Brent Is Dated

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Dated Brent and/or its siblings such as BFOE (Brent, Forties, Oseberg, and Ekofisk) have been the key benchmarks for global crude markets for more than thirty years. The market emerged in the early eighties in response to the British government's administration of taxes on crude produced from the UK sector of the North Sea. The market quickly became a key indicator of the global crude price—often **THE** key indicator of the global price.

In recent years, though, the indicator has suffered as Brent crude production has declined. Price-reporting agencies (PRAs) have made valiant efforts to sustain it by adding other types of crude produced in the North Sea to what experts call the Brent "stream." Forties, a crude produced in the United Kingdom, was added in 2002 along with Oseberg, a Norwegian crude. In 2007, Platts added the Ekofisk crude from Norway. In 2018, yet another Norwegian crude, Troll has been added, effectively making the stream BFOET rather than BFOE.[2]

These additions were required to maintain the market's liquidity. Liquidity, of course, is the *sine qua non* of commodity markets.

The introduction of other crudes into the calculation, designed to improve "liquidity" in the Dated Brent market in the past, seems to reflect an effort by large North Sea producers to retain some control over

[1] The author wishes to thank Argus Media and particularly Gustavo Vasquez and James Gooder for their extraordinary support in developing the competitive measures of the US crude market. Kim Pederson did his usual exceptional job in editing and finalizing the paper. Any remaining errors are the responsibility of the author.
[2] US Energy Information Administration, "Another type of crude oil to be included in calculation of the Brent price benchmark," March 10, 2017 [https://goo.gl/eVRYSr].

the way in which oil prices are set. Buyers may be independent refiners or trading companies, but the production of the commodity being sold begins with the large companies.

Platts recently acknowledged Brent's growing deficiencies. In an article titled "Brent and the beauty of benchmarks," Jonty Rushforth, Senior Director of S&P Global Platts Oil and Shipping Price Group, noted that the oil production volume supporting the Brent benchmark was declining. He also admitted that the potential substitutes produced in the North Sea were unsatisfactory because they were not light sweet crudes.[3]

The large oil companies that benefit from the importance of Brent have suggested ways in which the base could be expanded. These efforts would extend Brent's life as the global benchmark. For example, Shell proposed adding Urals, a crude produced in Russia, to the other crudes included in the BFOE calculation. In that respect, Mike Muller, former head of trading at Shell, made this assertion:

> "A good benchmark need not only be representative of what the region produces…. If you had to pick one grade of crude, Urals is the one which northwest European refineries should be designed to run optimally."[4]

Officials at Platts likely resisted this suggestion because Urals is not a light sweet crude.

The weakness of current procedures for measuring North Sea prices became obvious at the end of 2017 when the pipeline system connecting the various Forties offshore platforms to the terminal in Scotland had to be closed for repairs. The closure stopped trade in a key component of the BFOE price.

[3] Jonty Rushforth, "Brent and the beauty of benchmarks," *Insight*, December 2017 [https://goo.gl/AHLZoF].
[4] "Shell proposes adding Russian oil to Brent benchmark," Reuters, May 10, 2017 [https://goo.gl/7RnQzF].

Rushford suggested that Dated Brent might be improved by including other light crudes such as Azeri Light from Azerbaijan. Ultimately, though, these proposals seem unlikely to resolve the problem because the oils are produced in distant locations. The conclusion from this is that Brent must be abandoned as a benchmark. Hence, the title of this paper: "Brent Is Dated." Brent is no longer suited to be a benchmark for global crude. As I explain below, its coming demise in this regard can be attributed to several important factors.

First, Brent will be displaced by a new crude having very similar characteristics: WTI delivered in Houston. The production of this light sweet crude is increasing rapidly thanks to ongoing advances in fracking. The recent removal of the US ban on crude exports makes WTI highly attractive to buyers in Europe. For these reasons, one can envision, tongue in cheek, Platts concluding that the price of WTI delivered in Rotterdam would be a better surrogate for Dated Brent than BFOE.

Second, the WTI Houston market is more competitive than the BFOE market. Data compiled by Argus Media show that the BFOE (and Dated Brent) markets are highly concentrated under the merger guidelines issued by the US Department of Justice and Federal Trade Commission, guidelines that are used around the world. In contrast, the WTI Houston market is unconcentrated by these standards. The Justice guidelines note that participants in a concentrated market can raise or lower prices through their actions, while those in unconcentrated markets have no such power. Buyers naturally prefer unconcentrated markets. Looking over a wide range of commodities, one concludes that buyers and traders will move away from the concentrated BFOE market to the unconcentrated WTI Houston market to get better deals. The WTI Houston market will become even less concentrated and more competitive in the future as supply increases due to new pipeline completions and Permian output rising to perhaps four million barrels per day.

Third, the expanding WTI market enjoys two unique advantages denied to traders in the North Sea markets. First, the WTI Houston market is characterized by more frequent trades because the standard unit of trade, referred to as a "lot" in economics literature, can be smaller than North Sea lots. The latter can be as much as five hundred times larger, which reduces the number and frequency of trades. Second, Houston has the advantage of a very large storage infrastructure. In contrast, traders in the BFOE market have no access to storage. Delivery there must be accomplished by loading ships, which then can be directed to a destination or moored off Scotland to await possible transfer of the oil to another buyer. Understandably, storage in the BFOE market is complicated and costly. In contrast, the storage options in the United States are easy and relatively inexpensive.

Fourth, participants in the US market are working to remove the remaining barriers to bringing large and increasing volumes of US crudes into the international market. These efforts include hedging future production and constructing new pipelines. Soon, the amount of US crude available to the market will be double or triple the declining volume of North Sea crude.

Despite the availability of US crudes, some entities such as S&P Global Platts are taking steps to preserve Brent in one form or another as a global benchmark. Their efforts will fail, though, unless they accept the inevitable and include WTI delivered to Rotterdam as a component of Dated Brent and do so with WTI at a weight of, say, sixty percent in the computation.

Such adjustments are unlikely. Instead, Brent as a benchmark will follow the buggy whip into oblivion. Again, the title: "Brent Is Dated."

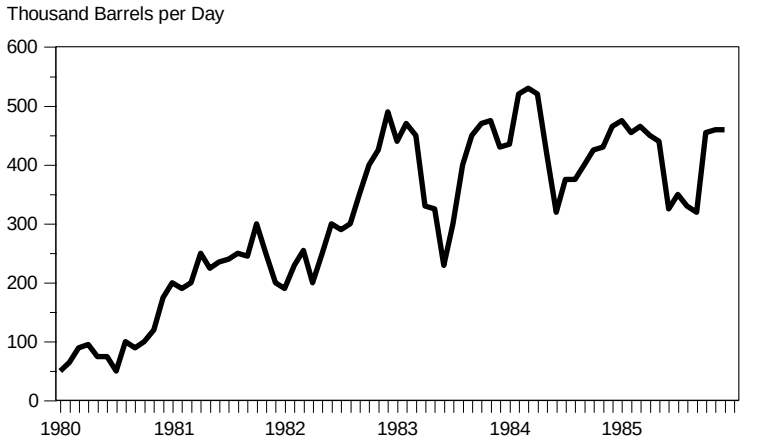
The analysis here details the coming death of Dated Brent and the BFOE market as global benchmarks. The pending demise can be attributed to four primary causes: (1) the decline in North Sea production as US output surges thanks to the fracking; (2) the removal of the export ban on US crude, which has been

followed by investment in pipelines and terminals along the US Gulf; (3) the increase in concentration in the North Sea market as an extraordinarily competitive market in the US Gulf developed; and (4) the fact that the North Sea market never really qualified as a satisfactory commodity market due to the large size of required transactions and the absence of storage.

The Production Conflict

The production of North Sea crude began in 1976. It could not have come at a better time for the global economy as it occurred just as oil-exporting countries were starting to flex their economic muscles through OPEC. Production from the Brent field began before 1980. Output reached one hundred twenty-six thousand barrels per day in January 1980 and rose to more than five hundred eighty-five thousand barrels per day by the end of 1985.[5] Figure 1 above tracks Brent output from 1980 to 1985 as compiled by Mabro et al.

Figure 1
Monthly UK Brent Oilfield Output, 1980 to 1985



Source: Mabro et al. (see text).

From the beginning, Brent was a blend of production from nineteen separate oilfields collected through two discrete pipeline systems. Reserves in the system totaled more than five billion barrels, with Brent

[5] Robert Mabro et al., *The Market for North Sea Oil* (Oxford, England: Oxford University Press for the Oxford Institute for Energy Studies, 1986), p.79.

accounting for roughly forty percent and Ninian thirty percent.[6] Table 1, originally published in Horsnell and Mabro, shows the distribution of reserves. Production from the Brent "system" (which included the Ninian fields) is show in Table 2.

Since the 1980s, production from the Brent system has declined steadily. Shell, the Brent field's operator, has begun to decommission and shut it down.[7] Currently, production from other fields is supplying less than one hundred thousand barrels per day to the market.

The initial production rise, however, combined with policies adopted by various UK governments, led to the Brent market's development, a market in spot cargos. This was an innovation. Prior to 1980, few spot trades had been made. As Silvan Robinson explains, at the start of the second oil crisis in 1979 "the market was still dominated by long term

Table 1. Brent and Ninian System Reserves in 1986 (Million Barrels)

	Oil and NGLs
Brent System	
Brent	2,180
Thistle	453
Dunlin	370
South Cormorant	200
Murchison	410
North Cormorant	410
NW Hutton	135
Hutton	215
Deveron	20
Eider	85
Tern	170
Don	25
Osprey	60
Hudson	85
Ninian System	
Heather	100
Ninian	1,160
Magnus	790
Alwyn North	220
Staffa	8
Lyell	40
Strathspey	90
Dunbar	120

Source: Horsnell and Mabro (see text), p. 12.

Table 2. Crude Oil Production from Brent System, 1986 to 1993 (Thousand Barrels per Day)

	Brent	Ninian	Total
1986	885	346	1231
1987	791	302	1093
1988	734	373	1107
1989	503	374	877
1990	405	355	760
1991	396	357	753
1992	450	324	774
1993	547	309	856

Source: Horsnell and Mabro (see text), p. 16.

[6] Paul Horsnell and Robert Mabro, *Oil Markets and Prices: The Brent Market and the Formation of World Oil Prices* (Oxford, England: Oxford University Press for the Oxford Institute of Energy Studies, 1993), pp. 11-12.
[7] Shell United Kingdom, "The Brent Story" [https://goo.gl/JYLQYV].

contracts and prices based on official selling prices."[8] During the crisis, though, "traditional supply patterns were disrupted, price premia were introduced to the market by some producers, oil was withdrawn from the contract market and offered at spot. The actual size of the spot market was not enormous, but rather like a volcano, pressure exerted on a narrow front exaggerated the impact."

The spot market might have died had global economic conditions eased or oil-exporting countries better managed the global economic slowdown that followed the tightening of US monetary policy in 1980 and 1981. Producers did not, however, cut production. Instead, they tried to coerce term buyers into taking oil volumes at high prices while product prices were falling. Robinson describes the consequences:

> Refiners put pressure on their suppliers to supply crude at bargain prices, with the very real threat that they could always look elsewhere. Increasingly trading companies had to subordinate supply security to the best short-term buy, however much this upset Managing Directors in their ivory towers, who did not like the threat to their authority any more than OPEC did.[9]

This market pressure led to the Brent market's opening and quick expansion. Thanks to the foresight of economists in the 1970s, Brent and the other UK oilfields provided substantial cash flow to the British government from taxes and introduced competition to a business that, prior to the 1980s, had been highly concentrated. The design of the British tax seems to have been led by Nicholas Kaldor, a well-known Oxford economist who was an adviser to Prime Minister Harold Wilson's treasury. Kaldor favored a high per-barrel rate, seeking large revenues for the government to boost the then-suffering British economy.[10]

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[8] See Silvan Robinson, "If 1973 was repeated," *IAEE Newsletter* (Third-Quarter 1998) [https://goo.gl/eM8VUU], pp. 30-31.
[9] Robinson, p. 31.
[10] Alex Kemp, *The Official History of North Sea Oil and Gas*, Volume 1 (London: Routledge, 2013), pp. 314-324.

The high tax rate would create a future problem because crude prices were established depending on whether oil was sold at arm's length or retained for refining by an integrated company. This later contributed to the Brent market's growth.

The leasing of North Sea blocks, undertaken in the mid-1960s, was designed to promote competition for acreage. The size of blocks leased was deliberately limited to five hundred square miles to boost bidding. The effort was viewed as promoting more intensive exploration activities by the companies seeking to develop the North Sea and thus greater production, which would lead to larger tax revenues for the state.[11]

In 1975, the British government created the British National Oil Company (BNOC and later Britoil) to take part of the nation's oil production. The theory was that the state company would secure revenue for the government, "exercise control over depletion rates and the disposal/destination of oil," and directly participate in new activities.[12] Ultimately, the company had more than four hundred cargos per year to market and a significant share of North Sea production.

The Arab Embargo and its impact on oil distribution across the world was the cause of the government's decision to intervene. Silvan Robinson's article may provide an explanation. Until 1990, Robinson headed Shell's trading arm. He was noted for his articles on the market's transformation. In his 1998 piece, he noted that the Arab boycott on oil shipments to the United States and the Netherlands was "circumvented primarily by the ability of the central supply functions of the oil majors to reallocate supplies around the globe on the principle of equal misery."[13] As a result, the UK faced electricity

[11] Kemp, Volume 1, p. 37.
[12] Kemp, Volume 1, p. 342.
[13] Robinson, p. 31.

shortages due to a lack of oil for generating plants even though Britain was not one of the targeted countries.

Robinson then explained that Prime Minister Edward Heath sent Peter Walker, Secretary of State for Trade and Industry, to Saudi Arabia to negotiate an additional supply of three hundred thousand barrels per day for Britain. Britain did not get the oil because, as Robinson observed, "unwisely Walker handed this [the oil] over to Shell and BP to administer, who promptly fed the oil into their general supply system to make up, inter alia, for the boycott of Holland." This left Britain with a problem when coal miners went on strike. Prime Minister Heath's government fell.

Kemp does not tie the effort to obtain replacement oil to the formation of BNOC. However, he dates the decision to create BNOC to the "change of government in 1974," adding that "the policy debates on how to increase the state's control proceeded apace in parallel with those on the taxation side."[14]

As BNOC's production came onto the market, the firm entered term contracts with buyers seeking assured supplies of oil. The sales were made at the official price set by BNOC. BNOC did not cooperate with OPEC, but oil-exporting countries, especially Nigeria, followed the BNOC prices. When a global surplus emerged in the early 1980s, some buyers refused to renew their contracts, and the firm had to sell significant volumes in the spot market. *Petroleum Intelligence Weekly* (*PIW*) reported that BNOC was buying[15] and selling two hundred thousand barrels per day in early 1984, effectively three cargos per week.[16] At the same time, the company adjusted its official price in an attempt to sustain contracts as opposed to growing the spot market. BNOC, though, suffered large losses from this effort.

[14] Kemp, Volume 1, p. 341.
[15] This may seem a surprise. However, BNOC was buying and selling forward cargos. Kemp documents the discussion that occurred between 1979 and 1982 regarding the company's expanded role. See Kemp, *The Official History of North Sea Oil and Gas*, Volume 2, pp. 77-78.
[16] "Active spot trading reducing BNOC's price vulnerability," *PIW*, April 30, 1984.

In 1984, the British government began a review of the organization. In 1985, *PIW* reported, it made one last ditch effort "to minimalize the impact of North Sea oil trading on world markets."[17] The effort was three-pronged. First, BNOC was blocked from taking more "participation crude" so it could reduce its trading presence. Second, companies were pressed to use the crude they produced in their own systems. *PIW* added, "There are hints of an understanding that the companies will not suffer higher tax liabilities by keeping their oil off the spot market." Third, there were reports that BNOC's forward sales might be constrained "to limit speculative trading." These efforts failed, and in February 1985, the Thatcher government closed BNOC, which ended the posting of a North Sea crude price.

In 1985, *PIW* had suggested that the government should refine the petroleum revenue tax to discourage companies from moving large volumes of oil on the spot market.[18] The tax was not reformed. Thus, the companies moved to sell oil at arm's length to third-party buyers rather than process it in their own facilities.[19]

The high marginal tax rate left North Sea producers almost indifferent to the absolute price level but very aware of price changes. From 1983 to 1986, UK producers were also very aware that income from oil sold at arm's length to unrelated buyers (a condition required by the UK's Inland Revenue) could be known with certainty while income from oil processed at their own refineries could not be known because Inland Revenue would decide the proper price retrospectively for taxation purposes.[20] The arbitrary price determined by Inland Revenue could result in a marginal tax greater than one hundred

[17] "UK may reduce state trading role in North Sea crude," *PIW*, February 18, 1985.
[18] "UK price abdication may reshape oil trading worldwide," *PIW*, March 18, 1985.
[19] Philip Verleger, "The evolution of oil as a commodity," in Richard L. Gordon, Henry D. Jacoby, and Martin B. Zimmerman (eds.), *Energy, Markets and Regulation* (Cambridge, MA: MIT Press, 1987), p. 197.
[20] Kemp, Volume 2, pp. 320-324.

percent during times of falling prices. This situation boosted the incentive to sell to third parties and contributed to the growth of the trading companies, which helped increase market liquidity.[21]

Mabro et al. and Horsnell and Mabro tracked the formation of the Brent market. By 1990, Horsnell and Mabro reported, between forty-three hundred and forty-five hundred cargos of five hundred thousand barrels were bought and sold each quarter, a trade volume of twenty-three million barrels per day. As Robinson and others noted, though, few of the sales were consummated with delivery. Instead, cargos were sold repeatedly. Mabro et al., for example, related how one cargo passed through thirty-seven owners between producer and the final buyer.[22]

Several publishers—referred to as price-reporting agencies or PRAs—documented the prices of these transactions. Platts and Argus Media were two of the leading PRA firms at the time. The companies would contact the buyers and sellers of cargos to confirm dates and prices. Their reporting increased the amount of oil bought and sold because it made prices more transparent and hence reduced uncertainty regarding the market clearing price for current or future delivery.

The Brent market could not be sustained, though, as production declined. The problems became acute after 2010. In 2012, the Oxford Institute for Energy Studies published an *Oxford Energy Forum* issue on oil price benchmarks. Ten oil-market experts provided input. One, Jorge Montepeque, then a senior official with S&P Global Platts, described in detail the efforts undertaken by Platts to maintain Brent as a benchmark. Brent, in its various forms—cash, forwards, partials, and futures—had no competitor.

> Physical Brent matured as the core world indicator of value, stemming from its strong underlying North Sea base and its ability to reflect the power of arbitrage from Russia and Central Asia to

[21] Verleger, p. 179.
[22] Mabro et al., p. 178.

> Asia and the Americas. Dated Brent also ratified its position as the global marker of crude due to its response to geopolitics. The price of Dated Brent rises in times of crude shortness, or perceived constraints, due to political issues and falls when those supply issues have dissipated.
>
> While challenges and evolution in the crude pricing systems will continue as flows of oil and the logistics change, Dated Brent is better positioned than its competitors as its price formation is in an open market and free of logistical, legal or political constraints. [23]

Montepeque's 2012 assessment is outdated. Brent's role has been and is being steadily diminished by the increasing US oil production. The removal of the export ban on US crude essentially sealed the North Sea market's fate. However, its decline was well underway before the US policy change due to its decreasing production.

Likewise, trade volumes have declined substantially with the falling production. Whereas Horsnell and Mabro counted forty-three hundred to forty-five hundred transactions in the first quarter of 1990, Argus Media reported fewer than twenty transactions in the BFOE market in the third quarter of 2017, with the physical trade decreasing to three hundred thirty thousand barrels per day.[24] Figure 2 (page 13) shows the oil volumes and Brent's diminished state, including the recently added Troll crude.

The problem Platts and other PRAs such as Argus Media encounter is that the BFOE crudes are not homogenous. Troll is different from Brent, which is different from Oseberg, which is different yet again from Ekofisk. To create a single price measure, the PRAs must adjust prices for each to reflect quality differences. These adjustments are announced in advance.

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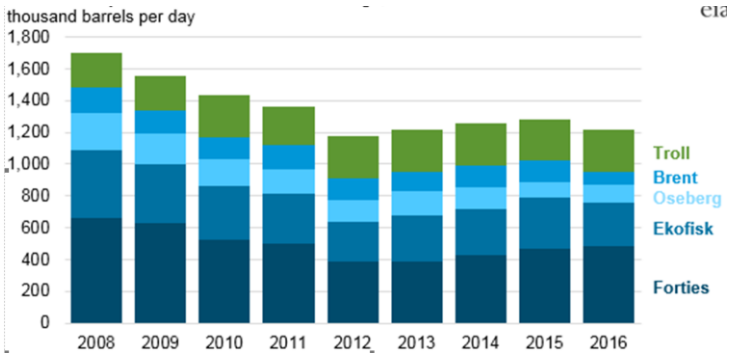
[23] Jorge Montepeque, "Oil Price Benchmarks in International Trade," *Oxford Energy Forum* 87 (February 2012) [https://goo.gl/wKfyVd].
[24] See Argus Media, "Forties pipeline outage opens way to US gulf benchmarking," 2017 [https://goo.gl/PFYPb7].

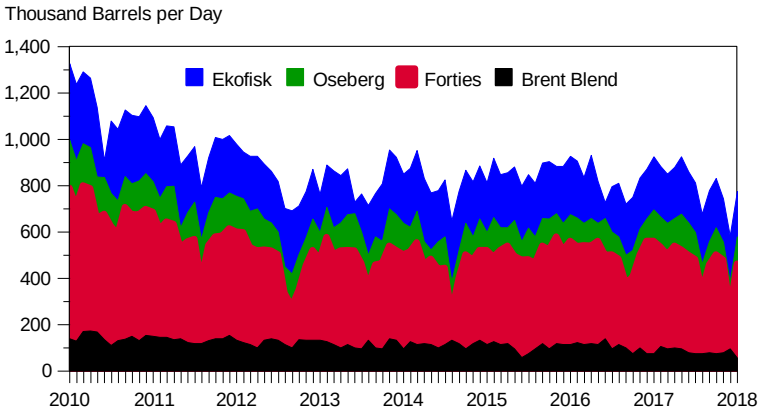
Figure 3 makes it clear that the output volume underlying the Brent market is relatively small, totaling roughly one million barrels per day. (To date, apparently no transactions in Troll have occurred.) Thus, when the Forties system was disrupted in December 2017, the market size dropped to approximately six hundred thousand barrels per day, or around one cargo per day.

Figure 2
Dated Brent Price Assessed Crude Oil Loadings, 2008 to 2016



Source: US EIA.

Figure 3
Crude Oil Production Volume Feeding the BFOE Market, Monthly Data, 2010 to 2018



Source: PKVerleger LLC.

Platts' Jonty Rushforth acknowledged the decreasing North Sea light crude production in his paper "Brent and the beauty of benchmarks" and suggested two revisions for computing the Dated Brent price. First, the computation could include production of a heavy crude such as that from the Johan Sverdrup development, which will come on stream in 2019. However, the various forms of Brent are light crudes. Including a heavy crude would make Brent an unreliable indicator. Alternatively, Rushforth wrote,

> It [the stream] may need to change tack entirely and reflect crudes delivered into Europe from outside the region, such as Azari light. Or as some have suggested, it may need to do both, bringing in a sour, sulfur heavy crude such as Russia's Urals.

Logically, Rushforth might also include WTI Houston, which is being exported to Europe in large volumes. However, there is a PRA competitive issue with this because Platts has not yet developed a benchmark for WTI Houston embraced by the industry, while Argus Media has.

In sum, after twenty-five to thirty years as the global crude benchmark, Brent, as this paper's title implies, has become obsolete. It could survive if there were no alternative. However, we have an alternative in North America: WTI Houston. The natural evolution, then, is to shift to a WTI benchmark priced on the US Gulf Coast.

Two of the factors sealing Dated Brent's demise as a global benchmark are fracking and the financial revolution. Fracking was virtually unknown in 2008 when the first oil well was fracked in Texas.[25] Today, it has altered the global oil market completely, transforming the United States from a minor, diminishing crude oil producer into the world's second or third largest producer.

Moreover, the output expansion in the United States has been and is *economically uncontrolled* because fracking is a low-cost drilling method compared to the techniques used to develop major oil fields. This means governments can do little to affect output rates or oil sales levels. Thus, whereas *PIW* reported in 1984 that companies operating in the UK sector of the North Sea were pressured to process oil in their own systems to keep oil off the market and support prices, no such pressure can be applied in the US, where many companies operate and few, if any, have refining systems.

[25] Russell Gold, *The Boom* (New York: Simon & Schuster, 2014).

Here, the unique nature of the US economy combined with the technological innovation of fracking combine to effectively displace the North Sea. Because resources in the United States are the property of the landowner, not the government, development can occur at a very rapid rate if prices are correct. Furthermore, the fracking technology revolution has lowered barriers to entry and brought many firms into the business, encouraged by hundreds of private landowners who want their property developed. One indicator of this "land rush," or competitive push, lies in the fact that over one hundred firms drilled at least one well in the Permian Basin in 2017.[26]

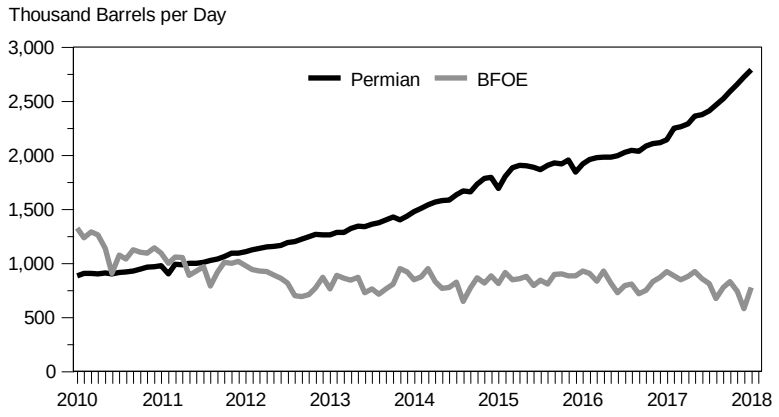
The Permian Basin, a field that spans Texas and New Mexico, is propelling the United States oil boom, although other areas such as the Bakken in North Dakota, the Anadarko in Kansas, Oklahoma, and northern Texas, and the Julesburg in Colorado have contributed significantly to the surge. Within the Permian, one formation, the Wolfcamp, is estimated by the US Geological Survey to hold twenty billion barrels of oil.[27] In contrast, the Brent field was thought to hold 2.1 billion barrels, according to Horsnell and Mabro, and the Brent and Ninian system reserves less than five billion barrels, one fourth the size of Wolfcamp.[28] And Wolfcamp is but a portion of the entire Permian Basin!

Figure 4 (page 16) tracks the rise of the production from the Permian Basin and compares it to the fall in the crudes underpinning the BFOE market. This graph shows monthly oil production for the Permian Basin (WTI) and for four BFOE crudes. In early 2010, as the fracking boom began, their output was roughly equal. By January 2018, Permian production was four times that of BFOE.

[26] Liam Denning, "Time for Shale's Loners to Settle Down," Bloomberg, June 20, 2017 [https://goo.gl/zvjViG].
[27] "USGS Estimates 20 Billion Barrels of Oil in Texas's Wolfcamp Shale Formation," USGS press release, November 15, 2015 [https://goo.gl/BrNDyk].
[28] Horsnell and Mabro, p. 12.

The oil produced in the Permian is generally a very light sweet crude, like Brent and many other North Sea crudes, which makes it a viable alternative to those crudes.

Figure 4
Crude Oil Production from Permian Basin vs. Output from BFOE Market, Monthly Data, 2010 to 2018



Source: Argus Media; US EIA.

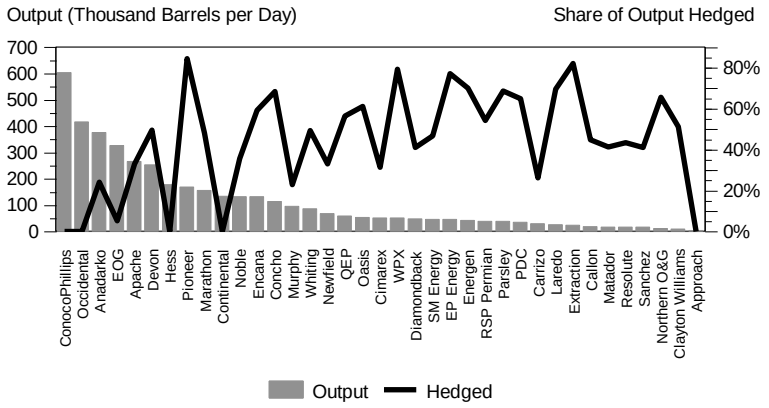
Permian production is also projected to increase substantially. A 2017 presentation by Artem Abramov of Rystad Energy during an EIA-sponsored webinar suggested that Permian output might rise from 2.5 million barrels per day to more than 3.9 million barrels per day by the end of 2020 if WTI prices (presumably at Cushing) rose above $55 per barrel.[29] An extrapolation of his calculation suggests that, at current prices of $65 per barrel, Permian production might reach 5.5 million barrels per day. The Permian, in short, is the new North Sea.

Robust US financial markets are further hastening Brent's displacement. These enable producers to hedge future production. A survey of hedging by US companies prepared by Bloomberg showed that US independent producers hedged twelve percent (one hundred twenty-three thousand barrels per day) of the projected 2017 production of 4.2 million barrels per day, as can be seen from Figure 5 (page 17). This graph shows estimated annual output by firm and the percentage hedged. Firms are sorted by size from largest to smallest. Note that the smaller producers, who are spearheading the production surge, tend to have the most production hedged.

[29] Artem Abramov, "Permian Basin: Latest Trends and Perspectives," Rystad Energy, November 16, 2017 [https://goo.gl/vLnfs1].

The development of robust futures markets makes it easier for smaller firms to enter the market, particularly when those with capital seeking investment opportunities are rushing to find and fund new firms to explore and develop oil. This opportunity was not available forty years ago when the North Sea was developed and was no doubt unwanted by the large oil companies, which preferred that crude production be restricted to a closed club of a few major companies and exporting countries.

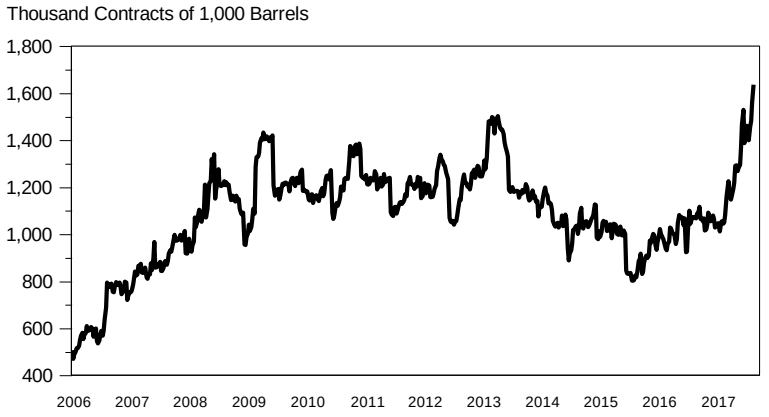
Figure 5
Estimated 2017 Output of US Oil Producers as of December 2016 and Percentage of Output Hedged



Source: Bloomberg.

The percentage of forward production hedged to the end of 2017 has almost certainly increased from December 2016. Most firms hedge future production with options sold by swap dealers such as Cargill Financial Services. The positions of these firms are noted in the Commodity Futures Trading Commission's large trader report. Figure 6 shows the rise in the short and spread

Figure 6
Short and Spread Positions of Swap Dealers in WTI Futures and Options, June 2006 to January 2018



Source: CFTC.

positions of swap dealers in WTI (Cushing) futures from 2006 to the present on ICE and CME. At the end of January 2018, the short position had increased sixty percent from January 2017 to 1.6 billion barrels.

This ability to hedge forward production acts as financial insurance for the smaller firms developing oil in the Permian and other US areas. Like other small producers such as farmers, they can protect income and assure business continuity.

Hedging also reduces the uncertainty of forward forecasts such as those made by Rystad and others. The likelihood of greater production from the Permian offers the prospect of a larger oil supply to underpin the US crude market and eventually swamp the BFOE market.

Authorizing Exports

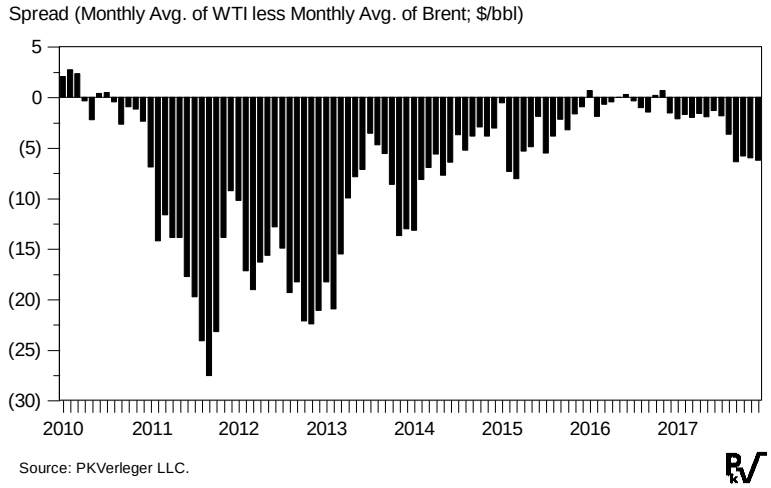
The US Congress repealed the ban on exporting US crude oil in December 2015. This action may constitute the largest single contribution to the end of the Dated Brent market. The prohibition on exports had been in force since the passage of energy legislation at the time of the 1973 Arab Embargo. It was enacted as part of the congressional compromise that authorized the construction of the Alaskan crude oil pipeline, a step that made production from the North Slope feasible.

Most of the increase in US crude output came from fracking. The production was light and sweet. The US market for this was limited, though, because US Gulf Coast refiners were configured to process heavy sour crudes such are those produced in Canada, Mexico, Saudi Arabia, and Venezuela.

The incompatibility between the increasing light sweet crude output and the refining capacity caused a large discount to develop between the WTI Cushing price and the Brent price, as can be seen from Figure 7 (page 19).

The removal of the export ban eliminated much of the discount. The action was followed by a rush to construct pipelines to Houston and Corpus Christi in Texas and St. James in Louisiana from the Bakken, the Eagle Ford, and the Permian Basin. Table 3 lists some of the pipelines and capacity being proposed today. (Note that the promoters of the Cactus II line are now proceeding with construction.)

Figure 7
The Brent/WTI Cushing Spread, Monthly Data, 2010 to 2017



Source: PKVerleger LLC.

Table 3. Crude Oil Pipelines Planned for Texas

Company	Pipeline Name	Capacity (mbd)	Start Date
Buckeye	South Texas Gateway	600	2020
EPIC	EPIC	590	Q1 2019
Phillips 66/Enbridge	Gray Oak	385	H2 2019
Magellan	Unnamed	350	Early 2019
Enterprise Products	Unnamed	200	Early 2020
Plains All American	Cactus II	185	Q3 2019
Total		2,310	

Source: Platts (see text).

The increase in US crude supply is also leading to a rearrangement of pipelines within the United States. The rising flow of oil from Canada and Colorado received at Cushing is flowing to the Northeast and to the South as new lines are built.

The oil supply to the Gulf is further increased by the completion of a line that flows from Cushing to Tennessee. Reuters' Kurar and Sims explain that the opening of the Diamond Pipeline has altered crude flow around the US Gulf. The line allows Valero's refinery in Tennessee to access crude from Cushing. Previously, the refinery received much of its crude oil supply via the Capline, a pipeline with the capacity

to move 1.2 million barrels per day from the Gulf Coast north to Chicago and Michigan. Flows on this line have dropped, according to these authors, from around three hundred thousand barrels per day in July 2017 to around two hundred thousand barrels per day this January.

Kumar and Sims also report that the opening of the Diamond line has caused prices for the crude oils produced in the Gulf of Mexico (Mars and LLS) to decline relative to other crudes because these oils must now seek other buyers, most probably ones from abroad.[30]

The lifting of the export prohibition also led to the expansion of crude storage capacity in the Gulf Coast area. The Department of Energy publishes a semiannual report on US tank capacity by region. Prior to the decision to allow exports, the Gulf Coast had two hundred twenty-six million barrels of crude oil storage facilities in tank farms. Since the ban was lifted, this capacity has been increased to two hundred sixty-eight million barrels, as can be seen from Table 4.

Table 4. Crude Oil Tank Farm Storage Capacity on US Gulf Coast excluding Pipeline Fill (Million Barrels)

Date	Working and Net Available Shell Capacity
9/30/2015	226.1
3/31/2016	240.7
9/30/2016	250.6
3/31/2017	260.2
9/30/2017	268.2

Source: PKVerleger LLC.

The increasing storage in the Gulf, combined with the new pipelines, enables Permian Basin production to flow directly to terminals in Houston or Corpus Christi. This means that much of the 2.7 million barrels per day of WTI output, as well as the WTI or blended WTI stored at Cushing, is readily available for shipping abroad.

In contrast, no storage is available at the point of exportation in the BFOE market. Buyers there must take delivery of production and, should they choose to store it while seeking economic opportunities, hold it in ships anchored off Scotland. The storage availability at Houston—in some cases at terminals

[30] Devika Krishna Kumar and Bryan Sims, "Diamond Pipeline disrupts oil flows around the U.S.," Reuters, January 29, 2018 [https://goo.gl/QxsqDf].

with adjacent docks from which oil can be loaded—increases the Gulf Coast advantage over the BFOE market and Dated Brent.

To recap, the export ban's removal provided an incentive to boost production. It further provided an incentive to expand pipeline systems to bring output from the Bakken, Eagle Ford, and Permian to Houston. These developments resulted in a large, fluid market in light sweet crude easily available to all parties, a competitive market. As is often the case, buyers prefer such markets, and thus Brent is being left behind.

A More Competitive Market

The petroleum industry and market have always tended to move toward monopoly and away from competition. In the conclusion to a volume titled *Crude Volatility*, McNally noted that "for the better part of the last hundred years, to protect a vital industry, economic growth and national security, the oil industry and governments in major producing countries felt compelled to regulate supply with the primary goal of stabilizing oil prices. [31] McNally explains that the Texas Railroad Commission and the Seven Sisters provided the stability until the early 1970s. They were then followed by OPEC and from time to time by the British government. The control broke down in 2014, at least temporarily.

McNally's explanation is limited, though, because no thought is given to the economic causes of volatility. Seventy years earlier, an astute economist, Paul Frankel, provided a basis for understanding the issue that McNally had attempted to explain in *The Essentials of Petroleum*, published in 1946. Frankel asked and answered this question: "Was competition ever 'free?'" As he explained,

> Unless my reading of the oil industry's structure and history is altogether wrong, there is no question that there has been, always and everywhere, an overwhelming tendency towards

[31] Robert McNally, *Crude Volatility* (New York: Columbia University Press, 2017), p. 225.

> concentration, integration and cartelization of the petroleum industry. This goes deeper than Adam Smith's taunt that "people in the same trade seldom meet together, even for merriment and diversion, but the conversation ends in a conspiracy against the public or in some contrivance to raise prices."[32]

Frankel observed that "all-out competition, where it is allowed to prevail in the oil industry, leads either straight to general bankruptcy or monopoly of the survivor." He cites an even earlier economist, George Stocking, who in 1925 wrote that "the scientific and economic development of oil production is opposed rather than promoted by the competitive system."[33] The Frankel and Stocking stories explain why, historically, the industry sought to control production.

The technological innovation of fracking has made these observations obsolete, though. Today, the cost of entry into crude oil production, at least in the United States, is modest compared to most industries. Furthermore, the oil industry's fragmentation that has happened since Frankel wrote (described by some as "deintegration") has made it easy to move produced crude oil to buyers. This means that today the "scientific and economic development of oil production supports and promotes rather than opposing the competitive system."

In a way, the industry, at least in the United States, has returned to the structure observed in the 1920s, many producers competing to sell their oil, with the result being that prices can and have collapsed. There is, though, a significant structural change in the economy. Today, there is a general preference to leave markets unregulated except where there are natural monopolies, whereas fifty years ago there was a preference for systems that stabilized prices. Thus, the proliferation of production in an

[32] Paul H. Frankel, *The Essentials of Petroleum* (London: Frank Cass, 1946 [1983 edition]), p. 127.
[33] George W. Stocking, *The Oil Industry and the Competitive System* (New York: Houghton Mifflin, 1925), p. 118.

uncontrolled way in the United States has resulted in a very competitive source of crude supply for the world market.

Due its structure, the North Sea oil market is less competitive. The cost of projects there is in the tens and hundreds of millions, not a few million as is the case with shale. Furthermore, due to its circumstances, the North Sea distribution system was designed for delivery of shiploads (crude oil cargos of five hundred thousand barrels plus or minus fifty thousand barrels). The size of North Sea operations greatly restricts the number of firms that can invest and produce oil from the area, while the size of cargo deliveries greatly restricts the number of firms that can participate in the market as consumers. The market's physical structure and the investment costs confirm Stocking's observation that "the scientific and economic development of oil production is opposed rather than promoted by the competitive system."

Data compiled by Argus Media adds weight to this view. Its "Forties pipeline outage" paper describes four contrasts between the North Sea and US markets.[34] These relate to

- the volume of trade, which is measured in the daily volume of crude turnover;
- the numbers of days during a quarter where there are no transactions in the physical market;
- the number of transactions per calendar month; and
- the number of unique participants in the market.

The Argus statistics provide a compelling picture of two different markets.

<u>Data on trade volume underlying the two markets seem to favor BFOE.</u> According to Argus Media, average volume in the third quarter of 2017 was 313,044 barrels per day in the BFOE market but only

[34] See Argus Media, "Forties pipeline outage opens way to US gulf benchmarking," 2017 [https://goo.gl/PFYPb7].

210,590 barrels per day in the WTI market. However, barrels per day hides an important fact because BFOE transactions are of fifty thousand barrels or more while WTI transactions can be as small as ten thousand barrels. Thus, there were far fewer deals in the BFOE market than in the WTI market.

The BFOE market suffers in comparison to WTI because trades in it do not occur every day. Argus Media reports that deals were recorded every day in the case of WTI but less frequently in the BFOE market during the third quarter of 2017.

Data on deal counts underlying the two markets emphasize the difference in size. Argus Media counted eighteen deals per month in the BFOE physical market during the third quarter of 2017 versus one hundred twenty-one deals per month in the WTI Houston market. Thus, the average size of the BFOE transaction was around five hundred fifty thousand barrels, while the average size of the WTI transaction was one tenth of that size.

The difference in the number of transactions points to a lack of liquidity in the BFOE market. The Argus paper notes that concerns regarding liquidity in benchmarks for Asian crude, particularly Malaysian Tapis and Indonesian Minas, caused buyers to seek another market indicator or benchmark. Brent was selected as the alternative for the following reason:

> The rationale for this replacement was that the number of cargos of Tapis and Minas available for spot trade declined to a point where they were unable to generate a reliable price signal for the critical Asia-Pacific Market.[35]

[35] Argus Media, "Forties pipeline outage opens way to US gulf benchmarking," 2017, p. 2.

Here, the term "liquidity" takes on critical importance. It is a word one hears used often in the discussion of markets. Yet, there seems to be no widely accepted definition. The Energy Intelligence Group offers this explanation:

> In the oil market context, this [liquidity] refers to the volume of trading activity of participants in a particular area. Greater liquidity allows trades to be executed quickly and easily at a uniform price; a lack of liquidity tends to prevent some interested participants from finding a buyer or seller at a given time. High-volume oil futures markets are the most liquid.[36]

This description is satisfactory. However, this more useful one appears in a volume first published in 1929 by Julius Baer and Owen Glenn Saxon:

> By liquidity is meant (1) that the commodity may always be bought or sold at some price readily, instantaneously, and in any amount without the necessity of sharp price reactions, protracted bargaining or searching for a buyer or seller; (2) that the sale of the commodity may be effected by sellers to buyers through a standardized contract which requires no attention to its technical terms and conditions on the part of either party to the transactions, except as to the price and time of delivery; and (3) that title to the commodity may be transferred by delivery of a negotiable warehouse receipt which passes from hand to hand, is everywhere accepted as representative of the stored commodity it controls, and is accompanied by an unimpeachable certificate of the quality of the merchandise.[37]

The Brent and BFOE market originally met these criteria. Production was significant. There were usually willing sellers available at almost any time, the specifications were clearly understood, and the buyers would receive an "unimpeachable" telex informing them of the loading date and cargo number of the oil

[36] Energy Intelligence Group, *The International Crude Oil Market Handbook* (New York: EIG, 2006), p. A112.
[37] Julius B. Baer and Olin Glenn Saxon, *Commodity Exchanges and Futures Trading: Principles and Operating Methods* (New York: Harper Brothers, 1949), p. 86.

to be delivered from the loading facility in Sullum Voe, Scotland, as well as the date range for the cargo's arrival.

Liquidity in the Brent contract alone, though, declined over time, as noted above. Mabro et al. put Brent production at eight hundred ninety-three thousand barrels per day in 1984.[38] By early 2017, Brent production had declined to around one hundred eighty thousand barrels per day. The decrease in the number of Brent Blend cargo loadings to around eight per month contrasts with the roughly sixty to seventy cargos per month thirty years earlier.

Another key measure of a market's viability (and usefulness as a benchmark) lies in the market concentration of sellers. A market with a single seller is not, of course, competitive. No one today would, for example, describe the market of an important pharmaceutical drug as competitive if there were only one seller that used its patent on a unique product to extract a price well above the cost of production. The firm's ability to obtain the high price would be enhanced if there were no close substitutes.

The Herfindahl-Hirschman Index (HHI) is the standard measure of market concentration. A market's HHI is computed as the sum of the squared participation in it. A market will have an HHI of 10,000 if one producer controls the market and no close substitutes exist for the item being sold. In contrast, the HHI would fall to 100 if there were one hundred producers of a similar item, each with a market share of one percent.

The US Department of Justice and the US Federal Trade Commission have published estimates of the HHI levels associated with unconcentrated, moderately concentrated, and concentrated markets. The computed HHIs are used to vet mergers.

[38] Mabro et al., 1986, p. 20.

DOJ and FTC research has shown that sellers (or buyers) are unlikely to have influence over price levels where markets are unconcentrated. Thus, mergers that leave markets unconcentrated are unlikely to be challenged. Mergers that boost the HHI in a moderately concentrated market raise concerns, however, while mergers that increase the HHI in highly concentrated industries are seen as likely to raise market power.[39] The three HHI levels defined in the DOJ/FTC guidelines are as follows:

- Unconcentrated markets have an HHI below 1,500.
- Moderately concentrated markets have HHIs between 1,500 and 2,500.
- Highly concentrated markets have an HHI above 2,500.

The Brent market was unconcentrated by these standards when Mabro et al. published their study. At the time, the computed HHI was 980. The low concentration occurred because there were many cargos and eighteen unique firms were involved in producing North Sea oil. Today, the number of firms has dwindled to eight, although recently one or two firms not listed here have acquired assets that formerly belonged to the major producers. For example, Shell sold its assets to Chrysaor in January 2017 [40], while BP agreed to sell its stake in some fields in November 2017.

The production decline boosted market concentration among sellers. At the beginning of 2017, the market concentration in the BFOE physical market was as high as 2,600. It also fell as low as 927 in November 2017. The story was similar in the BFOE forward market. Concentration there rose as high as 2,600 in July 2017 but dropped to 900 in October.

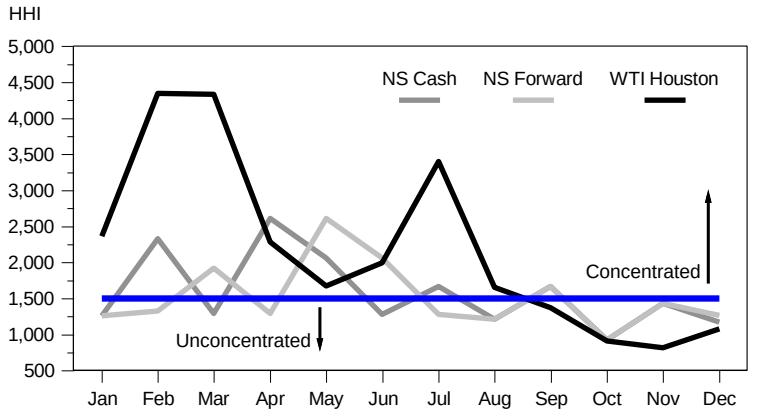
[39] US Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, August 19, 2010 [https://goo.gl/1L5Y7J].
[40] Karolin Schaps and Ron Bousso, "Shell agrees to UK North Sea, Thai asset sales worth $4.7 billon," Reuters, January 31, 2017 [https://goo.gl/3sWqik].

The Houston market was highly concentrated through the first two thirds of 2017 but then became "unconcentrated" following the completion of new pipelines. The HHI reached a peak of 4,300, likely higher than any HHI ever observed in the Brent or BFOE market, but then dropped to less than 900 in the fourth quarter of 2017 as new pipeline capacity came on line.

The completion of more lines to Houston will probably bring the HHI in Houston down to perhaps as low as 500. Concentration in the North Sea market may decrease as well as multinationals such as Shell sell assets to smaller firms.

Figure 8 tracks the movement of concentration in the BFOE cash market, the BFOE forward market, and the WTI Houston market by month in 2017.

Figure 8
Market Concentration of Sellers: North Sea Physical and Forward Markets vs. WTI Houston Market, 2017



Source: PKVerleger LLC.

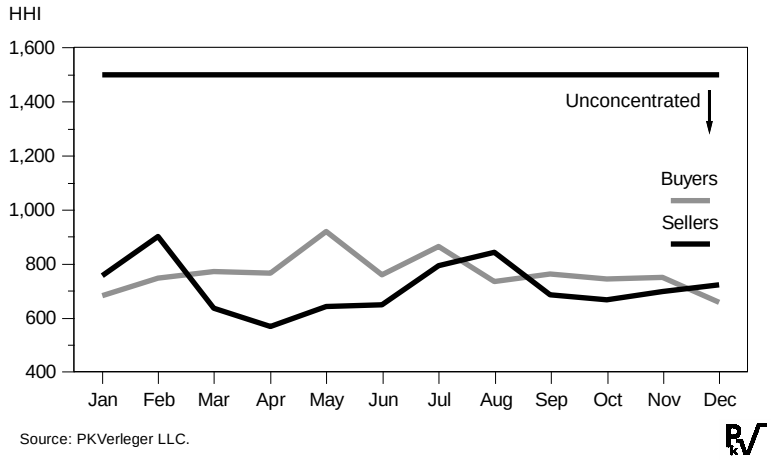
However, Figure 8 overstates the concentration of US markets because it ignores several other markets for crude oil on the US Gulf Coast. These can be found east of Houston in Louisiana and west in Corpus Christi and include such diverse crudes as West Texas Sour, West Texas Intermediate not delivered in Houston, Eagle Ford Shale, Mars Blend, and Light Louisiana Sweet (LLS). Many buyers can substitute between the crudes.

Competition authorities examine the extent of a market when testing whether it is fully competitive or monopolized. In their studies, the authorities seek to determine whether readily available substitutes

exist for the products supplied by merging firms. If substitutes are available, this is taken into account. To do this, they test whether a hypothetical monopolist could raise and sustain a price increase of five percent within a specific geographic area. The area is defined as the "geographic market" if the increase can be sustained.[41]

The geographic or regional market definition is widened if the agencies determine that the price increase could not be sustained. In the case of crude oil sold on the Gulf Coast, it seems clear that no company in one location could sustain a price increase of five percent. Thus, here we define this US market not as Houston but the entire Gulf Coast.

Figure 9
HHI Computed for US Gulf Coast Crude Oil Market by Month in 2017



Source: PKVerleger LLC.

The level of Gulf Coast competition is measured using the crude oil volumes bought and sold in the various Gulf markets. Argus Media has developed such data. The firm tracks information on oil volumes purchased and sold by companies in the major markets. These data cover seventy-one unique firms. The volumes traded ranged from 1.3 million barrels per day to 1.7 million barrels per day. Figure 9 above shows the computed HHIs by month for the Gulf Coast in 2017.

[41] *Horizontal Merger Guidelines*, p. 14.

These HHIs range from a high of around 900 to a low of 600. One can assert that the US Gulf Coast crude market is very competitive after recalling that the US FTC and the Justice Department have concluded that markets with HHIs below 1,500 are unconcentrated. Were more data added for the trades that are missing, one would almost certainly find the US crude market to be highly competitive.

Never a Suitable Benchmark

That Brent ever became a benchmark for oil should be a surprise. That Brent survived as a benchmark for so many years is also a surprise. Indeed, it is surprising that trading in crude produced from all North Sea fields ever exerted such an influence on the global oil prices because the volumes are small relative to other areas.

Dated Brent, the Brent BFOE market, and the influence of the Brent futures market are an anomaly in the history of commodity markets. In no other case has such a relatively minor supply source played such a large part in determining prices. At its peak, Brent accounted for less than two percent of world production. In contrast, production of the benchmark used for other commodities will represent a very significant percentage of global output.

The coffee futures contract, for example, specifies the Arabica grade. According to the International Coffee Organization, Arabica accounts for sixty-one percent of global coffee production.[42] The wheat futures contract allows for delivery of hard red winter wheat, soft red winter wheat, and northern spring wheat, along with other types at slight discounts. These strains encompass almost one hundred percent of US wheat production.[43] It is the same for most other agricultural commodities and other commodities.

[42] ICO, *Coffee Market Report,* December 2016 [https://goo.gl/tpXGYc].
[43] US Department of Agriculture, Economic Research Service, *Wheat, Background* [https://goo.gl/Jbp77W].

Yet, despite the small and diminishing size of its market, Dated Brent has been used to determine the price for roughly two-thirds of the world's oil trade, according to Bossley.[44] It is as if the price of a mouse is used to set the value of an elephant.

Brent became a benchmark for the determination of crude prices because the North Sea was the only source of waterborne crude oil supplies that could be purchased and sold with no constraints. As many, but especially the late Robert Mabro, have noted, Arab Light or the Middle East light crudes produced by countries bordering the Persian Gulf should have been the crude oils used as key price indicators across the globe.

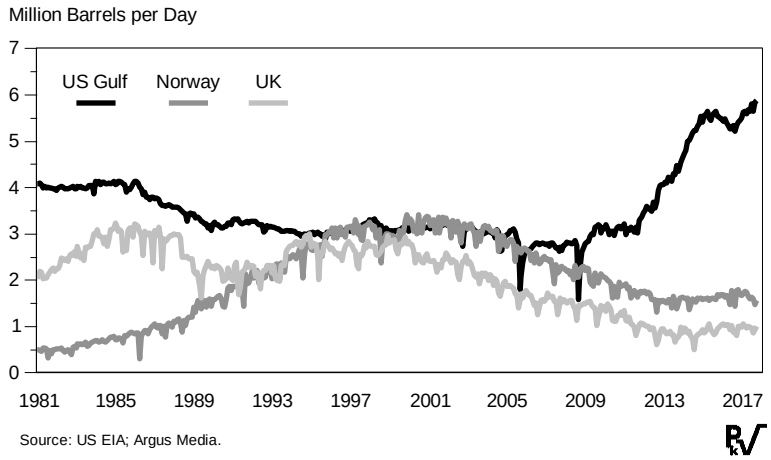
However, the companies that produced these crudes in Iran, Iraq, Kuwait, and Saudi Arabia, and then the producing nations themselves prohibited buyers from trading the oils. Resale of cargos was generally proscribed. Furthermore, the selling countries often imposed destination restrictions, requiring the oil to be transported to specific refineries. These restrictions allowed the sellers to practice price discrimination and raise profits.

Thus, Brent by default became the key indicator of global crude values. For almost forty years, it has remained the principal determinant of crude prices as Montepeque and more recently Rushforth have explained. With the removal of the United States' prohibition on crude oil exports and the surge in domestic oil production, though, far more suitable benchmarks have emerged. Absent an act of god, they will replace Brent.

[44] Liz Bossley, "Oil Benchmarks in International Trade," *Oxford Energy Forum* 87 (February 2012) [https://goo.gl/wKfyVd], p. 6.

The surge in US oil production will assure that one or more US crudes replaces Brent. US output now dwarfs production from the various North Sea countries. Figure 10 provides an indication of the change. This graph compares the volume of crude available on the US Gulf Coast for domestic refiners or for export with the total production of Norway and the United Kingdom. Included in the US data are output from Louisiana, New Mexico, and Texas, as well as production from the federal offshore leases. The key types of crude included in this production are West Texas Intermediate, West Texas Sour, Light Louisiana Sweet, Mars, and Eagle Ford. Each of these streams provides sufficient output to produce at least one North Sea cargo lot of five hundred thousand barrels every day.

Figure 10
US Crude Oil Output Available to Gulf Coast Refiners or for Export vs. Output from Norway and UK, 1981 to 2017



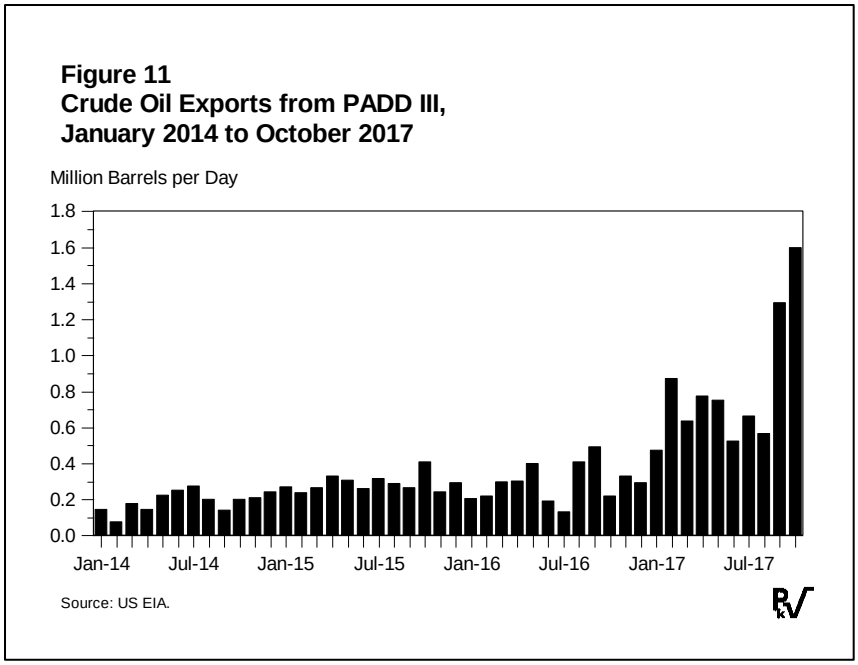
Source: US EIA; Argus Media.

Bakken crude oil is not included in the data shown in Figure 10. However, it should be included today given the completion of the Dakota Access pipeline.

These crude oils were not seen as global benchmarks in the past because exports were prohibited. Today, however, the US Gulf Coast may be exporting more crude that all the North Sea producers combined. This threshold will soon be passed if it has not been already.

The surge in US exports can be seen from Figure 11 (page 33), which tracks exports from PADD III by month from January 2014. Note that exports did not surpass one million barrels per day until September 2017 and then passed 1.5 million barrels per day in October, the latest date for which data are available.

In October, total exports from the US Gulf Coast exceeded the production of fields in Norway and fields in the United Kingdom.



In the coming years, if not the coming months, US output will exceed the total output of other large oil-producing countries, including Saudi Arabia and Russia. If projections offered by firms such as ExxonMobil are realized, output from the Permian Basin could exceed the global output of Arab Light in the five major Middle Eastern producing countries. Furthermore, it will trade freely without destination limits.

In time, the US market will benefit from the addition of oil shipped from Canada. Today, Canadian producers must limit production because they have no way to move it to market. Most of their output originates in Alberta. Two *Wall Street Journal* reporters explain the problem:

> The existing pipeline to the west across British Columbia is at capacity and proposals to expand it are being blocked by the government of British Columbia.
>
> Pipeline capacity to move oil to the east is fully utilized. Proposals to add additional capacity have been blocked by eastern Provinces.

> The two Canadian railroads have refused to add additional capacity to move oil because producers will not sign long term contracts.[45]

At the same time, fracking has moved to Canada. Producers are exploring the Duvernay and Montney formations, which some expect to rival the Permian. The National Energy Board puts reserves at around five billion barrels. Production is now at three hundred thousand barrels per day but could increase quickly as firms such as Chevron and Shell fund expansion. The incentive to boost production is driven by property rights like those in the US. Capital spending is increasing in the shale area while declining in the oil sands.[46]

The blockage of export routes west through British Columbia or east through Ontario and the limits on rail capacity mean that much of Alberta's incremental production will find its way to the US Gulf. The Keystone XL Pipeline will likely move up to eight hundred thousand barrels per day of Canadian crude to the Gulf by 2020.

The Gulf Coast already receives more than four hundred thousand barrels per day from Canada. By 2020, the volumes could surpass one million barrels per day. Much of the oil will be sold for export to Asia, Europe, or South America. Canadian grades will trade with US grades.

These flows of oil from many sellers via many pipelines will further expand the Gulf Coast market. Today, a rough calculation suggests its size could total as much as 7.5 million barrels per day, excluding the oil from Canada. The market may total eight million barrels a day when Canadian supplies are

[45] Vipal Monga and David George-Cosh, "Canada's Oil Producers, in Standoff With Railways, Sit Out Oil-Price Rally," *The Wall Street Journal*, January 28, 2018 [https://goo.gl/JY8k7b].
[46] Nia Williams, "Why Canada is the next frontier for shale oil," Reuters, January 29, 2018 [https://goo.gl/hkPTyv].

included. In contrast, the total production from the major North Sea fields today amounts to less than two million barrels per day.

Of course, much of the eight million barrels per day available in the Gulf market, as well as the North Sea volumes, is taken directly into dedicated refinery systems and never reaches the market. Still, the Gulf market's size dwarfs the North Sea market by any metric, and the US market will increase in size in coming years. The market might be augmented, for example, by another three hundred to five hundred thousand barrels per day from Canada. The more optimistic forecasts suggest that increase could be three times as large. By 2020, the US Gulf market could be four or five times the size of the North Sea market, and the US market will be much more competitive due to its logistical and structural characteristics.

With respect to logistics, the US is a pipeline market, whereas the North Sea is a tanker market. This means that lot sizes are smaller in the US and thus there are many more lots. The smaller lot size will promote trading activity in the physical, forward, and futures markets.

Structural differences will also make the US a far more active market. Much of the increase in US (and Canadian) output will come from expansion of onshore fields through fracking. While large companies will contribute much of the increase, fracking is an economically democratic business that encourages entry by smaller independent firms. There will be more firms involved. Many will not practice the cost discipline observed in the large companies. The ability to hedge through futures will embolden many of the smaller firms to press on with expansion as executives from larger firms call for caution.[47] Supply will be plentiful, and prices will frequently come under pressure.

[47] Harold Hamm, CEO of Continental Resources, has been trying to encourage such discipline recently but to no avail. See Bradley Olson and Lynn Cook, "Wall Street Tells Frackers to Stop Counting Barrels, Start Making Profits," *The Wall Street Journal*, December 13, 2017 [https://goo.gl/KAFZhG].

The separation of US refiners from crude production will intensify competitive forces. US Gulf Coast refiners generally will not be interested in much of the light crude produced and marketed in Texas and Louisiana, preferring the heavy, sour grades from Canada, Mexico, Saudi Arabia, or possibly Venezuela. This aspect of the industry in the United States differentiates it from Europe, where European refiners are configured for and tend to absorb much of the North Sea production. The United States thus will be a large seller of crude to world buyers and a significant buyer.

Inevitably, then, the United States, not the North Sea, will become the place where the world price of crude is discovered. Brent will gradually fade into oblivion despite attempts to maintain its viability.

WTI delivered in Houston will likely emerge as the global benchmark simply because the volumes available will dominate all other crudes and because the constrictions of market concentration on WTI are fewest. WTI and/or WTS and/or Eagle Ford come closest to meeting all the conditions required for a real commodity. The anticipated production increases only help cement their status.

The strength of these three crudes as the dominant determinants of world oil prices can be seen from Table 5 (page 37). This table shows estimates of production for crudes produced in the North Sea and the US, as well as delivery mechanisms, cost of entry, market liquidity, and producer concentration.

All US markets fare better than the North Sea markets for one reason: they are connected to pipelines. Thus, the six US Gulf of Mexico crudes shown in Table 5 can more easily reach a wide range of buyers than any North Sea crude because they are brought on shore by pipeline and pass through terminals. Their volumes can then be sold in small amounts to US buyers or large amounts to European or Asian buyers seeking cargos. North Sea crudes can only be loaded on ships.

Table 5. Comparison of Economic Characteristics of Various Oil Commodity Markets

	Production (mbd)	Delivery Method	Cost of Entry	Liquid Market?	Producers Concentrated?
North Sea					
UK	90	Ship	High	Yes	Yes
Forties	400	Ship	High	Yes	Yes
Norway					
Ekofisk	200	Ship	High	No	Yes
Gullfaks	150	Ship	High	No	Yes
Oseberg	120	Ship	High	No	Yes
Statfjord	125	Ship	High	No	Yes
Troll	205	Ship	High	No	Yes
United States					
Offshore					
Mars	425	Pipeline	High	Yes	Yes
Poseidon	225	Pipeline	High	No	Yes
S. Green Canyon	250	Pipeline	High	No	Yes
LLS	50	Pipeline	High	Yes	Yes
HLS	240	Pipeline	High	No	Yes
Thunderhorse	140	Pipeline	High	Yes	Yes
Other	270	Pipeline	High	Yes	Yes
Onshore					
Bakken	1,200	Pipeline	Low	Yes	No
Eagle Ford	1,200	Pipeline	Low	Yes	No
WTI	2,400	Pipeline	Low	Yes	No
WTS	1,200	Pipeline	Low	Yes	No

Source: Author's estimates; company filings; Argus Media.

The cost of entry into production in the North Sea or the US offshore is also high, limiting the number of firms that can participate. The markets tend to be concentrated. The cost of entry into the onshore US and Canadian fracking sector is minimal in comparison. Thus, even to this day new firms are being formed with the goal of profiting from fracking. Their entry boosts competition and supply to the market.

For these reasons, one must expect the US to become the center of global price discovery. If current trends continue, WTI delivered in Houston will become the global crude benchmark, and Brent will become irrelevant.