SHALE GAS INVENTORY: PROBLEM OR OPPORTUNITY?

WHY INVESTORS ARE WRONG ABOUT LONG-TERM NATURAL GAS FUNDAMENTALS

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SAILINGSTONE CAPITAL PARTNERS LLC

Executive Summary

Natural gas and renewables represent the long-term future of the energy business. While coal and oil demand will not be eliminated anytime soon, they will continue to lose share over time. This transition will meaningfully reduce CO_2 emissions and improve air quality, particularly in emerging market economies.

Unlike shale oil, which is higher-cost globally and limited in duration, North America has a very large and low-cost shale gas resource base that is well-positioned to meet growing global demand for natural gas for several decades.

In addition, the shale gas business is characterized by having lower decline rates, more free cash flow, and higher returns, on average, than the shale oil business which is highly fragmented and increasingly dominated by the major oil companies. In natural gas, the winners are the few publicly-traded E&P companies that have the scale and the drilling inventory needed to generate attractive returns and free cash flow for many years.

Nonetheless, public equity valuations do not reflect the positive long-term fundamentals for natural gas and the more favorable industry dynamics. Indeed, several advantaged producers now trade below the value of their proved developed producing reserves using the depressed futures strip. We believe that public equity investors remain overly concerned about associated gas and do not appreciate the scarcity value of drilling inventory that works below $3/mcf.

Using well data, we walk through the actual impact of associated gas, the call on shale gas, and the remaining drilling inventory in the various shale gas basins. We believe that the data helps to provide context for some of the common misconceptions that have impacted the natural gas market and natural gas equities.

Shale Gas Inventory: Problem or Opportunity?

Why Investors Are Wrong About Long-Term Natural Gas Fundamentals

> *"A man should look for what is, and not for what he thinks should be."* – Albert Einstein
>
> *"A reliable way to make people believe falsehoods is frequent repetition, because familiarity is not easily distinguished from truth."* – Daniel Kahneman, *Thinking Fast and Slow*
>
> *"When you develop your opinions on the basis of weak evidence, you have difficulty interpreting subsequent information that contradicts these opinions, even if this new information is obviously more accurate."* – Nassim Taleb, *The Black Swan: The Impact of the Highly Improbable*

Introduction

Natural gas prices have declined over the last decade as production from low-cost shale gas basins has displaced higher-cost conventional sources of supply. More recently, growth in associated gas production, driven largely by increased drilling activity in the Permian Basin, has helped push long-term natural gas price expectations even lower, to below $2.50/mcf, even as prices have averaged nearly $3.00/mcf for the last three years.

Conventional wisdom suggests that natural gas prices will decline for the foreseeable future due to the growth in zero-cost associated gas production and the availability of low-cost shale gas supply. The consensus view regarding the outlook for natural gas is underpinned by the widely-held belief that core inventory in most shale plays remains abundant and that technology will support continued improvements in well productivity.

Our research shows that core inventory in most shale gas basins is, in fact, extremely limited. We believe that a surprisingly large portion of the growth in shale gas production recently has been driven more by private operators in higher-cost plays than by an overabundance of low-cost drilling locations. Importantly, high levels of drilling activity are rapidly depleting the remaining inventory in the core parts of a number of shale gas basins.

In addition, infrastructure constraints and productivity declines will result in slowing growth in both associated gas production and shale gas supply, particularly as core inventory is exhausted. As a result, we believe that natural gas prices will need to move ***higher*** over time - not lower - as higher-cost sources of supply will be needed to meet rising global demand for clean-burning natural gas.

To be clear, North America isn't running out of natural gas; it will remain a low-cost producer and exporter of natural gas for many years. However, contrary to common belief, North America is beginning to run low on sub-$3/mcf gas. As natural gas demand continues to grow, as the core parts of low-cost shale gas plays are drilled out, and as the gap between natural gas prices in North America and other parts of the world expands, natural gas prices will need to move well above $3/mcf longer-term. Nevertheless, even in a $3-5/mcf world, North America will be a low-cost producer for a very long time.

In this paper, we attempt to quantify the remaining drilling inventory in the core parts of the largest shale gas basins today. We conclude by discussing some of the important implications of the rapid depletion of core inventory for the natural gas market and for natural gas equities.

Part I – Understanding the Call on Shale Gas and Why Drilling Inventory Matters

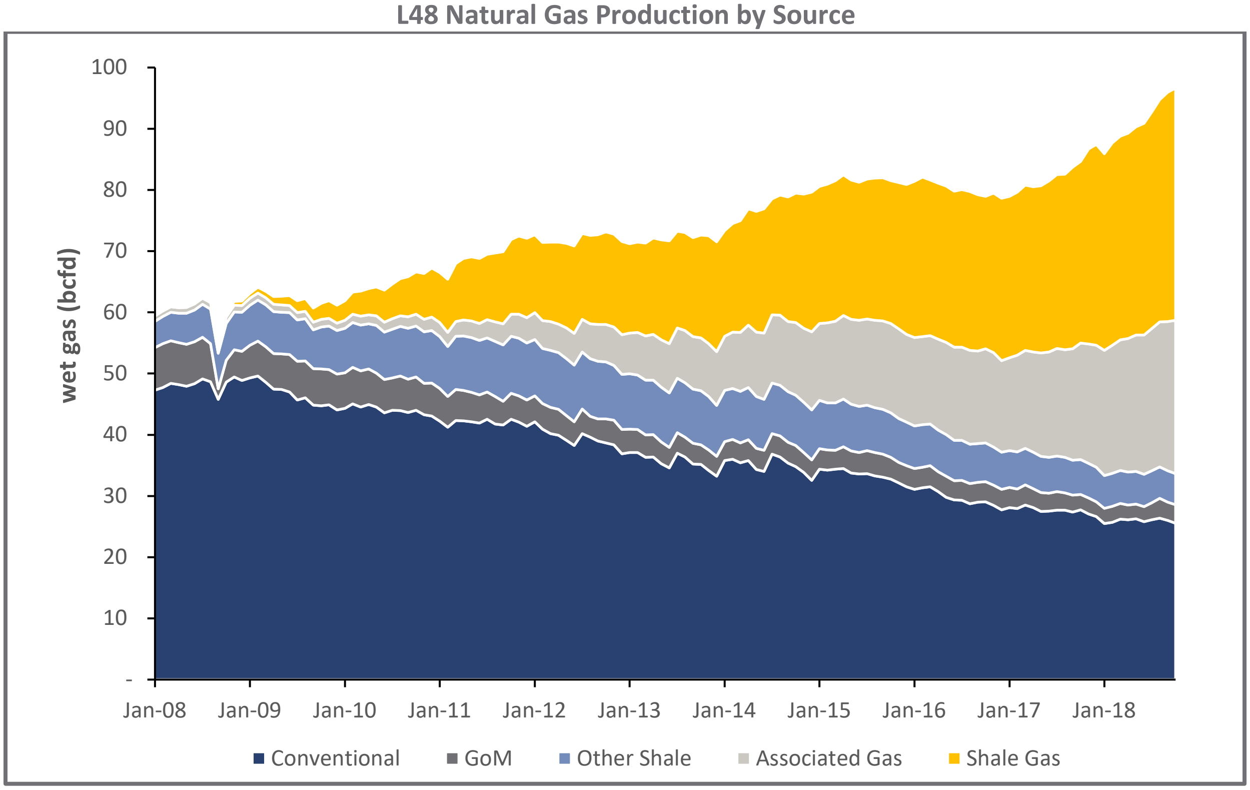
Associated Gas – Negative Short-Term, Positive Long-Term

One of the biggest concerns regarding the outlook for natural gas prices is the significant growth in natural gas production from the drilling of oil wells, particularly in the Permian Basin. Indeed, associated gas production from shale oil basins has increased by roughly 22-bcfd over the last decade, since the start of shale oil drilling, and is up by more than 5-bcfd in the last year alone. The growth in associated gas production has been remarkable.

Given the continued level of drilling activity in shale oil plays today, most investors believe that the growth in associated gas production alone will meet rising demand for natural gas and significantly reduce the call on new shale gas supply. As a result, natural gas prices will remain depressed for the next 5-10 years, so the story goes. However, there are a few problems with this overly simplistic view.

First, although associated gas production has increased significantly, the reality is that declining production from conventional basins, the Gulf of Mexico, and higher-cost shale gas plays, such as the Barnett Shale and the Fayetteville Shale, has more than offset this growth. Over the last decade, production from mature basins has declined by roughly 26-bcfd – 4-bcfd more than the growth in associated gas supply. Going forward, we expect increases in associated gas production to more than offset declines in mature basins, but only by about 1-2-bcfd per year, on average, over the next few years. While most industry pundits focus on the growth in associated gas production, few appreciate the fact that declines in conventional production have been more meaningful.

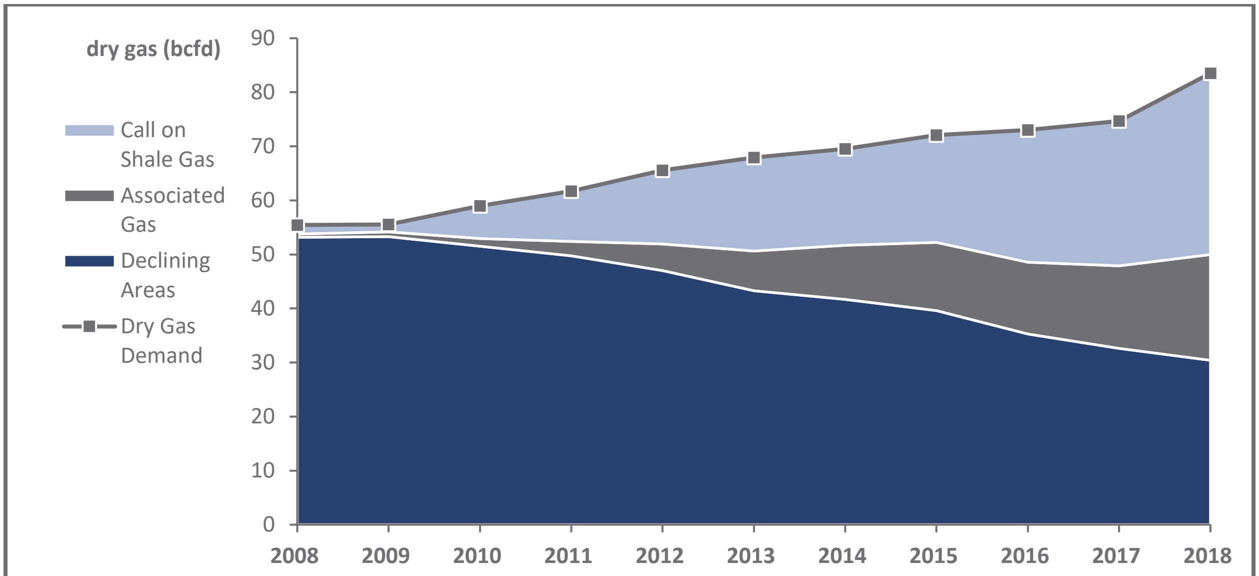
L48 Natural Gas Production by Source



Sources: DrillingInfo, EIA, SailingStone Capital Partners, Q1 2019.

As natural gas demand has increased, and as conventional declines have more than offset the growth in associated gas production, the call on shale gas has, in fact, risen quite dramatically over the last several years. The call on shale gas has increased by nearly 32-bcfd since 2008 and 9-bcfd since 2016. Importantly, while the growth in associated gas production has reduced the growth in the call on shale gas, it has not kept it from increasing significantly.

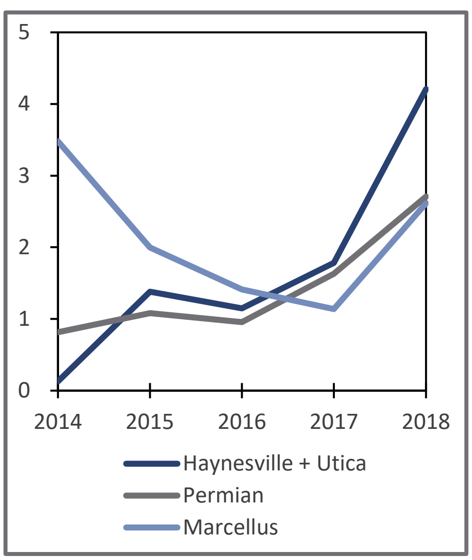
Call on Shale Gas



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Dry Gas Demand	**55.4**	**55.5**	**59.0**	**61.7**	**65.6**	**68.0**	**69.6**	**72.0**	**73.0**	**74.7**	**83.5**
- Declining Areas	(53.2)	(53.3)	(51.5)	(49.7)	(47.0)	(43.3)	(41.7)	(39.6)	(35.3)	(32.6)	(30.4)
- Associated Gas	(0.6)	(0.9)	(1.4)	(2.7)	(4.9)	(7.3)	(10.0)	(12.6)	(13.3)	(15.3)	(19.6)
Call on Shale Gas	**1.7**	**1.4**	**6.1**	**9.3**	**13.6**	**17.3**	**17.8**	**19.8**	**24.5**	**26.8**	**33.5**
Growth		*-18%*	*344%*	*54%*	*46%*	*27%*	*3%*	*11%*	*24%*	*9%*	*25%*

Sources: DrillingInfo, EIA, SailingStone Capital Partners, Q1 2019.

Annual Wet Gas Growth, bcfd



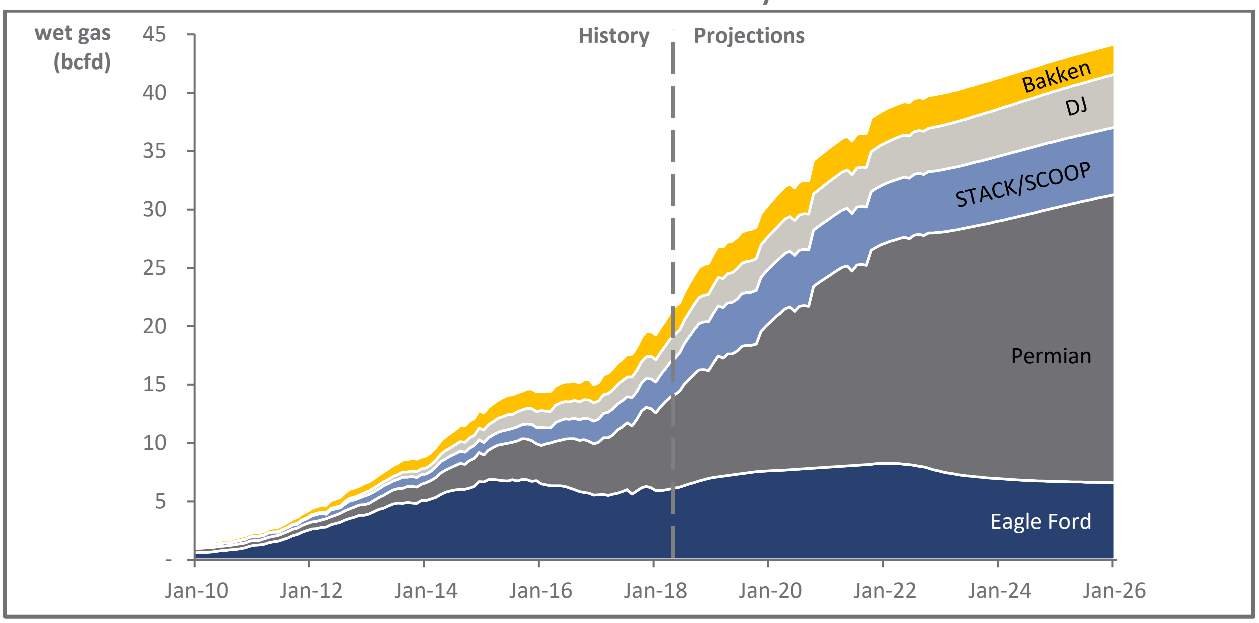
Sources: IHS Markit, SailingStone Capital Partners, Q1 2019.

By focusing solely on the increase in associated gas production, investors miss the bigger point that the call on shale gas has increased so much that drilling in higher-cost shale gas basins has been required to balance the natural gas market. Since production growth from the prolific and low-cost Marcellus Shale has not kept pace with the increased demand for dry gas, drilling activity in higher-cost shale gas plays, such as the Utica Shale and the Haynesville Shale, has accelerated to help fill the void. Over the last three years, natural gas production in the Utica Shale and Haynesville Shale combined has grown more than production in either the Permian Basin or Marcellus Shale. **The growing importance of these higher-cost plays reflects the fact that the significant growth in natural gas production from shale oil plays and the Marcellus Shale has not been enough to offset underlying depletion and meet growing demand.**

The second reason why associated gas is less problematic than currently feared is that the growth in associated gas production will begin to slow over the next several years, initially due to infrastructure bottlenecks in the Permian Basin, and eventually owing to the depletion of core inventory in mature shale oil basins. As it relates to infrastructure, natural gas production from the Permian Basin is becoming increasingly constrained by pipeline access out of the basin. While new pipelines will eventually be built, we expect that pipeline bottlenecks will limit the growth in Permian gas supply to a maximum of about 2.0-2.5-bcfd per year, on average, over the next few years, beginning at the end of 2019. Until then, we expect incremental associated gas production from the Permian Basin to increase by less than 1-bcfd.

Beyond the 2020-22 timeframe, when a number of new pipelines out of the Permian are expected to start up, increases in associated gas production will begin to slow considerably as the core parts of shale oil basins, which are limited aerially, are drilled up. Mature basins, such as the Bakken Shale and Eagle Ford Shale, which combined produce almost as much as the Permian Basin at nearly 10-bcfd of wet gas, will be first to slow before eventually going into decline. In addition, the transition to development mode in newer plays such as the Permian and the STACK/SCOOP will result in increasing well interference and declining well productivity – as we are already witnessing. Declining associated gas production in mature basins, combined with slowing growth from the Permian Basin and STACK/SCOOP plays, will drive much slower growth during the early to mid-2020s.

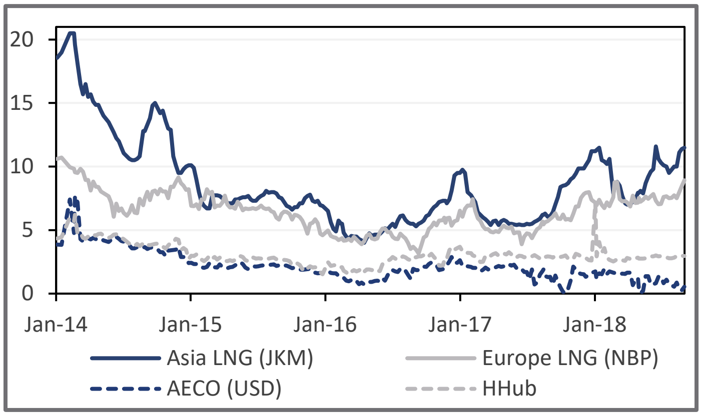
Associated Gas Production by Basin



Sources: DrillingInfo, EIA, SailingStone Capital Partners, Q1 2019.

Although there will be brief periods when growth in associated gas production temporarily exceeds natural gas demand, particularly during the 2020-22 period when LNG demand growth slows and new pipelines are brought online, associated gas will gradually become less important over time as shale oil basins mature, as core inventory is depleted, and as declines in well productivity accelerate. Concerns regarding the impact of associated gas are prevalent today because the current rate of growth in associated gas production is being extrapolated too far into the future by industry observers that are straight-lining EIA production data, rather than doing bottom-up supply forecasts using actual well data.

Global Gas Prices, $/mmbtu



Source: Goldman Sachs, Q1 2019.

Lastly, and most importantly, the growth in associated gas production is extremely positive for long-term natural gas demand. By temporarily reducing the growth in the call on shale gas, associated gas has helped to constrain North American natural gas prices. As a result, natural gas prices in North America have been well below natural gas prices in other parts of the world since converging during the 2015-16 cyclical downturn.

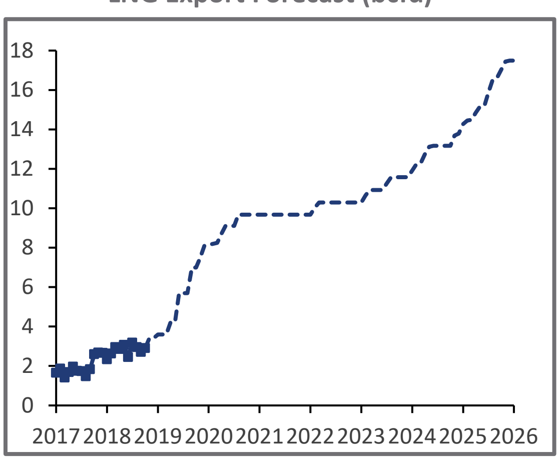
The lower natural gas prices in North America have helped spur the development of new projects in gas-intensive industries given the significant economic advantage associated with sourcing natural gas from North America. Unlike associated gas production, which will eventually decline over time, these new projects will permanently increase the installed demand base for natural gas. Over the last two years alone, natural gas demand for the industrial, power, and LNG sectors have risen by 6-bcfd.

U.S. Natural Gas Demand (bcfd)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Residential/Commercial	22.0	21.7	21.7	21.7	19.3	22.5	23.6	21.6	20.4	20.8	23.0
Industrial	18.2	16.9	18.7	19.2	19.7	20.3	21.0	20.6	21.1	21.8	22.7
Power	18.2	18.8	20.2	20.7	24.9	22.3	22.2	26.2	27.2	25.2	28.8
Fuel & Transporation	5.1	5.3	5.4	5.5	5.8	6.3	6.1	6.2	6.1	6.3	7.0
Domestic Demand	**63.6**	**62.8**	**66.0**	**67.1**	**69.7**	**71.5**	**72.8**	**74.6**	**74.8**	**74.1**	**81.4**
LNG Imports	(1.0)	(1.2)	(1.2)	(1.0)	(0.5)	(0.3)	(0.2)	(0.3)	(0.2)	(0.2)	(0.2)
Canada Imports	(9.8)	(9.0)	(9.0)	(8.5)	(8.1)	(7.6)	(7.2)	(7.2)	(8.0)	(8.1)	(7.8)
Canada Exports	1.5	1.9	2.0	2.6	2.7	2.5	2.1	1.9	2.1	2.5	2.2
Mexico Exports	1.0	0.9	0.9	1.4	1.7	1.8	2.0	2.9	3.8	4.2	4.7
LNG Exports	0.1	0.1	0.2	0.2	0.1	0.0	0.0	0.1	0.6	2.2	3.2
Net Exports	**(8.1)**	**(7.3)**	**(7.0)**	**(5.4)**	**(4.1)**	**(3.6)**	**(3.2)**	**(2.6)**	**(1.8)**	**0.6**	**2.1**
Total Demand	**55.4**	**55.5**	**59.0**	**61.7**	**65.6**	**68.0**	**69.6**	**72.0**	**73.0**	**74.7**	**83.5**
Growth		*0%*	*6%*	*5%*	*6%*	*4%*	*2%*	*4%*	*1%*	*2%*	*12%*

Source: EIA, Q1 2019.

LNG Export Forecast (bcfd)



Sources: EIA, SailingStone Capital Partners, Q1 2019.

As long as associated gas helps to keep natural gas prices in North America below prices in other regions, demand will continue to increase materially, albeit with a lag. Two new LNG projects were sanctioned during 2018 and we expect to see another two to four projects move forward in 2019. While some analysts forecast relatively flat natural gas demand post-2020, we believe that there will be another wave of LNG projects that startup in the 2023-27 timeframe, representing anywhere from 6 to 10-bcfd of additional demand. In addition, we expect natural gas and renewables to continue to take share from coal in the power sector over time.

So, while higher oil prices will result in increased associated gas production in the near term, it will also support higher natural gas demand and, eventually, higher natural gas prices. While it takes time to build new LNG, chemical, and power plants, the growing gap between oil and natural gas prices is quite positive for natural gas demand, and ultimately natural gas prices in North America.

In the short run, associated gas has temporarily reduced the growth in the call on shale gas and prevented natural gas prices from moving higher than they otherwise would have without the development of shale oil basins. However, from a longer-term perspective, associated gas should be thought of as permanently expanding the installed demand base for North American natural gas. As natural gas demand increases, and as growth in associated gas production slows and eventually declines, the call on shale gas will rise quite dramatically. While associated gas reduces the outlook for natural gas prices in the short run, it also significantly increases the upside potential of the commodity longer-term.

The Call on Shale Gas – A Plateau Before Significant Growth

Assessing the long-term price outlook for any commodity requires an understanding of the supply cost curve. In natural gas, high underlying decline rates mean that a significant amount of natural gas needs to be added each year from new wells. The natural gas that is added from new wells is known as “wedge gas.”

With underlying depletion in the North American natural gas industry running at over 25% per year, wedge gas must offset annual depletion and meet any changes in demand. Since associated gas comes into the market at a very low supply cost, if not zero cost, the call on dry gas drilling is the portion of wedge gas that needs to come from new dry gas wells after backing out the gas production added from new shale oil wells. For any given year, this relationship can be thought of as a simple equation:

Call on dry gas drilling = Δ Demand + Underlying depletion – Associated gas additions

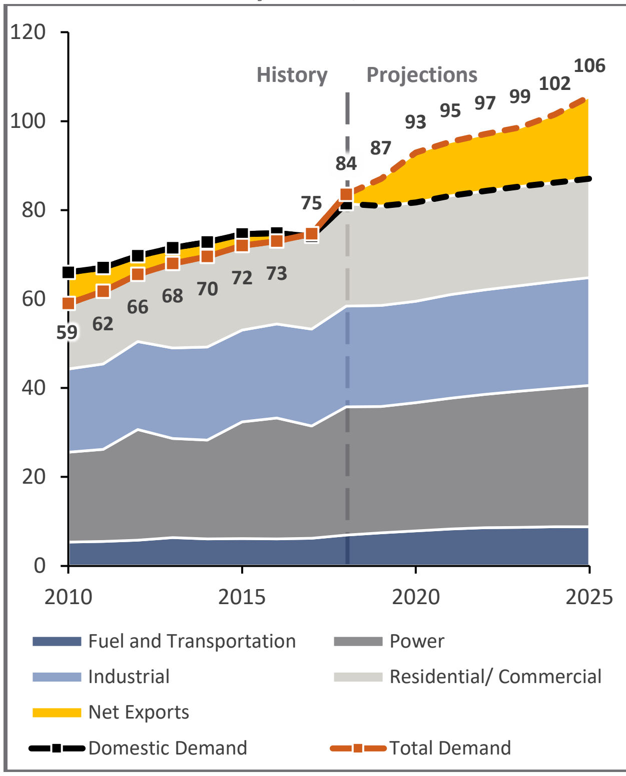
As natural gas demand has increased considerably over the last decade, the annual wedge gas needed to balance the market has also grown significantly, from 13-bcfd in 2008 to over 22-bcfd in 2018. Furthermore, since declines in conventional production have more than offset increases in associated gas production, the call on dry gas drilling has risen even more dramatically. Since 2008, the call on dry gas has risen by around 32-bcfd (or around 35-bcfd in wet gas terms as shown in the table below). This has been met by drilling activity in the Marcellus Shale, Haynesville Shale, and Utica Shale plays, which in total need to add roughly 8-bcfd of new supply each year today.

Shale Gas Production (wet gas, bcfd)											
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Marcellus	0.0	0.2	1.2	3.4	6.4	10.0	13.5	15.5	16.9	18.0	20.6
Utica	-	-	-	0.0	0.0	0.3	1.3	2.8	4.1	5.1	7.0
Haynesville	0.4	1.6	4.3	7.4	7.6	5.9	5.0	4.8	4.7	5.5	7.8
Shale Gas Total	**0.4**	**1.8**	**5.5**	**10.8**	**14.0**	**16.1**	**19.8**	**23.1**	**25.7**	**28.6**	**35.4**

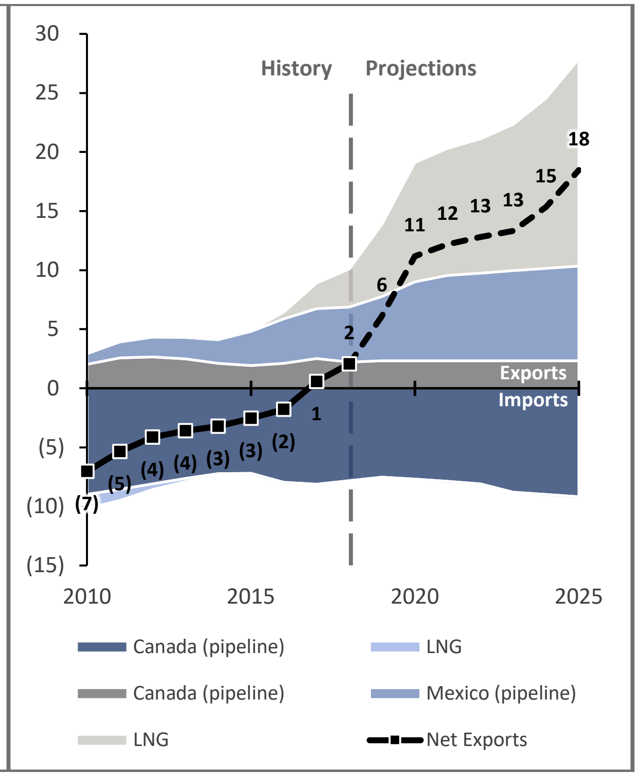
Sources: EIA, DrillingInfo, SailingStone Capital Partners, Q1 2019.

In order to estimate the call on shale gas drilling going forward, we need to forecast natural gas demand, conventional declines, and associated gas production. Starting first with natural gas demand, we expect increases in natural gas consumption to be driven by the startup of new LNG projects, the continued shift from coal to natural gas and renewables in the power generation sector, and the startup of new chemical plants. Below is our natural gas demand forecast. It is important to point out that demand projections are highly sensitive to price. If natural gas prices are as low as implied by the futures strip or analyst estimates, we believe that demand growth will be much greater than we are currently forecasting, particularly in the power generation sector.

Total and Domestic Natural Gas Demand by Sector, bcfd



U.S. Natural Gas Trade Balance, bcfd



Sources: EIA, SailingStone Capital Partners, Q1 2019.

In estimating the call on dry gas, it is also important to understand the depletion of mature gas basins, which still represent more than a third of total production today. While the impact of associated gas and shale gas has been well documented, far less research has been devoted to quantifying production declines in mature areas. Yet, small differences in decline rate assumptions have a meaningful impact on the estimated supply/demand balance for natural gas. Well data shows that decline rates in mature basins have averaged roughly 10-15% per year, which have been partially offset by new wells in the past few years. Going forward, we estimate that production from mature basins will decline by close to 8-10% per year. We believe that most industry observers are underestimating future depletion from mature basins, with some analyses using a base decline rate of less than 5% per annum.

In our supply forecast, we estimate that associated gas production will continue to increase significantly over the next few years. However, we believe that the rate of growth will slow due to infrastructure bottlenecks and eventually declining well productivity in shale oil plays. Our associated gas production forecasts are in-line with consensus estimates in the near-term but are meaningfully lower than analyst projections beyond 2022. The primary reason for this is that our analysis is done on a well-by-well basis and incorporates the impact of drilling wells in less productive areas and downspacing.

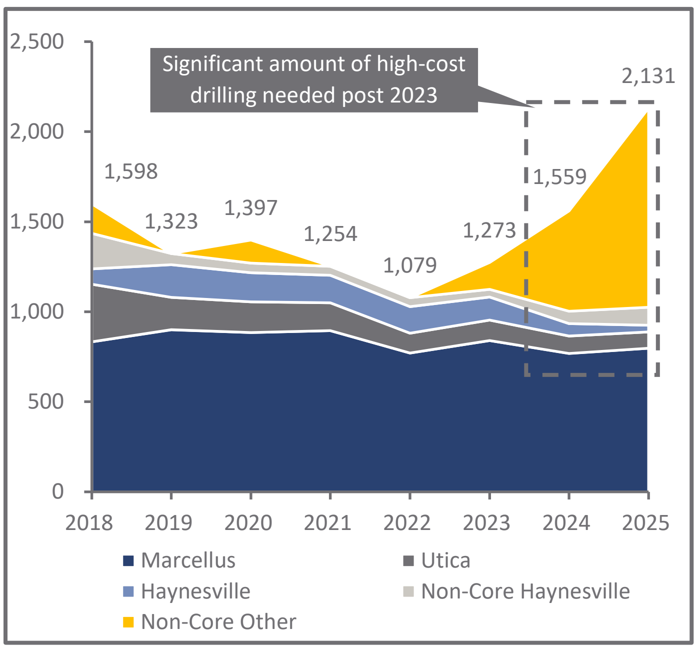
The call on dry gas is simply the plug that is needed to balance the North American natural gas market. It is calculated by taking natural gas demand and subtracting associated gas production and conventional production. The call on dry gas drilling is then the difference between the call on dry gas and dry gas depletion. Below is our forecast of the call on dry gas and dry gas *drilling* by year, as well as the estimated prices needed to bring on that level of supply in a normal weather environment.

Call on Dry Gas (bcfd)								
	2018	2019	2020	2021	2022	2023	2024	2025
Dry Gas Demand	**83.5**	**87.0**	**92.9**	**95.4**	**97.1**	**98.6**	**101.5**	**105.5**
- Declining Areas	(30.4)	(27.8)	(25.8)	(24.1)	(22.7)	(21.4)	(20.3)	(19.2)
- Associated Gas	(19.6)	(23.9)	(27.6)	(30.9)	(33.0)	(33.8)	(34.9)	(36.0)
Call on Dry Gas	**33.5**	**35.3**	**39.4**	**40.4**	**41.4**	**43.4**	**46.4**	**50.4**
- Existing (Depleted) Shale Gas	(22.3)	(27.2)	(29.9)	(31.9)	(34.3)	(35.0)	(36.0)	(36.0)
Call on Dry Gas Drilling	**11.3**	**8.1**	**9.5**	**8.4**	**7.1**	**8.3**	**10.4**	**14.4**
Est. Price Needed, $/mcf	*3.25*	*2.85*	*2.90*	*2.90*	*2.95*	*3.10*	*3.30*	*3.40*

Sources: EIA, DrillingInfo, SailingStone Capital Partners, Q1 2019.

Despite the growth in associated gas production, the call on dry gas should continue to increase over the next few years, albeit at a slower rate than it has in the past. The call on shale gas should reach 40-bcfd by 2020-21 and 50-bcfd by 2025. As underlying depletion rates for shale gas basins decline, the call on new gas drilling will hover around 8-bcfd per year over the next few years before increasing substantially in the 2024-25 period. By 2025, we estimate that the call on dry gas drilling will reach 14-bcfd and increase further going forward.

Call on Shale Gas Wells



Source: SailingStone Capital Partners, Q1 2019.

In order to meet the call on dry gas drilling, the industry must drill, on average, 850 wells per year in the Marcellus Shale and 230 wells per year in the Haynesville Shale over the next few years. In addition, drilling is required in higher-cost plays such as the Utica Shale, which will remain the marginal source of supply over the next few years. By 2023, however, the natural gas market will require drilling activity in even higher-cost basins, such as the non-core parts of the Marcellus and Haynesville Shale plays, as core inventory is drilled up. By the middle of the next decade, we estimate that over 1,100 wells per year will be required outside of the core parts of the Marcellus, Haynesville, and Utica Shale plays.

Although there are enough drilling locations to meet the growing call on shale gas, our research shows that there are not enough drilling locations in the core parts of the Marcellus Shale and the Haynesville Shale, alone, to meet the growing call on shale gas by the early to middle part of the next decade. As such, we believe that natural gas prices will need to increase materially by the early to mid-2020s in order to incentivize drilling in higher-cost areas.

In the next section, we analyze the remaining drilling inventory in the large shale gas basins.

Part II – How Much Core Inventory is Actually Left?

Drilling Inventory Study

"Many a small thing has been made large by the right kind of advertising." – Mark Twain

Long-term natural gas price expectations are currently too low due in large part to the way in which some companies market themselves. Many E&P companies claim to have thousands of drilling locations remaining, though few provide the disclosures necessary to evaluate the natural gas prices that are required for those locations to be economic.

In addition, few industry observers have gone through the exercise of mapping what locations have been drilled already and what locations remain to be drilled in the core parts of the larger shale gas basins. Instead, many investors rely on company marketing presentations which are frequently misleading.

In order to assess the outlook for the wedge supply cost curve and natural gas prices, we believe that it is critical to understand the remaining drilling inventory in the various shale gas basins, and the prices at which this inventory is economic. As such, we conducted a study to analyze the remaining drilling inventory in the four largest dry gas producing regions: 1) the northeastern Marcellus Shale, 2) the southwestern Marcellus Shale, 3) the Haynesville Shale, and 4) the Utica Shale.

Drilling inventory is not infinite. It is governed by geology and economics. Our analysis shows that there are clearly-defined limitations to the core parts of the most prolific shale gas basins, including the Marcellus Shale. These limitations will have significant implications for natural gas prices as well as company valuations and M&A activity.

Northeastern Marcellus Shale – 10-bcfd

"Show me the money." – Jerry Maguire

Starting with the lowest-cost and most productive natural gas wells in North America, the core of the northeastern Marcellus Shale covers roughly 2.3 million acres across parts of Bradford, Lycoming, Sullivan, Susquehanna, Tioga, and Wyoming counties in northeastern Pennsylvania.

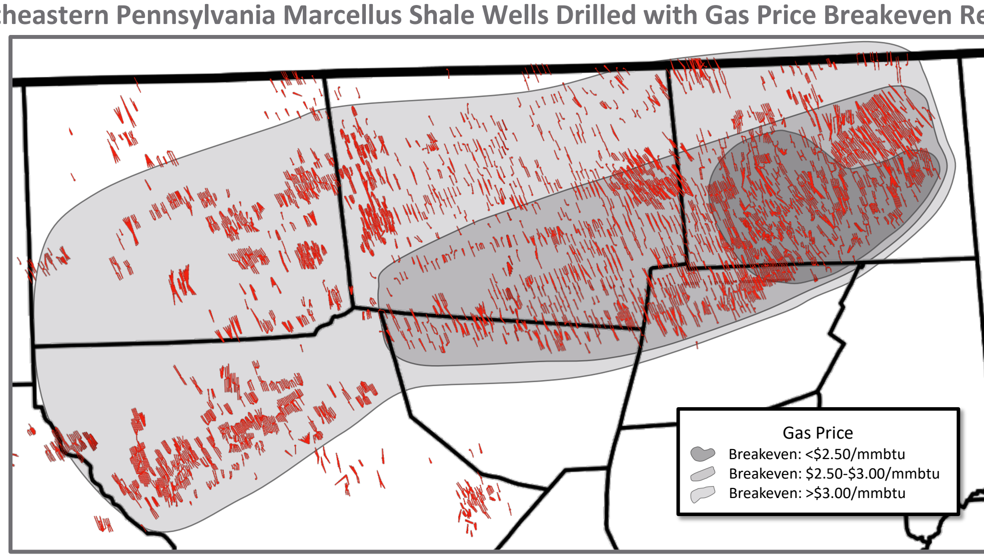
To date, nearly 5,000 wells have been drilled across the core part of the play in the Lower Marcellus formation, with over half of those wells located in Bradford and Susquehanna counties. Estimated ultimate recoveries (EURs) range from 1.5-2.0-bcf/1000' in the less productive areas to as much as 3.0-4.0-bcf/1,000' in the most productive areas of southeastern Bradford, southern Susquehanna, and northern Wyoming counties. The less productive parts of the play require $3.00-4.00/mcf gas to generate a reasonable return, while the most productive area works at less than $2.50/mcf.

While the northeastern Marcellus Shale is the most productive shale gas play in North America, it is also one of the more mature shale gas basins. We estimate that there are just over 300 wells (at 10,000' lateral length) left to drill in the core part of the field that work at $2.50/mcf or below, with most of those locations in Susquehanna County. Unlike other parts of the play, wells in this area can be drilled at 700-800' spacing due to the thickness of the Lower Marcellus formation. In other areas, where the Lower Marcellus formation is thinner, the optimal well spacing is closer to 1,000-1,250'. At $2.50-3.00/mcf, we estimate that there are roughly 800 wells remaining in the Lower Marcellus formation, primarily in Bradford and Susquehanna counties. At the current pace of activity, we estimate that there are just 3-5 years of inventory remaining in the Lower Marcellus that work at less than $3.00/mcf.

Although the remaining inventory that is economic below $3.00/mcf is quite limited in this region, there is quite a bit of undeveloped acreage that generates a reasonable return at $3.00-4.00/mcf, particularly in northern Susquehanna, northern Bradford, Tioga, and northern Lycoming counties. We estimate that there are nearly 2,500 wells remaining to be drilled in this area, though some wells in this region require prices above $3.50/mcf. We expect production to be limited by pipeline capacity in the nearer-term, and inventory/well economics longer-term.

While growth will slow considerably going forward, the basin should generate quite a bit of free cash flow for the lower-cost companies in the core part of the field.

Northeastern Pennsylvania Marcellus Shale Wells Drilled with Gas Price Breakeven Regions



Source: IHS Markit, SailingStone Capital Partners, Q1 2019.

Southwestern Marcellus Shale – 12-bcfd

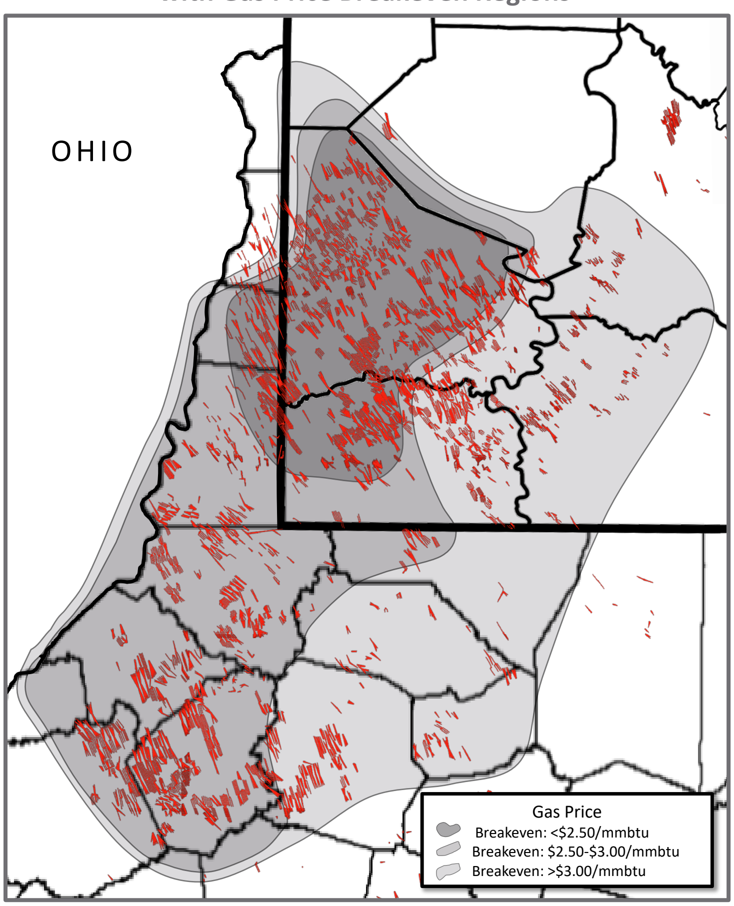
"The stuff that dreams are made of." – The Maltese Falcon

Although the wells in the core part of the southwestern Marcellus Shale are, on average, not as productive as the wells in the core part of the northeastern Marcellus Shale, the economics in the core part of the southwestern Marcellus Shale rival the well economics in Susquehanna County due to the liquids uplift and better natural gas realizations. In addition, there is much more running room left in core part of the southwestern Marcellus Shale given its size.

The core part of the southwestern Marcellus Shale spans roughly 3.3 million acres across 6 counties in southwestern Pennsylvania and 11 counties in northwestern West Virginia. It is a vast area. There have been approximately 5,500 wells drilled to-date, with the majority of wells drilled in Greene and Washington counties in Pennsylvania and Doddridge, Tyler, and Wetzel counties in West Virginia. EURs range from 1.5-2.0-bcf/1,000' in less productive parts of the play to as much as 3.0-4.0-bcf/1,000' in the more productive parts of Green and Washington counties. Throughout much of the western portion of the play, wells need $2.50/mcf or less, while the wells in the eastern part of the play require prices of at least $3.00-3.50/mcf to generate an attractive return.

The southwestern Marcellus Shale is unique when compared with other dry gas basins in terms of the remaining inventory that is economic below $3.00/mcf. We estimate that there are more than 1,400 wells (at 10,000' lateral length) left to drill that work at or below $2.50/mcf and nearly 2,300 additional wells that are economic at between $2.50-3.00/mcf. More than 80% of the remaining shale gas wells in the U.S. that are economic below $2.50/mcf are in the southwestern Marcellus Shale and nearly 60% of all natural gas wells that work between $2.50-3.00/mcf are in the basin. At the current pace of activity, we estimate that there are over 10 years of development activity at $3.00/mcf or less.

Southwestern Pennsylvania Marcellus Shale Wells Drilled with Gas Price Breakeven Regions



Source: IHS Markit, SailingStone Capital Partners, Q1 2019.

In addition, there is quite a bit of drilling inventory that is economic above $3.00/mcf. We estimate that there are an additional 2,300 wells that can be drilled in the basin at higher prices. So, in addition to possessing a significant portion of the remaining low-cost drilling inventory in the U.S., the region also contains roughly 25% of the shale gas locations that work between $3.00-4.00/mcf. As a result, the southwestern Marcellus Shale will be the largest and lowest-cost shale gas basin for many years to come.

Haynesville Shale – 9-bcfd

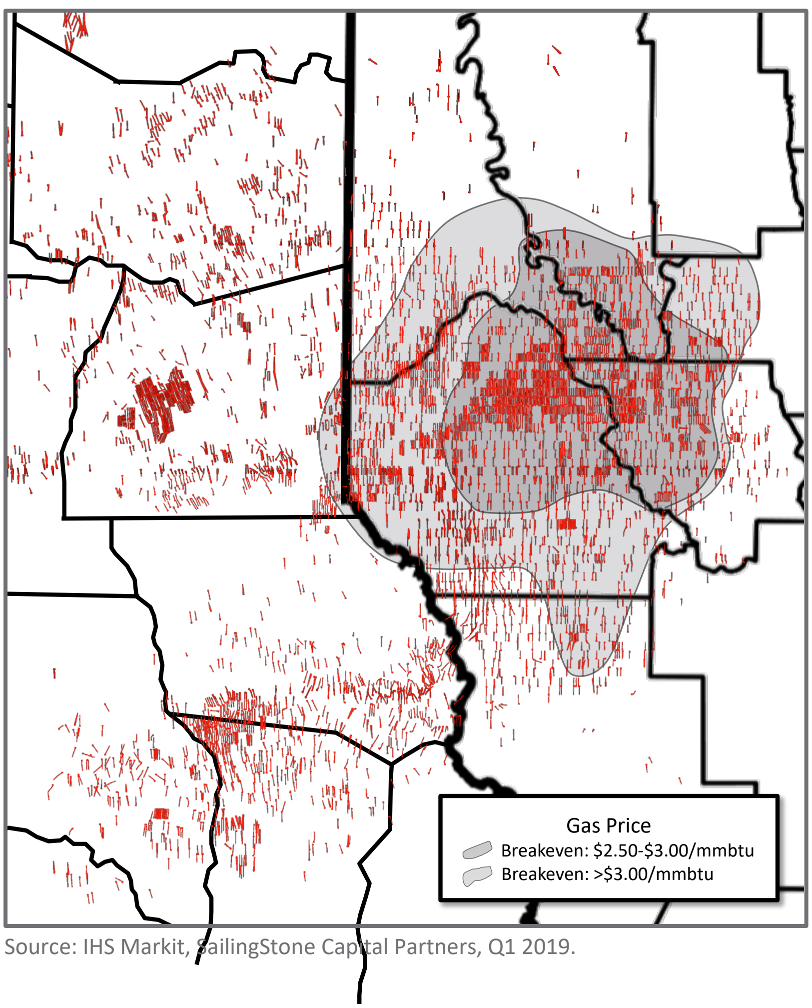
"Fasten your seatbelts." – All About Eve

The reemergence of the Haynesville Shale has as much to do with private capital as it does technology. After peaking at over 8-bcfd in 2011, natural gas production in the basin fell to below 5-bcfd in 2016 before growing to nearly 9-bcfd again today. The increase reflects the improvement in drilling economics in the basin as well as a substantial increase in drilling activity among private equity (PE)-backed companies. Today, more than 60% of drilling activity in the basin is done by private operators.

The core part of the Haynesville Shale covers 1.1 million acres across 5 parishes in Louisiana, which is relatively small when compared with other shale gas basins such as the Marcellus Shale. EURs are also much lower than in the Marcellus Shale, with recoveries averaging 1.5-2.5-bcf/1,000', and well costs are more than 25% higher per lateral foot than in the Marcellus Shale. As a result, drilling returns are much lower in the Haynesville Shale than in the core parts of the Marcellus Shale even with lower differentials.

In addition, the basin is relatively mature, reflecting the amount of drilling that has occurred over a relatively small area. To date, more than 3,500 wells have been drilled, with two thirds of them having been drilled in the core part of the Haynesville Shale in Bienville, Bossier, Caddo, De Soto, and Red River parishes. Given the sub-par economics, there are no wells that work below $2.50/mcf. However, there are roughly 1,200 drilling locations (at 7,500' lateral length) remaining that are economic between $2.50-3.00/mcf. Much of this inventory works at prices closer to $3.00/mcf than $2.50/mcf, though. At the current pace of activity, this represents just over 6 years of inventory. The depletion of core inventory in the Haynesville Shale will be a material event for the natural gas industry, since the growth in the basin has been so prolific over the last several years.

Haynesville Shale Wells Drilled with Gas Price Breakeven Regions



Source: IHS Markit, SailingStone Capital Partners, Q1 2019.

Outside of the core, we estimate that there are an additional 1,600 wells that are economic between $3.00-4.00/mcf. Furthermore, we believe that there is quite a bit of inventory in the broader basin that works at prices north of $4.00/mcf. As the call on shale gas grows and as low-cost inventory is exhausted, we expect the non-core Haynesville Shale to become a more important source of supply in the future. However, as a marginal producer, this supply will be quite sensitive to changes in natural gas prices.

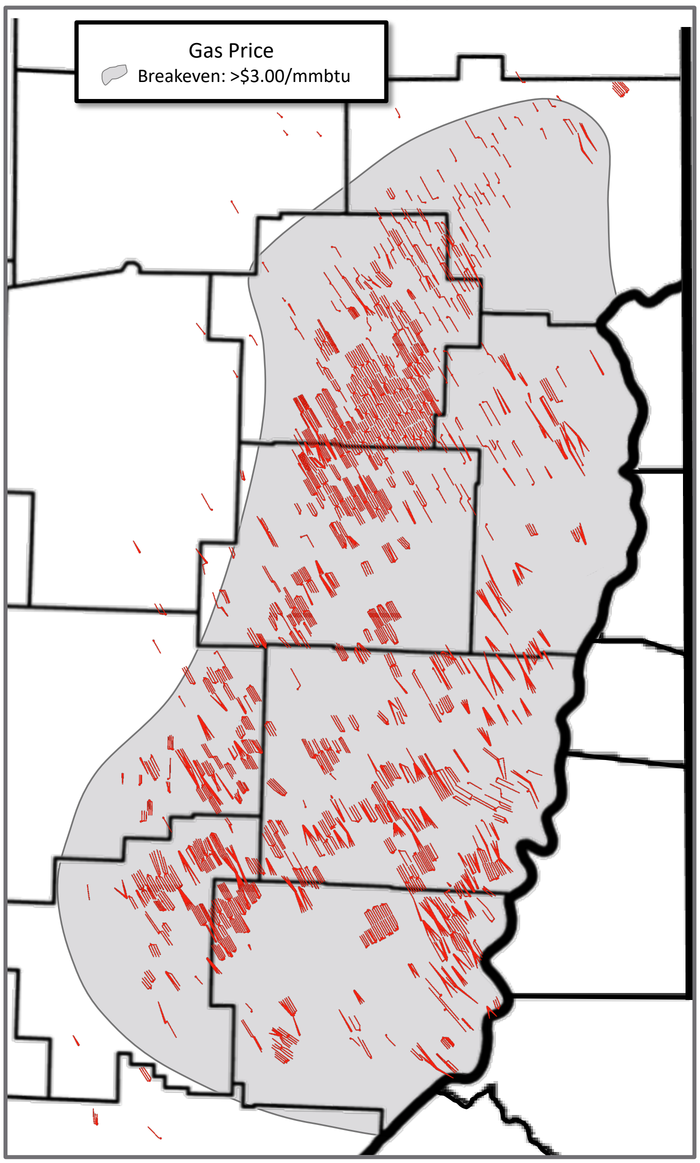
Utica Shale – 8-bcfd

"If you build it, he will come." – Field of Dreams

The Utica Shale spans 1.9 million acres over 8 counties in eastern Ohio and extends into southwestern Pennsylvania and northeastern West Virginia (where most activity is focused on the more economic Marcellus Shale). So far, more than 2,300 wells have been drilled in the basin, with production increasing from less than 0.5-bcfd in 2013 to nearly 8-bcfd today.

The rapid growth of the Utica Shale has been driven less by economics than by companies drilling to meet midstream commitments and by private operators looking to achieve the scale needed to go public. Similar to the Haynesville Shale, drilling activity in the basin is dominated by private equity-backed companies, which today represent 50% of the rig count. While much has been made about the impact of associated gas on the natural gas market, the reality is that PE-backed drilling activity in the Haynesville Shale and Utica Shale plays have had a bigger effect on the supply/demand balance.

Ohio Utica Shale Wells Drilled with Gas Price Breakeven Regions



Source: IHS Markit, SailingStone Capital Partners, Q1 2019.

Unlike the Marcellus Shale and the Haynesville Shale plays though, there are few wells in the Utica Shale that are economic below $3.00/mcf. EURs in the basin average just 1.5-2.5-bcf/1,000' with well costs that are 20% higher than in the Marcellus Shale and below-average netbacks. As such, the Utica Shale is the marginal dry gas basin today and will remain the marginal producer for the next several years.

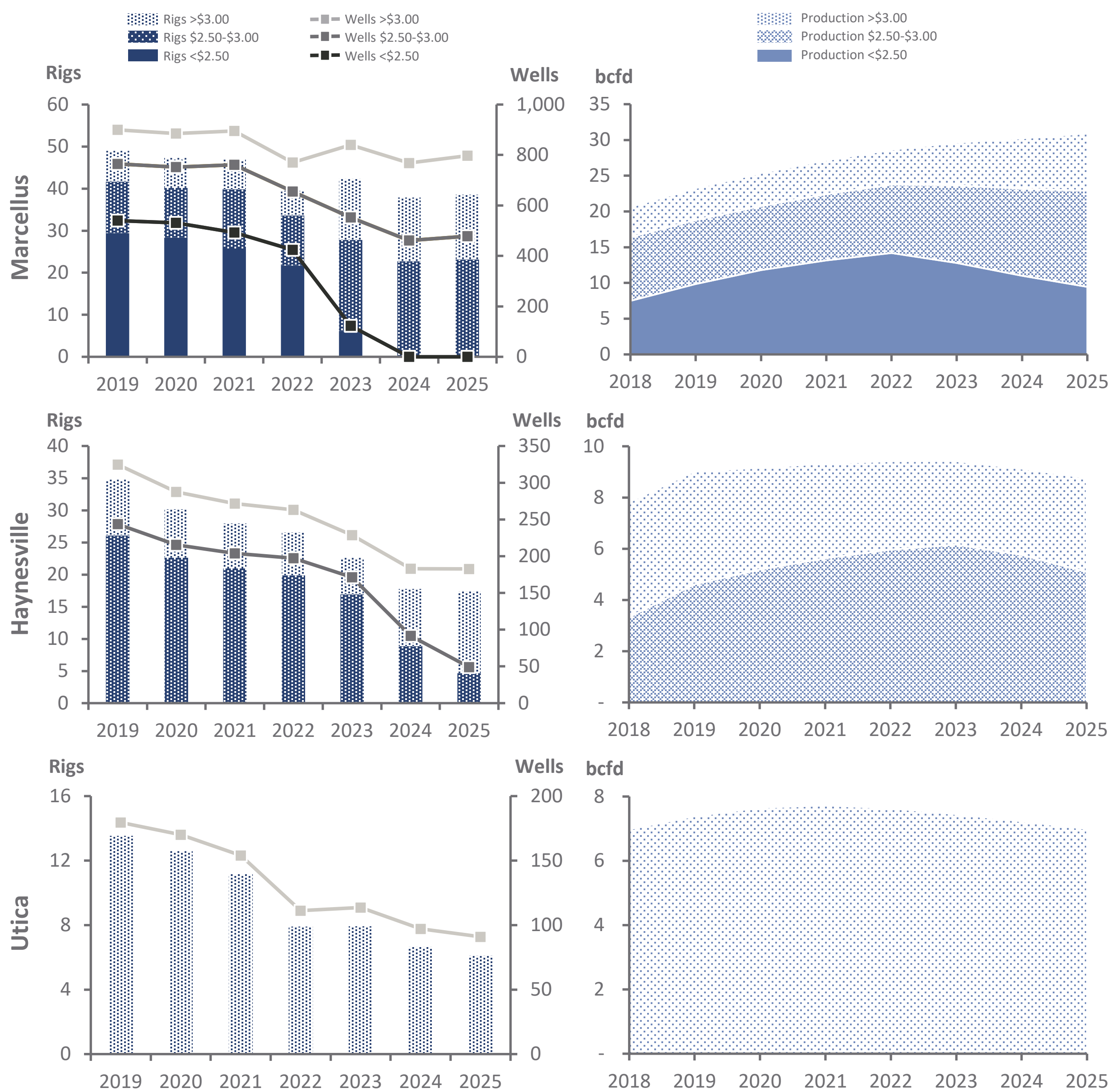
We estimate that there are nearly 3,500 wells (at 10,000' lateral length) left to drill in the Utica Shale that are economic at $3.00-4.00/mcf, with a significant portion of those locations requiring prices above $3.50/mcf. The Utica Shale should grow in importance as low-cost drilling inventory in other basins is depleted.

We expect natural gas production in the Utica Shale to continue to increase over the next few years, albeit at a much slower pace than it has in recent years. The growth will be driven primarily by private companies. However, given the marginal economics in the basin, we believe production could decline if natural gas prices fall much below $3.00/mcf. Our well count and production forecasts are highly sensitive to changes in prices.

Shale Gas Basin Activity Projections

Given the remaining drilling inventory in the Marcellus Shale, we expect production to continue to grow, albeit at a slower pace than in the past due to pipeline and inventory constraints in the Northeast. As companies in the basin meet their transportation obligations, and as operators become more focused on generating attractive returns and free cash flow, we expect the basin to offer investors an attractive combination of moderate growth, strong returns, and significant free cash flow. In the Haynesville Shale, we expect production to peak at roughly 10-bcfd by 2022. While declines in the core part of the field will be quite severe, as they were when drilling activity fell after 2011, we expect higher natural gas prices to spur development in areas that are uneconomic today. Growth in the Utica Shale has been driven primarily by private companies, and we expect this growth to slow; however, if gas prices fall much below $3.00/mcf we believe production could decline due to the marginal economics in the basin.

Rig Count and Well Count by Gas Price | **Wet Gas Production by Gas Price**



Source: SailingStone Capital Partners, Q1 2019.

Drilling Inventory Summary

Though not the consensus view, our analysis clearly shows that there isn't much shale gas drilling inventory remaining that is economic at $2.50/mcf or below. Most of the inventory that works at less than $2.50/mcf is owned by just a few companies in the very core parts of the Marcellus Shale. The idea that long-term natural gas prices will be $2.50/mcf or less is naive and reflects a lack of understanding regarding the call on dry gas and the economics of the remaining drilling locations in the major shale gas basins.

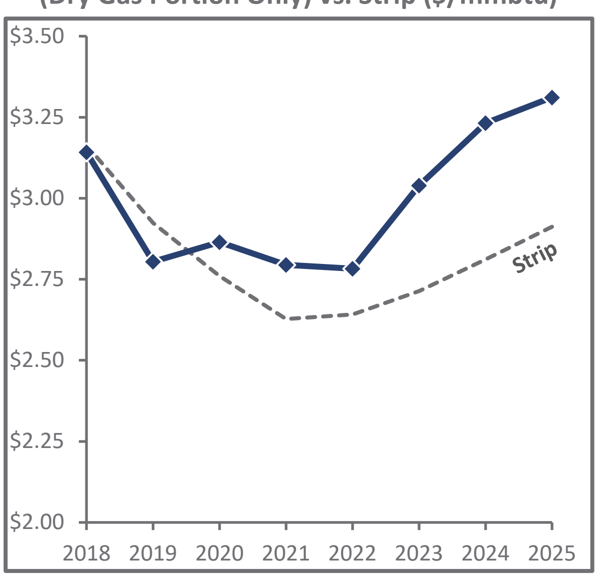
Furthermore, the analysis also shows the remaining drilling inventory that is economic below $3.00/mcf is quite limited as well. After a decade of development, and at the current pace of activity, there are just 6 years of drilling inventory remaining in core part of the Haynesville Shale that works at $3.00/mcf or below. The Utica Shale, which also produces nearly 8-bcfd today, requires natural gas prices of $3.00/mcf or greater. And, even in the prolific northeastern Marcellus Shale, there are just 3-5 years of inventory remaining that is economic at less than $3.00/mcf at the current pace of development. As this inventory is drilled up over the next 3-5 years, natural gas prices will need to increase above $3.00/mcf to incentivize drilling in the non-core areas of the Marcellus Shale and the Haynesville Shale, as well as the Utica Shale. The table below summarizes the remaining drilling locations across the four shale gas basins by break-evens.

Remaining Economic Inventory[1] by Play and Breakeven Gas Price

Region	<$2.50	$2.50 to $3.00	>$3.00	Total
NE Marcellus	308	816	2,367	**3,491**
SW Marcellus	1,422	2,296	2,248	**5,966**
Utica	-	-	3,476	**3,476**
Total Appalachia	1,730	3,112	8,091	**12,933**
Haynesville	-	879	1,225	**2,104**
Total Core	1,730	3,991	9,316	**15,037**
% of Total	*12%*	*27%*	*62%*	*100%*

[1] Inventory counts normalized to 10,000' lateral length.
Source: SailingStone Capital Partners, Q1 2019.

Weighted Average Breakeven of Wedge Gas (Dry Gas Portion Only) vs. Strip ($/mmbtu)



Source: SailingStone Capital analysis, Q1 2019.

We believe that the rapid depletion of shale gas drilling inventory remains underappreciated by most investors, many of whom remain convinced that natural gas prices will trade between $2.00-2.50/mcf forever due the growth in associated gas production and the near-limitless availability of low-cost shale gas. While there is quite a bit of shale gas drilling inventory remaining, most of it is economic at between $3.00-4.00/mcf, and natural gas prices will need to increase over time as the call on shale gas grows and as low-cost shale gas inventory is depleted.

In the next section, we discuss some of the implications of the decline in core drilling locations for the natural gas market and the E&P industry.

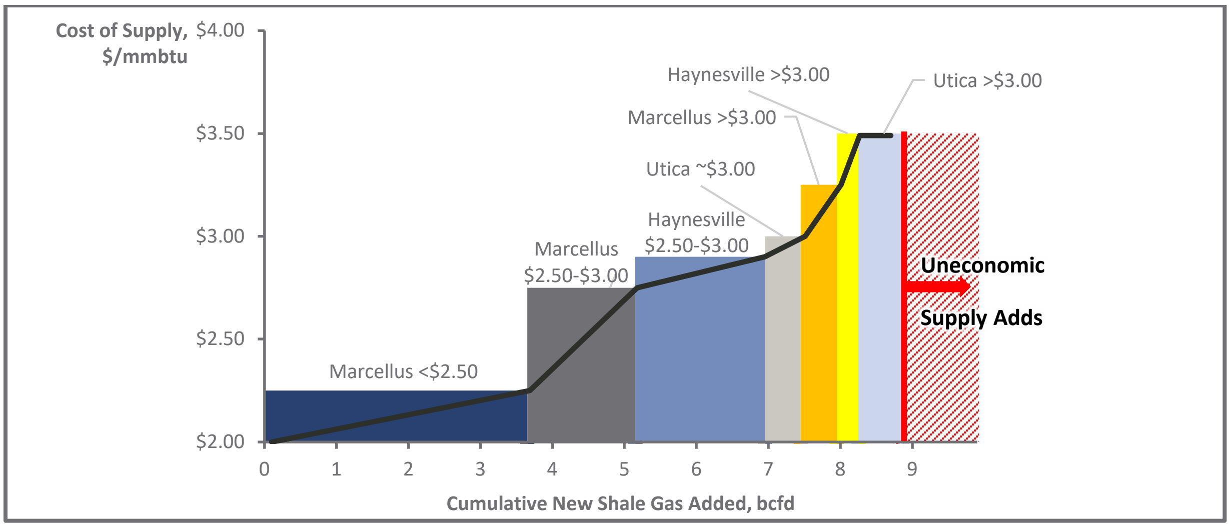
Part III – Implications of Core Inventory Exhaustion and Higher Natural Gas Prices

Long-term Price Expectations are Way Too Low

Natural gas prices need to be at a level that supports the drilling of enough new dry gas wells to balance the market. The natural gas supply cost curve and the marginal cost of supply will change over time as the demand curve shifts out to the right, as associated gas volumes fluctuate, and as the economics of shale gas change with drilling inventory.

Today, the dry gas portion of the wedge gas supply cost curve is comprised of low-cost wells in the Marcellus Shale, the Haynesville Shale, and higher-cost wells in the Utica Shale and non-core parts of the Marcellus Shale. The marginal cost of supply today is set by the higher-cost sources of supply as shown in the right-hand portion of the supply cost curve below.

2019 Wedge Gas Cost Curve (Dry Gas Portion Only)



Source: SailingStone Capital Partners, Q1 2019.

We estimate that the Utica Shale and Haynesville Shale require natural gas prices of around $3.00/mcf to generate a 15% project return. Cash operating costs, including differentials, range from $1.00/mcfe to $2.00/mcfe across the various shale gas basins. In addition to cash costs, capital costs for new shale gas wells are $0.30-1.00/mcfe, depending on the basin. In total, cash supply costs, before providing for a return on capital, are as low as $1.50/mcf in parts of the Marcellus Shale and as high as $2.50/mcf in the Utica Shale. The price required to generate a 15% project return varies from $2.00/mcf in the low-cost regions of the Marcellus Shale to more than $3.00/mcf in the Utica Shale, as shown in the table below.

2018 Estimated Financials				
$/mcfe	**NE Marcellus**	**SW Marcellus**	**Utica Shale**	**Haynesville Shale**
2018 Gas Price	3.16	3.16	3.16	3.16
Revenue	2.60	3.25	3.15	3.00
Cash Costs	0.95	1.65	1.65	1.20
Cash Margin	1.65	1.60	1.50	1.80
PD F&D	0.38	0.40	0.85	0.95
Recycle Ratio	4.3x	4.0x	1.8x	1.9x
Drillng Returns	**33%**	**30%**	**13%**	**14%**

Source: SailingStone Capital Partners, Q1 2019.

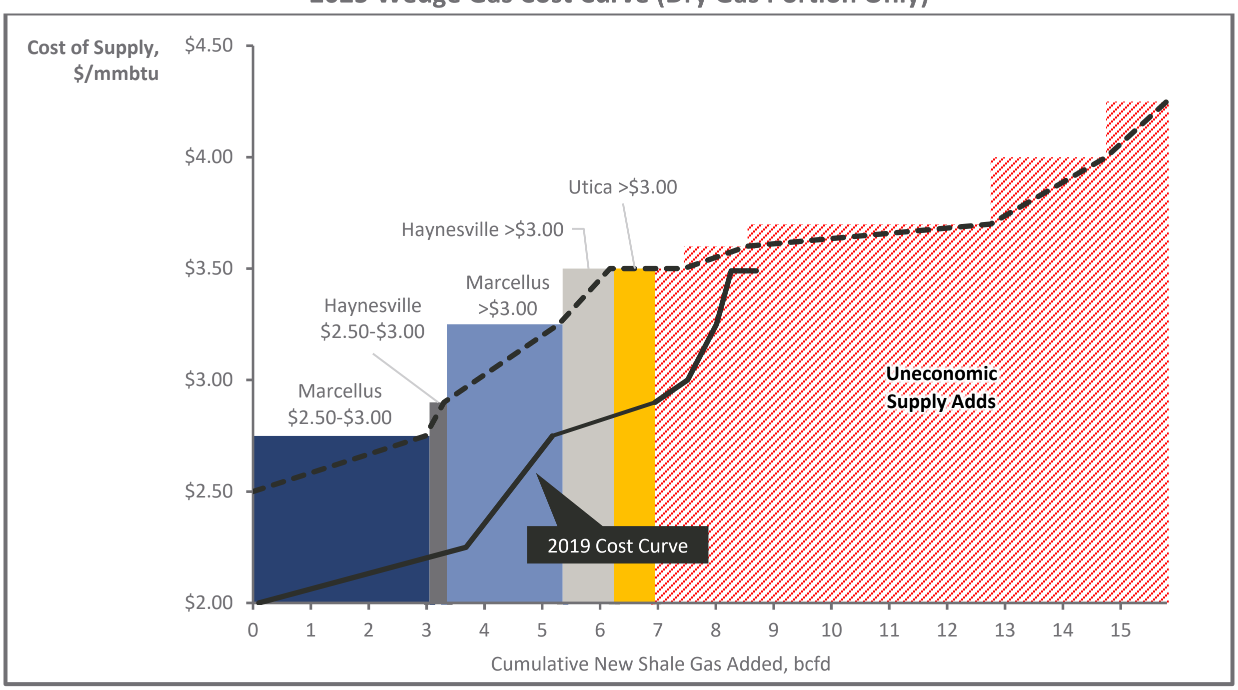
Shale gas economics explain why natural gas prices have averaged around $3.00/mcf since mid-2016. They also explain why natural gas prices cannot average $2.50/mcf or less for a prolonged period of time. While natural gas prices may decline toward cash operating costs at $2.00/mcf in an oversupplied market, the reality is that there is very little drilling inventory that works at $2.50/mcf or less, especially in the Haynesville Shale and Utica Shale. And, so long as new wells in these basins are required to balance the market, natural gas prices will need to be above this level.

Another way to think about shale gas economics is to assess what happens to cash flows at $2.50/mcf. The reality is that natural gas companies do not generate enough cash flow at $2.50/mcf to drill enough wells to meet the call on dry gas drilling. In fact, in a $2.50/mcf environment, most natural gas companies would not be able to hold production flat using internally generated cash flow.

Simply put, expectations that natural gas prices will be $2.50/mcf or less longer-term are not based on the economic and geological realities of the shale gas business. The $2.50/mcf or less forever case is based on unrealistic assumptions regarding the call on dry gas, shale gas drilling inventory, and shale gas economics.

Through 2021-22, we believe that natural gas prices will need to average around $2.75-3.00/mcf in order to balance the market. However, by middle of the next decade, we believe that rising demand, declining growth in associated gas production, and the exhaustion of core shale gas inventory will push natural gas prices well above $3.00/mcf to incentivize drilling in higher-cost areas within the Haynesville Shale and the Utica Shale. Below is our estimate of the wedge gas supply cost curve in 2025.

2025 Wedge Gas Cost Curve (Dry Gas Portion Only)



Source: SailingStone Capital Partners, Q1 2019.

As the call on shale gas continues to increase, as core inventory is depleted, as well productivity begins to deteriorate in shale gas basins, and as supply costs begin to rise, we expect long-term natural gas price expectations to eventually move much higher, from $2.25-2.50/mcf today to $3.00-3.50/mcf over the next 3-5 years.

Private Operators are a Bigger Problem than Associated Gas

The real issue in the natural gas market isn't associated gas, but rather the pace of drilling by some private operators in higher-cost shale gas basins. This has been the single greatest area of surprise in our supply models. While public companies remain capital-constrained, fund flows into private equity funds have supported the drilling of marginal wells in the Utica Shale and the Haynesville Shale plays. Much of this activity has been driven less by economics than by the need to deploy capital, the high initial production rates of wells in these basins, and the misguided notion that securing midstream commitments and growing will allow them to achieve the scale necessary to go public.

While the continued development of the Utica Shale and the Haynesville Shale is negative for the natural gas market, we believe that the challenging economics in the Utica Shale and the limited drilling inventory in the Haynesville Shale will reduce the impact of these basins going forward. We expect production growth in the Utica Shale to slow considerably if natural gas prices remain below $3.00/mcf and we expect production in the Haynesville Shale to fall once the core is drilled up.

Public Marks Don't Make Sense

Many publicly-traded natural gas companies discount a long-term natural gas price of just $2.25-2.50/mcf or less – well below the prices implied by the futures strip and the $3.00-4.00/mcf that, in our view, will be needed to balance the market in the future.

Using the futures strip, some publicly-traded companies are now trading below the value of their proved developed producing (PDP) reserves despite owning large undeveloped acreage positions in some of the lowest-cost parts of the Marcellus Shale. Given the significant value of low-cost/high-return drilling locations, as well as the prices being paid for core Marcellus acreage in the private market, these valuations do not make sense.

At the same time, there are a few publicly-traded natural gas companies that are trading closer to the value of their proved plus probable (2P) reserves using the future strip despite possessing less drilling inventory. These companies have low leverage, generate free cash flow, and are returning capital to their owners through dividends and share buybacks. Thus, the valuation discrepancies that exist in the public market today reflect transitory financial factors, such as market capitalization, leverage, and free cash flow more than asset quality, future returns, or drilling inventory. Scale, corporate costs, and the cost of capital matter more today than asset quality and drilling locations given the poor historical returns generated by E&P companies and the view that inventory is limitless.

Nonetheless, these valuations are unsustainable longer-term. Companies with low-cost inventory have a number of attractive options available to them to address the valuation gap. First, they can sell a portion of their inventory to reduce leverage and accelerate the return of capital. At current valuations, some companies could buy back as much as 20% of their shares outstanding by maintaining production at current levels and using free cash flow to buy back stock. Second, these companies can sell assets to strategic buyers that understand the value of core acreage and low-cost drilling inventory. And third, these companies could consider selling themselves to the larger companies that have a cost of capital advantage but need low-cost drilling inventory. Eventually, the scarcity value of core inventory will be recognized – if not by public equity investors, then by other buyers.

Shale Gas is a Real Business

Unlike shale oil, which is in the middle of the global supply cost curve, shale gas in North America is low-cost globally. This explains why advantaged shale gas companies have generated returns that compare favorably with the lower-cost shale oil companies despite the weakness in natural gas prices over the last few years.

	Shale Gas ($/mcfe)		Shale Oil ($/boe)	
	NE Marcellus	SW Marcellus	Permian Delaware	Permian Midland
Revenue	2.60	3.25	43.00	45.00
Cash Costs	0.95	1.65	10.00	10.00
Cash Margin	1.65	1.60	33.00	35.00
PD F&D	0.38	0.40	9.00	10.00
Recycle Ratio	4.3x	4.0x	3.7x	3.5x
Drillng Returns	**33%**	**30%**	**27%**	**25%**

Source: SailingStone Capital Partners, Q1 2019.

In addition, the shale gas business generates much more free cash flow than the shale oil business due to the much lower decline rates found in shale gas basins. We estimate that corporate decline rates for shale oil companies are in the 30-50% range, versus just 15-30% for the shale gas companies. Terminal decline rates are much lower as well. The lower decline rates allow shale gas companies to generate more free cash flow than shale oil companies, which should support better shareholder returns, on average, over time.

Lastly, advantaged shale gas companies have more drilling inventory than most shale oil companies, albeit in the $3-4/mcf range. As shale oil basins become increasingly developed over the next 5-10 years, we believe that most shale oil companies will need to evaluate strategic alternatives, since very few of them are going-concern entities. As shale oil basins mature, as well productivity deteriorates, and as core inventory is exhausted over the next few years, we expect both companies and investors to become more attracted to natural gas.

M&A Activity Will Pick Up

We believe that North American shale gas is a low-cost, long-lived resource that is well-positioned to meet the growing global demand for natural gas. Shale oil, on the other hand, is not low-cost globally, suffers from high decline rates, and has a limited runway. For most companies, shale oil will prove to be nothing more than a 10-20-year roller coaster ride, characterized by rapid increases in production and capital spending and then equally-rapid declines in production.

Today, public equity investors overvalue many shale oil companies, extrapolating production growth rates too far into the future and not properly accounting for the growing impact of well interference, accelerating decline rates, and core inventory exhaustion. On the other hand, public equity investors undervalue the low-cost shale gas producers that have better returns, more free cash flow, and attractive reinvestment opportunities.

With many advantaged shale gas companies now trading below PDP value, we would expect to see a significant increase in M&A activity given the unusual disconnect that exists between valuations and business quality.

Summary

Long-term natural gas price expectations are way too low. The low expectations reflect a lack of understanding regarding the call on shale gas and the remaining core inventory in the large shale gas basins.

Associated gas is less problematic than commonly believed. The rapid growth in associated gas production has been offset by conventional declines, allowing the call on shale gas to increase materially over the last several years. As shale oil basins become more mature, increased well interference and core inventory exhaustion will result in slowing supply growth. Lastly, the growth in associated gas production is supporting a significant increase in the installed demand base for natural gas, which will eventually be quite bullish for the call on dry gas and natural gas prices.

Private companies operating in higher-cost basins have been a bigger problem for the natural gas market than associated gas. Indeed, growth from the Utica and Haynesville Shale plays has been greater than the increase in associated gas production in the Permian Basin. Nonetheless, we believe that the depletion of core inventory in the Haynesville Shale and the high-cost nature of the Utica Shale will limit growth from these basins longer-term, particularly if natural gas prices remain below $3/mcf.

The call on shale gas will increase significantly post 2022 as natural gas demand growth accelerates and as the growth in associated gas production begins to slow. At the same time, the depletion of low-cost drilling inventory in the core parts of the Haynesville Shale and northeastern Marcellus Shale will require increased drilling activity in higher-cost shale gas basins, including the non-core Haynesville Shale, the non-core Marcellus Shale, and the Utica Shale. As such, natural gas prices will need to increase to $3-4/mcf in order to balance the market.

The overwhelmingly bearish view regarding long-term natural gas price expectations is based on the linear extrapolation of production data from the U.S. Energy Information Administration and misleading company investor presentations, as opposed to a detailed bottom-up analysis of underlying well data and an evaluation of the remaining drilling inventory. Our work shows that core inventory is quite limited in both shale gas and shale oil basins, and that investors are far too complacent about significant long-term impact of the inevitable exhaustion of core drilling locations.

In addition to the favorable longer-term fundamentals, shale gas is a much better business than shale oil. Shale gas is low-cost globally and the long-term demand outlook is quite positive, especially when compared with other fossil fuels. With better through-cycle returns, lower decline rates, and more free cash flow, low-cost shale gas companies are well positioned to generate attractive returns for shareholders – particularly as they pursue the Shale 2.0 business model and prioritize the return of capital.

Despite the improving natural gas and company-specific fundamentals, many natural gas producers are now trading below the value of their PDPs at the futures strip, which we believe is too low. This implies that either the futures strip is too high or that core acreage in the Marcellus Shale is worthless. We believe that both are incorrect.

Public equity market valuations clearly do not make sense and reflect the increased short-termism of public equity investors. We believe that these dynamics are creating an unusually attractive investment opportunity for those investors, public, private, or corporate, that are able to invest with a multi-year horizon.

Disclosures