Operation and Maintenance of Multiphase Flow Meters (MPFMs) on BC-10 in Deepwater Brazil

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Abstract

The Shell operated BC-10 field located in deepwater, 1650-1920m, offshore Brazil produces heavy oil in the range of API 16-24. The fields are produced using an entirely subsea development concept tied back to the host FPSO located approximately 8-10km from the producing fields. Given the high cost of subsea wells and the associated pipelines and artificial lift pumps, surveillance and optimization of each well becomes increasingly important in the operation of an efficient production system. In the case of BC-10, the entire development concept was based around having accurate subsea metering as this allowed significant design changes including:

- CAPEX reduction through the elimination of test separators and the use of fewer but larger production risers,
- The elimination of well testing deferment caused by testing by difference,
- A robust flow assurance strategy as wells would not need to flow alone over long distances (up to 16km)

In addition to this, the ability to measure continuously and accurately has been a huge driver for production optimization.

What makes the operation of MPFMs successful is continuous monitoring and tuning as project assumptions are replaced by field data.

In this paper real world examples of operating and tuning MPFMs will be given including:

- Continuous monitoring of topsides measurements vs subsea measurements
- Setup of MPFM after first oil prior to samples being available
- Adjustments for changes in reservoir fluid properties
- Tuning when water salinity changes
- Setup for high watercut wells
- Validation of gas rates using GVF models and MPFM measurements

The goal is to share the challenges encountered operating subsea MPFMs over 5 years of production together with solutions for maintaining accuracy in an environment where well testing was not feasible. Whilst by no means exhaustive, it is hoped that some of the learnings here will be applicable to other fields which have similar concerns.

Introduction

An MPFM is multiphase flow meter, capable of measuring at least 3 discrete phases: oil, gas and water. In operation the advantageous of using MPFMs include:

1. Real time production data for reservoir and flow assurance management
2. Allocation of fiscal oil and gas back to individual wells without the need for well tests
3. Reduction in CAPEX as test separators and test flowlines are not required
4. Removal of deferment associated with by difference well testing
5. Field/well optimization on a daily basis
6. Real time rate data for leak detection models

Multiple technologies for multiphase metering are available, however the basic principle is to determine the phase fractions present and then apply a venturi equation to convert the measurement data into phase flow rates. The models required to do this must factor in the phase behaviour and phases densities together with their impact on the primary measurements. The phase measurement typically is performed by deploying a radioactive source together with a detector system which can differentiate the presence of gas and liquid. The proportions of the liquid can then be determined either through conductivities or through further radiation attenuation. The meters used in the BC-10 project are all One Subsea Vx type 52 meters and from this point on all references to MPFMs are references to this specific meter.

The BC-10 Field

BC-10 is an all subsea development located in deepwater Brazil. Partners in the development are Shell (50%), ONGC (27%) and Qatar Petroleum International (23%). Production comes from 4 fields located in water depths ranging from 1640-1920m, these are moderately heavy oil relatively low gas content – see table 1. The subsea architecture which enabled the development of these separate reservoirs consists of multiple drill centres coupled to production manifolds. Manifolds are routed to caisson ESPs (Electrical Submersible Pumps) which provide the necessary energy to bring the fluids to surface. To minimize equipment costs, each field has only two production flowlines routed to the host, one for production and the second for hot oil displacement and/or production. In the case of Ostra, a third riser for gas separated subsea is also present – figure 1. Such a design reduced the number of risers required - an important consideration as on the host, a turret moored FPSO, turret routes are bulky and expensive. In line with this philosophy, there are only 3 production trains on the host, one for each field with Abalone being produced together with Ostra. In total the use of MPFMs allowed the removal of 3 additional risers and the test separator, not to mention additional lower capacity ESPs which could deal with single well flow rates. Further benefits come from integration of water flood management with continuous producer well monitoring and its ability to observe if a particular injector – producer pair are in direct communication. In Brazil the regulatory regime requires that individual wells be tested at least every 45-90 days, which in a system with reduced CAPEX, would lead to additional deferment as testing by difference would be required.

Field	Phase	Density (API)	GOR (SCF/bbl) [Sm3/Sm3]	Oil Viscosity at flowing wellhead conditions (cP)	MPFMs installed / Wells
Ostra	1	24	278 [49]	7-8	7 /7
B-West	1	16	200 [35]	90-100	0 / 2*
Abalone	1	42-45	3200-4000	1-2	1 / 1
O-North	2	16	350-325 [62-58]	50-70	7 / 7

*Future well tie-ins require MPFMs to be retrofitted.

Table 1. Oil properties for the various operating fields in the BC-10 development

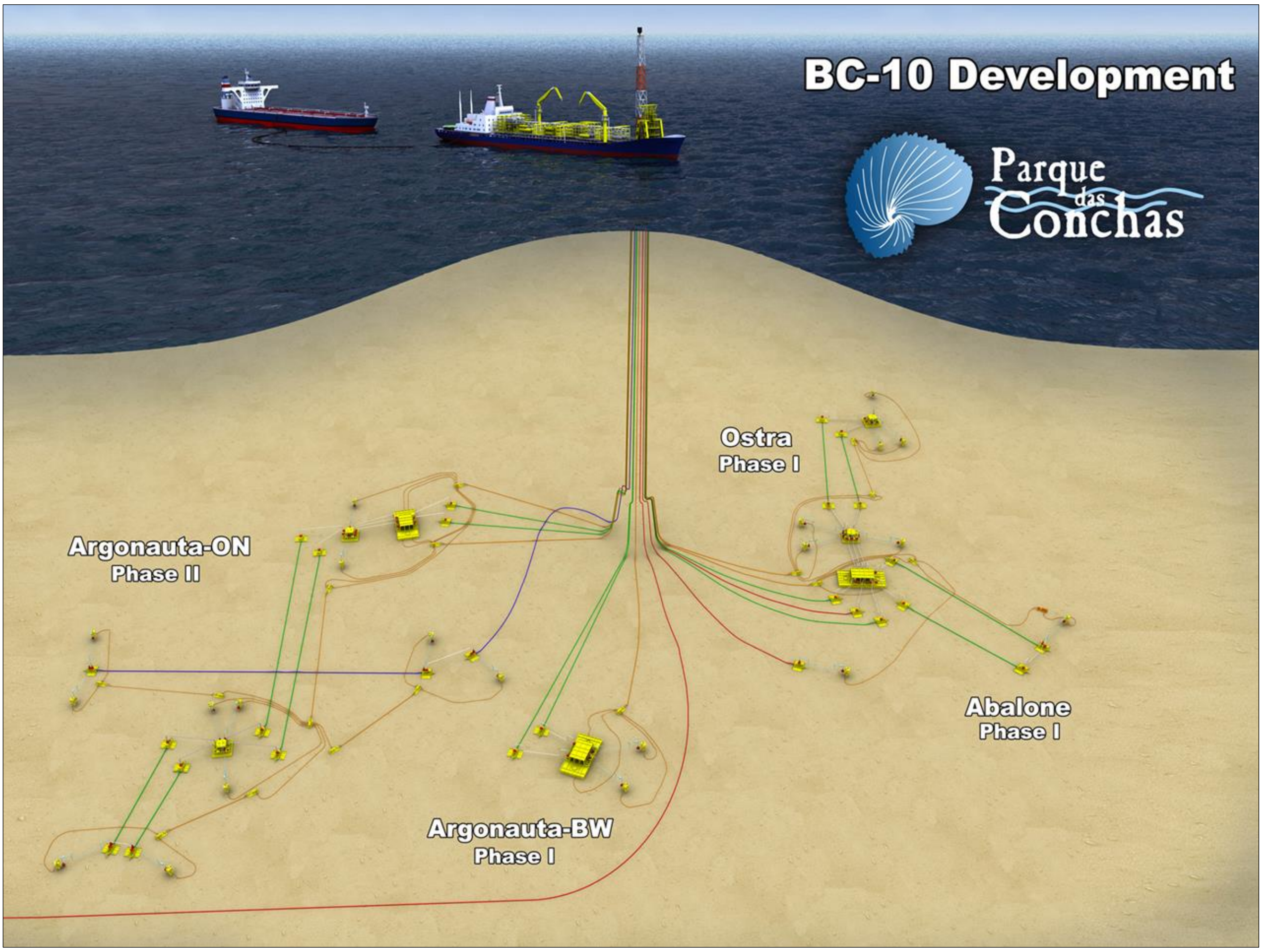


Figure 1. Diagram showing the field layout: Gas lines – red, Oil/Water/Gas lines – Green and Water Injection - Blue

History of Petroleum Legislation in Brazil

On August 6th 1997, the Brazilian government issued the Law 9.478, known as “Lei do Petróleo”, that liberalised the petroleum industry in Brazil and created the “Agência Nacional do Petróleo (ANP – Petroleum National Agency)” as the state department responsible to control, regulate and inspect the oil and gas industry. In order to ensure oil production was being correctly measured, which has a direct impact on royalties payment, ANP has issued on June 19th 2000, the “Portaria Conjunta N°1”, which was the first Brazilian legislation on Oil and Gas Metering. Multiphase metering was not included as an approved method for measurement, but the legislation indicates that other technologies could be used following prior approval from ANP.

The BC-10 Allocation philosophy was based on well allocation using the MPFM results as it is challenging to perform a good well test due to the oil properties and field hardware design. In this sense, ANP approved the use of the MPFM for well allocation in Ostra and Abalone Fields, part of the BC10 Phase 1.

On 1st of June 2013, ANP issued a reviewed legislation for metering, “Resolução Conjunta ANP/Inmetro n°1”, which included for the first time the multiphase metering. The legislation stated that the “measurement systems that uses MPFMs should comply with the technical metrological requirements established by Inmetro”. However, Inmetro has indicated that the regulation requires further metrological and technological knowledge that is currently not available in the agency. In this case, MPFM applications continues to be approved as deviations by ANP, which is the case of the approval for the use of MPFM for well allocation in O-North, authorized in September 2013.

Principles of Operation

The Vx type MPFM works using a radioactive Barium 133 (Ba-133) source and a full spectrum gamma detector. The Ba-133 source is located in the throat of a metallic venturi meter and is installed behind a ceramic window which allows the radiation to pass directly though the fluid inside the venturi throat and into the ceramic window protecting the gamma detector opposite it. The venturi is instrumented with dual differential pressure gauges (throat to inlet) and dual line pressure and temperature sensors which measure the conditions at the inlet. Critical to obtaining a repeatable fluid inlet pattern, a blind tee is installed upstream and conditions the fluid such that the feed to the venturi always conforms to the assumptions contained in the slip model. Figure 2 shows the general assembly.

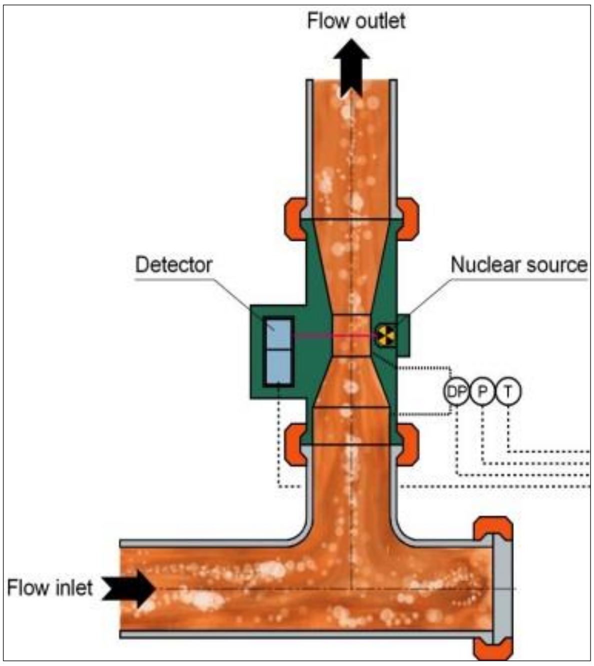


Figure 2. Overview of meter construction showing the key sensors and blind tee

The raw gamma counts are grouped into three energy peaks (32keV-Low, 81keV-High and 356keV) based on the output of the gamma detector.

From these raw inputs, the flow computer calculates the attenuation of the radiation coming from the source. This requires an "empty pipe reference", a measurement point when the venturi throat was known to be clean and air filled – the three gamma peaks are recorded together with the date and time. Such a profile is show in figure 3. A nuclear decay model is then applied and a new empty pipe reference created for the current moment in time. From this the attenuation is calculated using the ratio of measured counts to the calculated current empty pipe counts.

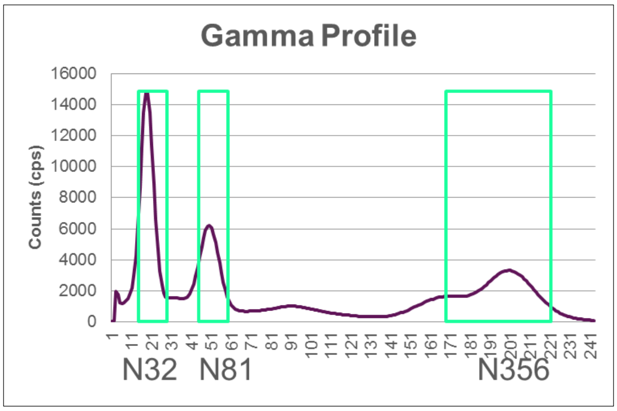


Figure 3. Detector count of the Ba-133 source for an empty pipe

Each peak, the Low (32keV), High (81keV) and 356 keV is thus converted into an attenuation.
Atomically different substances absorb varying radiation levels differently according to inherent properties and this is modeled by the attenuation equation below:

$$I = I_0 e^{-\mu d}$$

Where: I – the gamma intensity, I_0 – the initial gamma intensity, μ - the attenuation coefficient for the medium and d – length travelled through the medium. Note that this equation needs a different mass attenuation coefficient for each energy level and for each phase. Mass attenuation is obtained from attenuation thus:

$$\frac{\mu}{\rho}$$

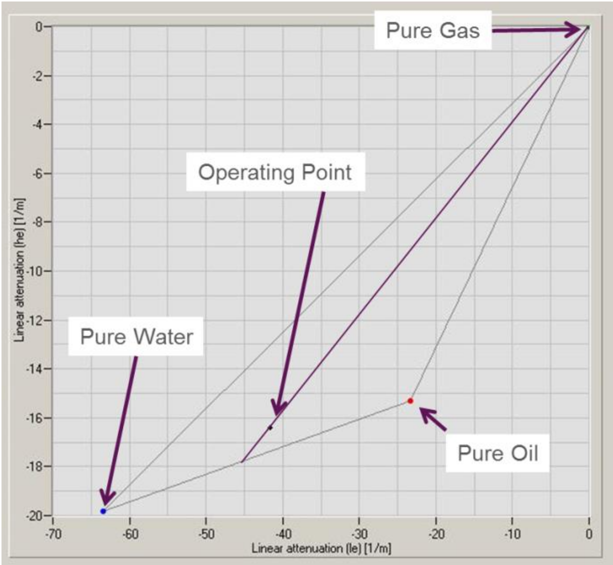


Figure 4. Example solution triangle showing the 3 pure phases and the operating point

Higher radiation energy levels are far too energetic to react with anything less massive than the nucleus of an atom. This makes the attenuation of high energy gamma rays dependent on the number of nuclei between the source and the detector which of course is proportional to density, adjusted for composition and pressure and temperature.

Lower energy gamma rays, specifically much lower than 300 keV, begin to interact more and more with the electron clouds of the medium. There are two of these effects that dominate in the electron cloud interaction, Compton Scattering and Photoelectric Absorption. Whichever is dominant will depend on the energy level of the gamma rays and the specific medium. This secondary dependence on the medium allows us to differentiate between mediums of similar densities such as oil and water.

The denser the substance, the more atoms there are present to interact with the radiation and hence the higher the attenuation coefficient. Ions also increase the attenuation of a substance. Formation water always contains some level of salt. Gas, with a density lower than either water or oil, is the easiest phase to detect. Mass attenuation of a substance is a largely fixed property, assuming of that the composition does not change (H2S, CO2 as these dissolve in oil and flash off changing the oil properties and salinity).

The specific mass attenuation of each phase can be measured using a pure sample of formation brine and a separate sample of oil. This is carried out using a test cell consisting of a source and detector of the same type as will be used in the field. The meter measures linear attenuation, the amount of peak attenuation for a given throat size and as such it is necessary to convert mass attenuation into linear attenuation by multiplying by the phase density. Here is where the configuration file in the flow computer comes in; it provides a pressure and temperature dependent relationship for the gas, oil and water densities allowing the line pressure and temperature measured to be used to calculate accurately the density of each phase. With this the meter can now solve the two energy level attenuations to derive the gas volume fraction and water – liquid ratio inside the venturi. This can be graphically represented in a solution triangle, an example of which is shown in figure 4. By visual inspection it can be seen than each pure phase has a unique linear attenuation of the high and low energy (LE and HE respectively) gamma peaks. The gas fraction is the area between the operating point and the pure oil and pure water points, divided by the total area of the triangle from gas to oil to water. In the same manner the ratio of oil to liquids may be found and also converted to a volumetric fraction. By difference what is not gas or oil is assumed to be water. Due to phenomena known as slip, the gas in the venturi travels much faster than the liquid phases and consequently the gas fraction measured in the venturi needs to be corrected to account for this effect. In the Vx meter this process is handled by a propriety slip law equation. At this point the meter computer has the venturi throat phase fractions, this allows the density to be determined of the multiphase mixture and then the standard venturi equation used to solve for the total volumetric flow rate (where: q- volumetric flow rate, d – throat diameter, D – inlet diameter, Cd – discharge coefficient, ΔP – throat to inlet differential pressure, ρ fluid density):

$$q = C_d \frac{\pi d^2}{4} \sqrt{\left[\frac{2\Delta P}{\rho (1 - \frac{d^4}{D^4})} \right]}$$

The meter computer also adjusts the discharge coefficient based on the fluid fractions measured in the meter which is used to calculate a mixture viscosity and Reynolds number used to determine the correct coefficient. This is important as the basis for the venturi equation is zero viscosity (implying that all differential pressure change is the result of acceleration, not due to friction on the venturi wall) and in heavy oil or emulsion prone systems, this assumption is not correct and would otherwise compromise meter accuracy.

From this point, the actual volumetric flows are known and it is required to convert them to standard conditions. This is calculated using volume formation factors, as are commonly used in reservoir engineering, where the actual volume is converted by the following equation:

$$Q_{(standard)} = Q_{(actual)} . B_x$$

Where Q is the flow rate in standard and actual (also called line) conditions and Bx is the formation factor also called the shrinkage factor. As an example, a typical oil shrinkage factor could be in the range 0.7-0.95 depending on the temperature, pressure and GOR. The shrinkage factor is computed from the line pressure and temperature using the information contained in the configuration file which has been set up based on a PVT report for the specific crude being produced.

In addition to the measured phases, there are certain quantities which cannot be measured by the meter.

One example is the solution gas, since the meter typically operates at pressures well above standard conditions, there will be gas which is dissolved in the oil and water phases which will flash off at stock tank conditions but not in the meter. At high pressures the solution gas can easily be a factor higher than the measured “free gas” and is accounted for using the PVT behaviour contained in the configuration file, which calculates a solution GOR and applies this to the standard oil rate to determine the solution gas rate. To this the gas dissolved in the water phase is also calculated and added to the free gas (at standard conditions) to produce the final gas rate.

Metering Assurance

Having MPFMs installed and producing flow rate data, the question arises as to how to validate it. In traditional oil and gas production facilities to measure the production of a well it would be removed from the other production and routed to a test separator, which would have separation and metering of the individual phases together with the option of taking samples to determine gas and oil density together with BS&W to allow the readings to be corrected for incomplete separation. This option may be available in some facilities which have MPFMs and allows periodic verification of the results. However MPFMs add the most value in situations where such well tests are either difficult or impossible, for example in complex subsea production systems which have long tie backs and where flow instabilities in the pipeline make out flow unstable and hence testing by difference challenging. Gas condensate wells provide such a challenge, as at low rates, pipeline liquid hold up can take days or even weeks to establish steady conditions, leading to an underestimate of well liquid rates if testing by difference. For oil wells in deep water, hydrate prevention by heat retention may make it risky to flow wells at low rates into a dedicated test line for fear of forming hydrates or wax in the pipeline. One solution to this problem is the use of reconciliation factors (RF) comparing the topsides metering with the sum of the MPFMs aligned to it as below:

$$RF_{(phase)} = \frac{Surface\ daily\ total_{(phase)}}{\sum_{1}^{number\ of\ aligned\ meters} MPFM\ daily\ total_{(phase)}}$$

With this approach and careful surveillance a reconciliation factor of 1.0 indicates that the MPFMs are reading correctly. When wells are brought offline, the RF should not change once the system returns to steady state, otherwise this suggests that that meter was contributing more or less than is being measured.

Other methods such as applying a well bore model to the production and matching the measured pressure data by adjusting the rates, GOR and BS&W until it matches can further confirm if the meter is likely correct. In most instances an adjustment of GOR is not acceptable for non-gas lifted wells where the GOR is fixed by operating the reservoir above bubble point.

A method which was successfully used on BC-10 was turret BS&W sampling, this was helpful in early field life where the watercut of the combined fluid was very low <1% and as such was required to prove the wells were dry. In-well water soluble tracers provide additional support to determine that no formation water is being produced.

Finally step tests can be employed to try and detect that performance is correct over several well bean ups. However this method is least reliable as it involves disturbing the steady state and if other wells are of similar BS&Ws it may be hard to determine anything accurately.

The effects of Salinity on the Vx

The Vx was developed with the conscience choice of Barium as its gamma ray source. This was done for many reasons, not the least of which was the ability to distinguish between the three phases of Water, Oil, and Gas, but also the relative insensitivity to the salinity of the flow. The measurements robustness to salinity makes it possible to reliably use the Vx in any conditions with a change of Salinity of around 5-6%.

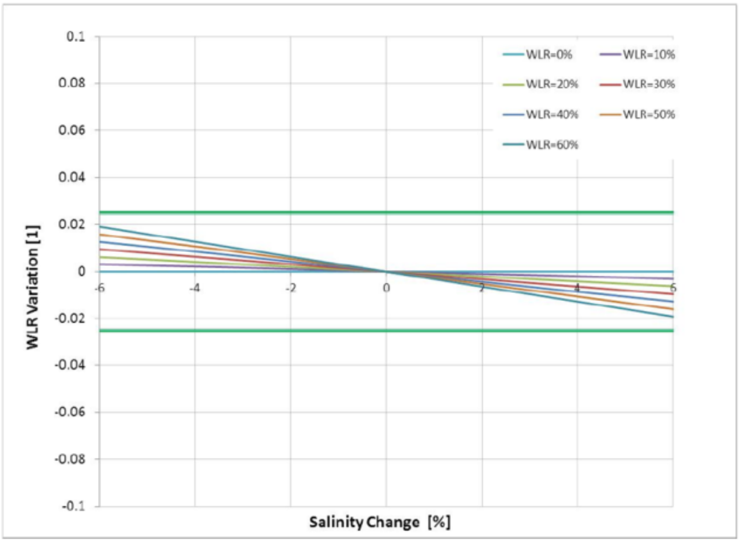


Figure 5. Variation in water liquid ratio for various salinity changes.

In order to differentiate the fresh and briny solutions, figure 5 displays the attenuation of 100% of each phase. If we assume a typical WLR of no more than 50 to 60% as in a gas well then the salinity change from 0 to 10% affects the WLR by less than 2%. Concurrently the oil and water flow rate are equally minimally affected by the same amount.

This strength can also be a weakness where salinity change is a concern for flow assurance and first water production requires a sensitivity greater than 125ppm. It should be noted that it is possible to detect salinity changes with the Barium system through the use of the third energy level, but this method is limited to WLR's > 30% and GVF's over 70%.

Phase 2 Start-up Tuning

BC-10 Phase 2 (O-North) was started in September 2013 and it was agreed with ANP that each meter would be individually verified against the topsides separator meters before the next well could be opened, hence at any one time there was never more than one well with an unproved MPFM. As there was not sufficient O-North oil for a test cell to measure the mass attenuation of the oil the meters were started up with estimated parameters for oil and an assumed formation water salinity. Due to the design of the BC-10 system, there is a minimum flow rate which can be produced without encountering slugging or running into viscosity and hydrate issues. This rate, around 15000 BPD, was well above the rates expected from a single well and as such the system was started up by circulating gas spiked dead oil from the Ostra field. This allowed for the initial well unloads and clean up but prevented the taking of a pure oil sample of O-North. Once four wells had been brought online and all their completion brine had cleaned up, all their watercuts tended to a flat line in the range 3-4%, the figure 6 shows this for 2 wells where the initial clean up can be clearly observed followed by a steady state. Topsides samples were taken and this confirmed that there was <0.5% BS&W meaning the MPFMs were not correct with respect to watercut and water rate. After examining the meter solution triangle it was noted that the pure oil operating point was most likely incorrect, since this had been estimated due to the lack of a suitable sample. Adjusting it for both LE and HE attenuation resulted in a reduction of the BS&W from 3 to 4% to -0.25 to 0.5%. The solution triangles below illustrate the changes – figure 7 showing the initial setup which had produced the 3.5% watercut and figure 8 which shows the final tuned values matched for BS&W and GVF. As the position on the gas-oil line also affects the GVF and hence free gas rate, the new oil point had to be adjusted such that the GVF was in line with the PVT expectations. This required several iterations to achieve as only small changes were necessary.

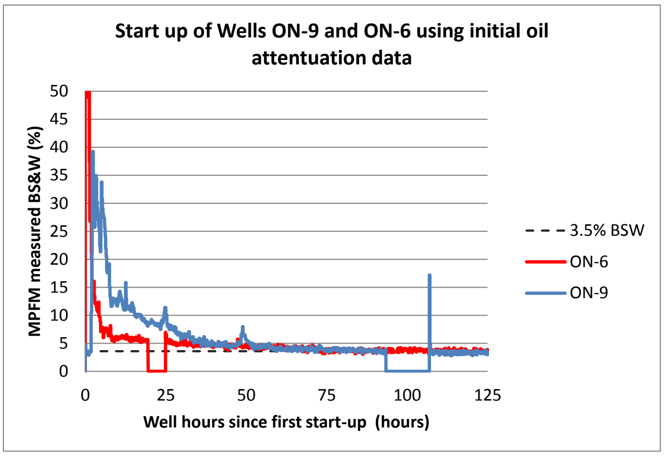


Figure 6. Start up of two new wells with the same configuration files as the completition brine unloads and the well becomes dry.

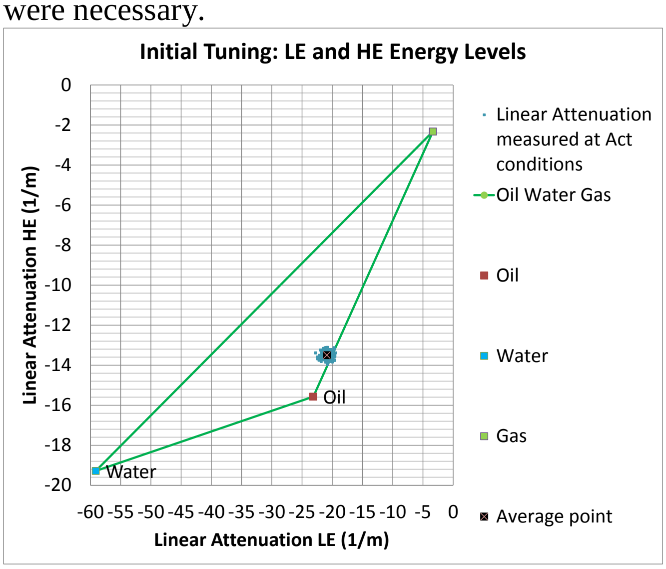


Figure 7. O-North initial MPFM configuration which resulted in a meter BS&W of 3.5%. Surface samples indicated no measurable water.

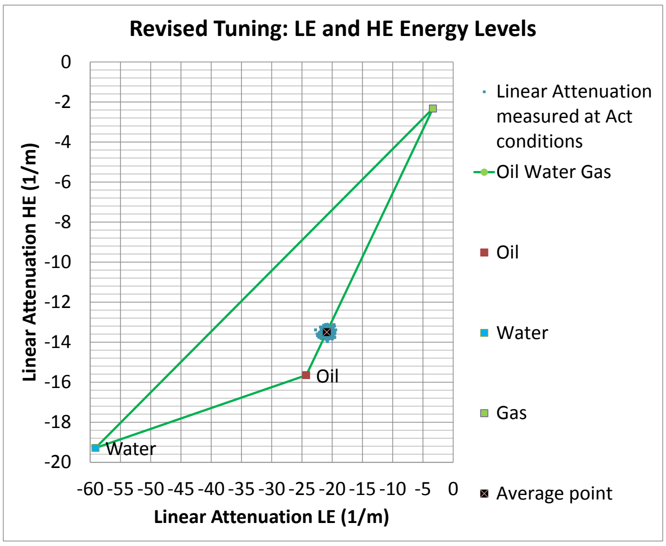


Figure 8. O-North final MPFM configuration after minor tuning to reduce watercut to match the surface.

Phase 2 Comparison with Lab Data

Once a pure sample of O-North oil uncontaminated by the gas spiked Ostra oil was collected it was sent for lab analysis to determine the density and the mass attenuation. However the lab results were significantly different from the tuned values, which had given good agreement with the topsides measurements of zero water and GOR. The table 2 below shows what happened after these lab results were uploaded to the config file. Note that the comparison included the change in oil mass attenuation but also the use of the original PVT which had a target GOR at reservoir initial conditions of 62 Sm3/Sm3 [350SCF/bbl] which had been proven to be higher than surface metering suggested.

Using the new lab values, the GOR dropped by about 10% despite using a higher solution GOR in the configuration file – had this not been the case, the lower GVF of around 5% would have had an even more dramatic impact on the overall GOR reported by the meter. After this testing period, the original file was put back into service and metering reconciliation factors reverted to normal.

Test Period	18th July 2014		9th December 2014	
Parameter	Start up tuning with GOR of 58Sm3/Sm3 File: 005	Lab data for oil attenuation, GOR 62 Sm3/Sm3 File: 006	Start up tuning with GOR of 58Sm3/Sm3 File: 005	Lab data for oil attenuation, GOR 62 Sm3/Sm3 File: 006
Oil Rate (Sm3/h)	21.2	22.5	18.1	19.0
Water Rate (Sm3/h)	2.4	2.0	8.0	7.6
Gas Rate (Sm3/h)	1231	1167	1030	983
Free Gas Rate (Sm3/h)	439	247	382	262
GVF (%)	9.2	4.8	7.9	5.0
GVF using PVT data at line temperature and pressure (%)	8.5		8.3	
BS&W	10.2%	8.2%	30.7%	28.6
GOR (Sm3/Sm3) [SCF/bbl]	58.1	51.9	56.9	51.7
GOR (Sm3/Sm3) [SCF/bbl] : PVT Report / Surface Rates	62.4 / 57.9 [350]/ [325]			

Table 2. Two test periods where the oil attenuation used was changed to that obtained from the lab analysis for mass attenuation. Between tests several months elapsed as can been seen from the different watercuts.

The lab data config file reduced the GVF from 9.5% to 5%, indicating that the oil point had moved up, towards the gas point. This was suspicious as it did not agree with the GVF which would be expected based on PVT behaviour alone, which was 8.5% at line conditions using a GOR of 350SCF/bbl. This in turn affected the GOR, since the free gas is a direct function of the measured GVF, reducing it below the GOR measured at the surface and in the original PVT report range. Alone these results were enough to give confidence that the lab data did not accurately represent the field operating conditions and the "revised tuning" parameters were retained in all meters. One possible explanation, and one which was not examined at the time, was that the slip law which converts the measured GVF into the reported GVF, could be introducing some error into the calculation – for example if the viscosity model was wrong then the slip between the phases might be effected. A second explanation could be errors in the oil density measurement in the original PVT report; however no attempt was made to tune the density since there was no subsequent PVT analysis to base changes on.

Ostra Gas Rate Offset

During the operation of Ostra, the reconciliation factor on gas had been gradually rising until it was above the recommended limit (1.1). Investigation was focused on the water attenuation initially but in consultation with experts it was noticed that the water density, which for Ostra should be around 1110kg/m3, was in fact 990 kg/m3 at operating conditions.

This may have been a remnant of the commissioning phase, where condensed water was expected, but it was unsuitable for higher watercuts and had reached the point where it was seriously affecting the gas reading. Once this was realised, the configuration files were updated to match the water density expected and the gas reading improved dramatically. The entire update process of the 7 meters took almost 2 days, owing in part to the technician carrying out multiple tasks, but also due to the low communications speed on the subsea communications architecture. Figure 9 shows the metering of subsea gas and topsides gas for 10 days, before, during and after the update. The impact to the oil and water rates was not significant, figure 10 shows them before and after and only the total water shows a notable reduction of 2-3%.

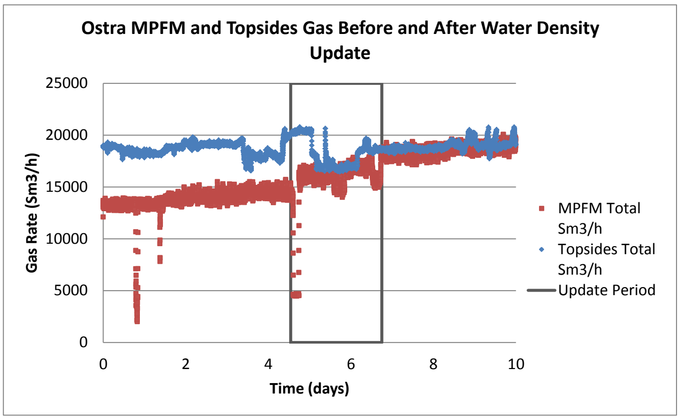
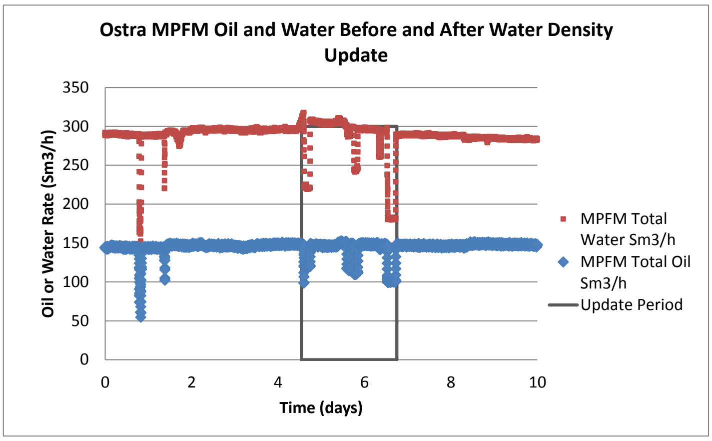


Figure 9. Trend of surface gas and MPFM gas before, during and after the water density update.



Figue 10. Trend of the MPFM oil and water rates during the update process.

Phase 1 High Watercut Well

As the average BS&W of the Ostra field continued to rise as the field aged, some of the MPFMs started to show suspicious results, especially a well (C7) which exhibited a BS&W of around 95-100%, with some occasions that showing it exceeding even 100%. Initially scale or a weak nuclear source was suspected, but after the correction for the incorrect salinity was made, as covered in the previous section, the offset became far worse – suggesting there was something related to the attenuation. As a cross check for the possibility of scale, the meter was filled with methanol and the nuclear counts compared to what would be expected for the scale free signal, this was unfortunately inconclusive. Figures 11-13 show 3 different well start-ups on C7 from a 1 year period with different configuration files, the changes are summarised in table 3.

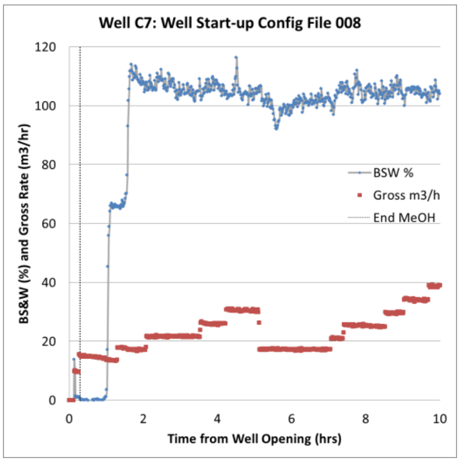


Figure 11.

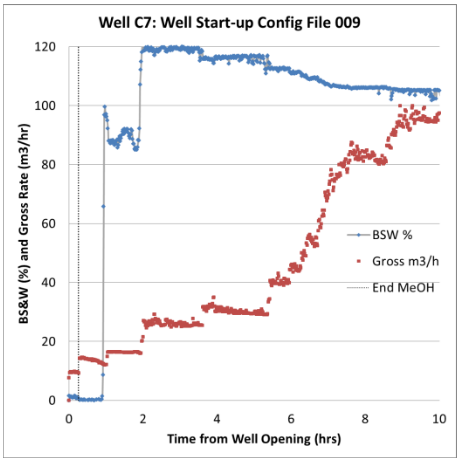


Figure 12.

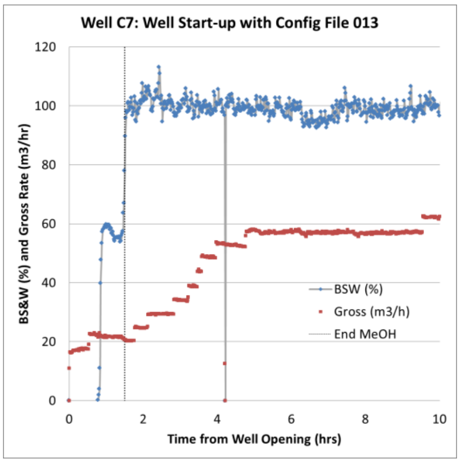


Figure 13.

The start up data from well C7 showing the gross flow rate and BS&W. Note that the time when methanol injection is stopped is also marked since this introduces an error on the meter since methanol appears like a light hydrocarbon plus water and hence gives a false reading. All well starts have a meter pressure higher than the bubble point of the oil so no free gas is present.

Figure	11	12	13
Change	Base file, water density incorrect (using fresh water density but actual salinity for attenuation)	Water density corrected (using formation water density and actual salinity for attenuation)	Mass attenuation for water adjusted to give feasible BS&W

Table 3. Meter configurations for the corresponding figures above.

Adjusting the water density, which was around 995 kg/m3 when using the fresh water setup (figure 11) and 1110 kg/m3 when set up for the salinity measured at the surface (figure 12), made a huge impact. This is to be expected if the solution triangle is considered. At these higher watercuts, the meter is operating extremely close to the pure water point, so moving this even slightly will have a dramatic impact - as can be seen by the BS&W exceeding 100% (figures 11 and 12), which requires a negative oil flow rate, results from the meter having an operating point beyond the water point in the solution triangle – see figure 14. Tuning to get good operation at this set of conditions is not easy, but is necessary as the lab attenuations did not give physically meaningful results and other likely explanations had been exhausted. Once completed, the new tuning parameters were applied to all of the Ostra field MPFMs, since they all produce the same oil and same water salinity, what works for one meter must work for the rest if the assumption that the meter is not at fault. This also allows the reconciliation factor to be checked to confirm that the change was correct overall or not.

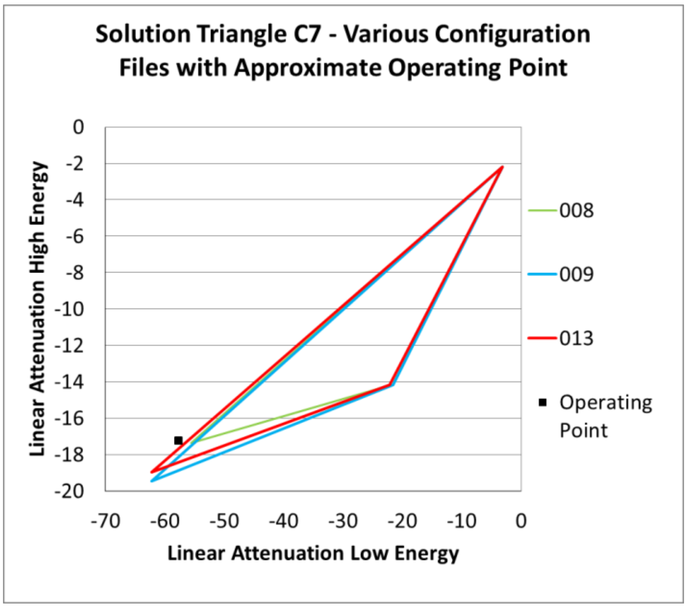


Figure 14. Solution triangles for the figures 11-13 together with the operating point.

Ostra Gas Oil Ratio

During an investigation into GOR present on some Ostra wells, specifically ones which had very high watercuts, the GOR was noted to be unexpectedly high in the range 80-100 Sm3/Sm3 compared to the 49 Sm3/Sm3 of the initial PVT report. Due to gas injection into the reservoir via the gas disposal well, certain wells did already have a higher GOR, but they also exhibited a higher GVF. These other wells did not. The answer lay inside the configuration file, which had a water gas ratio (WGR) of around 2.2 Sm3/Sm3 at operating conditions, corresponding to the gas saturation of fresh water. The true saturation of gas in the Ostra formation water was 0.8Sm3/Sm3 due to the salt making dissolution of gas more difficult. At the high water cuts on the well, for example at 95%, and at high pressure so with no free gas, the total gas rate would be:

Oil Rate x Solution GOR + Water x WGR = 5 x 48.8 + 95 x 2.2 = 453 Sm3 / 100Sm3 liquid
(GOR = 453 / 5 = 90.6 Sm3/Sm3)

Compared to the correct WGR of 0.8Sm3/Sm3 giving:

5 x 48.8 + 95 x 0.8 = 320 Sm3 / 100Sm3 liquid
(GOR =320 / 5 = 64 Sm3/Sm3)

Thus the discrepancy was due only to the added gas from the water by the meters' computer. This highlights the importance of understanding the contents of the configuration files, as there can be some confusion around a number such as this – how can the GOR exceed that of the initial reservoir, and for modelling purposes, should a GOR of the pure oil or the combined fluid be used? Normally, the gas held in the water would not be considered for metering purposes, as it represents a very small stream when at surface processing conditions and indeed may not even be directly measured – gas leaving the water treatment plant for example may be mixed with nitrogen complicating metering (if it is metered at all). So at a high level a choice must be made as to whether pursue as high a fidelity model as possible, and hence include these effects, or to make the model simple to allow easier detection of anomalies. It also raised the question of whether the entire aquifer is saturated in gas, and if so what was the mechanism and will this change as new water in-flows.

Data Verification Tools

With the MPFM running and producing data, this can be validated against the expected behaviour. One measure which has proven to be useful is GVF, since this is a physical property of the oil and should only vary with pressure, temperature, watercut and is a good reference point for the meter operation. For example, a meter operating at a pressure above the bubble point should not read any GVF, since there should not be any gas present, conversely, when the meter is operated inside the 2 phase region, gas must be present and any absence indicates that something is not correct. A more sophisticated approach is to compare the expected GVF with that measured. This type of surveillance is similar to checking GOR, but has the added benefit that it is less dependent on the PVT information in the configuration file. For the Ostra and O-North meters, online calculations were created which allow the theoretical PVT GVF to be calculated and compared to the output of the meter. Two well start ups are shown in figures 15 and 16, indicating that after the initial gas cap is blown off the well, the meter GVF and theoretical GVF match well. Start-up is a good time to check, as the meter will pass through a wider range of pressures and temperatures as the flow rate is increased – allowing a wider operating range to be validated. Some wells in the field are not suitable for this treatment, as due to gas injection they have a variable GOR and hence the GVF cannot be calculated without already assuming that the meter gas and oil are correct. This would also apply in the case of a gas lifted well, however BC-10 do not use gas lift so this technique is helpful.

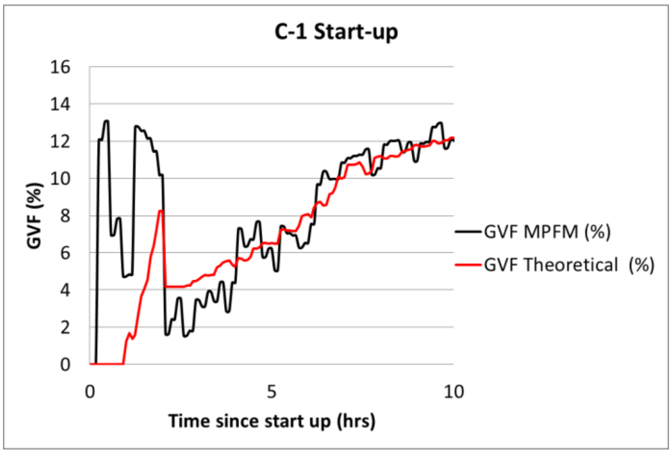


Figure 15. Start up of Ostra well C-1 showing the metered GVF compared to the GVF calculated using PVT software.

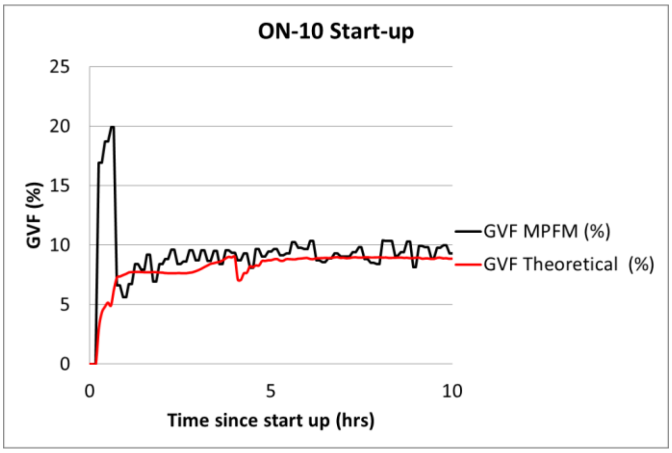


Figure 16. Start up of O-North well ON-10 showing the metered GVF compared to the GVF calculated using PVT software.

Conclusions

Several examples of troubleshooting subsea MPFMs have been shared here. The central learning is that MPFMs, whilst still a flow meter, require a different approach which is much more cross disciplinary than a more conventional meter. They require a deep understanding of the physical behaviour of the oil, gas and water being produced as the conditions are radically different from those in a surface facility. This information, traditionally obtained and owned by the reservoir engineers and flow assurance engineers must be shared and understood in order to correctly setup the meter and to understand possible reasons when results may appear to be drifting as the field ages and conditions change. Challenges exist in the future for BC-10 MPFMs, not least the addition of 3 new fields which will bring new PVT data and the continued use of water flood, which will impact the salinity of the produced water on a per well basis, making recalibration necessary more frequently. The BC-10 project has proven the value of continuous well monitoring, for production optimisation in addition to allocation using subsea MPFMs.

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References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.