WHITE PAPER / **GAS ANALYSIS FOR LNG PROJECTS**

IDENTIFYING CONTAMINANTS IN LNG WITH A PROPER GAS ANALYSIS

BY Megan Reusser, PE

When present, contaminants can pose challenges in the liquefaction process to make liquified natural gas (LNG). Some freeze, which can slow or complicate the liquefaction. Others corrode equipment or, in some cases, violate contractual pipeline and LNG quality agreements. These realities have boosted the need for accurate analysis of natural gas contaminants.

A surge in natural gas production and a push for less reliance on fossil fuels has placed increasing demand on the nation's pipelines and LNG facilities. These assets are expected to transport and store as much capacity in the smallest space possible to deliver a reliable, economical supply to markets.

Natural gas that has been cooled into LNG at cryogenic LNG temperatures (roughly -260° F) takes up roughly 1/600 the volume of the gas form. Prior to liquification, however, any contaminants found in natural gas must first be identified. Information about contaminants in the natural gas feeding into a liquification facility will guide the process design and determine the key equipment needed to remove or properly handle the contaminants.

This paper takes a closer look at constituents that can sometimes be found in natural gas, including the issues they create and the best ways to handle them. An accurate analysis of these constituents, along with guidelines on their acceptable levels in LNG products, can inform the design of new facilities and upgrades to and expansion of LNG storage and production facilities.

CONSTITUENTS THAT AFFECT LNG PROCESSING

CARBON DIOXIDE

Because carbon dioxide freezes into dry ice at these very low temperatures, any CO2 that is present is likely to clog valves and equipment, reducing or preventing gas liquefaction.

There are two primary ways to remove carbon dioxide from natural gas. The first and most common approach involves an amine system, a closed-loop liquid solvent system that absorbs carbon dioxide from the natural gas stream. These systems, which regenerate and reuse amine over and over again, can accommodate a wide range of carbon dioxide concentrations. However, the higher the concentration, the higher the amine circulation rate required. The gas exiting the amine system is water-saturated and requires dehydration afterwards. The carbon dioxide removed from the feed gas is vented directly to atmosphere or if required, such as when hydrogen sulfide is present, burned in a thermal oxidizer. In smaller facilities with lower carbon dioxide concentrations, a multiple-bed, molecular sieve (mol-sieve) system can be used to remove carbon dioxide and water from natural gas at the same time. These systems involve filling beds with adsorbent materials and regenerating them with dry feed gas. They can typically handle concentrations up to 2% (by volume) of carbon dioxide in the feed gas.

Because used regeneration gas in mol-sieve systems contains carbon dioxide that must be purged from the system, the gas must be disposed of by burning it for fuel, flaring it, or returning it to a pipeline. If returned to a pipeline, any carbon dioxide in the tail gas must be monitored so that it does not exceed pipeline limits. Regeneration gas from mol-sieve units cannot be recycled to the front of the plant because that will cause a buildup of carbon dioxide.

While amine systems are more complex than mol-sieve units, they are typically a better choice for larger LNG systems and those with higher carbon dioxide concentrations because they do not require the disposal of large regeneration gas flows. With both of these systems, carbon dioxide is typically removed down to less than 50 parts per million volume (ppmv).

WATER

Like carbon dioxide, water also freezes at cryogenic LNG temperatures. Ice crystals that clog equipment and valves can reduce or prevent liquefaction.

There are two primary ways to remove water from natural gas. The same multiple-bed mol-sieve system described previously can be used to reduce water-saturated gas to the required level of less than 0.1 ppmv. Regeneration gas can also be recycled to the front of the plant and reused.

Water can also be removed in bulk from natural gas using a glycol dehydration unit. This approach alone, however, cannot achieve the less than 0.1 ppmv level. A mol-sieve system will be needed downstream of the glycol unit to reach the required low concentration. Depending on the amount of natural gas being processed, the combination of the two systems may be the most economical choice.

NITROGEN

High nitrogen content in natural gas makes the feed gas liquefaction process less efficient. That's because nitrogen liquefies at a lower temperature than methane, requiring the system to work harder to provide the additional cooling needed to liquefy it. While higher nitrogen concentrations in feed gas reduce liquefaction system efficiency, they do not have detrimental effects on the LNG equipment or system.

Nitrogen is one of the first components to boil off from an LNG tank due to heat leak. For that reason, some LNG users specify nitrogen concentrations of less than 1% (by volume) in the LNG product, in order to reduce the amount of vapor generated while the product is being stored and transported. Lower nitrogen content also increases the heating value of the gas, which means end users need to burn less of it to get the same energy content.

There are several options for reducing the amount of nitrogen in the LNG product. Depending on the amount of nitrogen in the feed gas, flashing across the LNG product valves will sometimes remove a sufficient amount of nitrogen, making no further removal methods necessary. In other cases, a nitrogen removal unit (NRU) may need to be added to the LNG product to remove additional nitrogen. An NRU is a stainless steel tower that may also have a reboiler and condenser. Through this unit, nitrogen is vented from the top to the atmosphere, while LNG exits from the bottom. Depending on the process configuration, other nitrogen removal processes may be more optimal. These options should be assessed on a case-by-case basis.

Like carbon dioxide, high nitrogen concentration in the feed gas may limit the amount of regeneration gas or boil-off gas that can be returned to the pipeline. Some pipelines, in fact, have limits on the amount of nitrogen or "non-hydrocarbons" allowed. In cases where there are no LNG specifications, nitrogen may not need to be removed at all.

HYDROGEN SULFIDE

Hydrogen sulfide ppm(v) can be deadly even at concentrations as low as 100 ppm, according to the Occupational Safety and Health Administration (OSHA). This gas cannot be vented directly to the atmosphere since it can be fatal at these low levels. If present in feed gas, therefore, hydrogen sulfide must be handled safely.

When amine units are used to remove carbon dioxide, any hydrogen sulfide present also must be removed and concentrated in the acid gas that comes off the amine regeneration tower. In these cases, a thermal oxidizer will be needed on the acid gas vent to destroy the hydrogen sulfide. Operators and others on-site must be made aware that the incoming feed gas contains this deadly gas and take appropriate precautions when working with pipeline gas to prevent exposure.

OXYGEN

The presence of oxygen in an LNG system can impact mol-sieve design and require an alternate process flow scheme. If present, oxygen can react with hydrocarbons at high regeneration temperatures and create water, which greatly diminishes the beds' effectiveness at removing water from feed gas. If an amine system is used, the oxygen can react with the amine — creating heat stable salts (HSS) and degrade the amine over time.

While oxygen does not necessarily need to be removed, it can impact process design. Special types of amines may be required to prevent reactions, and any mol-sieve systems may need to be redesigned as closed systems. Because traditional gas chromatographs do not measure oxygen, special testing may be needed to identify its presence. No design changes are often required on oxygen levels of up to 10 ppm(v).

HEAVY HYDROCARBONS

Heavy hydrocarbons freeze at LNG cryogenic temperatures. Depending on the kind and amount present, heavy hydrocarbons can sometimes be removed using either a non-regenerative adsorption bed or a simple flash drum at the midpoint of the brazed aluminum heat exchanger (BAHE). If separation becomes more complicated, a traditional separation tower, including a reboiler and/or condenser, can be used to complete removal.

Again, depending on the amount present, removed heavy hydrocarbons can be used for fuel, stabilized and sold as a blended product, or further fractionated into ethane, propane, butane and other products.

BENZENE, TOLUENE, ETHYLBENZENE, XYLENE (BTEX)

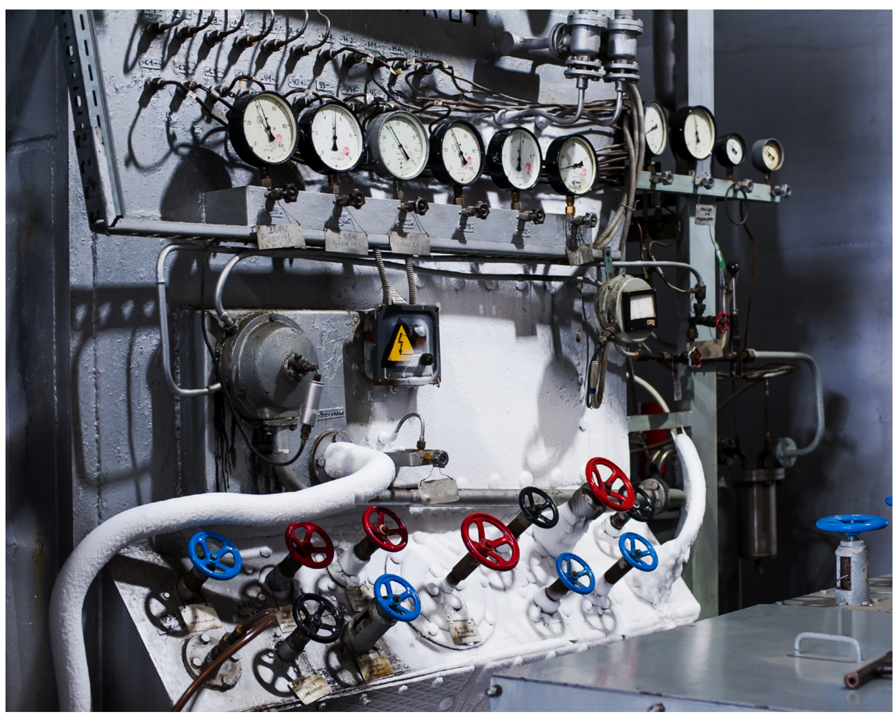
BTEX in natural gas readily freezes at the cold temperatures required in the liquefaction process. When blocked or coated by these solids, liquefaction equipment will likely need to be shut down for maintenance. As a preemptive measure, LNG producers are well-served by removing BTEX from natural gas before liquefaction. Validation of the BTEX concentration in pre-liquefied natural gas allows efficient BTEX removal to protect downstream equipment.

BTEX components can freeze even at very low concentrations — less than 100 ppm. Depending on gas composition, the separation and removal of these components can be challenging. High benzene content in a lean gas, for example, is the most challenging to separate. A traditional stripper tower, including a reboiler and/or condenser and, in some cases, a non-regenerative adsorption bed, are required to complete these separations.

Keep in mind that most traditional gas chromatographs do not measure specifically for BTEX. Instead, BTEX is likely combined and measured with heavy hydrocarbons. Special testing may be required to determine if these components are present.

ETHANE

While not considered a contaminant in natural gas, ethane can impact the sizing and design of a heavy hydrocarbon separation system. Its presence could make separation at the BAHE midpoint more difficult. It does not need to be removed unless specific limits are set for the ethane allowed in an LNG product.



MERCURY

While mercury levels are not typically measured in natural gas, mercury can corrode the brazed aluminum heat exchanger that lies at the heart of low-temperature natural gas processes. Mercury is typically removed using a non-regenerative mercury removal bed. While not required, installation of a mercury removal bed is relatively low-cost insurance to protect the BAHE if it is present.

CONCLUSION

Accurate analysis of contaminants in feed gas plays an important role in setting the process design by defining boundaries on individual constituents and laying the foundation for reliable and successful LNG infrastructure projects. Gas analysis can lower maintenance costs, improve liquefaction efficiency and enable compliance with contractual agreements on gas contents.

BIOGRAPHY

MEGAN REUSSER, PE, is a senior development engineer at Burns & McDonnell specializing in LNG projects. Her experience includes process engineering, proposal management and cost estimation — creating a unique blend of technical and commercial knowledge that she uses to support EPC projects and proposals and to provide clients with technical solutions that optimize process design, reduce energy consumption and decrease overall costs. She also has experience with gas processing, NGL fractionation and floating LNG projects.

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