

# Contents

Preface .....	xiii
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## Chapter 1

---

<b>Introduction</b> .....	1
Industry Segments .....	1
Natural Gas Act of 1938 .....	2
The Phillips Decision .....	2
Natural Gas Policy Act of 1978 .....	3
Orders 436 and 500 .....	4
Mega-NOPR .....	5

## Chapter 2

---

<b>The Physical (Cash) Market for Natural Gas</b> .....	7
Business Activity .....	7
Supply .....	10
Supply Data Summary .....	16
Demand .....	16
Demand Components .....	18
Demand Data Summary .....	23
Storage .....	23
Physical Transaction Types .....	40

## Chapter 3

---

<b>The Financial Natural Gas Market</b> .....	43
Value .....	43
Perceived vs. Market Value .....	43
Pricing and Trading .....	44

## Chapter 4

---

<b>Hedging and Trading Instruments</b> .....	47
Financial Market Terminology .....	47
Futures .....	50
Indexes .....	54
Swaps .....	57
Basis Swaps .....	67

Index Swaps . . . . . 77  
 Swing Swaps . . . . . 91  
 EFPs . . . . . 98  
 Triggers . . . . . 116  
 Options . . . . . 124  
 Summary of Hedging and Trading Instruments . . . . . 133

**Chapter 5**

**Structured Transactions** . . . . . 135  
 Buying High and Selling Low for a Profit . . . . . 135  
 Hedging Firm Transportation . . . . . 137  
 Selling Physical Swing Options to Producers . . . . . 140  
 Selling Physical Swing Options to End-users . . . . . 144  
 Selling Index Gas with a Cap to a Buyer . . . . . 153  
 Hedging and Trading Storage Capacity . . . . . 154  
 Buying Gas at a Floating Nearby Futures Price . . . . . 162  
 Selling Gas at a Floating Nearby Futures Price . . . . . 165  
 Paying a Premium Over Market to a Supplier and Making a Profit . . . . . 168  
 Selling at a Discount to Market to a Buyer for a Profit . . . . . 170

**Chapter 6**

**Building a Risk Management Model** . . . . . 173  
 Centralized Risk Management . . . . . 173  
 The Fixed-Price Book . . . . . 174  
 The Index Book . . . . . 174  
 The Basis Book . . . . . 175  
 The Transport Book . . . . . 175  
 Organization of Regional Desks . . . . . 176  
 Sample Transaction . . . . . 178

**Chapter 7**

**Natural Gas in the Electric Power Market** . . . . . 181  
 Electricity Market Overview . . . . . 182  
 Characteristics of Electric Power Market Fundamentals . . . . . 185  
 Managing the Grid . . . . . 188  
 Chapter Summary . . . . . 207

**Chapter 8**

**The Liquefied Natural Gas (LNG) Market** . . . . . 209  
 Terms and Conversions . . . . . 209  
 Market Fundamentals . . . . . 211  
 LNG Trading . . . . . 217

**Conclusion** . . . . . 223

# Figures

<b>Fig. 4–1.</b> Generic Swap .....	57
<b>Fig. 4–2.</b> Hedging Futures Swap Sale with Futures Contracts.....	61
<b>Fig. 4–3.</b> Unwinding Futures Swap and Offsetting Futures Contract Position.....	62
<b>Fig. 4–4.</b> Physical Sale at Floating Price to Futures .....	64
<b>Fig. 4–5.</b> Hedging Physical Sale with Futures Swap and Physical Purchase.....	65
<b>Fig. 4–6.</b> Hedging Physical Purchase with Futures .....	66
<b>Fig. 4–7.</b> Generic Basis Swap .....	68
<b>Fig. 4–8a.</b> Hedging Fixed-Price Sale at Alternate Delivery Location with Futures .....	70
<b>Fig. 4–8b.</b> Hedging Fixed-Price Sale at Alternate Delivery Location with Futures and Basis Swap.....	72
<b>Fig. 4–9a.</b> Hedging Fixed-Price Purchase at Alternate Delivery Location with Futures .....	73
<b>Fig. 4–9b.</b> Hedging Fixed-Price Purchase at Alternate Delivery Location with Futures and Basis Swap.....	75
<b>Fig. 4–10.</b> Generic Index Swap .....	78
<b>Fig. 4–11.</b> Buying Permian Index Swap .....	79
<b>Fig. 4–12.</b> Buying Permian Basis Swap and Buying Futures Swap .....	79
<b>Fig. 4–13.</b> Physical Sale at Index with Physical Purchase at Fixed-Price.....	80
<b>Fig. 4–14.</b> Selling a Fixed-Float Index Swap to Hedge Fixed-Price Purchase .....	81
<b>Fig. 4–15.</b> Buying a Fixed-Float Index Swap to Hedge Fixed-Price Sale.....	82
<b>Fig. 4–16.</b> Creating Short Futures Swap Position by Selling Index Swap and Buying Basis Swap .....	87
<b>Fig. 4–17.</b> Creating Short Basis Swap Position by Selling Index Swap and Buying Futures Swap.....	88
<b>Fig. 4–18.</b> Creating Short Index Swap Position by Selling Futures Swap and Selling Basis Swap .....	88
<b>Fig. 4–19.</b> Combining Futures Swap Sale and Basis Swap Purchase Yields Two Unhedged Positions.....	89
<b>Fig. 4–20.</b> Buying a Swing Swap to Re-float a Fixed-Price Sale.....	93
<b>Fig. 4–21.</b> Selling a Swing Swap to Re-float a Fixed-Price Purchase .....	94
<b>Fig. 4–22.</b> Hedging Swing Swap Sale by Buying Fixed-Price Physical Gas.....	95
<b>Fig. 4–23.</b> Hedging Swing Swap Sale by Buying Fixed-Price Physical Gas and Selling Physical Gas at Index.....	96

**Fig. 4–24a.** Buying EFP and Fixing Effective Purchase Price . . . . . 101

**Fig. 4–24b.** Buying EFP and Fixing Effective Purchase Price . . . . . 102

**Fig. 4–25a.** Selling EFP and Fixing Effective Sales Price. . . . . 103

**Fig. 4–25b.** Selling EFP and Fixing Effective Sales Price . . . . . 104

**Fig. 4–26a.** Original Long EFP Position. . . . . 107

**Fig. 4–26b.** Adding Basis Swap . . . . . 107

**Fig. 4–26c.** Adding Futures Contracts Purchased . . . . . 108

**Fig. 4–27a.** Original Long EFP Position. . . . . 110

**Fig. 4–27b.** Adding Physical Index Gas Sale. . . . . 110

**Fig. 4–27c.** Adding Futures Contracts Purchased . . . . . 110

**Fig. 4–28a.** Original Long EFP Position. . . . . 112

**Fig. 4–28b.** Adding Physical Index Gas Sale. . . . . 113

**Fig. 4–28c.** Adding Basis Swap Sale . . . . . 113

**Fig. 4–28d.** Adding Futures Contracts Purchased. . . . . 113

**Fig. 4–29a.** Original Long EFP Position. . . . . 114

**Fig. 4–29b.** Adding Physical Index Gas Sale. . . . . 115

**Fig. 4–29c.** Adding Futures Contracts Purchased . . . . . 115

**Fig. 4–29d.** Adding Futures Swap Purchased . . . . . 115

**Fig. 4–30a.** Hedging Trigger Sale with EFP Purchase. . . . . 118

**Fig. 4–30b.** Hedging “Triggered” Sale by Buying Futures . . . . . 119

**Fig. 4–31a.** Hedging Trigger Sale with Physical Index Supply . . . . . 120

**Fig. 4–31b.** Hedging Trigger Sale with Physical Index Supply  
and Basis Swap. . . . . 120

**Fig. 4–31c.** Hedging “Triggered” Sale by Buying Futures. . . . . 121

**Fig. 4–32a.** Hedging Trigger Sale with Physical Fixed-Price Supply . . . . . 122

**Fig. 4–32b.** Hedging Trigger Sale with Physical Fixed-Price Supply  
and Basis Swap. . . . . 122

**Fig. 4–32c.** Hedging Trigger Sale with Physical Fixed-Price Supply,  
Basis Swap, & Futures. . . . . 123

**Fig. 4–33.** Payout Profile for Long \$2.15 Put Position at \$0.15 Premium Paid. . . 130

**Fig. 4–34.** Payout Profile for Short \$2.15 Put Position at \$0.15  
Premium Collected . . . . . 131

**Fig. 5–1.** Buying High and Selling Low for a Profit . . . . . 136

**Fig. 5–2.** Hedging Firm Transportation. . . . . 138

**Fig. 5–3.** Firm Transportation Arbitrage . . . . . 140

**Fig. 5–4.** Selling Physical Swing Options to Producers. . . . . 143

**Fig. 5–5.** Selling Physical Swing Options to End-Users . . . . . 147

**Fig. 5–6a.** Hedging Purchase in One Location Priced at Index for Alternate Location. . . . . 150

**Fig. 5–6b.** Hedging Purchase in One Location Priced at Index for Alternate Location. . . . . 151

**Fig. 5–7.** Hedging Inter-month Trades with Storage . . . . . 157

**Fig. 5–8a.** Purchase Priced at Floating Nearby Futures Price . . . . . 163

**Fig. 5–8b.** Hedging Purchase Priced at Floating Nearby Futures Price with Futures . . . . . 164

**Fig. 5–9a.** Sale Priced at Floating Nearby Futures Price. . . . . 166

**Fig. 5–9b.** Hedging Sale Priced at Floating Nearby Futures Price with Futures . . . . . 167

**Fig. 5–10.** Paying Premium Over Market and Making Profit . . . . . 170

**Fig. 5–11.** Selling Discount to Market and Making Profit . . . . . 172

**Fig. 6–1.** The Risk Management Function on a Commodity Trading Desk. . . . . 178

**Fig. 7–1.** Average Daily Natural Gas Production (Dry) and Total Natural Gas-fired Power Generation Capacity, Reported at Year-end, from 2004-2018 . . . . . 182

**Fig. 7–2.** U.S. Electric Power Markets . . . . . 185

**Fig. 7–3.** Generation Stack Depicted as Price with Step Quantities . . . . . 191

**Fig. 7–4.** Manual Dispatching . . . . . 192

**Fig. 7–5.** UPG Natural Gas Demand Curve . . . . . 203

**Fig. 7–6.** Henry Hub Front Month Futures Historical Prices . . . . . 205

**Fig. 8–1.** Components of an LNG Liquefaction Plant . . . . . 211



# Tables

<b>Table 2–1.</b> Total U.S. supply . . . . .	11
<b>Table 2–2.</b> Lower 48 states with largest annual marketed production in Bcf/d . . . . .	13
<b>Table 2–3.</b> Largest natural gas shale plays. . . . .	13
<b>Table 2–4.</b> Historical US natural gas imports from Canada via pipeline and from LNG via shipping vessels. . . . .	14
<b>Table 2–5.</b> U.S. supply analysis. . . . .	16
<b>Table 2–6.</b> Annual demand for U.S. natural gas in billion cubic feet per day (Bcf/d.) . . . . .	17
<b>Table 2–7.</b> Actual residential and commercial demand in Bcf/d for Jan19-Jun19 . . . . .	18
<b>Table 2–8.</b> Actual industrial demand in Bcf/d for Jan19-Jun19:. . . . .	19
<b>Table 2–9.</b> Actual electric generation demand in Bcf/d for Apr19-Sep19:. . . . .	19
<b>Table 2–10.</b> Actual monthly Res/Com demand in Bcf (total) for Nov13-Oct14, and actual monthly Electric Generation demand in Bcf (total) for Nov18-Oct19:. . . . .	21
<b>Table 2–11.</b> Annual natural gas consumption in the industrial sector in Bcf (total) from 2007-2011 with 2009 highlighted . . . . .	22
<b>Table 2–12.</b> U.S. demand analysis. . . . .	23
<b>Table 2–13.</b> Breakdown between the various types of facilities and respective working gas capacities. . . . .	26
<b>Table 2–14.</b> Sample balance sheet (all data in Bcf/d except storage balance, which is total Bcf) . . . . .	28
<b>Table 2–15.</b> End of cycle storage balance (Left side in Bcf), with Henry Hub prices (Right side in \$/MMBtu) shows cause/effect relationship. . . . .	30
<b>Table 4–1.</b> Basis swaps visual pricing. . . . .	69
<b>Table 4–2.</b> Outcome of this trade shows various price assumptions for April Permian index and LD1 April. . . . .	73
<b>Table 4–3.</b> Outcome of this trade shows various price assumptions for April Permian index and LD1 April. . . . .	76
<b>Table 4–4.</b> The outcomes given various assumptions for Index and LD1 . . . . .	90
<b>Table 4–5.</b> Daily index price. . . . .	133
<b>Table 5–1.</b> Storage spreadsheet Example 1. . . . .	156
<b>Table 5–2.</b> Storage spreadsheet Example 2. . . . .	160
<b>Table 7–1.</b> Primary energy sources in all generator types (thousand MWh) . . . . .	186

**Table 7–2.** Monthly electricity generation (utility-scale facilities) for 2018 (thousand MWh)..... 187

**Table 7–3.** UPG supply stack showing Marginal Cost, Unit Capacity, and Cumulative Capacity ..... 190

**Table 7–3.** Calendar year 2018 heat rates (Btu/kWh) for different natural gas generator types (EIA)..... 195

**Table 7–4.** Natural gas burned in generation to replace lost nuclear plant . . . . . 196

**Table 7–5.** Natural gas consumption vs. electric power net generation. . . . . 207

**Table 8–1.** Conversions . . . . . 210

**Table 8–2.** List of the Projects in Commercial Operation by Baseload Nameplate Liquefaction and Export Capacity in Bcf/d and MTPA year-end 2019..... 212

**Table 8–3.** Annual LNG exports from the U.S. in billion cubic feet (Bcf). . . . . 214

**Table 8–4.** Top 10 LNG Exporting Countries According to 2019 Data in Millions of Tonnes (MT). [Source: GIIGNL Annual Report 2020 Edition] ..... 214

**Table 8–5.** Top 10 LNG Importing Countries According to 2019 Data in Millions of Tonnes (MT). [Source: GIIGNL Annual Report 2020 Edition]. . . . . 217

**Table 8–6.** Percent of Total Imports from Each Region for the Top 10 Importing Countries in 2019. (Source: GIIGNL Annual Report 2020 Edition) ..... 220

**Table 8–7.** Prices and Spreads for TTF, NBP, and Henry Hub for July 2020 Futures Contracts as a Proxy for Spot, Short-term Prices. . . . . 222



# 1

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## Introduction

The natural gas industry is a dynamic, complex, and exciting place to be at the current time. Employing more than a million people in North America alone, the market continues to grow due to ever-increasing opportunities, from exploration and production to marketing and trading to transportation and consumption. Although most widely used in North America, natural gas consumption is spreading throughout the world. Many emerging countries and even more advanced industrialized nations are diversifying their energy consumption by encouraging the exploration for natural gas and the development of transmission systems to distribute natural gas throughout their countries for its many uses.

This chapter provides the reader with a general understanding of the evolution of the natural gas market from its early regulated environment to the current stage of the industry. I will refer the reader to other sources for information pertaining to the discovery of natural gas, production methodologies, legal issues stemming from deregulation, and other topics not related to the subsequent material in this book.

## Industry Segments

In the United States, the natural gas industry was originally comprised of two segments: exploration and production, and distribution and sales. Initially, the exploration and production segment was not viewed as a part of the industry in need of regulation, but as a natural resource extraction industry. The distribution and sales segment, however, was controlled exclusively by the major natural gas pipeline companies and was viewed as a business in need of regulation primarily because transmission of the product by these pipelines served the public interest most effectively and efficiently. Due to the high cost of entry to the market, geographical limitations, and environmental feasibility, local governments felt a monopolistic threat could develop among these few transmission companies. Consequently, local governments declared authority over the geographic areas containing natural gas pipelines.

As the natural gas market continued to grow, pipelines began to spread from one geographic region to another, crossing state borders and hence local government jurisdictions. The rules governing one state differed from those in others,

From the wellhead, gas enters a small-diameter pipeline system called a *gathering system*. Each wellhead in the vicinity is connected to the gathering system. From there, the natural gas is brought to a central location where it can be processed and then measured by a metering device. Volumes are processed to extract liquids and other by-products so the gas will meet standard pipeline specifications. This is usually done by a party other than the operator of the gathering system because there is an active market for bulk quantities of certain by-products, such as butane and propane. The metering device is most important in the context of this text in that this is where title transfer to another party occurs if the gas is resold at this point.

Located on the other side of the processing facility is the *pipeline interconnect*, the point at which the gas is received by a major, larger-diameter pipeline, or *mainline*, as they are commonly referred to. This point is called the *receipt point*, of which there are hundreds on a typical pipeline system, connecting gathering systems from various locations. These pipelines can either be interstate (crossing state lines) or intrastate, and they typically interconnect with several other major, large-diameter pipelines. The vast pipeline network in North America spans from Mexico to Canada, all four corners of the U.S., and almost everywhere in between. Title transfers can and do occur at thousands of interconnects at varying times, for varying quantities, each headed for potentially different destinations.

The mainline, or pipeline, provides the basic transportation of natural gas from one location to another. Pipelines typically connect regions of supply with market areas, and as such, the direction of flow of natural gas on a mainline system is usually from the supply source to the burner-tip. However, some pipelines have been built to bridge the gap between other pipelines and/or storage facilities.

From an operational standpoint, gas volumes will only flow from an area of high pressure to an area of low pressure. Consequently, to move the gas along a pipeline, *compressor stations* are set up along the way to pressurize the gas so that it will flow to the next compressor station or interconnect. Also, each pipeline has a maximum capacity of gas it can handle at any one time and therefore requires that the total volume received at all receipt points should equal the total volume delivered at all interconnects and other delivery points (e.g., burner-tips) along the system.

To help in balancing receipts and deliveries, *storage facilities* are located anywhere from the field (gathering area), along the pipeline systems, to the market areas. Natural gas storage facilities allow a pipeline or other shipper to *inject* or *withdraw* volumes periodically to balance any discrepancies between receipts and deliveries. These facilities are usually operated by the pipeline along which they are located, although some third parties also provide storage services from privately owned facilities. Most storage facilities are located underground, some of which are salt-dome caverns, aquifers, or depleted oil/gas reservoir fields—the most common. These types of caverns have properties that are excellent for maintaining correct pressures, necessary for operational reasons.

Finally, *end-users* are situated at the end of (or various points along) the pipelines. It is at the burner-tip or burning point where the flow of gas stops and is consumed. There are several types of end-users, some of which are regulated depending on what type of business they are in. For example, *local distribution companies* (LDCs) provide a pipeline or distribution system with gas supply for consumers in towns and cities. Since LDCs are considered public utilities, they are subject to rate approval and regulation by their state Public Utility Commission (PUC).

Other end-users include non-regulated *industrial consumers* that burn natural gas to generate heat to power machines that manufacture their products—or they burn it outright as part of a chemical process. Also, *cogeneration* plants utilize natural gas in an energy conversion process whereby water is heated to produce steam that in turn generates electricity. *Commercial* end-users burn gas at their place of business to provide spacing heat and to boil water. These types of consumers include offices, schools, hotels, and restaurants. *Electric utilities* are the single largest end-users of natural gas in terms of the volume of natural gas consumed per user. Electric utilities burn huge quantities of natural gas to generate electricity. In turn, these utilities sell to all types of electricity buyers: residential, industrial, and commercial consumers. But, because they are utilities, the price they can charge for electricity is regulated by their state's PUC. (The electricity market is currently being deregulated, and this may not be the case for long.) Consequently, if natural gas prices rise to the point where it is no longer economical to make the energy conversion based on the price received for the electricity, the utility will switch to alternate fuels such as coal or maybe heavy fuel oil to generate electricity.

Although they are not technically producers or end-users, *merchant energy companies* play a big role in the business activity along a pipeline. Also known as resellers or third parties, these companies are in the business of capturing profitable opportunities that present themselves in any of the business activities. For example, some merchants provide services, such as acting as an agent for a large industrial end-user by procuring supply, or as agent for a producer by selling supply. Another opportunity is performing administrative functions for either or both of these parties.

Perhaps the best-known function of merchant energy companies is their role as *trading companies*. Trading companies are those that are in the business of buying and reselling natural gas for a profit. These companies are not paid a fee by anyone but earn the difference or take a loss between what they can buy natural gas for versus what they can sell it for. (Some companies will act as both service marketing companies and trading companies.) As a result of deregulation, any company is free to buy and sell natural gas to anyone. Also, it is entitled to enter into a contract for pipeline capacity on almost any pipeline system. The ability to enter the market with opportunities like these has led to the explosive growth in the number of natural gas trading companies. There are hundreds of these trading companies which provide services such as those mentioned above, as well as buying and selling with other market participants, trying to “make a spread”. A *spread* is the difference between the buy price and the selling price. Many producers, LDCs, and electric

utilities have established marketing or trading departments within their respective businesses to participate in these profitable opportunities or to specialize in administering the services necessary to conduct their business with natural gas.

Each day, these trading companies are looking for areas of excess supply or high demand. If they find a region that is temporarily oversupplied, for example, they can buy and take title to the supply from one counterparty (producer, another trader, or even an end-user) and sell and transfer title to another counterparty, capturing a profitable spread in between. Transactions like this can occur either at the same interconnect or at another location after transporting the supply on as few as one or as many as five or more pipelines. In the end, the goal is to earn a profitable spread.

Service marketing and trading companies are important to the natural gas industry for several reasons. As a service provider, these companies can perform many of the necessary administrative business procedures at a low cost for those companies that don't have established departments, or the know-how to perform these functions. As traders, they keep the supply and demand balance in constant equilibrium by searching for profitable arbitrage opportunities where discrepancies between supply and demand exist. In general, they help the market by providing efficiency, competition, and liquidity.

Beginning with the "Physical Transactions" section of this chapter, and throughout the remainder of this book, the material presented in this text will be most useful to those who are more interested in how trading companies, or those companies which have this function within their organization, conduct their business through the use of trading tools, trading techniques, and risk management concepts. First, however, the most important section to understand when looking for trading opportunities is the analysis of the fundamentals of supply, demand, and storage.

## Supply

### Supply Fundamentals

Natural gas is an underground natural resource. As such, it must be found, drilled for, and extracted to use, similar to crude oil. Natural gas is most commonly found wherever oil has been located, as it is a natural petroleum by-product. Natural gas, however, because of its composition, is usually found at shallower depths from the ground surface than crude oil and is therefore considered easier and less expensive to drill for and extract. Another characteristic of natural gas that is different from oil is that in its original state, natural gas is both odorless and colorless. When it has been brought up to the wellhead and gathering system, a sulfur-like perfume is added to the pipeline to give it an odor so its presence can be more easily detected by the smell in the case of a leak.

Natural gas production in the United States has grown considerably over the past 20 years; the highest rate of growth occurring since 2008 through the most

recent data for 2019. My definition of *Total Supply* is dry production plus imports from Canada plus LNG imports. The table below shows the annual U.S. supply of natural gas in billion cubic feet per day (Bcf/d).

**Table 2–1.** Total U.S. supply

Year	Total Supply	=	Dry Production	+	Canadian Imports	+	LNG Imports
2000	62.7		52.4		9.7		0.6
2001	64.6		53.7		10.2		0.7
2002	62.9		51.9		10.4		0.6
2003	63.1		52.3		9.4		1.4
2004	62.4		50.8		9.9		1.8
2005	61.3		49.5		10.1		1.7
2006	62.1		50.7		9.8		1.6
2007	65.3		52.8		10.4		2.1
2008	65.8		55.1		9.8		1.0
2009	66.7		56.5		9.0		1.2
2010	68.6		58.4		9.0		1.2
2011	72.2		62.7		8.5		1.0
2012	74.2		65.7		8.1		0.5
2013	74.2		66.3		7.6		0.3
2014	78.3		70.9		7.2		0.2
2015	81.6		74.2		7.2		0.3
2016	80.9		72.7		8.0		0.2
2017	83.1		74.8		8.1		0.2
2018	91.7		83.8		7.7		0.2
2019	99.7		92.2		7.4		0.1

Notice the jump in U.S. dry natural gas production since 2008 and the resulting drop in Canadian imports and LNG imports. The jump in production is due to the widespread utilization of a horizontal drilling technique known as hydraulic fracturing, or *fracking*, which has given rise to the term *shale revolution* to describe the massive growth in U.S. natural gas production from shale plays since 2008. To put it simply, fracking is the process of stimulating production from an underground rock formation (shale) rich in natural gas (or crude oil) reserves, by drilling horizontally through the play and then injecting fluid under extremely high pressure to expand the fissures in the shale to allow the natural gas (or crude oil) to escape more freely. Needless to say, it has been wildly successful.

## Supply Components

There are two main categories of my definition of Total Supply of natural gas: production and imports. Each has its components, and I have listed them below, after which I will discuss in more detail.

1. Production
  - a. Wet
  - b. Dry
2. Imports
  - a. Canadian Pipeline
  - b. LNG

## Natural Gas Production and Producing Regions

In terms of product characteristics, natural gas reserves, when discovered, contain varying quantities of natural gas and have varying “life spans” depending on how much pressure the reserves are under. In other words, a small reserve that is under high pressure will produce at a faster rate, thereby depleting faster, than would a large reserve under moderate pressure. There really is no way of pumping natural gas out of the ground; it must simply flow from its higher pressure area (underground) to an area of lower pressure (gathering system) until the two pressures are equal. The pressure in the gathering system is, however, maintained at the lowest possible level, thereby maximizing the amount of natural gas able to be produced from a reserve.

When initially discovered and brought to the surface, natural gas (ethane) contains varying amounts of other hydrocarbon compounds and is usually referred to as *wet gas* in this condition. Wet gas must be processed to strip out these other elements to meet standard mainline pipeline specifications. The difference, or *shrink*, is roughly 7 Bcf/d for the country as a whole; wet gas or *marketed production* for 2019 was 99.2 Bcf/d vs dry production of 92.2 Bcf/d. State-by-state data is only available for *marketed wet gas* production. However, throughout the rest of this book, with the exception of state-level data, I will be referring to dry natural gas when citing statistics, data, quantities, or any other numerical references to natural gas production, consumption, storage, or transportation. In addition, all of the data cited has been pulled from the publicly accessible [www.EIA.gov](http://www.EIA.gov) website unless otherwise noted.

At the moment, there are several prolific natural gas supply regions in North America. The largest U.S. reserves are located in the Appalachian Basin—specifically, the Marcellus and Utica shale plays. These two plays overlap the states of Pennsylvania, Ohio, and West Virginia. For 2019, of the 92.2 Bcf/d of production, 69.2 Bcf/d was from shale production, and of that, 29.6 Bcf/d was from PA, OH, and WV.

This next table shows annual marketed production in Bcf/d for the largest of the lower 48 states:

**Table 2–2.** Lower 48 states with largest annual marketed production in Bcf/d

State	Marketed Production Bcf/d			
	2019	2014	2009	2004
TX	24.6	21.9	18.7	13.8
PA	19.1	11.7	0.8	0.5
OK	8.7	6.4	5.2	4.5
LA	8.6	5.4	4.2	3.7
OH	7.1	1.4	0.2	0.2
WV	5.9	2.9	0.7	0.5
CO	5.4	4.5	4.1	2.9
NM	5.0	3.4	3.8	4.5
WY	4.0	4.9	6.4	4.4
Gulf Mex	2.7	3.4	6.7	10.8
ND	2.4	0.9	0.2	0.2
AR	1.5	3.1	1.9	0.5

According to the data for 2004, offshore production in the Gulf of Mexico was the second-largest producing region after Texas. However, the gulf has since dwindled to one of the smallest regions as less expensive shallow plays onshore in the shale basins have become the favored targets.

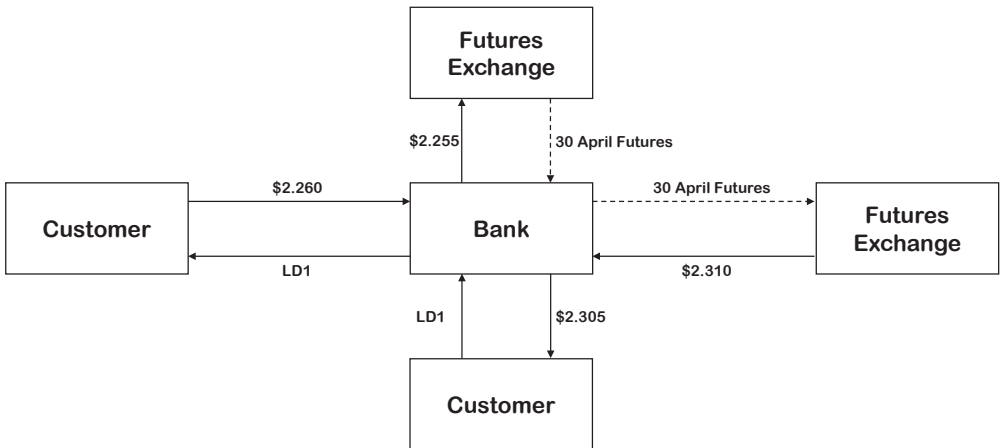
**Table 2–3.** Largest natural gas shale plays

Shale Play Name	State(s)	Dry Shale Production Bcf/d			
		2019	2014	2009	2004
Marcellus	PA, WV, OH, NY	22.2	13.2	0.2	0.0
Utica	OH, PA, WV	7.4	1.2	0.0	0.0
Permian	TX, NM	9.9	2.8	0.9	0.6
Haynesville	LA, TX	9.0	4.1	1.2	0.1
Eagle Ford	TX	4.3	4.3	0.0	0.0
Barnett	TX	2.3	4.3	4.3	0.9
Woodford	OK	3.1	1.8	0.8	0.0
Bakken	ND, MT	1.9	0.8	0.1	0.0
Niobrara-Codell	CO, WY	2.5	1.0	0.5	0.4
Mississippian	OK	2.8	1.1	0.7	0.8
Fayetteville	AR	1.2	2.8	1.4	0.0
Rest of U.S. Shale	various	2.5	2.0	1.7	1.4
Totals		69.2	39.4	12.0	4.1

result, Eric needs to sell 30 April futures contracts because he bought a total of 30 contract equivalents as a swap, so he quickly places an order to sell 30 April at \$2.31, and the order fills. Eric can count his money now that this trade is closed, effectively unwinding the previous trade. Figure 4.3 illustrates what the two transactions look like together, and the schedule of payments and receipts that follows shows the total profit/loss for the two trades. Dotted lines represent futures contracts, not physical gas.

Receive from 1st swap (+)	\$2.26
Pay to 1st swap (-)	LD1
Receive from 2nd swap (+)	LD1
Pay to 2nd swap (-)	\$2.305
Futures bought (-)	\$2.255
Futures sold (+)	\$2.310
Profit/loss on trade	+\$0.01 per contract x 30 contracts = \$3,000

Liquidating, in terms of a commodity or security, is the process of eliminating a futures position created from a previous trade or series of trades, accomplished by buying or selling the futures contracts in the equal and opposite direction of the position.



**Fig. 4–3.** Unwinding Futures Swap and Offsetting Futures Contract Position

The other way for Eric to liquidate is not quite as easy. Eric has the difficult task of selling his futures contracts at a price equal to or better (higher) than LD1 April, assuming he hasn't been able to unwind the original futures swap by selling another futures swap. There are two ways to do the job: 1) Speculate by selling the futures before the last trading day expiration period (final 30 min of trading) at a price hopefully equal to or higher than LD1, or 2) Attempt



to replicate LD1 April by selling the contracts during the settlement period on expiration day. The first alternative needs no explanation, just some expert forecasting abilities—and lots of luck! The second alternative, however, is the most common method of liquidating futures contracts, aside from unwinding the position with another futures swap.

From the sound of it, liquidating a futures position over the final 30 minutes of trade on the last trading day by trying to buy or sell and match the settlement price seems like a daunting task. First, the settlement price (the weighted-average price of all trades done during the settlement period) is a moving target by its very nature. Second, how does a trader know the volume trading at each price over the settlement period, to attempt to get a feel for what the settlement price might be? Lastly, how does a trader know (depending on the position), when to buy or sell during the settlement period? This confusion is known as liquidation risk—the risk that a trader cannot successfully eliminate an open futures position at a price exactly equal to LD1. Liquidation risk must be managed unless the positions are offset with futures and futures swaps before expiration.

### Helpful Hints for Liquidating Futures

- a. Break down the number of contracts that you need to buy or sell into 30 equal tranches.
- b. Buy or sell (depending on the open position) one tranche every minute, no matter what the market is doing.
- c. Keep your fingers crossed that your final average price comes out close to the final futures settlement price!

As a general rule, if it comes down to it and you have to liquidate during the closing range, the more rhythmically you can execute the trades over the 30 minutes, the better chance you have of matching the settlement. (I would rather pay \$0.001 and trade an exchange of futures for swap-EFS that allow for giving up futures for a swap with a counterparty that has the opposite position.)

### Example of Hedging a Physical Trade with a Futures Swap

Let's suppose that during October (Oct.), FJS trading company has sold gas to a market at Henry Hub in Louisiana for November (Nov.) with this pricing structure:

$$\text{Price} = \text{LD1 Nov.} + \$0.02$$

The sale price is the settlement price for the November futures contract at expiration plus a \$0.02 / MMBtu premium. As a result, FJS has made a physical sale for Nov. at a floating price (LD1 + \$0.02), which it must cover with physical supply before the end of Nov bid-week. To demonstrate the use of a fixed-float

**Table 5–1.** Storage spreadsheet Example 1.

Storage Example #1

Current Month				31 days	Next Month			30 days											
Day	Inject Volume	Withdrawal Volume	Daily Balance	Day	Inject Volume	Withdrawal Volume	Daily Balance												
							300,000												
1	0	0	0	1	0	-10,000	290,000												
2	0	0	0	2	0	-10,000	280,000												
3	0	0	0	3	0	-10,000	270,000												
4	0	0	0	4	0	-10,000	260,000												
5	0	0	0	5	0	-10,000	250,000												
6	0	0	0	6	0	-10,000	240,000												
7	0	0	0	7	0	-10,000	230,000												
8	0	0	0	8	0	-10,000	220,000												
9	0	0	0	9	0	-10,000	210,000												
10	0	0	0	10	0	-10,000	200,000												
11	0	0	0	11	0	-10,000	190,000												
12	0	0	0	12	0	-10,000	180,000												
13	0	0	0	13	0	-10,000	170,000												
14	0	0	0	14	0	-10,000	160,000												
15	0	0	0	15	0	-10,000	150,000												
16	0	0	0	16	0	-10,000	140,000												
17	0	0	0	17	0	-10,000	130,000												
18	0	0	0	18	0	-10,000	120,000												
19	0	0	0	19	0	-10,000	110,000												
20	0	0	0	20	0	-10,000	100,000												
21	0	0	0	21	0	-10,000	90,000												
22	30,000	0	30,000	22	0	-10,000	80,000												
23	30,000	0	60,000	23	0	-10,000	70,000												
24	30,000	0	90,000	24	0	-10,000	60,000												
25	30,000	0	120,000	25	0	-10,000	50,000												
26	30,000	0	150,000	26	0	-10,000	40,000												
27	30,000	0	180,000	27	0	-10,000	30,000												
28	30,000	0	210,000	28	0	-10,000	20,000												
29	30,000	0	240,000	29	0	-10,000	10,000												
30	30,000	0	270,000	30	0	-10,000	0												
31	30,000	0	300,000																
<hr/>				<hr/>															
Total Inject / Withdrawal	300,000	0			0	-300,000													
Inject fee / Withdrawal fee	\$0.025	\$0.025			\$0.025	\$0.025													
Total Inject / Withdrawal Costs	\$7,500	\$0			\$0	\$7,500													
Average Daily Balance			53,226				155,000												
Carrying fee			\$0.050				\$0.050												
Total Carrying Costs			\$2,661				\$7,750												
<table border="1" style="margin-left: auto;"> <tr> <td colspan="2">Total Storage Costs:</td> </tr> <tr> <td>Inject / Withdrawal Current Month</td> <td style="text-align: right;">\$7,500</td> </tr> <tr> <td>Inject / Withdrawal Next Month</td> <td style="text-align: right;">\$7,500</td> </tr> <tr> <td>Carrying Costs Current Month</td> <td style="text-align: right;">\$2,661</td> </tr> <tr> <td>Carrying Costs Next Month</td> <td style="text-align: right;">\$7,750</td> </tr> <tr> <td></td> <td style="text-align: right; border-top: 1px solid black;">\$25,411</td> </tr> </table>								Total Storage Costs:		Inject / Withdrawal Current Month	\$7,500	Inject / Withdrawal Next Month	\$7,500	Carrying Costs Current Month	\$2,661	Carrying Costs Next Month	\$7,750		\$25,411
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