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Hydraulic, Modelling and Hydrate Inhibition for the New Gas Wellhead Flowlines in Gas Project-Part 1

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Abstract

Multiphase flow occurs frequently in the natural gas gathering and transmission pipelines for both onshore and offshore operations. Literature and experimental investigations reveal that dispersed droplet and stratified flow patterns are obtained when gas and small quantities of liquids flow concurrently in a pipe. Eight new gas wells were discovered and these wells need be connected with the existing process facilities in the gas project. Different reservoir layers exist in each well and contain fluid of differing composition and CGR. Lean and rich gas compositions from each layer may mix in the well but there is no facility in the well completion to control mixing. Steady state thermal hydraulic models in PIPESIM software and transient model in OLGA software at richest gas and leanest gas production from each gas well in the gas project were built to determine the suitable line sizes for all the new gas wellhead flowlines based on the normal production and turndown conditions. This includes analysis of liquids handling issues, velocity limits for effective corrosion inhibition and erosional velocity limits. Also, establish operating envelopes in terms of pressure, temperature, velocity, liquid holdup and other key thermal hydraulic variables for all flowlines. Finally assess the potential for hydrate formation in flowlines to be checked and options for hydrate mitigation identified. It can be concluded that the size for the wellhead flowline for gas well &1 is 6 while 4'' or 6'' line size is feasible for gas well 2,3 and 4, the flow regime for the all gas wells is Stratified Wavy. Hydrate inhibitor is required for the all gas wells and the injection rate is varying between 2.2 to 8.8 SCMD.A comparison was carried out to benchmark the steady state pressure and temperature predictions obtained using dynamic 'OLGA' modelling against corresponding estimates obtained from the steady state 'PIPESIM' modelling. The results obtained from the two software are very close.

Keywords: *Wellhead flowline; OLGA; PIPESIM; FWHP; FWHT; GOR; Erosion velocity; CPF.*

1. Introduction

Natural gas is becoming one of the most widely used sources of energy in the world due to its environmentally friendly characteristic. Natural gas consists mainly of methane , ethane, propane & butane and heavier hydrocarbons (C_{5+}) also known as condensates and all hydrocarbon components other than methane are known as natural gas liquids. In addition to hydrocarbon components there is gas impurities as carbon dioxide, nitrogen, hydrogen sulphide and water vapor [1-3]. The demand of natural gas in recent decade has been dramatic. In fact, natural gas poses a huge rule in the recent world economy and development [4].

Since 1995, the consumption and production of natural gas throughout world has been steadily growing from nearly 1600 billion cubic meters to closely 3200 billion cubic meters in 2011. Moreover, it is estimated that natural gas consumption rate will continue to grow geometrically to nearly 4.33 trillion cubic meters in 2035, with an average growth rate of about 1.6% per year. Production of natural gas increased by 7.3% in 2011 in the world, the largest increase since 1984 [5-7].

In the oil and gas industry, the flowlines are pipelines that connect a single wellhead to a manifold or process equipment. In a larger well field, multiple flowlines may connect individual

wells to a manifold. Then a gathering line may transfer the flow from the manifold to a pre-process stage or to a transportation facility or vessel [8-9].
The flowlines may be in a land or subsea well field and may be buried or at grade on the surface of land or seafloor. Gathering lines are like flowlines but collect the flow from multiple flowlines . Flowlines are located at the well site tied to a specific well [10-11].
Oil and gas production are gas-liquid multiphase flow rather than single-phase or liquid flow . Both transient and steady state flow needs to be simulated by a proper software to design such a system and safety operate it [12-13].

The steady state models should only be used for steady state events, transient flow models would be required to simulate transient events, such as flow ramp-up, pipeline pigging, and terrain slugging [14]. Danielson *et al.* discussed in more detail where the transient models should be used, and where steady state models may suffice [15].

Over the years, multiphase flow inside a pipe has been widely studied and correlations have been proposed to model the multiphase flow phenomena. These correlations include Beggs & Brill [16], Oliemans *et al.* [17], Eaton *et al.* [18], Flanigan *et al.* [19]. These correlations have been used for describing steady state multiphase flow. Sheael has compared several empirical correlations, mechanistic methods, and dynamic simulation results with experimental data [20].

The main objective of this study is to connected the eight gas wells which were discovered in the one of the north African countries with the existing gas and condensate process facilities in this area. Steady state thermal hydraulic models in PIPESIM and transient model in OLGA at richest gas and leanest gas production from each gas well were built to determine the suitable line sizes for all gas wellhead flowlines based on normal production and turndown conditions for the new gas project to build the optimum network required to transfer the natural gas from these new gas wells to the central process facilities in the gas project . This includes analysis of liquids handling issues, velocity limits for effective corrosion inhibition and erosional velocity limits. Also, establish operating envelopes in terms of pressure, temperature, velocity, liquid holdup, and other key thermal-hydraulic variables for all flowlines. Assess the potential for hydrate formation in flowlines to be checked and options for hydrate mitigation identified.

2. Gas wells data

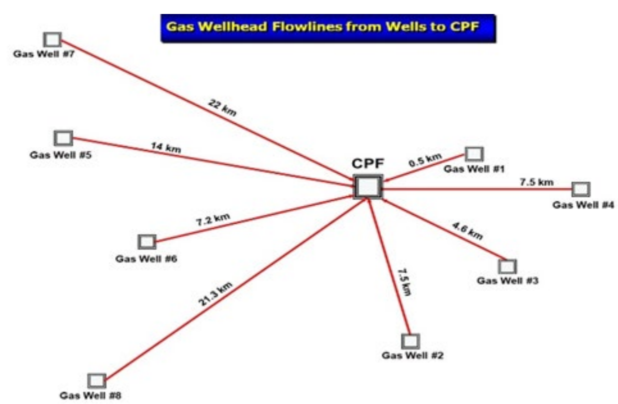

Figure 1. Gas Wellhead Flowlines from Wells to CPF.

Figure 1 demonstrates the new gas wells and the length for each wellhead gas flow line. A gas wellhead pressure of 267 bara, gas 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 for the simulation to identify the exact size for each gas wellhead flowline. Also, the turndown flowrate for the lean and rich compositions were identified. The maximum water cut for each gas well is 10 % based on the confirmation received from the reservoir department

Design gas flow rate of each well:	0.425 MSCMD (15 MMSCFD).
Turn down flow – lean gas:	0.1 MSCMD (3.5 MMSCFD).
Turn down flow – rich gas:	0.21 MSCMD (7.5 MMSCFD).
Maximum water cut of each well:	10 % of total liquids.

It is assumed that the all the gas wells have the same design flowrate which is 0.425 MSCMD. A range of compositions of different condensate gas ratios (CGRs) can be delivered by each well depending on the layer being produced. The richest and leanest gas condensate ratio from each well is presented in the Table 1. Different reservoir layers exist in each well and contain fluid of differing composition and CGR. Lean and rich gas compositions from each layer may mix in the well but there is no facility in the well completion to control mixing. Each flowline shall therefore be capable of operating with the full range of relevant fluid compositions from the leanest to the richest.

Table 1. Design production flowrates

Well	Simulation case	CGR SCM/MSCM	Gas flowrate MSCMD	Condensate flowrate SCMD	Water flowrate SCMD
Gas well #1	Richest case (volatile oil)	2115	0.425	899	300
	Richest case (excluding volatile oil)	867.4	0.425	367	123
	Leanest case	149	0.425	63	21
Gas well #2	Richest case	282	0.425	120	40
	Leanest case	28	0.425	12	4
Gas well #3	-	37	0.425	16	5
Gas well #4	Richest case	451	0.425	192	64
	Leanest case	2	0.425	0.9	0.3

2.1. Gas well fluid compositions

Fluid compositions are based on the latest zone compositions based on the data received from the reservoir department. Each gas well has different compositions layers varying between the lean and rich compositions. Table 2 illustrates the well compositions.

Table 2. Well compositions %mol.

Component	Lean	Rich	Component	Lean	Rich
Nitrogen	0.3230	0.438	PC6A*	0.2180	0.036
CO_2	2.5102	2.187	PS1A*	0.5500	0.110
Methane	86.5701	82.076	PS2A*	0.1950	0.064
Ethane	5.2734	6.689	PS3A*	0.1160	0.041
Propane	2.3702	3.166	PS4A*	0.0490	0.022
i-Butane	0.4940	0.691	PS5A*	0.0090	0.006
n-Butane	0.6650	0.887	C_{6+}	0.0700	2.783
i-Pentane	0.3590	0.504	H_2O	0.0000	0.000
n-Pentane	0.2280	0.299			

3. Design criteria of the gas wellhead flowlines

The design criteria of the gas wellhead flowlines in the gas project are as follow: - Maximum arrival pressure at the central process facilities (CPF) of the gas project is 55 barg. All materials assessments are to be based on the specified design life of 25 years. All corrosion allowances or materials will be recommended to give a reasonable expectation of the wellhead flowlines components lasting for this design life taking into account the range of design, operating, transient and credible upset conditions over the field life.

Materials selection for new gas wellhead flowlines from the wellhead up to the choke valve is recommended to be Duplex Stainless Steel (DSS) grade UNS S32750 while the material selection for the new gas wellhead flowlines downstream the choke valve to the production manifold is carbon steel with nominal corrosion allowance of 3 mm

The gas wellhead flowlines for the new eight gas wells should be sized primarily on the basis of flow velocity. Experience has shown that loss of wall thickness occurs by a process of erosion/corrosion. This process is accelerated by high fluid velocities, presence of sand, corrosive contaminants such as CO_2 and H_2S, and fittings which disturb the flow path such as elbows.

3.1. Mathematical models

The American Petroleum Institute’s Recommended Practice 14E (API RP14E) is an industry guideline for the treatment of erosive services and suggests limiting flow velocity for the single flow and multiphase flow in the pipeline [23].

3.1.1. Vapor phase flow in the pipeline

The maximum velocity in the single gas phase pipeline should not exceed above 18 meter /second to avoid noise problem in the pipelines.

The general pressure drop equation for the single phase pipeline is as follow:

$$P1^2P2^2 = 25.2SQ_g^2ZT_1f/d^5 \tag{1}$$

The gas velocity is calculated as follow:

$$V_g = 60.ZQ_gT/d21P \tag{2}$$

3.1.2. Liquid Gas flow in the pipeline

The mixture velocity should be kept below the so-called "erosional velocity" obtained from the following empirical equation

$$V_e = \frac{c}{\sqrt{\rho_m}} \tag{3}$$

Erosion velocity checks to be based on standard API RP 14E [API 14 E,2019] 'C' factor of 100 ((ft/s)/(lb/ft^3))$^{1/2}$ for carbon steel shall be used in the calculations . This assumes minimum solids loading not exceeding 0.1 lb/MMscfd. To satisfy this criterion, the erosional velocity ratio (EVR) should be below 1.0. For lines with continuous flow, the velocity shall not exceed 90% of the erosional velocity calculated by the method of API RP 14E. The minimum velocity in flowlines at the design flowrate should be >3 m/s to minimize slugging in the flowlines. The velocity shall be enough to ensure good mixing of corrosion inhibitor

The density of the gas/ liquid mixture is calculated with the following equation:

$$\rho_m = \frac{12409.S_lP+2.7.RS_gP}{198.7P+RTZ} \tag{4}$$

The minimum velocity in the gas / liquid pipeline is 3 meter / second to minimize slugging in the downstream equipment

Once the erosion velocity is known, the minimum cross sectional area required to avoid fluid erosion may be determined from the following derived equation:

$$A = \frac{9.35+\frac{ZRT}{21.25\,P}}{V_e} \tag{5}$$

The pressure drop in the gas / liquid lines is calculated with the following equation

$$\Delta P = \frac{0.00033.f.W^2}{d_i^5.\rho_m} \tag{6}$$

The prediction of hydrate formation temperatures shall include a 2ºC design margin. Typically, a 5ºC margin would be used. Where hydrate formation conditions and/or low entry temperatures are predicted for a flowline, mitigation methods shall be proposed including, e.g., an inline heater to ensure that the flowline operates outside the hydrate formation region and above the flowline minimum design metal temperature. In addition, hydrate inhibition of the flowline may be required (e.g., using methanol or LDHI/AA).

4. Simulation basis

Eight new gas wells were discovered and these wells need be connected with the existing process facilities in the gas project. Different reservoir layers exist in each well and contain fluid of differing composition and CGR. Lean and rich gas compositions from each layer may mix in the well but there is no facility in the well completion to control mixing.

The composition reaching the CPF, however, will be a mixture of production from each gas well. There are 8 wells with different compositions in the gas project. Each gas well has different compositions from differ layers (lean and rich layers). The size of each gas wellhead flowline needs to be identified by the available simulation software.

The steady-state pipeline simulator was used for the modelling wellhead flowlines of the gas project for the base case (rich and lean) and turndown cases, the results obtained from PIPESIM 2019 [21]. OLGA was used for transient modelling of the wellhead flowlines of the gas project [22]. Compositional method based upon Peng Robinson equation of state is to be used to characterize the gas/condensate fluid.

OLGA 2019 multiphase flow correlation is to be used for multiphase flow simulation. The fluid files used for the OLGA simulations were generated using PVTSIM with the Peng Robinson Equation of state used to create the fluid properties using the relevant fluid composition and pseudo properties. PIPESIM 2019 was used to get the blended compositions from the lean and reach layer for each well. The mix of the production from each well shall be selected so as not to exceed the liquid handling capacity of the CPF, i.e., 10000 SBPD of condensate product whilst maintaining a maximum production of 2.7 MSCMD export gas.

4.1. Simulation cases

To cover all possible flow situations in the lines, 6 simulation cases were initially run for each flowline using PIPESIM 2019. These cases are summarized in table 3. Base case for the lean and rich gas compositions were identified for each gas well and also, the turndown & depletion case for the lean and rich gas compositions. Table 3 depicts the simulation cases conducted by PIPESIM and OLGA simulation software.

Table 3. Simulation cases for gas wellhead flowlines

Case No.	Description	CPF arrival pressure (bara)	Wellhead temperature (ºC)	Flowrate per well (MSCMD)	Composition
1	Base Case-rich Gas	50-60	50	0.425	Rich
2	Base Case-lean Gas	50-60	50	0.425	Lean
3	Turndown Case 1	50-60	24	0.10	Lean
4	Turndown Case 2	50-60	43	0.213	Rich
5	Depletion Case 1	25	20	0.14	Lean
6	Depletion Case 2	10	20	0.14	Lean

5. Results and discussions

5.1. Steady state results

PIPESIM 2019 was used to simulate the new gas wellhead flowlines of the gas project at different compositions (lean and rich compositions) .

5.1.1. Gas Well #1

Tables 4 & 5 reveal the results obtained from PIPESIM simulation software for gas well #1 at different compositions from different layers of the gas well #1 (rich and lean gas compositions). From Tables 4 &5, it can be noticed the following:

5.1.1.1. Base case composition

Based on the 4” wellhead flowline for gas well #1 , the mixture velocity at line outlet is 11.9 m /s, maximum EVR is 1.3 for volatile oil production; and 9.9 m /s, and maximum EVR is 0.9 for rich condensate gas production. Hence, a 4” line size is not considered feasible for gas well #1 flowline based on standard API 14E. 4’’ size cannot be used for gas well #1. Based on 6” flowline and volatile oil production from the gas well # 1 as pr its reservoir compositions, the mixture outlet velocity is 5 m/s with maximum EVR of 0.6. The fluid velocity is higher than normal liquid velocity in the pipeline (4 m/s). However, for a short length pipeline like gas well# 1, it is considered feasible. 6’’ pipeline size is accepted for this case

Based on 6” flowline and rich condensate gas production from the well, mixture outlet velocity is 4.3 m/s with maximum EVR of 0.4. The fluid velocity is marginally higher than normal liquid velocity in the line (4 m/s). However, for a short length flowline like gas well # 1, it is considered feasible. Based on 6” flowline and lean gas production, temperature drop across the choke is 40ºC and pipeline arrival temperature is 10ºC, which is below hydrate formation temperature of 17ºC; hydrate will form, and hydrate inhibitor injection will be required for base case. The maximum calculated methanol inhibitor rate required to overcome the hydrate problem in the wellhead flowline of gas well # 1 is 4.8 SCMD for the base case.

5.1.1.2. Depletion case composition

For depletion case, the minimum temperature in the line is 19ºC, which is above the hydrate formation temperature of 5ºC. Hence, there is no risk of hydrate formation in the line.

5.1.1.3. Turndown case composition

For turndown production flowrate of 0.1 MSCMD of lean gas, temperature drops to -19ºC downstream the choke valve, which is below carbon steel minimum design temperature. This is also below hydrate formation temperature of 17ºC, hence there will be the risk of hydrate in the line for the turndown case. Hydrate inhibition by methanol and/or wellhead heating will be required for the low flowing temperature cases.

For turndown production flowrate of 0.21 MSCMD of volatile oil, liquid holdup volume % in the line is at its maximum which is 38 % and total liquid holdup volume is 1.3 m^3. For turndown production flowrate of 0.21 MSCMD of rich condensate gas, the predicted liquid holdup volume % in the line is at its maximum which is 26 % and total liquid holdup volume is 0.9 m^3. Figure 2 reveals the temperature profile for the gas well #1 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #1.

Figure 3 illustrate the pressure profile for the gas well #1 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #1. It can be noticed that the variation of the temperature and the pressure across the wellhead flowlines is neglected because the total length of the wellhead flowline of gas well#1 is not long (500 meter only) and the elevation of the line is zero.

Table 4. Steady state hydraulic results for Gas Well #1 Flowline (including richest gas, volatile oil)

Hydrate Temp (Inlet), ºC	Hydrate Temp, (Outlet) ºC	Summer /Winter	Case	Fluid	CGR, SCM / MSCM	Condensate Sm^3/d	Water, Sm^3/d	Methanol, Sm^3/d	Gas Flowrate, MSCMD
18	18	S	Base Case	Rich	2115	898.9	299.6	0.0	0.425
18	18	S	Base Case	Rich	2115	898.9	299.6	0.0	0.425
18	18	W	Base Case	Rich	2115	898.9	299.6	0.0	0.425
18	18	W	Base Case	Rich	2115	898.9	299.6	0.0	0.425
17	17	W	Base Case	Lean	149	63.3	21.1	4.9	0.425
17	17	W	Base Case	Lean	149	63.3	21.1	4.8	0.425
12	12	W	Depletion-25	Lean	149	20.9	7.0	0.0	0.14
12	12	W	Depletion-25	Lean	149	20.9	7.0	0.0	0.14
5	5	W	Depletion-11	Lean	149	20.9	7.0	0.0	0.14
5	5	W	Depletion-10	Lean	149	20.9	7.0	0.0	0.14
17	17	W	Turndown1	Lean	149	14.9	5.0	5.6	0.10
17	17	W	Turndown1	Lean	149	14.9	5.0	5.6	0.10
18	18	W	Turndown2	Rich	2115	449.4	149.8	0.0	0.21
18	18	W	Turndown2	Rich	2115	449.4	149.8	0.0	0.21

Size, in	Temp In, ºC	Temp Out, ºC	Press in, bara	Press out (CPF), bara	Mix. velocity at outlet, m/s	Max. EVR	Potential hydrate	Flow regime	Total liquid holdup volume, m^3
4	43	43	60	56	11.9	1.30	No	S Wavy	0.40
6	43	43	57	56	5.0	0.60	No	Slug/S Wavy	1.00
4	43	43	60	56	11.7	1.30	No	S Wavy	0.36
6	43	43	57	56	5.0	0.60	No	Slug/S Wavy	1.00
4	10	10	57	56	9.6	0.70	Yes	S Wavy	0.08
6	10	10	56	56	4.1	0.30	Yes	S Wavy	0.28
4	20	19.7	26.3	26	7.9	0.34	No	S Wavy	0.06
6	20	19.8	26	26	3.4	0.15	No	S Wavy	0.20
4	20	19.3	12	11	19.5	0.54	No	S Wavy	0.03
6	20	19.7	11.1	11	8.5	0.23	No	S Wavy	0.10
4	-19	-17	56	56	1.9	0.10	Yes	S Wavy	0.16
6	-19	-17	56	56	0.8	0.06	Yes	S Wavy	0.60
4	37	37	57	56	5.7	0.70	No	Slug/S Wavy	0.40
6	37	37	56	56	2.4	0.30	No	S Wavy	1.30

Table 5. Steady State hydraulic results for Gas Well #1 Flowline (richest gas, excluding volatile oil)

Hydrate temp (inlet), ºC	Hydrate Temp (Outlet), ºC	Summer/Winter	Case	Fluid	CGR, SCM / MSCM	Condensate, SCMD	Water, SCMD	Methanol, SCMD	Gas Flowrate, MSCMD	Size, in	Temp in, ºC	Temp out, ºC	Press in, bara	Press out (CPF), bara	Mix. velocity at outlet, m/s	Max. EVR	Potential hydrate	Flow regime	Total liquid holdup volume, m^3
12	12	S	Base Case	Rich (excl. volatile oil)	867.4	368.6	122.9	0.0	0.425	4	25	24.5	58.2	56	10	0.93	No	S Wavy	0.24
12	12	S	Base Case		867.4	368.6	122.9	0.0	0.425	6	25	24.9	56.3	56	4.3	0.40	No	S Wavy	0.78
12	12	W	Base Case		867.4	368.6	122.9	0.0	0.425	4	25	24.5	58.2	56	9.9	0.93	No	S Wavy	0.24
12	12	W	Base Case		867.4	368.6	122.9	0.0	0.425	6	25	24.9	56.3	56	0.4	0.40	No	S Wavy	0.78
12	12	W	Turndown2		867.4	184.3	61.4	0.0	0.21	4	19	19.0	57.0	56	4.8	0.46	No	S Wavy	0.32
12	12	W	Turndown2		867.4	184.3	61.4	0.0	0.21	6	19	19.0	56.0	56	2.1	0.20	Yes	S Wavy	0.89

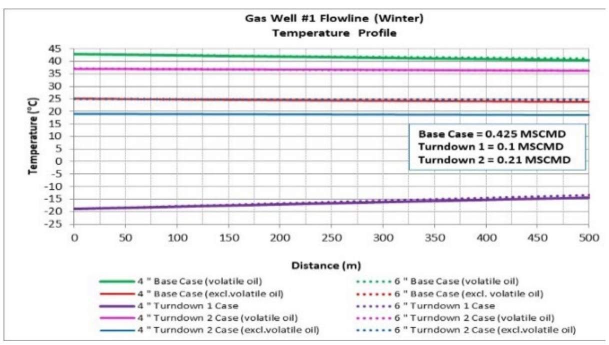

Figure 2. Gas Well #1 Flowline temperature profile in winter

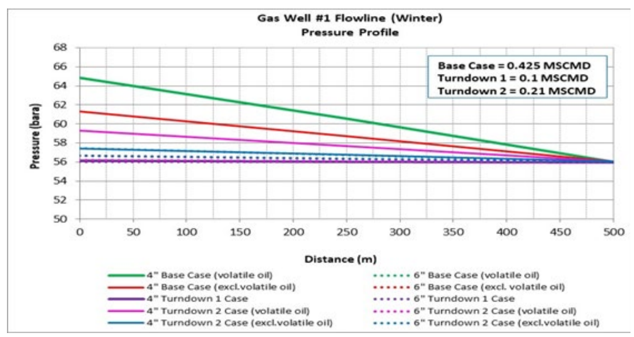

Figure 3. Gas Well #1 Flowline pressure profile in winter

5.1.2. Gas Well # 2

Table 6 displays the results obtained from PIPESIM simulation program for gas well #2 at base case compositions , depletion case compositions and turndown case compositions. The key findings are:

5.1.2.1. Base case compositions

Based on the 4" flowline and rich gas production, pressure drop in the line is 39 bar with unit pressure drop of 5 bar/km. Maximum fluid velocity is 9 m/s and maximum EVR is 0.7. Based on the 6" flowline and rich gas production, pressure drop in the line is 6 bar with unit pressure drop of 0.8 bar/km. Maximum fluid velocity is 4 m/s and maximum EVR is 0.3. Based on 6" flowline and lean gas production, temperature drop across the choke is 48ºC and flowline inlet temperature is 2ºC, which is below hydrate formation temperature of 19ºC; there is the risk of hydrate formation and hydrate inhibitor injection will be required for base case.

Based on 6" flowline and rich gas production, temperature drop across the choke is 36ºC and flowline inlet temperature is 14ºC, which is below hydrate formation temperature of 20ºC; there is the risk of hydrate formation and hydrate inhibitor injection is required for base case. The maximum predicted methanol inhibitor rate required is 8.2 SCMD for the 6" line (base case, rich gas). Flow regime in the 4" and 6" lines, base case, rich and lean gas are predominantly stratified wavy and no slug flow is predicted anywhere in the flowline during steady-state operation.

5.1.2.2. Depletion case compositions

For depletion case, the minimum temperature in the line is 16ºC, which is above hydrate formation temperature of 14ºC. Hence, there is no risk of hydrate formation in the line.

5.1.2.3. Turndown case compositions

For turndown production flowrate of 0.1 MSCMD of lean gas, temperature drops to -23 ºC downstream the choke valve, which is below the hydrate formation temperature of 19 ºC. Hence, there is the risk of hydrate formation in the line for the turndown case. Note: hydrate inhibition and/or wellhead heating will be required for the low flowing temperature cases. The maximum predicted methanol inhibitor rate required is 8.8 SCMD for the turndown 2 case. For turndown production flowrate of 0.21 MSCMD of rich gas, the predicted liquid holdup volume % in the line is in the range of 3 to 32 % for 6" line and 7 to 17 % for 4" line. The total liquid holdup volume is 19.2 m^3 for 6" line and 7.4 m^3 for 4" line. Figure 4 illustrates the temperature profile for the gas well #2 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #2 while figure 5 displays the pressure profile for the gas well #1 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #2.

It can be noticed that the temperature and the pressure are changing across the wellhead flowline of gas well #2 because the total length of the wellhead flowline of gas well#2 is long (7.5 km) and the elevation of the line is 70 meter between the highest and lowest point.

Table 6. Steady State hydraulic results for Gas Well #2 Flowline

Hydrate Temp (Inlet), ºC	Hydrate Temp, (Outlet) ºC	Summer /Winter	Case	Fluid	CGR, SCM / MSCM	Condensate Sm^3/d	Water, Sm^3/d	Methanol, Sm^3/d	Gas Flowrate, MSCMD
20	19	S	Base Case	Rich	282	119.9	40	6.9	0.42
22	19	W	Base Case	Rich	282	119.9	40	10.7	0.42
20	19	W	Base Case	Rich	282	119.9	40	8.2	0.42
21	19	W	Base Case	Lean	28	11.9	4	2.3	0.42
19	19	W	Base Case	Lean	28	11.9	4	2.1	0.42
16	13	W	Depletion-25	Lean	28	3.9	1.3	0.1	0.14
13	13	W	Depletion-25	Lean	28	3.9	1.3	0.0	0.14
14	6	W	Depletion-11	Lean	28	3.9	1.3	0.0	0.14
14	6	W	Depletion-10	Lean	28	3.9	1.3	0.0	0.14
19	19	W	Turndown1	Lean	28	2.8	0.9	1.2	0.10
19	19	W	Turndown1	Lean	28	2.8	0.9	1.2	0.10
20	19	W	Turndown2	Rich	282	59.9	20	7.5	0.21
19	19	W	Turndown2	Rich	282	59.9	20	8.8	0.21

Size, in	Temp In, ºC	Temp Out, ºC	Press in, bara	Press out (CPF), bara	Mix. velocity at outlet, m/s	Max. EVR	Potential hydrate	Flow regime	Total liquid holdup volume, m^3
6	14	18	62	56	4	0.3	Yes	S Wavy	15.5
4	26	13	95	56	9	0.7	Yes	S Wavy	5.9
6	14	13	62	56	4	0.3	Yes	S Wavy	16.0
4	12	3	84	56	9	0.6	Yes	S Wavy	1.7
6	2	7	60	56	4	0.27	Yes	S Wavy	5.2
4	20	14	35	26	8	0.3	Yes	S Wavy	1.0
6	20	16	28	26	3.6	0.14	No	Slug/S Wavy	3.4
4	20	11	27	11	19	0.5	No	S Wavy	0.7
6	20	16	15	11	9	0.22	No	S Wavy	1.3
4	-23	11	58	56	2.2	0.15	Yes	S Wavy	3.6
6	-23	13	57	56	1	0.06	Yes	Slug/S Wavy	19.5
4	8	10	68	56	5	0.4	Yes	S Wavy	7.4
6	5	11	58	56	2	0.2	Yes	Slug/S Wavy	19.2

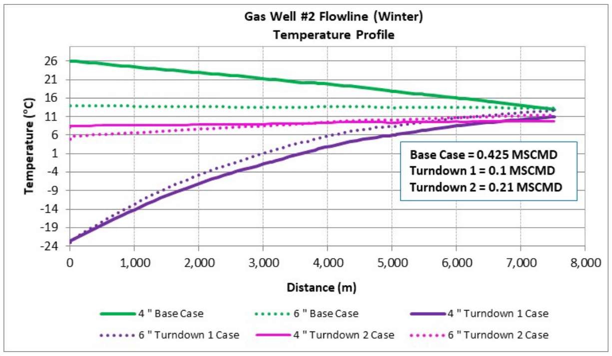

Figure 4. Gas Well #2 flowline Temperature Profile in Winter

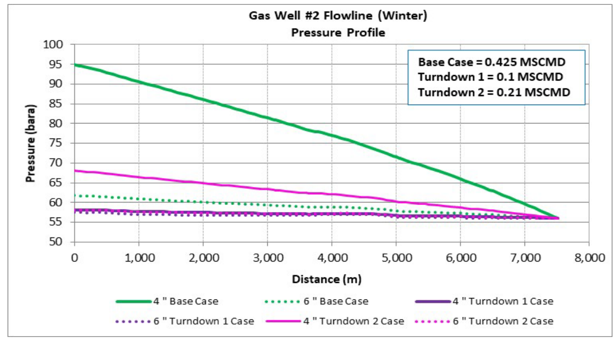

Figure 5. Gas Well #2 Flowline Pressure Profile in Winter

5.1.3. Gas Well # 3

Table 7 illustrate the results obtained from PIPESIM simulation program for gas well #3 at base case compositions , depletion case compositions and turndown case compositions. The key findings are:

5.1.3.1. Base case compositions

Based on the 4” flowline and rich gas production, pressure drop in the line is 30 bar with unit pressure drop of 6.5 bar/km. Maximum fluid velocity is 9.8 m/s and maximum EVR is 0.8. Based on the 6” flowline and rich gas production, pressure drop in the line is 4 bar with unit pressure drop of 0.9 bar/km. Maximum fluid velocity is 4 m/s and maximum EVR is 0.36. Based on 6” flowline and lean gas production, temperature downstream of the choke is -1 ºC which will be increased to 5 ºC at the flowline outlet. Hydrate formation temperature is 21 ºC; hence, the risk of hydrate formation is significant and hydrate inhibitor injection will be required for base case. Flow regime in the 6” flowline, base case, rich gas is predominantly stratified wavy/ slug, whilst in 4” flowline no slug flow is predicted. No slug flow regime is predicted anywhere in 4” and 6” flowlines for base case, lean gas and the flow regime is predominantly stratified wavy.

5.1.3.2. Depletion case compositions

For depletion case, the minimum temperature in the wellhead flowline of gas well #3 is 14ºC, which is above the hydrate formation temperature of 3ºC. Hence, there is no risk of hydrate formation in the line for the depletion case.

5.1.3.3. Turndown case compositions

For turndown production flowrate of 0.1 MSCMD of lean gas, temperature drops to -34ºC downstream the choke valve, which is below carbon steel minimum design temperature. The risk of hydrate formation during turndown is also significant. Note: hydrate inhibition and/or wellhead heating will be required for the low flowing temperature cases. The maximum predicted methanol inhibitor rate required is 2.2 SCMD (turndown 2 case). For turndown production flowrate of 0.21 MSCMD of rich gas, the predicted liquid holdup volume % in the line is in the range of 8 to 31 % for 6” line and 15 to 19 % for 4” line. The total liquid holdup volume is 14 m^3 for 6” line and 5.5 m^3 for 4” line. Figure 6 shows the temperature profile for the gas well #3 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #3 while figure 7 reveals the pressure profile for the gas well #1 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #3.

It can be noticed that the temperature and the pressure are changing across the wellhead flowline of gas well #3 because the total length of the wellhead flowline of gas well#3 is long (4.6 km) and the elevation of the line is 23 meter between the highest and lowest point.

Table 7. Steady State Hydraulic Results for Gas Well #3 Flowline

Hydrate Temp (Inlet), ºC	Hydrate Temp, (Outlet) ºC	Summer /Winter	Case	Fluid	CGR, SCM / MSCM	Condensate Sm^3/d	Water, Sm^3/d	Methanol, Sm^3/d	Gas Flowrate, MSCMD
21	17	S	Base Case	Rich	451	191.7	63.9	0.0	0.425
18	17	S	Base Case	Rich	451	191.7	63.9	0.0	0.425
21	17	W	Base Case	Rich	451	191.7	63.9	0.0	0.425
18	17	W	Base Case	Rich	451	191.7	63.9	0.0	0.425
18	16	W	Base Case	Lean	2	0.9	0.3	0.1	0.425
16	16	W	Base Case	Lean	2	0.9	0.3	0.2	0.425
11	10	W	Depletion-25	Lean	2	0.3	0.1	0.0	0.14
10	10	W	Depletion-25	Lean	2	0.3	0.1	0.0	0.14
8	3	W	Depletion-11	Lean	2	0.3	0.1	0.0	0.14
4	3	W	Depletion-10	Lean	2	0.3	0.1	0.0	0.14
16	16	W	Turndown1	Lean	2	0.2	0.1	0.1	0.10
16	16	W	Turndown1	Lean	2	0.2	0.1	0.1	0.10
18	17	W	Turndown2	Rich	451	95.8	31.9	1.0	0.21
17	17	W	Turndown2	Rich	451	95.8	31.9	2.2	0.21

Size, in	Temp In, ºC	Temp Out, ºC	Press in, bara	Press out (CPF), bara	Mix. velocity at outlet, m/s	Max. EVR	Potential hydrate	Flow regime	Total liquid holdup volume, m^3
4	30	22	86	56	9.8	0.8	No	S Wavy	4.5
6	24	24	60	56	4.2	0.36	No	Slug/S Wavy	12.6
4	30	20	86	56	9.6	0.8	No	S Wavy	4.6
6	24	21	60	56	4.2	0.3	No	Slug/S Wavy	12.7
4	7	3	73	56	9.5	0.6	Yes	S Wavy	0.3
6	-1	5	58	56	4.1	0.25	Yes	S Wavy	0.9
4	20	16	31	26	7.9	0.3	No	S Wavy	0.2
6	20	17	27	26	3.4	0.13	No	Slug/S Wavy	1.2
4	20	14	21	11	19.3	0.47	No	S Wavy	0.1
6	20	17	13	11	8.4	0.2	No	Slug/S Wavy	0.3
4	-34	17	57	56	2.4	0.14	Yes	Slug/S Wavy	0.6
6	-34	17	57	56	1	0.06	Yes	Slug/S Wavy	8.9
4	17	17	65	56	4.7	0.4	Yes	Slug/S Wavy	5.5
6	15	18	57	56	2	0.17	Yes	Slug/S Wavy	14.0

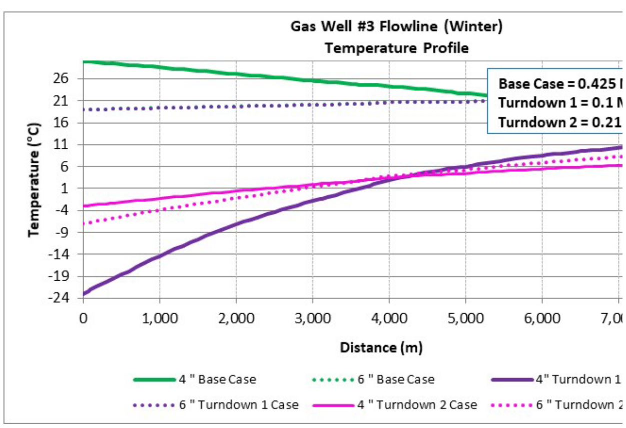

Figure 6. Gas Well #3 Flowline Temperature Profile in Winter

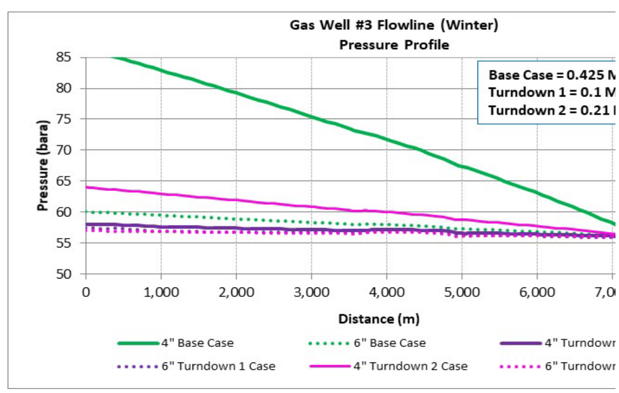

Figure 7. Gas Well #3 Flowline Pressure Profile in Winter

5.1.4. Gas Well # 4

Table 8 displays the results obtained from PIPESIM simulation program for gas well #4 at base case compositions , depletion case compositions and turndown case compositions. The key findings are:

5.1.4.1. Base Case Compositions

The production from gas Well #4 is lean gas condensate with CGR of 37 SCM/MSCM and based on the 4″ flowline, the pressure drop in the wellhead flowline is 30 bar with unit pressure drop of 4 bar/km. Maximum fluid velocity is 9.5 m/s and maximum EVR is 0.6. 4′′ pipeline size is accepted for this scenario. Based on the 6″ flowline, pressure drop in the line is 4 bar with unit pressure drop of 0.5 bar/km. Maximum fluid velocity is 4 m/s and maximum EVR is 0.3. Based on 6″ flowline, temperature downstream of the choke is 19 ºC, which will be further dropped to 17ºC at flowline outlet. Hydrate formation temperature is 19 ºC; hence there is the risk of hydrate formation and hydrate methanol inhibitor injection will be required for base case scenario. The maximum predicted methanol inhibitor rate required is 0.4 SCMD for base case. Flow regime in the 4″ and 6″ lines, base case, is predominantly stratified wavy and no slug flow is predicted anywhere in the flowline during normal operation.

5.1.4.2. Depletion Case Compositions

For depletion case, the minimum temperature in the line is 11 ºC, which is above hydrate formation temperature of 6 ºC. Hence, there is no risk of hydrate formation in the line for the depletion case.

5.1.4.3. Turndown case compositions

For turndown production flowrate of 0.1 MSCMD of lean gas, temperature drops to -23 ºC downstream the choke valve which is below hydrate formation temperature of 19 ºC; there is the risk of hydrate formation and hydrate inhibitor injection will be required for base case. The maximum predicted methanol inhibitor rate required is 2.1 SCMD (turndown 2 case). For turndown production flowrate of 0.21 MSCMD of rich gas, the predicted liquid holdup volume % in the line is in the range of 2 to 28 % for 6″ line and 4 to 7 % for 4″ line. The total liquid holdup volume is 8.7 m^3 for 6″ line and 3 m^3 for 4″ line. Figure 8 illustrate the temperature profile for the gas well #4 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #4 while figure 9 reveals the pressure profile for the gas well #4 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #4.

It can be noticed that the temperature and the pressure are changing across the wellhead flowline of gas well #4 because the total length of the wellhead flowline of gas well#4 is long (7.5 km) and the elevation of the line is 78 meter between the highest and lowest point.

Table 8. Steady State Hydraulic Results for Gas Well #4 Flowline

Hydrate Temp (Inlet), ºC	Hydrate Temp, (Outlet) ºC	Summer /Winter	Case	Fluid	CGR, SCM / MSCM	Condensate Sm^3/d	Water, Sm^3/d	Methanol, Sm^3/d	Gas Flowrate, MSCMD
19	19	S	Base Case	Rich	37	15.7	5.2	0.1	19
22	19	W	Base Case	Rich	37	15.7	5.2	1.3	22
19	19	W	Base Case	Rich	37	15.7	5.2	0.4	19
16	13	W	Depletion-25	Rich	37	5.2	1.7	0.1	16
14	13	W	Depletion-25	Lean	37	5.2	1.7	0.0	14
14	6	W	Depletion-10	Lean	37	5.2	1.7	0.0	14
8	6	W	Depletion-10	Lean	37	5.2	1.7	0.0	8
19	19	W	Turndown1	Lean	37	3.7	1.2	1.6	19
19	19	W	Turndown1	Lean	37	3.7	1.2	1.6	19
20	19	W	Turndown2	Lean	37	7.8	2.6	1.9	20
19	19	W	Turndown2	Lean	37	7.8	2.6	2.1	19

Size, in	Temp In, ºC	Temp Out, ºC	Press in, bara	Press out (CPF), bara	Mix. velocity at outlet, m/s	Max. EVR	Potential hydrate	Flow regime	Total liquid holdup volume, m^3
6	19	22	60	56	4.3	0.28	Yes	S Wavy	4.8
4	30	14	86	56	9.5	0.63	Yes	S Wavy	1.6
6	19	17	60	56	4	0.28	Yes	S Wavy	5.0
4	20	14	35	26	7.7	0.30	Yes	S Wavy	1.3
6	20	16	27.4	26	3.3	0.14	No	Slug/S Wavy	3.8
4	20	11	27	11	19	0.51	No	S Wavy	0.9
6	20	16	14	11	8.3	0.20	No	S Wavy	1.8
4	-23	11	58	56	2.2	0.15	Yes	S Wavy	4.0
6	-23	12	57	56	1	0.06	Yes	Slug/S Wavy	16.8
4	-3	7	64	56	4.5	0.30	Yes	S Wavy	3.0
6	-7	9	57	56	2	0.13	Yes	Slug/S Wavy	8.7

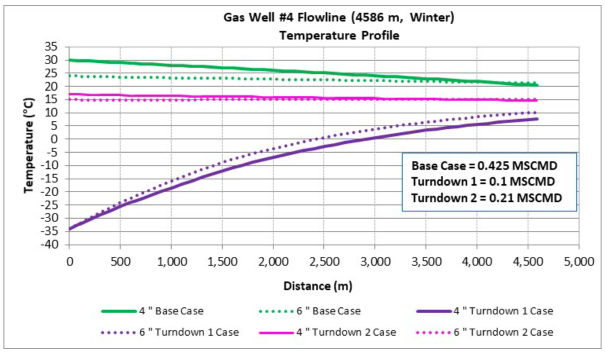

Figure 8. Gas Well #4 Flowline Temperature Profile in Winter

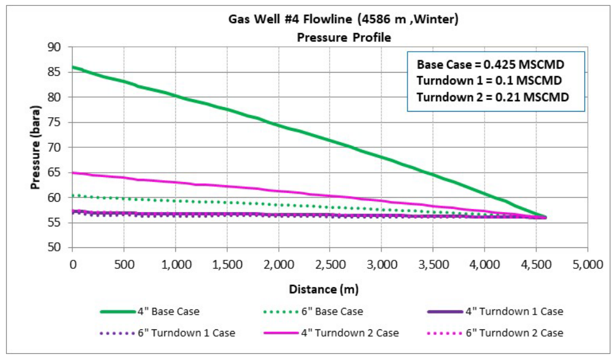

Figure 9. Gas Well #4 Flowline Pressure Profile in Winter

5.2. OLGA results summary

Table 9 displays the transient hydraulic results when OLGA software was used to simulate the new gas wellhead flowlines for the gas project. Tables 10 & 11 illustrate the comparison between the results obtained from PIPESIM software and OLGA software at different conditions. a comparison was first carried out to benchmark the steady state pressure and temperature predictions obtained using dynamic 'OLGA' modelling against corresponding estimates obtained om the steady state 'PIPESIM' modelling. This benchmarking exercise was performed for the 6" line size operating at base and turndown 1 Case conditions.

From the comparison table between the results of PIPESIM software and OLGA software, it can be noticed that the results obtained from the two software are very close. Table 12 summarizes the results for each well.

Table 9. Transient hydraulic results by OLGA software for all Gas Wellhead Flowlines

Well Name	Simu. Case	Comp.	Wellhead Temp., ºC	Wellhead Pressure, bara	Inlet to Flowline Temp., ºC	Inlet to Flowline Pressure (Pipesim), bara	Arrival at CPF Temp. (Pipesim.), ºC
Gas Well#1	Base	Rich	50	267	25	59.4	23.9
	Base	Lean	50	267	10	57.7	10
	Base	Rich	50	267	25	59.4	23
	Base	Lean	50	267	10	57.7	8.5
	Base	Rich	50	267	25	59.4	23.3
	Base	Lean	50	267	10	57.7	9
	Base	Rich	50	267	25	59.4	23.5
	Base	Lean	50	267	10	57.7	9.4
Gas Well#2	Base	Rich	50	267	14	61.8	13.3
	Base	Lean	50	267	2	59.7	7.4

Well Name	Simu. Case	Comp.	Wellhead Temp., ºC	Wellhead Pressure, bara	Inlet to Flow-line Temp., ºC	Inlet to Flowline Pressure (Pipesim), bara	Arrival at CPF Temp. (Pipesim.), ºC
	Base	Rich	50	267	14	61.7	7.7
	Base	Lean	50	267	2	59.6	0.3
	Base	Rich	50	267	14	61.7	9.7
	Base	Lean	50	267	2	59.7	2.5
	Base	Rich	50	267	14	61.7	11.3
	Base	Lean	50	267	2	59.7	4.4
Gas Well#3	Base	Rich	63	245	19	60.1	16.5
	Base	Rich	63	245	19	60.0	9.5
	Base	Rich	63	245	19	60	11.9
	Base	Rich	63	245	19	60.1	13.8
Gas Well#4	Base	Rich	50	267	24	59.7	21.7
	Base	Lean	50	267	-1	57.8	4.2
	Base	Rich	50	267	24	59.1	18.8
	Base	Lean	50	267	-1	57.7	-1.1
	Base	Rich	50	267	24	59.7	19.8
	Base	Lean	50	267	-1	57.7	0.6
	Base	Rich	50	267	24	59.7	20.6

Well Name	Hydrate Form. Temp at Inlet P, ºC	Temp. Depression required based on Pipesim, ºC	Arrival at CPF Temp. (OLGA Simu. With Amb. Soil Temp as Amb Cond.), ºC	MeOH Rate based on OLGA with Amb Soil (with 4 deg C margin), SCMD	MeOH Rate based on OLGA with Amb Air (with 4 ºC margin), SCMD	Arrival at CPF Pressure, bara	Ambient Air Temp., ºC
Gas Well#1	17.0	0.0	23.4	0.0	0.0	56	10
	15.9	9.9	10.4	6.7	7.6	56	10
	17.0	0.0	21.9	0.0	0.0	56	-5
	15.9	11.4	7.4	9.1	11.8	56	-5
	17.3	0.0	22.4	0.0		56	0
	15.9	10.9	8.4	8.4		56	0
	17.3	0.0	22.8	0.0		56	4
	15.9	10.5	9.2	7.7		56	4
Gas Well#2	17.1	7.8	13.9	11.0	14.8	56	10
	17.6	14.2	10.5	3.2	6.4	56	10
	17.1	13.4	5.5	25.9	23.3	56	-5
	17.6	21.3	0.4	6.6	7.6	56	-5
	17.1	11.4	8.3	20.9		56	0
	17.6	19.1	3.7	5.5		56	0
	17.1	9.8	10.6	16.6		56	4
	17.6	17.2	6.4	4.6		56	4
Gas Well#3	17.6	5.1	16	1.6	3.9	56	10
	17.6	12.1	6	5.0	7.4	56	-5
	17.6	9.7	9.3	3.8		56	0
	17.6	7.8	12	2.9		56	4
Gas Well#4	17.6	0.0	20.6	0.8	5.7	56	10
	14.3	14.1	8.1	1.8	2.9	56	10
	17.6	2.8	15.8	8.6	18.9	56	-5
	14.3	19.4	-0.6	0.1	3.4	56	-5
	17.6	1.8	17.5	5.5		56	0
	14.3	17.7	2.0	2.9		56	0
	17.6	1.0	18.7	3.7		56	4

Table 10. OLGA Software vs PIPESIM Software Benchmarking Results (base case, 10 % W.C)

Flowline	Software	Length	Case	Gas	Gas Flowrate	size	Temp, in	Temp, out	Press, in	Press, out (CPF)	Mix. Velocity at outlet	Max. EVR	Total Liquid Holdup Volume	Flow Regime
		m			MMSCMD	in	ºC	ºC	bara	bara	m/s	-	m3	
Gas Well#1	PIPESIM	500	Base Case	Volatile oil	0.425	6	43	43.0	57.0	56	5	0.60	1.0	Slug/S Wavy
	OLGA		Base Case	Volatile oil	0.425	6	43	42.5	56.4	56	5.5	0.50	1.0	Strat.
Gas Well#2	PIPESIM	7,500	Base Case	Rich	0.425	6	14	13.0	62.0	56	4.0	0.30	16.0	S Wavy
	OLGA		Base Case	Rich	0.425	6	14	14.3	60.9	56	4.3	0.29	11.7	Strat.
Gas Well#3	PIPESIM	4,600	Base Case	-	0.425	6	19	16.5	60.0	56	4.0	0.28	5.0	S Wavy
	OLGA		Base Case	-	0.425	6	19	15.9	59.9	56	4.3	0.27	4.3	Strat.
Gas Well#4	PIPESIM	7,500	Base Case	Rich	0.425	6	24	21.0	60.0	56	4.2	0.30	12.7	Slug/S Wavy
	OLGA		Base Case	Rich	0.425	6	24	19.4	59.7	56	4.4	0.31	10.0	Strat.

Table 11. OLGA software vs PIPESIM software benchmarking results (turndown case, 10 % W.C)

Flowline	Software	Length	Case	Gas	Gas Flowrate	size	Temp, in	Temp, out	Press, in	Press, out (CPF)	Mix. Velocity at outlet	Max. EVR	Total Liquid Holdup Volume	Flow regime
		m			MSCMD	in	ºC	ºC	bara	bara	m/s	-	m3	
Gas Well#1	PIPESIM	500	Turndown	Lean	0.100	6	-19	-17.0	56.0	56	0.8	0.06	0.6	S Wavy
	OLGA		Turndown	Lean	0.100	6	-19	-14.6	56.0	56	0.9	0.06	0.4	Strat.
Gas Well#2	PIPESIM	7,500	Turndown	Lean	0.100	6	-23	13.0	57.4	56	1.0	0.06	19.5	slug
	OLGA		Turndown	Lean	0.100	6	-23	15.8	57.2	56	1.0	0.06	15.9	Int. Strat
Gas Well#3	PIPESIM	4,600	Turndown	-	0.100	6	-23	12.0	56.8	56	1.0	0.06	16.8	Slug/S Wavy
	OLGA		Turndown	-	0.100	6	-23	15.8	56.6	56	1.0	0.06	14.1	Int. Slug

Table 12. Results summary for each well

Well name	Minimum operating temperature on flowline, ºC	Hydrate formation temperature, ºC	Hydrate inhibitor requirements	Maximum methanol inhibitor rate, SCMD	Type of flow regime	Slug flow Regime formation
Gas Well #1	-19	18	Required	5.6 in turndown case	Stratified-Wavy	Slug flow regime is predicted in some sections of the line during normal production of volatile oil. No slugging for rich condensate gas
Gas Well #2	-23	22 for 4'' line, 20 for 6'' line	Required	8.8 in turndown case	Stratified-Wavy	Slug flow regime is predicted in some sections of the line during depletion, turndown and normal production of lean Gas, and turndown production of rich Gas.
Gas Well #3	-23	22 for 4" line and 19 for 6" line.	Required	2.1 in turndown case	Stratified-Wavy	Slug flow regime is predicted in some sections of the line during depletion and turndown production of gas for the 6" line size.
Gas Well #4	-34	21 for 4" line and 18 for 6" line.	Required	2.2 in turndown case	Stratified-Wavy	Slug flow regime is predicted in some sections of the 6" line for all cases considered

6. Conclusions & recommendations

Based on the steady state simulation conducted by PIPESIM software and transient simulation performed by OLGA software , it can be concluded with the following:-

For gas well # 1, 6” pipelines are considered feasible. For gas well #2, Gas well #3 and Gas well #4, 4” and 6” line sizes are feasible.

Erosional velocity checks in accordance with API RP 14E using a C-factor of 100 indicate that EVR is less than 1.0 for all cases; hence, there is no risk of erosion in the flowlines.

The impact of heating the flowing temperature for each flowline was investigated to mitigate against hydrate formation in the flowline at low flowing temperatures. The results revealed that for the Gas well # 1 flowline, a flowing temperature of 25ºC is enough to ensure that the flowline operates outside the hydrate region. For all other flowlines, the maximum flowing temperature of 60ºC will not be adequate in ensuring that the flowlines operate completely outside the hydrate region. The effect of mixing well fluids in varying ratios of richest fluid / leanest fluid has no significant impact on hydrate formation conditions in the flowlines. A comparison was carried out to benchmark the steady state pressure and temperature predictions obtained using dynamic ‘OLGA’ modelling against corresponding estimates obtained from the steady state ‘PIPESIM’ modelling. The results obtained from the two software are very close.

Nomenclature

A	*Minimum pipe cross-sectional flow area required, in^2/1000 barrels liquid per day.*
API RP	*American Petroleum Institute Recommended Practice*
Bpd	*Barrels Per Day*
C	*Empirical constant*
CGR	*Condensate Gas Ratio*
CPF	*Central Processing Facility*
D	*pipe ID, in*
DP	*Pressure Drop*
EVR	*Erosional Velocity Ratio*
f	*moody friction factor*
FWHP	*Flowing Well Head Pressure*
FWHT	*Flowing Well Head Temperature*
GOR	*Gas-Oil Ratio*
HP	*High Pressure*
ID	*Internal Diameter*
LDHI	*Low Dosage Hydrate Inhibitors*
LP	*Low Pressure*
MP	*Medium Pressure*
MMSCFD	*million standard cubic feet per day*
MSCMD	*million standard cubic meter per day*
NB	*Nominal Bore*
L	*Length , feet*
LPG	*Liquefied Petroleum Gas*
MSCD	*Standard Cubic Meter Per Day*
P	*operating pressure , psia*
R	*gas liquid/ ratio*
S	*gas specifc gravity*
S1	*liquid specifc gravity*
Sg	*gas specifc gravity (air=1) at standard condations*
T	*Operating temperature , oR*
W	*total liquid plus vapor rate, Ibs/hr.*
W.C	*Water Cut*
WHP	*Wellhead Pressure*
WHT	*Wellhead Temperature*
Z	*Compressibility factor for gas*
d1	*pipe inside diamter, inch*
P1	*upstream Pressure , psia*

P2	*downstream Pressure , psia*
T1	*Flowing temeprture , oR*
Qg	*gas flowrate , MMSCFD (at 14.7 psig and 60 oF)*
Ve	*Erosion velocity*
Vg	*gas velocity, feet/ second*
ρm	*mixture density*
ΔP	*Pressure drop*

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