ISSN 2278-7763

SMART CONTROL OF HYDRODYNAMIC SLUG FLOW

Inyiama, Fidelis Chidozie; e-mail: < f.c.inyiama@cranfield.ac.uk>

Yi Cao; e-mail: <Y.Cao@cranfield.ac.uk>

Department of Offshore, Process Systems and Energy Engineering

Cranfield University, MK43 0AL, Bedfordshire, England, United Kingdom

Abstract

Slugging is the intermittent flow regime in which large bubbles of gas flow alternately with liquid slugs at randomly fluctuating frequency in pipelines. This occurs when the velocity difference between the gas flow rate and liquid flow rate is high enough resulting in an unstable hydrodynamic behaviour usually caused by the Kelvin-Helmholtz instability.

Smart control technology, though effective for the control of severe slugs, has not been applied for hydrodynamic slug mitigation. This work investigated the application of smart control for mitigating hydrodynamic slug problem to enhance oil production and recovery.

Smart Proportional-Integral (PI) control strategy based on measurement of pressure at the riser base as controlled variable with topside valve choking as manipulated variable was therefore investigated through Olga simulation. A control system that used the topside choke valve to keep the pressure at the riser base at or below the average pressure in the riser slug cycle was contrived. This was found to prevent liquid accumulation or blockage of the flow line.

OLGA (Olga is a commercial software widely tested and used in the oil industry) has been used to assess the capability of smart control strategy for hydrodynamic slug control and has been found to give useful results and most interestingly increase in oil production and recovery. The riser slugging was suppressed and the choke valve opening was increased from 8% to 12.65%, representing an improvement of 4.65% in the valve opening. Secondly, implementing smart control at open-loop condition reduced the riser base pressure from 15.3881bar to 13.4016bar.

Keywords: Bifurcation map, choking, close-loop, feedback control, flow regime, multiphase, open-loop, OLGA

1.0 Introduction

The ever increasing population and urbanization with the attendant high demand for energy, coupled with increase in oil prices since 1970s, has necessitated extensive research on finding new technologies that can increase oil production and recovery from different oil fields. Today many oil wells are located at satellite fields and hostile offshore environment where the productions from several wells are transported via manifolds in tie-in long distant pipeline from seabed to the receiving process facility. In this regard, a mixture of gas, oil, water and sometimes sand, hydrates, asphaltenes and wax are transported through distant pipelines to the platform for processing. The flow assurance challenges cover an entire spectrum of design tools, methods, equipment, knowledge and professional skills needed to ensure the safe, uninterrupted and simultaneous transport of gas, oil and water from reservoirs to the processing facility (Storkaas, 2005). The cost of processing offshore is enormous in terms of Capital Expenditure (CAPEX) and Operation Expenditure (OPEX) due to technical difficulties of producing offshore, and considering the limited space available and other consideration such as harsh weather.

Slug flow that arises in multiphase (gas, oil, water) transport is a major challenge in oil exploration, production, recovery and transport. Slugging is the intermittent flow regime in which large bubbles of gas flow alternately with liquid slugs at randomly fluctuating frequency (Issa and Kempf, 2003) in pipeline. Slug causes a lot of problems due to rapid changes in gas and liquid rate entering the separators and the large variations in system pressure. Slug flow is a regular phenomenon in many engineering applications such as the transport of hydrocarbon fluids in pipelines, liquid-vapour flow in power plants and buoyancy-driven equipment (Fabre and Line', 1992). The slug can be formed in low-points in the topography of the pipeline. It can be hydrodynamic induced slugging, terrain induced slugging or operation induced slugging.

Hydrodynamic slugging, which is the main subject of this paper occur in a horizontal or near horizontal upward inclined pipes and can be generated by two main mechanisms

(i) natural growth of hydrocarbon instability and (ii) liquid accumulation due to instantaneous imbalance between pressure and gravitational forces caused by pipe undulations (Issa and Kempf, 2003) .

For the natural growth phenomenon, small random perturbation of short wavelengths arising naturally may grow into larger and longer waves on the surface of the liquid due to the Kelvin-Helmholtz instability (Ansari, 1998). These waves may continue to grow as they travel the length of the pipe line, picking up liquid flowing ahead of them, until they bridge the pipe cross-section, thereby forming slug. At this point the liquid volume fraction (holdup) is unit as the gas volume fraction tends to zero. When the slug front travels faster than the slug tail, the slug grows. Conversely, if the slug tail travels faster than the slug front, the slug decays. If the slug front and the slug tail travel at the same speed, a stable slug is obtained. When the gas velocity is high enough, gas will be entrained in the liquid as gas entrainment Figure 1-1.

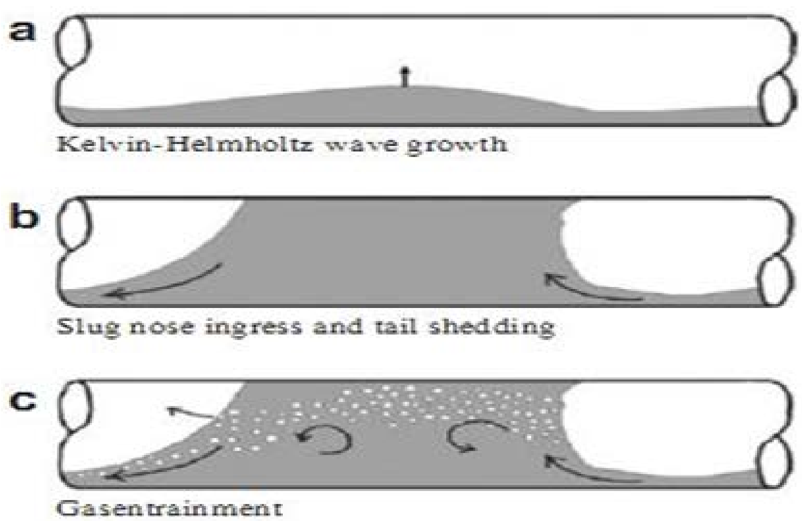


Figure **Error! No text of specified style in document.**-1 Hydrodynamic slug propagation (Varne, V. 2010)

The holdup and surging from the horizontal flow line are transmitted to the relatively short riser and the riser may have to handle far more liquid than normal as a result of the surge from the plug of liquid. Hydrodynamic slug mitigation, which is the main thrust of this paper, is a non-zero limit flow of liquid slug and gas pocket due to wave instability and velocity difference between the gas and liquid. Due to the dynamics of the wave instability, it is usually difficult to predict hydrodynamic slug volume.

As the multiphase fluid travels the length of the pipeline, due to the velocity difference between the gas and the liquid and other related phenomena like wave instability, the flow regime changes from stratified to a wavy and plugged hydrodynamic slugging that may block the passage of gas in the flow line as depicted in Figures 1.1 and 1-2 (Varne, V. 2010).

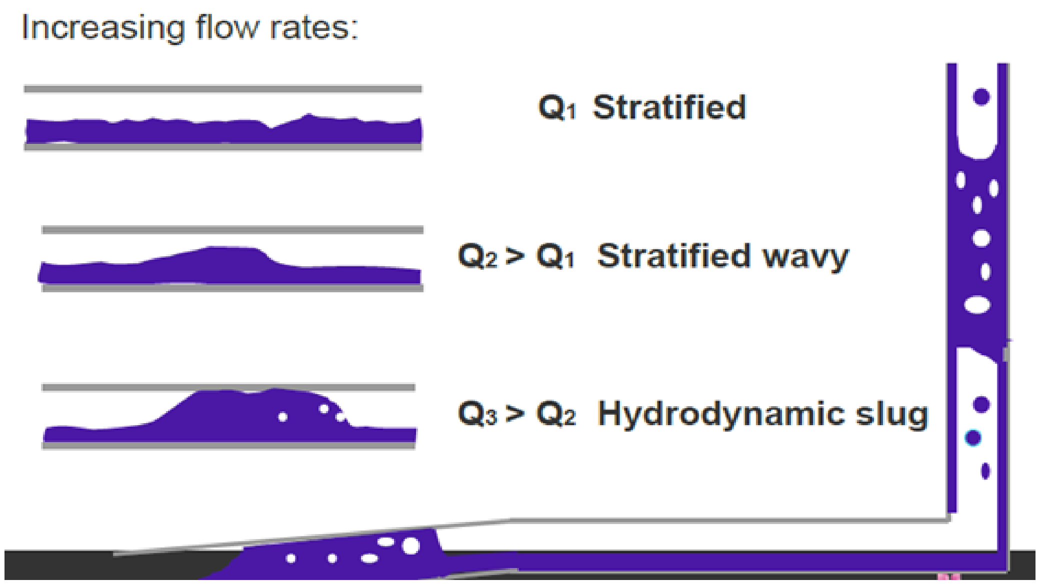


Figure **Error! No text of specified style in document.**-2 Hydrodynamic slug flow regimes (Varne, V. 2010)

In real flow, all these events take place at different times, hence some slugs grow, while others collapse and they may travel at different speeds leading to the merging of some slugs with others (Taitel and Barnea, 1990).

In the case of liquid accumulation, slug flow may form at pipe dips due to the retardation and subsequent accumulation of liquid in the dips, leading to the filling up of the cross-section with liquid. This is an extreme example of terrain induced slug flow also called “severe slugging” and it occurs when a slightly downward inclined pipeline meets a vertical riser (Schmidt et at, 1985; Jansen et al, 1996).

ISSN 2278-7763

Slug may arise by the combination of the mentioned mechanisms simultaneously in long hydrocarbon transport pipelines. In such cases, the slugs generated from one mechanism interact with those arising from the second leading to a complex pattern of slugs (Issa and Kempf, 2003).

The intermittency of slug flow causes severe unsteady loading on the pipelines carrying fluid as well as on the receiving facility such as the separators. This gives rise to problems in design and therefore it is important to be able to predict the onset and subsequent development of slug flow and its control.

The purpose of this work was to investigate the capability of smart feedback control strategy based on measurement of pressure at the riser base as controlled variable with topside valve choking as manipulated variable with PI controller in Olga simulation to mitigate hydrodynamic slug flow.

1.1 Why is Slugging a Problem?

The resulting increased topside instability caused by pressure build-up can lead to:

- Liquid overflow in the separator
- High pressure in the separator
- Poor phase separation
- Fatigue due to repeated impact
- Overload on gas compressors (Mehrdad, 2006)
- Platform trips and possible early platform abandonment
- Long term damage to the reservoir due to resulting bottom-hole pressure variations, causing permanent decrease in the production of oil and gas from the reservoir (Ogazi et al, 2010)

1.2 Slug Mitigation and Prevention Methods

There are a number of slug mitigation and prevention methods, which includes:

- “Increasing the flow rate
- Slug catcher
- Riser base gas injection

ISSN 2278-7763

- Gas lift in the well
- Fixed topside choking
- Combination of gas injection and topside choking
- Smart feedback control
- Multivariable control
- Modified flow line layout and riser base geometry to avoid a dip" (Yocum, 1973).

2.0 Modelling the Case Problem / Methodology

An industrial scale case study of 6km flow-line and 46.2m high riser which was developed by (Burke and Kashou 1996), was modelled in Olga 7.1.3 and adapted for the current work for the current investigation.

Smart feedback control of hydrodynamic slug using topside choke valve assured smooth flow and improved oil production and recovery.

2.1 Building Olga Model for the Numerical Simulation.

The real case problem which was extensively described by Burke and Kashou (1996) was an offshore platform suffering hydrodynamic slug and located off the coast of Nigeria in West Africa. This case problem was used as starting point to model the Olga case. The detail of the case is explained hereunder.

2.2 Numerical Simulation

Numerical simulation is a machine thinking approach in predicting transient multiphase flow behaviour in pipeline by imitating a real industrial situation. A number of software is available in the market to deal with numerical analysis of multiphase problems. Olga is one of the most used and tested software in the market. Olga 7.1.3 is used in this project to study the effectiveness of smart feedback control and choking at the topside to mitigate hydrodynamic slugging.

ISSN 2278-7763

- The case study platform located off the coast of Nigeria in West African suffering hydrodynamic slug flow was described by (Burke and Kashou,1996).The paper was used as starting point to build an Olga model.
- Manual choking of the valve opening was investigated till stability was attained. The maximum percentage valve opening to attain stability was recorded. Stabilisation is attained when the holdup and pressure oscillation at the riser top and riser base are reduced or eliminated.

A Hopf bifurcation map of the manual choke was generated from the simulation and a PI controller was designed at the critical valve position.

2.3 Pipeline Inlet Flow Rate:

Oil production 5,318 stb/d.

Gas production 5,351MMscf/d.

Water production 257stb/d.

Liquid production 5,575stb/d (oil plus water = 5,318+257).

Gas Oil Ratio (GOR) 1,006scf/stbo.

Gas Liquid Ratio (GLR) 960 scf/stbl.

Water-cut 4.61%.

Oil gravity 31.9° API.

Liquid production, GOR, percentage water-cut and oil gravity are used in the Olga model, while the balance of parameters is obtained from the former as well as the PVT table.

ISSN 2278-7763

Table 2-1 shows the fluid composition as applied in the fluid PVT calculations.

Table 2-1 Burke and Kashou (1996) fluid PVT composition.

Component	Mole %
C_1	45.88
C_2	6.64
C_3	4.72
$i\text{-}C_4$	1.2
$n\text{-}C_4$	2.13
$i\text{-}C_5$	1.21
$n\text{-}C_5$	1.12
C_6	2.03
C_7	2.98
C_8	3.62
C_9	2.98
C_{10}	2.67
C_{11}	2.26
C_{12}^{+}	19.01
CO_2	0.19

N_2	0.59
Total	99.23
Sub-total C_1 to n-C_5	63.68%

Gas mole % in the fluid composition is the sum of mole percentages of C_1 till n-C_5 in Table 2-1 = 63.68%.

Hence, CO_2 *mole percent* in the gas phase = 0.19/63.68x100 = 0.3%.

N_2 mole percent in the gas phase = 0.59/63.68x100 = 0.93%.

2.4 Pipeline Inlet Condition.

The pipeline inlet condition stated below was adapted for the investigation and hence initialised in the Olga model window for the numerical simulation.

Pressure in the range 20.3–21.0 bar.

Temperature 83.3°C.

2.5 Pipeline Outlet Condition.

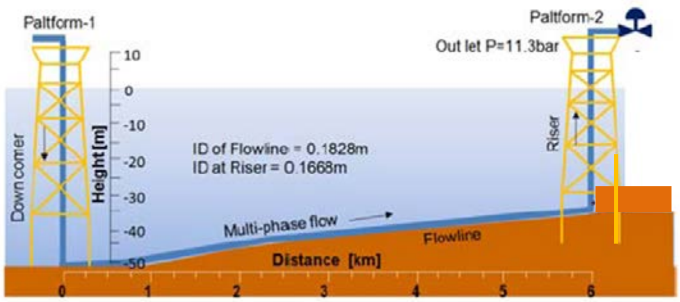
In a similar vein the outlet condition depicted below was adapted for the investigation hence initialised in the Olga window to specify the outlet condition for the numerical simulation.

Pressure in the range 11.3-14.8 bar.

Temperature 23.9°C.

2.6 Burke and Kashou (1996) Pipeline Profile.

The detail of Burke and Kashou (1996) case study platform profile is explained in Figure 2-1 and was adapted for the analysis. The case problem definition, inlet and outlet condition parameters were calculated and initialised in the Olga window.



.

Figure 2-1 Schematic diagram of pipeline adapted from (Burke and Kashou, 1996).

The pipeline profile consists of 59.7m down-comer, 11m above the sea level, 6km flow line and 46.2m high riser.

The pipeline outlet is at 12.2m above the sea level. The ambient temperature surrounding of the sea water is 22° C. It is noted that the pipeline is not buried and roughness is assumed to be 0.0018"(0.04572mm).

An inlet source named oil at the first section of the pipeline was configured as closed node, implying that analysis was from the wellhead only while the pipeline outlet was configured as pressure node with pressure set at 11.3bar and temperature set at 23.9℃. Figure 2-2 shows the pipeline configuration with the nodes and the source inlet.

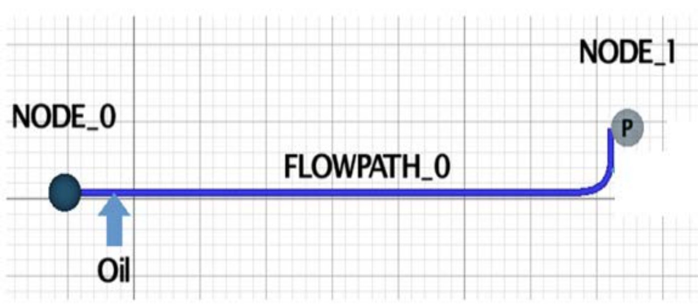


Figure 2-2 Schematic diagram of Olga model with the nodes and source inlet.

3.0 Results and Discussion

The model was validated by a profile plot of the flow regimes as calculated by Olga model depicted in Figure 3-1. From the plot Figure 3-1 the flow regime at inlet was annular (2) and as the fluid travels the length of the pipeline, the flow regime changed to slug flow (3).

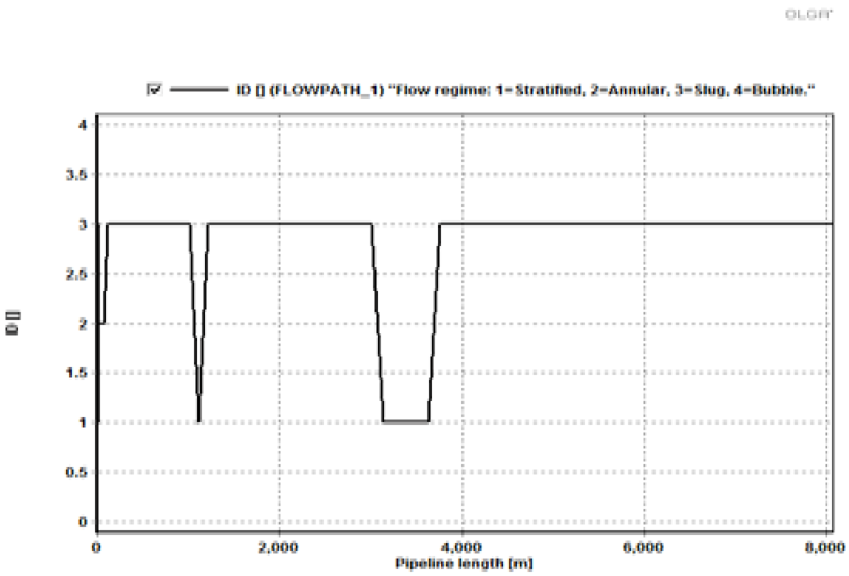


Figure 3-1 Flow regimes observed in the case platform indicating that flow was in slug region shown as 3.

The flow regime map for the riser as obtained from Olga simulation at the operating point of 5,575stb/d liquid production, 960scf/stbl GLR and 4.61% water cut is marked red in the flow regime map. It is evident from the map that the operating point marked red is within hydrodynamic slug region close to churn flow Figure 3-2.

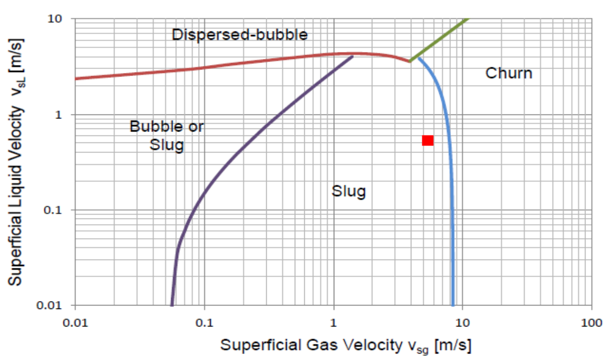


Figure 3-2 Flow regime map of the industrial riser system

3.1 Hopf Bifurcation Map

A bifurcation map was generated through parametric study and the matrix of the topside choke valve opening were [100, 90, 80, 70, 60, 50, 40, 30, 20, 18, 16, 14, 12, 10, 9, 8, 7, 6, 5, 4, 3, 2, 1].
From the plot of valve opening on the x-axis and pressure on the y- axis the bifurcation map Figure 3-3 was generated.

Bifurcation occurs in a dynamic system, when the system loose stability due to changes in the independent variable (Thompson and Stewart, 1986). For the riser pipeline system, Hopf bifurcation can occur if a change of the valve opening causes the system to become unstable at an operating point. Below this valve opening, the riser slugging does not exist and the flow is stable, but pressure in the pipeline is considerably high for optimal production. This is the flow regime used when the choke valve opening is kept low as described in a bifurcation map. This implies that the point where slugging starts (onset of slugging) in open loop system (bifurcation point) is a specific parameter value where the qualitative behaviour of nonlinear differential equation system, changes from equilibrium solution to a periodic solution (Verhulst 1990). This unstable equilibrium was the operating point that was stabilized using smart feedback control as shown in (Figure 3-3). Hopf bifurcation map of the industrial riser system shows that the pressure oscillates between a maximum (red line) and minimum (blue line) values as shown in solid lines while the dotted (black line) represents the virtual steady state value. This bifurcation map was generated through simulation studies. The open-loop control of the industrial riser system requires the manual choke valve in order to transform the unstable flow condition in the system to stable flow condition.

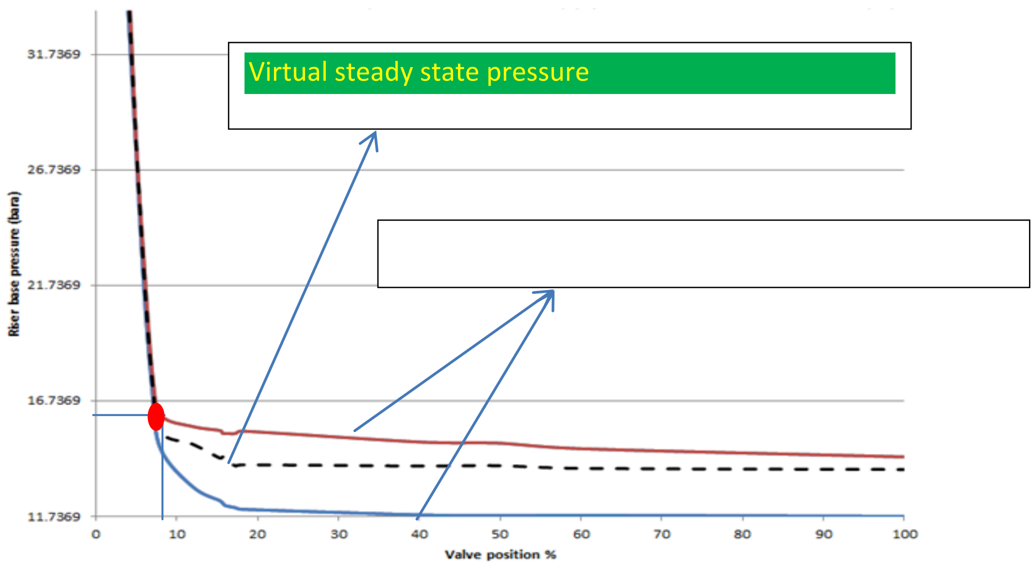


Figure 3-3 Hopf bifurcation map of the industrial riser system at liquid source flow rate 5,575std/d, GOR 1006 scf/stbo and 4.61% water-cut.

The bifurcation map indicates that the maximum valve opening corresponding to a stable system $u_{max} =$ 8%. For $u > u_{max}$ the system become unstable and oscillates between a maximum and minimum pressure values. Thus u_{max} is known as the bifurcation point marked red in Figure 3-3. The riser base pressure P_{RB} was calculated from the system for 8% $< u \leq$ 100%. The critical value indicated by the bifurcation map gives a minimum pressure 15.3881 bar P_{RB} and maximum value of u the system can be stabilized by manual choking. The interest is to stabilise the system at unstable operating points, where the values of u are larger than this critical value such that the total pressure drop across the riser and the valve is reduced and thus the overall production is increased.

The Hopf bifurcation map shows the maximum valve opening that can stabilise the system as an open –loop and a maximum manual valve opening of 8% was achieved. This valve opening is also known as the critical valve opening beyond which the system will be unstable as in Figure 3-3

At and below this valve position, slugging does not exist and the system can be operated as an open-loop stable system without oscillation and without control. Above

8% valve opening, the system will become unstable, with a pressure oscillation between a minimum and maximum pressure value as shown by the solid lines in Figure 3-3. The dotted line represents the virtual steady state pressure value.

3-2 Implementing Riser Base Pressure P_{RB} Control and Effect of the Smart Feedback Control

The riser base pressure $\boldsymbol{P_{RB}}$ is the sum of the downstream pressure plus the hydrostatic pressure as a result of the weight of the riser content, friction loss and pressure due to acceleration in the riser (Storkaas, 2005). It has a very significant role in the slug control objective of stabilised flow and optimal production as in equation 1-1.

$$Q_T = \int_0^t G_M \, dt \; = \; B_0(P_0 \; - \bar{P}_{RB})T = \; Q_0 - \; Q_P \qquad (1-1)$$

The target is to reduce the riser base $\bar{P}_{RB}$ pressure and keep the pressure at the riser base at or below the average pressure in the riser slug cycle, thus preventing liquid accumulation or blockage of the flow line by manipulating the topside choke valve position to control the riser base pressure.

3-3 Effect of Smart Control of Topside Choke Valve Opening

The application of automatic PI feedback control on the topside choke valve, transformed the system to close-loop system and the system operated in the open-loop unstable region with increased valve opening and reduced riser base pressure represented by the green and yellow curves of (Figure 3-4). The controller was designed at the riser base pressure of 15.3881 bar. As the pressure set-point was gradually reduced, the valve opening increased from 8% to 12.65%, a 4.65% increase in valve opening. A further increase beyond this valve position caused the system to lose stability and the riser base slugging reappeared.

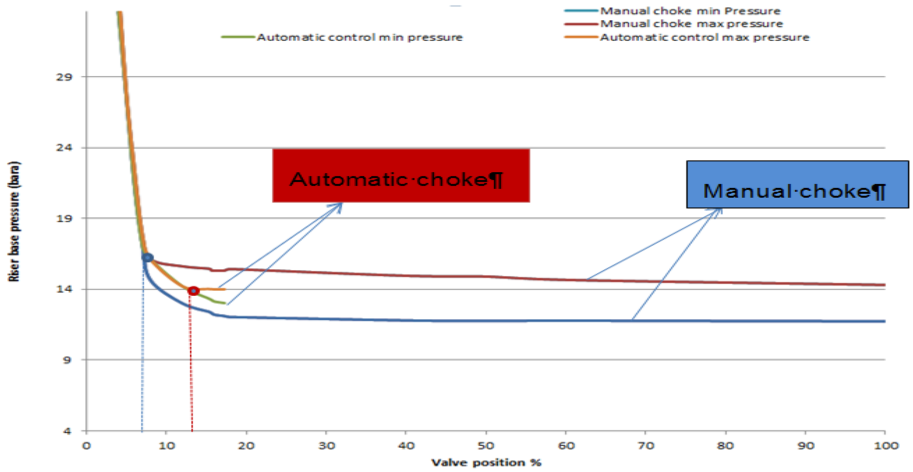


Figure 3-4 Comparison of the improvement of the automatic topside choke over the manual topside choke using riser base pressure automatic control $\boldsymbol{u_C} = \mathbf{12.65}$ %, $\boldsymbol{P_{RB}} = \mathbf{13.4016}$ bar, $\boldsymbol{K_c} = \mathbf{0.001}$, $\boldsymbol{\tau_I} =$ 100 (s), $\tau_{d} = 0$(s) and pressure set-point 14.6675 bar. The valve opening improved by 4.65% from the manual choke.

The blue and red solid curves represents the manual choke minimum and maximum pressures while the green and yellow curves represents the automatic controller minimum and maximum pressures as compared with the result of the manual control.

ISSN 2278-7763

4.0 Conclusion and Recommendation

Hydrodynamic slugs have been found to occur in a horizontal or near horizontal pipeline by two main mechanisms (i) natural growth of hydrocarbon instability due to Kelvin-Helmholtz instability (ii) liquid accumulation due to instantaneous imbalance between pressure and gravitational forces caused by pipe undulations. Slug may also arise by the combination of the two mechanisms presented simultaneously in long hydrocarbon transport pipeline. In such a case, the slug generated from one mechanism interacts with those arising from the second mechanism leading to a complex pattern of slugs which may overtake and combine. The slug may grow when the slug front travels faster than the slug tail or travelling an upward inclination. It may decay when the slug tail travels faster than the slug front or travelling a downward inclination. If both the slug front and the slug tail travel at the same speed, a stable slug may be formed.

Smart feedback control technology has not been extended for the investigation of hydrodynamic slug control in the literature. This extension of the capability of smart feedback control technology with topside choke valve to mitigate hydrodynamic slug flow is the main contribution of the present paper.

An Olga model was built on the case study platform. The case definition statement, the inlet and outlet conditions, the fluid PVT file and the flow geometry were applied to calculate the parameters that were initialised in the Olga window to model the dynamics of the case problem in line with the field characteristics.

A review of hydrodynamic slug control techniques, including their applications, limitations and challenges were discussed in the paper. These techniques include manual choke valve technique, slug catcher, gas-injection, combination of gas-injection and choking, smart feedback control of the topside choke, flow line modification and layout to avoid dips and splitting of flow into multiple streams. From the result of the investigation obtained from Olga simulation it was evident that:

❖ The use of manual topside choke valve alone as control strategy results in low valve opening 8%.

- The application of feedback control improved the choke valve opening from 8% to 12.65%..
- Feedback control was able to stabilise the system at limited valve opening of 12.65% achievable.
- There was significant reduction in back-pressure by implementing control at open-loop condition from 15.3881bar to 13.4016bar.
- Lower back-pressure than using manual choke method thus supressing the riser base slugging.
- The valve opening was increased from 8% to 12.65% with smart control representing more than 58.12% increase in the valve opening, when compared with manual choke.

This translates to an improvement in production.

4-1 Recommendation

- The result is recommended for laboratory verification
- It is subsequently recommended for physical field verification

5.0 Reference

Asari, M.R, (1998). *Dynamical behavior of slug initiation generated by short waves in two-phase air-water stratified flow*. ASME HTD 361. 289-295

Burke, N. E. and Kashou, S. F. (1996), Slug-sizing/slug-volume prediction: State of the art review and simulation", *SPE Production and Facilities,* vol. 11, no. 3, pp. 166-172.

Fabre, J. Line, A. Peresson, L. (1992). Two fluid/two flow pattern model for transient gas liquid flow in pipes. *In 4th International conference on Multiphase Flow*, Nice, pp 269-284

Issa, R.I and Kempf, M.H.W, 2003. Simulation of slug flow in horizontal and near horizontal pipes with two-fluid model. *International Journal of Multiphase Flow*. Pergamon

Mehrdad,P.Fard, John-Morten Godhavn and Svein, Ivar Sagatun. (2006) Modelling of severe slug and slug control with OLGA. *SPE International symposium and exhibition on formation damage control*. Lafayette, Louisiana

Ogazi, A. I, Cao, Y, Yeung, H and Lao, L. (2010), Slug control in large valve openings to maximize oil production, *Journal of Society of Petroleum Engineers. SPE*

Schmidt, Z., Doty, D. R. and Dutta-Roy, K. (1985), *Severe slugging in offshore pipeline riser-pipe systems*, vol. 25, no. 1.

Storkaas, E (2005), *Anti-slug control in pipeline riser systems*. PHD Thesis, Norwegian University of Science and Technology

Taitel, Y., Barnea, D, (1990).Two-phase slug flow. *Advanced Heat Transfer 20*, 83-132

Thompson, J.M.T. and Stewart, H.B. (1986). *Nonlinear dynamics and chaos*. John Wiley and Sons Ltd Chichester Great Britain, 1st edition

Varne Valle, (2010) *Field experience and analysis of hydrodynamic slugging*. Dynamic simulation seminar, Oct. 20 2010. www.statoil.com

Verhulst, F.A. (1990), *Nonlinear differential equations and dynamical systems.* New York: Springer-Verlag

Yocum, B. T. (1973), Offshore riser slug flow avoidance: Mathematical models for design and optimization", *SPE European Meeting,* 01/01/1973, London

6.0 List of Nomenclature

$\bar{P}_{RB}$ = Average riser base pressure over time T (bar)

B_0 = Production index

G_M = Production rate

$P_{\max}$ = Maximum pressure (bar)

$P_{\min}$ = Minimum pressure (bar)

P_0 = Flow line pressure (bar)

P_{RB} = Riser base pressure (bar)

P_{res} = Pressure of the reservoir (bar)

Q_T = Total production over time T (stb/d)

ISSN 2278-7763

V_{SG} = Superficial gas velocity (m/s)

V_{SL} = Superficial liquid velocity (m/s)

k_c = Process gain

u_c = Critical valve position

u_{max} = Maximum valve position

α_G = Gas volume fraction or gas fraction

α_L = Liquid volume fraction or liquid fraction

τ_I = Integral time constant

τ_d = Derivative time constant

API = Oil gravity

GLR = Gas-liquid ratio

GOR = Gas-oil ratio

MMscf/d = Million standard cubic feet per day

OLGA = OiLGAs

PI = Proportional-Integral control

PT = Pressure transmitter

PVT = Pressure-volume-temperature relationship

Scf/stbl = Standard cubic feet per stock tank barrel liquid

Scf/stbo = Standard cubic feet per stock tank barrel oil

Stb/d = Stock tank barrel per day

u = Valve position

