CONTROL SOLUTIONS FOR SUBSEA PROCESSING AND MULTIPHASE TRANSPORT

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Abstract: To increase the oil production for the Tordis subsea oilfield located at the Norwegian Continental Shelf, a subsea separation and boosting station will be installed. Most of the water will be injected into a subsea reservoir instead of being transported up to the platform. Several challenges conserning process control need to be addressed before the implementation process, and dynamic simulations have therefore been performed in order to develop and test different control strategies to deal with these challenges. The results from some of these simulations will be presented in this paper.

Keywords: Process control, control system design, PI controllers, cascade control, pipelines

1. INTRODUCTION

The Tordis field operated by Statoil has proved to be even more productive than anticipated when production began in 1994 (Godhavn *et al.*, 2005). To increase production and total recovery for the field in the last years of production, processing equipment is planned installed at the sea bed. This in order to separate produced water from the production stream, inject this water into a reservoir, and increase the production rate.

Subsea processing enables production from low-pressure reservoirs over long distances, and may increase the daily oil and gas production or even the total recovery from the reservoir. By injecting produced water into a reservoir, the water emission from topside to sea can be reduced, and the subsea transportation pipelines are better exploited. Compression and pumping enable a lower wellhead pressure, and hence an increased production.

However, the installation of new subsea equipment leads to several new challenges, also related to process control. There can be several ways to solve these problems, so the first question that needed answering was; which solutions are feasible and which one will solve the problems the best.

Having control of the subsea separator pressure and liquid levels are important as it determines the flow rates and compositions for the entire system. In Section 3, some solutions to achieve control of the separator will be presented. These control solutions are then expanded to achieve other benefits, such as faster well tests and control of the water rate that is transported with the oil and gas to the platform.

Under certain conditions a flow regime called riser slugging can develop in the pipelines, which is undesirable because it can introduce large pressure oscillations in the system. In the end of Section 3 it will be shown that this problem can be solved using feedback control.

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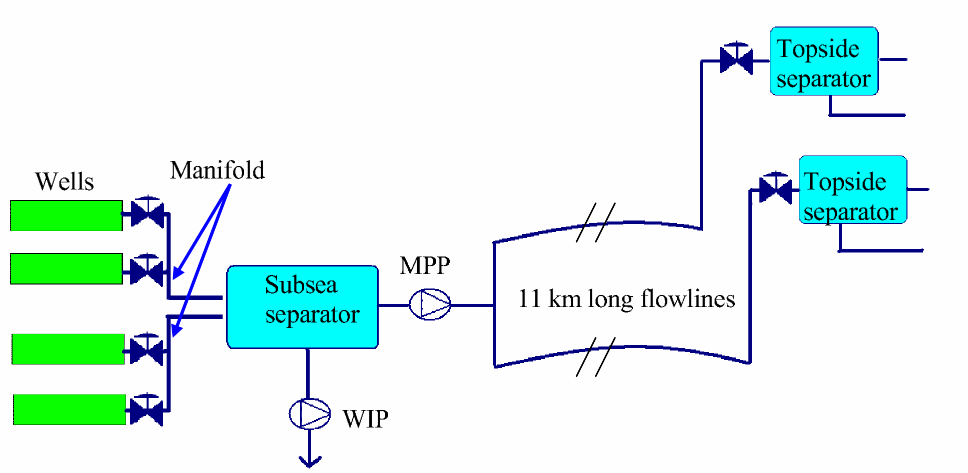

Fig. 1. Subsea processing equipment

The control solutions presented in this paper are illustrated with dynamic simulations including all equipment from the wells to the two topside receiving separators at the Gullfaks C platform (Figure 1). It is important to notice that these simulations were performed at a very early stage in the process of determining how to run the process, where the aim was to find feasible control solutions and not to find optimal control parameters. The controllers have therefore not been fine-tuned and simplified models for the equipment and pipelines have been used. This is also the reason why the absolute values for the different variables have been left out in this paper.

To simulate flow in the pipelines, OLGA 2000 dynamic multiphase simulator (`www.olga2000.com`), provided by Scandpower Petroleum Technologies (`www.scandpowerpt.com`) has been used. Most of the process equipment is simulated using Simulink. The OLGA - MATLAB toolbox enables the Simulink application to simulate multiphase flow in pipelines in OLGA together with additional process equipment and controllers modeled in Simulink.

2. SUBSEA PROCESSING EQUIPMENT

Oil, gas and water are transported from the manifold to the subsea separator through two pipelines. From the separator some of the water is to be injected into a disposal reservoir. The remaining water will be transported along with the oil and gas through two pipelines into each topside separator at the Gullfaks C platform. A multiphase boosting pump will be installed downstream the separator.

2.1 Wells

There will be a total of eight wells producing oil, water and gas to the Gullfaks C platform. The flows from the wells are merged at the manifold. Two short pipelines, each receiving the production from four wells, transport the fluid to the subsea separator.

2.2 Pipelines

To simulate the pipelines between the wells, the subsea separator and the topside separators, OLGA 2000 have been used. OLGA 2000 is a commercial available dynamic multiphase flow simulator. In our study OLGA has been run from Simulink. From OLGA, it is possible to get all the information about the flow and the equipment that is modeled in OLGA, into Simulink.

2.3 Subsea Separator

The subsea separator is illustrated in Figure 2. In the separator the water, oil and gas will separate due to gravity. The water, which is heaviest, will sink to the bottom. Most of the water is to be injected into a disposal reservoir through an outlet in the bottom of the separator. It is important that no oil enters this reservoir. The rest of the water is transported to the platform along with the gas and oil.

The thickness of the water layer and the oil layer is determined by the inlet and outlet flow rates. The multiphase pump and the water pump speed will therefore influence the thickness of these layers. The rest of the separator is filled with gas.

The separator is simulated using a simple Simulink model. It computes the separator pressure, density and composition for the flow to topside and the water and oil levels in the separator. It is assumed that the pressure is independent of gravity, that is: the pressure at the bottom is the same as in the gas layer at the top of the separator. The composition of the flow going to the platform is determined by the thickness of the water and oil layer. If the level of the water is below the outlet leading topside, no water will

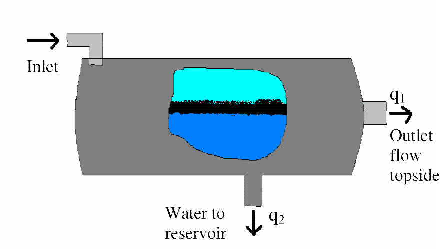

Fig. 2. Subsea separator

be transported topside. The same goes for the oil level, which depends both on the oil and water layer thickness. As already mentioned, the flow rate will be determined by the multiphase pump speed and the pressure in the separator and the pipelines.

2.4 Pumps

Multiphase pump To be able to operate the subsea separator at a low pressure despite the friction loss caused by the 11 km long pipelines to the Gullfaks C platform, pumps or compressors can be installed.

The plan is to install a multiphase boosting pump downstream the subsea separator. In this way it is possible to control the separator pressure by adjusting the pump speed and thereby the flow rate to topside, q_1.

Water pump There is also a need for a water pump to pump the water into the disposal reservoir, holding a higher pressure than the subsea separator.

The water rate through the water pump, q_2, depends on the pressure difference between the reservoir and the subsea separator, and also the pump speed. Pump speed and pressure drop over the *multiphase* pump will in the same way determine the topside production rate, but composition and density of the flow will also influence these flow rates.

2.5 Chokes

There are chokes for each of the eight wells, which make it possible to adjust the flow from each well independently. These chokes can be used for well tests, where one well after another is shut down.

At the top of each riser there are topside production chokes. They make it possible to control the flow into each of the topside separators, and can be adjusted manually or by a controller.

2.6 Measurements

Several measurements will be available, monitoring pressure, density, flow rates and other values which are necessary for controlling the different parts of the system. Measurements used directly for control are the manifold pressure, the subsea separator pressure and water level, pressure drop and density over topside production chokes, water rate out of topside separators and the pressure downstream the multiphase subsea pump. The pressure drop and density across the topside chokes are used to calculate the flow rate through the topside chokes as there are no flow measurements available.

3. CONTROL STRATEGIES

Several dynamic simulations were performed to test different control strategies for controlling the system, and some of these will be presented here. The results will be used in the design of the control system and this way serve as a basis for further studies. The solutions presented here might therefore not be the ones implemented in the end.

3.1 Control of subsea separator pressure and levels

3.1.1. Decentralized PI control of subsea separator pressure and water level To keep the oil contents in the injected water below a given limit, it is important to control the separator water level. By increasing the flow rate of the water injected into the reservoir, the water level will decrease. The flow rate through the water injection pump depends on the pressure difference across the pump and the pump speed. The speed of the pump can be set by a controller.

It is also important to control the separator pressure as this pressure will affect the wells and their production. The separator pressure can be controlled by changing the total flow rate to topside, which again is influenced by the speed of the multiphase pump. During the simulations this flow rate was set by the controller directly. The reason for this is that there was no model of the multiphase pump available at the time of the simulations.

Even though there are quite strong interactions between the level and pressure control, as will be shown, simple PI controllers were used to see how well the separator could be controlled. This is illustrated in Figure 3.

Figure 4 shows the results for a simulation where the input rates of water, gas and oil are reduced by 50% after 30 min. The pressure drops as the flow rates are reduced, but after about 15 min the pressure is back to normal due to the controller action.

What might seem surprising is that the water and liquid level start to increase at the time the inlet rates are reduced, before they decrease and end up at lower levels than they initially had. The reason for this is that the separator pressure and water level affect each other. When the separator pressure decreases due to

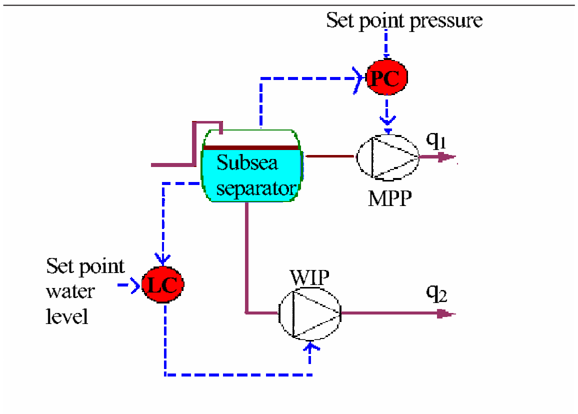

Fig. 3. PI control of subsea separator pressure and water level

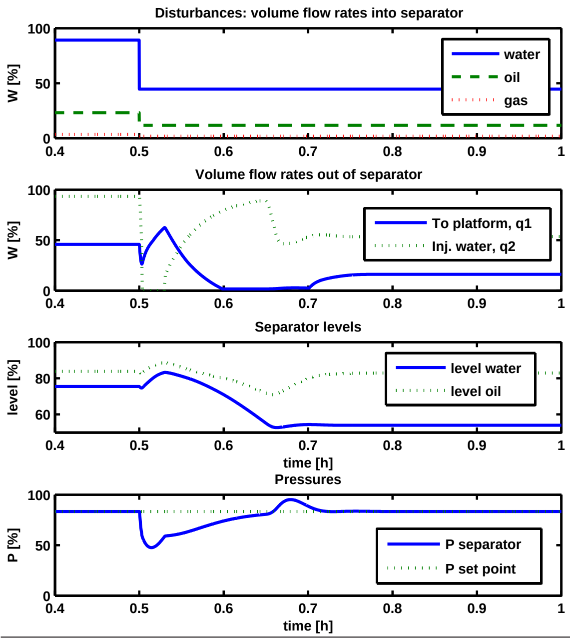

Fig. 4. Results using PI controllers to control subsea separator pressure and water level

the reduced inlet flow rates, it makes it harder for the water pump to inject water into the reservoir. Because of this, the water rate injected to the reservoir, q_2, temporarily goes down to zero, explaining the increase in levels.

In practice, a zero flow rate will cause problems for the water pump, but better tuning of the controller or other control configurations will remove this problem. Another way of avoiding this problem could be to use some other control configuration, e.g. a cascade controller where the inner loop controls the flow rate through the water pump and the outer loop controls the water level in the separator.

3.1.2. Cascade control : Control of water rate to topside At the Gullfaks C platform, the water that is transported to topside along with the gas and oil needs to be taken care of. There are limits to the amount of water the downstream process equipment can handle, and having control of this water rate can be an advantage.

By changing the water level in the subsea separator it is possible to control the water rate that is transported to the Gullfaks C platform. Figure 5 shows one way of doing this. It is an extension of the control structure presented in 3.1.1. An increased water level will lead to increased water rate topside (see Figure 2). A cascade configuration using the water rate out of the topside separator, q_3, in a slow outer loop and the water level in the inner loop, was developed to handle this.

Figure 6 shows the results from a simulation where the inlet flow rates are reduced by 50% after 1h. The set-point for the water level controller is increased when too little water is transported topside due to reduced inlet rates.

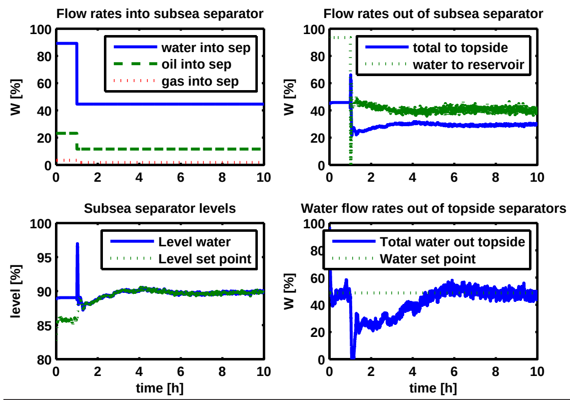

Fig. 6. Results using a cascade controller to control subsea separator water level and water rate topside

We see that after about 5 hours the water flow rate is back at its set-point, even though the flow rates into the subsea separator have been reduced substantially.

3.2 Well head pressure control

During a well test, one well after the other is shut down in order to determine the production rate from each individual well (deduction principle for tie-ins). Performing well tests is costly, as the production is reduced for the time the well test lasts. Being able to reduce the duration of a test, has therefore a large economic potential. Using active control might reduce the time needed to perform a well test.

However, when a well is shut down, the pressure drop in the pipeline will decrease due to the reduced flow rate in the pipe. This way the other wells will produce more, leading to a wrong estimate of the production from the well that is closed. Therefore, during well testing, the pressure at the *manifold* is kept constant rather than the subsea separator pressure which is normally controlled (Figure 3). There actually is a need for the subsea separator pressure to increase

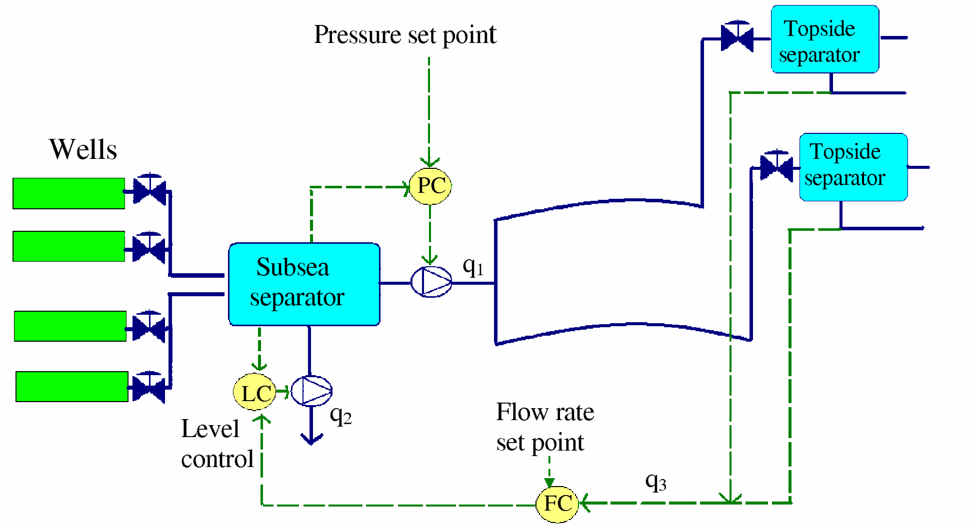

Fig. 5. Cascade controller for subsea separator water level and water rate topside

during a well test. The alternative would be to reduce the well choke openings accordingly.

There are several ways to do this. Using a cascade control configuration is one possibility. The outer loop controls the manifold pressure where the set-point is the initial pressure before the well test. The inner loop controls the subsea separator pressure. This way the set-point for the subsea separator pressure will automatically increase for every well that is shut down. The cascade control configuration is illustrated in Figure 7.

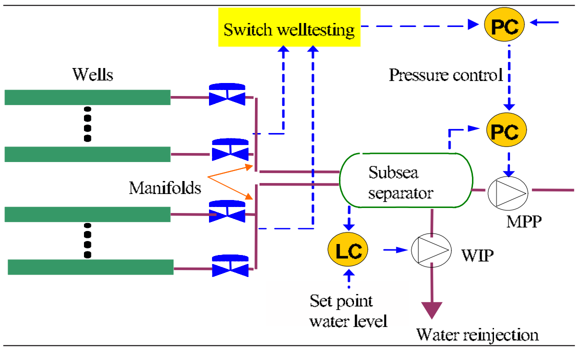

Fig. 7. Welltest using cascade configuration

Using the cascade controller for the well test, it was possible to bring the manifold pressure back to its original value. Figure 8 shows the results when three of the wells are shut down one after another. The plot at the bottom shows how the subsea separator pressure increases to counteract the effect of the reduced pressure loss in the pipelines upstream the separator.

Another way of controlling the manifold pressure is to estimate how much the manifold pressure will drop when a well is shut down, and then increase the set-point for the subsea separator pressure accordingly. This way the simple pressure PI controller described in Section 3.1.1 can be used, as long as steps in the set-point are introduced. It is important to find good estimates of how much the separator pressure need

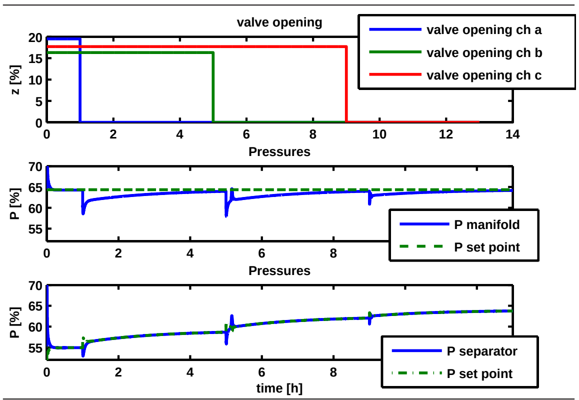

Fig. 8. Welltest results

to increase in order to use this method. Results from simulations show that it is possible to reduce the time before the manifold pressure reaches its initial value to less than 15 min. This is illustrated in Figure 9.

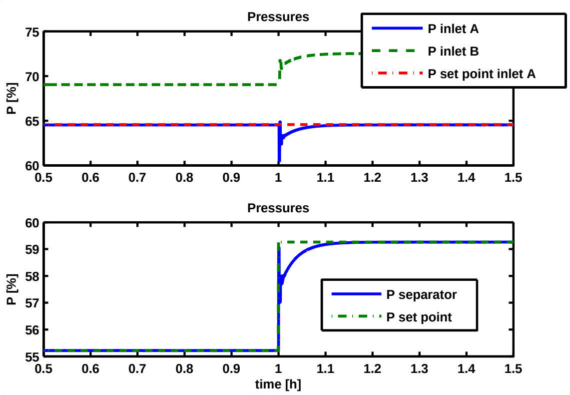

Fig. 9. Welltest results using a PI controller with setpoint changes

It is important to find a good estimate of how much the pressure drops at the manifold when a well is shut-in, in order to use this solution.

The results from the simulations show how long it takes for the manifold pressure to retain its initial value after a well is shut down. This information can be used to predict the duration of a well test.

3.3 *Slugging*

Riser slugging is a well known problem offshore, where alternating bulks of liquid and gas enter the receiving facilities and cause problems due to pressure and separator level oscillations. The results are poor separation and wear on the equipment.

There are several ways to deal with the problem, but using active control has in the last years been the preferred way to avoid riser slugging, (Courbot, 1996), (Havre *et al.*, 2000), (Hedne and Linga, 1990), (Skofteland and Godhavn, 2003). Today a combination of active slug control and model predictive control (MPC) is used at Gullfaks C (Godhavn *et al.*, 2005).

A simple PI controller using the pressure upstream the flow-line ending in the riser and a control valve at the top of the riser has proved to be effective. This pressure oscillates heavily during slugging, due to the changing composition in the riser. Keeping this pressure stable forces the flow into another flow regime. In (Storkaas, 2005) control theory proves that using this measurement one is able to stabilize the flow and also to achieve good performance. This control configuration is illustrated in Figure 10.

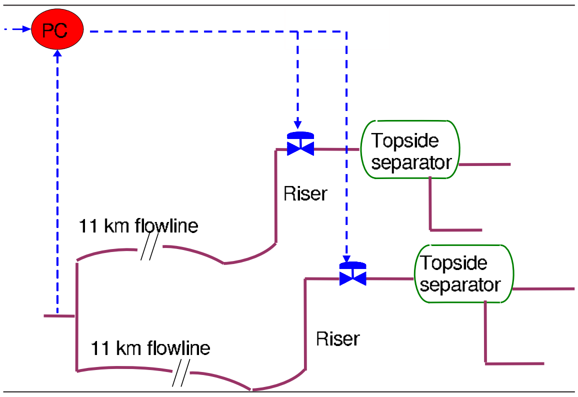

Fig. 10. Slug control applied to Tordis

Results from a simulation with the slug controller are shown in Figure 11. During the first 4 hours the controller is inactive, resulting in slugging in the pipeline and the pressure variations shown in the upper plot. When the controller starts working, the pressure stabilizes at the desired set-point.

4. CONCLUSIONS

The implementation of new subsea processing equipment to improve the productivity for a subsea oilfield is expected to introduce several new challenges regarding operation and process control that need to be addressed before the start-up. This paper presents some results from dynamic simulations performed in

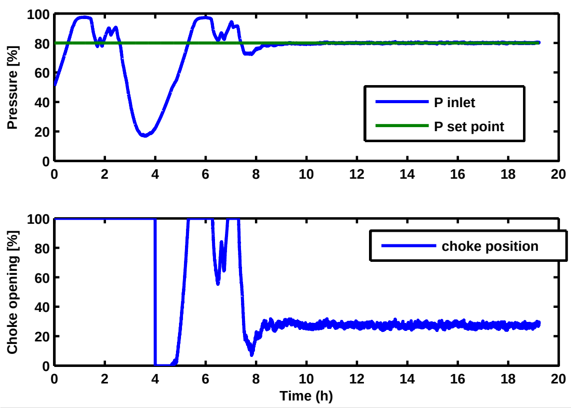

Fig. 11. Slug control results

order to investigate how the use of automatic control might deal with these challenges. For the different scenarios presented here, automatic control shows good results.

The simulations have been performed at a very early stage, before the final decisions about equipment and operation have been made. Because of this, simplified models of the pipelines and equipment were used. Also, the controllers have not been fine-tuned to get the best results at this stage. The results from this study will therefore differ from the final results. The simulations can, however, be used as a basis for later studies.

Examples of what better suited controllers can accomplish are; decreasing the time of well tests (Figure 8) and removing the effect that leads to the topside choke saturating in the first 4 hours of slug control (Figure 11).

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