SPE 71540

Active Feedback Control as the Solution to Severe Slugging

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This paper was prepared for presentation at the 2001 SPE Annual Technical Conference and Exhibition held in New Orleans, Louisiana, 30 September–3 October 2001.

Abstract

Severe slugging in multiphase pipelines can cause serious and troublesome operational problems for downstream receiving production facilities. Recent results demonstrating the feasibility and the potential of applying *dynamic feedback control* to unstable multiphase flow like severe slugging and casing heading have been published (Refs. 4,9,1,5 and 2). This paper summarizes our findings on terrain-induced slug flow (Ref. 2). Results from field tests and as well as results from dynamic multiphase flow simulations are presented. The simulations were performed with the pipeline code OLGA2000.

The controllers applied to all of these cases aim to *stabilize* the flow conditions by applying feedback control rather than coping with the slug flow in the downstream processing unit. The results from simulations with feedback control show in all cases stable process conditions both at the pipeline inlet and outlet, whereas without control severe slug flow is experienced. Pipeline profile plots of liquid volume fraction through a typical slug flow cycle are compared against corresponding plots with feedback control applied. The comparison is used to justify internal stability of the pipeline. Feedback control enables in many cases a reduced pipeline inlet pressure, which again means increased production rate.

The paper summarizes the experience gained with active feedback control applied to severe slugging. Focus will be on extracting similarities and differences between the cases. The main contribution is to demonstrate that dynamic feedback control can be a solution to the severe slugging problem.

Introduction

Multiphase pipelines connecting remote wellhead platforms and subsea wells are already common in offshore oil production, and even more of them will be laid in the years to come. In addition, the proven feasibility of using long-distance tie back pipelines to connect subsea processing units directly to on-shore processing plants makes it likely that these will appear also in the future. Such developments are turning the spotlight on one of the biggest challenges for control and operation of offshore processing facilities and subsea separation units: *controlling the feed disturbance to the separation process*. That is, smoothening or avoiding flow variations at the outlet of the multiphase pipelines connecting wells and remote installations to the processing unit.

Common forms of flow variations are slug flow in multiphase pipelines and casing heading in gas lifted oil wells. In both cases the liquid flows intermittently along the pipe in a concentrated mass, called a slug. The unstable behaviour of slug flow and casing heading has a negative impact on the operation of offshore production facilities. Severe slugging can even cause platform trips and plant shutdown. More frequently, the large and rapid flow variation causes unwanted flaring and limits the operating capacity in the separation and the compression units. This reduction is due to the need for larger operating margins for both separation (to meet the product specifications) and compression (to ensure safe operation with minimum flaring). Backing off the plant's optimal operating in this way reduces its throughput.

A lot of effort and money has been spent trying to avoid the operational problems with severe slugging and reduce the effects of the slugs. Roughly speaking, there are three main categories of principles for avoiding or reducing the effects of slugs:

1. Design changes
2. Operational changes and procedures
3. Control methods
    - A. Feed forward control
    - B. Slug choking
    - C. Active feedback control

An example of a typical slug handling technique involving design changes is to install slug catchers (on-shore) or increase

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the size of the first stage separator(s) to provide the necessary buffer capacity. A different compact process design change is reported in Ref. 10, where the authors introduce an additional small pressurized closed vessel upstream the first stage separator in order to cope with slug flow. An example of operational change is to increase the flow-line pressure so that operation of the pipeline/well is outside the slug flow regime (Refs. 13,6). For older wells with reduced lifting capacity this is not viable option. For gas lifted wells an option would be to increase the gas injection rate (see Ref. 1). For already existing installations where problems with slug flow are present and for compact separation units, these design and operational changes may not be appropriate.

Control methods for slug handling are characterized by the use of process and/or pipeline information to adjust available degrees of freedom (pipeline chokes, pressure and levels) to reduce or eliminate the effect of slugs in the downstream separation and compression units. The idea of *feed-forward control* is to detect the build-up of slugs and, accordingly, prepare the separators to receive them, e.g. via feed-forward control to the separator level and pressure control loops. The aim of *slug choking* is to avoid overloading the process facilities with liquid or gas. These methods make use of a topside pipeline choke by reducing - it's opening in the presence of a slug, and thereby protecting the downstream equipment. The slug choking may utilize measurements in the separation unit and/or the output from a slug detection device/algorithm. For a more complete assessment of current technology for slug handling refer to Ref. 9. However, in this assessment, active control methods are not properly addressed.

Recently, results demonstrating the feasibility and the potential of applying *dynamic feedback control* to unstable multiphase flow like severe slugging and casing heading have been published (Refs. 4,9,1,5 and 2). Like slug choking, active feedback control makes use of a topside choke. However, with dynamic feedback control, the approach is to solve the slug problem by *stabilizing* the multiphase flow. Despite the promising results first reported in 1990 (Ref. 4) the use of active slug control on multiphase flow has been limited. To our knowledge only two installations in operation has stabilizing controllers installed. These are the Dunbar-Alwyn pipeline (Refs. 5,9) and the Hod-Valhall pipeline (Ref. 2). One reason for this might be that control engineering and fluid flow dynamics usually are separated technical fields, i.e. the control engineers have limited knowledge about multiphase flow and the experts in fluid flow dynamics have limited insights into what can be achieved with feedback control. Indeed, when presenting the results on the Hod–Valhall pipeline (Ref. 2), we had a hard time in convincing several of the fluid flow dynamics engineers that one can avoid the slug formation in severe slugging by active control. Hence, one objective of this paper is to provide insights and understanding into how feedback control can be used to avoid severe slugging, and thereby contribute to bridging the gap between control and petroleum engineering.

Previous work

Elimination of terrain and riser-induced slug flow by choking was first suggested by Schmidt et. al. (Ref. 13). Taitel (Ref. 6) state that stable flow can be achieved by using a choke to control the pipeline backpressure. He state that an unstable system can still operate around equilibrium steady state provided a feedback control system is used to stabilize the system. Furthermore, he refers to Schmidt (1980, Ref. 14) who found experimentally that it is possible to stabilize the flow by choking at the top of the riser upstream the separator. Taitel used stability analysis to define a theoretical control law. The control law relates the backpressure to the propagation of the slug tail into the riser. In Ref. 6 Taitel claims [sic] "It is interesting to observe that, to a good approximation, little movement of the choking valve is needed for such a control system. This makes it possible to set the valve in a pre-calculated constant value''. In the experiments reported in the paper, no feedback control system is used. Instead, the choke is *fixed in a pre-calculated position*. Note that the derived stability condition is related to quasi-equilibrium flow conditions with bubble flow in the riser and no or limited propagation of the slug tail into the riser. From control theory it is well known that feedback control is needed to operate in an unstable operating point, otherwise disturbances will push the operation out of the desired operating point. Our conclusion is that the quasi-equilibrium flow conditions comprises a stable operating point with an *unnecessary high riser base pressure* which must be higher than the corresponding pressure which can be achieved by applying stabilizing feedback control. Furthermore, we believe that the riser base pressure at quasi equilibrium flow conditions is equal to, or larger than, the peak riser base pressure with slug flow. Typical flow maps showing the slug flow region's dependency on the pressure, justifies these statements by fact that the slug flow region shrinks with increasing pressure and that the bubble flow region lies above slug flow region (see Fig. 1 and Fig. 2).

In Ref. 4, experiments on suppression of terrain-induced slugging by means of a remotely controlled control valve, installed in the riser top, are presented. Manual valve closure about 80% was necessary to remove the terrain-induced slugging, with a pressure difference about 7bar over the valve. In automatic mode the valve was controlled by PI algorithm with the pressure over the riser as the input signal. Terrain-induced slugging was successfully alleviated with PI control algorithm operating the valve. The resulting pressure difference across the valve was typically 1-2.5bar. From Fig. 7 in Ref. 4 it appears that they were able to split terrain-induced slugs into several smaller slugs.

In Ref. 9 riser base pressure control is used to avoid riser-induced slug flow at low flow rates in the Dunbar-Alwyn pipeline. Besides having pressure control in the riser base the control schemes includes necessary override control and manual controls to implement the developed operating strategies. The control scheme uses a control valve in parallel with the pipeline choke to control the riser base pressure (see

Fig. 8 in ref. 9). At low flow rates, where riser-induced slug flow occurs as a problem, the pipeline choke is closed and the control valve is used to control the pressure at riser base according to a PID algorithm. The pressure difference across the control valve with the slug control algorithm in operation was designed to be 15bar. The selected control scheme consists of throttling the pipeline sufficiently to maintain pressure above the peak pressure (around 81barg) to prevent liquid blockage at the riser base. The set-point to the riser base pressure was therefore set to 89barg. It is reasonable to believe that this results in controlled bubble flow in the riser, which of course might be acceptable if the necessary backpressure/lifting capacity is available. The large differential pressure across the control valve was chosen to obtain a robust system with a large margin to instability.

Ref. 5 presents simulation studies on the Dunbar-Alwyn pipeline using the TACITE multiphase simulator. In this work the authors look at several operational schemes to avoid riser-induced slug flow. The scheme of most interest for this paper is the simulation of riser base pressure control to avoid liquid blockage in the riser base. The difference between this work and the work on the real pipeline (Ref. 9) is that the set point to the riser base pressure controller is below the peak value in the slug flow regime. Actually, the set point is put as low as 77bar, which is approximately 4bar less than the slug release pressure around 81bar.

In Ref. 2 the use of feedback control to remove terrain-induced slug flow in the Hod-Valhall pipeline is presented. Both results from simulations and field tests are shown. This work will be further discussed in the present paper. The main differences between the work on the Hod-Valhall pipeline and the work on the Dunbar-Alwyn pipeline (Refs. 9 and 5) are:

1. A pressure transmitter at the pipeline inlet replaces the pressure measurement at the riser base in the Dunbar case. This means that the pressure transmitter is moved 12 km upstream the riser base. Knowing that it is possible to stabilize riser-induced slug flow using riser base pressure control, it is by no means obvious that stabilizing control can be achieved with the pressure transmitter moved to the pipeline inlet (12km upstream).
2. The pressure at the pipeline outlet is used in the control algorithm.
3. The pressure set-point at the pipeline inlet is always less than the slug release pressure with severe slug flow in the pipeline.

In Ref. 11 the authors present work on active control of riser-induced slug flow. Here, the pressure is measured at the base of the riser and a control system is used to adjust the gas outlet valve of the first stage separator. Experimental results show a reduction in the pressure variations caused by slugging.

The combination of a small-pressurized vessel or a compact cyclone separator where the gas outlet valve is used for slug control seems to be the most feasible solution for hydrodynamic slug flow. The reason for this is that a single-phase gas valve can be made much smaller and faster than a control valve for multiphase flow. In addition, the extra volume has the ability to cut/filter the large rapid flow peaks appearing in hydrodynamic slug flow.

Despite the structural differences between gas lifted oil wells and multiphase pipelines the limit cycle in riser- and terrain-induced slug flow is very similar to the limit cycle that occurs in deep casing heading in gas lifted oil wells. In Ref. 1 casing heading in gas lifted oil wells is studied. Thus, a separate section in the present paper is devoted to compare casing heading with severe slug flow. The work reported in Ref. 1 was partly based on a simple first principles non-linear model of a gas-lifted well with the ability to describe casing heading. Clearly, some of the insights provided by this model can be transferred to severe slug flow.

Riser- and terrain-induced slug flow cycle

For a full description of riser and terrain-induced slug flow refer to Refs. 6,4,12,13 and 14. The following description is a modified version of the description given in Ref. 2, fitted to Fig. 3-Fig. 6 borrowed from Ref 6.

Slug formation (Fig. 3 and Fig. 7, t=1-1.1h): Riser and terrain-induced slug flow is initiated by a period during which liquid, in terms of oil and water, accumulate in the lower parts of the pipeline or at the bottom of the riser.

Pressure build-up (Fig. 3 and Fig. 7, t=1.1-1.6h): After a certain time, the liquid will block the passage of the gas. Some of the gas will bubble through the liquid plug, but most of it accumulates upstream, causing an increase in pressure. The plug continues to grow until the forces acting on it are able to accelerate the plug.

Slug movement (Fig. 4 and Fig. 7, t=1.6-3.1h): At a certain pressure, the liquid plug starts to move due to forces acting on it. This can be identified as a pressure decrease upstream the liquid plug and a pressure increase downstream the liquid plug followed by a constant liquid production rate. Depending on the pipeline geometry downstream the liquid plug and the operating conditions, the plug may either die out or be transported to the outlet of the pipeline. In the slug movement period the pipeline pressure is almost constant.

Blowout/pressure reduction (Fig. 5 and Fig. 7, t=3.1-3.2h): When the tail of the slug reaches the riser base or the low point (dip) in the pipeline, gas starts to penetrate into the riser/upward parts of the pipeline. This causes the pressure at the riser base/low point to decrease since the hydrostatic pressure decreases. This causes more gas to flow into the riser/upward parts of the pipeline with the consequence that the flow rate increases rapidly.

Liquid fallback (Fig. 6 and Fig. 7, t=3.2-3.6h): As the gas and liquid are transported out of the pipeline, the upstream pressure continues to decrease. At some time the gas behind the plug starts to penetrate into and escape from (pass) the liquid plug. The liquid flow from the pipeline then ceases and any remaining liquid in the riser/upward parts of the pipeline will fall back to the riser base/low point of the pipeline.

The process then starts over again, resulting in an unstable multiphase flow pattern in which the liquid flow rate varies from zero to a significant constant value followed by a large peak value in a cycle.

During the *blowout/pressure reduction* the pipeline is exponentially unstable, and that the trajectory passes from an exponentially unstable manifold (zone) to a stable manifold. The classical *riser-induced slug flow* cycle contains all the stages as described above and the slug grows until the head of the slug reaches the top of the riser and is produced into the separator. At that point the cycle goes from pressure build-up to slug movement. However, the slug may start to move before the head of the slug reaches the top of the riser. From pressure trends of the pipeline inlet and outlet pressure, it is not always possible to observe the slug movement phase. Riser-induced slug flow where the slug movement phase is not present is often regard as terrain-induced slug flow.

Riser- and terrain-induced slug flow occurs typically for relatively low liquid and gas flow rates and is dependent on the gas oil ratio. Typically an increase in the gas oil ratio makes the flow more stable and a decrease makes the flow more unstable for constant total flow rate.

Casing heading

Deep casing heading in gas lifted oil wells undergo a limit cycle which is very similar to terrain-induced slug flow. In Ref. 1, the heading cycle is described in more detail. When comparing the two cycles following observations are important. The casing in gas lifted oil wells play the role of the pipe upstream the liquid plug. The gas injection choke plays the role of the plug. The tubing plays the role of the pipe downstream the liquid plug (the riser). Finally, the production choke play the role of the pipeline valve. The pressure cycle in the casing corresponds to the pressure cycle at the inlet or riser base, and the pressure cycles at the tubing outlet corresponds to the pressure cycles in the outlet or riser. When gas starts to penetrate into the tubing then a blowout of the tubing similar to the blowout in riser- and terrain-induced slug flow appears. For gas lifted wells the following applies:

1. <u>Fixed gas injection point</u>: The point where the gas starts to penetrate into the tubing is fixed and clearly defined by design in gas lifted oil wells.
2. <u>Unidirectional flow</u>: There is a check valve in combination with the gas injection nozzle making sure that the fluid does not flow from the tubing into the casing.
3 <u>Two versus one degree of freedom for control</u>: The gas injection valve might be used as an extra degree of freedom for control leading to a multivariable control problem, whereas only one manipulated variable (actuator) is available in riser- and terrain-induced slug flow problems.

A simplified model describing the dynamics of casing heading was derived in the work presented in Ref. 1. By using this model it was possible to analyze stability of different operating points on the severe heading cycle. This analysis suggests that during the tubing *blowout situation the* gas lift *system is exponential unstable*. This experience can directly be transferred to severe slug flow since the blowout situation is similar in the two cases. Another use of the simplified gas-lift model is to synthesize robust controllers taking the coupling between several variables in the system into account (see Ref. 1. for further details).

Slug control

The intuitive approach to the problem of slug flow is to detect the slug and try to limit its size in order to restrict the effect it has on the separator train and compressors at the production facility. The active slug controller described in the present paper solves the slug problem by *stabilizing* riser- and terrain-induced slug flow in terms of a fixed profile plot of the liquid volume fraction. The method involves active actuation of the production choke, in which the production choke is moved in accordance with a dynamic feedback control algorithm. By applying feedback control from pressure upstream the point where the slug is generated, it is possible to avoid slugging with an average pipeline pressure that is lower than the pressure that is typically introduced by simple constant choking. Furthermore, it is possible to achieve a stable pipeline inlet pressure that is less than the peak inlet pressure with severe slug flow.

The present slug controller has the following main functionality:

❒ **Slug control**:
- ✓ *Dynamic feedback control* to ensure stable operation of the pipeline based on feedback from the pressure upstream the point where the slug is generated.
- ✓ *Slug choking* to limit the effect the slug has on the separation and compression units based on feedback from pressure at the pipeline outlet.
- ✓ *Feed-forward control* to adjust the nominal operating point and parameters in the dynamic feedback controller, using the pipeline inlet flow rate and the mean pipeline choke opening as inputs.
- ✓ *Slug controller startup condition*. When the operator requests “active slug control” by putting it into automatic mode, a particular startup condition has to be fulfilled before the controller starts updating the slug control valve on the pipeline.

❒ **Slug signature**: for detecting slugs and monitoring the performance of the dynamic feedback controller. The slug signature is driven by pipeline inlet pressure, pipeline outlet pressure upstream the valve and pressure difference across the valve. These signals are filtered, the time derivative are calculated and again filtered to remove noise. The filtered pressures and the filtered time derivatives are used to drive a so-called state machine reflecting the severe slug flow cycle described in the preceding section.

❒ **Interface to separator train control**:
- ✓ Output to separator feed-forward control
- ✓ Override slug control (in case of a critical situation or an error in the separator train)

❒ **Operator interface**:
- ✓ Starting and stopping the controller
- ✓ Starting/stopping logging
- ✓ Monitoring the performance of the feedback controller
- ✓ Trends and graphs
- ✓ Access to controller parameters

The slug controller configuration is presented in Fig. 8. Here it is shown how pressure measurements at the pipeline inlet and outlet are used to adjust the pipeline valve. If flow measurements are available, they may also be used for feed-forward control of the nominal operating point and to adjust tuning parameters in the controller.

There are several reasons why measuring the pressure upstream the point where the slug is generated is important. First of all pressure has the capability to propagate upstream as long as liquid blockage is avoided, i.e. closing the valve at the outlet has an effect on the pressure in the upstream parts of the pipeline. From control theory it is necessary to observe any instability in order to stabilize the system. In the blowout situation where the tail of the slug penetrates the riser, the signs of the instability is first observed in the riser base pressure as a pressure reduction. The characteristic of the instability is then a continuing pressure reduction until the slug ceases. The *underlying approach to counteract the instability is to stop this pressure reduction by closing the valve*. The pressure reduction propagates upstream against the flow direction with the speed of sound in the fluid. However, downstream the plug, in the upper part of the riser, the pressure increases until the tail of the plug has passed the point of observation. When the tail of the slug pass the point of observation in the riser the pressure decreases at this moment of time it *might* be too late to apply feedback control to counteract the pressure reduction. Note that the time to slow down the slug and stabilize the system gets shorter the further up in the riser the pressure measurement is located. Not only due to the shorter distance to the top of the riser but also since the instability has increased the velocity of the plug. Moving the pressure measurement the opposite direction does not impose the same degree of conflict.

Slug choking, in the present version of the slug controller, consists of closing the valve when the pressure in the upper part of the riser increases. We note that this has a positive feedback effect, since closing the valve will further increase the pressure. Therefore, we use a control law that has no steady-state effect from the outlet pressure to the valve. This means that slug choking only reacts on rapid outlet variations, whereas the feedback stabilization reacts on slower inlet variations. The effect of slug choking has been studied on dynamic simulations, where it has been observed that is has a stabilizing effect on the pipeline flow in connection with startup of the controller. The reason for this is that one needs to close the valve rapidly to conserve the energy and then release (open the valve) the energy in a controlled manner to stabilize the pipeline during startup of the controller. Otherwise, the slug may easily carry with it too much liquid and gas to stabilize the flow.

Taming riser-induced slug flow in deep-water riser

In this section we will present some results from a deep-water pipeline-riser system that has been simulated using OLGA. Fig. 9 shows the pipeline geometry. The total length is approximately 6.5km with a 5km pipeline on the seabed and a 1.5km long riser. The inclination from wellhead to riser base is 1° downward slope. The sea depth at riser base is 1320m. A source is located at the inlet of the pipeline. The boundary conditions at the inlet are closed and at the outlet the pressure is set equal to 15bar. A control valve is located at the top of the riser. This control valve will be used to control the multiphase flow in the riser.

Two different inlet conditions have been simulated. The first case is at the start of the production profile. The input flow rate is set to 6000Sm3/d and the gas fraction is read from the PVT table with the pressure and temperature in the inflow section (the first section in the pipeline) as input to the table. This means that the gas fraction and thereby also the gas oil ratio may vary to some degree around $125 Sm^3/Sm^3$. In the second case the gas oil ratio is set equal to $250 Sm^3/Sm^3$ and the flow rate is reduced to 2000Sm3/d. In both cases the water cut is zero, i.e. only two phase simulations are considered.

Fig. 7 shows severe riser-induced slug flow. The following facts should be noted:

1. The large variation in the pipeline inlet pressure and outlet pressure.
2. The outlet oil flow rate is nonzero for large portion of the time as opposed to terrain-induced slug flow. The reason is that the liquid plug extends far into the nearly horizontal pipeline before the riser and it takes some time to produce the liquid in the pipeline, cf. Fig. 4.
3. By analyzing the simulations more carefully we find considerable amount of flashing which gives rise to a gas-lift effect. The gas-lift effect gives a rapid increase in the outlet oil flow rate observed as the first peak in the slug flow cycle. The latter larger peak in the oil outlet flow rate is related to the blowout of the riser, i.e., emptying the riser, cf. Fig. 5.

Fig. 10 shows the effect of a stepwise closing of the pipeline valve from 100% to 20%. It should be noted that:

1. In order to get out of the region with unstable riser-induced slug flow we see that we need to close the valve more than 20%.
2. In order to reduce the peak in the outlet oil flow rate significantly by *constant* choking, one needs to close the valve more than 40%.

Fig. 11 shows that one needs to close the valve as much as 14% to achieve stable flow conditions by constant choking with a corresponding pipeline inlet pressure of approximately 135bar. Fig. 12 shows profile plots (900 lines laid on top of each other) of liquid volume fraction through one slug flow cycle. The profile plots are sampled each 10 seconds and they illustrate the span in the amount of liquid in different parts of the pipeline. The following conclusions can be made:

1. The liquid plug covers a distance of 1.3km upstream the riser base.
2. The liquid volume fraction in the local maximum point in the S-shaped riser is never larger than 50%.

For the same pipeline inlet conditions the simulations where repeated but with slug control applied to the pipeline. First the controller is in manual with a valve opening of 70%. Then, at t=5h the slug controller is activated. The controller waits for the best startup condition to occur. This condition occurs at approximately t=6h and at this point the controller starts updating the valve. During slug control the flow is stabilized, and from Fig. 13 the controller eventually seems to reach a *constant* output of about 43%. However, this is not what actually happens. If the controller output is magnified, it becomes clear that the controller constantly makes *small* movements (varying in the range of 43.1-43.2%) around its mean value. The small movements in the valve position are necessary to keep the flow stable. This is illustrated at time t=16 hours when the controller is put into manual mode with a fixed output of 43%. In this position, one might expect the pipeline to stay stable, however, riser-induced slug flow again builds up. We note that no other changes are made. Slug flow with approximately the same valve opening (40%) is also predicted from the simulations without control (see Fig. 10). Note that the inlet pressure with the controller in operation is lower (103bar) than for stable flow achieved by constant choking (136bar). Fig. 14 shows the profile plot of liquid volume fractions during slug control. The plot shows 360 profile plots, 10 seconds apart. They all lie on top of each other, implying that the pipeline indeed is stable. Other important observations include:

1. Less pressure drop over pipeline with control than the mean pressure drop without control (this also applies to terrain-induced slug flow).
2. Increased pressure upstream choke with control resulting in a larger pressure drop over the valve. This is necessary to have an effect of the movements in the valve.
3. With control, liquid plugs do not occur, only minor movements in the profile plot of liquid volume fraction can be observed during control.

All the simulations where repeated but with total flow rate reduced to 2000Sm3/d and the gas oil ratio set equal to 250Sm3/Sm^3. From the simulation with stepwise reducing the choke opening we find that that one needs to close the valve as much as 10% to achieve stable flow conditions by constant choking. The corresponding pipeline inlet pressure is then approximately 65bar. The reason for the lower pipeline inlet pressure in this case is the larger gas oil ratio. Other observations include:

1. The characteristics of the riser-induced slug cycles are different from the first case. From the simulation we see that the mass transportation period with constant outlet flow rate is also missing. Still large oscillations in the inlet and outlet pressure appear.
2. The liquid flow rate is zero for a larger portion of the time and the slug cycles in this case are much more similar to terrain-induced slug flow.

Fig. 15 shows active slug control for the deep-water case with an input flow rate of 2000Sm3/d and GOR=250Sm3/Sm^3. From the figure we see that the controller is able to stabilize the flow with the controller valve varying in the range from 34 to 35% and an inlet pressure of 41bar, which is much less than the corresponding 65bar that can be achieved with constant choking (10%). Other observations include:

1. Less pressure drop over pipeline with control than the mean pressure drop without control
2. Increased pressure, upstream choke with control, resulting in larger pressure drop over the valve. This is necessary to have an effect of the movements in the valve.

Taming terrain-induced slug flow in pipelines

Hod-Valhall site

The Hod-Valhall site consists of an unmanned, remote-controlled wellhead platform, Hod, a 13-km-long multi-phase pipeline, and the main production platform, Valhall. The gas, oil and water produced at Hod are transported through the pipeline to the Valhall platform, where it is merged with the oil produced by the Valhall wells (see Fig. 16). The combined stream then enters the separation unit, which consists of two first-stage and two second-stage separators in parallel. At the Hod and Valhall platforms the water depth is approximately 70m. The pipeline diameter is 12 inches and the pipeline profile is shown in Fig. 17. Included in the pipeline instrumentation are pressure and temperature transmitters at Hod and a pressure transmitter upstream the pipeline choke at Valhall. The gas and liquid flows from the Hod wells are measured separately at the outlet of a test separator before the streams enter the pipeline to Valhall.

Despite the fact that the Hod platform produces less than 5% of the total produced by the wells at the Valhall platform, the slugs are large and intense enough to cause considerable operational problems in the separation unit. These problems include:

- Large disturbances in the separator train, causing:
  - Poor separation (water carry-over to the export pipeline due to rapidly varying separator feed rates).
  - Varying water quality at the separator water outlets, leading to major problems in the downstream water treatment system and possible violation of environmental restrictions.
- Large and rapidly varying compressor loads, causing:
  - Inefficient compressor operation.
  - Limited compression capacity due to a larger margin being needed to handle gas hold-up behind the liquid.
  - Unwanted flaring (a result of the limited compression capacity).

The pressure variations at the Hod end of the pipeline are also visible in the Hod wells, resulting in limited production from wells suffering from reduced lifting capacity.

Simulation results

Fig. 18 shows the performance of the slug controller with the pipeline simulated in OLGA. During the first eight hours the controller is in manual mode, as indicated by the characteristic pressure fluctuations in the pipeline inlet and outlet pressure. The controller starts at t=28h and spends the next 5 to 7 hours stabilizing the pipeline. The controller seems to have settled at a constant output value at t=38h. However, this is not true. If the control value is magnified, it is easily seen that it moves constantly around its mean value. The controller is set to manual at t=45h, with its output equal to the mean value over the previous three hours. Afterwards, the slug flow builds up slowly. From Fig. 18 it seems reasonable to conclude that the pipeline flow is stable at least at the input and at the output, since the pressures are stable in these locations. However, due to the length of the pipeline, it could be claimed that internal instability might occur in it. Fig. 19 shows profile plots of the liquid volume fraction, sampled at 60-second intervals between t=41h and t=45h. In total, 241 plots are therefore shown. They all lie on top of each other, indeed implying that stability is achieved throughout the pipeline.

Field tests

The prototype of the slug controller was tested twice in 1999 and has been operating at the Hod-Valhall site in periods since the end of January 2000. Fig. 20 to Fig. 27 show some of the slug controller test results:

1. Fig. 20 and Fig. 21 show typical pipeline operation without slug control.
2. Fig. 22 and Fig. 23 show the controller startup and operation on low pipeline flow rate. Included is startup of two wells.
3. Fig. 24 and Fig. 25 show controller startup and operation on high pipeline flowrate.
4. Fig. 26 and Fig. 27 show controller operation, startup of a large producer and stop on high pipeline flow rate.

For all the four cases presented, the figures show the same variables. The first figure in each case shows the pipeline inlet and outlet pressures in relation to the choke opening. The second figure shows the pipeline inlet gas and liquid flow rates. Both 30 minute and 8 hours moving average are shown. The 30 minute moving average shows in all cases that the pipeline inlet flow rates vary a lot due to slugging in the wells connected to the Hod platform.

In order to understand the test results it is important to know that the wells at Hod are operated cyclically, as the well flow rate decreases over time. When production from a well has reached a lower limit, the well is put on hold. The operating time and the hold time differ from well to well; some of the wells only remain in operation for a couple of days before being put on hold.

Fig. 20 and Fig. 21 show the pipeline in operation without the slug controller. In Fig. 20 one clearly see the characteristic oscillations in the pressure for terrain-induced slug flow.

Fig. 22 and Fig. 23 show the slug controller in operation. During the first eight hours the choke (see Fig. 22) is operated manually 20% open. In this situation we see the terrain-induced slug flow cycle. The controller is started October 2nd, just after 8am, the controller then moves the pipeline choke to 25% open and keeps it in this position until the startup condition is satisfied. At time 11:18am the startup condition is fulfilled and the controller starts updating the choke. The choke is only allowed to be within 5% to 35% open. The controller stabilizes the pipeline for the next 36 hours. From Fig. 22 the mean pipeline inlet pressure decreases with some PSI when no slug cycles appears. During the four days and 6 hours shown in the figures two of the Hod wells, which have been on hold, are put into operation. The first one is put into operation October 4th at 4am and the second one October 5th at 12am. The startup of the wells can be seen in Fig. 22 as large pressure spikes both at the inlet and the outlet of the pipeline. A well startup is a large disturbance to the slug controller, which can introduce instability into the pipeline, and from Fig. 22 a terrain-induced slug flow cycle appears just after the first well startup. Fig. 23 shows the pipeline input flow rates. During the first 19 hours the Hod wells are bypassed the test separator, which is the reason for the missing pipeline inlet flow rates in that time period. The different Hod wells have their own characteristics. The frequent changes in the flow rates are due to one well, whereas the large peaks are due to slugging in another well. After the first well startup the frequent changes in the flow rate become different, which is due to interactions between the wells. The changes in pipeline input flow rates together with well startup are major disturbances to the slug controller. However, the slug controller handles these disturbances satisfactorily, which proves that the chosen control scheme in the slug controller is robust with respect to such changes.

Fig. 24 and Fig. 25 show a controller startup for a much larger mean pipeline flow rate. First well H8, which is one of the two largest producers at Hod, is put into operation. Next the slug controller is started. The slug controller stabilizes the pipeline. Experience shows that for this well it only takes a few terrain-induced slug flow cycles before the production rate from the well starts to drop Eventually after a couple of days in operation, the well is normally put on hold. However, with the slug controller operating the pipeline choke, it has been verified that this well can be kept in operation for a longer period of time.

Fig. 26 and Fig. 27 show the slug controller in operation. Well H8 is put into operation on May 1st at 10am, and the pipeline inlet flow increases and a large spike in the pressure appears. The controller is already in auto when this happens. The large pressure causes the controller to saturate on 35%. When the pressure drops the pipeline is stable. The controller is stopped on May 2nd at 8pm. Terrain-induced slug flow with growing amplitude in the pressure swings appears during the next hours. Also notice how the pipeline inlet liquid flow rate drops when terrain-induced slug flow appears.

Summary of experience

Implications on the Hod wells

The varying flow rates and the cyclic operation of the Hod platform wells make it very difficult to finally conclude to what extent the slug controller affects the Hod wells, i.e., whether the wells produce less, more, or about the same as before the slug controller was installed. The experience shows that it is possible to keep the wells in operation for a longer period of time before they need to be taken out of operation, and thereby indirectly increasing the production by increasing the fraction of the time the wells are in operation. This is particularly true for well H8. This well has been in continuos operation for as long as two weeks with the slug controller in operation, compared to a typical mean operation time of only a few days without the slug controller in operation.

Robustness to rapid varying pipeline inlet flow rate and well startup

The field tests so far have shown that the chosen structure in the slug controller is robust with respect to large and rapid inlet flow variations (ranging from less than 1000bbl/d liquid throughput to 15-20kbbl/d) due to slugging wells. We note that very little re-tuning of the controller has been required during the test period and between the different test cases. Also well startup represents large and rapid disturbances to the slug controller. However we find that the controller handles well inclusions satisfactory. The controller output is limited within selected bounds. We think that these bounds are important tuning factors, and that the selection of these bounds is one of several key issues to the robust behavior. In addition the way integral windup is implemented is of importance. And, last but not least, the knowledge about the tuning factors *combined* with the process knowledge is a large contributor to the success.

Occasional slugging

Despite the controller's robustness to rapid changes, we have observed that slugs appear occasionally. One theory is that the more stable flow condition resulting from active slug control may cause the water to be separated out and generate infrequent water slugs. This theory has partly been verified by a sudden increase in the water produced in the time period following the cease of such an occasional slug in the pipeline.In order to handle such events in a robust manner the slug signature is implemented. The purpose of the slug signature is to restart the controller in the event of a severe slug (see Fig. 8). This approach has been tested manually and it has been verified that such action results in a stable pipeline after the controller restart.

Benefits of applying slug control to the downstream production plant

Additional benefits that the slug controller has brought to the Valhall production facility include:

- ❖ Smaller disturbances in the separator train, resulting in smoother operation:
  - ✓ Improved separation
  - ✓ Larger throughput
- ❖ Smoother operation of the compressors:
  - ✓ Increased compressor operational stability and reduced flaring.

By considering the stable inlet and outlet pipeline pressures, and also the insights provided by the multiphase flow simulation, it is reasonable to state that the slug controller greatly improves the stability of multiphase flow in the pipeline.

Conclusions

For some time it has been known that riser base pressure control can stabilize riser-induced slug flow. In this paper we have demonstrated that severe slug flow in terms of riser- and terrain-induced slug flow can be stabilized with dynamic feedback control of pipeline inlet pressure to a pipeline valve at the outlet. We have argued that moderate choking triggered by a rapid pressure increase in the pipeline outlet can improve stability, and the robustness of the control scheme. Simulations have been used to verify this. From plots of inlet and outlet pressures in the simulations and the field tests it seems reasonable to state that the pipeline is stable at least at these two points. Profile plots of the liquid volume fractions in the simulations with control implies that whole pipeline is stable. The actual minimum achievable pipeline inlet pressure depends on the inlet flow rate and the gas oil ratio (water cut). In the case studies it has been shown that this pressure is much less than the corresponding pressure achieved by constant choking and the peak inlet pressure with slug flow. This reduction in inlet pressure has great impact on the operation of the wells connected to the pipeline. For wells with reduced lifting capacity we have experienced that the variation in the pipeline pressure can cause the well to stop producing.

Besides demonstrating how active feedback control can be used to avoid riser- and terrain-induced slug flow without reducing oil production, the tests with the prototype algorithm have further proved the beneficial effects that exists for applying active feedback control to multiphase fluid flow processes.

Acknowledgement

BP is gratefully acknowledged for letting us publish the results achieved on the Hod-Valhall pipeline. Special thanks to K.O. Stornes at BP for fruitful discussions and for making the arrangements for field-tests. Support from Scandpower AS is acknowledged.

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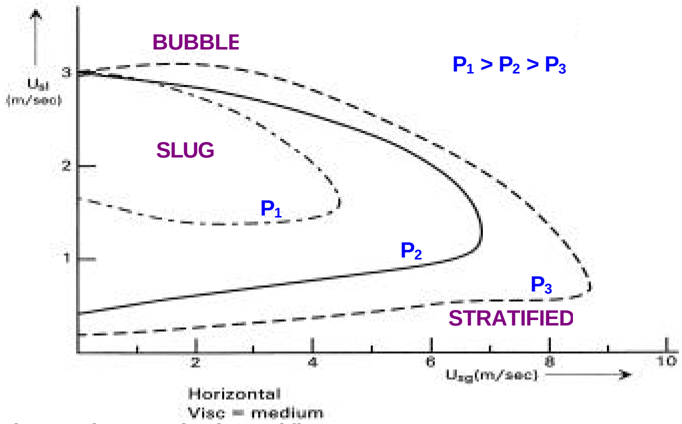

Fig. 1—Flow map horizontal flow

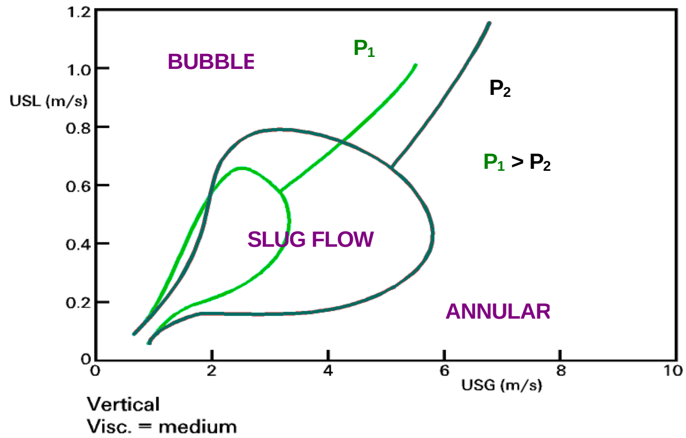

Fig. 2—Flow map vertical flow

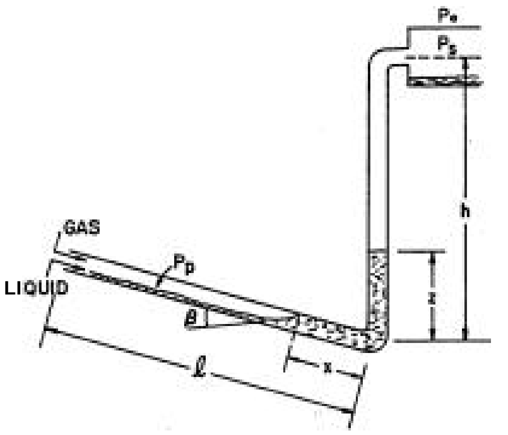

Fig. 3—Slug formation, pressure build-up (Ref. 6)

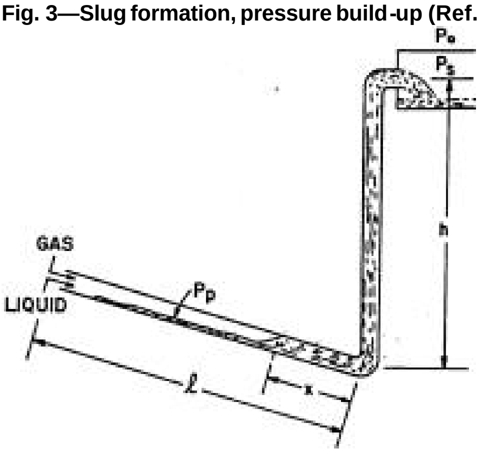

Fig. 4—Slug movement (Ref. 6)

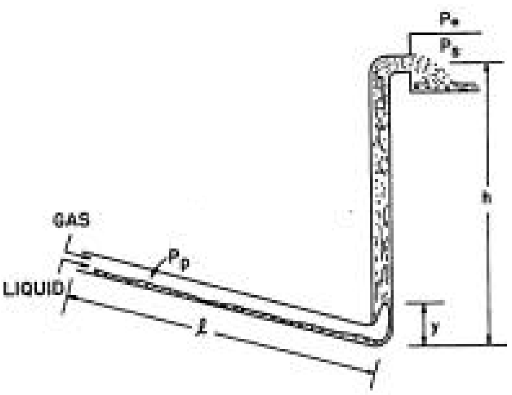

Fig. 5—Blowout, pressure reduction (Ref. 6)

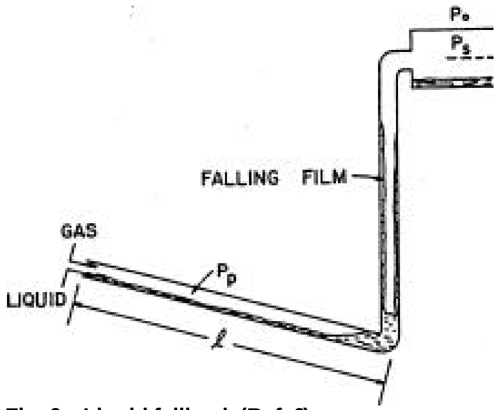

Fig. 6—Liquid fallback (Ref. 6)

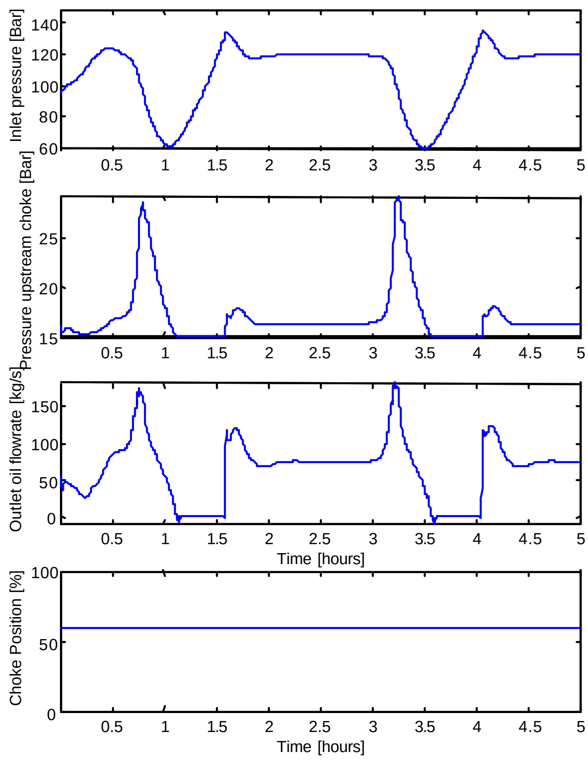

Fig. 7—Riser-induced slug flow cycle in deep-water case

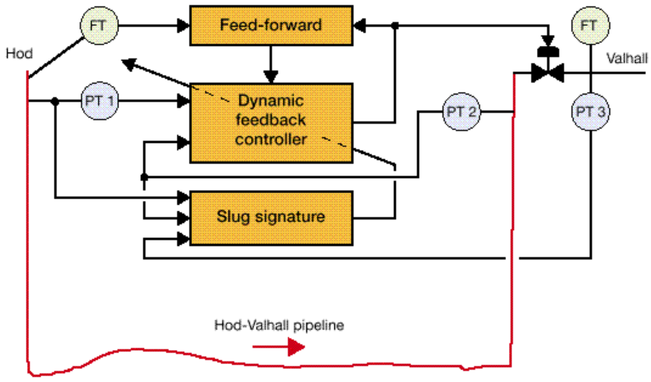

Fig. 8—Slug controller feedback structure for flow stabilization

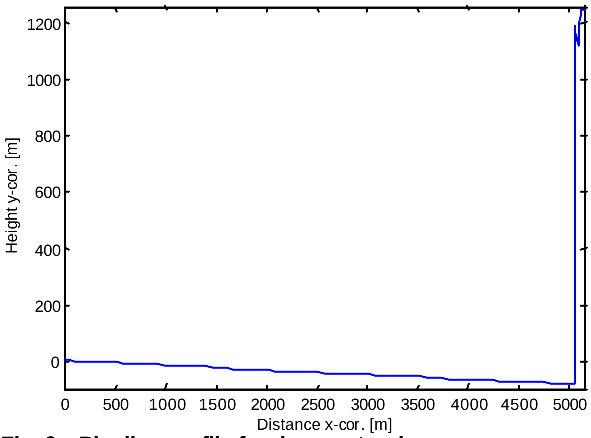

Fig. 9—Pipeline profile for deep-water riser case

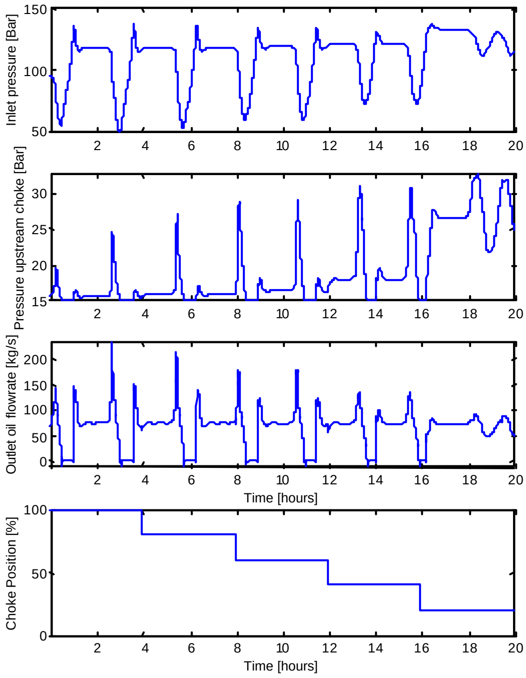

Fig. 10—Severe slugging in deep-water riser, step vise closing the valve from 100% to 20%

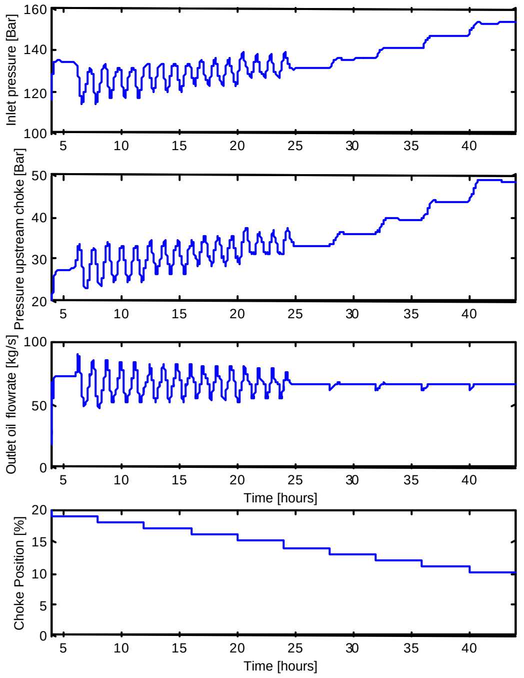

Fig. 11—Severe slugging in deep-water riser, step vise closing the valve from 19% to 10%

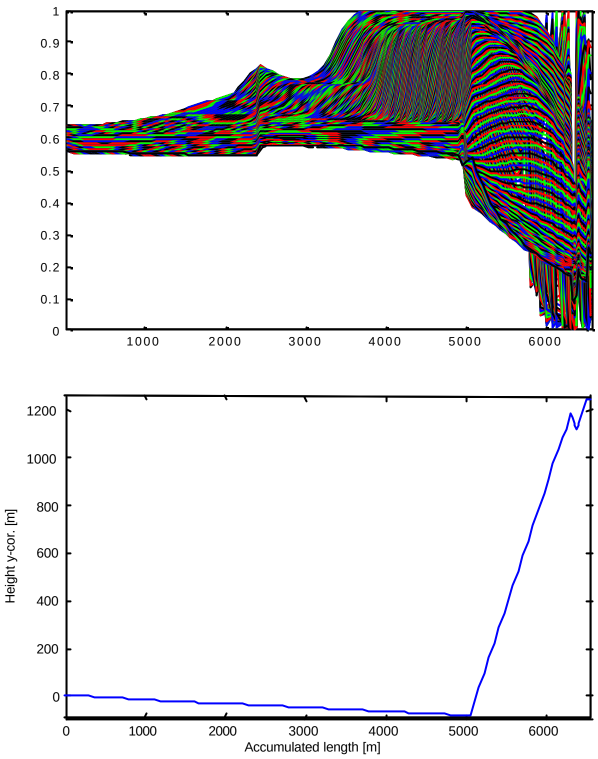

Fig. 12—Profile plots (900 lines) of liquid volume fraction through one riser-induced slug cycle

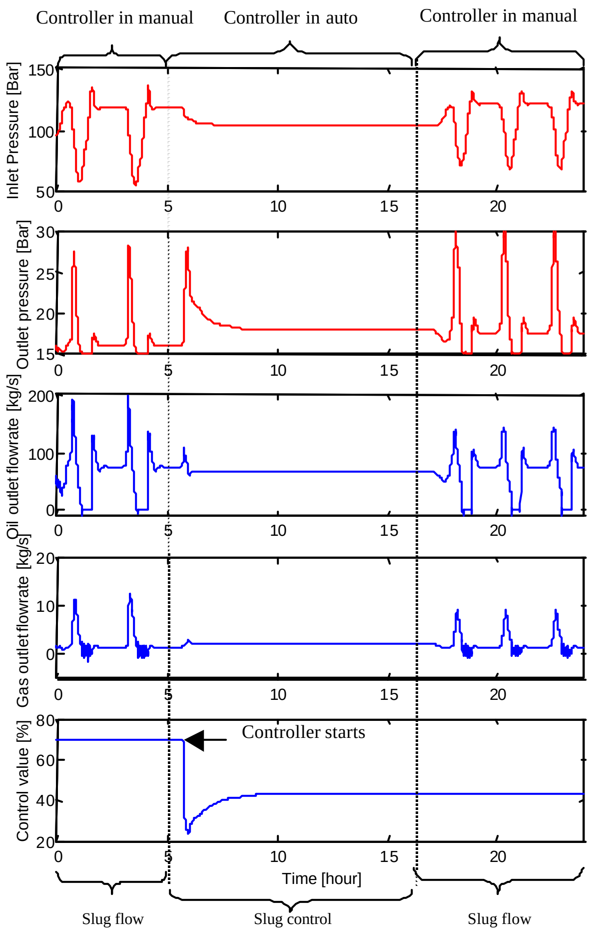

Fig. 13—Severe riser-induced slugging with slug control

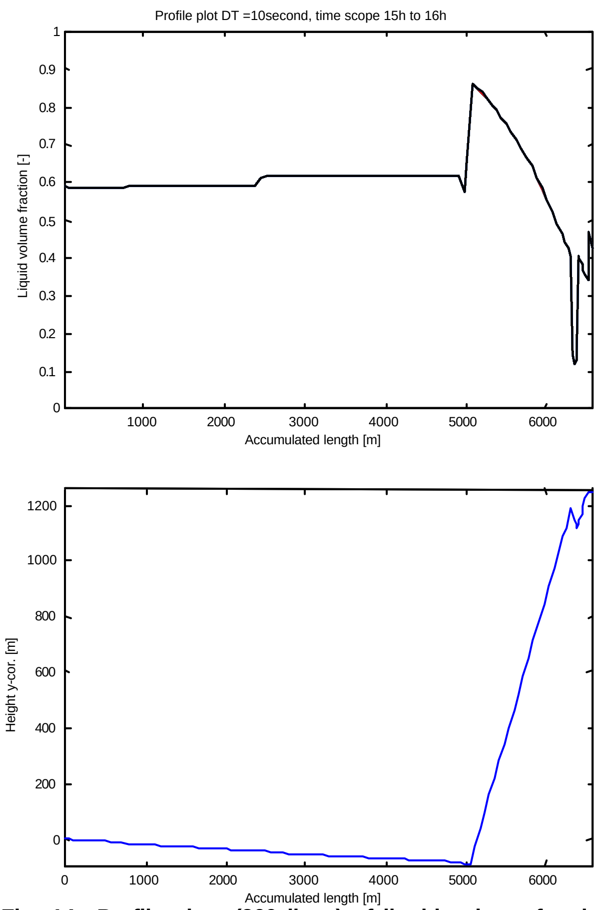

Fig. 14—Profile plots (360 lines) of liquid volume fraction with slug control

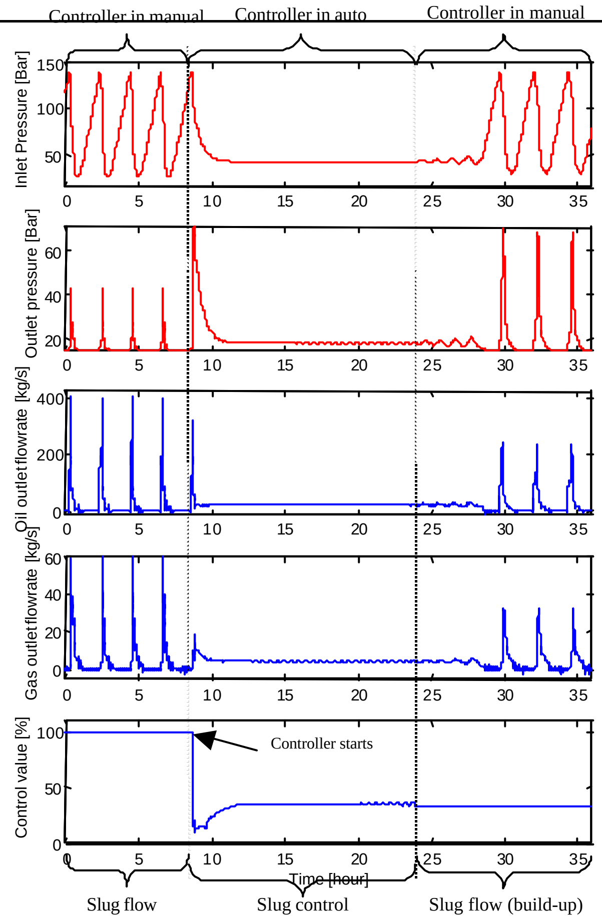

Fig. 15—Severe riser-induced slugging with slug control. Input flow rate 2000Sm3/d with GOR=250Sm3/Sm3

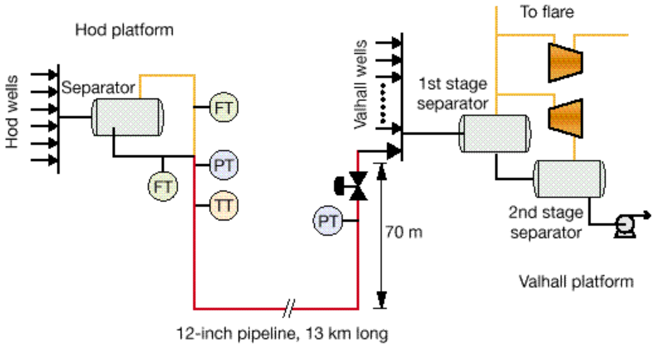

Fig. 16—Schematic of the Hod-Valhall offshore site. The pipeline instrumentation includes flow transmitters (FT), pressure transmitters (PT) and temperature transmitters (TT)

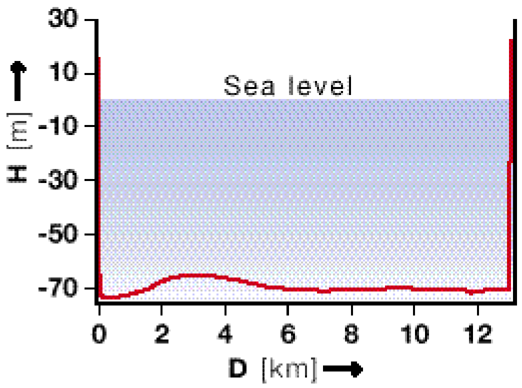

Fig. 17: Hod-Valhall pipeline profile

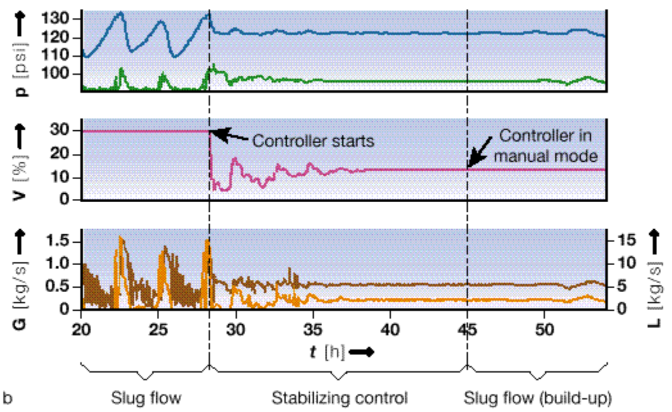

Fig. 18—Active control of terrain-induced slug flow. The controller starts up at t=28h and runs until t=45h, after which the valve position is kept constant and slug flow slowly builds up. Pressure at pipeline inlet (blue) and outlet (green), G: Gas flow rate (brown), L: Liquid flow rate (orange), V: Valve opening, t: Time

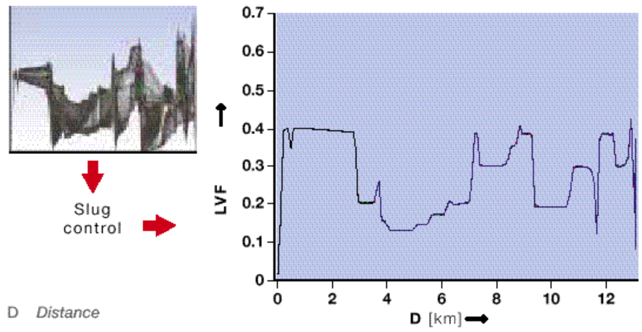

Fig. 19—Pipeline profile of the liquid volume fraction (LVF) with slug control. 241 profile plots are shown. Sampling interval 60 s. All lines lie on top of each other, implying that the whole pipeline is stable

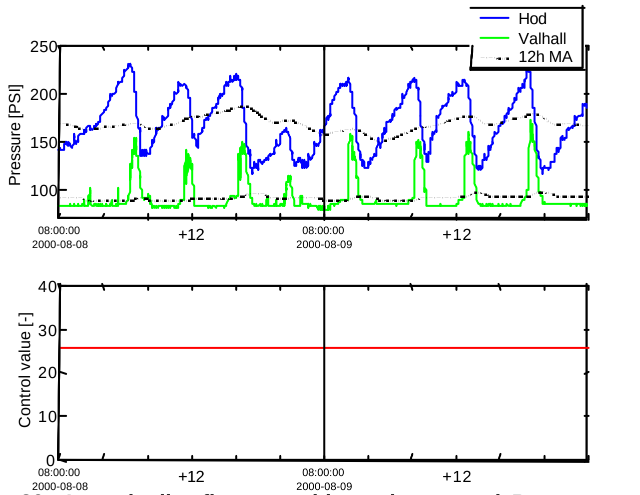

Fig. 20—Low pipeline flow rate without slug control. Pressure p at the pipeline inlet (Hod, blue) and outlet (Valhall, green) and choke position C. In addition is the 12-hour moving average (MA) of the pipeline pressures shown

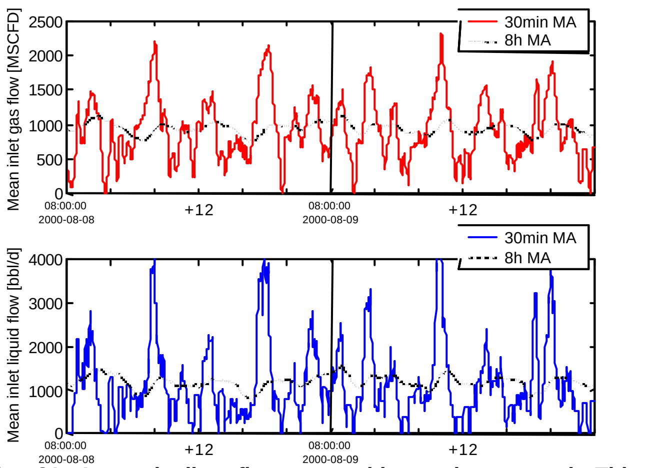

Fig. 21—Low pipeline flow rate without slug control. Thirty minutes and eight-hour moving average of the gas (G) and liquid (L) flow rates at the pipeline inlet (Hod)

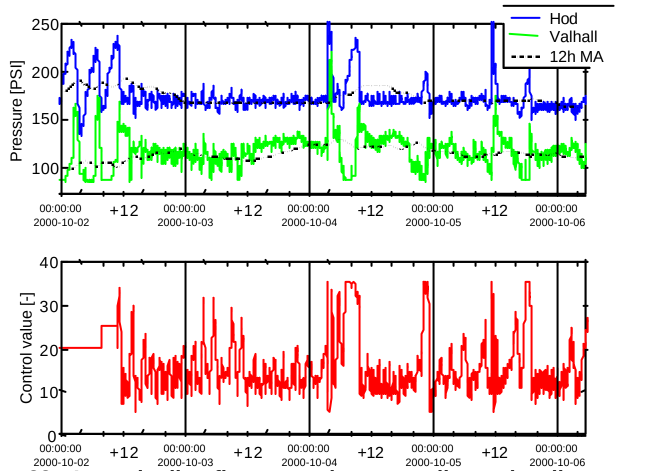

Fig. 22—Low pipeline flow rate, slug controller and well startup. Pressure p at the pipeline inlet (Hod, blue) and outlet (Valhall, green) and choke position C. Also shown is the 12-hour moving average (MA) of the pipeline pressures

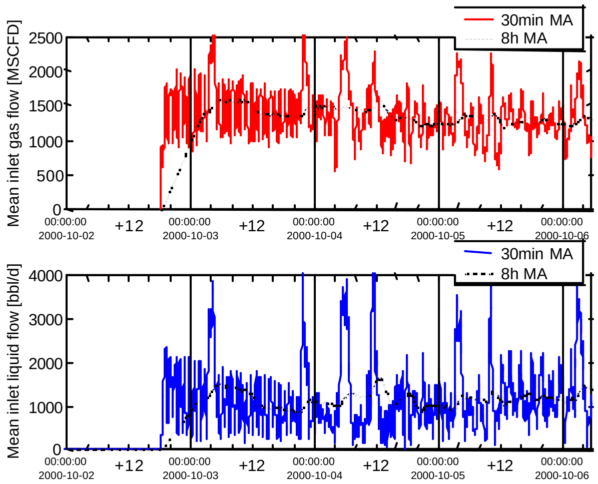

Fig. 23—Low pipeline flow rate, slug controller and well startup. Thirty minutes and eight-hour moving average of the gas (G) and liquid (L) flow rates at the pipeline inlet (Hod)

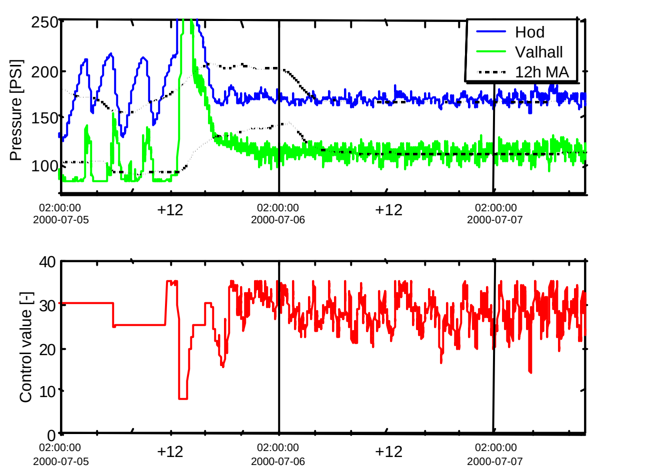

Fig. 24—High pipeline flow rate slug controller startup. Pressure p at the pipeline inlet (Hod, blue) and outlet (Valhall, green) and choke position C. Also shown is the 12-hour moving average (MA) of the pipeline pressures

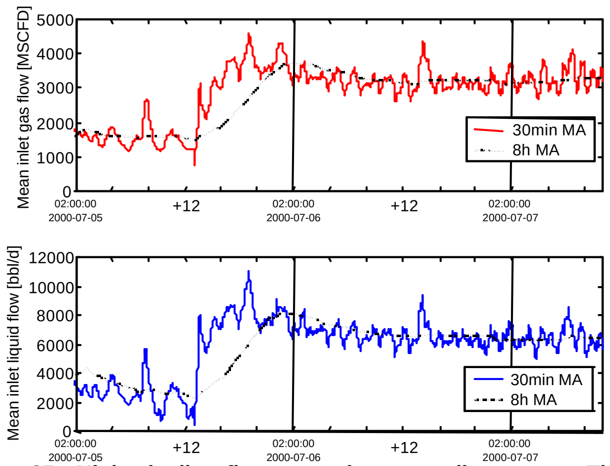

Fig. 25—High pipeline flow rate, slug controller startup. Thirty minutes and eight-hour moving average of the gas (G) and liquid (L) flow rates at the pipeline inlet (Hod)

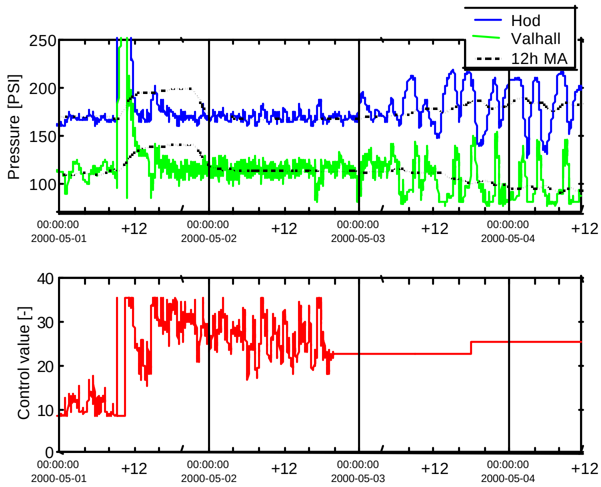

Fig. 26—High pipeline flow rate with slug control, well startup and controller stop. Pressure p at the pipeline inlet (Hod, blue) and outlet (Valhall, green) and choke position C. Also shown is the 12-hour moving average (MA) of the pipeline pressures

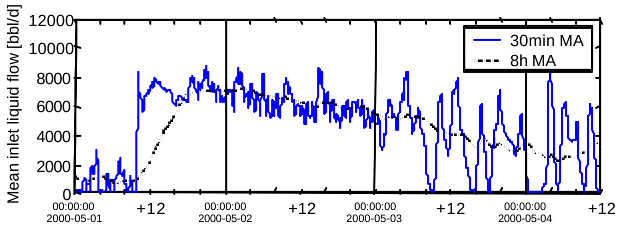

Fig. 27—High pipeline flow rate with slug control, well startup and controller stop. Thirty minutes and eight-hour moving average of the liquid (L) flow rates at the pipeline inlet (Hod)