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North American Natural Gas Market Outlook

The Oil & Gas Value Chain: The Next Two Decades

The oil and gas industry is ruled by two sides of a deterministic equation: the forces driving energy demand and the resources available to meet this demand. As globalization increases and developing economies expand at rapidly rate, this supply and demand equation is moving beyond domestic market models to a fully globalized one.

Often oil and gas companies view the industry in terms of separate categories—exploration and production (E&P) companies focus on upstream production, refiners are concerned with creating the right products for the market, and mid-stream organizations, including pipeline operators and shippers, have the job of transporting the product to markets. Even the few integrated oil and gas companies tend to manage their business elements separately, with the view across the entire value chain limited to the corporate level.

In this article we consider the demand for energy at a global level over the next 20 years, along with anticipated changes in the supply base. We can then consider the movement of product and how this all ties together to create an integrated value chain, from wellhead to burner tip. This holistic view of the industry is essential as the market becomes more globalized and product is moved over greater distances.

Demand Growth

In its *Energy Outlook 2035*, BP forecasts that China will be the largest contributor to growth in energy demand over the next two decades, with consumption growing by 7 million barrels per day (Mbd) to 18 Mbd by 2035, surpassing U.S. demand. China's import requirements are likely to more than double, to around 13 Mbd, accounting for three-quarters of its total oil consumption. China holds 24.4 billion barrels of proven oil reserves, according to the U.S. Energy Information Administration (EIA), and its total oil and liquids production has risen by about 54% over the past two decades, making it the fourth largest producer in the world. This production serves only the domestic market.

The second largest contributor to world demand growth is India, where demand is forecast to grow by 4 Mbd by 2035. India's import requirements grew from 42% of its consumption in 1990 to 71% in 2012—a trend that is expected to continue due to voracious demand growth and lethargic increases in production. The EIA reports that India consumed and imported more oil and petroleum products in 2013 than all but three other nations.

In short, it's clear that Asia, in particular China and India, will drive demand growth over the next two decades. Still, U.S. consumption per capita is still expected to be 3.5 times greater than China's in 2035. Much of the demand growth from Asian economies will come from the transportation sector, as vehicle ownership rises, and from petrochemicals. Both of these industries are flat or declining in OECD countries, due to efficiency improvements and the spread of vehicles powered by natural gas or electricity.

Similarly, the natural gas market is also expected to have significant regional imbalances, as Asia supplants Europe as the key importing region. Thanks to the shale gas revolution, North America is expected to become a net exporter of natural gas (see the March issue of *Oil & Gas Market Notes*). Most of the gas transported internationally is expected to be liquefied natural gas (LNG), which is shipped via tankers, with supply moving by pipeline increasing at a much slower rate.

Securing Supply

Asia's crude oil and petroleum imports are forecast in BP's Energy Outlook to account for nearly 80% of net international imports by 2035, up from around 60% today; yet China is the only country in Asia-Pacific that ranks in the top 15 world oil producers. While domestic crude oil production is expected to grow in China, the EIA reports that most other countries in the region forecast domestic production that will only replenish current declines, keeping their output at a level similar to today's.

As energy demand increases in these countries, outstripping domestic supply, governments are looking to invest upstream in the oil and gas sector to secure supply and shield the domestic energy sector from global price volatility.

The Indian government, for example, has encouraged companies to acquire overseas upstream assets in other countries. Indian companies now hold large stakes in Sudan's GNOP block, Russia's Sakhalin-1 project, and Venezuela's San Cristobal and Carabobo blocks. Indian oil and gas companies have also taken stakes in gas plays in Mozambique, shale gas production in the United States and Canada, and oil and gas assets in Myanmar, and are actively pursuing other overseas upstream deals.

Overseas E&P plays an essential role in South Korea's oil industry, as well. The South Korean government has encouraged private E&P investment overseas through tax benefits and the extension of credit lines to international oil companies (IOCs) by the Korea Export-Import bank, and has provided diplomatic aid in overseas negotiations. As of February 2013, the most recent reported information available, the Korean National Oil company (KNOC) had invested in 226 projects, 94 of which were in the production stage, in 24 countries. By purchasing stakes in North American oil sands and shale formations, KNOC has diversified its market to include shale and other tight formations of oil and gas.

Similarly, Asian demand for LNG, at over 70% of global energy demand, is expected to drive significant growth, with Australia and the U.S. each contributing around a third of the LNG supply increase to meet the market requirement. Traded gas supplied via pipelines is expected to decline as imports move from the U.S. and Europe to Asia.

The Right Products

Refiners must respond to these global market shifts by maximizing the production of transportation fuels and creating the right range of products for the market. Feedstock and product flexibility are key requirements to deliver on this effort, and refiners are seeking to increase the complexity of refineries in order to achieve greater flexibility in terms of both the feedstock they can take and of the products they are able to produce.

For countries where energy demand is increasing rapidly, it is important to be able to diversify the import sources and feedstock for refineries as mature production regions begin to decline. As with oil and gas imports, the refining

industry is relocating to high growth regions. In China and India alone, 12 new coking and cracking refineries are expected to come online in the next 10 years. Along with expansions in current facilities, these new facilities will increase refining capacity in the two countries by 6.5 Mbd. These more sophisticated refineries can produce the required range of petroleum products using heavier crudes, such as bitumen from Canadian oil sands and heavy oil from Venezuela, taking advantage of the discounted price of these feedstocks.

Refiners in mature markets, on the other hand, face challenges from alternative supplies to the market, such as natural gas liquids and biofuels, resulting in increases in overcapacity. In mature refining centers in declining markets, large capacity reductions are expected.

At the same time, current refineries must invest in technology upgrades to be able to process these heavier feedstocks. This is true of established Gulf of Mexico refineries, as well newer facilities in Asia. Often reaching into the billions of dollars, such capital investment must be weighed against likely demand and future prices in order to assess the business case for costly upgrades.

Natural gas liquefaction to make LNG isn't about creating the right end product, but rather making the product easier to ship. It also adds another step to the process of getting product to market. While building liquefaction facilities is less complex than constructing a new refinery, the capital costs involved are of a similar magnitude.

New Feedstock from New Plays

Global conventional production of crude oil is expected to remain flat through 2035; all of the forecast production growth, in other words, will come from other sources. Current key suppliers of crude oil will remain critical to meeting global demand. While the OPEC countries will remain the largest net exporters, their market share as a percentage of overall production is forecast to decrease. Russia is expected to remain the largest energy exporting country.

Mature plays, such as the North Sea, are in decline, and newer sources will be required to replace this supply in order to keep up with current demand and forecast growth. Abundant shale gas and tight oil resources are critical to making up this deficit, with most of it coming from North America. The U.S.A. is forecasted to supply 6 Mbd by 2035, while Brazil and Canada, also critical to

maintaining this required production level, are expected to make up 3 Mbd each of supply by 2035.

This domestic supply is expected to result in the United States shifting from a net importer to a net exporter in the 2020 time frame. This growth is concentrated in tight oil, NGLs and oil sands.

Production from South and Central America is expected to expand by 4 Mbd by 2035, mainly in Brazil, and is also expected to play a key role in meeting global demand. From 2008 to 2013, this region expanded crude oil and petroleum exports to Asia by 171%, from 655 thousand barrels per day (kbd) to 1778kbd, and these countries will continue to be key suppliers going forward.

Moving Product to Market

As domestic consumption in developed economies flattens, and demand in countries that are unable to meet their needs domestically increases, shipping product to market becomes an increasingly critical component of the value chain. Moving crude and other liquid products significant distances across both land and sea is a costly and controversial undertaking. Because shipping adds additional costs, increasing the price to the end user, it is essential to find the most effective, efficient, and economic way to move product.

The transport of bitumen produced in oil sands in Alberta provides a perfect illustration of the challenges. The EIA's 2013 World Proved Reserves estimate shows that Canada holds the third-largest oil reserves globally, at 173.1 billion barrels, and is the fifth-largest producer globally with production forecasted to expand by 2.5Mbd over the next 15 years. This production is critical to replacing global supply from mature plays, but these fields are landlocked and quite distant from large markets. To date, the majority of Canadian crude has been exported to the U.S., due to proximity and the fact that the market can take advantage of a discount against West Texas Intermediate pricing. As the U.S. becomes self-sufficient, however, Canadian producers must diversify their markets for both conventional and oil sands production. Three key routes are under consideration: eastward to meet Eastern Canadian and U.S. market demand and export to Europe, south to the U.S. Gulf Coast, and westward for export to Asia. While railways can handle a certain volume of projected supply, pipeline routes are key to moving the capacity of product required. Pipeline expansions face unique challenges across the region.

To move west, pipelines must cross mountainous terrain in British Columbia, a liberal province with significant public opposition to the movement of bitumen to and from its coastline. In the other direction, reversing TransCanada's mainline to move product east (TransCanada's "Energy East" project) is a capital-intensive venture that crosses many jurisdictions over a significant distance. Most newsworthy is the Keystone XL expansion, which has become a political minefield for the Obama Administration. Social license to operate—the acceptance within local communities of both oil and gas companies and their projects, granted by all stakeholders that are or can be affected by the projects (e.g. local communities, indigenous people, and so on) as well as other groups of interests (e.g. local governments, NGOs)—is a key concern for many organizations in making the necessary infrastructure enhancements to be able to bring this product to market.

While only 3% of crude oil in North America is shipped by rail, the network is large and delivers product to key markets. Amid the North American energy boom, and with pipeline capacity lacking, crude oil shipping by rail is increasing. This mode faces its own challenges, as the first quarter of 2015 saw a series of spectacular and destructive derailments of crude tankers that highlighted the risk of moving oil by rail. While rail is an important element of the transport portfolio, shippers face increasing risk premiums and public opposition. In Canada it is possible to move product by rail through difficult terrain where there are no pipelines, and the Canadian Association of Petroleum Producers (CAPP) forecasts that 700,000b/d of crude oil—approximately 18% of forecasted production—could potentially be transported to markets by rail in 2016.

In a low-price environment, shipping costs become increasingly important. To the operational costs of moving product through pipelines and on rail tankers must be added levies to local and federal governments and other stakeholders. At under \$50 a barrel, this can present a serious barrier to shipping product to new markets. Even so, products with significant discounts, such as Western Canadian Select, can remain competitive with more traditional sources of production in markets where demand significantly outstrips supply.

Similarly, countries where demand for natural gas significantly outpaces supply will be faced with paying a transport premium to attract larger LNG supplies. Ultimately, these increased supplies will likely lead to more integrated markets and gas prices moving in greater unison across regions.

Conclusions

All elements of the value chain, from getting product out of the ground to the end user, contribute to the ability to have the end product at the point of use and the cost to the end user. This cost is not only financial, but also has wider social, political, and environmental considerations in the global market.

Despite widespread and increasing use of renewable energy, demand continues to grow, particularly in Asia, for oil and gas in the resource-based global economy. Countries in Asia Pacific lack the resource base locally to provide the energy required to support continued high rates of economic growth. It is important to recognize that the decisions made across the value chain for getting hydrocarbons to market have large impacts on the lives of people elsewhere in the world.

While predictions of the "end of OPEC" are surely premature, North America will have an increasingly central role to play in meeting this demand. As Canada seeks new markets for its oil and natural gas in order to reduce dependence on the U.S. as its key customer, and the U.S. seeks to become a net exporter of LNG, effective cost-management across the entire value chain will enable competitive pricing in new markets.

— *Katherine Chance*

About the Author »

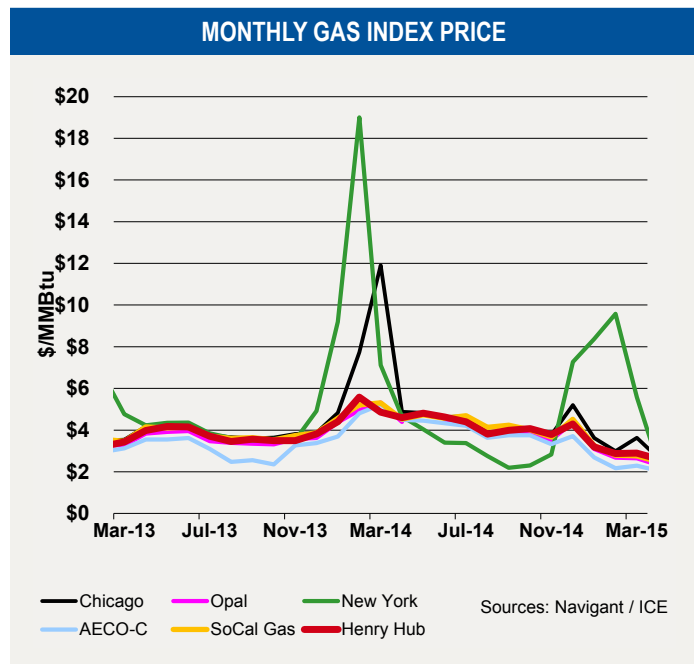
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The opinions expressed in this article are those of the author and do not necessarily represent the views of Navigant Consulting, Inc.

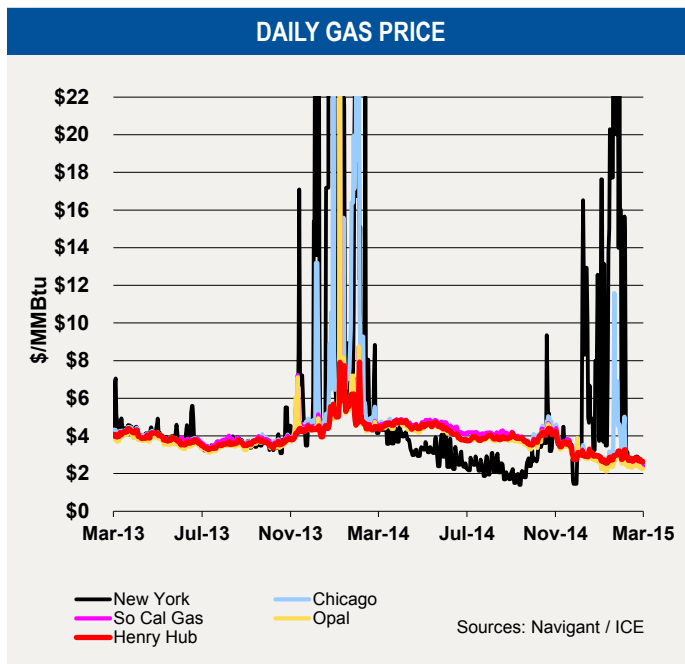
26th World Gas Conference Paris 2015 June 1-5, 2015 – Paris, France

Please join Navigant's Nick Allen and Gordon Pickering at the 26th World Gas Conference 2015, sponsored by the International Gas Union (IGU) in Paris, France from June 1-5, 2015. Allen and Pickering will be presenting, and will unveil Navigant's new global gas market model. Presentations made at the conference will be available on the Navigant website following the conference. Please contact Gordon Pickering at gpickering@navigant.com for more information or to schedule a demonstration of the global gas model at the conference or afterwards.

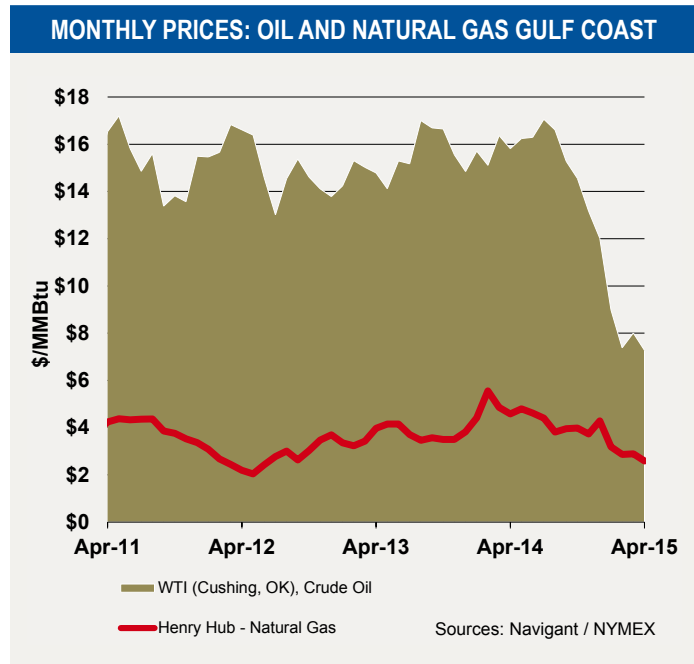
Natural Gas Market Charts



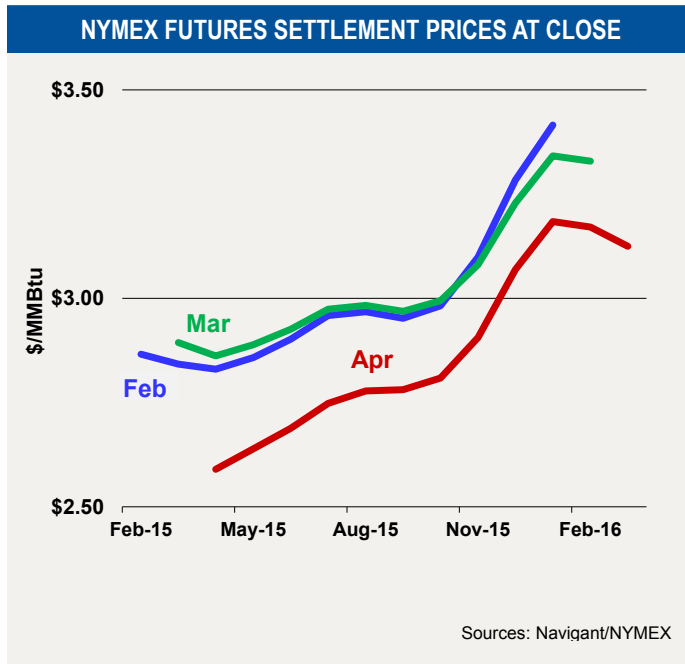
Monthly index gas prices increased 1% last month, with Henry Hub at \$2.90/MMBtu for March versus \$2.87/MMBtu for February. The March 2015 price was below the March 2014 price of \$4.86/MMBtu by \$0.96/MMBtu.



The daily spot prices ended March down 16% versus the end of February, with Henry Hub at \$2.61/MMBtu versus \$3.11/MMBtu.

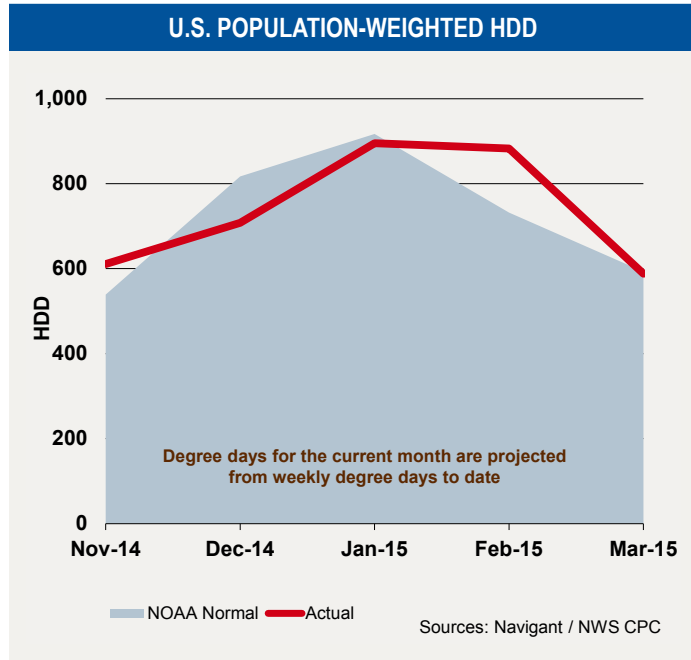


The most recent gas/oil price ratio remained at 2.8 times, with Henry Hub natural gas price at \$2.59 versus WTI crude oil price at \$7.27. The ratio one year prior was 3.5 times.

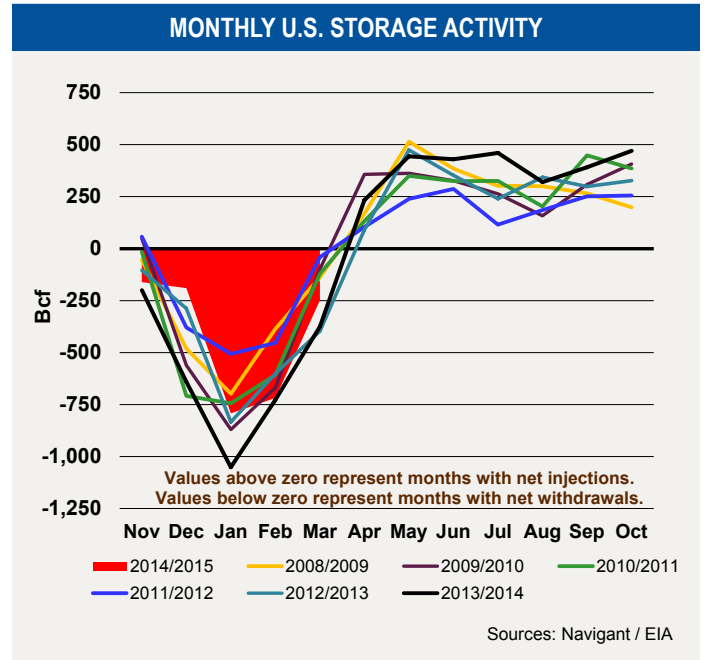


The average 12-month strip price decreased by 17 cents, or down 6%, to \$2.87/MMBtu for the strip starting April 2015.

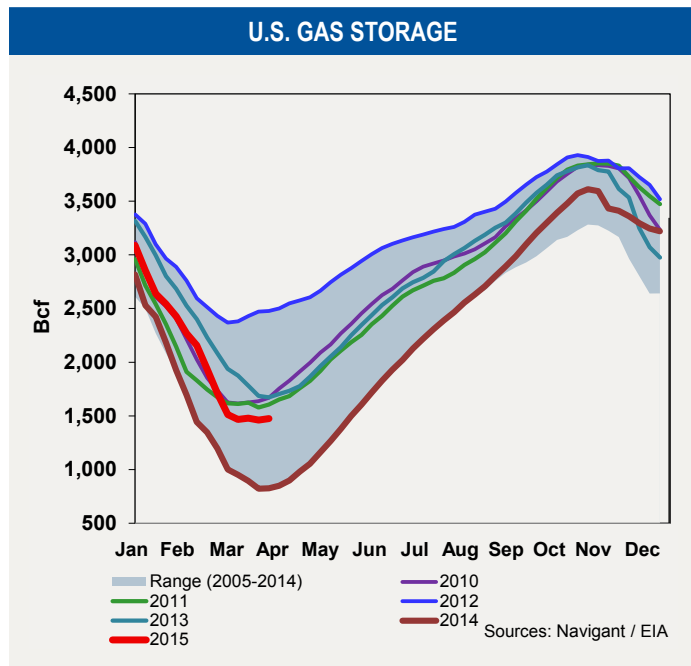
Natural Gas Market Charts



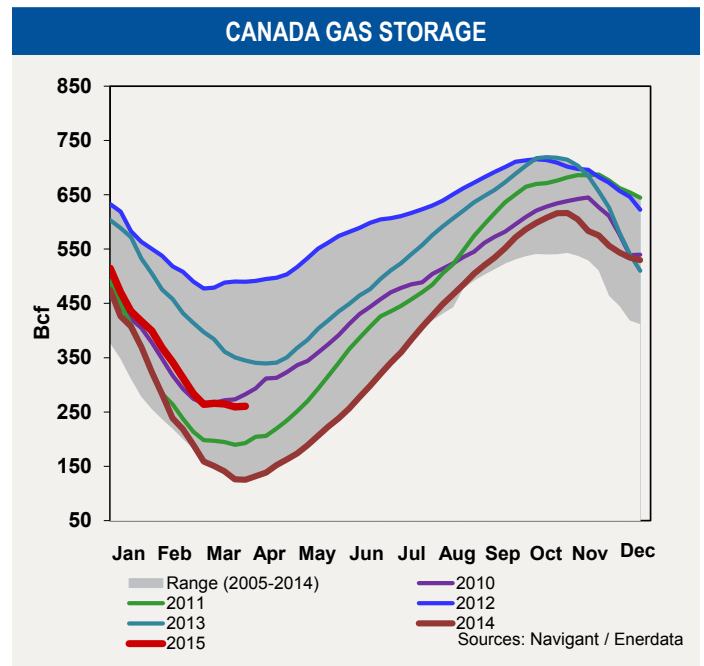
Normal weather returned in March after a cold February, moving the season total to 2.4% cooler than normal.



Normal weather in March brought storage withdrawals close to the average for the prior ten years at this time, at 249 Bcf versus 222 Bcf.

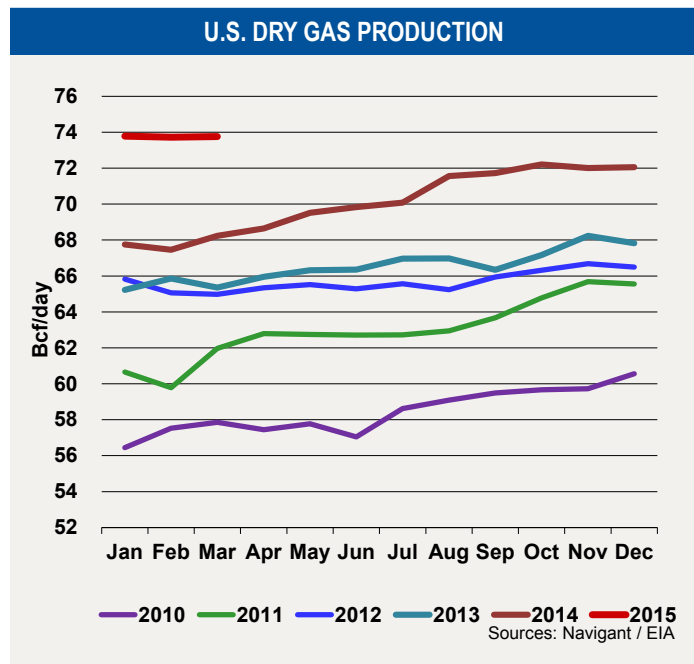


U.S. storage inventories bottomed out in March at 1,461 Bcf, about 6% lower than the average of the prior ten years.

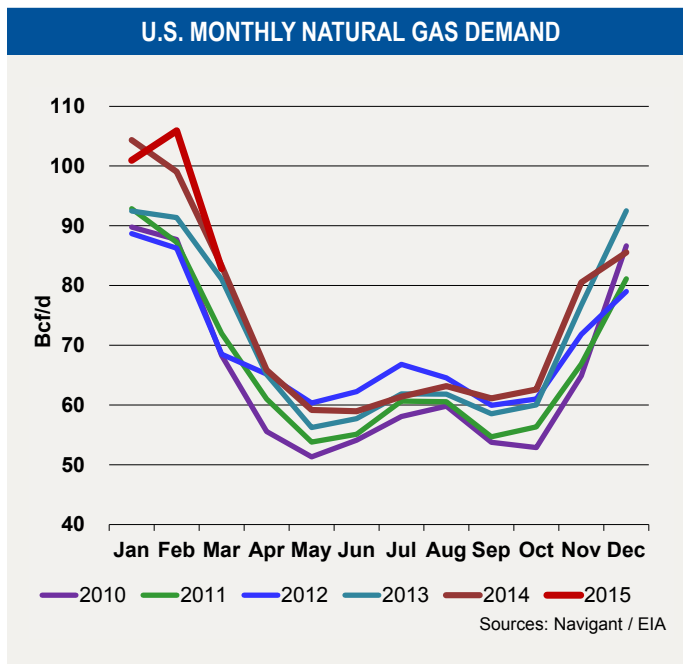


Canadian storage inventories ended the withdrawal season about 6% above average for the last ten years, at 261 Bcf.

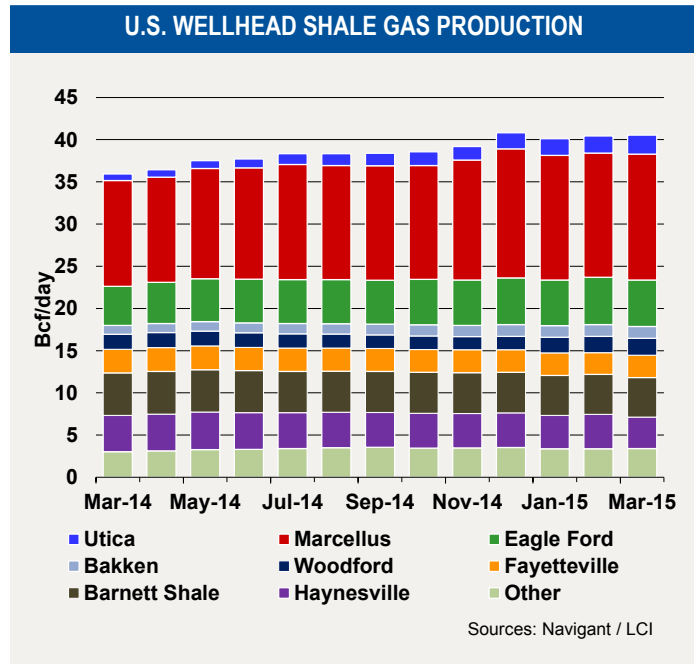
Natural Gas Market Charts



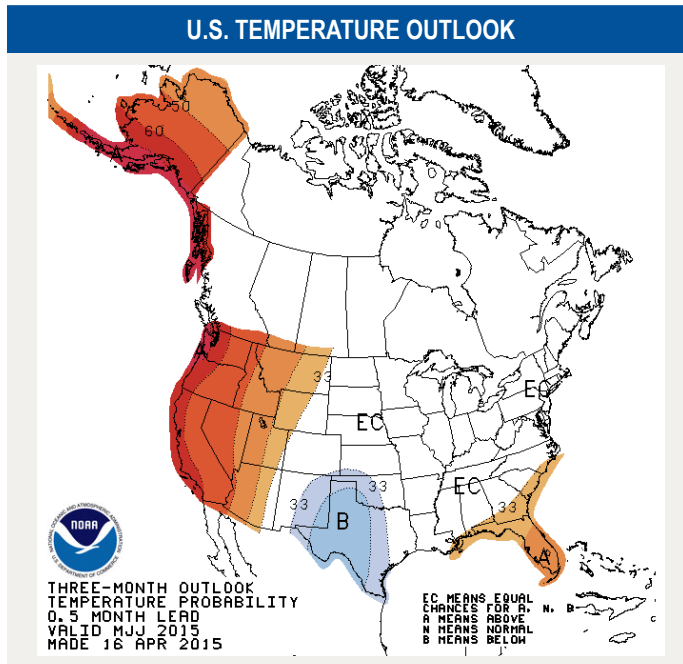
U.S. dry gas production continued at all-time high levels, at almost 74 Bcf/d.



Following an all-time high demand in February of 105.9 Bcf/d, U.S. gas demand decreased to just under last year's high for March of 83 Bcf/d.

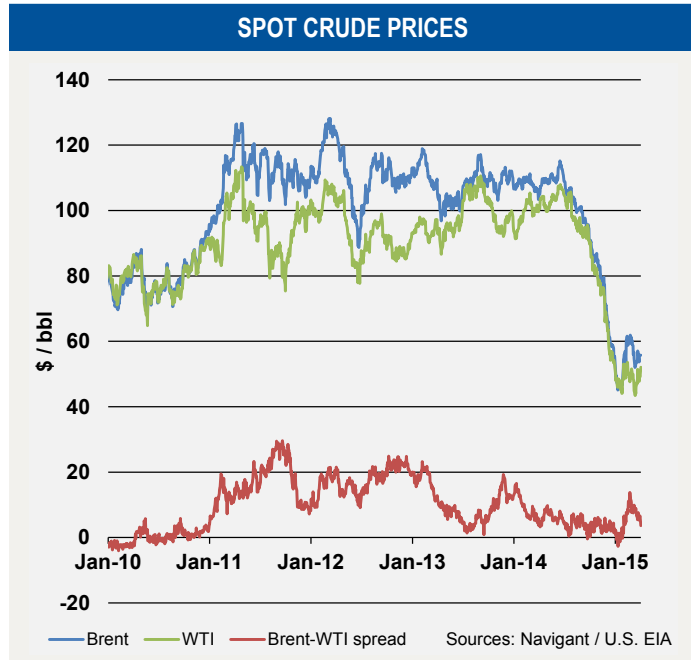


U.S. shale gas production showed a second consecutive month of slight increase, to 40.5 Bcf/d.

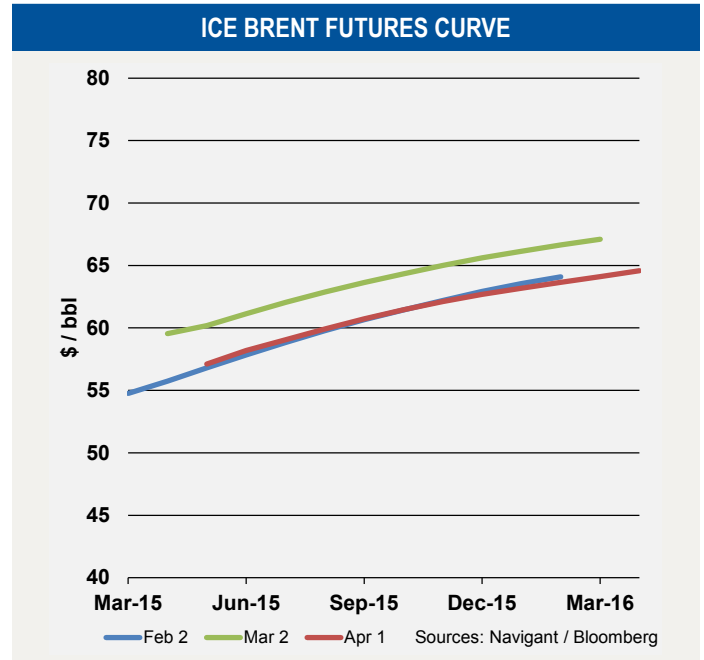


The temperature outlook is for above normal temperatures for the U.S. west of the Rockies and the norther Great Plains out through the western Great Lakes states. Below normal temperatures are favored for eastern New Mexico and western Texas.

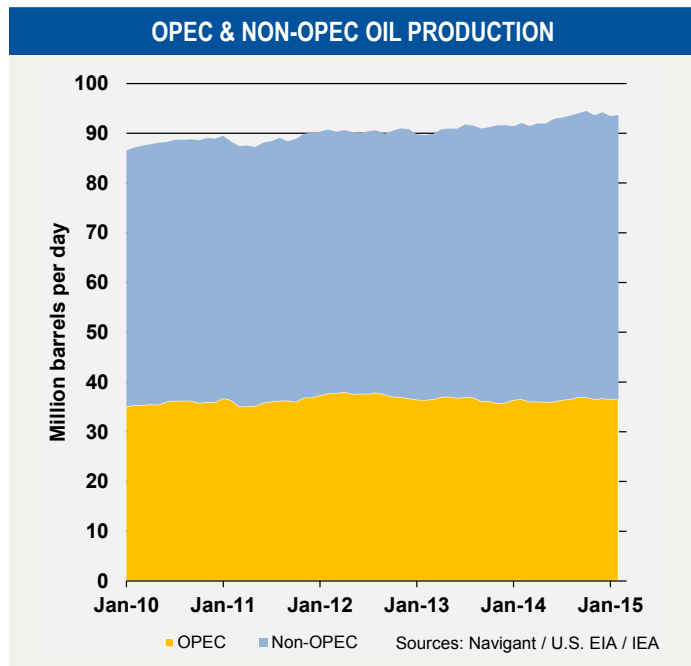
Oil Market Charts



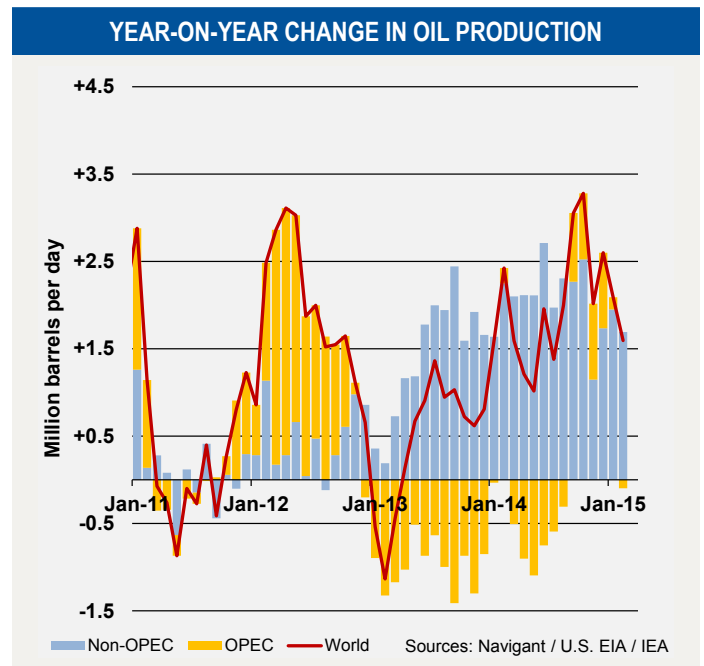
After three years of relative stability in the \$90-110/bbl range, crude prices plunged 60% from June 2014 levels. Prices have since recovered slightly to average \$56/bbl (Brent) and \$48/bbl (WTI) in March 2015.



The Brent futures curve has tracked spot prices. The average 12-month strip price at the beginning of April was \$61/bbl, a fall of 4% from the previous month.

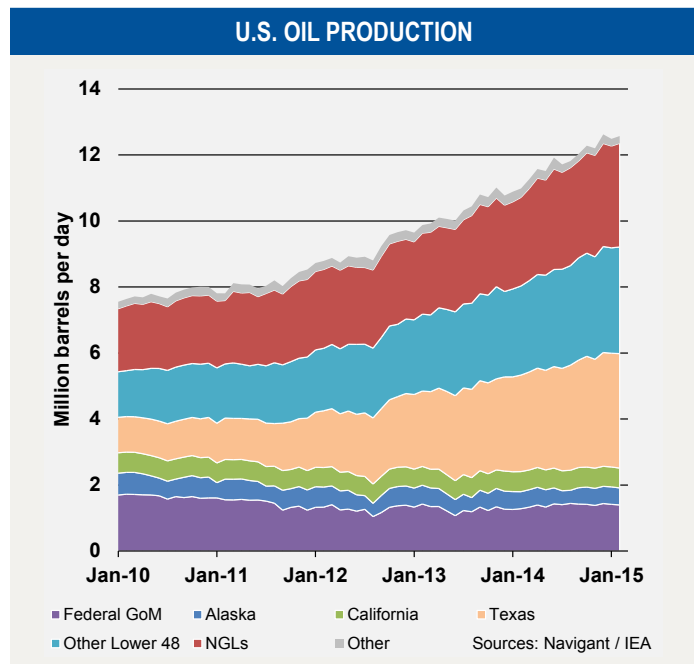


Global oil production increased from 92.1 million barrels per day a year ago to an estimated 93.7 million barrels per day in February 2015, of which 39% was supplied by OPEC.

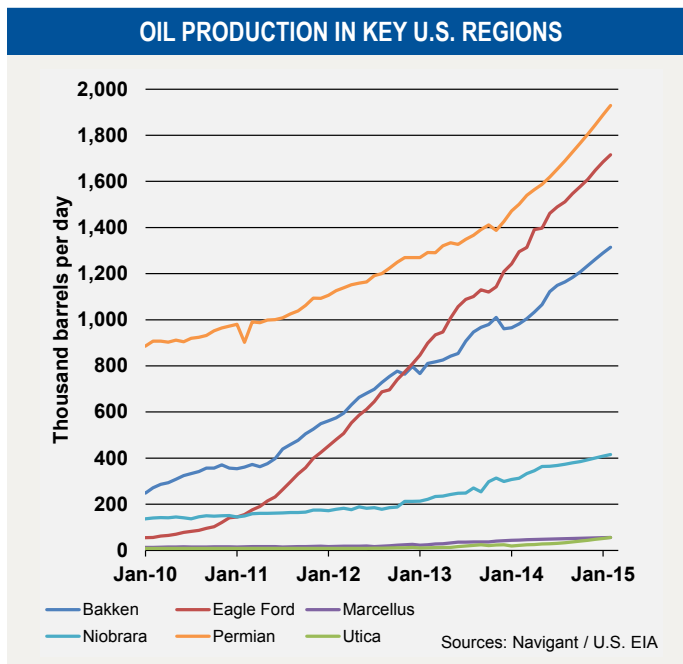


Oil production growth in recent years has been led by non-OPEC countries, particularly the U.S.

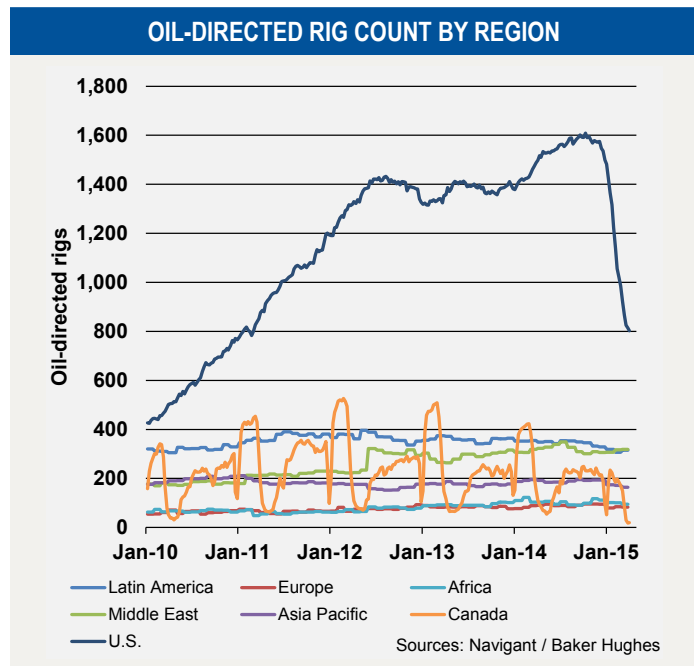
Oil Market Charts



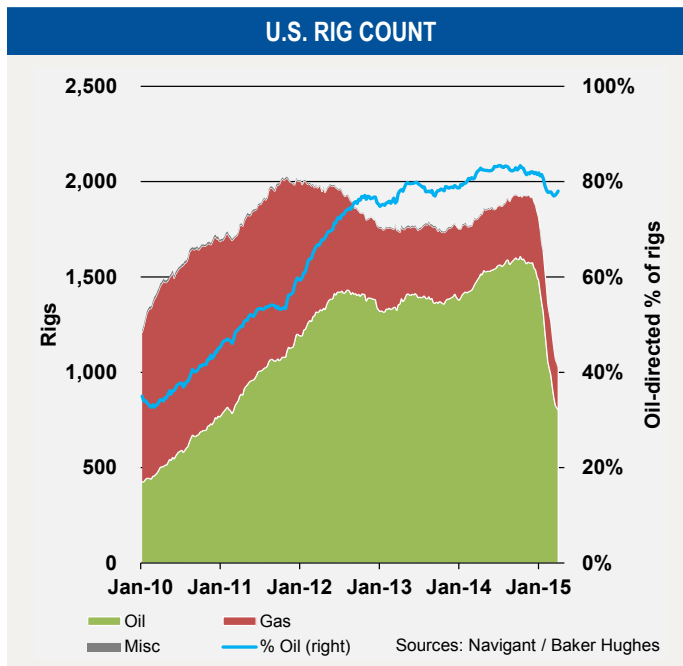
In the United States, oil production climbed by 14% over the year to an estimated 12.6 million barrels per day in February 2015. Increases have come mainly from crude produced in the lower 48 states (especially Texas) and NGLs.



In February 2015, oil production reached an estimated 1.9 million barrels per day in the Permian (+29% YoY), 1.7 million barrels per day in Eagle Ford (+32% YoY) and 1.3 million barrels per day in Bakken (+34% YoY).

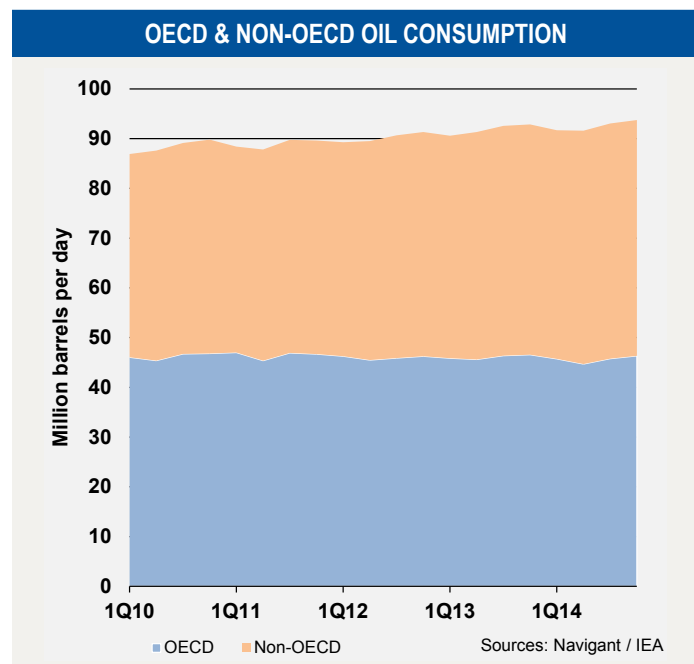


The impact of lower crude prices can be seen in oil-directed rig counts. The U.S. had 802 active oil rigs at the start of April 2015, a level last seen in March 2011.

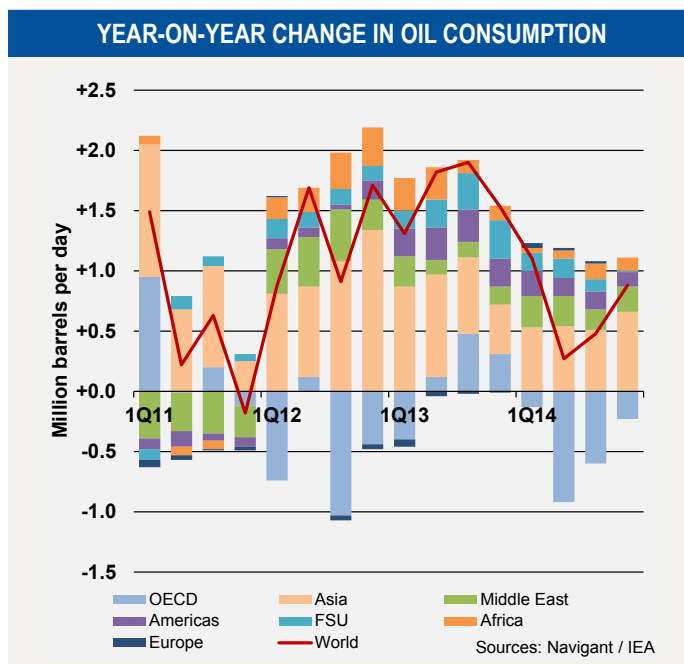


While U.S. rig counts for both oil and gas have fallen, oil rigs have decreased more steeply. 78% of U.S. rigs were oil-directed at the start of April.

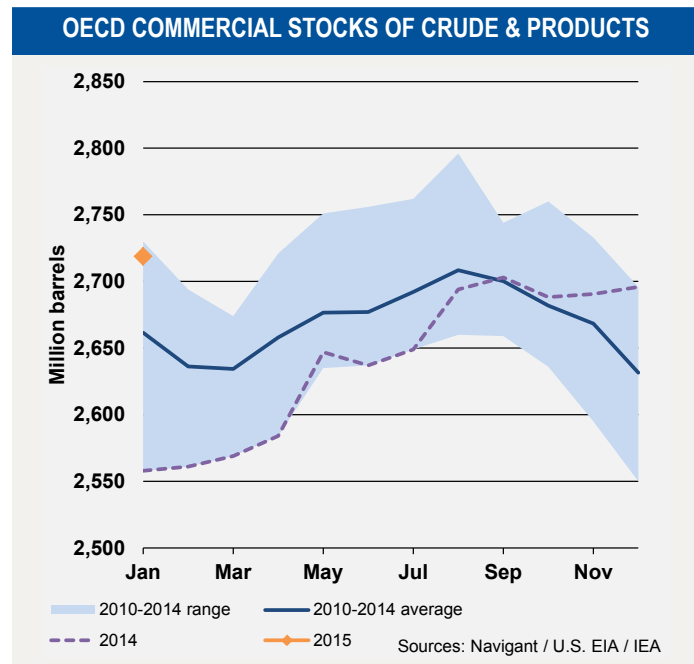
Oil Market Charts



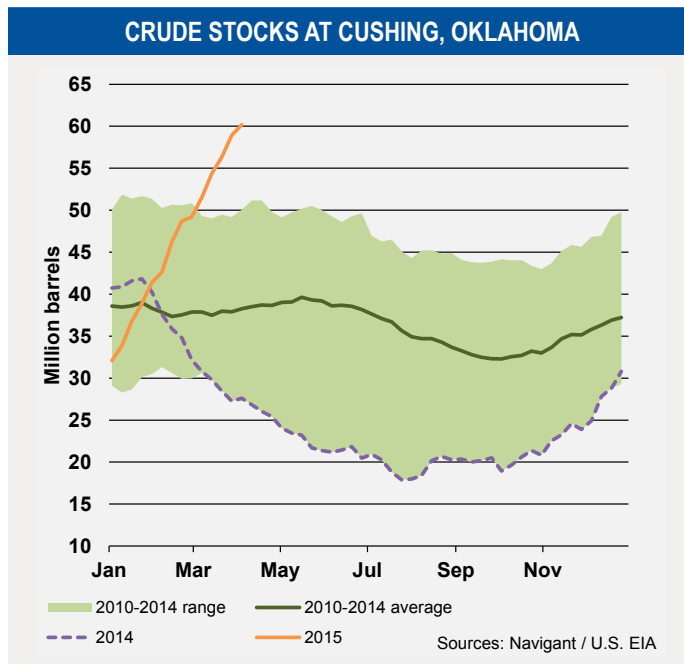
Global oil consumption increased from 92.9 million barrels per day in Q4 2013 to an estimated 93.7 million barrels per day in Q4 2014, of which 49% was consumed by OECD countries.



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



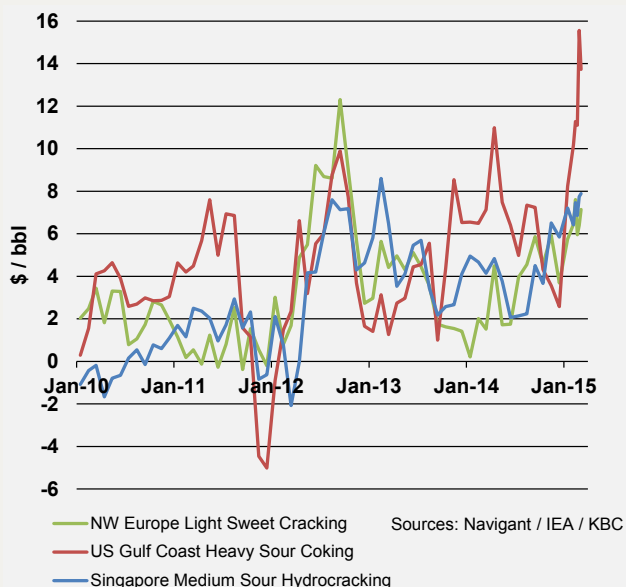
OECD commercial inventories rebounded during the second half of 2014 to reach an estimated 2,719 million barrels of crude and products in January 2015, at the top end of the five-year range.



Crude inventories at the Cushing hub (the delivery point of the WTI contract) have accumulated rapidly in 2015 to reach 60.2 million barrels at the start of April, 57% above the five-year average.

Oil Market Charts

INDICATIVE REFINING MARGINS



In March 2015, indicative refining margins were \$7.14/bbl for NWE light sweet cracking (+\$5.63/bbl YoY), \$13.73/bbl for USGC heavy sour coking (+\$6.60/bbl YoY) and \$7.89/bbl for Singapore medium sour hydrocracking (+\$3.75/bbl YoY).

EU CARBON ALLOWANCE PRICES



EU allowances for carbon have recovered to EUR 7.01/tonne from the lows of April 2013.

U.S. ETHANOL RIN PRICES



U.S. RINs for ethanol started April at 70 cents/gallon for the 2014 vintage and 68 cents/gallon for the 2015 vintage.

U.S. BIODIESEL RIN PRICES



U.S. RINs for biodiesel started April at 74 cents/gallon for the 2014 vintage and 81 cents/gallon for the 2015 vintage.

Legislative and Regulatory Highlights



National

Interior Department Releases Final Rule Updating Federal Well-Drilling Regulations

On March 20, the Department of the Interior released final standards, applicable on public and tribal lands, updating the federal regulations on drilling of oil and gas wells. Key components include the requirement for companies to publically disclose hydraulic fracturing chemicals on the FracFocus website, the requirement for cement barriers between wellbore and water zones and validation procedures regarding well integrity, higher standards for interim storage of hydro fracking waste fluids, and additional data requirements regarding pre-existing wells near hydro fracking operations. The new rule follows four years of development and the release of both a draft rule and supplemental draft rule by the BLM.

Northeast

Algonquin's AIM Project Approved by FERC

On March 3, the Federal Energy Regulatory Commission approved Algonquin Gas Transmission's application to construct and operate its Algonquin Incremental Market Project in New York, Connecticut, Rhode Island, and Massachusetts. The 342 MMcfd AIM Project will provide transport capacity between Algonquin's existing receipt points in Ramapo, New York and various New England city gates. All of the capacity of the \$971 million project is subject to precedent agreements with eight local distribution companies and two municipal utilities. Primary components of the AIM Project include the replacement of 20 miles of 26-inch pipeline with 42-inch pipeline, looping and lateral additions, and 82,000 horsepower of compression additions.

Southeast

Transco Files Application for Dalton Expansion Project for Transport of Marcellus Supply

On March 19, Williams Partner's Transcontinental Gas Pipe Line Co. applied for FERC approval of its proposed Dalton Expansion Project to provide 448 MMcfd of firm transport capacity to allow movement of Marcellus shale gas to the Southeast. The project would increase capacity on the Transco mainline as far south as Mississippi,

as well as add a new 111-mile lateral to Murray County, Georgia. Transco is planning for construction to begin in Q3 of 2016, with completion targeted for 2017.

Gulf

Three Brownsville LNG Export Projects Begin FERC Pre-Filing Process

The Federal Energy Regulatory Commission has recently approved the requests of three LNG export project developers to initiate FERC's pre-filing process. All three projects are proposed for Brownsville, Texas. The projects are: Annova LNG (0.94 Bcfd); Rio Grande LNG (3.6 Bcfd); and Texas LNG (0.27 Bcfd). The dockets are PF 15-15, PF 15-20, and PF 15-14, respectively.

South Texas LNG Withdraws LNG Export Application

On April 14, the Department of Energy granted the February 9 request of South Texas LNG Export Project (Pangea LNG Holdings) to withdraw its application for authority to export LNG from the proposed project in Corpus Christi. A planned corporate restructuring with NextDecade Partners has not materialized.



British Columbia

NEB Recommends Approval of NGTL's North Montney Mainline Project

On April 15, the National Energy Board issued its report recommending federal approval of an application by TransCanada's NOVA Gas Transmission Ltd. (NGTL) to build and operate its proposed North Montney Mainline Project. The project involves the construction and operation of a 300-km, 42-inch diameter sweet natural gas pipeline connecting NGTL's Groundbirch Mainline to the North Montney area in northeastern British Columbia. The pipeline would have an interconnection with TransCanada's proposed Prince Rupert Gas Transmission Project providing gas supply to the proposed Pacific NorthWest LNG export project. NGTL expects the North Montney Mainline sections to be operational in 2016 and 2017, providing a total of 2.4 Bcfd of transport capacity, with 2 Bcfd already contracted by Petronas, developer of Pacific NorthWest LNG.