NAVIGANT

Oil & Gas
Market Notes

Contents

Marcellus Supplies Strike Again — Recent Trends in Northeast Gas Displacement

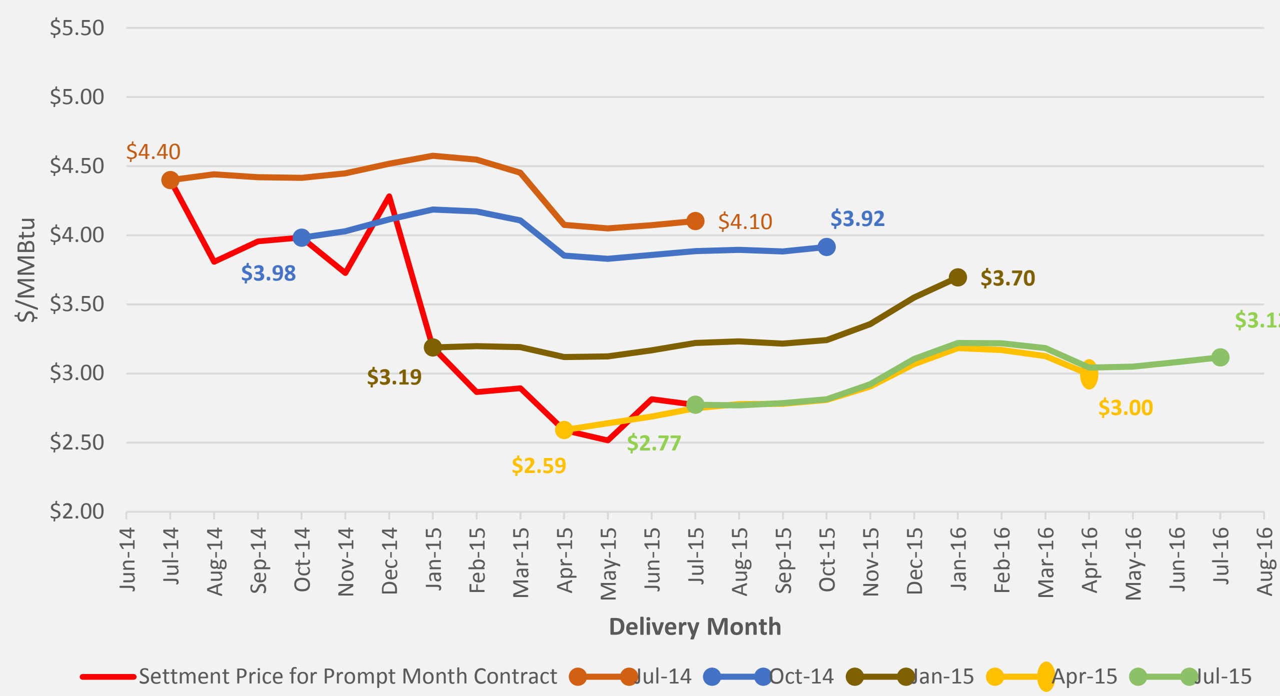
Non-casual market observers have noted that even the prolific U.S. natural gas industry, with exponentially increasing gas production levels driven by gas shale even as drilling has declined dramatically, is not immune to market forces that appear to have caught up with the technological breakthrough that forever changed the North American gas market 6 years ago. For historical perspective, U.S. gas shale production since 2008 has defied all odds and exploded from 9 billion cubic feet per day (Bcfd) to 40 Bcfd today, driving current U.S. natural gas production to 74 Bcfd—levels never reached before. This growth occurred in spite of many obstacles, such as a fundamental belief once held by many that questioned the continuing existence of natural gas as a viable resource, as LNG imports caused concerns about supply security and enormous potential economic costs to the national economy. During a period when the country faced the most significant national economic downturn since before World War II, when interest in the environment and climate change increased dramatically, and when the emergence of Asia (especially China) was beginning to alter the shape of global politics and the international economy, gas production continued to rise dramatically with new technologies and increased efficiency. That is, up until very recently, when the gas market has finally, reluctantly shown signs of slowing production growth in the face of low natural gas prices.

In particular, prices in the U.S. Northeast, in the Marcellus gas producing basin that has become the poster child for U.S. gas shale growth and success, have continued to decline despite both moderating production growth and the continued market displacement of out-of-region sources of supply that had historically served the U.S. Northeast market. These trends have sent conflicting market signals in this increasingly important market region for supply, which now affect the national and continental gas market. While the market appears to foretell a slight rebound in supply basin prices over the next year, it remains to be seen how the interplay of production, takeaway capacity, and competition from other supplies will play out, even as the explosive production growth in Marcellus gas shale has become the key feature of the region, and the Marcellus basin appears poised to provide supply to an increasingly expanding market area.

Price Trends and Continued Displacement of Non-Marcellus Supply in the Northeast

With respect to the national market, monthly index prices at Henry Hub have declined over the past year and a half, dropping from the $4–$5 per million British thermal unit (MMBtu) range in early 2014 to $2.52 per MMBtu in May 2015, the lowest price in 3 years (following the long-term low of $2.03 per MMBtu reached in May 2012). By July, prices rebounded to $2.77 per MMBtu. As shown in Figure 1, the current short-term outlook for prices at Henry Hub (as reflected by 12-month New York Mercantile Exchange [NYMEX] futures strips) is for prices to rebound somewhat to the $3.00 per MMBtu range, an increase of about $0.35 per MMBtu, or 13% over today's price. This is in contrast to what the futures outlook was 1 year ago, which estimated a continued price decrease from about $4.40 per MMBtu to about $4.10 per MMBtu. The switch to an increasing price outlook over the next 1-year period began in January 2015 in the dead of winter—generally a period of high seasonal demand—when there was about a $0.50 per MMBtu spread from the then-current $3.20 per MMBtu to the January 2016 expectation of prices at $3.70 per MMBtu. More recent 1-year strip outlooks beginning April 2015 were for more moderately increasing prices over the next year, with all monthly prices below $3.30 per MMBtu. Most recently, the NYMEX futures market continued to indicate increasing prices over the next year but still on a level very similar to the April strip—gently trending upward but still below the $3.30 per MMBtu mark through August 2016.

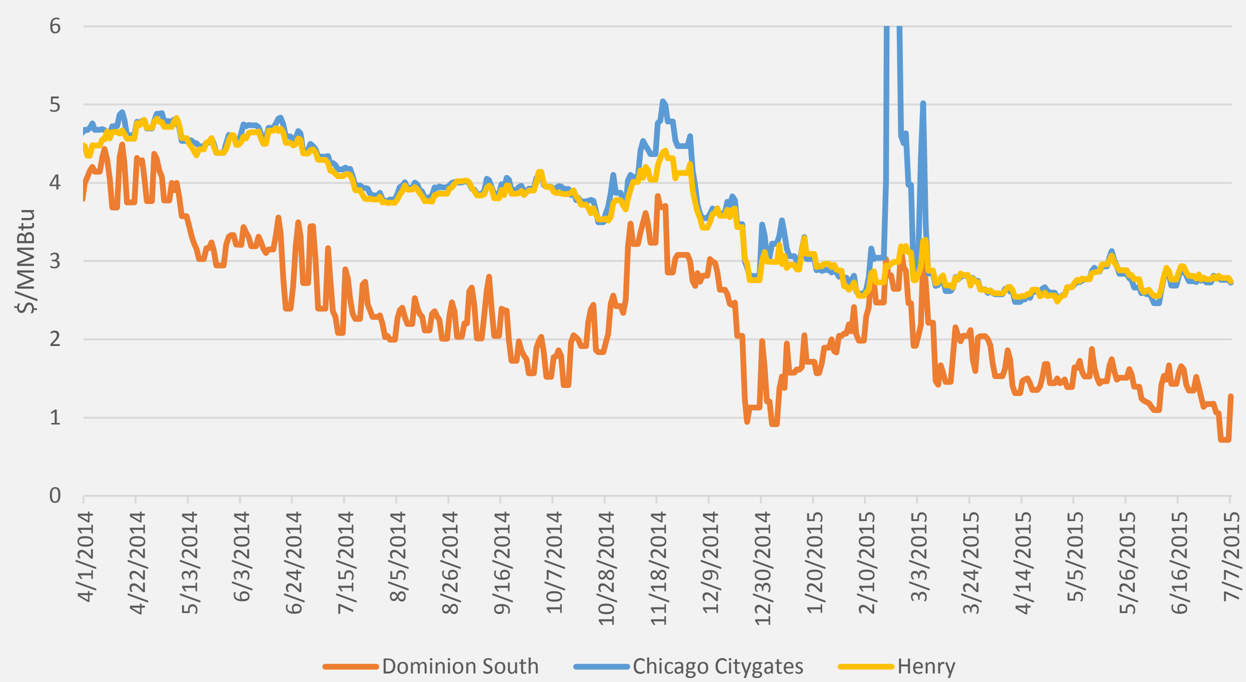
FIGURE 1. NYMEX STRIPS FOR HENRY HUB NATURAL GAS



Sources: Navigant, Ventyx

Perhaps the more telling story is that drilling down to the Dominion South Point (DSP) market hub, located in the heart of the Marcellus supply area, prices have dropped even further, perhaps unsurprisingly, down to about $1.25 per MMBtu presently, as shown in Figure 2. DSP's pattern of very low prices has led to increasingly negative spreads to both Henry Hub and Chicago, with the basis to Henry Hub becoming consistently negative starting in early 2014, at amounts generally between $1 and $2 per MMBtu. While the Chicago market prices—at about $2.80 per MMBtu—have generally stopped dropping since March, they are still low compared to their recent historical levels, which averaged $4.08 per MMBtu over the prior 4 years, or $3.60 per MMBtu over the 3 years before the polar vortex of winter 2013–2014. As discussed below, the low Chicago prices can at least be partially explained by the increasing connection of the Chicago market to the low prices in the Marcellus basin (such as at DSP), as well as the displacement of Rockies-sourced natural gas supplies on the Rockies Express Pipeline (REX) previously bound for Northeast markets by reversal volumes being delivered east-to-west from the Marcellus to Chicago.

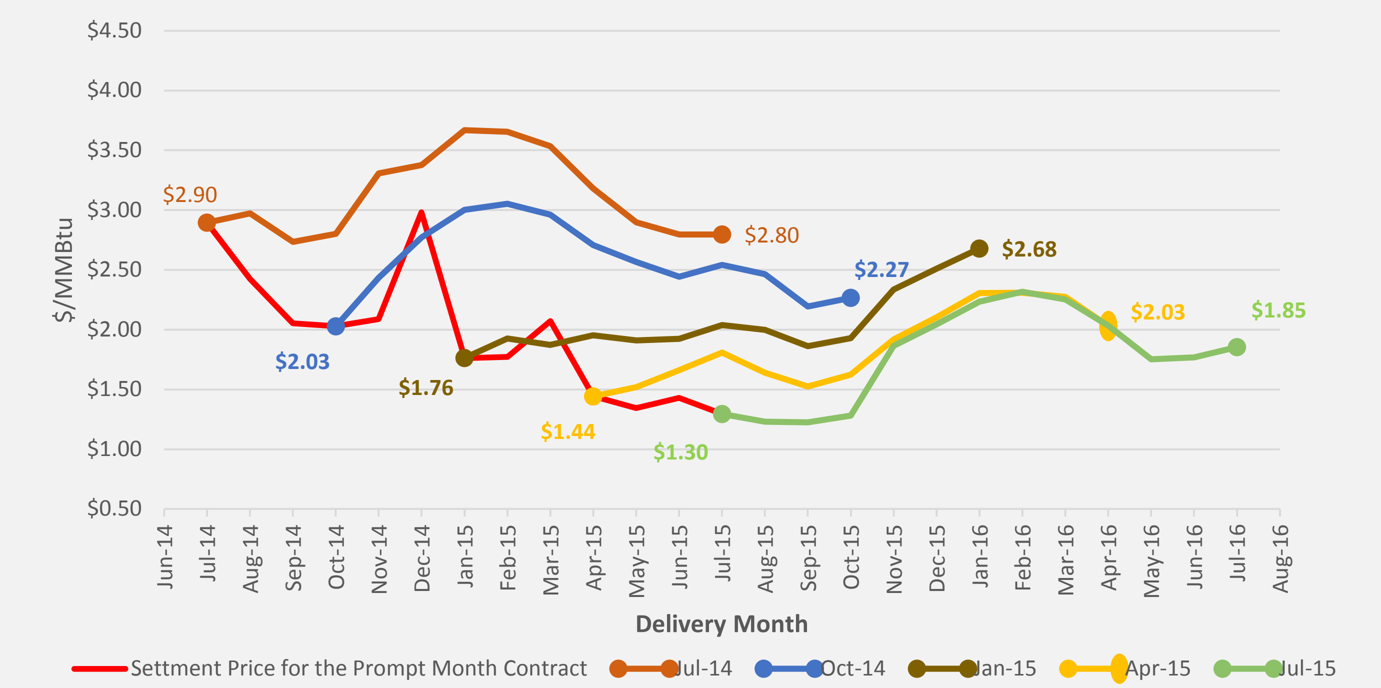
FIGURE 2. DAILY NATURAL GAS PRICES



Sources: Navigant, Ventyx, Intercontinental Exchange (ICE)

Using a similar short-term outlook for prices based on NYMEX strips at DSP and at the Chicago Citygates, the current futures indicate increases of $0.50–$0.60 per MMBtu over the next year at DSP, as shown in Figure 3. This is, interestingly, a stronger price increase over the period than for Henry Hub, but does come from an overall price level that is substantially lower than the prices either in Chicago or at Henry Hub. The increase still reflects DSP prices that carry a negative basis or spread greater than one dollar currently (July 2015), i.e. that are below Chicago or Henry Hub by more than one dollar.

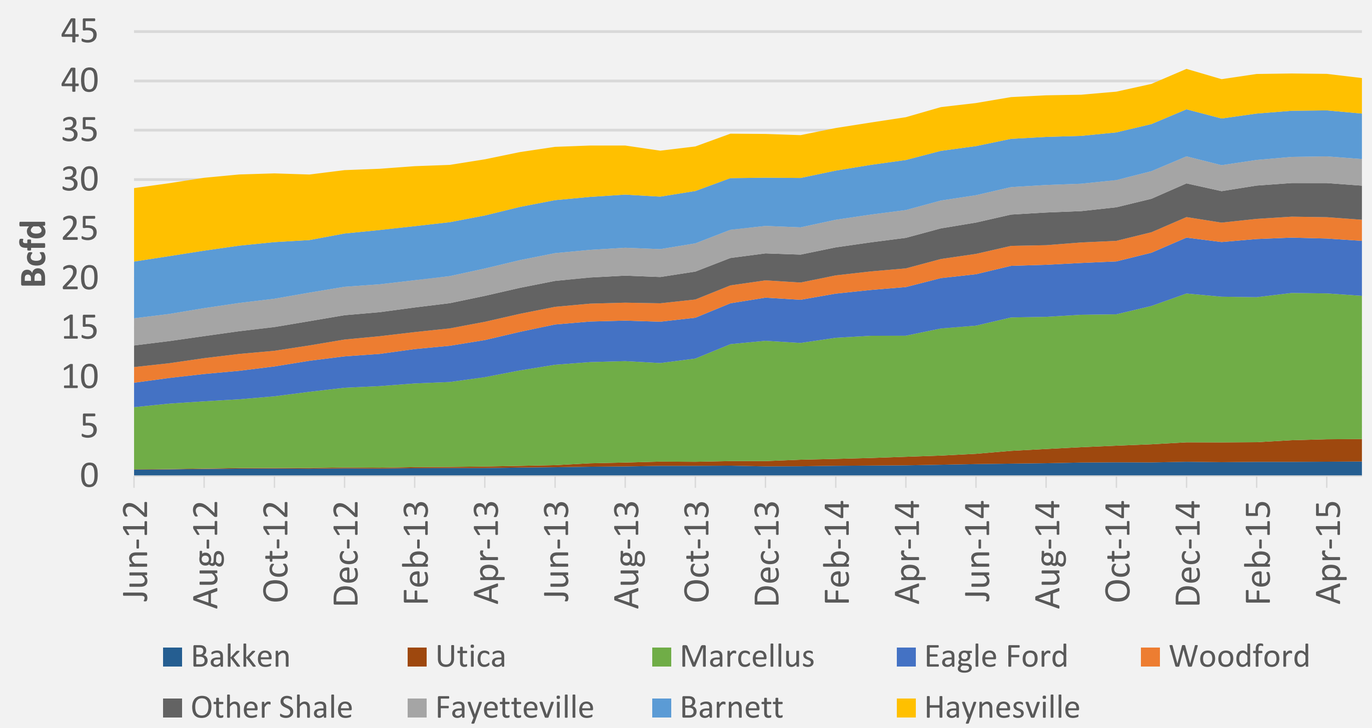
FIGURE 3. NYMEX STRIPS FOR DOMINION SOUTH POINT NATURAL GAS



Sources: Navigant, Ventyx

The moderately declining price strip back in July 2014 seems to be reflective of the strong actual growth in Marcellus production over the prior 3 years, as shown in Figure 4. More recently, however, the low natural gas prices at DSP appear to have caused even the mighty Marcellus gas shale production to plateau, at least temporarily. What we are seeing is that for the last 8 months, Marcellus production has plateaued while still managing to maintain an overall share of the U.S. gas shale market of over 35 percent, a level it had achieved at the end of 2013 following a 26% share of shale production in 2012, 19% in 2011, and 11% at the end of 2010. Despite the price levels in the Marcellus, gas shale production from the basin continues to be the dominant component of U.S. natural gas production, having come from levels of 0.5 Bcfd at the beginning of 2010. The continuing low prices in the Marcellus as reflected by the DSP market hub are to some extent reflective of the surplus of Marcellus supplies that have been enough to carry the basin through a period of overall flat production over the last 8 months.

FIGURE 4. U.S. SHALE GAS PRODUCTION

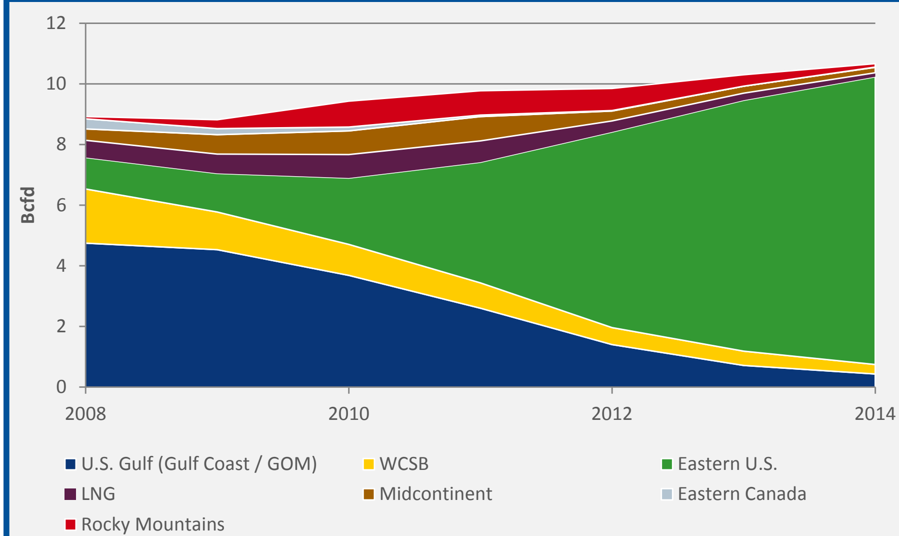


Sources: Navigant, PointLogic

The abundant supplies and low natural gas prices in the Marcellus have led to the displacement of gas volumes on REX from U.S. Northeast markets (i.e., volumes that had been serving U.S. Northeast markets are diminishing as Marcellus supplies have taken over the market). The REX pipeline came into service in 2009 to move Rockies natural gas supplies to Eastern U.S. markets that had traditionally needed inflows of gas from other regions to meet demand. The impact of the strong production growth in the Marcellus and the U.S. Northeast can be seen in Figure 5, showing the changing mix of gas supply regions serving the Northeast. Prior to the shale revolution, the key production area was the U.S. Gulf, providing 53% of Northeast supply. In the last several years, the dominance of the Marcellus spurred the growth that took off in 2010, and in 2014, the Marcellus' share of Northeast supply had increased to 89%, up from 80% in 2013. Like other regions, Rockies supplies have also noticeably decreased.

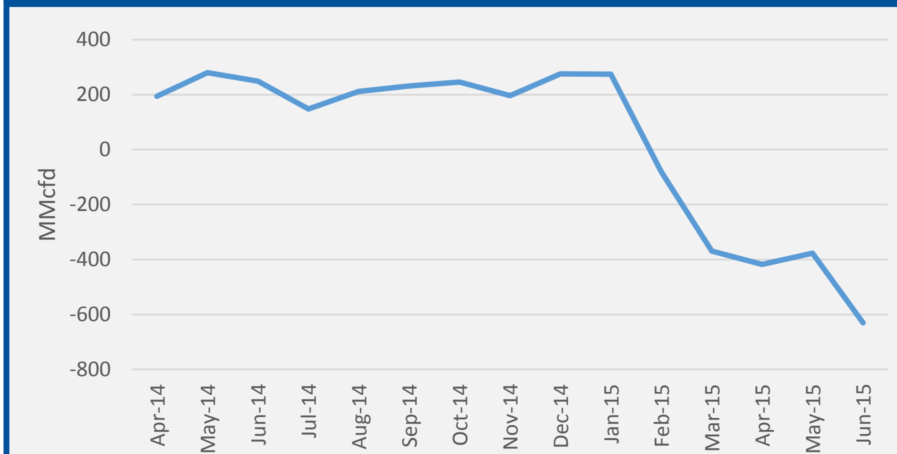
The displacement of outside supplies in the Eastern U.S. can be readily illustrated by examining the changes in flows on REX. While the reductions in REX flows into the Eastern U.S. have been ongoing since 2011, we will focus on the more recent period after the polar vortex event in the winter of 2013–2014. Between April 2014 and June 2015, there have been net reductions in the flows on REX from Indiana to Ohio of about 850 million cubic feet per day (MMcfd). As can be seen in Figure 6, this net reduction is composed of displacement of about 250 MMcfd of existing flows into Ohio, followed by about 600 MMcfd of actual reversed flows moving gas from Ohio into Indiana starting in February 2015.

FIGURE 5. GAS SUPPLY REGIONS SERVING U.S. NORTHEAST



Sources: Navigant, RBAC

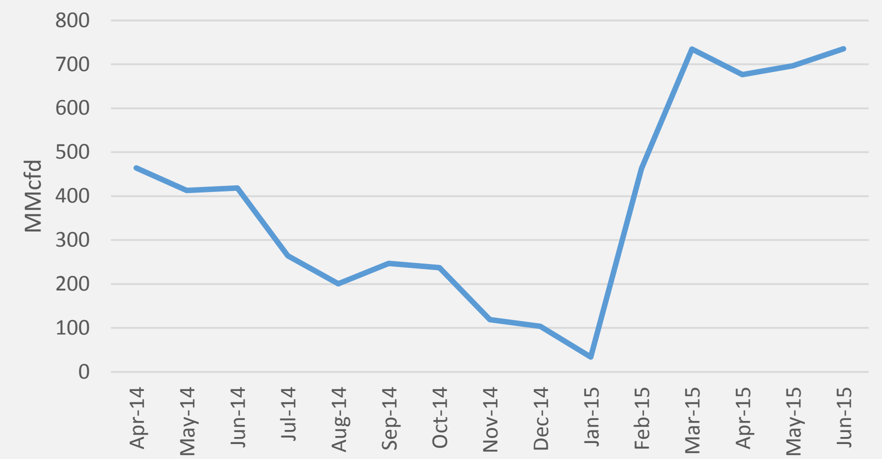
FIGURE 6. REX THROUGHPUT, INDIANA TO OHIO



Sources: Navigant, PointLogic

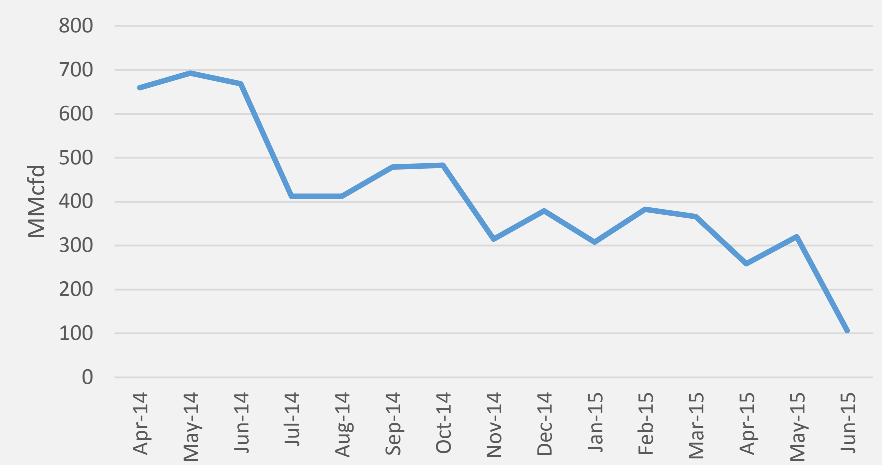
The 850 MMcfd swing in flows out of Indiana was generated by an increase of Indiana consumption off of REX of about 300 MMcfd and a reduction of flows from Illinois into Indiana (i.e., shifted displacement) on REX of about 550 MMcfd. This can be seen in Figure 7 and Figure 8, which show the increasing consumption of REX gas in Indiana[1] and trends in REX flows from Illinois into Indiana, respectively.

FIGURE 7. INDIANA CONSUMPTION OFF REX



Sources: Navigant, PointLogic

FIGURE 8. REX THROUGHPUT, ILLINOIS TO INDIANA



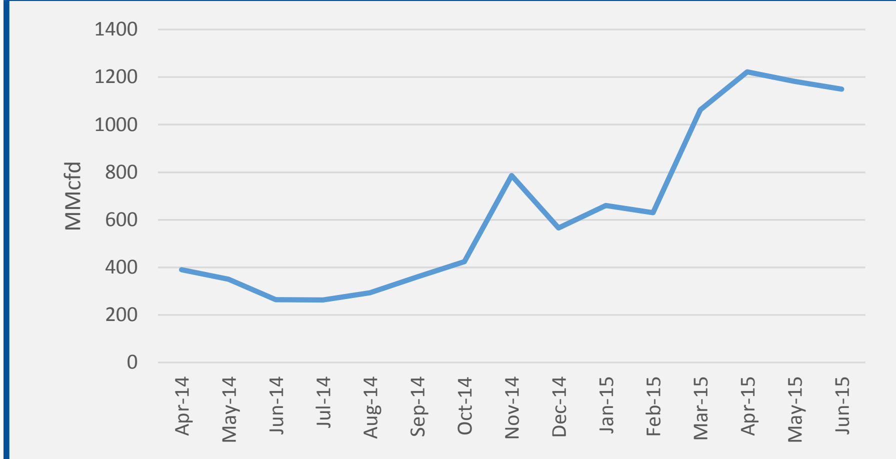
Sources: Navigant, PointLogic

1. In-state consumption is based on throughput into the state minus throughput out of the state.

Somewhat similar to the situation in Indiana, the 550 MMcfd of reduced REX flows from Illinois into Indiana resulted from increased Illinois consumption off of REX of 750 MMcfd, as can be seen in Figure 9, as well as increased flows of 200 MMcfd coming from Missouri into Illinois on REX. The recent Illinois consumption off of REX at about 1050 MMcfd occurs by increasing flows on three pipelines serving the Chicago market from interconnections on REX (i.e., Trunkline, Midwestern Gas, and NGPL, as shown in Figure 10).

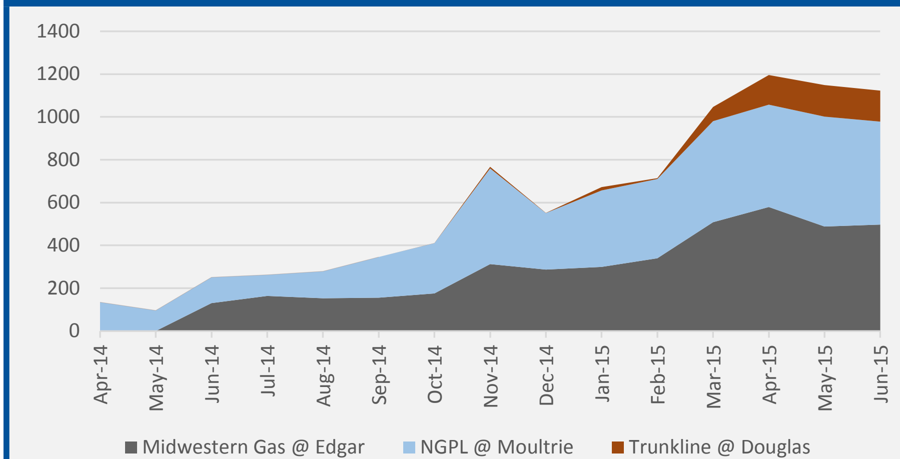
As further capacity for REX reversals is added, we can expect increasing flows of Marcellus gas from Ohio back into Indiana, causing further displacement of eastward REX flows out of Illinois. Similar to the situation that has already occurred, future displacement—as well as actual Marcellus supplies to the Midwest—could likely result in increased consumption of REX supplies in the Chicago market, helping to keep prices there low. There is already evidence of increased Marcellus supplies serving the Midwest, as shown in Figure 11. A noticeable increase in Eastern U.S. gas supply to the Midwest is evident beginning in 2012, with strong growth in 2014 from a 13% to a 19% share, a total increase of 43%. During 2014, the only gas supply region to increase its supply volumes to the Midwest was the Marcellus/Eastern U.S.; other regions either decreased or held steady.

FIGURE 9. ILLINOIS CONSUMPTION OFF REX



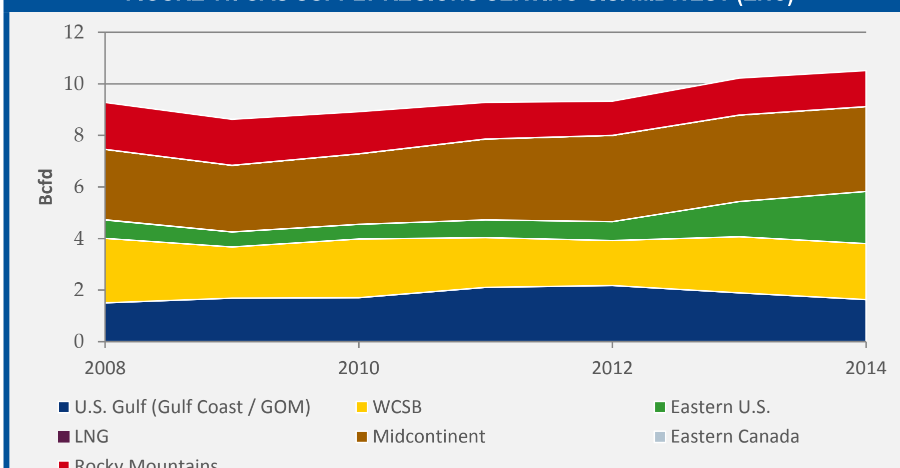
Sources: Navigant, PointLogic

FIGURE 10. FLOWS ON REX INTERCONNECTS TO CHICAGO



Sources: Navigant, PointLogic

FIGURE 11. GAS SUPPLY REGIONS SERVING U.S. MIDWEST (ENC)

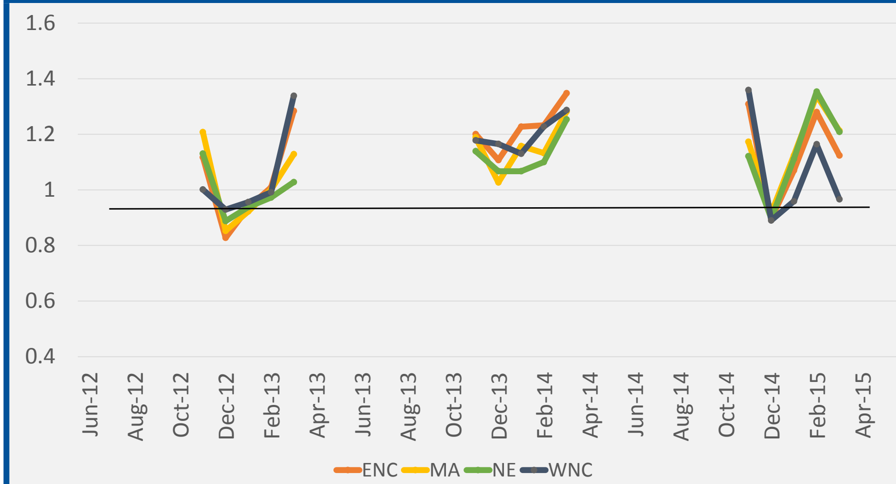


Sources: Navigant, RBAC

Other Market Metrics

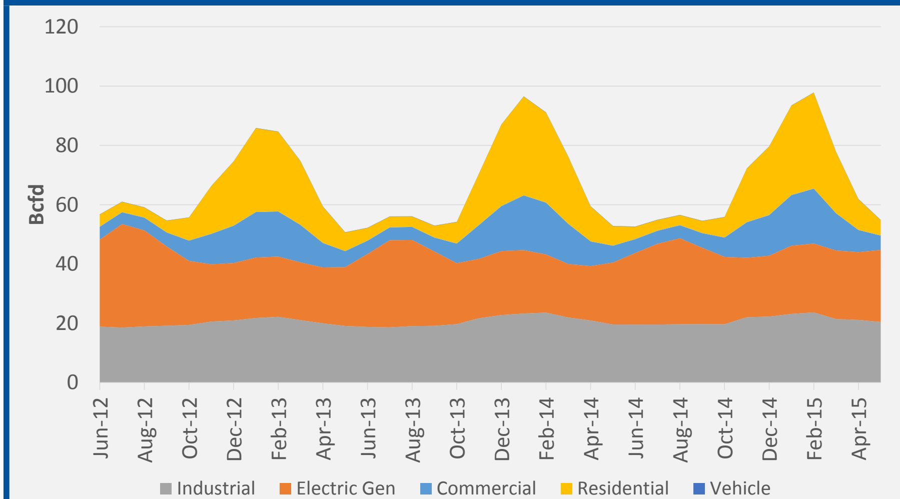
Throughout winter 2014–2015, the weather was slightly warmer than the winter of 2013–2014, which was characterized by a severe polar vortex. Heating degree days for the United States were down 5% during winter 2014–2015, and heating degree days for the U.S. census regions making up the primary cold weather areas of the country[2] were down 3.5%. However, while the temperatures were comparable during the two time periods, the temperature pattern was different in the winter of 2014–2015. Specifically, while the temperatures during the winter of 2013–2014 in the cold weather regions of the country were colder than normal during each of the five winter months (i.e., November—March), during the winter of 2014–2015 there was a break in that pattern, with a warmer-than-normal December, which was partially offset by a February that was even colder than in 2013–2014. A regional shift that occurred was the movement of the coldest weather from the North Central regions to the Northeast. A comparison of heating degree days to the prior 10-year average is shown in Figure 12.

FIGURE 12. HEATING DEGREE DAYS: PERCENT OF 10-YEAR AVERAGE



Sources: Navigant, U.S. Energy Information Administration

FIGURE 13. U.S. CONSUMPTION



Sources: Navigant, U.S. Energy Information Administration

Just as weather was roughly comparable between the last two winters, so was natural gas consumption. Consumption during the November–March period was virtually unchanged between 2013–2014 and 2014–2015, with both totaling 12.7 trillion cubic feet (TCF). As with the weather pattern, there was a change in the consumption pattern, with the peak month moving from January to February. Looking at a 3-year history shows that natural gas consumption during the last two winters was noticeably higher (~9%) than in 2012–2013. Monthly natural gas consumption is shown in Figure 13.

2. The East North Central or ENC (Michigan, Ohio, Indiana, Illinois, Wisconsin), the West North Central (Minnesota, Iowa, Missouri, Kansas, Nebraska, South Dakota, North Dakota), and the U.S. Northeast, composed of New England (Massachusetts, Rhode Island, Connecticut, Maine, New Hampshire, Vermont) and the Middle Atlantic (New York, Pennsylvania, New Jersey).

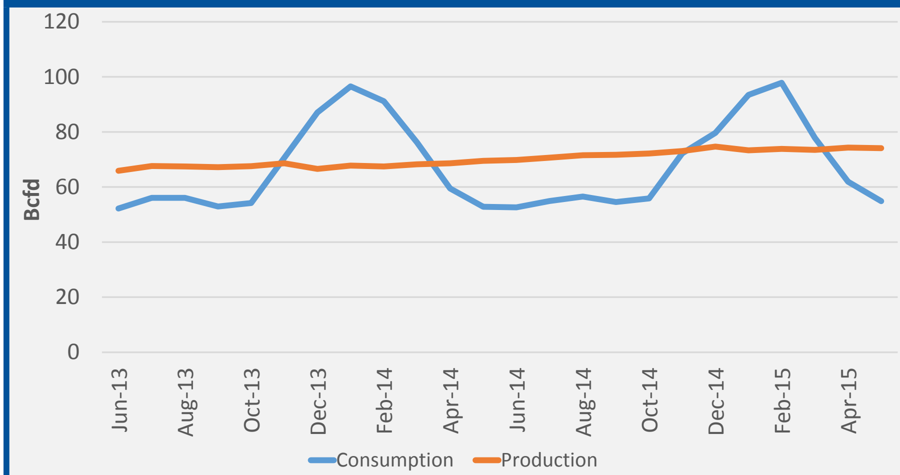
While consumption was unchanged during the last two winters, there has been an upward trend in natural gas production that can be seen in Figure 14. During the winter periods, U.S. production increased 9%, from 10.2 TCF to 11.1 TCF. As a consequence of the higher production levels alongside steady consumption levels, there was less pressure on storage inventories to meet demand as the winter progressed, evidenced by the smaller amount of excess consumption over production shown for winter 2014–2015 in Figure 14.

Compounding the effect noted above was the alteration of the weather pattern to bring a warm month of December near the beginning of the storage withdrawal season, lessening the need for early season withdrawals. The overall result of the different temperature patterns and production levels was a much more comfortable storage inventory trajectory. As can be seen in Figure 15, despite lower starting storage inventories in October, with a more moderate withdrawal season, the ending inventories were above those of the 2013–2014 winter by more than 70%, at 1,482 Bcf versus 857 Bcf.

U.S. pipeline imports from Canada have shown a generally declining trend over the last several years. As can be seen in Figure 16, summertime imports have consistently decreased, from 8.6 Bcfd in July 2012 to 7.4 Bcfd in July 2013 and to 6.3 Bcfd in July 2014.

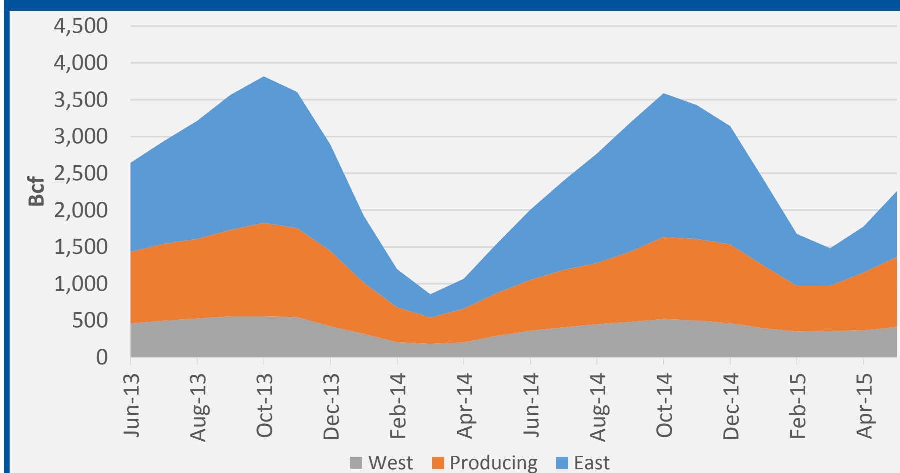
U.S. pipeline export to Mexico were level to slightly increasing until the end of 2014, when new pipelines at the Rio Grande, Texas border point came into service and began a more pronounced increasing trend, as shown in Figure 17. The NET Mexico pipeline, with a capacity of 2.1 Bcfd, began service this year and will move additional export quantities from the Rio Grande border point to serve increasing Mexican demand for new power generation and other uses.

FIGURE 14. U.S. DRY PRODUCTION AND CONSUMPTION



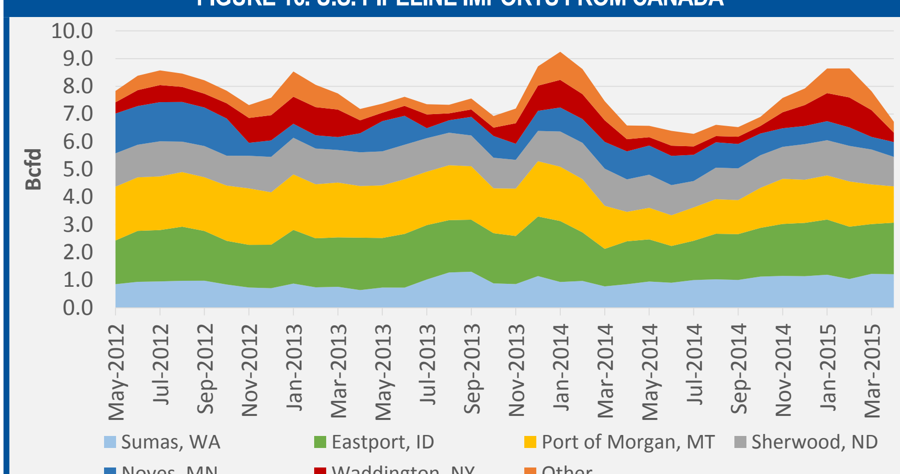
Sources: Navigant, U.S. Energy Information Administration

FIGURE 15. U.S. STORAGE



Sources: Navigant, U.S. Energy Information Administration

FIGURE 16. U.S. PIPELINE IMPORTS FROM CANADA



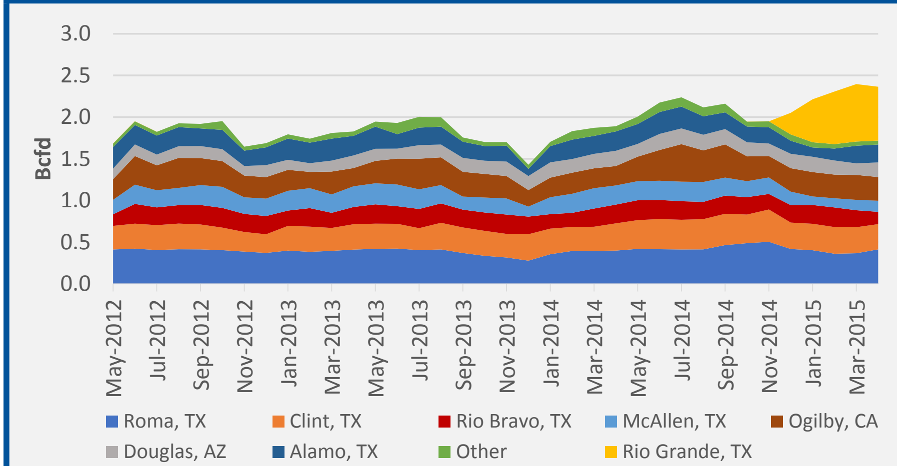
Sources: Navigant, U.S. Energy Information Administration

Finally, the effect of the recent natural gas price decreases on the generation fuel mix between coal and natural gas can be seen in Figure 18. Similar to the situation in 2012, when gas prices were last as low as they currently are, the proportion of natural gas as a power generation fuel has risen to approach and actually exceed that of coal, at 32% versus 31% in April 2015.

This is a truly momentous event that seems to have gone mostly unnoticed by members of the gas industry and others. With significant economic and other ramifications on matters as far reaching as health and climate change, it shows the vast movement in the U.S., on what is still viewed as aspirational in many other areas of the world. It is one of the truly defining matters of the gas industry's success in this country, with important implications for the global community and the climate we all share.

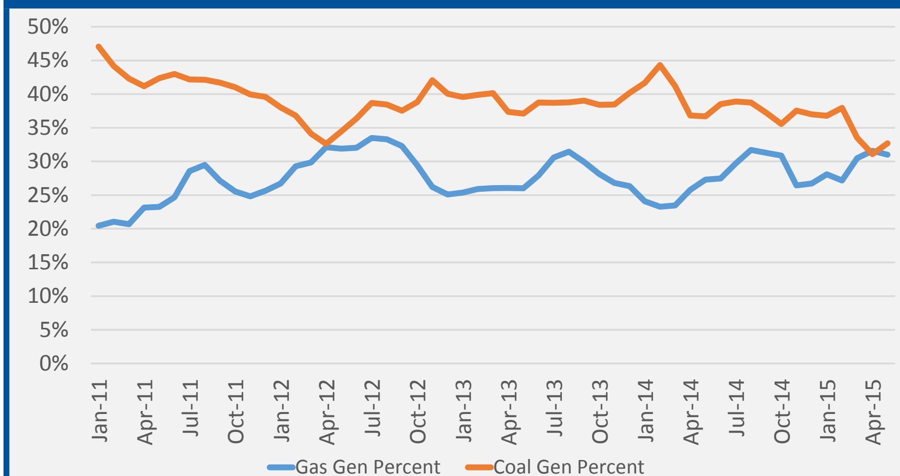
Navigant furthermore expects such coal-to-gas switching to continue to occur in response not only to price signals, but also as additional coal-fired power plants retire, a trend now being spurred on by various U.S. regulatory initiatives such as the Clean Power Plan and the Environmental Protection Agency's Mercury and Air Toxics Standards (MATS)[3].

FIGURE 17. U.S. PIPELINE EXPORTS TO MEXICO



Sources: Navigant, U.S. Energy Information Administration

FIGURE 18. ELECTRIC GENERATION FUEL MIX--GAS AND COAL



Sources: Navigant, U.S. Energy Information Administration

In any event, with all the current developments in the U.S. Northeast gas market as a result of gas shale abundance, we fully expect the natural gas market to meet most any level of increased power generation gas demand from growth partially as a result of coal-to-gas switching, just as Marcellus production has been meeting increasing demand over an expanding geographical region. Both are events that were not even being contemplated not very long ago!

How Can Navigant Help?

Using in-depth industry knowledge and experience, our Oil and Gas consulting practice specializes in helping clients understand the issues, develop solutions, and execute on their strategy. Our team has deep experience in helping to drive value in highly volatile times through upstream, midstream, refining, and chemical operation, as well as asset and commercial optimization.

— *Gordon Pickering and Jeff Van Horne*

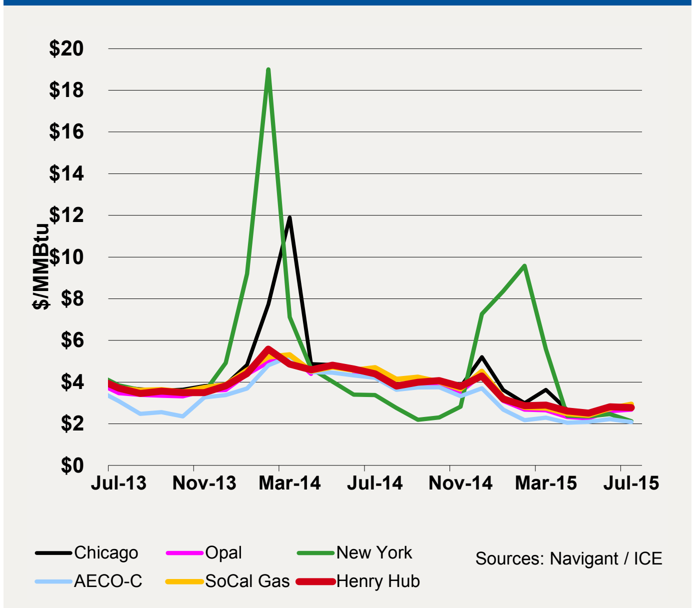
About the Authors »
Gordon Pickering is a Director and Jeff Van Horne is a Managing Consultant in Navigant's Energy Practice.

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

3. On June 29, 2015, the U.S. Supreme Court remanded a challenge to the MATS to ensure compliance with procedural regulatory requirements.

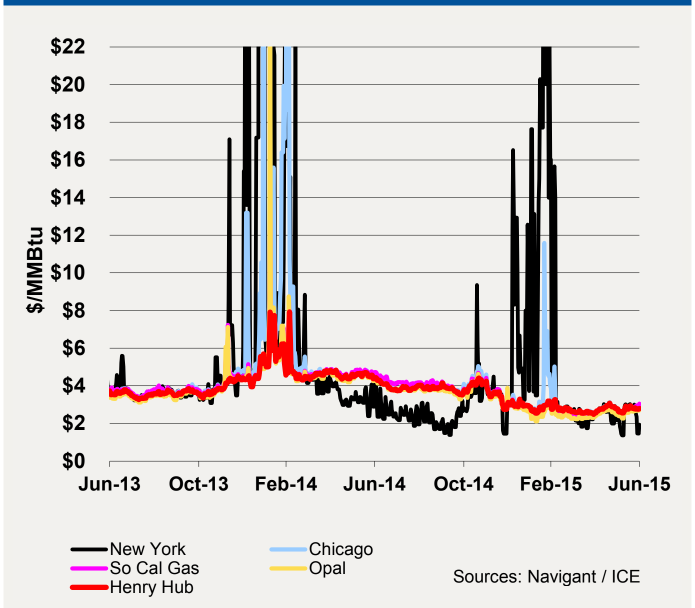
Natural Gas Market Charts

MONTHLY GAS INDEX PRICE



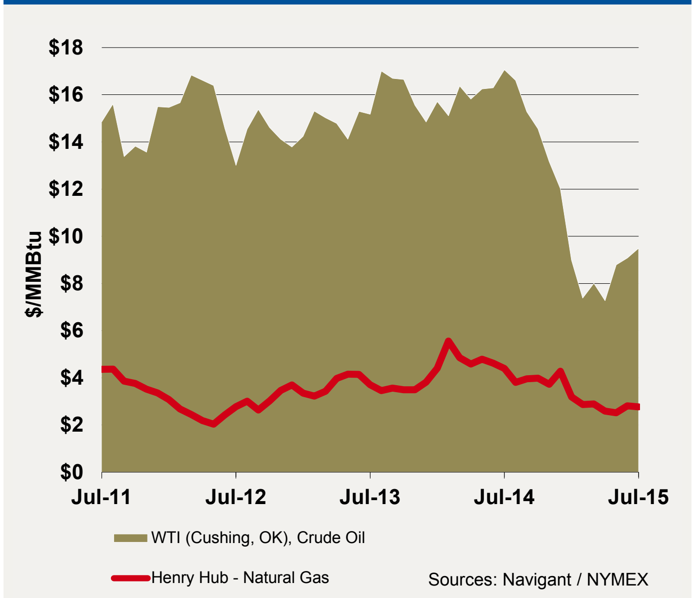
Monthly index gas prices decreased 2% last month, with Henry Hub at $2.77/MMBtu for July versus $2.82/MMBtu for June. The July 2015 price was below the July 2014 price of $4.40/MMBtu by $1.63/MMBtu.

DAILY GAS PRICE



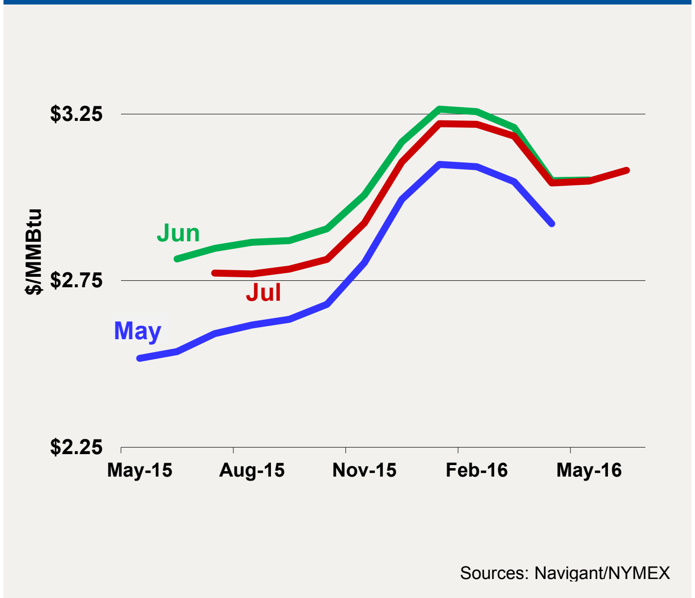
The daily spot prices ended June up 1% versus the end of May, with Henry Hub at $2.80/MMBtu versus $2.77/MMBtu.

MONTHLY PRICES: OIL AND NATURAL GAS GULF COAST



The most recent gas/oil price ratio increased to 3.4 times, with Henry Hub natural gas price at $2.77 versus WTI crude oil price at $9.49. The ratio one year prior was 3.9 times.

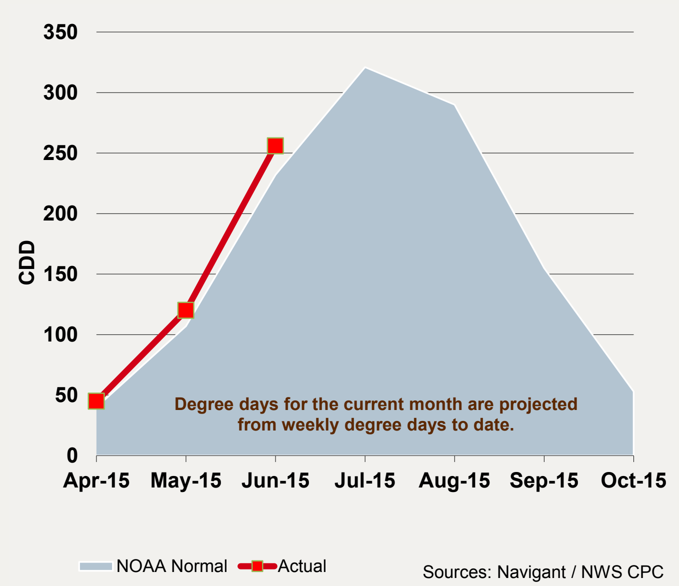
NYMEX FUTURES SETTLEMENT PRICES AT CLOSE



The average 12-month strip price decreased by 3 cents, or down 1%, to $3.00/MMBtu for the strip starting July 2015.

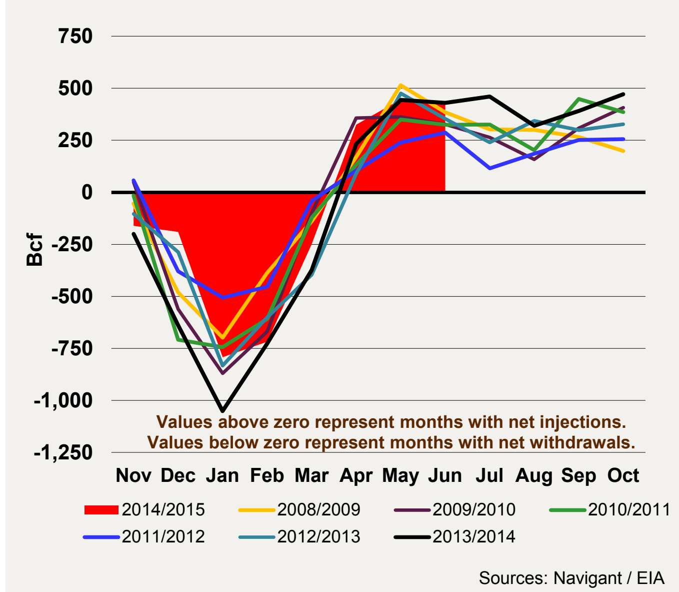
Natural Gas Market Charts

U.S. POPULATION-WEIGHTED CDD



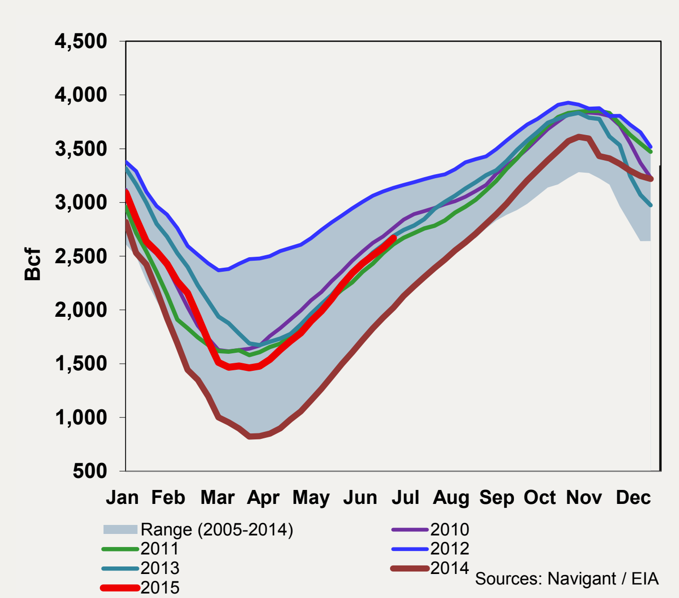
The cooling degree day season continued warmer than normal, at 11% above normal for the season.

MONTHLY U.S. STORAGE ACTIVITY



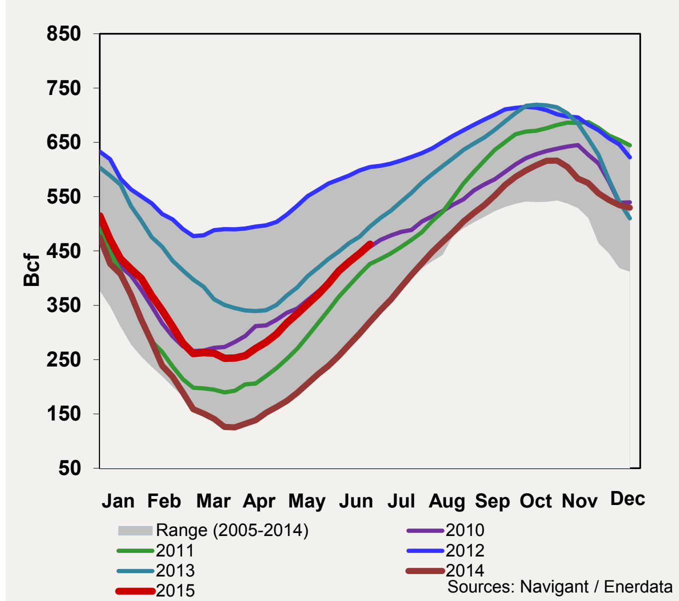
Continued warm weather in June kept storage injections strong at 435 Bcf, greater than nine of the prior ten years at this time.

U.S. GAS STORAGE



U.S. storage inventories increased in June to 2,668 Bcf, 3% above the average of the prior ten years at this time.

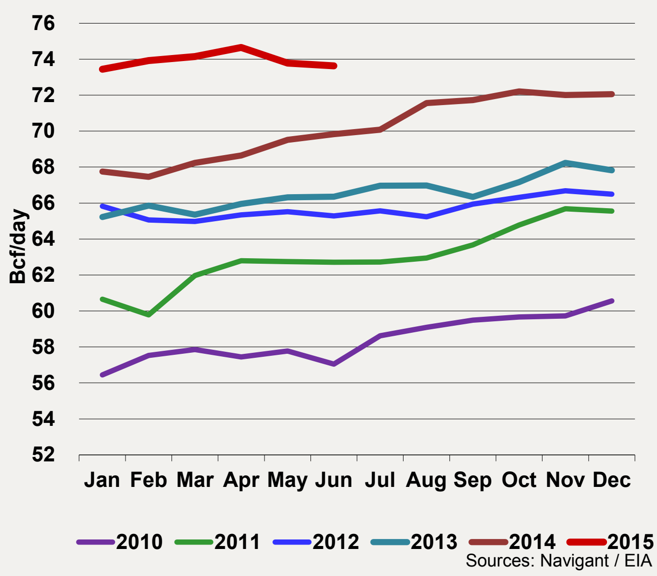
CANADA GAS STORAGE



Canadian storage inventories increased in June to 462 Bcf, about 5% above the 439 Bcf average for the last ten years at this time.

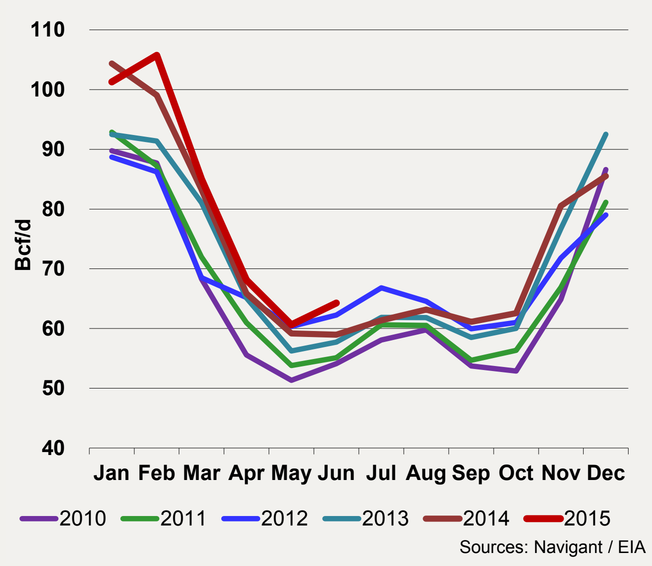
Natural Gas Market Charts

U.S. DRY GAS PRODUCTION



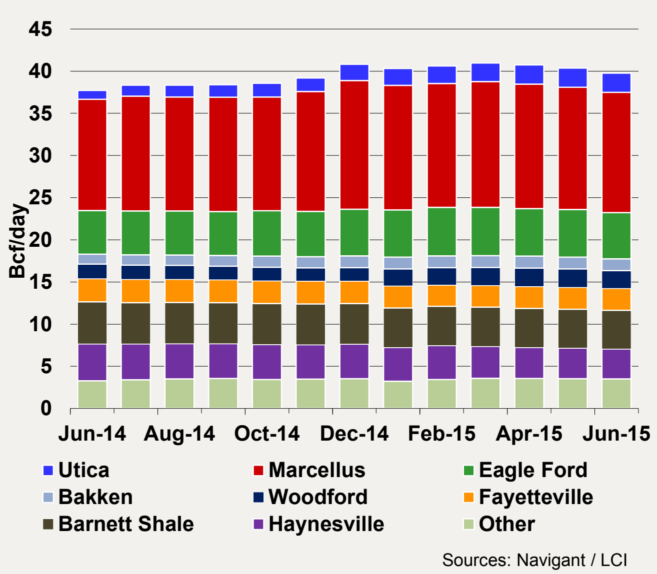
U.S. dry gas production eased off slightly from all-time high levels, at just under 74 Bcfd.

U.S. MONTHLY NATURAL GAS DEMAND



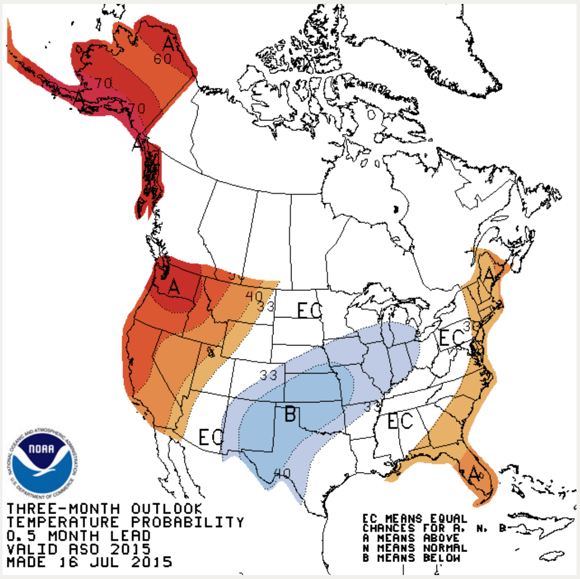
U.S. gas demand continued at all-time high levels, with demand for the month of June at 64 Bcf, about 3% greater than the prior high for the month.

U.S. WELLHEAD SHALE GAS PRODUCTION



U.S. shale gas production dropped slightly from 40.4 Bcfd to 39.8 Bcfd.

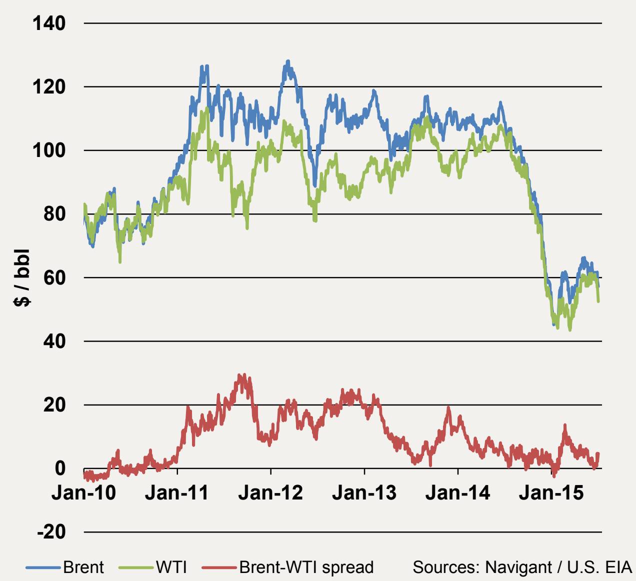
U.S. TEMPERATURE OUTLOOK



The temperature outlook is for above normal temperatures for the U.S. eastern seaboard and areas west of the Rockies. Below normal temperatures are favored eastward from the front range of the central and southern Rockies through the central U.S., and Midwest.

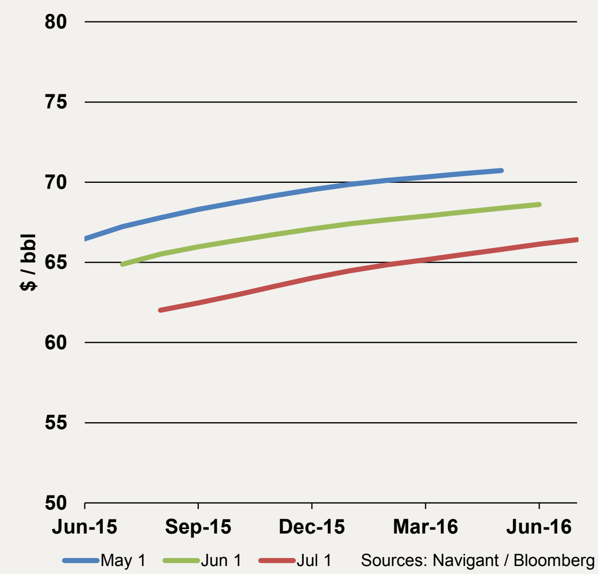
Oil Market Charts

SPOT CRUDE PRICES



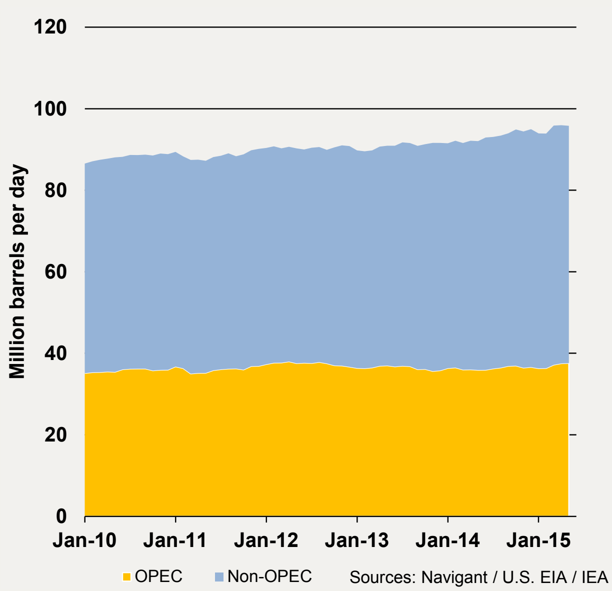
After three years of relative stability in the $90-110/bbl range, crude prices plunged 60% from June 2014 levels. Prices have since recovered slightly to average $61/bbl (Brent) and $60/bbl (WTI) in June 2015.

ICE BRENT FUTURES CURVE



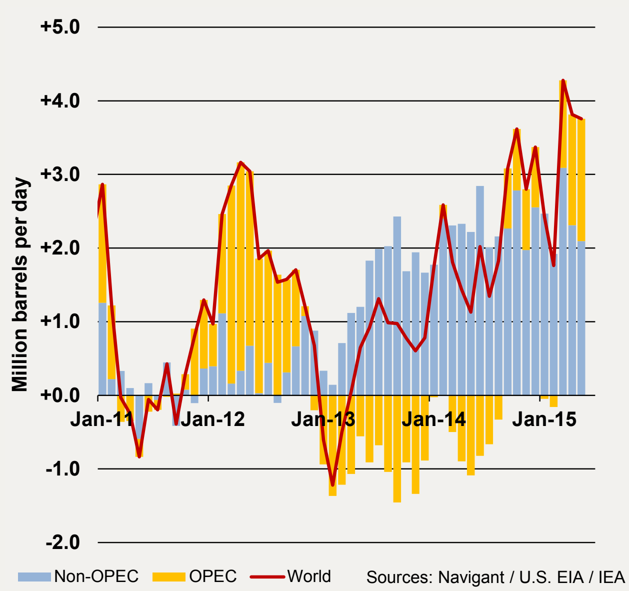
The average 12-month strip price at the beginning of July was $64/bbl, a 4% fall from the previous month.

OPEC & NON-OPEC OIL PRODUCTION



Global oil production increased from 92 million barrels per day a year ago to an estimated 95.8 million barrels per day in May 2015, of which 39% was supplied by OPEC.

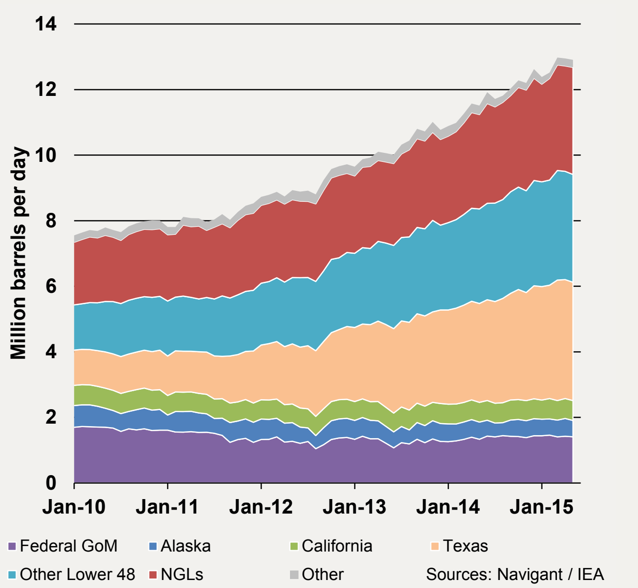
YEAR-ON-YEAR CHANGE IN OIL PRODUCTION



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

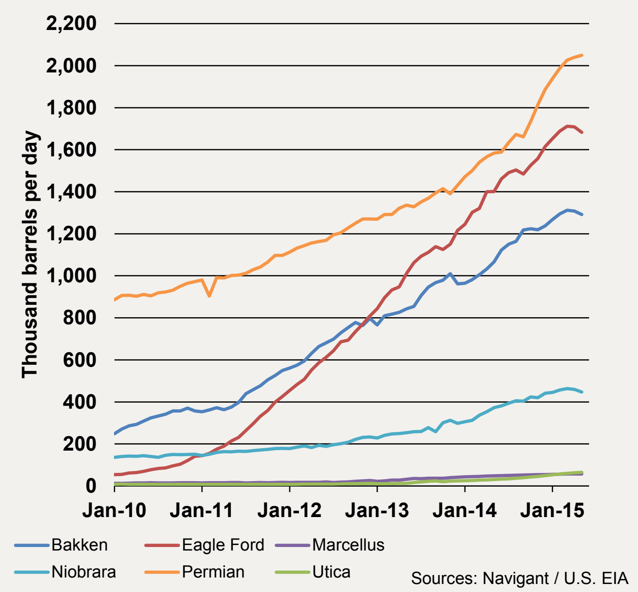
Oil Market Charts

U.S. OIL PRODUCTION



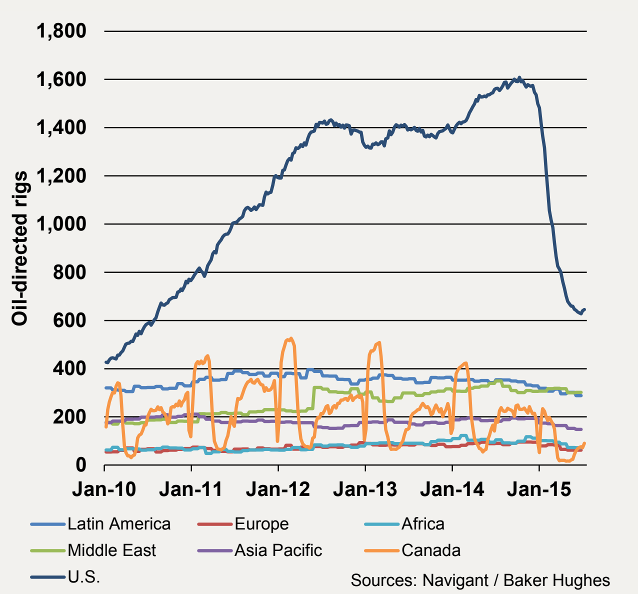
In the United States, oil production climbed by 12% over the year to an estimated 12.9 million barrels per day in May 2015. However, production has plateaued since March.

OIL PRODUCTION IN KEY U.S. REGIONS



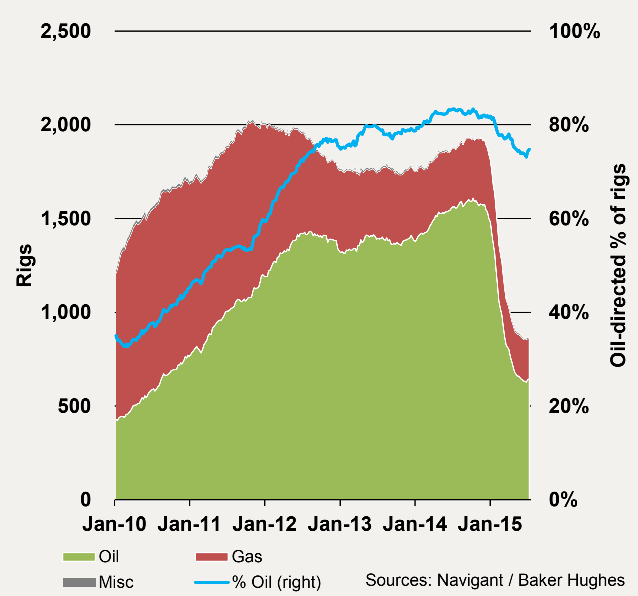
In May 2015, oil production reached an estimated 2.05 million barrels per day in the Permian (+29% YoY) but production continued to slow in Eagle Ford, Bakken and Niobrara.

OIL-DIRECTED RIG COUNT BY REGION



Rig counts collapsed in response to lower crude prices. However, the U.S. may have found a bottom in June 2015 at 628 active oil rigs, rising for two consecutive weeks since then.

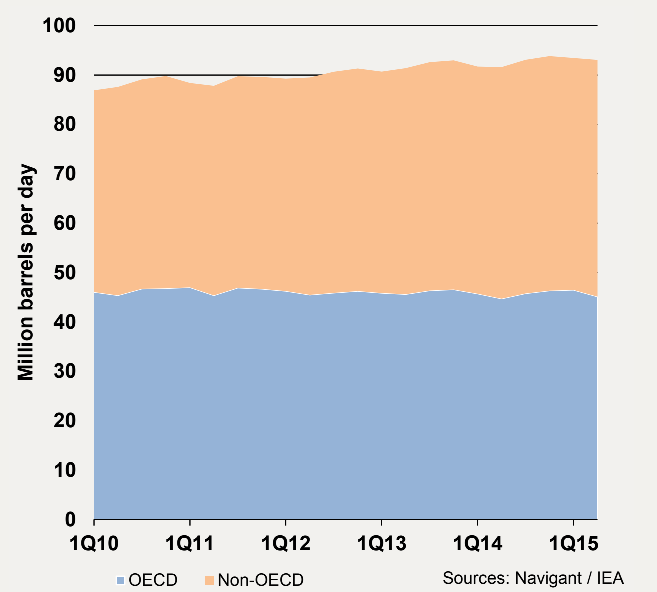
U.S. RIG COUNT



75% of U.S. rigs were oil-directed at the beginning of July.

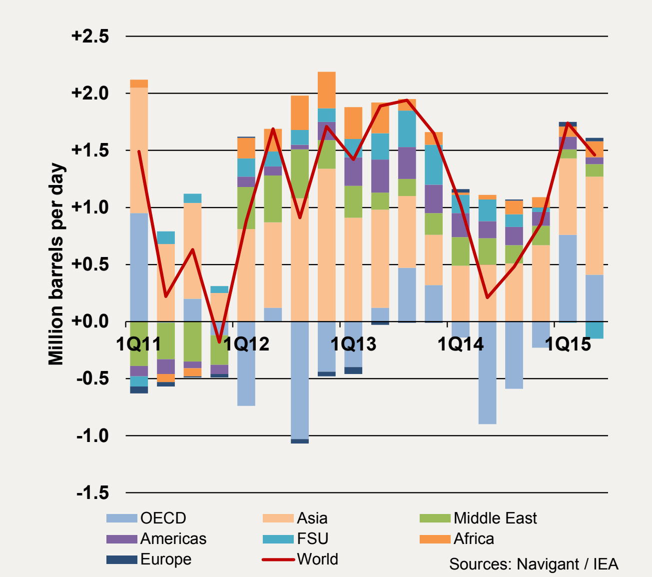
Oil Market Charts

OECD & NON-OECD OIL CONSUMPTION



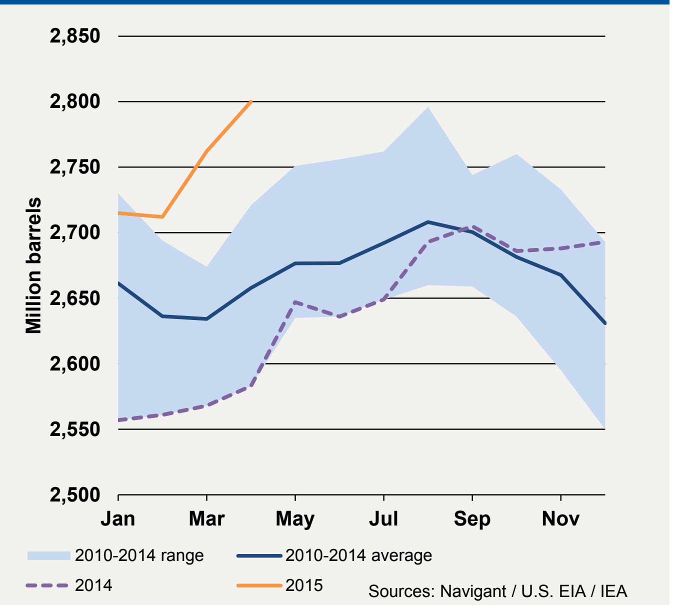
Global oil consumption increased from 91.6 million barrels per day in Q2 2014 to an estimated 93.1 million barrels per day in Q2 2015, of which 48% was consumed by OECD countries.

YEAR-ON-YEAR CHANGE IN OIL CONSUMPTION



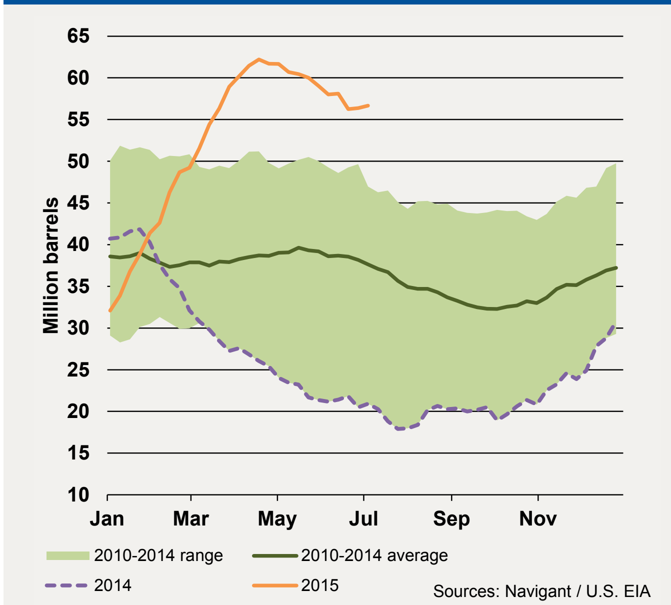
Oil demand growth in recent years has been led by non-OECD countries, particularly in Asia (e.g. China).

OECD COMMERCIAL STOCKS OF CRUDE & PRODUCTS



OECD commercial inventories reached an estimated 2,800 million barrels of crude and products in April 2015, remaining above the five-year range.

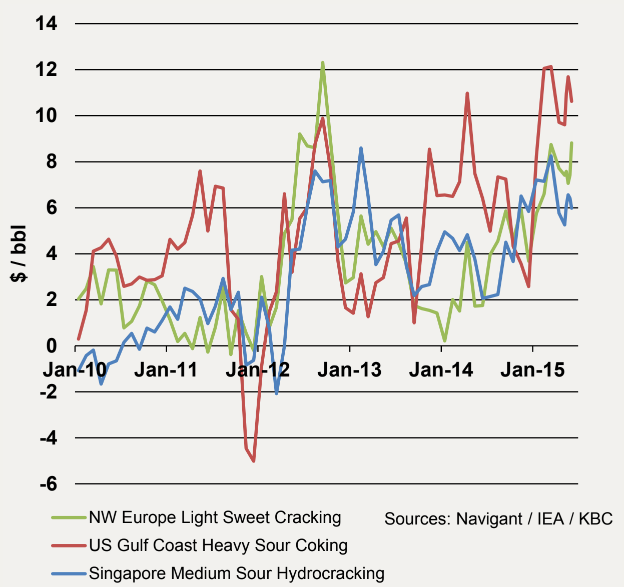
CRUDE STOCKS AT CUSHING, OKLAHOMA



Crude inventories at the Cushing hub (the delivery point of the WTI contract) totalled 56.7 million barrels at the start of July, remaining 51% above the five-year average.

Oil Market Charts

INDICATOR REFINING MARGINS



In June 2015, indicative refining margins were $8.82/bbl for NWE light sweet cracking, $10.62/bbl for USGC heavy sour coking and $5.98/bbl for Singapore medium sour hydrocracking.

EU CARBON ALLOWANCE PRICES

EU carbon allowances have recovered to €7.40/tonne from the lows of April 2013.

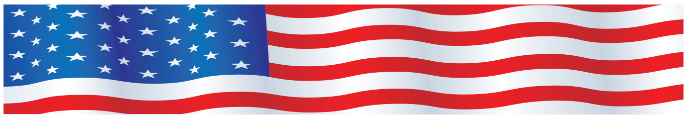
U.S. ETHANOL RIN PRICES

U.S. ethanol RINs nearly halved in value in May when the EPA announced proposals to cut quotas, but have since recovered slightly.

U.S. BIODIESEL RIN PRICES

U.S. biodiesel RINs began July at 75 cents/gallon for the 2014 vintage and 80 cents/gallon for the 2015 vintage.

Legislative and Regulatory Highlights



National

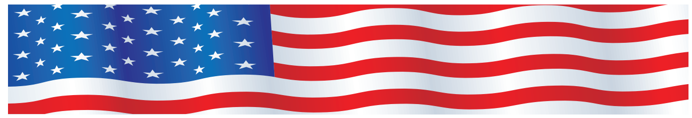
Supreme Court Rejects EPA's Final Rule on MATS

On June 29, the U.S. Supreme Court remanded the U.S. Environmental Protection Agency's Final Rule on its Mercury and Air Toxics Standards (MATS) to a lower court to ensure compliance with the required regulatory procedures for rule development. Specifically, the court ruled that the EPA did not properly incorporate a cost analysis into the first stage of the rulemaking process, where the threshold question of whether regulation is "appropriate and necessary" is decided. Some observers believe that the issue is not a serious threat MATS since the EPA's later rulemaking analysis to determine how to set the MATS standards did consider costs. An important issue that presumably will be decided by the U.S. Court of Appeals for the D.C. Circuit will be whether to let MATS stay in force while the case is on remand.

Northeast

Susquehanna River Basin Commission Releases Annual Report Showing Little to No Impacts of Shale Drilling on Water Quality

On July 1, the Susquehanna River Basin Commission released its third annual study on the water quality of the 58 streams in the basin, covering much of the eastern half of Pennsylvania. The data in the study relates to pH, temperature, dissolved oxygen, conductance, turbidity, metals, nutrients, ions and radionuclides. Based on continuous monitoring during 2010-2013, the study concludes that there has been little to no impact from shale drilling in producing counties such as Susquehanna, Bradford and Lycoming.



Gulf

Cheniere Announces Positive FID on Train 5 of Sabine Pass LNG

On June 30, Cheniere Energy Partners announced that its Board of Directors had made a positive Final Investment Decision for Train 5 at its Sabine Pass liquefaction project in Cameron Parish, Louisiana. Cheniere's decision follows the granting by the Department of Energy of Final Order 3669 on June 26 approving LNG exports to non-Free Trade Agreement nations from Trains 5 and 6. The first four liquefactions trains at Cheniere's Sabine Pass project are already under construction, with completion expected in 2016. Train 5 is expected to begin commercial operations as early as 2018.

British Columbia

NEB Approves LNG Export Application by Quicksilver Resources

On June 30, the National Energy Board issued a Letter Decision approving the application of Quicksilver Resources Canada Inc. to export natural gas in the form of LNG totaling 28,875 Bcf over the course of a 25-year term. The approved export point will be the proposed Discovery LNG project on the Campbell River, British Columbia. The NEB determined that the quantity of gas to be exported is surplus to Canadian needs.

Government of British Columbia Concludes Project Development Agreement with Pacific NorthWest LNG to Limit Regulatory Changes Affecting the Project

On July 6, the Ministry of Finance of British Columbia announced the execution of a Project Development Agreement with Pacific NorthWest LNG specifying that the tax regime and development rules to be in place over the long term with respect to the liquefaction project planned for Prince Rupert will not result in significant cost increases. The agreement calls for legislative debate and approval of appropriate terms. The government tabled a bill in support of the agreement on July 13.