Petro sudah di index oleh Google Scholar dan ipi

DAFTAR ISI

LIQUID HOLDUP MANAGEMENT BY PREDICTING STEADY STATE TURNDOWN RATE IN WET GAS PIPELINE NETWORK

Kartika Fajarwati Hartono[1], M. Taufiq Fatthadin[2], Reno Pratiwi[3]

[1, 2, 3]Department of Petroleum Engineering, Faculty Technology of Earth and Energy, Universitas Trisakti[1], Jakarta 11440, Indonesia
[1]*Email: kartika@trisakti.ac.id, Telp : 021-5663232 ext 8509*

ABSTRACT

Now days, one of the greatest challenges in gas development is transport the fluid especially multiphase fluid to long distances and multiphase pipeline to sell point. Yet, a challenge to transport multiphase fluid is how to operate the systemsin operating a long distance, large diameter, and multiphase pipeline.The operating system include how to manage high liquid holdup, mainly built during low production rate (turn down rate) periods especially during transient operations such as restart and ramp-up, so that liquid surge arriving onshore will not exceed the liquid handling capacity of the slug catcher. The objective of this research is to predict liquid trapped in pipeline network by analysis turn down rate in order to determine minimal gas production rate for stable operation. This research was carried out by two steps: Simulation Approach and Optimization Techniques. Simulation approach include define fluid composition and built pipeline network configuration while optimization technique include conduct scenario for turn down rate. The fluid composition from wellhead to manifold is wet gas. First scenario and Second scenario of turndown rate yield minimum gas rate for stable operation. The pipeline has to be operated above 600 MMSCFD from peak gas production rate is 1200 MMSCFD (A-Manifold Mainline) and 60 MMSCFD from peak gas production rate is 150 MMSCFD for D-Manifold Mainline.

Keywords: Multiphase pipeline, pipeline network, liquid hold up, turndown rate

1. INTRODUCTION

In the gas transportation operation using long and large diameter pipeline, it is possible for liquid to appear inside of pipeline, even though the gas is single-phase. This phenomena happened when the pressure and temperature changes cross the two-phase region of the phase envelope such that the system changes from single-phase to two-phase [2]. As the system enters the two-phase region, mass transfer takes place from the gas phase to the liquid phase. This mass transfer causes condensation and gives rise to two-phase flow in the pipeline.

The old gas/condensate development had a process facility close to field and the fluids would be exported through a single-phase gas line and single phase liquid line. This process involved expensive process facilities at remote locations and multiple pipelines. Now days, one of the greatest challenges in gas development is transport the fluid especially multiphase fluid to long distances and multiphase pipeline to sell point [1]. Yet, a challenge to transport multiphase fluid is how to operate the systemsin operating a long distance, large diameter, and multiphase pipeline.The operating system include how to manage high liquid holdup, mainly built during low production rate (turn down rate) periods especially during transient operations such as restart and ramp-up, so that liquid surge arriving onshore will not exceed the liquid handling capacity of the slug catcher [3]. Therefore, it is very important to analysis and study about liquid condensation in multiphase gas/condensate especially for pipeline network in order to stability of operations.

The objective of this research is to predict liquid trapped in pipeline network by analysis turn down rate in order to determine minimal gas production rate for stable operation.

2. PROBLEMS STATEMENT

One of the biggestchallenges in operating a long distance, large diameter, multiphase pipeline system is to manage high liquid holdup, especially during low production rate operation [1]. The problem is how to operate the system safely and prevent flooding in arriving onshore facility by estimating liquid content trapped in pipeline with lower pressure drop.

2.1 Liquid Holdup
Generally, liquid holdup will increase as gas production rate decreases. This research was conducted how to manage liquid holdup occurred during low production rate operation [3].

2.2 Multiphase Fluid
The fluid system that used to simulate in this research is wet gas as seen as in phase envelope/phase diagram in figure 2. All these phases needed to be analyzed separately to better predict liquid holdup behavior. Due to density and viscosity differences between condensate and water, these two behaviors of fluid phases are different especially during unsteady state period. Defining the true operating envelope of the pipeline is a key component to the operability of the system [2].

3. METHODS
This research was carried out by two steps: (1) simulation approach, and (2)optimization technique.Data used as input in the simulation include pipeline network configuration, pipeline elevation, fluid composition, inlet temperature, pressure on the arrival manifold, ambient temperature, and overall heat transfer. The pipeline consists of two main line; there are A-Manifold line with inside diameter (40 in), 54 km length of pipe and D-Manifold line with inside diameter (20 in), 15 km length of pipe. The configuration of simplified pipeline network model used in this simulation is shown in figure 1.

3.1 Simulation Approach
Simulation approach in this research was divided into two simulations. First simulation was to define field oil composition and yield phase envelope/PVT diagram of fluid composition using PVT simulation software. Phase envelope/PVT diagram of field fluid composition can be seen in figure 2. Second simulation was to determine the minimum flow rate for stable operation (minimum liquid content trapped in pipeline with lower pressure drop) from turn down rate. These simulations were performed for all cases in this research using transient multiphase simulation software.

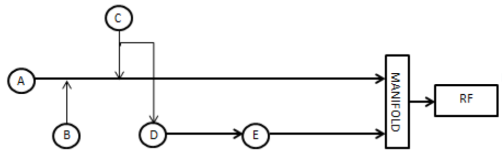

Figure 1 Simplified Configuration Pipeline Network

3.2 Optimization Technique
The optimization technique was conduct to turn down rate scenarios/cases in order to determine the minimum flow rate for stable operation by estimating minimum liquid content trapped in pipeline with lower pressure drop. There are two cases for determining the turndown rate. The first case was simulated several different inlet gas production rates alongA-Manifoldpipeline (50 km; 40 in) from A platform while the other sources (B and C) were in constant nominal flow rate. The second case was simulated different inlet flow rate along D-Manifold (14 km; 20 in) line from D platform while the other sources Ewas in constant nominal flow rate.The nominal flow rate from each source/platform and turndown rate scenarios for first case and second case was tabulated in table 1, table 2, and table 3, respectively.

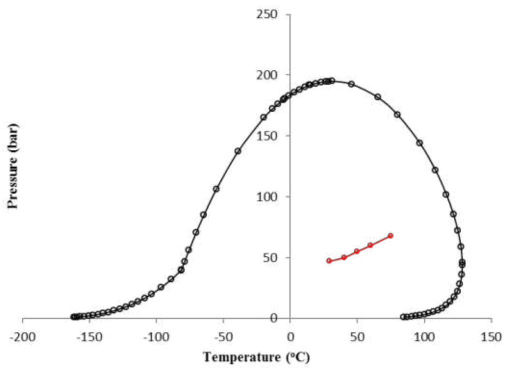

Figure 2 Phase envelope and operating condition of mixing fluid composition

Table 1 Nominal Gas Production Rate each Source/Platform

Source/ Platform	Nominal Gas Rate (MMSCFD)	Nominal Peak Gas Rate (MMSCFD)
A	750	1200
B	20	60
C	130	190
D	90	150
E	130	190

Table 2 First Case Steady State Turndown Rate

Turn down Scenario	Gas Rate A-Manifold (40 in), MMSCFD			D-Manifold (20 in), MMSCFD	
	A	B	C	D	E
1	750	20	130	150	130
2	750	20	130	120	130
3	750	20	130	100	130
4	750	20	130	85	130
5	750	20	130	60	130
6	750	20	130	40	130
7	750	20	130	20	130
8	750	20	130	-	130

Table 3 Second Case Steady State Turndown Rate

Turn down Scenario	Gas Rate A-Manifold (40 in), MMSCFD			D-Manifold (20 in), MMSCFD	
	A	B	C	D	E
1	1200	20	130	90	130
2	1000	20	130	90	130
3	850	20	130	90	130
4	770	20	130	90	130
5	600	20	130	90	130
6	500	20	130	90	130
7	400	20	130	90	130
8	300	20	130	90	130

4. RESULTS AND DISCUSSION

4.1 Analysis of Field Fluid Mixing Composition

Analysis of fluid composition were carried out to find information about fluid properties and phase of fluid which affecting the problems caused by fluid production from reservoir and transported to processing through long and large diameter pipeline. Fluid composition in this field that used in this study is wet gas. Phase diagram/phase envelope of fluid mixing composition can be seen in figure 2. From figure 2, the red line inside phase envelope shows operating condition of fluid from wellhead platform transported to manifold/receiving facility. The operating condition (red line inside phase envelope) shows that the fluid in two phase region. It means that the reservoir fluid is wet gas. The phase envelope was made by PVT Simulation using correlation *Soave-Redlich-Kwong (SRK)* Equation of State (EoS). From figure 2, it can be seen that the wet gas compositions are rich content of C_2 + C_{6+}. Fluid of wet gas often generate operating problems especially flow assurance problems. So that, identification of PVT behavior of reservoir fluid is very important in order to create the proper design of pipeline network and reduce operating problems.

4.2 Modeling of Pipeline Network Configuration

The simplified pipeline network configuration for this study can be seen in figure 1. Pipeline was divided into two main line, A-Manifold line (40 in) and D-Manifold line (20 in). The fluid flows into main line itself, it comes from wellhead/platform, A, B, C, D, and E. Field topography affect the elevation and undulation of pipeline network from wellhead to manifold/receiving facility. Beside reservoir fluid composition, elevation and undulation of pipeline can affect the formation of liquid hold up inside the pipeline. Wellhead A to manifold is a long pipe (50 km) and large diameter (40 in), while E to Manifold is long pipe also (14 km) and large diameter (20 in).

4.3 Steady State Turndown First Scenario

Turn down rate scenarios/cases were carried out to determine the minimum flow rate for stable operation by estimating minimum liquid content trapped in pipeline with lower pressure drop. First scenario of turndown rate was conducted to several different inlet gas production rates alongA-Manifoldpipeline (50 km; 40 in) from A platform while the other sources (B and C) were in constant nominal flow rate. The first scenario was simulating several different inlet gas production rates for A-Manifold main line: 1200, 1000, 850, 770, 600, 500, 400, and 300 MMSCFD while the other wellheadwas in constant nominal flow rate. The gas production rate data for first scenario can be tabulated in table 2. First scenario yield total liquid volume occurred in pipeline (A-Manifold) and pressure drop.

Turndown rate was performed by drawing pressure drop and liquid volume function gas production rate. Pressure drop and liquid volume along the pipeline is obtained by steady state simulation in different inlet flow rate for each scenario. Profile of total liquid volume and pressure drop occurred in A-Manifold can be seen in figure 3. Figure 3 presents to total liquid content into the line and the pressure drop from wellhead to manifold. A low flow rate, the liquid tends to accumulate in uphill section as the gas cannot carry out the liquid. When the flow increases, the liquid is better transported and the total liquid content decreases. From figure 3, it can be seen that for stability and liquid accumulation reason, the pipeline has to be operated above 600 MMSCFD from peak gas production rate is 1200 MMSCFD.

4.4 Steady State Turndown Second Scenario

Second scenario of turndown rate was conducted to several different inlet gas production rates alongD-Manifoldpipeline (14 km; 20 in) from D wellhead platform while the other source (E) was in constant nominal flow rate. Thisscenario was simulating several different inlet gas production rates for D-Manifold main line:150, 120, 100, 85, 60, 40, 20

MMSCFD while the other wellhead(E) was in constant nominal flow rate, 130 MMSCFD. The gas production rate data for second scenario can be tabulated in table 3.

Profile of total liquid volume and pressure drop occurred in A-Manifold can be seen in figure 4. Figure 4 presents the same profile to total liquid content into the line and the pressure drop from wellhead (platform D) to manifold. From figure 4, it can be seen that minimal flow gas rate for stable operation is above 60 MMSCFD from peak gas production rate is 150 MMSCFD.

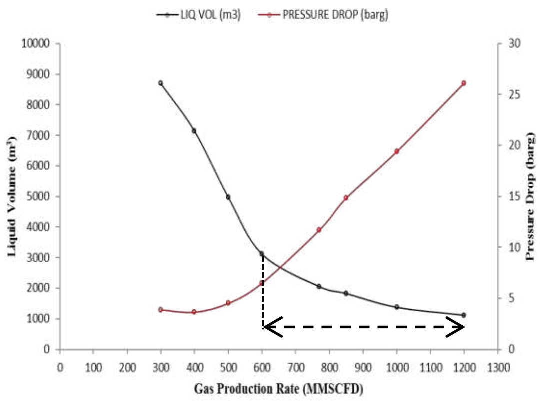

Figure 3 Steady State Turndown Rate A-Manifold (First Scenario)

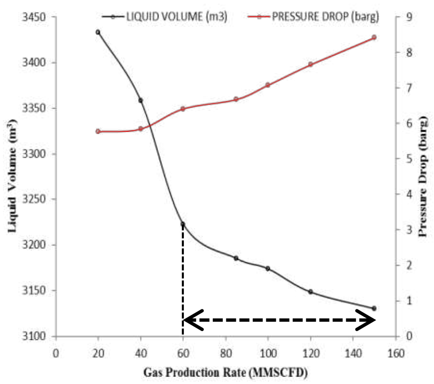

Figure 4 Steady State Turndown Rate D-Manifold (Second Scenario)

5. CONCLUSION AND RECOMMENDATION

Turndown rate was performed by drawing pressure drop and liquid volume function gas production rate. Pressure drop and liquid volume along the pipeline is obtained by steady state simulation in different inlet flow rate for each scenario. A low flow rate, the liquid tends to accumulate in uphill section as the gas cannot carry out the liquid. When the flow increases, the liquid is better transported and the total liquid content decreases. For steady state turndown rate first scenario, it can be concluded that the pipeline has to be operated above 600 MMSCFD from peak gas production rate is 1200 MMSCFD. While for second scenario, minimal flow rate.

6. ACKNOWLEDGEMENTS

The authors express gratitude to Faculty of Earth and Energy, Petroleum Engineering partment, Trisakti University for opportunity to conduct and write this research.

We are also thankful to Mr. Utjok W.Siagian, Ph.D (Petroleum Department ITB) as advisor who give a lot of support and facility to carry out this research.

7. REFFERENCES

- Harun, A.F.,Choate,T.G.A., Cochran, S.W.,INTEC Engineering. 2003.Liquid Inventory Management Issues in a Dual Large Diameter Long-Distance Subsea Wet Gas Pipeline System. Society of Petroleum Engineering, SPE 84507 presented at SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA. 5-8 October 2003.

- Golczynski, T.S.and Multiphase Solution Inc. 2003. Defining Operating Envelopes for Multiphase Pipelines – A Flow Assurance Approach. Pipeline Simulation Interest Group. PSIG 03B4. Presented at PSIG Annual Meeting held in Bern, Switzerland. 15-17 October 2003.

- Eidsmoen, H., Roberts, I., Scandpower Petroleum TechnologyInc. 2005. Issues Relating to Proper Modelling of the Profile of Long Gas Condensate Pipeline. 2005. Pipeline Simulation Interest Group. Presented at PSIG Annual Meeting held in San Antorio, Texas 7-9 November 2005.

- El-Chun,Z. 1990. Gas-Liquid Two-Phase Flow in Pipelines. SPE 20645. Presented at 65th Annual Technical Conference and Exhibition held in New Orleans, LA. 23-26 September 1990.

- Norris, H.L., Rydahl, A. 2003. Onshore Gas Condensate Pipeline Transient Hydraulic. Canadian International Petroleum Conference. Paper 2003-141.Presented at Petroleum Society's Canadian International Petroleum Conference, Calgary, Alberta, Canada. 10-12 June 2003.

- Gregory, G.A. and Aziz, K. 1975. Design of Pipelines for Multiphase (Gas-Condensate) Flow. The Journal of Canadian Petroleum.

- Lima, P.C.R., Yeung, H. 1998. Modelling of Transient Two-Phase Flow Operations and Offshore Pigging. SPE 49208. Presented at SPE Annual technical Conference and Exhibition held in New Orleans, Lousiana. 27-30 September 1998.

- Osman,El-Sayed. 2004. Artificial Neural Network Models for Identifying Flow Regimes and Predicting Liquid Holdup in Horizontal Multiphase Flow. SPE 68219.Presented at the 2001 SPE Middle East Oil Show, Bahrain. 17-20 March 2003.

- Yisheng, F., Baozhu,L., Zhidao,S., and Yuxin, Z. 1998. Condensate Gas Phase Behavior and Development. SPE 50925. Presented at SPE International Conference and Exhibition in China held Beijing, 2-5 November 1998.