

GAS FUEL CLEAN-UP SYSTEM DESIGN CONSIDERATIONS FOR GE HEAVY-DUTY GAS TURBINES

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INTRODUCTION

GE heavy-duty gas turbines are capable of burning a variety of gaseous and liquid fuels, including low heating value gases (e.g., syngas and steel mill gas), land fill gas, petroleum naphthas and residuals. These fuels vary in hydrocarbon composition, physical properties, concentrations of potential pollutants and trace metals.

Within the last decade, GE has developed advanced-technology combustion systems that can burn natural gas and achieve NO_x emissions of 15 ppmv or less without the need for water or steam injection. During this same period, the quality of the natural gas supply within the U.S. has changed. More specifically, heavy hydrocarbon liquids are now commonly found in the gas supply delivered to power plants.

What happened during the past 10 years to promote this situation? The passage of the Federal Energy Regulatory Commission (FERC) Order 636 (Reference 1) in 1991 opened access to transportation pipelines to all gas suppliers and eliminated the semi-monopolistic contracts that limited access to one or more suppliers.

In addition, FERC 636 changed the way in which natural gas is sold by requiring producers, transporters and local distributors to sell gas on a therm or energy basis. This created increased competition within the natural gas industry and drove suppliers to produce gas at minimum cost in order to compete on the open market. It is now not uncommon for large users to negotiate daily contracts based on the lowest gas price available for that day.

Higher hydrocarbons in the form of gas or liquid can contribute significantly to the heating value and are, therefore, a valuable constituent of natural gas. As a result of stiff competition, stripping these heavier components from the gas in cryogenic processing plants has become less economic. A consequence of this change is that hydrocarbons beyond C₆ are now common in many gas supplies. Depending on pressure, temperature and concentration levels, the heavier hydrocarbons can form liquids and have a very significant effect on hydrocarbon dew point.

Worldwide, with a few exceptions such as Canada, gas fuel liquids have been a problem for many years. Problems first arose when liquid slugging caused major problems with standard combustor machines, often causing hot gas path damage. Application of advanced-technology combustion systems in these areas requires close attention to the gas clean-up system to ensure that both condensed liquids and practically all particulate matter are eliminated at the inlet to the gas fuel control module.

Untreated gas can result in fuel nozzle plugging from particulates and erosion of components exposed to high velocities in the gas system. Liquid carry-over in natural gas has resulted in premature combustion component distress (liners, cross-fire tubes and fuel nozzles) and has affected reliability and availability for all types of combustion systems, including Dry Low NO_x (DLN).

For DLN advanced technology combustors to operate properly, it is absolutely essential that the gas fuel supplied meet the GE specification and be free of all liquids and particulates. This specification is documented in GEI 41040E (Reference 2).

This paper discusses where particulates and liquids in gas fuel originate and why they are not being removed with the wide range of gas processing equipment available in the market.

GAS CLEANLINESS AND QUALITY REQUIREMENTS

It is important that only clean dry gas be used as a fuel for advanced-technology gas turbines. Particulate matter, such as rust, scale, and dirt, can usually be removed easily through filtration and separation techniques. The removal of liquids, such as water and liquid hydrocarbons, can be more difficult. Many factors that influence liquid removal, such as droplet size and distribution, are hard to quantify. This can result in liquid hydrocarbons being admitted into gas turbine fuel system and combustion equipment. Even extremely small amounts, if allowed to accumulate in downstream piping, can cause

damage. This fact, combined with the general degradation of gas quality in the U.S., makes it especially important to carefully monitor gas quality and to take corrective actions, if necessary, to meet GE fuel specification GEI 41040E in order to prevent equipment damage.

GE Gas Fuel Specification GEI 41040E

In summary, this document defines for limitations on particulate matter size to no more than approximately 10 microns, calls for the elimination of all liquids at the inlet to the gas turbine control module and specifies the minimum and maximum requirements for fuel supply pressure. Other limitations and qualifications may also apply and the user is encouraged to review the details in this document.

A superheat temperature of at least 50 F/28 C above the moisture or hydrocarbon dew point is required to eliminate liquids. Meeting this requirement may require heating the gas if heavy hydrocarbons are present. Reasons for specifying gas superheat are:

- Superheating is the only sure method for eliminating all liquids at the inlet to the gas control module
- It provides margin to prevent the formation of liquids as the gas expands and cools when passing through the control valves

Why 50 F/28 C minimum superheat?

- It is an ASME-recommended standard (Reference 3) that 45 F to 54F (25 to 30 C) of superheat be used for combustion turbine gaseous fuel.
- Calculations show the 50 F/28 C minimum superheat requirement will prevent liquid formation downstream from the control valves and is verified by field experience
- Some margin is provided to cover daily variations in dew point
- Vaporization time for liquid droplets decreases as superheat temperature increases

Gas Fuel Contaminants

Some of the contaminants that are introduced into the natural gas supply as a result of the production and transportation processes are:

- Water and salt water
- Sand and clay
- Rust
- Iron sulfate, iron and copper sulfide
- Lubricating oil, wet scrubber oil, crude oil and hydrocarbon liquids

- Glycols from dehydration processes
- Calcium carbonate
- Gas hydrates and ice
- Construction debris

Construction debris is common and includes materials such as weld slag, grinding particles, grit, portions of welding rod, metal shavings, etc. Despite gas line pigging and vigorous blow-downs, which are necessary and recommended, some contaminants will be found in the gas supply, especially during the early commissioning period. During this phase, extra precautions are taken by installing temporary “witch hat” fine mesh strainers at the inlet to the gas control module and selected sections of gas piping within the turbine enclosure.

Once satisfactory operation has been achieved and the temporary strainers no longer pick up debris and contaminants, they are removed. Installation of these strainers does not provide a substitute for a properly engineered gas clean-up system and frequent outages will be required to clean or replace the strainers if an adequate filtration system is not installed.

GAS CLEANLINESS AND QUALITY ISSUES

Gas fuel quality and cleanliness issues that affect the gas turbine operation are:

- Variation in heating value
- Autoignition or hydrocarbon liquids
- Particulates that lead to erosion and plugging

Variations in Heating Value

Variation in the heating value as a result of gas phase composition variation affect gas turbine emissions, output and combustor stability. Changes greater than 10% require gas control hardware modifications, but are not a common problem in a stabilized distribution systems.

Some local distribution companies use propane/air injection as a method for stabilizing variations in heating value. The quantity of air injected is well below that required to reach the rich flammability limit of the gas and poses no safety issues.

Variations in heating value could be an issue if gas is purchased from a variety of suppliers depending on the daily or weekly variations in gas price. In this situation, the user should ensure that the variations are within the values allowed by the contract agreement with GE. On-line instruments that determine and monitor heating value are available from several suppli-

ers and should be used if significant variations are expected.

Slugging of hydrocarbon liquids affects the energy delivered to the turbine and can result in significant control problems and potential hardware damage. For this and other reasons described below, all liquids must be eliminated from the gas supplied to the turbine.

Autoignition of Hydrocarbon Liquids

Removal of liquids has become more of a concern during the past several years as gas quality has decreased. Liquids are formed from the condensable higher hydrocarbons found in natural gas, generally those higher than about pentane (C_5), as well as moisture from water vapor. Moisture is undesirable because it can combine with methane and other hydrocarbons to generate solids in the form of hydrates. Hydrate formation and prevention is discussed in “Formation of Solids — Particulates and Hydrates.”

Hydrocarbon liquids are a much more serious issue because liquids can condense and collect over long periods of time, then result in liquid slugging as gas flow rates are increased after a period of reduced power operation. This can lead to:

- Uncontrolled heat addition
- Autoignition at compressor discharge temperature (625 F to 825 F/329 C to 451 C range)
- Potential for promoting flashback and secondary/quaternary re-ignitions
- Varnish-like deposits

Carry-over of liquids to the turbine can result in uncontrolled heat release rates if sufficient quantities are present, resulting in possible damage to the hot gas path. A more common problem, however, is with the exposure of small quantities of hydrocarbon liquids to compressor discharge air. Dry Low NO_x combustion systems require pre-mixing of gas fuel and compressor discharge air in order to produce a uniform fuel/air mixture and to minimize locally fuel-rich NO_x -producing regions in the combustor. Typical autoignition temperatures (AIT), the temperatures required for spontaneous combustion with no ignition source, for these liquids are in the 400 F to 550 F (204 C to 288 C) range and fall below compressor discharge temperature. Exposure to compressor discharge air above the AIT will result in instantaneous ignition of the liquid droplets, causing, in some

cases, premature ignition of the pre-mixed gases, often called “flashback.”

Because of the seriousness of the problem, GE specification 41040E does not allow any liquids in the gas fuel. Furthermore, to prevent condensation in the gas fuel manifolds, which is caused by gas expansion through the control valves, this specification requires a minimum of 50 F/28 C of superheat at the turbine speed ratio valve inlet flange. This value provides a degree of safety and is within the ASME recommended values for dry gas fuel (Reference 3).

Particulates in the Gas Stream

The gas turbine operating issues with particulates in the gas stream are fuel nozzle plugging, erosion and deposition.

Of the three, fuel nozzle plugging has a more severe and immediate impact on normal operation. Since the gas fuel nozzle hole sizes on DLN systems are smaller than those used in diffusion flame combustors, they are more prone to plugging. Plugging will result in poor fuel distribution from nozzle to nozzle and combustor to combustor and increase emissions and exhaust temperature spreads. Plugging could also lead to fuel flow split deviations between gas manifolds, which could lead to poor emissions and, in worst case, to autoignition and flashback.

Eliminating plugging is especially important during commissioning and early commercial operation, or after work has been performed on the pipeline, when accumulated dirt and construction debris can become entrained with the fuel.

If plugging occurs, the nozzles will need to be cleaned. Since the disassembly, cleaning and reassembly process can take several days, the availability of the unit can be adversely impacted.

Erosion problems can result if excessive quantities of particulates are present, depending on the nature and size of the material. The GEI 41040E fuel specification calls for removal of particulates greater in size than approximately 10 microns (see specification for added qualifications) to prevent erosion and deposition. Particles smaller than about 10 microns tend to follow the gas stream, rather than striking the pressure containment vessel walls and, therefore, result in a significant decrease in erosion rate.

The gas control valves are designed to operate in a choked flow condition and are, therefore, exposed to velocities up to the local speed of sound. Erosion rates are exponentially proportional to particle velocity and areas that experi-

ence high gas velocities, such as orifices and valve seats, are more susceptible to erosion.

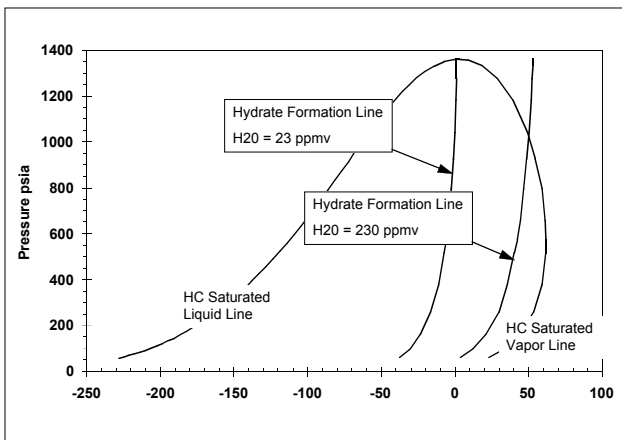
Nozzle and bucket deposition can also be a problem, depending on the nature and concentration of the particles, even for those of less than 10 microns in diameter. For this reason, GEI 41040E limits the concentration of particulates from all sources and sizes to no more than 600 ppb at the first stage nozzle inlet.

Formation and Carry-Over of Solids: Particulates and Hydrates

Most solids found in natural gas are due to the slow oxidation and corrosion of the pipeline and are in the form of fine iron oxide particles. Construction debris such as weld slag, metal shavings, sand and even foreign objects are also commonly found in new pipelines, especially during the initial commissioning phase.

Another type of solid material that may be present is gas hydrates. Gas hydrates are crystalline materials that are formed when excess water is present in a high-pressure gas line. These solids are formed when water combines with natural gas compounds, including condensates, when the gas temperature is below the equilibrium hydrate formation temperature. Although commonly associated with ice-type crystals, formation temperatures can be significantly above 32 F/0 C at pipeline delivery pressures. Hydrates can deposit in stagnant areas upstream and downstream from orifice plates, valves, tee sections and instrumentation lines, causing plugging and lack of process control.

Figure 1 shows hydrate formation lines for two water concentrations for the natural gas listed in Table 3. Location of these lines will vary with gas composition and fall above or below the saturated hydrocarbon vapor line.



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Figure 1. Equilibrium temperature lines for hydrate formation

Hydrate formation is more likely to be found in offshore pipeline systems because of the high pressures and cooler temperatures. Fortunately, all transportation companies recognize the need to remove water to prevent hydrate formation and resulting pipeline equipment blockage problems. Water is typically limited to a nominal value of between 4 and 7 lbs per million standard cu ft. (64.1 to 112.1 kg/mmscm). It is removed to this level by treatment equipment that use chemical scrubbing with methanol or ethylene glycol; some carry-over of the scrubbing liquid may occur. Occasionally, a process upset may occur and spillover of inhibitors into the gas supply can present a hazard by raising the hydrocarbon dew point.

Other preventative methods include gas heating upstream from pressure-reducing stations to maintain the gas temperature above the hydrate formation temperature.

Formation and Carry-Over of Liquids: Hydrocarbons and Moisture

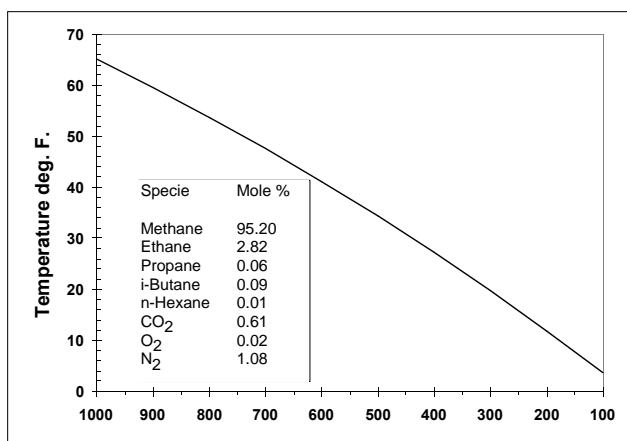
As the gas fuel is brought to the gas turbine, it often passes through a series of pressure-reducing stations before it enters the gas control module. Further pressure reductions then take place before the gas enters the gas manifold system. At each pressure-reducing station, the gas will also experience a temperature reduction due to the Joule-Thompson effect.

Temperature reductions for a typical natural gas are shown in Figure 2, which are approximately equal to 7 F for every 100 psid (5.6 C per 1,000 kPa) reduction in pressure, with no heat transfer to or from the gas. Actual temperature reduction will vary depending on the gas composition and local heat transfer conditions.

A system with gas entering the site at 900 psia/6,205.3 kPa and 60 F/16 C can experience a temperature reduction of 31 F/17.2 C prior to entering the gas module at the maximum allowable pressure of 450 psia/3,102.6 kPa for FA-technology machines. Further temperature reductions will be experienced as the gas passes through the control valves and will be the greatest at low load when control valve throttling is at the highest level.

Reports of frost appearing on the outside of the gas piping downstream from the control valves is not uncommon and is not a cause for alarm, provided the hydrocarbon and moisture dew points are significantly less than the local gas temperature.

GEI 41040E calls for a minimum of 50 F/28 C



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Figure 2. Joule-Thompson cooling with pressure reduction

of superheat above the hydrocarbon dew point at the entry to the gas module at all operating conditions. Unfortunately, as liquid carry-over becomes more common, the hydrocarbon dew point increases and condensation has become a serious issue. Separation of the free liquids alone is not adequate, as this results in, at best, a saturated gas with a dew point equal to the gas temperature.

Further reductions in temperature downstream from the separation equipment will, therefore, result in immediate condensation and formation of additional liquids. For incoming wet gas, a filter separator and a superheater are essential to prevent the formation of liquids. Equipment required for this purpose is discussed in "Recommendations for Clean-Up Equipment and Sizing."

NATURAL GAS COMPOSITION VARIATIONS AND IMPACT ON GAS TURBINE OPERATION

Pipeline natural gas is not a homogeneous

Country	HHV	HHV	C ₆₊	C ₆₊
	Btu/SCFT Maximum	Btu/SCFT Minimum	Vol. % Maximum	Vol. % Minimum
U.S.	1,208	970	0.5	0.0
Canada	1,106	965	0.4	0.0

entity, nor is it constant with time or geographic location. As noted in Reference 4, there is significant variation in composition and physical properties of the natural gas supplied to various areas of the U.S. This report, prepared by the American Gas Association, quantifies potential regional and seasonal variations in the composition and properties of natural gas, documents the peak shaving practices in the U.S. and assesses the contribution of the gas composition variability on the formation of condensates.

While the variation in the composition of the gas has a small impact on the gas turbine operation (e.g., emissions), the principal point of concern is the formation of condensates as the composition of hexanes+ varies. For example, Table 1 of Reference 2 summarizes the maximum and minimum values of higher or gross heating value (HHV) and C₆₊ variations found in natural gas in the U.S. and Canada.

Depending on the hexanes+ species, this constituent of the natural gas could lead to liquid hydrocarbon condensation in the gas stream supplied to the gas turbine resulting in serious damage to the unit. The results of the survey of U.S. natural gas do not show a strong relationship between an increase in heating value and an increase in concentration of C₆₊ compounds. Location does not appear to be a factor, either; samples from Texas pipelines show both the highest and lowest values for C₆₊ compounds.

INDUSTRY EXPERIENCE WITH GAS FUEL LIQUIDS

In recent years, industry experience with liquids in natural gas has been poor. Reports of incidents resulting from carry-over of liquids are frequent and affect gas turbine from all manufacturers equipped with various types of combustion systems.

These reports clearly show that this problem is quite widespread in the eastern half of the U.S. The absence of data from other sites, however, should not imply that the western U.S. is exempt from these problems. Table 2 lists the reported concentration for hexanes+, an indicator of potential liquids, is distributed throughout the U.S. Since the potential consequential damage to the hot gas path from these liquid hydrocarbons is quite severe on dry low emission units, the gas handling system must be designed to eliminate this threat under all conditions.

Table 2
REPORTED HEATING VALUES AND C₆+ HYDROCARBONS THROUGHOUT THE U.S.

	Higher Heating Value, Btu/scft			Hexanes plus Hydrocarbons (C ₆ +)		
	Mean	Min	Max	Mean	Min	Max
California #1 - A	1,042.2	1,031.1	1,053.9	0.0	0.0	0.1
California #1 - B	1,029.7	1,022.1	1,060.3	0.1	0.0	0.1
California #1 - C	1,039.6	1,032.9	1,049.1	0.1	0.0	0.1
California #1 - D	1,029.4	1,023.6	1,038.2	0.1	0.1	0.1
California #1 - E	1,048.4	1,040.1	1,055.8	0.1	0.1	0.2
California #2 - A	1,039.0	1,024.9	1,050.8	0.1	0.1	0.1
California #2 - B	1,028.4	1,020.2	1,038.2	0.1	0.0	0.1
California #3	1,033.2	1,028.5	1,043.0	0.0	0.0	0.0
California #4	1,017.9	1,005.0	1,038.0	0.0	0.0	0.2
California #5	995.3	986.0	1,011.0	0.1	0.0	0.1
Colorado #1	991.9	971.0	1,035.6	0.0	0.0	0.1
Colorado #2	980.2	970.3	1,006.5	0.0	0.0	0.1
Colorado #3	984.4	974.3	1,012.5	0.0	0.0	0.1
Connecticut	1,027.2	1,022.8	1,033.4	0.1	0.1	0.1
Georgia	1,026.9	1,015.0	1,047.0	0.1	0.0	0.2
Illinois #1	1,028.2	1,017.6	1,081.4	0.1	0.0	0.2
Illinois #2	1,031.3	1,015.2	1,043.6	0.1	0.0	0.2
Louisiana	1,023.1	997.7	1,053.1	0.1	0.0	0.2
Maryland #1	1,033.2	1,027.0	1,046.7	0.1	0.0	0.2
Maryland #2	1,102.3	1,032.1	1,208.1	0.1	0.0	0.1
Maryland #3	1,032.2	1,026.9	1,041.6	0.1	0.0	0.1
Maryland #4	1,030.7	1,025.4	1,039.0	0.1	0.0	0.1
Maryland #5	1,037.2	1,030.3	1,055.6	0.1	0.1	0.1
Maryland #6	1,041.0	1,033.4	1,062.0	0.1	0.1	0.1
Massachusetts #1	1,060.9	1,017.1	1,190.5	0.0	0.0	0.1
Massachusetts #2	1,034.6	1,032.4	1,036.4	0.1	0.1	0.1
Michigan	1,031.4	1,010.5	1,043.7	0.0	0.0	0.1
New Jersey	1,030.4	1,021.0	1,048.0	0.0	0.0	0.2
New York	1,029.6	1,017.5	1,039.4	0.0	0.0	0.0
Ohio	1,044.9	1,010.3	1,096.2	0.1	0.1	0.2
Oklahoma	1,029.6	1,005.5	1,085.9	0.0	0.0	0.2
Pennsylvania #1 - 1	1,029.8	1,023.0	1,041.0	0.1	0.0	0.2
Pennsylvania #1 - 2	1,029.1	1,022.0	1,038.0	0.1	0.0	0.1
Pennsylvania #2 - 1	1,030.0	1,022.2	1,038.4	0.1	0.0	0.2
Pennsylvania #2 - 2	1,029.8	1,023.1	1,048.7	0.1	0.0	0.2
Rhode Island	1,029.6	1,027.0	1,033.9	0.1	0.1	0.1
Texas #1	1,081.2	1,043.6	1,126.8	0.2	0.1	0.5
Texas #2	1,023.8	1,017.0	1,036.0	0.0	0.0	0.0
Texas #3	1,059.3	1,020.0	1,105.0	0.2	0.1	0.4
Virginia #1	1,044.4	1,032.6	1,088.5	0.1	0.1	0.1
Virginia #2	1,039.7	1,029.8	1,088.5	0.1	0.1	0.1
Washington	1,038.5	1,013.0	1,056.0	0.0	0.0	0.0
Wisconsin	1,005.9	980.7	1,043.7	0.0	0.0	0.1

HYDROCARBON AND MOISTURE DEW POINT DETERMINATION

Two approaches can be used to determine the hydrocarbon and moisture dew points: a calculation method using a representative gas sample and extended analysis to C₁₄, and a direct measurement using a dew point instrument.

The calculation method has been used with some success, but requires careful attention to the details required to obtain a representative

gas sample and requires analysis to C₁₄ at the ppmv level. Recent experience has shown the direct measurement of dew point to be a simple, practical and now preferred approach to dew point determination.

If the gas entering the facility is known to be wet, i.e., contains liquids at the operating pressure, then there is no need to sample or monitor the gas quality. Installation of adequate liquids removal equipment, as described in "Liquids Removal System," will remove practically 100% of all liquids present. At the discharge of the separator, however, the resulting gas will

be in a saturated condition. That is, the gas temperature will equal the dew point temperature and superheating by a minimum of 50 F/28 C is required in order to meet the GEI 41040E fuel specification.

If the incoming gas is in a dry condition, i.e., the gas temperature is at an undetermined level of superheat, then gas sampling or dew point monitoring is necessary in order to determine the gas quality.

Gas Sampling

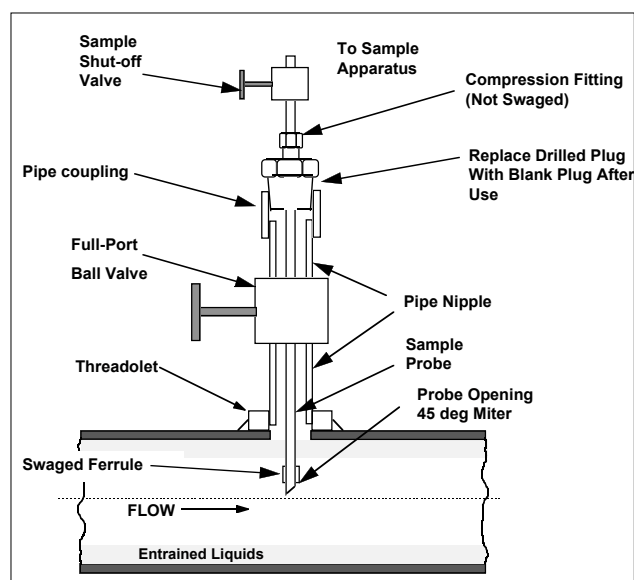
Three types of samples are commonly used for gas analysis. A continuous sample is drawn constantly from the pipeline into a gas chromatograph to monitor btu content. A composite sample consists of many smaller samples, each withdrawn at a specified time interval, to obtain an average value over a period of several days or weeks. The third type of sample is known as the spot sample. This is the sample most often used to determine hydrocarbon dew point. It is withdrawn from the pipeline by an operator using a sample flask.

Obtaining a spot gas-phase sample from dry gas that is both representative and repeatable is essential for dew point calculation and is the result of using proper sampling techniques. Sampling procedures can be found in GPA 2166-95 (Reference 5).

Others have devised their own sampling procedures, e.g., Welker (Reference 6), that are variations of those found in GPA 2166-95. The procedure selected will depend primarily on the nature (wetness) and temperature of the gas. As mentioned above, however, if the gas is wet, there is no need to sample for dew point determination. A gas analysis will be required if the gas fuel delivery system is to be fully analyzed.

Obtaining a representative gas sample to the degree of accuracy required for calculation of the hydrocarbon dew point is difficult, and special precautions must be taken to avoid generation of liquids during the sampling process. For best results, the sample should be taken at or close to the gas line operating temperature and pressure to avoid cooling as a result of expansion.

A sampling probe should always be used to extract the sample from the gas line. The sampling probe is a short piece of tubing that extends into the middle one-third of the gas stream. The sampling probe helps to minimize contamination of the sample with liquids and particulates that may be present on the walls. If the gas is wet and the sample consists only of the



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Figure 3. Gas sampling probe

gas phase, then the calculated dew point will equal the gas flowing temperature. Note that if the calculations result in a dew point temperature above the gas flowing temperature, then the sample must have been contaminated with liquids and either the gas is wet or liquids were generated during the sampling process.

A diagram of a sampling probe is shown in Figure 3. Note that the opening of the probe faces downstream. This assists in the elimination of entrained liquids from the sample.

Temporary sampling probes can be installed and removed from a pressurized line by use of a packing gland seal and isolated from the line using a high-quality ball valve. When the probe and packing gland are removed, a pipe plug is installed to provide a second seal in case the ball valve leaks. Figure 3 shows this arrangement and incorporates an adjustable probe insertion depth feature that allows the probe to be installed and removed without de-pressurizing the pipeline. A pipe fitting is welded to the gas line, which is attached to a pipe nipple, the ball valve, a second pipe nipple and pipe plug or pipe plug with a packing gland. Care must be taken when removing the probe from a pressurized line to avoid loss of the probe and possible operator injury. Commercial probes have expanded sample tips or mechanical stops that prevent full extraction of the probe from the packing gland.

Gas Analysis

A gas chromatograph is used in the laborato-

ry or the field to analyze the gas sample and determine the gas composition. The analysis will check for the presence of both hydrocarbons and non-hydrocarbons. Once the gas' composition is determined, the hydrocarbon and moisture dew point can be calculated using one of several available software packages.

Standard Gas Analysis to C₆+

A common method for heating value determination is to use the standard analysis. The standard analysis is performed in accordance with ASTM D1945 (Reference 7) or GPA 2261-95 (Reference 8) and lumps together all hydrocarbons above C₆ and reports them as "C₆+" The results of the standard analysis should not be used for dew point determination unless assurance can be given that no hydrocarbons above C₆ are present (i.e., C₆ may be present, but no C₆+).

Small quantities of heavy hydrocarbons above C₆ raise the dew point significantly. Using a standard analysis can result in an artificially low dew point determination (see example below). Instead, an extended analysis should be used except where no C₆+ compounds are present.

Extended Gas Analysis to C₁₄

This type of analysis checks for the presence of the heavy hydrocarbons and quantifies their amounts to the level of C₁₄. The extended analysis is more complicated and expensive than the standard analysis, and not all laboratories can provide this service. It is, however, the only type of analysis that will result in an accurate dew point determination. An analysis procedure for C₁ through C₁₄ is described in GPA 2286-95 (Reference 9).

When choosing a lab to perform the gas analysis, one should always seek a facility that specializes in petroleum product testing and analysis. They are familiar with the unique aspects of natural gas analysis and sampling; many offer services and advice that cannot be obtained elsewhere.

Analysis to the single-digit ppmw level should be requested, but nothing less than two digits (tens of ppmw) should be accepted. It is important to confirm that the reported laboratory values are obtained by measurement and not through a simple mathematical normalization procedure to six decimal places. It should be clear that when dealing with concentrations at this level, absolute cleanliness is essential and samples can be easily contaminated in the field.

Samples must also be taken at the actual pipeline pressure and temperature to avoid gas expansion and possible liquid condensation.

Comparison of Standard and Extended Analysis

Consider the gas analysis shown in Table 3, which was taken from an operating power plant gas supply. In this case, an extended analysis was performed and the standard analysis mathematically generated by summing the C₆+ constituents. The calculated dew point from the extended analysis is more than 23 F/12.8 C above that calculated from the standard analysis.

In extreme cases, differences of as much as 100 F/56 C have been observed. The results shown in Table 3 also illustrate the need for representative gas sampling and accurate analysis due to the sensitivity of the dew point calculation to small concentrations of the heavier hydrocarbons. Where possible, the gas analysis should be determined to within less than 10 ppmv.

Use of the standard analysis for dew point calculation could lead to falsely concluding that the gas has an acceptable degree of superheat, or the superheater could be undersized based on these results. An exception to this generalization may be made when the gas is exceptionally dry and where no hydrocarbons above C₆ are detected. In this situation, a standard analysis is acceptable for dew point calculation. Typical hydrocarbon dew point values for this gas would be in the -30 F to -70 F (-34 C to -57 C) range. Care must be taken when selecting an analytical service, however, to ensure that the laboratory has the capability to analyze beyond C₆.

Further information on trace constituents that may be present in natural gas can be found in Gas Research Institute report GRI-94/0243.2 (Reference 10).

Dew Point Measurement

A method for measuring natural gas hydrocarbon and moisture dew points has been available for almost 60 years. The U.S. Bureau of Mines developed a dew point tester in 1938 (Reference 11) that works on the principle of a chilled mirror. The mirror is contained within a pressure vessel and is exposed to the gas stream at pipeline pressure. The mirror is gradually cooled until condensation droplets begin to appear on the surface of the mirror. Two separate dew points, moisture and hydrocarbon, are measured depending on the nature of the droplets on the mirrored surface. This type of

Table 3
COMPARISON OF STANDARD AND EXTENDED
GAS ANALYSES ON CALCULATED HC DEW POINT

Specie	Name	Standard Analysis to C ₆₊ Weight %	Extended Analysis to C ₁₄ Weight %
N ₂	Nitrogen	2.6206	2.6206
CO ₂	Carbon Dioxide	21.0489	21.0489
H ₂ O	Water Vapor	0.0023	0.0023
CH ₄	Methane	53.4414	53.4414
C ₂ H ₆	Ethane	9.4684	9.4684
C ₃ H ₈	Propane	7.5156	7.5156
C ₄ H ₁₀	i-Butane	1.8906	1.8906
C ₄ H ₁₀	n-Butane	0.7127	0.7127
C ₅ H ₁₂	n-Pentane	0.4612	0.4612
C ₆ H ₁₄	n-Hexane	0.8252	0.3840
C ₇ H ₁₆	n-Heptane	—	0.3169
C ₈ H ₁₈	n-Octane	—	0.1132
C ₉ H ₂₀	n-Nonane	—	0.0102
C ₁₀ H ₂₂	n-Decane	—	0.0006
C ₁₁ H ₂₄	u-Undane	—	0.0001
C ₁₂ H ₂₆	Dodecane	—	0.0000
C ₁₃ H ₂₈	n-Tridecane	—	0.0002
C ₁₄ H ₃₀	n-Tetradecane	—	0.0000
Totals		100.0000	100.0000
HC Dew Point @ 465 psia		37.6	60.9

measurement provides a direct reading of dew point without the need to apply corrections. Pressure within the chamber can be varied to determine the effect on dew point.

Bureau of Mines Dew Point Detector

The simple instrument developed by the Bureau of Mines has been commercialized by at least one manufacturer in the U.S. The principle of operation is described above. This type of instrument is portable and intended for spot sampling, requiring an operator with some skill and experience to achieve repeatable results. GE has experience with this instrument and can provide a limited amount of information and advice on its use.

This method of determining dew point has become the preferred approach because it is a direct measurement requiring no calibration or calculation and interpolation of physical properties data of complex hydrocarbon compounds. For gas system modeling, however, gas samples and subsequent analysis are still required in order to determine temperature reductions

from expansion and the risk of liquid condensation. Dew point measurements complement the gas samples and help with model calibration.

The advantages of the Bureau of Mines dew point tester are:

- Elimination of the uncertainty associated with sampling and analysis as the primary means of dew point determination
- Simple and easy to use
- Claimed accuracy is +/-0.2 F (+/-0.1 C) for an experienced user
- Identifies moisture, hydrocarbon, glycol and alcohol dew points
- No electrical power required — intrinsically safe

Automatic Dew Point Monitor

An on-line device to automatically determine hydrocarbon dew point has many advantages over the difficulties involved with gas sampling and extended analyses. As of August 1996, however, only one commercial manufacturer has been identified that makes this type of equipment. The advantages of automatically monitoring hydrocarbon dew point include:

- Elimination of the uncertainty associated with sampling and analysis as the primary means of dew point determination
- Potential for automatically adjusting gas temperature with changes in hydrocarbon dew point as a result of both transient and long term gas composition changes
- Elimination of unnecessary heat addition and possible decrease in overall plant efficiency
- An alarm to alert plant operators that potential damage may result if corrective action is not taken, e.g. increase superheat temperature

GE is in the process of evaluating a monitor of this type and expects to field test a unit during late 1996 and early 1997.

Gas Liquids Detector

An alternative liquids detection device has been used by Gasunie, a pipeline transportation company in the Netherlands. This device extracts a small gas sample that is cooled to the maximum allowable dew point for incoming gas. If liquids are condensed, then the gas supplier is shut off until corrective action is taken. A commercial supplier in Europe sells a device that works on this principle.

RECOMMENDATIONS FOR CLEAN-UP EQUIPMENT AND SIZING

When specifying gas clean-up equipment, it is important that consideration be given not only to equipment size and removal capabilities, but also to the overall solids and liquids removal process. If liquid separation equipment is required, including a coalescing filter, then solids removal is automatically taken care of.

If the gas is known to be dry, meets the 50 F/28 C minimum superheat requirement and no liquids removal equipment is installed (e.g., some LNG meet this requirement), then a particulate removal filtration system will be required.

Particulate Removal System

The recommended particulate removal equipment is a filter system that is designed with an absolute removal rating of 3 microns or less. The equipment is normally available in a vertical configuration and consists of a series of parallel filter elements attached to a tube sheet. The elements are changed once a predetermined pres-

sure drop is reached for a given volumetric flow rate of gas.

For peaking units, it is acceptable to install one filter vessel, but for base loaded units, two units located in a duplexed arrangement are required. The duplexed arrangement permits isolation of one vessel for maintenance while the other is in operation. Under no circumstances should a bypass line be installed with the intention of using the bypass line for maintenance purposes.

Sizing of the equipment can be determined based on discussions with the vendor. In general, the only considerations for sizing are dirt holding capacity and allowable pressure drop, which determine the size of the vessel and the number of elements. If the gas is to be heated prior to filtration, then the filter elements must meet the maximum gas temperature requirements.

Special considerations must be given to starting up a new installation or after work has been conducted on the gas supply line. Under these circumstances, construction debris will most likely be present and will be carried along with the gas as the flow rate increases. Fine mesh strainers are installed in the gas line as last chance filters immediately upstream from the control valves and the gas manifolds to protect the fuel nozzles from plugging. The strainers at the inlet to the gas manifolds are temporary and will be removed prior to commercial operation. Forty micron strainers will prevent short-term nozzle plugging but do not fully protect against long-term erosion problems. For this reason, installation of last-chance strainers should not be considered a substitute for a properly design simplex or duplex particulate filter or filter/separator.

The strainer in the inlet supply pipe is permanently installed (removable for cleaning purposes) and protects the fuel nozzles and acts as a flag to indicate non-compliance with GEI 41040E. A well-designed filtration system will prevent particulate build-up on the strainer once the initial dirt and other contaminants have been removed from the system.

Liquids Removal System

The recommended clean-up system will include the following equipment in the following order:

- Pressure-reducing station
- Dry scrubber
- Filter/separator
- Superheater

In special circumstances, an additional heater may be required upstream from the pressure reducing station if the incoming gas pressure is unusually high, above approximately 1,000 psia/6,895 kPa, or if the gas has a high moisture content. In this situation the expansion and cooling downstream from the pressure-reducing valve may require upstream heating to avoid the formation of hydrates and slugging of condensed hydrocarbons that would otherwise remain in the gas phase throughout the liquids removal process. This heater, most likely, will not provide sufficient energy to meet the 50 F/28 C minimum superheat requirement at the gas control module inlet, while at the same time, may prevent collection of free liquids for the reasons stated above.

Heaters are commonly found upstream from scrubbers and filter/separators. While this may be acceptable for some applications, this arrangement is not recommended for gas turbine applications. Heating the fuel upstream from a separator will raise the gas temperature, possibly above the dew point, and little or no liquids will be removed. A lack of liquids in the separator drain tank is no guarantee that the fuel will meet GEI 41040E requirements. Further heating may be required in order to meet the 50 F/28 C minimum superheat requirement.

Processing Equipment

To ensure the correct equipment is specified for a given gas fuel, the following should be investigated before supplying and installing any gas processing equipment to a particular site.

- For an existing power plant, an accurate gas sampling and analysis from the site taken upstream and prior to any fuel gas treatment equipment, and also at the combustion gas turbine fuel gas manifold.
- For new construction, the sample should be taken from a flowing gas stream in the pipeline as near as possible to the proposed site
- Site reviews of in-line gas treatment equipment by manufacturers' technical representatives
- Fuel gas treatment equipment flow design review by the responsible engineer

DESIGN STEPS FOR SIZING AND LOCATION

Fuel gas conditioning requires the removal of

both liquid and solid contaminants from the gas stream. There are several ways to accomplish this, the most common being the use of centrifugal separators, slug and mist eliminators followed by gas filters and combination liquid/solid separators.

The first item that is required for selecting the correct equipment is a detailed analysis of the available gas. This should include a gas sample analysis from various sources, such as after pressure reduction or compressor station, or another source that will be representative of the gas just upstream from the combustion gas turbine.

The second stage in the selection process is equipment sizing. Since the efficiency of the equipment in item 1 above will fall with a reduction throughout, it is recommended that the design point of inertial separation equipment be selected at 5% to 10% below the maximum expected flow rate. Most inertial separators will maintain high efficiency up to 10% above the design flow rate; check with the supplier for details.

Equipment should be located as close as possible to the combustion gas turbine. This is especially true of the superheater since liquids can condense in the line downstream from the heater after the unit has shut down — the shorter the line, the lower the volume of condensates.

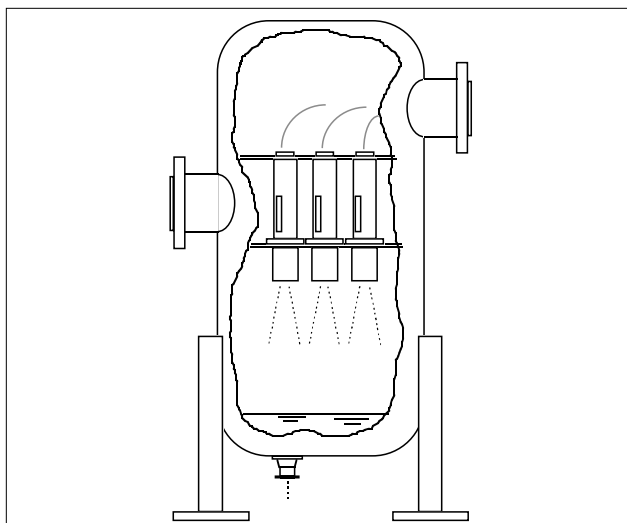
Processing Equipment Description

A brief description and simplified sketches of the various types of clean-up equipment follows.

Dry Scrubbers

Dry scrubbers are multiple-cyclone (multi-clones) inertial separators that remove both liquids and solid materials without the use of scrubbing oils or liquids. A typical cross-section is shown in Figure 4. They are virtually maintenance-free except for blowdown of the drain tank. A multi-clone scrubber will operate with a high separation efficiency greater than about a 4:1 turndown in volumetric flow rate. Only one gas turbine should, therefore, be placed downstream of each dry scrubber. A dry scrubber is not generally recommended for slugging conditions; however, a modified dry scrubber design to handle slugs can be made available.

Dry scrubbers should be combined with coalescing filters in order to provide protection over the entire operating range of the gas turbine. Both vertical and horizontal configurations are available. Typically, vertical units are



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Figure 4. A vertical multi-clone dry scrubber

used for the relatively small volumetric flow rates for a single gas turbine; the horizontal units are used to treat larger volumetric flow rates experienced in gas pipelines.

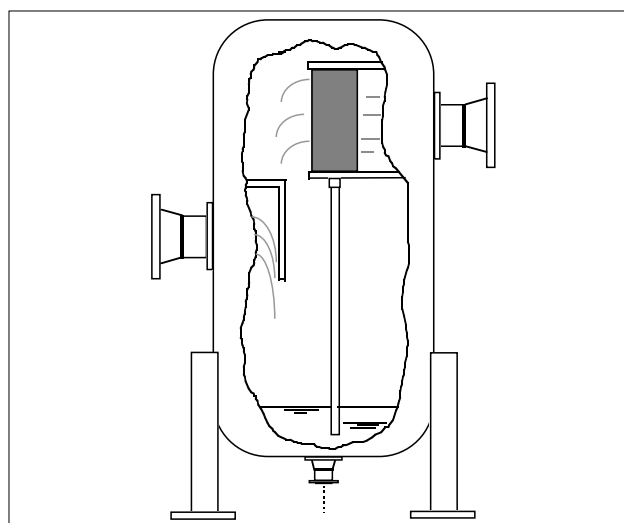
In some cases, a dry scrubber may be installed to protect a pressure-reducing station serving multiple gas turbines. In this situation, some liquid carry-over can be expected when the gas demand is low because of low load or out of service operation that extends the turndown beyond the manufacturers recommendations.

Gas Separator

A gas separator operates on a similar inertial separation principle as the multi-clone dry scrubber. Figure 5 shows a sectional view of a typical gas separator of this type. Wet gas passes through an inlet baffle to remove liquid slugs and then through a series of angled vanes that impart inertial forces on the remaining liquid droplets. The droplets strike the vanes and are removed from the flow stream by gravity. Vane separators are available in either vertical or horizontal configurations and are recommended for applications where slugging can occur.

Coalescing Filter

Coalescing filters are normally used in conjunction with a dry scrubber where removal of practically all liquid droplets is required. Typically, coalescing filters will remove all droplets and solids larger than about 0.3 microns. The filter unit consists of a vertical pressure vessel that contains a number of parallel tubular filter cartridges. Depending on the supplier, inlet gas flow can be either from the



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Figure 5. Vertical gas separator (inertial vane-type)

inside of the tube or from the outside of the tube. A baffle at the inlet to the filter housing will deflect liquid slugs and larger particulates to the sump. The wet gas containing fine droplets flows through the filter where the droplets collide with the fibrous filter material. The droplets coalesce with others and form larger droplets that are then removed from the filter element by gravity and collected in the sump.

A sectional view of a coalescing filter is shown in Figure 6. The gas enters the inside of the filter elements and flows outward. Very small liquid droplets are coalesced into larger droplets as they travel through the filter elements. These large droplets then fall away from the outer surface of the elements and are collected in the bottom of the vessel. A properly sized filter will prevent the re-entrainment of liquid droplets into the gas stream, but the efficiency of this device will drop off dramatically if operated beyond its design flow rate.

Coalescing filters should always be preceded by a stage 1 liquid and solid removal device to prevent the entry of gross amounts of contamination. Filter elements require periodic replacement; duplexing may be desirable. Installation of coalescing filters should be seriously considered where gas compressors are located; these are the only devices capable of removing the fine oil mists that are sometimes introduced into the gas stream from the compressor.

Combination Separators

The filter separator combines changeable filter elements along with vane mist eliminator in a single vessel, as illustrated in Figure 7. The gas first passes through the filter elements, enabling

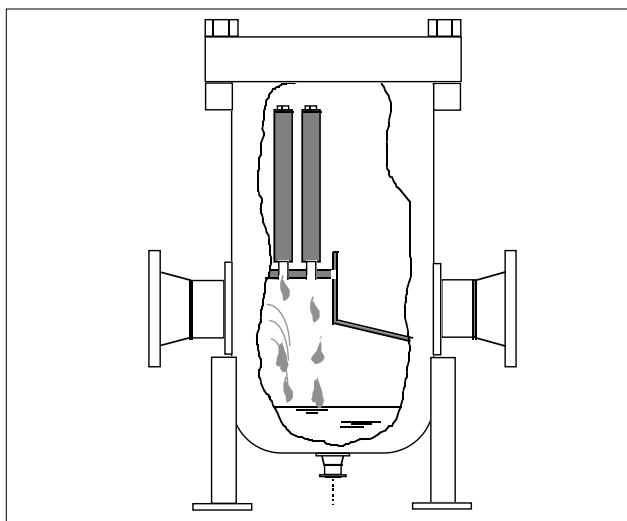


Figure 6. Coalescing filter

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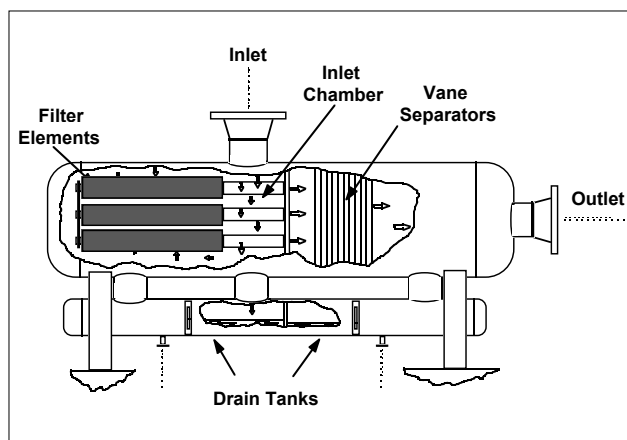


Figure 7. Combined filter-separator

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smaller liquid particles to be coalesced while the solids are removed. Because of the coalescing effect, the vane is able to remove more free liquid particles than either the dry scrubber or the vertical gas separator alone. This combines the efficiency of the vane separator with that of the coalescing filter in one vessel.

As with the coalescing filter described above, the filter separator maintains its guaranteed separation efficiency from 0% to 100% of its design flow capacity. Filter separators are often used in lieu of filters when high liquid rates are expected. The filter separator also removes solids from the gas stream, but must be taken off-line periodically in order to replace the dirty filter elements. For this reason, base-loaded units require a duplex arrangement that permits maintenance to be performed on one unit while the other is in service.

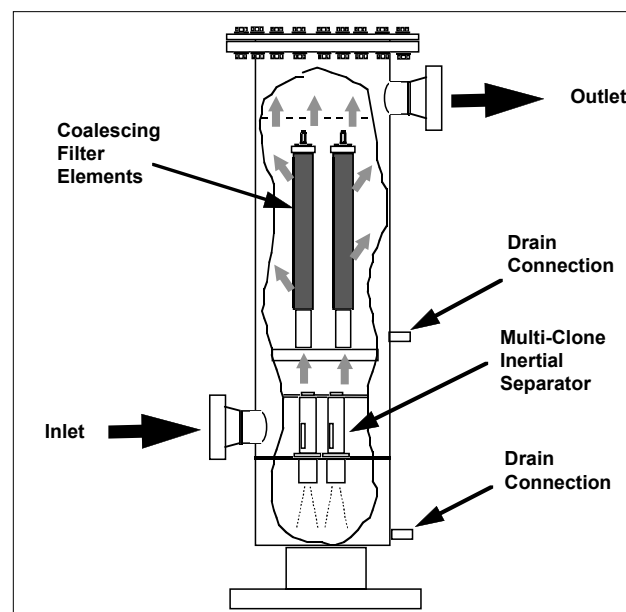


Figure 8. Absolute separator

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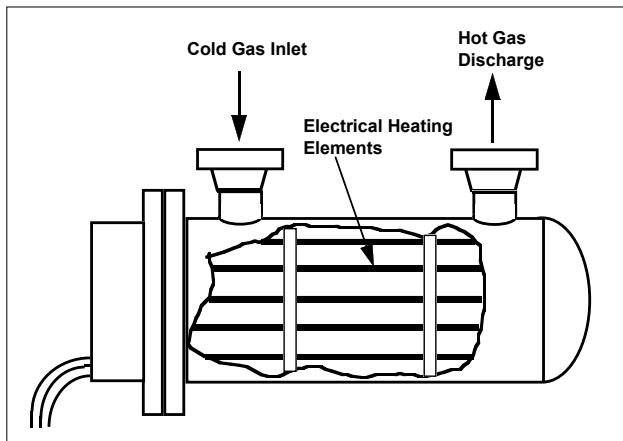
Absolute Separator

The absolute separator shown in Figure 8 is a two-stage device similar to the filter/separator, except the unit is configured in a vertical arrangement and the method of separation is reversed. Here, multi-cyclones or vanes are used to inertially separate the larger droplets in the first stage.

The partially cleaned gas passes on to stage 2, which consists of coalescing filters. Flow through the filters is from the inside out. The coalesced droplets form on the outside of the filter and are then drained by gravity to a collection tank. There are several advantages to this type of liquid removal device, including a higher removal efficiency in the droplet diameter range of 0.01 microns to 4 microns. Inertial removal of solids and liquids in the primary separator section also unloads the filter elements in the second section, allowing fewer to be used and reducing the overall vessel diameter.

Fuel Heating

Fuel heating to raise the temperature of the gas to 50 F/28 C above the hydrocarbon dew point may be required per the GEI 41040E fuel specification. Three basic types of heater are available; each has economic, maintenance and operating advantages and disadvantages.



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Figure 9. Electrical gas heater

Electrical Heaters

Electrical heaters are the most convenient type of fuel heater to use and install. Figure 9 shows a sectional view of an electrical heater. A simple control system can maintain a constant exit temperature or a constant temperature rise within the capacity limits of the equipment as fuel flow rate varies. Thermal efficiency is close to 100% in that all of the electricity used is converted into heat and is used to raise the gas temperature, neglecting losses to the ambient surroundings. The electricity used to power the equipment, however, is being produced at 30% to 40% efficiency for simple-cycle machines; the overall energy efficiency is approximately one-half, or less than that of gas- or oil-fired heaters.

The capital cost is the lowest of the three types, but the operating expense is, therefore, the highest, while maintenance cost are relatively low. The electrical heater is simple in construction, compact and requires a smaller founda-

tion. Heating elements can be easily replaced and no intermediate heat transfer fluid is required, a concern in freezing climates, which reduces maintenance costs.

Gas- or Oil-Fired Heaters

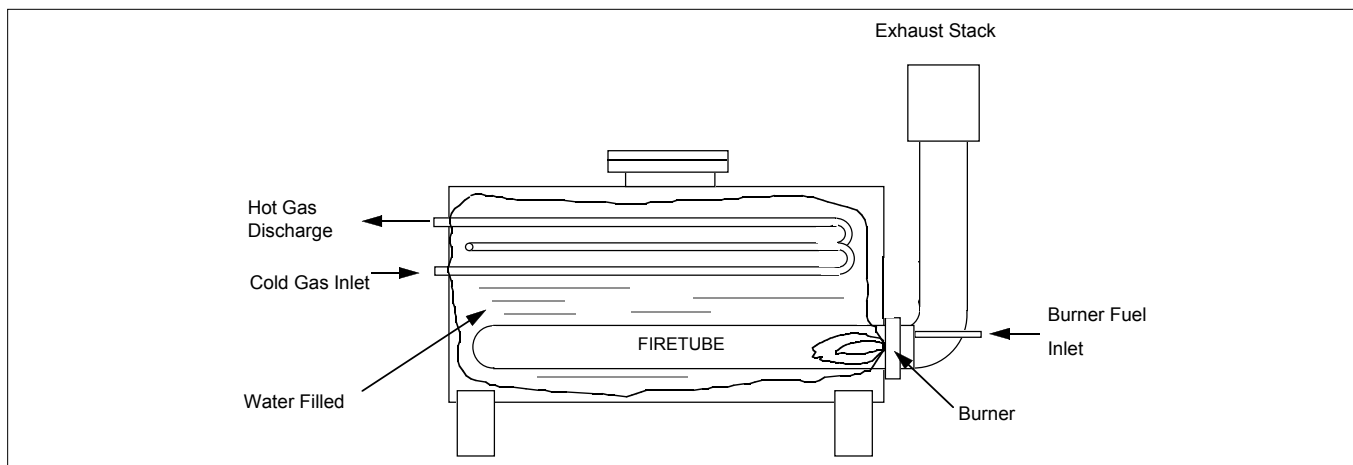
Heaters of this type are readily available and already in use throughout the world. Figure 10 shows a sectional view of this type of heater. An intermediate heat transfer fluid is generally used for safety purposes.

In cold climates, a mixture of ethylene glycol and water or equivalent prevents freezing, elevates the boiling temperature of the water and reduces the heat exchanger surface area. The thermal efficiency of these units is reasonably high; about 80% of the heat generated is transferred to the gas and the remainder is discharged in the flue gas. Heat added to the gas fuel, however, reduces the quantity of fuel required by the gas turbine and offsets the fuel required by the heater to some extent.

Larger foundations are required for this type of heater, and several burners may be required in order to provide improved thermal response and turndown capabilities. Operating costs are significantly lower than an electrical heater, but maintenance and capital costs are higher. Difficulty in tracking rapid fuel demand changes of the gas turbine may be an issue for peaking units or during startup.

Waste-Heat-Fired Fuel Heaters

This an option for combined-cycle units where low-grade heat (hot water) may be readily available. The advantage of this type of heater is that no fuel penalty is incurred and the overall thermal efficiency of the power plant may be increased. Disadvantages are higher capital cost,



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Figure 10. Indirect-fired gas heater

increased maintenance and installation costs for larger foundations.

This type of a system is more suited for base-loaded units because of lack of heating during startup. Construction is of the tube and shell type and is heavier than the indirect-fired heater to accommodate the 400+ psia/2758+ kPa pressurized water supply. A typical shell and tube heater is shown in Figure 11.

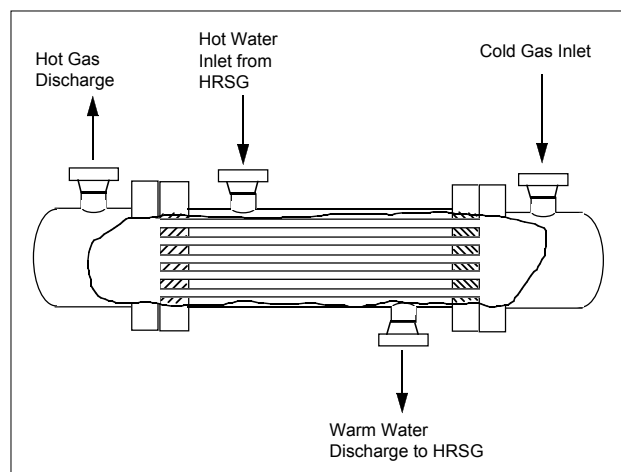
Dual-Source Heaters

These gas fuel heaters are similar to the waste-heat-fired heater but can also be fired using a remote gas burner. The advantage of this type of heater is that the remote burner can be used if the gas turbine is operating in simple-cycle mode and during startup to ensure that the gas is completely free of liquids during all phases of the operation. Figure 12 shows a simplified schematic — less control valves — that illustrates the dual heat source.

Equipment Arrangement

For sites where the specific quality of the gas is unknown, a vertical gas separator followed by either duplex multi-tube filters or filter separator and superheater is recommended. Each of the duplex units must be designed for 100% of the system flow rate so that one can stay on-line while maintenance is being performed on the other.

The following are six gas conditioning systems, from the simplest scrubber to the most complex skid package engineered specifically to meet the individual need of a customer.

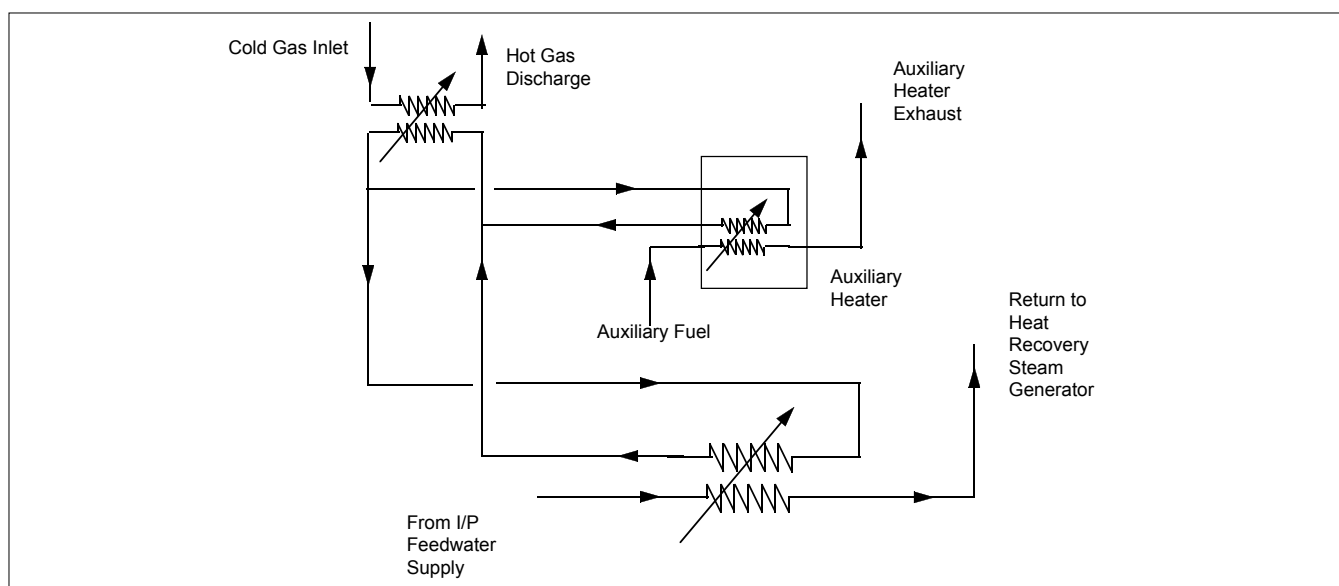


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Figure 11. Waste-heat gas fuel heater

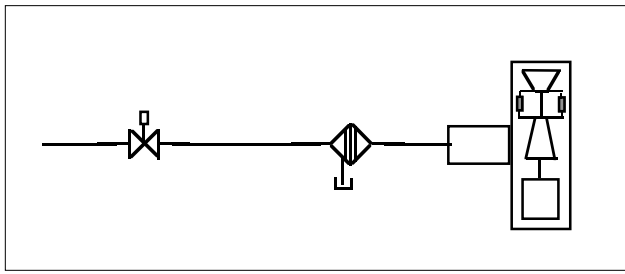
If the gas is dry with ample superheat and the expected daily, weekly and monthly variations are well known, then a simplex or duplex particulate filter, as shown in Figure 13, is all that may be required. An example of this type of application is a site burning LNG where the supplier has guaranteed no hydrocarbons higher than C₅ and where the gas temperature delivered to the site is well above the hydrocarbon dew point. For example, a gas with a moisture and hydrocarbon dew point of less than -50 F/-46 C and a gas delivery temperature of about 55 F/13 C would meet this description.

Allowance must be made for temperature drop through the pressure-reducing station, but with a superheat temperature of 105 F/35 C, there should be no concerns with liquid condensation.



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Figure 12. Simplified schematic for a dual-source gas fuel heater



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Figure 13. Simple particulate filtration used for dry gas

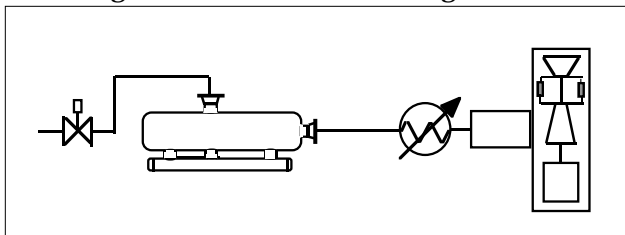
There is a need for particulate removal, regardless of the quality of the gas, since particulates can be generated by spallation of rust and other corrosion products within the pipeline. Stainless steel piping is required downstream from the particulate filter.

If the gas is wet but without excessive liquids and no slugging potential upstream from the pressure-reducing station, then single- or duplexed-filter/separators are recommended, followed by a heater that will provide a minimum of 50 F/28 C of superheat. Figure 14 shows this arrangement with a single filter/separator.

If the pressure drop through the pressure-reducing valve is greater than about 300 psi/2,068 kPa and the temperature reduction could cause slugging downstream, then a dry scrubber upstream from the filter separator may be required depending on the manufacturer's recommendations. Figure 15 shows this arrangement.

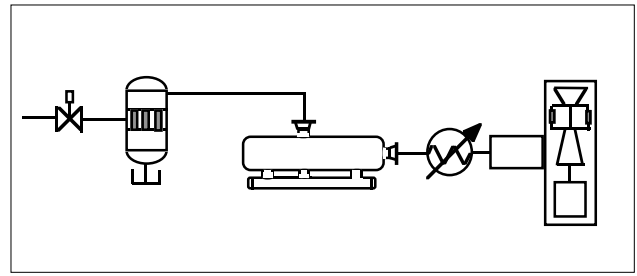
If the gas is wet and slugging is present in the incoming gas supply, a dry scrubber may be required upstream from the pressure reducing station. Figure 16 illustrates this arrangement. A filter separator is also required to provide protection over 100% of the flow range and to minimize any liquid carry-over to the heater.

If the incoming gas has a potential for hydrate formation, a dry scrubber and heater may be required upstream from the pressure-reducing station, as shown in Figure 17. A fil-



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Figure 14. For wet gas with non-slugging conditions upstream from pressure-reducing station



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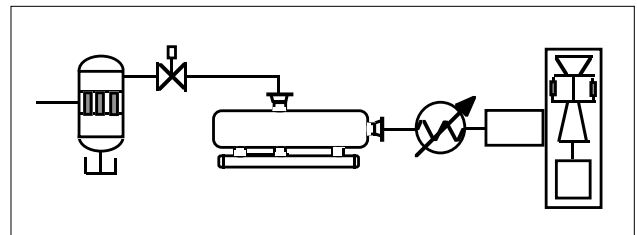
Figure 15. Dry scrubber installed to protect filter separator against excessive slugging conditions

ter/separator and superheater are required as before. The heat input can be minimized upstream, heating to a level that avoids hydrate formation and allowing the downstream filter/separator to remove liquids by physical separation.

The hydrate formation temperature may be above or below the hydrocarbon dew point temperature, depending on gas composition and moisture content. If it is above the hydrocarbon dew point, then a re-arrangement of equipment may be beneficial to avoid installation of two heaters. A minimum superheat temperature of 50 F/28 C must be maintained at the gas module inlet.

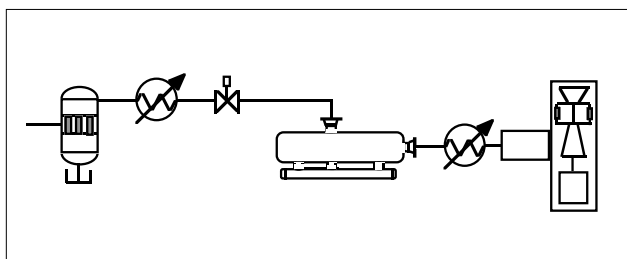
If multiple units are present on-site, a common clean-up system is often used to protect the pressure-reducing station, but individual filter/separators and heaters must then be installed downstream to protect each unit. Figure 18 shows the arrangement of individual filter/separators and superheaters.

Figure 19 shows a typical gas compression system used where the incoming gas supply pressure is too low to meet the GEI 41040E pressure requirements. In this situation, advantage can be taken of the heat of compression to avoid the cost of a gas superheater. Sufficient heat is normally added to the gas stream that the gas is superheated, much greater than the 50 F/28 C minimum requirement.



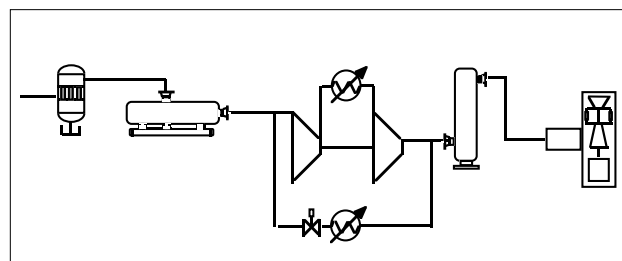
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Figure 16. Incoming wet gas with slugging potential upstream from pressure-reducing station



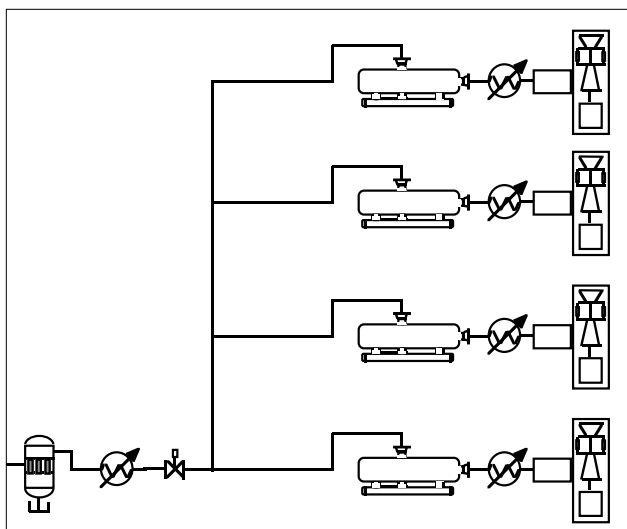
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Figure 17. Dry scrubber and heater to protect pressure-reducing station from build-up of gas hydrates



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Figure 19. Two-stage gas compressor providing more than 50 F/28 C superheat



GT25738

Figure 18. Common protection for pressure-reducing station and multiple-gas turbines, each individually protected

Attention must be paid to potential spill-over of compressor lubricating oil, however, and installation of a coalescing filter or absolute separator should be provided as part of the compressor package. If the heat loss in the gas line to the turbine is excessive, then a coalescing filter and superheater may be required downstream from the compressor station in order to regain the 50 F/28 C superheat.

Depending on the recirculation intercooler exit temperature, the recirculation line may be introduced at the compressor inlet or upstream from the gas clean-up equipment. There is some advantage to introducing the recirculation line upstream from the clean-up equipment in that the volumetric flow through the separation equipment will be closer to a constant value as load on the gas turbine increases or decreases.

The gas clean-up systems described here are only examples. The specific needs of each individual site must be carefully assessed, and the equipment and system design selected accord-

ingly. It is not sufficient, however, to independently select equipment based on claimed high efficiency alone; the entire system must be evaluated and preferably modeled to determine the overall system sensitivity to changes in gas composition, pressure temperature and mass flow rate. GE offers an engineering survey service that will provide answers to these questions.

CORRECTIVE ACTIONS IF WET GAS IS PRESENT

If wet gas is known to be present at the gas module inlet, it is highly recommended that the unit be shut down where practical until the extent of the problem can be determined. A failure to take action significantly increases the risk of an incident that may result in hardware damage ranging from combustor or fuel nozzle damage to stage 1 nozzle and bucket damage.

If the recommendations contained in this report have been followed, then the problem could be as simple as a tripped fuel heater. If this is a pre-existing condition and clean-up equipment has not been installed or is inadequate, then one or more clean-up equipment suppliers or GE Global Services Engineering should be consulted for advice.

As a minimum, if wet gas is known to be present, then free liquids must be removed and the gas superheated.

GE GAS FUEL SYSTEM ENGINEERING SURVEY SERVICE

To assist customers with the design of new gas fuel systems or to survey existing systems, GE offers an engineering service to evaluate proposed or existing designs and to make recommendations for upgrades to meet current fuel specifications. The survey may include a site visit, gas analysis and modeling of the system to

show where liquid condensation will occur and calculation of the required heat input to maintain 50 F/28 C of superheat.

SUMMARY

Appropriate gas conditioning is critical to the proper operation of advanced-technology low-emission combustion equipment. It is also applicable to pre-DLN combustion systems in order to fully protect the hot gas path equipment as the quality of the delivered gas continues to deteriorate under the pressure of economic forces both in the U.S. and overseas.

Gas fuel characteristics and quality requirements are addressed by the GE gas fuel specification. This paper provides background information and can be used as a guide to the specification and arrangement of clean-up equipment that is necessary to meet this requirement. Several aspects are considered, including cleanup of liquids, particulates and other contaminants, together with recommendations for gas sampling, analysis and dew point measurement.

Clean-up equipment is often provided to protect the pressure-reducing station, but this alone should not be relied upon without a system evaluation to meet GEI 41040E. Prior to purchasing equipment, it is recommended that the entire gas fuel system from a point just upstream from the custody transfer station to the purchaser's connection at the gas fuel module inlet be considered in the evaluation over the expected range of operating conditions. Several process simulator programs are commercially available that will assist with this task, or GE can provide this evaluation as a service.

ACKNOWLEDGEMENT

This document is the result of several discussions with customers and GE personnel in the Power Generation division and at the Corporate Research and Development Center. The author would like to acknowledge the contribution the many people involved without whom this compilation would not have been possible.

APPENDIX

A: Hydrocarbon Compounds Found in Natural Gas

Continuous-Chain Saturated Hydrocarbons

Table 1A shows a list of continuous-chain saturated hydrocarbons through C₁₄, known as alkanes (also called paraffins). These are hydrocarbons that will not react with hydrogen; they can be readily recognized by the compound name ending in -ane. Formulae for saturated hydrocarbons follow the simple rule of C_nH_{2n+2}.

For isomeric saturated hydrocarbon compounds, the chemical formula can be readily determined from the name, i.e. di-methyl heptane is an isomer of a hydrocarbon higher than heptane (C₇) that has attached two methylene (CH₂) chains. The number of carbon atoms is therefore 2xC + C₇ = C₉, and since it is a saturated hydrocarbon (ends in -ane), the complete formula is C₉H₂₀.

Care should be taken not to confuse isomer structure notation, e.g. 2-methyl heptane, which is C₈H₁₈, and is not the same as di-methyl heptane, which is C₉H₂₀.

Cycloalkanes (Ring Structures)

Some hydrocarbons that end in -ane are ring compounds such as cyclo-heptane C₇H₁₄, or cyclo-octane C₈H₁₆, and follow the general formula of C_nH_{2n}.

Combinations also exist such as:

dimethyl cyclo-hexane C₈H₁₆ (2xC + unsaturated C₆ = C₈H₁₆)

Table 1A
SATURATED HYDROCARBON
COMPOUNDS TO C₁₄

CH ₄	Methane	C ₈ H ₁₈	Octane
C ₂ H ₆	Ethane	C ₉ H ₂₀	Nonane
C ₃ H ₈	Propane	C ₁₀ H ₂₆	Decane
C ₄ H ₁₀	Butane	C ₁₁ H ₂₄	Undecane
C ₅ H ₁₂	Pentane	C ₁₂ H ₂₆	Dodecane
C ₆ H ₁₄	Hexane	C ₁₃ H ₂₈	Tridecane
C ₇ H ₁₆	Heptane	C ₁₄ H ₃₀	Tetradecane

Unsaturated Hydrocarbon Compounds

Some reported compounds may be unsaturated, such as benzene (C₆H₆) or toluene (C₇H₈), and can be recognized by the compound name ending in something other than -ane. Unsaturated hydrocarbons have hydrogen atoms that number less than 2n+2 and are compounds that will react with hydrogen to varying degrees.

To avoid possible confusion and resulting errors in the dew point calculation, it is advisable to request that the gas analysis include identification of the hydrocarbon compounds by chemical formula or carbon number and by name. A standard convention for naming compounds has been developed and is called the IUPAC system (International Union of Pure and Applied Chemistry). For more information on this subject, refer to standard texts of organic chemistry, such as that listed in Reference 12.

B: Typical Component Removal Efficiencies

The following information is for reference purposes only. The equipment manufacturer should be contacted for details of performance characteristics, including separation efficiency variation with flow, particulate size and density.

Vertical Gas Separators

Vertical vane-type separator with inlet baffle for high liquid loads.

Liquid Removal Efficiency	
10 microns and larger	100%
Turndown	2:1

Filter Separators

Vertical or horizontal two-stage separator for removal of solids and liquids.

Liquid Removal Efficiency	
8 microns and larger	100%
0.5 to 8 microns	99.5%
Solids Removal Efficiency	
3 microns and larger	100%
0.5 to 3 microns	99.5%
Turndown	100%

Multi-Tube Filter

Vertical or horizontal single-stage filters for removal of solids.

Solids Removal Efficiency	
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3 microns and larger	100%
0.5 to 3 microns	99.5%

Vertical Dry Scrubber

Vertical multi-cyclone separator for removal of solids and liquids.

Liquid Removal Efficiency	
10 microns and larger	100%
Solids Removal Efficiency	
8 microns and larger	100%
6 to 8 microns	99%
4 to 6 microns	90%
2 to 4 microns	85%
Turndown	4:1

Vertical Absolute Separators

Vertical single- or two-stage separator for removal of solids and very fine mist.

Liquid removal efficiency	
3 microns and larger	100%
Less than 3 microns	99.98%

Solids removal efficiency	
3 microns and larger	100%
0.5 to 3 microns	99.5%
Turndown	100%

Line Separator

Vertical vane type separator	
Liquid removal efficiency	
10 microns and larger	100%
Turndown	2:1

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LIST OF FIGURES

- Figure 1. Equilibrium temperature lines for hydrate formation
- Figure 2. Joule-Thompson cooling with pressure reduction
- Figure 3. Gas sampling probe
- Figure 4. Vertical multi-clone dry scrubber
- Figure 5. Vertical gas separator (inertial vane type)
- Figure 6. Coalescing filter
- Figure 7. Combined filter-separator
- Figure 8. Absolute separator
- Figure 9. Electrical gas heater
- Figure 10. Indirect-fired gas heater
- Figure 11. Waste-heat gas fuel heater
- Figure 12. Simplified schematic for a dual-source gas fuel heater
- Figure 13. Simple particulate filtration used for dry gas
- Figure 14. For wet gas with non-slugging conditions upstream from pressure-reducing station
- Figure 15. Dry scrubber installed to protect filter separator against excessive slugging conditions
- Figure 16. Incoming wet gas with slugging potential upstream from pressure-reducing station
- Figure 17. Dry scrubber and heater to protect pressure-reducing station from build-up of gas hydrates
- Figure 18. Common protection for pressure-reducing station and multiple-gas turbines each protected individually
- Figure 19. Two-stage gas compressor providing more than 50 F/28 C superheat

LIST OF TABLES

- Table 1. Variation of heating value and C_{6+} for U.S. and Canadian natural gas
- Table 2. Reported heating values and C_{6+} hydrocarbons throughout the U.S.
- Table 3. Comparison of standard and extended gas analyses on Calculated HC dew point
- Table 1A. Saturated hydrocarbon Compounds to C_{14}



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