

Measurement of vertical oil-in-water two-phase flow using dual-modality ERT–EMF system



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ABSTRACT

Oil-in-water two-phase flows are often encountered in the upstream petroleum industry. The measurement of phase flow rates is of particular importance for managing oil production and water disposal and/or water reinjection. The complexity of oil-in-water flow structures creates a challenge to flow measurement. This paper proposes a new method of two-phase flow metering, which is based on the use of dual-modality system and multidimensional data fusion. The Electrical Resistance Tomography system (ERT) is used in combination with a commercial off-the-shelf Electromagnetic Flow meter (EMF) to measure the volumetric flow rate of each constituent phase. The water flow rate is determined from the EMF with an input of the mean oil-fraction measured by the ERT. The dispersed oil-phase flow rate is determined from the mean oil-fraction and the mean oil velocity measured by the ERT cross-correlation velocity profiling. Experiments were carried out on a vertical upward oil-in-water pipe flow, 50 mm inner-diameter test section, at different total liquid flow rates covering the range of 8–16 m³/hr. The oil and water flow rate measurements obtained from the ERT and the EMF are compared to their respective references. The accuracy of these measurements is discussed and the capability of the measurement system is assessed.

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1. Introduction

Oil-in-water two-phase flows are often encountered in the upstream petroleum industry. The measurement of phase flow rates is of particular importance for managing oil production and water disposal and/or water reinjection. The need for a measurement system, by which each constituent phase flow quantity is determined, has always been present since oil industry started. For example, in order to know the productivity of an oil reservoir, accurate information regarding the producing wells is required. Therefore, a reliable measurement system or method is required to satisfy these needs. In return it enables optimization of the oil production and ensures long term recovery from the reservoir. However, in the later stage of oil production the complexity of oil-in-water high water-cut flows (a small subset of oil–water–gas three-phase flows), which is caused by differences in densities and

viscosities of each phase, can create a challenge to flow measurement [12,13,7].

Over the years a considerable number of methods have been evaluated, in the aim of accurately measuring oil–water flows in horizontal, inclined or vertical pipes. Some of these methods include the use of flow-constriction differential-pressure (DP) sensors [10,17,8], Coriolis, vortex shedding or turbine ‘single-phase’ flow meters [10], electrical conductance sensor combined with a DP sensor [11]. There are still some drawbacks in the investigated methods, such as the flow-distribution dependency (separated vs. well-mixed flow), use of flow-restriction (in the DP measurement) and of the moving parts. It is desirable to have a full-bore oil–water flow metering method that has the potential to be extended to the measurement of oil–water–gas three-phase flows, without the use of a radioactive source.

Since 1990s tomography techniques have gone through a major development and are used to provide a novel technique of non-intrusive flow measurement and rapid visualization of the internal structure of process industry [15]. The Electrical Resistance Tomography (ERT), amongst the family of tomography techniques,

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can be used as a viable tool to non-intrusively and safely interrogate the internal structure of oil–water (or gas–water) flow. It is worth pointing out that in two-phase flow metering it is almost impossible to determine flow parameters of each constituent phase using only one conventional flow meter. Thus, a secondary sensor is required.

Therefore, the objective of this research work is to develop an on-line two-phase oil-in-water flow dual-modality measurement system, in which the ERT is used as the main subsystem and an off-the-shelf Electromagnetic Flow meter (EMF) as a secondary subsystem (sensor). The novel dual-modality system is developed for on-line rapid phase volumetric flow rate measurement. The dispersed oil-phase flow rate is determined from the mean oil volume fraction and the mean oil velocity measured by the ERT and cross-correlation velocity profiling. The water flow rate is determined from the EMF with an input of the mean oil volume fraction measured by the ERT.

2. Measurement concepts

The principle of the method, ERT–EMF dual-modality system and multi-dimensional data fusion, for phase flow-rate determination is described in this section.

2.1. Phase fraction and velocity determination

The schematic diagram of phase determination concept for two-phase oil-in-water flow is illustrated in Fig 1. In two-phase oil-in-water flow, the ERT technique is used to extract the local volume fraction distribution α_0 and the local flow velocity distribution (V_0) of the dispersed oil phase across the pipe cross-section. The ERT measurement is based on the relative change between the conductivity of the two-phase mixture and the conductivity of conducting water phase (water conductivity can be monitored online separately, [3]).

In order to determine the dispersed oil phase volume fraction within the host continuous phase (water), it is rather preferable to play with the permittivity of the constituent phases of the two-phase mixture. It is therefore a mixing rule is used to provide a relationship between the permittivity of the media and volume fraction. Perhaps the most common and basic mixing rule is the Maxwell Garnett mixing rule (Eq. (1)) [6], where the effective mixture permittivity of the material is connected to the parameters of the constituent phases.

$$\varepsilon_{mc} = \varepsilon_1 + 3\alpha_0\varepsilon_1 \frac{\varepsilon_2 - \varepsilon_1}{\varepsilon_2 + 2\varepsilon_1 - \alpha_0(\varepsilon_2 - \varepsilon_1)} \quad (1)$$

Eq. (1) gives the effective permittivity ε_{mc} of the two-phase mixture, where spherical inclusions (oil phase) of permittivity ε_2 occupy a volume fraction α_0 in the background water phase with permittivity ε_1 .

The ERT is used to determine the local oil volume fraction α_0 on each pixel of cross-sectional tomographic image based on the conductivity rather than permittivity. As this the case, the Maxwell Garnett mixing formula (Eq. (1)) is converted and expressed in terms of conductivity ($\varepsilon = \sigma/j\omega\varepsilon_0$), as shown in Eq. (2).

$$\sigma_{mc} = \sigma_1 + 3\alpha_0\sigma_1 \frac{\sigma_2 - \sigma_1}{\sigma_2 + 2\sigma_1 - \alpha_0(\sigma_2 - \sigma_1)} \quad (2)$$

Where σ_{mc} is the effective mixture conductivity, which is measured by the ERT, σ_1 is the conductivity of water; σ_2 is the conductivity of the dispersed oil phase.

Rewriting Eq. (2) to give the dispersed phase oil volume fraction, as follows:

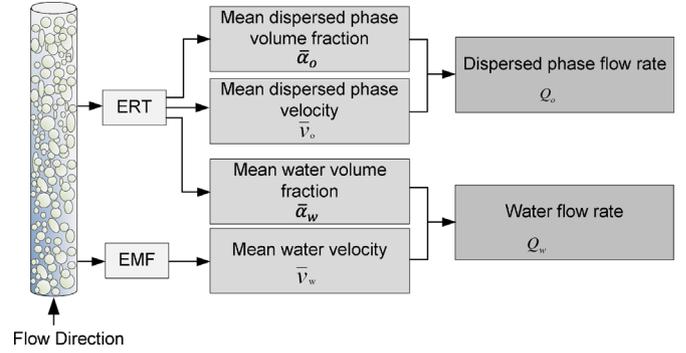


Fig. 1. ERT–EMF phase flow rate determination concept for two-phase oil-in-water flow.

$$\alpha_0 = \frac{2\sigma_1 + \sigma_2 - 2\sigma_{mc} - \frac{\sigma_{mc}\sigma_2}{\sigma_1}}{\sigma_{mc} - \frac{\sigma_{mc}\sigma_2}{\sigma_1} + 2(\sigma_1 - \sigma_2)} \quad (3)$$

It is worth mentioning that the effectiveness of the Maxwell Garnett formula is in its simple appearance can be combined with broad applicability. It satisfies the limiting processes in the absence of one of the constituent phases (i.e. $0 \leq \sigma_{mc} \leq 1$). In other words, if the oil volume fraction is 0, then $\sigma_{mc} = \sigma_1$, on the other hand, in the case of oil volume fraction is 1, the $\sigma_{mc} = \sigma_2$.

The estimation of oil volume fraction from the ERT is based on the average of the oil volume fractions of individual square pixels within the entire reconstructed image, as shown in Eq. (4). In other words, α_0 , σ_1 , σ_2 and σ_{mc} in Eq. (3) are vectors within m elements. Each element of the vector represents the value in the square pixel.

$$\alpha_0 = \frac{\sum_{i=1}^m \alpha_{0,i} A_i}{A} \quad (4)$$

Where A_i , A and $\alpha_{0,i}$ are the pixel area, the area of the reconstructed image (pipe cross-sectional area) and in-situ local volume fraction. Considering the dispersed oil phase is non-conductive (i.e. σ_2 is zero) and water as a continuous conductive phase, then Eq. (3) can be formulated to a simpler form, as shown in Eq. (5).

$$\alpha_0 = \frac{2\sigma_1 - 2\sigma_{mc}}{\sigma_{mc} + 2\sigma_1} \quad (5)$$

Eq. (5) can be rearranged to obtain σ_{mc}/σ_1 as the only variable, as shown in Eq. (6), which describes the correlation between oil volume fraction α_0 and σ_{mc}/σ_1 (the detailed description of such correlation is highlighted elsewhere, [2]). All the local oil volume fractions are then averaged to determine the oil volume fraction across one frame of ERT image.

$$\alpha_0 = \frac{2 - 2\frac{\sigma_{mc}}{\sigma_1}}{2 + \frac{\sigma_{mc}}{\sigma_1}} \quad (6)$$

The theory of Electromagnetic Flow meter was first introduced by Shercliff [9] for single-phase flow. Shercliff proposed a weight function, which describes the contribution of the fluid velocity to the signal at the pipe cross-section, as shown in Eq. 7.

$$\Delta U_{SP} = BV_m d = \frac{4BQ_w}{\pi d} \quad (7)$$

Where ΔU_{SP} is the potential difference in single-phase water flow, B is the magnetic flux density, V_m is the average velocity at the pipe cross-section, d is the distance between the EMF electrodes and Q_w is the conductive phase flow rate, which is water in this study.

The use of Electromagnetic Flow meters in two-phase flow was investigated by [1]; who concluded that a homogeneous two-phase flow would give rise to a potential difference, irrespective of flow regime or homogeneity of electrical conductivity. This potential difference in oil–water two-phase flow can be expressed as shown in Eq. (8).

$$\Delta U_{TP} = \frac{\Delta U_{SP}}{(1 - \alpha_0)} = \frac{4BQ_w}{\pi d(1 - \alpha_0)} \quad (8)$$

Where ΔU_{TP} is the potential difference in two-phase flow, ΔU_{SP} is the potential difference induced by the water flow rate only and α_0 is the oil volume fraction.

For single-phase water flow, the EMF flow rate represents the water flow rate with the average water velocity V_w across the pipe cross-sectional area A , as shown in Eq. (9).

$$Q_{EMF} = \bar{v}_w A \quad (9)$$

The simplified form of Eq. (8) can be expressed as Eq. (10) [16].

$$Q_w = (1 - \alpha_0) Q_{EMF} \quad (10)$$

Substitution of Eq. (9) in Eq. (10) yields Eq. (11), which can be used to determine the water flow rate in oil-in-water flow with an input of the mean oil volume fraction measured by the ERT, as shown in Eq. (12) and water velocity measured by the EMF.

$$Q_w = (1 - \alpha_0) \bar{v}_w A \quad (11)$$

$$\bar{\alpha}_0 = \bar{\alpha}_{ERT} \quad (12)$$

It is worth pointing out that the average water velocity was taken from direct reading of the EMF. Thus the EMF is used to measure only the average velocity of the continuous water phase (V_w), while the mean volume fraction of the continuous water phase α_w is determined from the ERT, as shown in Eq. (14).

$$\bar{\alpha}_0 + \bar{\alpha}_w = 1 \quad (13)$$

The mean water local volume fraction can be obtained by substituting Eq. (12) in Eq. (13).

$$\bar{\alpha}_w = 1 - \bar{\alpha}_{ERT} \quad (14)$$

2.2. Phase volumetric flow rate determination

The phase volume flow rate can be determined through combination of the dual-plane ERT and the EMF measurements. The oil flow rate can be obtained from the local mean oil volume fraction distribution and mean axial oil velocity distribution, which are both obtained from the ERT, across the pipe cross-sectional area (A), as shown in Eq. (15). The oil velocity is determined from the cross-correlation of dual-plane oil fraction distributions. The water flow rate is obtained from the product of mean water volume fraction, obtained from the ERT, and mean axial water velocity measured by the EMF, across the pipe cross-sectional area (A), as shown in Eq. (16). The subscripts, ERT and EMF, in both equations denote the method (or technique) used to measure the relevant parameter.

$$Q_o = \bar{\alpha}_{o(ERT)} \bar{v}_{o(ERT)} A \quad (15)$$

$$Q_w = \bar{\alpha}_{w(ERT)} \bar{v}_{w(EMF)} A \quad (16)$$

2.3. Water-in-Liquid Ratio determination

The Water-in-Liquid Ratio (WLR) can be estimated from the measured water and oil volumetric flow rates (Q_w & Q_o), obtained

from the dual modality ERT–EMF measurement system, as shown in Eq. (17).

$$WLR_{meas}(\%) = \left(\frac{Q_w}{Q_w + Q_o} \right) \times 100 \quad (17)$$

Substituting Eqs. (15) and (16) in Eq. (17) to yield:

$$WLR_{meas}(\%) = \left(\frac{\bar{\alpha}_{w(ERT)} \bar{v}_{w(EMF)}}{\bar{\alpha}_{w(ERT)} \bar{v}_{w(EMF)} + \bar{\alpha}_{o(ERT)} \bar{v}_{o(ERT)}} \right) \times 100 \quad (18)$$

Eq. 18 can be used for estimation of WLR using ERT in conjunction with EMF.

3. Experimental set-up and data processing

3.1. The experimental flow facility

Experiments were carried out using the inclinable three-phase flow facility at Schlumberger Gould Research (SGR). Fig. 2 illustrates the schematic diagram of the test section. The two-phase oil-in-water measurement system was installed on the flow loop and tested mainly for vertical upward flows. The measurement system was located at approximately 6 m from the inlet of the SGR flow loop, with a transparent pipe section 500 mm in length installed downstream for the purpose of visual observation during the experiments. The test section is approximately 1 m long with 50 mm internal diameter and composed of a dual-plane ERT sensor (designed and manufactured by the University of Leeds), an off-the-shelf EMF (OPTIFLUX 4000, from KROHNE), two absolute pressure transducers (PXM209-2.50A10V, from OMEGA) and one

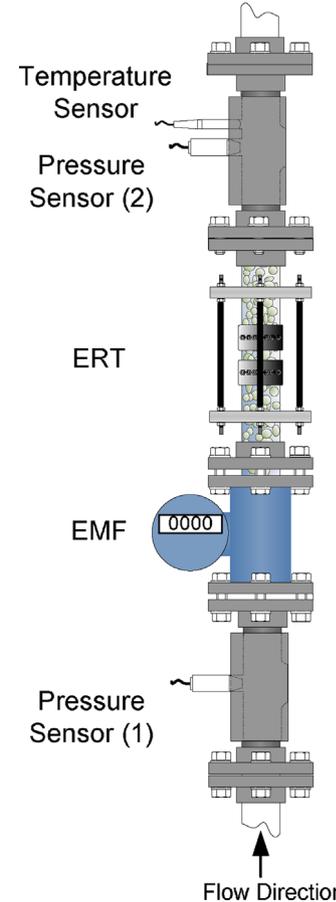


Fig. 2. Schematic diagram of the test section.

Table 1
Summary of the test matrix for vertical upward oil-in-water flow.

System conditions	2.2 bar, $\approx 18.5^\circ\text{C}$
Oil phase	Total-D75 Kerosene
Water phase	Local tap water
Pipe ID (mm)	50
Inclination from vertical ($^\circ$)	0
Water superficial velocity (m/s)	0.6–1.6
Oil superficial velocity (m/s)	0.15–1.13
WLR (%)	50–91.66
Flow regime	Dispersed oil in water flow (droplets)
Test points	9

temperature sensor (SPRTX-M1, from OMEGA).

Water and oil were pumped from the flow loop separator, measured respectively by electromagnetic and turbine single-phase liquid reference flow meters, and introduced into the flow loop as a two-phase mixture. The oil fluid was low-viscosity (2.1 cP) Total-D75 Kerosene and local tap water (≈ 0.7 mS/cm at 20°C). The range of oil flow rate and water flow rate used in the experiments were $1\text{--}8\text{ m}^3/\text{hr}$ and $4\text{--}11\text{ m}^3/\text{hr}$ respectively. The total liquid flow rate was $8\text{--}16\text{ m}^3/\text{hr}$, with a maximum line pressure 2.2 bar. The range of WLR used in this study was 50–91.66%, which is within the range of water continuous. Two groups of experiments were carried out, each with different mixture velocity and different Water-in-Liquid Ratio (WLR). It is worth mentioning that all the experiments were carried out within water continuous region ($\text{WLR} > 30\%$). The summary of the test matrix is illustrated in Table 1.

3.2. The dual-modality ERT–EMF flow measurement system

The oil-in-water measurement system is composed of a dual-plane ERT sensor and an off-the-shelf Electromagnetic Flow meter. The EMF is an OPTIFLUX 4000 with Hastelloy C22 fixed electrodes with a 2-electrode construction. The accuracy of the EMF is $\pm 0.2\%$. The EMF is installed at the upstream of and next to the dual-plane ERT sensor.

The ERT based hardware system is a novel on-line measurement system, which has been developed by the University of Leeds. The dual-plane ERT sensor was in-house built with each sensor plane consisting of 16 equally spaced stainless-steel electrodes, which are flush mounted at the periphery of each sensor plane. The sensor planes are separated by an axial distance of 50 mm to realize the application of cross-correlation dispersed-phase velocity profiling method. The hardware system enables the use of either 8 electrodes or 16 electrodes per plane, depending on the purpose and the application. In the experiments highlighted in this paper, only 8-electrode arrangement was used for the image reconstruction of the mixture conductivity distribution (for dispersed oil-phase fraction determination).

A total of 20,000 dual frames were acquired for each flow condition (approximately 20-s duration). The algorithm used for the image reconstruction is the Modified Sensitivity Back Projection (MSBP). The axial oil velocity distribution is calculated through the combination of the ERT and pixel-to-pixel cross-correlation. The phase flow rates are determined through the combination of the ERT and EMF measurements (Section 2).

4. Results and discussions

The flow quantities obtained from the experimental measurements are presented in the final form of water and oil volumetric flow rates (Q_w & Q_o) in this paper, as shown in Table 2.

The experimental conditions were split into two separate test

Table 2
Reference and measured phase volumetric flow rate.

	Reference		Measured		Relative error (%)	
	Q_w (m^3/hr)	Q_o (m^3/hr)	Q_w (m^3/hr)	Q_o (m^3/hr)	Q_w	Q_o
Variable WLR ($Q_T=12\text{ m}^3/\text{hr}$)	8	4	7.98	4.52	–0.26	12.99
	9	3	8.98	3.20	–0.25	6.56
	10	2	9.95	2.13	–0.55	6.39
	11	1	10.91	1.05	–0.84	5.15
Variable liquid velocity ($\text{WLR}=50\%$)	4	4	4.15	4.21	3.71	5.31
	5	5	5.13	5.40	2.61	7.92
	6	6	6.06	6.92	1.07	15.26
	7	7	7.18	7.87	2.57	12.38
	8	8	8.05	9.14	0.59	14.22

groups. In the first test group; the WLR is variable and liquid velocity (total liquid rate) is constant ($Q_T=12\text{ m}^3/\text{hr}$), while in the second test group; the liquid velocity is variable and WLR is constant (at 50%). The main reason for splitting the test conditions into two separate groups was to evaluate the effect of WLR and liquid velocity on the measurement scheme. Each test group is individually analysed by comparing the measured phase volumetric flow rate with the reference phase volumetric flow rate. Since the constituent phases are incompressible fluids, then it is reasonable to use the inlet condition of each phase as a reference to validate the ERT based measurement system. The relative error is, in the measured phase volumetric flow rates with respect to the reference values, also highlighted in the aforementioned table (Table 2).

4.1. Effect of WLR on the measurement scheme

The effect of WLR was determined by comparing measured phase volumetric flow rate, obtained from the ERT based two-phase flow measurement system, with that of the reference as a function of water cut (or WLR).

Fig. 3 shows the comparison of measured phase flow rate with that of the reference for the variable WLR test group. It can be seen that the measured water flow rate agrees well with that of the reference (Fig. 3 right plot). On the other hand, by observing Fig. 3 (left plot), it is quite evident that the oil flow rates are overestimated with decreasing WLR, probably due to overestimation in the mean oil velocity as the oil volume fraction increases.

4.2. Effect of liquid velocity on the measurement scheme

The effect of varying liquid velocity on the measurement scheme is highlighted by comparing the measured phase volume flow rates with those of the references as a function of total liquid flow rate. The comparison results, for each phase, are illustrated in Fig. 4.

It can be seen that the measured water flow rate again agrees well with that of the reference (Fig. 4 right plot). On the other hand, the measured oil flow rate shows an increasing overestimation, relative to the reference, with increasing total liquid rate or velocity (Fig. 4 left plot). This may be attributed to the increasing error in mean oil velocity (determined from the dual-plane cross-correlation transit-time τ) when liquid flow velocity V_L increases (the relative error $\delta V_L/V_L = -\delta\tau/\tau = -(V_L/L)\delta\tau$; with transit-time resolution $\delta\tau=1\text{ ms}$, $V_L=1.2$ to 2.4 m/s , dual-plane spacing $L=50\text{ mm}$, $\delta V/V = -2.4\%$ to -4.8%).

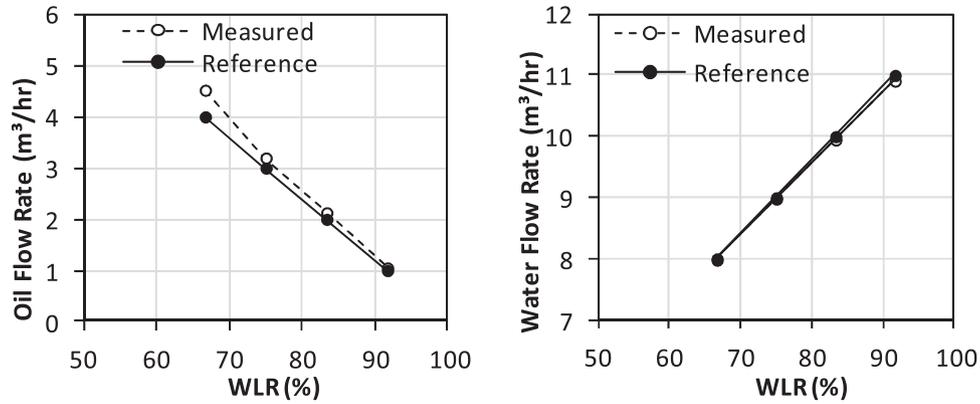


Fig. 3. Effect of WLR ($Q_T=12 \text{ m}^3/\text{hr}$); (left) oil flow rate, (right) water flow rate.

4.3. Estimation of WLR using ERT–EMF system

The Water-in-Liquid Ratio (WLR) can be estimated from the measured water and oil volumetric flow rates (Q_w & Q_o), obtained from the dual modality measurement system, as shown in Eq. (17).

In order to determine the accuracy of the estimated WLR, a comparison between the estimated WLR and that of the reference was carried out, as illustrated in Fig. 5. By observing the aforementioned figure, it can be seen that the estimated WLR is underestimated for the given test conditions. The deviation increases as the reference WLR decreases. Therefore, the accuracy of the estimated WLR is increasingly affected as oil flow rate increases. Similarly, this may be due to the increasing error in mean oil velocity, as mentioned above.

4.4. Evaluation of the measurement scheme

In order to evaluate the measurement scheme, a quantitative and qualitative error analysis was carried out for all the measured phase volume flow rates. By observing Table 2, it can be seen that the relative error in the measured oil flow rates are above +5% and up to about 15%; this implies that the measured oil flow rates are overall overestimated. The water flow rate is measured within $\pm 4\%$ of reading, indicating that combining the EMF-measured mean water velocity with ERT-measured mean water-fraction (from the mean oil-fraction) is sound.

Fig. 6 shows the comparison of measured oil and water phase volumetric flow rates for both test groups (variable WLR and variable liquid velocity) with their respective references. It can be seen that the initial measured data (before calibration) increasingly overestimated. However, it is possible to correct the measured phase flow rates, using linear calibration functions determined from the SGR respective references. It can clearly be seen

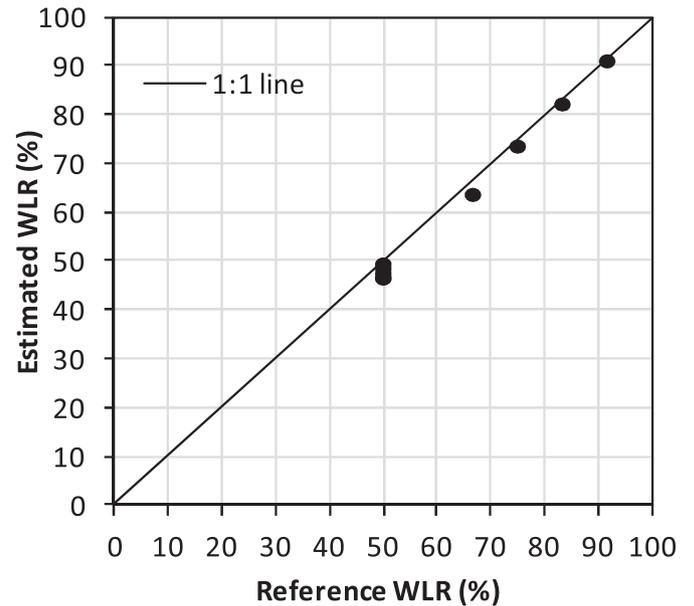


Fig. 5. Comparison of estimated WLR, before calibration, with that of the reference.

that after calibration, the deviation of the measured flow rates is significantly reduced, particularly for the measured oil flow rates.

The absolute-error band associated with the measured phase flow rates after calibration is presented in Fig. 7. It illustrates the measurement uncertainty for both test groups and the range of conditions used in the experiments.

The uncertainty in measuring oil flow rates is about $\pm 3\%$ absolute, while that in measuring water flow rate is about $\pm 2\%$ absolute. It is worth pointing out that the above absolute-error

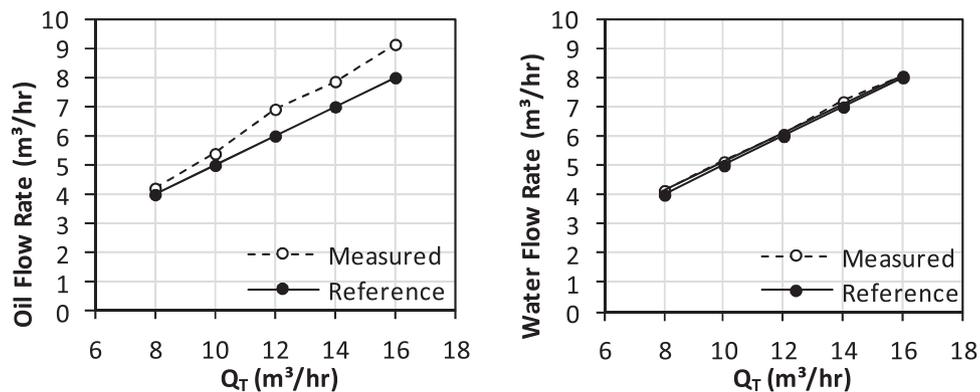


Fig. 4. Effect of liquid rate (velocity) with WLR=50%; (left) oil flow rate, (right) water flow rate.

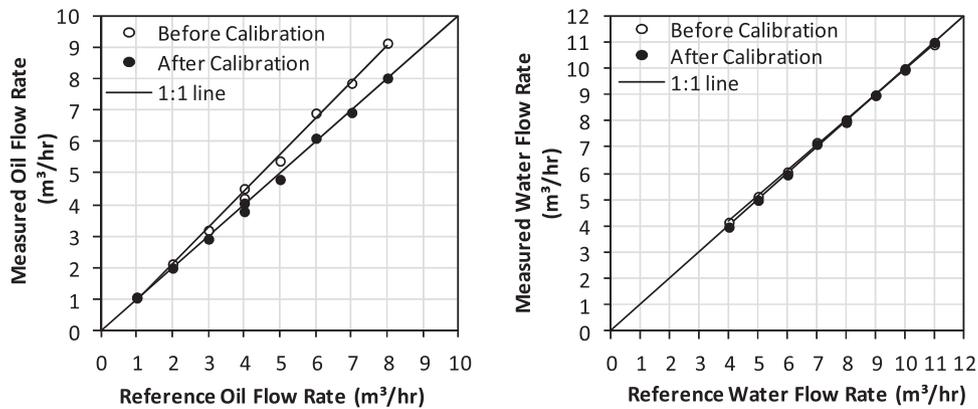


Fig. 6. Comparison of measured phase flow rate, before and after calibration, with that of the reference; (left) oil flow rate, (right) water flow rate.

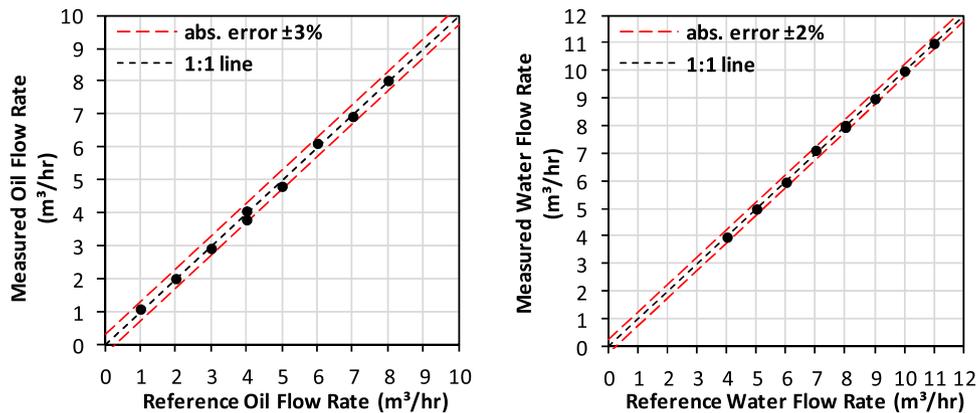


Fig. 7. Measurement absolute error band for; (left) oil flow rate, (right) water flow rate.

values are based on the final calibrated flow rates of oil and water phases.

As previously mentioned in Section 3.2, the accuracy of the off-the-shelf EMF is $\pm 0.2\%$ for single-phase flow, while the measured volumetric water flow rate in oil-in-water flow using the dual-modality ERT-EMF is associated with $\pm 2\%$ absolute error. In order to determine whether the accuracy of the EMF can be maintained in two-phase oil-in-water flow, further analysis were carried out.

Typically, the accuracy of EMF is around 0.5%, for measuring the flow rate of single-phase flow. Some vendors indicate even higher accuracies, e.g. 0.2%, similar to the one used in this study, providing that the velocity profile is symmetric. It is worth mentioning that high non-uniform velocity profiles are often encountered downstream of partially open valves, horizontal and upward inclined multi-phase flows, in which axial velocity variations occur in the direction of gravity [4,5]. However, in this study, the flow orientation is upward vertical, in which only dispersed globules and droplets were observed, during the measurement, for the given test conditions. The oil droplets were small, while the globules were comparatively larger. The visual observation of these discrete oil globules and droplets in water revealed that they were quasi-symmetrically distributed across the pipe cross section. At lower WLR (50%), the discrete oil droplets were much more sparsely distributed across the pipe cross sectional area, while at higher WLR, the effect of turbulence resulted in breakup of oil droplets into finer sizes, which were dispersed uniformly across the pipe cross sectional area. No slug or churn flow was observed for the test conditions used in this study, hence, it is apparent that the axial flow profiles are symmetric (or quasi symmetric). Therefore, one would not expect that, in such uniform (or quasi-uniform) velocity profiles, the accuracy of the EMF would seriously be affected. Based on this analysis, it is apparent that the accuracy of EMF can still be maintained around 0.2%.

5. Conclusions

This paper demonstrated the performance of a novel ERT-EMF dual-modality measurement system for the measurement of phase volumetric flow rate of vertical upward oil-in-water flows. Based on the comparison, between the measured oil and water phase flow rates and those of the respective references, a good agreement was noted for the flow rate of the continuous water phase (determined from the EMF-measured mean water velocity and the ERT-measured mean water fraction). Nevertheless, a large deviation in the measured dispersed-phase oil flow rate was observed, particularly at lower WLR and higher liquid velocities. The main-contributing error is believed to be attributed from the mean (dispersed-phase) oil-velocity determined from the transit time of dual-plane cross-correlation. After error-correction, based on the flow loop reference (calibration) data, the measured oil flow rates could potentially be corrected to $\pm 3\%$ absolute error, while the measured water flow rates corrected to $\pm 2\%$ absolute error, for the given test conditions. Based on the outcome of this study, the novel dual-modality flow measurement system can be extended for measurement of three-phase gas-liquid (gas, oil and water) flows, which is reported elsewhere [14].

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