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

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ABSTRACT

Over the past decade the primary U.S. crude benchmark, WTI, diverged considerably from its foreign counterpart, Brent, sometimes selling at a steep discount. Some studies pointed to the ban on exporting U.S. crude oil production as the main culprit for this divergence. We find that scarce domestic pipeline capacity explains half to three quarters of the deviation of mid-continent crude oil prices from their long-run relationship with Brent crude. We are unable to find evidence that mismatch between domestic refining configurations and domestic crude characteristics contributed significantly to this deviation. This implies that the short-run deleterious effects of the export ban may have been exaggerated.

Keywords: Crude oil prices, Crude oil export ban, Shale oil, Crude oil pipelines, Crude-by-rail, Congestion pricing, Oil refining

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1. INTRODUCTION

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

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

In December 2015, the export ban was lifted. During the preceding debate, 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 prices of refined products, such as gasoline, and would reduce the the security of the nation's energy supply. Proponents of lifting the ban refuted these concerns. First, they argued that exporting crude oil would not increase gasoline prices; if anything it would lead to a decrease in gasoline prices (Yergin

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et al., 2014; Ebinger and Greenley, 2014; Medlock, 2015).[1] Second, they argued that increasing domestic prices to parity with international ones would spur new investment and oil production, creating hundreds of thousands of domestic jobs (Yergin et al., 2014; Ebinger and Greenley, 2014).[2] Our interest is not in the merits of lifting the export ban; rather, we are interested in whether the export ban or an alternative explanation, scarce pipeline capacity, caused the domestic crude oil discounts.

Yergin et al. (2014) and Ebinger and Greenley (2014) give the following economic argument for why the export ban lowered domestic crude oil prices. Since there is no ban on the import of crude oil—only its export—refineries in the U.S. are able to purchase both foreign and domestic crude. Because domestic and foreign crudes are substitutes in production, the two generally trade at similar prices. After decades of declining domestic crude oil production, domestic refineries had gradually reconfigured themselves to process available imported crudes. Oils from unconventional sources (termed light-tight oils, or LTOs) have a different chemical composition than foreign crudes, and domestic refineries were not optimized to handle the large quantities of LTOs that shale plays were producing. Because of the mismatch between refinery configurations and domestic crude characteristics, refiners could only process LTOs profitably if they could purchase them at a discount. Even though lighter crudes, like those from shale, were trading at a premium to heavier ones in the international market, the export ban eliminated foreign sources of demand: selling to domestic refineries at a substantial discount was the only option. The combination of the export ban and refineries' inability to process the new LTOs caused sustained price differentials. A necessary condition for the export ban to have acted as a binding constraint is that domestic refineries were unable to absorb new sources of domestic crude without significant additional cost.

An alternative economic explanation, which we argue was more important, has to do with shipping constraints *within* the U.S.—not the prohibition on exporting the crude *outside* of the country. In addition to large discounts between domestic and international crudes, the shale boom coincided with large price discounts within the U.S. For a time, 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. The ensuing excess demand for pipeline capacity within the U.S. created a wedge between Brent and WTI prices. Facing insufficient pipeline capacity, oil producers in the mid-continent had two alternatives: store increasing amounts of crude oil in mid-continent inventories, or resort to more costly transportation modes like rail and barge. Several studies have associated internal shipping constraints with internal price differentials (Upton, 2015; Borenstein and Kellogg, 2014; Kaminski, 2014; Büyüksahin et al., 2013; Fattouh, 2007, 2010, 2009; Kao and Wan, 2012). In fact, McRae (2015) argues that vertically integrated ConocoPhillips delayed pipeline expansions for the purpose of sustaining the price differential, thereby improving refinery profits. In contrast to the previous studies, we empirically evaluate the roles of these two possible physical constraints—internal and external—and consider the policy implications.

The degree to which the WTI–Brent discount was due to a constraint on *external* trade with other countries (refinery constraints in conjunction with the ban) or *internal* trade between producing and refining regions (pipeline congestion) is an empirical question. If the constraint was

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

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

internal, then the opportunity to arbitrage spatial differences in price would have led to new pipeline construction and the elimination of the discount whether or not the export ban was in place. However, if the discount was due to a mis-match of refining capacity with new U.S. crude supplies, then an earlier lifting of the export ban might have raised domestic wellhead prices for oil producers, increasing their profitability and mitigating the extent to which domestic refineries had to make investments or operational changes to handle this new source of crude.

2. OIL PRICE DIFFERENTIALS AND ARBITRAGE

2.1 Refining and export restrictions

Crude oil is an intermediate good, and there are two major sources of demand for domestic crude production: refining and export to the world market. Refineries transform crude oil inputs into petroleum product outputs. Global petroleum product prices track international crude oil prices closely because oil is the primary input in the production process. The 1975–2015 export ban implied that domestic refining was the only major source of demand for domestic crude oil.[3] Domestic refiners were thus the only firms who could freely arbitrage price differences between discounted domestic crude and undiscounted international petroleum product prices. Producers were unable to do so.[4]

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

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

Refiners can also make physical plant additions and alterations to allow for a different mix of crude to be processed, though these capital expenditures can be expensive. While refiners are unlikely to make significant changes to their equipment and operations in response to a transitory

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

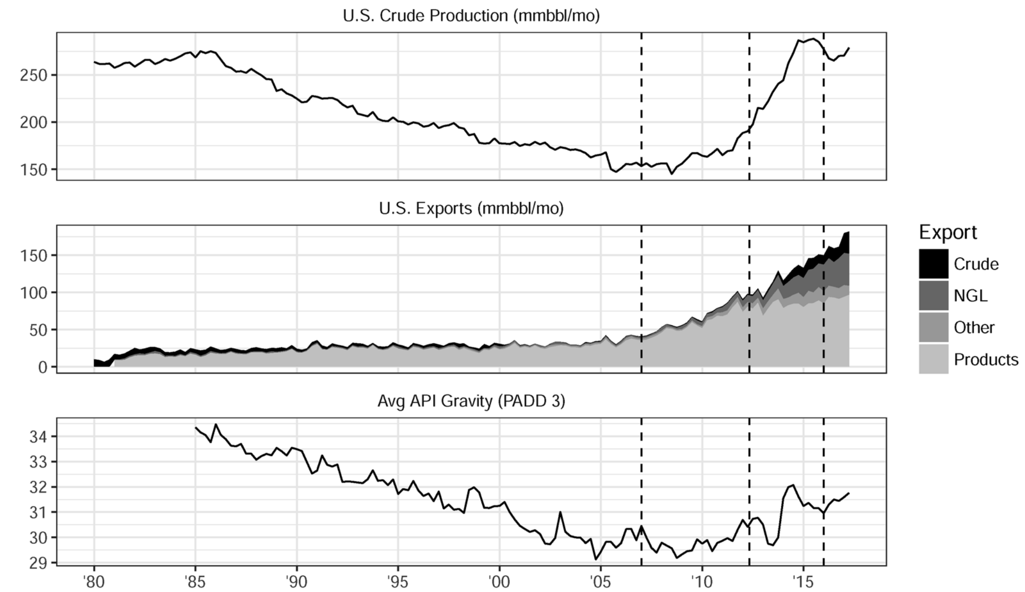
4. It should be noted, that while not associated with oil specifically, similar export restrictions on raw materials but not final products have been studied. For instance, certain types of logs have similar export restrictions (Fooks et al., 2013) while the wood products produced from these logs are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

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

shock, they are able to make significant changes to accommodate structural changes in crude availability. [6]

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

Figure 1: Refining, exports, and production



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

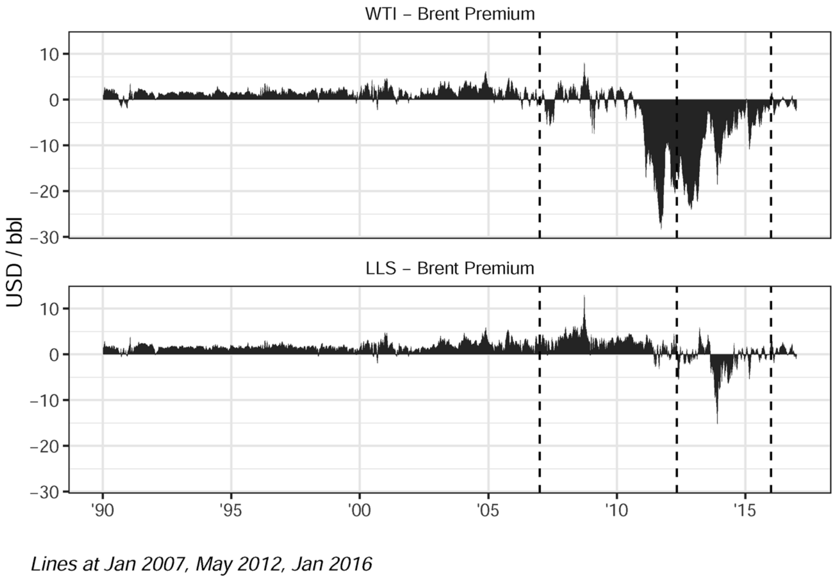
2.2 Producers and transportation constraints

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

As shown in Figure 2, for over a decade, West Texas Intermediate (WTI) and Louisiana Light Sweet (LLS) traded in close proximity to each other (and Brent). However, beginning in the late 2000s, a large price gap emerged. With sufficient transportation infrastructure, a profit-maximizing producer or buyer of crude oil in the mid-continent would have seen an arbitrage oppor-

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

Figure 2: WTI and LLS premia over Brent



tunity, 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 difference. Some in the industry have interpreted the WTI–LLS differential as representative of the value of transportation constraints between the mid-continent and Gulf Coast refining.[7] Büyüksahin et al. (2013) also interpret the WTI–LLS differential in this way.

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

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

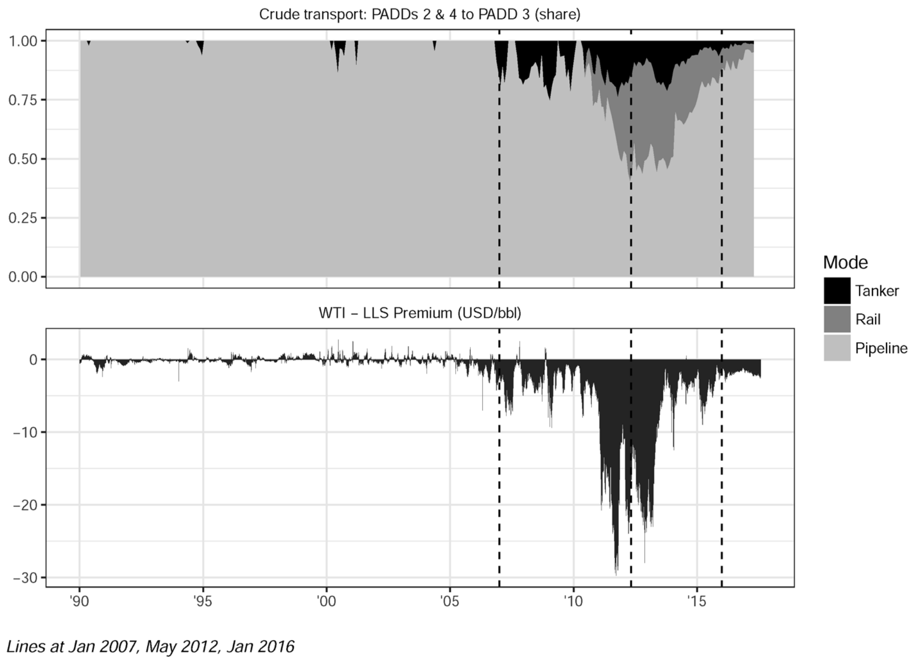
Figure 4 compares total mid-continent oil production (PADDs 2 and 4) with the total volumes of crude transported to PADD 3 by mode of transport. During the 1990s and early 2000s, oil production in PADDs 2 and 4 went into a secular decline, and existing pipeline capacity sufficed to meet transportation needs. The advent of LTO production from shale, however, increased oil

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

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

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

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

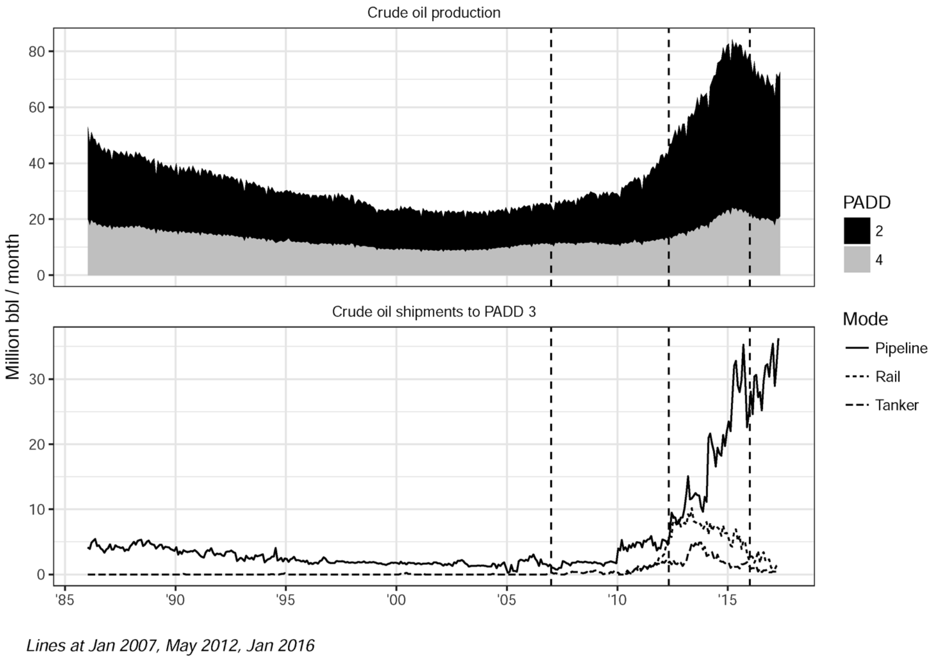


production in the mid-continent from approximately 300 million barrels in 2006, to more than 955 million in 2015. Demand for transportation from the mid-continent to refineries on the Gulf Coast quickly outstripped pipeline capacity, and producers had to utilize alternative rail and barge as well as pipelines. Figure 4 shows that in April 2012, more crude was shipped via rail than pipeline from the mid-continent to the Gulf Coast. Subsequent construction increased the availability of low-cost pipeline transportation services, allowing producers to transport more than 36 million bbl/month in April 2017.

Producers' willingness to pay high marginal transportation costs was a signal to pipeline firms to invest in new infrastructure. One noteable major investment was the reversal of the Seaway Pipeline that runs from Freeport, Texas 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. In November of 2011, the co-owner, ConocoPhilips, announced the sale of its share in the pipeline, and in May of 2012 the Seaway Pipeline reversed direction, relieving the transportation bottleneck.[10] 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. In January of 2013, the pipeline's capacity was upgraded from its initial capacity of 150,000 barrels

10. 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 maintaining low crude prices in order to boost profits of its down-stream refining operations. Estimates suggest that the delay of the reversal cost ConocoPhillips approximately $200,000 per day in pipeline profits, yet it gained approximately $2 million per day in higher profits on its Midwest refining operations. It should be noted that ConocoPhillips was in the process of selling many of its refining assets during the process of the pipeline reversal. Once ConocoPhillips sold its share of Seaway, the pipeline could be reversed.

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



per day (bbl/d) to approximately 400,000 bbl/d.[11] By the time the export ban was lifted in December of 2015, about 12% of crude was being moved to the Gulf Coast by tanker and rail, down from the peak of 60%. The most recent data available from April 2017 show that more than 35 mmbbl/month are moved from the mid-continent to the US Gulf Coast each month, representing more than 10% of monthly US production (Figure 4).

3. DATA, VARIABLES, AND SUMMARY STATISTICS

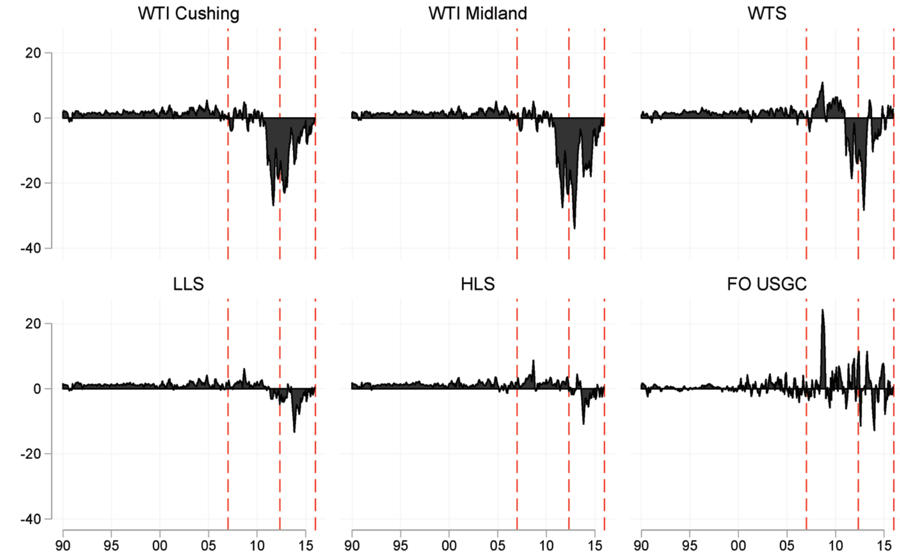
3.1 Crude oil data

We use monthly time series data from 1990 through the end of 2015. Our outcome of interest is the difference in the spot price of a domestic U.S. crude and the international Brent crude benchmark. We use two data sources for our crude oil prices. First, we gather daily spot prices from Bloomberg for Brent crude and five domestic benchmarks.[12] We average them to a monthly frequency for all time-series analysis. The first three are mid-continent crudes: West Texas Intermediate (WTI), priced for delivery at Cushing, Oklahoma; WTI Midland, priced at Midland, Texas where the Permian Basin is located; and West Texas Sour (WTS). The last two are coastal crudes: Louisiana Light Sweet Crude (LLS), priced at St. James, Louisiana; and Heavy Louisiana Sweet

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

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

Figure 5: Mid-continent (top) and coastal (bottom) premiums to Brent



Crude (HLS), priced at Empire, Louisiana. Bloomberg does not track our sixth crude, Federal Offshore Gulf of Mexico (FO USGC), so we use the monthly average first-purchase price compiled by the EIA from administrative reports.[13,14] See Table 3 in the Online Appendix for API gravity and sulfur content information.

The six domestic price differentials[15] are plotted in Figure 5. The top three are inland crudes and must to be transported to a refinery (often the Gulf Coast, where more than half of the nation's refining capacity is located) after they exit the wellhead or, in the absence of the export ban, a port where they can be shipped overseas. All three crudes would be affected by both pipeline constraints and the export ban. These mid-continent crudes are then juxtaposed against the coastal crudes that are already located on the Gulf Coast and in close proximity to refineries and deepwater ports. Though FO USGC crude prices became more volatile over the last few years, they do not appear to have developed any sustained discount.

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

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

14. In Online Appendix 4, we also consider all other geography-specific wellhead prices provided by EIA (there are more than 30). We run an identical analysis on these series as a robustness check and find no qualitative difference in our results

15. See Section 4 and the Online Appendix for how these are calculated.

Information Administration (EIA). The first variable relates to shipping. EIA provides estimates of all crude movements between PADD regions. These crude movements are broken up into three primary categories: pipeline, tanker, and rail. We consider movements from PADD 2 (the Midwest) and PADD 4 (Rocky Mountain states) to PADD 3 (the Gulf Coast). This represents the transport of crude produced in the mid-continent, primarily from the Bakken and Niobrara shale plays, towards the Gulf Coast where more than half of the country's refining capacity resides. To represent the presence of pipeline constraints, we compute the share of crude movements from PADDs 2 and 4 to PADD 3 via barge or rail relative to total movements from PADDs 2 and 4 to PADD 3:[16]

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

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

4. EMPIRICAL STRATEGY

Our analysis of domestic crude oil price differentials proceeds in three stages. In the first stage, we estimate the cointegrating relationship between domestic crudes and Brent crude during the period 1990–2006, which preceded the shale boom. We construct price differentials as deviations from these baseline long-run relationships, which we estimate using Dynamic OLS (see the Online Appendix for details). In the second stage, we test for breaks in the level and trend of price differentials at the beginning of the "shale boom" and at the time when pipeline investments relieved the shipping constraints. In the third stage, we decompose the price differentials into shipping and refining constraints.[18,19]

Our empirical strategy is similar in spirit to Bausell et al. (2001), who examine the impact of lifting the Alaskan Oil Export Ban on the prices of Alaskan crude and West Coast refined products, though our situation and exact methodology differ. First, Bausell et al. (2001) study a market

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

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

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

19. In Tables 5 and 6, listed in the Online Appendix, we also add try adding two lagged values of the price differentials 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 least at the 5% level for all grades except HLS.

in a constrained, steady-state equilibrium which experiences a sudden relief in the constraint and moves to a new steady-state. In contrast, our period of interest is not a steady-state. Over our time frame, increasing shale production would have caused market constraints, be they pipeline or export constraints, to bind more and more tightly at first. Then those constraints would have been gradually relieved over time by incremental investments into pipelines and refineries. These ongoing investments mean our constraint cannot be captured with a simple indicator variable for the post-ban period. We address this complication by allowing for two breaks in both level and trend of the series. Second, we are interested in disentangling the impacts of two different constraints: shipping as well as refining constraints.[20] Our analysis is closely related to Büyüksahin et al. (2013), who regress the WTI–Brent spread on a variety of economic, physical, and financial variables (but not the export ban). The authors focus on statistical links between storage and financial markets, whereas we focus purely on the physical market and assess the roles of transportation and export constraints across a number of domestic prices.

4.1 Testing for constraints with breakpoints

In our first model, we test for breaks in the level and trend of the price premiums for domestic crude oil benchmarks over the international benchmark, Brent. Denote the price differentials for crude c at time t as PD_{ct} and the set of break-times as $\{T_e\}_{e=0}^{E}$. We 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:

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

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

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

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:

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

Table 1: Structural break time periods

Time Period	Event	Description
Jan 1990 to Dec 2006	Pre-Shale Boom	EIA's drilling productivity report begins tracking shale play production in 2007.
Jan 2007 to Apr 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 Dec 2015	Shale Boom and Pipeline Upgrades Occurring	The export ban was lifted in December of 2015.

$\beta_{mid,1} < 0$. 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 $\beta_{gulf,1} < 0$. We can thus infer that lifting the export ban would have plausibly relieved this constraint, allowing these Gulf Coast crudes to sell to foreign buyers to the extent the discount exceeded transportation costs. However, if there was no constraint in the refineries' abilities to process this crude, then we would expect for $\beta_{gulf,1} = 0$. The difference between $\beta_{gulf,1} - \beta_{mid,1}$ represents the difference in the rate at which pipeline constraints caused discounts relative to refinery constraints.

The last regime coincides with a time of pipeline reversals and upgrades before the export ban was lifted: May 2012 to December 2015. If the transportation constraints were binding for mid-continent crudes, and therefore 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 when pipelines increased capacity to relieve constraints. Thus, we expect that $\beta_{mid,2} > 0$. 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, $\beta_{mid,2} = 0$.[21]

4.2 Decomposing for pipeline vs refining constraints

In our second model we decompose the price differentials into the two components corresponding to increased marginal transport and refining costs.[22] Specifically, for crude *c* at time *t*, we decompose the price differential as

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

The first explanatory variable is the share of crude oil movements via rail and barge from the mid-continent (PADDs 2 and 4) to the Gulf Coast (PADD 3), shown previously in Figure 3.

Because shipping crude via barge or rail is more costly than via pipeline, we expect that mid-continent discounts will grow as more crude is moved via these two modes. Conversely, we

21. We also included prices from the post-export ban time period, but have chosen to exclude this period. The global oil price drop occurred shortly after OPEC's announcement of continuing production in September of 2014. While crude production began to grow, it peaked in August of 2015. At the time of this writing, production has continued to decline. Testing for structural breaks after the supply decrease is problematic for our analysis, as reductions in supply might relieve both pipeline and refinery constraints.

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

expect the discount to shrink as the share of crude transported via barge and rail decreases. 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 refineries were not able to perfectly substitute their previous grades of crude for domestic LTOs, then increases in the API of inputs should have depressed domestic crudes compared to Brent, that is $\gamma^{api} < 0$.

5. RESULTS

5.1 Testing for breaks

Table 2 presents the baseline results for equation (1). In a regime *e*, the corresponding level term is α_{ce}, and the trend term is β_{ce}.

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.[23] WTI Midland experiences a similar \$3.85/year devaluation per year over this time period. WTS experiences devaluation at a slightly slower rate of about \$2.39/year over this time period.

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

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

5.2 Testing for transport vs. refining constraints

Table 3 shows estimates for equation (2), which decomposes the price differential into marginal shipping costs and marginal refining costs.

The shipping constraint coefficient, γ^{ship}, is statistically significantly and negatively associated with price differentials for the three mid-continent crudes plus LLS. It is negative and

23. Recall that the time-trend, *t*, is measured in years.

Table 2: Price differential break tests, OLS

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

Standard errors in parentheses and p-values in brackets.
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 of the Online Appendix.

statistically significant at the 10% level for HLS, but it is not significant at any conventional levels for FO USGC. Since $other\_share_t$ is between zero and one, 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 $2.10 to $3.80 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 $12.61–22.78 per barrel discount. Given that Brent crude prices average $47.90/bbl during our sample and range from $9.80 to $133.90, 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 $0.93 per barrel discount—a much smaller amount than for the mid-continent crudes. HLS may have developed a minor discount to Brent due to shipping constraints, but FO USGC appears not to have been affected in the slightest.

Table 3 also shows the relationship between the API gravity of refinery inputs and crude price differentials. We do find that increases in API gravity (i.e. movement towards lighter crudes) is associated with a discount in domestic crudes relative to Brent. The corresponding coefficient, γ^{api} , is significant at the 5% level for WTI Midland, WTS, LLS, and HLS, but not WTI Cushing or FO USGC. As Figure 1 shows, between January 2006 and December 2015, the average API of PADD 3 refinery inputs ranged between approximately 29 and 32.5. With estimates for γ^{api} ranging from

Table 3: Price differential decomposition: OLS

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

Standard errors in parentheses and p-values in brackets.
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 of the Online Appendix.

–0.78 to –0.30, this implies that the maximum discount due to increased average API gravity of crude oil inputs to refining would have reached \$2.72, 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 price impact from refining mismatch lacks in intensity, it makes up in longevity.

Our estimates assume that the supply curve for rail transportation and the demand curve for LTOs by refiners are both fixed. This implies that any changes in the share of crude transported by rail or the share of LTOs purchased by refiners must be caused by increased supply of LTOs. Rail and refinery upgrades require costly capital investments that take time. Moreover, railroads are likely to have anticipated that future pipelines would limit long-run demand for rail transport, making these investments less attractive. Given the relatively short time-frame of our analysis, we find the assumption of fixed rail supply and fixed refining demand to be palatable. Nevertheless, crude price differentials and our regressors are determined simultaneously, so our estimates could suffer from bias due to endogeneity. If railroads and refineries had indeed made capital investments that increased capacity to handle new LTO production, this would bias our negative coefficients towards zero (up). To address this concern, we instrument the share of non-pipeline crude movements and average API gravity in PADD 3 with their one and two-month lagged values (i.e., we instrument x_t with x_{t-1} and x_{t-2}). The Online Appendix contains these IV estimates in Table 4 for our six main crude differentials and Table 11 for all domestic crude differentials.[24] We fail to reject exogeneity of our explanatory variables at the 5% level for around half of our price differentials. Where we do, γ^{api} and γ^{ship} increase slightly in magnitude (become more negative). Neither changes signs, statistical significance, or economic significance. As we argue above and as statistical results indicate, this

24. The instruments are very strongly correlated with the potentially endogenous variables, and we fail to reject overidentifying restrictions at the 1% level for any crude.

bias appears to be minimal. Our main result that internal constraints, not external constraints, drove domestic crude oil discounts stands unchanged.

5.3 Decomposition: internal vs external constraints

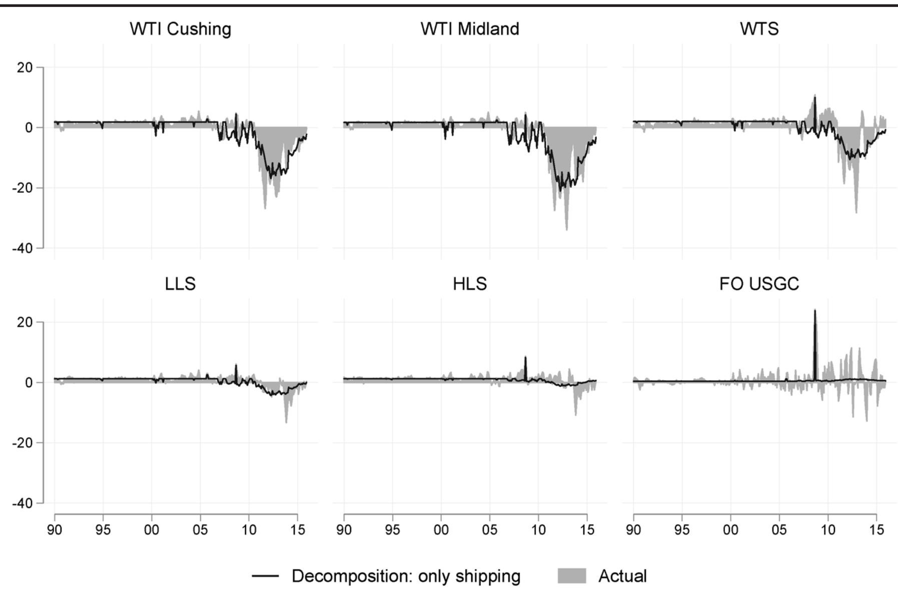
To decompose the relative effects of shipping constraints and the export ban, we shut down each of the respective channels and compute the predicted price differential using our regression coefficients. When we shut down one of the variables, we set it to its mean during the pre-shale period January 1990 to December 2006. We compute these decompositions[25] as

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

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

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

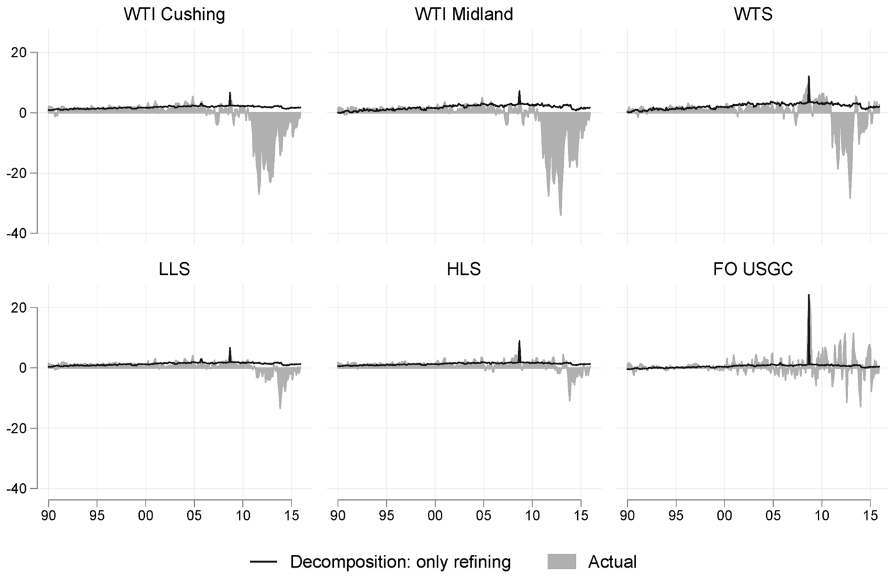
Figure 6: Predicted differentials using only $other\_share_t$ **(plus hurricane dummies)**



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

26. The pattern is the same when we examine all of the EIA price differentials (Table 10 in the Online Appendix, with the notable exception of South Dakota, which is a minor oil-producer.)

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



6 CONCLUSION

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

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

There are significant policy implications of our results. First and foremost, they 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 much smaller than those of domestic transportation constraints. Gulf Cost crudes LLS and HLS did sell at a discount to the internationally traded Brent crude, but to a much smaller degree than for mid-continent crudes like WTI. 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. Economists have begun to recognize that the interaction of national trade policies and local economies is a pressing issue. Shale oil and gas production has led to shifts in U.S. trade flows, and it has also had major impacts for local economies that experience the associated booms and busts (Feyrer et al., 2017; Marchand, 2012; Agerton et al., 2017; Weber, 2017; Marchand and Weber, 2018; Komarek, 2016; McCollum and Upton, 2018; Decker et al., 2018; Upton and Yu, 2018). As we study these impacts, it is important to incorporate the existence of regional price differences in resource prices.

There are two important limitations to our empirical approach. First, we are only able to observe average trading prices, aggregate shipping and aggregate refinery input data. The strong statistical significance of our shipping constraint variable allays concerns about whether we have adequately captured this factor. Refinery processes, inputs, and outputs, however, are much more complex and heterogeneous than simple pipeline movements. Furthermore, 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. Therefore, while we fail to find evidence that the export ban affected price differentials via refining constraints, that does not mean the export ban had no price impact.

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 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 firms were not impacted by the export ban (either adversely or positively), but instead that in aggregate, internal shipping constraints can explain a significant share of observed price differentials.

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