Chapter 4

Natural Gas Liquids:
What Are They, Where Do They Go,
and Under What Contract Terms?

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§ 4.01. The Midstream Segment — What Is It?


To provide context for the midstream segment, its function, and its importance to the natural gas industry requires an understanding of the other industry segments. For purposes of this chapter, there are four basic segments in the natural gas industry.

Production. The production segment involves the exploration and development of natural gas reserves, both offshore and onshore. Businesses in the production segment are expert in finding and exploring for recoverable (able to be produced) natural gas reserves and acquiring the right to drill, access, and produce those reserves in an efficient manner from subsurface formations usually owned by others. The right to explore and drill to recover natural gas reserves is usually acquired by the production company through a lease with the landowner who owns the natural gas in any number of subsurface formations. In exchange for this right, including the right to recover and sell the natural gas for profit, the production company pays the landowner a royalty, or percentage or portion of the realized proceeds from the sale of the natural gas.

The various forms of possible payments between the production company and landowner, and their calculation, are beyond the scope of this chapter. In recent years, the industry standard for such payments has been changing, as payments have become increasingly subject to negotiation. This is due, in part, to the general increase in public knowledge and understanding of the value of natural gas (including of the value of the liquids entrained therein) and the extent to which “shale plays” (drilling for natural gas in shale rock
formations and recovering it through so-called “fracing” technology) are touching millions of acres and their owners throughout the United States.

From the production segment perspective, the natural gas produced requires two basic things before it can be sold to realize its value. First, the gas wells must be connected with the pipeline systems that will ultimately transport the gas to consuming markets. Second, the produced gas must be of a certain quality, which means it (a) must not exceed a certain heating value, typically measured in British thermal units (Btus) and (b) may not contain certain constituents or elements that detract from its ability to be consumed or used. This is where the next segment, the midstream segment, comes into the picture.

**Midstream.** As used in this discussion, the midstream segment is comprised of the functions of gathering and processing gas and fractionating the natural gas liquids (or NGLs) removed. The name “gathering” is descriptive of the pipeline’s function: to collect gas from multiple points and to deliver it to points of interconnection with the intrastate or interstate pipeline network (the “transmission” segment). Historically in the Appalachian region, the gathering and transmission pipelines systems were bundled along with the sale of gas itself; there was no distinction between gathering and transmission lines, and when someone purchased gas, the price included the commodity and all services required to move the gas from the wellhead to the point of sale. Over the last 30 years the commodity has been unbundled from the underlying services, and the interstate (transmission) service has been separated from local (gathering) service. The result is that pipelines between the production and interstate transmission segments, if satisfying various state (e.g., state public service or utility commissions) and federal (e.g., the Federal Energy Regulatory Commission, or FERC) agency-level

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2 Some produced gas meets the quality specifications required before it can be sold, but most requires at least some form of treatment.

3 Some include the transmission segment as part of midstream. However, over the last decade, the way business is conducted when providing gathering, processing and fractionation services has diverged from transmission, with the latter having its own separate rate-regulated structure while the others are generally not rate regulated.
definitions in statutes or regulations, are largely exempt from state or federal siting and economic regulation, but remain subject to certain state and federal safety regulation.4

Because it is not rate-regulated, service is rendered pursuant to written agreements between the producer and the pipeline owner and reflects a negotiated fee or rate, which may include a monthly fixed component (rental or demand) or only a volumetric component (per Mcf or MMBtu of gas actually transported). The owner of a gathering pipeline system is typically a producer or a stand-alone midstream company, though more recently it has trended to the latter. This trend is due to several factors: (a) “pure” midstream companies do not have their own production to favor when it comes to space in the line; (b) there are economies of scale and efficiencies when a large pipeline serves all producers in the area; and (c) midstream service requires large amounts of capital, and most production companies would prefer to employ their capital to drill wells and produce gas.

In a producing area where mostly dry natural gas is produced, the gas consists primarily of methane, some ethane, and little-to-no heavier hydrocarbons,5 and the function of the midstream segment is largely to transport the gas in gathering pipelines. Treatment, if any, is usually limited to removing water and other unwanted constituents such as sulfur. The midstream segment becomes more complex — both from a technical and engineering perspective and a commercial perspective — when the midstream segment also has to process the produced natural gas to extract the natural gas liquids so that the gas is suitable for delivery into interstate pipelines and fractionate and sell the natural gas liquids removed from the gas.6

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4 While not rate or service regulated, construction of gathering lines remains subject to environmental regulation and permitting, with the specific regulations varying by state.
5 Sometimes dry gas refers to an absence or minimal presence of water in the stream, but here it refers to the absence of heavier hydrocarbons: propane (C3), isobutane (iC4), normal butane (nC4), and natural gasoline, also known as pentanes plus (C5+).
6 A more detailed discussion of natural gas liquids is contained in §§ 4.02 and 4.03, below.
The processing and fractionation portion of the midstream business model has existed for over a century in the United States where natural gas production resulted in the production of liquids, oil, or heavy hydrocarbons. One of the first processing plants was built in 1913 just outside of Pine Grove Valley, West Virginia. This plant, like others in the northeast United States, was part of the bundled services performed by interstate pipelines (more as an ancillary necessity rather than as a core part of the interstate pipelines’ business when natural gas pipelines primarily bought and sold all of the gas they transported), but processing service is now a core business function for midstream companies.

The growth of this pure midstream-only business model in Appalachia is directly correlated to the discovery of and viable production from the Marcellus and now Utica Shales in West Virginia, Ohio and Pennsylvania. As a result of these discoveries and the resulting production, the need for investment in midstream and all other pipeline-related infrastructure has skyrocketed. One recent study suggests that as much as $641 billion of infrastructure investment is required over the next two decades to keep up with gas, oil, and natural gas liquids flowing from United States producing fields. Sections 4.04 and 4.05, below, contain a discussion of some of the basic commercial terms in typical agreements between midstream companies and producers on the one hand and midstream companies and purchasers of NGLs on the other.

Transmission. The term “transmission” in the natural gas context is more often than not a reference to interstate transportation of natural gas by pipelines regulated by FERC, which regulation covers both economics (rate and tariff) and new construction. These pipelines are the interstate highways for natural gas and extend from sea to shining sea to bring gas to

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7 The Hastings Plant, currently owned by a subsidiary of Dominion Resources, Inc., remains active today and has been through at least three major renovations over the last 100 years as technology changed and the ability to fractionate all heavy hydrocarbons became possible.

distribution companies throughout the country. Distribution companies are major consumers of natural gas and are crucial to meeting the heating and cooking needs of residents throughout the county. Natural gas producers seek to have their gas delivered into these transmission pipelines so that they can access the distribution company markets they serve. Access is so important that producers will acquire firm capacity in these lines so that their production is not curtailed.

There are numerous points or locations on the natural gas interstate pipeline grid (some physical, some virtual) where natural gas trading and transactions (physical and financial) — and, thus, pricing — have become customary and transparent; at these points, it is easy to buy and sell gas because there are numerous buyers and sellers willing to make transactions. As discussed briefly above, before the 1990s interstate pipelines were the purchasers and sellers (and even producers) of natural gas. However, due to a major FERC-initiated industry restructuring in the 1980s, interstate pipelines no longer buy and sell gas; rather, they are involved only in transportation of the gas on their pipelines for a fee, with others (producers, gas marketing companies,9 and gas distribution companies) engaged in the buying and selling of gas transported by the pipeline.

Before the producer can deliver its gas into these essential interstate markets, the producer’s gas must meet stringent natural gas quality restrictions and requirements contained in great detail in the interstate pipeline companies’ FERC gas tariffs. With science and engineering as their basis, these tariff provisions are approved by the FERC, but only after a legal review process that involves the pipeline company, its shippers or customers (which includes producers, midstream companies, distribution companies, and end users of natural gas), and the regulator. If gas to be delivered into the pipeline does not meet the tariff standards and limitations, the pipeline may legally choose not to accept that gas into its pipeline system, which has an obvious

9 Since this industry restructuring, gas marketing and trading companies (and other financial gas trading vehicles and markets) have become another major industry segment. They play a significant role in the natural gas marketplace, matching willing sellers and buyers. A discussion of this segment and its role is not essential to understanding the midstream segment, which is the focus of this chapter.
economic impact on the producer (and corresponding midstream company) whose gas is rejected. A common tariff requirement is that the Btu content of the gas may not exceed a specified level. To meet this standard, producers and midstream companies have to invest large sums of capital. Consequently, they will often fight to have a higher or no heat content limit. On the other end, due to their own economic interests, distribution companies are interested in lower heat content levels and may try and insist that the interstate pipeline have a lower tariff specification. Given the economic impact tariff provisions have on those involved, they are often hotly contested, debated, and sometimes the subject of litigation before the FERC.

Midstream companies are the bridge between the natural gas producing fields and the interstate pipelines where they deliver the producer’s natural gas (after processing and extraction of liquids). Thus, it is imperative that the midstream company know and understand the natural gas quality requirements contained in the FERC gas tariff of the interstate pipeline with which it will be interconnecting and delivering gas. In fact, if possible, there will be interconnections with several interstate pipelines to provide producers with access to diverse markets (and prices) for their natural gas. The gas quality provisions in each pipeline’s tariff vary and some offer variations within their tariff depending upon the physical location where the gas is received into the pipeline.\(^{10}\) Generally speaking, the gas quality provisions in a FERC gas tariff will set forth minimum or maximum standards with respect to gas delivered both into and out of the pipeline.\(^{11}\)

\(^{10}\) Interstate pipelines largely attempt to cooperate with producers, midstream companies, and others delivering gas into their systems. If, for example, the pipeline can accommodate receipt of high Btu or Btu-rich gas at a point on its system because elsewhere — in close proximity — the pipeline receives lower Btu gas, it will attempt to make accommodations for this “blending” in its tariff so that both types of gas can be received. Restrictions or limitations are also possible depending upon their location vis-à-vis delivery points out of the pipeline system.

\(^{11}\) As stated above, more often than not reference to transmission is reference to the transportation of natural gas on FERC-regulated interstate pipelines. However, it is common for any pipeline company (including unregulated gathering or intrastate pipelines) to have its own gas quality standards and restrictions with which a producer or shipper on its system must comply. If a regulated tariff is not required, these standards and restrictions are often part of and imposed by contract.
Some of the common specifications for gas to be received by the pipeline from the midstream company or producer are that the gas

- Meet a minimum Btu content;
- Not contain objectionable particles (dust, dirt, and other impurities) that might interfere with the merchantability of the gas;
- Not contain more than specified quantities of hydrogen sulfide and total sulfur (usually in grains per cubic feet);
- Not contain more than a small, combined total percentage (e.g., 2–5 percent) of inert gases, such as carbon dioxide and nitrogen;
- Contain very little oxygen;
- Be free from or be under established limits for water vapor and other liquids, including hydrocarbon liquids (again, which may vary by location or the pressure of the pipeline) such that they do not condense out in the pipeline’s system; and
- Be free from bacterial agents.

Distribution. Local distribution companies (or LDCs) that deliver gas to homes and businesses mostly receive gas they have purchased on the interstate pipeline grid. Their services and pricing (or rates) are regulated by state public service or public utility commissions. They, too, have regulated tariffs that often contain gas quality standards and restrictions with respect to the gas they receive and deliver. If natural gas production is located close to consuming markets — as are the Utica and Marcellus shales — it is common for LDCs to purchase and receive gas directly from the producer or midstream company.

§ 4.02. Natural Gas Liquids — What Are They?


[a] — Shale Gas Production and the Resurgence in Liquids Production.

We now turn to a look at how a relatively recent, major expansion in natural gas production due to shale drilling has impacted production of natural gas liquids. At the turn of the millennium, producers began to utilize
both hydraulic fracturing and horizontal drilling technologies in concert, making large shale gas reserves, including the Marcellus and Utica shales, accessible. Horizontal drilling involves drilling vertically to a point several thousand feet below the surface — well below the water table — until the target formation is reached and then slowly turning the drill bit so that drilling can continue horizontally for a distance of five to ten thousand feet or more. It is the horizontal leg that allows producers to access a much larger area of the shale than vertical drilling. By drilling multiple laterals (wells) from a single pad in multiple directions, even more of the shale can be accessed with much less surface disturbance than would be required if only conventional, vertical wells were drilled. Once a well is drilled, hydraulic (water) fracturing under very high pressures is used to create tiny fractures in the tight, dense shale, allowing gas to escape and be brought to the surface. It was the combination of these two technologies that made production from these tight reservoirs deep below the earth’s surface cost-effective.

Expansion into this new form of shale gas production began slowly, partly due to the high cost of drilling unconventional wells; at $6 – $8 million, a single horizontal well can cost several times as much as a vertical well. However, beginning in the early 2000s it became apparent to many producers that the cost was worth the expense, and the shale gas boom began. In 2000, shale gas accounted for only 1.6 percent of total U.S. natural gas production; by 2005, this figure had risen to 4.1 percent, and by 2010, 23.1 percent.\textsuperscript{12} Publically available data from Ohio, Pennsylvania, and West Virginia\textsuperscript{13} shows incredible growth, with 15 unconventional wells drilled between 2004 and 2005 in those states, increasing to 4,285 unconventional wells drilled in 2010 and 2011, and 3,186 unconventional wells drilled in 2012 through mid-November 2013.\textsuperscript{14} Because significantly more area within the target

\begin{footnotesize}
\textsuperscript{13} See The Ohio Division of Oil and Gas Resources’ “Shale Well Drilling and Permitting” data, the Pennsylvania Department of Environmental Protection’s “SPUD” Data Report, and the West Virginia Department of Environmental Protection’s “Oil and Gas Data Viewer.”
\textsuperscript{14} Animation: Tri-State Shale Wells, Marcellus Center for Outreach and Research, Penn State University, http://www.marcellus.psu.edu/images/TriState\%20Mapv2.gif.
\end{footnotesize}
formation can be recovered by a single unconventional well, considerably more product flows through the pipelines, meaning that successful horizontal wells have impressive rates of return.

A consequence of the increased production realized from the shale drilling frenzy is a surplus in natural gas, resulting in a drop in natural gas prices. The price of natural gas hit a 10-year low in the spring of 2012, dropping from a high in July 2008 of $10.79 per thousand cubic feet to a low in April 2012 of $1.89 per thousand cubic feet.\textsuperscript{15} To maintain profitability at such low prices, producers have migrated their drilling operations to target wet gas plays, such as those found in southeastern Ohio, northern West Virginia and southeastern Pennsylvania, rather than the dry gas plays of northeastern and central Pennsylvania.

\textbf{[b] — Wet Gas Versus Dry Gas.}

Not all gas is equal. In fact, the composition of natural gas can vary widely. In some areas, the natural gas stream will be comprised mostly of methane gas, while in other areas the natural gas stream will also include several other hydrocarbons. Gas composed primarily of methane is generally referred to as “dry gas” or “lean gas.” Gas that contains methane plus greater amounts of other, heavier hydrocarbons is generally referred to as “wet gas” or “rich gas.”

The reason for this variation in gas stream composition is differences in thermal maturity. Thermal maturation is the process rocks undergo when organic compounds are broken down under increasingly higher temperatures. The higher the temperatures the rock has been exposed to, the “more mature” it becomes. Dry gas is “more mature” than wet gas. Both the Marcellus Shale and the Utica Shale formations in the Appalachian Basin have a “wet-to-dry” pattern that moves from west to east. This is why a producer drilling the Marcellus Shale in northeastern Pennsylvania is more likely to recover a gas stream composed predominantly of methane, while a Marcellus

Shale producer in southwestern Pennsylvania is more likely to recover gas that includes a greater concentration of other hydrocarbons in addition to methane. It is because these other hydrocarbons have inherent value of their own when separated from the gas stream that producers have targeted the areas of rich natural gas to increase profits.


[a] — The Liquids Stream and Its Component Parts.

As previously mentioned, rich natural gas contains hydrocarbons other than methane. While methane is still the predominant hydrocarbon contained in the rich gas stream, it is not classified as an NGL because its boiling point is too low to reach a liquid state by normal processes. Ethane, propane, normal butane, isobutane, and pentanes plus are the hydrocarbons typically found in natural gas that make the gas “rich.” The term “liquids stream” is used to describe the liquids which are siphoned off from the gas when the gas is processed. After being siphoned off, the raw liquids stream is fractionated to separate the liquid hydrocarbons into their component parts: ethane, propane, butane, and natural gasoline. Each is valuable in its own right in the manufacturing, commercial, residential, or transportation sectors, or a combination of these sectors, which will be explored in greater detail below. The relative value is higher the heavier the hydrocarbon: ethane is worth less than propane which is worth less than butane which is worth less than natural gasoline, etc.

The chemical formulas for each NGL are very similar, with the difference in each hydrocarbon being the addition of one carbon atom and two hydrogen atoms, from “light” hydrocarbons to “heavy” hydrocarbons. For example, the formula of ethane, the lightest of the NGLs, is \( \text{C}_2\text{H}_6 \), and propane’s formula is \( \text{C}_3\text{H}_8 \). The chemical formula of both normal butane and isobutane is \( \text{C}_4\text{H}_{10} \), but isobutane is a structural isomer of normal butane; that is, although they have the same chemical formula, their chemical structures are different.

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Whereas normal butane’s carbon atoms are aligned in a row, or “unbranched,” isobutane has one carbon atom on the middle, with the remaining three “branching” off of it. This minor difference in structure results in different physical characteristics. In fact, each of the NGLs has different physical characteristics, such as boiling point, ranging from ethane’s very low boiling point of approximately negative 127 degrees Fahrenheit to normal butane’s much higher boiling point of approximately 30–35 degrees Fahrenheit.

[b] — The Role of Processing and Fractionation (Liquid Separation).

As discussed in Section 4.01, when the natural gas stream contains these heavier hydrocarbons, processing is required to extract the NGLs and other unusable and unwanted constituents17 before the residue gas is qualitatively acceptable for delivery into the interstate transmission system. Although we speak of the rich gas stream as containing these “other hydrocarbons,” NGLs are typically entrained in the gas stream — that is, they are in gaseous form — and are not fully removed until the gas has been processed to convert them to a liquid state and to cause them to drop out as mixed NGLs.18

One of the processes used to remove the NGLs is a cryogenic turbo-expander process. In this process, the natural gas stream is compressed to pressures approaching 1,000 pounds and then sent through an expander where the pressure rapidly drops creating an extreme cooling effect. The temperature of the gas drops as low as minus 140 degrees Fahrenheit and results in the heavier hydrocarbons converting to liquid form. The result is two separate streams: one consisting primarily of methane and some ethane and one consisting of the other, heavier hydrocarbons. Although the cryogenic turbo-expanding process is very effective, it does not result in 100 percent NGL recovery. In particular, it is generally not cost-effective to remove all

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17 An example is carbon dioxide which has an affinity for ethane. While CO₂ in the gas stream may not be a problem, it is a serious problem for ethane and has to be removed, or at least significantly reduced.

18 It is common for some NGLs to convert to liquid form and fall out of the gas stream as the temperature of the gas cools or as pressure changes when the gas is compressed or as it moves through the underground pipelines.
of the ethane, and, for reasons usually related to price, much of the ethane will be left in the natural gas stream. The amount left in is limited by the Btu limits in the pipeline’s tariff discussed previously. A rule of thumb is that the gas can contain up to about 12 percent ethane, with the rest being methane, and still meet gas quality specifications.

Once removed, the NGLs’ value cannot be realized until the liquid stream has been fractionated. Fractionation occurs by sending the stream through a series of towers where the temperature is carefully, gradually increased. First, the NGL stream goes through the de-ethanizer to remove ethane, or “C₂.” In this step the gas is warmed to a temperature colder than minus 50 degrees Fahrenheit but warmer than minus 127 degrees Fahrenheit. This causes the ethane to boil off, thereby separating itself from the other NGLs. Second, the remaining stream goes through the de-propanizer to remove propane, also called “C₃.” It boils off at temperatures warmer than minus 43 degrees Fahrenheit. Third, the remaining stream goes through the de-butanizer to remove butane, also called “C₄.” It boils off at temperatures warmer than 34 degrees Fahrenheit. This leaves only the pentanes and heavier molecules (such as C₆–C₉), which are abbreviated as “C₅+.” There are usually few molecules heavier than C₁₀.


Natural gas liquids being delivered from processing and fractionation facilities to market may be transported by one of several methods. Pipelines are the preferred method when large volumes of liquids need to be moved safely and reliably. In fact, because of the high pressure and/or low temperature required to keep ethane in a liquids state, it is essentially only transportable via pipeline or barge (or ship).

Transportation by truck, rail car, or barge (or ship) is an option for the other NGL products. The dearth of pipeline facilities coupled with the volume of product and the distance to market has made transportation by rail car

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19 Once separated out, the butane stream may be run through a de-isobutanizer to split C₄ between normal butane (“nC₄”) and isobutane (“iC₄”).
the predominant mode in the northeast. However, as compared with pipeline transportation, transportation by rail car is more expensive. As new pipeline projects come to fruition, pipelines will replace rail as the predominant mode of transportation.

Worthy of note is the expected increase in transporting NGLs by ocean borne cargo ships. This mode of transportation is being used to export ethane, propane, and butane to their final destinations all around the world.20 Larger ships are being built and the Panama Canal is being expanded to accommodate them, both of which will make it even more economical to serve overseas markets in northwest Europe and Far East Asia.


Now that we know what NGLs are, it may be easier to understand why they have a positive effect on the value of the natural gas stream. The concept known as “frac spread” gets at the heart of the NGL value addition. “Frac spread” is the difference between the revenue from sales of NGLs derived from the natural gas stream as liquids, versus their value if left in the natural gas stream and sold at gas prices; that is, it is the value added by processing rich gas into higher-value products, such as propane and butane.

For example, assume rich gas sells at $5.60 per thousand cubic feet (Mcf) prior to processing. After the gas undergoes processing to remove NGLs from the natural gas stream, assume that the amount of gas (i.e., methane and some ethane) remaining sells at $3.16 per Mcf. Now, assume that the NGL stream that was siphoned off gets fractionated into component products, each part being sold at its market value per Mcf, which we will assume is a total of $3.74. The total value of the processed stream in this hypothetical is $6.90, a full $1.30 more per Mcf than the unprocessed, gas-only value of the entire stream.21 Although $1.30 may seem like a small and relatively insignificant amount of money, it is a price increase of almost 25 percent over the original price. When viewed on a large scale and in the context of high levels of rich

20 There are restrictions on the export of oil, natural gasoline and condensate. There are indications that this may change, but for now the restrictions are an impediment to export.
gas production, this value addition means billions of dollars in additional revenue to producers over the course of a year.

The numbers used here are representative of recent experience. Future values will, of course, differ but they are not expected to change at this time. That is because NGL prices tend to correlate with oil, which has increased in price over the last five years, while gas has gone down significantly. In fact, the ratio of the price of a barrel of oil at the turn of the century was six to eight times that of gas. Today that ratio is almost 25:1 or more.

§ 4.03. Natural Gas Liquids – Where Do They Go?

The Commercial Uses and Markets for Natural Gas Liquids.

NGLs are valuable in large part because of their uses in various industries, including commercial, residential, industrial, and transportation sectors of the economy.22 Although each of the NGLs has some similar uses (e.g., most have use as a petrochemical feedstock), the minor differences in their chemical makeup are evident by their other varying uses. Ethane has two primary uses: one is to make ethylene glycol (antifreeze), and the other is to make polyethylene for use as a petrochemical feedstock in the manufacture of plastics. The end uses of polyethylene products include plastics, plastic bags, and detergent. Propane, with its addition of only one carbon atom, is used as a petrochemical feedstock, but also in residential and commercial heating and as fuel for cooking. Normal butane is used as a petrochemical feedstock, but it may be blended with gasoline. Its end-use products include lighter fluid and synthetic rubber for tires. Isobutane is used as a refinery and petrochemical feedstock, and its end-use products include alkylate for gasoline, aerosols, and refrigerants. The pentanes plus have use in the transportation sectors, especially as a gasoline additive or as a diluent where, particularly in Canada, the C5+ is blended with tar sands oil to facilitate its movement in pipelines from Canada to the United States.


Each of the NGLs is priced differently, reflecting their unique value. Current prices at Mont Belvieu, a common trading location for NGLs, show ethane being sold for about $0.29 per gallon, while propane is about $1.03. Normal butane prices are about $1.23 per gallon, while isobutane is closer to $1.32. Gasoline is the premium NGL, and is currently trading for $2.29 per gallon. There has been downward pressure recently on NGLs due to the rapid growth in supply, but they have held up reasonably well, and new markets are developing both domestically and abroad that should help put a floor under NGL prices.


In a wet gas shale play, the midstream company will provide gas gathering (transportation), gas processing, and fractionation services to a producer pursuant to the terms of an agreement, usually by the same name, e.g., a “Gas Gathering, Processing, and Fractionation Agreement” or other similarly named agreement (for purposes of this § 4.04, the “agreement” or “agreements”). These agreements have become lengthy, stretching as long as 50 pages. Their length and complexity is primarily a result of (a) the detail required to separate, measure, and account for the various component parts of a producer’s gas stream (as between the midstream company, the producer, and other producers moving their comingleld gas through the same facilities); (b) the producer making either (i) a minimum volume commitment or (ii) dedicating gas reserves to the midstream company within a specific geographic area with detail on production projections; and (c) in

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conjunction with (b), the midstream company agreeing to construct expensive facilities, including pipelines to well locations (some existing, some yet-to-be-determined), that are right-sized and in-service at the time they are needed.

For its extensive capital investments in physical facilities and the services those facilities are used to render, the midstream company collects various fees, sometimes including retention of a portion of the proceeds from the sale of NGLs extracted from the producer’s gas stream. In exchange for paying for the services, the producer receives gas and NGLs that can be sold.

[2] — Key Commercial Terms in Contracts Between Producers and Midstream Companies

The Economic Model; Dedication of Acreage. To understand these agreements from the midstream perspective, it is important to remember the general economic model employed by the midstream company, which, generally, does not involve the midstream company charging or collecting from the producer any fixed monthly fees or demand charges. Doing so would certainly lessen the risk to the midstream company of the need to collect a requisite level of revenue from the producer. Instead, and favorable to the producer, the midstream company generally collects its revenues and fees under the agreement only when the producer actually tenders gas to the midstream facility for transport or movement on the midstream facilities; that is, a pay as you go model, although, it is conceivable that the producer has committed to flow or transport a minimum volume of gas per month (which is effectively a minimum revenue commitment per month, like a fixed monthly fee or demand charge, payable to the midstream company).

To manage its risk under this model, the midstream company requires the producer to dedicate for gathering and processing all of the gas produced from a certain geographic region or area (often called the “Area of Mutual Interest” or “AMI”). While this does not assure the midstream company when gas will be produced or in what quantity, it does assure that its competitors will not get the business. In addition, by consulting with geologists, the midstream company has some confidence of the production volumes it is likely to receive. It is in relying on the producer’s commitment and the geologists’ forecasts that the midstream can justify the capital expenditure required to build pipelines, processing, and fractionation facilities to serve the producer.
Formulas and Defined Terms. The pipelines and facilities constructed by the midstream company are rarely designed to serve only one producer. More commonly, there are multiple producers in an area delivering gas from their wells into the midstream pipelines thereby creating a commingled gas stream. Thus, perhaps to state the obvious, it is imperative that gas (as to volume and composition) be accurately measured as it is delivered into the pipeline by the producer. This measured input forms the basis by which the midstream allocates back to the producer its proportionate share of gas and liquids after processing and fractionation. This measurement is effectively the producer’s cash register because it determines the payments the producer will receive for its inputs into the midstream company’s pipeline.

Because of the importance of this measurement, these agreements are filled with language setting forth precise formulas for allocating, balancing, and adjusting (or “truing up” from month to month to account for accounting and actual measured quantities) a producer’s share of gas and liquids. Correspondingly, for the formulas to be clear and precise, numerous defined terms are used in the agreement. It would not be uncommon for more than 100 terms to be defined in a gas gathering, processing, and fractionation agreement with the producer. While pricing, fees, and the sharing of proceeds from the sale of liquids might be eligible for negotiation, these precise formulas are not, as they work in concert with the formulas contained in agreements entered into by the midstream company with other producers. It is imperative that these formulas work in the same manner among the producers delivering gas into the midstream company’s facilities so that there are not conflicts in the allocation process.

Facilities. Like a simple gas transportation agreement, the gathering and processing agreement specifies the physical points where gas will be delivered by the producer into the midstream company’s pipeline and where the residue gas will be re-delivered after processing. It also specifies the maximum quantity of gas that the midstream is obligated to receive, gather

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25 As discussed above, the producer’s methane gas stream is ultimately delivered from the midstream’s facilities into interstate pipelines.
(transport), and process on a firm basis. All volumes in excess of the specified level are typically subject to interruption unless the agreement provides for an increased level of firm service.

Because the midstream is accepting the obligation to build the facilities needed to gather and process all gas that is produced, the agreement will typically contain a requirement for the producer to regularly prepare and establish to the satisfaction of the midstream company its drilling plans and on what time frame gas, in increasing quantities, will be ready for delivery into the midstream facilities; and, on what time frame and size the midstream company will need to have certain facilities constructed to match the producer’s production plans. In summary, the agreement’s provisions provide for a precise and thorough coordination between the midstream and producer on these issues. By analogy, these provisions are coordinating nothing less than two parties building railroad track toward one another from a distance and so that they meet at a precise time. However, in this context, the track (pipeline) is being constructed to potentially multiple well locations, some of which have yet to be established by the producer vis-à-vis its own drilling plans, so the precise location of where the tracks will connect is not known. Needless to say, the midstream company is greatly concerned about the prospect of constructing pipeline to a location (potential well site or producing location) where the producer’s production plans do not develop or fall through. These complex provisions help ensure that such catastrophes do not occur.

Given that these agreements pertain to acreage that will be developed over a period of years, if not a decade or more, these provisions are often written in terms of “phases” of development or construction. Agreements as to pipeline, processing, or fractionation capacity, and producer gas volume commitments, vary by phase of development and construction. Of course, the midstream must coordinate all of this activity with not just one producer, but with all of the producers with whom it has entered into agreements to provide midstream services. For example, it is usually the case that one large, downstream fractionation plant will be installed on the midstream company’s facilities to service gas from multiple producers. Properly sizing these larger, downstream facilities involves significant judgment and risk
based on producers’ plans communicated to the midstream under the terms of the agreements.

Fees, LAUF Gas, and Fuel Gas. In exchange for the services provided by the midstream company to the producer, the producer compensates the midstream company through the payment of various fees and charges. Typically, the midstream company charges a gathering or processing fee per million cubic feet (Mcf) or dekatherm (Dth) of gas that is transported and processed. Because a small portion of natural gas becomes lost or otherwise unaccounted for — often due to measurement inaccuracies — as it is transported from point A to point B on the midstream system, an ordinary course event on any natural gas pipeline system, the producer bears the burden for so-called lost and unaccounted-for (hereinafter “LAUF”) gas associated with transporting its gas. The amount of LAUF for which the producer is responsible is determined by the midstream company as it measures the inputs and outputs on its system. This LAUF amount, stated as a small percentage of the gas received by the midstream from the producer at receipt points on the midstream system, can either be a calculated amount based on a formula set forth in the agreement or by using a fixed percentage of the gas handled. When LAUF is fixed, it is common for the percentage to be subject to adjustment from time to time based on the midstream company’s actual operations and experience. Similarly, the producer is also responsible for LAUF gas that occurs during the processing and fractionation processes.

In addition to being responsible for its share of LAUF on the system, a producer is responsible for providing the midstream with natural gas as fuel to run compressors or other equipment or processes. These quantities are referred to as “fuel” or “plant fuel,” which is also assessed against the producer and which represents a small percentage of the gas that the producer delivers into the midstream company’s system at receipt points on that system. If a fuel other than gas is used, e.g., electric, the cost will be allocated proportionately, typically based on the quantity of gas being handled.

Besides the fees and charges just mentioned for transporting and processing gas, the producer pays the midstream fees for the fractionation of NGLs. These fees are usually assessed in cents per gallon of NGLs. The producer, more often than not, looks to the midstream to take care of the
logistics of selling and further transporting away from the fractionation plant the valuable NGLs that the midstream separates (through fractionation) from the producer’s natural gas stream. For this service, the producer pays the midstream a marketing fee and, as a deduction from gross proceeds, logistics fees related to the sale and dispositions of those NGLs. Sometimes, as an incentive for the midstream to sell the producer’s NGLs at the best possible price (given any applicable logistical limitations), the producer agrees to give the midstream a “percent of proceeds,” or a percentage of the proceeds the midstream realizes upon the sale of the producer’s various NGLs. Elsewhere in this chapter, the specific NGLs, their markets, their value or prices, and pricing are discussed.

Not surprisingly, due to the complicated nature of these agreements and the methods by which money changes hands pursuant to their terms, it is not uncommon for parties to disagree, for example, about the difference between gas, NGLs, and condensate, and how proceeds from their sale are to be allocated. In a 2011 case, the Court of Appeals of Texas was asked to interpret a contract by which producer, Forest Oil Corporation (Forest), agreed to sell its natural gas and NGLs exclusively to processor, Eagle Rock Field Services, LP (Eagle Rock).26 The contract provided that Forest was to receive compensation for 85 percent of the NGLs and residue gas up to a particular quantity and 92 percent of the NGLs and residue gas exceeding that quantity.27 At issue was whether Forest should be compensated for the liquids that condensed and dropped out of the natural gas stream in Eagle Rock’s compression facilities prior to their delivery to the processing plant.28 Forest argued that, based on the unambiguous language of the agreement, NGLs extracted and recovered from the natural gas stream

27 Id. at 697.
28 See generally id. (“Under the agreement, Forest agreed to contract exclusively with Eagle Rock ‘for the purchase of [Forest’s] Gas and the right to process and extract [NGLs] attributable to [Forest’s] Gas’ from wells on specified lands and leases. [‘NGLs’] are defined in the agreement as “those liquid hydrocarbons extracted from the Gas from processing.’ But ‘processing,’ — the term central to this dispute — is not defined, even though the words ‘process,’ ‘processed,’ and processing’ are used throughout the agreement.” Id. at 701 (emphasis added)).
“from compression involving mechanically induced, significant pressure increases and temperature changes are the result of ‘processing’ within the plain, ordinary use of the word, as well as within the context of oil and gas industry custom and usage.” However, Eagle Rock argued, and the court agreed, as follows:

[T]he agreement unambiguously requires Forest to maintain delivery pressures sufficient to enter Eagle Rock’s gathering system and to refrain from processing the gas before delivering it to Eagle Rock. [B]ecause the parties contemplated that Forest may be required to compress its gas before delivery to maintain the agreed delivery pressure, its use of compression could not be considered “processing” under the unambiguous terms of the agreement, because only Eagle Rock was permitted to perform processing.

Accordingly, the court held that Eagle Rock was not required to pay for condensate that falls out in separators used during compression before the natural gas stream is processed for sale at the plant tailgate. Effectively, the court was saying that compression is not processing, and any condensate that falls out of the gas stream at compression facilities belongs to the company providing the compression. The Forest Oil court relied in part on an earlier decision by the Supreme Court of Texas, Dynegy Midstream Services, LP v. Apache Corp.

29 Id. at 698.
30 Id. at 698–99 (“Because the Agreement precludes ‘processing’ by [Forest], liquids that condensed within Eagle Rock’s gathering system after compression but prior to the Arrington Plant’s lean oil facilities could not be NGLs. They were, therefore, contractual Condensate and this Condensate belongs exclusively to Eagle Rock. Therefore, because Forest has no claim to a “percentage of proceeds” earned from Eagle Rock’s sale of contractual Condensate, this Court finds no breach of contract as a matter of law from the contractual interpretation of this unambiguous agreement.” Id. at 703.)
31 Id. at 708.
32 Id. at 706–08; see also Dynegy Midstream Servs. v. Apache Corp., 294 S.W.3d 164, 172–74 (Tex. 2008) (“In sum, . . . we agree . . . that none of the contracts require Versado to compensate Apache for field condensate that fell out of the gas stream at the Eunice North and South compressor stations.” Id. at 174.).
As well as the pre-processing condensate issue, the Dynegy case also involved another matter for the court: “unaccounted-for” gas that went missing, or that was “unaccounted for” between production in the field and sale at the processing facility.\(^{33}\) The various contracts at issue provided that Versado Gas Processors, LLP (Versado), the gas processor, was to sell gas that reached the tailgate after processing, and Apache Corporation (Apache), the producer, was to receive a percentage of the net proceeds derived from that sale.\(^{34}\) Although none of the contracts specifically addressed “unaccounted-for” gas,\(^{35}\) they generally provided that Apache was not to be paid for gas consumed as fuel and gas that was flared, leaked, or otherwise lost in the operation of the Plant and Gathering System.\(^{36}\) The court determined that the parties were free to contractually set a cap on the amount of gas that could be consumed as fuel or lost during operations, and an expert testified that industry practice caps such losses at two percent; however, the relevant contracts contained no such caps, and the court concluded that it would be inappropriate to consider the expert’s testimony as parol evidence to establish a cap when the unambiguous terms of the contract provided for no cap.\(^{37}\)

“Because the contracts unambiguously do not impose an obligation on Versado to compensate Apache for ‘unaccounted-for’ gas that was not sold at the plant tailgate, contract damages for gas lost between the wellhead and the tailgate are not recoverable.”\(^{38}\)

The litigation in both of the above-referenced cases was based in large part on the parties’ differing interpretation of undefined or missing terms. To avoid litigation, parties should not rely on their understandings of industry terminology and custom, or how they believe a court would define a particular term in the absence of strong precedent, but instead play close

\(^{33}\) Dynegy, 294 S.W.3d at 165.

\(^{34}\) Id. at 169.

\(^{35}\) Unaccounted-for gas is common throughout the natural gas industry and can result from many factors including loss, unmeasured usage, and inaccurate measurement.

\(^{36}\) Id. at 166.

\(^{37}\) Id. at 170.

\(^{38}\) Id.
attention to detail and the minute aspects of midstream contracts and define those terms that are crucial to proper interpretation of the agreement. This is especially true in the northeast because while there is a body of law in the southwest gas-producing states, there is a dearth of case law in the northeast. A logical expectation is that litigation will increase in the northeast until the law becomes settled.

_Fixed Recovery Concept_, One might think that with all the technology available today, upon separation of the NGL (or “Y-grade”) stream into its component parts during the fractionation process, the midstream company would be able to determine on a real-time basis which gas and which NGLs belong to each of its producer-customers. Unfortunately, this is not commercially practicable. There are simply (a) too many points where expensive measuring equipment is needed, (b) processing agreements are not standardized — each producer negotiates enough unique terms that this is not possible, and (c) some information, such as fuel costs and product losses (often, measurement inaccuracies), is not known on a real time basis. Consequently, after the end of each month, midstream companies take the next 20 to 25 days to determine who owns the NGLs produced and sold and who owns the residue gas delivered to each downstream pipeline. To make this determination, the midstream company must have a plethora of data, including the quantity and composition of gas received into the gathering system, received into the plant, and delivered to the downstream pipeline(s); the quantity of each NGL sold and whether it was pursuant to a long- or short-term contract — some producers do not allow the midstream company to commit their NGLs for more than a year; to which pipeline each producer wanted their residue gas delivered; the amount of fuel consumed and its cost; and, the amount of LAUF.

The challenges associated with such a complex allocation are leading some to simplify the process by fixing the recovery percentage for each NGL that is contained in the Y-grade stream. To implement this, the agreement sets forth a list of the various NGL components contained in the producer’s Y-grade stream and the fixed, pre-determined recovery percentage that both parties agree will be applied to a particular NGL contained in the producer’s gas or Y-grade stream. For example, it might be pre-determined
that 99 percent of the natural gasoline contained in the producer’s gas will be recovered.39 These fixed recovery percentages can provide a fair, reasonable allocation to the producer that it will receive what it expects. Fixed factors also incentivize the midstream company to be as efficient as possible because if they do not achieve the agreed recovery factors, they will lose money to the extent they fall short.

*Shipper or Customer Take In-Kind Rights.* When the producer delivers its gas into the midstream system, the producer has title to that gas and the NGLs entrained therein. Title remains with the producer throughout transportation, processing, and fractionation such that the residue gas leaving the processing plant and the NGLs leaving the fractionator remain the producer’s to sell. Under contemporary processing agreements,40 the producer will either sell the residue gas at the outlet of the processing plant to a marketer or it will acquire transportation rights on the interstate pipeline system to (hopefully) access higher priced, downstream gas markets. NGLs, on the other hand, are typically sold for the producer by the midstream company. To facilitate the sale of NGLs, the producer will either transfer title to the midstream company as the NGLs exit the fractionator or they will designate the midstream company as their agent to sell them. In either case, this is done in exchange for the midstream company agreeing to remit the net proceeds from the sale to the producer.

The midstream company is usually chosen to sell the NGLs, especially by smaller producers, because of the specialized expertise required to sell them. Not only are NGLs sold into unique and varied markets, the logistics associated with the timely scheduling of tanker trucks, rail cars, and liquid pipeline transportation arrangements is complex. Adding to the challenge, transportation arrangements have to be made for each NGL to different markets. To fulfill its obligation to sell NGLs not taken in kind by a producer,

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39 Typically the amount of natural gasoline in the producer’s gas is reduced by some amount to account for gas that is lost, unaccounted for, or used as fuel. The recovery percentage is applied to the remainder.

40 Historically, it was common for the midstream company to sell the gas as well as the NGLs for the producer, but as access to interstate pipeline capacity has become constrained, producers have taken over the sale of residue gas.
the midstream companies have staffs to sell all types of NGLs and to manage truck, rail, and pipeline transportation for each. Sometimes they also will even acquire NGL transportation and storage rights to facilitate NGL sales. Producers are challenged to cost-effectively replicate these capabilities.

To compensate each producer for their NGLs, the midstream company typically pays each producer the average net price derived from their sale. To derive the net price, all costs incurred by the midstream company to sell the NGLs are deducted. These costs include items such as pipeline costs, rail car lease costs, storage costs, and marketing fees.

Transportation of NGLs out of the plant by the midstream company has to occur like clockwork. That is because there is limited physical storage for NGLs at the fractionation plant, and if NGLs are not timely transported away from the plant, operations will have to be shut down. If the plant shuts down, the entire “upstream” cycle stops — producers must stop producing gas until NGL products can resume being transported away from the fractionation plant.

While the sale of NGLs is typically performed by the midstream company, the natural gas liquids extracted from the producer’s gas stream are extremely valuable. In fact, they are much more valuable than the gas itself and can be the difference between whether an investment in a well is profitable or not. To protect this value, producers will often reserve the right to “take-in-kind” their NGLs at the outlet of the fractionator and to sell them. To deal with the possibility that either the midstream company or the producer could end up selling the NGLs, it is important that the agreement address in great detail the responsibilities of both parties under each scenario.

When producers elect to assume responsibility for the marketing, sale, and transportation of their NGLs, they take on significant tasks that must be executed with the same timely precision as when done by the midstream company when it sells NGLs for them. Having another entity be responsible for moving products out of a plant makes plant operations even more complicated for the midstream company. Now, not only does the midstream

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41 This concept is explored in greater depth in § 4.02[4], above.
42 Product Sales Agreements are the discussed in § 4.05, below.
company need to make sure its own sales operations run smoothly, it must monitor the operations of the producers selling their own NGLs because if they fail to execute their responsibilities precisely and timely, that can also shut down plant operations.

Transitioning the sales responsibility from the midstream company to the producers requires significant planning. That is partially due to the producer needing to make preparations to sell and transport the NGLs and partially because in the Appalachian region where the Marcellus and Utica Shales are located, most NGLs are typically sold for periods of a year or more. As a result, it is not uncommon for a producer to be required to give at least six months’ notice to the midstream company before they can exercise their take-in-kind rights. Conversely, to preserve the value of its take-in-kind rights, the producer will often include a provision in the processing agreement that limits the right of the midstream company to commit a producer’s NGLs for more than one year. A typical provision would be that the midstream company cannot sell a producer’s NGLs for a period exceeding one year without the producer’s written consent.

To deal with the burgeoning growth of NGLs, large NGL pipeline projects are being built. As part of this, it is not uncommon to see commitments of 10 years or more, forcing producers to decide now whether they want to rely on historic NGL markets and modes of transportation or whether they want to make longer commitments through the midstream company in hopes of getting better prices for their NGLs. The midstream company will normally bring long-term opportunities like this to its producer customers via a term sheet containing the important details of the transaction to enable the producer to decide whether to allow its NGLs to be committed long term. If the long-term commitment is not made, the midstream company will still sell the producer’s NGLs into other markets or the producer can switch to selling and managing the sale of its own NGLs.

In summary, the logistical challenge of efficiently handling and transporting NGLs at the outlet of the fractionation plant cannot be overstated. Unlike the producer’s gas stream that can be transported in a single, commingled stream, NGLs must be handled and transported individually via a number of distinct transport options for redelivery to multiple buyers.
Even if a producer elects to take its NGLs in kind, given that the midstream company operates the fractionation plant for the benefit of all of its producer customers, the midstream company retains ultimate control (and default control) over the NGL disposal and transport process. As a result, if a producer electing to take its NGLs in kind fails to adequately manage the logistical take away of its NGLs from the fractionation plant, it becomes subject to financial penalties established in the agreement, as well as the midstream company’s right to take over control of marketing, selling, and transporting that producer’s NGLs.

**Force Majeure.** Given that the midstream company is operating a complex system of high-pressure pipelines, rotating equipment, and processes that require both heating and cooling, the agreement excuses the midstream company’s performance for *force majeure* events, many of which are specified in the agreement. The definition of *force majeure* is unique to the midstream industry in the region. For example, there are hillside slips where the ground over and under a pipeline slides down the mountain. The loose dirt has to be removed, new dirt hauled in and compacted, and the surface restored before it is safe to resume operation of the pipeline.

The *force majeure* clause not only defines “*force majeure* event,” but it also settles what will happen and what the respective parties’ rights are in such an event. *Force majeure* clauses generally contain notice provisions requiring the affected party to notify the other party of the *force majeure* event. Furthermore, the provision will likely provide what happens if a party is prevented from performing due to a *force majeure* event, such as, that the affected party’s obligations (other than obligations to pay money) are suspended during the event.

One feature that is becoming increasingly popular in these agreements is a limitation on the number of days a *force majeure* event may last before certain rights accrue to the parties. The inclusion of these rights is a recognition that if the midstream company has become unable to gather and process gas, at some point, it becomes an unfair burden on the producer who still has an urgent need to produce gas. Therefore, *force majeure* provisions are beginning to state that after the *force majeure* event has lasted a set number of consecutive days, the producer may look elsewhere for service.
If the event lasts an extraordinary amount of time, the provision might allow the producer to terminate the agreement.

*Gas Quality.* The midstream company does much more than transport raw produced gas through pipelines. It operates processing and fractionation plant facilities that are sensitive to the contents in the gas stream and that may cease operating if the produced gas stream contains certain objectionable liquids or solids, or contains too much of a naturally occurring product (*e.g.*, hydrogen sulfide, sulfur, carbon dioxide, water, and so forth). Thus, the agreement contains gas quality criteria and specifications for gas delivered by producers into the midstream company’s system. As a result, producers must pay close attention to the quality of the gas they are producing. Delivering gas that fails to satisfy the gas quality criteria and restrictions contained in the agreement threatens the safe and continued operation of the midstream system. As a result the midstream company will often have the unilateral right to shut in production until a producer remedies the problems with its gas.

§ 4.05. Contract Terms for Sale and Disposal of Liquids in Contracts Between Midstream Companies and Liquids Purchasers.


*Basic Overview.* As has already been discussed, natural gas producers typically rely on midstream companies to market and sell their NGL products following fractionation. In order to market NGLs, midstream companies will enter into a Product Sales Agreement (for purposes of this § 4.05, the “agreement” or “agreements”) with a particular purchaser. The custom in the industry is to execute a base agreement that contains general terms that will apply to all sales. These general terms will normally provide that the midstream company will sell one or more “Products,” defined as one or more of ethane, propane, isobutane, normal butane, etc., to the purchaser, and the purchaser agrees to buy those Products from the midstream company, and that the purpose of the agreement is to set the stage for such transactions. As individual sales are agreed upon, the parties enter into individual “Term Sheets,” which address the details of the specific sales transaction such
as which Product is being sold, at what price, in what quantity, for what 
duration, and how it is to be delivered, e.g., by truck, railcar, barge, pipeline, 
or a combination of them all.

[2] — Key Commercial Terms in Contracts Between 
Midstream Companies and NGL Purchasers.

Quantity Provisions. A particular Term Sheet will specify the quantity of 
the Product being sold. This commitment is serious but due to the uneven rate 
of growth of shale gas production and uncertainty over the exact composition, 
acknowledgement is often made that the midstream company cannot 
guarantee the volume of NGLs it will have available for sale. Additionally, 
there are other extenuating circumstances that must be considered, such as 
equipment failures, plant shutdowns due to routine maintenance, availability 
of transportation, and other factors that could cause disruptions in processing 
and thus the availability of NGLs. In exchange for this flexibility on the 
part of the midstream company, the purchaser will likely require notice of 
fluctuations to the extent practicable and to communicate regularly about 
volume availability.

Quality Provision. The same way it is important to set quantity standards, 
the agreements must also set quality standards. The purchaser likely has 
downstream uses in mind for the Product it buys, which use may have a 
particular quality requirement (e.g., a downstream use may limit the amount 
of ethane allowed in propane to two percent). To determine compliance with 
quality requirement, fortunately, there are generally accepted standards set by 
the Gas Processor’s Association (GPA), and agreements typically incorporate 
them. For example, an agreement may say that unless otherwise specified 
in an applicable Term Sheet, all Products sold by the midstream company 
to the purchaser shall meet a particular GPA quality specification (which 
will be specified for each NGL) at the delivery point on the date of delivery.

Of course, the quality standards may not always be met. When they are 
not, the agreement must have provisions to deal with that eventuality. The 
parties may agree that the purchaser can reject Products that do not meet the 
quality specifications set forth in the agreement. However, the purchaser may
want the option to accept a Product although it may not meet the set standards because the purchaser has the capability to blend its Product. Because of the uncertainty over exactly what quality issues may be encountered, the agreement should provide for both parties’ cooperation in dealing with Product that does not meet quality standards.

Measurement Provision. Measurement is just as important in these agreements as it is in processing agreements. Similar to the quality standards just discussed, there are generally accepted measurement standards set by the GPA, and agreements typically incorporate them. The precise form of measurement will vary based on the method of transportation being utilized. For example, if delivery is by railcar, the measurement may be taken by the gauging method; if delivery is into trucks, measurement is by scales; and, for pipeline deliveries, measurement is by metering. To insure accurate measurement, the GPA standards may need to be coupled with additional details on things like the temperature at which measurement will be taken and the gravity on which such measurement will be based.

§ 4.06. Conclusion.

Natural gas production is growing dramatically in the northeast United States due to the emergence of the Marcellus and Utica Shale gas plays. With the emphasis on producing wet gas to obtain greater value, the midstream sector of the natural gas industry is expected to continue expanding rapidly. With that expansion will come new contracting issues and challenges as the industry evolves. An understanding of the industry is crucial when drafting contracts where terminology is crucial. This applies not only to the contracts between the producer and the midstream company, but also between the midstream company and the purchaser of the NGLs removed from the gas stream.

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43 See FN 10, supra.