31st North Sea Flow Measurement Workshop
22-25 October 2013

Subsea Sampling on the Critical Path of Flow Assurance

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1. ABSTRACT

The subsea oilfield development business is growing rapidly around the world, and it is going into ever deeper waters and involving increasingly long tiebacks. In such situations it is no longer viable to produce each well through one pipeline or riser. It is common for tiebacks to result in comingling of fluids from different reservoirs, often with different properties, in order to minimize the cost of production up to the FPSO or host platform before processing. In addition, in areas including the North Sea, some operators are simultaneously producing fluids as diverse as gas condensate and heavy oil to the same platform from different layers of the same reservoir.

Flow assurance is becoming an increasing concern, as stopping flow could lead to situations posing safety risks and financial loss. It is, for example, extremely difficult to reduce production for a train of liquefied natural gas (LNG). Challenges include how to guarantee the flow; what to do to mitigate deposition; how to plan a shutdown of production and address collateral effects inside the riser. Other challenges include ensuring that the reservoir model is correct, identifying possibilities for optimizing production, and considering whether the fluids from tiebacks and/or multi-level reservoir production are compatible for efficient flow when comingled. These and more are all challenges that subsea operators face from the field development design phase to their daily operations. Subsea sampling of representative samples is a key source of relevant information to help mitigate flow assurance problems. For multiphase flow, a representative sample is defined as a sample where each individual phase has the same composition as the flow. This supposes that a thermodynamic equilibrium exists.

Over the last 16 years, subsea sampling technology has been available for the subsea oil and gas market. In an increasing number of examples, the cost of gaining the knowledge provided by representative samples has been recovered many times over through early intervention to resolve issues such as localized water influx. The first operator to adopt the new technology was BP, which has applied it in the North Sea and West Africa. Experiences from these installations have been already documented in technical papers. This paper looks into the evolution of subsea sampling technology and how the hardware has evolved into today's high-technology solution for multiphase subsea sampling. The process has seen development of the capabilities from the simple collection of a sample liquid to an understanding of the flow regime that has allowed multiphase sampling at representative subsea conditions.

This paper investigates the main drivers experienced from the point-of-view of an oilfield services and solutions provider over the last decade, and how these drivers have influenced the evolution of its subsea sampling technology. The paper explains the benefits of representative subsea multiphase sampling and the beneficial outcomes that are enabled when this is combined with reservoir modeling and flow

assurance modeling. In addition, the paper discusses what is possible to achieve today and what might be needed in the future to meet the demands of new business drivers that are coming in.

An explanation is given of the relationship between subsea sampling and a multiphase flowmeter (MPFM) in order to demystify this relationship and create a common understanding between the two unique and independent technologies. It is becoming increasingly apparent that accurate knowledge of fluid properties – especially density – is essential for calibrating multiphase flow measurements.

Finally the paper considers the current status of subsea sampling compared to expected future technical and regulatory needs for an increasingly accurate picture of reservoir and field production.

2. INTRODUCTION

Oil and gas exploration and production operators are increasingly moving into deep and ultra-deep waters to explore and develop new fields. This has resulted in considerable success in areas such as Brazil, West Africa and the Gulf of Mexico despite the increasing need for more reliance on subsea production infrastructure. Increased water depths, longer tiebacks, complex reservoirs and the continuous effort to reduce the cost of the subsea infrastructure, while still ensuring the highest possible recovery rates, raise new challenges in terms of reservoir and production management, flow assurance and enhanced oil recovery.

In this scenario, subsea sampling is rapidly becoming a simple but effective way to gather representative samples of the produced fluids through the life of the field, enabling reliable measurements of their properties, and of the changes that occur in these properties through the years.

Subsea sampling, combined with the expanding use of subsea multiphase meters, provides new levels of understanding of subsea reservoirs and of their behavior, improving the decision making process thanks to increased accuracy, and leading to extended recovery rates, while also enabling simpler and more cost effective architectures of the subsea infrastructures.

Subsea sampling is a commonly used expression for the functionality where equipment permanently installed on the seabed allows a deployed unit to capture samples of liquid or gas from subsea oil and gas installations. Common terminologies do not distinguish between the different methods that have been used for this process, and this paper focuses on explanation of the terminology and technology used by OneSubsea™.

3. THE NEED FOR SUBSEA SAMPLES

Production management processes and workflows can be grouped into three main sets of activities, as depicted in Figure 1. These are:

- Monitoring and Reporting
- Surveillance and Analysis

- Diagnosis and Optimization

All of these activities require reliable measurement of the quantities of each phase (oil, water, gas) being produced by each well in the field, and on the properties of the produced fluids. The need for subsea flow measurements is already addressed by the use of subsea multiphase meters, which are already widely accepted in the industry. Subsea sampling, particularly in deep and ultra-deep waters, is gaining increasing acceptance as the preferred method for achieving high-quality representative measurements of produced fluid properties that enable effective production management. In addition, knowledge derived from subsea sampling improves the accuracy of subsea multiphase meter measurements, which not only supports better reservoir development decisions, but also enables more reliable reporting of production data. This is becoming more important with increasingly stringent production allocation guidelines and regulations.

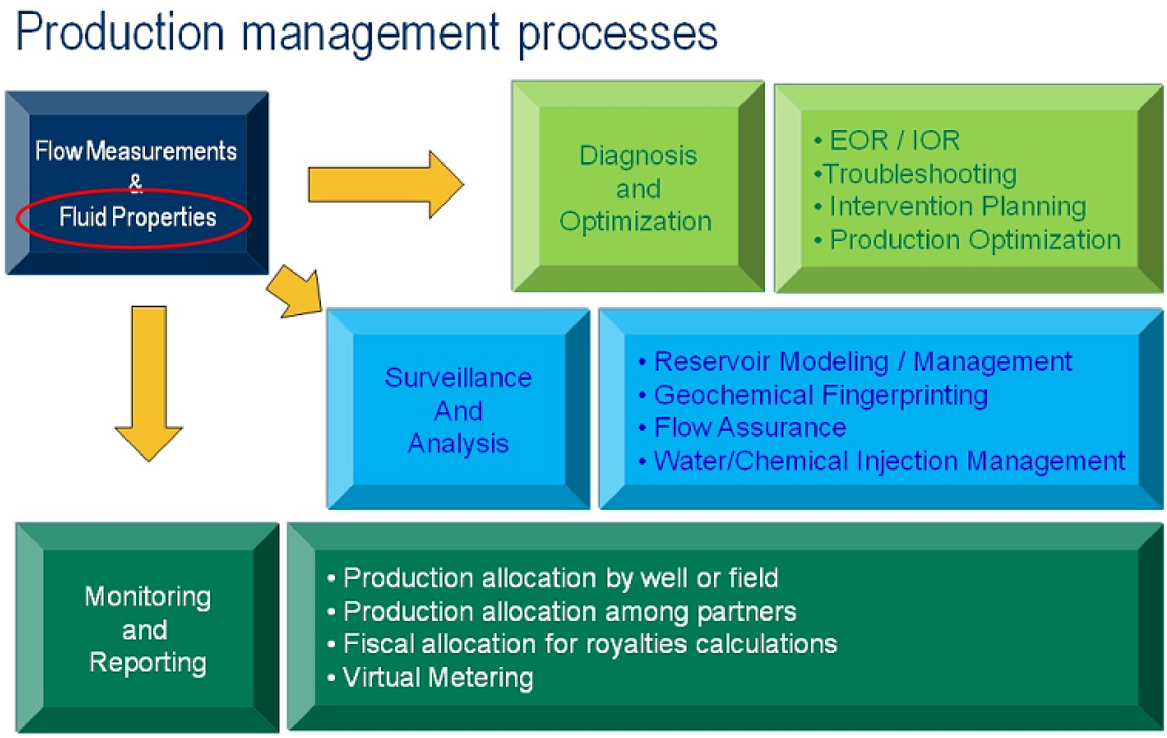


Figure 1. The need for fluid properties as input to production management processes.

Monitoring and reporting well, reservoir, and field performance is usually more complicated in deepwater subsea developments due to commingling of fluids from multiple wells and increasingly long tiebacks to other fields. Reservoirs and individual wells that are commingled at the seabed are often operated by different company partnership groups, and reliable flow measurement is key to accurate allocation of production and royalties. Gaining representative seabed samples prior to commingling enables geochemical fingerprinting and reduced uncertainty of flow measurements for calculating these allocations.

Reservoir surveillance and analysis activities are at the core of any production management workflow. It is important to understand and predict reservoir behavior while ensuring uninterrupted production through the subsea infrastructure. The main activities in this group are:

- Reservoir modeling and management
- Water/gas/chemical injection management
- Flow assurance

In addition to flow rates, knowledge of the physical properties of the produced fluids is essential. Changes in these properties during the life of the field, if not detected and not properly accounted for, can lead to significant inaccuracies in the models used for the decision-making process, with significant financial impact for the operator.

Geochemical fingerprinting is another important activity enabled by subsea sampling, which combined with flow measurements, allows the operator to allocate the production to each zone of a well. This is important because it enables multi-zone wells in situations that might otherwise require separate wells for each zone. Drilling one well per zone to meet allocation requirements could result in a decision that the discovery is not commercially viable.

Diagnosis of production problems and corresponding production optimization activities requires accurate reservoir models. Reliable knowledge of fluid properties at line conditions reduces uncertainty and inaccuracies in these models and subsequent fluid dynamics simulations. Combined with multiphase flow measurements, subsea sampling provides essential information to support:

- EOR / IOR
- Production optimization
- Production troubleshooting
- Intervention planning

Knowledge of the exact composition of the fluids produced from each well at line conditions enables reliable evaluation of pressure, volume, temperature (PVT) relationships and determination of a tuned equation of state (EoS). These are essential in the management of potential challenges such as scale, waxing, and hydrate deposition.

4. SUBSEA SAMPLING ADDING VALUE TO THE OILFIELD

Subsea sampling plays an important role in the whole production management process for subsea field developments. An increasing number of operators are realizing the additional value provided by subsea sampling and are including the requirements of the sampling system in their subsea architecture designs.

Figure 2 summarizes the most significant trends experienced in the subsea production world and how these trends represent important technical drivers for the subsea sampling market, particularly in deep and ultra-deep waters.

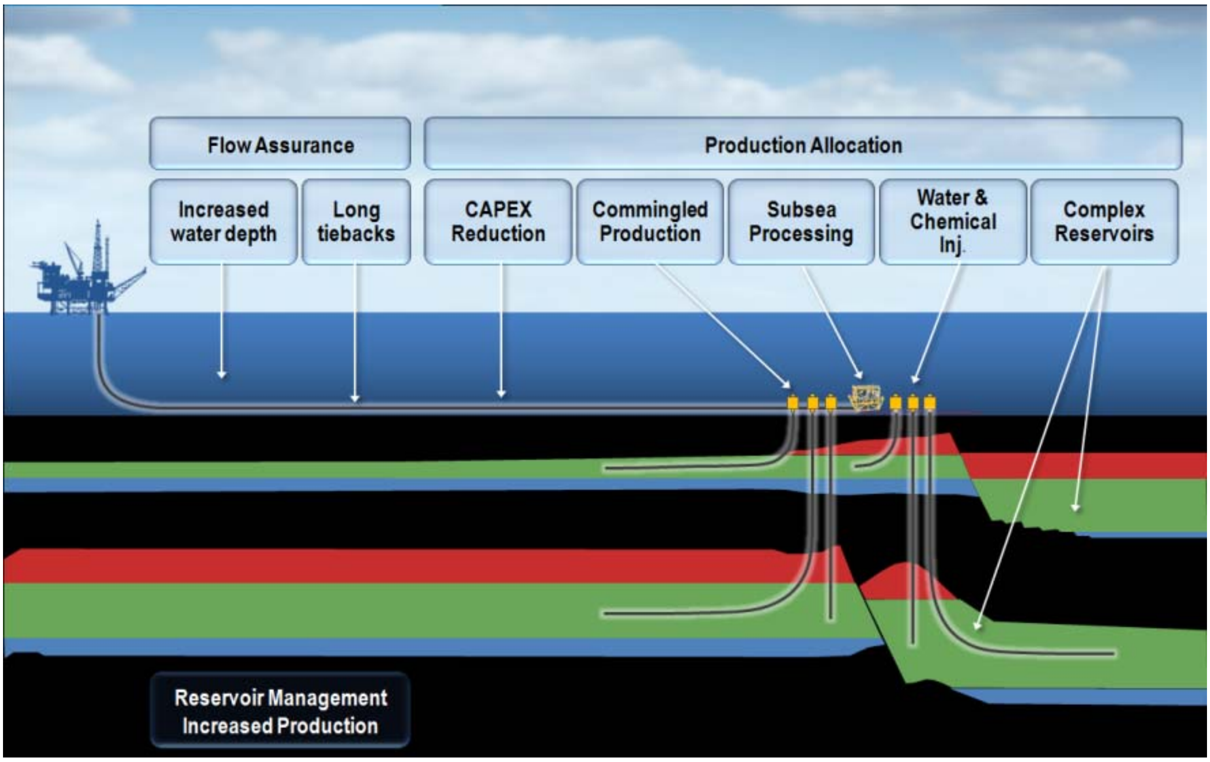


Figure 1. Subsea production trends and drivers for subsea sampling.

In addition to addressing technical challenges in deepwater developments, subsea sampling also supports more accurate production allocation through more accurate inputs to flow measurement systems. This is important not only for individual operating and partner companies, but also to meet increasingly stringent industry standards and national regulations.

API published its Manual of Petroleum Measurement Standards (MPMS) Chapter 20.3 in January 2013, superseding API Recommended Practice 86-2005, which is withdrawn. The new standard addresses multiphase flow measurement in the production environment, upstream of the custody transfer (single-phase) measurement point, where allocation is applied. The document addresses operational requirements or constraints in multiphase measurement systems, including expectations for flow meter acceptance, calibration criteria, flow-loop and *in-situ* verifications. It specifically describes representative sampling as the ultimate way of setting up any MPFM. Furthermore, API MPMS Chapter 20.3 points to the importance of representative sampling as essential to reduce uncertainty in the overall measurement.

The API MPMS 20.3 also points to the challenges of capturing representative subsea samples, and includes the following suggestions:

- The sampling point should be in a vertical leg of the flow line; the best position is immediately downstream of a flow line component providing a mixing effect.

- Multiple subsequent samples should be taken, allowing each sample to completely separate before the WLR is measured. For some crude oils, this will require the use of a de-emulsifier.

- The sampling point should be close to the MPFM. An acceptable sample should contain all of the fluid constituents and the time frame for the samples shall be selected such that the samples are representative for the liquid constituents passing through the MPFM during the same time frame.

The API MPMS 20.3 includes the phrase “NOTE 1 Verification techniques are used by some meters to determine fluid property changes, hence reducing or potentially eliminating the need for physical sampling”. It is the understanding of this paper’s authors that while this is the industry’s ultimate goal for the future, vendors are not there yet. Automatic updates based on an assumed salinity and non-representative *in-situ* measurements do not provide accurate and reliable information that can eliminate the need for physical sampling.

It is also important to note that API 20.3 is aware of the challenge of obtaining phase representative samples. Phase representative samples measure water-liquid-ratio (WLR) and gas volume fraction (GVF) from the content of sampling bottles. It is our understanding that these parameters can be challenging to obtain from subsea samples considering the complex nature of multiphase flow and difficulties such as slug flow and emulsions. The document includes “NOTE 2 Due to the issues with multiphase sampling, samples may not fully represent the volume fractions.”

The Norwegian Petroleum Directorate (NPD) recently issued new requirements in its “Måleforskriften”, which addresses metering for production allocation for fiscal regulations. This also states that subsea inline MPFMs are typically set-up using samples obtained during drilling. The composition of produced hydrocarbons changes over time and these changes are likely to be significant over the life of a deep sea development. Obtaining representative samples from the production system at line conditions enables maintenance of the inputs of multiphase and wet gas flow meters, leading to more accurate allocation.

Of all the main drivers for subsea sampling mentioned previously, the need for more accurate conversion of flow rate data from line to standard condition is one of the most valuable (Figure 3). In allocation regimes where actual flow is being allocated according to ownership structures, a small failure in the conversion can lead to a significant value loss for one or some of the partners. These conversions are factors added more or less directly to the bottom line for projects.

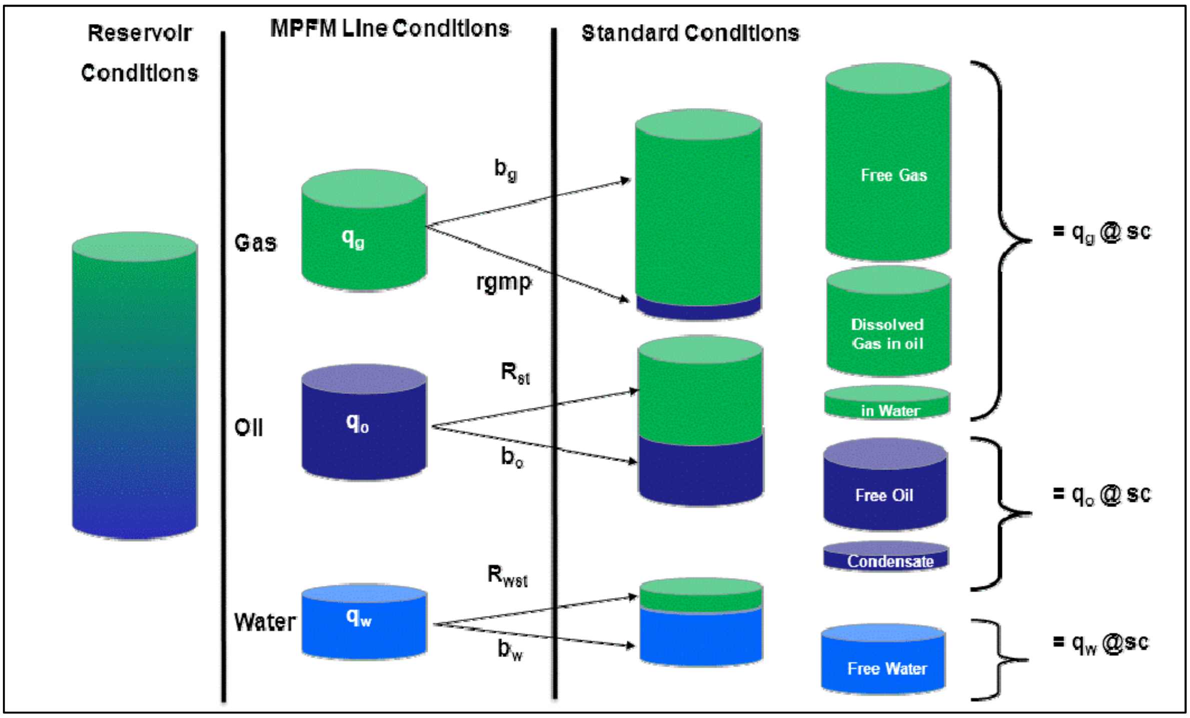


Figure 2. Calculation of flow rates at standard conditions based on measurement at line conditions.

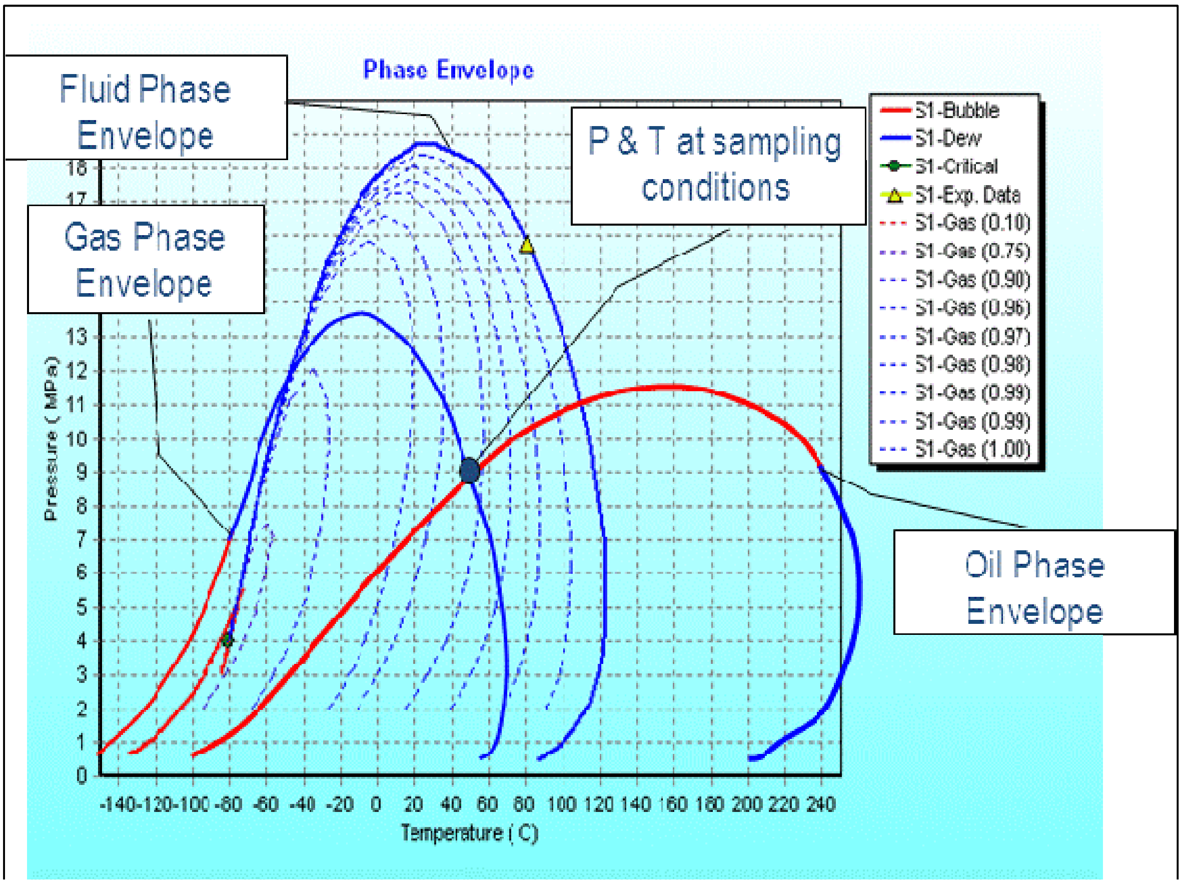


Figure 3 Mathematical recombination of a representative sample

The term PVT is well described in literature. The most common definitions are simplified and understandable for inexperienced readers who are exploring the topic. For the method of PVT correction described in this paper, a more detailed definition and understanding has been used; We define PVT (pressure, volume, temperature) as the knowledge about the volumetric changes caused by the shrinkage, expansion and density variations for all three phases present at different stages in a multiphase stream of oil water and gas. This knowledge can be summarized as the fluid behavior path. It is important to note that the density of a single fluid at line conditions does not supply adequate data to generate the PVT relationship between the produced fluids. Hence a suggestion that a multiphase meter can, through the use of a densitometer, compensate for changing PVT relationships is misleading and a gross misstatement. Another fact that is important to highlight is that the hydrocarbon mass remains the same through the journey from line to standard conditions, so this can be used for production allocation for true three-phase meters that measure oil, water, and gas without the input of GOR. Obviously, the volumetric proportion of oil and gas will change with the different stages in the fluid behavior path as pressure and temperature drop.

The mathematical recombination based on the compositional analysis and assumed GOR gives a new phase envelope of the fluid as described earlier and then leads to a new definition of the following six parameters:

- **bo** Oil shrinkage factor
- **bw** Water shrinkage factor
- **bg** Gas expansion factor
- **Rst** Stock tank gas oil ratio
- **Rwst** Stock tank gas water ratio
- **rgmp** Gas phase condensate ratio

Figure 4 shows the phase envelope for the gas and oil sample, separately analyzed. Combining both and having a given GOR defines the fluid phase envelope. It should be noted that the interception point of the gas and liquid envelope defines the operating pressure and temperature conditions, and this should represent the exact conditions where both samples (oil and gas) have been taken. This is an important point, because if they do not cross at this location it can indicate that the sample has been contaminated or suffered some other damage, such as failure in maintaining the thermo equilibrium conditions during the sampling process.

This new EoS can then be used to post-process the raw data of the MPFM collected at the time of the sampling. This in turn will generate an updated and improved GOR and associated new flow rates. This GOR can be used to recombine (still mathematically) the initial sample of gas and liquid to obtain a new EoS. As depicted in Figure 5, this is an iterative process. In practice, the convergence is very quick, and typically less than 3 iterations are necessary.

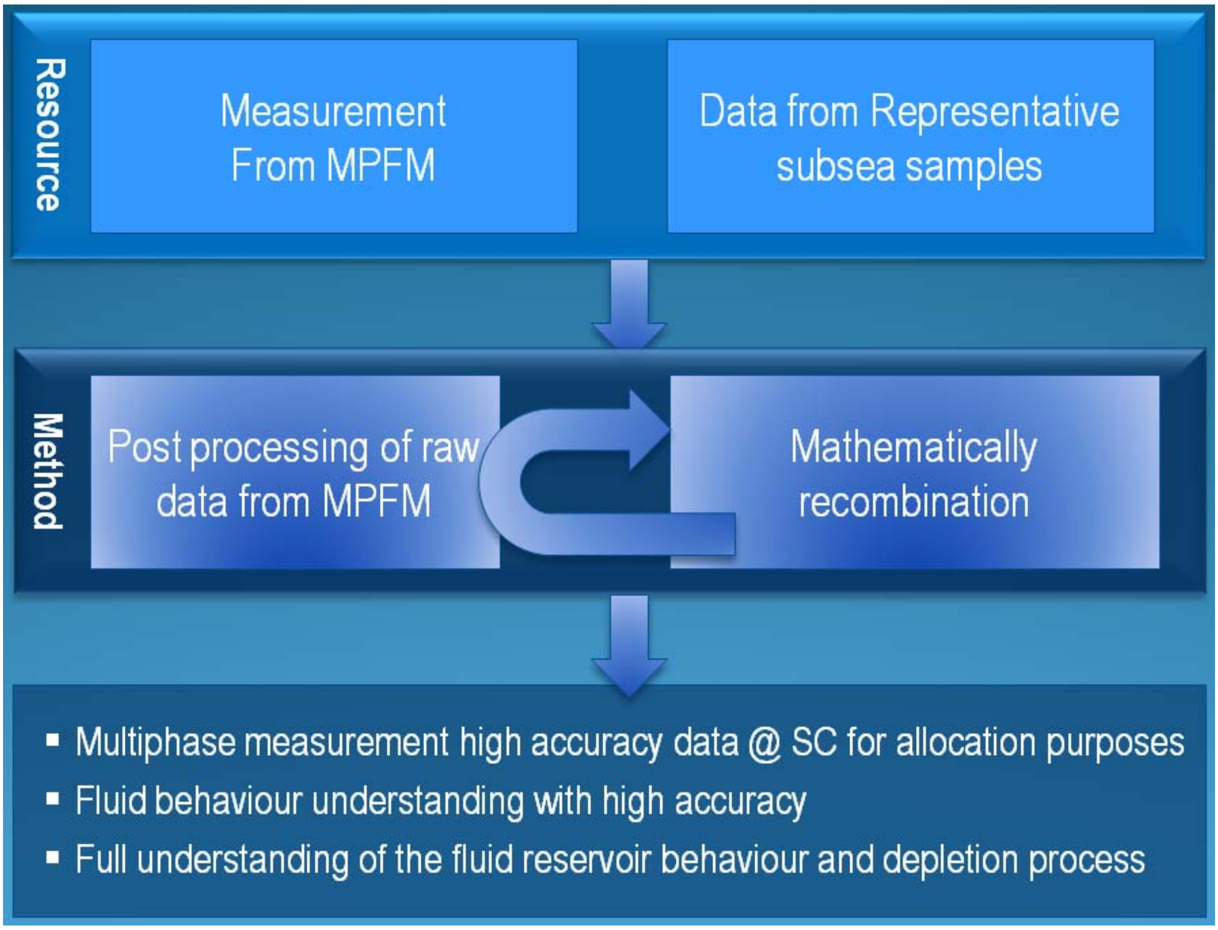


Figure 4. Mathematical recombination of an oil and water sample to redefine the reservoir fluid composition.

Defining the new EoS provides clear benefits for the reservoir, allocation and flow assurance, enabling the possibility to identify potential pitfalls and, if necessary, adjust the development plans of the field to improve the recovery factor, which is the ultimate goal from an operator's point of view.

It is always the optimum situation to have good downhole sample from the reservoir during the exploration phase. A "good sample" here means an uncontaminated sample obtained as a single phase fluid at, or near to, known reservoir conditions and with a sufficient quantity to allow comprehensive fluid and flow assurance analyses. Integration of reservoir properties and robust understanding of the fluid characteristics and behavior allows a thorough assessment of the field development concept, plan and operating philosophy that will be the most economically and technically viable.

Nevertheless, obtaining a sufficiently good downhole sample is often a challenge during field development, especially when sampling is done without proper planning for analysis requirements. It is also not uncommon for a field development plan to commence many years after the exploration phase, which was the time when the first samples were taken, either downhole or at the well test separator. Although details of the sample may have been recorded precisely, fluid compositions, properties and characteristics might have changed. As a result, assumptions are often made based on limited knowledge of the history of the fluid sample, limited fluid data (e.g. single fluid data but not the commingled fluid), operational experience, and reference to nearby reservoirs to provide some safety margins in the design of production system and operating philosophy. There are also uncertainties in reservoir properties, geological systems, and simulation tools. All of these uncertainties will result in operational challenges that must be resolved reactively or proactively.

Apart from the uncertainty in the fluid data available from the early phase of a field development, there is a potential for changes in reservoir fluid compositions over the life of a field due to issues such as injection gas breakthrough; injection water breakthrough; unexpected communication with other reservoirs that have different fluid composition; commingling of production from different wells, zones, reservoirs or tie-ins; and microbiological activities that induce souring. Reservoir production optimization and maintenance teams often face fire-fighting and production management issues, in which case they need to quickly identify the causes of problems and the current status of the system in order to manage the response appropriately and effectively.

There are three main varying factors in the system during the life of a field: reservoir condition; fluid composition, condition, properties and characteristics; and operating condition. For a well-planned and maintained production system, continuous measurements of downhole and subsea pressure/temperature/flow rate at points along the flow line is used with the PVT of the surface sample recombined from the gas and liquid phases obtained at the test separator to identify potential causes of production issues and the current status of the system. Unfortunately, production fluid arriving at the surface has often left behind some of its components along its flow journey. The recombined surface sample is not able to represent the reservoir fluid and can lead to misinterpretation or faulty analysis. The availability of the well stream compositions from each well (subsea sampling at the wellheads) and in the main flow line (subsea sampling at the manifolds), will reduce uncertainties and increase the efficiency and confidence of investigation to achieve more effective operational responses.

A subsea sample can still suffer loss of some elements (e.g. wax/scale precipitation/deposition in the wellbore) or change of properties (e.g. increased viscosity due to cooling or emulsion) when travelling up the well or from the wellhead to the manifold. While the ideal situation is to investigate the full fluid journey from reservoir to the top side separator, subsea sampling at wellheads and manifolds, when integrated with the pressure, temperature and flow rate measurements, helps to find out where events take place along the fluid journey, which makes trouble-shooting faster and more efficient. It is helpful to know the well stream composition at the manifold, as this helps in the understanding of the characteristics and behaviors of commingled well streams, which are usually assumed, or are based on limited information during the design phase. Production monitoring models can then be updated to better predict system behaviors that allow good production optimization and planning.

Production allocation is an important activity for an operator. Production allocation in deepwater fields with complex commingled streams and royalty allocations can be challenging, and inefficient measurement can lead to costly resolution. Production flow meters are often set-up based on fluids obtained from exploration samples, which can change over the field life. To have reliable flow metering, it is important to periodically update the meters with fluid properties from each well and commingled fluid, if applicable, over the field life. This fluid composition also enables fluid fingerprint identification when checking the change in fluid composition or tracing specific streams or fluid components.

Subsea sampling, in addition to topside sampling, extends the ability to understand a subsea production system with increased confidence. Continuously updated information about the fluids over the field life, when integrated with reservoir information and flow conditions (pressure, temperature and flow rates), form a powerful surveillance database to support proactive operational actions, production optimization, and flow maintenance.

Early identification of discrepancies between the crude compositions of samples obtained during the exploration phase (subject to correction for contamination and changes over time between sampling and testing) and compositions from periodic subsea sampling enables timely investigation of possible causes and, if required, appropriate adjustment of operating strategies and production requirements. Subsea sampling at the wellhead and manifold helps to identify the *in-situ* fluid composition and hence a cross-check of the current status of the fluid characteristics and behaviors in the reservoir and along the production systems. This information allows fine-tuning of the reservoir, well and production models over the production life, and consequently enables good prediction of system response for planned or unplanned activities with increased confidence.

Up-to-date fluid composition and PVT data increases the confidence and reduces the time required for trouble-shooting production issues. Earlier and effective responses can be taken to assure optimum production uptime with minimum risks. Confident fluid data that is available continuously without interruption to production helps to optimize operations and the run life of equipment in the production system. It improves system integrity and minimizes risk of production downtime and supply interruption. Representative samples of produced fluids can be used to update and fine-tune reservoir, well, production and facilities models, and are an important factor in production surveillance, monitoring, planning and system modifications or upgrading. The data also support efficient and reliable production allocation by periodically providing updated information for EoS modeling.

5. SUBSEA SAMPLING TECHNOLOGY

OneSubsea offers a subsea sampling system for the industry in its ability to provide high-quality multiphase fluid samples for full recombination and EoS modeling. The sampling module is manipulated by a remotely operated underwater vehicle (ROV) and connects hydraulically with the subsea infrastructure at a “blind-tee”. Subsea architectures of the OneSubsea PhaseWatcher Subsea Multiphase Flow Meter with Vx technology include a sampling interface as a standard option. Interface systems are also available for integration into the design of other subsea metering systems. It should be noted that the incremental CAPEX cost of including the interface in subsea architecture design is negligible, especially considering the long-term potential benefits.

The sampling module, which is the mobile unit that connects with the permanent sampling interface, is initially configured as a loop to flush and pre-heat the sampling lines. When the flushing is complete, the sample is captured in pressure compensated bottles. The ROV-enabled operation is usually performed in a campaign that sequentially samples multiple wells in a field. The subsea sampling system comprises several key components in order to achieve the target of capturing truly representative subsea samples, these key components are briefly described in the following section.

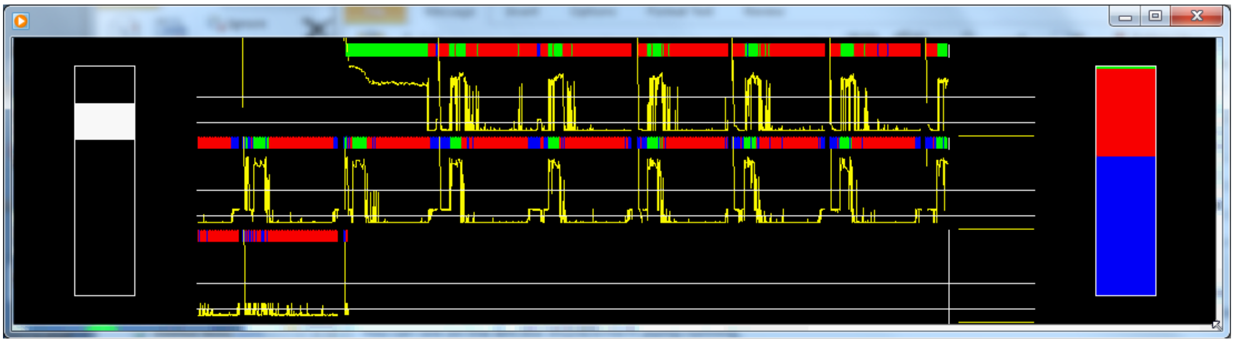


Figure 5 Sampling cycles of displacement of fluid.

A Schlumberger custom-designed displacement pump displaces the sample fluid with a minimal differential pressure (Figure 6). The design of this pump is an adaptation of a technology used in wireline sampling tools to the subsea environment. This pump is able to move fluids at a controlled rate from a high pressure point to another high pressure point. Incidentally, it also generates low mixing and pre-separation of the phases. All pumped volumes are measured by volumetric meters.

In order to fully control which phases are being collected, optical phase detector (OPD) probes are used in the flow lines (Figure 7). Using these probes allows the sampling engineer to select which phase will be collected in the sample bottles. This is also an adaptation of an existing Schlumberger technology used in production logging and surface sampling tools to the subsea environment.

The system (Figure 8) makes use of a small separator to enable sampling of the phase of interest. This is particularly required to collect the “minority” phase. For instance if there is only 1% water in the production flow and the requirement is to collect a water sample, the separator enables the enrichment of the water content in the sample.

The full system is maintained in a “heated bath” at line temperature until the sample is captured (isothermal sampling). This prevents composition change in the sample and particularly the precipitation of asphaltene and other heavy components. (Note that asphaltene deposition is more dependent on pressure than temperature).

The sample bottles are US Department of Transportation (D.O.T.) approved and can be shipped directly from the sampling module. An internal piston ensures controlled filling of the sample bottle during operations and a nitrogen precharge in the bottle ensures the sample is maintained above line pressure during recovery to surface and transportation to the laboratory. The sampling lines are short and maintained at temperature.

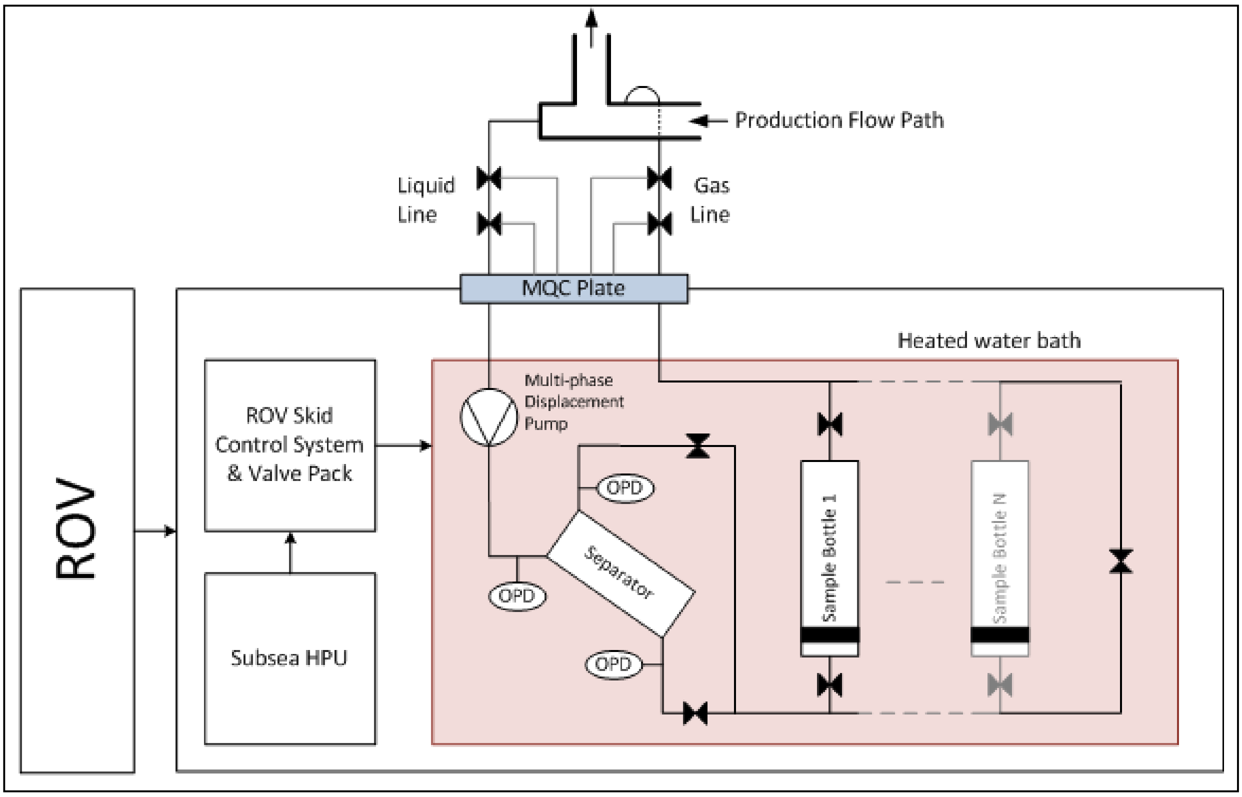
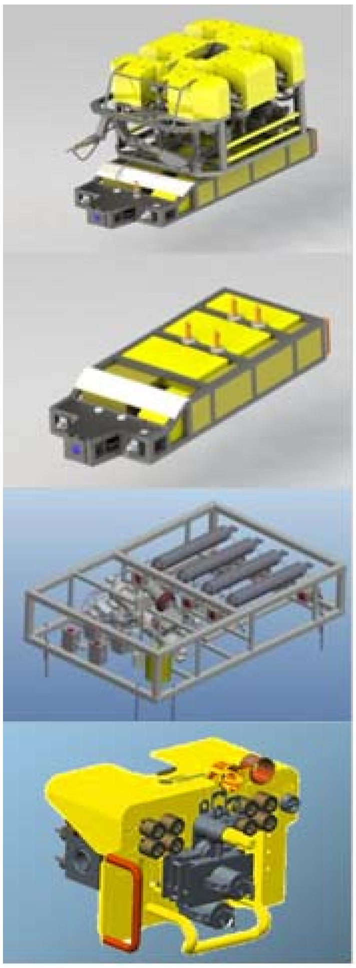


Figure 6 Simplified subsea sampling system diagram



On the permanently installed subsea sampling Interface, the sampling ports are located in a “blind tee” ensuring a partial separation of the liquid and gas phases. The blind tee sampling interface can be deployed as a standalone device or together with MPFMs.

When at the laboratory it is only necessary to heat the fluid back to the line conditions. The capability to monitor and control the pressure and temperature during the subsea sampling operation is also essential to prevent hydrates, waxes, scale, or asphaltene deposition.

Figure 7. Parts of the subsea sampling system.

5. SUBSEA SAMPLING AND MULTIPHASE METERING

One of the main advantages of capturing a representative subsea sample is the ability to take samples in close conjunction with a subsea MPFM – for example, a PhaseWatcher subsea multiphase flow meter with Vx technology. Since the subsea sampling interface is based on a blind tee that is also a required inlet conditioner for the MPFM it forms a powerful combination with three key benefits.

Firstly, the combination allows for recombination of the gas and oil samples, as described earlier. This enables analysis to generate a tuned EoS for the sampled well. This is not possible with only one of the devices by itself. It will reduce the uncertainty of PVT effects in an allocation regime, if volumes are utilized.

Secondly, the combination of flow rates of oil, water and gas with their known compositions enables more in-depth flow assurance analysis. This can, for example, identify risks of commingling production subsea from different reservoirs.

The third benefit of combining subsea sampling with the PhaseWatcher subsea multiphase flow meter is that it provides two unique measurements. The multiphase flow meter provides a unique measurement by use of a gamma system. This is based on a Barium 133 source which emits gamma rays at various energy levels. The traditional set up for the PhaseWatcher subsea multiphase flow meter is by use of two energy levels, also known as dual energy gamma ray detection. These are the measurements that provide and reliable WLR and GVF. These measurements are based on the hold up of gamma rays i.e. theoretical known properties.

Figure 9 shows a schematic of an MPFM with a blind tee sampling interface. The green encircled area is the gamma system measurement, the orange encircled area the Venturi measurement, and the dotted black oval encompasses the blind tee at the inlet as the area from where the samples will be withdrawn. The blind tee sampling point provides the ability to withdraw representative samples, the Venturi measurement provides total mass flow rate, and the dual gamma system provides the rate of oil, water and gas flow at actual conditions. These measurements are logged as raw data files from which dedicated processing software is used to derive gamma hold up information with the analyzed composition from a truly representative sample. Operators can establish a correct EoS state in the MPFM computer and hence generate a more correct conversion from line to standard conditions.

The focus in this case is set on the conversion from line to standard conditions because this is the biggest uncertainty contributor. MPFMs such as the PhaseWatcher subsea multiphase flow meter need input data as a reference, including attenuation for the energy levels in use for oil, water and gas as well as the densities. However this information is not as critical in the overall uncertainty budget as the conversion from line to standard.

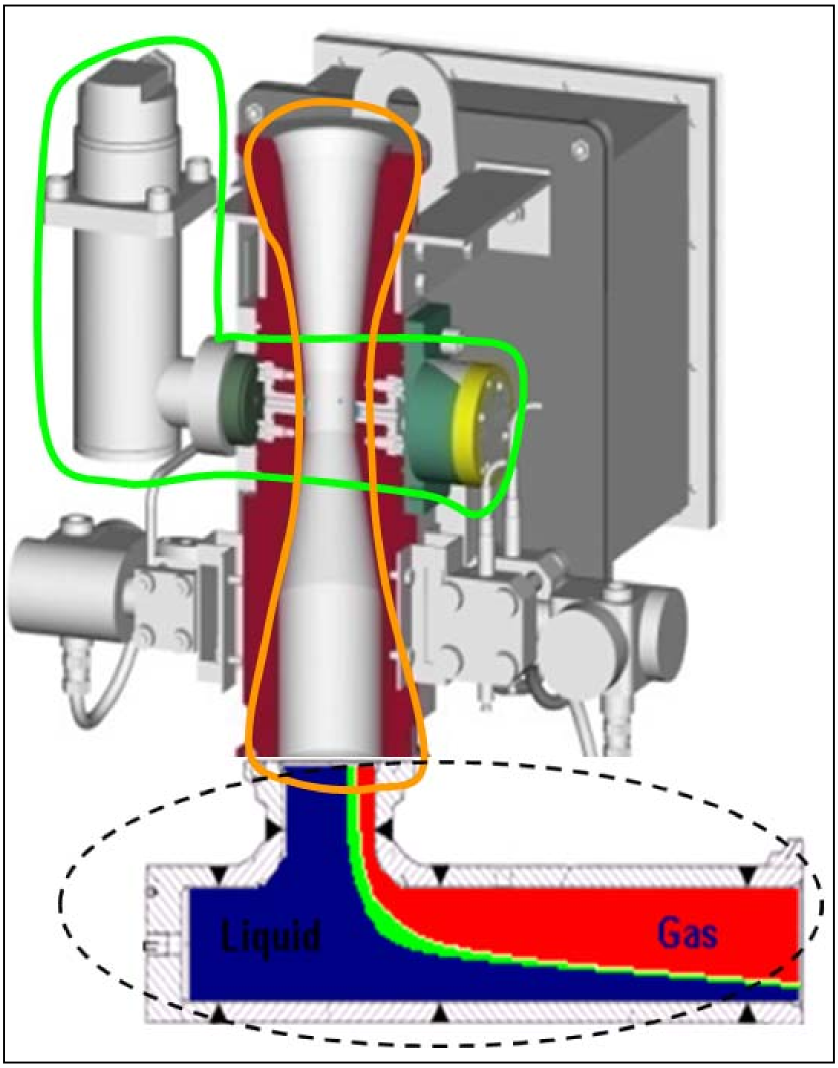


Figure 8 Schematic of MPFM with blind tee sampling interface(within black dotted oval line).

To summarize the main points of the combination of subsea sampling and multiphase metering:

- Subsea sampling and multiphase metering are not dependent on each other

- Subsea sampling and multiphase metering can form a powerful combination in the following cases:
  - EoS determination for allocation
  - fluid compositional analysis combined with flow rates for flow assurance workflows and modeling.

- All multiphase meter measurements can gain from having a full compositional analysis from a truly representative subsea sample to provide up-to-date input parameters such as mass attenuation coefficients, densities, and permittivity of oil water and gas.

6. CONCLUSIONS

Subsea sampling is already acknowledged as a valuable requirement for some applications throughout the world and is being increasingly recognized as such by government regulations. Flow assurance is a major driver for subsea sampling and some recent projects have utilized the technology specifically for that purpose. Representative subsea sampling forms a basis of knowledge about the produced fluid and its behavior that can be used in many flow assurance and measurement related situations, and forms an important source of securing investment in subsea fields.

There has been a tendency in the subsea measurement market to not take into account the value of obtaining up-to-date representative samples as well as suggest inaccurate solutions to overcome challenges, such as use of densitometers to gather fluid properties in a producing well. Associated required assumptions such as that the pipe is clean and that the fluids are pure are likely to be inaccurate in upstream oil and gas production.

The subsea sampling technology discussed in this paper has undergone an extensive qualification program even though it is, to a large extent, based on existing proven technology from topside and downhole solutions. Experience using the technology provides confidence that it can address safety issues when opening a subsea pipeline and is able to take representative samples that, with proper handling and analysis, provide operators with valuable knowledge.

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