Analysis of Hydrate Formation Temperature and Water Dew Point of Processed Crude oil and Gas using Unism Simulator

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***Abstract*—Flow assurance has been a topic of concern since the start of crude oil and gas production and transportation. The formation of Hydrates is an important issue likely to cause clogs in pipelines during production and transportation of oil and gas. Therefore, production and transportation of such fluids are simulated using software's like Unism to know the possibility of hydrate occurrence so they can be avoided. This work is based on the simulation of processed well effluents from Rose Field to analyze the hydrate formation temperature and water dew point at different points of the process facility. At the crude oil line the hydrate formation temperature was -69.9565°C, while the water dew point was not defined because it's a liquid phase. At the gas line the hydrate formation temperature was 4.7975°C at 1803psia and water dew point was -42.7°C. These values are parameters necessary for hydrate formation prediction, hence, they were analyzed and recommendations made to manage effective flow assurance.**

***Index Terms*—Hydrate Formation Temperature, Water Dew Point, Flow Assurance, Unism Simulator.**

I. Introduction

According to Young Bai et. al., flow assurance is a process analysis in engineering where designs are developed with guidelines of operation for the effective control of problems caused by deposited solids such as wax, asphaltenes and hydrates in subsea systems [7]. Also, erosion, corrosion and scale formation are considered as flow assurance challenges since they also hinder flow in some cases. However, they are dependent on the characteristics of the hydrocarbon fluid produced.

During production of oil and gas the engineer is tasked to ensure that the oil is efficiently transmitted from the reservoir to the end user without hitches, hence, flow assurance problems are foreseen during simulation and mechanisms to avert them are put in place.

Basic flow assurance challenges are:

1) Corrosion
2) Erosion
3) Scale formation
4) Asphaltene
5) Wax
6) **Hydrates**

Hydrates: these are deposits formed when tiny nonpolar molecules (<9Å) mixes up with water at typical temperatures less than 100°F folloed by a pressure typically above 180psia. The crystal formed in this process is known as hydrates.

For hydrates to form, the following should be present;

1) High Pressure
2) Low Temperature
3) Water
4) Gas composition

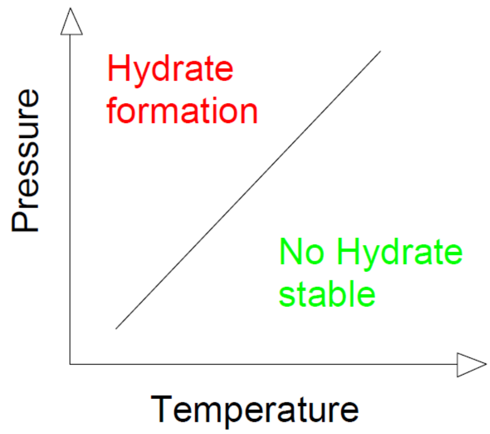

Fig. 1. Location of hydrate zone on a Pressure vs. Temperature plot

Water Dew Point: This is the point on the temperature scale below which vapors of water in air or a body in air will not be able to wholly remain in vapor state.

The dew point of a body in air is dependent on the pressure and water vapor content. The water dew point at different points of transportation of oil and gas is a very important parameter to check when analyzing for hydrate formation.

Unism Simulator: This is a software used for process design and simulation. It performs similar process analysis as ASPEN HYSYS process simulator. It also develops dynamic models and steady state models for managing assets, designing plants, monitoring performance, business planning, and troubleshooting. This study used Unism as its simulator for flow assurance analysis on reservoir effluent processed and transported.

II. Literature Review

Mahmood explained that hydrate formation is dependent on time. Also, goes deeper to emphasize that the rate of hydrate formation depends on presence of crystal nucleation sites in the liquid phase, level of agitation, gas composition, etc. and concluded that in TEG system design water dew point should be considered strongly ahead of the hydrate formation temperature [5]

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Jerome Joel Rajnauth, in his analysis of the different components that could lead to the formation of hydrates, highlighted Carbon dioxide, Nitrogen and Hydrogen Sulphides as major impurities that affects hydrate formation in natural gas production [3].

Maurice Stewart et. al. used the Vapor–solid equilibrium constant to predict the formation of hydrates during his research. However, assumptions made was the composition of streams should be known [6].

The review of the Petroleum Engineers Guide to Oil field chemicals and fluids buttressed on the use of antifreeze agents to reduce hydrate formation temperatures. Some common Antifreeze agents are Glycols, Brines, Methanol, etc. However, with regards to brine, its corrosive nature makes it unsuitable [4].

J. A. Prajaka noted that hydrate formation clogs pipelines and occurs mostly at Dew Point Control Units when there is a rapid drop in temperature during separation of natural gas from heavy ends using Joule-Thompson effect. It was also shown in his work that hydrates form when water dew points are higher than the hydrate formation temperature. Prajaka also noted that water dew point is not influenced by the composition of natural gas but rather by the pressure [2].

III. METHODOLOGY

The name of this field used for this simulation is known as Rose field and contains the following fluid composition [1].

TABLE I: FLUID COMPOSITION OF ROSE FIELD

Names	Mol. %
H2S	0.25
N2	0.15
CO2	0.49
C1	46.57
C2	7.83
C3	7.25
IC4	1.26
nC4	3.5
iC5	1.14
nC5	1.82
C6	2.35
C7	3.37
C8	3.17
C9	2.39
C10	1.58
Oil - C11+	16.88
Total	100

The meteorological and oceanographic data from the rose field has shown that the coldest month during the year is February at air temperature of 3.1℃ while the sea water can get as low as 2℃.

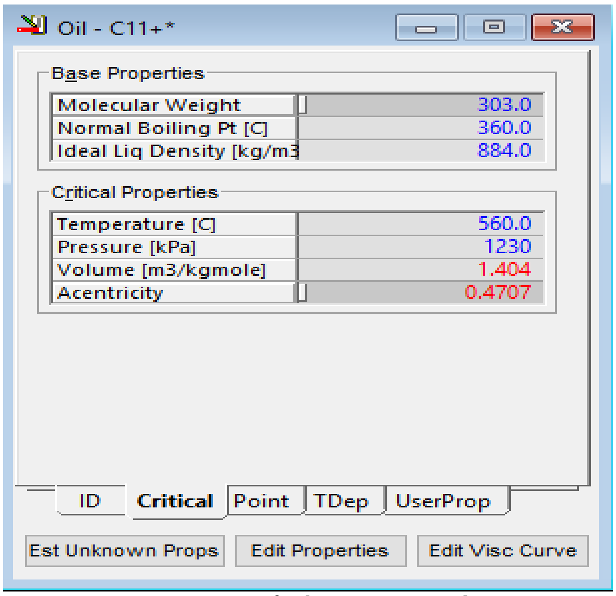

Fig. 2. Base properties of Oil – C11+ generated in Unism

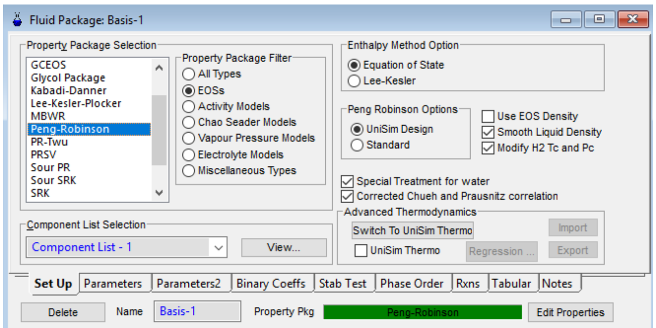

Fig. 3. Peng Robinson Equation of State model used in simulation

Conditions for production are as follows:

1) Average Well head pressure = 1758 psia
2) Average Well head temperature = 76℃
3) Oil production rate = 22,000 bbl/day
4) Total Liquid production rate = 24,440 bbl/day
5) GOR = 700 scf/stb

TABLE II: RESERVOIR PROPERTIES OF ROSE FIELD

Reservoir	Rose CE	Rose SW	Rose NW	Rose CW
Fluid type	Undersaturated Oil			
P Initial (psi)	5400	5500	5380	5465
Temp °C	112	113	114	113
API	32.5	33.5	35	33
GOR (scf/bbl)	665	695	705	680
Top of reservoir TVD SS	10500 ft	10590 ft	10540 ft	10590 ft
OWC m TVD SS	10640 ft	10685 ft	10650 ft	10675 ft
Porosity %	13 – 18	12- 16	12 - 17	10 - 15
Average Permeability (md)	100	120	100	110

The work was made more tasking by the fact that the simulated effluent was made up of reservoir fluids from different reservoirs having different properties as shown in Table II.

The average of most of the properties across reservoirs in the Rose field was used during Simulation.

Ten wells were drilled and shared among the four sections of the Rose field. During simulation the streams which represented the wells where given an average property across all wells.

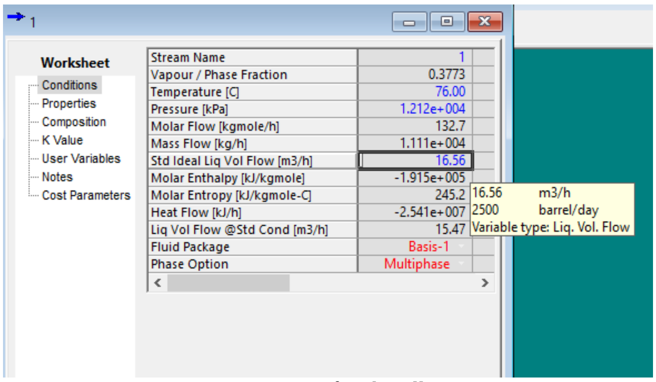

Fig. 4. Properties of each well stream

TABLE III: CRUDE OIL PROCESSING UNIT OPERATIONS

EQUIPMENT	UNIT	SPECIFICATIONS
3 phase horizontal separator	3	1800, 190 and 20 psia respectively and RT of 5-10 mins
Electrostatic Desalter	1	Operating Voltage = 15-20 kV and 20-30 minutes RT
Single stage Centrifugal pumps	3	265hp and 75 % efficiency
Multistage Centrifugal pump	1	265hp and 75 % efficiency

TABLE IV: ASSOCIATED GAS PROCESSING UNIT OPERATION

EQUIPMENT	UNIT	SPECIFICATIOS
Cooler	5	Duty = 10710 kJ/h
Regeneration unit	1	8 stages
Absorber Unit	1	10 stages
Multistage Centrifugal Compressor	1	12.41 pressure ratio 75 % efficiency
Reciprocating Piston Compressor	4	3.5 pressure ratio 75 % efficiency
FWKO Drum or Scrubber	5	350-1200 psia rating

IV. RESULTS AND FINDINGS

After imputing the required data for this simulation work, Unism made all calculations using the Peng Robinson Equation of State model and other default models at various steps of the process.

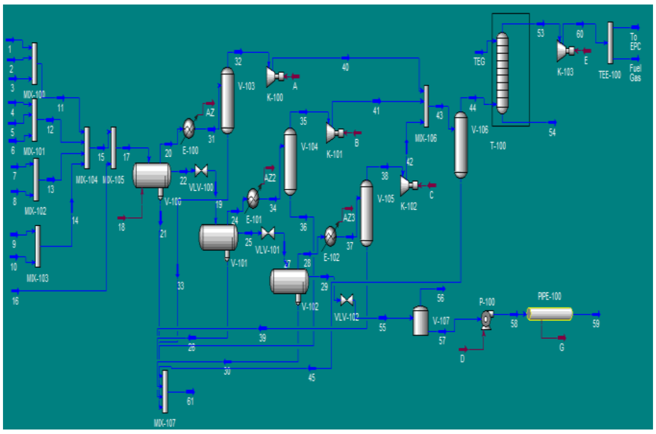
Fig. 5. Crude Oil Processing Simulation using Unism (showing the oil line and the gas line).

The Hydrate formation temperature of both the gas line and the oil line was generated.

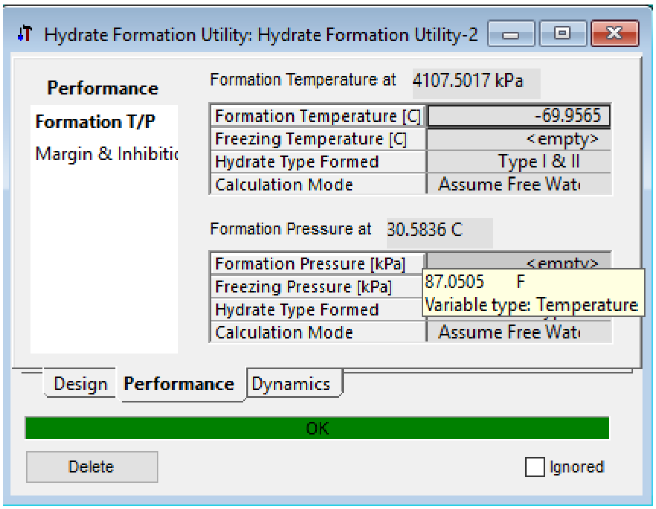

Fig. 6. Hydrate formation Temperature (HTF) for Crude Oil Processing line using Unism Simulator

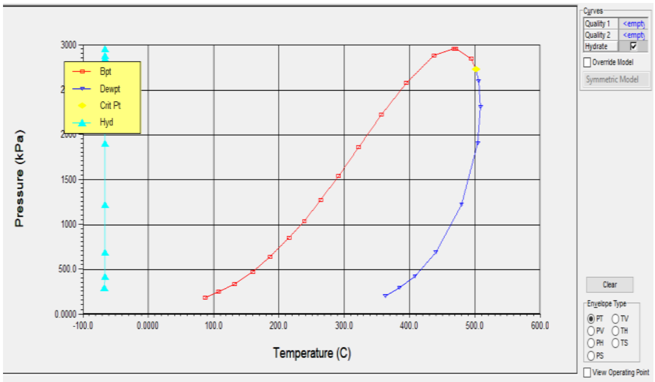

Fig. 7. Phase Envelope showing the Hydrate Formation Temperature (HTF) for Crude Oil Processing line using Unism Simulator

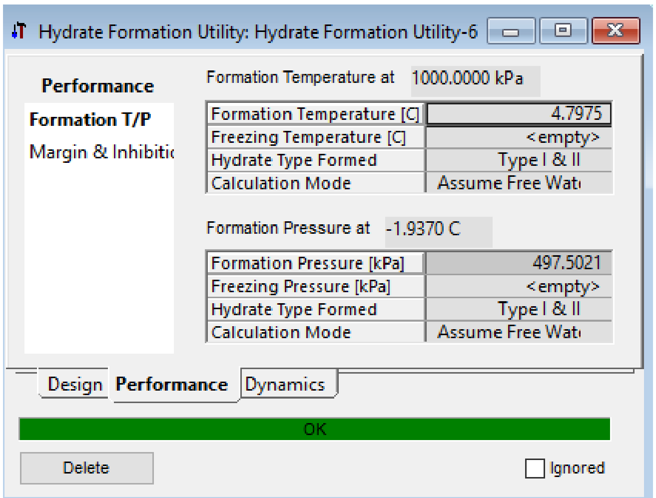

Fig. 8. Hydrate formation Temperature (HTF) for Crude Oil Processing line using Unism Simulator

TABLE V: RESULTS FOR ASSOCIATED GAS PROCESSING

Specification	Results
Water Dew point	-42.7 ˚C
HC Dew point	-29.3 ˚C
Delivery Pressure	1803 psia

As expected, the hydrate formation temperature for the processed crude came out in the negative (-69.95650ºC) due to the absence of water which is necessary for the formation of hydrate and no value for water due point because dew point is a gaseous phase property. However, at the associated gas process line, the hydrate formation

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temperature was 4.7975℃ while the water dew point was -42.7℃ at 1803psia. The low water dew point is as a result of effective dehydration at the TEG column during process. We are now faced with the challenge of making a decision to ascertain the if hydrate will form or not since varying system pressure could also affect the HTF.

V. CONCLUSION

From the above analysis, hydrate would not form in the processed crude oil line unless there is an unlikely change in transmission temperature leading to a drastic and unlikely reduction in the crude oil temperature to a value below the HFT (-69.9565℃) temperature at high pressure. While, for the gas line whose result was more technical, the low water dew point shows that there is very little or no water in the gas phase at 1803psia which implies that theoretically, at working condition lower than the HTF (4.7975℃) but higher than -42.7℃ the likelihood for hydrates formation is slim. Water is necessary in the formation of hydrates, therefore without water present it will be difficult for hydrate to form from gaseous to solid state.

VI. RECOMMENDATION

Irrespective of the fact that simulations have been carried out and results obtained, adequate monitoring of the system properties (pressure and temperature) should be carried out throughout the gas transmission to prevent the system from entering the hydrate phase. Also, adequate simulation should be carried out to determine the hydrate formation temperature at varying transmission pressures.

The case of the gas line which showed a low water dew point is theoretical, therefore in cases like this, the engineer should be careful in decision making, therefore, all necessary equipment and procedures such as pigs, shut down maintenance plan, inhibitors, etc. which could help in averting hydrates should always be available.

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