Liquidity Issues in the U.S. Natural Gas Market: Part 2 of 2

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Introduction

This paper is the second in a two-part series. In part 1, which appeared in the Winter 2019 edition of the *GCARD*, we examined different liquidity measures and considered their relevance to the natural gas markets.

In the current paper, we review unique features of the U.S. natural gas market and how price formation occurs for the various types of natural gas products traded. Natural gas demand is highly sensitive to weather conditions, and market prices can fluctuate widely from day to day and from location to location. This means that gas traders turn over a new leaf every day and have to go through the process of price discovery every morning with the previous day's prices being often of limited usefulness in the determination of prices for the current day. Price discovery on the Intercontinental Exchange (ICE) platform is instantaneous through the interaction of bids and offers posted by traders. The process of price formation is squeezed into a relatively narrow window of a few hours and has to be completed before the deadline for pipeline nominations with most of the volumes being committed by 1 p.m. Central.[1] The market has no designated central price maker with many market participants operating both as providers and consumers of liquidity, depending on market conditions and location. There is always a potential for liquidity providers to abandon the market or become liquidity consumers: this is especially true of financial companies who do not have firm supply commitments and are often opportunistic players. The use of price indexes is also an important feature of the industry as they are used to establish hub prices and price risk-management products. However, since 2003 index-priced transactions have been increasing as a portion of overall transactions reported in FERC's Form 552[2] at the same time that the share of fixed-priced transactions used to compile the indexes has been steadily declining.

We next discuss assessing liquidity in the U.S. natural gas market. Data limitations restrict the measurement of liquidity because access to intraday prices and transaction volumes is only on ICE and the Chicago Mercantile Exchange (CME). Only aggregate information is available on the trades underlying the indexes calculated by the Price Reporting Agencies (PRAs). Over-the-Counter (OTC) transactions are only reported with a delay and on an aggregated basis as well. Furthermore, the U.S. gas market is fragmented by trading venue and geography. Different trading venues coexist for the same class of assets with each having different levels of transparency, price formation and discovery processes. There is unequal access to available information for different members of the trading community and the public at large. At the same time gas markets often become fragmented during times of supply or demand shocks, which create pipeline constraints that in turn limit the geographic scope of the market. Nonetheless, ICE price data still serves as an important barometer of the U.S. natural gas market and is useful in estimating various liquidity measures.

This task of following liquidity trends in the U.S. market has become particularly important in the aftermath of the shale revolution, shifting spatial production patterns and changing market conditions at different market hubs. Market liquidity is changing as new production areas and infrastructure come online, linking the new shale natural gas plays to market hubs and new Liquefied Natural Gas (LNG) export terminals. U.S. shale production is expected to maintain considerable growth to satisfy growing LNG and Mexican exports as well as the continued increase in domestic gas-fired electric generation. Using ICE price data to estimate liquidity trends by hub will help us to assess efficiency of the U.S. natural gas market and to identify locations that may be more prone to manipulation.

U.S. Natural Gas Market Structure

Overview

The U.S. natural gas markets have many unique features that are a result of historical developments and cross pollination between the energy and financial markets. The most important features include:

- Natural gas is traded actively at many locations, referred to as market hubs, the intersections of multiple intra- and inter-state pipelines, and interfaces of the pipelines with the local distribution systems.

- Natural gas markets are based both on physical (i.e., involving physical delivery) and purely financial (cash-settled) transactions. Settlements of financial transactions are based on publicly available price benchmarks of natural gas in physical and/or other financial markets.

- In the past, physical markets were organized around monthly transactions for baseload gas, delivered at roughly equal quantities over the course of a calendar month. The prices of baseload gas at specific locations are referred to as monthly indexes. Monthly markets are still very important, but the importance of daily markets is increasing.

- The development of the natural gas industry led to the emergence of short-term markets for gas flowing over the next day. Increasingly, we can see frequent transactions for natural gas traded intraday, with pipelines offering multiple nomination cycles (up to four per day or even at hourly frequency.)

- Another unique feature of the North American natural gas market is the use of a central pricing benchmark, the natural gas futures contract with delivery at Henry Hub, Erath, Louisiana. Natural gas at other locations can be priced by adding the so-called basis to the NYMEX futures price. The basis represents the differential between the index (i.e., locational price) and the NYMEX contract price.

- The locational basis in the U.S. and Canadian natural gas markets is traded, for most locations, as a standalone contract. This creates a unique triangular relationship between three types of prices: the NYMEX futures contract price, the locational index and the basis. One can replicate an index position by entering simultaneously into a NYMEX position and a basis position. One can also enter directly into an index transaction and a NYMEX transaction, implicitly assuming a basis position.

The U.S. is becoming increasingly dependent on electricity generated from gas-fired power plants. Interactions between natural gas and electricity, as well as transactions referencing prices of these two commodities, create unique price dynamics, which favor traders present in and familiar with both markets. Different power pools are increasingly using gas indexes in their tariffs. For example, the growth of the Energy Imbalance Markets in the western United States is one area where natural gas indexes are used to set reference prices for electricity transactions. U.S. natural gas prices have also evolved into important international benchmarks with liquefied natural gas exported from the U.S. often being indexed to domestic prices. It is conceivable that Henry Hub (the delivery point for the CME futures) could become the central reference point for the integrated global gas market.

The U.S. natural gas market acquired its current form in the 1990s as a system based on related physical and financial products with unique price formation and discovery features. The critical components of this system include:

1. The natural gas NYMEX futures contract;

2. Interconnected natural gas market hubs with location-specific daily and monthly prices for physical contracts;

3. A system of financial forward, swap and option contracts that are both OTC and exchange traded; and

4. Long-term physical transactions based on different pricing schemes.

The NYMEX[3] natural gas futures contract was launched in April 1990 and became one of the most successful derivatives instruments in the history of the commodity markets. It is used as a critical benchmark for pricing natural gas related transactions in the U.S., including many OTC and exchange traded derivatives with the potential for becoming an international reference price, given its growing use for structuring long-term LNG contracts.[4] The delivery point for the contract is at Henry Hub in Erath, Louisiana, an intersection of several pipelines with vast storage capacity available in the area. This location was a logical choice in 1990 as Texas and Louisiana were the most important U.S. supply areas. The shale revolution shifted the industry's center of gravity from the South and the Southwest to the Northeast with the Marcellus in Pennsylvania being the fastest growing production region in the U.S. Some market participants expressed an opinion that the U.S. market would need either another central pricing benchmark or multiple benchmarks, given the evolution of natural gas spatial production patterns. Many industry practitioners believe that the use of multiple price benchmarks is imperative from the point of view of risk management. This is one of the critical issues for this market, and we are signaling this to the reader.

<u>Classification of Transactions</u>

Transactions in the U.S. physical natural gas markets can be classified using multiple criteria such as:

- Tenor;
- Mode of execution;
- Design; and
- Price formation process.

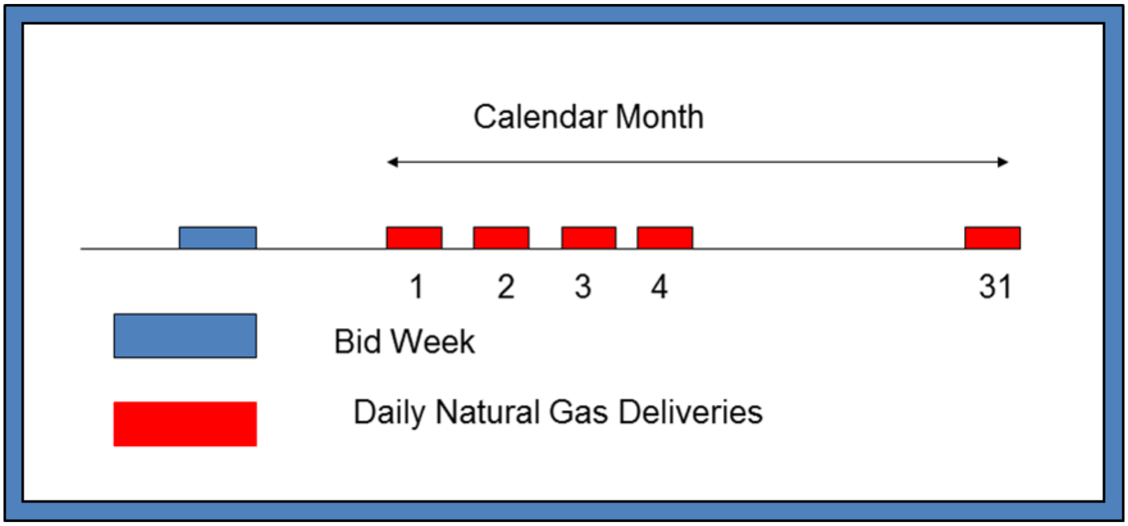
Classification of Transactions by Tenor

The tenors of physical natural gas transactions range from less than a day to many years; in some rare cases the time horizon may be as long as 20 to 30 years. Intraday transactions represent adjustment trades executed in order to address unexpected imbalances due to infrastructure outages, unexpected extreme weather events or pipeline scheduling mistakes. Day-ahead transactions, executed in the morning of a gas day, are for natural gas flowing during the next day (or on Saturday through Monday in the case of Friday trades.) The day-ahead transactions are mostly squeezed into a narrow window of time between 8:00 and 11:00 a.m. Central Prevailing Time, ahead of the pipeline nomination schedules. Some transactions may be executed later during the gas day.[5]

The natural gas markets in the U.S. were historically organized around monthly transactions for baseload gas delivered ratably over the course of a calendar month. The transactions were negotiated during a period of five days close to the end of the calendar month preceding the delivery month, known as the "Bid Week." For a long time, the volumetric adjustments over the period of the month would be accomplished by over-drawing or under-drawing natural gas from a pipeline on a daily basis as the flows were usually balanced over the monthly time period. The Local Distribution Companies (LDCs) have a strong preference for this strategy and their risk-managing decisions drive the gas market activity during the shoulder periods as they prepare to meet summer and winter demand in a cost-efficient way (particularly the latter.) Today, the volumetric adjustments happen through intramonth transactions, for the next day delivery, or for the balance of the month. Figure 1 on the next page illustrates the monthly transactions schematically. The monthly market developed around the market hubs, usually located at the intersection of multiple pipelines or at the points of interface between the pipelines and local distribution systems (the so-called city gate hubs.)

An example will help to explain the mechanics of this market. One of the most important market hubs in the U.S. natural gas industry is the Houston Ship Channel (HSC), a location with access to many intra- and interstate pipelines that supply one of the biggest clusters of chemical plants in the world and move natural gas from production areas to other parts of the U.S. Transactions for baseload natural gas at HSC and other hubs happen during the period of a few days around the NYMEX futures contract expiration dates, traditionally called Bid Week.[6] The Bid Week transactions can take place over-the-counter or on electronic trading platforms such as on the ICE platform.

Figure 1
Monthly Baseload Natural Gas Transactions



Transactions with longer tenors than one month are based on long-term contracts that range from fairly standardized agreements to highly complex structures which are a product of time-consuming negotiations involving teams of traders, structurers and lawyers.[7]

Mode of Execution

Physical natural gas transactions can be executed on an exchange or transacted bilaterally either with the assistance of brokers or directly between two counterparties who have a long term-business relationship based on mutual trust and access to the same transportation and storage infrastructure. The most important next day exchange-traded contract is hosted by the Intercontinental Exchange and is screen based. The definition of a next day contract is somewhat flexible, given intervening holiday schedules. Levitan & Associates (2018) documented the definition of a next day contract as follows:

> "The standard Next Day product is for a constant rate of delivery over its term, and the term is often longer than one day because trading is only done on non-holiday weekdays and multi-day deliveries across calendar months are split into separate sessions in order for the sum of Next Day terms within a month to be identical to its monthly product. These Next Day product definition and trading rules reduce spot market trading opportunities in any of three ways:
>
> - Regular Friday trading is for a three-day block (Saturday, Sunday, Monday) with typically higher demand on Monday than on the weekend days.
>
> - Before holidays, when the Next Day gas markets on NYMEX and ICE are closed, the Next Day product delivery term is extended for at least one more day. For example, trading on the day before Thanksgiving is for a five-day product (Thursday through Monday.)

- Whenever a multi-day delivery term would otherwise cross a calendar month boundary, the last day(s) of the current month are traded two days before the start of delivery and the first day(s) of the next month are traded on the last trading day of the current month."

Transactions executed through brokers and directly among the counterparties dominate the volume of ICE-based transactions. Unfortunately, the information about these transactions is only available in a highly aggregated form once a year from a FERC-mandated report that in turn is discussed below.

Price Discovery

Price discovery on the ICE platform is instantaneous and is arrived at through the interaction of bids and offers posted by traders representing different entities approved for trading on the platform. There is no single entity that operates as a designated market maker, and different traders can switch from operating as market makers (posting bid and/or offer prices to set the market) to behaving as passive price takers.

Currently in the U.S., information about bilateral transactions is incomplete and based on voluntary submissions of trade data to the PRAs, which in turn are referred to in the industry jargon as newsletters. PRAs collect information about the transactions, including volumes and agreed-upon prices to calculate quantity-weighted price indexes. The day-ahead price indexes are published Monday through Friday with Friday transaction prices used for gas flowing on weekends and Monday. The monthly indexes are published on the first business day of a calendar month. The difference between the index price and the settlement price of the NYMEX expiring contract for the same calendar delivery month is known as the "realized basis." Twelve specific basis numbers are calculated during the course of the year for a given location for which a published index is available. The basis may be either positive or negative, depending on the relationship between the prices of natural gas at a given place and the NYMEX contract price. As a rule of thumb, locations east and north of Henry Hub were historically associated with a positive basis, and locations to the west were associated with a negative basis.[8]

Most energy traders use price indexes calculated and published by the publication known as *Inside FERC Gas Market Report*. The price index published by this newsletter is referred to as an IFERC index.

The monthly price indexes for natural gas are calculated in two different ways using fixed price transactions or physical basis transactions. Fixed price transactions are very straightforward: for example, the buyer commits to pay $4.5 per million British Thermal Units (MMBTU) for baseload natural gas delivered over the next month at a given location. Physical basis is negotiated as a fixed difference in price, or price differential, to NYMEX before the final settlement price of the NYMEX is known; once the NYMEX price settles on the contract expiration day, the negotiated differential is added to the NYMEX price, and the total determines the price of natural gas at the specific location. In other words, after the NYMEX contract settles, the transaction mutates from floating to fixed, and the monthly price crystallizes.

Pricing

Pricing in the U.S. natural gas markets can be based on the following rules:

- Outright (flat price);
- Floating price; and
- Formulaic price.

Outright prices are used mostly in the day-ahead and month-ahead transactions and are the most straightforward. An example would be a physical transaction for delivery of 10,000 MMBTUs of natural gas at Houston Ship Channel on Wednesday, January 2, 2019. The outright prices are important because they are used by PRAs in calculation of price indexes explained below.

Floating price transactions (referred to in the industry as index deals) are based on published price indexes that the counterparties agree to accept. The published index may be adjusted by a negotiated differential, reflecting modifications of delivery conditions, variability in volumes, or other options embedded in the contract.

Formulaic prices are used in long-term transactions and typically reflect the need to protect the interest of both parties against future adverse market developments. The provisions may include indexation to prices of other commodities (for example, electricity), the use of moving window averages of historical prices as a reference, or the right to exit or renegotiate the contract under certain circumstances.

The Importance of Index Prices

The importance of the index prices for the natural gas industry is difficult to overstate. Many market participants use the monthly prices for the so-called index transactions that are effectively floating price deals with natural gas delivered over long time periods at prices determined during Bid Week and calculated by the index publishers. Such transactions are typically priced at index, adjusted by the so-called premium, a differential contained typically in the range of (-2, 2) cents. In many markets, the producers receive prices equal to an agreed percentage of a specified index. The index prices are also used in financial swaps and the so-called basis swaps, which are explained below. There are many different justifications for a premium to an index in a floating price transaction:

- The premium may be charged to cover transaction costs and the profit margin of a marketer and is equivalent to a bid / offer spread;

- The producers often want to maximize market share and are willing to sell gas at a small discount to the index in order to attract customers; and

- Sometimes natural gas is delivered not at the hub location but at a meter at some distance from the market and the premium captures the physical delivery cost differential, i.e., the extra transportations cost.

Insights into the role of price indexes in the U.S. natural gas markets can be obtained from the data collected by FERC on Form 552, "Annual Report of Natural Gas Transactions." The submissions on this form, following FERC Order 704 (December 26, 2007), apply to market participants that sell or purchase 2.2 million MMBTU or more of natural gas annually. This is approximately the amount of gas used by a 90-MW peaker power plant running every day for 9 hours. It is obvious that this form does not capture all transactions, but it still provides a good snapshot for the bulk of trades.

Daily physical transactions take place every morning for next day delivery[9] at many trading hubs. The daily transaction prices are reported to the *Gas Daily* publication and become available on the day of the transaction when the newsletter is distributed electronically to the subscribers, usually between 5 and 6 p.m. Central Time. The publication uses fixed price transactions in calculation of the volume weighted indexes. It is important to remember that the reported prices may be identified by the transaction date or the flow date. Ignoring this obvious distinction leads in practice to many costly snafus.

Liquidity in the U.S. Natural Gas Markets

The features of the U.S. physical natural gas markets summarized above explain why measurement of its liquidity is a challenging task, irrespective of which measure discussed in part 1 of this series of articles is used.

Data Limitations

Fragmentation of the U.S. physical natural gas market limits the amount of information available to the trading community. The levels of intraday prices and transaction volumes are available only for the Intercontinental Exchange. Information about the trades underlying the indexes calculated by the PRAs is incomplete and available only in an aggregated format. The information is incomplete because transaction reporting, as described above, is voluntary. Another issue is that the number of respondents and the reported volumes have been falling over the last few years. The reported transactions are used to calculate volume weighted average prices (with additional data regarding total reported volumes, price ranges and number of transactions also made available.) This information is insufficient to identify intraday liquidity trends and draw conclusions about the distribution of transaction volumes between different trading venues. Information about prices underlying long-term transactions is generally not available and can only be approximated relying on the industry grapevine or estimated from regulatory filings. Even if the long-term transaction prices were exactly known, the value of this information would be limited. The long-term contracts contain many embedded options (such as volume and delivery location flexibility and early termination clauses) and prices are subject to modification under different market conditions. An analyst would need detailed information about all such provisions and have the intellectual firepower and input data to value all the optionality.

Market Fragmentation

Market fragmentation can be defined as the coexistence of different trading venues for the same class of assets, characterized by different levels of transparency, price formation and discovery processes, unequal access to information available to different members of the trading community and the public at large, and often preferential treatment granted to some classes of market participants. In many cases, market fragmentation may be seen as a positive development under the following conditions:

- The range of choices available to the market participants is expanded;
- No market segment offers privileged treatment to some classes of traders;
- Information about different markets (such as volumes and prices) is widely available at a reasonable cost; and
- There exist market participants who specialize in arbitraging away price differentials between different markets.

In other words, fragmentation may be beneficial if different market segments do not form completely isolated silos, dominated by a few large players, with very limited, or no information at all, available to the rest of the market.

The U.S. and European financial markets in the last two decades have become more fragmented, which is a development that is often very troubling to many market participants, regulators and academics. The U.S. energy market is no different, and fragmentation is observed both geographically (across different market hubs) and across different trading venues. Geographical fragmentation is not a fixed feature of the markets but a condition which is dependent on the state of the physical transportation and storage infrastructure, which in turn varies with weather, and is subject to demand or supply shocks. Such conditions may be temporary or may last a few years and may result either in extremely high or depressed prices.

At some locations, weather or pipeline outages may isolate a given market hub (or a group of hubs) turning it into an island with no ability to deliver more natural gas or to move excess supplies to other market locations. The best-known example of a market where temporary shortages may produce extreme price spikes is Transco Zone 6 New York during winter months and the Algonquin hub. Pipeline maintenance may result in excess volumes of natural gas "looking for a home" with prices in the temporarily isolated area falling close to zero. Sometimes geographical fragmentation of natural gas markets may become a chronic condition. New England's natural gas market is one example. As explained in Lander (2015):[10]

> "New England's natural gas problem would most accurately be termed a '50 day on-peak deliverability problem. That is, for some portion of around 50 days per year the near-simultaneous and high demands of regional heating and natural gas for electric generation loads are not being met efficiently."

The Appalachian region is an opposite example: growing production from the Marcellus and Utica basins, combined with lagging pipeline expansion, resulted in a protracted period of depressed prices and reduced liquidity at some market hubs (Dominion South and Dominion North.)

The trading venues for physical natural gas are equally fragmented. The producers and end users of natural gas have the option of selling/acquiring gas in a number of ways:

- Physical trading of natural gas on ICE;
- Natural gas futures contract traded on the CME;[11]
- Brokered bilateral transactions;
- Bilateral transactions negotiated directly and often based on long-term relationships; and
- Long-term structured transactions.

A recent trend is the direct acquisition of natural gas reserves by utilities to satisfy their long-term needs at predictable costs and with reliability guarantees.

Transparency of different trading venues for natural gas varies from reasonably good to rather unsatisfactory. Information about market activity on ICE and CME is available to the trading community and market analysts though more detailed data may be obtained at a price.

Information about direct, bilateral markets is available with a delay in a highly aggregated report, the aforementioned FERC Form 552. Partial pricing information is available in a highly compressed form through price indexes published by PRAs such as *Platts* or *Argus*. The indexes are based on transactions reported to PRAs on a voluntary basis. Many market participants engage in the so-called index (floating price transactions) which reference price indexes published by PRAs or derived from transaction prices established on ICE or CME. As reported by Leonard and Moran (2017):

> "Since 2013, the index-priced transactions have comprised an increasing fraction of overall Form 552 transactions each year while the portion of transactions that have fixed prices has steadily declined. From 2012 to 2016, index price transactions increased from approximately 72 percent to 79 percent of all Form 552 transactions."

The share of fixed (outright) price transactions that underlie index prices has been shrinking and only a subset of these transactions is reported to the PRAs.

Given limited transparency of the market segment comprising direct bilateral transactions, one can pose a question whether any statements can be made with respect to this segment's liquidity. One option is to use the Amihud Index[12] based on *Gas Daily* prices that are reported by *Platts*. (*Argus* and *Natural Gas Intelligence* (*NGI*) also publish corresponding price indexes.)

The applicability of *Gas Daily* prices to the measurement of liquidity can be validated through a correlation analysis of ICE-based liquidity measures (a more transparent market) with the *Gas Daily*-based index. Table 1 on the next page shows correlation coefficients for selected hubs.

Table 1
Correlation between Amihud Indexes: *Platts Gas Daily* vs. ICE Next Day Index

Henry Hub	0.88263
Transco Zone 6 NY	0.87525
TETCOM3	0.78054
Katy Oasis	0.70439
PGE Citygate	0.8363
Transco85	0.94762
TCO	0.76408
Dominion South	0.93334
CG Mainline	0.88027

Note: Calculations based on daily prices, November 2013 through December 2017.

The correlation coefficients reported above may be affected by differences in the definition of different market hubs between ICE and *Platts* (namely, the specific pipeline zones and meters included in the definition of a hub) and the differences in market participant characteristics between traders on ICE and entities reporting to *Platts*. In our view, the results reported above provide limited support to extending conclusions based on the analysis of ICE transaction data to other segments of the natural gas market. ICE, being the most transparent U.S. platform for physical natural gas can be used as the proverbial "canary in the mine," a proxy for overall liquidity conditions in the U.S. physical natural gas markets. Unfortunately, this gauge tends to break down under extreme market conditions when trading migrates to the opaque regions of the market and transparency and full information are most needed.

Liquidity Leakage

One important aspect of liquidity patterns is the transfer of liquidity between different trading venues, depending on market conditions. One of the important trends in the commodity markets was the transformation of organized exchanges (such as CME) and electronic trading platforms (such as ICE), which were historically established as conduits between producers and end users and providers of risk management instruments. Over time, this role of exchanges has been overshadowed by another important function: price discovery for market participants who choose to trade away from the exchanges either by using OTC markets or relying on direct bilateral relationships. Futures contracts traded on the exchanges are mostly cash settled, but a very small percentage of the traded contracts is settled through physical delivery. In the U.S. natural gas markets, this trend is further amplified by special considerations related to reliability concerns and access to physical infrastructure. In the case of ICE, this manifests itself as leakage of liquidity from ICE to other trading venues.

Conversation with traders provided specific examples why and how this would happen. Physical traders often observe trading activity on ICE but prefer to execute large volume transactions away from ICE by contacting potential counterparties directly with whom they have long-term relationships based on mutual trust and who have access to the transportation/storage infrastructure and logistical apparatus to make delivery. In some cases, next-day gas prices are based on the average price of trades observed on ICE during a certain time window (for example, from 8:00 to 10:00 a.m. Central time.) The traders gave a different rationale for this way of trading, emphasizing the importance of reliability and trust in operational skills of a selected counterparty. Another important factor was the objective of avoiding market impacts of a transaction. As one trader explained, ICE is a very transparent market and the price action is closely watched by the trading community. A large transaction volume is likely to move the market to a significant degree. Another important factor is the desire to transact large volumes in one step. For example, a natural gas storage capacity owner does not want to rely on a large number of small volume transactions to make decisions regarding injection or withdrawal of natural gas. Another reason to transact directly is to simplify and streamline logistical operations and avoid overwhelming the back office with a large number of confirmations and invoices, and make physical operations and accounting more straightforward.

Liquidity leakage from ICE to direct bilateral transactions markets is most pronounced during periods of market stress, exactly when transparency becomes most important to market participants. The recent episodes of Polar Vortexes provide the best illustrations of such trends.

In the natural gas and electricity trading community, a polar vortex[13] is associated with periods of extreme market stress caused by abnormally cold winter temperatures in the Northeast and Midcontinent areas of the U.S. The demand shock results in extreme price spikes, potential shortages and elevated trading losses (or profits) for energy traders.

The cold weather spell of January 2018 and associated demand shock affected trading of natural gas on ICE, particularly at the locations where extreme weather conditions coincided with infrastructure constraints. One example comes from Transco Zone 6 (New York) on January 2, 2018 where trading was fairly typical for this time of the year with some symptoms of stress. The bid-offer spreads were initially posted at levels approaching $40 and stabilized around $1, once active trading started. On Wednesday, January 3, 2018, quoted bid-offer spreads continued at punitive levels, but some transactions were evidently executed within the bid-offer spreads. On Friday, January 5, 2018, only one transaction took place on ICE (for 7,500 MMBTUs.) The *Platts Gas Daily* index for the period Saturday – Monday, January 6 – 8, 2018, printed at $48.89/MMBTU, with 10 transactions and a volume of 17,000 MMBTUs, according to *Gas Daily* (2018). Such a small transaction size may be due to the need to obtain a price print by marketers who operate under long-term contracts, which reference ICE or *Gas Daily* prices. As the temperatures in New York City continued to decrease through the week, trading on Monday, January 8, 2018 came to a grinding halt.

When trading on ICE during the periods of extreme weather conditions comes to a halt, the exchange ceases to function as both a price discovery platform and as a link in the supply chain. Pipeline congestion makes it impossible to react to developing market shortages and market participants without access to physical infrastructure (such as transportation contracts and storage contracts) withdraw from the market. Market participants who have available supplies choose to hoard them as it is difficult to predict how long extreme conditions will last. The transactions that take place often happen at extreme prices when the pipelines announce Operational Flow Orders[14] under which imbalances are settled at punitive prices. Economic rationality leads market participants to trade up to the penalty level.

The liquidity leakage described above happens intraday and may become significant on certain days, especially during periods of extreme weather. More troubling is the liquidity leakage from active markets to passive transactions based on floating prices. As explained above, the so-called index deals are medium- and long-term transactions referencing an agreed-upon monthly or daily price index (as reported by *Platts*, *Argus* or *NGI*), adjusted by a negotiated differential. Migration to index deals happens at the expense of flat (outright) price transactions. This means that price discovery is impaired as fewer market participants collect and process information required to support active trading and a portion of supply and demand is removed from the public view. There are several factors explaining growing industry preference for index transactions: the common denominator is the U.S. shale revolution and its consequences.

On the buy side, the growing supply of natural gas suppressed prices and price volatility, which in turn reduced the appetite of end users for hedging transactions. Many local distribution companies were criticized for hedging their future supplies at elevated prices and passing the costs to the ratepayers. Buying natural gas in the forward markets under conditions of a contango[15] in the oversupplied market with chronically depressed spot prices is a prescription for incurring significant losses. Buying natural gas at floating prices through index transactions is a safe policy, shielding management from criticism by regulators and complaints by ratepayers.

On the sell side, the producers see index transactions as a way to reduce royalty payments to the lease holders.[16] Index prices are used to calculate the value of produced natural gas (as these are the prices received by producers), but if production flows are hedged in the forward markets the benefits from financial trading are not passed to the lessor. This treatment of hedging profits in calculating royalties is supported by the Federal courts (Sartain, 2013). As Cimarex Corporation argued in a commercial dispute case:

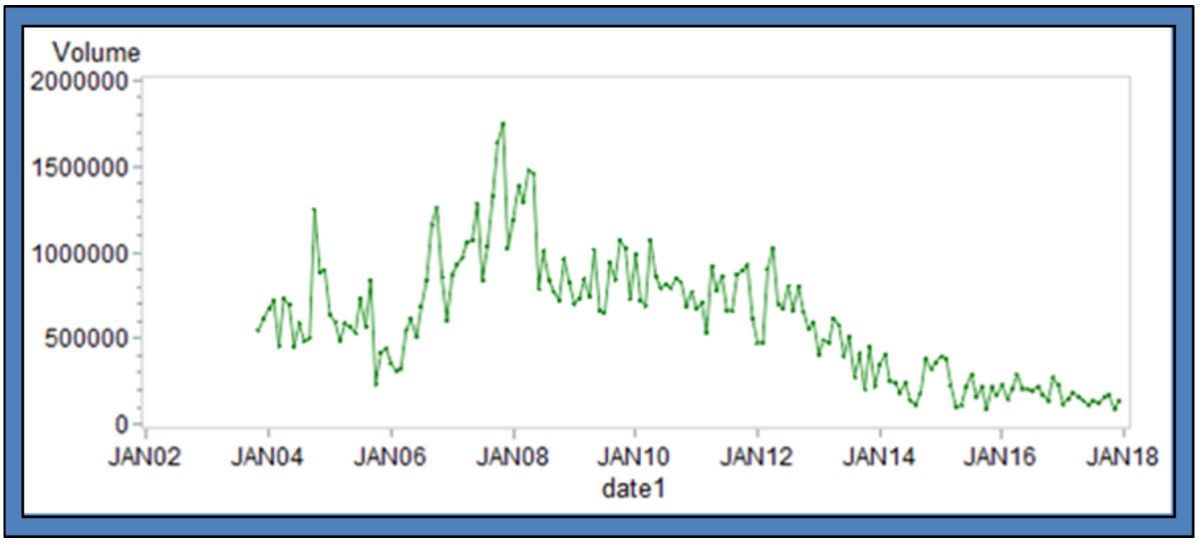
> "Louisiana law […] is equally clear that royalties are due on the market value of the natural gas or crude oil at the well, lease, or field, where it is produced. As a matter of Louisiana law, royalties are a share of the production itself, which entitle the lessor to a share of oil or gas where it is produced, free of the expense of drilling and production." (United States District Court, Western District of Louisiana, Lafayette Division, 2012)

The plaintiff in this case argued that he was entitled to profits from the separate hedging activity by the Cimarex. The court sided with the producer.

Market Liquidity Trends

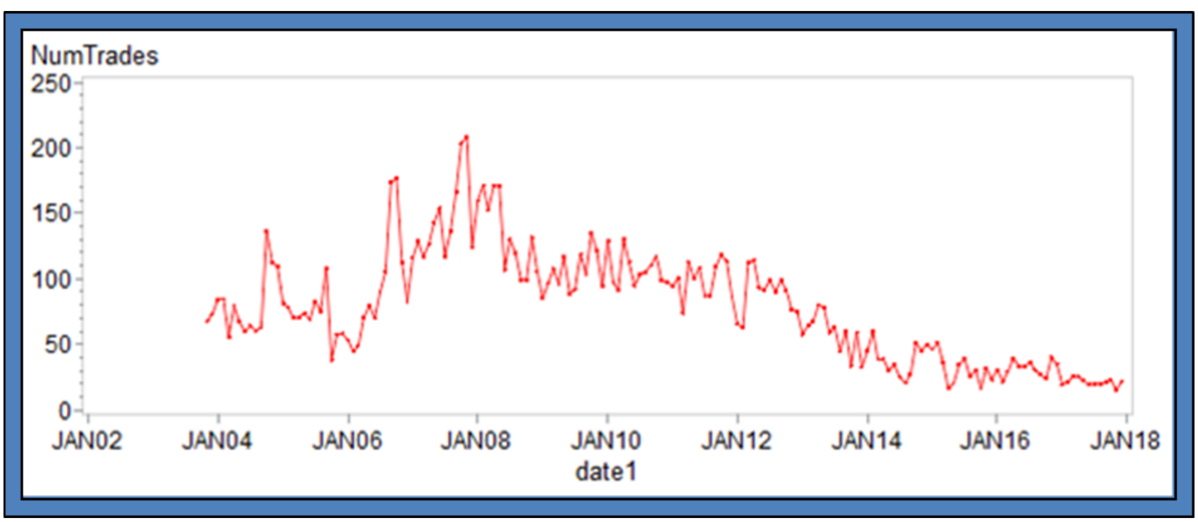
The factors discussed above have reduced the liquidity of the U.S. natural gas markets over the last few years. One example is a decreasing level of trading activity on ICE for spot natural gas at Henry Hub, once the most active market hub in the U.S. Figures 2 through 4 on the following two pages show the evolution of average daily transaction volume, average daily number of transactions, average daily number of market participants (by month in all cases.) The trends at other market hubs are similar though one can see improvements of liquidity at some hubs. The improved hubs are those where trading has been adversely affected through recent alleviations of pipeline constraints due to new construction (for example, Dominion South, a pricing point for natural gas produced in the Marcellus Basin.)

Figure 2
Average Daily Transaction Volume (MMBTU) by Month, Henry Hub



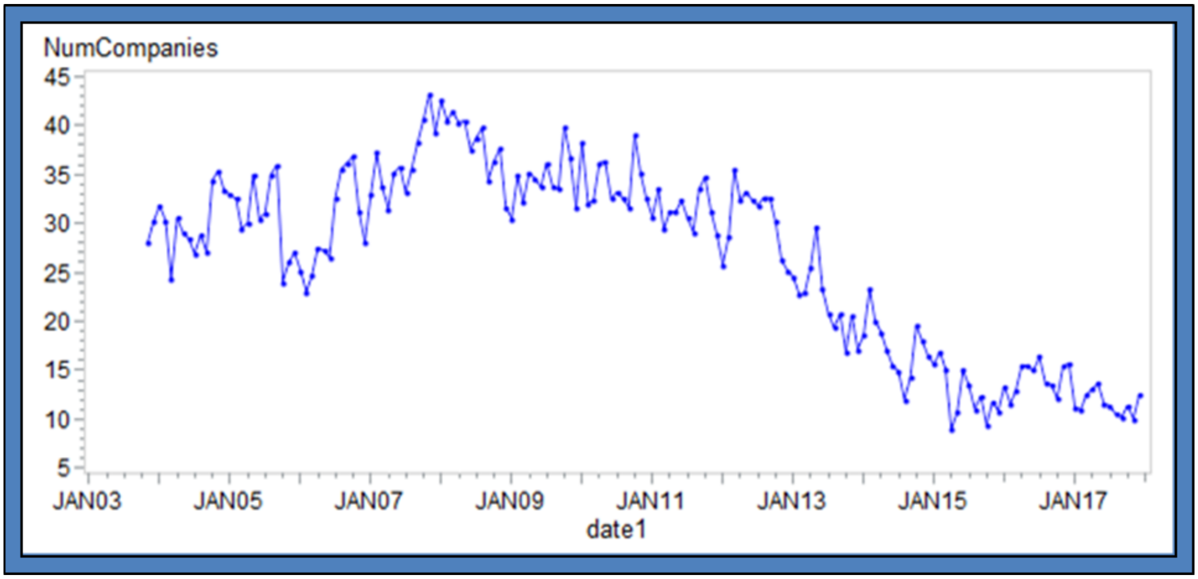
Source: U.S. Energy Information Administration

Figure 3
Average Daily Number of Transactions by Month, Henry Hub



Source: U.S. Energy Information Administration

Figure 4
Average Daily Number of Market Participants by Month, Henry Hub



Source: U.S. Energy Information Administration

Conclusions

Adequate liquidity is an important aspect of a well-functioning, efficient natural gas market. It is generally associated with a low bid-ask spread, and the ability to transact large volumes on short notice without significant price impact. The ability to buy and sell natural gas quickly helps to lower transaction costs and facilitates effective responses to market developments, including emergencies such as outages of pipelines or gas-fired power plants, and unanticipated weather changes.

Enhancing natural gas market liquidity is an important objective of the Federal Energy Regulatory Commission. It is a component of a wider policy designed to promote the goal of integrating the U.S. natural gas market, insuring greater price uniformity across trading hubs at a given point in time. Moreover, greater liquidity reduces the price impact of a trade, improves price discovery processes and helps both producers and consumers manage price and volume risk. It allows market participants to optimize the portfolios of physical and financial products to meet the needs of consumers of natural gas at a lower cost. Greater liquidity increases the confidence of industry participants in the efficiency of the market mechanism and increases their ability to warehouse risks associated with highly volatile prices, fluctuating demand and evolving daily load profiles in both natural gas and electricity industries. It allows producers and distributors of natural gas to be adequately compensated for important services they provide to the rest of the national economy. It also accelerates the transition to a more environmentally friendly future through greater use of natural gas, particularly the move toward greater use of gas-fired generation.

Market liquidity is critical to the ability of power generators to take full advantage of the intraday nomination opportunities created through FERC Order No. 809, which provided an additional intraday pipeline nomination cycle to meet unexpected changes in supply or demand in order to stay in balance and maintain reliable electricity service. Enhanced liquidity also helps to promote coordination between the gas and electricity markets, an important concern of industry regulators, given the differences in the markets' designs (namely, the differences between definitions of Gas Day and Electricity Day across the ISO electricity markets and regional gas markets.) Greater liquidity can also help to facilitate entry in electricity generation and natural gas supply by helping to accommodate greater depth of forward trading.

Identifying illiquid hubs helps regulators know where market manipulation is more likely and also where to look to enhance market efficiency. Natural gas market liquidity at key supply hubs has changed over time as the traditional sources of supply declined and new regional sources emerged. Liquidity at market center hubs has also changed as new sources of demand emerged, driven by growth in gas-fired generation and changes in the regional generation mix. It is important to assess hubs where there are significant changes in liquidity over time as these changes can impact price formation and signal major market realignments. The challenge any market analyst faces is capturing many different aspects of market liquidity in a few indexes that can enable meaningful comparisons across space (different market hubs) and time (evolution of liquidity at the same location and across different regions.)

Endnotes

For further coverage of the natural gas markets, the reader is invited to read past *GCARD* articles on these markets.

1 FERC Order 809 changed the nationwide Timely Nomination Cycle nomination deadline for scheduling natural gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1:00 p.m. CCT.

2 FERC Form No. 552 is used to collect transactional information from natural gas market participants, which is further explained in https://www.ferc.gov/resources/faqs/form-552.asp.

3 NYMEX was acquired by CME in 2008.

4 For example, many Cheniere LNG contracts are indexed to 115% of the Henry Hub first available futures contract price.

5 A typical set of circumstances leading to a late day-ahead transaction is a power generator with surplus gas supply due to an outage or not being dispatched by the power pool operator (or a reverse situation.) More frequent pipeline nomination cycles (down to hourly nominations) may in the future increase the importance of day-ahead transactions and distribute them more evenly over the gas day. The FERC issued Order No. 809 in April 2015 that in part provided for an additional intraday nomination cycle later during the gas day to help better coordinate the wholesale natural gas and electricity markets (Apr 16, 2015 - 18 CFR Part 284). [Docket No. RM14-2-000; Order No. 809].

6 The name survives though most market activity is now often squeezed into a period of a few hours in the NYMEX contract expiration day.

7 Examples of a long-term contract are the so-called volumetric production payments and municipal prepay transactions (involving issuance of tax-advantaged bonds by local governments buying natural gas.) See Kaminski (2013).

8 Growing natural gas production from the shale formations (especially from the prolific Marcellus formation) and construction of new pipelines changed these historical patterns, which now tend to evolve much faster than in the past. Traders and risk managers have to monitor production statistics and pipeline expansion plans to avoid costly surprises.

9 Transactions executed on Fridays are for Saturday, Sunday and Monday delivery.

10 As observed in Lander (2015), "pipelines ... are an extremely uneconomic way to meet demand spikes, like the system-wide peak demand each winter. This is so because any pipeline capacity needed for such short time periods must be built (to have a big enough pipeline) and then purchased (as the result of pipeline regulation and economics) on a 365-days-a-year basis. As a result, a significant percentage of the capacity within any pipeline built to handle such peak demand spikes will only be used for a few days each year."

11 Only a very small percentage of futures transactions leads to physical delivery of natural gas.

12 As covered in part 1 of this series of articles, "the logic behind Amihud's index of liquidity is very simple, and this explains its popularity in applied financial economics. The value of the index increases with greater absolute return, i.e., greater market impact, for a given level of volume (turnover.) A higher value for Amihud's index means that the market becomes more illiquid: the price reaction measured by the price return is stronger for a given transaction volume."

13 The term "polar vortex," introduced by scientists studying the earth's atmosphere in 1853, denotes "a large-scale region of air that is contained by a strong west-to-east jet stream that circles the polar region. This jet stream is usually referred to as the polar night jet," noted Berwyn (2017).

14 An Operational Flow Order (OFO) is a system of operational procedures to protect the integrity of pipeline operations when capacity usage exceeds or falls short of safety limits.

15 In a contango market, spot short-term forward prices are below long-term forward prices. The forward price curve for natural gas displays pronounced seasonality with prices fluctuating around an upwardly sloping trend line.

16 A royalty is a payment to the owner of mineral rights for the right to produce natural gas or oil. The level of royalties (typically calculated as a percentage of the value of the volumetric production flow) is determined through negotiations, and the agreed rates are part of a lease agreement.

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