Decomposing Crude Price Differentials: Domestic Shipping Constraints or the Crude Oil Export Ban?*

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Abstract

Over the past decade the U.S. domestic crude benchmark, WTI, diverged considerably from its foreign counterpart, Brent. Some studies pointed to the crude oil export ban as the main culprit for this divergence, but pipeline capacity was also scarce during this time. To understand the drivers of domestic crude oil discounts, we estimate the extent to which transportation constraints can explain price differentials. We find that scarce pipeline capacity explains half to three quarters of the deviation of mid-continent crude oil prices from their long-run relationship with Brent crude. We are unable to find evidence that refining constraints contributed significantly to this differential. This implies that the short-run deleterious effects of the export ban may have been exaggerated.

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1 Introduction

In 1975, United States President Gerald Ford signed the Energy Policy and Conservation Act (EPCA), which prohibited the export of domestically produced crude oil and created the Strategic Petroleum Reserve. Decades later, in the late 2000s and after many years of declining U.S. crude oil production, the combination of horizontal drilling and hydraulic fracturing techniques enabled companies to produce oil and gas from geological formations that had been, heretofore, uneconomic. This technological innovation sparked a production renaissance; by the end of 2014 U.S. production had reached levels not seen since the 1970s.

As U.S. production rose, price differentials between domestic and international crudes grew to unprecedented levels. At its peak, the most widely cited U.S. crude benchmark, West Texas Intermediate (WTI), was trading at more than a $25 discount to the international benchmark, Brent crude (see Figure 2). The unprecidented differential spurred a robust debate over the cause of the steep discount and whether it could be eliminated by removing the export ban.

In December 2015, the export ban was lifted. While the policy change was heavily debated, those for and those against lifting the ban tended to associate it with the domestic crude discount. Those against lifting the ban argued that allowing crude exports would cause increases in domestic refined product prices, like gasoline, and they argued that exporting crude would reduce the the security of the nation's energy supply. Proponents of lifting the ban refuted these concerns. First, they argued that exporting crude oil would not increase gasoline prices; if anything it would lead to a decrease in gasoline prices (Yergin et al., 2014; Ebinger and Greenley, 2014; Medlock, 2015).[1] Second, they argued that increasing domestic prices to parity with international ones would spur new investment and oil production, creating hundreds of thousands of domestic jobs Yergin et al. (2014); Ebinger and Greenley (2014).[2]

Counter to the conventional wisdom of the time, our analysis points to pipeline constraints as the primary cause of domestic crude price discounts.

Two competing explanations Two widely cited studies in support of lifting the export ban (Yergin et al., 2014; Ebinger and Greenley, 2014) argued that the ban contributed significantly to this price differential. Their explanation for this phenomenon can be summarized as follows. Refineries in the U.S. are able to purchase both foreign and domestic crude, as there is no ban on the import of crude oil, only its export. Because domestic and foreign crudes are substitutes in production, the two generally trade at similar prices. After decades of declining domestic crude

[1] For example, Yergin et al. (2014) argued that "By boosting global supplies, the elimination of the ban will result in lower global oil prices. Since US gasoline is priced off global gasoline prices, not domestic crude prices, the reduction will flow back into lower prices at the pump–reducing the gasoline price 8 cents a gallon. The savings for motorists is $265 billion over the 2016-2030 period."

[2] For example, Yergin et al. (2014) estimated that the lifting of the ban would create 1 million jobs, increase GDP by $135 billion, and increase per household income by $391 in the US.

oil production, domestic refineries had gradually reconfigured themselves to process avaiable imported crudes that were more viscous and had higher sulfur content, i.e. heavy, sour grades (EIA, 2015). Oils from unconventional sources (termed light-tight oils, or LTOs) have a different chemical composition: they are less viscous and have lower sulfur content (lighter and sweeter) than foreign crudes, and domestic refineries were not optimized to handle the large quantities of LTOs that shales were producing. Because of this mismatch, refiners were only able to profitably process LTOs if they could purchase them at a discount. Even though lighter crudes, like those from shale, were trading at a premium to heavier ones in the international market, the export ban eliminated foreign sources of demand: selling to domestic refineries at a substantial discount was the only option. Thus, the export ban in conjunction with refineries' inability to process the new LTOs caused sustained price differentials. The export ban is a binding constraint only if domestic refineries are unable to absorb this new source of domestic crude without significant additional cost.

An alternative explanation, and the one we argue was more important, has to do with shipping constraints *within* the U.S.—not the prohibition on exporting the crude *outside* of the country. In addition to unusual discounts between domestic and international crudes, the shale boom coincided with unusual price differentials within the U.S. For a time, unprecedented new volumes of crude overwhelmed existing pipeline capacity between locations like North Dakota's Bakken formation in the mid-continent and refineries located in the Gulf Coast region. As oil inventories grew and producers resorted to more costly transportation alternatives like rail and barges. These transportation constraints within the U.S. created the price differentials between Brent and WTI. Several studies have associated internal shipping constraints with internal price differentials (Borenstein and Kellogg, 2014; Kaminski, 2014; Büyükşahin et al., 2013; Fattouh, 2007, 2010, 2009). In fact, McRae (2015) argues that transportation constraints were exacerbated by vertically integrated ConocoPhillips for the purpose of sustaining the price differential, therefore improving refinery profits. Unlike these previous studies, we opine into the debate over the role of the export ban in causing domestic crude oil discounts and empirically evaluate the role of internal versus external constraints.

While this is the first paper to empirically disentangle these two competing explanations, a number of papers have examined on the Brent–WTI price differential, taking a more financial perspective (Fattouh, 2007, 2009, 2010; Büyükşahin et al., 2013; Kao and Wan, 2012). Ours is the first to investigate which physical constraints might have driven this differential and the first to consider the specific policy implications.

Empirical approach The degree to which the WTI–Brent discount was due to a constraint on *external* trade (refinery constraints in conjunction with the ban) or *internal* trade (pipeline congestion) is an empirical question. If the constraint was internal, then the opportunity to arbitrage spatial differences in price would have led to new pipeline construction and the elimination of the discount independent of whether the export ban was in place. However, if the discount was due to a mis-match of refining capacity with new U.S. crude supplies, then an earlier lifting of the export ban might have raised domestic wellhead prices for oil producers, increasing their profitability and mitigating the extent to which domestic refineries had to make investments and/or operational changes to handle this new source of crude.

2 Oil price differentials and arbitrage

2.1 Refining and export restrictions

There are two major sources of demand for domestic crude oil, which is an intermediate good: refining and export to the world market. Refineries transform crude oil inputs into petroleum product outputs. Global petroleum product prices track international crude oil prices closely because oil is the primary input in the production process. Domestic refiners are able to arbitrage differences between increasing supplies of discounted domestic crude and undiscounted international petroleum product prices. The 1975–2015 export ban meant refining was the only major source of demand for domestic crude oil.[3] Producers were unable to arbitrage the domestic crude discount, but refiners, who faced no restrictions on exporting their products, could do so freely.[4]

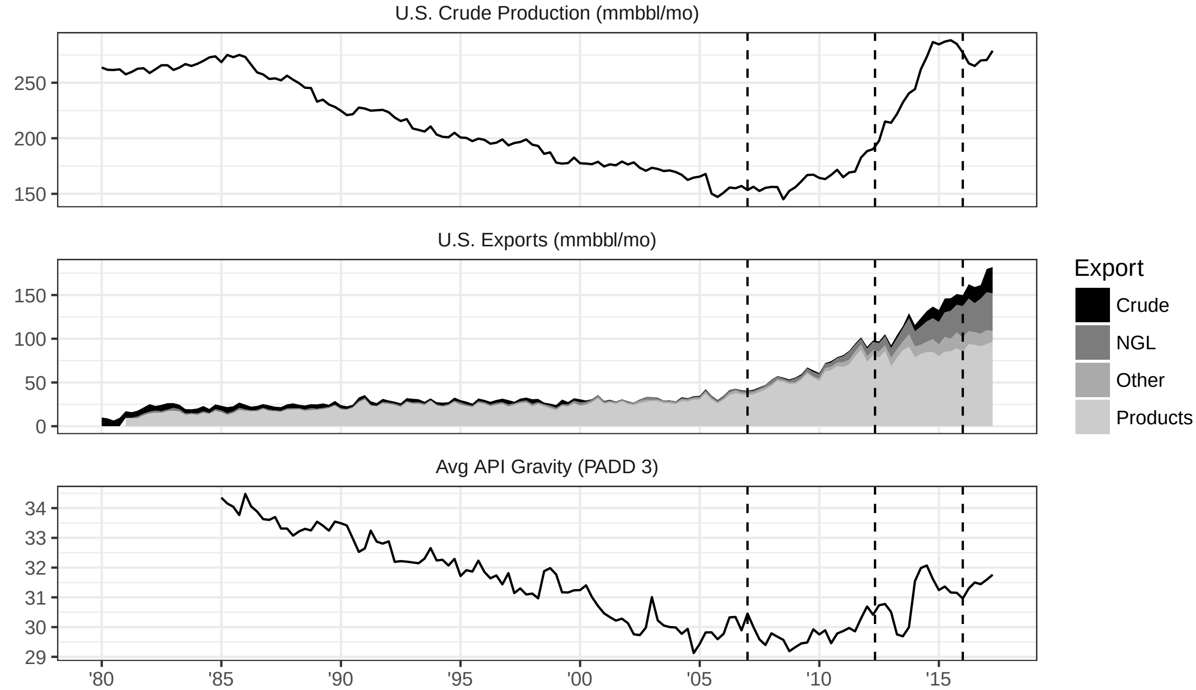
Crude oils are heterogeneous in their chemical compositions, and refineries are fine tuned to a particular slate of crude oil varieties. Historically, the U.S. has produced "light sweet" crude that has a relatively low density ("light") and relatively low sulfur content ("sweet"). U.S. refineries were originally built to process this domestically produced light sweet crude. Starting in the 1970s, domestic oil production fell and demand for refined products grew. Over time, refineries retooled and adjusted their diets to use a higher share of "heavy-sour" crude from overseas.

Refineries had several options to adjust to increased domestic supplies of light sweet crude. As prices of products and particular crude oils change, refiners can, subject to constraints, modify the mix of inputs while maintaining an overall chemical composition.[5] For instance, if light crude is relatively inexpensive, a refinery might purchase more light crude *and* more heavy crude, causing the refinery to substitute away from a medium grade crude to take advantage of the relatively inexpensive light crude. This mixing gives the refinery flexibility to change its purchases to adapt to

[3] A few exceptions allowed limited exports to specific refineries in countries like Canada and Mexico, for instance, as well as from the Alaskan North Slope.

[4] It should be noted, that while not associated with oil specifically, similar export restrictions on raw materials but not final products have been studied. For instance, certain types of logs have similar export restrictions (Fooks et al., 2013) while the wood products produced from these logs are traded freely. On one hand, these restrictions are meant to encourage investment in the domestic processing industry and therefore support domestic employment (Dudley, 2004). On the other, these restrictions have been found to lower log prices and therefore reduce the incentive to harvest (von Amsberg, 1998). Similar export restrictions have also been observed in developing nations for products such as fish, wildlife and raw grains (Bale and Lutz, 1981; Anderson, 2009).

[5] EIA (2015) discusses the technical options for refining additional LTOs in light of the recent shale oil boom.



Series averaged by quarter for readability. Lines at Jan 2007, May 2012, Jan 2016.

Figure 1: Refining, exports, and production

changing relative availability and prices. In addition, refiners can make physical plant additions and alterations to allow for a different mix of crude to be processed, though these capital expenditures can be expensive. While refiners are unlikely to make significant changes to their equipment and operations in response to a transitory shock, they are able to make significant changes to accommodate structural changes in crude availability.[6]

The top two panes of Figure 1 show that as domestic oil production increased, both U.S. production *and* exports of petroleum products increased dramatically. Simultaneously (as shown in the bottom pane), the average API gravity of refiners' crude inputs (the inverse of crude oil density) increased sharply. This suggests that refiners were either changing their diets and/or that there was an increased utilization of simple refineries that were already configured to handle these light oils. It also suggests that weak domestic demand and low input prices allowed refiners to sell more abroad.

[6] According to Eric Smith, Associate Director of the Tulane Energy Institute, this overall market transition towards processing more-or-less all light crude could take as long as 20 years and would be associated with significant capital expenses and stranded assets.

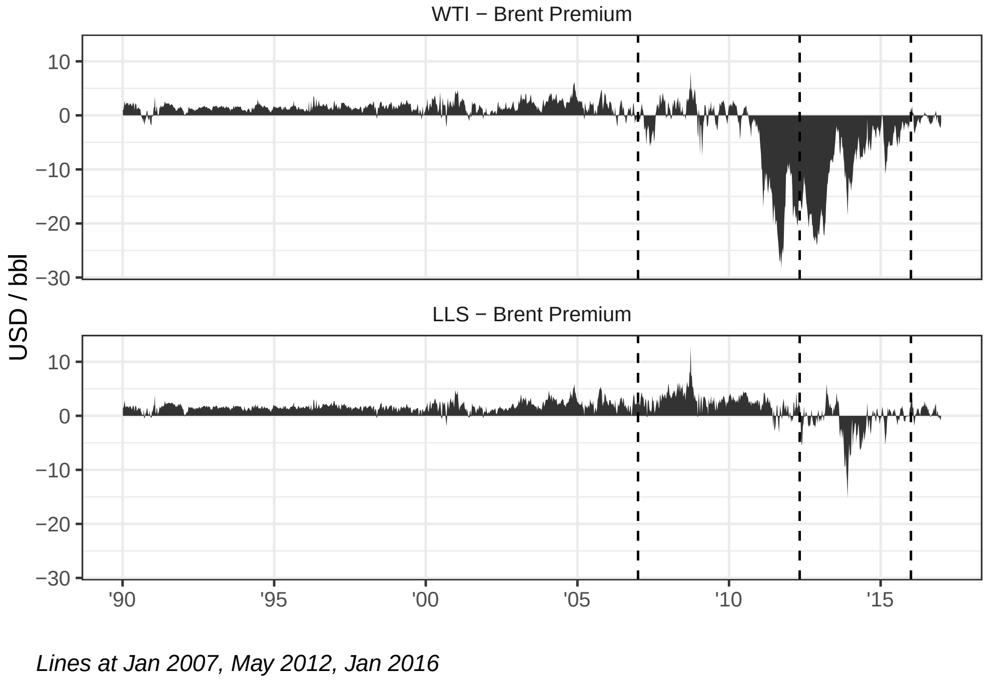


Figure 2: WTI and LLS premia over Brent

2.2 Producers and transportation constraints

U.S. oil production, transport, and refining is reported regionally by Petroleum Administration Defense Districts (PADDs). Much of the oil production and refining demand takes place in PADDs 2, 3, and 4, which are the Midwest, Gulf Coast, and Rocky Mountains, respectively. One of the biggest sources of new shale oil, North Dakota, is in PADD 2. PADD 2 also contains Cushing, Oklahoma, where WTI is traded and priced. Much of the nation's refining lies in PADD 3 along the Gulf Coast.

As shown in Figure 2, for over a decade, WTI and LLS traded in close proximity to each other. However, beginning in the late 2000s, a large price gap emerged. With sufficient transportation infrastructure, a profit-maximizing producer or buyer of crude oil in the mid-continent would see an arbitrage opportunity, transport its oil to the Gulf Coast, and sell it there. Such a price difference could only be sustained in presence of infrastructure constraints or high transportation costs equal to the price differences. Some in the industry have interpreted the WTI–LLS differential as representative of the value of transportation constraints between the mid-continent and Gulf Coast refining,[7] and Büyükşahin et al. (2013) also interpret the WTI–LLS differential in this way.

Crude oil transportation has, historically, been primarily via pipeline. This is because trans-

[7]Thanks to Anna Temple, an analyst at market intelligence firm Wood Mackenzie, for pointing this out. See also, for example, Fielden (2013) and Investor's Business Daily (2014).

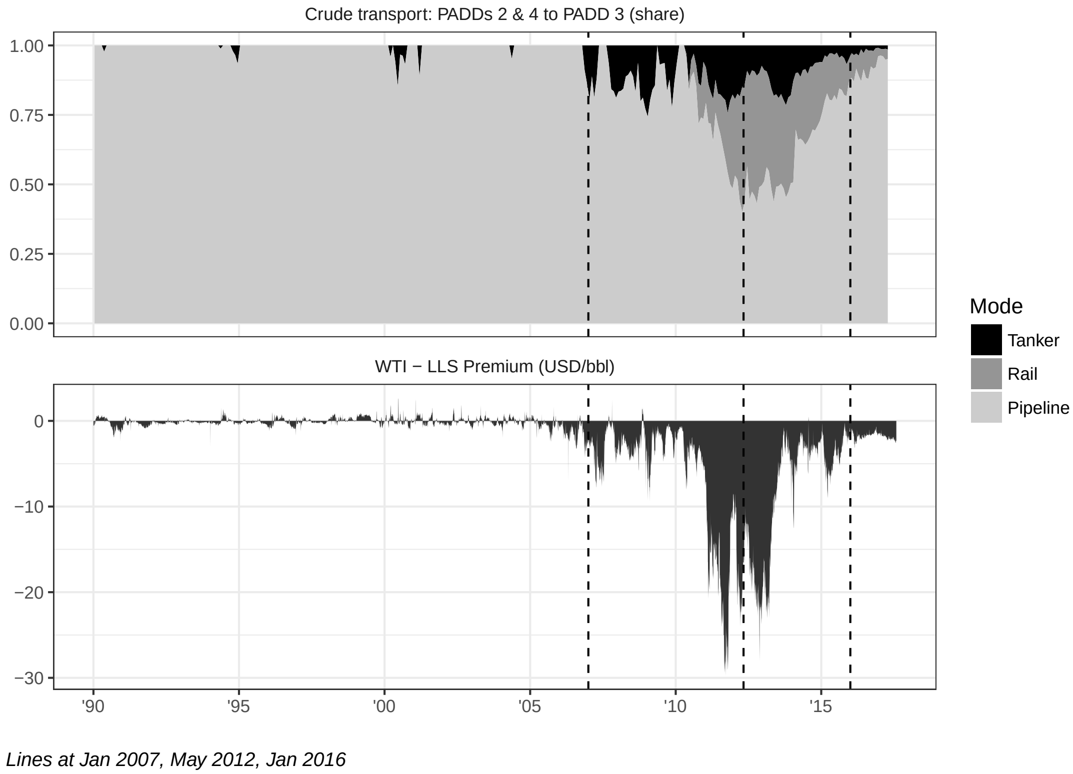


Figure 3: Mode of crude oil transport and WTI–LLS discount

porting crude oil via pipeline costs less, on the margin, than alternatives (typically rail and barge). Pipelines, however, require large, fixed capital investments and a long time to construct, unlike rail and barge which require less up-front investment and posess greater destination flexibility. If there is excess demand for pipeline capacity, we expect temporary increases in utilization of relatively higher marginal cost rail and barge. Should firms expect increased demand for transportation to continue, a exceed current pipeline capacity for the foreseeable future, pipeline builders will respond to profitable investment opportunities and build new capacity.

Figure 3 relates the share of pipeline, rail, and tanker in transporting crude from the mid-continent (PADDs 2 and 4) to the Gulf Coast (PADD 3) with the WTI–LLS price differential. The dashed line at January 2007 represents the start of the boom in LTO production.[8] The line at May 2012 marks the opening of the Seaway pipeline that started relieving transportation bottlenecks,[9] and the line at January 2016 marks the lifting of the export ban. Visual inspection of the figure suggests that this intra-U.S. difference in crude oil prices is highly correlated with transportation modes.

[8]Section 4.1 discusses how we date the start of the boom in LTO production from shale.

[9]We discuss the May 2012 break later in this section.

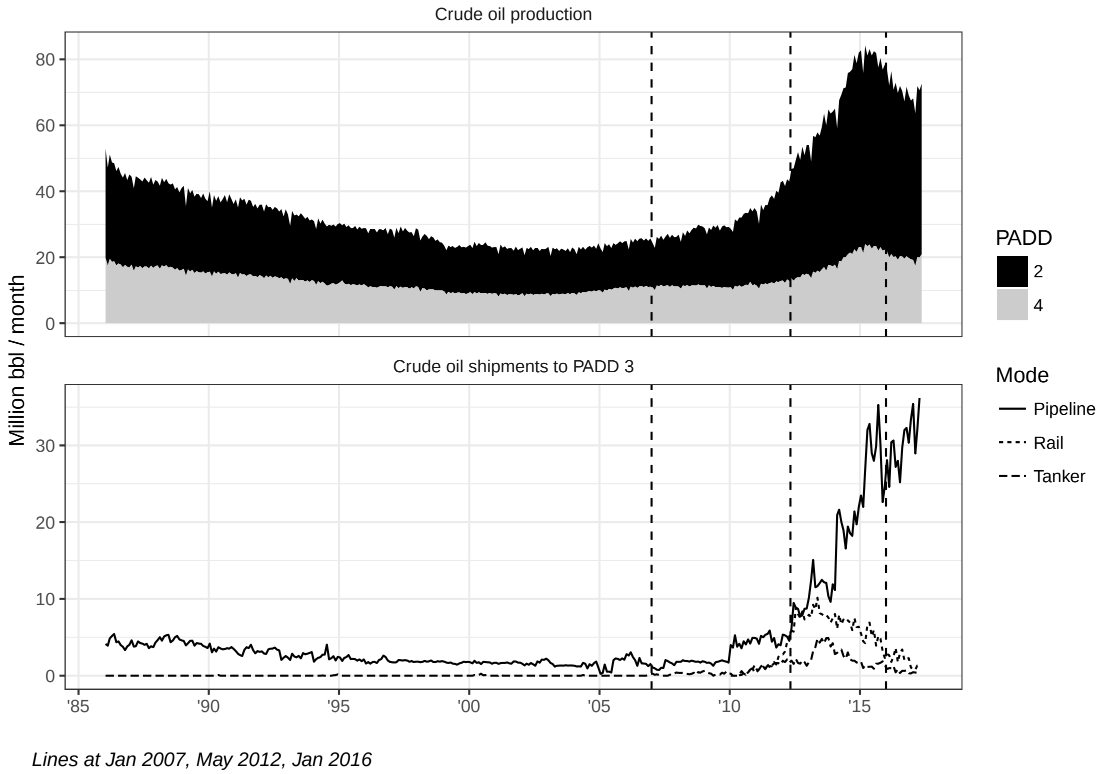


Figure 4: Oil production and transportation from PADDs 2 and 4

Figure 4 compares total mid-continent oil production (PADDs 2 and 4) with the total volumes of crude transported to PADD 3 by mode. During the 1990s and early 2000s, oil production in these areas continued down a long-run decline curve, and existing pipeline capacity sufficed to meet transportation needs. The advent of LTO production from shale, however, increased oil production in the mid-continent from approximately 300 million barrels in 2006, to more than 955 million in 2015. Demand for transportation from the mid-continent to refineries on the Gulf Coast quickly outstripped pipeline capacity, and producers had to utilize alternative rail and barge as well as pipelines. Figure 4 shows that in April 2012, more crude was shipped via rail than pipeline from the mid-continent to the Gulf Coast. Subsequent construction increased the availability of low-cost pipeline transportation services, allowing producers to transport more than 36 million bbl/month in April 2017.

Producers' willingness to pay high marginal transportation costs was a signal to pipeline firms to invest in new infrastructure. The most notable such investment was the reversal of the Seaway Pipeline that runs from Freeport, TX to Cushing, Oklahoma, where WTI is priced. The pipeline came online in 1976 with the purpose of transporting foreign crude imported to the Gulf Coast to the refineries in the Midwest. During the peak of the crude price differentials, the Seaway pipeline was jointly owned by ConocoPhillips and Enterprise Products Partners, LP. ConocoPhilips is a vertically integrated company owning significant refining capacity, while Enterprise Partners is a mid-stream pipeline company. McRae (2015) argues that vertically integrated ConocoPhilips made the explicit decision *not* to reverse the pipeline for the purposes of sustaining this price differential to boost profits of its down-stream refining operations. Estimates suggest that the delay of the reversal cost the ConocoPhillips approximately $200,000 per day in profits, yet it gained approximately $2 million per day in higher profits on its Midwest refining operations.

In November of 2011, ConocoPhilips announced the sale of its share in the pipeline, and in May of 2012 the Seaway Pipeline reversed direction, relieving the transportation bottleneck.[10] However, even after the reversal was completed, producers required yet more pipeline capacity to move the glut of LTOs coming from the mid-continent to the Gulf Coast, so in January of 2013, the pipeline's capacity was upgraded from its initial capacity of 150,000 barrels per day (bbl/d) to approximately 400,000 bbl/d.[11] By the time the export ban was lifted in December of 2015, about 12% of crude was being moved to the Gulf Coast by tanker and rail, down from the peak of 60%. The most recent data available from April 2017 show that more than 35 mmbbl/month are moved from the mid-continent to the US Gulf Coast each month, more than 10% of monthly US production (Figure 4).

3 Data, Variables, and Summary Statistics

3.1 Crude Oil Data

We utilize monthly time series data from 1990 through the end of 2015 for purposes of this analysis. For each empirical specification, the outcome variable of interest is the difference in the spot price of a domestic U.S. crude and the international Brent crude benchmark. We use two data sources for our crude oil prices. First, we gather daily spot prices from Bloomberg for Brent crude and five domestic benchmarks.[12] These daily prices are associated with major crude trading hub on five daily spot prices, and we average them to a monthly frequency for all time-series analysis. The first three are mid-continent crudes: West Texas Intermediate (WTI), priced for delivery at Cushing,

[10]It should be noted that ConocoPhillips was in the process of selling many of its refining assets during the process of the pipeline removal. Thus the selling of its share of Seaway, and therefore allowance of its reversal coincided with this decision.

[11]While the Seaway Pipeline received a great deal of attention, it was by no means the only pipeline reversal or expansion that occurred in response to the shale boom. For instance, the Longhorn Pipeline reversal in 2013 allowed for crude to get from West Texas' Permian basin to Houston for refining. Another example is the Houma-to-Houston pipeline reversal in late 2013 and early 2014. Even at the time of this writing, the Bayou Bridge pipeline from Nederland, Texas to St. James, Louisiana is in the permitting process for moving crude to refineries in southeast Louisiana.

[12]According to Bloomberg, "Bloomberg's spot crude oil price indications use benchmark WTI crude at Cushing, Oklahoma and other U.S. crude grade prices are derived by adding spot market spreads to WTI also priced at Midland."

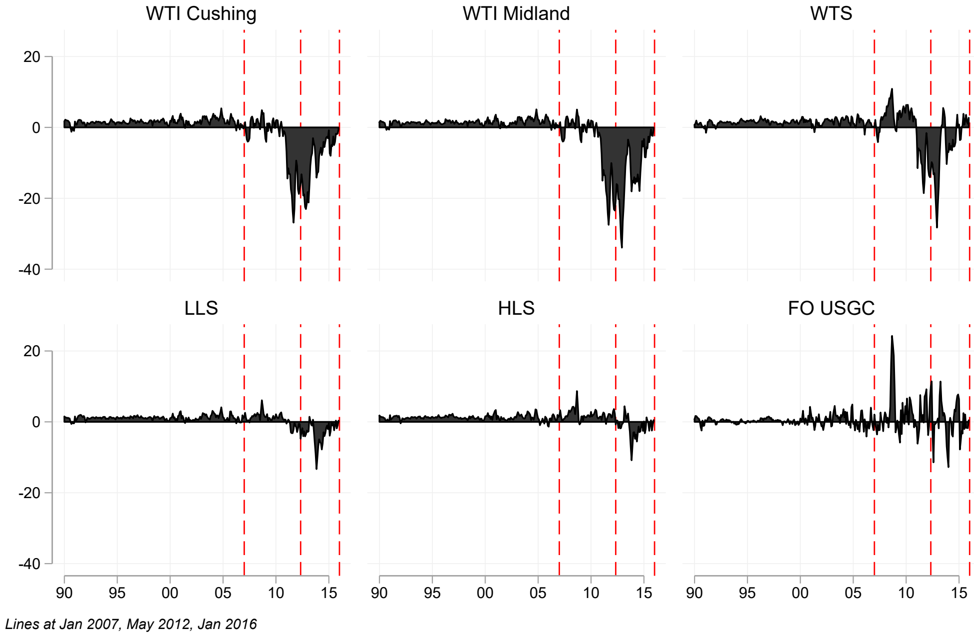


Figure 5: Midcontinent (top) and coastal (bottom) premiums to Brent

Oklahoma; WTI Midland, priced at Midland, Texas where the Permian Basin is located; and West Texas Sour (WTS). The last two are coastal crudes: Louisiana Light Sweet Crude (LLS), priced at St. James, Louisiana; and Heavy Louisiana Sweet Crude (HLS), priced at Empire, Louisiana. Bloomberg does not track a Federal Offshore Gulf of Mexico (FO USGC) price, therefore, the second data source is the monthly average first-purchase price compiled by EIA from administrative reports.[13] [14]

The six domestic price differentials[15] are plotted in Figure 5. The top three are inland crudes and must to be transported to a refinery (often the Gulf Coast, where more than half of the nation's refining capacity is located) after they exit the wellhead or, in the absence of the export ban, a port where they can be shipped overseas. All three crudes would be affected by both pipeline constraints and the export ban. These mid-continent crudes are then juxtaposed against the coastal crudes

[13] Like the other state-specific crude oil streams analyzed in the Online Appendix, this price series is based on the EIA's Form EIA-182 survey, not market data. The EIA defines "'first purchase' [as] a transfer of ownership of crude oil during or immediately after the physical removal of the crude oil from a production property for the first time. Transactions between affiliated companies are reported as if they were arms-length transactions." The EIA notes that the price is composed of a sample of specific crude streams. Since the price is not a liquid market benchmark but partially based on internal transfer prices, this may be a more volitile, and perhaps less reliable, measure of prices.

[14] In Appendix A.3, we also consider all other geography-specific wellhead prices provided by EIA (there are more than 30). We run an identical analysis on these series as a robustness check and find no qualitative difference in our results

[15]See Section 4 and Online Appendix A.2 for how these are calculated.

are already located on the Gulf Coast and in close proximity to refineries and deepwater ports. Though FO USGC crude prices became more volatile over the last few years, they do not appear to have developed any sustained discount. Some of the higher volatility is likely due to the increased vulnerability of offshore crudes to severe weather, as well as the fact that the price is derived from an EIA surveys that do not control for crude quality.

3.2 Shipping and Refining Constraint Variables

Our empirical goal is to distinguish the roles of transportation and refining constraints in generating crude oil price differentials. We capture these with two variables from the U.S. Energy Information Administration (EIA). The first variable relates to shipping. EIA provides estimates of all crude movements between PADD regions. These crude movements are broken up into three primary categories: pipeline, tanker, and rail. We consider movements from PADD 2 (the Midwest) and PADD 4 (Rocky Mountain states) to PADD 3 (the Gulf Coast). This represent the transport of crude produced in the mid-continent, primarily from the Bakken and Niobrara shale plays, towards the Gulf Coast where more than half of the country's refining capacity resides. To represent the presence of pipeline constraints, we consider the volume of crude movements from PADDs 2 and 4 to PADD 3 via barge or rail as a share of total movements:[16]

$$other\_share_t = \frac{Tanker_t + Rail_t}{Tanker_t + Rail_t + Pipeline_t}.$$

The next explanatory variable represents potential refining constraints: it is the weighted average API gravity of crude input into PADD 3 refineries (api_t). If we find a that this weighted average of API gravity has explanatory power in predicting price differentials, then this provides evidence that it is refining constraints, not transportation constraints that caused the large price differentials.[17]

[16] Our measure of pipeline constraints is a much more direct measure of this constraint than the proxy previous academic studies have used, which is the level of crude inventories at Cushing (Büyükşahin et al., 2013; Fattouh, 2007, 2009; Kao and Wan, 2012).

[17] There is no one variable that captures the distribution of hydrocarbon inputs to refineries. Public EIA data on the quality of refining inputs is coarse, and it is not possible to accurately describe the distribution of molecular weights of refinery inputs from the aggregate measures provided. We did try imputing measures of heavy products (vacuum gas oil and residuum) exiting the primary refinery atmospheric distillation units to detect changes in the distribution of crude gravity. Like API gravity, these had no meaningful explanatory power. Thus, while we do not find sufficient evidence of refinery constraints on the price differential, there is still opportunity for future research to capture potential refinery constraints. In addition, to double check that the price drop is not driving our results, we truncated our sample in two places: after prices hit their June 2014 high and after the November 2014 OPEC meeting that precipitated the collapse in U.S. drilling. The truncation also had no substantial effect on our estimates.

4 Empirical strategy

Our analysis of domestic crude oil price differentials proceeds in three stages. In the first stage, we estimate the cointegrating relationship between domestic crudes and Brent crude for the pre-shale 1990–2006 period at the monthly frequency. We construct price differentials as deviations from these baseline long-run relationships (see Online Appendix 2 for details of this.)

In the second stage, we test for breaks in the level and trend of price differentials at the beginning of the "shale boom" and at the time when pipeline investments relieved the shipping constraints. In the third stage, we decompose deviations of the price differentials from zero into shipping and refining constraints.[18][19]

Our empirical strategy is similar in spirit to Bausell et al. (2001), who examine the impact of lifting the Alaskan Oil Export Ban on the prices of Alaskan crude and West Coast refined products, though our situation and methodology differ. First, Bausell et al. (2001) study a market in a constrained, steady-state equilibrium which experiences a sudden relief in the constraint and moves to a new steady-state. In constrast, our period of interest is not at all a steady-state. Over our time frame, increasing shale production would have caused market constraints, be they pipeline or export constraints, to bind ever more tightly. Then, those constraints would have been gradually relieved over time by incremental investments into pipelines and refineries. This means our constraint cannot be captured with a simple indicator variable for the post-ban period. We address this by allowing for two breaks in both level and trend of the series. Second, we are interested in disentangling the impacts of two different constraints: shipping as well as refining constraints.[20] This is closely related to Büyükşahin et al. (2013), who regress the WTI–Brent spread on a variety of economic, physical, and financial variables (but not the export ban). The authors focus on statistical links between storage and financial markets whereas we focus purely on the physical market and assess the roles of transportation and export constraints across many a number of domestic prices.

[18] In all of regressions we compute our standard errors using an Andrews (1991) heteroskedasticity and autocorrelation-consistent (HAC) estimator to correct for the effects of serial correlation and heteroskedasticity.We implement the estimator with the Stata package `lrcov` (Wang and Wu, 2012).

[19] In Tables 5 and 6, listed in the Appendix, we also add try adding two lagged values of $PD_{c,t}$ to parametrically account for autocorrelation. This reduces the magnitudes and significance of the explanatory variables, but does not cause signs to change or change the fact that shipping constraints are significant at at least the 5% level for all grades except HLS.

[20] We also differ somewhat our modeling choices for standard errors: rather than explicitly model conditional heteroskedasticity with a GARCH model, we instead use a robust, HAC estimator for the variance.

4.1 Testing for constraints with breakpoints

In our first model we allow for these time series to have a broken time trend and denote it as μ_t.[21] We denote the set of break-times as $\{T_e\}_{e=0}^{E}$ and follow the convention that the first and last break times are the start and end of our sample: $T_0 = 0$ and $T_E = T$. A regime e includes the set of months $t \in \{T_e + 1, \ldots, T_{e+1}\}$. This implies that there are up to $E - 1$ intervals and gives us our first econometric specification:

$$PD_{c,t} = \sum_{e=0}^{E-1} \mathbb{1}\left[T_e < t \leq T_{e+1}\right](\alpha_{c,e} + \beta_{c,e}t) + \nu_{ct}^{Ike/Gustav} + \nu_{ct}^{Katrina/Rita} + \epsilon_{c,t}, \tag{1}$$

where $\mathbb{1}\left[T_e < t \leq T_{e+1}\right]$ represents a dummy variable that takes the value 1 only when t falls within regime e and 0 otherwise, and the parameters $\nu_t^{Ike/Gustav}$ and $\nu_t^{Katrina/Rita}$ capture the effect of US Gulf Coast hurricanes Ike and Gustav (September 2008) and Katrina and Rita (September—October 2005) which temporarily impacted Gulf Coast refining.

We allow for two structural breaks at exogenously-chosen breakpoints that partition our sample into three separate time periods. The first break date marks the end of the "pre-shale boom" period and the onset of the "initial shale boom" period. We date this break at January 2007, consistent with EIA's Drilling Productivity Reports. The second breakpoint is May of 2012 when the Seaway Pipeline was reversed. Historically, the Seaway pipeline moved crude from Freeport, TX (on the Gulf Coast) to Cushing, Oklahoma (in the mid-continent). The reversal expanded capacity for the glut of new crude production in the mid-continent to reach the Gulf Coast. Even though the share of crude transported by pipeline did not start to trend back up until later, we choose the Seaway reversal since it was the first of several such major investments in pipeline capacity that alleviated transportation constraints. The third event is the lifting of the export ban in December of 2015, and marks the end of the time period considered in this analysis. This timeline is summarized in Table 1.

During the initial shale boom period before the internal shipping constraints are alleviated (January 2007 through April 2012), we hypothesize that crudes located inland (hereafter referred to as "mid-continent crudes") will sell at increasing discounts due to shipping and refining constraints: $\beta_{mid,1} < 0$. Since mid-continent crudes face additional constraints compared to coastal crudes, we hypothesize that $\beta_{mid,1} \leq \beta_{gulf,1}$. If refinery constraints are binding, Gulf Coast crudes will also sell at an increasing discount and $\beta_{gulf,1} < 0$. This would mean that lifting the export ban would have plausibly relieved this constraint, allowing these Gulf Coast crudes to sell to foreign buyers (of course, to the extent this differential exceeded transportation costs). However, if there is no

[21] Before proceeding with our first model, we verify that LOOP holds during the pre-shale period. These standard econometric test results can be found in Appendix Section A.2.

Table 1: Structural Break Time Periods

Time Period	Event	Description
January 1990 to December 2006	Pre-Shale Boom Era	EIA's drilling productivity report begins tracking shale play production in 2007.
January 2007 to April 2012	Shale Boom and Pre-Pipeline Upgrades	In April of 2012, the Seaway Pipeline was reversed. Throughout the next several years, other significant reversals and upgrades were also completed.
May 2012 to December 2015	Shale Boom and Pipeline Upgrades Occurring	The export ban was lifted in December of 2015.

constraint in the refineries inability to process this crude, then we would expect for $\beta_{gulf,1} = 0$. Thus, the difference between $\beta_{gulf,1} - \beta_{mid,1}$ represents the difference in the rate at which pipeline constraints bound more than refinery constraints.

The last regime coincides with the time of pipeline reversals and upgrades and before the export ban was lifted, from May 2012 to December 2015. If the transportation constraints were binding for the mid-continent crudes, and therefore were responsible for some share of their price discount, we would expect for these mid-continent crude prices to begin to converge to Brent during this time where these transportation constraints were being alleviated, so $\beta_{mid,2} > 0$. However, if these transportation constraints were not responsible for the price differential, but instead the export ban, we would expect for the price differential to persist, $\beta_{mid,2} = 0$.[22]

4.2 Decomposing for pipeline vs refining constraints

In our second model, instead of using time-trends and breaks to coarsely capture the evolution of pipeline constraints, we decompose the price differentials into the two components corresponding to increased marginal transport and refining costs.[23] Specifically, for crude c at time t, we decompose the price differential as

$$PD_{c,t} = \alpha_0 + \gamma_c^{ship} other\_share_t + \gamma_c^{api} api_t + \nu_{ct}^{Ike/Gustav} + \nu_{ct}^{Katrina/Rita} + \epsilon_{c,t} \quad (2)$$

[22]It should be noted that we also have considered the post-export ban lifting time period, but have excluded from this analysis purposefully. The global oil price drop occurred shortly after OPEC's announcement of continuing production in September of 2014. While crude production began to grow, it peaked in August of 2015, and at the time of this writing has continued to decline. Therefore, testing for structural breaks after the supply decrease is problematic for our analysis, as reductions in supply might relieve both pipeline and refinery constraints simultaneously.

[23] While we did estimate models with both broken time-trends and the explanatory variables, it is not possible to interpret the results as a decomposition since it is not clear what constraints the time-trends are capturing beyond what the transporation and refining variables are. For this reason, we view the two models as separate.

The first explanatory variable is the share of crude oil movements via rail and barge from the mid-continent (PADDs 2 and 4) to the Gulf Coast (PADD 3), shown previously in Figure 3. Because shipping crude via barge or rail is more costly than via pipeline, we expect that mid-continent discounts will grow as more crude is moved via these two modes. Conversely, we expect the discount to shrink as the share via barge and rail attenuates. This is equivalent to $\gamma_{mid}^{ship} < 0$. At the same time, we do not expect Gulf Coast crudes to be nearly as affected by mid-continent to Gulf Coast pipeline capacity. Therefore, we expect that $\gamma_{mid}^{ship} < \gamma_{gulf}^{ship} \leq 0$.

The weighted average API of refining inputs captures PADD 3 refining constraints. The coefficient γ^{api} measures the association between these variables and domestic price premiums. If these refineries were not able to perfectly substitute their previous grades of crude for domestic LTOs, then changes API of inputs should depress domestic crudes compared to Brent.

5 Results

Breaks in trend Table 2 presents the baseline results for equation (1). In a regime e, the corresponding level term is $\alpha_{c,e}$, and the trend term is $\beta_{c,e}$. As expected, $\hat{\alpha}_0 > 0$ for all crudes except FO USGC (in which case it is positive, but not statistically different from zero). This means that in the pre-shale time period, domestic crudes (except for FO USGC) traded on average at higher prices relative to Brent. In addition, we fail to reject the hypothesis that $\beta_0 = 0$ for all crudes. This provides evidence that price differentials were stable in the pre-shale time period.

For WTI and WTS, we find evidence of significant devaluation in the post-shale boom time period before transportation constraint alleviations began: $\hat{\beta}_1 < 0$. More specifically, we estimate that WTI Cushing was losing value relative to Brent at a rate of about \$3.50 per year.[24] WTI Midland experiences a similar \$3.85/year devaluation per year over this time period. WTS experience devaluation at a slightly slower rate, of about \$2.39/year over this time period.

Results for Gulf Coast crudes differ significantly from results for mid-continent crudes. We estimate that LLS decreased in price relative to Brent crude at a rate of about \$0.59 per year. Thus, while we do find that it experienced a discount, this is a much smaller magnitude than for the mid-continent crudes. HLS and FO USGC do not experience a statistically significant decrease at all. These results are consistent with the hypothesis that transportation constraints in the mid-continent played primary role in generating price differentials.

Next, we turn to β_2, the rate at which domestic crude prices rose as pipeline constraints eased over the May 2012–December 2015 period. WTI Cushing, WTI Midland, and WTS rose in value quickly relative to Brent: estimated rates are between \$4.96 and \$5.74 per year. This recovery was substantially faster than the rate at which these prices fell during the initial boom period. The

[24] Recall that the time-trend, t, is measured in years.

Table 2: Price differential break tests, OLS

	Mid-continent			Gulf Coast		
	WTI Cushing	WTI Midland	WTS*	LLS*	HLS	FO USGC*
Level						
α_0	1.223***	1.127***	1.210***	1.040***	1.209***	0.275
	(0.179)	(0.143)	(0.222)	(0.129)	(0.133)	(0.208)
α_1	64.79**	71.18**	47.07*	12.35**	2.858	-2.709
	(21.44)	(23.26)	(22.02)	(4.360)	(2.625)	(9.996)
α_2	-129.9***	-150.6***	-124.5***	-17.83	4.449	17.26
	(14.30)	(13.26)	(17.82)	(13.60)	(10.79)	(14.25)
Trend						
β_0	0.0389	0.0343	0.0297	0.0123	-0.00134	0.00728
	(0.0309)	(0.0261)	(0.0244)	(0.0210)	(0.0212)	(0.0308)
β_1	-3.499**	-3.847**	-2.394*	-0.591**	-0.0484	0.231
	(1.106)	(1.204)	(1.132)	(0.223)	(0.127)	(0.486)
β_2	5.012***	5.741***	4.954***	0.609	-0.247	-0.702
	(0.587)	(0.535)	(0.716)	(0.561)	(0.444)	(0.580)
Hurricanes						
$\nu^{Ike/Gustav}$	5.393**	5.683**	8.516***	4.777***	6.735***	22.65***
	(1.903)	(2.012)	(1.937)	(0.372)	(0.296)	(1.226)
$\nu^{Katrina/Rita}$	1.364***	1.580***	0.815***	1.708***	0.144	1.219*
	(0.351)	(0.298)	(0.215)	(0.224)	(0.227)	(0.478)
N	312	312	312	312	312	312
$\chi^2(6)$	33.67	37.31	33.75	24.82	21.84	23.54
	(0.00000778)	(0.00000153)	(0.00000751)	(0.000369)	(0.00129)	(0.000636)
$F_{\beta_0=\beta_1}$	10.03	10.25	4.529	6.987	0.133	0.211
	(0.00170)	(0.00151)	(0.0341)	(0.00864)	(0.715)	(0.646)
$F_{\beta_1=\beta_2}$	36.73	49.97	24.15	4.408	0.175	1.425
	(4.01e-09)	(1.07e-11)	(0.00000146)	(0.0366)	(0.676)	(0.233)
$F_{\beta_0=\beta_1=\beta_2}$	36.10	59.90	23.67	4.625	0.238	0.819
	(8.60e-15)	(1.17e-22)	(2.80e-10)	(0.0105)	(0.788)	(0.442)

Standard errors in parentheses for coefficients, and p-values for test-statistics.

Significance tests against normal distribution: $^{+}$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection.

$\chi^2(6)$ is Cumby and Huizinga (1992) statistic for autocorrelation of order 6

Starred dependent variables computed using initial LOOP regressions in Table 9

Table 3: Price differential decomposition: OLS

	Mid-continent			Gulf Coast		
	WTI Cushing	WTI Midland	WTS*	LLS*	HLS	FO USGC*
γ^{ship}	-31.19***	-37.97***	-21.02***	-9.298***	-4.157+	1.300
	(4.077)	(3.356)	(4.443)	(2.047)	(2.298)	(2.476)
γ^{api}	-0.355	-0.708*	-0.777*	-0.357*	-0.303*	-0.370
	(0.257)	(0.307)	(0.377)	(0.141)	(0.150)	(0.248)
$\nu^{Ike/Gustav}$	4.573***	4.843***	9.250***	5.018***	7.322***	23.34***
	(0.457)	(0.501)	(0.664)	(0.194)	(0.211)	(0.415)
$\nu^{Katrina/Rita}$	0.984*	0.723	-0.416	1.304***	-0.274	0.789
	(0.412)	(0.453)	(0.685)	(0.227)	(0.247)	(0.536)
α_0	12.91	23.86*	26.30*	12.38**	10.74*	11.98
	(8.099)	(9.644)	(12.01)	(4.440)	(4.723)	(7.858)
N	312	312	312	312	312	312
$\chi^2(6)$	30.39	31.56	28.30	23.20	31.52	22.58
	(0.0000332)	(0.0000199)	(0.0000826)	(0.000733)	(0.0000201)	(0.000952)
R^2	0.724	0.755	0.480	0.517	0.221	0.158
R^2_{ship}	0.720	0.742	0.448	0.480	0.181	0.145
R^2_{ref}	0.00661	0.00608	0.00488	0.0143	0.0698	0.155

Standard errors in parentheses for coefficients, and p-values for test-statistics.

Significance tests against normal distribution: $^{+}$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection.

$\chi^2(6)$ is Cumby and Huizinga (1992) statistic for autocorrelation of order 6

Starred dependent variables computed using initial LOOP regressions in Table 9

trend coefficients for LLS, HLS, and FO USGC are not statistically different from zero, suggesting that relief of transportation constraints did not increase the price of these crudes.

Transport vs. refining Table 3 shows estimates for equation (2), which decomposes the price differential into marginal shipping costs and marginal refining costs. The shipping constraint coefficient, γ^{ship}, is statistically significantly and negatively associated with price differentials for the three mid-continent crudes plus LLS. It is negative and statistically significant at the 10% level for HLS, but it is not significant at any conventional levels for FO USGC. Our estimates of γ^{ship} suggest that a 10% increase in the share of crude being shipped from the mid-continent to Gulf Coast via rail and barge is associated with a \$2.01 to \$3.79 dollar per barrel discount relative to Brent for our three mid-continent crudes. Rail and barge made up 60% of crude oil movements at one point in time, which would have corresponded to a \$12.58–22.72 per barrel discount. This is an economically significant amount. Pipeline constraints do appear to have impacted LLS, with a 10% increase in the share of rail and barge shipping leading to a \$0.92 per barrel discount—a much smaller amount than for the mid-continent crudes. HLS may have developed a minor discount to Brent due to shipping constraints, but FO USGC appears not to have been affected in the slightest.

Table 3 also shows the relationship between the API gravity of refinery inputs and crude price differentials. We do find that increases in API gravity (i.e. movement towards lighter crudes) is associated with a discount in domestic crudes relative to Brent. The corresponding coefficient, γ_c^{api}, is significant at the 5% level for WTI Midland, LLS, and HLS, but not WTI Cushing or FO USGC. It is statistically significant at the 10% level for WTS. As Figure 1 shows, between January 2006 and December 2015, the average API of PADD 3 refinery inputs ranged between approximately 29 and 32.5. With estimates for γ^{api} ranging from -0.73 to -0.31, this implies that the maximum discount due to increased average API gravity of crude oil inputs to refining would have reached \$2.57, an order of magnitude below the maximum discount due to shipping constraints. That being said, it is important to remember that changes in refinery inputs have persisted, and pipeline constraints have not. Thus, what the refining constraint lacks in intensity, it makes up in longevity.

5.1 Decomposition

To decompose the relative effects of shipping constraints and the export ban, we shut down each of the respective channels and compute the predicted price differential using our regression coefficients. When we shut down one of the variables, we set it to its mean during the pre-shale period January

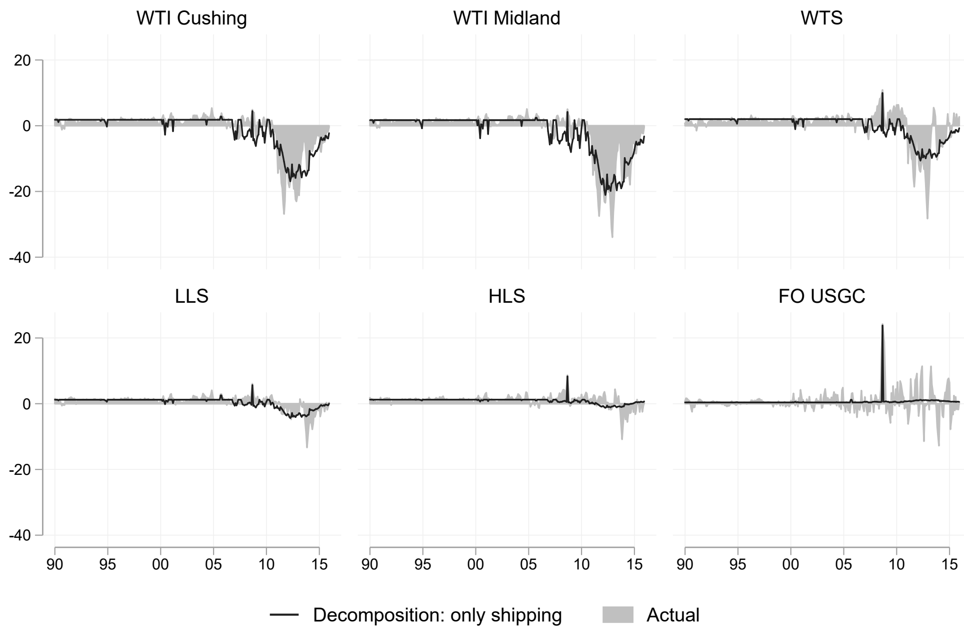


Figure 6: Predicted differentials using only $other\_share_t$ (plus hurricane dummies)

1990 to December 2006. We compute these decompositions[25] as

$$\widehat{PD}_{ct}^{\text{shipping}} = \hat{\alpha}_0 + \hat{\gamma}_c^{ship} other\_share_t + \hat{\gamma}_c^{api}\overline{api} + \widehat{\nu}_{ct}^{Ike/Gustav} + \widehat{\nu}_{ct}^{Katrina/Rita} \tag{3}$$

$$\widehat{PD}_{ct}^{\text{refining}} = \hat{\alpha}_0 + \hat{\gamma}_c^{ship}\overline{other\_share} + \hat{\gamma}_c^{api} api_t + \widehat{\nu}_{ct}^{Ike/Gustav} + \widehat{\nu}_{ct}^{Katrina/Rita}. \tag{4}$$

The two decompositions are graphed in Figures 6 and 7 for each price differential. To measure the explanatory power of each variable, we also compute pseudo R^2 measures as the squared correlations between PD_{ct} and $\widehat{PD}_{ct}^{\text{shipping}}$ or $\widehat{PD}_{ct}^{\text{refining}}$, and we compare them with the original regression R^2 in Table 3. Both the table and the graph show that the ability of shipping constraints to explain the price differentials is usually at least an order of magnitude greater than refining constraints for all crudes except FO USGC, which is equally (un)related to shipping and refining constraints.[26]

[25]Note, our two decompositions are not true counterfactuals because we do not know how refiners would have handled additional LTO volumes should pipeline constraints not have existed. Knowing this would require knowledge of the parameters characterizing the short-run and long-run marginal costs of incorporating additional LTO barrels in refining slates. Thus, our estimates should be taken as a decomposition of the crude differentials under a particular set of circumstances.

[26]The pattern is the same when we examine all of the EIA price differentials (Table 12, with the notable exception of South Dakota, which is a minor oil-producer.)

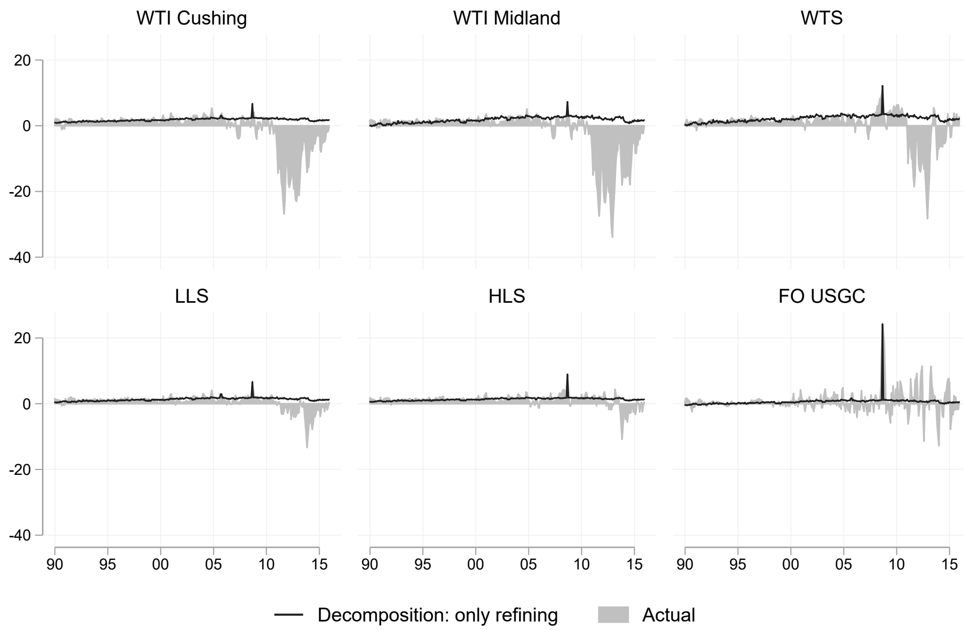


Figure 7: Predicted differentials using only api_t (plus hurricane dummies)

6 Conclusion

In this paper, we investigate the extent to which transportation constraints between the mid-continent and gulf coast can explain the significant price discount of U.S. crudes during the U.S. "shale boom". Some studies have claimed that the price differential was due to refineries' inability to process light tight oils (LTOs) being produced at record levels from shale plays. These studies postulate that the alleviation of the export ban could have eliminated this price differential. Other studies, though, have associated price differentials with transportation constraints within the U.S. that were gradually alleviated due to pipeline reversals and upgrades.

Based on the pseudo-R^2 measures that we calculate, we estimate that around half to three-quarters of the domestic mid-continent crude oil to Brent price differential can be explained by internal pipeline constraints. It is plausible conceptually that part of the price differential could have been associated with refineries' inability to absorb domestic LTOs. And it is also plausible conceptually that this could have been alleviated with the lifting of the export ban. Though results of this research suggest that the lion's share of this short run price differential was likely associated with transportation constraints–not the long standing policy of the export ban.

There are significant policy implications of this research. First and foremost, results of this research suggest that with or without the crude export ban in place, significant price differentials would have emerged between U.S. and foreign crudes. In particular, we argue that the price differentials between mid-continent and Gulf Coast crudes were mostly associated with transportation bottlenecks within the U.S.

Second, Gulf Coast crudes may have been impacted by the export ban, but the magnitudes of these impacts were likely small and short lived. LLS and HLS did sell at a discount to Brent, but this to a much smaller degree than for mid-continent crudes. Depending on the cost to ship Gulf Coast crudes abroad, this discount may or may not have justified exporting crudes and incurring higher, international shipping costs.

There are two important limitations to our empirical approach. First, we are only able to observe average trading prices, aggregate shipping and aggregate refinery input data. The strong statistical significance of our shipping constraint variable allays concerns about whether we have adequately captured this factor. However, the lack of more precise estimates of the impact of refining constraints is more problematic. Refinery processes, inputs, and outputs are much more complex and heterogeneous than simple pipeline movements, and refiners are able to adjust their process over time to increase efficiency. Thus, what may be a sub-optimal crude slate at one time may become an optimal crude slate at another. In contrast, rail and tanker transport of crude over longer distances is always more costly than pipeline transport.

Second, our results are more concerned with the market-level effects of the export ban on domestic crude prices, not the effects of the crude ban on particular producers or refiners. Some producers may have had capacity rights on pipelines and been less affected by differentials. Some individual refiners may have already been set up to handle lighter crude slates and not required steep discounts to handle additional LTOs. Thus, these results should not be used to argue that individual producers were not adversely impacted by the export ban, but instead that in aggregate, internal shipping constraints can explain a significant share of observed price differentials.

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A Appendix: For Online Publication Only

A.1 Additional Tables and Figures

Table 4: Summary statistics

	Mean	SD	Min	Max	N	D-Fuller	Pr($DFuller$)	First obs.	Last obs.
Brent	47.80	34.88	9.80	133.90	312	-1.29	0.63	1990m1	2015m12
Mid-continent crudes									
WTI Cushing	46.78	31.07	11.31	133.93	312	-1.40	0.58	1990m1	2015m12
WTI Midland	46.16	30.37	11.06	134.11	312	-1.45	0.56	1990m1	2015m12
WTS	44.24	30.16	10.07	131.15	312	-1.48	0.54	1990m1	2015m12
Coastal crudes									
LLS	49.34	34.63	11.27	137.99	312	-1.31	0.63	1990m1	2015m12
HLS	48.79	34.64	11.00	136.92	312	-1.32	0.62	1990m1	2015m12
FO USGC	45.61	33.34	9.48	130.06	312	-1.20	0.67	1990m1	2015m12
Explanatory variables									
Avg API: PADD 3	30.95	1.15	28.96	33.69	312	.	.	1990m1	2015m12
Rail/Tanker share from PADDs 2 & 4 to PADD 3	0.09	0.16	0.00	0.60	312	.	.	1990m1	2015m12

Dickey-Fuller test is for null hypothesis of a unit root.

Table 5: Price differential break tests, AR(2)

	Mid-continent			Gulf Coast		
	WTI Cushing	WTI Midland	WTS*	LLS*	HLS	FO USGC*
Level						
α_0	0.264*	0.239**	0.288**	0.336***	0.524***	0.138
	(0.104)	(0.0840)	(0.105)	(0.0933)	(0.110)	(0.119)
α_1	14.86**	16.72**	12.59*	3.887*	1.149	-1.897
	(5.388)	(5.777)	(5.243)	(1.611)	(1.493)	(5.728)
α_2	-26.98*	-31.04*	-27.31*	-8.958+	-0.254	4.857
	(11.27)	(13.97)	(12.63)	(5.054)	(5.410)	(14.59)
Trend						
β_0	0.00377	0.00429	0.00358	0.00147	-0.00116	-0.000275
	(0.00971)	(0.00802)	(0.0103)	(0.00859)	(0.00981)	(0.0188)
β_1	-0.805**	-0.906**	-0.646*	-0.188*	-0.0175	0.144
	(0.282)	(0.304)	(0.272)	(0.0820)	(0.0749)	(0.292)
β_2	1.052*	1.195*	1.094*	0.331	-0.0168	-0.198
	(0.441)	(0.549)	(0.504)	(0.203)	(0.222)	(0.594)
Lags						
ρ_1	1.015***	1.125***	1.097***	0.760***	0.719***	0.663***
	(0.0823)	(0.0837)	(0.101)	(0.130)	(0.117)	(0.105)
ρ_2	-0.219*	-0.329***	-0.320**	-0.0743	-0.153	-0.149
	(0.0992)	(0.0946)	(0.105)	(0.0960)	(0.0961)	(0.0924)
Hurricanes						
$\nu^{Ike/Gustav}$	2.100***	2.084***	2.443***	3.394***	4.706***	13.08***
	(0.404)	(0.406)	(0.525)	(0.325)	(0.360)	(1.806)
$\nu^{Katrina/Rita}$	1.353***	1.082***	0.761	1.433**	0.459	2.096***
	(0.149)	(0.245)	(0.489)	(0.520)	(0.513)	(0.350)
N	310	310	310	310	310	310
$\chi^2(6)$	1.549	2.269	3.092	2.574	2.013	3.007
	(0.956)	(0.893)	(0.797)	(0.860)	(0.918)	(0.808)
$F_{\beta_0=\beta_1}$	8.120	8.900	5.684	5.251	0.0470	0.245
	(0.00468)	(0.00309)	(0.0177)	(0.0226)	(0.829)	(0.621)
$F_{\beta_1=\beta_2}$	9.545	9.071	8.695	5.419	0.0000107	0.243
	(0.00219)	(0.00282)	(0.00344)	(0.0206)	(0.997)	(0.623)
$F_{\beta_0=\beta_1=\beta_2}$	5.151	5.418	4.825	3.768	0.0266	0.160
	(0.00632)	(0.00488)	(0.00866)	(0.0242)	(0.974)	(0.853)

Standard errors in parentheses for coefficients, and p-values for test-statistics.

Significance tests against normal distribution: $^{+}$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection.

$\chi^2(6)$ is Cumby and Huizinga (1992) statistic for autocorrelation of order 6

Starred dependent variables computed using initial LOOP regressions in Table 9

Table 6: Price differential decomposition, AR(2)

	Mid-continent			Gulf Coast		
	WTI Cushing	WTI Midland	WTS*	LLS*	HLS	FO USGC*
γ^{ship}	-5.669**	-7.947***	-4.392**	-2.695***	-1.445*	0.428
	(1.945)	(2.042)	(1.378)	(0.661)	(0.588)	(1.611)
γ^{api}	-0.0163	-0.112	-0.137+	-0.0572	-0.0659	-0.150
	(0.0764)	(0.0768)	(0.0800)	(0.0412)	(0.0433)	(0.123)
ρ_1	1.041***	1.128***	1.109***	0.779***	0.787***	0.667***
	(0.0868)	(0.0911)	(0.104)	(0.105)	(0.107)	(0.101)
ρ_2	-0.229*	-0.338***	-0.320**	-0.0567	-0.0951	-0.145
	(0.0938)	(0.0862)	(0.0982)	(0.0864)	(0.0954)	(0.0915)
$\nu^{Ike/Gustav}$	1.858***	1.873***	2.527***	3.447***	4.683***	13.38***
	(0.280)	(0.280)	(0.459)	(0.259)	(0.318)	(1.564)
$\nu^{Katrina/Rita}$	1.301***	0.907**	0.496	1.345+	0.464	1.879***
	(0.184)	(0.300)	(0.646)	(0.785)	(0.615)	(0.361)
α_0	0.833	3.873	4.714+	2.138	2.457+	4.880
	(2.468)	(2.463)	(2.563)	(1.324)	(1.382)	(3.908)
N	310	310	310	310	310	310
$\chi^2(6)$	1.714	1.532	2.756	3.350	4.482	2.780
	(0.944)	(0.957)	(0.839)	(0.764)	(0.612)	(0.836)
$\tilde{\gamma}^{ship}_{LRM}$	-30.09	-37.74	-20.88	-9.711	-4.688	0.897
	(5.230)	(5.643)	(5.597)	(2.254)	(2.143)	(3.369)
$\tilde{\gamma}^{api}_{LRM}$	-0.0866	-0.534	-0.652	-0.206	-0.214	-0.314
	(0.389)	(0.317)	(0.343)	(0.137)	(0.139)	(0.258)

Standard errors in parentheses for coefficients, and p-values for test-statistics.

Significance tests against normal distribution: $^{+}$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection.

$\chi^2(6)$ is Cumby and Huizinga (1992) statistic for autocorrelation of order 6

Starred dependent variables computed using initial LOOP regressions in Table 9

Long-run multipliers and their standard errors are below.

A.2 Estimating long-run relationships

An absolute version of the Law of One Price (LOOP) means that the price of crude oil in one market must move one-for-one in another. If LOOP holds, then the difference in crude prices, $P_{c,t} - P_{brent,t}$, must be stationary and cannot have a unit root. Otherwise, the two markets are not well-arbitraged. In econometric terms, it must be that[27]

$$P_{c,t} - P_{brent,t} = \mu + \epsilon_t. \tag{5}$$

The mean price differential, μ, represents differences in crude oil quality and any steady-state transportation costs. The shock, ϵ_t, is mean-zero and may exhibit autocorrelation and heteroskedasticity.

Before proceeding, we check the unit root properties of the weekly average of each crude oil price using a Dickey-Fuller test. The null hypothesis of a unit root during 1990–2006 and the full sample cannot be rejected at the 10% level.[28] The t-statistic for this test is included in Table 4 of summary statistics. Then for each weekly domestic crude oil price, $P_{c,t}$, we use Dynamic OLS (Stock and Watson, 1993; Saikkonen, 1991) to estimate the following cointegrating relationship for the pre-shale period 1990–2006 when the market was in its long-run equilibrium:

$$P_{c,t} = \mu + \delta P_{brent,t} + \sum_{j=-l}^{l} \pi_j P_{brent,t-j} + \epsilon_t. \tag{6}$$

A cross-correlogram suggests that the appropriate number of leads and lags of Brent crude differences is $l = 2$, and we calculate our standard errors using a HAC matrix computed using a Bartlett kernel and Andrews (1991) automatic bandwidth selection.[29]

To verify that our estimates are not spurious, we conduct an Engle-Granger test for a spurious relationship between $P_{c,t}$ and $P_{brent,t}$ by applying a Dickey-Fuller test applied to the estimated residuals equation (6). The 1%, 5%, and 10% critical values for 200 observations are -3.954, -3.368, and -3.067, respectively (Enders, 2008). We reject the null of no cointegration at the 1% level for our six series. This confirms that at minimum, a relative form of LOOP holds for all six crudes. To further distinguish whether the stronger, absolute version of LOOP holds, we use a t-test to test the null hypothesis that $\delta = 1$ versus $\delta \neq 1$. If the test is rejected at the 0.01 level, we use $\hat{\delta}$ to compute price differentials. Otherwise, we simply use $\delta = 1$ to compute these.

Table 9 shows estimates for equation (6). In addition to confirming that LOOP holds for each series, we fail to reject the null hypothesis that $\delta = 1$ for WTI Midland, WTI Cushing and HLS. For these three, we compute price differentials as

$$PD_{c,t} = P_{c,t} - P_{brent,t}. \tag{7}$$

Equation (7) shows that the price differential, $PD_{c,t}$, is an estimate of $\mu + \epsilon_t$.

[27]We considered estimating our model using the logarithm of oil prices; however, the absolute version of LOOP was rejected in all cases. Given our strong priors that an absolute version of LOOP should hold, particularly for Brent and WTI, we chose to estimate our model in levels. This is also the functional form used by Bausell et al. (2001).

[28]There has been a robust debate about the stationarity properties of oil prices after Perron (1989) showed that one can reject a unit root if trends and structural breaks are allowed. Noguera (2013) and Ghoshray (2014) confirm this. The unit root properties of oil prices, however, are not the central focus of this paper. Thus, whether oil prices truly have unit roots is somewhat moot in this context.

[29]This was implemented using the `cointreg` command in Stata's `lrcov` package.

Table 7: All variables: summary statistics

	Mean	SD	Min	Max	N	D-Fuller	Pr($DFuller$)	First obs.	Last obs.
Brent	47.80	34.88	9.80	133.90	312	-1.29	0.63	1990m1	2015m12
Mid-continent crudes									
WTI Cushing	46.78	31.07	11.31	133.93	312	-1.40	0.58	1990m1	2015m12
WTI Midland	46.16	30.37	11.06	134.11	312	-1.45	0.56	1990m1	2015m12
WTS	44.24	30.16	10.07	131.15	312	-1.48	0.54	1990m1	2015m12
Coastal crudes									
LLS	49.34	34.63	11.27	137.99	312	-1.31	0.63	1990m1	2015m12
HLS	48.79	34.64	11.00	136.92	312	-1.32	0.62	1990m1	2015m12
FO USGC	45.61	33.34	9.48	130.06	312	-1.20	0.67	1990m1	2015m12
EIA FPP: Stream									
CA Midway-Sunset	45.65	33.50	7.05	120.20	267	-1.40	0.58	1993m10	2015m12
WTI (EIA)	48.71	30.97	9.69	132.21	267	-1.43	0.57	1993m10	2015m12
WTS (EIA)	46.85	30.59	8.60	129.56	267	-1.49	0.54	1993m10	2015m12
EIA FPP: PADD 1									
PADD 1	43.44	29.57	10.49	130.20	312	-1.38	0.59	1990m1	2015m12
PA	59.53	26.24	18.40	130.11	188	-1.50	0.53	2000m5	2015m12
EIA FPP: PADD 2									
PADD 2	43.03	29.16	9.29	128.49	312	-1.45	0.56	1990m1	2015m12
IL	43.31	29.23	9.79	127.60	312	-1.44	0.56	1990m1	2015m12
KS	43.02	29.30	8.98	127.72	312	-1.44	0.56	1990m1	2015m12
KY	42.03	28.72	8.26	123.85	312	-1.44	0.56	1990m1	2015m12
NE	41.19	28.05	8.63	123.77	312	-1.51	0.53	1990m1	2015m12
ND	41.87	28.69	8.62	126.68	312	-1.49	0.54	1990m1	2015m12
OH	43.30	30.03	9.22	129.33	312	-1.37	0.60	1990m1	2015m12
OK	44.33	30.20	9.74	131.37	312	-1.42	0.57	1990m1	2015m12
SD	61.72	24.02	23.31	124.79	163	-1.86	0.35	2002m6	2015m12
EIA FPP: PADD 3									
PADD 3	44.53	31.30	9.31	130.79	312	-1.28	0.64	1990m1	2015m12
AL	45.40	33.11	9.15	130.65	312	-1.31	0.62	1990m1	2015m12
LA	46.91	33.56	9.75	133.74	312	-1.33	0.62	1990m1	2015m12
MS	43.78	32.73	7.71	128.91	312	-1.32	0.62	1990m1	2015m12
NM	43.67	29.73	9.08	130.78	312	-1.43	0.57	1990m1	2015m12
TX	44.05	30.63	9.20	131.33	312	-1.40	0.58	1990m1	2015m12
EIA FPP: PADD 4									
PADD 4	40.97	27.80	8.56	123.09	312	-1.50	0.53	1990m1	2015m12
CO	43.12	28.54	9.65	126.07	312	-1.45	0.56	1990m1	2015m12
MT	41.29	28.56	8.48	126.80	312	-1.55	0.51	1990m1	2015m12
UT	41.50	26.65	9.25	120.63	312	-1.52	0.52	1990m1	2015m12
WY	39.54	27.18	8.10	120.15	312	-1.59	0.49	1990m1	2015m12
EIA FPP: PADD 5									
PADD 5	41.18	33.21	6.17	124.69	312	-1.26	0.65	1990m1	2015m12
AK North Slope	40.25	32.78	5.34	125.77	312	-1.24	0.65	1990m1	2015m12
CA	42.45	33.55	7.38	123.89	312	-1.30	0.63	1990m1	2015m12
FO CA	38.42	31.95	5.01	119.63	305	-1.33	0.61	1990m1	2015m5
Refining									
Imputed vacuum gas oil cut (PADD 1, percent)	0.40	0.04	0.26	0.53	312	.	.	1990m1	2015m12
Imputed vacuum gas oil cut (PADD 2, percent)	0.38	0.02	0.33	0.42	312	.	.	1990m1	2015m12
Imputed vacuum gas oil cut (PADD 3, percent)	0.41	0.02	0.36	0.46	312	.	.	1990m1	2015m12
Imputed vacuum gas oil cut (PADD 4, percent)	0.32	0.03	0.25	0.39	312	.	.	1990m1	2015m12
Imputed vacuum gas oil cut (PADD 5, percent)	0.45	0.02	0.38	0.53	312	.	.	1990m1	2015m12
Imputed vacuum gas oil cut (U.S., percent)	0.41	0.01	0.37	0.44	312	.	.	1990m1	2015m12
Imputed residuum cut (PADD 1, percent)	0.03	0.02	-0.07	0.07	312	.	.	1990m1	2015m12
Imputed residuum cut (PADD 2, percent)	0.10	0.01	0.07	0.13	312	.	.	1990m1	2015m12
Imputed residuum cut (PADD 3, percent)	0.11	0.02	0.05	0.15	312	.	.	1990m1	2015m12
Imputed residuum cut (PADD 4, percent)	0.08	0.02	0.03	0.13	312	.	.	1990m1	2015m12
Imputed residuum cut (PADD 5, percent)	0.19	0.01	0.15	0.22	312	.	.	1990m1	2015m12
Imputed residuum cut (U.S., percent)	0.12	0.01	0.08	0.14	312	.	.	1990m1	2015m12
Avg API: PADD 1	32.53	1.23	29.82	35.39	312	.	.	1990m1	2015m12
Avg API: PADD 2	33.15	0.79	31.12	35.06	312	.	.	1990m1	2015m12
Avg API: PADD 3	30.95	1.15	28.96	33.69	312	.	.	1990m1	2015m12
Avg API: PADD 4	33.62	1.06	31.56	36.75	312	.	.	1990m1	2015m12
Avg API: PADD 5	26.86	1.22	23.99	29.71	312	.	.	1990m1	2015m12
Avg API: TXGC	30.25	1.70	26.97	34.23	312	.	.	1990m1	2015m12
Avg API: U.S.	30.94	0.55	29.75	32.23	312	.	.	1990m1	2015m12
Transport									
Rail/Tanker share from PADDs 2 & 4 to PADD 3	0.09	0.16	0.00	0.60	312	.	.	1990m1	2015m12
Share of crude via rail / barge out of PADDs 2 + 4 (PADD 2 only)	0.21	0.17	0.00	0.70	312	.	.	1990m1	2015m12
Share of crude via rail / barge out of PADDs 2 + 4 (PADD 4 only)	0.13	0.29	0.00	1.00	312	.	.	1990m1	2015m12
Share of crude via rail / barge out of PADDs 2 + 4 (PADDs 2+4)	0.19	0.19	0.00	0.71	312	.	.	1990m1	2015m12

Dickey-Fuller test is for null hypothesis of a unit root.

Table 8: Crude quality

Crude	API gravity	Sulfur Content
WTI Cushing	39	0.34%
WTI Midland	39	0.34%
WTS	34	1.9%
LLS	35.7	0.44%
HLS	33.7	0.39%

Crude characteristics taken from Bloomberg

For the other three crudes, WTS, LLS, and FO USGC, we reject the null hypothesis that $\delta = 0$ in favor of the alternative ($\delta \neq 1$). This means that only a relative version of LOOP holds for these three crudes, so we compute price differentials as

$$PD_{c,t} = P_{c,t} - \hat{\delta}_c P_{brent,t}. \tag{8}$$

While we statically reject $\delta_c = 1$ for these crudes, the coefficient is still very close to 1.[30] Since $\hat{\delta}_c$ is a superconsistent estimator of the true δ_c, sampling error from estimating δ will not affect the consistency or distribution of our estimator when we use $PD_{c,t}$ as the dependent variable in subsequent regressions.

[30] We cannot definitively explain why $\delta \neq 1$ for these crudes, but we do note that these crudes are heavier and/or more sour than the others. Table 8 shows the crude oil characteristics Bloomberg cites. EIA documentation of the FO USGC crude price explains that the price is a blend of several offshore crudes. A number of these have been tracked by Bloomberg periodically, and the documentation for them shows that they are heavier and more sour than WTI or LLS.

Table 9: LOOP regressions for 1990m1–2006m12

	Mid-continent			Gulf Coast		
	WTI Cushing	WTI Midland	WTS	LLS	HLS	FO USGC
δ	1.005***	1.009***	0.919***	1.022***	0.992***	0.939***
	(0.00929)	(0.00830)	(0.00727)	(0.00694)	(0.00651)	(0.0108)
μ	1.463***	1.214***	1.448***	1.159***	1.400***	0.398
	(0.266)	(0.237)	(0.208)	(0.198)	(0.186)	(0.308)
N	199	199	199	199	199	199
$z_{\delta-1}$	0.488	1.032	-11.12	3.158	-1.207	-5.661
$\Pr(\|z\|)$	0.626	0.302	9.72e-29	0.00159	0.228	1.51e-08
D-Fuller	-6.346	-6.639	-6.820	-6.958	-7.112	-9.298

Standard errors in parentheses

Dynamic OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection.

$z_{\delta-1}$ is a t-test for absolute version of LOOP, and δ chosen based on rejection of Absolote LOOP at 0.01 level

* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

A.3 All crudes

Table 10: All crudes: LOOP regressions for 1990m1–2006m12

	δ		μ		D-Fuller	$z_{\delta-1}$	δ	N
Mid-continent crudes								
WTI Cushing	1.005***	(0.00929)	1.463***	(0.266)	-6.346	0.488	1	199
WTI Midland	1.009***	(0.00830)	1.214***	(0.237)	-6.639	1.032	1	199
WTS	0.919***	(0.00727)	1.448***	(0.208)	-6.820	-11.12***	0.919	199
Coastal crudes								
LLS	1.022***	(0.00694)	1.159***	(0.198)	-6.958	3.158**	1.022	199
HLS	0.992***	(0.00651)	1.400***	(0.186)	-7.112	-1.207	1	199
FO USGC	0.939***	(0.0108)	0.398	(0.308)	-9.298	-5.661***	0.939	199
EIA FPP: Stream								
CA Midway-Sunset	0.883***	(0.0239)	-1.726	(0.727)	-4.600	-4.878***	0.883	154
WTI (EIA)	0.980***	(0.0129)	0.630	(0.393)	-4.737	-1.567	1	154
WTS (EIA)	0.924***	(0.0152)	0.281	(0.461)	-4.743	-4.983***	0.924	154
EIA FPP: PADD 1								
PADD 1	0.984***	(0.0138)	0.153	(0.395)	-7.044	-1.131	1	199
PA	0.969***	(0.0137)	1.334	(0.545)	-4.835	-2.256	1	75
EIA FPP: PADD 2								
PADD 2	0.956***	(0.0167)	0.486	(0.476)	-4.094	-2.656**	0.956	199
IL	0.909***	(0.0140)	1.736***	(0.401)	-4.461	-6.464***	0.909	199
KS	0.959***	(0.0156)	0.247	(0.447)	-4.120	-2.632**	0.959	199
KY	0.885***	(0.0131)	1.303***	(0.374)	-5.029	-8.773***	0.885	199
NE	0.932***	(0.0245)	0.134	(0.700)	-2.500	-2.765**	0.932	199
ND	0.927***	(0.0275)	0.417	(0.787)	-4.209	-2.641**	0.927	199
OH	0.976***	(0.0141)	-0.228	(0.404)	-6.525	-1.709	1	199
OK	0.990***	(0.0150)	0.145	(0.429)	-4.609	-0.675	1	199
SD	0.696***	(0.0651)	9.975**	(3.055)	-2.138	-4.669***	0.696	50
EIA FPP: PADD 3								
PADD 3	0.959***	(0.0130)	0.204	(0.371)	-6.508	-3.133**	0.959	199
AL	0.993***	(0.0109)	-0.638	(0.311)	-7.581	-0.648	1	199
LA	1.005***	(0.0142)	0.0578	(0.406)	-6.012	0.320	1	199
MS	0.943***	(0.0144)	-1.210**	(0.413)	-4.802	-3.912***	0.943	199
NM	0.965***	(0.0151)	0.396	(0.431)	-4.966	-2.326	1	199
TX	0.960***	(0.0145)	0.231	(0.416)	-5.087	-2.767**	0.960	199
EIA FPP: PADD 4								
PADD 4	0.907***	(0.0181)	0.544	(0.518)	-3.686	-5.158***	0.907	199
CO	1.007***	(0.0165)	-0.101	(0.470)	-5.644	0.451	1	199
MT	0.934***	(0.0271)	-0.248	(0.773)	-2.775	-2.436	1	199
UT	0.940***	(0.0154)	1.268**	(0.439)	-2.828	-3.926***	0.940	199
WY	0.817***	(0.0219)	1.618**	(0.627)	-4.024	-8.338***	0.817	199
EIA FPP: PADD 5								
PADD 5	0.951***	(0.0340)	-4.210***	(0.970)	-4.618	-1.448	1	199
AK North Slope	0.964***	(0.0307)	-5.130***	(0.878)	-5.898	-1.169	1	199
CA	0.926***	(0.0330)	-2.559**	(0.942)	-3.831	-2.243	1	199
FO CA	0.903***	(0.0380)	-4.570***	(1.087)	-3.160	-2.544	1	199

Standard errors in parentheses

Dynamic OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection.

$z_{\delta-1}$ is a t-test of the null that $\delta = 1$ versus $\delta \neq 1$ (an absolute version of LOOP). If we reject the null at the 0.01 level, we use $\hat{\delta}$.

** $p < 0.01$, *** $p < 0.001$

Robustness: serial correlation Our estimates of equations (1) and (2) both suffer from serial correlation of the residuals, as evidenced by the Cumby and Huizinga (1992) statistics in the bottom of Tables 2 and 3. While the Andrews (1991) HAC estimator corrects standard errors for this issue, we also try parametrically correcting for serial correlation by adding two lags of $PD_{c,t}$ and re-estimating our model (still with the HAC standard errors). Results are given in Tables 5 and 6 in the Appendix. Because adjustment of price differentials is now dynamic, the relevant quantities of interest are the long-run multipliers, not the simple coefficients. Given a generic coefficient, γ, the associated long-run multiplier is

$$\gamma^{LRM} = \frac{\gamma}{1 - \rho_1 - \rho_2}.$$

The long-run multipliers are very close to the coefficients estimated in static regressions (Tables 2 and 3), so we are comfortable that our results are robust to serial correlation.

Robustness: other crudes As mentioned, we repeat our analysis for all of the geography-specific crude oil prices reported by the EIA at the monthly level (plus the six main prices we focus on). The majority of these are state or PADD-specific average crude oil wellhead prices. Summary statistics are given in Table 7. Table 10 gives results from our stage one pre-shale model, equation (5). We compute price differentials from these quantities exactly as before and estimate models (1) and (2) both without lags (Tables 11 and 12) and with lags (Tables 13 and 14). We find qualitatively similar results as before. Crudes along the US Gulf Coast (AL, LA, and MS) do exhibit strucutral breaks, but rejection of the null of no breaks is weaker than for inland crudes, and the trend in the post-pipeline regime is not statistically different from zero. Statistical support for breaks in PADD 5 crudes is much weaker, and a number of the trend terms have the opposite signs from mid-continent crudes. This is as expected. PADD 5 is not well connected to the rest of the country via crude pipelines, so mid-continent transmission constraints should have small effects.

In PADDs 1, 2, and 4, the coefficient on γ^{ship} is negative and significant for all states except South Dakota, which has minimal crude production. The shipping constraint coefficient (γ^{ship}) for Gulf Coast and PADD 5 crudes has much smaller magnitudes. In contrast, the coefficient on API gravity, γ^{api}, has limited statistical significance for all regressions, and is not significant at all for most. In total, these results support our conclusion that crude-oil discounts were mainly related to shipping constraints, not export (refining) constraints.

Table 11: All crudes: price differential break tests, OLS

	Intercepts						Trends						Break tests			Stats	
	α_0		α_1		α_2		β_0		β_1		β_2		$F_{\beta_0=\beta_1}$	$F_{\beta_1=\beta_2}$	$F_{\beta_0=\beta_1=\beta_2}$	N	$\chi^2(6)$
Mid-continent crudes																	
WTI Cushing	1.223***	(0.18)	64.79**	(21.44)	-129.9***	(14.30)	0.0389	(0.03)	-3.499**	(1.11)	5.012***	(0.59)	10.03**	36.73***	36.10***	312	33.67***
WTI Midland	1.127***	(0.14)	71.18**	(23.26)	-150.6***	(13.26)	0.0343	(0.03)	-3.847**	(1.20)	5.741***	(0.54)	10.25**	49.97***	59.90***	312	37.31***
WTS	1.210***	(0.22)	47.07*	(22.02)	-124.5***	(17.82)	0.0297	(0.02)	-2.394*	(1.13)	4.954***	(0.72)	4.529*	24.15***	23.67***	312	33.75***
Coastal crudes																	
LLS	1.040***	(0.13)	12.35**	(4.36)	-17.83	(13.60)	0.0123	(0.02)	-0.591**	(0.22)	0.609	(0.56)	6.987**	4.408*	4.625*	312	24.82***
HLS	1.209***	(0.13)	2.858	(2.62)	4.449	(10.79)	-0.00134	(0.02)	-0.0484	(0.13)	-0.247	(0.44)	0.133	0.175	0.238	312	21.84**
FO USGC	0.275	(0.21)	-2.709	(10.00)	17.26	(14.25)	0.00728	(0.03)	0.231	(0.49)	-0.702	(0.58)	0.211	1.425	0.819	312	23.54***
EIA FPP: Stream																	
CA Midway-Sunset	-2.694***	(0.71)	-29.50***	(7.18)	65.49***	(12.53)	0.0850	(0.09)	1.527***	(0.35)	-2.646***	(0.51)	14.93***	59.77***	30.24***	267	37.17***
WTI (EIA)	0.590	(0.61)	62.99**	(20.24)	-114.4***	(10.98)	-0.0580	(0.07)	-3.546***	(1.05)	4.199***	(0.44)	10.51**	38.49***	45.85***	267	40.91***
WTS (EIA)	-0.199	(0.62)	49.70*	(20.57)	-121.9***	(20.65)	0.0413	(0.08)	-2.644*	(1.06)	4.734***	(0.83)	6.098*	25.01***	16.98***	267	41.74***
EIA FPP: PADD 1																	
PADD 1	-0.319	(0.47)	69.28***	(16.12)	-57.81***	(10.61)	0.000474	(0.05)	-3.976***	(0.83)	1.692***	(0.44)	22.56***	37.64***	19.71***	312	33.14***
PA	3.207*	(1.42)	83.13***	(18.66)	-100.4***	(17.28)	-0.234*	(0.11)	-4.741***	(0.95)	3.410***	(0.73)	20.54***	53.73***	28.13***	188	33.86***
EIA FPP: PADD 2																	
PADD 2	0.192	(0.34)	63.53**	(19.67)	-107.0***	(13.00)	0.0305	(0.06)	-3.570***	(1.02)	3.954***	(0.53)	11.90***	32.42***	27.68***	312	45.79***
IL	1.691***	(0.26)	51.19**	(18.58)	-84.66***	(21.23)	0.00368	(0.05)	-2.733**	(0.96)	3.273***	(0.87)	7.906**	16.35***	8.607***	312	40.51***
KS	0.137	(0.37)	58.97**	(18.24)	-116.6***	(17.33)	0.0124	(0.06)	-3.357***	(0.94)	4.367***	(0.71)	12.18***	32.53***	20.24***	312	37.35***
KY	1.727***	(0.24)	46.90**	(17.21)	-96.80***	(19.53)	-0.0522	(0.04)	-2.531**	(0.89)	3.841***	(0.81)	7.635**	22.01***	12.79***	312	37.38***
NE	-0.396	(0.53)	47.47**	(17.17)	-111.7***	(15.70)	0.0585	(0.09)	-2.831**	(0.89)	4.097***	(0.64)	9.611**	30.79***	20.92***	312	42.91***
ND	-0.137	(0.52)	58.40**	(19.29)	-91.81***	(14.67)	0.0556	(0.10)	-3.284**	(1.00)	3.373***	(0.60)	10.51**	23.89***	16.13***	312	49.78***
OH	-0.0271	(0.34)	57.95**	(18.43)	-51.85***	(11.14)	-0.103**	(0.04)	-3.394***	(0.95)	1.511***	(0.45)	11.78***	18.24***	9.994***	312	32.57***
OK	-0.415	(0.34)	65.89***	(19.68)	-134.3***	(14.88)	0.0324	(0.06)	-3.755***	(1.02)	5.037***	(0.61)	13.23***	43.30***	34.56***	312	38.78***
SD	10.71	(8.80)	31.62^{+}	(19.17)	19.51	(36.43)	-0.0904	(0.62)	-1.017	(0.94)	-0.384	(1.49)	0.487	0.106	0.247	163	34.19***
EIA FPP: PADD 3																	
PADD 3	-0.0824	(0.24)	37.54*	(15.59)	-60.73***	(10.24)	0.0290	(0.04)	-2.033*	(0.80)	2.227***	(0.41)	6.520*	22.16***	17.45***	312	40.49***
AL	-0.882**	(0.28)	16.36**	(6.21)	10.96	(12.85)	0.0000942	(0.04)	-1.033***	(0.31)	-0.762	(0.53)	10.98**	0.192	6.623**	312	28.29***
LA	-0.286	(0.25)	18.37**	(6.80)	-12.92	(9.74)	0.0506	(0.04)	-1.032**	(0.34)	0.352	(0.39)	9.382**	6.905**	5.000**	312	29.50***
MS	-1.347***	(0.24)	14.98	(9.75)	-13.27	(9.59)	0.0147	(0.04)	-0.795	(0.50)	0.426	(0.39)	2.570	3.818^{+}	1.917	312	41.04***
NM	-0.331	(0.47)	64.37**	(21.58)	-148.0***	(12.80)	-0.0268	(0.07)	-3.678***	(1.12)	5.493***	(0.52)	10.19**	48.13***	57.76***	312	44.49***
TX	-0.163	(0.29)	54.33**	(19.18)	-84.17***	(11.78)	0.0434	(0.05)	-2.955**	(0.99)	3.125***	(0.48)	8.887**	24.00***	21.26***	312	38.26***
EIA FPP: PADD 4																	
PADD 4	0.143	(0.37)	50.80**	(18.35)	-102.7***	(12.86)	0.0435	(0.06)	-2.887**	(0.96)	3.808***	(0.52)	8.984**	29.88***	26.41***	312	44.91***
CO	-0.465	(0.30)	61.49**	(19.71)	-134.8***	(8.94)	0.0622	(0.05)	-3.695***	(1.03)	4.860***	(0.36)	12.78***	53.28***	87.54***	312	38.56***
MT	-1.481*	(0.72)	65.16**	(20.84)	-139.0***	(9.65)	-0.0658	(0.13)	-3.953***	(1.09)	4.984***	(0.39)	11.74***	49.94***	76.49***	312	46.38***
UT	1.270**	(0.39)	54.40**	(17.59)	-132.0***	(6.61)	-0.00633	(0.06)	-3.288***	(0.92)	4.835***	(0.26)	12.06***	72.29***	173.5***	312	35.18***
WY	1.198**	(0.43)	36.88^{+}	(19.27)	-70.35**	(22.30)	0.0490	(0.06)	-1.901^{+}	(0.99)	2.766**	(0.91)	3.785^{+}	9.579**	5.229**	312	52.83***
EIA FPP: PADD 5																	
PADD 5	-5.998***	(0.79)	-0.499	(7.14)	-22.08**	(7.95)	0.0562	(0.09)	-0.383	(0.37)	0.512	(0.33)	1.216	3.655^{+}	1.880	312	81.62***
AK North Slope	-6.726***	(0.72)	8.527	(9.35)	-32.37***	(9.40)	0.0722	(0.08)	-0.884^{+}	(0.48)	0.824*	(0.39)	3.728^{+}	9.504**	4.847**	312	71.81***
CA	-4.463***	(1.04)	-10.33*	(4.96)	-9.081	(7.37)	-0.00364	(0.13)	0.174	(0.26)	0.0824	(0.30)	0.330	0.0492	0.178	312	81.48***
FO CA	-6.765***	(1.13)	-9.339	(8.54)	25.47**	(9.72)	-0.0367	(0.16)	-0.131	(0.44)	-1.801***	(0.40)	0.0336	12.25***	10.60***	305	74.56***

Standard errors in parentheses. Significance tests against normal distribution: $^{+}$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection. Included hurricane dummies. $\chi^2(6)$ is Cumby and Huizinga (1992) statistic for autocorrelation of order 6

Standard errors in parentheses for coefficients, and p-values for test-statistics.

Significance tests against normal distribution: $^{+}$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 12: All crudes: price differential decomposition: OLS

	Shipping		Refining		Stats			Explanatory power		
	γ^{ship}		γ^{api}		F_{ref}	N	$\chi^2(6)$	R^2	R^2_{ship}	R^2_{ref}
Mid-continent crudes										
WTI Cushing	-31.19***	(4.08)	-0.355	(0.26)	1.916	312	30.39***	0.724	0.720	0.00661
WTI Midland	-37.97***	(3.36)	-0.708*	(0.31)	5.321*	312	31.56***	0.755	0.742	0.00608
WTS	-21.02***	(4.44)	-0.777*	(0.38)	4.237*	312	28.30***	0.480	0.448	0.00488
Coastal crudes										
LLS	-9.298***	(2.05)	-0.357*	(0.14)	6.429*	312	23.20***	0.517	0.480	0.0143
HLS	-4.157$^+$	(2.30)	-0.303*	(0.15)	4.105*	312	31.52***	0.221	0.181	0.0698
FO USGC	1.300	(2.48)	-0.370	(0.25)	2.230	312	22.58***	0.158	0.145	0.155
EIA FPP: Stream										
CA Midway-Sunset	10.93***	(1.59)	-0.334	(0.27)	1.501	267	35.92***	0.360	0.351	0.0351
WTI (EIA)	-34.93***	(3.06)	-0.452	(0.39)	1.322	267	34.40***	0.738	0.735	0.000000822
WTS (EIA)	-23.39***	(4.21)	-0.899*	(0.45)	4.051*	267	34.38***	0.510	0.487	0.0123
EIA FPP: PADD 1										
PADD 1	-39.62***	(3.05)	-0.203	(0.35)	0.336	312	37.03***	0.765	0.764	0.00328
PA	-42.21***	(4.00)	-1.634	(1.08)	2.285	188	36.62***	0.755	0.740	0.131
EIA FPP: PADD 2										
PADD 2	-33.91***	(3.64)	-0.235	(0.24)	0.972	312	36.22***	0.776	0.774	0.00574
IL	-22.34***	(4.20)	-0.197	(0.26)	0.584	312	32.31***	0.582	0.579	0.000410
KS	-32.23***	(3.94)	-0.0461	(0.26)	0.0327	312	31.68***	0.739	0.739	0.000500
KY	-18.76***	(4.60)	0.140	(0.27)	0.270	312	30.43***	0.509	0.507	0.0320
NE	-34.62***	(3.26)	-0.0935	(0.27)	0.119	312	37.83***	0.757	0.757	0.00000767
ND	-31.26***	(3.77)	-0.353	(0.26)	1.818	312	41.63***	0.724	0.719	0.00307
OH	-34.60***	(3.20)	0.131	(0.31)	0.180	312	34.81***	0.727	0.726	0.0284
OK	-35.84***	(3.97)	-0.135	(0.25)	0.303	312	35.29***	0.762	0.761	0.00310
SD	-0.653	(4.70)	-0.741	(1.21)	0.374	163	30.42***	0.0341	0.0257	0.0337
EIA FPP: PADD 3										
PADD 3	-19.16***	(1.80)	-0.502*	(0.23)	4.726*	312	37.27***	0.571	0.552	0.00368
AL	-12.85***	(3.01)	-0.0849	(0.26)	0.108	312	43.30***	0.352	0.352	0.00140
LA	-10.71***	(1.71)	-0.280$^+$	(0.16)	3.142$^+$	312	30.91***	0.348	0.337	0.00519
MS	-5.023***	(1.08)	-0.413*	(0.21)	4.003*	312	46.69***	0.161	0.123	0.0477
NM	-39.77***	(3.12)	-0.335	(0.28)	1.391	312	35.64***	0.761	0.759	0.0117
TX	-25.44***	(3.00)	-0.555*	(0.26)	4.472*	312	33.49***	0.632	0.617	0.0000940
EIA FPP: PADD 4										
PADD 4	-31.43***	(3.04)	-0.232	(0.20)	1.306	312	33.57***	0.752	0.750	0.00686
CO	-46.26***	(3.15)	-0.0456	(0.26)	0.0304	312	33.36***	0.833	0.833	0.0000532
MT	-45.33***	(3.64)	0.142	(0.28)	0.256	312	36.38***	0.834	0.833	0.0521
UT	-43.52***	(2.78)	0.326	(0.32)	1.026	312	35.01***	0.838	0.835	0.0707
WY	-16.85***	(3.84)	-0.418	(0.31)	1.789	312	45.23***	0.371	0.360	0.000508
EIA FPP: PADD 5										
PADD 5	-10.29***	(1.46)	-0.139	(0.25)	0.298	312	79.46***	0.356	0.353	0.00181
AK North Slope	-15.20***	(1.33)	-0.337	(0.22)	2.452	312	71.86***	0.539	0.525	0.00181
CA	-5.860**	(1.89)	0.176	(0.32)	0.308	312	87.74***	0.145	0.140	0.0283
FO CA	-19.35***	(4.24)	0.165	(0.44)	0.144	305	82.88***	0.513	0.511	0.0333

Standard errors in parentheses. Significance tests against normal distribution: $^+$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection. Included hurricane dummies.

F_{ref} is joint test for significance of refining variables. $\chi^2(6)$ is Cumby and Huizinga (1992) statistic for autocorrelation of order 6

Table 13: All crudes: price differential break tests, AR(2)

	Intercepts						Trends						Break tests			Stats	
	α_0		α_1		α_2		β_0		β_1		β_2		$F_{\beta_0=\beta_1}$	$F_{\beta_1=\beta_2}$	$F_{\beta_0=\beta_1=\beta_2}$	N	$\chi^2(6)$
Mid-continent crudes																	
WTI Cushing	0.264*	(0.10)	14.86**	(5.39)	-26.98*	(11.27)	0.00377	(0.01)	-0.805**	(0.28)	1.052*	(0.44)	8.120**	9.545**	5.151**	310	1.549
WTI Midland	0.239**	(0.08)	16.72**	(5.78)	-31.04*	(13.97)	0.00429	(0.01)	-0.906**	(0.30)	1.195*	(0.55)	8.900**	9.071**	5.418**	310	2.269
WTS	0.288**	(0.11)	12.59*	(5.24)	-27.31*	(12.63)	0.00358	(0.01)	-0.646*	(0.27)	1.094*	(0.50)	5.684*	8.695**	4.825**	310	3.092
Coastal crudes																	
LLS	0.336***	(0.09)	3.887*	(1.61)	-8.958^{+}	(5.05)	0.00147	(0.01)	-0.188*	(0.08)	0.331	(0.20)	5.251*	5.419*	3.768*	310	2.574
HLS	0.524***	(0.11)	1.149	(1.49)	-0.254	(5.41)	-0.00116	(0.01)	-0.0175	(0.07)	-0.0168	(0.22)	0.0470	0.0000107	0.0266	310	2.013
FO USGC	0.138	(0.12)	-1.897	(5.73)	4.857	(14.59)	-0.000275	(0.02)	0.144	(0.29)	-0.198	(0.59)	0.245	0.243	0.160	310	3.007
EIA FPP: Stream																	
CA Midway-Sunset	-0.910**	(0.32)	-11.73*	(4.99)	24.06**	(9.02)	0.0204	(0.03)	0.611*	(0.26)	-0.976**	(0.36)	5.258*	9.357**	4.680*	265	1.147
WTI (EIA)	0.238^{+}	(0.14)	16.77**	(5.99)	-27.99**	(9.84)	-0.0259	(0.02)	-0.941**	(0.32)	1.034**	(0.38)	8.289**	11.90***	5.992**	265	3.012
WTS (EIA)	0.0292	(0.16)	14.34*	(5.82)	-29.65**	(11.27)	0.00175	(0.02)	-0.762*	(0.30)	1.154**	(0.45)	6.336*	11.02**	5.623**	265	1.646
EIA FPP: PADD 1																	
PADD 1	-0.0661	(0.13)	21.25***	(5.53)	-19.91*	(8.94)	-0.00668	(0.01)	-1.224***	(0.30)	0.617^{+}	(0.35)	16.69***	13.73***	8.939***	310	1.567
PA	1.456*	(0.67)	21.75***	(5.62)	-30.08**	(11.16)	-0.110*	(0.05)	-1.246***	(0.30)	1.064*	(0.43)	14.15***	14.80***	8.461***	186	1.885
EIA FPP: PADD 2																	
PADD 2	0.0698	(0.09)	18.66**	(6.35)	-26.31*	(10.45)	0.00224	(0.02)	-1.045**	(0.34)	0.972*	(0.40)	9.436**	10.51**	5.551**	310	2.642
IL	0.355**	(0.11)	11.83*	(4.67)	-16.49^{+}	(9.10)	-0.00329	(0.01)	-0.633**	(0.24)	0.641^{+}	(0.36)	6.787**	7.699**	4.479*	310	1.770
KS	0.0347	(0.08)	13.52**	(4.93)	-24.64*	(10.09)	-0.00130	(0.01)	-0.769**	(0.26)	0.930*	(0.39)	8.495**	10.08**	5.442**	310	1.006
KY	0.375**	(0.12)	11.13*	(4.52)	-19.50*	(9.39)	-0.0159	(0.01)	-0.601*	(0.23)	0.778*	(0.38)	6.293*	8.842**	4.865**	310	1.463
NE	-0.0520	(0.10)	11.22*	(4.48)	-24.05*	(9.51)	0.00441	(0.02)	-0.662**	(0.24)	0.893*	(0.36)	7.694**	11.12***	5.878**	310	1.748
ND	-0.00464	(0.15)	20.99**	(6.80)	-25.35*	(10.81)	0.00835	(0.03)	-1.172**	(0.36)	0.924*	(0.42)	10.54**	11.29***	6.190**	310	5.517
OH	0.00575	(0.11)	15.48**	(5.00)	-15.39^{+}	(8.88)	-0.0318*	(0.01)	-0.910***	(0.27)	0.476	(0.35)	10.83**	8.766**	5.901**	310	1.787
OK	-0.0686	(0.09)	15.61**	(5.42)	-29.45**	(10.84)	0.00142	(0.01)	-0.889**	(0.29)	1.113**	(0.42)	9.222**	11.31***	5.918**	310	2.747
SD	4.568	(3.35)	10.96^{+}	(5.89)	12.80	(10.48)	-0.166	(0.24)	-0.424	(0.30)	-0.433	(0.43)	0.438	0.000256	0.276	161	3.468
EIA FPP: PADD 3																	
PADD 3	-0.0168	(0.09)	13.56**	(5.22)	-21.46*	(8.47)	0.00541	(0.01)	-0.732**	(0.27)	0.796*	(0.33)	7.387**	11.34***	5.831**	310	1.586
AL	-0.451**	(0.14)	8.089	(4.94)	2.621	(9.28)	-0.00356	(0.02)	-0.515*	(0.26)	-0.271	(0.38)	3.859^{+}	0.286	2.141	310	1.757
LA	-0.158	(0.12)	9.320*	(4.40)	-8.849	(8.44)	0.0254	(0.02)	-0.525*	(0.23)	0.268	(0.34)	5.658*	3.753^{+}	3.116*	310	0.346
MS	-0.543***	(0.13)	6.327	(4.11)	-6.581	(6.65)	0.00403	(0.01)	-0.333	(0.21)	0.222	(0.27)	2.493	2.690	1.609	310	0.417
NM	-0.0521	(0.10)	16.97**	(6.04)	-35.27**	(11.46)	-0.0123	(0.01)	-0.965**	(0.32)	1.318**	(0.44)	8.678**	13.45***	6.795**	310	2.862
TX	-0.0292	(0.09)	14.86**	(5.67)	-20.73*	(8.73)	0.00678	(0.01)	-0.808**	(0.29)	0.774*	(0.34)	7.493**	9.962**	5.132**	310	2.508
EIA FPP: PADD 4																	
PADD 4	0.0471	(0.09)	15.81**	(5.47)	-26.64*	(10.59)	0.00782	(0.02)	-0.891**	(0.29)	0.988*	(0.41)	9.478**	11.59***	6.293**	310	2.834
CO	-0.0887	(0.10)	15.93**	(5.72)	-34.09**	(12.42)	0.00811	(0.01)	-0.956**	(0.32)	1.248**	(0.47)	9.157**	11.37***	5.958**	310	2.329
MT	-0.371^{+}	(0.20)	20.92***	(6.30)	-35.62**	(12.67)	-0.0266	(0.03)	-1.250***	(0.34)	1.276**	(0.48)	12.43***	14.47***	7.875***	310	3.548
UT	0.329*	(0.13)	13.78**	(5.24)	-31.57*	(12.65)	-0.0108	(0.02)	-0.827**	(0.29)	1.176*	(0.48)	7.892**	9.950**	5.309**	310	3.516
WY	0.336**	(0.12)	13.33*	(6.18)	-15.94	(12.17)	0.0128	(0.02)	-0.688*	(0.32)	0.623	(0.49)	4.771*	4.933*	3.098*	310	4.006
EIA FPP: PADD 5																	
PADD 5	-1.781***	(0.33)	0.350	(3.67)	-8.597	(7.06)	0.00866	(0.02)	-0.142	(0.19)	0.234	(0.28)	0.644	1.177	0.612	310	1.195
AK North Slope	-2.165***	(0.41)	4.242	(3.98)	-12.17	(9.47)	0.0121	(0.02)	-0.366^{+}	(0.20)	0.334	(0.38)	3.355^{+}	2.480	1.927	310	1.519
CA	-1.301***	(0.30)	-3.204	(4.21)	-5.137	(6.68)	-0.00551	(0.02)	0.0608	(0.22)	0.127	(0.27)	0.0940	0.0366	0.168	310	2.541
FO CA	-1.531***	(0.41)	-2.017	(3.99)	0.727	(10.64)	-0.0153	(0.02)	-0.0367	(0.20)	-0.202	(0.45)	0.0117	0.107	0.0974	303	4.021

Standard errors in parentheses. Significance tests against normal distribution: $^{+}$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection. Included 2 lags of $pd_{c,t}$ and hurricane dummies.

$\chi^2(6)$ is Cumby and Huizinga (1992) statistic for autocorrelation of order 6

Table 14: All crudes: price differential decomposition, AR(2)

	Shipping		Refining		LRM: Ship		LRM: Refining		Stats		
	γ^{ship}		γ^{api}		$\widetilde{\gamma}^{ship}$		$\widetilde{\gamma}^{api}$		F_{ref}	N	$\chi^2(6)$
Mid-continent crudes											
WTI Cushing	-5.669**	(1.94)	-0.0163	(0.08)	-30.09***	(5.23)	-0.0866	(0.39)	0.0457	310	1.714
WTI Midland	-7.947***	(2.04)	-0.112	(0.08)	-37.74***	(5.64)	-0.534^{+}	(0.32)	2.142	310	1.532
WTS	-4.392**	(1.38)	-0.137^{+}	(0.08)	-20.88***	(5.60)	-0.652^{+}	(0.34)	2.940^{+}	310	2.756
Coastal crudes											
LLS	-2.695***	(0.66)	-0.0572	(0.04)	-9.711***	(2.25)	-0.206	(0.14)	1.924	310	3.350
HLS	-1.445*	(0.59)	-0.0659	(0.04)	-4.688*	(2.14)	-0.214	(0.14)	2.311	310	4.482
FO USGC	0.428	(1.61)	-0.150	(0.12)	0.897	(3.37)	-0.314	(0.26)	1.476	310	2.780
EIA FPP: Stream											
CA Midway-Sunset	3.176*	(1.35)	-0.0840	(0.13)	10.18***	(2.97)	-0.269	(0.38)	0.433	265	1.092
WTI (EIA)	-7.886***	(2.04)	-0.0396	(0.11)	-34.96***	(4.49)	-0.176	(0.48)	0.127	265	4.494
WTS (EIA)	-5.533***	(1.67)	-0.171	(0.13)	-23.52***	(5.05)	-0.727	(0.49)	1.617	265	2.287
EIA FPP: PADD 1											
PADD 1	-6.582***	(1.91)	0.0370	(0.07)	-39.15***	(6.24)	0.220	(0.46)	0.256	310	4.341
PA	-6.617**	(2.26)	0.00763	(0.31)	-43.26***	(8.69)	0.0499	(2.06)	0.000592	186	2.898
EIA FPP: PADD 2											
PADD 2	-8.249***	(2.13)	-0.00825	(0.07)	-33.18***	(4.36)	-0.0332	(0.29)	0.0130	310	3.842
IL	-3.912**	(1.33)	-0.00368	(0.07)	-21.16***	(4.97)	-0.0199	(0.36)	0.00304	310	2.328
KS	-5.602**	(1.86)	0.0343	(0.06)	-31.24***	(5.22)	0.191	(0.38)	0.293	310	1.821
KY	-3.070**	(1.19)	0.0698	(0.07)	-17.16***	(5.08)	0.390	(0.41)	1.075	310	1.457
NE	-6.367***	(1.86)	0.0244	(0.07)	-33.77***	(5.10)	0.129	(0.37)	0.132	310	2.397
ND	-9.984***	(2.23)	-0.0560	(0.10)	-30.43***	(3.98)	-0.171	(0.29)	0.338	310	6.456
OH	-6.339***	(1.90)	0.0806	(0.07)	-34.10***	(5.68)	0.434	(0.40)	1.343	310	2.860
OK	-6.463**	(2.05)	0.0280	(0.07)	-34.86***	(5.25)	0.151	(0.39)	0.167	310	3.698
SD	-0.580	(1.67)	-0.00548	(0.34)	-2.654	(7.69)	-0.0251	(1.54)	0.000266	161	2.945
EIA FPP: PADD 3											
PADD 3	-6.299***	(1.46)	-0.142^{+}	(0.08)	-19.33***	(3.04)	-0.435^{+}	(0.24)	2.881^{+}	310	2.197
AL	-4.810***	(1.43)	-0.00326	(0.09)	-12.97***	(3.34)	-0.00879	(0.23)	0.00144	310	7.368
LA	-5.122***	(1.21)	-0.121	(0.08)	-10.76***	(2.30)	-0.255^{+}	(0.15)	2.541	310	0.970
MS	-1.937*	(0.89)	-0.144*	(0.07)	-5.044*	(2.38)	-0.376*	(0.16)	4.383*	310	1.023
NM	-8.831***	(2.35)	-0.0371	(0.08)	-39.60***	(5.20)	-0.166	(0.34)	0.221	310	3.238
TX	-6.176***	(1.57)	-0.108	(0.08)	-25.48***	(4.06)	-0.446	(0.29)	1.783	310	4.135
EIA FPP: PADD 4											
PADD 4	-8.713***	(2.16)	-0.0270	(0.07)	-30.60***	(3.83)	-0.0949	(0.25)	0.135	310	2.574
CO	-9.038**	(2.79)	0.0708	(0.07)	-45.02***	(6.07)	0.353	(0.41)	0.913	310	1.866
MT	-13.15***	(3.28)	0.112	(0.09)	-44.46***	(4.79)	0.380	(0.31)	1.740	310	3.983
UT	-7.968**	(2.74)	0.130^{+}	(0.07)	-42.31***	(5.82)	0.690	(0.43)	3.671^{+}	310	2.821
WY	-4.831**	(1.55)	-0.110	(0.09)	-16.06***	(4.24)	-0.366	(0.30)	1.417	310	3.705
EIA FPP: PADD 5											
PADD 5	-3.139***	(0.95)	-0.0192	(0.08)	-10.40***	(2.65)	-0.0636	(0.25)	0.0646	310	1.649
AK North Slope	-5.162***	(1.21)	-0.0797	(0.09)	-15.41***	(2.58)	-0.238	(0.25)	0.869	310	2.086
CA	-1.653^{+}	(0.95)	0.0559	(0.07)	-6.016^{+}	(3.19)	0.203	(0.28)	0.564	310	3.385
FO CA	-3.327**	(1.28)	0.0542	(0.07)	-20.44***	(5.66)	0.333	(0.47)	0.542	303	4.607

Standard errors in parentheses. Significance tests against normal distribution: $^{+}$ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

OLS with HAC estimator using Bartlett kernel and Andrews (1991) bandwidth selection. Included 2 lags of $pd_{c,t}$ and hurricane dummies.

F_{ref} is joint test for significance of refining variables. $\chi^2(6)$ is Cumby and Huizinga (1992) statistic for autocorrelation of order 6