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GE Energy

Specification for Fuel Gases for Combustion in Heavy-Duty Gas Turbines

These instructions do not purport to cover all details or variations in equipment nor to provide for every possible contingency to be met in connection with installation, operation or maintenance. Should further information be desired or should particular problems arise which are not covered sufficiently for the purchaser's purposes the matter should be referred to the GE Company.

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I. INTRODUCTION

General Electric heavy-duty gas turbines have the ability to burn a wide classification of gaseous fuels as shown in Table 1. The properties of these gases can vary significantly due to the relative concentrations of the reactant and inert constituents. In order to protect the gas turbine and to burn these fuels in an efficient and trouble free manner, allowable ranges are defined in this specification for physical properties, constituents and contaminants.

Table 2a specifies the allowable limits for the fuel properties and constituents and Table 2b lists the limitation on contaminants. These tables provide a screen for fuels that are acceptable for all frame sizes and combustor types. Fuels that fall outside of these limits may be acceptable for specific applications e.g. a high hydrogen fuel can be used with standard combustors in most cases. Contact GE for further evaluation of these fuels.

Table 3 identifies the acceptable test methods to be used for determining gas fuel properties shown in Tables 2a and 2b.

TABLE 1 FUEL GAS CLASSIFICATION		
FUEL	LHV Btu/scft	MAJOR COMPONENTS
Natural Gas and Liquefied Natural Gas	800-1200	Methane
Liquefied Petroleum Gas	2300-3200	Propane, Butane
Gasification Gases -Air Blown -Oxygen Blown	100-150 200-400	Carbon Monoxide, Hydrogen, Nitrogen, Water Vapor Carbon Monoxide, Hydrogen, Water Vapor
Process Gases	300-1000	Methane, Hydrogen, Carbon Monoxide, Carbon Dioxide

TABLE 2a GAS FUEL SPECIFICATION (see note 1 and 2)			
FUEL PROPERTIES	MAX	MIN	NOTES
Gas Fuel Pressure	Varies with unit and combustor type	Varies with unit and combustor type	See note 3
Gas Fuel Temperature, °F	see note 4	Varies With gas pressure	see note 4
Lower Heating Value, Btu/scft	None	100–300	See note 5
Modified Wobbe Index (MWI)			See note 6
- Absolute Limits	54	40	See note 7
- Range Within Limits	+5%	-5%	See note 8
Flammability Ratio	See Note 9	2.2:1	Rich: Lean Fuel/Air Ratio volume basis. See Note 10
Constituent Limits, mole %			
Methane	100	85	% of reactant species
Ethane	15	0	% of reactant species
Propane	15	0	% of reactant species
Butane + higher paraffins (C4+)	5	0	% of reactant species
Hydrogen	Trace	0	% of reactant species
Carbon Monoxide	Trace	0	% of reactant species
Oxygen	Trace	0	% of reactant species
Total Inerts (N2+CO2+Ar)	15	0	% of total (reactants + inerts).
Aromatics (Benzene, Toluene etc.)	Report	0	See Note 11
Sulfur	Report	0	See Note 12

Table 2b Allowable Gas Fuel Contaminant levels						
Trace Metals	Turbine Inlet Limit, Xe ppbw		Fuel Equivalent Limit, XFe, See notes 13 ppmw			
	Machine Model		Machine Model			
	MS3000 MS5000 B, E and F- Class	6C, FB, H- CLASS	MS3000MS5000 B, E and F- Class		6C, FB, H-Class	
			Turbine inlet flow/fuel flow (E/F)			
			50	12	4	
Lead (Pb)	20	20	1.00	0.240	0.080	The limits for Pb, V, Ca, Mg for FB, H-Class machines are identical to the limits for other machines. For Alkali metal limits (Na and K) see GEK 107230 ⁽¹⁾
Vanadium (V)	10	10	0.5	0.120	0.040	
Calcium (Ca)	40	40	2.0	0.480	0.160	
Magnesium (Mg)	40	40	2.0	0.480	0.160	
Sodium+Potassium See note 14						
(Na/K)=28	20	See GEK 107230 ⁽¹⁾	1.00	0.24	0.080	
(Na/K)=3	10		0.50	0.12	0.040	
(Na/K)=<1	6		0.30	0.072	0.024	
Particulates see note 15						
Total	600	600	30	7.2	2.4	Consult GE for particulate limits in 6C, FB, H-Class machines.
Above 10 microns	6	6	0.3	0.072	0.024	
Liquids: No Liquids allowed, gas must be superheated. See note 16						

Fuel Property and Contaminant Notes:

1. All fuel properties must meet the requirements from ignition to base load unless otherwise stated.
2. Values and limits apply at the inlet of the gas fuel control module, typically the purchaser's connection, FG1.
3. Minimum and maximum gas fuel supply pressure requirements are furnished by GE as part of the unit proposal.
4. The minimum fuel gas temperature must meet the required superheat as described in section III–C. Separate requirements are included for hydrocarbon and moisture superheat. The maximum allowable fuel temperature is defined in GER 4189 (2).
5. Heating value ranges shown are provided as guidelines. Specific fuel analysis must be furnished to GE for proper analysis. (See section III–A)
6. See section III–B for definition of Modified Wobbe Index (MWI).
7. The upper and lower limits for MWI shown are what can be accommodated within the standard dry low NO_x fuel system designs. Fuels outside of this range may need additional design and development effort. Performance fuel heating may be restricted on fuel with high inert content to stay above the minimum MWI limit.
8. Variations of MWI greater than + 5% or –5% may be acceptable for some applications, (i.e. on units that incorporate gas fuel heating). GE must analyze and approve all conditions where the 5% variation is to be exceeded.
9. There is no defined maximum flammability ratio limit. Fuel with flammability ratio significantly larger than those of natural gas may require a start-up fuel.
10. Candidate fuels, which do not meet these limits, should be referred to GE for further review. All fuels will be reviewed by GE on a case-by-case basis. (see section III–G)
11. When fuel heating for thermal efficiency improvements is utilized (e.g. T_{gas} > 300°F) there is a possibility of gum formation if excess aromatics are present. Contact GE for further information.
12. The quantity of sulfur in gas fuels not limited by this specification. Experience has shown that fuel sulphur levels up to 1% by volume do not significantly affect oxidation/corrosion rates. Hot corrosion of hot gas path parts is controlled by the specified trace metal limits. Sulfur levels shall be considered when addressing HRSG Corrosion, Selective Catalytic Reduction (SCR) Deposition, Exhaust Emissions, System Material Requirements, Elemental Sulfur Deposition and Iron Sulfide. (refer to Section IV–D)
13. The contamination limits identified represent the total allowable limit at the inlet to the turbine section. These limits will be reduced if comparable contaminants are present in the compressor inlet air and combustion steam/water injection. Consult with GE for limits for specific applications.
14. Sodium and potassium, from salt water, are the only corrosive trace metal contaminants normally found in natural gases. Na/K =28 is nominal sea salt ratio. Other trace metal contaminants may be found in Gasification and Process Gases. GE will review these on a case-by-case basis.

15. The fuel gas delivery system shall be designed to prevent the generation or the admittance of solid particulate to the gas turbine gas fuel system. This shall include but not be limited to particulate filtration and non-corrosive (i.e. stainless steel) piping from the particulate filtration to the inlet of the gas turbine equipment. Fuel gas piping systems shall be properly cleaned/flushed and maintained prior to gas turbine operation. (See section IV–A)
16. The fuel gas supply shall be 100% free of liquids. Admission of liquids can result in combustion and/or hot gas path component damage. (See section III–C) GE will require an input signal from the conditioning system liquid level indication closest to the GE Speed Ratio Valve or Gas Control Valve. This liquid level indication will be brought into the turbine controller and used as a signal to stop Gas Turbine operation when the liquid level reaches a fault level. It is highly recommended that this device have redundancy. The supplier of the gas conditioning system should provide this signal.

**TABLE 3
TEST METHODS FOR GASEOUS FUELS**

PROPERTY	METHOD
Gas Sampling Procedure	GPA 2166 ⁽³⁾
Gas Composition to C6 + (gas chromatography)	ASTM D 1945
Extended Gas Composition to C14	GPA 2286 ⁽⁶⁾
Heating Value	ASTM D 3588
Specific Gravity	ASTM D 3588
Compressibility Factor	ASTM D 3588
Dew Point (see Test Method note 1)	ASTM D 1142
Sulfur (see Test method note 2)	ASTM D 3246

Test Method Notes:

1. Hydrocarbon and water dew points shall be determined by direct dew point measurement (Chilled Mirror Device). If dew point cannot be measured, an extended gas analysis, which identifies hydrocarbon components from C1 through C14, shall be performed. This analysis must provide an accuracy of greater than 10 ppmv. A standard gas analysis to C6+ is normally not acceptable for dew point calculation unless it is known that heavier hydrocarbons are not present, as is most often the case with liquefied natural gases
2. This test method will not detect the presence of condensable sulfur vapor. Specialized filtration equipment is required to measure sulfur at concentrations present in vapor form. Contact GE for more information.

II. FUEL GAS CLASSIFICATION

A. Natural Gas, Liquefied Natural Gas (LNG) And Liquefied Petroleum Gas (LPG)

Natural gases are predominantly methane with much smaller quantities of the slightly heavier hydrocarbons such as ethane, propane and butane. Liquefied petroleum gas is propane and/or butane with traces of heavier hydrocarbons.

1. Natural Gas

Natural gases normally fall within the calorific heating value range of 800 to 1200 Btu per standard cubic foot. Actual calorific heating values are dependent on the percentages of hydrocarbons and inert gases contained in the gas. Natural gases are found in and extracted from underground reservoirs. These “raw gases” may contain varying degrees of nitrogen, carbon dioxide, hydrogen sulfide, and contain contaminants such as salt water, sand and dirt. Processing by the gas supplier normally reduces and/or removes these constituents and contaminants prior to distribution. A gas analysis must be performed to ensure that the fuel supply to the gas turbine meets the requirements of this specification.

2. Liquefied Natural Gas (LNG)

Liquefied natural gas is produced by drying, compressing, cooling and expanding natural gas to approximately -260° F at 14.7 psia. The product is transported as a liquid and delivered as a gas after pressurizing and heating to ambient temperature. The composition is free of inerts and moisture and can be treated as a high quality natural gas. LNG can pick up moisture that is present in the pipeline but it is not a source of the moisture.

The hydrocarbon dew point is typically less than -10° F at 500 psia but, depending on the processing steps and tank size, the dew point may increase if the boil-off is continuously extracted between deliveries. Cooling and recompression of the boil-off will avoid this potential problem. The expected range in component concentrations should be obtained from the gas supplier to determine the potential change in dew point.

3. Liquefied Petroleum Gases

The heating values of Liquefied Petroleum Gases (LPGs) normally fall between 2300 and 3200 Btu/scft (LHV). Based on their high commercial value, these fuels are normally utilized as a back-up fuel to the primary gas fuel for gas turbines. Since LPGs are normally stored in a liquid state, it is critical that the vaporization process and gas supply system maintains the fuel at a temperature above the minimum required superheat value. Fuel heating and heat tracing are required to meet these requirements.

B. Gasification Fuels

Gasification fuels are produced by either an oxygen blown or air blown gasification process and are formed using coal, petroleum coke or heavy liquids as a feedstock. In general, the heating values of gasification fuel are substantially lower than other fuel gases. The reduced heating value of gasification fuels result in the effective areas of the fuel nozzles being larger than those utilized for natural gas fuels.

1. Oxygen Blown Gasification

The heating values of gases produced by oxygen blown gasification fall in the range of 200 to 400 Btu/scft. The hydrogen (H₂) content of these fuels are normally above 30% by volume and have H₂ /CO mole ratio between 0.5 to 0.8. Oxygen blown gasification fuels are often mixed with steam for thermal NO_x control, cycle efficiency improvement and/or power augmentation. When utilized, the steam is injected into the combustor by an independent passage. Due to the high hydrogen content of these fuels, oxygen blown gasification fuels are normally not suitable for Dry Low NO_x (DLN) applications (see Table 2a). The high flame speeds resulting from high

hydrogen fuels can result in flashback or primary zone re-ignition on DLN pre-mixed combustion systems. Utilization of these fuels requires evaluation by GE.

2. Air Blown Gasification

Gases produced by air blown gasification normally have heating values between 100 and 150 Btu/scft. The H₂ content of these fuels can range from 8% to 20% by volume and have a H₂/CO mole ratio 0.3 to 3:1. The use and treatment of these fuels is similar to that identified for oxygen blown gasification.

Gasification fuels provide a significant fraction of the total turbine mass flow rate. With oxygen blown fuels the diluents addition (typically nitrogen) also assists with NO_x control. Careful integration of the gas turbine with the gasification plant is required to assure an operable system. Due to the low volumetric heating value of both oxygen and air blown gases, a special fuel system and fuel nozzles are required.

C. Process Gases

Many chemical processes generate surplus gases that may be utilized as fuel for gas turbines. (e.g. tail or refinery gases). These gases often consist of methane, hydrogen, carbon monoxide, and carbon dioxide that are normally byproducts of petrochemical processes. The hydrogen and carbon monoxide content, these fuels result in a high rich-to-lean flammability limit. These types of fuels often require inerting and purging of the gas turbine gas fuel system upon unit shutdown or a transfer to more a more conventional fuel. When process gas fuels have extreme flammability limits such that the fuel will auto ignite at turbine exhaust conditions, a more “conventional” start-up fuel is required. Additional process gases that are utilized as gas turbine fuels are byproducts of steel production. These are:

1. Blast Furnace Gases

Blast Furnace Gases (BFGs), alone, have heating values below the minimal allowable limits. These gases must be blended with other fuels such as coke oven gas, natural gas or hydrocarbons such as propane or butane to raise the heating value above the required lower limit.

2. Coke Oven Gases

Coke oven gases are high in hydrogen and methane and may be used as fuel for non-DLN combustion systems. These fuels often contain trace amounts of heavy hydrocarbons, which may lead to carbon buildup on the fuel nozzles. The heavy hydrocarbons must be “scrubbed” or removed from the fuel prior to delivery to the gas turbine.

3. COREX Gases

COREX gases are similar to oxygen blown gasified fuels, and may be treated as such. They are usually lower in H₂ content and have heating values lower than oxygen blown gasified fuels. Further combustion related guidelines may be found in Bureau of Mines Circulars 503 ⁽⁵⁾ and 622 ⁽⁶⁾.

III. FUEL PROPERTIES

A. Heating Values

The heat of combustion, heating value or calorific value of a fuel is the amount of energy generated by the complete combustion of a unit mass of fuel. The US system of measurement uses British thermal units (Btu) per pound or Btu per standard cubic foot when expressed on a volume basis. The heating value of a gas fuel may be determined experimentally using a calorimeter in which fuel is burned in the presence of air at constant pressure. The products are allowed to cool to the initial temperature and a measurement is made of the energy released during complete combustion. All fuels that contain hydrogen release water vapor as a product of combustion, which is subsequently condensed in the calorimeter. The resulting measurement of the heat released is the higher heating value (HHV), also known as the gross heating value, and includes the heat of vaporization of water. The lower heating value (LHV), also known as the net heating value, is calculated by subtracting the heat of vaporization of water from the measured HHV and assumes that all products of combustion including water remain in the gaseous phase. Both the HHV and LHV may also be calculated from the gas compositional analysis using the procedure described in ASTM D 3588. For most gas fuels, a standard gas analysis to C6+ is adequate for determination of heating value, but an extended C14 analysis (4) may also be used if available. Gas turbines do not operate with condensing exhaust systems and it is common gas turbine industry practice to utilize the LHV when calculating the overall cycle thermal efficiency.

B. Modified Wobbe Index (MWI)

Gas turbines can operate with fuel gases having a very wide range of heating values, but the amount of variation that a specific fuel system design can accommodate is limited. The fuel nozzles are designed to operate within a fixed range of pressure ratios and changes in heating value are accommodated for by increasing or decreasing the fuel nozzle area or gas temperature. A measure of the interchangeability of gas fuels for a given system design is the MWI (7). This term is used as a relative measure of the energy injected to the combustor at a fixed pressure ratio and is calculated using the fuel lower heating value, the specific gravity with respect to air and the fuel temperature. The mathematical definition is as follows:

$$\text{Modified Wobbe Index} = \frac{\text{LHV}}{\sqrt{\text{SG}_{\text{gas}} \times T_{\text{gas}}}} \quad (1)$$

This is equivalent to:

$$\text{Modified Wobbe Index} = \frac{\text{LHV}}{\sqrt{\frac{\text{MW}_{\text{gas}}}{28.96} \times T_{\text{gas}}}} \quad (2)$$

LHV = Lower Heating Value of the Gas Fuel (Btu/scf)

SG_{gas} = Specific Gravity of the Gas Fuel relative to Air

MW_{gas} = Molecular Weight of the Gas Fuel

T_{gas} = Absolute Temperature of the Gas Fuel (°Rankine)

28.96 = Molecular Weight of Dry Air

The allowable MWI range is established to ensure that required fuel nozzle pressure ratios are maintained during all combustion/turbine modes of operation. When multiple gas fuels are supplied and/or if variable fuel temperatures result in a MWI that exceed the 5% limitation, independent fuel gas trains, which could include control valves, manifolds and fuel nozzles, may be required for standard combustion systems. For DLN systems, an alternate control method may be required to ensure that the required fuel nozzle pressure ratios are met. An accurate analysis of all gas fuels, along with fuel gas temperature- time profiles shall be submitted to GE for proper evaluation.

C. Superheat Requirement

The superheat requirement is established to ensure that the fuel gas supply to the gas turbine is 100% free of liquids. Superheat is the temperature difference between the gas temperature and the respective dew point. The requirement is independent of the hydrocarbon and moisture concentration.

Dependent its constituents, gas entrained liquids could cause degradation of gas fuel nozzles, and for DLN applications, premixed flame flashbacks or re-ignitions. Condensation of moisture must be avoided to prevent the formation of gas hydrates and collection of water in low points of the gas fuel system. The superheat requirement is specified to provide enough margin to compensate for the temperature reduction as the gas expands across the gas fuel control valves. The requirements are applicable at all operating conditions and apply to all units including those installed with either standard or DLN combustion systems. Exceptions are units burning coal derived low Btu fuels, the requirements for which must be determined on a case-by-case basis. The superheat requirements take into account the gas temperature drop and the relationship of the moisture and hydrocarbon dew point lines to the gas fuel pressure. Because of differences between the dew point line characteristics in the region of interest (less than 700 psia), the opportunity for moisture condensation as the gas expands is less than that for hydrocarbons. Advantage has been taken of this physical property to provide users with two separate requirements in order to minimize the cost of superheating. In addition, the superheat requirements depend on the expansion ratio across the control valves and are therefore be expressed as a function of the incoming gas pressure at the inlet to the gas fuel control system.

To avoid hydrocarbon condensation the superheat requirement is:

$$T_{sh} = 2.33 \times \left(\frac{P_{gas}}{100} \right)^2 - 2.8 \times \left(\frac{P_{gas}}{100} \right) \quad (3)$$

where:

T_{sh} is the hydrocarbon superheat requirement in °F (incremental temperature above the hydrocarbon dew point)

P_{gas} is the gas fuel delivery pressure at the inlet to the gas turbine control system, psia

To avoid moisture and hydrate formation the superheat requirements is:

$$T_{sm} = 5.15 \times \left(\frac{P_{gas}}{100} \right) - 7 \quad (4)$$

where:

T_{sm} is the moisture superheat requirement in °F (incremental temperature above the moisture dew point)

The superheat requirements are shown graphically on Figure 1 for moisture and hydrocarbons. Both should be determined and added to the respective dew points (moisture and hydrocarbon) at the gas turbine fuel delivery pressure. The higher of the two values, superheat plus dew point, will determine the preliminary minimum gas fuel temperature that is required in order to meet the superheat requirements. In some cases, the hydrocarbon dew point may be low enough, that the requirement for meeting the moisture superheat will dominate. However, if the hydrocarbon dew point is close to the moisture dew point, and the hydrocarbon dew point varies sufficiently, the moisture and hydrocarbon superheat requirements may flip-flop on which one dominates. In order to avoid this situation, GE has developed a breakpoint strategy. The breakpoints that will be used are based on gas supply pressure, as seen in the table below:

Gas Supply Pressure	Hydrocarbon Dew Point Breakpoint
500 psia or less	-25°F
501 psia to 600 psia	-35°F
601 psia to 700 psia	-50°F

Maximum Hydrocarbon Dew Point less than Breakpoint

If the maximum hydrocarbon dew point, calculated during the Order to Requisition process, is below the breakpoint level, then GE will assume that the hydrocarbon superheat requirements are less than the moisture superheat requirements. Therefore, the minimum gas temperature will be determined by the moisture dew point plus the moisture superheat.

Maximum Hydrocarbon Dew Point greater than Breakpoint

However, if the maximum hydrocarbon dew point, calculated during the Order to Requisition process, is above a breakpoint, then GE will assume the unconditioned gas is saturated. This will require the full hydrocarbon superheat to be applied to the unconditioned gas. The resulting gas temperature may be higher than just adding the hydrocarbon dew point and hydrocarbon superheat. See Appendix 4 for a sample calculation.

Continuous Hydrocarbon Dew Point Measurement

An alternate approach, to the use of a breakpoint, is to provide instrumentation to measure the hydrocarbon dew point continuously, and provide that signal to GE through the gas turbine controller. The turbine controller will then use the hydrocarbon dew point, along with the moisture dew point, provided during the Order to Requisition process, to determine if sufficient superheat has been provided.

Non-superheated Gas Temperature Signal

GE will require an input signal, into the turbine controller, of the gas fuel temperature upstream of any performance or superheating system. The turbine controller will take action if sufficient superheat is not supplied.

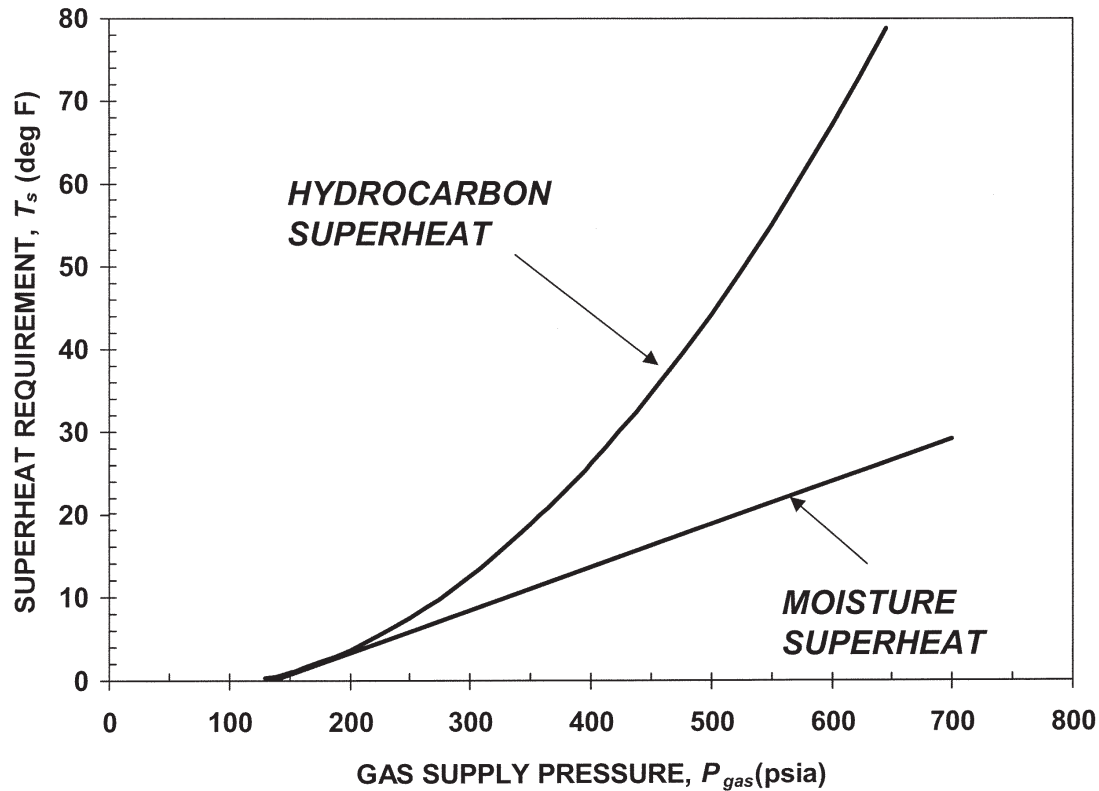


Figure 1. Hydrocarbon and Moisture Superheat Requirements

D. Hydrocarbon Dew Point

The hydrocarbon dew point is the temperature at which the first droplet of hydrocarbon forms as the gas temperature is reduced at a given pressure and is analogous to the moisture dew point. The hydrocarbon dew point is very sensitive to small concentrations of heavy hydrocarbons (C6+) and contamination of the gas sample during sampling can be an issue. The use of a sample probe and following the sampling procedure described in GPA 2166⁽³⁾, particularly with respect to sample cylinder purging, can avoid these problems. For this reason the recommended method for hydrocarbon dew point determination is by direct measurement using a chilled mirror instrument (ASTM D 1142). If a direct measurement cannot be performed, the dew point may be calculated from the extended C14 gas fuel analysis⁽⁴⁾. Use of a C6+ analysis for dew point determination may result in an under-estimation of 30°F to 40°F or more. Exceptions are fuels that do not contain heavy hydrocarbons such as liquefied natural gas.

E. Moisture Dew Point

The gas fuel moisture dew point is dependent upon the moisture concentration and the gas fuel pressure. When expressed in units of lbs/mmscft (pounds per million standard cubic feet), the resulting dew point is practically independent of the gas fuel composition (other than moisture). Typically, many pipeline tariffs limit the maximum allowable moisture content to 7 lbs/mmscft while the actual value may be significantly less. It is the maximum allowable value, however, that determines the design requirements for superheat. Figure 2 is included to provide a guide for determining the expected moisture dew point from the moisture concentration and gas fuel pressure of a typical natural gas. The actual dew point will vary slightly with gas composition changes.

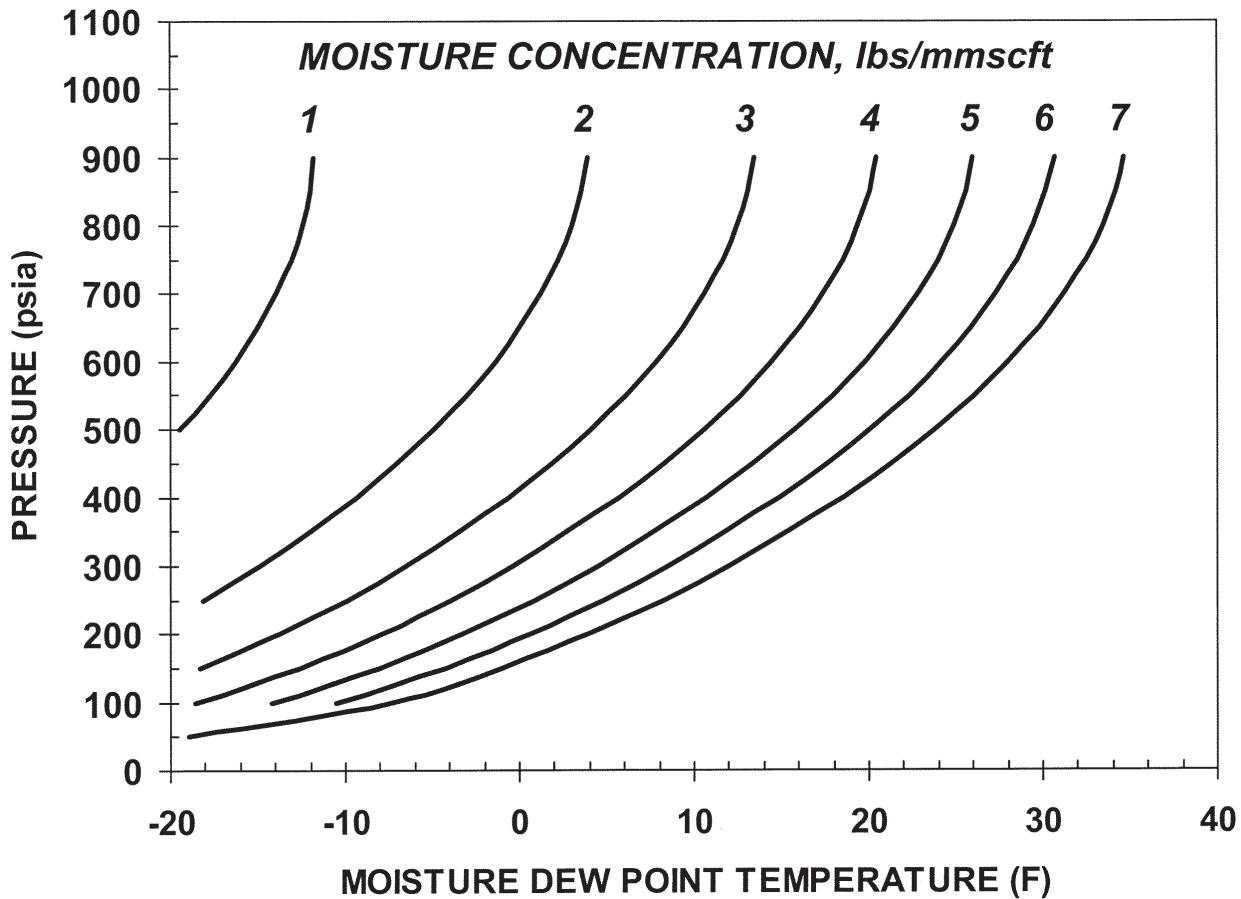


Figure 2. Moisture Dew Point as a Function of Concentration and Gas Pressure for a Typical Natural Gas Fuel

F. Flammability Ratio

Fuel gases containing hydrogen and/or carbon monoxide will have a ratio of rich-to-lean flammability limits that is significantly greater than that of natural gas. Typically, gases with greater than 5% hydrogen by volume fall into this range and require a separate startup fuel. GE will evaluate the gas analysis to determine the requirement for a start-up fuel. Fuel gases with large percentages of an inert gas such as nitrogen or carbon dioxide will have a ratio of rich-to-lean flammability limits less than that of natural gas. Flammability ratios of less than 2.2 to 1 based on volume at ISO conditions (14.696 psia and 59° F), may experience problems maintaining stable combustion over the full operating range of the turbine.

G. Gas Constituent Limits

Gas constituent limits are specified to assure stable combustion through all gas turbine loads and modes of operation. A detailed gas analysis must be furnished to GE for proper evaluation. See reference ⁽³⁾ for the recommended sampling procedure and ASTM D1945 for a C6+ analysis procedure.

H. Gas Fuel Supply Pressure

Gas fuel supply pressure requirements are dependent on the gas turbine model, the combustion system design, the fuel gas analysis and unit specific site conditions. As part of the unit proposal, GE will furnish minimum and maximum gas fuel supply pressure requirements.

IV. CONTAMINANTS

Dependent on the type of fuel gas, the geographical location and the forwarding means there is the potential for the “raw” gas supply to contain one or more of the following contaminants:

1. Tar, lamp black, coke
2. Water, salt water
3. Sand, clay
4. Rust
5. Iron sulfide
6. Scrubber oil or liquid
7. Compressor Lube oil
8. Naphthalene
9. Gas Hydrates

It is critical that the fuel gas is properly conditioned prior to being utilized as gas turbine fuel. This conditioning can be performed by a variety of methods. These include, but are not limited to: media filtration, inertial separation, coalescing and fuel heating. Table 2b identifies the trace metal, particulate and liquid contamination limits. It is critical that fuel gas conditioning equipment be designed and sized so that these limits are not exceeded. For further information on gas fuel conditioning, see publication GER 3942 (8).

A. Particulates

Contamination limits for particulates are established to prevent fouling and excessive erosion of hot gas path parts, erosion and plugging of combustion fuel nozzles and erosion of the gas fuel system control valves. The utilization of gas filtration or inertial separation is instrumental in ensuring that the particulate requirements as defined in Table 2b are met. GE recommends the use of stainless steel piping down-stream of this last level of filtration to prevent the generation of corrosion-derived particulates.

B. Liquids

As identified in Table 2b, zero liquids are allowed in the gas turbine fuel gas supply. Refer to Note 16 of table 2b for current input requirements and turbine controller actions. The introduction of liquids with gas fuel can result in nuisance and/or hardware damaging conditions. These include rapid excursions in firing temperature and gas turbine load, primary zone re-ignition and flashback of pre-mixed flames. In severe conditions, liquid carryover to the first stage turbine nozzle may result in damage to downstream hot gas path components. When liquids are identified in the gas fuel supply, phase separation and heating must be employed to achieve the required superheat level.

C. Sulfur

There are several concerns relative to the levels of sulfur contained in the fuel gas supply. Many of these are not directly related to the gas turbine but to associated equipment and emissions requirements. These concerns include but not limited to:

1. Hot Gas Path Corrosion

Typically, use of sulfur bearing fuels will not be limited by concerns for corrosion in the turbine hot gas path. Experience has shown that fuel sulfur levels up to about 1% sulfur do not significantly affect oxidation/corrosion rates. Specifying the fuel alkali levels to values shown in Table 2b controls hot corrosion of hot gas path parts resulting from alkali sulfate formation. Unless sulfur levels are extremely low, alkali levels are usually limiting in determining hot corrosion of hot gas path materials. For low Btu gases, the fuel mass flow rate at the turbine inlet is increased over that for natural gas, and the alkali limit in the fuel is therefore decreased.

2. HRSG Corrosion

If heat recovery equipment is used, the gas fuel sulfur concentration must be known so that the appropriate design for the equipment can be specified. Severe corrosion from condensed sulfurous acid results if a heat recovery steam generator (HRSG) has metal temperatures below the acid dew point.

3. Selective Catalytic Reduction (SCR) Deposition

Units utilizing ammonia injection downstream of the gas turbine for NO_x control can experience the formation of deposits containing ammonium sulfate and bisulfate on low temperature evaporator and economizer tubes. Such deposits are quite acidic and therefore corrosive. These deposits and the corrosion that they cause may also decrease HRSG performance and increase backpressure on the gas turbine. Deposition rates of ammonium sulfate and bisulfate are determined by the sulphur content of the fuel, ammonia content in the exhaust gas, tube temperature and boiler design. Fuels having sulfur levels above those used as odorants for natural gas should be reported to GE. In addition, the presence of minute quantities of chlorides in the compressor inlet air may result in cracking of ANSI 300 series stainless steels in the hot gas path.

4. Exhaust Emissions

Sulfur burns mostly to sulfur dioxide, but 5%-10% oxidizes to sulfur trioxide. The latter can result in sulfate formation, and may be counted as particulate matter in some jurisdictions. The remainder will be discharged as sulfur dioxide. To limit the discharge of acid gas, some localities may restrict the allowable concentration of sulfur in the fuel.

5. System Material Requirements

When considering fuel gases containing H₂S (sour gas fuels) material selection for system piping and components shall comply with NACE Standard, MR0175 ⁽⁹⁾.

6. Elemental Sulfur Deposition

Solid elemental sulfur deposits can occur in gas fuel systems downstream of pressure reducing stations or gas control valves under certain conditions. These conditions may be present if the gas

fuel contains elemental sulfur vapor, even when the concentration of the vapor is a few parts per billion by weight. Concentrations of this magnitude cannot be measured by commercially available instrumentation and deposition cannot therefore be anticipated based on a standard gas analysis. Should deposition take place, fuel heating will be required to maintain the sulfur in vapor phase and avoid deposition. A gas temperature of 130°F or higher may be required at the inlet to the gas control valves to avoid deposition, depending on the sulfur vapor concentration. The sulfur vapor concentration can be measured by specialized filtering equipment. Contact GE for further information on this subject.

7. Iron Sulfide

The presence of sulfur in the gas may promote the formation of iron sulfides. Under certain conditions, iron sulfide is a pyrophoric material that can auto ignite at atmospheric pressure and temperature when exposed to air. Extreme care must be taken when servicing gas fuel cleanup equipment to avoid accidental exposure to oxygen and subsequent combustion of filter material.

D. Trace Metals

Sodium is the only trace metal contaminant normally found in natural gas. The source of sodium in natural gas is salt water. Limits on trace metals are established to prevent the formation of corrosive deposits on hot gas path components. These deposits can be detrimental to gas turbine parts life. In addition to sodium, additionally harmful trace metal contaminants can be found in gasification and process gases. GE will determine limits on these contaminants on a case-by-case basis.

V. SOURCES OF CONTAMINANTS

A. Particulates

The major source of particulates is from corrosion products in the pipeline. These products are continuously formed over the life of the pipeline at rates that are determined by the corrosive components and water content of the gas. For this reason most gas suppliers control moisture content to avoid the possibility of water condensing and forming acid with CO₂ or H₂S.

B. Liquids

Gas at the wellhead is typically produced in a wet saturated condition and is treated to remove water and heavy hydrocarbon liquids. Depending on the degree of treatment and the supply pressure, the gas may be delivered in a dry condition. After pressure reduction it is possible for condensates to form as the gas cools during expansion. The condensates may be either water or hydrocarbons or both. Carry over of lubricating oil from compressor stations is another source of liquids.

C. Sulfur

Sulfur is usually combined with either hydrogen as H₂S or carbon as COS. It is produced with the natural gas. Typically the gas supplier will limit H₂S to a concentration of less than approximately 20 ppmv by removing sulfur in a treatment system. Sulfur may also be present in very low concentrations (< 100 ppbv) in the form of elemental sulfur vapor.

D. Trace Metals

The details of various sources of alkali contaminants in the following text apply to MS 3000, MS 5000, B, E and F class machines. The sources of contaminants for 6C, FB and H-class machines are discussed in GEK 107230 ⁽¹⁾.

Contributions to the alkali content of the combustion gases can come from any of the material streams supplied to the combustor; fuel, air, water or steam. The basic parameter which can be used to define the allowable alkali metal content admitted to the turbine is X_t , the combined sodium and potassium content of the combustion gas at the entry to the first stage nozzle. This concentration must not exceed the values stated in Table 2b. Since there is no simple test method for measuring X_t in an operating turbine, it must be calculated from the alkali metal contents of the fuel, air, water and steam flows.

$$T(X_t) = A(X_a) + F(X_f) + S(X_s) + W(X_w)$$

Where T = total flow to turbine ($= A + F + S + W$):

X_t = alkali contaminant concentration in total flow as Na.

A = Air flow,

X_a = contaminant concentration in air.

F = Fuel flow,

S = Steam flow,

X_s = contaminant concentration in steam.

W = water flow

X_w = contaminant concentration in water.

The allowable levels of alkali contamination in the different flows entering the gas turbine are discussed below:

E. Air

There are four sources of alkali metal contained in the compressor discharge air, (a) Inlet filter carry over of sodium chloride in ambient air (b) carry over of sodium dissolved in water used for evaporative cooling (c) carry over of sodium dissolved in water used for inlet fogging and (d) carry over of sodium from water used for on-line water washing.

When concentrations of trace metals in fuel, water or steam are not precisely known, a value of 0.005 ppmw, GER 3419 ⁽¹⁰⁾, can be used for systems with or without evaporative coolers. This value, based on experience, would cause an insignificant contribution to the overall contamination level and have a minor impact on parts lives.

For systems with inlet foggers, the water carry over is 100% compared with approximately 0.003% for evaporative coolers and the potential sodium carry over is therefore proportionally higher. The maximum inlet fogging water flow rate is approximately 1/3 of the natural gas flow rate and, depending on

the sodium concentration, could use up a significant portion of the total allowed at the turbine inlet. Refer to GEK 101944 ⁽¹¹⁾ for information on water purity requirements. If it is anticipated that the specification could be exceeded, General Electric should be consulted for recommendations on the selection of the water source and use of proper air filtration equipment.

F. Steam

Steam for gas turbine injection is typically taken from a suitable extraction point on a steam turbine or HRSG. The limiting purity requirements for this steam are those for the steam turbine. These limits are defined in GEK 72281 ⁽¹²⁾

G. Water

The maximum alkali metal (sodium plus potassium) content of water to be used for injection is discussed in GEK 101944 ⁽¹¹⁾. The maximum water injection rate is approximately equal to the fuel injection rate. If the alkali content approaches the maximum allowable value stated in GEK 101944 ⁽¹¹⁾, it may use all of the allowable margin at the turbine inlet, leaving none available for the fuel. If it is anticipated that the specification could be exceeded, General Electric should be consulted for recommendations on the selection of the water source.

NOTE

The concentration of sodium in steam and water, at the levels specified, can be measured directly using an on-line sodium analyzer or, in the laboratory, with an ion or pH meter fitted with a “sodium specific” electrode or by an atomic absorption spectrometer fitted with a graphite furnace.

H. Fuel

The final source of contamination to be considered is the fuel. Most cases of alkali metal contamination and corrosion of hot gas path components are related to liquid fuel contamination. It is rare that natural gas will contain trace metals but gasification fuels may contain alkalis carried over from the gas clean up system. The issues and requirements with gas fuels are discussed separately in the prior sections.

APPENDIX 1

I. DEFINITIONS

Dew Point

This is the temperature at which the first liquid droplet will form as the gas temperature is reduced. Common liquids found in gas fuel are hydrocarbons, water and glycol. Each has a separate and measurable dew point. The dew point varies considerably with pressure and both temperature and pressure must be stated to properly define the gas property. Typically, the hydrocarbon dew point will peak in the 300 to 600 psia range.

Dry Saturated Conditions

The gas temperature is at, but not below or above, the dew point temperature. No free liquids are present.

Gas Hydrates

Gas hydrates are semi-solid materials that can cause deposits that plug instrumentation lines, control valves and filters. They are formed when free water combines with one or more of the C1 through C4 hydrocarbons. Typically the formation will take place downstream of a pressure reducing station where the temperature drop is sufficient to cause moisture condensation in a region of high turbulence. Because hydrates can cause major problems in the gas distribution network, the moisture content is usually controlled upstream at a dehydration process station.

Gas Hydrate Formation Line

This is similar to the dew point line. A potential for hydrate formation exists if free water is present. Calculations performed using the commercial software Hysys⁽¹⁵⁾ show that the hydrate formation line is approximately 10°F above the moisture dew point line. Maintaining the required degree of superheat above the moisture dew point will eliminate hydrate formation problems. (see section III–C Superheat Requirement)

Glycol

Glycol is not a natural constituent of natural gas but is introduced during the dehydration process. Various forms of glycol are used, di-ethylene and tri-ethylene glycol being two most common. In some cases glycol is injected into the pipeline as a preservative. In most cases, glycol may only be a problem during commissioning of a new pipeline or if an upset has taken place at an upstream dehydration station.

Odorant

Odorants are injected into natural and LP gas to make leaks readily detectable. The odorant commonly used for natural gas is tertiary butyl mercaptan, while ethyl mercaptan is used for LP gas.

Superheat

This is defined as the difference between the gas temperature minus the liquid dew point. The difference is always positive or zero. A negative value implies that the value is being measured at two differing states of pressure and temperature and is not valid. A measured gas temperature below the theoretical dew point means that the gas is in a wet saturated state with free liquids present.

Saturation Line

This is the same as the dew point line.

Wet (Saturated) Conditions

A mixture consisting of both vapor and liquids.

APPENDIX 2

I. PARTICLE SIZE LIMITATIONS

The effective particle size for erosion considerations is determined by a particle's terminal settling velocity. The size and density distribution of the solid particles must be such that not more than 1.0 percent by weight of the particles shall have a terminal settling velocity in air (70°F and 30 inches Hg, absolute) greater than 14 inches per minute, and not more than 0.1 percent shall have a terminal settling velocity in excess of 23 inches per minute. For a solid spherical particle, Stoke's Law of settling permits calculating the terminal settling velocity if the particle size and shape and particle specific gravity are known. The following tabulation gives the spherical particle diameters equivalent to the limiting terminal settling velocities for particles of specific gravity 2.0 and 4.

Settling Velocity (inches/min)	Specific Gravity (base on water)	Equivalent Spherical Particle Diameter (microns)
14	2	10
23	2	13
14	4	7
23	4	9

APPENDIX 3

I. EQUIVALENT CONTAMINANT RELATIONSHIPS (ALL MACHINES EXCEPT FB, H-CLASS)

The following relationships can be used to determine turbine inlet contaminant and fuel equivalent contaminant concentrations to compare to limits given in Table 2b. In general, for mass balances on the flows and on the contaminants from fuel, air and steam/water at the turbine inlet.

$$E = F + A + S \quad (5)$$

$$(XE)E = (XF)F + (XA)A + (XS)S \quad (6)$$

where:

A, F, S and E are the mass flows of air, fuel, injected steam/water and combustion gases at the turbine inlet, respectively

XA, XF, XS, and XE are the contaminant concentrations (ppm by weight) in the inlet air, in the fuel, in the injected steam/water, and in the combustion gases at the turbine inlet, respectively.

The fuel equivalent concentration of contaminants (XFe) is (dividing (5) and (6) by F)

$$XFe = XE(1 + A/F + S/F) = XF + XA(A/F) + XS(S/F) \quad (7)$$

For example for a natural gas contaminated with salt at a sodium concentration of 0.1 ppm, an air sodium contamination of 5 ppb, and a steam contamination of 5 ppb, the equivalent sodium in the fuel for $A/F=50$ and $S/F=1$ is from equation (7)

$$XFe = 0.1 + 0.005(50) + 0.005(1) = 0.355ppm \quad (8)$$

This is the amount of sodium considered to come from a fuel source only, which gives the same sodium concentration at the turbine inlet as from the combined three sources.

The turbine inlet concentration, XE, is found by rearranging (7)

$$XE = XFe / (1 + A/F + S/F) = 0.355 / (1 + 50 + 1) = 0.006827ppm = 6.827 ppb \quad (9)$$

These values are well within the sodium specification values of 1 ppm on a fuel basis (XFe), and 20 ppb for the turbine inlet concentration (XE). XE and XFe values for all contaminants are given in Table 2B.

For equivalent contaminant relationships in 6C, FB, and H-Class machines, refer GEK 107230 ⁽¹⁾.

APPENDIX 4

I. MINIMUM GAS FUEL TEMPERATURE REQUIREMENT CALCULATIONS

The gas fuel pressure at the purchaser's connection FG1 should first be determined. The hydrocarbon and moisture superheat can then be calculated from the equations shown on Figure 1. For example, at a gas fuel pressure of 490 psia, the moisture and hydrocarbon superheat requirements are 18°F and 42°F respectively.

For a typical pipeline gas the maximum allowable moisture content is 7 lbs/mmscft. At 490 psia the moisture dew point can be determined from figure 2 and is equal to 23°F. The minimum gas temperature to avoid moisture condensation is equal to the moisture dew point plus the required superheat, or $23^{\circ} + 18^{\circ} = 41^{\circ}\text{F}$.

For hydrocarbons, the maximum expected hydrocarbon dew point should be determined by consultation with the gas supplier and a review of historical data if available. The hydrocarbon dew point will be dependent on the source of the gas, the degree of gas processing and may vary seasonally with overall gas demand and the economics associated with liquids removal and recovery. For a fuel with a maximum hydrocarbon dew point of, for example, 35°F at 490 psia, the theoretical minimum gas fuel temperature is $42^{\circ} + 35^{\circ} = 77^{\circ}\text{F}$. The temperature, in this example, is higher than the minimum required to avoid moisture condensation, therefore it establishes the minimum gas temperature to avoid both hydrocarbon and moisture condensation. However, the actual minimum gas fuel temperature will be based on the hydrocarbon dew point breakpoint. (see section III-C) In the example above, the assumed hydrocarbon dew point was 35°F. (at 490 psia) The hydrocarbon dew point for this case is higher than the breakpoint. (-25°F) Therefore, GE will assume that the gas entering the superheating system is saturated, and will require the full hydrocarbon superheat be applied. For example, if the gas entering the superheating system is at a temperature of 55°F, then the minimum gas temperature would be 97°F. ($55^{\circ}\text{F} + 42^{\circ}\text{F}$) The 97°F temperature is what the turbine controller will begin to take protective action on. The use of the 97°F temperature, instead of the 77°F temperature is based on GE's experience of gas fuel dew point variation on sites.

For another example, if the hydrocarbon dew point is calculated as -30°F, (at 490 psia) then the hydrocarbon dew point would be less than the breakpoint. (-25°F) Therefore, the minimum gas fuel temperature would be based on the moisture dew point and superheat. Assuming a 7 lbs/mmscft, the dew point is 23°F and superheat required is 18°F, resulting in a theoretical and actual minimum gas temperature of 41°F. ($23^{\circ}\text{F} + 18^{\circ}\text{F}$)

APPENDIX 5**I. RELATED SPECIFICATION DOCUMENTS**

GER 3419 ⁽¹⁰⁾ - Includes specifications for compressor inlet air quality

GER 4189 ⁽²⁾ - Includes heated gas fuel temperature limits

GER 72281 ⁽¹²⁾ - Includes steam purity requirements in steam turbines

GER 101944 ⁽¹¹⁾ - Includes water and steam purity requirements in gas turbines

GEK 106669 ⁽¹³⁾ - Includes cooling steam purity requirements for H class gas turbines

GEK 107230 ⁽¹⁾ - Includes allowable alkali metal concentrations for 6C, FB and H class gas fuels

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2. GER 4189 Design Considerations for Heated Gas Fuel
3. Obtaining Natural Gas Samples for Analysis by Gas Chromatography, GPA Standard 2166, Gas Producers association, 6526 East 60th Street, Tulsa, Oklahoma
4. Tentative Method of Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography, GPA Standard GPA 2286, Gas Producers association, 6526 East 60th Street, Tulsa, Oklahoma 74145
5. Bureau of Mines Bulletin 503, Flammability Characteristics of Combustible Gases and Vapors, 1950
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9. MR0175, NACE Standard, Sulfide Stress Cracking Resistant Metallic Material for Oilfield Equipment
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11. GEK 101944 Requirements for Water/Steam Purity in Gas Turbines
12. GEK 72281 Steam Purity Recommendations for Utility Steam Turbines
13. GEK 106669 Specification for Cooling Steam Purity for Closed Circuit Steam Cooled Gas Turbine
14. ASME Handbook "Water Technology for Thermal Power Systems", chapter 12.

15. Hysys, a gas process simulation program. Hyprotech Corporate Headquarters, Suite 800, 707 – 8th Avenue SW, Calgary, Alberta T2P 1H5, Canada, Phone: 403 520 6000



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