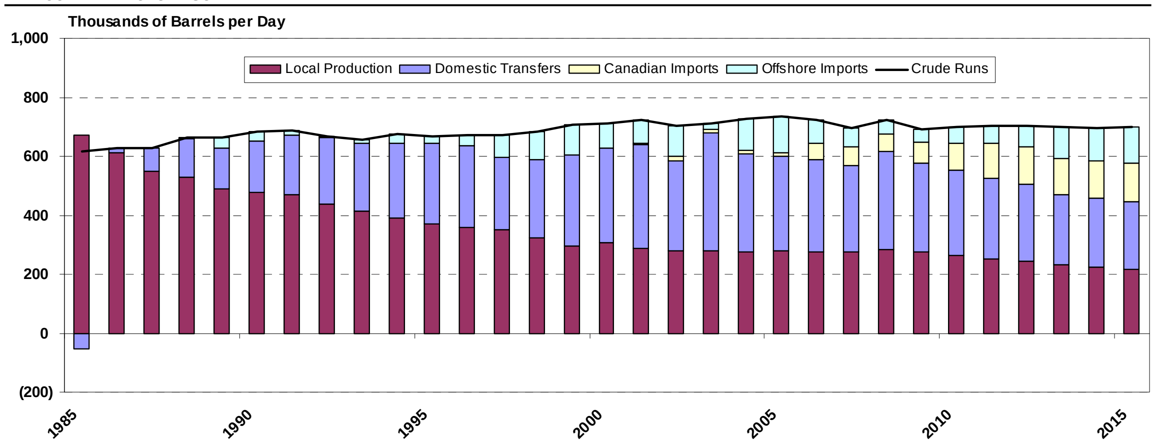
To put things in perspective, we will first examine the underlying fundamentals of this analysis over the time frame that has the most relevance to the transitional dynamics of the WTI trade and pricing relationships. For the purpose of this discussion, that will lead to our analysis of the pricing issues, we will be looking primarily at the trade flows that directly involve the Midcontinent area which encompasses the Cushing, Oklahoma terminals and pipeline convergence and distribution points. These trade flows include constant and active interaction between the U.S. Gulf Coast, the Midwest, and the Midcontinent, though periodic disruptions can occur. The overall trends in prices, and particularly price relationships for WTI, are critically linked to these dynamics. As mentioned earlier, a much more detailed chronological physical infrastructure and trade analysis, upon which this summary is drawn, is presented in the next section of this study.

Figure III-8, following, shows the Midcontinent total crude supply balance over the period from 1985 to the present time in late 2009 and onward into the moderate term future. It is clear from this analysis that the trade into this area has been anything but stable over the years with respect to sourcing, though refinery runs of crude have been relatively constant, considering the time frame. It is also important to note that that there will be further changes in this area in the future. Each of the periods of change in trade can be tied to global and/or regional fundamental changes, all of which interact on a daily basis, often initiated by key events that were described in the preceding section of this report.

This chart shows the supply to the region broken down by its source. From 1985 and back in history, it can be seen that the runs to the refineries in that area were totally supplied volumetrically by the domestic production from that local region. That does not mean that this is the only crude processed by these local refineries, however, as there were also supplies of crude coming in from West Texas/New Mexico and North Texas that made up part of the local mix of sweet crudes (Oklahoma and Kansas sweets) and sour crudes (primarily Oklahoma sours).

But, what is important at that point in time and for years historically, is that there was actually an excess of supply in the local area relative to the local refinery demand. Some of the volume of total crude in the area actually left the area into the Texas Panhandle and Midwest markets, headed for the refining centers there, along with the pass through of substantial volumes of the West Texas supply with Cushing being the collection and distribution hub for these volumes. This balance situation can be seen in the bars for 1985 in the chart.

FIGURE III - 8
MIDCONTINENT CRUDE SUPPLY

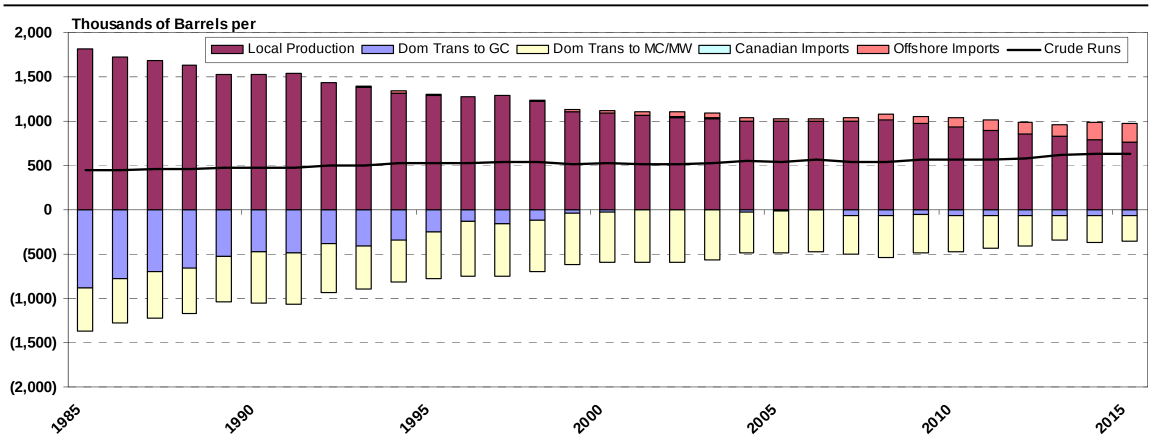


From 1986 forward, however, these balances changed dramatically and this would not just be a short term event. The price crash that began in early 1986, due to OPEC's inability to manage an oversupplied market, had an immediate and sustained impact on U. S. production, including the West Texas and Midcontinent output. This was discussed in the previous subsection and shown in Figure III-3. As noted in Figure III-8, above, the excess of crude in the Midcontinent that had existed for years disappeared in 1986 and the region then quickly ran short of crude. This required that the first line of balance supply from domestic transfers be utilized to make up the deficit.

Then, as the local domestic supply continued to decline in the lower price environment, more and more of these domestic transfers were required to fill the gap. Initially, there was enough West Texas supply to meet those requirements, with volumes being pulled out of the Gulf Coast deliveries and holding back volumes that had been historically destined for the Midwest. But, eventually these supplies began to run short as well and the next sourcing of supply to meet the demand was offshore imports into Cushing and into the Midwest. These trends had a significant impact on the pricing relationships for WTI delivered to the various regions where it was utilized, as well as the relationship of WTI to other regional benchmarks. In essence the "price-setting" market location began to change, even as the liquidity of the paper trade at the Cushing hub increased. The evolution of the pricing and relationship trends are described in detail in the next subsection.

Figure III-9, following, presents another, even more compelling view of the drastic impact of the 1986 price crash on the trade in the West Texas crudes due to the domestic crude production decline. It is also a clear indicator of some of the key fundamentals that will drive the price relationship trends for these crudes through the next 20 years and beyond, though the balance in an around the Cushing area will be relevant to the parity pricing analysis that will be covered later.

FIGURE III - 9
WEST TEXAS CRUDE BALANCE HISTORY AND FORECAST



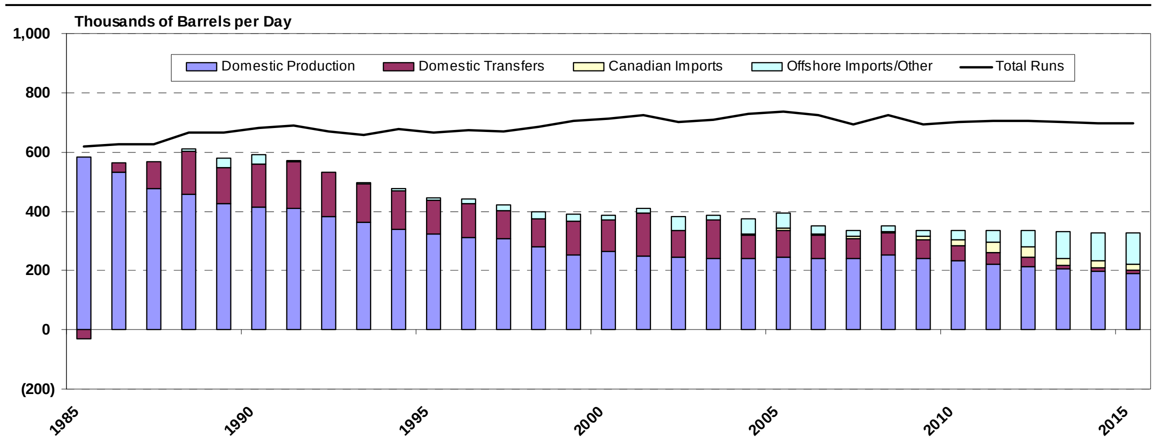
This figure shows relatively small and steady demand for the crude in the local area refineries. Most of the crude was headed for the Gulf Coast and for the Midcontinent/Midwest refinery centers. However, as the production of crude from the West Texas/New Mexico area steadily declined over the years, the first element of the balance to give way was the delivery of the crude to the Gulf Coast refining centers. Eventually, the volumes to the USGC diminished to nothing, with only a small volume of Southwest Texas supply connected into the Southwest Texas refineries. The major pipelines out of West Texas toward the extensive USGC refinery systems in the Houston/Beaumont/Port Arthur areas were shut down, with one system eventually being reversed and put into products service headed out to El Paso. Deliveries out of West Texas toward the Midcontinent/Midwest, on the other hand, will continue on for years to come, though at diminished rates. Out into the next decade, there will actually need to be offshore imports into the area to meet the local refinery needs.

But, a key fundamental issue here that is crucial to the pricing relationship analysis relates to the Midcontinent Sweet crude balance. Figure III-10, following, shows the evolution of this balance over the same time frame. As with the total balance for the Midcontinent, in 1985 there was adequate supply in the local area to meet refining needs. Some of the sweet supply on net actually left the area. But, in 1986 and forward the domestic transfers from West Texas would be needed there to meet the local demand.

Even as early as the late 1980s there were offshore imports coming in to close the balance through a 1988 pipeline reversal that allowed that flow (see detailed discussions in Section IV). **Though not large in proportion to the total runs of sweet crude, averaging about 35,000 barrels per day in 1989 and 1990, this represented the first direct inflow of oil from the US Gulf to Cushing.** Shortly thereafter, the NYMEX began the process of accommodating delivery of foreign crude streams which was (and still is) permitted under the contract. This started with North Sea Brent and five other crude streams. Purvin & Gertz, Inc was engaged by the NYMEX during that time to assess the value relationships among these crudes for purposes of accounting for quality differences.

There would continue to be offshore sweet crudes coming periodically to the area beyond those early years, though the most active periods would be in the early 2000s. For example, the average annual import level in 2002 was close to 50,000 barrels per day and after a lull in 2003, those peaks would again be reached in 2004 and 2005. **However, an interesting and significant trend that had been occurring over the years, from the early 1990s up to the early 2000s, is clear from this chart, and that is the steady decline in overall sweet crude runs in the region as refiners upgraded their facilities to process more sour and heavier grades.** In fact, this kept the requirements for sweet imports from rising even further during these earlier years. That trend stabilized through mid-decade, but then drifted down again from 2006 to 2009. The amount of sweet imports into the Midcontinent dropped to very low levels through this period as a result of weaker refinery demand part of the time and some gains in the local production as the much higher prices induced increased drilling and stripper well workovers. Total U.S. producing wells rose by about 25,000 wells from 2006 to 2008 and combined production from Oklahoma and Kansas rose by 20,000 barrels per day during the same period. Pricing of the WTI in comparison to the regional benchmarks during that time, as will be detailed further, reflected this supply excess.

FIGURE III - 10
MIDCONTINENT SWEET CRUDE RUNS



Now, for the longer term outlook, it can be seen that the production in the area is expected to resume its decline, with diminishing availability of domestic sweet transfers for the region. It is expected that there will be steady increases in deliveries of Canadian sweet Synthetic Crude Oil (SCO) into the area on new pipeline connections, though these volumes will not be large until well into the next decade. **Even with this new supply, there will still remain a requirement for additional sweet crude from outside the area to meet the local refinery requirements. This is a very important issue with respect to the evolving outlook for trading dynamics and prices in the area, and the relationships of those local prices with regional benchmarks.** There are several potential components to that additional supply, including, but not limited to, the important offshore imports component. First, SCO volumes could be larger depending on the projects scenarios envisioned for the future. Second, there are new pipelines being proposed to bring the new Bakken production into the area, though this is not a given and assessment of the total volumes available long term is still evolving. **In any event, the Cushing area supply/demand dynamics remain active regardless of the sourcing, though the ultimate price dynamics do depend on the means of sourcing. It is important, therefore, for users of the commodity to be aware of the fundamental issues and the resultant potential basis risk. Other commodity crudes in the Atlantic Basin, however, are not free of similar fundamental issues, as will be discussed in the following overview of pricing relationships.**

WTI PRICE RELATIONSHIP TRENDS AND ANALYSIS

Introduction and Overview

With the above overview of the changing market dynamics that have evolved over many years for the U.S. and particularly for the Midwest and Midcontinent areas of the country, the focus of the discussion now turns to analysis of the resultant price relationship trends that have been driven by these changing fundamentals. This discussion intends to show the unique features of these fundamental trends that specifically relate to certain pricing and price relationship scenarios. The results should provide an understanding of WTI market pricing dynamics from a longer term perspective as well as deal with the short term volatility most recently that has been a key underlying focus in the initiation of this study.

In this discussion the concept of **"Parity Pricing"** will be introduced, laying the foundation for understanding how the pricing and pricing relationships tie to the fundamentals that were detailed in the previous section. Parity pricing simply defines the location at which the competitive crudes directly interface in the marketplace. At that point of interface, the crudes being analyzed will be in parity with each other if the prices of each produce the same margin for a refiner who purchases them. From a trading standpoint, the relationships define the "arbitrage" (the arb) conditions at any point in time that will determine the competitive standing of the different crudes and what choice will be made by the refiner who wants to maximize margin. Most important, the shifting parity will define whether or not there is an actual economic incentive to deliver a crude into a particular refining location at any specific point in time or over any specific period of time, such as delivery of USGC crudes into the Cushing market hub. These parity conditions are directly related to the fundamental drivers and those will change over time.

The key to understanding the WTI pricing and price relationship trends is calculating those arb positions over time by incorporating the flow dynamics and costs of transportation to compare the prices at various market locations, thereby defining the actual physical interface that is setting the market price for the crude being analyzed versus its competition. If there is no parity for an extra-regional delivery at a market location, it implies a disincentive to move it into that location as it would produce a lower margin than crudes that are already available at that location. Another part of the analysis is being able to identify critical market factors that may also be influencing one or the other of the crudes being compared (e.g., hurricane influence on USGC crudes or the impact of excess stocks on prices in an area such as the Midcontinent).

The parity conditions for the WTI prices have changed over the years due to the supply fundamentals that were discussed in the previous sections of this report. From a macro perspective, there have been three major expressions of parity conditions that govern WTI pricing, each reflecting the specific supply/demand and trade interactions between the US Gulf Coast, Midwest and Midcontinent regions at a particular point in time. First, West Texas crudes moved south to the USGC for many years due to an oversupply relative to the demand locally and farther north. Pricing in West Texas during those periods reflected USGC netbacks. This is called **"USGC Parity",** meaning that WTI would be priced based on a transportation netback from marginal values, determined through competition, at the U.S. Gulf**.** This condition actually determines WTI, Midland Texas prices, with WTI, Cushing Oklahoma prices set by incremental pipeline transportation costs from Midland to Cushing. Prices in other locations would be determined by the WTI, Cushing price plus transportation to those other locations. This condition existed continuously in the years prior to the 1986 price collapse, and then at least seasonally for some years following, until flows to the USGC from West Texas ceased due to lack of supply.

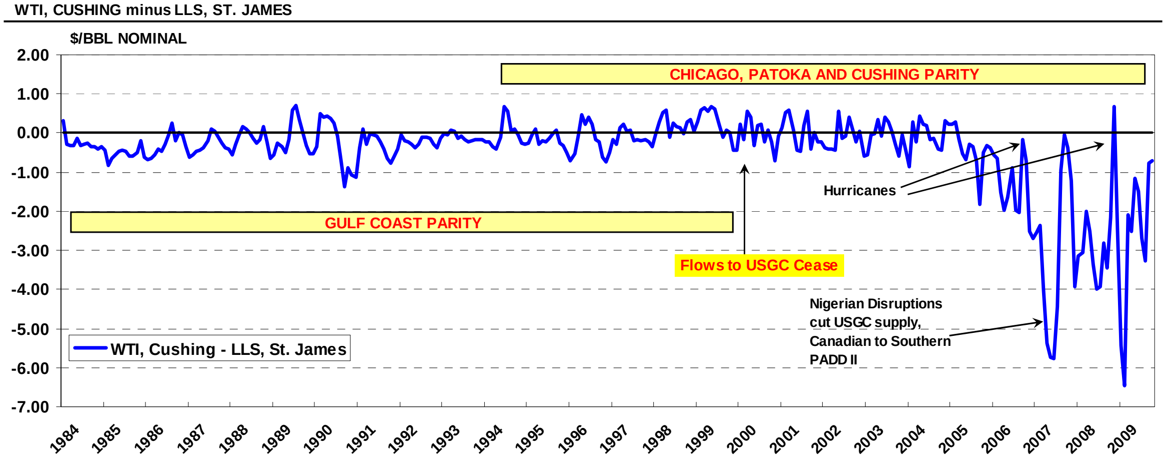
Second, **"Chicago Parity"** occurs when the demand in the Chicago refining area exceeds the maximum available supply of WTI (midcontinent sweet), requiring USGC domestic and offshore deliveries into the Chicago area. In this case, the arbitrage would open for direct economic interface between the WTI delivered out of Cushing to Chicago and a USGC sweet domestic or offshore crude delivered to Chicago by another route (e.g., Capline). WTI, Cushing prices would then be based on a netback from the Chicago refining center. Third, **"Cushing Parity"** is a condition where pricing is based on the need to deliver offshore volumes directly to refiners in the Midcontinent area due to deficiency in the availability of domestic sweets. Cushing prices then would simply be based on the USGC price for sweet crude directly delivered to Cushing. Prices at other locations would then be based on the Cushing parity price plus transportation to those other locations, meaning that the other locations would become "taker" markets rather than "setter" markets. Lower cost supplies could, however, be available to Chicago from the USGC to the point of full utilization of the other transportation corridors to that location. There is also an intermediate parity point that can be defined as **"Patoka Parity",** which represents another pipeline interface of competition between WTI and USGC sweet or offshore crudes moving to that area**.**

Each of these parity conditions has been seasonally transitional, as well as annually transitional over time. The conditions are not necessarily instantaneous, but rather a continuum related to normal ongoing flows related to the supply and demand in the different market regions. USGC parity eventually ceased to exist by the late 1980s as the domestic supplies in the Midcontinent declined severely, demanding maximum amounts of the West Texas crudes in northern markets. Pipelines moving to the USGC region were eventually shut down and/or reversed. Other transitions have continued to occur since then, and more will come with the new supplies from Canada through new pipelines, permanently changing the trade dynamics of the combined US Gulf Coast, Midwest and Midcontinent market. These will create new parity conditions related to Canadian flows into the Midcontinent and Midwest. Longer term, however, we may again see a period of sweet crude supply tightness in the Midcontinent that could influence the parity conditions seasonally, similar to earlier years. **What is important to note here, as was reflected in Figure III-8, earlier, is that the Cushing location will likely continue to maintain its status as a key gathering and distribution hub regardless of the exact evolution of these trade patterns, though there are certainly new lines being proposed that would bypass Cushing.** Most of those new lines, however, will be focused on moving Canadian Heavy crudes to the USGC, while imported sweet crudes would still be needed in the Midcontinent area to supply the local refineries.

Analysis of Parity Price Fundamentals and Resulting Price Relationships

First, it is worthwhile to show the actual price relationships that have occurred over time to have a perspective on what must be analyzed in terms of the arbitrage conditions short term and longer term. A logical and easy to understand way to present this is to look at the actual WTI prices by month as compared to other benchmarks. On the USGC, an ideal competitive benchmark is Light Louisiana Sweet (LLS), which is actively traded and is a good competitive benchmark for also examining the arbitrage conditions of the key offshore crudes such as North Sea Brent. Figure III-11, following presents this relationship. The arb analysis for Brent will also be discussed later in this section and a detailed development of the Brent market evolution is presented in Section VI of this report.

FIGURE III - 11
WTI, CUSHING minus LLS, ST. JAMES



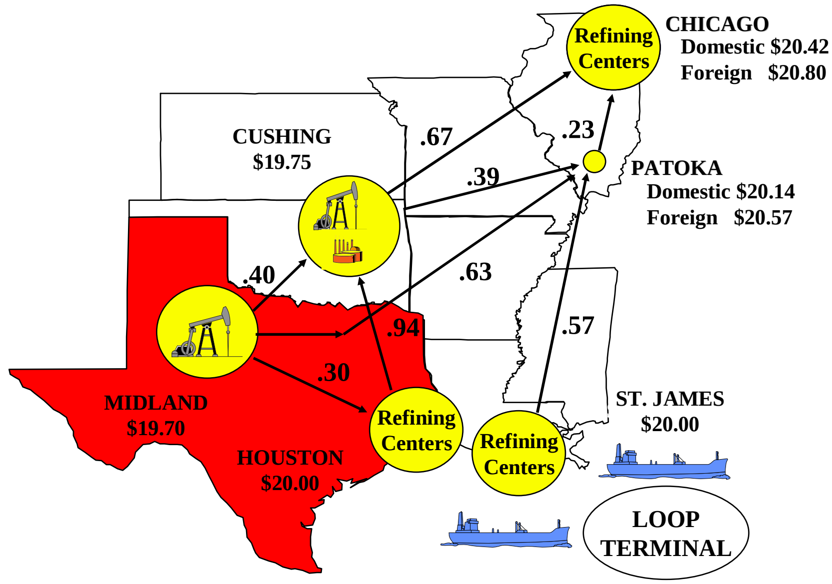
It can be seen in the figure that prior to the 1986 market events, WTI at the Cushing location (prices shown are physical or "wet market" spot quotations) were traditionally much lower than the LLS trade at the USGC. This physically reflected a continuous flow of the West Texas crudes to the USGC refineries with the remainder flowing into a well supplied Midcontinent/Midwest market. But then in 1986, as a fundamental transition was underway, these relationships drifted toward a lower discount on average, and, seasonally, WTI began to show premiums to LLS, reflecting periodic movement of the "Parity Point" to more northern refining centers versus the USGC. In addition, routine volatility in the relationship evolved. That seasonal volatility continued for quite a few years with a deviation of about plus/minus $0.50/Bbl and annual averages near breakeven.

Then from 2005 to the present this volatility became extreme. These later years will be discussed in particular detail later as this is the period under which the most scrutiny of the WTI benchmark has occurred. **It is particularly relevant to point out here, as shown on the chart, that this recent extreme volatility often can be the result of physical disruptions and trading issues related to the USGC market versus something related to the Cushing location trading dynamics.** For example, hurricanes impact the USCG supply of domestic offshore crudes and the imports of foreign crudes first before the physical shortfalls penetrate inland. Typically, however, these events also shut down Gulf Coast refining capacity countering the supply shortfall there, while the shortfall actually occurs in the inland market where refineries continue to run. This can raise the price of WTI against LLS. On the other hand, shortages of sweet import availability due to political disruptions can raise the price of LLS against the WTI just as unanticipated increases in stocks in the Midcontinent can lower the price of WTI.

Figure III-12, following, shows a representation of the arb circumstances involved in a condition of **"Gulf Coast Parity."** This is the condition that existed almost entirely prior to 1986. Then, following 1986 this condition would occur only seasonally as the demand for crude in the northern markets of PADD II changed seasonally. Then this condition began to be replaced by parity conditions elsewhere (the Midwest) with the continuing decline in the West Texas and Midcontinent production to the point when there was no more flow to the USGC from the West Texas area (refer to the regional balance charts shown earlier).

FIGURE III- 12

GULF COAST PARITY RELATIONSHIPS

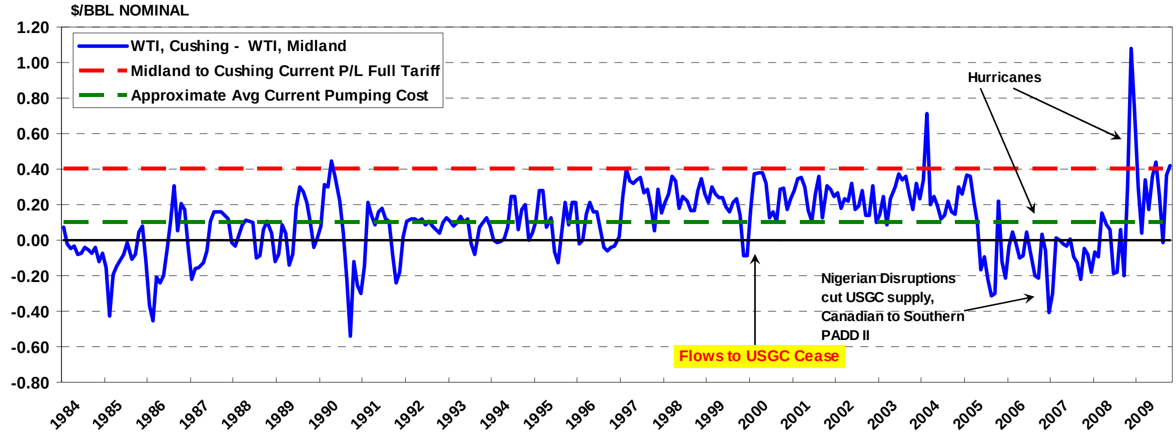


Illustrative Purposes—Prices and Tariffs reflect early 2000s, excluding loss/insurance and credit float. Through tariffs not reflected.

The absolute base prices shown on the above chart are hypothetical, but not far off the averages of WTI through the period from 1986 to about 2000 when the flows to the USGC ceased and this pricing was completely replaced by others. The prices at the various locations are a function of the direction of flow and the tariff on the pipelines. The base price set at the USGC is $20/Bbl. The price at Houston and St. James are essentially equal for similar quality crudes since both the regions are common destinations for the same foreign sweets. At that point the flow of crude from West Texas was toward the USGC refineries as well as northbound toward Cushing and on to the Midwest refining centers at Patoka, IL and Chicago IL. The Midland Texas gathering hub for the West Texas/New Mexico crudes had pipelines headed in both directions. Midland WTI netbacks at that point would be $19.70/Bbl assuming a representative rate for the systems existing for that delivery. But, the actual data for prices show WTI at Cushing averaging only in the $19.75/Bbl range and well below the full tariff for the delivery from Midland to Cushing, representing the approximate incremental cost of pumping the crude from Midland to Cushing.

The actual historical relationship between WTI at Midland and WTI at the Cushing hub is shown in Figure III-13, following. Actually, there is a slight quality difference between the Midland average WTI and the Midcontinent Sweet at Cushing, designated as WTI, but the differences are not large and the comparative relationship is a reasonable reflection of the transportation factor.

FIGURE III - 13
WTI, CUSHING minus WTI, MIDLAND



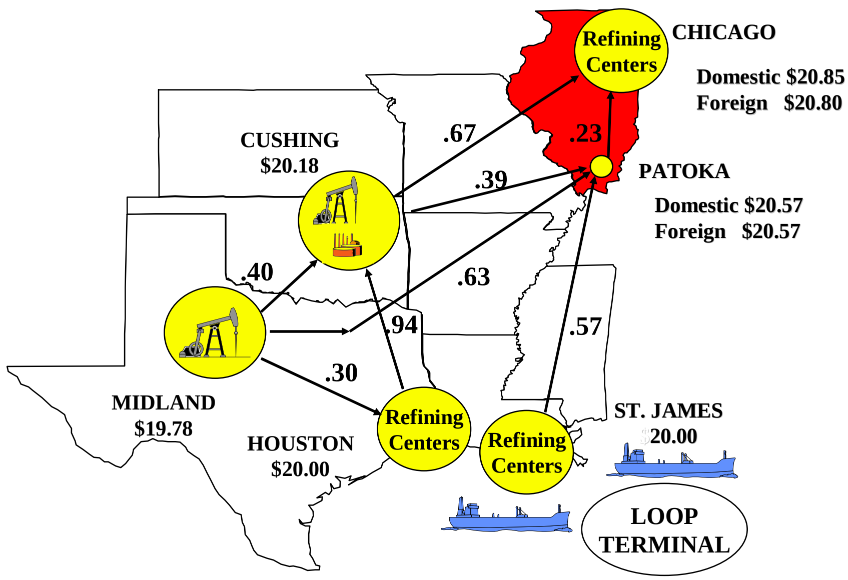
Under the conditions depicted in Figure III-12, the USGC pricing netbacks are considered the price parity mechanics. It can be seen that the most optimal supply in Patoka under this scenario would be the domestic choice rather than the USGC origin of domestic or foreign sweet. This is also true for Chicago, with the higher of the available shipper tariffs chosen as the basis on the chart since the lower tariff alternatives by the posting companies would typically fill first and then the incremental supply would roll to the other shippers. Data also confirm over the years that the international alternative drops to seasonal minimum flows during this parity scenario. This Gulf Coast Parity scenario would evolve from the only scenario prior to 1986 to a seasonal scenario from then to about 2000. Then it would cease to exist at all as the flows south would end and the associated pipelines would be shut down.

But, after 1986 there were other scenarios that enter the picture. In addition to the Gulf Coast scenario occurring seasonally, usually during the low refinery demand period of the year, as the season progressed and demand steadily rose in the high capacity refining centers in the Midwest, the parity location would steadily shift. The first of these northbound scenarios would be the Patoka IL parity point. Patoka is a pipeline hub from which supplies originating from the Cushing area, and also from the Gulf Coast, are redistributed toward Chicago and eastward toward Ohio refining centers. So, Patoka is a location that saw direct competitive interface between the domestic sweet out of Cushing and the domestic and/or foreign sweets coming up the Capline system to Patoka. Flows of crude into this parity point would reflect the economic incentive for such movements.

Figure III-14 shows this set of conditions and the respective prices that result. First, note that the prices at Patoka are equal (assuming same quality) for the domestic and the international/domestic alternative coming from the USGC, thus the designation as Patoka parity. The Patoka base price is set by the USGC supply alternative that is required to meet that local demand. Subsequently, this also sets and raises the parity price for the domestic sweet WTI. Now, the prices of the WTI at the other locations are simply set by the netbacks from Patoka forward to those other locations based on the pipeline tariffs. The price at Cushing, thus, becomes $20.18/Bbl while the price of the sweet crude at the USGC, set by the international interface, is still $20.00/Bbl. This is a change of plus $0.43/Bbl for the WTI without any change at all to the base price at the USGC. The WTI is still linked to the USGC underlying price basis, but the location of the parity condition has shifted, changing the final price of the Cushing WTI. Note also that the netback price at Midland now reflects the full tariff because there is a demand for the Cushing crude outside that area and it pulls down the excess supply from the previous parity scenario. The netback to Midland directly from Patoka would yield a higher Midland price, but this route would be filled first, leaving the incremental or last barrels set by the higher overall tariff route.

FIGURE III- 14

PATOKA PARITY RELATIONSHIPS

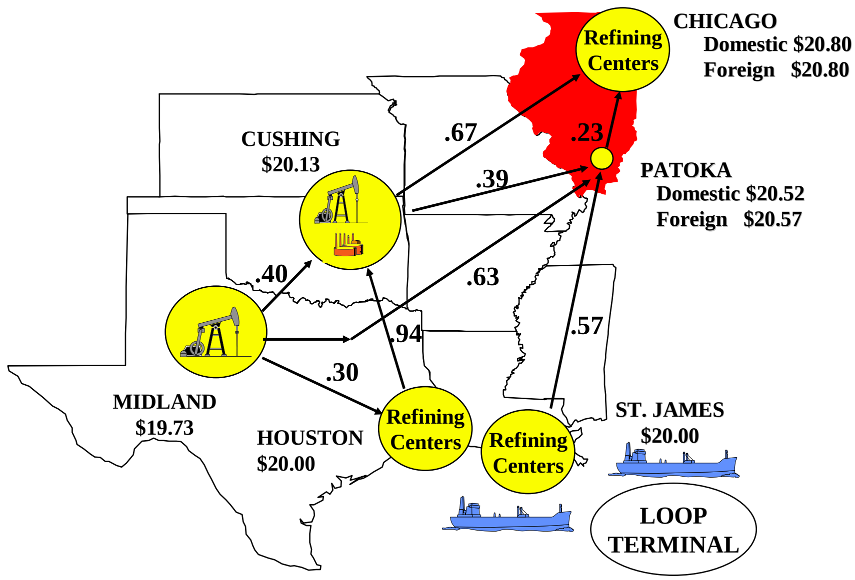


Illustrative Purposes—Prices and Tariffs reflect early 2000s, excluding loss/insurance and credit float. Through tariffs not reflected.

Progressing forward into the maximum demand cycle for the Midwest refining system, the next phase achieved for the arb is created by the need for the international/domestic supply in the Chicago area. The Chicago refiners will have already taken all the lower cost domestic out of the Cushing area, but will have ultimately bid up these barrels to the same price (assuming equal quality) as the alternative USGC supply. Now the prices from both sources will be the same at Chicago, thus the designation as **"Chicago Parity."** The price of the WTI at other locations will now be based on the Chicago Parity price netted back to the origin locations by the respective pipeline tariffs. Note that in this scenario, the WTI Cushing price will still be above the USGC sweet price. The Midland price will also remain below the USGC sweet price with the economic incentive still slightly in favor of pulling barrels out of southbound delivery.

FIGURE III- 15

CHICAGO PARITY RELATIONSHIPS

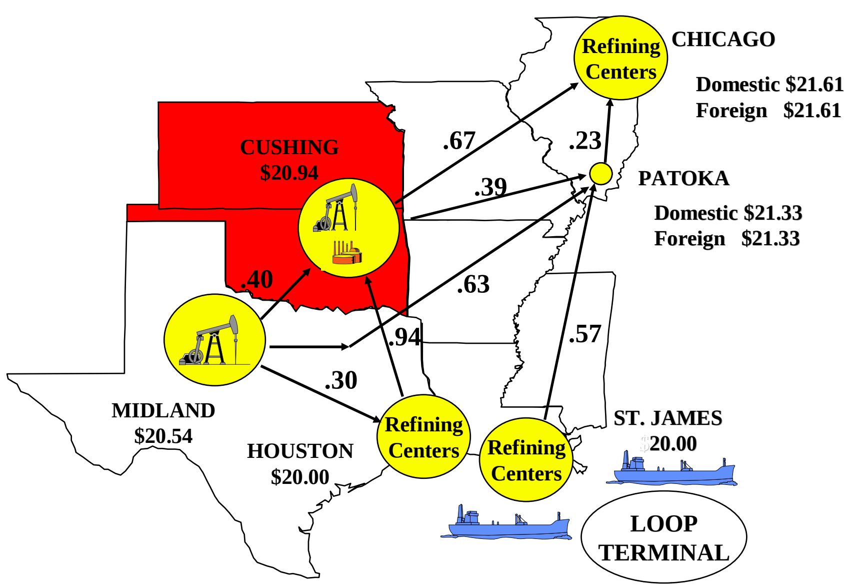


Illustrative Purposes—Prices and Tariffs reflect early 2000s, excluding loss/insurance and credit float. Through tariffs not reflected.

The next scenario is designated as **"Cushing Parity".** The conditions necessary for this maximum price for the WTI is a demand for supply in the Midcontinent area itself that exceeds the amount available from the local production plus the amount of available from transferred West Texas. Offshore supply is needed and the price is equal to the Gulf Coast price plus the pipeline tariff. WTI will be almost $1.00/Bbl above the Gulf Coast price.

FIGURE III- 16

CUSHING PARITY RELATIONSHIPS



Illustrative Purposes—Prices and Tariffs reflect early 2000s, excluding loss/insurance and credit float. Through tariffs not reflected.

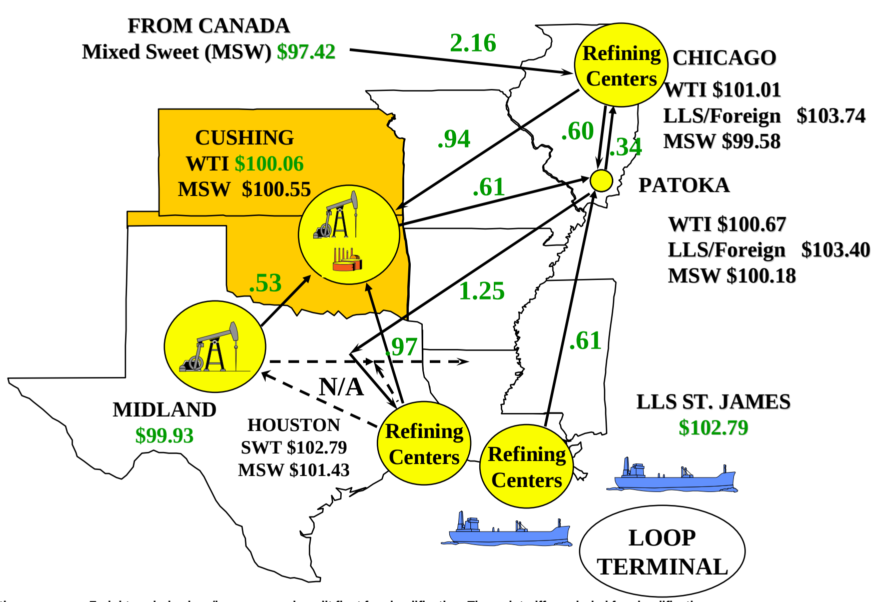
In the above scenario, the prices for the majority of the sweet crude in the Patoka and Chicago area will actually be lower than the Cushing price delivered forward to those areas, assuming the availability of pipeline space on the Capline system for accessing the lower cost USGC supply. The case shown here is for the final volumes to meet full demand having to originate from Cushing due to a full Capline condition. The tariff used in this example is an ownership weighted average. If additional supply were needed beyond this then the prices would rise to a higher level represented by the Cushing price plus the appropriate tariffs and would include the WTI and foreign out of Cushing originating through Seaway.

As time progressed into the mid 2000s, the dynamics of the region continued to change. The key elements of this change involved the upgrading of the refineries in the Midcontinent to process more sour and heavy crudes, as was discussed in the previous subsection on the fundamental trends (Figure III-10). Also, a critical component was the growth of availability of Canadian crudes penetrating farther south into the U.S. market. By 2006 there already was a reversal of the Cushing to Chicago pipeline, with new ownership by Enbridge and named the Spearhead Pipeline. There are numerous other pipeline projects underway and others in the planning stages which will continue the progression of Canadian supply all the way to the Cushing market and even beyond to the USGC. For the most part these projects are geared toward delivering Canadian Heavy crudes south, but Canadian MSW and SCO can also be delivered. These conditions will be changing the pricing dynamics again.

Combining these fundamentals with some very unusual circumstances over the last several years has created the most volatile market ever experienced with respect to price relationships for WTI versus other benchmarks like LLS and Brent. The actual average 2008 scenario is depicted in the parity chart format below, Figure III-17, and then a more definitive description of how these relationships evolved will be presented.

FIGURE III- 17

2008 ACTUAL PRICE AND PARITY RELATIONSHIPS



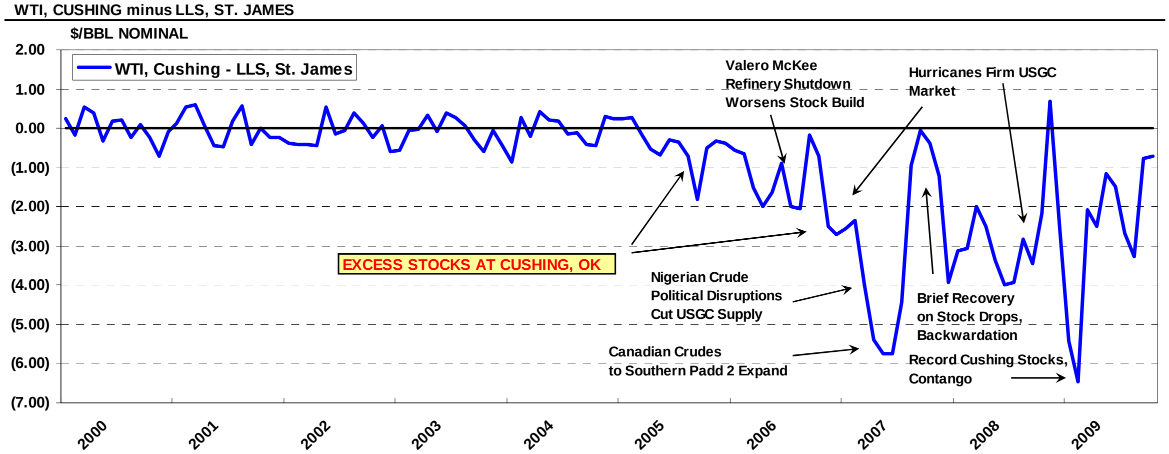
Illustrative purposes—Freight excludes loss/insurance and credit float for simplification. Through tariffs excluded for simplification.

In the chart above, the actual quoted prices for WTI, Midland TX and WTI, Cushing OK are shown. The actual price of LLS, St. James LA is also represented, with the Houston area sweet reflective of the offshore sweets that are delivered there and to the St. James terminal in competition with the LLS. The other prices represent those of the WTI or offshore (similar quality) delivered by pipeline to the respective locations. Canadian prices are represented by Mixed Sweet (MSW). **The figure is intended to be illustrative and, for simplicity, the calculated delivered values are based on the tariffs only and do not include losses/insurance or time value of money, nor are potential through tariffs represented.**

Among the important parity comparison results here is that the Cushing WTI price is quite substantially lower than the sweet crude prices, LLS in particular, at the USGC, especially considering the tariff of almost $1.00/Bbl to deliver the offshore volumes to the Cushing area. There was a substantial flow of oil from the USGC directly to Cushing during 2008—150,000 barrel per day—so, clearly arbitrage was active, but the arbitrage, was not consistently LLS to WTI, but rather represented other crude streams, primarily domestic and offshore sours. The flow of sweet crude did amount to an average of about 20,000 barrels per day during the period. This implies a closed arb for those deliveries during much of this period, but often transactions are completed when the opportunity arises for short periods and the delivery volume timing may not be consistent with the price timing when the pricing relationship would indicate open arbitrage.

Figure III-18 shows the WTI relationship to LLS again, but focusing now on the shorter term trends from 2000 forward and with notations of key market events that have been among those influencing this relationship over the last few years.

FIGURE III - 18
WTI, CUSHING minus LLS, ST. JAMES

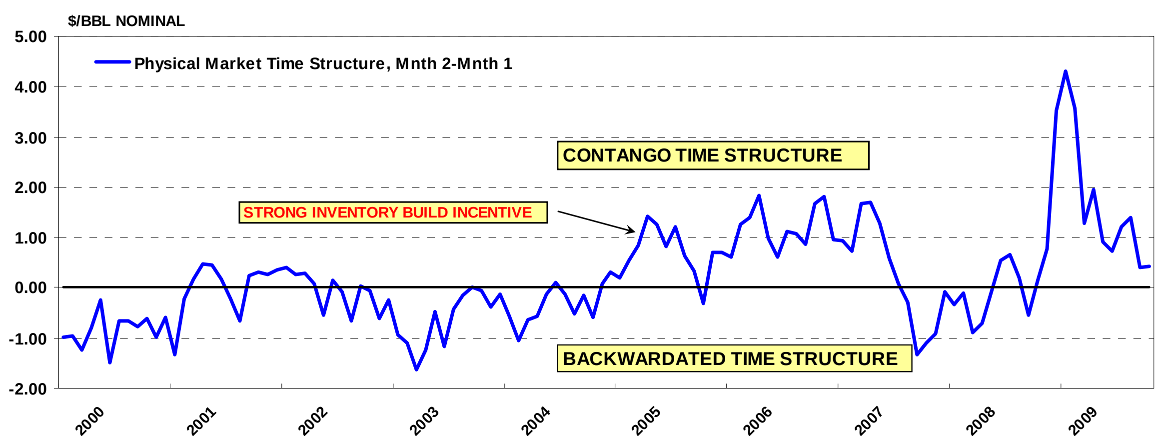


From 2000 through 2004, the WTI/LLS spreads oscillated in a mostly typical seasonal fashion, ranging from about plus $0.50/Bbl to minus $0.50/Bbl, and averaging near zero. But, from 2005 forward the relationship began to change significantly from this pattern. Through 2005 and early 2006, the discounting of the WTI to LLS went hand-in-hand with the build of stocks in the PADD II and Cushing area. This build occurred for two reasons. First, for a part of that period in 2006 the market suffered an exogenous shock when an explosion shutdown the Valero McKee Texas refinery for several months. That refinery takes a steady flow of sweet crude out of

Cushing, and the shutdown forced a short term backup of that supply into the area at a time when other factors had already led to abnormally high stocks in the region.

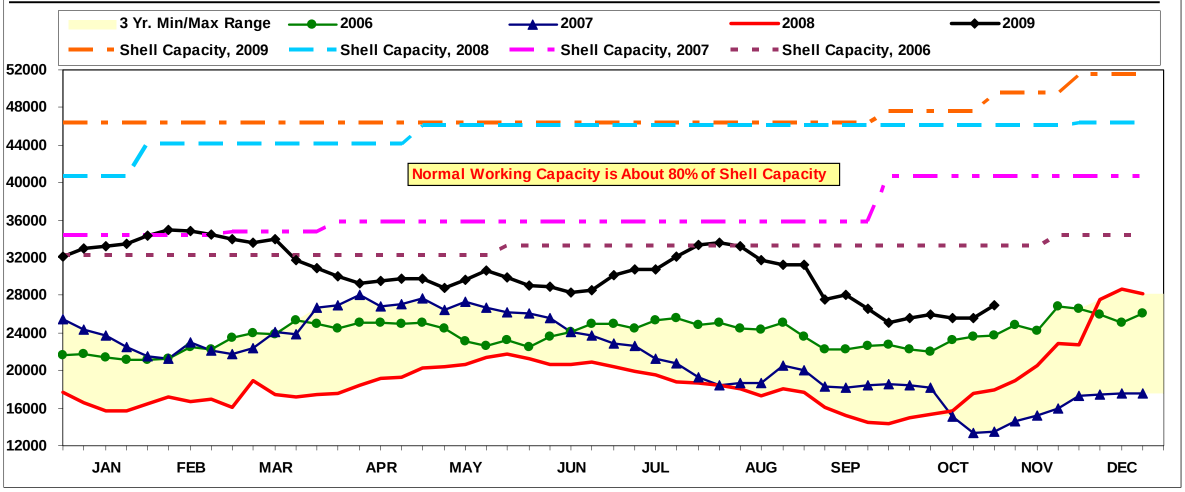
Second, through this period, there were also trading issues that drove the inventory builds. Figure III-19, following, shows the time structure of the physical WTI market. This is the price for the second month delivery (two months forward of the current month) less the near month delivery (month following the current month). From 2000 to 2004 the market was almost always in a "backwardated" configuration. This means that the forward prices were lower than the current prices, leaving a negative financial incentive to carry anything other than the minimum operating level of stocks with due consideration to the other supply risks related to geopolitics. But, at the end of 2004 the market time structure shifted to "contango" which has the opposite influence on inventory policies and economics. A forward price higher than the current levels allows carriage of stocks that can be fully hedged on the NYMEX exchange and this induces builds in stocks. Then in late 2007 through early 2008 the market dropped back into backwardation, followed in late 2008 through 2009 by a shift to contango again. These volatile time structure trends translate into volatile prices and price relationships, especially when combined with other market factors like hurricanes.

FIGURE III - 19
MARKET TIME STRUCTURE HISTORY, WTI (Mnth 2) - WTI (Mnth 1)



The chart following, Figure III-20, shows the physical impact on the market of the time structure changes. There is little doubt about how the major buyers of the physical crude respond to the time structure. Very high stock levels existed through 2006 and through the early part of 2007 in line with the time structure. In fact, at the peaks through this period, stocks rose to near the operating maximums. Then as the economic incentive dissolved toward the end of 2007, stocks were drawn back down to operating minimums. This condition lasted through most of 2008 and then a reversal took place again with inventories rising to maximum levels late in 2008 and into the early part of 2009. Once again, in early 2009, stock levels moved to the operating maximums, and they have remained high through the year.

FIGURE III - 20
CUSHING OKLAHOMA HISTORICAL CRUDE OIL CAPACITY and INVENTORIES, THOUSAND BARRELS



Now, back to the parity chart, Figure III-17, the Canadian sweet prices at Patoka and Chicago were also lower than the respective WTI or offshore foreign crudes delivered to these locations. This, at least partially, reflects the push of the Canadian supply into the Midwest market, backing out the Midcontinent supply and lowering the prices in the upper Midwest to a Cushing netback. This situation was a factor recently when the price of WTI versus the Gulf Coast was temporarily much lower than it had been historically. **It is anticipated that the increased flows from Canada are going to persist and grow, but the total supply/demand balance, as reviewed earlier, shows the need for additional supplies in the Midcontinent beyond these volumes, including offshore sweets in the future. This reinforces the dynamic nature of the combined USGC, Midwest and Midcontinent market, and this dynamic nature is itself a reflection of the ongoing interactions, arbitrage and competition that takes place in this market. These are the very factors that have consistently contributed to WTI serving as such a liquid and relied upon benchmark for the world oil market.**

IV. MIDCONTINENT/U.S. GULF COAST INFRASTRUCTURE

INTRODUCTION

This section presents the details of the history and outlook of the logistical infrastructure including the sources, destinations and physical delivery and storage systems related to WTI and the crudes that can interface with the WTI in the competitive feedstock market. This physical system discussion and the resultant logical mechanisms of pricing that exist in the commercial trade, are crucial components in this study with respect to the educational value for understanding the relationships that have evolved over time, and for understanding the mechanisms that have caused the extensive volatility over the last several years. The topics to be discussed are outlined below:

A. **Storage—**This section will describe the physical crude oil storage infrastructure that is relevant to the regional market competitive trade dynamics. This would particularly include the storage history of the Cushing region, to the best of our ability to develop the historical details. But, it will also present the quantitative analysis for other commercial storage in this trade, including the storage in the USGC directly related to the pipeline connections to Cushing. It will also include commercial crude storage all along the Gulf Coast, such as the LOOP and other systems capable of storing crude for commercial trade.

B. **Pipeline Infrastructure and Capacity—**This section will present maps showing the logistics infrastructure of the primary crude oil gathering and delivery systems relevant to this study. It will define the historical capacities and ownerships of these relevant systems and the role they have played in the evolution of the trade and the respective pricing relationships. The discussion will also clearly define the likely and potential outlook scenarios for further transitions in the competitive delivery systems, especially as related to the interface of new Canadian supplies into the area.

C. **Refinery Connectivity—**Consistent with the item above, will identify all the refineries and refinery regions that are tied into the relevant systems. This will include the Midcontinent region facilities directly linked as well as the rest of the PADD II refiners that have access to the domestic streams and offshore supplies that can be delivered through the pipeline systems to competitively interface with WTI.

D. **Sources and Destinations—**This subsection would include a listing and description of the origins of competitive crudes in the commercial trade interface with the Cushing market flows. Likewise, the final destinations for these competitive supplies would be defined with a qualitative assessment of these transactions, as appropriate for each refinery.

E. Crude Oil Flows (Domestic and Foreign)—Detailed assessments of the flows of crude oils through the primary pipeline corridors feeding all the relevant competitive markets and refining centers will be discussed. This assessment, based on proprietary Purvin & Gertz, Inc models, extensively defines the volumetrics of the entire logistics systems including the deliveries by crude source (foreign/domestic) and type into all the major refining centers. This modeling system also incorporates the forecasts of flows based on the regional crude production outlook and the projected refinery runs in all the regions based on demand. This outlook is crucial in understanding the future evolution of pricing and economic drivers for trade in the Cushing region. The analysis derives from detailed projections of the demand for refined products over time and the analysis of capacity expansions based on a detailed refinery and projects database. The refinery runs, by foreign and domestic categories by crude type, generates insight on the volumetric flows into the refining centers through the existing and potential future pipeline systems.

This part of the analysis presents in text/graphics and map forms, the history and outlook for the underlying supply/demand dynamics of the Gulf Coast, Midwest and Midcontinent, with focus on the volumes of crudes needed and where they will come from in general.

CRUDE STORAGE INFRASTRUCTURE

CUSHING AREA STORAGE

As the delivery point for NYMEX futures contracts, the Cushing area is one of the largest commercial crude storage terminals in the U.S. A recent estimate put the shell capacity at the beginning of 2009 at 46.3 million barrels, with a working capacity of around 37.0 million barrels to allow for tank heels, safety concerns, maintenance, blending, and operability. The following table shows this capacity by operator.

CRUDE STORAGE CAPACITY AT CUSHING (Million Barrels)

Operator	January 2009 Shell Capacity
Enbridge	15.7
Plains	10.8
SemGroup	7.8
BP	7.8
TEPPCO	3.1
ConocoPhillips	0.8
Sunoco	0.3
Total	46.3

During 2009, there were projects underway to expand Cushing's storage capacity by another 8.3 million barrels. Both SemGroup and TEPPCO had announced expansions of about 3 million barrels each. In June 2009, Enterprise Products Partners announced that it was acquiring TEPPCO Partners, and reported capacity at Cushing as of November 2009 indicates that the project was completed.

Additionally, SemGroup filed for Chapter 11 bankruptcy last year, and although a separate master limited partnership (SemGroup Energy Partners, LP) owns most of the Cushing assets, it was at risk due to the extensive commercial relationships with SemGroup and its dependence upon that business for a large portion of its revenues. Reported capacity information for Cushing as of November indicates that the 3 million barrel project was completed.

During October 2009, Vitol announced that it was acquiring SemGroup Energy Partners and its 6.7 million barrels of Cushing storage assets. Vitol completed the transaction in November 2009 and renamed the partnership Blueknight Energy Partners, LP. There is also speculation that Vitol may add up to 4 million barrels of additional storage at Cushing, but no firm plans have been announced.

Plains All American Pipeline, the second largest storage operator at Cushing, is also expanding its facilities. Construction began during 2009 on 1.7 million barrels of storage, with an option to increase that by another 570,000 barrels. Completion is expected during the first half of 2010.

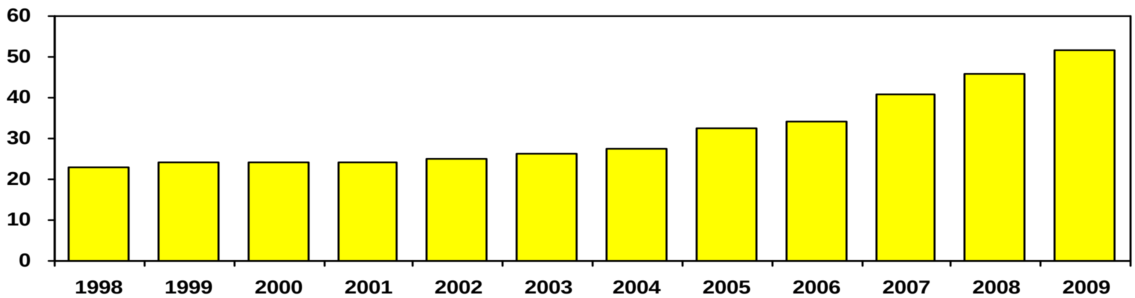
Finally, Enbridge removed some older tanks from service in 2009 and thereby decreased its total crude storage capacity by about 800,000 barrels. The following table shows the changes in Cushing's crude storage capacity during 2009. The total capacity is now 51.5 million barrels, with an operating capacity estimated at around 42 million barrels.

CRUDE STORAGE CAPACITY AT CUSHING
(Million Barrels)

Operator	January 2009 Shell Capacity	November 2009 Shell Capacity
Enbridge	15.7	14.9
Plains	10.8	10.8
SemGroup	7.8	4.1
Blueknight	--	6.7
BP	7.8	7.8
Enterprise/TEPPCO	3.1	6.1
ConocoPhillips	0.8	0.8
Sunoco	0.3	0.3
Total	46.3	51.5

Storage capacity at Cushing has only recently been this high. Total capacity had been around 23 million barrels since the mid-1990s. Capacity began to increase slowly in the early part of this decade at around 1 million barrels per year. However, between 2004 and 2009, capacity was increased by almost 90%, bringing the total storage capacity to 51.5 million barrels.

FIGURE IV-1
CUSHING CRUDE STORAGE CAPACITY
(Million Barrels)



Four firms—Enbridge, Plains, SemGroup, and TEPPCO—did most of the expansion. Enbridge purchased Shell's storage and acquired some of BP's capacity when it acquired BP's Cushing-to-Chicago pipeline with the intention of reversing it to bring Canadian crude to Cushing. As part of that effort, Enbridge has also built around 6 million barrels of new storage since 2005.

SemGroup purchased a small amount of capacity (0.8 million barrels) in Cushing in 2000, but had expanded that to 10.8 million barrels by late 2009. TEPPCO acquired assets from other parties in the early part of this decade and expanded its capacity twice, reaching 6.1 million barrels in 2009. Plains completed construction on 2 million barrels of storage at Cushing in 1994, and began adding capacity in small increments beginning in 1999. By the end of 2008, Plains had built its capacity to almost 11 million barrels, and has over 2 million more barrels of storage slated for completion in 2010.

PIPELINE-RELATED STORAGE

Many pipeline systems deliver crude to Cushing and will be discussed in the following section. These pipeline systems typically have storage assets associated with them to accumulate crude for shipment and to facilitate pipeline operations. Although this information is not published and readily available for all pipelines, the following table summarizes the publicly available data.

PIPELINE-RELATED STORAGE FACILITIES (Million Barrels)

Pipeline	Storage Capacity
Seaway	6.5
Spearhead	4.3
Osage	1.2
Basin	7.0
White Cliffs	0.1
West Texas Gulf	2.9
Capline	10.0
Centurion	5.0
Mid-Valley	4.2

US GULF COAST STORAGE

In addition to storage belonging to the various pipeline systems that can reach Cushing, there are several terminals along the Gulf Coast that can receive both foreign and domestic crude and supply those pipelines.

LOOP

The Louisiana Offshore Oil Port (LOOP) is a facility designed to directly unload deep draft crude tankers that are too large to enter U.S. ports and river systems. Normally these vessels must be "lightered", which refers to unloading the crude cargo while still offshore onto several smaller ships for transportation to the ports. Unloading the larger ships directly is faster and more economical, and reduces the chances for handling errors.

The LOOP facility began operations in 1981. Offshore, it consists of 3 mooring buoys 18 miles off the coast of Louisiana where large crude tankers tie up to unload. The cargoes are pumped to onshore facilities and stored in one of eight underground caverns or in newly completed above ground storage tanks. The cavern storage is quite large at 50 million barrels, and the above ground tanks have about 3.6 million barrels of capacity. LOOP also receives domestic crude production from the Gulf of Mexico.

Several pipelines connect LOOP's storage facility to both Louisiana and other Gulf Coast refiners. LOOP also operates a 53 mile pipeline called LOCAP that connects its facilities to Capline's St. James origination terminal.

LOOP was underutilized in its early years due to reduced refined product demand brought on by rising crude prices and expectations of inadequate crude supplies.

OilTanking

OilTanking is a German-owned company that provides terminal services around the world. They have three existing facilities along the U.S. Gulf Coast and one project under consideration.

OilTanking's Beaumont facility contains 4.2 million barrels of capacity and has connections to nearby refineries. The Houston terminal has over 11 million barrels of capacity and serves the Houston refining and petrochemical industry. Finally, OilTanking's Texas City facility has 3.2 million barrels of capacity with connections to the Texas City refining and chemical plants. The Seaway Pipeline travels nearby and appears to have connectivity to this facility.

The project under consideration is an offshore oil port, similar to LOOP, called the Texas Offshore Port System (TOPS). Oil tankers would unload at sea and the oil would be pumped to storage facilities in Texas City and potentially Port Arthur, TX. The current plans for the Texas City terminal are for 3.9 million barrels of storage capacity, and if the Port Arthur option was selected, it would contain 1.2 million barrels of capacity.

OilTanking began working on this project in August 2008 with two other companies—Enterprise Products Partners, LP and TEPPCO Partners, LP. In April 2009, both of those companies decided to exit from the venture. The project is currently stalled as the former partners work out the legal issues related to the Enterprise and TEPPCO withdrawal.

Sunoco Logistics

Sunoco Logistics operates a very large facility in Nederland, TX, near the Beaumont/Port Arthur refining center, with 17.8 million barrels of storage capacity. The terminal can receive foreign crude tankers and has connections to the area refineries and two of the U.S. Strategic Petroleum Reserve storage sites. Additionally, the Nederland facility is connected to the Millennium Pipeline, which transports crude to Longview, TX where connections can be made to the Mid-Valley Pipeline, which runs through southern Arkansas, northern Louisiana and the Midwestern states of Ohio and Michigan.

Vopak

Vopak is a Dutch company and operator of terminals worldwide. Vopak operates two terminals on the Gulf Coast, both of which are in the Houston area.

Vopak's Deer Park, TX terminal is on the Houston ship channel and serves the area's refineries and petrochemical plants. It has a capacity of over 7 million barrels. The Vopak Galena Park, TX terminal is also near the Houston ship channel and has about 1 million barrels of capacity.

Intercontinental Terminals (ITC)

ITC has a very large storage facility also located along the Houston ship channel where it has the capability to receive foreign crude cargoes. The terminal's capacity is just over 8 million barrels and has connections to the area's refineries.

The following table summarizes the Gulf Coast terminal locations and capacities.

KEY GULF COAST CRUDE STORAGE FACILITIES
(Million Barrels)

Storage Facility	Location	Capacity
Louisiana Offshore Oil Port (LOOP)	Clovelly, LA	53.60
OilTanking	Beaumont, TX	4.20
	Houston, TX	11.07
	Texas City, TX	3.24
Sunoco Logistics	Nederland, TX	17.80
Vopak	Deer Park, TX	7.01
	Galena Park, TX	1.04
Intercontinental Terminals Co.	Deer Park, TX	8.05
Texas Offshore Port System (TOPS) **	Texas City, TX	3.90

** potential

PIPELINE INFRASTRUCTURE AND CAPACITY

There have been many changes to the Midcontinent/Midwest crude pipeline systems, and many other changes are anticipated over the next five to ten years. At the end of this section, a summary of the historical, current, and expected future pipeline infrastructure is provided. Included in the summary are the following:

- Four maps (Figures IV-24 through IV-27) showing how the major pipeline infrastructure has changed over time. Each map represents a different year and corresponds to significant changes in the infrastructure. Comparisons between the maps show how the crude supply capabilities in the Midcontinent and the Midwest have changed over time.

- One table (Table IV-10) that serves as a compilation of the pipelines as they currently exist, along with their capacities, ownership information, and relevant commentary.

- Another table (Table IV-11) which depicts the major changes that have occurred in the pipeline infrastructure in a time line format.

The following includes more detail on the major pipelines that currently serve the Midcontinent and Midwest refining centers and those that are planned to begin operations with the next few years.

ALBERTA CLIPPER PIPELINE

Enbridge's Alberta Clipper project is an expansion of its Lakehead system that brings Canadian crude from Hardisty, Alberta to the U. S. Midwest at Chicago. Its purpose is to resolve expected capacity constraints between Hardisty and Superior, WI. When completed in mid-

2010, it will have a capacity of 450,000 barrels per day, and be expandable to 800,000 barrels per day.

BASIN PIPELINE

The Basin Pipeline is one of two major pipeline systems that move crude from the Permian Basin to Cushing. Gathering systems collect crude from various parts of southeastern New Mexico and western Texas and deliver it to Midland for transport on the Basin Pipeline. Because the Basin Pipeline is segmented and telescoping, the throughput capacity differs depending on the segment. Current capacities range from 144,000 barrels per day to 400,000 barrels per day.

The Basin system can also receive foreign crude and Gulf of Mexico production at its Wichita Falls, TX station for further transportation to Cushing.

BP NO. 1 / GULF ACCESS PIPELINE

This pipeline was formerly owned and operated by Amoco, which used it to transport crude from Cushing and from PADD IV (via a connection in Missouri) to its Whiting, IN refinery near Chicago. BP acquired the line when it purchased Amoco in the late 1990s. The capacity of the pipeline is about 175,000 barrels per day.

The PADD IV pipeline portion was sold in 1996, so after that point, only crude delivered through Cushing was transported on the line.

In 2007, BP initiated an open season concerning a project to reverse the No. 1 pipeline. Although there was significant interest from potential shippers, BP did not receive enough firm commitments to go forward with the project, and it was put on hold. The original plans called for completion in 2010 with a capacity of 100,000 barrels per day.

The No. 1 pipeline is now part of a joint venture project between BP and Enbridge. As part of Phase 1 of Enbridge's Gulf Access Pipeline, the pair intends to reverse the No. 1 pipeline and combine it with some new construction to enable movement of Canadian crude from Flanagan, IL (near Chicago) to Cushing. A new pipeline would also be built from Cushing southward to Houston area refiners, with a possible spur to Nederland, TX. The initial capacities of these lines are expected to be 150,000 barrels per day between Flanagan and Cushing and 250,000 barrels per day between Cushing and Houston. The project is targeted for completion in late 2012.

CAPLINE PIPELINE

The Capline Pipeline is a key system for moving Gulf of Mexico and foreign crudes to refineries in the Midwest. The pipeline has its origin at St. James, LA (between New Orleans and Baton Rouge) and is connected by the LOCAP pipeline to the LOOP on-shore storage facilities. Capline moves crude northward through several states before terminating in Patoka, IL, and has a capacity of about 1.2 million barrels per day when transporting lighter crudes.

Heavier crudes with higher viscosities reduce the capacity to below 1.1 million barrels per day, and viscosity surcharges have been applied to the tariff rates.

The pipeline has several owners, including BP, Marathon, Plains, and Southcap Pipeline. Although not an owner, Shell operates the Capline system.

CAPWOOD PIPELINE

The Capwood Pipeline is a short 57 mile pipeline that originates at the Patoka, IL crude terminal and connects with the crude terminal in Wood River, IL. It has a capacity of about 277,000 barrels per day and is operated by Plains All American Pipeline, LP.

CENTURION PIPELINE

This pipeline was formerly owned by Amoco and was acquired by BP when it bought Amoco in the late 1990s. In June 2007, Occidental Petroleum purchased this pipeline and renamed it Centurion. The line originates in southeastern New Mexico and brings Permian Basin crude to the Cushing terminal. It has a capacity of around 175,000 barrels per day.

Occidental has plans to reverse this pipeline in order to transport heavy Canadian crude arriving at Cushing to Slaughter, TX near the pipeline's origin. U.S. independent refiner Holly has completed a project to build connecting infrastructure to transport the crude from Slaughter to their refinery in Artesia, NM. The reversal is planned for implementation in the 4th quarter of 2009, and will have a capacity of 60,000 barrels per day.

CHICAP PIPELINE

The Chicap Pipeline originates at Patoka, IL where numerous other pipeline systems intersect. It delivers crude from Patoka to the refiners in the Chicago area market. BP operates the pipeline, which has a capacity of about 400,000 barrels per day.

CONOCOPHILLIPS PIPELINES

ConocoPhillips operates two pipelines that deliver crude from Cushing to its refineries in the region. The first is a twelve-inch line that serves ConocoPhillips' refinery in Ponca City, OK. The other pipeline is a ten-inch line that connects to the WRB Refining Borger refinery, which is a joint venture between ConocoPhillips and EnCana.

EXXONMOBIL PIPELINES

ExxonMobil operates a pipeline that brings West Texas crude from Midland to Corsicana. In prior years, once the crude reached Corsicana, it could continue on ExxonMobil's line to the Beaumont area, travel on the Pegasus Pipeline to Patoka, or enter other systems to reach Cushing. It had a capacity of about 215,000 barrels per day from Midland to Corsicana and a capacity of 150,000 barrels per day to Patoka.

In 1995, ExxonMobil reversed the Corsicana to Beaumont section of the pipeline. This allowed foreign crude imports into the Beaumont area to move onward to Cushing and Patoka. In 2006, the Pegasus Pipeline was also reversed, which combined with a re-reversal of the Corsicana-to-Beaumont line, provided the first route for Canadian crude to reach refineries on the Gulf Coast.

FORMER ARCO PIPELINE

This pipeline originally moved domestic crude from Jacksboro, TX (near Wichita Falls) to Houston. The line was under-utilized and in 1988, ARCO reversed the line and added tankage and additional pumping capacity to move imported crude from the Gulf Coast to Cushing. The capacity of the system was 120,000 barrels per day of light crude by early 1991. As more heavy crudes began to be needed in the Midwest and due to high viscosity premiums on the Capline system, the ARCO line began to see higher volumes, and as a result capacity was expanded to 160,000 barrels per day in 1993.

In 1995, ARCO and Phillips formed a joint venture to develop the Seaway Pipeline. ARCO contributed this pipeline to the venture.

GULF ACCESS PIPELINE

In addition to the aforementioned pipeline reversals (BP No. 1 and Ozark), Enbridge's Gulf Access project also involves construction of a new pipeline from Cushing to the Houston and Beaumont areas. This pipeline will serve to move Canadian crude along with other crude delivered into Cushing to Gulf Coast refiners. The system capacity is expected to be 400,000 to 500,000 barrels per day initially, but could be higher given the early stage of the project. Additionally, the expected completion of the new build part of the project is during 2012 at the earliest.

KEYSTONE PIPELINE

Like the Spearhead Pipeline, the Keystone Pipeline also serves as a way to bring Canadian crude to the U.S. Midcontinent region. Originating in Hardisty, Alberta, the project involves 232 miles of new pipeline in Canada along with the conversion of 537 miles of natural gas pipeline to crude oil service to the border with the U.S. On the U. S. side, 1,379 miles of new pipeline will be installed from the Canadian border through the Dakotas to the Nebraska/Kansas border where the line will split to take crude to Cushing, Wood River, IL, and Patoka, IL.

TransCanada and ConocoPhillips were joint venture partners in the Keystone project, but in 2008 ConocoPhillips decided to exercise its option to reduce its stake from 50% to 20%. In June 2009, TransCanada announced that it would purchase ConocoPhillips' entire stake and become the sole owner of the Keystone Pipeline.

Commission of the connection to Patoka, IL began in late 2009, and the pipeline will have an initial capacity of around 435,000 barrels per day. The extension to Cushing should be completed in late 2010 with a capacity of 155,000 barrels per day, which gives the system a total capacity of around 590,000 barrels per day. Considerable line fill is underway at the end of 2009 at this writing, which is influencing the pricing in the region.

In addition, an expansion of the Keystone system (called Keystone XL) has been proposed. This new pipeline would also originate in Hardisty, Alberta, but would travel in a more southeasterly direction to join with the original Keystone pipeline at the Nebraska/Kansas border. From there, Keystone XL would utilize the Keystone pipeline to Cushing, but would continue further to the Gulf Coast to reach Houston and Port Arthur, TX. This pipeline is designed for a capacity of 500,000 barrels per day and could be operational in 2012 if all regulatory approvals are received in a timely manner.

MID-VALLEY PIPELINE

The Mid-Valley Pipeline is nearly 1,000 miles long and is the primary means to transport crude from West Texas and the Gulf Coast to refineries in the eastern Midwest. The line originates at Longview, TX, terminates in Samaria, MI, and has a capacity of around 238,000 barrels per day.

MOBIL PEGASUS PIPELINE

Before its reversal in 2006, the Pegasus Pipeline served to move both domestic and foreign crude from Texas to the Patoka, IL terminal where it could be distributed to Midwestern refiners through various pipeline systems. It had a capacity of around 150,000 barrels per day.

Now that the pipeline is reversed, it serves as a channel (along with other lines) to bring Canadian crude to the Gulf Coast. In its current service, it has a capacity of about 96,000 barrels per day.

MUSTANG PIPELINE

The Mustang Pipeline originally carried crude from Patoka to Chicago, like the Chicap Pipeline, with a capacity of 100,000 barrels per day. It was reversed to move Canadian crude delivered through the Lakehead system south to Patoka for further delivery to refiners. Enbridge purchased a 30% interest in the pipeline in 1996 from ExxonMobil.

OSAGE PIPELINE

The Osage Pipeline is a 135 mile line that delivers crude from Cushing to El Dorado and McPherson, KS. It is owned by Magellan Midstream Partners and NCRA, a cooperative that produces fuel for farms, and has a capacity of about 135,000 barrels per day. The crude transported on this pipeline is processed by the Frontier refinery in El Dorado and the NCRA refinery in McPherson.

OZARK / GULF ACCESS PIPELINE

The Ozark Pipeline was acquired by Enbridge in 2004 from Shell and transports crude oil out of the Cushing hub to Wood River, IL. The capacity of the pipeline is about 170,000 barrels per day. From the Wood River terminal, crude can be delivered to the WRB Refining Wood River refinery, enter the WoodPat pipeline to go to the Patoka terminal, or head north on the Wood River pipeline for delivery to St. Paul, MN refineries.

As part of Phase 2 of its Gulf Access project, Enbridge plans to construct a new pipeline from its Flanagan, IL terminal to Wood River, and then reverse the Ozark Pipeline to deliver Canadian crude to Cushing. This project is expected to have a completion date in 2012 or beyond, and will have a capacity of around 200,000 barrels per day.

SEAWAY PIPELINE

The Seaway Pipeline is jointly owned by TEPPCO and ConocoPhillips and has a crude delivery capacity of about 350,000 barrels per day. It originates from the Jones Creek Tank Farm near Freeport, TX. A nearby marine terminal is capable of receiving foreign cargoes of crude oil and can offload those cargoes into the Jones Creek Tank Farm for shipment on the Seaway Pipeline to Cushing. Additionally, the Seaway line can also ship domestic on-shore and off-shore crude.

In addition to serving Cushing, the Seaway pipeline supplies a marine terminal in Texas City, TX. About 4.2 million barrels of storage capacity is in place in Texas City and Galena Park, TX to serve refineries in the Houston area.

The Seaway Pipeline was built to transport crude from Freeport, TX to Cushing, OK with a capacity of 300,000 barrels per day, but was converted to gas service in 1984 as the need for imports into the Midcontinent diminished in the early 1980s. As crude began to be needed again in the Midcontinent region in the 1990s, it was converted back to crude service in 1996 as part of the joint venture. An ARCO line from Texas City to Cushing (discussed later) was also part of the joint venture.

The Seaway system was originally composed of three pipelines, but the volumes could be handled on only two lines. Consequently, one of the lines was converted to refined products service in spring 1998. This reduced the Seaway capacity to 270,000 barrels per day. In 2000, as part of BP's purchase of ARCO, TEPPCO bought ARCO's share of the joint venture. The capacity of the line was subsequently increased to around 350,000 barrels per day.

There has been some consideration of reversing the Seaway Pipeline to move Canadian crude received into Cushing onward to Texas City refiners. However, no firm plans have been announced.

SOUTHERN ACCESS PIPELINE

The Southern Access project is also an expansion of Enbridge's Lakehead system. The first stage of Southern Access expanded capacity from Superior to Delavan, WI, and was completed in April 2008. The second stage extended from Wisconsin to the terminal at Flanagan, IL, and was completed in April 2009. The combined impact of both stages increases the capacity of the Lakehead system by 400,000 barrels per day.

Another related project, the Southern Access extension, will connect the Flanagan terminal with Patoka, providing more options for Canadian crude to reach U.S. refiners, including the Gulf Coast. It is expected to be in operation in late 2010 or early 2011, and have a capacity of 300,000 barrels per day.

SPEARHEAD PIPELINE

This pipeline was operated by ARCO before the company was purchased by BP in 2000, and was called the Cushing-to-Chicago pipeline. It was originally built to move crude from Cushing to ARCO's refinery in East Chicago. Although that refinery has been shut down, the pipeline continued to transport crude to other Chicago area refiners. The pipeline had a capacity of about 300,000 barrels per day.

In 1988, ARCO reversed a line that had previously transported crude from Wichita Falls to Houston. This provided a vehicle to allow foreign crude delivered to the Gulf Coast to move to Cushing, and then onward to Chicago if necessary on the Cushing-to-Chicago pipeline. In the mid 1990s, significant volumes of heavy crude were moved through these pipelines to avoid the surcharges on Capline for higher viscosity crudes.

As part of its efforts to move Canadian crude into new U.S. markets, Enbridge acquired the Cushing-to-Chicago pipeline from BP in 2005, reversed it, and in 2006 began shipping Canadian crude to Cushing. The pipeline had a capacity of 125,000 barrels per day at that time, and a project was completed in early 2009 to expand the capacity to 193,300 barrels per day.

During 2009, Enbridge completed Stage 2 of its Southern Access Pipeline expansion, which brought Canadian crude to its terminal in Flanagan, IL. At the same time, the initiation point of the Spearhead line was changed from Chicago to the terminal at Flanagan. The portion of the pipeline from Flanagan to Cushing is now called Spearhead South. The section of the line between Flanagan and Chicago has been reversed to allow Canadian crude reaching the Flanagan terminal to also flow north to Chicago. This section of the pipeline system is called Spearhead North, has a capacity of around 130,000 barrels per day, and was put into service in the 3rd quarter of 2009.

SUNOCO PIPELINES

Sunoco has a pipeline that originates at its Nederland terminal near Beaumont, TX and transports foreign crudes to the Longview, TX area terminal. The capacity of this line is around 35,000 barrels per day. However, Sun has leased capacity on other pipelines to move an additional 50,000 barrels per day to Longview. Crude moved to Longview via this route can join with shipments on the West Texas Gulf pipeline for further transport on the Mid-Valley system.

Additionally, Sunoco has a pipeline that can move crude from its Nederland terminal on the Gulf Coast to the Wortham/Corsicana terminal. Here the crude can enter the WTG line going to Longview, or continue northward to Wichita Falls, TX and Cushing. This pipeline was previously part of the WTG system and moved crude from Corsicana to Beaumont, TX area refineries, but was reversed in 1995. The capacity of this line is around 150,000 barrels per day.

However, in response to the large increases in Canadian crude planned to be delivered into Cushing, Sunoco has proposed to build a new pipeline from Cushing to its Wortham/Corsicana terminal, and then reverse its pipeline connecting to Wortham with Nederland to provide another pathway for Canadian crude to reach the Gulf Coast. The Cushing to Wortham/Corsicana segment is expected to have a capacity of around 300,000 barrels per day.

TEXAS ACCESS PIPELINE

The Texas Access project is in the early stages and involves the construction of a new pipeline between Patoka and the Texas Gulf Coast. This is a joint venture between Enbridge and ExxonMobil, and will bring Canadian crude directly from Patoka to the Nederland terminal near refiners in Beaumont without having to go through terminals at Corsicana or Cushing. Also proposed is a short pipeline from Nederland to Houston to allow the option to deliver Canadian crude to Houston area refiners. The capacity on the pipeline is expected to be around 400,000 barrels per day, and will be completed in 2013 or 2014.

WEST TEXAS GULF PIPELINE

The West Texas Gulf (WTG) Pipeline has several owners, including Sunoco Logistics and BP. Sunoco Logistics operates the pipeline, which transports crude from West Texas to the Wortham/Corsicana, TX area terminals before continuing on to Longview, TX. The capacity of this pipeline is about 300,000 barrels per day. At Longview, the crude can access other pipeline systems, including Sunoco’s Mid-Valley Pipeline, which serves refineries in Ohio and Michigan.

WEST TULSA PIPELINE

The West Tulsa Pipeline was also acquired by Enbridge from Shell in 2004 and moves crude from Cushing a short distance to Tulsa area refineries. It has a capacity of about 55,000 barrels per day.

WHITE CLIFFS PIPELINE

The White Cliffs Pipeline began operation in June 2009 to bring crude from Colorado to Cushing. SemGroup owns the pipeline, which has a capacity of 30,000 barrels per day. The system also includes a 100,000 barrel tank in Colorado to aggregate crudes for shipment.

WOODPAT PIPELINE

The Woodpat pipeline originates in Wood River, IL and connects to the Patoka, IL terminal. It is operated by Marathon and has a capacity of around 315,000 barrels per day.

REFINERY CONNECTIVITY

The refineries in PADD II depend on the various pipeline systems to supply both foreign and domestic crude. The following section outlines the refiners supplied by Cushing and by competitive flows, and includes a summary table at the end.

OKLAHOMA REFINERIES

The largest refinery in Oklahoma is the 194,000 barrels per day ConocoPhillips refinery in Ponca City. It is supplied from Cushing by a short, ConocoPhillips-owned northbound pipeline.

The Tulsa area has two refineries—a 70,000 barrels per day plant formerly owned by Sinclair and an 85,000 barrels per day facility formerly owned by Sunoco. Both plants were purchased by Holly in 2009, and are supplied by the West Tulsa pipeline from Cushing.

Southern Oklahoma contains the 84,000 barrels per day Valero Ardmore refinery and the 72,000 barrels per day Wynnewood refinery owned by Gary Williams Energy. These refineries are primarily supplied by regional crude production and by larger pipelines transporting crude to Cushing.

KANSAS REFINERIES

The three refineries in Kansas are somewhat larger. The Frontier refinery in El Dorado and the NCRA refinery in McPherson have capacities of 118,000 barrels per day and 81,000 barrels per day, respectively, and are supplied by the Osage Pipeline from Cushing as well as other pipelines.

The other refinery is located in Coffeyville and is owned by Coffeyville Resources, LLC. The refinery's capacity is 122,000 barrels per day and is supplied by a Plains pipeline from Cushing.

ILLINOIS/INDIANA REFINERIES

Refineries in Illinois are located in two major areas—the Chicago region and the central part of the state. The central region is also home to two large terminal areas—Wood River and Patoka. These two locations receive domestic crude from Cushing as well as Canadian crude from the north and foreign cargoes from the Gulf Coast.

Refineries in the central part of the state include the 306,000 barrels per day Wood River refinery (owned by WRB Refining, a joint venture between ConocoPhillips and EnCana) and the 204,000 barrels per day Marathon refinery in Robinson, IL. Both refineries are near the Patoka and Wood River terminals and can be supplied by many sources.

The Chicago area is home to several large refineries. The largest is the BP facility in Whiting, IN (just across the Illinois state line) at 410,000 barrels per day. ExxonMobil's Joliet, IL refinery has a capacity of 239,000 barrels per day and CITGO owns a 167,000 barrels per day refinery in Lemont, IL. These refineries can receive Canadian crude via the Lakehead system, and can also receive domestic or foreign barrels from the Wood River area via the ChiCap pipeline.

TEXAS REFINERIES

Two refineries in the Texas Panhandle are also supplied by Cushing. The WRB Refining, LLC Borger refinery (joint venture of ConocoPhillips and EnCana) has a capacity of about 146,000 barrels per day and receives crude from Cushing as well as areas in West Texas. The refinery can also receive foreign crude through company-owned pipelines.

The other refinery is owned by Valero and is located in Sunray, TX. It has a crude capacity of about 170,000 barrels per day. Crude is supplied by pipeline from regional sources as well as from Cushing. Additionally, pipelines connect the refinery to Wichita Falls, where it can receive foreign crudes delivered via the Texas Gulf Coast.

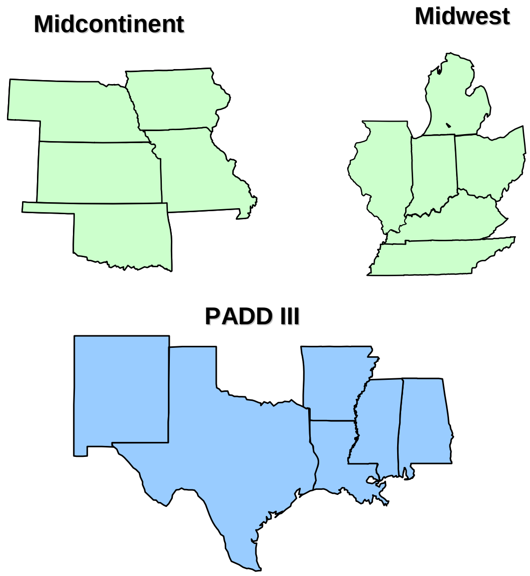
PADD II AND III REFINERIES WHERE WTI COMPETES

Company	City	State	Capacity (Barrels/Day)
Holly (former Sinclair)	Tulsa	OK	70,000
Holly (former Sunoco)	Tulsa	OK	85,000
Frontier	El Dorado	KS	118,000
NCRA	McPherson	KS	81,000
WRB Refining	Wood River	IL	306,000
Marathon	Robinson	IL	204,000
BP	Whiting	IN	410,000
ExxonMobil	Joliet	IL	239,000
Citgo	Lemont (Chicago area)	IL	167,000
WRB Refining	Borger	TX	146,000
Valero	Sunray	TX	170,000

CRUDE OIL FLOWS

The flow of crude oil from domestic and foreign sources to the varying U. S. refining centers has been influenced by many factors, such as availability of different types of crude, changes in crude distillation and conversion capacity, pipeline capacity and availability, pipeline tariffs, etc. The following section describes the historical flows of crude oil, by grade, source, and pipeline corridor, to the Gulf Coast (PADD III), Midwest and Midcontinent refining centers and provides an outlook on how those flows will change over time. The figure below outlines the areas that compose each of these regions.

FIGURE IV-2
MIDCONTINENT, MIDWEST, AND PADD III REGIONS



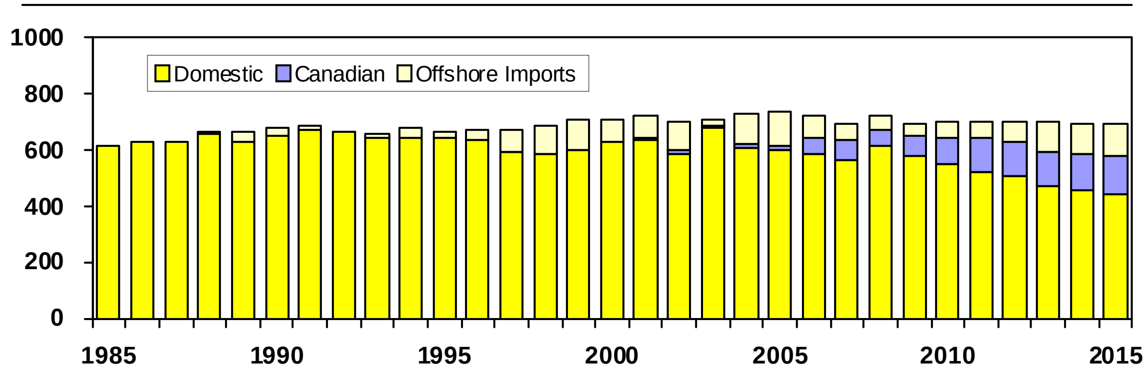
As used below, the crudes processed by the refining centers are categorized into grades based on their qualities. Sweet crude is defined as having an API gravity of 30 or higher and a sulfur content of less than 1%. Heavy crude is defined as having an API gravity below 28, and includes heavy, high sulfur grades as well as crudes that are heavy and low in sulfur, but have a high acid content. Finally, light sour is used to define those crudes that do not meet the criteria for inclusion into either the sweet or heavy categories.

MIDCONTINENT CRUDE RUNS

Given their inland location, the Midcontinent refiners have historically processed primarily domestic crude. With the startup of the Seaway Pipeline in 1996, foreign crude imports into the Midcontinent began to grow and continue to represent a significant part of the crude slate. Additionally, the reversal of the Cushing-to-Chicago pipeline to form the Spearhead Pipeline in 2005 led to increasing volumes of Canadian crude being delivered into Cushing for processing by area refiners.

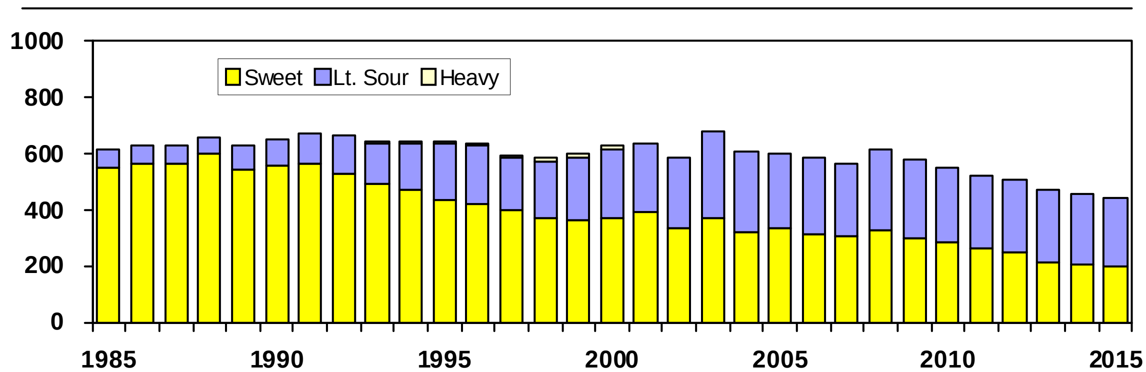
In the coming years, the decline in crude production in the region combined with the completion of the Keystone and Gulf Access pipeline systems is expected to result in the proportion of both Canadian and offshore imports in the crude slate continuing to rise.

FIGURE IV-3
MIDCONTINENT CRUDE RUNS BY SOURCE
(Thousand Barrels per Day)



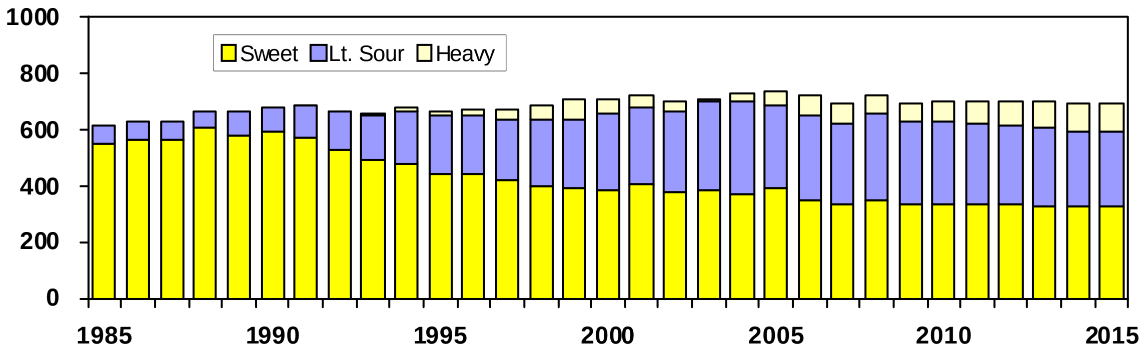
Midcontinent crude runs were largely composed of sweet crude in the late 1980s and early 1990s, with some light sour crude mixed in. The light sour portion of the domestic volumes processed began to increase rapidly around 1992, going from 16% of domestic runs in 1991 to 40% by 2000. This trend is expected to continue.

FIGURE IV-4
MIDCONTINENT DOMESTIC CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



Because such a large percentage of the entire crude slate is composed of domestic crude, the overall crude slate mirrored this trend of becoming increasingly light sour.

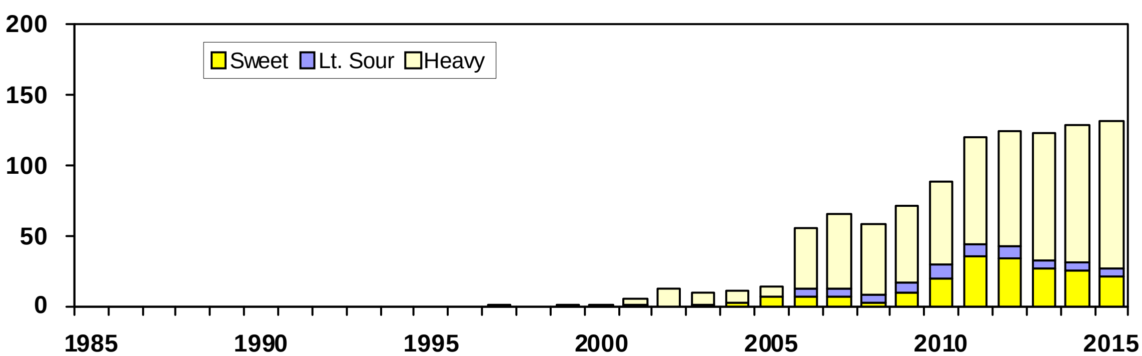
FIGURE IV-5
MIDCONTINENT CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



Heavy crude runs in the Midcontinent were very small until after the Seaway Pipeline started operations in 1996. Both light sour and heavy crude imports increased in the late 1990s as a result. The volume of heavy crude processed in the Midcontinent is expected to increase gradually over time.

In addition, the Canadian crude arriving into Cushing via the Spearhead Pipeline has been primarily heavy. As the heavy Canadian volumes increase with the completion of new pipelines, it is expected that the offshore imports brought to the Midcontinent via the Seaway Pipeline will increasingly be light sweet grades to balance the area refinery upgrading capacities.

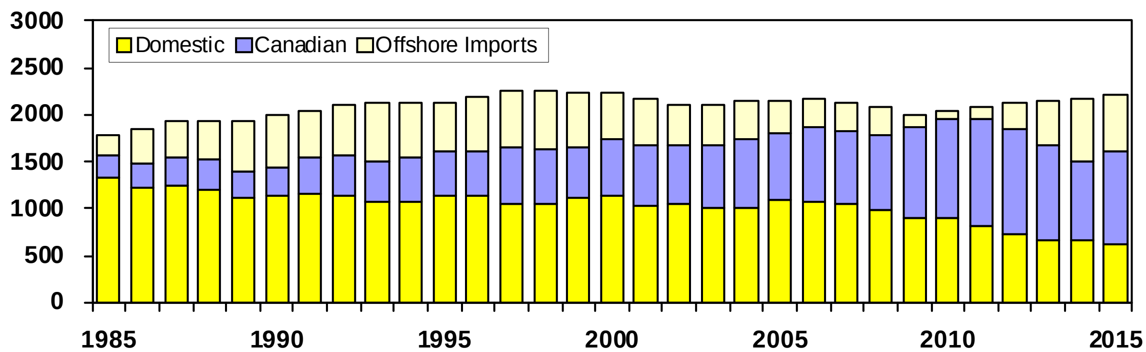
FIGURE IV-6
MIDCONTINENT CANADIAN CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



MIDWEST CRUDE RUNS

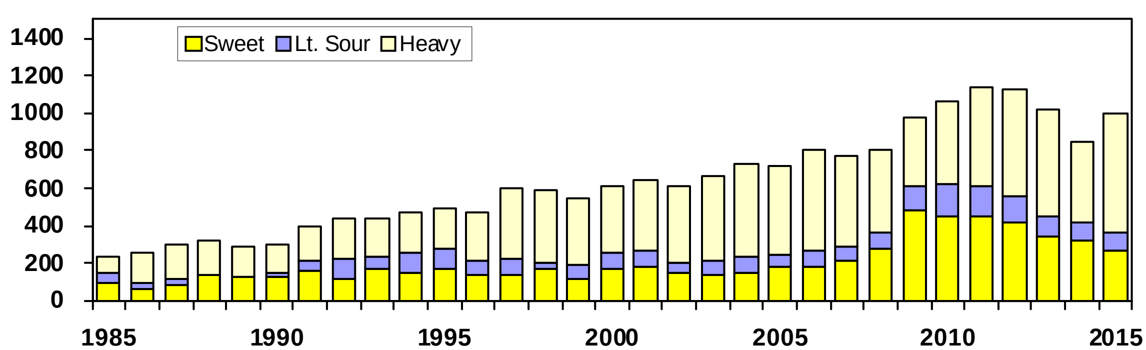
Midwestern refiners also processed primarily domestic crude in the late 1980s, but due to its closer proximity to Canada, began receiving Canadian crude in increasing amounts starting around 1991. This reduced the domestic crude share of crude runs from 76% in 1985 to around 50% by 1993, where it has remained. Expansions in Enbridge and TransCanada's pipeline capacities that will be completed in the coming years will continue to displace both domestic and offshore imported crude from the Midwest refiners' crude slates.

FIGURE IV-7
MIDWEST CRUDE RUNS BY SOURCE
(Thousand Barrels per Day)



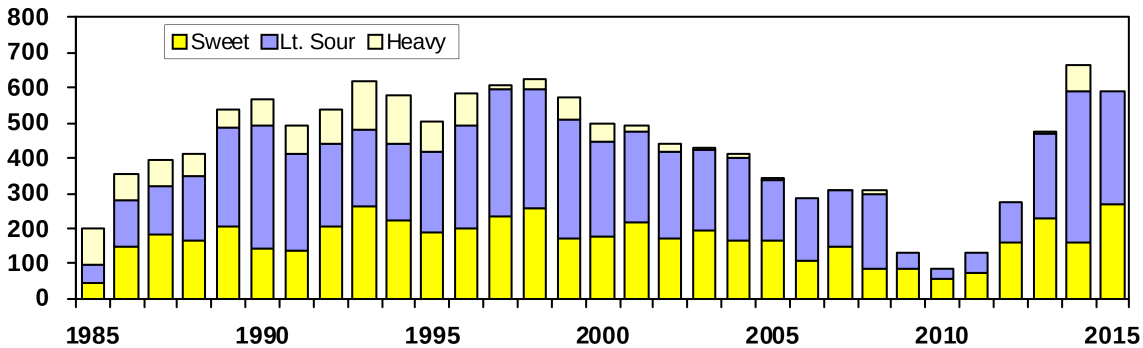
Canadian crude runs in the Midwest have been composed of mostly heavy crudes. In the early 1990s, heavy crude represented about half of the Canadian volumes brought into the Midwest. That figure moved to the 60-70% range after 1996. Heavy crude will continue to be a large share of the Midwest refiners' crude slates, although volumes of Canadian sweet crude and synthetic crude are also expected to rise in the near term.

FIGURE IV-8
MIDWEST CANADIAN CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



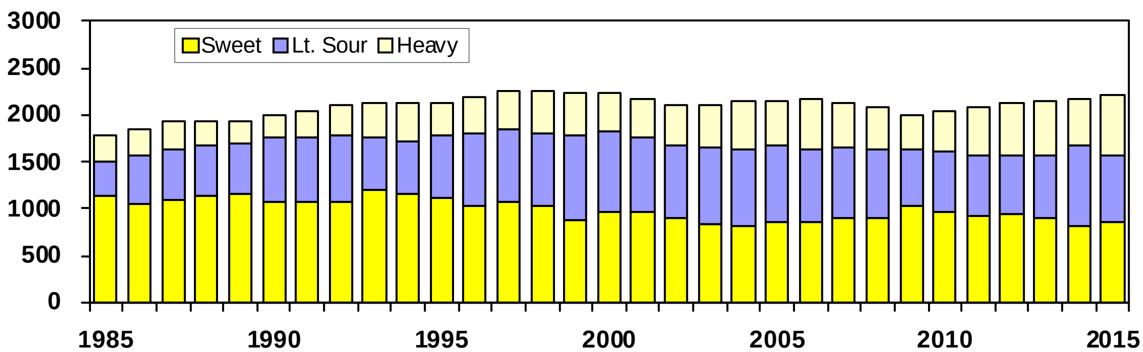
Offshore imports averaged about 25% of Midwest refiners' crude runs in the 1990s, but declined in the following decade to about 15% as increasing Canadian flows displaced them. Most of these offshore import volumes were light sour, with a significant amount of sweet volume in addition. These imports were mostly supplied by the Capline Pipeline, with some amounts also transported on the Mid-Valley Pipeline, the Pegasus Pipeline, and Ozark Pipeline via Cushing.

FIGURE IV-9
MIDWEST OFFSHORE CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



The combination of the crude sources into the Midwest has resulted in a fairly stable crude mix over time. Light sour volumes have been 30-40% of the crude slate since 1990, although there has been some gradual displacement of sweet by heavy crude from Canada since then. After 2014, light sour offshore imports are expected to begin declining as additional heavy Canadian supplies begin to arrive in the Midwest.

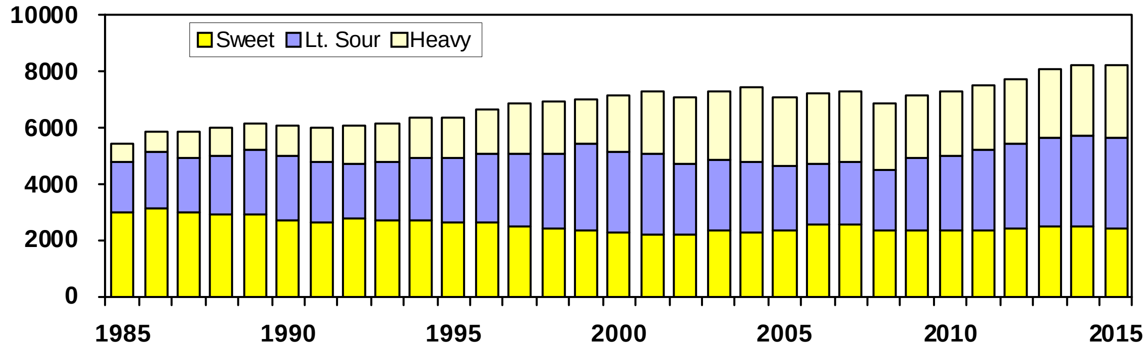
FIGURE IV-10
MIDWEST CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



GULF COAST (PADD III) CRUDE RUNS

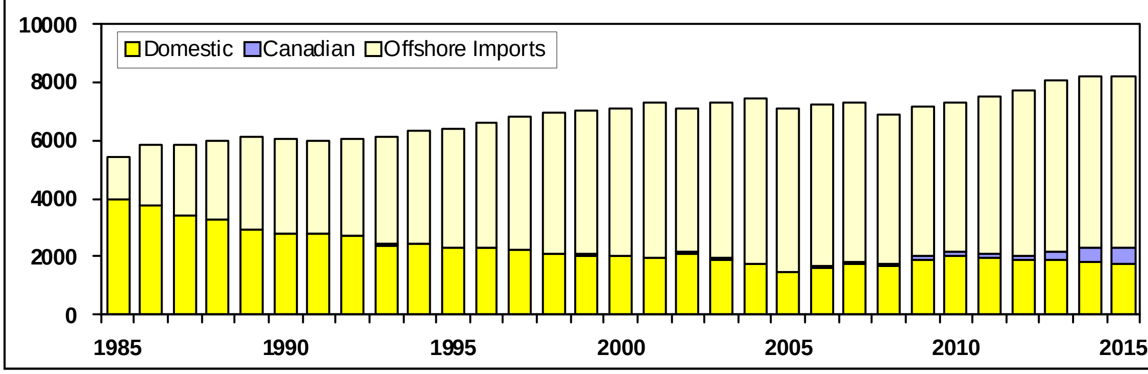
Refiners in PADD III have access to a large variety of crude oils, and over time have built a large amount of capacity to process heavier grades of crude. The fraction of total PADD III crude runs that are classified as heavy rose from under 20% before 1990 to about one-third of total runs currently. This increase in heavy crude runs has come at the expense of lighter sweet grades. Heavy crude is expected to continue to represent around 30% of crude runs in PADD III.

FIGURE IV-11
PADD III CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



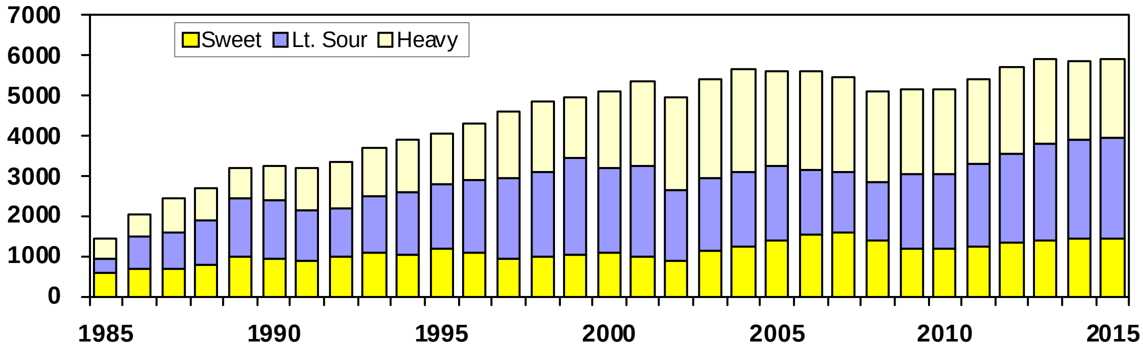
Total crude runs in PADD III have risen dramatically since the late 1980s as refiners have expanded capacity. As domestic volumes have declined, offshore imports have been brought in to fill the capacity.

FIGURE IV-12
PADD III CRUDE RUNS BY SOURCE
(Thousand Barrels per Day)



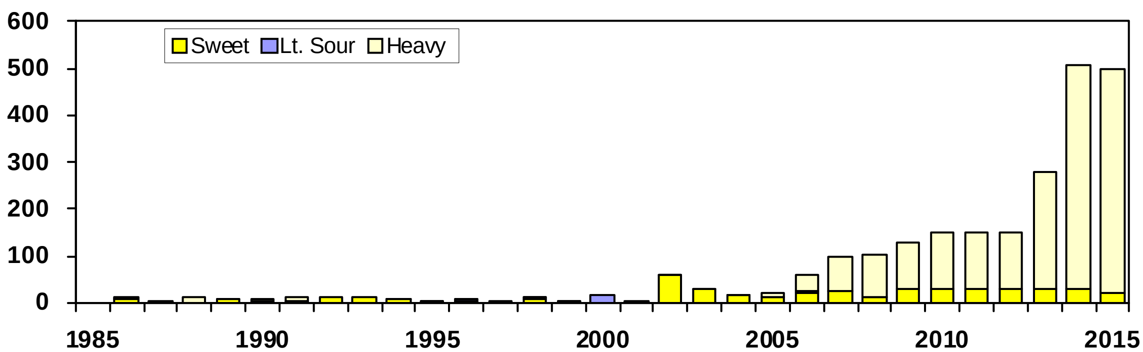
Offshore imports of crude into PADD III were about 30% heavy and 40% light sour around 1990. Heavy crude volumes grew faster than light sour, to reach nearly 45% currently. Sweet imports also increased as refiners sought to balance their crude slates to their individual capacities.

FIGURE IV-13
PADD III OFFSHORE CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



The reversal of the Pegasus Pipeline in 2006 created a pipeline route for heavy Canadian crude to reach refineries on the Gulf Coast. Heavy Canadian volumes began increasing after that point. Once the Keystone and Gulf Access Pipeline projects are completed in the 2010 to 2012 time frame, additional Canadian heavy crude will begin flowing to the Gulf Coast. These volumes are expected to reduce some of the offshore heavy crude imports, with light sour offshore imports making up most of the difference.

FIGURE IV-14
PADD III CANADIAN CRUDE RUNS BY TYPE
(Thousand Barrels per Day)



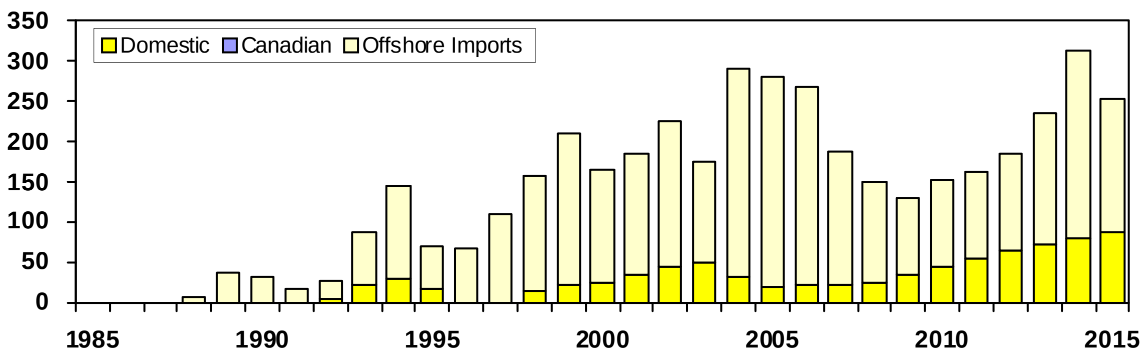
CRUDE FLOWS ON THE MAJOR REGIONAL PIPELINE SYSTEMS

Seaway Corridor

The Seaway Corridor consists of pipelines that transport crude from the Houston area to Cushing. The current Seaway Pipeline is a part of this corridor, including those lines that performed the same function before 1996 when the Seaway joint venture between ARCO and Phillips began operating. Some of the crude transported on this system to Cushing is processed in that region, but substantial volumes have also historically moved on to the Midwest and Upper Midwest on other systems. That portion, however, has been primarily the sour and heavy crudes, with the sweet imports more often staying in the Cushing area systems.

Flows in the Seaway Corridor have been primarily offshore imports, since the need for additional crude at inland refineries drove the need for the pipeline reversals and the Seaway system. Some domestic crude from local onshore fields and the Gulf of Mexico are also transported along with the foreign cargoes.

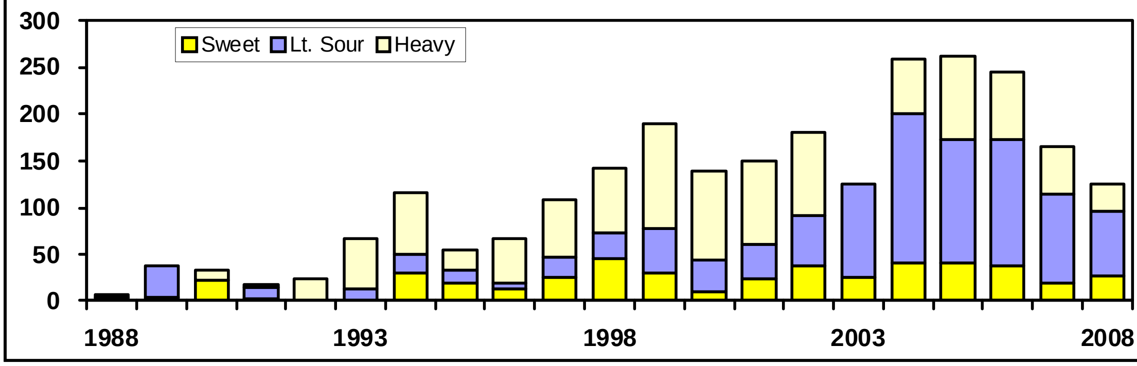
FIGURE IV-15
SEAWAY CORRIDOR CRUDE FLOWS BY SOURCE
(Thousand Barrels per Day)



As seen in the chart above, flows began once an ARCO line from Wichita Falls to Houston was reversed in 1988. Increased movements in the early 1990s spurred the formation of the Seaway joint venture, and volumes increased rapidly once the pipeline began operating in 1996.

A substantial portion of the offshore crude imports flowing through the corridor in the 1990s was heavy crude. Some of this volume was destined for Midwestern refineries and was shipped on the Seaway system through Cushing to avoid viscosity tariffs on the Capline system. As Canadian heavy crude began to be received in the Midwest in significant volumes in the 2002 to 2006 time frame, heavy crude shipped on the Seaway system began to fall toward levels needed by the Midcontinent refiners. Light sour volumes saw a corresponding increase as refiners balanced their crude slates to their capacities.

FIGURE IV-16
SEAWAY CORRIDOR OFFSHORE IMPORT FLOWS BY TYPE
(Thousand Barrels per Day)

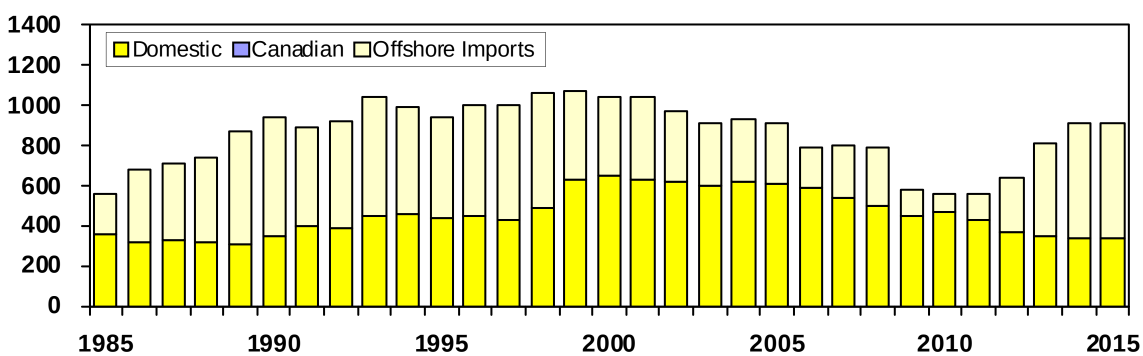


Capline Pipeline

The Capline Pipeline transports crude from St. James on the Louisiana Gulf Coast to the crude terminal facilities at Patoka, IL. From Patoka, crude can reach multiple destinations in the Midwest and Upper Midwest via other pipeline systems.

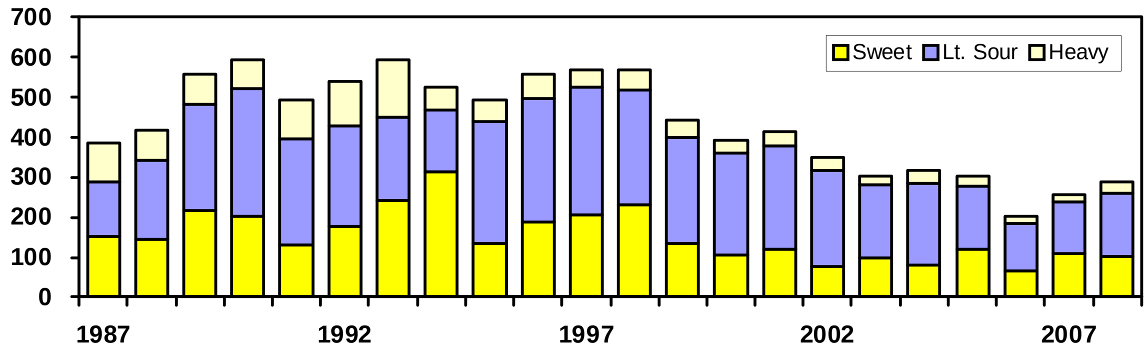
Due to the LOOP facility and associated onshore storage in Louisiana, a large amount of foreign crude is imported through southern Louisiana. Additionally, there is a substantial amount of crude production in the Gulf of Mexico off the Louisiana coast. Consequently, the Capline Pipeline transports significant amounts of both domestic crude and offshore imports to refiners in the Midwest. The percentage of offshore imports began declining around 1999 as increases in both domestic crude production and Canadian crude imports displaced some cargoes of foreign crude.

FIGURE IV-17
CAPLINE PIPELINE CRUDE FLOWS BY SOURCE
(Thousand Barrels per Day)



Offshore imports transported on the Capline Pipeline have been primarily light sour. Heavy crude has represented only about 10% of the Capline offshore imports volumes since the mid 1990s, in part due to the tariff on higher viscosity crudes. As mentioned above, many of these heavy crudes moved to the Midwest on the Seaway system instead.

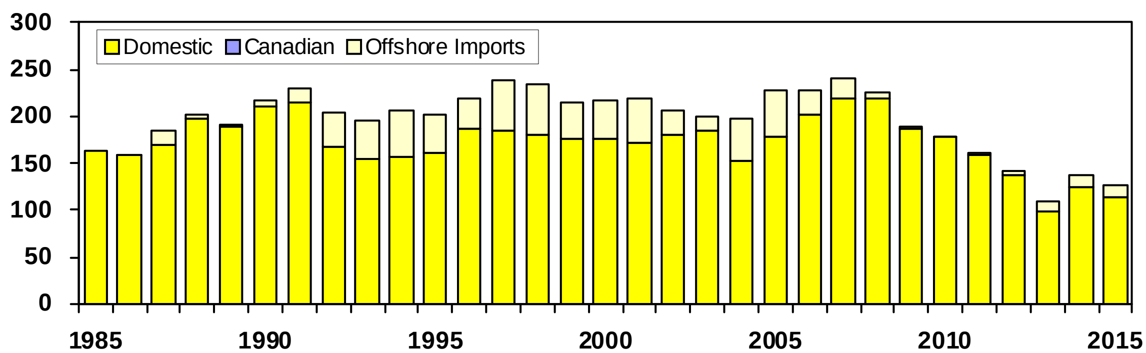
FIGURE IV-18
CAPLINE PIPELINE OFFSHORE IMPORT FLOWS BY TYPE
(Thousand Barrels per Day)



Mid-Valley Pipeline

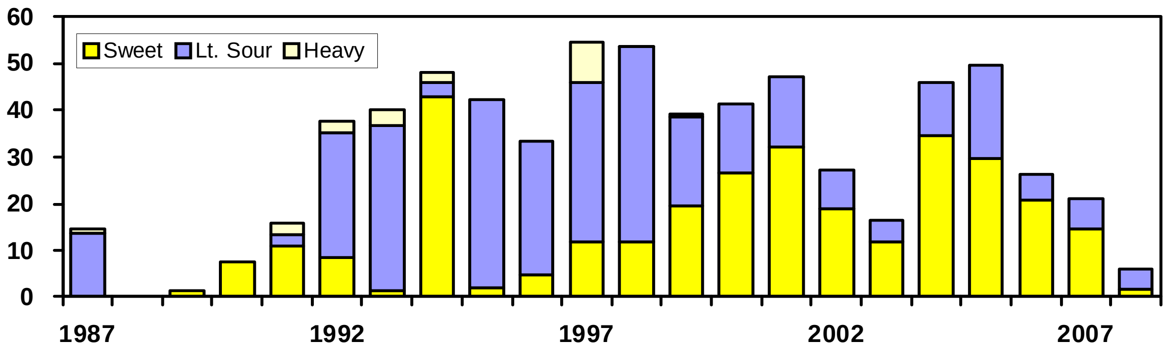
The Mid-Valley Pipeline has predominantly been a transporter of sweet, domestic crudes to the eastern part of the Midwest. Domestic crude has historically represented 75% or more of the total barrels moved on the pipeline.

FIGURE IV-19
MID-VALLEY PIPELINE CRUDE FLOWS BY SOURCE
(Thousand Barrels per Day)



Of the offshore imports that are shipped on the pipeline, both sweet and light sour grades have accounted for the majority of the volume. Some heavy crude has been shipped, but it has been sporadic and in small volumes.

FIGURE IV-20
MID-VALLEY PIPELINE OFFSHORE IMPORT FLOWS BY TYPE
(Thousand Barrels per Day)



CHANGES IN REGIONAL CRUDE FLOWS

The pipelines systems described above deliver crude based on the needs of refining centers to which they are connected. As changes such as additional capacity within refineries, additional crude supply, and pipeline reversals occur, the logistics of how the refineries are supplied also change. The graphics below provide an illustration the changes in crude flows experienced by the Midcontinent and Midwest crude supply systems. Only two comparisons are made here, but detail on other years is provided in tables at the end of this section.

1988 vs. 1998

The two diagrams, following, show the crude flows via pipeline corridors between crude supply areas and refining centers.

FIGURE IV-21
1988 ESTIMATED MIDCONTINENT/MIDWEST CRUDE OIL FLOWS
(Thousand B/D)

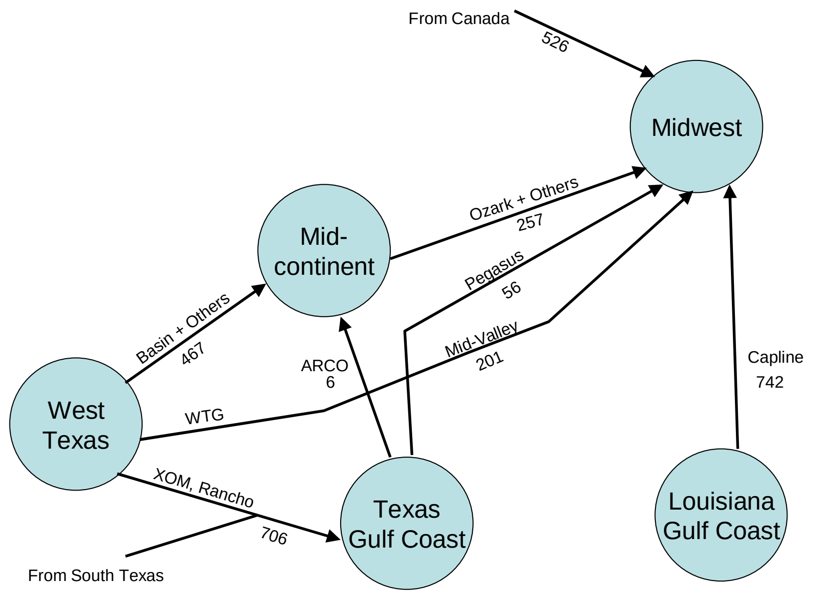
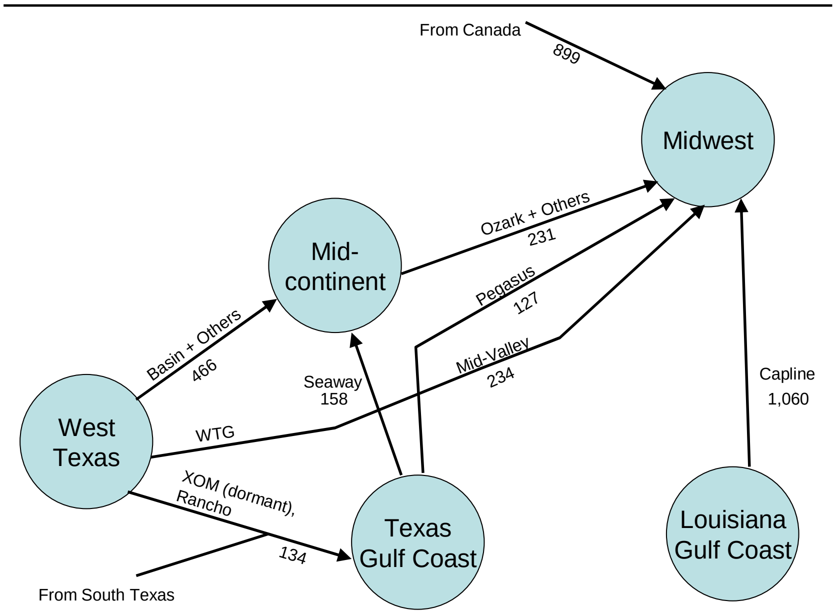


FIGURE IV-22
1998 ESTIMATED MIDCONTINENT/MIDWEST CRUDE OIL FLOWS
(Thousand B/D)



The supply of Canadian crude into the Midwest increased dramatically over this time period. Flows in 1988 were around 526,000 barrels per day and rose to nearly 900,000 barrels per day over ten years. At the same time, lighter grades supplied by Capline and others increased to balance crude slates with process unit capacities.

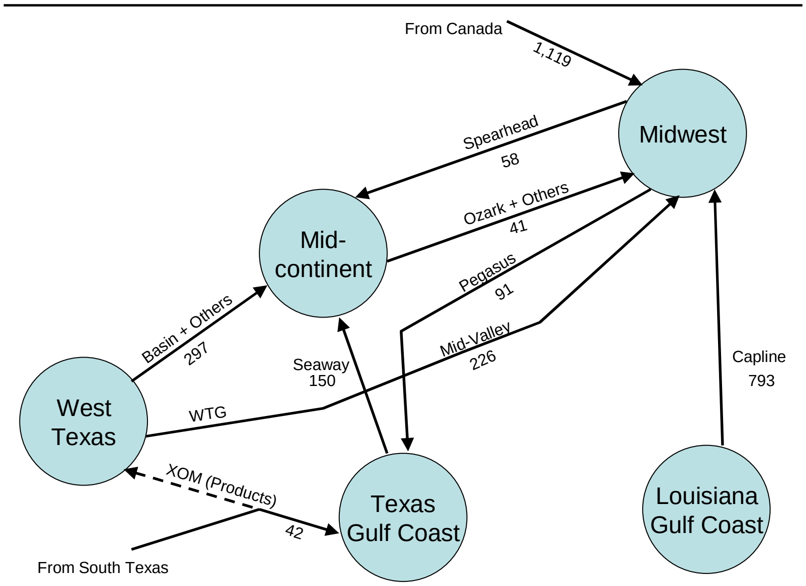
Additionally, a large reduction in West Texas crude supplied to the Gulf Coast occurred over this period. Volumes were around 700,000 barrels per day in 1988 but dropped to only 134,000 barrels per day in 1998. This reduction in WTI reaching the Gulf Coast began to cause pricing parity differentials between WTI at Cushing and other similar crudes at the Gulf Coast.

Also during this period, the Seaway Pipeline began operations and expanded the capacity to move crude from the Texas Gulf Coast to the Midcontinent. Volumes moved in this corridor in 1988 were near zero as there was little need for additional crude volume. As this need increased and could not be met with domestic production, imports from the Gulf Coast were required and stood at 158,000 barrels per day in 1998.

1998 vs. 2008

The diagram below shows crude flows from 2008. Domestic crude from West Texas supplied to the Midcontinent continued to fall, and was compensated for in 2008 by Canadian supply via the Spearhead Pipeline and reduced transfers to the Midwest.

FIGURE IV-23
2008 ESTIMATED MIDCONTINENT/MIDWEST CRUDE OIL FLOWS
(Thousand B/D)



Canadian flows to the Midwest also increased, and the Pegasus Pipeline was reversed in 2006 to allow Canadian crude to reach the Gulf Coast. The additional Canadian crude plus economy-driven reductions in crude runs in 2008 resulted in a declining need for offshore crude imports, as exemplified by lower Capline volumes.

West Texas crude production continued to fall and little if any volume reached the Gulf Coast, although Gulf Coast refineries did process small amounts of regional production from southern Texas. This further exacerbated the pricing parity issues between Cushing and the Gulf Coast. Due to low volumes, the ExxonMobil line was dormant for a period of time before becoming part of the Longhorn Pipeline in the late 1990s carrying refined products from Houston to El Paso. Additionally, the Rancho Pipeline shut down in 2003 and was converted to natural gas service in 2005.

TABLE IV-1
MIDCONTINENT CRUDE RUNS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
Total Crude Runs by Type																			
Sweet	552	591	445	441	422	398	391	388	411	381	387	375	394	349	336	350	334	336	328
Lt. Sour	65	92	208	212	217	238	244	273	272	282	313	325	291	304	288	310	294	291	265
Heavy	0	0	15	19	31	48	71	51	41	39	9	28	50	70	70	65	66	74	105
Total Crude Runs by Source																			
Domestic	617	650	643	637	595	588	604	627	638	586	681	609	598	587	568	617	577	553	445
Canadian	0	0	0	0	1	0	0	0	5	13	10	11	14	56	65	58	72	89	131
Offshore Imports	0	33	24	35	75	96	102	85	81	102	19	108	123	80	61	49	44	58	121
Domestic Crude Runs by Type																			
Sweet	552	558	439	425	401	375	365	369	393	334	371	319	335	318	308	328	304	283	200
Lt. Sour	65	92	199	207	184	198	219	250	245	252	310	290	264	270	260	290	274	271	245
Heavy	0	0	5	5	10	15	20	8	0	0	0	0	0	0	0	0	0	0	0
Canadian Crude Runs by Type																			
Sweet	0	0	0	0	0	0	0	0	1	0	1	3	6	7	6	2	10	20	21
Lt. Sour	0	0	0	0	1	0	0	0	1	0	0	0	0	6	7	6	7	9	6
Heavy	0	0	0	0	0	0	0	0	3	13	9	9	7	43	53	50	55	60	105
Offshore Crude Runs by Type																			
Sweet	0	33	6	15	22	23	25	19	17	47	16	53	53	24	22	20	20	33	107
Lt. Sour	0	0	9	5	32	40	25	23	26	30	3	35	27	28	21	14	13	11	14
Heavy	0	0	10	14	21	33	51	43	38	26	0	19	43	28	18	15	11	14	0

TABLE IV-2
MIDWEST CRUDE RUNS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
Total Crude Runs by Type																			
Sweet	1,139	1,081	1,108	1,026	1,064	1,023	876	964	960	894	843	809	848	854	891	901	1,026	954	855
Lt. Sour	374	682	672	784	772	784	901	870	810	775	806	830	818	774	753	736	612	650	713
Heavy	264	244	341	372	420	457	455	405	396	439	458	517	476	533	487	453	367	446	638
Total Crude Runs by Source	**1985**	**1990**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2015**
Domestic	1,342	1,142	1,129	1,128	1,048	1,046	1,111	1,132	1,031	1,052	1,013	1,010	1,087	1,073	1,045	978	902	903	620
Canadian	233	295	490	472	597	591	547	608	642	616	663	733	715	804	775	806	973	1,062	998
Offshore Imports	202	570	502	582	611	627	574	498	493	441	431	414	341	283	311	306	130	85	587
Domestic Crude Runs by Type	**1985**	**1990**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2015**
Sweet	1,004	806	779	706	671	590	572	628	451	426	501	572	622	659	715	634	555	526	340
Lt. Sour	267	318	304	395	349	424	506	503	579	625	510	437	464	413	329	343	345	376	279
Heavy	71	18	45	27	28	32	33	1	1	1	1	1	1	1	1	1	1	1	1
Canadian Crude Runs by Type	**1985**	**1990**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2015**
Sweet	93	132	174	142	140	173	115	167	185	145	135	145	178	179	208	283	478	449	271
Lt. Sour	53	13	104	76	80	23	73	88	81	59	79	83	66	91	83	82	129	168	91
Heavy	87	150	211	255	378	394	359	353	376	412	449	505	470	533	483	442	366	445	637
Offshore Crude Runs by Type	**1985**	**1990**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2015**
Sweet	42	144	188	201	235	259	173	178	219	170	196	167	162	106	146	85	82	58	270
Lt. Sour	54	351	230	291	362	337	339	269	255	245	227	236	174	179	162	211	48	27	318
Heavy	106	75	85	91	14	31	63	51	19	26	8	11	5	(1)	3	10	(0)	0	0

TABLE IV-3
PADD II CRUDE RUNS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
Total Crude Runs by Type																			
Sweet	1,823	1,803	1,696	1,636	1,636	1,564	1,411	1,496	1,508	1,397	1,343	1,313	1,371	1,354	1,381	1,407	1,510	1,452	1,346
Lt. Sour	441	792	894	1,013	1,013	1,089	1,232	1,198	1,132	1,088	1,149	1,182	1,138	1,092	1,044	1,056	913	951	999
Heavy	415	417	577	605	701	719	687	679	663	725	720	793	789	850	801	757	671	752	977
Total Crude Runs by Source																			
Domestic	2,089	1,889	1,837	1,848	1,716	1,709	1,802	1,844	1,747	1,716	1,759	1,704	1,782	1,783	1,730	1,745	1,619	1,605	1,208
Canadian	388	491	762	770	905	899	810	915	962	946	994	1,054	1,039	1,150	1,125	1,119	1,301	1,406	1,406
Offshore Imports	202	632	568	636	729	763	718	614	594	548	459	530	477	363	372	357	174	143	708
Domestic Crude Runs by Type																			
Sweet	1,686	1,461	1,283	1,214	1,145	1,040	1,025	1,083	922	839	938	976	1,054	1,099	1,140	1,110	999	957	683
Lt. Sour	332	410	503	602	533	622	725	753	824	877	820	727	727	683	589	633	619	647	524
Heavy	71	18	50	32	38	47	53	9	1	1	1	1	1	1	1	1	1	1	1
Canadian Crude Runs by Type																			
Sweet	95	155	253	228	215	225	168	227	244	188	183	191	215	216	252	292	498	482	312
Lt. Sour	55	17	112	92	102	83	143	132	116	86	99	102	87	112	93	98	143	187	118
Heavy	238	319	398	450	588	591	498	556	602	672	711	760	737	823	780	730	659	737	976
Offshore Crude Runs by Type																			
Sweet	42	186	193	216	258	298	203	196	237	217	211	220	217	130	167	105	102	92	376
Lt. Sour	54	365	246	296	396	384	380	304	297	280	240	279	209	206	184	225	61	38	332
Heavy	106	80	129	124	75	81	135	114	60	52	8	32	51	27	21	26	11	14	0

TABLE IV-4
PADD III CRUDE RUNS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
Total Crude Runs by Type																			
Sweet	2,987	2,697	2,634	2,641	2,485	2,433	2,357	2,275	2,230	2,202	2,336	2,314	2,361	2,580	2,554	2,333	2,370	2,337	2,433
Lt. Sour	1,833	2,324	2,334	2,421	2,591	2,645	3,087	2,898	2,871	2,518	2,511	2,501	2,319	2,165	2,252	2,157	2,571	2,688	3,257
Heavy	602	1,039	1,426	1,581	1,769	1,879	1,568	1,965	2,177	2,388	2,486	2,623	2,419	2,516	2,509	2,407	2,256	2,267	2,525
Total Crude Runs by Source																			
Domestic	4,003	2,805	2,332	2,308	2,233	2,073	2,067	2,013	1,925	2,084	1,906	1,750	1,474	1,604	1,737	1,661	1,889	1,996	1,780
Canadian	0	8	4	9	2	13	3	16	3	59	29	18	20	59	96	104	128	148	500
Offshore Imports	1,419	3,247	4,057	4,325	4,609	4,871	4,942	5,110	5,351	4,966	5,398	5,670	5,604	5,597	5,482	5,132	5,180	5,149	5,936
Domestic Crude Runs by Type																			
Sweet	2,305	1,665	1,444	1,594	1,469	1,418	1,428	1,290	1,234	1,379	1,179	965	784	824	820	816	1,033	1,023	894
Lt. Sour	1,551	974	726	558	647	564	561	654	624	643	668	729	636	726	860	789	804	922	845
Heavy	147	166	163	156	118	90	78	69	66	62	58	56	55	54	56	57	52	50	41
Canadian Crude Runs by Type																			
Sweet	0	3	3	5	2	8	1	(0)	0	58	28	16	11	22	26	13	28	28	20
Lt. Sour	0	0	1	2	0	2	0	16	3	0	0	1	0	2	0	0	0	0	0
Heavy	0	5	0	2	0	3	1	0	0	1	1	1	9	35	71	91	100	120	480
Offshore Crude Runs by Type																			
Sweet	611	933	1,170	1,074	943	1,008	1,026	1,071	997	912	1,125	1,248	1,393	1,541	1,570	1,378	1,193	1,181	1,469
Lt. Sour	353	1,446	1,624	1,828	2,015	2,077	2,427	2,144	2,243	1,728	1,846	1,856	1,856	1,629	1,530	1,496	1,883	1,871	2,462
Heavy	455	868	1,263	1,423	1,651	1,785	1,489	1,896	2,111	2,326	2,426	2,566	2,355	2,427	2,382	2,259	2,104	2,097	2,004

TABLE IV-5
SEAWAY PIPELINE CRUDE OIL MOVEMENTS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
Crude Flows by Type																			
Sweet	0	33	6	17	23	42	43	19	18	57	22	61	65	38	22	25	33	54	159
Lt. Sour	0	0	23	5	34	66	61	71	124	140	154	210	171	202	149	98	85	85	94
Heavy	0	0	42	45	52	50	107	75	43	29	0	21	46	29	18	26	11	14	0
Crude Flows by Source																			
Domestic	0	0	16	0	0	16	22	25	35	46	51	33	20	22	23	24	35	45	87
Canadian	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore Imports	0	33	54	67	109	143	190	140	149	180	126	259	262	246	166	126	94	107	166

TABLE IV-6
CAPLINE PIPELINE CRUDE OIL MOVEMENTS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
Crude Flows by Source																			
Domestic	358	346	444	446	435	492	633	653	629	627	605	619	611	589	540	503	453	473	335
Canadian	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore Imports	202	595	494	558	567	568	442	392	416	350	305	316	303	202	258	290	128	84	576

TABLE IV-7
MID-VALLEY PIPELINE CRUDE OIL MOVEMENTS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
Crude Flows by Source																			
Domestic	163	210	161	186	184	180	177	176	173	179	184	152	178	201	219	220	187	178	114
Canadian	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore Imports	0	8	42	33	55	54	39	41	47	27	16	46	50	26	21	6	3	2	12

TABLE IV-8
PEGASUS PIPELINE CRUDE OIL MOVEMENTS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
Crude Flows by Source																			
Domestic	76	67	50	63	80	93	95	90	116	134	104	0	0	0	0	0	0	0	0
Canadian	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offshore Imports	0	0	0	15	63	34	72	71	66	78	98	8	0	0	0	0	0	0	0

TABLE IV-9
MIDCONTINENT/MIDWEST CRUDE OIL FLOWS
(Thousand Barrels per Day)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015
West/South Texas to Gulf Coast	936	509	338	214	192	134	50	30	(8)	(24)	(34)	(0)	(10)	(48)	38	42	38	35	22
West Texas to Midcontinent	346	517	530	548	497	466	456	403	421	391	384	350	347	352	251	297	279	266	201
Gulf Coast to Midcontinent (Seaway Corrido	0	33	71	67	109	158	212	165	185	226	176	292	282	268	188	150	129	152	253
Midcontinent to Midwest	330	276	244	266	256	231	223	130	127	161	81	156	143	192	61	41	25	25	16
Mid-Valley Corridor to Midwest	163	218	203	220	239	234	216	217	220	207	200	198	227	228	240	226	189	179	125
Pegasus Corridor to Midwest	76	67	50	78	143	127	167	161	182	212	202	8	0	0	0	0	0	0	0
Capline Corridor to Midwest	560	947	941	1,011	1,014	1,060	1,075	1,045	1,045	977	910	935	914	791	798	793	581	556	911
Canada to Midwest	388	491	762	770	905	899	810	915	962	946	994	1,054	1,039	1,150	1,125	1,119	1,301	1,406	1,406
Canada to Midcontinent	0	0	0	0	1	0	0	0	5	13	10	11	14	56	65	58	72	89	131
Canada to Gulf Coast	0	5	0	2	0	3	1	0	0	1	1	1	9	35	71	91	100	120	480

TABLE IV-10
KEY PIPELINE SYSTEMS

Pipeline	Origin	Destination	Capacity (B/D)	Crude Origin *	Owners	Comments
Alberta Clipper **	Hardisty, Alberta	Superior, WI	450,000	C	Enbridge	Expands capacity of the Lakehead system.
Basin	Midland, TX	Cushing, OK	up to 400,000	D, F	TEPPCO Plains	
BP No. 1	Cushing	Chicago	175,000	D, F currently; C in future	BP	Reversal in mid 2009 as part of Enbridge Gulf Access Pipeline (GAP) Phase 1.
Capline	St. James, LA	Patoka, IL	1,200,000	D, F	Plains BP Marathon Southcap Pipeline	
Capwood	Patoka, IL	Wood River, IL	277,000	D, F, C	Plains	
Centurion	Southeast NM, West Texas	Cushing, OK	175,000	D	Occidental	Formerly BP West Texas pipeline. Planned for reversal in 4Q 2009.
Chicap	Patoka, IL	Chicago, IL	400,000	D, F, C	BP Unocal Enbridge	
ConocoPhillips	Cushing	Ponca City, OK	102,000	D, F	ConocoPhillips	
ConocoPhillips	Cushing	Borger, TX		D, F	ConocoPhillips	
ExxonMobil	Corsicana, TX	Beaumont, TX	150,000	C	ExxonMobil	Reversed in 1995. Reversed again in 2006.
Gulf Access **	Chicago, IL	Houston & Beaumont, TX	400,000	D, F, C	Enbridge	Reversal of former BP No. 1 pipeline, potential reveral of Ozark, plus new pipeline from Cushing to Houston/Beaumont in 2012+.
Keystone **	Hardisty, Alberta	Patoka, IL Cushing, OK	435,000 155,000	C C	TransCanada TransCanada	Completion in late 2009. Expected completion in late 2010.
Keystone XL **	Hardisty, Alberta	Houston, TX Port Arthur, TX	500,000	C	TransCanada	Expected completion in 2012.
Mid-Valley	Longview, TX	Samaria, MI	238,000	D, F	Sunoco BP	
Mustang	Chicago, IL	Patoka, IL	100,000	C	Enbridge ExxonMobil	
Osage	Cushing, OK	El Dorado, KS McPherson, KS	135,000	D, F	Magellan NCRA	
Ozark	Cushing, OK	Wood River, IL	170,000	D, F currently; C in future	Enbridge	Reversal planned as part of Gulf Access Pipeline (GAP) Phase 2. Could occur in 2012.
Pegasus	Patoka, IL	Corsicana, TX	96,000	C	ExxonMobil	Reversed in 2006.
Seaway	Freeport, TX	Cushing, OK	350,000	D, F	TEPPCO ConocoPhillips	
Southern Access	Superior, WI	Flanagan, IL	400,000	C	Enbridge	Expands capacity of the Lakehead system.
Southern Access Extension **	Flanagan, IL	Patoka, IL	300,000	C	Enbridge	Expands capacity of the Lakehead system.
Spearhead North **	Flanagan, IL	Chicago, IL	130,000	C	Enbridge	Completion in 3Q2009.
Spearhead South	Flanagan, IL	Cushing, OK	193,300	C	Enbridge	2005 Reversal of Cushing-to-Chicago P/L.
Sunoco	Nederland, TX	Longview, TX	85,000	D, F	Sunoco	
Sunoco	Nederland, TX	Wortham, TX	150,000	D, F	Sunoco	Reversed in 1995. Proposal to reverse again to bring Canadian crude to the Gulf Coast.
Sunoco **	Cushing	Corsicana, TX	300,000	D, F, C	Sunoco	Proposed
Texas Access **	Patoka, IL	Houston & Beaumont, TX	400,000	C	Enbridge ExxonMobil	Completion expected in 2013 or 2014.
West Texas Gulf	Colorado City, TX	Wortham, TX Longview, TX	300,000	D	Sunoco Logistics BP Chevron Citgo	
West Tulsa	Cushing, OK	Tulsa, OK	55,000	D, F	Enbridge	
White Cliffs	Platteville, CO	Cushing, OK	30,000	D	SemGroup	Started up in 2009.
Woodpat	Wood River, IL	Patoka, IL	315,000	D, F, C	Enbridge Marathon	

* (D)omestic, (F)oreign, (C)anadian
** under construction or proposed

TABLE IV-11
TIMELINE OF PIPELINE SYSTEM CHANGES

1980 1985 1990 1995 2000 2005 2010

Seaway Pipeline	Flow from Freeport to Cushing	**1984** Changed to gas service	**1996** Changed to crude service as part of the Seaway JV Flow from Freeport to Cushing
ARCO line	Flow from Wichita Falls to Houston	**1988** Reversed, Houston to Cushing via Wichita Falls	**1996** Became part of the Seaway system
Cushing-to-Chicago/ Spearhead Pipeline	Flow from Cushing to Chicago	**2005** Reversed, renamed Spearhead Flow from Chicago/Flanagan to Cushing	
WTG/Sun	Flow from Corsicana to Beaumont	**1995** Reversed, flow from Beaumont to Corsicana	
BP No. 1/ Gulf Access	Flow from Cushing to Chicago/Whiting, IN	**2009** Reversed, flow from Chicago to Cushing	
Pegasus Pipeline	Flow from Corsicana to Patoka, IL	**2006** Reversed, flow from Patoka to Corsicana	
Mobil line	Flow from Corsicana to Beaumont	**1995** Reversed, flow from Beaumont to Corsicana	**2006** Reversed as part of Pegasus reversal; flow from Corsicana to Beaumont
Centurion Pipeline	Flow from West Texas to Cushing	**2009** Reversed, flow from Cushing to West Texas and Artesia,NM	

FIGURE IV-24
1988 MIDCONTINENT/MIDWEST CRUDE OIL LOGISTICS SYSTEM

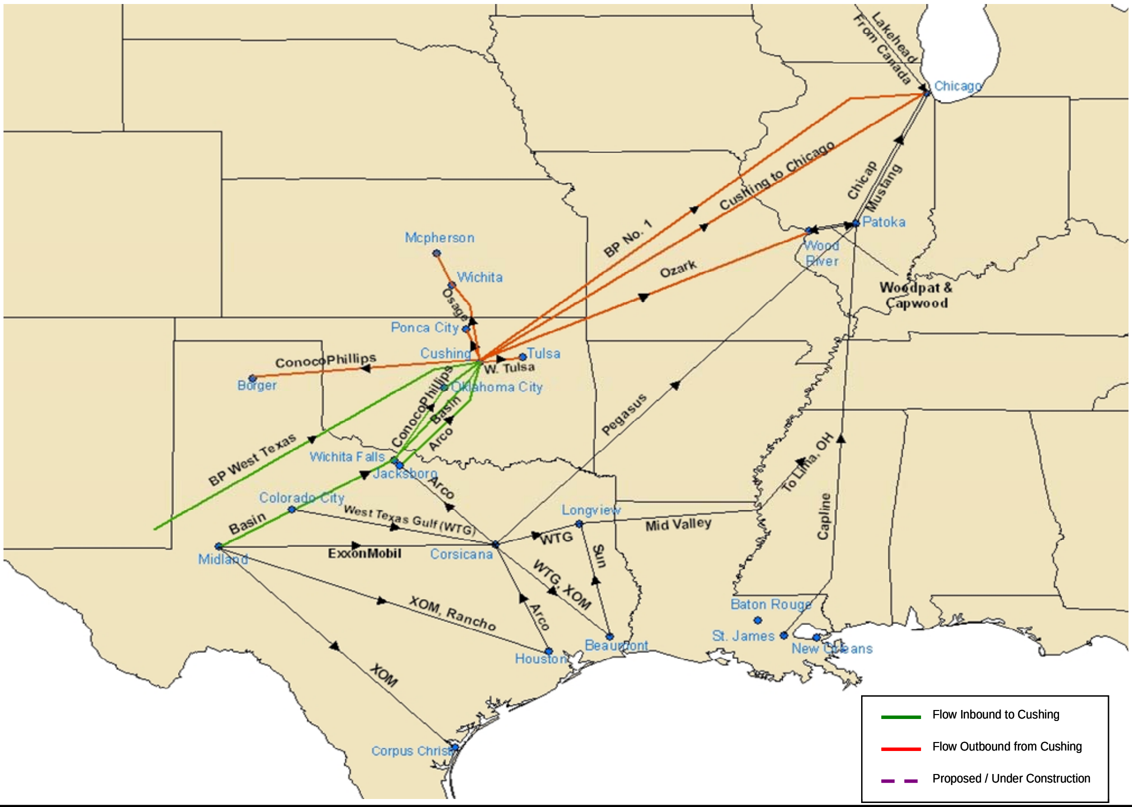


FIGURE IV-25
1996 MIDCONTINENT/MIDWEST CRUDE OIL LOGISTICS SYSTEM

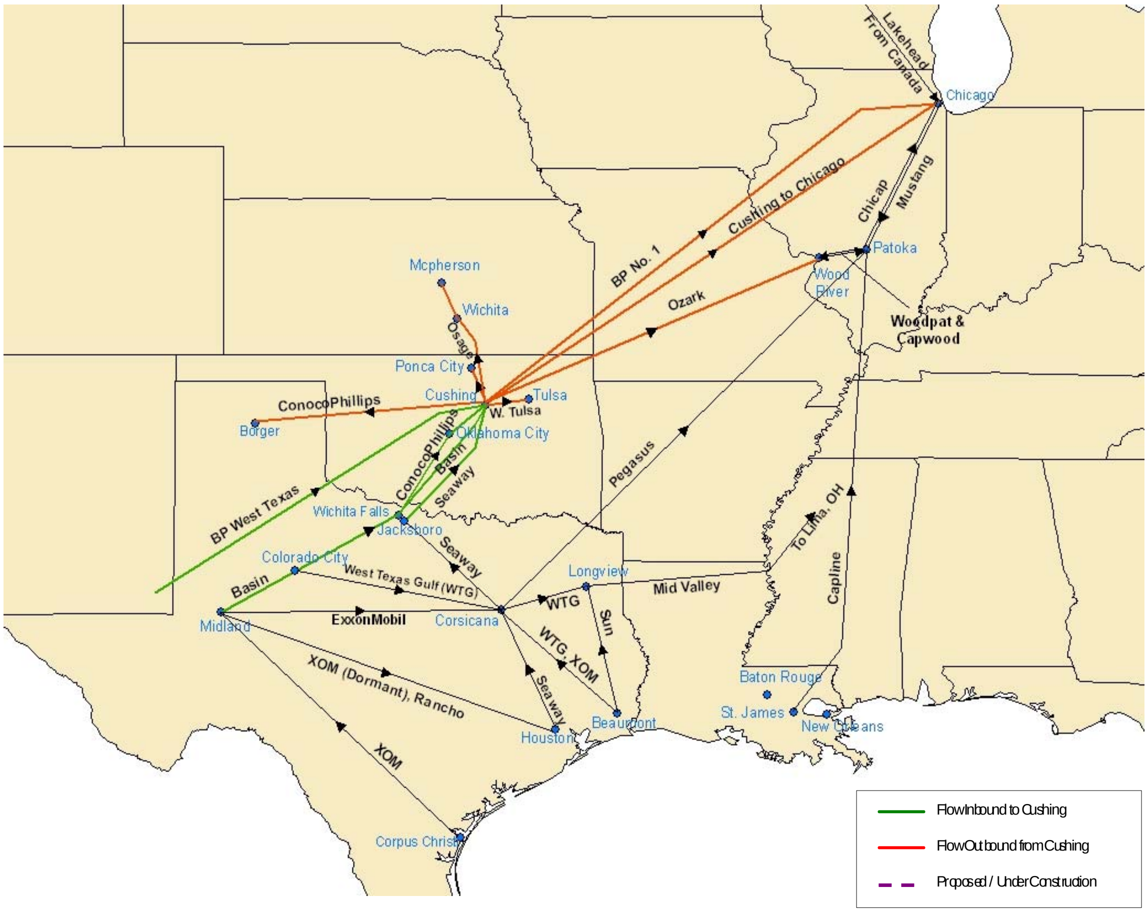


FIGURE IV-26
2006 MIDCONTINENT/MIDWEST CRUDE OIL LOGISTICS SYSTEM

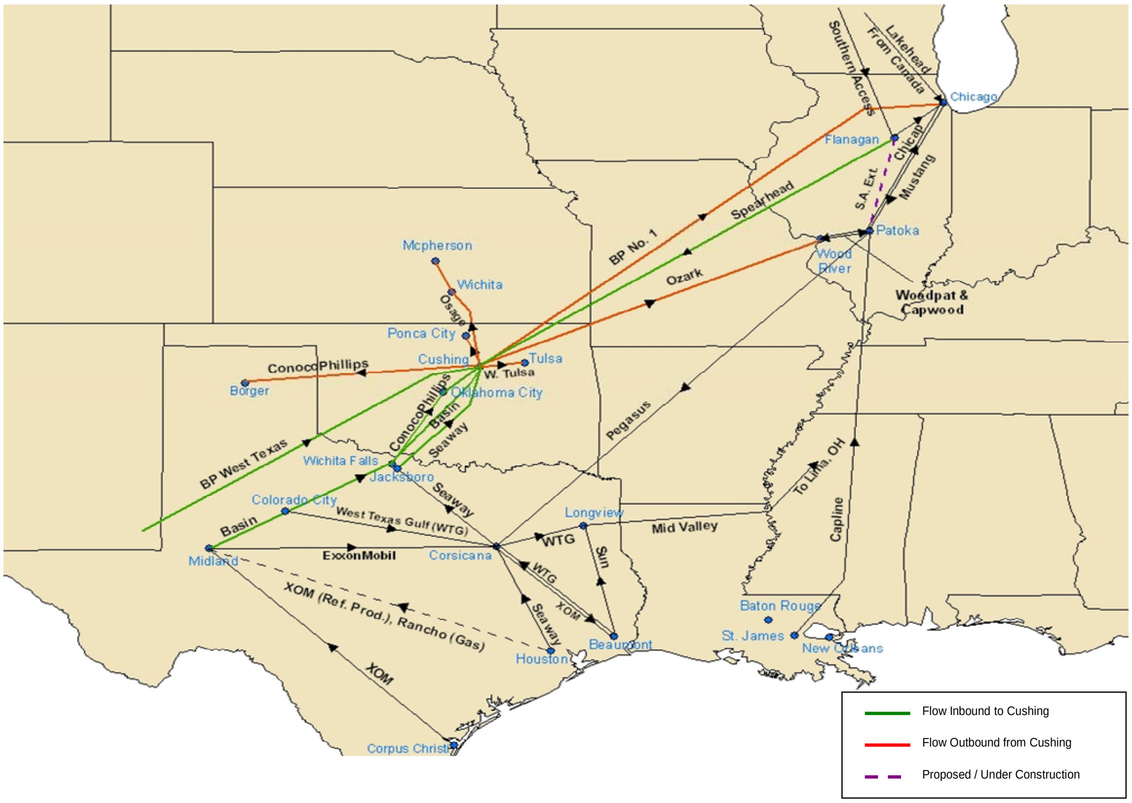
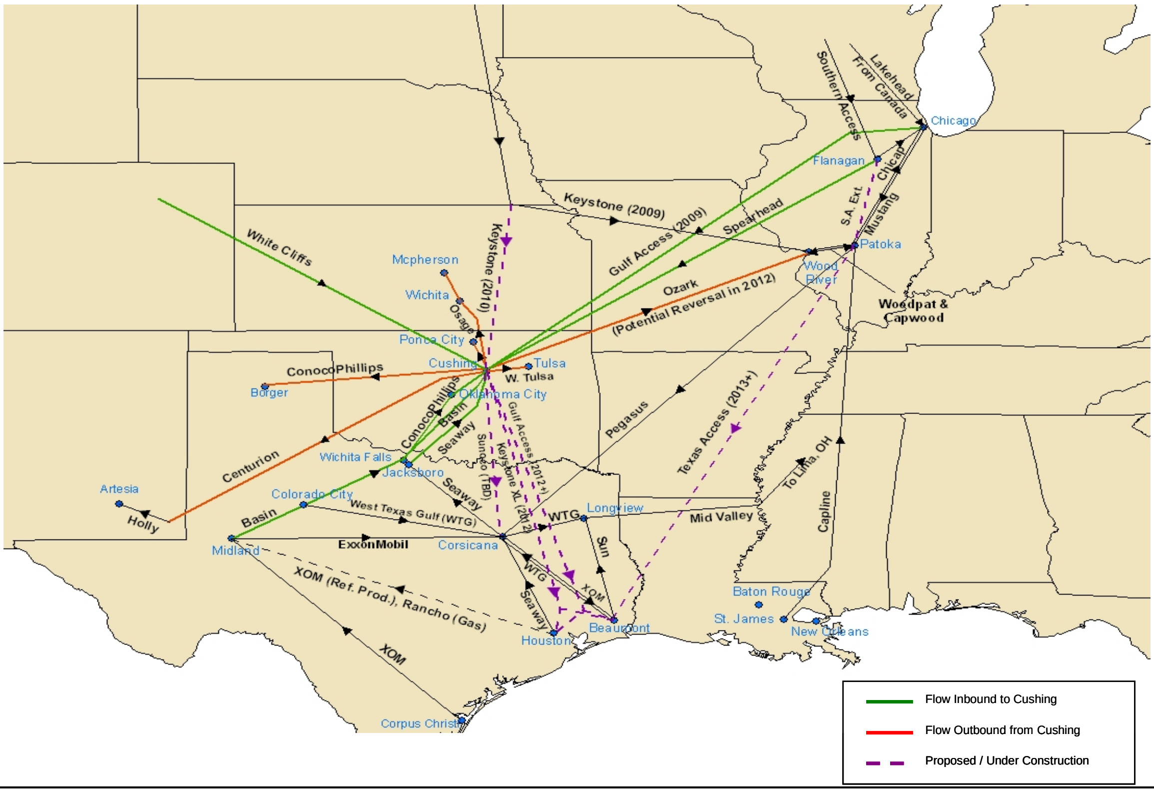


FIGURE IV-27
2009 MIDCONTINENT/MIDWEST CRUDE OIL LOGISTICS SYSTEM



V. ROLE OF WTI IN CRUDE OIL PRICING

INTRODUCTION

This section will review the role of WTI in the routine daily pricing of crude oils in the U.S. domestic markets and internationally, including the use of physical WTI price quotes as the key benchmark in pricing formulas of major regional producers as well as Mideast producer sales into the U.S. market. Recent changes in these mechanisms are occurring with the late 2009 announcement by Saudi Arabia that it would shift on January 1, 2009 to the use of the **Argus Sour Crude Index (ASCI)** quotation as the base index of their crude pricing formulas. This is a significant event in the time line of the dynamics of the WTI market, and the implications will be briefly reviewed in this section. In addition, a discussion of the use of WTI as a trading reference for many other transactions in the U.S. market will be reviewed, including the actual linkage of the ASCI components to the WTI differentials, which perpetuates the activity of the WTI trade and the liquidity of the NYMEX contract.

WTI INDEXATION IN OFFICIAL PRICE FORMULAS

Over the years, because of the commoditization of WTI, and its use as a hedging tool for crude buyers and sellers alike, it has become the index crude for the official price formulas of a number of countries selling crude into the U.S. market. Logically, most of the local regional producers in Latin America have chosen to use the WTI reference for both sweet and sour crudes, but major Mideast producers of sour crudes such as Saudi Arabia and Kuwait have also used this index for many years. African producers typically set their FOB formulas on a Brent index, even for U.S. and Asian deliveries, but most crudes destined for Asia are typically linked to the benchmark Dubai and Oman crudes.

The following table summarizes the more prominent producers whose formulas are transparently reported in the industry press and are represented by WTI less an adjustment factor that reflects a combination of value differences, logistics and market factors. Saudi Arabia exported over 1.5 million barrels per day of crude to the U.S. market in 2008 and all of those volumes were sold using formulas which were indexed to the WTI spot quotes of the physical market trade in WTI by the Platts reporting service. Saudi Arabia reports and uses formulas for both FOB sales as well as CIF sales delivered into the USGC. All of their sales are based on the Month 1 quotation, though they also apply the 2nd month quotation for a period of time toward the end of the trade cycle to smooth out the impacts of late month trade volatility. Most of the other countries use the Month 1 quotation, as well, though Iraqi sales are based on FOB and they chose to take the delivery timing into account by using the Month 2 basis of the WTI quote.

TRANSPARENT REPORTED PRICE FORMULAS BASED ON WTI INDEXATION

COUNTRY/CRUDE	POINT OF SALE	INDEX	2008 U.S. IMPORTS Thousand B/D
Saudi Arabia			1503
Extra Light	FOB and CIF	Platts WTI, Mnth 1	
Light	FOB and CIF	Platts WTI, Mnth 1	
Medium	FOB and CIF	Platts WTI, Mnth 1	
Heavy	FOB and CIF	Platts WTI, Mnth 1	
Kuwait			206
Kuwait Export Crude (KEC)	CIF	Platts WTI, Mnth 1	
Iraq			627
Iraq Kirkuk	Ceyhan	Platts WTI, Mnth 2	
Iraq Basrah	FOB	Platts WTI, Mnth 2	
Colombia			178
Cano Limon	FOB	Platts WTI, Mnth 1	
Cusiana	FOB	Platts WTI, Mnth 1	
Ecuador			214
Oriente	FOB	Platts WTI, Mnth 1	
Napo	FOB	Platts WTI, Mnth 1	
Venezuela (1)			1039
Furrial	FOB	Platts WTI, Mnth 1	

NOTE: (1) Venezuela price formulas are typically non-transparent with Furrial reported. Other Venezuelan crudes are known to be sold on a WTI index, but actual contracts are customer based and may not all be WTI linked

As indicated by its title, this table reflects specific transparent price formulas that are released by the producing countries to the public domain and the formula “K” factors relative to the WTI index used are reported in the industry press for each month’s sales. The K factor is usually set in the month prior to the month of its use and the actual “trigger” point in time when the price is set is based on the approximate time it takes to deliver the crude from its load port to the USGC refiner. In essence, this feature is a built in hedge as the buyer would thus not take the time risk of market change while the cargo was in route.

This list, however, is by no means all inclusive since sales of many other crudes are indexed to WTI. For example, with respect to official contractual price formulas, research shows that WTI is used as a benchmark for the sales of other crudes produced by Venezuela, even some of the heavier grades, whereas most of the heavier grades will typically utilize a basket of crudes similar to the Mexican grades that do not specifically incorporate the WTI price. The Mexican crude prices have for years been based on a basket of crudes including Brent, WTS

(West Texas Sour) and LLS (Light Louisiana Sweet) plus a component of the price of 3 wt% sulfur residual fuel oil for its Maya grade. Argentina also exports various grades to the U.S. and they are known to be priced based a WTI index.

As indicated earlier, Saudi Arabia has just recently announced its decision to abandon the WTI index in their formulas in exchange for the relatively new, but well established and tested index that consists of the volume weighted average of the physical market trades in the USGC offshore crudes Mars, Poseidon and Southern Green Canyon (SGC). This change should result in far less volatile final prices since the Saudi crudes are high sulfur crudes more closely valued to the USGC offshore grades than they are to the USGC sweet crudes like LLS or to the WTI Cushing grade. The important factor in this pricing dynamic is that for most all producer sales of formula based crudes, the formulas are analyzed, developed and announced in advance for forward sales. Though the final price is not usually "triggered" until a set period in the advanced month, thus providing a "gross" hedge against overall market trends, there always remains other components of volatility related to the changes in relative values of the sour crudes versus a sweet benchmark in the month of delivery as compared to the market conditions that existed when the price formula was developed. In addition, the relationship between the WTI and the USGC sweet market as represented by LLS can also result in unexpected volatility of the final formula price versus the real value in the market of the crude being sold into that market (see relationship trends in Section III) . Purvin & Gertz, Inc. refers to these deviations as **"Formula Lag."** Indexation of high sulfur crudes, such as those from Saudi Arabia, to actual USGC high sulfur crudes will eliminate much of this Formula Lag volatility and this is the driver for the Saudi decision to make this change in index.

With respect to the change to the ASCI index from the WTI index, it is very important to note, however, that the prices of the actual components of the ASCI index are still linked to WTI since the data collected on the transactions of the individual ASCI components will reference a discount to WTI, as do the predominance of trades in other USGC grades. An excerpt from a **Petroleum Argus Media Ltd** White Paper entitled ***"The Argus Sour Crude Index"*** states the following: "The *ASCI* price is also undergirded by the breadth and depth of the WTI market. The trades that are averaged into the index are transacted as differentials to WTI and so embed the value of the WTI futures market, the most robust crude hedging vehicle available. **The index is not looking to replace WTI as a fixed price benchmark, but instead works in conjunction with other markets to provide a tool for valuing sour crude at the U.S. Gulf Coast."** (http://web04.us.argusmedia.com/ArgusStaticContent/snips/sectors/pdfs/ASCIWhitePaper.pdf).

VI. DATED BRENT AS A CRUDE OIL BENCHMARK

INTRODUCTION AND PURPOSE

This section will now review the history of the development and evolution of the North Sea Brent crude market that has led to the commoditization of this crude and its crucial place in the world oil trade as a leading benchmark. As will be noted later, Dated Brent and its associated derivatives are the benchmarks used as the indexes of pricing for as much as 65% of the world's crude trade. As such, the industry, especially the price reporting services, has gone through substantial trials in attempts to stabilize the integrity of this benchmark, in the face of its significant physical transformations over time. These transformations, related to physical availability and related trade liquidity issues, which have also caused quality variations, have resulted in periods of high volatility and disconnects from the other markets and even within the family of related instruments. The dynamics of these trends over time are described in the following sections.

The comparison of this Brent history and its tribulations, along with the history of the WTI market and its commoditization, makes note of the fact that in the crude oil markets, unfortunately, each benchmark carries certain basis risks and each represents a non-renewable resource, unlike other familiar petroleum or non-petroleum seasonal commodities that are replaceable and renewable each cycle. Given this, it means that the crude oil benchmarks and their relationships to other crude streams will inevitably evolve and change over time.

Similar to the history and near term outlook for the trade and dynamics of the WTI market, Brent has gone through a number of significant changes over time, and more changes are to come. It therefore is an important objective of this report, and particularly this chapter, to highlight these changes and to develop a better understanding of the reasons for periodic disconnects between these commodities as each moves through its own set of transitional dynamics, mostly on different timelines. These individual features can result in significant volatility among the relationships and quite often a misinterpretation of the results, with flawed conclusions regarding the solutions to this volatility or improper consideration of the basis risk associated with each. This section, therefore, will endeavor to develop a better understanding of the dynamics and fundamentals of the important WTI/Brent spread, which has been one of the focal points recently of industry concerns related to benchmark acceptability.

A BRIEF HISTORY OF NORTH SEA OIL

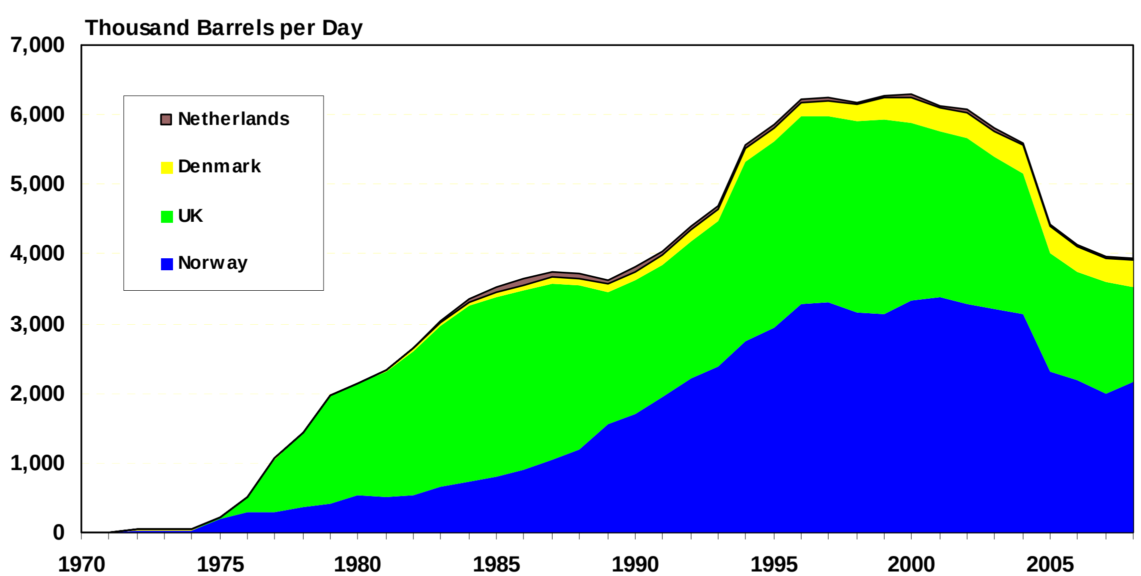
In December 1969 the Ekofisk oilfield was discovered in the Norwegian North Sea by Phillips Petroleum, and in the same month the Montrose field (now part of the UK Forties field system) was discovered by Amoco. The following year BP discovered the giant Forties field, and in 1971 Shell Expro discovered the giant Brent field. Oil production began from the Ekofisk field in 1971 with the Forties field coming in stream in 1975 and Brent in 1976. Rapid expansion of

North Sea production capability followed such that production exceeded 1 million barrels per day in 1977 and reached 2 million barrels per day by 1980.

The rapid growth of the North Sea oil producing region took place against the backdrop of significant turmoil in the world oil markets including the nationalization of the oil industry in the various Middle East countries during the 1970s, and the oil price shocks of 1973 (Middle East crude supply boycotts associated with Yom-Kippur war) and 1979 (Iranian revolution). Oil prices were at 3 $/bbl in 1973 and had risen to 35 $/bbl in 1981. The increase in world oil prices and requirement for secure independent sources of supply prompted significant exploration and production outside of OPEC countries. As a result, the North Sea rapidly became a very important source of non-OPEC crude oil.

Production peaked in the late 1990s at around 6.2 million barrels per day, before beginning a slow decline. In 2008 North Sea oil production was around 4.8 million barrels per day. See Figure VI-1.

FIGURE VI - 1
NORTH SEA OIL PRODUCTION



THE DEVELOPMENT OF THE BRENT CRUDE OIL BENCHMARK

As North Sea oil production developed in the 1970's, production was not only from the traditional established oil majors, but also from a number of independent upstream companies with no downstream refineries of their own to supply. These independent producers were in the market solely to produce and sell crude oil. Trade of crude oil around the North Sea developed as a result and the North Sea crude oil prices were published, making them publically known. This significant crude oil production capacity in a politically stable region with free market economics provided the necessary conditions for the development of a crude oil benchmark.

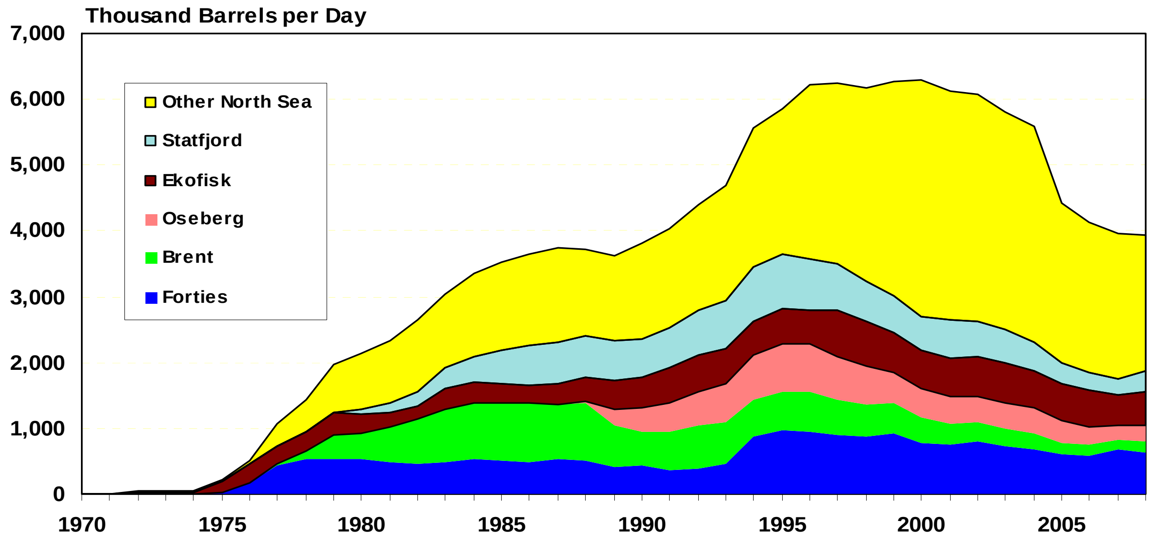
During the 1980's some OPEC producers who were losing market share as a result of the increased availability of non-OPEC crude attempted to price their crude oil on a refinery netback basis. Under this system, the price of crude oil was set in relation to a basket of refined products, so as to provide a guaranteed margin to refiners. This guaranteed refinery margin created additional demand for crude priced on a netback basis, which in turn added to product oversupply and so destabilized the market further. In 1986 the OPEC producers decided to link the price of their export crude to market prices for competing traded crudes. This was the beginning of a new era.

In response to the increase in trade of North Sea crude oil, Platts launched its "Crude Oil Market Wire" price reporting service in 1978. In 1980 a group of energy and futures companies launched the International Petroleum Exchange (IPE), to facilitate the trade of crude and oil products. In 1981, the forward Brent market (15-day Brent) developed based on trade in forward paper contracts associated with physical Brent cargos. In June 1988 the IPE successfully launched the Brent Crude futures contract which was linked to the forward Brent market through the settlement price at expiry of the futures contract. North Sea crude was competing with Middle East and West African crudes for crude supply into both North West Europe and North America. This, combined with the availability of the Brent futures contract paved the way for Brent to become the most widely used marker crude globally in the 1990s.

In 1988 the Brent System was the largest single producing group of fields in the North Sea, producing more than 800,000 barrels per day of crude oil, from a total North Sea output of around 3.5 million barrels per day, (i.e. around 23% of total North Sea production). See figure VI-2. The oil came ashore via the Brent System pipeline at Sullom Voe in The Shetlands, Scotland, and production from all fields was co-mingled, forming Brent System crude oil.

Also landed at Sullom Voe was the Ninian crude oil blend, which came ashore via the Ninian pipeline. Originally Brent System and Ninian crude were stored separately at Sullom Voe and exported as separate blends. However in 1990 in response to declining production of both Brent and Ninian crudes, the two blends were co-mingled for better efficiency, and since then have been sold as one single blend, labeled Brent Blend.

FIGURE VI - 2
SELECTED NORTH SEA CRUDE OIL PRODUCTION



KEY ELEMENTS OF THE BRENT PRICING COMPLEX

The definitions of the key elements of the Brent price complex are as follows:

Dated Brent

Originally the assessed price of Brent cargos sold on a spot basis but now includes Ekofisk, Forties and Oseberg.

Forward Brent

The forward paper market for full Brent cargos originally 15-day Brent and later 21-day Brent and including Ekofisk, Forties and Oseberg.

Brent Futures

Futures contract originally traded on the International Petroleum Exchange (IPE) and later on the Intercontinental Exchange (ICE).

INITIAL DATED BRENT ASSESSMENT

Brent forward contracts (each linked to a real physical cargo) were traded and 15 days before the specified cargo lifting date the Brent equity producer would call a contracting party and nominate that party as the lifter of that cargo at the agreed paper contract price. The nominated party then had the choice of accepting the cargo nomination and physically loading the crude or passing the nomination on to a third party who is the buyer identified in a second paper contract. As a result, contract chains were formed until a party decided to take delivery.

There were many contracts per cargo and often circular chains were formed that could then be cash settled through a "book-out."

At 5 p.m. 15 days before the cargo lifting date, the Brent cargo became "wet" and the party holding the nomination at that time either had to lift the cargo or find an alternative buyer. Trade in these "wet" cargoes became the basis for the assessment of the price of Dated Brent. The assessment was in fact for Brent System Crude (Brent Blend from 1990), Free on Board (FOB) at Sullom Voe.

PROBLEMS WITH THE DATED BRENT ASSESSMENT

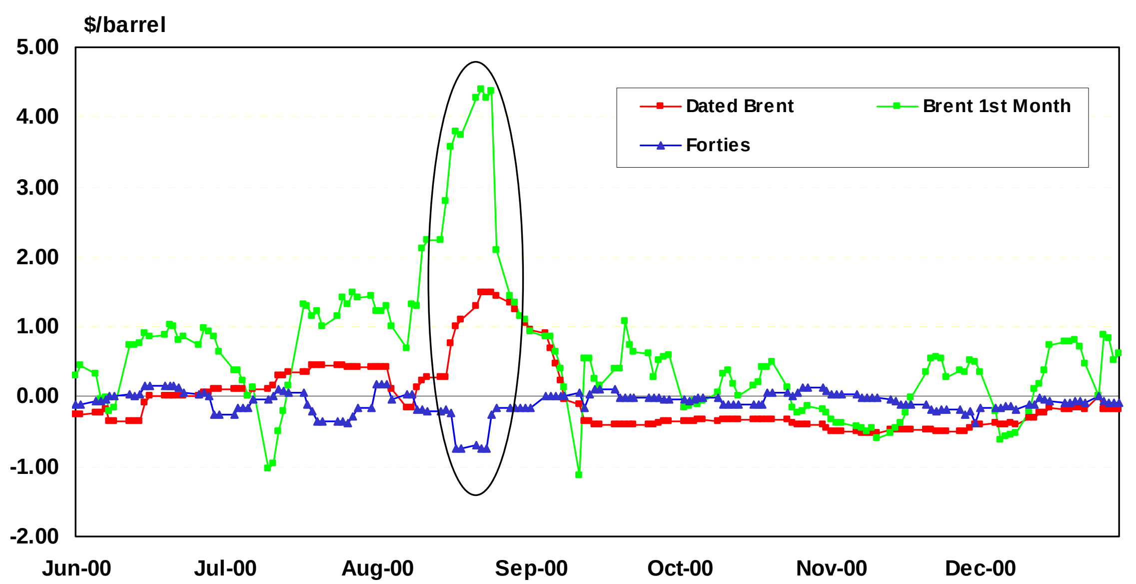
As shown above, production of crude oil from the North Sea reached its zenith in the late 1990s and then volumes began to decline. Up until 1991, the UK was the largest producer, with the Brent System making up a significant volume of the UK production. From 1991 onward, Norway became the largest producer, with production from both countries continuing to rise until 1999, when UK production reached its height. Norwegian production peaked in 2001. Since then despite numerous new field additions, overall North Sea crude production has been in decline. The Brent System reached its maximum production capability through 1984 to 1988 with production around 850,000 barrels per day, before entering a steady decline. By 2000, Brent production was down to 380,000 barrels per day, by 2002 down to 300,000 barrels per day, and by 2008 down to only 165,000 barrels per day.

This significant reduction in Brent System production (and the associated Ninian crude production) increased the possibility of one party holding enough of the Brent Blend cargoes for lifting in a given month with the result of squeezing the market and pushing up the price of Dated Brent. A squeeze occurs when a trader goes long in a forward market by more than the amount of actual physical cargos that can be loaded that month. A corner is the ultimate squeeze, when a trader has acquired the entire physical cargos for a particular month (and hence "corners the market"). With cargo size of around 500,000 barrels, during the mid 1980s around 50 cargos of Brent System crude were physically loaded each month. By 2000 this figure had dropped to around 23 cargos per month, making it significantly easier for one party to hold enough of a forward position or physical cargos to squeeze the price.

Perhaps the most notable allegation of this took place in August/September 2000. U.S. refiner Tosco filed a lawsuit against the Japanese owned and London based trading company Arcadia, alleging "illegal and monopolistic conduct" in the Brent market to force companies like Tosco "to pay substantially more for crude oil than they would have if Arcadia had not manipulated the market". The lawsuit also named trading company Glencore and "other unnamed co-conspirators." It claimed that Arcadia gained a monopoly position in the Brent market in August and September by knowingly obtaining a larger number of 15-day Brent contracts than could be delivered. The lawsuit stated "By causing September Brent crude prices to spike, Arcadia's squeeze on the market caused injury to every buyer in the September Brent Index market." It also said that Arcadia's actions added an average of $3 per barrel to the price of September (2000) Brent Crude. As the Dated Brent assessment was used to price the vast majority of crude oil that trades in the Atlantic basin (North West Europe, West Africa, and North American Eastern seaboard) the impact of the squeeze on approximately 380,000 barrels per day of Brent System production affected the pricing of an estimated 25 million barrels per day of crude oil. The case did not actually go to court, but was settled out of court.

Figure VI-3 shows that whatever the true facts behind the event, the price of Brent crude (both Dated Brent and forward Brent) relative to other similar crudes (Oseberg, and Forties) did rise substantially. Consequently the price of crudes that priced off of the Dated Brent benchmark with a fixed formula premium or penalty would also have risen substantially.

FIGURE VI - 3
PRICE DIFFERENTIAL VERSUS OSEBERG



This was not the first time that accusations of manipulation of the Dated Brent price had taken place. A few weeks before the Tosco-Arcadia affair, BP was accused by some traders of implementing tactics that artificially inflated the price of Brent crude, accusations that BP strongly denied. Arcadia had also been accused of similar price manipulation in 1998. It was certainly becoming clear that the dwindling production from the Brent System was leaving the Dated Brent benchmark more open to speculative influence, and that to retain its status as a benchmark crude, changes to the Dated Brent assessment would be required.

USE OF B-WAVE IN PLACE OF DATED BRENT

In June 2000, Saudi Arabia moved to pricing crude destined to Europe from formulae based on Dated Brent to formulae based on a weighted average of Brent futures prices (B-wave). This was partly to counteract the influence of speculation on Dated Brent from pricing of Saudi crude oil, and partly to bring the price paid for Saudi crude closer to an expected price at the actual delivery date. In January 2001, Kuwait and Iran joined Saudi Arabia in using formulae based on the B-wave Index for pricing of their crude to all points west of Suez.

The IPE's Brent Weighted Average (B-wave) price Index is calculated by dividing the value of business in the Brent futures contract transacted for each contract month on any given day by the volume of trade on that day.

As a result of the long delivery times from the Middle East to Mediterranean Europe (typically 2 to 3 weeks) and North West Europe (typically 5 to 8 weeks) Middle East crude to Mediterranean Europe is often priced by formula to the B-wave Index for the following month (M+1) and to North West Europe to the B-wave Index for two months ahead (M+2).

CHANGES TO THE DATED BRENT ASSESSMENT

In 1988, the "Brent" crude on which the Dated Brent assessment was based was a blend of the crude fields making up the "Brent System." Total production was 860,000 barrels per day. By 1990, production from the Brent System had fallen to 520,000 barrels per day and for operational reasons at Sullom Voe, the Brent System stream was combined with the also declining Ninian crude stream to create Brent Blend. After combining the two streams the net Brent Blend production was 810,000 barrels per day. The Brent-Ninian blend remained the basis for the Dated Brent assessment until 2002.

BFO (BRENT FORTIES OSEBERG) 2002

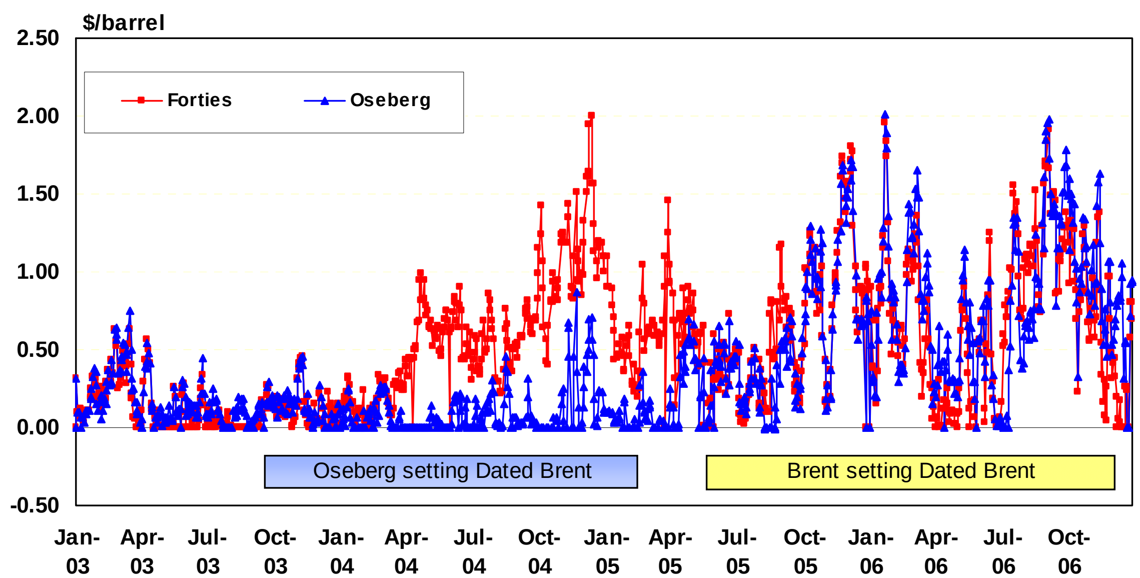
By 2002 Brent Blend production had fallen to 403,000 barrels per day. Following on from the Tosco-Arcadia affair in 2000, and various other accusations around deliberate manipulation of the Brent benchmark, industry dissatisfaction with the benchmark resulted in Platts changing the basis for their Dated Brent benchmark, with the intent to make it less susceptible to potential manipulation.

From 10th July 2002 the definition of the Dated Brent benchmark was widened to include market activity in Forties (UK) and Oseberg (Norwegian) crudes, giving rise to the Dated Brent (BFO) benchmark. At the time, Forties production was around 800,000 barrels per day, and Oseberg 390,000 barrels per day. The Forties system comes ashore via the Forties pipeline at Hound Point, Scotland, close to the Grangemouth refinery. Oseberg lands at Sture terminal, Norway via the Oseberg Transport System (OTS).

This move was designed to prevent single parties buying up enough of the Brent forward contracts to artificially influence the benchmark price. The volume on which the assessment was based rose from 403,000 barrels per day to 1,600,000 barrels per day, with actual loadings taking place at 3 different locations. The Dated Brent benchmark was assessed as the lowest price of the three crudes. At the same time as the change to Brent (BFO) assessment, the Dated Brent (BFO) forward contract changed to a 21 day forward basis.

Forties and Oseberg both had a slightly higher quality than Brent, and therefore were generally priced higher than Brent. Thus the Brent System crude initially formed the basis for the benchmark as the lowest priced crude of the three crudes. However, any attempted squeeze on the Brent System, driving the Brent System price up, would be capped in the assessment by either of the Forties or Oseberg prices, with the intent to maintain the integrity of the benchmark, and limit any corresponding impacts on the price of other crudes which priced off the Dated Brent benchmark. Oseberg set the benchmark for most of 2004 and into 2005, due to temporary quality effects from the inclusion of Grane in the Oseberg blend, before Brent again took over from July 2005 (see Figure VI-4).

FIGURE VI - 4
FORTIES AND OSEBERG PRICE DIFFERENTIALS VERSUS DATED BRENT (PLATTS)



BFOE (BRENT FORTIES OSEBERG EKOFISK) 2007

By 2007 the combined production from the Brent, Forties and Oseberg systems had fallen to around 1,120,000 barrels per day, with production figures expected to decline further. To counteract this drop in volume, Platts added market activity in Ekofisk crude to the basket of crudes used to determine the Dated Brent benchmark, giving the current Dated Brent (BFOE) assessment. Ekofisk (primarily a Norwegian crude) is brought ashore at Teesside, England, via the Norpipe pipeline. Inclusion of Ekofisk boosted the assessment volume to 1,580,000 barrels per day, and added an additional loading location. The Dated Brent benchmark continued to be assessed based on the lowest price of the four crudes. Like Oseberg and Forties at the time, Ekofisk is a higher quality crude than Brent Blend itself.

IMPACT OF CHANGE IN QUALITY OF FORTIES CRUDE IN 2007

The Buzzard field was started up in early 2007. Buzzard is the largest field discovered in the North Sea in twenty years and production rapidly increased to its expected plateau of 215,000 barrels per day. Buzzard is transported through the Forties Pipeline System, therefore co-mingling with the other Forties system crudes. Pure Buzzard is a lower quality crude than the other crudes that make up the Forties Blend. Therefore when Buzzard was introduced into the Forties Blend the overall Forties quality was reduced. Since February 2007 the Dated Brent price has generally been set by Forties since Forties is now a lower quality than either Brent Oseberg or Ekofisk. See Figures VI-5 and VI-6. Note that Platts do not publish a price assessment for pure Brent Blend, whereas rival price reporting organization Argus does.

FIGURE VI - 5
FORTIES, OSEBERG AND EKOFISK PRICE DIFFERENTIALS VERSUS DATED BRENT (PLATTS)

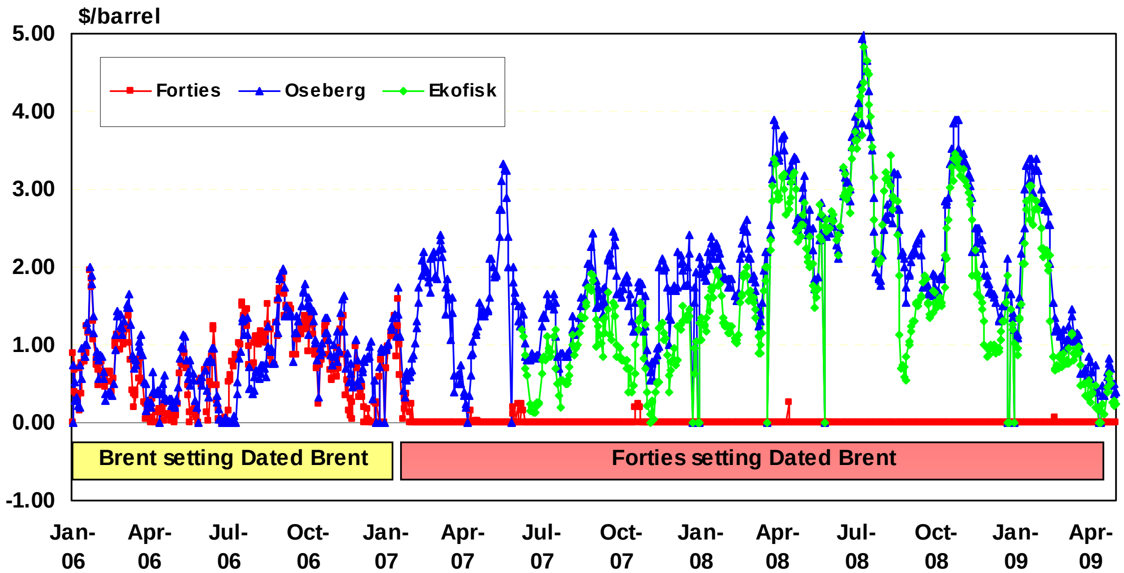
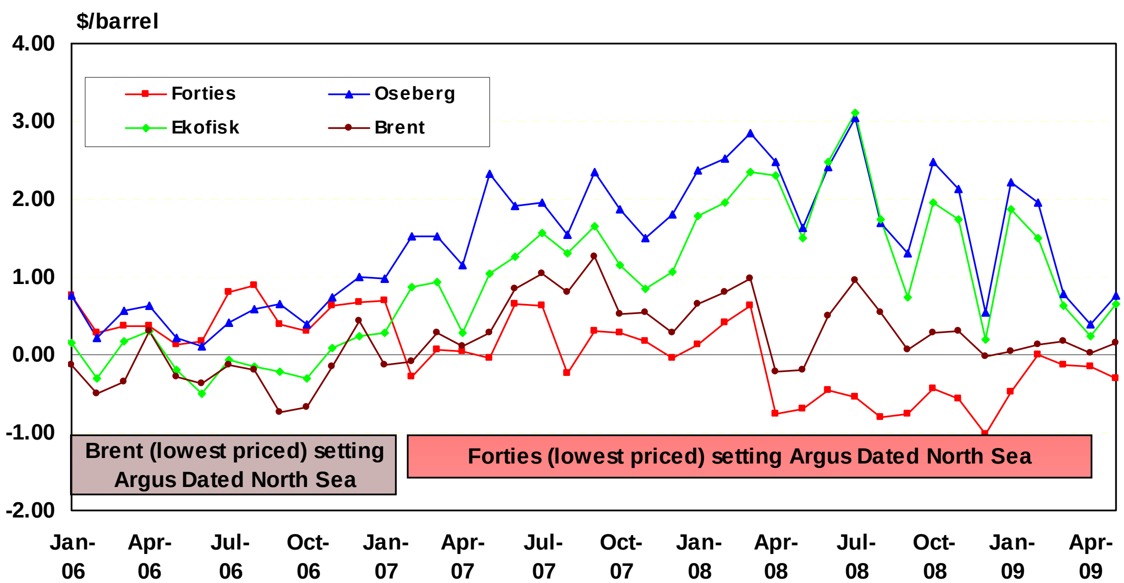


FIGURE VI - 6
INDIVIDUAL CRUDE MONTH AVERAGE PRICE DIFFERENTIALS VERSUS DATED NORTH SEA (ARGUS)



THE BRENT FUTURES CONTRACT

Several versions of the Brent Futures contract were tried by the IPE in the 1980s. The version which became successful was the Brent Crude Futures contract launched in 1988. Trade was in 1000 barrel lots of Brent crude up to 36 months forward. Originally these futures contracts expired 15 days prior to the month of delivery i.e. when the first cargo of the next month became "wet". Open futures contracts were cash settled on the basis of prevailing 15-day Brent prices at the time of expiry. Traders in Brent Futures can take physical delivery via the Exchange of Futures for Physical (EFP) mechanism but this option is not widely used.

The Brent futures market allows smaller companies with lower credit, not wishing to risk trading in the Brent 21-day market in full Brent cargos of 600,000 barrels or to take physical delivery, to hedge or speculate on future price trends, rather than being limited to a few large players, and has emerged as a key price discovery tool. As mentioned above it also provides the basis for B-wave pricing for crude oil supplied from the Middle East to Europe.

POTENTIAL FUTURE ISSUES WITH DATED BRENT

According to the ICE, in 2009, the Dated Brent crude benchmark and its associated derivatives (such as B-wave) is used to price approximately 65% of the world's crude oil. Maintenance of the integrity of and industry confidence in the benchmark is therefore very important.

However, predictions for North Sea crude production are for a relatively rapid decline, reducing the physical volume of crude available to benchmark against (See Figures VI-7, VI-8), with the volumes of Brent, Forties, Oseberg and Ekofisk expected to decline to very low levels (less than 580,000 barrels per day by 2015 and below 200,000 barrels per day by 2020).

FIGURE VI - 7
HISTORICAL AND PREDICTED NORTH SEA OIL PRODUCTION

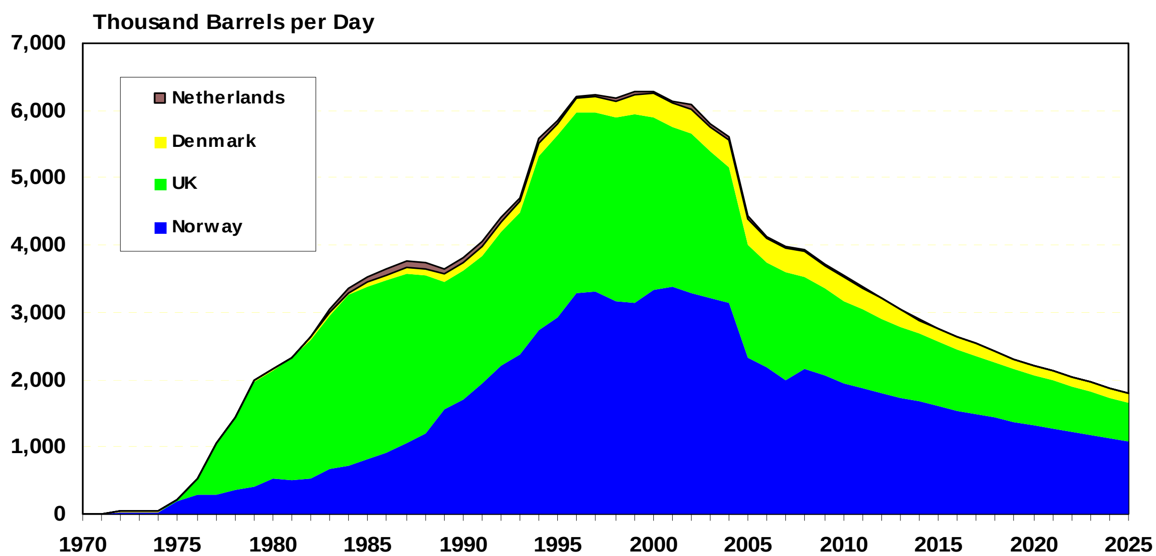
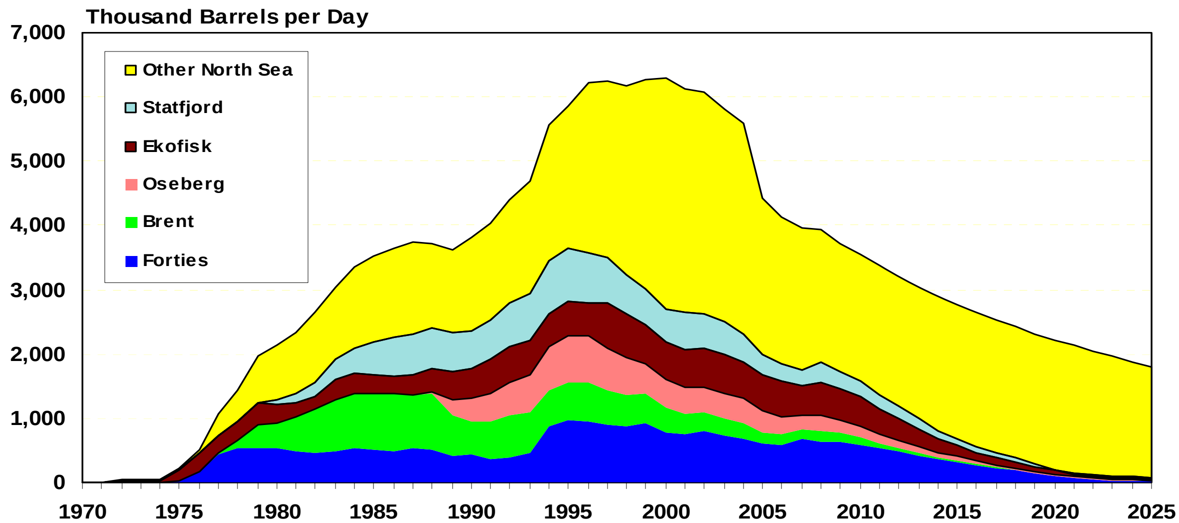


FIGURE VI - 8
HISTORICAL AND PREDICTED PRODUCTION FOR SELECTED NORTH SEA CRUDES



Quality changes within the Forties blend may also cause issues. Buzzard production is expected to be maintained at plateau rates through 2014 due to additional field development. Most other fields in Forties Blend are declining so the proportion of Buzzard in Forties will increase which will reduce the value of Forties relative to Brent, Oseberg and Ekofisk crudes. If the Forties value moves too far from the other three crudes, Platts may have to consider dropping Forties from the Dated Brent assessment and continuing with BOE or some other variation. However this would reduce the volume of oil that the Dated Brent assessment is based on from around 1,500,000 barrels per day to around 800,000 barrels per day (2009 values) and bring forward the date at which the combined production would be low enough to leave the benchmark again open to manipulation.

Other variations considered in the past included adding Statfjord to the assessment. This was rejected in favor of adding Forties and Oseberg in 2002. However, Statfjord is also in decline and subsequently adding it to the Dated Brent BFOE benchmark would potentially only extend the life of the benchmark by 1 to 2 years.

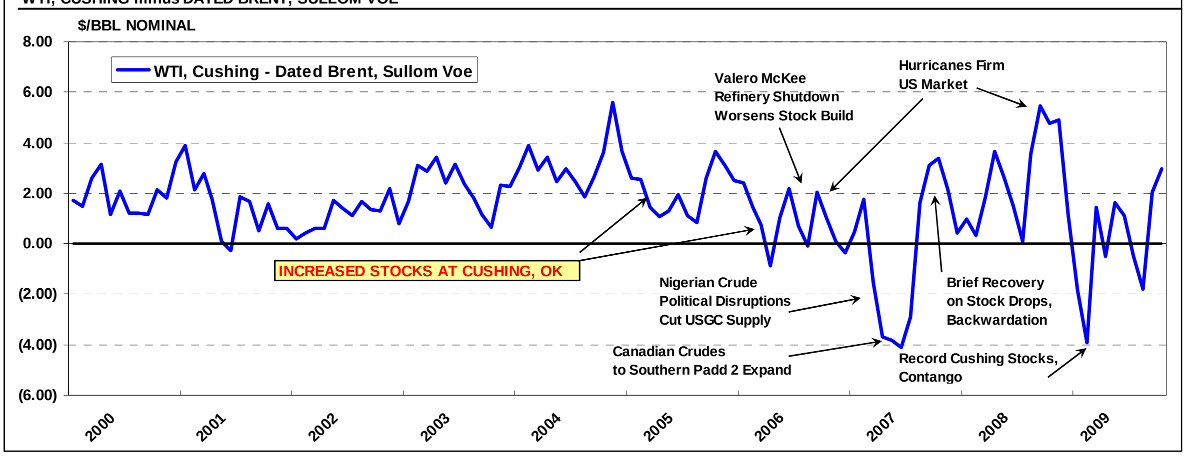
Recognizing these issues, Platts launched a dated "North Sea Light" benchmark as far back as 2002 to run alongside the dated Brent benchmark, in preparation for the day when there is effectively no more Brent. Not widely referred to, this benchmark is currently identical to the Dated Brent assessment, but could easily be adopted when the Dated Brent (BFOE) effectively becomes exhausted and the credibility of a benchmark with the name "Brent" in the title becomes unsustainable. A new assessment methodology would also have to be defined, probably referring to a weighted average pricing of a basket of remaining North Sea crudes.

UNDERSTANDING THE WTI/BRENT RELATIONSHIP

Over the last several years, as reviewed in the market chronology in Section III, the oil markets have undergone some of the most volatile periods in the history of the trade. Relationships among the various benchmarks have also exhibited unprecedented volatility. Some of the more prominent of these relationship aberrations have occurred between WTI and Brent and among the Brent relationships themselves, prompting adverse concerns within the industry related to this important differential. Given the background in this section with respect to the rocky history for the key Brent benchmark, it is important to tie the major benchmarks together to develop a better understanding of the reasons for periodic unusual deviations in the WTI/Brent relationships.

It is important to understand and acknowledge that the deviations of WTI versus LLS, and/or versus offshore imports such as the North Sea crudes can frequently involve the economics and fundamental dynamics of the other benchmark, fully or in part. The notations on Figure III-18 pointed out several instances of these circumstances and they are repeated in Figure VI-9, below, now showing the relationship of WTI to the benchmark Brent crude.

FIGURE VI-9
WTI, CUSHING minus DATED BRENT, SULLOM VOE



There is much press given to the spread between WTI, Cushing and benchmark commodity Dated Brent crude, the analysis of which is often quite shallow. **It is the volatility of this relationship that has exacerbated the concerns of market participants over recent times and it is important to understand the real drivers behind these in order not to misrepresent the validity of the benchmarks.**

In fact, in recent times these crudes have not been exclusively linked to logistics factors only as they typically were for years in the past. It is not uncommon to see references implying that the spread should be in the $1.50-2.00/Bbl range, and if not, something must be wrong with one of the benchmarks or the other. Over the period from 2000 to about 2004 the spread between WTI and Brent would, in fact, on average reflect mostly the influence of the freight to deliver the North Sea crude to the U.S. market where it would interface competitively. The freight rate trends through the 2000 to 2009 time frame are shown below in Figure VI-10 on a spot rate basis and in Figure VI-12 on a dollar per barrel basis, clearly showing that influence. The VLCC rate is shown in the figures as the typical delivery basis, though rates would be higher in smaller LR2 vessels on the increment. Key here is that freight rates have been extremely volatile over this time frame due to freight fundamentals and the impact of crude price changes on fuel costs. **This has directly caused volatility between the benchmarks and in no way reflects on the credibility of either of the individual benchmarks. It does, however, reinforce how important it is for the user of these commodities to be aware of those factors that increase basis risk and, most importantly, not to use historical correlations or average trends to anticipate spreads, without understanding the real fundamentals behind the pricing dynamics.**

FIGURE VI-10
FREIGHT RATES, SPOT % of Wordscale, VLCC EUROPE TO USGC

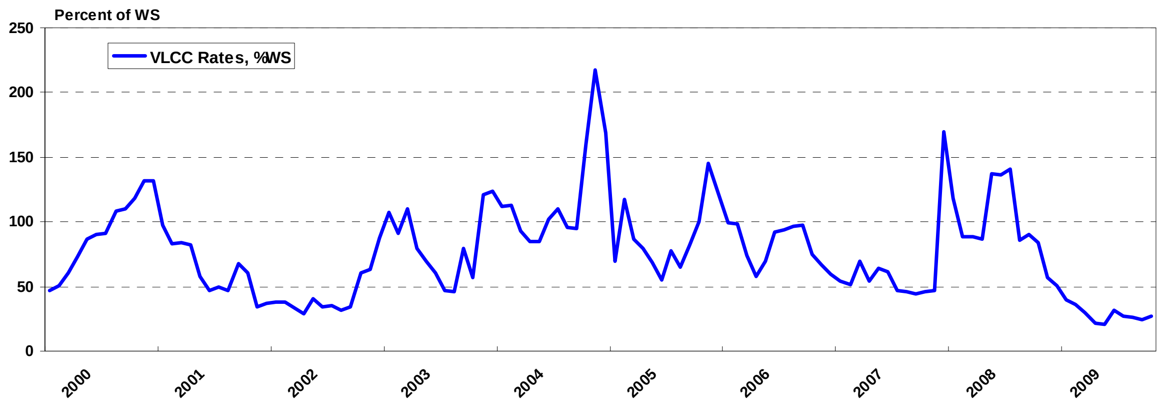
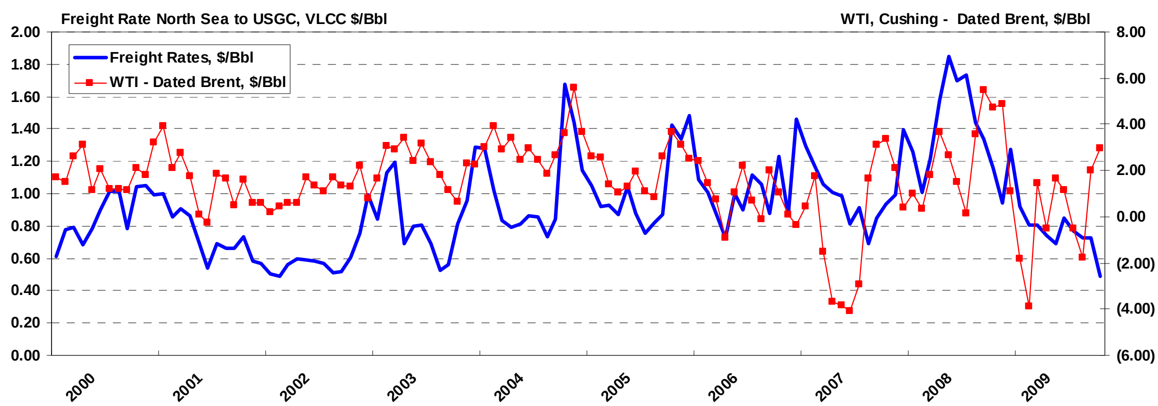


FIGURE VI-11
FREIGHT RATES, VLCC NORTH SEA TO USGC versus WTI/BRENT SPREAD, $/Bbl

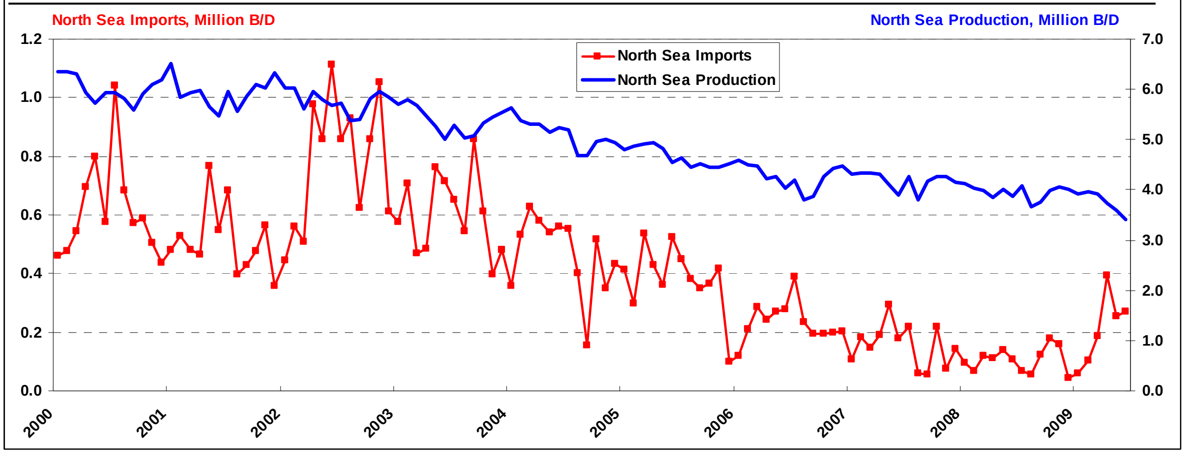


Freight rates have oscillated sharply on a seasonal basis over the years for the obvious supply/demand factors involved. This became even more pronounced through the 2004 to 2005 time frame, when tight shipping availability spiked rates during the surge in China demand. But, rates were also steadily increasing on average through the 2000 to 2008 time frame along with the increases in fuel costs, and this would directionally increase the FOB spread between WTI and Brent as just one of the underlying economic or market components affecting the spread.

During 2008 the spike in rates was extreme and the influence of this one component on the WTI/Brent spread is evident on comparison of this data with the spread itself in Figure VI-11.

Another important economic and fundamental reality of the benchmark comparisons relates to the interregional trade dynamics, especially as related to the unique features of the Brent market itself. In Figure VI-12 the total production of North Sea crude oil is shown just since the beginning of the decade. The loss of volume is dramatic, with recent output down to about 3.5 million barrels per day from well over 6 million barrels per day in 2000.

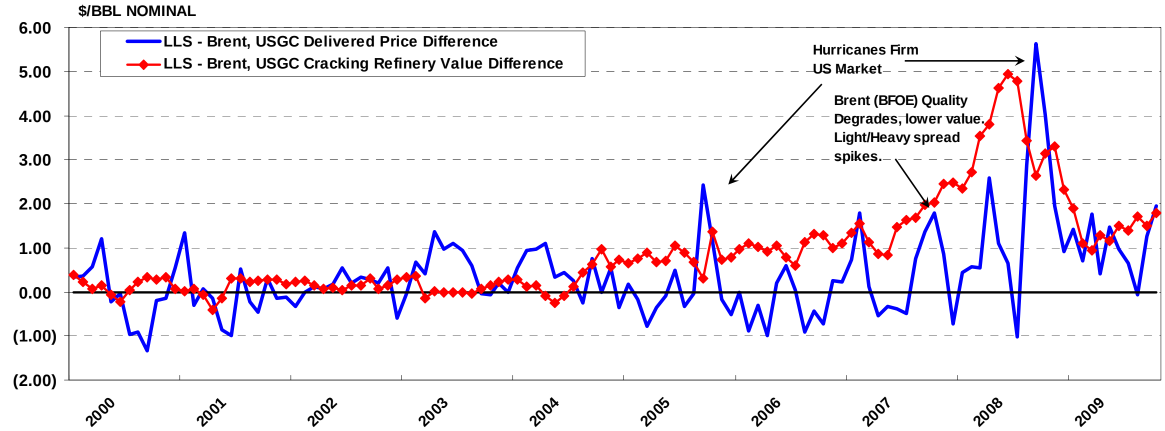
FIGURE VI-12
NORTH SEA PRODUCTION AND U.S. IMPORTS



It is important to note here that as North Sea production declined, the proportion of these crudes remaining to be consumed in Europe grew and the availability for export to the U.S. dropped sharply to almost nothing through 2008. In addition, most of what was imported came to the East Coast with its logistics advantage relative to the USGC. This trend resulted in an arbitrage delink between the North Sea prices and the USGC prices for a good portion of the time during this period. Though the volumes increased somewhat through mid 2009 as a result of the demand decline in Europe and the influence of curtailed African sweet supply due to political turmoil in Nigeria, the pricing parity of Brent with the USGC market began to weaken sharply in 2006, even assuming optimized economics using large vessels for delivery (VLCC). **During these periods, there would also be no physical link between WTI and Brent, except infrequently in the PADD II market, resulting in volatile price relationships between WTI and Brent.**

Figure VI-13 shows the direct comparison between Brent and LLS, both delivered to a USGC refinery. The economic parity mismatch here reflects the rising physical delink that has occurred over the last 3-4 years as the fundamentals changed, and this delink became very pronounced through 2007 and most of 2008, up until Hurricane Ike. The delivered price spreads have been much narrower than the refining value spreads, generating a large premium for Brent in the U.S. and killing the arbitrage. The fundamental result is clear in the preceding figure. The imports rose and the parity meshed consistent with this again in early 2009 when the volumes being delivered the Gulf Coast rose.

FIGURE VI-13
LLS - BRENT, USGC Price and Value Differentials



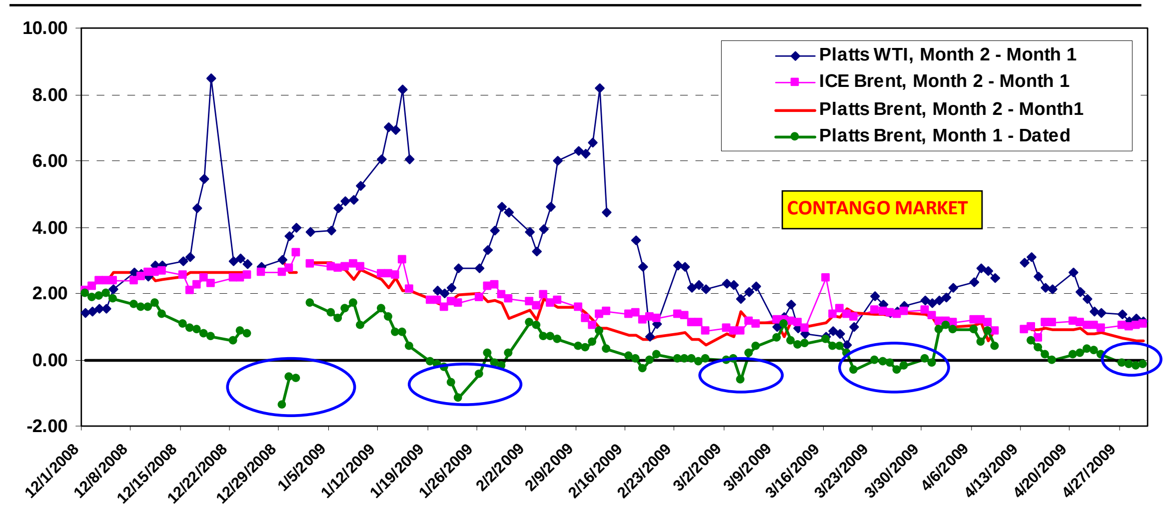
Another very important feature that can be seen in the above figure is that the quality of the Brent has changed significantly over the last several years. Brent prices no longer reflect neat Brent beginning in about 2007. Brent quotes have actually been represented by a method of choosing the lower of the quotes for Brent, Forties, Oseberg and Ekofisk (BFOE), as described in detail early in this section. Recently, it has been the Forties that has been the benchmark primarily since Forties quality has degraded at the same time. This distorts the relationships to LLS and to WTI. The value comparison takes into account the new qualities.

So, it is very important that the direct comparison of the WTI with Brent not be misinterpreted. All of the features of the respective benchmarks must be recognized and understood when evaluating the relationships among these crudes. Without this analysis result it could be mistakenly concluded that the LLS was the culprit, being discounted during this period. An exaggerated perspective on the WTI differential to Brent would also result. In the above figure, the actual spread between Brent and LLS would be, on average, equal to the value difference if they were in competitive parity. But, the price spread has been much lower in recent years, reflecting a premium on the Brent, generating a lower margin for a refiner versus the processing of the local USGC benchmark.

There are also, even recently, important anomalies within the Brent family itself that often go unrecognized as contributing causes of volatility among the regional benchmarks. Figure VI-14, following, shows an analysis of the various quotations for the Brent market reflecting the time structure resulting from each source. Also, shown on the figure are the cash market WTI quotations. Except for the Intercontinental Exchange (ICE) Brent futures, all the quotations are from Platts, which is the typical source reference for formula indexation when the cash basis Dated Brent is used. Saudi Arabia and others, however, have long since moved to the use of the ICE contract data as a reference due to the recognized liquidity issues related to the Dated Brent.

Despite the continuous efforts by the industry to stabilize the Brent trade through the expansion of liquidity by adding on new crude delivery options and price quotation availability, there are still periods when anomalies can occur. As noted in the figure, late in 2008 and through early 2009, there were a number of occasions, some persistent, where the Dated Brent was out of sync with the time structure of the rest of the Brent family and out of sync with the time structure of WTI. Except for the Platts Month 1 minus Dated Brent during the indicated periods, all the other benchmarks reflected the strong contango that was referenced earlier as the driver for inventory builds throughout the market. It is unclear within the data framework whether it is the Dated or the first month quotation that is the cause of the anomaly, but given the contrarian result versus the fundamentals in the market and the character of all the other forward market characteristics, that Brent can show trade anomalies that may still due to the liquidity of this market. It is also notable that there is considerable volatility in the WTI forward market when looking at only the current trade month versus the next forward month. This volatility is primarily associated with the necessity of rollover coverage related to low actual physical delivery of the associated volumes. This volatility appeared to coincide with rollover activity near the end of the physical trade cycle.

Figure II-14
TIME STRUCTURE, WTI and BRENT, $/BBL



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