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Investigation Of Gas Hydrates Formation In Gas Lines After Contacting Water Pipes During Water Alternating Gas Injection Enhanced Oil Recovery

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Abstract

Tertiary recovery, the third stage of production, was that obtained after water flooding (or whatever secondary process was used). Tertiary processes used miscible gases to displace additional oil after the secondary recovery process became uneconomical. Several gases have been injected in hydrocarbon reservoirs as part of EOR process. Natural gas is a mixture of hydrocarbons and a few non-hydrocarbons. In combination with water, many of components, commonly found in natural gas, form hydrates. One of the problems in the production, processing, and transportation of natural gas and liquids derived from natural gas is the formation of hydrates. The beginning of the process of gas hydrate formation depends on gas composition. In this work, HYSYS and PVT sim software have been used to investigate the hydrate formation under typical flow line conditions, and to check and compare the capability of these software to predict the hydrate formation conditions. Finally, compare the obtained results, check hydrate formation during normal operation, and depressurization of wells for two option individual and header flow lines.

Keywords: Gas hydrates; enhanced oil recovery; gas injection; pipes; HYSYS; PVT Sim software.

1. Introduction

Water alternating Gas (WAG) Process

This process was developed to combine the advantages of water flooding and gas injection techniques. Water flooding, gas injection and water-alternating-gas injection (WAG) are well-established methods for improving oil recovery.

Problems associated with WAG

Gas hydrates formation

Gas hydrates are ice-like crystalline structures with gas components as guest molecules entrapped into cavities formed by water molecules. Whenever a system of natural gas and water exists at specific conditions, especially at high pressure and low temperature, we expect the formation of hydrates. The most common guest molecules are methane, ethane, propane, isobutene, normal butane, nitrogen, carbon dioxide and hydrogen sulfide, of which methane occurs most abundantly in natural hydrates. An inherent problem with natural gas production or transmission is the formation of gas hydrates, which can lead to safety hazards to production/transportation systems and to substantial economic risks. Therefore, an understanding of how, when and where hydrates form is necessary to overcoming hydrate problems.

2. WAG Process Description A typical Water Alternating Gas (WAG) Project

A selected (typical) WAG project is described below: Reservoir studies have identified that an increased recovery of oil from the reservoir is probable using water alternating gas (WAG) injection process. The EOR project has been established to perform the necessary front-end engineering design for the new compression and gas distribution. A new gas compression facility will provide approximately 175 mmscfd of lean gas from the NGL unit and will be compressed to 460 Kg/cm^2 and distributed to six nominated gas injection wells.
The gas is compressed in a three-stages centrifugal compressor by a gas turbine with inter cooling between the stages. Gas flow to each well is controlled by flow meters flow control valves (sometimes referred to as chokes).
As gas injection occurs at high pressure and water injection at lower pressure the changeover system is to be carefully designed to avoid over pressuring the water system.

Gas Transmission

There are two basic configuration options for the gas injection flow line network.
The options considered are:

- Single (i.e. individual) flowlines to each well from a manifold located at the gas compression plant.
- A main header forming a "backbone", with a flow line to each well branching off this header.

2.1. Single Flow lines Option

Case description

Refer to Figure (4.1) for a sketch of this option. The flow from the compressor discharge at 460.6 Kg/cm2(45260 KPa) enters a manifold with six take-offs to the gas injection well 1 and the five WAG wells:

2.2. Header Option

Case description

Refer to Figure (4.2) for a sketch of this option. The flow from the compressor discharge at 460.6 Kg/cm^2g (45260 KPa) is routed down an 8-inch main header starting at the compression plant battery limit and running up to the furthest well, Well 66 Along the way, there are five take-offs to Wells 11,22, 33, 44, 55, unit it reaches Well 66, where the pig receiver serving the trunk line header is located. The flowline size reduces to 6-inch for the wellhead itself.

Investigation of Hydrate Formation for Selected WAG Project

Injection gas was used in this study. A commercial package software's (HYSYS) and PVT sim were utilized to determine the Hydrate Formation Conditions.

Problems Associated with WAG Process

WAG in this process water and gas are injected, the purpose of WAG injection is to improve oil recovery.
The major problems in the evaluation of WAG are:-

Estimation of Gas Hydrate Formation

For a given gas composition, the hydrate formation temperature can be determined at any given pressure.
The calculated hydrate forming temperature for gas with different composition, the hydrate forming temperatures have been calculated by using HYSYS and PVT sim software at given hydrate pressures, and the obtained results have been compared between them, and followed plotting each set of points which has the same composition in one Figure to show clearly the obtained results and how much are close together or far, as Figure (3.3).
Injection gas is to be injected into six wells. Two options are considered, single flow lines and common header. Stabilized gas injection conditions for the WAG injection wells are estimated to be as presented in tables (2.4) and (2.5). For each option, HYSYS simulation program was utilized to determine Hydrate formation temperature.
Tables (2.4) and (2.5) Presents summary of the obtained results hydrate formation temperature at operating conditions, injection pressure and injection temperature to any injection well for single flowlines and header option. Hydrates will form whenever gas temperature and pressure values plot to the left of the hydrate formation line for the subject gas, where the region of hydrate formation is clearly shown in the left side of the curve (high pressure, low temperature)

Table 2.1: Presents the details of piping, flow rate and pressures required for each well for single flowline

Wells	I Diameter	Length(Km)	Flow(MMscfd)	PressureKPa
MANIFOLD	8- inch	Nominal		45260
Well 1	4- inch	2.8	20	45000
Well 2	8- inch	4.5	60	45160
Well 3	6- inch	3.2	60	42410
Well 4	4- inch	10	35	42240
Well 5	6- inch	14	58	43920
Well 6	6-inch	16	38	44610

Table 2.2: Presents the details of piping, flow rate and pressures required for each well for Header option

Well		I Diameter	Length (Km)	Flow (MMscfd)
HEADER	8- inch	15		45260
Well 11	4- inch	2.0	20	40680
Well 22	8- inch	3.5	60	40300
Well 33	4- inch	0.5	60	40300
Well 44	4- inch	2.1	35	39200
Well 55	6- inch	1.5	58	40580
Well 66	6-inch	0.5	38	41370

Table 2.3: Composition of the injection gas

Component	Mol %	Mol wt	Liquid density kg/m^3
Nitrogen	0.935	28.014	
Methane	83.248	16.043	
Ethane	13.973	30.070	
Propane	1.593	44.097	
Iso-Butane	0.018	58.124	
n-Butane	0.184	58.124	
Iso-Pentane	0.028	72.151	
n-Pentane	0.018	72.151	
Hexane	0.004	86.178	663.9999
Heptane	0.0001	96.000	737.9999

Depressurization of Gas Injection System

Depressuring occurs following pressure equalization. Flaring will be required at the new WAG wellheads in order to burn hydrocarbon from venting of the wellhead or gas piping at shutdown, or when changing over from gas to water. For individual flow line each flow line can be depressurized individually back to the plant flare system rather than to the local burn pit. This will allow the entire piping volume of gas to be reduced from 44990 KPa to 4484 KPa in under 103 minutes and the lowest temperature envisaged is 262 K compare with hydrate formation temperature is 285.76 K.
For the Header cannot be depressurized without shutting down all the injection wells. This will allow the entire piping volume of gas to be reduced from 37980 KPa to 102 KPa in 295 minutes and the lowest temperature envisaged is 286.5 K compare with hydrate formation temperature is 226 K.
Formation of hydrates during depressurization is conditional on the presence of free water and dependent on the initial temperature and pressure. Figures 6 and 7 presents the lowest temperature during depressurization of wells for both individual flowlines and Header.

3. Results and Discussion

The calculated hydrate formation temperatures by both software (HYSYS and PVT sim) were in an excellent agreement. Figure (3.3) Shows minimum deviation between obtained results.
In this work, in order to check hydrate formation for two option individual flow lines and common header, the hydrate formation temperature will form for both options as noted from below tables. The reaching gas temperature to any injection well must be higher than hydrate formation temperature.
According to Figure (3.1) it noticed:

- Increase the gas temperature above 302.24 K will be hydrate disintegration.
- Decrease the pressure at operating temperature will be hydrate disintegration.

The lowest temperature during depressurization for individual flowlines option envisaged is 262 K compare with hydrate formation temperature is 285.76 K, when reduced pressure to 4484 KPa.
The lowest temperature for common header option during depressurization envisaged is 286.5 K compare with hydrate formation temperature is 226 K, when reduced pressure to atmospheric pressure. As can seen Figure (3.6) and (3.7).

Table 2.4: Individual flow lines

Well	T, K	P, (KPa)	H F T, K
1	307.43	44990	301.884
2	309.21	45160	301.911
3	310.45	42310	301.421
4	302.65	42150	301.392
5	297.26	43920	301.694
6	298.51	44600	301.817

Table 2.5: Common Header

Well	T, K	P, (KPa)	H F T, K
11	305.84	40780	301.148
22	306.67	40300	301.060
33	308.96	40300	301.060
44	306.62	38230	300.676
55	307.46	40580	301.110
66	308.91	41370	301.250

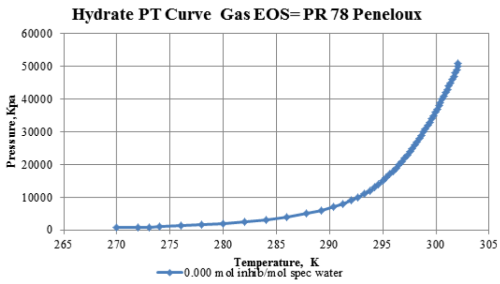

Figure 3.1: Pressure-Temperature Curve for Predicting Hydrate Formation

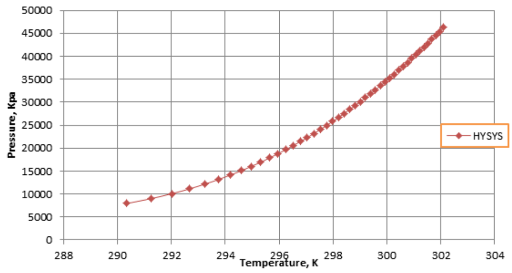

Figure 3.2: Pressure-Temperature Curve for Predicting Hydrate Formation

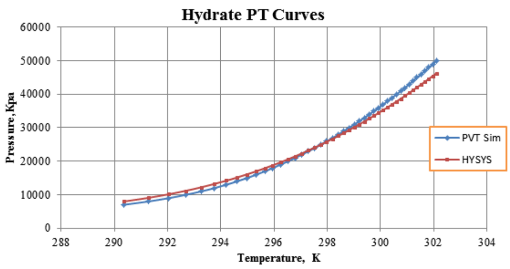

Figure 3.3: Compare of HYSYS and PVT sim software of hydrate-formation temperature

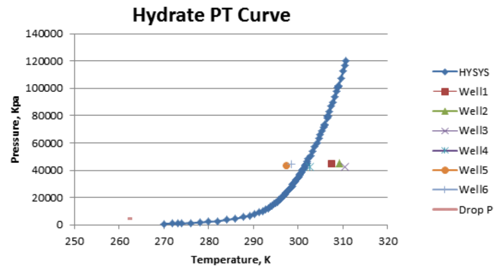

Figure 3.4: Pressure-Temperature Curve for Predicting Hydrate Formation, Illustrates check Hydrate Formation on pipelines for Individual flow lines

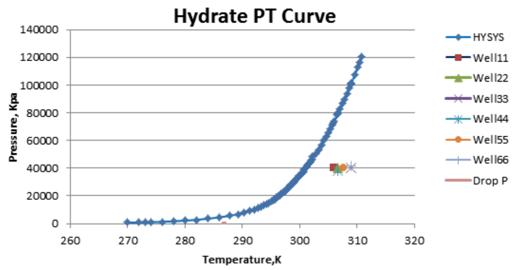

Figure 3.5: Pressure-Temperature Curve for Predicting Hydrate Formation, Illustrates check Hydrate Formation on pipelines for Common Header

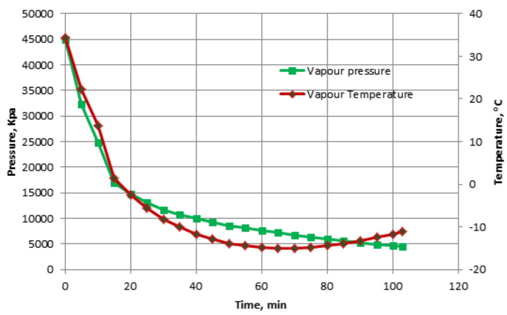

Figure 3.6: Depressurization of Gas Injection System

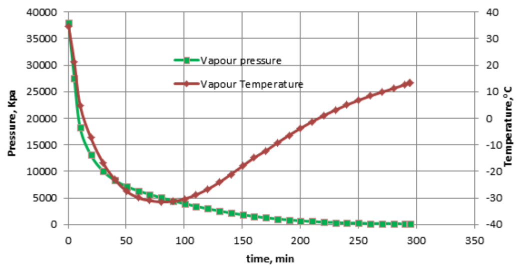

Figure 3.7: Depressurization of Gas Injection System

4. Conclusion

For each option, PVT sim and HYSYS simulation program were utilized to determine Hydrate formation temperature.
Figure (3.3) shows good agreement between results obtained using PVT sim program and HYSYS, except a little deviation. It can be concluded as showing on Figure (3.4) at these conditions during normal operation for individual flow lines option to any injection well from table (2.4), some these points or values are under down the hydrate curve including wells 1,2,3 and well 4 that mean where no hydrate formation in injection wells, but other points are well 5 and well 6 these points above the hydrate curve that mean there is hydrate formation in injection wells.
As showing on Figure (3.5) for common header option at these conditions during normal operation to any injection well from table (2.5), these points or values are full in the right side within the non hydrate region under down the hydrate curve where no hydrate formation in injection wells for this option.
It can be concluded from figure (3.4) at these conditions during depressurization for individual flow lines option that formation of hydrates will not be expected, as showing on Figure (3.5) when reduced to atmospheric pressure this point is full in the right side within the non hydrate region under down the curve where no hydrate formation during depressurization.

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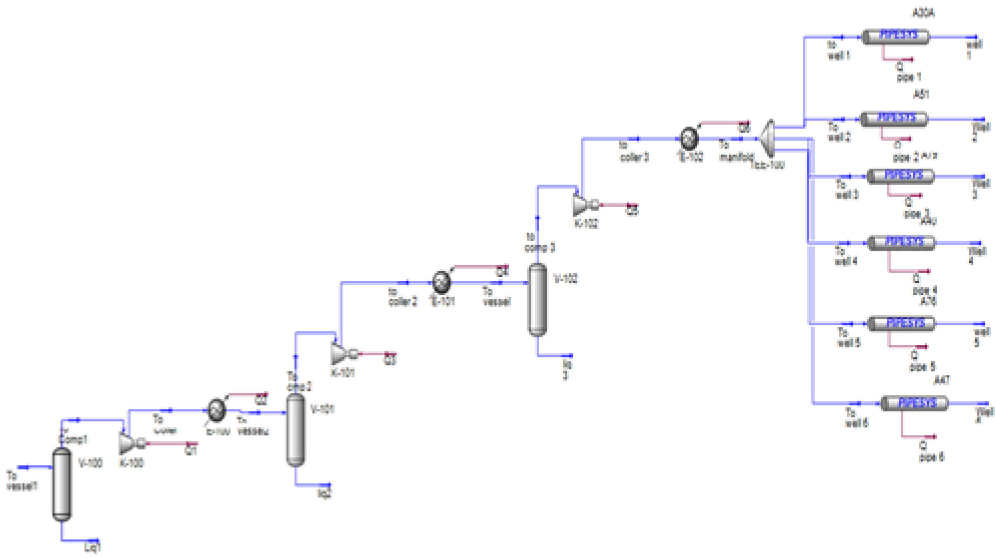

Figure 4.1: Process Sketch Single Flow Lines and Header Option

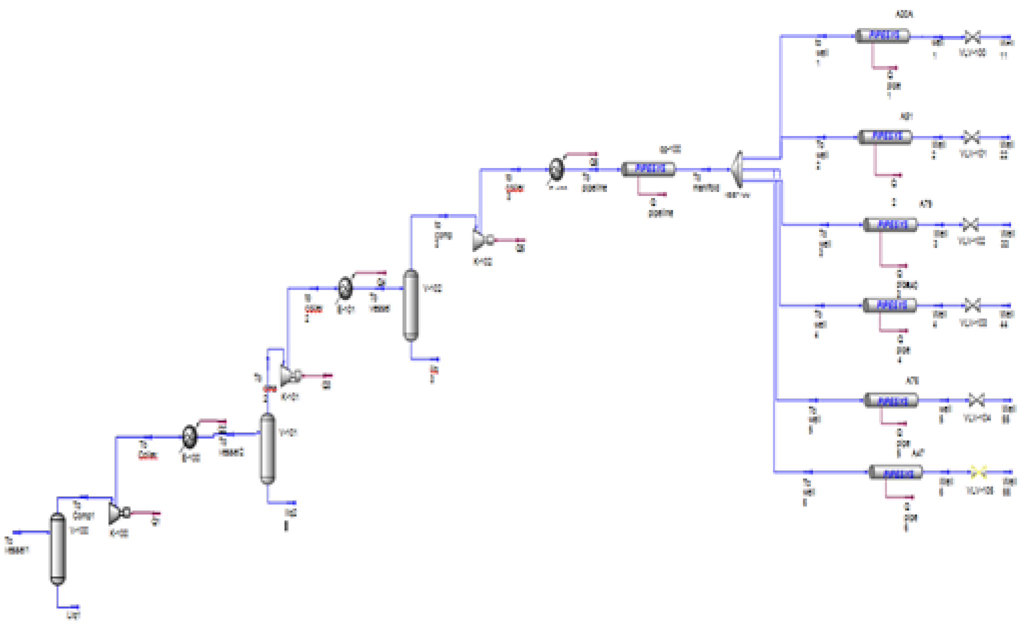

Figure 4.2: Process Sketch Single Flow Lines and Header Option