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Field Applications of Model-Based Multiphase Flow Computing

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FIELD APPLICATIONS OF MODEL-BASED MULTIPHASE FLOW COMPUTING

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1 ABSTRACT

A virtual flow meter is an alternative or supplement to the traditional multiphase flow meters. The technology makes use of all existing instrumentation, combined with models of the production system, to estimate the flow in wells and flow lines.

The advantage of using virtual flow meters is that the model provides additional information of the flowing conditions in the entire production system, as opposed to at the meter positions only. Thus it is well suited as basis for a Flow Management System (FMS).

A FMS typically provides a set of tools to extract important information from available data, give access to additional information using process models, and include automatic controllers which adjust the control variables in an optimal way. Vast improvement can be achieved in processes where quality measurements are a commodity in short supply and the natural control loops are interacting. The need for a FMS is even more conspicuous when there is a need for measurement redundancy, and constraint handling and profit maximization are important parts of the control purpose. The basis of such a production support system is a mathematical model of the underlying processes. In short, the combination of multiphase flow models and available measurements has numerous field applications with a considerable economic potential compared to using the measurements alone, also when multiphase flow meters are available.

This paper demonstrates some of the capabilities of FlowManager™ applied to subsea wells and pipeline networks. The concepts will be illustrated by field applications. Future possibilities using the technology will also be addressed.

2 INTRODUCTION

Metering of pressure and temperature through the entire production system has been common practise for years. The measurements are used to estimate the contribution of the different wells, and to supervise the condition of the production system.

Every production system design today is based, to a certain extent, on numerical flow correlations. The correlations are already adequately proven to base the field design on.

The idea behind virtual metering is to combine the numerical correlations that were used to design the field, with the metering that is already in place. Combined these two pieces of information can give a full field online production diagnostic. In this sense virtual metering is nothing new; it is only a way of refining the information that is already available.

The virtual meter is inherently a link between the available measurements, and a numerical model. Prediction of any event that has an accurate model is possible within this framework. Such a system easily lends itself to production optimization on a well by well basis, or de-bottlenecking of the full production system.

3 PRINCIPLES

Virtual metering can be performed online or offline. The only prerequisite is that all sensor information is gathered within the same time frame to facilitate the steady state correlations used. The basic idea is to combine the sensory input with the numerical flow models.

The virtual meter calculates a flow field through the entire production system. The flow field will inherently contain the calculated sensor responses at all sensor locations. The discrepancies between measured and calculated properties are quantified within an object function, and the object function is minimized through an iterative search. The procedure is described in its simplest form in Figure 3.1. The figure shows how the analytically solvable problem of one phase flow through a venturi can be solved iteratively by imposing an object function.

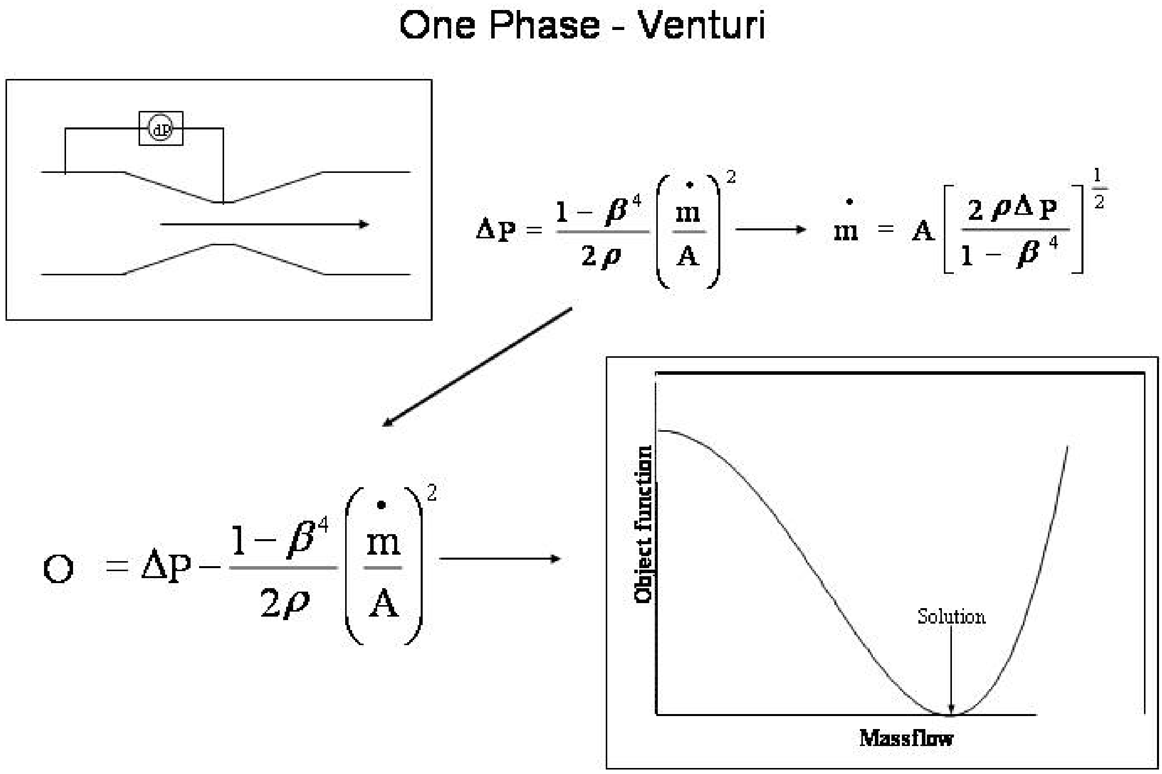

Figure 3.1 The concept of the Object function.

The one dimensional problem lends it self easier to illustration than the three dimensional problem consisting of three flow rates, oil, gas and water, flowing through an oil well with multiple sensors. The principle however, is the same.

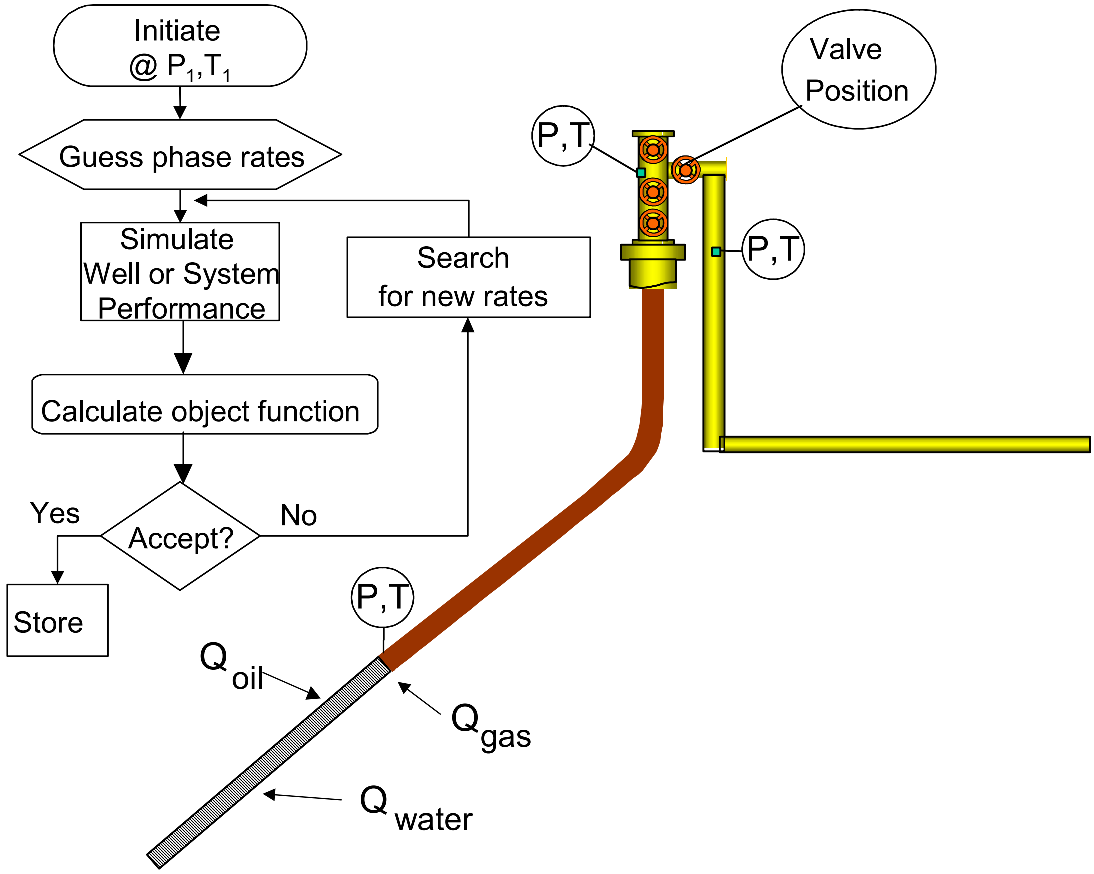

Figure 3.2 Oil well with standard instrumentation

Figure 3.2 shows the operating principles of a virtual meter. All required information is fed into the model either on an on- or offline basis. The model makes an initial guess of the rates and calculates the equivalent sensor responses. The discrepancy between the measured and the calculated system responses are quantified through the object function and evaluated. The procedure is repeated iteratively until the value of the object function reaches one of a set of cut off criteria.

In order to obtain a well-posed mathematical problem, there needs to be at least one measurement pr unknown, the unknowns being the three flow rates. The previous figures demonstrate the procedure with one and three unknowns. The system can be expanded to a full converging network of wells and lines. Recent implementations of the software have included the production separator measurements and/or the fiscal export measurements. By increasing the number of available measurements the calculations will become over determined, and the virtual meter will become increasingly redundant towards errors and failures in the individual sensors. To enable the software to use the separator measurements, or the results from a multiphase meter, it is necessary to have a solution that allows for a controlled difference between the measured and the calculated quantity. The FlowManager™ software contains a weighted object function. Assigning different weights to the different measurements allows the user to accentuate or discard certain measurements. In an over determined system this feature gives an operator the possibility to use the system for sensor evaluation.

Any fluid property that can be both measured and modelled is available to be included in the virtual meter. In this sense the meter can be used as both an addition to, and/or a substitute for traditional multiphase meters. The virtual meter can incorporate the individual sensor readings that a multiphase flow meter consists of, or it may use the calculated rates directly.

The readings from the multiphase meters are incorporated with all other measurements within the production system, to give a best fit solution for the whole production system. In many fields were multiphase meters are employed the uncertainty caused by discrepancies between the sum of all meters, and the fiscal measurements, causes uncertainty in all measurements. The virtual meter is not limited to giving a spot reading at the sampling position. Hence, it may be used as a supervision tool to establish the most likely source of error.

4 EXPERIENCE

4.1 Closed loop control

One of greatest success stories so far in using virtual meters is to link the output from the rate calculations directly with a closed loop choke controller. This functionality is currently applied on the TrollB and TrollC fields in the North Sea. The reservoirs are characterized by their high mobility and large gas cap. Consequently, the reservoir has very rapid transients following the onset of a gas breakthrough. The optimum production point is a constant level of gas breakthrough to provide the wells with additional lift. On the other hand, if a choke is opened to much, the well oil production will "die" temporarily due to the high mobility of the gas phase. Figure 4.1 shows a simplified schematic of the anticipated behaviour of a Troll well.

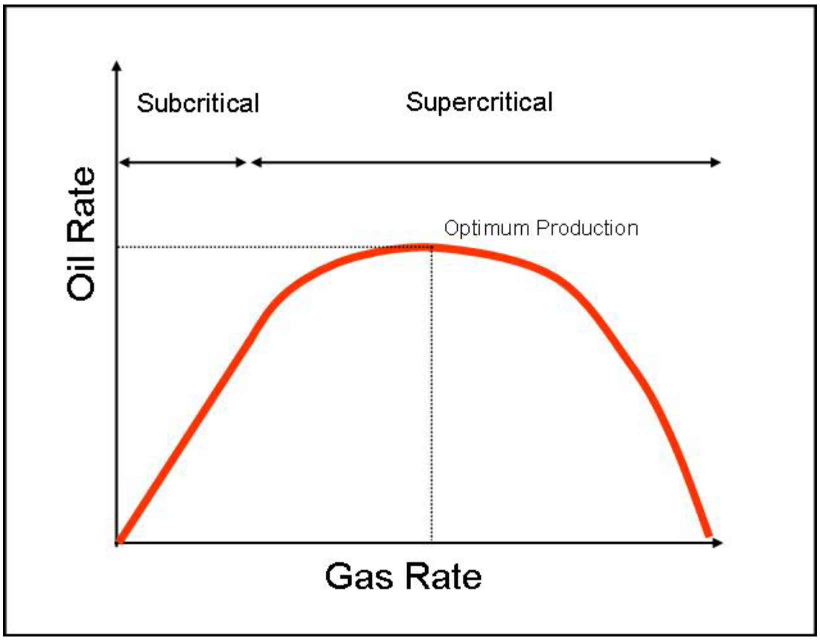

Figure 4.1 Simplified production curve for Troll Oil well

Because of the high mobility and rapid transients, in addition to the fact that there are more than 110 wells for the two fields combined, it would be virtually impossible for the operators to control this situation if operating all wells by hand.

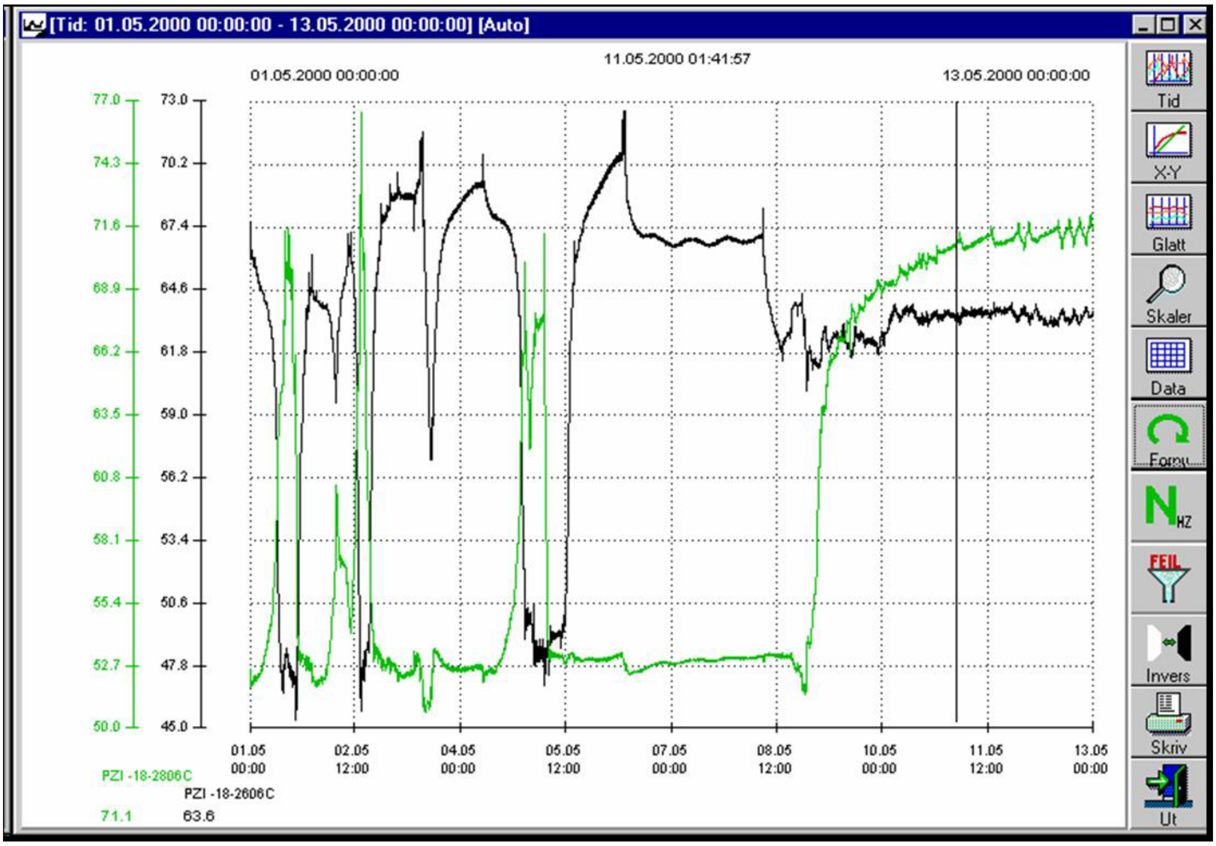

Figure 4.2 Wellhead pressures of two wells, before and after applying Production Control.

Figure 4.2 shows the wellhead pressure of two wells before and after the closed loop control was applied. In addition to stabilizing the two wells, the sum of the oil production from the two wells was increased by 300 Sm3/day (1890 bbl/day). The increase in wellhead pressure correlates with a higher oil production due to the increased gas production (Figure 4.1).

4.1.1 Deduction Testing

The previous paragraph shows a scenario where the financial benefits of closed loop control are quite obvious. For other fields with less permeable reservoirs, the benefits might not be as pronounced. However, there are several scenarios were test separator availability is low. Due to the increased cost focus in developing new fields, fields are being equipped with single manifold risers, and maybe even without a test separator. This kind of production system is cost effective to develop, but will most likely suffer in both recovery speed and overall recovery if the contribution of the individual wells can not be established. Other commonly encountered scenarios are in the latter stages of a field life when gas and water production exceed the test separator capacity, prohibiting testing at full production, or the test separator may be tied up to producing low pressure wells. Any of these scenarios will leave the operator dependant on deduction testing to establish the contribution of the individual wells.

A virtual meter may be used to calculate the contribution of each well, but a software based solution will be dependant on the available calibration data to provide correct flow rates. Without the calibration data the results from the virtual meter will be as uncertain as the model and measurement uncertainties combined.

Deduction of the measured rate on the production separator is a valuable tool to increase the accuracy of the well allocation, but this tool will only give information if the remaining wells are kept at constant production. The effect of closing or reducing the flow from one well to enable deduction testing might significantly alter the flow rates of other wells. To facilitate deduction testing one is dependant on having a tool that will ensure consistent flow rates from all wells in spite of the varying backpressures. By applying a tool such as closed loop rate control, one can ensure that all other wells than the one being tested are held at a constant rate. The closed loop control can be set to maintain the upstream choke pressure at a constant level for all wells except the one being tested. Even without significant calibration of the remaining wells, the choke controller is able to maintain the pressure based on standard regulation principles. By running the wells continuously in the control loop, all controlled choke changes will inherently function as a differential test.

4.2 Chameleon Case

Due to time limits there was not enough time to clear the release of the data with the operator of the field. However, we were allowed to use the data as long as all presented data would be rescaled and made anonymous. For presentation purposes we will address the field as the Chameleon field.

Initially a three well subsea development with pressure and temperature readings bottom hole – and upstream and downstream the production choke of each well (Figure 4.3). The bottom hole gauges on well B-2 failed prior to first oil from the well. In addition something got caught in the production choke of the well, which rendered the choke calculations useless. This rendered the virtual meter with no useful information for the well, and in turn unable to calculate rates, even with fixed ratios.

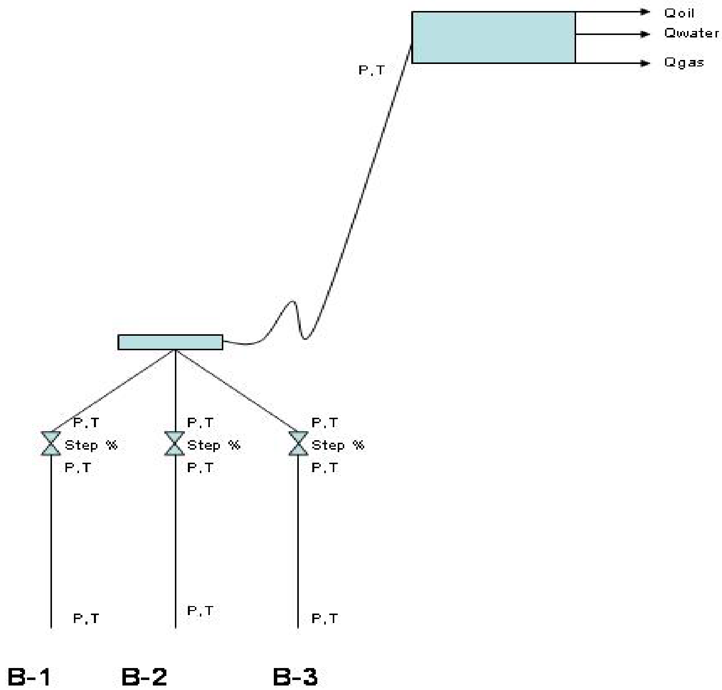

Figure 4.3 Schematic of the Chameleon Field

Wells B-1 and B-2 are completed in the same reservoir zone, at approximately the same depth. As an immediate solution, the bottom hole pressure reading from B-1 was used on B-2 to calculate rates. This scheme would only work provided that the wells had fairly similar or very high Productivity Indexes, or were produced at approximately the same rates. To allow for a greater variation in the production from B-1, a network solution was applied. The obvious danger in using a network solver in a case like this is that one is no longer able to determine whether there are errors in the calculations of the two remaining fully instrumented wells, because all production not accounted for will automatically be attributed to the well without any functioning measurement elements. Hence, an error in the calculations of B-1 or B-3 would most likely be overseen. To circumvent this problem we opted for an intermediate solution; Running single well calculations on all three wells, calculating the contribution of well B-2 by using the bottom hole sensor of B-1, and continuously verifying the sum of the three wells against the production separator.

One of the critical issues in this paper is to show how a virtual meter will enable an operator to establish individual sensor errors through modelling the full field. In July of this year a discrepancy between the field flow measurements, and the FlowManager™ calculations arose. The reason was found to be an error in the separator oil measurement. The sensors would no longer detect oil flow rates below a certain threshold value.

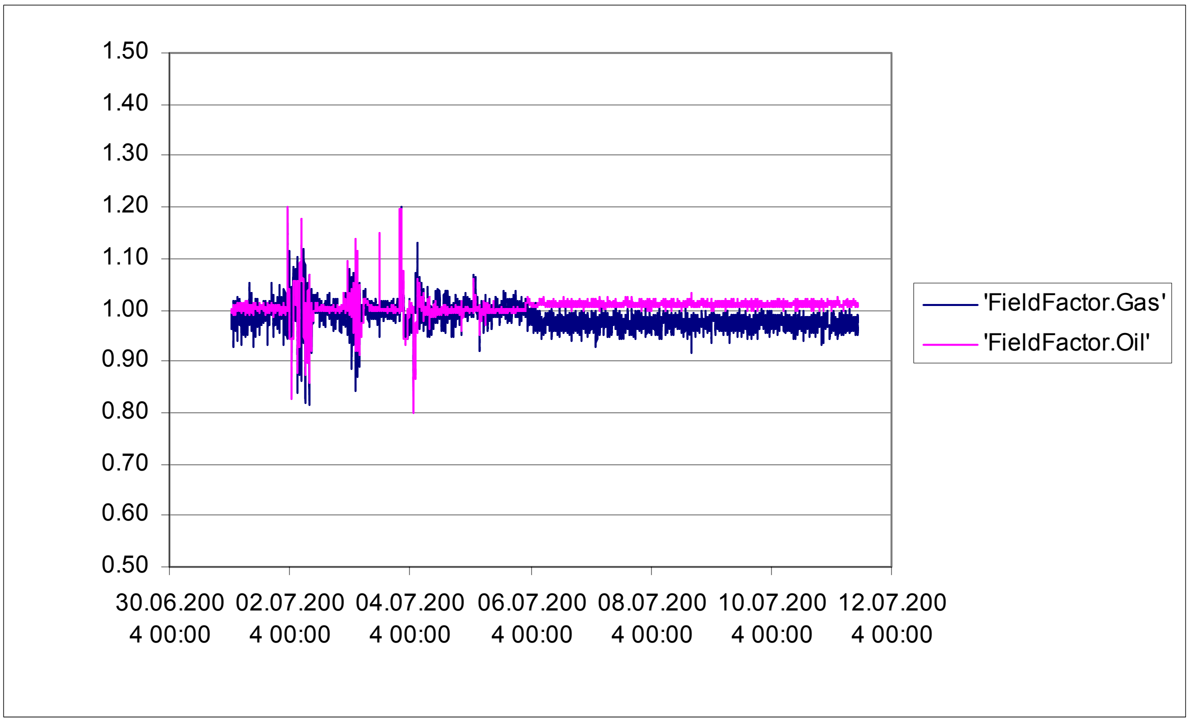

Figure 4.4 Field Factor development.

Figure 4.4 shows the development the Field factors over a period of two weeks. The field factor is defined as the calculated production divided by the measured production. On July 6th there is a pronounced increase in deviation between the measure and the calculated rates.

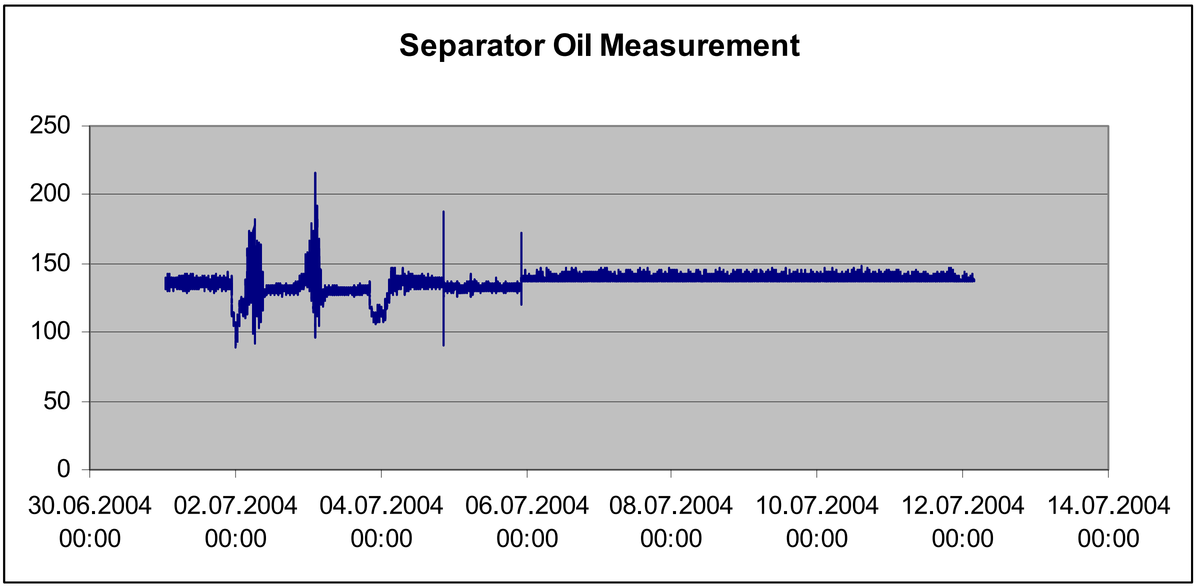

Figure 4.5 Separator oil measurements

Figure 4.5 shows the measured oil production over the same time frame. After July 6^{th} there is not one single measurement beneath the threshold value of 136,67 Sm3/day. The sudden increase in production does not correlate with changes in any of the three wells. The discrepancy was initially seen as an error in the virtual meter, but after examining the system closely, the origin was found to be the production separator. The error was first detected, not by the operating personnel, but by the virtual meter. Without continuously monitoring of the production system response, the error might have gone on "virtually" undetected.

4.3 Standard Instrumentation

The more wells contained within a production system, the less extra information is gained by solving the full production system as a network. In some scenarios it might even be beneficial to split the system in to smaller units to gain an overview of the calculations. The capability for using network solution is a fairly new development within the FlowManager™ framework. Hence, most of our experience has been gained in fields were the calculations are run on a well by well basis. In this scenario the most common problem is fallout of down hole sensors. For all fields where FlowManager™ is currently employed, the pressure drop between the down hole and the upstream choke pressure sensors is one of the most important measurements. The reason being that it is often the largest pressure drop in the system, and is therefore least affected by the individual measurement errors. When the down hole sensors fail, which they quite often do, the program is limited to using the choke Dp and well bore temperature drop as its primary measurements.

The choke Dp is governed by the choke geometry, in other words choke calculations are determined by the choke Cv-curve supplied by the choke vendor. There are several different difficulties encountered when using the choke Dp as a measurement. The most obvious obstacle is low pressure drops at large choke openings. We have no experience with using chokes with dedicated Dp-cells. Hence, the choke Dp reading is a product of two sensors with individual errors. For very low pressure drops, the sum of the errors may be larger than the actual pressure drop.

Secondly, the transition zone between sub-critical and critical flow through the choke is a difficult area. The Speed of sound of each of the individual phases may be established through laboratory testing, or through numerical pvt relations. The speed of sound of the three mixed phases is established through the Woods equation. The accuracy of the individual phase speed of sounds are imperative to the accuracy of the calculations. Laboratory measurements of the phase speeds are very accurate, but also very costly. Hence, we have no experience with measured phase speeds for the fields we operate. The transitional area is therefore a somewhat grey area for determining the flow rates based on the pressure drop.

Another commonly encountered problem is the step actuators. Our input is usually in the form of a step percentage, which we convert into a percentage of the maximum area. After a choke has been run for a while, it is very common that the reported step percentage starts to deviate from the actual. Over time this deviation may grow quite large. The reason for the deviation is that the choke does not always move the exact amount of instructed steps. Over time the deviation from the measured step percentage will grow. The error will be reset every time a choke goes to full open or full closed.

Overall the choke pressure drop is an excellent measurement for determining the mass flow rate provided that it is sufficiently large, and that the flow rate is either higher or lower than the transitional flow rate between critical and sub-critical conditions.

Temperature measurements are somewhat less accurate than the pressure readings. The primary reason is that the sensors rarely give an accurate indication to the average temperature of the flowing liquids. In most cases temperature sensors are non intrusive, and to a certain degree influenced by both the flowing temperature and the ambient temperature. For down hole sensors this does not affect the measurements to a disturbing degree. For measurements in areas where the ambient fluid is seawater, the deviation might be substantial. Ambient temperatures are subject to seasonal changes, this can to a certain degree be accounted for by monitoring the seawater temperature, or even using previously established seabed temperature statistics. But even more importantly is the convective heat loss that arises as soon as the water surrounding the sensor area starts moving. Underwater currents may substantially affect the temperature readings. This effect is even more prominent if one is attempting to model heat losses through a seabed to surface riser. In this situation it is not the actual temperature measurement, but the modelling of the U-value of the riser that is the problem.

Another difficulty with using temperature as a primary measurement is the long transient times compared to the pressure responses. The time to reach temperature equilibrium is further increased by the fact that the measurements are conducted in the surrounding metallic casing, and not within the actual flow. For allocation purposes this effect might be marginal since most chokes are held at constant positions for time intervals that are much longer than the temperature transients. However, in a situation were closed loop control (Chapter 4.1) is applied; the temperature responses are too slow to be used as a primary measurement.

Increasing use of isolation for hydrate prevention purposes is another obstacle. Better isolation of risers and flow lines may reduce the information available from temperature sensors, or it may accentuate the need for high quality intrusive temperature sensors.

As stated in chapter 3, any flow related quantity that can be measured – and modelled, may be used as input to a virtual meter. We have very good experience with using Venturi pressure drop readings in addition to standard sensory input. Other possibilities are densitometers, water cut meters, speed of sound meters and cross correlation based flow meters. In sum a virtual meter may easily link up with the individual components of a multiphase meter, and combine this information with all other available information in the production system to establish a best fit scenario for the whole production system, not limited to spot readings at the position of the multiphase meters.

5 FLOW MANAGEMENT

One of the greatest added benefits of using a virtual meter, compared to other forms of single point meters, is that it automatically gives a tuned model of the full production system. For de-bottlenecking of a production system an operator is constantly dependant on being able to model the process. Usually this is done by tuning the individual wells to the latest well tests. The frequency of testing is very variable. Especially in the later stages of a field life we frequently see test separators being tied up to producing low pressure wells, or unable to test wells at full capacity due to gas and water limitations. Hence, the predictions and the optimizations suffer from having inaccurate model input. The fact that one already has a fully functioning, and calibrated model of the full production system allows for quick and easy assessments of both short and long term production predictions. For long term predictions the FlowManager™ software has built in functionality for communicating directly with the Eclipse® reservoir simulator. For more short term predictions one can use the calculated rates from previous days and run them through an optimization loop. This loop starts with the actual rates from previous days, and then optimizes and maximizes production based on a set of constraints given by the operator.

The constraints naturally include the PI and formation pressure of each well. Gas and water production can be controlled as a function of time and/or flowing bottom hole pressure. All major naturally occurring variations in the production system can be expressed mathematically as constraints, to accurately predict how the system will respond to different production scenarios.

Linking the model of the production system gives the benefit of accurate production estimates based on the reservoir models. Vice versa the increased accuracy in the model of the production system will actually increase the accuracy of the reservoir predictions. The reservoir models have more accurate input with regards to how much has been recovered from where.

The virtual meter is inherently a link between the measurements, and a numerical model. Prediction of any event that has an accurate model is possible within this framework. Possible future model expansions include slug, wax and scale predictions, along with erosion estimates and inherently all other predictions needed to optimize the production from a hydrocarbon reservoir.

PUBLICATIONS AND PRESENTATIONS

The following publications and presentations highlight the methodology and field examples of the Idun allocation application.

[1] Berg, K. and Davalath, J., “Field Applications of Idun Production Measurement System”, OTC, Houston, TX, May 2002.

[2] Andfossen, P.O. ”Idun Multiphase Metering: Subsea Processing in Deepwater” OTC, Houston, TX, May 2000

[3] Friedemann, J.D. ”Data Acquisition, Cost Benefit Evaluation” Challenges of Multiphase Flow in Horizontal Wells Workshop, Porsgrunn, Norway, June 1999.

[4] Nerby, G., Sæther, G, and O.J. Velle, ”A Cost Effective Technique for Production Well Testing” OTC, Houston, TX, May 1995

[5] Sæther, G. ”Software Determines Multiphase Flow without Meters”, Petroleum Engineer International, Dec. 1998