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Ministry of High Education
& Scientific Research

Emirate International University
Faculty of Engineering
Department of Petroleum Engineering

STUDY THE EFFECT OF PRESSURE & TEMPERATURE ON HYDRATION FORMATION IN THE NATURAL GAS PIPELINE TRANSMISSION AS CASE STUDY MA'ARIB - BELHAF

(MA'ARIB - BLOCK 18)

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Declaration

We hereby declare that this Bachelor’s Project is the result of our own work, except for quotations and summaries which have been duly acknowledged.

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APPROVAL

This is to certify that the graduation project titled "***Study the Effect of Pressure & Temperature on Hydration Formation in the Natural Gas Pipeline Transmission as Case study Marib – Belhaf** by Using **PIPESIM** Simulation Software*" has been read and approved for meeting part of the requirement and regulations governing the award of the Bachelor of Petroleum Engineering (Oil and Gas) degree of Emirate International University, Sana'a, Yemen.

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LIST OF ABBREVIATIONS

Icon	Abbreviations
S I	Structure I
S II	Structure II
S H	Structure H
TCF	Trillion cubic feet
BSR	Bottom simulating reflector
NW	Number of water
MW	Molar mass of water
BOP	Blow out preventer
DST	Drill stem test
WHU's	Well heating units
ESP	Electrical submersible pump
MMS	Minerals Management Service. Or Magnetic Multi Shot
RIH	Run-in-hole or Running pipe in the hole
POOH	Pull-out-of-hole or Pull out of the hole
THI	Thermodynamic Inhibitors
LDHI	Low dosage hydrate inhibitors
TEG	Triethylene Glycol
MEG	Monoethylene Glycol
DEG	Diethylene Glycol
QUATS	Quaternary Ammonium Site
LTX	Low Temperature exchange
KPU	Kamil Processing Unit
CPU	Central Processing Unit
ROW	Right of Way
SCADA	Supervisory control and data acquisition
MTPA	Million ton per annum
GHG	Green-house gases
OGP	Oil and gas producers

LIST OF ABBREVIATIONS CONT.

Icon	Abbreviations
H_2O	Water
H_2S	Hydrogen Sulfide
CO_2	Carbon Dioxide
CO	Carbon Monoxide or circulate out
NO	Nitrous Oxide
CH	Methane
C_2H_6	Ethane
C_3H_8	Propane
CL	Chlorine
N_2	Nitrogen
O_2	Oxygen
OH	Hydroxyl
CH_3OH	Methanol
SO_2	Sulfur Dioxide
NACL	Sodium Chloride Salt
KCL	Potassium Chloride Salt
$CACL_2$	Calcium Chloride Salt.
NABR	Bromide Sodium.
$CABR_2$	Calcium Bromide
$ZNBR_2$	Zinc Bromide
H	Hydrogen
ROW	Right of Way
CSMHYD	Comparison of Hydrates Formation Modeling Software
ESIA	Environmental and Social Impact Assessment
CNG	Compressed Natural Gas
VOC	Volatile Organic Compounds
NOx	Nitrogen oxides

LIST OF ABBREVIATIONS CONT.

Icon	Abbreviations
NUP	Net Utilized Production
lb	Pound
MMSCF	Million Standard Cubic Feet
FTP	Flowing Tubing Pressure
YLNG	Yemen Liquefied Natural Gas
LNG	Liquefied Natural Gas
ANSI	American National Standards Institute
AAAS	American Association for The Advancement of Science
LPG	Liquefied Petroleum Gas
PPD	Pour Point Depressant
PFD	Process Flow Diagram

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ABSTRACT

As known the production of crude oil and natural gas is being from the too far place that are not near to the refining industry or the seaports of the exporting, so the crude oil and natural gas must be pass through one or more operations to transport and storage it in the true methods and conditions. For these reasons we have chosen our project titled "*Study the Effect of Pressure & Temperature on Hydration Formation in the Natural Gas Pipeline Transmission as case study* ***Marib - Balhaf***", to discuss the effect of pressure & temperature on hydration formation in the natural Gas pipelines transmission from **CPU** to **KPU** in **Marib** block (18) to **Balhaf** port in **Shabwa**. And our project was focusing on the production & transportation of the natural gas form that block (18) and the main process of the natural gas transportation.

The main aim of study is design a pipelines transmission model using **PIPESIM** simulator software to analyze natural gas field data and create a gas compositional fluid model (mole components). And calculated the energy (i.e., pressure) required to transport the flowing fluid through the pipelines, in every case (scenario). This study utilized **PIPESIM** simulator to calculate the pressure and temperature (P/T) losses encountered during the gas pipeline transmission distance.

And we running the system simulation of the gas pipeline transmission operations to enable the calculation of the hydrate sub-cooling temperature, the difference between the hydrate formation temperature and the flowing fluid temperature (i.e. $T_{hyd} - T_f$). And to find ideal and optimal flowing gas that can be achieved under operational conditions for treatment from the presence of hydrate inhibitors during that processes.

At the end we will suppose three scenarios that the natural gas production increasing to 25%, 50% or 100% in the 20 future years, and will asking from the **PIPESIM** simulator to forecasting and to make accurate decision for the additional parallel pipeline transmission inside diameter with the lowest cost, for future planning and for development the pipelines transmission. And the **PIPESIM** simulator has been selected the optimum scenario, among all other scenarios, based on the lowest cost of the additional parallel pipeline transmission.

CHAPTER ONE
INTRODUCTION

CHAPTER I - INTRODUCTION

1. INTRODUCTION

Pipeline in the oil and gas industry refers to a long line of connected segment of pipe with pumps, valves and other facilities needed for operating the system. Pipelines usually have a minimum diameter of 0.1 m and a minimum length of 1.6 km unless stated (Guha and Berrones, 2008). As the demand for energy continues to increase globally, exploration and production firms adapt to operational practices to meet the world's energy demand. This energy demand has led to the growing development of gas activities, which requires safe and guaranteed means of transporting natural gas (condensate gas?). Other means of transmitting natural gas include use of tankers, conversion into **Liquefied Natural Gas (LNG)**, **Compressed Natural Gas (CNG)**, and gas to solid among others.

However, transmission using pipelines are considered safe, economical, friendly to the environment and highly reliable (Singh and Nain, 2012). Although pipelines better guarantee continuous delivery and assures lower operating and maintenance cost, more challenges arise when transporting natural gas from onshore to offshore processing plant because temperature and pressure variations affect the physiochemical properties of the fluid transported (Ayala and Adewumi, 2003).

1.1. BACKGROUND:

Gas hydrate formation is one of the main problems encountered during natural gas production and transmission via pipelines which results in additional expenditures. The estimation of gas hydrate volume has great importance in flow assurance.

Natural gas hydrates are solid crystalline inclusion compounds which belong to the gas clathrates group due to its ability to encapsulate gas molecules in structural cages of water molecules at high pressure and low temperature. The gas hydrate looks quite similar to ice, but the chemical compound and some of its properties are different. The formation of gas hydrate plugs in production pipelines. Such plugs may cause severe damages on infrastructure and cause large safety issues. The Initial industrial interest on gas hydrates was in effort to avoid such hydrate plugging of pipelines.

In other hand, Gas hydrate and ice formation surrounding a producing well is a problem in gas production from gas hydrate reservoirs. Rapid cooling rates caused by the Joule Thompson effect caused by high production rates result in the creation of gas hydrates and ice around the wellbore, reducing or terminating gas production from the reservoir.

This graduation research project will focus on the study of the effect of pressure and temperature on hydration formation in the natural gas pipelines transmission and the conditions causing forming the gas hydrate, the reasons of its formation, the sequences and the possible techniques for avoiding the gas hydrate formation.

1.2. PROBLEM STATEMENT

Study the effect of pressure and temperature on hydration formation in the natural gas pipelines transmission using **PIPESIM** simulator software to calculate the pressure and temperature (P/T) losses encountered during the gas pipelines transmission distance. And create a gas compositional fluid model (mole components) for a compositional simulation, and analyze natural gas field data. In compositional fluid models we can specify a number of components to make up the fluid phase behavior and thermodynamic properties are determined by an **equation of state (EOS)**. These can be real molecules, such as methane, ethane or water, known as petroleum fractions. By using the **nodal analysis** which is a methodology that views the total producing system as a group of components. An improper design of any one component, or a mismatch of components, adversely affects the performance of the entire system.

Gas hydrates form inside the pipelines transmission of natural gas at subsea levels and low-temperature regions. They form around the surfaces of the pipelines and gradually accumulate until they constrict the flow or cause variations in flow pressure. They can cause catastrophic rupture of the pipelines and the failure of the gas transmission system. As a result, the safest and most cost-effective way of preventing gas hydrates is by predicting the temperature or pressure in which it will form for a natural gas mixture.

Many correlations have been developed to predict the conditions of hydrate formation, but the models require a complex computation, or their accuracy is limited to certain gas mixtures. Some of them can only be used in a limited range of temperature, pressure, or specific gravity and show a significant error at higher pressure. Also, some correlations are only useful when a comprehensive analysis of gas is accessible.

Gas hydrates still continue to plague the oil and gas industry, as they cause a severe risk of blockages in oil and gas pipelines, both onshore and offshore. Deepwater offshore oil fields have enhanced high pressure and low temperature environments; thus, the risk of gas hydrate blockages in pipelines and offshore facilities is extreme. As such, gas hydrates are the primary problem for flow assurance, the field concerned with ensuring continuous flow of fluids in oil/gas flowlines and facilities.

1.3. AIMS

The main aim of this project is to study the effect of pressure and temperature on hydration formation in the natural gas pipelines transmission by using **PIPESIM** simulator software, through design a transmission pipelines model, and analyze natural gas field data, and calculated the pressure energy required to transport the flowing fluid through the pipelines, in every case (scenario), and to calculate the pressure and temperature (P/T) losses encountered and predicting & avoiding gas hydrate formation temperatures over a wide range of gas compositions and pressures.

1.4. THE PROJECT OBJECTIVES

The following are the main objectives of this research:

1. Design the pipelines transmission model, and analyze natural gas field data and create a gas compositional fluid model (mole components) by using the **PIPESIM** simulator software.
2. Determine the main parameters affecting gas hydrate formation and estimating the hydrate formation temperature of natural gas compositions acquired from the formation.
3. Investigate the formation of gas hydrates and ice phases under high sub cooling rate settings in order to determine the effect of various parameters on the ice and gas hydrate formation temperatures.
4. Predicting and avoiding gas hydrate formation from the presence of hydrate inhibitors in a closed system according to pressure and temperature data during transmission processes by using **PIPESIM** simulator software as efficient and accurate technique.
5. Study the natural gas properties change & compositional fluid (mole components) during transmission via pipelines.
6. Calculate the pressure and temperature (P/T) losses encountered during the gas pipelines transmission distance by using **PIPESIM** simulator software.
7. Design and simulate the three scenarios if we supposes that the natural gas production increasing to 25%, 50% or 100% in the 20 future years, and will do forecasting and to make accurate decision for the additional parallel transmission pipelines (ID) inside diameter with the lowest cost by using **PIPESIM** simulator software.

WHY STUDY GAS HYDRATES?

- Hydrates have potential as a future energy resource.
- Related to climate change.

- Affect strength of sediments in which they are found (care in constructing underwater structures).
- Hydrates currently cause blocking in some underwater natural gas pipelines.
- Hydrates may be an alternative to pipeline transmission as a way to move natural gas from deep water to the terminals of existing offshore pipelines.

1.5. NATURAL GAS HYDRATES:

Natural gas hydrates are solid crystalline inclusion compounds which belong to the gas clathrates group due to its ability to encapsulate gas molecules in structural cages of water molecules at high pressure and low temperature. The gas hydrate looks quite similar to ice, but the chemical compound and some of its properties are different. Water molecules are connected through hydrogen bonds and form a lattice or crystalline structure, where a hydrophobic gas molecule is enclosed in the cavity of the structure. The encaged gas molecule is often referred to as a guest molecule, and typical guest molecules are methane (CH_4), ethane, and propane or carbon dioxide. CH_4 is the most common guest molecule found in natural gas hydrates, and is therefore the main hydrate former in this work.

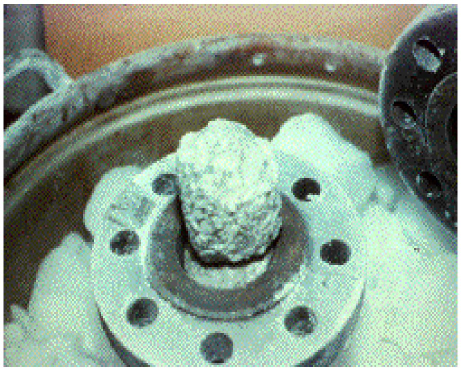


Figure (1.1): Crystal Structure of Gas hydrate

The formation of gas hydrate plugs in production pipelines has for a long time been a large challenge for the oil industry (Hammer Schmidt, 1934). Removal of such plugs is time consuming, and certain risks are involved. By adding inhibitors such as methanol, these plugs can be removed. Hydrate dissociation will first start along the pipe wall, and thus the plug may become a high velocity projectile due to the differential pressure. Such plugs may cause severe damages on infrastructure and cause large safety issues. Initial industrial interest on gas hydrates was in effort to avoid such hydrate plugging of pipelines transmission.

Natural gas hydrates also represent a vast energy resource distributed in regions of permafrost and in sub-marine environments. The amount of in situ gas hydrates is still uncertain, but even conservative estimates suggests that if only a small fraction is recoverable it should still be considered a possible energy source due to its sheer size. It is estimated that energy stored in gas hydrates is twice the energy stored in other fossil energy sources like oil, conventional gas and coal (Kvenvolden, 1988). Estimates of gas stored in hydrates vary between 1-120 x 10^{15} m^3 (Sloan and Koh, 2008). Uncertainty in these estimates is rather significant, but even for the less optimistic estimate the gas hydrates represents a vast energy source. In comparison, estimated recoverable gas left in conventional reservoirs is approximately 4.4 x 10 m 143. For the more optimistic estimates, the amount of energy stored in hydrates exceeds all fossil fuels combined by several multiples (Grace et al., 2008).

The gas stored in gas hydrates provides cleaner energy upon combustion compared to oil and gas - as concerns are raised on environmental issues – gained increased attention in industrial and scientific communities.

A major problem in the gas industry is the effect of water vapor during the transmission and measurement of natural gas. Water liquefies, freezes, and accumulates within the system causing interruptions in pipeline transmission of gas. The solid crystals that form resemble snow and the flow of gas causes it to compress and accumulate at the lower spots of the pipeline, these snow-like crystals are called gas hydrates and they are known to cause plugging in gas pipelines. **Figure** (1.2) shows a typical example of a gas hydrate from a pipeline (Hammer Schmidt, 1934).

Figure (1.2): Gas hydrate showing its snow-like appearance

Gas hydrates are clathrates structures in which guest molecules are enclosed in cages of a host lattice. They are crystalline forms of water in which the stabilization of the solid is facilitated by the presence of gas molecules inside the crystal matrix (cage) at temperatures significantly above the normal freezing point of water. It is composed of gas molecules (methane predominantly) surrounded by a cavity of water molecules (Saleh, 2002). Gas hydrates usually form when 90% of the cage is occupied which gives the gas a solid volume ratio of about 160% (Riedel, et al 2010). The molecular arrangement of gas hydrates is shown in **Figure** (1.3).

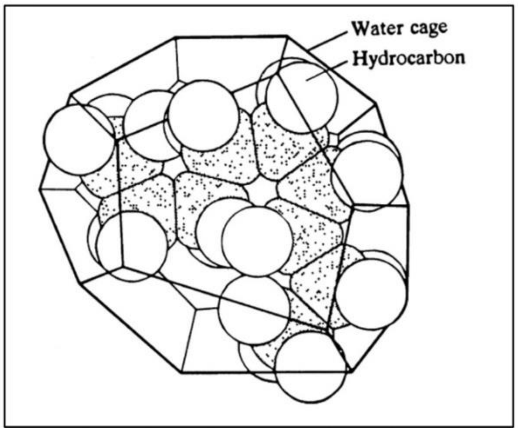


Figure (1.3): Molecular configuration of gas hydrates (Saleh, 2002)

Gas hydrate cages usually contain a single gas molecule and are composed of hydrogen-bonded water molecules. The structure of hydrates is called clathrates due to the entrapped (caged) nature of hydrogen molecules inside the crystal lattice of water molecules (Saleh, 2002), They form when water and gas combine at low temperature and high pressure in pipelines transmission natural gas, hydrates are lighter than water and as a result, they often reside at the point of interface between oil and water (Bellarby, 2009). The crystals have a honeycombed structure with small channels that allow gases to pass through, but with further accumulation, the flow in the pipe is entirely blocked.

Gas hydrates also exist in subsea and ocean floors where conditions are ideal for formation; they trap large amounts of energy near subsea seeps and around midline reservoirs (Saleh, 2002). Favorable conditions of natural gas hydrates exist in the sediment of Polar Regions and sediments covering 90% of the ocean floor. Most natural gas hydrates have more than 99% of their hydrocarbon as methane, low amounts of CO_2, and H_2S are present (Puall, et al 2001).

In the scientific jargon they are termed as natural gas hydrates, indicating that methane gas occupies most of the cavities in the hydrates. The nomenclature is in accordance to the petroleum industry, where methane is formed under subsurface earth by natural process (Hunt 1996). The methane gas contained in the gas hydrates burns more efficiently with lesser emission of hazardous gases when compared to convention petroleum and coal. On the utility front methane gas is fast replacing as feedstock in power plants as well as running cars and other conveyance modes (Sloan, 2003).

Hydrates normally form when a gas stream is cooled below its hydrate formation temperature. At high pressure these solids may form at temperatures well above 32°F. Hydrate formation is almost always undesirable because the crystals may cause plugging of flow lines, chokes, valves, and instrumentation; reduce line capacities; or cause physical damage. This is especially true in chokes and control valves where there are large pressure drops and small orifices. The pressure drops cause the temperature to decrease, and the small orifices are susceptible to plugging if hydrates form. Hydrate formation leading to flow restrictions is referred to as "freezing."

The two major conditions that promote hydrate formation are (1) the gas being at the appropriate temperature and pressure, and (2) the gas being at or below its water dew point with "free water" present. For any particular composition of gas at a given pressure there is a temperature below which hydrates will form and above which hydrates will not form. As the pressure increases, the hydrate formation temperature also increases. If there is no free water, that is, liquid water, hydrates cannot form. Secondary conditions such as high gas velocities, agitation of any type, and the formation of a nucleation site may also help form hydrates. These secondary conditions are almost always present in the process piping stream.

Methods of preventing hydrate formation include adding heat to assure that the temperature is always above the hydrate formation temperature, lowering the hydrate formation temperature with chemical inhibition, or dehydrating the gas so that water vapor will not condense into free water. It is also feasible to design the process so that if hydrates form they can be melted before they plug equipment.

Before choosing a method of hydrate prevention or dehydration, the operating system should be optimized so as to minimize the necessary treating. Some general factors to consider include the following:

(1) Reduce pressure drops by minimizing line lengths and restrictions,

(2) Take required pressure drops at the warmest conditions possible, and

(3) Check the economics of insulating pipe in cold areas.

This chapter discusses the procedures used to calculate the temperature at which hydrates will form for a given pressure (or the pressure at which hydrates will form for a given temperature), the amount of dehydration required to assure that water vapor does not condense from a natural gas stream, and the amount of chemical inhibitor that must be added to lower the hydrate formation temperature. It also discusses the temperature drop that occurs as gas is expanded across a choke. This latter calculation is vital to the calculation of whether hydrates will form in a given stream.

CHAPTER TWO
LITERATURE REVIEW

CHAPTER II - LITERATURE REVIEW

2.1 STUDY REVIEW

- **Researchers** have usually studied the hydrate formation process to better understand the performance of kinetic inhibitors. However more recently, hydrate formation has been in focus in the production of hydrates for storage and transport of natural gas, gas separation, exploitation of gas hydrate deposits and depositing of CO_2 hydrates on the sea floor. The increasing number of published articles on hydrate formation in the four consecutive **international gas hydrate conferences** (Sloan, Happel and Hnatow, 1994, Monfort, 1996, Holder and Bishnoi, 2000, Mori, 2002) illustrates the large interest in hydrate formation issues.
- **Sir Humphry Davy first discovered gas hydrates in 1810** when he noticed that a solid was formed from a solution of chlorine gas (then known as oxy-muriatic gas) and water above the ice point. The discovery may have even preceded Davy, as in 1778 Priestley discovered compounds (formed from freezing SO_2 in water) that may have been clathrate hydrates, but the lack of adequate documentation makes this earlier discovery uncertain.
- **Gas hydrates** were not considered to have any practical relevance until 1934, when Hammer Schmidt discovered that gas hydrates rather than ice were responsible for plugging gas transmission lines in Canada.
- Although hydrates were probably encountered by others earlier, credit for their discovery is usually given to the famous English chemist, Sir Humphrey Davy. He reported of the hydrate of chlorine in the early nineteenth century. In particular, he noted (1) that the ice-like solid formed at temperatures greater than the freezing point of water, and (2) that the solid was composed of more than just water. When melted, the hydrate of chlorine released chlorine gas.
- Davy’s equally famous assistant, Michael Faraday, also studied the hydrate of chlorine. In 1823, Faraday reported the composition of the chlorine hydrate. Although his result was inaccurate, it was the first time that the composition of a hydrate was measured.
- Throughout the nineteenth century, hydrates remained basically an intellectual curiosity. Early efforts focused on finding which compounds formed hydrates and under what temperatures and pressures they would form. Many of the important hydrate formers were discovered during this era.

2.2. HYDRATES DEFINITION

Natural Gas hydrates are crystalline compounds with ice-like consistency that occur when small gas molecules come into contact with water at or below a certain temperature.

Figure (2.1): Crystal Structure of Gas Hydrates

2.3. GAS HYDRATES STRUCTURES

Gas hydrates form pentagonal cubic structures in their crystal lattice. The hydrocarbon molecules (in this case methane) are lodged in the center of the cubes and bounded (caged) by water molecules.

There are three different forms of hydrate crystal structures. These are; the **cubic structure I (SI)**, **cubic structure II (SII)** and **hexagonal structure (isometric) lattice H (SH).** Gas such as methane (CH_4) and carbon dioxide (CO_2) mostly form SI hydrates while natural gas form (SII) hydrates. The properties of structures I and II hydrates are well defined. Research into structure **H** hydrates is relatively new, and their properties are less well defined. All the structures contain large and small cavities but only molecules with the appropriate size and geometry enter the cavities (Dorstewitz, et al 1994). **Figure** (2.2) shows the physical geometry and lattice structure of methane hydrates, it shows that the gas molecule is located at the center of the water cavity.

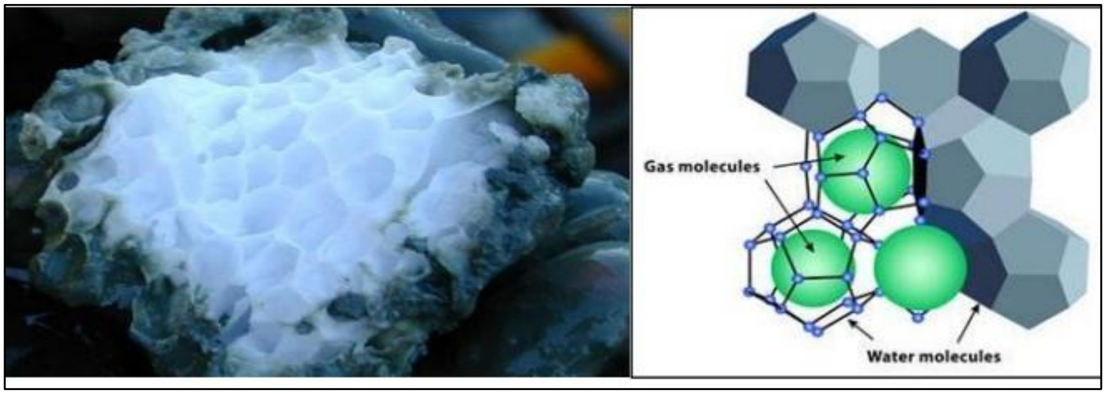


Figure (2.2): Physical Geometry and Lattice Structure of Gas Hydrates (Studentenergy.org)

Methane and natural gas typically form hydrate Structure (I) but forms Structure (II) or H if higher hydrocarbons are present in the gas mixture as is the case with thermogenic gas components (Riedel, et al 2010). Figure (2.3) shows the lattice structure of the gas hydrate.

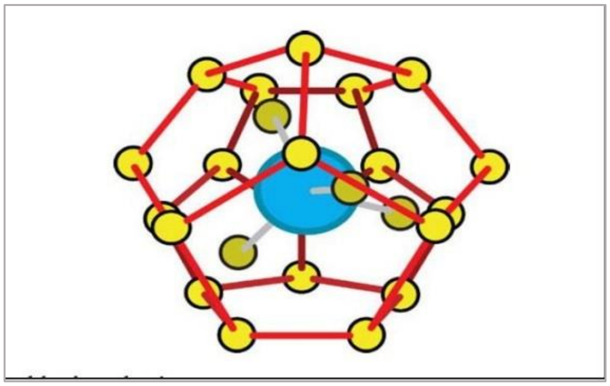


Figure (2.3): Lattice structure of gas hydrates (Bellarby, 2009)

2.3.1. The Structure I (SI)

Structure (I) has two main structures of cavities: a small pentagonal dodecahedral cavity which consists of 12 pentagonal rings of water (20 molecules of water) and a large tetra-kaidekahedral cavity consisting of 2 hexagonal and 12 pentagonal rings of water (24 molecules of water) (Koh, et al 2002). The arrangement of the cubic cavities is an in-body-centered packing and the cavities are large enough to contain methane, ethane, and gases having a similar range of molecular diameter such as hydrogen sulfide and carbon dioxide hydrates (Sami, et al 2013).

2.3.2. Structure II (SII)

Structure (II) also has two main structures: a pentagonal dodecahedral cavity and a large hexakai-decahedral cavity which consists of 12 pentagonal and 4 hexagonal rings of water (28 molecules of water). They are packed like diamonds in an octagonal shape, this leads to some cavities being large enough to contain not only ethane and methane but also larger gas molecules such as isobutane and propane.

2.3.3. Structure H

This structure requires both small molecules such as methane and larger molecules of typical gas condensates or oil fractions. Figure (2.4) shows the cell units and structures of hydrates (Sami, et al 2013).

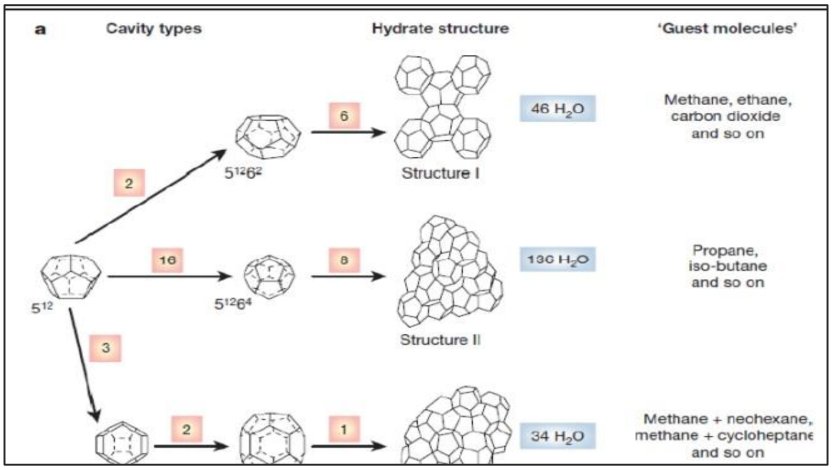


Figure (2.4): Cell unit structures of gas hydrate structure I, II, and H (Sami, et al 2013)

2.4 GAS HYDRATE FORMATION

Gas hydrates are formed when water and gas (having lower molecular weight) Combine at low temperature and generally high pressure (e.g. temperatures below 2°C and pressures greater than 1.5MPa for natural gas hydrates) (Koh, et al 2001), precise conditions vary depending on the composition of the fluid. The gases that can form gas hydrates include methane (predominantly), propane, ethane, butane, chlorine, CO_2, nitrogen even oxygen can create hydrates. At high pressure, gas hydrates can exist at temperatures greater than the freezing point of water. The solid hydrate compounds form with the aforementioned gases at elevated pressures in the presence of water.

The hydrate formation temperature increases with increasing pressure, therefore the hydrate risk is greatest at higher pressures and lower temperatures. When hydrates form inside pipelines, they can form plugs which obstruct flow. In even worse scenarios, where the presence of a hydrate plug was undetected, pipeline depressurization has resulted in the plug being dislodged unexpectedly, resulting in serious injury and even fatalities. These are some of the reasons that hydrates are a serious flow assurance concern.

Hydrates can very easily form downstream of a choke where fluid temperature can drop into the hydrate formation region due to Joule-Thompson cooling effects.

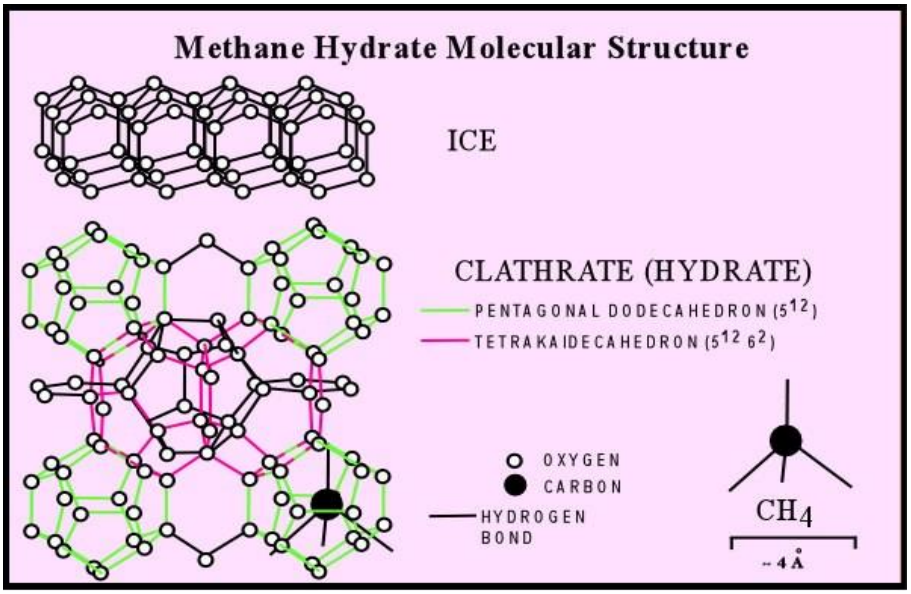


Figure (**2.5**): Methane Hydrate Molecular Structure

The following figure shows a typical gas hydrate curve which is very useful for subsea pipeline design and operations.

On the left side of the curve is the hydrate formation region. When pressures and temperatures are in this region, hydrates will form from the water and gas molecules.

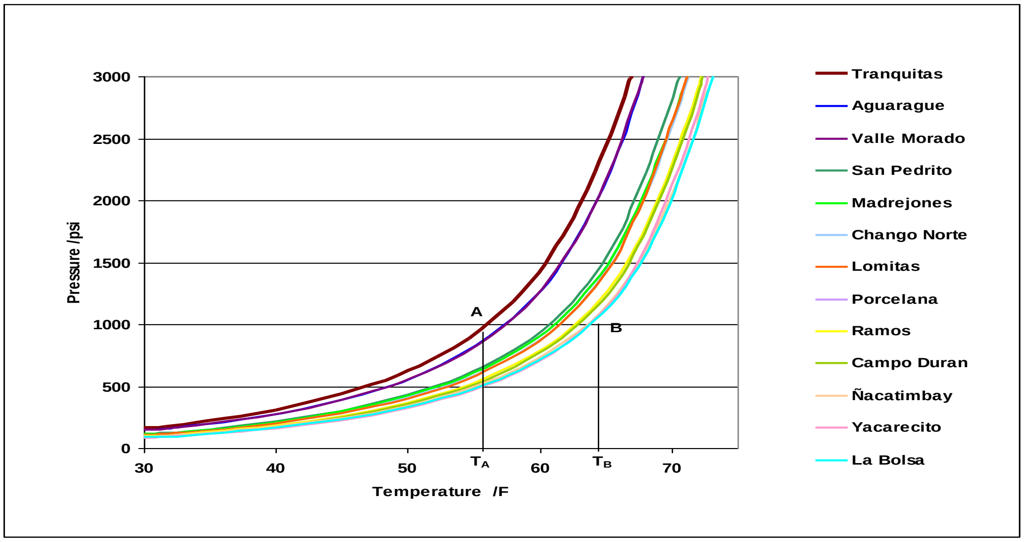


Figure (2.6): Typical Hydrate Press. / Temp. Curve

Many factors impact the hydrate curve including fluid composition, water salinity and the presence of hydrate inhibitors.

Note: Generating Hydrate curves requires the **PIPESIM** Multi-flash Hydrate license feature. Hydrate curves cannot be generated with the E300 or GERG Flash packages.

2.4.1 Stages of Hydrate Formation

There are three main stages of hydrate formation: gas dissolution, hydrate nucleation, and lastly agglomeration as shown in Figure (2.7)

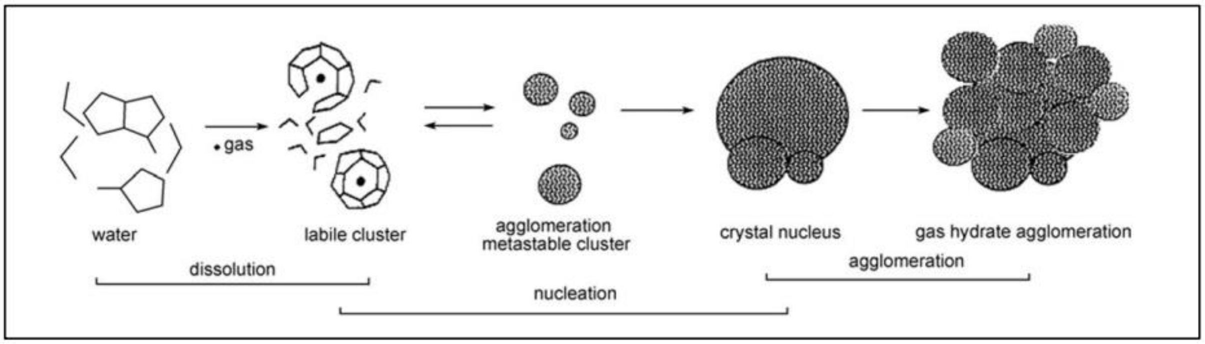


Figure (2.7): Stages of Hydrate Formation (Tang, et al 2010)

Tang, et al, 2010 found that under suitable conditions, water molecules form quasi-cavities from hydrogen bonds. Gas molecules are trapped inside these quasi-cavities when the gases dissolve, forming labile clusters. The clusters which are in quasi-equilibrium agglomerate and continue to attach until a critical radius is reached from which a stable hydrate nucleus is formed. It was found that during hydrate formation, ethane and methane occupy the smaller cavities while propane occupies large cavities. Also, when hydrates form there is a significant depletion of gas content, therefore gases in the fluid stream are consumed significantly (Tang, et al 2010).

2.4.2. Mechanisms of Hydrate Formation

The formation and deposition of hydrates in pipelines involve several processes from the formation of hydrate particles to the deposition and accumulation (growth) of the hydrate layer on the surface of the pipe. To forecast this dynamic deposition of hydrates in a pipeline, a model was developed by Zhang, et al 2019 in which the heat transfer and the hydrodynamic hydrate behavior in the pipeline were investigated. The model consisted mainly of two parts: Hydrate deposition and water condensation.

2.4.2.1 Heat Transfer

The temperature difference between the cold environment and the hot gas in the pipeline is large enough to cause heat transfer between gas pipelines in cold regions and the subsea floor (Gu, et al 2019), as a result, water condenses when the temperature of the fluid falls below the dew point temperature. In cold regions and subsea levels, low temperature and high flow pressure in pipelines causes the molecules of natural gas to diffuse around the surface of water to form hydrates which adhere to the inner surface of the pipe, this leads to variations in fluid velocity, effective inner diameter and the pressure in the pipeline relative to position and time (Rao, et al 2013). The heat exchange between the external environment and fluid leads to a decrease in fluid temperature and this takes place along the direction of fluid flow as shown in Figure (2.8) (Zhang, et al 2019).

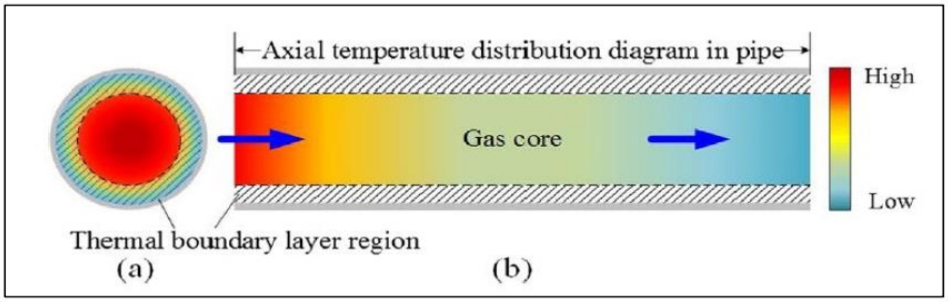


Figure (2.8): Fluid flow in a pipe showing its Thermal boundary layer region (Zhang, et al 2019)

2.4.2.2 Dissolved Water Condensate

There are two sources of liquid moisture in gas pipelines in cold regions and subsea levels: small droplets in the gas core and the liquid condensate film near the wall (Zhang, et al 2019). A heat boundary layer having a high variation in temperature forms on the surface of the pipe as shown in Figure (2.9). This is due to a significant difference in temperature between the fluid and the environment during long-distance gas transmission in cold regions and subsea levels (Dorstewitz, et al 1994). When the fluid temperature falls below the dew point, the free water condenses and precipitate around the heat boundary layer, a liquid film forms on the pipe wall and there is a significant drop in temperature along the axis of the pipeline, as a result, water condenses on the surface of insoluble particles and small droplets form on the gas core (Gorbunov, et al 1998). Gas molecules continue to diffuse around the liquid condensate in the fluid system which consists of a thin liquid film near the pipe wall and small droplets in the gas core. A hydrate shell forms rapidly on the surface of liquid droplets when the pressure and temperature satisfy equilibrium conditions for hydrate formation, the shell grows inside the droplet to form hydrates. Also, the liquid film on the surface of the pipe wall crystallizes with gas molecules to form hydrates. These two types of hydrates deposit and accumulate on the inner wall of the pipeline to form larger hydrate layers. These processes continue until the thickness of the hydrate increases as shown in Figure (2.9).

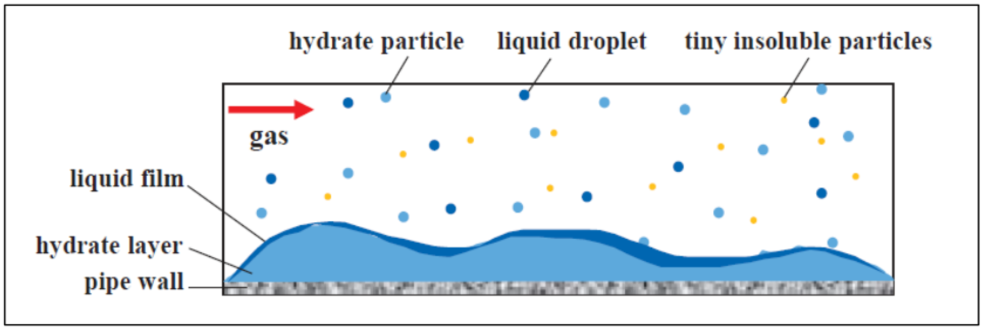


Figure (2.9): Schematic of hydrate formation and deposition mechanism in subsea and cold region long distance gas transmission pipelines (Zhang, et al 2019)

The formed hydrate particles and the condensate droplets are transported downstream by the high-speed fluid due to their densities being in the same range.

2.4.2.3 Hydrate Layer Growth

The growth of hydrate layers is primarily due to the deposition process which combines the hydrates from scattered drops and thin condensate film (Zhang, etc. al2019). The hydrate particles adhere to the pipeline wall due to strong adhesive forces between the wet pipe wall and the hydrates. New hydrate particles form from condensed water keeping the hydrate concentration in the pipe in constant dynamic equilibrium.

2.5. CAUSES OF HYDRATE FORMATION

The causes of gas hydrate are subdivided into primary and secondary causes.

2.5.1. Primary Causes of Hydrate Formation

The formation of gas hydrates in natural gas transmission pipelines depends primarily on the temperature, pressure, and composition of the gas-water vapor mixture (Hammer Schmidt, 1934). After all primary conditions are in effect, hydrate formation is accelerated by pressure, high velocities of the gas stream, and pulsations. As shown by the melting point diagram in **figure** (2.12), high pressure and low temperature are favorable to the formation of hydrates. On a practical basis, water vapor is the only component that can be controlled regarding the composition of the gas. Although removing moisture from the gas will eliminate the possibility of any hydrate forming, it is not necessary for the gas to be free of water vapor since hydrates only form when the gas reaches the dew point. Also, if the partial pressure of water vapor in the gas is less than the vapor pressure, the gas hydrate will lose water and dissociate. The driving force behind phase change from gas to solid hydrates is thermal sub-cooling. In this case, the phase change is caused by the temperature difference between the bulk temperature and the hydrate dissociation temperature (Hammer Schmidt, 1934).

The conditions of temperature and pressure are represented in disassociation curves where hydrates separate into gas and water as shown in Figure (2.10). The point of hydrate formation lies within the curve, this means that hydrates are certain to form within the curve but will not form immediately if the temperature/ pressure point lay outside the disassociation curves (Saleh, 2002). The risk of hydrate agglomeration increases further inside the curve although there is a time delay with an undefined duration. The curves are generated based on experimental values or numerical predictions using the Katz gas gravity chart (Zhang, et al 2019).

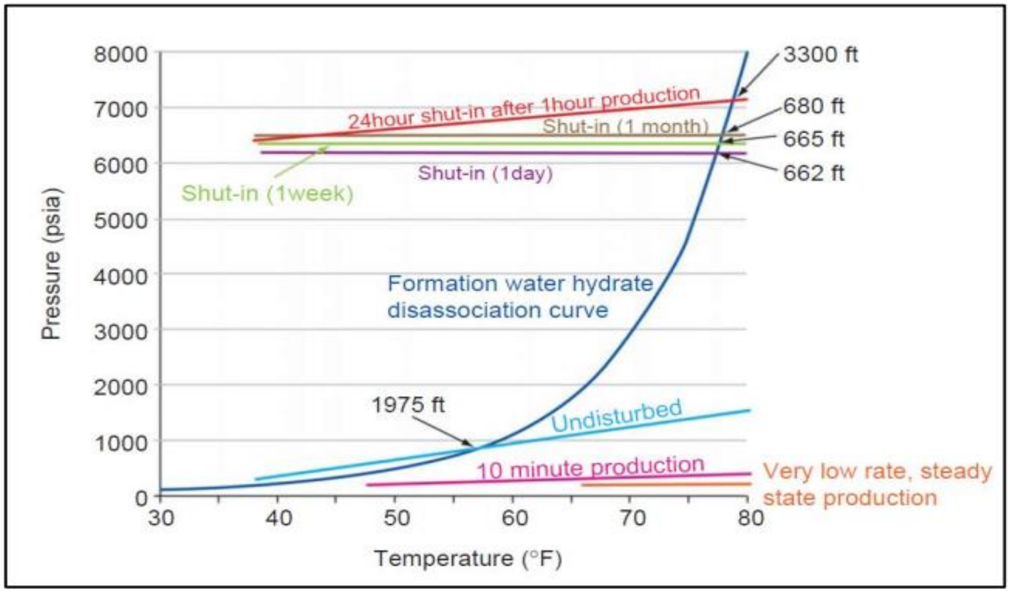


Figure (2.10): Disassociation curves showing the conditions of temperature and pressure (Zhang, et al 2019).

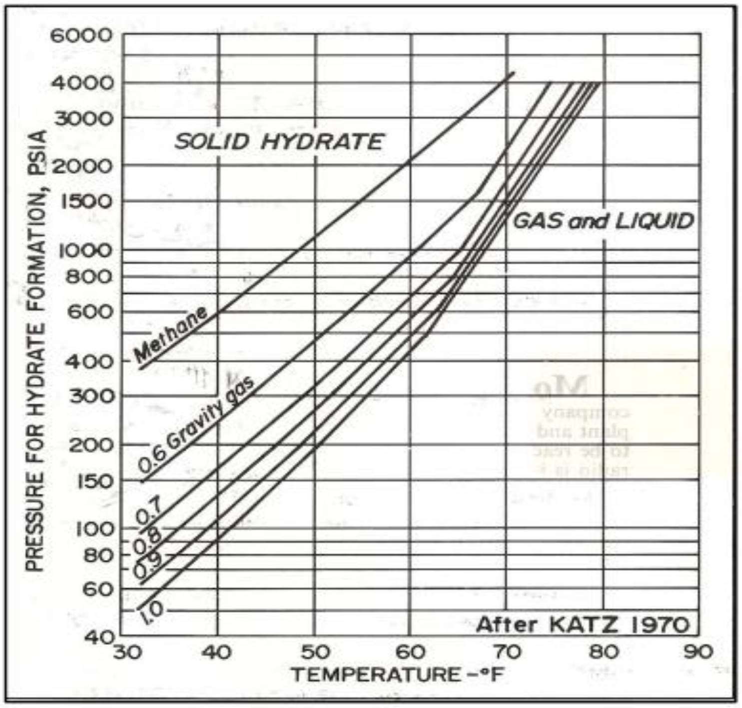


Figure (2.11): Shows Katz’s 1945 gas gravity chart (Bahadori and Vuthaluru, 2009)

2.5.2 Secondary Causes of Hydrate Formation

As previously stated, a definite pressure, temperature, and gas-water composition are necessary for gas hydrates to form. However, it is not certain that hydrates will crystallize even after these conditions are met (Hammer Schmidt, 1934). Certain secondary factors influence the formation of hydrates, these are:

1. Gas Stream velocity.
2. Arrangement of the molecule of crystals.
3. Water saturation (water vapor).
4. Porosity.

2.5.2.1. Gas Stream Velocity

High gas velocity, pressure pulsation of the gas (due to compressors), or introducing small amounts of hydrate crystal can hasten the formation of hydrates. Under operating conditions, high gas stream velocity in the pipeline creates almost ideal conditions for the formation of hydrates provided the proper conditions of temperature, pressure, and water composition are established (Eucken. 1925).

2.5.2.2 Arrangement of crystal molecules

The general behavior of crystal formation described by Eucken (1925) explains the secondary causes of hydrate formation, it states that the formation of a crystal requires mostly a definite adjustment or generally a certain arrangement of molecules, this may not always is established at once and the lack of which is characterized by the liquid phase. Ideally, a certain amount of time elapses before the required numbers of molecules align into the correct position either by coincidence or accident. It is only after a nucleus or elementary crystal is formed that crystallization proceeds smoothly, this exerts a certain directional force on the neighboring liquid molecules and causes them to merge. As a result, hydrate formation is promoted by forces which tend to stir or mix, because the probability of the molecules aligning into the correct position is increased by those forces. Also, high-pressure pulsations and velocity impact a mixing action on the droplets of condensed moisture (Hammer Schmidt, 1934).

2.5.2.3 Water Saturation (Water Vapor)

During the process of transporting natural gas, water is removed from the gas before transporting through pipelines; this is called separation and dehydration. However, these processes only remove the free water in the gas, therefore the pipeline system is a water-saturated gas transmission system. The phenomenon of hydrate deposition in pipelines was observed by (Lingelem, et al 1994), they suggested that for a water saturated gas system the mechanism is similar in a continuous gas system, having small proportions of free water. Gorbunov, et al 1998 verified that condensation of water vapor takes place on the surface of small-size insoluble particles, it also determined that vapor heterogeneous phase nucleation forms alone on the surface of suspended particles with soluble sites. Gas molecules constantly diffuse in the gas core around the surface of the condensate liquid drops.

2.5.2.4 Porosity

Natural gas produced from the reservoir stratum generally contains small-sized insoluble particles, as a result, in an environment where small-sized in soluble particles are suspended, supersaturated vapor molecules collide constantly and undergo initial heterogeneous phase nucleation on particle surfaces. Nicholas, et al. 2008 found in a study that porosity influenced the thickness of hydrate deposition in the pipelines significantly. Free water is the main constraint of hydrate formation/ deposition when conditions of pressure and temperature reach hydrate has equilibrium in a water-saturated gas system. The study proposed that the condensate of free vapor on the cold walls of the pipe formed the free water in a water-saturated system.

2.5.3 Other Factors Affecting Hydrate Formation

Other factors that influence hydrate formation include (Zhang, et al 2019):

1. Adhesion between hydrate particles and the pipe wall.
2. Spatial distribution characteristic of the gas-liquid phase, and
3. Fluid flow rate.

Particle surface energy, the thickness of the dielectric layer, and Haymaker number affect the nature of deposition of the particles (Chein, et al 2005). A parametric analysis was carried out by (Chaudhari, et al 2018) to investigate the effect of mixture velocity, liquid loading, and interfacial tension on hydrate formation with the use of hydrate risk correlation which uses the steady-state and transient dynamic multiphase flow simulation on a long subsea tieback. The study deduced that the flow assurance risk increases with an increase in mixture velocity and liquid loading, however it decreases with a decrease in the interfacial tension.

2.6 CONDITIONS FOR HYDRATE FORMATION

The gas hydrate stability region is restricted to the left of curve CD **Figure** (2.12), where the nucleation driving force is very high and nucleation occurs easily. In the metastable region nucleation may also occur, but will probably have an increased induction time relative to the stable region. The driving force, as most processes in thermodynamics, is related to Gibbs free energy. Assuming an isothermal and isobaric process Gibbs free energy for a vapor and water system will be given as:

$$\Delta G^{\text{driving}} = \Delta G^{\text{reactants}} - \Delta G^{\text{products}} = \Delta G^{\text{Water}} + \Delta G^{\text{Vapor}} - \Delta G^{\text{Hydrate}} \qquad (1)$$

$$\Delta G^{\text{Water}} = x_w^{II}(\mu_i^{II} - \mu_i^{I}) = V_W(P^{eq} - P^{I}). \qquad (2)$$

$$\Delta G^{\text{Vapor}} = \sum X_i^{II}(\mu_i^{II} - \mu_i^{I}) = RT \sum X_i^{II} \ln\left(\frac{f_i^{II}}{f_i^{I}}\right). \qquad (3)$$

$$\Delta G^{\text{Hydrate}} = x_w^{H,II}(\mu_w^{H,II} - \mu_w^{H,I}) + \sum x_i^{H,I}(\mu_i^{H,II} - \mu_i^{H,I}) = v_H(P^{I} - P^{eq}). \qquad (4)$$

Combining these equations leads to the following expression for the nucleation force:

$$\Delta G^{\text{driving}} = v_w(P^{eq} - P^{I}) + RT \sum x_i^{II} \ln\left(\frac{f_i^{II}}{f_i^{I}}\right) + v_H(P^{I} - P^{eq}) \qquad (5)$$

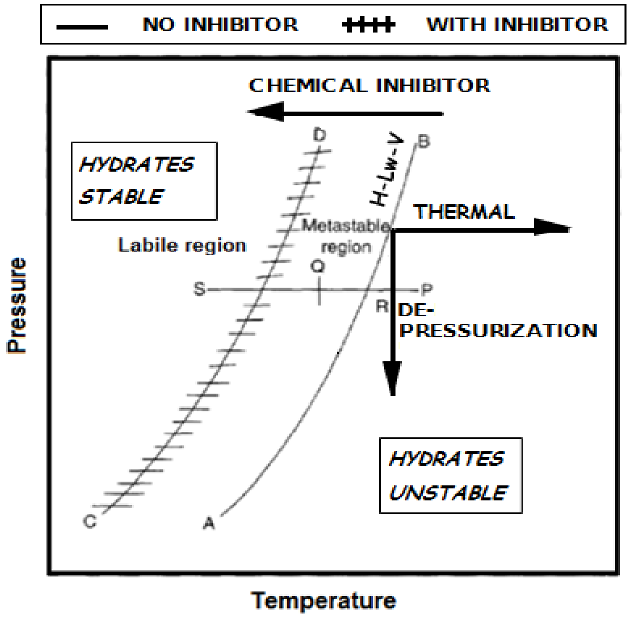


Figure (2.12): Stability region for hydrate nucleation (Sloan and Koh, 2008).

From equation (5) it is easily observed that differences in Gibbs free energy may occurs as changes in chemical potential, fugacity, pressure and temperature. By varying these parameters hydrate formation or dissociation can be controlled. Makogon (Makogon et al., 1999) summarized the following conditions for hydrate formation:

1. It has to be thermodynamically favorable ($\Delta G < 0$).
2. Availability of hydrate constituents (water and hydrate former).
3. Heat transport during hydrate formation to remove latent heat of fusion.

2.6.1 Hydrate Forming Conditions

Hydrates can form when 4 ingredients are present:

- ☐ Free water
- ☐ Natural gas (N_2, H_2S, CO_2, C_1, C_2, C_3, iC_4)
- ☐ Reduced temperature
- ☐ Increased pressure

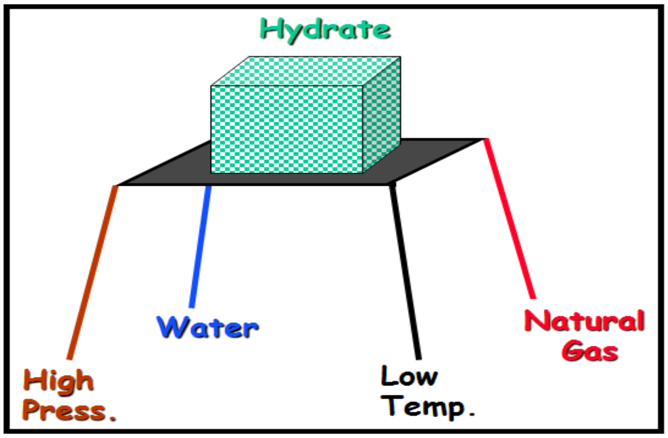


Figure (2.13): Elements Necessary for Hydrate Formation

2.7. PHYSICAL PROPERTIES OF HYDRATES

In the design of processes, the physical properties are important. This is no less true when the processes involve hydrates. The estimation of the properties of hydrates is complicated by the fact that the properties depend on:

1. The type of the hydrate,
2. The guest molecule engaged in the hydrate, and
3. The degree of saturation (remember that hydrates are non-stoichiometric).

It is unfortunate, but most hydrate programs do not give the saturation numbers as a part of their calculations. An exception is CSMHYD, which does give saturation values. The newer CSMGEM gives composition of the hydrate phase, but not specifically the cell saturation. The heat capacity, electrical, and mechanical properties of hydrates are similar to those for ice. The thermal conductivity is unique because itis significantly different from that of ice (Handa and Cook, 1987), as we shall see.

2.7.1. MOLAR MASS

The molar mass (molecular weight) of a hydrate can be determined from its crystal structure and the degree of saturation. The molar mass of the hydrate, **M**, is given by:

$$M = \frac{N_W M_W + \sum_{j=1}^{c} \sum_{i=1}^{n} Y_{ij} v_i M_j}{N_W + \sum_{j=1}^{c} \sum_{i=1}^{n} Y_{ij} v_i} \qquad (6)$$

<u>Where</u>:

N_W - is the number of water molecules per unit cell (46 for Type I, 136 for Type II, and 34 for Type H),

M_W - is the molar mass of water,

Y_{ij} - is the fractional occupancy of cavities of type **i** by component **j**,

ni - is the number of type **i** cavities, **n** is the number of cavities of type **i** (two for both Type I and II, but is three for Type H), and **c** is the number of components in the cell. Although this equation looks fairly complicated, it is just accounting for all of the molecules present and then using a number average to get the molar mass.

Table (2.1) Molar Masses of Some Hydrates at 0 C

		Saturation		
	Hydrate type	Small	Large	Molar mass (g/mol)
Methane	I	0.8723	0.9730	17.74
Ethane	I	0.0000	0.9864	19.39
Propane	II	0.0000	0.9987	19.49
Isobutane	II	0.0000	0.9987	20.24
CO_2	I	0.7295	0.9813	21.59
H_2S	I	0.9075	0.9707	20.87

Note: calculated using Equation (6). The saturation values were calculated using CSMHYD.

Table ( ) Summarizes the molar masses of a few hydrate formers. It is a little surprising that the molar masses of all six components are approximately equal (w20 g/mol). This is because the hydrate is composed mostly of water (18.015 g/mol). It is interesting that the molar masses of hydrates are a function of the temperature and the pressure, since the degree of saturation is a function of these variables. We usually think of molar masses as being constants for a given substance.

2.7.2. DENSITY

The density of a hydrate, r, can be calculated using the following formula:

$$\rho = \frac{N_W M_W + \sum_{j=1}^{c} \sum_{i=1}^{n} Y_{ij} v_i M_j}{N_A V_{cell}} \qquad (7)$$

Where:

N_W - is the number of water molecules per unit cell (46 for Type I, 136 for Type II, and 34 for Type H),

N_A - is Avogadro's number (6.023 1023 molecules/mole),

M_W - is the molar mass of water,
Y_{ij} - is the fractional occupancy of cavities of type i by component j,
ni - is the number of type **i** cavities,
V_{cell} - is the volume of the unit cell (see Table 2.1),
n - is the number of cavities types (two for both Type I and II, but is three for Type H), and **c** is the number of components in the cell.

Equation (7) can be reduced for a single component in either a Type **I** or Type **II** hydrate to:

$$\rho = \frac{N_W M_W + (Y_1 v_1 + Y_2 v_2) M_j}{N_A V_{cell}} \qquad (8)$$

Again, although Equations. (7) and (8) look complicated; they are just accounting for the number of molecules in a unit cell of hydrate. The mass of all of these molecules divided by the unit volume of the crystal gives the density of the hydrate.

Table (2.2) Densities of Some Hydrates at 0 °C

Components	Hydrate type	Density (g/cm^3)	Density (Ib/ft^3)
Methane	I	0.913	57.0
Ethane	I	0.967	60.3
Propane	II	0.899	56.1
Isobutane	II	0.934	58.3
CO_2	I	1.107	69.1
H_2S	I	1.046	65.3
Ice	-	0.917	57.2
Water	-	1.000	62.4

Note: calculated using Equation (8). The saturation values were calculated using CSMHYD. Properties of ice and water from Keenan et al. (1978)

When using these equations, be careful with the units. Follow the examples at the end of the chapter closely. As noted earlier; most hydrate software packages do not give the degree of saturation, making it difficult to calculate the density of the hydrate. The K-factors from the Katz method (Chapter) do not give the saturation, even though they have the appearance of doing so. Remember, the compositions thus calculated are on a water-free basis.

The densities of some pure hydrates at 0 °C are given in Table ( ). Note that the densities of the hydrates of the hydrocarbons are similar to ice. The hydrates of carbon dioxide and hydrogen sulfide are significantly denser. In fact, they are denser than water.

2.7.3. ENTHALPY OF FUSION

Another useful property is the enthalpy of fusion of the hydrate (sometimes called the heat of formation). From this, the amount of heat required to melta hydrate can be estimated. Table ( ) lists some enthalpies of fusion for a few hydrates. Ice is included for comparison. These values represent the formation of a hydrate from liquid water and a gaseous guest molecule. This explains why they are significantly larger than the heat of fusion of water. For pure water, the ice is becoming liquid. When a hydrate melts, it forms a liquid and a gas and the gas is a more highly energetic state.

On the other hand, the enthalpies of fusion are comparable to the enthalpy of sublimation of ice (the phase change going from a solid directly to a gas).

Table (2.3) Enthalpies of Fusion for Some Gas Hydrates

	Hydrate Type	Enthalpy of fusion (Kj/g)	Enthalpy of fusion (Kj/mol)	Enthalpy of fusion (Btu/Ib)
Methane	I	3.06	54.2	1320
Ethane	I	3.70	71.8	1590
Propane	II	6.64	129.2	2850
Isobutane	II	6.58	133.2	2830
Ice	-	0.333	6.01	143

<u>Note</u>: Molar enthalpies of fusion converted to specific values (i.e., per unit mass) by using the molar masses from Table 8.1.Original values from Sloan (1998). Properties of ice and water from Keenan et al. (1978).

For water, this is 2.83 kJ/g or 51.0 kJ/mol. This process is probably more comparable to the formation of a hydrate than is the simple melting of ice. One method for estimating the effect of temperature on the heat of fusion is the so-called Clapeyron approach. A Clapeyron-type equation is applied to the three-phase locus. The Clapeyron-type equation used in this application is:

$$\frac{\mathrm{d}\ln P}{\mathrm{d}1/\mathrm{T}} = -\frac{\Delta \mathrm{H}}{zR} \qquad (9)$$

<u>Where</u>:

DH - is the enthalpy of fusion, **z** is the compressibility factor of the gas at the conditions of interest, and

R - is the universal gas constant. Inherent in this equation is the assumption that the molar volume of the liquid and the hydrate are insignificantly small in comparison to that of the gas; also, this is the only assumption in Equ. (9).

From the correlation provided in chapter, the derivative required for Equ. (9) is obtained as follows:

$$\frac{d\ln P}{d1/T} = BT^2 - C + DT \qquad (10)$$

Therefore, to calculate the heat of fusion, an analytical expression is required for the three-phase locus. This expression is then differentiated and the enthalpy of fusion is calculated.

2.7.4. HEAT CAPACITY

There are limited experimental data for the heat capacity of hydrates. Table ( ) Lists some values. For comparison, ice is also included in this table. Over the narrow range of temperatures that hydrates can exist, it is probably safe to assume that these values are constants.

Table (2.4) Heat Capacities for Some Gas Hydrates

	Hydrate Type	Heat capacity (J/g C°)	Heat capacity (J/mol C°)	Heat capacity (Btu/Ib F°)
Methane	I	2.25	40	0.54
Ethane	I	2.2	43	0.53
Propane	II	2.2	43	0.53
Isobutane	II	2.2	45	0.53
Ice	-	2.06	37.1	0.492

Original values from Makogon (1997). Properties of ice and water from Keenan et al. (1978).

2.7.5 THERMAL CONDUCTIVITY

There have been limited studies into the thermal conductivity of hydrates. However, they show that hydrates are much less conductive than ice. The thermal conductivity of ice is 2.2 W/m K, whereas the thermal conductivities of hydrates of hydrocarbons are in the range 0.50 0.01 W/m K. The thermal conductivity is a key parameter in the process to melt-hydrates. This relatively small value is one of the reasons why hydrates take a long time to melt.

2.7.6. MECHANICAL PROPERTIES

In general, the mechanical properties of hydrates are comparable to those of ice. In the absence of additional information, it is safe to assume that the mechanical properties of the hydrate equal those of ice. One should not assume that hydrates are soft, slushy material. Hydrate blocks can be as hard as ice. When projected from a pipe under **high velocity** they can do significant damage.

$$V = nRT/P = (7.257)(8.314)(15+273)/101.325$$
$$= 171.5\ \mathrm{Sm}^3$$

2.7.7. VOLUME OF GAS IN HYDRATE

The purpose of this section is to demonstrate the volume of gas engaged in a hydrate. For the purposes of this section, we will examine only the methane hydrate. The following are the properties of the methane hydrate at 0 C: the density is 913 kg/m^3, the molar mass (molecular weight) is 17.74 kg/kmol, and methane concentration is 14.1 mol percent d this means there are 141molecules of methane per 859 molecules of water in the methane hydrate. The density and the molar mass are from earlier in this chapter and the concentration is from Chapter.

This information can be used to determine the volume of gas in the methane hydrate. From the density, 1 m^3 of hydrate has a mass of 913 kg. Converting this to moles, 913/17.74 ¼ 51.45 kmol of hydrate, of which 7.257 kmol are methane. The ideal gas law can be used to calculate the volume of gas when expanded to standard conditions (15 C and 1 atm or 101.325 kPa). Therefore, 1 m^3 of hydrate contains about 170 Sm^3 of methane gas. Or, in American Engineering Units, this converts to 1 ft^3 of hydrate contains 170 SCF of gas don't a difficult conversion. And 1 ft^3 of hydrate weighs about 14.6 lb, so 1 lb of hydrate contains 11.6 SCF of methane. By comparison, 1 m^3 of liquid methane (at its boiling point 111.7 K or 161.5 C) contains 26.33 kmol, which converts to 622 m^3 of gas at standard conditions. Alternatively, 1 m^3 compressed methane at 7 MPa and 300 K (27 C) (1015 psia and 80 °F) contains 3.15 kmol or 74.4 Sm^3 of methane gas. The properties of pure methane are from Wagner and de Reuck (1996). To look at this way, to store 25,000 Sm^3 (0.88 MMSCF) of methane requires about 150 m^3 (5300 ft^3) of hydrates. This compares with 40 m^3 (1400 ft^3) of liquefied methane, or 335 m^3 (11,900 ft^3) of compressed methane.

2.7.8. ICE VERSUS HYDRATE

The properties of hydrates over wide ranges of conditions are not readily available. In the absence of additional information, one might be tempted to assume that the property of the hydrate is the same as that for ice. However, as some of the examples have shown, this may lead to significant errors Different dielectric constant.

Different thermal conductivity (2.23 W/m-K ice, vs 0.5 W/m-K hydrate).

Ice has thirteen a different crystalline phases which exist at different temperatures and pressures. Hexagonal ice (ice Ih) is the most common solid form of water, and due to tetra-hydral bonded waters, it has some resemblance to gas hydrates. Ice Ih forms by freezing water at atmospheric pressure and is stable to 150 K. At temperatures lower than 150 K and at high pressures other phases of ice will form, as shown in **Figure** (2.14).

Figure (2.14) illustrates the molecular structural lattice of ice III developed by Pauling in 1935, where none of the interconnected water molecules have the same directional orientation.

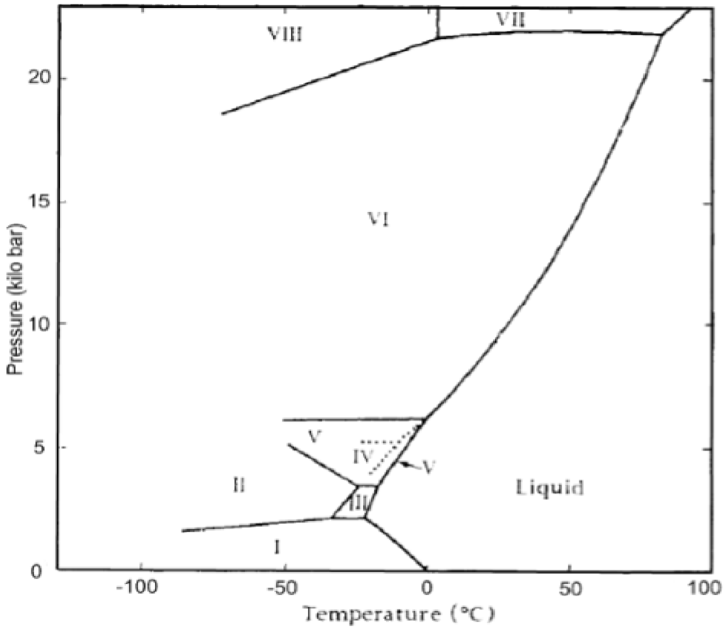


Figure (2.14): Phase diagram illustrating stability regions for the different phases of ice. This figure does not include all phases of ice, only the first nine.

The oxygen atoms are separated by a hydrogen atom or a proton in both ice III and hydrates, and the hydrogen bond is only 1% longer in the hydrate. In ice there is a tetrahedral O-O-O angle (109.5°) between the oxygen atoms connected through hydrogen bonding, which results in almost no geometrical distortion. In hydrates this angle only differs by a few degrees, 3.7° for structure I and

3.0º for structure II, which is less deviation than for the high pressure ices II, III, V and VI (Davidson, 1973). The angle between the two hydrogen atoms in the water molecule is similar as well for ice III and gas hydrates.

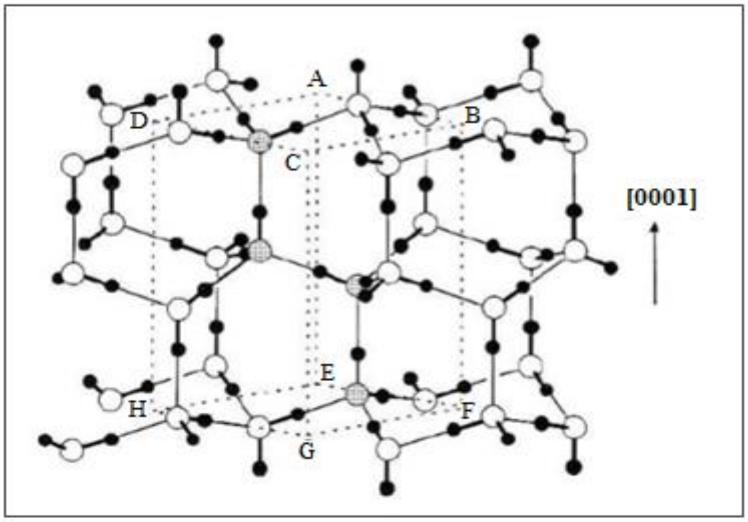


Figure (2.15): Crystal structure of ice, where the open circles illustrate oxygen atoms and the dark circles represent the hydrogen atoms

A structural feature that distinguishes clathrate hydrates from the different ice structures is the predominance of planar five-membered rings in structure II and almost planar five-membered rings in structure I. Gas hydrates on the other hand, form non-planar puckered hexagonal rings (Sloan and Koh, 2008). Comparisons of some properties among ice III and the two most common hydrate structures are shown in Table (2.5).

Table (2.5): Comparison some properties of ice and hydrate (Sloan and Koh, 2008).

Property	Ice	Structure I	Structure II
Number of water molecules	4 A=4.52	46	136
Lattice parameters (at 273K) [À]	C=7.36	12	17.30
Dielectric constant at 273K	94	58	58
H2O reorientation time [μs]	21	10	10
H2O diffusion jump time [μs]	2.70	>200	>200
Thermal conductivity [$Wm^{-1}K^{-1}$]	2.23	0.49+/-0.02	0.51+/-0.02
Density [g/cm^3]	0.91	0.91^b	1.291^c

2.8. CHEMICAL PROPERTIES OF POTENTIAL GUESTS

Another limiting factor is the chemical properties of the potential hydrate former. A molecule may be sufficiently small but it may not form a hydrate. Typically, if a gas is highly soluble in water, it will not form a hydrate. It has been shown that CO_2 and H_2S, which have significant solubility in water, form hydrates. In addition, SO_2, which is quite soluble in water, is also a hydrate former. As a rule of thumb, these represent the upper limit in terms of solubility. Gases that are highly soluble in water, such as ammonia and hydrogen chloride, do not form hydrates even though their size might lead one to believe that they should.

Alternatively, if the molecule interferes with the hydrogen bonding, a hydrate will not form. Methanol, which is a small molecule, does not form a hydrate because it is hydrogen bonded and, hence, interferes with the hydrogen bonding among the water molecules. In addition, methanol is highly soluble in water.

2.9. EFFECTS OF GAS HYDRATES

Gas hydrates have a wide range of effects on the oil and gas industry from upstream drilling and production to the midstream transmission, compression, and separation systems of natural gas. Gas hydrates are responsible for plugging in natural gas pipelines, they deposit on walls of the pipeline thereby reducing the effective flow diameter of the pipe. This causes fluctuations in the pressure of the fluid stream by causing an increase in pressure in areas where there are hydrate deposits and a decrease where there are no deposits (Sami, et al 2013).

2.9.1 .Gas Hydrate Occurrence during Drilling in Offshore Regions

The complexity and challenges of offshore drilling, increases with increase in water depth. One main challenge is the formation of gas hydrates, during deep-water drilling it is likely to encounter shallow sediments containing natural gas, if encountered; the gas could enter the drilling fluid causing gas hydrate formation under high pressure and low temperature (Poberezhny, et al 2019). Also, gas hydrates could easily form when drilling mud circulation is stopped and gas enter into the fluid, in cases where the drilling mud is not treated with hydrate inhibitors, this can lead to unexpected gas kick during drilling which can block the annular clearance, pipe or other equipment such as the blowout preventer (BOP) which may result in catastrophic failure of the system in some situations. (Xiaolan, 2011). Solid hydrates can plug well kill-lines and chokes causing problems in well control. Hydrates can stop the circulation of drilling fluid and prevent the drill string from moving if it forms in the annulus between the drilling string and casing, this can seriously affect drilling operations. Hydrates can also form in the riser, plugging the flow of drilling fluid. Figure (2.16) shows a summary of the major problems caused by gas hydrates while drilling through gas hydrate formations (Sami, et al 2013).

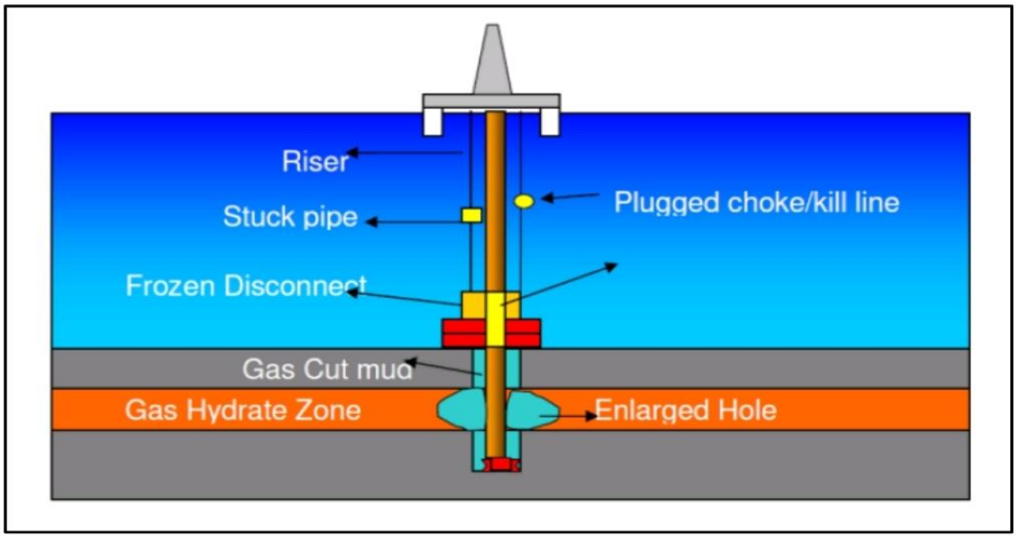


Figure (2.16): Pictorial summary of the major problems encountered during drilling operations through a hydrate formation (Sami, et al 2013).

- ☐ Plugging of choke and kill lines
- ☐ Formation of a plug at or below BOP, preventing monitoring of pressures below BOP.
- ☐ Plugging tubing, downhole tools and wireline during DST operation.
- ☐ Free water tied up with hydrates can cause thickening of the mud.

2.9.2. Problems with Flow Assurance

Pipeline transportation is a common means of transporting oil and gas from the wellhead to production sites. Gas hydrate particles form when the pressure and temperature of the fluid in the pipeline falls within the hydrate zone in the phase diagram, these hydrate particles could eventually plug the pipeline. When gas hydrates plug transmission pipelines, operations become uneconomical, production stops for weeks or sometimes months in large extended pipelines. The propagation of hydrates tends to develop a plug that gradually separates the pipe into two pressure zones: a high-pressure zone between the high-pressure gas source and the plug, and allow-pressure zone between the plug and the gas recovery section. Figure (2.17) shows atypical hydrate plug in a gas transmission pipeline (Sami, et al 2013).

Figure (2.17) Gas hydrate plugging of gas transportation pipeline (Polartrec.com)

A pipe leak and explosion can occur due to the growth in pressure. The higher pressure can destroy the pipe when there is a large difference in pressure between the upstream and downstream sections. Both failures can put personnel in danger and damage equipment.

2.9.3. Corrosion in Gas Pipelines

Gas hydrates cause pitting corrosion of pipelines that are in acidic or neutral environments. Acidic gases such as CO_2 and H_2S, when dissolved in water accelerate the internal corrosion of pipelines as the gas components of hydrate formation (Poberezhny, et al. 2017). Specimen with gas hydrates formed on the inner surface show an increased rate of localized and general corrosion on their surfaces as shown in Figure (2.18).

Figure (2.18) General view of corrosion damage of the specimen after exposure to gas hydrates (Poberezhny, et al 2019).

Poberezhny (Poberezhny, et al 2019) investigated the influence of gas hydrates on the fatigue test of a St 20 steel pipe where tests were performed at pure bending in air. Specimens were tested after exposure to gas hydrate and without any pretreatment. The curve in Figure (2.19) shows a three-stage kinetics growth of fatigue crack, also a slight higher level cyclic deformation on the fatigue growth curve was observed in the pipe after exposure to gas hydrates, it may be attributed to corrosion damage of the pipe surface.

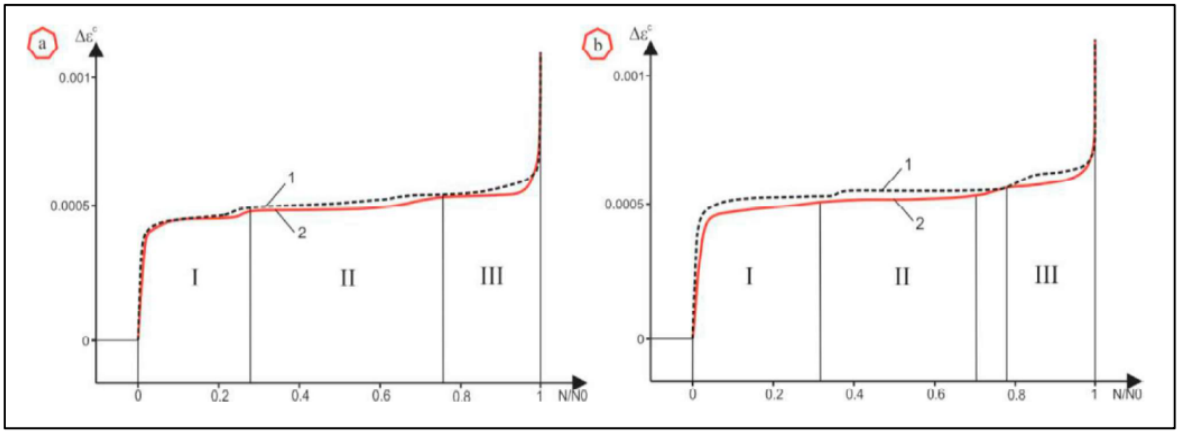


Figure (2.19): Fatigue crack growth curves for steel specimen (a) without exposure, (b) after exposure to hydrates (Poberezhny, et al 2019)

The rate of growth of fatigue crack was higher by 5-7% for the pipe specimen after exposure to hydrates compared to the specimen without pretreatment it was attributed to the increase in surface damage due to the formation of hydrates. The fatigue test shows that the duration of the low-frequency fatigue stage was influenced by hydrates causing a shortening of the stage (III) shown in Figure 2.12, this corresponds to the serviceability of the pipeline. It also shows an increase in the deformation for steel specimen exposed to hydrates. Similar behaviors were noted for materials of sea pipelines and drill pipes (Poberezhny, et al 2019).

2.9.4. The Effect of Salts on Gas Hydrate Equilibrium Pressure

The presence of salts in solution causes shift in equilibrium pressures and temperatures. For the calculation of this shift, the concept of **NaCl** equivalent weight percent was used [31, 32]. The procedure for the calculation of **NaCl** equivalent weight percent is discussed in references 84 and 85. After the calculation of **NaCl** equivalent, the shift in gas hydrate equilibrium temperature could be calculated according to the following formula (11). [31].

$$\Delta \mathbf{T} = (\mathrm{C1W} + \mathrm{C2W2} + \mathrm{C3W3}) \times (\mathrm{C4\ Ld(P)} + \mathrm{C5}) \times (\mathrm{C6(P0} - 1000) + 1) \quad (11)$$

Where:

W - is NaCl equivalent weight percent,

P - is pressure in KPa and

P0 - is the equilibrium pressure of gas hydrate formation for a water-gas system without any salt.

Also the coefficients **C1** to **C6** are given in next Table (2.6).

Table (2.6): The constants of formula (2.19)

Constant	Value
C1	3.534×10^{-1}
C2	1.375×10^{-3}
C3	2.433×10^{-4}
C4	4.056×10^{-4}
C5	7.994×10^{-1}
C6	2.250×10^{-5}

2.10. CURRENT HYDRATE PREVENTION METHODS

The most effective strategy for managing hydrates in an oil production system is staying outside the temperature/pressure envelope where hydrates are stable. Examples of this are insulating the flow path or adding heat source which can keep the temperature of the fluid sufficiently above the predicted hydrate formation temperature during steady-state operation, this will also allow for adequate time to reduce or depressurize the flow.

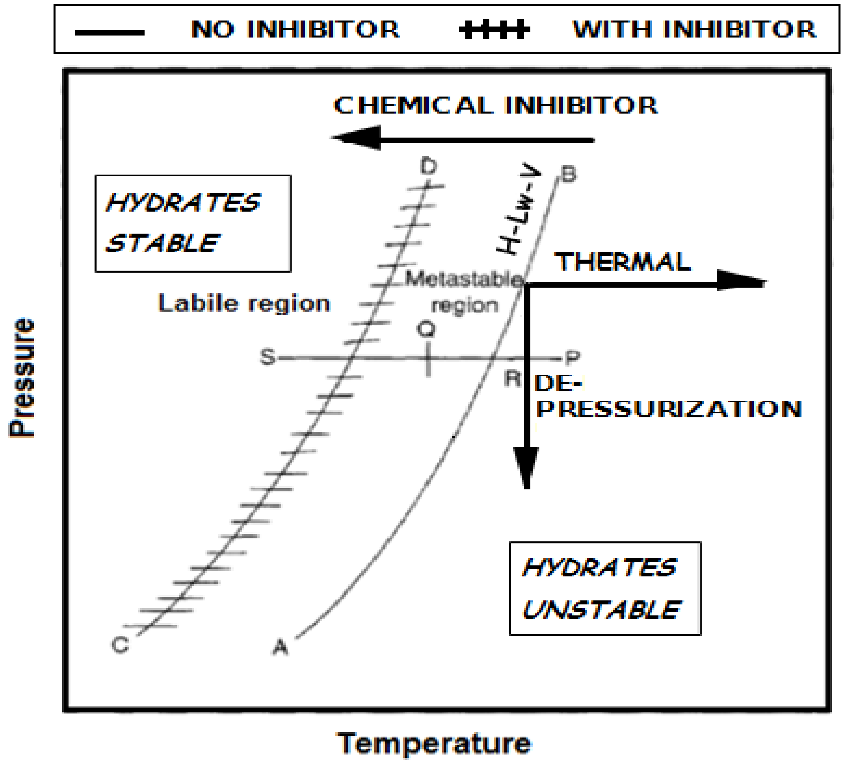


Figure (2.20): Hydrate melting schemes

The purpose of reducing the pressure is to lower the temperature of hydrate formation to below the ambient temperature to allow for an extended shut-in time (Saleh, 2002).

There are four main methods of combating gas hydrate plugs to ensure a continuous flow.

1. Hydraulic (Depressurization) method
2. Thermal method
3. Mechanical method
4. Chemical method

2.10.1. Hydraulic Method

The hydraulic removal method involves depressurizing the fluid stream there by dissociating the hydrate plug, due to the porous structure of the plugs in the gas pipelines, this method appears promising. However, it is only suitable for gaseous hydrocarbon as depressurization in liquid causes vaporization. Lowering the flow pressure does not dissolve a hydrate plug immediately, this is because the disassociation of hydrates is highly endothermic (absorbs heat from the surroundings) which delays the break-up of the plug (Saleh, 2002).

2.10.2. Thermal Method

The thermal method involves an in-situ delivery of high temperature (heat) flow towards the hydrate plug area through the pipeline wall to raise the temperature of the system above the hydrate formation temperature. This method can be achieved for external pipelines but not suitable for subsea pipelines.

Asphaltenes accumulation, wax crystallization and gas-hydrate internal pipeline and tubing surface are the sorest problems of oilfields both as at an oil production and transmission.

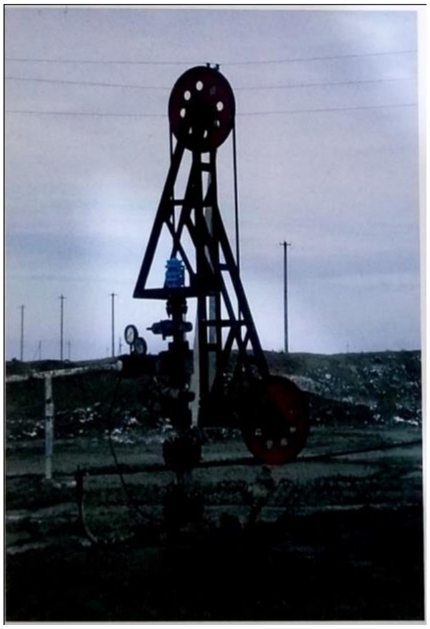
Figure (2.21): Asphaltenes Accumulation

While developing oilfields with high viscosity and waxy oils, the following issues comes to the front:

- Weak inflow of formation fluid;
- Tubing flow capacity decrease due to wax accumulation;
- Pipeline flow capacity decrease due to wax accumulation.

A plenty of various methods (mechanical, chemical, thermal), are being used for struggling against accumulation of wax in the tubing of oil-producing wells, this allowing to support an average level of an oil production successfully enough. But in the majority cases being periodic, such methods do not achieve the primary goal-the prevention of wax and asphaltenes.

The exact given problem is solved by means of stationary Well Heating Unit, actually an electro cable heating unit and its modifications intended, first of all, for prevention wax and asphaltenes accumulation by such a method which fluid allows to warm up the internal space of the tubing and to maintain temperature above those of firm wax and hydrate accumulation. (Operating principle is to heat tubing inside space with a purpose heating cable located in the area of intensive wax accumulation).



Our company executes design, manufacturing, sale and after sales cervices of the WELL HEATING UNITS (WHU's). **WHU** is wore effective remedy for asphaltenes, wax and wax-hydrated accumulations in oil wells and pipelines.

WHU ("Fountan-S" modification) is design for heating the wells with high viscosity oil for wireline and other works and the wells, equipped with sucker road pumps and small ID tubing.

2.10.2.1. WELL HEATING UNITS (WHU's)

WHU's are designed to prevent asphaltenes, wax and wax-hydrated accumulations in oil wells, to reduce heavy oil emulsion viscosity, to heat water wells and injectors, to heat pipelines for wax and high-viscosity oils.

Operating principle is to heat tubing inside volume with a purpose heating cable located inside/outside of tubing and inside of rods. The cable is located within the interval of wax crystallization and heats fluid to the temperature exceeding the wax crystallization point.

When a cable operates the oil is heated to temperature exceeding wax crystallization point. The WHU principle of work consists in heating inner space of oil-well tube by means of the special isolated heating cable placed inside tubing or placed on outside surface of tubing or placed in a column of hollow rods of a sucker rod pump (WHU with the length equal to the interval of maximum wax crystallization).

During work of the cable the oil liquid is heated up to the temperature exceeding temperature of crystallization of wax. Thus it provides:

- Permanent cleanness of tubing inside volume, X-mass tree and adjacent flow lines;
- Increasing of capacity and overhaul life of ESP;
- Operating continuity for a well and flow lines;
- Exclusion of necessity for other de-waxing operations;
- Environmental safety around a well;
- Easy well operation3;
- Decreasing of oil losses and increasing a well utilization rate;
- Continuous well operation in remote areas and wells producing high viscosity oil.

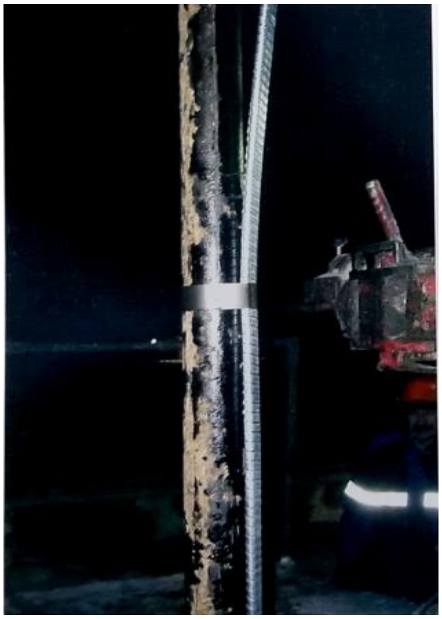
MODIFICATIONS:

WHU «Fountan» It is designed to heat wells with a heating cable located inside of tubing.

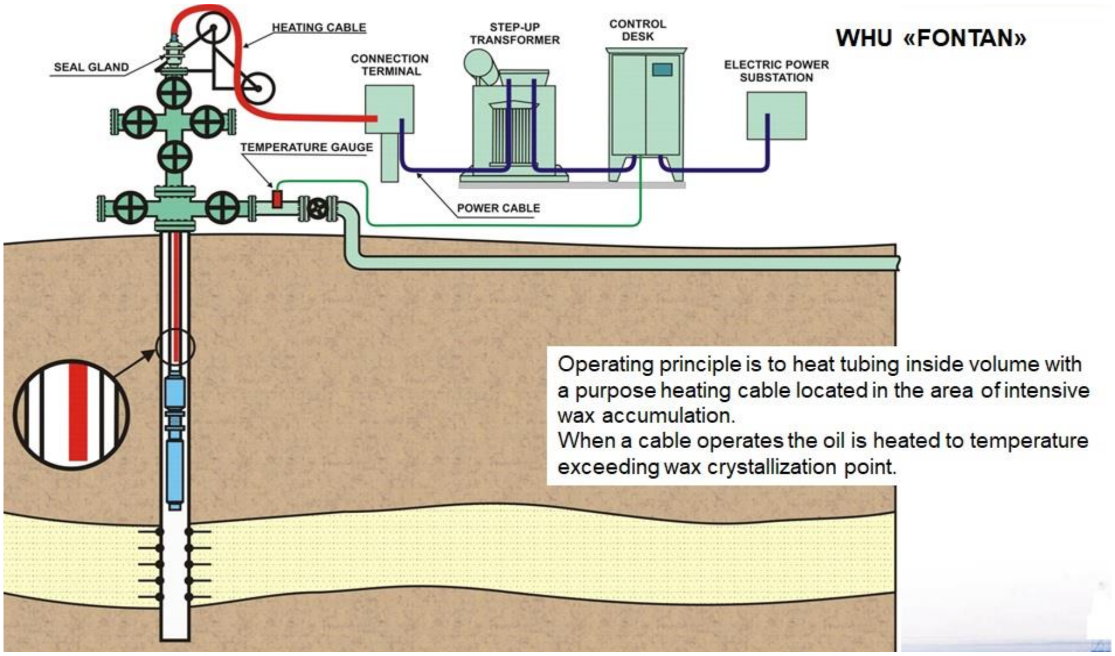
WHU «Fountan-N» It is designed to heat wells with a heating cable located on outside surface of tubing.

WHU «Fountan-S» It is designed to heat wells equipped with rod pumps through a heating cable located inside a pump rod.

MINI COIL-TUBING - It is designed to re-enter plugged wells by means of hydrodynamic drilling and to work over.



2.10.2.1.1. WHU <<FONTAN>>



Operating principle is to heat tubing inside volume with a purpose heating cable located in the area of intensive wax accumulation.
When a cable operates the oil is heated to temperature exceeding wax crystallization point.

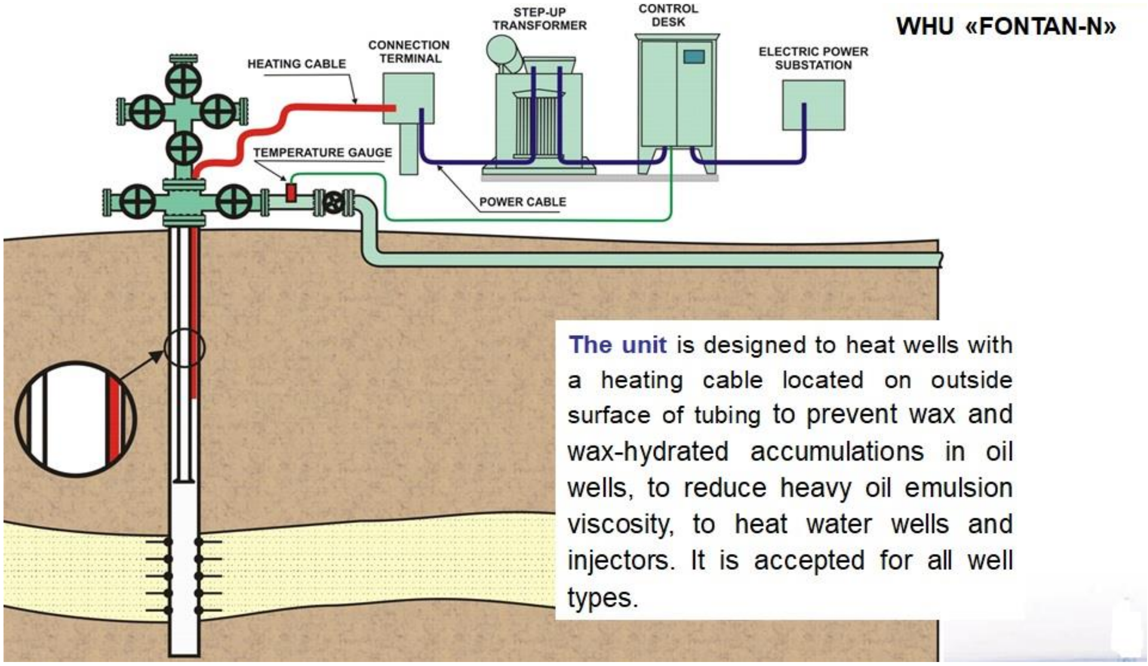
This provides:

- Permanent cleanness of tubing inside volume, X- mass tree and adjacent flow lines;
- Increasing of capacity and overhaul life for ESP,
- Operating continuity for a well and flow lines.

- Exclusion of necessity for other de-waxing operations;
- Environmental safety around a well.
- Easy well operation;
- Decreasing of oil losses and increasing a well utilization rate;
- Continuous well operation in remote areas and wells producing high viscosity oil.

2.10.2.1.2 WHU <<FONTAN-N>>

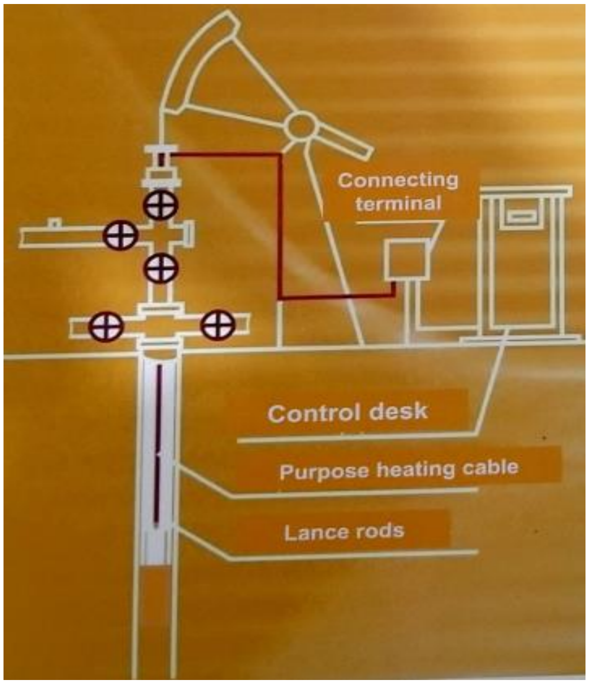
It is designed to heat wells with a heating cable located on outside surface of tubing.



The unit is designed to heat wells with a heating cable located on outside surface of tubing to prevent wax and wax-hydrated accumulations in oil wells, to reduce heavy oil emulsion viscosity, to heat water wells and injectors. It is accepted for all well types.

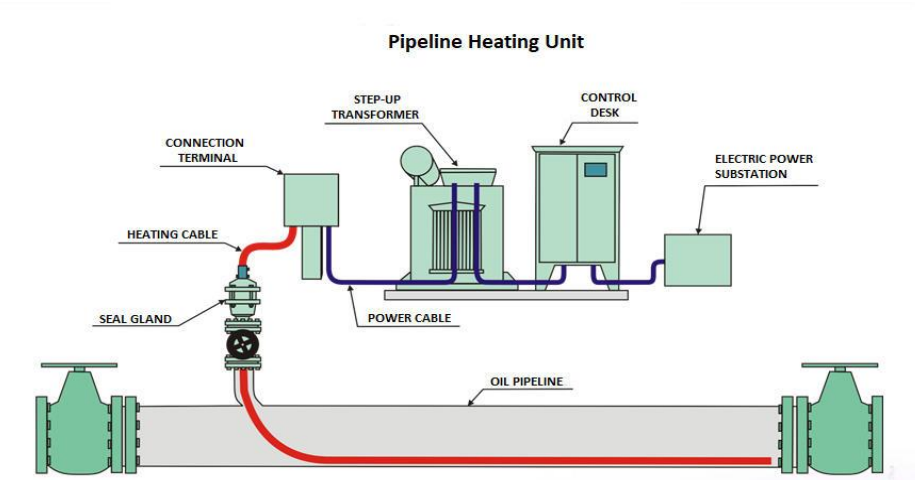
2.10.2.1.3. WHU <<FONTAN-S>>

The unit is designed to prevent asphaltenes, wax and wax-hydrated accumulations in oil wells, to reduce heavy oil emulsion viscosity, to heat water wells and injectors. It is accepted for oil wells equipped with sucker rod pumps.



2.10.2.2 PIPELINE HEATING

Operating principle is to heat pipeline inside volume with a heating cable located inside the pipeline. When a cable operates the oil is heated to temperature exceeding wax crystallization point. Installation method depends on a pipeline design (buried, surface), length, diameter and angle of expansion joints.



Standard set of equipment:

1. Heating cable;
2. Control desk with spare parts
3. Well head packer;
4. Connection terminal;
5. Wellhead wired temperature gauge,

6. Flash memory (MMS-card):
7. Software

Additional set of equipment:

1. Step-up transformer (if cable length is more than 1150M):
2. Wellhead RIH/POOH heating cable device;
3. Draw works;
4. Cable forced RIH device.

2.10.2.3. CONTROL DESK FOR CABLE HEATING

The Control Desk is fully automatic and runs the following:

1. Switch on/off cable heating
2. Cable voltage and load current control
3. Cable temperature change control
4. Maintenance of cable heating through switching off when it exceeds the target temperature.
5. Decrease in heating power when pump unit is off.
6. Protection of heating cable from short circuit through loss of current control.

7. Automatic switch on after power interruption or when temperature drops below wax crystallization point.
8. Monitoring of operation parameters.
9. Mode of operation for temperature setting.
10. Recording of operations.

Equipment of the station allows for data transmission to a dispatch control room or personal computer. In this regard it is possible to remotely monitor heating parameters on-line, correct input data, receive information from the station controller' data backup archives without going out to the field. Data can be transmitted through one of the following communication channels:

- Through a wire link using a modem. The advantage of the above communication channel setup is in being unaffected by the remoteness of a well and the land topography, availability of cellular communication in the area. Its drawback is poor availability of wire communication lines on pads and well sites in sparsely populated areas.

- Through cellular communication operators using **GSM**-modems.

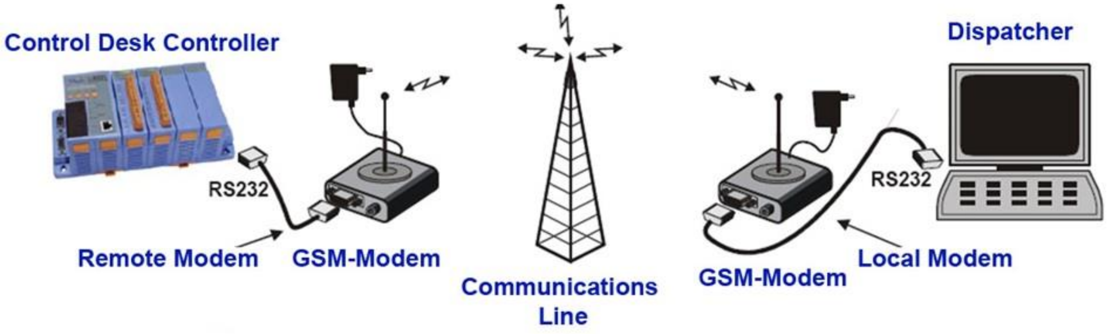
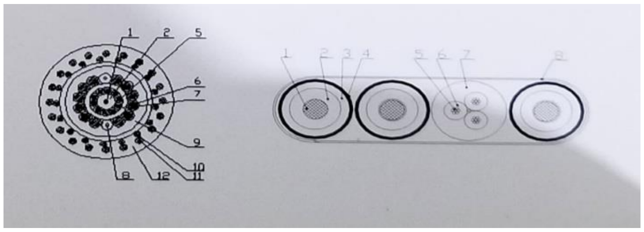


Figure (2.22): Station of cellular communication using **GSM**-modems.

Constructional cable features mean, first of all, its features of operation: its fastening on a well mouth and its working in the suspended position, at the raised temperature of heating strands, in aggressive gas-liquid environment, Therefore the cable except for wirelines of load-bearing shield has the armored polymeric skin, and while using building cable lengths from above 2000 meters (6500ft) - central load-bearing wire-line. For increase of cable reliability the heating conductors connected to various poles of a feed supply, are divided into groups through isolating wire bundles.



2.10.3 Mechanical Method

The mechanical method involves pigging to clean the pipeline of hydrate deposits. This method involves moving a large spherical or cylindrical disc made of a flexible material, having an outside diameter almost equal to the inside diameter of the pipeline. An example of these flexible materials includes neoprene rubber. The disadvantage of this method is that shutting down production to pig the pipeline is expensive and causes downtime (Sorheim, 2005). Figure (2.23) shows an example of a pipeline pigging operation.

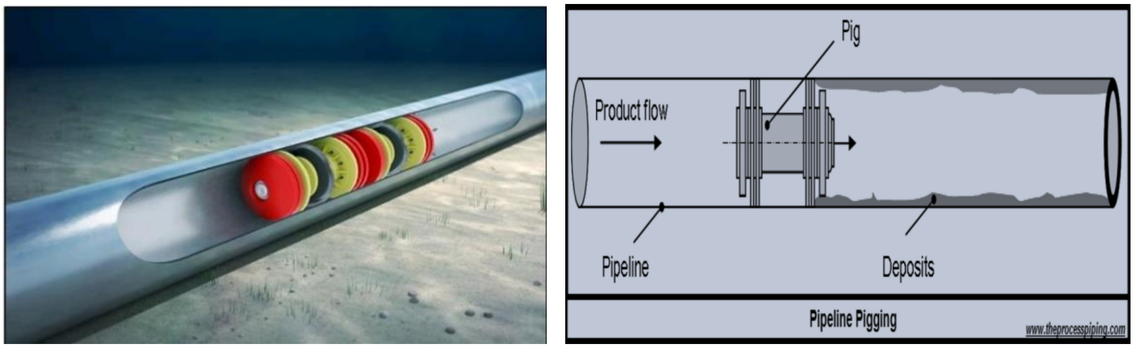


Figure (2.23): Pipeline pigging (Picchemicals, 2019).

2.10.4 Chemical Method

The technology adopted by the oil and gas industry for the prevention of gas hydrates in pipeline transmission involves the introduction of a thermodynamic inhibitor such as methanol into the natural gas fluid flow. However, as oil and gas exploration moves into extreme environments (such as deep-sea, offshore exploration, and production) the temperature and pressure conditions become more severe in the field, as such the concentration of inhibitors required for the prevention of hydrate formation increases significantly, most times to excess levels. Hence other technologies have been developed in the form of low-dosage chemicals such as kinetic or anti-agglomerate inhibitors. These compounds function by retarding the hydrate formation time to longer periods than the resident time of the gas inside the hydrate-prone area of the pipeline. Compared to thermodynamic inhibitors these low dosage inhibitors offer significant environmental and economic advantages. The main aim of low dosage inhibitors is to interfere with the mechanism of hydrate formation (Koh, et al 2002).

The chemical process involves the use of two types of additives thermodynamic inhibitors (THI) and Low dosage hydrate inhibitors (LDHI), they are further sub divided into the following (Sami, et al 2013).

1. Thermodynamic Inhibitors (THI)
    i. Alcohols (e.g. Methanol)
    ii. Glycols
    iii. Salts

2. Low-dosage hydrate inhibitors (LDHI)
    i. Surfactants
    ii. Kinetic Inhibitors
    iii. Anti-agglomerates

2.10.4.1 Thermodynamic Inhibitors (THI)

Thermodynamic inhibitors reduce the water movement and reaction by shifting the hydrate phase boundary to a higher pressure and lower temperature; this can prevent hydrate formation effectively (Sami, et al 2013). Considering that hydrates are similar to ice, chemical deicers that remove or prevent ice from accumulating can also work for gas hydrates.

A clear understanding of the thermodynamic properties of gas hydrate systems is critical in all gas hydrate applications, from determining the temperature and pressure conditions at which a pipeline will be within the hydrate stability zone, to assessing the conditions necessary to dissociate a gas hydrate plug in a pipeline or a natural gas hydrate reservoir for energy production, to simply establishing the conditions at which a gas hydrate system can be synthesized in the laboratory. Gas hydrate stability depends on temperature, pressure, gas composition, and condensed phase composition (including liquid hydrocarbon phase, salt content, and chemical inhibitor concentration).

Figure (2.24): illustrates the pressure and temperature profile to which fluids can be subjected within an oil/gas pipeline from a deep water well to the platform and central processing facility. The shaded envelope is the hydrate formation/ stability region; any fluid within the pipeline section in this region can form gas hydrates, which could result in hydrate plug formation.

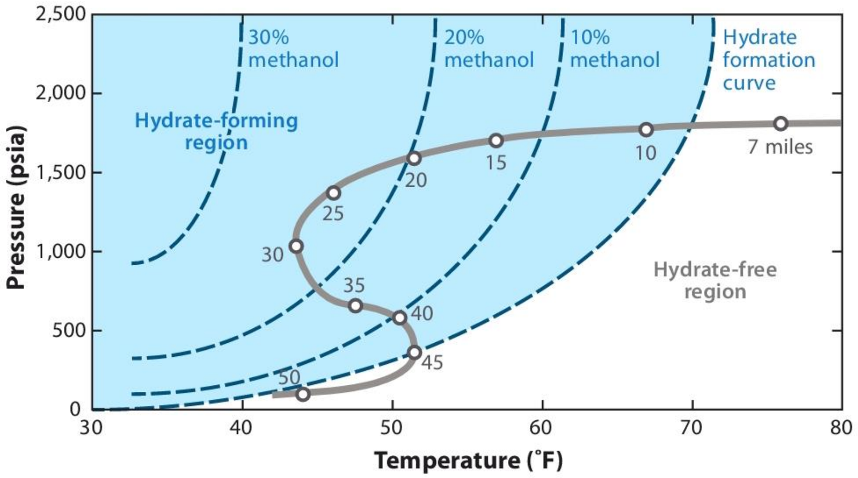


Figure (2.24): Schematic of the pressure and temperature conditions of fluids (gas/water/oil) in a subsea pipeline and the gas hydrate formation/stability region.

As indicated in **Figure (2.29)**, adding a chemical inhibitor such as methanol (or mono-ethylene glycol), typically called a thermodynamic inhibitor, will result in the hydrate stability zone shifting to colder temperature sand/or higher pressures. As an example, adding 30% methanol in this case will shift the hydrate stability curve to the left such that the previously hydrate-prone pipeline section illustrated here will no longer be within the hydrate stability zone, and therefore hydrates will be prevented from forming. This methodology of preventing gas hydrate formation using thermodynamic inhibition is also known as gas hydrate avoidance**.**

2.10.4.1.1 Alcohols (Methanol)

Alcohols have proven effective in combating ice formation and gas hydrate control. They contain the hydroxyl (OH) group which ensures solubility in water. The simplest form of alcohol is methanol (CH_3OH) and it is the most available/ widely used in the gas industry. The addition of sufficient amounts of these compounds creates a condition whereby the temperature and/or pressure required for hydrate formation needs to be lower for it to form (Koh, et al 2002). Methanol has a relatively low molecular weight; this allows it to penetrate the hydrate cavities and layers to effectively dissolve the hydrates. However, due to this low molecular weight, methanol is lighter than water and as a result, may prove ineffective injecting it from the wellhead down-hole into the hydrate plug submerged with oil. It is effective when dealing with very light oil.

Thermodynamic inhibitors such as methanol are used to prevent hydrate formation after a shut-down where the range of time is much longer.

Plots showing the effectiveness of alcohols in hydrate inhibition are used to formulate the required dosage rates for hydrate inhibition of completion and intervention fluids, keeping in mind that less methanol or glycol should be used when brine is used in drilling fluid due to its inherent inhibition characteristics. Figure (2.25) is a curve showing the effectiveness of various alcohols in hydrate inhibition (Bellarby, 2009).

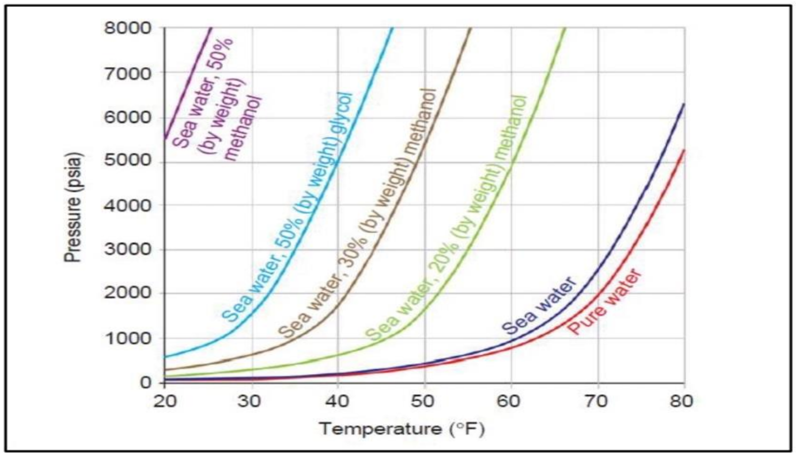


Figure (2.25) Hydrate inhibition with methanol and glycol (Bellarby, 2009)

In some fields, it is common for higher concentrations of methanol (up to 60 mass %) to be used and may also require the addition of glycol. These large volumes of methanol and glycol raise concerns about the environment, higher cost, and logistics. Low dosage hydrate inhibitors in contrast are new categories of chemical additives that can be effective at low volumes (mass %) for the same application. (Sami, et al2013).

- ❑ The Hydroxyl Group Hydrogen Bonds. The Water Molecules. In Direct Competition With The Dissolved A polar Molecules
- ❑ Inhibition Ability - Decreases With Volatility

<u>Examples:</u>

  - o Methanol
  - o Ethanol
  - o Isopropanol

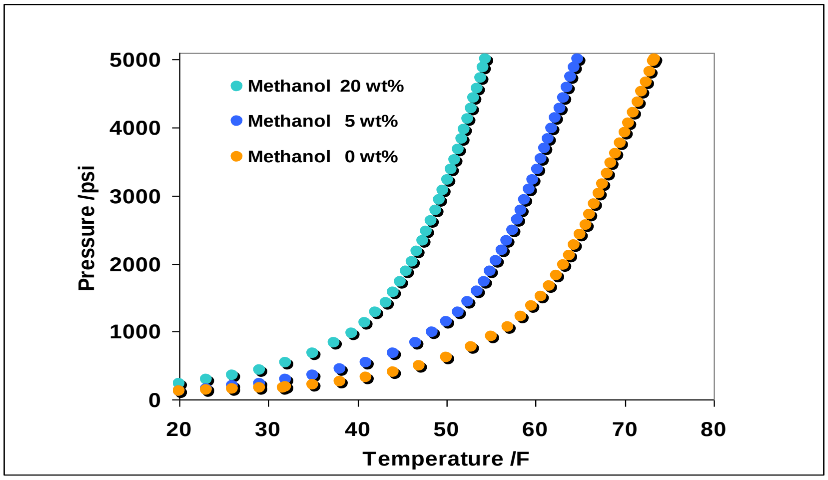


Figure (2.26): Effect of Methanol

2.10.4.1.2. Glycols

Glycols are other types of hydrate inhibitors used in the industry. Two frequently used glycols are **Tri-ethylene glycol** (TEG) ($HO–C_2H_4–O–C_2H_4–O–C_2H_4–OH$) and Mono-ethylene glycol (MEG) ($HO–C_2H_4–OH$) also diethylene glycol (DEG) is used occasionally (Elhady, 2005). MEG is denser and more viscous than water, it is flammable (but its flash point is higher than methanol). TEG is slightly denser and more viscous than methanol, this is due to the higher molecular weight of TEG. The greater viscosity and density of the inhibitors compared to methanol provide a useful means of removing hydrates when the glycol is injected above the hydrate plug if the glycol can migrate down the tubing and stay atop the plug before it circulates into water. Compared to methanol, glycols are easier to extract in the production system, for this reason, they are frequently used in wet gas pipelines (Brustad, et al 2005).

- ❑ More Hydrogen Bonding Opportunity With Water Through One More Hydroxyl Group Than Alcohols.
- ❑ Glycols Generally Have Higher Molecular Weights Which Inhibit Volatility.
- ❑ **Examples:**
    - o Ethylene Glycol
    - o Triethylene Glycol

2.10.4.1.3 Salts

- Normally sodium chloride, 20-24% by wt.
- Potassium chloride can be used but it is significantly more expensive, and saturated **KCl** muds have performed poorly in offshore environments.
- Calcium Chloride, very expensive and not as effective as NaCl for hydrate suppression.

- Salt ionizes in solution and interacts with the dipoles of the water molecules and causes clustering.
- This clustering also causes a decrease in the solubility of potential hydrate guest molecules in the water.
- These combine to require substantially more **sub-cooling** to cause hydrates to form. Examples: sodium chloride and calcium chloride.
- Salts – Effectiveness:

  NaCl >KCl> $CaCl_2$>NaBr>
  Na Format > Ca Nitrate

Typical Sample Formulations			
	Equilibrium		
	F^o	Psi	ΔT
20% NaCl + 10% Aq	45	5360	36.5
20% NaCl + 10% HF-100	44.9	5067	37.1
20% KCl	66.1	5580	16.7
10% KCl + 10% Aqua-Col	71.2	5245	11.1
10% KCl + 10% HF-100	70.2	5460	12.4
10% KCl + 10% NaCl	61.6	4936	20.2
10% KCl + 10% NaCl + 10% Aqua-Col	51.0	4825	30.2
10% Aqua-Col	79.2	5500	3.5
% Na Format + 10% Aqua-Col	50.6	4570	30.5
Seawater	80	5500	2.7

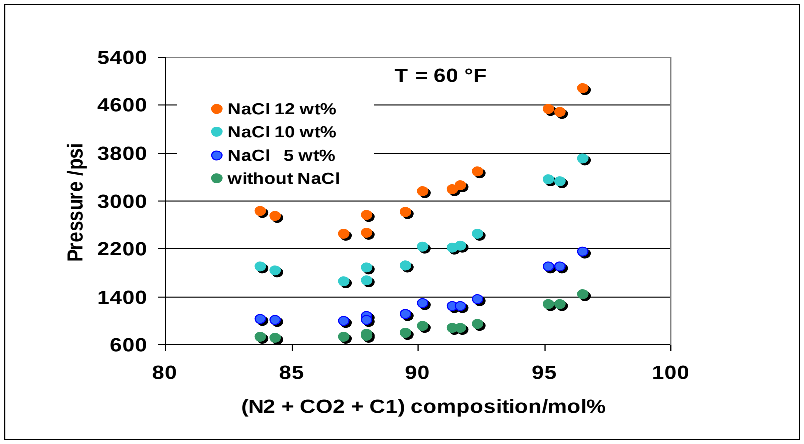


Figure (2.27): Effect of Sodium Chloride (NaCl)

Effect of NaCl

Common Thermodynamic Hydrate Inhibitors

Salts	Alcohol/diols
NaCl	Methanol
KCl	Ethanol
CaCl2	Glycerol
Na-Formate	Ethylene Glycol
K-Formate	Propylene Glycol
NaBr	Polyalkylene Glycol
CaBr2	
ZnBr2	

2.10.4.2 Low-Dosage Hydrate Inhibitors (LDHI)

LDHI can prevent the formation of gas hydrates during the nucleation and agglomeration stages. Examples of commercial low-dosage hydrate inhibitors are Inhibex 100, Inhibex 501, PVP, and GHI1 (Bellarby, 2009). Ping et al 2010 found that neither GHI1 nor PVP was able to inhibit gas hydrate nucleation, but GHI1 has a greater ability to inhibit hydrates than PVP. This higher inhibition ability is caused by di-ethylene glycol mono-butyl-ether. The categories of low-dosage hydrate inhibitors are:

1. Surfactants
2. Kinetic Inhibitors
3. Anti-agglomerates

2.10.4.2.1 Surfactants

These chemicals disperse hydrate crystals as they form, preventing the accumulation of the hydrates in a particular location in the pipeline. A typical example of such a chemical is Lecithin which is environmentally friendly and is used as a food antioxidant. Lecithin is sometimes used as a drilling fluid additive to stop blowout preventers from freezing when gas influx occurs in deep-water. Pakulski, (2007) reported an increase in hydrate formation when natural or introduced surfactant (such as anti-agglomerates) are present.

2.10.4.2.2 Kinetic Inhibitors

Kinetic inhibitors are **polymers** of various types such as polyvinyl caprolactam, they work by preventing or reducing the nucleation and subsequent crystal growth of the hydrates, thereby delaying the hydrate formation (Sami, et al 2013). A one mass % concentration is sufficient to control the formation process of gas hydrates until the gas is transported to its destination where the thermodynamic conditions for hydrate formation do not exist. A major disadvantage to these inhibitors is that once nucleation occurs, these inhibitors are unable to prevent further crystallization of hydrates (Bellarby, 2009).

<u>Strategy:</u>

- An additive(s) that renders the formed hydrate into pump able slurry.
- Focused on emulsifying environmentally acceptable synthetic oils with the objective of having the synthetic oil coat the forming hydrates, preventing agglomeration**.**
- Delay the onset of formation
- Slow the rate of formation
- Prevent the agglomeration of hydrates (slush)
- Reduce the amount of hydrate that form

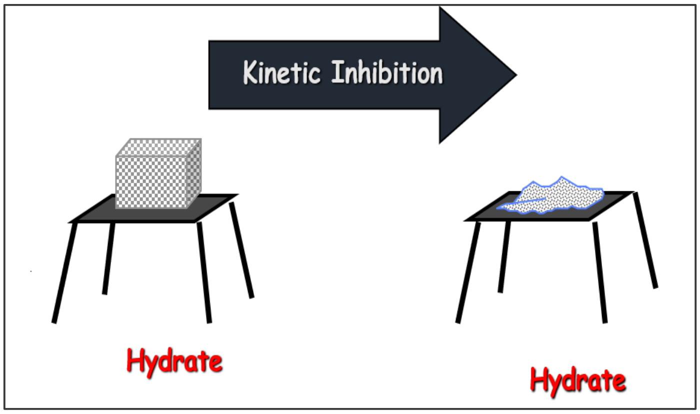


Figure (2.28) Kinetic inhibitors

2.10.4.2.3 Anti-agglomerates

These inhibitors work by making the surface of the hydrate hydrophobic (avoid or repel when it makes contact with water) enabling it to be dispersed in the oil phase. Anti-agglomerates do not prevent hydrates from forming but hinders already formed gas hydrates from agglomerating into lumps that cause plugging, an example of an anti-agglomerate is quaternary ammonium salt (QUATS) which is the main active component used in corrosion inhibitors (Sami, et al 2013).

2.10.4.3 Dehydration of Natural Gas

Dehydration is the process by which water is removed from natural gas. This is a common method used for preventing hydrate formation. If there is no water present, then it is impossible for a hydrate to form. If there is only a small amount of water present, then the formation of hydrate is less likely.

There are other reasons for **dehydrating natural gas**. The removal of water vapor reduces the risk of corrosion in transmission lines. Furthermore, dehydration improves the efficiency of pipelines by reducing the amount of liquid accumulating in the lines or even eliminates it completely.

There are several methods of dehydrating natural gas. The most common of these are:

(1) Glycol dehydration (liquid desiccant),

(2) Molecular sieves (solid adsorbent), and

(3) Refrigeration.

2.10.4.3.1 DEHYDRATION

One of the criteria for hydrate formation is that a sufficient amount of water be present. The hand calculations presented in Chapter 3 all assumed that plenty of water was present. The calculations presented from the software.

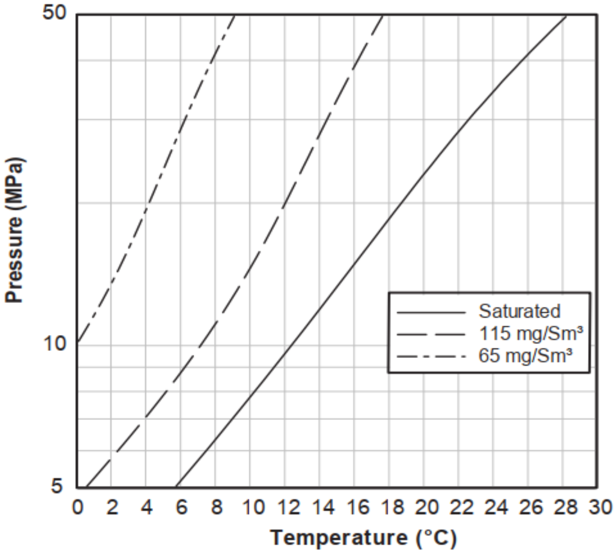


Figure (2.29): Hydrate Loci of Methane after Dehydration.

One of the advantages of a properly designed software package is that it can be used to predict the effect of dehydration on the hydrate formation conditions. Unfortunately, there is not a lot of experimental data available in the literature for building these models, **Figure** (2.29) Shows some calculations for the effect of water content on the hydrate formation conditions. These calculations were performed using **PIPESIM**. The solid line on this plot labeled “saturation” is where plenty of water is present. This is the same curve as was plotted in **Figure** (2.29). The other two plots on this figure are for a water content of 115 mg/Sm^3 (151 ppm or 7 lb/MMSCF) and the other is for 65 mg/Sm^3 (85.5 ppm or 4 lb/MMSCF). Finally, it is probably fair to anticipate that the errors in the predictions shown on this plot are about 2 C.

2.10.4.3.2. Gas Dehydrators

Removing most of the water vapor from the gas is required by most gas sales contracts, because it prevents hydrates from forming when the gas is cooled in the transmission and distribution systems and prevents water vapor from condensing and creating a corrosion problem. Dehydration also increases line capacity marginally.

Most sales contracts in the southern United States call for reducing the water content in the gas to less than 7 Ib/MMscf. In colder climates, sales requirements of 3 to 5 Ib/MMscf are common. The following methods can be used for drying the gas:

1. Cool to the hydrate formation level and separate the water that forms. This can only be done where high water contents (±30 Ib/MMscfd) are acceptable.
2. Use a Low-temperature exchange (LTX) unit designed to melt the hydrates as they are formed. **Figure** (2-35) shows the process. LTX units require inlet pressures greater than 2,500 psi to work effectively. Although they were common in the past, they are not normally used because of their tendency to freeze and their inability to operate at lower inlet pressure as the well FTP declines.
3. Contact the gas with a solid bed of $CaCl_2$. The $CaCl_2$ will reduce the moisture to low levels, but it cannot be regenerated and is very corrosive.
4. Use a solid desiccant, such as activated alumina, silica gel or molecular sieve, which can be regenerated. These are relatively expensive units, but they can get the moisture content to very low levels. Therefore, they tend to be used on the inlets to low temperature gas processing plants, but are not common in production facilities.
5. Use a liquid desiccant, such as methanol or ethylene glycol, which cannot be regenerated. These are relatively inexpensive. Extensive use is made of methanol to lower the hydrate temperature of gas well flowlines to keep hydrates from freezing the choke.
6. Use a glycol liquid desiccant, which can be regenerated. This is the most common type of gas dehydration system and is the one shown on the example process flowsheet.

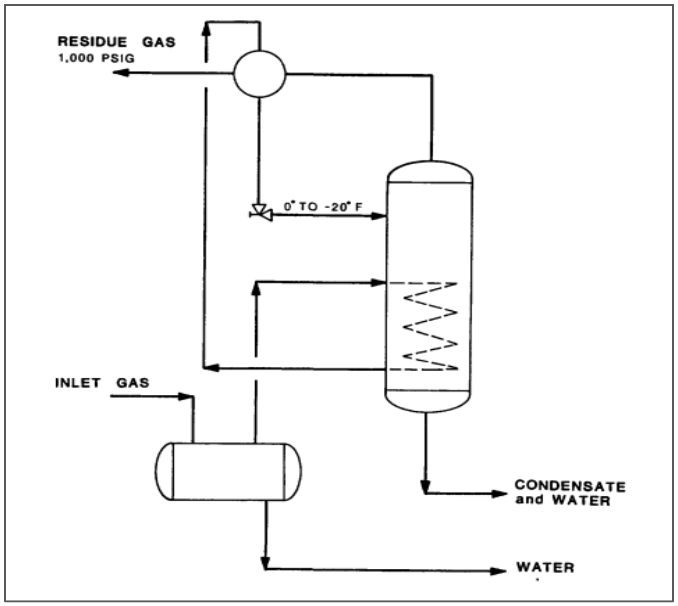


Figure (2.30): Low-Temperature Exchange Unit

Figure (2-30) shows how a typical bubble-cap glycol contact tower works. Wet gas enters the base of the tower and flows upward through the bubble caps. Dry glycol enters the top of the tower, and because of the down comer wire on the edge of each tray, flows across the tray and down to the next. There are typically six to eight trays in most applications. The bubble caps assure that the upward flowing gas is dispersed into small bubbles to maximize its contact area with the glycol.

Before entering the contactor the dry glycol is cooled by the outlet gas to minimize vapor losses when it enters the tower. The wet glycol leaves from the base of the tower and flows to the re-concentrator (reboiler) by way of heat exchangers, a gas separator, and filters, as shown in **Figure** (2-31). In the reboiler the glycol is heated to a sufficiently high temperature to drive off the water as steam. The dry glycol is then pumped back to the contact tower. Most glycol dehydrators use tri-ethylene glycol, which can be heated to 340°F to 400°F in the re-concentrator and work with gas temperatures up to 120°F. Tetra ethylene glycol is more expensive but it can handle hotter gas without high losses and can be heated in the re-concentrator to 400°F to 430°F.

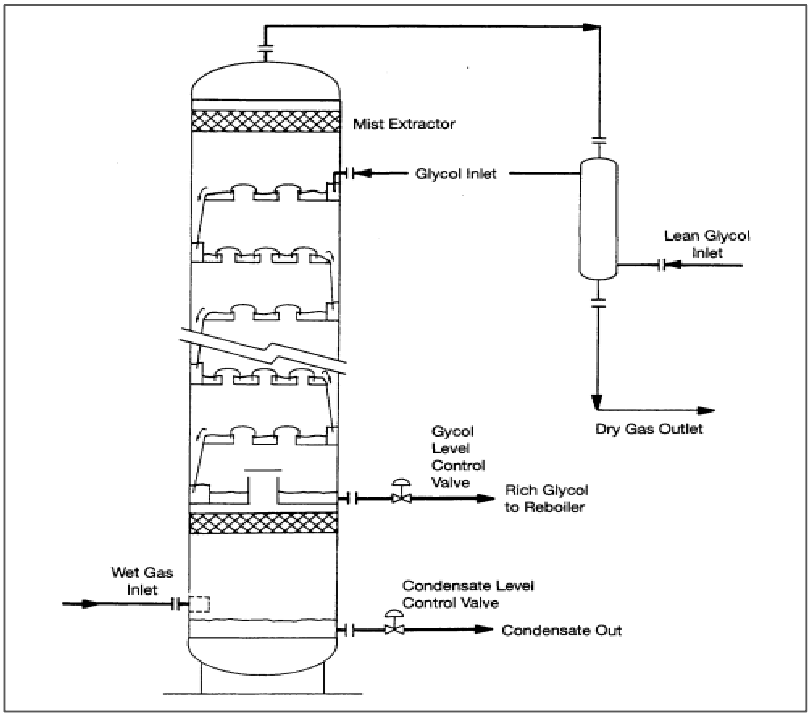


Figure (2.31): Typical Glycol Contact Tower.

DEW POINT

Dew points is a temperature below which some of the hydrocarbons in the gas can condense at pipeline pressure, forming liquid slugs that can damage the pipeline. The gas must also be clear of all water vapor to prevent the formation of methane hydrates within the gas processing plant or within the sales gas transmission pipeline.

It is common to express water content in terms of dew point and usually the dew point temperature, usually expressed in F or C. With ambient air, we have a feel for the dew point. As the air cools overnight, water will condense out and form a film of water on the grass, car, or any object that is outside. We refer to this film of water as “dew”. Thus the dew point is the temperature to which the air must be cooled before this condensation occurs.

What happens if the ambient temperature is below the freezing point of pure water?

In this case, the water condenses out as a solid phase called “frost” and the frost point is the temperature at which this occurs. The process of forming frost can occur without the formation of free water. The weather forecast will often report dew points even if the temperature is below the freezing point of pure water. This is done by extrapolating the high temperature dew points to lower temperatures. The value reported may have no physical meaning, but it is a sort of a standard in meteorology to do this. A common method for measuring dew points is to use a chilled mirror. A mirror is placed in a process stream and it is cooled until the mirror "fogs" until some kind of condensation occurs. This point is the called the dew point. Unfortunately, it is difficult to determine whether this is a water dew point or a hydrocarbon dew point. Water is a colorless liquid and the same is true for light hydrocarbons. From visual inspection, it is impossible to determine the type of liquid formed.

Next, it may not be possible to conclude whether the fog that forms on the mirror is a liquid or solid. This is particularly true if an automated system is used. Furthermore, it is impossible to tell whether the solid forming on the mirror is ice (pure water in the solid form) or hydrate. The convention is to call the temperature at which the mirror fogs a dew point regardless of whether the phase that condenses is a solid or a liquid.

2.11. RESEARCH AND EXPERIMENTS ON GASHYDRATES

The Following studies are notable research and experiments on the formation and effects of gas hydrate.

2.11.1. Prediction of Hydrate Deposition in Pipelines to Improve Gas Transmission Efficiency and Safety- By (Zhang, Et Al 2019)

The study simulated a 48 km long subsea pipeline transporting natural gas to predict the hydrate phase equilibrium region in the gas pipeline. The result shown in **figure (2.32)** indicates that the region of hydrate phase equilibrium in the pipeline is around **220-48000m** away from the pipe inlet. This suggests that hydrate deposition takes place at a distance of 220m away from the inlet.

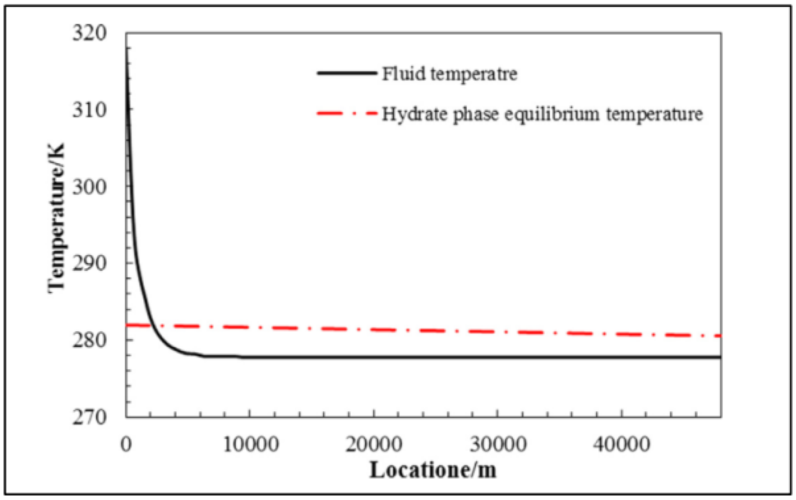


Figure (2.32): Prediction of hydrate phase equilibrium region in the subsea gas pipeline (Zhang, et al2019).

Hence the safety and efficiency of the gas transportation system are significantly reduced by the formation and deposition of hydrates. It can be seen from the curve that the outlet pressure of the pipeline decreased significantly under the effect of hydrate deposition which decreased the effective inner diameter of the pipe and increased the flow velocity, this leads to an increase in pressure in the pipeline.

Figure (2.33) shows a comparison between the effective radius of the pipeline and the proposed radius obtained from a test model, the results show that with an increase in hydrate deposition the effective radius of the pipe reduces. Also, there is a region of high-risk of hydrate deposition in the pipeline in which the two models showed similar results within the range of (5-20m) from the pipe inlet. Fluctuations in the outlet pressure of the pipeline due to hydrate deposition can damage pipeline joints and pumps, inducing severe accidents in production (Zhang, et al 2019).

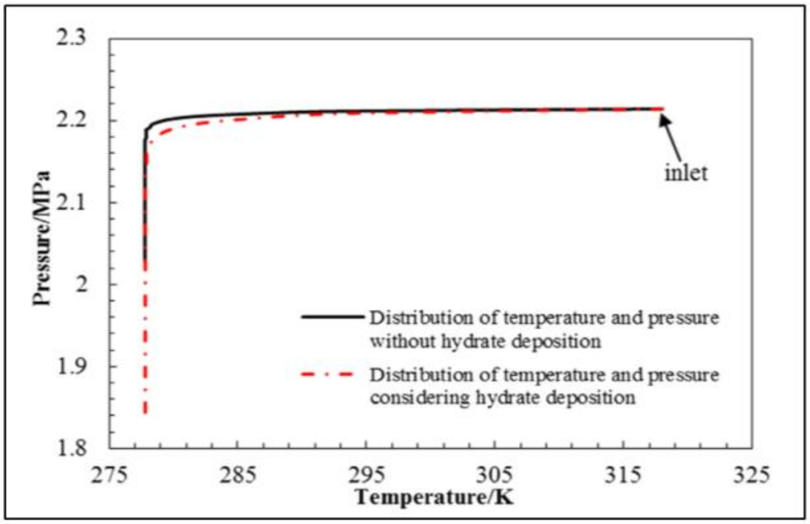


Figure (2.33): Comparison between temperature and pressure distribution in the pipeline (Zhang, al 2019)

2.11.2. Hydrate Formation in Pipelines by (Dorstewitz And Mewes, 1995)

Hydrate formation was investigated experimentally in a horizontal pipe flow of gas and water by **Dorstewitz**, 1995. The pressure, temperature, and volumetric flow rate of each fluid were measured. The tubing made of glass had an inner diameter of 15mm. The formation of plugs starts on the pipe wall because the heat transfer is directed radially outwards. The onset of hydrate formation on the pipe wall is located at the interface between water and gas. Flow regime changed from the stratified flow of water and gas to intermittent flow pattern. Water was conveyed into the upper part of the pipe. The whole perimeter of the wall was covered by hydrates and a closed hydrate layer was achieved. The hydrate layer grew radially towards the center of the pipe. In certain volumetric flow rates and heat fluxes the hydrate, layer growth lead to plugging of the pipeline as shown in Figure (2.34).

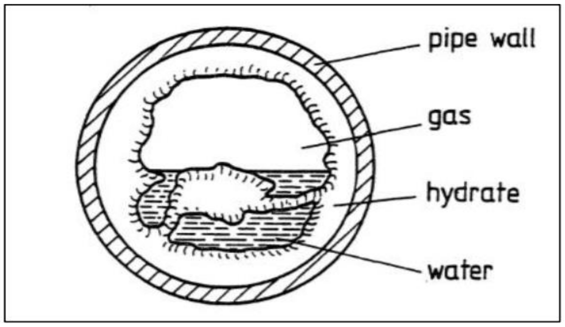


Figure (2.34): Hydrate formation pattern in a 15mm test pipe (Dorstewitz and Mewes, 1995).

Due to the void distribution, the value of the related pressure loss is low. The onset of hydrate formation occurred after 50 minutes. Only small hydrate particles were observed on the pipe wall. The particles were dragged along with the flow and the hydrates decompose in the bulk flow. Due to further deposition of hydrates, the whole perimeter of the pipe was covered by hydrates after 59 minutes and a solid hydrate layer developed.

2.11.3. Hydrate Mitigation Strategies

Two common strategies to mitigate hydrate formation are thermal insulation and the injection of chemical inhibitors. Both strategies can be simulated in **PIPESIM**. Thermal insulation carries a higher up-front capital cost, whereas chemical inhibition carries a higher operational cost.

2.11.3.1 Thermal Insulation

The heat transfer between the fluid in the pipeline and the environment surrounding the pipeline is dependent on the temperature gradient and the thermal conductivity of the material between the two. There are two options for modeling the heat transfer in **PIPESIM**:

- **Input U value:** This option allows the user to define an overall heat transfer coefficient (U value). The heat transfer rate per unit area is calculated based on the pipe outside diameter.
- **Calculate U value:** This option computes the overall heat transfer coefficient based on the following parameters:
- **Pipe coatings:** Thickness of each pipe coating & K (Thermal conductivity) of the material.
- Pipe material conductivity.

- Ambient fluid (Air or Water).
- Ambient fluid velocity (The faster fluid flows over the pipe, the greater the heat loss).
- Pipe burial depth.
- Ground conductivity (for flowlines only).

2.11.3.2 Chemical inhibitors

Thermodynamic inhibitors can be used to shift the hydrate line (to the left in the curve shown previously), thereby lowering the hydrate formation temperature and increasing the hydrate-free operating envelope.

Examples of inhibitors include methanol and ethylene glycol. The effect of thermodynamic inhibitors on hydrate precipitation can be modeled in **PIPESIM**.

Kinetic and anti-agglomerate inhibitors comprise a category of inhibitors known as **Low Dosage Hydrate Inhibitors (LDHIs)**. These inhibitors do not lower the hydrate formation temperature; instead, they help prevent the nucleation and agglomeration of hydrates to avoid blockage formation. The effects of these types of inhibitors cannot be modeled with **PIPESIM**.

CHAPTER THREE
METHODOLOGY

CHAPTER III - METHODOLOGY

3.1. PROJECT OVERVIEW (MAIN LINE - TRANSFER LINE)

The YLNG Project comprises connection to the existing gas production facilities of the **Marib** fields in the **block 18**, to extract the required gas to feed the projected Liquefied Natural Gas **(LNG)** plant located in **Balhaf** on the **Gulf of Aden**. The present ESIA concerns the following two pipelines(25):

- **The Main Line** supply the **LNG** plant with gas from the **Kamil Processing Unit** (**KPU**) located in **Marib** Province, **Yemen** to the **Balhaf LNG plant**;
- **The bi-directional Transfer Line** links the **KPU** and the Central Processing Unit (**CPU**) at Alif.

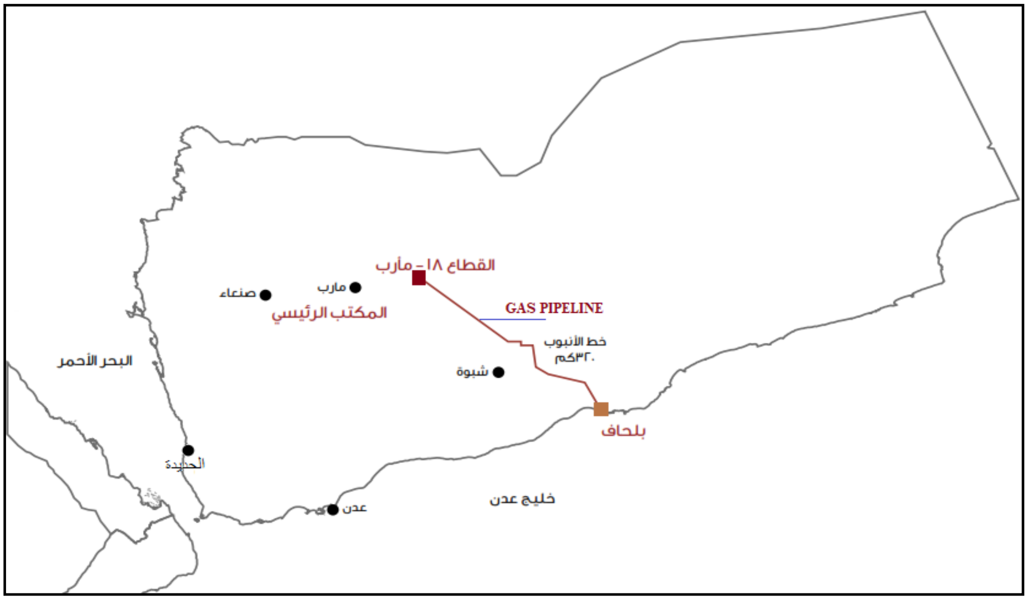


Figure (3.1): Gas Pipeline Location

A reliable version of **PIPESIM 2019** simulator software was used to **simulate** the **Gas flow** after creating the pipeline model and defining the flowing Gas. Two types of pour point depressant were used in the simulation. An optimum dose of pour point depressant was chosen after comparing and analyzing the two types with different doses for each.

3.2. PIPESIM OVERVIEW:

PIPESIM software was originally developed by a company called **Baker Jardine**. **Baker Jardine** was formed in 1985 to provide software and consultancy services to the oil and gas industry. In April 2001, Baker Jardine was acquired by **Schlumberger**.

Schlumberger has invested in the redevelopment of the world's leading Production Engineering Software to ensure that it can cope with the fast moving computer industry. **PIPESIM** incorporates leading-edge Graphical User Interface technology coupled with a field-proven computation engine.

3.2.1. PIPESIM DEFINITION:

PIPESIM is a steady-state multiphase flow simulator used for the design and diagnostic analysis of oil and gas production systems, with its rigorous simulation algorithms, **PIPESIM** helps to optimize your production and injection operations. **PIPESIM** also analyzes flowline and surface facility performance to generate comprehensive production system analysis.

PIPESIM has more engineering tools for **flow assurance** analysis (hydrates, asphaltenes, wax).

The concept of **flowline** in **PIPESIM** has been used to simulate **Balhaf LNG Pipeline**.

3.2.2. PIPESIM MAIN OBJECTIVES:

- To present a summary of the main principles of flow modelling in multiphase hydrocarbon systems.

3.2.3. NODAL ANALYSIS

Nodal analysis is a methodology that views the total producing system as a group of components potentially encompassing the flowlines and risers. An improper design of any one component, or a mismatch of components, adversely affects the performance of the entire system.

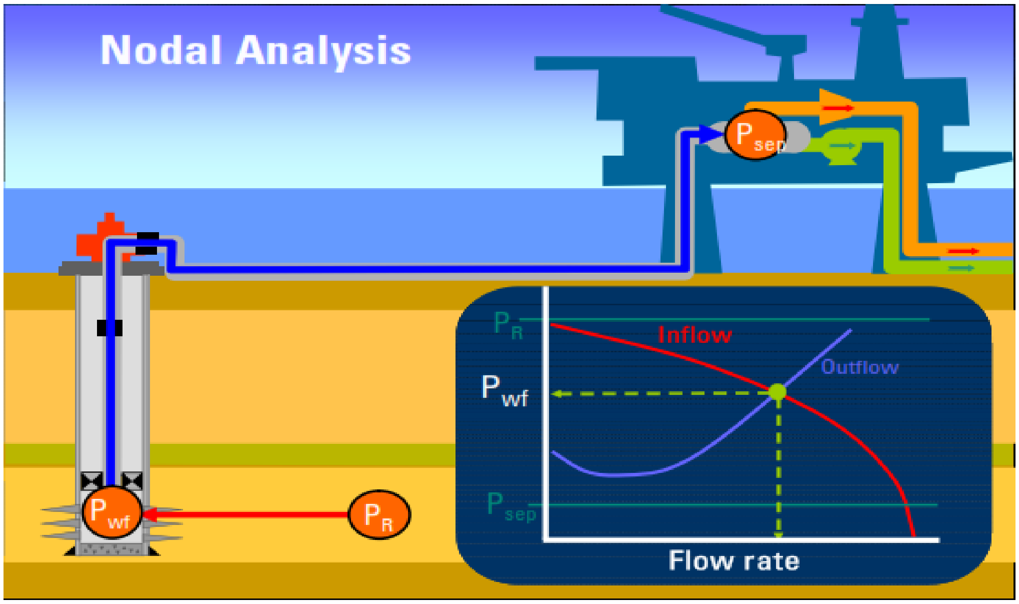


Figure (3.2): Nodal Analysis - Production System

Nodal analysis points are used to split the system into two parts for analysis of an inflow and an outflow. The nodal point can be placed between any two equipment objects or at any point along the tubing or casing in a well so long as it is located at or above the uppermost completion.

For example, we can use nodal analysis to:

- **Identify flow assurance issues**, if any (by combining other modules in **PIPESIM**).
- **Analyze abnormal flow** restrictions in an existing system.

Typically, nodal analysis is performed at the riser base with the nodal point placed between the flowline and the riser

3.2.3.1. OPERATING POINTS:

An operating point (sometimes called the solution node) is defined as the condition where the pressure differential upstream (inflow) and downstream (outflow) of the nodal point is **zero**. The operating point is represented graphically by the intersection of the inflow and outflow performance curves. It is possible to infer the system flowrate geometrically from the line intersections alone; however, it is more accurate and far safer to calculate the flowrate by simulating the system end-to-end. The resulting pressure and flowrate appears on the nodal analysis graph as an operating point. This explicit calculation ensures the inflow and outflow fluid properties and temperature are identical, which eliminates the possibility of a mismatch and consequent error in answer interpretation.

3.3 PIPESIM FLOWLINE - SIMPLE MODEL PROPERTIES:

By using **PIPESIM** you can define a flowline in a simple model (with basic minimum data) or detailed model (to capture detailed profile as well as heat transfer calculations). The property pane and the parameter displayed will depend on the options that you choose.

- **SIMPLE MODEL:**

  Use this mode if the flowline is relatively linear (horizontal pipe, vertical pipe, or inclined pipe with constant inclination angle) and you want to perform a simplistic heat transfer calculation using the known heat transfer coefficient and a constant ambient temperature.

- **DETAILED MODEL:**

  Allows you to capture complex flowline geometry and at the same time, you will be able to perform detailed heat transfer calculation including pipeline coating, variation in environmental conditions, pipe burial data, etc.

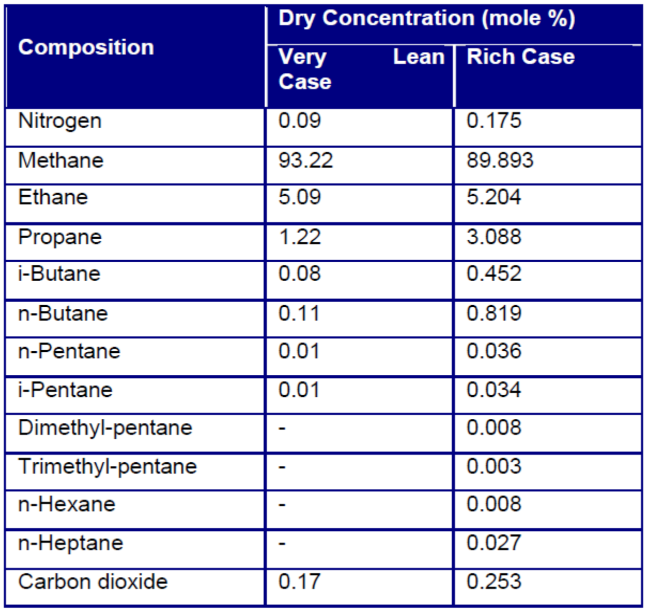
3.3.1. DEFINE COMPOSITIONAL FLUIDS

Compositional fluid modeling involves defining mole fractions for each individual molecular component or petroleum fraction. Equations of state (**EOS**) are used to flash the fluid (calculate vapor-liquid equilibrium) and determine thermodynamic and transport properties. Compositional fluid modeling is generally regarded as the most accurate approach, especially for wet gas, condensate and volatile oil systems which require more rigorous heat transfer calculations and more accurate phase fractions.

3.3.2. GAS COMPOSITION

The gas composition in the Main Line, which feeds the **LNG** plant (25), can be summarized in **Table 3-1** as follows:

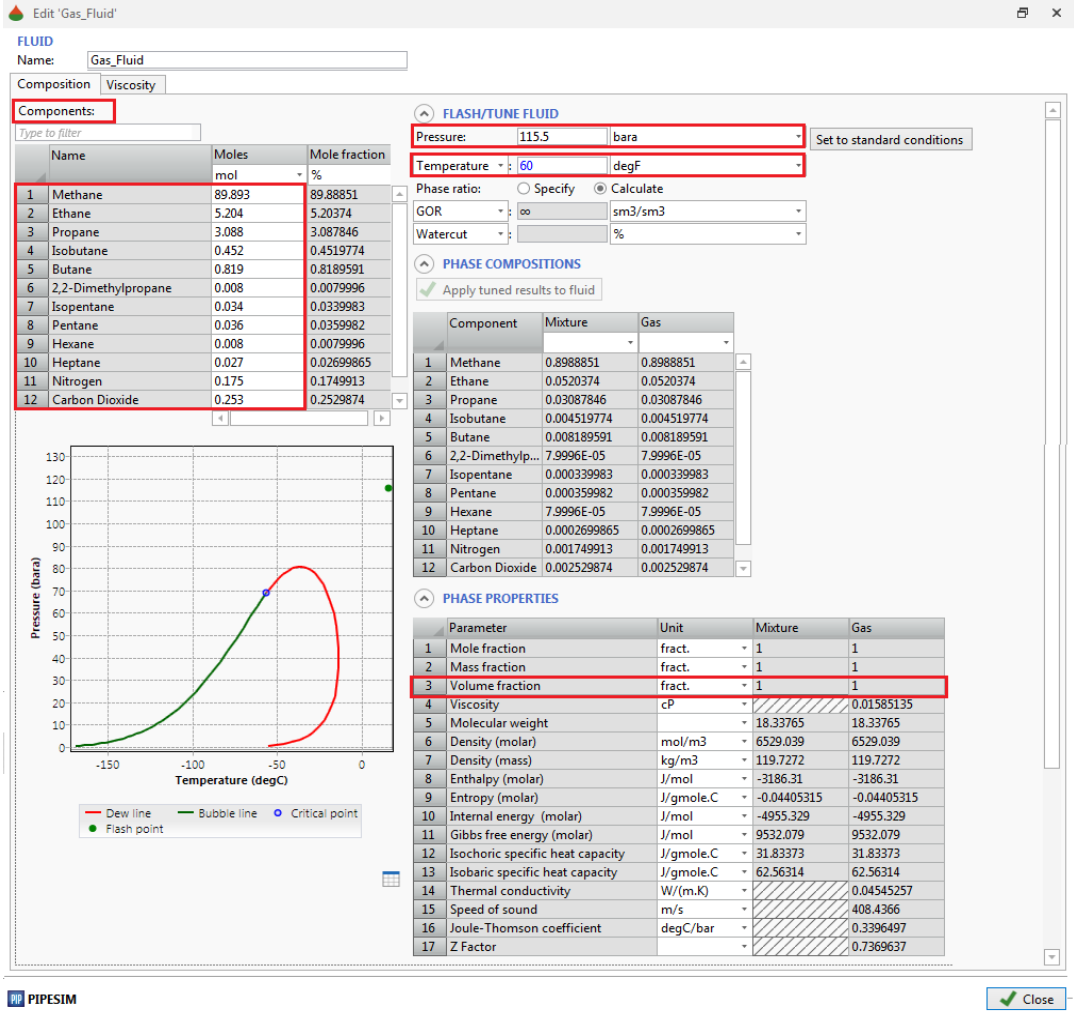
Table (3.1): Gas Composition



Composition	Dry Concentration (mole %)	
	Very Lean Case	Rich Case
Nitrogen	0.09	0.175
Methane	93.22	89.893
Ethane	5.09	5.204
Propane	1.22	3.088
i-Butane	0.08	0.452
n-Butane	0.11	0.819
n-Pentane	0.01	0.036
i-Pentane	0.01	0.034
Dimethyl-pentane	-	0.008
Trimethyl-pentane	-	0.003
n-Hexane	-	0.008
n-Heptane	-	0.027
Carbon dioxide	0.17	0.253

3.3.3. COMPOSITIONAL FLUID MODELING

PIPESIM can handle a maximum of 50 components for a compositional simulation. In compositional fluid models the user can specify a number of components that make up the fluid. These can be real molecules, such as methane, ethane or water, known as petroleum fractions. The phase behavior and thermodynamic properties are determined by an **equation of state (EOS)**. This equation of state is either a cubic equation (this is a modified form of the Van der Waals equation) or a non-cubic equation.



FLUID

Name: Gas_Fluid

Components:

	Name	Moles	Mole fraction
		mol	%
1	Methane	89.893	89.88851
2	Ethane	5.204	5.20374
3	Propane	3.088	3.087846
4	Isobutane	0.452	0.4519774
5	Butane	0.819	0.8189591
6	2,2-Dimethylpropane	0.008	0.0079996
7	Isopentane	0.034	0.0339983
8	Pentane	0.036	0.0359982
9	Hexane	0.008	0.0079996
10	Heptane	0.027	0.02699865
11	Nitrogen	0.175	0.1749913
12	Carbon Dioxide	0.253	0.2529874

FLASH/TUNE FLUID

Pressure: 115.5 bara

Set to standard conditions

Temperature : 60 degF

Phase ratio: ○ Specify ● Calculate

GOR : ∞ sm3/sm3

Watercut : %

PHASE COMPOSITIONS

Apply tuned results to fluid

	Component	Mixture	Gas
1	Methane	0.8988851	0.8988851
2	Ethane	0.0520374	0.0520374
3	Propane	0.03087846	0.03087846
4	Isobutane	0.004519774	0.004519774
5	Butane	0.008189591	0.008189591
6	2,2-Dimethylp...	7.9996E-05	7.9996E-05
7	Isopentane	0.000339983	0.000339983
8	Pentane	0.000359982	0.000359982
9	Hexane	7.9996E-05	7.9996E-05
10	Heptane	0.0002699865	0.0002699865
11	Nitrogen	0.001749913	0.001749913
12	Carbon Dioxide	0.002529874	0.002529874

PHASE PROPERTIES

	Parameter	Unit	Mixture	Gas
1	Mole fraction	fract.	1	1
2	Mass fraction	fract.	1	1
3	Volume fraction	fract.	1	1
4	Viscosity	cP	▨	0.01585135
5	Molecular weight		18.33765	18.33765
6	Density (molar)	mol/m3	6529.039	6529.039
7	Density (mass)	kg/m3	119.7272	119.7272
8	Enthalpy (molar)	J/mol	-3186.31	-3186.31
9	Entropy (molar)	J/gmole.C	-0.04405315	-0.04405315
10	Internal energy (molar)	J/mol	-4955.329	-4955.329
11	Gibbs free energy (molar)	J/mol	9532.079	9532.079
12	Isochoric specific heat capacity	J/gmole.C	31.83373	31.83373
13	Isobaric specific heat capacity	J/gmole.C	62.56314	62.56314
14	Thermal conductivity	W/(m.K)	▨	0.04545257
15	Speed of sound	m/s	▨	408.4366
16	Joule-Thomson coefficient	degC/bar	▨	0.3396497
17	Z Factor		▨	0.7369637

Figure (3.3): Gas Compositional Fluid Modeling in **PIPESIM**

3.4 MODELING THE BALHAF LNG PIPELINE:

The pipeline operation can be modeled and simulated using **PIPESIM** by the following steps:

1. Definition of the physical model
2. Definition of Gas fluid components data
3. Running of the model.

3.4.1. DEFINITION OF THE PHYSICAL MODEL

The model (**Balhaf LNG Pipeline**) consists of flow-line & compressor stations. The first station is considered as a source in the pipeline model. The other stations are ordinary compressor stations. The model also includes two flow lines and a compressor between them, which stands for the terminal station.

The final physical model of the pipeline in **PIPESIM** is shown in next **figure** (3.4).

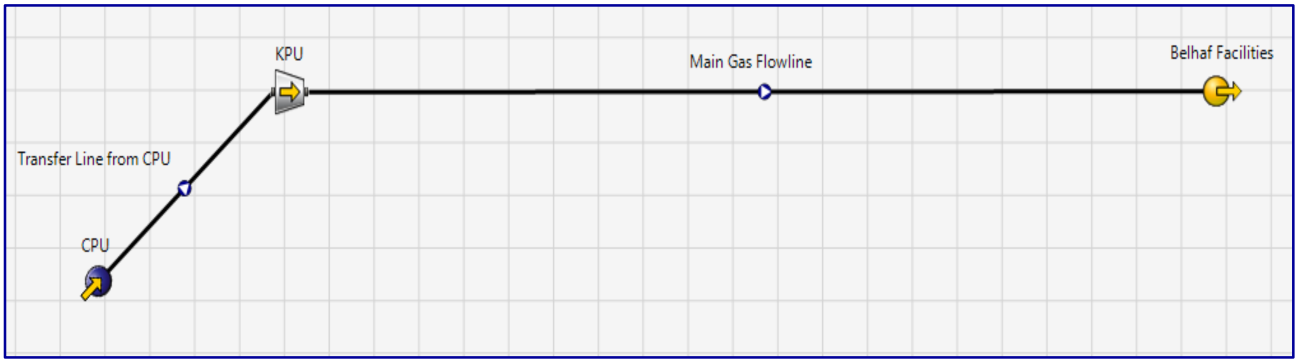
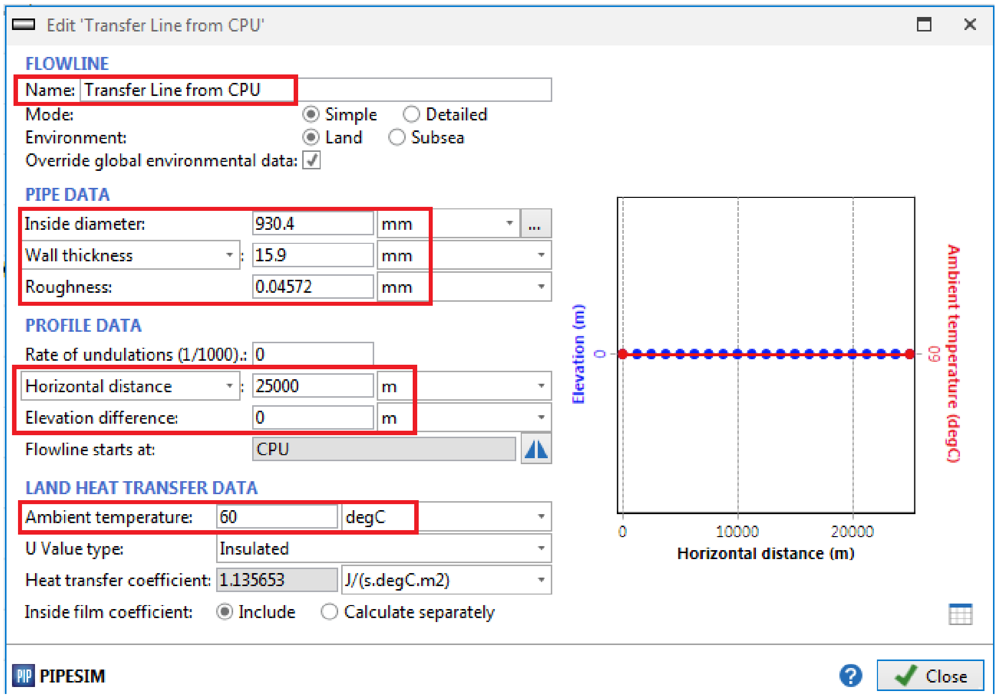


Figure (3.4) The physical model of the pipeline in **PIPESIM**.

The 1st Transfer Line Data (from CPU):


Edit 'Transfer Line from CPU'

FLOWLINE

Name: Transfer Line from CPU

Mode: ● Simple ○ Detailed

Environment: ● Land ○ Subsea

Override global environmental data: ☑

PIPE DATA

Inside diameter: 930.4 mm

Wall thickness: 15.9 mm

Roughness: 0.04572 mm

PROFILE DATA

Rate of undulations (1/1000).: 0

Horizontal distance: 25000 m

Elevation difference: 0 m

Flowline starts at: CPU

LAND HEAT TRANSFER DATA

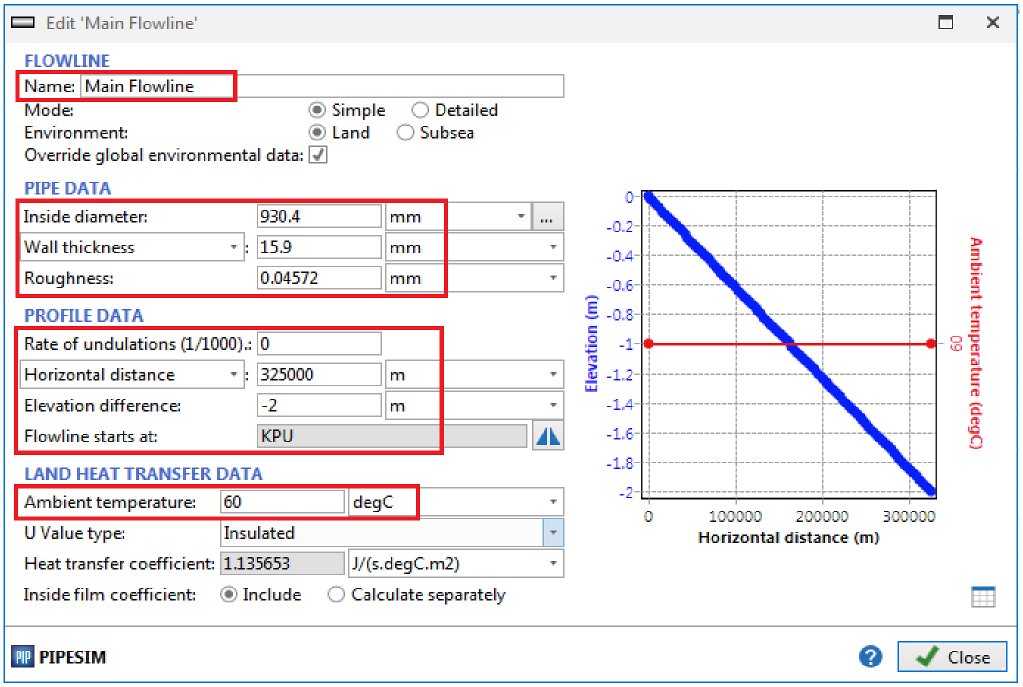
Ambient temperature: 60 degC

U Value type: Insulated

Heat transfer coefficient: 1.135653 J/(s.degC.m2)

Inside film coefficient: ● Include ○ Calculate separately

The 2nd Main Flow-Line Data:



FLOWLINE

Name: Main Flowline

Mode: ● Simple ○ Detailed

Environment: ● Land ○ Subsea

Override global environmental data: ☑

PIPE DATA

Inside diameter: 930.4 mm

Wall thickness: 15.9 mm

Roughness: 0.04572 mm

PROFILE DATA

Rate of undulations (1/1000).: 0

Horizontal distance: 325000 m

Elevation difference: -2 m

Flowline starts at: KPU

LAND HEAT TRANSFER DATA

Ambient temperature: 60 degC

U Value type: Insulated

Heat transfer coefficient: 1.135653 J/(s.degC.m2)

Inside film coefficient: ● Include ○ Calculate separately

3.4.1.1. MAIN FLOW-LINE

The Main pipeline will consist of a **325 km** long, and internal diameter **ID** is **930.4 mm** (36.63 in) and the wall thickness is **15.9 mm** (0.626 in), here after referred to as 38-inch diameter pipeline, starting from **KPU** to **Balhaf** site. The design flow capacity is 1,280 MMSCFD. This system could eventually be expanded to approximately 1,600 MMSCFD.

The Main Line takes a side stream off the gas reinjection header from **KPU** and let the pressure down for transport to **Balhaf** through the pipeline. And the **Main Line** starts at Kilometric Point 0 (**KP 0**) from the **KPU**, at an elevation of **960** m. The pipeline route travels south-east through the sand dunes and across a flat desert plain for about **134** km, and then ascends to a plateau at an elevation of approximately 1.420 m. On the plateau, the route gradually climbs over a distance of 64 km to an elevation of 1,720 m, before descending to **Wadi Salmun**. The route then avoids the wadi by taking an east turn. Then it travels across the generally flat coastal desert plain gradually descending to 260 m before reaching the coastal sand dunes and **Balhaf** at KPU 320.

The pipeline grade (API 5LX70 steel grade) buried. The design pressure is between 117 barg (1755.149 psia) and 134.5 barg (1965.454 psia) depending on the location. The pipeline predominantly qualifies as **ANSI** Class 1 design, with Class 2 design in the last 23 km of the **Main Line** (**Balhaf** side) and in the **CPU-KPU** vicinity, since most of the pipeline route stays well clear of all dwellings. The pipeline route generally remains at least 200m from any dwellings for safety reasons. To achieve this requirement in the coastal plain to **Balhaf**, additional relocation has been planned to stay away from the new dwellings and agriculture that have developed in the area since the performance of the 1997 baseline survey. The current design with two trains at **Balhaf** plant does not comprise an intermediate compressor station at the foot of the plateau.

The right of way (ROW) for the pipelines typically 17m to 30m in width depending on the area (**Figure** 3.4). Sectional valves allow the Main Line to be isolated by section.

3.4.1.2. TRANSFER LINE

The transfer pipeline connects from **KPU** to **CPU**. It consists of a **20** km long, and inside diameter of pipeline **ID** = **930.4 mm** (36.63 in) and the wall thickness is **15.9mm** (0.626 in), which constructed parallel to two other existing 12" and 6" diameter pipelines of Yemen HOC (YHOC). The transfer line is located in a flat desert region of low sand dunes approximately **75** km northeast of the City of **Marib** between **KPU** and **CPU**. It buried (25).

3.4.1.3. KPU AND CPU FACILITIES

The existing gas processing plants in the **Marib** area, which have been in operation for about 12 years, extract pentanes and heavier for export, **LPG** for domestic consumption, **and return the residue gas for re-injection into the oil fields**. They are concentrated in two main gas processing facilities at **Alif** (**CPU**) and **Kamil** (**KPU**), located 22 kilometers apart:

- The **KPU** facility comprises two **420** MMCFD cryogenic **gas plants** and four compressor trains which process **over 1 billion cubic feet of gas per day**. At KPU facilities, gas is compressed to 220 bars and cooled to a maximum of 15°C above ambient temperature or 60°C maximum for re-injection into the field.
- The **CPU** facilities include two cryogenic plants: a **500** MMCFD lean oil plant and a **420** MMCFD cryogenic plant, with their six re-injection compressors which process over **1.2 billion cubic feet of gas per day,** (25).

The combination of these four gas treatment plants provide sufficient feed gas availability to the **LNG** plant, three plants being normally needed to meet the peak flow rate requirement. The design of the upstream facility expansion and upgrade related to the **YLNG** Project (CPU-KPU) is currently in the conceptual stage. ***Preliminary and final design phases have not yet begun. Accordingly, details regarding the construction and operation of upstream facilities related to the YLNG Project are not yet available.?***

3.4.2. SPECIFIC CONSTRUCTION TECHNIQUES

Special construction techniques required for some areas, including the following:

- **Construction of pipeline in large dunes:** The sand cleared over a width of 33 m and piled on each side of the ROW. The trench hade a width of 15 m at the top and 7 m at the bottom depth of 2 m;
- **Ascent and descent of the plateau:** The ROW width reduced to approximately 17 m and the trench width 10 m. The ROW on the ascent and descent of the plateau will be used for equipment and supply transport to the plateau. For slopes greater than 25° the equipment secured by a winch cable. These accesses to the plateau maintained at the end of the construction for pipeline maintenance operations.
- **Shallow Wadi crossings**: standard trenching used in construction with concrete coating of the pipe for additional stability and minimum cover of 1.70 m;
- **Blasting:** the trench excavated in hard rock using drilling and blasting;
- **Topsoil Separation:** in agricultural and pasture land the topsoil saved and stockpiled separately from the subsoil; after pipe laying, topsoil replaced as the upper surface of the ROW;
- **Minimum Cover:** the normal ditch will normally be excavated to provide a minimum cover of 1m; however, certain soil or terrain conditions would require depths of cover as follows:

Consolidated rock:	0.60 m;
Agricultural land:	1.20 m;
Wadi crossing:	1.70 m.

3.4.3. PIPELINES PROCESS OPERATIONS

The pipelines operated dry, i.e. free of liquid hydrocarbons and water. Operational activities mainly consist of pipeline scraper trapping and monitoring. A maintenance track will follow the pipeline **ROW**.

3.4.3.1. Maintenance

Scraper traps constructed at both ends of the Transfer Line and Main Line to allow scraping operations for cleaning and inspection. The scraper sent from **KPU** to **Balhaf**.

Corrosion protection provided by 3 layers of polyethylene coating plus an impressed current **cathodic protection** system using thermoelectric generators.

3.4.3.2. Control / Inspection

The pipeline regularly inspected and the process monitored. These take several forms, as described below:

- Pipeline pressure, flow rate and block valves continuously monitored by a Supervisory Control and Data Acquisition (SCADA) system from a Central Control Room in the LNG plant. Block valves are located approximately every **32** km along the pipeline. Joints and gaskets which could initiate leaks are limited to block valves. The rest of the pipeline is welded and pressure tested. A fiber optic cable will be installed in parallel with the pipeline for communication links
- Control and maintenance patrols will drive regularly the route of the pipeline using the access road adjacent to the pipeline this will check for third party surface disturbance or other potential activities or risks to pipeline integrity.

3.5. BALHAF LNG PLANT

3.5.1. PROJECT OVERVIEW

The **LNG** plant process natural gas transported via pipeline from the **KPU** facility. The site is located near **Balhaf** on the south coast of **Yemen**, approximately 140 km west of the port city of **AL-Mukalla** and 380 km east of **Aden**. Coordinates are as follows: 13'59'00' N. 48°10'50' E.

The **LNG** plant comprises two processing trains of **3.45** Million tons per annum (Mtpa) each, thus a design production capacity of **6.9 Mtpa**. The quality of the **LNG** plant feed gas is presented in the following **Table** (3.2):

Table (3-2): LNG Plant Feed Gas Composition

Composition	**Dry Concentration (mole %)**	
	Very Lean Case	**Rich Case**
Nitrogen	0.09	0.175
Methane	93.22	89.893
Ethane	5.09	5.204
Propane	1.22	3.088
i-Butane	0.08	0.452
n-Butane	0.11	0.819
n-Pentane	0.01	0.036
i-Pentane	0.01	0.034
Dimethyl-pentane	-	0.008
Trimethyl-pentane	-	0.003
n-Hexane	-	0.008
n-Heptane	-	0.027
Carbon dioxide	0.17	0.253

3.5.2. ATMOSPHERIC EMISSIONS

PIPELINE CONSTRUCTION ATMOSPHERIC EMISSIONS

Combustion contaminants from heavy duty vehicles are estimated based on the anticipated level of vehicle activity. For pipeline sections constructed in open areas consisting of uncovered ground and dirt roads (rural spread), the rate of progress can move rapidly. Rural spreads generally use a 22 m construction zone. Construction equipment in a spread would include machinery such as trenchers, welding machines, tracked side booms and support vehicles. Based on emissions for the installation of a pipeline (Aspen Environmental Group, 1996) constructed in open areas, the table below presents estimated vehicle emissions as a function of distance. These values are based on a semi-arid region and a typical depth of 1.2 meters for the pipeline trench.

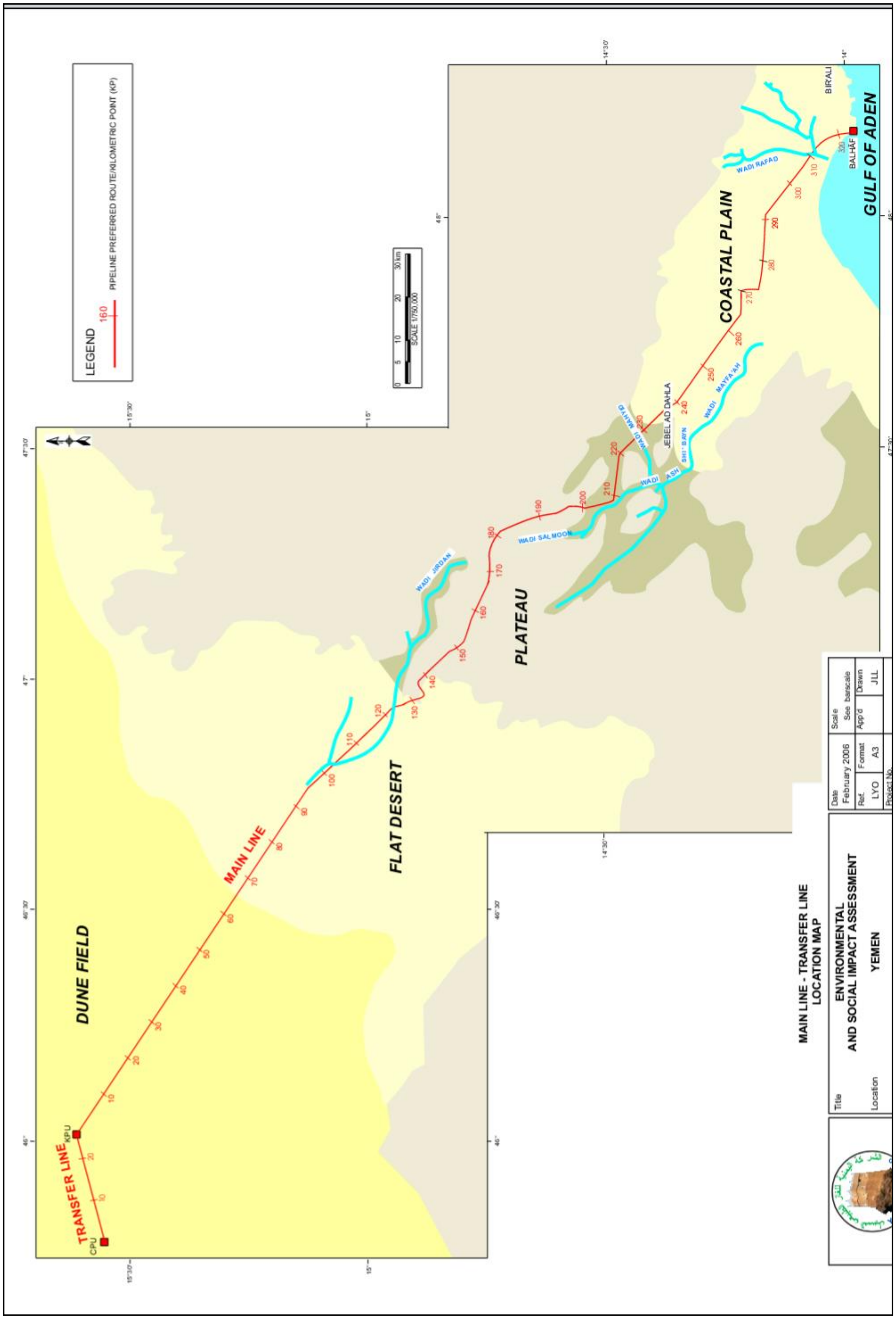


Figure (3.5): Main Line Transfer Line Location Map

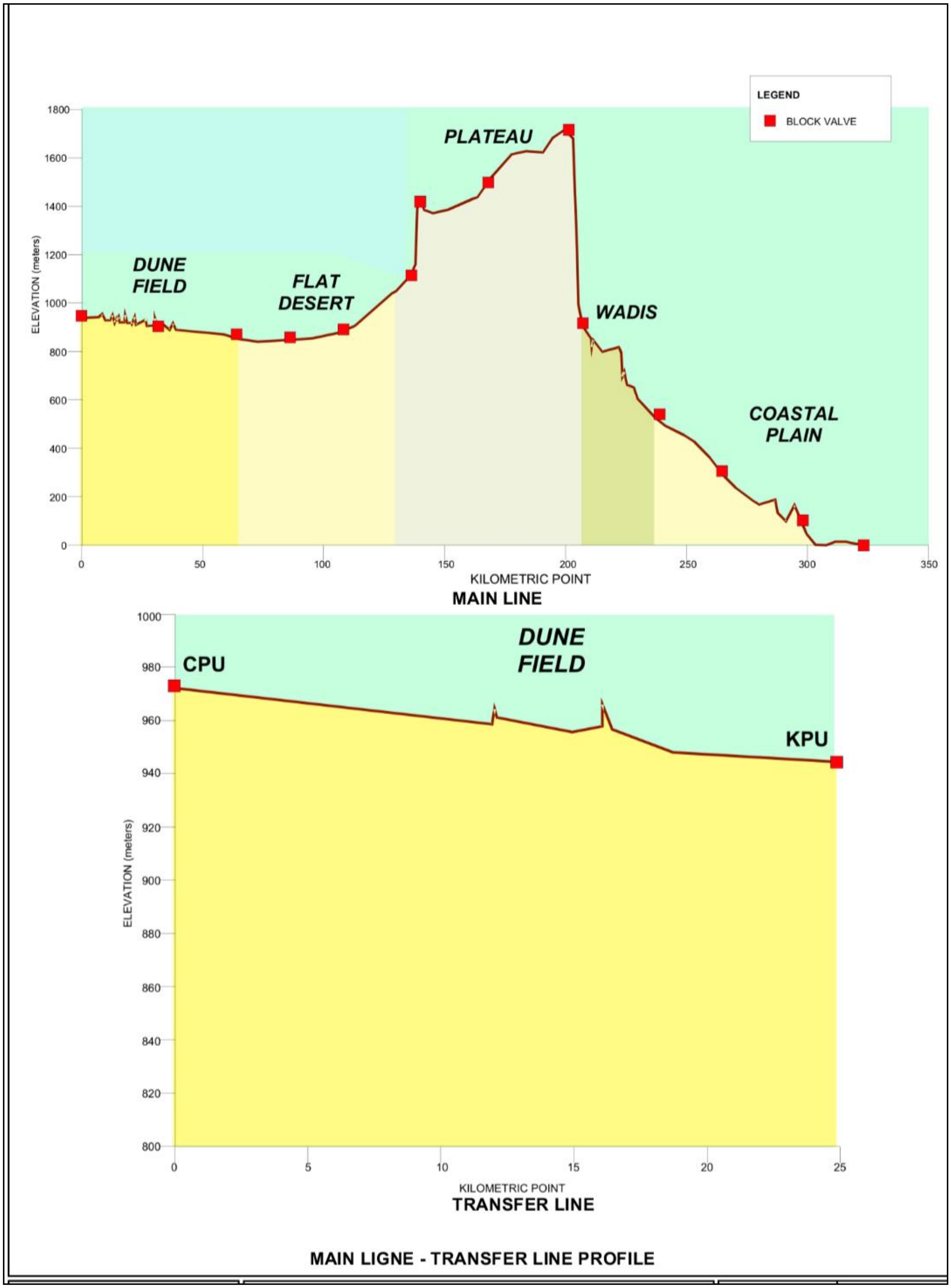


Figure (3.6): Main Line and Transfer Line Profiles

KPU

CPU

CPU AND KPU FACILITIES IN MARIB

Figure (3.7): CPU and KPU Facilities in **Marib**

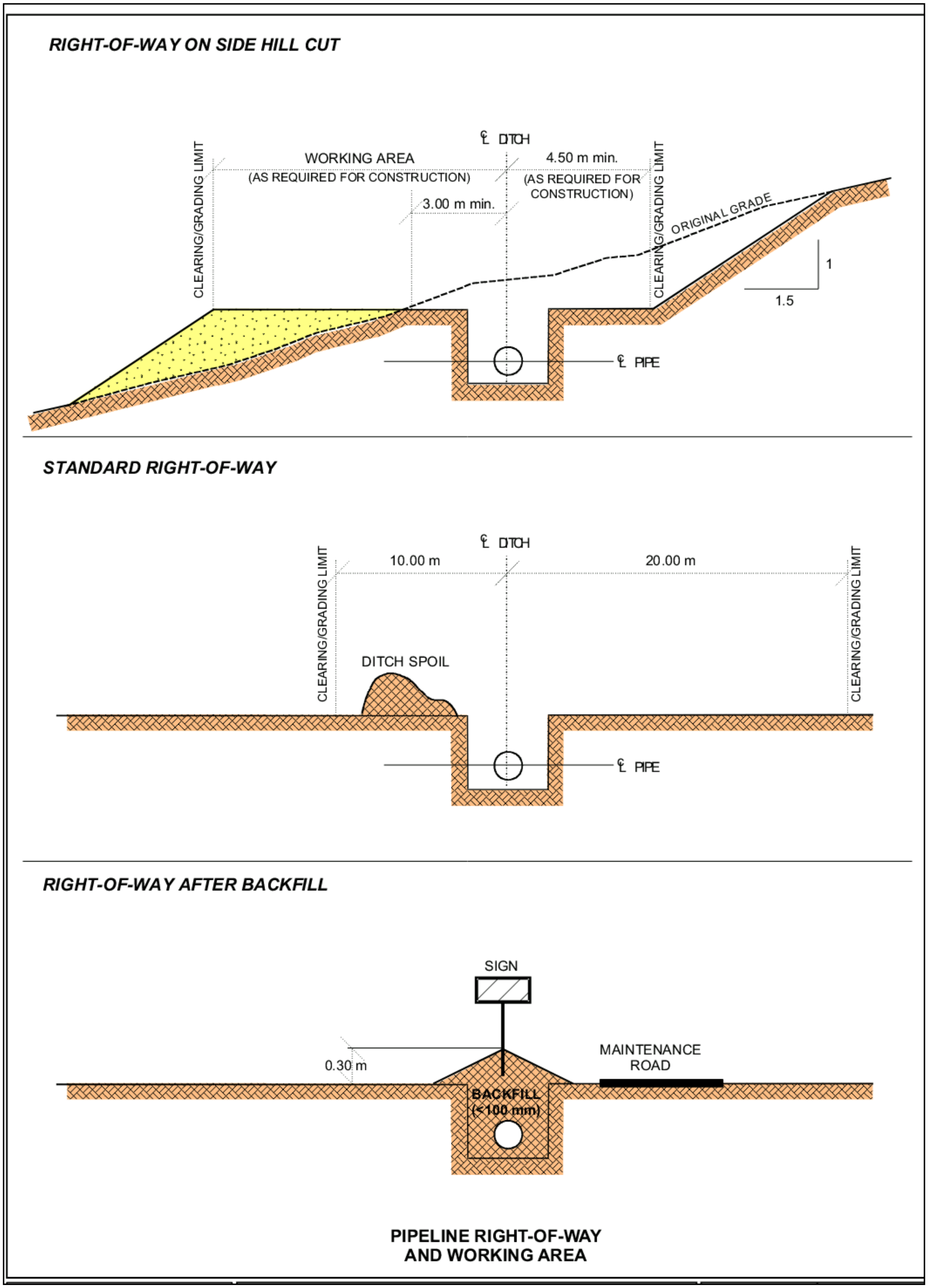


Figure (3.8): Pipeline Right-of-Way and Working Area

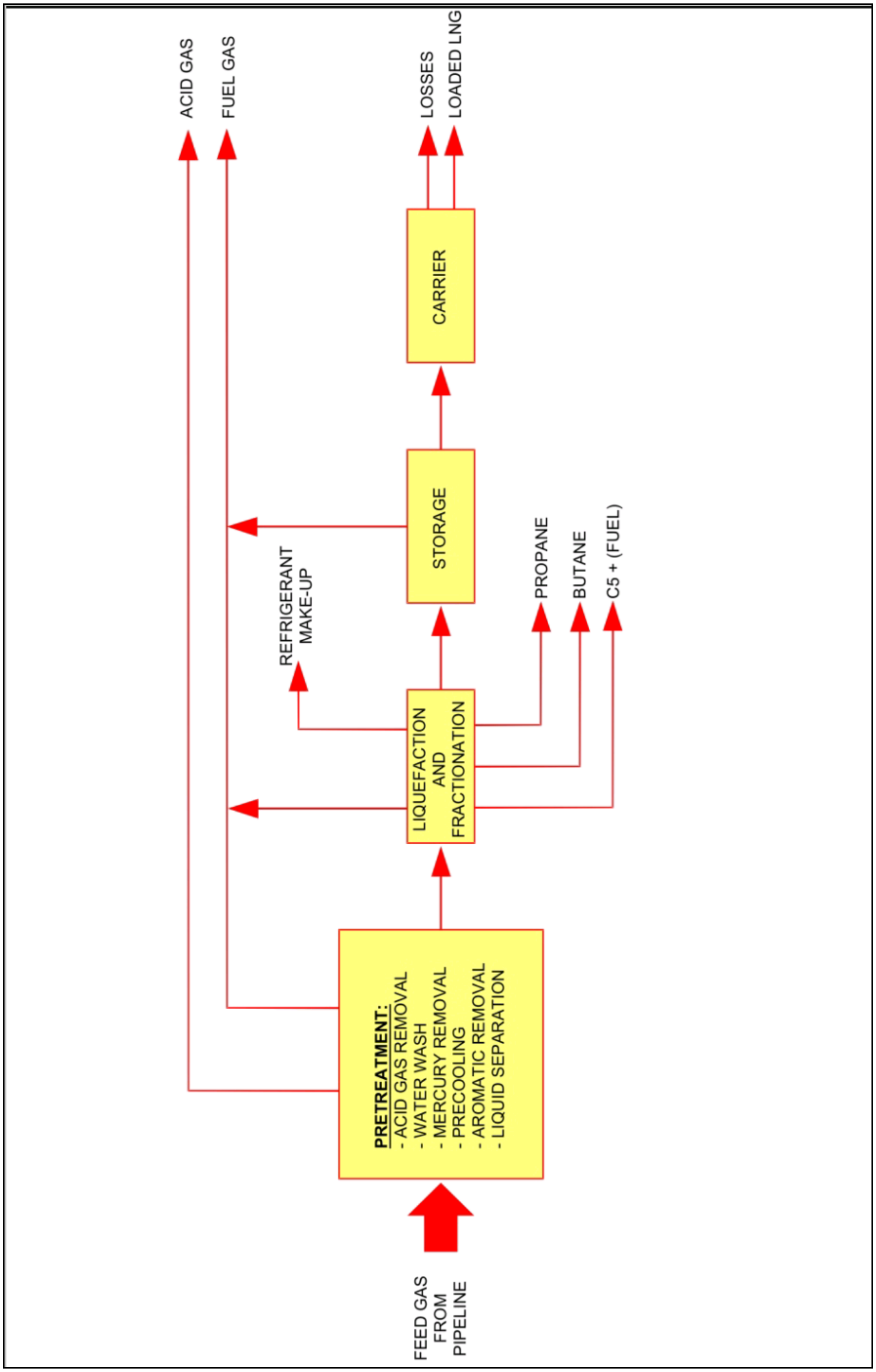


Figure (3.9): LNG Treatment Train Block Flow Diagrams

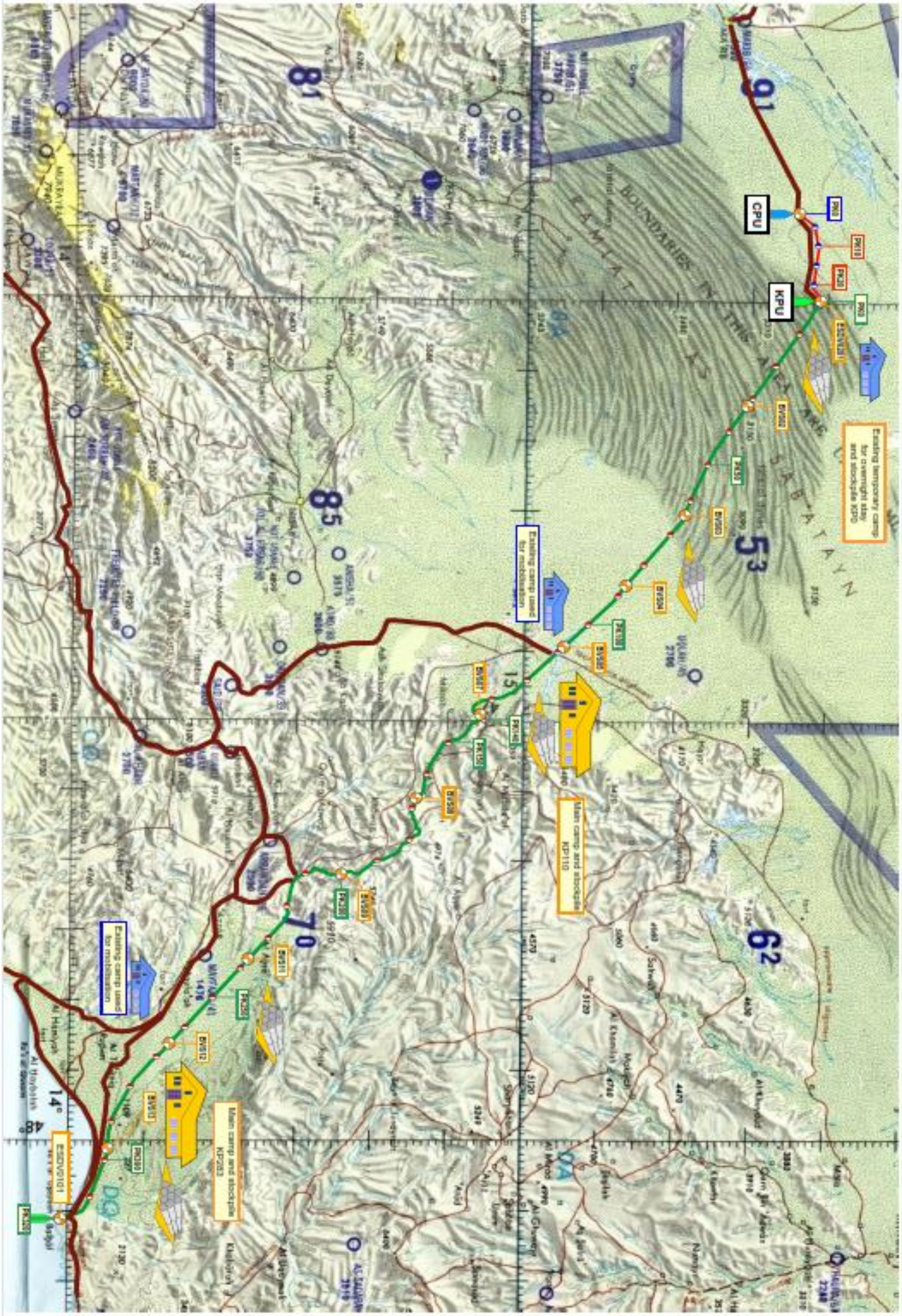
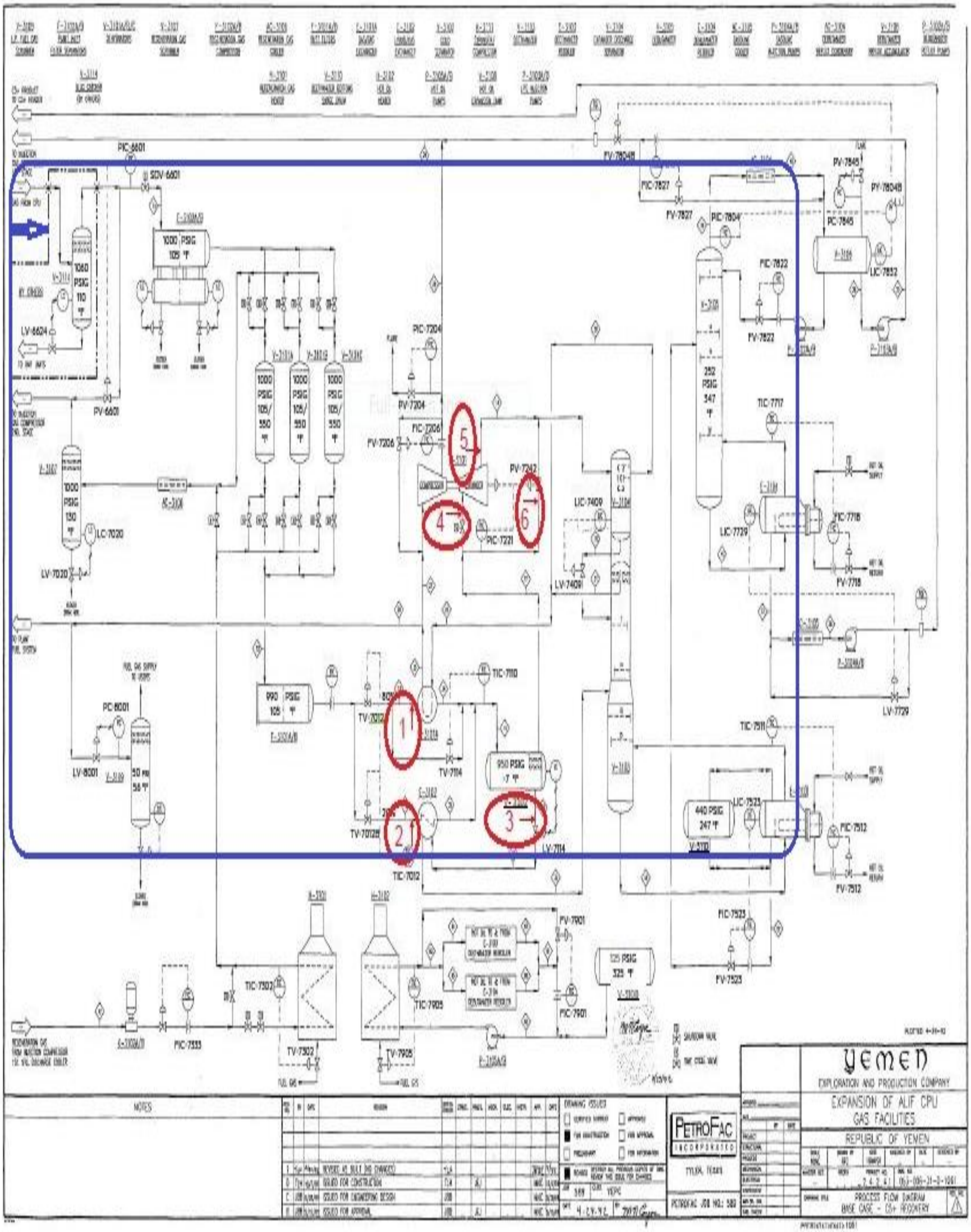
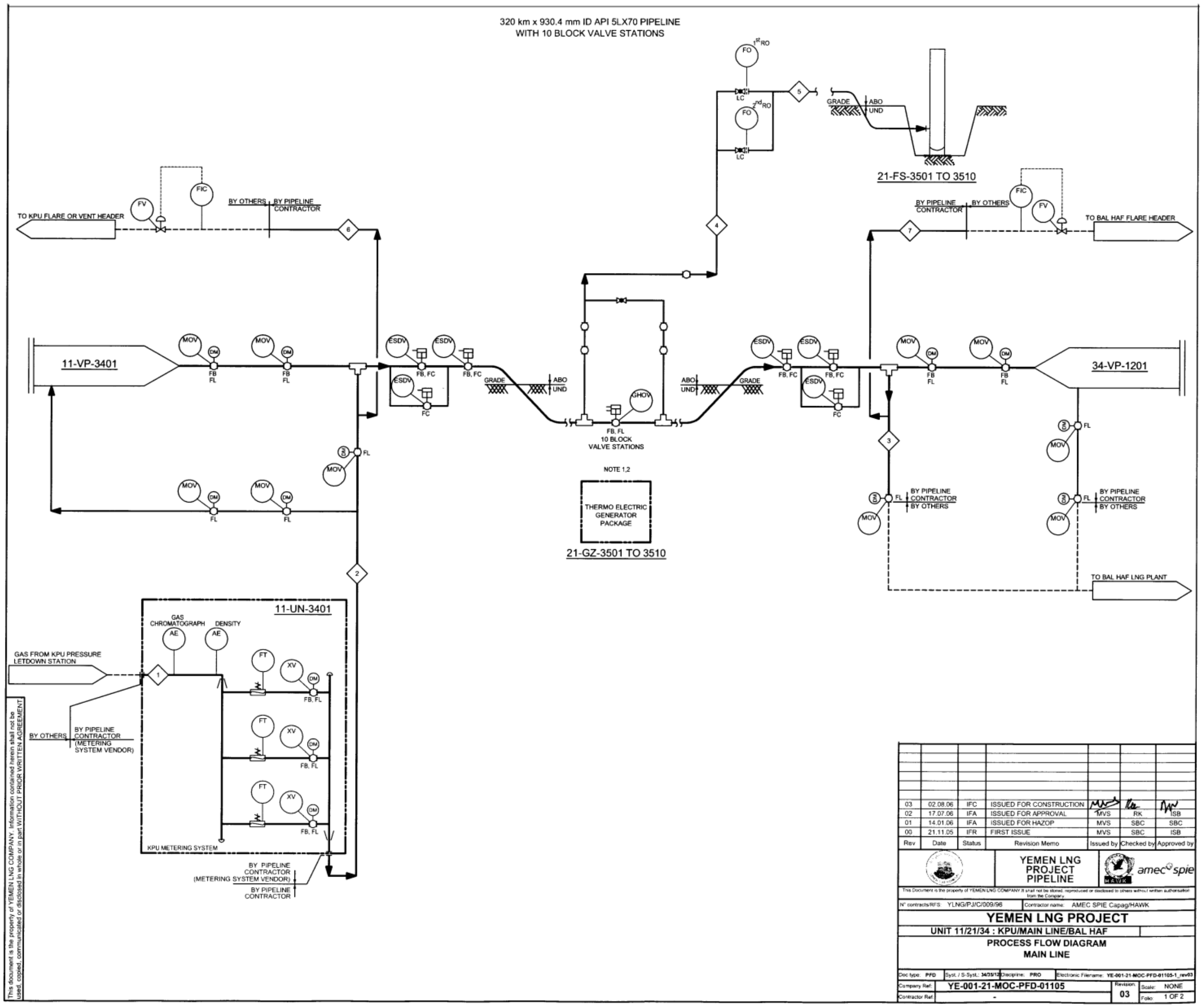


Figure (3.10) PIPELINE CONSTRUCTION CAMP & STOCK PILES LOCATION MAP

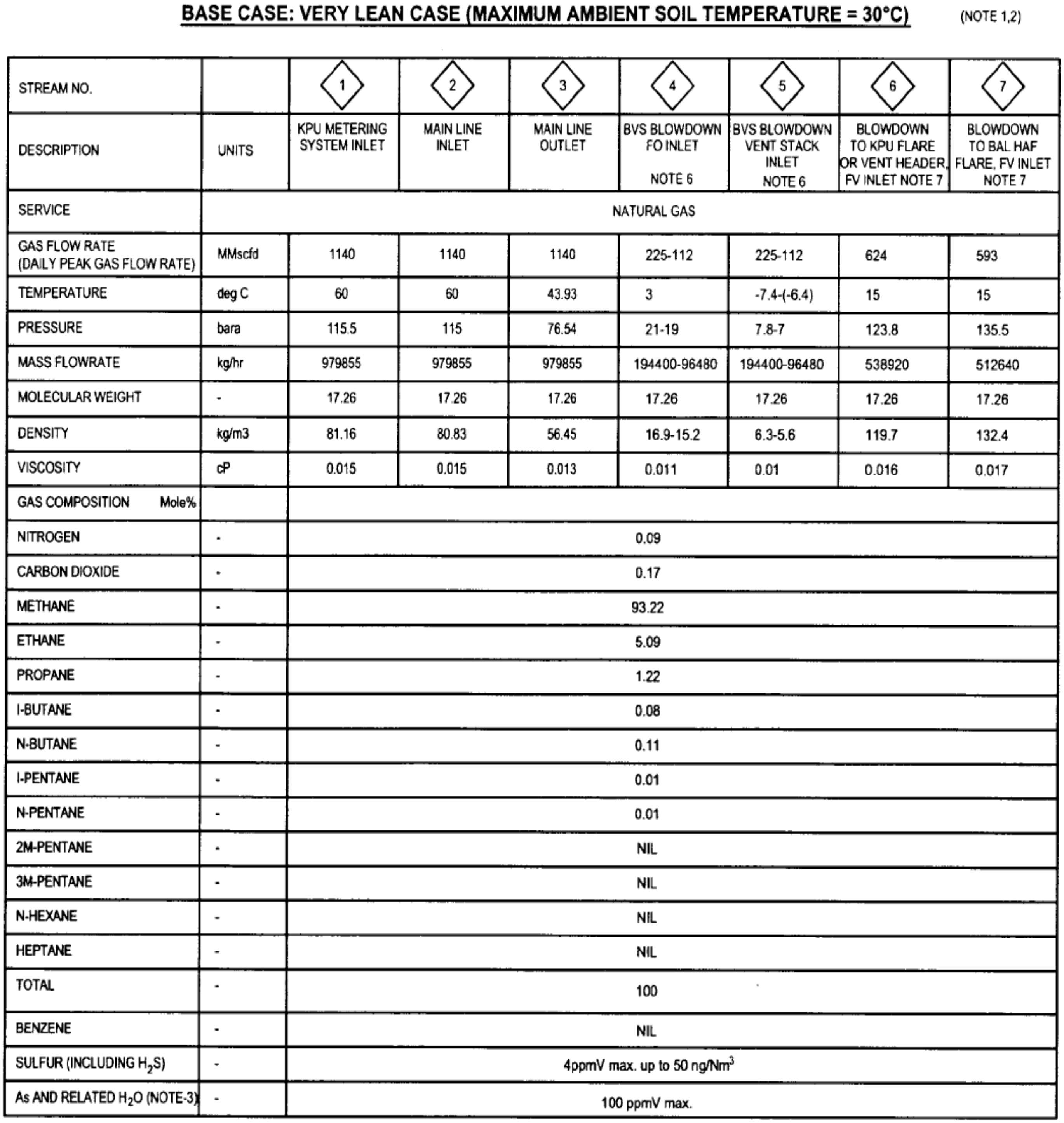
PROCESS FLOW DIAGRAM - PFD (KPU GAS PLANT) (A)



PROCESS FLOW DIAGRAM - PFD (KPU GAS PLANT) (B)



PIPELINE INPUT DATA FOR PIPESIM PROGRAM (1)



BASE CASE: VERY LEAN CASE (MAXIMUM AMBIENT SOIL TEMPERATURE = 30°C) (NOTE 1,2)

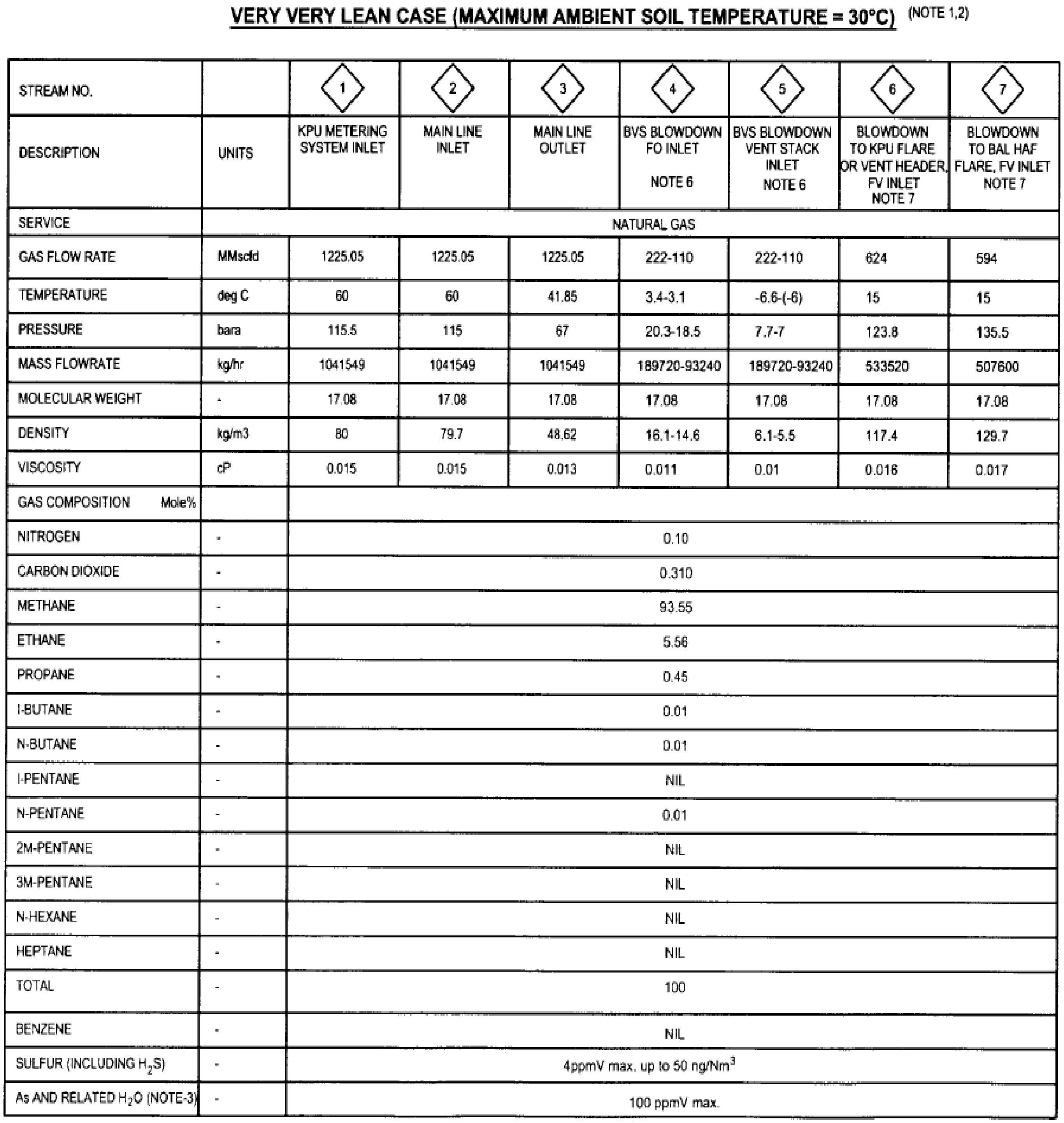
STREAM NO.		1	2	3	4	5	6	7
DESCRIPTION	UNITS	KPU METERING SYSTEM INLET	MAIN LINE INLET	MAIN LINE OUTLET	BVS BLOWDOWN FO INLET NOTE 6	BVS BLOWDOWN VENT STACK INLET NOTE 6	BLOWDOWN TO KPU FLARE OR VENT HEADER, FV INLET NOTE 7	BLOWDOWN TO BAL HAF FLARE, FV INLET NOTE 7
SERVICE	NATURAL GAS							
GAS FLOW RATE (DAILY PEAK GAS FLOW RATE)	MMscfd	1140	1140	1140	225-112	225-112	624	593
TEMPERATURE	deg C	60	60	43.93	3	-7.4-(-6.4)	15	15
PRESSURE	bara	115.5	115	76.54	21-19	7.8-7	123.8	135.5
MASS FLOWRATE	kg/hr	979855	979855	979855	194400-96480	194400-96480	538920	512640
MOLECULAR WEIGHT	-	17.26	17.26	17.26	17.26	17.26	17.26	17.26
DENSITY	kg/m3	81.16	80.83	56.45	16.9-15.2	6.3-5.6	119.7	132.4
VISCOSITY	cP	0.015	0.015	0.013	0.011	0.01	0.016	0.017
GAS COMPOSITION Mole%								
NITROGEN	-	0.09						
CARBON DIOXIDE	-	0.17						
METHANE	-	93.22						
ETHANE	-	5.09						
PROPANE	-	1.22						
I-BUTANE	-	0.08						
N-BUTANE	-	0.11						
I-PENTANE	-	0.01						
N-PENTANE	-	0.01						
2M-PENTANE	-	NIL						
3M-PENTANE	-	NIL						
N-HEXANE	-	NIL						
HEPTANE	-	NIL						
TOTAL	-	100						
BENZENE	-	NIL						
SULFUR (INCLUDING H_2S)	-	4ppmV max. up to 50 ng/Nm^3						
As AND RELATED H_2O (NOTE-3)	-	100 ppmV max.						

PIPELINE INPUT DATA FOR PIPESIM PROGRAM (2)

RICH CASE (MAXIMUM AMBIENT SOIL TEMPERATURE = 30°C) (NOTE 1,2)

STREAM NO.		1	2	3	4	5	6	7
DESCRIPTION	UNITS	KPU METERING SYSTEM INLET	MAIN LINE INLET	MAIN LINE OUTLET	BVS BLOWDOWN FO INLET NOTE 6	BVS BLOWDOWN VENT STACK INLET NOTE 6	BLOWDOWN TO KPU FLARE OR VENT HEADER, FV INLET NOTE 7	BLOWDOWN TO BAL HAF FLARE, FV INLET NOTE 7
SERVICE		NATURAL GAS						
GAS FLOW RATE	MMscfd	1212.9	1212.9	1212.9	228-116	228-116	621	591
TEMPERATURE	deg C	60	60	41.7	3	-5	15	15
PRESSURE	bara	115.5	115	67	21.9	9	123.8	135.5
MASS FLOWRATE	kg/hr	1065816	1065816	1065816	201600-102600	201600-202600	548640	522000
MOLECULAR WEIGHT	-	17.65	17.65	17.65	17.65	17.65	17.65	17.65
DENSITY	kg/m3	83.6	83.2	50.72	18.14	7.5	124.4	137.5
VISCOSITY	cP	0.015	0.015	0.013	0.011	0.011	0.017	0.017
GAS COMPOSITION Mole%								
NITROGEN	-	0.10						
CARBON DIOXIDE	-	0.286						
METHANE	-	91.92						
ETHANE	-	5.66						
PROPANE	-	1.482						
I-BUTANE	-	0.128						
N-BUTANE	-	0.239						
I-PENTANE	-	0.04						
N-PENTANE	-	0.047						
2M-PENTANE (NOTE-5)	-	0.015						
3M-PENTANE (NOTE-5)	-	0.006						
N-HEXANE	-	0.015						
HEPTANE	-	0.062						
TOTAL	-	100						
BENZENE (NOTE-4)	-	up to 100 ppmV						
SULFUR (INCLUDING H_2S)	-	4ppmV max. up to 50 ng/Nm^3						
As AND RELATED H_2O (NOTE-3)	-	100 ppmV max.						

PIPELINE INPUT DATA FOR PIPESIM PROGRAM (3)



VERY VERY LEAN CASE (MAXIMUM AMBIENT SOIL TEMPERATURE = 30°C) (NOTE 1,2)

STREAM NO.		1	2	3	4	5	6	7
DESCRIPTION	UNITS	KPU METERING SYSTEM INLET	MAIN LINE INLET	MAIN LINE OUTLET	BVS BLOWDOWN FO INLET NOTE 6	BVS BLOWDOWN VENT STACK INLET NOTE 6	BLOWDOWN TO KPU FLARE OR VENT HEADER, FV INLET NOTE 7	BLOWDOWN TO BAL HAF FLARE, FV INLET NOTE 7
SERVICE		NATURAL GAS						
GAS FLOW RATE	MMscfd	1225.05	1225.05	1225.05	222-110	222-110	624	594
TEMPERATURE	deg C	60	60	41.85	3.4-3.1	-6.6-(-6)	15	15
PRESSURE	bara	115.5	115	67	20.3-18.5	7.7-7	123.8	135.5
MASS FLOWRATE	kg/hr	1041549	1041549	1041549	189720-93240	189720-93240	533520	507600
MOLECULAR WEIGHT	-	17.08	17.08	17.08	17.08	17.08	17.08	17.08
DENSITY	kg/m3	80	79.7	48.62	16.1-14.6	6.1-5.5	117.4	129.7
VISCOSITY	cP	0.015	0.015	0.013	0.011	0.01	0.016	0.017
GAS COMPOSITION Mole%								
NITROGEN	-	0.10						
CARBON DIOXIDE	-	0.310						
METHANE	-	93.55						
ETHANE	-	5.56						
PROPANE	-	0.45						
I-BUTANE	-	0.01						
N-BUTANE	-	0.01						
I-PENTANE	-	NIL						
N-PENTANE	-	0.01						
2M-PENTANE	-	NIL						
3M-PENTANE	-	NIL						
N-HEXANE	-	NIL						
HEPTANE	-	NIL						
TOTAL	-	100						
BENZENE	-	NIL						
SULFUR (INCLUDING H_2S)	-	4ppmV max. up to 50 ng/Nm^3						
As AND RELATED H_2O (NOTE-3)	-	100 ppmV max.						

CHAPTER FOUR
DATA INPUT & ANALYSIS

4.1. DESIGN THE MODEL OF GAS PIPELINES TRANSMISSION

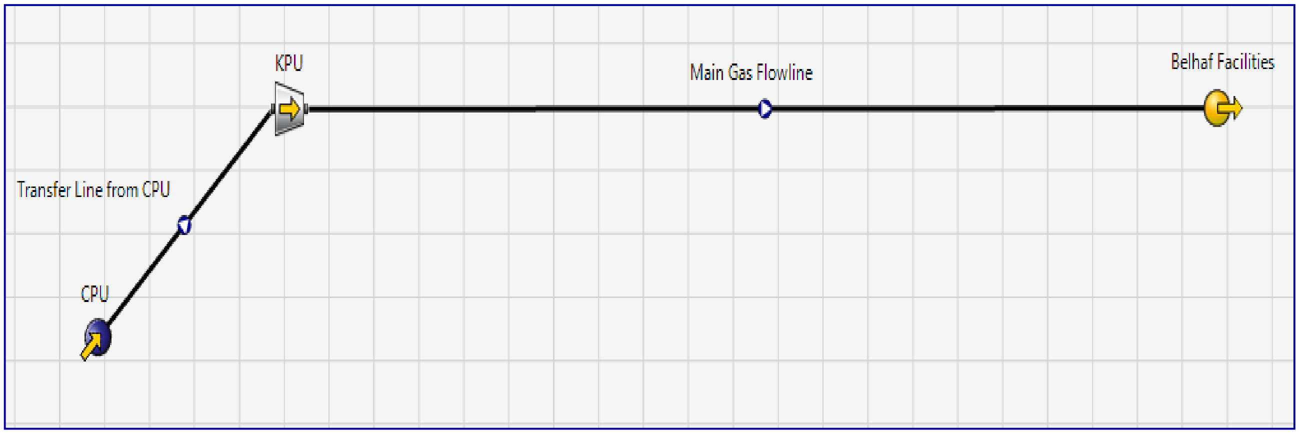
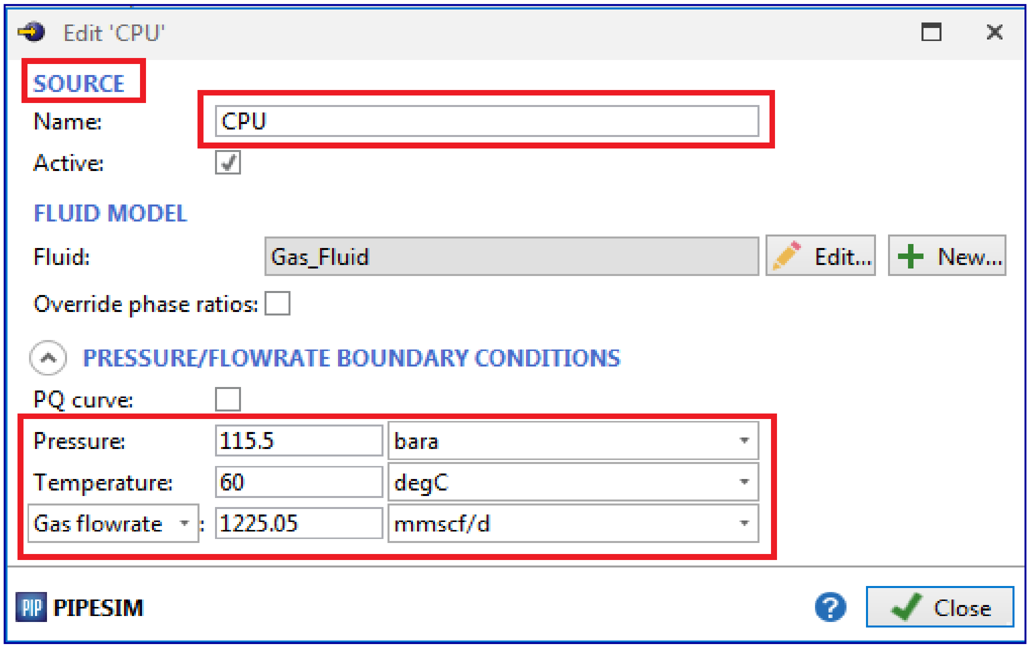


FIGURE (4.1): DESIGN THE PIPELINES TRANSMISSION MODEL IN PIPESIM

4.2. INPUT DATA FOR START POINT (SOURCE = CPU) IN PIPESIM

Enter the pressure, temperature and Gas flow-rate data as shown in next:



SOURCE

Name: CPU

Active: ☑

FLUID MODEL

Fluid: Gas_Fluid

Override phase ratios: ☐

PRESSURE/FLOWRATE BOUNDARY CONDITIONS

PQ curve: ☐

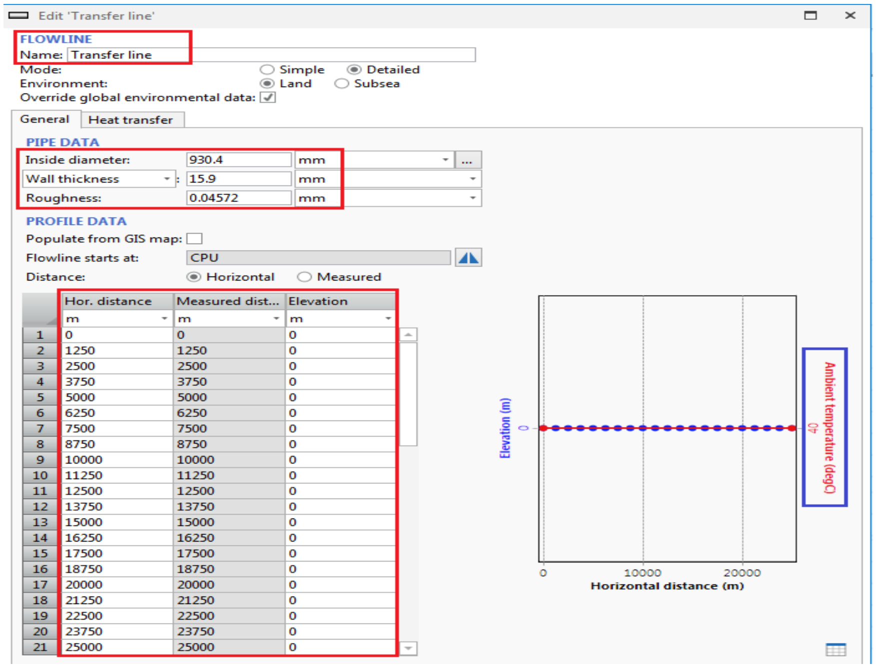
Pressure: 115.5 bara

Temperature: 60 degC

Gas flowrate: 1225.05 mmscf/d

4.3. TRANSFER LINE 1= 25 Km - INPUT DATA FOR PIPESIM

Enter the data of transfer pipeline line from **CPU** to **KPU** (Name, inside diameter, wall thickness, and roughness) as shown in next table:



Edit 'Transfer line'

FLOWLINE

Name: Transfer line

Mode: ○ Simple ● Detailed

Environment: ● Land ○ Subsea

Override global environmental data: ☑

General | Heat transfer

PIPE DATA

Inside diameter: 930.4 mm

Wall thickness: 15.9 mm

Roughness: 0.04572 mm

PROFILE DATA

Populate from GIS map: ☐

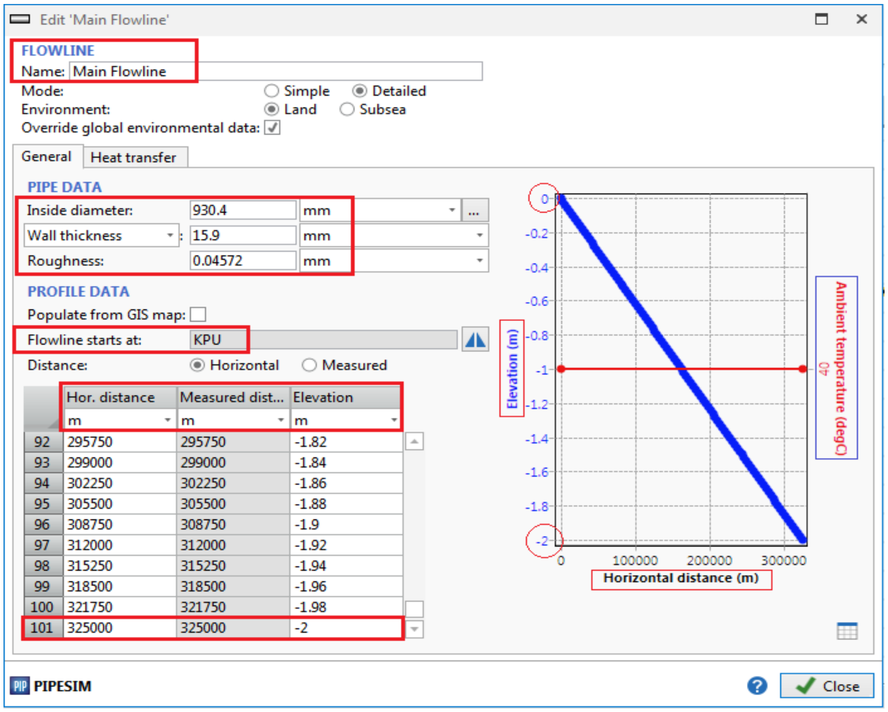
Flowline starts at: CPU

Distance: ● Horizontal ○ Measured

	Hor. distance	Measured dist...	Elevation
	m	m	m
1	0	0	0
2	1250	1250	0
3	2500	2500	0
4	3750	3750	0
5	5000	5000	0
6	6250	6250	0
7	7500	7500	0
8	8750	8750	0
9	10000	10000	0
10	11250	11250	0
11	12500	12500	0
12	13750	13750	0
13	15000	15000	0
14	16250	16250	0
15	17500	17500	0
16	18750	18750	0
17	20000	20000	0
18	21250	21250	0
19	22500	22500	0
20	23750	23750	0
21	25000	25000	0

4.4. MAIN LINE 2= 325 Km - INPUT DATA FOR PIPESIM

Enter the data of **Main pipeline** from **KPU to Balhaf port** (Name, inside diameter, wall thickness, and roughness) as shown in next table:



Edit 'Main Flowline'

FLOWLINE

Name: Main Flowline

Mode: ○ Simple ● Detailed

Environment: ● Land ○ Subsea

Override global environmental data: ☑

General | Heat transfer

PIPE DATA

Inside diameter: 930.4 mm

Wall thickness: 15.9 mm

Roughness: 0.04572 mm

PROFILE DATA

Populate from GIS map: ☐

Flowline starts at: KPU

Distance: ● Horizontal ○ Measured

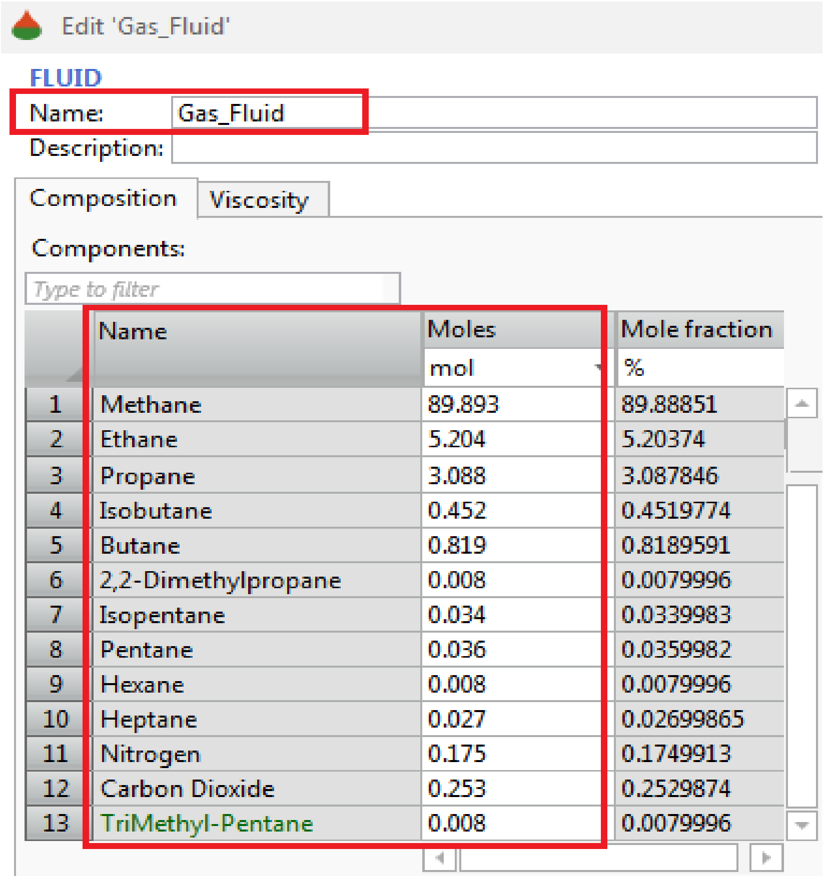
	Hor. distance	Measured dist...	Elevation
	m	m	m
92	295750	295750	-1.82
93	299000	299000	-1.84
94	302250	302250	-1.86
95	305500	305500	-1.88
96	308750	308750	-1.9
97	312000	312000	-1.92
98	315250	315250	-1.94
99	318500	318500	-1.96
100	321750	321750	-1.98
101	325000	325000	-2

4.5. GAS COMPOSITION (MOLES) - INPUT DATA FOR PIPESIM

4.5.1. Create a Gas Compositional Fluid Model:

- Add the gas components to the fluid template from the Fluid Components list. There are 13 components.
- Enter the moles for each component as shown in the following Table (4.1).

TABLE (4.1): INPUT DATA FOR GAS FLUID COMPOSITION (MOLES)

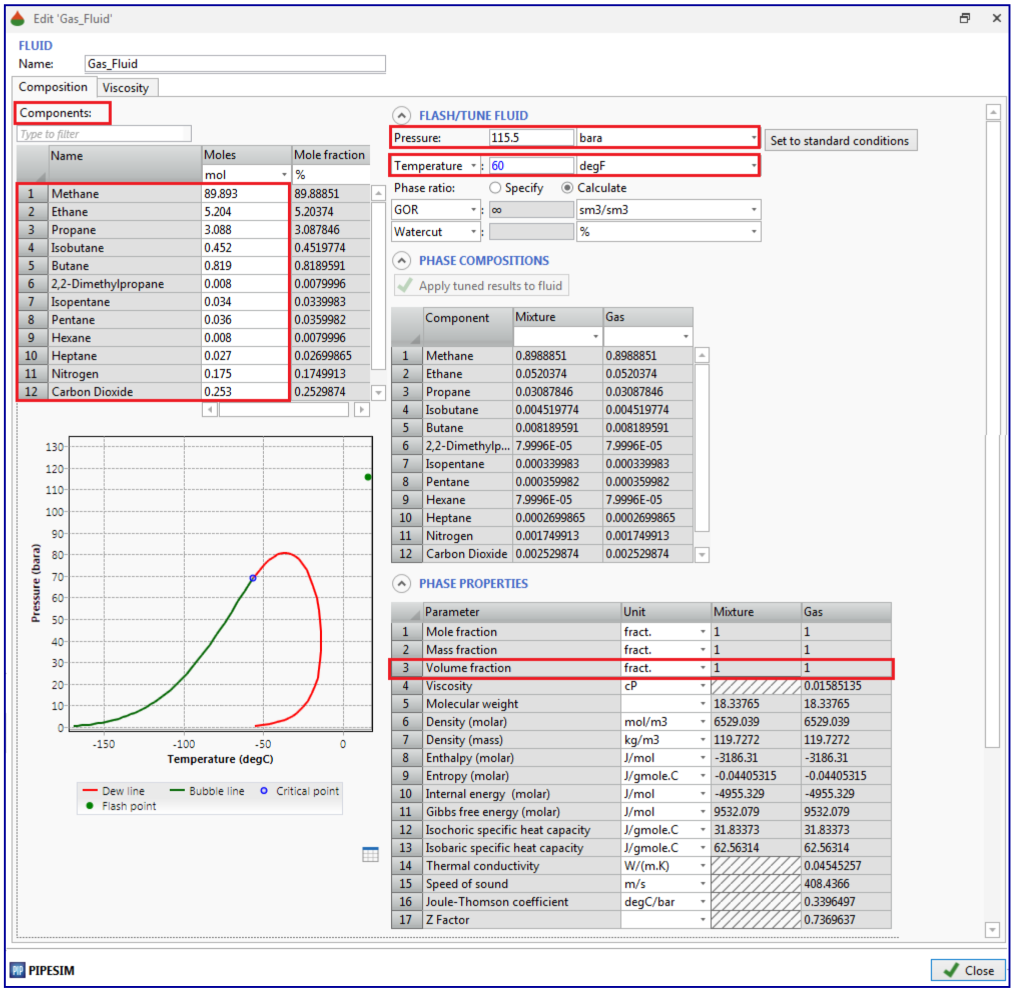


Name: Gas_Fluid

Description:

	Name	Moles mol	Mole fraction %
1	Methane	89.893	89.88851
2	Ethane	5.204	5.20374
3	Propane	3.088	3.087846
4	Isobutane	0.452	0.4519774
5	Butane	0.819	0.8189591
6	2,2-Dimethylpropane	0.008	0.0079996
7	Isopentane	0.034	0.0339983
8	Pentane	0.036	0.0359982
9	Hexane	0.008	0.0079996
10	Heptane	0.027	0.02699865
11	Nitrogen	0.175	0.1749913
12	Carbon Dioxide	0.253	0.2529874
13	TriMethyl-Pentane	0.008	0.0079996

- When entering the moles fractions (**Source:** Yemen LNG Company) for any component we notice that the phase diagram automatically updates as you enter the moles for each component and they are as the following:



Name: Gas_Fluid

	Name	Moles mol	Mole fraction %
1	Methane	89.893	89.88851
2	Ethane	5.204	5.20374
3	Propane	3.088	3.087846
4	Isobutane	0.452	0.4519774
5	Butane	0.819	0.8189591
6	2,2-Dimethylpropane	0.008	0.0079996
7	Isopentane	0.034	0.0339983
8	Pentane	0.036	0.0359982
9	Hexane	0.008	0.0079996
10	Heptane	0.027	0.02699865
11	Nitrogen	0.175	0.1749913
12	Carbon Dioxide	0.253	0.2529874

Pressure: 115.5 bara

Temperature: 60 degF

Phase ratio: ○ Specify ● Calculate

GOR: ∞ sm3/sm3

Watercut: %

	Component	Mixture	Gas
1	Methane	0.8988851	0.8988851
2	Ethane	0.0520374	0.0520374
3	Propane	0.03087846	0.03087846
4	Isobutane	0.004519774	0.004519774
5	Butane	0.008189591	0.008189591
6	2,2-Dimethylp...	7.9996E-05	7.9996E-05
7	Isopentane	0.000339983	0.000339983
8	Pentane	0.000359982	0.000359982
9	Hexane	7.9996E-05	7.9996E-05
10	Heptane	0.0002699865	0.0002699865
11	Nitrogen	0.001749913	0.001749913
12	Carbon Dioxide	0.002529874	0.002529874

	Parameter	Unit	Mixture	Gas
1	Mole fraction	fract.	1	1
2	Mass fraction	fract.	1	1
3	Volume fraction	fract.	1	1
4	Viscosity	cP	▨	0.01585135
5	Molecular weight		18.33765	18.33765
6	Density (molar)	mol/m3	6529.039	6529.039
7	Density (mass)	kg/m3	119.7272	119.7272
8	Enthalpy (molar)	J/mol	-3186.31	-3186.31
9	Entropy (molar)	J/gmole.C	-0.04405315	-0.04405315
10	Internal energy (molar)	J/mol	-4955.329	-4955.329
11	Gibbs free energy (molar)	J/mol	9532.079	9532.079
12	Isochoric specific heat capacity	J/gmole.C	31.83373	31.83373
13	Isobaric specific heat capacity	J/gmole.C	62.56314	62.56314
14	Thermal conductivity	W/(m.K)	▨	0.04545257
15	Speed of sound	m/s	▨	408.4366
16	Joule-Thomson coefficient	degC/bar	▨	0.3396497
17	Z Factor		▨	0.7369637

FIGURE (4.2): THE PHASE DIAGRAM OF THE MOLES COMPONENT IN PIPESIM

4.6. NATURAL GAS PIPELINE ANALYSIS:

In the PIPESIM we use the pressure/temperature profile (P/T profile) task to generate pressure and temperature profiles as a function of pipeline distance or elevation along the defined single-branch flow path.

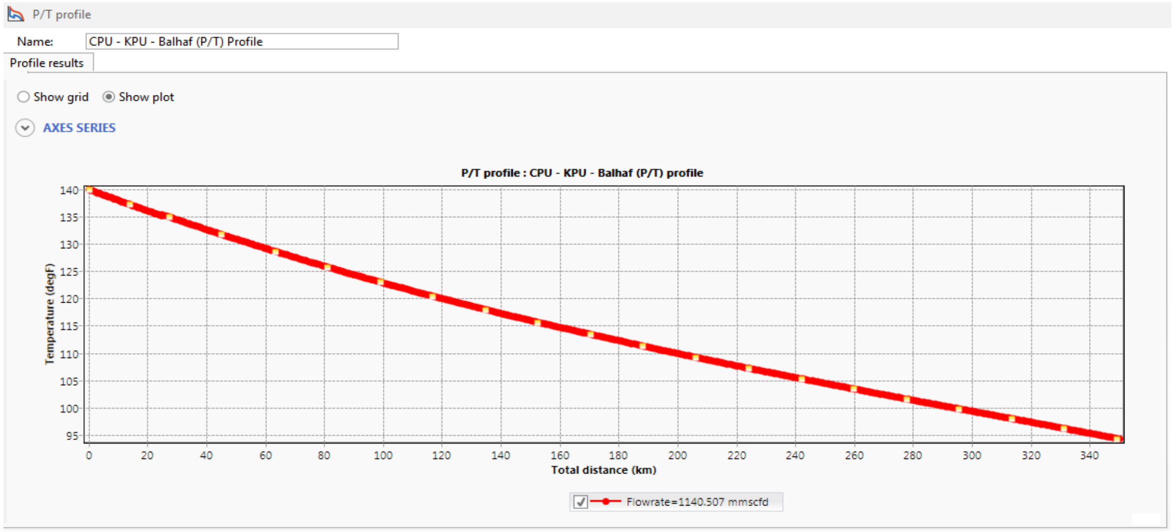
1. On the pipeline network diagram, select the start point (source = CPU) where the analysis will start.
2. In the tasks pane, double-click P/T profile.
3. On the Parameters tab, enter the properties, including the branch endpoint (sink = Balhaf), the calculated variable, and any sensitivity variables.
4. Calculated variable properties:

   In this area, specify one of three key variables (inlet pressure, outlet pressure, or flow-rate) as the calculated variable. The calculated variable is derived from the other two values.
5. Click **Run**.
6. View the profile results by clicking the System results tab or the Profile results tab.

7. Default profile plot properties:

   In this area, define the **X** and **Y axes** that will appear by default on the Profile plot tab, which displays the results of the P/T Profile task.

8. By clicking on the Profile Results tab, select the Show plot and will see the temperature curve changed (dropping) inside the gas pipeline as a function of pipeline distance as in the next Figures. (4.3), (4.4) & (4.5).



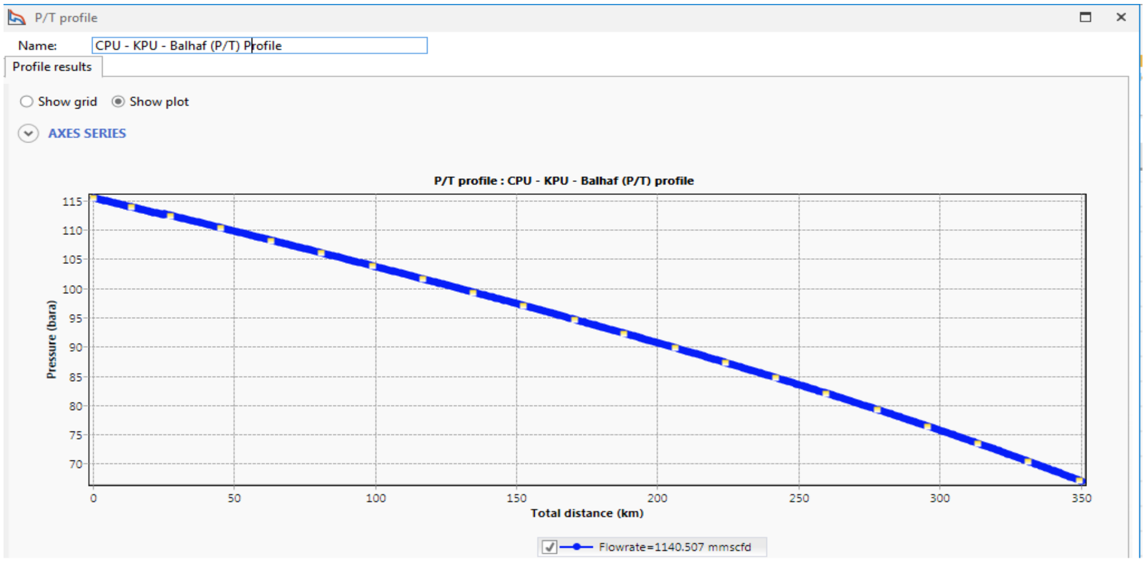
P/T profile

Name: CPU - KPU - Balhaf (P/T) Profile

Profile results

○ Show grid ● Show plot

FIGURE (4.3): TEMPERATURE AGAINST TOTAL DISTANCE CURVE INSIDE PIPELINES



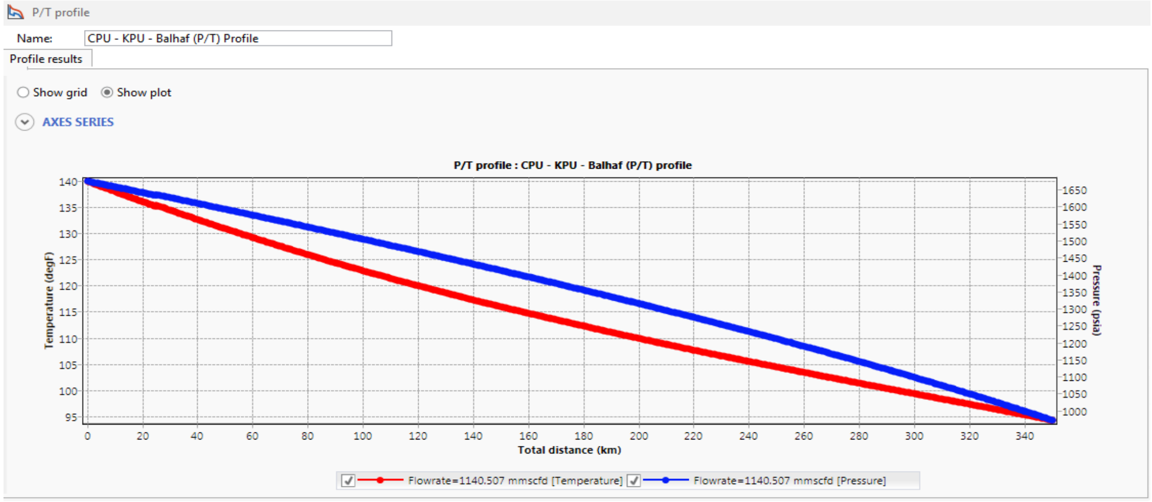
P/T profile

Name: CPU - KPU - Balhaf (P/T) Profile

Profile results

○ Show grid ● Show plot

FIGURE (4.4): PRESSURE AGAINST TOTAL DISTANCE CURVE INSIDE PIPELINES



P/T profile

Name: CPU - KPU - Balhaf (P/T) Profile

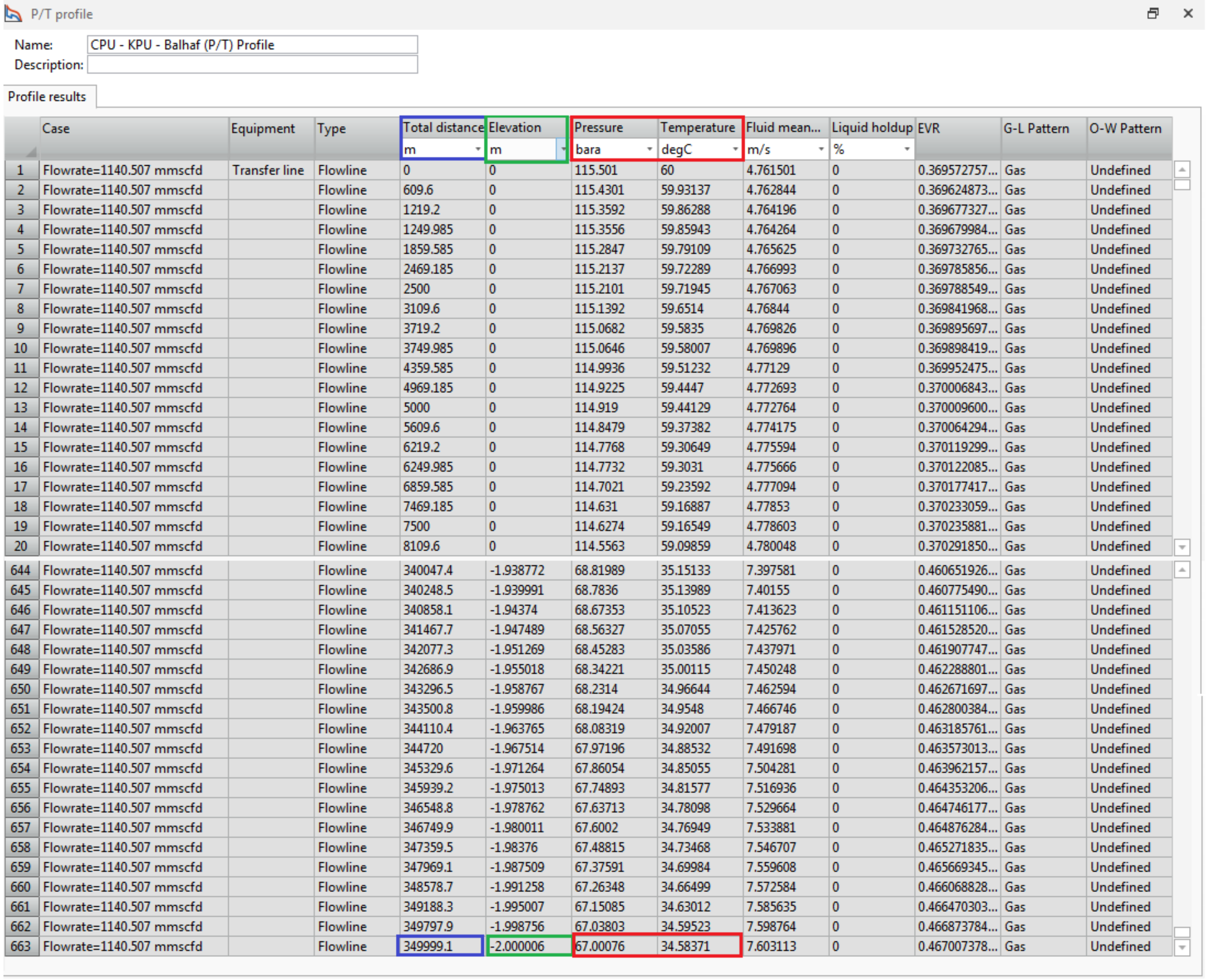
Profile results

○ Show grid ● Show plot

FIGURE (4.5): TEMPERATURE & PRESSURE AGAINST TOTAL DISTANCE CURVE INSIDE PIPELINES

9. From the Profile results tab, select the Show grid and will see the following table (4.2):

TABLE (4.2): TEMPERATURE & PRESSURE AGAINST TOTAL DISTANCE



P/T profile

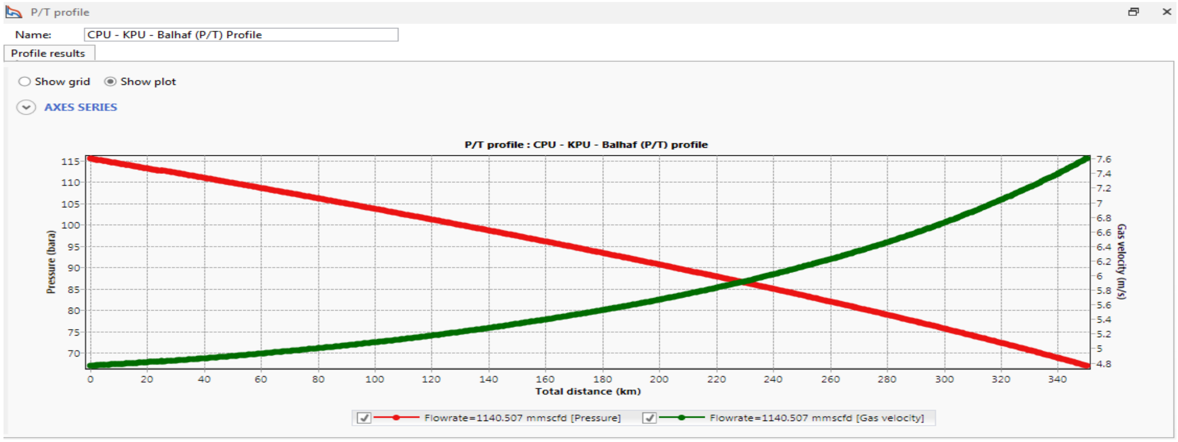
Name: CPU - KPU - Balhaf (P/T) Profile

Description:

Profile results

	Case	Equipment	Type	Total distance	Elevation	Pressure	Temperature	Fluid mean...	Liquid holdup	EVR	G-L Pattern	O-W Pattern
				m	m	bara	degC	m/s	%			
1	Flowrate=1140.507 mmscfd	Transfer line	Flowline	0	0	115.501	60	4.761501	0	0.369572757...	Gas	Undefined
2	Flowrate=1140.507 mmscfd		Flowline	609.6	0	115.4301	59.93137	4.762844	0	0.369624873...	Gas	Undefined
3	Flowrate=1140.507 mmscfd		Flowline	1219.2	0	115.3592	59.86288	4.764196	0	0.369677327...	Gas	Undefined
4	Flowrate=1140.507 mmscfd		Flowline	1249.985	0	115.3556	59.85943	4.764264	0	0.369679984...	Gas	Undefined
5	Flowrate=1140.507 mmscfd		Flowline	1859.585	0	115.2847	59.79109	4.765625	0	0.369732765...	Gas	Undefined
6	Flowrate=1140.507 mmscfd		Flowline	2469.185	0	115.2137	59.72289	4.766993	0	0.369785856...	Gas	Undefined
7	Flowrate=1140.507 mmscfd		Flowline	2500	0	115.2101	59.71945	4.767063	0	0.369788549...	Gas	Undefined
8	Flowrate=1140.507 mmscfd		Flowline	3109.6	0	115.1392	59.6514	4.76844	0	0.369841968...	Gas	Undefined
9	Flowrate=1140.507 mmscfd		Flowline	3719.2	0	115.0682	59.5835	4.769826	0	0.369895697...	Gas	Undefined
10	Flowrate=1140.507 mmscfd		Flowline	3749.985	0	115.0646	59.58007	4.769896	0	0.369898419...	Gas	Undefined
11	Flowrate=1140.507 mmscfd		Flowline	4359.585	0	114.9936	59.51232	4.77129	0	0.369952475...	Gas	Undefined
12	Flowrate=1140.507 mmscfd		Flowline	4969.185	0	114.9225	59.4447	4.772693	0	0.370006843...	Gas	Undefined
13	Flowrate=1140.507 mmscfd		Flowline	5000	0	114.919	59.44129	4.772764	0	0.370009600...	Gas	Undefined
14	Flowrate=1140.507 mmscfd		Flowline	5609.6	0	114.8479	59.37382	4.774175	0	0.370064294...	Gas	Undefined
15	Flowrate=1140.507 mmscfd		Flowline	6219.2	0	114.7768	59.30649	4.775594	0	0.370119299...	Gas	Undefined
16	Flowrate=1140.507 mmscfd		Flowline	6249.985	0	114.7732	59.3031	4.775666	0	0.370122085...	Gas	Undefined
17	Flowrate=1140.507 mmscfd		Flowline	6859.585	0	114.7021	59.23592	4.777094	0	0.370177417...	Gas	Undefined
18	Flowrate=1140.507 mmscfd		Flowline	7469.185	0	114.631	59.16887	4.77853	0	0.370233059...	Gas	Undefined
19	Flowrate=1140.507 mmscfd		Flowline	7500	0	114.6274	59.16549	4.778603	0	0.370235881...	Gas	Undefined
20	Flowrate=1140.507 mmscfd		Flowline	8109.6	0	114.5563	59.09859	4.780048	0	0.370291850...	Gas	Undefined
644	Flowrate=1140.507 mmscfd		Flowline	340047.4	-1.938772	68.81989	35.15133	7.397581	0	0.460651926...	Gas	Undefined
645	Flowrate=1140.507 mmscfd		Flowline	340248.5	-1.939991	68.7836	35.13989	7.40155	0	0.460775490...	Gas	Undefined
646	Flowrate=1140.507 mmscfd		Flowline	340858.1	-1.94374	68.67353	35.10523	7.413623	0	0.461151106...	Gas	Undefined
647	Flowrate=1140.507 mmscfd		Flowline	341467.7	-1.947489	68.56327	35.07055	7.425762	0	0.461528520...	Gas	Undefined
648	Flowrate=1140.507 mmscfd		Flowline	342077.3	-1.951269	68.45283	35.03586	7.437971	0	0.461907747...	Gas	Undefined
649	Flowrate=1140.507 mmscfd		Flowline	342686.9	-1.955018	68.34221	35.00115	7.450248	0	0.462288801...	Gas	Undefined
650	Flowrate=1140.507 mmscfd		Flowline	343296.5	-1.958767	68.2314	34.96644	7.462594	0	0.462671697...	Gas	Undefined
651	Flowrate=1140.507 mmscfd		Flowline	343500.8	-1.959986	68.19424	34.9548	7.466746	0	0.462800384...	Gas	Undefined
652	Flowrate=1140.507 mmscfd		Flowline	344110.4	-1.963765	68.08319	34.92007	7.479187	0	0.463185761...	Gas	Undefined
653	Flowrate=1140.507 mmscfd		Flowline	344720	-1.967514	67.97196	34.88532	7.491698	0	0.463573013...	Gas	Undefined
654	Flowrate=1140.507 mmscfd		Flowline	345329.6	-1.971264	67.86054	34.85055	7.504281	0	0.463962157...	Gas	Undefined
655	Flowrate=1140.507 mmscfd		Flowline	345939.2	-1.975013	67.74893	34.81577	7.516936	0	0.464353206...	Gas	Undefined
656	Flowrate=1140.507 mmscfd		Flowline	346548.8	-1.978762	67.63713	34.78098	7.529664	0	0.464746177...	Gas	Undefined
657	Flowrate=1140.507 mmscfd		Flowline	346749.9	-1.980011	67.6002	34.76949	7.533881	0	0.464876284...	Gas	Undefined
658	Flowrate=1140.507 mmscfd		Flowline	347359.5	-1.98376	67.48815	34.73468	7.546707	0	0.465271835...	Gas	Undefined
659	Flowrate=1140.507 mmscfd		Flowline	347969.1	-1.987509	67.37591	34.69984	7.559608	0	0.465669345...	Gas	Undefined
660	Flowrate=1140.507 mmscfd		Flowline	348578.7	-1.991258	67.26348	34.66499	7.572584	0	0.466068828...	Gas	Undefined
661	Flowrate=1140.507 mmscfd		Flowline	349188.3	-1.995007	67.15085	34.63012	7.585635	0	0.466470303...	Gas	Undefined
662	Flowrate=1140.507 mmscfd		Flowline	349797.9	-1.998756	67.03803	34.59523	7.598764	0	0.466873784...	Gas	Undefined
663	Flowrate=1140.507 mmscfd		Flowline	349999.1	-2.000006	67.00076	34.58371	7.603113	0	0.467007378...	Gas	Undefined

10. By clicking the **Y axes** and selecting the **Gas Fluid Velocity**, you will see the Gas Fluid Velocity curve changed (increased) inside the gas pipeline as a function of pipeline distance as in the next **Figure** (4.6).


P/T profile

Name: CPU - KPU - Balhaf (P/T) Profile

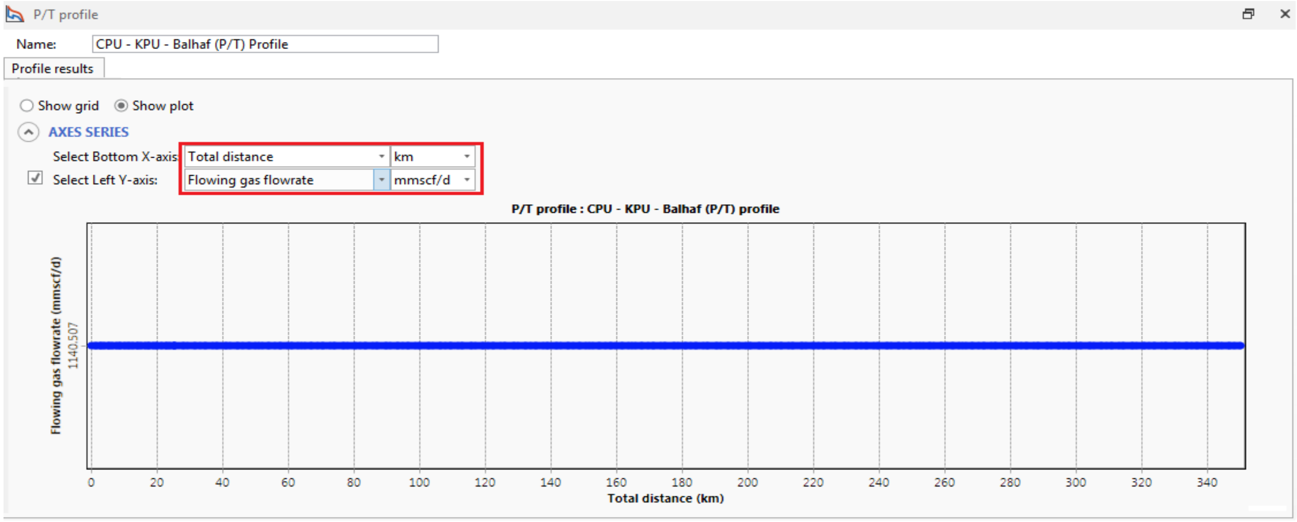
Profile results

○ Show grid ● Show plot

AXES SERIES

FIGURE (4.6): PRESSURE & GAS FLUID VELOCITY AGAINST TOTAL DISTANCE CURVE INSIDE PIPELINES

11. By clicking the **X axes** and selecting the Gas Flow-rate, you will see the Gas Flow-rate curve constant =1140.507mmscf, inside the gas pipeline as a function of pipeline distance as in the next **Figure** (4.7).


P/T profile

Name: CPU - KPU - Balhaf (P/T) Profile

Profile results

○ Show grid ● Show plot

AXES SERIES

Select Bottom X-axis: Total distance km

☑ Select Left Y-axis: Flowing gas flowrate mmscf/d

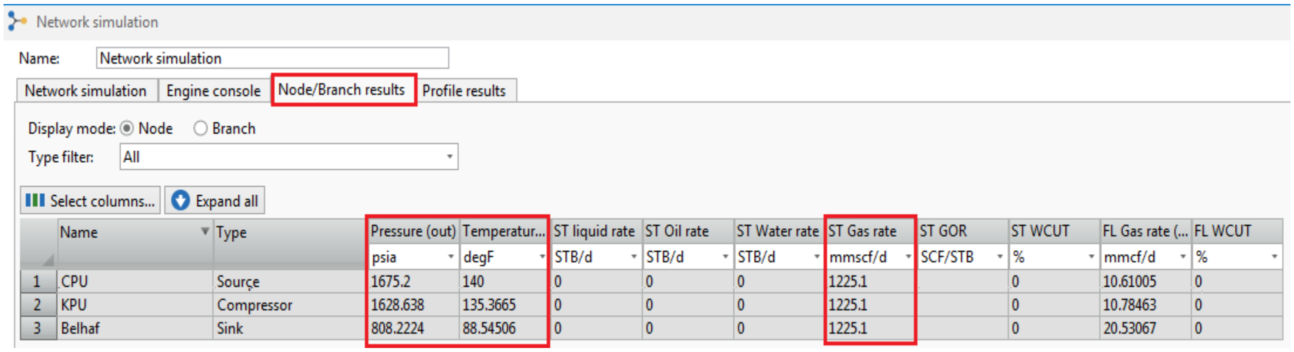
FIGURE (4.7): GAS FLOW-RATE AGAINST TOTAL DISTANCE CURVE INSIDE PIPELINES

4.7. NATURAL GAS PIPELINE NETWORK SIMULATION:

In the **PIPESIM** we use the network simulation (P/T profile) task to generate pressure and temperature profiles as a function of pipeline distance or elevation along the defined single-branch flow path.

- On the pipeline network diagram, select the start point (**Source** = **CPU**) where the analysis will start.
- Click network simulation and select Node/Branch results tab, click in the Node from the Display mode.
- Select All from Type filter, and you see the results of the pressure, temperature & Gas Flow-rate in the all three points in the gas pipeline: start point (**CPU**), **KPU** & in the end-point (**Sink = Balhaf**) as shown in the following **Table** (4.3).

TABLE (4.3): PIPELINES NETWORK SIMULATION



Name: Network simulation

Display mode: ● Node ○ Branch

Type filter: All

	Name	Type	Pressure (out)	Temperatur...	ST liquid rate	ST Oil rate	ST Water rate	ST Gas rate	ST GOR	ST WCUT	FL Gas rate (...	FL WCUT
			psia	degF	STB/d	STB/d	STB/d	mmscf/d	SCF/STB	%	mmcf/d	%
1	CPU	Source	1675.2	140	0	0	0	1225.1		0	10.61005	0
2	KPU	Compressor	1628.638	135.3665	0	0	0	1225.1		0	10.78463	0
3	Belhaf	Sink	808.2224	88.54506	0	0	0	1225.1		0	20.53067	0

4.8. GAS HYDRATES:

Gas hydrates are crystalline compounds with a snow-like consistency that occur when small gas molecules come into contact with water at or below a certain temperature. The hydrate formation temperature increases with increasing pressure, therefore the hydrate risk is greatest at higher pressures and lower temperatures. When hydrates form inside pipelines, they can form plugs which obstruct flow. In even worse scenarios, where the presence of a hydrate plug was undetected, pipeline depressurization has resulted in the plug being dislodged unexpectedly, resulting in serious injury and even fatalities. These are some of the reasons that hydrates are a serious flow assurance concern.

- **Hydrate forming molecules** most commonly include *methane, ethane, propane, carbon dioxide, and hydrogen sulfide.*
- **Hydrates can very easily form downstream** of a choke where fluid temperature can drop into the hydrate formation region due to Joule-Thompson cooling effects.
- **The following figure** (**4.8**) shows a **typical gas hydrate curve** which is very useful for subsea pipeline design and operations. On the left side of the curve is the hydrate formation region. When pressures and temperatures are in this region, hydrates will form from the water and gas molecules.

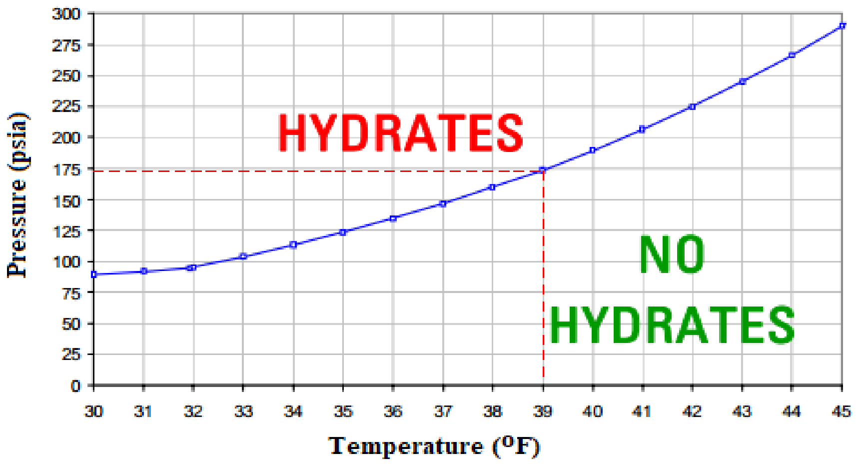
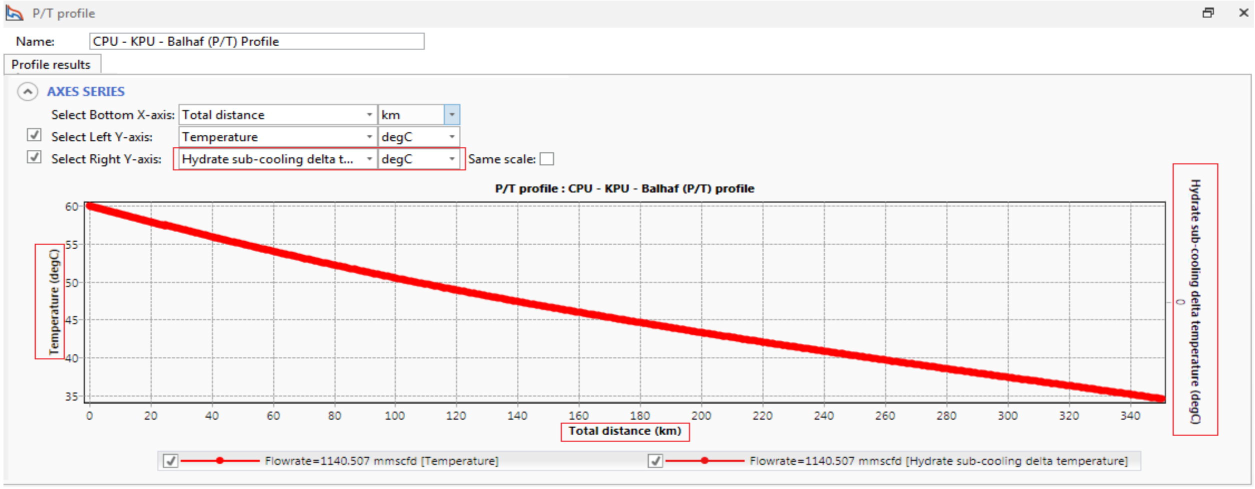


FIGURE (4.8): TYPICAL GAS HYDRATE CURVE

- **To enable the calculation of the hydrate sub-cooling temperature difference**, this is the difference between the hydrate formation temperature and the flowing fluid temperature (i.e. $T_{hyd} - T_f$). If this difference is **positive**, then the fluid is in the **hydrate formation region** at that location in the system.
- **In the simulation settings**, click the **Output** variables tab and change the Report template to **Flow Assurance**. This template includes the important flow assurance variables; specifically the following hydrate variables of interest.
  - Hydrate formation temperature (profile variable)
  - Hydrate sub-cooling delta temperature (profile variable)
  - Maximum hydrate sub-cooling temperature differential (system variable)
- **Many factors impact the hydrate curve** including fluid composition, **water salinity** and the presence of **hydrate inhibitors**.
- From the next **figure** (4.9), shows that the Hydrate sub-cooling temperature = 0, so that means **no hydrates** at every point in the network pipelines transmission system.



Name: CPU - KPU - Balhaf (P/T) Profile

Select Bottom X-axis: Total distance km

☑ Select Left Y-axis: Temperature degC

☑ Select Right Y-axis: Hydrate sub-cooling delta t... degC

Same scale: ☐

FIGURE (4.9): TEMPERATURE & HYDRATE SUBCOOLING CURVE (NO HYDRATE)

4.9. DISPLAY PHASE ENVELOPES FOR COMPOSITIONAL FLUID

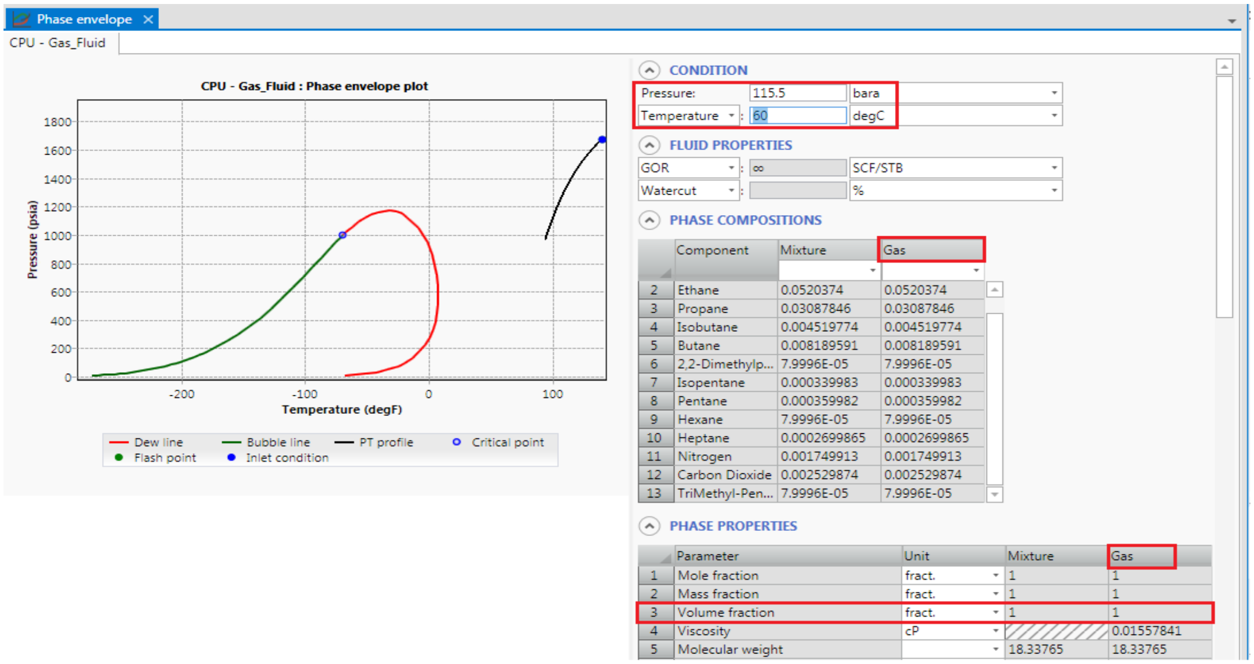
In **PIPESIM** simulator, when we working with compositional fluid models we will find it helpful to display phase envelopes and fluid properties associated with individual sources using the Phase envelope viewer. This is useful for quickly inspecting fluid models associated with source branches. Additionally, after running a simulation task, you may view the simulated flowing pressure/temperature (P/T) profile superimposed on a phase envelope for each source branch.

2) To flash a fluid at other conditions of interest, and display the detailed fluid property information, perform one of the following actions. The flash results will be automatically re-calculated and updated. The option to flash a fluid is currently only available for compositional fluids.

- On the Phase envelope tab, under Condition, enter a Pressure and Temperature.
- In the phase envelope, right-click a point of interest, and then click Flash at this point.

3) To display the simulated flowing pressure or temperature (P/T) profile in the phase envelope, run a simulation task, and then perform one of the following actions depending on the selected Perspective.

- In the Network perspective, click the well or source object, and then on the Home tab, in the Viewers and results group, click Phase envelope.
- Then on the Home tab, in the Viewers and results group, click Phase envelope. The phase envelope display with the simulated flowing pressure-temperature (P/T) profile from the last simulation task superimposed on it as in the following **Figure (4.10)**.



Pressure: 115.5 bara

Temperature: 60 degC

GOR: ∞ SCF/STB

Watercut: %

	Component	Mixture	Gas
2	Ethane	0.0520374	0.0520374
3	Propane	0.03087846	0.03087846
4	Isobutane	0.004519774	0.004519774
5	Butane	0.008189591	0.008189591
6	2,2-Dimethylp...	7.9996E-05	7.9996E-05
7	Isopentane	0.000339983	0.000339983
8	Pentane	0.000359982	0.000359982
9	Hexane	7.9996E-05	7.9996E-05
10	Heptane	0.0002699865	0.0002699865
11	Nitrogen	0.001749913	0.001749913
12	Carbon Dioxide	0.002529874	0.002529874
13	TriMethyl-Pen...	7.9996E-05	7.9996E-05

	Parameter	Unit	Mixture	Gas
1	Mole fraction	fract.	1	1
2	Mass fraction	fract.	1	1
3	Volume fraction	fract.	1	1
4	Viscosity	cP		0.01557841
5	Molecular weight		18.33765	18.33765

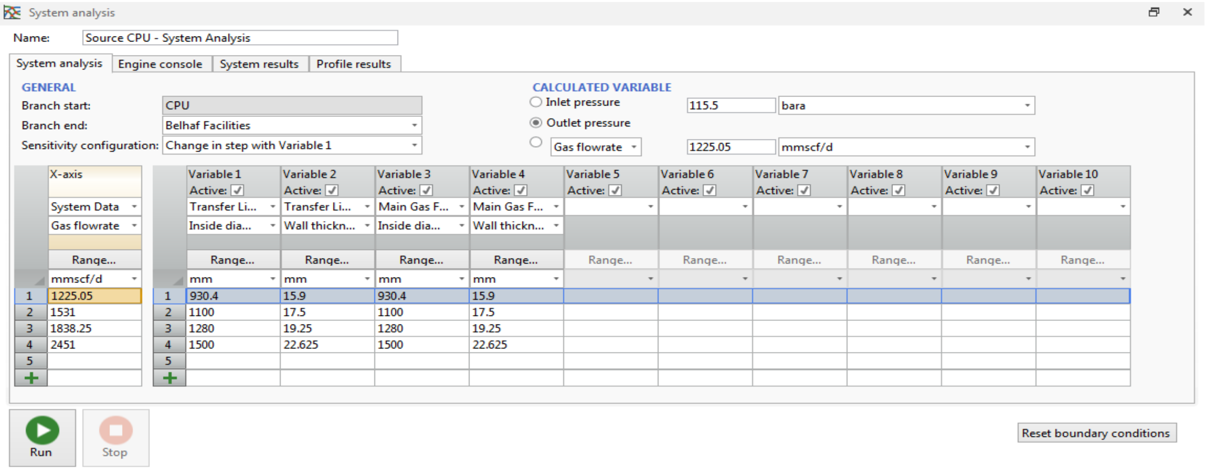
FIGURE (4.10): HYDRATE PHASE ENVELOPE SHOWING NO HYDRATE FORMATION TEMPERATURE

4.10. ANALYSIS FOR THE HIGHER GAS FLOW RATES IN THE FUTURE:

An alternate design that eliminates the need for capacity increase of the gas flow-lines for the higher projected gas flow rates in future was considered.

- **We choose three increasing capacity** of the gas flow for the **higher** projected gas flow rates in the **future** as 25%, 50%, 100%.
- And we added three different inside diameter (**ID**) with different thickness of the pipeline as the following, and as shown in **Table** (4.4):
  1. For increasing the gas flow 25%: Gas flow-rate=1531 MMSCF/D, pipeline ID= 1100mm, and pipeline thickness=17.5mm.
  2. For increasing the gas flow 50%: Gas flow-rate=1838.25 MMSCF/D, pipeline ID= 1280mm, and pipeline thickness=19.25mm.
  3. For increasing the gas flow 100%: Gas flow-rate=2451 MMSCF/D, pipeline ID= 1500mm, and pipeline thickness=22.625mm.

TABLE (4.4): SYSTEM DATA ANALYSIS FOR SUGGESTIONS THREE ID-PIPELINE FOR HIGHER GAS FLOW RATES IN THE FUTURE



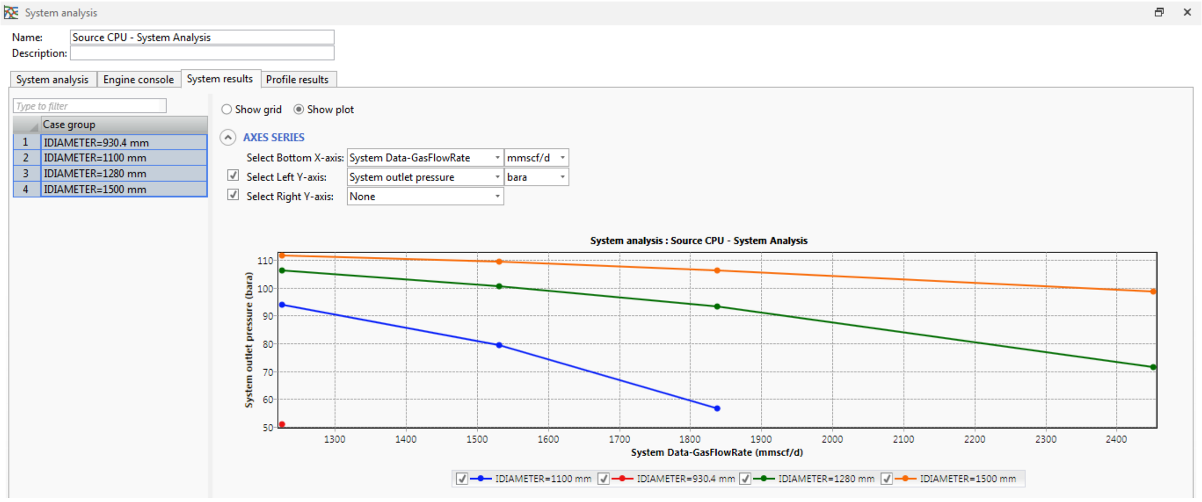
Name: Source CPU - System Analysis

GENERAL
Branch start: CPU
Branch end: Belhaf Facilities
Sensitivity configuration: Change in step with Variable 1

CALCULATED VARIABLE
○ Inlet pressure 115.5 bara
● Outlet pressure
○ Gas flowrate 1225.05 mmscf/d

	X-axis		Variable 1	Variable 2	Variable 3	Variable 4	Variable 5	Variable 6	Variable 7	Variable 8	Variable 9	Variable 10
			Active: ☑	Active: ☑	Active: ☑	Active: ☑	Active: ☑	Active: ☑	Active: ☑	Active: ☑	Active: ☑	Active: ☑
	System Data		Transfer Li...	Transfer Li...	Main Gas F...	Main Gas F...						
	Gas flowrate		Inside dia...	Wall thickn...	Inside dia...	Wall thickn...						
	Range...		Range...	Range...	Range...	Range...	Range...	Range...	Range...	Range...	Range...	Range...
	mmscf/d		mm	mm	mm	mm						
1	1225.05	1	930.4	15.9	930.4	15.9						
2	1531	2	1100	17.5	1100	17.5						
3	1838.25	3	1280	19.25	1280	19.25						
4	2451	4	1500	22.625	1500	22.625						
5		5										

- Then click **Run**, and the result of the optimum pipeline ID will show in the next fig. (4.11)



Name: Source CPU - System Analysis
Description:

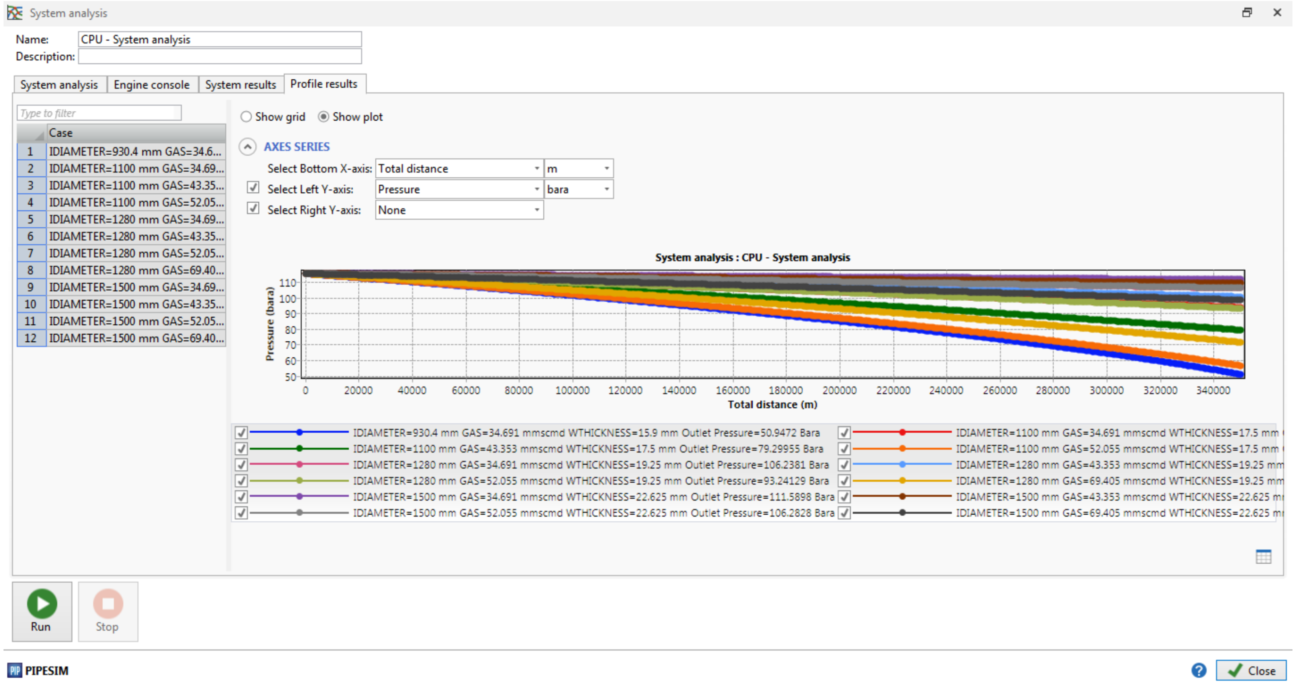
	Case group
1	IDIAMETER=930.4 mm
2	IDIAMETER=1100 mm
3	IDIAMETER=1280 mm
4	IDIAMETER=1500 mm

○ Show grid ● Show plot

AXES SERIES
Select Bottom X-axis: System Data-GasFlowRate mmscf/d
☑ Select Left Y-axis: System outlet pressure bara
☑ Select Right Y-axis: None

FIGURE (4.11): SYSTEM ANALYSIS FOR SUGGESTIONS THREE ID-PIPELINES FOR HIGHER GAS FLOW RATES

- Click **Profile results**, and the result for all different pipelines ID with different flow-rate will show in the next fig. (4.12)



Name: CPU - System analysis
Description:

	Case
1	IDIAMETER=930.4 mm GAS=34.6...
2	IDIAMETER=1100 mm GAS=34.69...
3	IDIAMETER=1100 mm GAS=43.35...
4	IDIAMETER=1100 mm GAS=52.05...
5	IDIAMETER=1280 mm GAS=34.69...
6	IDIAMETER=1280 mm GAS=43.35...
7	IDIAMETER=1280 mm GAS=52.05...
8	IDIAMETER=1280 mm GAS=69.40...
9	IDIAMETER=1500 mm GAS=34.69...
10	IDIAMETER=1500 mm GAS=43.35...
11	IDIAMETER=1500 mm GAS=52.05...
12	IDIAMETER=1500 mm GAS=69.40...

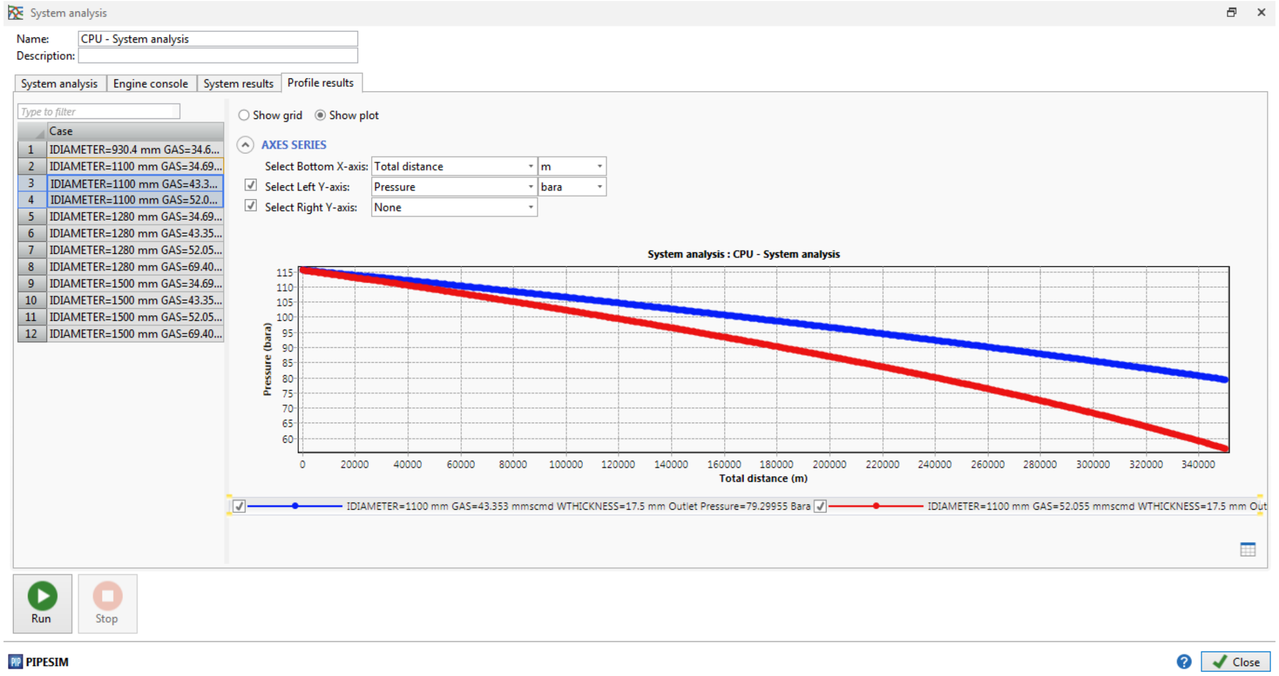
○ Show grid ● Show plot

AXES SERIES

Select Bottom X-axis: Total distance m
☑ Select Left Y-axis: Pressure bara
☑ Select Right Y-axis: None

☑ IDIAMETER=930.4 mm GAS=34.691 mmscmd WTHICKNESS=15.9 mm Outlet Pressure=50.9472 Bara
☑ IDIAMETER=1100 mm GAS=34.691 mmscmd WTHICKNESS=17.5 mm
☑ IDIAMETER=1100 mm GAS=43.353 mmscmd WTHICKNESS=17.5 mm Outlet Pressure=79.29955 Bara
☑ IDIAMETER=1100 mm GAS=52.055 mmscmd WTHICKNESS=17.5 mm
☑ IDIAMETER=1280 mm GAS=34.691 mmscmd WTHICKNESS=19.25 mm Outlet Pressure=106.2381 Bara
☑ IDIAMETER=1280 mm GAS=43.353 mmscmd WTHICKNESS=19.25 mm
☑ IDIAMETER=1280 mm GAS=52.055 mmscmd WTHICKNESS=19.25 mm Outlet Pressure=93.24129 Bara
☑ IDIAMETER=1280 mm GAS=69.405 mmscmd WTHICKNESS=19.25 mm
☑ IDIAMETER=1500 mm GAS=34.691 mmscmd WTHICKNESS=22.625 mm Outlet Pressure=111.5898 Bara
☑ IDIAMETER=1500 mm GAS=43.353 mmscmd WTHICKNESS=22.625 m
☑ IDIAMETER=1500 mm GAS=52.055 mmscmd WTHICKNESS=22.625 mm Outlet Pressure=106.2828 Bara
☑ IDIAMETER=1500 mm GAS=69.405 mmscmd WTHICKNESS=22.625 m

FIGURE (4.12): SYSTEM ANALYSIS FOR SUGGESTIONS THREE ID-PIPELINE WITH DIFFERENT PRESSURES FOR HIGHER GAS FLOW RATES



Name: CPU - System analysis
Description:

	Case
1	IDIAMETER=930.4 mm GAS=34.6...
2	IDIAMETER=1100 mm GAS=34.69...
3	IDIAMETER=1100 mm GAS=43.3...
4	IDIAMETER=1100 mm GAS=52.0...
5	IDIAMETER=1280 mm GAS=34.69...
6	IDIAMETER=1280 mm GAS=43.35...
7	IDIAMETER=1280 mm GAS=52.05...
8	IDIAMETER=1280 mm GAS=69.40...
9	IDIAMETER=1500 mm GAS=34.69...
10	IDIAMETER=1500 mm GAS=43.35...
11	IDIAMETER=1500 mm GAS=52.05...
12	IDIAMETER=1500 mm GAS=69.40...

○ Show grid ● Show plot

AXES SERIES

Select Bottom X-axis: Total distance m
☑ Select Left Y-axis: Pressure bara
☑ Select Right Y-axis: None

☑ IDIAMETER=1100 mm GAS=43.353 mmscmd WTHICKNESS=17.5 mm Outlet Pressure=79.29955 Bara
☑ IDIAMETER=1100 mm GAS=52.055 mmscmd WTHICKNESS=17.5 mm Out

FIGURE (4.13): SYSTEM ANALYSIS RESULT FOR PIPELINE DISTANCE WITH DIFFERENT PRESSURES FOR HIGHER GAS FLOW RATES (**OPTIMUM PIPELINE ID=1100MM**) FOR ADDITIONAL **PARALLEL PIPELINE** (**170MM**)

4.11. KPU GAS PLANT NETWORK FACILITES

Design the KPU Gas plant network facilities in **PIPESIM** by using the tools in the main window

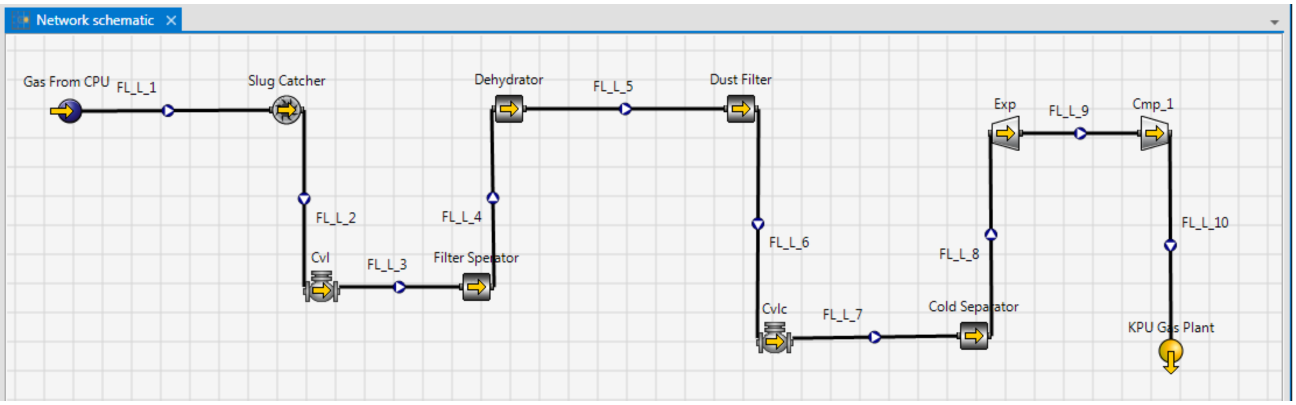
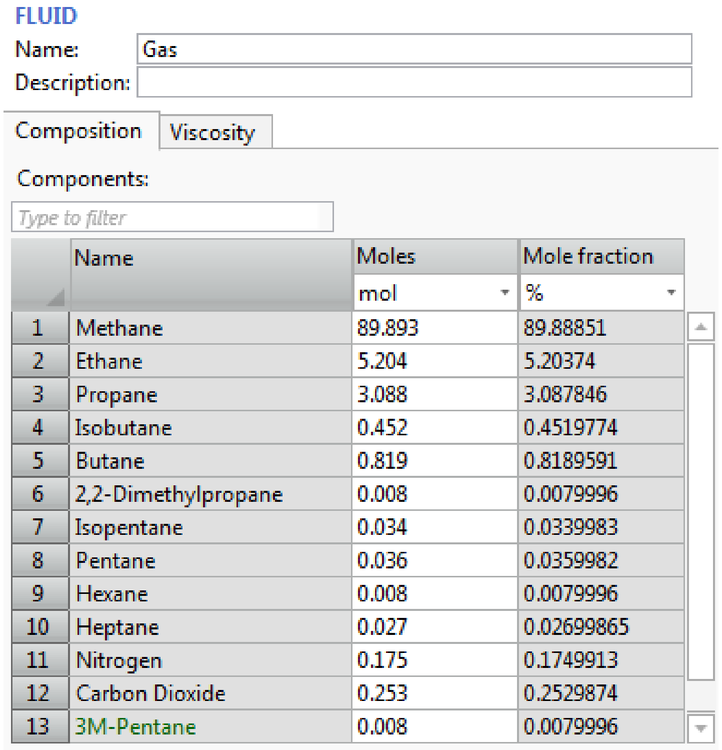


FIGURE (4.14): DESIGN THE GAS PLANT NETWORK FACILITIES IN PIPESIM

4.11.1. CREATE A GAS COMPOSITIONAL FLUID MODEL:

- Add the gas components to the fluid template from the Fluid Components list. There are 13 components.
- Enter the moles for each component as shown in the following **Table** (4.5).

TABLE (4.5): INPUT DATA FOR GAS COMPOSITION (MOLES)



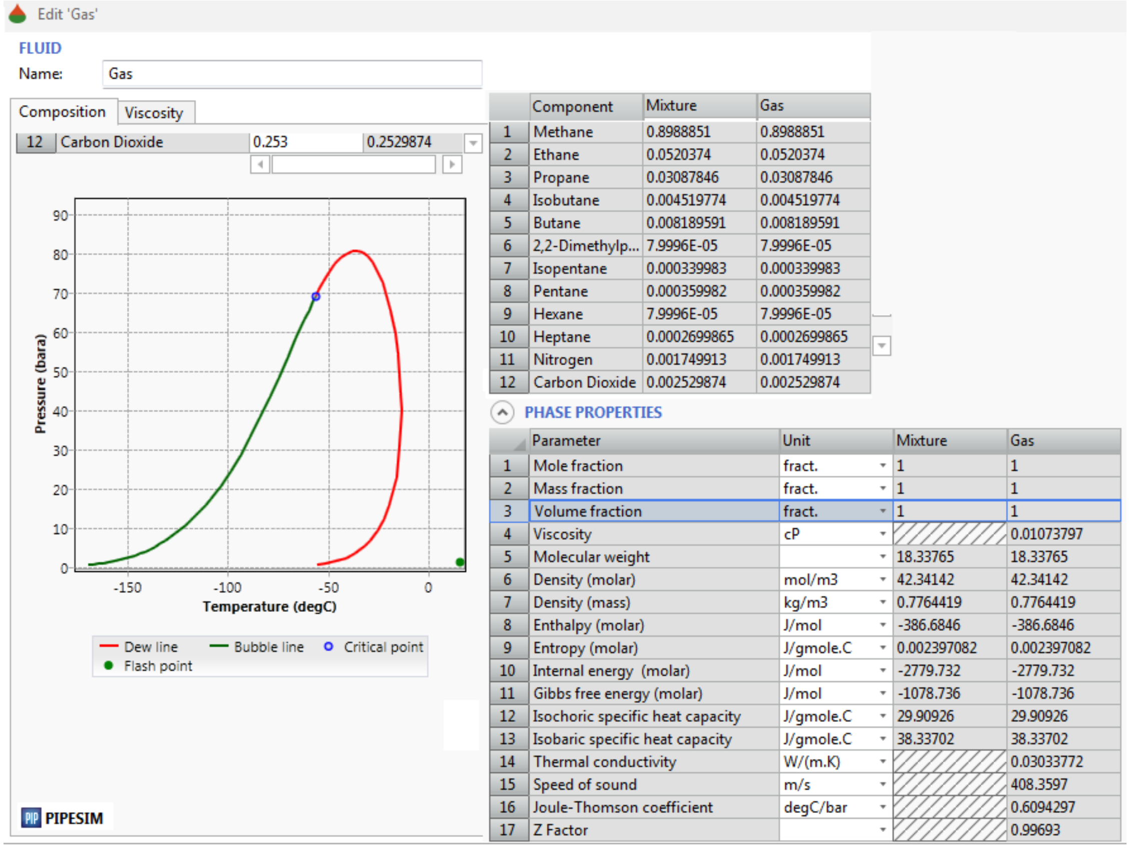
FLUID

Name: Gas

Description:

	Name	Moles	Mole fraction
		mol	%
1	Methane	89.893	89.88851
2	Ethane	5.204	5.20374
3	Propane	3.088	3.087846
4	Isobutane	0.452	0.4519774
5	Butane	0.819	0.8189591
6	2,2-Dimethylpropane	0.008	0.0079996
7	Isopentane	0.034	0.0339983
8	Pentane	0.036	0.0359982
9	Hexane	0.008	0.0079996
10	Heptane	0.027	0.02699865
11	Nitrogen	0.175	0.1749913
12	Carbon Dioxide	0.253	0.2529874
13	3M-Pentane	0.008	0.0079996

- When entering the moles for each component we notice that the phase diagram automatically updates as you enter the moles for each component and they are shown in **figure** (4.15) as the following:



Name: Gas

12 Carbon Dioxide 0.253 0.2529874

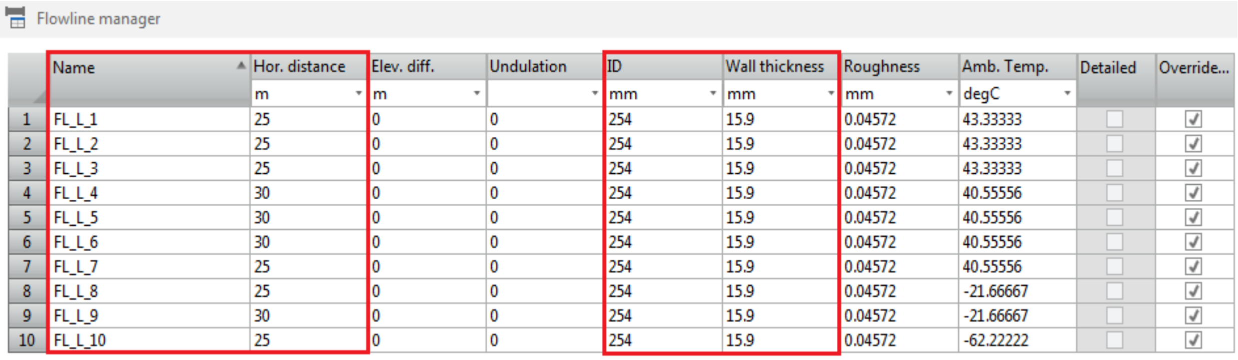
	Component	Mixture	Gas
1	Methane	0.8988851	0.8988851
2	Ethane	0.0520374	0.0520374
3	Propane	0.03087846	0.03087846
4	Isobutane	0.004519774	0.004519774
5	Butane	0.008189591	0.008189591
6	2,2-Dimethylp...	7.9996E-05	7.9996E-05
7	Isopentane	0.000339983	0.000339983
8	Pentane	0.000359982	0.000359982
9	Hexane	7.9996E-05	7.9996E-05
10	Heptane	0.0002699865	0.0002699865
11	Nitrogen	0.001749913	0.001749913
12	Carbon Dioxide	0.002529874	0.002529874

	Parameter	Unit	Mixture	Gas
1	Mole fraction	fract.	1	1
2	Mass fraction	fract.	1	1
3	Volume fraction	fract.	1	1
4	Viscosity	cP	▨	0.01073797
5	Molecular weight		18.33765	18.33765
6	Density (molar)	mol/m3	42.34142	42.34142
7	Density (mass)	kg/m3	0.7764419	0.7764419
8	Enthalpy (molar)	J/mol	-386.6846	-386.6846
9	Entropy (molar)	J/gmole.C	0.002397082	0.002397082
10	Internal energy (molar)	J/mol	-2779.732	-2779.732
11	Gibbs free energy (molar)	J/mol	-1078.736	-1078.736
12	Isochoric specific heat capacity	J/gmole.C	29.90926	29.90926
13	Isobaric specific heat capacity	J/gmole.C	38.33702	38.33702
14	Thermal conductivity	W/(m.K)	▨	0.03033772
15	Speed of sound	m/s	▨	408.3597
16	Joule-Thomson coefficient	degC/bar	▨	0.6094297
17	Z Factor		▨	0.99693

FIGURE (4.15): FLUID GAS COMPONENTS FOR GAS PLANT

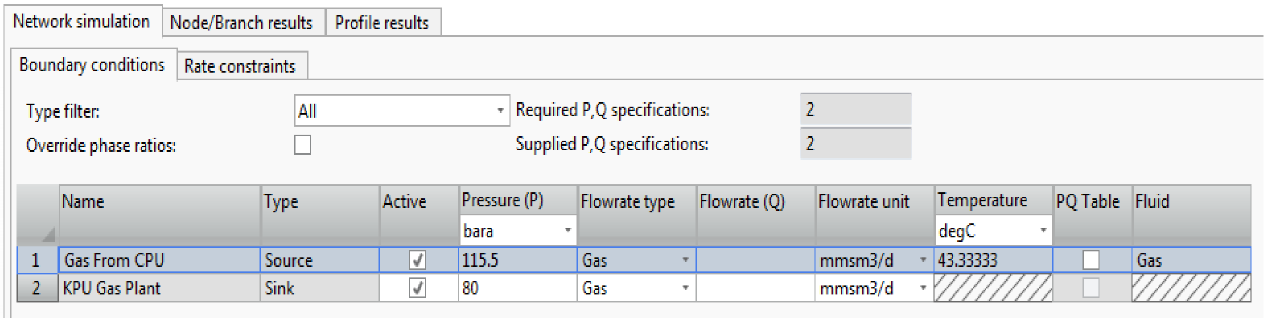
4.11.2. FLOWLINE MANAGER OF THE KPU NETWORK FACILITES

TABLE (4.6): FLOWLINES MANAGER OF THE KPU GAS PLANT NETWORK



	Name	Hor. distance m	Elev. diff. m	Undulation	ID mm	Wall thickness mm	Roughness mm	Amb. Temp. degC	Detailed	Override...
1	FL_L_1	25	0	0	254	15.9	0.04572	43.33333	☐	☑
2	FL_L_2	25	0	0	254	15.9	0.04572	43.33333	☐	☑
3	FL_L_3	25	0	0	254	15.9	0.04572	43.33333	☐	☑
4	FL_L_4	30	0	0	254	15.9	0.04572	40.55556	☐	☑
5	FL_L_5	30	0	0	254	15.9	0.04572	40.55556	☐	☑
6	FL_L_6	30	0	0	254	15.9	0.04572	40.55556	☐	☑
7	FL_L_7	25	0	0	254	15.9	0.04572	40.55556	☐	☑
8	FL_L_8	25	0	0	254	15.9	0.04572	-21.66667	☐	☑
9	FL_L_9	30	0	0	254	15.9	0.04572	-21.66667	☐	☑
10	FL_L_10	25	0	0	254	15.9	0.04572	-62.22222	☐	☑

TABLE (4.7): GAS FROM CPU TO KPU GAS PLANT FLOWLINE NETWORK



Type filter: All

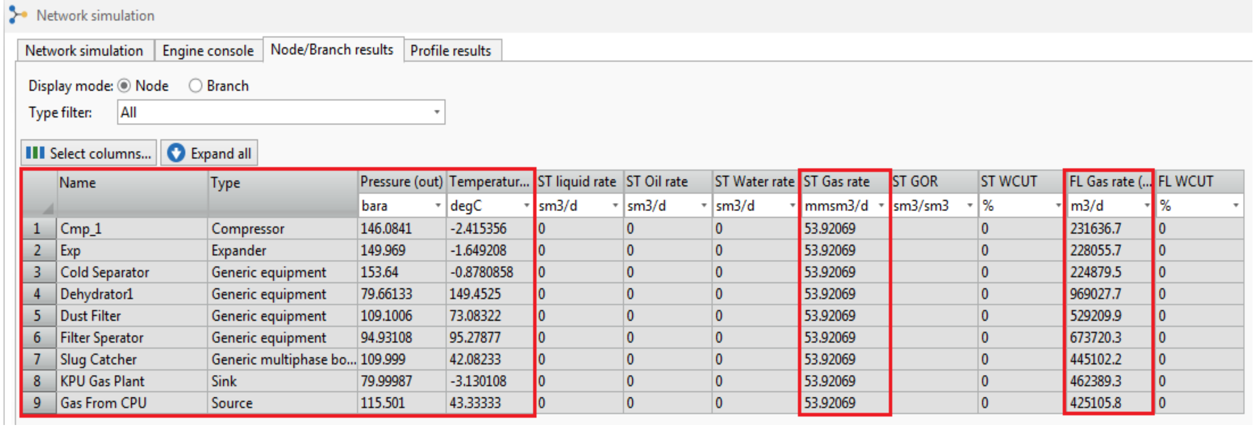
Override phase ratios: ☐

Required P,Q specifications: 2

Supplied P,Q specifications: 2

	Name	Type	Active	Pressure (P)	Flowrate type	Flowrate (Q)	Flowrate unit	Temperature	PQ Table	Fluid
				bara				degC		
1	Gas From CPU	Source	☑	115.5	Gas		mmsm3/d	43.33333	☐	Gas
2	KPU Gas Plant	Sink	☑	80	Gas		mmsm3/d	▨	☐	▨

TABLE (4.8): NETWORK SIMULATION RESULTS FROM PIPESIM

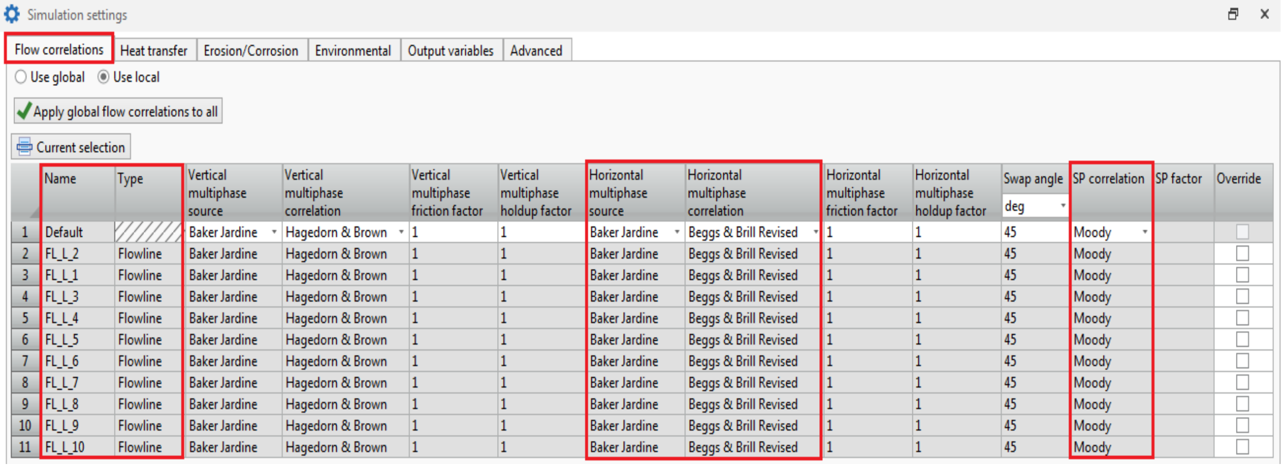


Display mode: ● Node ○ Branch

Type filter: All

	Name	Type	Pressure (out)	Temperatur...	ST liquid rate	ST Oil rate	ST Water rate	ST Gas rate	ST GOR	ST WCUT	FL Gas rate (...	FL WCUT
			bara	degC	sm3/d	sm3/d	sm3/d	mmsm3/d	sm3/sm3	%	m3/d	%
1	Cmp_1	Compressor	146.0841	-2.415356	0	0	0	53.92069		0	231636.7	0
2	Exp	Expander	149.969	-1.649208	0	0	0	53.92069		0	228055.7	0
3	Cold Separator	Generic equipment	153.64	-0.8780858	0	0	0	53.92069		0	224879.5	0
4	Dehydrator1	Generic equipment	79.66133	149.4525	0	0	0	53.92069		0	969027.7	0
5	Dust Filter	Generic equipment	109.1006	73.08322	0	0	0	53.92069		0	529209.9	0
6	Filter Sperator	Generic equipment	94.93108	95.27877	0	0	0	53.92069		0	673720.3	0
7	Slug Catcher	Generic multiphase bo...	109.999	42.08233	0	0	0	53.92069		0	445102.2	0
8	KPU Gas Plant	Sink	79.99987	-3.130108	0	0	0	53.92069		0	462389.3	0
9	Gas From CPU	Source	115.501	43.33333	0	0	0	53.92069		0	425105.8	0

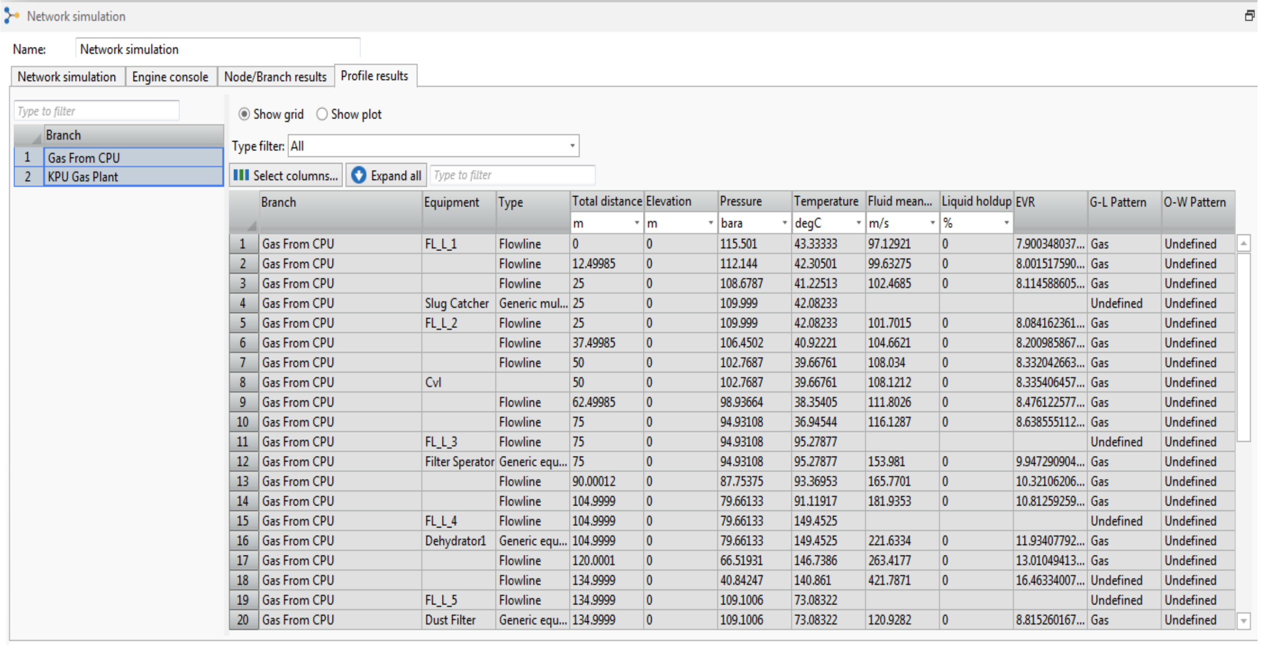
TABLE (4.9): PIPESIM GAS FLOW CORRELATION METHODS



○ Use global ● Use local

	Name	Type	Vertical multiphase source	Vertical multiphase correlation	Vertical multiphase friction factor	Vertical multiphase holdup factor	Horizontal multiphase source	Horizontal multiphase correlation	Horizontal multiphase friction factor	Horizontal multiphase holdup factor	Swap angle	SP correlation	SP factor	Override
											deg			
1	Default	▨	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
2	FL_L_2	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
3	FL_L_1	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
4	FL_L_3	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
5	FL_L_4	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
6	FL_L_5	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
7	FL_L_6	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
8	FL_L_7	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
9	FL_L_8	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
10	FL_L_9	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐
11	FL_L_10	Flowline	Baker Jardine	Hagedorn & Brown	1	1	Baker Jardine	Beggs & Brill Revised	1	1	45	Moody		☐

TABLE (4.10): GAS FLOW CORRELATION & NETWORK SIMULATION RESULTS



Name: Network simulation

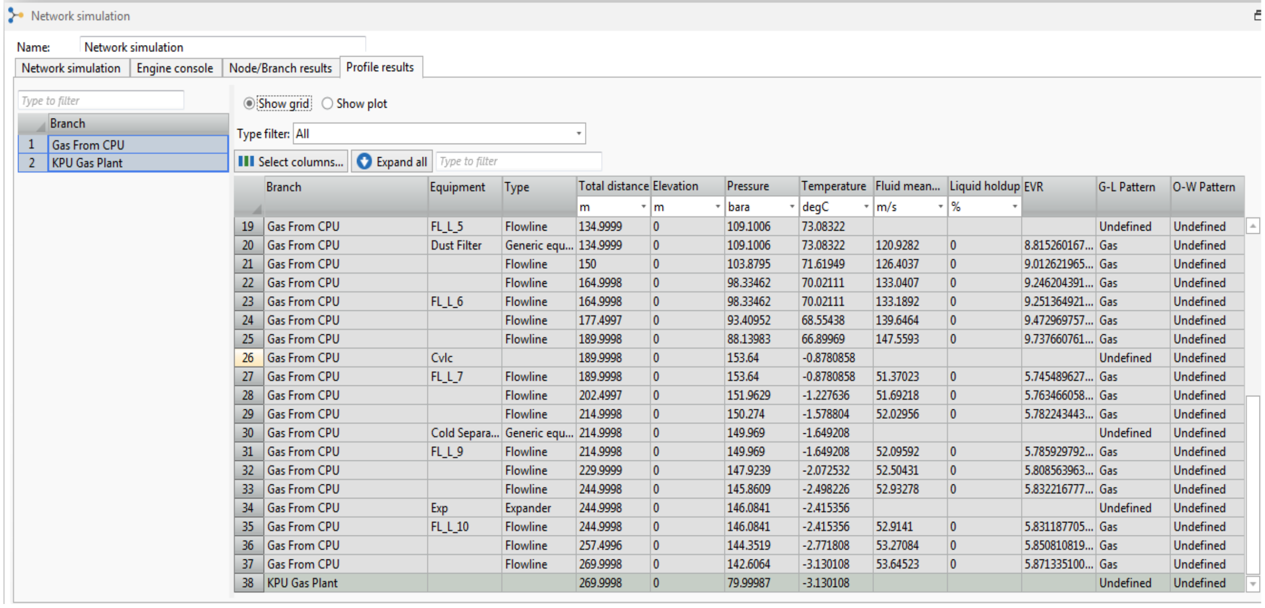
● Show grid ○ Show plot

Type filter: All

	Branch
1	Gas From CPU
2	KPU Gas Plant

	Branch	Equipment	Type	Total distance	Elevation	Pressure	Temperature	Fluid mean...	Liquid holdup	EVR	G-L Pattern	O-W Pattern
				m	m	bara	degC	m/s	%			
1	Gas From CPU	FL_L_1	Flowline	0	0	115.501	43.33333	97.12921	0	7.900348037...	Gas	Undefined
2	Gas From CPU		Flowline	12.49985	0	112.144	42.30501	99.63275	0	8.001517590...	Gas	Undefined
3	Gas From CPU		Flowline	25	0	108.6787	41.22513	102.4685	0	8.114588605...	Gas	Undefined
4	Gas From CPU	Slug Catcher	Generic mul...	25	0	109.999	42.08233				Undefined	Undefined
5	Gas From CPU	FL_L_2	Flowline	25	0	109.999	42.08233	101.7015	0	8.084162361...	Gas	Undefined
6	Gas From CPU		Flowline	37.49985	0	106.4502	40.92221	104.6621	0	8.200985867...	Gas	Undefined
7	Gas From CPU		Flowline	50	0	102.7687	39.66761	108.034	0	8.332042663...	Gas	Undefined
8	Gas From CPU	Cvl		50	0	102.7687	39.66761	108.1212	0	8.335406457...	Gas	Undefined
9	Gas From CPU		Flowline	62.49985	0	98.93664	38.35405	111.8026	0	8.476122577...	Gas	Undefined
10	Gas From CPU		Flowline	75	0	94.93108	36.94544	116.1287	0	8.638555112...	Gas	Undefined
11	Gas From CPU	FL_L_3	Flowline	75	0	94.93108	95.27877				Undefined	Undefined
12	Gas From CPU	Filter Sperator	Generic equ...	75	0	94.93108	95.27877	153.981	0	9.947290904...	Gas	Undefined
13	Gas From CPU		Flowline	90.00012	0	87.75375	93.36953	165.7701	0	10.32106206...	Gas	Undefined
14	Gas From CPU		Flowline	104.9999	0	79.66133	91.11917	181.9353	0	10.81259259...	Gas	Undefined
15	Gas From CPU	FL_L_4	Flowline	104.9999	0	79.66133	149.4525				Undefined	Undefined
16	Gas From CPU	Dehydrator1	Generic equ...	104.9999	0	79.66133	149.4525	221.6334	0	11.93407792...	Gas	Undefined
17	Gas From CPU		Flowline	120.0001	0	66.51931	146.7386	263.4177	0	13.01049413...	Gas	Undefined
18	Gas From CPU		Flowline	134.9999	0	40.84247	140.861	421.7871	0	16.46334007...	Undefined	Undefined
19	Gas From CPU	FL_L_5	Flowline	134.9999	0	109.1006	73.08322				Undefined	Undefined
20	Gas From CPU	Dust Filter	Generic equ...	134.9999	0	109.1006	73.08322	120.9282	0	8.815260167...	Gas	Undefined

TABLE (4.11): FLOW CORRELATION & NETWORK SIMULATION RESULTS CONT.



Name: Network simulation

● Show grid ○ Show plot

Type filter: All

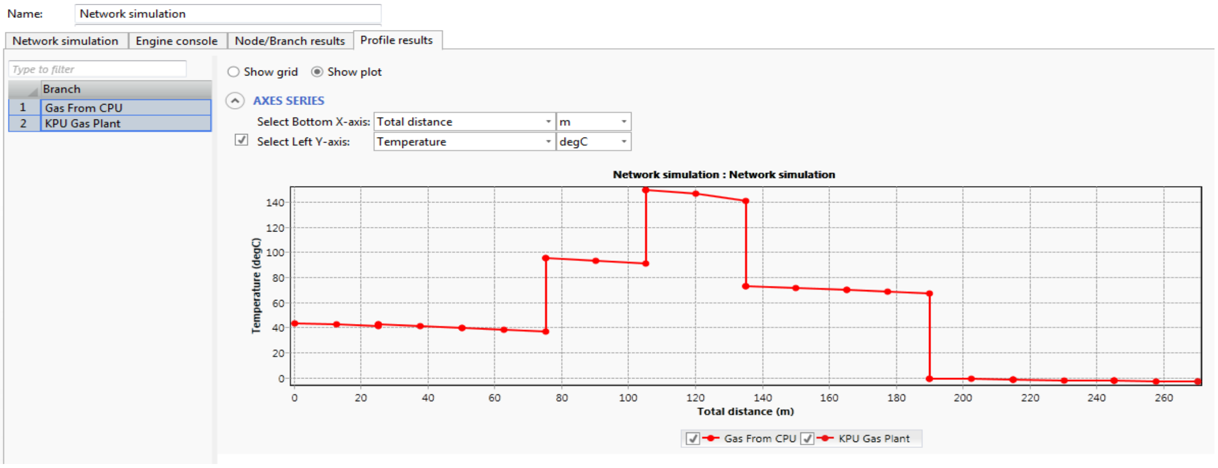
	Branch
1	Gas From CPU
2	KPU Gas Plant

	Branch	Equipment	Type	Total distance	Elevation	Pressure	Temperature	Fluid mean...	Liquid holdup	EVR	G-L Pattern	O-W Pattern
				m	m	bara	degC	m/s	%			
19	Gas From CPU	FL_L_5	Flowline	134.9999	0	109.1006	73.08322				Undefined	Undefined
20	Gas From CPU	Dust Filter	Generic equ...	134.9999	0	109.1006	73.08322	120.9282	0	8.815260167...	Gas	Undefined
21	Gas From CPU		Flowline	150	0	103.8795	71.61949	126.4037	0	9.012621965...	Gas	Undefined
22	Gas From CPU		Flowline	164.9998	0	98.33462	70.02111	133.0407	0	9.246204391...	Gas	Undefined
23	Gas From CPU	FL_L_6	Flowline	164.9998	0	98.33462	70.02111	133.1892	0	9.251364921...	Gas	Undefined
24	Gas From CPU		Flowline	177.4997	0	93.40952	68.55438	139.6464	0	9.472969757...	Gas	Undefined
25	Gas From CPU		Flowline	189.9998	0	88.13983	66.89969	147.5593	0	9.737660761...	Gas	Undefined
26	Gas From CPU	Cvlc		189.9998	0	153.64	-0.8780858				Undefined	Undefined
27	Gas From CPU	FL_L_7	Flowline	189.9998	0	153.64	-0.8780858	51.37023	0	5.745489627...	Gas	Undefined
28	Gas From CPU		Flowline	202.4997	0	151.9629	-1.227636	51.69218	0	5.763466058...	Gas	Undefined
29	Gas From CPU		Flowline	214.9998	0	150.274	-1.578804	52.02956	0	5.782243443...	Gas	Undefined
30	Gas From CPU	Cold Separa...	Generic equ...	214.9998	0	149.969	-1.649208				Undefined	Undefined
31	Gas From CPU	FL_L_9	Flowline	214.9998	0	149.969	-1.649208	52.09592	0	5.785929792...	Gas	Undefined
32	Gas From CPU		Flowline	229.9999	0	147.9239	-2.072532	52.50431	0	5.808563963...	Gas	Undefined
33	Gas From CPU		Flowline	244.9998	0	145.8609	-2.498226	52.93278	0	5.832216777...	Gas	Undefined
34	Gas From CPU	Exp	Expander	244.9998	0	146.0841	-2.415356				Undefined	Undefined
35	Gas From CPU	FL_L_10	Flowline	244.9998	0	146.0841	-2.415356	52.9141	0	5.831187705...	Gas	Undefined
36	Gas From CPU		Flowline	257.4996	0	144.3519	-2.771808	53.27084	0	5.850810819...	Gas	Undefined
37	Gas From CPU		Flowline	269.9998	0	142.6064	-3.130108	53.64523	0	5.871335100...	Gas	Undefined
38	KPU Gas Plant			269.9998	0	79.99987	-3.130108				Undefined	Undefined

4.11.3. THE PRESSURE/TEMPERATURE (P/T) PROFILE FOR GAS PLANT FLOWLINE NETWORK

The pressure/temperature profile (P/T profile) task used to generate pressure and temperature profiles as a function of total pipeline distance or elevation along the defined flow path.

- After designing the Gas Plant network and entering the data in the PIPESIM, we can clicking on the Profile Results tab, and select the Show plot and will see the temperature curve changed (dropping) inside the gas plant as a function of pipeline distance as shown in the following Figures. (4.16), (4.17) & (4.18).



Name: Network simulation

Network simulation | Engine console | Node/Branch results | Profile results

Type to filter

	Branch
1	Gas From CPU
2	KPU Gas Plant

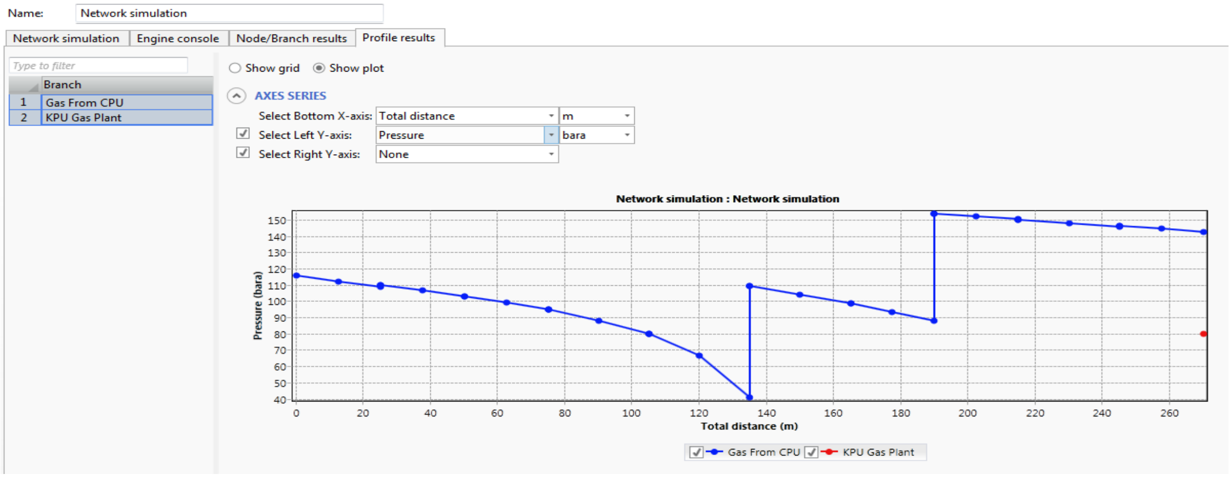
○ Show grid ● Show plot

AXES SERIES

Select Bottom X-axis: Total distance m

☑ Select Left Y-axis: Temperature degC

FIGURE (4.16): TEMPERATURE AGAINST TOTAL DISTANCE CURVE INSIDE GAS PLANT



Name: Network simulation

Network simulation | Engine console | Node/Branch results | Profile results

Type to filter

	Branch
1	Gas From CPU
2	KPU Gas Plant

○ Show grid ● Show plot

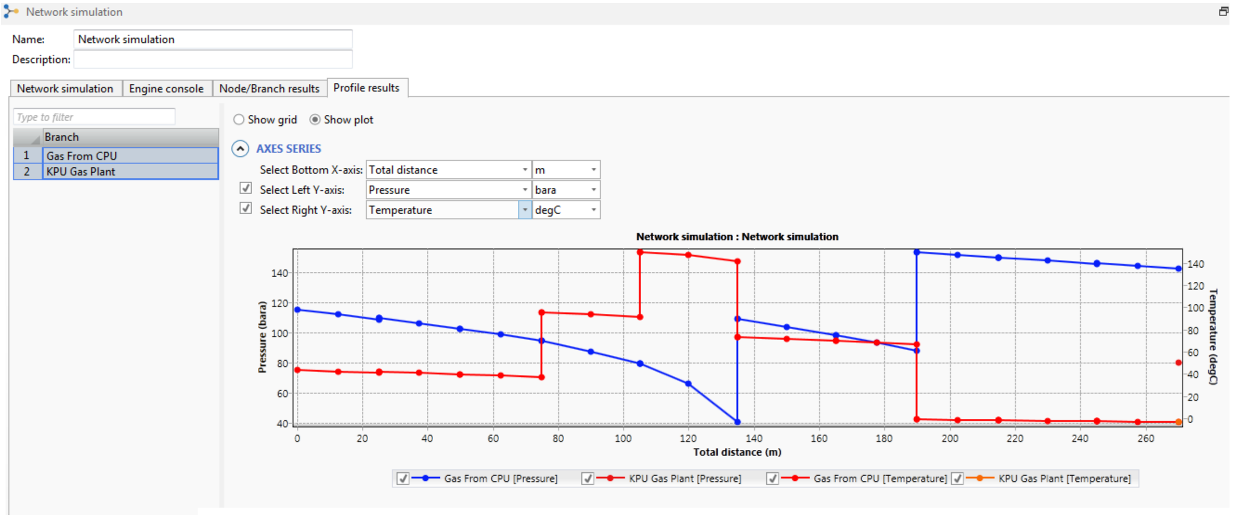
AXES SERIES

Select Bottom X-axis: Total distance m

☑ Select Left Y-axis: Pressure bara

☑ Select Right Y-axis: None

FIGURE (4.17): PRESSURE AGAINST TOTAL DISTANCE CURVE INSIDE GAS PLANT



Network simulation

Name: Network simulation

Description:

Network simulation | Engine console | Node/Branch results | Profile results

Type to filter

	Branch
1	Gas From CPU
2	KPU Gas Plant

○ Show grid ● Show plot

AXES SERIES

Select Bottom X-axis: Total distance m

☑ Select Left Y-axis: Pressure bara

☑ Select Right Y-axis: Temperature degC

FIGURE (4.18): PRESSURE /TEMPERATURE AGAINST TOTAL DISTANCE CURVE INSIDE GAS PLANT

CHAPTER FIVE
CONCLUSION & RECOMMENDATION

CHAPTER 5: CONCLUSION & RECOMMENDATION

5.1. CONCLUSION

The findings of this project are relevant in the transportation of condensate gas from the **Kamil Processing Unit** (**KPU**) located in **Marib** Province, Yemen to the **Balhaf Liquefied Natural Gas (LNG)** plant. The following conclusions can be drawn from this study;

- The Gas pipeline for transporting condensate from the gas production facilities of the **Marib** fields in the block-18 to extract the required gas to **Gas Processing Plant** of LNG plant which located in **Balhaf** on the Gulf of Aden has been designed. The design employs two flow-line temperature control mechanism; insulation of the pipeline and the application of direct electrical heating to the pipelines in order to raise the surrounding temperature above the **hydrate** formation temperature = **39 ºF** (LNG) [25].
- During the processing of transporting natural gas, water is removed from the gas before transporting through pipelines; this is called separation and dehydration. However, these processes only remove the free water from the gas.
- A model using **PIPESIM** software to simulate fluid phase behavior and temperature-pressure (T/P) profiles in gas pipeline by means of gas-pipeline has been developed. This model was tested against the measured temperature-pressure data for both pipelines distance (25km + 325km), also to study and monitoring the gas behavior, pressures and temperatures inside the pipeline. The results showed that matching of calculated temperature-pressure profiles depended on the internal diameter & the distance of pipelines and the multipoint pressure loss correlation.
- The developed model can be used to get insight into severity of the hydrate deposition. Overall compositional changes inside the pipeline and were not formed any hydrate inside the gas pipeline.
- To Hydrates Prevention removes any of the 4 ingredients component needed for hydrates to form (Water, Gas).
- Alcohols & Glycols when dissolved in aqueous solutions form hydrogen bond with the water molecules and make it difficult for the water molecules to participate in the hydrate structure.
    - Electrolytes (salts) form ionic bonds with free water.
    - Polar compounds (alcohols, glycols) compete with hydrates for hydrogen bonding.
    - Salts (Sodium Chloride And Calcium Chloride).
    - Alcohols (Methanol, Ethanol & Isopropanol).
    - Glycols (Ethylene Glycol & Triethylene Glycol).

5.2. RECOMMENDATION

1. The maximum designed Gas flow rate is 1225.05 MMSCF/D. The main pipelines transmission consist of a 325 km long, and internal diameter ID is 930.4 mm (36.63 in) and the wall thickness is 15.9mm (0.626 in). ID flow-line 1 in order to meet the higher operating flow rate to the processing plant.

2. For the future 20 years we suggesting the increasing of the gas flow from 25% to 50%, and did the analysis in **PIPESIM** and the result was to add other parallel pipeline with 170mm ID (6.693 in), and this pipelines distance (350 km) and this pipeline will supporting the increase of gas flow rate to 278.95 MMSCF/D if increasing the gas flow 25%, and the same pipeline will used for the increasing of the gas flow rate to 586.20 MMSCF/D if increasing the gas flow 50%, it's by increasing 50% times, which meets flow capacity to the plant in the subsequent years.

3. Using the PIPESIM simulation software for modeling the three-phase (solid, liquid, and gas) equilibria and you need the models for fugacity three-phase coefficients. Also to simulate the hydrate formation curves for (P/T, gas composition) and saturation boundary.

4. To Hydrates prevention in the gas pipeline transmission we should removes anyone of the 4 ingredients component needed for hydrates to form (Water, Natural Gas, High Pressure or Low Temperature).
    - Remove one component (Water, Gas).
    - Increase Temperature.
    - Decrease System Pressure.
    - Use an Inhibitor in the water phase (thermodynamic).

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