Columbia | SIPA
Center on Global Energy Policy

LOW US STORAGE LEVELS POINT TO WINTER NATURAL GAS PRICE SPIKE RISK

BY KATHERINE SPECTOR
OCTOBER 2018

Market memories are short, and the fact that US natural gas benchmark Henry Hub hasn't seen a bullish winter since 2013–14 may explain apparent complacency about unusually low storage levels heading into winter. The market is failing to price in considerable spike risk in regional gas basis prices at a minimum, and most likely in benchmark Henry Hub as well. The goal of this paper is to explain the important role that gas storage plays in the North American winter, demonstrate how unusual and price-supportive storage fundamentals look going into this coming season, and preemptively explain what might be unanticipated price spikes.

Impressive gas production growth — whether from shale gas plays or associated with oil production — has been the dominant narrative in US gas markets in 2018 and for many years now. US dry gas production did indeed grow by an impressive 7.9 billion cubic feet (Bcf) per day in the first half of 2018, but domestic gas consumption grew by nearly 9.5 Bcf per day in the same period, and net exports also grew (consumption has grown by nearly 5.5 Bcf/day year-over-year since May, which would have had nothing to do with winter cold). As a result US gas storage is some 700 Bcf below normal. To put that number into context, the market would have to find an extra 7.8 Bcf per day over the next three months, for example, to refill that deficit.

Underhedging by consumers may exacerbate any price jump this season by leaving consumers fully exposed to market moves. However, winter price spikes will also gift gas producers with a prime hedging opportunity, which is one reason why prices spikes will most likely be just that — temporary jumps in a market that is still structurally bearish.

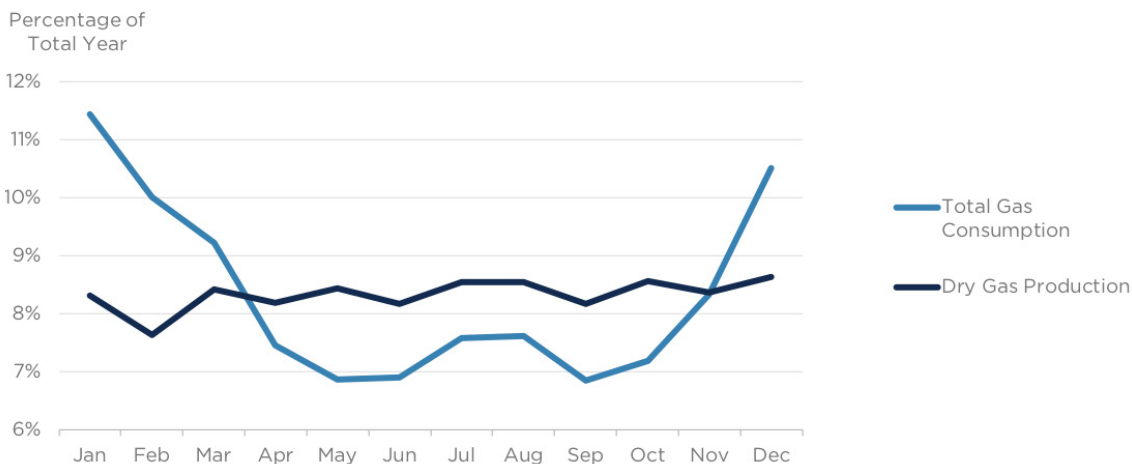
The Role of Storage in a Highly Seasonal Gas Market

While in some markets the primary role of storage is to smooth market inefficiencies and plug temporary mismatches of supply and demand, for North American natural gas, the role of storage is much more structural and consistent. Simply put, there is always a large excess of natural gas supply in the summer, and it has to go into storage. And even in recent years, when gas production has grown so significantly, production never matches winter demand, which as a rule must be supplied out of storage.

Residential and commercial consumers use gas primarily for heating and account for 40–50 percent of gas use in the peak winter months, but just 10–12 percent in the summer. US gas consumption in the winter can be as much as two times consumption in the "shoulder season," when gas consumption is at its lowest — that is, between seasons, when gas is no longer used for heating but not yet used to produce incremental electricity for meaningful cooling. (There is a second, smaller seasonal "bump" in gas demand from power generation in the summer, but it is nowhere near the magnitude of winter consumption.)

Gas production, on the other hand, shows very little seasonality aside from a slight dip in February, on average, when the most severe cold can sometimes "freeze off" gas production temporarily. As a result, gas is almost always injected into storage from May through October and almost always withdrawn from November through April (the precise beginnings and ends of injection and withdrawal seasons can of course vary slightly with the weather). Figure 1 shows the relative seasonality (or lack thereof) of US gas consumption and production.

Figure 1: The Relative Seasonality — and Lack Thereof — of US Gas Consumption and Production



Source: Author calculations based on Energy Information Administration data

The gas market functions to reflect this paradigm: storage contracts typically include dates by which gas must be injected and withdrawn, and the Henry Hub futures curve itself demonstrates a "wavy" seasonal pattern, where prices for winter-month contracts price higher than summer-month contracts. This pattern not only reflects how gas prices typically end up each year — more or less — but also provides the economic incentive that storage operators need to build inventory ahead of winter. Theoretically, the shape of the futures curve allows the purchase of cheap gas in the summer to be put into storage, which is delivered in the winter against the sale of relatively more expensive winter futures. Storage operators earn the spread between summer gas prices and winter gas prices.

There are many factors that determine exactly how much gas is withdrawn from storage in the winter, but weather is by far the most influential variable in any season or even in any given week. Near the end of the winter in particular, contractual obligations to withdraw gas from storage also come into play.

Storage capacity is concentrated in gas production areas in North America and certain consumption areas. However, certain major consumption areas have no "local" storage or have limited local storage, which is why a very complex network of continental pipelines is so critical for meeting real-time peak winter demand. While Henry Hub, traded on the New York Mercantile Exchange, serves as the North American benchmark gas price, there are also many actively traded regional gas "basis" markets that trade as a differential to Henry Hub to reflect regionally specific dynamics. In regions with no nearby production or storage, basis pricing reflects deliverability, or the ability of the pipeline system to deliver gas to consumers when they need it.

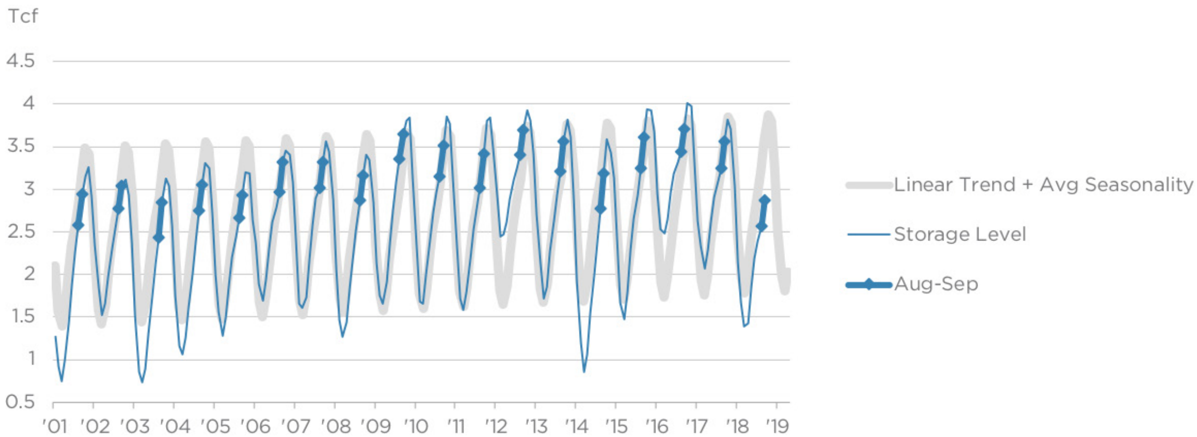
Constrained deliverability affects at least one or two basis markets every year, no matter how high storage is nationally or regionally. In certain key consumption areas, like the New York City and Boston Citygates, there will simply never be enough deliverability to adequately supply the coldest days of the year. It will never make economic sense to build enough pipeline capacity to supply those areas for just a few days when demand is highest—capacity that would by definition be idle most of the time. So on those days, price has to ration demand, and it does with occasional—and usually very temporary—spikes as high as $80–$100/MMBtu in basis markets like Algonquin and Transco-8 NYC. This is an issue of deliverability, not an issue of supply per se.

When gas prices go up in the winter, it is either because of a lack of *deliverability* (pipeline capacity to get the right amount of gas to the right consumers at the right time) or a lack of *supply* (gas produced and withdrawn from storage to meet seasonal demand). Constrained deliverability tends to affect localized basis prices, though in extreme scenarios it can also affect benchmark Henry Hub. Constrained supply, on the other hand, is much more likely to have a generalized effect on gas prices across the board. What is interesting about 2018 — because it does not happen every year and has not happened in the last several years — is that gas storage is indeed very low, and the risk that poses for gas prices seems underappreciated.

Low Storage Any Way You Slice It

North American, and particularly US, natural gas storage levels are extremely low by any measure. Figure 2 below compares current US natural gas storage levels (highlighting August–September levels) to "normal," represented here by the yellow line showing the 10-year linear trend in storage overlaid with average seasonality. Figure 3 shows the deviation of current storage from that "normal" line, again highlighting the August–September periods. This method is preferable to simply comparing current levels to year-ago levels or even the previous five-year average because, at any given time, the last year or the five-year average may or may not be a good representation of "normal." Rampant production growth in the past five years, for example, and constrained takeaway capacity for that new volume arguably forced more molecules into storage than would otherwise have been there, possibly providing an artificially high base for comparison. The long-term (10-year) linear trend and average seasonality provide a more credible context for current storage levels.

Figure 2: Lower 48 Working Gas Storage Level Falls Well Below "Normal"



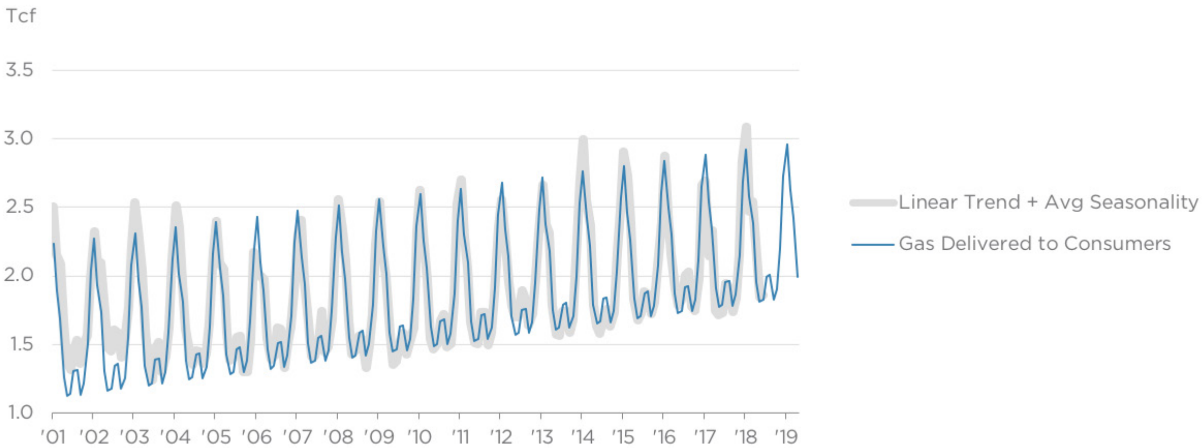
Source: Author calculations based on Energy Information Administration data

Figure 3: Lower 48 Working Gas Storage — Tracking Well Below Trend and Average Seasonality

Source: Author calculations based on Energy Information Administration data

While the recent focus in North America has been on rampant gas production growth, US natural gas consumption has also grown meaningfully. US gas consumption has grown by an average of 12.7 percent in 2018 to date, which puts it well above trend (figure 4).

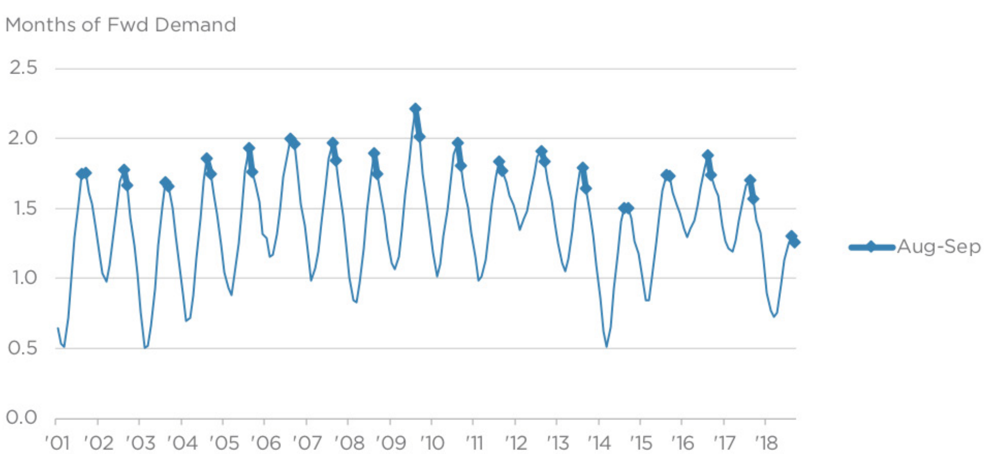
Figure 4: US Natural Gas Deliveries to Consumers



Source: Author calculations based on Energy Information Administration data

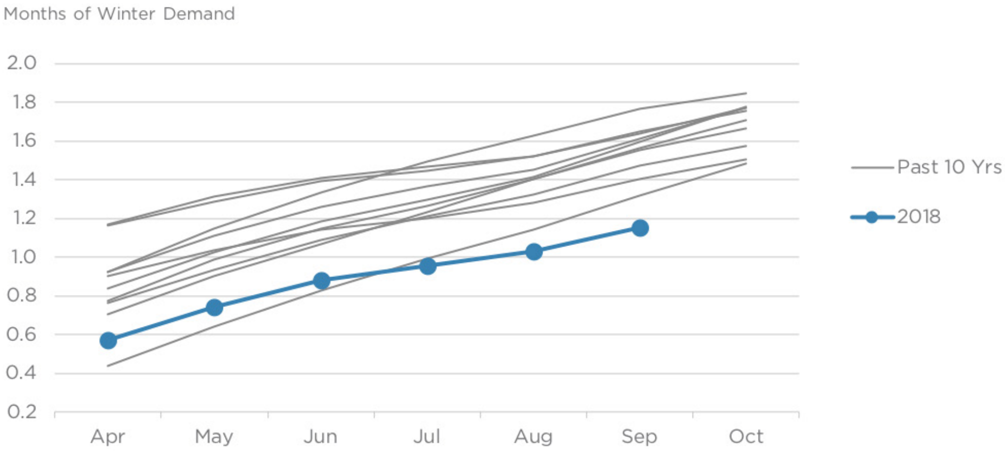
That means that this year, and every year, winter storage needs to support a larger base level of consumption whether or not weather is unusually severe. For that reason, it is also important to look at storage levels in the context of forward demand cover, and that paints just as dire a picture of the current storage situation. Figure 5 below shows a long-term view of natural gas storage in months of forward demand cover (three months forward, in this case). Figure 6 shows storage in months of winter demand cover specifically, throughout the past decade of injection seasons.

Figure 5: Lower 48 Working Gas Storage is Also Low in Terms of Months of Forward Demand Cover



Source: Author calculations based on Energy Information Administration data

Figure 6: Lower 48 Working Gas Storage in Months of Winter Demand Cover



Source: Author calculations based on Energy Information Administration data

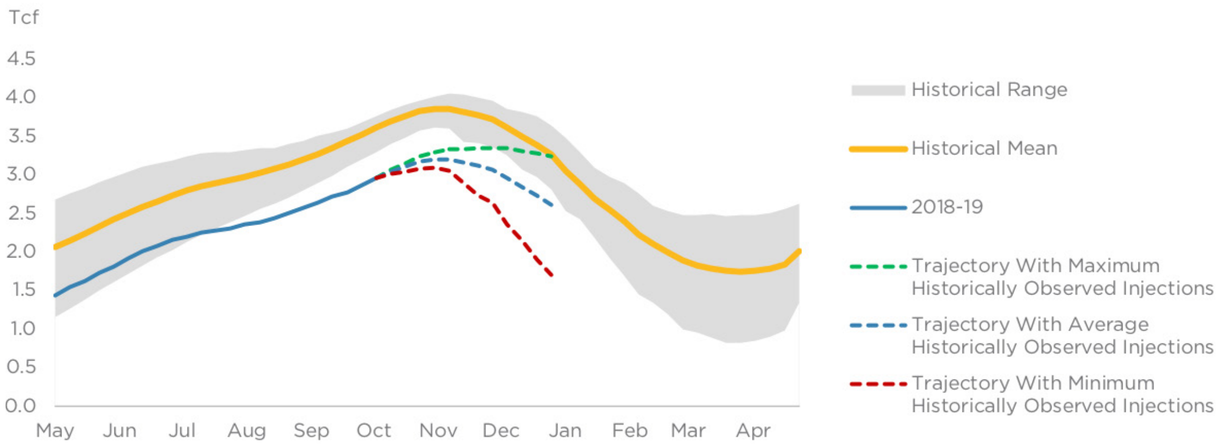
DUCs Won't Save You Now… Weather Might

One favorite argument for sanguine attitudes toward low storage is not only high US gas production in general but the "easy on, easy off" characteristics of shale production specifically, and the sizable inventory of drilled but uncompleted wells (DUCs) and ample volumes of gas being produced in association with oil production. While this "gas behind pipe" may be price responsive to a degree, that price response would not happen overnight, and DUC completion is more frequently constrained by insufficient takeaway capacity and thus most responsive to incremental pipeline additions. The inventory of DUCs fell most significantly in 2016, for example, after a significant amount of new pipeline capacity came online and production from previously uncompleted wells could be "tied in" to the distribution network. This winter, whether DUC completions pad supply will depend more on takeaway capacity than price incentive per se.

Perhaps the best bearish argument for winter gas is the weather forecast. NOAA, the Farmer's Almanac, and private forecasts all predict a warm winter thanks to el Nino, and, more specifically, anticipate a warm start to the winter. This is important because early-winter temperatures tend to matter more for gas prices than late-winter temperatures, when fundamentals are essentially already a foregone conclusion.

However, even with maximum historical weekly injections (or historical minimum withdrawals) in every week through December — a tough if not impossible bar — the United States will still enter the peak winter demand season only with storage roughly in line with the historical average, not above it. Figure 7 below shows the theoretical gas storage trajectory if weekly injections/withdrawals were in line with the historical average between now and the end of December and the trajectories if every week matched the (noncoincidental) maximum and minimum historically observed weekly storage changes. In other words, the green line shows the trajectory for storage if each week's injection is equal to the biggest injection observed historically in that calendar week, no matter the year. For reference, injections so far in the 2018 season have been unremarkable and mostly in line with the historical average.

Figure 7: Possible Storage Level Trajectories Based on Historical Precedent



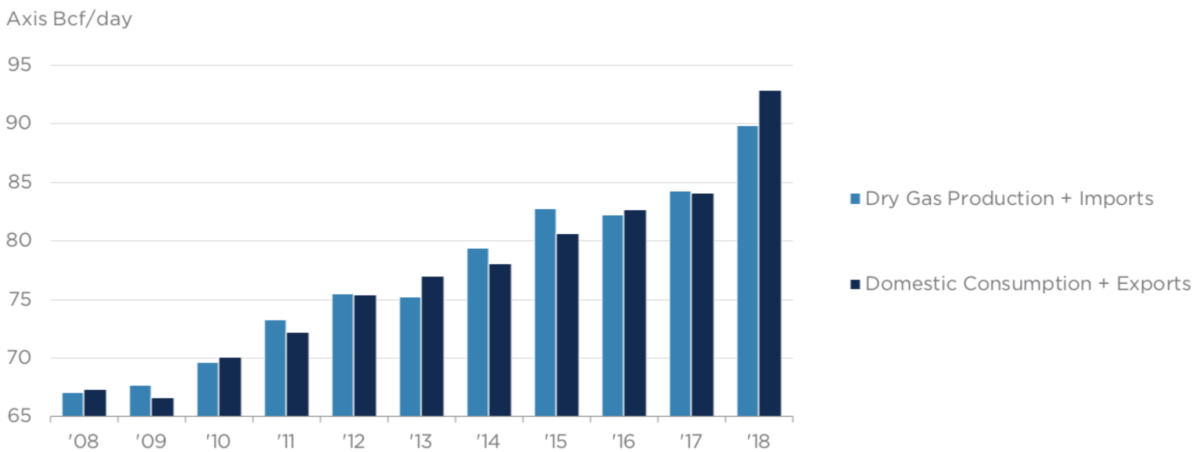
Source: Author calculations based on Energy Information Administration data

Canadian gas may offer one other mitigating factor in an otherwise bullish fundamental North American gas outlook. North American — and in particular US and Canadian — gas markets are highly integrated via a network of cross-border pipelines. While all regional markets are subject to unique fundamentals and pricing to a degree, the US and Canadian gas markets do tend to follow the same general trends each year, and in fact, the major Canadian gas hub, AECO, prices as a differential to Henry Hub. For that reason, it is also useful to consider Canadian gas storage for clues about the winter outlook. Canadian gas storage also started the injection season at low levels, though the situation there is less dire and recovering more quickly than in the United States. Additionally, stranded West Canadian AECO gas remains so persistently cheap that it is bound to fill supply deficits to some degree as deliverability permits.

Why Is Storage So Low When Production Is So High?

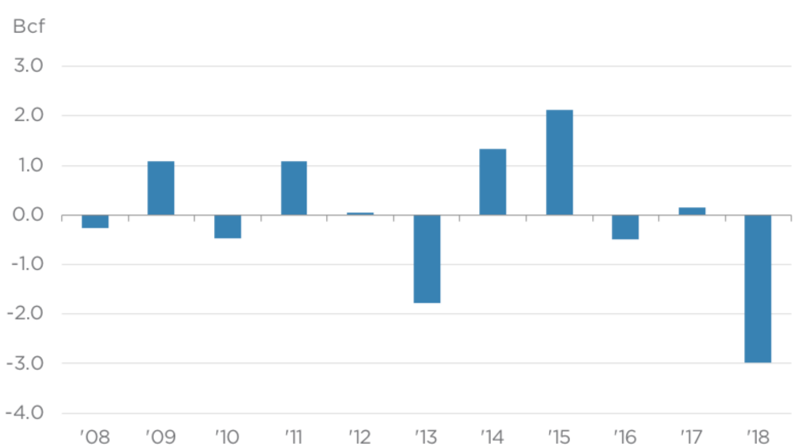
Why is storage low? First, North America exited last winter with relatively low storage levels, leaving a larger than normal deficit to refill. And to put it simply, gas disposition has been growing more quickly than gas supply, on average, for the past two-plus years. That may seem hard to believe given the dominant and persistent narrative of abundant US gas production, but the data is clear. Figure 8 below shows annual US gas disposition (domestic consumption plus exports) and gas supply (domestic dry gas production plus imports). Figure 9 shows annual average gas supply minus gas disposition.

Figure 8: Annual Average US Gas Supply and Disposition



Source: Author calculations based on Energy Information Administration data

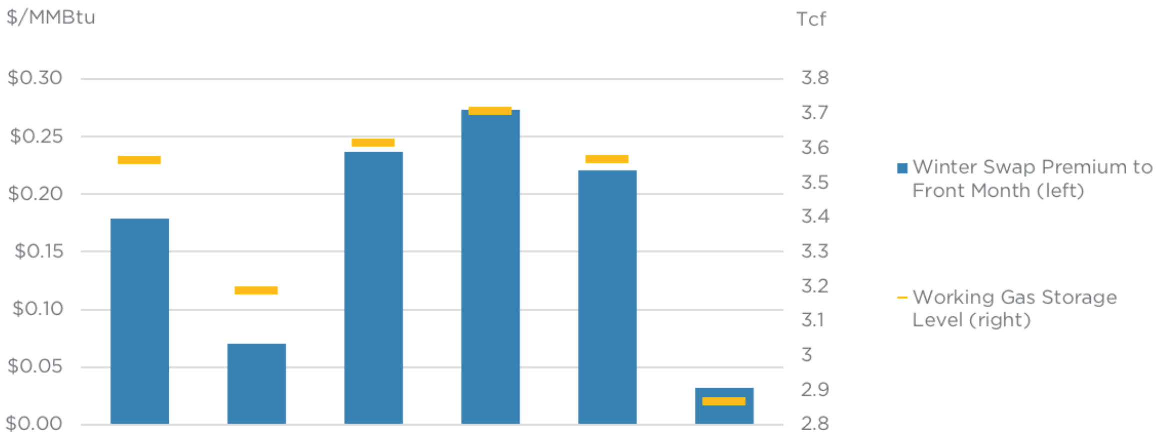
Figure 9: Annual Average US Gas Supply Minus Disposition



Source: Author calculations based on Energy Information Administration data

On top of that fundamental backdrop, the natural gas forward curve has not paid well for storage during this injection season. The Henry Hub futures curve always demonstrates seasonality, where winter futures price higher than summer futures. In other words, the natural gas curve trades in contango from the summer to winter months. This effectively incentivizes storage during the injection season; theoretically, storage operators can buy cheaper physical natural gas to put into storage and sell higher-priced futures against which stored gas will be delivered come winter. The shape of the futures curve and its relationship to storage levels is something of a chicken-to-egg relationship, though. High storage levels tend to steepen contango, which then further improves storage economics. Strength in the prompt futures contract relative to deferred months, on the other hands, signals tight immediate supply and disincentivizes storage, effectively compounding the optics of shortage. This year's winter contango is the smallest it has been in recent memory— reflecting not only what are very low storage levels but also the poor economics for storage (figure 10).

Figure 10: Premium of the Winter Henry Hub Strip to the Front-Month Henry Hub Future

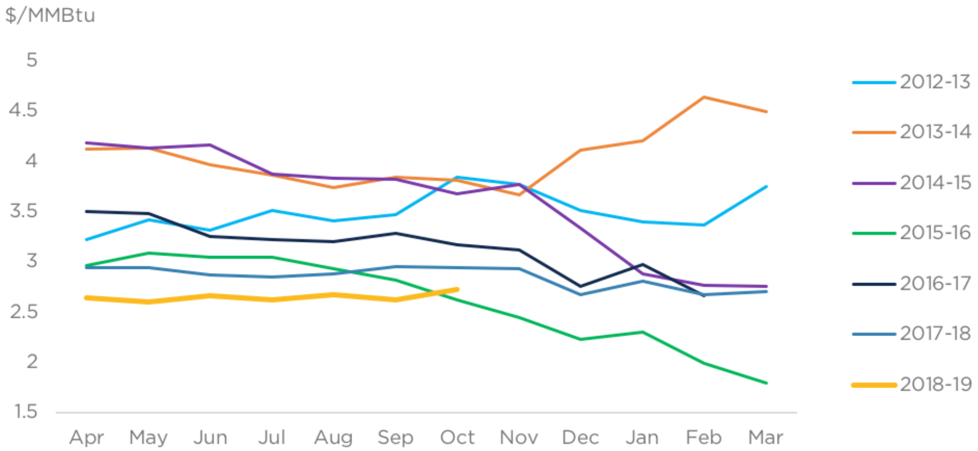


Source: Author calculations based on Bloomberg data

Market Complacency in the Face of Low Storage

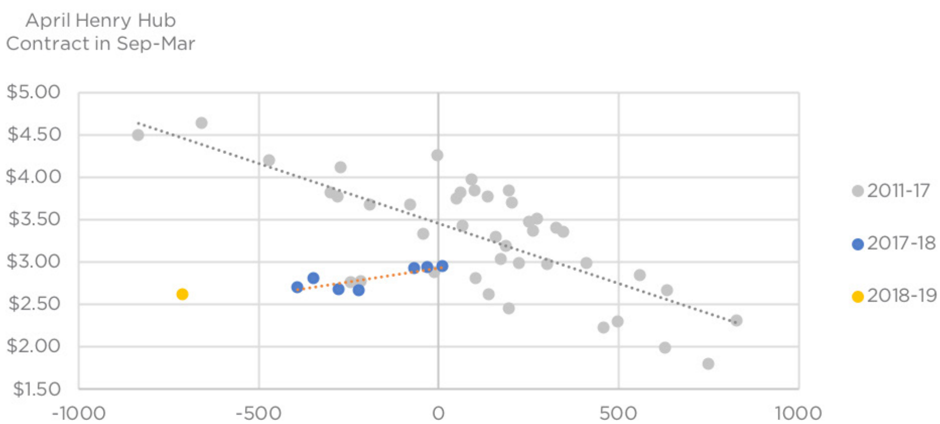
Neither current nor forward pricing in Henry Hub or even key basis markets reflect 2018's comparatively supportive storage levels. Even if one believes that this year's fundamental outlook is more benign than storage levels suggest, it is hard to justify an April contract that is pricing lower than previous Aprils did in any of the last several years, when storage was more comfortable or even on target to start the winter practically full. Figure 11 shows how past years' April Henry Hub futures contracts traded during the injection season and then the winter season, preceding expiry. Through most of this injection season the April 2019 contract priced lower than any April contract has in recent years; only in the last month has a 17¢/MMBtu rally lifted the contract from recent lows, but pricing is still extremely subdued given unusually low storage. Looked at another way, figure 12 shows a scatter plot between the deviation from "normal" storage in September through March (x-axis) versus the price of the April Henry Hub futures contract in those months (y-axis). This statistical relationship alone would predict an April 2019 futures price some 50 percent higher than today's <$3/MMBtu price — a massive divergence, even if production surprises to the upside or weather turns out to be mild.

Figure 11: 2019 April Henry Hub Looks Radically Underpriced Relative to Past Years



Source: Author calculations based on Bloomberg data

Figure 12: April Gas Looks Radically Underpriced Relative to Storage



Source: Author calculations based on Bloomberg data

While the supply outlook still underpins a structurally bearish North American natural gas price, it is worth noting that statistically, average and maximum winter Henry Hub prices do inform the calendar average price in the subsequent year. This has been true even in the several recent bearish years. That means that statistically, the average and peak prices in the winter of 2018–19 should influence the average price for calendar year 2019 in a fairly predictable way. And right now, the Calendar 2019 swap is pricing cheap even relative to what is arguably a radically underpriced Winter 2018–19 swap.

This is all to say that both historical precedent and current fundamentals point to not only higher prices in the winter of 2018 but also at least marginally higher on average in 2019 compared to what the forward curve is currently pricing.

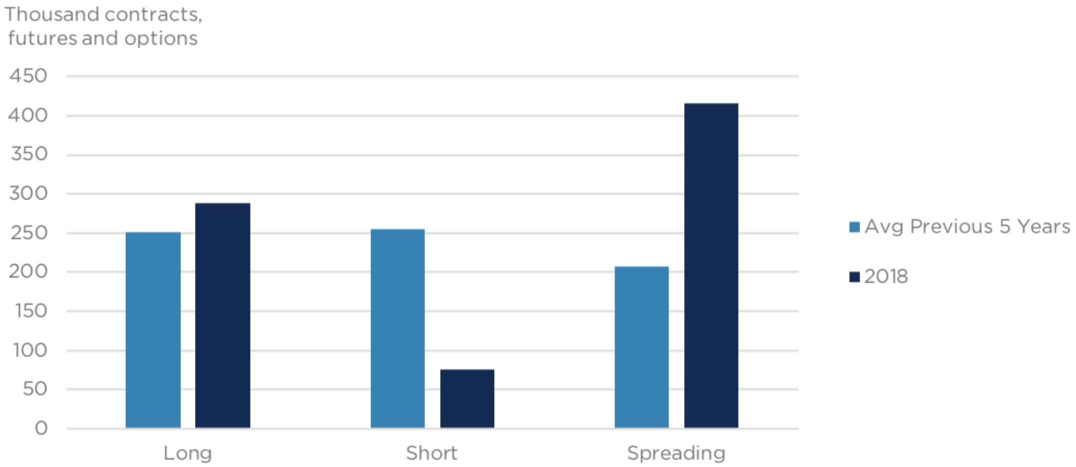
Market Positioning May Both Exacerbate and Mitigate Price Spikes

How market participants are positioned can either exacerbate or mitigate how prices respond to fundamentals. This winter, it could be both. Anecdotally, while North American natural gas industrial and utility consumers do hedge consistently and systematically and have done so in 2018 as well, many may be underhedged going into this season. It may be a case of the market crying wolf for so many years in a row; for the past five years, consumers have not been rewarded for hedging their winter price risk, and some have reduced hedging volumes as a result. Market lore dictates that prices spike as soon as consumers stop hedging in a bear market and that prices collapse as soon as producers stop hedging in a bull market.

Producers, on the other hand, will likely be quick on the trigger if attractive hedging levels emerge in either benchmark Henry Hub or basis markets this winter, after a dearth of hedging opportunities for the past several years. Producers have already taken advantage of the rally in prices since mid-September (the Calendar 2019 swap is up about 20 cents, for example), but more opportunistic hedging is likely. Short-term winter price spikes don't always lift the longer-dated part of the forward curve — where producers would want to sell — but if they do, producers will jump on it. This is one reason why any price spike is likely to be short term in what is still a structurally bearish market — the more gas that North American producers are able to hedge at relatively attractive levels, the more gas they can produce at a profitable price. In a market where the resource base is ample, high prices inevitably correct themselves.

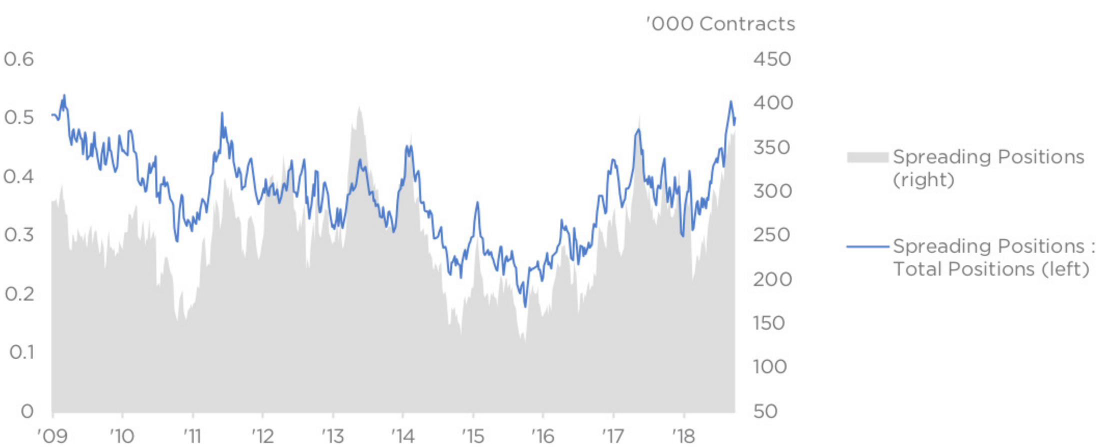
One notable feature of managed money, or speculative market positioning in Henry Hub futures is the concentration of open interest in spreads as opposed to flat price (figures 13 and 14). That means that a large number of market participants are long one part of the curve and short another, as opposed to being outright long or short gas. And, while the number of long positions in Henry Hub is fairly typical of this time of year based on recent history (and likely reflects some base level of passive, institutional investment in gas through index-style products), the number of speculative short positions is unusually small. An interpretation of this phenomenon is that it is a defensive expression of bullish winter risk in a market where prices so far have been stubbornly unmoved for years. In other words, managed money traders clearly don't want to be short gas going into this winter, but would prefer to position for price upside via spreads than through flat price positions.

Figure 13: Managed Money Traders Favor Spreads But Are Loath to Short Gas Going Into the Winter



Source: Author calculations based on Bloomberg data

Figure 14: Managed Money Spreading Positions as a Ratio to Total Managed Money Positions (Futures and Options)



Source: Author calculations based on Bloomberg data

Conclusion and Areas for Future Study

The bottom line for both benchmark Henry Hub and regional North American gas basis markets is that there is significant winter price spike risk that is not currently reflected in forward pricing. That spike risk could be exacerbated by market complacency in the short run but ultimately countered by pent-up hedging demand from gas producers. This is still a structurally bearish market but one that seems to have forgotten that even bearish markets can rally hard now and then.

If and when gas prices do spike this winter, it will provide data points for a number of questions that merit further investigation.

First, gas prices have not rallied meaningfully since US liquefied natural gas exports have really ramped up. That means that we really don't have a template for what happens to supplies intended for export when domestic prices increase sharply. The winter of 2018-19 could provide interesting preliminary data points for the degree to which would-be LNG feed can be diverted to the domestic market. This means not only data points on the theoretical economics that are necessary to divert gas, but also the contractual and logistical pieces that have to fall into place to displace exports. Exactly how nimble are sellers, and how price sensitive are buyers of US LNG? Similarly, might LNG exports attract renewed negative rhetorical attention from opponents of exports if prices spike?

Second, certain regions will inevitably see bigger price spikes than others this winter, and the Great Lakes region—Michigan in particular—stands out as at risk for a bullish winter. The Great Lakes is an interesting region in terms of pipeline complexity, consumer sophistication, and cross-border dynamics. Based on (admittedly lagged) Energy Information Administration state-level data, the area not only has one of the biggest storage deficits in both percentage and volume terms but also has seen one of the highest rates of five-year gas consumption growth. In addition to the usual suspects — Boston and New York — major population centers like Chicago and Detroit are prime candidates for price spikes this season. Significant changes to pipeline capacity, direction, and tariffing in recent years make this area a complicated story to follow. How the Great Lakes region responds to spikes this winter will provide clues to how new pipeline dynamics affect key basis hubs in this region.

Finally, in the past decade, the financial commodities trade in general, including the natural gas trade, has seen significant changes that have reduced the number of pure-strategy, fundamentally based speculative traders in the space. In other words, the number of hedge funds with dedicated commodity traders that express market views based on firsthand knowledge of physical commodity fundamentals has decreased. This is particularly true for natural gas, which has not offered the same volatility that oil has in recent years. Speculative trade in gas basis markets has always been minimal. That begs the question of who is left in the market who can not only analyze but take a discretionary trading view on gas fundamentals.

About the Author

Katherine Spector is a Research Scholar at the Center on Global Energy Policy. She is a longtime energy market analyst, having spent the past fifteen years producing thought-leading commodity derivatives research at major banks, including JPMorgan Chase, Deutsche Bank, and CIBC World Markets. Ms. Spector also serves on the board of the New York Energy Forum, an educational organization dedicated to increasing public knowledge about energy issues. Ms. Spector graduated with honors with a degree in Political Science from Yale University, where her research focused on patterns of rent distribution in petro-states, and implications for democratization.

This work was made possible by support from the Center on Global Energy Policy. More information is available at http://energypolicy.columbia.edu/about/mission.

ABOUT THE CENTER ON GLOBAL ENERGY POLICY

The Center on Global Energy Policy provides independent, balanced, data-driven analysis to help policymakers navigate the complex world of energy. We approach energy as an economic, security, and environmental concern. And we draw on the resources of a world-class institution, faculty with real-world experience, and a location in the world's finance and media capital.

Visit us at www.energypolicy.columbia.edu

@ColumbiaUenergy

ABOUT THE SCHOOL OF INTERNATIONAL AND PUBLIC AFFAIRS

SIPA's mission is to empower people to serve the global public interest. Our goal is to foster economic growth, sustainable development, social progress, and democratic governance by educating public policy professionals, producing policy-related research, and conveying the results to the world. Based in New York City, with a student body that is 50 percent international and educational partners in cities around the world, SIPA is the most global of public policy schools.

For more information, please visit www.sipa.columbia.edu