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CONSIDERATIONS FOR GAS TURBINE FUEL GAS CONDITIONING

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Abstract

Industrial and aeroderivative gas turbines are capable of operating with a wide range of liquid and gaseous fuels. The present paper will specifically deal with natural gas fired gas turbines and various considerations for conditioning the fuel gas. Fuel gas quality is one of the most important aspects of a gas turbine and it heavily governs the reliability, operability, integrity and emissions compliance in a gas turbine. Various factors such as dew point, moisture content and other contaminants in the fuel gas determine the complexity of the fuel gas conditioning system. Important aspects of fuel gas conditioning including some best practices and considerations for appropriate fuel gas characterization shall be covered in this paper.

1. Introduction

Gas turbines can successfully operate on various liquid and gaseous fuels; however the focus of current paper will be on natural gas used as a fuel gas for firing gas turbines in pipeline applications. For an overview of different fuels and their impact on gas turbine operation, refer to Homji et al [1]. Supply of clean fuel gas is imperative for reliable and compliant operation of natural gas fired gas turbines. Natural gas is most widely used as the fuel gas for gas turbines because of its availability, price, and smaller carbon foot print compared to other fuels. Natural gas composition and characteristics vary widely from region to region based on its origin, level of processing, and dynamics therein. Particularly in North America, over the last decade this variance has become more predominant with the advent of shale gas, associated gas from various formations, LNG, and gas processing industry economic market drivers.

Poor quality fuel gas can severely damage the hot end components of the gas turbine leading to reduced reliability, increased repair and overhaul costs, non-compliant emissions, and costly unplanned outages in the system. Dry Low Emissions/Dry Low NOx (DLE/DLN) gas turbines are especially very sensitive to poor quality fuel gas. It is therefore very critical to have appropriate fuel gas conditioning systems and infrastructure in place to treat the fuel gas to make them suitable for reliable gas turbine operation. In most cases, complying with minimum original equipment manufacturer (OEM) specified fuel gas quality is sufficient. However consideration should be given to any anticipated upset or transient conditions leading to poor quality gas, the operational history of a particular gas turbine within the system and the source of fuel gas, to see if there is a more stringent requirement on the fuel gas quality that might be prudent to apply.

2. Fuel gas quality and various contaminants

For pipeline applications, the gas that is being transported by the pipeline system is governed by gas quality tariffs that stipulate the quality of gas entering the system. This same gas is used to power the gas turbine drivers on the pipeline systems which in turn drive the compressors to boost the pipeline pressure.

In a perfect world pipeline gas would have no contaminants in the gas stream and be composed mostly of methane with trace of heavier hydrocarbons and few other components (see Table 1 for an example of pipeline quality gas in Canada, after processing). Pipeline tariffs limit certain constituents such as carbon dioxide, oxygen, H2S, sulfur, and water in natural gas in addition to having limits on the dew point, heating values, and wobbe index.

There are widely varying definitions on what the acceptable limits of methane are for pipeline quality gas. For example, US EPA defines pipeline quality gas as containing at least 70 percent methane by volume [8] while environment Canada (BLIERs) defines it as containing at least 85% methane by volume [7].

This means that tariffs alone are not sufficient to ensure a gas turbine compliant fuel gas, especially in terms of dew point and heating values. These factors become especially important for DLE/DLN gas turbines because these gas turbines operate within a very tight band of operability window in order to maintain low compliant emissions. Tariffs have to be periodically revisited and modified to account for this variability in gas composition.

Table 1: Typical Pipeline quality gas composition

Component	% Mole
Methane(C1)	93.1896
Ethane(C2)	3.37659
Propane(C3)	0.97276
Iso Butane (iC4)	0.14996
Normal Butane (nC4)	0.18914
Iso Pentane(iC5)	0.04936
Normal Pentane(nC5)	0.03694
Hexanes(C6+)	0.03037
Carbon Di Oxide(CO2)	0.54468
Nitrogen (N2)	1.45017

This perfect gas composition meeting all limits is not always possible because of gas processing plant upsets, and/or the addition of newer receipt points with different quality natural gas and market dynamics which will dictate how the gas is processed.

The source of natural gas entering the pipeline is not always consistent. In North America the following are typical; associated gas, non-associated gas and from coal seams (coal bed methane) [2]. For this reason the gas quality is not always the same with varying contaminants and gas properties depending on the source of the gas. Typical contaminants which might be encountered are solids (rust, weldslag, metal shavings sand, etc), water, oils, H2S, CO2, CO, siloxanes, elemental sulfur, gycols, dissolved salts and amines. The source of the natural gas should be understood better in order to understand the contaminants that might be of issue and in the process will help determine the best fuel gas conditioning equipment and infrastructure to minimize the detrimental effect of the contaminants in the fuel gas.

The contaminants together with the variance in the fuel gas composition will influence the heating value (LHV or HHV), specific gravity and dew point of the fuel gas. These parameters influence the operation of combustion systems in the gas turbine and any excursions in these parameters affect the hot end component life and operation of gas turbines. DLN combustors also usually have a limited range of Wobbe Index in which they can operate reliably. Specifically, C4+ constituents adversely influence mixture flame speed and autoignition delay times which are important parameters, more so for higher pressure ratio gas turbines, in respect to pre-mixer function and avoidance of damaging flashback and autoignition events.

One of the most important parameters which needs to be understood and characterized appropriately is the hydrocarbon dew point (HCDP) of the fuel gas. The temperature in fuel gas supply system of a gas turbine will drop as the pressure of the fuel gas is reduced through the pressure regulators and fuel metering valves (by virtue of Joule Thompson Effect). This means that accurate knowledge of dew point becomes imperative to make sure that no liquid hydrocarbon drops out as the temperature and pressure of the fuel is throttled through the fuel gas system of the gas turbine.

HCDP of the gas can be calculated by knowing the gas composition and by employing appropriate Equation of State (EOS). However, the uncertainty in the calculated value of the HCDP can be quite significant based on the EOS used and also the kind of assumptions that go into splitting the heavier ends of the gas composition. In North America C6+ Gas Chromatographs (GCs) are most common for cost efficiency, with some C9+ GCs used occasionally as well. HCDP is heavily influenced by hydrocarbons C6 and above, however C6+ GC analysis provides insufficient data for accurate HCDP calculation [3]. An example is shown in Figure 1 showing how the HCDP can vary in a sample based on the C6+ GC only and then assuming a split of heavier components. The plot also shows typical pressures encountered in a gas turbine fuel gas system to give a perspective of fuel gas phase envelope in relation to turbine fuel system pressures. It can be seen from Figure1 that HCDP (cricondentherm) could be underestimated by as much as 20℃ depending on what splits are used to account for heavier hydrocarbons (C6 and above). For example, for a C6+ GC, 60-30-10 split means, splitting heavier ends of the gas composition into 60% C6, 30% C7 & 10% C8 by volume instead of lumping all the heavier hydrocarbons as C6+.

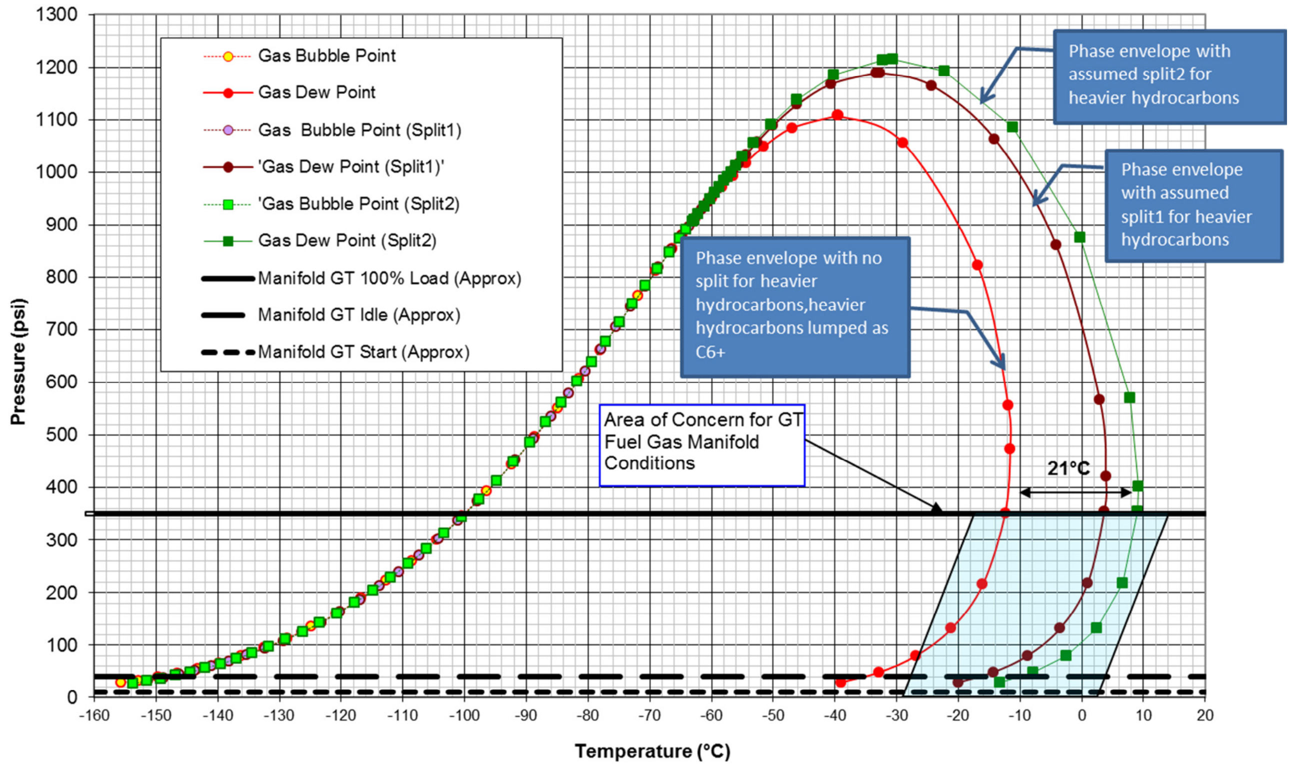

Figure 1: Calculated HCDP values of fuel gas with different splits of heavier hydrocarbons

It is therefore a good practice to always do an extended hydrocarbon analysis (C14+), even though it is a difficult analysis to perform, and direct measurement using a dew point analyzer to validate and get a more accurate HCDP. Particular attention needs to be paid when sampling gas for extended hydrocarbon analysis (C14+) by making sure that heavier ends don't drop out during sampling process.

Whilst previous paragraphs talked more about HCDP of fuel gas, attention should also be paid to moisture dew point if there is evidence of moisture in the fuel gas, as there is a potential of hydrate formation and acid formation in the fuel lines in presence of H_2S or CO_2 [4] .Also, in presence of moisture there is high probability of carrying over dissolved salts into the fuel gas system. Moisture level in pipeline gas is usually well monitored and better understood compared to the HCDP, however the threat from presence of moisture even if under pipeline tariffs limits, should not be neglected.

3. Impact of low quality fuel gas on gas turbine integrity

Direct impact of low quality fuel gas can be seen on the hot section of the gas turbine. Fuel gas quality has different elements to it as discussed in the previous section; there might be combined or individual excursions in these parameters of fuel gas quality leading to a repertoire of integrity problems in the gas turbines.

Lean premix combustors (also called Dry Low NOx DLE/DLN engines) are becoming common across all fleets and their operation is usually optimized for a narrow range of conditions to minimize emissions. DLE/DLN gas turbines are more susceptible and less tolerant to low quality fuel gas compared to the conventional combustor gas turbines. More often than not, it is very hard to isolate the integrity threats because of any one element of the fuel gas quality. It is usually a cascading effect with one issue feeding into other.

Presence of hydrocarbon liquids in the fuel gases either as compressor oils or as condensate tend to damage the fuel nozzles of the gas turbines by blocking the injector holes in the fuel nozzle, this plugging will be more pronounced in the DLE/DLN gas turbines because of the smaller fuel injector holes. Coking or pyrolysis from these hydrocarbon liquids also creates blockage inside internal delivery channels of the fuel injector. This eventually leads to unstable flame pattern and poor or unintended fuel distribution resulting in increased emissions and exhaust temperature spreads. In extreme cases it might also result in partial or complete flameout of combustors resulting in operability problems and thermal hardships on the equipment. Unintended fuel distribution and heat release can result in changes to gas path radial traverse and can lead to over firing and excessive temperatures downstream of the combustors. Eventually these effects will lead to accelerated loss of thermal barrier coatings, coating deterioration, hot section thermal erosion, oxidation and loss of seal segments in the high pressure and low pressure turbine sections. It should also be noted that, because of the combustion anomalies caused by hydrocarbon liquid entrainment there might also be exacerbated combustion noise issues coupled with control problems in the systems. Variation in air/fuel mixture will directly affect the auto ignition temperature, auto ignition delay time, and flame speed which are the primary parameters influencing the flame behavior. Anomalous flame behavior causes issues such as flash back, uncontrolled heat release, and emissions compliance problems.

Variations in heating value as a result of different gas compositions can affect the emissions performance of the gas turbine combustion systems. Some OEM's can offer NOx Scalars that define such impacts which may be important if tightly constrained and if the GC is not directly interfaced to a fuel controller. In some cases, if realistic gas composition knowledge is not available to the controller, starting problems can be encountered as well as errors in the control of flame temperatures. Such errors can lead to acoustics problems, in some cases forcing the turbine to operate in non DLE/DLN mode or lead to reduced output power of the turbine. Thus decisions about interfacing a GC or calorimeter need to be made with an understanding of expected gas composition variability.

Moisture is highly undesirable in the fuel gas system of a gas turbine, it can combine with methane under suitable conditions to form hydrates resulting in blockage of valve and orifice elements of the fuel gas system leading to control and stability issues. Moisture can also combine with other elements to form acids and can result in corrosion issues within the fuel gas lines. Salts that could be dissolved in water can deposit themselves in fuel injectors and other orifices under favorable conditions and cause plugging of these elements, and will lead to most of the issues discussed above.

One of the lesser known , but now well investigated issue is the damages caused to the gas turbines due to desublimation of elemental sulfur (S8) within the fuel gas system and turbine section. Elemental sulfur can also manifest as S2 and S6, which is better understood in terms of kinetics and its control compared to S8. S8 concentrations are hard to measure under pipeline and turbine operating conditions and its kinetics of formation is not very well understood. Chesnoy et al [5] provide excellent background information on how S8 can be characterized and future steps on that front. S8 levels even at parts per billion by volume (ppbv) in natural gas can pose a threat to the fuel gas systems, particularly when there is inadequate fuel temperature available. Sulfur can cause a myriad of problems within the gas turbine system from hot corrosion to blocking of fuel injectors, combustion instability and stability and accuracy issues with gas turbine control and eventually has adverse effect on the integrity of the gas turbine by reducing the gas turbine life and operational reliability.

Some of the most common indicators of issues with fuel gas quality in a gas turbine are as enunciated below:

- High gas turbine exhaust temperature spread (commonly called as T5 spread).
- Combustion instability and acoustic noise issues.
- Combustor flameouts.
- Loss of DLE mode and emission issues.
- Abnormal changes in the output power of the gas turbine.
- Sign of oxidation, erosion, and abnormal wear in the hot end components during routine boroscope inspections of the gas turbine.
- Yellow deposits on the control elements of the fuel gas system (telltale signs of sulfur).
- Issues with control of fuel gas valves
- Issues with freezing/seizing of pressure regulators on the fuel gas systems.

4. Fuel gas conditioning and best practices

From a gas turbine operator's perspective, it is very important to have specifications that mandate the requirements of a fuel gas conditioning system. A good starting point would be to start with OEM specified fuel gas quality requirements and work progressively to develop a fuel gas conditioning specification that caters to a particular make of the gas turbine, reliability requirements and addresses specific fuel gas quality issues which might be local to a particular geographical area. When a gas turbine package is envisioned for any particular application it is imperative that a cohesive approach be adopted across all the departments (such as process, mechanical, gas quality, etc) in terms of evaluating the fuel gas characteristics and plan for fuel gas conditioning system. This activity needs to be planned and executed as the gas turbine package is being designed and installed. Typically to install a fuel gas conditioning system after the installation of the gas turbine package would be very expensive (at least 50 % more than the new fuel gas conditioning installation itself).

In absence of sufficient information about the fuel gas quality It is a best practice to assume that hydrocarbon liquids will always be present in the fuel gas and plan for sufficient infrastructure to address this problem. Gas Turbine users should always be cognizant of the fact that cost of damage because of liquids entering a gas turbine as a contaminant outweighs the installation cost of fuel gas conditioning systems by many orders.

The goal of the fuel gas conditioning equipment should be to continuously clean the fuel gas and make it contaminant free, and deliver a continuous reliable stream of clean fuel gas to the gas turbine. Fuel gas conditioning systems should be able to remove all the particulates as specified by the OEM, or even better, remove all particulates (both solids and liquids) with an absolute removal rating of 3 microns or less. Another important function of the fuel gas conditioning system should be to provide sufficient super heat to the fuel gas so that no hydrocarbon liquid condenses out in the fuel gas system as a result of series of pressure cuts within the system. ASME B133.7M 1992 recommends that 25-30 ℃ of superheat margin be provided above the dew point of the fuel gas for gas turbine combustion [6]. It should be noted here that superheat margin should be provided accounting for the highest dew point temperature encountered at fuel gas pressures of the gas turbines. Upsets and transient conditions in the system should be considered when providing fuel gas heating system, and not the best case scenarios. For example, if the highest (worst case) dew point temperature at typical turbine fuel gas manifold pressure is 10 ℃ @ 300 psig, then super heat should be provided so that the temperature at the fuel gas manifold is 35-40 ℃ as a minimum. Temperature limitations of the piping and control elements should also be considered to make sure that whatever superheat is provided to the fuel gas stays within the design limits of these elements. OEM of the gas turbines should be consulted in extreme cases to make sure that super heat provided to the fuel gas should not adversely interfere with the combustion dynamics of the gas turbine.

A typical fuel gas system with very minimal fuel gas conditioning is as shown in figure2.

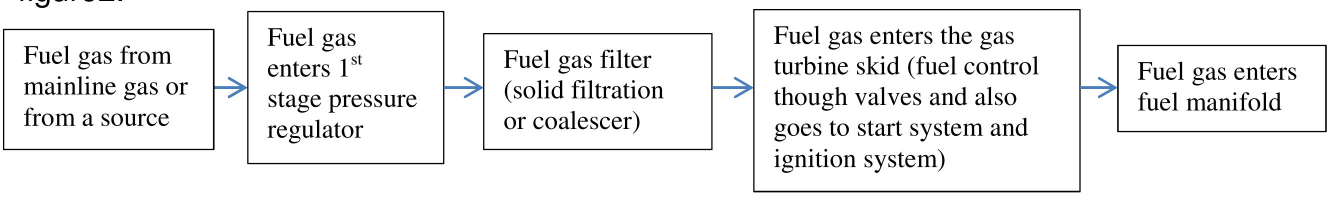

Figure 2: Typical fuel gas system with minimum conditioning

A system as shown in Figure 2 is probably very economical and has no elements built in to tackle any upset conditions. As stated in the previous paragraphs, fuel gas conditioning systems should always be designed to cater for worst case operating (upset) conditions. Therefore even if a clean & contaminant free gas is "guaranteed", it is prudent to have atleast the following elements in the fuel gas conditioning system as a best case scenario. See Figure 3 for a schematic representation.

1. Fuel gas separator or a coalescing filter before the fuel gas enters the 1st stage of pressure regulation (1st stage fuel gas filter), capable of arresting slugs.
2. A heater downstream of 1st stage fuel gas filter.
3. A high efficiency coalescing filter downstream of the first stage pressure regulation (2nd stage fuel gas filter)
4. A fuel gas super-heater downstream of 2nd stage fuel gas filter
5. Last stage solids or coalescing filter (3rd stage fuel gas filter).

The design and specification of this equipment will not be covered in this paper. Only a high level description of these elements will be discussed. If large amounts of liquids are anticipated in the fuel gas stream of the gas, more complicated systems for hydrocarbon liquid knockout and dewpoint control needs to be looked at. These systems are out of the scope of the present paper.

For gas turbines in pipeline applications, initially fuel gas usually goes through a preliminary stage of very coarse filtering wherein large particles and big liquid slugs are removed, this would be accomplished through a mainline scrubber. First stage fuel gas filters are installed after this preliminary stage of scrubbing. Ideally, this stage of filters should have the capability to handle small liquid slugs and also to coalesce small liquid particles up to atleast 10 microns. This can be accomplished by having a combined filter separator that has interial or multicyclonic elements in combination with coalescing filters in a single vessel.

The next element in the system would be a 1st stage heater, which would ensure that any traces or moisture or heavy hydrocarbon liquids are kept in vapor phase before the first stage of pressure regulation. Ideally, this stage of heating is more suited if the incoming gas is known to have moisture excursions and vulnerable to hydrate formations. It has to be noted that this 1st stage heater in most cases should not be capable of providing all of the super heat required for the fuel gas as the fuel gas will further go through a series of pressure cuts, and also heat is lost by virtue of thermal losses before it enters the gas turbine fuel gas manifold. This heater's purpose should be to avoid operability problems in the regulators and NOT to provide superheat, as the latter would defeat the effectiveness of subsequent high-efficiency coalescers.

Second stage fuel gas filter can usually be a single stage coalescing filter with about 1 micron or less filtration capability. This will ensure that any small residual hydrocarbons in liquid mist form after the first stage pressure regulation will also be eliminated. This filter ideally resides in the coldest point in the stream, downstream of the regulators. After this filter, a last stage of fuel gas heating will provide the adequate superheat to make sure that all the hydrocarbon fractions in the fuel gas system remains in the vapor state through the fuel metering skid of the gas turbine.

It should also be noted that if elemental sulfur (S8) is deemed as a problem in fuel gas quality, then providing that adequate amount of superheat, and maintaining fuel gas temperatures in the range of 40-50℃ at the skid edge of the gas turbine package would help mitigate the issue by allowing S8 to stay in vapor and abating its desublimation. The OEM should be consulted if element sulfur issues are present to work out a solution in conjunction with fuel gas heating.

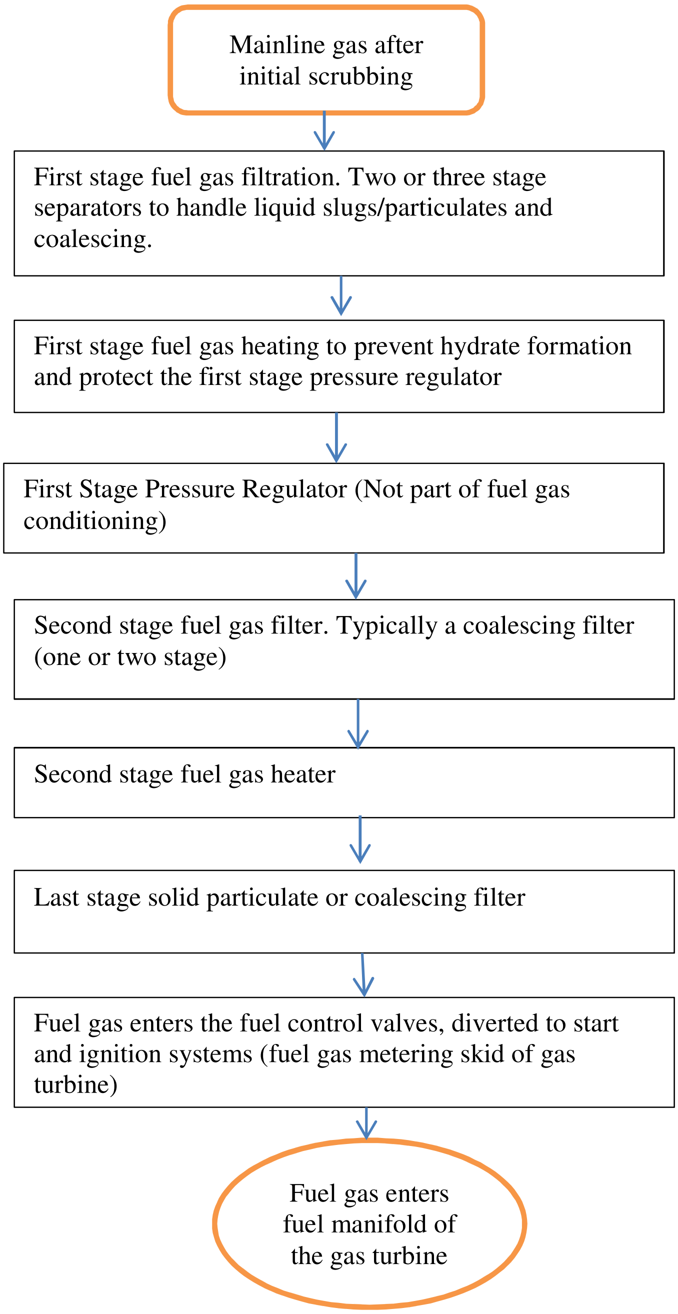

Figure 4: Ideal fuel gas conditioning system configuration

Aspects of the fuel gas conditioning system design can be modified or enhanced depending on the severity of the fuel gas quality issues. A complete engineering audit is recommended as a best practice to determine the factors that dictate the design and overall fuel gas system components. For existing fuel gas conditioning systems, it is a good practice to maintain periodic plant maintenance schedules to ensure that all the elements of the fuel gas conditioning system are in proper working order, and also it is a good practice to regularly sample the fuel gas to ensure that it is in compliance with gas turbine requirements.

The following are some of the important aspects to consider when specifying a new or updating an existing fuel gas conditioning system:

- Gas analysis to calculate various properties based on extended analysis (up to C14+). Recognize that, for DLE/DLN machines, the worst case including

variability (or margin for) of higher order components should be considered. “Expected” or “Typical” compositions may lead to underestimating threats.
- Validating dew point with field measurements using dew point analyzers.
- Determine appropriate HV and Wobbe Index limits based on the gas turbine selected, and also watch out for changes in these limits periodically.
- If new sources of gas is anticipated on an existing system, thoroughly characterize and model its properties.
- Anticipate upsets and excursions in the processing plant, and be aware of the kind of contaminants that could get into the fuel gas systems in case of an upset in any of the upstream processes that are feeding fuel gas. Have adequate capabilities to sample the gas periodically if changes are anticipated in the gas quality.
- Avoid undersizing superheating heat exchangers and provide for some margin (typically 10-20%) to account for fouling and gas supply changes and compositional variation.

5. Conclusions

This paper has provided a high level overview of the issues related to fuel gas quality, and proper specification of fuel gas conditioning system for gas turbines as applicable to pipeline operations. Fuel gas conditioning is of primary importance in ensuring that gas turbines are emissions compliant and operationally reliable without integrity issues. Some of the important aspects related to fuel gas quality that requires close attention are dew point control, wobbe index, and accurate gas characterization. For new installations, it is prudent to specify the fuel gas conditioning systems upfront by taking into considerations all the factors described in the paper. Upset conditions need to be taken into account while designing and specifying fuel gas conditioning systems.

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