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Research Article

Investigation of Self-Lifting Approach for Slug Attenuation in Inclined Pipeline-Riser System

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Abstract

This study evaluates the use of self-gas lifting in the mitigation of severe slugs. OLGA was used to develop the pipeline model and Multiflash for fluid characterization. Two OLGA cases were created, a base case pipeline model which was inclined at 5° to the riser base and also a 5° inclined pipeline to the riser base but with an auxiliary bypass line to lift the flow at a certain point above the riser base. A phase splitter process equipment which acts as a take-off point along the pipeline and function as an internal node and a separator network was place along the pipeline and riser. The phase splitter allows only gas to pass through the 'bypass line' and liquid through the 'Subsea Tieback'. The bypass pipe of internal diameter 3-inch was connected to the take-off point at 535.455ft from the riser base along the pipeline and to an internal node which serves as the injection point into the riser at 20ft from the riser base. Results shows that an auxiliary self-lift bypass line was very effective in attenuating severe slugging in a pipeline-riser system and a stable liquid production of 2728.93bbl/day at the topsides was obtained when an auxiliary bypass line was used as a gas re-injection line into the riser column whereas for the case of 5° inclined pipeline without a bypass line, the total liquid flow was oscillating between 46776.3bbl/day and -3646.44bbl/day. Slug flow was completely eliminated for the model with bypass line as evidenced by the more stable pressure. The highest riser pressure was 291.327psia over the duration of the 2hrs, which was lower than the slugging model without a bypass line (299.595psia). The auxiliary self-lift bypass line was very effective in mitigating slugging in the pipeline -system.

Keywords	*Self-Lifting Approach; Slug Attenuation; Inclined Pipeline-Riser System*
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Introduction

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. 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). 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.

Numerous changes in pipeline inclination are always encountered since the distance from the well to central gathering stations is often many miles (Kang *et al.,* 2000). These changes in inclinations affect the flow pattern and flow characteristics. Slug flow can be observed in many two-phase flow engineering applications such as flow in oil and gas pipelines (Pedersen *et al.,* 2016) and other process industries (Chhabra and Richardson, 1999). The formation of slug flow regime is transient in nature, passing from stratified to wavy flow, and then onto slug flow (Hassanlouei *et al.,* 2012). Riser induced slugging occurs in a production system when the liquid forms a blockage at the base of the riser mostly before the upward inclination. The blockage hinders the flow of gas into the riser section and gas accumulates behind the liquid, thereby decreasing downstream gas production to possible complete cessation. When the blockage occurs, downstream gas production decreases and may completely stop. There are several established approaches to the mitigation of slugging in deep-water oil fields and they include; top side choking, riser-based gas lift, pipe insertion, flow rate control, increasing pipeline pressure, riser base pressure control with surface control valve, multiple riser base lift, foaming agents, gas-lift and choking combination and self-lift approach. Jones *et al.,* (2014) stated that the most effective mitigation approach to slugging is riser top valve 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. 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. 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 but concluded that this approach is quite costly due to the large gas volumes needed to obtain a satisfactory stability of the flow in the riser. For the flow rate control approach of mitigation, the back pressures increase three times higher before the system becomes stable (Pots et al.,1987; Gomez *et al.,* 2000). Sarica and Tengesdal (2000) showed that the increasing back pressure severely lowers production capacity, which is not viable for both shallow- and deep-water and proposed the transfer of pipeline gas (in-situ gas) to the riser section at the pit slightly above the riser base as a solution to eliminate slugging regime. Riser base pressure control with surface control valve approach results to high back pressures and an overall pressure increase in the production system and not suitable for deep-water applications, where a major reduction in the production rate is anticipated due to high back pressures (Courbot, 1996).For the foaming agent application, it is possible to achieve homogeneity of the multiphase and achieve a separation at the low-pressure topside but a reduction in the quality of the fluid (Pedersen *et al.,* 2016). Yaw *et al.,* (2014) reported on the viability of the gas-lift and choking combination to alleviate some of the cooling and excessive frictional pressure loss problems but will require injection of gas and the necessary gas lift installation which is costly.

Tangesdal *et al.* (2003) proposed the self-lift technique (slug mitigation approach) which involves tapping off gas from the upstream pipeline system via a by-pass pipe, into the riser column to mitigate slug flow by breaking the liquid slugs within the riser column. This approach has been validated experimentally, but no mention has been made in literature to adapting this strategy for mitigation of slugging in sample deep-water oil fields.

Therefore, this work will investigate and verify self-lifting approach in slug mitigation in a riser system through simulation.

Materials and Methods

Materials and Data

Fluid properties data (compositional analysis of the fluid, components and composition, properties of the plus fractions), pipeline properties and geometry data (length and elevation or x- and y-coordinates, wall thickness, inside diameter, wall roughness), pipeline materials data (materials type, heat capacity, thermal conductivity and density), boundary condition data (inlet and outlet pressure and temperature, flow rate at inlet), heat transfer data (ambient temperature, inner wall heat transfer coefficient, ambient heat transfer coefficient) used in this study are presented in Table 1, 2 and 3.

Table 1: Fluid Composition Analysis

Components	*Mole %*
Carbon Dioxide	0.54
N2	0.69
C1	54.85
C2	4.85
C3	2.23
i-C4	2.15
n-C4	2.44
i-C5	2.56
n-C5	5.31
nC6	5.57
C7+	18.81

Table 2: Properties of the pipeline materials (Nemoto, *et al.,* 2010)

Material	*Density (kg/m^3)*	*Specific heat (J/kg K)*	*Thermal conductivity (W/m K)*	*Wall thickness (mm)*
Steel	7850	500	50	9
Insulation	1000	1500	0.135	15.24

The pipeline is 4300ft in length. In order to simulate using OLGA tool, it was assumed to consist of 3 pipe segments (one for pipeline and two for riser). Table 3 shows the pipeline geometry data when it was laid at angle 5° to the riser base. Both the riser and the pipeline have a diameter of 12inches and a wall roughness of 0.028mm

Table 3. Profile of pipeline at 5 degrees

Pipe	*X-Coordinate (ft)*	*Y-Coordinate (ft)*	*Diameter (in)*	*Wall Roughness (mm)*
Pipeline start	0	-268.97	12	0.028
Pipeline end	4283.64	-270	12	0.028
Riser base	4283.64	-270	12	0.028
Riser Top	4283.64	30	12	0.028

Simulation Tool and Approach

OLGA was used to develop the pipeline model and Multiflash was used for fluid characterization. Mutiflash was utilized as a phase behavior properties package to generate input files into the OLGA model and it calculates the properties of the fluids based on components and compositions. A PVT table file was generated and imported into

OLGA. OLGA reads these fluid properties at condition of pressures and temperatures within the system and use it for multiphase calculations. Two OLGA cases were created: a base case pipeline model which was inclined at 5° to the riser base and also a pipeline model which was inclined at 5° to the riser base but with a bypass line to lift the flow at a certain point above the riser base. The flowline-riser has an overall heat transfer coefficient of 8-W/m^2-C. The pipeline consists of a closed node in the beginning and then a mass source at the first section of the pipeline, a flowpath and then an outlet node (which might be a separator) at the end represented by a pressure node with boundary condition of 22°C and 20 bar. The fluids source was located at the first section of the pipeline (Subsea Tieback). The fluids temperature was set to 212°F with a mass flow rate of 5kg/s. The OLGA simulation tools model the pipeline as a number of pipes stretching between two points in space and divided into a number of segments (control volume).

The model was run for 2hrs to see the harsh nature of the slug on total liquid volume flow, the pressure at the pipeline-riser outlet, surge liquid volume, accumulated liquid volume and the flow regime indicator. The flow model used was the OLGA High Definition (HD) stratified flow model, which gives a three-dimensional (3D) flow.

The model visualization for the pipeline riser system with an auxiliary self-lift bypass line is shown in figure 1.

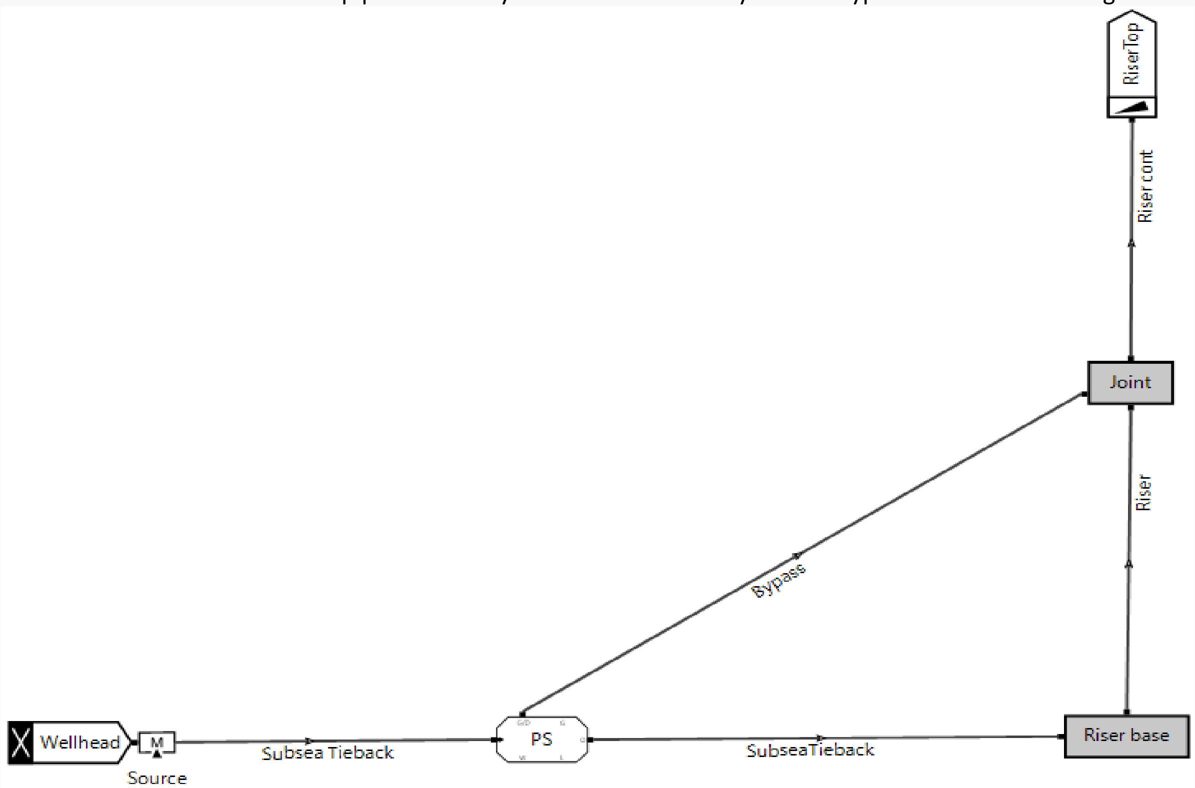

Figure 1: Visual representation of the self-lift OLGA model

The simulation workflow for this study is shown in figure 2

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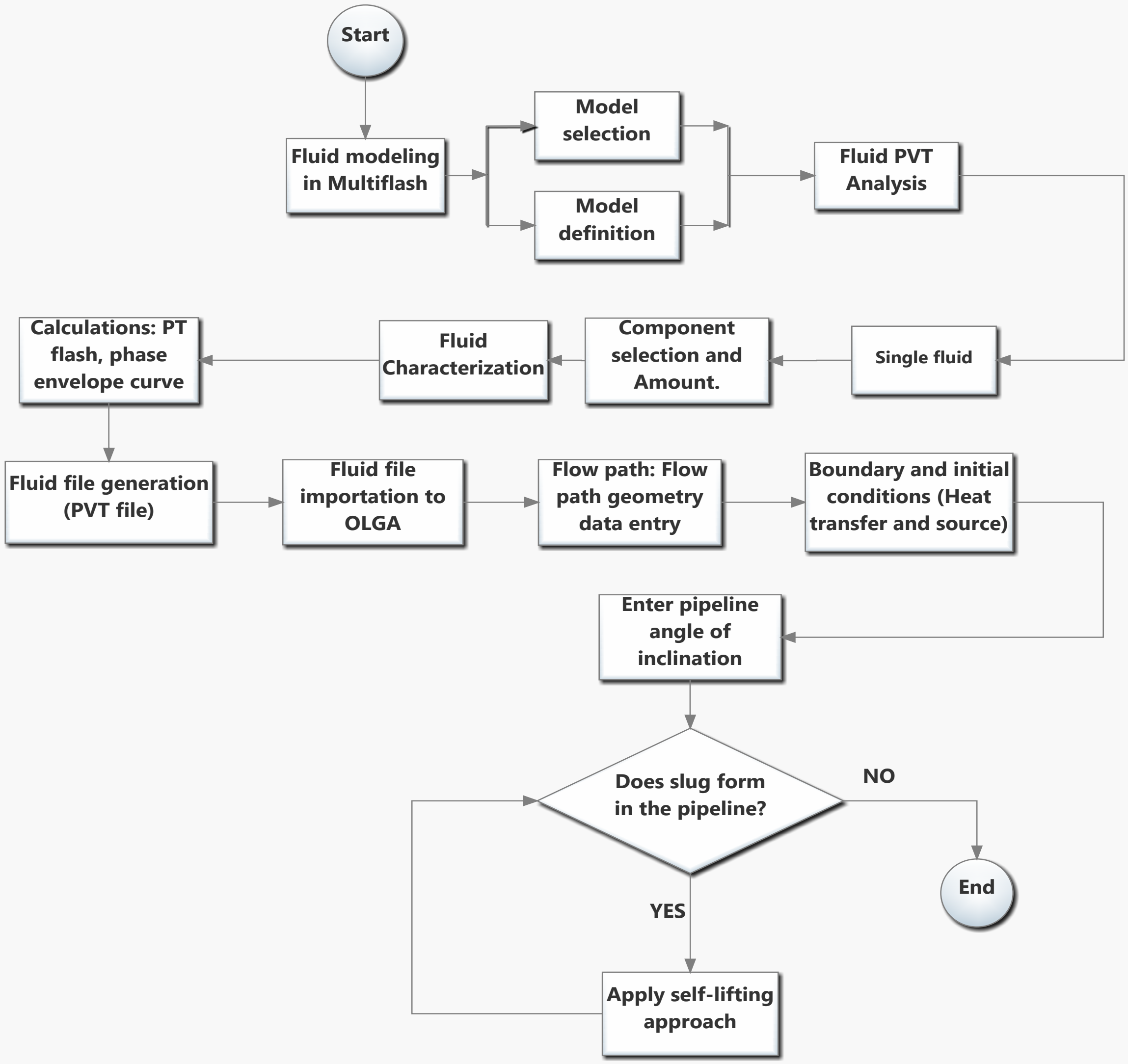

Figure 2: Simulation Workflow

Results

Slug Formation Tendencies in Pipeline Inclined at 5° to the Riser Base

Total Liquid Volume Flow

In this case, the pipeline was inclined at 5° to the riser base. Figure 3 shows the total liquid volume flow at the outlet of the pipeline-riser system for the case when the pipeline was inclined at 5° to the riser base. Result also reports an intermittent nature of the total liquid volume flow. The model predicts that about 0.283635hrs, the total liquid volume flow was 52778.9bbl/day. At about 2.00009hrs the total liquid volume flow was -92.8537bbl/day at the outlet.

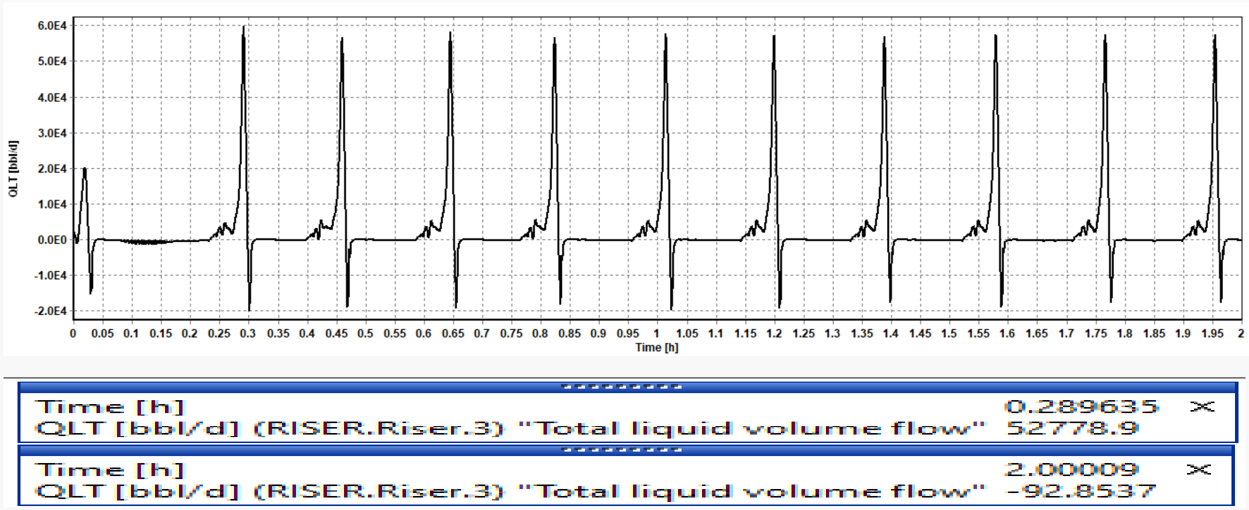

Figure 3: Total liquid volume flow at the outlet for pipeline inclined at 5°

Fluid pressure at the riser top

Figure 4 shows the fluid pressure at the outlet of the pipeline-riser system. Results show an intermittent nature of fluid pressure at the outlet of the system. A pressure of 295.211psia was observed at the outlet of the system just before the simulation start. After 0.635589hrs into the simulation run time, the pressure increases from 295.211psia to 299.595psia.

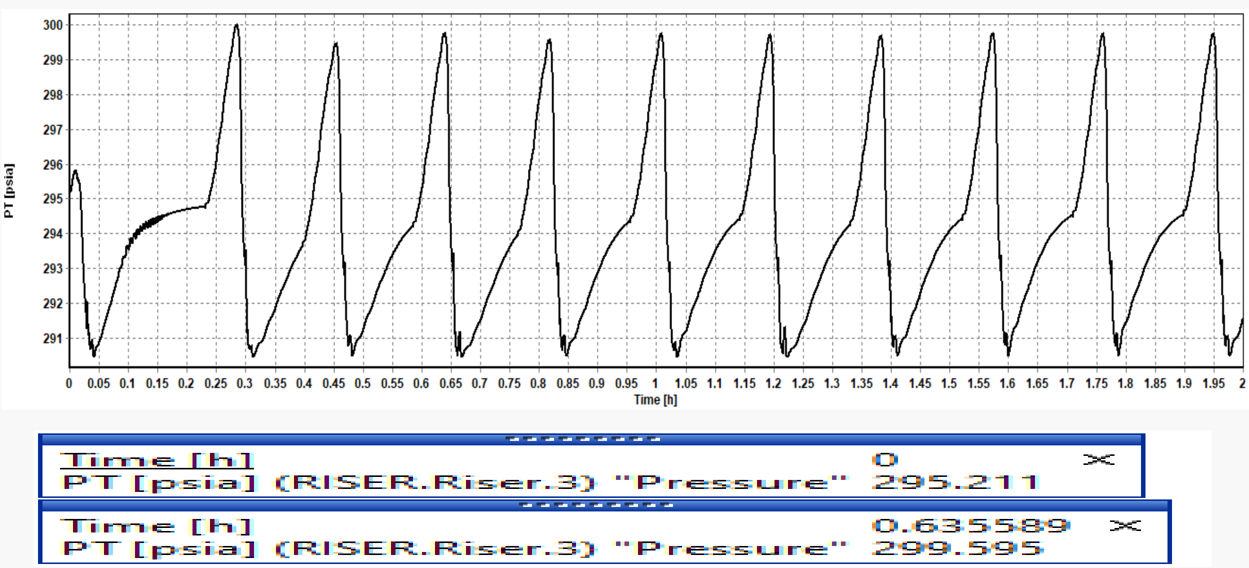

Figure 4: Fluid pressure at outlet for pipeline inclined at 5°

Accumulated liquid volume flow

Figure 5 shows the accumulated liquid volume flow at the end of the pipeline-riser system. Result reports shows that the accumulated liquid volume flow was 0-bbl at time zero and increased to 232.885bbl at the end of the simulation. This implies that after the simulation time elapses, 232.885bbl volume of liquid was present at the outlet of the pipeline-riser system.

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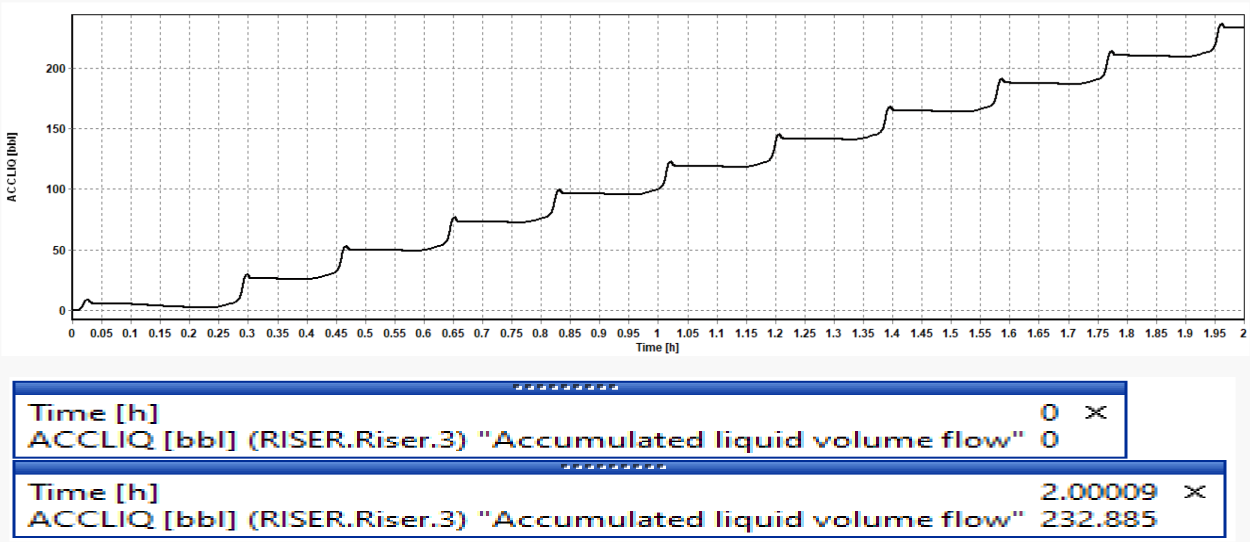

Figure 5: Accumulated liquid volume flow for pipeline inclined at 5°

Surge liquid volume

This is the liquid volume which would build in an assumed outlet separator with an assumed and insufficient maximum liquid drain capacity. The surge liquid volume is auto generated from the accumulated liquid volume. A surge volume of zero represent any reference volume corresponding to e.g., normal liquid level in a separator. The liquid volume only increases whenever the rate of liquid flowing into the container exceeds the maximum drainage rate. The generation of the surge liquid volume assumed that the drain rate at the end of the pipeline equals the average value of the total liquid volume flow (QLT) in the pipeline and based on that drain rate, OLGA calculate the surge liquid volume in the separator or at the end of the facility. Figure 6 shows the surge liquid volume. At the start of the simulation, the model predicts a surge liquid volume of 0bbl, this indicates the normal liquid level in the facility at the end of the pipeline-riser system. At simulation end time (2hrs), the model predicts a surge volume of 26.228bbl. Result also reveal a maximum surge volume of 34.157bbl at an average maximum liquid drain rate of 2794.4874bbl/day. If the drain rate is reduced to zero, meaning that there is no drain at the end of the pipeline, the surge liquid volume will be equal to the accumulated liquid volume of 232.885bbl at the end of the pipeline.

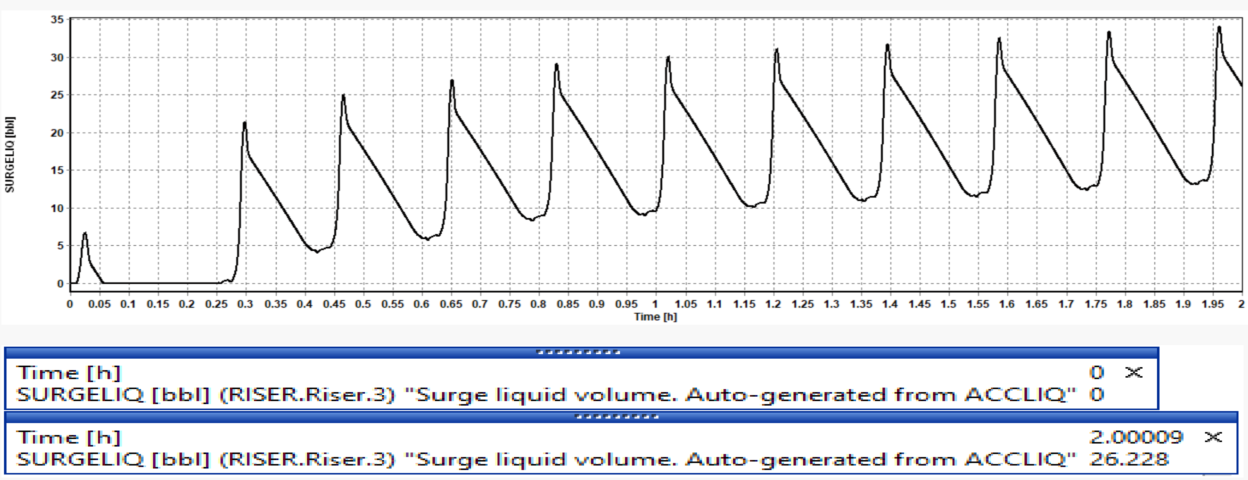

Figure 6: Surge liquid volume for pipeline inclined at 5°

Self-Lifting approach in 5° inclined pipeline

Total liquid volume flow at the riser top

Figure 7 shows the total liquid volume flow at the riser top for a pipeline inclined at 5° to the riser base. The red line shows the total liquid volume flow for a 5° inclined pipeline without an auxiliary bypass line while the black line shows the total liquid volume flow for a 5° inclined pipeline with a bypass line for self-lifting. Results shows a stable liquid production of approximately 2728.93bbl/day at the top side when an auxiliary bypass line was used as a gas re-injection line into the riser column whereas for the case a 5° inclined pipeline without a bypass line, the total liquid flow was oscillating between 46776.3bbl/day at about 1.39025hrs and -3646.44bbl/day at about 1.40151hrs. Slugs of short length that form and dissipate intermittently confirms the cyclic fluctuations in total liquid volume flow in the column and the flow was not stable.

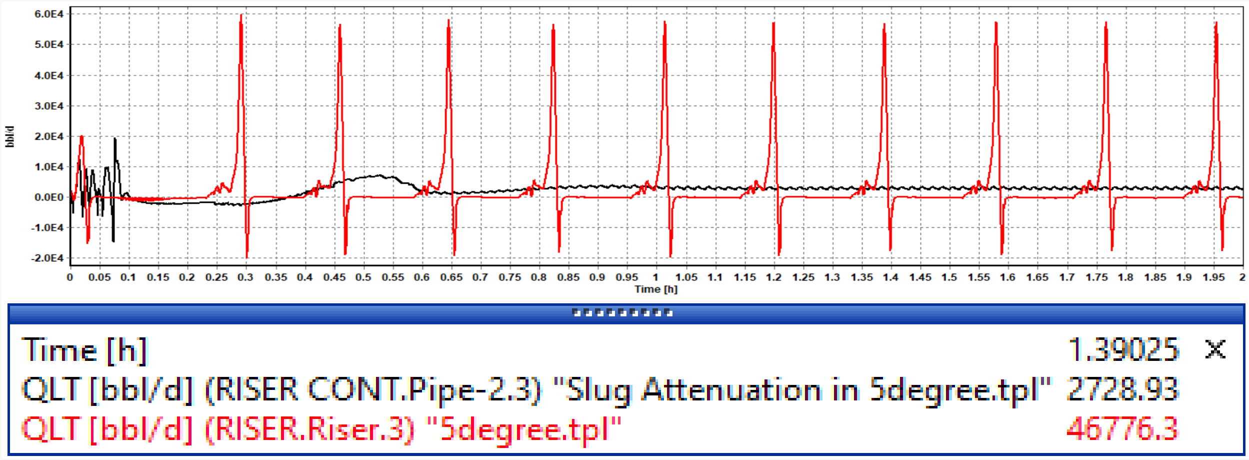

Figure 7: Total liquid volume flow at the riser top for 5° inclined pipeline with and without a bypass line

Fluid pressure at the outlet

Figure 8 shows the fluid pressure at the riser top for both cases. The red line shows the fluid pressure at the riser top for a 5° inclined pipeline without a bypass line and a phase splitter while the black line shows the fluid pressure at the riser top for a 5° inclined pipeline with a bypass line and a phase splitter. Results reveal a stable fluid pressure at the riser top for the system with an auxiliary bypass line, whereas for the system without a bypass line, the fluid pressure was changing with time. Severe slugging was observed at the riser top where a higher pressure of 299.595psia was reached over the duration of 2hrs simulation. The cyclic fluctuation of pressure at the riser top implies the presence of severe slugging for the case with no bypass self-lift line. For the case with an auxiliary self-lift bypass line, slug flow was completely eliminated as evidenced by the more stable pressure. As shown in figure 4.8, the highest riser top pressure was recorded at 291.327psia over the duration of the 2hrs, which is quite reduced from that recorded in the severe slugging model (299.595psia). This agrees with the work of Fabre *et al.,* (1990).

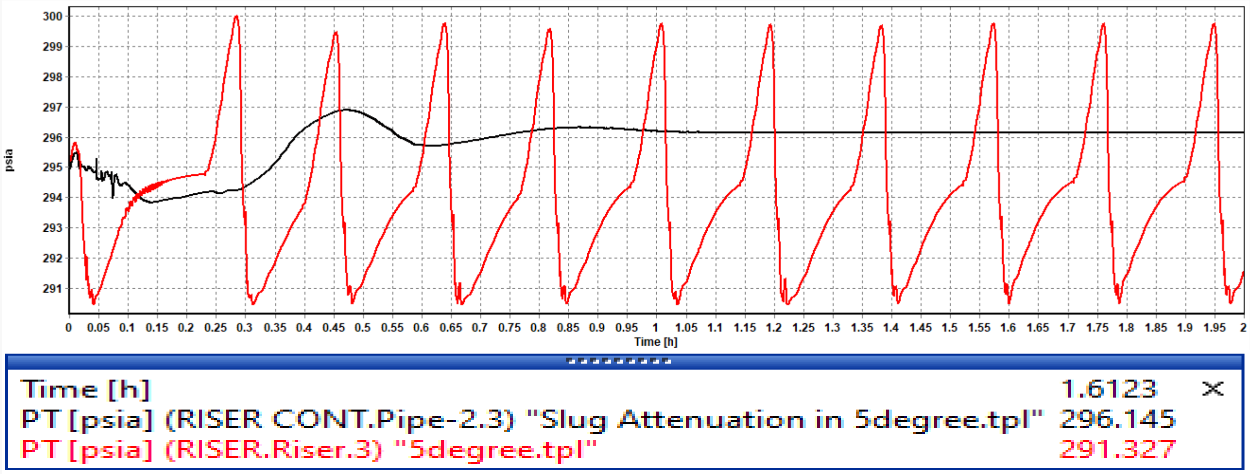

Figure 8: Fluid pressure at the riser top for 5° inclined pipeline with and without a bypass line

Accumulated liquid volume flow

Figure 9 shows the accumulated liquid volume flow at the riser top for 5° inclined pipeline. The red line shows the accumulated liquid volume flow for the pipeline without an auxiliary self-lift bypass line while the black line shows the accumulated liquid volume flow for a pipeline-riser system with an auxiliary self-lift bypass line. Results shows a linear increase in the accumulated liquid volume flow at the riser top with a value of 196.091bbl for 5° inclined pipeline with an auxiliary bypass self-lift line whereas for a 5° inclined pipeline with an auxiliary bypass line, a cyclic and increasing fluctuation in the accumulated liquid volume flow was recorded having a value of 232.885bbl at 2hrs of simulation.

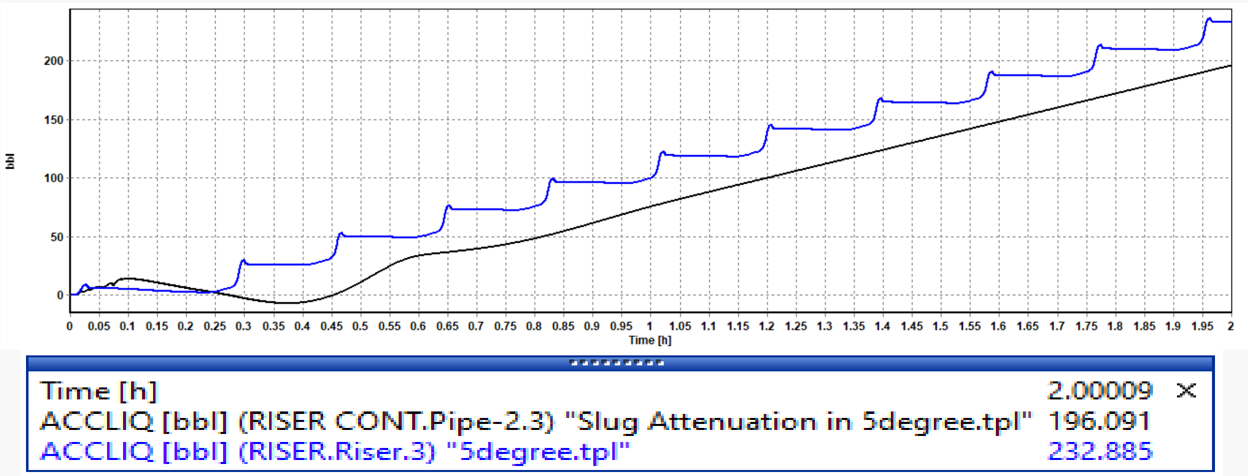

Figure 9: Accumulated liquid volume flow at the riser top for 5° inclined pipeline with and without a bypass line

Surge liquid volume at the riser top

Figure 10 shows a comparison of the surge liquid volume for both cases. The red line shows the surge liquid volume for a 5° inclined pipeline without a bypass self-lift line and the black line shows the surge liquid volume for the 5° inclined pipeline with a bypass self-lift line. Results shows a cyclic fluctuation in the surge liquid volume between 27.0772bbl and 8.57504bbl for the case with no bypass line. For the case with an auxiliary self-lift bypass line, results show a linear increase in the surge liquid volume with the highest riser top surge liquid volume recorded at

45.7952bbl over the duration of the 2hrs simulation. Although, this volume was higher than that recorded for the 5° inclined pipeline without an auxiliary bypass line, but a stable surge liquid volume was attained,

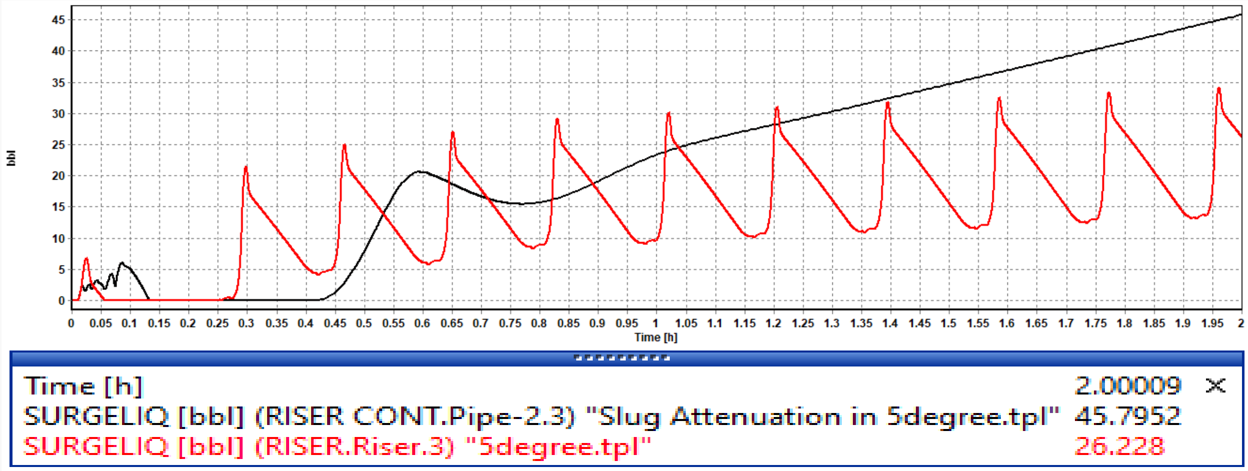

Figure 10: Surge liquid volume at the riser top for 5° inclined pipeline with and without a bypass line

Conclusion

In this work, the method of self-lifting approach for slug attenuation in pipeline-riser system was evaluated with OLGA dynamic multiphase flow simulator. Multiflash fluid modeling package was utilized for fluid characterization and for the generation of fluid file for importation into OLGA. A base case model was built considering a 5° inclined pipeline to the riser base without a bypass line and was used to investigate slug formation tendencies in the pipeline-riser system. With slug formation tendencies established, the base case model was modified to include a bypass line of internal diameter 3-inch connected to the take-off point at 535.455ft from the riser base along the pipeline. The bypass line was then connected to an internal node which serves as the injection point into the riser at 20ft from the riser base.

The conclusions made from this study include:

i. That an auxiliary self-lift bypass line was very effective in attenuating severe slugging in a pipeline-riser system.
ii. There is a stable liquid production at the top side when an auxiliary bypass line was used as a gas re-injection line into the riser column whereas for the case a 5° inclined pipeline without a bypass line, the total liquid flow was oscillating Slugs of short length that form and dissipate intermittently confirms the cyclic fluctuations in total liquid volume flow in the column and the flow was not stable.
iii. For the system without a bypass line, the fluid pressure was changing with time. For the case with an auxiliary self-lift bypass line, slug flow was completely eliminated as evidenced by the more stable pressure.

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