North Sea FLOW Measurement Workshop

Challenges and Opportunities for Subsea Multiphase Meters in the Brazilian Pre-salt

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1 INTRODUCTION

The Brazilian pre-salt discoveries are among the most important made in the world over the last decade. This province comprises large accumulations of high commercial value light oil - a reality that puts Brazil in a strategic position to meet the ever increasing global demand for energy. Based on conservative estimates, and only considering the portion already discovered, the pre-salt could double the country's oil reserves to 31 billion barrels.

Multiphase flow meters (MPFM) have been in development since the 1980s. However, it was not until recently that the technology has matured sufficiently to be used in subsea allocation applications. For operators, the use of subsea multiphase meters may bring important cost savings in CAPEX via the simplification of subsea field layouts as well as in OPEX as they provide continuous real-time reservoir and production monitoring capabilities. In Brazil, the National Agency of Petroleum, Natural Gas and Biofuels (ANP) adopted resolution No.44/2015[1] in October 2015 covering the use of multiphase meters for production allocation.

In recent ANP auctions, interest in the pre-salt has been high among International Oil Companies (IOCs). With a continued relatively low oil price, a premium must be placed on technologies that can reduce CAPEX and OPEX on the cost side and/or contribute to improved reservoir and production management on the revenue side. Multiphase metering is a technology that is able do both and can thereby have a significant impact on the overall viability of pre-salt field developments.

The paper outlines how the deployment of multiphase meters can facilitate a wider range of possible subsea layouts – potentially more cost effective that a single-riser philosophy. This is important in Brazil as most fields – and particularly the pre-salt, lie in ultra-deep water. The paper summarizes the significant points of the ANP resolution that impact subsea field layouts. Finally and most importantly, the specific measurement challenges for multiphase metering in the pre-salt will be outlined.

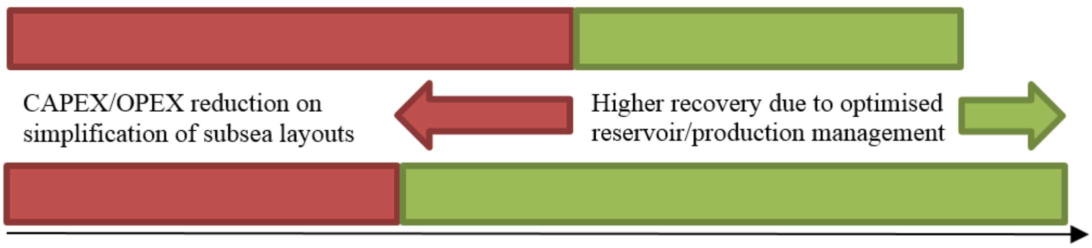

Fig. 1 - Using subsea MPFM to improve field profitability via increased recovery and cost reduction

2 SUBSEA FIELD DEVELOPMENT USING MPFM

To illustrate how the field architecture could be impacted by the use of MPFM, three hypothetical layouts shall be compared [1]. The main design parameters for this example are:

- Water depth: 2,000 m
- Design pressure/temperature: 10,000 psi (690 bar)/90 deg C
- Production per well: 10,000 bpd

The field layout comprises of three production wells forming a drill center with a fourth well located 2000 m from the cluster. All wells are tied back to a single Floating Production Storage and Offloading (FPSO) spread-moored. Flowline and riser diameters will vary according to the field layout considered.

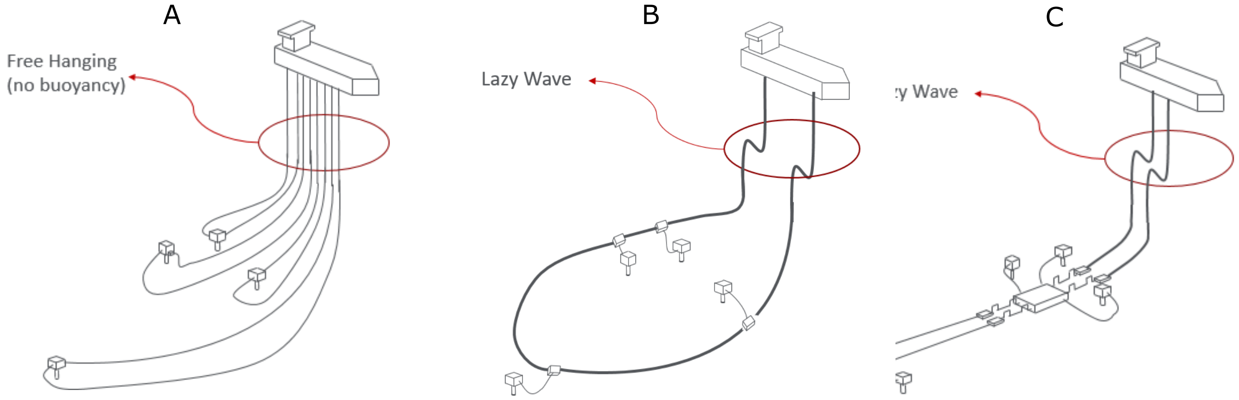

Fig. 2 - Three alternate field layouts

The base-case field architecture scenario A, is a satellite solution with each production tree connected to two flowlines/risers enabling round-trip pigging or hot-oil circulation to control wax and hydrates. The only point for chemical injection (CI) is the tree. This layout does not include subsea MPFM as the production allocation can be performed topside. As shown in Figure 2, a total of eight risers and flowlines with 6" ID are connected to the FPSO. The flowlines are connected directly to the trees without the need for Pipe Line End Terminations (PLETs) and jumpers. The riser configuration is free-hanging.

Scenario B is a daisy-chain configuration, with inline tees per tree connected through well jumpers. This layout maintains the ability of round-trip pigging and has multiples points for CI to mitigate wax and hydrates problem. The tree is designed to accommodate an MPFM. The layout considers two 8" ID risers in a lazy-wave configuration, 8" flowlines and four 6" ID well jumpers. Different operational philosophies may be considered, however in this case it is assumed that each pair of wells would flow to one riser.

Scenario C is based on a typical GoM layout using manifold. The manifold is connected to the FPSO via two 8" ID risers in a lazy-wave configuration, two PLETs and two 8" ID flowline jumpers. The manifold is tied-in to a combination of four PLETs, two flowlines and a pigging loop so that the more distant tree can be connected, whilst maintaining the dual-header functionality. The pigging loop also helps mitigate flow assurance problems as wax and hydrates and both manifold and PLETs would have CI points. This layout allows future expansion without additional infrastructure. The manifold co-mingles the production of the three trees which are connected via 6" ID well jumpers. Each tree is designed to incorporate an MPFM.

Table 1 - Comparison Of Subsea Layouts

	Scenario A (Satellite)	Scenario B (Daisy Chain)	Scenario C (Manifold)
6" ID risers and flowlines (km)	120		
8" ID risers and flowlines (km)		52	45
Buoyance Module		X[1]	X[1]
Vertical tree	4	4	4
Inline Sled		4	
Manifold			1
PLET			4
8" ID flowline jumpers			4
6" ID well jumpers		4	4
Subsea MPFM		4	4[3]
Installation time[2]	100%	75%	80%

[1]A similar module would be required for scenarios B and C. The number depends on specifics.
[2]Installation days does not consider mobilization/demobilization of vessels
[3]This layout could also include a fifth MPFM on the manifold for verification testing

There is no one-size-fits-all architecture for a given field. There are many variables to be assessed, e.g. reservoir conditions, flow assurance, installation campaign, operational philosophies, etc. As shown in Figure 2, scenario A is the simplest design but has an order of magnitude longer distance of total riser/flowline. This may be expensive depending on installation vessel. Scenario B is also relatively simple, however uses larger ID flowline (more expansive vessel day rate) and it has the ability for reservoir/production monitoring with MPFM. Scenario C, also uses a more expensive installation vessel day rate, has the same monitoring capabilities, offers a more flexible solution for tie-in of future wells and for verification of subsea MPFM by installing a meter in the manifold. This fifth MPFM may offers useful redundancy in that individual wellhead MPFM can be verified easily subsea without shutting-in wells, and in that it can be used as a primary measurement in the event of a wellhead meter failure.

The subsea architeture being adopted in typical Santos Basin pre-salt projects is based on the production satellite wells individually connected to a FPSO (A above). This configuration fits very well in the scenario of high production-rate wells and provides sufficient flexibility to optimise the locating of wellheads [2].

The attractiveness of offshore projects can be severely impacted by the drop in oil price. In this scenario, once attractive projects may become marginal or even unfeasible economically. As a consequence, the project implementation timeframe is expected to increase due to the need for more economical exploitation scenarios. It is therefore interesting to look for subsea systems that demand low deployment cost. Scenarios B and C require fewer subsea risers, flow lines and umbilicals than scenario A, so they have a potentially lower CAPEX. In addition to the CAPEX benefit, this scenario also provides:

- With the smallest number of risers, the pull-in campaign is reduced, allowing for faster production ramp-up
- Increased spacing between risers, minimizing interference problems
- Platform design can be optimized (e.g. weight and space savings can be used to accommodate more processing equipment, enabling increased processing capacity)
- Less congested subsea layout
- Smaller inventory of pipelines and risers to inspect (integrity management), providing reduction in inspection costs.

3 REGULATORY OVERSIGHT FOR MPFM IN BRAZIL

The ANP, along with the National Institute of Metrology Standardization and Industrial Quality (INMETRO) enforces the Resolution N.1 'Oil and Gas Measurement' of June 2013. This resolution provides norms that must be followed by concessionaires operating in Brazil to guarantee the integrity of the calculation of royalties and other taxes that must be paid to the federal government, states, and municipalities.

There are three different types of measurement regulated by the ANP: fiscal allocation (class 1 measurement), and production allocation (class 2 measurement). Fiscal metering is used to calculate taxation, requiring oil Basic Sediment and Water (BSW) lower than 1.0% and flow measurement uncertainties as low as 1.0% for oil and 1.5% for gas. Metering for custody transfer occurs at the point where the ownership of the hydrocarbons is transferred from seller to buyer, downstream of the fiscal metering. Production allocation is used to determine the hydrocarbon volumes to be allocated to each well in a field or a set of fields and may similarly be called 'appropriation'. The frequency of well testing for allocation is 42 days where the platform receives well produtions from two or more different fields; or 90 days if from only one field [3].

The use of MPFM technology presents a relatively high measurement uncertainty as compared to fiscal or custody transfer metering and is therefore not currently applicable in these situations. ANP deems the use of MPFMs adequate only for production allocation purposes. The ANP approved MPFM for use in Brazil through Resolution No.44/2015 'Technical Production Allocation Metering Regulation for Multiphase Flow' in October 2015 [4], [5]. This resolution regulates and establishes minimum requirements for the adoption of this technology in Brazil.

3.1 History

Historically in Brazil, MPFM have had little penetration in measurement systems installed at onshore and offshore production stations. ANP regulations were only released in the year 2015 whereas the design phase of production units (particularly offshore) takes place on average 5 years before the start of production from the field. Therefore, the completion of the first projects where MPFM are permitted will occur approximately after the year 2020.

Another important factor has been the local content policy applied to concession contracts aimed at encouraging the use of Brazilian technology throughout the exploration and development process. This has made it difficult to incorporate MPFM which are generally manufactured outside Brazil. In the past, contracts included a categorized sub-index specific to measurement systems, determining that a large part of these systems had local technology, making the use of MPFM impossible. This local content policy was revised in 2016 and now provides for greater use of MPFM.

The policy for the definition of exploration blocks can also be cited as an important influencer. In Brazil, exploration blocks do not necessarily respect the delimitations of the reservoirs nor of the municipalities/states. This means that a single well may have a different royalty scheme than an immediately adjacent well flowing to the same topside facility. In this case, production allocation using a dedicated MPFM would be of fundamental importance. Therefore, according to the ANP resolution, scenarios B and C must have dedicated subsea MPFM for allocation if they don’t have dedicated lines for well testing. Usually, in Scenario A, allocation measurements are made using a topside test separator.

3.2 A Note on Separators vs. MPFM for Allocation

Test separators are heavy systems, require considerable space for their installation, have high manufacturing, operation and maintenance costs and require long periods of process stabilization before starting well tests [6].

MPFM are lighter and smaller than separators where space and weight are critical resources subsea or on remote platforms. They can perform continuous well monitoring which allows quick diagnosis of problems and ultimately avoids lost production.

However, it is not expected that MPFM have the same measurment uncertainty as the test separator for all possible flow conditions. Periodic performance verification of MPFM in the field is therefore generally necessary along with regular maintenance and possibly re-calibration/re-configuration [7].

3.3 Overview of Resolution No.44/2015

The general overview has been treated elsewhere, but the following is an assessment of the most pertinent points from the view of subsea field development. Each of the below must be described and submitted as a project plan to ANP by the operator to obtain approval for the use of MPFM for production allocation [5].

- Measurement Performance; is the uncertainty specification of the MPFM technology typically varies with GVF, WLR, pressure, velocity, salinity, and viscosity. It is therefore required that the operator ensure that the meter has been verified through a flow test at the relevant conditions for the well/field in question. The operator may choose to accept existing performance data provided by the manufacturer or perform a new independent flow test at a third-party laboratory. The operator must be satisfied that the proposed MPFM will achieve the performance required by ANP/INMETRO over the life of the well.

- Field Configuration; is a process in which samples of pressurized fluid are collected from the well/reservoir for further PVT analysis and used to configure the MPFM for the well/field/reservoir. All MPFM require information on the single-phase properties of the oil, gas, and water - though not all technologies have equal sensitivities to these parameters. The operator must provide a fluid sampling proposal including a detailed description for the periodicity and the objective of PVT sampling, where required. The validity of PVT data used to configure the MPFM will have a direct influence on the measurement performance.

- Performance Verification; is an operational procedure aimed at evaluating the measurement performance of subsea MPFM versus a reference. The operator's verification plan must include a detailed methodology outlining which parameters are to be controlled in the process and the periodicity, with justification, in which this evaluation will be done. A test or production separator is a typical reference device, though the ANP will accept another MPFM as a reference. A meter performance evaluation report must be submitted to ANP every 180 days, though this period can be extended if the system demonstrates sufficient accuracy during the successive checks.

- Action and Contingency Plans; are the procedures to be executed in case of differences between the MPFM measurements and the reference system. These plans must describe the activities to be performed when the planned performance verification fails. It must include the methodology and objectives of the plan, including the justifications. An investigation report must be submitted to ANP of the causes of triggering of the total or partial unavailability of the MPFM. For subsea wells, the operator is required to resolve meter verification issues within 120 days of occurrence.

4 METHODOLOGIES FOR PERFORMANCE VERIFICATION

The ANP resolution No.44/2015 requires that operators have a performance verification plan for MPFM. The regulation does not specify how this should be done, but the operator must inform ANP of the the periodicity and methodology of this plan in order to obtain approval for operating the field using MPFM.

Performance verification of MPFM in the field is generally carried out against a test separator as the reference standard [8]. Moreover the ANP presents this methodology in regulation 44/2015 as the most acceptable. The production separator can alternatively be used if equipped with calibrated meters on oil, gas and water outlets.

The reconciliation factor (RF) is a means of monitoring the quality of operational data and can be a simple and effective method of verifying subsea MPFM [7]. This method involves generating a factor by the division of the sum of production of the subesa wells equipped with MPFM by the total production measured at the reference system – potentially production/test separator or even a topside MPFM (1).

$$\mathrm{RF} = \frac{Sum\ of\ subsea\ MPFM}{Total\ flowline\ production} \qquad (1)$$

The better the overal allocation system performance, the closer the RF to a value of 1.0. However, the most important characteristic is the stability rather than the absolute value. Monitoring the RF allows the observation of the change in the trend of the measurement and it may indicate the appearance of a systematic error.

The RF analysis should be performed over long periods of production, usually monthly or perhaps annually according to figure 3. Using this method of analysis over short periods of time, for example daily, may show a factor that does not correctly represent the MPFM performance.

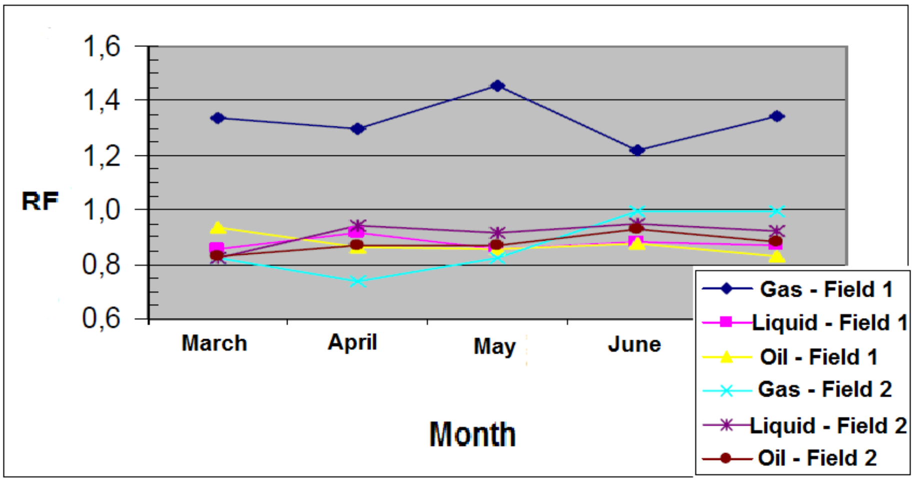

Fig. 3 – An example of RF monitoring for two oil and gas fields.

Another example subsea production allocation system using MPFM is shown below. MPFM are installed on each subsea well and on the topside flow line. In this case, the topside flow line MPFM would be a large-bore meter (10-14") to accommodate the entire flow line production. A field example of such a system is described in [9].

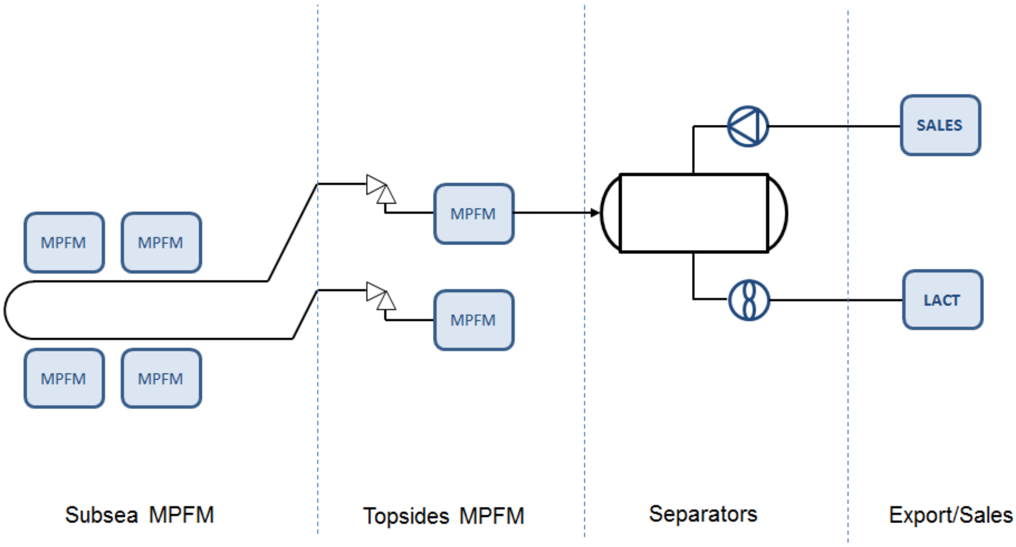

Fig. 4 – Example of a subsea production allocation system using MPFM

Produced fluids are metered at each subsea well and the whole production from a group of wells is metered co-mingled topside, preferably using the same MPFM technology. The subsea meters provide the operator with real-time reservoir and production monitoring whilst being continuously compared against a topside MPFM. The topside meter can in turn be periodically compared against a topside separator. A real-time comparison of the total hydrocarbon mass flow rate for the totalized subsea production and the topside reference avoids the conversion of oil and gas volumes between different operating and reference conditions thus eliminating this component of the total uncertainty [10].

Both the topside and subsea meters themselves require periodic verification in terms of hardware/software and configuration, which could be carried out as follows:

- regular in-situ verification on all five MPFM via a remote connection
- continuous, real-time comparison between the topside MPFM and combined flow measured by all four subsea meters
- a periodic (6-12 months) comparison of the topside meter versus a separator

This methodology significantly reduces the usage of the topside separator whilst avoiding the need to connect a single well to a topside reference. This can free the separator for other uses and minimize the lost production from shutting-in wells. This system effectively distinguishes between the verification of MPFM and the calculation of final flow rates. The MPFM is verified on a total hydrocarbon mass flow rate basis in real-time for verification, whilst the final flow rates are calculated according to the appropriate process-conversion as per the topside facilities.

5 THE PRE-SALT SCENARIO

The Santos basin pre-salt reservoir in southeast Brazil, is a heterogeneous carbonate reservoir 300 km from the coast. Reservoir depths are between 5,000 and 6,000 meters below the sea level. The reservoir lies below a salt layer which may reach thicknesses of up to 2,000 meters. There are very few similar reservoirs globally and certainly none in ultra-deep water. Oil properties are in the range of 28 to 32 API, gas-oil-ratios between 200 and 350 m^3/m^3 [11].

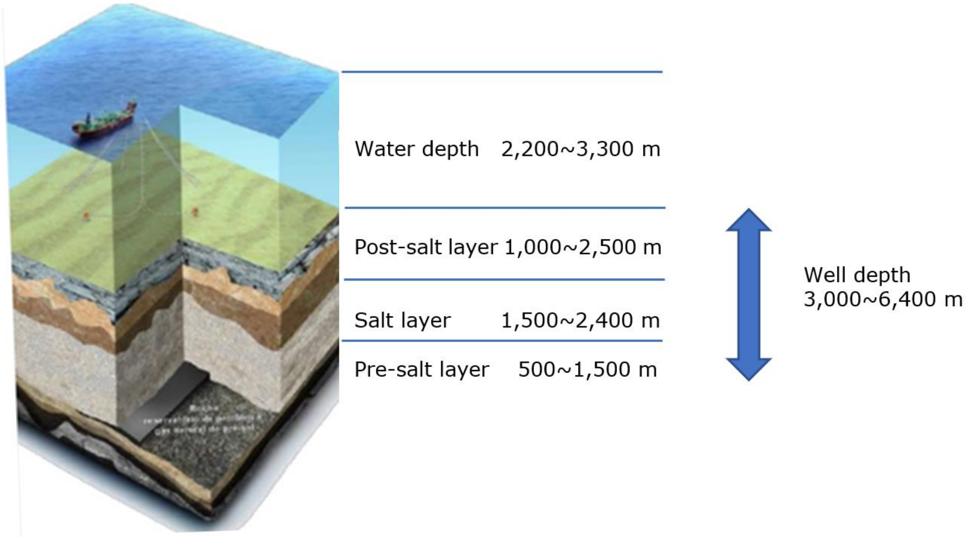

Fig.5 – Pre-salt scenario

The important characteristics of the pre-salt as they relate to multiphase flow measurement are:

1) High total volume flow rates requiring large-bore MPFM with a minimum internal diameter of 5”, and potentially higher. The high produtivity of pre-salt wells was proven in extended well testing in the Mero field in Libra block in 2018. The well reached a production of 58,000 barrels of oil equivalent per day (boed), a major result in ultra-deep water.

2) Very high formation water salinity of up to 260,000 mg/l. At the same time, Water Injection (WI) and Alternating Gas Injection (WAG) using sea water is being applied [12]. FPSOs have been designed with specific operating philosophies in order to allow changing the injected fluid according to specific alternating cycles, defined over well lifetime. Mixing of highly saline formation water with low salinity injected sea water means that water properties at the operating conditions of the MPFM may vary widely.

3) High CO2 content in the gas of up to 40-50 mol% that increases over time with subsea gas re-injection. A significant Health, Safety and Environment decision for pre-salt development by Petrobras, was the decision of not venting the naturally occurring CO2. This decision forced the implementation of compact technologies for capturing and storage of the produced CO2. It also brought opportunities for increased oil recovery using miscible CO2 injection [12]. It is therefore expected that CO2 content will increase along the production lifetime of each area. It must be noted that at the operating conditions of subsea MPFM in the pre-salt, CO2 will exist in a super-critical state.

5.1 Pre-salt Challenges for MPFM – High/Variable Water Salinity

The methods most commonly used in commercial MPFM are based on gamma attenuation, electrical impedance and/or microwave tomopgraphy. In all these technologies, there exists a limitation in the power of the transmitted signal (whatever that may be) versus the amount of attenuation that results from the flowing fluids and the distance across the pipe. For example, a low energy gamma wave may be 100% absorbed by the large volumes of dense water present at pre-salt conditions. The same is true for microwaves (high frequency) and capacitance/inductance systems (low frequency) where attention results in little or no measurable signal. As the water liquid ratio increase over well life, there may come a point where the MPFM simply stops measuring due to this high measurement signal attenuation.

With sea water injection for water flood/pressure support, the produced water at the MPFM may exhibity a wide variation in properties. Mixing of highly saline formation water with sea water will result in falling produced water salinty over time. Whilst this serves to potentially alleviate the problems of signal attentuation described above, it may also make field configuration of MPFM more complex. Water properties are a critical configuration parameter, particularly at high WLR. Salinty may ultimately range between 3.5% and 25%. High uncertainty in water properties can result in systematic bias in measured flow rates. In scenarios B and C, the subsea layout promotes a reduced number of flow lines, risers and umbilicals. In these scenarios it may be impossible to collect subsea samples of each well’s fluids topside, if there is no dedicated well test line. An salinty measurement device integtrated into the MPFM should be able to accurately measure up to 25% salinity in order to avoid the need for highly complex and expensive subsea sampling.

5.2 Pre-salt Challenges for MPFM – Super-critical CO2

At wellhead operating conditions, the CO2-rich gas will be in a supercritical condition where the fluid has both gas and liquid characteristics simultaneously. For pure-CO2, a supercritical state occurs at pressures and temperatures above 73.8 bar and 31.1ºC. The supercritical fluid has densities similar to liquids, while viscosity is closer to gas.

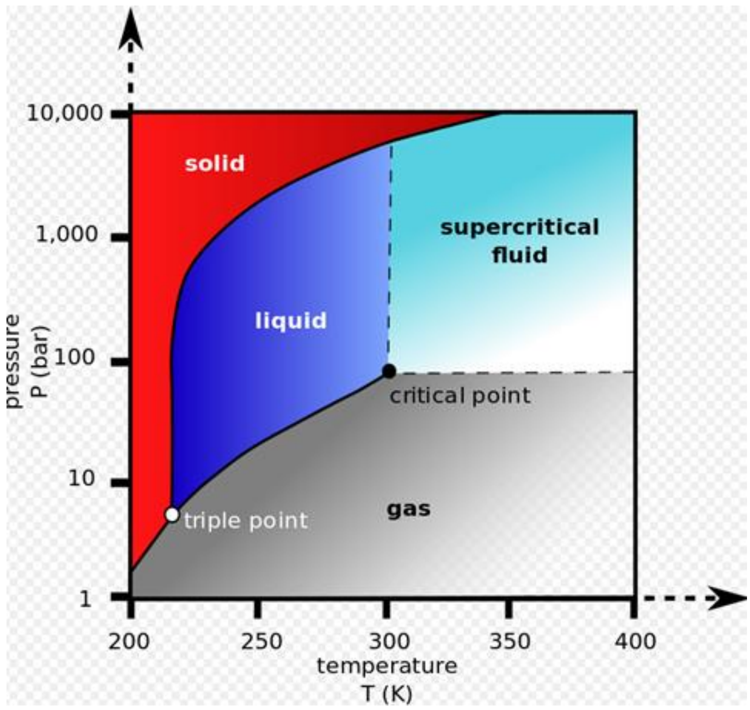

Fig. 6 – Pure CO2 phase diagram

To further complicate the matter, as shown below, slight variations in fluid composition result in important variations in the phase diagram, i.e. thermodynamic behaviour.

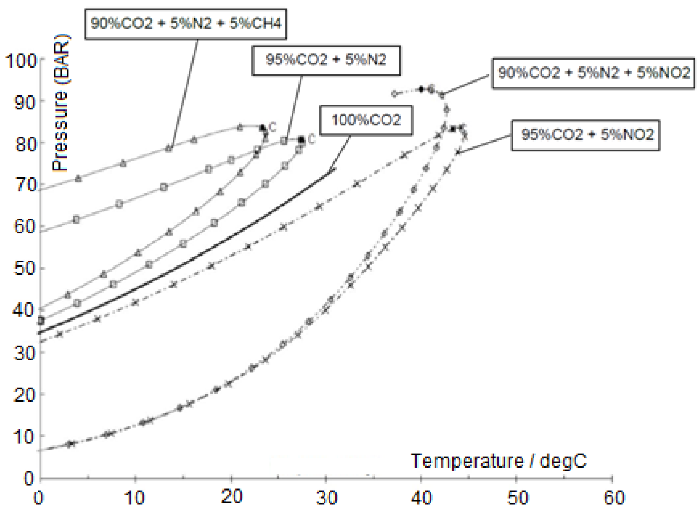

Fig. 7 – Effect of compositional changes on phase diagram critical point

All MPFM need configuration information on physical properties of the single-phases, e.g. density, viscosity, surface tension, permittivity etc. All subsea MPFM also make use of multiphase flow models for momentum devices such as Venturis or V-cones. In pre-salt reservoirs where reservoir fluid compositions contain 40-50 mol% CO_2 in a super-critical state with behaviour somewhere between liquid and gas, several areas may need to be re-examined:

- Validity of traditional Equation of State (EoS) models for modelling such fluids
- Validity and uncertainty in prediction of fluid properties at supercritical conditions
- Flow behaviour of supercritical CO_2, particularly for Venturis and V-cones
- Method of calibration for Venturis and V-cones

Furthermore, CO_2 mol% is expected to increase over time due to CO_2 reinjection via WAG. In somewhat of a parallel to the necessity to measure produced water properties in-situ; it may therefore be necessary to measure % CO_2 in-situ in order to allow accurate field configuration of MPFM without the need to take expensive subsea samples. As shown in Figure 6, small composition changes can have a strong impact on fluid properties at supercritical conditions. This behaviour may be particularly difficult for certain MPFM technologies which have high sensitivty to PVT properties; noting that each MPFM measurement principle will have a varying degree of sensitivity to such variations.

6.0 CONCLUSION

MPFM have become a standard element of subsea production systems. Brazil has lagged the global uptake of this technology for various reasons. However, with the ANP resolution of 2015, all the advantages in terms of simplification of subsea layouts, replacement of test separators and production/reservoir monitoring are now accessible to operators. Considering the ultra-deep water environment, the return on investment in the use of MPFM may in fact be higher in Brazil than in other areas globally. However, the Brazilian pre-salt presents a significant challenge for MPFM due to high flowrates, high/variable water salinity and high/variable CO_2 content. For an already complex science, multiphase metering under these circumstances may even be impossible when taking into consideration the acceptable uncertainty for production allocation. It is doubtful that the current state of technology is up to this challenge and further work must be carried out by operators, manufacturers and indeed flow loops. As of today, there is no flow loop globally that can simulate the exact conditions of the pre-salt. This may eventually represent a road-block to testing any technologies which are developed.

7.0 REFERENCES

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Tekna

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