# Natural gas interchangeability in focus as sources of LNG widen

## David Wood and Saeid Mokhatab explain how national quality specification guidelines with respect to LNG imports have yet to be fully resolved from the contract awards to deliveries of natural gas

Natural gas interchangeability is a common issue for distribution networks to address in major markets where supplies are coming from many different sources of varying qualities.

In continental Europe, for example, there have been about 20 different qualities of pipeline gas and about 15 different imported LNG gas compositions (Figure 1) supplying the market.

Certain countries, such as Belgium, France, Germany and the Netherlands, operate both a high-calorific and a low-calorific gas pipeline distribution network.

The gas supply chains in these countries have evolved in an environment where interchangeability is an ongoing issue that had to be managed and a range of parties along the supply chains had to agree compositional regulations to cope with this compositional diversity.

In contrast, North America and the United Kingdom, where grid gas specifications have historically preferred a relative low calorific gas and compositions have been dominated by domestic production entering the network through large gathering networks, are only recently having to come to terms with fluctuating compositions from a range of import sources in small but significant batches.

Hence, gas interchangeability is yet to be fully resolved in terms of national quality specification guidelines with respect to LNG imports and non-conventional gas sources in both US and the UK.

Many international gas markets have adopted interchangeability parameters to ensure end-user protection while dealing with multiple supply sources.

Practically all global gas markets (and even some regions of the US) have adopted the use of interchangeability parameters in their contractual terms and conditions.

The most commonly used reference is the Wobbe Index. Indeed, California, Wyoming and Colorado, have long established specifications for interchangeability, primarily because local gas production of variable

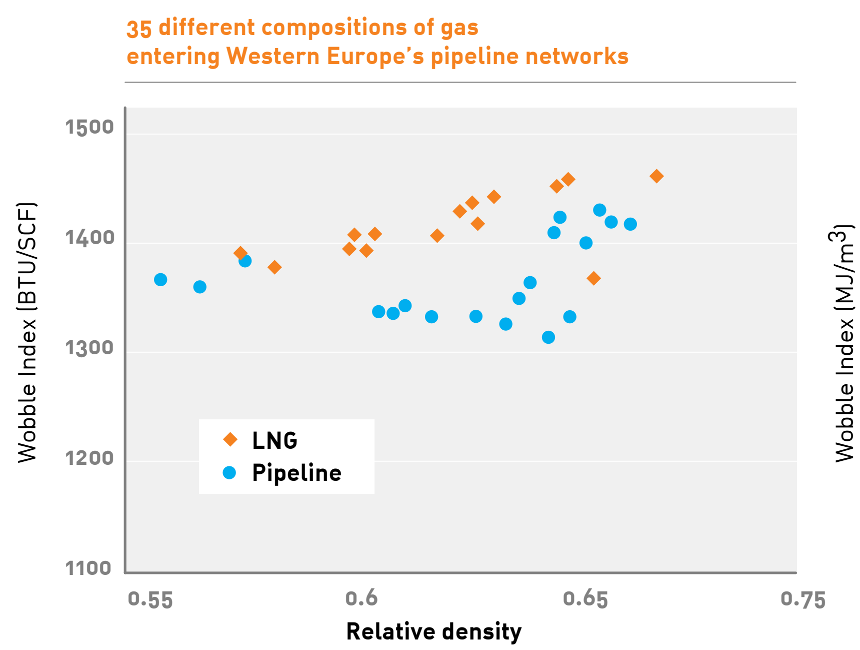


**Figure 1: Source gas entering pipeline networks in Western Europe. Interchangeability is has to be resolved when new source enters market**

compositions forms a significant component of gas supplied into these markets. Gas tariffs in these US states are based on such gas specifications.

## Wobbe Index

The current specifications found in most US pipeline tariffs are based upon the overall heating value (or gas calorific value, GCV) of the gas. All networks specify a minimum and maximum for heating value. For heating value, existing networks consist of three major groups.

- ***Asia*** (Japan, South Korea, Taiwan), where the distributed gas is rich, with a heating value greater than 43 million Joules/cu m (1,090 btu/scf).
- ***UK and US,*** where distributed gas is lean, with a heating value usually less than 42 million Joules/cu m (1,065 btu/scf).
- ***Continental Europe,*** where the acceptable heating value range is quite wide—about 39-46 million Joules/cu m (990-1,160 btu/scf).

However, heating value does not address the burner performance of the gas, just its energy content.

It is burner performance that many end users are primarily interested in and adjust their combustion equipment to optimise that performance.

There must be an adjustment of the heating value of the gas for its relative density (as is done in an interchangeability index calculation) to establish a specification that directly relates to the performance of a gas burner.

The Wobbe Index adjusts the heating value for the relative density of the gas. It is internationally the most widely accepted measure of interchangeability.

From the lower heating value (LHV) in Btu/scf [kJ/Nm3] and the specific gravity (SG), the Wobbe Index (WI) of the gas can be calculated as the LHV divided by the square root of the relative density:

$$WI = LHV / \sqrt{SG}$$

This index is frequently used as a parameter, particularly in the UK, for which the upper limit constitutes a major constraint on the import of rich gases.

Other limits for main gas components are a minimum amount of methane, and maximum amounts of ethane, propane, butane, pentanes and heavier, and inert gases, particularly nitrogen, oxygen, and carbon dioxide.

Most US gas specifications are based upon heating value, not Wobbe Index. This has historically been adequate because most gas supplies came from interstate transmission pipelines with very homogeneous gas compositions.

However, in the future as the domestic conventional natural gas supply in the US is not capable of meeting the gas demand, the US supply mix will increasingly involve imported LNG and smaller non-conventional gas sources (e.g. coal bed methane).

US pipeline gas compositions, therefore, will become less homogenous.

Estimates indicate that by 2010, 10 percent of US demand could be met by LNG. Many participants in the US market have called for pipeline standards to clarify issues surrounding gas interchangeability to ensure consistently safe and reliable sources of supply.

## LNG imports

Many gas liquefaction plants are located in remote locations far from natural gas liquids (NGL) markets, making it commercially unacceptable to separate the lighter NGL components from the gas, especially ethane (C2) and in some cases propane (C3) and butane (C4).

Some NGLs are liquefied along with the methane. Indeed, Japanese LNG buyers that have dominated the LNG markets for decades prefer high calorific gas and often choose to add C3 and C4 to boost the NGL and energy content of the gas derived from the delivered LNG.

Much LNG produced is therefore richer in NGLs than the US and UK gas grid specifications.

On the other hand, most of the inert gases such as nitrogen and corrosive acid gases such as carbon dioxide and hydrogen sulphide are removed prior to gas liquefaction.

This results in regasified LNG having a higher heating value than US pipeline gas, where the ethane is routinely stripped from the gas stream and sold to process gas customers (e.g. petrochemical plants) in the main gas supply regions (e.g. Gulf of Mexico) and the inert components and more carbon dioxide are left in the gas.

There is, therefore, a clear discrepancy between the acceptable heating value ranges for Asia and the US. This is also true for the Wobbe Index in Japan and the UK. This is the main challenge for LNG producers wishing to sell to the Asian, US, and UK markets at the same time.

Existing LNG receiving terminals in the US have been feeding gas derived from LNG into the existing pipeline system for a number of years, but in relatively small quantities compared to other domestic sources of supply.

Such gas has raised some concerns about its suitability and reliability as fuel for some large gas consumers, especially for gas turbines using dry-low-nitrogen oxide combustion systems, which have to burn below threshold temperatures to be effective.

## LNG quality options

Many US gas pipelines which are in positions to take gas from LNG terminals have heating value limits of 1050 -1070 BTU/SCF (HHV).

Imported LNG from many sources have heating values from 1080 -1160 BTU/SCF (see table). To import such LNG and comply with gas send-out requirements, the heating value must somehow be reduced.

The most common approach is to inject inert gas (e.g. nitrogen) up to the pipeline limit for inert content, usually 2 percent to 3 percent.

Air injection is also technically feasible, but is only used for minor adjustments of heating value to avoid the gas exceeding the minimum free-oxygen content specifications, which are 0.01-0.2 percent.

The BTU reduction possible by adding inerts alone is limited to about 20-30 BTU/SCF. This may be sufficient to adjust quality for some LNG streams, but will be insufficient for other streams.

Under the current heat content-based pipeline tariff specifications common in the US few supplies of imported LNG meet the restrictive gas quality provisions.

Only LNG from Trinidad & Tobago could be directly delivered into most gas markets in 2005 along the East Coast of the US using such criteria. However, if the US pipelines translate their current heat content specification into a corresponding Wobbe Index (generally in the range 1330 –1370 BTU/SCF), most LNG supplies throughout the world (Wobbe Index generally in the range 1380 –1440 BTU/SCF), when blended with allowable concentrations of an inert gas such as nitrogen, would meet the tariff specification for interchangeability (on that Wobbe Index basis).

In cases where inerts cannot meet the US heating value constraints to reduce the heating value, the C2 and heavier components need to be removed at extra cost to the LNG receiving terminal.

Systems to reduce C2+ or C3+ gases at LNG receiving terminals can be more cost effective in terms of capital investment and operating costs than systems that involve injection of inerts or boosting gas sendout pressure to achieve heating value constraints, according to published papers.

A benefit of C2+ removal solutions is the production of a high-value NGL stream at the LNG receiving terminal, which can significantly enhance the overall economics of the terminal.

The NGL removal could be conducted on regasified LNG by additional processing in a cryogenic expander processing plant downstream of the terminal.

However, it is less costly and more efficient to integrate fractionation columns into the receiving terminal and remove C2+ (or C3+) components from the LNG before vaporization (Yang et al., 2003; Price et al., 2005).

## Turbines, fuel quality

Industrial gas turbines, a key consumer of natural gas, do allow operation with a wide variety of gaseous and liquid fuels.

However, the quality and composition of fuel burned in a gas turbine impacts its life expectancy and maintenance requirements, particularly its combustion system and turbine section.

*In recent years some gas turbine operators in the US have voiced concerns about gas quality fluctuations in pipeline gas.*

The composition of suitable turbine fuel gases varies, from gas with significant amounts of NGLs and heavier hydrocarbons to pipeline gas consisting mostly of methane, to lean gas with significant amounts of non-combustible components such as nitrogen or carbon dioxide.

In recent years some gas turbine operators in the US have voiced concerns about gas quality fluctuations in pipeline gas.

Two possible causes are likely: (1) insufficient NGL extraction at gas processing plants due to lack of commerciality for LPG products, resulting in high calorific value gas with high hydrocarbon dew points; (2) introduction into a pipeline grid of slugs of imported high NGL LNG-derived gas with low hydrocarbon and water dew points and a low carbon dioxide content compared to the usual pipeline supply of domestic gas. Gas derived from LNG produced from domestic pipeline gas for peak shaving purposes is unlikely to cause such gas interchangeability problems.

The combustible components in natural gas consist of methane, other low molecular weight hydrocarbons (NGLs), hydrogen and carbon monoxide.

Free water and heavy hydrocarbons as liquids are the main cause of combustion performance problems for gas turbines. Higher concentrations of water and acid gases increase corrosion problems (also an issue for pipelines and underground gas storage facilities).

Water in the gas may combine with other small molecules to produce a hydrate – a solid with an ice-like appearance.

Hydrate production is influenced, in turn, by gas composition; gas temperature, gas pressure and the pressure drop in the gas fuel system. Liquid water in the presence of $H_2S$ or $CO_2$ forms acid gases that can attack and corrode fuel supply lines and components.

Free water can also cause turbine flameouts or operating instability if ingested in the combustor or fuel control components. LNG is unlikely to be responsible for free water as water is also a problem for the liquefaction process.

Heavy hydrocarbon gases present as liquids in the fuel gas provide many times the heating value per unit volume than they would if maintained in a gaseous state.

Since turbine fuel systems meter the fuel based on the fuel being a gas, this creates a safety problem, especially during the engine start-up sequence when the supply line to the turbine is cooler. Hydrocarbon liquids present in a fuel gas can cause a range of problems for gas turbines (Kurz, 2005), including:

- Turbine over-fuelling, which can cause an explosion or severe turbine damage.
- Fuel control stability problems, because the system gain will vary as liquid slugs or droplets move through the control system.
- Combustor hot streaks and subsequent engine hot section damage.
- Over-fuelling the bottom section of the combustor when liquids gravitate towards the bottom of the manifold.
- Internal injector blockage over time, when trapped liquids pyrolyze in the hot gas passages.

Liquid carryover is a known cause for rapid degradation of the hot gas path components in a turbine.

NGL rich gas derived from LNG could lead to such problems related to heavy hydrocarbon gas liquids present in the turbine fuel gas.

If such problems are being experienced then it follows that more maintenance attention of the turbine may be required to assure that combustion components are in premium condition.

This may require that fuel nozzles be inspected and cleaned at more regular intervals or that improved fuel filtration and fuel treatment components be installed at additional cost.

Protection against heavy gases and water present as liquids can be achieved by heating the fuel downstream of knockout drums and coalescing filters.

A superheat of at least 50ºF (28K) (an industry standard) over the dew point is required to ensure that no liquid dropout occurs in the fuel system components downstream of the heater.

A standard gas analysis alone may not be entirely sufficient for the detection of heavy hydrocarbons, because it may only include the gases, but not the liquids in the stream.

Also, it is common practice to aggregate all hydrocarbons from hexane and heavier into one value in such analysis and not record trace contents of heavier hydrocarbons.

While this is perfectly acceptable for the calculation of the lower heating value (LHV) as long as the hexane and heavier hydrocarbons constitute a minute fraction of the gas, it can lead to an incorrect estimate of the hydrocarbon dew point.

The Gas Processors Association (GPA) amongst others recommended in 2005 that the determination of hydrocarbon dew point should be done using extended gas analyses (C9+) combined with equation of state calculations to overcome this problem.

The composition of a gas also affects other important combustion parameters regarding gas interchangeability, such as the sooting index, incomplete combustion factor, yellow tip index, and flashback, which need to be considered from specification and consumer perspectives.

A standard gas turbine fuel system may for example be designed for a Wobbe Index of 1220 ±10% Btu/scf (48,031 ±10% kJ/ Nm3) based on the LHV of the fuel.

Different gas compositions could yield the same Wobbe Index, but they may have widely different hydrocarbon dew points.

Gas fuel supply and package lines may need to be heat-traced to keep the gas fuel supply above the gas dew point during periods when the engine is not operating.

Minimum engine flameout fuel flows will also vary if the fuel contains high percentages of non-combustible gases. A turbine expected to operate with gaseous fuels exhibiting a wide Wobbe Index range will need to be configured differently and more rigorously than one that will only operate with a small variance in Wobbe Index.

The fuel supply contract should ideally specify the allowable variations in composition and temperature.

## US policies

Many in the US industry have called in the past two years for the adoption of nationwide gas quality and interchangeability regulatory specifications, including such bodies as the Natural Gas Supply Association. Four key specifications are typically referred to in such calls:

- Cricondentherm hydrocarbon dew point (CHDP)
- Maximum Wobbe Index
- Maximum Inert
- Maximum Butanes Plus (C4+)

The NGSA's 2005 petition requested that FERC establish: (1) a minimum "safe harbor" national CHDP limit of 15 degrees Fahrenheit to apply at pipeline delivery points; (2) require pipelines to adopt interchangeability standards of a maximum 1400 Wobbe Index number; a maximum 4 percent inert gas limit; 1.5 percent maximum Butanes Plus and; (3) require pipelines to implement tariff language implementing a non-discriminatory safe harbor mechanism establishing the use of aggregation, blending and the contractual "pairing" of natural gas volumes of differing qualities for the purpose of blending to achieve a desired quality.

Many bodies commented as part of the consultation process preferred alternative values or points of application and many from upstream, midstream, transportation and consumer sectors of the industry aligned with the more flexible values included in the Natural Gas Council (NGC) interim guidelines: for example range of plus and minus four percent of local historical Wobbe Index number subject to a maximum of 1400 and a minimum of 1200 to provide some flexibility in the standards.

In any event FERC (June, 2006) decided against NGSA rulemaking petition and stated "that the best approach at the present time is to proceed case-by-case, with the Commission's action in dealing with gas quality and interchangeability issues informed by a statement of policy on these issues".

Further FERC states (June 2006) "that every natural gas company subject to the Commission's jurisdiction should include in its tariffs, specific terms and conditions of service that address gas quality and interchangeability issues. In essence, pipelines should adopt gas quality and interchangeability standards in their tariffs that are modeled on the NGC+ interim guidelines or explain how their tariff provisions differ".

The NGC is an organization made up of the representatives of the trade associations of the different sectors of the natural gas industry, such as the producers, pipelines, and local distribution companies (the plus refers to other bodies from the industry that aligned with them). One of FERC's concerns was that "generic application of NGSA's proposed interchangeability specification would appear to require potentially significant and industry-wide changes from the historic gas quality experienced in different regions."

A "safe harbor" standard is one that remains fixed and ensures a producer that its gas will be accepted for transportation by the pipeline absent extraordinary circumstances if its gas conforms to the specification.

As natural gas is transported and distributed, it may experience changes in temperature and pressure, which cause heavy hydrocarbons in the gas stream to assume a liquid form (i.e. liquid dropout).

When this happens, pipelines and other downstream equipment and customers may experience inefficient operations and unsafe conditions.

## Problem

The potential for this problem to occur can be measured in terms of cricondentherm hydrocarbon dew point (CHDP).

However CHDP varies with temperature and pressure, and therefore can vary daily or within a single day, presenting producers with significant commercial uncertainty that their gas will meet very narrow gas specification ranges.

CHDP ranges of 10oF to 40oF provide more flexibility than a rigid value of 15oF.

Even though the NGSA proposed standard has not been adopted, these variables as described in the NGC guidelines will clearly influence contracts and tariffs involved in gas sales contracts going forward, as they do many existing contracts, but flexibility is retained by avoiding the nationwide application of a rigid standard.

LNG compositions are close to typical compositions found for US pipeline quality gas, but with lower methane contents and somewhat higher contents in ethane, butane and propane, while hexane and other heavy hydrocarbons are virtually absent.

The Wobbe Index and BTU contents are therefore higher than for typical pipeline quality gas, but the dew points are usually lower.

The fuel gas characteristics that are relevant for the combustion process in the LNG derived gases shown (i.e. Wobbe Index, dew point and flame temperature) are well within the normal range that a well-designed fuel and combustion system of a gas turbine can handle.

When LNG is shipped in tankers or stored in tanks for long periods, its composition changes slightly due to an ongoing boil-off process.

Some LNG evaporates due to heat entering through the tank insulation. More volatile components such as nitrogen and methane evaporate faster than the heavier components such as C2 and C2+.

Evaporation therefore increases the gas heating value. If an LNG delivery is rich in heavy components with low nitrogen content, this aging effect will increase the heating value even more.

It is the composition of delivered LNG or blended LNG in the receiving terminals tanks that is important, not the composition produced at the liquefaction plant.

If transportation distance is long or storage periods are extended this compositional change has to be taken into account when establishing the composition of the sendout gas.

It is unlikely that this process would change the heating value by more than about 1 percent, but such a change could be significant if it pushes the sendout gas into "off-spec" compositions.

Gas composition in a pipeline system fed predominantly by LNG-derived gas may see significant swings if batches coming from different LNG cargoes from different origins are fed sequentially into that system.

Such instability in gas composition is problematic for gas turbines. Some "Dry Low Nox" systems that meet typical emissions requirements allow swings in the Wobbe Index of up to 10 percent, while other designs may be limited to 2 or 3 percent swings.

This is a key reason for concern about LNG terminals as a source of gas supply among gas turbine operators.

In practice, each LNG terminal agreement can involve negotiations that result in slightly different specifications for the LNG qualities it can accept.

Terminal operators can use a range of processes to adjust gas quality (add inerts or LPG or remove LPG) and have opportunities to blend batches of LNG in their storage tanks prior to shipping gas into pipeline networks downstream.

A terminal operator's ability to handle an LNG with a borderline quality without adversely impacting the quality of the sendout gas will vary according to whether it is a single spot cargo or one of a series of multiple cargoes delivered under a long-term contract with a specific liquefaction plant.

## Conclusions

The diversification of international LNG supply chains means that LNG producers now plan to supply a range of countries through deliveries at multiple destinations from each specific liquefaction plant.

In the past, most liquefaction plants were designed to serve clearly identified markets in long-term supply contracts. These contracts also specified the particular LNG quality parameters that the plant had to meet.

Increasingly different gas specifications and standards in the expanding destination gas markets mean that the quality of the LNG they deliver is more important than when the industry consisted of simple linear supply chains.

Delivery of significant quantities of high heating value LNG produced from rich gas into receiving terminals connected to low-calorific-value gas pipeline networks is a challenge for both ends of the LNG supply chain.

LNG producers have to decide whether to produce more than one LNG specification to satisfy all potential customers in Asian, European or North American gas markets, which would require additional capital investment and operating costs, or to produce LNG of only one quality and potentially limit their marketing opportunities.

Clarity of gas specification throughout the US gas network and in supply contract, incorporating Wobbe Index numbers and dew point ranges, would undoubtedly help LNG receiving terminal operators manage their LNG inventories and would also seem to be in the interest of most of their gas customers throughout the supply chain, particularly power generators.

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