MODELING, IDENTIFICATION AND CONTROL, 2005, VOL. 26, NO. 2, 95–109
doi:10.4173/mic.2005.2.3

Riser slugging—a mathematical model and the practical consequences†

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Keywords: *Multiphase, slug, riser*

This article presents a novel approach to estimate severe riser slug build up time and consequently the slug period. The slug model is based on a simplified mechanical model. This information has subsequently been used to illustrate the effects of the traditional actions to prevent severe riser slugging. New field data from an offshore floating production platform and large scale experimental data are included. The experimental set up is described in detail. The estimate on the slug built up time provided by the simplified model matches data from the experiments, the full scale data and data in relevant references.
Published in SPE Journal of Production and Facilities August 2004, SPE 87355.

1. Introduction

This article contains a method for estimating the build up time for riser slugging and consequently the slug period. The developed model is subsequently used to explain the effect of traditional measures used to prevent riser slugging. The method presented is also useful to identify new methods and explain how and why these methods work. Riser slugging, also called severe slugging is a phenomena which is characterized as a low rate (relative to the dimension of the riser) phenomena. Severe slugging may therefore occur during startup and tail production of a field. Severe riser slugging is also experienced during startup of flowlines after temporary shutdowns of wells, when the wells are routed one by one to the flowline. This problem is frequently experienced on floating production platforms (FPO) with satellite wells tied to the FPO though marine risers in a lazy S or a similar configurations. Figure 1 contains a plot of a time series of severe riser slugs occurring during startup of one flowline to the Troll C floating production platform operating west of Bergen Norway. Severe riser slugging may cause damage to the first stage separator internals due to the impulse energy in the liquid slug. Reduced efficiency of the separation in the first stage separator and fluctuations in the rest of the oil-water treatment plant are other undesired effects from large severe riser slugs. Slugging may also cause flaring which is not environmentally benign and also costly. This is particular true in areas where a CO_2 gas tax regime is enforced.

This article uses a simplified mechanistic model to predict severe slug build up time. The use of simplified mechanistic models to model two phase flow is a well proven technique. Reference Taitel & Barnea (1990) contains a simplified mechanistic two phase model for slug flow. Various correlations are used to calculate the friction components. A transient simulator is then developed in Taitel & Barnea (1990) based on a extended mechanistic model with the momentum equations. Neither of these contain explicit expressions for the slug build up time. Reference Schmidt *et al.* (1980) also

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†This paper was originally presented as SPE 87355 in Journal of SPE Production of Facilities, Vol. 19, No. 3, pp. 168–175, August 2004.

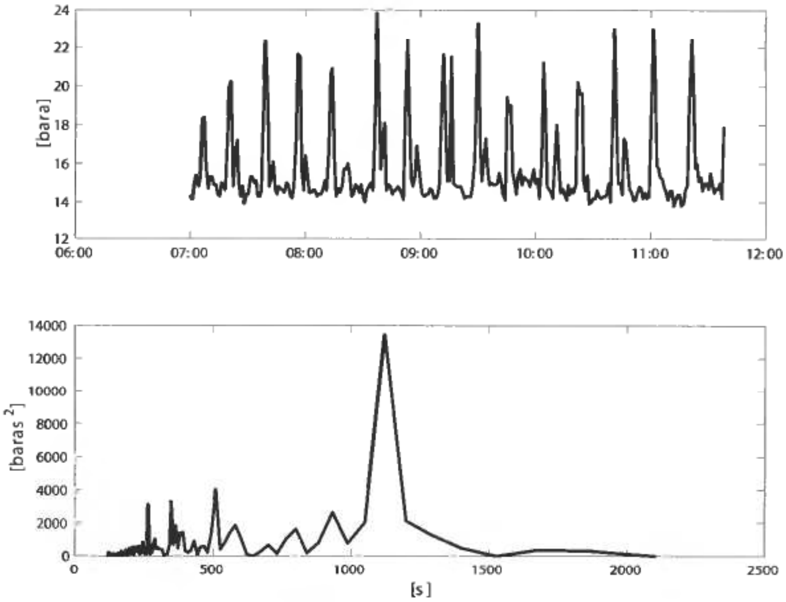

Figure 1. Example of severe riser slugs during startup of a flowline to the Troll C FPO. The top plot contains the pressure before the platform chokes as a function of time. The bottom plot contains the same time series in the frequency domain.

contains a simplified mechanical model based on a set of differential equations. The model uses correlation data to model liquid fallback and hold up. Estimates for the slug build up time is then achieved by integrating the equations with respect to time, thus no explicit expression is used to predict the build up time. In a recent article Tengesdal *et al.* (2003) a steady state mechanistic model is developed to predict the effect of riser base gas injection to prevent severe slugging. Since the reference contains a steady state model no slug build up time estimate is provided. The simplified two phase flow model in Taitel & Barnea (1990) is the starting point for this article.

1.1. *Alternative slug control mechanisms*

Several methods are used to avoid or reduce the effect of riser based slugging. A common way is to use riser based gas lift. The gas injected at the bottom of the riser increases the superficial gas velocity and reduce the pressure at the riser bottom, thus the flow is forced outside the slug regime. Increasing the pressure in the line by reducing the opening of the platform choke is also a common measure. This may for some wells have the downside that the increased well head pressure reduces the production. An other method is to install a slug catcher. A slug catcher is a large drum with volume large enough to contain the liquid and gas from one slug. The gas and liquid is then transferred separately to the first stage separator. This method is rarely used on offshore installations due to the extra cost related to the space and weight of the slug catcher drum. A method which uses the principle of a slug catcher together with active control is the S3 slug suppression system Dill-Quip (2002). This system uses a small drum which acts like a mini separator which crudely separates the gas and the liquid. The pressure and the liquid level is automatically controlled and the gas and liquid flow separately to the first stage separator in a controlled manner. Active suppression of severe riser slugs by automatic control of the platform production valves is a relatively new approach.

Feedback may be taken from the choke position and the riser bottom pressure. One of the first references addressing the issue of automatic control of terrain slugging is Hedne & Linga (1990). Recent developments related to automatic control of slugging in wells Jansen *et al.* (1999) and pipelines (Courbot, 1996; Bjune, 2001; Havre *et al.*, 2000 and Storkaas *et al.*, 2001) are related, but not similar phenomena. References Fard & Godhavn (2001); Skofteland & Godhavn (2003) and Godhavn *et al.* (2003) contains more experimental results from these experiments and a full scale implementation on the Heidrun tension leg platform located in the North Sea. These references also contain experimental results from different control structures including cascade type controllers with feedback from other states i.e. feedback from riser top pressure, manifold pressure and density measured at the riser top.

The mathematical model developed in this article is useful to explain why and how the traditional methods for slug suppression work. Included in this article are both field data and results from large scale experiments. The next section will analyze the severe riser slug phenomena with a pure mechanistic approach. The final result from this section is an estimate of the slug build up time and consequently the slug period. Section 3 contains the analysis of why and how riser based gas lift and adjustment of the platform based production choke works, while section 4 and 5 present the experimental setup and the experimental results. Section 6 and 7 contain a field description and field data.

2. A mechanistic slug model

The aim of this section is to establish an analytical expression for the severe slug period. Reference Taitel & Barnea (1990) is used as a starting point for this analysis. A pure mechanistic dynamic model of the slug in the pipe will be derived using the following assumptions Schmidt *et al.* (1980):

A1 The input flux rates of gas and liquid are constant.
A2 The pressure before the valve is constant.
A3 The effect of gas bubbles in the slugs are neglected.
A4 The liquid hold up in the pipe is constant.
A5 The process is isothermal.

The starting point of this analysis is when the slug front is at the valve, see Figure 2. The liquid mass in the pipe is

$$m_L = A\rho_L\left[z_i + (l - \alpha\,(l - x_i)) + \int^t u_{LS}dt\right] \tag{1}$$

where u_{LS} is the superficial velocity of the liquid defined as

$$u_{LS} = \frac{v_L}{A}$$

where v_L is liquid volumetric flow rate. α is the void fraction, ρ_L is the density of the liquid phase, A is the pipe cross sectional area and z_i, x_i and l are defined in Figure 2. Hence, $\dot{m}_L$ becomes:

$$\dot{m}_L = A\rho_L u_{LS} \tag{2}$$

Expressing the liquid mass as a function of x and z yields:

$$m_L = \rho_L A[(x + z) + (1 - \alpha)(l - x)] \tag{3}$$

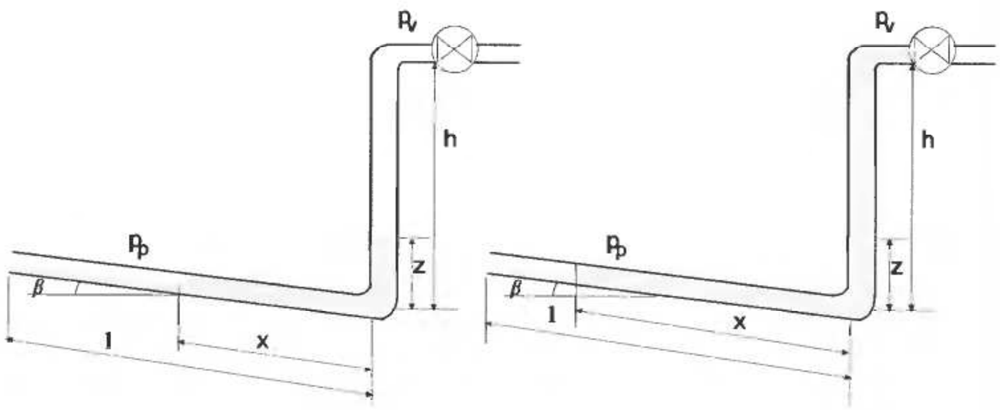

Figure 2. Left plot: The riser-pipeline during the slug formation. The shaded area represents liquid and the white area is gas. Right plot: The riser-pipeline at $t = T_1$.

The corresponding equation for the gas in the pipe becomes:

$$m_G = \rho_{Gi} V_{Gi} + \int^t A u_{gS0} \rho_{G0} dt \tag{4}$$

or

$$m_G = \frac{M_w}{RT} p_{Pi} V_{Gi} + \int^t A u_{GS0} \rho_{G0} dt \tag{5}$$

where the initial pipe pressure p_{Pi} and initial gas volume V_{Gi} are found from the following expressions:

$$p_{pi} = p_v + \rho_L g(z - z_P(x_i)) \tag{6}$$

$$V_{Gi} = \alpha(l - x) \tag{7}$$

The subscripts GO represents gas velocity and density at standard conditions. $z_P(x_i)$ is the elevation in the pipe of the tail of the initial slug. $z_P(x_i)$ may be approximated to $x_i \sin \beta$ for a relatively straight pipe with negative inclination β. M_w is the molecular weight, R is the universal gas constant and T represents the temperature. The pressure p_v is the top riser pressure. Hence, $\dot{m}_G$ becomes:

$$\dot{m}_G = A u_{GS0} \rho_{G0} \tag{8}$$

Combining (1) and (3) results in the following equation:

$$x = x_i + \frac{1}{\alpha}[u_{LS} t - (z - z_i)] \tag{9}$$

whereas, combining (4–6) yields, for the gas Taitel & Barnea (1990):

$$\alpha(l - x)\left[\frac{p_v}{\rho_L g} + (z - x \sin \beta)\right] - \alpha(l - x_i)\left[\frac{p_v}{\rho_L g} + (z_i - x_i \sin \beta)\right] = \frac{RT}{M_w \rho_L g} u_{GS0} \rho_{G0} t \tag{10}$$

Inserting (9) into (10) and letting $z = h$ results in the following polynomial in time t.

$$at^2 + bt + c = 0 \tag{11}$$

where

$$a = \frac{u_{LS}^2}{\alpha}\sin\beta \tag{12}$$

$$b = u_{LS}\left[\sin\beta\left(\frac{2}{\alpha}(z_i - z) + 2x_i - l\right) - \frac{p_v}{\rho_L g} - z\right] - \frac{RT}{M_w \rho_L g}\, u_{GS0}\rho_{G0}$$

$$c = (z - z_i)\left[\sin\beta\left(l - 2x_i + \frac{1}{\alpha}(z - z_i)\right) + \alpha(l - x_i) + \frac{p_v}{\rho_L g} + z\right]$$

Solving (11) with respect to time setting $z = h$ results in an estimate of the slug build up time T_1. Rewriting the a and the b parameters in (12) to:

$$a = u_{LS}^2 a_t \tag{13}$$

$$b = u_{LS} b_{t1} - u_{GS0} b_{t2}$$

results in the following analytical expression for T_1:

$$T_1 = \frac{1}{u_{LS}^2 a_t}\left[-u_{LS} b_{t1} + u_{GS0} b_{t2} \pm \sqrt{(u_{LS} b_{t1} - u_{GS0} b_{t2})^2 - 4u_{LS}^2 a_t c}\right] \tag{14}$$

assuming T_1 is positive and real. The slug period is the sum of the liquid build up time T_1, and the time necessary to transport the slug into the separator denoted T_2. According to Schmidt *et al.* (1980) T_2 is experimentally determined to be in the range $0.5T_1 - T_1$, thus using T_1 as an estimate of the slug period is conservative for slug control design.

Notice that (14) can not be used as a slug criteria. Equation (14) can only be used to estimate the slug build up time when the flow is in severe slugging regime.

2.1. *Verification of the estimate of the slug period*

The liquid build up time prediction given by (14) has been tested on two different cases reported in the literature, full scale date logged on the Troll C floating production unit and on our experimental set up. The experimental setup and the full scale case reported in Schmidt *et al.* (1980) are used as external references. Table 1 presents the results from the tests. The estimate is consistently conservative in the sense that the liquid build up time is estimated to be faster than the actual values. Effects like friction and the assumption that the liquid hold up is constant over time will both increase the liquid build up time.

Table 1. Comparison between estimated and measured T_1

Reference	actual T_1 in s	predicted T_1 in s (14)
Schmidt *et al.*, experimental setup	~ 50	38
Schmidt *et al.*, field data	~ 600	524
Tiller experimental setup	~ 206	112
Troll C field data	~ 900–1000	867

Table 1: Verification of the prediction of T_1. The following parameters are used in the calculation: the superficial liquid velocity u_{LS}, the superficial gas velocity at standard condition u_{GS0}, the inclination of the inflow pipe β, the void fraction α, acceleration of gravity g, liquid and gas densities ρ_L and ρ_{G0}, the gas property fraction

$$\frac{RT}{M_w},$$

the pressure at the riser top p_v, the riser height h, the pipe length l and initial liquid positions x_i and z_i.

3. Traditional actions to suppress severe riser slugging

The traditional actions usually employed offshore to suppress severe riser slugging are either by adjusting the choke opening of the platform production choke or using riser based gas lift. The latter action increases the superficial gas velocity u_{GS0} and reduce the pressure at the riser base. An increase of the platform choke results in a lower riser and production line pressure. This will result in an increased liquid rate from wells with little or no differential pressure over the subsea chokes. A decrease in the platform choke results in a higher riser pressure, thus p_v increases. If possible, the riser slugging can also be suppressed by routing more liquid in to the production pipe connected to the riser. This will increase the superficial liquid velocity, thus moving the flow away from the severe slug regime.

3.1. *Adjustment of the platform choke*

Choking action on the platform choke results a higher line pressure and consequently an increase in the p_v. Using (12 and 13), we notice that an increase in the p_v pressure results in an increase of c and a decrease of the b_{t1} parameter. We observe by inspection of (14) that both these changes reduces the value of the minimum positive real T_1, thus the slug period reduces and likewise the amount of liquid in the slug. Hence, increased line pressure improves the line conditions with respect to severe riser slugging. The increased riser and production line pressure does not necessarily affect the production. This is in accordance with the findings in Schmidt *et al.* (1980). Production wells with high gas liquid ratio have usually a well head pressure much higher than the required line pressure, thus there is a large differential pressure over the subsea production choke.

3.2. *Riser based gas lift*

Adding riser based gas lift increases the superficial gas velocity denoted u_{GS0}. In the same manner as above we can analyze this effect. Using (12 and 13), we notice that an increase in the superficial gas velocity u_{GS0} results in an reduction of the absolute value of the term $(u_{LS}b_{t1} - u_{GS0}b_{t2})$ in (14). Thus the minimum positive value of T_1 is reduced. Addition of gas at the riser base will also increase the pressure p_v at the riser top, which also contributes to the reduction of slug periods, see the paragraph above. The effect of riser based gas lift is also investigated in Tengesdal *et al.* (2003).

3.3. *Increasing the liquid flow rate*

Routing more wells or increasing the production rate from existing wells are also beneficial when severe riser slugging is experienced. Increasing the liquid rate by opening the platform choke is also possible for some field. An increase of the platform choke opening will reduce the riser and line pressure. This will result in an increase in the liquid rate for wells with little or no differential pressure over the subsea production choke. These wells are typically wells with low GOR and a high productivity index. A decrease in the well head pressure with less than a bar may result in substantial increase in the liquid rate with a negligible increase in the superficial gas rates. If the well head pressure is lowered substantial the increase in the superficial gas rate (due to expansion of free gas) may be significant. The increase in the gas rate is beneficial with respect to severe slugging since the superficial gas rate will increase. An increase of the liquid flow results in an increases of the superficial liquid velocity. Equation (14) reveals (not trivially) that

$$\frac{\partial T_1}{\partial u_{LS}} < 0.$$

Thus, the volume of each slug and consequently the consequences of each slug will be reduced. The effect on the liquid rate is increased with increased PI. A typical Troll C well has a PI larger $> 2000\ \mathrm{Sm}^3/d/bar$, thus, opening the platform choke is very efficient with respect to reducing the riser slugs on production lines dominated by wells with low GOR.

4. The experimental setup

The experiments were carried out at SINTEF Multiphase laboratory in Trondheim, Norway. The experimental setup and the operations of the facility are carried out according to internal safety and quality procedures according to Norwegian rules and regulations. The test facility is a 231 *m*, 3 *in* closed loop with a vertical riser for circulation of oil and gas. The SF_6 gas and the Exxsol D80 test oil is used in the experiments. The first 100 *m* have a -0.1 *deg* declination, then a 180 *deg* horizontal U-turn. The diameter of the U-turn is 3.5 *m*, corresponding to a length of 70 diameters. After the U-turn, the pipe is declined -0.7 *deg* for about 100 *m*, and finally a 15 *m* vertical riser. The riser ends in a double bend, where the flow is directed downwards into an 8 *in* vertical drop-leg. The vertical 8 *inch* drop leg ends in a gas-liquid separator, where the gas is drawn into a de-mister to remove droplets and then into the compressor. The oil is drained to the horizontal separator and recycled through the oil pump. The separated phases are fed to the singlephase velocity measurement stations and routed through the correct flow meters by manually operated valves. At the inlet section the gas is mixed with the oil through a 45 *deg* downward inclined pipe. The oil and gas then passes through a 7 *m* long flexible (rubber) pipe section, and on to the initial -0.1 *deg* section. The scientific instrumentation is located along the entire loop, but mostly along the last 100 meter section and in the riser. Here the flow regime, pressure gradient, absolute pressures, and hold-up are measured. This pipe section is declined approximately -0.7 *deg* downwards. The hold-up is measured by means of seven single-energy narrow-beam gamma densitometers distributed along the pipe, with the two last ones in the riser. Mainly, acid proof 316L steel pipes are used, but in this project, two steel sections were replaced with PVC pipes for visualization purposes. The design pressure is 10 *bara*, and in the current experiments the nominal system pressure varied from 2.2 to 3.0 *bara*.

The loop is equipped with basic process and scientific measurement instrumentation. The instrumentation consists of single-phase flow rate meters, temperature sensors, differential and gauge pressure sensors, and gamma densitometers. The flow rate meters are mounted on single-phase flow lines upstream the mixing point, and the signals from the oil and water rate meters are converted to velocity in a 69 *mm* pipe to directly measure the superficial velocity in the test section. All superficial velocities are calculated using the absolute loop pressure, which is defined at the 165 *m* location. The temperature sensors, pressure cells and gamma densitometers are distributed along the test section of the loop. Vortex meters are used to measure the gas volumetric flow rate, and the compressibility/expansion is accounted for by means of a simple thermodynamic correction based on the ideal gas law. The compressibility factor is assumed to be constant within the experiment conditions. A Coriolis meter is used to measure the oil volumetric flow rate and density. The density measurement function has been utilized to monitor the oil density. Absolute densities and hold up can be estimated from the seven gamma densitometers distributed along the test loop with the two last ones in the riser. The data acquisition and control system was implemented using PCs and LabView. The experimental setup and more results are extensively reported in Fard & Godhavn (2001); Skofteland & Godhavn (2003) and Godhavn *et al.* (2003).

A fast acting valve with manual/automatic choking was used to control the pressure at the top of the riser. The valve has a modified equal percentage valve characteristics with a stroke length of 0.04 m. The valve characteristic were calibrated with respect to both gas and liquid. The volumetric rate q_v of the multiphase flow from the valve is found from the following expression

$$q_v = ak_V f(u)\sqrt{\frac{\Delta p}{\rho}}$$

or

$$q_v = ak_V\bar{u}\sqrt{\frac{\Delta p}{\rho}} \tag{15}$$

where q_v is volumetric rate in m^3s^{-1} at actual conditions k_V is $0.0018 - 0.0022\%^{-1}$ for a multiphase flow and the area a is 0.0037 m^2. The function $f(u)$ with unit % (see Figure 3) can be approximated with a second order polynomial as $f(u) = 0.0112u^2 + 2.12u$ where u is the stroke in % and $\bar{u}$ is the linearization of $f(u)$ around a mean operational value u. The average density ρ of the multiphase flow is found to be approximately 400 kgm^{-3} and the pipe area a is 0.0037 m^2. Δp represents the pressure drop over the valve.

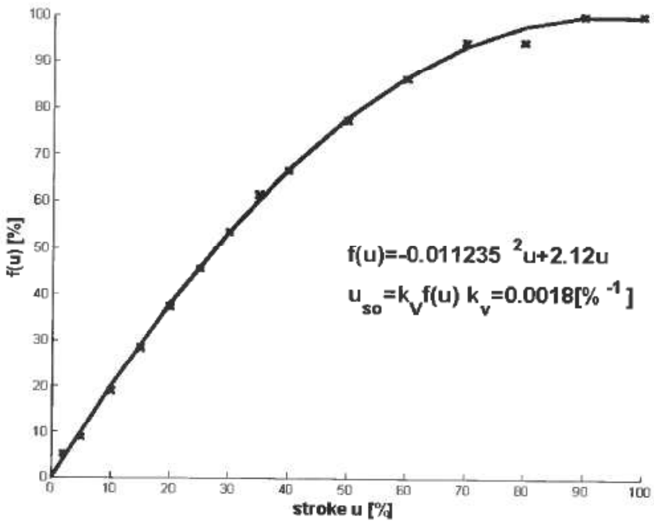

Figure 3. Some results from the valve calibrating procedure.

5. Experimental results

The experiments resulted in two flowmaps. One maps represents the situation with a fully open valve and one map represents the case with a valve with 15% stroke opening. They are shown in Figure 4. The parameter

$$h = \frac{p_B - p_v}{\rho_L g h_r}$$

is used to characterize the flow regimes Godhavn *et al.* (2003), h_r is the riser height, p_B and p_v is the measured pressure at the riser top and bottom respectively. The slug flow regime is defined when a period of $h > 0.9$—is followed with $h < 0.25$—after a blow out. The pulsating flow regime is established when a semi steady state situation is present with $h_{\max} - h_{\min} > 0.25$—. A bubble flow is defined as a situation when h varies with less than ± 0.125—. All experimental results are taken from Fard & Godhavn (2001). It can be observed from the flowmaps that the experiments confirm the analysis carried out in a previous chapter. Thus, increasing the riser pressure is efficient with respect to slug reduction. Figure 5 and Figure 6 contain the results from one experiment. The superficial gas velocity u_{GS0} and liquid velocity u_{LS} are kept constant to 0.18 and 0.22 ms^{-1} during the experiment. Figure 5 is a plot of the riser top and riser bottom pressure. Notice that the flow is in the severe slugging regime before the choke is actuated. The measured slug period is 210 s with a measured build up time of. 195 s. The estimated build up time using (14) is 112 s. Figure 6 plots the corresponding choke valve opening and the parameter h. It is easily observed by looking on the parameter h that the riser is in severe slugging before the valve is actuated.

Remark, one should notice that the experiments were carried out with the same liquid and gas rate before and after the pressure was increased. This is an idealized situation which may be difficult to implement for some fields. An increase in the riser pressure will consequently increase the production line pressure and result in a subsequent reduction in the production. This will be the case for production lines with wells with little differential pressure over the subsea production choke.

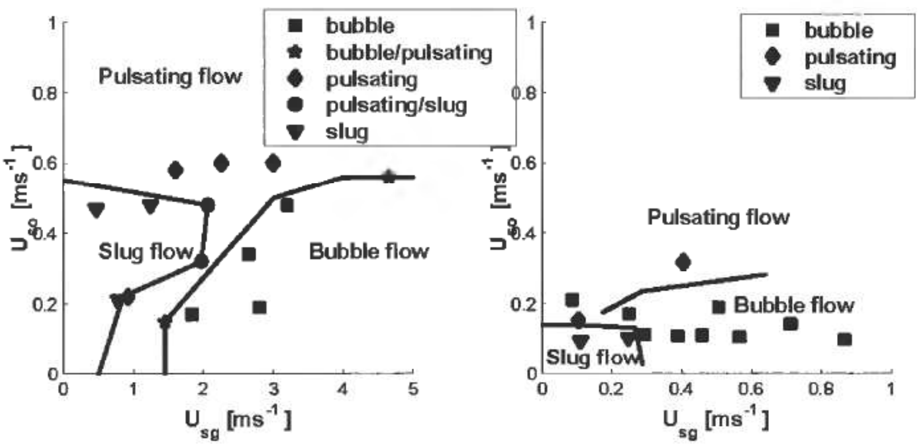

Figure 4. Left plot: the flow map for a 100% open valve. Right plot: the flow map for a valve with 15% stroke.

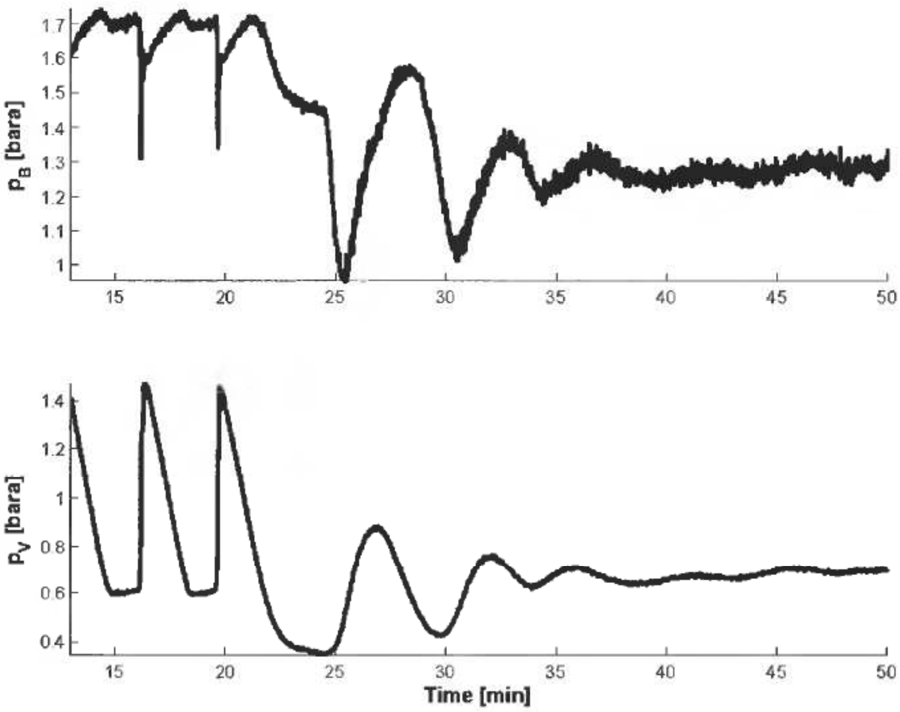

Figure 5. Top plot: the pressure at the top of the riser upstream the choke. Bottom plot: the pressure at the bottom of the riser.

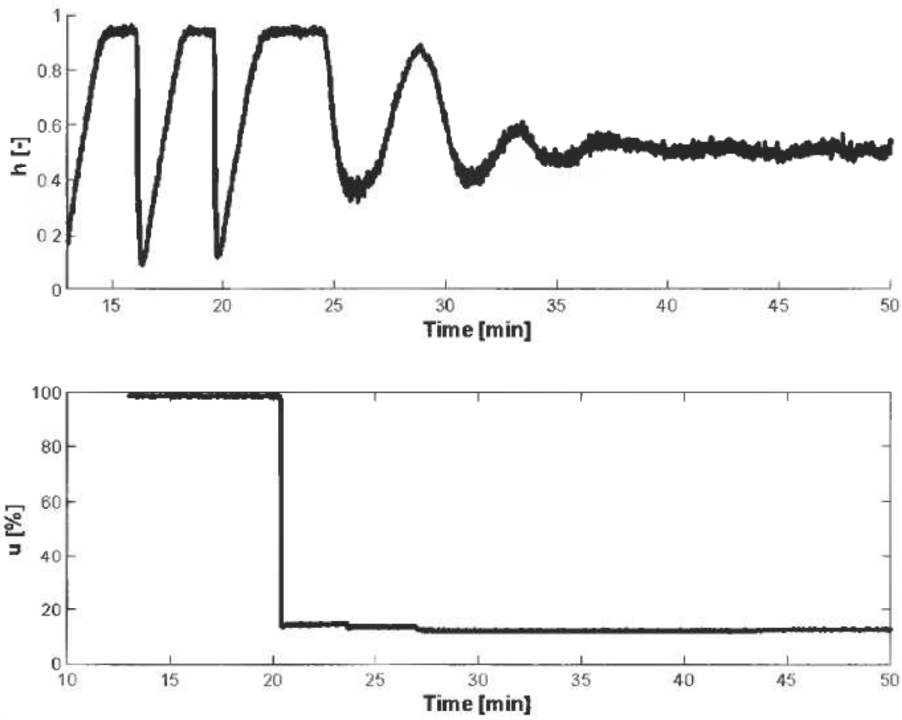

Figure 6. Top plot: the non-dimensional parameter h plottet versus time. Bottom plot: the valve opening.

6. Field data

The field data are taken from Troll C a floating production platform (FPO) operating in the North Sea west of Bergen Norway. The Troll C is operating on approximately 350 *m* water depth. The field lay out consist of a number of well clusters (four wells on each cluster) tied to the FPO with subsea pipelines and flexible marine risers in a lazy S riser configuration, see Figure 7. The pipelines and the marine risers all have a ID of 10 *in*. The length of the subsea pipelines are between 2000 to 10000 *m* and the marine riser are approximately 720 *m*. The wells are controlled with a subsea production choke on the well head and a platform production choke on the top of the riser. The riser water cut (WC) is in the range between 10–70% and the riser gas oil ratio (GOR) is in the range of 58–250—. The density of the oil and gas are approximately 893 kgm^3 and 0.861 kgm^3 at standard conditions. Each riser has the capability of riser gas injection at the riser bottom. Typical pressure at the riser top is between 15 and 35 *bara*. Measurements available are pressure and temperature before and after the topside production choke and the same measurements before and after the subsea chokes. The gas oil and water rates are estimated using an online state estimator using the measurements and test separator data as input. The uncertainties of the volumetric rates of the three phases are for the cases presented in this article assessed to be within $\pm 10\%$. The volumetric rates of the riser gas lift is consistently under predicted and the error of the gas lift rates are estimated from comparisons on the test separator to be -10–50%. There are no measurements at the bottom of the risers.

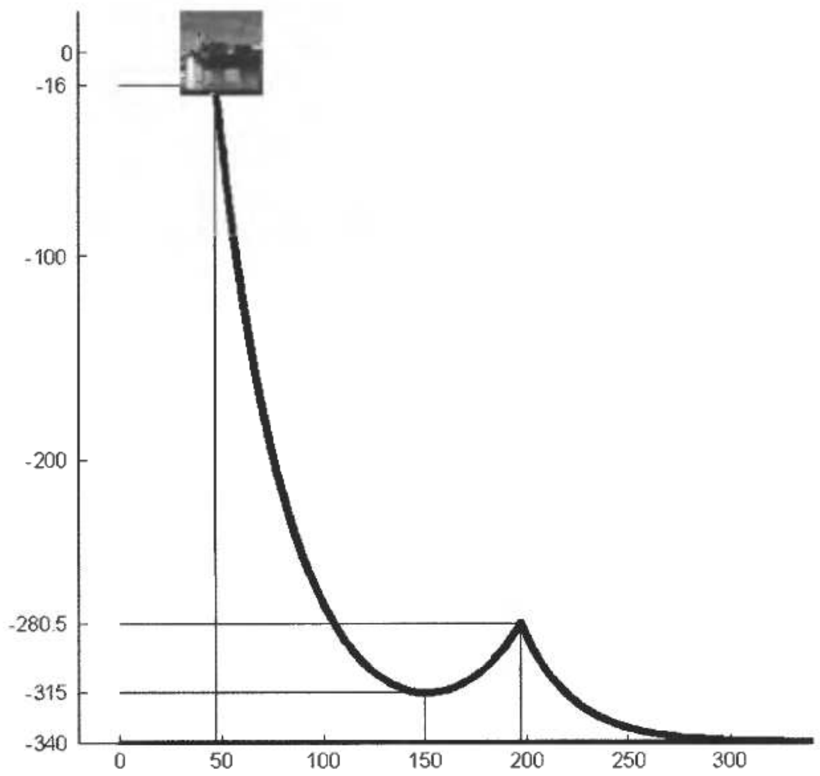

Figure 7. The Troll C riser configuration.

Two cases are recorded in this article. The first case demonstrate the effect of increasing the riser gas lift rate on the slug frequency. The other case shows the effect of adding more liquid to the riser by increasing the opening of the top side choke.

6.1. *Case 1—Riser based gas lift*

Figure 8 illustrates nicely the effect of increasing the superficial gas velocity in the riser. The riser gas lift rate is increased from 0 to 3000 Sm^3h^{-1}. The period of the slugs is reduced from approximately 1450 s to 200 s. The variance of the pressure on the riser top is reduced from 4.2 to 1.4 bar^2 or a reduction of 67%. The variance of the pressure may be used as a metric f the energy in the slugs and may be useful to quantify the reduction in wear and tear of process equipment from fatigue cased by the slugs. It is also beneficial for the separator efficiency to have an even liquid flow into the separator to reduce the liquid-gas shear forces and fluctuations of the separator level. The period of the slug is a measure on the slug size, thus it is beneficial to reduce the slug period as much as possible. The total gas rate before the rise gas lift was added was estimated to approximately 6500 Sm^3h^{-1} and the liquid rate was approximately 80 Sm^3h^{-1} before the riser gas was added. A significant increase of the liquid production was observed after the gas lift was added. The increase of the liquid rate is mostly due to that the pressure in the production line is reduced. Consequently, a new three branched well with little differential pressure over the subsea choke produced significantly more to this production line. The water cut was approximately 52%. The predicted slug build up time (using (14)) before the increase of liquid rate was 877 s while an estimated build up time from looking on a detail from Figure 8, see Figure 9 is approximately 1100 s.

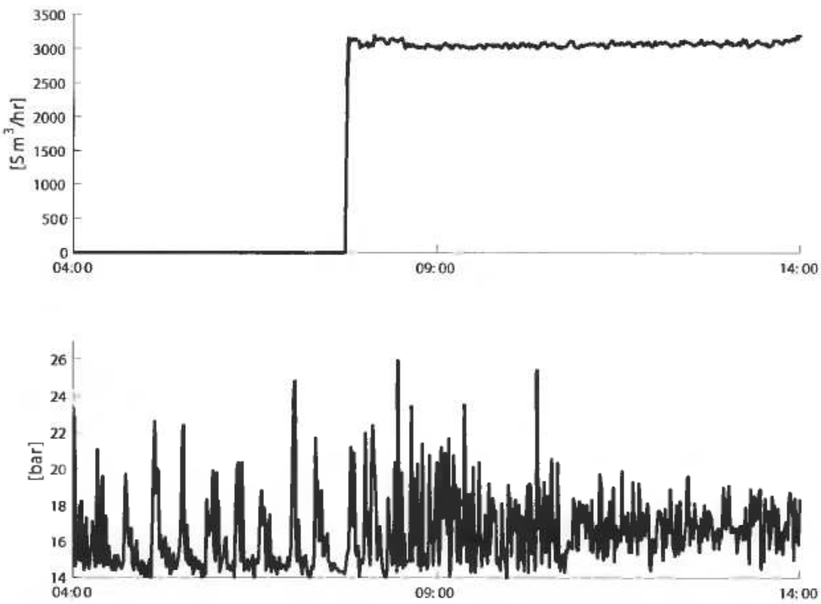

Figure 8. Top plot: the volumetric rate [Sm^3] of the riser gase lift. Bottom plot: the pressure before the platform choke on the top of the riser.

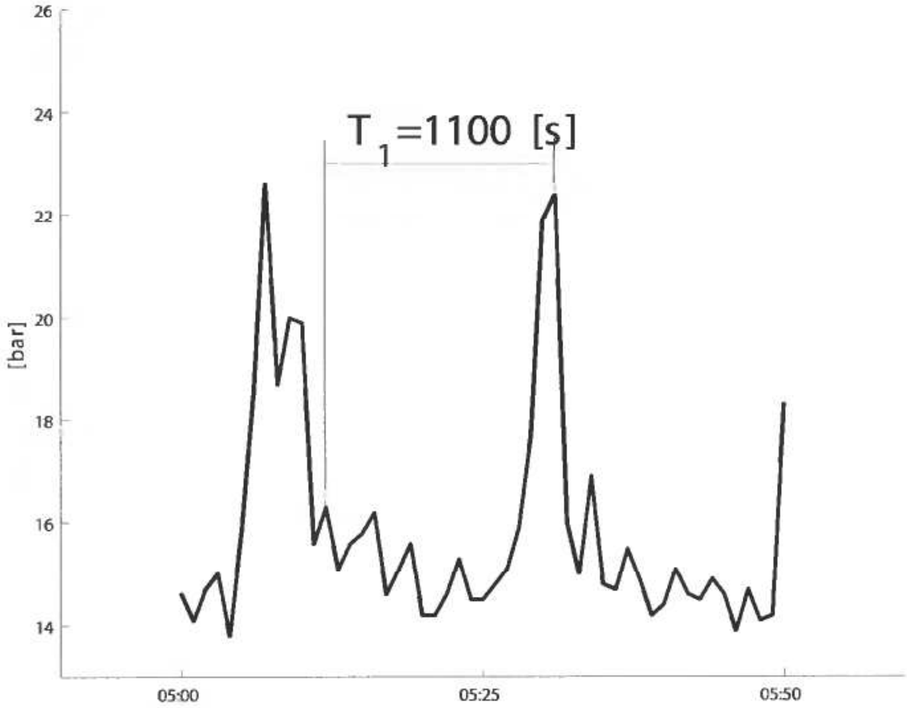

Figure 9. Detail from Fig. 8 estimating the slug build up time T_1.

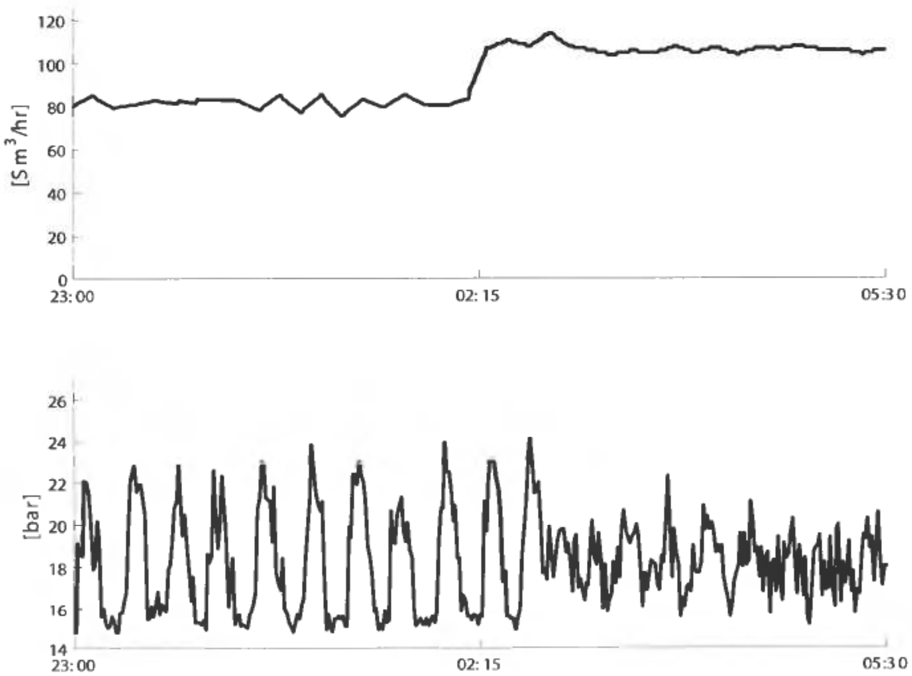

Figure 10. The effect of increased liquid rate (increased superficial liquid velocity u_{LS}) on severe riser slugging. Top plot: the volumetric liquid rate before and after the subsea choke of one well is increased. Bottom plot: the pressure upstream the top side choke on the top of the riser.

6.2. *Case 2—Increasing the liquid flow rate*

Figure 10 shows the effect of increasing the superficial liquid velocity on severe slugging. The riser gas lift rate and the top side choke position are both kept constant. The liquid rate is increased by opening a subsea production choke. The pronounced liquid slugs with a period of 1200 s are reduced both in pressure magnitude and period. The variance of the pressure on the riser top is reduced from 7.7 to 1.9 bar^2 or a reduction of 75%. The total gas rate was estimated to approximately 3900 Sm^3h^{-1} and the water cut was 22%. The liquid rate went from 81 Sm^3h^{-1} to 107 Sm^3h^{-1}. The predicted slug build up time (using (14)) before the increase of liquid rate was 867 s while an estimated build up time by looking on Figure 10 is between 900 to 1000 s.

7. Conclusion

This article presents a novel approach to estimate slug build up time and consequently a slug period. This estimate has been successfully compared with several sets of field data and a large scale experiment. The model is used to explain why and how the traditional means of reducing severe slugging works. The increase in liquid rate is much more efficient than increasing the volumetric riser gas lift rate. The former will automatically follow the latter on the Troll field where an reduction in line pressure automatically leads to a higher liquid production. In terms of 14,this implies that

$$\frac{\partial T_1}{\partial u_{LS}} \Big/ \frac{\partial T_1}{\partial u_{GS0}} \gg 1.$$

Experimental results as well as observation from a producing field is used to illustrate the model. The method presented is useful to identify new methods and explain how and why methods for severe slug suppression work. The estimated slug period may also be useful in initial settings of control gains an time constants for automatic slug control systems.

Notice that the method in this article does not consist a slug criteria. The method will only work when the flow is in the severe slugging regime.

Acknowledgements

The author is grateful to Hydro and the Troll field licence partners for allowing this article to be published. The author will like to thank Dr. M. Fard (Hydro), Dr. J.M. Godhavn (Statoil) and Dr. J.R. Sagli (Statoil) with their cooperation with the large scale experiments.

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