Modelling and Simulation of The Processes of A Working Fuel Gas Conditioning Unit for A Gas Turbine

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Abstract- This research examines the design and simulation of a fuel gas conditioning unit (FGCU) for gas turbines using Aspen HYSYS. Gas turbines demand high-quality, contaminant-free fuel gas for optimal performance and longevity. The study focuses on developing a comprehensive model to remove impurities, regulate pressure, and control the dew point of natural gas to meet turbine specifications. The methodology involves modelling FGCU components, including separators, chillers, and dew point control units, to process a mixed feed containing hydrocarbons and contaminants. Simulations in Aspen HYSYS captured the behavior of these units under various operating conditions. Critical performance metrics such as gas purity, temperature, and pressure were optimized during the simulation. Results indicate that the FGCU effectively removes liquid hydrocarbons and moisture, achieving a 99.5% purity level in the processed gas. The final gas stream was delivered at a temperature of 15.57°F and a pressure of 800 psia, meeting stringent gas turbine requirements. The simulation also highlighted areas for energy optimization and operational efficiency. The study concludes that FGCUs significantly enhance gas turbine efficiency by ensuring fuel gas quality. Challenges such as energy consumption during conditioning and potential system inefficiencies were addressed, providing actionable insights for improvement. It is recommended to integrate advanced monitoring systems and optimize heat exchange processes to enhance system efficiency further. This research offers a robust framework for implementing FGCUs in industrial applications, contributing to cleaner and more reliable power generation

I. INTRODUCTION

1.1 Background of study

Power generation from fossil fuels has long since been the preferred method. Initially, coal was burnt to produce steam that could power turbines that, in turn, would drive generators to produce electricity supplied to the grid. This process made electricity cheaper even though there were always drawbacks and the most significant ones in this case were the smoke, smog, waste heat emissions and thermal inefficiency (Weston, 1992). Natural gas, because of its cleaner burning nature, has become a very popular fuel for the generation of electricity. Over the years, due to economic, environmental and technological changes, natural gas has become the fuel of choice for power plants as well (Lai and Hui, 2009). Although the theory of gas turbines and their anticipated functions were established over the past four centuries, the manufacturing of a gas turbine was faced with great challenges. The shortage of required materials impeded the implementation of the theory into practice. The gas turbine operation requires components capable of sustaining excessive temperatures for an extended period. Moreover, additional challenges such as the growing power demand and fuel price have highlighted the importance of efficient gas turbine performance.

A gas turbine is a type of internal combustion engine. It uses compressed air to turn a turbine blade, which rotates an output shaft that is connected to a generator which produces electricity. Gas turbines can be used to generate electricity, power ships and power aircrafts. They are also used in industrial applications such as to power large pumps and compressors (Weston, 1992). The operation of a gas turbine is described by Brayton cycle which is a cycle where both compression and expansion processes take place in the same rotating machinery (Saddiq, Perry, Ndagana & Mohammed, 2015).

Reserves of natural gas all over the world have made it possible for gas turbines to be fuelled efficiently which has led to its widespread. Although it is present in nature, natural gas must be conditioned before use in turbines because turbines are extremely sensitive to contaminant carryover into the combustors (Lokhandwala & Jacobs, 2008). This requires fuel gas to be treated to high levels of purity for total protection and optimal operation. Natural gas is commonly extracted through the process of drilling vertical or horizontal wells into the earth surface, the extracted gas after this process is said to be at its most flammable form. It is loaded with natural gas liquids (NGLs) and other impurities that make the raw product unusable and quite dangerous to transport (Wilson & Korakianitis, 2014). Fuel gas conditioning is the process of removing impurities and natural gas liquids from natural gas and making a specific oil and gas product that is safe for transportation and ready for use at gas pumps and the factories of several industries that rely on different forms of fuel for production. Fuel that is not well conditioned stands the chance of ruining an equipment that uses it for operation, this can be due to an exposure to the combination of contaminants and NGLs leading to the equipment eroding (Arinkoola, Salam, Jimoh & Oghafua, 2016). The gas must not contain liquid droplets and at least the 99.5% of particles must be removed from the gas (Arnold & Stewart, 1999).

A fuel gas conditioning unit is a system designed to clean, condition and regulate natural gas before it is used as a fuel in a combustion engine or turbine. The system removes impurities like water, solids and hydrocarbons from the gas stream and it also controls the pressure and temperature of the gas to the injection requirements (Schneider & Sommer, 2013). Fuel gas conditioning units are usually comprised of a scrubber, gas heater, pressure control, filtration and occasionally temporary gas storage for fuel switching (Arnold & Stewart, 1999). The conditioning process is highly prioritized in the industrial world. The system is an essential part of the fuel system and it helps to ensure that the engine or turbine runs efficiently and safely. Gas conditioning is used also for many other applications, such as gas engines on platforms, fertilizer plants for clean feedstock, refineries and any other mega industries with captive power plants.

2.1 Overview of Gas Conditioning

Gas flaring in Nigeria has become a major pollution concern for the environment and health of Nigerians. The Niger Delta region in Nigeria is rated as the most oil-impacted environment and polluted area in the world. Burning natural gases brings about emitting of carbon monoxide into the environment as well as warm up the environment, thereby contributing to the global warming scourge (Oriji & Ekpeti, 2016). The lack of processing this gas has also led to loss of revenue in this sector where there is a likelihood of otherwise generating more revenue in the country (Abam, Ugot & Igbong, 2011).

According to World Bank (2009), Nigeria loses up to 30.6 billion US Dollars annually due to gas flaring and the effects of unconditioned fuel gas which stem from poorly designed plants or inability to properly transport gases. For sake of accessibility, fuel gas conditioning units have been designed into skids to help transport the system to sites and even offshore. This would negate the risks in cost and safety of long pipeline transportation (Oriji & Ekpeti, 2016). Due to the abundance of petroleum resources in Nigeria, the dependence on cleaner burning fossil fuels is a step in the right direction. According to Sambo (2008), the likelihood of solving the power generation needs in Nigeria are greatly enhanced once greater investment is done into methods of conditioning and recycling natural gas and gas excrements during the processing of petroleum products. Also, with the an extensive amount of rehabilitation for already polluted areas like the Niger Delta region is essential for the healing process (Emoyan, Akpogorie & Akporhonor, 2008). Saturday and Ebieto (2020) go on to speculate that if properly employed, such measures could completely eradicate the gulf between the electricity demand and production levels in the country in a few decades.

2.2 Importance of fuel gas conditioning for gas turbine health

Fuel gas conditioning is essential for any gas processing plant. Gas turbines are aided by proper conditioning of gas over longer periods as this reduces the likelihood of damaged pipes and metals due to corrosion. After conditioning, concerns and issues can be identified at earlier stages to allow preventive measures, such as fuel treatment to be taken. Conditioning aids the recovery of hydrocarbon natural gas liquids (NGLs) and after processes of fractionation and stabilization, these specific natural gas liquids (NGLs) can be extracted and used for other purposes (usually C_3-C_5).

Abbott, Bowers & James (2012) state that there is a common misconception that gas turbines can burn any combustible gas and that fuel variability is not a significant issue. Going further, they outline that despite it being true that there are gas turbines firing a wide range of gases including natural gas, syngas (from coal, biomass and wastes), steelworks gases (coke oven gas and blast furnace gas) and gases with high hydrogen content (such as refinery gases), individual gas turbines can only tolerate limited changes in composition depending on the gas turbine design and the setup of the hardware and controls. Therefore gas for turbines must be tuned for the required fuel composition range. Since the composition of fuel gas for turbines can widely vary from gas with significant amounts of heavier hydrocarbons (butane and heavier), to pipeline quality gas consisting mostly of methane, to fuel gas with significant amounts of non-combustible gases (such as nitrogen or carbon dioxide), it is essential to condition fuel gas to the accepted composition range for a turbine. Higher hydrocarbons influence the hydrocarbon dew point and a high supply temperature is thus required. If the temperature is not maintained then liquid dropout (condensate) will result and can cause problems in the fuel system, or, more seriously, impinge on combustor surfaces leading to localized burning and component failure (Welch & Igoe, 2012).

Application of advanced-technology combustion systems requires close attention to gas conditioning systems as unconditioned gas could lead to numerous complications in running a gas turbine. Gases with free water can produce hydrates (a solid with ice-like appearance) in the turbine system. Liquid water in the presence of H_2S and CO_2 will form acids that can attack fuel supply lines and components by corrosion. Heavy hydrocarbon gases present as liquids provide many times the heating value per unit volume than they would as a gas. This creates a safety problem especially during engine start-up sequences when the turbine may be cold. Hydrocarbon liquids are said to likely cause turbine over-fuelling (which can lead to an explosion or severe turbine damage), fuel control stability problems and combustor hot streaks which lead to engine hot section damage (Kurz, Etheridge, & Kaiser, 2004). Presence of mercury (Hg) can cause metal embrittlement of aluminium equipment and piping while nitrogen (N_2) reduces the heating value of the gas (Campbell, Hubbard & Snow-McGregor, 2017). Super-heating specifications on a gas can also have effects on the long term health of a gas turbine. Superheat is a term that describes an inlet gas temperature in a gas turbine above the hydrocarbon dew point and water dew point temperatures. The American Society of Mechanical Engineers (ASME) fuel specification B133.7M (1985) states that the maximum condensation temperature for gas fuel must be below the minimum system temperature by a safe margin. It recommends that a typical margin of 25^{o}C to 30^{o}C of superheat be used on fuel gas for combustion turbines. The margin is provided to cover daily variations in dew point. Less superheat can lead to water condensation in the low pressure areas of the turbines (which can easily lead to leakages and quicker wearing down of skids and pipes) whereas unnecessary high superheat increases fuel gas consumption in the boilers (Wilkes, 1999). As a result, superheat regulation by composition of natural gas is essential to the long term efficiency of a gas turbine. Continuous use of natural gas without proper conditioning leads to further damage in a turbine ultimately leading to premature combustion component distress (in cross-fire tubes, liners and fuel nozzles) from liquid carry-over in the turbine which affects the reliability of the turbine and in turn, renders the turbine system dangerous and ultimately unusable over time.

2.3 Overview of natural gas

Natural gas is known as a fossil fuel. Henningser and Bergenson (1974) define natural gas as a colourless and highly flammable gaseous hydrocarbon consisting primarily of methane and ethane. It is a variation of petroleum that commonly occurs in association with crude oil.

Natural gas is often found dissolved in oil at high pressures existing in a reservoir and it can be present as a gas cap above the oil. The combination of compression and high temperature causes the carbon bonds in the organic matter to break down. This molecular breakdown produces thermogenic methane (Gupta, Rehman & Sarviya, 2010). In many instances it is the pressure of natural gas exerted upon the subterranean oil reservoir that provides the drive to force oil up to the surface. Methane is likely one of the most abundant organic compounds on Earth and its presence in the atmosphere is seemingly ever growing due to negative human effects (Oyedepo, Adefila & Fagbenle, 2015). Some common characteristics of natural gas include;

- Gas is colourless and tasteless.
- It is free of any kind of toxin, there is no smoke on burning and it has high calorific value.
- The gas is odourless. However, a chemical called mercaptan is added to it in small amounts to give it distinctive smell of eggs. This helps to find out any gas leaks.
- It occurs naturally in the rocks beneath the earth’s surface, in sedimentary rocks that are porous.
- It is a combustible gas with a low flammability range and a high ignition temperature.

- It's a mixture of simple hydrocarbon compounds.
- It contains primarily methane, along with small amounts of ethane, butane, pentane and propane.
- The by-products of this gas are water vapour and carbon dioxide.
- Air is 60% heavier than natural gas.

Compared to a fossil fuel like coal, natural gas emits about half as much carbon dioxide (CO_2) to produce the same amount of energy. Burning of natural gas also produces very little sulphur, mercury or particulate matter (Younger, 2004). With the right quality requirements, natural gas use in gas turbines can be relatively cleaner and used its by-products utilised effectively. Higher hydrocarbon (C_6+) in the form of gas or liquid are a valuable constituent of natural gas as they can contribute significantly to the heating value. Heavy hydrocarbons (C_6+) as a consequence, are now common in many gas supplies. Depending on pressure, temperature and concentration levels, the heavier hydrocarbons (C6+) can form liquids and have a very significant effect on hydrocarbon dew point of the gas.

2.4 Brief history of natural gas in Nigeria

Nigeria joined the league of oil and gas producing countries in 1956 after oil was discovered in commercial quantity in the present day Oloibiri in Bayelsa State, Nigeria. As of today, Nigeria is the twelfth biggest producer of natural gas in the world and second in Africa with 3,009,650,245 million standard cubic feet (MMscf) yearly. This aberration from a gas reserve of about 209.5 trillion shows that Nigeria's natural gas reserves are underutilised (Okafor, 2008).

Nigeria's natural gas is low in hydrogen sulphide (H_2S) and carbon dioxide (CO_2) impurities. This makes it marginally cleaner than most other sources in the world (Saturday & Ebieto, 2020). Despite this advantage, a lot of revenue and gas is lost due to flaring gas into the atmosphere as it is considered a by-product of oil due to lack in market conditions and processing capacity. According to Oyedepo et al. (2015), Nigeria operates about 36 gas powered turbines that generate power alone for the country's electricity grid.

2.5 Types of natural gas reservoirs

Natural gas is extracted from reservoirs beneath the earth's surface using a variety of methods depending on geology. A gas reservoir is a subsurface accumulation of hydrocarbons in a gaseous state contained in porous or fractured rock formations. Such reservoirs form when kerogen is created in surrounding rock by the presence of high heat and pressure in the Earth's crust (Gupta et al, 2010). Gas can be produced from many different types of reservoirs. The composition of natural gas that comes out of the ground is set by the reservoir composition and type which can vary widely. Natural gas reservoirs are often found using hydrocarbon exploration methods and are further characterised into the following;

2.5.1 Conventional gas reservoirs

these are cases where natural gas is trapped in reservoirs in porous rock such as sandstone or by overlying rock formations with higher permeability. In a natural (single phase) gas reservoir it should be possible to recover nearly all of the in-place gas by dropping the pressure sufficiently. If the pressure is effectively maintained by the encroachment of water in the sedimentary rock formation, however, some of the gas will be lost to production by being trapped by capillarity behind the advancing water front. Therefore in practice, only about 80% of the in-place gas can be recovered. On the other hand, if the pressure declines, there is an economic limit at which the cost of compression exceeds the value of the recovered gas. Depending on formation permeability, actual gas recovery can be as high as 75% to 80% of the original in-place gas in the reservoir. Associated gas is produced along with the oil and is separated at the surface. Natural gas from a conventional reservoir is easier to extract using more traditional drilling methods.

2.5.2 Unconventional gas reservoirs

these are natural gas found in tight rock formations with lower permeability, such as shales and coal seams. In addition, large amounts of gas are locked into methane hydrates in cold polar and undersea regions, and gas is also present dissolved or entrained in hot geo-pressured formations of waters. These resources are recovered through combinations of horizontal drilling, hydraulic fracturing and special extraction technologies as these reservoirs cannot be produced using the conventional techniques. Using these methods to extract natural gas that was previously inaccessible with traditional drilling greatly increases recoverable natural gas and lessens the risk of loss (Campbell, Hubbard & Snow-McGregor, 2017). Another benefit is the ability to drill multiple wells from the same well pad on the surface, allowing for greater resource recovery on a reduced land footprint.

Natural gas deposits are often found near oil deposits as natural gas deposits closer to the surface are usually dwarfed by nearby oil deposits (Alumina, Enemuoh, Anyaegbu & Nwachukwu, 2014). Deeper deposits formed at higher temperatures and under more rock formations have more natural gas than oil. The deepest of deposits rather, can be made up of a much purer natural gas composition than most found higher up the reservoirs (Henningser & Bergenson, 1974).

Although methane can escape into the atmosphere by passing through permeable materials like porous rocks before dissipating, most thermogenic methane molecules that rise towards the surface encounters geological formations that are too impermeable for it to escape. These rocks formations are called sedimentary basins (Abam, Ugot & Igbong, 2012). Sedimentary basins rich in natural gas are found all over the world. Sedimentary basins trap huge reservoirs of natural gas. In order to gain access to these natural gas reservoirs a hole or well must be drilled through the rock to allow the gas to escape and be harvested.

2.6 Types of natural gas

Generally, the type of gas conditioning and processing operations recommended for any specific plant depends on the kind of gas under consideration along with the distribution of the hydrocarbons found in the gas (Campbell, 1982). Gas compositions are wholly defined by the conditions in the reservoirs which they are formed in. Each gas type would determine the processes and approaches taken to analyse and condition the natural gas. Some types of natural gas found in reservoirs are;

2.6.1 Wet gas (Rich Gas)

this is a natural gas that contains significantly heavy hydrocarbons such as propane, butane and other liquid hydrocarbons. Wet gas contains more amounts of ethane and other condensable hydrocarbons than most types of gas and less methane (typically less than 85%). A significant volume of NGLs can also observed from wet gas. This form of gas is usually characterised by the volume or weight of the condensable compounds contained in a given volume of total gas produced. Wet gas exists solely as a gas in the reservoir throughout the reduction in reservoir pressure.

2.6.2 Retrograde Condensate Gas

This reservoir is initially contains a single-phase fluid, which changes to two phases (condensate and gas) in the reservoir when the reservoir pressure decreases. The fluid exists as a gas at initial reservoir conditions, as reservoir pressure declines. As pressure is reduced in a condensate gas reservoir, the fluid will pass through the dew point and large volumes of liquid will condense in the reservoir. Additional condensate forms with changes in pressure and temperature in the tubing and during lease separation. Since the gas flows preferentially to oil, much of this oil will be unrecoverable. Consequently, it is important to recognise that a reservoir contains a condensate gas and re-inject dry gas to maintain reservoir pressure above the dew point to maximise recovery of the liquids.

2.6.3 Dry Gas

Natural gas that occurs in the absence of condensate or condensable hydrocarbons is called dry gas. It is primarily methane with some intermediates. According to Younger (2004), dry gases are defined as those that contain less than 0.1 gallon of condensable compounds per 1,000 cubic feet of produced gas. The hydrocarbon mixture is solely gas in the reservoir and there is no liquid formed either in the reservoir or at the surface. The pressure path line does not enter into the phase envelope in the phase diagram, thus there is only dry gas in the reservoir (Younger, 2004). Note, the surface separator conditions also fall outside the phase envelope (in contrast to wet gas), hence no liquid is formed at the surface separator (Konig, Marquardt, Mitsos, Viell & Dahmen, 2020).

Other forms of natural gas include some by analysis of reservoirs;

Associated Gas; this is a form of natural gas that is formed of gas which is found with deposits of petroleum, either dissolved in the oil or as a free gas above the oil in the reservoir. In this form many oil reservoirs exist at the bubble point of the fluid system at initial conditions (Abam, et al, 2011). Free gas can be produced from the gas cap of such systems. Gas which is originally dissolved in the oil can also be produced as free gas at the surface. Non-associated gas may or may not possess condensate together with the gas.

2.7 Composition of natural gas

Pipeline natural gas is a combination of many hydrocarbon compounds, the relative concentrations of which may vary with time and geographic location (Wilkes, 1999).

The complex nature of natural gas is exemplified by the American Petroleum Institute's Research Project 6, which determines the individual constituents of a naturally occurring petroleum hydrocarbon mixture. Using a sample of Ponca City Field petroleum, this project isolated 172 compounds. Natural gases may have a similar complexity. Fortunately, the major components in most natural gases are paraffin hydrocarbons with smaller amounts (usually only traces of olefin hydrocarbons, naphthenic hydrocarbons, mercaptans and non-hydrocarbon compounds) (Richardson, Smith & Younger, 1979). The components of natural gas are either aliphatic (chain) or cyclic (ring) hydrocarbons. Their structures are as follows;

2.7.1 Aliphatic or Chain Hydrocarbons

These hydrocarbons occur in two forms; paraffin hydrocarbons and olefin hydrocarbons. The most common of which are saturated hydrocarbons like methane CH_4 (predominantly), ethane C_2H_6, propane C_3H_8, butane C_4H_{10}, pentane C_5H_{12}, hexane C_6H_{14}, heptane C_8H_{16}. Olefin hydrocarbons have the general formula of C_nH_{2n} and are classed as unsaturated hydrocarbons, some of which are ethene C_2H_4, propene C_3H_6, butane C_4H_8. They usually occur only in traces.

2.7.2 Cyclic or Ring Hydrocarbons

These occur most of the time. They are of two kinds; naphthenic and aromatic hydrocarbons. Naphthenic hydrocarbons are saturated cyclic hydrocarbons with the general formula of C_nH_{2n} while aromatic hydrocarbons are unsaturated cyclic hydrocarbons classified by the number of six-carbon rings in the molecule. Examples of these include benzene, toluene (methyl benzene) and ethyl benzene.

Isomers; these are compounds having the same composition and molecular weight but different properties due to a different structural arrangement. The isomers like isobutane are found in natural gas. There is also a presence of nonhydrocarbon components in natural gas like nitrogen (N_2), carbon dioxide (CO_2), hydrogen sulphide (H_2S), helium (He), water vapour (H_2O), carbonyl sulphide (COS), carbon disulphide (CS_2), sulphur (S), mercaptans; methyl mercaptan (CH_3SH) and ethyl mercaptan (C_2H_5SH) are compounds most commonly found in natural gas (Richardson et al, 1979).

Some of the common contaminants that are introduced into the natural gas supply through production and transportation processes are;

- Water
- Iron sulphate, iron and copper sulphide.
- Lubricating oil, wet scrubber oil, crude oil, hydrocarbon liquids.
- Glycols from dehydration processes.
- Calcium carbonate, carbon dioxide and carbon monoxide.
- Gas hydrates, ice.

Hydrocarbon liquids are a more serious issue as they can accumulate over long periods of time and result in liquid slugging as gas flow rates are increased after a period of reduced power operation. There is some room for error in the measurement of fuel gas compositions, but accuracy is important, especially in the C_{6+} range where a small error in the concentrations of heavy hydrocarbons can translate to large dew point shifts. Seeing as gas compositions may vary within any given 24 hour period due to gas process change, pipeline operations and even changes in weather, analysis and proper understanding of these effects in correlation to the sources of gas fuel, complexity of the fuel gas system and the environment (Newbound & Al-Showiman, 2004). Ofodu and Abam (2002) analysed the effects of variable exergies in Afam thermal plant in Port Harcourt, Nigeria. In this research, initial analysis was carried out to determine the composition of natural gas required for the power plant in scope. The result of the analysis carried out is tabulated below;

Compound	Formula	Approximate value in mole percent (%)
Methane	CH_4	88.0
Ethane	C_2H_6	5.0
Propane	C_3H_6	2.0
Butane	C_4H_{10}	0.6
Pentane	C_5H_{12}	-
Carbon dioxide	CO_2	4.4
Hexane	C_6H_{14}	-
Nitrogen	N_2	-
Other trace compounds	-	-

Table 1; Composition of natural gas in Afam thermal plant in Nigeria (Ofodu & Abam, 2002).

2.8 Gas conditioning process

Campbell (1982) described the term conditioning as one referring to the portion of the gas treatment process necessary to meet residue gas specifications. Accepted gas specifications are similar globally as the objective is to attain pure natural gas with the lower to no impurities. Processes that occur in a fuel gas conditioning system include;

- Gas dehydration to prevent condensation of water
- Hydrocarbon dew point control to prevent condensation of hydrocarbons.
- Removal of sulphur compounds and/or carbon dioxide to meet 'sweetness' specifications and process needs.

Sweetening refers to the removal of all acid gas contaminants (CO_2 and H_2S). The selection of technology to meet the acid gas specifications depends largely on the concentration of the contaminants to be removed, and the inlet gas flow rate (Arinkoola et al, 2016). Technically, carbon dioxide (CO_2) is not a sour component but is often removed in the sweetening unit (amine treating). Amine treating is the work-horse in the gas processing industry for contaminant removal. This process is done before dehydration because the amine solution is generally about 50% by weight water (Richardson et al, 1979). The gas will be saturated with water after it leaves the acid gas treating unit as a result. Dehydration of gas can then be carried out. This is the removal of water content to a specified level depending upon either downstream processing requirements or end user. Mercury removal is often critical in large base load LNG facilities (Oriji & Ekpeti, 2016).

For easy transportation and effective safety measures, fuel conditioning systems on skids are now more useful. The skids allow for the systems to be transported and mounted with relative ease. This is very essential as gas can now be conditioned at any reservoir as opposed to transporting gas by pipeline or other measures. Fuel gas conditioning skids are equipped with the necessary tools to properly condition fuel gas of choice. Also, variations to design and processes are always made by manufacturers based on preference, safety protocols or nature of gas or product desired (Konig et al, 2020).

Fig. 2.1. A fuel gas conditioning skid.

The importance of providing a comprehensive fuel composition in order to determine the suitability of such fuels should not be under-estimated (Welch & Igoe, 2012). The basic fuel gas conditioning skid is equipped with the following sections for proper conditioning of fuel gas;

2.8.1 Scrubber

This is the first step where the gas enters and the liquid particles are removed from the gas. A scrubber is a cleaning installation in which the gas flow is brought in intensive contact with a fluid which is aimed to remove gaseous components from the gas to the fluid. A natural gas scrubber system works by using particle filters, coalescers, mesh pads and other devices to remove pollutants from a gas stream (Cannon, 1983). Coalescing filters should be located between the particulate filters (upstream) and the gas super-heater (downstream) (Newbound & Al-Showiman, 2004). Additionally, natural gas treatment can be used for removal of CO_2 and H_2S by bubbling the natural gas through a scrubbing liquid like amine. This type of natural gas treatment is called absorption because the amine absorbs the unwanted CO_2 and H_2S. The rich amine that now contains the CO_2 and H_2S is then regenerated and reused (Campbell et al, 2017). Gas scrubbers can also be applied as an emission control technique at various gaseous emission points.

2.8.2 Pre-Heater

Here the gas is heated to prevent hydrates from forming, which can occur when there is high pressure or low temperature. This is an optional process which is installed due to the properties of untreated gas. The reduction of natural gas pressure before use causes a drop in temperature. In physics, this is known as the Joule Thompson effect. These drops can create operational and material quality problems in distribution networks of natural gas. This may cause the water vapour dew point to fall causing icing within and outside of pipelines (Rai, 2003). This brings the necessity of preheating natural gas before the pressure reduction process. Heating the gas before transmission can overcome the Joule Thompson effect. The preheating of natural gas to raise temperature enough so that after pressure throttling and temperature reduction, it still reaches the optimal required temperature (Campbell et al, 2017). Electrical block type heaters and heat exchangers are two of the commonly used heating devices for the preheating of natural gas.

2.8.3 Pressure Reduction

pressure is reduced to meet the equipment pressure requirements and prevent hydrates from forming. Pressure reducing components vary depending on pressure levels, pressure differences and allowable pressure drop across the system for low inlet pressures. Incoming natural gas is led through filters which protect downstream regulating valves and gas turbines from contaminants coming from pipelines. Pressure reduction values and specifications are then set and controlled through regulatory valves and hydraulic damping. The latter has an advantage that it compensates oscillations from the system preventing upswings and transfers of vibration to the gas turbine (Jansohn, 2013). The filters integrated in the control valve further increase the operational reliability of the system as they prevent clogging caused by any existing dirt particles. This serves to extend life span of the equipment.

2.8.4 Filtration Unit

After stabilising pressure, the gas flows through the filtration unit where entrained solids and liquids as well as fine and medium-sized contaminants are removed from gas stream. These units are equipped to remove any further impurity that exists in natural gas as a result of previous process systems such as dehydrators, lubrication and gas feed impurities. The filtration unit is usually consisted of two filter separators to enable changing of the filters without disrupting the fuel supply. Filter separators are designed for high gas/low liquid flow operations (Cannon, 1983). In conditioning, a filter separator is also required to prevent foaming due to chemical contamination. Solid removal efficiency of the filter separator is 100% when size is 3 microns and larger (99% when size of solids are 0.5-3 microns), while liquid removal efficiency is 98% when size is 8 microns and larger (Campbell, 1982). Efficiency of filter separators largely depend on particle size, distribution of particles and liquid loading. Coalescing filters are also used to prevent any form of mist from getting through the system.

2.8.5 Dew Point Control Unit

Classical dew point control units are typically featured with propane refrigeration to achieve the gas specification and desired gas dew points. It is the most used technology, especially for gas fields where the operating pressure of the plant is below the critical point of the gas mixture (Foglietta, 2004). The hydrocarbon dew point (HCDP) indicates the temperature at which heavy hydrocarbon components begin to condense out of the gaseous phase when the gas is cooled at constant pressure. At this point the gas is saturated as all the free liquid has been removed due to proper filtration. Reducing the dew point by Joule-Thomson expansion or mechanical refrigeration is more common for smaller flow rates of feed gas and turbo expander based units are often used for higher flow rates (Campbell et al, 2017). An earlier used method was the adsorption method which involved use of adsorbents like silica gel that have the capability to adsorb heavy hydrocarbons (Foglietta, 2004). These processes require gas re-compression to deliver the treated gas to the pipeline. The heating unit (electric or gas fired depending on the flow rates) serves to prevent condensation due to pressure loss as gas moves across the turbine nozzles. Alternatively, the feed gas is cooled by direct refrigeration by use of a chilling unit which is normally based on propane refrigerant. All the cooling processes require a gas dehydration to avoid hydrate deposition in cold section. The direct refrigeration by means of propane chiller unit is more suited for treating a low or medium pressure associated gas stream (El-Wakil, 1984). Other methods of dew point control include static expansion devices and membranes.

In field operations, hydrocarbon recovery is necessary for fuel conditioning or dew point control. There have been many dew point control units built using the turbo-expander process, especially in offshore environments, where weights and space limitations benefit this process. Refrigeration is also a means by which these hydrocarbons are condensed out of the gaseous phase. The methods include mechanical refrigeration, Joule-Thomson (JT) valve refrigeration (Low Temperature Separation) and cryogenic refrigeration by turbo-expander (Kidnay & Parrish, 2006).

For the sake of this research, emphasis was made on the following methods due to easier access to documentation for analysis;

Joule-Thomson Expansion
Natural gas pipelines usually cool with distance as pressure drops. The Joule-Thomson effect refers to the effect on natural gas where temperature is gradually controlled by the reduction or increase of gas pressure. The pressure drop through the reducing valves leads to the gas expansion and a temperature decrease. The fluids consisting of pentane and heavier components as well as water are recovered in a low temperature separator (LTS). This process is seen as an effective hydrocarbon and water dew point control process.

Mechanical Refrigeration
Mechanical refrigeration is supplied by a vapour-compression refrigeration cycle that usually uses propane as the refrigerant and reciprocating or centrifugal types of compressors to move the refrigerants from the low to high pressure operating conditions (Mokhatab & Poe, 2012). It is the most direct and simplest process for NGL recovery and dew point control (Aftab et al, 2016).

There are a variety of factors to consider when choosing the right hydrocarbon dew point control technology. Consideration must be given to the inlet, downstream and overall conditions. Among the most crucial technical characteristics of any process are the feed gas pressure, the permissible unit pressure drop as well as the feed gas composition and the mode of operation (Mokhatab & Poe, 2012).

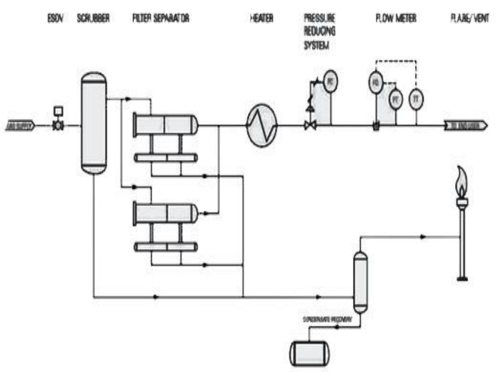


Fig 2.1. Schematic diagram of gas conditioning in a gas turbine (Multitex group, 2021).

After conditioning, processing is carried out to recover commercial quantities of liquids from the natural gas. The components include ethane, commercial propane, commercial butane, natural gasoline and propane-butane mixes (commonly referred to as liquefied petroleum gas – LPG). Which of the products recovered will often depend on price and demand for each. In a gas turbine, after conditioning the gas is then channelled to the system for heating (Alumona et al, 2014).3.1 Materials and Equipment

The materials that will be used to archive the stated objectives in chapter one with the sole aims of modelling and simulating the processes of a working fuel gas conditioning unit for a gas turbine.using ASPEN HYSYS include:

1. Aspen HYSYS version 11.0
2. Aspen Economic Analyser
3. Aspen Optimization tool
4. Aspen Energy Analyzer
5. Aspen Material property data sheet

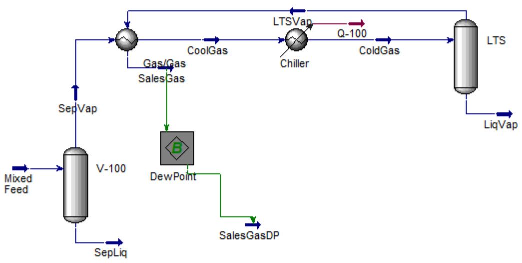
3.2 Aspen Hysys Overview
Aspen HYSYS is a chemical process simulator used to mathematically model chemical processes, from unit operations to full chemical plants and refineries. It is a proprietary software created by AspenTech and Hyprotech for use in many chemical engineering processes. HYSYS is able to perform many of the core calculations of chemical engineering, including those concerned with mass balance, energy balance, vapour-liquid equilibrium, heat transfer, mass transfer, chemical kinetics, fractionation and pressure drop. HYSYS is used extensively in industry and academia for steady-state and dynamic simulation, process design, performance modelling and optimization. Given a process design and appropriate selection of thermodynamic models. HYSYS uses mathematical models to predict the performance of the process. Engineers typically simulate using the software in order to optimize the design and improve existing ones. The accurate modelling of thermodynamic properties is particularly important in the separation of non-ideal mixtures. One of the best advantages is that HYSYS has already an existing database of species and their pure/binary regressed parameters with a user friendly graphic user interphase (GUI). It can also handle more complex processes, such as;

- Dedicated unit operations for the refinery industry (crackers, coker, reformer, FCC unit, etc.)
- Multiple-column separation systems.

- Chemical reactors.
- Simulation of petroleum crude oils (based on their properties).
- Complex recycle – bypass stream in processes.

Aspen HYSYS will be the chosen software for this design project based on the capability and relative accessibility of the programme with respect to the required task. Its database offered a healthy number of options that will be essential in achieving the desired results.

3.3 Flowsheet development using Aspen Plus



3.4 Modelling & Simulation procedure

The modelling and simulation of a gas turbine fuel conditioning unit using Aspen HYSYS will be carried out following the steps outlined below;

1. Defining components; before modelling can begin, an outlay of the components in a fuel gas conditioning unit is needed. The components of a fuel gas conditioning unit which include; gas inlet, preheater, scrubber, filter, control valves and compressor. These components will be identified from the Aspen HYSYS database and singled out for the modelling and simulation process.
2. Creating the process flow diagram; once the components had been defined, the next step will be to create the process flow diagram for the fuel gas conditioning unit. This is a diagrammatic representation of the step-by-step approach showing the workflow of the fuel gas conditioning unit. The process of conditioning is then organised from the gas inlet to the outlet. This process will be carried out by inputting and connecting each component of the fuel gas conditioning unit to each other in the order at which their processes are carried out. The flow diagram will align with processes going from left to right.
3. Defining the process conditions; after creating the process flow diagram, exact specifications for flow rates, pressures and temperatures of the gas through each stage of the process of conditioning will be required. For each component, the software will be able to measure the process conditions (the rates of gas flow, pressure and temperature) which in turn aid the smooth simulation process afterwards. These properties help to regulate the process in general. Physical and thermodynamic properties of the gas (such as composition, density, viscosity and heat capacity) are also essential for the modelling process and as a result, the necessary properties for the proper simulation will also be observed and documented. Gas properties at the inlets and requirements at the outlets after simulation are observed to ensure efficient gas processing. The Aspen HYSYS application possesses a data browser panel to observe and input variables for the process.
4. Run the simulator; once the other processes is done, the simulator will be turned on to analyse the performance of the fuel gas conditioning unit as well as the process conditions, physical and thermodynamic properties at each stage of the process. Errors in the modelling will also be observed and can easily be corrected before/after the simulation.
5. Analyse the simulation results; this analysis will be carried out to ascertain whether the process will be a successful simulation. After running the simulator, the summary report of each process by the component will be generated by Aspen HYSYS whereby the desired composition of gas will be compared to the results attained through the process of fuel gas conditioning modelled. The summary report presented the opportunity to analyse for further optimization of the process and will be explored to utilise the unit to its utmost efficiency. On completion of the above processes, the model of the fuel gas conditioning unit will completely be analysed and simulated to with successful trials. Data will then be compiled and recorded for proper presentation and discussion.

For the simulation of dew point control, the available methods on Aspen HYSYS will be the Joule-Thomson method and mechanical refrigeration method. It will be well noted that Shamsi, Farokhi, Pourghafari & Bayat (2022) after a technical, energy and exergy analysis, found that the mechanical refrigeration process is more energy and exergy efficient as the Joule-Thomson method had greater energy degradation and exergy destruction.

4.1 RESULT

4.1.1 Mixed Feed

The process begins with a mixed feed stream, which was a combination of various hydrocarbon gases. This stream may contain a mixture of methane, ethane, propane, and heavier hydrocarbons, along with other impurities such as water vapor and contaminants. The purpose of this unit was to condition this feed stream to meet the specifications required for safe and efficient operation of the gas turbine. Below are the conditions of the feed;

Table 4.1 Worksheet of the Mixed Feed

Stream Name	Mixed Feed	Vapour Phase
Vapour/Phase Fraction	1.0	1
Temperature (F)	120	120
Pressure (psia)	114.7	114.7
Molar Flow (MMSCFD)	48	48
Mass Flow (lb/hr)	1.212e+005	1.212e+005
Std Ideal Liq Vol Flow (barrel/day)	2.235e+004	2.235e+004
Molar Enthalpy (Btu/lbmole)	-3.675e+004	-3.675e+004
Heat Flow (Btu/h)	-1.937e+008	-1.937e+008
Liq Vol Flow @ Std Cond (Barrel/day)	8.492e+006	8.492e+006
Fluid Package Utility Type	Basis-1	

SG4.1.2 Separator

The mixed feed enters a separator, where the gas and liquid phases are separated. This step was crucial for removing any liquids from the gas stream, as liquid hydrocarbons or water can cause operational issues in downstream equipment and the gas turbine. The separator produces two streams: a gas stream (SepVap) and a liquid stream (SepLiq). The liquid stream was typically sent to a separate processing unit or storage, while the gas stream proceeds to further conditioning.

Table 4.2 Worksheet of Separator

Stream Name	Mixed Feed	Sep liq	Sep Vap
Vapour/Phase Fraction	1.0	0	1
Temperature (F)	120	120	120
Pressure (psia)	114.7	114.7	114.7
Molar Flow (MMSCFD)	48	0	48
Mass Flow (lb/hr)	1.212e+005	0	1.212e+005
Std Ideal Liq Vol Flow (barrel/day)	2.235e+004	0	2.235e+004
Molar Enthalpy (Btu/lbmole)	-3.675e+004	-8.276e+004	-3.675e+004
Molar Entropy (Btu/lbmoleF)	42.11	51.71	42.11
Heat Flow (Btu/h)	-1.937e+008	0.00	-1.937e+008

4.1.3 Gas Chiller

The gas stream (SepVap) was first cooled in a gas cooler, where heat exchange with a cooler medium reduces the temperature of the gas. The cooling process continues in a chiller, which further lowers the gas temperature, enabling the condensation of heavier hydrocarbons and other condensable components. The cooling process generates a colder gas stream (ColdGas) and a vapor stream (LTSVap). The colder gas was now conditioned to meet the low-temperature requirements for further processing or combustion in the gas turbine.

Table 4.3 Worksheet of the Gas chiller

Stream Name	Cool Gas	Cold Gas	Q-100
Vapour/Phase Fraction	0.9722	0.9235	
Temperature (F)	34.05	-33.00	
Pressure (psia)	104.7	94.7	
Molar Flow (MMSCFD)	48	48	
Mass Flow (lb/hr)	1.212e+005	1.212e+005	
Std Ideal Liq Vol Flow (barrel/day)	2.235e+004	2.235e+004	
Molar Enthalpy (Btu/lbmole)	-3.803e+004	-3.917e+004	
Molar Entropy (Btu/lbmoleF)	39.89	37.59	
Heat Flow (Btu/h)	-2.004e+008	-2.064e+008	6.007e+006

4.1.4 Low-Temperature Separator

The cold gas from the chiller enters a Low-Temperature Separator (LTS), where any remaining liquid hydrocarbons and water are separated from the gas stream. This was an essential step to ensure that the gas fed to the turbine was dry and free of liquids. The LTS produces a cold gas stream (ColdGas) that was suitable for further processing or direct use as fuel gas. The liquid stream (LiqVap) from the LTS was removed and typically sent to storage or further processing.

Table 4.4 Worksheet of Low-Temperature Separator

Stream Name	Cold gas	Liq Vap	LTS Vap
Vapour/Phase Fraction	0.9235	0	1
Temperature (F)	-33	-33	-33
Pressure (psia)	94.7	94.7	94.7
Molar Flow (MMSCFD)	48	3.674	44.33
Mass Flow (lb/hr)	1.212e+005	2.510e+004	9.609e+004
Std Ideal Liq Vol Flow (barrel/day)	2.235e+004	2927	1.942e+004
Molar Enthalpy (Btu/lbmole)	-3.917e+004	-7.093e+004	-3.653e+004
Molar Entropy (Btu/lbmoleF)	37.59	21.40	38.93
Heat Flow (Btu/h)	-2.064e+008	-2.861e+007	-1.778e+008

4.1.5 Dew Point Control

The gas stream from the separator, now referred to as SalesGas, undergoes a dew point control process. This process involves adjusting the temperature and pressure to ensure that the gas meets the dew point requirements, which was crucial for preventing condensation in pipelines and turbines. The dew point-controlled gas (SalesGasDP) was now within the required specifications for safe and efficient combustion in a gas turbine.

Table 4.5 Worksheet of Dew Point Control

Stream Name	Sales Gas	Sales Gas DP
Vapour/Phase Fraction	1.0	1.0
Temperature (F)	110	15.57
Pressure (psia)	84.70	800
Molar Flow (MMSCFD)	44.33	44.33
Mass Flow (lb/hr)	9.609e+004	9.609e+004
Std Ideal Liq Vol Flow (barrel/day)	1.942e+004	1.942e+004
Molar Enthalpy (Btu/lbmole)	-3.515e+004	-3.681e+004
Molar Entropy (Btu/lbmoleF)	41.93	34.61
Heat Flow (Btu/h)	-1.711e+008	-1.792e+008

4.1.6 Final Gas Stream

The final sales gas stream (SalesGas) was now fully conditioned and meets the stringent quality and safety standards required for gas turbine fuel. This stream was free of liquids, heavy hydrocarbons, and contaminants, making it ideal for use in power generation. The conditioned gas was ready for delivery to the gas turbine, where it will be combusted to generate electricity. The quality of this gas was critical for the performance and longevity of the gas turbine.

Table 4.6 Worksheet of Final Gas stream

Stream Name	Sales Gas DP	Vapour Phase
Vapour/Phase Fraction	1.0	1.0
Temperature (F)	15.57	15.57
Pressure (psia)	800	800
Molar Flow (MMSCFD)	44.33	44.33
Mass Flow (lb/hr)	9.609e+004	9.609e+004
Std Ideal Liq Vol Flow (barrel/day)	1.942e+004	1.942e+004
Molar Enthalpy (Btu/lbmole)	-3.681e+004	-3.681e+004
Molar Entropy (Btu/lbmoleF)	34.61	34.61
Heat Flow (Btu/h)	-1.792e+008	-1.792e+008
Fluid Package	Basis-1	

4.2 Overall Treatment Efficiency:

Removal of Contaminants: The system efficiently removes liquid hydrocarbons and moisture, ensuring that the gas is dry and free from impurities that could damage the turbine.

Temperature and Pressure Adjustments: The gas is conditioned to an optimal state, ensuring a controlled dew point and preventing condensation, which is crucial for the efficiency and safety of the turbine.

Table 4.4 Overall Treatment Efficiency

Parameter	Initial Value	Final Value	Efficiency	Remarks
Contaminant Removal	25,100 lb/hr	0 lb/hr	100%	Complete removal of liquid hydrocarbons and moisture.
Temperature Adjustment	120°F	15.57 °F	87%	Significant cooling to meet dew point requirements.
Pressure Regulation	114.7 psia	800 psia	100%	Achieved required turbine inlet pressure.
Final Gas Purity	Mixed hydrocarbons	99.5 % pure gas	99.5%	High purity gas suitable for turbine operation.
Overall Efficiency	-	-	96.6%	Weighted average of individual efficiencies.

CONCLUSION

In conclusion, the fuel gas conditioning unit for a gas turbine, as depicted in the process diagram, plays a critical role in ensuring that the fuel gas meets the stringent quality requirements necessary for efficient and safe turbine operation. The unit effectively handles the complex task of separating liquid hydrocarbons, cooling the gas stream, and adjusting the gas temperature through the use of components such as separators, chillers, and heat exchangers. Each step in the process was meticulously designed to optimize the gas's composition, removing impurities and ensuring that the final product was a clean, dry, and stable fuel suitable for combustion. The integration of the heat exchanger within the system was particularly noteworthy, as it allows for precise temperature control, which was essential for the proper functioning of the Low-Temperature Separator (LTS). This ensures that any remaining condensable components are efficiently removed, further enhancing the gas's purity and stability.By conditioning the gas to the required specifications, the unit not only protects the gas turbine from potential damage caused by impurities but also enhances the overall efficiency and reliability of the power generation process. The thorough conditioning of the fuel gas ultimately leads to a more sustainable and economically viable operation, highlighting the importance of such advanced processing units in modern energy systems.

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