Handling Natural Gas Liquids

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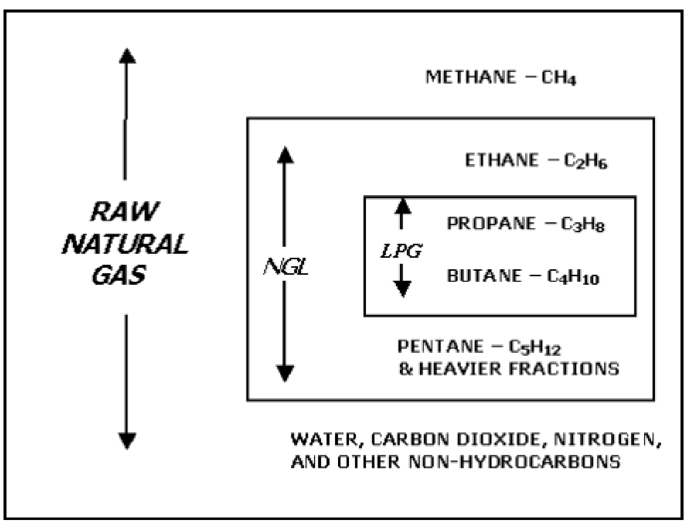
The term "Natural Gas Liquids" is used frequently, but what are they and how do they differ from dry gas in both value and handling considerations?

What Are Natural Gas Liquids?

The pressure and high temperatures found in deep underground gas reservoirs means that some low boiling point hydrocarbon compounds – which would be liquids at normal temperatures and pressures above the ground – become gases under the ground. These gasified liquids then become part of the flow of gas when piped up from the reservoir and condense as the pressure and temperature drop.

Natural gas, as sold to the consumer, is methane. Wet gas – a term for raw gas – typically contains 5% to 20% of gases and "gasified liquids" that are not methane. The other hydrocarbons in the methane stream are either liquid at normal temperatures and pressures (known as condensates) or gases that can be relatively easily turned into a liquid with application of moderate pressure or freezing. The picture below illustrates the typically composition of raw natural gas.

Relationship of LPG to NGL and Raw Natural Gas



http://www.sbcountyplanning.org/energy/mitigation/NGLTransportation.asp

Natural Gas Liquids Versus Methane

Historically, Natural Gas Liquids (NGLs) are more valuable separated from the gas stream than the total gas stream if the NGLs remained part of the stream. For example, ethane is important feedstock for the chemical industry (ethylene), and propane is used in home heating and cooking. If not sold separately, the fractionates can be mixed together to form Liquid Petroleum Gases (LPG) which must remain pressurized to be liquid. LPG can be held in relatively thin walled bottles and therefore is sold worldwide for various uses including domestic cooking and as a transport fuel.

That said, depending on the value of natural gas versus NGLs, suppliers and processors may elect to reduce extraction levels or bypass processing. This economic environment creates two issues for transmission, distribution, and utilization of domestic natural gas. First, a decreased level of processing causes the presence of larger amounts of liquefiable hydrocarbons in the gas stream resulting in a greater potential for liquids to drop out of the gas phase while in transit to end use equipment. This increases the potential for problems in pipeline and local distribution company operations with compression, measurement, pressure regulation, over-pressure protection devices, and potential interference with odorization. Second, problems can also occur in end-use applications such as flame extinguishing, over-firing in home appliances, or physical damage to gas turbines used to generate electricity.

With the advent of horizontal drilling & hydraulic fracturing in the mid-2000's, upstream operators are now able to access significantly more recoverable oil & gas than previously attainable. Over time, they have focused their resources on the most profitable fields which are those that contain either oil or rich gas. Rich gas is the term for wet gas that contains comparably higher levels of NGLs than normal concentrations.

Challenges In Handling Natural Gas Liquids

As the overall volume of NGLs and percentage of NGLs in the production streams increase, operators face a variety of challenges in handling the NGLs.

1. **Existing infrastructure is typically designed to handle dry gas.**

   Most pipelines have been designed throughout the years with a variety of means to capture small incidental volumes of liquids to protect downstream facilities. Putting rich gas – high in NGLs – into pipelines that are not designed to handle it can result in a variety of issues.

   At high velocities, liquids become entrained, forming a mist. The mist may coalesce on the walls of the downstream pipeline and begin to collect in low spots of the pipeline system. Eventually, liquids can be swept along by the gas flow until reaching an exit point on the system – a customer meter and burner. Liquids reaching a burner are a serious safety concern.

   Hydrocarbon liquids in sensing lines to the equipment used for controlling pressure can cause erratic pressure variations in the delivered pipeline pressure. Such variations can impact nearby regulating stations - upsetting large portions of a gas distribution system. This results in potential adverse impacts on system reliability or safety including overpressure protection devices. Hydrocarbon liquids present in a pipeline may not only cause operational and safety problems, but also result in significant measurement error and unaccounted volume / energy losses.

   Additional reliability and safety concerns for local distribution companies and end users due to NGLs include the impact to polyethylene plastic piping, plastic piping components and current handling / pipe joining methodologies.

2. **Two-phase pipelines are an option, but bring challenges.**

   Some pipeline companies have installed various two-phase (gas and liquid) lines to accommodate the presumption of liquid formation. These special lines are located in proximity to and upstream of liquids handling infrastructure such as condensate removal facilities or a processing plant.

   The design of a two-phase pipeline to handle both gas and liquids involves calculations similar to those used for a single-phase pipeline. The key difference is that pressure drop is much more difficult to determine when both gas and liquid are flowing in the same pipeline, especially if the pipeline is carrying a two-phase multi-component stream – gas, oil, & water. Flow of the two phases can take several forms, and pressure drop can vary widely, depending on flow conditions. Changes in elevation over the route of a two-phase line are much more significant than in a single-phase pipeline. Besides pressure drop, liquid holdup is an important consideration in design of a two-phase pipeline.

3. **Gas treatment & separation can be accomplished at various points in the system.**

   Produced gas can be partially treated at the wellhead to remove solids and liquids through simple, rudimentary physical separation equipment. Gas processing entails two separate and distinct functions prior to the produced gas being deemed marketable. The gas will first be "treated" to remove major contaminants such as CO_2, H_2S, and water vapor from the hydrocarbon gases if necessary. Then, if there are sufficient levels of NGLs, the NGLs will be removed from the hydrocarbon stream. These functions can be done separately or in an integrated facility. They can be done at the wellhead, at the terminus of gathering systems, or on a transmission pipeline near production areas. There are pros and cons associated with each treating location.

Collaborative Approach Required

To be the most efficient, safe, and cost effective, a holistic approach is needed so that consideration can be given to items such as existing infrastructure capability, future field development plans, gas stream characteristics, and opportunities for equipment standardization. To do this, technical competency in several key areas is required, and there are several important project aspects that must be considered: the characteristics of the gas that will be handled, the anticipated drilling plan, and the existing infrastructure available are a few of the key items. Typically there are additional constraints that must also be taken into consideration such as regulatory requirements and business commitments such as gas quality to be delivered. Having a knowledgeable and qualified team is key to successfully developing an optimal approach.