NAVIGANT

Oil & Gas Market Notes

Contents

Editor's Note

You will notice that this month's issue of what was through January known as ***NG Market Notes*** is now ***Oil & Gas Market Notes***. This change reflects both internal shifts within Navigant and external market developments. With the arrival of Managing Director Lee Laviolette and other senior members of Navigant's global Oil & Gas team, beginning last June, Navigant has significantly boosted its presence and activity in the global oil and gas sector. Recasting *NG Market Notes* to cover the oil industry as well reflects that expansion. At the same time, the shale gas revolution, the spread of natural gas vehicles, and the beginnings of a world market in liquid natural gas shipped by tanker all have contributed to the increasing interconnections in the energy sector, including geological ties at the wellhead and intersections at the end of the pipe.

As always, Navigant strives to bring readers our independent, authoritative, and insightful coverage and data on the oil and gas markets in North America and around the globe. We look forward to your comments.

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Eight Questions Facing Oil Executives in the Low-Price Era

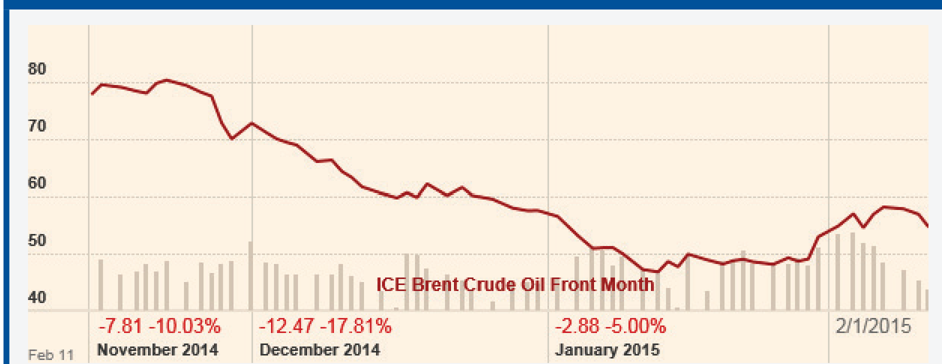
Introduction

Navigant's December *Market Notes* asked the question, *is $70 the new $15*? The question of the future direction of oil prices remains top-of-mind for executives, investors, and government officials as we move into the spring.

Oil prices continued to fall through January 2015 with new signals of softening global demand, especially in China, where GDP growth fell to 7.1% in the final quarter of 2014. At the same time, despite more and more current and new production appearing to be above the marginal cost curve, supply has been slow to respond.

However, Brent Crude pricing data from early February is starting to indicate that potentially, the floor has been reached. A floor has potentially been reached on January 14, and Brent Crude rose 21% through early February. One jump doesn't make a recovery, though, and this could possibly be a false signal—a dead cat bounce.

BRENT CRUDE PRICING CHART



Source: FT.com

Looking forward, as with the study of climate change, we need to distinguish between the weather (what we see and experience in front of us today and next week) and the climate (the longer term effect). As with climate change, what we do today has an impact on the long term.

To sustain a stable market, investments in new production need to keep up with future projections of demand. These will never be in perfect balance, and any misalignment will be felt through pricing adjustments. However, sustained under-investment in new capacity (including renewables) risks creating wild price volatility, which cannot be corrected in the short term given the relative inflexibility of capacity growth.

With this in mind, let's examine some of the main questions occupying the minds of senior oil and gas executives right now.

1. Is this the start of a recovery, or a dead cat bounce?

While there is little sign of demand recovery, there are increasing signals of supply contraction. In February, the United States saw a 24% drop in the number of rigs drilling for oil compared to October 2014, indicating that production will start to rebalance as non-OPEC production falls in 2015.

Also, since the turn of the year, there have been announcements of significant cuts in capital expenditure by the majors and national oil companies. Chevron and ConocoPhillips announced plans to cut upstream capital expenditure by 13% and 33%, respectively, compared to 2014. In Europe, Total and BP announced plans to cut year-on-year capital expenditure by 10% and 20%, respectively. Even Shell, which has taken a measured approach to spending shifts, announced a 14% cut over the next 3 years. More surprising was the announcement by CNOOC, China's third largest oil producer, that it was cutting capital expenditure by 35% compared to 2014—the first time a Chinese oil company has made such a public announcement. More are expected to follow.

Two other important indicators are the substantial growth in U.S. commercial crude stocks, now at an 80-year high, and the impact of Saudi Arabia's cut in the official selling price of its Arab Light Crude in Asia.

To be sure, in the long term a price recovery is highly likely. That may take some time: Bob Dudley, CEO of BP, speaking to reporters at the World Economic Forum in Davos, Switzerland, predicted that crude prices could remain low for "2 and maybe 3 years," but added that ultimately, he believes that $80/barrel (bbl) is a robust price level to screen new business opportunities against".

2. Will OPEC maintain its resolve on not cutting production?

Although the price collapse started in the summer of 2014, a critical moment came at OPEC's November 27 meeting, where the organization decided to hold production at 30 million barrels per day (mbpd). This signaled that certain OPEC countries—most notably Saudi Arabia, which has traditionally been the swing producer that would cut production to support prices—were changing strategy.

Since OPEC's November meeting, more messages have emerged on the resolve of Saudi Arabian officials to let the market play out. In December, Saudi oil minister Ali al-Naimi, speaking to the Middle East Economic Survey, said "It is not in the interest of OPEC producers to cut their production, whatever the price is, whether it goes down to $20, $40, $50, $60, it is irrelevant." With the passing of King Abdullah of Saudi Arabia in January, it is too early to conclude whether his successor, King Salman, will change the strategy, but early signs indicate it is business as usual.

Despite the fact that one OPEC member, Venezuela, now faces the prospect of economic default, there is little evidence that this is changing the resolve of the organization as a whole. Although it has the world's largest proven oil reserves, Venezuela is also one of the most financially vulnerable of the OPEC countries, due to its heavy reliance on oil exports and its relatively low financial reserves to buffer the impact of low prices.

Whether OPEC holds firm or not, this may be the beginning of the end of OPEC as the dominant force in the market.

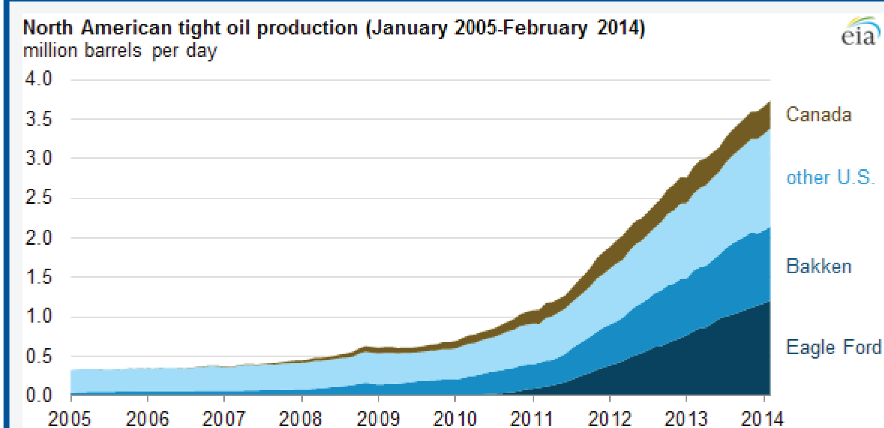
As Nick Butler suggested in his blog on FT.com, we may be entering the fourth act of the "oil industry drama." The first three acts were the story of the pioneers, the dominance of the large global oil companies (the "seven sisters"), and the emergence of OPEC. Act four is the era of the global market, dictated by supply, demand, and costs. The continued growth in more affordable renewable energy will further erode the power of the major resource holders, helping to draw the curtain on act three.

3. What will be the impact on U.S. light tight oil?

Over the last 10 years, U.S. light tight oil (LTO) has grown significantly, from 300,000 barrels per day to nearly 3.5 mbpd. LTO, also known as shale oil, is a light crude oil contained in petroleum-bearing formations, and is extracted using the same hydraulic fracking process used to extract shale gas.

The early consensus after OPEC's November meeting was that its target was U.S. LTO production, choking off new investment in order to halve annual shale oil growth rates. OPEC's Secretary General Abdallah Salem el-Badri was quoted as saying at the annual Oil and Money conference in October in London that half of shale oil production could be curtailed at a price of $85 a barrel.

TIGHT OIL PRODUCTION CHART



Sources: EIA / Canadian National Energy Board

(Note: Actual Canadian tight oil production figures are only available through June 2013. Canadian tight oil production through February 2014 is estimated based on national production averaging 0.34 million barrels per day for 2013, and projected growth rates through the first two months of 2014.)

While this doomsday scenario has not played out, it is clear that U.S. shale production has been affected, particularly due to the precariousness of financing, the fact that investments tend to be small, and the fast ramp-up/ramp-down times. As the rig count data indicates, the sub $50/bbl environment has affected both current production, and, more importantly, spooked new investments.

However, the very nature of the short ramp up/ramp down cycle means that U.S. light tight oil may be down a little but it is definitely not out. If prices continue to rise, the industry will come back.

4. Will the majors go on the acquisition hunt again?

In March 1999, when the price of oil collapsed to $15/bbl, the industry saw a round of super-major mergers, as the largest oil companies sought to cut costs and build scale. Exxon merged with Mobil, BP with Amoco and Arco, Chevron with Texaco, and Total with Elf and Petrofina.

In the intervening years, a number of companies have continued to flirt with the idea. Ten years ago, John Browne (now Lord Browne), then CEO of BP, considered the prospect of a mega-merger with his company's biggest rival, Shell, but ultimately pulled back.

Today the market is again full of talk of mergers. The current volatility, though, puts off buyers, who are concerned that if prices fall further they will have over-valued assets; and sellers, who are concerned that if they sell now and prices rise, they will underprice themselves. Once the oil price stabilizes, a new round of activity is likely.

The size of individual deals, however, is likely to be smaller. More likely than mega-deals are "clip-ins," with the majors picking up distressed assets or companies to continue to build their portfolios.

The two most talked about are ExxonMobil and Shell, the largest oil and gas companies in the U.S. and Europe, respectively. ExxonMobil, armed with a prized AAA rating and a robust cash flow, openly stated at the beginning of February that it is "alert" to possible clip-in acquisitions.

Likewise, Shell, which has been more balanced than others in its response to the current market, is reportedly actively considering a number of options.

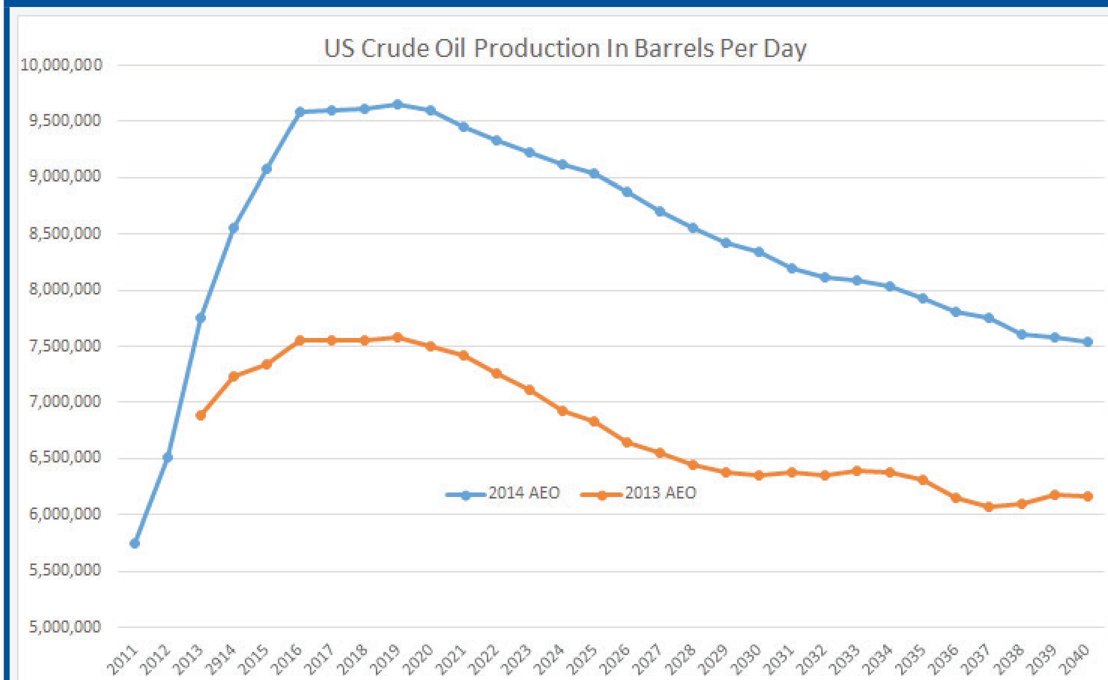
This brings us back to the question: Is the time right now for BP and Shell to merge, forming the world's largest oil major? With BP's financial exposure from the Deepwater Horizon spill still not bottomed out, it would be a risk. In addition, although Lord Browne talked in his memoirs about the potential for $9 billion of synergy savings from the union, the complexity of such a merger would be significant.

Another option that cannot be dismissed would be for ExxonMobil to take over BP. It has history in successfully integrating a large competitor, and the two companies' geographic profiles would align well.

5. What will be the impact on U.S. crude and condensate exports?

The federal restrictions on U.S. crude oil exports, imposed in the aftermath of the mid-70s oil crisis to help ensure energy security, remain in place today. However, the logic of sustaining the ban is being aggressively challenged, triggered by the expectation that international markets will need to be found for the growing LTO volume to support its price. With the complex U.S. Gulf Coast refineries geared toward processing medium and heavy crudes rather than lighter crudes, the rising volumes of LTO, which is which is unexportable under current federal law, will have to be sold at an increasing discount. As the chart below shows, U.S. crude production is forecast to continue to rise dramatically through 2015 and remain high for many years thereafter. Much of this will be LTO. Paradoxically, while oversupply will hurt oil producers, it benefits operators of simple refineries geared toward lighter crudes—so long as exports are proscribed.

US CRUDE OIL PRODUCTION CHART



Source: EIA

Meanwhile, the U.S. government has sanctioned the export of condensates (i.e., ultra-light oil that exists as a gas underground but condenses into liquid when pumped to the surface). The expectation is that this move is a precursor to the ending of the self-imposed export ban.

Still, the predicted export boom is hardly a given. At the beginning of February, Reuters reported that companies that have secured government endorsements have found it difficult to find Asian and Middle Eastern buyers for their crude, due to a narrowing of the arbitrage between West Texas Intermediate (WTI) and Brent Crude oil prices.

Ultimately, whether President Obama lifts the restrictions on U.S. crude exports will likely come down to politics. Environmentalists strongly oppose the reversal, citing methane leakage from fracking wells. Methane is a greenhouse gas 30 times more potent than CO_2 over 100 years. While there are conflicting studies of the level of methane emissions from fracking, it is increasingly becoming an environmental battle ground. In the year when world leaders will meet in Paris for the most important climate conference in 15 years, this dispute is made more urgent by the President's commitment to making climate change part of his legacy.

The unanswerable question is: Whatever happens in 2015, what will be the position of the 45th President in 2016?

6. What is the impact on climate change regulation?

In recent discussions of falling oil prices, one factor that has often been overlooked is the impact on climate change regulation, designed to help ensure that average temperatures do not rise more than 2° C compared to pre-industrial levels. With the Paris meeting of the United Nations Framework Convention on Climate Change scheduled for December, the question is, what will be the impact of low oil prices on international climate change regulations?

Many government regulations and incentives are predicated on high fuel prices and the ability to demonstrate a financial incentive from switching sources of energy or modes of transport. The extent to which these will be affected by low crude oil prices is very much dependent upon the time frame for bringing alternatives online. For utility scale renewable capacity that is planned years in advance—such as wind and solar—the effect may be minimal. For shorter-term solutions, such as the purchase of an electric vehicle, lower gasoline prices may delay the purchase but not undermine the logic of the purchase—supporting the view that the regulation is likely sound in construction, although the capture of the decarbonization benefits may be slower.

The larger question is whether low prices may provide governments with a unique window in which to reset energy regulation. Carbon pricing mechanisms (carbon taxes, consumption taxes, or cap and trade schemes) are traditionally unpopular with businesses and voters because the cost passes through to the end user, and there are few votes in raising energy prices.

However, as *The Economist* strongly advocated in a recent article, at a time of falling energy prices, now is a once-in-a-generation opportunity for cash-strapped developing countries—such as India and Indonesia—to cut fuel subsidies to encourage greater efficiency and free up cash for social goods, and for developed countries to encourage even greater efficiency and to raise new revenue to help fund the transition to a low-carbon economy.

Will governments have the will or latitude to execute such a bold approach? History is not encouraging on that question.

7. What will happen to the North Sea?

Since the issuing of the first license in 1964, the U.K. North Sea oil and gas industry has grown to employ 450,000 people and contributed significantly to the U.K. economy, paying £6.8 billion ($10.5 billion) in taxes in 2012-13 alone. It has been a critical element in sustaining a level of energy security for the United Kingdom, supplying 67% of the country's oil and 53% of its gas requirements. The infrastructure is aging, and production peaked in 1999, but an estimated 30-40 years of producible remains. The question is, can the North Sea industry ride out this current storm?

In 2013, Sir Ian Wood published a milestone report on the future of the industry and made a range of recommendations, including more investment to drive efficiency and new exploration and production. Since the Wood report was published, oil prices have collapsed, and given that the average break-even cost of extracting North Sea oil is $55/bbl, the current environment is challenging the viability of the industry as a whole.

In recent months, Shell, Chevron, BP, and ConocoPhillips have all announced job cuts in their North Sea operations. The industry is advocating hard for government support in the form of incentive tax breaks to support continued exploration, maintenance programs, and sustained production though the price downturn, plus a reduction in the supplementary tax on profits from 30% to 20%, in order to give investors confidence that the North Sea remains a sound investment.

At the same time, the industry itself urgently needs to take action on Sir Ian Wood's other recommendations. A new industry regulator started work in January. But operators themselves have yet to demonstrate new ways of working, a more commercial focus, industry collaboration, or more flexible responses to challenge and change.

What is really needed is a more fundamental restructuring of the North Sea industry. Many observers point out that during the $100/bbl era, upstream costs spiraled. There are lessons to be learned from the Dutch and Norwegian sectors, particularly in the area of collaboration between government, operators, service companies, and employees. Many operators are wary of decommissioning old infrastructure, but this will become inevitable if no way can be found to cut costs.

8. What will be the effect on gas pricing?

No evaluation of the current pricing environment would be complete without a look at the impact on the price of natural gas. As we have seen, crude is a global market, with global price benchmarks, and very strong geopolitical players able to influence the price through supply-side actions. The gas market has few of these.

Traditionally dominated by long-term supply contracts with prices linked to crude and high transportation costs, the European and Asian natural gas markets have limited fungibility. The picture in North America, where gas-on-gas competition sets pricing, is different.

In a world of high crude prices, buyers increasingly challenged the logic of linking gas to crude prices. The clamor has died down somewhat in the last year, as falling crude prices have dragged down gas prices. The other driver of lower gas prices has been simply the law of supply and demand. In recent years, investment-driven supply growth across the world—attracted by the prospect of high prices, particularly in Asia—has created imbalances in the gas market. This may lead to a new wave of price renegotiations, led by gas and LNG sellers seeking to redress the price reductions achieved by gas buyers in recent years.

Eventually, market forces will play out, supply and demand will equalize, and players will continue to look for niches to exploit the gas-crude arbitrage where it exists (e.g., North American gas-to-chemical plays). The current recovery may be a temporary bounce, but long-term <$50/bbl oil is unsustainable. As crude prices start to rise again, calls to delink gas and crude prices will grow again, and a global infrastructure will develop to support increasingly fungible gas markets. Crude delinking is not dead; it's just been delayed.

How can Navigant help?

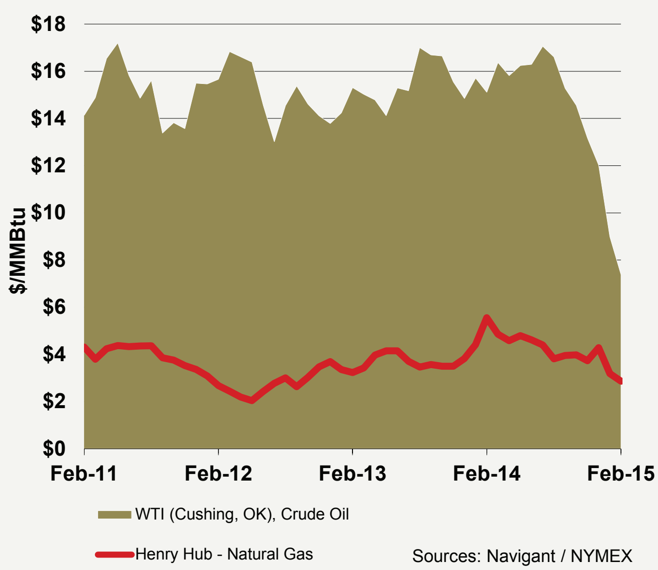
Using its in-depth industry knowledge and experience, Navigant's team of upstream and downstream oil and gas experts specialize in helping clients understand the issues, develop solutions, execute their strategy, and drive operational excellence in highly volatile times.

— Nick Allen and Mike Dyson

About the Author »
Nick Allen is a Director in the Global Energy practice, based in London. He leads the Downstream segment of the Oil & Gas sub-practice across Europe. Mike Dyson is a Director in the Global Energy Practice, based in London. He leads Navigant's upstream oil and gas consulting business outside North America.

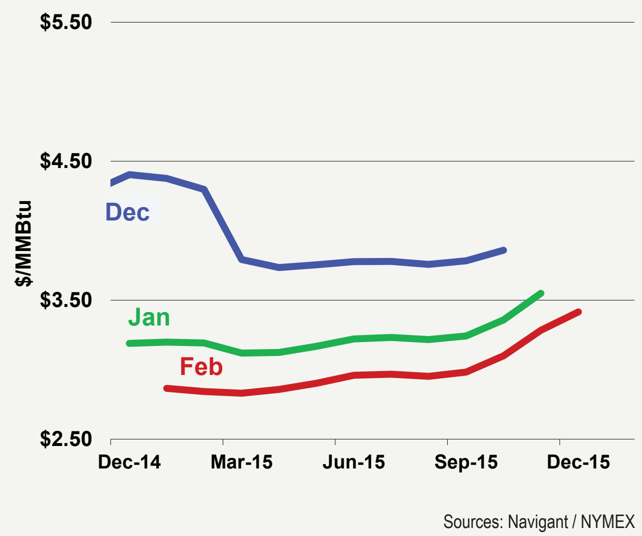
Natural Gas Market Charts

MONTHLY PRICES: OIL AND NATURAL GAS GULF COAST



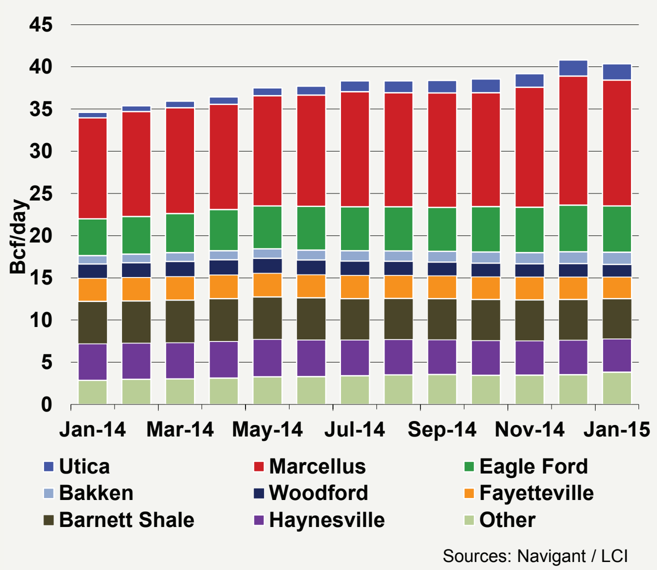
The most recent gas/oil price ratio fell to 2.6 times, with Henry Hub natural gas price at $2.87 versus WTI crude oil price at $7.38. The ratio one year prior was 2.7 times.

NYMEX FUTURES SETTLEMENT PRICES AT CLOSE



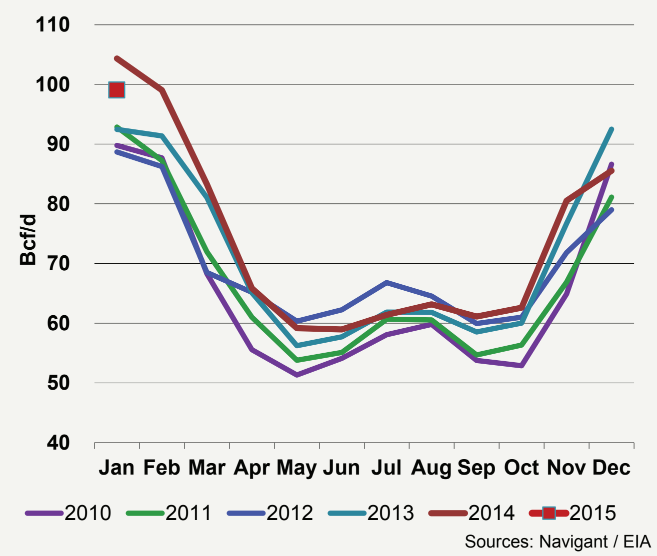
The average 12-month strip price decreased by 23 cents, or down 7%, to $3.00/MMbtu for the strip starting February 2015.

U.S. WELLHEAD SHALE GAS PRODUCTION



U.S. shale gas production backed off slightly from the December all-time high, to 40.4 Bcfd.

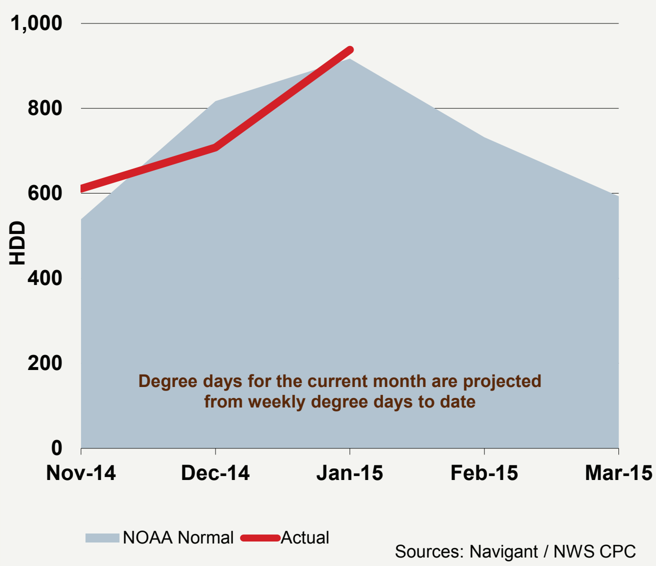
U.S. MONTHLY NATURAL GAS DEMAND



U.S. gas demand followed seasonal patterns to over 99 Bcfd and exceeded 10 of the last 11 years at this time.

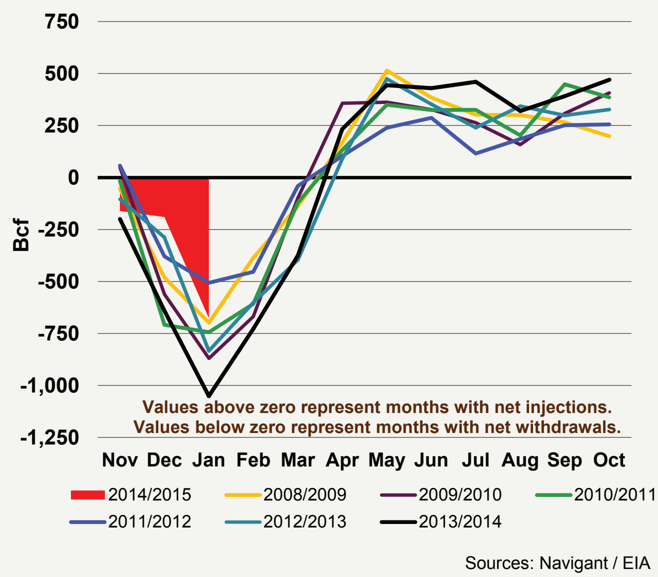
Natural Gas Market Charts

U.S. POPULATION-WEIGHTED HDD



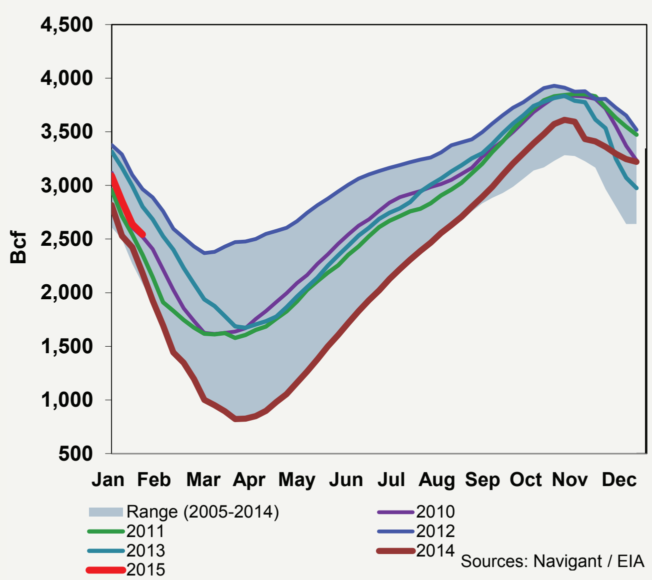
Heating degree days for January were 2% below normal, with the season now 1% below normal.

MONTHLY U.S. STORAGE ACTIVITY



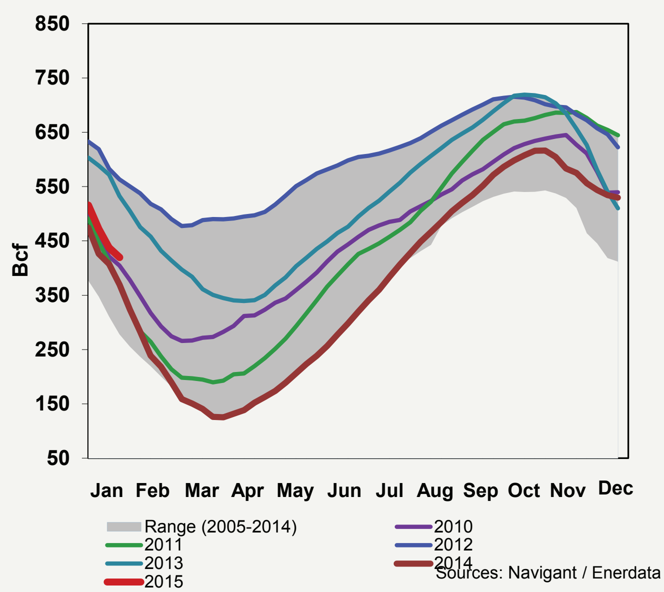
Cooler weather brought January storage withdrawals back into the normal range, at 677 Bcf.

U.S. GAS STORAGE



U.S. storage inventories continued at 4% above the average for January over the prior 10 years, at 2,543 Bcf.

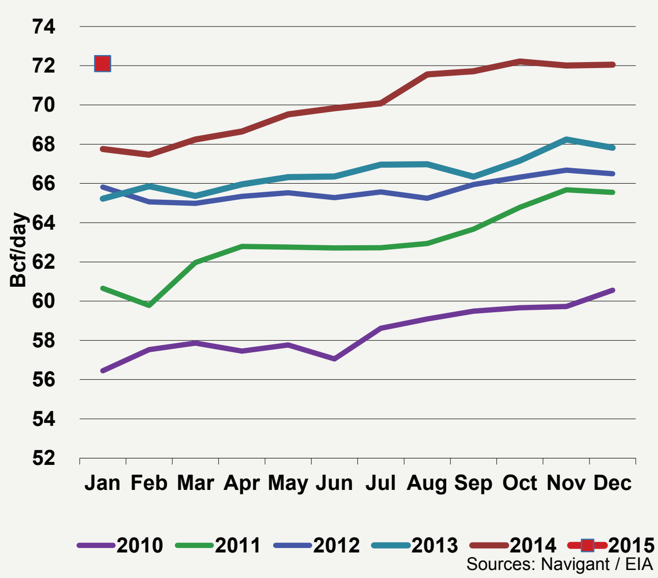
CANADA GAS STORAGE



Canadian storage inventories continued the withdrawal season just above average for the last 10 years, at 420 Bcf.

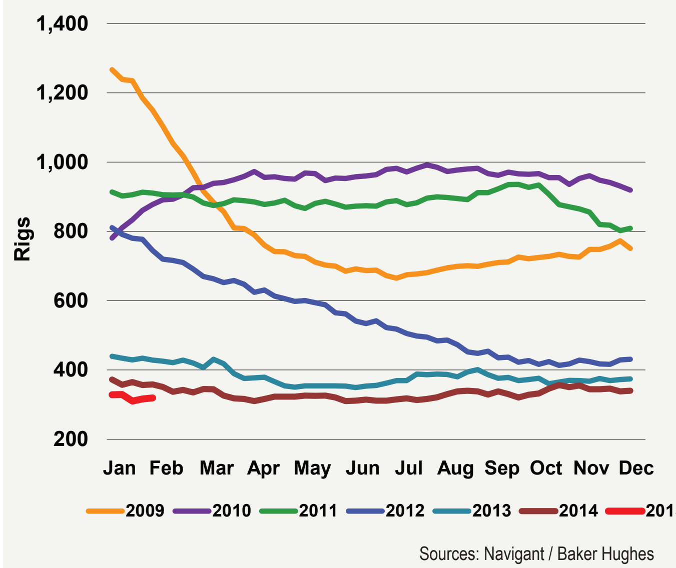
Natural Gas Market Charts

U.S. DRY GAS PRODUCTION



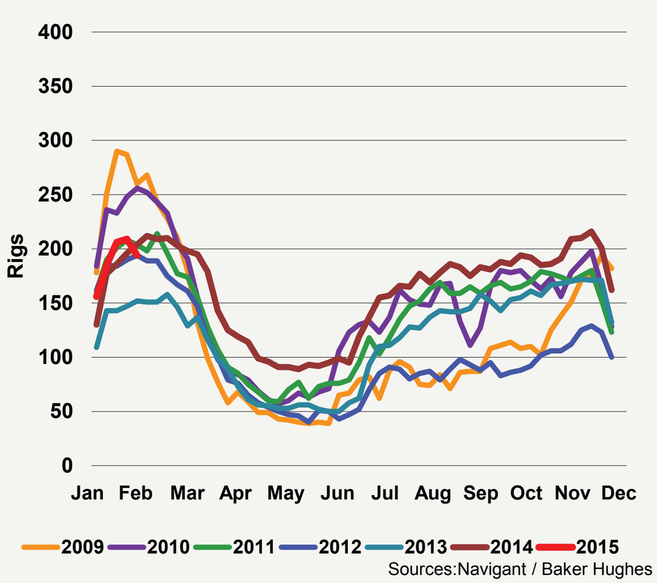
U.S. dry gas production began the year at a new high, at 72.1 Bcfd.

U.S. WEEKLY NATURAL GAS RIG COUNT



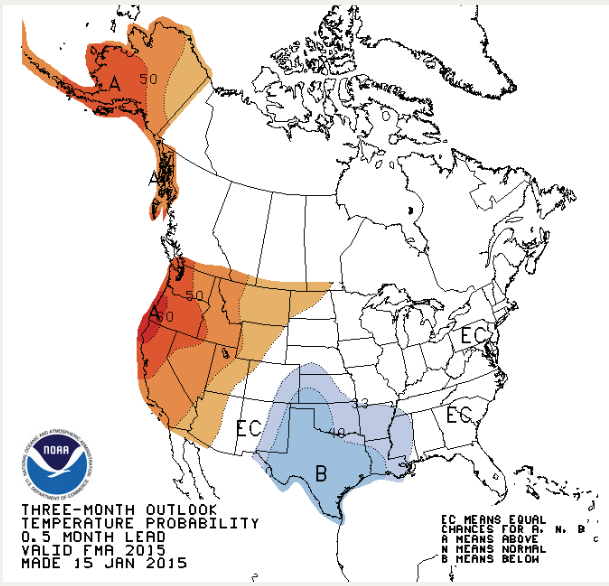
U.S. natural gas rig counts continued at historically low levels of about 320 rigs.

CANADIAN WEEKLY NATURAL GAS RIG COUNT



Canadian natural gas rig counts dropped to about 8% below average for the last 6 years, at 194 rigs versus 211 rigs.

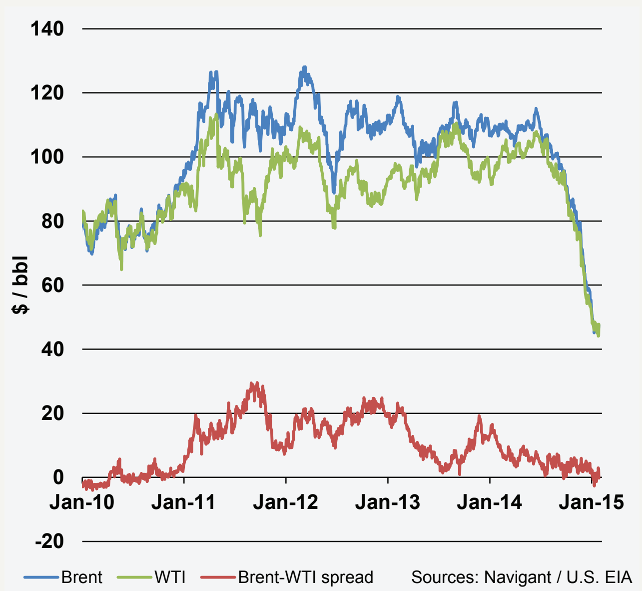
U.S. TEMPERATURE OUTLOOK



The temperature outlook is for above-normal temperatures for the most of the United States west of the Rockies plus western North Dakota. Below-normal temperatures are favored for the south-central United States and the lower Mississippi River Valley.

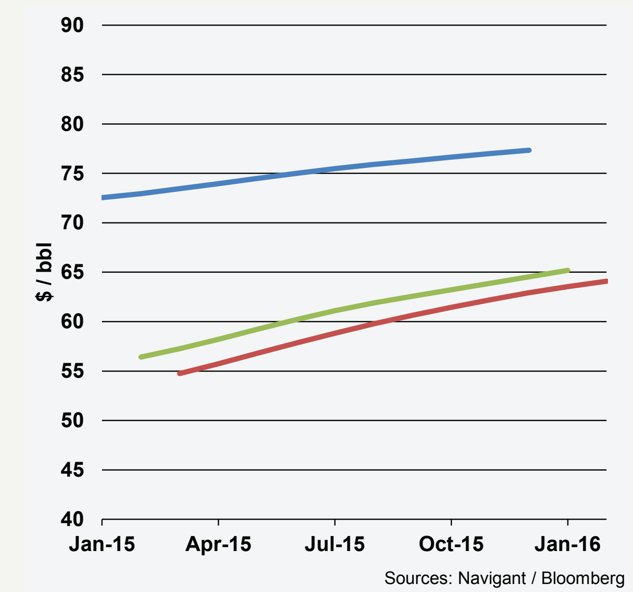
Oil Market Charts

SPOT CRUDE PRICES



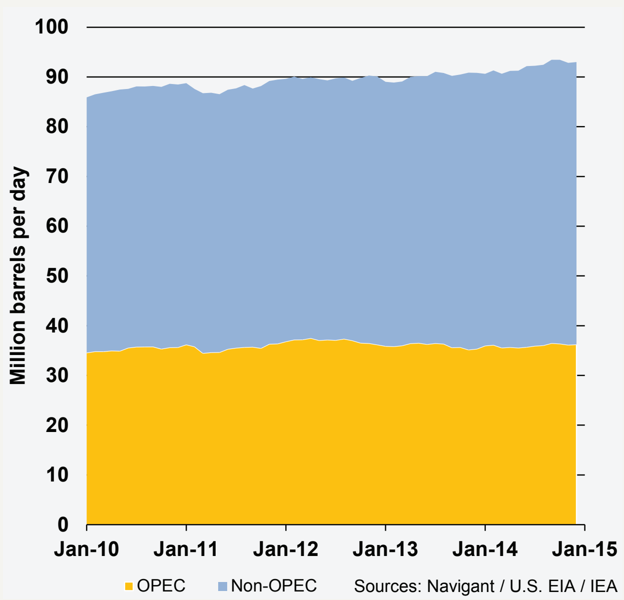
After 3 years of relative stability in the $90-110/bbl range, crude prices plunged 60% from June 2014 levels, averaging $48/bbl (Brent) and $47/bbl (WTI) in January 2015.

ICE BRENT FUTURES CURVE



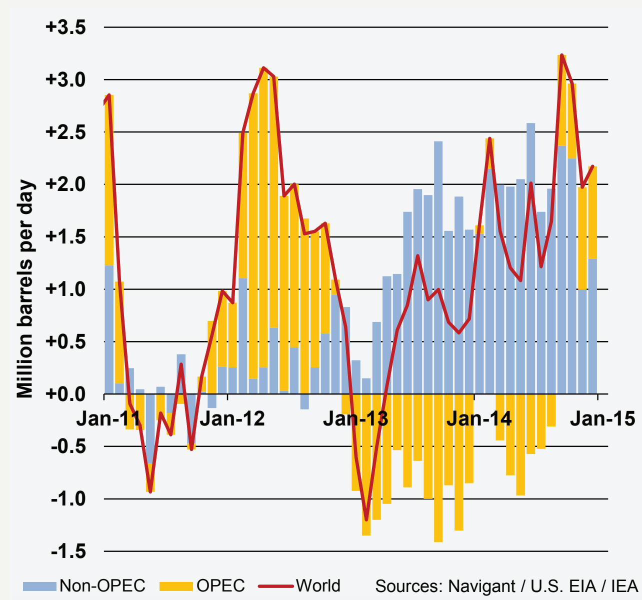
The Brent futures curve followed spot prices downward. The average 12-month strip price at the beginning of February was $59.88/bbl, a decrease of 2% from the previous month.

OPEC & NON-OPEC OIL PRODUCTION



Global oil production increased from 90.8 million barrels per day a year ago to an estimated 93 million barrels per day in December 2014, of which 39% was supplied by OPEC.

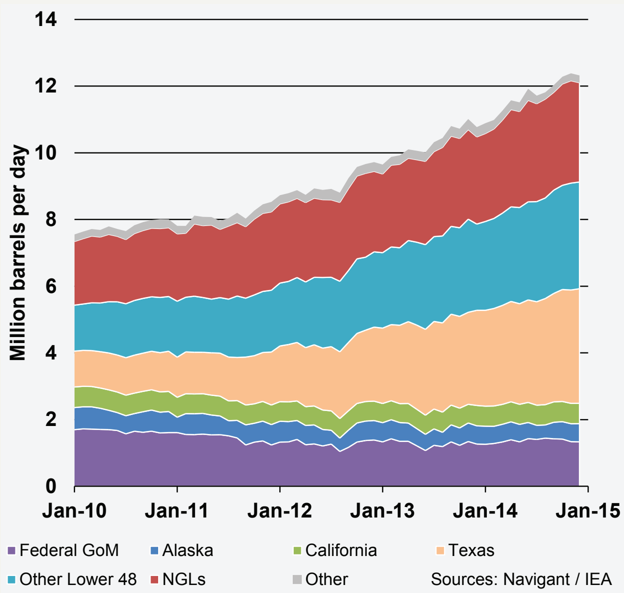
YEAR-ON-YEAR CHANGE IN OIL PRODUCTION



Oil production growth in recent years has been led by non-OPEC countries, particularly the United States.

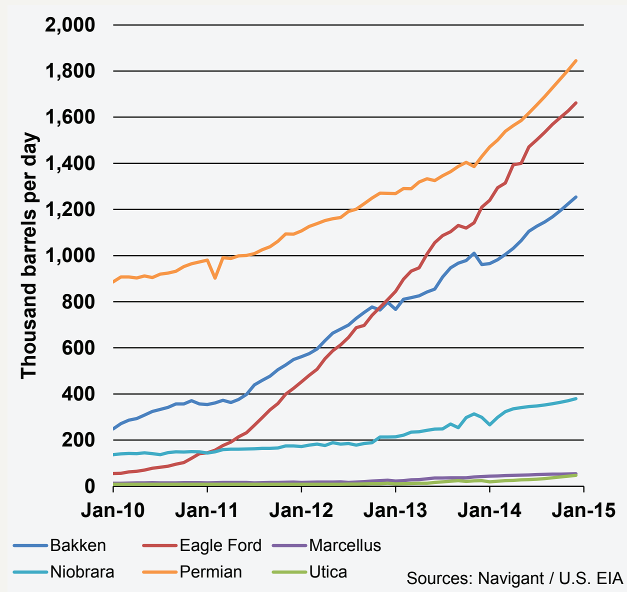
Oil Market Charts

U.S. OIL PRODUCTION



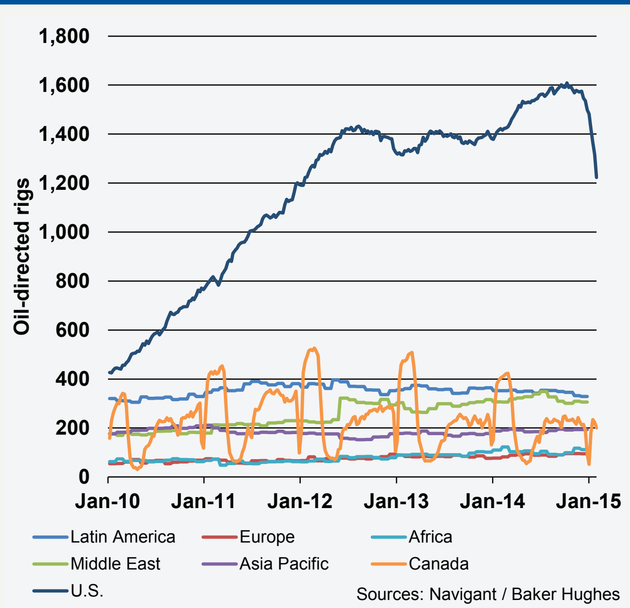
In the United States, oil production climbed by 14% over the year to an estimated 12.3 million barrels per day in December 2014.

OIL PRODUCTION IN KEY U.S. REGIONS



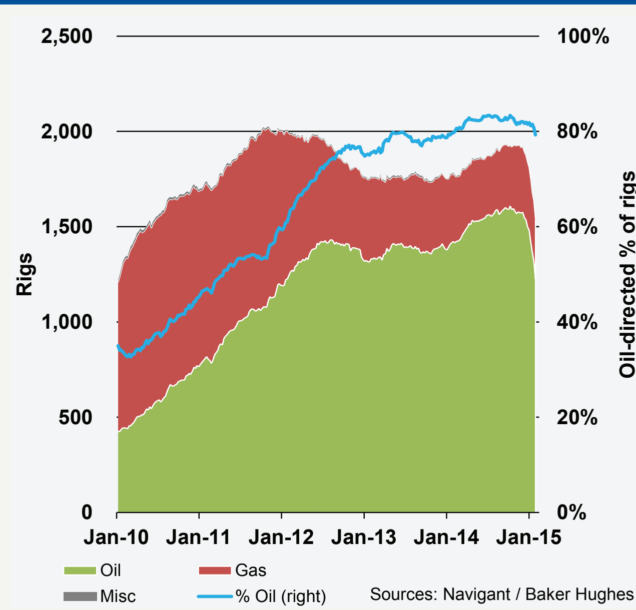
In December 2014, oil production reached an estimated 1.8 million barrels per day in the Permian (+29% YoY), 1.7 million barrels per day in Eagle Ford (+37% YoY) and 1.3 million barrels per day in Bakken (+31% YoY).

OIL-DIRECTED RIG COUNT BY REGION



The impact of lower crude prices can already be seen in oil-directed rig counts. The United States had 1,223 active oil rigs at the end of January 2015, a level last seen in January 2012.

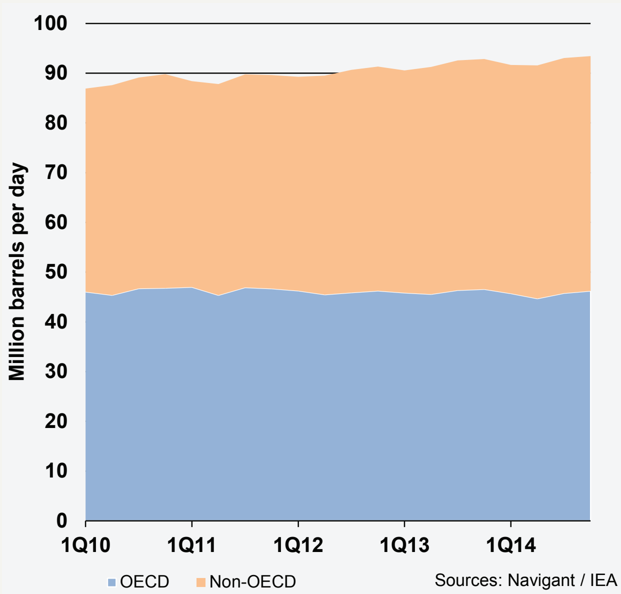
U.S. RIG COUNT



While U.S. rig counts for both oil and gas have fallen, oil rigs have decreased more steeply. 79% of U.S. rigs were oil-directed at the end of January.

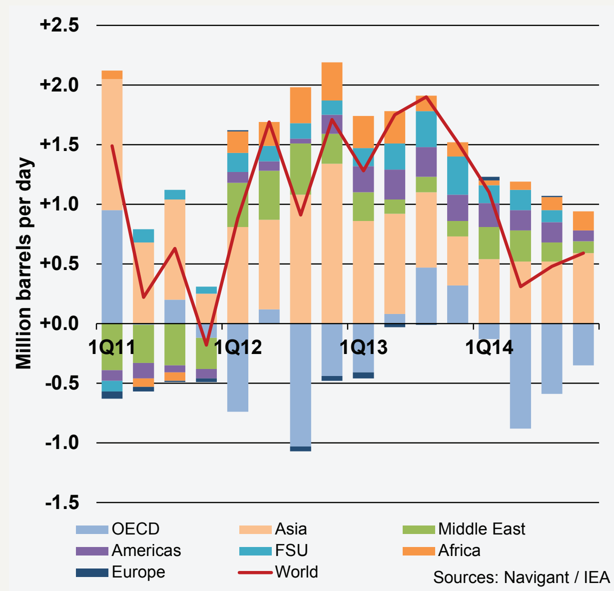
Oil Market Charts

OECD & NON-OECD OIL CONSUMPTION



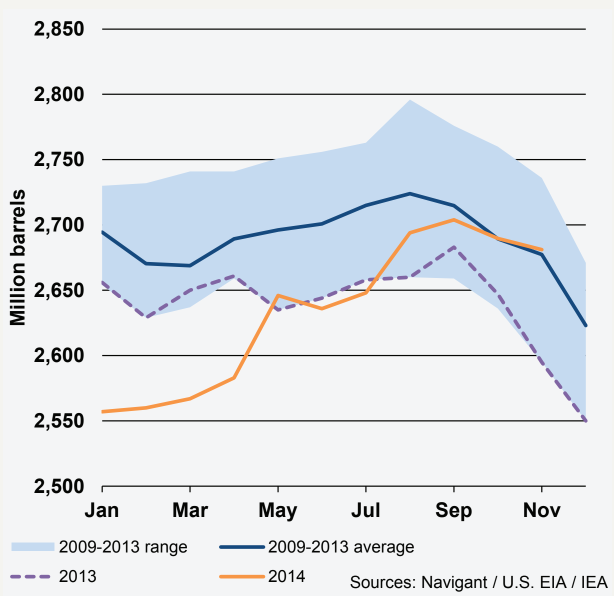
Global oil consumption increased from 92.8 million barrels per day in Q4 2013 to an estimated 93.4 million barrels per day in Q4 2014.

YEAR-ON-YEAR CHANGE IN OIL CONSUMPTION



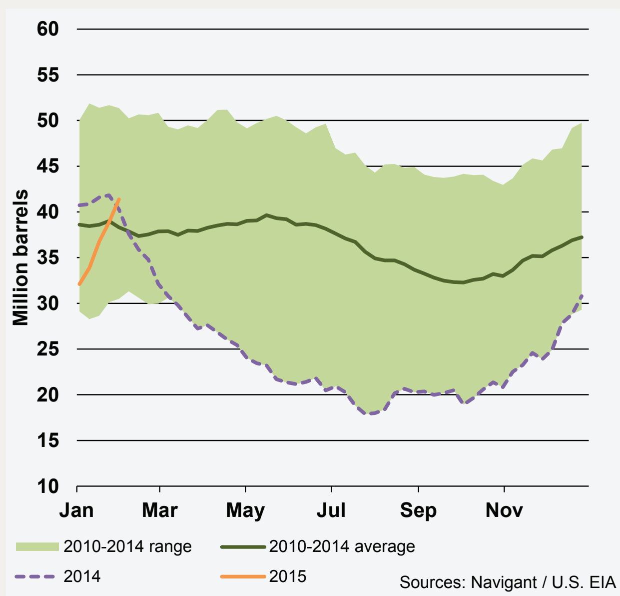
Oil demand growth in recent years has been led by non-OECD countries, particularly in Asia (e.g. China).

OECD COMMERCIAL STOCKS OF CRUDE & PRODUCTS



OECD commercial inventories recovered from low levels during 2013 and 2014 to reach 2,681 million barrels of crude and products in November 2014, about equal with the 5-year average.

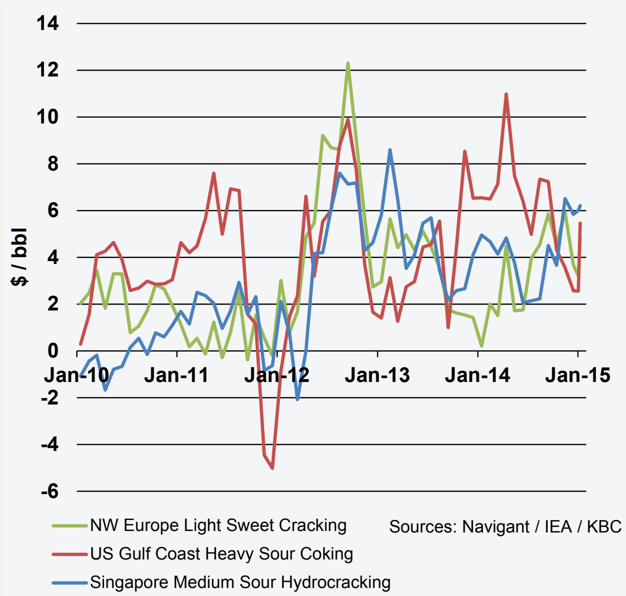
CRUDE STOCKS AT CUSHING, OKLAHOMA



Crude inventories at the Cushing hub recovered from low levels during 2014 to reach 41.4 million barrels at the end of January, 8% above the 5-year average.

Oil Market Charts

INDICATOR REFINING MARGINS



In January 2015, indicative refining margins were $4.87/bbl for NWE light sweet cracking (+$4.66/bbl YoY), $5.46/bbl for USGC heavy sour coking (-$1.09/bbl YoY) and $6.21/bbl for Singapore medium sour hydrocracking (+$1.26/bbl YoY).

EU CARBON ALLOWANCE PRICES

EU allowances for carbon ended January at EUR 7.09/tonne, an increase of 28% from a year ago.

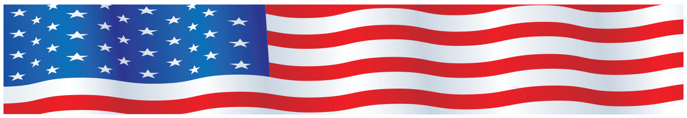
U.S. ETHANOL RIN PRICES

U.S. RINs for ethanol ended January at 67 cents/gallon.

U.S. BIODIESEL RIN PRICES

U.S. RINs for biodiesel ended January at 74 cents/gallon for the 2014 vintage and 93 cents/gallon for the 2015 vintage.

Legislative and Regulatory Highlights



Midwest

FERC Approves Pre-Filing Status for NEXUS Pipeline

On January 9, the Federal Energy Regulatory Commission accepted the request for pre-filing process approval by NEXUS Gas Transmission. NEXUS plans to construct a 250-mile long, 42-inch wide greenfield pipeline and associated meter, compression, and regulation stations between Columbiana County, Ohio and Washtenaw County, Michigan. The project would provide 1.5 Bcfd of natural gas to markets in the Midwest and Canada. DTE Energy Company and Spectra Energy Partners are the lead developers of the project. The majority of the capacity is already subject to signed precedent agreements, with an in-service date of November 2017.

Oregon

Oregon Department of Land Conservation and Development Stays Reviews of Jordan Cove and Oregon LNG Project Certifications

In January, the Oregon Department of Land Conservation and Development executed stay agreements with the Jordan Cove Energy Project and LNG Development Company (d/b/a/ Oregon LNG) regarding the department's obligations to review the companies' certifications of consistency with the Oregon Coastal Management Program. Under the stay agreements, the department's deadlines for review were extended to April 27, 2015 (OLNG/Oregon Pipeline Company) and July 30, 2015 (Jordan Cove Energy Project/Pacific Connector Gas Pipeline).

British Columbia

Province to Prohibit Shipment of Oil on Pipelines Supplying Natural Gas to LNG Facilities

On January 6, the British Columbia Ministry of Gas Development announced the establishment of a new regulation to ensure that pipelines built to support LNG facilities will not be permitted to transport oil or diluted bitumen. The new regulation will prohibit the Oil and Gas Commission from permitting any conversion of an LNG facility supply pipeline.

Province Provides CPCN Exemption for FortisBC Tilbury LNG Expansion

On January 23, the British Columbia Ministry of Energy and Mines announced its decision to exempt FortisBC's Tilbury Island LNG plant expansion and associated transmission infrastructure upgrades from the requirement to obtain a certificate of public convenience and necessity. The exemption was provided in order to facilitate final investment decisions by LNG proponents and large volume natural gas customers. FortisBC will still be required to complete environmental approvals and other permits.

Douglas Channel LNG Project Under New Consortium Ownership and Control

On January 28, AltaGas, Idemitsu, Exmar, and EDF Trading announced that their Douglas Channel LNG Consortium has achieved full ownership and control of the Douglas Channel LNG Project. The Project had been in limbo since entering proceedings under the Companies' Creditors Arrangement Act. The Consortium also announced the execution of long-term lease arrangements with the Haisla Nation, and with Pacific Northern Gas for long-term pipeline capacity to supply the project. The Consortium expects a final investment decision in late 2015, with a target operations date in 2018 for the 0.55 million tons per annum project.

National Energy Board Approves LNG Exports by Woodside Energy's Grassy Point LNG

On January 29, the National Energy Board announced its approval of a natural gas export license for Woodside Energy Holdings' Grassy Point LNG project, located north of Prince Rupert. The Board found that the 807 billion cubic meters of gas sought to be exported as LNG over the project's 25-year term (28 Bcm/year, before 15% tolerance, or 2.7 Bcfd) is surplus to Canadian requirements, recognizing the free trade that exists within the North American energy market.