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Technical Paper

Investigation of slug mitigation: self-lifting approach in a deepwater oil field

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Abstract

Slug flow is a flow assurance issue that staggers production and, in some cases, 'kills the flow' of the well. Severe slugging, a type of slugging which usually occurs at the base of the riser column, causes large amplitudes in the fluctuation of pressure within the riser column and consequently damages equipment placed topside. An adaptation of a novel concept to slug mitigation: the self-lifting model, is presented. This model presents variations to the internal diameter of the self-lift bypass to produce effective mitigation to severe slugging.

Keywords: slug, severe slugging, self-lift, riser base pressure, OLGA

1. Introduction

An understanding of the multiphase flow phenomenon (a flow characterised by the gas and liquid phases), as well as the overall potential effects to the processing facilities, is required in the design of multiphase flow pipelines (Al-Kandari and Koleshwar, 1999). Al-Kandari and Koleshwar (1999) also argued that under or over-design of the piping can be counterproductive and may significantly affect process plant operability as well as the mechanised part of pipeline system. Therefore, the paper emphasizes the understanding of flow assurance and severe slugging in multiphase flow.

A major flow assurance issue in multiphase flow is the slugging phenomenon. The formation of slug arises from the flow regimes commonly found with the liquid and gaseous phases of hydrocarbon (crude oil and gas) in transit (Al-Kandari and Koleshwar, 1999). Shotbolt (1986) defined slugging as an intermittent flow that 'results in alternate delivery of liquid and gas phases'. This delivery is caused by the difference in superficial velocities of the phases, which can cause liquid surges within the pipes.

Slugging can be observed within the vertical or inclined flexible riser and within the horizontal section of the piping lying on the seabed (Oseyande, 2010). The inclined orientation of flowlines, with hydrocarbon content flowing upwards, does tend to assist the initiation of slug flow (Al-Kandari and Koleshwar, 1999). Shotbolt (1986) emphasises that slug flow affects three major areas of concern:

1. It impacts the 'volume and arrival rate of the worst liquid slug expected', as well as the 'differences between pressures and flowrates at the start and end of the gas bubble flow'.
2. Sufficient riser base pressures capable of stopping flow within the pipeline (i.e. 'kill' the well flow) can be generated when the riser is filled completely with liquid. Research carried out by Yocum (1973) stated that 50 % capacity losses in flow have been observed to avoid slugging in risers.
3. Vibrations may be generated along the riser owing to momentum change reactions and its dead weight as gas and liquid phases alternately flow through the piping.

Sagatun (2004) corroborates this by stating that the pressure differentials created during slug flow causes fatigue and consequently wear and tear of the process equipment. These areas of concern also affect the delivery of the hydrocarbon content at the receiving facilities; for example flow irregularities observed in the oil-water separator causing liquid surges in volume.

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1.1. Multiphase severe slug flow

Depending on the severity of the slug flow, three different types of slugging can be identified in multiphase flow (Tang and Danielson, 2006):

- hydrodynamic slugging;
- slugging due to 'operationally induced surges'; and
- severe or terrain slugging.

The conditions for each type of slug flow occur on a regular basis during the production of hydrocarbon in deepwater oil fields. However, severe or terrain slugging is observed mainly at the riser base. Therefore, this paper focuses on investigating a self-lifting approach as mitigation for severe slugging at the riser base due to the inclination needed for the technique to be effective.

Severe slug is observed at low gas rates of hydrocarbon and Barbuto (1995) describes how severe slugging can occur when:

- There is a 'stratified downward flow in the production line' to the riser base.
- Pressure builds up in the production line that exceeds the designed allowable riser pressure.

Severe slug occurs from the accumulation/blockage of liquid at the low point-elevation of negatively inclined/vertical piping or flowline (riser). The inclination is caused by the geometry of the pipeline (usually a dip at the riser base) or the terrain (seabed bathymetry).

The accumulation of liquid at the low point-elevation causes liquid slugs to form. Jones et al. (2014) states that this type of slugging is a cyclic process and liquid slugs formed are of 'at least one riser height'. As depicted in Fig 1, Ogazi (2011) summarised four major stages of severe slug as:

- slug build up/formation;
- slug production;
- slug blow-out;
- liquid fall-back.

A study by Schmidt et al. (1979) classified severe slugging into two different types: severe slugging with liquid slugs usually of riser length, and severe slugging with slightly aerated liquid slugs, the length of which did not exceed the height of the riser pipe. They also stated that the first type of severe slugging could be eliminated by varying either the flowrate of the liquid or the flowrate of the gas.

However, with the second type of slugging, depending on the flowrate of the liquid, an increase in the flowrate of the gas could cause annular flow or slug flow to form (Schmidt et al., 1979). Malekzadeh et al. (2012) later categorised severe slugging into three types: severe slugging type 1 ('pure liquid slug length larger than the riser height'), severe slugging type 2 ('pure liquid slug length smaller than the riser height') and severe slugging type 3 ('growing long aerated liquid slug in the riser followed by a gas blow down stage').

1.2. Slug mitigation approaches

There are several established approaches to the mitigation of slugging in deepwater oil fields.

Jones et al. (2014) stated that the most effective mitigation approach to slugging is riser top valve

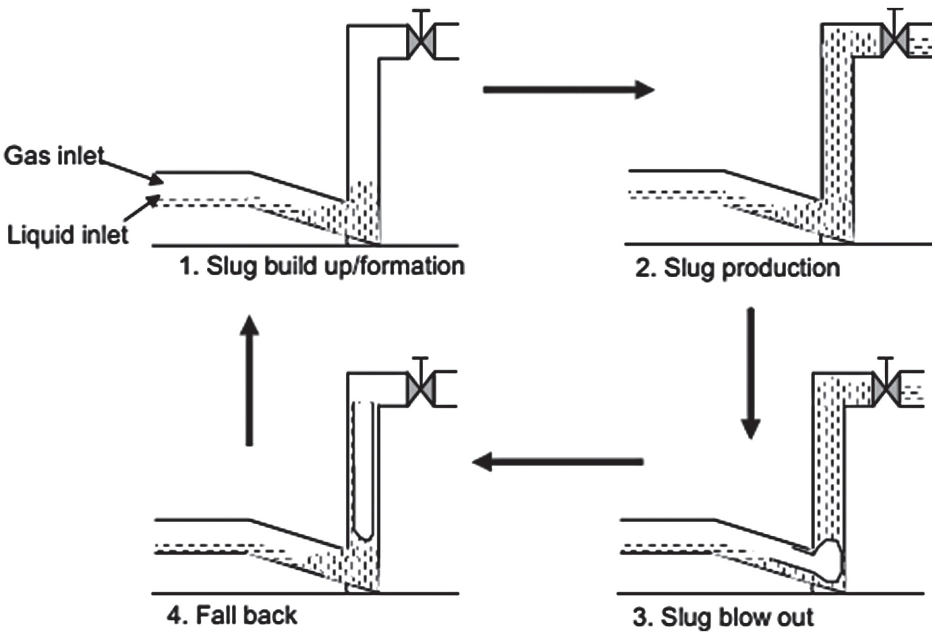

Fig 1: Different stages of severe slug (Ogazi, 2011)

choking (topside choking). Jansen et al. (1996) agreed with Schmidt et al. (1979) that 'choking eliminates severe slug by increasing the back pressure and acting as a flow resistance proportionally to the velocity of the liquid slug in the riser'. This meant that choking could potentially balance and maintain the multiphase flow with 'minimal back pressure'. However, Ogazi et al. (2011) argued that an inherent disadvantage with this approach is the extra back pressure induced on the pipeline and recommended the use of an active feedback control (dynamic choke) that could attenuate the slug flow and increase production.

Another slug mitigation approach is the use of a rise base gas injection system (gas lift). Jansen et al. (1996) prescribed gas lift as a viable method for eliminating severe slug, by 'increasing the velocity and reducing the liquid holdup in the riser'. However, Al-Kandari and Koleshwar (1999), through a successful trial, stated that an increase in gas-to-oil ratio (GOR) led to slug-like flow regime within a 36-inch crude transfer line and there were consequent problems in 'associated separator train at the gathering centre'. However, Jansen et al. (1996) highlighted this approach as being quite costly due to the 'large gas volumes needed to obtain a satisfactory stability of the flow in the riser'. Jones et al. (2014) describe other passive methods including:

- altering the pipeline geometry to reduce or eliminate slugging, although this approach is not cost-effective for already existing subsea pipelines; and
- using slug catchers, which can be comparatively cheap, but space and weight of installation topside is a crucial issue.

This study, however, focuses on a relatively novel approach in the mitigation of severe slugs through the use of 'self-gas lifting'.

1.3. Self-lift approach in severe slug mitigation

The self-lift approach was invented and developed as a 'method to eliminate severe slug in multiphase flow subsea lines' (Barbuto, 1995). Barbuto (1995) described this novel approach as the use of an auxiliary line that connects the downwards inclined flowline with the main riser. A basic schematic is provided in Fig 2 detailing the configurations of the connection points:

- Point A – the connection point between the auxiliary line and the vertical line (main riser);
- Point B – the connection point between the production line and the auxiliary line; and
- Point C – the connection point between the production line and the vertical line.

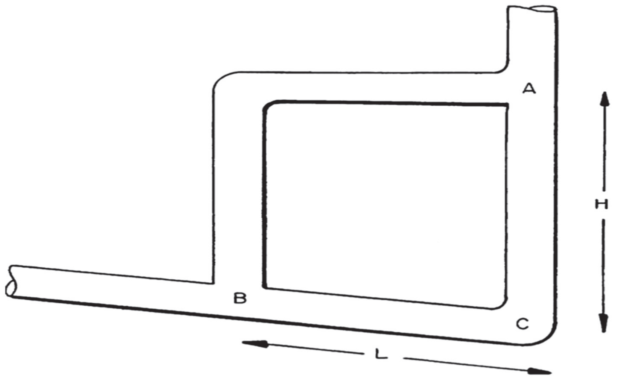

Fig 2: Schematic diagram of self-lift approach (Barbuto, 1995)

This design mitigates severe slug by conveying the gas of the multiphase flow from point B to point A; this is possible due to the differences in pressure at point B and A. (Barbuto, 1995). The gas bubbles conveyed into the vertical line 'help break up the liquid slugs' (Ogazi, 2011). Moreover, the quantities of gas contained in oilfields were either greater or lesser compared to the oil (Shotbolt, 1986). That meant that although the gas cap of a reservoir was not noticeable, the oil still contained a considerable amount of dissolved gas.

Tengesdal (2002) used this novel approach to model the mitigation of severe slug at the riser base. The approach was not considered to need any additional gas injection from the platform and was therefore termed 'self-gas lifting' (Tengesdal, 2002). This approach appeared to be quite beneficial as any extra-cost needed to compress external gas for mitigation of severe slugs, to transport the gas, and to store it on platforms topside, could all be reduced or completely waived.

The research concluded that:

- The approach caused a reduction of hydrostatic head within the riser and of the pressure in the production line.
- From experimental observations, it is ideal to have the 'injection point at the same level or slightly higher than the take-off point for optimum performance'.
- From experiments, it was observed that a 'small choking was needed to stabilize the flow when the injection point is at a higher level than the take-off point'.
- This approach to mitigating severe slug was 'not sensitive to changes with liquid and gas flowrates'.

Tengesdal (2002) suggested that a variable choke controlled by a PC-based system would improve the flow as shown in Fig 3.

Further studies proposed by Tengesdal to improve its adaptability in the industry included: the study of self-lift with variations in the internal

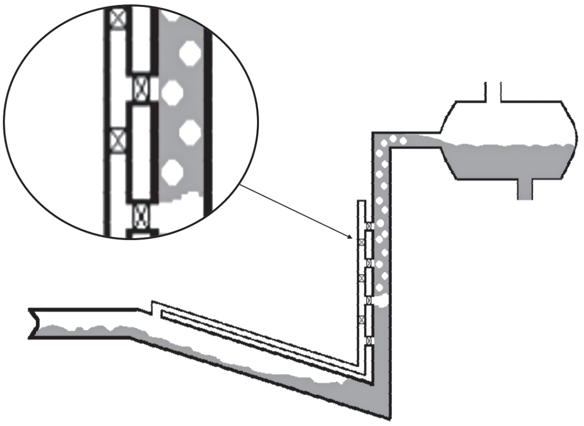

Fig 3: Self-lift with small choking at injection points (Tengesdal, 2002)

diameter of the self-lift bypass and an application of choke at the bypass. Previous applications of self-lift have focused on experiments in the laboratory, which do not truly approximate real life scenarios. Therefore, this study focused on the effectiveness of self-lift with data obtained from an oil field.

2. Self-lift model

2.1. Background, numerical model and validation

An experimental slug (Fabre et al., 1990) was first modelled for validation of the numerical tool, OLGA, after which the self-lift method was applied to prove the concept.

A few experiments were conducted by Fabre et al. (1990) using a 2.09" internal diameter transparent polyvinyl inclined pipe of length 25 m (designated 'pipeline') and a connecting vertical pipe of height 13.5 m (designated 'riser'). Both pipes were connected using a 0.5 m radius bend. The test facility used an air/water mixture as fluid. The velocity of the air as the gaseous phase was obtained from the mass flowrate using its density at standard temperature and pressure (20 °C and 100 kPa). However, this study will focus on one experiment (Exp-1) to validate the model.

Exp-1 superficial velocities for gas and liquid at standard conditions were superficial velocities of gas (V_{sg}) = 0.45 m/s and water (V_{sl}) = 0.13 m/s, respectively. The pipeline was inclined to a negative slope (–1 %). The experiment agreed with literature that 'negative slope is generally considered a necessary condition for an unstable cycle' (Fabre et al., 1990; Schmidt et al., 1979).

The geometry of the model in Fig 4 corresponds with the experiment. An increase in meshing (more section lengths) enabled better accuracy; therefore, three different mesh sizes at constant time-step were analysed. The time-step used was 0.0001 s. The coordinates of the pipe

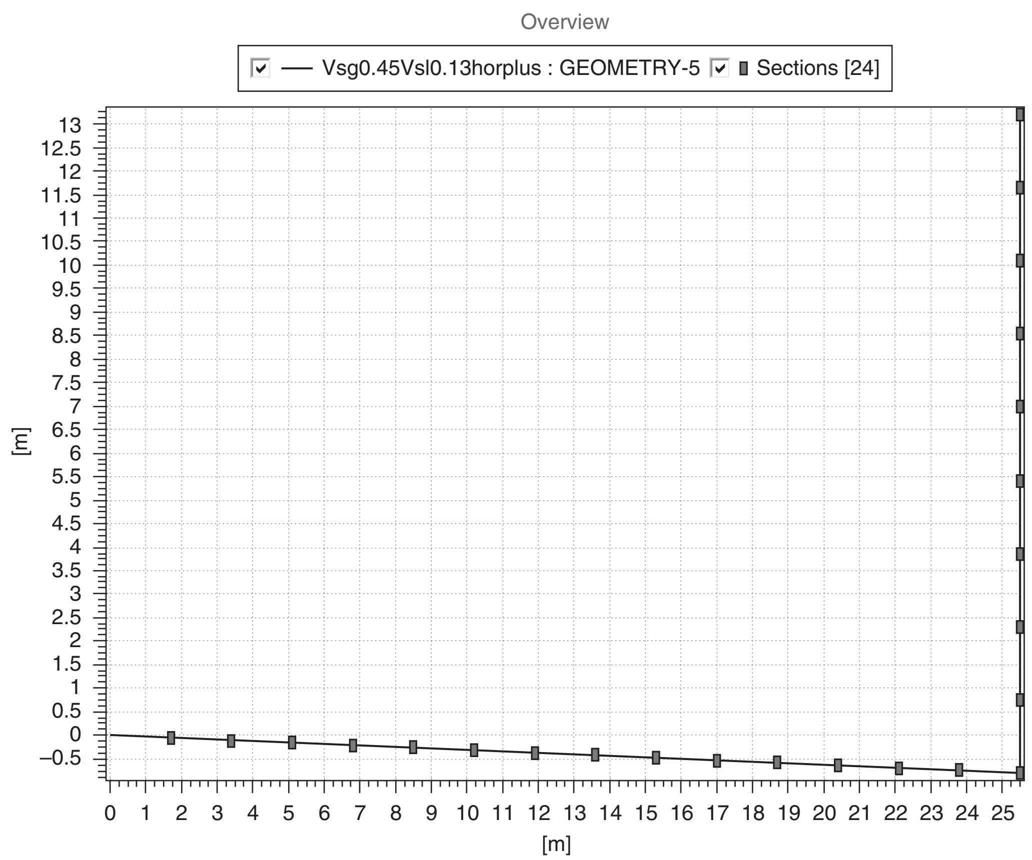

Fig 4: Model geometry of Exp-1

Table 1: Pipe coordinates and section lengths

Pipe	x [m]	y [m]	Length [m]	Elevation [m]	No. of Sections		
Starting point	0	0			**Mesh 1**	**Mesh 2**	**Mesh 3**
Negatively inclined pipe (pipeline)	25.5	–0.801	25.513	–0.801	**25**	**50**	**55**
Vertical pipe (riser)	25.5	13.199	14	14	**14**	**28**	**28**
	Total number of sections				**39**	**78**	**83**

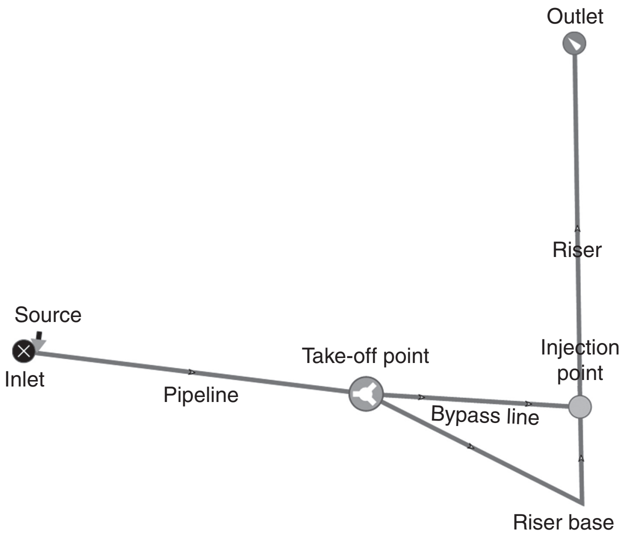

Fig 5: Visual representation of the self-lift literature model (not geometrically accurate)

and section lengths are given in Table 1. For results of analysis, see section 3. For more detail on the OLGA numerical model of the experiment, see Appendix A.

The self-lift concept uses a bypass line to 'lift' the flow at a certain point above the riser base (Tengesdal, 2002), as shown in Fig 5. The OLGA model of this concept uses two additional functions: a process equipment called the 'phase-splitter' and an internal node. The phase-splitter, which acts as the take-off point along the pipeline, functions between an internal network node and a network separator. A bypass pipe of internal diameter 1.299" is connected to the take-off point at 2.567 m from the riser base, along the pipeline. The bypass pipe is then connected to an internal node which serves as the injection point into the riser at 20 cm from the riser base (see Table 2).

2.2. Field data

Field data from a Chevron deepwater oil field in West Africa were obtained for study of the self-lift concept. In a previous study, the field experienced hydrodynamic slugging at low production rates in one of its flow loops (which will henceforth be referred to as flow loop F1). However, the focus of this study is severe slugging; the conditions of hydrodynamic slugging were aggravated to result in an example of typical severe slugging type one (1) and three (3): SS1 and SS3.

The field operates at a depth greater than 1000 m with four flow loops connected to the topside via a riser system. For the purpose of this study, only flow loop F1 will be considered. Hydrocarbon is drawn from well 1 (W1) to the manifold through a 6" pipeline. Flow loop F1 comingles well 1 (W1) and well 2 (W2) using the manifold, and transports the hydrocarbon via an 8" pipeline from the manifold to the riser. The geometry of F1 as well as its pressure and temperature are given in Table 3.

The fluid flowing through flow loop F1 was defined using PVTsim 20. The water-cut of the fluid is defined at 3 % from the field data. GOR using the PT flash is verified as 385.91 Sm^3/Sm^3 at a minimum pressure of 1 bar and maximum pressure of 300 bar, and minimum temperature of –20 °C and

Table 3: Flow loop F1 geometry, pressure and temperature.

Station	Flow loop F1		
	Total vertical depth (ft)	**Pressure (psia)**	**Temperature (°F)**
Separator (TS)	164	290	150
Manifold (MF)	–4800	1300	168
Wellhead (W1)	–4750	1678	180

Table 2: Pipe coordinates and section lengths

Pipe	x [m]	y [m]	Length [m]	Elevation [m]	No. of sections
Starting point	0	0			**Mesh**
Pipeline to take-off point	22.933	–0.720	22.944	–0.720	**25**
Bypass line to injection point	22.936	–0.601	0.119	0.119	**2**
Take-off point to riser base	25.5	–0.801	2.568	–0.081	**5**
Riser base to injection point	25.5	–0.601	0.2	0.2	**1**
Riser	25.5	13.2	11	11	**22**

maximum temperature of 120 °C. The API of the fluid is given as API 47°. The densities of the oil and gas (641 kg/m^3 and 18.2 kg/m^3, respectively) were also flashed from the fluid. The properties of the fluid are given in Table 4.

Two wells (W1 and W2) were comingled along flow loop F1 at the manifold. Oil, gas and water flowed at volumetric flowrates of 6722 BoPD, 4 MMScf/d and 0 STB/d, respectively, for W1. Oil, gas and water flowed at volumetric flowrates of 22 157 BoPD, 23 MMScf/d and 6 STB/d, respectively, for W2. The mass flowrates were then converted and adjusted from the volumetric flowrates for easier input in OLGA. For mathematical conversion of the flowrates, see Appendix A.

Table 4: Fluid properties

Component	Mol. %
	Flow loop F1
Carbon dioxide	0.81
Nitrogen	0.13
Methane	43.3
Ethane	7.49
Propane	7.29
Iso-butane	2.61
N-butane	3.28
Iso-pentane	1.98
N-pentane	1.56
Hexanes	2.72
Heptane plus	28.83

Fluid flows to W1 to comingle at the manifold through a 6" pipeline, and from the manifold to the riser through an 8" pipeline. The pipeline has a pipe roughness of 0.002 m and has two walls; the outer wall serves as insulation. Wall 1 and 2 have thicknesses of 0.009 m and 0.011 m, respectively. The ambient temperature is 5 °C, and the mean heat transfer coefficient on the outer wall is 2.3 W/m^{2}K.

A total number of 142 sections were allocated for the meshing of the model, which is depicted in Fig 6. The model time-step was: 0.0001 s. The coordinates of the pipe and section lengths are given in Table 5.

The self-lift bypass was connected to the pipeline at the take-off (TK) at a distance of 274.67 m from

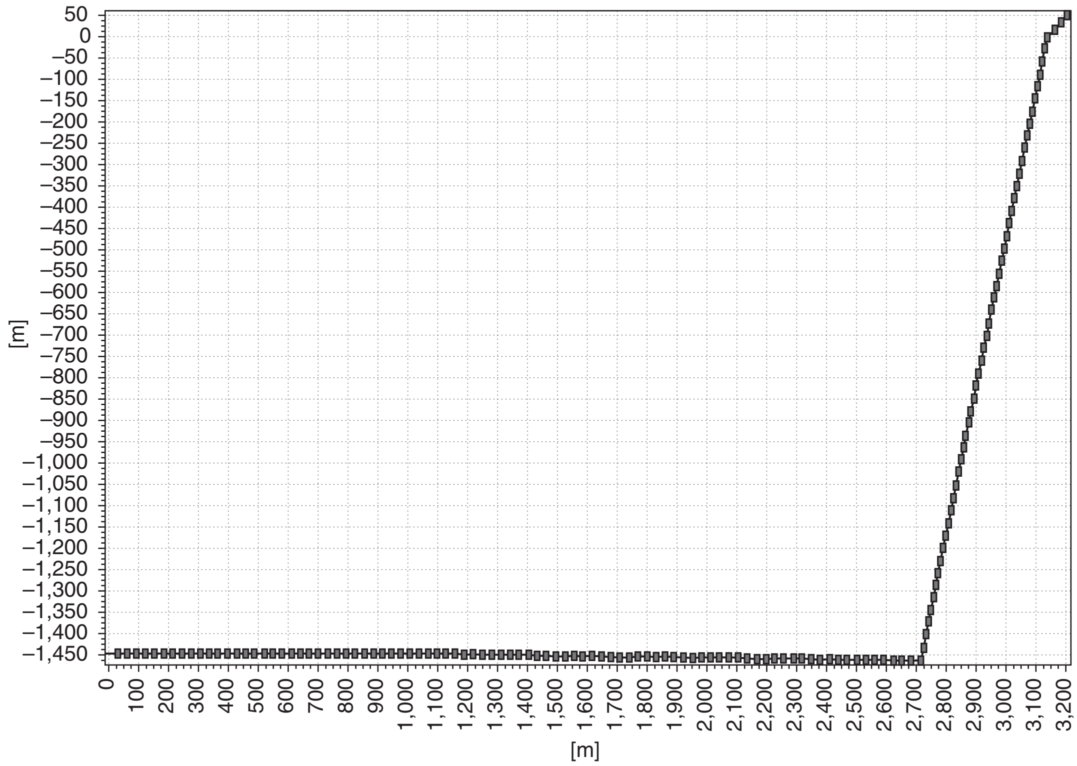

Fig 6: Model geometry of field data

Table 5: Pipe coordinates and section lengths

Pipe	x [m]	y [m]	Length [m]	Elevation [m]	No. of sections
Starting point	0	–1447.8			**Mesh**
Pipe 1 (W1-MF)	1066.8	–1447.8	1066.8	0	**35**
Pipe 2 (MF-RB)	2712.649	–1463.04	1645.92	–15.24	**54**
Pipe 3 (RB-FPSO)	3139.369	0	1524	1463.04	**50**
Pipe 4 (FPSO-Sep)	3204.745	49.987	82.296	49.987	**3**

Table 6: Pipe coordinates and section lengths

Pipe	x [m]	y [m]	Length [m]	Elevation [m]	No. of sections
Starting point	0	–1447.8			**Mesh**
Pipe 1 (W1-MF)	1066.8	–1447.8	1066.8	0	**35**
Pipe 2 (MF-TK)	2438.05	–1460.5	1371.309	–12.7	**45**
Pipe 3 (TK-RB)	2712.72	–1463.04	274.232	–2.54	**9**
Pipe 4 (RB-INJ)	2721.254	–1433.779	30.48	29.261	**1**
Pipe 5 (Bypass)	2721.254	–1433.779	284.014	26.721	**9**
Pipe 6 (INJ-FPSO)	3139.369	0	1493.5002	1433.7792	**49**
Pipe 7 (FPSO-Sep)	3204.745	49.987	82.296	49.987	**3**

the riser base and reinjected into the riser column at 30.48 m from the riser base (see Fig 7 and Table 6). This is supported by literature: the re-injection point should be located at a distance from the riser base which is 2–3 % the length of the riser (Sarica and Tengesdal, 2000). Due to an increased number of total sections (151 sections), the time-step was reduced to 0.000000001 s to enable transient convergence.

3. Results and discussion: numerical models

3.1. Literature data: validation

Simulations involving Fabre et al. (1990) research studies were run at an angle of –1 % to simulate severe slugging experimentally. The numerical model on OLGA first had to be validated to depict the conditions of the experiment correctly, and then self-lift was applied to the model to mitigate severe slugging.

The air-water fluid numerical model was validated correctly against experiments at superficial velocities of gas (V_{sg}) and water (V_{sl}) of 0.45 m/s and 0.13 m/s, respectively. Severe slugging was observed at riser base as shown in Fig 8, where the higher pressure of 2.249 Bar was reached over the duration of the 30 min simulation. The cyclic fluctuations of pressure in the prediction of the numerical model matched the experiment. This implied that the model could correctly predict the effect and presence of severe slugging.

In order to achieve more precise results without decreasing to a smaller time-step needlessly, three different types of mesh (sectioning) were compared. The mesh with 78 sections in Fig 9 had the best convergence with the literature data.

The self-lift concept was applied to severe slugging modelled from published data. Tengesdal (2002) numerically modelled the gas re-entry point at a distance of 20 cm from the riser base to depict a complete elimination of slug flow.

Slug flow was completely eliminated using self-lift at the riser base and at the top of the riser of the experimental slug case (Fabre et al., 1990), as evidenced by the more stable pressure. As shown in

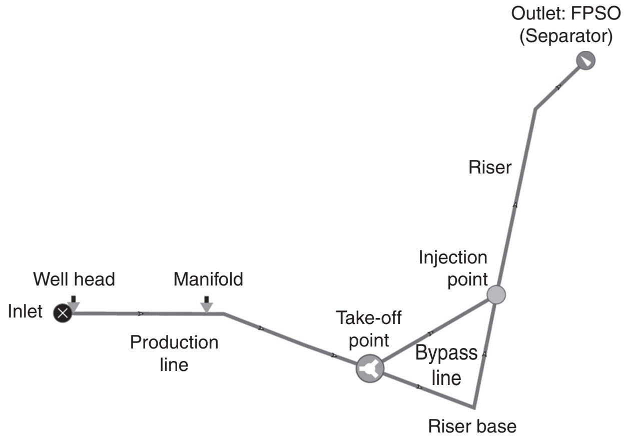

Fig 7: Visual representation of the self-lift OLGA model based on field data (not geometrically accurate)

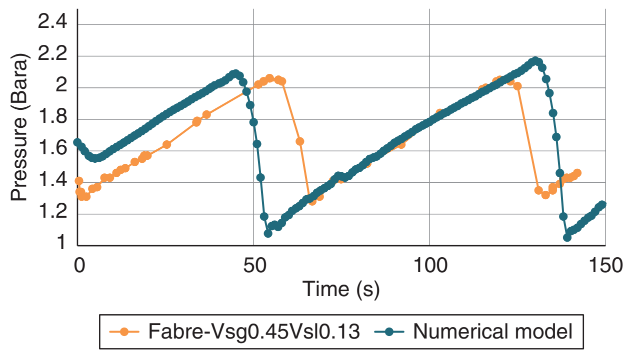

Fig 8: Validation of numerical model

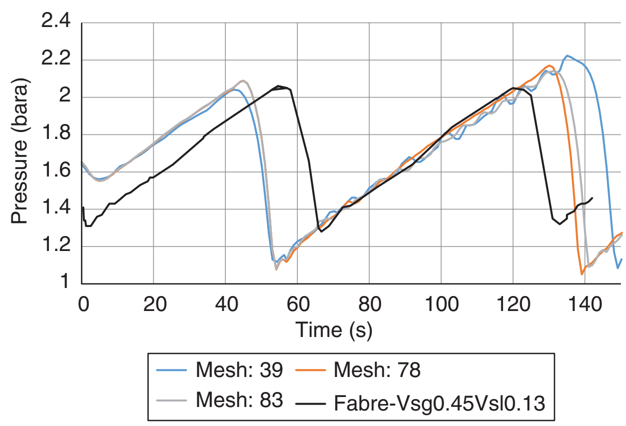

Fig 9: Mesh convergence of numerical model with literature data

Fig 10, the highest riser base pressure was recorded at 2.114 Bara over the duration of the 30 min simulation, which is quite reduced from that recorded in the severe slugging model (2.249 Bara).

It can also be observed from the liquid hold-up shown in Fig 11 that the riser base is full of more stable liquid and no gas. The liquid hold-up is the fraction of the liquid volume with respect to the internal diameter of the pipe. This implies that the self-lift technique was effective in diverting the gas from the riser base and just liquid remained.

Effects of the self-gas lift were more noticeable from the bypass pipe connecting the take-off point and the injection point through the riser column. As shown in Fig 12, liquid was passed through the bypass pipe to the injection point. Further analysis (see Fig 13) showed that gas and liquid were flowing through the bypass pipe, and that 'short slugs' (slugs of short length that form and dissipate intermittently) formed.

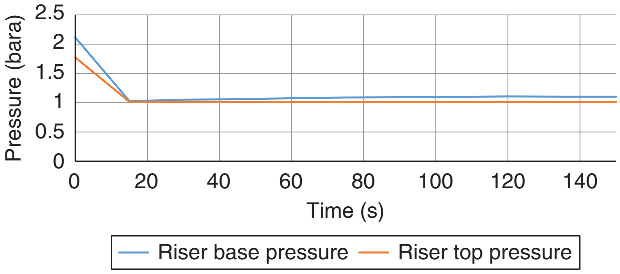

Fig 10: Self-lift riser base and riser top pressure

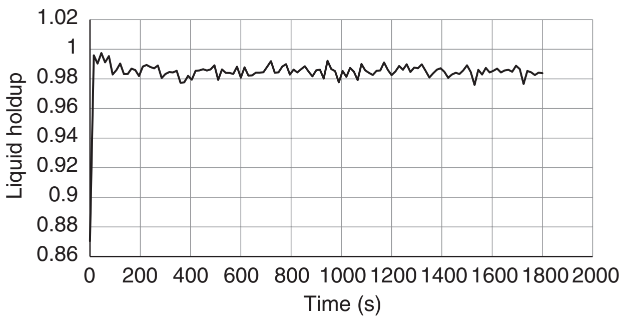

Fig 11: Liquid hold-up at riser base

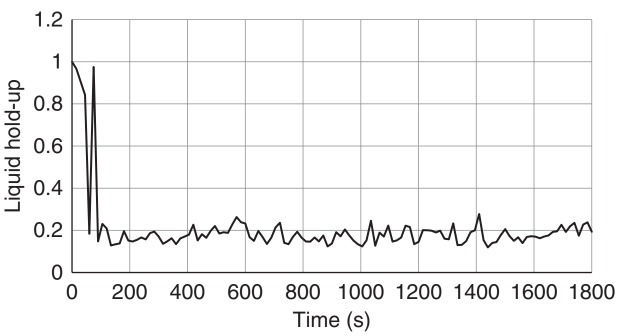

Fig 12: Liquid hold-up at bypass

The trend, shown in Fig 14, of the flow regime at the bypass pipe further confirmed this fact. This implied that the flow in the bypass could create more 'turbulence' when re-joining the flow in the riser column, as well as the formation of slugs. The riser column trend of its pressure, liquid hold-up and flow regime (see Fig 15 and Fig 16) confirms that although there are no cyclic fluctuations in pressure, the flow of the liquid in the column was not stable; the flow was fluctuating between a bubble flow and slug flow.

3.2. Field data: slugging

A West Africa, Chevron-operated deepwater oil field experienced hydrodynamic slugging from one of its wells. Hydrodynamic slugging was observed from

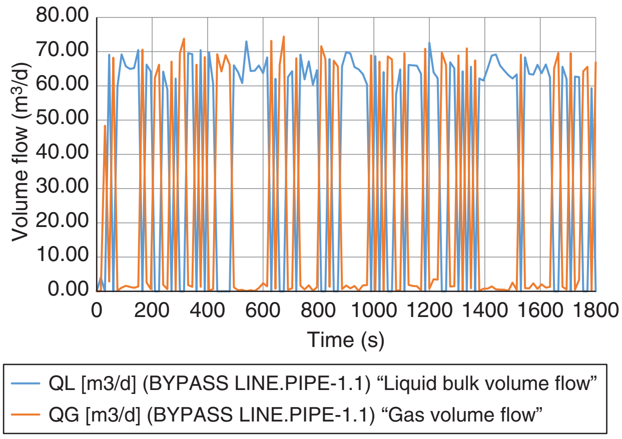

Fig 13: Gas and liquid flow at bypass

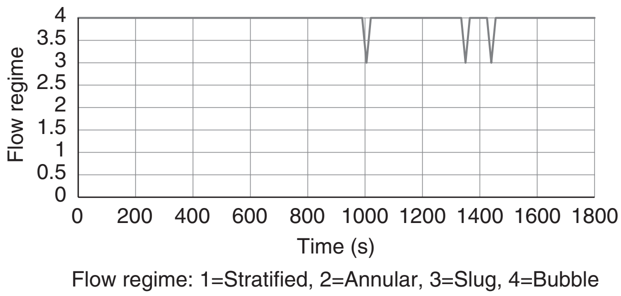

Fig 14: Flow regime at bypass

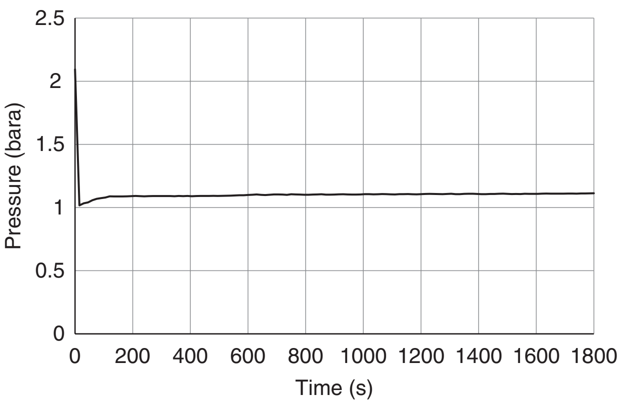

Fig 15: Pressure in the riser column

W1 along flow loop F1 at production rates that were lower than 3000 barrels of oil per day (BOPD) and low reservoir pressure within the vicinity of the well. The same conditions were first modelled to observe the reported hydrodynamic with the pressure fluctuations (Fig 17).

Due to the geometry of the flow loop, severe slugging could not form easily at the riser base. Well 2, comingling with the flow at the manifold, is a fast-flowing well and also acts as a gas injection well for the flow loop.

3.2.1. Adjusted field data: severe slugging

The conditions for hydrodynamic slugging observed with the field data were aggravated by tuning the superficial velocities of oil, gas and water of W1, to model a severe slugging condition at the riser base. To observe slugging, the flow of crude oil from W2 leading into the manifold was turned off. Severe slugging was observed within a 24 hr simulation time, with cyclic fluctuations of pressure at superficial velocities of gas and liquid (oil and water) as 0.523 m/s^2 and 0.303 m/s^2, respectively, and a higher pressure of 109.846 Bara, as seen in Fig 18. Fig 19 shows that the number of slugs recorded in the flow loop were as high as 34 slugs per second after the first 2 hrs.

3.2.2. Self-lift numerical model

The self-lift concept was applied to the severe slugging modelled from the field data with varying degrees of effectiveness. Slug flow persisted with the application of self-lift to the severe slugging observed from the model. Fig 20 shows that transitional severe slugging at the riser base was observed in the numerical model with a higher riser base pressure of 108.069 Bara. The highest total number of slugs per second recorded along the flow loop was 4 slugs per second, as seen in Fig 21.

From literature, finding the optimal re-injection point in the riser is crucial to the mitigation of slugging, with the optimal re-injection point prescribed as 2 % to 3 % of the riser length (Sarica and Tengesdal, 2000). However, Fig 22 shows that

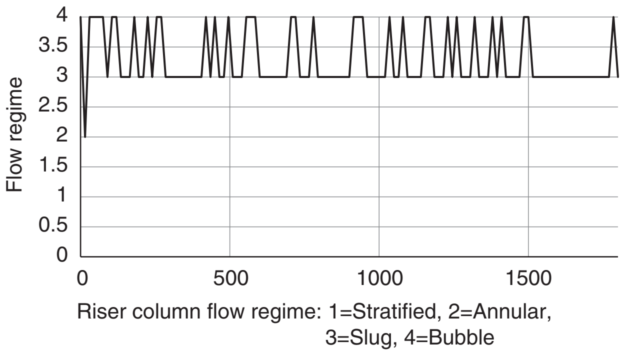

Fig 16: Flow regime in the riser column

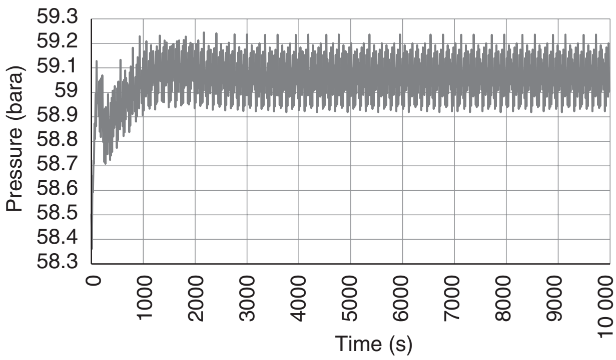

Fig 17: Hydrodynamic slugging

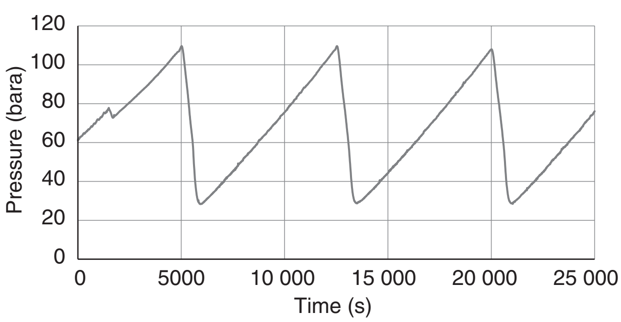

Fig 18: Severe slugging

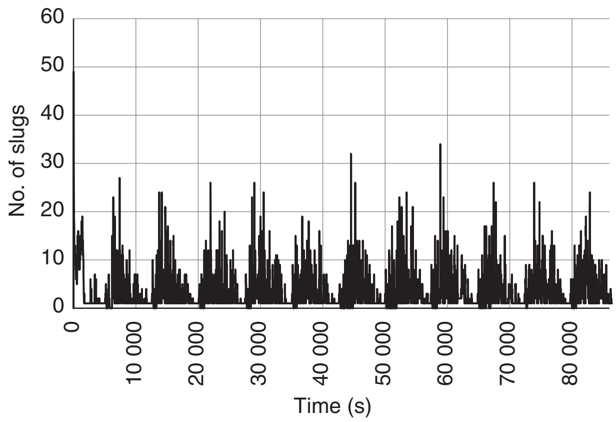

Fig 19: Number of slugs in the pipeline

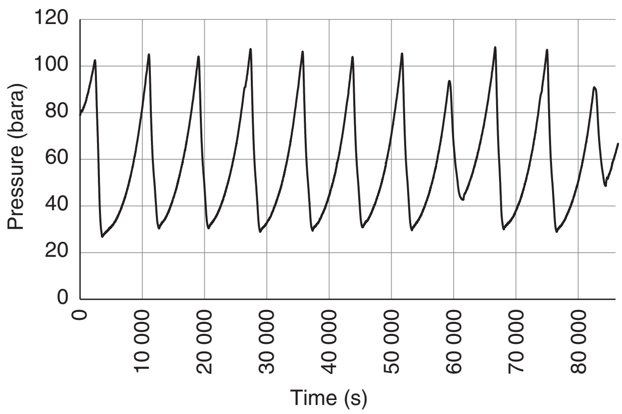

Fig 20: Self-lift with severe slugging

changing the re-injection points (30.48 m, 41.15 m, and 45.72 m along the riser length) did not eliminate the slug flow.

A study was also conducted to ensure only the flow of gas in the bypass pipe, by applying different sizes of the internal diameter of the bypass pipe: 0.55 m; 0.2032 m; 0.20 m; 0.18 m; 0.16 m; 0.15 m; 0.14 m; 0.12 m; 0.10 m; 0.08 m; and 0.06 m. Although severe slugging was observed in the bypass pipe, the bypass internal diameter, 0.16 m, 0.10 m, 0.06 m showed the most effective change in trend of the severe slugging (see Fig 23). Fig 24 shows that liquid and gas flow were present in the bypass pipe.

In Fig 25, the application of a choke at the bypass increased the slug formation time and, consequently, the length of the slug. This meant that the riser base pressure was increasing over a longer duration, and the length of the liquid accumulation increased beyond the height of the riser into the production pipeline.

3.2.3. Self-lift in conjunction with gas injection

Riser base gas-lift (RBGL) was also explored and modelled using field data, to compare its effectiveness with self-lift. Gas was injected into the riser column at 86 °F and mass flowrate of 1.5 kg/s. This successfully eliminated severe slugging at riser base, with a stabilised pressure of 35 Bara.

Applying self-lift with RBGL yielded unique results: the pressure at the riser base exceeded the design parameters. This result can be explained from the concept of slug flow; pressure fluctuations in slug flow are usually caused by the trapping of gas pockets behind varying lengths of liquid accumulations (Luo et al., 2011; Tang and Danielson, 2006). The bypass pipe reintroduced slug flow (severe slugging) into the riser column at a point beyond the riser base, therefore trapping the inflow of gas from the RBGL, and consequently increasing the pressure at the riser base. This meant that RBGL cannot be applied with self-lift.

However, external gas injection was modelled with self-lift by placing the entry point of gas further downstream, beyond the re-injection point of the bypass pipe. Injecting gas at mass flowrate of 1.5 kg/s further downstream showed a more stabilised fluid flow at an average pressure of 44.71 Bara. It is observed that the pressure of the combined slug mitigation techniques was higher than RBGL and also less stable, unlike with just RBGL (see Fig 26).

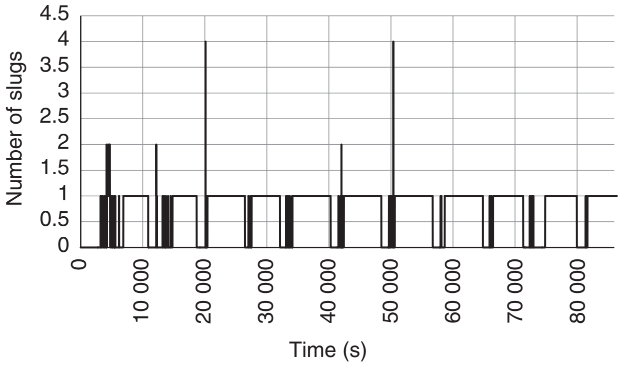

Fig 21: Self-lift 2 % total number of slugs in the pipeline

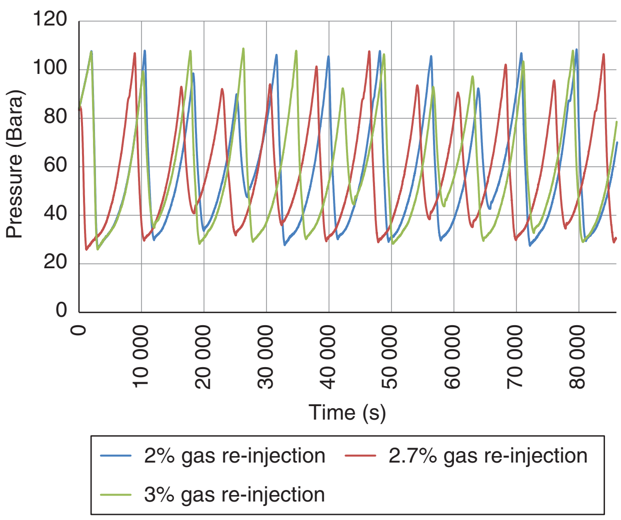

Fig 22: Self-lift gas re-injection points

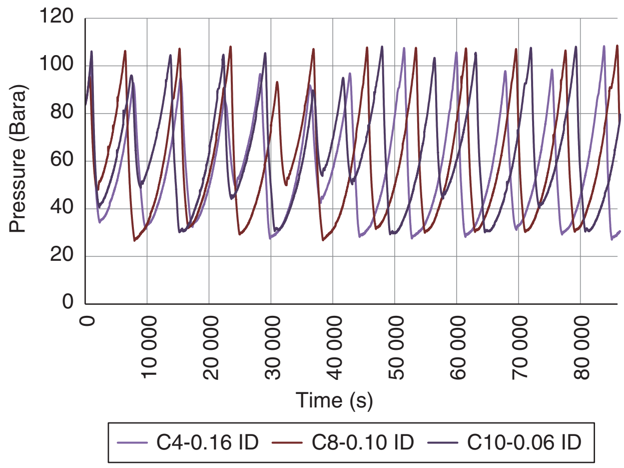

Fig 23: Self-lift 2 % bypass internal diameter sizing

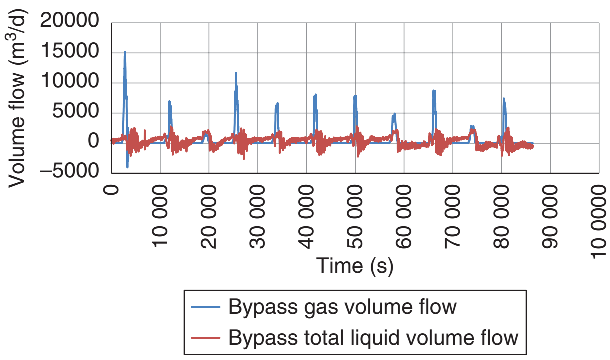

Fig 24: Self-lift bypass volume flows

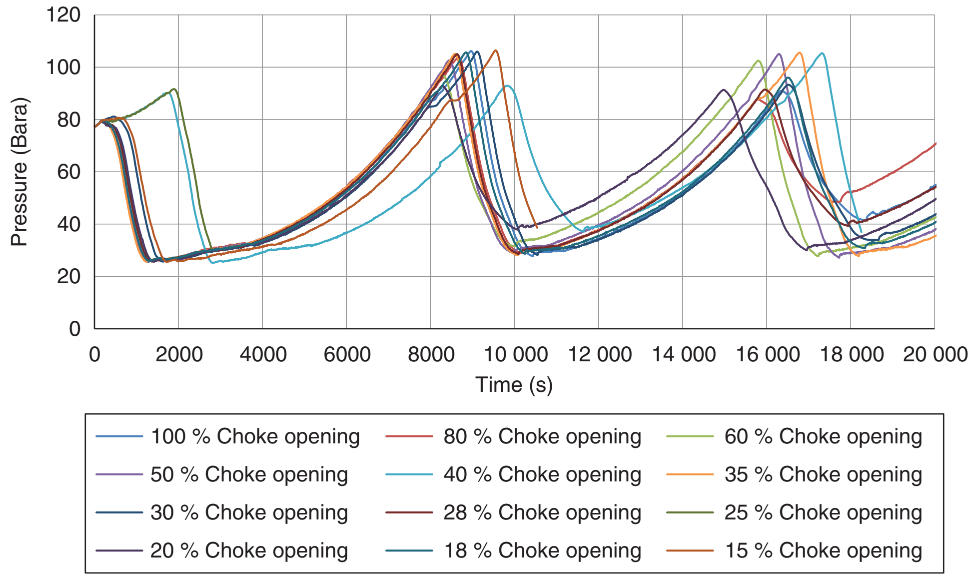

Fig 25: Self-lift manual choke at bypass

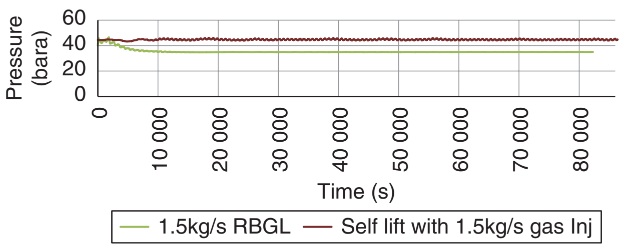

Fig 26: Self-lift with gas injection

4. Conclusion

Self-lift, which has not been deployed in a field situation, may be adopted as a passive slug mitigation technique, which must be adapted on a case-by-case basis, to produce maximum effectiveness. Self-lift was verified by numerically modelling it to severe slugging observed experimentally in literature (Fabre et al., 1990). Self-lift completely eliminated slug flow and yielded a more stable pressure at the riser base. The application of self-lift reduced the riser base pressure by 6 % from 2.249 Bara to 2.114 Bara.

Self-lift achieved a complete separation of the fluid phases (gas and liquid) at the riser base using published data. Short slugs were observed in self-lift bypass pipe. The results of self-lift modelled from published data showed that liquid accumulated in the bypass pipe, leading to slugging within the pipe. It was observed that slugs were reintroduced into the riser column, leading to surges in liquid volume. Field data were successfully modelled numerically to depict the reported hydrodynamic slugging.

Self-lift was applied to the severe slugging numerical model based on field data. Although it did not eliminate severe slugging at the riser base, the total number of slugs per second at riser base were reduced from 34 to 4 and the higher pressure reduced from 109.846 Bara to 108.069 Bara. This meant that self-lift resulted in a 1.62 % reduction in riser base pressure and an 88 % reduction in slugs per second within the flow loop. Self-lift modelled using field data also showed that liquid and gas volume flows were observed in the bypass pipe. Consequently, severe slugging was also observed within the bypass pipe. The variations of internal diameter of the self-lift bypass pipe with field data showed that the most effective change in trend of severe slugging occurred with 0.16 m, 0.1 m and 0.06 m. Self-lift modelled using field data, with a manual choke at the bypass, increased the slug formation time; pressure build up and liquid accumulation were longer.

Using field data, the self-lift technique applied in conjunction with the RBGL caused the riser base pressure to exceed its design parameters, although external gas injection could occur at a point beyond self-lift bypass re-injection point. Self-lift was also applied in conjunction with gas injection. The combination yielded a more stable pressure at riser base, but the RBGL technique was more effective alone than with self-lift. With the presence of liquid in the bypass, the numerical modelling tool was simply splitting the fluid flow rather than splitting the fluid into its phases. Self-lift is dependent on fluid flow as well as the gas-to-oil ratio of the hydrocarbon; it is more suitable for fluid flows of relatively low mass flowrates. It is also not easily adaptable to work in conjunction with RBGL in deepwater oil fields. Slugging at riser base is aggravated by the slug flow reintroduced into the riser column through the self-lift bypass, and consequently increases the riser column pressure. It can be inferred that improving the geometry design of the self-lift bypass pipe would reduce the likelihood of slugging within the pipe.

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Appendix A: Mathematical conversion of volumetric flowrates to mass flowrates

Barrels of oil per day (BOPD)	1 BOPD =	0.159m^3/d, or 1.8402778e-006 m^3/s
Million standard cubic feet per day (MMScf/d)	1 MMScf/d =	28,316.85 m^3/d, or 0.32774132 m^3/s
Stock tank barrels per day (STB/d)	1 STB/d =	0.119 m^3/d, or 1.3773148e-006 m^3/s (density of water is taken at 60 °F)

Well 1

Volumetric flowrates:

- Oil, Q_o: 6722 BoPD
- Gas, Q_{gas}: 4 MMScf/d
- Water, Q_{water}: 0 STB/d

$$Q_o = 6722 \text{ BoPD} = 1.2370347\text{e-}002 \text{ m}^3/\text{s}$$
$$\dot{m}_o = 7.9293927 \text{ kg/s}$$

$$Q_{gas} = 4 \text{ MMScf/d} = 1.31096528 \text{ m}^3/\text{s}$$
@ STP: 101.325 kPa, 60 °F

At operating pressure, using ideal gas law:

$$Q_{gas}: \frac{1.310965*101.325*355.37222*1}{288.706*11569.404*1}$$
$$= 0.01413268 \text{ m}^3/\text{s}$$
$$\dot{m}_{gas} = 0.25721475 \text{ kg/s}$$
$$Q_{water} = 0, \text{m}^{\cdot}\ \dot{\text{m}}_{water} = 0$$

Well 2

Volumetric flowrates:

- Oil, Q_o: 22157 BoPD
- Gas, Q_{gas}: 23 MMScf/d
- Water, Q_{water}: 6 STB/d

Q_o = 22157 BoPD = 4.0775035e-002 m^3/s

$\dot{m}_o$ = 26.1367975726 kg/s

Q_{gas} = 23 MMScf/d = 7.53805036 m^3/s
@ STP: 101.325 kPa, 60 °F

At operating pressure, using ideal gas law:

$$Q_{gas}: = \frac{7.538055036*101.325*348.70556*1}{288.706*8963.1853*1}$$

$$= 0.1029239238 \text{ m}^3/\text{s}$$

$\dot{m}_{gas}$ = 1.873215413 kg/s

Q_{water} = 6 STB/d = 8.2638888e-006 m^3/s

$\dot{m}_{water}$ = 8.2482089e-003 kg/s