THE ROLE OF FINANCIAL MARKETS IN THE PRICING OF CRUDE OIL: AN EXAMINATION OF OIL PRICING THROUGH THE STRUCTURAL CHANGES OF THE EARLY TWENTY-FIRST CENTURY

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ABSTRACT

The debate over the causes of the path of the price of oil over the twenty-first century has failed to address the method of oil pricing. The thesis guiding this dissertation is that the crude oil pricing method constrains the influence of financial investors in oil futures via (1) a two-part price system, (2) the role of both spot and contract markets, and (3) the connections between the futures market and the specific physical market related to the futures contract. Market participants construct the pricing method and adjust it through historical time and context, similar to methods of pricing found in manufacturing and retail markets. The details of the physical oil market, grounded in the pricing method, leads to the application in chapter 5. The chapter examines the behavior of prices for WTI and Brent-related futures markets as well as for one light sweet and one medium sour crude oil at the US Gulf coast. Data pertinent to conditions in the physical oil market includes levels and quality of production and imports to the US, changing environmental standards, US refining complexity, demand

growth and others clearly supports the path of these prices. The following illustrates the limits placed on financial investors in determination of the price of oil through the method of pricing and the conditions in the physical oil market.

APPROVAL PAGE

The faculty listed below, appointed by the Dean of the School of Graduate Studies, have examined a dissertation titled "The Role of Financial Markets in the Pricing of Crude Oil: An Examination of Oil Pricing through the Structural Changes of the early Twenty-first Century," presented by Stephanie L. Sheldon, candidate for the Doctorate of Philosophy degree, and certify that in their opinion it is worthy of acceptance.

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CHAPTER 1

INTRODUCTION

The following seeks to develop an empirically grounded post-Keynesian and Institutional theory of commodity pricing, starting with the role of financial investors in oil pricing. The work follows the path laid out by Post-Keynesian and Institutionalist scholars who have developed an empirically grounded theory of pricing based on institutions of market governance, where prices occupy an important position as the means of continuity for a business enterprise. This includes analyzing the business enterprise as a going concern.

Previous heterodox literature on pricing theory focuses mainly on those methods and institutions related to industrial or manufacturing and retail prices, while the method of commodity pricing remains largely unexamined. Many of the same themes of market governance, including administered prices, likely exist in commodity markets, but these markets also contain mechanisms and structures unique to commodity prices.

A heterodox analysis enables identification of systems of market governance, including those that diminish the incentive to compete over market share via prices. The heterodox foundation requires an examination of pricing, rather than exclusive focus on coordination of the market via a naturally given price mechanism that adjusts to equate marginal cost and marginal supply.

The debate surrounding the spike and collapse in oil prices involved whether "fictitious" demand for commodities from financial investors ruined the accuracy of the pricing mechanism. The assumption was, in the absence of financial investors becoming active in futures markets, the price would adjust to where the fundamentals of supply and demand meet.

This dissertation contributes to this pricing debate within the heterodox viewpoint by outlining the limits to financial investors imposed through the structures and mechanisms related to physical oil pricing.

The following chapters engage in disciplines, in addition to economics, by analyzing markets as social institutions. Producers and other interested market participants, acting through associations and other existing institutions, create, shape and adjust market structures and mechanisms. Vested interests establish, shape and adjust the pricing method through time, as changing circumstances warrant.

The pricing method is reflective of the market structure, the power of the various market players as well as the historical context within which the market exists. A pricing method is developed and adjusted within an historical context – within cultural norms, institutions and industry structure – and industry participants amend the pricing mechanisms and even the pricing method through time as required or enabled through changing circumstances. This evolutionary philosophical perspective guides the research through the various disciplines.

An additional aspect of interdisciplinary studies arises in the breadth of the examination into the potential causes of the latest oil price cycle. The context of the oil market highlights many potential 'fundamental' causes for the run-up in oil prices from the early 2000s to 2008, as well as the eventual declines. Researching these possibilities, involves understanding some aspects of refining and petroleum product specifications, including Environmental Protection Agency (EPA) regulations, as well as political science and policy in understanding the passage of renewable fuel standards and the ban – and eventual repeal – on crude oil exports.

Developing an understanding of the context of the oil market also entails moving outside of scholarly journals to areas such as niche and business journalism, analyst and financial publications as well as government publications, legislation and industry comments on proposed legislation.

Delving into the formation of the method of pricing and the implications thereof requires moving beyond economics. A purely economics-based approach can assume the method of pricing and motives of the market players, and in the extreme, can limit the question and analysis to correlations between the activities of financial players and the price of oil futures contracts.

The oil market stands out as a starting point for understanding the role of financial investors within a commodity pricing method. The cost of crude oil is included in the price of many other commodities. Crude oil is a storable commodity, making institutions of price stability for oil more complex than those related to perishable commodities. Some form of hydrocarbon is an input in the production and transportation of nearly all goods. Lastly, the price of oil drew much attention in the discussion over the financialization of commodity prices and the debate over whether financial investors were driving commodity prices in the twenty-first century

Oil Pricing—basic concepts

The price of physical oil actually consists of two prices. Typically, the overwhelming majority of the price is a reference price. West Texas Intermediate (WTI), Brent and Dubai-Oman are the three markets from which reference prices derive. While each of these is a physical crude oil(s), there are multiple markets, or prices, constructed around each of the physical crude streams, and the various markets serve different purposes and potentially contain varying participants. Each of the reference crude streams has a futures contract associated with the physical crude. The debate over the role of financial investors in the oil price cycle of the twenty-first century revolved almost entirely around the futures market price for one or two of these crude streams (WTI and Brent).

The second part of the price of physical oil is the differential. The differential shows the price of a specific crude oil at a specific location, relative to the reference price. The differential represents the crude quality and local conditions relative to the reference price quality and location. The differential for a particular crude oil tends to reflect granular details of a specific location, such as area infrastructure or demand conditions in the typical destination market. The portion of the differential related to quality is not constant, but rather moves with demand conditions in an area – area conditions for locally consumed grades of crude oil – or those in destination markets.

In addition to the price of physical oil consisting of two values, exchanges of physical oil take place in different types of markets. Physical crude oil is exchanged though spot markets and contracts markets. The value of both the reference and the differential varies from spot to contract markets.

Spot market transactions are a one-time exchange of physical crude oil, where neither party is obliged to exchange further volumes of crude beyond the one agreed-upon transaction. In contract markets, parties are obliged to buy/sell physical crude volumes regularly over the period of the contract.

The following details the physical market surrounding financial oil benchmarks, lays out the literature for and against "speculation" as a driver of the price of oil and conveys the physical context of the oil market during the period of increased financial participation in commodity futures. Finally, a close examination of physical markets at the US Gulf coast illuminates the role of the differential and the importance of the method of pricing as a check to the role of purely financial players.

An examination of oil *pricing* and the movement of the basis and differentials since 2000 shows that physical players and physical oil market issues are a driving factor in determination of the price of physical oil and prices in the futures market.

The Speculation versus Fundamentals Debate
The and Pricing in the Physical Oil Market

Just after the turn of the century, commodity prices diverted from their former long-run trend, rising and falling within wide ranges not previously seen. After the first rise and fall, a new range was established within which prices tended. More recently, prices have declined once again. Some stylized facts led researchers to examine the role of financial flows and market fundamentals in an attempt to understand the cause of the first run up, collapse and newly established range.

By 2003, financial investors became interested in commodity markets. This later translated into their increasing participation in commodities futures. Through the commodity price spike, concerns increased over the consequences of financial investments in commodity futures.

If financial interest overwhelms the traditional future markets participants, it is possible financial interests could dictate the price of the futures contract as opposed to traditional futures markets participants engaging in price discovery. Concerns over growing financial investments point to an apparent fundamental grounding of the price of oil in the long term prior to commodities futures becoming increasingly popular as a financial investment.

Putting aside financial markets, the physical oil market was becoming increasingly tight as demand was strong and growing while excess capacity was shrinking. The relatively low prices of the 1980s and 1990s discouraged investment in production and refining. Moreover, the refining industry was designed to handle to higher quality crude oil – less dense, with lower sulfur content – while the demand for oil products was moving more to lighter product as demand for heavier fuels. Environmental regulations through the first decade of the twenty-first century consistently reduced the allowable level of emissions and sulfur from petroleum products, further enhancing the value of higher quality, light crude oil.

Academics, policy analysts, government bodies and other institutions have published extensive literature over the last several years in an attempt to understand the effect of financial flows on the price of crude oil. After a careful review of the existing literature, it is clear the question remains unanswered.

Much of the existing literature investigating speculation within the oil market revolves around assessing the correlation between the financial flows in futures markets and the price of crude oil. The type of model, corrections to the model, the variables chosen, including what represents both speculator flows and the price of oil, all influence the results obtained. Much of the discussion lacks acknowledgement of the pricing method and an emphasis on the historical context.

A one-to-one change in the price of physical oil via futures prices is not evident when viewed within the broader context of the pricing method. The path of the futures price has changed dramatically from its origin in the 1980s. Growing financial interest likely did change the way the price of futures contracts behave. How the change in the path of the futures price translates to the physical market is dependent on oil *pricing*. Moreover, market participants respond to changes in the behavior of futures markets in multiple ways, including adjusting the pricing method, such that a one-to-one connection fails. For instance, OPEC producers Kuwait, Saudi Arabia and Iraq changed their reference price for imports to the US in response to the failure of WTI to represent conditions at the coastal points of entry.

It is to the above referenced literature that the discussion now turns.

CHAPTER 2

LITERATURE REVIEW

Introduction

Minimal consensus exists concerning which variables and methods researchers should use when attempting to understand what has driven oil prices since the turn of the century. In addition to data and statistical methods, some have pointed out that most of the research fails to account for basic structural details of the oil industry.

The literature review is in three broad sections. The first section consists mostly of research seeking to identify whether a correlation exists between financial flows and the futures prices of WTI. Open interest in futures contracts and prices of oil futures contracts are common data examined in the first section.

The second part opens the discussion to include the basic context of the physical oil market, while still addressing financial factors as possible sources of volatility. Some of the literature explicitly acknowledges and works within the reference-pricing framework, present in the industry while examining the role of financial investors.

The third section focuses on research involving relationships between multiple prices, including petroleum products and/or oil prices. Some of the third section includes data on financial investors, while other authors focus exclusively on price relationships in energy markets. This third section finds energy prices tend to be nonstationary and cointegrated. The literature assesses these relationships using error-correction models.

The review concludes with research by industry-related institutions, which typically publish data on the industry itself. Included in this final section are the Energy Information Administration (EIA) and the International Energy Agency (IEA). Both the EIA and the IEA address financial investment in commodity markets, while focusing on more granular details of the physical oil market than much of the previously discussed literature.

Oil Futures Prices through the 2008 Spike and Crash

Passive Investors

Michael Masters and Adam K. White's Accidental Hunt Brothers I & II, both published in 2008, argue index investing directly caused the run-up and eventual crash in commodity prices. Conversely, Stoll and Whaley (2009) argue that index investing did not contribute to the rise and crash in commodity prices. While Irwin and Sanders (2012) agree with Stoll and Whaley (2010), the former directs their article at rejecting Masters and White (2008).

According to Masters and White (2008a), index investing pushes futures prices higher as well as damages the price-discovery function of the futures market. Index investors invest in long-only futures contracts, invest for long periods, and are insensitive not only to price but also to market fundamentals (10-11).

Index investors are ignorant of the market conditions of individual commodities and so cannot respond to mispricing in the expected manner. Index investors allocate a percentage of their portfolio to long-only futures contracts thereby failing to provide the liquidity of traditional speculators, who engage both sides of the market. The number of contracts purchased by index investors depends on the desired diversity, the total size of the portfolio, and the weights given to each commodity within the chosen index.

Investors' insensitivity to the relationship between price and market fundamentals is precisely the reason index investing is harmful for futures markets. Since futures markets determine spot prices in physical markets[1] (Masters and White 2008a), incentives related to market fundamentals should drive activity in futures markets.

The evidence provided by Masters and White (2008a) consists of the correlation between the amounts of money flowing into futures contracts for commodities listed on the indices and the prices of said futures contracts over the same period.

Masters and White extrapolated from the public data available for agricultural markets published in the CFTC Commitment of Traders Supplemental report on index traders. Using the COT supplemental, in combination with the weights published by the two major indices, Masters and White calculate the amount of index flows in energy markets (Masters and White 2008, 49).

In addition, according to the authors, there are few reported shortages of physical commodities.

> [F]rom 2003 to July 1, 2008 commodity index investment rose by a factor of 25 times from $13 billion to $317 billion and commodity prices have tripled … It is *prices*, not *supply*, that has led to food riots around the globe. (Masters and White 2008a, 14)

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[1] This is a controversial statement in both its conclusions and transmission mechanism.

According to Masters and White, there has been an increase in demand for physical commodities, much of which results from the growing Chinese economy. However, index investors have equivalently increased the demand for futures contracts (Masters and White 2008a, 15-18).

The amount of the increase in demand for physical barrels of oil is equivalent to the increase in demand for paper barrels of oil on behalf of index investors. The authors track the data and the greater the inflows from index investors, the greater the rise in commodity prices[2] (20-22).

Index investors have come to dominate the futures market: from 2003-2008, index investors purchased a greater portion of futures "…contracts than both Physical Hedgers and Traditional Speculators combined" (19)[3,4].

In 1998, physical hedgers held more than three long futures contracts for every long futures contract held by speculators (33). In 2008, speculators - traditional and index investors combined – held more than two long futures contracts for every long futures contract held by physical hedgers (33).

Index investors served as a catalyst to the recent commodity bubble. As the bubble began to form, traditional speculators abandoned their previous trading strategies and adapted to new drivers of the market – the new set of conditions put into place by index investing.

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[2] The actual relationship under examination is between the price of futures contracts and the flow of funds in futures markets, for which index investors are responsible.

[3] These calculations are the source of much criticism. See below.

[4] Due to the calculation excluding both spread and "non-reported trades," it overstates the portion of index investors, as index investors are not involved in spread trading. While Masters and White mention the exclusion, they do not explain the bias involved in the exclusion.

Index-investor dominance replaced physical-hedger dominance leading traditional speculators to disregard market fundamentals.

> At the point that commodities futures markets 'tip' into excessive speculative territory, Traditional Speculators wake up to the new market reality and abandon the 'supply and demand' camp in favor of the 'inflation hedge,' 'weak dollar,' 'uncorrelated alpha,' et cetera camp. (33)

According to Masters and White, traders have adapted their mentality and habits to the new situation, such that futures markets can no longer perform the price discovery function appropriately.

According to Masters and White (2008) oil futures markets were too small to absorb the substantial and growing inflows of index investors looking to gain exposure to commodity markets as a component of a diversified portfolio[5].

Prior to the rise in popularity of index investing, market fundamentals drove the activities of participants in the futures market for crude oil. The tension between sellers and buyers in the physical market, who also trade in futures markets, enabled accurate price-discovery.

The role of "traditional" speculators is to provide liquidity to hedgers. Speculators take on price risk in an attempt to gain. Prior to the rise of the index investor, the physical market grounded the interactions of physical market players and traditional speculators.

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[5] According to Masters and White, the bear-equity markets from 2000-2002 initially attracted investors. A significant portion of the funds invested in commodity indices results from institutional investors, therefore legal changes at the state level to the Prudent Man rule in the early 1990s were a pre-requisite for the increased appetite for index investments. Rather than examine the asset in isolation, consideration expands to role of an individual asset within the entire portfolio. Lastly, the CFTC began exempting financial institutions from position limits in the early 1990s, and essentially absolved them of any limit in 1998 (Masters and White 2008, 40).

Index investors transformed the foundation of the price-discovery process by overwhelming the negotiations of physical hedgers and traditional speculators. Once physical hedgers lost influence in the crude futures market, traditional speculators shied away from trading on the characteristics of the physical market and adapted to the new relevant variables of price-determination, whatever they may be at the time[6].

Irwin and Sanders criticize the method and conclusions of Masters and White in multiple publications. Faulty data leads Masters and White to reach incorrect conclusions regarding the effect of speculation, according to Irwin and Sanders (2012, 268).

Irwin and Sanders (2012) use data that was not available in 2008: the CFTC Index Investment Data (IID), which includes data specifically on energy markets. In claiming to possess superior data, the IID data, Irwin and Sanders conclude the data used by Masters and White is now unacceptable.

The IID data proves the inaccuracy of extrapolations from the COT Supplemental[7], according to Irwin and Sanders. There is virtually no correlation between the IID data and

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[6] Traditional speculators stand to lose money if they continue to follow old patterns in a new market; moreover, given the emphasis on relative returns, traders who resist adapting to the new situation are likely to become unemployed.

[7] This should have come as no surprise to the researchers, as there are major differences in the two data sets. If the primary function of a trader is deemed index investing, all trades are classified as index investments on the COT supplemental. Most importantly, the COT supplemental covers only netted trades. Conversely, the IID is a better representation of the books of swap dealers rather than their actual activity on futures markets. Whereas the COT classifies all trades on futures exchanges as index investing when that is deemed the primary function of the trader, the IID includes all of the deals made with clients, rather than actual trades that made it to the futures market. The IID relates to the amount of funds committed to commodity indices whereas the COT relates to the amount of investment in commodity indices that actually flows into futures markets. The CFTC originally published IID quarterly, and then monthly. The supplemental is published weekly (CFTC Explanatory Notes IID).

Masters and White's calculations about the amount of money invested in energy futures. Moreover, "the net long IID position in crude oil is negatively correlated with those of agricultural commodities from 2007 to 2011" (Irwin and Sanders 2012, 268). Since Masters and White extrapolated from agricultural numbers in the COT supplemental, the analysis is invalid.

Despite Irwin and Sanders conclusion, the lack of correlation between the two data sets expected from the definitions of the data. The COT classifies all trades on futures exchanges as index investing when that is deemed the primary function of the trader.

Conversely, the IID includes all of the deals made with clients, rather than actual trades on the futures market. The IID relates to the amount of funds committed to commodity indices on behalf of a dealer's clients, whereas the COT relates to the amount of investment in commodity indices that flows into futures markets, albeit for agricultural commodities (CFTC IID explanatory notes).

According to Irwin and Sanders (2012) there are only three possible ways for index investors to affect the futures market, all of which cause contemporaneous correlation between "index fund position and price changes" (257)[8]. The first way occurs if futures markets are not liquid enough to handle the inflow of index positions, and as index positions enter and exit, prices in futures markets should adjust accordingly. The second way index funds may affect the futures market is to interfere with the flow of funds by informed traders,

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[8] 1. Futures markets are not liquid enough to handle the inflow of index positions and as the enter and exit, prices in futures markets should adjust accordingly; 2. Index funds interfere with the flow of funds by informed traders and may push prices above or below fundamentals; 3. The "noise" created by the flows of index funds leads other traders to adjust their viewpoints and, thereafter, their trading positions (Irwin and Sanders 2012, 257).

thereby moving prices above or below fundamentals. Lastly, the “noise” created by index flows may lead other traders to adjust their viewpoints and, thereafter, their trading positions (Irwin and Sanders 2012, 257).

After conducting several regressions using the IID data, Irwin and Sanders conclude that index investments were not a statistically significant cause of price changes in energy futures markets (2012, 269). Because contemporaneous correlation is lacking, index investment is not driving futures prices.

Moreover, traders did not identify index funds as a reason to adjust perceptions about market fundamentals and index funds did not cause prices to diverge from that which is justified by the fundamentals.

According to the several regression results of Stoll and Whaley (2010), index investors are unlikely to cause changes in the price of commodities futures although speculators may (Stoll and Whaley 2010, 47, 65-66). The net flows of speculators[9] are correlated with futures returns for all 12 commodities examined.

In contrast to speculator flows, the results of Stoll and Whaley imply a lack of causation regarding the net flows of passive investors and the prices of commodities. Additionally, they find correlation among commodity prices, regardless of whether they are included in popular indices. According to Stoll and Whaley, this suggests fundamentals are driving both analytical groups – the prices of both commodities included and excluded from popular indices.

[9] Speculators are ‘active’ financial investors as opposed to ‘passive’ index investors.

Researchers at the CFTC have examined the role of new investors on the performance of futures markets in a number of articles. The CFTC staff report, “Commodity swap dealers and index traders with commission recommendations” (2008), concludes that index traders were likely a stabilizing force in the run-up in oil prices from December 2007 to June 2008.

The price of oil continued to rise while the number of contracts held by index investors declined. Moreover, much of the interest in index activity fails to show up in the futures market as demand for futures contracts, because of internal hedging[10] by swaps dealers.

During “normal” times, index investors are beneficial to large swings in the price of oil. When prices rise substantially relative to other commodities, index investors sell oil contracts in order to rebalance their holdings of commodities generally (Verleger 2009, 9-10).

Beyond Index Investing

“Price dynamics, price discovery and large futures trader interactions in the energy complex” (2005) and “Price volatility, liquidity provision and the role of managed money traders in energy futures markets” (2005) focus on the role of an active group, labeled managed money traders (MMT) by the CFTC.

The researchers conclude that rather than cause changes in the prices of futures contracts, large financial traders respond to the trades of physical hedgers. Commercial hedgers respond to changes in the prices of futures contracts. Additionally, the CFTC

[10] A swap dealer need only hedge net exposure to risk. In exchanging exposure with multiple parties, a transaction with one party will offset the risk exposure of a transaction with another partner.

research finds a negative correlation between the trades of MMTs and the price of crude oil futures contracts.

The CFTC publication, "Fundamentals, trader activity and derivatives pricing" examines growing financial flows into the market for crude oil and the shape of the futures curve (Büyükşahin, et al 2008). Prior to 2002, the short-term price of oil futures varied but the long-term price remained stable. Even when the price was volatile in the short term, the price one or two years out remained anchored–implying participants believed in the existence of market feedbacks in the long term (Büyükşahin, et al 2008; Fattouh 2010). In 2002, near futures prices cointegrated with one-year-out futures prices. In 2004, the same cointegration occurred between near and two-year-out futures contracts.

The 2008 CFTC study utilized non-public data and thereby was able to connect the change to increased participation of financial traders at the far end of the curve. Hedge funds and other financial traders conducted an increasing number of trades at farther out on the futures curve. The CFTC paper associates the shift with oil market fundamentals as well as financial traders.

The conclusions of publications in 2009 (Harris et al) and 2010 (Brunetti et al) are consistent with previous CFTC research. Speculators do not cause changes in the price of crude oil, and speculator flows help reduce volatility in the price of crude oil.

The following research helps illuminate some aspects of the futures price.

King et al (2012) analyze the role of multiple groups of non-commercial traders, as defined by the CFTC, on the price of oil with a VEC or VAR model where appropriate. The period of analysis is broken into four segments, as defined by the behavior of prices therein:

June 13, 2006 – June 19, 2007 (stability); June 19, 2007 – July 15, 2008 (increasing); July 15, 2008 – February 17, 2009 (downturn); and February 17, 2009 – October 31 2009 (recovery). Variables included in the model are the price of the front-month WTI contract and the net positions of each group: Producer-Merchants (PM), Money Managers (MM) and Swap Dealers (SD).

During the stable period, PM and oil price Granger cause each other and are negatively related. Deviations from the long run equilibrium between PM and oil price Granger cause SD (negative). In the short run, MM Granger causes PM and PM Granger causes SD (positive). Non-linear tests revealed Granger causality from SD to “the oil price at the second lag” (positive) (King et al 2012, 40).

In the run-up period, oil price and PM Granger cause each other. In contrast to the stable period, the relationship is positive. Deviations from the long run equilibrium Granger caused MM but not SD. Whether the relationship is positive depends on the source of the deviation. The relationship is negative in the case of oil price deviations and positive when the deviation results from the PM net position variable.

During the downturn, no significant relationships were established.

In the recovery phase of oil prices, there is no identifiable relationship between PM and the oil price directly. Instead, SD Granger caused the oil price (positive). In the short run, SD and MM Granger caused the oil price and the oil price Granger caused both SD and MM. Additionally in the short run, both SD and PM Granger caused MM.

Interestingly, the only long-term relationship between financial traders and the oil price appears in the recovery period rather than the run-up or downturn period.

Lonnie Stevens and David Sessions (2008) find that the end of the futures curve under examination will change the results. Through regression analysis, they claim supply conditions dominate the near end of the futures curve, while speculative activity dominates the far end.

In addition to Stevens and Sessions (2008), other academics have begun to parse the term structure of the futures curve in an attempt to ascertain causes of recent breaks with historical trend.

In, “No theory? No evidence? No problem! The CFTC has no sound justification for its proposed energy speculative position limits” (2010) Craig Pirrong slams the CFTC for imposing speculative position limits. He concludes a positive correlation between financial funds and the price of crude futures is insufficient justification for imposing position limits.

The CFTC risks harming the functions of the futures market without any proven benefit, according to Pirrong (2010). The CFTC failed to connect activity in the futures market to prices in the physical oil market. Speculators participate in financial markets rather than physical markets.

Financial investors sell futures contracts prior to taking delivery of physical crude oil. If speculators stockpiled physical crude, prices and inventory levels would move together, but they have not, according to Pirrong (2010). There is no demonstrable connection between speculators buying in futures markets and the physical price of oil.

Several researchers have pointed out some of the market tightness and the increase in financial flows into energy futures markets and have concluded that fundamentals drove prices, but financial flows exacerbated what would have been a smaller absolute increase.

Acharya, *et al*., (2010) show that market fundamentals were largely responsible for rising energy prices by utilizing NYMEX futures prices, CFTC total open interest and EIA data on US petroleum product inventories – aggregated – in a regression analysis. Although they admit financialization of commodities may have played a role in rising prices, they conclude speculation likely decreased volatility.

In 2009, E. James, through regression analysis based on a model of convenience yield – imputed through the price of futures contracts at various dates of expiration – claims to show the rise in the price of oil up to $100 was a result of market fundamentals, while the rise from $100 to $140 was a result of speculative activity. The subsequent crash in the price of crude oil was temporary and a result of collapsing demand. Upon the expected recovery in demand, the price of crude oil will rise, once again.

Both a Government Accountability report in 2007 and Behr (2009) of the Global Public Policy Institute conclude that both speculation and market fundamentals likely contributed to the rise in commodity prices, but the debate will continue to remain unsettled until sufficient data exists.

Christopher Gilbert concludes, for commodities generally, fundamentals explain the price movements although index fund activity likely amplified the process. James Hamilton (2005; 2009a; 2009b) comes to a similar conclusion, finding evidence in supply and demand fundamentals. Although he believes market fundamentals led to a speculative bubble, owing to the elasticity of supply and demand.

Kahn 2009, Kaufmann 2011, and Kaufmann and Ullman 2009 and Saporta, et al 2009 find evidence in fundamentals for rising prices, but not for prices to rise as high as they did; the rise was amplified by speculation.

Silverio and Szklo (2012) trace the influence of the futures market on the spot market price from 1990 – 2010 and find the futures market had an increasing influence during the 2003-2008 price cycle. The authors use EIA data for the daily WTI spot price and front-month NYMEX light sweet crude contract price in a cointegrated error correction model with a Kalman filter. They use the Kalman filter technique to identify changes in the influence of the futures market over time (Silverio and Szklo 2012, 1803).

Fan and Xu (2011) use a multifactor model with structural breaks to discern the role of speculation and other market factors on the price of near-month WTI futures. The following periods result from identification of structural breaks: January 7, 2000 – March 12, 2004; March 19, 2004 – June 6, 2008; and June 13, 2008 – September 11, 2009. Speculation took the form of two variables: percent of total open interest held by non-commercial traders and net long non-commercial futures contracts as a percent of total non-commercial open interest.

During the first period, the variables representing speculation and the dummy variables accounting for the September 11th attacks and the start of the second US war in Iraq are significant. The remaining variables, Baltic Dry Index, US Dollar Index, COMEX next month gold futures price and the S&P 500 Index are not significant.

In the second period, the variables representing speculation, gold futures, US dollar index and S&P 500 Index are all significant; the variable, Baltic Dry Index is not significant.

In the final period, both of the variables representing speculation and the US Dollar Index are not significant, while the remaining variables are significant.

In spite of myriad papers espousing one or the other side of the issue – fundamentals or speculation – the matter remains unsettled. Ederington, et al (2011) conclude the evidence on both sides is inconclusive while, Fattouh, et al (2012) concludes speculators did not play a significant role in the dramatic changes in prices, although further research is necessary. In spite of the plethora of research, “no definitive or compelling conclusion has been reached” (MTOMR 2009, 97).

The one issue within much of the literature that appears settled is the acceptance of the futures market as a representation of the oil price. While not always made explicit, the variable termed the “spot” price is the closest-to-expire futures contract. Reliance on the closest-to-expiry futures contract as the representation of the spot price of oil and use of aggregate supply and demand numbers to represent ‘market fundamentals’ potentially invalidate much of the research and confuse the discussion.

Market Context and Financial Flows in Oil Futures Markets

Verleger (2011) argues the non-homogeneity of crude oil supply and demand negate the conclusions of researchers on both sides of the issue. Likewise, Carollo (2012) adds, without including some representation of the refining industry, a model that turns out to be correct, can be correct only by accident (pg. 82). Fattouh (2011) focuses on the different financial and non-financial layers of the oil-pricing regime and finds that a dualistic separation of the financial flows of purely financial players from those of physically involved players is not feasible, owing to the relationships between physical market prices and futures market prices.

Verleger has been a proponent of the market fundamentals side, although he does find financial investors capable of affecting the physical oil market. While Verleger finds sufficient ‘fundamental’ reasons for the prices of crude to increase and then collapse, he identifies some consequences of large inflows by passive investors (2009).

Verleger identifies three price cycles, the first of which began in 1995 and continued until March of 1999. He identifies this as a period of surplus capacity and growing inventories.

In March 1999 and continuing through early 2004, OPEC producers, namely Saudi Arabia, began targeting inventory levels in addition to consumption in an effort to drain excess supplies of oil from the market. OPEC successfully drained the accumulated stocks and maintained a backwardated futures curve, beginning in 1999 through 2005 (Verleger 2009, 13). This artificially low supply led to rising crude prices, and thereby, rising product prices.

Beginning in the spring of 2004, strained refining capacity led to increasing product prices during the next price cycle. Arbitrage in financial and physical markets led to rising crude prices in response. According to Verleger, traders understand the varieties of crudes and the varying product slates that result. As product prices rise, crude prices follow, just as rising crude prices feeds into product prices (Verleger 2006).

Also in 2004, hedge funds began purchasing large quantities of oil futures contracts. Additional financial institutions soon followed hedge funds, in search for greater returns.

By 2005, producers and other commercials active in physical oil markets reduced their participation in the futures markets. Rising and volatile prices of the recent past minimized potential gain for physical market players who hedged the sale price of crude (Verleger 2007; Dittrick 2005).

In addition to forgoing higher prices, firms record foregone profit resulting from derivatives contracts as a loss on financial statements (Dittrick 2005). An increase in demand for oil futures, without a corresponding increase in supply led to a rising price of futures contracts.

According to Philip Verleger, Hurricanes Katrina and Rita[11], environmental specifications, lackluster historical performance of the refinery industry and growing global demand all contributed to the strained refinery capacity, which characterized the middle part of the decade. In 2006, according to Verleger's estimation, oil and product prices needed to grow by twenty percent annually, if global growth was to continue at three percent (Verleger 2009).

The market for crude oil used to be essentially one, with lower quality crudes priced slightly lower, because of the greater portion of less valuable heavy ends (Verleger 2009, 14). After the enactment of the more strict environmental standards, some refineries lacked sufficient capacity to process lower quality crude oils into light products that met the new stricter standards.

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[11] After the hurricanes (late 2005), President George W. Bush requested the refining industry put off previously-scheduled maintenance to compensate for the temporary loss in US refining capacity (capacity after the hurricane was one-quarter less than prior to the hurricanes).

Refiners came to view the crude oil market as two: sweet and sour (Verleger 2009, 3; 2011). The actions of OPEC further compound the problem. OPEC acts to maintain a stable differential between high and low quality crudes (Verleger 2009, 5; 2011). OPEC avoids a drastic decline in the price of lower quality crude oil by absorbing the burden of the decline in demand for the lower quality crudes.

Lastly, Verleger addresses the most notable increase in the price of oil – the rise from second half of 2007 through the first half of 2008. Typically, crude oil prices move cyclically, peaking during peak demand and declining during lulls in demand. From the end of summer until the beginning of the following year, crude prices tend to be relatively low. From the end of July 2007, strains in the physical market, caused by a limited supply of light-sweet crude oil, were beginning to subside and the price of crude oil began the usual cyclical decline.

As in previous years, the end of July 2007 brought with it a decline in the price of crude oil. However, rather than continue to decline, the price of WTI began an ascent to $147/bl, reached the following year.

Aspects of both the physical and financial markets led to a break away from the seasonal cycle. In mid-August, the US began refilling the Strategic Petroleum Reserve with light-sweet crude oil and August 2007 marked the beginning of the US financial crisis (Verleger 2008).

The actions of the Department of Energy brought the return of a tight light sweet market and the activities of the Federal Reserve led investors to flee from dollar-denominated assets. As the value of the dollar plummeted, investors moved their funds into assets they believed provided a hedge against dollar inflation: particularly, commodity futures markets.

The Fed initiated rate cuts beginning in August 2007, with two of the largest cuts occurring in January 2008. The fear of rising inflation and/or stagflation sent investors to the commodity futures markets – index investors, hedge funds, pension funds, etc. CALpers alone, reduced fixed-income assets and increased commodity investments "sixteen-fold," or seven billion dollars (Verleger 2008).

While financial investors were increasing participation in commodity futures, physical market players reduced activities in the futures markets, evidenced by the decline in total open interest beginning in November 2007 (Verleger 2008). According to Verleger, addressing the constraints in the physical oil market alleviates the impact of financial investors, both passive and active.

As is the case with others who have examined the oil market – beyond the upstream – Salvatore Carollo (2012) identifies an extremely tight market for specific products – namely middle distillates that satisfy the ultra-low sulfur (ULS) specification.

However, Carollo takes this a step farther in seeing no medium or long-term solution to the market tightness. Rather than upgrade refineries sufficiently to deal with the worsening crude slate and higher environmental standards, individual refineries have found a substitution: profiting on crack spreads in the futures market that are significantly higher than actual refinery earnings Carollo (2012).

Another analyst who approaches the issue by encompassing aspects of both the financial and physical market is Robert Mabro of the Oxford Institute for Energy Studies.

Reference pricing has been common to the oil industry, but the utilization of a futures market rather than a physical reference market is a relatively new phenomenon.

Concerns about the objectivity of price reporting agencies as well as potential manipulation of illiquid physical marker streams led participants in the physical oil market to set price differentials relative to futures prices rather than prices established in 'spot' markets, according to Mabro.

The change from physical spot markets to futures markets appeared as the next logical step in market pricing. Futures markets are more difficult to manipulate relative to smaller physical markets and exchanges/clearinghouses report prices in a transparent manner without the services of any third-party assessor or interpreter.

According to Mabro (2001; 2005), financial investors rely on information that is unreliable and act according to inaccurate market structures. The dominance of financial investors causes the price of crude to diverge from where it would settle if traders acted on accurate information. More importantly, he questions the advisability of determining the price of oil via a contract traded with motives so unlike those involved in the trading of the physical product.

Unlike reference pricing of the past, the "reference" market utilized today is of a purely financial nature. When futures markets serve as reference prices, the price of oil is in part, a result of portfolio decisions (passive traders) and decisions of traders utilizing unreliable data (active traders) in a market regarding a contract that concerns the price of oil rather than the delivery of actual physical oil.

Mabro finds the downstream to contain the answers to recent changes in the oil market, but analysts rely on data about the upstream, US inventories and general macroeconomic data. Instead of reliable and timely data about the downstream markets, futures market prices move on information that is timelier than it is relevant.

Of the oil-related factors that influence prices in the futures market, Mabro singles out the International Energy Agency's monthly *Oil Market Report*. It is not that the data is necessarily accurate or relevant, but that traders know other traders will trade on information in the report.

Additionally, since accurate and timely data about world inventory levels is unavailable, traders, especially in the market for WTI, over-rely on US inventory data, according to Mabro. US inventory data has little to do with the condition of the world oil market, but as long as traders are aware that US inventory data moves markets, the influence remains.

While there may be speculative pressures in futures markets, according to Bassam Fattouh, also of the Oxford Institute for Energy Studies, arbitrage between the financial and physical markets reduces the ability of the speculator to drive prices without limit.

According to Fattouh (2010; 2011), there are several related markets that all influence the prices of crude oil. The multiple markets encompass different players for diverse reasons. These markets have varying degrees of exclusivity as well as degrees of distance from physical markets. While some of the markets are exclusive they remain closely connected to markets that are more transparent.

Fattouh examines the multiple physical and financial markets that make up the Brent complex. Recall the three main markets: Dated Brent, (considered the spot market, but actually priced 10-25 days from loading), Forward Brent or 25-BFOE, (a highly exclusive market, wherein traders may be forced to accept 600,000 barrels of physical crude oil) and Brent futures (1000 barrels, cash-settled, at a price that converges to the price of 25-day BFOE at expiry).

Multiple financial markets connect the three Brent markets to each other and to other markets around the world. For Fattouh, even though reference prices are futures prices, speculation in futures markets are unlikely to be a driving factor in the price of oil. Physical market players dominate other markets that are closely related enough to constrain financial markets.

King et al (2012) also examine whether and to what extent OPEC affects the price of oil. The VEC model includes OPEC production quotas, OPEC deviations from quotas, the average monthly NYMEX futures price and days of consumption in OECD stocks. All variables other than OECD stocks are non-stationary and cointegrated.

Of the cointegrated variables, OPEC quota tends to “overshoot” in response to a deviation from equilibrium relationship. The responses of the oil price and OPEC deviations compensate, thereby maintaining the cointegrated relationship. Sequential testing reveals that OPEC quotas Granger cause oil prices, oil prices and deviations Granger cause each other, and “quotas and deviations both Granger cause each other” (King et al 2012, 45). In the short run, days of OECD stocks is significant and negatively related to the oil price.

Kaufmann et al (2008) uses dynamic OLS (long-term) and OLS (short-term ECM) to examine the impact of refinery capacity, OPEC capacity utilization as a cubic function, the term structure of NYMEX crude prices and days forward of OECD stocks on the average F.O.B. price of US crude oil imports.

Results are interesting because of the negative sign on refinery capacity, i.e., as refinery capacity increases, the price of crude oil declines. Further investigation of the relationship between refinery utilization and Arabian Heavy and Medium reveals that this likely results from the originally chosen dependent variable – it includes multiple grades of crude oil. Once broken into specific qualities of oil, Kaufmann shows, as refinery utilization increases, the price of Arabian Heavy declines relative to Arabian Medium.

Kaufmann and Ullman (2009) compare multiple spot crude oil prices and futures prices for front-month and five-month contracts in an attempt to establish causal relations (Granger causality) among the price series. Using data from both Morningstar and the EIA, the authors run pair-wise error correction models on the following crude oils: WTI, Brent, Maya, Bonny Light and Dubia-Fetah. The WTI and Brent futures contracts at one and five months and the Dubia-Fetah futures at one-month are also included.

The results suggest price innovations originate from Dubia spot and month five WTI futures; these markets are weakly exogenous, i.e., they do not adjust to re-establish the long-run equilibrium. Brent near-month and Dubia-Fetah each granger cause five of the other markets. Bonny light spot granger causes four of the other markets and WTI five-month futures granger causes three of the other markets.

Kaufmann and Ulman (2009) identified a structural break on August 26, 2004, where before this date the two leading crudes were cointegrated, but not after the break (Dubia-Fetah spot and five-month WTI futures).

AlMadi and Zhang (2011) compare oil benchmark prices in a VEC model after establishing a long-run equilibrium relationship between the price series. The authors use daily price data on WTI, Brent, Oman and Dubai, although the source of the data as well as the precise market used remains unclear. The authors find: (1) WTI leads Brent, Dubai and Oman (2) Brent leads Dubai and Oman and (3) Oman moderately leads Dubai.

Blair and Mixon (2011) show that there is a difference between the connection of WTI prices and retail gasoline prices in different PADDs using the weekly average of the WTI-Cushing spot price and "the weekly Monday price of conventional regular gasoline reported geographically according to" PADDs (Blair and Mixon 2011, 2).

Blair and Mixon (2011) find all price series are integrated of order one, and therefore set up a seemingly unrelated error correction model. WTI crude price increases affect gasoline prices in PADDs II and III the most and PADDs IV and V the least. WTI crude price decreases influence PADD II significantly more than other districts, and affect PADDs IV and V the least.

Although the authors do not suggest as much, it is possible prices of international crude oils relate closer to retail gasoline prices in PADDs I and IV, since WTI is a land-locked crude oil. Additionally, the price of gasoline in California entails special regulatory standards unique to California.

Lanza, et al., (2005) compare multiple ‘heavy’ crude oils to the relevant benchmark, as well as compare crudes of multiple qualities to both a light and a heavy product. The qualities of the American crudes are substantially different from the benchmark, in contrast to the rest of the regions examined. The authors find the prices of each crude oil examined are cointegrated with the reference crude (Brent or WTI) and product prices (Gasoline and Fuel oil). Crude oil with qualities similar to the marker or reference crude adjusts faster to the long-run equilibrium when the marker crude price changes and the marker price is the “driving force” of examined crude oils[12] in the short run as well (2005, 845).

Denni and Frewer (2006) examine the relationship between the price of Brent and multiple product prices at Rotterdam, allowing for asymmetric responses to price changes. In the final section, they account for whether past refining margins were positive or negative. The authors chose a pair-wise single equation error correction model[13] because the price of Brent is cointegrated with the product price series and the Brent crude oil price is weakly exogenous[14].

Their results distinguish between heavy, light and middle products: lighter product and middle distillate prices adjust more quickly to changes in the crude oil price than do heavy product prices.

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[12] Given that the marker crude makes up a large portion of the price of the other crude oils examined, this should have been expected.
[13] The test is set up so that for the Brent variable, the co-efficient representing the adjustment to long-run equilibrium is equal to zero, i.e., the Brent price does not adjust to disturbances in the long-run equilibrium, but rather product prices adjust in order to maintain the long-run equilibrium with the Brent price.
[14] In the case of premium gasoline the null hypothesis is rejected at the 1% level of significance.

Whether there are asymmetric price responses to Brent crude oil price changes was inconclusive across all products, until the authors included dummy variables to represent whether refining margins were previously positive. The responses to price increases/decreases are dependent on past refining margins. Negative past profits leads to greater pass-through effects of an increase in the price of crude oil and vice versa.

Both Chen et al. (2009) and Refalo (2009) with data from the period 1997 - 2007 find that rather than China causing price increases, price innovations result from oil markets in Saudi Arabia and the United States. Price innovations that originate in China tend to remain in China, rather than reverberate to other oil markets.

Li and Lin (2011) expand the oil pricing equation developed in Kaufmann et al (2004) by adding the combined total of China and India oil imports. The Kaufmann equation already included the number of days of supply in OECD stocks, OPEC quota, OPEC cheat and OPEC capacity utilization (the Brent price is the independent variable).

China and India are both included because the authors could not verify a cointegrated relationship until they included a variable for China and India's share of world imports. The variables "Chindia" and OPEC quota are significant, although all variables remain in the equation to maintain the long-term relationship.

The following research examines the details of the oil market that may influence the price of oil as well as recent financial activity. The context of the crude oil market entails relevant detail in excess of crude oil supply and demand figures. The following literature shows that to understand the effects of financial flows in the price of physical crudes, research must go beyond the behavior of the futures price.

As early as 2003, the Energy Information Administration (EIA) addressed recent volatility, rising prices and the speculation issue in its publication, This Week in Petroleum. The EIA concluded: market fundamentals drive the prices of crude oil, although factors other than fundamentals drive day-to-day price movements (EIA 2003).

In 2005, the EIA estimated OPEC spare capacity to be around 1 mb/d (EIA 2005). The slightest fear of instability in any one of the more than twenty countries that produced at least 1 mb/d could cause prices to rise. Similarly, utilized capacity in the downstream was persistently near or above ninety percent. Any seemingly-"innocuous" event can change expectations and lead to large price swings.

In a market where flexibility is still very limited, "in the sense of capacity to produce significant incremental volumes of crude oil or light products" volatility will remain, regardless of the activities of any speculator (EIA 2005)[15].

In addition to the EIA, the International Energy Agency (IEA) examines the speculation question in multiple issues of its annual publication, "Medium Term Oil Market Report." In 2008, 2009, 2010 and 2011 the IEA concludes that market fundamentals drive the long-term price of oil, but "clearly other factors – ranging from macroeconomic developments, equity and other derivative markets to government policies and geopolitical events – can also play a role in influencing oil price levels in the short term" (IEA 2010, 29).

[15] The EIA also addresses the numerous fuel specifications that have passed as of late, although they assess the impact to be short term; after an initial adjustment period, prices will stabilize, albeit at a higher level, reflecting the increased cost of producing higher quality fuels.

In the 2009 report, the IEA addresses the reasons the physical market warranted a rise and collapse in oil prices and the transmission mechanism whereby the futures market affects the spot market.

Traditional literature claims that inventories are the mechanism whereby the futures market affects the spot market. If there is an increase in demand for long-only futures contracts, and no corresponding increase in short futures contracts, the price of futures contracts increases. An increase in the future price of oil leads to an increase in inventories. Since the quantity supplied to the spot market declines, the spot price rises.

Conversely, if speculation leads spot prices to rise higher than that justified by the physical market, excess supply will be forthcoming and inventories must increase to maintain the elevated price level. “Indeed, any price above the equilibrium warranted by supply and demand, if caused by speculation, must be explained by an act of hoarding in the form of inventory builds or withholding production” (IEA 2009, 99). Multiple researchers have identified a lack of excessive inventory building as evidence that speculation is not driving crude oil prices.

The caveat to the traditional literature rests on the pricing mechanism within the oil market (IEA 2009). Negotiations between sellers and buyers in the crude oil market revolve around a differential to a price derived in a futures market. If speculation increases the price of crude in futures markets, and the value of the differential remains unchanged, the elevated price affects the spot market via the method of pricing in oil markets. The spot oil price can potentially rise without any change in inventories or production.

While the IEA admits speculation in the futures market can temporarily distort prices in the spot market, the report examines multiple issues within the physical market that justify a break from trend in the price of oil.

OPEC spare capacity fell from 2.3 million barrels per day (mbd) in April 2008 to 1.5 mbd in July 2008 and the price of oil rose thirty-five dollars. The correlation between OPEC spare capacity and the price of oil is as convincing as that of speculator flows and the price of oil (MTOMR 2009). Non-OPEC supply has been stagnant or declining, leaving OPEC producers holding the spare capacity and drawing attention to their potential power.

The response of prices to relatively small changes in the oil market can seem exaggerated owing to a very low elasticity of supply – estimates vary from .02 - .07 (IEA 2009). A rising price will elucidate immediate supply responses. However, firms producing near capacity can only incrementally increase the production of crude oil. More substantive supply responses take longer to initiate because of uncertainty regarding the long-term path of the price of oil. After a firm decides a price increase is indicative of a longer-term trend, it takes five to ten years for production to begin from new project.

The elasticity of the demand for crude oil is also relatively low. Much of the remaining demand in OECD countries relates to transportation, but changes in transportation infrastructure as well as gains in efficiencies take years to actualize. Reductions in demand in response to price increases do occur, but taxes in most OECD countries and subsidies in several non-OECD countries mute these potential responses.

The causes of the price run-up during 2007 and the first half of 2008 also have to do with the relationship between crude oil and petroleum products. OECD sulfur regulations[16], an outdated refinery industry, waning light sweet crude oil supply and a "surge in demand for middle distillates" led to a tight market for light sweet crude oil (IEA 2009).

The market for light sweet crude oil was supply-constrained, and heavier sour crudes were not a suitable substitute. The small differential between heavy and light crudes, characteristic of the time, further disadvantaged heavier crudes.

Lastly, the IEA identifies the oil-dollar connection as a contributing factor to the latest oil price cycle. A general decline in the value of the dollar benefits consumers and harms producers operating in non-dollar economies. When the value of the dollar is falling, the price of crude oil may rise even though nothing has changed in the oil market. It is possible for changes in the value of the dollar, relative to other currencies, to affect the price of oil.

The International Energy Agency examined the speculation versus fundamentals debate in its Medium-Term Oil Market Report (IEA) in June 2009 as well as June 2008. The 2008 report concludes market fundamentals drive the price of oil. The 2009 report finds sufficient justification in the market fundamentals for rising and subsequently falling prices, but does allow for the possibility that speculative funds "play a role" in price formation (IEA 2009, 109).

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[16] The US reduced sulfur maximums in 2004 and 2005 (gasoline) and 2006 and 2010 (diesel) (EPA Emissions standards reference guide). The EU reduced sulfur allowances in 2000 and 2005 and the 2005 regulations moved from "must offer" to mandatory in 2009. There have been multiple other specification changes aimed at improving the environment since the early 1990s. Based on the regulations given the most attention, those with the most significant long-term impact are the reductions in maximum allowable sulfur content.

In 2010 the IEA remained consistent (IEA 2010, 29). In 2011, the IEA concludes the following regarding the argument that speculators determine oil prices: “Persuasive as though those arguments might be, rigorous analysis suggests otherwise” (IEA 2011, 16). Data is still not sufficient to draw conclusions with certainty, but rigorous research suggests speculators do not determine oil prices[17].

[17] The IEA changed the publication back to the original name in 2012.

CHAPTER 3

BASIS PRICING IN THE CRUDE OIL MARKET

Introduction

This chapter discusses the evolving method of oil pricing through to the development of the current method. Tracing the development of the system answers why and how the existing system arose, including the adoption of futures markets as a part of pricing. The three reference markets, including the most important physical and financial markets of each are detailed in the chapter, with focus directed to the US and the international benchmarks, West Texas Intermediate (WTI) and the North Sea Market, 'Brent' for short. The chapter ends after a discussion of the differential to the reference price, which is included in the price of all physical oil transactions.

The Development of Reference Pricing of Crude Oil

The history of the oil industry is in large part describable as a struggle to control the quantity of crude coming out of the ground at any one point in time, in an attempt to sustain prices that are high enough to continue the process of production in the long-term. Potential over-supply in the oil industry results from the vast quantity of oil in the earth relative to the amount needed to satisfy current and near-future demand. Shortages can also result if low prices suppress investments, owing to the long lag between the decision to develop an area, and the resulting increase in production.

The costs of production and market share vary widely across market participants as well. Costs are dissimilar, in large part, owing to widely varying characteristics of oil fields. A large number of small and medium independents, a handful of large independents and integrated firms – both nationally owned and corporate are all operating within the oil market. The market also includes the Organization for Petroleum Exporting Countries (OPEC).

The market for crude oil requires governance mechanisms to tame uncertainty and calm chaos, as does any other market. Successful mechanisms will account for the particular characteristics of the oil market. As a relatively old industry, various pricing and other governance mechanisms have arisen and been replaced, as the power of particular participants and the cultural context, including legal institutions, shift through time.

In the years that followed the first successful attempt to drill for oil in 1859, prices were erratic (Yergin 1991, 27). Through the first half of the 1860s, large swings in price occurred as over-supply followed the discovery of a new large oil field, which later led to high and rising prices as the same pools began to decline (Yergin 1991, 30-33).

In the latter half of the 1860s and through the 1870s the industry was plagued by overcapacity in the refining sector and oversupply of oil (Yergin 1991, 39-43). In this era of overcapacity, the Standard Oil Joint Stock Company was born as was the first period of stabilization – that achieved through combination (*Ibid*).

The 1911 dissolution of Standard Oil, the anti-monopoly statutes and the development of a handful of large integrated enterprises led to cooperation-oriented governance, aimed at taming current supply on the market via coordinating production and establishing rules over market share (Yergin 1991, 261).

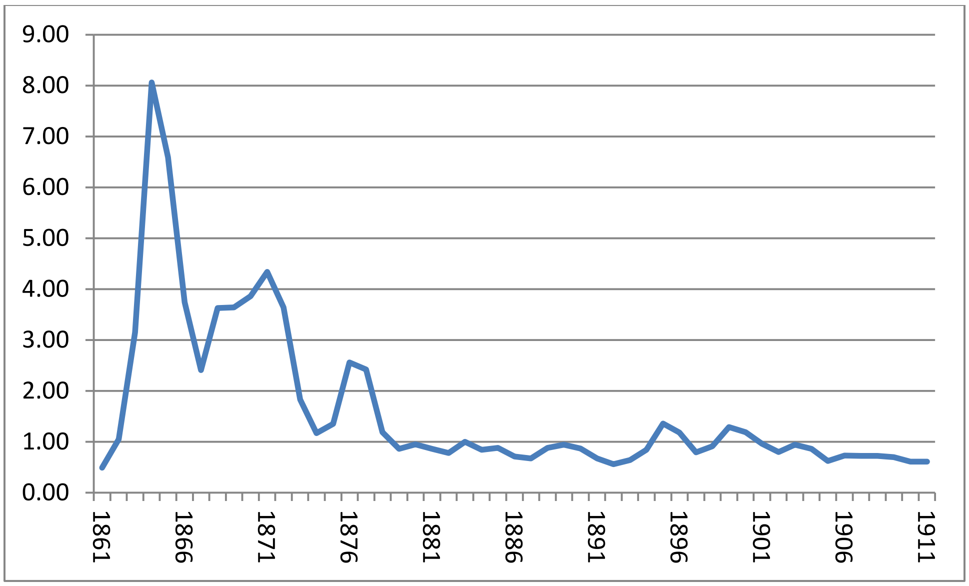

Figure 3.1 Price of Oil 1861-1911. BP Statistical Review 2015 US nominal price annual average per barrel

The 'As-Is' or Achnacarry agreement, first laid out in August 1928, referred to as the Pool Association, established rules to maintain current market shares for all members, required joint ventures for expanded production in the middle east and endorsed price stability through a system of base point pricing (Yergin 1991, 263-264; Bhattacharyya 2011, 328-329; Roncaglia 1985, 54-56; Penrose 1968 (1976), 179-180). Members adjusted the agreement regularly, owing to internal conflicts and pressures exerted through the activities of non-members (Yergin 1991, 265-268).

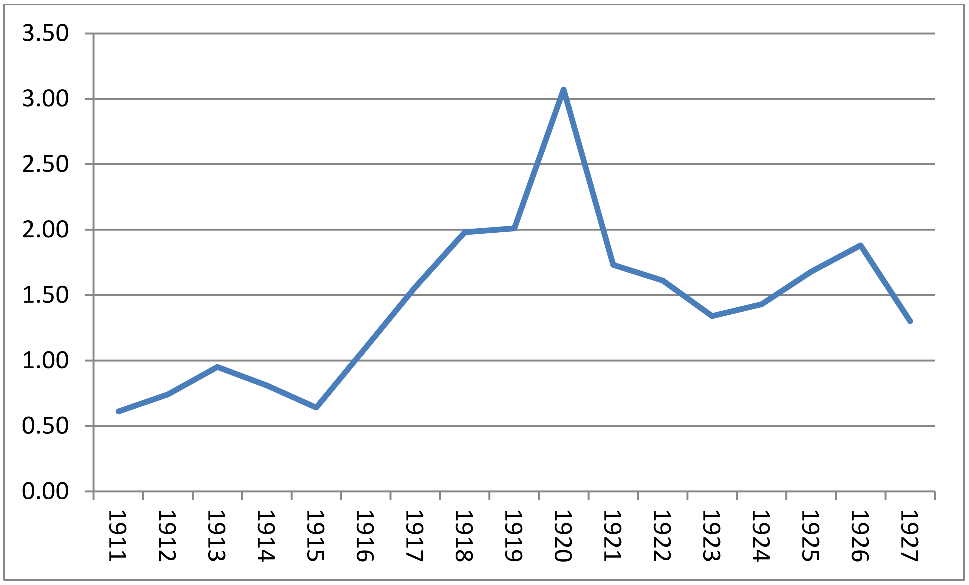

Figure 3.2 Price of Oil 1911-1927. BP Statistical Review 2015 US nominal price annual average per barrel

Under the 'As-Is' agreement, prices began with the price at the Gulf of Mexico. The cost of freight from the Gulf of Mexico to a particular destination was added to the Gulf of Mexico price in order to determine the price at another location (Yergin 1991, 263-264; Bhattacharyya 2011, 328-329; Roncaglia 1985, 55). Regardless of the actual location of origin, prices were determined *as though* the oil originated at the Gulf of Mexico and the cost of freight[18] to the destination of interest was added to the Gulf of Mexico price.

Parties to the agreement met within what had become a familiar context: that of overproduction and overcapacity. They enacted the new agreement in an effort to avoid price wars, by setting a standard price for all transactions, and these prices acted as administered prices (Roncaglia 1985, 57).

[18] According to Penrose, the freight charge was not actually the cost of freight, but a standardized freight rate (1976, 180). This would encourage a uniform price as freight rates can vary by route and over time.

At the time of the agreement, refineries were near to the centers of crude production and the US Gulf of Mexico price was chosen because the US was a high cost production area and an exporter of petroleum products to the rest of the world (Penrose 1976, 178-180). The importance of the agreement, according to Penrose, was the institutionalization of a pricing system that encourages stable prices and minimizes price competition:

> a very effective device for ensuring not only that uniform prices are quoted by all sellers but *also that low-cost producers cannot use their lower costs to expand their share of the market by reducing prices*. The system is restrictive precisely because, when adhered to by all sellers, it prevents the expansion of low-cost production by price competition. *Ibid* 180

The base point pricing system relied on the prices of petroleum products at the Gulf of Mexico because there was almost no market for crude oil outside of the integrated companies and some regular transfers between the large enterprises (Penrose 1967, 178-179).

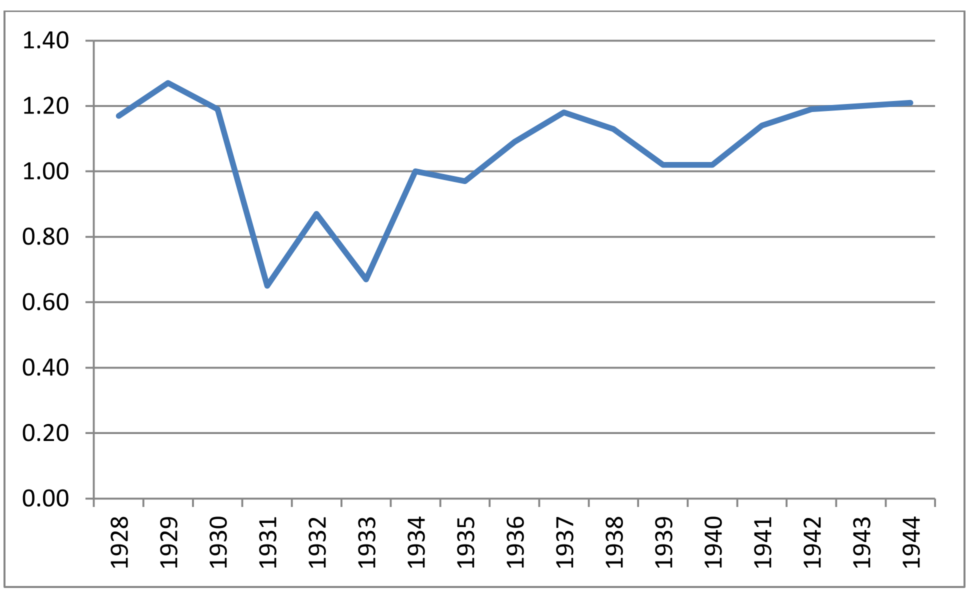

Figure 3.3 Price of Oil 1928-1944. BP Statistical Review 2015 US nominal price annual average per barrel

During the war, a crude oil and an additional product price were added to the base point system, at the Persian Gulf (*Ibid*, 182). By 1948, the base-pricing system was adjusted to include two price points in the Middle East (Bhattacharyya 2011, 330-331; Roncaglia 1985, 57).

According to Roncaglia, rather than a competitive system of prices, the Middle East pricing points were used as internal transfer prices within integrated companies and for the purposes of royalty payments to the government of the producing-country (1985, 56). Fattouh in Mabro (Ed) agrees, these posted prices for Middle East supplies did not change and were a mere fiscal and tax parameter (2006, 45).

According to Penrose, the new prices were introduced to provide Middle East oil to refineries which had been built up nearer to areas of consumption and which were owned by the integrated firms (1967, 183-184).

The increased role of independent producers in the Middle East, the marketing of equity oil by producer countries, which began in the 1940s in Venezuela (Yergin 1991, 436), and rising Russian exports, led to an excessive supply of oil by the latter half of the 1950s. The end of the exclusive control over the price of oil by a handful of large integrated companies was nearing (Roncaglia 1985; Bhattacharyya 2011; Yergin 1991; Fattouh in Mabro (Ed) 2006).

The royalty payment to Middle Eastern countries and Venezuela was fifty percent of the posted price (minus production costs), but by the 1950s rising supply meant the posted price was higher than the actual price oil producers received in the market (Yergin 1991, 515).

In the presence of over-supply there was little producing countries could do in response to oil companies beginning to reduce the posted price in the late 1950s. However, the price reductions encouraged the formation of the Organization for Petroleum Exporting Countries (OPEC) (Yergin 1991, 516, 523).

OPEC originally formed in 1960 merely to increase and then stabilize the royalty payments made to the governments of producing countries. By the early 1970s, OPEC became a more dominant institution in the oil markets, including in setting the price of oil.

In the 1960s through to 1973, producing companies in the Middle East set the price of Arab Light in Saudi Arabia as the posted price (Carollo 2012). “The prices of all other crudes were established by referring to the benchmark and fixing a differential…” (Carollo 2012, 31). Prices were stable as producers matched supply to demand, including for Arab Light (*Ibid*), although in December of 1970, OPEC members pushed for a higher posted price.

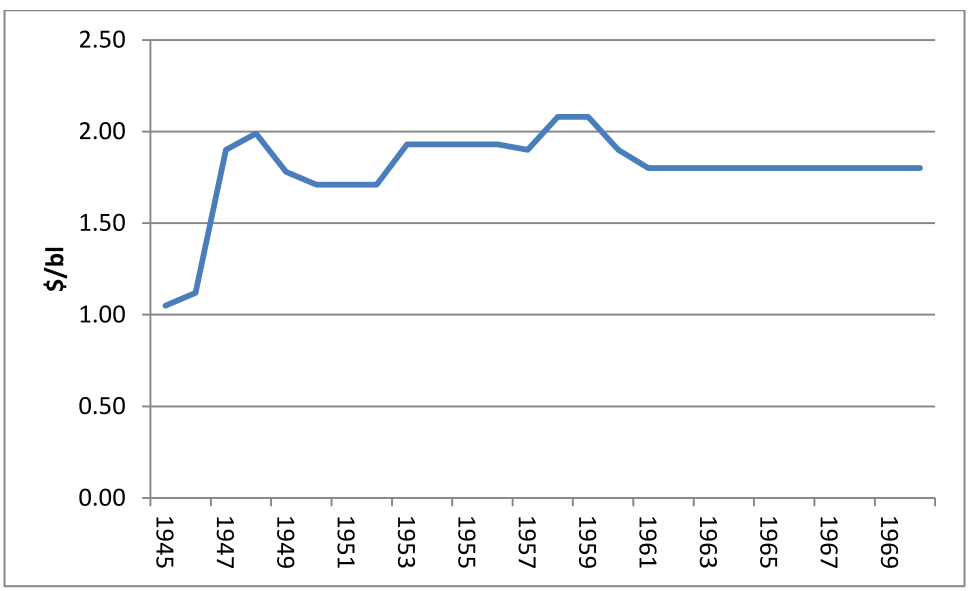

Figure 3.4 Price of Oil 1945-1970. BP Statistical Review 2015 Arabian Light posted at Ras Tanura nominal annual average per barrel

In 1973, OPEC members, exempting Iraq, unilaterally began increasing the posted price of Arab Light (Fattouh in Mabro (Ed.) 2006, 46). By 1975, OPEC administered the price of Arab Light and individual countries set an official selling price (OSP), relative to the price of Arab Light – the differential to the price of Arab light to reflect the quality and location of a member's particular production (Fattouh in Mabro (Ed.) 2006, 47).

OPEC set a yearly price for Arab Light and as the producer of Arab Light, Saudi Arabia managed the supply of the benchmark crude to ensure the official price reflected the price achieved by Arab Light (Carollo 2012, 31). Other members of OPEC maintained some influence over the price of the domestic production in setting the value of the differential to the price of Arab Light.

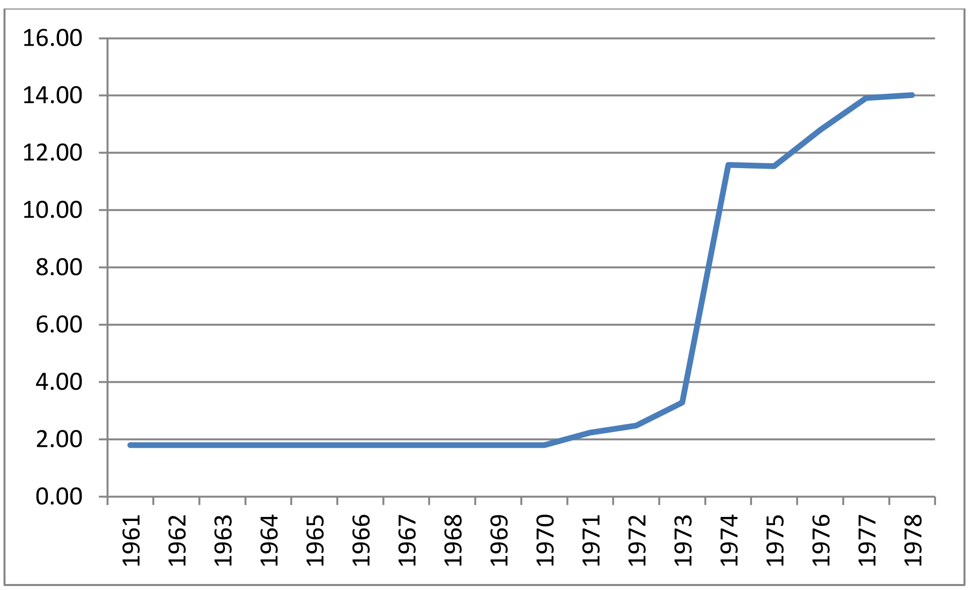

Figure 3.5 Price of Oil 1961-1978. BP Statistical Review 2015 Arabian Light posted at Ras Tanura nominal annual average per barrel

While a market for crude oil, outside of the control of the large integrated firms began in the late 1940s and 1950s and slowly grew in size, the system of administered prices – administered at first by large integrated firms, followed by OPEC – remained intact until the late 1970s (Fattouh in Mabro (Ed.) 2006, 48-49; Yergin 1991, 435-438, 525-527, 531-532). Even through to the late 1970s, producing countries sold most equity production back to the integrated oil companies who had originally turned over the volumes to the state (Fattouh in Mabro (Ed) 2006, 49).

In 1979, "the seizure of power by Saddam Hussein in Iraq, the revolution in Iran and the break-out of the Iran-Iraq war in September 1980" (Carollo 2012, 32) led to falling supply and rising demand and a second round of price increases (Bhattacharyya 2011, 334; Fattouh in Mabro 2006, 49).

Falling production along with panic buying led prices for one-time exchanges of crude oil, or "spot market transactions" to soar beyond the official administered price (*Ibid*.). This secondary market, where independent parties engaged in exchanges of oil outside of long-term deals had slowly but steadily developed, and was now taking on an increasing significance[19]. The war-related loss of production plunged OPEC volumes to just under 22mn b/d in 1981, from over 30mn b/d in 1979 (BP 2014).

Some OPEC countries nullified contracts in an effort to stop companies from purchasing equity contract-volumes, based on the administered price or OSP, only to sell the

[19] Unless otherwise specified, the remainder of the paper uses 'spot market' as this one-off type of exchange. This contrasts with most of the literature discussed in chapter two, where spot market refers to the near-term price of oil or the closest-to-expiry futures contract.

volumes at a profit in the spot market (Bhattacharyya 2011). According to Bhattacharyya, 25 percent of OPEC sales occurred in spot markets (2011, 334).

The panic buying drove crude oil stocks up to record levels, capable of covering 180 days of demand – previously, crude oil stocks tended to cover between 30 and 50 days of demand (Carollo 2012, 33).

The bold moves of the producing countries and the second oil price shock provoked two important responses. Major oil companies invested in new sources of crude oil to replace their reserves in the Middle East, and interest in energy conservation and diversification of energy sources in consuming countries arose. Both of these reactions diminished the price administering capabilities of OPEC (Carollo 2012, 34; Bhattacharyya 2011, 334; Fattouh in Mabro 2006, 50).

The increased level of non-OPEC production and the high levels of stocks resulted in falling demand for OPEC crude. Growing numbers of sellers and buyers resulted in a more active spot market for crude oil, diminishing the volumes that contract buyers would take from OPEC sellers (Fattouh in Mabro 2006, 50). Even OPEC members would turn to spot markets to dispose of oil they could not sell in contract markets (Carollo 2012, 34).

Non-OPEC production had been on the rise since 1975, but was still lower than OPEC production by 1979, at just under 24.25mn b/d – OPEC production was more than 30mn b/d (BP 2014). Non-OPEC production steadily increased, and by 1985 it was about 29.57mn b/d, while OPEC production had fallen to 15.87mn b/d (BP 2014). Of the almost 15mn b/d loss in OPEC production, Saudi Arabia had given up about 6.7mn b/d (BP 2014).

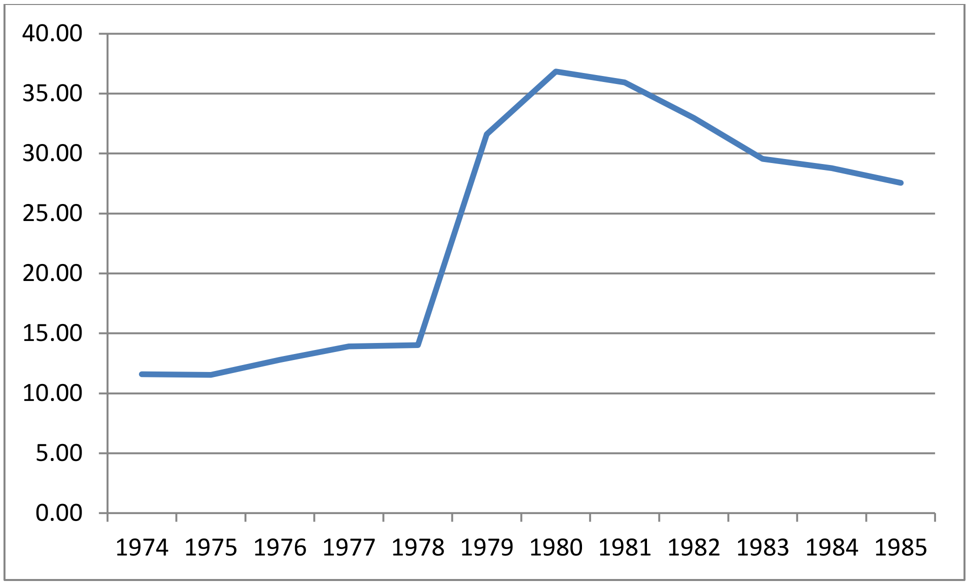

Figure 3.6 Price of Oil 1974-1985. BP Statistical Review 2015 Arabian Light posted at Ras Tanura 1974-1983, Dated Brent 1984-1985, nominal annual average per barrel

In 1985, Saudi Arabia chose to abandon the role of swing producer as well as the system of OPEC-administered prices. Saudi Arabia had been defending the price of Arab Light, and giving up significant market share in the process. In 1980, Saudi production peaked at a yearly average of nearly 10.3mn b/d and by 1985, the yearly average stood at 3.6mn b/d (BP 2014).

In September 1985, Saudi Arabia warned market participants of their intention to abandon the pricing system and adopt netback pricing, in an effort to regain their market share. Netback pricing guarantees a refiner a given profit margin by adjusting the price of crude, relative to the sale price of oil products.

The refining margin – or the difference in the sale prices of petroleum products and the price of the crude – is the variable of interest to a refiner. Refiners view the cost of crude oil in relation to the sale prices of products. Under netback pricing, refiners can run at capacity while maintaining a guaranteed margin - Saudi Arabia's pricing mechanism would account for falling product prices as refiners increased output.

Netback pricing incentivized refiners to increase crude oil flows regardless of the price of the petroleum, because netback crude pricing adjusts the price of crude downward to account for falling product prices. If increased throughput at refineries pressured product prices downward, Saudi Arabia would compensate by reducing crude prices – thereby enabling refiners to maintain a profit, while the market share of Saudi Arabia increased.

The National oil company of Mexico, commonly referred to as Pemex, faced a difficult choice: continue attempting to administer prices to the market, which if prices were not competitive, would cause great losses in the quantity of crude sold, adopt netback prices or adopt a different mechanism.

Pemex lacked sufficient staff to decipher the constantly changing competitive market prices for the available quantities of crude oil. Negotiating prices and margins with refineries was less than optimal. Refineries not only held superior information regarding cost and structure, they also could threaten to purchase from any one of Pemex's competitors as soon as the terms appeared less than competitive, making administering prices to the market difficult (Mabro 2005, 7).

If Pemex officials were directly involved in the setting of oil prices and Pemex lost significant sums, those officials could potentially be criminally charged, even if they acted "*in good faith*" owing to the 1985 passage of the Federal Law of Responsibilities for Public Servants (Flores-Macias 2009, 9).

Pemex instead adopted reference or marker-based pricing. The marker price consisted of a basket of prices determined in US domestic spot markets (Mabro 2005, 9). Pemex would set an adjustment factor, or differential, to the spot market determined basket price (Mabro 2005). The method Pemex adopted was familiar, while introducing a fundamental change.

The system of administered prices was failing, in part, because of trade in spot markets and the inability of the administered price to adapt quickly to changing spot market prices. Pemex maintained the familiar differential pricing method, *but Pemex attached the differential to prices determined in spot markets*.

The choice by Pemex management enabled the implementation of prices that are in line with those in spot markets, with minimal managerial discretion. Pemex adopted a pricing mechanism the rest of the oil-producing industry soon copied, with Saudi Arabia adopting a similar method in 1987 (Flores-Macias 2010, 172). Formula, reference or basis pricing—via prices determined in spot markets—replaced OPEC administered pricing (Fattouh 2007).

Reference pricing requires assessing relative values in the crude oil market, although such was not a new phenomenon, as when OPEC administered the price of Arab Light, OPEC members set their official selling price at a differential to Arab Light.

Formula, reference, benchmark or basis pricing, in its simplest form, follows:

"$\mathcal{D}$" represents the pricing differential between reference crude "X" and an individual crude, "Y":

$$P_y = P_x \pm \mathcal{D}$$

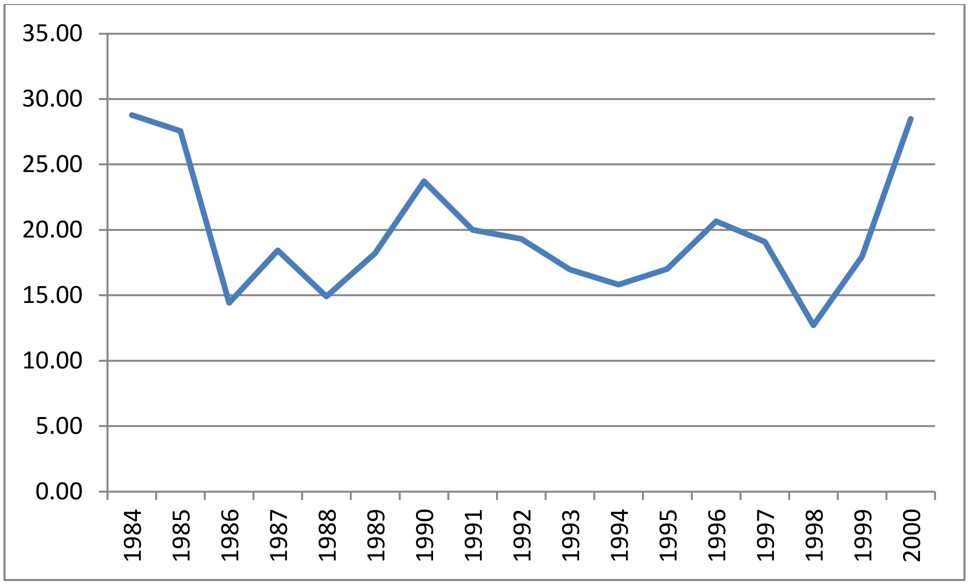

Figure 3.7 Price of Oil 1984-2000. BP Statistical Review 2015 Dated Brent nominal annual average per barrel

Under formula pricing, the price of crude Y is set relative to the price of benchmark crude, X. Crude producers determine the direction and magnitude of the difference between the value of the benchmark crude and their own crude, without setting the price of either.

Several factors are capable of changing the price of a particular crude oil. In giving up administering the entire price to the market, producers no longer have to play catch up or try to anticipate precise prices determined in spot markets. Instead, producers determine the value of their particular crude oil in relation to a separate market for crude oil – the latter price is determined through trade in spot markets.

The increased role of spot markets and other transactions outside of large integrated firms forced an adjustment to the system of administered prices. By moving away from administering prices to the market, producers alleviated the growing tension between prices in spot markets and those in longer-term contract markets.

Just as in the era of OPEC-administered prices, in the modern era, the price of oil is comprised of a minimum of two values. Today's version of Arab Light is typically one of three reference prices: one related to the market for domestic light sweet production in the US, one from offshore production in the North Sea, and the latest addition, produced nearer to the newest large oil consumer – China – comprised of the Oman-Dubai markets.

All three of these markets have a futures contract associated with the relevant physical crude oil. Futures markets for crude oil developed alongside the move to using spot-market prices for exchanges of oil in longer term or contract markets. After crude oil futures markets became more transparent and liquid, prices determined in futures markets began to replace prices determined in the trade of physical oil, as the reference or basis price in some markets. However, as is shown below, these futures markets are highly connected to the related physical market.

The current reference price in the US is a light sweet crude oil delivered to/priced at Cushing, Oklahoma. West Texas Intermediate (WTI) is the colloquial name of the US benchmark, although the market consists of light sweet crude not necessarily originating from west Texas. A related Light Sweet crude oil contract is traded on the NYMEX exchange, hosted by the Chicago Mercantile Exchange (CME). Cushing, Oklahoma is the pricing point for the futures contract. Some form of the price of domestic light sweet or 'WTI' serves as the reference price for much of the domestically transferred crude oil within the US, as well as serves as a part of the price of some of the oil imported into the US.

The North Sea crude oil market makes up the international reference market sometimes referred to as Brent. The North Sea market, in part, consists of a closely related physical, forward and futures market. Some form of the North Sea market price plays the role of the market price in most internationally exchanged crude oil, including some US imports.

The final and third main reference price is somewhat controversial as a benchmark as commentators debate the role of the Dubai-Oman market. Dubai-Oman prices tend to represent conditions of demand in the Asian market, but also closely relate to the North Sea market. The Dubai-Oman market also consists of several related markets.

The North Sea Market (Brent)

The North Sea benchmark developed out of the spot and forward market for Brent crude oil. "In the early 1980s, the Brent market only consisted of the spot market and the informal physical forward market," created largely for tax spinning (Fattouh in Mabro (ed.) 2006, 52). Tax spinning was the term used for selling or buying in the Brent spot and forward markets, in an effort to minimize taxable assets, thereby minimizing tax liabilities. Integrated oil companies would weigh the tax liabilities associated with internal transfer prices relative to those levied through selling and buying in both the spot and forward markets[20].

Those who desired a Western replacement for the role Arabian Light embraced the North Sea market as a benchmark (Carollo 2012, 90). Moreover, OPEC thought the physical benchmark role would make the producers in the North Sea restrict quantity as necessary - share the role of swing producer (Carollo 2012, 101; Fattouh 2007, 26).

The original physical base of the North Sea benchmark, Brent, was a mix of several crude oils from fields in the North Sea brought together and transported to a terminal at

[20] For more about the role of tax-spinning on the development of spot and forward markets in the North Sea, see Mabro (Ed.) 1986 and Horsnell and Mabro 1993.

Sollum Voe via pipeline. Although the way oil is extracted will affect the overall amount of oil recovered as well as the amount that can be recovered before production decline sets in, production in individual fields begins to decline eventually (Adelman 1993; Mabro (Ed.) 2006).

As production naturally declined, the physical base of the benchmark was expanded in order for the North Sea market to remain an international pricing benchmark. The smaller the physical production of a benchmark, the more easily market participants can corner the market, and the more likely it is to tend to a contango market structure.

In a contango market, prices increase in the future. Contracts for delivery farther in the future are more expensive than contracts with a nearer delivery date. At any point in time, the farther forward the contract, the more expensive the oil. If production is falling, market participants may be convinced that the price will indefinitely rise in the future as supply continues to decline.

In 1990, in order to increase the liquidity of the Brent benchmark, Brent and Ninian were blended. Ninian was a separate crude oil that previously traded as an individual grade. After the comingling of the Brent and Ninian crudes, the Brent blend consisted of "the production of around 15 fields in the North Sea" (Carollo 2012, 89).

To assure market participants a sufficient number of trades were involved in the assessment of such an important benchmark, as production of the Brent/Ninian blend began to decline, another expansion of Brent became necessary. In 2002, two other grades of crude oil were added to the North Sea benchmark price, Forties and Oseberg, and a third, Ekofisk, was added in 2007 (Platts 2015).

Since 2007, and as of 2015, transactions involving (1) the Brent/Ninian blend, which is carried through pipeline to the Shetland Islands, UK, (2) Forties, which is also carried by pipeline, but to Hound Point, UK, (3) Oseberg, a Norwegian crude oil delivered to the Sture terminal, and (4) Ekofisk (Teesside, UK) are acceptable for inclusion in the North Sea benchmark (Fattouh 2011, 37-38; Argus 2012; Platts 2011, 2; Fielden 2012).

The North Sea market is the most commonly utilized benchmark for the international transfer of physical crude oil. Although estimates vary, 50-70% of all internationally traded crude oil utilizes some form of the North Sea market as a benchmark in pricing formulas (Energy Intelligence 2006, A22; Fattouh 2011, 20; Platts 2011, 2; Carollo 2012).

The international status is in part a result of the market being waterborne. North Sea crude is capable of representing any demand center in the world, through delivery to the region willing to pay the highest price in the spot market.

Three markets within the North Sea complex of markets are essential to the pricing of the North Sea benchmark. Of the three markets, the physical, forward and futures markets, the first two have existed since the days of tax spinning. Several other markets serve to connect the three general markets to each other[21].

The prompt physical North Sea market, termed "Dated"[22] refers to a 600,000-barrel cargo or 100,000-barrel partial cargo of crude oil with a known date of loading. Terminal operators communicate loading dates to producers no less than one month in advance of the

[21] There are many other paper markets in addition to those mentioned. The peripheral paper markets serve to offer greater hedging protection and increase the connections between the various paper markets and between the paper markets and the physical market.

[22] Platts uses the term Dated Brent while Argus uses North Sea Dated. Both terms refer to the prompt physical market for the North Sea benchmark crudes.

first of the three days of loading. A date of loading is a necessary but not sufficient condition for a cargo to be included in the price of the Dated benchmark.

The daily price of Dated represents the price of physical crude in the North Sea market loading 10 days to one month in the future. Every business day, the dates under consideration “roll” forward by one (Argus 2015; Platts 2015). A transaction for a cargo of crude scheduled for loading nine or fewer days in the future will not be included in the calculation of the price of Dated.

Dated does not include transactions occurring for cargos loadings nine or fewer days ahead because such transactions tend to concern ‘distressed’ cargoes. A distressed trade – a desperate seller or buyer – is not representative of the broader market. The term “spot” used to describe the Dated market can be considered as a contrast to contract markets, rather than as the price of crude oil delivered today.

The Dated market originally included transactions for cargoes loading up to 15-days ahead, then 21-days followed by 25-days, and most recently, as of January 2015, one month ahead. The Dated and forward markets are closely related, as the forward market is a market for the same four crude streams, but the contract refers to loading months without a particular loading window.

The buyer and seller of a North Sea forward contract know the *month* during which the cargo will load. However, in contrast to a Dated contract, the particular dates of loading for the crude transferred in the forward market remain undetermined.

Similar to the Dated market, the forward market consists of bi-lateral contracts to buy/sell 600,000 barrels or 100,000 partial cargoes of Brent, Forties, Oseberg or Ekofisk, but the precise three-day loading window is unknown to both parties.

Upon notification of the three-day loading window, if the holder of a long or buy forward contract does not wish to take possession of the 600,000 or 100,000 barrels of crude oil *and* he is holding a short or sell contract, he notifies the buyer of his sell contract. It is common practice for a single cargo of crude oil to move through several contract-holders, after the original seller identifies his three-day loading window and before the trading ceases.

That is, "if the original cargo purchaser has already sold another [month ahead] contract," and does not wish to take delivery upon notification, "he must give notice to the new buyer to take the cargo at least [one month] in advance" (Fattouh 2011, 41). The "daisy chain" ceases when a nominated buyer accepts delivery – either by preference or because he does not have a sell contract for the relevant month – or the minimum period for notification passes. A participant "is said to have been 'five-o-clocked'" if he did not want to acquire the actual physical oil, but he is out of time to notify the next potential buyer (Fattouh 2011, 41).

Forward contracts are cash settled most of the time but can potentially end in a transaction of 600,000 or 100,000 barrels of physical crude oil. If every buyer in the forward Brent market desired to take possession of physical oil, a discrepancy between supply and demand would arise. There have been times of chaos in the forward Brent market as contract-holders discerned daisy chains, but large suppliers in the North Sea have been willing to calm the fury (Mabro 1986).

Once the notification period has passed and a loading window has been determined, the cargo is 'wet' and the physical oil involved in the forward Brent contract becomes Dated, if the cargo is involved in another exchange prior to ten or more days from loading.

> The underlying Brent physical market consists of two different but related kinds of physical Brent: 'Cash BFOE' which is a 'paper' or 'forward' cargo (within a stated contract or delivery month, but without a vessel, date or number attached) and 'Dated Brent' which has all of these three elements. (ICE Brent FAQ 2013, 6)

The Intercontinental Exchange (ICE) and the Chicago Mercantile Exchange (CME) host the Brent futures contract, named after the first physical North Sea crude oil used as a benchmark or reference price. The Brent futures contract relates to the price of Brent, Forties, Oseberg or Ekofisk cargos loading within a particular month.

There are several distinctions between the Brent futures markets and the other two reference markets – the Dated and forward markets. The most important difference in the futures market and the other two markets is the lack of physical delivery in the former. Brent futures contracts enable exposure to the price of the North Sea benchmark but do not involve the exchange of physical crude oil.

The Brent futures contract is a purely financial instrument used by genuine hedgers, traders, bankers and other financial investors. The only way a holder of a Brent futures contract can acquire physical oil is by taking the trade "off-exchange" and transacting in the exchange of futures for physicals (EFP) market.

An exchange, such as the CME or the ICE, stands between counterparties who are anonymous to each other in the futures market. The exchange is exposed to counterparty risk, rather than the participants in a futures market. This is in contrast to over-the-counter

(OTC) markets, such as the Dated and forward markets, where parties to a transaction are exposed to the risk of a counterparty defaulting, or credit risk.

The Brent futures market is the most transparent and least exclusive of three main North Sea markets. A single futures contract concerns the price of 1000 barrels of crude oil – compared to the 600,000 barrels or 100,000-barrel partial in the Dated and forward markets. Investors purchase the contracts on margin, although the exchange protects itself by requiring the parties to settle loses regularly.

In addition to these three Brent markets, several ancillary markets have developed, all of which connect to the primary markets and aid in the process of price determination. The most important ancillary markets for pricing of the Brent complex, are the contract for differences (CFD) and EFP swaps markets. A swap is an over-the-counter exchange of price exposure (Platts 2012, 2).

The CFD market, "allow[s] the buyer and seller to gain exposure to the price differential between [D]ated BFOE and forward Brent" (Fattouh 2011, 45). Increasing volatility between the price in the Dated and forward market and the need of physical players to hedge this price discrepancy, led to the creation of the CFD market (Fattouh 2011, 45).

Since the forward market is the price of Dated farther in the future, the CFD differentials in the CFD market show the 'anticipated' price of Dated. The forward price plus or minus the value of the CFD shows the perception today for the price of Dated beyond the current 10 day to month ahead pricing period for Dated. This value is the expected or anticipated value of Dated.

The EFP market relies on a concept similar to that of the CFD market, although it relates the forward price to the Brent futures price. Market participants use the EFP market to hedge the price discrepancy between the price of Brent futures and those in the forward market.

The value of the EFP shows the price difference between the Brent futures market and the forward market. If there is no trade in the forward market, the price in the EFP and the price of the Brent futures contract show the perceived price in the forward market.

The particular crude streams that make up the North Sea market, Brent, Forties, Oseberg and Ekofisk, are traded at differentials to the North Sea Dated benchmark price around the time of loading. At the time of the agreement, the outright price is unknown, as the price of North Sea Dated around the dates of loading is unknown.

In order to determine the price of Dated on a particular day, values for each of the four grades must be constructed in order to determine the cheapest of the four grades. The cheapest of the grades sets the price of the benchmark because anyone required to deliver one of the grades will always chose to deliver the crude with the lowest price.

The differentials determined by negotiations for trades of each of the four grades are applied either to the value of anticipated dated or the forward price, “whichever is in favor by the market at the time,” typically anticipated Dated (Argus 2015).

The differentials resulting from spot negotiations for all four grades are applied to value of anticipated Dated or BFOE forward around the dates of loading for the period related to the relevant transaction. The cheapest of the four constructed prices sets the price of North Sea Dated. In order to determine the price of each of the four grades, Brent, Forties, Ekofisk, and Oseberg, the respective differentials are applied to the price of North Sea Dated.

Following the addition of the Buzzard field to the Forties blend, Forties usually set the price of Brent. The quality of the four crudes is as follows: Brent 37.9 API and .45% sulfur; Forties 40.3 API and .56% sulfur; Oseberg API 37.8 and .27 sulfur; Ekofisk 37.5 API and .23 sulfur (Argus April 2015, 9). The relatively higher sulfur content in Forties makes it the least valuable, and thereby, typically the price-setter.

Owing to the variance in the quality of the grades of crude used to make up the benchmark, market premiums are subtracted from the grades of relatively better quality, Ekofisk and Oseberg. Without the quality premiums, the crude with the lowest quality – Forties – would always set the benchmark.

Forward market trade for the North Sea benchmark crude takes place under the Shell UK oil contract or the SUKO-90. The quality premiums as laid out in the contract are equal to "sixty percent of the daily average of the Oseberg Differential less the Lowest Grade Differential for [Month 2]…" (Modifications to SUKO-90, 2). The same calculation is applied for Ekofisk based on the spread between the Ekofisk differential and the lowest of the four grades. Quality premiums began June 2013 (Platts April 2013; Argus April 2015).

The relevant quality premiums are subtracted from Oesberg and Ekofisk prior to determination of the lowest price of the four grades of crude oil. If a seller delivers Ekofisk or Oseberg in fulfillment of the forward contract, the price will be adjusted, making the buyer responsible for the quality premium. If the average between Ekofisk/Oseberg and the lowest price of the four is less than 25¢/bl, the quality premium is zero.

Despite all of the attention given to the futures market and participants therein, the Brent futures market does not play a direct role in the price assessment of Dated Brent. Rather, the markets that directly inform the assessed price of Dated Brent are more exclusive and opaque than are futures markets.

According to *Argus*, if the market for forward Brent is illiquid – considered less than 100,000 barrels reported in one day – the futures market will indirectly affect the determination of the price of forward Brent (Argus 2012, 4). Specifically, in times of illiquidity, forward Brent is a function of the front-month futures contract and "the value of an exchange for physicals [EFP] contract[23]" (Argus 2012, 4). However, "this almost never happens," (Barret, 6) exempting some rare periods of exceptionally low liquidity in late 2007 and late 2008. Even in 2007 and 2008, most trading days had greater than the 100,000 barrel minimum (Fattouh 2011, 41-43). Even in these rare times of illiquidity, the futures market alone does not determine the assessed price of Dated BFOE.

The futures price is determined through anonymous sellers and buyers, transacting through an exchange, except for the settlement price on the day of expiry. At expiry, the Brent futures market converges to the price of the volume-weighted average of first and second month forward Brent, taking account of market structure – contango or backwardation. The method of settlement ensures the futures contract remains closely tied to the physical market despite the inability to take physical delivery through the futures exchange.

[23] "EFPs are often quoted as differentials to the Brent futures price but usually do not exceed it by more than a few cents" (Fattouh 2011, 44).

Trading in the Brent forward market has become increasingly concentrated. In 1986, the largest ten firms accounted "for about 50% of trading," but "over 80% by 1998" (Energy Intelligence 2006, A23-A24). Of the less than 40 traders in 2001, "the number of traders with market muscle had shrunk to a dozen" and the number of trades per day was around three (Energy Intelligence 2006, A24). According to data from Argus, in Fattouh (2011), between 2007 and 2010, there were four to twelve companies per month operating in the forward Brent market in a typical month[24].

Along with the futures contract, the forward contract also trades on a flat price – an outright price. This is in contrast to the Dated market, where traders negotiate only a differential to the flat price.

West Texas Intermediate (WTI)

In the United States, WTI includes land-based crudes from Kansas, Oklahoma, Texas and New Mexico. WTI travels via a pipeline system to several locations within the Midwest and Gulf coast. Cushing, OK and Midland, TX are the traditional pricing centers of WTI crude oil and prices in the two locations are not typically at parity (as of the March 2015 trade month, both Argus and Platts launched a third WTI pricing location – Houston, Texas).

Cushing is the pricing center of the futures contract as well as a storage and pipeline hub for crude oil unrelated to the futures market. Multiple pipelines meet in Cushing and Cushing is one of the largest storage sites for crude oil in the US.

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[24] Argus and Platts attempt contact with all market participants, however, those represented in the data may not include all traders.

The CME NYMEX Light Sweet futures contract relates to domestic light sweet crude (WTI) at the Cushing, OK pricing point. A WTI futures contract is a contract to buy or sell 1,000 barrels of WTI crude oil (or an accepted substitute) through the Cushing hub. Unlike Brent futures, a WTI futures contract guarantees access to physical crude, although most traders close their contracts prior to expiry, thereby abstaining from the physical side of the market. The WTI futures market is the most transparent and least exclusive of the WTI markets.

The pipeline delivery scheduling process for physical crude oil delivered to Cushing, OK guides the expiration date of the futures contract. “For US pipelines, shipments must be scheduled no later than the 25th day of the preceding month” (Argus 2012, 5). By the 25th of the calendar month, traders finalized schedules for the transfer of crude via pipeline during the following calendar month, known as the delivery month. The front-month futures contract expires – the front month rolls forward – three business days prior to the pipeline-scheduling deadline[25].

A discrepancy in time exists between the physical and futures front-month for three days after expiry of the futures contract and prior to the pipeline-scheduling deadline. Physical WTI trade refers to deliveries made in the following calendar month, while WTI futures contracts refer to two calendar months ahead.

For example, from 26 October until 25 November, physical spot trade relates to crude delivered in the calendar month of December. This calendar period is the December pipeline

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[25] The closest preceding business day replaces weekend and holiday deadlines for pipeline scheduling as well as futures expiration.

trade month. In contrast, from 23 October until 22 November, December is the front-month futures contract or futures contract trade month.

Argus and Platts publish the spot price of WTI-Cushing daily. Exempting the three-day window discussed above, according to *Argus*, the assessed spot price of WTI-Cushing is equal to “Nymex sweet crude futures settlements at 1:30 p.m. Central time” for each of the next four months (Argus 2012, 5). Platts uses reported WTI trade at 2:15 p.m. to determine the daily price of WTI.

For each of the three days of the physical and financial discrepancy in the prompt trade month, *Argus* assesses the WTI spot price at Cushing from the “Month-One/Month-Two Cash Roll” market[26] (Argus 2012, 5). Conversely, the Platts assessment of the WTI-Cushing market rolls forward one day prior to front-month expiry of the futures contract, i.e., from the example above, 21 November.

Market participants use the WTI trade month average, WTI Calendar month average (CMA) and WTI postings plus (P-Plus) prices as a WTI benchmark, rather than the price of a WTI futures contract at a single point in time.

The WTI trade month average is an average of the daily settlement price of the NYMEX futures contract over the entire trade month. If an Argus trade month average is used, the three days of roll trades are included in the average, while the Platts’ WTI trade month average will include four fewer days, as Platts’ WTI rolls one day prior to the NYMEX expiry.

[26] The month-one/month-two cash roll refers to the cost of rolling month-one physical WTI into a month two-deliveries of WTI. Argus assesses the price daily as a volume-weighted average of trade occurring throughout each of the three days.

The WTI CMA is used as a benchmark in an attempt to account for the time discrepancy between the trade month and the delivery month. The average of the daily closing price of WTI front-month futures over the calendar month equals that month's CMA basic price.

For most of the calendar month (roughly two-thirds), the front-month futures contract relates to delivery in the following calendar month. For the remainder of the calendar month, the front-month futures contract is two calendar months ahead. The largest portion of the CMA price is the average of the daily front-month prices during the calendar or delivery month.

The "NYMEX CMA roll adjust" compensates for the forward-looking foundation of the "basic" CMA calculation (Fielden 2012). The basic CMA price for delivery $Month_t$ is based on an average of daily prices in the futures market for $Month_{t+1}$ and $Month_{t+2}$ during every trading day[27] of the calendar month.

The CMA roll adjust assesses the difference between the price of (1) $Month_t$ and $Month_{t+1}$ and (2) $Month_t$ and $Month_{t+2}$.

In order to assess the roll adjust, a "trade month average" must be calculated for $Month_t$, $Month_{t+1}$ and $Month_{t+2}$. A trade month average is an average of the settlement price of a single futures contract during a single trade month. An average for each of the futures contracts $Month_t$, $Month_{t+1}$ and $Month_{t+2}$, during trade $Month_t$, is used to "adjust" the basic CMA calculation.

[27] Most CMA calculations include values for days when the NYMEX is open, i.e., "Merc Days" although some extend the preceding settlement price to weekends and holidays, thereby including all "Calendar Days" (Argus 2012, 5).

The CMA calculation for $Month_t$ is adjusted by the value of the difference between the $Month_t$ trade month average and $Month_{t+1}$ and $Month_t$ and $Month_{t+2}$, weighted for the number of days each futures contract spent as the front month during calendar $Month_t$.

Another WTI price is the posted price. Posting companies "post" the daily prices they are willing to pay or at which they will sell WTI crudes. Some posting companies are purchasers while others are producers. Posted prices are typically the price of crude oil "at the wellhead," (Fielden 2012). The WTI posting-plus price represents the posted price, adjusted for transportation costs to Cushing.

According to RBN Energy[28], the P-Plus price contains two components, each of which accounts for a distinct period: the trade month and the delivery month. The average posting price during the delivery month and the average posting premium during the trade month (the month prior to delivery, ending on the 25th day of the preceding month) equals the WTI P-Plus price.

The most commonly used posting within the industry, according to Argus Media, is the Phillips 66 posting price (Argus 2012, 6).

Oman/Dubai

Much of Asian-delivered oil is priced via a Dubai benchmark. Originally, the Dubai benchmark referred only to crude oil produced by the Dubai Petroleum Company (a consortium of several majors as well as a government stake) operating offshore of the Dubai territory of The United Arab Emirates. However, similar to the Brent and WTI markets, multiple markets make up what traders refer to as the 'Dubai' benchmark. While the methods

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[28] Neither Platts nor Argus provides details regarding the calculation of WTI P-Plus.

of Platts and Argus differ, the interplay of multiple markets results in prices for the reference crudes.

Dubai crude oil is a medium sour crude oil, with a sulfur content of 2.04% and typical API gravity of 31° (Argus 2013, 14). The Dubai price, as a benchmark has fallen out of favor since production of Dubai crude has declined to 80,000 bpd in 2009 (Leaver 2010, 3) and the Dubai market fails to satisfy any diversity of ownership criterion. In 2007, the government replaced equity producers with a government-owned company (Fattouh 2012, 62).

As production declined, the physical base of the benchmark expanded to include crude oil produced in Oman. Omani production, at close to 800,000 bpd in 2009, is substantially greater than Dubai (Leaver 2010, 3). Oman, with a typical sulfur content of 1.06% and API gravity of 33.3° is slightly heavier and has about half of the sulfur content of Dubai (Argus 2013, 14).

The price of Dubai is determined in two different ways. Platts assesses the price based on trades in the Platts MOC window, where the buyer must accept Dubai, Oman or Upper Zakum[29] crude oil. If the buyer is not willing to accept Oman and Upper Zakum in place of Dubai, Platts will not consider the trade in their assessment of Dubai (Platts January 2013, 13).

In addition to expanding the accepted crude oils, in 2004 Platts also expanded the assessment to the trading of partial cargoes. Partial cargoes are 25,000-barrel ‘slices’ of a 500,000 barrel cargo. Since such a small lifting does not occur, partial trades are cash settled

[29] The UAE also produces Upper Zakum.

unless a seller trades "19 partials with a single counterparty[30]" (Platts January 2013, 13). Immediately upon selling the 19th parcel, the trade becomes physical. The buyer is obligated to take delivery and the seller is obligated to lift crude. At the time of physical convergence, the seller must declare which of the three grades he will lift (Platts March 2013).

Platts assess the Dubai price on the trading of partials in the Platts window for three months forward. However, at the time of assessment, traders are discussing crude oil that will be loaded two or three months forward. The front-month Platts Dubai assessment is always at least one month away. At the first of each new month, the assessment rolls forward. In January, Platts will assess the Dubai price for the months of March, April and May. On February 1, the assessment changes to April, May and June.

In addition to the price of physical Dubai, Platts also assesses the price of Dubai swaps – cash-settled financial Dubai. Platts assesses prices for three months forward, although the assessment lags the assessment of physical Dubai by one month. "In January, for example, the first month swap assessed is February, followed by March and April" (Platts March 2013, 14). During the same period, Platts' assessments of physical Dubai is for the months March, April and May. Similar to the physical market, assessments roll over on the first of every month.

In the event that there are no partials traded in the Platts MOC window, Platts assess the price of Dubai through additional financial swap markets. Similar to other benchmarks, multiple OTC swap markets exist around Dubai, wherein traders exchange exposure to time

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[30] The discrepancy between the 19 partials and a 500,000-barrel cargo results from volume tolerance of -5% (Platts March 2013, 14). Contracts for crude oil include a specified volume tolerance (both positive and negative) – the amount by which the physical volume transferred varies from the contracted volume agreed upon by the traders prior to the physical transfer.

and crude oil differentials. As of Leaver's publication in June of 2010, since October 2008 traders used the Platts window only half of the time that Platts assessed Dubai (2010, 3).

Instead of using a partials trading window, Argus assesses the price of Dubai through the swap markets surrounding the physical Dubai benchmark. Specifically, Argus uses the Dubai/Brent and Dubai intermonth swap markets to assess the price of Dubai.

The Dubai/Brent swap is an exchange of futures for swaps (EFS): the swap enables traders to exchange exposure to the price of Dubai for exposure to the price of Brent futures. Exposure to the Brent futures price is much easier to hedge. However, the price in the EFS market relates to the price of Dubai loading two months forward. The EFS price is quoted as a differential to the Brent futures price. Once the EFS has been subtracted from the Brent price, the price of Dubai in two months is known.

The Dubai intermonth swaps market enables identification of the current Dubai price. The spread between the price of Dubai in two months and the price of Dubai in one month gives the price of Dubai one month forward.

For instance, in January, the EFS price quoted refers to the differential between the current Brent futures price and the price of Dubai trading in March. Argus identifies the price of Dubai in March by subtracting the EFS price from the price of Brent futures. The March forward Dubai price enables identification of the February forward Dubai price via the March-February swap price. After Argus identifies the February forward Dubai price, identification of the February-January swap leads to the January Dubai price.

In order to assess the price of Oman, Argus uses a method similar to that of the method used for Dubai: identification of the price through the OTC swaps market. The anticipated price of Dubai "plus the market premium or discount of Oman" identifies the Oman price. Conversely, Platts uses the partials method to assess Oman. Failing partials trading, Platts identifies the Oman price through the swaps markets.

Clearinghouses have opened futures trading in UAE crudes multiple times and the contracts have failed to gain liquidity almost as many times. An exception occurred in 2007 when the Dubai Mercantile Exchange (DME) began offering an Omani futures contract for 1,000 barrels of Omani crude. Much like the NYMEX Light Sweet contract, the DME Oman futures contract entitles the buyer to physical oil and obligates the seller to deliver physical oil. Much of the trading of the Oman futures contract ends in physical barrels of oil rather than a cash settlement, unlike the fewer deliveries for the WTI contract (Argus 2013, 13).

Some form of one of these three benchmark markets – Brent, WTI or Dubai-Oman – ultimately provides the basis for almost all crude oil that is transferred between parties. Researchers debate whether Dubai serves this function, since some argue it is largely determined by relation to the Brent markets. Regardless of the role of Oman, Brent remains the most important benchmark for internationally traded crude oil.

Despite the involvement of the Brent markets, the Dubai-Oman benchmark is the price reference for heavier and sourer crude oils, especially those exported to Asia from the Middle East. Since the benchmark prices are not at parity, there is an argument to be made that the Dubai market represents an additional aspect not necessarily captured by the Brent market. According to the Handbook, the 'Dubai' benchmark provides a market signal for heavy sour crudes as well as demand for crude oil east of "the Suez Canal" (Energy Intelligence 2006, A36).

Benchmarks Summary

While the North Sea and WTI benchmarks are older than the Dubai benchmark, all include several markets surrounding the physical oil, including financial markets, markets for pricing spreads, such as between a particular physical and a particular financial market, and physical spot markets.

The North Sea benchmark consists of several crude oil fields and has several markets surrounding the physical oil, including futures, forwards and physical spot markets. The markets are adjusted regularly to improve liquidity and deal with production declines, which are natural to any one field. The North Sea market is considered the international benchmark as it can be used anywhere in the world to price oil, since waterborne cargos can travel to any part of the world. Lastly, the futures contract is the only one of the benchmark market that does not entitle a holder to physical crude, but the contract settles on the price established in the forward market, where holders are entitled to physical crude.

The WTI benchmark is a pipeline market, and as such, WTI trades in smaller batches than the other waterborne markets which trade in large cargoes of 600,000bl. The benchmark, being located in the middle of the US is used nearly exclusively for oil produced and/or purchased within the US. Similar to the Brent benchmark, WTI has changed over time as the market context changed. For instance, as the supply of domestic production declined, the Cushing benchmark was adjusted to include foreign oil blended to a WTI specification. More recently, the Cushing benchmark is typically a blend of lighter shale production and heavy Canadian, blended to meet the WTI API gravity and sulfur specifications.

The Oman-Dubai benchmark is the newest of the three and it arose with the increase in oil consumption in Asian countries. Similar to the North Sea market, additional fields have been added to the benchmark to address liquidity issues as production naturally declines. The benchmark tends to be used for the sale of OPEC and other Middle Eastern crude into Asia. As the dissertation is focused largely on the US, WTI, followed by the North Sea market garner the most attention of the three possible benchmarks.

The Differential

Oil pricing formulas include several components, including one or more differentials as well as a particular construction of a reference price. The benchmark price reflects the value of the benchmark quality of crude oil at the benchmark pricing point of the particular benchmark, for instance, Cushing, Oklahoma and WTI. Differentials represent the value of a particular type of crude oil within the context of a particular location, relative to the context of the location of the benchmark crude oil.

The differential for a particular crude oil will reflect the quality difference between it and the benchmark crude, but this quality premium or discount changes over time and across locations, as well as seasonally. Heavier and sourer crudes tend to sell at a discount to sweet and lighter crudes. However, if light sweet crude is more readily available in a particular area and area refiners are designed to process heavier quality crude, the differential for heavier crudes can move nearer to or rise above that for lighter ones. Conversely, if several refineries take units designed to process heavier crude offline during seasonal refinery maintenance, the premium for light sweet crude can increase beyond typical non-maintenance levels.

Spot market differentials respond to local conditions of the crude oil under consideration or to the conditions in typical outlets available to that particular crude oil. If for instance, a large refinery goes into an unplanned shut down, the types of crude oil typically consumed by the refinery output will weaken in value – the differential weakens away from the benchmark. If crude oil is consumed away from the area of production, the differential changes in relation to the conditions to typical destinations. However, local conditions can play a constraining role regardless of the eventual destination. If the production location lacks infrastructure, including access to pipelines or export terminals, the differential will respond by weakening relative to the benchmark price.

A growing differential, either an increasing discount or premium to a benchmark price acts as a market signal, to which market participants respond. Areas of over and under-supply or a lack or excess of infrastructure are observed through the value of the differential. Responses of market participants tend to decrease the magnitude of the differential over time.

Differential pricing to an 'administered' price – the reference price – enables the flexibility required for the success and survival of the pricing system. Benchmark prices are not capable of representing the various conditions found in each individual market, but rather serve as a uniform starting point for a large portion of price of crude oil. The reference price is taken as given by the market during negotiations over the differential[31].

Market participants negotiate almost entirely over the value of the differential, significantly reducing the portion of the price involved in the discussion. If a seller or buyer

[31] Not only is the benchmark given, most markets already have an institutionally ingrained particular construction of the benchmark price to which market participants attach the differential.

become increasingly desperate, the price is likely to move against the desperate party. Reference pricing should increase the chance that movements away from the reference price remain a relatively small portion of the total price. More importantly, a localized desperate situation is likely to remain local rather than spill over to the 'administered' or uniform reference price by a flexible differential.

The differential enables the uniform pricing point achieved in the benchmark markets, by allowing local conditions to influence a portion of the price. If each market price were exactly equal to one of the benchmark prices, sellers and buyers would move away from the administered price as local conditions warranted, given the number and varying costs of producers. The use of differentials allows for this inevitability, without forcing participants to abandon the pricing method. The current pricing method includes an 'administered' price as well as an adjustment factor – the differential.

Agreed-upon differentials are largely unknown outside of the parties involved in a transaction, and possibly, a handful of other market participants. Price reporting agencies (PRAs) illuminate opaque spot markets by assessing benchmark prices as well as differentials for multiple crude oil markets.

Market participants communicate the differentials at which they exchanged spot volumes as well as other market information, including bids, offers and perceptions of value to PRAs. PRAs use the information from spot market participants and their representatives to assess differentials for pre-defined and well-structured crude oil spot markets. Links between markets – both paper and physical – can also inform differentials. Every differential assessed by PRAs relates to a particular benchmark.

PRAs publish the method by which they assess various spot markets for crude oil. Moreover, each agency defines what they consider a legitimate trade and retains the right to use discretion to exclude non-representative and suspect deals.

The methods utilized by PRAs vary for each market under examination and, according to Argus, aim to reflect the "unique characteristics [of the market] based on contractual terms, scheduling logistics, liquidity and transparency" (Argus 2012, 2). As market details change, so too will the price assessment for the particular market. Conversely, changes in the method of price assessment can lead to changes in the market details, such as the extension of the 21-day Brent to 25 days (Bossley *Oxford Energy Forum* 2012).

Oil market participants purchase price data from PRAs, which is then inserted in the pricing formulas used for the exchange of crude oil via contracts – long term transfers of crude oil with a contract that obliges the exchanges to continue. Contracts specify the PRA(s) and the data series used in the pricing formula. Differentials and reference prices arising in spot market exchanges determine prices in contract markets.

The Development of Paper Contracts and Electronic Trading

Other commodities had traded in futures markets long before the development of oil futures. Since large integrated companies, followed by OPEC, administered the price of oil to the market, and trading oil in an open market was rare, there was little need for an oil futures contract.

Parties transferring crude via contract, as well as those transacting in spot markets, deal with price uncertainty, which first arose in the 1970s. The eventual development of spot markets brought tension to the old method of OPEC-administered pricing, and gave rise to increasingly active financial markets in the 1980s.

The current pricing method ensures market negotiations begin with a similar price – arising from one of three reference markets. Since the determination of reference prices in spot markets began, reference prices change daily and are susceptible to periods of increased volatility. Most physical crude oil market participants engage in financial market transactions to reduce price uncertainty, guarantee revenue streams, increase profits or a combination thereof. Financial markets existed prior to spot market pricing, but the number and complexity of financial contracts has grown.

The rise of resource nationalization, independent producers, exploration and production activity in higher-cost areas and the introduction of refinery complexity all increased the need for a financial market for oil (Davis 2006). From 1985, paper markets in the oil industry grew as oil companies looked to assure supplies and lock in prices, including farther in the future (Davis 2006). OPEC now looks to the forward curve to make decisions regarding production levels (Davis 2006).

The International Petroleum Exchange (IPE) began as a mutual society, formed by energy and financial firms in 1980 (Banks 2003). A gasoil contact was listed in 1980, and the IPE successfully launched the Brent futures contract in 1988.

IPE formed into a holding company in early 2000, with a goal of becoming more commercially oriented, including adopting electronic trading of energy futures (Banks 2003; Brown 2013). IPE agreed to become a subsidiary of the Intercontinental Exchange (ICE) in 2001 in order to implement an electronic platform for the trading of energy futures (Banks

2003). ICE is exclusively an electronic exchange, originally including the following energy and financial firms: BP Amoco, Deutsche Bank, Goldman Sachs, Morgan Stanley, Royal Dutch Shell, Societe Generale Investment Banking and Totalfina Elf Group (McKay 2000).

ICE was formerly the Continental Power Exchange (CPE), an electronic platform for trading power (Brown 2013). CPE became ICE when the owner of CPE, Jeffery Sprecher, brought in a few large banks, selling them 80pc of ownership of CPE (Brown 2013). The banks then brought in several energy companies, turning over a portion of ownership (Brown 2013). ICE electronic trading of gasoil and crude futures began in 2001 and by 2005, trade was exclusively electronic, as ICE ceased IPE floor trading (Dicker 2011, 145).

Energy companies started energy commodity futures contracts and other paper markets, and continue to support them in the present. Market participants in the Brent forward market continue to use Shell's SUKO-90 contract in the forward markets. Major oil companies participate in financial markets and embraced the use of futures markets in place of physical markets for determination of the reference price of oil. As circumstances change, oil industry participants adjust the pricing method, and these adjustments have included greater reliance on financial or paper markets in the determination of the reference price of oil.

OPEC countries have also embraced the financial or paper markets in the pricing of oil. Saudi Arabia, Kuwait and Iran replaced spot market formula prices for some destination-markets with a futures price in 2000. The OPEC countries moved from spot price assessments of dated Brent with ICE BWAVE, or a volume-weighted average price established in the ICE Brent futures market.

In contrast to energy origins like IPE/ICE, the NYMEX name originated in 1882 in an effort to attract a broad range of customers interested in agricultural commodities, after being formed in 1872 as the Butter and Cheese exchange of New York (Banks 2003, 143). NYMEX first launched energy contracts in 1978, beginning with heating oil, and adding the Light Sweet Crude contract, known as WTI, in 1983, in response to the price volatility in energy markets (*Ibid*). Although energy companies did not form NYMEX, multiple oil companies owned seats at the exchange from the 1980s through to the merger with CME (Dicker 2011, 101-104)[32]. NYMEX also moved to electronic trading, through the adoption of CME software in 2006[33], although the process was drawn out, owing to the influence of and resistance from floor traders.

Complex financial layers surround multiple crude and product markets. Multiple financial contracts relate to some form of or spread related to the three main reference crude oil streams: Brent, WTI and Dubai-Oman. Sellers and buyers of any of the more than 200 types of crude oil around the world can hedge most of the price of their particular crude oil using the financial layers surrounding their relevant marker crude.

In 1986, transactions of physical barrels of crude oil in the benchmark market determined the reference price. Presently, prices achieved in paper – financial – markets determine the benchmark price. As each futures contract is associated with an active physical spot market, moving to the financial representation of the benchmark price was a minor

[32] According to Dicker (2011), just before the NYMEX IPO in 2006, each of the following oil companies owned two or more seats on the exchange: Amerada Hess, BP, Chevron, ConocoPhillips, ExxonMobil, MarathonAshland, Shell, Sunoco, Total and Valero (102-104).
[33] NYMEX offered electronic trading prior to 2006, but some contracts only traded when the trading floor was closed, there were a limited number and type of contracts offered, and the trading community did not embrace the software.

adjustment to the overall pricing method. Attaching differentials to one of a handful of cointegrated reference prices remained the dominant pricing institution.

CHAPTER 4

CONTEXT OF THE CRUDE OIL MARKET

Introduction

The chapter places the latest oil price cycle within an historical context by looking at important but possibly ancillary issues within the oil price spike and collapse including petroleum products and financial investment. Demand for crude oil ultimately results from demand for petroleum products. Refiners are between the consumers of petroleum products and crude oil: crude oil serves as an input, while consumers demand the outputs. A review of product specifications and major changes therein as well as a brief overview of the main refinery units makes brings to light some of the rigidities and constraints in the physical market. These constraints have price impacts in both crude oil and petroleum product markets. The second part of the chapter addresses the development and evolution of financial markets related to crude oil pricing. The section looks at the commodity futures market, including the opening up of the market to a broader class of investors, without which the question of whether financial investment determines the price of oil would not be asked.

Petroleum Products and Environmental Standards

Crude oil varies in composition and content, including density, levels and types of impurities, including sulfur, acids and metals and various other qualities. There are more than 150 different types of crude oil, according to The International Crude Oil Handbook (Energy

Intelligence 2006, A9), from which at any one time, may come a portion of the supply of crude oil. Crude oil is not a homogenous product and the characteristics that distinguish one stream from another are reflected in the relative prices of individual crude oils. The cost and value involved in refining a barrel of crude oil varies with the density, sulfur and other impurities of the crude oil, the capabilities of the refinery and the prices of petroleum products.

The combination of increasing environmental standards since 2000, the declining quality of marginal barrels and inadequate investment in the refining sector led predictably to seasonally tight markets for particular products. The tightness in product markets potentially reverberates back to the crude oil market, especially given the increased liquidity in financial markets.

The capabilities and capacity of refineries, the composition of the available crude slate and relative product prices can change the relative value of different types of crude oil and possibly, the price level of crude oil generally. Refinery complexity and major changes in fuel specifications are addressed in order to better understand the latest oil price cycle.

Lower density (higher API value) crude oil is called light crude oil and results in a greater amount of lighter products through a simple refinery process, while heavier crude result in a greater portion of heavier, less valuable products. Sweet crudes contain relatively minimal sulfur, whereas sour crudes have at least .5% sulfur content[34]. Light sweet crude refers to low density and minimal sulfur content and it requires the least complicated and least costly method of transformation.

[34] Medium Sour has .5% to 1.5% and Sour has greater than 1.5% sulfur content (Energy Intelligence 2006, A99).

At any given time, the type of crude oil transferred between sellers and buyers is of various qualities, and will likely consist of "blended crude." Production and infrastructure systems, blenders and marketers blend multiple crude oils from different fields to create a type of crude oil that is marketed to buyers[35]. The characteristics of the particular crude will affect the quality and proportion of the resulting products, and the capacity utilization of the refinery.

Whether one crude oil is more valuable at any given time will depend on the prices of the relative products produced from the crude oil as well as the technology available to refineries. Refineries tend to run a particular blend of crude oil In order to utilize fully, all processing plants and cannot easily switch to different qualities of crude oil blends[36], without sacrificing utilization of downstream plants. Similarly, producers of crude cannot change the quality of the crude available for sale at will, although the quality will change over the life of the field and varies predictably during scheduled field maintenance.

Gross product worth is the total amount of value a refiner can obtain from a barrel of crude oil and this value changes with the technology of the refiner, crude quality and product prices. Simple refineries contain distillation units and partake in blending processes. The flexibility of a particular refiner or the refinery industry is constrained by the level of complex technology within the system.

During atmospheric distillation, the basic unit of the refinery, molecules of similar composition come together and separate from dissimilar molecules. Straight-run feedstocks

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[35] Both WTI and Brent markets refer to blended crudes.

[36] Refiners blend various qualities of crude oil to the particular quality the plant is set up to process.

are the fractions of untreated components resulting from simple distillation. The blending components and process applied to each fraction will differ, owing to varying specifications, the impurities within the specific crude oil and refiner technology. Feedstocks range from light ends to heavy residuum and require further processing before they are saleable to end-users.

The EIA tracks refinery output among 15 different categories in the Petroleum Supply Monthly: LPG, finished motor gasoline[37], finished aviation gasoline, kerosene-type jet fuel, kerosene, distillate fuel oil, residual fuel oil, naphtha for petroleum feedstock use, other oils for petroleum feedstock use, special naphtha, lubricants, waxes, petroleum coke, asphalt and road oil, still gas and miscellaneous production (EIA 2016).

Of all the products derived from petroleum refining, processing and blending, gasoline and distillate fuel oil comprise over two-thirds of output. While prices of heavier products are generally lower than prices of lighter products[38], theoretically, a miss-match between supply and demand will cause a change in the price of a particular product and refineries will adjust output accordingly.

In addition to distillation units, almost all refiners have catalytic reforming capability (Carollo 2012, 51). The catalytic reforming plant transforms low-octane naphtha, a straight-run feedstock resulting from simple distillation, into a high-octane blending component for gasoline called reformed gasoline (Energy Intelligence 2006, A90; Carollo 2012, 52).

[37] Finished motor gasoline includes blending components, some of which do not derive from petroleum.
[38] In the extreme, refiners typically sell residual fuel oil at a loss. See below for the introduction of coking plants that transform residual fuel oil into lighter products and petroleum coke.

Reformed gasoline requires further processing prior to qualifying as an acceptable component of gasoline[39] (Carollo 2012, 52).

Cracking plants enable the creation of lighter products out of heavy fuel oil, thereby increasing the gross product worth of every barrel of crude oil and reducing residuum to a minimum. Refiners added cracking plants because of the drastic decline in demand for heavy fuel oil and increase in demand for lighter products.

Cracking also enables the refiner to vary the proportional output of the products produced as required seasonally[40]. Hydrocracking is preferable to catalytic cracking because hydrocracking enables greater flexibility regarding product proportions and "[m]ore light hydrocarbons are created than in cat cracking, the cracked residue is eliminated, and high-sulfur feedstocks are desulfurized" (Energy Intelligence 2006, A90).

Lastly, refiners with coking units are able to transform cracked and other residue leftover from the cracking process into lighter, more valuable products. The coking unit transforms residuum into lighter feedstock and a solid known as coke, which has properties similar to that of coal[41].

After minimizing residue and maximizing middle and lighter products, the fractions are still not saleable to end-users. Each product has legal and/or industrial standards. Further blending and processing is required in order for products to meet these required specifications.

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[39] Specifically, the level of benzene and aromatics in reformed gasoline are well beyond current legal limits (Carollo 2012 52).

[40] Cracking units transform heavy molecules into light and middle products. The relative proportions are adjusted as demand requires.

[41] There are additional processing units that make up a modern refinery.

Refineries limited to atmospheric distillation and some other simple secondary processing capacities are the least technologically complex and thereby the most constrained. The type of crude oil refined will largely determine the resulting mix of products and the profit margin. A complex refinery increases the proportion of light and medium hydrocarbons produced from a barrel of oil through the release of lighter hydrocarbons via the cracking of heavy carbons.

In order to transform the supply of crude oil into the particular quantities of products demanded by end-users, while avoiding bottlenecks and price spikes, the refinery industry as a whole should be flexible and maintain excess capacity in normal times.

The level of complexity of refiners around the world varies greatly. The more developed countries tend to have a greater number of complex refineries to meet stringent environmental specifications as well as the greater demand for lighter products (Energy Intelligence 2006, A92). The composition of demand for the products derived from crude oil differs between countries and regions.

While less developed countries tend to demand relatively more heavy products, there is still variation among developed nations. For instance, the EU relies heavily on diesel for transportation whereas the US transportation is heavily dependent on gasoline. Diesel is comprised of a heavier hydrocarbon than is gasoline (diesel is within the middle distillate category and gasoline is a light distillate). Additionally, producing gasoline requires additional processes and blending that are not required in the production of diesel.

The prices of gasoline components and distillate fuel oil move with their respective seasonal demand cycles. In the US, the price of gasoline peaks in the summer, while distillate fuel oil peaks in the winter. Gasoline is in greater demand during the summer travel season while distillate fuel oil is in greater demand in the winter months for heating purposes, especially in the Northeastern part of the US.

The Clean Air Amendments of 1990 required the Environmental Protection Agency (EPA) to make specifications for motor fuels increasingly stringent in an effort to improve air quality. The changes eventually rendered 'traditional' refineries unequipped to produce gasoline out of most varieties of crude currently on the market at the time (Carrollo 2012). After consultation with industry, the EPA introduced the new standards over a period of several years with exemptions and other flexibilities over time to account for the necessary technological updates required of refineries.

The Clean Air Act Amendments of 1990 required the use of higher quality gasoline in the geographical regions with the lowest air quality. Congress passed the Act, "requiring that gasoline sold in certain areas[42] be reformulated to reduce vehicle emissions of toxic and ozone-forming compounds" (Federal Register 1994). Under the new standards, the properties of gasoline that result in emissions harmful to human health and plant life were reduced.

As required by the 1990 amendments (40 CFR 50), the EPA sets National Ambient Air Quality Standards (NAAQS), covering six 'criteria' pollutants, "considered harmful to public health and the environment" (EPA website: NAAQS homepage http://www.epa.gov/ttn/naaqs/). The pollutants are carbon monoxide, lead, nitrogen dioxide, ozone, particle pollution and sulfur dioxide (EPA website "National Ambient Air Quality Standards" http://epa.gov/air/criteria.html).

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[42] In the most polluted metropolitans, specifically EPA-designated ozone non-attainment areas.

Geographical locations with air quality worse than the NAAQS are labeled non-attainment areas. Non-attainment areas are required to submit state implementation plans (SIP) showing how the area will attain the NAAQ standards in the future. Reformulated gasoline is required in the areas with the worst air quality, and is optional everywhere else.

When the Clean Air Act amendments first passed, it required nine metropolitan areas to provide reformulated gasoline. Including voluntary opt-in areas and non-attainment areas, currently "about thirty percent of the gasoline sold in the United States is reformulated" (EPA website Fuels and Fuel Additives: Reformulated gasoline. http://www.epa.gov/otaq/fuels/gasolinefuels/rfg/index.htm).

The three major groups of emissions addressed in creation of reformulated gasoline through passage of the Clean Air Act amendments and subsequent fuel specification regulations are toxic air pollutants (TAP), volatile organic compounds (VOC) and nitrogen oxides (NO_x). However, in the original 1990 amendments, Congress did not address nitrogen oxides directly: "the primary purposes of reformulated gasoline are to reduce ozone-forming VOC emissions during the high ozone season and emissions of toxic air pollutants during the entire year" (Federal Register 1990).

The chemical reaction of VOC and NO_x creates tropospheric ozone. Tropospheric ozone is ozone in the atmosphere within six miles of the earth (ozone beyond the tropospheric level, from six to thirty miles, is beneficial in filtering UV rays). 'Ground-level' or tropospheric ozone is harmful to humans, other animals and plants and it is the main contributor to smog.

The first phase of the program began at the start of 1995 and continued until the start of 2000. Phase I required refiners 'reformulate' gasoline to reduce volatile organic compounds (VOC) and toxics (TAP) by a minimum of fifteen percent, relative to EPA-estimated 1990 baseline levels (Federal Register 1994).

Adherence to the Phase I standards was possible via a simple or complex model until the beginning of 1998, after which, only the complex model was acceptable. During Phase II of the program, the reductions in harmful emissions increase beyond those of Phase I.

The simple model identifies precise maximum allowable contents of the following: "Reid vapor pressure, fuel oxygen, benzene and aromatics" through establishing an estimate of the 1990 baseline. The maximums change from winter to summer and vary in Northern and Southern regions. The total content of other properties of gasoline known to be harmful had to be equal or less than the average content in 1990 for that particular refiner[43] until the introduction of the complex model in 1998. Under the simple model, sulfur, olefins and E300 must be no worse than the refiner's average in 1990.

The EPA justified the simple model because it would result in the legislated fifteen percent reduction in VOCs and TAPs, while also allowing refiners necessary lead-time to introduce technological changes, i.e., refiners producing a relatively lower quality fuel in 1990, had an extended period to improve fuel quality (until 1998).

[43] During negotiations for Phase I, there were yet to be accurate estimates for the impact of sulfur, olefins and other compounds (Federal Register 1994).

Table 4.1 Gasoline Requirements Phase I Simple

RVP – South	7.2 psi max
RVP – North	8.1 psi max
Oxygen Summer	2.0 - 2.7%
Oxygen Winter	2.0 - 3.5%
Heavy metals	None
sulfur	Particular refiner 1990 average
olefins	Particular refiner 1990 average
E300[44]	Particular refiner 1990 average

"Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline; Final Rule." (Federal Register, 1994).

The 15% reduction in VOC results from the reduction in RVP and addition of oxygen in reformulated gasoline thereby complying with the law. Additionally, the EPA assumed the oxygen maximum of 2.7 and 3.5, in the summer and winter respectively, did not contribute to an increase in NO_x. Of the five contributors to TAP, benzene is the only one regulated under the simple model (the rest are products of combustion rather than gasoline). At the time of the finalization of the simple model, data and models were insufficient to determine the quantifiable effects of all potential pollutants.

The substantive difference between the simple and complex is the disappearance of the importance of the individual refiner's average. The EPA-estimated baseline or "statutory baseline" replaced the refiner average when the complex model replaced the simple model on 1 January 1998.

[44] Percent of fuel that evaporates at 300°F

Table 4.2 Statutory Baseline for Complex Model

Fuel Characteristic	Summer[45]	Winter
RVP (psi)	8.7	11.5
Benzene (Volume %)	1.53	1.64
Aromatics (Vl. %)	32	26.4
Olefins (Vl. %)	9.2	11.9
Sulfur (ppm)	339	338
E200 (%)	41.0	50.0
E300 (%)	83.0	83.0
Oxygen (weight %)	0.0	0.0

"Refiners switch to reformulated gasoline complex model."
Energy Information Administration.

Under the Phase I complex model properties that had yet to be quantified at the time of the simplified model, acquired absolute specifications. "The complex model quantifies not only the effects of oxygen, benzene aromatics and RVP on emissions, but also olefins, sulfur and the percent of fuel evaporated at 200 and 300 degrees Fahrenheit (E200 and E300 respectively)" (EIA 1998, 2).

Table 4.3 Reductions in pollutants (per gallon)[46]

Pollutant	Phase I - Simple	Phase I - Complex
TAP Emissions reduction	15% minimum	15% minimum
NOx Emission reduction	N/A	Cannot increase
VOC Emission reduction - Southern	N/A	35.1%
VOC Emission reduction - Northern	N/A	15.6%

"Refiners switch to reformulated gasoline complex model."
Energy Information Administration.

[45] June 1 – September 15 (June 1 – retailers; May 1 – upstream)
[46] Standards are more strict when calculated as a refinery average

The EPA formulated an emission equation, with which regulators determine whether a particular fuel complies with the complex model standards. The EPA does not specify maximums for most properties[47] since the interaction of the properties change the level and type of emissions.

The EPA, in not specifying every property, provides refiners with flexibility in producing reformulated gasoline. For example, while RVP has the greatest impact on "the VOC emissions calculation," reducing sulfur or aromatics also reduces VOC emissions. Additionally, "increasing E200, E300 and olefins" reduces VOC emissions as well (EIA 2000, 18). Refiners can meet the minimum emission standards in a variety of ways.

Phase II (the current phase) requires the following emission reductions from the 1990 baseline: 21.5% reduction in TAP emissions; 29% reduction in VOC emissions in the southern region and 27.4% in the northern region; 6.8% reduction in NO_x emissions during the summer and 1.5% in the winter (EIA 2000, 17-18).

While the emission equation changed slightly when Phase II began, the EPA continued to offer refiners similar flexibility in meeting the required emissions reductions (EIA 2000).

Aromatics and sulfur are the main contributors of the NO_x category, while aromatics, sulfur and benzene are the main contributors of TAP emissions. Refiners are able to reduce VOC emissions most effectively via reductions in RVP, reductions in sulfur and/or aromatics, but increases in E200, E300 and olefins may also be necessary to achieve the required reduction in each region (EIA 2000, 18).

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[47] Oxygen still has a minimum content of 2% and benzene has a maximum of 1% per gallon maximum.

Table 4.4 Emissions reductions

Emission type	Phase I actual reductions (%)	Phase II required reductions (%)
TAP	18.0	21.5
NO_x Summer	1.5	6.8
NO_x Winter	1.5	1.5
VOC South	20.8	29.0
VOC North	10.5	27.4

Figures from "Demand and price outlook for phase 2 reformulated gasoline, 2000." Energy Information Administration.

On February 10, 2000, the EPA published the final rule regarding implementation of the new gasoline sulfur standards (Federal Register 2000.) While finalized in early 2000, specified[48] reductions in sulfur were not required until 2004, in order to enable refiners to acquire the latest and most cost-effective technology.

The exceedance allowance during the year 2004, the averaging-banking and trading system, the geographic phase in areas and the small-refiner extensions allow refiners added flexibility.

Table 4.5 Gasoline Sulfur Standards

Compliance as of	2004	2005	2006 +
Refinery Average ppm	-----	30	30
Corporate Pool Average ppm	120	90	-----
Per Gallon Cap ppm	300	300	80

"Gasoline Sulfur Standards for Refiners, Importers, and Individual Refineries." Federal Register 2000, 6754.

[48] Previous legislation indirectly led to reductions in sulfur by requiring reductions in emissions.

In 2004, an individual batch of gasoline can exceed the per-gallon cap of 300 ppm by up to 50 ppm. "However, in 2005, the cap for all batches will be reduced by the magnitude of the exceedance" (Federal Register 2000, 6754). In 2005, the per-gallon cap remains at 300 ppm, for refiners who did not exceed the cap in 2004.

Given that the EPA-estimated 1990-baseline gasoline had 338-9 ppm of sulfur content and the effect of the previously enacted emission standards of the Phase I complex model, many refiners likely did not feel the pressure of the new sulfur standards prior to 2005, or possibly even 2006. According to the EPA, "…national average sulfur levels when both conventional and reformulated gasolines are considered dropped to 306 ppm in 1997 and 268 ppm in 1998…" (Federal Register 2000, 6760).

The EPA instituted the corporate average standard in 2004 and 2005 so that companies did not need to update all refineries simultaneously. The EPA was aware that some refineries would exceed the 120-ppm cap in 2004 and some would exceed the 80-ppm cap in 2005. However, refiners that updated facilities prior to the deadline would compensated for those who delayed the change. If the immediate demand for desulfurization technology was too large, rising prices, and possibly, material and labor shortages would result.

The EPA expected the delay to be sufficient for most refiners to install desulfurization units. However, the final rule establishes a credit and allotment-trading program to allow for further delay the installations. The EPA wanted to allow "for a smoother transition" (6752) that enabled some refiners to wait until the beginning of 2006 (Federal Register 2000, 6752 – 6753).

The final rule institutes a sulfur allotment-and-credit-trading program in another effort to enable technological diffusion over a longer period. In 2003, any refiner producing gasoline with less than 60 ppm of sulfur (annual volume-weighted average) received sulfur allotments to sell or use in the future. Refineries producing gasoline with less than 60 ppm but more than 30 ppm of sulfur received discounted allotments (20% discount).

In 2004 and 2005, any corporation producing gasoline below the applicable standard of 120 in 2004 and 90 in 2005 on an annual volume-weighted average basis, receives sulfur allotments to use or sell to another refiner.

Corporations that had yet to install proper desulfurization technology at all refineries could purchase allotments in order to meet corporate average standards in 2004 and 2005 and refinery average standards in 2005. In 2005, excess allotments from 2003 and 2004 are discounted 50% in order to account for the increased impact of sulfur on Tier 2 vehicles in 2005 (Federal Register 2000, 6760). Refineries could not use allotments or credits to circumvent the per-gallon standard.

In addition to other flexibilities, the final rule established a geographic phase-in area (GPA) to address industry concerns regarding the competition over limited resources required to construct and install desulphurization facilities (Federal Register 2000, 6755-56). Air pollution in the geographic phase-in area is of a “less urgent” concern than in other areas and small and rather isolated refineries supply most of the gasoline consumed with the GPA (Federal Register 2000, 6756).

To allow for less competitive refiners to comply with the law while reducing the pressure of competition over resources prior to the compliance period, sulfur standards in the

GPA lagged behind requirements in the rest of the country by one year. The GPA consists of "Alaska, Colorado, Idaho, Montana, New Mexico, North Dakota, Utah and Wyoming" as well as the border counties these same smaller refineries supply[49] (Federal Register 2000, 6756). Refineries supplying more than fifty percent of their gasoline to the GPA qualified for the expended deadline; i.e., were not required to adhere to the 2004-2005 corporate average standards of 120 and 90.

Table 4.6 Gasoline Sulfur in Geographic Phase-In

Compliance as of	2004	2005	2006	2007[50]
Refinery Average ppm	150[51]	150	150	30
Corporate average ppm	120	90	-----	-----
Per-Gallon Cap ppm	300	300	300	80

"Gasoline Sulfur Standards for the Geographic Phase-In Area". Table from Federal Register 2000, 6758.

According to the EPA's analysis, small businesses supply about four percent of US gasoline per year. The EPA instituted a small refinery exemption in order to account for the disadvantaged position of a small business in raising adequate capital, and to enable smaller refineries to take advantage of the cost declines in desulfurization technology that the EPA expected to occur in the future as well as reduced pressure from competition for materials and labor (Federal Register 2000, 6766-6767).

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[49] There is also a small-refiner extension available. Most small refiners in the GPA do not qualify for the exemption because they "are not owned by small businesses" (Federal Register 2000, 6756).

[50] This column is not in the original table.

[51] Refineries in the GPA that were already producing gasoline with a sulfur content below the 2004 standard are held to their "1997-1998 baseline plus 30 ppm" up to 150 ppm.

In order to qualify as a small refinery, the average number of employees in the corporation from the beginning of 1998 to the beginning of 1999 cannot exceed 1500[52] and the corporation's total refining capacity cannot exceed 155,000 barrels per calendar day (Federal Register 2000, 6768). The average baseline sulfur level for the years 1997 and 1998 determine sulfur allotments for qualifying small refiners from 2004-2007. Small refiners must meet the national sulfur standards by January 1, 2008. Small refiners that cannot meet the national standards by the end of 2007 can request a hardship extension that lasts up to two years (Federal Register 2000, 6769).

By 2006, the EPA required all individual refineries to produce gasoline with an average sulfur level of 30 ppm and instituted a per-gallon cap of no more than 80 ppm. The industry was aware of the standards since at least 2000, giving them six years to upgrade their facilities to meet the new sulfur standards.

The EPA published a final rule outlining Tier 3 gasoline and vehicle emissions standards in April 2014 (Federal Register). Tier 3 standards reduce allowable levels of sulfur to 10 ppm, from the Tier 2 standard of 30 ppm (Federal Register 2014). By 1 January 2017, refiners and gasoline importers are required to supply, gasoline with a maximum of 10 ppm sulfur content on an average annual basis.

Tier 3, like Tier 2 regulations, view both the vehicle and the fuel together as a system by enhancing the emissions control systems in vehicles and Reductions in emissions require a new vehicle fleet and accommodating fuel. The new motor vehicles, produced from 2017 and beyond, require lower levels of sulfur in gasoline to protect the catalytic converter and

[52] Small business administration definition of a small refiner (Federal Register 2000, 6766)

the precious metal catalysts within it to meet emissions reductions required under Tier 3 (Federal Register 2014, 23441-23442). Sulfur comprises the effectiveness of the catalyst in the catalytic converter, thereby compromising the reduction in harmful emissions. Additionally, a reduced sulfur level in gasoline has beneficial effects independent of the state of the vehicle fleet, in reduced NO_x, CO and HC (total hydrocarbons) (Federal Register 2014, 23442).

The new Tier also includes the Averaging, Banking and Trading (ABT) credit system, common to previous regulation, in an effort to institute flexibility into upgrading the refining system. Refiners who comply with the new standards – prior to the deadline receive – credits. Companies can use the credits to cover other locations they have yet to upgrade or they can sell the credits to companies who have yet to meet the new standards. Refiners currently acquiring credits for producing gasoline with less than 30 ppm on an average annual basis (Tier 2 maximum) are able to transfer those credits to comply with the new Tier 3 system and refiners are able to acquire credits for the Tier 3 requirements beginning in 2014 (Federal Register 2014, 23419). Small refinery and hardship extensions also exist to enhance flexibility (Federal Register 2014, 23419).

Beginning in 2006, diesel became what is referred to as ultra-low sulfur diesel (ULSD), meaning the sulfur content is 15 parts per million, or 97 percent less than prior to Summer 2006. As of June 2006, refiners were required to produce diesel with the 15 ppm maximum sulfur content, although exceptions similar to those for new gasoline regulations were also put into place for diesel regulations. Flexibilities included the geographical phase in areas and a credit system with transferable credits that can be purchased by non-compliant refiners.

The Energy Policy Act of 2005 amended the Clean Air Act by making mandatory, the use of renewable fuels in motor fuel. The legislation dictates the total quantity of renewable fuels the industry is supposed to integrate into the US motor fuel supply from 2006 to 2012, starting with 4 billion gallons in 2006 and increasing each following year – reaching 7.5 billion gallons in 2012.

The legislation requires the EPA, working with the Department of Energy, determine the percentage of fuel sold by refiners, blenders and importers that must be renewable, in order to meet the 4 billion gallon requirement in 2006 (Energy Policy Act of 2005, 477). The percentage is the same for all parties. If the EPA does not determine the percentage in time for 2006, refiners, blenders and importers are responsible for integrating renewable fuels in the amount of 2.78 percent of total volume of gasoline distributed in the US in 2006 (*Ibid.*, 477).

The Act privileges ethanol from years 2006 through to 2012 (*Ibid.*, 478-479), where integrating one gallon of ethanol into the motor fuel supply results in 2.5 gallons of renewable fuel credits.

From years 2013 and beyond, the EPA, in concert with the Department of Energy and the Department of Agriculture, will study the issue to determine the effects of the program and the productive capability of the renewable fuels industry (*Ibid.*, 477). The amount of renewable fuels going forward after 2012 will be approximately equal to the percentage of renewable fuels in the fuel supply, given the 7.5 billion gallon requirement for 2012 *Ibid.*, 478).

Small refiners are exempt from the required percentage of renewable fuels until 2011 (*Ibid.*, 481). The average daily operation for a refinery to be qualified as small is 75,000 b/d or less (*Ibid.*, 476). The Secretary of Energy can issue extensions for a small refiner's compliance if the refiner can establish "disproportionate economic hardship" would result from compliance (*Ibid.*, 481).

Credits will be given to any refiner, importer or blender who exceeds the necessary minimum requirement for renewable fuels (*Ibid.*, 479). The credits can be transferred to another party who is deficient in renewable fuel credits and the credits are good for one year after the credit is generated (*Ibid.*). Small refiners who decide to opt in to the renewable fuels program also qualifies for credits (*Ibid.*). The production of biodiesel entitles one to renewable fuel credits (*Ibid.*).

The Energy Independence and Security Act of 2007 (EISA) amended the Clean Air Act, by adjusting the amount and types of renewable fuels for use in motor fuels – including gasoline, diesel and jet fuel – as well as heating oil (Energy Independence and Security Act 2007, 28-41). EISA also specified the annual amount of renewable fuels required through to 2022, from the year 2012 established in The Energy Policy Act of 2005 (*Ibid*. 31-33).

EISA increases the amount of renewable fuels required annually and established required levels of advanced biofuels, cellulosic biofuels and biodiesel. By 2012, US motor fuels are to include 15.2 billion gallons of renewable fuel, compared to the 7.5 billion required by The Energy Policy Act of 2005. Every year the required amount of renewable fuel increases, ultimately reaching 36 billion gallons in 2022. However, the 2007 legislation includes all motor fuel, while that from 2005 referred only to gasoline (*Ibid.*, 33).

EISA continues the method previous legislation included, legislating absolute amounts of renewable fuels, rather than percentages of total fuel consumed. The administrator of the EIA provides an estimate of motor fuel consumption for the following year to the administrator of the EPA, who then determines the applicable percentage required to meet the legislated amount of biofuel.

These absolute quantities of renewable fuels have raised concerns of a potential "blend wall". A blend wall occurs when fuel demand growth is insufficient to meet the legislated amounts of renewable fuels, i.e., overall, vehicles are not able to use fuel with a renewable content as high as would be required to use the legislated quantity.

Commodities as a Financial Asset

Robert Greer was the first to suggest the potential of commodities as an asset class, in, in "Conservative commodities: A key inflation hedge," (1978). Commodities held as an asset provided inflation protection. The correct mix of commodities, stocks and debt is potentially a better portfolio than one without commodities, since the former contains an inflation hedge (Greer 1978, 26).

The inflation-hedged portfolio is more likely to provide stable real returns than a portfolio without commodity futures (Greer 1978, 27-28). However, during times of low inflation, the rate of return on alternative assets is higher (Greer 1978, 26).

While Greer introduced the idea in 1978, legal hurdles and technical complexities served as obstacles to commodity futures gaining in popularity as a new class of financial assets. Decades passed before institutional investors began viewing commodity futures as an asset class. Until 1994, the Prudent Man Rule prevented institutional investors from investing in commodities because they were too risky.

The Uniform Prudent Investor Act – approved in 1994 – replaced the Prudent Man rule, and by 2004, 41 states had replaced the Prudent Man Rule with the Prudent Investor Act. Under the new governance rules, the riskiness of the portfolio is examined as one unit, rather than examining an asses in isolation. Under the 1994 Act, an individual asset is within or one part of a complete portfolio.

Upon the removal of legal restrictions, commodity investments arose as an option for diversifying returns so that the portfolio does not suffer or stagnate when stocks and bonds are performing poorly. The lack of correlation to traditional investments made commodity-investing look increasingly attractive during periods of low returns, including post-crises.

Commodity futures are one form of ‘alternative’ investment strategies where returns are ‘ideally’ uncorrelated with stocks and bonds. Typically investors do not have the time nor technical knowledge to participate in futures markets, so they turn over a portion of their portfolio to a person or institution that invests in futures markets on their behalf.

Individuals who advise and invest client funds in futures markets must register with the Commodity Futures Trading Commission (CFTC) and the National Futures Association (NFA) as a commodity trade advisor (CTA).

In order to diversify beyond the skills of a single CTA, investors may also pool funds under a commodity pool operator who hires a variety of CTAs to manage the pool. Commodity pool operators (CPO) must also register with the CFTC and NFA. Registering the fund with the CFTC and the NFA requires supplying various documents related to the investments, strategies and risks involved in the fund on at least an annual basis.

From 2003 until 2013, most hedge funds and other forms of private investment funds investing in futures and other derivative markets were exempt from registration under CFTC Rule 4.13(a)(4). Private funds consisting exclusively of investments from clients that are considered sophisticated investors were exempt from registration. Exempted investors included managers of pension, insurance and other funds.

The CFTC rescinded rule 4.13(a)(4) following the passage of The Dodd-Frank Wall Street Reform and Consumer Protection Act. The rule change was to help identify threats to the financial stability of the United States as stated in the Dodd-Frank legislation.

Beginning in 2013, the exemptions reverted to the pre-2003 rule. If the fund is not primarily invested in speculative futures and OTC derivatives contracts; i.e., if the find "engaged in a *de minimis* amount of derivatives trading," and consists only of qualified exempt persons it will remain exempt from registration (CFTC 17 CFR Parts 4, 145, and 147, 9).

If either the total net investment in futures is not leveraged beyond the value of the liquidated portfolio or the initial margin and premiums do not exceed five percent of the liquidated portfolio, *and* all clients are considered qualified exempt persons, the fund may still qualify for exemption from CFTC and NFA registration, under the rule 4.13(a)(3).

Commodity index investments consist of long-only futures positions, i.e., index investors only participate on the buy side of the futures market. Passive investors are looking for exposure to the prices of commodities over the long term, which leads them to purchase long-only futures and regularly roll over the contracts prior to expiry.

As far as the potential for undesirable effects, some researchers postulate that inattention to prices by passive investors distorts price discovery in the futures market (Masters and White 2008). Opponents to the method of Passive or "index" investing argue against the long-only aspect of the method.

A less direct form of investment in commodity prices entails investing in the equities of companies heavily involved in commodity production. However, there are other risks associated with this sort of indirect investment, such as "corporate management risk and general market risk" and, most importantly, the performance of commodity-related equities is less related to the price of commodities than it is to the S&P 500 (Englke and Yuen 2008, 566). Commodity futures markets represent the most direct form of financial investment into commodities, without taking possession of physical commodities.

Goldman Sachs and Dow Jones-UBS operated popular commodity indices during the price rise. According to the Goldman manual, the GSCI is composed of "commodities that are the subject of production or distribution processes in the world economy and that have a direct effect on price levels and inflation" (GSCI Manual 2004, 15).

The Goldman Sachs Commodity Index was created in 1991 and weighted each commodity by total world production over the past five years, while the volume of futures contracts traded determined which commodities would be included in the index[53] (GSCI 2011, 25-28).

In 2009, the DJ-UBS Commodity Index replaced the DJ-AIG Commodity Index. AIG launched the DJ-AIG in 1998 (DJ-UBS 2012, 1). Liquidity in futures markets determines which commodities are included in the Dow Jones-UBS Commodity Index.

Liquidity and production data determined the weights[54] given to each commodity included in the DJ-UBS index. Within the DJ-UBS index, a single sector could not comprise more than 33 or less than 2 percent of the index (DJ-UBS 2012, 2). This maximum in the DJ-UBS index leads to the biggest difference between the two indices, where Goldman gives greater weight to energy-related commodity futures.

Replicating a commodity index, like investing in other indices, enables investors to gain exposure to a large variety of assets through a single investment. Unlike traditional indices, the commodities indices are based on the prices of contracts that expire every month. Therefore, the replication of returns requires regularly 'rolling over' contracts prior to expiration.

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[53] The calculation requires additional steps as futures contracts for individual commodities are not necessarily comparable – consider a single contract representing 1000 barrels of sweet light crude compared to a contract representing cattle. (See GSCI Methodology 2004, 26).

[54] Calculations for total world production and contracts traded include the past five years in an attempt to smooth temporary trends.

The number of each futures contract in the index changes as the relative prices of the futures contracts change[55]. When relative prices change, commodity portfolios must be "rebalanced" according to pre-determined weights given to each commodity.

Given the complexity of commodity-index investing, index investors turn over a pre-determined allocation of funds to "swap dealers" or money managers who provide the returns/assess the losses resulting from changes in commodity futures prices. Investors are thereby able to gain price exposure to physical commodity price movements in proportions represented by world production and liquidity, without dealing with the process involved in monthly rollovers.

The pre-determined allocation is the percentage of the total portfolio invested in commodities for the purpose of diversification. As the size of the total portfolio changes, so too does the dollar-amount invested in commodity futures.

Financial institutions, on behalf of their clients, will sell the near-month contracts prior to expiration, and replace them with a contract that expires the following month[56]. Every index has a specified method governing the 'roll' process. The method stipulated by those in charge of the index governs the replacement of contracts near expiry.

During a specified time of month, a specified percentage of the contracts are sold each successive day until there are no more contracts near expiration. While those in charge

[55] According to Verleger, it is precisely this reason that index investors can stabilize rather than exaggerate runaway prices.

[56] The original indices were based on second-month futures contracts. However, beginning in 2006 several 'second-generation' indices began to use contracts that expired several months out. This development increased the demand for far-away contracts relative to near-month contracts. Given the illiquidity of far-month futures contracts, passive investors will make up a greater portion of that market (Wheat 2009, 94; 103-104).

of valuing the commodity index never actually purchase and sell contracts, the accepted methodology governs their calculations of the prices that would result if they did trade the contracts according to the accepted methodology.

Commodity indices result in an increased demand for futures contracts because the financial institutions hedge their own exposure. The funds replicate the commodity index for investors, and they purchase commodity futures to hedge their own risk created by replicating the indices for their clients. The money managers probably only purchase contracts related to net exposure, which results from the particular composition of his clients, rather than purchase all contracts for every client.

Investors potentially earn three returns from investing in commodity indices: 'spot', roll and collateral returns. 'Spot' returns result from changes in the prices of commodities futures included in the commodity index: an increase/decrease in the price increases/decreases the value of the index. A roll return is the difference between the price of the near-month futures contract at the time of sale and the price of the futures contract that replaces it. A contango market causes a negative roll return and in a backwardated market, the roll return is positive[57]. Lastly, the collateral return is the return obtained from the interest earned on the collateral of the client.

If a pension funds wants to gain exposure to commodities worth one million dollars, the fund manager turns over the full sum to a swap dealer. The swap dealer then invests the collateral in a low-risk, low-return investment, such as Treasury Bills. The interest earned on

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[57] The roll return in a contango market is precisely the reason for the development of second-generation indices, wherein the roll period and the replacement contract are much more flexible in order to enable maximum returns (Wheat 2009, 103).

the treasuries is the collateral return. The dealer need not invest the full sum because futures contracts are purchased on margin. Second, the dealers have multiple clients, whose diverse trades act as a natural hedge for the exposure of the dealer. All major commodity indices include at least the spot and roll return, others include the collateral return as well (Wheat 2009, 89).

The long-only aspect of index investors raises concerns regarding their possible contributions to rising crude oil prices. The motives of traditional futures market traders and active commodity investors lead them to purchase both long and short futures contracts. Rather than provide liquidity to both sides of the market, index investors potentially siphon liquidity away from traditional hedgers[58] and speculators, by engaging only the buy side of the market.

Concerns about index investors relate to liquidity, ignorance of market signals and an initial run-up in prices when index investing rose in popularity. In contrast, managed futures participate in both sides of the market, so the issues related to commodities as an asset class change.

Technical Trading

Systemic, also called trend-based trading, guides the majority of active investment in futures markets, although alternate strategies are growing in popularity (Abrams, et al. 2010, 5; Barclay Hedge).

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[58] "Traditional" distinguishes physical from financial hedgers. Financial hedgers purchase futures contracts as a hedge against some other financial position. Physical hedgers are involved in the specific physical commodity represented as a financial asset in the futures market. Prior to September 14, 1987, the CFTC did not consider financial hedgers as *bona fide* hedgers (CFTC 2008). As hedgers, financial players are not subjected to position limits; they are however, subjected to other constraints (see p. 15).

Technical trading enables traders to profit by participating in a trend or pattern, once identified, using an understanding of typical patterns and tools to identify these patterns. Empirical data, along with the tendency of patterns to repeat, aid in the identification of trends and associated patterns.

Systemic or technical strategies can be contrasted with fundamental analysis, where traders look to market context, but fundamental traders also look to technical analysis, at least to time changes in positions. Fundamental trading involves an understanding of a particular market, or of macroeconomics and macroeconomic effects on a particular market or group of markets. It is likely many fund managers utilize both fundamental and technical data while deciding investment strategies.

Empirical analysis of technical signals allows trading without being captive to the typical human psychological tendencies and emotions that determine the identified and repeated patters. Whereas investors operate via human tendencies, technical traders identify and predict the price changes driven by such motivations. Because human psyche drives the patterns, they tend to repeat across time and markets.

Resistance levels identify a ceiling, beyond which the price has not been lately or ever. Levels of support, or support prices are a floor below which the price has not fallen recently. Lines of support and resistance help traders identify when a trend begins.

A horizontal line drawn on a chart connecting the last string of high prices identifies the resistance level or ceiling. A horizontal line connecting a string of low prices shows the level of support, or floor. The lines connect at least two points and are not to cross over any price activity. A price breaking through a level of resistance or support may indicate an uptrend or downtrend, respectively

Resistance and support lines are diagonal rather than horizontal in markets trending higher or lower. In a bullish market, the trend line will connect the low prices and the more points that touch the line, the greater the likelihood of a stronger trend. In a bearish market, the line connects the price peaks.

When the price moves beyond the line, the trend may be changing. Traders have different rules to guide their trading, but to avoid the pitfalls of human emotion, strict rules govern most technical trading. (Technical Analysis 2010).

The faster a trader identifies a trend, the more profit potential the trend carries. The faster a trader identifies a break in the trend, the lesser the loss of the profit so far gained, before cashing out of the position.

Moving averages crossovers provide another tool for the identification of a break in trend. However, the moving average lags the price movement and therefore provides a delayed signal of a new trend.

The moving average is plotted on the same chart as the price series and when the price series "crosses over" the moving average, a change in trend has occurred. The identification is further strengthened when the moving average line begins to move in the same direction as the price series (Technical Analysis 2010). In gaining further support for trend changes, technical analysts will include multiple moving averages of varying periods in addition to the price series. A trend is reinforced when a shorter-term moving average crosses over a longer-term moving average.

Momentum indicators are used in combination with moving averages, owing to the lag of the latter (Technical Analysis 2010). Momentum indicators measure the change in prices over time, rather than the absolute price. The greater the magnitude of the change in price, the stronger the trend indicated. As the trend begins to change, the rate of change tends to decrease prior to reversing, aiding in the identification of a break with the current trend.

Technical analysis provides traders with signals and ways to try to recognize a trend early. Other ideas have developed that aid traders in predicting the direction of price movements, including Elliott Wave Theory Elliot wave and Fibonacci Numbers (Technical Analysis 2010).

The increase of financial investment in commodity futures may have overrode the influence of traditional speculators. Newer entrants in the oil futures market, those using technical trading techniques, may have changed the relevant variables by relying on a different range of data (Mabro 2001) and historical trends (Carollo 2012).

CHAPTER 5

AN APPLICATION OF THE PRICING METHOD: THE US GULF COAST

Introduction

For much of the history of the oil industry, the US Gulf coast has been at the center of US oil markets. The US Gulf coast represents the largest refining center in the United States, and remains a major hub for US crude imports, petroleum product exports and more recently, rising crude oil exports.

This chapter examines the price cycle from the start of the current century through early 2016, including the path of differentials for one light sweet and one medium sour grade of crude oil at the US Gulf coast, within the framework laid out in chapter three. The chapter takes from chapters two and four, the context of the physical market and the multiple possible causes of drastically changing prices form the early 2000s through to the peak in 2008 and the collapse thereafter.

Market participants established the pricing method within a specific historical context and they adjust the method as the context changed over time. One such adjustment, introduced and accepted by market participants, has been the use of financial markets in the pricing of physical oil. The analysis shows how the pricing method grounds the price of oil to conditions in physical oil markets, despite the potential of financial conditions to determine futures markets prices in the short term or exaggerate price movement caused by conditions in the physical market. Moreover, participants in the physical oil market respond to prices determined in financial markets.

The current method of pricing arose within conditions of oversupply following high and rising prices through the 1970s, and so far remains intact and appears appropriate for the current situation – one of oversupply following the high and rising prices for much of the twenty-first century. While interested parties adjusted the pricing method regularly, since its formation in 1980s, the basic structure remains. Reference prices and differentials comprise the price of physical oil and prices in spot markets still determine those in contract markets.

Pricing at the US Gulf Coast

The most commonly known crude oil, of the domestic grades at the US Gulf coast, is Light Louisiana Sweet (LLS), possibly followed by Mars. The values of these two crude oils represent the particular grade of crude oil at their respective pipeline delivery points. LLS represents the value of light sweet crude at the US Gulf coast, particularly, St. James, Louisiana. Mars represents the value of medium sour crude at the US gulf coast, explicitly, Clovelly, Louisiana.

The values of both higher quality light, sweet crude as well as heavier sourer crude are central to the price cycle, as through to 2010 the oil slate was expected to become increasingly heavier and sourer, while legal specifications for petroleum products became increasingly stringent. These two trends were expected to continue indefinitely. Following the onslaught of shale production, the crude oil slate became increasingly lighter as US shale production is almost entirely light crude oil.

Most transactions of LLS consist of various crude oils blended to a strict specification, i.e., a mix of crude oil of varying quality, originating from multiple fields/locations, blended in proportions that result in the specifications that define LLS[59]. The Capline pipeline, which originates in St. James, sets the specifications for LLS. Specifically, the specification is for LLS that will go into the Capline pipeline at St. James, Louisiana. The storage and pipeline transport facilities at the St. James hub have also incorporated the same specification, meaning buyers purchasing LLS at St. James expect the quality to adhere to the Capline LLS specification, regardless of whether the volumes actually go into the Capline pipeline.

In contrast to LLS, Mars is a blend of offshore field production exclusively, that travels ashore as Mars blend. A handful of majors and independent producers own the several offshore production fields that makes up the Mars blend. There is not active blending of other crude oil to the Mars specification, sold as Mars, in contrast to the blending that is common to the LLS market, where the origin of the crude oil blended into LLS is unknown.

WTI is the reference price to which the differentials for LLS and Mars refer. The differentials for LLS and Mars represent the market context at the specific pricing location, relative to the context for WTI at Cushing, Oklahoma. The physical market surrounding LLS and Mars determines the differentials for LLS and Mars.

The quality of LLS and WTI are similar as they are both light sweet crude oil, relative to Mars, a heavier sourer crude. Owing to the similar quality of LLS and WTI, much of the

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[59] Most crude oil is a blend consisting of production from multiple oil fields. Moreover, refiners tend to purchase multiple varieties of these blended crude oil streams and engage in extensive blending prior to processing crude oil.

differential for LLS represents the difference in value between Cushing, Oklahoma and the Louisiana coast, specifically, St. James. The differential for Mars includes both the locational disparity and the discount typically incurred by a relatively lower quality crude oil.

LLS, Mars and WTI are pipeline-delivered crude oil. Crude originating both on and offshore in the Gulf of Mexico, as well as imports, tends to travel throughout the US via an extensive network of pipelines, although the shale boom has increased the use of rail, barges and trucks. Pipeline crude oil markets, like waterborne markets, trade ahead of delivery.

The delivery of pipeline crude oil tends to take place over the entire month. The buyer arranges to accept say, 5,000 barrels per calendar day (5,000 b/d). Scheduling for crude oil deliveries for the following month is finalized no later than the 25th of the prior month, which is also the final session of the pipeline trade month.

The pipeline trade month runs from the 26th of each month to the 25th of the next month. The market rolls to the following traced month on the 26th, two months prior to the delivery month. The December trade month begins on 26 October, or the following business day, and continues until 25 November, or the prior business day.

The CME's light sweet futures contract – WTI – outlined in chapter three, synchronizes with the pipeline trade month, as the details of the Cushing, Oklahoma pipeline hub informed the CME futures contract. The futures contract rolls forward to a new prompt trade month three days prior to expiration of the pipeline month. Delivery schedules are finalized for the following month – the delivery month – during the final three days of the pipeline trade month. In the final scheduling days, prices tend to be more volatile as market participants square up final monthly totals. As these days are known to be volatile, traders will tend to secure or sell volumes before these final sessions. This illiquidity then likely contributes to the volatility.

While trade for LLS and Mars may occur following the trade month deadline, PRAs exclude such trades as they are likely distressed and are thereby not representative of the market. Trade in ultra-spot markets – trade that takes place following the end trade month – however, can influence values in the current trade month if the volumes are substantial.

Spot negotiations over the differentials for actively traded pipeline grades occur throughout each trading session. PRAs calculate or assess differentials daily. The trade month average consists of an average of approximately 21-23 daily differentials.

Buyers and sellers in the spot market for domestic crude oil at the coast negotiate over the value of, say, Mars, relative to the US benchmark, 'WTI'. Spot market participants are more concerned with the value of the differential, than with the outright price of the crude oil.

In most LLS and Mars spot market trades, as with other established domestic pipeline grades, traders exchange WTI, the LLS or Mars as well as the value of the differential. The money exchanged in spot market transactions relates exclusively to the differential to WTI. For example, in a typical LLS spot market transaction, alongside the transfer of LLS, parties also transfer WTI. A seller of 1,000 b/d of LLS receives the value of the negotiated differential for LLS[60] to WTI, say $3/bl, as well as an equivalent quantity of WTI. The buyer of the LLS receives the LLS, provides the seller with the value of the differential for LLS as well as 1,000 b/d of WTI, delivered at Cushing, Oklahoma.

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[60] LLS typically trades at a premium to WTI, i.e., a positive differential.

Outright prices, as opposed to differentials, marked at the time of an agreement to trade are likely to be different from the price the buyer paid or the revenue the seller received. The discrepancy results from a constantly changing price of WTI. The prices marked at the time of the agreement of the LLS transaction use the current price of WTI, whereas the WTI exchanged in the spot trade was likely acquired at a different time, and therefore, at a different price. Many market participants hedge their WTI exposure in the futures market, adding another layer of complexity to the price or cost construction, as the hedge should offset changes in the value of the physical position of the hedger.

Market participants may exchange physical WTI or futures contracts in spot trade. However, the level of margin required by futures exchanges tends to make physical WTI more attractive. Counterparties with established relationships are likely to provide better terms of credit than those required by the CME and ICE.

The WTI exchange ensures the differential is the sole point of negotiation in spot trade, and therefore represents the relative market value of the crude to WTI. PRAs disseminate these differentials, which are then included in the pricing formulas for long-term contracts. For instance, the trade month average of the differential for LLS is typically included in the pricing formula for transfers of light sweet crude oil at the US Gulf coast, including in contracted transfers of LLS itself. The contract specifies which PRA will be used as each is unlikely to have exactly the same value, depending on the various PRA methodologies and information received from the market.

The WTI CMA is the dominant reference price in contracted transfers of domestic crude oil, although the postings-plus price remains common in the midcontinent (Fielden

2012) and posted prices are common at the wellhead. The posted-plus price includes the cost of transporting the WTI to Cushing, Oklahoma, and since at least 2006, the posting accounts for the structure of the forward curve (Argus Media 2006). The 'plus' or differential to the posted price arises through spot transactions of WTI, using the posted price as the reference price. The differential, or the 'plus' and the posting is the WTI postings-plus, which is used in contracted transfers of crude oil.

The Koch posting served as a common reference price up to mid-2006, and existed ten years prior to the NYMEX light sweet futures contract (Argus Media 2006). The Koch WTI posting was the price Koch was willing to pay for crude at the wellhead, in West Texas and New Mexico (Fielden 2012). After Koch cancelled their WTI posting in mid-2006, the ConocoPhillips posting became the next commonly utilized posting, followed by the Phillips 66 posting, after Conoco and Phillips split into two companies.

While the WTI CMA serves as the most common contract reference price, the Phillips 66 posting follows a similar pattern. The Phillips 66 monthly posting will be the same as the WTI CMA minus $3.38/bl. Since April 2008, Phillips 66 sets the posting at a discount of $3.38/bl to the NYMEX settlement price (Fielden 2012). Much of the liquidity for physical WTI in the spot market has moved to the CMA-related market, although PRAs still cover the postings-plus WTI spot market.

The WTI cash market was another market for physical WTI, popular before the rise of WTI CMA. After the NYMEX settled, traders would buy and sell physical WTI at a differential to that day's settlement price. As electronic trading took off, this cash market became illiquid and PRAs ceased coverage owing to illiquidity. That is, market participants moved to the electronic trading from OTC aftermarket trading.

Currently, some form of the NYMEX settlement price serves as the reference price of most physically traded WTI, and most domestic transfers of other grades of crude oil. WTI tends to be exchanged via the WTI CMA, the WTI postings price or sometimes even a single session's NYMEX settlement price. The futures market price, albeit typically adjusted, is the price of physical oil, both WTI-type oil and other grades as well.

The contract price of non-WTI domestic crude tends to include the WTI CMA price, and most likely, a 'roll' adjustment[61], a trade month differential and lastly, a custom differential to the formula price[62].

The NYMEX light sweet futures settlement price is also included in some imports of foreign crude oil, including those from Saudi Arabia, Kuwait and Iraq. Rather than turn away from the futures market, oil companies embraced the increased liquidity in the market.

The Path of the Benchmark Price (WTI)

Following the 1986 decision by Saudi Arabia to regain market share by adopting netback prices, non-OPEC oil production began to fall, for the first time since at least 1966[63]. Non-OPEC production was steady in 1988 and fell each year from 1989 through to 1993,

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[61] See chapter three for a description of the WTI cash roll. The traded market for WTI differential to NYMEX CMA is also used as a 'roll' adjustment in contracts (described in chapter three) although the values are likely to be similar.

[62] A typical contract pricing formula also includes a 'custom' discount or premium in addition to the reference price and the differential determined in spot trade (for grades other than WTI) (Fielden 2012).

[63] The yearly average increase in non-OPEC oil production was, on average, 1.186mn b/d from 1966 through 1985, with 1985 seeing the smallest increase at 427,000 b/d (BP 2015).

with annual declines averaging 527,200 b/d over the period. The physical market responded to the lower price level. There exists, however, a lag between production levels changing and decisions regarding production.

Near the end of the 1980s and into the early 1990s, the daily price tended to settle within \$20/bl and \$25/bl, aside from a temporary spike at the start of the first Iraq war. From 1993, the price tended to remain between \$15/bl to \$20/bl until the Asian financial crisis of 1997, during which prices fell to the low teens. Non-OPEC oil production responded, rising by a mere 113,000 b/d in 1998 and falling by 80,000 b/d in 1999, while yearly OPEC production did not fall until 1999.

The price of oil was recovering in 1999, with OPEC agreeing to production cuts in both 1998 and 1999, and, in 2000 OPEC adopted a price band (Fattouh 2007). Through 1999, the WTI price consistently increased. The minimum price hit in 2000 was greater than the average price in 1999 by \$4.55/bl, illustrating a continuation of the uptrend that began in 1999.

WTI futures prices sustained a relatively higher range in the upper \$20s/bl and lower \$30s/bl, until the US recession and the attack on 11 September 2001 temporarily constrained the uptrend. Following September 11, prices dropped, bottoming out at slightly under \$20/bl (see Figure 5.1 on following page).

By 2003, the price of WTI returned to levels not seen since before the events of 2001. The average price of WTI in 2003, around \$31/bl, was slightly more than the average of \$30.27/bl in 2000.

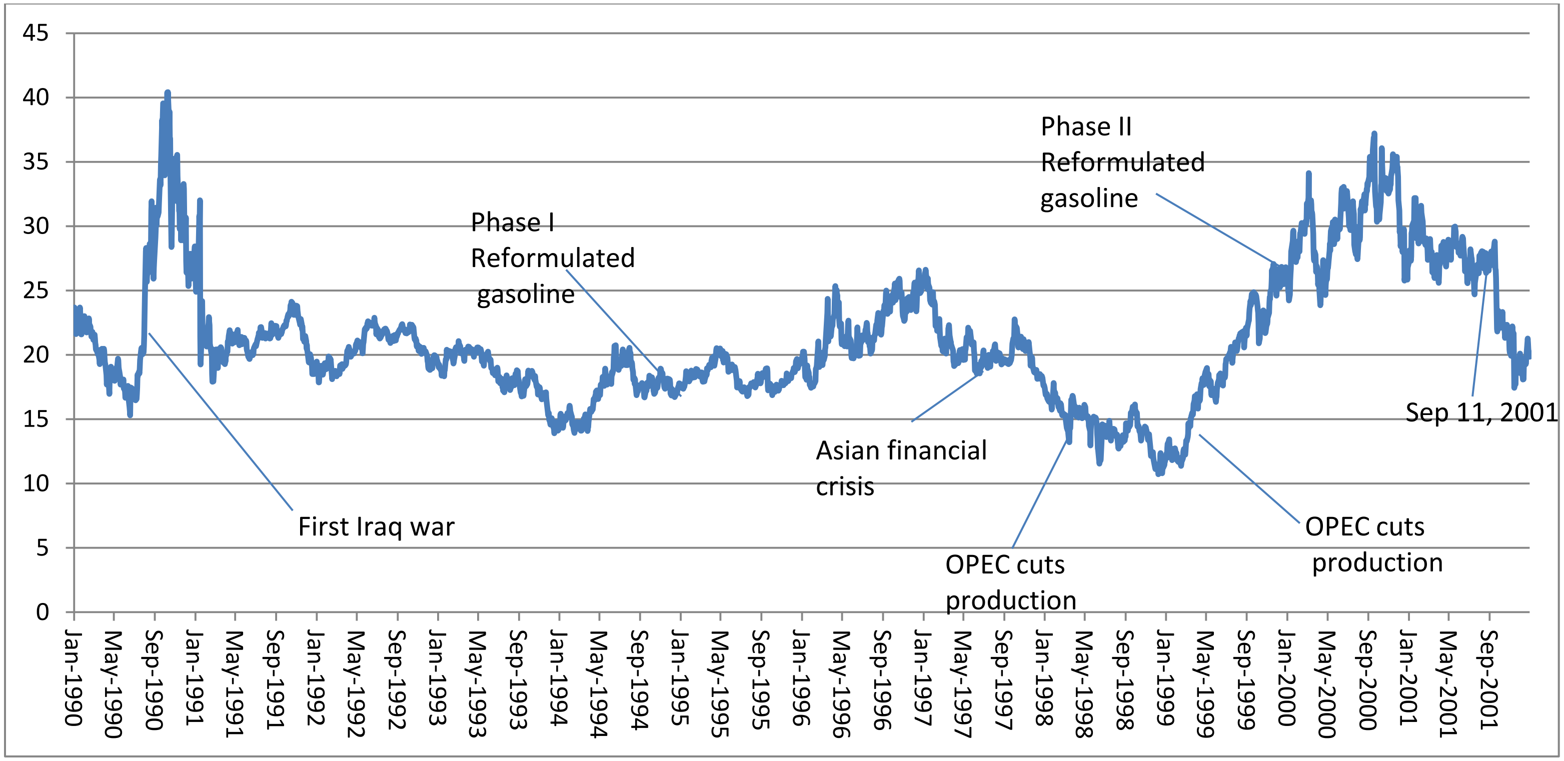

Figure 5.1 Price of Oil 1990-2001. NYMEX Light Sweet month 1 contract daily settlement price per barrel

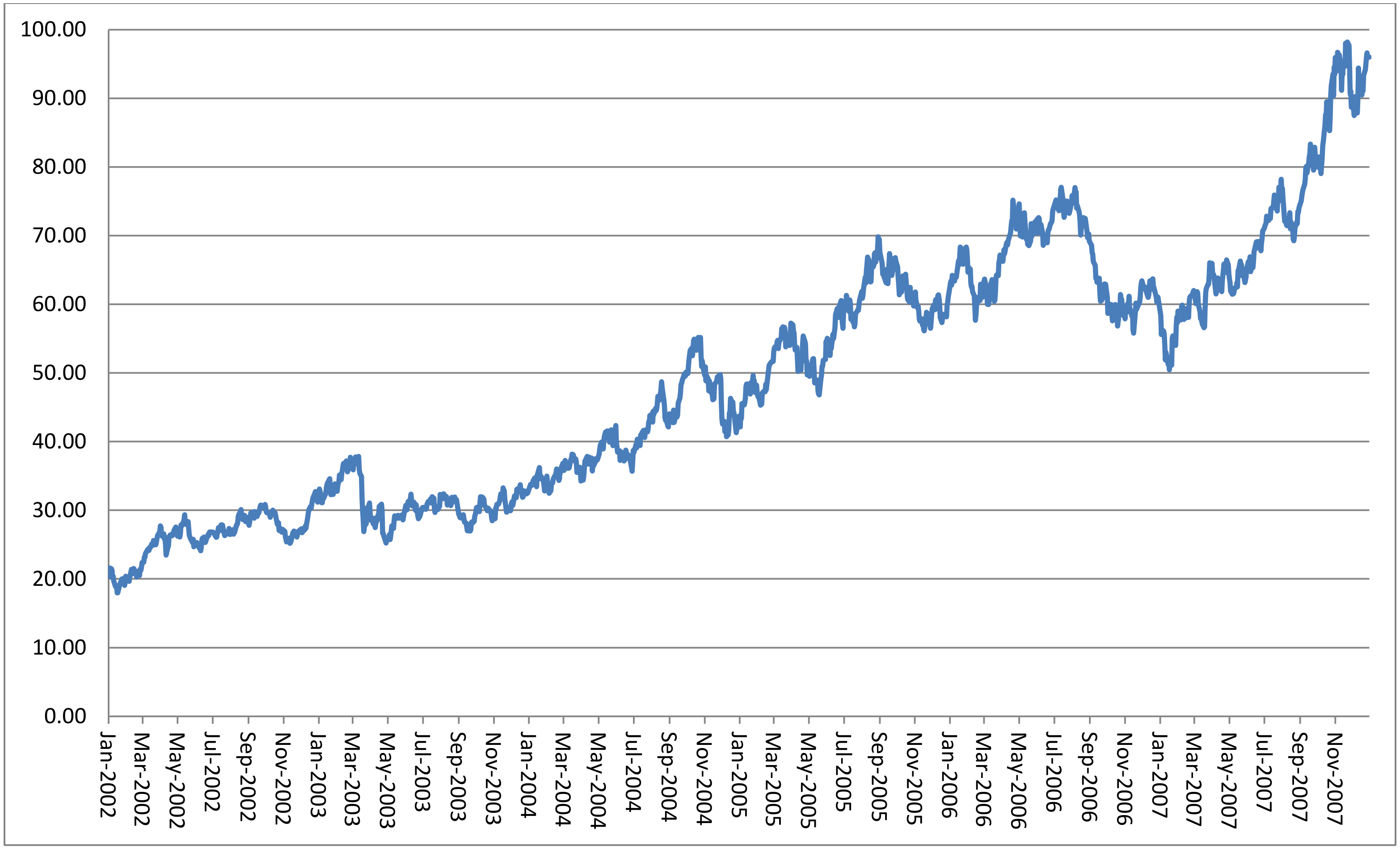

Figure 5.2 Price of Oil 2002-2007. NYMEX Light Sweet month 1 contract daily settlement price per barrel

The uptrend continued in 2004 with the average price higher by more than $10/bl, compared to the 2003 average. In 2005, the average price rises by $15/bl, followed by increases of $10/bl in 2006 and nearly $6/bl in 2007 (see figure 5.2).

WTI futures prices strengthened and, while choppy at times steadily increased, with the second half of 2006 marking the only notable period during which prices did not trend stronger. The price fell from the low $70s/bl to the mid $50s/bl, although prices recovered and strengthened further by the spring of 2007 (figures 5.2-3). The following year, the average price soars to nearly $100/bl, an increase of more than $25/bl from the 2007 average.

OPEC production increased at an average of 2.354mn b/d while non-OPEC production increased by an average of 386,000 b/d (see figure 5.3) from 2003 through 2005 (BP 2015). Non-OPEC production does not appear to have responded significantly to the rising prices of the period.

Much of the overall slow growth rates in non-OPEC production resulted from the contributions made by declining production in mature fields in OECD countries (BP 2015). In 2007, US production was lower by 503,000 b/d compared to 2003, while production in the UK and Norway combined was lower by 1.35mn b/d (BP 2015). These locations represent the US and international benchmarks, WTI and Brent, respectively.

OPEC production grew by a little more than 300,000 b/d in 2006 and fell by slightly more than that in the following year, while non-OPEC supply increases by slightly less than 135,000 b/d in both 2006 and 2007 (BP 2015).

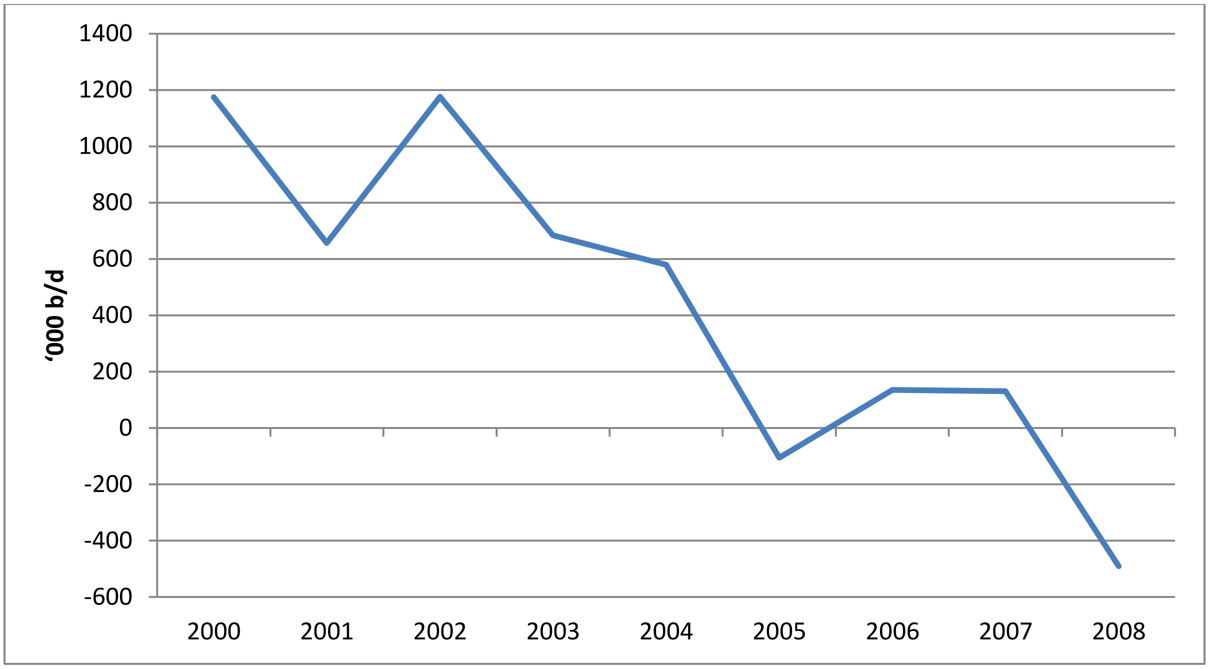

Figure 5.3 Change in World Oil Supply less change in OPEC Oil Supply. BP Statistical Review of World Energy 2015 Annual data (author calculation)

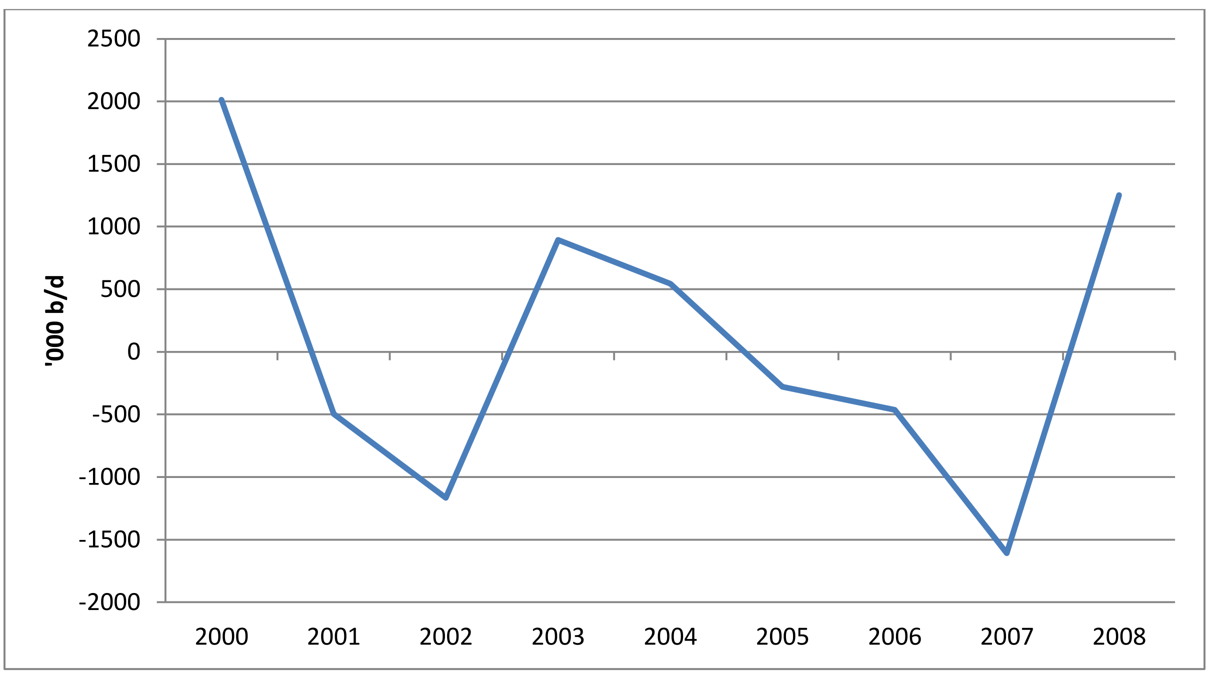

Figure 5.4 Change in Oil Supply less change in Oil-Product Consumption. BP Statistical Review of World Energy 2015 Annual data (author calculation)

Oil product consumption increased by a little more than 900,000 b/d while production increased by just over 450,000 b/d in 2006 (BP 2015). By 2007 the gap widens, with demand rising by 1.4mn b/d and world supply falling by just over 195,000 b/d (BP 2015). Consumption of oil products increased by an annual average of 1.65mn b/d from 2003 through 2007, with 2004 seeing the largest jump, at 2.845mn b/d (BP 2015). The yearly average increase for China and India were 511,000 b/d and 105,000 b/d, respectively (BP 2015). Consumption was on the rise in 2006 and 2007, but production was not responding (see figure 5.4).

In the late summer of 2007, the price for WTI begins to recede, as is typical when the US gasoline season closes. Unexpectedly, the price moves higher soon after, rising well over highs established during the peak US driving season, and continues increasing through much of the remainder of 2007.

Deliveries into the US Strategic Petroleum Reserves (SPR) began in September 2007, with reserve stocks higher by 6mn bl by year's end (EIA weekly SPR inventory data). The gap between the increase in consumption and the increase in production occurring in 2007 as well as SPR deliveries likely helped sustain higher prices through the end of 2008. However, there were additional factors to consider.

In August 2007, the Federal Reserve started to reduce the Federal Funds Rate, with the effective rate moving weaker by 25 basis points per month, from August 2007 through January 2008, exempting September (Federal Reserve Economic Data Monthly Effective Federal Funds rate). December's effective rate was about 4.25pc, from July's 5.25pc (*Ibid.*). The rate decreases likely exasperated previously existing concerns over the weakening dollar.

The price of WTI in the futures market receded somewhat by early February, falling to less than $90/bl but prices quickly recovered hitting nearly $102/bl by February's end. The Federal Funds rate was lowered by almost 100 basis points from January, with February's effective rate just below 3pc (*Ibid.*). The effective rate held was reduced until May, after which it was held at 2pc through August (*Ibid.*). From September it was weakened, reaching nearly zero percent by year's end (*Ibid.*).

From late February, the price begins the ascent to the July peak of $145/bl, which lasts for two sessions. From July through the rest of 2008, the price collapses to the low $30s/bl as the financial crisis and accompanying recession emerge. The one exception to the price decline occurs in September, likely owing to an active hurricane season. However, the Department of Energy began draining the Strategic Reserve, in response to shut-in production and the price begins to descend, once again. The price of WTI futures bottomed out at $33.87/bl on 19 December.

It is very likely fears of inflation and a credit crunch influenced prices on the way to July's peak and December's bottom, respectively. The final ascent to the record high, established mid-year 2008 does appear to be influenced by financial interest in commodity futures. Both the peak and the bottom are not sustained, and arguably, neither were sustainable.

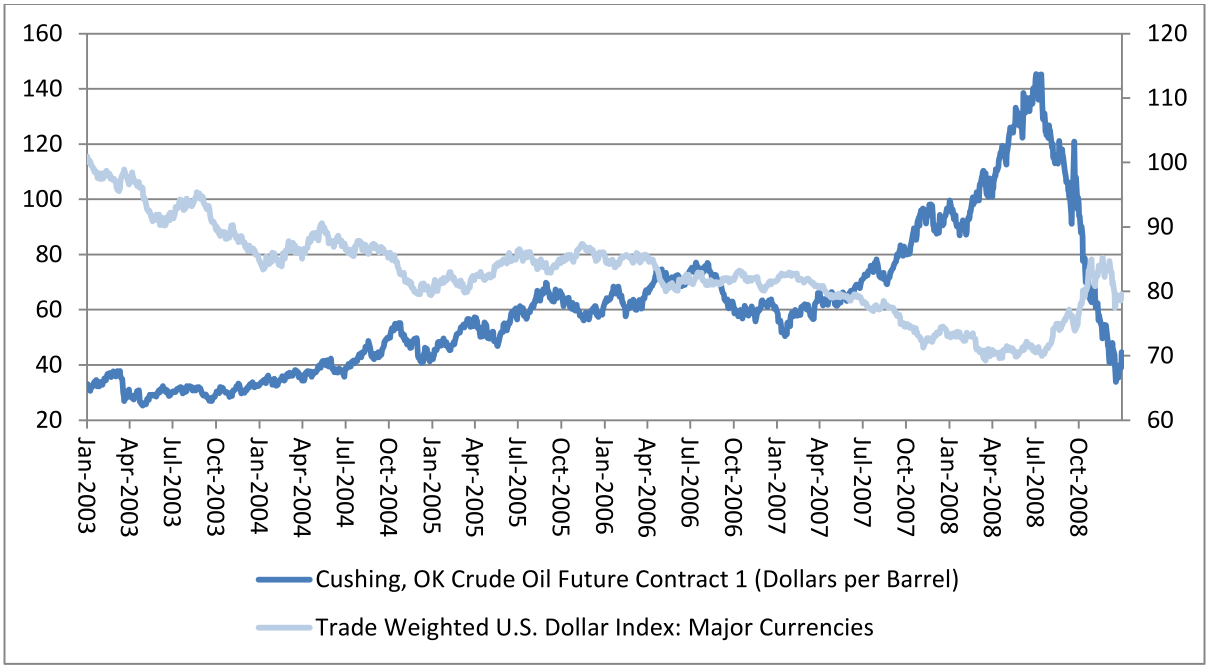

Figure 5.5 WTI and Trade Weighted Dollar Index 2003-2008 (daily). Energy Information Administration and Federal Reserve Economic Data (FRED) NYMEX WTI month 1 contract daily settlement per barrel and Trade Weighted Dollar Index

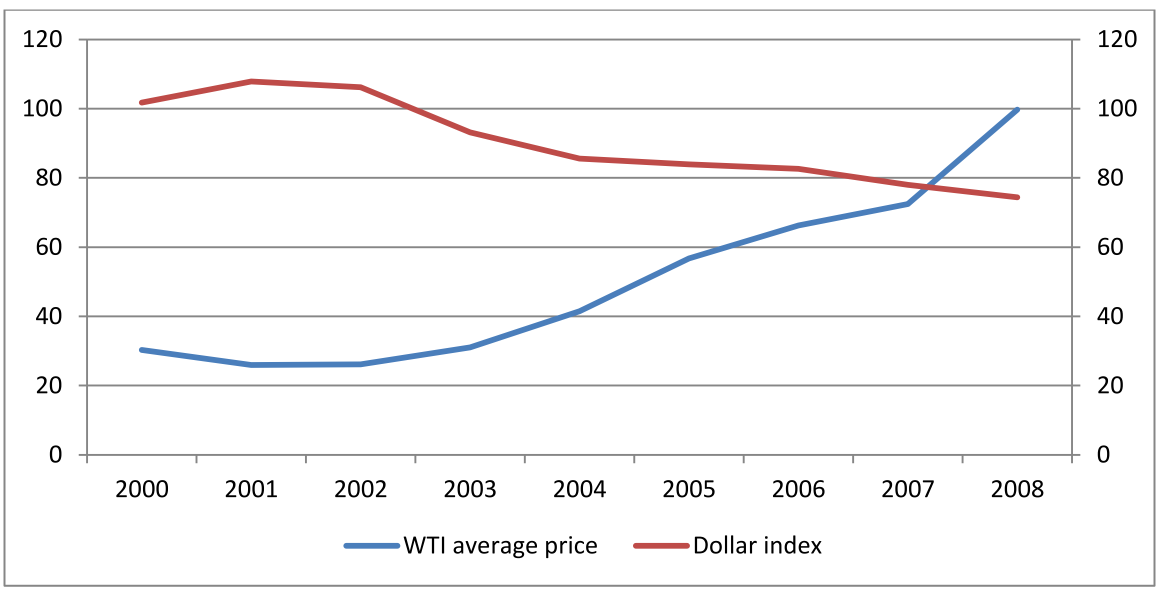

Figure 5.6 WTI and Trade Weighted Dollar Index 2003-2008 (annual). Energy Information Administration and Federal Reserve Economic Data (FRED) NYMEX WTI month 1 contract daily settlement per barrel and Trade Weighted Dollar Index annual average

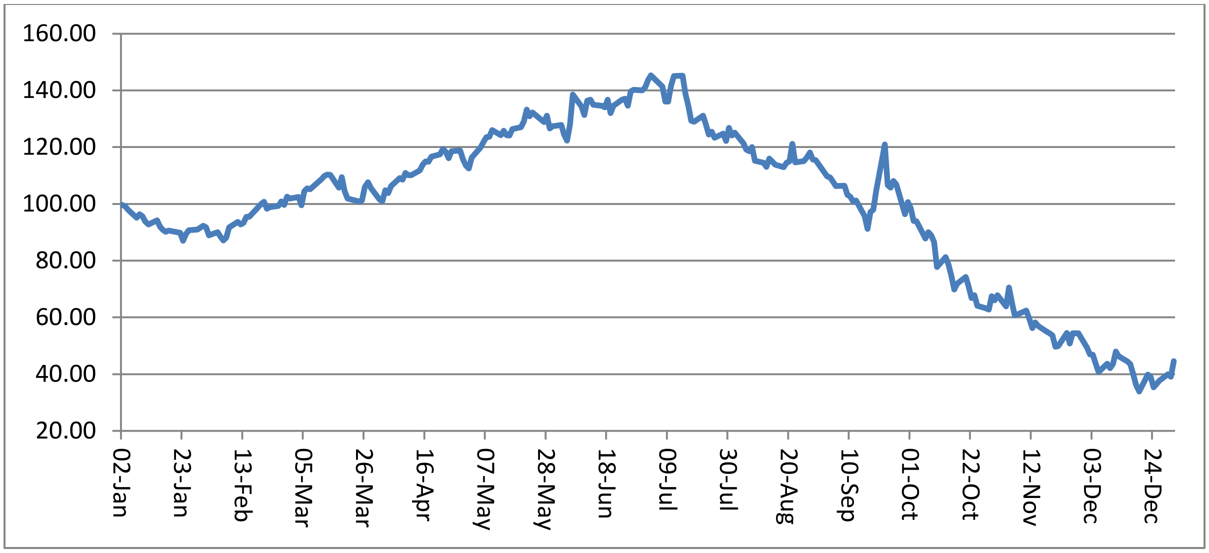

Figure 5.7 WTI 2008 Peak and Crash. NYMEX WTI month 1 contract daily settlement price per barrel

Table 5.1 WTI Price 2000-2008

Year	Min	Max	Average
2000	23.85	37.20	30.27
2001	17.45	32.19	25.95
2002	17.97	32.72	26.15
2003	25.24	37.83	31.00
2004	32.48	43.45	41.47
2005	42.12	69.81	56.69
2006	55.81	77.03	66.28
2007	50.48	98.18	72.41
2008	33.87	145.29	99.75

NYMEX WTI month 1 contract daily settlement price per barrel

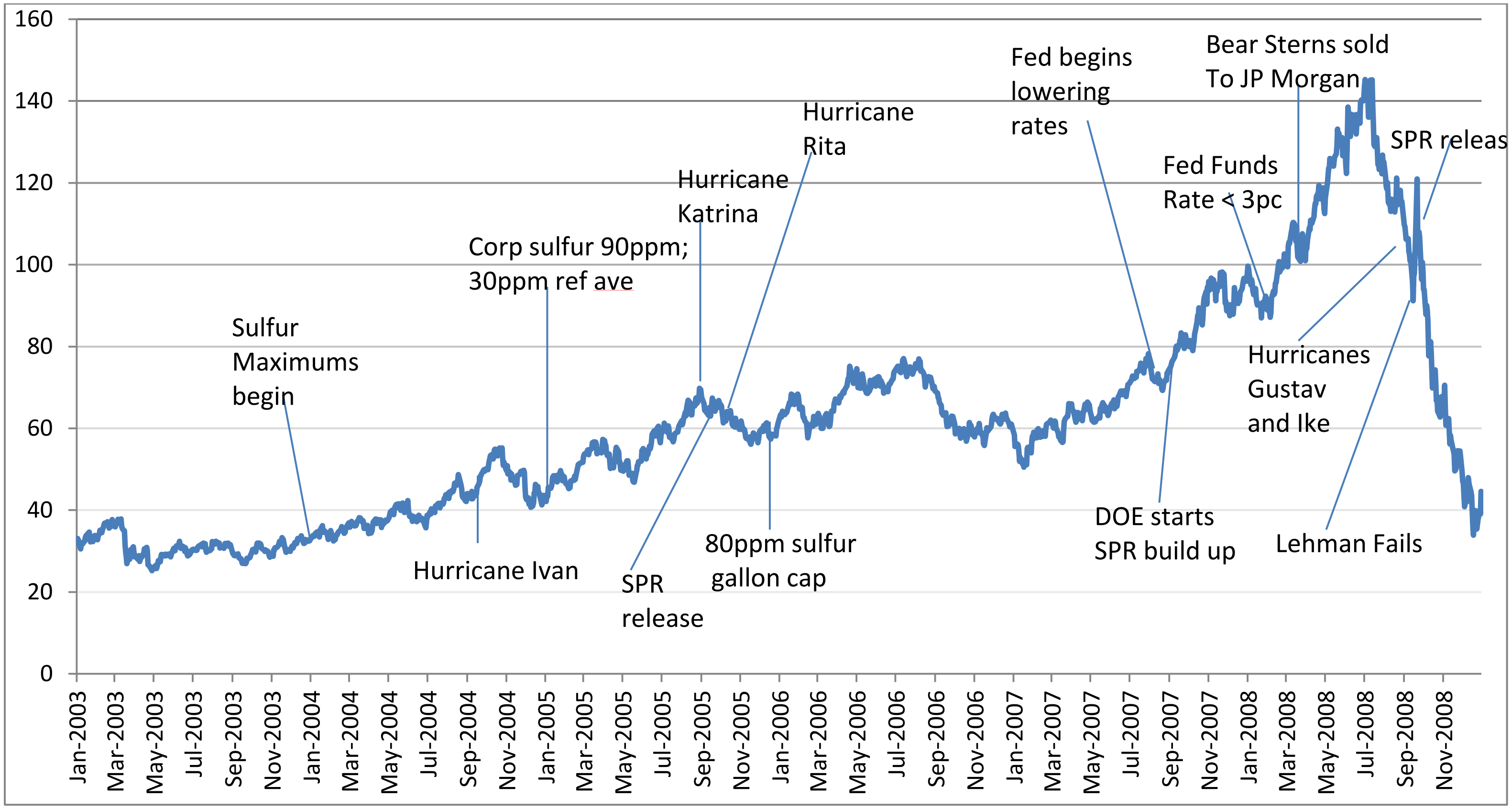

Figure 5.8 Timeline of Crude Oil Price 2003-2008. NYMEX WTI Month 1 contract daily settlement price per barrel

Table 5.2 Change in Oil Supply and Oil Product Demand

Year	Δ oil consumption	Δ non-OECD consumption	Δ China oil consumption	Δ oil supply	Δ OPEC oil supply	Δ supply less Δ OPEC
2000	619	586	314	2632	1457	1175
2001	722	710	94	225	-431	656
2002	917	927	403	-249	-1425	1176
2003	1755	1144	509	2649	1965	684
2004	2845	2065	968	3388	2809	580
2005	1304	941	183	1025	1131	-106
2006	917	1111	514	453	318	135
2007	1412	1612	380	-196	-328	131
2008	-626	989	120	627	1118	-490

BP Statistical review of world energy 2015 Thousands of barrels per day

The Path of Differentials: LLS and Mars

From 1999, the daily differential of LLS to WTI, averaged out over the year to a negligible amount - significantly narrower than a premium or discount of $1/bl, until 2006[64]. Large movements away from the US benchmark are contained to the very end of the trade month, which tends to be the most volatile time of the month.

LLS had an average premium of $1.45/bl to WTI in 2006 and LLS was, on average, at a premium of $3.10/bl to WTI the following year. The rising premium of LLS to WTI provides at least minimal support that the WTI price increases through 2007 were at least somewhat justified by conditions in the physical market. The spot market price for LLS was slightly above the price established in the futures market. This lends some support to the idea that a speculative bubble was not pressuring the price beyond which the physical market could sustain.

[64] All LLS and Mars differentials from Argus Media daily LLS and Mars assessments

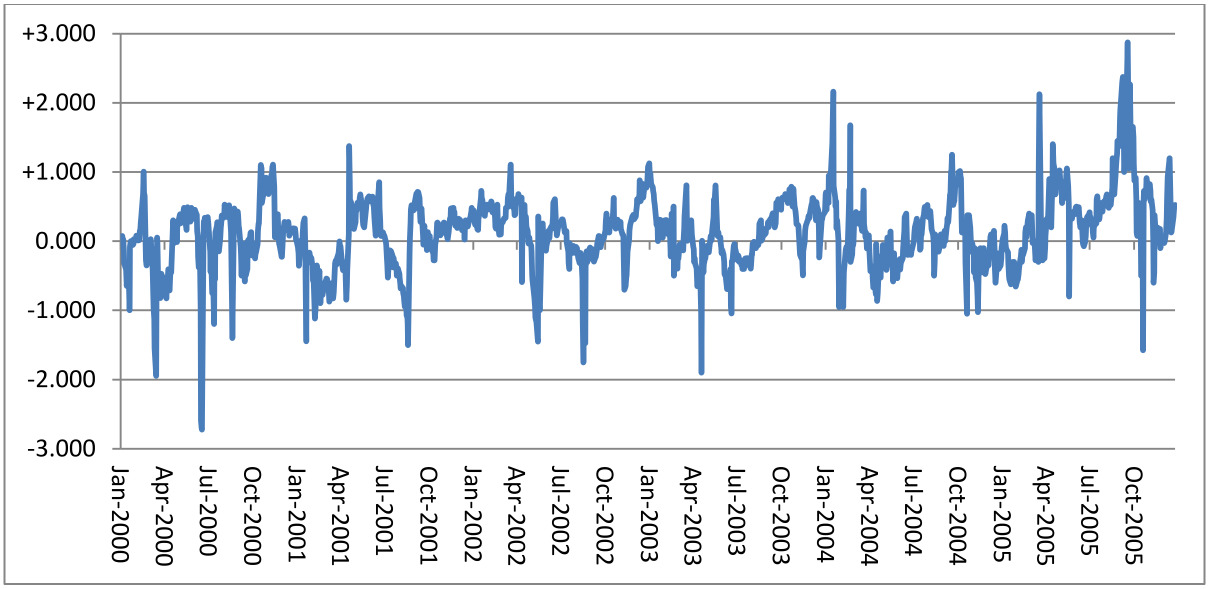

Figure 5.9 LLS Differential to WTI 2000-2005. Argus LLS differential midpoint daily value per barrel Argus Media

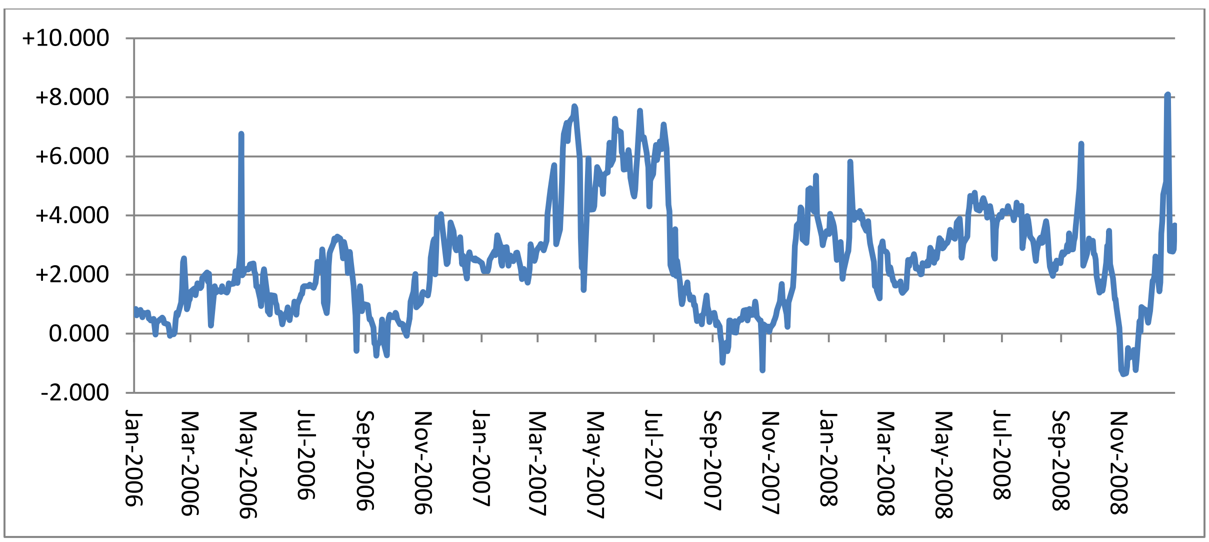

Figure 5.10 LLS Differential to WTI 2006-2008. Argus LLS differential weighted average daily value per barrel Argus Media

Examining the differential for Mars and the spread between Mars and LLS over the run up in the price of crude oil illustrates the relationship between different qualities of crude oil at the US Gulf coast.

The differential for medium sour crude was weakening relative to the price of WTI and LLS over the run-up in prices. From 1999 through 2003, the average yearly differential for Mars ranged from a discount of $2.48/bl to $4.89/bl. The average yearly premium of LLS to Mars ranged from $2.30/bl to $4.85/bl. Similar to LLS, Mars tends to be erratic at the very end of the trade month.

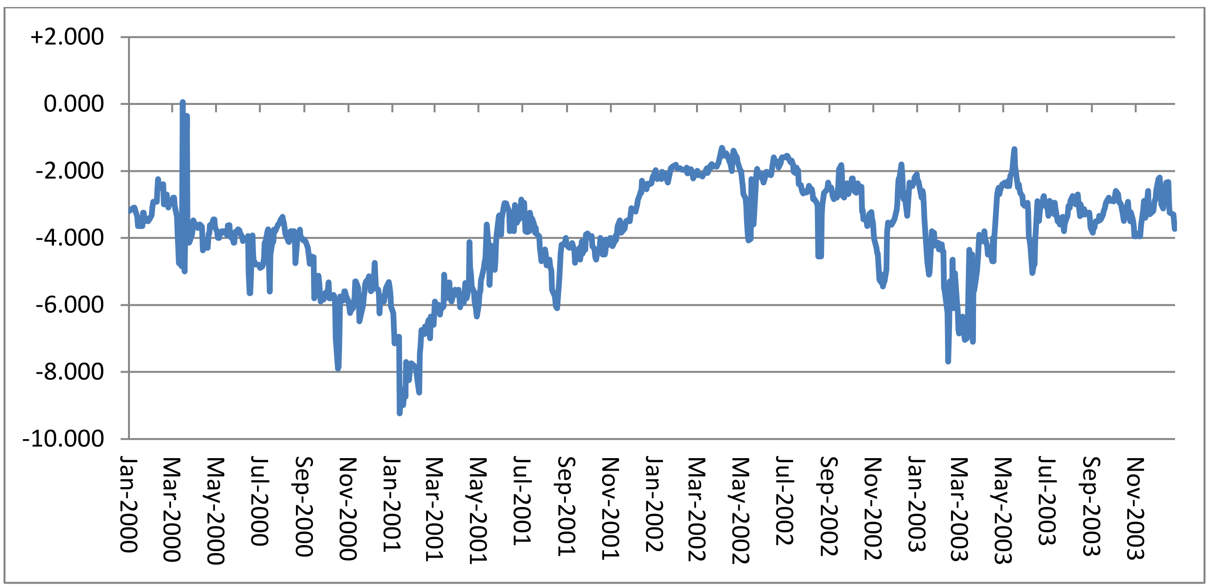

Figure 5.11 Mars Differential to WTI 2000-2003. Daily Argus Mars differential midpoint daily value per barrel Argus Media

From 2004 to 2008, the discount of Mars to WTI and to LLS moved to a new range, with the yearly average over the period between $5.57/bl and $7.07/bl under WTI and from $6.23/bl to $8.91/bl under LLS. The discount of Mars to WTI was the narrowest of the period in 2007 - $5.57 - but the discount to LLS was one of the wider discounts of the period, at $8.67/bl.

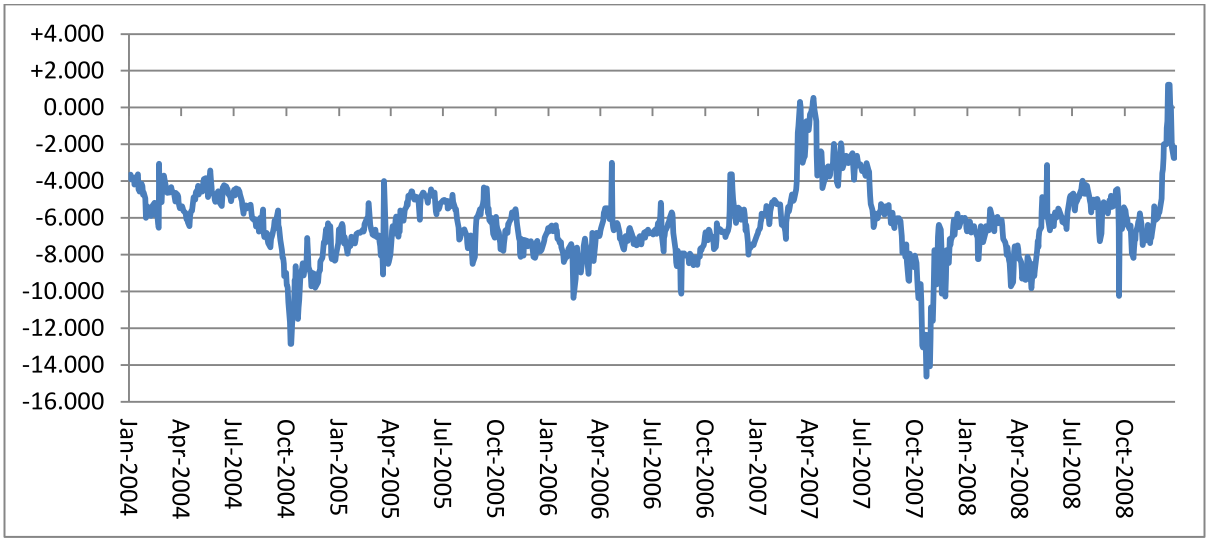

Figure 5.12 Mars differential to WTI 2004-2008. Argus Mars differential midpoint daily value per barrel Argus Media

That Mars weakened away from light sweet crudes from 2004 onwards supports the idea that light sweet crude was becoming more valuable or medium sour less so. From 2004, nearly all the increased production came from OPEC suppliers, many of which are associated with medium and heavy crude oil, as is the spare capacity held by Saudi Arabia. The average yearly Non-OPEC supply change was about 50,000 b/d from 2004 through 2008, and the average OPEC change was 1mn b/d, while the average change in consumption was 1.17mn b/d (BP). The timing also coincides with the introduction of more rigorous sulfur specifications in the US, which began in 2004.

The widening spread between the differential for LLS and for Mars, points to the legitimacy of the WTI price in physical markets, with both achieving larger differentials to WTI, but in opposite directions. The value of LLS at the coast was increasing as WTI was increasing in price, while the value of medium sour crude was falling relative to light sweet crude at the coast and in most years, relative to WTI as well.

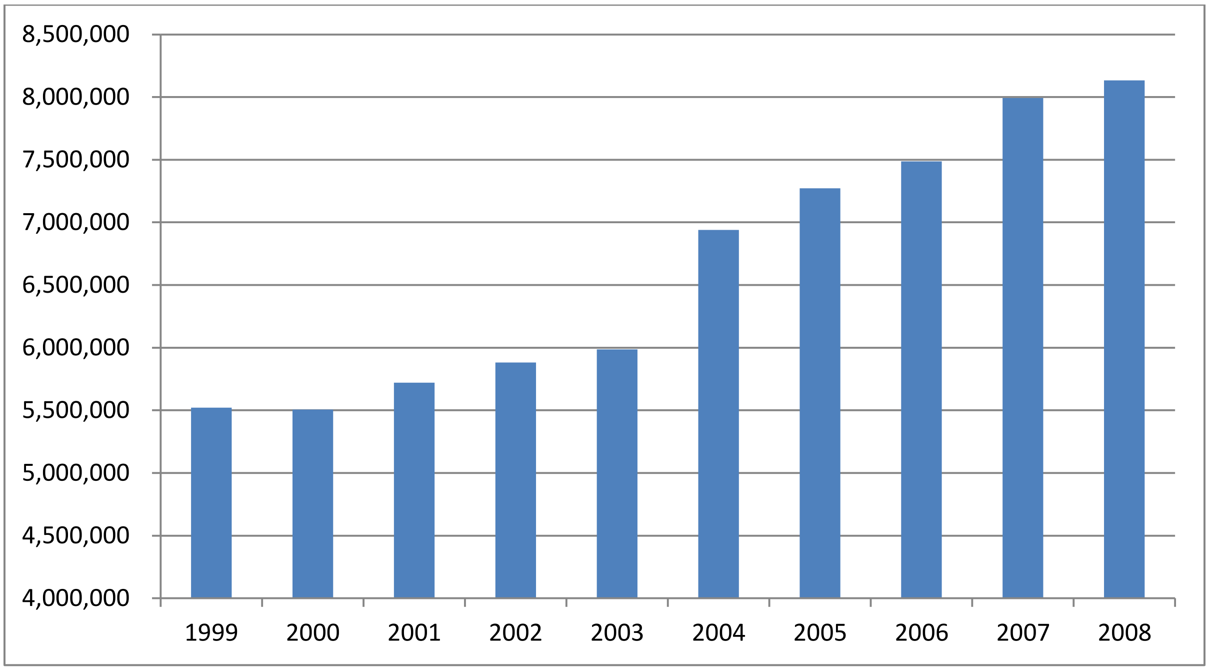

Figure 5.13 Desulfurization Capacity US Gulf Coast. PADD 3 US Gulf Coast Desulfurization Capacity annual data, barrels per day Energy Information Administration

As WTI was rising in 2008, eventually peaking on 3 July 2008 at $145.29/bl, the price of LLS never fell below that for WTI. LLS did fall faster than WTI amid a credit crunch, following the September 2008 Lehman Brothers collapse. Prior to WTI bottoming out at $33.87/bl on 19 December 2008, the differential for LLS reversed, returning to positive territory. As WTI fell farther below $50/bl, the premium for LLS increased, and the discount for Mars to WTI narrowed, with Mars even moving to a premium to a falling WTI, temporarily, indicating the price in the futures market was likely lower than that justified by conditions in the physical market.

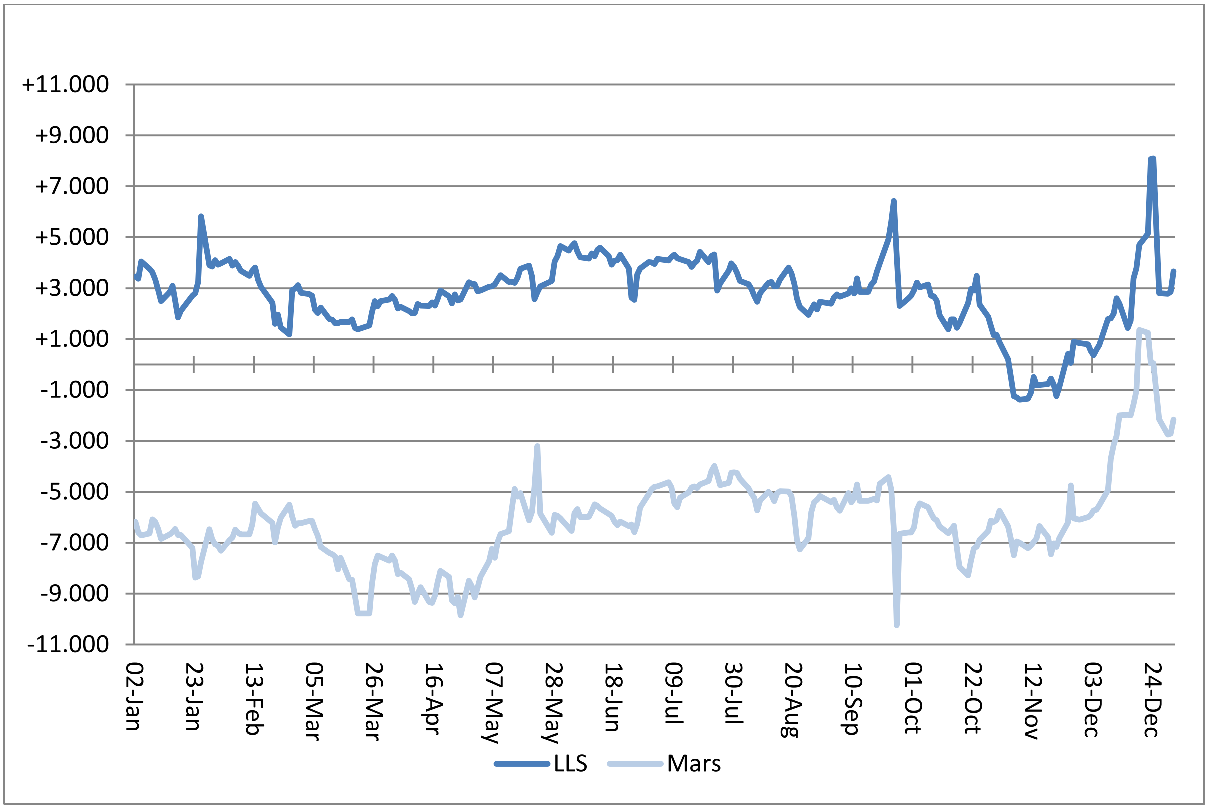

Figure 5.14 LLS and Mars Differential to WTI 2008. Argus Mars and Argus LLS daily differential weighted average, per barrel. Argus Media

Table 5.3 LLS differential to WTI 2000-2008

Year	Min	Max	Ave
2000	-2.75	1.11	0.01
2001	-1.50	1.38	-0.04
2002	-1.75	1.11	0.13
2003	-1.90	1.13	0.10
2004	-1.05	2.16	0.06
2005	-1.64	2.88	0.65
2006	-0.75	6.76	1.45
2007	-1.25	7.70	3.10
2008	-1.38	8.10	2.78

Argus LLS daily differential midpoint, per barrel. Argus Media (author calculation)

Table 5.4 Mars differential to WTI 2000-2008

Year	Min	Max	Ave
2000	-7.90	0.06	-4.34
2001	-9.25	-2.30	-4.89
2002	-5.45	-1.31	-2.48
2003	-7.70	-1.35	-3.60
2004	-12.85	-3.06	-6.16
2005	-8.39	-4.35	-6.16
2006	-10.36	-3.00	-7.07
2007	-14.34	0.54	-5.57
2008	-10.25	1.36	-6.13

Argus Mars daily differential midpoint per barrel. Argus Media (author calculation)

The Path of Prices Post-2008 Crash

Since the peak and subsequent crash in 2008, the WTI price recovered from the lows of the financial crisis and was moving within a steady range. During both the recovery of 2009 and the stability of 2010, the average LLS differential returned to a range of more than $2.50/bl but less than $3.50/bl, while Mars averaged a discount of less than $1.50/bl. Beginning in

2009, the WTI price would periodically recede from other crude oil prices as stocks in Cushing surged. When WTI moved to a large discount to the rest of the world, differentials at the US Gulf coast moved above WTI to compensate.

Even if rising prices, beginning 2003 and continuing into 2008, were not entirely justified by conditions in the physical market, higher prices solicited a response from participants in the oil industry and non-OPEC oil supplies began growing once again. The higher prices justified higher cost production areas, both conventional and unconventional. The increase in production resulted directly from higher price levels.

Horizontal drilling, hydraulic fracturing and ultra-deep offshore drilling in the Gulf of Mexico[65] reversed the downtrend in US oil production[66], which had been on the declining since the mid-1980s. Projects or unconventional methods once considered too expensive were profitable at the higher price levels. Unconventional sources of oil or methods of production include ‘shale’ production, or properly, light tight oil (LTO) and heavy bitumen, or tar sands, typical in the US and Canada, respectively, were uneconomical until the oil price spike of the early twentieth century. Production costs have since declined as unconventional production became routine.

The largest gains in oil production from unconventional methods came from the Eagle Ford, Permian and Bakken production areas. The Eagle Ford formation is in south Texas, the Permian formation is in west Texas and North Dakota is home to the Bakken

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[65] Offshore production growth was stalled by the historical BP oil leak in April 2010. Offshore oil production also has a longer lag between actual output and the decision to take on a specific project, making it less responsive in the short and medium term to oil prices.
[66] While overall US production was falling, production in the Gulf of Mexico continued to grow into the early 2000s.

formation. Shale or LTO, tends to be a higher quality oil, with higher API gravity and low levels of sulfur[67].

An increased level of domestic and Canadian production and an inability to adapt infrastructure as quickly as new production centers arose led to a deep discount between the US benchmark, which represents the cost of light sweet at Cushing, Oklahoma, and the cost of crude oil in the rest of the world. Inland areas of the US had larger supplies than infrastructure could handle, leading to a lower price.

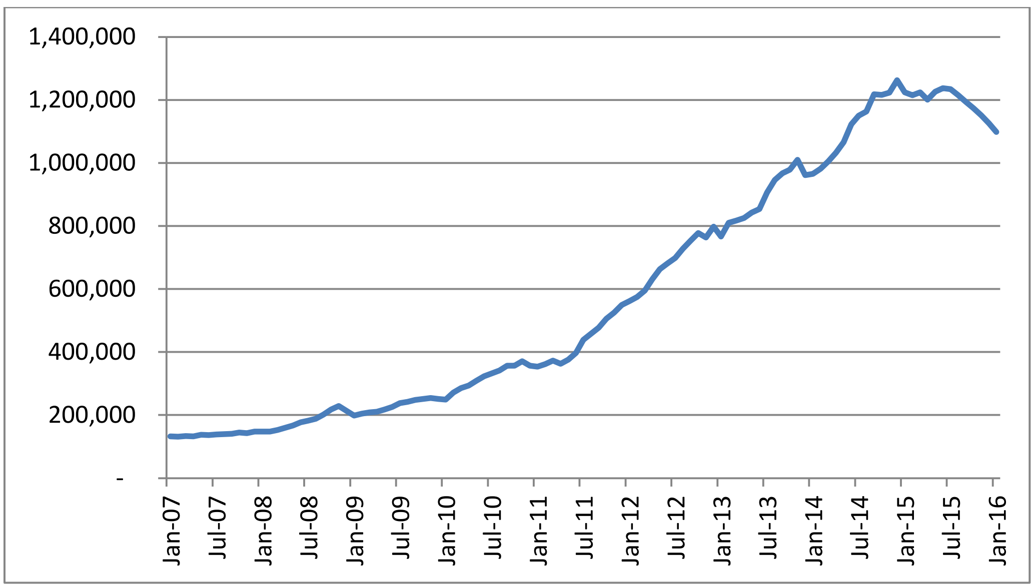

Figure 5.15 Bakken Oil Production. Bakken oil production estimate barrels per day Drilling Productivity Report Energy Information Administration

[67] Canadian oil sands are very heavy crude oil that is typically high in sulfur and can also have higher acids and metals content.

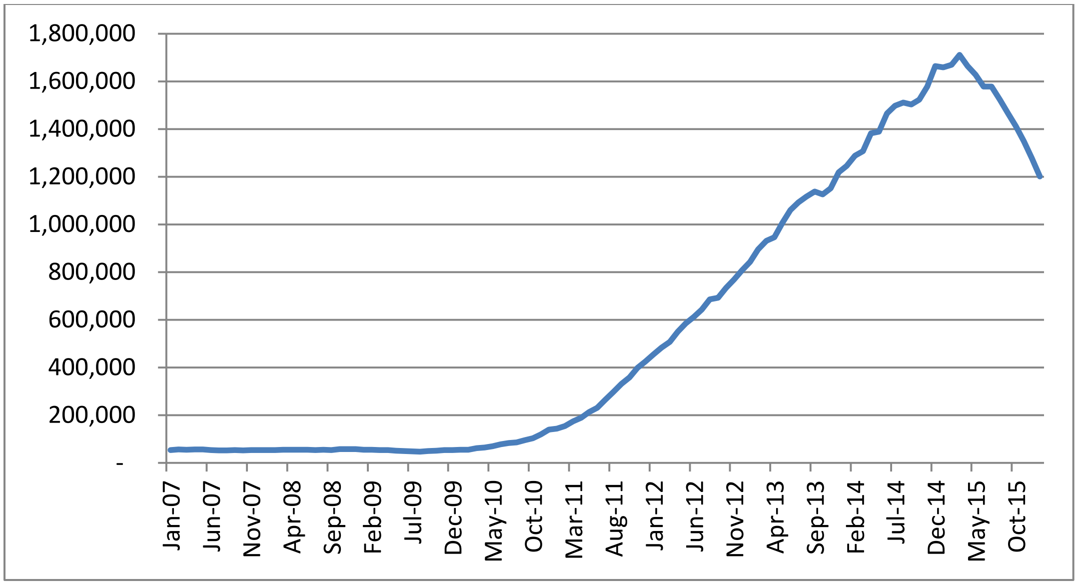

Figure 5.16 Eagle Ford Oil Production. Eagle Ford oil production estimate barrels per day Drilling Productivity Report Energy Information Administration

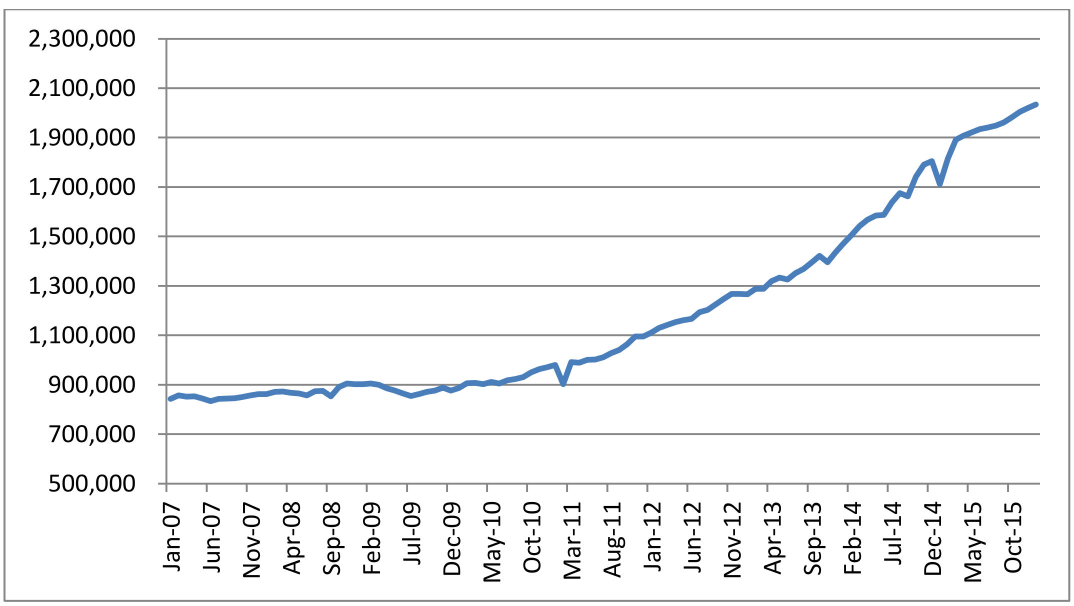

Figure 5.17 Permian Oil Production. Permian oil production estimate barrels per day Drilling Productivity Report Energy Information Administration

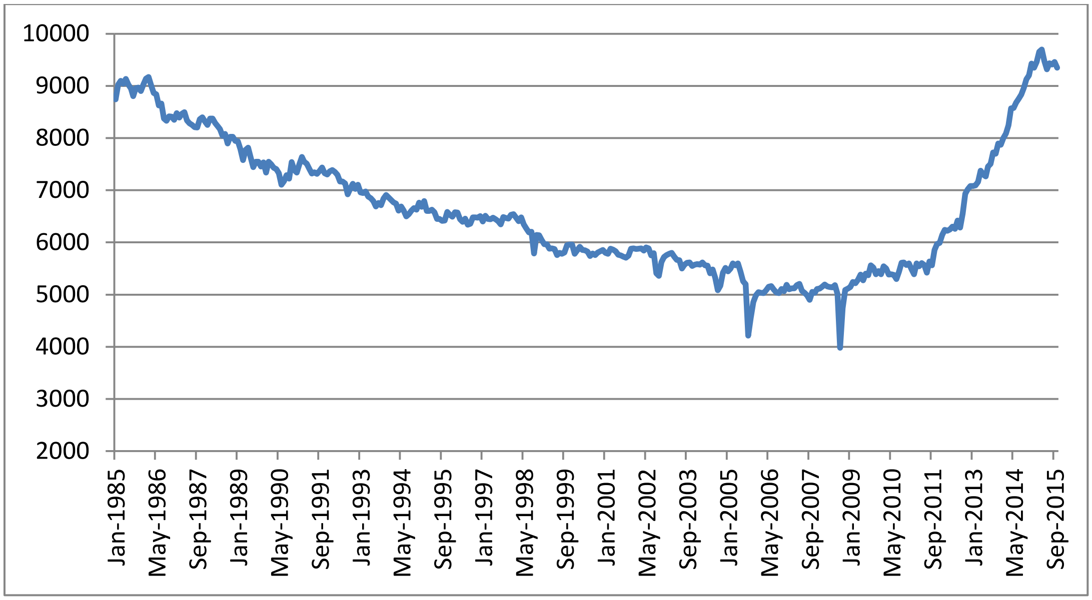

Figure 5.18 US Oil Production. US oil production thousands of barrels per day Energy Information Administration

Much of the Canadian, Bakken and other LTO production was routed to Cushing, Oklahoma, as it is a storage and pipeline hub. However, there were significantly large volumes of crude oil unable to move out of Cushing as fast as new production was arriving.

Owing to the physical context at the pricing point for WTI, the price of WTI in the futures market moved well below the price of oil in the rest of the world, most importantly, the Brent benchmark. The delivery point for WTI was oversupplied with oil and the price in the futures market reflected this situation.

The divergent conditions at Cushing from the rest of the world, including the US coasts eventually caused the Brent or North Sea market to take the title of international benchmark, in contrast to the WTI benchmark, which represented conditions in the middle of the United States, where supplies were growing. WTI fell below the Brent benchmark, by over $20.00/bl at times, because supply was trapped in Cushing, OK.

Pipelines were set up to deliver imports and production from the Gulf of Mexico inland, with several pipelines destined for the Cushing, Oklahoma hub[68]. Midcontinent refiners were connected to the Cushing hub, from where they would get their needed volumes. The larger volumes of inland and Canadian production could not be piped to the refining and storage centers along the US Gulf coast. Eventually inland production and western Canadian production delivered to Cushing oversupplied the hub and the midcontinent generally.

Because the supply was stuck in the midcontinent, differentials at the coast immediately grew in magnitude, reflecting the fact that the benchmark at Cushing failed to represent the value of oil at the coast. The average differential for LLS reflected a very different context, relative to that at Cushing, Oklahoma, at an average premium of more than $17/bl in 2011 and 2012. Mars was representing divergent conditions as well, with average yearly premiums at $12/bl to WTI over the same period. In 2013, the premiums were narrower, with LLS averaging $9.35/bl over WTI while Mars was average $4.25/bl to WTI over the year.

Pipeline owners expanded Cushing storage, reversed existing and built additional pipelines to carry excess crude oil supplies out of the midcontinent and to the Gulf Coast, but

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[68] When US production was falling through the 1980s and 1990s, domestic onshore production became too small to feed both midcontinent and US Gulf coast refiners, leading industry participants to reverse pipelines. Lines began to carry imports from the Gulf to the middle of the country instead of delivering domestic onshore production to the Gulf coast refiners.

building adequate infrastructure took several years. Following greater connectivity from the WTI pricing point to the US Gulf coast, the size of the discount of WTI to ICE Brent decreased. However, until very recently, WTI remained at a discount to ICE Brent, given the higher level of domestic crude production in the US and a ban on domestic crude exports. For most of 2014-2015 WTI was within a $5/bl discount to Ice Brent. WTI moved to a premium to Ice Brent in December 2015 as the US repealed the ban on domestic crude exports[69]. By early 2016, WTI moved back to a small discount to the international benchmark, which spurred an increase in exports and tamed surging imports.

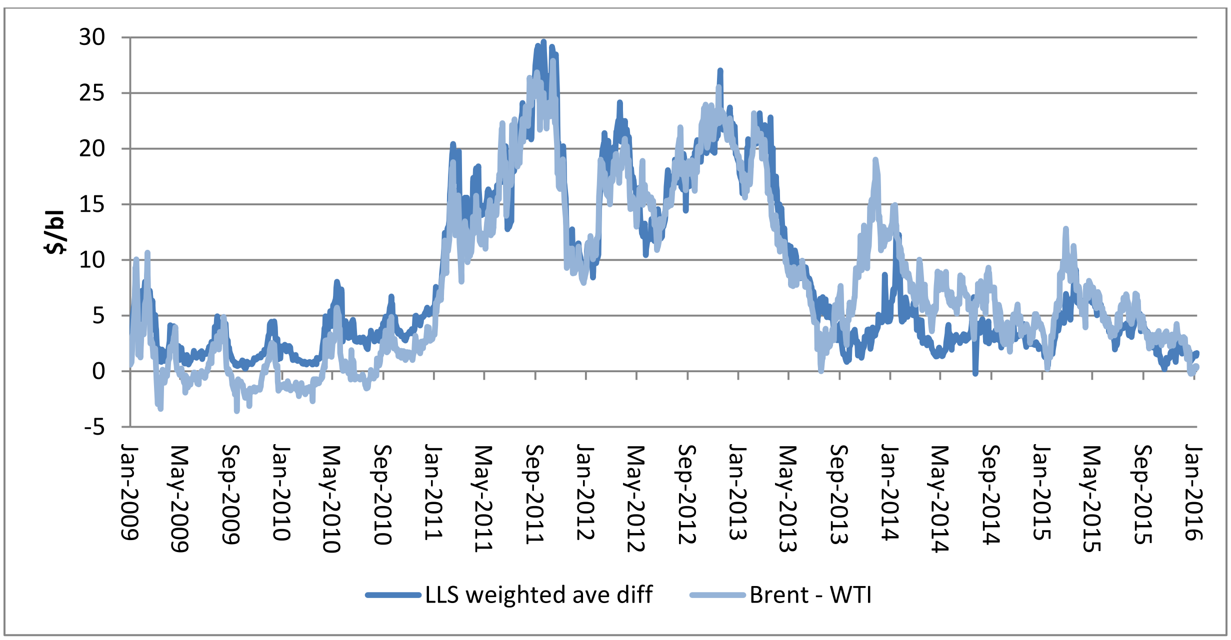

Figure 5.19 LLS Differential to WTI and ICE Brent less NYMEX WTI. Argus LLS weighted average differential and ICE Brent and NYMEX WTI month 1 daily settlement prices per barrel Argus Media and Energy Information Administration

[69] The motivation behind the repeal was narrowing the gap between the US benchmark and international prices, although as WTI moved above international prices, fewer exports were less likely and imports began to increase.

Adjustments to Pricing Imports to the US

Just as physical infrastructure responded to the WTI futures price, producers exporting to the US market changed their pricing formulas as well. The change in pricing formulas can sometimes also happen with a lag, depending on the contract language and length of time covered.

Saudi Arabia, Kuwait and Iraq replaced WTI as their reference price, owing to the deep discount of WTI to the international marker in 2010. The OPEC producers adopted the Argus Sour Crude index (ASCI™) to which they set differentials for their crude oil sales to the US.

The new 'benchmark' price better represents the price of crude oil at the point of import – the US coasts – as opposed to Cushing, Oklahoma[70]. ASCI™ is a volume-weighted average of trade for medium sour offshore crude oils, specifically, Mars, Poseidon and Southern Green Canyon (SGC). Mars is delivered to Clovelly, Louisiana, Poseidon is priced at Houma, Louisiana and SGC comes ashore and is priced at both Nederland, Texas and Texas City, Texas. Differentials for SGC and Poseidon are determined in the same manner as those for Mars and LLS – via spot transactions.

WTI is the reference price of all of the crude oil streams that make up the index. The differential of medium sours at the US Gulf coast compensates for divergent conditions at Cushing, Oklahoma, the WTI marker, and the conditions at the coast. The OPEC producers set an official selling price for sales into the US, which comes in the form of a differential to the ASCI™ price. In setting a differential to the value of ASCI™, OPEC producers maintain

[70] Argus refers to these differentials, to which other crude oil is priced as "secondary benchmarks" (Argus LLS White Paper).

further discretion, and it is through changes in this differential that producers can increase or decrease their market share over time.

Domestic medium sour crude oil cannot compete via price with imports from Saudi Arabia. If sellers in the domestic market agree to sell Poseidon, Mars or SGC at a deep discount to WTI, the price of crude oil from Saudi Arabia will follow the domestic price via a falling value of the ASCI index. If non-ASCI medium sour crude falls in price at the US Gulf coast it is likely that price weakness will spill over onto the value of Mars, Poseidon and/or SGC, thereby pressuring the ASCI index weaker.

Rising US production changes global market

Despite a ban on US crude exports, existing from the 1970s through to late 2015, US production ultimately helped usher in the current era of oversupply. As US production continued, the US market required fewer crude imports. Imports of crude oil to the US peaked at just over 10mn b/d, using annual EIA data. From 2004 through 2007, crude imports were over 10mn b/d (EIA US imports of crude oil, annual, b/d). Imports have fallen every year since 2010 with the largest annual decline occurring in 2013, when imports fell to 7.7mn b/d from 8.5mn b/d in 2012. The average of monthly import data for 2015 is 7.3mn b/d. Crude imports to the US fell by an average of 467,000 b/d each year from 201 through 2014. An additional change, not captured in aggregate imports, is the change in the composition of US imports. As Canadian production increased, imports of Canadian volumes to the US grew, changing mix of imports to the US, and causing additional producers to find new buyers. Increasing Canadian imports (see figure 5.21) and overall declining levels of imports to the US equates to nearly 3mn b/d of international production that has been replaced by US refiners.

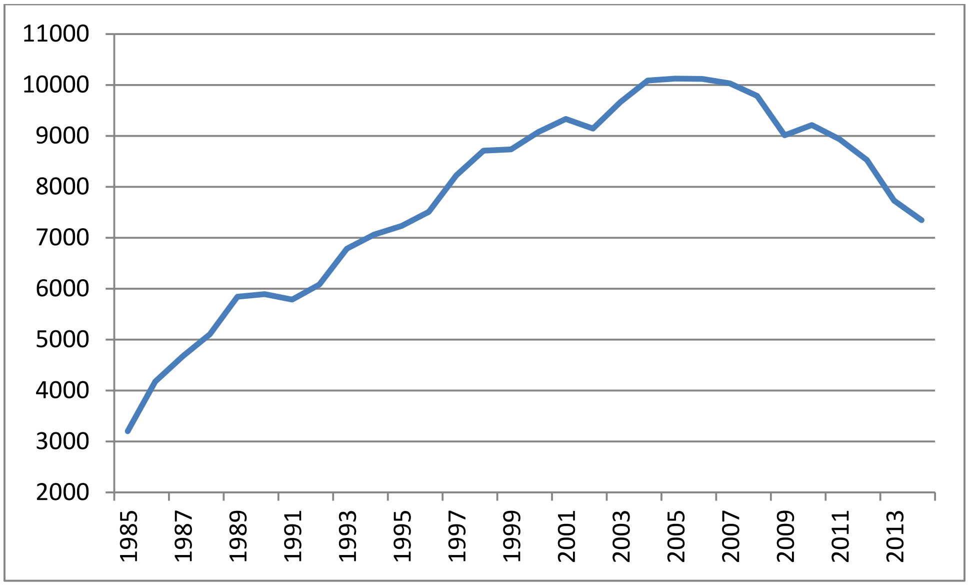

Figure 5.20 US Crude Oil Imports 1985-2014. Crude oil imports to the US thousands of barrels per day Annual average Energy Information Administration

By 2014 the excess global supply of crude oil was more than apparent and prices began to drop in response, near the end of the US gasoline season, after peaking at $107.26/bl in June 2014[71]. Prices were nearing $75/bl as market participants awaited the outcome of the OPEC decision after their November 2014 meeting.

[71] All NYMEX WTI and ICE Brent price are daily settle prices pulled from the EIA.

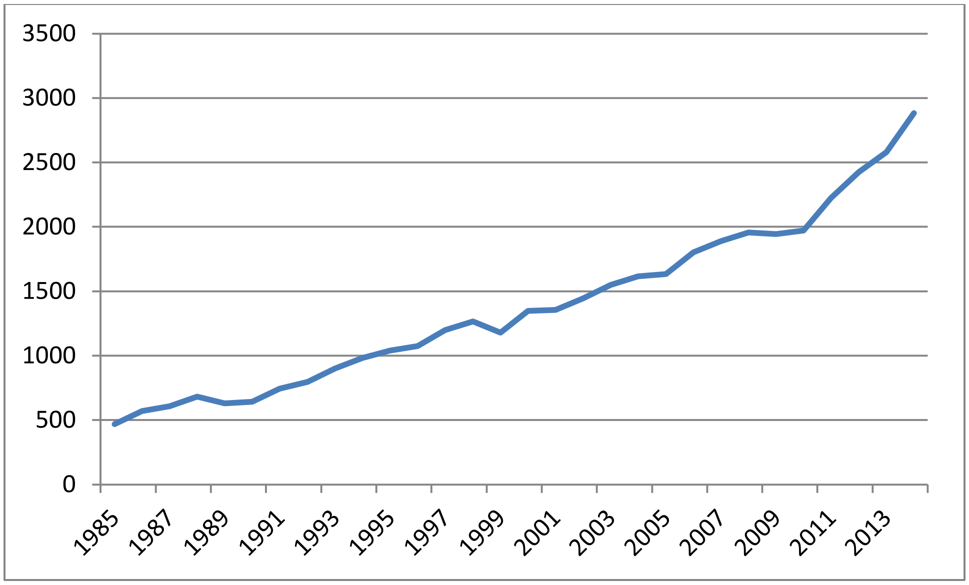

Figure 5.21 Canadian Crude Oil Imports to the US 1985-2014. Canadian imports to the US thousands of barrels per day Annual data Energy Information Administration

At the meeting, Saudi Arabia declared their intention to maintain their market share, rather than engage in the structurally changed market as a swing producer. Following the OPEC announcement not to reduce production levels, the price of oil resumed falling, until it bottomed out in the mid $40s in early 2015. The price then quickly recovered to $60/bl to $65/bl for some time, induced higher by the growing contango in the market.

As the supply overhang continued and storage volumes increased, by the end of 2015 prices had slipped once again to the upper $30s and early 2016 saw prices fall into the $20s/bl, as Europe lifted Iranian sanctions and fears over global growth increased. Overall production has been slow to respond to the lower price level, also aiding in the move to lower prices.

The recent change in the level of production is not a period of temporary oversupply, for instance, brought about by a recessionary-induced drop in demand. Rather, production has increased via conventional and unconventional methods such as hydraulic fracturing, the use of horizontal and directional wells and mining for heavy Bitumen in Canada. The higher prices brought about a structural change in the market. If Saudi Arabia had continued to pull back production to make room for recent increases, an end-date, at which point they would regain their market share, was not in sight.

Saudi Arabia faced a similar decision in the 1980s, and they eventually chose to fight for market share via netback pricing. At the time, they abandoned the pricing method they had supported previously – OPEC-administered pricing. Production in OECD countries responded to the lower price levels.

Saudi Arabia is using the current pricing method to maintain their share of the market, by accommodating demand as the price falls lower, in part because of their decision to fight for market share. The current pricing method arose under a condition of oversupply and appears to be well-suited for dealing with the current situation. Several independent US producers have yet to respond in the way the market expected: slashing production. Overall US production is falling extremely slowly and some individual participants have increased production to attain higher revenues in a lower price environment. Independent producer that alone do not produce enough to move the market price are incentivized to increase production when the market price falls in an attempt to maintain revenue.

Prices had stabilized in the $60/bl range in 2014 under the assumption that US shale production was too expensive to continue production at that low price level. However, the costs of production have fallen as service companies reduce prices, the most productive areas become the only areas of expansion and attempts at efficiency gains begin. Moreover, since some producers hedge in the financial markets, they were obtaining far greater revenue than sales of physical oil provide. Some producers locked in higher prices in the futures market before the price collapse and during the recovery in the $60s/bl. So far, shale production has yet to respond the way the market anticipated, leading prices to drop well below the $60/bl range.

In every OPEC meeting since November 2014, Saudi Arabia has reiterated the plan to defend market share rather than price. As the low cost producer, they are unwilling to lose market share to high-cost production areas over the long term by supporting an artificially high price.

While production will respond over time, it is possible every sustained price recovery leads to a jump in production thereby destroying the recovery that made growing production possible. Moreover, significant volumes currently sit in storage, and this storage will likely make it to the market when prices rise.

Light tight oil production can be 'turned' off and on more quickly and easily than traditional deposits of oil. Since the oil is trapped in rock, the production can be quickly brought online as soon as the rock is fractured, as long as a well has already been drilled[72]. Additionally, light tight oil has decline rates that are significantly faster than traditional oil wells, meaning if producers do not continue to drill more wells, production declines faster than in traditional fields.

[72] Relative to traditional production in the US

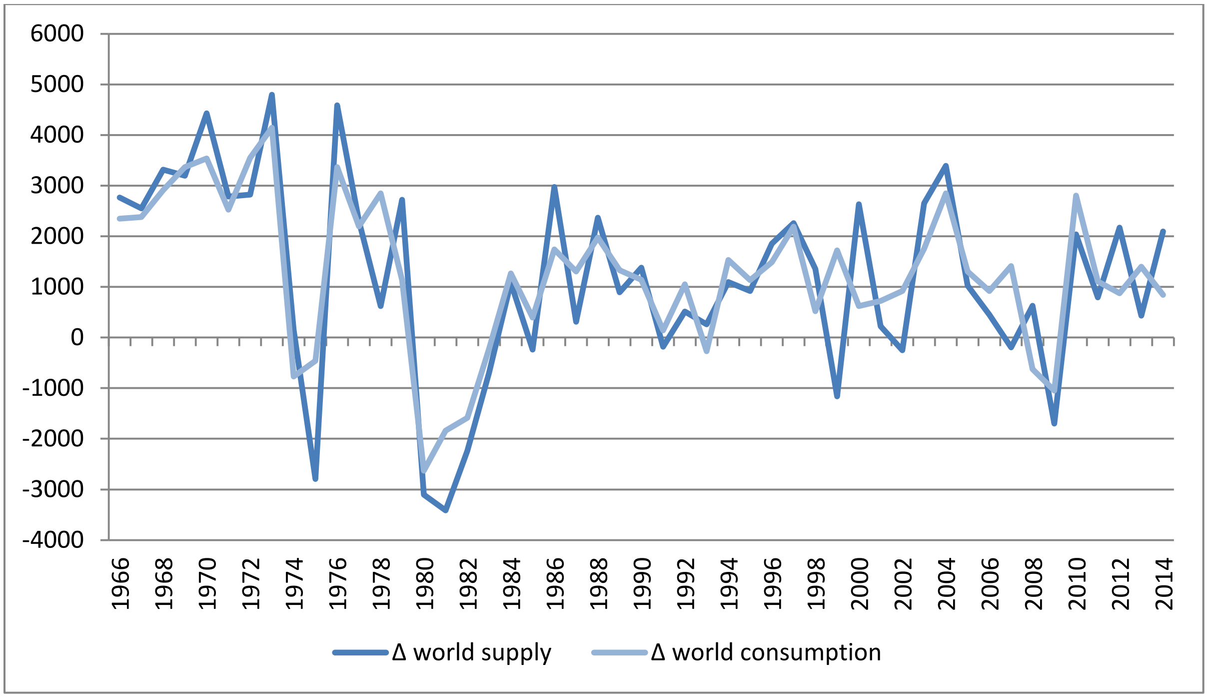

Figure 5.22 Change in Oil Supply and change in Oil Product Consumption. World oil supply and world oil production consumption thousands of barrels per day. BP Statistical Review of World Energy 2015

The activities futures markets participants necessarily *influence* the price of physical oil. However, feedback exists between the two realms, and many, if not most, oil companies operate in both the financial and physical markets for oil. Regardless of the cause of the behavior of the run-up in the price of oil futures contracts, the connections between the futures market and the physical market leads participants in the physical oil market to respond to prices determined in oil futures markets.

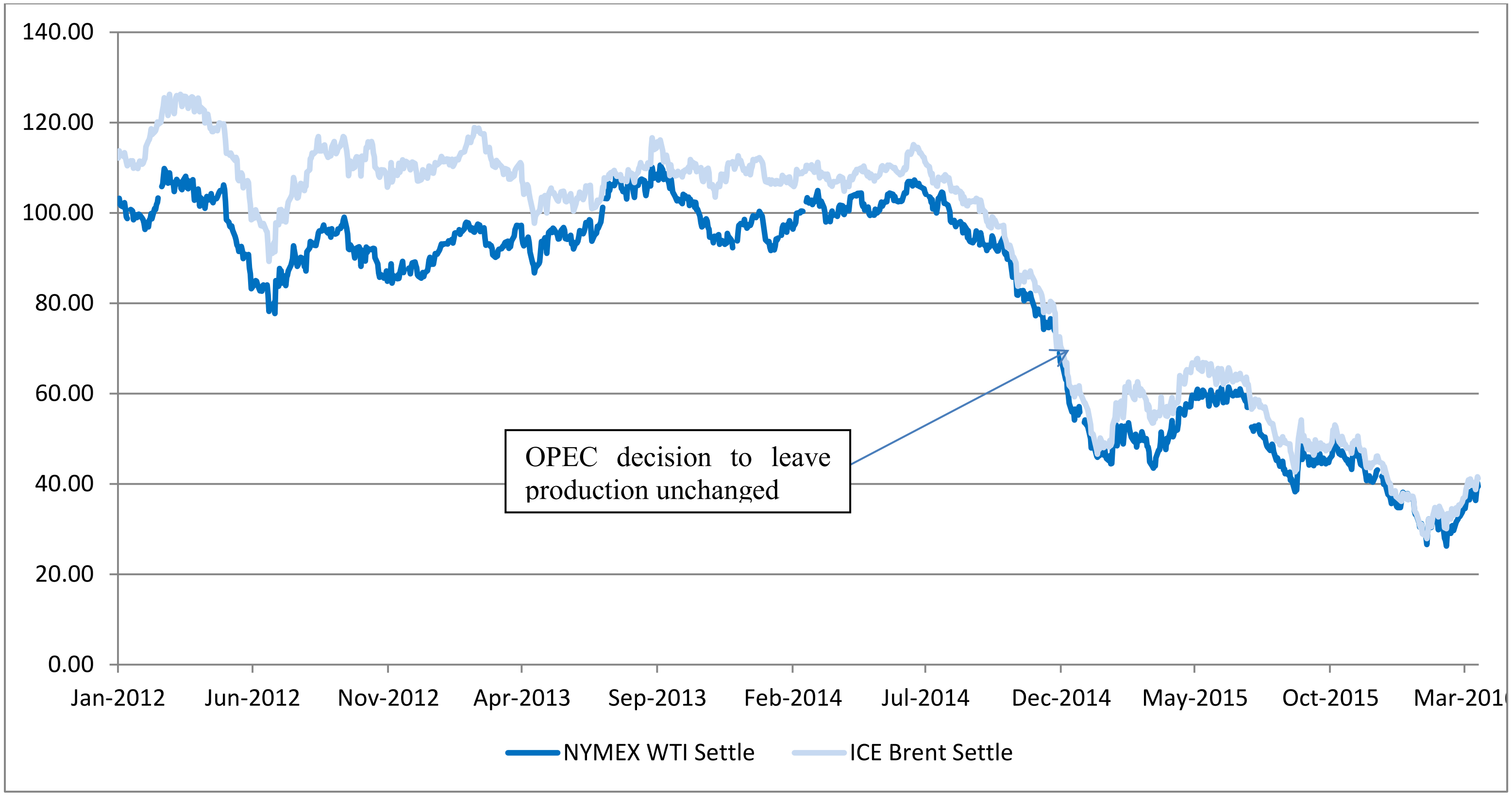

Figure 5.23 NYMEX WTI and ICE Brent Jan 2012 – March 2016. NYMEX WTI and ICE Brent month 1 contract daily settlement price per barrel

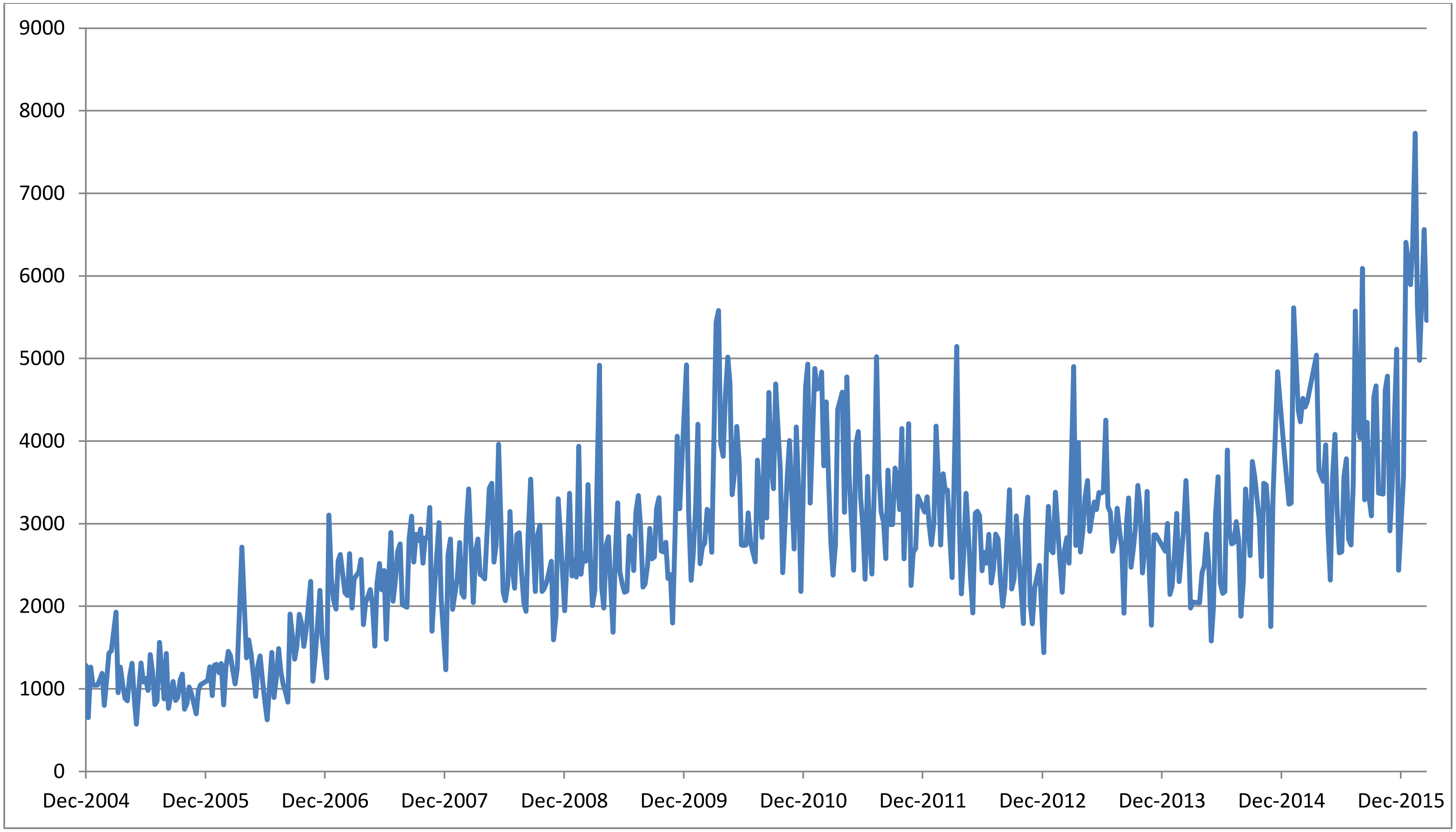

Figure 5.24 NYMEX WTI Open Interest 2005-2015. Total open interest in NYMEX Light Sweet Futures contract one-thousand barrel contracts weekly data Commitment of Traders (COT) CFTC

CHAPTER 6

CONCLUSIONS AND FURTHER RESEARCH

An accounting of the structure, details and development of the oil pricing method illuminates some limits to the activities of purely financial participants on the price of oil in physical markets. An examination of the relationship between the basis and the differential at the US Gulf coast illustrates the constraints of the speculative group of players by emphasizing the role of oil market conditions on the outright price of oil as well as the involvement of physical market participants in the pricing of crude oil. Lastly, the method of crude oil pricing encourages a uniform price via cointegrated reference prices.

The constraints to financial investor-activity on the physical price of oil are four-fold. First: the futures market relates to a specific physical market, which influences the futures price. Second: the exchange of physical oil nearly always entails at least one differential to the reference price, possibly including a value the producer determines. Third: industry participants change the physical market in response to both prices determined in the futures market and differentials. Lastly and most importantly, industry participants put the method in place and they continue to make adjustments as they see fit, including adopting financial markets in the pricing process and supporting electronic trading, thereby opening up financial markets beyond the traditional ‘speculators’ on a trading floor.

The first constraint arises from the connections between the futures market and the specific physical oil market related to a particular financial market. The Ice Brent contract price is determined via forward trade for cargoes and partial cargoes of physical North Sea oil, while the NYMEX Light Sweet contract relates the futures price to the physical light sweet market at the storage and pipeline hub, Cushing, Oklahoma. The deliverability of the NYMEX contract ensures that the price of light sweet crude at Cushing, Oklahoma is identical to the price in the futures market.

The influence of the physical oil market at the benchmark location becomes clearest in the most extreme of circumstances, for example when the WTI benchmark moved below other world market prices as physical oil saturated the middle part of the US. The price accurately represented the price of physical oil at Cushing, Oklahoma. However, reference prices move together, as many others have shown, and in that sense, WTI as a reference price 'failed'.

The strong connection between the futures market and the physical oil market at Cushing, Oklahoma was the direct cause of what has been labeled the "disconnect" of WTI from prices in the rest of the world. WTI, despite being a reference price with a large financial market, remains receptive to physical market conditions in Cushing, Oklahoma. The physical market context at the location attached to the futures contract constrained the price of the futures contract.

While the futures market and financial flows absorbed therein, forms a part of the price of the great majority of physical crude oil sold across the globe, a physical oil market at the delivery location of the futures contract grounds the futures price. Moreover, if the physical market price diverges from the price in the futures market, physical market participants are likely to respond. Given that physical oil market participants are active in financial oil markets, a discrepancy in the two should close as physical market participants move between financial and physical trade.

Spreads between reference markets also encourages physical movements. Following the removal of the US ban on US crude oil exports, NYMEX WTI went to a premium to ICE Brent, causing a surge in foreign imports, since imports were advantageous to domestic supplies, as foreign crude uses ICE Brent as a reference. US imports and commercial stocks of crude oil surged in December 2015 and WTI moved back to a discount to ICE Brent shortly thereafter.

Differentials provide both price signals and flexibility to the reference price system. Part of this flexibility insulates physical oil markets from a potentially unrepresentative reference (or futures) price. Differentials respond to local market conditions, including adjusting away from an unrepresentative reference price, as happened at the US Gulf coast beginning in 2009.

Large moves in differentials can be in either direction, as crude oil throughout the midcontinent that lacked infrastructure to move to the coast or to Cushing, was discounted heavily, even to a relatively low WTI price. These large discounts spurred the return of transporting crude oil by rail and increased the amount of crude oil transported and distance traveled by truck. Following the construction of sufficient pipeline capacity for the formerly stranded production, the higher cost of rail and trucking were no longer captured in what became a smaller differential.

Differentials behaved precisely as they should when the benchmark price does not represent the context of a specific physical oil market in another location. The increase in the magnitude of differentials and the responses of market participants to this change, further illustrates the influence of the physical market conditions on the price of oil.

Producers and other industry participants responded to changes in both futures market and pricing differentials to adapt to a changing physical market. Growing production in the US resulted from the action of industry participants responding to the higher prices of the previous decade. Market participants built out infrastructure following the surge in production, which the price of WTI and differentials illuminated as an issue.

OPEC members maintained the current pricing method, but adjusted the reference price for imports to the US, in response to an unrepresentative basis price. However, in adopting the ASCI price, Saudi Arabia did not abandon the WTI reference price, but rather added an adjustment value to it. In using ASCI, rather than raising producer-determined differentials, they did not have to predict the values that would arise in the spot market. Had they instituted large premiums, it would have been difficult to keep premiums competitive. Additionally, with Mars averaging $12/bl over WTI, the size of the producer-determined premium may have drawn unwanted attention.

Market participants chose to adopt the NYMEX futures prices as the reference price in US contract markets. Prior to Koch cancelling their posting in 2006, the posting was already set it in line with the NYMEX CMA. Once the posting was cancelled, market participants moved to the NYMEX CMA pricing reference. The Phillips66 posting is a somewhat common price used to exchange physical WTI and other types of crude oil. The

Phillips 66 posting is \$3.38/bl under the NYMEX CMA. Some Postings contracts use a combination of posted price and spot market trade to determine the postings plus.

Spot markets had originally existed alongside contract market owing to the rise of independents, national oil companies, tax-spinning and declining integration among vertically integrated oil companies (Fattouh 2011; Mabro (Ed.) 1986; Mabro (Ed.) 2005 Chapter 3 Fattouh, 52). Price competition between spot and contract markets arises periodically during periods of perceived or feared shortage or during periods containing excess supply (*Ibid*). Spot-market determined contract prices reduce price competition between the two types of markets, while using a common reference price assures greater price uniformity.

Since differentials in spot markets set the price in contract markets, participants are privy to prices in spot markets and can match any discounts arising from sellers of non-WTI grades. Smaller producers cannot compete for market share via price because the transparent nature of spot markets illuminates price cuts, nearly immediately.

Exchanges of WTI alongside Mars, LLS and other grades in the spot market, eliminate the ability of independents to 'dump' production in the price-setting spot market. In the domestic US markets, independents remain a significant influence. If independent producers bring down the price of WTI in an attempt to compete for market share via price discounts, market participants immediately match discounts simply by using the WTI price as a reference price.

The 'financialization' of oil occurred through historical time within a given context, including both the opening up of commodity markets and the legal changes required for unsophisticated investors to buy commodity futures. Moreover, the financialization of oil pricing, i.e., using futures prices in the pricing of oil, was a deliberate choice, made by producers and other vested interests within the oil industry. Financial investors, using technical trading techniques, fundamental data, dollar-hedging or any other variable to trade oil futures cannot alone dictate the price of physical oil. Physical market responses to the price of oil determined in the futures market.

When viewed through the lens of the current pricing method, crude oil markets begin to look much more like those of manufacturing, where agents within the market erect and maintain institutions that impute structure to a market thereby reducing price instability as well as uncertainty.

That benchmark prices were cointegrated was one of the few points of consensus emerging from the empirical literature related to the oil speculation debate. The international oil market is then highly connected via the reference prices of oil, resulting in some semblance of price uniformity. The use of spot market differentials in contract prices also aids in market-price uniformity among contract sellers and between spot and contract sellers.

Further research on the similarities and differences between the method of pricing commodities and that for pricing manufacturing goods is overdue. Commodities are distinct from manufacturing markets, as the price is constantly changing and sellers of the same type of crude oil are selling a nearly identical product. However, similar to the activities of manufacturing companies, market participants have put mechanisms and structures in place to help stabilize the market by encouraging uniform prices and minimizing excessive price competition.

This dissertation has only touched on the subject of commodity pricing, as it related solely to oil. Other commodities are likely to have similar methods of pricing, with some distinct differences. Further research is required on the similarities and differences in the methods of pricing a variety of other commodities, through an historical perspective, where industry participants establish and adjust market institutions, including those related to pricing.

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