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Subsea Solution for Anti-Slug Control of Multiphase Risers*

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***Abstract*— A top-side choke valve is usually used as the manipulated variable for anti-slug control of multi-phase risers at offshore oil-fields. With new advances in the subsea technology, it is now possible to move top-side facilities to the sea floor. The two main contributions in this paper are to consider an alternative location for the control valve and to consider how to deal with nonlinearity. This research involved controllability analysis based on a simplified model fitted to experiments, simulations using the OLGA simulator, as well as an experimental study. It was concluded that a control valve close to the riser-base is very suitable for anti-slug control, and its operation range is the same as the top-side valve. However, a subsea choke valve placed at the well-head can not be used for preventing the riser-slugging.**

I. INTRODUCTION

The oscillatory flow condition in offshore multi-phase pipelines is undesirable and an effective solution is needed to suppress it [1]. Active control of the topside choke valve is the recommended solution to maintain a non-oscillatory flow regime [2]. It also allows for larger valve openings and consequently higher production rate [3]. The control system used for this purpose is called anti-slug control. This control system uses measurements such as pressure, flow rate or fluid density as the control variables and a choke valve located at the top-side platform is the usual manipulated variable.

By new advances in the mid-stream technologies, the subsea engineering is an integral part of the oil production. The subsea separation and the subsea compression are now standardized technologies used in practice, and moving all the facilities to the sea floor is the ongoing trend. However, having all facilities at the subsea, the produced oil and gas are needed to be transported to the sea level which involves using risers.

If we need to use the top-side choke valve for purposes other than the stabilizing control (e.g. safety and shut-down), a subsea solution for anti-slug control could be attractive. In order to explore possibilities of doing anti-slug control integrated with the subsea technology, we consider anti-slug control using subsea control valves in this paper.

To use such a solution we first need to consider if manipulating a subsea choke can prevent the riser slugging, and then where the control valve must be located for an effective stabilizing control. Next, one must look into input-output pairing to choose the best controlled variable in terms of robustness and performance of the control loop.

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We compare different manipulated variables (inputs, MVs) and controlled variables (outputs, CVs) in terms of robustness and performance for stabilizing control. This controllability analysis is done based on a simplified model of the system. We have extended the four-state simplified model in [4] to include two subsea choke valves, one at the wellhead and one close to the riser-base. The simplified model is fitted to both the OLGA model and experiments. Moreover, results from the controllability analysis are verified by simulations using the OLGA simulator as well as experiments.

The system is highly nonlinear and the gain of the system decreases drastically as we open the valve. In the closed-loop system we want to keep the loop gain approximately constant for different operating points. Therefore, we need to increase the controller gain for large valve openings (lower pressure set-points).

This paper is organized as follows. The experimental rig, the OLGA model and the simple model for sever-slugging are introduced in Section II. Afterwards, the controllability analysis results are presented in Section III. Experimental and simulations results for the alternative manipulated variables are shown respectively in Section IV and Section V. Then, we discuss the result in Section VI. Finally, the main conclusions and remarks are summarized in Section VII.

II. PIPELINE-RISER SYSTEM

A. Experimental Setup

The experiments were performed on a laboratory setup for anti-slug control at the Chemical Engineering Department at NTNU. Fig. 1 shows a schematic presentation of the laboratory setup. The pipeline and riser in the L-shaped setup are made from flexible pipes with 2 cm inner diameter. The length of the pipeline is 3 m, inclined downward with a 15° angle, and the height of the riser is 3 m. A buffer tank for gas is used to simulate the effect of a long pipe with the same volume, such that the total resulting length of the pipe would be about 70 m. There are two valves that may be used for control puposes; a topside valve and a subsea valve located close to the riser base (see Fig. 1).

The feed into the pipeline is at constant flow rates; 4 $litre/min$ of water and 4.5 $litre/min$ of air. The separator pressure after the topside choke valve is nominally constant at the atmospheric pressure. With these boundary conditions, the system switches from stable to unstable operation at 15% opening of the top-side valve when the subsea choke valve is fully (100%) open. To stabilize the system using manual choking of the riser-base subsea valve, we need to close this valve to 8%.

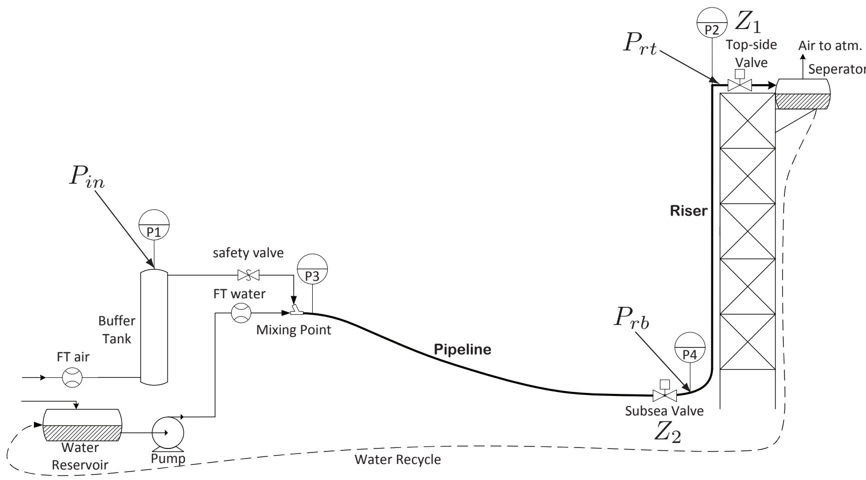

Fig. 1. Schematic diagram of experimental setup

B. Olga model

OLGA is an advanced dynamical multi-phase flow simulator widely used in the oil and gas industry [5]. First, we simulated the experimental rig in the OLGA simulator using the same dimensions, and even including the buffer tank. The results for this are not included in the paper, because we found them to be quite similar to our extended OLGA model which includes an hypothetical oil well and its related wellhead valve. Fig.2 shows a schematic of the final model that was used in this work. The oil well is vertical with height of 20 m, inner diameter of 0.02 m, and the reservoir pressure is fixed at 3.45 bar. We choose these parameters such that inflow conditions would be similar to the experimental setup. The other dimensions and parameters are chosen very similar to the experimental setup.

In the final model with the oil well, we replaced the buffer tank by a 220 m horizontal pipe, much longer than our estimate of 70 m, to get the same slug frequency as the experiments. In the experimental setup, the buffer tank contains only the gas phase while in the OLGA model, similar to practical conditions, more than half of the pipeline volume is occupied by liquid. To adjust the slug frequency, the volume occupied by the gas phase in the pipeline is important. The period of oscillations was $T = 68$ sec.

C. Simplified model

A four-state simplified model for severe-slugging flow in pipeline-riser systems was presented in [4]. We have extended this model to include two subsea valves; one at the well-head and one near the riser base. The oil well dynamics are modelled by an additional state variable representing the total fluid mass in the well. The state variables of the augmented system model are as these:

- m_{tw}: mass of total fluid in well [kg]
- m_{gp}: mass of gas in pipeline [kg]
- m_{lp}: mass of liquid in pipeline [kg]
- m_{gr}: mass of gas in riser [kg]
- m_{lr}: mass of liquid in riser [kg]

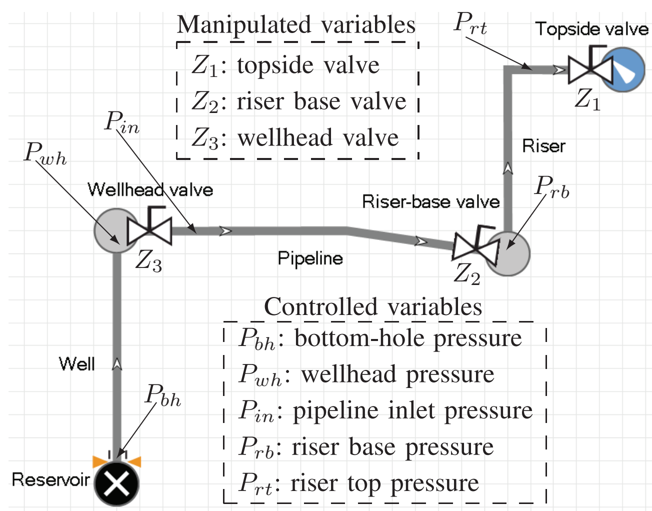

Fig. 2. OLGA model used in all simulations

The state equations are the mass conservation laws,

$$\dot{m}_{tw} = w_{res} - w_{wh} \tag{1a}$$

$$\dot{m}_{gp} = w_{g,in} - w_{g,rb} \tag{1b}$$

$$\dot{m}_{lp} = w_{l,in} - w_{l,rb} \tag{1c}$$

$$\dot{m}_{gr} = w_{g,rb} - w_{g,out} \tag{1d}$$

$$\dot{m}_{lr} = w_{l,rb} - w_{l,out} \tag{1e}$$

where,

- w_{res}: mass flow from reservoir to well [kg/s]
- w_{wh}: mass flow from wellhead to pipeline [kg/s]
- $w_{g,rb}$: mass flow of gas at riser base [kg/s]
- $w_{l,rb}$: mass flow of liquid at riser base [kg/s]
- $w_{g,out}$: outlet gas mass flow [kg/s]
- $w_{l,out}$: outlet liquid mass flow [kg/s]

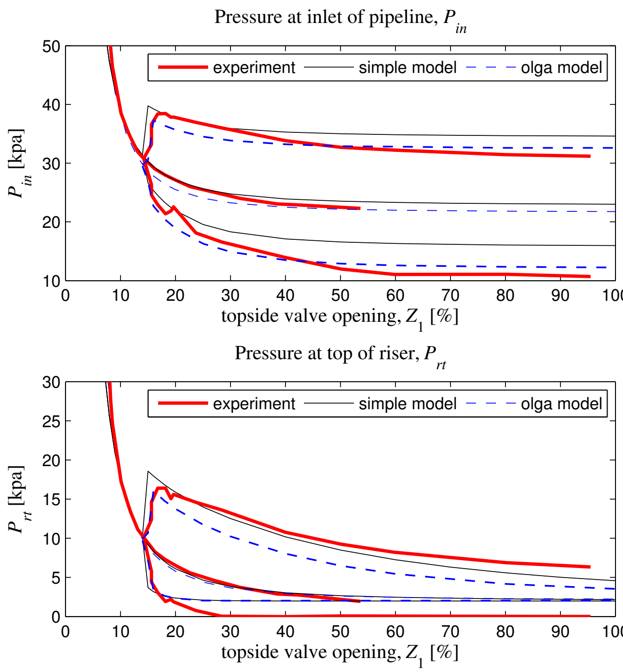

Fig. 3. Bifurcation diagrams for topside choke valve (two other valves fully open).

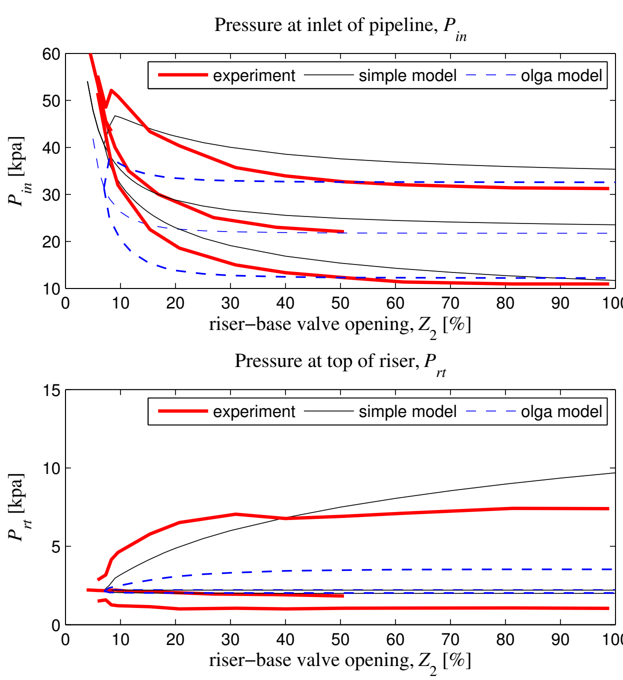

Fig. 4. Bifurcation diagrams for riser-base subsea valve (two other valves fully open).

These flow rates are calculated by valve type equations as given in [6]. The simple model was fitted to the experiments by adjusting the following six parameters:

- K_a: correction factor for average gas fraction in well
- K_{wh}: wellhead choke valve constant
- K_h: correction factor for level of liquid in pipeline
- K_{pc}: production choke valve constant
- K_g: coefficient for gas flow through low point
- K_l: coefficient for liquid flow through low point

We refer to [4] and [6] for more details. The bifurcations diagrams, describing the steady-state behaviour of the system as a function of the valve opening and the transition from stability to instability, are used to compare the simplified model with experiments and the OLGA model [8]. Fig. 3 and Fig. 4 show the bifurcation diagrams for the topside valve and the subsea valve, respectively. The simplified model (thin solid lines) is compared to the experiments (red solid lines) and the OLGA model (dashed lines). In Fig. 3, the system has a stable (non-slug) flow when the topside valve opening Z_1 is smaller than $Z_1^* = 15\%$, and it switches to slugging flow conditions for $Z_1 > 15\%$. We see three lines for slugging conditions. They are minimum and maximum pressure of the oscillations for slugging and the non-slug flow pressure. The non-slug flow regime is unstable for $Z_1 > 15\%$, but it can be stabilized by using feedback control.

The corresponding bifurcation diagram for the riser-base valve is shown in Fig. 4. The OLGA model could not capture both steady-state and the critical valve opening ($Z_2^* = 8\%$) at the same time for the riser-base valve; it was only possible to get the critical valve opening correct by adjusting the Coefficient of Discharge of this valve. On the other hand, in the simplified model, we have more free parameters and we could fit the simplified model closer to the experiments (Fig. 4).

III. CONTROLLABILITY ANALYSIS

A controllability analysis should reveal limitations on the achievable performance of a given input(s) and output(s) combination [9]. A controllability analysis were used in [7],[8] to find suitable controlled variables for anti-slug control when using the top-side choke valve as the manipulated variable. In this work, we use a similar controllability analysis to compare the three alternative manipulated variables of the system (three control valves).

We compare minimum achievable peaks of three closed-loop transfer functions (S, KS and SG), the output pole vectors and the steady-state gain as given in Tables I, II and III. It is desirable with a large steady-state gain $|G(0)|$, a large output pole vector and small peaks for $|S|$, $|KS|$ and $|SG|$.

The results for the top-side valve (Table I) are similar to what was presented in [7], [8]. The four subsea pressures are all suitable candidates, but the topside pressure (P_{rt}) is not a good controlled variable because of a large peak on $|S|$.

The controllability analysis for the riser-base subsea control valve (Table II) shows that the pressure measurements

TABLE I

CONTROLLABILITY DATA FOR TOP-SIDE CHOKE VALVE $Z_1 = 40\%$

measurement	value	$G(0)$	pole vec.	$\lvert S\rvert$	$\lvert KS\rvert$	$\lvert SG\rvert$
P_{bh} $[kpa]$	174.12	-1.26	12.09	1.00	2.69	0.00
P_{wh} $[kPa]$	38.96	-1.48	13.17	1.00	2.47	0.00
P_{in} $[kpa]$	24.02	-1.99	15.02	1.00	2.17	0.00
P_{rb} $[kpa]$	21.37	-2.08	23.41	1.00	1.39	0.00
P_{rt} $[kpa]$	3.07	-2.09	8.28	7.00	3.93	5.19
w_{out} $[l/min]$	4.17	0.08	13.47	1.00	2.42	0.00

TABLE II

CONTROLLABILITY DATA FOR RISER-BASE CHOKE VALVE $Z_2 = 40\%$

measurement	value	$G(0)$	pole vec.	$\lvert S\rvert$	$\lvert KS\rvert$	$\lvert SG\rvert$
P_{bh} $[kpa]$	164.26	-3.24	17.19	1.00	1.11	0.00
P_{wh} $[kpa]$	28.86	-3.31	17.53	1.00	1.09	0.00
P_{in} $[kpa]$	26.85	-3.47	18.30	1.00	1.05	0.00
P_{rb} $[kpa]$	22.82	0.18	28.66	1.30	0.67	0.94
P_{rt} $[kpa]$	2.25	0.02	2.08	1.00	9.23	0.00
w_{out} $[l/min]$	4.76	0.19	15.76	1.00	1.22	0.00

upstream of this valve (P_{bh}, P_{wh} and P_{in}) are good candidate controlled variables. The measurements downstream this valve (P_{rb}, P_{rt} and w_{out}) have small steady-state gains and are not suitable.

The controllability analysis for the wellhead control valve (Table III) shows that none of the candidate control variables are very promising. The two pressure measurements upstream this valve have good steady-state gains, but have very large peaks for the sensitivity function. Among the four measurements downstream of this valve, the best is the pressure at inlet of the pipeline (P_{in}). It has relatively high steady-state gain and the peaks of the sensitivities are not large. We will therefore investigate this candidate controlled variable further in the simulations.

IV. EXPERIMENTAL RESULTS

The middle line in the bifurcations diagrams (Fig. 3 and Fig. 4) represents the desired non-slug flow. The slope of this line ($\frac{\partial y}{\partial u} = \frac{\partial P}{\partial Z}$) represents the process gain, and we note that the gain decreases in magnitude and approaches zero as the valve opening increases. In order to stabilize the system with larger valve openings (lower pressure set-points) we need to increase the controller gain. We used a simple PI controller implemented in LabView in the experiments. The integral time ($T_i = 120\ s$) was kept constant in the two experiments, and values of K_c for different pressure set-pints are given in Table IV. These values for the proportional gain were found by trial and error. Developing a procedure for tuning the controller parameters considering nonlinearity of the system is subject of another paper.

TABLE III

CONTROLLABILITY DATA FOR WELL-HEAD CHOKE VALVE $Z_3 = 40\%$

measurement	value	$G(0)$	pole vec.	$\lvert S\rvert$	$\lvert KS\rvert$	$\lvert SG\rvert$
P_{bh} $[kpa]$	170.37	-2.78	15.52	4.80	1.73	13.92
P_{wh} $[kpa]$	27.67	-2.01	15.72	3.78	1.70	8.23
P_{in} $[kpa]$	26.37	0.49	16.26	1.00	1.65	0.00
P_{rb} $[kpa]$	20.46	0.03	29.35	1.01	0.91	0.06
P_{rt} $[kpa]$	2.30	0.02	1.65	1.60	16.28	0.07
w_{out} $[l/min]$	4.40	0.17	11.17	1.81	2.40	0.64

TABLE IV

PROPORTIONAL GAINS USED FOR DIFFERENT PRESSURE SET-POINTS

Experiments		OLGA Simulations	
P_{set} $[kPa]$	K_c	P_{set} $[kPa]$	K_c
25.0	15	24.8	0.2
24.0	20	23.9	0.4
23.5	25	23.2	0.6
23.0	30	22.7	0.8
22.5	40	22.5	1.0
22.0	50	22.2	1.2
21.7	60	22.0	1.4
21.5	70	21.8	1.8
21.3	80		
21.0	90		

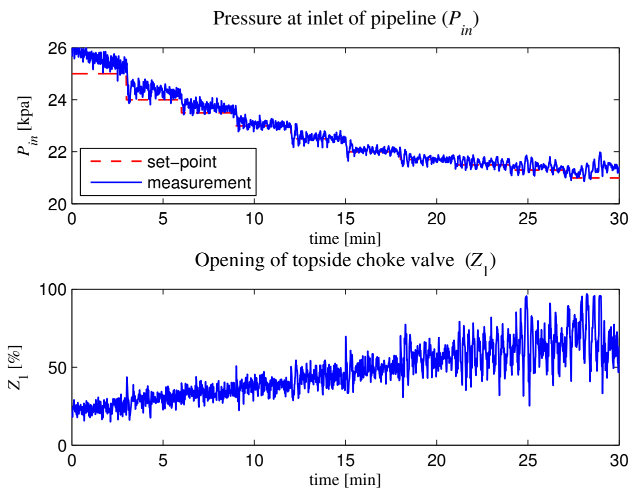

Fig. 5. Control experiment using top-side valve, controlled variable P_{in}

The same set of set-point dependant controller gains (Table IV) were used for all experiments, both with the topside and the subsea riser-base valve. The results are shown in Fig. 5 and Fig. 6, respectively. For the both valve locations we could stabilize the system without saturating the valve down to a set-point of $21.5\ kPa$. The average valve opening with this set-point is 63% for the top-side valve and 59% for the subsea valve.

V. OLGA SIMULATION RESULTS

As for the experiments, a simple PI controller was used in the OLGA simulations with tunings obtained by trial and error. Tuning values for different pressure set-points are given in Table IV. Simulation results of control using the top-side choke valve are shown in Fig. 7 and the results using the riser-base control valve are shown in Fig. 8. The maximum achievable valve opening can be used as a measure of the benefit achieved from anti-slug control. However, if two control valves have different sizes or Coefficients of Discharge, they produce different amount of pressure drop for the same valve opening. Therefore, the minimum pressure set-point is used as a better measure, as it was used also

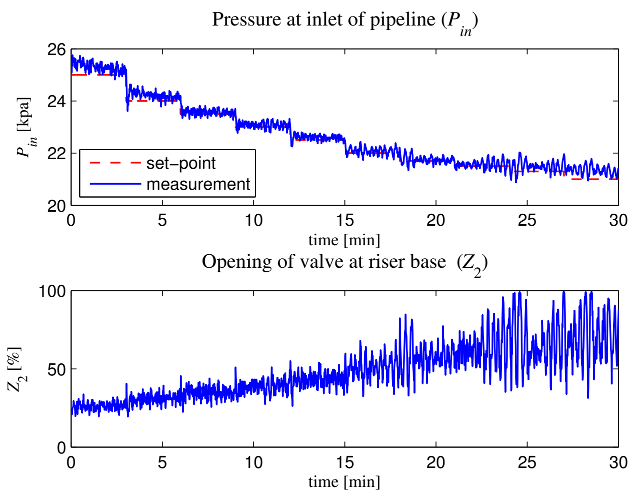

Fig. 6. Control experiment using riser-base valve, controlled variable P_{in}

in [3], especially when comparing two different valves. As shown in Fig. 7 and Fig. 8, in the OLGA Simulations, both the control valves can stabilize the system down to the same pressure set-point of 22 *kPa*. The valve opening with this set-point for the top-side valve is 42%, and for the subsea valve, it is 21%.

In the OLGA simulations in Fig. 7 and Fig. 8, we use an oil well as the boundary condition such that the inflow rates are pressure driven. Indeed, one can notice from Fig. 7 and Fig. 8 that when we decrease the pressure set-point, the inlet mass flow rate from the oil well increase. Thus, in addition to the pressure set-point, we can see the benefit of the stabilizing control by looking at the inflow rates. The final production rate achieved by using the both control valves is the same value of 4.4 *kg/min*.

Next, we consider using the wellhead valve. From the controllability analysis in the previous section, we predicted that control of the bottom-hole pressure (P_{bh}) and well-head pressure (P_{wh}) using the valve at the well-head (Z_3) is difficult because of large peaks of the sensitivity transfer function. Indeed, it was not possible to control these two variables by manipulating the wellhead valve in the OLGA simulations. On the other hand, the steady-state gain of the inlet pressure (P_{in}) is larger than for the other measurements downstream of the wellhead and it does not show any high peak. The simulation results in Fig. 9 and Fig. 10 show that the inlet pressure can be regulated, but it causes the valve to close, thus it shuts down the production. In Fig. 9, we increase the set-point, but it does not have much effect and flow rate decreases again after a while. Because of small steady-state gain, by increasing the set-point the valve opening does not change considerably. We decrease the set-point in Fig. 10. Since the lower set-point is infeasible, the valve closes completely but the pressure can not track the given set-point. In summary, the wellhead valve cannot be used for anti-slug control.

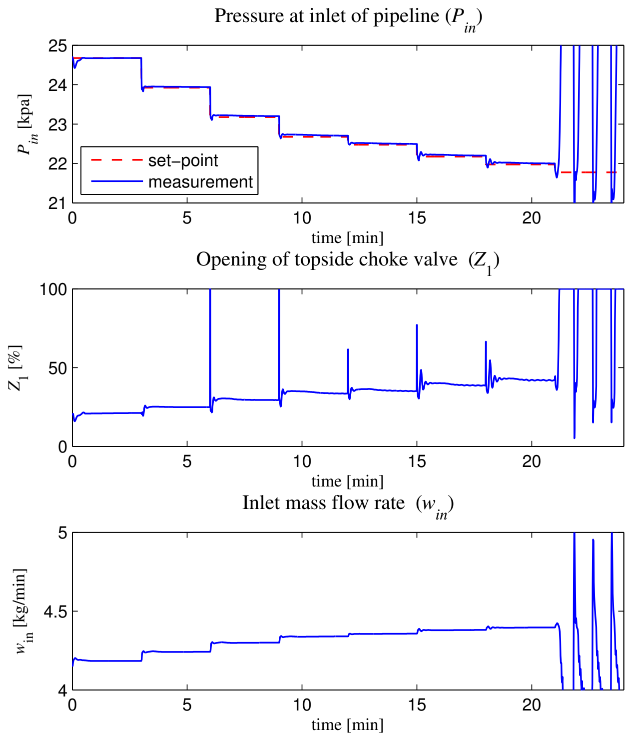

Fig. 7. Anti-slug control using top-side valve simulated in OLGA, controlled variable P_{in}

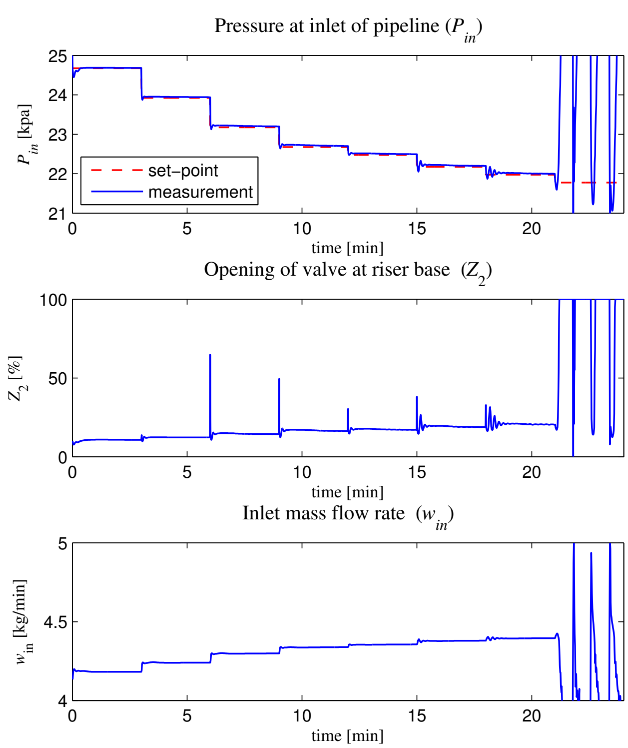

Fig. 8. Anti-slug control using riser-base valve simulated in OLGA, controlled variable P_{in}

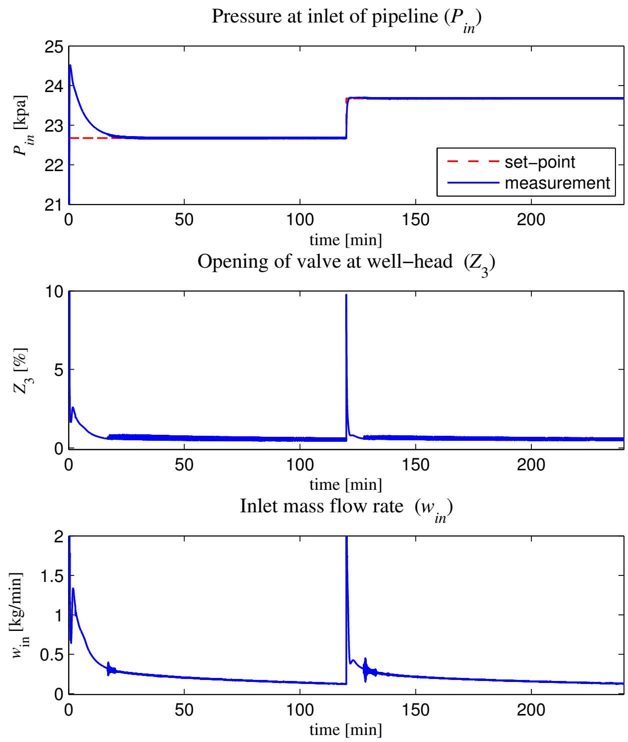

Fig. 9. Anti-slug control using well-head valve and increasing set-point simulated in OLGA, controlled variable P_{in}

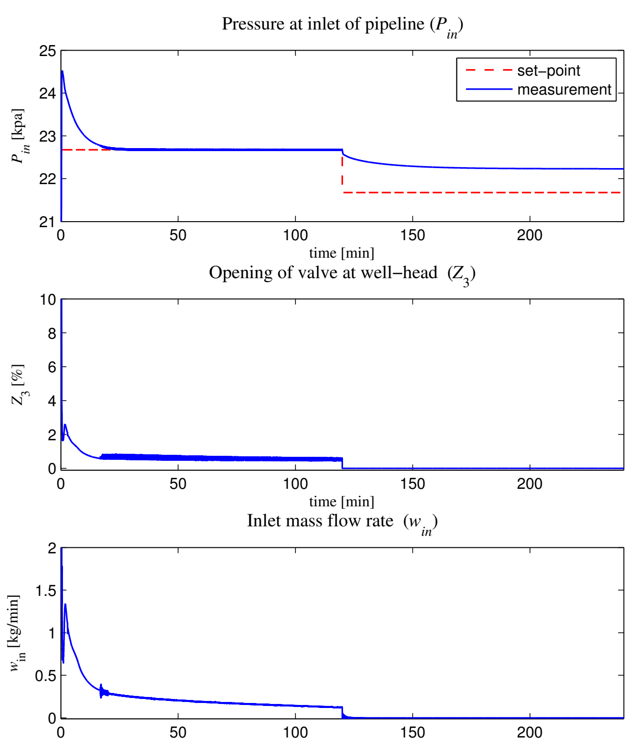

Fig. 10. Anti-slug control using well-head valve and decreasing set-point simulated in OLGA, controlled variable P_{in}

VI. Discussion

In addition to the controllability analysis, there are some physical reasons for the wellhead valve could not be used to stabilize the system. One intuitive reason is that the riser-slugging instability is because of dynamics between the pipeline (volume of gas) and the riser (weight of liquid). Therefore, manipulating a valve at the inlet does not have any effect on this and cannot stabilize the unstable dynamics.

Considering the simulations in Fig. 9 and Fig. 10 using the wellhead valve, the valve tends to close down. The reason for this is that the closed-loop system is internally unstable. In this case, the riser becomes full of liquid and some bubble of gas go up the riser. The weight of the column of liquid in the riser maintains the pressure regulation without considerable flow out of the riser.

VII. Conclusion

There is a good agreement between the OLGA model, simplified model and the experiments in bifurcations diagrams for the topside valve. We could fit the simple model closer to the experiments compared to the OLGA model for the subsea valve. The controllability analysis results based on the simplified model are also consistent with the simulations and experiments.

The control valve close to the riser-base is very suitable for anti-slug control, and the resulted benefit in terms of the production rate is same as using the top-side valve. However, a subsea choke valve placed at the wellhead can not be used for preventing the riser-slugging. This valve closes down and decreases the production rate drastically.

We could stabilize the system in the OLGA simulations and experiments up to very large valve openings by considering nonlinearity of the system and gain-scheduling of the proportional gain for the PI controller.

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