NATURAL GAS PRODUCTION

ENGINEERING ESSENTIALS & BEST PRACTICES

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Chapter Summaries

Chapter 1—Natural Gas Basics

As natural gas moves through the value chain from a raw field mixture of hydrocarbon and nonhydrocarbon gases and liquids to a commodity that can be traded on national and international trading platforms, it undergoes a large number of processes that tend to stabilize the fluids and divide them into their constituent parts. Upstream deals with raw fluids and processes that are quite rudimentary. Midstream deals with a stream which has had most of the liquids removed and the process is primarily transportation. Downstream includes all the processes that convert the slightly refined stream to a commodity. Accomplishing this refinement requires an understanding of the possible fluids and how they are going to react to changes in pressure and temperature.

Chapter 2—Natural Gas Reservoir, Exploration, Drilling, and Well Completion

Turning natural gas into a commercial product first requires accessing the reservoir. First, the reservoir must be found (exploration) and rights to exploit the reservoir must be acquired. Then it must be accessed (drilling), and if it likely contains commercial quantities of natural gas, it must be made ready to produce (well completion). Each of these activities is done by specialists in the field who typically deal only with the other disciplines on the margins of their work (e.g., while a completions engineer has a significant interest in how a well is drilled, he cannot begin his work until the drilling rig has rigged down and moved off the well). There are a number of terms and concepts that are common to exploration, drilling, completions, and production. Words like porosity, permeability, gas in place, reservoir pressure and temperature, unconventional gas, etc. are important terms across the exploration-to-production spectrum, and this chapter begins by discussing those concepts.

Chapter 3—Natural Gas Production

Production engineering is focused on the question "What tools, equipment, and techniques can be applied to a well to optimize well performance while controlling costs?" This deceptively simple description belies the complexity of finding the right tools, equipment, and techniques and then making them work together. One of the primary tools of the Production Engineer is downhole logging discussed in the previous chapter. Based on the data available, the Production Engineer has to decide if the existing surface pressure is appropriate to optimize production (and if not, how to modify that pressure); if the well is appropriately lifting liquids to the surface (and if not, how to improve liquid management); and if downhole performance is impeded by near-wellbore conditions. Solutions to any of these issues may be a combination of "rig work" and "facilities work". Rig work includes erecting a workover rig to change the tubing configuration (e.g., change tubing size and/or bottom hole location), to install a deliquification method, to mitigate the accumulation of debris (typically called a "cleanout"), or to change the perforated interval. Rig work is generally preceded by "slick line" or "wireline" work. This work involves a crew on a service truck running a tool on a cable (slick line) into the hole, or running a powered tool on a cable with a power cable (wireline or "electric line") into the hole. Facilities work includes efforts made on the surface to remove the things that can hinder production (e.g., replacing piping that is too small for the flow rate, equipment that is not properly sized or configured, cleaning out accumulated solids, or adding compression and/or electrical power).

Chapter 4—Upstream Production Operations

Upstream production operations are generally defined as being confined to the piping and equipment after the wellhead "Christmas Tree" up to the beginning of a gas gathering system. Gas wells are distinct from oil wells in that oil wells tend to have very limited wellsite facilities, while gas wells have significant wellsite facilities. The reason for this difference is more historical than technical—oil is sold at the lease level, and gas is sold at the individual well level. It is reasonable to send all the wells on an oil lease to central facilities for oil/water separation, settling, and gas extraction prior to custody transfer. However, raw gas-well fluids are always a mixture of gases and liquids, with some of the liquids having significant economic value. The problem is that those valuable liquids do not necessarily arrive at the wellhead at a constant rate, nor at consistent gas:liquid ratios from well to well. These complexities led the industry to separate gases from liquids and oil from water at the wellsite, and to collect the liquids at the wellsite for sales. To do that requires separators, compressors, pumps, tanks, measurement equipment, and (occasionally) dehydration and H_2S mitigation.

Chapter 5—Gas Compression

Reservoir gas is rarely suitable for delivery to end users. First, it is not located where the end user is located, so it must be transported. Reservoir gas is rarely of a suitable quality for end-user equipment, so it must be processed to the required quality-standard with the proper energy content. Every step in the transportation and processing of reservoir gas reduces the pressure of the gas. To boost the gas pressure to the values required for the next step, the gas is compressed. This compression-and-use-of-energy cycle may be repeated several times in the journey of a molecule of gas from the reservoir to the burner tip. As the gas moves through the systems, it evolves towards becoming a commodity that is universally consistent for all end-users. The most appropriate choice for compression technology evolves as well.

Chapter 6—Piping, Valves, and Accessories

The only way to get raw, well-site gas from a well to a plant is by pipes. Once the gas has been converted to a manufactured product inside a plant, there are other transportation options such as liquefaction followed by conveyance by truck, train, or ship. However, that can't be done with well-site gas, gathering system gas, midstream gas, or local-distribution system gas—these must be put into a piping system. Despite the alternative transportation options for mainline gas described above, most of it is transported via pipe as well. This chapter deals with the differences between the five categories of piping that natural gas goes through, and then the things common to all five categories.

Chapter 7—Produced Water

Every gas well will produce some amount of liquid over its productive period. Some of this liquid may be hydrocarbons with commercial value, but some is going to be nonpotable water. For the hydrocarbon liquids, an economic case is easy to make for capturing and marketing those liquids. For nonpotable water, the economics become quite murky. There is no way to produce the gas and leave the water behind, so it is necessary to accumulate it, transport it, often treat it, and dispose of it in a manner consistent with local regulations.

Chapter 8—Plant Processing of Natural Gas

Gas from a given natural gas reservoir is a mixture of components that may vary from well to well and from day to day. Some of the individual components may have heating values that far exceed the heating value of natural gas intended for residential or industrial use; other components may hinder the combustion process, and yet others can be toxic. Natural gas sold to wholesalers and end users is a commodity, and as such, each volume unit of gas must meet certain specifications. The transition from raw gas to commodity gas is done in conditioning facilities. While the terms "gas treating" and "gas processing" are often used interchangeably in the literature, this is not strictly correct. Gas treating implies the removal of contaminants (including water), while gas processing implies the recovery of liquid hydrocarbons for sale. Gas conditioning is a broader term that encompasses both treating and processing. Gas sweetening involves the removal of "sour" components (primarily H_2S and CO_2) and is generally synonymous with gas treating.

Chapter 9—Transportation of Commodity Natural Gas

"Gas transportation" generally refers to moving gas from one location to another. After raw wellhead gas is treated to meet sales specifications, it is deemed "commodity" natural gas. Commodity gas is transported primarily via pipelines in the United States and other developed countries. Pipelines are by far the most effective and lowest cost option for transporting commodity gas anywhere that a pipeline is a reasonable option. A pipeline across an ocean is not a cost-effective option. Pipelines through tropical rainforests have proven to be very costly and prone to disruption. For larger distances, alternative methods of transporting commodity gas, including changing its form, or extracting energy from it and transporting the energy are evolving. These alternatives include such technologies as liquified natural gas, "gas to liquid" and "gas to wire" (i.e., power generation).

Chapter 10—The Role of Natural Gas in the Future of Energy

The role of natural gas in the world's energy future must be viewed from the perspective of transportation, residential use, electricity generation, and chemical feedstocks weighed in the scale of changing climate and changing political priorities. This chapter reviews each of these sectors to compare proposed paths away from natural gas with the potential consequences of those paths.

1

NATURAL GAS BASICS

Natural gas is a naturally occurring substance that is primarily made up of methane (CH_4) with varying amounts of heavier hydrocarbons and various contaminants including inert substances (e.g., carbon dioxide and nitrogen) and non-commercial volatile substances (e.g., hydrogen sulfide). Natural gas from any given well can be very different from the next well, the next formation, the next field, the next basin, etc. These differences range from minor (e.g., a small amount of CO_2 in the gas may not have any impact at all on the ability of the gas to work in an industrial furnace) to major (e.g., a gas stream with 20 mole percent hydrogen sulfide would be deadly to any mammal breathing it) and everything in between.

As natural gas moves through the value chain it is converted from the naturally occurring mix of gases, liquids, and solids that comes out of the ground into a precisely defined commodity that is largely indistinguishable from one area of the world to the next.

The value chain is typically broken into "upstream", "midstream", and "downstream". Each of these terms relates to the amount of processing that has been applied to the gas. In upstream, the gas is often subjected to mechanical separation to remove liquids and trace solids, and occasionally to rudimentary chemical processes to remove water vapor and/or poisonous gases. In midstream, the gas is largely free of liquids and solids, but some of the components are at or near their dew point and condensation of liquids is common. Midstream gas is frequently dehydrated to some extent to reduce condensation and to reduce the transport costs (i.e., removing water vapor means that one does not have to compress and transport that mass at pipeline pressures). Downstream gas is fundamentally identical at the tailgate of every plant in the world. Water vapor has been taken to a very low level, heavy hydrocarbon gases have been largely removed, contaminants have been reduced to trace amounts, and the heating value of the gas has been confirmed to be in a very narrow range. The gas that arrives at a home water heater is indistinguishable from the gas that leaves the plant.

This chapter lays out some key concepts and terminology associated with upstream operations. It includes discussions of natural gas properties, reservoir concepts, and field classifications.

Table 1.6. Selected gas measurement standard temperature and pressure

	"Standard" Pressure	"Standard" Temperature	Methane Density at std conditions
Undergrad Chemistry Texts	14.696 psia [101.325 kPaa]	60°F [15.56°C]	0.04237 lbm/ft3
Gas Measurement (USA)	14.73 psia [101.56 kPaa]	60°F [15.56°C]	0.04246 lbm/ft3
NIST and EPA (New source emissions standards)	14.696 psia [101.325 kPaa]	20°C [68°F]	0.04172 lbm/ft3
NM and LA State Reporting	15.025 psia [103.59 kPaa]	60°F [15.56°C]	0.04332 lbm/ft3
DIN	101.33 kPaa [14.696 psia]	0°C [32°F]	0.04480 lbm/ft3
SPE	100.0 kPaa [14.5038 psia]	15°C [59°F]	0.04188 lbm/ft3
ISO 2314	101.325 kPaa [14.696 psia]	15°C [59°F]	0.04245 lbm/ft3
EPA (for air quality standards)	101.325 kPaa [14.696 psia]	25°C [77°F]	0.04102 lbm/ft3

This probably seems straightforward enough, but it has a significant twist to it. Every regulator, every contract, every company has (or should have) a definition for "standard pressure" and "standard temperature" and they can vary significantly (Table 1.6).

The numbers all look very similar, but using the EPA air-quality number as the denominator yields a 9 percent spread in this data. If worldwide gas production is 10 BSCm/day [353 BSCF/day], and average wellhead price is USD $1.50/MSCF then the variance in producer revenue might be as high as ±USD $50 million/day. Then the gas is processed (and sold again), transported (and sold again), and distributed to end users (and sold again). A nine percent swing in the basis for all of these sales can easily turn into real money.

There is no "right" answer, and every jurisdiction, every company, and every contract has what it considers a valid reason for a particular choice of standard temperature and pressure. It would be a significant benefit to the world if they could get together and agree on a single set of values, but there is not really any momentum in that direction (in fact, when the U.S. EPA revised its *New Source Performance Standard* in 2012, they decided that the "right" standard temperature was 25°C [77°F] in spite of the U.S not being on the metric system, and 25°C not being anyone else's published standard temperature).

It is absolutely incumbent on any engineer that participates in contract negotiations for gas sales, or who works in gas measurement, to verify that an explicit value is specified for "standard pressure" and "standard temperature" and that those explicit values are compatible with the way data is stored in the company databases. There was an example with a major Oil & Gas company in the early 1980s where standard bulges that could be salt domes. The salt plug tends to be impermeable, so it can act as the stratigraphic trap for reservoirs located on the flanks of the diapir. Further, bulges in formations above the diapir can act as traps some considerable distance above the salt plug.

- **Anticline**. Webster's dictionary defines an anticline as "An arch of stratified rock in which the layers bend downward in opposite directions from the crest". A lot of things can cause an anticline to form, one of the more common mechanisms is a salt dome that was stopped in mid travel.
- **Pinchout**. When a reservoir is sitting on rock that would be a suitable cap rock at the same time it is below a suitable cap rock, the fringes of the reservoir can have a situation where the reservoir rock simply peters out and the impermeable rock above and below the reservoir rock come together. This is a form of a stratigraphic trap.
- **Fault**. Finally, geological actions can create a displacement of a section of the rock column by a considerable distance. One of the things that can happen in a displacement event is that a cap rock can be inserted into the midst of the reservoir rock. This can lead to three reservoirs being created, as depicted in Figure 2.2.

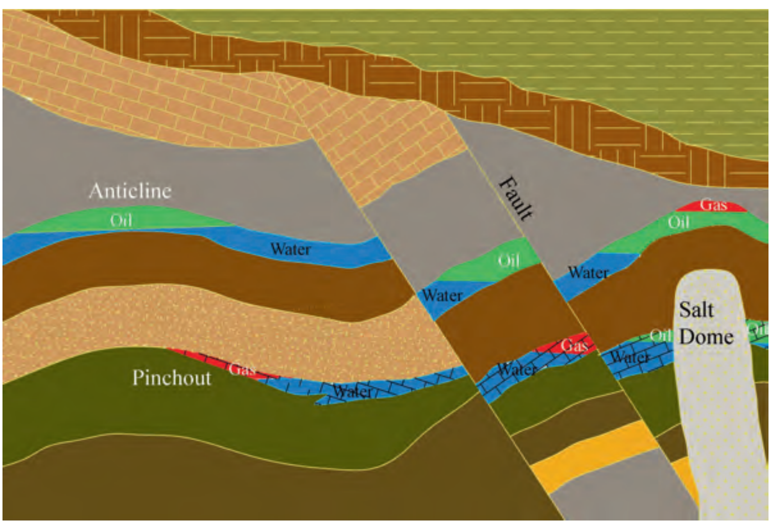

Figure 2.2. Types of reservoir traps (Simpson, 2017)

leaves falling from trees in the autumn—it is unsightly and smelly so it MUST be a pollutant. Rules too often stem from a bias towards pretty things that smell good.

Environmental regulations mostly deal with: (1) air quality; (2) water quality; (3) protection of underground aquifers; and (4) protection of local plants and wildlife. The restrictions in each of these areas are vastly different from jurisdiction to jurisdiction, and (sometimes) from day to day. A practice that has "always been acceptable" can be declared "unacceptable" by a regulator or field inspector without any justification at all. For example, one regulator may look at the regulation that one cannot set an evaporation pond over an aquifer as "test wells on the site cannot produce enough water to supply one home", and the next regulator might find any water in a test wellbore disqualifies the site. When that happens, there is very little recourse beyond complying with the new (and possibly arbitrary) rule that might only last as long as a particular regulator or inspector is in that job at that location.

Field abandonment

Even fields that were initially huge will eventually stop generating positive economics. This does not mean to imply that the field is out of gas, just that it is no longer economic (i.e., it costs more to produce the gas than it can be sold for). Often a field may be uneconomic for one company, but extremely profitable for another (usually smaller, with lower overhead) company. In those cases, the field will change operators. Eventually, the field will fail to meet the economic criteria of the new company. If the new company is unable to find a buyer, the field must be abandoned.

Figure 2.22. Cahn Gas Com 1 Abandonment Marker (Original photo)

One goal of the abandonment process is to ensure that downhole structures are protected from any residual chemicals that may exist in the producing formation. These residual chemicals may be the remaining hydrocarbons, or some substance added to the reservoir by the production company. This goal is met by pulling out all of the downhole equipment, filling the wellbore with concrete, welding a cap on the casing, and placing a permanent marker on it. Figure 2.22 is the abandonment marker for the discovery well in the San Juan Basin Fruitland Coal CBM Fairway formation; the well name, location, and abandonment permit number have been added to the pipe freehand by a welder. The marker in Figure 2.22 is typical, but abruptly and the driller knows that the top plug is on the bottom. Both plugs can then be drilled out.

Filling the entire annular space between the bore hole and the casing with cement is crucial to the functions of a primary cement job. If the pipe is close to the borehole on one side, then it is common for the cement to fail to displace the mud. Since the mud is not designed to perform the functions of a primary cement job, this can be a major problem. Off center pipe is corrected using centralizers which are clipped to the outside of the pipe as it is run in the hole.

In a normal cement job, there is full hydrostatic pressure of the column of cement from a given formation to surface. When a weaker seam is in the cemented interval, this pressure can be too high, and cement can flow into that formation. When there is concern about the mechanical strength of a given formation, the driller can use down-hole tools to do the job in two stages. The first stage is conventional and fills the annulus from the bottom. When the first stage cement should have reached the location of the ports for the second stage, they stop, set a packer, and reposition a down-hole fitting to open ports in the production casing to allow the cement to enter the annulus from the location of the ports and rise to the surface with much lower hydrostatic pressure. When the cement job is finished, the ports are closed to maintain the steel/cement isolation system in that location.

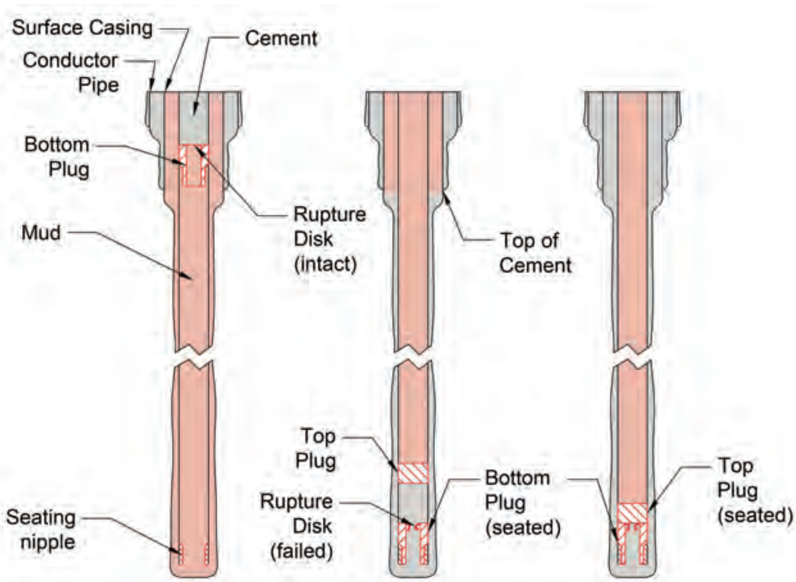

Figure 2.36. Primary Cementing (Original Image)