Using Multiphase and Wetgas meters for revenue allocation

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A Key Component in Field Decision Making

The increasingly complex infrastructure in the upstream area of today's oil and gas production facilities creates a challenge for the measurement of the individual gas, oil (condensate) and water flow rates.

Conventional test lines and test separators with the associated measurement equipment are no longer economically viable. More advanced measurement technology is required, and the use of multiphase meters (MPFMs) and wet gas meters (WGFM) both topside and subsea, has increased significantly over the last decade.

The output of MPFMs and WGFMs is used to improve reservoir modelling/management, optimise production and manage flow assurance. The output is even used to determine the financial transactions between oil companies for allocation purposes, or between oil companies and the host government for royalty purposes.

In all cases the costs of metering should always be compared with the value of information from the meter. Uncertainties in measurements, which are different for each metering concept, but also potential systematic errors, e.g. when the fluid properties of the flowing fluids are not equal to the fluid properties used to configure the MPFM, determine the magnitude of the financial risk and the money at stake.

When selecting an MPFM or WGFM, it is strongly recommended to consider the total life cycle costs, which is both the CapEx and OpEx, next to performance criteria like uncertainty and repeatability [3]. For remote and subsea applications the operating costs increase significantly if it is necessary to sample and analyse frequently to calibrate or reconfigure the meter.

The Economic Drivers

The production measurement process is more than just measurement hardware in the field but is the entire chain from data collection in the field up to the final production reporting. It includes all intermediate steps such as measurement and sampling, operational procedures, field configuration, data transmission and reconciliation/allocation procedures. The "customers" or "data users" of this measurement process are generally spread over several disciplines in the oil and gas companies and their partners or government bodies. Obviously, each of these "customers" will have their own wishes, requirements and specifications for production data.

All meters and analysers installed in oil and gas production facilities will increase the CapEx and OpEx of a development. The meters do however provide data which are used in optimisation processes to maximise the revenue generated. Hence, careful consideration needs to be made to justify the metering costs and compare these costs with the value of information coming from the meter. If MPFMs are considered for revenue allocation, the technology should have a very high level of confidence, adequate measurement accuracy, high reliability, an availability of close to 100% and a very low sensitivity for changing fluid properties. Possibilities to verify the meter performance or, even better, possibilities to carry out in-situ measurements to re-configure the meter are of great benefit.

Removal of Test Separators and Test Lines

This was the main justification in the early to mid 90's in developing and implementing MPFMs. The aim was to replace the complex, bulky and expensive test separator with MPFMs and remove dedicated test lines in satellite oil and gas developments. One MPFM per satellite development means that the meter still needs to be manifolded in order to test individual wells.

The removal of a topside separator from the design may lead to a few millions US$ in cost saving. The removal of subsea pipelines may result in additional cost savings with an order of magnitude of a million US$ per km subsea pipeline. These cost savings are often an order of magnitude higher than the costs of installing a MPFM.

Furthermore, significant further cost savings can be made as the operation of an advanced MPFM (not the case for conventional MPFMs) is much lower in OpEx and much safer than operating a conventional test separator (unmanned operations and remote control).

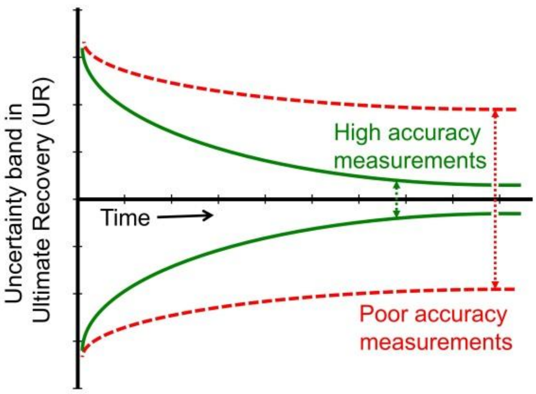
Example of a Subsea Multiphase and Wetgas Meter

Simplification of Manifolds

A step further than just replacing the test separator with an MPFM is to install MPFMs per individual well. This will not only increase the availability of production data, ensuring the right decisions at the right time (continuous flow rate measurement), but it may also result in a reduction in CapEx. Where an MPFM is installed in a manifold, two valves per well are still required (one for the MPFM header and one for the bulk header). For high pressure facilities or H_2S developments in particular, these valves increase CapEx, OpEx and safety risk and it is considered safer and more economical to remove these two manifold valves per well from the design and install an MPFM per well instead. The costs of two valves (high pressure, sour application, large diameter) are in the same order of magnitude or even higher than an MPFM.

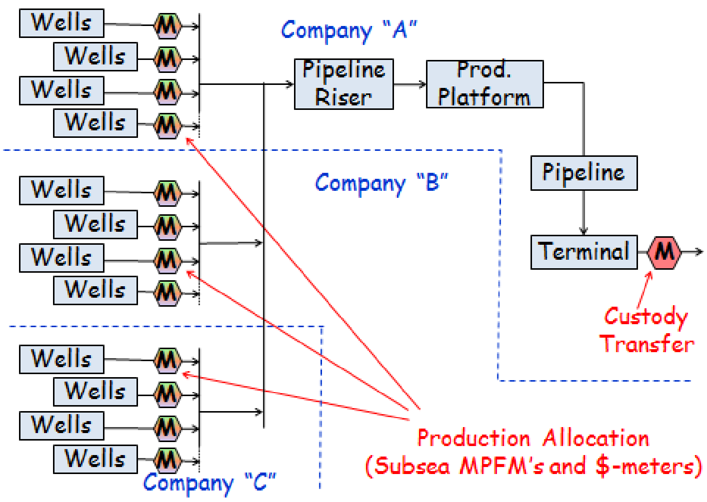
Lower Uncertainty for Ultimate Recovery (UR)

In general, data obtained by production measurement is one of the inputs in reservoir modelling and it is accepted that better data leads to better models and thus easier decision making on how to further develop the reservoir. This is graphically demonstrated on the right with the uncertainty band of the ultimate recovery (UR). With poor data (high uncertainty or low frequency measurements) the uncertainty in UR stays large but with good data (low uncertainty measurements and/or continuous measurements) the uncertainty in UR reduces. It is accepted that with a lower uncertainty in UR the financial risk of further development decisions and investments is also reduced.



Hydrocarbon Product Allocation

Commingled subsea multiphase oil and gas production from various concessions or licence areas (each with different partners and/or different royalty regimes) is often processed at a single host production system. This is currently the most economical way to develop subsea oil and gas fields. The consequences are that MPFMs are required upstream of the subsea commingling and that the output of these MPFMs has a direct impact on the financial transactions between the oil companies operating in the licence area (product allocation or transportation fees), or between oil company and host government (royalty).



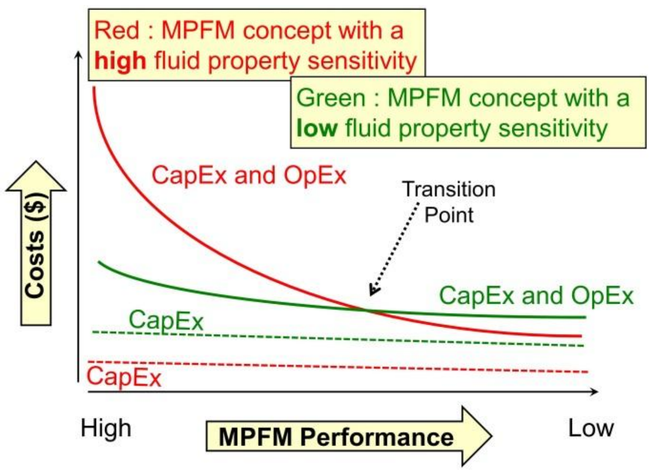
Any systematic error made by the MPFM will have a direct systematic impact (either gain or loss) on the financial transactions and it is therefore paramount that the MPFM have as low an uncertainty as possible.

Reducing the OpEx in Remote, Marginal or Deep Water Fields

The OpEx required to operate MPFMs, i.e. maintenance, verification processes, sampling for fluid properties, is different for each MPFM concept. It is therefore strongly recommended that both the CapEx and OpEx are considered very carefully in the MPFM selection process.

Ultimately it is the total life cycle cost that should be the driver from an economic point of view – followed by the performance driver (i.e. uncertainty, repeatability and availability). Two examples are given below for MPFMs that have a similar performance:

1) A low cost MPFM with high dependency on fluid properties. The additional hardware for extensive sampling and analyses for fluid properties will increase the CapEx. At the same time, the sampling and analyses during operation will make the OpEx relatively high, in particular in applications where accessibility to the MPFM is low, like subsea applications. See the red curve on the right.



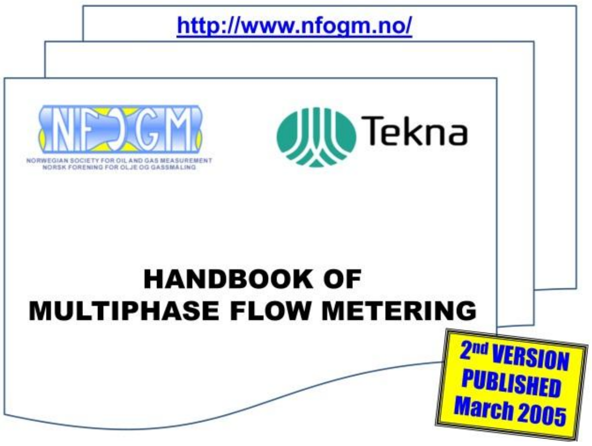
2) A higher cost flow meter, where the MPFM has no or minimum dependency on fluid properties, or where the MPFM has the possibility of performing in-situ fluid property and salinity measurement, will require less operational activity to determine these fluid properties and thus the OpEx will be much lower than item 1 above. See the green lines on the right.

If fluid sampling and analyses is required to properly tune a MPFM or WGFM and the location is remote (subsea) this will increase the OpEx significantly. Executing subsea sampling at 2 to 3 km water depth for this purpose is not only very cumbersome and extremely expensive but also carries a significant environmental risk.

Standardization and Best Practices

With the large diversity in current MPFM concepts it is not possible to publish similar standards as have been published in the single phase flow measurement business.

However, the huge development progress made in the last two decades and the vast amount of experience collected has enabled the publication of recommended practises [1] and a multiphase flow metering handbook [2]. It is these documents that describe the definitions, the applications, the technology, the uncertainties, the testing, the operational aspects, etc. and ensure there is some consistency among the manufacturers and users.



References

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[2] *"Handbook of Multiphase Flow Metering"*, Norwegian Society for Oil and Gas Measurement (NFOGM), 2005-03

[3] Lex Scheers,
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