A CASE STUDY IN FLOW ASSURANCE OF A PIPELINE-RISER SYSTEM USING OLGA

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Abstract. *In this paper, a case study in flow assurance is performed considering an offshore operating system, using the software OLGA. As operating system we consider a pipeline-riser geometry with typical dimensions of offshore oil production systems, and a three-phase flow of oil, gas and water. The model developed in OLGA considers the composition and dimensions of the tubes, heat transfer parameters, process equipment and fluid sources. The fluids properties are calculated using the software PVTsim. Simulations are ran in order to determine the pipeline inner diameter and insulation required to satisfy pressure and temperature requirements. It is also possible to simulate the transient behavior of the system, which allows to evaluate if production instabilities are present. In case instabilities exist, two mitigation alternatives are evaluated: closure of a choke valve before the separator and gas lift. Considering a possible production shutdown, the tubes insulation is calculated in order to avoid hydrate formation.*

Keywords: *flow assurance, multiphase flow, petroleum production systems, black oil model, OLGA*

1. INTRODUCTION

The flow assurance is an engineering analysis process that aims to prevent the formation of solids and the occurrence of flow instabilities in order to ensure continued production at desired levels for project profitability [2]. To prevent costly downtime and intervention activities, the design and operating guidelines for subsea oil systems are based in the following principles:

- Do not allow the system to enter a pressure/temperature region where hydrates are stable.
- Prevent wax deposition on the tube walls controlling the temperature.
- Design to inhibit and remove asphaltenes.
- Do not allow the system to operate in the unstable region (severe slugging or hydrodynamic slug).

In this work, a typical offshore system is analyzed according to the flow assurance guidelines. The system consists of a pipeline connected to a catenary-shaped riser in which there is a gas, oil and water flow. It is calculated the insulation thickness in the tubes for normal operation and in case a production shutdown occur. Is is also verified the occurrence of production instabilities and, in the case instabilities exist, mitigation alternatives.

The software OLGA [5] was used to model and simulate the flow dynamic of the system. OLGA is a computational program developed to simulate multiphase flow in pipelines and pipelines networks, with processing equipment included. The program solves separate continuity equations for the gas, liquid bulk and liquid droplets, two momentum equations, one for the continuous liquid phase and one for the combination of gas and possible liquid droplets and one mixture energy equation, considering that both phases are at same temperature. The equation are solved using the finite volume method and a semi-implicit time integration.

The fluid properties were determined using the software PVTsim [4]. It calculates the properties of the fluids based on the oil components and its quantity. The program database was obtained from an extensive experimental study.

2. DEFINITION OF THE CASE STUDY

A recently discovered petroleum field will be developed via a single subsea wellhead and pipeline to a platform located close to the wellhead. A flexible riser was preinstalled during the construction of the platform to accommodate future subsea field developments.

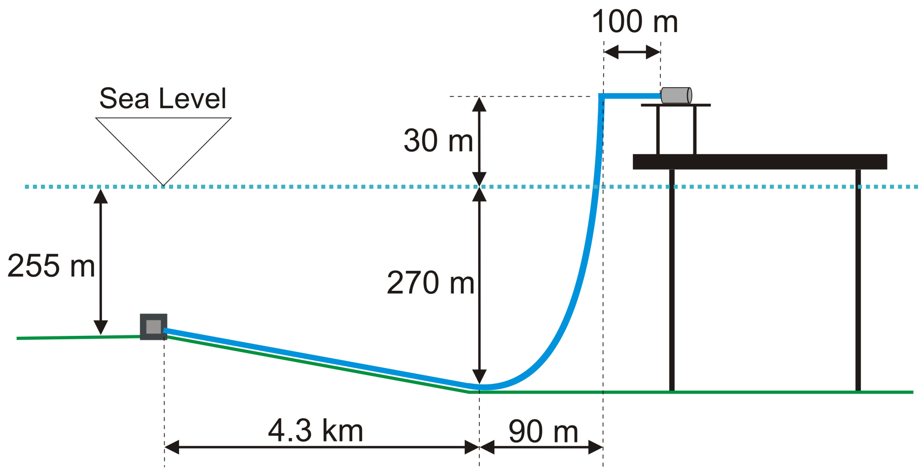

Figure 1. Schema of the production system.

2.1 Available data

A schema of the system is shown in Fig. 1 and the available data is: a) The wellhead is located in a depth of 255 m and is located 4.3 km from the riser base; b) The platform stands in 270 m of water with the production deck located 30 m above sea level; c) The riser forms a catenary with zero slope at the base and is 300 m high. It has an internal diameter of 4 in with a steel wall thickness of 7.5 mm and no insulation; d) There is a 100 m horizontal pipe at the top of the riser with the same characteristics of the riser; e) The pipeline has a steel wall thickness of 7.5 mm and an insulation layer; f) The roughness of the pipes is 0.028 mm; g) The separator pressure is kept constant at 50 $bara$; h) The flow rate must be between 5 kg/s and 15 kg/s; i) The fluids that leave the wellhead have a temperature of 62 ^oC; j) The minimum ambient temperature can be assumed to be 6 ^oC and the ambient heat transfer coefficient (from the outside of the pipe structure to the surroundings) can be assumed to be 6.5 $W/m^2\,^oC$ for the entire pipeline-riser system; k) The composition of the fluids is given in Tab. 1 and the water mass fraction is 8 %; l) The properties of pipe steel and insulation are given in Tab. 2.

Table 1. Components of the oil and its molar percentage [3].

Component	Molar percentage	Component	Molar percentage	Component	Molar percentage
C1	72.3926	C2	3.9559	C3	1.9255
iC4	0.4267	nC4	0.8707	iC5	0.2657
nC5	0.3694	C6	0.6521	C7	0.8089
C8	0.9728	C9	0.9472	C10	0.8035
C11	0.8183	C12	0.7203	C13	0.6129
C14	0.6856	C15	0.7077	C16	0.5276
C17	0.4486	C18	0.4802	C19	0.4234
C20+	8.0818	N2	0.1026	CO2	2.00

Table 2. Properties of the pipe materials.

Material	Density (kg/m^3)	Specific heat ($J/kg\,K$)	Thermal conductivity ($W/m\,K$)
Steel	7850	500	50
Insulation	1000	1500	0.135

2.2 Tasks

The following tasks should be accomplished: a) Determine the pipeline size (inner diameter), considering that the maximum allowed pipeline inlet pressure is 80 $bara$; b) Determine the pipeline insulation thickness, considering that the minimum required arrival temperature at the separator is 27 ^oC (to avoid wax formation); c) Verify if there are production instabilities; d) In case instabilities exist, evaluate mitigation alternatives; e) Determine the thickness of the insulation layer necessary to prevent the hydrate formation during a production shutdown of 4 hours. Consider that the configuration of the riser wall is the same as the configuration of the pipeline wall, i.e. the riser wall has a steel layer and also an insulation layer.

3. MODELING WITH OLGA

Based in the available data the pipeline-riser system can be modeled using OLGA. The first step is the definition of the materials based in Tab. 2. The pipeline wall is defined by a steel thickness of 7.5 mm and the insulation thickness is an unknown parameter, which is calculated based on the minimum required arrival temperature at the separator. The riser wall is constructed of a steel thickness of 7.5 mm.

The flowpath is modeled considering two nodes. The upstream node is defined as a closed node and the downstream node is modeled as a pressure node, in which the pressure is given by the separator pressure of 50 $bara$.

The geometry of the system is determined considering that the discretization of the pipes must be done based on linear pieces, which are separated in sections. The pipeline is modeled as an unique linear piece with 1100 sections of about $4\,m$ long each one. The riser is modeled as 12 connected linear pieces, in order to approximately follow the catenary shape. The pieces have different number of sections, but all sections have about $4\,m$ long. The diameter of the riser is given by 4 in and the pipeline diameter must be determined based on the maximum allowed pipeline inlet pressure.

The fluids source is located at the first section of the pipeline. The fluids temperature must be set to 62 ^oC and the mass flow rate assumes different values for each simulation (between 5 and 15 kg/s). The heat transfer also must be configured, considering that the ambient temperature is 6 ^oC and the ambient heat transfer coefficient is 6.5 $W/m^2\,^oC$ for the entire pipeline-riser system.

Oil and gas properties are calculated using PVTsim based on Tab. 1 and the water properties are included in the OLGA database.

4. PIPELINE SIZING

The steel-pipe and insulation are produced in standard sizes. Assume that the available pipes have the inner diameter of 8, 10, 12 and 14 cm and the available insulation have the thickness of 15, 20, 25, 30, 35 and 40 mm. It is necessary to determine the minimum insulation and minimum inner diameter that satisfy the requirements, in order to cut costs. The pipeline sizing is performed using steady state simulations.

4.1 Pipeline inner diameter

The minimum pipeline inner diameter is determined in terms of the maximum allowed inlet pressure, that is given by 80 $bara$. To assure that the maximum inlet pressure is respected for the specified range of mass flow rates, the pipeline is sized considering the worst case, in which the mass flow rate is 15 kg/s.

Figure 2 shows the pressure curves along the pipe length for four different cases, which consider a inner diameter of 8, 10, 12 and 14 cm; from the curves, the corresponding pipeline inlet pressures are 164, 111, 89 and 75 $bara$. Since the maximum allowed inlet pressure is 80 $bara$, the pipeline inner diameter should be set to 14 cm.

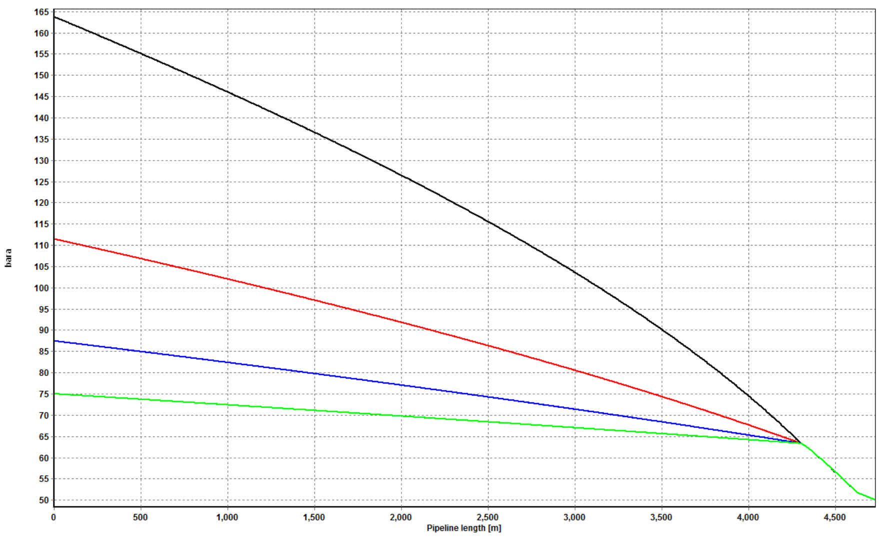

Figure 2. Pressure along the pipes for different pipeline inner diameters: 8 cm (black), 10 cm (red), 12 cm (blue) and 14 cm (green).

4.2 Insulation sizing

The minimum insulation required is determined in terms of the fluids arrival temperature at the separator, which should be above and as close as possible to 27 ^oC. To assure that the arrival temperature is respected for the specified range of mass flow rates, the insulation is sized considering the worst case, in which the mass flow rate is 5 kg/s.

Figure 3 shows the temperature curves along the pipe length for six different cases, which consider a insulation thickness of 15, 20, 25, 30, 35 and 40 mm. Observe that for the insulation thickness of 15 mm the arrival temperature at the separator is given by 29 ^oC. The other thicknesses make the fluids arrive in the separator with temperatures higher than 29 ^oC.

The minimum arrival temperature specified is 27 ^oC, thus the thickness of 15 mm is enough to assure that the specifications are respected.

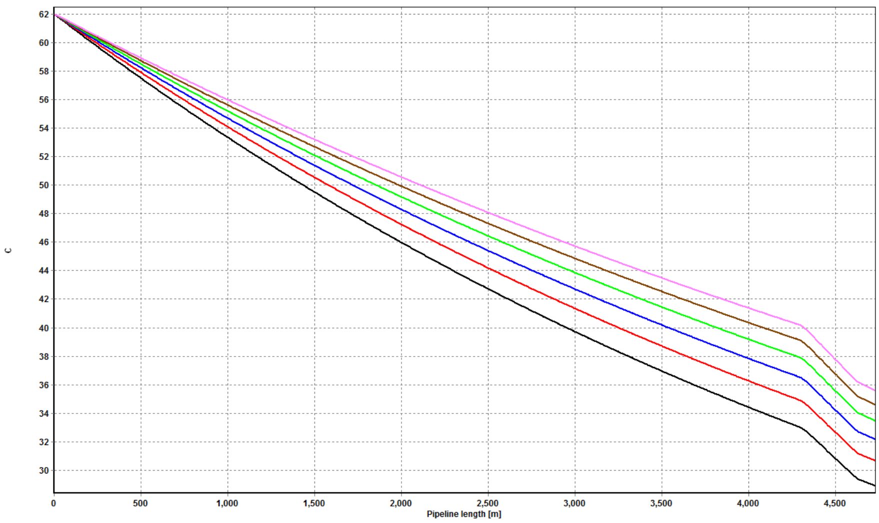

Figure 3. Temperature along the pipes for different insulation thicknesses: 15 mm (black), 20 mm (red), 25 mm (blue), 30 mm (green), 35 mm (brown) and 40 mm (pink).

5. PRODUCTION INSTABILITIES

Instabilities, such as severe slugging and hydrodynamic slug, is a terrain dominated phenomenon, characterized by the formation and cyclical production of long liquid slugs and fast gas blowdown. The instabilities may appear for low gas and liquid flow rates when a section with downward inclination angle (pipeline) is followed by another section with an upward inclination angle (riser) [1]. Main issues related to severe slugging are: a) High average back pressure at well head, causing tremendous production losses; b) High instantaneous flow rates, causing instabilities in the liquid control system of the separators and eventually shutdown; c) Reservoir flow oscillations.

For the evaluation of production instabilities, suppose that a more detailed pipeline profile is now available. Table 3 shows the coordinates that characterizes the new profile; the vertical distances are measured with relation to the sea level and the horizontal distances are measured in relation to the wellhead. This study is performed based on transient simulations, with a simulation time interval of 2 hours.

Table 3. New pipeline profile.

Location	Horizontal distance (m)	Vertical distance (m)
Wellhead	0	-255
End of Pipe 1	1000	-255
End of Pipe 2	1400	-250
End of Pipe 3	1800	-255
End of Pipe 4	3400	-255
End of Pipe 5/ Riser base	4300	-270

Figures 4 and 5 show respectively the pressure evolution in the separator inlet and in the pipeline inlet over time, for mass flow rates of 5, 10 and 15 kg/s. Observe that, for the mass flow rate of 5 kg/s, large oscillations are present in both observation points, showing that instabilities exist in the system.

The next sections consider two modifications in the system that could attenuate the instabilities: a) Choking the flow at the top of the platform; b) Injecting gas at the bottom of the riser.

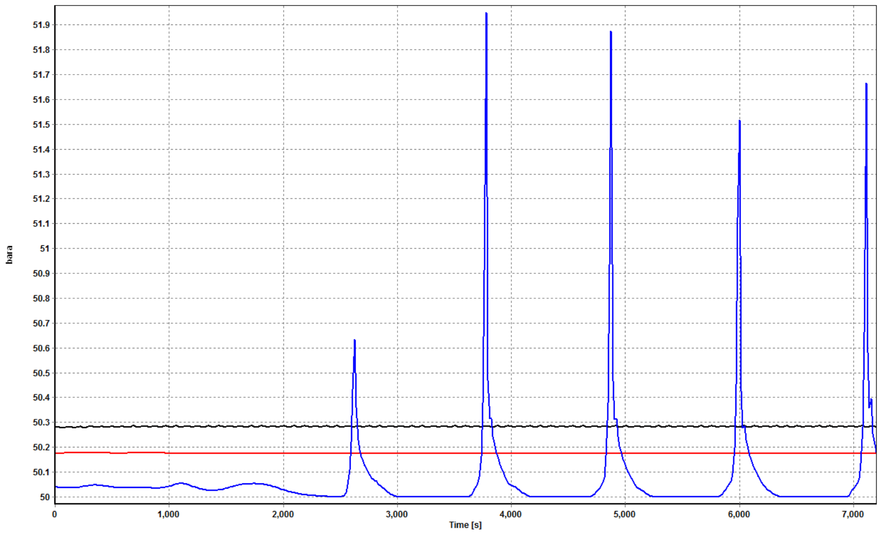

Figure 4. Pressure in the separator inlet over time for different mass flow rates: 5 kg/s (blue), 10 kg/s (red) and 15 kg/s (black).

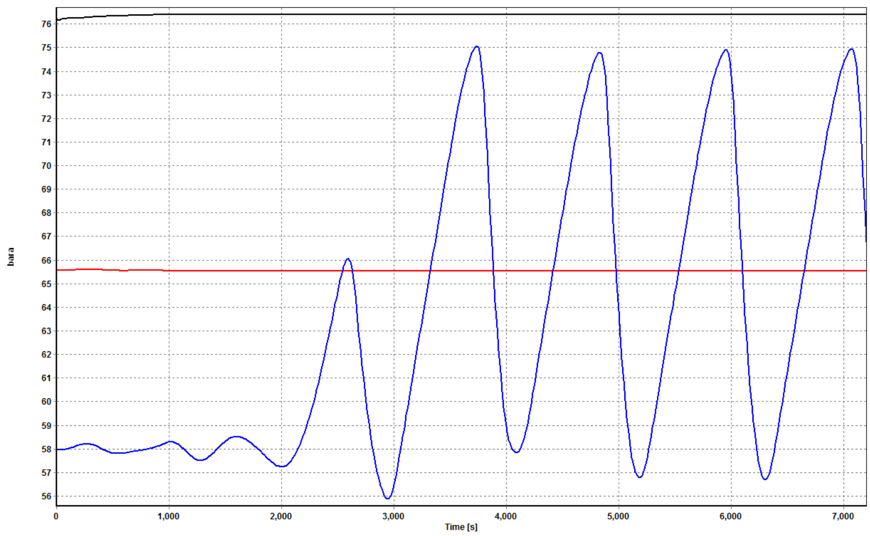

Figure 5. Pressure in the pipeline inlet over time for different mass flow rates: 5 kg/s (blue), 10 kg/s (red) and 15 kg/s (black).

5.1 Choke valve

A choke valve must be included in the model with maximum opening diameter of 4 in. It is located in the penultimate section boundary of the last pipe piece. The mass flow rate considered in the simulation is 5 kg/s, which leads to the instabilities in the original system. The simulation time interval is 4 hours.

Figures 6 and 7 show respectively the pressure evolution in the separator inlet and in the pipeline inlet for the choked flow over time, for valve openings of 2, 4, 6, 8 and 10 %. Observe that the valve opening of 10 % is not enough to eliminate the severe slugging from the system. To eliminate it, it is necessary to set the valve opening to 8 % or smaller. It is also possible to observe that the pressure in the pipeline inlet is about 99 $bara$ for the valve opening of 2 %, what exceeds the maximum allowed pressure in this position. So the valve opening should be set to 6 % to eliminate the instability and obey the system requirements.

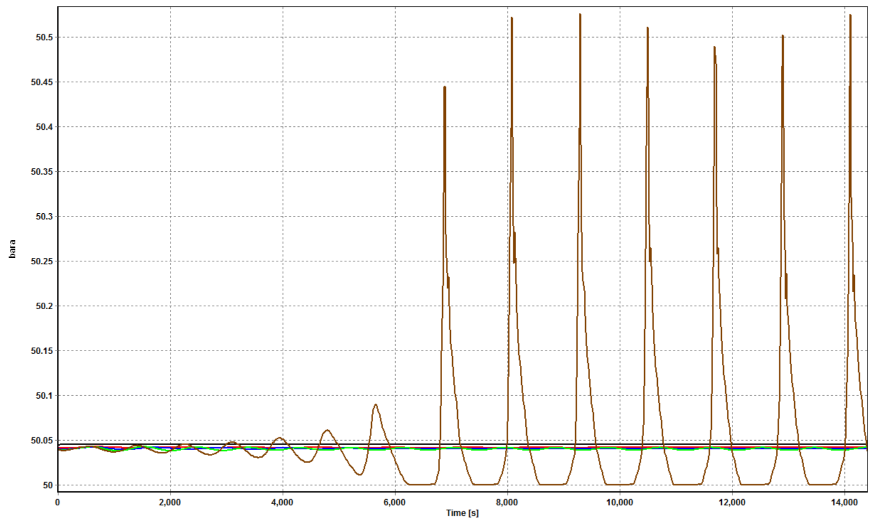

Figure 6. Pressure in the separator inlet over time for choked flow, for different valve openings: 2 % (black), 4 % (red), 6 % (blue), 8 % (green) and 10 % (brown).

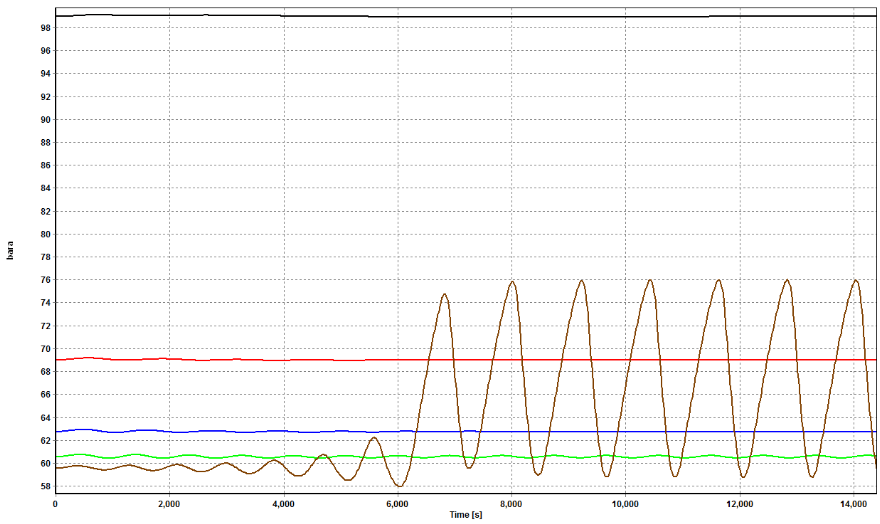

Figure 7. Pressure in the pipeline inlet over time for choked flow, for different valve openings: 2 % (black), 4 % (red), 6 % (blue), 8 % (green) and 10 % (brown).

5.2 Gas lift

The gas lift is modeled as a gas source located on the riser base with a gas inlet temperature of 32 ^oC. The mass flow rate in the pipeline inlet is 5 kg/s and the injection gas mass flow rate assumes the values of 0.2, 0.6 and 1.2 kg/s. To better evaluate the effects of the gas lift injection, the simulation time interval is set to 4 hours.

Figure 8 and 9 show respectively the pressure evolution in the separator inlet and in the pipeline inlet over time for the simulation including gas lift, for injection gas mass flows rates of 0.2, 0.6 and 1.2 kg/s. Observe that severe slugging is eliminated from the system for gas mass flow rates greater than or equal to 0.6 kg/s and the maximum allowed pressure in the pipeline inlet, 80 $bara$, is not reached for any case.

Figure 10 shows that the temperature in the separator inlet is greater than 27 ^oC, the predetermined minimum arrival temperature, for the gas mass flow rate of 0.6 and 1.2 kg/s. Therefore, if gas lift is used to eliminate severe slugging, the gas mass flow rate of 0.6 kg/s should be injected at the riser base.

6. SHUTDOWN SIMULATION

It must be determined the thickness of the insulation layer to keep the fluid temperature 5 ^oC above the hydrate formation temperature during a 4 hour shutdown period. For the shutdown simulation, it is considered that there is also an insulation layer in the riser, so that the configuration of the riser wall is the same as the pipeline wall. The mass flow rate used is 5 kg/s.

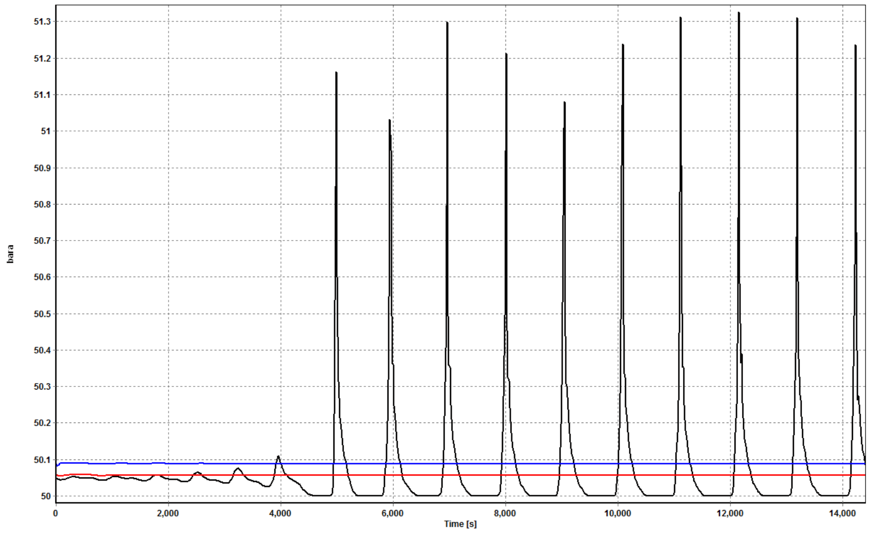

Figure 8. Pressure in the separator inlet over time with gas lift, for different injection gas mass flow rates: 0.2 kg/s (black), 0.6 kg/s (red) and 1.2 kg/s (blue).

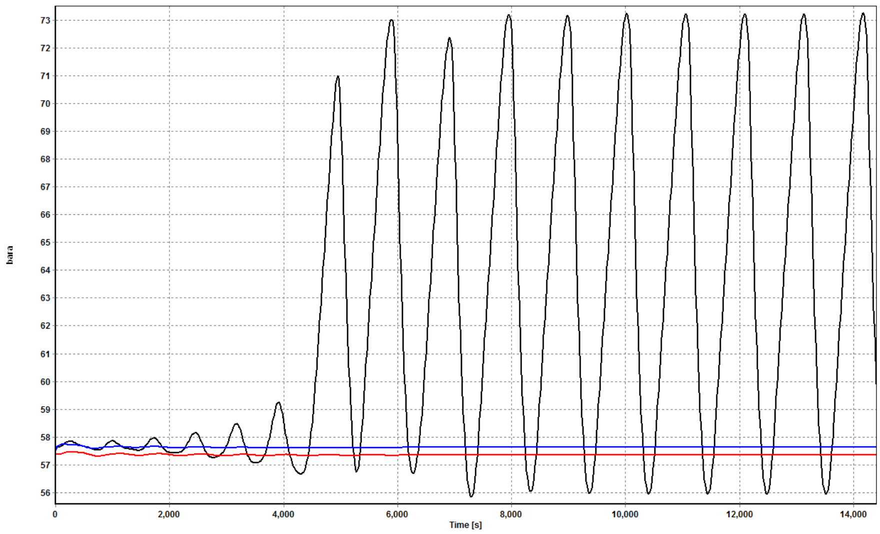

Figure 9. Pressure in the pipeline inlet over time with gas lift, for different injection gas mass flow rates: 0.2 kg/s (black), 0.6 kg/s (red) and 1.2 kg/s (blue).

To perform such simulation, it is necessary to add two valves to the system, one located at the pipeline inlet and other located at the riser outlet. During the simulation, after 2 hours of production, both valves are closed for a period of 4 hours. To determine if hydrate is formed during the shutdown, it is necessary to know the hydrate formation curve, which depends on the fluids composition. Assume that the hydrate formation curve is given by Fig. 11, in which the red region shows the favorable region for the hydrate formation.

OLGA has a variable called DTHYD that shows the difference between the hydrate formation temperature and the local fluid temperature at the local pressure.

Figure 12 shows that after 4 hours shutdown, the highest value that the variable DTHYD assumes is 9 ^oC, i.e. given the local pressure, the fluids temperature is 9 ^oC below the temperature of the hydrate formation curve. This means that hydrate formation is possible for the system with only 15 mm of insulation thickness.

Figure 13 shows the variable DTHYD along the pipes after 4 hour shutdown for insulation thicknesses of 30, 40, 50, 60, 70 and 80 mm.

Observe that the minimum thickness that maintain the temperature in the entire system 5 ^oC above the temperature of the hydrate formation curve is 50 mm.

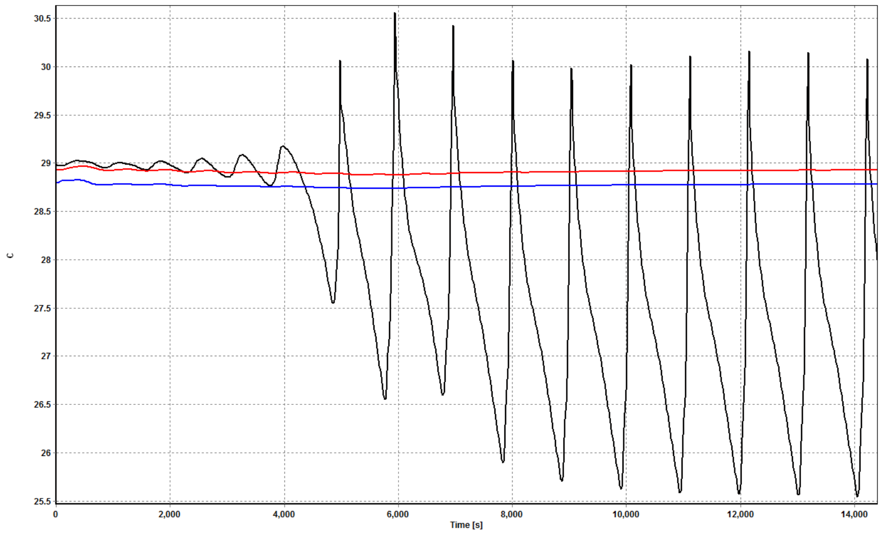

Figure 10. Temperature in the separator inlet over time with gas lift, for different injection gas mass flow rates: 0.2 kg/s (black), 0.6 kg/s (red) and 1.2 kg/s (blue).

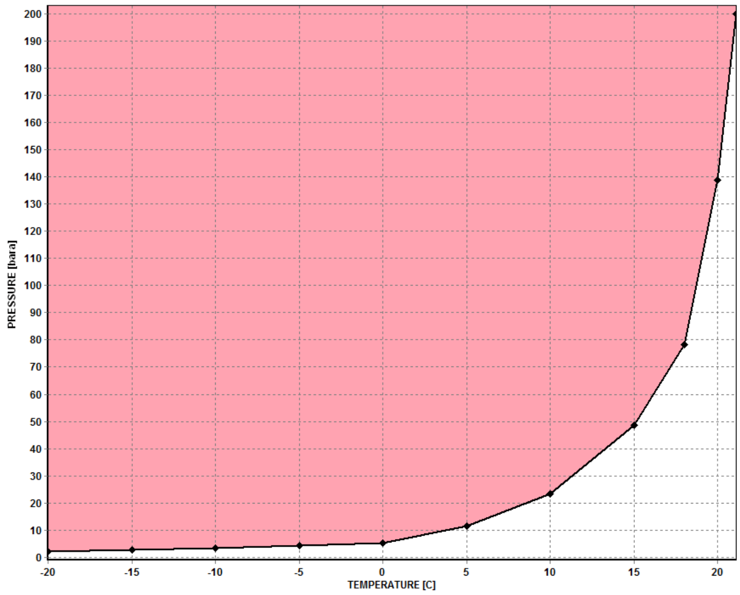

Figure 11. Hydrate formation curve.

7. CONCLUSIONS

Some of the flow assurance principles were applied to the thermal-hydraulic design of an offshore petroleum production system in order to avoid future downtime and intervention necessity. OLGA was used during the entire project process and PVTsim was used to calculate the properties of the fluids.

The pipeline inner diameter was dimensioned to keep the pipeline inlet pressure under predetermined limits and different insulation thicknesses were tested to assure that the fluids arrival temperature is above the wax and hydrate formation temperature.

Using a more detailed pipeline profile, it was observed that production instabilities exist and to eliminate the big pressure and flow variations, two modifications in the system were tested. Either valve closure or gas lift were able of stabilizing the flow.

During a production shutdown the fluid temperature decreases, so that hydrate formation becomes possible. The pipeline and riser insulation thickness was calculated to avoid this phenomenon, that could cause blockage of the fluid flow.

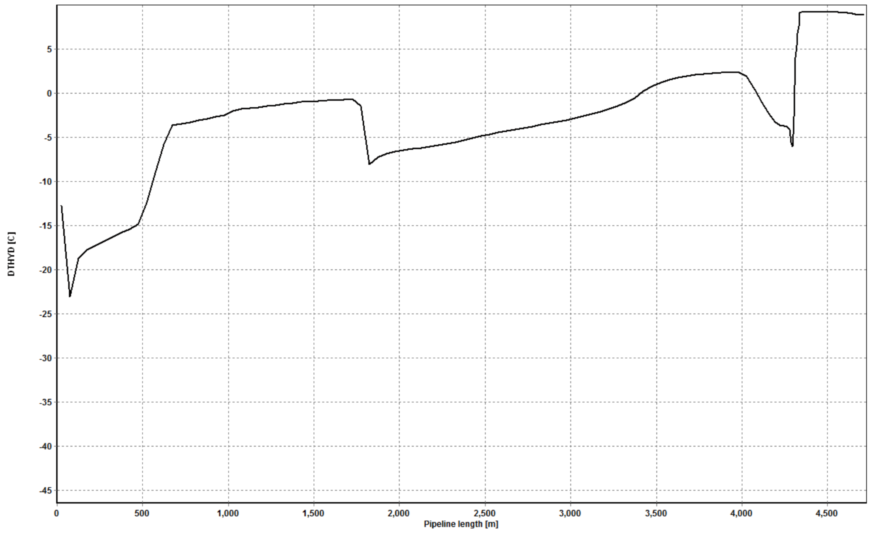

Figure 12. Variable DTHYD along the pipes after 4 hour shutdown for the original system.

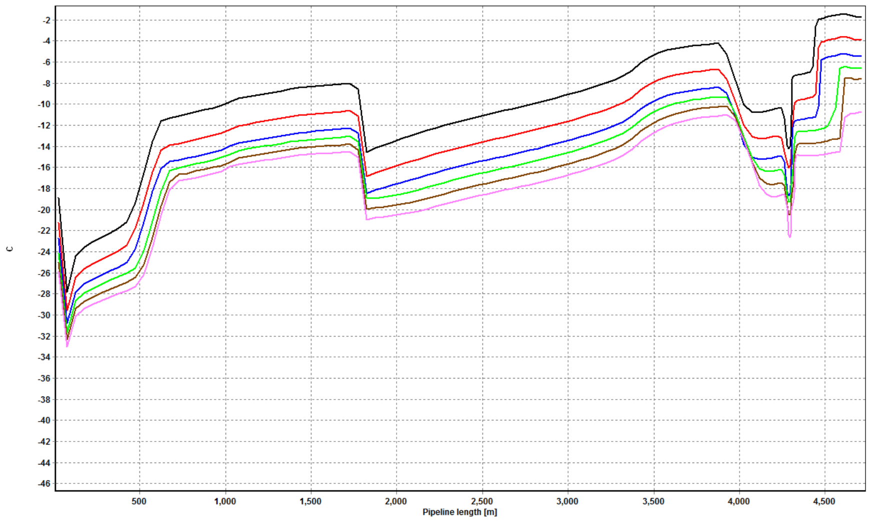

Figure 13. Variable DTHYD along the pipes after 4 hour shutdown for different insulation thickness: 30 mm (black), 40 mm (red), 50 mm (blue), 60 mm (green), 70 mm (brown) and 80 mm (pink).

8. ACKNOWLEDGEMENTS

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9. REFERENCES

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