Software That Enables Flow Metering of Well Rates With Long Tiebacks and With Limited or Inaccurate Instrumentation

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Abstract

Accurate metering of flow rates and prediction of water breakthrough are important issues in offshore oil production. The multiphase flow rates can be found for instance from frequent well testing, from multiphase flow meters, or from software simulations. Multiphase flow meters are very expensive and so are single-well tests, especially in cases with long tiebacks. On the contrary, software simulations are cheap, they can be made accurate, and simulations can usually be based on existing sensors. Also, software is easy to install, operate, and maintain compared to hardware multiphase meters.

In this article we describe the main components needed in a flexible software system for flow metering that can handle sparsely instrumented production facilities. Several sources of implicit information are pointed out, and a tuning strategy that avoids single-well tests is described. We also present examples that show the power of advanced simulations in situations that are not well handled by multiphase flow meters and standard software because of very low flow rates. What makes the situation in the examples even harder is that: There is no available information about the choke, the bottom hole sensors fail, and the temperature measurements are influenced by the seawater temperature. Despite this, good results are obtained.

Introduction

The offshore oil industry is facing a market where the number of brown fields is growing, and where more and more of the green fields are marginal fields. In addition, many of the new findings are on deep water. These facts all point in the direction of more production networks with long tiebacks, a stronger need for limiting the number of expensive well tests, and a push towards minimizing OPEX in general. The need for reliable monitoring of the production from each well in a production network is therefore continuously increasing. Furthermore, reservoirs may have more than one owner, whereas the various owners may share the same infrastructure and production facilities. In such cases reliable production monitoring is of course highly demanded.

A software system for flow rate estimation may satisfy the above needs. Software is relatively cheap, and both installation and usage can be made very easy. Furthermore, software is easily maintained and supervised from remote, whereas hardware, such as a multiphase flow meter, usually needs to be maintained on the site. This is an important issue since many larger green fields are far away from where many of the oil companies’ expertise traditionally is situated. Remote access can easily be obtained using standard web browsers and internet technology.

However, if the instrumentation is sparse or inaccurate most software systems will not give reliable rate estimates. In this article we will look at how to deal with such problems. We will present the main building blocks for a flexible software system that can handle almost any production network configuration. We also show how inaccurate measurements and what may look like useless information may contribute to good rate estimates. In addition it will be described how the software can be tuned without performing single-well tests. This is indeed valuable since it means that no well needs to be shut down to re-tune the production rate estimator. In cases with long tiebacks single-well testing may even be impossible.

Finally we present examples from two wells on the British sector in the North Sea. The wells are sparsely instrumented, and additional major challenges arise due to low flow rates. For sufficiently low rates the pressure drop along the tubing does not give unique information about the actual flow. This causes difficulties for standard software, but the examples show that even this situation can be handled. The software used in the examples is ABB’s Well Monitoring System, WMS. This software system has also been discussed in [3] and [4], and a similar software system is described in [2].
Software and models

A flexible software system for rate estimation should, as in most other applications, be made modular and reusable. The system needs to be configurable such that it can fit all relevant production facilities and such that it can adapt to changes in both production conditions and facilities. It needs to be easy to tune and use, both on the site and from remote, and it must provide secure handling of all data. On the modeling side the estimates should make efficient use of all available measurements that carry information about the actual flow in the production network, and this is what we will focus on in the following.

The main components needed by state-of-the-art rate estimators for production networks are: Fluid and flow models for simulating the physical behavior inside each piece of equipment, measurements of physical properties of the actual flow, and an optimization algorithm for determining rates that give the best possible fit of the simulated values to the measured properties.

The most central part in the simulation system is the fluid model. The system used in the examples applies a compositional model, which means the flow is subdivided into its separate hydrocarbon components. Each component has known physical properties, and the fluid model uses these to determine physical properties of the total flow at any given combination of pressure and temperature. This makes the model capable of handling almost any type of fluid in a unified way based on well-founded physical principles. The fluid model can be tuned using lab reports. In the examples the equation-of-state by Peng and Robinson was applied, see [6] and [5].

Once the fluid model is in place, a set of flow models needs to be selected. The purpose of these models is to estimate the change in physical properties when a given flow with given inlet conditions runs through a piece of equipment, e.g. a pipe, a choke, a venturi, or the near-well domain; see [1] for the state-of-the-art pipe models used in the examples. The current guess of rates, determined by the optimization algorithm, is let into the models through sources, for instance the reservoir providing produced oil, gas, and water, or the gaslift system providing lift gas.

Finally, the simulated properties are compared to the actual physical measurements, which typically are pressures, temperatures, flow rates, etc. The mismatch between simulated and measured values provides the necessary information for the optimization algorithm to improve its temporary solution. However, the comparison of mismatches in different physical properties, e.g. pressure and temperature, is not a straightforward matter. To keep the number of different properties down one may choose to use raw measurements, such as the pressure drop across a venturi, instead of secondary values such as flow rate. Furthermore, the mismatches need to be weighted depending on the accuracy of the measurements and the models.

Measurements

Primary Measurements. Allocation of rates to each individual well in a network requires a set of physical measurements at corresponding points in time. Typical measurements used by the software system applied in the examples are pressures and temperatures. Also other types of measurements may be considered, such as capacitance, conductivity, and gamma ray absorbance. The obvious solution is then to interpret all mismatches in terms of statistical quantities such that all comparison is done in a unified framework.

Classical tuning of models requires additional measurements such as measured single-well rates together with corresponding measurements used for allocation. In addition, detailed and accurate lab reports of the involved fluids are essential for tuning advanced compositional fluid models.

Implicit information. Often measurements may seem less informative than one could wish for, but if the software is flexible such measurements may still be used.

A typical example would be a gas lifted well with no working down-hole sensor. Rate estimation is a lot easier if there are working down-hole sensors available, but in this case the sensor may be replaced by measurements on the gaslift system. As long as the lift gas velocity is sub-sonic, the pressure at the point of gas injection can be computed provided the gaslift system has a venturi or other relevant equipment. This computed pressure may act as a down-hole pressure sensor, and the well can then be modeled with that point as the lowest point. To make use of all available information, one will in practice use both the measurements on the gaslift system and the down-hole sensor if all sensors are working.

Another typical example is temperature measurements that are influenced by the seawater temperature. This often happens if the temperature probe is placed in the piping steel and the insulation outside the pipe is poor. Such measurements may seem almost useless. However, they can be made useful by constructing a heat transfer model for determining the fluid temperature as a function of measured temperature. Such models can easily be tuned from well tests, and as will be seen in the examples, this may be the only adjustment needed to provide a reliable piece of information based only on the existing equipment.

At nodes in the production network a temperature measurement may provide especially useful information. We define a node to be the point where two or more flows meet. This can for instance be a manifold or a point where methanol or other fluids are injected. If at a point of methanol injection the rate and the temperature of the methanol are known, one can determine the production rate from the blending temperature. This eliminates all uncertainty in the heat transfer coefficient for the pipe, which is present in most other temperature calculations. Alternatively one could measure the concentration of the injected fluid after the blending, which would also determine the rate.

A more obvious example is that the down-hole temperature at a given depth is often close to constant in time and space. Therefore, if a down-hole temperature sensor fails, the temperature can often still be regarded as known. Likewise, if no down-hole temperature sensor has ever been present in a well, it may still be found from a computed temperature gradient in the soil based on measurements from nearby wells. Yet another possibility is to use soft sensing to tune the
unknown reservoir temperature early in the production phase when all measurements are likely to be very accurate. This means that the reservoir temperature is treated as an unknown in the simulations, and thereafter it is assumed to be constant.

The assumption about properties being constant in space may also be applied to the reservoir pressure if the connectivity in the reservoir is good. Then the reservoir pressure can be found during shutdown of one well, and the measured value may be used as reservoir pressure for all other wells that have a good connection to the one being shut down.

A final and illuminating example is related to the pressure at nodes in a production network. It is obvious that the pressure at the outlet of the incoming flows must be the same, but it is easily overseen that this provides a new piece of information, a new equation that is, for each new flow which is connected to the node. A node with \( n \) inlet flows will therefore provide \( n-1 \) equations although there is no sensor at the node.

**Tuning models without single-well tests**

Single-well tests are generally very expensive, and they are especially costly in cases with long tiebacks. In such cases single-well testing may even be impossible due to flow assurance issues such as scaling or instabilities caused by low flow rates and low temperatures. The cost of such tests is one of the main reasons for installing software for estimating flow rates. As long as the software models are well tuned there is hardly any need for well testing. However, software models need tuning once in a while, and if this could be done without single-well tests it would be a great economical advantage. This is indeed possible, and the solution is to perform multi-rate tests, which is the focus of this section.

**Allocation** can be viewed as an optimization problem where the deviation between simulated and measured data is to be minimized by adjusting the rates used in the models. On the other hand, **classical tuning** is also an optimization problem, where the rates are known from single-well tests and the deviation between simulated and measured data is minimized by adjusting the tuning parameters, e.g. roughness, heat transfer coefficients, etc. **Multi-rate tuning** is a mixture between allocation and classical tuning: The main idea is to avoid shutting down any well, and instead only change the flow rates from the individual wells to obtain a set of independent flow cases. For each of these cases the total flow rates and all other available flow measurements in the production network, typically pressures and temperatures, are recorded. All these test cases are now considered simultaneously and viewed as one large optimization problem where the free variables are the oil, gas, and water rate from each well for each test, and the tuning variables, which are the same for all tests. The solution that gives the best overall fit to the measured data provides the optimal tuning variables. The necessary changes in flow rates may be obtained by e.g. changing the choke positions, changing the lift gas rates, or by other means changing conditions affecting the individual flow rates.

Let \( w \) be the number of wells, let \( f \) be the number of flowlines, let \( t_i \) be the number of tuning variables for well or flowline number \( i \), and let \( c \) be the number of independent test cases. We then get the following expression for the number of unknowns, \( N \), in the multi-rate tuning problem:

\[ N = 3wc + \sum_{i=1}^{w+f} t_i. \]

The factor 3 represents the oil, gas, and water rate from each well. What is important to note is that the number of unknowns has a very limited growth with respect to the number of test cases, \( c \). The number of equations for determining these unknowns depends on the instrumentation. Each measured rate and each measured pressure or temperature drop gives one equation. The number of equations therefore obviously grows with the number of test cases, and to obtain robust estimates it should be larger than the number of unknowns. This requirement can be stated more precisely as follows: It must be possible to assign at least one equation to each free variable such that the equation is sensitive to changes in the free variable and such that once an equation has been assigned to a free variable it cannot be assigned to any other free variable. In other words, one needs a sufficiently large number of independent equations, but the system does not need to be solvable as only a best-fit solution is sought.

If the instrumentation is limited it is possible to reduce the number of unknowns by assuming the gas-oil ratio and/or the water-oil ratio to be constant for some of the wells in some of the test cases. If all wells are treated equally this reduces the factor 3 in the above equation to 2 or 1. Similar perturbation techniques are addressed in [7].

**Examples**

In this section two examples will be considered, and the example wells will be referred to as Well A and Well B. Both examples are taken from a field on the British sector in the North Sea, and the wells have very limited instrumentation as can be seen from Figure 1. One thing to notice about the examples is that the measured flow rates are so low that the pressure information does not point towards one unique solution. However, utilizing temperature information the correct solution may still be identified, but most standard software is not capable of handling this.

In one example there is a working down-hole pressure sensor, whereas in the other example there is no such sensor. We also show what happens if the working bottom hole sensor fails. The pressure and temperature measurements are logged with an accuracy of only 1 bar and 1 Kelvin, respectively, which are rather coarse scales.

**Tuning.** In each of the examples the flow models are tuned using only a few of the measured data points which were made available from single-well tests. A general tuning was performed, and the optimal value of the overall heat transfer coefficient was also estimated. In addition, a model for the fluid temperature was made based on temperature measurements that, according to simulations, seemed to be affected by the seawater temperature. This model was tuned using 3 data points. The temperature model was only used for Well B.
Well A. This well has a working down-hole pressure sensor, but the down-hole temperature is estimated from neighboring wells. In addition, there is a pressure and temperature sensor upstream of the choke. This information was used to predict the oil and water rate assuming the gas-oil ratio to be constant. The result is seen in Figure 2. There it is clear that the allocated oil rates are close to the measured ones, and the time of the water breakthrough is estimated correctly.

Figure 3 shows the estimated and measured tubing head temperature and pressure drop as a function of oil rate. The figure clearly shows the non-uniqueness of the rate for a given pressure drop, both for the measured rates and for their estimated counterparts. However, the temperature drop ensures a unique solution.

In Figure 4 is shown the results when the information from the down-hole sensor is left out. The tuning is the same as when the down-hole sensor was included. The pressure at the inlet is now left as a free variable, a “soft sensor”. In this case there is one equation less and we are forced to assume the water-oil ratio (WOR) to be known. In the example we have assumed WOR=0, which is close to correct for most of the test cases.

Well B. This well has no working down-hole sensor, and the down-hole temperature is estimated from neighboring wells. As for Well A the down-hole pressure is left as a free variable, since there is no information about its value. There is a working pressure and temperature sensor upstream of the choke, but what makes this case hard is that the seawater temperature influences the temperature measurement. As already mentioned a simple heat transfer model was made relating the measured temperature to the actual fluid temperature.

This system provides only one equation and therefore only one unknown can be determined. An easy way of seeing this is to look at the tubing in the following way: The flow model for the tubing is simply a set of two ordinary differential equations, one for pressure and one for temperature, and there are three measurements available. Two of these are needed to provide a sufficient number of “initial conditions”, or rather “control points”, and the third measurement provides an equation for determining one unknown. We have chosen to assume the gas-oil ratio to be known and that WOR=0. These assumptions are close to being satisfied in all the test cases in this example.

The results are shown in Figure 5. The estimated oil rate is very close to the measured one although the instrumentation is extremely sparse and inaccurate. The relation between the measured and calculated oil rate and the tubing head temperature is shown in Figure 6. This figure also shows the relation between measured and calculated oil rate and the tubing head pressure. Note that hardly any information about the oil rate can be extracted from the measured tubing head pressure.

Conclusion
In this article we have presented a concept for building a software system for estimating flow rates from individual wells in oil production networks. The concept is suitable also for sparsely instrumented production facilities. The main advantages of such a software system are: It reduces the need for well testing, it is accurate and cheap, it may be based on existing sensors, and it can be monitored and maintained from remote. Furthermore, it has been shown how low quality measurements can be used for rate estimation, and how the software can be tuned without performing single-well tests.

We have shown through two examples that it is possible to obtain good results also in cases where the pressure information does not identify a unique solution, even with both oil and water rates as free variables. Good results were obtained with limited instrumentation and with temperature measurements containing significant (systematic) errors. Usually more measurements are available, which gives a more accurate and robust solution and less dependence on the accuracy of each individual sensor.

Nomenclature
Abbreviations
BHP Bottom hole pressure (= down-hole pressure)
BHT Bottom hole temperature (= down-hole temperature)
OPEX Operational Expenditure
THP Tubing head pressure
THT Tubing head temperature
WOR Water-oil ratio

Units
d day
m meter

References
Appendix A: Figures

Figure 1. Instrumentation in Well A and Well B. P indicates a pressure measurement and T indicates a temperature measurement. An asterisk indicates that the measurement is in some way modeled. The bottom hole temperatures are modeled from temperatures in nearby wells, whereas the tubing head temperature in Well B is measured, but the measurement is influenced by the seawater temperature.
Figure 2. Well A, working down-hole pressure sensor, no down-hole temperature sensor. The top two lines show the measured and calculated oil rate. The two lines at the bottom show the measured and calculated water rate. The bottom hole temperature is estimated from surrounding wells.

Figure 3. Well A, working down-hole pressure sensor. Left: Measured tubing head temperature plotted against measured oil rate, and calculated tubing head temperature plotted against the calculated oil rate. Right: The pressure drop in the well (bottom hole pressure – tubing head pressure) plotted against oil rate. The plot shows measured pressure drop versus measured oil rate and calculated pressure drop versus calculated oil rate. In both cases the bottom hole pressure is measured.

Figure 4. Well A, down-hole sensor fails. Measured and calculated oil rates are plotted. The calculation does not make use of the down-hole pressure sensor values. Water rate is assumed to be zero. No re-tuning of the model.
Figure 5. Well B, estimation of oil rate. No down-hole pressure sensor, no down-hole temperature sensor, tubing head temperature sensor is influenced by the seawater temperature, tubing head pressure sensor is working. The bottom hole temperature is estimated from surrounding wells, and the influence of seawater temperature on the tubing head pressure sensor is modeled.

Figure 6. Well B. Left: The modeled tubing head temperature is plotted against the measured oil rate, and the calculated tubing head temperature is plotted against the calculated oil rate. On average the measured temperature deviates from the modeled temperature by about 15 Kelvin. Right: The measured tubing head pressure is plotted against the measured oil rate, and the calculated tubing head pressure is plotted against the calculated oil rate.