The Emperor's New Clothes? - Oil with Water Flow Metering

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1. Introduction

Oil with water production flows is a significant problem to the hydrocarbon production industry. It may sound like poor measurement practice to try and measure oil production flows with greater than a few percent 'water cut'. However, production realities are making it essential to do so.

With oil prices tending to be in excess of US$100 / barrel, production of high 'water cut' oil flows is commercially viable. As oil reservoirs age they tend to naturally produce slower production flow rates and higher 'water cut' flows. Water injection is a common method of increasing the pressure in a well to stimulate higher production rates. However, this technique not only increases the oil production flow rate, but also further increases the 'water cut'. Furthermore, due to rising oil prices, low quality oil wells previously considered commercially unviable are now being produced with their high 'water-cuts'. As a result of these developments some wells are now producing oil at water cuts over 50%, with a few cases even reaching 90%. However, while the number of high water cut production flow is increasing, the practice of flow measurement without separation is becoming more prevalent as operators strive to reduce production costs.

Oil with water metering techniques are becoming increasingly important. However, from a recent investigation by CEESI, it appears that the independent data available on the performance of oil flow custody transfer metering systems operating with high water content of 5-90% is both scattered and sparse.

2. Present Industry Oil with Water Measurement Philosophy

It would appear that oil with water flow metering is a classic 'multi-phase meter' problem, and that typical multiphase metering uncertainties in the region of 5-15% would be acceptable. Although the fluid dynamic problem is similar, the oil with water flow measurement philosophy is very different. The assumption is that flow meters should to read the combined volume of the two fluids to "custody transfer" levels of accuracy.

The typical approach of oil with water flow measurement is to utilise a volume flow meter to measure the total volume flow. A mixer element is used to create a 'homogenous' flow that can be sampled to produce a water to total volume flow rate ratio (or equivalent parameter). Combining these two separate measurements produces the individual oil and water flow rate predictions. Therefore, in order for the typical approach to give custody transfer flow rate prediction uncertainties, both the meters total volume flow rate prediction and sampling techniques must have low uncertainties. This is all very different to the currently recognised multi-phase measurement uncertainties.

3. What is Considered a "High Water Cut"?

'Water cut' (ω) is defined as the ratio of water produced compared to the volume of total liquids produced at standard conditions. Equation 1 shows the water cut. It is a

description of the water content contained in produced oil. Note that Q_{water} is the volume flow rate of the water, Q_{oil} is the volume flow rate of the oil, and Q_{total} is the volume flow rate of the combined oil and water flow.

$$\omega = \frac{Q_{water}}{Q_{water} + Q_{oil}} = \frac{Q_{water}}{Q_{total}} \tag{1}$$

The WLR is defined as the ratio of water to the volume of total liquids produced at line conditions. The conversion of the volume at line conditions to standard conditions is complicated in a two liquid system by determining the coefficient of expansion of the combined liquids. Even when fully mixed this is subject to an increased uncertainty. In this paper water cut is assumed to be representative of the flow at line conditions.

Most standards concentrate on the measurement of water content, whereas, what is of real interest is the measurement of oil content. It could be argued it would be more appropriate to describe the relative amount of oil and water in terms of the ratio of oil to total liquids produced, i.e. equation 1a. The aim of the typical oil with water metering approach is to apply the oil flow rate prediction equation 2.

$$1 - \omega = \frac{Q_{oil}}{Q_{water} + Q_{oil}} = \frac{Q_{oil}}{Q_{total}} \tag{1a}$$

$$Q_{oil} = Q_{total} * (1 - \omega) \tag{2}$$

The standards discuss sample uncertainty in terms of water cut. That is, the standards focus on water measurement uncertainty instead of the oil measurement uncertainty. Setting a required sampling 'quality' by fixing a required water cut uncertainty produces an increasing allowable oil flow rate measurement uncertainty as the water cut increases.

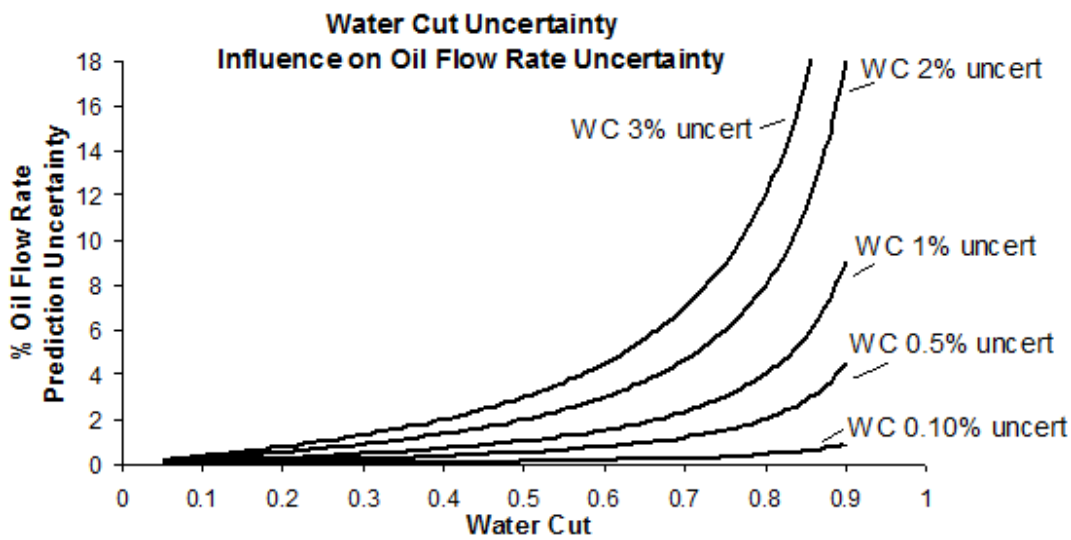

Figure 1. Water Cut vs. Oil Flow Rate Prediction Uncertainty for Various Water Cut Uncertainties

Figure 1 shows a graph of the relationship between the flows water cut, the allowable water cut uncertainty and the oil flow rate metering uncertainty. With traditional low water cut production flows the associated oil flow rate prediction uncertainty is low,

even for relatively high water cut uncertainties. However, as the water cut increases (as it is doing across many modern production flows) the effect of water cut uncertainty on oil flow rate prediction increases significantly. For example, let us say there are 100 units of total volume flow. Let us say a water cut measurement (by sample) is allowed an uncertainty of 1%.

Case 1: Consider a water cut of 0.1, i.e. 10 units of water and 90 units of oil flow. Water cut measurement uncertainty is set here at +/-1%, i.e. the water cut measurement is in the range 0.1 +/- 0.001. That is, the water cut is found to be within the 0.099 to 0.101 range. Therefore, when a volume meter shows that the total volume flow rate is 100 units, the oil flow rate prediction is somewhere in the 89.9 to 90.1 units of flow range, i.e. 90 units of flow +/- 0.11% uncertainty.

Case 2: Consider a water cut of 0.9, i.e. 90 units of water and 10 units of oil flow. Water cut measurement uncertainty is set here at +/-1%, i.e. the water cut measurement is in the range 0.9 +/- 0.009. That is the water cut is found to be within the 0.891 to 0.909 range. Therefore, when a volume meter shows that the total volume flow rate is 100 units, the oil flow rate prediction is somewhere in the 9.1 and 10.9 units of flow range, i.e. 10 units of flow +/- 9% uncertainty.

It used to be practically acceptable to discuss sampling quality in terms of water-cut uncertainty. However, as industry copes with much higher water cuts it may become more questionable if this is the most appropriate way to describe sampling uncertainty. It is noteworthy, that if the industry chose to discuss sampling quality in terms of 'oil-cut' uncertainty, i.e. the uncertainty of a samples oil to total flow rate ratio, the uncertainty of the oil flow rate prediction would remain constant (for a known correct total volume flow rate) across the water cut range.

There is no industry wide agreement to what constitutes a "high" water cut. Ideally, for custody transfer oil flow metering there should be no water present. In reality, even after refining, oil flows can still contain some water (and sediment). Traditionally, in the US at least, industry has tended to consider the uncorrected oil flow rate meter output uncertainty associated with water cuts $\leq$ 0.5% acceptable. A general definition of 'high' water cut, therefore, could be a water cut higher than the accepted industry standards for water content, i.e. > 0.5% water cut.

If sampling is required for higher water cuts, the generally accepted upper limit inferred from API 8.2 [1] for an acceptable sampling and mixing operation is 5% water cut. API 8.2 does not explicitly state an upper water cut limit, but the worked examples are all for < 5%, and it was written at a time where < 5% was normal across most of production. Therefore, for sampling procedures, traditionally water cuts > 5% could be considered high. ISO 3171, does discuss the mixing and conditions relating to higher water cuts, up to 30%, but does not go into any great detail on the issues likely to be encountered at these higher values.

With the oil industry set to encounter oil production from fields that can produce water cuts anywhere between 0% to in excess of 90%, the very question "… what constitutes a 'high' water cut?" is perhaps becoming irrelevant, and even meaningless. The reality of modern oil production is that industry will increasingly have to cope with production flows that fall across the full range of water cut, i.e. $0\% \leq \omega < 100\%$. However, presently there is not a clear guidance as to how to approach such metering challenges, and what uncertainties can practically be achieved.

4. The Known Issues with Current Practice

It is generally accepted that the following issues will arise due to waters presence with oil:

- an increase in the flow meters volume flow rate prediction uncertainty
- a more complex volume conversion between actual and standard conditions
- increase in samplings oil component uncertainty with increasing water cut
- increasing difficulty to determine water content of a sample as water cut increases.

4.1 Flow Metering

The most commonly applied flow meter types to oil production custody transfer are the turbine meter, the positive displacement meter, the Coriolis meter and the ultrasonic meter. The Differential Pressure (DP) meter is not commonly applied to this particular flow metering application.

For such an important subject there is surprisingly little independent data regarding the performance of flow meters with high water cut oil flows. Individual meter performance will depend on the meter type, and individual design. For Reynolds number and viscosity dependent meters the combined and relative viscosities may affect the performance. A flow meters performance may depend on how the oil and water are dispersed in the flow, i.e. the meter performance depends on how well mixed the oil and water flows are.

4.1.1 Coriolis Meters

Coriolis meters are joint mass flow meters and densitometers that utilise the principle of the Coriolis force. This has led some engineers to assume that it doesn't matter what the flow consists of, the total mass flow and average density will be metered. If this was the case the Coriolis meter would be a 'silver bullet' to many long standing flow metering problems, such as wet gas flow, multiphase flow, flow with particulate, and water cut oil flows. Unfortunately this is not the case.

Coriolis meters are good single phase flow meters. If the fluid is homogenous then a Coriolis meter is an excellent mass flow meter and a good densitometer. (It is for this reason that CEESI has utilised Coriolis meters as the water and oil flow reference meters in the new oil with water test facility described in Section 5.) However, if a flow is not homogenous, then the Coriolis meter can be adversely affected, e.g. see GRI report No. 04/0172 [2] for wet gas flow metering. Different Coriolis meter designs with excellent single phase homogenous gas flow and liquid flow performance were shown to be very significantly affected by the presence of wet gas flow. Hence, it does not stand to reason that a Coriolis meter should be automatically assumed to be able to read an accurate total mass flow rate and mean density with a water and oil flow mix. Operators should demand third party independent data as proof of any performance claims.

Coriolis meter manufacturers have released research into multiphase flow performance of Coriolis meters (e.g. Wienstein [3]) where sophisticated correction factors and meter diagnostics have come into play. It is therefore possible that individual manufacturers have confidential methods of coping with water cut flows. Again however, operators should demand third party independent data as proof of any performance claims.

Some Coriolis meter manufacturers claim (e.g. Wienstein [3]) that the mixture oil and water flow density and total mass flow rate will be measured by the Coriolis meter. Knowledge of the individual oil and water densities then allow the water cut and individual oil and water flow rates to be determined. However, the manufacturers have not shown any data and have not stated any uncertainties to these mixture, total low rate and individual oil and water flow rates predictions.

One independent research project (Andersen [4]) showed that Coriolis meters with oil and water flows have a performance that is dependent on the level of fluid mixing. The Coriolis meters performance with oil and water flow deteriorated as the flow rate reduced. Low flow facilitates separation of the oil and water flow. Water 'hold-up' in the Coriolis meters U-bend tubing can cause significant meter output biases. It was shown by Andersen et al that a mixing element reducing separation upstream of the Coriolis meter significantly improved the meters performance at low flow rate oil and water flows. A further issue that may require investigation is the effect of low Reynolds number in combination with high water content. As there are linearity challenges at low Reynolds numbers with a single phase flow, the extra dimension of water content may be expected to increase the problem. Many of the higher water content applications will be with heavy, high viscosity oils, producing low Reynolds number flows.

4.1.2 Turbine Meters

Turbine meters are often a meter of choice for oil with water flow measurement, but yet there is surprisingly little published research into turbine meters performance with water cut oil flows. One of the perceived benefits of using a turbine meter is that even with these adverse flow conditions they do tend to keep producing a flow rate prediction output. However, a largely unasked question appears to be what does this output actually represent?

There are many questions regarding turbine meter performance with high water cut oil flows. For example, in horizontal flow (which is the most common turbine meter installation) how do turbine meters cope with unmixed phases (i.e. separated oil and water flows)? Does the level of mixing at the meter inlet change the meters performance? Does the presence of the turbine meters alter the level of mixing?

4.1.3 Ultrasonic Meters

There is some data on ultrasonic meter reaction to oil with water flow, but there is little independent data, and little data on different meter designs. Some manufacturers have publicly reported on the issue with in-house research and data, e.g. Brown [5]. Here it was shown that the oil with water flow causes a degradation on the single phase meters performance (as would be expected). However, it was shown that but that averaging results over time, the meter could predict the flow rate, all be it at an increased uncertainty compared to that achieved when the flow is a homogenous fluid.

Oil with water flow generally causes the standard deviation of each chords signal to increase. Various distributions of oil and water can cause various deformations of the wave signal. Lost signals are common (hence the benefits of averaging results over time requirement). With stratified oil and water flows ultrasonic paths in the vicinity of the interface are particularly vulnerable to such problems.

The presence of two fluids also has a significant adverse effect on the ultrasonic meter diagnostic suite. The ultrasonic meter diagnostics signal that the meter performance is very much different and poorer to the standard homogenous flow operation. The diagnostics can indicate the presence of stratified water oil mixture. However, in general, extracting meaningful quantitative information from these diagnostics for various meter sizes, flow rate, water cuts and oil fluid properties is an extremely complex issue.

One ultrasonic meter manufacturers has informed the authors that when quoting meters for an oil with water application they prefer to modify the meter design, e.g. lower frequency transducers are deemed beneficial as this reduces the number of lost signals.

4.1.4 Positive Displacement Meters

Positive Displacement (PD) have the advantage of reading the actual total volume flow rate regardless of how the oil and water are dispersed in the flow. However, it has also long been known that PD meters, with their moving parts and gears, are susceptible to damage from adverse flow conditions such as being over sped and wear from contaminates in the flow. Reliability is often an important requirement in custody transfer oil metering, and as such PD meters would be chosen for niche applications. There is very little information in the public domain regards the performance of PD meters with oil and water flows.

4.1.5 Provers and Oil with Water Flows

If a flow meter is calibrated in-situ by a prover, is the calibration only valid for oil only flow, or is it valid for all subsequent water cuts?

With Coriolis, turbine, PD and ultrasonic meters widely assumed suitable for use with oil with water flows there is a lack of independent data showing the various meter designs performances across different oil with water flow conditions.

4.2 Corrections for Meter Compensation

Whatever flow meter is utilised, its actual volume flow rate output needs to be converted to standard flow conditions. Single phase homogenous oil flow conversions between actual and standard conditions require that the oil's thermal expansion factor and compressibility are known. In the case of an oil and water mix it is not clear what thermal expansion factor and compressibility are appropriate or the combined fluid. There is also a lack of data on the performance of densitometers when applied to oil with water flow applications. There is some data, mainly theoretical produced in Norway by CMI [6].

4.3 Sampling

Sampling techniques used across the full range of water cut and production flow conditions found in the oil production industry today, including the more traditionally common low water cut range, are not fully independently tested and verified. For higher water cut production flows there is little independent verification of the integrity of the sampling techniques used.

Sample systems often use a 'mixer' component upstream of the sample probe array. This mixers purpose is to mix the oil and water flow such that the flow is effectively

homogenous at the sample point, thus making the sample representative of the water to total flow rate ratio, i.e. the water cut. However, it is well known that oil and water are 'immiscible'. The definition of 'immiscible' fluids according to the Webster Dictionary is: "incapable of mixing or attaining homogeneity". So a mixer that homogenizes immiscible fluids is an oxymoron, these mixers are attempting to mix the unmixable. In reality, the best that can be reasonably hoped for is that a mixer can produce 'near' homogenous flow at the sample position directly downstream of the mixer, where the sample approximates the actual water cut to an acceptable uncertainty.

Static ('passive') mixers are obstructions in the pipe on which the flow does work, i.e. the flow supplies the work to mix the flow. Dynamic ('active') mixers are powered mixing elements that do work on the flow, i.e. an external source supplies the work to mix the flow. Presently, there is little research describing the effectiveness of static or dynamic mixers.

It is generally assumed that dynamic mixers are very effective in any sampling application. It is an open question to what static mixer designs have what performance, especially at low flow rates and at the newer area of increasing interest, high water cut flows. Industry does not yet know the limitations of different static mixer designs. Questions needing answered include:

- What is the optimum static mixer design?
- Do static mixer designs have different optimum performance water cut ranges?
- Does pipe / mixer diameter affect a mixers performance?
- Do fluid properties significantly affect a mixers performance, and if so, how?
- What is a realistic sample / water cut uncertainty expectation across the water cut range?
- How much more effective is a static mixer in vertical flow to horizontal flow?
- Is vertical down flow a better static mixer / sample location than vertical up flow?
- Can any dynamic (or 'active') mixer design be relied upon to give a near homogenous mix and associated low uncertainty sample in any applications flow conditions?

The standards API 8.2 [1] and ISO 3171[7] describe the mixing properties of different fittings in theoretical terms. API 8.2 sets a limit to be 5% of water. ISO 3171 discusses higher volumes of water. However, neither document states a required type of mixer design, with a precise set of procedures and expected uncertainties. Neither of these documents give any method for calculating the ability of a proprietary mixer to mix the fluid. The only information on these issues is therefore supplied by the mixer manufacturer. API 8.2 shows a rough guideline table to indicate the performance of different mixing configurations, but it is short in technical detail, and very general in nature.

4.4 Determination of Water Cut

The standard methods of water cut determination are not feasible for high water cuts. Combined methods have to be utilised. First, the majority of the entrained water in a sample (which has separated out) is removed and measured. The oil with the remaining water residue (i.e. dissolved water and water in an emulsion) can then be analysed with standard water cut analysis methods, such as distillation. Measuring

cylinders appear to also give good results. A good description is given in the API test document on high water cuts [8].

During commissioning of the CEESI oil with water flow facility CEESI requested a test sample water cut determination service from several companies throughout the US. No quotations were received. The samples were deemed to have too high water cuts for the service companies analysis techniques to operate correctly.

5. CEESI Oil with Water Test Facility

A CEESI review of industrial practice has indicted that:

- sampling tends to be neglected by most operators of metering systems – there is a dearth of independent higher water cut test sampling data,
- there is a dearth of independent, higher water cut oil flow metering data, and,
- high water cut flow sampling and metering is becoming increasingly important.

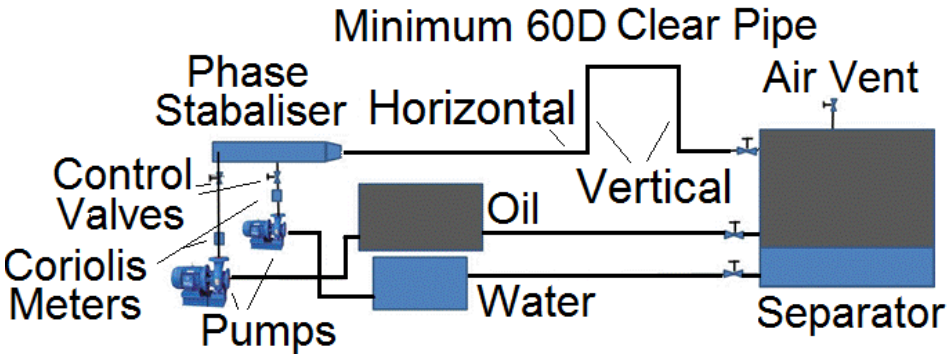

Figure 2. Schematic of CEESI Oil with Water Test Facility.

CEESI has built an oil with water flow test facility, which has Coriolis meter individually measured oil and water inputs, a 2” to 8” pipe test section capability, long clear viewing sections in horizontal and vertical piping, a flexible working section for testing flow meters in different orientations, and a sampling section to determine the distribution of mixing across the pipe cross sections. The water content can be ranged from 1% to greater than 90%. The test facility operates at ambient conditions. This paper discusses the design of this flow facility and some of the initial lessons learned from commissioning this facility with different flow meters.

The system, shown in Figure 2, comprises two centrifugal pumps, that draw from individual water and oil tanks. These pumps have controllers, but for lower flows, control valves are required. The pumps are set to their respective required flow rates according to the downstream oil and water Coriolis meter outputs. These set flow rates set the water, oil and total flow rates as well as the water cut. Both pump outlets send the flow to a phase stabilizer to reduce any instability caused by the pumps, flow meters and control valves. Figure 3 shows the design of the phase stabilizer. It is a header split by a dividing sealed plate such that the oil and water can flow separately inside the header. Each cross sectional area is relatively large to induce low velocity flow. This allows a relatively long retention time for the flow in the header where the flow has time to settle. The oil and water flows are combined at the exit of a long (seven degree) reducer, designed to minimize turbulence during mixing. This is to reduce the distance required after comingling for the flow to mimic a flow of oil and water in a long straight production pipe.

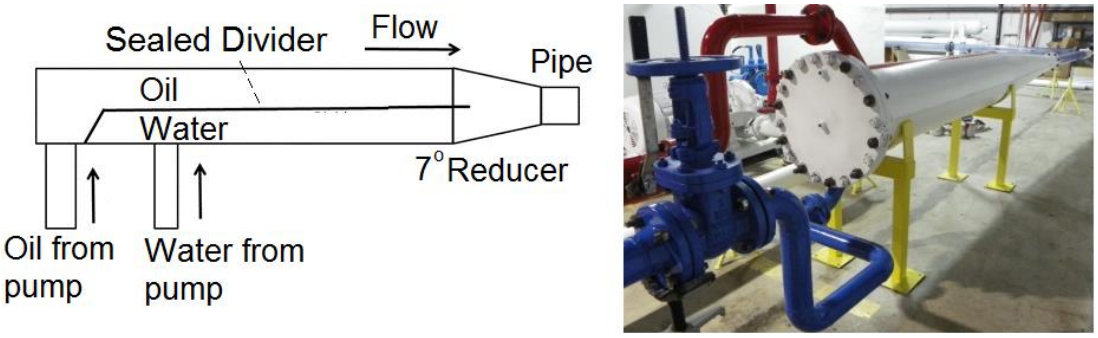

Figure 3. The Design of the Phase Stabilizer.

The test pipe section is in excess of 40 ft long, so for 2” ≤ D ≤ 8” there is at least 60D available. The majority of the pipe length is clear plastic, allowing a clear view of the mixing levels along the pipe. The test section configuration is versatile and can be modified, changed and developed depending on the equipment being tested and the aims of the test. In Figure 2, the objective was to model an actual sampler installation mounted in a vertical down orientation. The sampling took place in the vertical down leg, after a static mixer. However, this section can be replaced by any configuration for testing, including a complete system if required. Flow meters and mixer / sample systems can be tested in both the horizontal and vertical orientation. Figures 4 & 5 show photographs of previous configurations. After the test section the flow enters an oil / water separator, from where the separated constituents return to the oil and water supply tanks. Table 1 shows the present CEESI water in oil flow facility.

Figure 4. 4” & 6” Meter Sections

Figure 5. Vertical Down Sample Section

Parameter	Value
Pipe Diameter	2” ≤ Diameter ≤ 8” (up to 12” feasible)
Oil Grade	Various (currently Shellsol D80 dyed red)
Maximum Average Velocity	14 ft/s
Water Cut (with salt if required)	0.2% to 90%
Oil Reference Uncertainty	0.2%
Water Reference Uncertainty	0.2%
Water Cut Reference Uncertainty	0.28% at 50% water cut

Table 1. CEESI Water in Oil Flow Facility Specifications.

The clear piping allows good flow visualisation along the test section. Figures 6 through 9 show sample 6” horizontal oil with water flow patterns (or ‘flow regimes’) created with long upstream pipe runs at different water cuts and average flow velocities. Figures 6 & 7 shows the oil and water are separated at the low average

Fig 6. Horizontal flow, 50%WC, 0.6 m/s

Fig 7. Horizontal flow, 30%WC, 0.6 m/s

Fig 8. Horizontal flow, 5%WC, 0.6 m/s

Fig 9. Horizontal flow, 50%WC, 0.9 m/s

Figure 10. 4”, 0.6 m/s, Water and Oil Flow
(80% WC) with Horizontal to Vertical Up Flow.

flow of 0.6 m/s (i.e. 2 ft/s) for 50% & 30% water cut respectively. Figure 8 shows that the oil and water flow of 5% water cut was more mixed at the low flow of 0.6 m/s. Figure 9 shows 50% water cut at the increased average flow velocity of 0.9 m/s (i.e. 2.25 times the dynamic pressure). Although still separated, there is visual evidence here of the water phase having more entrained oil compared to the 0.6 m/s case in Figure 6. Figure 10 shows the effect on the flow pattern of turning a 4”, 80% water cut flow of average flow velocity of 0.6 m/s from horizontal flow to vertical up flow. Significant mixing by the elbow and change of orientation is clearly visible. Unlike mixing caused by horizontal bends this mixed flow continued downstream without any visual evidence of separation occurring.

The specific results of the first tests on the effect of large water cuts on static mixers for sampling systems are confidential, but one general point can be made from that test program. *Mixer design is critical*. If the mixing mechanism induces a swirl component to the flow, although this is a very large upheaval of the flow, centrifugal forces move the heavier fluid (i.e. the water) to the outside of the pipe. That is, such a ‘mixer’ design acts as a *vortex separator*. This phenomenon was found for a particular mixer design that produced an unchecked swirl component. A multi-point sampler

downstream of this ‘mixer’ design showed more oil at the centre of the pipe than the periphery of the pipe. Further confirmation of this phenomenon came from CFD simulations carried out by CPA [8]. Figure 11 show CFD results for 6” pipe with a 50% water cut and an average flow velocity of 0.6 m/s. Flow is from right to left. Blue and red represents water and oil flow respectively. The horizontal inlet flow has separated flow (as had the actual test case – see Figure 6). Mixing occurs at the 90° vertical up bend, and the flow remains mixed as the flow turns another 90° bend back to horizontal flow. This mixed flow begins to separate out after only a few horizontal diameters. These CFD results were similar to what was observed at CEESI. A mixer design that induced a swirl component on the flow was installed in the vertical down section. Although a significant disturbance is evident from this CFD elevation view, a cross sectional view of the flow at the exit of the mixer is inlaid onto Figure 11. The swirl induced centrifugal force has caused a higher proportion of water at the pipe periphery, and a higher proportion of oil at the pipe centre line. Figure 12 shows a typical result for a multiport sample system downstream of such a mixer. In this particular case the water cut was 50%. The mixer design inducing the swirl is not mixing the flow effectively.

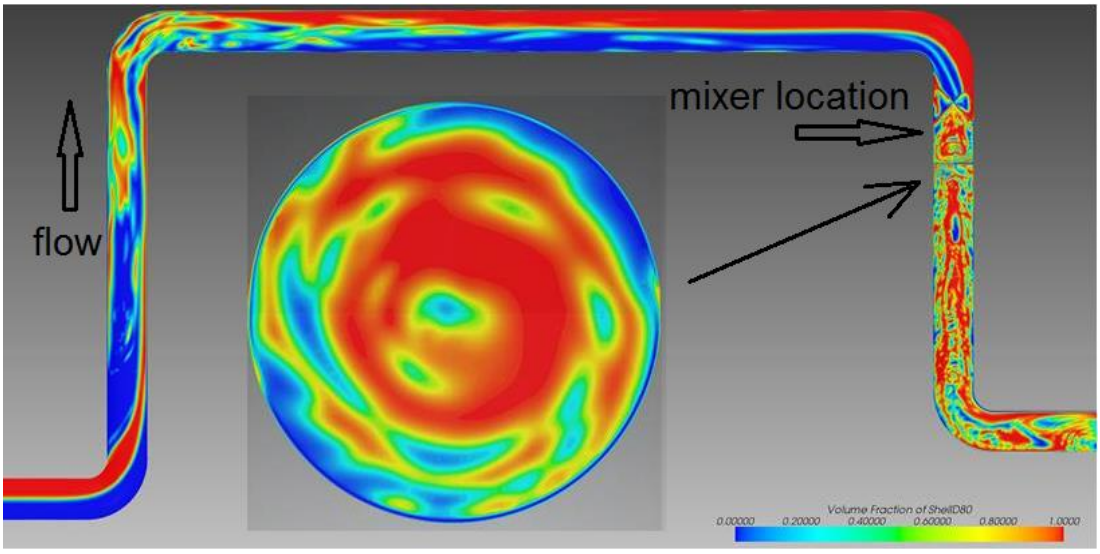

Figure 11. CFD result for 6”, 0.5%WC, 0.6 m/s.

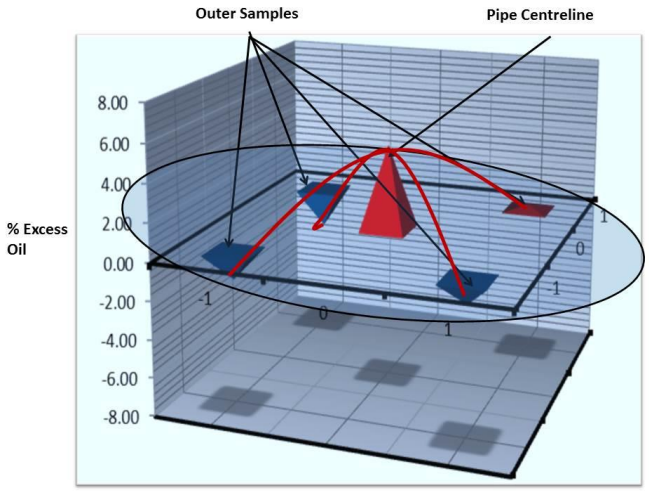

Figure 12. Typical Multi-Port Sample Result Downstream of a Mixer that Induces an Unchecked Swirl Component.

6. Oil with Water Flow Metering

The water cut prediction attained from the sampling system will be combined with the total volume flow rate prediction from a flow meter to give the desired measurements, i.e. the oil and water flow rates. Hence, the uncertainty of the oil and water flow rate predictions will be dictated by both the sampling and flow meter uncertainties. As discussed in Section 4.1 industry has yet to fully research the methodology of metering oil with water flows.

During commissioning of the CEESI oil with water flow facility there was the opportunity to test flow meters. Two of the meter designs tested are discussed in this paper. The chosen meters are the turbine meter (chosen due to its popularity for this application) and the cone DP meter.

6a. Turbine Meters

CEESI had available for testing a 4" Potter turbine meter (see Figure 13) and a 4" Daniel turbine meter (see Figure 14). These meters were tested in the horizontal orientation at various oil with water flow conditions. CEESI also built a 4" clear body turbine meter for visual testing (see Figure 15 & 28). This meter was tested specifically for visual confirmation of a turbine meters inter-action with various oil with water flows.

Turbine meters link rotor revolution to volume flow. The number of revolutions per unit time, i.e. the rotor rotational frequency (*f*), represents a volume flow rate (*Q*). The rotor frequency and volume flow rate are related through the meters "K-factor" (*K*). Equation 3 shows the generic turbine meter volume flow rate equation.

$$Q = f/K \tag{3}$$

Some turbine meter designs take a reading, or "pulse", as each rotor blade passes the counter, usually a magnetic pick off (see Figure 16). Some turbine meter rotors are "rimmed" (see Figures 16 & 17), i.e. they have a band around the rotor blade tip circumference with several magnetic 'pips' equally spaced between blade tips. This increases the measurement resolution by significantly increasing the pulse count. The Potter turbine meter tested is not rimmed, while the Daniel turbine meter tested is rimmed. Adding a rim to the rotor design alters the flow around the blade tip region. Therefore, rimmed and un-rimmed rotors can have different performances.

CEESI chose a Potter turbine meter to test as it is a basic traditional 'un-rimmed' turbine meter design that is widely accepted as trustworthy and reliable. CEESI had a 4" Potter meter available with a significant quantity of water flow test data. The 4" Daniel turbine meter was tested as it was more common in industry, and was rimmed, therefore allowing the two different turbine rotor designs to be tested. All turbine meters tested were given > 50D straight run of pipe upstream of the meter inlet. This initial series of ambient condition oil with water tests on these turbine meters produced unexpected results which are as yet not fully unexplained.

Figure 18 shows all the oil with water flow data recorded on the horizontally installed 4" Potter turbine meter. With several operators reporting turbine meter operation in very high water cut ranges, CEESI selected a desired water cut flow range of $0\% \leq \omega < 100\%$.

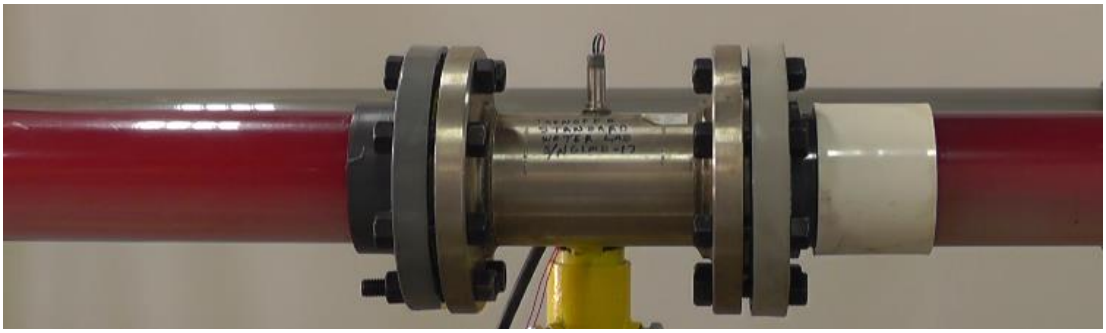

Figure 13. 4”, Potter Turbine Meter

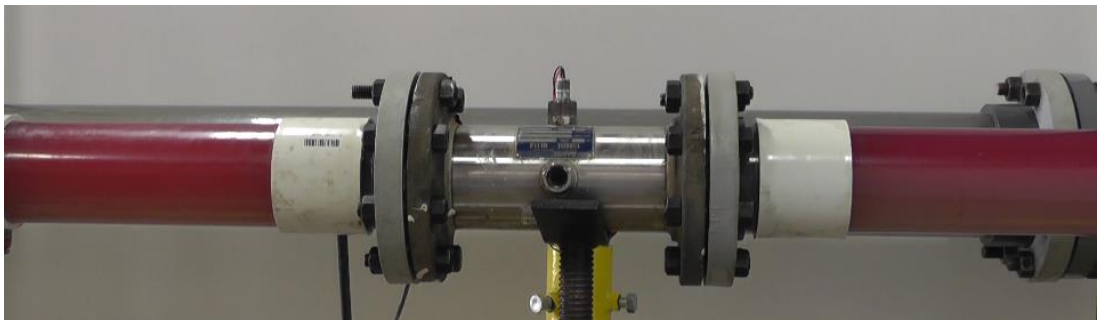

Figure 14. 4” Daniel Turbine Meter

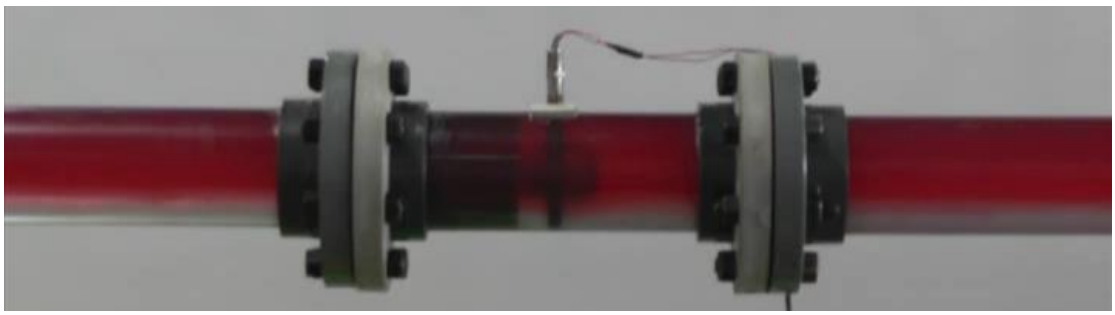

Figure 15. 4” Clear Body Turbine Meter

Turbine meter K-factors tend to be Reynolds number sensitive. The Reynolds number is defined by equation 4, where ‘*m*’ is the mass flow rate, ‘μ’ is the viscosity, ‘ρ’ is the fluid density, and ‘*D*’ is the meter diameter.

$$\mathrm{Re} = \frac{\rho U D}{\mu} = \frac{4m}{\pi \mu D} \tag{4}$$

For any typical single component liquid flow application where the fluid pressure and temperature do not significantly vary, the meter size (i.e. the diameter ‘*D*’) and the fluid properties are fixed. Hence, it is possible to relate a turbine meter K-factor directly to the average flow velocity ‘*U*’ instead of Reynolds number.

With oil with water flow tests, examining the data in this way has an added advantage. The level of mixing between a horizontal oil and water flow is dictated by the energy in the flow, i.e. the fluid dynamic pressure. For oil and water at given densities, and a given water cut, the dynamic pressure, and hence the level of mixing of a horizontal flow is dictated by the velocity. That is, the velocity is an indicator to the level of oil and water mixing. A low velocity means separated flow (e.g. Figure 6), while a high velocity means a well-mixed flow (e.g. Figure 8).

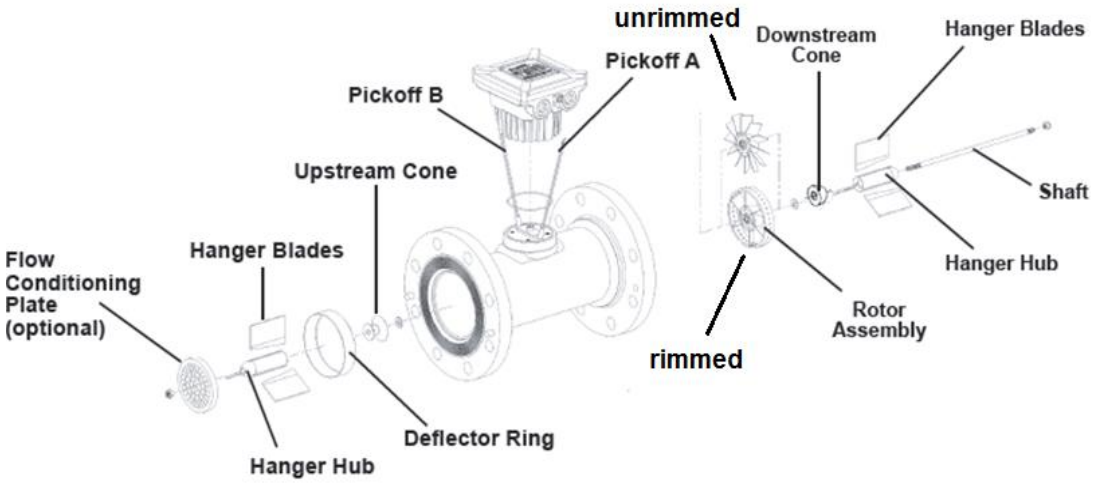

Figure 16. Assembly of a Liquid Turbine Meter with Rimmed or Un-Rimmed Rotor.

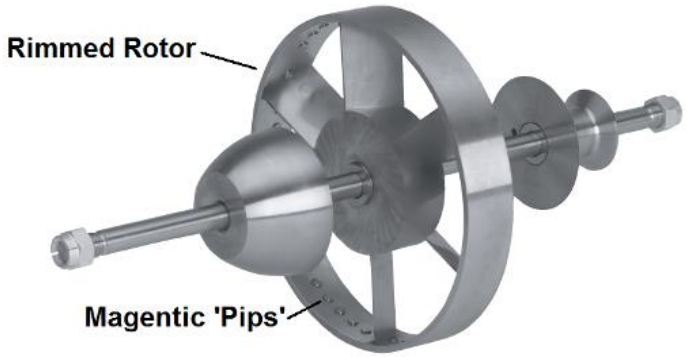

Figure 17. A Rimmed Turbine Meter Rotor with Magnetic ‘Pips’.

Figure 18 shows that the Potter meter has similar performance with oil only flow (i.e. 0% water cut) and water only flow (i.e. 100% water cut). That is, for a single component flow the Potter turbine meter was found to have a repeatable performance, regardless of the different fluid properties of oil and water. It is generally accepted that such a result cannot be automatically assumed before calibration. Turbine meter K-factors typically need to be re-established by proving, with any significant change in flow conditions, e.g. change in viscosity and Reynolds number.

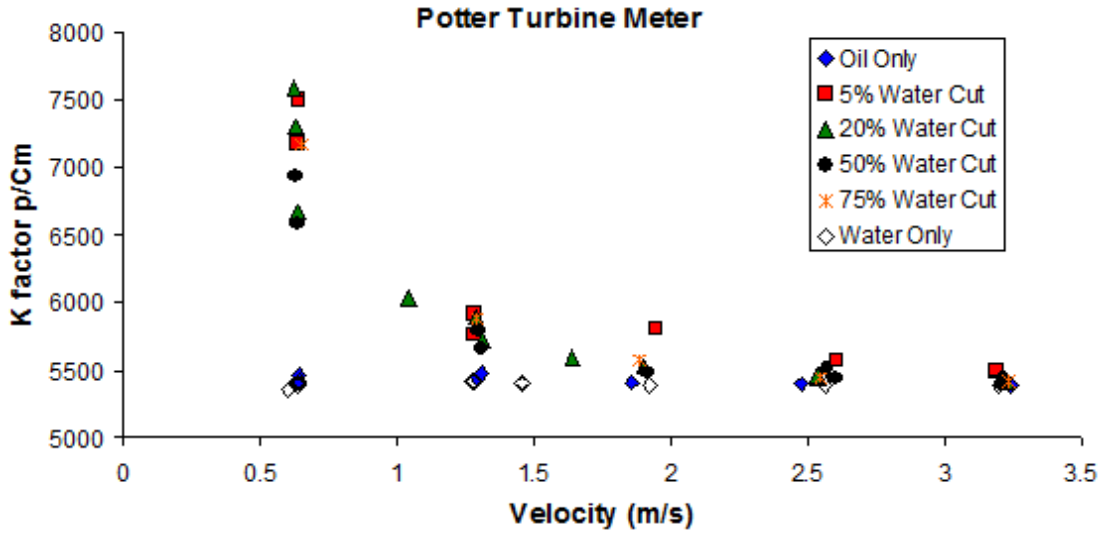

Figure 18. 4”, Un-Rimmed Potter Turbine Meter.

The Potter turbine meter water cut data was so surprising that initially it was assume that there was an experimental problem. It is noted that at < 1 m/s this 4" turbine meter was at the bottom end of its range. Low flow repeatability is a potential problem, as it is with all flow meters. However, the tests were repeated to confirm the results. The results were repeatable.

There is a general industry rule of thumb that oil with water horizontal flows are separated at ≤ 1.5 m/s. It was observed at CEESI that this was approximately correct for the Shellsol D80 oil used, with the water and oil horizontal flows looking well mixed at > 2 m/s, in transition between 2 > U (m/s) > 1.5, and separated at < 1.5 m/s.

At higher velocities of approximately ≥ 2 m/s, where the oil and water were well mixed, regardless of the water cut the Potter meter behaved similarly to water or oil only flows. However, as the average flow velocity reduced below 2 m/s, a flow of ***any*** water cut within the range tested of 5% ≤ ω ≤ 75% showed an increasing K-factor. The fact that the K-factor shift coincides with physical observations of oil and water dispersion through the meter gave CEESI some confidence in the first data sets in this relatively new research area.

It had been expected that either the Potter meter would be immune to the fact that the flow is a mix of oil and water (as current industry practice assumes) or, as the water cut increased, an increasing discrepancy between performance and the oil only flow calibration result would be seen. Although the Potter turbine meter did appear to be immune to the > 2 m/s well mixed water cut flows, the < 2 m/s data for separated flows (which is common in industry) showed that the meter performance was adversely affected in the same way across the water cut range tested, i.e. 5% ≤ ω ≤ 75%.

It is counter intuitive that 5% water cut can cause as great an adverse effect as 75% water cut. The experiment method was scrutinized. The tests were repeated. The result was consistent. CEESI does not claim to understand these results and reports them as found.

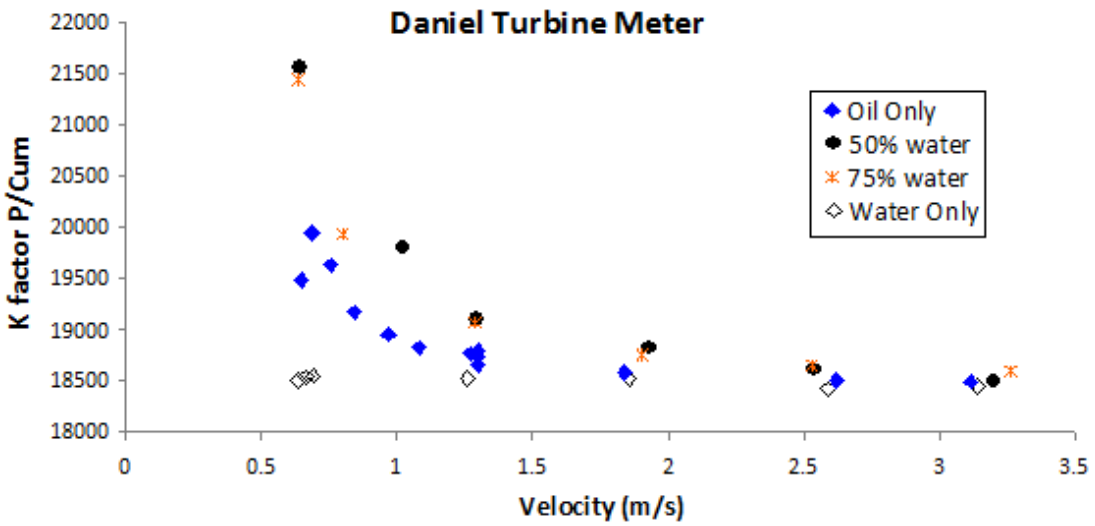

Figure 19. 4", Rimmed Daniel Turbine Meter

It was noted that the Potter turbine meter is an un-rimmed meter. Rimmed and un-rimmed turbine meters can have different performances, and as rimed meters are more

common in industry, it was decided it was necessary to test a rimmed meter. Figure 19 shows all the data gathered from the subsequent 4" Daniel rimmed turbine meter.

Due to the number of repeat tests on the Potter turbine meter to confirm the validity of the unexpected results there was a reduced time frame available for testing the Daniel meter. Hence, the 4" Daniel turbine meter was tested with water and oil flows only, and then with 50% and 75% water cuts. Again, at < 1 m/s this 4" turbine meter was at the bottom end of its range. Low flow repeatability is a potential problem, as it is with all flow meters. In this case the test data was not repeated due to time constraints. Repeatability is only assumed with this particular meters data set.

Figure 19 shows an apparent discrepancy between the 4" Daniel turbine meter's performance (K-factor) with water only and oil only. Across the velocity range tested the water flow produced a near constant K-factor. Across the same velocity range the oil flow produced the same K-factor as water at the high flow rates, but then the K-factor increased as the flow reduced. Although repeat tests would be beneficial to confirm this result it is noteworthy that this apparent discrepancy can be reasonably explained by considering the water and oil data in terms of K-factor vs. Reynolds numbers.

Figure 20 shows the Potter turbine meter data expressed as K-factor vs. Reynolds number. It shows good overlap of the water and oil K-factors for the same Reynolds number range. As the oil flows Reynolds number was reduced below that of the water data the K-factor tended to rise. The Potter turbine meters K factor was fixed to a constant value fit. A tighter fit was easily obtainable if the K-factor was to be fitted to Reynolds number.

Figure 21 shows the Daniel turbine meter data. It shows good overlap of the water and oil K-factors for the same Reynolds number range. As the oil flows Reynolds number was reduced below that of the water data the K-factor began to significantly rise. The Daniel turbine meters K-factor was fixed to a constant value fit from the water flow data. Within the water flow rate range the meter performance with oil flow was the same as the water flow. Only at lower Reynolds numbers did the K-factor diverge.

The oil flow data's tendency to have a rising K-factor as the Reynolds number reduces below the water flows test range is likely to be the normal turbine meter performance when the Reynolds number has reduced below the point where bearing friction becomes significant. The lowest three Reynolds number points tested in Figure 21 were taken below the meters stated range, but are included for completeness. As Potter and Daniel turbine meter are different designs there is no concern about their performances being different at low Reynolds number tests.

The 4" Daniel turbine meters performance with water only and oil only appears to be understandable and trustworthy. Turning attention to the water cut data, the 50% & 75% Water Cut data suggests that the Daniel turbine meters response to water-cut flows is similar to the Potter turbine meters response. At higher flow rates the Daniel turbine meters K-factor is similar to the calibration data of oil or water only flow, but as the velocity drops the K-factor rises. Again, CEESI does not claim to understand these results and reports them as found.

Finally, it was found from visual tests on the clear body turbine meter that the presence of the turbine rotor had no effect on the dispersion of the oil and water, e.g.

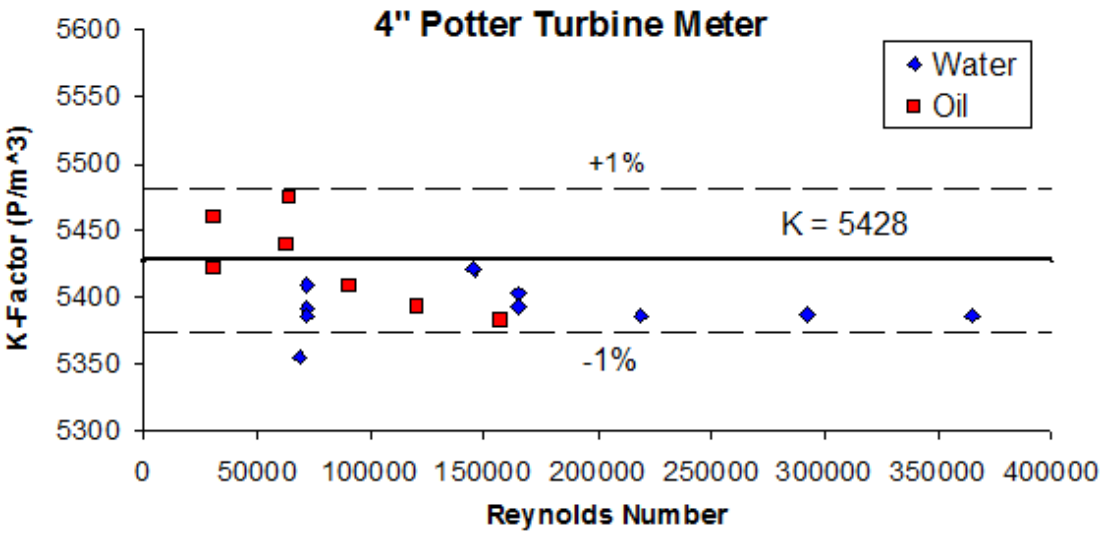

Fig 20. 4" Potter Turbine Meter Oil & Water Only Data Sets.

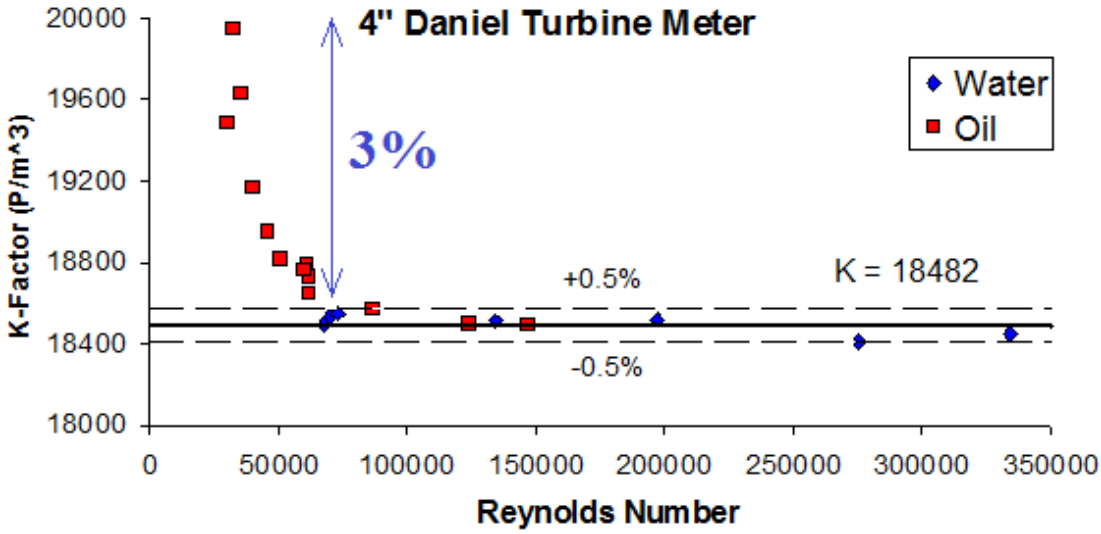

Fig 21. 4" Daniel Turbine Meter Oil & Water Only Data Sets.

see Figure 15. The stratified flow recorded here (at 1 m/s at 20% water cut) was completely unaffected by the presence of the fully serviceable freely rotating un-rimmed turbine rotor. It had been expected that the turbine would facilitate a reasonable amount of mixing. This was found not to be the case. Whatever flow regime (i.e. oil and water dispersion) existed at the inlet to the turbine rotor remained the flow regime through the rotor and downstream of the rotor.

A common industry assumption when metering oil with water flows is that a turbine meter can give a total volume flow rate prediction. These turbines are usually calibrated in single component liquid flow. These initial turbine meter results suggest that both rimmed and un-rimmed turbine meters may produce volume flow rate prediction biases if the effect of water cut is not accounted for, especially at moderate to low total volume flow rates. The performance of turbine meters in oil with water flow application appears to be difficult to predict, as may be expected when a single phase, single component flow meter is applied to the adverse flow condition of multiphase or multi-component immiscible liquid flows. The fluid mechanics involved could be complex, e.g. oil properties could have an s impact on the turbine meters performance in oil with water flow applications. CEESI does not profess to

understand the results of this small preliminary test program. CEESI is continuing to conduct turbine meter oil with water flow tests with the aim of further developing an understanding of the phenomena affecting the turbine meters performance.

6b. Cone Meters

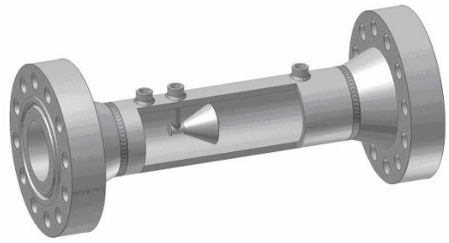

Figure 22: Sectioned view of a Cone Meter (flow is left to right)

Figure 22 shows a sketch of a cone DP meter. The cone meter homogenous flow mass flow rate equations are shown as equation 5. Cone meters are not traditionally utilised for oil with water flow metering.

$$m = EA_t C_d \sqrt{2\rho\Delta P_t} = EA_t K_r \sqrt{2\rho\Delta P_r} = AK_{ppl}\sqrt{2\rho\Delta P_{PPL}} \qquad (5)$$

Note:

m is the mass flow rate
E is the "velocity of approach" (a geometric constant)
A_t is the minimum cross sectional (or "throat") area
C_d, K_r & K_{PPL} are the discharge, expansion & PPL coefficients respectively
ρ is the fluid density
ΔP_t , ΔP_r & ΔP_{PPL} are the traditional, recovered & PPL DPs respectively.

Figures 23 through 27 show photographs of horizontal cone meter flow tests carried out at CEESI. Water and oil (Shellsol D80) at ambient conditions were flowed through a clear body 6", 0.438 beta ratio (β) cone meter. Note the cone meter beta ratio is defined as:

$$\beta = \sqrt{\frac{A_t}{A}} = \sqrt{\frac{A - A_c}{A}} = \sqrt{1 - \left(\frac{A_c}{A}\right)} = \sqrt{1 - \left(\frac{d_c}{D}\right)^2} \qquad (6)$$

where A & D are the inlet cross sectional area and diameter respectively, A_c & d_c are the cone element cross sectional area and diameter respectively, and A_t is the minimum cross sectional (or "throat") area.

The beta ratio of a cone meter, i.e. the relative size of the cone to the pipe diameter, significantly affects the meters mixing capability. The smaller the beta ratio, the higher the local cone flow velocity and the better the oil and water mixing. However, the smaller the beta ratio, the greater the permanent pressure drop. Lower beta ratios improve mixing but this advantage comes with increased operational cost.

The 0.438 β tested here has a relatively small beta ratio. Figure 23 shows a low speed of 0.6 m/s (left to right) and a high water to total mass flow ratio (ω_m) of 50%. At this low speed the upstream flow is entirely separated. A significant amount of mixing is seen to occur downstream the large cone even for this low speed. Figure 24 shows a moderate speed of 1.6 m/s and a lower (but still substantial) water to total mass flow ratio of 20%. Whereas the flow visually looked well mixed in the upstream pipe (with the cone meter being installed >70D downstream of 90 degree bend), there is a

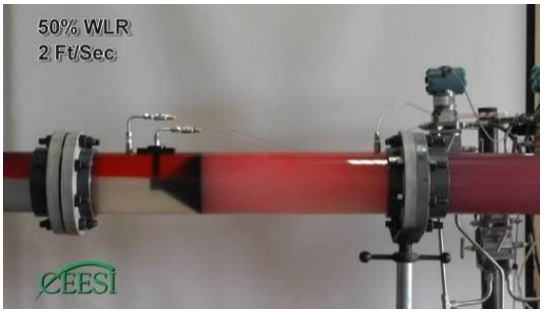

Fig 23. Cone meter, 0.6 m/s, ω_m 0.5.

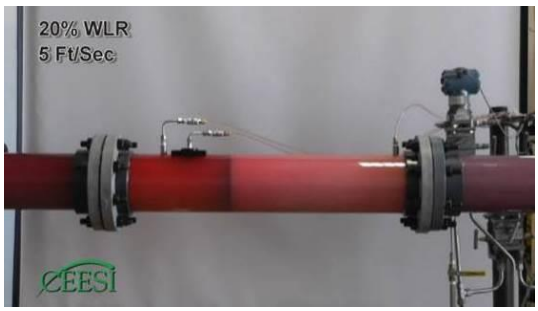

Fig 24. Cone meter 1.6 m/s, ω_m 0.2.

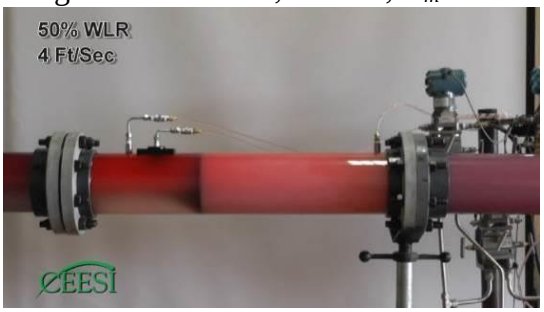

Fig 25. Cone 1.2 m/s, ω_m 0.5.

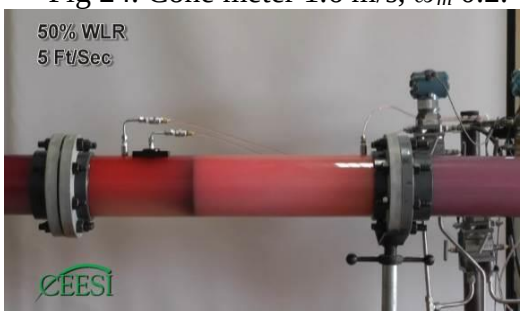

Fig 26. Cone meter 1.6 m/s, ω_m 0.5.

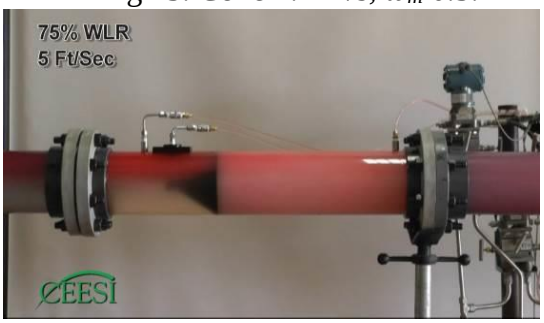

Fig 27. Cone meter 1.6 m/s, ω_m 0.75.

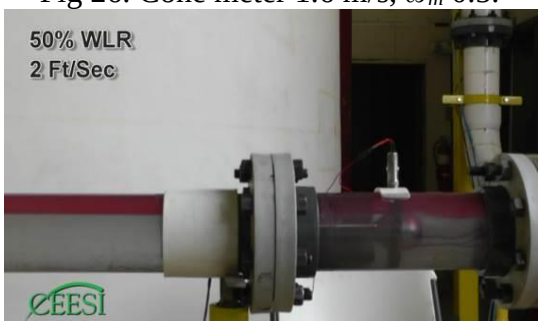

Fig 28. Turbine meter 0.6 m/s,ω_m 0.2

distinct change in colour downstream of the cone indicting a significant increase in mixing. This pattern was consistent across all tests. Figures 25 & 26 both show a high water to total mass flow ratio of 50%. Figure 25 shows 1.2 m/s produced a moderately separated upstream flow and Figure 26 shows 1.6 m/s produced a more mixed upstream flow. Both flows were significantly more mixed downstream of the cone. Even at a water to total mass flow ratio of 75% at 1.6 m/s (see Figure 27) where the inlet flow is stratified, the flow downstream of the cone element is mixed. In all tests the mixing effect extended dozens of diameters downstream before separation began to be evident.

The cone element looks to be a good oil with water mixer. Furthermore, it is simpler than the traditional mixer designs, and can also be used as the flow meter. That is, a cone meter could potentially be used as a joint mixer and flow meter instead of the current practice of having a mixer component and a separate meter component. Like all mixer designs, a cone would benefit from vertical flow to increase mixing before the cone.

6b.1. Oil with Water Flow and the Analogy with Wet Gas Flow

There is no methodology in the public literature for analysing oil with water flow through a cone (or any generic DP) meter. However, there is a direct analogy with wet gas flow through a DP meter. Whereas wet gas flow is a two-phase flow of gas and liquid, water cut flow metering is a single phase two component flow of oil and water.

Therefore, by replacing the gas phase with the oil, and the liquid phase with the water, parameters developed for analysing DP meter wet gas flow can be converted to an equivalent for analysing water cut flows. In this way, the substantial wet gas flow DP meter research can be utilised to analyse a cone meters reaction to oil with water flows. The following is a description of these modified parameters.

A modified Lockhart-Martinelli parameter (X_{LM}^{*}) can be defined as:

$$X_{LM}^{*} = \frac{m_{water}}{m_{oil}} \sqrt{\frac{\rho_{oil}}{\rho_{water}}} \tag{7}$$

where m_{oil} an m_{water} are the oil and water mass flow rates and ρ_{oil} and ρ_{water} are the oil and water densities respectively. The density ratio (DR^{*}) is defined as equation 8.

$$DR^{*} = \rho_{oil} / \rho_{water} \tag{8}$$

An oil densimetric Froude number (Fr_{oil}*) can be defined as equation 9. Here, g is the gravitational constant (9.81m/s^2).

$$Fr_{oil}^{*} = \frac{m_{oil}}{A\sqrt{gD}} \sqrt{\frac{1}{\rho_{oil}(\rho_{water} - \rho_{oil})}} \tag{9}$$

The uncorrected oil mass flow rate prediction can be called the 'apparent' oil mass flow, $m_{oil,apparent}$. This is calculated by equation 10.

$$m_{oil,apparent} = EA_t C_d \sqrt{2\rho_{oil}\Delta P_t} \tag{10}$$

The oil flow rate prediction positive bias induced by the presence of the water can be called an 'over-reading' (OR_{oil}). This can be expressed as a ratio (equation 11) or as a percentage.

$$OR_{oil} = \frac{m_{oil,\ apparent}}{m_{oil}} \tag{11}$$

The water-cut (ω) is defined as equation 12. Note that Q_{water} and Q_{oil} are the water and oil actual volume flow rates.

$$\omega = \frac{Q_{water}}{Q_{water} + Q_{oil}} = \frac{Q_{water}}{Q_{total}} \tag{12}$$

A water to total mass flow ratio (ω_m) can be utilised, as shown in equation 13.

$$\omega_m = \frac{m_{water}}{m_{water} + m_{oil}} = \frac{m_{water}}{m_{total}} \tag{13}$$

If fully mixed the homogenous density (ρ_h) can be calculated by equation 14.

$$\rho_h = \frac{\rho_{oil} \cdot \rho_{water}}{\rho_{water}(1 - \omega_m) + \rho_{oil}\omega_m} \tag{14}$$

6b.2. DP Meter Diagnostics

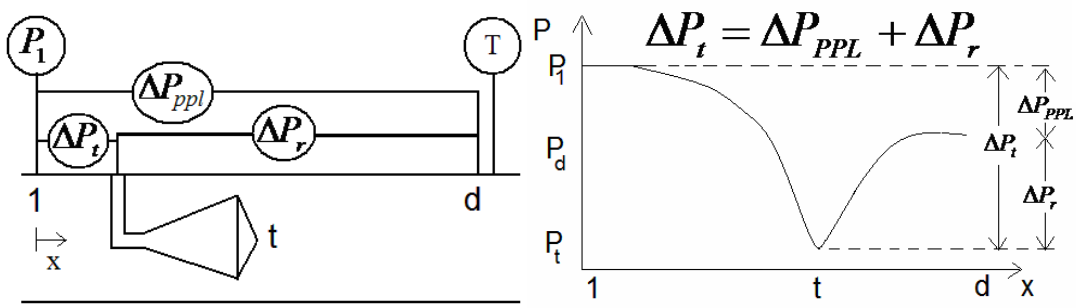

Figure 29. Cone meter with instrumentation sketch and pressure fluctuation graph.

Figure 29 shows a cone meter with a third pressure tap allowing the traditional DP (ΔP_t), a recovered DP (ΔP_r), and a permanent pressure loss DP (ΔP_{ppl}) to be read. This allows a full patented generic DP meter diagnostic suite to be available. Stobie et al [9] gives a detailed review of these diagnostics. A summary is given below.

The sum of ΔP_r and ΔP_{ppl} **must** equal ΔP_t (equation 15). This fact allows a DP reading check. Each DP offers an independent flow rate prediction, i.e. the traditional DP meter flow rate prediction (equation 16), the expansion DP meter flow rate prediction (equation 17), and the PPL DP meter flow rate prediction (equation 18).

$$\Delta P_t = \Delta P_r + \Delta P_{PPL} \qquad \text{uncertainty} \pm \theta\% \qquad (15)$$

Traditional Flow Equation: $$m = EA_t C_d \sqrt{2\rho\Delta P_t} \qquad \text{uncertainty} \pm x\% \qquad (16)$$

Expansion Flow Equation: $$m = EA_t K_r \sqrt{2\rho\Delta P_r} \qquad \text{uncertainty} \pm y\% \qquad (17)$$

PPL Flow Equation: $$m = AK_{ppl} \sqrt{2\rho\Delta P_{PPL}} \qquad \text{uncertainty} \pm z\% \qquad (18)$$

Every cone meter body is in effect three flow meters. These three flow rate predictions can be compared. The percentage difference between any two flow rate predictions should not be greater than the root mean square of the two flow rate prediction uncertainties. Table 2 shows the flow rate prediction pair diagnostics.

Flow Prediction Pair	% Actual Difference	% Allowed Difference	Diagnostic Check
Traditional & PPL	$\phi\%$	$\psi\%$	$-1 \le \psi\%/\phi\% \le +1$
Traditional & Expansion	$\xi\%$	$\lambda\%$	$-1 \le \lambda\%/\xi\% \le +1$
PPL & Expansion	$\upsilon\%$	$\chi\%$	$-1 \le \chi\%/\upsilon\% \le +1$

Table 2: Flow rate prediction pair diagnostics

With three DPs read, there are three DP ratios:

PPL to Traditional DP ratio (PLR): $(\Delta P_{PPL} / \Delta P_t)_{reference}$, uncertainty ± a%

Recovered to Traditional DP ratio (PRR): $(\Delta P_r / \Delta P_t)_{reference}$, uncertainty ± b%

Recovered to PPL DP ratio (RPR): $(\Delta P_r / \Delta P_{PPL})_{reference}$, uncertainty ± c%

A cone meter's DP ratios are characteristics of that meter. DP ratios found in service can be compared to their expected values. The difference between a found and expected value should not be greater than the reference DP ratio uncertainty. Table 3 shows the flow rate prediction pair diagnostics.

DP Ratio	% Actual to Ref Difference	% Reference Uncertainty	Diagnostic Check
PLR	$\alpha\%$	$a\%$	$-1 \le \alpha\%/a\% \le +1$
PRR	$\gamma\%$	$b\%$	$-1 \le \gamma\%/b\% \le +1$
RPR	$\eta\%$	$c\%$	$-1 \le \eta\%/c\% \le +1$

Table 3: DP Ratio diagnostics

Any inference that Equation 15 does not hold is a statement that there is a malfunction in one or more of the DP transmitters. The sum of ΔP_r and ΔP_{ppl} gives an 'inferred' $\Delta P_{t,inf}$. The inferred and directly read traditional DP should not be greater than the root mean square of the combined DP transmitter uncertainties. Table 4 shows the DP reading integrity diagnostics.

% Actual to Inferred Traditional DP Difference	% RMS Combined DP Reading Uncertainty	Diagnostic Check
$\delta\%$	$\theta\%$	$-1 \le \delta\%/\theta\% \le +1$

Table 4: DP Reading Integrity Diagnostic

Table 5 shows the seven possible situations where these diagnostic would signal a warning. For convenience we use the following naming convention:

Normalized flow rate inter-comparisons: $x_1 = \psi\%/\phi\%$, $x_2 = \lambda\%/\xi\%$, $x_3 = \chi\%/\upsilon\%$

Normalized DP ratio comparisons: $y_1 = \alpha\%/a\%$, $y_2 = \gamma\%/b\%$, $y_3 = \eta\%/c\%$

Normalized DP sum comparison: $x_4 = \delta\%/\theta\%$

DP Pair	No Warning	WARNING	No Warning	WARNING
ΔP_t & ΔP_{ppl}	$-1 \le x_1 \le 1$	$-1 < x_1$ or $x_1 > 1$	$1 \le y_1 \le 1$	$-1 < y_1$ or $y_1 > 1$
ΔP_t & ΔP_r	$-1 \le x_2 \le 1$	$-1 < x_2$ or $x_2 > 1$	$1 \le y_2 \le 1$	$-1 < y_2$ or $y_2 > 1$
ΔP_r & ΔP_{ppl}	$-1 \le x_3 \le 1$	$-1 < x_3$ or $x_3 > 1$	$1 \le y_3 \le 1$	$-1 < y_3$ or $y_3 > 1$
$\Delta P_{t,read}$ & $\Delta P_{t,\inf}$	$-1 \le x_4 \le 1$	$-1 < x_4$ or $x_4 > 1$	N/A	N/A

Table 5: The DP meter possible diagnostic results

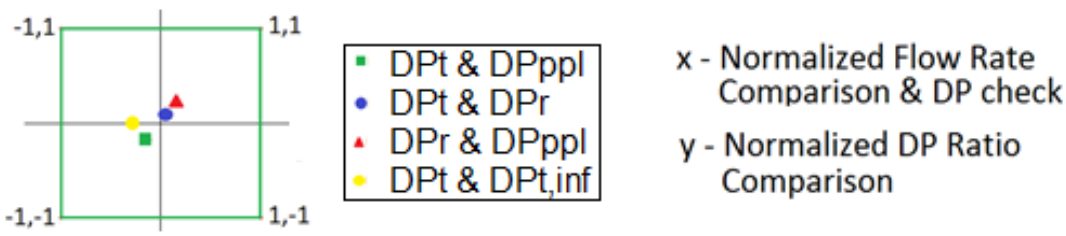

Figure 30: Normalized diagnostic box (NDB) & results, DP check included.

A box can be drawn, centred on a graph's origin, and four points plotted representing seven diagnostic checks (as shown in Figure 30). If the meter is fully serviceable all points must be inside the box. One or more points outside the box indicate a malfunction. The diagnostic pattern of an alarm offers information on the source of the malfunction. Different malfunctions can cause different diagnostic patterns.

6b.3. Cone Meter Baseline Flow Data

The cone meter with a downstream pressure tap has three flow rate calculations, i.e. equations 16, 17 & 18, with the discharge coefficient (C_d), the expansion coefficient (K_r), and the PPL coefficient (K_{PPL}) respectively. Initial testing was conducted on oil flow only and then water flow only. These 'baseline' results for the flow coefficients and DP ratios are show in Figures 31 & 32.

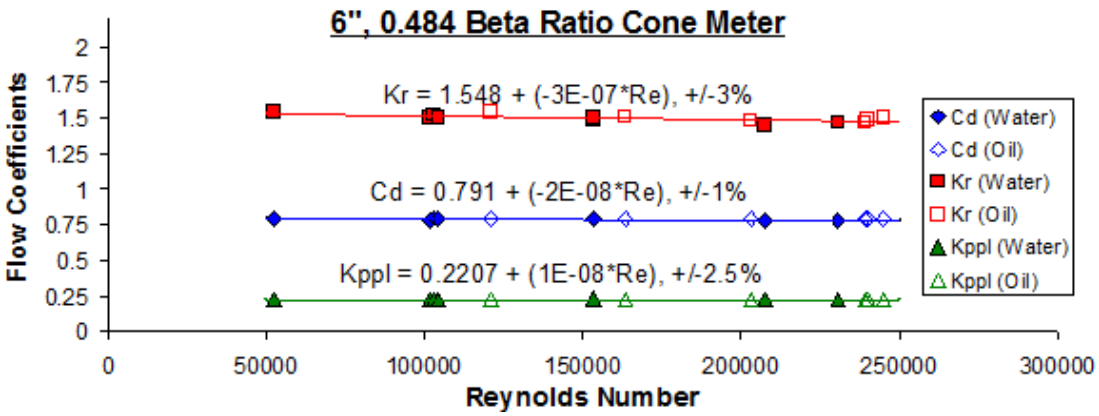

Figure 31. 6", 0.483β Cone Meter Flow Coefficients in Homogenous Liquid Flow.

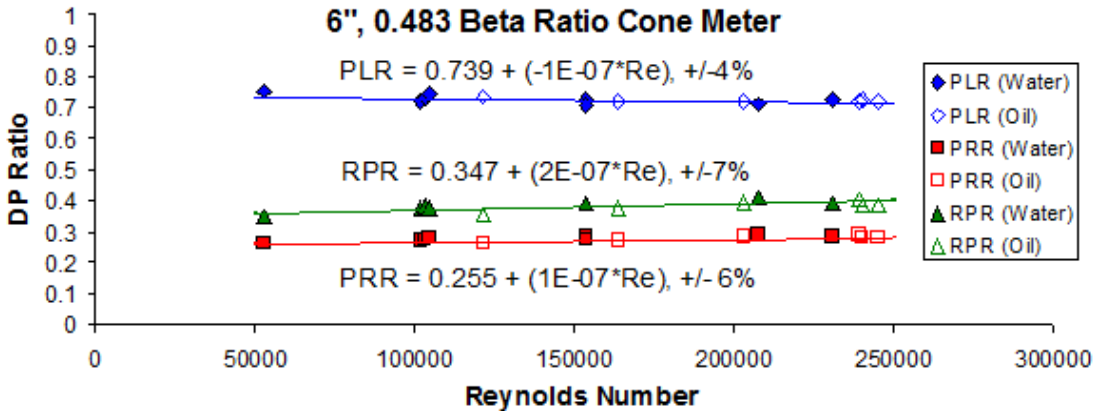

Figure 32. 6", 0.483β Cone Meter DP Ratios in Homogenous Liquid Flow.

Figure 31 shows the cone meter had a fitted discharge coefficient with a 1% uncertainty for either water or oil flow. The expansion and PPL coefficients were fitted to 3% and 2.5% respectively. These check meters are not as accurate as the traditional meter, but give important secondary flow rate information for diagnostics. The DP ratios shown in Figure 32 are unaffected by whether the flow is oil or water, and have been fitted to liner lines. The PLR fit has 4% uncertainty, the PRR fit has 6% uncertainty, and the RPR fit has 7% uncertainty. These uncertainties may look large but diagnostic examples show these results are still very useful in practice.

6b.4. Cone Meter and Water in Oil Flow Data

Figure 33 shows the three flow rate prediction responses to oil with water flow in terms of the percentage over-reading (OR_{oil}%) vs. the modified Lockhart-Martinelli parameter (X_{LM}^*). All three flow rate predictions give approximately the same over-reading. For wet gas flow, research has shown that a combination of the traditional, expansion & PPL flow rate predictions being approximately equal is a signature of fully homogenized flow. Furthermore, it was noted that for this constant density ratio

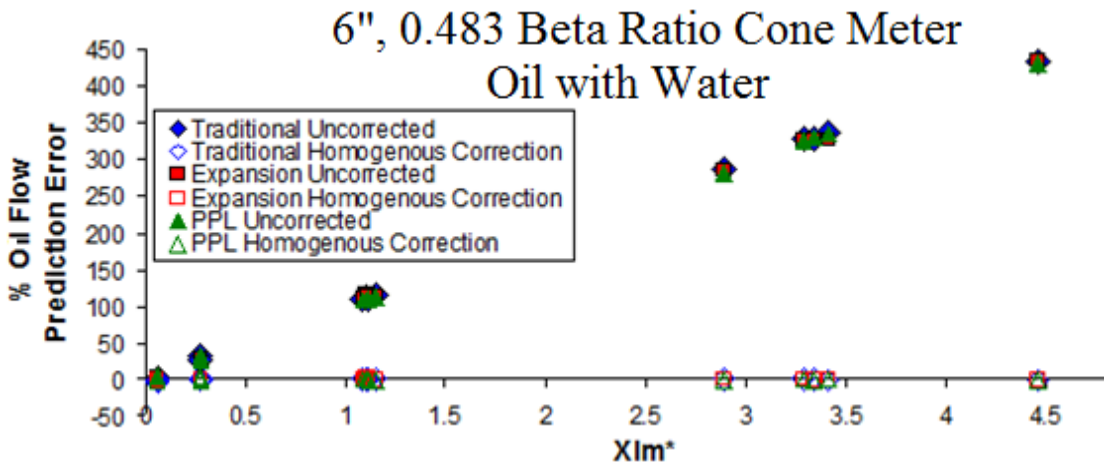

Figure 33. 6", 0.483β Cone Meter Oil with Water Data.

(DR^*) of 0.82, varying the oil densiometric Froude number (Fr_{oil}*) had no appreciable effect on the over-reading. For wet gas flow, research has shown that this too is a signature of fully homogenized flow. Hence, the three flow rate predictions matching each other is a diagnostic check that the cone meter is mixing the oil with water flow to a near homogenous flow.

The theoretical correction factor for a DP meter with a fully homoginized oil with water flow can be shown to be equation set 18 & 19.

$$m_{oil} = \frac{m_{oil,\ apparent}}{OR_{oil}} = \frac{m_{oil,\ apparent}}{\sqrt{1 + CX^*_{LM} + \left(X^*_{LM}\right)^2}} \tag{18}$$

$$C = \sqrt{\frac{\rho_{oil}}{\rho_{water}}} + \sqrt{\frac{\rho_{water}}{\rho_{oil}}} \tag{19}$$

Figure 33 shows the homogenous oil with water correction results. It is assumed from the outset that the oil and water densities are known. To apply equation set 18 & 19, equations 7 & 10 must be used. Equation 7 requires the water to oil flow rate ratio be supplied from an external source. In Figure 33 this external source is the test facility reference meters. In the field, the external source is the sampling results. The homogenous correction method offers a dramatic improvement of the oil flow prediction.

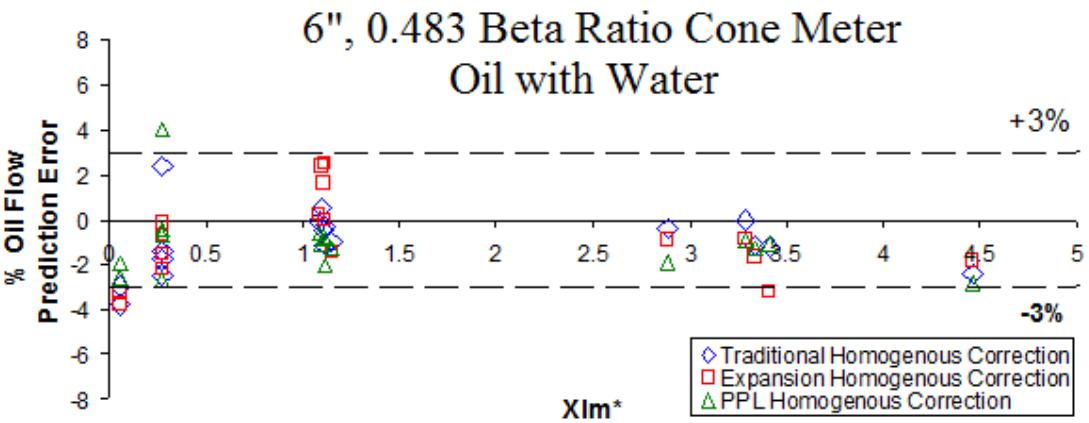

Figure 33a. 6", 0.483β Cone Meter Oil with Water Homogenous Model Correction.

Figure 33a only shows the homogenous models correction results. All three oil flow predictions have approximately 3% uncertainty. It is noteable that the correction is **not** a data fit, but rather a fully theoretical correction factor. This is the reason there is a slight negative bias in the results in Figure 33a, especially at higher modified Lockhart Martinelli parameter (X_{LM}^*) values. It is expected that if the cone meter had been installed vertically up, the enhanced mixing would mean the meter performance would be closer still to homogenous flow.

This data can be fitted to a tighter fit. Linear data fits i.e. the form shown as equation 20, have been fitted here as a simple example. (Other more complicated data fits can be chosen.)

$$m_{oil} = \frac{m_{oil,\ apparent}}{OR_{oil}} = \frac{m_{oil,\ apparent}}{1 + MX_{LM}^*} \tag{20}$$

The three gradients for the three meters were found to be:

$$M_{traditional} = 0.9857,\ M_{expansion} = 0.9825\ \&\ M_{PPL} = 0.9650.$$

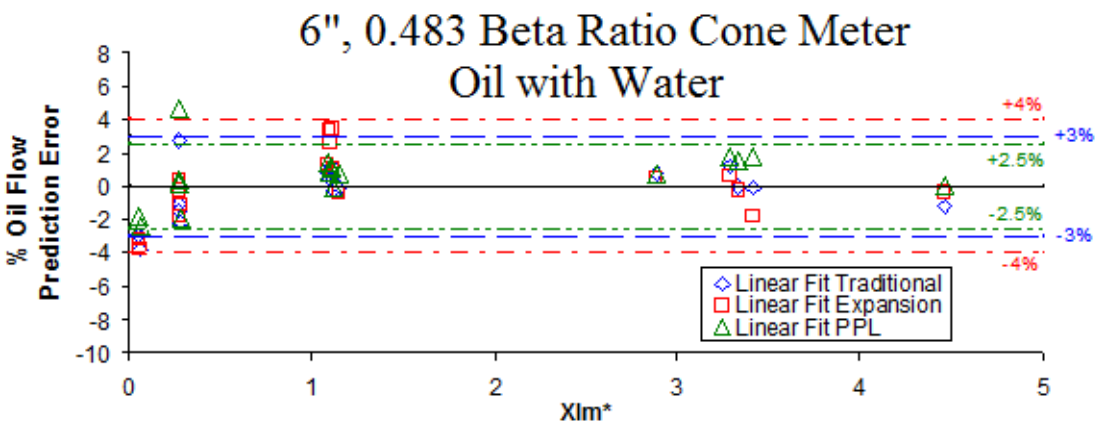

Figure 34. 6", 0.483β Cone Meter Water in Oil Linear Fit Corrected Results.

Figure 34 shows the 6", 0.483β cone meter water with oil results when the oil flow rate over-reading is corrected for a known water to oil flow rate ratio with these linear fits. The traditional meter has the same corrected oil flow rate prediction uncertainty as the theoretical homogenous model. The expansion meter has a slightly higher corrected oil flow rate prediction uncertainty. With the exception of a single outlier, the PPL meter has a slightly reduced corrected oil flow rate prediction uncertainty. It is therefore possible that cone expansion meters, or cone PPL meters, may give as good or better an oil over-reading correction, as the traditional meter correction.

6b.5. <u>The DP / Cone Meter Diagnostic System Applied to Water with Oil Flows</u>

The diagnostics summarized in Section 6b.2 work with cone meters. These diagnostics are designed as homogenous flow DP meter diagnostics. The literature shows these patented diagnostics correctly indicate that a problem exists when a cone meter suffers various common problems, such as:

- incorrect keypad entered inlet or cone diameter
- DP transmitters problems (e.g. drift, over-ranging or incorrect calibration)
- partial blockage at cone
- deformation / shift in alignment of the cone element

- disturbed flow at cone meter
- incorrect keypad entry of flow parameters (e.g. discharge coefficient)
- wet gas flow (in the common event the wet gas is not homogenously mixed)

Of the diagnostics described in Section 6b.2 for single phase homogenous flow, the only known problem that the diagnostic system does not monitor for is density errors. Whereas this is a minor limitation to the diagnostic system when applied in its normal homogenous flow applications, it is a benefit in an oil with water application.

The integrity of the traditional mixer / sampler and volume meter oil with water metering system is wholly dependent on the integrity of the sample system and the integrity of the volume meter output. However, traditionally the volume meters (primarily ultrasonic and turbine meters) diagnostics are compromised when applied to oil with water flows. Furthermore, traditionally the mixer / sample system has no internal method of monitoring its own effectiveness.

A cone meter could be developed to be both mixer and flow meter, thereby eliminating the requirement for two separate pipe components of a mixer and a meter. Such a system can be installed in any pipe orientation. It could be installed in vertical flow, as is common practice for stand-alone mixer designs with sample systems downstream. However, flow velocity and beta ratio dependent, it is potentially possible that such a system could be successfully installed in horizontal flow, thereby alleviating the requirement for vertical flow sections to aid mixing. If the cone effectively mixes the flow, the homogenous fluid diagnostic system will be unaffected by the fluid being a mix of oil and water. Hence, cone meters have the potential to have workable diagnostics in oil with water applications.

Finally, note that traditional mixer designs have no diagnostic system, i.e. no way of indicating the quality of the mixing. If a cone meter with a downstream pressure tap is used as a mixer, the cone meters comparison of the three separate flow rate predictions offers a monitoring system to the quality of the mixing. The closer the three flow rate predictions match, the better mixed the oil and water are.

6b.5.1. Cone Meter Diagnostics in Operation using Oil with Water Flow Data

The 6”, 0.483β clear body cone meter (shown in Fig 23 through 27) was calibrated with water only flow and oil only flow. The results are shown in Figures 31 & 32. Random samples of this correct baseline data diagnostic results plotted on a NDB (see Section 6b.2 , Figure 30) are shown in Figure 35.

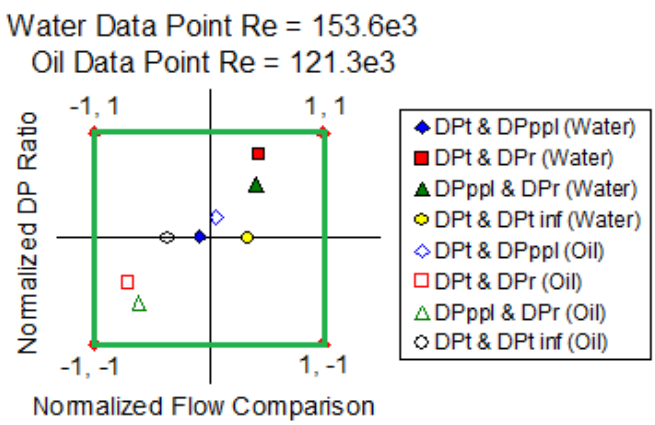

Figure 35. Random Examples of Baseline Diagnostic Results.

First, consider random examples of the DP meter in use with water **or** oil flows when there is a problem. Say there was an inlet diameter keypad entry bias where the inlet diameter 6.065” (i.e. 6”, schedule 40) was used instead of the correct value of 6.00”. The traditional flow prediction has an error induced of +10%. Figure 36 shows the diagnostic result for correct and incorrect inlet geometries on a randomly chosen oil only flow. The diagnostics can identify a problem exists.

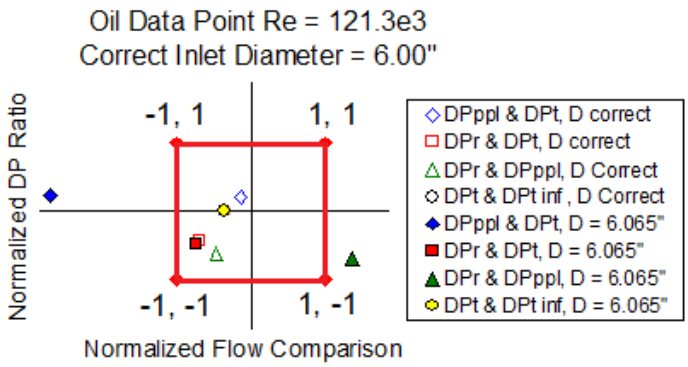

Figure 36. Results from Oil Flow Example for Incorrect Inlet Diameter

Say there was a cone diameter keypad entry bias where the cone diameter of 5.252” was incorrectly entered as 5.3”. The traditional flow prediction has an error induced of -5.5%. Figure 37 shows the diagnostic result for the correct and incorrect cone geometry being used. The diagnostics clearly identified when the problem exists. The diagnostic system is shown to operate correctly with water **or** oil flows, as required.

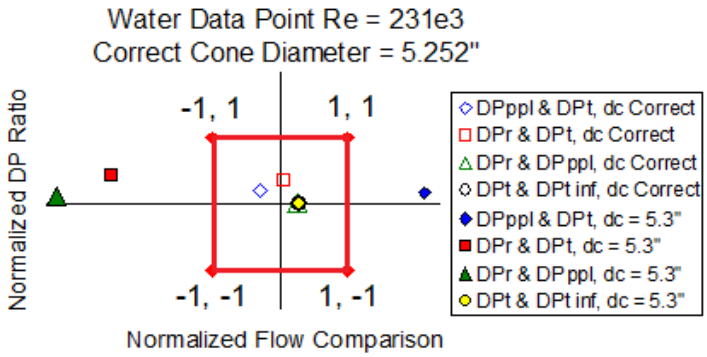

Figure 37. Results from Water Flow Example for Incorrect Cone Diameter

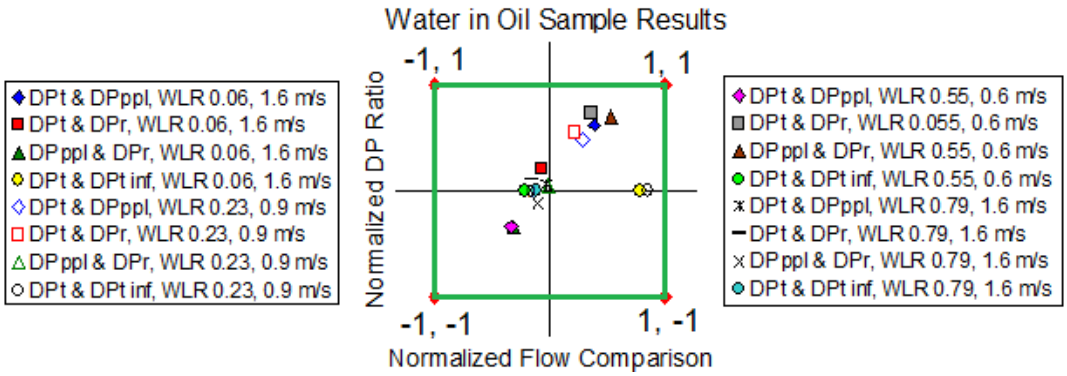

Figure 38. Results from Water in Oil Flows when the Cone Meter is Serviceable.

Figure 38 shows sample data only (so as not to over-crowd the NDB), of various oil with water flow examples, when the cone meter is fully operation. The diagnostic system (’Prognosis’) does not look for density errors. Therefore, the diagnostic system

is immune, or 'tolerant', of the oil with water density 'issue'. The presence of two immiscible fluids does not adversely affect the operation of the diagnostic system. The diagnostics monitor the meters serviceability in oil with water flow applications.

Figure 39 shows diagnostics results from a serviceable cone meter with oil with water flow, and when that meter has an error induced by an incorrectly entered discharge coefficient. The correct discharge coefficient is: C_d=0.791+(-2e-8*Re). In this example the erroneous discharge coefficient used is: C_d=0.791+(-2e-7*Re). The induced error was -4.6%. When the meter was serviceable no alarm was given. When the discharge coefficient was incorrect an alarm was raised.

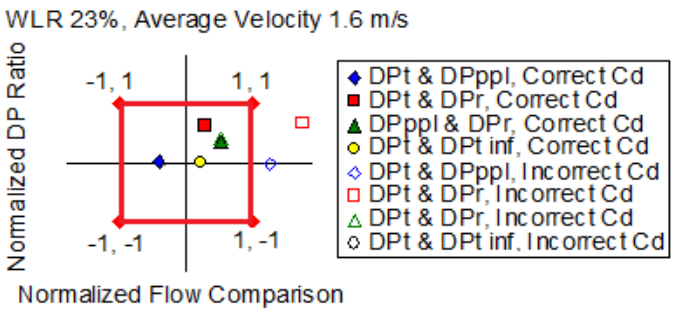

Figure 39. Results for Correct and Incorrect C_d in Oil with Water Flow Application.

Figure 40 shows diagnostics results for when a DP transmitter read the traditional DP correctly and for when it was saturated (or 'over-ranged). The saturated transmitter associated flow rate prediction error was -2.8%. When the meter was serviceable no alarm was given. When the DP transmitter failed an alarm was raised.

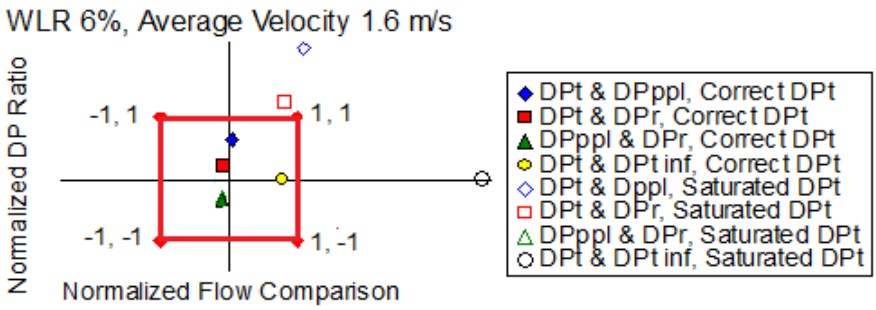

Figure 40. Results from DP_t Read Correctly & When Saturated / Artificially Low.

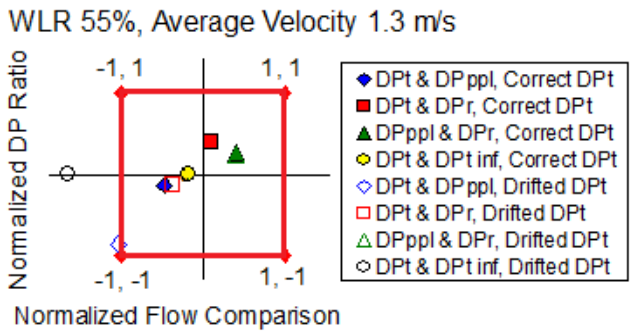

Figure 41. Results from DP_t Read Correctly & When Drifted / Artificially Low

Figure 41 shows diagnostics results for when a DP transmitter read the traditional DP correctly and for when it had drifted low. The drifted transmitter associated flow rate prediction error was +1.5%. When the meter was serviceable no alarm was given. When the DP transmitter failed an alarm was raised.

Conclusions

There is an increasing commercial requirement for low uncertainty oil with water flow measurement across the entire water cut range, i.e. $0\% \leq \omega < 100\%$. The literature, and the standards documents, do not give a comprehensive description of the mixing, sampling and flow measurement procedures required to obtain some metering output uncertainties. A great deal of flow testing is required for industry to improve its knowledge of the operation and performance of meters and sampling systems at high water cuts.

CEESI have developed an oil with water facility designed specifically to carry out testing at high water cuts with a good reference uncertainty. This flow line has been commissioned and used successfully for testing of static mixers and flow meters.

The turbine flow meters were found to be adversely affected by oil with water flows, especially at lower flow velocities, in a way that has not been adequately explained. The cone meter was found to be adversely affected by oil with water flows. Utilising a wet gas flow meter analogy, it was found that a 6", 483β cone meter's performance in oil with water flow applications could be characterised by the homogenous model. As such, a sampling systems water cut result could be used with the homogenous model to allow the cone meter to predict the oil and water flow rates. It was also found that the generic DP meter diagnostic system 'Prognosis' was unaffected by the 'adverse' flow conditions when applied on a cone meter in an oil with water flow application.

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