Australian Journal of Basic and Applied Sciences

ISSN :1991-8178
EISSN: 2309-8414

2022 January; 16(1): pages 9-25
DOI: 10.22587/ajbas.2022.16.1.2

Original paper AENSI Publications

Optimization and Controlling of Gas Hydrate Mitigation Methods in the Gas Wellhead Flowlines

Abdelaziz A. Noaman

Chemical Engineering Department, Faculty of Engineering, Minia University, Minia, Egypt
Email: abdelaziz.noaman@outlook.com]

Correspondence Author: Abdelaziz A. Noaman, Chemical Engineering Department, Faculty of Engineering, Minia University, Minia, Egypt
Email: abdelaziz.noaman@outlook.com

Received date: 20 June 2020 Accepted date: 28 January 2022, Online date: 29 January 2022

Citation: Abdelaziz A. Noaman., 2022. Optimization and Controlling of Gas Hydrate Mitigation Methods in the Gas Wellhead Flowlines. Australian Journal of Basic and Applied Sciences, 16(1): 9-25. DOI: 10.22587/ajbas.2022.16.1.2.

ABSTRACT: **Natural gas hydrate is a crystal composed of water molecules and light hydrocarbons. The high pressure and low temperature are satisfactory conditions for hydrate formation. However, the formation of hydrates causes clogs in gas-carrying pipelines, preventing transportation. Every day over two million US dollars are spent in the petroleum industry to prevent the formation of hydrates. The purpose of this paper is to investigate the hydrate formation phenomena at the eight gas wells of the gas project at different gas compositions in winter, different operating temperatures and pressures, and examine all available hydrate inhibition methods to select the most known method to solve the hydrate problems in the gas wells during the winter period mitigate. The available hydrate inhibition are methanol injection, monoethylene glycol (MEG) injection by piggyback with regeneration at CPF, low dosage of hydrate inhibitors (LHID), wellhead heating before pressure reduction e.g. B. using a gas-fired water bath heater. The PIPESIM steady-state simulator was used to calculate the hydration temperature for the eight wells in lean and rich winter gas compositions at different operating pressures and temperatures. Based on the hydration formation curves for the eight gas wells at rich and lean compositions, it can be stated that hydration inhibition is required at each flow line of the gas well head, especially in winter. Technical and economic comparisons were made between these available methods, based on suitability in North African countries, to select the most applicable method required for gas projects to mitigate the hydration problems in the gas wellhead flowlines. It has been determined that the methanol injection process is the best available process to use. Wellhead heating is considered a viable alternative to the methanol injection method, the required heat output for heating is 200 kW. Ambient temperature and water cut sensitivities were run on the eight gas wellhead flowlines at lean and rich gas compositions by the PIPESIM software. It has been found that the methanol dosing rate increases with decreasing ambient air temperature and increasing water fraction. The OLGA transient simulator was used to calculate the methanol dosing rate for each gas source at different ambient and soil temperatures. A comparison was made between the results of the two simulators and it was found that the methanal dosing rates in the OLGA results are 48% higher than the methanal dosing rates in the PIPESIM results.**

Keywords: Gas Hydrate, Methanol, Heater, Mono Ethylene Glycol, Low Dosage Hydrate Inhibitors

INTRODUCTION

Hydrates are ice-like crystalline compounds formed when water and gas contact at low temperatures and high pressures. These conditions occur naturally beneath the oceans and the permafrost. Hydrate begins typically when the gas stream is cooled below its hydrate formation temperature (Speight, 2019, Mokhatab et al., 2019, Kidnay et al., 2020). The water molecules can form cavities because of their hydrogen bonding properties, accommodating low molecular weight molecules. The inclusion of these gas molecules stabilizes the metastable water lattice structure. Hydrates consist of geometric lattices of water molecules containing cavities occupied by light hydrocarbons and other gaseous components, such as nitrogen, carbon dioxide, and hydrogen sulfide (Rajnauth, J., el., 2010, Al-Eisa, R., et al.,2015).

Gas hydrates or gas clathrates are solid structures comprised of hydrocarbon gases trapped within the cavities of a rigid "cage-like" lattice of water molecules (Ghosh et al., 2019). Clathrate hydrates are composed of water and eight molecules: methane, ethane, Propane, isobutane, normal butane, Nitrogen, Carbon Dioxide and hydrogen sulfide. These compounds contain clusters

Copyright © The Author(s) 2022. This is an open-access article distributed under the terms of the Creative Commons Attribution License, which permits unrestricted use, distribution, and reproduction in any medium, provided the original author and source are credited

(two or more) of gas-trapping polyhedra formed by pentagonally and hexagonally arranged hydrogen-bonded water molecules (Carroll, 2014, Kinnari et al., 2015).
Van der Waals interactions between the guest molecule and the surrounding water cage walls stabilize and support the individual polyhedra forming the hydrate lattice and restrict the translational motion of the guest molecule (Sayani et al., 2020). Hydrate structures are classified into three categories based on the geometries of their constituent water cages: cubic structures I and II and hexagonal structure H. Each crystalline structure contains geometrically distinct water cages with different size cavities, typically accommodating only one guest molecule ranging in diameter from 0.40 - 0.90 nm. The structure I hydrate is the most encountered naturally occurring hydrate structure that encases small diameter molecules (0.40 - 0.55 nm) such as methane or ethane gas. Structures II and H hydrates accommodate larger guest molecules, typically propane or iso-butane for structure II or combinations of methane gas and nexohexane or cycloheptane for structure H (Ke et al., 2016, Lanlan et al., 2020, Palodkar et al., 2020).

The study and research on hydrate became of interest to the oil and gas industry in 1934 when Hamrnerschmidt observed the first pipeline blockage. This was due to hydrates' crystalline, non-flowing nature (Lullo et al., 2019). Hydrates have been one of the flow assurance problems in gas production and transportation. Different models and approaches have been adopted to solve the gas hydrate problems. Hydrates block the conduit of oil and gas pipelines and transportation systems with significant economic impacts (Cox et al., 2018, Meyer et al., 2018, Wan et al., 2019).

The main objective of this study is to investigate the hydrate formation in the eight gas wells at different gas compositions and different operating pressures & temperatures in the wintertime. All available hydrate inhibition methods were studied technically and economically to choose the best available methods for the gas wells in the gas project. The different available methods for natural gas hydrate inhibition methods that are widely applied in industry Methanol injection, MEG injection through the piggyback line with regeneration at CPF, Other low dosage hydrate inhibitors (LDHI), heating at the wellhead before pressure reduction, e.g., using gas fired water bath heater.

Technical and economic comparisons were performed between these methods to select the available ones. PIPESIM steady-state and OLGA transient software's were used in this study

2. Gas Project Description

2.1 Central Process Facilities (CPF)

Figure 1 reveals the major processing units which make up the central processing facility CPF. The gas project consists of eight wells, a gathering system and CPF, where the production stream from the various fields will be separated into condensate and dew pointed gas products for export. The gas processing involves inlet facilities for liquid separation, mercury removal unit, CO_2 removal unit, dehydration unit, and a hydrocarbon dew-pointing unit to meet the export gas specifications. The condensate separated from the gas in the inlet facilities is stabilized to meet the RVP specification for export condensate. The gas will be exported via export gas pipeline and treated in a dedicated Liquefied Petroleum Gas (LPG) extraction facility to commercial specifications required for end-user consumption. The condensate will be exported via export pipeline to the oil terminal.

Mercury has been detected up to 70 ng/Sm3 in some well samples. Well, examples are reported to contain no elemental Sulphur, no wax, and no paraffin. Also, the H_2S content of the wells is zero.

2.2. Gas Wellhead Flowlines

Eight producing wells are initially considered for the gas project. Figure 2 demonstrates the wells and the length for each wellhead flow line. A wellhead pressure of 267 bara, wellhead temperature of 50°C and the flowline pressure of 56 bar at the design flow rate of 0.425 MSCMD (15 MMSCFD) shall be used. All eight gas wells have the same design flow rate of 0.425 MSCMD. Therefore, a range of compositions of different condensate gas ratios (CGRs) can be delivered by each well, depending on the layer being produced.

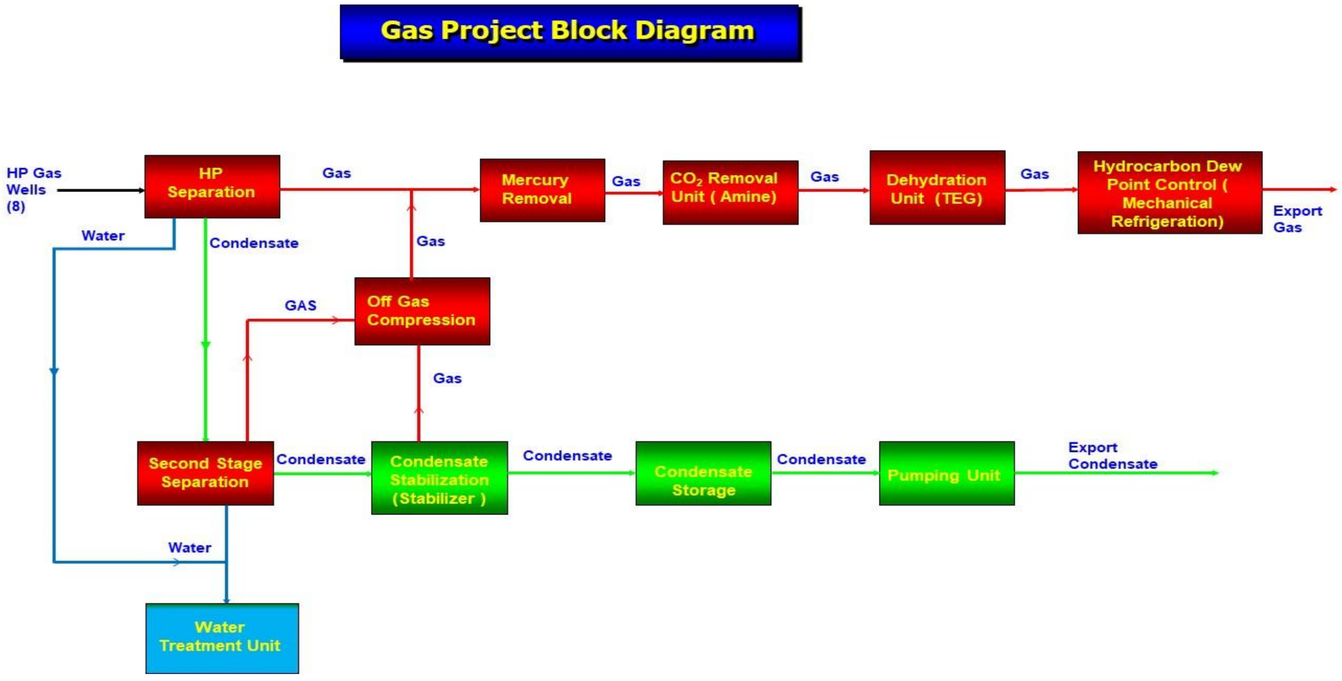

Figure 1: Schematic of the CPF Process Units.

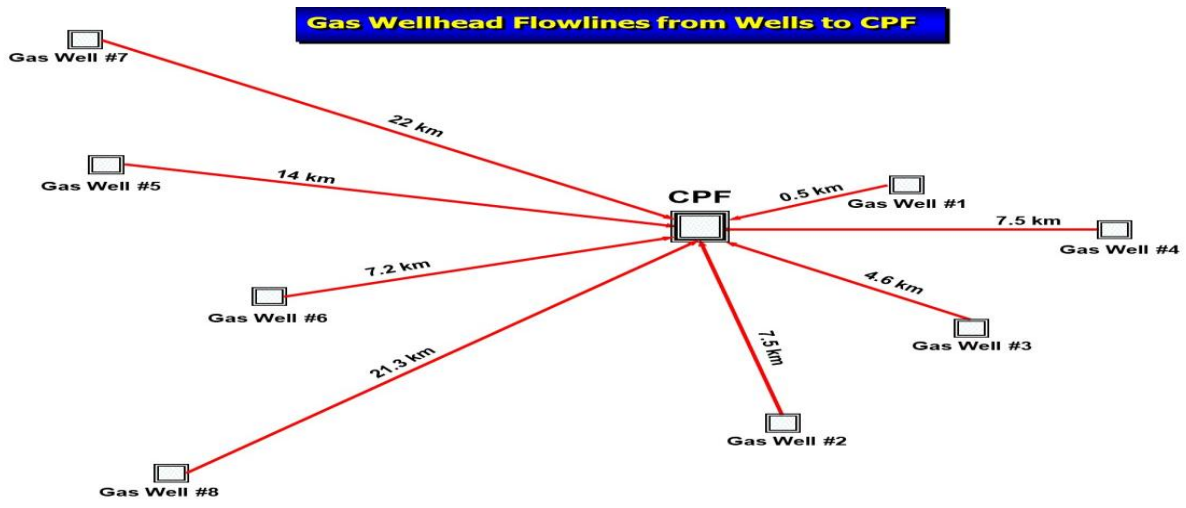

Figure 2: Gas Wellhead Flowlines from Wells to CPF

3. GAS PROJECT DESIGN CAPACITIES

The gas project is designed to produce 2.7 MSCMD export gas and 10,000 STB/day export condensate. Table 1 displays the design flow rates for the process facilities of the gas project.

Table 1: Flowrates Design Production

Design Capacity	**Unit**	**Value**
Production from wells (Note 1)	MSCMD	2.9 (lean gas) 3.3 (rich gas)
Gas Export (for gas pipeline design)	MSCMD	2.7
Condensate Export, maximum	STB/day	10,000
Water Production, water-cut	% Vol.	10

Note1- Includes 0.1 MSCMD of fuel gas.

3.1 Product Specifications

The following are the gas and condensate specifications for pipeline export and water specification for disposal.

3.1.1 Export Gas Specifications
The export gas specifications for gas are:

- Water dew point: -12°C.
- Hydrocarbon dew point at 35 barg: +10°C.
- CO_2 content: < 2.0 mole %.

The pressure of the export gas is 44 barg.

3.1.1 Export Condensate Specifications

The condensate export specification requires the removal of water and light hydrocarbons to meet the BS&W (< 1 %v/v) and RVP (< 0.8 bar & 37.8 °C) specifications.

4. METHODOLOGY

The options to avoid gas hydrates formation in the gas wellhead flowlines in the gas pant were included methanol injection, mono ethylene glycol (MEG) injection through piggy backline with regeneration at CPF. Other low dosage hydrate inhibitors (e.g., THI), heating at the wellhead before pressure reduction, e.g., using gas-fired water bath heater and choking the flow at the CPF (but this requires a higher design pressure for flowlines).

4.1. Hydrate Formation Conditions

Nominal hydrate formation temperature for the flowlines is between 16 and 20 °C; the precise value depends on composition and operating pressure. There is, therefore, a risk of hydrate formation when well pressures are high because of the high-pressure drop across the choke valve and resultant cooling due to the Joule Thomson effect or when the fluid attains the soil temperature nearer the CPF.

An ambient soil temperature of 16°C, for an ambient air temperature of 10 °C, and of 1 °C, for the minimum ambient air temperature of 5 °C have been considered. Information currently available suggests that during normal operation, the initial flowing wellhead pressure (FWHP) for most wells will be around 266 barg and the flowing wellhead temperature (FWHT) will be 50 °C. This results in a large temperature drop at the wellhead to typically 10 °C, well below the hydrate formation temperature.

The greatest propensity for hydrate formation at the wellhead will be at the start of field life when wellhead pressures are high, fluid composition is lean and the resultant temperature drop on pressure reduction across the choke valve due to the Joule Thomson effect is a maximum. Early production will tend to contain no formation water; vapor is assumed to be water saturated at reservoir conditions and the only water in the flowline will be water that condenses as the gas cools.

4.2. Hydrate Inhibition Methods

The rate of inhibitor injection required is dependent on the ambient temperature and the hydrate formation temperature, which is dependent on the amount of free water in the system. Therefore, the gas well fluids are expected to be dry when the wells first produce, with the only free water in the flowline being that which condenses from the saturated gas as it cools. In the future, formation water will be produced with the gas and condensate; the anticipated volume of formation water will be up to 25% of total liquids for any single gas well. There are different methods for hydrate inhibitions and these methods can be summarized as follow: -

4.2.1 Methanol Injection
4.2.2.1.1. PIPESIM and OLGA Software
The steady-state pipeline simulator, PIPESIM 2019, was used to model the flowlines (PIPESIM, 2019). The four °C design margin was added in all simulation cases to calculate the required hydrate inhibitor dosage rate calculated the hydrate formation temperature and the dosage rate for the flowlines. Two different gas compositions from gas wells were used, lean and rich. Ambient air temperature and water cut sensitivities were conducted by PIPESIM software. Hydrate formation temperature also was obtained from PIPESIM software.
OLGA 2019 software was used for the transient modelling of the flowlines and confirmed the methanol dosage rate on each well (OLGA, 2019)

4.2.2.1.2. Hammer Schmidt's equation

Hammer Schmidt's equation is used to estimate the hydrate inhibitor requirement for each flowline.

Required inhibitor concentration from Hammer Schmidt's equation is given by (Hammerschmidt, 1969) :

$$d = \frac{K_H X_I}{MW_I(1-X_I)}$$

$$X_I = \frac{dMW_I}{KH + dMW_I}$$

Where:

X_I '= Inhibitor mass fraction
K_H (methanol) = 2335
d = Hydrate depression required

MW_I = Inhibitor Molecular weight: 33 for Methanol

Injection rates have been based on injection upstream of the choke valve to prevent hydrate formation anywhere in the flow line up to the CPF.

4.2.2 Low Dosage Hydrate Inhibitors (LDHI)

Low dosage hydrate inhibitors can provide significant benefits compared to another inhibition method, including significantly lower inhibitor concentrations and therefore dosage rates, lower inhibitor loss caused by evaporation, reduced capital expenses through decreased chemical storage and injection rate requirement and no need for regeneration because the chemicals are not currently recovered, reduced operating expenses in many cases through reduced chemical consumption and delivery frequency, increased production rates, where inhibitor injection capacity or flowline capacity is limited and lower toxicity(Peytavy et al.,2008, Netusil et al., 2011)

There are two types of low dosage hydrate inhibitor (LDHI), these types are as follow: -

4.2.2.1 Kinetic Hydrate Inhibitors (KHI)

A KHI is a chemical product composed of active matters formulated in a solvent. They act by delaying hydrate nucleation step and by slowing down the initial crystal growth during a finite period commonly defined as “hold-time”. The hold-time due to KHI is dependent on the sub-cooling but also on the test pressure. Consequently, the efficiency and thus the applicability of a KHI depend upon two factors: the sub-cooling to which the produced effluents are exposed, and the residence time of the water inside the hydrate stability zone (Zhang,2020)

Sub-cooling can be defined as the difference between the thermodynamic hydrate forming temperature and the ambient temperature. The sub-cooling is indeed the “driving force” of the kinetics of hydrate crystallization; so, the higher the sub-cooling, the lower the efficiency of the KHI. The use of KHI, on a continuous injection basis, is limited to situations where the sub-cooling is rather mild (typically 14-15°C) (GPSA,2017)

4.2.2.2 Anti-Agglomerants (AA)

Anti-Agglomerants (AA) are generally surface-active products mixed in a solvent. They can be water or oil-soluble depending on the technology used. Contrary to KHI, they do not avoid hydrate formation, but they mitigate their growth and agglomeration so that the tiny hydrate crystals can be transported in the oil phase as a kind of slurry. Contrary to KHI also, they can sustain high sub-cooling levels, up to 18-20°C (Salmin et al., 2017). The main drawback of AA is that their efficiency is limited to a certain water cut: as soon as the water cut is higher than 30-40%, the hydrate particles concentration in the slurry becomes so high that AA are no longer able to allow the transport of the suspension (Cruz et al., 2019)

4.2.3 Mono ethylene glycol Injection

A piggyback line transporting mono ethylene glycol (MEG) to the well for injection as hydrate inhibitor, with subsequent recovery and regeneration of MEG at the CPF and recycling to the well, is an expensive option for the relatively low volumes of gas being produced (Haque et al., 2012, Paz et al.,2019). Figure 3 illustrate the schematic of the mono ethylene glycol

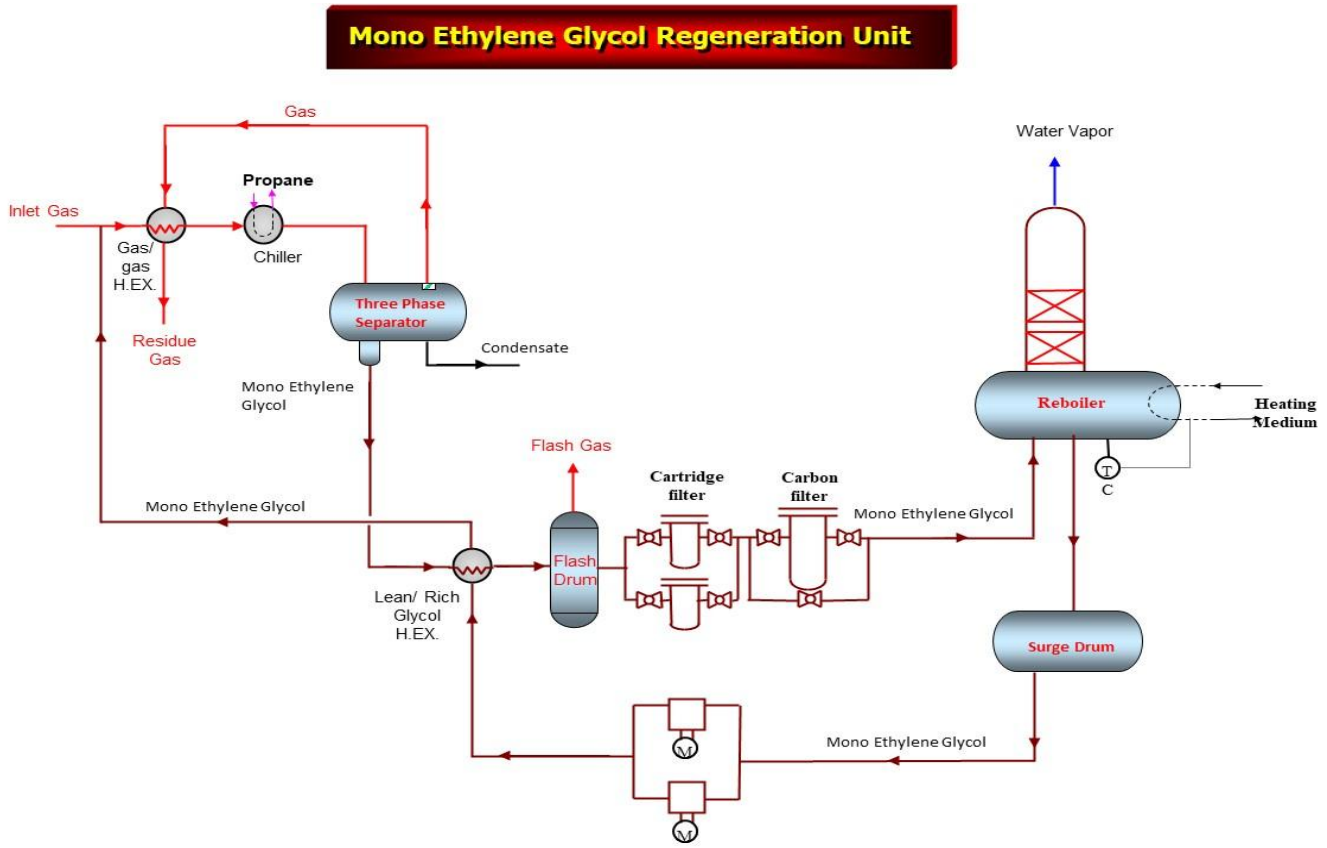

Figure 3: Schematic of the Mono Ethylene Glycol Regeneration Unit (Chong et al, 2016)

4.2.4 Wellhead Heating

If hydrates are expected to form in normal operation over a prolonged period, wellhead heating may be considered an alternative to methanol injection, which may be labour-intensive and attract a high OPEX cost. Hydrate formation can be avoided by controlling the temperature at the wellhead to 25oC minimum after the choke valve. To ensure this, fluids may be heated upstream of the choke valve so that after pressure reduction, the temperature is well above the hydrate temperature.

A conventional design of a wellhead heater is a gas fired, indirect water bath heater with a natural draft burner, as shown in figure 4. The burner has its own ignition and burner management system with flame detection and automatic shutdown. The water bath provides a “heat sink” to safely heat hydrocarbon fluids with varying flowrate and CGR (Molnar et al., 2016, Vaferi, 2019)

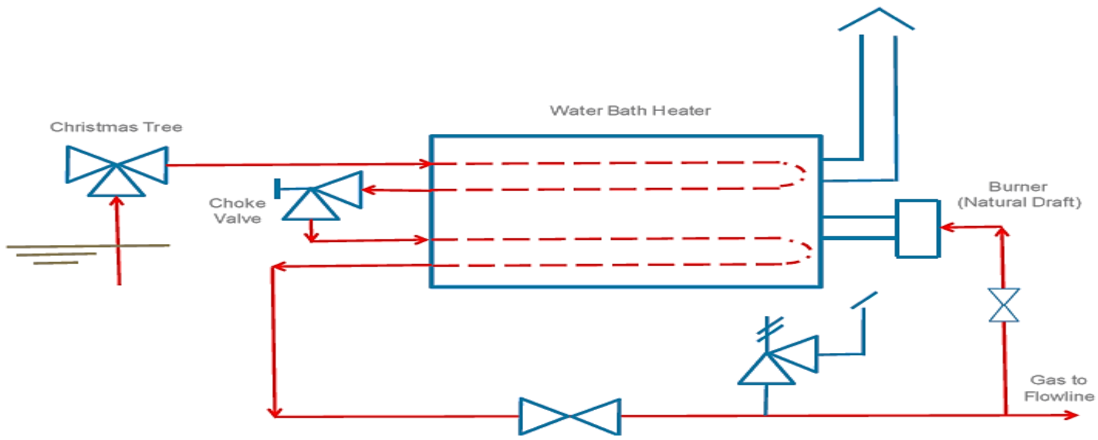

Figure 4: Indirect Water Bath Wellhead Heater

5. RESULTS & DISCUSSIONS

5.1. Gas Wells Hydrate Formation Curves

PIPESIM 2019 software was used to calculate the hydrate formation temperature for the eight wells at lean and rich gas compositions in the wintertime at operating different pressures and temperatures.

Figure 5 illustrate the hydrate formation curve for gas well #1 at lean & rich gas compositions in wintertime. It can be noticed that the hydrate temperature of gas well # 1 is 17 C for rich and lean gas composition at inlet flowline pressure 56 bar.

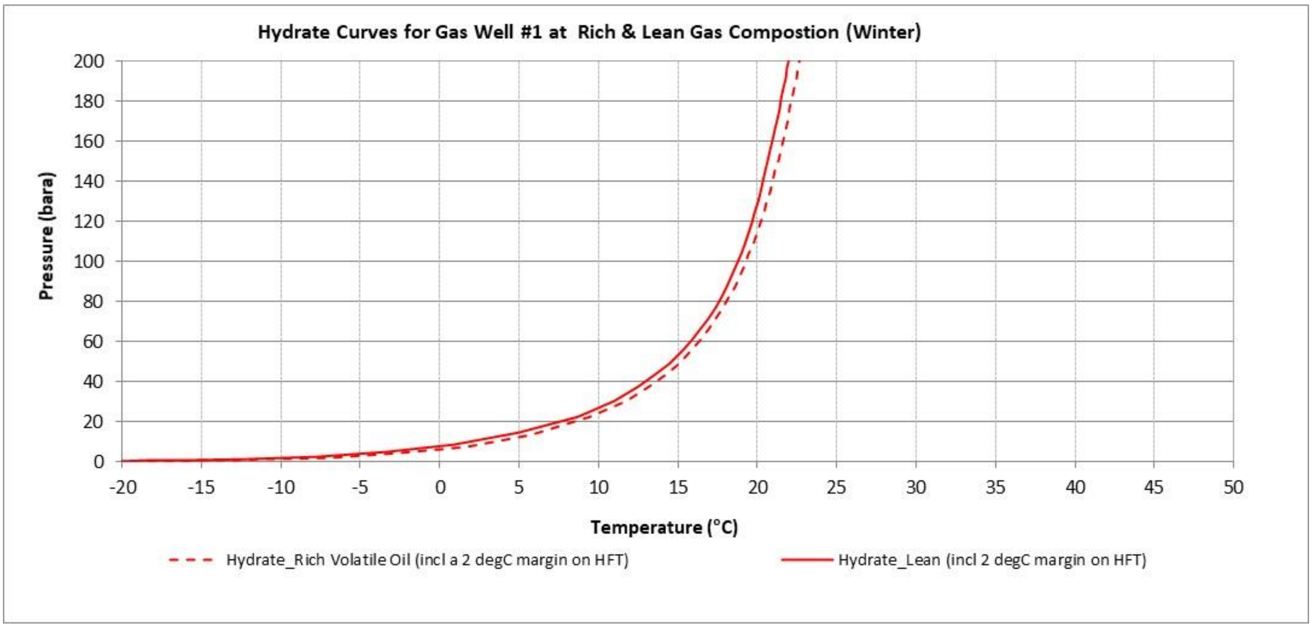

Figure 5: Hydrate Curve for Gas Well #1 at Rich and Lean Gas Composition in Winter.

Figure 6 illustrate the hydrate formation curve for gas well #2 at lean & rich gas compositions in wintertime. it can be noticed that the hydrate temperature of gas well # 2 is 19 C for rich and lean gas composition at inlet flowline pressure 60 bar.

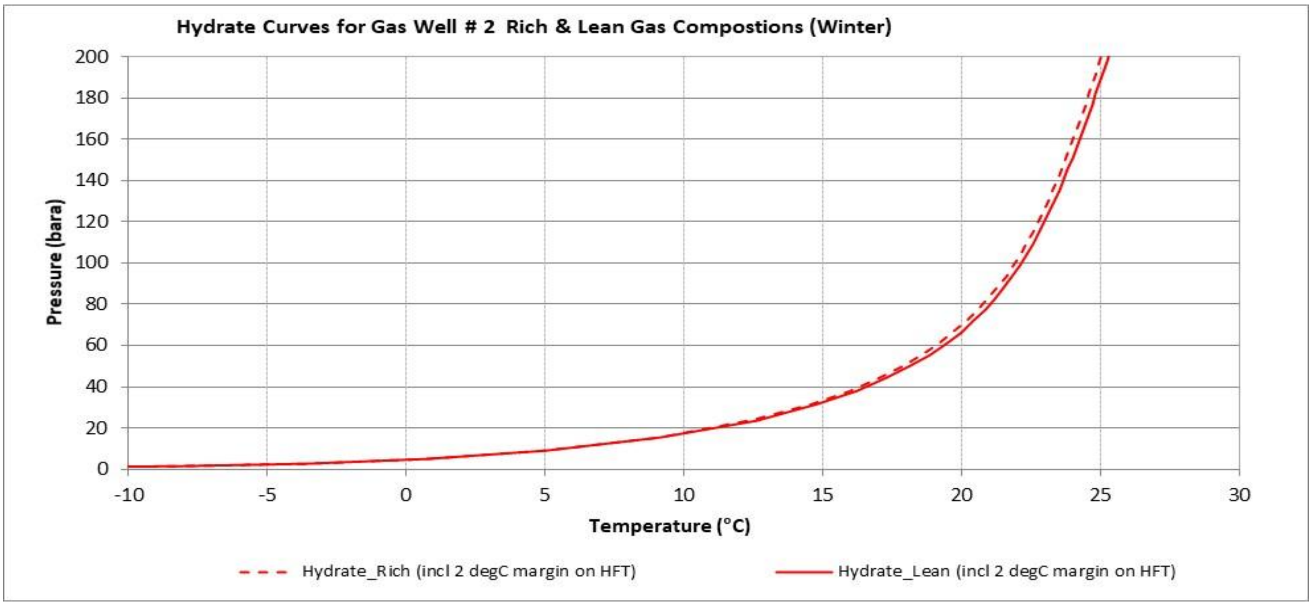

Figure 6: Hydrate Curve for Gas Well #2 at Rich and Lean Gas Composition in Winter.

Figure 7 illustrate the hydrate formation curve for gas well #3 at lean & rich gas compositions in wintertime. It can be noticed that the hydrate temperature of gas well # 3 is 21 C for rich gas composition at inlet flowline pressure 60 bar and 17 C for lean gas composition at inlet flowline pressure 60 bar.

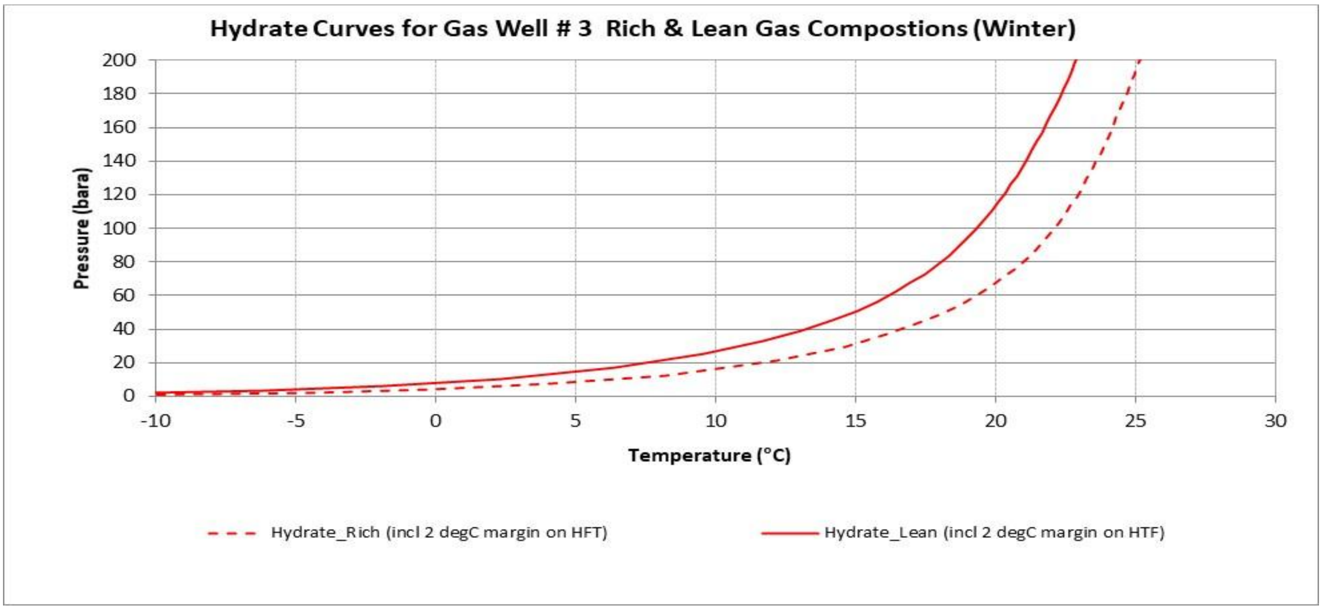

Figure 7: Hydrate Curve for Gas Well #3 at Rich and Lean Gas Composition in Winter.

Figure 8 reveals the hydrate formation curve for gas well #4 in wintertime. It can be noticed that the hydrate temperature of gas well # 4 is 19 C at inlet flowline pressure 60 bar.

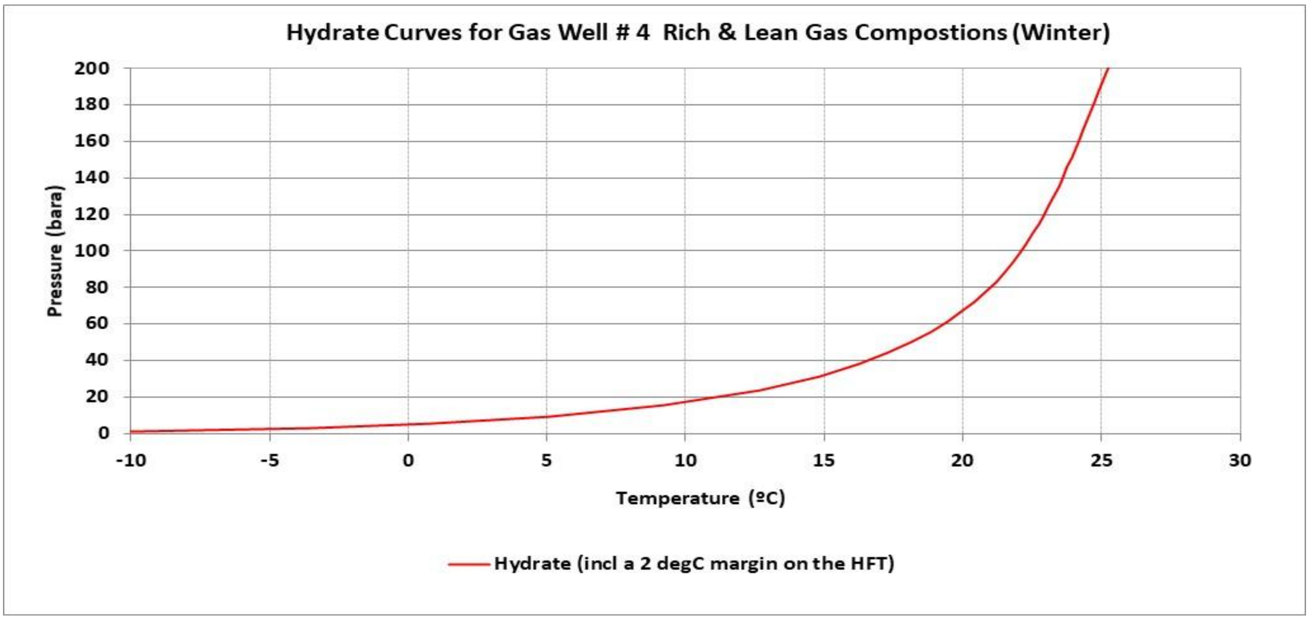

Figure 8: Hydrate Curve for Gas Well #4 at Rich and Lean Gas Composition in Winter.

Figure 9 illustrate the hydrate formation curve for gas well #5 at lean & rich gas compositions in wintertime. It can be noticed that the hydrate temperature of gas well # 5 is 17 C for lean gas composition at inlet flowline pressure 60 bar and 19 C for rich gas composition at inlet flowline pressure 60 bar.

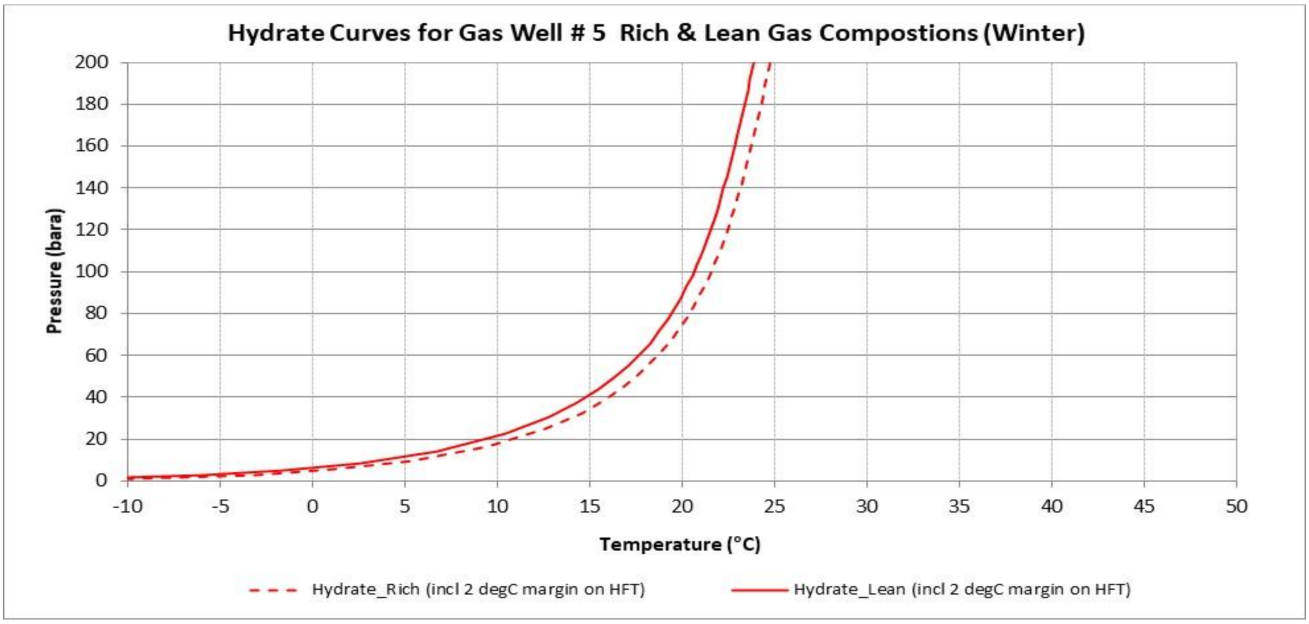

Figure 9: Hydrate Curve for Gas Well #5 at Rich and Lean Gas Composition in Winter.

Figure 10 illustrate the hydrate formation curve for Gas well #6 at lean & rich gas compositions in wintertime. It can be noticed that the hydrate temperature of gas well # 6 is 17 C for lean gas composition at inlet flowline pressure 60 bar and 19 C for rich gas composition at inlet flowline pressure 60 bar.

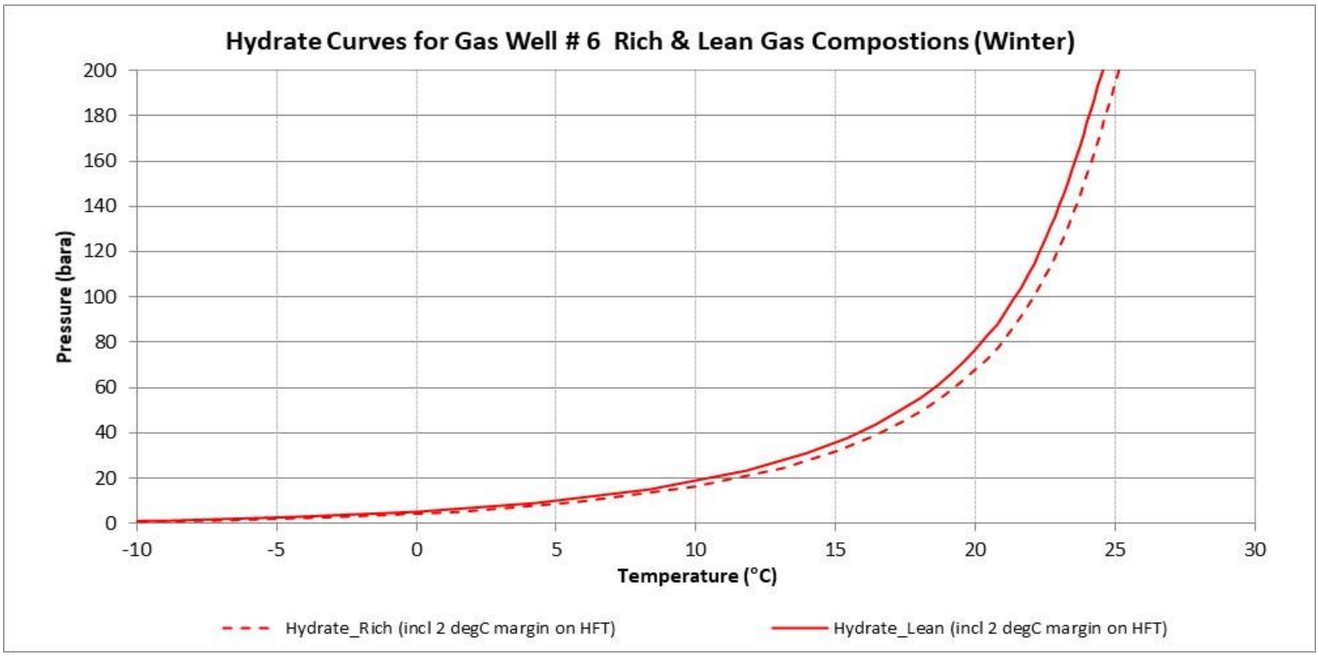

Figure 10: Hydrate Curve for Gas Well #6 at Rich and Lean Gas Composition in Winter.

Figure 11 illustrate the hydrate formation curve for Gas well #7 at lean & rich gas compositions in wintertime. It can be noticed that the hydrate temperature of gas well # 7 is 18 C for lean gas composition at inlet flowline pressure 80 bar and 20 C for rich gas composition at inlet flowline pressure 80 bar.

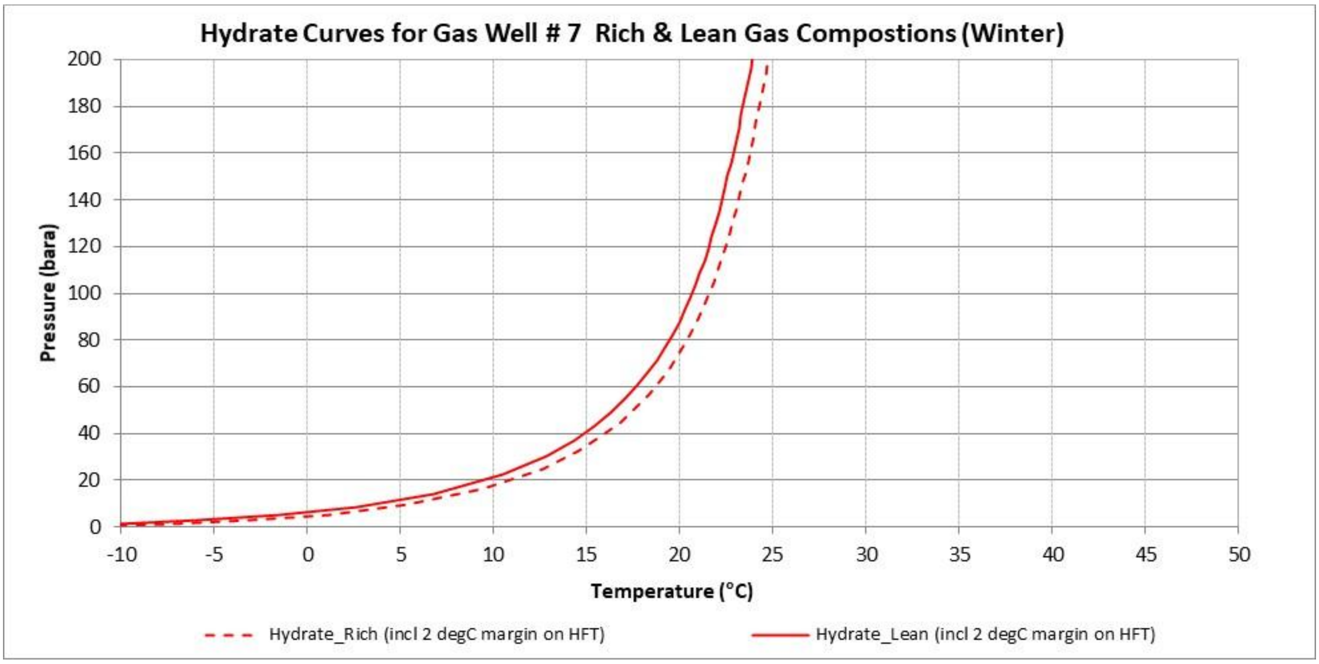

Figure 11: Hydrate Curve for Gas Well #7 at Rich and Lean Gas Composition in Winter.

Figure 12 illustrate the hydrate formation curve for Gas well #8 at lean & rich gas compositions in wintertime. It can be noticed that the hydrate temperature of gas well # 8 is 17 C for rich and lean gas composition at inlet flowline pressure 56 bar.

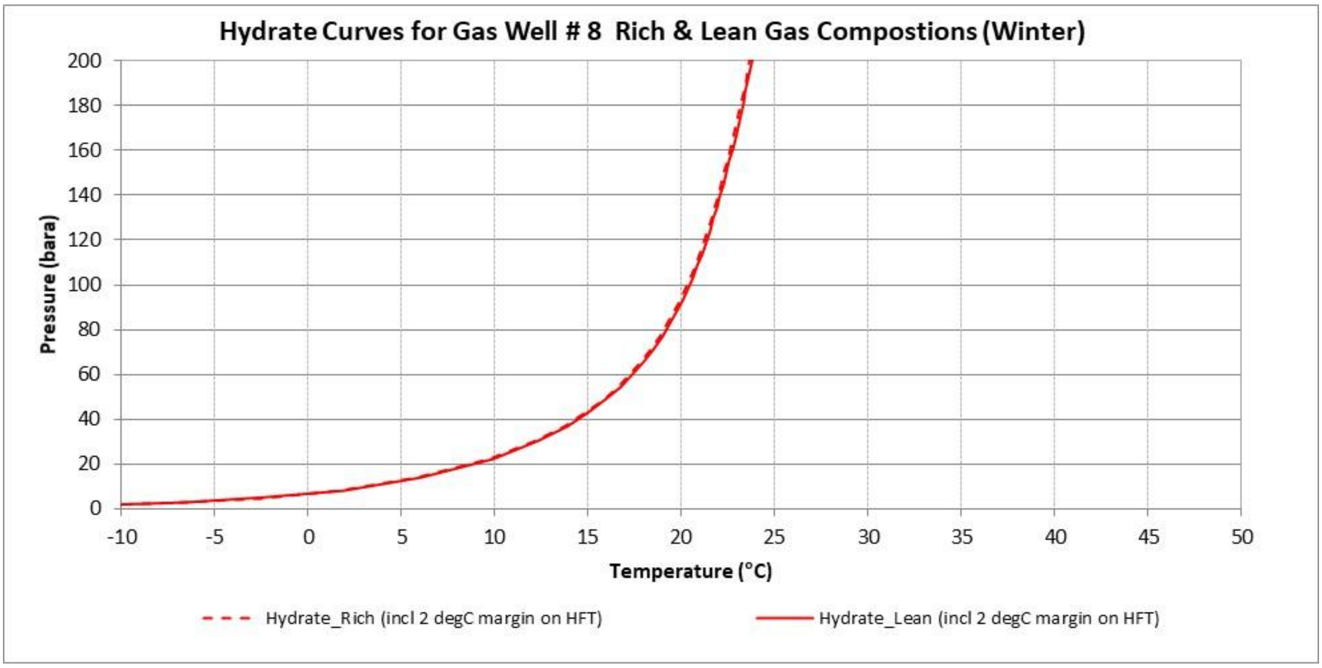

Figure 12: Hydrate Curve for Gas Well #8 at Rich and Lean Gas Composition in Winter.

5.2 Technical Comparison of Hydrate Mitigation Methods

5.2.1 Hydrate Inhibition by Methanol

Sensitivity analyses were conducted using PPIEPSIM software on the rich and lean gas compositions of the gas project at different ambient air temperatures and 10 % % 25 water cut to calculate the methanol injection rate required for each gas wellhead flowline in the gas project.

5.2.1.1 Ambient Temperature Sensitivity by PIPESIM Software

Figure 13 reveals the hydrate inhibitor rate for the eight gas wellhead flowlines at rich gas compositions and 25 % water cut at different ambient air temperatures. It can be noticed that the methanol dosage rate is increasing with decreasing the ambient air temperature

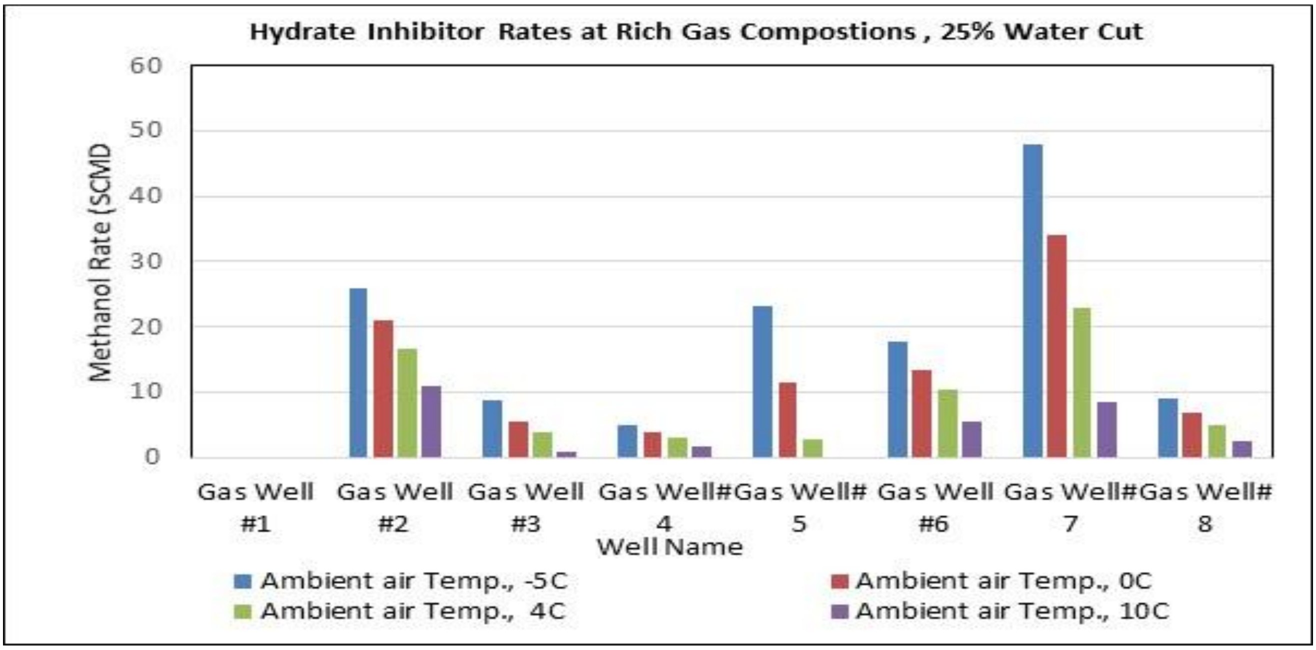

Figure 13: Methanol Injection Rate at Rich Gas Compositions, Different Ambient air Temperature and 25 % Water Cut.

Figure 14 displays the hydrate inhibitor rate for the eight gas wellhead flowlines at lean gas compositions and 25 % water cut at different ambient air temperatures. It can be noticed that the methanol dosage rate is increasing with decreasing the ambient air temperature

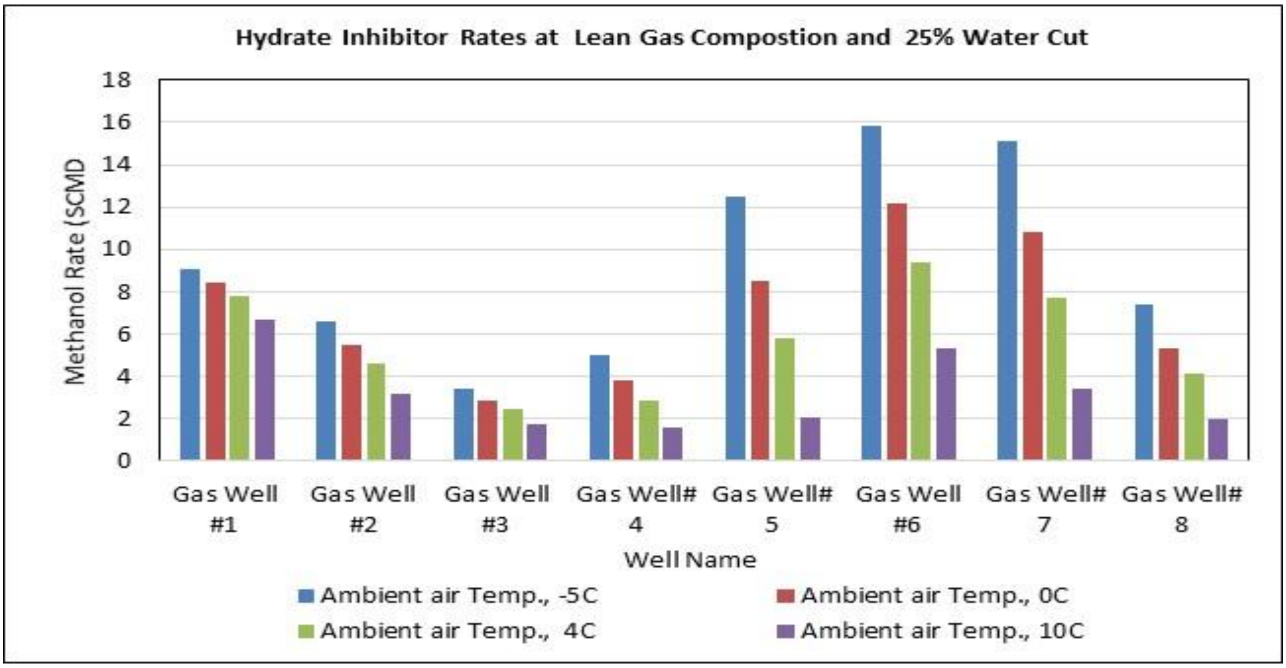

Figure 14: Methanol Injection Rate at Lean Gas Compositions, Different Ambient air Temperature and 25 % Water Cut.

5.2.1.2 Water Cut Sensitivity by PIPESIM Software

Figure 15 illustrate the hydrate inhibitor rate for the eight gas wellhead flowlines at rich gas compositions and 10 % & 25 % water cut. It can be noticed that the methanol dosage rate is increasing with increasing the water content in the gas wells.

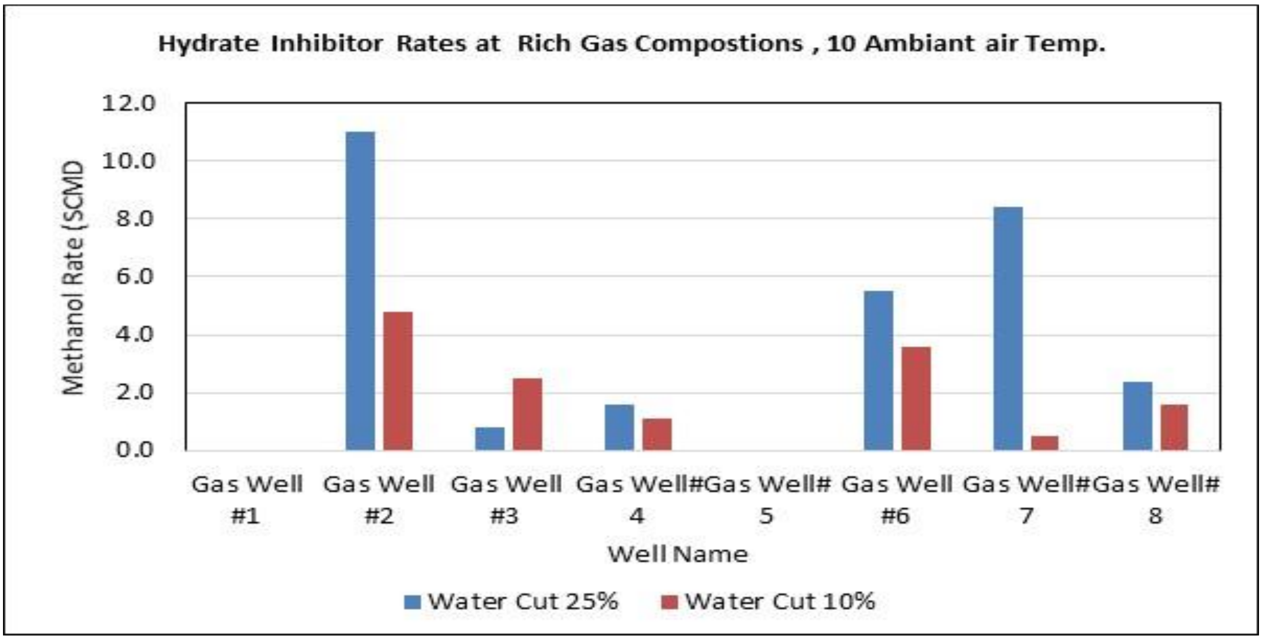

Figure 15: Methanol Injection Rate at Rich Gas Compositions and 10%, 25 % Water Cut.

Figure 16 shows the hydrate inhibitor rate for the eight gas wellhead flowlines at lean gas compositions and 10 % & 25 % water cut. It can be noticed that the methanol dosage rate is increasing with increasing the water content in the gas wells.

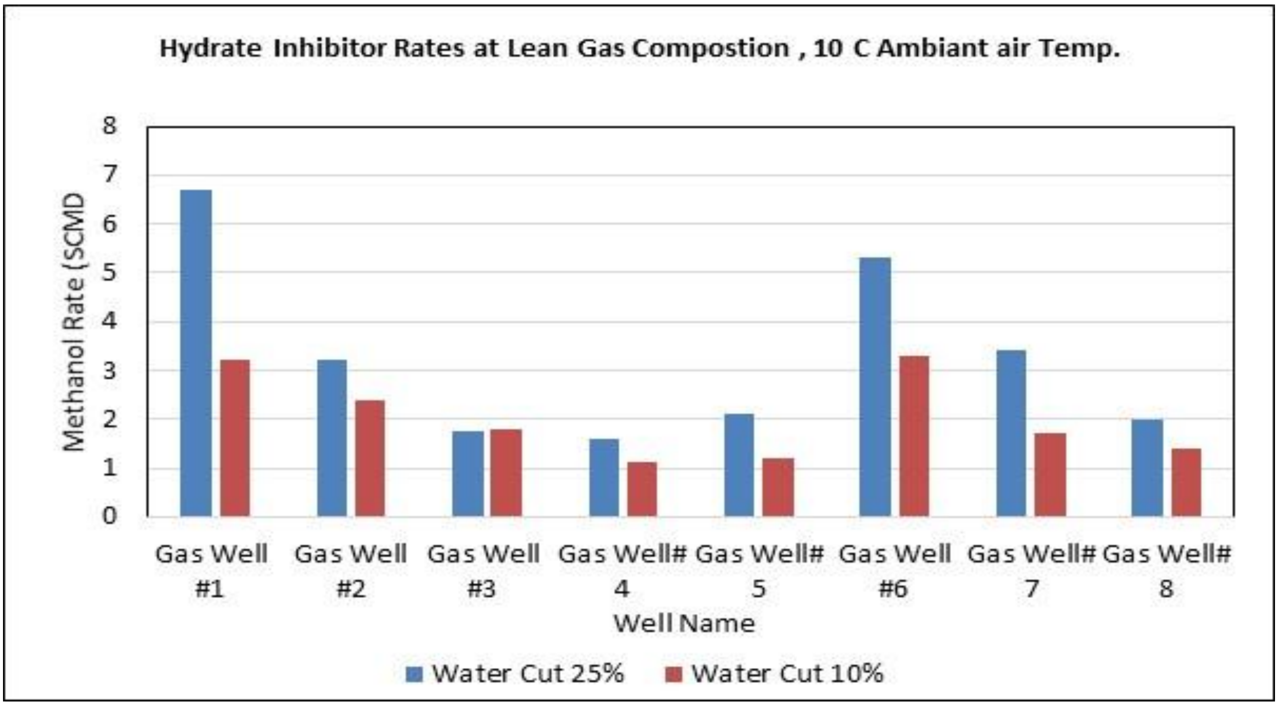

Figure 16: Methanol Injection Rate at Lean Gas Compositions and 10%, 25 % Water Cut.

5.2.1.3 Comparison between OLGA and PIPESIM Results

Table 2 compares the results obtained from PIPESIM steady-state software and OLGA transient software concerning the Methanal injection at different ambient air temperatures and different soil temperatures. It can be noticed that the methanol injection rate is increasing with decreasing the ambient air temperature in both OLGA and PIPESIM results, also increasing with reducing the soil temperature for the two software's. The methanal injection rate in OLGA results is higher than that in PIPESIM results with 48 %. Therefore, the OLGA results are more accurate than their dynamic simulation.

Table 2: Comparison between OLGA and PIPESIM Results

Well	Comp.	Wellhead Temp., °C	Wellhead Pressure, bara	Methanol Rate based on PIPESIM (with 4 C margin), SCMD	Methanol Rate based on OLGA with (with 4 C margin), SCMD	Arrival at CPF Pressure, bara	Ambient Air Temp., °C	Ambient Soil Temp., °C	Deviation Methanol Injection Volumes (PIPESIM versus OLGA)
Gas Well #1	Rich	50	267	**0.0**	0.0	56	**10**	16	[0%]
	Lean	50	267	**7.1**	7.6	56	**10**	16	[-6.2 %]
	Rich	50	267	**0.0**	0.0	56	**-5**	1	[0%]
	Lean	50	267	**8.3**	11.8	56	**-5**	1	[-29.6 %]
Gas Well #2	Rich	50	267	**12.2**	14.8	56	**10**	16	[-17.3 %]
	Lean	50	267	**4.3**	6.4	56	**10**	16	[-33.3 %]
	Rich	50	267	**20.8**	23.3	56	**-5**	1	[-10.9 %]
	Lean	50	267	**6.6**	7.6	56	**-5**	1	[-12.5 %]
Gas Well #3	Rich	50	267	**0.0**	5.7	56	**10**	16	[-100 %]
	Lean	50	267	**2.2**	2.9	56	**10**	16	[-23 %]
	Rich	50	267	**3.5**	18.9	56	**-5**	1	[-81.6 %]
	Lean	50	267	**3.3**	3.4	56	**-5**	1	[-1.9 %]
Gas Well # 4	Rich	63	245	**1.4**	3.9	56	**10**	16	[-63.1 %]
	Rich	63	245	**3.9**	7.4	56	**-5**	1	[-47.6 %]
Gas Well #5	Rich	61	228	**0.0**	10.7	56	**10**	16	[-100 %]
	Lean	61	228	**0.8**	7.4	56	**10**	16	[-23 %]
	Rich	61	228	**1.9**	51.0	56	**-5**	1	[-81.6 %]
	Lean	61	228	**8.0**	26.1	56	**-5**	1	[-1.9 %]
Gas Well #6	Rich	50	267	**4.0**	16.6	56	**10**	16	[-76.1 %]
	Lean	50	267	**5.2**	12.7	56	**10**	16	[-59.4 %]
	Rich	50	267	**12.0**	30.9	56	**-5**	1	[-61.2 %]
	Lean	50	267	**11.9**	26.1	56	**-5**	1	[-54.5 %]
Gas Well #7	Rich	61	228	**0.0**	30.7	56	**10**	16	[-100 %]
	Lean	61	228	**2.5**	8.0	56	**10**	16	[-68.5 %]
	Rich	61	228	**22.2**	83.2	56	**-5**	1	[-73.3 %]
	Lean	61	228	**12.5**	23.6	56	**-5**	1	[-47.2 %]
Gas Well #8	Rich	50	267	**3.1**	5.0	56	**10**	16	[-37.6 %]
	Lean	50	267	**2.7**	4.9	56	**10**	16	[-44.7 %]
	Rich	50	267	**9.3**	13.3	56	**-5**	1	[-30.3 %]
	Lean	50	267	**7.6**	10.1	56	**-5**	1	[-24.7 %]
									[-48.6%]

5.2.2 Hydrate Inhibition by Mono Ethanol Glycol (MEG)

Mono ethylene glycol (MEG), diethylene glycol (DEG), and triethylene glycol (TEG) can be used for hydrate inhibition. The most popular is mono ethylene glycol because of its lower cost, lower viscosity, and lower solubility in liquid hydrocarbons [25].

5.2.3 Wellhead Heater

A natural draft burner may be unreliable in sandstorms when sand can be drawn into the flame arrestor housing, creating a blockage, and starving the flame of oxygen. In these conditions, the flame will become Smokey and ultimately go out. A flame failure will be detected and cause the well to shut down. By drawing air into the flame arrestor some distance above grades, drawing in the sand can be reduced but not eliminated.

Although there are reliability problems associated with the installation of a water bath heater with a natural draught burner in a sandy desert environment, it is considered that heating at the wellhead minimizes impact on the CPF design.

The approximate duty for a wellhead heater in this service for a flowrate of 0,425 MSCMD (15 MMSCFD) is 200 kW. However, this duty is too large for electrical heating using solar panels and providing power supply through cable, or overhead lines would be expensive for this potentially short-term requirement.

5.2.4 Low Dosage Hydrate Inhibitors (LDHI)

Indicative data of the injection rates of KHI compared to injection rates of MEG, suggest the latter are approximately 2.5 – 5 times greater to achieve comparative hydrate inhibition. This would be equivalent to a storage volume at the CPF of 30-40 m^3 and pump capacity 3.9 – 5.6 m^3/day. The benefits of low dosage hydrate inhibitors are less volatile and flammable, and relatively more environmentally friendly than methanol, resulting in reducing HSE risks. However, the low dosage hydrate inhibitor option is not well known in North African countries.

5.3 CAPEX Comparison of Hydrate Mitigation Methods

5.3.1 Methanol Injection

Methanol is available in the North African countries in 1 m^3 tote tanks at concentrations greater than 99.85%. Therefore, it is either necessary to store a supply of methanol at the wellhead for at least one week to avoid interruption of injection due to unavailability of methanol, e.g. B. as a result of sandstorms that prevent travel to the well site or to supply methanol from the tank at the CPF to the individual wellheads. For individual methanol systems at each wellhead, all systems are assumed to be designed for 4.8 m^3/day. For one week's storage of 4.8 m^3/day, 34 x 1 m^3 tote tanks shall be required. Two pumps, one duty and one standby, will also be needed for each wellhead. These shall be designed for an installed power of 11 kW. The equipment cost for two electric driven pumps is $130,609.

A single methanol system at the CPF should be designed for the total expected methanol injection requirements at 16°C ambient soil temperature and 10% water cut, as would be expected for regular operation at the minimum design ambient temperature. Therefore, a single tank at the CPF should be sized for approximately 150 m^3, based on one week's supply of the maximum methanol requirements at 16°C ambient soil temperature (138 m^3, based on the sum of the maximum methanol rate for each well for 10% water cut. The cost of an individual tank of this capacity is $35,550.

Two pumps, one duty and one standby, are required at the CPF to deliver methanol to all wells. Maximum methanol demand at 10°C ambient requires a total flow rate of 19.7 m3/day (0.82 m3/h) based on the maximum methanol rate for each well for 10% water cut. The pump must discharge at 383 barg to reach the pressure upstream of the choke valve for all wells. Assuming a pump efficiency of 65%, the pump power requirement would be 13.4 kW. The equipment cost for two pumps (installed power: 18.5 kW) is $157,353.

A piggyback line is proposed to transport the methanol from the CPF to each wellsite, following the flowline trench and branching to each wellhead as required. A total of 60 km of 1" NB Schedule 160 ASTM A106 Gr. B line pipe is assumed with appropriate allowances for coating. The total installed cost for the line pipes is $1,830,000.

5.3.2 Low Dosage Hydrate Inhibitor Injection

Owing to their low dosage, the most attractive economic advantage expected from LDHI should be the reduction of OPEX, but it is not because their price is very high ($6.3/l so that their dose rate multiplied by their price leads to about the same OPEX cost as for methanol ($0.4/l). Therefore, on most of the oil fields, where the water flow rate becomes unavoidably very high at a specific field lifetime, it is unacceptable, just as it is for methanol or MEG, to contemplate a continuous injection of LDHI. Therefore, the total installed cost for the LDHI has assumed half of the total installed price for methanol. Thus, the main economic incentive of using LDHI is the large reduction of CAPEX via the decline of the size of the storage, pumping and piping facilities.

5.3.3 Wellhead Heater

A wellhead heater is insufficient to prevent hydrate formation on its own and impractical to be used in conjunction with methanol injection. The cost for a 300-kW mobile gas fired, indirect water bath heater is $246,950 per well (the total cost for eight wells are 1,975,600 $).

5.3.4 Mono Ethylene Glycol

The CAPEX of mono ethylene glycol injection to prevent hydrate formation in the gas wellhead flowlines will be approximately 6 million $, including installing piggyback lines.

Figure 17 illustrates the CAPEX of applicable methods which can be used to prevent hydrate formation in the gas wellhead flowlines in the gas project. It can be noticed from Figure 17 that the option of using mono ethylene glycol injection is considered an expensive option compared to the other options due to requirements for MEG recovery, regeneration and recycling system at the CPF. Low dosage inhibitors would be regarded as, but it is not known in the northern African countries. Wellhead heating is considered a viable alternative to the methanol injection method. Therefore, the methanol injection option is the best option to be used.

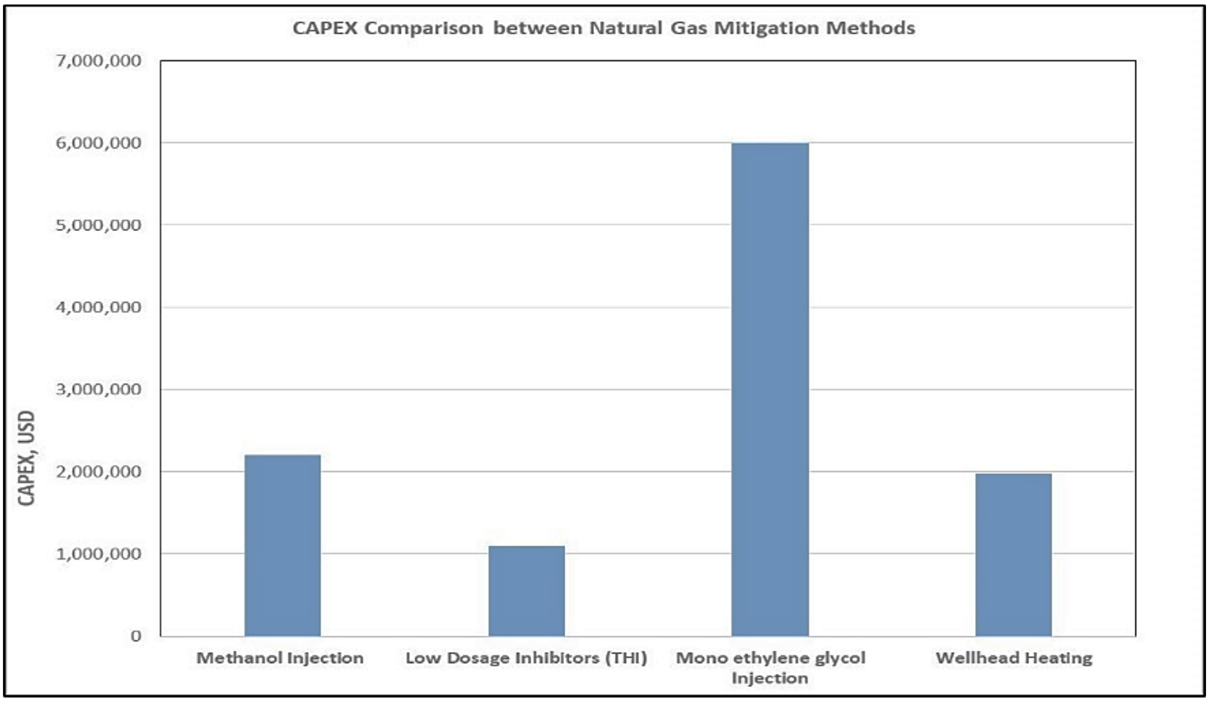

Figure 17: CAPEX Comparison between Natural Gas Mitigation Methods

6. CONCLUSIONS

The conclusions and recommendations can be summarized as follow: -

- Based on the hydrate formation curves for the eight gas wells at rich and lean compositions, it can be noticed that hydration inhibition is required on each gas wellhead flowline, especially in the wintertime.
- Mono ethylene glycol injection is considered an expensive option due to MEG recovery, regeneration and recycling system requirements at the CPF.
- Low dosage inhibitors would be considered if the volumes of methanol were required to prove unmanageable based on good pressure and water production profiles. also, it is not known in the northern African countries
- Choking the flow at the CPF, will require a higher design pressure for flowlines and increase the CAPEX of the project. This option is not considered as a solution to avoid hydrate formation on the wellhead gas flowlines,
- Although there are reliability problems associated with the installation of a water bath heater with a natural draught burner in a sandy desert environment, it is considered that heating at the wellhead minimizes impact on the CPF design. The approximate duty for a wellhead heater in this service for a flowrate of 0,425 MSCMD (15 MMSCFD) is 200 kW. This duty is too large for electrical heating using solar panels and providing power supply through cable or overhead lines would be expensive for this potentially short-term requirement.
- By technical and economic comparison of all applicable hydrate inhibition methods in the market, it can be noticed that methanol injection was considered a viable option for the gas wellhead flowlines in the gas project.
- Ambient temperature sensitivities were conducted on the eight gas wellhead flowlines at lean and rich gas compositions by PIPESIM software and it has been noticed that the methanol dosage rate is increasing with decreasing the ambient air temperature.
- Water cut sensitivities were conducted on the eight gas wellhead flowlines at lean and rich gas compositions by PIPESIM software and it has been noticed that the methanol dosage rate is increasing with water cut.
- The results obtained from PIPESIM steady-state software and OLGA transient software concerning the methanal injection rate for each gas well at different ambient air & soil temperatures were compared. It can be noticed that methanol injection rate is increasing with decreasing the ambient air temperature in both OLGA and PIPESIM results, also increasing with reducing the soil temperature for the two software's. The methanal injection rate in OLGA results is higher than that in PIPESIM results with 48 %. The OLGA results are more accurate as of its dynamic simulation

7. Nomenclature

Abbreviation	**Description**
ASTM	American Society for Testing and Materials
AA	Anti-Agglomerants
BS&W	Basic Sediment and Water
CAPEX	Capital Expenditure
CGR	Condensate to Gas Ratio
CPF	Central Processing Facility
DEG	Diethylene glycol
FWHP	Flowing Well Head Pressure
FWHT	Flowing Well Head Temperature
Gr.	Grade
HFT	Hydrate Formation Temperature
HSE	Health, Safety and Environment
HSSE	Health, Safety, Security and Environment
KHI	Kinetic Hydrate Inhibitor
kW	Kilowatt
LDHI	Low Dosage Hydrate Inhibitor
LPG	Liquified Petroleum Gas
MEG	Mono-Ethylene Glycol
MSCMD	Million Standard Cubic Meters per Day
MMSCFD	Million Standard Cubic Feet per Day
NB	Nominal Bore
OPEX	Operating Expenditure
RVP	Reid Vapor Pressure
SCF	Standard Cubic Feet
SCMD	Standard Cubic Meter per Day
STB	Standard barrel
TEG	Triethylene glycol
WC	Water Cut
OPEX	Capital Expenditure
Yr.	Year

7. CONFLICTS OF INTEREST

There are no conflicts to declare.

8. FUNDING SOURCES

The author declares that he has no known competing financial interests or personal relationships that could have influenced the work reported in this paper. The author will be responsible for his financial interest

REFERENCES

Al-Eisa, R.; Elanany, M.; Al-Majnouni, K.; Aj-Jabran, A.; AlJawad, H.; Abba, I.; Al-Maiki, 2015. A. Kinetic Hydrate Inhibitors for Natural Gas Fields: Rational Design and Experimental Development. Saudi Aramco J. Technol.

Carroll, J., 2014. Natural Gas Hydrates A Guide for Engineers, 3 rd edition Elsevier: Amsterdam, Netherland.

Chong, Zheng Rong; Yang, She Hern Bryan; Babu, Ponnivalavan; Linga, Praveen; Li, Xiao-Sen ,2016. Review of natural gas hydrates as an energy resource: Prospects and challenges. Applied Energy. 162: 1633–1652.

Cox, S.J.; Taylor, D.J.F.; Youngs, T.G.A.; Soper, A.K.; Totton, T.S.; Chapman, R.G.; Arjmandi, M.; Hodges, M.G.; Skipper, N.T.; Michaelides, A., 2018. Formation of methane hydrate in the presence of natural and synthetic nanoparticles. J. Am. Chem. Soc. 140, 3277–3284.

Cruz ,F.J.A.L., Alavi S.; Mota J.P.B. ,2019. Low-Temperature Thermodynamic Study of the Metastable Empty Clathrate Hydrates Using Molecular Simulations , ACS Earth Space Chem. 3 (5): 789–799.

Di Lullo, A.; Hester, K.C. , 2017.Revisiting the Hammerschmidt Equation: Effect of Operating Conditions on the Selection of the Hammerschmidt Constant. In Proceedings of the 13th Offshore Mediterranean Conference and Exhibition, Ravena, Italy,

E.G. Hammerschmidt, 1969. Possible Technical Control of Hydrate Formation in Natural Gas Pipelines, Brennstoff-Chemie vol. 50 , 117–123.

Ghosh, Jyotirmoy; Methikkalam, Rabin Rajan J.; Bhuin, Radha Gobinda; Ragupathy, Gopi; Choudhary, Nilesh; Kumar, Rajnish; Pradeep, Thalappil , 2019. Clathrate hydrates in interstellar environment. Proceedings of the National Academy of Sciences. 116 (5): 1526–1531.

GPSA Engineering Data Book, 14th edition. 2017. Gas Processors Suppliers Association, Tulsa, Oklahoma.

Haque, M. E. 2012. Ethylene Glycol Regeneration Plan: A Systematic Approach to Troubleshoot the Common Problems, Journal of Chemical Engineering, 21-26.

J. Rajnauth, M. Barrufet, G. Falcone,2010. Hydrate Formation: Considering the Effects of Pressure, Temperature, Composition and Water, 72nd Eur. Assoc. Geosci. Eng. Conf. Exhib. A New Spring Geosci. Inc. SPE Eur. Vol. 2, 824-833.

Ke, W.; Kelland, M. , 2016. Kinetic Hydrate Inhibitor Studies for Gas Hydrate Systems: A Review of Experimental Equipment and Test Methods. Energy Fuels , 30, 10015−10028.

Kidnay, A.J., W. R. Parrish, Daniel G., 2020. Fundamentals of Natural Gas Processing, third edition CRC Press, Boca Raton, FL.

Kinnari, K., Hundseid, J., Li, X., Askvik, K.M., 2015. Hydrate management in practice. Journal of Chemical & Engineering Data, 60(2), 437-446

Lanlan Jiang, Nan Xu, Qingbin Liu, ZuCheng Cheng, Yu Liu, Jiafei Zhao, 2020. Review of Morphology Studies on Gas Hydrate Formation for Hydrate-Based Technology. Crystal Growth & Design , 20 (12) , 8148-8161

Meyer, D. W., Flemings, P. B., DiCarlo, D. A., You, K., Phillips, S. C., & Kneafsey, T. ,2018. Experimental investigation of gas flow and hydrate formation within the hydrate stability zone. Journal of Geophysical Research: Solid Earth.

Molnar, C., Riley, M., 2016. Flow Assurance and Hydrate Prevention Methods Enabled by Medium Voltage Electric Heating Technology, In: Offshore Technology Conference Asia, Offshore Technology Conference, Kuala Lumpur-Malaysia.

Mokhatab, S., Poe, W.A., Speight, J.G., Handbook of Natural Gas Transmission and Processing , 4th edition , Gulf Professional Publishing, Burlington, MA, USA, 2019.

Netusil, M.; Ditl, P., 2011. Comparison of three methods for natural gas dehydration. J. Nat. Gas Chem. , 20, 471−476.

OLGA, 2019. Transient Multiphase Flow Simulator, Schlumberger Service Company.

Palodkar, A. V., Jana, A. K.,2020. Clathrate hydrate dynamics with synthetic and bio-surfactant in porous media: model formulation and validation, Chem. Eng. Sci.,

Paz, P.; Netto, T.A., 2019. Introducing a Novel MEG/EtOH Mixture to Improve Gas Hydrate Blockages Removal During Offshore Oil and Gas Production. In Proceedings of the ASME 2019 38th International Conference on Ocean, Offshore and Arctic Engineering, Volume 5A: Pipelines, Risers, and Subsea Systems, Glasgow, UK.

Peytavy, Jean-Louis; Glénat, Philippe; Bourg, Patrick, 2008. Qualification of Low Dose Hydrate Inhibitors (LDHIs): Field Cases Studies Demonstrate the Good Reproducibility of the Results Obtained from Flow Loops, Proceedings of the 6th International Conference on Gas Hydrates , Vancouver, British Columbia, Canada.

PIPESIM, 2019. Steady-State Multiphase Flow Simulator, Schlumberger Service Company.

Salmin, D. C., Majid, A. A., Wells, J., Sloan, E. D., Estanga, D., Kusinski, G., Koh, C. A. , 2017. Study of Anti-Agglomerant Low Dosage Hydrate Inhibitor Performance, In: Offshore Technology Conference, Offshore Technology Conference, Houston-USA.

Sayani, J. K. S., Pedapati, S. R. , Lal, B., 2020. Phase behavior study on gas hydrates formation in gas dominant multiphase pipelines with crude oil and high CO2 mixed gas. Sci. Rep. 10, 1–12.

Speight, James G., 2019. Natural gas: a basic handbook , Gulf Professional Publishing.

Wang, Y.; Fan, S.; Lang, X. , 2019.Reviews of gas hydrate inhibitors in gas-dominant pipelines and application of kinetic hydrate inhibitors in China. Chin. J. Chem. Eng. , 27, 2118–2132.

Vaferi, B., 2019. Prediction of methanol loss by hydrocarbon gas phase in hydrate inhibition unit by back propagation neural networks. J. Chem. Pet. Eng. 53, 253–264

Zhang, Q., Koyama, Y., Ihsan, A.B. et al. 2020. Kinetic Hydrate Inhibition of Glycyl-valine-based Alternating Peptoids with Tailor-made N-substituents. Energy & Fuels, 34(4), pp. 4849-4854.