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Gas Injection for Hydrodynamic Slug Control

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Abstract: Gas injection as an effective method to mitigate hydrodynamic slug has been studied using OLGA simulation. Different control strategies have been investigated to reduce the amount of injected gas required to mitigate slugs. The control strategies are based on using a PI controller to control the valve opening of gas injection through various riser measurements used as controlled variables. The results show that the holdup transmitter at the riser top as the controlled variable is the best control strategy, followed by the differential pressure across the riser. It is also concluded that using riser top choking reduces the requirement of injection gas.

Keywords: Gas lift, hydrodynamic slug, riser, multiphase flow, slug mitigation offshore.

1. INTRODUCTION

Gas injection can be used for enhancing oil production by reducing the average density of the fluid flowing in a vertical well. It is also considered to be an effective method of mitigating terrain induced slug which can occur when a gas and liquid mixture flows in a pipeline with a downward inclination followed by an upward inclination pipe or riser. Gas injection can also be used to give a smooth start up process (Jansen, and Shoham, 1994).

However, some disadvantages of using gas injection were identified, for example, a high cost as it requires a large amount of injection gas, consequently a big compressor. Gas availability is another concern because of the large volumetric gas flow requirement (Jansen and Shoham, 1994).

Nevertheless, recently there are two key changes in the oil and gas sector making gas injection more favourable. One change is "No flaring" environmental policy enforcing the requirement of gas compression facilities available to all new development for export/or re-injection of gas. The other is moving the development of oil and gas industry toward more hostile environment where reservoir located in deep waters. The characteristic of deep water reservoirs is mostly a low-energy reservoir as the formation below the sea bed tends to be rather small (Pickering et al., 2001). Thus hydrodynamic slug mitigation using gas injection in this case will have two folded effect: enhancing liquid production and smoothing the flow fluctuations in a production line, e.g. mitigating hydrodynamic slug if any.

Hydrodynamic slugs produce substantial flow rate fluctuations, which may induce significant pressure oscillations over a riser.

Due to the high flow turbulence and with present of sand, hydrodynamic slug could also induce erosion inside the pipe which can damage the pipeline, thus accelerate carbon steel pipeline corrosion, if CO2 present in hydrocarbons (Villarreal et al., 2006).

In this paper, a performance study using OLGA simulation relating to gas injection method for hydrodynamic slug control is presented. Different control strategies are compared in terms of the effectiveness and gas consumption for hydrodynamic slug mitigation. Finally, based on the simulation results detailed discussion and conclusions are given.

2. SIMULATION CASE STUDY

The design and operation of offshore platforms is very critical in terms of operation expenditure (OPEX) and capital expenditure (CAPX). Predicating transient multiphase flow behaviour is almost impossible without the use of a numerical analysis method. There are several software packages available in the market that utilise numerical methods to deal with multiphase flow problems. OLGA is one of the most used and tested software tools in the market. It has a slug tracking function which can simulate hydrodynamic slug in a pipeline. It also has a function to configure/simulate typical controllers for a flow process. For these reasons, OLGA 6.3.2 will be used in this study to assess the performances of the method using gas injection at the riser base to mitigate hydrodynamic slug.

The simulation study procedures are as follows:

Firstly, an OLGA model for a pipeline is set up. Burke and Kashou (1996) described a real case problem of an offshore platform of West Africa suffering hydrodynamic slug. This case is adopted in this work to study gas injection control. Fig. 1 shows the pipeline profile, which consists of 59.7m down comer from 11m above the sea level, about 6km flowline and 46.2m riser with the outlet at 12.2m above the sea level. Top riser choking and gas injection line are added for this study. The OLGA model was verified by comparing the holdup profile at the riser base against the one obtained by Burke and Kashou (1996).

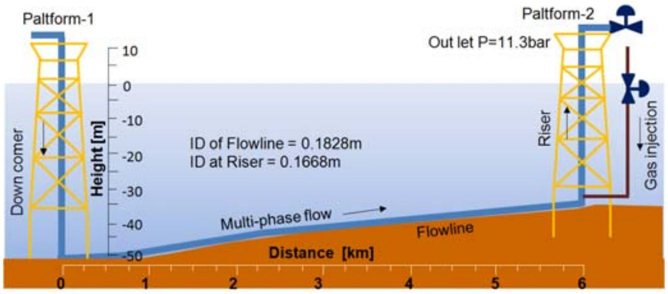

Fig. 1. Schematic diagram of pipeline with gas injection, pipeline profile as presented by Burke and Kashou (1996)

As shown in Fig.1, gas is injected at the riser base. The effect of injection flow rates are investigated through OLGA parametric study. The minimum amount of gas injection which can stabilise the flow in the riser.is obtained. The stabilisation will be attained when the holdup oscillation is reduced at the riser top and base, subsequently the pressure oscillation at the top and bottom of the riser will be reduced.

In order to reduce the required injection gas, active control of gas injection is introduced in the OLGA model. Different controlled variables are studied such as: pressure at the riser base, riser top, holdup, which is defined as the fraction of liquid occupied in a cross sectional area of the pipe, at the riser base and riser top, and differential pressure across the riser. A PI controller is used to manipulate the opening of a gas injection valve. A choking valve is installed downstream of the riser as shown in Fig.1. The valve is kept at an opening of 50% constantly for all cases studied in order to use the riser top measurement as a controlled variable.

3. RESULT AND DISCUSSION

The OLGA model developed in section 2 is configured with a choke valve at the riser outlet. Two opening positions; 100% and 50% are considered in the study and are referred to as "Texaco-1" and "Texaco-2", respectively.

2.1 Texaco-1 with constant mass gas injection

The OLGA model is operated at 5,575stb/d liquid production, 960scf/stb GLR and 4.61% water cut. Under this condition, hydrodynamic slug is observed in the riser. Fig.2 shows liquid slug at the bottom and top of the riser.

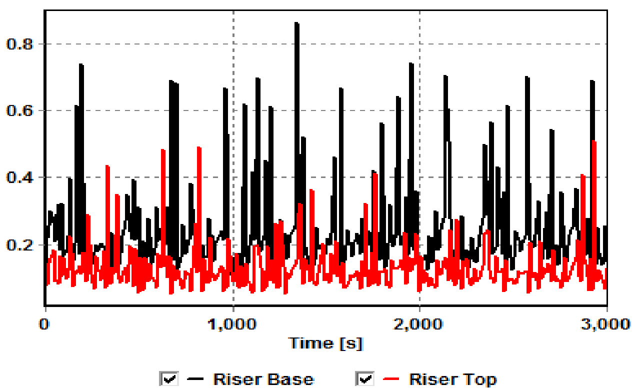

Fig. 2. Holdup at the bottom and top of the riser without gas injection

A parametric study is used to seek the minimum gas injection flow rate to eliminate slugging for Texaco-1 model. The minimum amount of gas injection obtained from the study is 1.282 MMscf/d. It is noted that if this amount of gas injection is reduced by 0.01MMscf/d, the riser will experience hydrodynamic slug. Fig.3 shows results where the OLGA model is run for a longer duration (3 hours) to confirm there is no hydrodynamic slug formation at this rate of gas injection.

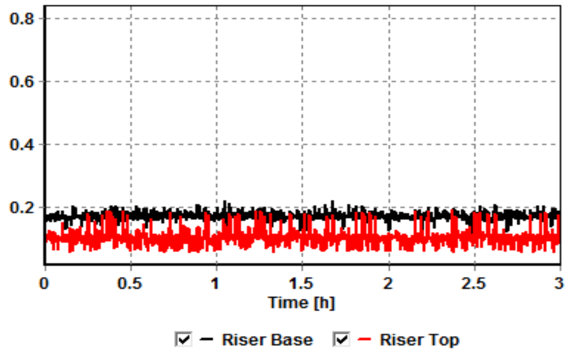

Fig.3. Holdup at the bottom and top of the riser with 1.282MMscf/d gas injection at the riser base

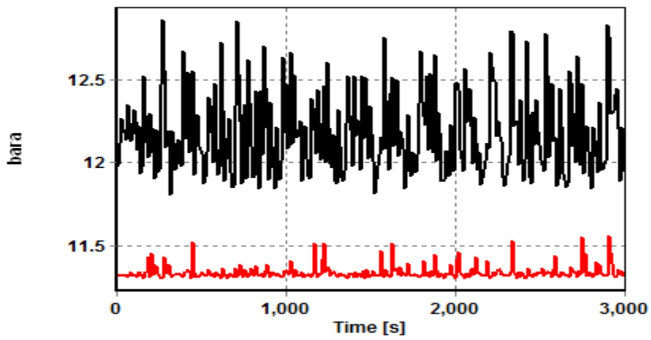

Fig.4. Riser bottom and top pressures without gas injection

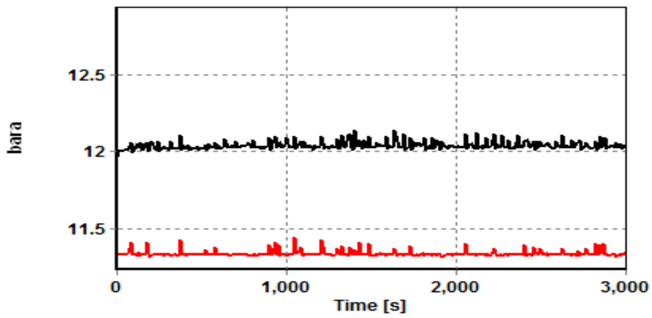

Fig.5. Riser bottom and top pressure at 1.282MMscf/d gas injection at the riser base.

Hydrodynamic slug induces riser pressure fluctuations. The riser bottom pressure exceeds 1bara fluctuation, whereas the pressure fluctuation is about 0.3bar at the riser top when there is no gas injection (Fig.4). It must be noted here that the top pressure is very much influenced by outlet pressure node, since it is configured as constant pressure. On the other hand, the pressure oscillation is very minor (less than 0.1bar in terms of standard deviation) both at the bottom and top of the riser with 1.282MMscf/d gas injection (Fig.5). The average bottom pressure in Fig.4 and Fig.5 are 12.172 and 12.040bara respectively. The bottom pressure is reduced when a gas is injected at the bottom of the riser, which is expected. The effect of gas injection by controlling the riser top pressure will be discussed with ‘Texaco-2’ model.

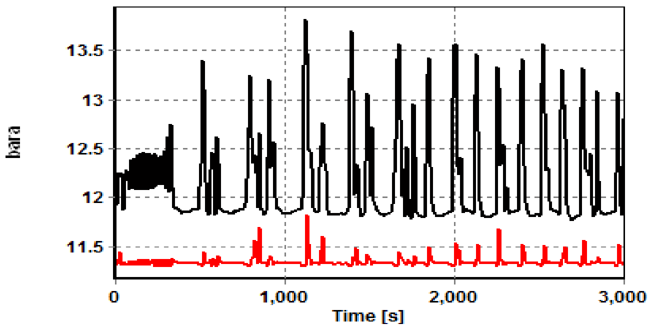

Fig.6. Riser bottom and top pressure at 1.282MMscf/d gas injection at the pipeline inlet

When the same amount of gas is injected at the pipeline inlet, different effect is observed in comparing with the case of riser base gas injection. Fig.6 shows the riser still experiences hydrodynamic slug at 1.282MMscf/d gas injected at the pipeline inlet. The effect of hydrodynamic slug under this operating condition is more severe compared with no gas injection case. This suggests the flow is still under slugging regime. This also shows that gas injection at the bottom of the riser is more effective than injecting the gas at the pipeline inlet. This result also suggests that hydrodynamic slug mitigation by gas injecting in the riser base can not be simply attributed to the increased superficial gas velocity in a gas/liquid flow system.

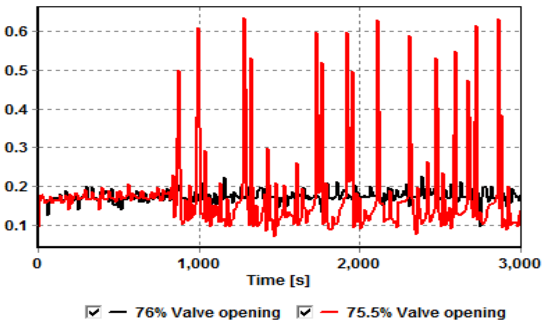

Fig.7.Holdup at the riser base at constant gas injection valve opening 76% and 75.5%

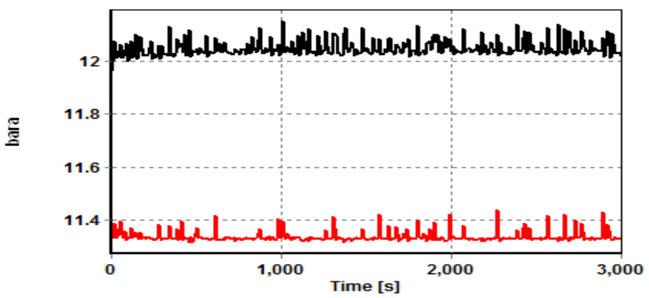

Fig.8. Riser bottom and top pressure at 76% gas injection valve opening

Constant valve opening is used as base line to assess the effectiveness of using different control strategies. Constant valve opening case represents more practical scenario than constant mass gas injection. Fig.7 compares riser base holdup at two different gas injection valve openings 76% and 75.5%. It is clear that the flow is stabilised at a valve opening of 76% while it is unstable at a valve opening of 75.5%. The riser base and top pressure oscillations are minor at 76% valve opening (Fig.8). The average volumetric gas injection flow rate is 1.232 MMscf/d.

2.2 *Texaco-1 with active control*

The control strategies used are riser base pressure and holdup as controlled variables (Fig.9). The results will be compared with the constant valve opening case.

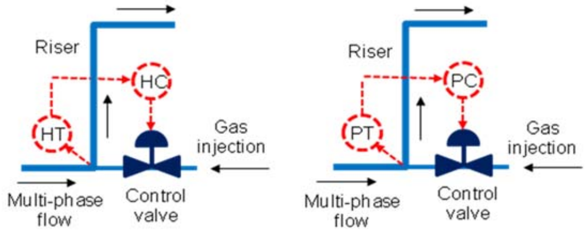

Fig.9. Holdup transmitter (HT) and pressure transmitter (PT) at the riser base.

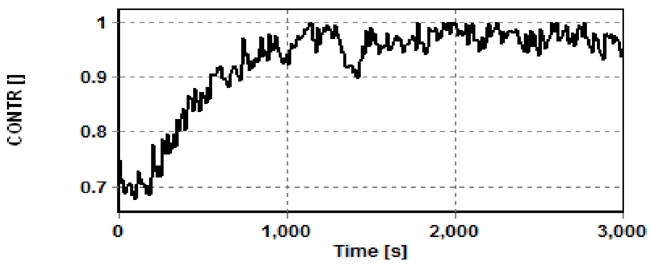

Fig.10. Controller response using pressure transmitter at the bottom of the riser, controller set point 12.03bara

Adopting control strategy with pressure at the riser base as controlled variable, a PI controller is used to manipulate gas injection valve opening. The hydrodynamic slugs are mitigated at pressure set point 12.03bara. The average amount of volumetric gas injection is 1.512 MMscf/d. This figure is much greater than using constant valve opening by 22.72%. Therefore; this control strategy does not reduce the amount of gas injection. There is a non-minimum phase response (Fig.10) where the controller response begins in the opposite direction of where it finishes.

Similar result is obtained with holdup at the riser base as controlled variable. The average volumetric gas injection flow rate is 1.284MMscf/d as, which is greater than that using constant valve opening by 4.22%. Although this concludes that the control strategy with holdup transmitter at the riser base is better than that using pressure transmitter at the bottom of the riser, however, both strategies do not reduce the amount of gas injection required to mitigate hydrodynamic slug in the riser. The controller with holdup transmitter at the riser base also experiences non-minimum phase response.

2.3 Texaco-2 model

In this model, the riser top choke valve is fixed at 50% opening in order to use topside pressure measurement. Fig.11 and Fig.12 show the riser experience hydrodynamic slug when there is no gas injection. The riser base pressure has fluctuations more than 1bar, while the riser top pressure has fluctuations over 0.5bar. The average bottom and top pressures are 12.34 and 11.49bara respectively. The increase of riser base and top average pressure due to choking are 0.17 and 0.15bara respectively. However, these are minor increases, which represent a 1.33 and 1.35% correspondingly.

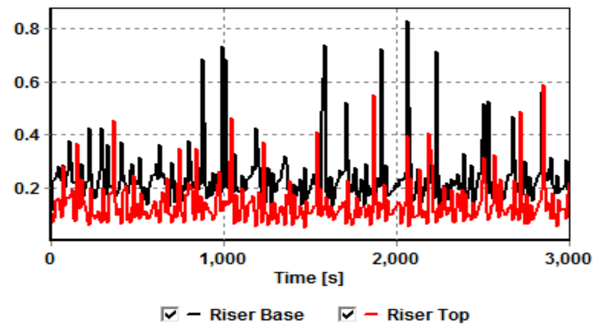

Fig.11. Holdup at the riser top and bottom at no gas injection

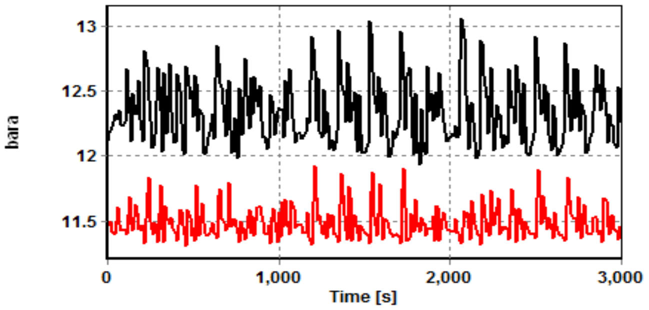

Fig.12 Pressure at the riser top and bottom at no gas injection

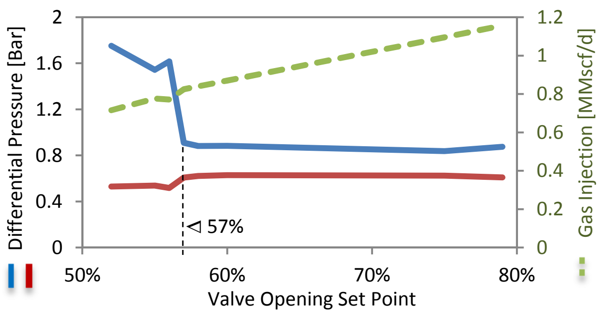

Fig.13. Bifurcation riser differential pressure (DP) and gas injection flow rate against constant valve opening

Constant valve opening is used as the base line for comparison with different control strategies. Fig.13 shows the flow become stable with the gas injection valve at an opening of 57%. The riser differential pressure oscillation reduced from more than 1.2bar to less than 0.3bar. The riser top and bas pressure oscillation reduced to less than 0.2 and 0.1bar respectively. The average gas injection flow rate is 0.825MMscf/d. This amount is less than the amount of gas injection required at constant valve opening using Texaco-1 model, where the riser top choke valve is fully open, (1.232MMscf/d) by 33%. The reduction represents the effect of choking valve downstream of the riser. The net effect to the riser base pressure from gas injection and choking is an increase by 0.08bar, which is a minor increase of back pressure.

2.4 Texaco-2 with active control

Adopting control strategy using PT and HT as controlled variable at the riser base and top, differential pressure (DP) across the riser, and controlled constant volumetric gas injection flow rate (FT) (Fig.14 and 15). The average gas injection to mitigate hydrodynamic slug using PT at riser base is 0.980MMscf/d (Fig.16), whereas the amount of gas injection when PT at riser top is 1.383MMscf/d (Fig.17). These amounts are higher than constant valve opening case by 18.8% and 67.6% correspondingly.

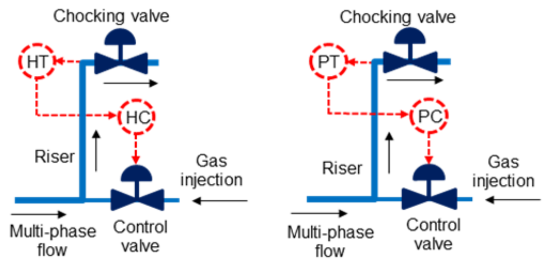

Fig.14. Holdup transmitter (HT) and pressure transmitter (PT) at the riser top.

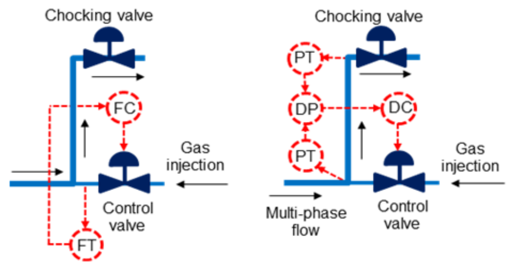

Fig.15. Flow transmitter (FT) downstream of the control valve and differential pressure (DP) across the riser.

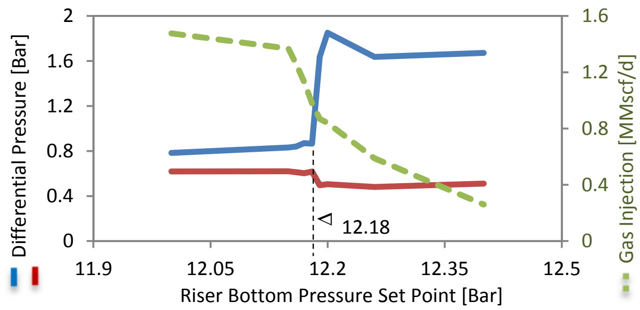

Fig.16. Bifurcation riser DP and gas injection flow rate against bottom pressure setpoint as controlled variable (CV)

In contrast, by using DP as controlled variable, the amount of gas injection is 0.688MMscf/d (Fig.18). This is an enormous reduction (-16.6%) compared with constant valve opening case.

Similarly, using control strategy with holdup at the riser base as controlled variable. The average gas injection flow rate to stabilise the flow in the riser are 0.822MMscf/d (Fig.19). This amount is almost the same as constant valve opening case with 0.4% less. This is an improvement from the same control strategy with Texaco-1 model. However, it is still not effective in reducing the amount of gas injection. In contrast, when holdup at the top of the riser is used as controlled variable, the average volumetric gas injection flow rate is 0.678MMscf/d (Fig.20 and Fig.21). This is the lowest amount of gas injection required to stabilise the flow in the riser compared with different control strategies and constant valve opening case. It is lower than that in constant valve opening case by 17.8%. This strategy also has the advantages of no subsea measurement requirement, which reduce the cost of maintenance.

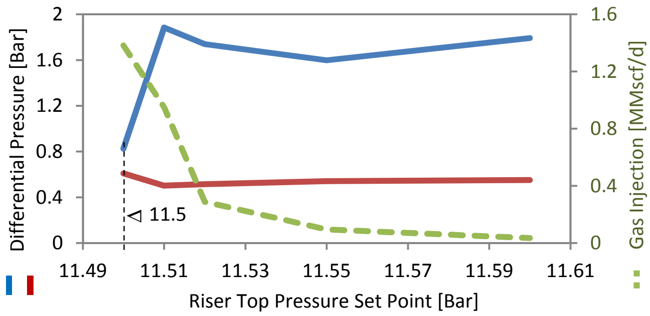

Fig.17. Bifurcation riser DP and gas injection flow rate against top pressure setpoint as CV

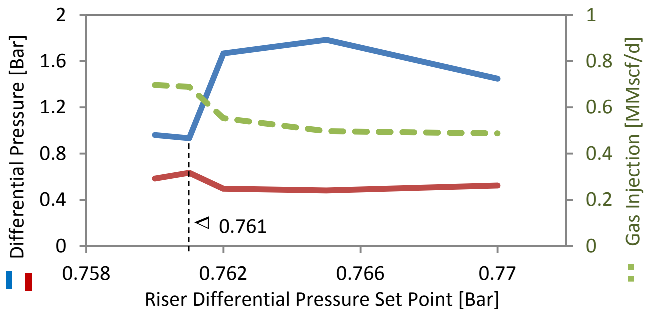

Fig.18. Bifurcation riser DP and gas injection flow rate against riser DP setpoint as CV

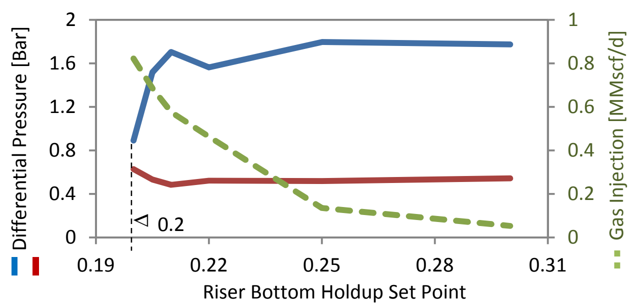

Fig.19. Bifurcation riser DP and gas injection flow rate against bottom holdup setpoint as CV

Constant volumetric gas injection strategy is the last control strategy used. This control strategy can be achieved by utilising gas flow rate at the gas injection pipe downstream of control valve as controlled variable. The hydrodynamic slug is mitigated by injecting 0.735MMscf/d average gas. This volumetric gas injection flow rate is less than constant valve opening case by 10.9%. Therefore; this control strategy is effective in reducing the amount of gas injection required to mitigate the hydrodynamic slug.

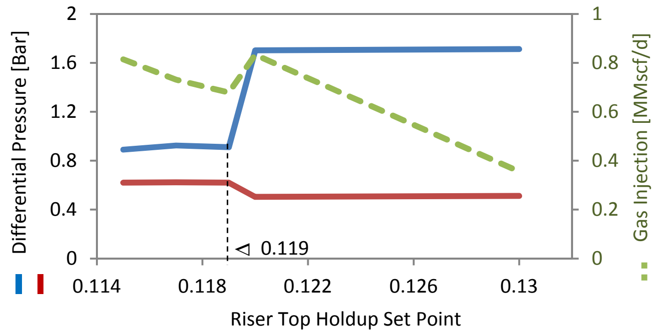

Fig.20. Bifurcation riser DP and gas injection flow rate against top holdup setpoint as CV

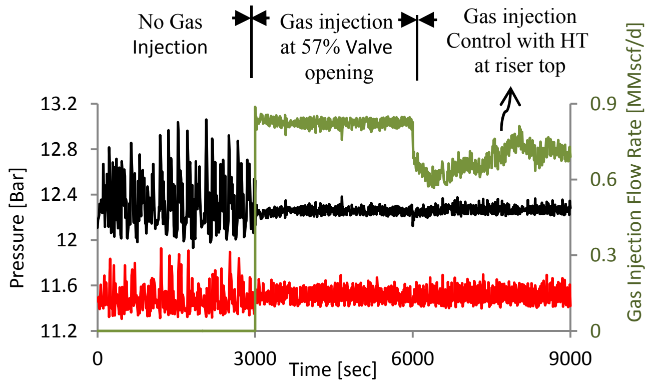

Fig.21. Pressure at the riser base and top and gas injection flow rate

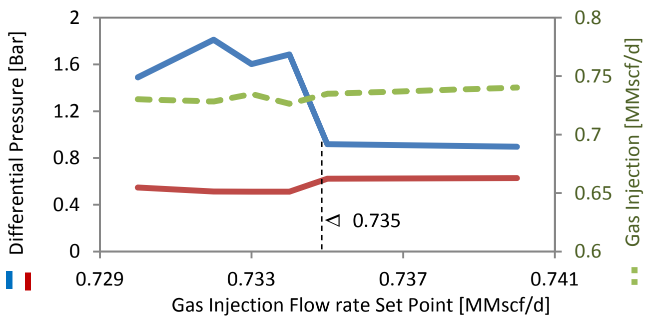

Fig.22. Bifurcation riser DP and gas injection flow rate against gas injection flow rate setpoint as CV

4. SUMMARY

All simulation results are summarised in Tables 1 and 2 below.

Table 1. Summary of gas injection required for different control strategies using Texaco-1 model

Control strategy	Gas injection [MMscf/d]	Reduction (-) / extra (+) gas injection
Constant valve opening	1.232	Base case
HT at riser base	1.284	+4.2%
PT at riser base	1.512	+22.7%

Table 2. Summary of gas injection required for different control strategies using Texaco-2 model

Control strategy	Gas injection [MMscf/d]	Reduction (-) / extra (+) gas injection
Constant valve opening	0.825	Base case
FC gas injection	0.735	-10.9%
HT at riser base	0.822	-0.4%
PT at riser base	0.98	+18.8%
PT at riser top	1.383	+67.6%
DP across the riser	0.688	-16.6%
HT at the riser top	0.678	-17.8%

5. CONCLUSIONS

4.1 Effect of gas injection to mitigate hydrodynamic slug

Injecting the gas at the riser base has been confirmed to be very effective method to mitigate hydrodynamic slug in the riser. It is noted that the amount of gas injection required to mitigate the slug is well within the amount produced by the platform. (The amount required in this study is 23% of volumetric gas produced by the platform, for example). It is also noted once a flow is stabilised at the bottom of the riser, the flow will stay stable along the whole riser. Reducing the riser base pressure is another advantage of using gas injection. This pressure reduction is a benefit to increase well production.

4.2 Effect of different control strategy to reduce the amount of gas injection

Two control strategies adapted with the Texaco-1 model: pressure and liquid holdup at the riser base as controlled variables, respectively, to manipulate the opening of gas injection's valve with the use of a PI controller. Both strategies do not reduce the amount of gas injection required, although using holdup at the riser base performs better than using pressure at the same location.

The control strategies used with the Texaco-2 model can be characterised as the use of different measurements in the riser base, top or both. The riser base measurements comprise of pressure and holdup transmitters, one at the time as controlled variable. These two control strategies do not show effectiveness in reducing the amount of gas injection required. The same result obtained when Texaco-1 model is used. Using top pressure transmitter as controlled variable is the worst control strategy to reduce the amount of gas injection required. The amount of gas required increased by 67.6% in contrast with constant valve opening case. However, combining pressures in riser top and base into differential pressure over riser as controlled variable proved to be very effective strategy. A 16.6% reduction of gas injection is achieved in comparing with the constant valve opening case. Furthermore, using holdup transmitter at riser top as controlled variable is the best control strategy. The gas injection required was reduced by 17.8% which is the highest reduction. In addition, it does not require subsea measurement which is expensive to install and maintain, and less reliable. Constant volumetric gas injection as control strategy proved to be effective in reducing the amount of gas injection required. The gas injection required is reduced by 10.9%

4.3 Effect of top riser choking in reducing the amount of gas injection

Evaluating the amount of gas injection required with the Texaco-1 model in contrast with the Texaco-2 model at constant valve opening case. The amount of gas injection required is reduced by 33% when the Texaco-2 model is used. This tremendous reduction in the amount of injected gas is solely related to the effect of choking at the riser top. The negative effect of choking on pressure loss through the choke is compensated by the positive effect of gas injection on reducing pressure loss across the riser. This confirms Jansen and Shoham (1994)'s outcome: combining gas injection with top riser choking exceed the effect of any single elimination in its own, although Jansen et al addressing severe slug mitigation in that study which has different characteristic from hydrodynamic slug.

6. FURTHER WORK

Extend the study to cover different gas to liquid ratio within the hydrodynamic slug region.

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