Energy Economics Research
at the Bureau of Economic Geology
Bureau of Economic Geology, Scott W. Tinker, Director
Jackson School of Geosciences, The University of Texas at Austin

INTERSTATE NATURAL GAS—QUALITY SPECIFICATIONS & INTERCHANGEABILITY

CEE
CENTER FOR ENERGY ECONOMICS

Michelle Michot Foss, Ph.D.
Chief Energy Economist and CEE Head
1650 Highway 6, Suite 300
Sugar Land, Texas 77478
Tel 281-313-9763 Fax 281-340-3482
energyecon@beg.utexas.edu
www.beg.utexas.edu/energyecon/lng

December 2004

INTERSTATE NATURAL GAS—QUALITY SPECIFICATIONS & INTERCHANGEABILITY[1]

I) INTRODUCTION & BACKGROUND

The interstate natural gas industry in the United States is nearing a crossroads. Driven by ever increasing demand, a diverse new supply mix is emerging. The gas quality characteristics defining this supply portfolio, most notably those characteristics associated with liquefied natural gas (LNG) and richer, casinghead gas, along with fundamental changes in the economics of traditional gas processing embedded in the value of natural gas vs. natural gas liquids (NGLs), underpin the need to reexamine historic business practices, regulations and tariffs.

This paper will address these issues, examining the historic evolution of natural gas quality standards in interstate commerce, analyze current standards and practices built into operational tariffs, address changing supply patterns gas and their impact on merchantability and fungibility of natural gas and evaluate the practical and financial impacts to suppliers, interstate natural gas pipelines, local distribution companies (LDC's) and end users. Finally, it will attempt to put forth viable and practical recommendations to address the concerns and risks posed and hopefully insure a robust and vital continuing natural gas industry in the United States.

II) OVERVIEW

The United States' demand for natural gas stood at 23.0 Tcf for 2002 and is expected to continue to rise to approximately 31.3 Tcf by 2025 according to the Energy Information Association (EIA)[2] and others. This demand growth pattern emerged through the 1980's and beyond as a reaction to a variety of drivers, most notably robust GDP increases, general environmental consciousness and increased usage in electric power generation.

---

[1] This publication was undertaken by the *Center for Energy Economics (CEE)* as the Institute for Energy, Law & Enterprise, University of Houston Law Center The paper was prepared by Mr. Joseph Wardzinski, Senior Associate, Dr. Michelle Michot Foss, Executive Director and Mr. Fisoye Delano, Senior Researcher, UH IELE. The views expressed in this paper are those of the authors.

[2] U.S. EIA, Annual Energy Outlook 2004, www.eia.doe.gov/oiaf/aeo/.

A new natural gas supply portfolio is emerging to meet this demand growth. Traditional domestic onshore and Gulf of Mexico (GOM) shelf production is waning. The relative economics of exploring for and producing natural gas has resulted in continued activity in the deepwater Gulf of Mexico and ever increasing development activity for liquefied natural gas (LNG) to be delivered to new domestic U. S. terminals sourced from stranded gas locations throughout the world. Longer term, in all likelihood, Arctic supplies and production from frontier areas in Canada will alter this supply portfolio as well.

The natural gas quality characteristics associated with this new supply mix are and will be different from traditional domestic supply sources and will impact economic and operational practices on the interstate natural gas grid and may permanently alter business methodologies and regulatory tariffs.

The changing supply portfolio and relative economic conditions of the natural gas and natural gas liquids (NGL's) markets pose interchangeability / fungibility and natural gas quality issues impacting merchantability, operational and safety concerns. These issues, for the most part, are not adequately addressed by current interstate natural gas pipeline tariffs as a whole.

These natural gas "quality" issues can be broadly categorized into two general areas of concern, which are related, but which nonetheless are separate and distinct.

(i) Domestic, unprocessed, rich, higher heating value (HHV) production entering interstate commerce-- ("Natural Gas Quality—Hydrocarbon Liquids & Dew Point Control").

Traditionally, domestic production has been processed after gathering and treating to remove, or strip, heavier, rich and valuable hydrocarbons such as ethane, butane, propane et al from the raw gas stream prior to introduction into interstate commerce. Processing served two vital roles, first it allowed an operationally safe, largely consistent quality and commercially fungible natural gas product to enter interstate commerce and secondly allowed a profitable petrochemical feedstock business for NGL's to emerge.

Today, the economic reality of gas processing has been largely inverted due to relative value changes in the natural gas and NGL markets, resulting in so called "upside down economics". That is, with commercial transactions being conducted on a thermal equivalency basis, dekatherms (dt's) remaining in the residue gas stream are more valuable than potential NGL's, and therefore processing plants are not running. How long these economic conditions will persist, no one can accurately predict.

There is a chemical property phenomenon of many substances to change phase under varying temperature and pressure conditions. The “dew point” refers to the temperature at which a substance will condense from its gaseous or vapor phase into a liquid. The richer, (i.e. heavier or larger molecular mass) hydrocarbon components which may be entrained in the composite gas stream in the absence of gas processing tend to possess dew points that predispose them to condense and “fallout” at favorable lower temperatures which may prevail downstream on the pipeline.

The frequency and magnitude of this issue may be further exacerbated by the ever increasing production of rich, casing head gas entering the interstate system from deepwater Gulf of Mexico developments, which in all likelihood will continue.

The end result is ever increasing concern over heavier hydrocarbons and inert gases entering interstate commerce and the associated operational, system integrity and safety problems this situation poses. In particular this is highlighted by the potential for hydrocarbon liquid fallout at varying temperature and pressure conditions as the natural gas stream traverses the grid and the potential impact on pipeline operations and end users.

(ii) Imported, higher heating value (HHV) Liquefied Natural Gas (LNG)—(“Natural Gas Quality--LNG Interchangeability”)

As noted above, there is ever increasing project development activity for liquefied natural gas (LNG) to be delivered to new domestic U.S. terminals sourced from stranded gas locations throughout the world to complement the existing terminals in use today. This activity is underpinned by the compelling economics of U. S. natural gas demand, making such projects economically viable and attractive to the sponsors.

While, in many respects, LNG is a very desirable product, having virtually no water vapor or inerts entrained, and most of the heavier hydrocarbons removed prior to or during the liquefaction process, it does contain a relatively large percentage of ethane which results in a higher heating value (HHV) product when compared to traditional gas in interstate commerce. HHV will vary depending on country of origin, producing formation and liquefaction process, but will generally range between 1050 and 1200 Btu per cubic foot. While vaporized LNG poses virtually no threat in regard to hydrocarbon liquid formation and fallout in the interstate grid and distribution systems, it's HHV and other characteristics pose potential concerns to process users, gas turbine applications and end user appliance utilization.

Both of the issues, "Natural Gas Quality—Hydrocarbon Liquids and Dew Point Control" and "Natural Gas Quality--LNG Interchangeability" can and must be dealt with. The changes underway in the U.S. natural gas supply portfolio are positive and must be embraced. From a policy perspective, these newer sources of supply will insure a long lived, stable and secure energy future for the United States. **From an operating and regulatory perspective, these supply sources provide higher heating value (HHV) natural gas which effectively increases the overall economic efficiency of the interstate natural gas network grid and associated distribution systems through increased thermal carriage per volumetric unit. This fact translates into greater operating returns for pipelines, distribution systems and end users alike and defers the need for construction of costly new infrastructure and capacity additions on the interstate grid.**

The merchantability, operational and safety concerns associated with the new supply portfolio must be addressed positively and constructively, through modifications to often antiquated tariffs to include newer, more pertinent standards, potentially including dew point control measures to counter hydrocarbon liquid fallout concerns and an effective interchangeability index that can be applied to LNG supplies, that will promote natural gas commerce while insuring pipeline, distribution system and end user facility integrity and safety.

Interstate pipelines and local distribution companies should be proactive in this regard and propose and implement market based tariff standards that reflect these realities and concurrently protect the operational integrity and safety of their systems and those of their customers.

We at the CEE urge the natural gas industry, to consider flexible, market-based approaches that can provide guidance and direction in this regard to insure supply diversity and security for the United States.

III) "EVOLUTION OF NATURAL GAS QUALITY STANDARDS / SPECIFICATIONS"

(i) Historic Operating Backdrop & Commercial Origins

Commercial production of natural gas and transportation in the United States dates back to 1859 when Edwin Drake struck oil near Titusville, Pennsylvania. Natural gas that accompanied the production of crude oil was an undesirable byproduct of petroleum production efforts that was often simply vented or flared. Soon however, small volumes of natural gas began to be piped to local municipalities to displace manufactured gas volumes which were used in early distribution systems for lighting and fuel. The first recorded instance of natural gas transmission dates to 1872 when a two (2) inch iron pipeline of about five (5) miles in length was constructed between Titusville and Newton, Pennsylvania which operated at a pressure of 80 pounds per square inch. The first natural gas pipeline that spanned a distance of more than one hundred (100) miles was constructed in 1891 and connected gas fields in central Indiana to Chicago.[3] Soon larger lines developed in Pennsylvania, New York, Kentucky, West Virginia and Ohio.

Many of these gas pipelines soon began to experience operational problems with plugging from a mixture of hydrocarbon liquids that was referred to as “drip gasoline”. These hydrocarbon liquids posed particular problems in colder conditions and stream crossings where lower temperatures were prevalent.[4]

The natural gas stream began to be “treated” for removal of “drip gasoline” or as often referred to as “casinghead gasoline”, which provided the origins of today’s modern gas processing industry. While initially there was very little demand for gasoline, the advent of the automobile in the early 1900’s forever changed this landscape. Automobiles were soon being built faster than the supply of natural gasoline could keep up with. Motor vehicles numbered around 2 million in 1915 and roughly doubled in the next two years. Demand and prices for gasoline soared.

Large gas fields were discovered in the Texas Panhandle, Oklahoma, Kansas and South Texas in the 1920’s and 1930’s (Panhandle, Hugoton, Carthage et al) but were far removed from energy markets of industry and population and thus diminished their potential value. But technology was about to change this.

Prior to 1925 pipelines were limited to short distances and relatively low pressures due to early construction techniques utilizing heavy walled steel or wrought iron materials and mechanical couplings. In the mid 1920’s

---

[3] “ The Natural Gas Industry: Evolution, Structure, and Economics”, Arlon R. Tussing and Bob Teppe, Pennwell Books, 1995

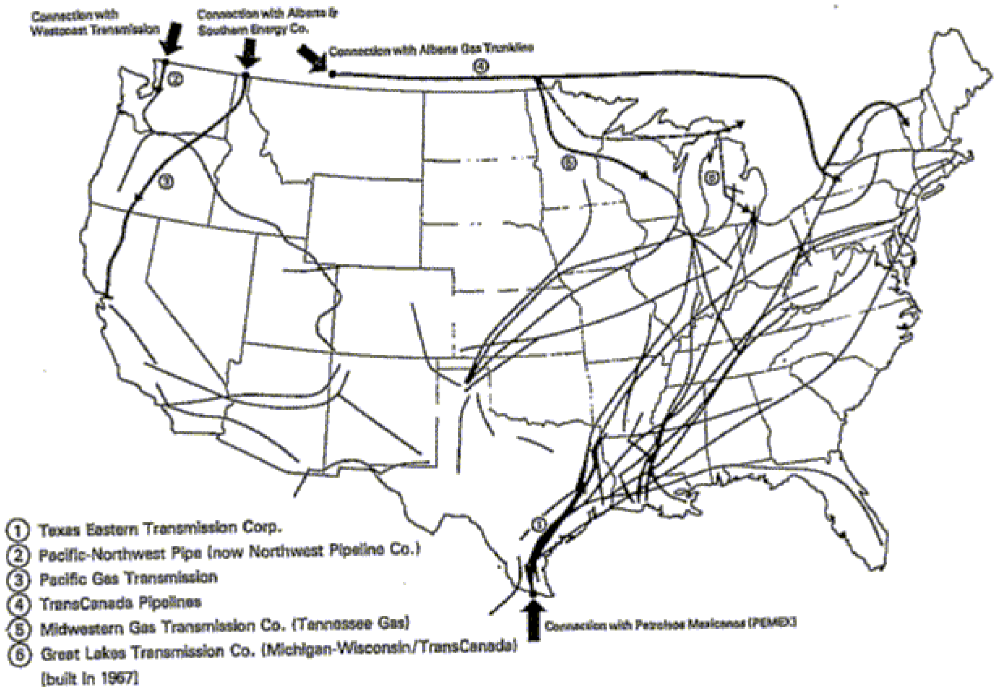
[4] “The Gas Processing Industry: Origins & Evolution”, Ronald E. Cannon, Gas Processors Association

technology advanced and thin walled, high tensile strength large diameter welded pipelines emerged. This advance enabled the construction of a new breed of modern pipeline and allowed the economic long distance transmission of natural gas. Regional pipelines were followed by long haul (1000+ mile) pipelines with the first three: Natural Gas Pipeline, Panhandle and Northern Natural, all being completed in 1931.[5]

Chronology of Gas-Pipeline Construction: The Late-1920's Construction Boom

Date Completed	From	To	By	Total Miles	Diameter (in.)
1925	S Texas	Houston TX	Houston Pipe Line Co.	220	12–18
1925	Monroe LA	Beaumont TX	Magnolia Petroleum Co.	214	14–18
1925	Monroe LA	Houston TX	Dixie-Gulf Gas Co.	217	22
1926	Monroe LA	Baton Rouge	Interstate N. G. Co.	170	22
1927	Panhandle N TX	Wichita KS	Cities Service Gas Co.	250	20
1928	Monroe LA	New Orleans	Interstate Natural Gas Co.	90	22
1928	Panhandle TX	N Central TX	Lone Star Gas Co.	200	18
1928	Panhandle TX	Denver CO	Colo. Interstate Gas Co.	350	20–22
1928	Jennings TX	Monterrey NL	United Gas Co & MX sub	141	18
1928	Monroe LA	St. Louis MO	Mississippi R. Fuel Corp.	350	20–22
1929	Permian Fld NM	El Paso TX	El Paso Natural Gas Co.	218	16
1929	Monroe LA	Atlanta GA	Southern Natural Gas Co.	460	20–22
1929	Monroe LA	Memphis TN	Texas Gas Transm. Co.	210	18
1929	Kettleman Hills CA	S. Francisco	Pacific Gas & Elec. Co.	297	16–22
1929	SW Wyoming	Salt Lake City	Mountain Fuel Supply Co.	290	14–18
1930	Panhandle/ Hugoton	Omaha/Mpls	Northern N. Gas Co.	1100	24–26
1931	Panhandle/ Hugoton	Chicago IL	N. G. P. L. of America	980	24
1931	Panhandle/ Hugoton	Indianapolis	Panhandle East. P/L Co.	900	20–24
1931	E Kentucky	Wash. DC	Columbia Gas & Elec. Co.	467	20

[5] "The Natural Gas Industry: Evolution, Structure and Economics", Arlon R. Tussing and Connie C. Barlow, Ballinger Publishing, 1984 (Chronology of Gas-Pipeline Construction: The late-1920's Boom and Map-The Pipeline Boom of the Late 1920's)

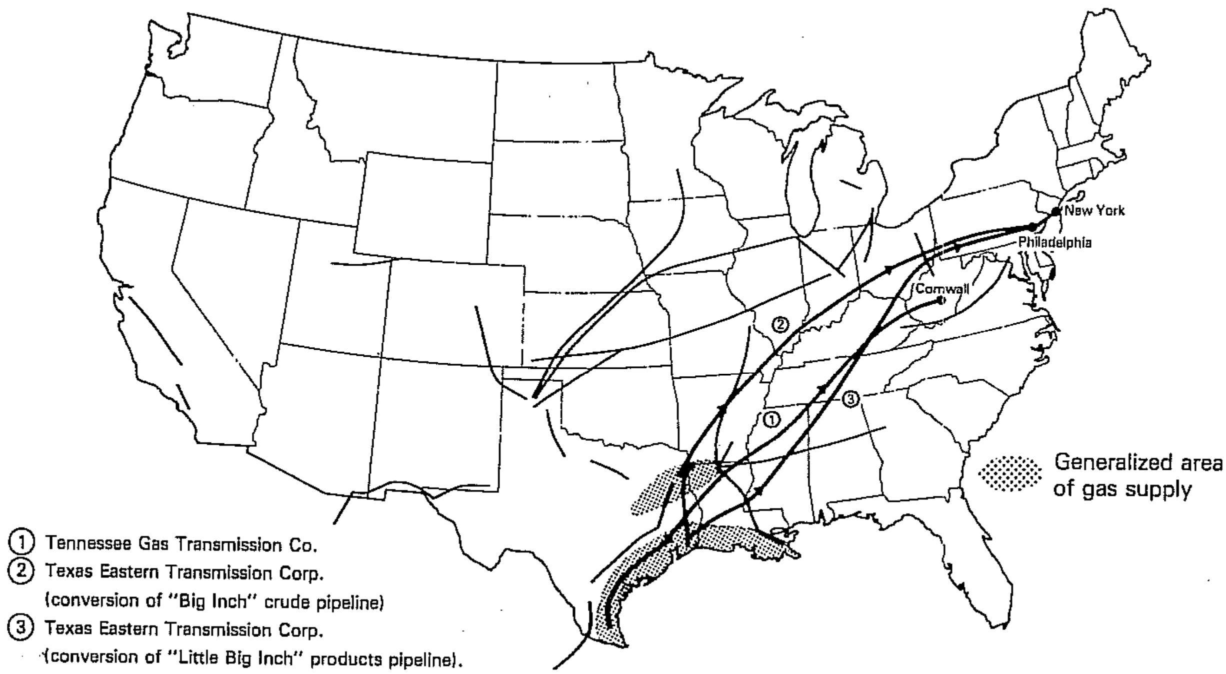


The Pipeline Boom of the Late 1920s

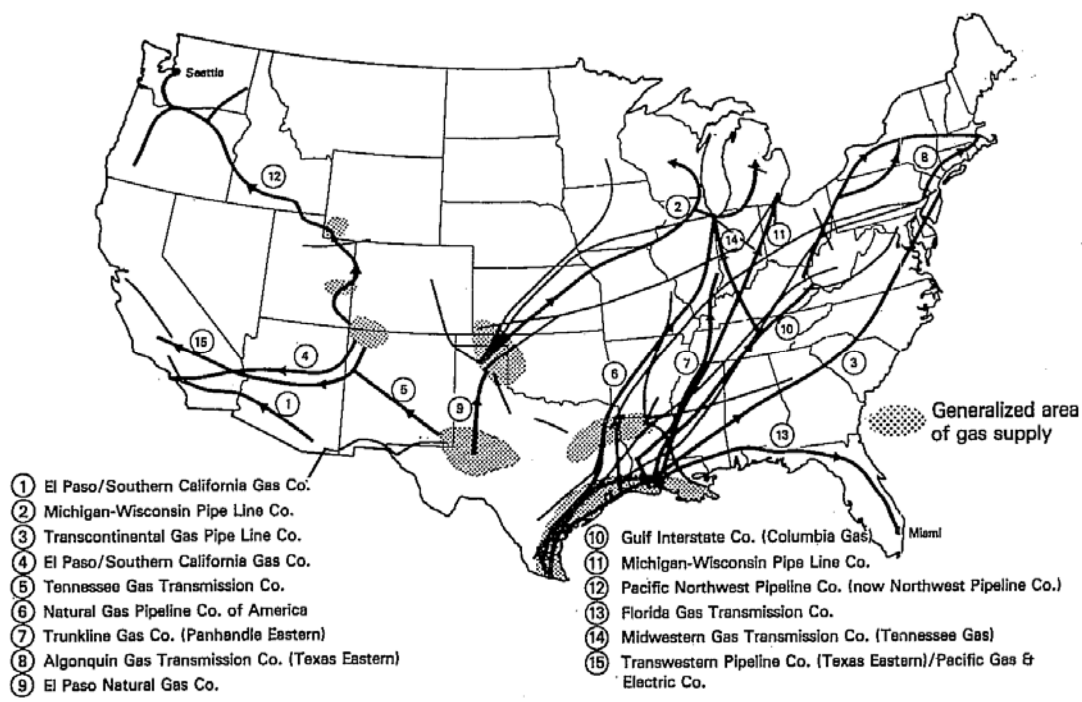
During the ensuing years, significant advances in gas compression technology also aided development of the industry, although the materials shortages of the Great Depression slowed pipeline construction from 1930 to 1940.

War era and post war expansions in the 1940's and 1950's lead to the next wave of long haul pipelines including the Tennessee, Texas Eastern, El Paso and Pacific Northwest systems among others[6], with post war expansions adding roughly 9 Tcf per year of natural gas market.

[6] "The Natural Gas Industry: Evolution, Structure, and Economics," Arlon R. Tussing and Connie C. Barlow, Ballinger Publishing, 1984 (Maps-Pipeline Construction During World War II and The Postwar Pipeline Boom).



Pipeline Construction During World War II



The Postwar Pipeline Boom

As the natural gas market developed and pipeline technology advanced, producers began to explore for non associated gas fields and together with associated gas began to "condition" production for transportation and merchantability purposes. Natural gas contains mostly methane and ethane, but as produced will often contain such heavier hydrocarbon components as propane, butanes and pentanes along with water, carbon dioxide, hydrogen sulfide, helium nitrogen and other trace elements. Conditioning generally consisted of the removal of water and any free liquids, partial or full dehydration of the gas stream and "sweetening of the gas" with chemical agents to offset carbon dioxide and hydrogen sulfide concentrations where required to make the gas merchantable and suitable for pipeline transportation.

The development of the natural gas processing industry was now maturing from the era of simple collection of casing head-natural gasoline. Beginning in the 1920's to about 1940 natural gasoline production was accomplished through early absorption plant technology. As this technology advanced in the 1940's, new, lighter end extraction products emerged, most notably Liquefied Petroleum or LP Gas, made up of a combination of butanes and propanes which were removed through more advanced lean oil absorption technology. Subsequently, propane emerged as the dominant natural gas liquid product, which by the mid 1950's exceeded production of natural gasoline. Again, technological progress coupled with economics allowed further advances in the industry which began to focus on the production of ethane in the late 1950's and early 1960's. Ethane production continued to grow and exceeded propane production by the early 1990's. It is interesting to note that the early economic drivers for ethane production included controlled wellhead natural gas prices and volumetric based pricing,[7] i.e. per Mcf, which largely ignored the heating content value of the residual gas stream. Most of the market demand for these products evolved as the refining and petrochemical industries developed.

Prior to federal regulation, commercial natural gas quality characteristics evolved over time and reflected generally accepted operating practices, the state of processing technology and market conditions. With the advancement and standardization of gas processing technology in large capacity "straddle" plants along major trunk lines, the conditioning and processing of the natural gas resulted in an ever increasingly stable, consistent and fungible end use product.

[7] "The Gas Processing Industry: Origins & Evolution", Ronald E. Cannon, Gas Processors Association

Gradually, pipeline tariffs emerged, as mandated by the Federal Power Commission (FPC), as the vehicle to define "pipeline quality" gas and merchantability standards. Tariffs were and are the documents filed by utilities with their regulatory agencies which detail their terms and conditions of service and associated prices for various classes of customers. "Pipeline-quality" gas came to be defined as natural gas (1) within + / - 5 percent of the heating value of pure methane, or 1,010 Btu per cubic foot under standard atmospheric conditions, and (2) free of water and toxic or corrosive contaminants.[8]

(ii) Regulatory History

During the 1920's and early 1930's the natural gas industry had but only very limited oversight by state and federal governments. Business was conducted in a largely free market environment with natural gas being purchased by pipelines at the wellhead, central gathering point in the producing field or tailgate of a conditioning facility. Pipelines enjoyed monopoly status and many of them subsequently gathered, processed, transported, stored and sold natural gas to downstream local distribution companies (LDC's). Until the advent of long haul interstate pipelines in the 1930's there was simply no reason for the involvement of federal authority or jurisdiction.

State public utility regulation dates to 1907 when New York and Wisconsin established the first public utility commissions, soon to be followed by all of the major gas consuming states, which were established to oversee and regulate transportation and consumption of local production, coal gas and other manufactured gas.

As technology advanced and permitted the introduction of interstate gas into established manufactured gas markets controversy arose and demand for federal intervention grew. Original federal government involvement dated to and was vested in the Federal Trade Commission, which investigated business practices in the natural gas industry beginning in 1936.

Federal natural gas regulation was firmly established in 1938 with passage of the Natural Gas Act which installed the basis for federal regulation of pricing and all of the activities of natural gas companies involved in

[8] "The Natural Gas Industry: Evolution, Structure, and Economics", Arlon R. Tussing and Bob Tippe, Pennwell Books, 1995

interstate commerce. It empowered the Federal Power Commission as the agent of federal regulation and left states to regulate local distribution companies. It gave the FPC certificate authority over gas supply issues and new sales, but excluded the production or gathering of natural gas.

Initially, pipelines purchased natural gas through long term life of lease contracts with the producers passing along the gas cost to local distribution company and industrial customers. These contracts also generally specified title issues, terms and conditions of delivery and gas quality parameters.

Following many years of supply / demand imbalances and pricing distortions, Congress enacted the Natural Gas Policy Act in 1978, which was intended to phase in deregulation of well head gas prices. The Federal Energy Regulatory Commission succeeded the FPC in 1977 as part of the Department of Energy Reorganization Act and was charged with implementation of the NGPA.

Until full unbundling occurred following FERC Order Nos. 380, 436, 451 490 and 497 and full separation of the merchant function was achieved, gas quality provisions were largely present in both pipeline transportation tariffs and gas purchase contracts.

Throughout the period of federal regulation of natural gas in interstate commerce the federal authorities have indirectly controlled the quality characteristics of natural gas through oversight of gas purchase arrangements and tariff authority over the interstate pipeline carriers. As such, tariff provisions dealing with natural gas quality issues date to the earliest tariffs over which the FPC presided and continues today with Federal Energy Regulatory Commission (FERC) oversight.

IV) OVERVIEW OF CURRENT QUALITY STANARDS / OPERATING PRACTICES

(i) Gas Gathering Practices / Standards

As noted above, the Natural Gas Act of 1938 specifically excludes natural gas production and gathering activities. What exactly constitutes gathering has been the matter of ongoing debate for a number of years. Functionally, after natural gas is produced from a particular well it is treated for the removal of basic sediment and water (bs&w), and then it is “collected” by way of field and gathering lines with other similar raw production and conditioned to varying degrees for removal of free liquids and extraneous materials. Additionally it may be sweetened with chemical agents to neutralize sulfur compounds and carbon dioxide and then is delivered to gathering and transmission pipelines for subsequent introduction into interstate commerce. The gas stream, depending on its hydrocarbon characteristics, may also be processed for removal of heavier hydrocarbon components. Generally, if gas is produced in an offshore environment, processing will be done onshore where processing facilities can be economically constructed and benefit from the economies of large volumes of available gas. With onshore production, processing will typically take place at some advantageous central field point. In both cases, the "gathering" function takes place upstream of the processing facilities, although technically, particularly in an offshore environment, the gas stream may have entered certificated, jurisdictional pipeline facilities which are owned and operated by interstate pipelines.

Beginning in the 1980's and accompanying industry restructuring, court rulings provided that the FERC jurisdiction did not extend to the "gathering" activities of interstate pipelines and that such functional gathering activity must be treated in a comparable fashion to the gathering activity of production companies. These decisions resulted in many interstate pipelines declaring certain certificated facilities to be non jurisdictional and efforts to "spin down" entire systems in attempts to remove them from federal jurisdiction and extract market based rents for utilization of these facilities, that is, rates that more closely approximate demand for gathering or transportation services as might be reflected by replacement cost economics. Not surprisingly, the interstates have been quite selective in promoting reclassification of facilities; primarily selecting those holding potential for generation of incremental income above depreciated cost of service economics.[9]

In regard to gas quality specifications, market area based interstate tariffs provisions have not been rigorously applied to the gathering function particularly in the context of heating value and entrained heavier hydrocarbon liquefiables, although liquid and liquefiable transportation fees may be collected and credited back to the cost of service (COS) calculation. As a practical matter, jurisdiction "gathering" lines are routinely "pigged" to drive and collect hydrocarbon liquids to downstream "slug catchers" where the liquids are separated and marketed. Nonetheless, great scrutiny is often given to other quality parameters that may cause operational difficulties, in

[9] "The Evolution of Federal Regulatory Policy, Contracting and Trading Practices for Natural gas in the United States", Jay Martin, Winstead Sechrest & Minnick, P.C., *Natural Gas Contracts*

particular in regard to free water and water vapor. Often times, interstates will provided fee based dehydration services and strictly enforce producer's obligation to dispose of free water. In many cases, particularly in offshore deepwater environments, the stream is required to be dehydrated to very low levels to prevent hydrate formations and plugging of the pipelines. Also, great care is taken in regard to production with high levels of hydrogen sulfide and carbon dioxide which will promote pipeline corrosion, particularly in the presence of free water and oxygen.

(ii) Survey of Current Interstate Tariffs (Note: Pipelines shown represent a random cross section of industry participants operating in diverse, geographical market areas.)

Snapshot of Selected U.S./Canada Natural Gas Transmission Pipeline's General Terms and Conditions on Gas Quality and OFO's (Table 1 of 4)

Pipeline (Parent Company)	Solids removed?	O2 limit	CO2 and N2	Liquids	H2S
Algonquin (Duke Energy)	commercially free				< 1 grain per 100 cft
ANR	commercially free	<1% oxygen	<2% of CO2 and <3% by volume of Nitrogen		
CIG (El Paso)	commercially free	<1% of Oxygen	<3% by volume of CO or Nitrogen		
Sheet 156: Transportation of Liquids and Liquifiables	Will not cause formation of hydrates in pipeline; cause damage; cause the gas to fail to meet quality specs.	Pay rates in accordance with Sheet No. 22	Pipeline has right to use gas from upstream of point of processing for operations.		
Columbia Gulf Transmission Company	commercially free	1% O2	<4% CO2 and carbon combined		
Dominion Transmission Inc.	commercially free	1% by vol	4% combined CO2 and N2		<1 grain per 100cft
	commercially free				<.25 grains of H2 per 100 cft
Dominion High Pressure Gas Transmission System	commercially free				
Dominion Appalachian Wet Gas System					
Dominion Dry Gas system	commercially free				
El Paso Natural Gas Pipeline	commercially free	<0.2% by volume	<2% by volume		<0.25 grain of hydrogen sulfide per 100 std cft
Florida Gas	commercially free	1/4% of O2	<3% CO2 or Nitrogen		
Kern River	Yes ("commercially free"); also no toxic or hazardous components	<0.2% by vol.	<3% CO2 or N2 by vol.; <4% total inerts by vol.	No liquid HC at delivery point T & P.	<0.25 grain per 100 ft3
Maritimes and North Eastern (MN&E) - U.S. (Duke Energy)	Yes ("commercially free")	<0.2% by vol.	<4% of total inert gases by vol.; <3% CO2 by vol.	No free water or HC at T&P of receipt and delivery	<0.25 grain per 100 ft3
Northern Border		free of oxygen <0.4% volume of oxygen	<2% by volume of carbon dioxide		
Panhandle	commercially free	<50 ppm of O2	<2% CO2		
PG&E (National Energy & Gas Transmission, formerly PG&E)	Yes ("commercially free")	<0.4% by vol.	<2% CO2	-	<0.25 grain per 100 ft3
Sonat	Yes ("commercially free")	<1% by vol.	<3% CO2 or N2 by vol.	No water or HC that could separate during course of transporation	<10 grains per 1000 ft3
Tennessee	commercially free	0.2% of oxygen	<4% by volume of combined total CO2 and NO2 and total CO2 cant exceed 3%		
Texaseastern (Duke Energy)	Yes ("commercially free")	<0.2% by vol.	<4% CO2 and N2 by vol.; <3% CO2 by vol.	No free water or HC at T&P of receipt and delivery	<0.5 grain (8 ppm) per 100 ft3
TransCanada (TransCanada)	commercially free	0.4% by vol	<2% of CO2	No free water or HC at T&P of receipt and delivery	23 mg per cm
Transco (Williams)	Yes ("commercially free")	-	-	-	<0.3 grain per 100 ft3
Transwestern (Enron)	Yes ("commercially free"); also no toxic or hazardous	<0.2% by vol.	<2% CO2; <3% of CO2 and N2	No liquid HC at the delivery T & P	<0.25 grain per 100 ft3
Trunkline (CMS Energy)	no toxic or hazardous substances	< 50 ppm by vol.	<2% CO2; <3% of N2 (by vol.)	No free water or HC in liquid form	< 1 grain per 100 cft

Snapshot of Selected U.S./Canada Natural Gas Transmission Pipeline's General Terms and Conditions on Gas Quality and OFO's (Table 2 of 4)

Pipeline / Parent Company	Total Sulfur	H2O	Btu (lower)
Algonquin (Duke Energy)	< 20 grains per 100 cft	<7 lbs of water vapor per million cft	960
ANR	<16 ppm or 1 grain per 100 cft of gas from South east and Southwest facilities; <1/4 grain per 100 cft of gas from Mainline Area. Shall not contain more than 20 grains ot total sulfur per 100 cft	<7 lbs of water vapor per million cft	>967 Btu Can waive limits if pipeline is able to accept outside limits without affecting pipeline system
CIG (El Paso)	<200 grains of total sulfur or 10 grains of Hydrogen sulfide or 0.30 gallons of isopentane and heavier hydrocarbons	<7 lbs of water per 1,000 Mcf	>950Btu
Sheet 156: Transportation of Liquids and Liquifiables			Pipeline will redeliver same amount of gallons of propane and heavier hydrocarbons.
Columbia Gulf Transmission Company	<1 grain of hydrogen sulfide and 20 grains total sulfur	<7 lbs water vapor	>978 Btu per c.ft
Dominion Transmission Inc.	<20 grains per 1000cft	<7 lbs	>978 Btu per c.ft
	<20 grains per 100 cft		>967 Btu
Dominion High Pressure Gas Transmission System			>967 Btu
Dominion Appalachian Wet Gas System		not contain water vapor in excess of amount for saturation of gas' or contain >20 lbs in vapor phase per 1 mcf	>1100 Btu per cft
Dominion Dry Gas system		not contain water vapor which may condense to free liquids	>967 Btu
El Paso Natural Gas Pipeline	<5 grains of total sulfur per 100 cft, which includes hydrogen sulfide, carbonyl sulfide, carbon disulfide, mercaptans and mono-di- and poly sulfides. Mercaptun sulfur shall not exceed 0.75 grain per 100 cft. Organic sulfur shall not exceed 1.25 grains	<7 lbs of water per mcf. Hydrogen dew point shall not exceed 20degrees F	>967 Btu
Florida Gas	<1/4 grain hydrogen sulfide ; <10 grains sulfur	<7 lbs water vapor	>1000 Btu
Kern River	<0.3 grain of mercaptan per 100 ft3; <0.75 grain total sulfur per 100 ft3	<7 lbs. per MMcf	970
Maritimes and North Eastern (MN&E) - U.S. (Duke Energy)	<20 grains, excluding mercaptans, per 100 ft3	<7 lbs. per MMcf (U.S. receipt); 5 lbs. for Canadian	967
Northern Border	<0.3 grains of hydrogen sulfide; <2grains sulfur; ,0.3 grains mercaptan sulfur or such higher content approved by Company;	Dewpoint less than -5 degrees F at 800 psia; -10 degrees F at 1000 psia; -18 degrees at 1100psia or such higher dew point as approved by the Company. Water content <4 lbs	>967 Btu per cf
Panhandle	<1 grain of hydrogen sulfide and 20 grains total sulfur.	<7 lbs water	>950 Btu
PG&E (National Energy & Gas Transmission, formerly PG&E)	<10 grains of total sulfur per 100 ft3	<4 lbs. per MMcf	995
Sonat	<200 grains per 1000 ft3	<7 lbs. per MMcf	950
Tennessee	<20 grains of total sulfur and >1.4 grain of hydrogen sulphide per 100 cft	Shall have been dehydrated by Shipper for removal of entrained water. <7 lbs oer mcf	>967 Btu
Texaseastern (Duke	<10 grains, excluding mercaptans, per 100 ft3	<7 lbs. per MMcf	967
TransCanada (TransCanada)	115mg per cm	65 mgs of water vapor per cm	36.00MJ/m3
Transco (Williams)	<20 grains per 100 ft3	<7 lbs. per MMcf	980
Transwestern (Enron)	<0.3 grain of mercaptan per 100 ft3; <0.75 grain total sulfur per 100 ft3	<7 lbs. per MMcf	970
Trunkline (CMS Energy)	< 20 grains per 100 cft	< 7 lbs. Per MMcf	950

Snapshot of Selected U.S./Canada Natural Gas Transmission Pipeline's General Terms and Conditions on Gas Quality and OFO's (Table 3 of 4)

Pipeline / Parent Company	Temp. (oF)	Liquefiable HC's	Microbio. Org.	Dew Point Limits
Algonquin (Duke Energy)	Adequate to prevent interference w/ proper operation of lines and equipment			
ANR				Yes
CIG (El Paso)				Yes
Sheet 156: Transportation of Liquids and Liquifiables				
Columbia Gulf Transmission Company		Transporter may proces the gas to reduce Btu and other things. See 25.3		
Dominion Transmission Inc.	Temp >40 degrees F			
Dominion High Pressure Gas Transmission System				
Dominion Appalachian Wet Gas System				
Dominion Dry Gas				
El Paso Natural Gas				
Florida Gas				
Kern River	40<T<120	-	-	T>15oF at P<800 psig
Maritimes and North Eastern (MN&E) - U.S. (Duke Energy)	< 120	No liquid HC or liquefiable HC's at T>15oF and 100<P<1440 (psig)	No organisms, active bacteria, or agent that could corrode	(See liquefiable HC's)
Northern Border				Yes - Section 5.3 If gas fails to conform shall have the right to refuse to accpet any such gas through the issuance of an OFO
Panhandle				No
PG&E (National Energy & Gas Transmission, formerly PG&E)	<110 (at point of measurement)	-	-	T>15oF at P<800 psig
Sonat	40<T<120	<0.3 gal of i-C5 or heavier HC per 1000 ft3	-	-
Tennessee				Yes
Texaseastern (Duke Energy)	< 120	< 0.2 gal per 1000 ft3 (GPM) of "natural gasoline"	No organisms, active bacteria, or agent that could corrode	-
TransCanada (TransCanada)	<50 degrees Celsius	-	-	-
Transco (Williams)	< 120	-	-	-
Transwestern (Enron)	40<T<120	-	-	-
Trunkline (CMS Energy)	< 120		No active bacteria or agent or acid producing bacteria	

Snapshot of Selected U.S./Canada Natural Gas Transmission Pipeline's General Terms and Conditions on Gas Quality and OFO's (Table 4 of 4)

Pipeline / Parent Company	Interchangeability Index?	OFO?	Other	Geographic Market Region
Algonquin (Duke Energy)		Can refuse non-conforming gas; OFO initiated if they reasonably determine that a quantity of gas is required for use as Company Use Gas.		New England
ANR				Upper Midwest
CIG (El Paso)			CIG has a Gas Quality Control Surcharge listed on Sheet No. 10 of $0.2034 with reference to Note 5.	Rocky Mountains
Sheet 156: Transportation of Liquids and Liquifiables				
Columbia Gulf Transmission Company				Gulf Coast
Dominion Transmission Inc.			Other: reserves right to enter into agreement with different quality specs.	Mid-Atlantic
		yes. Processing of gas. Transporter may strip liquids	If higher than 1130Btu, Shipper must enter into a separate processing agreement.	
Dominion High Pressure Gas Transmission System	may not contain active bacteria or bacterial agent capable to contributing to or cause operational problems.			
Dominion Appalachian Wet Gas System				
Dominion Dry Gas system		yes	May remove liquids. Removed liquids remain property of pipeline.	
El Paso Natural Gas Pipeline	Free of diluents - <3% total diluents by volume	Where gas does not conform to the CO and total diluent specification shall be grandfathered up to level in effect as of July 31, 1990		Southwestern
Florida Gas				Gulf Coast/ Florida
Kern River	-	NOTE: Failure to conform to quality has a potential blending policy		Rocky Mountains/ California
Maritimes and North Eastern (MN&E) - U.S. (Duke Energy)	-	OFO can issue to maintain reliable service, proper pressures, provide adequate supplies, assure adequate fuel and Company Use Gas, and preserve system integrity.		Atlantic Canada/ New England
Northern Border				Western Canada/ NorthCentral U.S.
Panhandle				Mid Continent
PG&E (National Energy & Gas Transmission, formerly PG&E)	-	No		California
Sonat	-	OFO can issue when hourly or daily demand exceeds capacity, daily receipts exceed capacity, or imbalances threaten system integrity		Southeastern U.S.
Tennessee	Can contract for different quality specs (See NET Tariff schedule)		Transporter in its own right can process the natural gas and remove liquids prior to the delivery to shipper. Title to the products will remain with the party that has contracted for the processing rights and notified Transporter, otherwise they remain with transporter.	Mid Atlantic/ New England
Texaseastern (Duke Energy)	-	OFO can issue to alleviate conditions which threaten reliable service, to maintain pressures, have adequate supplies, and to maintain system balance.		Mid Atlantic/ New England
TransCanada	-	No		Canada
Transco (Williams)	-	OFO can issue to alleviate conitions which may threaten the integrity of the P/L system		Eastern Seaboard
Transwestern (Enron)	-	Can refuse gas that doesn't meet quality specifications		Rocky Mountains/ California
Trunkline (CMS Energy)		Right to issue OFO when reasonable to alleviate threatening conditions to pipeline integrity, safety or reliability of service or ensure compliance w/ tariff provisions.		Mid Continent/ Mid West

Uniformity of Standards & Downstream Implications

The above summary demonstrates the commonality of scope in interstate gas pipeline tariffs but also highlights the disparity in many gas quality provisions. Quality specifications differ from pipeline to pipeline having evolved over time and impacted by varying supply sources, operational constraints and end user requirements. As such, the non uniformity of interstate natural gas pipeline tariff quality provisions has many practical implications, particularly in regard to downstream, supply dependent pipelines who have historically received their system supply gas from upstream pipelines and not directly from production sources. The net effect of such supply interdependence has been the least common denominator effect with the most restrictive quality provisions in the supply chain potentially controlling commercial transactions.

As the domestic interstate natural gas grid has evolved the interaction and blending of gas from varying upstream supplying pipelines, common storage and trading hubs has resulted in large scale commingling of natural gas supplies that reach end users. To the extent merchantability requirements have been met and governed by title change and gas purchase contract requirements minimal problems with meeting tariff quality provisions have arisen. However, with new supply arrangements emerging with LNG and unprocessed rich domestic gas, tariff restrictions may be at the forefront of the quality controversy, particularly those associated with upstream receiving pipelines.

While there is much discussion today in regard to standardization of quality provisions for interchangeability and dew point control issues among others, it is important to note that individual pipeline tariff reforms conforming to the requirements of its customer base and various state jurisdictions (e. g. for emissions control levels) within which the pipeline may operate, would generate the most effective and market responsive solution to the issues posed.

In the absence of individual pipeline tariff reforms, regional or national standards will most likely prevail, and to a less effective extent, govern future commercial transactions.

(iii) Commercial Carriage Issues

Excluding some gathering and distribution transactions, virtually all commercial carriage and sales transactions in the U.S. natural gas industry today are done on a heating value (dekatherm) basis.

A dekatherm (dth) is a thermal unit of energy equal to 1,000,000 British thermal units, (Btu's), that is, the equivalent of 1,000 cubic feet of natural gas having a heating content of 1,000 Btu's per cubic foot.

As a matter of historic practice, natural gas was traditionally measured for pricing purposes according to volume, usually expressed in dollars and cents per thousand cubic foot units (Mcf). Following the Phillips decision in 1954 the FPC began to regulate producer sales pursuant to the NGA and consistent with traditional industry practices, the prices set by the Commission for wellhead gas sales were expressed volumetrically.[10]

Volumetric pricing of natural gas was prevalent into the era of deregulation and was gradually replaced with thermal based pricing on a dekatherm basis. While this practice both simplified and standardized commercial transactions it also holds tremendous practical importance today with the advent of higher heating value gases—as the aggregate Btu value on the interstate natural gas grid is raised the overall efficiency of the in situ grid is improved by allowing more dekatherms of transportation per unit of pipeline capacity.

As such, the introduction of higher heating value gas can offset or defer capacity construction additions to the interstate grid otherwise required to accommodate demand increases and generate tremendous cost savings. The net effect of raising the aggregate Btu of natural gas in commercial commerce from a hypothetical 1025 to 1075 per standard cubic foot, an increase of approximately 5 percent, would be 1.15 Tcf of deferred demand capacity increases, based on the above referenced 23.0 Tcf of U. S. demand in 2002.

[10] Federal Energy Regulatory Commission, Petitioner vs. Interstate Natural Gas Association of America, et al, No. 83-1173, Supreme Court of the United States, October Term, 1983

V) CHANGING SUPPLY PATTERNS--"NATURAL GAS QUALITY— HYDROCARBON LIQUIDS & DEW POINT CONTROL"

With domestic U. S. demand continuing to grow and with steady upward pressure on gas prices, domestic exploration and production efforts continue to pursue new avenues, primarily in the deepwater Gulf of Mexico and its potential for large scale, economically compelling discoveries.

As discussed above, "Natural Gas Quality—Hydrocarbon Liquids & Dew Point Control" issues center on unprocessed, rich, higher heating value (HHV) domestic production entering interstate commerce.

Natural gas occurs naturally in three (3) principal forms: associated or casing head gas, non associated or gas well gas and as a gas condensate and, as such, has widely varying quality and composition depending on the source field and reservoir characteristics from which it is produced.

The principal components of natural gas are methane and ethane with varying amounts of heavier hydrocarbons including propane, butanes, pentanes, hexanes, heptanes and octane as well as carbon dioxide, hydrogen sulfide, oxygen and water vapor.

Typical raw gas compositions are shown below[11]:

	Casinghead (Wet) Gas Mol %	Gas Well (Dry) Gas Mol%	Condensate Well Gas Mol%
Carbon Dioxide	0.63	-	-
Nitrogen	3.73	1.25	0.53
Hydrogen Sulfide	0.57	-	-
Methane	64.48	91.01	94.87
Ethane	11.98	4.88	2.89
Propane	8.75	1.69	0.92
Iso-Butane	0.93	0.14	0.31
n-Butane	2.91	0.52	0.22
iso-Pentane	0.54	0.09	0.09

[11] "The Gas Processing Industry: Its Function and Role in Energy Supplies", Gas Processors Association

n-Pentane	0.80	0.18	0.06
Hexanes	0.37	0.13	0.05
Heptanes plus	0.31	0.11	0.06
Totals	100.00	100.00	100.00

Natural gas as produced is almost never commercially merchantable or suitable or pipeline transportation. All natural gas is treated to remove solids, free liquids and reduce water vapor content to acceptable levels (typically 7 lbs. or less). Historically, most natural gas has also been processed to separate the heavier hydrocarbon components (ethane, propane, and butanes plus) that could derive higher economic value as natural gas liquids (NGLs) in the petrochemical feedstock market. As such, following conditioning, treatment and processing, residue natural gas entering interstate commerce has historically been a largely fungible commodity.

Interstate natural gas pipeline tariffs derived from this chemistry and these practices, with representative quality standards generally being characterized as shown below, with certain variances specific to individual pipeline tariffs.

Representative Pipeline Quality Natural Gas[12]

Major & Minor Components Mol%	Minimum	Maximum
Methane	75	--
Ethane	--	10
Propane	--	5
Butanes	--	2
Pentanes plus	--	0.5
Nitrogen & other inerts	--	3-4

[12] "The Gas Processing Industry: Its Function and Role in Energy Supplies", Gas Processors Association

Carbon Dioxide	--	3-4
<u>Trace Components</u>		
Hydrogen Sulfide	--	0.25-1.0 gr/100scf
Mercaptan Sulfur	--	0.25-1.0gr/100scf
Total Sulfur	--	5-20 gr/100scf
Water Vapor	--	7.0 lbs/mmcf
Oxygen	--	0.2-1.0 ppmv
<u>Heating Value</u>		
Heating Value, Btu/scf gross saturated	950	1150

<u>Liquids:</u> Free of liquid water and hydrocarbons at delivery temperature and pressure.
<u>Solids</u>: Free of particulates in amounts deleterious to transmission and utilization equipment.

Domestic natural gas production is increasingly being dominated by deepwater Gulf of Mexico activity where enormous associated gas discovery developments are underway, including Atlantis, Holstein, Mad Dog, NaKika, Thunder Horse et al. According to the Energy Information Administration, associated gas production accounts for roughly 24 % of all domestic natural gas production[13]. The increased richness of this gas, coupled with an unfriendly economic processing environment has brought to the forefront operating concerns for the interstate pipelines attributable to higher Btu gas (1050+ Btu) entering interstate commerce and the potential for hydrocarbon liquid formation and drop out and associated volatility problems to end users.

These facts are amply demonstrated and highlighted in current proceeds before the Federal Energy Regulatory Commission (FERC) and detailed in later discussion below.

The reaction of many interstate pipelines has been to "police" high aggregate BTU levels via operational flow orders (OFOs) and "must process" directives, particularly in periods where prevailing downstream temperature

[13] EIA - Natural Gas Production, 1949-2002, http://www.eia.doe.gov/emeu/aer/txt/ptb0602.html

conditions make liquid fallout at the suction side of the compressors more problematic.

But as demonstrated in the “Survey of Current Interstate Tariffs”, above, many current interstate tariffs permit higher Btu gas. As such it would appear that the hydrocarbon liquid formation and fallout issue is much more dependent on the hydrocarbon composition and chemistry of the natural gas stream in question than simply its Btu content. This suggests that a prediction vehicle for hydrocarbon liquid formation and fallout would be a more appropriate means to remedy this problem. Many parties have advocated the adoption of a dew point control measure. The dew point of a substance is the prevailing temperature and pressure condition at which a particular vaporized component will condense into its liquid phase. Knowing the dew points of problematic gas streams along with knowledge of prevailing downstream ambient conditions would allow a pipeline operator a much more effective tool to minimize the problems associated with hydrocarbon liquid formation and fallout and concurrently allow higher heating value gas to be transported through the system.

Unless and until, gas processing economics right themselves, these issues will continue. While certainly interstate pipeline companies have a right and an obligation to protect their operating integrity and the interests of their downstream customers and end users, it would appear that a greater sophistication in quality standards in tariffs, such as may be afforded by dew point control measures or other approaches, as opposed to strict adherence to Btu limitations may serve to balance the interests of producer / shippers and the pipelines, distributors and end users.

VI) CHANGING SUPPLY PATTERNS – “NATURAL GAS QUALITY--LNG INTERCHANGEABILITY ”

With domestic dry gas production standing at approximately 19 Tcf and current demand at 23 Tcf and projected to grow to 31 Tcf by 2025, the supply shortfall is being made up by Canadian supplies and increasingly by LNG imports due to their compelling economics.

Most Canadian supplies are sourced from non associated gas reserves in the Western sedimentary basin and as such contain only a relatively low level of heavier hydrocarbons and therefore pose little concern for domestic U. S. gas quality issues.

As discussed above, "Natural Gas Quality—LNG Interchangeability" is topical and focuses on the extent to which imported liquefied natural gas (LNG) product is "interchangeable" or fungible with domestic "pipeline quality" gas. What exactly constitutes interchangeability is the matter of some debate and current industry discussion, but centers on a particular LNG's combustion characteristics—primarily it's underlying thermal Btu value and associated burner tip behavior.

The LNG industry in the United States has emerged in the last several years after a period of long dormancy driven by the underlying economics of natural gas, and its projected volumetric growth and impact will certainly highlight the interchangeability issue.

i) LNG Import Capability

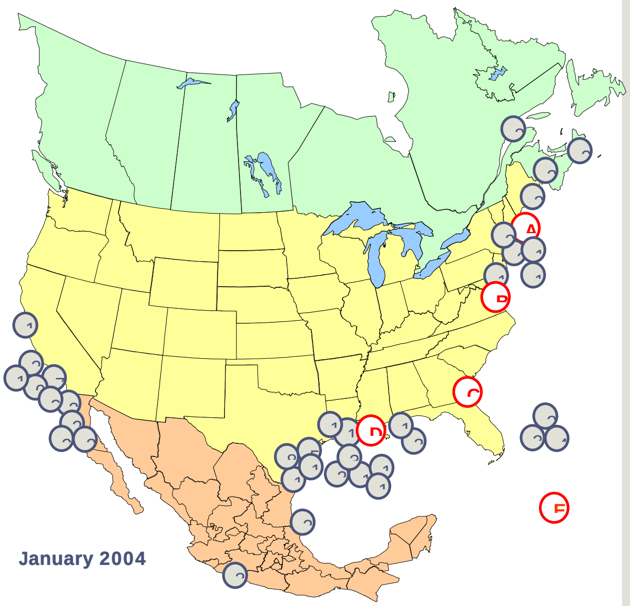
Currently, there four (4) existing domestic LNG import facilities, which maintain current aggregate capacity of approximately 1,015 Bcf per year with potential capacity of 1,637 Bcf per year as detailed below:

LNG IMPORT FACILITIES

FACILITY	OPERATOR	STORAGE	PRESENT CAPACITY	PROJECTED CAPACITY
Everett, MA	Tractebel	3.5 BCF	260 BCF/YR	260 BCF/YR
Cove Point, MD	Dominion	5.0 BCF	365 BCF/YR	657 BCF/YR
Elba Island, GA	El Paso	4.0 BCF	160 BCF/YR	280 BCF/YR
Lake Charles, LA	CMS	6.3 BCF	230 BCF/YR	440 BCF/YR
TOTALS		18.8 BCF	1,015 BCF/YR	1,637 BCF/YR

As such, these existing terminals represent the ability to meet approximately 4 to 5 % of current U. S. demand. Currently approved and proposed terminals, as detailed below, could contribute an additional capability of 7,400 BCF per year by 2009, but will most likely result in a net capacity addition of 3,000 BCF per year, or less, after factoring in technology challenges, local resident opposition and competitive pressures.

Existing and Proposed
LNG Terminals in North America



Sources: FERC

Existing Terminals with Expansions

A. Everett, MA : 1.035 Bcfd (Tractebel)
B. Cove Point, MD : 1.0 Bcfd (Dominion)
C. Elba Island, GA : 1.2 Bcfd (El Paso)
D. Lake Charles, LA : 1.2 Bcfd (Southern Union)
E. Guayanilla Bay, P.R.: 0.093 Bcfd (Eco Electrica)

Approved Terminals

1. Hackberry, LA : 1.5 Bcfd, (Sempra Energy)
2. Port Pelican: 1.6 Bcfd, (Chevron Texaco)
3. Bahamas : 0.84 Bcfd, (AES Ocean Express)*
4. Louisiana Offshore : 0.5 Bcfd, (Excelerate Energy/El Paso)

Proposed Terminals – FERC

5. Bahamas : 0.83 Bcfd, (Calypso Tractebel)
6. Freeport, TX : 1.5 Bcfd, (Freeport LNG Dev/Cheniere)
7. Fall River, MA : 0.8 Bcfd, (Weaver's Cove Energy)
8. Long Beach, CA : 0.7 Bcfd, (SES/Mitsubishi)
9. Corpus Christi, TX : 2.6 Bcfd, (Corpus Christi LNG/Cheniere)
9. Sabine, LA : 2.6 Bcfd (Sabin Pass LNG/Cheniere)
11. Corpus Christi, TX : 1.0 Bcfd (Vista Del Sol/ExxonMobil)
12. Sabine, TX : 1.0 Bcfd (Golden Pass/ExxonMobil)
13. Logan Township, NJ : 1.2 Bcfd (Crown Landing LNG – BP)

Proposed Terminals – Coast Guard

14. California Offshore: 1.5 Bcfd, (Cabrillo Port – BHP Billiton)
15. Louisiana Offshore : 1.0 Bcfd (Gulf Landing – Shell)
18. Louisiana Offshore : 1.0 Bcfd (McMoRan Exp.)

Planned Terminals

16. Brownsville, TX : n/a, (Cheniere LNG Partners)
17. Humboldt Bay, CA : 0.5 Bcfd, (Calpine)
18. Mobile Bay, AL: 1.0 Bcfd, (ExxonMobil)
19. Somerset, MA : 0.65 Bcfd (Somerset LNG)
19. Belmar, NJ Offshore : n/a (El Paso Global)
20. So. California Offshore : 0.5 Bcfd, (Crystal Energy)
21. Bahamas : 0.5 Bcfd, (Seafarer - El Paso/FPL)
22. Altamira, Tamulipas : 1.12 Bcfd, (Shell)
23. Baja California, MX : 1.0 Bcfd, (Sempra & Shell)
24. Baja California : 0.6 Bcfd (Conoco-Phillips)
25. Baja California - Offshore : 1.4 Bcfd, (Chevron Texaco)
27. California - Offshore : 0.5 Bcfd, (Chevron Texaco)
28. St. John, NB : 0.75 Bcfd, (Irving Oil & Chevron Canada)
29. Point Tupper, NS 0.75 Bcf/d (Access Northeast Energy)
30. Harpswell, ME : 0.5 Bcf/d (Fairwinds LNG – CP & TCPL)
31. St. Lawrence, QC : n/a (TCPL and/or Gaz Met)
32. Lázaro Cárdenas, MX : 0.5 Bcfd (Tractebel)
33. Gulf of Mexico : 1.0 Bcfd (ExxonMobil)
34. Providence, RI : 0.5 Bcfd (Keyspan & BG LNG)
35. Mobile Bay, AL: 1.0 (Cheniere LNG Partners)

ii) LNG Supply & Characteristics

Currently there are twelve (12) countries capable of producing approximately 5 TCF of LNG gas equivalent per year. The United States competes with twelve (12) other importing nations for these supplies.

In the Atlantic Basin, LNG is currently produced and supplied by Algeria, Libya, Nigeria and Trinidad with current production rates of approximately 1.5 TCF gas equivalent per year. Expansion capabilities in these countries and extension of supply arrangements to other producing countries where economics permit, should allow an ample supply of LNG for the planned domestic projects.

LNG is a an odorless, colorless, non toxic, non corrosive fuel that is produced by refrigerating treated natural gas to a point of liquefaction at minus 259 degrees Fahrenheit and at essentially atmospheric pressure. Imported LNG can be landed and handled safely to augment domestic supplies of natural gas in the U.S. and North America.[14] The pre treating eliminates all water vapor, and virtually all hydrogen sulfide, carbon dioxide and oxygen. Additionally, its hydrocarbon composition is almost entirely methane and ethane, with very little propane or higher representation.

Overall, produced LNG typically contains a higher heating value (HHV) than domestically produced and processed natural gas, which typically ranges between 1025 and 1060 Btu per cubic foot in interstate natural gas commerce.

The higher heat value of the produced LNG is both a function of the liquefaction process and the market demand outside of the United States, principally in Europe and Asia, for higher heat value fuel.

With the exception of Trinidad, LNG produced around the world typically ranges from 1100 to 1150 plus Btu per cubic foot. On the low end, Australia and Indonesia produce an 1100 plus Btu LNG product; in the middle is production from Nigeria and Qatar nearing 1150 Btu per cubic foot; on the high end is product from Abu Dhabi, Brunei, Libya and Oman which typically exceeds 1150 Btu per cubic foot. Further, there is a tendency for the values to increase over time through the transport and delivery cycle as “boil off” of the lighter hydrocarbons occurs.

[14] To review IELE’s findings regarding LNG safety and security access briefing papers available on our public education site, www.energy.uh.edu/lng.

These Btu characteristics and associated end use burner tip performance underlie the interchangeability debate.

iii) Defining LNG Interchangeability

The ability of two (2) distinct gases to be utilized in essentially the same manner with regard to end use applications, such as in appliance and gas turbine operations, defines interchangeability. Changes in gas properties from different gas sources, particularly in thermal (Btu) value and specific gravity impact this ability. Interchangeability requires that the two gases must be nearly identical with regard to combustion characteristics, efficiency and burner tip flame properties.

Historic research and testing has yielded a number of methodologies for predicting interchangeability, including the Wobbe Index, American Gas Association (AGA) Bulletin No. 36 and the Weaver Indices Method.

While none of these are in broad application today in the United States, perhaps the most widely used and popular of these, both domestically and world wide, is the Wobbe Index. The Wobbe Index is calculated by dividing the saturated Btu value by the square root of the specific gravity of the gas in question.

Wobbe Index = Saturated Btu Value / √ Specific Gravity

The index is a comparative measure of thermal energy flow through a given nozzle size, but not equal to heat input, and having units of energy per unit volume at a given pressure. The Wobbe Index does not relate to such technical factors as temperature, heat transfer coefficients or temperature gradients. If the Wobbe Index remains relatively constant between two gases they are defined as interchangeable.

AGA Bulletin No. 36, issued in 1946, developed empirical equations for the derivation of numerical indices for flashback, lifting and yellow tipping characteristics associated with high heating value, high methane and high inert gases.

While providing useful baseline comparisons and data, these guidelines were somewhat cumbersome, although continued work by the AGA in this arena appears promising.

E. R. Weaver of the National Bureau of Standards attempted to improve the workability and usefulness of the AGA Bulletin No. 36 standards in 1948, by introducing flame speed as a critical variable in computations. While advancing the evolution of interchangeability standards, these guidelines again were difficult to work with and were somewhat ill defined in terms of application.

As the interchangeability arena has evolved world wide, particularly in Europe and Asia, the Wobbe Index has received the widest application and popularity due to the advent of quick and reliable input data, its relative ease of calculation and predictability characteristics. It is simple to interpret and is easily applied in field operations.

While the AGA and Weaver Indices hold merit, it would seem that until further research and testing would yield a newer and more accurate and practical measure of gas interchangeability, the Wobbe Index should be applied domestically as the standard for interchangeability. Further, use of the Wobbe Index in possible conjunction with another complimentary index has received some discussion in the U. S. for domestic applications. This approach would seem to have considerable merit, given that this practice has been employed internationally for some time.

iv) Interchangeability—Transporters & End User Issues

By definition, interchangeable gases should pose little if any concern to interstate pipelines, LDCs and end users. Nonetheless, the reality of introducing LNG to system supplies dominated by domestic “pipeline quality” gas can result in varying and unstable quality characteristics to transporters and more importantly end users.

From the interstate pipeline perspective, vaporized LNG gas is a safe and predictable product that should pose little operational concern. As discussed above, the absence of oxygen, carbon dioxide and water vapor coupled with its extremely low dew points, makes it a very attractive product in regard to corrosion prevention and the potential for hydrocarbon liquid drop out. As such, it would appear that restrictive tariff provisions associated with Btu limitations are not warranted in regard to LNG applications.

Testimony before the Federal Energy Regulatory Commission (FERC) has evidenced that end use appliance and natural gas turbine applications have wide adaptability with regard to higher heating value gas products associated with LNG. It appears the greater danger lies in uncontrolled variability in the delivered product's heating value and Wobbe Index. Given this, it seems that scheduling coordination, blending, and inert gas injection could result in consistency of gas product and easily overcome the concerns associated with LNG supplies.

VII) CHANGING SUPPLY PATTERNS – IMPACT ON INTERSTATE PIPELINES / DISTRIBUTION COMPANIES / END USERS

(i) Regulatory Overview—Recent & Current Proceedings before the FERC

During the 2000 and 2001 winter heating seasons natural gas prices were such that producers and processors did not strip liquids or liquefiable components from the natural gas stream prior to delivery to the interstate pipelines, choosing to reap higher revenues as natural gas Btus rather than as NGLs. Many gas processing facilities shut down as a result. A secondary consequence of this decision was that the gas being transported had a higher heating value and was more prone to have liquids fall out during transportation.

As FERC stated in its Order on Complaints, "gas transported in interstate pipelines is rarely pure methane, but a composition of methane and several other heavier hydrocarbons. Each type of liquefiable hydrocarbon, such as propane or butane, condenses out of the gas stream and becomes a liquid at a specific temperature known as a dew point. At the same time, the heating value of each hydrocarbon constituent is different, with the heavier hydrocarbon molecules containing a higher heating value than the lighter constituents. Allowing the heavier molecules to remain in the gas stream raises the heat content of the gas and increases chance that these molecules will condense out of the gas stream and become a liquid when transported into colder regions." "106 FERC Para 61,040".

In response to this issue and consistent with their tariff authority, many interstate pipelines issued Critical Notices or Operational Flow Orders which established or limited dew point and/or the maximum Btu content of the gas.

In 2003, the gas quality controversy continued with six (6) cases pending before the Commission addressing this issue: Southern Natural Gas Co. Docket No. RP04-42-000; Toca Producers v. Southern Natural Gas Co and Amoco Production Co et al, Docket No. RP03-484-000 and RP01-208-000; Indicator Producers v. Trunkline Gas Co. Docket No. RP04-64-000; Indicated Producers v. ANR Pipeline Co., Docket No. RP04-65-000; Indicated Producers v. Tennessee Gas Pipeline Co. Docket No. RP04-99-000 and Indicated Producers v. Columbia Gulf Transmission Co., Docket No. RP04-98-000.

On December 30, 2003 FERC issued its "Order Granting Complaints and Cease and Desist" in which the Commission expressly stated that it would not address the issue of industry wide standards for gas quality in this order. Rather, it addressed at some length the purpose and function of Critical Notices and Operational Flow Orders.

First, the Commission found that both ANR and Trunkline had published gas quality standards in its tariff. Both pipelines had established a maximum Btu content of 1200 Btu per cubic foot. ANR's tariff states that the pipeline may waive this limitation and permit gas with even higher Btu content at the pipeline's discretion. However, neither tariff provides that the pipeline may reduce the Btu limits.

Between January, 2001 and December, 2003 both ANR and Trunkline published Operational Flow Orders or Critical Notices limiting gas quality on portions of their systems via their websites. On both pipelines the notices lowered the Btu content of the gas from 1,200 Btu to 1,050 Btu. These reductions were posted on the web site for continuous period from 2001 to 2003. The Commission found that "the result of these notices was that the gas quality standards in the pipeline's tariffs were superceded and the new lower limits contained in the OFOs and Critical Notices became the standards for large portions of the pipeline's systems. As such, the notices had the practical effect of changing the provisions of the pipeline tariffs without giving notice or making a filing with the Commission in accordance with Section 4(d) of the Natural Gas Act. The Commission held that Trunkline and ANR had improperly used OFOs or Critical Notices to make permanent changes to their tariffs.

The Commission stated that OFOs and Critical Notices "are concerned with the flow of gas and with maintaining the correct pressures in the pipeline to sustain the reliability of pipeline deliveries. They are intended to be used for temporary and transient emergency situations. OFOs are intended to provide pipelines with tools for them to render service pursuant to the terms of their tariffs and contracts, not to establish new terms and conditions of service." This position is consistent with the statement of policy the Commission issued in Order No. 637, that a pipeline must take all reasonable actions to minimize the issuance and adverse impacts of operational flow orders and other measures taken to respond to adverse operational events on its system to avoid the issuance of OFOs. Order 637-A at 31, 605, 31,598-599.

Accordingly, the Commission ordered ANR and Trunkline to remove the Critical Notice and OFO provisions from their web sites; meet with their respective customers and develop new terms and conditions of service; file the agreed upon limitations in their tariffs and to cease and desist from using either Operational Flow Orders or Critical Notices to manage quality issues.

Significant dicta on the liquids issue was provided by the Commission in its Order: the Commission stated that "liquids and liquefiable are a known fact of natural gas pipeline operations. Pipelines are constructed with the expectation that there will be liquid drop out. The general terms and conditions included in pipeline tariffs also routinely include limitations on the levels of liquids and liquefiable that may be included in the gas stream. Because pipelines often handle liquids and liquefiable they are required to account for the revenues derived from liquids collected in their system and transmission rates are often designed to include projected liquid revenue credits." (See CNG Transmission Corporation, 89 FERC Para 61,286-7 (1999) where CNG explains how liquid revenues are credited to the transportation rate.)

Approximately one (1) month later, the Commission issued its second Order on Complaints dealing with complaints filed by Indicated Shippers against Columbia Gulf Transmission Company and Tennessee Gas Pipeline Company. "106 FERC Para 61,040." In this case, Columbia's tariff did not include a maximum limit on the heat content of gas; instead it imposed a limit of 1,050 Btu per cubic feet through a Critical Notice published on its web site. Similarly, Tennessee's tariff sets no hydrocarbon dew limits; however, Tennessee issued a Critical Notice establishing a dew point limit of 20 degrees F or below.

The pipelines answers to the Complaint are informative in that they discuss the basis for the OFO or Critical Notice. Specifically, Columbia Gulf alleged that the limits imposed through Critical Notices are permissible and in accord with Section 25.2(a) of Colombia Gulf's tariff which states that "Transporter may refuse to accept gas or may impose additional gas quality specifications and restrictions if Transporter, in its reasonable judgment, determines that harm to transporter's facilities or operations could reasonably be expected to occur if it receives gas that fails to meet such additional specifications and restrictions".

With respect to Tennessee, the pipeline argued that its tariff provides gas quality standards and the authority to require shippers to meet those standards. (See Section 3(b) of its General Terms and Conditions which provides that gas entering its system must be commercially free from hydrocarbon liquids and Section 9 which requires gas to be processed before delivery to the pipelines.) Tennessee argued that its Critical Notice was acceptable because it required gas, without proof of processing, to limit its Btu content to 1050 or a dew point in excess of 20 degrees F in order to protect the operational conditions.

Interestingly, all commenters urged the Commission to require Tennessee and Columbia Gulf to file these provisions in their respective tariffs but asked that the Critical Notices remain in effect until after the winter season concluded.

Unlike its decision in ANR and Trunkline, the Commission here found that the change or addition of gas specifications that CGT and Tennessee promulgated did not violate their existing tariffs. In both cases, the Commission found that the tariff provisions gave the pipelines authority to change their gas quality specifications. Accordingly, they were not required to cease and desist immediately.

However, the Commission was concerned that the tariff provisions gave the pipelines too much discretion to vary gas quality standards with inadequate notice and explanation to the customers. The Commission found that the two tariffs at issue were not similar to the tariff approved in Natural Gas Pipeline[15], because unlike NGPL, Colombia's tariff does not set out a mechanism by which gas standards will be changed, provide for shippers notice of impending change and ensure that shippers understand the calculation underlying the proposed change. Moreover, neither Colombia nor Tennessee's tariffs provide "safe harbor" dew point and Btu limits which would set a minimum level that is acceptable.

---

[15] Compare the Commission's decisions in these two cases with its decision in Natural Gas Pipeline Company of America, 102 FERC Para 61,234 at p5, reh'g 104 FERC Para 61,322 at pps 7 and 8 (2003). In this case, the Commission permitted NGPL file tariffs that allowed it to post Btu and dew point limits for gas on its website 10 days before the beginning of each month and stating the expected duration of the posted limit.

Accordingly, the Commission required both pipelines to make compliance filings setting out the applicable dew point and Btu limits in their tariff and to the extent they desire flexibility to change these limits to set out the process by which the limits will be changed to ensure shippers have sufficient notice and knowledge about the proposed change.

Following these orders, the pipelines have become embroiled in further litigation concerning the actual tariff language and limits imposed. This is still ongoing and no Commission decision has been issued yet for these pipelines.

Simultaneously, the Commission convened a technical conference and on February 20, 2004, the Commission issued its "Notice Requesting Written Comments" on the issue of gas quality standards. The following provides some summary guidance as to the position of the different industry sectors:

Producer Comment Summary:

BP America Production and Indicated Shippers presented comments on this proceeding. Key concepts were as follows:

- Need for continuity and standards on what must be included in pipeline tariffs
- Need for standards that will not hamper supply from coming on stream; too restrictive limitations or artificial limitations result in increased costs for stripping and reduced supply
- Standard to address fallout issues is hydrocarbon dew point
- Standard to address interchangeability is WOBBE index
- All pipelines do not have to adopt same gas quality specifications. Interconnect pipes should permit interchangeability
- Pipelines should be required to post information about WOBBE index, Btu content, dew point, temperature and pressure to ensure creation of a record.
- Gas quality specification should be established with the premise of allowing the maximum range of gas qualities.

Alliance Pipeline urged the Commission to consider putting the onus on end users and LDCs to adapt and update their equipment so that higher Btu gas supply can be accommodated. The complexity and costs associated with updating control systems would be negligible as compared to the capital investment in pipelines and associated facilities required to meet growing demand. Alliance believes that most appliances can be operated safely at 1075 Btu/scf.

Indicated Producers stated that it was the variability in gas quality standards – i.e. the fact that the pipeline could change the limitations at will- that causes producers a problem. If they, the producers, knew what the standards were on each pipeline they could make decisions whether to connect a field to a specific pipeline or not and whether to continue to operate marginal producing fields. It was the constant changes in specifications without comments or notice that created the problem for both the producer and the end user.

LDC Comment Summary:

National Fuel Distribution argued that its gas quality specifications should govern what Tennessee imposes on producers. Tennessee has an obligation to meet its warrantee of merchantability. Therefore, according to National Fuel Distribution, it is Tennessee's obligation to ensure that the proposed 15 degree F dew point is appropriate.

Dominion Gas stated that should a higher Btu value reach Dominion East's city gate, Dominion would be adversely impacted in three ways: first it would have to ensure that it did not create any safety issue; secondly, it would need to address gas measurement issues since it is currently measured volumetrically using a Dth to Mcf conversion factor of 1.036. With a material change in Btu value, Dominion would either have to change its conversion factor or suffer increased lost and unaccounted for gas. Thirdly, Dominion would suffer a revenue shortfall directly proportional to the percentage increase in heating value. With hotter gas, a customer will consume fewer volumes of gas and the LDC will forever lose the rate base revenue associated with lost volume.

End User Comment Summary:

Process Gas Consumer Group: Fluctuations in quality cause the most significant harm to industrial users – rapid changes in Btu content and liquid fallout pose serious problems. Gas with a high amount of heavy hydrocarbons poses many problems: for boilers and furnaces the drop out of liquids in the gas supply can lead to inaccurate instrumentation inputs to the combustion control systems that could lead to fuel rich mixture which could lead to a furnace explosion; inoperable safety-off valves; gas regulators will also become less stable. Heating value fluctuations also adversely impact operations because too low of a Btu content could result in exceeding burner design flow rates; flame lifting could occur. Additionally, there is an environmental impact as the calculation of permitted NOX and CO emissions is based on the Btu level of the gas – if it changes the calculations will change as well making it much more difficult to ensure compliance. Finally, more liquids will require all pipelines to undertake more maintenance and pigging activities – this results in significant downtime for the industrial user (one end user claimed to have incurred over $400,000 in production losses during downtime for pigging of upstream pipelines).

Any solution needs to ensure that it doesn't discourage LNG supplies – LNG supplies appear to have high Btu content and low liquids which are very favorable for end users.

(ii) Operating / Reliability Issues

The increased operating and reliability challenges associated with natural gas quality—hydrocarbon liquids & dew point control and natural gas quality--LNG interchangeability under discussion appear to be manageable but will no doubt carry some significant cost in terms of increased surveillance, operation and maintenance and manpower.

1) Natural Gas Quality—Hydrocarbon Liquids & Dew Point Control

The absence of traditional gas processing and introduction of rich, unprocessed natural gas into the interstate grid may pose considerable operational problems to interstate pipelines and to a lesser extent downstream LDC and end use customers. While pipelines are and have historically been "pigged" to remove liquids and improve operating efficiencies, increased liquids and liquefiables in the gas stream will result in increased downtime and operation and maintenance costs attributable to liquids and materials handling, particularly in the production areas where such volumes will be most prevalent. Additionally, there may be capital requirements for incremental liquids handling facilities and disposal equipment. Downstream, in the market areas, the effects will most likely be muted but nonetheless pose increased operational problems to compressor stations, measurement and regulation facilities and to a more limited extent the distribution operations of LDCs.

2) Natural Gas Quality--LNG Interchangeability

The impact of LNG introduction appears much less problematic than that of rich, unprocessed gas into the domestic natural gas grid. As we have seen, apart from dealing with end use quality fluctuation issues attributable to variations in timing and supply blending, LNG is a very desirable product from an operating and reliability perspective.

The absence of potential for hydrocarbon liquid formation and fallout coupled with consistency of end use burner tip behavior should minimize operating cost and downtime concerns, however there may be substantial cost increases attributable to monitoring and manpower additions.

Nonetheless, the burden of maintaining consistent quality characteristics of the integrated gas stream while introducing “cycled slugs” of vaporized LNG into system supplies may be heavy. This may prove even more challenging to the extent that blending of the LNG stream with inert gases (e. g. nitrogen) is required to maintain desirable flame and combustion characteristics.

(iii) Environmental & Emissions Impacts

The environmental impacts associated with natural gas quality—hydrocarbon liquids & dew point control and natural gas quality--LNG interchangeability issues have not been fully analyzed although there appears to be considerable industry efforts underway. Certainly in regard to hydrocarbon liquid formation and fallout downstream in interstate pipelines there is increased environmental exposure to hazardous material handing and potential for spills that must be dealt with, but at this time the issues appear to be manageable.

The higher heating values associated with both LNG and unprocessed richer domestic gas pose another potential environmental concern in regard to end use combustion characteristics and the risks for increased NOx and carbon monoxide emissions if not properly understood and managed.

Given the growing dependence of electric power generation on natural gas fired units this issue is of considerable importance, particularly in environmentally sensitive jurisdictions.

At this juncture it would appear that considerable analysis is required to properly evaluated and weigh any risks associated with combustion applications of higher heating value natural gas, although it would appear that the benefits greatly outweigh the potential risks.

Additionally, and of overwhelming concern are the perceived environmental issues associated with LNG project siting and development. In many instances the environmental permitting process challenges are daunting, due to the prevailing attitudes in target jurisdictions, and will likely derail the development plans of many proposed LNG facilities.

(iv) Safety Issues & DOT Standards

The U. S. Department of Transportation maintains authority over interstate natural gas pipelines' operations and safety practices and has codified its standards in 49 CFR Part 192—"Transportation of Natural Gas and Other Gas By Pipeline: Minimum Safety Standards".

These standards govern materials, construction, operating and safety practices for transmission and distribution pipelines, compressor stations, measurement & regulation stations and ancillary facilities. Most of the operating and maintenance standards impacted by gas quality are covered by these regulations, particularly in regard to internal corrosion monitoring and prevention.

It would seem that in the case of rich, unprocessed domestic gas entering the interstate pipeline grid that the Btu level of higher heating value gas alone is of minimal concern, but the direct safety concerns associated with hydrocarbon liquids handling along with the potential inclusion of contaminants and additional water vapor, which may pose longer term internal corrosion and reliability concerns, should be fully evaluated.

Similarly, it would appear that higher heating value natural gas associated with LNG would have little, if any, effect on potential degradation of these operating standards and should pose little, if any, threat to internal corrosion exposure due to its preparation and chemical composition.

Again, and perhaps more importantly, are the safety issues and concerns associated with the current wave of LNG developments projects discussed above. Despite a proven track record of safety for many years, the LNG industry in the United States is nonetheless still plagued with misconceptions about the fundamental safety of LNG operations and the “NIMBY”—Not in My Back Yard Syndrome of avoidance. These issues were amply demonstrated by the recent defeat of the proposed LNG project in Maine by local citizenry.

VIII) SUMMARY & CONCLUSIONS

United States domestic natural gas demand continues to grow amid currently limited supply resulting in historic pricing premiums. The supply portfolio is evolving to meet this demand in creative ways. While domestic dry gas production has stood at approximately 19 Tcf per year over the last decade, this equilibrium has been the result of ever increasing production from large scale deepwater Gulf of Mexico projects offsetting falling production from many mature producing basins. With current demand standing at approximately 23 Tcf per year and projected by some to grow to as much as 31 Tcf by 2025, the shortfall is being made up by Canadian supplies and by LNG imports.

Looking forward, the supply shortfall will most likely be met by increased LNG imports and longer term by Arctic supplies and supply initiatives from the Maritimes provinces in Atlantic Canada.

The natural gas pricing environment that has evolved and been sustained over the last several years has borne two supply related phenomena: (1) Reactivation of “moth balled” LNG receiving terminals and large scale development efforts underway to establish new LNG import projects and terminals, underpinned by the estimate that LNG can be economically produced and delivered to the United States in a cost regime of between $2.00 and $3.70 per MMbtu and (2) Domestic, rich, unprocessed production being introduced into interstate commerce to capture natural gas pricing premiums on the heavier hydrocarbon components than would otherwise be attainable through extraction of NGL counterparts.

This environment and these two issues have intersected and caused much attention to be focused on the resulting impacts to natural gas quality characteristics in interstate commerce as a whole and particularly in regard to the safety and integrity of pipeline and distribution operations and merchantability to end users. As we have seen, these “quality” issues have been broadly categorized into two general areas of concern—“Natural Gas Quality—Hydrocarbon Liquids & Dew Point Control” referring to the issues associated with domestic, rich, unprocessed production and “Natural Gas Quality--LNG Interchangeability” referring to the fungibility issues associated with the introduction of vaporized LNG into interstate commerce.

(i) “Natural Gas Quality—Hydrocarbon Liquids & Dew Point Control”

Natural Gas Quality issues center on rich casing head natural gas entering the interstate market unprocessed, that is, not stripped of the heavier hydrocarbon components including ethane, butanes and propanes plus, and resulting in a high heating value gas product, often 1050+ Btu. While higher heating value product is not in and of itself an overriding concern, the potential associated with the chemical compositions make hydrocarbon liquid formation and fall out much more problematic. Hydrocarbon liquid formation and fall out is a function of varying temperature and pressure conditions in the pipeline as the gas is transported, and can cause considerable operational problems and equipment damage to pipelines and end users.

Most, if not all, interstate gas pipeline tariffs have historically limited exposure to these problems through institution and enforcement of Btu and other restrictions in their tariffs. However, as we have seen, these vehicles may be antiquated, broad and misplaced enforcement tools in dealing with the realities of today’s marketplace. Many parties have put forth the concept of augmenting or replacing the Btu tariff standards with a dew point control vehicle that would largely limit exposure to operating and safety concerns for the interstate pipelines, local distribution companies (LDCs) and end users associated with hydrocarbon liquid formations. We at the CEE believe this would be a prudent course of action to consider and in the best interest of free and open markets.

Additionally, we believes that more stringent controls on inert materials, carbon dioxide, oxygen and water vapor entering interstate pipelines would be appropriate and would contribute to increased operating integrity and safety and should be considered as part of an overall tariff review of gas quality provisions.

(ii) "Natural Gas Quality—LNG Interchangeability"

Natural Gas Quality--LNG Interchangeability issues focus on the introduction of vaporized LNG into interstate commerce and its associated fungibility with traditional "pipeline quality" gas.

As we have seen, vaporized LNG maintains Btu values ranging from 1050 to 1200 and higher and far beyond historic system supply averages of between 1025 and 1060 Btu. While in many ways vaporized LNG is an ideal fuel product, free of water vapor, carbon dioxide and oxygen and stripped of most heavier hydrocarbon components, its higher heating value, flame characteristics and blended end use quality variability can be of major concern to consumers. We endorse adoption in natural gas tariffs of an interchangeability index for vaporized LNG in lieu of rigid Btu restrictions that will insure fungibility and end use consistency. Until such time as research and testing efforts provide a more accurate and usable measure, we at CEE believe that the "Wobbe Index" could be adopted for general application and provide a workable solution. Again, in our opinion, this approach would be in the best interest of open and free commerce. We urge this approach as part of a comprehensive tariff review of gas quality provisions.

(iii) HHV Implications

Finally, we at the CEE believe that higher heating value (HHV) commercial carriage of natural gas has many positive and far reaching implications and should be embraced. As discussed above, a rise in the aggregate heating value of gas in interstate commerce of even modest proportions, e.g. 1025 to 1075 Btu per scf, or roughly 5%, has an enormous impact in supply efficiency and avoided cost or deferral of new interstate infrastructure to service demand growth.

We believe that the interstate natural gas companies and local distribution companies should voluntarily and proactively enter upon comprehensive tariffs reviews with input from producers and customers to address changes in their market places and supply portfolios and permit free market forces to shape this process. These issues are vital to the public interest in regard to supply security, diversity and economic efficiency. We urge to consideration of these recommendations and encourage efficient market based solutions.

ACKNOWLEDGEMENTS

The authors wish to acknowledge the contributions to this paper of Ms. Helene Long and Mr. Shaw Ottis, students at the University of Houston, Law Center who assembled much of the tariff summary detail and review of recent and current regulatory proceedings on gas quality issues.

EXHIBITS

Exhibit A, following, was assembled as a supplement to main work detailed above in an attempt to capture the European and Far East experience and practice in dealing with natural gas quality issues and hopefully to provide some degree of perspective as these issues are debated in the United States.

EXHIBIT A

“NATURAL GAS QUALITY—STANDARDS & PRACTICES IN THE EUROPEAN UNION AND JAPAN”

I) INTRODUCTION & BACKGROUND

As a backdrop to the current examination and policy review of U. S. interstate natural gas quality specifications and interchangeability issues, it was thought useful to review current natural gas standards and practices in the European Union and Japan.

This paper addresses those current standards and practices and puts forth recommendations for the United States industry and government involved in reshaping domestic policies and practices.

II) EUROPEAN UNION

Natural gas quality specifications and practices throughout Europe are quite sophisticated compared to U. S. standards. While country by country variations exist, the modern day European Union has long employed the Wobbe Index, dew point control and other measures not commonly seen in the United States.

While commercial frameworks in the European Union gas industry are evolving to mimic the U. S. model in the context of deregulation, unbundling and open access, from a technical and quality perspective, the EU appears somewhat more advanced than the U.S., most likely attributable to its history of diverse traditional gas supply and LNG via importation.

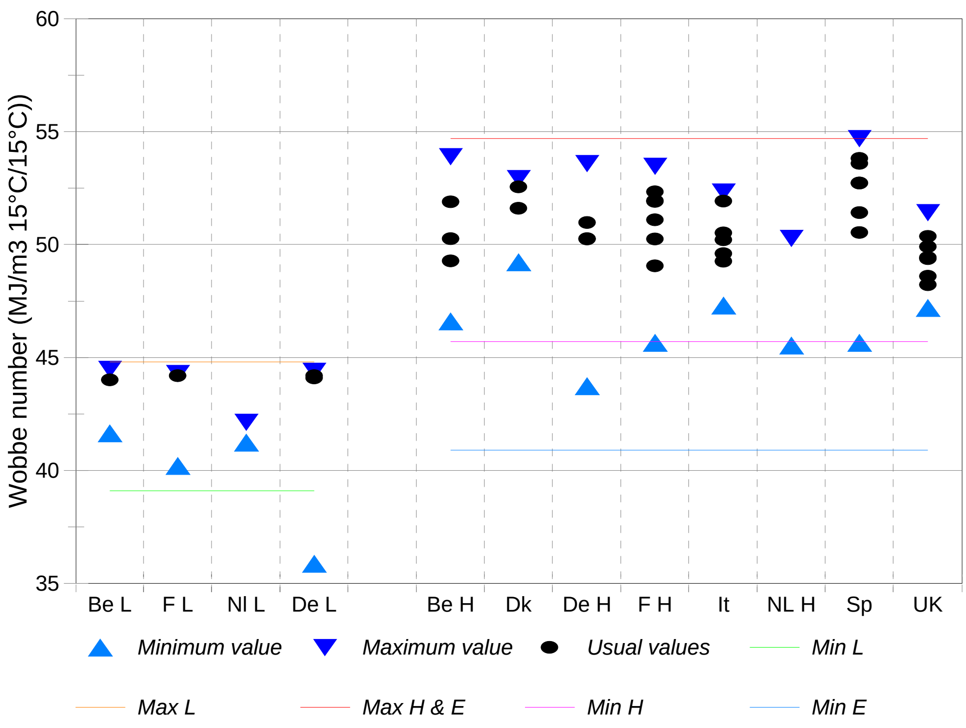
While these practices and standards have been in place for some time, their application has differed on a country to country basis. As such, the European Union is currently challenged to reach consensus on harmonization of such gas quality standards that will promote cross border and intra-union commerce.

According to “Marcogaz”, the Technical Association of the European Natural Gas Industry, natural gases in Europe are separated between the L and H quality as defined in EN 437. These “high” and “low” classes of gas are non interchangeable and supplied in separate networks. The only source of L Gas is the Netherlands, whereas H gases have numerous origins including the North Sea, Russia, Algeria and Nigeria. Transportation of natural gas to Europe is another cause for variations in the composition of H gases as some are liquefied thus stripping the gas of a number of heavier hydrocarbons.[16]

H gas is common throughout Europe. L gas is distributed in only four(4) countries; the Netherlands, France, Belgium and a small area in Germany. In these countries L gas and H gas are distributed in separate networks. In France, Belgium and Germany the L network is a regional network. In the Netherlands, the L network serves domestic, commercial and small industrial customers while H gas is distributed to larger industrial customers. Gases with widely varying composition are blended to a fairly narrow band of Wobbe Index values.

Wobbe Index Variations in European Nations[17]

[16] Marcogaz, “National Situations Regarding Gas Quality”, Marcogaz Working Group “Gaz Quality”, November, 2002
[17] Marcogaz, “National Situations Regarding Gas Quality”, Marcogaz Working Group “Gaz Quality”, November, 2002



Most Euorpean countries utilize limits in the Wobbe Inbex of gases as the principal means of ensuring safe combustion. At higher Wobbe values incomplete combustion occurs and appliances will emit high levels of carbon monoxide. At lower Wobbe values, flame lift can occur and flames may become unstable or extinguish.

As such, Marcogaz has proposed that the upper and lower limit vlues for the Wobbe Index should be set at 47.0 MJ/m3 and 54.0 MJ/m3 respectively.

In Europe there are two other types of appliance malfunction that occur which are not governed solely by the Wobbe Index value, these are (i) flashback, which is mainly associated with the presence of hydrogen and (ii) sooting, which is mainly associated with the presence of hydrocarbons heavier than methane. To control these malfunction risks, Marcogaz has proposed limits of 0.1% mol% hydrogen for flashback control and and a limit of 0.70 for maximum gas density for control of sooting.[18]

Note also that Gross Calorific Value, or GCV, is specified in all countries except the UK. However, this quality metric is never used for technical purposed. Rather, its specification is rooted in legal origins and is simply related to billing purposes as applied to volumetric usage.

The European Union vehicle to establish the recommended standards is the "GTE" or Gas Transmission Europe working group.

Gas Transmission Europe—"GTE" was borne from the Madrid Forum and the EASEE-Gas (European Association for Streamlining Energy Exchange—Gas). It appears that the group is on target to begin implementation of some common gas quality standards beginning in 2005.

Current quality issues under discussion by EASEE-Gas include i) Units of Measurement / Pressure Base ii) Combustion Qualities iii) Calorific Values and iv) Other Properties

Gas quality parameters and ranges proposed by EASEE-Gas for standardization are as follows:[19]

Gas parameters

The following parameters have been agreed for harmonisation:

WI	- Gross (Superior) Wobbe Index
d	- relative density
GCV	- Gross (Superior) Calorific Value[20]

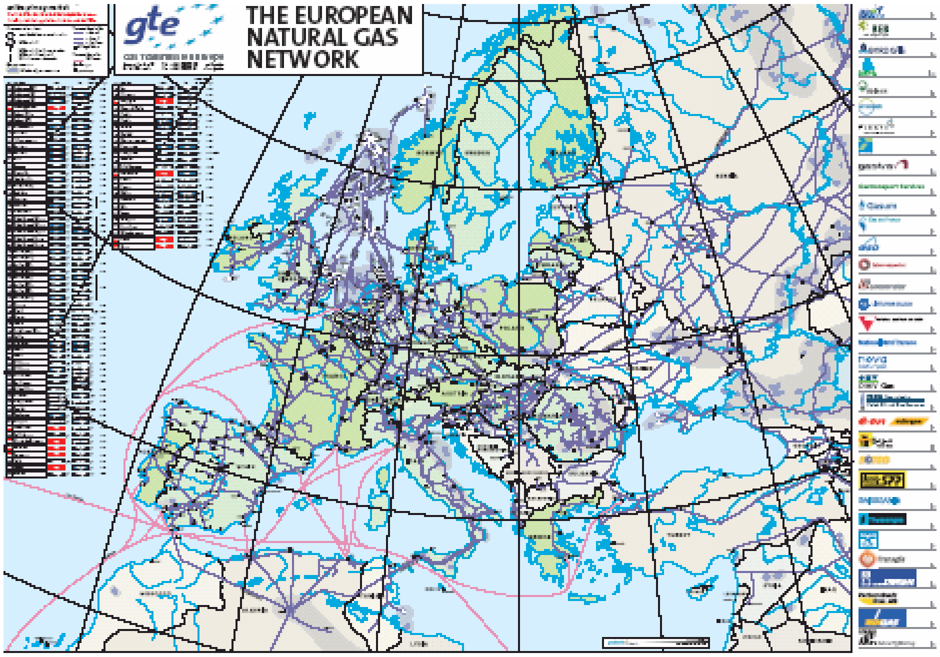
[18] Marcogaz WG "Gas Quality"—Second Position paper on European gas Quality Specification for Natural Gas Interchangeability, August, 2003

[19] EASEE-Gas Working Paper, Common Business Practice, "Harmonisation of Natural Gas Quality", 2004

S - Total Sulphur
H_2S + COS - Hydrogen sulphide + Carbonyl sulphide
RSH - Mercaptans
O_2 - Oxygen
CO_2 - Carbon dioxide
H_2O DP - Water dew point
HC DP - Hydrocarbon dew point

For definition of the parameters, reference is made to ISO 14532:2001 Natural gas – Vocabulary and ISO 6976:1995 Natural gas — Calculation of calorific values, density, relative density and Wobbe Index from composition.

Parameter	Unit	Min	Max
WI	**kWh/Nm^3**	**13.60**	**15.81**
d	**Nm^3/Nm^3**	**0.555**	**0.7**
Total S	**mg/Nm^3**	**-**	**30**
H_2S + COS (as S)	**mg/Nm^3**	**-**	**5**
RSH (as S)	**mg/Nm^3**	**-**	**6**
O_2	**mol%**	**-**	**0.01**
CO_2	**mol %**	**-**	**2.5**
H_2O DP	**°C at 70 bar (a)**	**-**	**- 8**
HC DP	**°C at 1- 70 bar (a)**	**-**	**- 2**



III) JAPAN

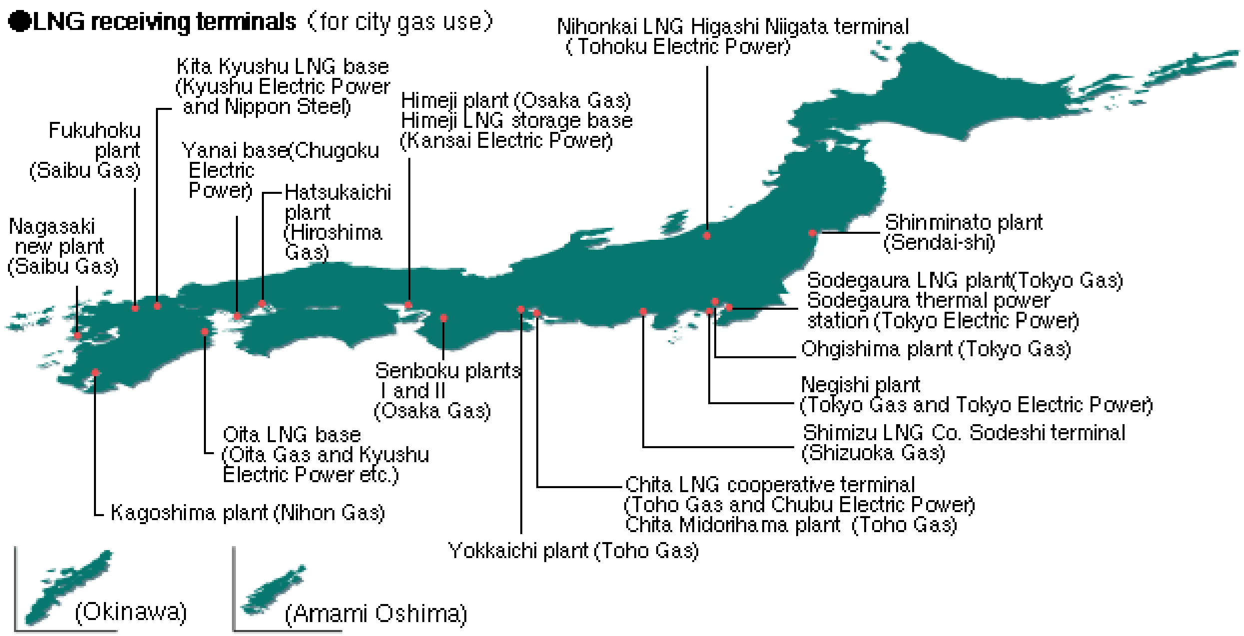
Japan, and collectively the Far East (including Korea and Taiwan), represents the largest LNG consumption market in the world.

Japan is the largest market, with "City-Gas" sales exceeding 27.4 Billion cubic meters in 2003, and the one which will be focused on for this analysis.

Major gas companies include; Hokkaido, Tohoku, Kanto, Tokai-Hokuriku, Kinki, Chugoku, Shikoku and Kyustu. Historically, the systems operated by these companies have operated independently, sourced LNG feedstock supplies separately and were not interconnected.

Major Japanese LNG Receiving Terminals[21]

[21] Source: Japan Gas Association

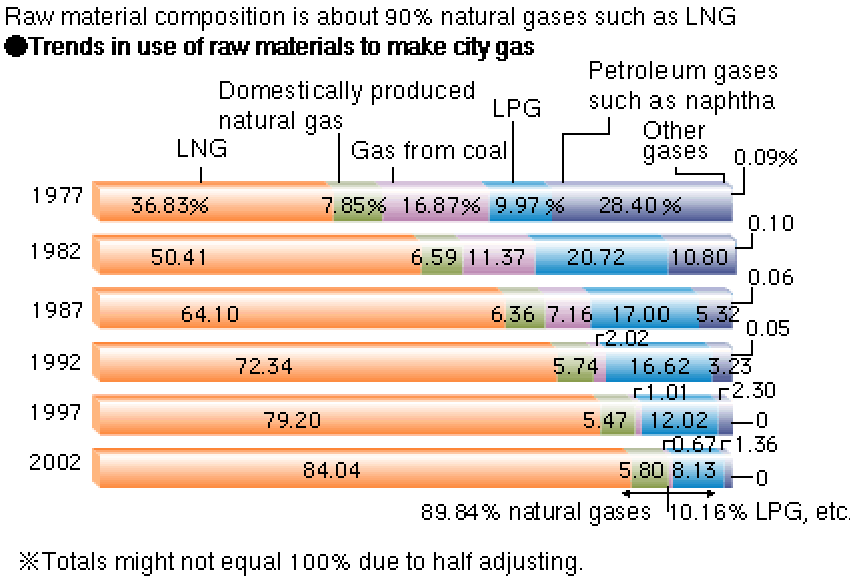


Japan's energy market is now undergoing a transition to a "less-regulated" environment and third-party access arrangements for major gas pipelines are being put in place. As such, gas quality specifications and interchangeability issues are somewhat topical with regulators and prospective service providers.

Gas feedstock to Japan has historically and today remains dominated by imported LNG—representing approximately 84% of total supply, with the balance being composed of liquefied petroleum gas (LPG) and some domestically produced gas. LNG is imported mainly from Pacific Rim countries. LNG offers a number of advantages in the manufacture of "city-gas", most notably it has a gasification efficiency of 100% and produces around double the heat content as manufactured gas which allows efficient use of existing pipeline infrastructure.

According to the Energy Information Administration, three Japanese companies, Tokyo Gas, Osaka gas and Toho Gas signed a binding agreement in 2002 for the import of LNG from Malaysia's MLNG Tiga project, with deliveries beginning in 2004 and also renewed their baseload contracts with Malaysia's first two LNG export terminals on terms more flexible than the original contracts provided. Tokyo Gas and Toho Gas have also signed a binding agreement for LNG from Australia's North West Shelf LNG project with a 2004 commencement date as well.[22]

Japanese "City-Gas" Composition[23]



As such, with this formulation, gas quality parameters have historically remained very consistent, with very little variance in heat content or other critical quality components. Nonetheless, with cross company trade and supply interaction developing, the Japan Gas Association is promoting nationwide standardization of high calorie gas via the "IGF 21 Plan."

LNG is also attractive to Japan for environmental reasons. When combusted, it produces only a small amounts of carbon dioxide, low levels of nitrogen oxides and no sulfur oxides which could lead to acid rain and atmospheric pollution.

---

[22] Energy Information Administration, Japan Country Analysis Brief, July 2003
[23] Source: Japan Gas Association

IV) SUMMARY

The World is rapidly moving towards an integrated energy market for natural gas—a global marketplace is developing.

In the United Kingdom and continental Europe, the European Union is in many respects playing "catch-up" to the United States in the context of commercial frameworks governing the respective gas industries. Nonetheless, the European Union appears to be outdistancing the U. S. in the application of natural gas quality standards, including the Wobbe Index, dew point control and other indices. While there is active work and debate on harmonization and commonality of these parameters for use in the European Union as a whole, they are nonetheless being employed today on a country to country basis.

Japan and the Far East, the world's largest and most sophisticated LNG end users, are deregulating their markets as well and are preparing for commonality of gas quality parameters, particularly in Japan through adoption and promotion of the IGF 21 Plan which seeks standardization of high calorie gas.

United States industry and government should adopt and promulgate "global standards" for the domestic U. S. industry and promote the use of advanced gas quality measures including the Wobbe Index, Dew Point Control parameters and others.