Taming slug flow in pipelines

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The development of slugs of liquid in multi-phase pipelines is a major, and expensive, headache for oil producers. In the Hod field operated by BP in the North Sea, problems caused by a drop in oil production have led to terrain-induced slug flow in the pipeline between the wellhead platform and the production platform. The irregular flow results in poor oil/water separation, limits the production capacity and causes flaring. A prototype feedback control algorithm developed jointly by ABB and BP to remove terrain-induced slug flow in the pipeline has been operating at the site since January 2000 – with interesting results.

1 Hod wellhead platform in the North Sea

Multiphase pipelines connecting remote wellhead platforms and subsea wells are a common feature of offshore oil production in the North Sea, and the signs are that even more of them will be laid in the coming decades. 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 also be deployed in the future.

Such developments are turning the spotlight on one of the biggest challenges involved in operating offshore processing facilities and subsea separation units: control of the disturbances in the feed to the separation process, ie smoothening or avoidance of flow variation at the outlet of the multi-phase pipelines connecting wells and remote installations to the processing unit.

One common form of flow variation is *slug flow*, in which the liquid flows inter-mittently along the pipes in a concen-trated mass, called a *slug*.

The unstable behavior of slug flow in multiphase pipelines 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 variation in flow causes unwanted flaring and reduces the operating capacity of the separation and 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 from the plant's optimal operating point in this way reduces its throughput.

A lot of money and effort has therefore been spent trying to avoid the problem associated with slug flow, for example by installing slug catchers on-shore or

increasing the size of the first-stage separators to provide the necessary buffer capacity. However, design changes of this kind are inappropriate for installations already experiencing slug flow problems and for compact separation units [1].

An alternative to process design changes is to reduce the effect of the slug by feed-forward control. The idea here is to detect the build-up of slugs and to

prepare the separators to receive them, eg via feed-forward control to the separator level and pressure control loops. A drawback of this approach, however, is that the volume of the separator unit is used as a buffer instead of for actual separation. Besides, feed-forward control is not very robust due to model uncertainty [2].

A third approach involves detecting the build-up of slugs and then using the

What are slugs?

Oil produced offshore is transported through pipelines as a complex mixture of oil, gas water and sand. One common flow regime is known as slug flow, in which the liquid flows intermittently along the pipes in a concentrated mass, called a slug.

Understanding slug flow is made difficult by its transient nature and the multi-dimensional fluid dynamic process that characterizes it. Because slug flow is highly complex and unstable, it is difficult to predict the pressure drop, heat and mass transfer. In addition, the flow nature will vary depending on whether the pipeline is horizontal, vertical or inclined!

Why are slugs a problem?

The arrival of a slug at production or processing equipment is unwelcome to say the least. Severe slugging can even cause platforms to automatically shut down.

Slug flow starts with an accumulation of oil and water in low-lying parts of the pipeline. Gas collects downstream of this growing slug, causing an increase in pressure. When the pressure reaches a certain level, the slug begins to move towards the pipeline outlet, followed by the gas. This process then repeats itself.
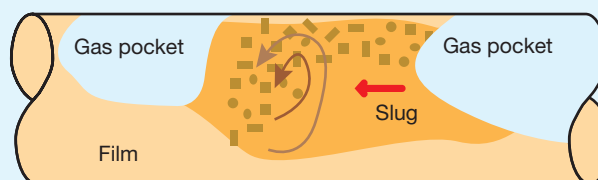
Where does slug theory stand today?

Slug flow research has been going on for many years, and various approximate methods have been developed for calculating slug hydrodynamics. In the past, these have relied on correlation with experimental data, but more recently modeling has been used to simulate the flow behavior sufficiently accurately to calculate pressure drops and other flow parameters with relative confidence.

These models, however, consider steady slug flow, in which the slug moves with constant velocity, so that the characteristic slug intermittency and irregularity are less well described.

Current research tends to target measurement and modeling of the development of liquid slug length distribution along the pipe as well as the dependence of various pipeline and flow parameters on the flow velocities. Knowledge of the time-averaged flow values may be inadequate due to an absence of information about the longitudinal distribution, which is often essential. Slug catchers, for example, which should eliminate slugs, are designed on the basis of the maximum slug length and not the average.

unstable multiphase fluid flow regimes are key to the feasibility of compact separation units for both topside and subsea use.

The Hod-Valhall site

The Hod-Valhall site consists of an unmanned, remote-controlled wellhead platform, Hod **1**, a 13-km-long multi-phase pipeline, and the main production platform, Valhall **2**. 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 **3**. 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 70 meters. The profile of the pipeline, which has a diameter of 12 inches, is shown in **4**. Included in the pipeline

pipeline choke to reduce their effect on the separator unit [3]. The main problem with this approach is that if the algorithm causes the choke to close too much, the slug returns to the bottom of the pipe and an even larger slug is formed.

In the case of the Hod-Valhall site in the North Sea, none of these approaches offered the hoped-for results. Design changes on the Valhall platform were not a realistic option, feed-forward slug control was found to be not robust enough, and choking in the presence of slugs did not work in the Hod-Valhall pipeline.
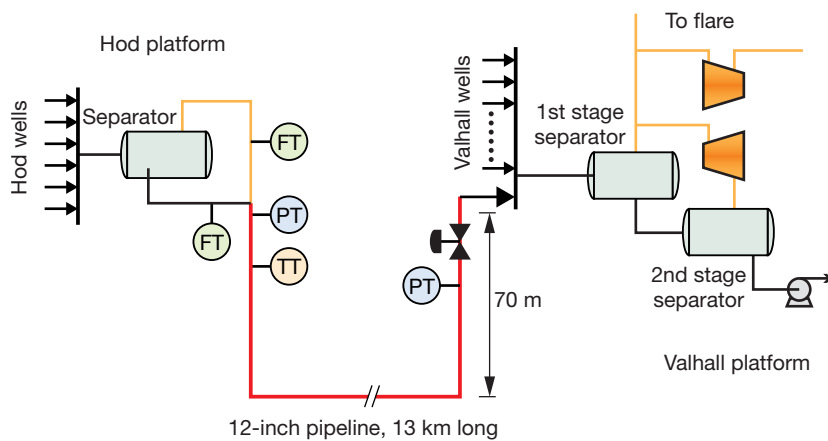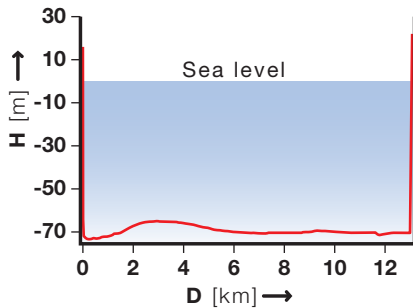
A fourth approach was therefore devised. Its underlying idea is to remove the slug flow regime by applying active feedback control, and thereby prevent the slug from entering the production process at the Valhall platform.

ABB has a considerable interest in the results of the Hod-Valhall pipeline project and in applying them to other types of slug phenomena. For instance, variations

of the method are foreseen for remove riser-induced slug flow and combinations of hydrodynamic induced slug flow and terrain-induced slug flow (the latter occurs frequently in pipelines connecting wells to the production facility). In fact, overcoming the problem of slug flow and creating control solutions that prevent

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

4 Hod-Valhall pipeline profile

H *Height/depth*

D *Distance*

5 Results of open-loop simulation of the Hod Valhall pipeline (two slug cycles)

a *Pressure (p) at pipeline inlet (Hod, blue) and outlet (Valhall, green)*

b *Gas (G, brown) and liquid (L, orange) flow rates at pipeline outlet*

t *Time*

Simulations performed with the dynamic multiphase simulator OLGA, using the OLGA/MATLAB link developed by ABB

instrumentation are pressure and temperature transmitters at Hod and a pressure transmitter upstream of 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 wells at the Hod platform produce 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. 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.

– Spurious flaring (a result of the limited compression capacity.

■ Large pressure variations at the Hod end of the pipeline, which are also visible in the Hod wells. Wells with a reduced lifting capacity produce less.

Terrain-induced slug flow cycle

Terrain-induced slug flow – the cause of the problems at the Hod-Valhall site – develops in five stages:

Liquid build-up: Terrain-induced slug flow is initiated by a period during which liquid, oil and water accumulate in the lower parts of the pipeline or at the bottom of the riser.

Pressure build-up: 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.

Mass acceleration: At a certain pressure, the liquid plug starts moving due to forces acting on it.

Mass transportation: 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/riser.

Pressure reduction: As the gas and liquid are transported out of the pipeline, the upstream pressure decreases and the liquid flow from the pipeline ceases.

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 value in one cycle, called the terrain-induced slug flow cycle.

6 Profile of the liquid volume fraction (LVF) through a slug in the Hod-Valhall pipeline. Each line represents the liquid volume fraction pipeline profile at a certain time (sample interval 60 s, time scope 22 h to 24 h).

D   *Distance*
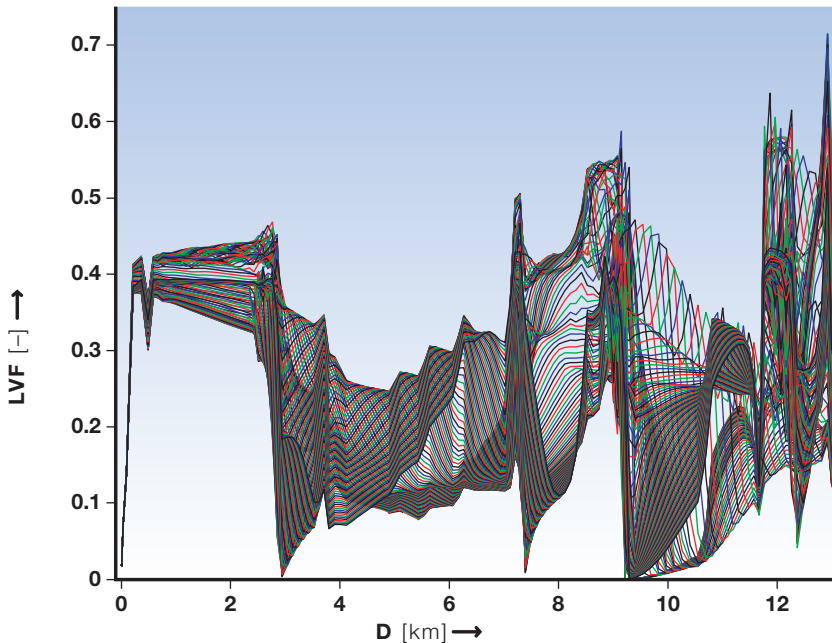
Multiphase fluid flow simulation

The Hod-Valhall pipeline was simulated using the multiphase fluid flow simulator OLGA. Application-specific data entered in the simulator included:

- Fluid characterization of the Hod oil
- Pipeline profile, diameters and material
- Data for the pipeline choke and its position

The model that was used is capable of simulating terrain-induced slug flow with approximately the same dynamics as those experienced by the pipeline. It should be said that some discrepancies were observed between the real pipeline data and the simulations of pressure at the inlet of the pipeline (Hod). Also, no effort was made to tune the multiphase model to the real pipeline.

The pipeline simulations shown in **5** were performed with a constant feed rate of 3 kg/s at the inlet, without control. It is seen that the liquid flow rate at the pipeline output is zero for a period of about 2 hours. During this time the pressure upstream of the liquid plug builds up. When it exceeds the hydrostatic pressure of the liquid column in the riser, the liquid accelerates and the pressure rises at the pipe outlet. The liquid is transported to the outlet of the pipe and the pressure decreases as the gas and liquid escapes through the pipeline. The process then repeats itself.

6 shows the pipeline profile plot of the liquid volume fraction, sampled each minute during one slug cycle. It is not what happens at different *times* which is important here, but what happens at different *positions* in the pipeline during the cycle. Positions where the difference between the maximum and the minimum liquid volume fractions are large have the potential to initiate terrain-induced slug flow.

The slug controller

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. With its new slug controller, SlugCon™, ABB has taken yet another approach in the sense that it stabilizes the flow and thereby *avoids slug formation.*

The slug controller software has the following functionality:

- Slug control:
- Dynamic feedback control: to ensure stable operation of the pipeline.
- Slug choking: to limit the effect the slug has on the separation and compression units.
- Feed-forward control: to adjust the nominal operating point and parameters in the dynamic feedback controller.
- Slug signature: for detecting slugs and monitoring the performance of the dynamic feedback controller.
- Interface to separator train control:
- Separator feed-forward control
- Override slug control (in case of a fault or 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 in **7** shows how pressure measurements at the inlet and outlet of the pipeline are used to adjust the pipeline choke valve. If flow measurements are available, they are also used for feed-forward control of the nominal operating point and tuning parameters of the controller.

The simulated performance of the slug controller is shown in **8**. During the first eight hours the controller is in manual mode, as indicated by the characteristic pressure swings in the pipeline inlet and outlet pressure. The controller starts at $t=28$h and spends the next 5 to 7 hours stabilizing the pipeline. The controller seems to have settled at a constant output value at $t=38$h. However, this is not true. If the control value were magnified, it would be seen that it moves constantly around its mean value. The controller is set to manual at $t=45$h, with its output equal to the mean value over the previous 3 hours. Afterwards, the slug flow builds up slowly.

It appears to be unrealistic to try and prove global stability mathematically. Nevertheless, from **8** it seems reasonable to assume that the pipeline flow is stable at least at the input and at the output, since the pressures are stable. However, due to the length of the pipeline it could be claimed that internal instability might occur in it. **9** shows profile plots of the liquid volume fraction, sampled at 60-second intervals between $t=41$h and $t=45$h. 241 plots are therefore shown. They all lie on top of each other, implying that stability is achieved throughout the pipeline.
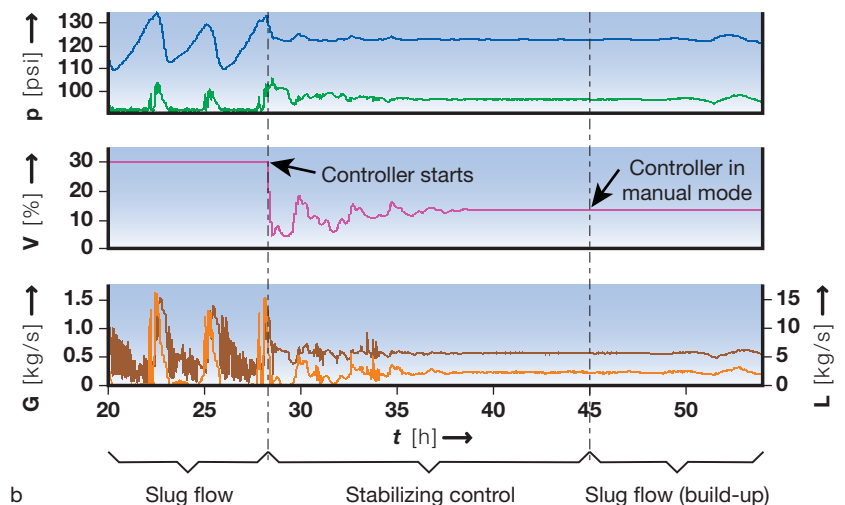
7 Slug controller feedback structure for flow stabilization

For explanation of symbols, see Fig. 3.
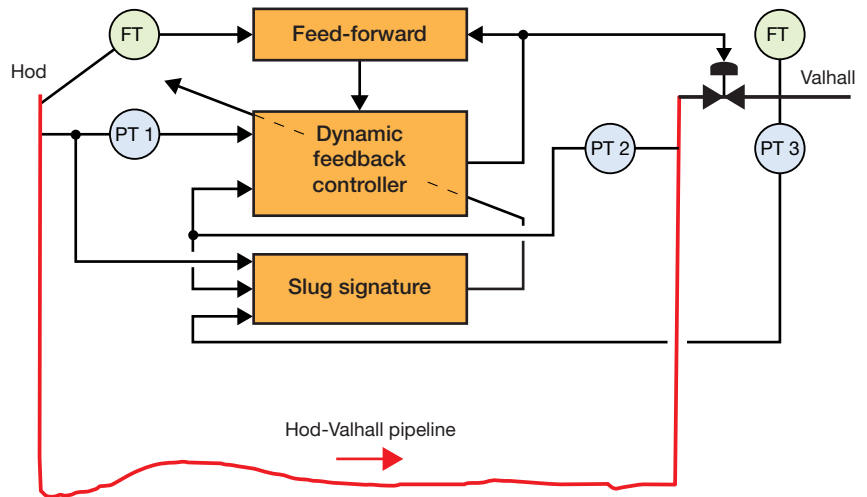
8 Active control of terrain-induced slug flow. The controller starts up at $t=28$h and runs until $t=45$h, after which the valve position is kept constant and slug flow slowly builds up.

p *Pressure at pipeline inlet (Hod, blue) and outlet (Valhall, green)*
G *Gas flow rate (brown)*
L *Liquid flow rate (orange)*
V *Valve opening*
t *Time*

Field tests

The prototype of the slug controller was tested twice in 1999 and has been operating at the Hod-Valhall site since the end of January 2000. **10** to **13** show some of the slug controller test results:

■ **10** and **11** show controller start-up and operation with a low pipeline flow rate (two wells are started up).

■ **12** and **13** show controller operation for start-up of a major well and controller stop with a high pipeline flow rate.

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.
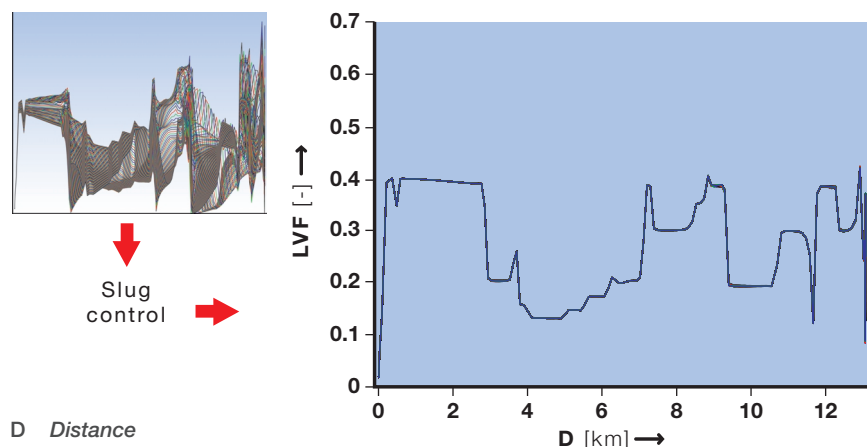
10 and **11** show the slug controller in operation. During the first eight hours the choke (see **10**) is opened manually to 20%. Under such conditions the terrain induced slug flow cycle can be seen well.

At 11:18 AM, the startup condition is fulfilled and the controller starts updating the choke. The choke is only allowed to be open in the range of 5% to 35%. The controller stabilizes the pipeline for the next 36 hours. From **10** it can be seen that the mean pipeline inlet pressure decreases considerably when no slug cycles appear.

During the four days and 6 hours shown in the figures, two of the Hod wells that had been on hold were taken into operation, the first on October 4 (at 4 AM) and the second on October 5 (12 AM), as shown by the pressure spikes in the plots. A well start-up represents a large disturbance to the slug controller, and can introduce instability into the pipeline. As **10** shows, a terrain-induced slug flow cycle appears just after the first well start-up. **11** shows the pipeline input flow rate. During the first 19 hours the Hod wells bypassed the test separator (which is why the pipeline inlet flow rates during that time are missing). Although the changes in the pipeline input flow

9 Pipeline profile of the liquid volume fraction (LVF) with slug control (compare Fig. 6, without 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.

D   *Distance*

10 Slug controller in operation with a low pipeline flow rate and well start-ups. Pressure p at the pipeline inlet (Hod, blue) and outlet (Valhall, green), plus choke position C. Also shown is the 12-hour moving average of the pipeline pressures.
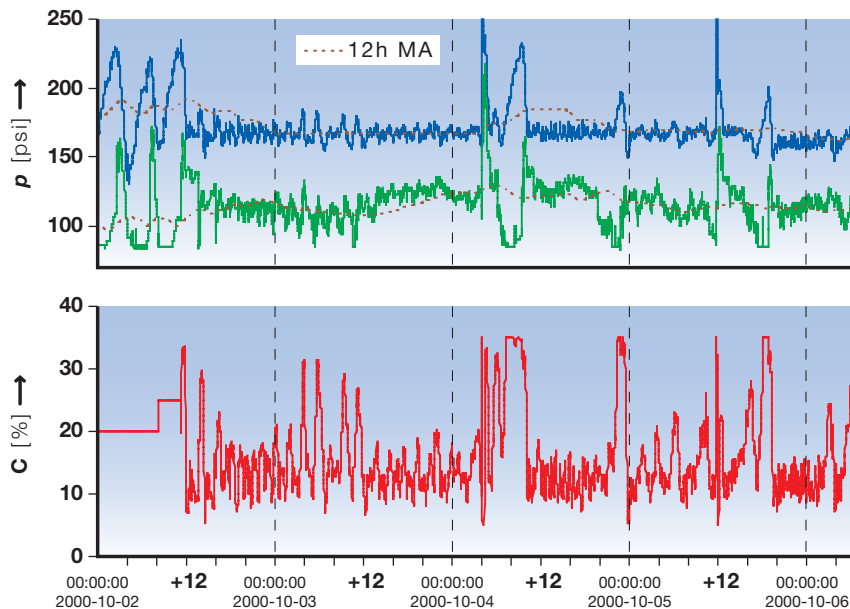
11 Slug controller in operation with a low pipeline flow rate and well start-ups. 30-minute and 8-hour moving average (MA) of the gas (G) and liquid (L) mean flow rates at the pipeline inlet (Hod).
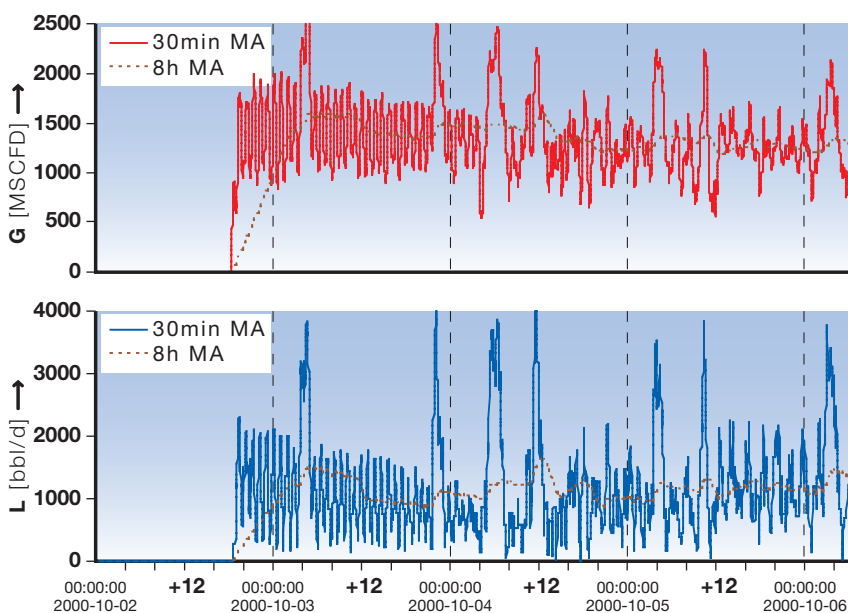
rates, plus the well start-up, constitute major disturbances, the slug controller copes quite well, proving that the chosen control scheme for the slug controller is robust under such conditions.

12 and **13** show the slug controller operating under a new set of conditions. When well H8 was taken into operation on May 1 at 10 AM, the controller was already in auto mode. The high pressure caused the controller to saturate at 35%; when the pressure drops the pipeline become stable. The controller was stopped at 8 PM on May 2, and terrain-induced slug flow with growing amplitude in the pressure swings is seen to form in the hours afterwards. It should also be noted how the pipeline inlet liquid flow rate drops when terrain-induced slug flow appears.

The varying flow rates and the cyclic operation of the Hod platform wells make it very difficult to determine conclusively the extent to which the slug controller affects the Hod wells – ie, whether the wells produce less, more, or about the same as before the slug controller was installed. Recent experience indicates that the wells can be kept operating longer, which increases production. This is particularly true in the case of well H8.

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

■ Smaller disturbances in the separator train, resulting in smoother operation:
–　Improved separation
–　Higher throughput
■ Smoother operation of the compressors:
–　More stable compressor operation and reduced flaring. Given the 'stable' inlet

and outlet pipeline pressure, 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.

The slug tamed

Besides demonstrating how active feedback control can be used to avoid terrain-induced slug flow without reducing oil production, the tests with the prototype algorithm have served to underscore the huge potential that exists for applying active feedback control to multiphase fluid flow processes.

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12 Effect of slug control with a high pipeline flow rate and well start-ups. Pressure p at the pipeline inlet (Hod, blue) and outlet (Valhall, green), plus choke position C. Also shown is the 12-hour moving average of the pipeline pressures.
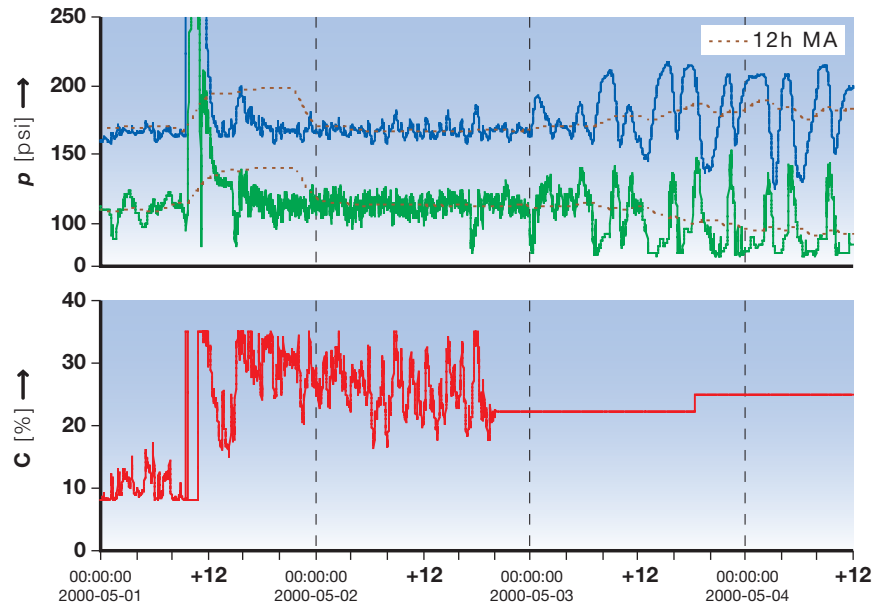
13 Effect of slug control with a high pipeline flow rate and well start-ups. 30-minute and 8-hour moving average (MA) of the liquid (L) mean flow rate at the pipeline inlet (Hod).
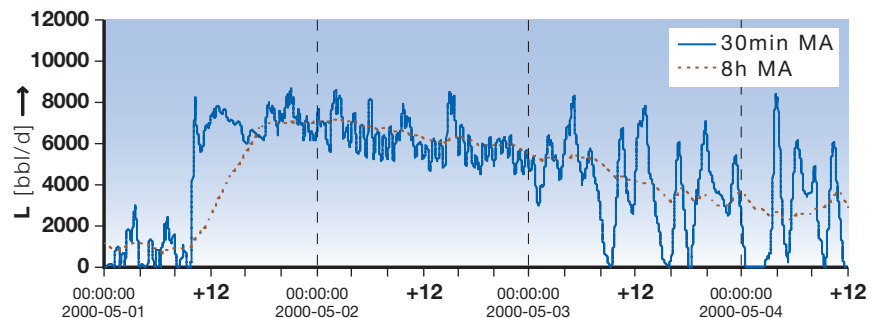
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