Energy Observer

February 2014

Shale Shock

How the Marcellus Shale Transformed the Domestic Natural Gas Landscape and What It Means for Supply in the Years Ahead

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Over the course of just a few years, the Marcellus Shale has gone from being a promising upstart to the undisputed champion of U.S. natural gas production. The speed with which it accomplished this feat has been nothing short of astounding—growing from 2% of domestic supply in 2007 to a little less than 20% by the end of 2013—and has kept forecasters on their toes trying to keep pace with ever-improving well results and production rates that continue to climb despite a sharp pullback in rig activity.

Having examined the performance of close to 6,000 wells dating back to 2009, we've uncovered a handful of unexpected factors behind the industry's ongoing underestimation of this play. Our bottom-up analysis leads us to conclude that Marcellus natural gas production—and by extension, that for the U.S. as a whole—is unlikely to reverse course anytime soon. We forecast domestic volumes to increase by almost 3 Bcf/d cumulatively (2% per annum) through 2015, with declines in areas like the Haynesville more than offset by the 5.5 Bcf/d of cumulative growth we expect in the Marcellus.

Importantly, however, we don't believe industrywide marginal cost has been meaningfully affected by continued production growth in the Marcellus. If over the next few years demand keeps pace with supply (as we expect), natural gas prices are likely to normalize between $5 and $6 per Mcf, consistent with our industrywide marginal cost estimate of $5.40.

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Key Takeaways

The Marcellus Shale and Its Impact on U.S. Natural Gas Production

- It's taken well-informed industry observers—Morningstar included—some time to recognize how big of an impact the Marcellus Shale could have on the domestic natural gas landscape. In the words of one analyst, early predictions about the path of Marcellus production have proven "embarrassingly conservative".

- To better understand the key drivers of the Marcellus, we tracked the performance of close to 6,000 wells across Pennsylvania and West Virginia dating back to 2009. Based on our analysis, two character-istics—each somewhat unique to the Marcellus—emerged as likely factors in the industry's ongoing underestimation of this play: first, the significant improvement in median IP rates, from less than 3 MMcf/d in late 2011 to 5 MMcf/d by mid-2013; second, the ability of these wells to sustain their high rates for a period of several months beyond initial production. See Pages 6–11

- We predict the Marcellus shale will be the biggest driver of U.S. gas production over the next few years, adding 3 Bcf/d in 2014 and another 2 Bcf/d in 2015, by which time it will account for close to one fourth of domestic volumes. See Pages 11–14

- Supporting our forecast for robust Marcellus growth is the significant backlog of wells awaiting completion and tie-in, which we estimate will take between two and three years to clear. In addition, the pace of infrastructure build-out in the northeastern United States should accommodate production growth, with wet gas processing and takeaway pipeline capacity up more than 200% and 40%, respectively, through 2015. See Pages 15–17

- The Marcellus is not immune to declines, with volumes falling by an average of 65% over any given three-year period. When weighing declines against new production, however, the dominant effect—at least through 2015—will be the latter. Incredibly, only 40 or so rigs would be needed to hold Marcellus volumes flat over the next few years. See Pages 14–15

- As volumes in the Marcellus have grown, they've likely supplanted more expensive sources of gas. Regardless, we don't believe industrywide marginal cost has been meaningfully affected. See Pages 18–19

- We think there exists a handful of plausible explanations for the disconnect between our estimated marginal cost of $5.40 per Mcf and natural gas futures prices that remain far below that level over the next several years. See Page 20

U.S. Natural Gas Production Forecast Through 2015

- As part of our forecast, we analyzed seven years' worth of data contained in the EIA's newly created Drilling Productivity Report, which tracks key production drivers across the six largest unconventional gas-producing regions in the country. The DPR allows access to data points that were previously unavailable to us, and which, in our opinion, are essential to developing a well-informed production forecast. See Page 21

- Our analysis of domestic gas volumes covers the period from January 2007 to December 2015 and includes discrete projections for 12 different gas-producing regions throughout the United States, with a focus on four key variables: dry gas cuts, rig counts, production per rig, and underlying declines. See Pages 22–27

- Based on how gas volumes have historically responded to shifts in rig counts, we've argued that it would be difficult for industry-wide gas production to remain elevated in the face of a slowdown in drilling activity, as declines eventually overwhelm new production adds. The Marcellus, among other factors, has forced us to re-examine this argument, however. See Pages 22, 24, 26 and 34

- Shale gas has been the biggest driver of domestic production over the past several years, helping boost volumes by 14 Bcf/d (or 25%) from 2007-13, to 66 Bcf/d. Growth has been led by unconventional areas like the Marcellus (+9 Bcf/d), Haynesville (+4 Bcf/d), Eagle Ford (+3 Bcf/d), and Barnett and Fayetteville (+2 Bcf/d each), offset by declines in conventional and Gulf of Mexico volumes. Without the Marcellus, it's probable that domestic natural gas production would have peaked in late 2011 or early 2012. See Pages 28–33

- Going forward, we expect domestic gas growth to be far less balanced, with only the Marcellus and Eagle Ford exhibiting any meaningful uptick in volumes. We project U.S. natural gas production to increase by approximately 3 Bcf/d (or 4% cumulatively) through 2015, to 69 Bcf/d. See Pages 28–34

- With regard to our supply forecast, wild cards to keep an eye on include the emergence of the Utica Shale in Ohio, the ongoing impact of ethane rejection and the pace of processing facility build-outs, natural gas demand (which influences prices and therefore gas-directed drilling activity), and oil prices (which, if they fell to a low enough level, could reduce oil-directed drilling activity and lead to a drop-off in associated gas production). See Pages 35–36

Intersection of Supply & Demand and Investment Conclusions

- If over the next few years demand keeps pace with supply as we expect, natural gas prices should normalize between $5 and $6 per Mcf. This is something of a "sweet spot" that serves to incentivize continued gas production while also mitigating the potential for demand destruction. Volatility is likely to remain a defining characteristic of the domestic gas market going forward, however, with seasonal imbalances in supply and demand, especially, contributing to lots of ups and downs in both natural gas prices and stock prices See Pages 37–38

- There are several ways investors can take advantage of continued growth in domestic gas production. In the upstream space, we favor Ultra Petroleum (UPL), Tourmaline Oil (TOU), and Canadian Natural Resources (CNQ). Within midstream, we like two names: Spectra Energy Partners (SEP) and Energy Transfer Partners (ETP). For services, we favor Halliburton (HAL), and to slightly lesser degree Schlumberger (SLB). In utilities, if rising natural gas prices lift power prices, several firms stand to benefit, most notably Exelon (EXC), Calpine (CPN), and FirstEnergy (FE). See Pages 38–39

The Marcellus Shale and Its Impact on U.S. Natural Gas Production

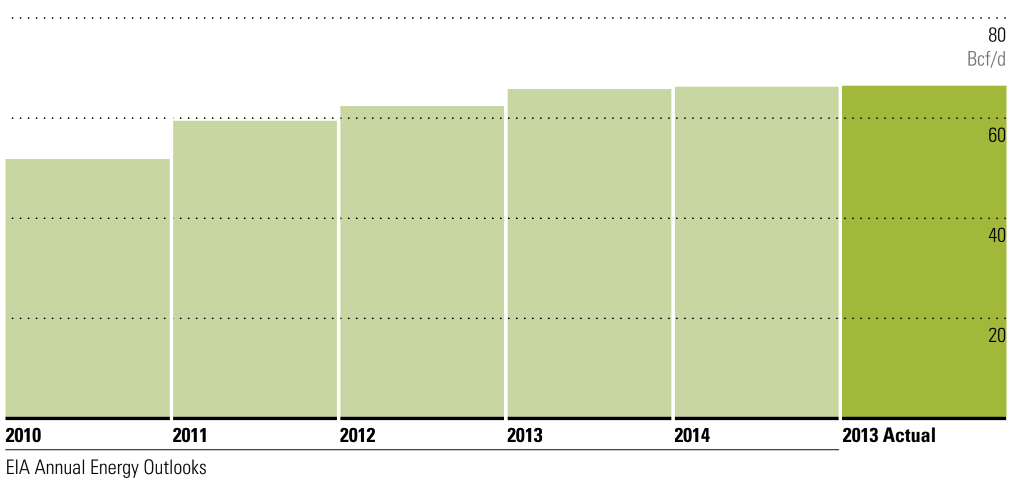
Mark P. Hanson, CFA

The Marcellus Shale: A Game-Changer for the Domestic Energy Industry (and the Bane of Forecasters Everywhere)

Since its emergence late last decade, the Marcellus Shale—the prolific gas-bearing rock formation that underlies a vast portion of the northeastern United States—has fundamentally reshaped how industry participants and observers think about the domestic natural gas complex. Over the next few years, the United States is likely to become a major exporter of natural gas, further reduce its dependence on foreign oil and gas, and once again become a cost-competitive chemicals producer, all of which were unthinkable prior to the rise of shale gas, in particular the Marcellus. It's taken well-informed industry observers—Morningstar included—some time to recognize just how impactful the Marcellus could be, in part because well results have continued to exceed expectations (in many cases even after baseline expectations had been meaningfully revised upward).

Take, for example, forecasts made by the Energy Information Administration, or EIA, over the past few years. As shown below in Exhibit 1, the EIA—arguably one of the most "in-the-know" groups regarding energy industry data collection and analysis—has consistently gotten its domestic gas forecasts wrong as part of its Annual Energy Outlooks, or AEOs. As we'll see later in this section, a big driver behind the EIA's forecast "misses" has likely been due to the Marcellus.

Exhibit 1 EIA Forecasts for 2013 U.S. Dry Natural Gas Production



Source: EIA, Morningstar Analysis

Beyond forecasting agencies, other "in the know" groups—in particular upstream firms and infrastructure operators—have also tended to underestimate (at times badly) the extent to which domestic shale gas volumes could grow. The oversupply conditions that have existed in the United States over the past few years have had a negative effect on a number of gas-weighted E&Ps, with cash flows, balance sheets, and stock prices all coming under pressure as a result of low natural gas prices. Midstream firms, meanwhile, have struggled to keep pace with the growing processing, gathering, and takeaway needs of Marcellus-levered areas such as Pennsylvania, Ohio, and West Virginia. Finally, gas importers have been forced to completely reinvent their business models given declining (and, today, nearly nonexistent) demand for liquefied natural gas.

Through a combination of efficiency and technology—and thanks to the high flow rates and relatively shallow declines of the average well in this play—upstream firms have been able to extract more and more gas from the Marcellus, even as they've pared rig counts over the past few quarters. As we'll see in the next section, the step-wise improvement in per-well production—rather than, say, a reduction in drilling days—has been the biggest driver of Marcellus production gains, and is probably the factor that has led most analysts to systematically underestimate the pace of Marcellus gas growth.

Examining Marcellus Outperformance

Efficiency improvements—including the shift toward pad drilling and 24-hour operations, as well as learning curve effects—have certainly played a role in driving Marcellus production growth, largely by increasing the number of wells able to be drilled with a given number of rigs. Drilling days per well, for example, have dropped by approximately 40%, from 23 to 14, over the past two years (although the pace of improvement has slowed as of late). Even more impressive, however, has been the improvement in production at the well level, with median flow rates steadily improving over time before a step-wise increase in the first half of 2013, likely due to the use of techniques such as reduced cluster spacing and the impact of higher levels of drilling activity in the Marcellus' more productive areas.

To see how the Marcellus has improved over time, we focus our analysis on a subset of counties within Pennsylvania, as Pennsylvania accounts for the majority of Marcellus production and because its data set relative to other states (West Virginia, in particular) is more robust. The counties that serve as the foundation for our work include Bradford, Greene, Lycoming, Susquehanna, Tioga, Washington, and Wyoming, with data sourced from the Pennsylvania Department of Environment Protection.

Exhibit 2 below shows median initial gas production, or IP, rates for wells less than 31 days old across seven counties (as well as for an "all-else" bucket), and then compares those rates with the median performance for the same set of wells in the subsequent six-month period. Our analysis highlights the following attributes of Pennsylvania Marcellus wells over the past few years:

- Median well performance (measured by IP rates) varies considerably across counties. Some of the highest IP rates are found in Greene, Lycoming, Susquehanna, and Wyoming counties. Incidentally, rates in these counties are among the best in the United States (offshore excluded).

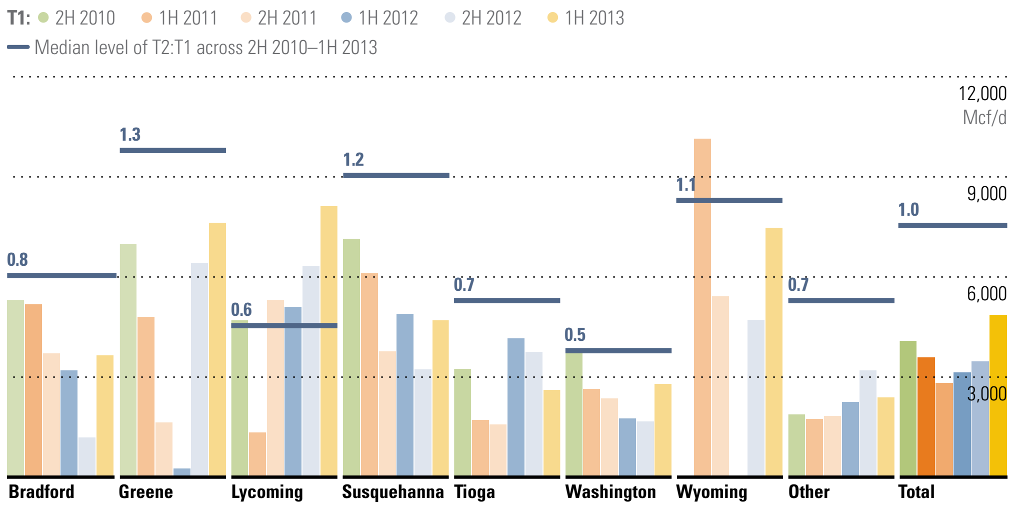
- As it does across counties, median well performance varies across time, with some counties showing improved IP rates over the past few years and some plateauing in recent periods.

- Certain counties experience meaningful production drop-offs from initial flow to the six-month mark, while others are actually able to increase flow rates over time. See Greene, Susquehanna, and Wyoming counties in Exhibit 2, for example, where daily production rates actually increase 10%–30% in the six months subsequent to initial flow. Such counterintuitive results (most shale gas wells experience steep declines over the first few months) help explain why Marcellus production has risen faster than many analysts' forecasts.

- As a group (see the "Total" column in Exhibit 2), Pennsylvania Marcellus wells have demonstrated meaningful improvement over time, going from a median IP rate of less than 3 MMcf/d in mid-2011 to around 5 MMcf/d by mid-2013, with a significant step-up in the most recent period. Impressively, these rates are for the median well, with results much higher in many instances. Equally as impressive, these wells (as a group) have been able to sustain their high rates for a period of several months beyond initial production. Again, we think this helps explain why Marcellus production has risen faster than many analysts' forecasts.

- Anecdotally, restricted chokes, increased line pressures (which can limit initial flow rates and lessen declines), the application of new technology, and targeted "core of the core" drilling have all contributed to improved well performance in the Marcellus. The impact of each of these factors is hard to disaggregate, however. In our Marcellus production forecast later in this document, we develop multiple scenarios that attempt to account for each of these factors.

Exhibit 2 PA Marcellus Well Performance for Wells < 31 Days Old Versus Performance in Subsequent Six-Month Period



Source: Morningstar Analysis

In Exhibit 3 below, we present more detail on each county in our Pennsylvania Marcellus subset. Our intent in providing this level of detail is fourfold: first, to highlight the differences in performance by county; second, to show how performance has changed for each county over time; third, to demonstrate that it's possible to quantify Marcellus performance on a granular basis (which should improve the quality of our Marcellus production forecast); and fourth, to provide confirmatory evidence that Marcellus wells, while delivering top-tier performance, are not immune to the laws of petrophysics (that is, they exhibit significant declines over long enough periods of time; moreover, these declines generally aren't getting "shallower" with each new cohort of wells brought on line).

A few points to note on Exhibit 3:

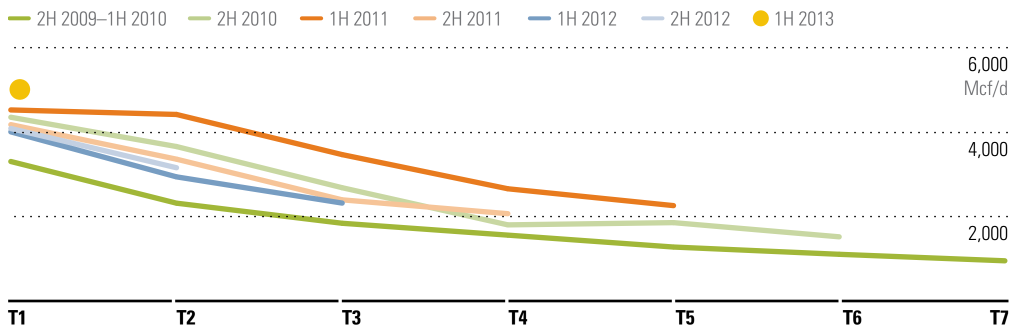
- The county-by-county charts show median well performance (measured as a daily production rate) for a series of "vintages," where each vintage is a successive six-month block of time (starting in the second half of 2009 and ending in the first half of 2013). By presenting the performance of each vintage on a time-zero basis, we're able to compare median production rates both across and within vintages (the latter of which gives a sense of what a vintage's type curve looks like).

- When completions are back-end weighted, the median daily production figure for the first period of a given vintage will be biased upward (we can think of this figure as the vintage's IP rate, where initial production is measured over a six-month time period instead of the industry-standard 30 days). For most counties below, however, the mix of "older" and "younger" wells has remained relatively constant across vintages, which increases the likelihood that performance improvements (when they appear) are the result of changes to the underlying parameters of the median well, rather than being the function of a "younger" data set.

Exhibit 3 Median Per-Well Gas Production for Key Counties in Pennsylvania, 2H09–1H13

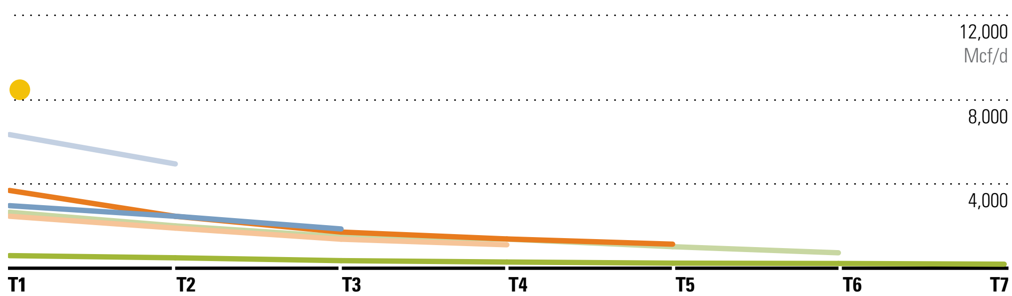
Bradford County

- Prior to 1H13, no clear pattern of improvement over time
- Based on our analysis, improvement in 1H13 most likely attributable to 1H13 sample being "younger"



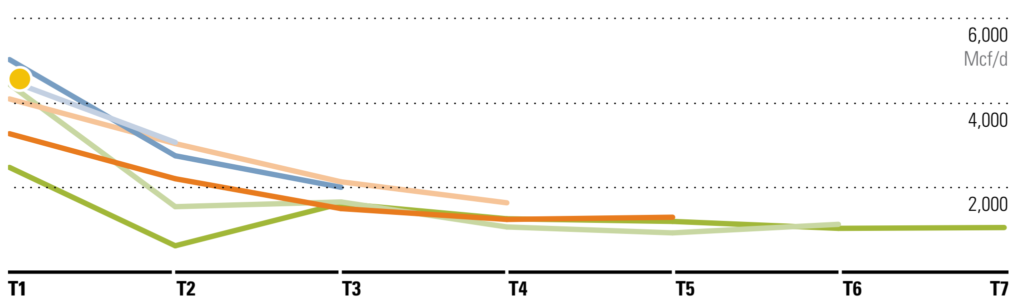
Greene County

- Impressive performance improvement over time; represents the biggest step change in median initial flow rates of any county in PA over the past two vintages
- Improvement likely the result of firms like Range Resources and others using reduced cluster spacing and related techniques



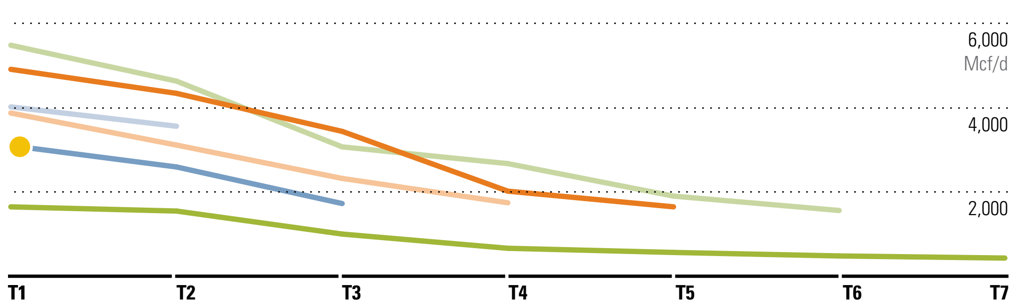
Lycoming County

- Performance improvement may have peaked
- Higher 30-day IP rates (see Exhibit 2) haven't necessarily led to stronger 6-month performance, likely due to rapid declines



Susquehanna County

- Initial-period flow rates among the best in PA, although improvements may have peaked (this is further substantiated in Exhibit 2)
- Production curves appear to be getting "flatter" for more recent vintages, however

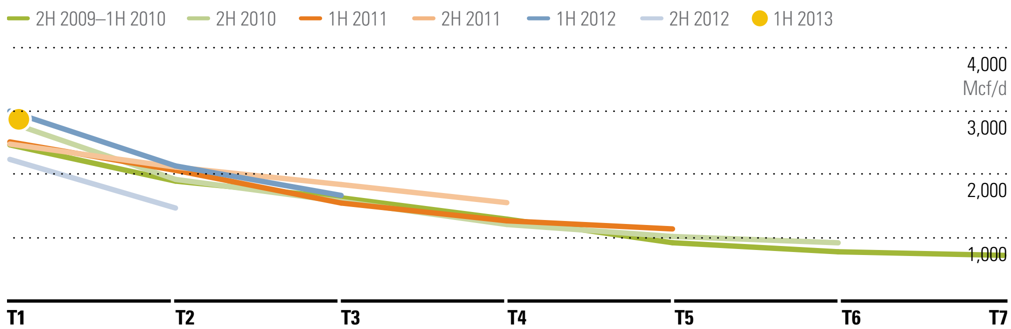


Source: Morningstar Analysis

Exhibit 3 (continued) Median Per-Well Gas Production for Key Counties in Pennsylvania, 2H09–1H13

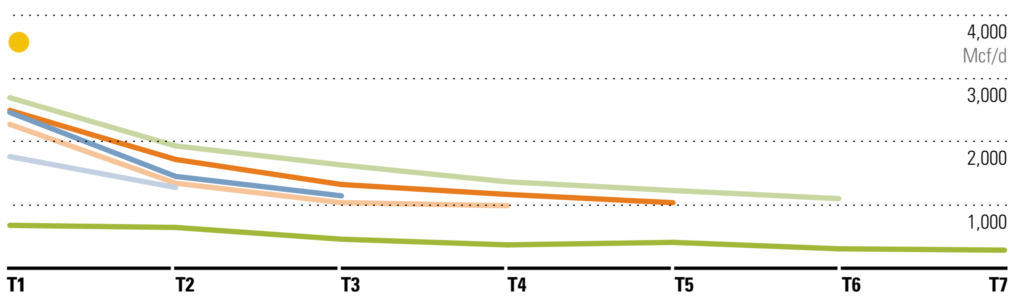
Tioga County

- Performance improvement may have peaked (this is further substantiated in Exhibit 2)



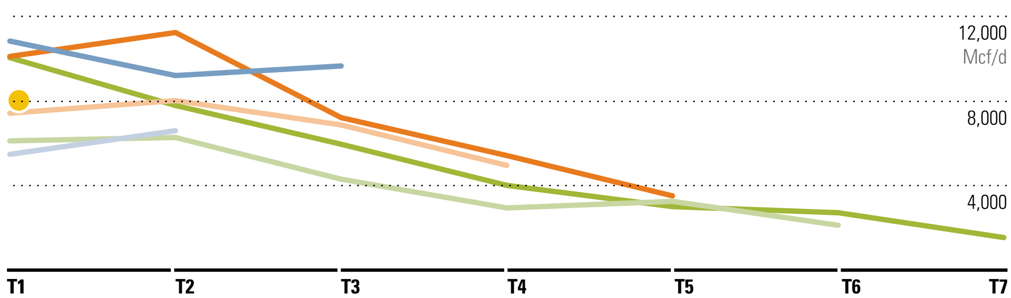
Washington County

- Meaningful step change in median initial flow rates from 2H12 to 1H13; prior to this, no clear pattern of improvement, however
- Based on our analysis, improvement in 1H13 most likely attributable to 1H13 sample being "younger", as well as the result of firms like Range Resources and others using reduced cluster spacing and related techniques



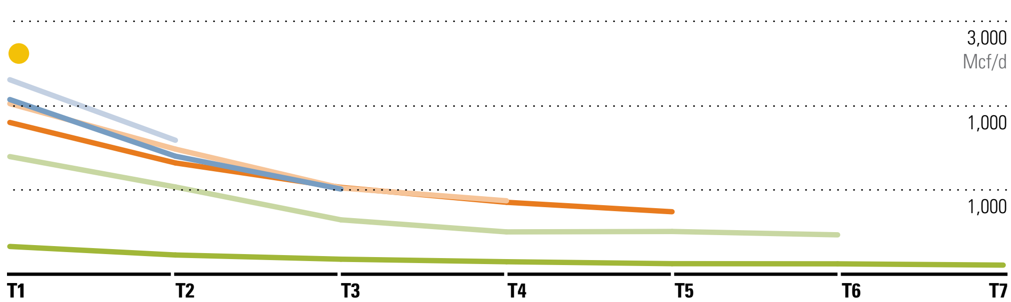
Wyoming County

- One of the emerging stars in PA, with some of the best performing wells in the state (measured by median initial-period flow rates)
- Jury still out on what type curves look like and whether improvements have peaked, given limited sample size of each vintage and limited number of production days for wells brought on line in 1H13



Other Counties

- Generally steady performance improvement over time, although median flow rates below some of the better counties in PA

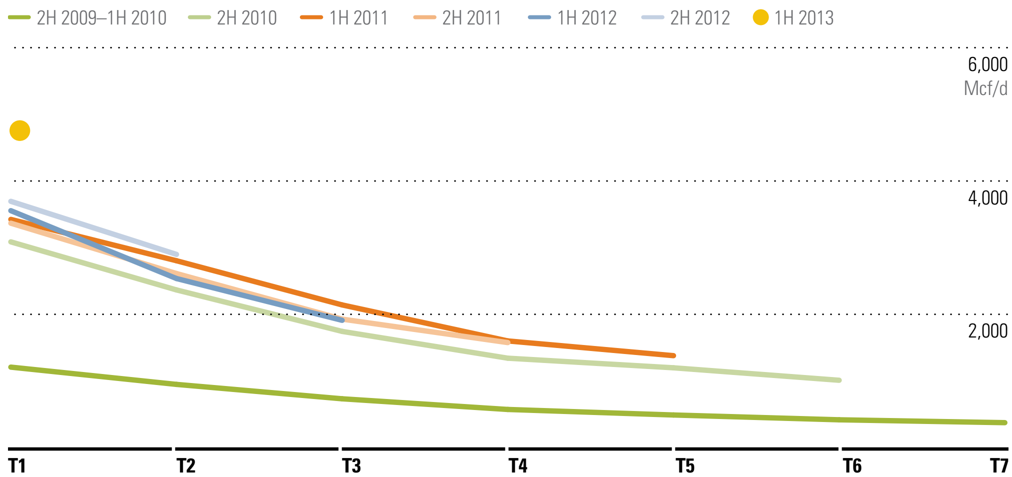


Source: Morningstar Analysis

Exhibit 3 (Summary) Median Per-Well Gas Production for Key Counties in Pennsylvania, 2H09–1H13

All Counties

- As a group, PA Marcellus wells have demonstrated steady improvement over time; Greene and Washington counties, among others, helped drive the meaningful increase in 1H13 flow rates
- To revisit some of our commentary from above, the step-wise change in 1H13 flow rates—coupled with shallower declines relative to areas like the Haynesville shale—has been the biggest driver behind Marcellus and Lower 48 U.S. natural gas production over the past several quarters, and helps explain why Marcellus production has risen faster than many analysts' predictions



Source: Morningstar Analysis

Morningstar's Forecast of Marcellus Natural Gas Production

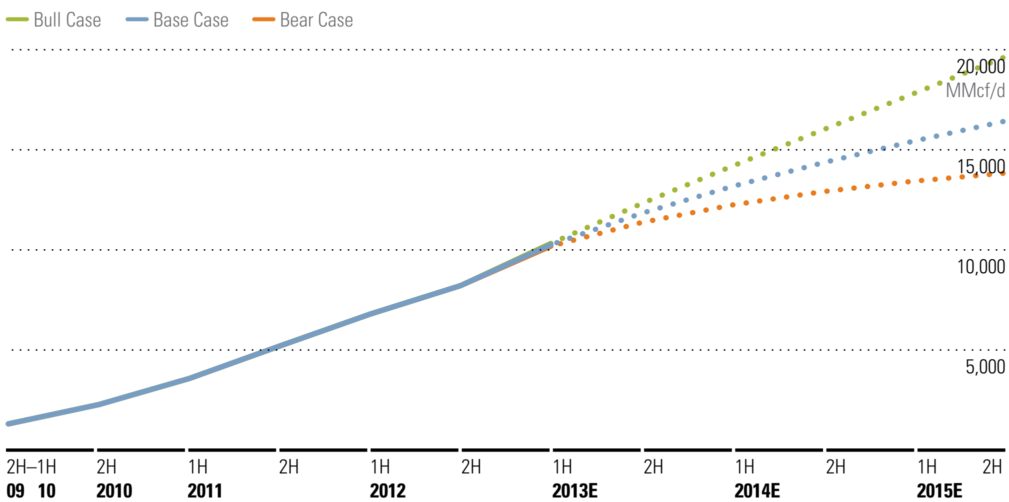
For a variety of reasons—including the high initial production rates and relatively shallow declines of wells, the ongoing application of new technologies, and a continued focus on more productive areas of the play—we don't believe Marcellus natural gas production will reverse course anytime soon. In fact, we estimate the Marcellus shale will be the biggest driver of U.S. dry gas production over the next few years, adding 3 Bcf/d in 2014 and another 2 Bcf/d in 2015, by which time it will account for close to one fourth of total domestic volumes. In short, the growth of the Marcellus over the next several years is likely to be nothing short of astounding.

Our forecast rests on our analysis of data from the states of Pennsylvania and West Virginia. In particular, we've tracked the performance of close to 4,500 wells in Pennsylvania and more than 1,000 wells in West Virginia dating back to 2009, analyzing parameters such as IP rates, decline rates, drilling and completion activity, and sweet spot migration, in order to better understand the underlying performance drivers of the Marcellus. As a result—with the caveat that forecasting any system as complex as the Marcellus is inherently difficult—we believe our projections are among the most analytically rigorous available, and that our framework (described below) is a reasonable one with which to assess industry trends and explore probable future outcomes.

Exhibit 4 below presents our forecast for Marcellus gas production through 2015. Our projections are done on a county-by-county basis, over six-month blocks of time, in keeping with reporting conventions from the state of Pennsylvania. We focus on well performance (IP rates and terminal decline rates) and completion activity as the key variables in our forecast. We then develop three scenarios—base, bull, and bear—for each of our key variables.

Looking across our three scenarios, note that we expect somewhere between 14 Bcf/d and 20 Bcf/d of gross natural production in the Marcellus by the end of 2015, depending on the path that our key variables take.[1] For example, in our bull case we assume 900 wells are completed across Pennsylvania and West Virginia in the first six-month block of our forecast, growing to 1,000 by year-end 2015, with modest sequential improvements in county-by-county initial-period production rates going forward. In our bear case, meanwhile, we assume 750 wells are completed in the first six-month block of our forecast, declining to 675 by year-end 2015, with modest deterioration in county-by-county initial-period production rates going forward. Our base case essentially holds steady the parameters of the most recent historical period for which we have data (825 wells completed during each six-month block[2], with no change to initial-period production rates throughout our forecast).

Exhibit 4 Marcellus Gross Natural Gas Production Scenarios, 2009–15E[3]



Source: Morningstar Analysis

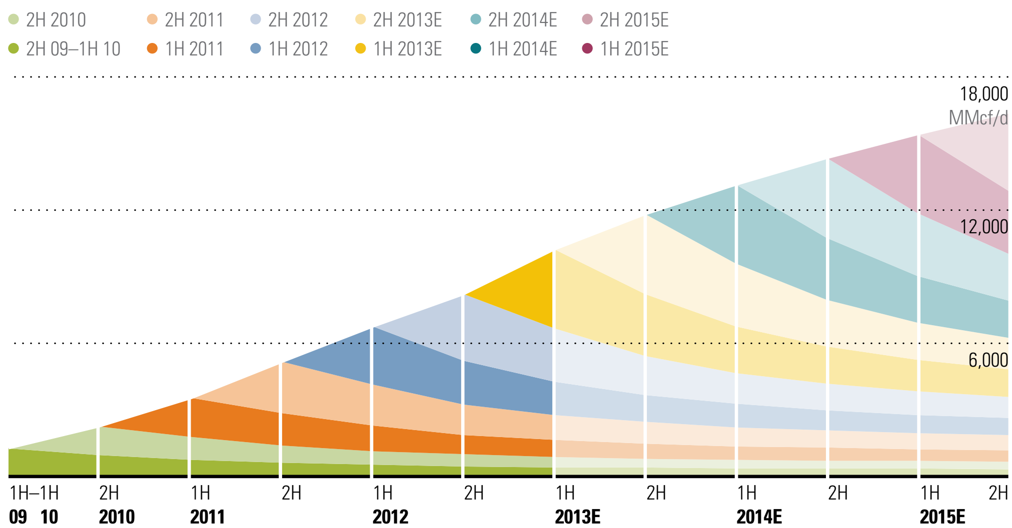
1 While our projections span a wide range of potential outcomes for a forecast that looks only two years out, we nevertheless believe they represent a reasonable cone of possibilities, given the speed with which the Marcellus has improved over the past few years and the high degree of uncertainty regarding the extent of improvement (or deterioration) that could take place going forward. With so much inherent uncertainty, projections for Marcellus production beyond the next few years are essentially meaningless, in our opinion. We intend to revisit our assumptions as additional data points from the states of Pennsylvania and West Virginia are released.

2 This compares with an average completion rate of 820 wells per six-month block from the first half of 2012 through the first half of 2013.

3 Natural gas production is typically reported as either "gross" (full well-stream volume, including NGLs and nonhydrocarbon gases, and before any volume losses due to venting, flaring, or field consumption) or "dry" (well-stream volume after NGLs and nonhydrocarbon gases have been removed, and after any volume losses due to venting, flaring, or field consumption). We estimate Marcellus dry gas production as 90% of gross volumes. More on Marcellus dry gas production starts on Page 28.

Exhibit 5 below presents our Marcellus production forecast in a slightly different manner, showing how each vintage performs over time in our base case scenario. Exhibit 5 reinforces our earlier point that the Marcellus is not immune to declining volumes over time, with average six-month and three-year cumulative declines of approximately 20% and 65%, respectively, measured on an intra-vintage basis. When weighing declining volumes against production additions, however, the dominant effect—at least over the next few years—will be the latter, with approximately 3.5 Bcf/d of gross volumes added versus declines of between 1.5 Bcf/d and 2.5 Bcf/d over each six-month period. (More on this in Exhibit 8.)

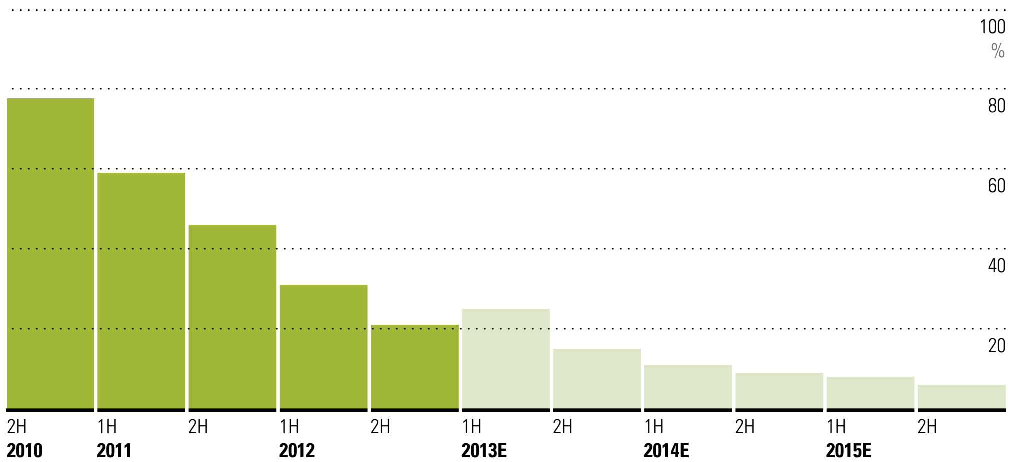
Exhibit 5 Marcellus Gross Natural Gas Production by Vintage (Base Case Scenario), 2009–15E



Source: Morningstar Analysis (Historical raw data from Offices of Oil and Gas, Pennsylvania and West Virginia)

Not surprisingly, as the "base" of Marcellus production becomes increasingly large, growth rates are likely to slow down meaningfully (despite continued additions of 3.5 Bcf/d per six-month block). Exhibit 6 below shows our forecast for sequential Marcellus growth rates, which trend from 15% in the second half of 2013 to the mid-single digits by the end of 2015. Given the sheer size of the Marcellus, however, even low-single-digit growth rates beyond our forecast period would imply annual volume increases of 1 Bcf/d or more.

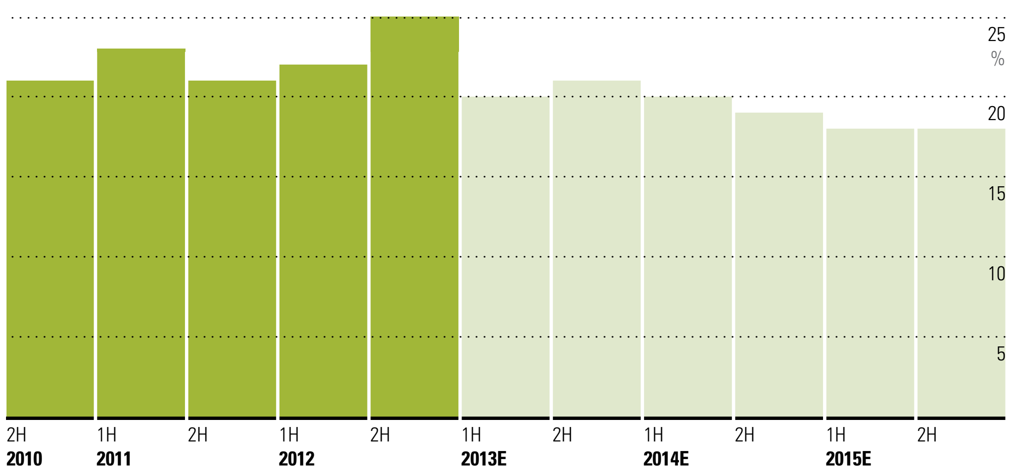
Exhibit 6 Sequential Growth Rates of Marcellus Gross Natural Gas Production (Base Case Scenario), 2010–15E



Source: Morningstar Analysis

Similar to the growth rates in Exhibit 6 above, Marcellus decline rates will likely fall as the base of production "matures," going from 20% to 18% or so over the next few years under our base case scenario.

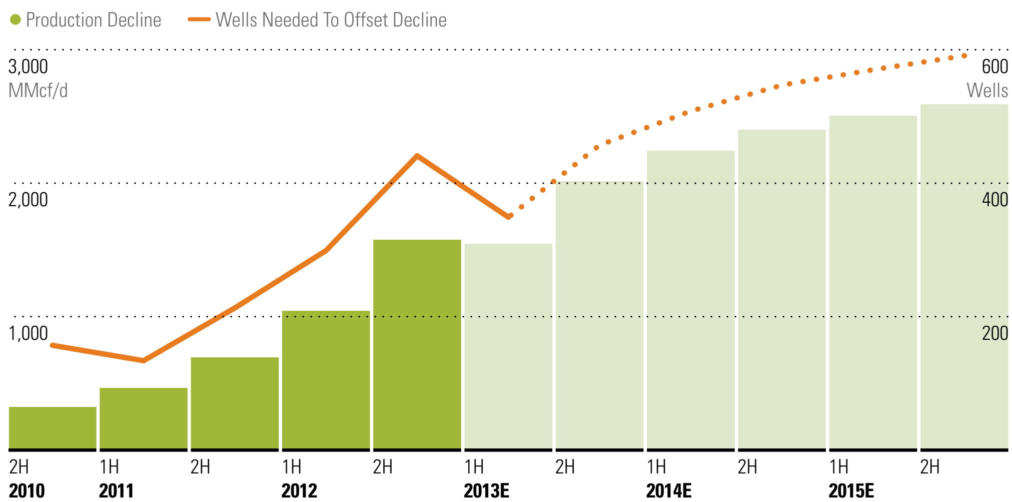
Exhibit 7 Marcellus Gross Natural Gas Decline Rates (Base Case Scenario), 2010–15E



Source: Morningstar Analysis

Even as rates fall, however, the increasing size of the Marcellus means that absolute volume declines will continue to grow over each six-month block of our forecast, from 1.5 Bcf/d in the first half of 2013 to more than 2.5 Bcf/d by the second half of 2015 (see Exhibit 8 below). Under our base case scenario, this implies that approximately 1,000 wells will need to be brought on line each year to hold gas production flat. Viewed another way, at roughly 15 days per well, only 40 or so rigs would be needed to hold Marcellus volumes flat over the next few years. With approximately 1,600 wells being completed each year of our forecast, however, volume additions from new wells should be more than sufficient to compensate for underlying production declines.

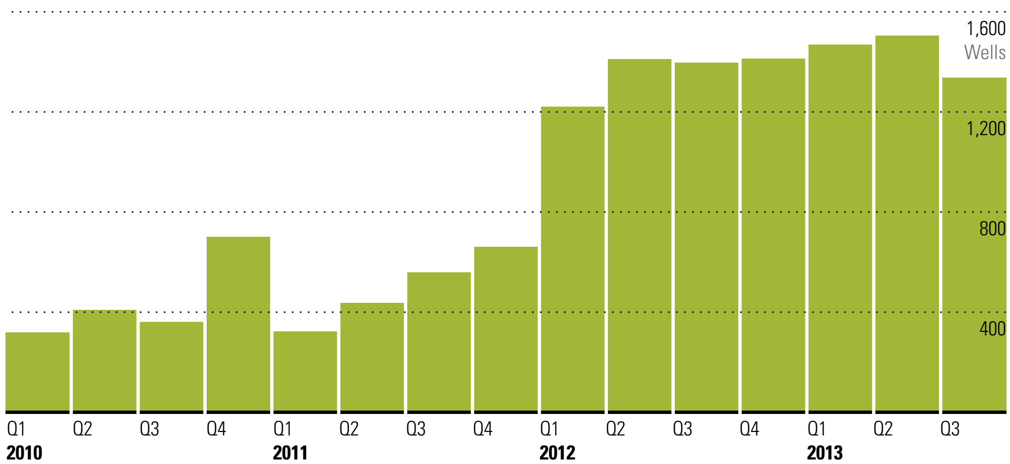
Exhibit 8 Marcellus Gross Natural Gas Decline Volumes (Base Case Scenario), 2010–15E



Source: Morningstar Analysis

Supporting our forecast for robust Marcellus production growth in the years ahead is the significant backlog of wells awaiting completion and infrastructure tie-in across Pennsylvania and West Virginia. This backlog has grown even as drilling activity has slowed (thanks to volume increases that have overwhelmed existing pipelines) and currently stands at around 1,300 wells, or roughly nine months of inventory. As a result, Marcellus producers could effectively shut down drilling for the next year and still deliver meaningful production growth, just based on wells that have already been drilled. Including the impact of ongoing drilling activity (100-plus wells per month across the play), we estimate the current Marcellus backlog will take between two and three years to clear.

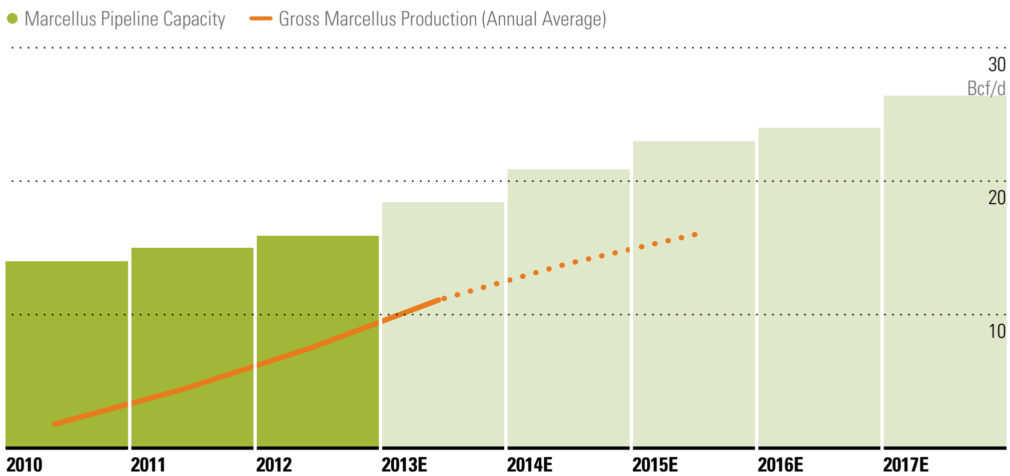
Exhibit 9 Marcellus Wells Awaiting Completion/Tie-In, 2010–13



Source: Company Reports, Morningstar Analysis

Also supporting our Marcellus forecast is that the pace of infrastructure build-out in the northeastern United States should accommodate production growth in the years ahead (notwithstanding the potential for intermittent capacity issues and resulting high basis differentials, especially during periods of seasonally-high demand). Wet gas processing capacity should increase more than threefold from 2012 to 2015, for example, while takeaway pipeline capacity will increase by more than 40% over the same time period. Beyond 2015, proposed infrastructure additions provide some insight into how midstream operators are thinking about Marcellus growth over the longer term. One other consideration: high line pressures have constrained gas production in certain areas of the Marcellus over the past few quarters; once alleviated, however, the reduction in line pressure can lead to an increase in volumes (all else equal) as older, less pressured wells begin to once again flow. It is difficult to quantify the potential impact of line pressure reduction as infrastructure continues to be built out, but it nevertheless remains a factor to watch, and could lead to Marcellus outperformance relative to our forecast.

Exhibit 10 Marcellus Pipeline Capacity Versus Morningstar Gross Natural Gas Production Forecast, 2010–17E



Source: EIA, Bentek, Company Reports, Morningstar Analysis

When Is the Marcellus Likely to Peak?

The short answer: not any time soon.

The first factor to consider is the extent of gas resource that has yet to be produced. Depending on the source, there exist somewhere between 30 and 75 years of Marcellus resource potential at current production rates. Of course, not all this gas is necessarily low-cost (more on this shortly). Nevertheless, there is a staggering amount of natural gas yet to be extracted from the prolific Marcellus over the coming decades, should demand warrant (and we believe it will).[4]

In addition to top-down resource estimates, we'd also point to drilling inventory figures from some of the most prominent, lowest-cost, and fastest-growing Marcellus players, including Cabot Oil & Gas, Range Resources, Chesapeake Energy, EQT Corporation, and Antero Resources. Each of these firms has identified between 10 and 30 years of drilling locations across the Marcellus, which should fuel several more years of production growth at relatively low cost.

Finally, there's the question of what formations such as the Upper Devonian and Utica (which sandwich the Marcellus across a broad swath of the northeastern United States) could add to production from this region over time. To-date most E&Ps in Pennsylvania and West Virginia have focused on the Marcellus formation, although early results from additional horizons have been promising.

4 See our Aug. 20, 2013 Energy Observer, Low-Cost Natural Gas, the Coming Boom in Demand, and Who in the U.S. is Set to Benefit, for more information.

As we noted earlier, as the Marcellus continues to ramp up, it's likely to experience a slowdown in growth rates. Even as growth slows, however, incremental volume additions will be meaningful, given the sheer size of the play. If we simplistically grow our 2015 base case Marcellus forecast at between 1% and 5% through 2020 (a reasonable range, in our opinion, given our expectation for approximately 15% annual growth in 2015)—and if the trend of new production additions dominating underlying declines continues to hold—Marcellus volumes will increase to between 17 Bcf/d and 20 Bcf/d by the end of this decade. As we stated above, it's unlikely the Marcellus peaks anytime soon.

How Does the Rise of the Marcellus Impact the Marginal Cost of Domestic Natural Gas Production?

Natural gas production in the Marcellus is among the lowest-cost in the United States, with breakeven levels in certain liquids-rich areas below $1 per thousand cubic feet (Mcf). As volumes in the Marcellus (and in other low-cost areas, such as the Eagle Ford and Bakken, where associated gas is essentially "free") have grown, they've likely supplanted higher-cost sources of gas on the far right side of the domestic supply stack. Regardless, we don't believe industrywide marginal cost has been meaningfully affected, for three reasons.

- First, the Marcellus is far from homogeneous, as demonstrated in Exhibits 2 and 3 above and Exhibit 11 below. Collectively, these exhibits indicate a wide range of well performance and breakeven levels across the areas in Pennsylvania and West Virginia where activity has been focused. Accordingly, not all Marcellus growth has necessarily been low-cost, with "marginal" counties like Tioga (Pa.) requiring $5 or more per Mcf to break even (see Exhibit 11). While we expect almost all incremental production to come from the most profitable areas of the Marcellus over the next few years, wells will continue to be brought on line in less economic counties (albeit at a slower pace than historically), implying a "marginal Marcellus cost" of somewhere between $4 and $5 per Mcf.

- Second, as domestic production has grown, so has domestic demand, and with the Marcellus still representing less than 20% of U.S. production (see Exhibit 18 on Page 30), higher-cost gas sources have been (and will be, in the coming years) required to meet consumption needs. These higher-cost areas include the Barnett and Haynesville Shales, where breakeven levels range from $5 to $6 per Mcf.

- Third, as we've demonstrated elsewhere,[5] the marginal cost to produce natural gas in the United States has ranged between $5 and $7 per Mcf over the past decade or so, with fluctuations largely driven by oilfield services pricing. Alongside our statistically-derived industrywide

5 See our Dec. 7, 2012 Oil & Gas Insights, The Shale Evolution—Examining Claims of a New Normal in the U.S. Natural Gas Market (pages 29–36), for more information.

marginal cost estimate of $5.40 per Mcf and our expectations for continued gas-directed activity in areas such as the Barnett and Haynesville, it's unlikely that the marginal cost to produce natural gas in the United States will meaningfully deviate from its historical range in the years ahead.[6]

Exhibit 11 Marcellus Breakeven Prices

State/County	Breakeven $/Mcf
Pennsylvania	
Wyoming	3.00
Susquehanna	3.08
Allegheny	3.39
Washington	3.41
Bradford	3.71
Greene	3.87
Lycoming	3.92
Butler	4.18
Westmoreland	4.64
Clinton	4.84
Fayette	5.13
Tioga	5.33
Armstrong	5.44
Jefferson	5.64
Indiana	6.47
Centre	7.20
Clearfield	7.87
Elk	7.92
Potter	8.24
McKean	9.42
West Virginia	
Marshall	3.32
Wetzel	3.48
Harrison	4.39
Doddridge	4.46
Marion	5.17
Taylor	7.44
Upshur	7.67

Source: ARC January 2014 Investor Presentation (ITG April 2013, DI Desktop, geoScout)

6 We intend to update our marginal cost analysis in the coming months, once all the firms included in our statistical survey file their Supplemental Oil & Gas Disclosures with the SEC.

One question that begs an answer: How do we explain the disconnect between what the futures market is implying about prices over the next several years and our estimated marginal cost of production? Given our belief that the marginal cost to produce natural gas in the U.S. is still above $5 per Mcf; the strong inverse relationship between relative storage levels and the ratio of price/marginal cost (when the market is undersupplied, price tends to be above marginal cost, and vice versa); current storage conditions indicating a meaningfully undersupplied market; and natural gas futures prices that don't rise above $5 for several more years, here are a few thoughts:

- The natural gas futures market has always been a less-than-perfect indicator of the price levels that ultimately prevail at a given point in time;

- The inverse relationship between relative storage levels and the ratio of price-to-marginal cost, while strong, is not perfectly correlated;

- "Marginal cost" is something of a nebulous concept, and with no real consensus on what the marginal cost of domestic gas production is, we suspect E&P drilling activity more often than not serves as the industry's "cost discovery" mechanism (and there can be a meaningful lag between E&P activity and the actual reporting of such activity);

- Upstream firms could be reluctant to hedge at current levels, believing natural gas prices will go up more than the futures market implies. Alternatively, counter-parties to upstream firms' hedges could be worried about a supply glut if prices remain above $5 per Mcf for an extended period of time, and therefore might be reluctant to lock in any purchases above current strip prices.

U.S. Natural Gas Production Forecast Through 2015

Mark P. Hanson, CFA

EIA's Drilling Productivity Report: The Starting Point for a Better Natural Gas Production Forecast

The task of forecasting natural gas volumes is a complex undertaking, requiring us to analyze how key variables such as well productivity, drilling efficiency, and underlying declines might change over time across the dozen or so major gas-producing areas in the United States. Our job is more tractable, however, by incorporating data from the EIA's newly-created Drilling Productivity Report, or DPR, which tracks on a monthly basis key production drivers across the six largest unconventional gas-producing regions in the country.[7]

The DPR is a useful addition to many analysts' toolkits (Morningstar included). It provides information in a much more timely fashion than many other EIA surveys of the oil and gas industry. It also allows access to data points (specifically, new-well production per rig and legacy volumes) that were previously unavailable to us—and which, in our opinion, are essential to developing a well-informed production forecast. Another useful element of the DPR: It disregards the distinction between oil- and gas-directed rig activity and instead focuses on oil and gas production as an integrated process.[8] Doing so allows the DPR to capture gas production from all rigs and wells, regardless of their classification as "oil" or "gas."

In short, the EIA's Drilling Productivity Report has given us the data to be able to develop a more robust—and we hope more accurate—natural gas production forecast.

7 The EIA introduced the DPR in October 2013 to deliver greater insight into unconventional oil and gas production, with a focus on six areas: the Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, and Permian. Combined, these areas represent close to half the country's domestic gas volumes and almost all of its incremental gas growth. The DPR data series goes back to January 2007, and offers informationon rig counts, oil and gas production (including both new and legacy volumes), and rig productivity, which measures the combined impact of new-well productivity and drilling efficiency.

Note, however, that the DPR does not actually provide any projections beyond month-ahead figures for each of the six areas on which it focuses, which leaves to us the task of forecasting both longer-term trends in these areas as well as production figures for the 50% of domestic volumes not covered by the DPR. Other shortcomings include the fact that the DPR conflates improvements in new-well production and drilling efficiency by measuring new-well production per rig. It also reports declines in such a way as to render comparison of production trends across vintages (say, wells drilled in the first half of 2011 versus those drilled in the first half of 2012) next to impossible, and it is compelled to estimate the timing of well completions, which is a crucial element in the analysis of production drivers but is not readily accessible.

Morningstar's Approach to Forecasting U.S. Natural Gas Production

As the basis for our domestic production forecast, we use the Marcellus projections we developed in the previous section as well as the significant amount of analysis we've done on the seven years of available DPR data. We also incorporate additional data points from Baker Hughes, RigData, various state regulatory bodies, and the EIA, among other sources. Our analysis covers the period from January 2007 to December 2015 and includes discrete projections for 12 different gas-producing regions throughout the United States.[9] We use the following approach to derive each region's forecast (except of course for the Marcellus, which, as stated above, we developed earlier in this document).

1. **Dry Gas Cuts**

   We estimate the percentage of gross natural gas production in each region that is ultimately sold as dry gas.

2. **Rig Counts**

   We project monthly rig counts for each region ex-Alaska and ex-Federal GOM, in most cases by continuing recent historical trends. Note that we don't make any distinction between oil- and gas-directed rigs in our forecast. (See Exhibit 12 on Page 24)

3. **Per-Rig Production, DPR Areas**

   For areas within the scope of the DPR (specifically the Eagle Ford, Bakken, Haynesville, Niobrara, and Permian), we forecast drilling days and gross natural gas production rates for each new well. Putting together rig counts and drilling days allows us to calculate well counts; putting together well counts, rig counts, and new-well production, meanwhile, allows us to calculate new-well production per rig (one of the key measures highlighted in the DPR). Note that we assume a six-month lag between drilling and initial production for each new well. (See Exhibits 13 and 14 on pages 25 and 26, respectively)

8 We formerly approximated natural gas production trends by looking solely at gas-directed rig activity. This top-down forecasting method has become less useful over time for three reasons. First, the combination of improved drilling efficiency and per-well productivity in areas such as the Marcellus has resulted in an unprecedented amount of gas being brought on line from a relatively small number of rigs, which means that even as gas-directed rig counts have dropped, we haven't seen a corresponding reduction in natural gas volumes. In fact, just the opposite has occurred, and is likely to continue occurring in the years ahead. Second, the classification of rigs as oil- or gas-directed is largely at the whim of upstream operators, and can change from day to day, which introduces the potential for error into any method that only focuses on one type of rig. Third, while associated gas from oil-rich areas such as the Bakken and Eagle Ford is unlikely to ever be as meaningful of a contributor to domestic supply as, say, the Marcellus, the rate of gas growth—especially in the Eagle Ford—has led us to conclude that our previous forecasting approach was insufficient for capturing the extent of production contribution from regions where oil is the primary target.

9 Marcellus, Eagle Ford, Bakken, Haynesville, Niobrara, Permian, Barnett, Fayetteville, Oklahoma, Alaska, Federal Gulf of Mexico (GOM), and Other.

4. **Per-Rig Production, Non-DPR Areas**

   For most areas outside the scope of the DPR (specifically the Barnett, Fayetteville, Oklahoma, and Other regions), we forecast gross gas production per rig by continuing recent historical trends. For Alaska and the Federal GOM, we forecast gross gas production (rather than production per rig) by continuing recent historical trends.[10]

5. **Decline Rates**

   For areas within the scope of the DPR, we calculate historical natural gas production declines and then forecast these rates on a monthly basis, for the most part by continuing recent historical trends. For areas not covered by the DPR, our per-rig production (and in the case of Alaska and Federal GOM, production) figures implicitly capture base decline rates.[10] (See Exhibit 15 on Page 27)

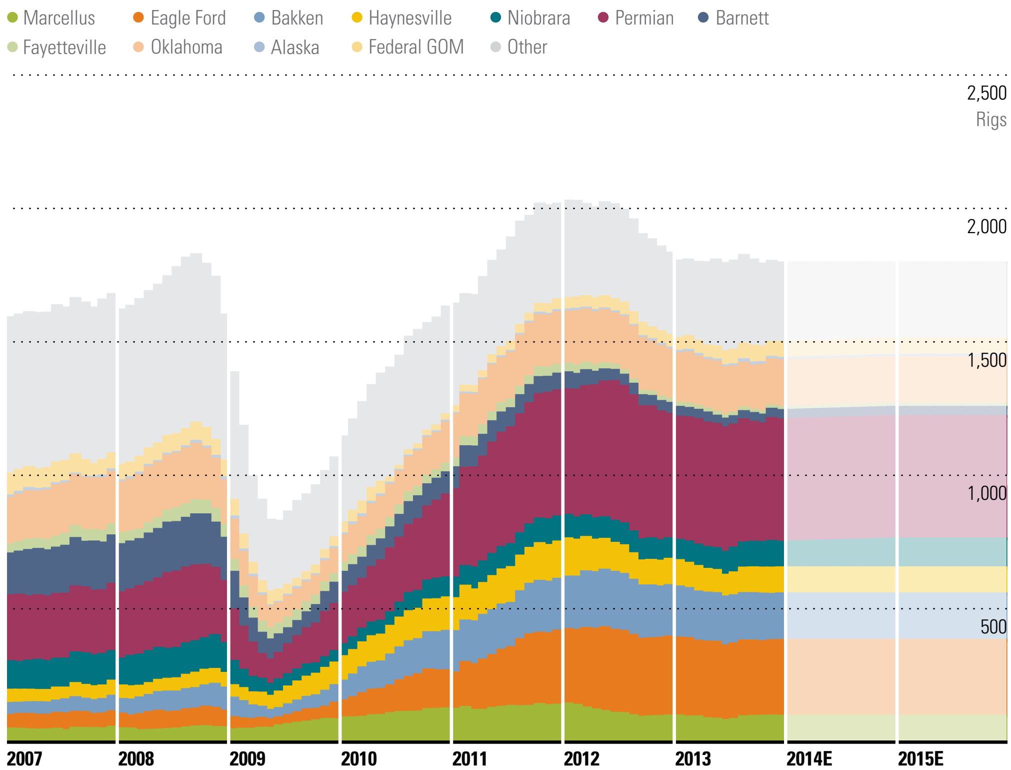
6. **Dry Gas Production Forecast**

   Putting together the output from steps 1–5—dry gas cuts, rig counts, production per rig, and underlying declines—and layering on our previously-developed Marcellus projections, we arrive at a monthly dry gas production forecast for the United States. To keep things simple, note that the only variable we change across our domestic production scenarios (base, bull, and bear) is our Marcellus forecast.[11] Our region-by-region dry gas production figures are provided starting on Page 28.

10 We're applying something of an 80/20 principle by not explicitly forecasting drilling days, new-well production, and declines for areas excluded from the DPR, in large part because their relative maturity has led to greater stability in each of these variables. Accordingly, we should be able to project with reasonable accuracy monthly production volumes using just rig counts and production per rig.

11 Unless otherwise noted, all exhibits, figures and commentary on Pages 24–34 incorporate our Marcellus base case projections.

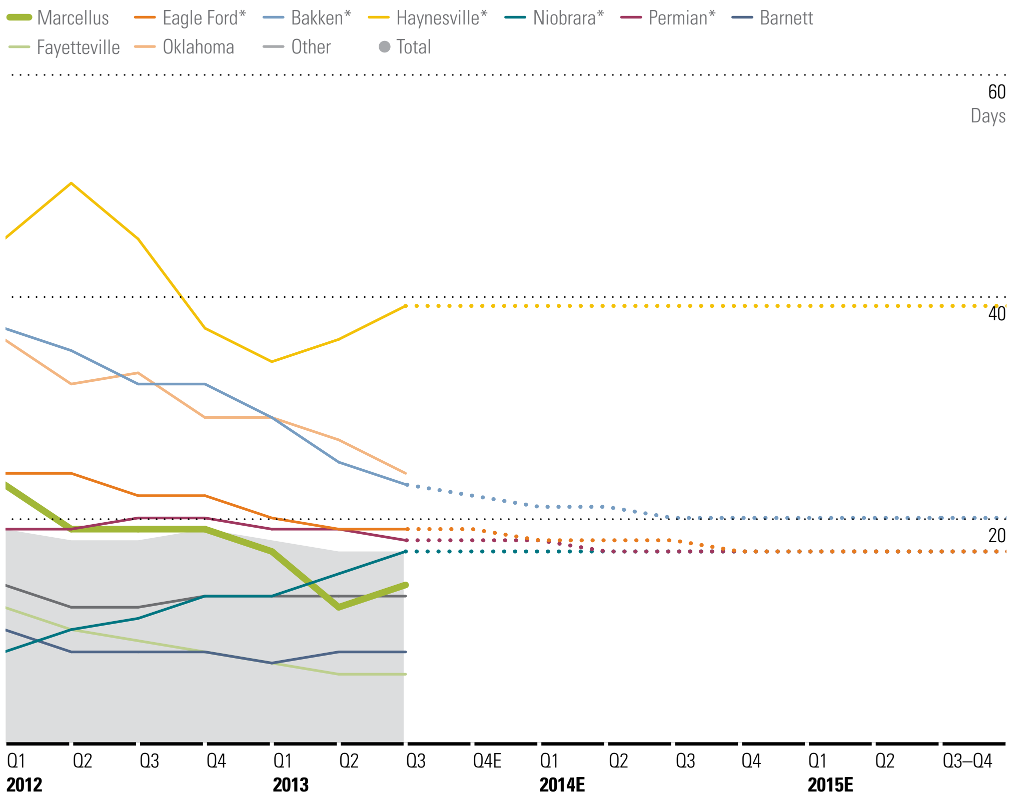
Exhibit 12 Combined U.S. Oil & Gas Rig Count by Region, 2007–15E



- The domestic rig count serves as something of a "fossil record" that marks (albeit imperfectly) the rise and fall of various oil- and gas-producing regions throughout the U.S. over time.
- Note that after peaking just north of 2,000 rigs in late 2011, U.S. drilling activity has fallen as of late, led by a reduction in Marcellus, Haynesville, and Other rigs.

Source: EIA, Baker Hughes, RigData, Morningstar Analysis

Exhibit 13 Drilling Days Per Well by Region, 2012–15E



- Although certain regions such as the Bakken, Eagle Ford, and Marcellus have experienced a dramatic improvement in drilling days over the last few quarters, efficiency gains for the U.S. as a whole have been more incremental, going from 19 days in early 2012 to 17 in late 2013.

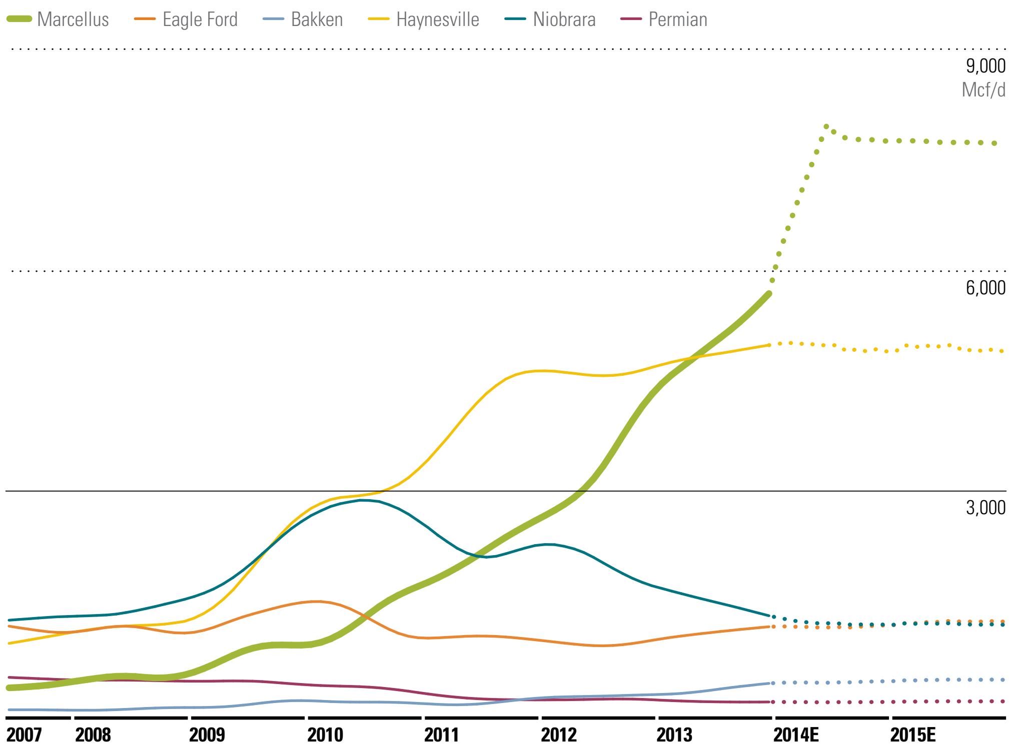
- As we've noted elsewhere, improvements in operating efficiency (as measured by drilling days, for example), don't necessarily correspond with an improvement in capital efficiency. See our Dec. 7, 2012 Oil & Gas Insights, The Shale Evolution—Examining Claims of a New Normal in the U.S. Natural Gas Market (pages 18–28), for more information.

- Note that we don't explicitly project Marcellus drilling days, as our production forecast for this area relies more on the pace of well completions than it does on new drilling activity, given the sizable backlog of uncompleted wells that exists here.

* Discretely forecast

Source: Baker Hughes, RigData, Morningstar Analysis

Exhibit 14 New-Well Gross Natural Gas Production[12] Per Combined Oil & Gas Rig (6-Month Rolling Average), 2007–15E



- The disparity in new-well volumes per rig across the various gas-producing regions of the United States makes it difficult to use a top-down, gas-directed rig count approach to forecasting domestic production.

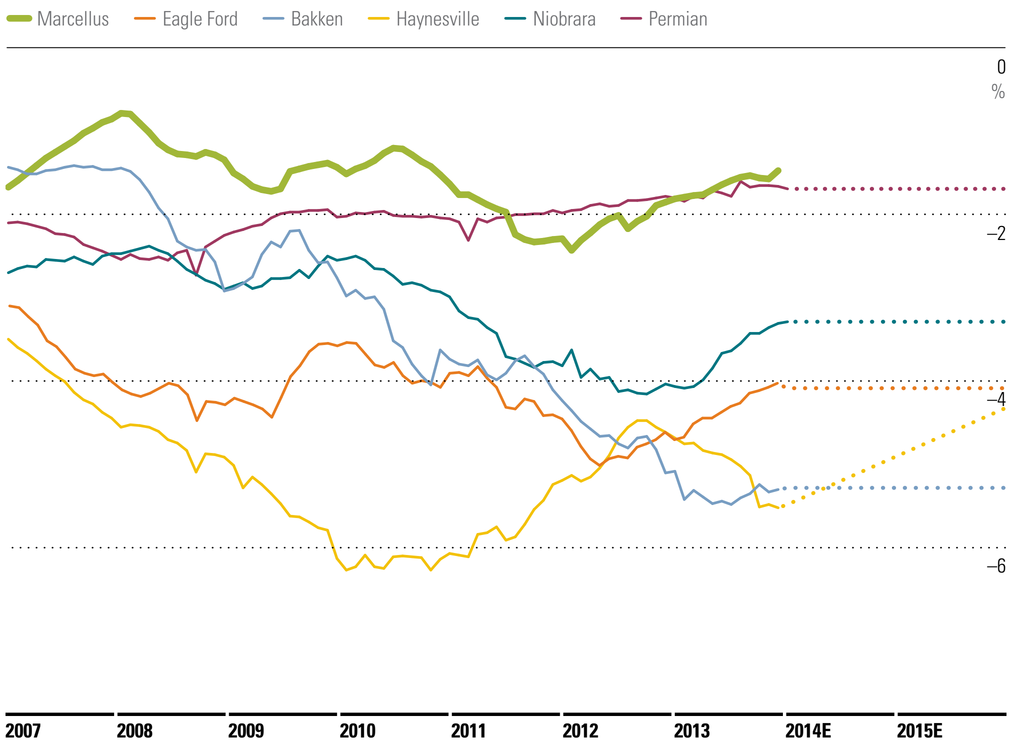
- We suspect that in areas where there have been (and continue to be) large backlogs of uncompleted wells, such as the Haynesville and Marcellus, new-well production per rig figures are upwardly biased, given the timing mismatch between drilling and completion activity. Still, it's hard to argue that timing alone accounts for such dramatic improvements. In our opinion, faster drilling times and a focus on more productive wells have likely played a much bigger role in improving per-rig production figures in these plays.

- Flat to declining trends across the Permian, Eagle Ford, and Niobrara are likely the result of operators directing more of their rig activity toward oil-rich targets over time, which on a per-rig basis reduces the amount of gas produced, all else equal.

Source: EIA, Morningstar Analysis

12 "New-well gross natural gas production" refers to the average flow rate over the first 30 days of a well's productive lifecycle.

Exhibit 15 Sequential Monthly Decline Rates of Gross Natural Gas Production by Region, 2007–15E



- The EIA calculates legacy production declines as the month-over-month change in volume for all wells greater than 30 days old. Legacy production is "reset" every month as a new group of 30-plus-day-old wells is added to a region's "base." Declines as defined by the EIA, therefore, differ from the typical manner in which they're understood, where production from a particular group of wells is tracked over a longer period of time. Thus, while illuminating, the EIA's decline figures don't provide much insight into longer-term well performance.

- Similar to our commentary on Exhibit 14, the disparity in monthly decline rates across the various gas-producing regions of the United States makes it difficult to use a top-down, gas-directed rig count approach to forecast domestic production.

- Except for the Marcellus (which we address below), there's generally a strong relationship between rapidly-increasing production volumes and higher month-over-month decline rates in a given region. Conversely, as production in a given area flattens out, decline rates also tend to slow.

- Recall from Exhibit 2 on Page 8 that the average Marcellus well exhibits fairly flat production rates over the first six months of its life. Accordingly, month-over-month declines in the Marcellus—as calculated by the EIA—tend to underestimate how quickly legacy production is actually falling (since each month the "base" is reset with a new group of ever more productive wells, the flow rates of which don't begin to drop until beyond the 30-day measurement window). Because we measure declines in our Marcellus forecast differently from the EIA, we omit them in Exhibit 15.

Source: EIA, Morningstar Analysis

A Visual Tour of Morningstar's U.S. Natural Gas Production Forecast

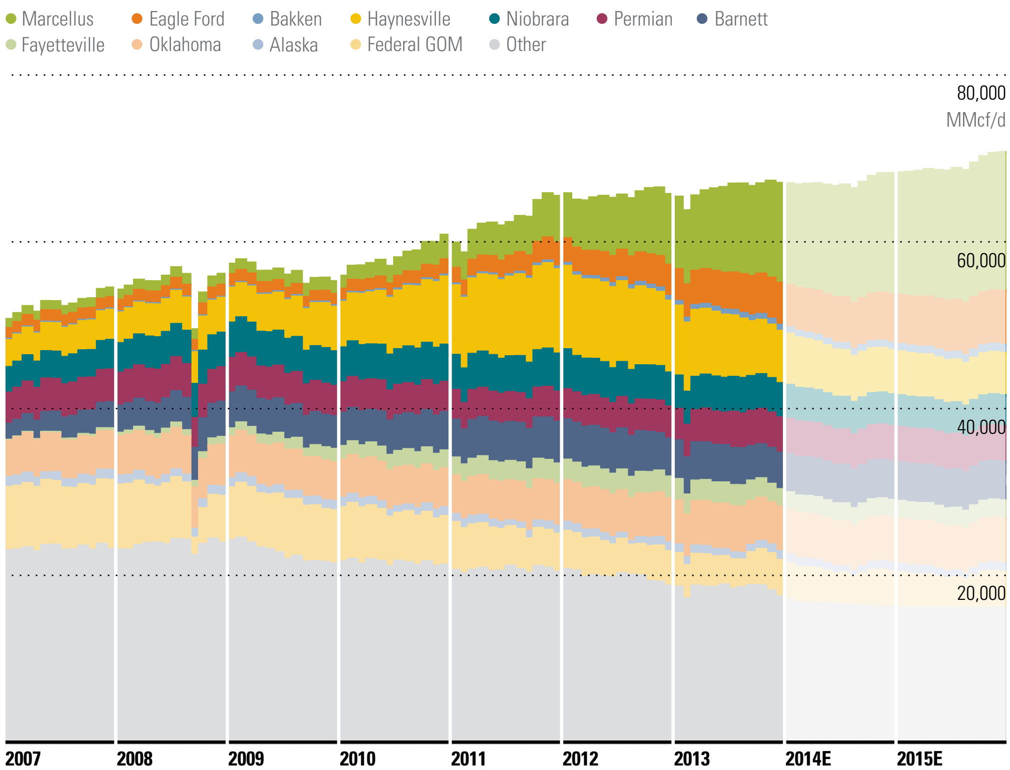
Over the next several pages, we present our domestic gas forecast using a variety of tables and charts in order to highlight the net impact of ongoing activity in areas such as the Marcellus, a slowdown in areas like the Barnett and Haynesville, associated gas contributions from oil-rich regions like the Eagle Ford and Bakken, and declines across the country's conventional production base. No matter how we slice the data, however, the conclusion is clear: U.S. natural gas volumes don't appear likely to reverse course anytime soon, with production growing by approximately 3 Bcf/d (or 4% cumulatively) over the next two years.

Exhibit 16 Summary of Morningstar's U.S. Natural Gas Production Forecast, 2012–2015E

	Bakken	Eagle Ford	Haynes.	Marcellus	Niobrara	Permian	Barnett	Fayette.	Oklahoma	Alaska	Federal GOM	Other	Total
Dry gas production MMcf/d													
2012	472	3,312	9,453	6,913	4,276	3,731	4,810	2,525	5,135	914	4,218	19,987	65,744
2013E	641	4,457	7,352	10,245	4,115	4,079	4,411	2,431	5,333	936	3,898	18,545	66,443
2014E	809	5,466	5,666	13,394	3,930	4,229	4,626	2,154	5,369	925	4,058	16,679	67,306
2015E	927	6,179	5,144	15,697	3,760	4,249	4,631	2,160	5,371	930	3,978	16,235	69,261
% of U.S. dry gas production													
2012	1	5	14	11	7	6	7	4	8	1	6	30	100
2013E	1	7	11	15	6	6	7	4	8	1	6	28	100
2014E	1	8	8	20	6	6	7	3	8	1	6	25	100
2015E	1	9	7	23	5	6	7	3	8	1	6	23	100
Incremental dry gas production MMcf/d													
2012	199	1,044	–44	2,668	–92	183	81	221	329	–4	–749	–811	3,024
2013E	169	1,145	–2,100	3,332	–160	348	–399	–95	198	22	–319	–1,442	699
2014E	169	1,009	–1,687	3,149	–185	150	215	–277	36	–11	160	–1,865	862
2015E	117	713	–522	2,303	–171	20	4	6	2	6	–80	–445	1,955
Dry gas production % change													
2012	73	46	0	63	–2	5	2	10	7	–0	–15	–4	5
2013E	36	35	–22	48	–4	9	–8	–4	4	2	–8	–7	1
2014E	26	23	–23	31	–4	4	5	–11	1	–1	4	–10	1
2015E	14	13	–9	17	–4	0	0	0	0	1	–2	–3	3
Rig Count													
2012	205	298	65	113	81	496	47	21	196	7	46	343	1,919
2013E	182	286	45	93	88	462	34	14	179	9	54	313	1,759
2014E	175	285	46	98	103	460	35	12	175	9	60	293	1,750
2015E	175	285	46	98	108	460	35	12	175	9	60	287	1,750
% of rigs													
2012	11	16	3	6	4	26	2	1	10	0	2	18	100
2013E	10	16	3	5	5	26	2	1	10	1	3	18	100
2014E	10	16	3	6	6	26	2	1	10	1	3	17	100
2015E	10	16	3	6	6	26	2	1	10	1	3	16	100

Source: Morningstar Analysis

Exhibit 17 U.S. Dry Gas Production by Month, 2007–15E



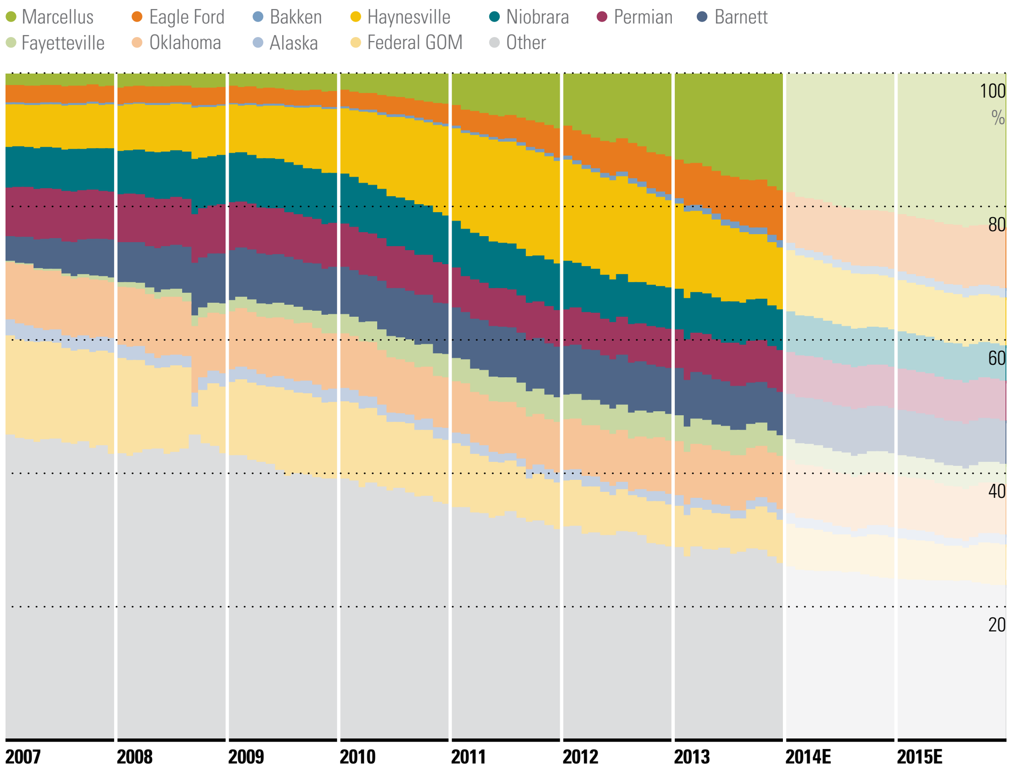
- Shale gas has been the biggest driver of domestic production over the past several years, and is likely to account for almost all incremental volume growth going forward, as production in areas such as the Marcellus and Eagle Ford continues to ramp up and declines in areas like the Haynesville slow down.

- It's the nature of unconventional production that as drilling activity slows, so too does volume growth, as underlying declines tend to overwhelm the impact of new production additions. There's no better example of this than the Haynesville. Of course there are exceptions, as we saw in the previous section with the Marcellus, where meaningful improvements in well performance have helped overcome the steep base declines of the play.

- Without the Marcellus, it's probable that domestic natural gas production would have peaked in late 2011 or early 2012 (assuming, of course, that in the absence of the Marcellus, gas prices would have remained at levels insufficient to encourage drilling activity in higher-cost areas like the Barnett and Haynesville).

Source: EIA, Railroad Commission of Texas, Morningstar Analysis

Exhibit 18 U.S. Dry Gas Production by Month (Relative Basis), 2007–15E

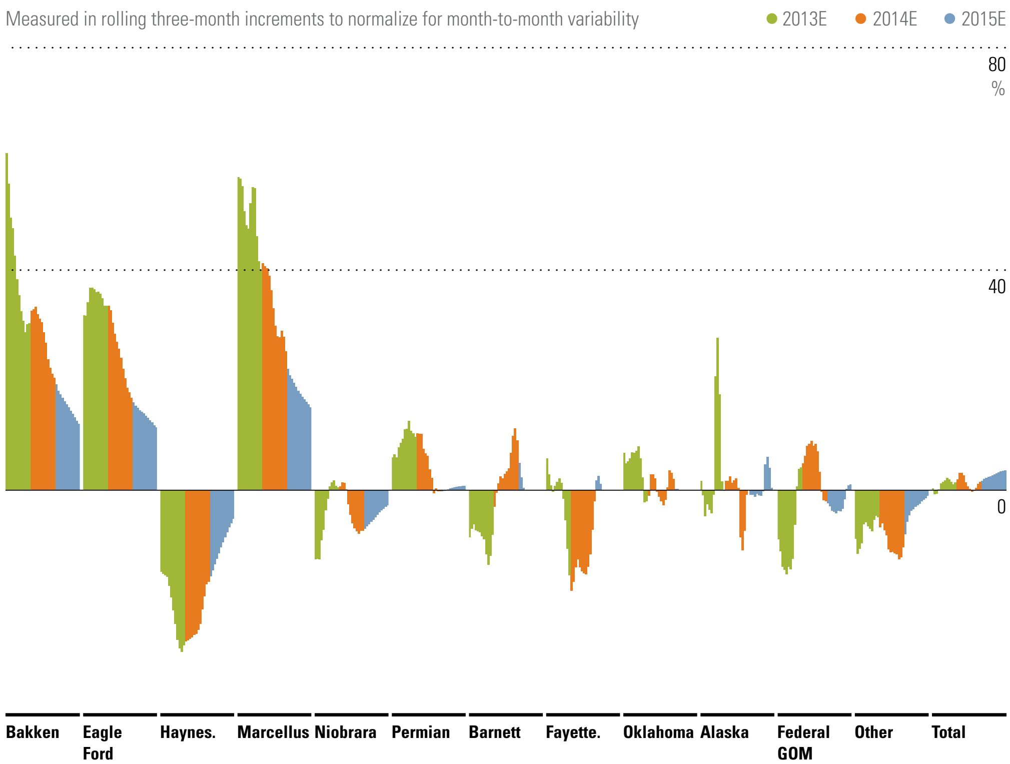


- Over the course of just a few years, the Marcellus has gone from relative obscurity to almost 20% of U.S. production.
- By the end of our forecast period, we expect unconventional gas to account for approximately 60% of domestic volumes, up from less than 10% in 2007.
- Conventional production and volumes from the Gulf of Mexico have become far less important contributors to U.S. supply over time.

Source: EIA, Railroad Commission of Texas, Morningstar Analysis

Exhibit 19 Year-Over-Year Percentage Change in Monthly Dry Gas Production, 2013E–15E

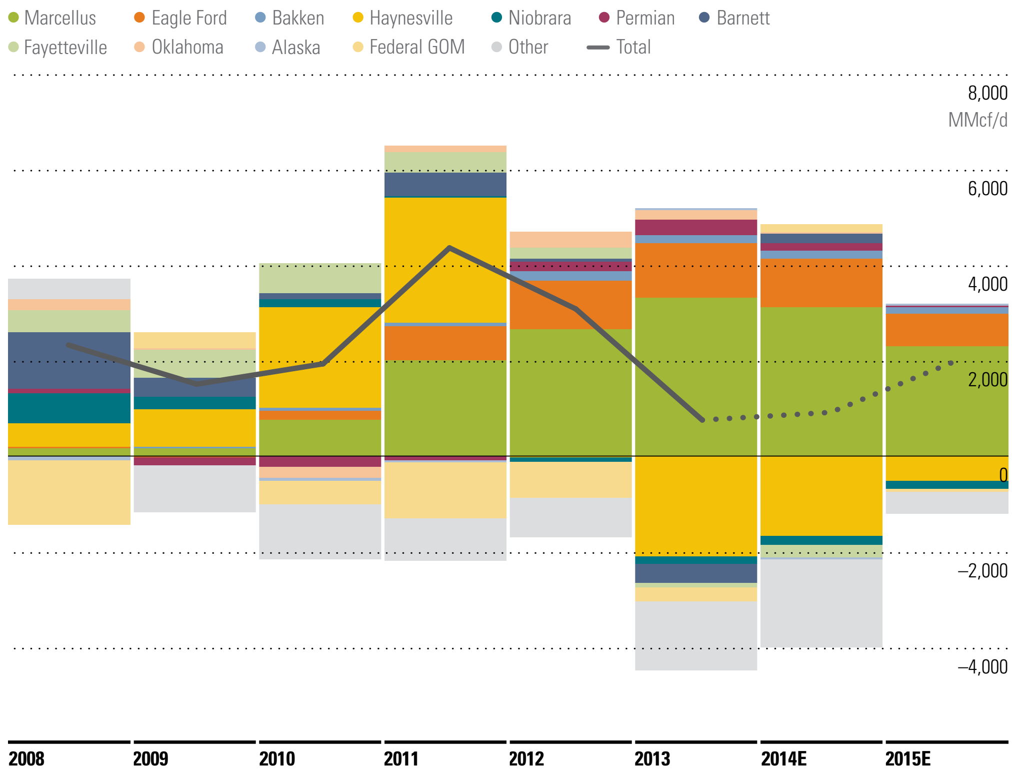
Measured in rolling three-month increments to normalize for month-to-month variability



- As production continues to increase, we expect growth rates in areas like the Marcellus, Eagle Ford, and Bakken to slow. Nevertheless, these regions should still be capable of delivering 10%-plus year-over-year growth by the end of our forecast period. Alongside flattening declines in the Haynesville and Other regions, the net impact on U.S. supply should be accelerating growth throughout 2015.

Source: EIA, Railroad Commission of Texas, Morningstar Analysis

Exhibit 20 Year-Over-Year Volume Change in Dry Gas Production, 2008–15E



- Exhibit 20 shows year-over-year changes in gas volume on a region-by-region basis. Areas below the x-axis indicate volume loss relative to the previous year, while areas above the x-axis indicate volume gains.

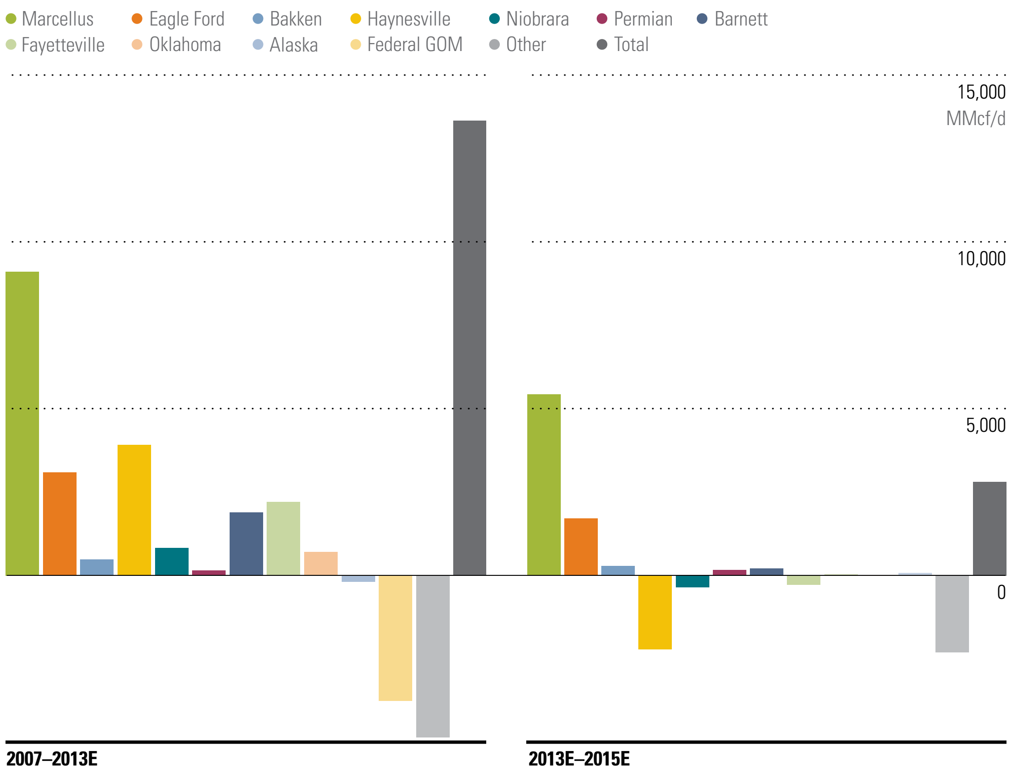
- As with Exhibit 12, the chart above serves as something of a "fossil record" that marks the rise and fall of various oil- and gas-producing regions throughout the United States. The Barnett, for example, was a meaningful contributor to domestic volume growth in 2008 before flattening out. The Haynesville, meanwhile, delivered significant incremental production for close to four years (2008-12) before it began a sharp reversal in the wake of a pullback in drilling activity.

- In 2013, net dry gas additions (measured by the line), while still positive (thanks to the Marcellus and Eagle Ford), were far below those from 2008-12, thanks to production declines that were more than double those of the previous five years.

- The Marcellus and Eagle Ford are likely to be the biggest contributors to U.S. supply growth over the next few years, offset by continued declines in the Haynesville and Other regions. As volume declines slow, we expect U.S. net dry gas additions to re-accelerate.

Source: EIA, Railroad Commission of Texas, Morningstar Analysis

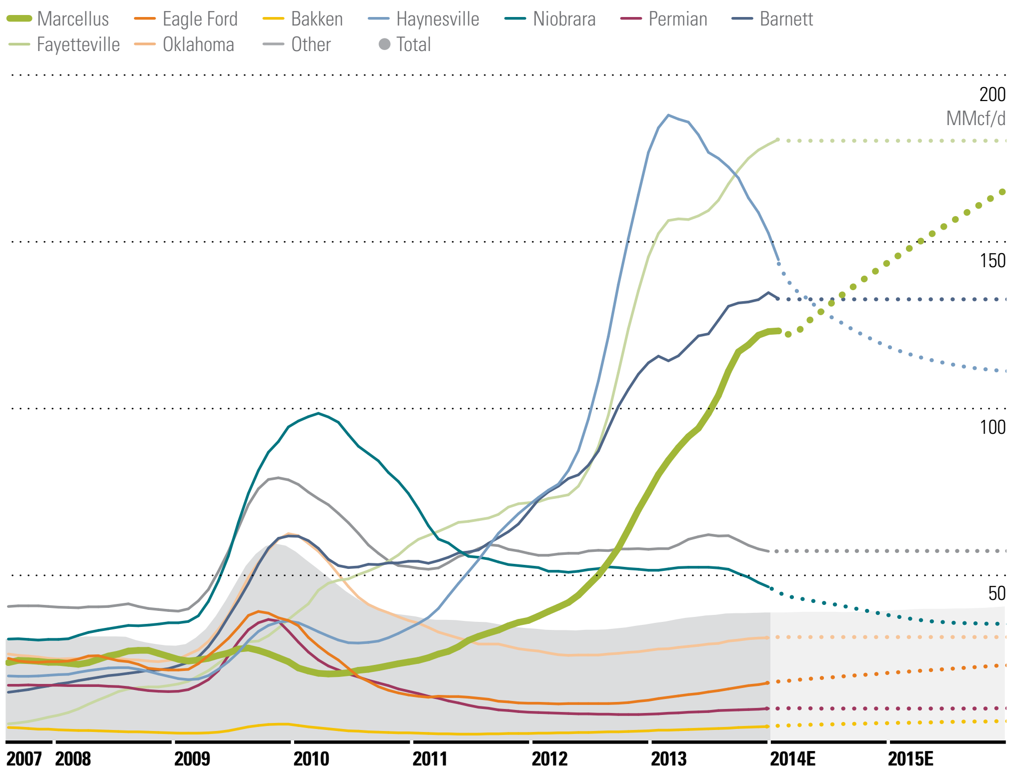
Exhibit 21 Cumulative Change in Dry Gas Production, 2007–15E



- Exhibit 21 shows the cumulative change in dry gas production across two different time periods: 2007–13E and 2013E–15E.
- From 2007–13E (the left panel above), we estimate domestic gas volumes increased by approximately 14 Bcf/d, led by unconventional areas like the Marcellus (9 Bcf/d), Haynesville (4 Bcf/d), Eagle Ford (3 Bcf/d), and Barnett and Fayetteville (2 Bcf/d each). Declines in conventional (4 Bcf/d) and Gulf of Mexico (5 Bcf/d) production offset a good amount of this unconventional growth, however.
- From 2013E–15E (the right panel above), we expect growth to be far less balanced than it has been historically, with only the Marcellus and Eagle Ford exhibiting any meaningful uptick in volumes. Gas production in almost every other region of the United States is likely to have reached (or be nearing) a local "peak" by the end of our forecast period. Higher prices, of course, could incentivize higher levels of activity across these maturing regions, which would push back the point at which we expect them to peak.

Source: EIA, Railroad Commission of Texas, Morningstar Analysis

Exhibit 22 U.S. Dry Gas Production Per Combined Oil & Gas Rig (Six-Month Rolling Average), 2007–15E



- Exhibit 22 shows gas production per rig on a rolling six-month basis. Each region's curve reflects a particular combination of new-well production, legacy volumes and underlying declines, and improvements in drilling efficiency.

- Based on historical precedent, we've argued that it would be difficult for industry-wide gas production on a per-rig basis to remain elevated in the face of a slowdown in drilling activity, as declines eventually overwhelm new production adds. The Marcellus, among other factors, has forced us to re-examine this argument, however.

- With a) step-wise changes in new-well production from the Marcellus generally adding more production than is lost to natural declines, b) activity in the Eagle Ford continuing at a breakneck pace, c) our assumptions for modest improvements in drilling efficiency going forward, industry-wide gas production on a per-basis rig is unlikely to reverse course any time soon.

Source: EIA, Baker Hughes, Railroad Commission of Texas, Morningstar Analysis

Scenario Analysis

Exhibit 23 on the following page presents our domestic production forecasts using our base, bull, and bear case scenarios for the Marcellus (recall that Exhibits 12–22 reflect just our base case for the Marcellus). To state the obvious, the path of the Marcellus in the years ahead will be the most important driver of U.S. gas production. Moreover, despite its size, there remains a good amount of uncertainty about how much larger it could get, as well as how fast it could get there. Accordingly, we'll be keeping a close eye on trends here in order to better understand the Marcellus' likely trajectory going forward.

Where Could Our Forecast Be Wrong?

In order to achieve a balance of usefulness (does our forecast enable more informed decision making?) and timeliness (are our ideas actionable over a reasonable period of time?), and to minimize the "error bands" around our projections, we've chosen to limit our forecast window to just two years. Beyond this, the confluence of natural, economic, technological, and regulatory factors—spread across multiple gas-producing basins throughout the U.S.—introduces so much uncertainty as to render our predictions almost meaningless. We expect to update our two-year forecast on a rolling basis, revisiting our assumptions and incorporating additional data points as they become available.

A few "wild cards" we think are worth paying attention to over the next several quarters—as they could lead to actual results meaningfully deviating from our projections—include:

- The emergence of the Utica Shale in Ohio, which, despite only contributing modestly to domestic supply over the next few years, could reach 3–4 Bcf/d of incremental production by the end of this decade, according to industry estimates.

- The ongoing impact of ethane rejection and the pace of processing facility build-outs ("rejected" ethane currently accounts for 1.5 Bcf/d of dry gas production and could increase if infrastructure continues to be overwhelmed by wet gas volumes going forward).

- Natural gas demand, which influences prices and therefore gas-directed drilling activity.

- Oil prices, which, given a substantial decline, could reduce oil-directed drilling activity and lead to a drop-off in associated gas production.

Exhibit 23 U.S. Dry Gas Production Forecast (Base, Bull, and Bear Case Scenarios for the Marcellus), 2010–2015E

	Base Case		Bull Case		Bear Case	
	Marcellus	Total	Marcellus	Total	Marcellus	Total
Dry Gas Production MMcf/d						
2010	1,113	52,777	1,113	52,777	1,113	52,777
2011	4,245	62,720	4,245	62,720	4,245	62,720
2012	6,913	65,744	6,913	65,744	6,913	65,744
2013E	10,245	66,443	10,245	66,443	10,245	66,443
2014E	13,394	67,306	13,917	67,828	12,908	66,820
2015E	15,697	69,261	17,470	71,033	14,165	67,728
% of U.S. Dry Gas Production						
2010	4		4		4	
2011	7		7		7	
2012	11		11		11	
2013E	15		15		15	
2014E	20		21		19	
2015E	23		25		21	
Incremental Dry Gas Production MMcf/d						
2010	773	1,879	773	1,879	773	1,879
2011	2,026	4,330	2,026	4,330	2,026	4,330
2012	2,668	3,024	2,668	3,024	2,668	3,024
2013E	3,332	699	3,332	699	3,332	699
2014E	3,149	862	3,671	1,385	2,663	377
2015E	2,303	1,955	3,553	3,204	1,257	908
Dry Gas Production % Change						
2010	53	3	53	3	5	3
2011	91	7	91	7	91	7
2012	63	5	63	5	63	5
2013E	48	1	48	1	48	1
2014E	31	1	36	2	26	1
2015E	17	3	26	5	10	1

Source: EIA, Morningstar Analysis

Intersection of Supply & Demand and Investment Conclusions

Mark P. Hanson, CFA

Intersection of Supply & Demand Through 2015

In the domestic natural gas market, price and marginal cost tend to converge when supply and demand levels are aligned, and tend to move apart when these levels are out of balance.[13] With our forecast for continued growth in dry gas production over the next few years, investors are right to be concerned about a potential repeat of 2012, when over-supply conditions drove prices down to less than $2 per Mcf and ignited fears about the industry hitting a "storage wall." Barring abnormally warm winters or cool summers, however, we believe there exists sufficient demand across a variety of end markets—even at meaningfully higher gas prices than implied by the strip—to help absorb this increased supply.

Exhibit 24 on the following page overlays our previously-developed base case demand projections[14] onto our base, bull, and bear case production forecasts. According to our model, the domestic gas market will likely remain undersupplied through 2015, which implies that prices could remain elevated (say, north of $5 per Mcf) over the next few years. (Note, however, that we're not making a short-term call on natural gas prices here. Rather, we're simply showing how the intersection of supply, demand, and storage could play out through 2015.)

Investment Conclusions

There are several ways investors can take advantage of continued growth in domestic gas production in the years ahead. If demand keeps pace with supply as we expect, natural gas prices should normalize between $5 and $6 per Mcf, which we believe is something of a "sweet spot" that serves to incentivize continued gas production (benefiting upstream, midstream, and services firms) while mitigating the potential for demand destruction. Note, however, that volatility is likely to remain a defining characteristic of the domestic gas market going forward, with seasonal imbalances in supply and demand, especially, contributing to lots of ups and downs in both natural gas prices and stock prices.

13 See our Dec. 7, 2012 Oil & Gas Insights, The Shale Evolution—Examining Claims of a New Normal in the U.S. Natural Gas Market (pages 32–33), for more information.

14 See our Aug. 20, 2013 Energy Observer, Low-Cost Natural Gas, the Coming Boom in Demand, and Who in the U.S. is Set to Benefit, for more information.

Exhibit 24 U.S. Natural Gas Supply-Demand Model, 2014E–15E

	Base Supply Case		Bull Supply Case		Bear Supply Case	
Bcf/d, except where noted	2014E	2015E	2014E	2015E	2014E	2015E
Beginning working gas in storage (Bcf)[1]	2,896	2,365	2,896	2,554	2,896	2,186
Production						
Dry gas production	67.3	69.3	67.8	71.0	66.8	67.7
Canadian imports, net[2]	4.2	3.8	4.2	3.8	4.2	3.8
LNG imports[2]	—	—	—	—	—	—
Total Supply	**71.5**	**73.0**	**72.0**	**74.8**	**71.0**	**71.5**
Consumption[3]						
Residential & Commerical	21.1	21.0	21.1	21.0	21.1	21.0
Industrial	24.1	24.7	24.1	24.7	24.1	24.7
Electric power generation	23.4	22.9	23.4	22.9	23.4	22.9
Mexican exports, net	2.3	2.6	2.3	2.6	2.3	2.6
LNG exports	—	0.1	—	0.1	—	0.1
Other	2.0	2.0	2.0	2.0	2.0	2.0
Total Demand	**72.9**	**73.3**	**72.9**	**73.3**	**72.9**	**73.3**
Oversupply (undersupply)	(1.5)	(0.2)	(0.9)	1.5	(1.9)	(1.8)
Ending working gas in storage (Bcf)	2,365	2,275	2,554	3,109	2,186	1,534
5-year average, 2009–13	3,202	3,202	3,202	3,202	3,202	3,202
% +/– 5-year average, 2009–13	(26%)	(29%)	(20%)	(3%)	(32%)	(52%)

1 Estimated using the average of storage figures from the last week of 2013 and the first week of 2014
2 Could be used to meet demand if the market is undersupplied (or conversely could be reduced if market is oversupplied)
3 Consumption held flat across different cases to isolate impact of dry gas production on ending working gas in storage

Source: Morningstar Analysis

- Within upstream, we favor low-cost companies whose acreage positions offer several more years (if not decades) of reinvestment opportunities. Even though firms such as Cabot Oil & Gas (COG), Range Resources (RRC), Southwestern Energy (SWN), and Peyto Exploration & Development (PEY) fit the bill from a cost and inventory perspective, they're less attractive from a valuation standpoint. We favor Ultra Petroleum (UPL), given its long runway for growth in the Pinedale field of Wyoming and Marcellus shale of Pennsylvania, its low breakeven level of less than $3 per Mcf, and its current discount to our estimate of intrinsic value. We also like Tourmaline Oil (TOU) for its 25 years of highly economic natural gas inventory in the Alberta Deep Basin, $2.50 per Mcf breakeven point, and attractive valuation. Canadian Natural Resources (CNQ) is another name to consider, as it's one of the largest and lowest-cost gas producers in Canada, with a balance sheet that ensures future development opportunities get funded.

- Within midstream, MarkWest (MWE), Williams/Williams Partners (WMB/WPZ), and Spectra/Spectra Energy Partners (SE/SEP) each offers meaningful exposure to Marcellus infrastructure opportunities, with Spectra Energy Partners the most compelling from a valuation perspective. Midstream names with LNG export potential offer another way to play surging domestic production, with Cheniere (LNG/CQP) and Energy Transfer (ETE/ETP) best positioned in terms of in-process projects; Energy Transfer Partners is the more attractively valued of the two.

- Within services, we favor Halliburton (HAL), and to slightly lesser degree Schlumberger (SLB), as each is positioned to benefit from continued U.S. onshore activity and a gradual recovery in the pressure pumping market.

- If rising natural gas prices lift power prices, several utilities stand to benefit, most notably Exelon (EXC), Calpine (CPN), and FirstEnergy (FE).

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