RICE UNIVERSITY'S
BAKER INSTITUTE
FOR PUBLIC POLICY

Working Paper

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

Mark Agerton
Graduate Fellow, Center for Energy Studies, Rice University's Baker Institute for Public Policy

Gregory B. Upton Jr., Ph.D.
Assistant Professor, Center for Energy Studies, Louisiana State University

Wherever feasible, papers are reviewed by outside experts before they are released. However, the research and views expressed in this paper are those of the individual researcher(s) and do not necessarily represent the views of the James A. Baker III Institute for Public Policy.

This paper is a work in progress and has not been submitted for editorial review.

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

Mark Agerton
Center for Energy Studies
James A Baker III Institute for Public Policy
Rice University

Gregory B. Upton Jr.
Center for Energy Studies
Louisiana State University

JEL Codes: Q33, Q35, Q43

Keywords: crude oil prices; crude oil export ban; shale oil; crude oil pipelines; crude-by-rail; congestion pricing; oil refining

March 14, 2017

Abstract

Over the past five years 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 decompose domestic price differentials for multiple crudes into the contributions of shipping and export constraints. We find that scarce pipeline capacity explains the majority of the deviation of mid-continent crude oil prices from their long-run relationship with Brent crude, while refining changes explain very little. This implies that the deleterious effects of the export ban may have been exaggerated.

*We would like to thank Karl Bartholomew (ICIS), Kevin Bruce (ANGA), Katie Ehly (ANGA), John Johnson III (State of Louisiana Board of Professional Geoscientists), James Kliess (Valero), Manuel Lam (Louisiana Department of Natural Resources), Edward O'Brien (LDNR), Edward Overton (LSU), Eric Smith (Tulane University Energy Institute), Anna Temple (Wood Mackenzie), Mohammed Aldossary (Saudi Aramco), Peter Hartley (Rice), and Kenneth B. Medlock, III (Rice) for many helpful comments. Research support was provided by the Center for Energy Studies at Rice University's James A. Baker III Institute for Public Policy. Any errors are our own.

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. Signed shortly after the OPEC oil embargo of 1973–74 and during a time when many feared the arrival of "peak oil," the ban was designed to keep domestic crude in the U.S. and enhance domestic energy security. For many years, the crude export ban—hereafter referred to as the "export ban" or more simply "the ban"—had little bite: declining domestic crude oil production and increasing domestic demand meant that the U.S. imported ever more crude oil.

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 renaissance in U.S. crude oil production, which began rising quickly. By the end of 2014, U.S. production had reached levels not seen since the 1970s.

As U.S. crude oil 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. This was unheard-of: WTI had consistently traded at a slight premium to Brent for decades. The large differential spurred a robust debate over what was causing domestic crudes to sell at such a steep discount to their foreign counterparts and whether the unusual discount could be eliminated by removing the export ban.

In December 2015, the export ban was lifted as part of an omnibus spending bill. While the policy change was controversial, 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 as oil prices dropped with expanded supply and depressed refined product prices (Yergin et al., 2014; Ebinger and Greenley, 2014; Medlock, 2015). 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).

Our analysis suggests that it was not the export ban which was the culprit for these price differentials. Instead we present evidence that internal transportation constraints within the U.S. explain half to three-fourths of price differentials, while refining and international exporting constraints can explain just a few percent.

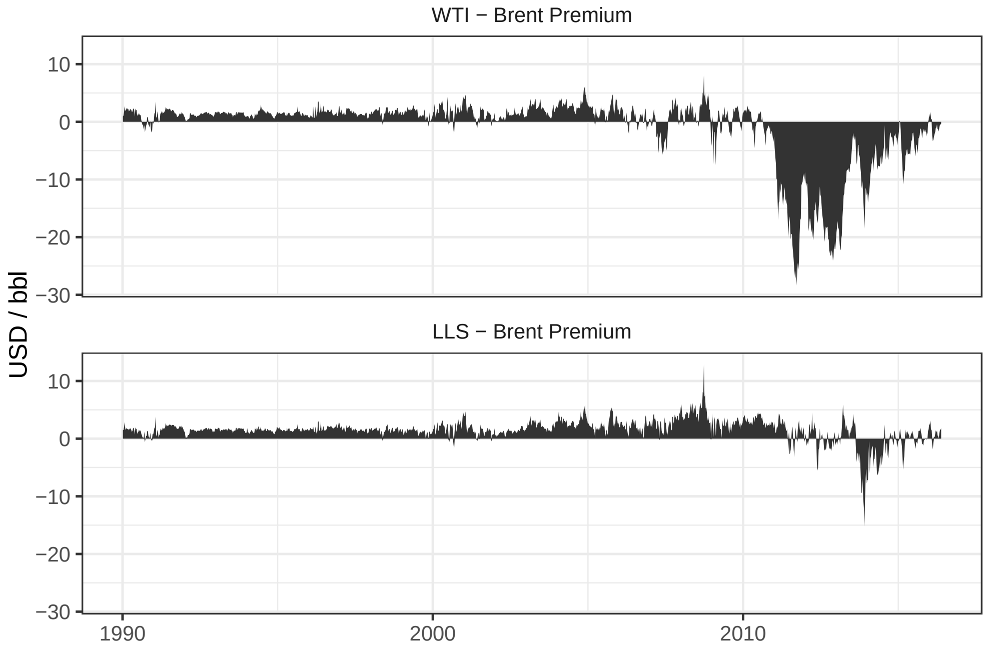


Figure 1: WTI and LLS premia over Brent

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. Any difference has historically been associated with quality differentials, transportation costs, or transitory shocks. After decades of declining domestic crude oil production, domestic refineries had gradually reconfigured themselves to process cheaper 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, in industry) 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, marginal 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 was the only option. Thus, crude from shales displaced imports, and domestic refineries sold their own excess production internationally.[1] These studies conclude that lifting the ban would have allowed for domestic producers to sell crude in the international market at a higher price instead of selling to domestic refineries at a lower price.

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. This theory points to the fact that in addition to unusual discounts between domestic and international crudes, the shale boom coincided with unusual price differentials within the U.S. In the short run, 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. Cushing, Oklahoma, the pricing point for the domestic crude oil benchmark, WTI, is in the mid-continent. Cushing oil inventories grew and producers resorted to alternative, more costly, transportation options: railroad and barges. These marginal transportation options only made economic sense when the price in the mid-continent was discounted to the price at the Gulf Coast. This theory suggests that it is these transportation constraints within the U.S. that created the price differentials between Brent and WTI, and several studies have associated internal shipping constraints with such 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 improving refinery profits.

Empirical approach The degree to which this discount was due to a constraint on *external* trade (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 without any new legislation. 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 operational changes to handle this new source of crude. 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); however, ours is the first paper to investigate which physical constraints have been driving this differential and the policy implications of these constraints.

We begin our analysis by discussing the interactions between oil production, transport, and demand in refining and the export-market: the upstream, midstream, and downstream market segments. We present descriptive evidence that increased shale production led to significant disruption in the midstream sector. The evidence is consistent with the presence—and subsequent relief—of

[1] Initially, the EPCA banned the export of both crude oil and refined products, but the ban on refined products was lifted under President Regan.

transportation constraints. We use econometric analysis to compare the difference between the price of Brent crude oil (subject to no U.S. constraints) and prices of mid-continent crudes (subject to both pipeline constraints and the ban) with the difference between Brent and coastal crudes (subject only to the ban). Using our estimates, we test for structural breaks in price differentials at discrete points coincident with when the internal and external constraints change. We find that the largest breaks happen for crudes subject to *internal* constraints (mid-continent crudes), not Gulf Coast crudes subject only to external constraints. Then, we regress price differentials on measures of transportation and refining constraints. We find that transportation constraints have an order of magnitude more explanatory power than refining constraints. Taken together, our results strongly suggest that the export ban was not the main cause of large domestic crude discounts. Instead, the majority of the price differential between WTI and Brent can be explained by internal shipping constraints within the U.S., not the export ban.

2 Oil price differentials and arbitrage

The *Law of One Price*—hereafter referred to as "LOOP"—means that two crude oils should trade at the same price, , conditional on quality differences (including location). Should one price depart from another, an opportunity for arbitrage exists, and competitive firms can make risk-free profits by buying low and selling high as long as the difference in prices is larger than marginal trading costs. Trading costs could be transportation costs or the opportunity cost of substituting one good for another, and long run price differences reflect these costs. Competition and free entry will ensure that profits—and excess price differences—are competed away.

Deviations from long-run pricing can arise because of frictions that prevent immediate adjustment to shocks. The most extreme example of such an adjustment friction is a binding constraint that rules out a certain type of arbitrage. In the U.S. market for crude oil, we should expect that producers and refiners will actively arbitrage away any disequilibrium price differences. The two sets of price differences we consider are the difference between mid-continent crudes (like WTI) and the international Brent crude benchmark, and the difference between crude prices on the U.S. Gulf Coast, such as Louisiana Light Sweet (LLS), and Brent crude. The former differential is likely to be affected by both pipeline and export constraints, but the latter, only refinery and/or export constraints. We discuss both of the economic actors' arbitrage possibilities, and the descriptive analysis in this section will serve as the basis for our empirical tests.

2.1 Refining and export restrictions

Refineries transform crude oil inputs into petroleum product outputs such as gasoline, diesel fuel, and lubricants. From the 1975 until December 2015, exports of crude oil—refineries' main input—

were illegal.[2] However, once the crude was refined into petroleum products, these could be sold on the world market with no restrictions. Harold Hamm, CEO of Continental Resources—an upstream oil and gas producer—summarizes this phenomenon, saying:

> *Major oil companies are exporting refined products with no limitations. Why shouldn't independent producers be allowed to do the same?... This would be equivalent to telling American farmers they can't export their wheat, yet allowing Pillsbury to export all the processed flour they want.*

Global petroleum product prices track international crude oil prices closely because oil is the primary input in the production process. This meant domestic refiners were in prime position to arbitrage differences between increasing supplies of discounted domestic crude and undiscounted international petroleum product prices. Because crude oil is an intermediate good; it is generally not useful without refining. Thus, before the export ban was lifted, domestic refineries were the only major source of demand for domestic U.S. crude oil.[3]

Refineries are highly optimized to maximize the profit from transforming hydrocarbon feedstocks into petroleum produts. Since crude oils are heterogeneous in their chemical compositions, part of this optimization involves tuning refineries to a particular diet of crude oil. 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. However, since domestic oil production started to decline in the 1970s while demand for refinery outputs continued, refineries have substituted towards cheaper "heavy-sour" crude imported from overseas that technologically advanced U.S. plants could handle. This has resulted in a shift towards a heavier slate of crude oil inputs to refineries.

Refineries can adjust to this new supply of light sweet crude in several ways. First, as prices of products and particular crude oils change, refiners can, to some extent, modify the mix of crudes while maintaining key aspects crude slate's overall chemical composition.[4] 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 changing relative availability and prices. Second, refineries can adjust to new domestic crude supplies by offsetting imports of light sweet crudes from other parts of the world. In fact, light

[2] 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.

[3] 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).

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

sweet crude oil imports have declined significantly, while heavy sour imports have actually slightly increased over the past decade.[5] Finally, refiners can make physical plant additions and alterations to allow for a different mix of crude to be processed, though these capital expenditures are 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. This means that different grades of crude oil are imperfect substitutes in the short run, but significant substitutions are possible in the longer run.[6]

When domestic crude oil prices are discounted to international crude prices, refiners have an indirect arbitrage opportunity. Because refined product prices typically follow international crude prices, domestic refineries can purchase discounted domestic crude while selling refined products on the higher priced global market. However, this requires refiners to substitute higher-priced foreign crudes for low-priced domestic ones in their operations. Such substitution may be as simple as changing the mix of crude inputs into the refinery by replacing heavier crudes with medium grades to mix with the domestic light crude. At the same time, such substitutions might cause the refinery to underutilize some of the specialized capital equipment designed to handle its previous crude oil diet. The change in diets may also require making changes to the refinery itself (EIA, 2015).[7]

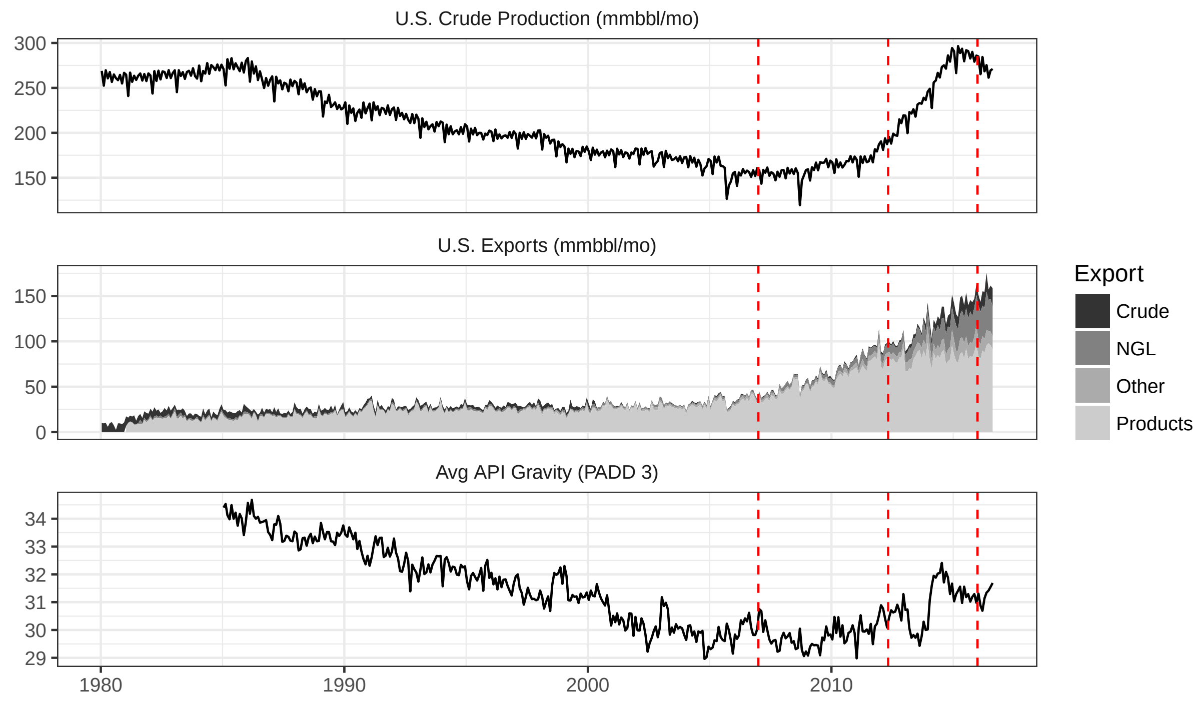
The top two panes of Figure 2 show that as domestic oil production increased, both U.S. production *and* exports of petroleum products increased dramatically. Simultaneously, the average API gravity of refiners' crude inputs (the inverse of crude oil density) increased sharply. This suggests that refiners either refiners substituted away from their traditional diets to ones that included higher concentrations of light oils, or that there was an increased utilization of simple refineries that were already configured to handle these light oils, or that both of these things happend.

The panels in Figure 2 show three things. First, the shift in mid-continent crude oil production was mirrored by the average API gravity of crude oils input into Gulf Coast refineries. Second, exports of refined products increased significantly over this time period. Third, crude oil exports did increase, as a few exceptions to the ban allowed limited exports to specific refineries in Canada and Mexico, for instance. Nevertheless, the growth of refined products exports in terms of volumes far exceeded this growth in crude exports. These three facts suggest that domestic refineries were able to successfully process increased volumes of LTOs, although plausibly at a lower operation efficiency or with significant capital expenditures. It does not appear to be the case that refiners were simply not able to process more crude. Depending on refiners' marginal rates of technical

[5] Compute import volumes by API using EIA data available at `https://www.eia.gov/dnav/pet/pet_move_ipct_k_m.htm` and `https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MTTIMUS1&f=M`.

[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.

[7] Some firms have also built "mini-refineries" that process the crude just enough to get around the export restriction (Nussbaum and Olson, 2014). The output is sold as a petroleum product on the world market.



Lines at Jan 2007, May 2012, Jan 2016

Figure 2: Refining, exports, and production

substitution between grades of crude, they may have required a price discount on LTOs to increase their share in the crude input mix, just as a discount would be required for more expensive modes of crude oil transport to be used. Thus, the relative share of refinery constraints on the the WTI-Brent discount is an empirical question and is addressed in this research.

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. Figure 3 shows the prices of WTI and Louisiana Light Sweet (LLS), a Gulf Coast crude from PADD 3. For over a decade, the two traded in close proximity to each other. However, beginning in the late 2000s, a large price gap was created. 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.[8]

Most transportation of crude oil has, historically, been via pipeline. This is because transporting crude oil via pipeline costs far less, on the margin, than via the alternatives, usually 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 should see temporary increases in the the use of with high marginal cost rail and barge. Should firms also expect demand for transportation to exceed current pipeline capacity for the foreseeable future, pipeline builders will respond to profitable investment opportunities and build new capacity. The increased supply of low-cost transportation will lead to subsequent decreases in the share of non-pipeline transport, and marginal transportation costs will also be lower. During the interim period, however, high marginal cost of transportation should induce significant price differentials between supply and demand locations.

Figure 4 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.[9] The line at May

[8] 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). In the preliminary part of their analysis, Büyükşahin et al. (2013) also interpret the WTI–LLS differential in this way.

[9] Section 4.2 discusses how we date the start of the boom in LTO production from shale.

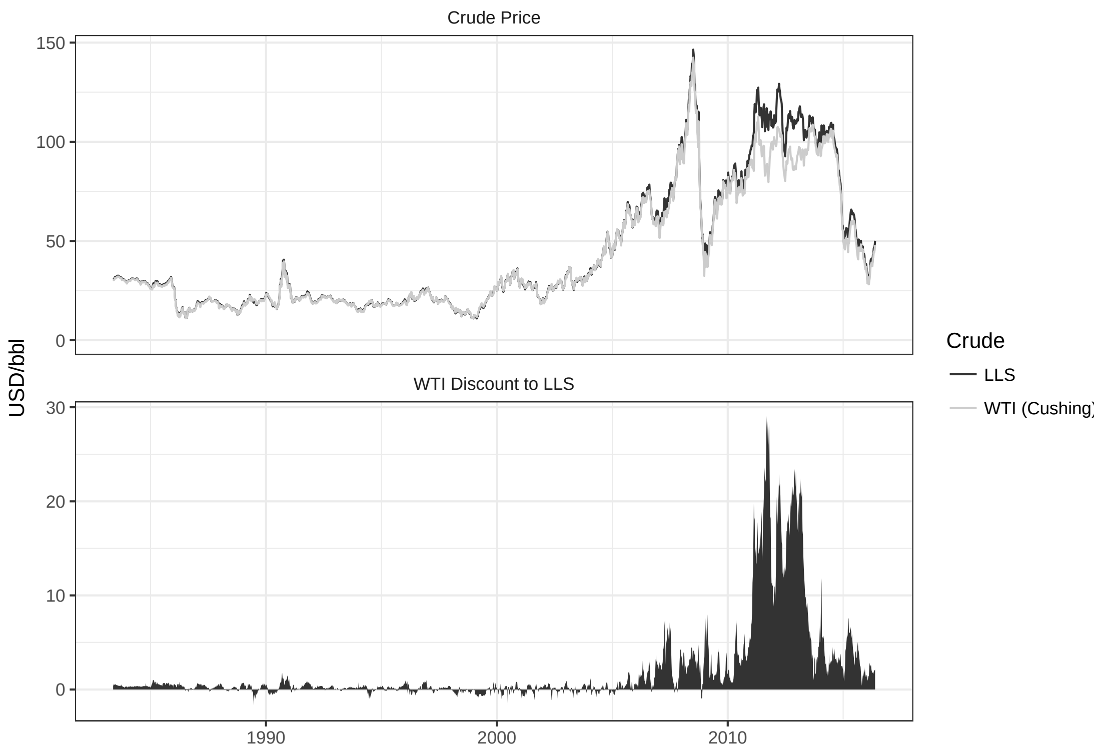


Figure 3: LLS vs WTI

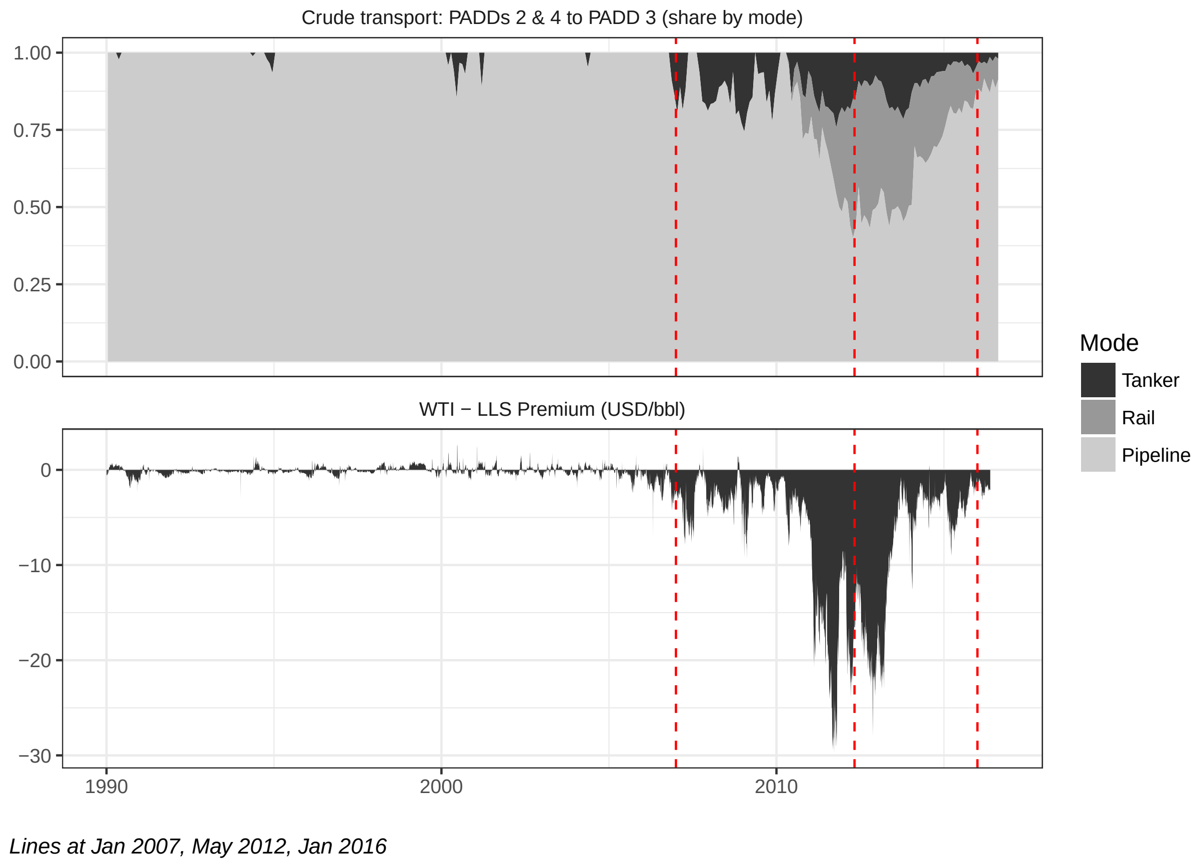


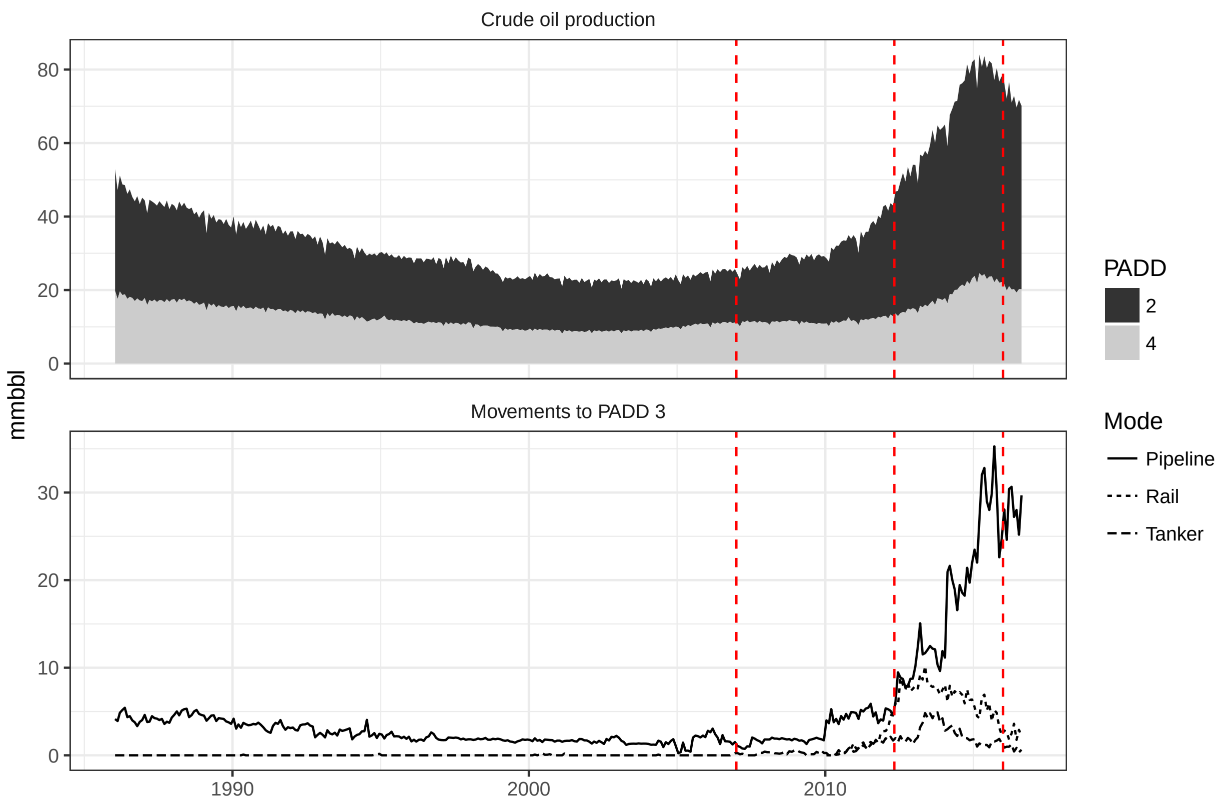
Figure 4: Mode of crude oil transport and WTI–LLS discount

2012 marks the opening of the Seaway pipeline that started relieving transportation bottlenecks,[10] 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.

The top panel of Figure 5 shows oil production in the mid-continent (PADDs 2 and 4). As oil production in these areas continued down a long-run decline curve, existing pipeline capacity was sufficient to meet transportation needs. The advent of LTO production from shale, however, increased oil production in the mid-continent from a total of approximately 300 million barrels in 2006, to more than 955 million in 2015 (EIA, 2016). Demand for transportation from the mid-continent to refineries on the Gulf Coast far outstripped pipeline capacity, and producers had to use other, more expensive, modes of transportation: rail and barge. Figure 5 shows transportation by mode from the mid-continent to the Gulf Coast. Before 2007, crude movements by tanker and rail are essentially zero; however, this quickly rises with production.

Producers' willingness to pay high marginal transportation costs was a signal to pipeline firms

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



Lines at Jan 2007, May 2012, Jan 2016

Figure 5: Oil production in and transportation from PADDs 2 and 4

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. McRae (2015) estimates that the delay of the Seaway Pipeline 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. Around the time of this reversal, the share of crude being shipped to the Gulf Coast via tanker and rail peaked at around 60 percent. 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 (BPD) to approximately 400,000 BPD.

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. As shown in Figure 5, by the time the export ban was lifted in December of 2015, only a small volume of crude (around 12 percent) was being moved to the Gulf Coast by tanker and rail, while the rest moved through the newly upgraded pipeline system, down from 60% in April 2012 during the peak of the shale boom.

2.3 Hypotheses

We have discussed two plausible causes for crude price differentials: transportation bottlenecks *within* the U.S. and the export ban that prevented producers from selling crude *outside* of the U.S. If transportation constraints existed during the recent shale boom, we expect to see mid-continent crudes (WTI and WTS) discounted relative to Gulf Coast crudes (LLS, HLS, and FO USGC). Conditional on the chemical composition of crudes, refining constraints should affect both mid-continent and coastal crudes equally.

We have three empirical hypotheses. First, the Law of One Price implies that prices of mid-continent crudes, Gulf Coast crudes, and foreign crude should track each other very closely over long time periods. Any differences in prices in the long run should be associated with transportation costs and quality differences. Second, during the shale boom, domestic prices should have decreased relative to the international benchmark, Brent. If internal shipping constraints within the U.S. were the primary culprit for these differentials, then we would expect to see mid-continent crudes sell at a significantly steeper discount than the Gulf Coast crudes that were already located near domestic refineries. However, if the export ban was the primary culprit for these differentials, then we would expect for both mid-continent and Gulf Coast crudes to sell at similar discounts. The contribution of each to the price differentials we have seen is, therefore, an empirical question. Third, if transportation was the primary constraint, price differentials between mid-continent and foreign crudes should converge as pipeline reversals and upgrades were completed. Alternatively, if the export ban was the primary constraint, we would expect for price differentials to continue despite these reversals until the lifting of the export ban. The extent of convergence post transportation constraints being lifted can provide insight into the relative importance of these two constraints.

3 Data, Variables, and Summary Statistics

3.1 Crude Oil Data

We utilize time series data from 1990 through the end of 2015 for purposes of this analysis. For all empirical specifications, the outcome variable of interest is the difference in the spot price of a domestic U.S. crude and the international Brent crude benchmark. Section 4 explains how we compute price differentials.

We use two data sources for our crude oil prices. First, we consider consider five spot prices from Bloomberg.[11] These daily prices are associated with major crude trading hub on five daily spot prices, and we average them to the monthly level. The first three are mid-continent crudes: West Texas Intermediate (WTI),[12] priced for delivery at Cushing, Oklahoma; WTI Midland,[13] priced at Midland, Texas where the Permian Basin is located; and West Texas Sour (WTS)[14]. The last two are coastal crudes: Louisiana Light Sweet Crude (LLS), priced at St. James, Louisiana[15]; and Heavy Louisiana Sweet Crude (HLS), priced at Empire, Louisiana.[16]

Second, we consider estimated wellhead crude oil prices as compiled by the U.S. Energy Information Administration (EIA). Unlike the Bloomberg prices that are trading prices at specific

[11] 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."
[12] API gravity: 39 deg; sulfur content: 0.34%
[13] API gravity: 39 deg; sulfur content: 0.34%
[14] API gravity: 34 deg; sulfur content: 1.9%.
[15] API gravity: 35.7 deg; sulfur content: 0.44%.
[16] API gravity: 33.7 deg; sulfur content: 0.39%.

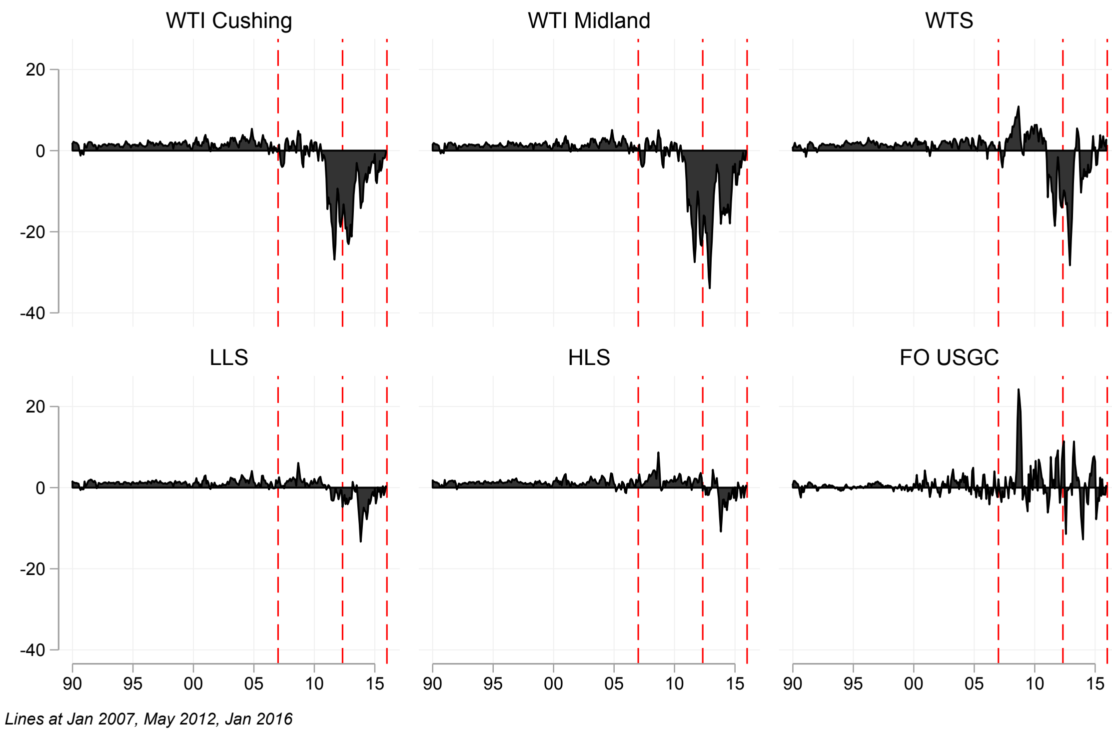


Figure 6: Midcontinent (top) and coastal (bottom) premiums to Brent

hub, these are EIA's estimates of the average price that producers receive at the wellhead across different geographic locations based on data reported by producers. In our main results, we use EIA as the source of the price for Federal Offshore Gulf of Mexico (FO USGC) production. In Appendix A.2, 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.

The six price differentials we analyze are plotted in Figure 6. 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 six crudes would be affected by both pipeline constraints and the export ban. Turning to the bottom three plots, LLS and HLS are produced primarily in the marshes of southern Louisiana and are priced for delivery nearby in the same state. The last crude, FO USGC, is an average of wellhead prices for crudes produced in Federally controlled offshore leases in the Gulf of Mexico. Because the coastal crudes are already located on the Gulf Coast and in close proximity to refineries and deepwater ports, these crudes are typically not brought to a trading hub in the way that WTI and WTS are. Instead they are typically bought directly from the producer by local refineries.[17] Thus, unlike the mid-continent crudes, coastal crudes are constrained only by the export ban, not pipeline capacity. Though FO USGC crude prices became more volatile over the last few years, they do not appear to have developed any sustained discount at all.

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). Movements from PADDs 2 and 4 to PADD 3 represents the movements 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:

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

[17] There are some exceptions. In particular, some crude is now traded at the Louisiana Offshore Oil Port.

Because barge and rail are high-cost modes of transport, if this ratio is above zero, especially for a sustained period of time, this suggests that pipeline constraints are likely present. 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).

The next explanatory variable represents potential refining constraints: it is the weighted average API gravity of crude input into 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.[18]

4 Empirical strategy

Our analysis of domestic crude oil price differentials proceeds in three stages. In the first stage, we estimate the statistical relationship between domestic crudes and Brent crude for the pre-shale 1990–2006 period. We assume that the market was in a long-run equilibrium during this time, that subsequent deviations from this are due to constraints, and that the market will return to its initial equilibrium once all constraints are relieved. Using this pre-boom relationship, we construct price differentials. 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.[19] In the third stage, we decompose deviations of the price differentials from zero into shipping and refining constraints. In all of our 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.[20][21]

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.

[18] 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. Furthermore, refinery analysts inform us that our imputed variables are poor measures of crude oil input quality, so we have not included them.

[19] The time-series are not long enough for us to test for a post-ban break, though this is a logical next-step.

[20] We implement the estimator with the Stata package `lrcov` (Wang and Wu, 2012).

[21] In Tables 6 and 7, 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.

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. One way we address this is to allow for two breaks in both mean *and* trend of the series. Second, we are interested in disentangling the impacts of two different constraints: shipping as well as refining constraints, which were driven by the export ban. Third, we 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.

Our research question and empirical approach are also related to Büyükşahin et al. (2013); however, there are important differences. Büyükşahin et al. (2013) are primarily concerned with decomposing the spread between Brent and WTI prompt month futures prices into physical, financial, and macroeconomic components. As we do, they note that structural breaks in mean WTI–Brent and LLS–Brent spreads are different. In the main portion of the paper, the authors regress daily prices from April 2004 through April 2012 on 19 different variables, including global spare oil capacity, crude oil inventories at Cushing, and measures of contango. They do not test whether the export ban had any impact on crude differentials. Our paper focuses only on the physical market: we test whether internal or external physical constraints better explain the large Brent–WTI differential and discuss the implications of our results for policy on infrastructure investment and export controls. Thus, we use a smaller set of explanatory variables exclusively relating to the physical market—transportation costs and refining inefficiencies. Finally, our data are available over a much longer horizon and a wider geography. This allows us to estimate unconstrained long-run relationships, see how constraints vary across space, and capture the tightening and loosening of pipeline constraints.

4.1 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[22]

$$P_{c,t} - P_{brent,t} = \mu + \epsilon_t. \tag{1}$$

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.

[22] 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).

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.[23] The t-statistic for this test is included in Table 5 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:

$$P_{c,t} = \mu + \delta P_{brent,t} \sum_{j=-l}^{l} \pi_j P_{brent,t-j} + \epsilon_t \tag{2}$$

To verify our assumption that LOOP holds, we test that $\delta = 1$ under the assumption that $P_{c,t}$ and $P_{brent,t}$ are cointegrated. 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.[24]

An Engle-Granger test for a spurious relationship between $P_{c,t}$ and $P_{brent,t}$ is simply a Dickey-Fuller test applied to the estimated residuals equation (2). 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 a relative form of LOOP holds for all six crudes at minimum.

Table 1 shows the regression results. In addition to confirming that LOOP holds, 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

$$PD_{c,t} = P_{c,t} - P_{brent,t}. \tag{3}$$

Equation (3) shows that the price differential, $PD_{c,t}$, is an estimate of $\mu + \epsilon_t$.

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

$$PD_{c,t} = P_{c,t} - \hat{\delta}_c P_{brent,t}. \tag{4}$$

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.

[23] 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.

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

Table 1: Loop regressions for 1990m1–2006m12

	Mid-continent			Gulf Coast		
	WTI Cushing	WTI Midland	WTS	LLS	HLS	FO USGC
δ	1.007***	1.009***	0.919***	1.022***	0.992***	0.939***
	(0.00965)	(0.00830)	(0.00727)	(0.00694)	(0.00651)	(0.0108)
μ	1.403***	1.214***	1.448***	1.159***	1.400***	0.398
	(0.276)	(0.237)	(0.208)	(0.198)	(0.186)	(0.308)
N	199	199	199	199	199	199
$z_{\delta-1}$	0.680	1.032	-11.12	3.158	-1.207	-5.661
$\Pr(\|z\|)$	0.497	0.302	9.72e-29	0.00159	0.228	1.51e-08
D-Fuller	-5.082	-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

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

4.2 Testing for constraints with breakpoints

Having verified that LOOP holds during the pre-shale period, we now assume that the crude oil market is, in fact, well-arbitraged, and that any change in the mean price differential, μ from equation (1), is due to temporary changes in the marginal cost of arbitraging price differences—either marginal transportation costs or the marginal cost of refining a lighter-than-normal grade of crude oil. In both empirical specifications, we relax the assumption that the mean price differential is constant since we are examining a period of transition when pipeline and refinery constraints are likely to have first become more binding and then, less binding. Thus, in our first model we allow for μ to have a broken time trend and denote it as μ_t. 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:

$$PD_{c,t} = \sum_{e=0}^{E-1} \mathbb{1}\left[T_e < t \leq T_{e+1}\right](\alpha_{c,e} + \beta_{c,e}t) + \nu_{ct}^{Ike/Gustav} + \nu_{ct}^{Katrina/Rita} + \epsilon_{c,t}, \tag{5}$$

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 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, which is when the U.S. EIA's Drilling Productivity Report began tracking U.S. shale production.[25] Figure 2 shows that the increase in oil production begins around this time. 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, and it was the first of several such investments in pipeline capacity. 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 2.

Table 2: 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.

Our initial testing step involves detecting the presence of structural breaks in the time trends. This is a test of the null that $\beta_e = \beta_{e'} \forall e \neq e'$ versus the alternative that $\beta_e \neq \beta_{e'}$ for some $e \neq e'$. We expect structural breaks to be present in the mid-continent crudes since these were affected by both types of constraints; however, we only expect structural breaks in coastal crudes if the export ban played a part in causing domestic crude discounts.

Our second step is to examine specific hypotheses about the signs and relative magnitudes of level and trend coefficients (α_e and β_e). In the pre-shale boom time period (January 1990 through December 2006) we expect for lighter domestic crudes to trade at a slight premium on average to Brent: $\alpha_{c,0} > 0$. More importantly, the price differential should remain approximately constant over this pre-shale period for all crudes: $\beta_{c,0} = 0 \forall c$.

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:

[25] Accessible online at `http://www.eia.gov/petroleum/drilling/`.

$\beta_{mid,1} < 0$. 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 constraint in the refineries inability to process this crude, the 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, $\beta_{mid,2} = 0$.

4.3 Testing for pipeline vs refining constraints

For this specification, instead of using time-trends and breaks, we decompose the price differentials into the two components corresponding to increased marginal transport and refining costs. Specifically, for crude c at time t, we decompose the price differential as

$$PD_{c,t} = \alpha_0 + \gamma_c^{ship} other\_share_t + \gamma_c^{api} api_t + \nu_{ct}^{Ike/Gustav} + \nu_{ct}^{Katrina/Rita} + \epsilon_{c,t}. \tag{6}$$

where $k \in \{other\_share, api\}$.

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 4. Though this variable does not capture possible constraints in moving new Texas and New Mexico production from the Permian Basin and Eagle Ford Shale regions, it does capture constraints in moving new crude oil supplies from the prolific Bakken Shale in North Dakota and inventory build at Cushing, Oklahoma where WTI is priced. 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 3 presents the baseline results for equation (5). Given how dummy variables are constructed, in any regime e, the corresponding level term is $\alpha_{c,e}$, and the trend term, $\beta_{c,e}$. The bottom portion of the table shows the results from Wald tests for equality of the time-trends. For both HLS and FO USGC, we find no evidence of any structural breaks in the time-trend. This suggests that neither crude was impacted by pipeline *or* refining constraints. The other four crudes, WTI Cushing, WTI Midland, WTS, and LLS do display some evidence of strucutral breaks. We very strongly reject equality of any trend coefficients for both WTI series. While we only reject $\beta_0 = \beta_1$ at the 5% level for WTS, we strongly reject the two null hypotheses $\beta_1 = \beta_2$ and $\beta_0 = \beta_1 = \beta_2$. LLS also appears to exhibit some breaks in trend, though statistical evidence for these is somewhat weaker, which is consistent with our hypothesis that LLS was not affected by transportation constraints.

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.[26] 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. 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

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

Table 3: 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)
Ike/Gustav	Yes	Yes	Yes	Yes	Yes	Yes
Katrina/Rita	Yes	Yes	Yes	Yes	Yes	Yes
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 1

Table 4: Price differential decomposition: OLS

	Mid-continent			Gulf Coast		
	WTI Cushing	WTI Midland	WTS*	LLS*	HLS	FO USGC*
γ^{ship}	-31.12***	-37.86***	-20.97***	-9.225***	-4.098+	1.345
	(3.957)	(3.235)	(4.369)	(2.042)	(2.282)	(2.446)
γ^{api}	-0.344	-0.687*	-0.733+	-0.361*	-0.311*	-0.384
	(0.264)	(0.315)	(0.382)	(0.143)	(0.153)	(0.252)
α_0	12.57	23.20*	24.96*	12.51**	10.99*	12.41
	(8.324)	(9.903)	(12.14)	(4.518)	(4.821)	(7.974)
Ike/Gustav	Yes	Yes	Yes	Yes	Yes	Yes
Katrina/Rita	Yes	Yes	Yes	Yes	Yes	Yes
N	312	312	312	312	312	312
$\chi^2(6)$	29.67	31.61	28.66	23.07	31.24	22.61
	(0.0000454)	(0.0000194)	(0.0000706)	(0.000772)	(0.0000228)	(0.000939)
R^2	0.729	0.760	0.484	0.516	0.221	0.160
R^2_{ship}	0.725	0.748	0.455	0.479	0.178	0.145
R^2_{ref}	0.00567	0.00548	0.00461	0.0157	0.0722	0.156

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 1

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 4 shows estimates for equation (6), which decomposes the price differential into marginal shipping costs and marginal refining costs. Recall that we capture these two factors by the share of rail plus tanker crude oil movements from PADDs 2 and 4 to PADD 3 and the Average API gravity of refining inputs in PADD 3.

The shipping constraint coefficient, γ^{ship}, is statistically significantly and negatively associated with price differentials for the three mid-continent crudes, as well as 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 4 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 2 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.

Robustness: serial correlation Our estimates of equations (5) and (6) both suffer from serial correlation of the residuals, as evidenced by the Cumby and Huizinga (1992) statistics in the bottom of Tables 3 and 4. 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 6 and 7 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 3 and 4), 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 8 of Appendix A.2. Table 9 gives results from our stage one pre-shale model, equation (1). We compute price differentials from these quantities exactly as before and estimate models (5) and (6) both without lags (Tables 10 and 11) and with lags (Tables 12 and 13). 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. Similarly, we find smaller magnitudes for our shipping constraint coefficient (γ^{ship}) with Gulf Coast and PADD 5 crudes. It is interesting to note that CA Midway-Sunset crude, a heavy crude stream, actually appears to *gain* in value compared to Brent when pipeline constraints bind. 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.

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 1990 to December 2006. We compute these decompositions[27] as

$$\widehat{PD}_{ct}^{\text{shipping}} = \hat{\alpha}_0 + \hat{\gamma}_c^{ship} other\_share_t + \hat{\gamma}_c^{api}\overline{api} + \widehat{\nu}_{ct}^{Ike/Gustav} + \widehat{\nu}_{ct}^{Katrina/Rita} \tag{7}$$

$$\widehat{PD}_{ct}^{\text{refining}} = \hat{\alpha}_0 + \hat{\gamma}_c^{ship}\overline{other\_share} + \hat{\gamma}_c^{api} api_t + \widehat{\nu}_{ct}^{Ike/Gustav} + \widehat{\nu}_{ct}^{Katrina/Rita}. \tag{8}$$

[27]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.

The two decompositions are graphed in Figures 7a and 7b 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 4. 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.[28]

6 Conclusion

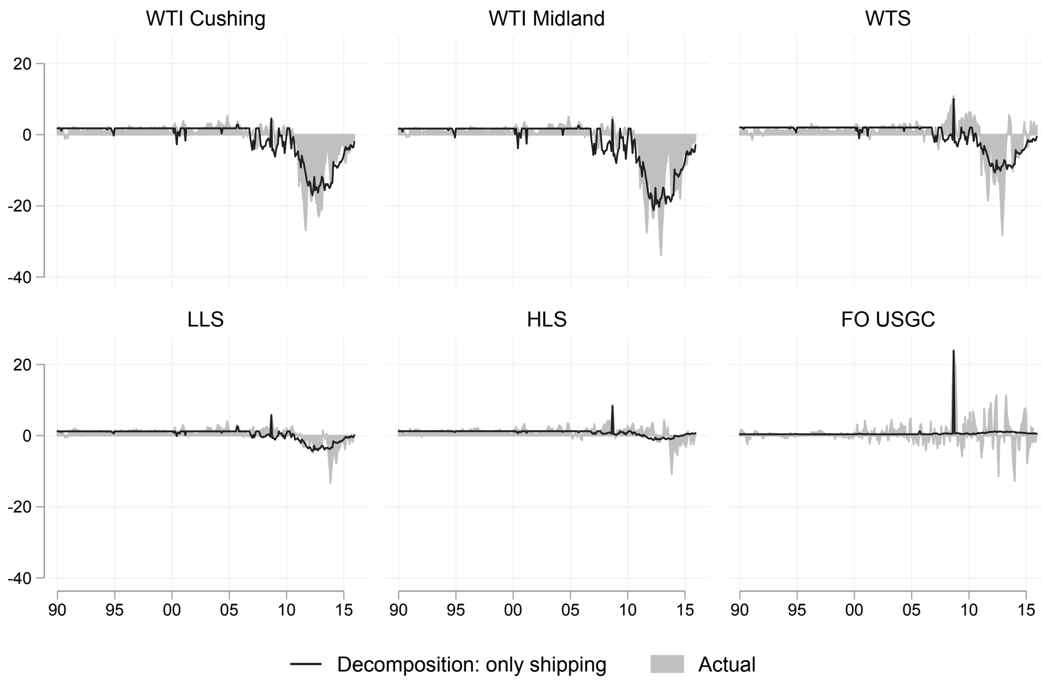
In this paper, we investigate two plausible causes for the significant price discount of U.S. crudes during the U.S. "shale boom" and evaluate how much each mattered. Some studies have claimed that the price differential was due to refineries' inability to process light tight oils (LTOs) being produced 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. We provide the first statistical decomposition of these differentials into these two competing factors.

Based on the pseudo-R^2 measures that we calculate, it appears that that around half to three-quarters of the domestic mid-continent crude oil to Brent price differential can be explained by internal pipeline constraints, while only a few percent of the differential can be explained by refineries' inability to absorb the glut of domestic LTOs as captured by PADD-specific average API gravity of inputs to refineries. It is plausible that part of the price differential associated with refineries' inability to absorb domestic LTOs could have been alleviated if the export ban were not to have been in place during the export ban, though it is unlikely that this would have had as large of an effect in the short run compared to relieving pipeline constraints.

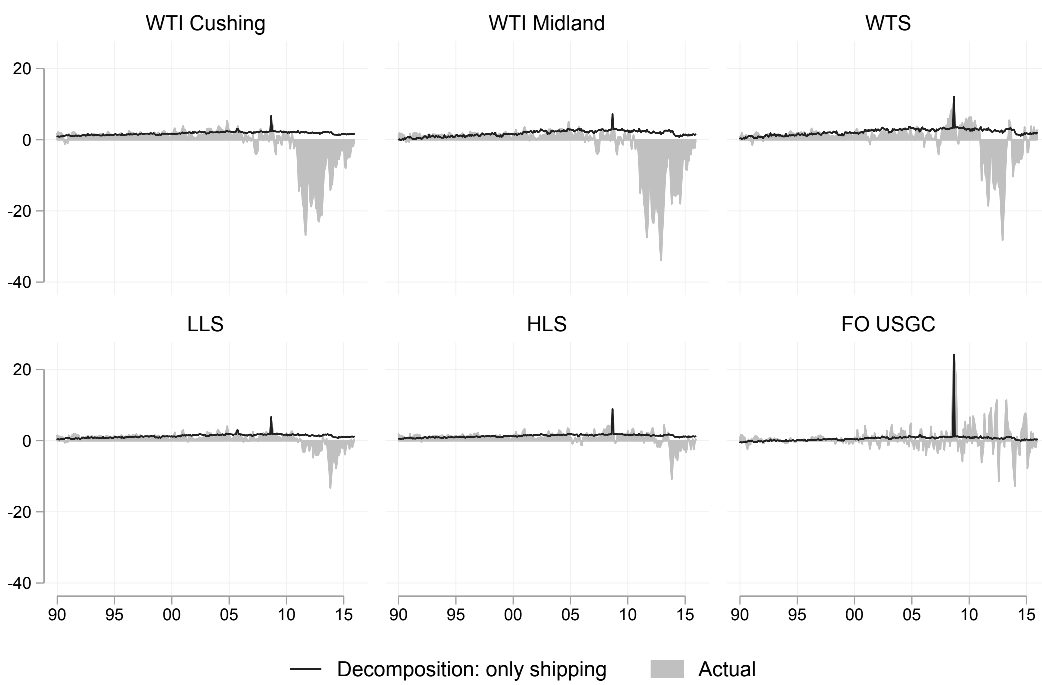
There are significant policy implications of this research. First and foremost, results of this research suggest that with or without the crude export ban in place, significant price differentials would have emerged between U.S. and foreign crudes. In particular, we argue that the price differentials 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.

[28] The pattern is the same when we examine all of the EIA price differentials (Table 11, with the notable exception of South Dakota, which is a minor oil-producer.)



(a) Using $other\_share_t$



(b) Using api_t only

Figure 7: Predicted differentials using only one set of explanatory variables (plus hurricane dummies)

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 concern about whether we have adequately captured this factor. However, the lack of a statistical "smoking gun" for 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.

References

Anderson, K. (2009). Distorted agricultural incentives and economic development: Asia's experience. *World Economy 32*(3), 351–384.

Andrews, D. W. (1991). Heteroskedasticity and autocorrelation consistent covariance matrix estimation. *Econometrica 59*(3), 817–858.

Bale, M. D. and E. Lutz (1981). Price distortions in agriculture and their effects: An international comparison. *American Journal of Agricultural Economics 63*(1), 8–15.

Bausell, Jr, C. W., F. W. Rusco, and W. D. Walls (2001). Lifting the alaskan oil export ban: An intervention analysis. *The Energy Journal*, 81–94.

Borenstein, S. and R. Kellogg (2014). The incidence of an oil glut: Who benefits from cheap crude oil in the midwest? *The Energy Journal 35*(1), 15–33.

Büyükşahin, B., T. K. Lee, J. T. Moser, and M. A. Robe (2013). Physical markets, paper markets and the WTI–Brent spread. *The Energy Journal 34*(3), 129.

Cumby, R. E. and J. Huizinga (1992). Testing the autocorrelation structure of disturbances in ordinary least squares and instrumental variables regressions. *Econometrica 60*(1), 185–195.

Dudley, R. G. (2004). Modeling the effects of a log export ban in indonesia. *System Dynamics Review 20*(2), 99–116.

Ebinger, C. and H. L. Greenley (2014). Changing markets. economic opportunities from lifting the u.s. ban on crude oil exports. Technical report, Brookings.

EIA (2015). Technical options for processing additional light tight oil volumes within the united states. Technical report, U.S. Energy Information Administration.

Enders, W. (2008). *Applied econometric time series*. John Wiley & Sons.

Fattouh, B. (2007). WTI benchmark temporarily breaks down: Is it really a big deal? *Middle East Economic Survey 50*(20), 7.

Fattouh, B. (2009). Reinforcing feedbacks, time spreads and oil prices. *Middle East Econmic Survey 52*, 17–27.

Fattouh, B. (2010). The dynamics of crude oil price differentials. *Energy Economics 32*(2), 334–342.

Fielden, S. (2013, December). Im Waiting For the Crude Crude Price Differentials at The Gulf Coast Part 1.

Fooks, J. R., S. J. Dundas, and T. O. Awokuse (2013). Are there efficiency gains from the removal of natural resource export restrictions? evidence from british columbia. *The World Economy 36*(8), 1098–1114.

Ghoshray, A. (2014). How persistent are shocks to oil prices? In *Online Proceedings of 37th IAEE International Conference*.

Investor's Business Daily (2014). WTI Vs. LLS: A Major Shift In The U.S. Oil Boom.

Kaminski, V. (2014). The microstructure of the north american oil market. *Energy Economics 46*, S1–S10.

Kao, C.-W. and J.-Y. Wan (2012). Price discount, inventories and the distortion of wti benchmark. *Energy Economics 34*(1), 117–124.

McRae, S. (2015). Vertical Integration and Price Differentials in the US Crude Oil Market.

Medlock, III, K. B. (2015). To Lift or Not to Lift? The U.S. Crude Oil Export Ban: Implications for Price and Energy Security. Study, James A. Baker III Institute for Public Policy.

Noguera, J. (2013). Oil prices: Breaks and trends. *Energy Economics 37*, 60–67.

Nussbaum, A. and B. Olson (2014, March). Bp splitter refinery seen skirting u.s. oil export ban.

Perron, P. (1989). The great crash, the oil price shock, and the unit root hypothesis. *Econometrica 57*(6), 1361–1401.

Saikkonen, P. (1991). Asymptotically efficient estimation of cointegration regressions. *Econometric Theory 7*(1), 1–21.

Stock, J. H. and M. W. Watson (1993). A simple estimator of cointegrating vectors in higher order integrated systems. *Econometrica 61*(4), 783–820.

von Amsberg, J. (1998). Economic parameters of deforestation. *World Bank Economic Review 12*(1), 133–153.

Wang, Q. and N. Wu (2012). Long-run covariance and its applications in cointegration regression. *Stata Journal 12*(3), 515–542.

Yergin, D., K. Barrow, J. Fallon, M. Bonakdarpur, S. Sayal, C. Smith, and J. Webster (2014). Us crude oil export decision. Technical report, IHS Energy.

A Appendix: For Online Publication Only

A.1 Additional Tables and Figures

Table 5: 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 6: 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)
Ike/Gustav	Yes	Yes	Yes	Yes	Yes	Yes
Katrina/Rita	Yes	Yes	Yes	Yes	Yes	Yes
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 1

Table 7: Price differential decomposition, AR(2)

	Mid-continent			Gulf Coast		
	WTI Cushing	WTI Midland	WTS*	LLS*	HLS	FO USGC*
γ^{ship}	-5.747**	-8.082***	-4.421**	-2.648***	-1.411*	0.468
	(1.984)	(2.077)	(1.383)	(0.662)	(0.579)	(1.599)
γ^{api}	-0.0124	-0.105	-0.123	-0.0526	-0.0618	-0.160
	(0.0779)	(0.0775)	(0.0799)	(0.0425)	(0.0445)	(0.124)
ρ_1	1.038***	1.124***	1.107***	0.781***	0.788***	0.667***
	(0.0875)	(0.0911)	(0.104)	(0.105)	(0.107)	(0.101)
ρ_2	-0.230*	-0.338***	-0.319**	-0.0562	-0.0946	-0.145
	(0.0937)	(0.0861)	(0.0982)	(0.0863)	(0.0951)	(0.0916)
α_0	0.717	3.655	4.270+	1.993	2.329	5.202
	(2.516)	(2.483)	(2.558)	(1.365)	(1.419)	(3.940)
Ike/Gustav	Yes	Yes	Yes	Yes	Yes	Yes
Katrina/Rita	Yes	Yes	Yes	Yes	Yes	Yes
N	310	310	310	310	310	310
$\chi^2(6)$	1.787	1.513	2.837	3.420	4.526	2.779
	(0.938)	(0.959)	(0.829)	(0.755)	(0.606)	(0.836)
$\widetilde{\gamma}^{ship}_{LRM}$	-30.02	-37.65	-20.86	-9.607	-4.596	0.979
	(5.118)	(5.518)	(5.566)	(2.250)	(2.117)	(3.336)
$\widetilde{\gamma}^{api}_{LRM}$	-0.0650	-0.490	-0.578	-0.191	-0.201	-0.335
	(0.394)	(0.315)	(0.343)	(0.142)	(0.142)	(0.260)

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 1

Long-run multipliers and their standard errors are below.

A.2 All crudes

Table 8: 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 9: All crudes: loop regressions for 1990m1–2006m12

	δ		μ		D-Fuller	$z_{\delta-1}$	δ	N
Mid-continent crudes								
WTI Cushing	1.007***	(0.00965)	1.403***	(0.276)	-5.082	0.680	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 for absolute version of LOOP, and δ chosen based on rejection of Absolote LOOP at 0.01 level

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

Table 10: 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 11: 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	-31.12***	(3.96)	-0.344	(0.26)	1.703	312	29.67***	0.729	0.725	0.00567
WTI Midland	-37.86***	(3.23)	-0.687*	(0.32)	4.752*	312	31.61***	0.760	0.748	0.00548
WTS	-20.97***	(4.37)	-0.733+	(0.38)	3.690+	312	28.66***	0.484	0.455	0.00461
Coastal crudes										
LLS	-9.225***	(2.04)	-0.361*	(0.14)	6.353*	312	23.07***	0.516	0.479	0.0157
HLS	-4.098+	(2.28)	-0.311*	(0.15)	4.149*	312	31.24***	0.221	0.178	0.0722
FO USGC	1.345	(2.45)	-0.384	(0.25)	2.329	312	22.61***	0.160	0.145	0.156
EIA FPP: Stream										
CA Midway-Sunset	10.91***	(1.53)	-0.348	(0.28)	1.543	267	35.41***	0.362	0.352	0.0354
WTI (EIA)	-34.83***	(2.98)	-0.464	(0.41)	1.277	267	33.70***	0.742	0.738	0.0000488
WTS (EIA)	-23.33***	(4.12)	-0.855+	(0.45)	3.559+	267	33.85***	0.513	0.492	0.0125
EIA FPP: PADD 1										
PADD 1	-39.53***	(3.06)	-0.280	(0.38)	0.546	312	37.09***	0.764	0.762	0.00554
PA	-41.70***	(3.92)	-1.857+	(1.03)	3.263+	188	36.68***	0.759	0.739	0.142
EIA FPP: PADD 2										
PADD 2	-33.84***	(3.53)	-0.255	(0.24)	1.094	312	35.58***	0.779	0.777	0.00566
IL	-22.32***	(4.12)	-0.200	(0.26)	0.585	312	31.78***	0.586	0.584	0.000511
KS	-32.18***	(3.83)	-0.0585	(0.26)	0.0505	312	30.98***	0.742	0.742	0.000165
KY	-18.76***	(4.50)	0.154	(0.27)	0.316	312	30.00***	0.514	0.512	0.0337
NE	-34.55***	(3.17)	-0.114	(0.28)	0.170	312	37.14***	0.759	0.759	0.0000757
ND	-31.19***	(3.67)	-0.376	(0.27)	2.006	312	41.69***	0.727	0.722	0.00268
OH	-34.54***	(3.20)	0.0752	(0.34)	0.0476	312	34.46***	0.726	0.725	0.0167
OK	-35.78***	(3.85)	-0.142	(0.25)	0.321	312	34.55***	0.765	0.765	0.00311
SD	-0.672	(4.77)	-0.770	(1.14)	0.457	163	30.43***	0.0355	0.0258	0.0350
EIA FPP: PADD 3										
PADD 3	-19.09***	(1.76)	-0.508*	(0.24)	4.578*	312	36.84***	0.573	0.554	0.00427
AL	-12.82***	(2.99)	-0.138	(0.27)	0.256	312	44.27***	0.350	0.348	0.000377
LA	-10.68***	(1.69)	-0.307+	(0.16)	3.465+	312	30.96***	0.350	0.336	0.00592
MS	-5.008***	(1.07)	-0.414*	(0.21)	4.015*	312	46.70***	0.162	0.124	0.0485
NM	-39.67***	(3.01)	-0.333	(0.29)	1.281	312	34.70***	0.765	0.762	0.0105
TX	-25.38***	(2.93)	-0.556*	(0.27)	4.197*	312	32.85***	0.636	0.621	0.0000216
EIA FPP: PADD 4										
PADD 4	-31.34***	(2.94)	-0.245	(0.21)	1.366	312	33.07***	0.754	0.752	0.00639
CO	-46.15***	(3.06)	-0.0783	(0.28)	0.0805	312	32.58***	0.834	0.834	0.000706
MT	-45.22***	(3.54)	0.120	(0.29)	0.169	312	37.03***	0.835	0.834	0.0439
UT	-43.41***	(2.73)	0.305	(0.33)	0.849	312	35.22***	0.837	0.836	0.0643
WY	-16.80***	(3.77)	-0.414	(0.31)	1.800	312	45.00***	0.374	0.362	0.000668
EIA FPP: PADD 5										
PADD 5	-10.25***	(1.47)	-0.147	(0.26)	0.324	312	79.66***	0.356	0.352	0.00148
AK North Slope	-15.12***	(1.35)	-0.354	(0.22)	2.606	312	72.05***	0.538	0.524	0.00110
CA	-5.849**	(1.89)	0.172	(0.32)	0.287	312	88.07***	0.145	0.140	0.0267
FO CA	-19.26***	(4.27)	0.142	(0.45)	0.0984	305	81.98***	0.509	0.508	0.0269

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 12: 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 13: 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	-5.747**	(1.98)	-0.0124	(0.08)	-30.02***	(5.12)	-0.0650	(0.39)	0.0256	310	1.787
WTI Midland	-8.082***	(2.08)	-0.105	(0.08)	-37.65***	(5.52)	-0.490	(0.32)	1.843	310	1.513
WTS	-4.421**	(1.38)	-0.123	(0.08)	-20.86***	(5.57)	-0.578^{+}	(0.34)	2.355	310	2.837
Coastal crudes											
LLS	-2.648***	(0.66)	-0.0526	(0.04)	-9.607***	(2.25)	-0.191	(0.14)	1.531	310	3.420
HLS	-1.411*	(0.58)	-0.0618	(0.04)	-4.596*	(2.12)	-0.201	(0.14)	1.933	310	4.526
FO USGC	0.468	(1.60)	-0.160	(0.12)	0.979	(3.34)	-0.335	(0.26)	1.660	310	2.779
EIA FPP: Stream											
CA Midway-Sunset	3.199*	(1.35)	-0.0822	(0.13)	10.21***	(2.94)	-0.262	(0.38)	0.395	265	1.098
WTI (EIA)	-7.947***	(2.07)	-0.0401	(0.12)	-34.86***	(4.42)	-0.176	(0.49)	0.120	265	4.813
WTS (EIA)	-5.560***	(1.68)	-0.159	(0.14)	-23.49***	(5.01)	-0.671	(0.50)	1.370	265	2.345
EIA FPP: PADD 1											
PADD 1	-6.486***	(1.90)	0.0294	(0.08)	-38.99***	(6.27)	0.177	(0.47)	0.150	310	4.560
PA	-6.523**	(2.29)	-0.0171	(0.33)	-42.71***	(8.70)	-0.112	(2.14)	0.00267	186	2.990
EIA FPP: PADD 2											
PADD 2	-8.332***	(2.17)	-0.0109	(0.07)	-33.13***	(4.29)	-0.0434	(0.29)	0.0218	310	4.037
IL	-3.943**	(1.34)	-0.00142	(0.07)	-21.13***	(4.91)	-0.00762	(0.37)	0.000430	310	2.364
KS	-5.650**	(1.89)	0.0353	(0.07)	-31.18***	(5.14)	0.195	(0.38)	0.294	310	1.940
KY	-3.106**	(1.20)	0.0727	(0.07)	-17.18***	(5.02)	0.402	(0.41)	1.129	310	1.491
NE	-6.404***	(1.87)	0.0244	(0.07)	-33.70***	(5.03)	0.129	(0.37)	0.126	310	2.537
ND	-10.05***	(2.26)	-0.0618	(0.10)	-30.37***	(3.93)	-0.187	(0.29)	0.399	310	6.675
OH	-6.279***	(1.90)	0.0728	(0.07)	-34.02***	(5.68)	0.394	(0.42)	1.014	310	3.043
OK	-6.546**	(2.09)	0.0296	(0.07)	-34.81***	(5.15)	0.157	(0.40)	0.177	310	3.886
SD	-0.606	(1.67)	-0.00419	(0.32)	-2.773	(7.70)	-0.0192	(1.48)	0.000167	161	2.939
EIA FPP: PADD 3											
PADD 3	-6.290***	(1.46)	-0.144^{+}	(0.09)	-19.22***	(3.00)	-0.440^{+}	(0.25)	2.765^{+}	310	2.297
AL	-4.757***	(1.42)	-0.0203	(0.09)	-12.89***	(3.34)	-0.0549	(0.24)	0.0527	310	7.568
LA	-5.096***	(1.21)	-0.132^{+}	(0.08)	-10.69***	(2.28)	-0.276^{+}	(0.16)	2.798^{+}	310	1.022
MS	-1.919*	(0.89)	-0.142*	(0.07)	-4.997*	(2.37)	-0.369*	(0.17)	3.995*	310	1.065
NM	-8.956***	(2.38)	-0.0362	(0.08)	-39.54***	(5.08)	-0.160	(0.34)	0.201	310	3.389
TX	-6.209***	(1.58)	-0.107	(0.08)	-25.39***	(4.00)	-0.437	(0.30)	1.639	310	4.341
EIA FPP: PADD 4											
PADD 4	-8.772***	(2.19)	-0.0305	(0.08)	-30.55***	(3.77)	-0.106	(0.25)	0.166	310	2.661
CO	-9.098**	(2.83)	0.0638	(0.08)	-44.97***	(5.98)	0.315	(0.41)	0.699	310	2.040
MT	-13.15***	(3.33)	0.110	(0.09)	-44.33***	(4.76)	0.371	(0.31)	1.636	310	4.275
UT	-7.956**	(2.74)	0.125^{+}	(0.07)	-42.23***	(5.78)	0.666	(0.44)	3.319^{+}	310	3.046
WY	-4.843**	(1.56)	-0.109	(0.09)	-16.05***	(4.22)	-0.362	(0.30)	1.384	310	3.749
EIA FPP: PADD 5											
PADD 5	-3.099**	(0.95)	-0.0171	(0.08)	-10.30***	(2.65)	-0.0570	(0.25)	0.0496	310	1.702
AK North Slope	-5.098***	(1.21)	-0.0812	(0.09)	-15.28***	(2.57)	-0.243	(0.25)	0.873	310	2.169
CA	-1.632^{+}	(0.95)	0.0597	(0.08)	-5.950^{+}	(3.18)	0.217	(0.29)	0.622	310	3.432
FO CA	-3.272*	(1.27)	0.0548	(0.08)	-20.29***	(5.68)	0.340	(0.49)	0.533	303	4.663

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