International Journal of Applied Engineering Research ISSN 0973-4562 Volume 11, Number 22 (2016) pp. 10782-10793


# Topside Pipeline Design for Slug Attenuation and Increased Oil Production

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**Abstract**

In oil and gas production system, slugging is frequently encountered when gas-liquid mixtures are transported through a common pipeline-riser system. This phenomenon usually manifests in significant fluctuation of flow and pressure which can impact the production system negatively. Topside choking is usually employed as a mitigation technique but with its attendant reduction in production capacity. The objective of this study therefore is to investigate the optimisation of topside pipeline diameter and choking for effective slug attenuation and optimised oil production.

In this paper, a new method for slug flow attenuation has been proposed. The potential of using effective topside pipeline-diameter design for slug flow attenuation was theoretically shown. Numerical studies were also done to show that the concept can indeed be adapted for effective slug attenuation using an industrial software. Experimental studies were conducted in a 4" pipeline-riser system to validate the numerical and theoretical studies.

The results showed that the optimised design of topside pipe diameter has potential for slug flow attenuation at larger valve opening which effectively translates to lower pressure and increased oil production. For the case studied, up to 49% reduction in the pressure drop across the topside choke valve was reported which practically implied increased flow capacity. An optimum volume which satisfied size, system stability and production constraints was obtained.

**Keywords:** Severe slugging, optimised pipeline diameter, slug attenuation, intermittent absorber, increased production, OLGA

## INTRODUCTION

Multiphase flows are commonly encountered in various industries ranging from oil and gas, aerospace, automotive, power generation and medicine. It is the concurrent flow of more than one phase in a single pipeline or conduit. The constituent phases could be liquid, gas and / or solid. The flow of gas, liquid and solid in a pipeline for example, is a three-phase system. When two of these phases are present, a two-phase flow is formed. A common example of a two-phase flow encountered in the petroleum industry is the gas-liquid flow.

The hydrodynamic interactions between these phases for a given pipe configuration (horizontal, inclined or vertical), subject to the flow rates of the constituent phases give rise to what is usually called flow regime/pattern. Many flow regimes have been proposed by many authors depending on the pipe configurations, the number of phases, properties and flow conditions. Few of such identified regimes include: annular Flow, bubble flow, churn flow, slug flow, plug flow stratified flow, stratified wavy flow [1]–[6].

Slug flow is an intermittent flow of liquid and gas with inherent unsteady behaviour that manifests in pressure and flow fluctuation capable of causing upset in topside process facilities and structural integrity issues in the pipeline-riser system. Three types of slugging are widely known: operation induced, hydrodynamic and terrain/severe slugging.

Operation-induced slug flow occurs due to operational changes such as flow ramp up, system depressurization, pigging operations and system restart. During these operations, huge volume of liquid is usually generated in form of slugs. This slug possesses characteristics capable of damaging the pipeline-riser system and also undermine the efficiency of topside facilities

Hydrodynamic slug flow is another type of slug flow usually encountered in horizontal or near horizontal multiphase pipelines. This slug is usually believed to be short and of high frequency. However, hydrodynamic slugging has been reported to possess the tendency to cause problems in pipeline-riser systems [7]–[10]. Prediction and characterisation of hydrodynamic slug flow have received great attention ,but only little has been done on its attenuation till date [11]–[16]. Figure 1 shows a typical hydrodynamic slugging blocking a pipe cross-section.

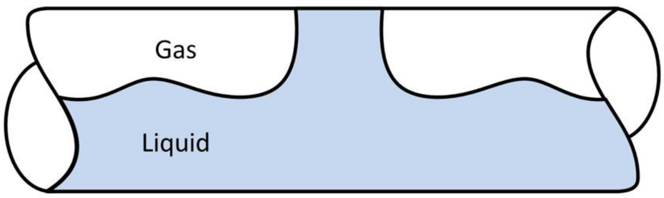


**Figure 1:** Hydrodynamic slug body

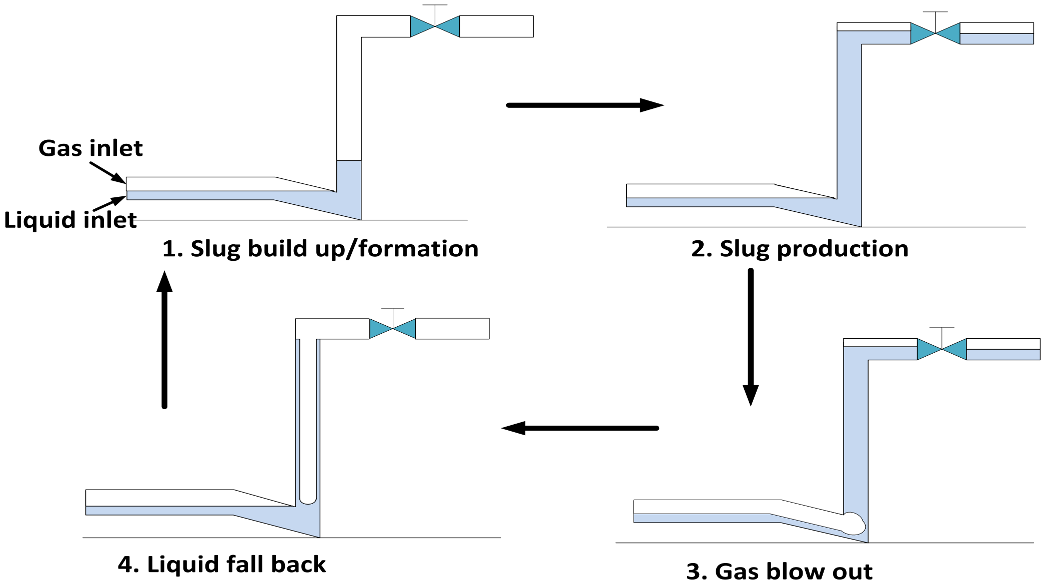


**Figure 2:** Severe slugging mechanism

Terrain/Severe slugging has been known to be of concern to the petroleum industry and continues to attract the attention of researchers and operators alike. This phenomenon is generally believed to be formed following the mechanism shown in Figure 2. Severe slug flow is known to exhibit large fluctuations in flowrates and pressure resulting in poor separator performance, pipeline fatigue, and sometimes eventual plant shutdown. Severe slugging has been researched and a number of solutions have been proffered, some of which have been tested on the fields and others still undergoing development. Some of the methods used for slug control include: subsea separation and processing, homogenizing multiphase flow, gas re-injection, riser base gas lift, design modification of upstream and downstream facilities. Other methods include the use of slug catcher, intermittent absorber and topside choke manipulation [17]–[24]. These methods have their limitations and have been well discussed in [16]. As oil and gas activities shift to deep offshore, there is a prediction that the impact of severe slugging on production might become so heightened [25] . There is therefore, the need to continually seek optimised ways of combating this undesired phenomenon and this is the objective of this study.

## THEORETICAL ANALYSIS OF TOPSIDE PIPELINE DESIGN FOR SLUG ATTENUATION

Depending on the type of slugging prevalent in a pipeline-riser system, increasing or decreasing the pipeline diameter may help attenuate the slug flow. For example, severe slugging can be mitigated by reducing pipeline diameter. In doing so, the velocity of the fluid increases and tendency for liquid accumulation in the riser eliminated. An increase in the pipeline diameter on the other hand can help stratify flow through the pipeline thereby eliminating hydrodynamic slug but with potential for severe slug initiation. Optimum pipeline design has been previously reported as having potential for partial severe slug mitigation. However, no established method exists to determine this optimum size and dynamic variables such as reservoir depletion, field operation requirements, market considerations may limit the implementation of this strategy [18]. In an attempt to circumvent these limitations, optimum design of the topside pipeline section was considered in conjunction with choking in this study.

***The intermittent absorber concept***

It has been previously shown that active feedback controller can help attenuate slug flow at a considerable valve opening for optimised oil production [17], [19], [24]. The ability of the intermittent absorber to perform similar function has been investigated and encouraging results reported. More details on the intermittent absorber can be found in Ehinmowo [16] and Ehinmowo et al.[26].

Ehinmowo [16] suggested that the autonomous system (intermittent absorber) must be strongly coupled to the unstable system in order provide significant attenuation. In this study, it was conceived that this condition of strong coupling can be achieved in form of optimised design of topside section of pipeline coupled to the parent pipeline-riser system for effective slug attenuation.

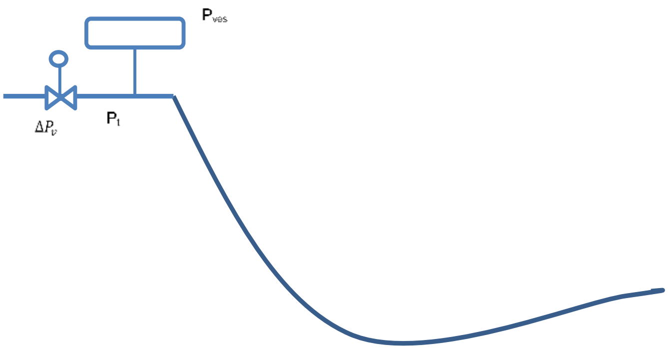


**Figure 3:** Simplified pipeline-riser system with intermittent absorber installed [26]

From Ehinmowo [16] and Ehinmowo et al.[26], for an intermittent absorber coupled to a pipeline-riser system at the top of the riser as shown in Figure 3, the unstable pipeline-riser system can be represented by a dynamic equation described by equation (1) following [27].

$$\dot{P} = f(P, x) \tag{1}$$

where $P$ is a vector representing the system variables such as riser base pressure, pressure drop across the valve etc. and $x$ is a vector denoting system parameters. Assuming the variable of interest is the pressure drop across the valve (since this is cardinal to system stability), the element of the $x$ vector are $Q$ and $u$ (flow rate and valve opening respectively). It has been established that a change in $x$ will alter P significantly. This property has been previously explored to stabilise the unstable system by varying any of the elements in $x$ [24].

The intermittent absorber concept is based on the fact that it is also possible to stabilise the unstable system by coupling another autonomous asymptotically stable system to the original unstable system. The role of the asymptotically stable R-subsystem is to alter the response of the unstable system. This additional system will increase the degree of freedom and provide stabilising effect [27], [28].

Considering an asymptotically stable autonomous system (the intermittent absorber) which can be described dynamically by equation (2)

$$\dot{R} = g(R, c) \tag{2}$$

Where $R$ is a vector describing the system variables such as pressure and the $c$ is a vector denoting the system parameters which can be varied. In this study, $c$ is the volume of the gas in the vessel.
The equation of the augmented system is given by equations (3) and (4).

$$\dot{P} = f(P, x) + \eta_r R \tag{3}$$

$$\dot{R} = g(R, c) + \eta_p P \tag{4}$$

Where $\eta_r$ and $\eta_p$ are the coupling matrices. The coupling matrices describe the connection behaviour of the two subsystems $P$ and $R$. When $\eta_r = 0$ and $\eta_p = 0$, the P and R subsystems in equations (3) and (4) are uncoupled and for $\|\eta_p\|$ and $\|\eta_r\| > 0$, stabilising impact is felt in the main system due to the R-subsystem. For a very small $\|\eta_p\|$ and $\|\eta_r\|$ , P(t) of the coupled system equations (3) and (4) will evolve in the neighbourhood of the original attractor of equation (1). This implies that the dynamics of the unstable system and the coupled system will remain qualitatively same for a significantly small values of $\|\eta_p\|$ and $\|\eta_r\|$. Therefore, autonomous system must be strongly coupled to the unstable system in order provide significant attenuation. This will happen at $\|\eta_p\|_\infty = 1$ and $\|\eta_r\|_\infty = 1$ as previously reported [16], [26] **.** In this study, it was conceived that this condition can be achieved in form of optimised design of topside pipeline section coupled to the parent pipeline-riser system as shown in Figure 4. More on the intermittent absorber can be found in Ehinmowo [16].

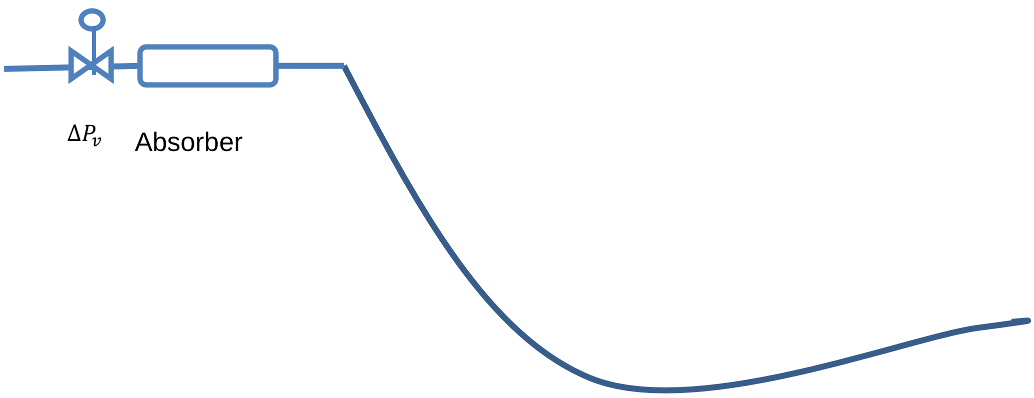


**Figure 4:** Inline coupled intermittent absorber

This configuration can help to increase the degree of freedom and provide stabilising effect like the intermittent absorber.

***Proof of Concept using a phenomenological model***

In this study, a 6-state dynamical model developed in Jahanshahi et al.[29] was adapted to investigate the possibility of optimising the topside pipeline for improved slug control. The model is based on six ordinary differential equations (ODEs) used to model a well-pipeline-riser system shown in Figure 5. Equations 5 and 6 describe the well, the upstream pipeline section was modelled by equations 7 and 8 while 9 and 10 describe the riser system. Equations 5, 7 and 9 are the state variables which describe the masses of gas while 6,8 and10 describe the masses of liquid in the well, pipeline and riser system respectively.

$$\dot{m}_{G,w} = \alpha_{G,t}^{m} w_r - w_{G,in} \tag{5}$$

$$\dot{m}_{L,w} = (1 - \alpha_{G,t}^{m}) w_r - w_{L,in} \tag{6}$$

$$\dot{m}_{G_1} = w_{G,in} - w_{G,lp} \tag{7}$$

$$\dot{m}_{L_1} = w_{L,in} - w_{L,lp} \tag{8}$$

$$\dot{m}_{G_2} = w_{G,lp} - w_{G,out} \tag{9}$$

$$\dot{m}_{L_2} = w_{L,lp} - w_{L,out} \tag{10}$$

where $\alpha_{G,t}^{m}$ is the gas mass fractions at the top of the well and $w_r$ is the production rate from the reservoir to the well. More details on the model assumptions and closure equations can be found in Jahanshahi et al.[29].

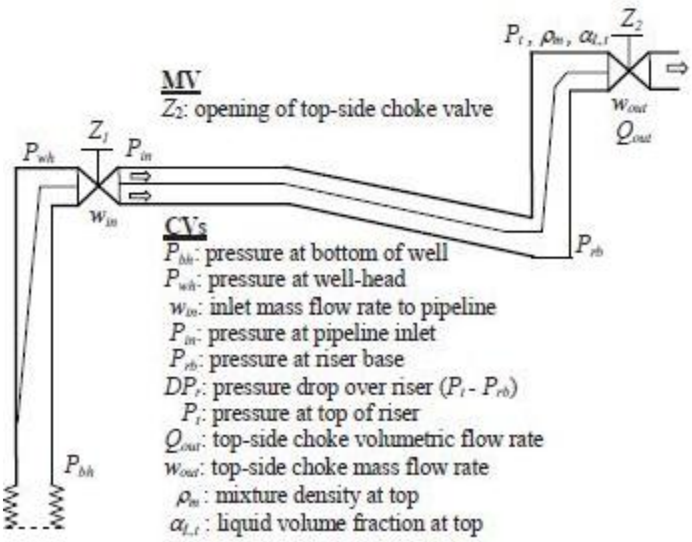


**Figure 5:** Schematic of well-pipeline-riser system [29]

Figure 5 shows the well-pipeline-riser system. The vertical well is 3000m deep and 0.12 diameter while the pipeline is also of 0.12m diameter and total length of 4300m with $1^0$ negative inclination from 2300 m which causes 40.14m descent immediately upstream the riser base. The vertical riser is a 300m length pipe and 0.1m diameter. The topside horizontal section which was optimised in this study was of original length of 100m and 0.1 m diameter. The default case (0.36 kg/s and 8.64 kg/s gas and oil flow rates respectively) considered in Jahanshahi et al.[29] was adapted. This system has been modelled using OLGA and the phenomenological model described here to obtain the bifurcation map and the bifurcation point was recorded at 5% valve opening. Beyond this valve opening the system was observed to suffer from severe slugging. Figure 6 for example shows the plot of various system variables at 10% valve opening. The system was observed to experience both flow and pressure fluctuations which is typical of severe slugging. This is an undesirable phenomenon. In practice choking is usually used to solve this problem but with attendant loss in production. It is therefore always desired to attenuate severe slugging at large valve opening to reduce loss in production due to choking. In this study, it was conceived that increasing topside pipeline volume would allow for this.

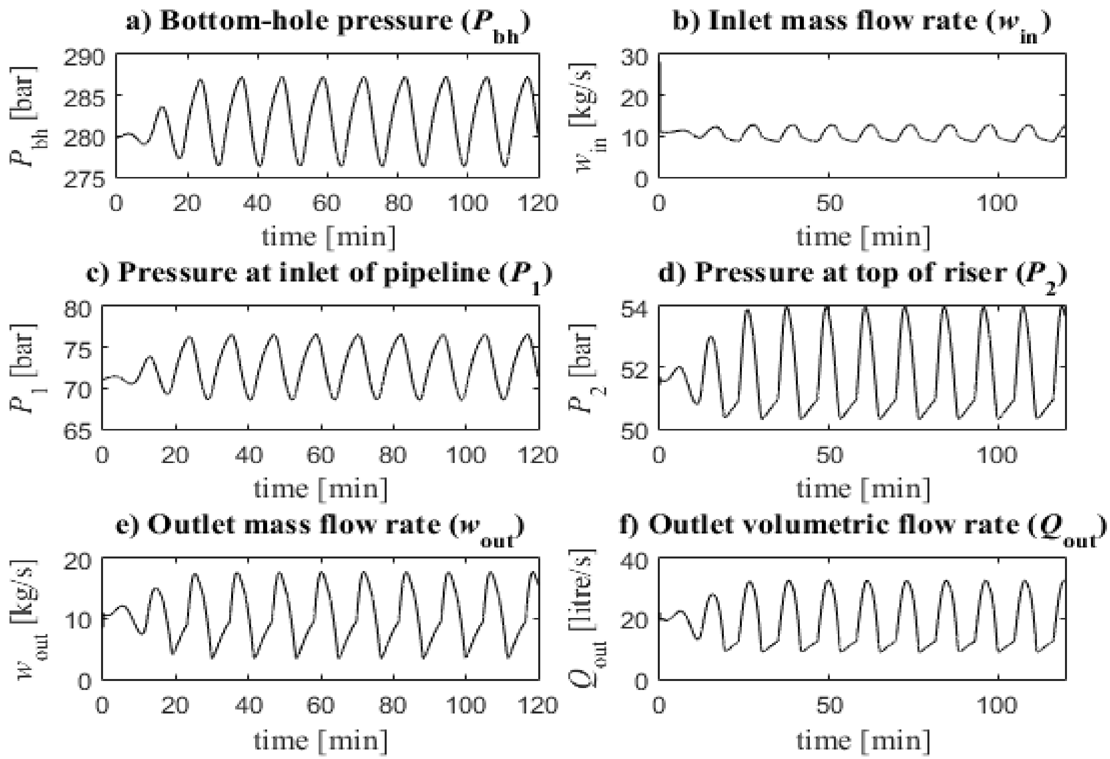


**Figure 6:** System variable showing slugging fluctuation at 10% valve opening

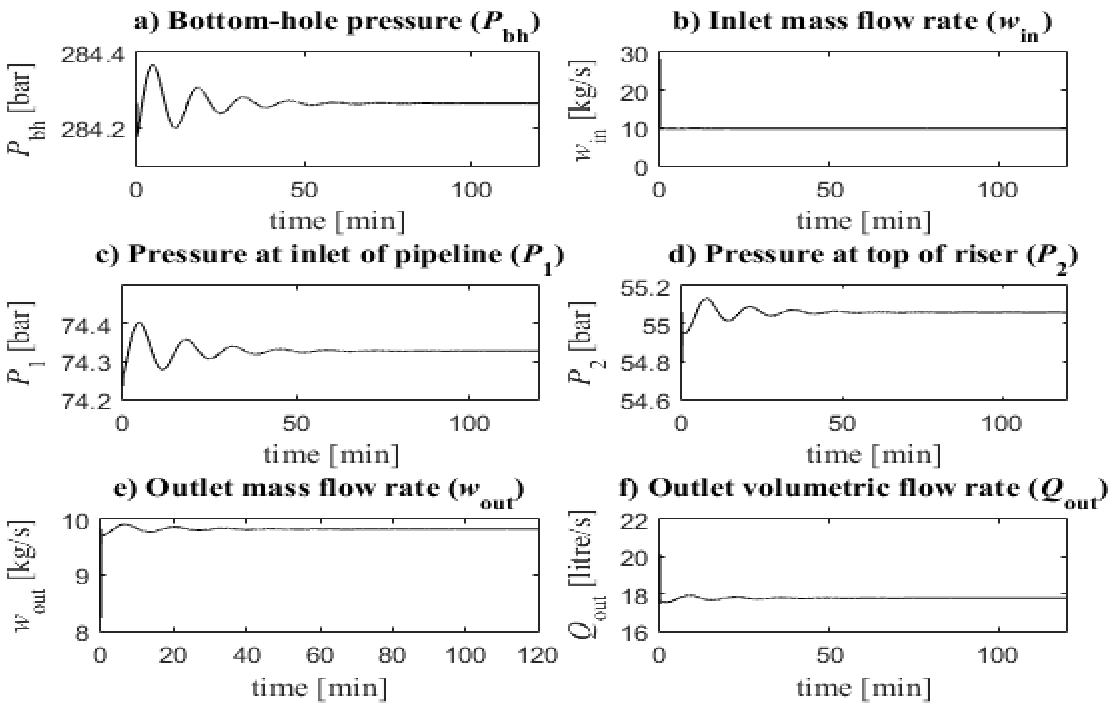


**Figure 7:** System variables at bifurcation point (5% valve opening)

Figure 7 shows that the system was brought to bifurcation point at 5% valve opening but understandably at this valve opening, the production would be greatly reduced. However, when the horizontal pipeline volume was increased from $1.13 m^3$ to $5.09\ m^3$, the system was stabilised at 10% valve opening as shown in Figure 8. This led to the reduction in bottomhole pressure which translated into about 11% increase in outlet volumetric flow rate. This confirms the theoretical analysis described in section 2.1.

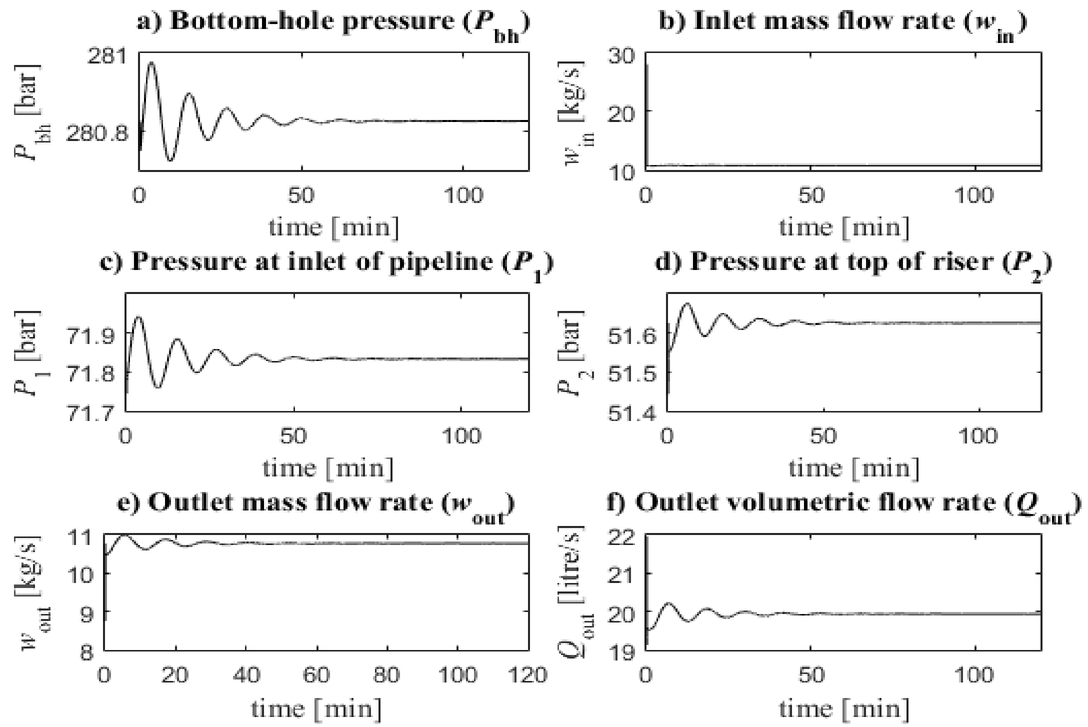


**Figure 8:** System variable at 10% valve opening with optimised topside pipeline volume

## NUMERICAL MODELLING, SIMULATION AND VALIDATION OF A 4" PIPELINE-RISER SYSTEM

It was established in section 2, that the topside pipeline volume can be manipulated to attenuate severe slugging at larger valve opening thereby leading to increased oil production. In this section, a further study was conducted using industrial code (OLGA, version 7.3.0) to ascertain this benefit and establish the limits. The 4" section of the Cranfield university multiphase experimental set up shown in Figure 9 was modelled and the results were compared with those obtained for an intermittent absorber reported in Ehinmowo et al.[26]. The intermittent absorber is an externally coupled extra volume (vessel) on a pipeline-riser system while the topside pipeline optimisation could be referred to as an inline coupling version of the intermittent absorber. The experimental set up has been well described in [16].

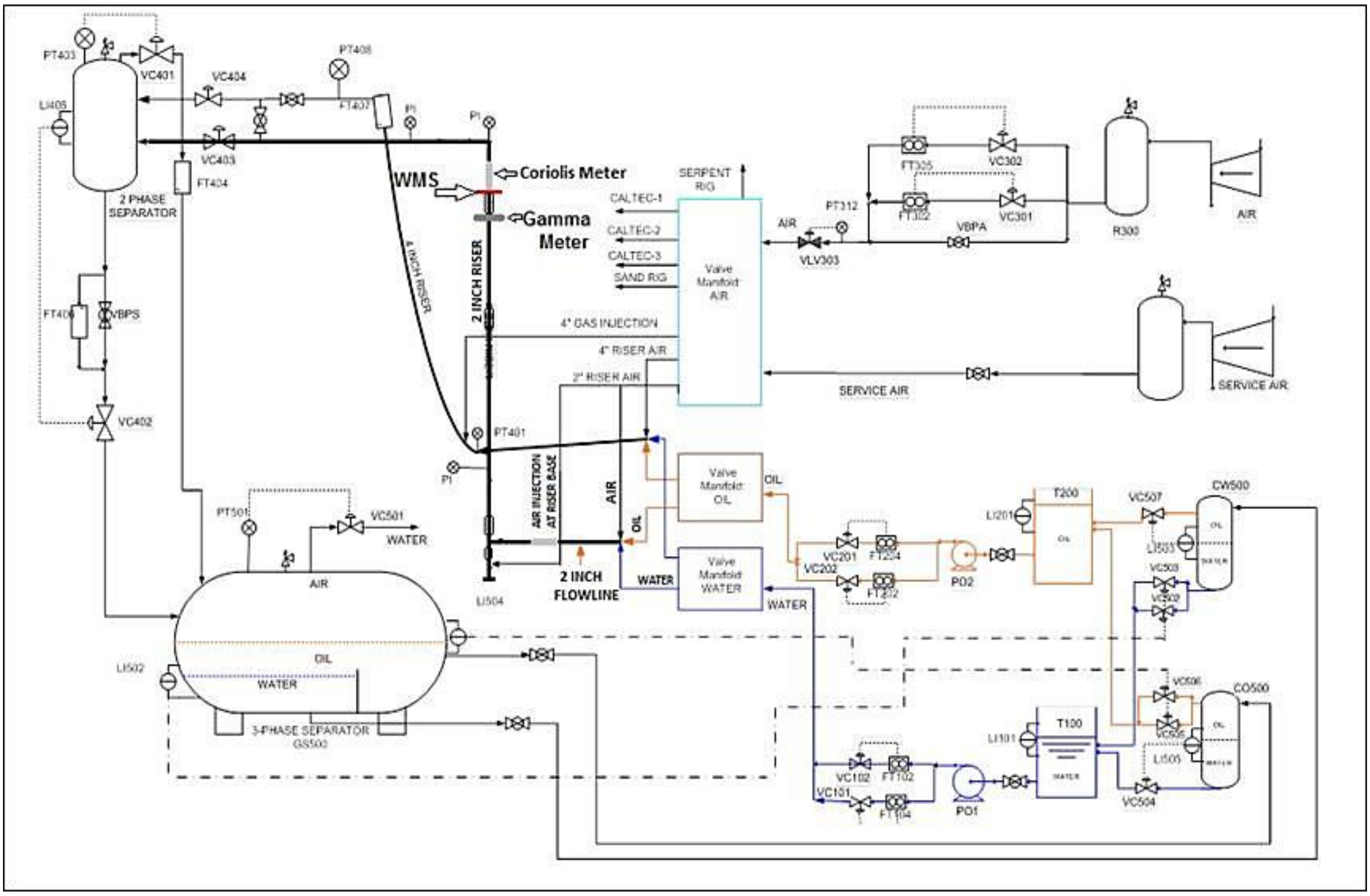


**Figure 9:** Cranfield University Multiphase Facility [30]

The 4" facility is a 55m long pipeline-riser system with 40 m horizontal pipe inclined at $-2^0$ connected to 12m high catenary riser followed by 3m horizontal topside section and its simplified geometry modelled in OLGA is shown in Figure 10.

The simplified geometry shown in Figure 10 was developed and discretised and grid convergence study was carried out. An optimum mesh size of 2 m was observed for the pipeline and 1.35 m for the riser pipe. A total of 30 grid cells were used for the pipeline-riser system with additional 12 grid cells for the 3m horizontal pipe linking the riser top to the two phase separator. A temperature value of 15$^o$C was used in consonance with what was observed for the experimental studies. The case study in this section is a typical classical severe slugging condition of 1kg/s and 0.0034 kg/s for water and air respectively. The outlet pressure was specified at 2 bar at the pressure node downstream the two phase separator.

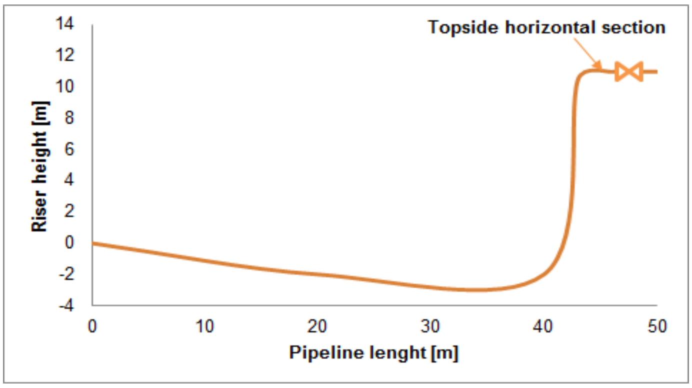


**Figure 10:** Schematic diagram of the 4" experimental rig

In this study, two strategies were adopted for the sensitivity studies on the volume of the topside horizontal pipeline and various slug attenuation benefits were recorded and compared with the benefit reported for the intermittent absorber. The first strategy was to leave the topside pipeline at default 4" pipeline of various volume while the second was to model topside pipeline as a 6" pipeline of various volume. These strategies are now referred to as mode 1 and mode 2 respectively for ease of description.

## RESULTS AND DISCUSSION

### *Experimental validation of numerical study*

The typical severe slugging condition described in section 3 was experimentally and numerically investigated and the results are compared next.

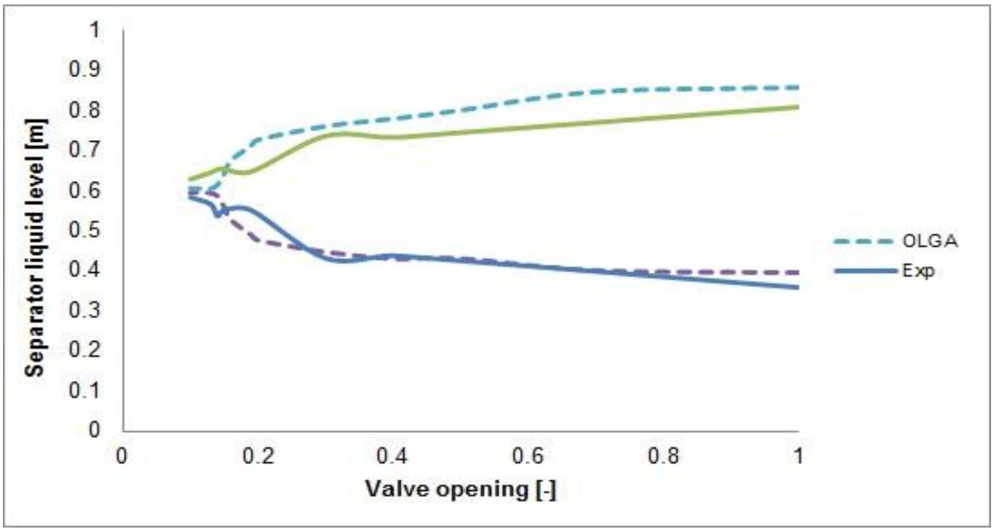


**Figure 11:** Separator liquid level bifurcation maps for experimental and numerical studies compared

Bifurcation maps were generated for this condition experimentally and numerically. The results for the separator liquid level fluctuation and riser base pressure are shown in Figures 11 and 12 respectively.

Figure 11 shows that the separator liquid level fluctuates between minimum and maximum values at various valve openings. The figure shows that the numerical code was able to reproduce the bifurcation point (13% valve opening) and the degree fluctuations considerably well.

Figure 12 shows the comparison of the riser base pressure bifurcation maps for the industrial multiphase code (OLGA) and experimental results. The riser base pressure fluctuates between minimum and maximum values for various valve openings. This is characteristic of slug flow. The code was able to reproduce the experimental results considerably well. Although the fluctuation magnitudes appeared to be slightly higher than those observed in the experimental study, the bifurcation point was accurately predicted. Having obtained the bifurcation point with manual choking, it was desired to stabilise the slug flow at a larger valve opening by manipulating the topside pipeline volume. The next section presents the result of the studies carried out in this regard.

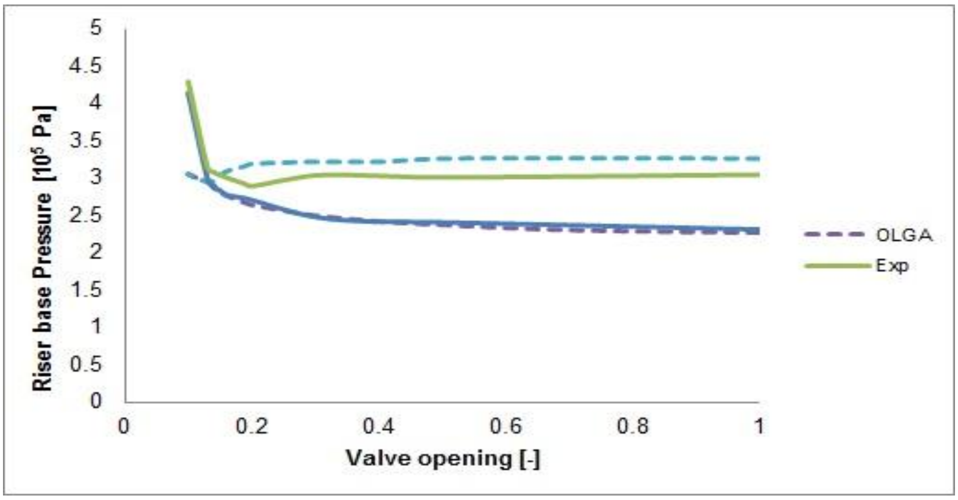


**Figure 12:** Riser base pressure bifurcation map for numerical and experimental studies compared

International Journal of Applied Engineering Research ISSN 0973-4562 Volume 11, Number 22 (2016) pp. 10782-10793


***Sensitivity studies on topside pipeline volume mode 1***

Numerical tools provide an advantage of simulating systems that are either not available due to cost, time and other constraints. This advantage was leverage on in this study to gain insight into the optimum topside volume that would yield stability and increased production simultaneously. In this section the result from the sensitivity studies from mode 1 is presented.

Figure 13 shows the various riser base pressure at various valve openings and riser top horizontal pipe volumes for mode 1.

Figure 13 (a) revealed that at 13% valve opening, there is no need for additional volume to stabilise the slug flow since the choke valve would accomplish this task at this valve opening. This is in consonance with the bifurcation maps shown in Figures 11 and 12 where the varied parameter is the valve opening. Interestingly, it was observed that an increase in the pipeline volume beyond 0.073 $m^3$ enhances the return of slug flow.

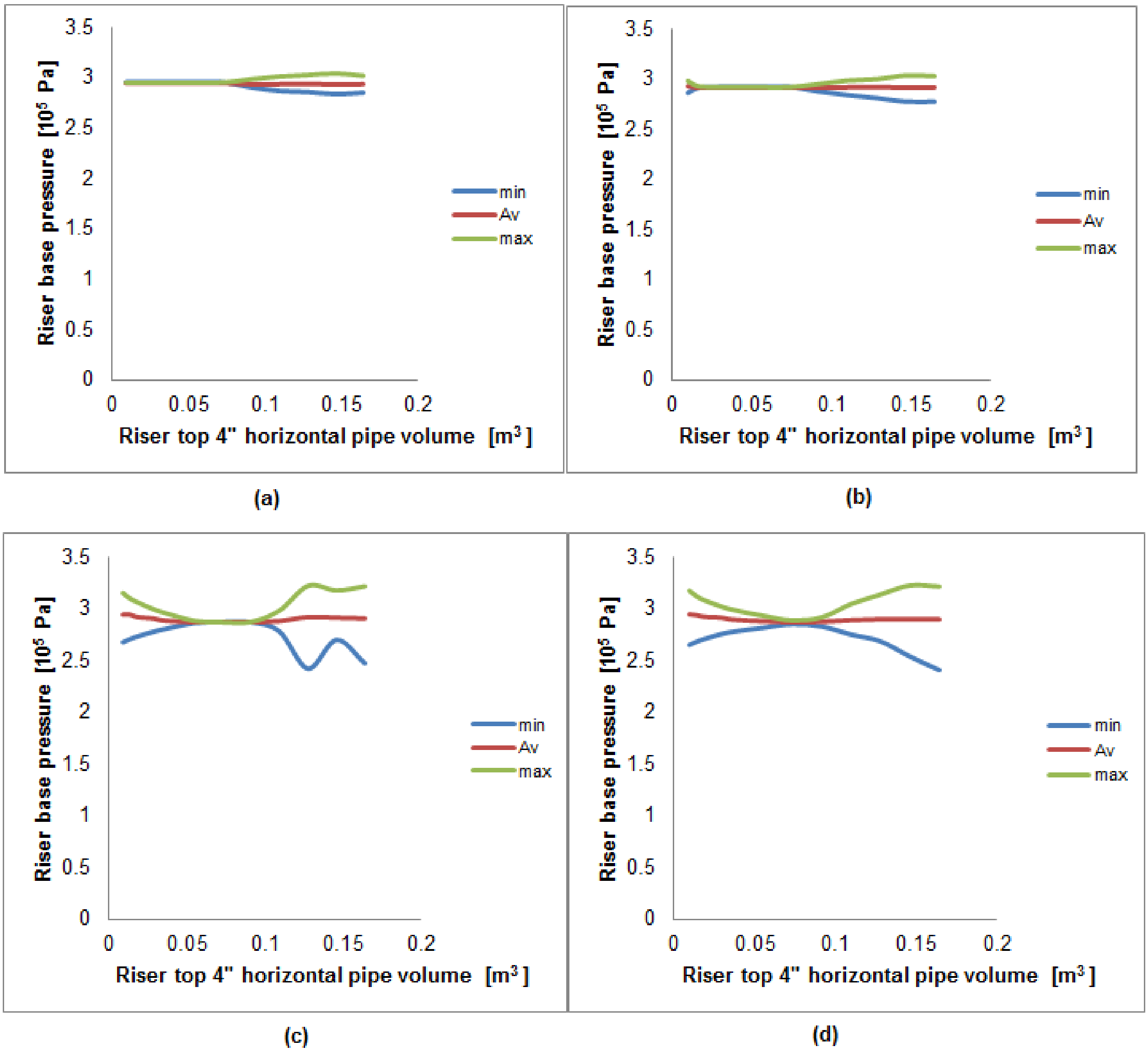


**Figure 13** Riser base pressure bifurcation map for mode 1 (a) 13 % valve opening (b) 15% valve opening (c) 19% valve opening (d) 20% valve opening

This clearly shows that the pipeline volume must be optimally designed to be able to deliver the slug attenuation benefit desired.

Figure 13(b) shows that at 15% valve opening the system is unstable. Its shown that a minimum of 0.014 $m^3$ pipeline volume must be added to stabilize the system at this valve opening. Although, the system can still be stabilised with additional riser top horizontal volume up to 0.073 $m^3$, it is more desirable to stabilise the system at smaller volume to satisfy space and cost constraints.

Figure 13 (c) shows that at 19% valve opening, the system can be stabilised with additional volumes between 0.055 $m^3$ and

0.091 $m^3$. Outside this range the system stability is lost. Figures 13 (d) shows that with the help of additional riser top pipe volume between 0.073 $m^3$ and 0.091 $m^3$, the slug flow can be stabilised. Beyond this range the system becomes unstable. These results showed that with the help of additional risr top volume, system stability can be achieved at larger valve opening. This in practical sense translates to increase in oil production.

***Sensitivity studies on topside pipeline volume mode 2***

The results obtained from mode 2 is shown in Figure 14. As previously shown in Figures 11 and 12, the case studied was stabilised with the help of choking at 13% valve opening. Again Figure 14 (a) shows clearly that pipeline-riser system was stabilised at this valve opening without additional topside volume. But when the valve opening was increased to 15% for example, Figure 14 (b) shows that a minimum 0.018 $m^3$ is required to stabilise the system at the valve opening. This trend was observed for other valve openings such as shown in Figure 14 (c). Although additional volume of topside pipeline was observed to provide reduction in the fluctuation at 20% valve opening, it appears the degree of benefit has drastically reduced at this point as the system appears to be largely unstable.

Figures 13 and 14 (b, c and d) suggest that at larger valve opening, there is a range of pipe volume where stability can be achieved, outside this range no attenuation was possible. This can be explained thus: The unstable left hand side shows that initially the system is unstable under the valve opening with/without additional pipe volume. The back pressure from the choke was not sufficient to cause stability.

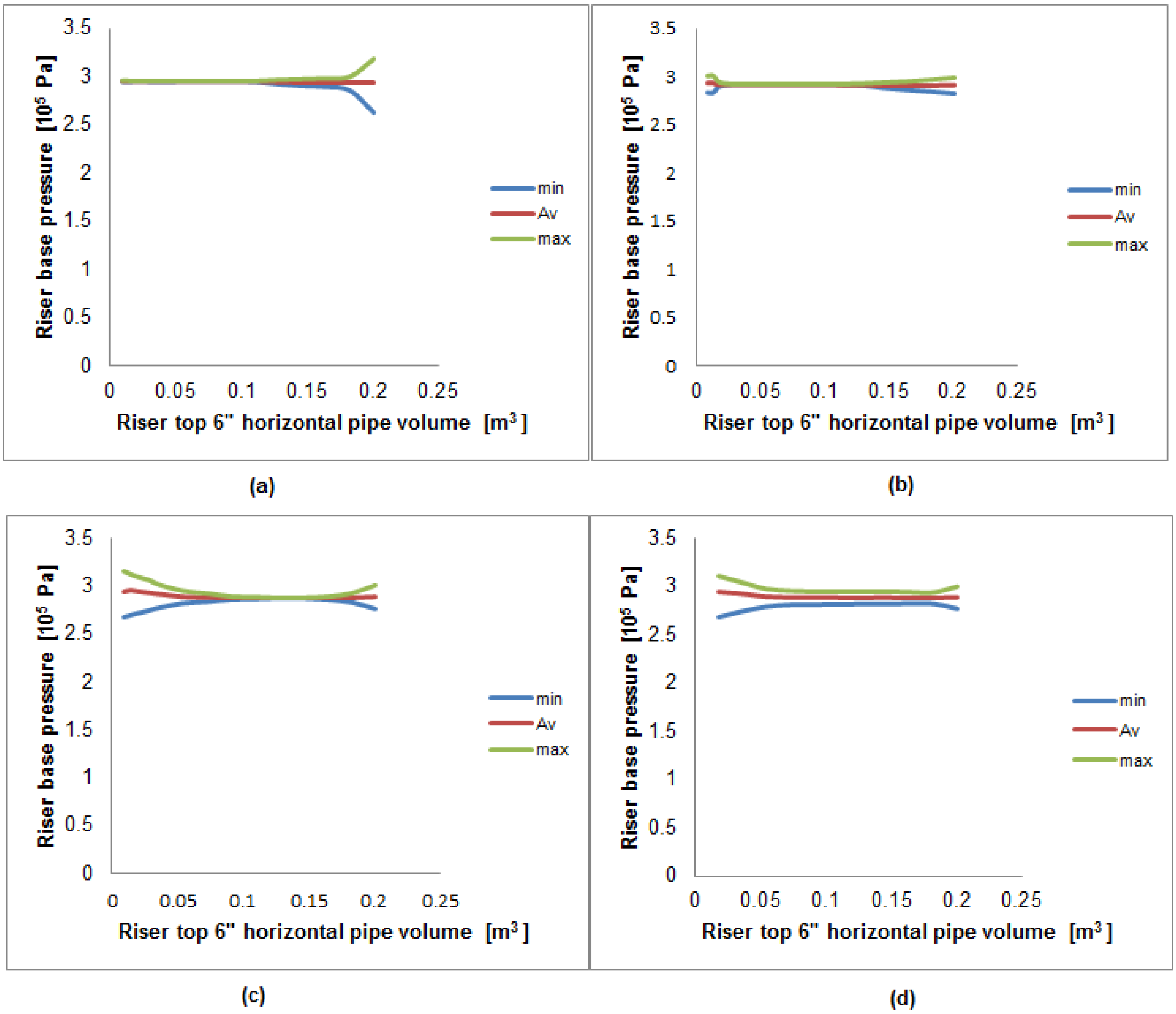


**Figure 14:** Riser base pressure bifurcation map for mode 2 (a) 13 % valve opening (b) 15% valve opening (c) 19% valve opening (d) 20% valve opening

The second region which is the region of stability shows that the pipe volume (length) provides sufficient buffer zone that can help attenuate the slug produced from the riser before entering the separator in a stable manner. The right hand unstable region could be explained to be region where increase in the volume/length contributes to the increase in gravitational pressure drop across the riser leading to slug growth and the slugging becomes more severe. The optimised horizontal pipe design concept helped to reduce the slug intensity by changing the severe slugging to short hydrodynamic slugging as the pipe volume increases. These results show that increasing the horizontal pipeline volume can provide stabilizing or destabilizing effects. Similar observation has been reported in Pickering et al.[25] for a study on the increase in riser height. However, no account was given for which of these effects was particularly dominant and to what extent. The results from the sensitivity studies on both modes have clearly shown these limits.

***Oil production benefit of the optimised topside design***

The pressure benefit index (PBI) previously proposed in Ehinmowo [16] for the intermittent absorber concept was applied to the optimised topside design in this work. The PBI was defined as the ratio of the difference between the pressure drop across the choke valve with and without additional volum to the pressure drop across the valve without additional volume. PBI is given by equation (11).

$$PBI = \left|\frac{(\Delta P\ accrossvalve)_{isolated} - (\Delta P\ accrossvalve)_{coupled}}{(\Delta P\ accrossvalve)_{isolated}}\right| \tag{11}$$

Where ΔP is the pressure drop across the valve

Figure 15 shows the PBI plots for the intermittent absorber and the two other modes. The plot shows that the three configurations can provide slug attenuation benefit. However, at relatively small size (L/D=6.5), the intermittent absorber concept provided greater benefit of 35% compared with 15% for modes 1 and 2. But at considerably large volume (L/D=19.6), modes 1 and 2 provided better benefits of 43% and 49% respectively compared to 15% for the intermittent absorber. For the intermittent absorber, the system stability was achieved at large valve openings with considerably smaller absorber size while modes 1 and 2 configurations show that a larger volume (longer length) would be required for system stability at larger valve opening. The PBI revealed that there exists an optimum volume where size, system stability and production constraints are satisfied. For the intermittent absorber, these constraints are satisfied at L/D=6.5 while mode1 was satisfied at L/D= 29.5 and 19.6 for mode 2. This implies that the intermittent absorber satisfied size and space constraints best followed by mode 2 and mode 1. The intermittent absorber could be better suited for existing field while mode 1 or 2 might be the preferred option for a new field. However,where space contraint is relatively relaxed, mode 2 would be more desired since a greater oil production benefit can be achieved with the design.

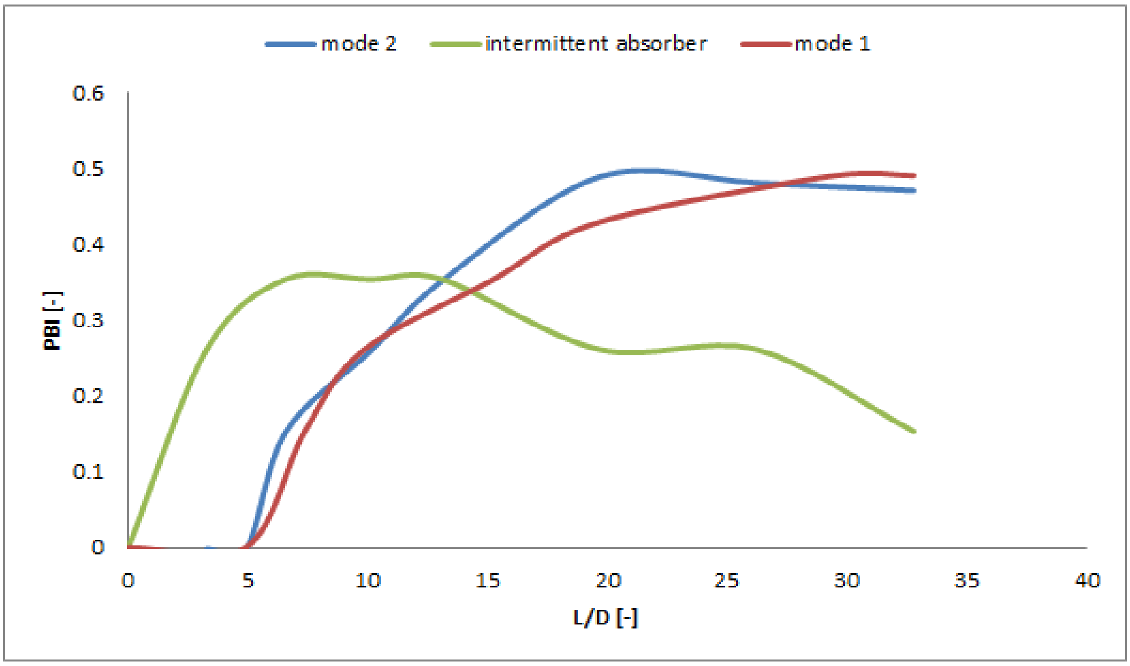


**Figure 15:** PBI Plots for intermittent Absorber, Modes 1 and 2 Compared

From Figure 15, mathematical expressions can be written for the range of pipe size volumes that can provide slug stabilising benefit.

$$\frac{d(PBI)}{d\left(\frac{L}{D}\right)} > 0 \tag{12}$$

$$\frac{d(PBI)}{d\left(\frac{L}{D}\right)} = 0 \tag{13}$$

$$\frac{d(PBI)}{d\left(\frac{L}{D}\right)} < 0 \tag{14}$$

Equation (12) shows that as long as the ratio is positive, attenuation benefit can be achieved while equation (14) revealed that a negative ratio yields no benefit but rather an escalated system instability. Equation (13) shows that when the ratio is equal to zero an optimum benefit was achieved. The graph shows that this condition can occur at various L/D but for economic reasons, the global optimum point is desired.

## CONCLUSION

A new method for slug flow attenuation based on the bifurcation analysis of optimised riser top horizontal pipeline has been proposed. The results showed that an optimum design of topside horizontal volume can achieve system stability at large valve opening resulting to increased oil production. The Pressure Benefit Index (PBI) for the two modes investigated in this work was compared with the intermittent absorber concept. For the case studied, a maximum PBI value of 35% was recorded for the intermittent absorber while up to 43% and 49% PBI values were obtained for modes 1 and 2 respectively. This provided a useful insight into the appropriateness of these configurations under different considerations and constraints. For a new field development, mode 1 or 2 could be the preferred option depending on space constraint while the intermittent absorber would be more suited for existing facilities. The PBI also revealed that there exists an optimum volume where size, system stability and production constraints are satisfied. The slug attenuation mechanism for the investigated modes have been revealed. From this study ,it has been demonstrated that the intermittent absorber must be strongly coupled to the unstable pipeline-riser system in order to provide significant attenuation as previously suggested in [16].

## ACKNOWLEDGEMENT

The authors thank the Niger Delta Development Commission (NDDC), Nigeria who supported the PhD of Adegboyega Ehinmowo.

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