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# Paper 4.1

# There's Oil In That There Water! – Impact of the OPPC 2005 Regulations; An Operators Response

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## 1 INTRODUCTION

Significant changes have been made in environmental legislation in recent years; operators have to manage the application of the legislation across portfolios and be able to demonstrate compliance, a requirement of OSPAR 2005/5 [1]. One of the main issues faced is the retrospective application of new requirements on legacy equipment which may not be appropriate or simply cannot meet the new standards required. Conflicts between resource application in a timely manner for all installation activities are severe, balancing requirements from all areas of legislation with essential activity programmes and shutdown dates requires strict constraints to be applied.

This paper focuses on one area of legislation, the overboard discharge of produced water from offshore installations. The introduction of The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 [2] has had an impact on offshore operators resulting in a tightening of the requirements for the measurement, sampling and analysis of produced water discharged to the sea. Also included are provisions for fines and allowance trading. An overview of one operator's response to meet the requirements of these changes is the subject of this paper.

To establish a good foundation for the future, a survey was commissioned covering some 19 discharging installations. Some of the key issues from the survey will be discussed together with a proposal to enable ongoing verification of systems that cannot easily be taken out of service for calibration.

One specific area of significance is that of system uncertainties. A method of calculating the uncertainty of volume at standard conditions when pressure and temperature measurements are not available has been developed. The impact of temperature on the volume of water discharged is not insignificant for those facilities operating at high temperatures and a proposal is made to cater for the varying conditions met in the UKCS operations. Not all water discharged is measured by a physical meter; the volume can be calculated from well tests or pseudo well tests. This is an alternative that is permitted under the regulations and the company's approach to such applications is discussed.

## 2 HISTORY TO THE REGULATIONS

The concerns over the pollution to the North Sea in particular go back to the late 1960's and 1970's. Following the Torrey Canyon disaster in 1967, the Bonn Agreement [3] was instituted in 1969 between the coastal countries surrounding the North Sea with the aim of co-operating to deal with pollution of the North Sea by oil. Further concerns over the dumping of other pollutants, including industrial waste, into the seas and oceans led to the formation of the "Oslo Convention", the Convention for the Prevention of Marine Pollution by Dumping from Ships and Aircraft. It came into force in 1974.

Following on from this came a document dealing with the prevention of marine pollution from land based sources which was developed as the Convention of the Prevention of Marine Pollution from Land Based Sources, the Paris Convention, and came into force in 1978. Commissions were established for the separate conventions: the Oslo Commission whose task it was, initially, to control and regulate the dumping of industrial wastes and materials at sea and the Paris Commission to control and regulate the discharges of both energy and substances to the sea from land based sources. The discharges from offshore platforms are associated with the Paris Commission, known as PARCOM.

It was recognised that both commissions were endeavouring to achieve the same aims and 1992, following the outcome of a Ministerial meeting, saw the adoption of a new Convention for the Protection of the Marine Environment of the North-East Atlantic, also known as the OSPAR Convention, i.e. an amalgam of Oslo and Paris. Whilst the convention did not come into force until 1998 the Oslo and Paris Commissions had worked as one since the inception of the new convention. Further details of the OSPAR convention, that merged and modernised the Oslo and Paris conventions, can be found at www.ospar.org. The important part of the convention for this aspect of the industry is Annex III: Prevention and Elimination of Pollution from Offshore Sources. Articles 4 and 10 make provision for the control of discharges from offshore sources and for implementing plans to reduce and phase out such discharges. The substances subject to these programmes include oils and hydrocarbons of petroleum origin and heavy metals and their compounds amongst others, and these are both found in produced water discharged overboard from offshore installations.

Out of these programmes came OSPAR Recommendation 2001/1 for the Management of Produced Water from Offshore Installations [4]. This recognised that:

1. Produced water needs to be controlled through the use of Best Available Techniques (BAT) and Best Environmental Practise (BEP) as it is a source of oil contamination and therefore a pollutant of the sea when discharged.
2. There is a need to control the quantities of water discharged to the sea, particularly for oil fields and increasingly as these fields mature, with a view to reducing the oil, including aromatics, and other substances.
3. It is necessary to reduce the concentration of oil and other substances in the discharged produced water.
4. Consideration must be given to the management of produced water from offshore installations.

From these requirements, goals were set to reduce the total quantity of oil discharged to the sea in 2006 by a minimum of 15% against the year 2000 discharged quantities from all offshore installations. From 2002 any new or substantially modified facility should aim to minimise discharges and achieve zero discharge to the sea; an ongoing reduction of oil to sea so that by 2020 any produced water will not harm the marine environment. It is envisaged that this will be achieved by a combination of a reduction in the quantity of water discharged overboard by implementing methods such as re-injection of water into dead wells or down-hole separation and/or the reduction of contaminants in the water through improved processing.

Performance standards have also been set as follows:

1. 30 mg/l of dispersed oil in produced water discharged to the sea by 01 January 2007.
2. Ongoing improvements to the quality of the discharge using BAT and BEP.
3. The use of dilution to reduce the average concentration is explicitly prohibited.
4. The quantities of dispersed oil discharged to be reported.
5. Provisions for the sampling and analysis of water also stated.

Members of OSPAR are duty bound to implement the requirements and to report progress in 2008.

## 3 NEW UK REGULATIONS

The adoption of these recommendations in the UK has been by the enactment of The Offshore Petroleum Activities (Oil Pollution Prevention & Control) Regulations 2005, referred hereafter as the OPPC Regulations or regulations.

Prior to this the discharge of oil in produced water was governed by the Prevention of Oil Pollution Act 1971 (POPA) whereby an exemption was granted by the Secretary of State (through the DTI) pursuant to Section 23 of said act, as amended by section 50 and schedule 4 of the Petroleum Act 1998, that allows a discharge containing oil to be made to the environment. The exemption specified, amongst other items:

1. The maximum discharge of oil in water to be 100 ppm for not more than 4% of the samples taken in any month.
2. The average ratio of oil in any mixture discharged shall not exceed 400 ppm.
3. Provisions to be made for samples to be taken at least 12 hourly.
4. Water to be discharged from a designated point and not to exceed a stated annual volume.
5. Details of the discharge to be recorded and submitted to the Secretary of State (DTI).

The new regulations were developed following the OSPAR recommendations with a number of drafts issued up until 2004; the final act coming into force in July 2005 as SI 2055. In addition to the statutory instrument a set of Guidance notes [5 & 6] for the proposed regulations were issued. The requirements of the new legislation are the UKCS' implementation of OSPAR and can be summarised as follows:

1. A permit is required to discharge produced water to the sea. The permit details the quantity of oil in mass terms that can be discharged. As an aside the permit contains a number of schedules covering other discharges containing oil, e.g. drains, and also re-injection quantities.

   The quality of the water will have a maximum monthly average oil content of 30 mg/l of dispersed oil and this was in force on 01 January 2006. The maximum permitted discharge quantity remains at 100 mg/l as per POPA and the reporting scheme for reporting discharges in excess of this has been updated. [7]
2. The permit will initially set the maximum quantity of oil permitted to be discharged from the facility for 2006 and will equate to the year 2000 value minus 15%.
3. The definition of oil has been modified to include condensate. This was a grey area and was only latterly included under POPA.
4. The volume of the water discharged is to be metered, or calculated, to an uncertainty of ±10%.
5. There is a requirement to investigate the use of online oil in water analysers for installations discharging >100 te per year.
6. Provision has been made for a Trading Scheme to trade oil allowances between facilities and/or operators in sector.
7. Similarly, provision has been made to impose fines on any operator that exceeds the permitted allowance of oil discharged overboard and who has not purchased allowances to cover the shortfall.

The financial impact of the final point above could be considerable with the value of fines estimated to be £108,000 per tonne of oil discharged in excess of the permitted limits and this equates to about £500,000 off the company bottom line as fines are not tax deductable. The legislation also covers other discharges that contain oil but these are not considered as part of this paper. McCabe [8] provides a good summary of the legislation and for full details see the DTI Environmental website.

Subsequent guidance notes on sampling and analysis [9 & 10] were issued in early 2006 and whilst these were draft consultation documents they provided detailed information on the methods to be employed in the analysis of produced water samples. In addition the specifications for sample points were also included and these reflect the OSPAR requirements and also the best practise from the Joint Industry Project (JIP) OIWAM [11].

As can be seen above there is a significant change to the legislation governing produced water discharges, particularly with the introduction of trading schemes and fines. In order to deal with this the operator formed an Oil in Produced Water Strategy Team consisting of representatives from a number of disciplines including Operations & Production, Production, Production Chemistry, Projects, Legal, Commercial and, of course, the Environmental arm of HSE.

This multi-disciplinary team began assessing the impact of the new legislation on the Company's business as it could be substantial in view of the fact that they operate approximately 30% of the UKCS facilities. Whilst the details of trading and penalty schemes were unknown, but could be resolved in the fullness of time, a number of fairly basic questions were posed that the team could not immediately answer:

1. What state are the produced water metering systems in?
2. How accurate are they?
3. Do the meters and sample points meet the OPPC requirements?
4. Does the reporting comply with the new requirements?

In response to these questions the operator decided to carry out a full review of the metering and sampling facilities installed on all 19 nodal facilities that constitute 'discharging installations' under the new regulations.

The review would consider all aspects of the produced water discharge systems from physical measurement and sampling through to reporting quantities and quality values in the Oil Log Book; this being the record book for reporting the quantities of water and oil based on reported analysis results, originally a hard copy report. Work on the review commenced in early 2005 with the offshore investigation phase running from April to September 2005.

At this time, the DTI guidance and regulations were still in draft form with most of the measurement information residing in various parts of the guidance notes issued in October 2004[5].

One of the clauses implied the DTI would verify the offshore metering systems during environmental inspections. The formation of the trading and fine scheme also gave impetus to testing the installed meters for performance, loosely meaning accuracy of reporting. A test programme using a clamp-on ultrasonic meter (USM) was therefore included in the review programme.

Before describing some of the findings from the review it must be borne in mind that all of the metering and sampling systems had been deemed as 'approved' stations under the POPA Exemptions scheme [12] operated by the DTI until the enactment of the new legislation [2]. In mid to late 2005 the DTI requirements specified for metering and sampling were fairly limited. Some information was obtained from the Oil in Water Analysis Method (OIWAM) Joint Industry Project (JIP) with regards to sampling as it was envisaged that the best practises would be carried through to the regulations. This proved to be correct with the issue of the Sampling and Analysis Guidance Notes in January 2006 [13] as a draft document for industry consultation. At the present time there is not a similar document relating to metering systems as there is a second JIP in progress; the Produced water Volume determination JIP, ProVol, and this is due to be completed later this year.

Armed with the limited amount of information available on the requirements, the systems were audited and verification testing carried out. All of the operator's facilities in the UK sector were visited, from the Northern sector to the Southern sector, and are associated with the majority of the major pipeline systems.

Of the facilities visited four are gas/condensate producers and the rest crude oil producers. Some facilities have multiple stream processing and overboard discharges.

## 4 REVIEW FINDINGS

During the review nineteen offshore facilities were visited, some twice, over a period of 5 months. The following sections discus various aspects of the review findings.

### 4.1 Types of Meter

A number of different technologies are employed on the facilities due in part to line sizes and associated production quantities. Line sizes range from 2" (50mm) to 24" (600mm) with five technologies in use. Table 1 indicates the numbers and types of meter found during the review.

**Table 1: Types of measurement technology in use.**

| Type | No |
|---|---|
| Electromagnetic MAG | 15 |
| Clamp-on USM | 13 |
| Coriolis | 2 |
| Tank radar | 2 |
| Insertion turbine | 2 |
| Turbine | 2 |
| dP devices (Orifice Plate & annubar) | 2 |

It was expected that MAG meters would feature prominently as they have a history of use on water, primarily in the water industry. The use of clamp-on USMs was not surprising but the numbers quoted in the above table may be misleading as 9 were installed on one platform, the reasons why will become apparent later.

Of the meters used, the insertion turbines appear to be the least reliable due generally to scaling problems on the impeller and bearing assembly.

In addition to the physical meters used for reporting, three facilities calculate the produced water that is discharged overboard. Two are based primarily on well test data and one on hydrocyclone vessel flow. The latter is essentially based on an orifice equation but hydrocyclones are not renowned for their efficiency in measurement terms as they are prone to clogging and contamination and this generally results in an increased differential pressure indication and hence increased erroneous flow rate as the bore reduces.

### 4.2 Meter Installation

Mixed results were found in relation to the installations. Considering the location first of all, a number of meters used for overboard reporting are upstream of one or more processing stages, e.g. upstream of hydrocyclones and produced water flash drums; both of which return liquids to the process. It is surmised that historically produced water measurement has not had a high priority resulting in process meters being selected to report the flow as if it were an overboard discharge. The main disadvantage of this is an overstatement of the actual discharge; in one case as much as 6% water volume. This particular installation uses a combination of 9 clamp-on USMs installed on 3 process streams to report produced water overboard; the meters are installed on the outlets of the main separators and inlets to hydrocyclones.

Most of the systems reviewed have very limited means of isolation associated with the meter, often limited to an ESD (Emergency Shut Down) valve on the discharge side. This will have a bearing on the maintenance regime that can be applied to the system whilst maintaining production.

The next consideration was the installation requirements in terms of upstream and downstream straight lengths for the installed meters. Bearing in mind the age of some of these installations, the straight length provided are generally in line with the manufacturers' requirements when they were installed, for example 10*D* up and 5*D* down was generally accepted for clamp-on USMs. However, there were one or two meters where this was not met due to pipe work geometry and incorrect installation of the meter.

The obvious recommendations have been made to install meters downstream of all processing to provide accurate measurement of overboard water. Where necessary and feasible the installation of the metering systems is to be improved.

### 4.3 Maintenance

In line with many operators there has been a significant rationalisation in the maintenance performed on process equipment and installation; a risk based assessment for schedule. As all of the produced water meters have been classified simply as process meters there is no routine maintenance scheduled save that required by legislation already in place, e.g. electrical integrity testing. This strategy is called 'on-failure maintenance'. Whilst this is laudable in reducing OPEX maintenance costs, failure can only be recognised if it is terminal, i.e. total failure of the meter, or if a comparison can be made with another process. In many cases though the meter is the singular method of determining volume flow; any drift in performance cannot, therefore, be detected.

The new regulations imply a requirement for maintenance, i.e. maintain an uncertainty. As a result the importance of these meters has increased significantly in the past year and so the maintenance regime has been reassessed and a schedule commensurate with the importance and level of uncertainty of the meter has been developed.

A similar and associated issue is obsolescence. As mentioned above, many of these installations are old with some equipment dating back to the 1980's. In many cases the original manufacturers cannot support the meters for spares or maintenance. This presents a potential exposure to the operator that to date has not had significant importance. Now, if an obsolete meter fails there is very little back up available or spares with which to return the system to service. In one or two cases the water volume can be estimated by using the water pump capacity x hours run or production x BS&W values. This is a fall back option and thus necessitates negotiation with the DTI to obtain consent to use an alternative method for a period of time and meter replacement is not a quick fix.

### 4.4 Verification

At an early stage of the project the question 'How good are our produced water meters?' was asked to which the answer was, quite simply, 'Don't know!'. A verification programme was incorporated into the offshore work scope using a Panametrics Transport™ PT878 Clamp-on USM. This part of the project turned out to be quite challenging in many ways.

The choice of the clamp-on USM for the verification programme was made because it really is the only device that is:

- Portable; capable of being transported as helicopter air freight.
- Capable of use on varying line sizes; the range was 2" (50mm) to 24" (600mm).
- Non-invasive; did not require a system shutdown to install or break containment.
- Operable without the need for external power supplies; although not intrinsically safe it was battery powered.

Every system verified offered its own challenges and these were generally surmounted; the only one that prevented verification testing was platform shutdown. Due to the aggressive schedule and offshore access availability two facilities were not verified; one due to an overrunning annual shutdown and the other was off production (peak shaver facility).

The main challenges faced were:

1. Access; anything from under a deck head 5m above the deck to down inside platform legs.
2. Straight length availability to meet BS8452 [14] for the test clamp-on meter.
3. Process conditions; post processing disturbances.
4. Temperature; many high temperature systems 90°C and 95°C.
5. None metered installations.

Each of these will be discussed.

### 4.4.1 Access

The routing of the pipe work for overboard discharge in the majority of cases is vertically downwards with short horizontal sections terminating at the caisson, be it a dedicated produced water caisson or one that serves a number of functions, e.g. including service water returns. This presented a number of problems in terms of finding a straight piece of pipe on which to mount the test meter, preferably upstream of the level control valves, and being able to gain access to the pipe to be able to install it. Scaffold platforms were required on a number of occasions. Four of the meters to be tested were located in the Utility Leg of the concrete leg structures in the Northern area and whilst these had the potential to offer long sections of upward flowing pipe access to them was a problem as the access stairways and platforms were not quite in the right place!

### 4.4.2 Straight Lengths

Straight length availability was a major challenge. As can be seen for Table 1, many of the installations utilise MAG meters and these require a short upstream straight length and even shorter downstream length; typically 5*D* and 3*D* respectively. This presented a problem for installing the test USM in the vicinity of the installed meter. Panametrics guidelines [14] for installing the meter is to have, wherever possible, at least 10*D* upstream and 5*D* downstream with the current industry standard [15] for a liquid clamp-on USM advocating the implementation of greater upstream straight lengths, 20*D* plus, for some pipe work configurations; all oddly enough, found on produced water systems!

In some cases the USM had to be installed on pipe work remote from the meter and required local operating procedures to be developed to ensure pipework was running full of liquid as the verification point was downstream of the level control valve (LCV). One system that this applied to can be seen in Fig 1 where the pipe is full of liquid only up to the bend at the top right of the picture.

**Fig 1: MAG meter installation**

On another system, straight lengths for the test meter proved not to be the problem, but the change in pipe size. It increased in diameter, resulting in a reduction in the flow velocity, also creating a time delay between the installed meter and the test meter. This was on a vertical line on a concrete leg structure; see Fig 2.

### 4.4.3 Process Conditions

Other challenges presented themselves in terms of water processing. Disc centrifuges and hydrocyclones are used extensively to remove oil from water and on some installations the metering is immediately downstream of the process vessel. Whilst the installed MAG meters appear to function correctly with varying flow indication the disturbance in the water severely affected the performance of the clamp-on USM; even when operated in single traverse mode, i.e. direct path signal, results ranged from poor to non-existent, even when tested several *D* downstream.

Another difficult situation involved a test on the outlet of an Induced Gas flotation Unit. This unit injects gas into the water as very small bubbles. The object is for the gas bubbles to attract the oil particles and lift them to the top of the vessel where they collect and are pumped back to the main process. The water/gas mixture passes through a number of chambers until it is discharged. However, the water still contains gas bubbles, millions of them; so much so that when sampled the water has a cloudy appearance a bit like lemonade. On this particular system the MAG meter does not have a problem with this type of fluid; conductivity is maintained and a small impact on accuracy would be seen as the minute gas voids are treated as water (a very small volume). The USM however, does not like this fluid. The gas bubbles scatter the sound pulses and the overall effect presents a random response from the meter. Depending on the process conditions the resulting flow rate indication can be anything from zero; in agreement with the installed meter; or significantly higher as the electronics fail to differentiate the signals. Normally, a horizontal flowing pipe is tested with the transducers in the horizontal plane but in this instance the installation on the test meter in the vertical plane produced good results.

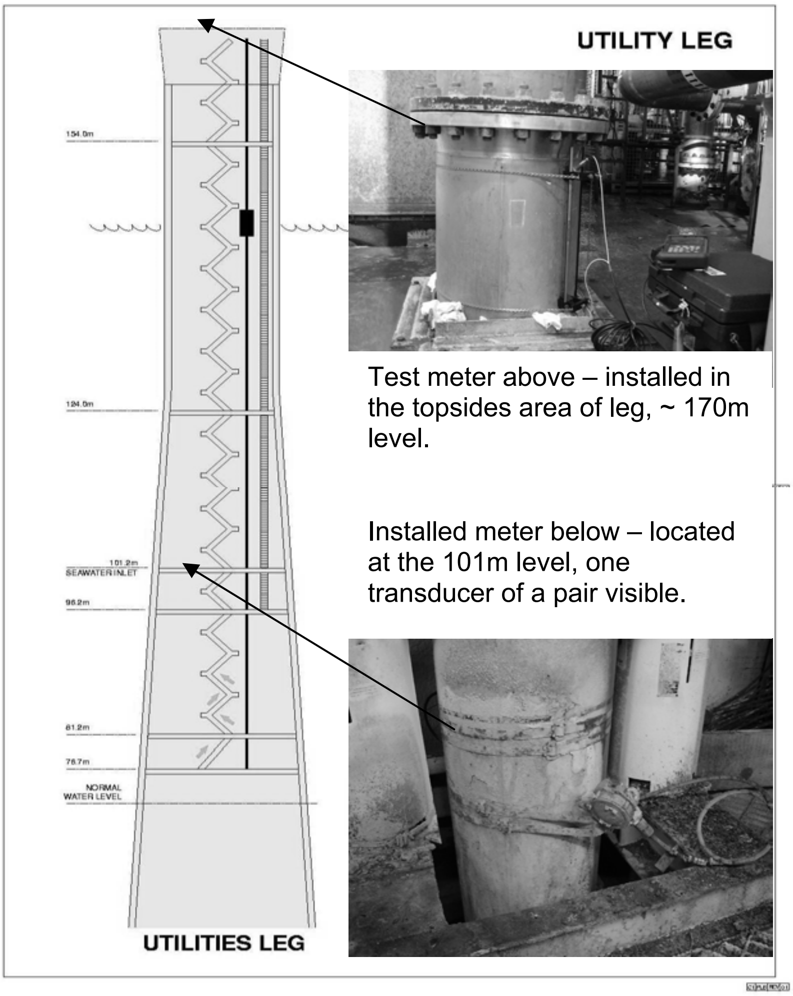



**Fig 2: Concrete leg structure with locations of meters.**

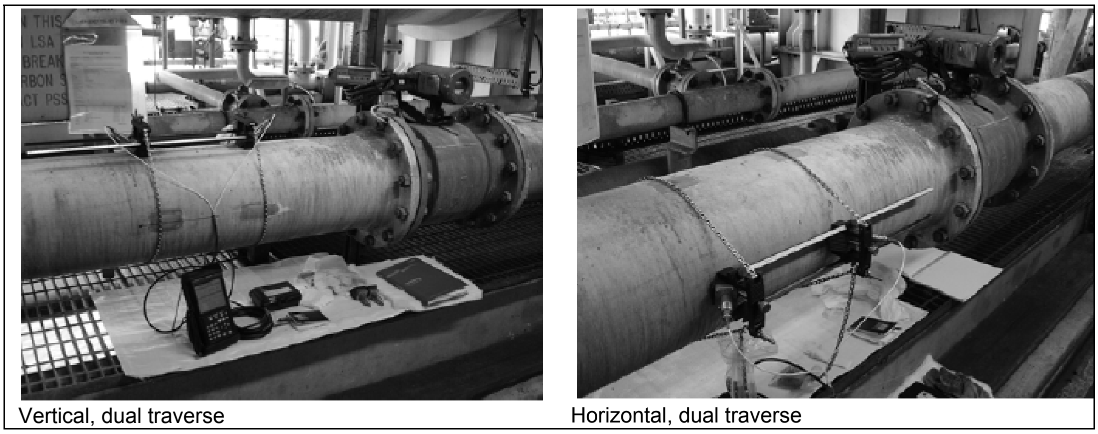



**Fig 3: Test meter installations.**

Tests on this particular installation were repeated as there was a concern that the pipe may not have been flowing full due to the release of the gas bubbles. Investigations indicated that this is not the case and that the verification is valid. Examples of the installation of the test meter are shown in Fig 3.

The other process condition that had an impact on testing was temperature.

### 4.4.4 Temperature

During the preliminary checks of the systems prior to the offshore visits it was not apparent that some of the produced water systems run 'hot'; typically in the 70°C to 95°C range. Not very useful when one arrives on the second platform of the visit schedule to find that the system is operating at 90°C plus and the transducers for the test meter are rated at 60°C! Fortunately, Panametrics (GE Sensing) saved the day and a set of high temperature transducers were flown out on the next helicopter and the tests completed.

Another problem related to temperature was steam flashing. On one facility the temperature out of the produced water flash drum was in excess of 100°C. A potential site for locating the test meter was identified and tested but found to be unsuitable; flashing was evident and could be heard in the pipe. However, relocating the meter some 50m downstream proved to be acceptable; good results obtained in the horizontal, vertical and diagonal planes.

### 4.4.5 Calculated systems

So far the discussion on verification has been in relation to comparisons with physical meters and process effects. Three of the facilities surveyed do not use direct physical meters for produced water; they use different forms of calculations.

The first to be considered utilises a test separator to determine the phase quantities of the individual well's production. Using this data and multiplying by the hours on line provides a value of the water quantity discharged overboard. There was some doubt whether the system could be successfully tested but completing a long test in excess of an hour and assuming stable production for the period gave a reasonable correlation.

The other method utilised a pseudo well test determining well production by difference. This is an old platform with an oversized test separator. Tests are completed by measuring the water flow rate from the production separators during stable flow periods with the tested well online and offline; the difference assumed to be the contribution of that well. A reasonable assumption if preferential flow is ignored, i.e. a well may tend to back out others when on line. Again using time in service for flowing wells the overboard quantity is calculated. It was interesting to find that this method of quantification actually provides reasonably good results, ±6%, compared to the USM for an extrapolated flow, particularly as the 'well test' does not take account of the water processing systems.

Tests on a pair of hydrocyclones provided some interesting results. Two identical hydrocyclones service two production separators. The flow measurement associated with this process are the water flow through the unit and the reject oil flow rate; both based on the differential pressure (dP) generated over the collection of liners, see Fig 4.

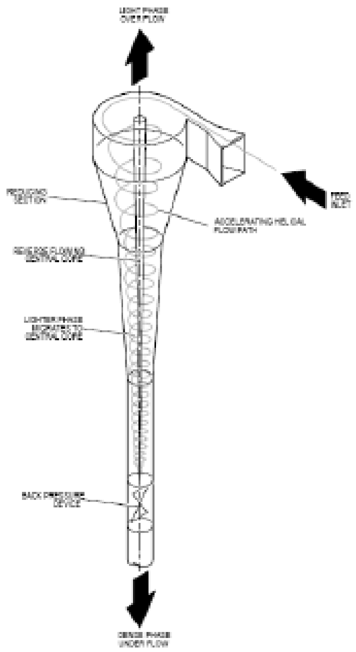


**Fig 4: Schematic of a hydrocyclone.**

The ratio of the reject oil to total flow is an indication of the unit's efficiency.

Hydrocyclones are, in some cases, prone to fouling resulting in a change in efficiency that the operators monitor and then take appropriate action, i.e. extended back flush or, in some cases, physical removal of the obstruction.

The results from one particular unit gave a significant difference between the calculated water flow and the test meter; hydrocyclone reading high. The test meter's installation in this case was good with a relatively long straight run upstream of the hydrocyclone. Cross checking the test meter on the other unit with a similar installation gave a reasonable closeness of results. The prognosis was fouling of the hydro cyclone although the efficiency was not significantly different but the flow rate was slightly higher than expected. A back flush did not improve the situation and the operators removed the system from service, opened the vessel and found significant fouling.

The indications of flow rate and efficiency had not given too much cause for concern but was resulting in an overstatement of water discharged overboard.

The results of the tests provided good information on the state of the systems used to determine the overboard discharge quantities, be they measured or calculated. It did identify a number of potential problem areas that were subsequently investigated. After all, it is very easy just to accept the values generated by a meter, particularly without any other point of reference. The one point that should be noted though is that the test results provide an indication of relative performance not actual performance and so the values obtained on the test meter could not be used to correct the values from the installed systems. However, as a maintenance tool this technique could be very useful; more of this later.

### 4.5 Sampling

The review of the sampling systems highlighted that there was not a standard type of installation. A few probes were found but the majority of sample points were wall tappings. It must be stressed at this point that all sample points reviewed are deemed acceptable as 'approved sample points' by the DTI under the POPA Exemptions.

During the review the OIWAM JIP was in progress and the proposal from this was for sample points to be constructed such that a probe is installed preferably in an upward flowing pipe, but horizontal would be acceptable, in or just after a period of turbulence. This became the best practise in the new DTI Guidance Note on sampling and analysis [13].

It was interesting to compare the existing systems against the requirements and what follows is a summary of the findings. The types of sample point found are tabulated in Table 2 below.

Of these, 2 were found to be taking samples from part filled pipes. On one facility the sample probe was on the bottom of a 20" pipe just before the entry to the overboard caisson; see Fig 5, frame 1. A second system required the installation of a weir in an adjacent flange to ensure that a sufficient level of water is available to be sampled via a side wall tapping; Fig 5 frame 2.

**Table 2: Summary of sample points**

| Type | Number |
|---|---|
| Probe, horizontal pipe | 1 |
| Probe, vertical pipe (down flow) | 2 |
| Side wall, vertical pipe | 1 |
| Top wall tapping | 3 |
| Side wall tapping | 14 |
| Bottom wall tapping | 8 |
| Instrument tapping | 3 |

A further anomaly was the use of a sample point on a multi function pipe. In this case, the line is used for cargo handling (crude and water) on an FPSO and also for the Slop tank overboard discharges; Fig 5, frame 3.

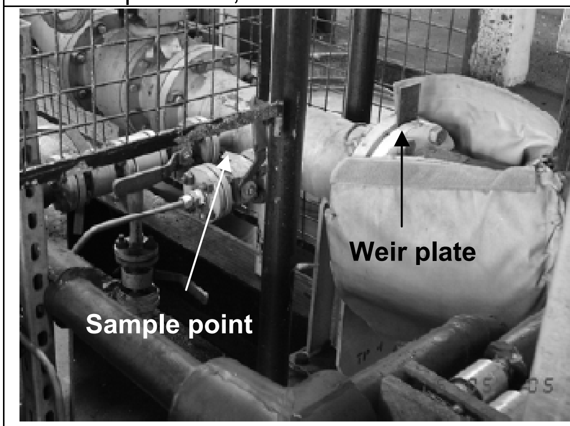
Whilst the latest Guidance Note for the regulations [16] does allow '*older installations, where installation of centre line pitots may prove difficult, sidewall sampling may be used together with a suitably designed sample point*', the caveat is that the sample system shall be well designed. This has, however, created a very unsatisfactory situation as the significance of the clause wording is open to interpretation; what is 'difficult' and what is a 'suitably designed sample point' if it does not meet the preceding requirements?

Assessing the sample points against good oilfield practise in lieu of any other guidance it is considered that bottom wall tappings and part filled pipes cannot be considered as constituting well designed sample points. One that could be considered to meet the requirements under proviso above is shown in Fig 5, frame 4, a top mounted wall tapping; however, even this has been identified for upgrade to a probe.

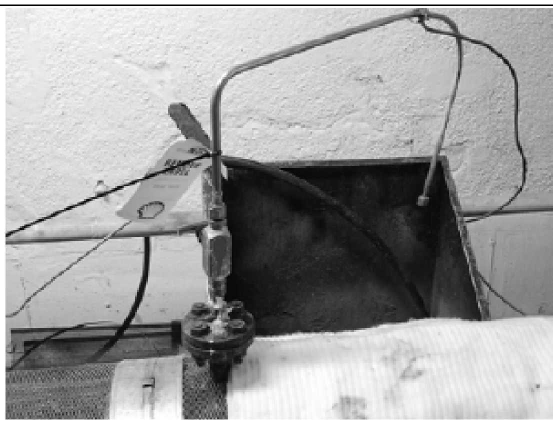
The requirement for an upward flowing pipe in the Guidance notes [16] in which to install a sample point is quite a tall order. Out of 19 facilities visited and 32 sample points reviewed only five could potentially have been installed on a rising pipe. Horizontal is the norm but there are a number of opportunities to install sample probes on vertical pipes flowing downwards immediately after vessels or a number of bends that are likely to create turbulence.

Frame1: part filled, bottom wall

Frame 3: multi function header




Frame 2: part filled, side wall



Frame 4: top wall

**Fig 5: Sample points**

### 4.6 Online Analysers

The new regulations make reference to the use of on-line analysers for facilities discharging more than 100te of oil overboard per year and require the operator to 'investigate' the use of these devices [17]. During the review a number of online analysers were found to be installed. In total nine analysers by three different manufacturers were installed but only one was partially working. Unfortunately there are significant problems with these installations but the fault should not be levelled solely at the analyser. It was apparent when reviewing the sampling systems that these contributed to the downfall of the analyser. A number of them were unable to provide sample water to the analyser at the required rate. One apparent problem with the only analyser that was working was the issue of fouling of the window caused by contaminants in the water, often corrosion inhibitors. Whilst these can sometimes be cleaned it does result in the operation of the analyser becoming labour intensive.

It is recognised that at present there are few analysers available on the market that can operate reliably and produce good results at low concentrations of oil with very little operator intervention. It is known that work is ongoing in this field at manufacturer and industry level and the operator also intends to initiate a trial of two different technologies on separate platforms. It has been highlighted that any trial must take into account the DTI's calibration requirements as specified in the guidance notes [18] if the tests are to be worthwhile and to consider these devices even for trending purposes.

One area that these analysers could be very useful for is where sample analysis is not done offshore, i.e. at an onshore laboratory, as there is a delay in obtaining the results. This would enable the offshore operations to trend the process and take appropriate actions if indicated oil levels rise thus pre-empting overboard excursions. These would otherwise take a few days to be reported in the analysis results causing unnecessary oil discharges and, potentially, high costs of buying allowances or fines with the attendant loss of reputation the latter would incur.

### 4.7 Reporting

The means of reporting produced water and the associated quantities of oil discharged is by means of the Oil Log Book. Historically this was a hardcopy, twin copy self carboning report book with one page completed per month. Recorded in this report are the date and time the sample is taken, the analysis result and the quantity of water discharged since the last sample was taken. At the end of the month the quantities are totalled and an average oil in water quality value determined. The report is then approved by the OIM and sent to the Environmental team for submission to the DTI.

With the computer age well established offshore the Oil Log Book had been transferred into an Excel™ spreadsheet. Whilst this is easier to maintain there were a number of problems noted during the review. An earlier reporting system used to report the quality value in mass terms requiring the water volume to be converted to mass by means of a density multiplier. When the quality value changed to mass/volume terms the spreadsheets were updated and the multiplier removed. Unfortunately, old versions of the sheet had been saved and came back into use and resulted in a small number of reports presenting higher returns than necessary. Also, being open spreadsheets they were not secure on the platform, however, as the OIM approved the report and sent it to the Environmental Team this copy was deemed to be the actual report.

Other problems associated with the log were the recording of flow data. Some facilities have multiple streams flowing to a single discharge and the Oil Log Book reported the combined flow. In some spreadsheets provision had been made for recording the individual streams but others were completed manually or in a separate sheet. This resulted in non-standard reports and also lacked traceability.

These types of fault appear to be common throughout the industry as noted by McCabe [19].

### 4.8 Documentation

A review of the documentation related to the produced water systems on the facilities produced a mixture of results. Whilst it was not expected to find such items as system measurement manuals or log books as one would find with a custody transfer oil or gas metering station, after all these are *just* process meters, there was an expectation to find the system described in the operations manuals. A review of all of the various Platform Operating

Procedures produced results that varied from a full description of the meter, sampling point and the legal requirements associated with the POPA Exemption, to no mention of any of the components at all. Needless to say a recommendation to update these documents is on the way to being resolved.

On the question of maintenance there were very few manufacturers' manuals available although there were the odd occasions when a dusty manual was produced for an obsolete meter. A search for procedures resulted in nothing, mainly due to the maintenance regime being changed to on-failure maintenance as many procedures were contained in the SAP maintenance system. Oddly enough a few calibration certificates were produced.

If effective maintenance is to be carried out then technical staff need procedures and reference documents. These have been captured in the development of system measurement manuals that fully describe the metering and sampling systems and included within this suite of documents are equipment manuals obtained from the manufacturers and a suite of procedures.

In order to demonstrate further that the systems are being managed, a system of log books, similar to the DTI Metering Log Books known to all that have worked on Custody Transfer or allocation metering, are to be adopted, albeit in a simple electronic format.

### 4.9 Overall Results

In answer to the question posed by the OIPW Strategy Team the response can be summarised as follows:

1. A number of meters are installed upstream of processing resulting in an overstatement of discharged water quantities.
2. Many meters, whilst still operating, were obsolete and cannot be supported by the manufacturers resulting in increased business risk.
3. Due to the adopted maintenance philosophy of 'on failure' maintenance no maintenance has been carried out as it appeared that the meters were fully functional and reporting accurately; some, however, had long standing faults.
4. Sample points are generally constrained in meeting the main criteria set out by the DTI.
5. Very limited documentation describing the produced water systems in terms of measurement and sampling with no traceability on the meters.

## 5 RESPONSE TO THE REVIEW

Following the issue of the review reports to the management teams controlling the facilities a number of recommendations were made. The intent of this was to implement a major programme to:

1. Install meters at the point of discharge.
2. Refurbish or replace obsolete systems.
3. Install, wherever possible, probes for sampling produced water.
4. Develop an electronic Oil Log Book and environmental data management system.
5. Develop a new maintenance strategy and implement preventive maintenance routines and testing.
6. Produce system measurement manuals, procedures and log book to demonstrate that the systems are managed and auditable; similar to gas and oil custody transfer measurement stations as noted above.

7. Install temperature measurement to enable volume correction to be completed on-line.

### 5.1 System Refurbishment/Upgrade

The review identified a number of biases in reporting caused by the installation of the meter upstream of processing. In order to remove this bias, and hence reduce the reported discharge quantities, a number of projects have been initiated with a view to installing meters at the point of discharge. Generally, MAG meters have been selected due to the limited straight pipe requirements and their proven record on water. In some cases, clamp-on USMs have been selected as there are potential locations to install these meters without requiring platform shutdowns and invasive pipe surgery. The selection of the meter has also taken into account standardisation of meter type, size and rating, where possible, and thus reduces spares holding. Whilst the meters have a greater importance now there is still the question of providing cost effective solutions.

Obsolete meters have also been recommended for replacement due to the increased business risk, particularly on systems that do not have a readily available fall-back position, e.g. use of produced water pump capacity x hours run.

### 5.2 Sample Point Upgrade

Even though there is an opportunity to continue using the existing sample points the ambiguity of the requirements noted previously has led the operator to review the possibilities of upgrading all sample points to simple, well manufactured probes wherever possible, even if it means relocating the approved sample point. Many of the existing points are flanged so the task may not be too arduous or costly.

### 5.3 Oil Log Book

The initial development of a new electronic Oil Log Book has been completed using a controlled scripted spreadsheet. It has been standardised for all facilities and where necessary secondary controlled workbooks have also been put in place. The new log books are totally secure requiring operators to log in to make entries. The entries can be amended but an audit trail is maintained of the original value, the person who made the update and the reason. Once the OIM approves the log it is secured and cannot be altered. Under the new regulations all sample results have to be recorded and the format of the log has accommodated this; a failing of the paper and early electronic logs. The intent is also to make actual performance visible at all times so that limits and allowances can be managed and monitored, at present this is achieved on the spreadsheet but will soon be available in the Operators desktop portal.

During the early trial period there have been very few problems with data being easily ported into the DTI EEMS system (Environmental Emissions Monitoring System); a clearing house for emissions reporting. It has been well received by the DTI who have inspected copies of it during environmental inspections.

### 5.4 Maintenance

The maintenance of produced water system would appear, on the surface, to be as easily achievable as oil or gas metering stations. However, there is generally only a single meter stream with very limited isolation to enable the meter to be removed; they tend to be flowing all of the time and production regimes are moving to extended periods between facility shutdowns. Produced water systems usually require a full platform shutdown. This poses a problem for maintaining the system.

Whilst it was found that many of the clamp-on USM test installations did not meet the requirements for straight lengths, thereby impacting the results, the results can still be useful. The difference between the two meters can be recorded and trended over time to give an indication of ongoing performance of the installed meter. A baseline measurement is made against the newly calibrated permanent meter soon after installation. This is important as the measurement is made with the meter in a known good condition. Subsequent testing can be carried out annually to allow the ongoing performance to be assessed. With many systems operating continually with no opportunity to inspect the meter for a number of years this will give an indication of any problems the installed meter may be suffering, e.g. bearing stiction on a turbine leading to under measurement that a zero check would not identify.

One aspect of this sort of testing that has been learnt is the period the system is tested for. Initially a 20 minute period sampling at 10 or 15 second intervals was used but it was noted that system flow variability and response time had a big impact on the interpretation of the results. On some facilities the data available initially was at 1 minute intervals. This did not provide good evidence of performance, particularly when the update time of the meter is significantly different to the USM. To tackle this issue the data would be recorded for a minimum of an hour at 10 second intervals to provide a minimum of 360 data points. If data monitoring systems are in place, such as PI/RTMS, then a larger data set can be obtained which improves the uncertainty of the test results. A tolerance of 1.5% has been set initially for this test and appears to be reasonable for the limited tests that have been completed to date.

In addition to the verification test a suite of tests covering raw data/signal inputs to flow computers or, more commonly, Process/Distribute Control Systems; calculation checks for flow rate and totalisation; and configuration checks have been scheduled for completion on an annual basis.

In addition, where possible, meter zero checks will also be carried out to determine whether any zero offsets have developed; a sign of deterioration of meter performance. For meters that have the capability of performing on-board diagnostic checks these will also be used to gauge the condition of the metering station.

Hopefully, by carrying out these tests the condition of the system will be known without the need to regularly remove the meter for flow testing. It is currently envisaged that the meters will be removed and calibrated at a UKAS accredited test facility every 4 or 5 years, depending on platform shutdown plans, with the exception of the clamp-on USMs as these cannot be flow calibrated unless installed on a dedicated, removable spool piece. In this case a combination of performance testing, zero check and diagnostic analysis will suffice.

One final item on the maintenance list will be the inspection of the sample probe on a 4 yearly basis. This is to ensure that the internal parts of the probe are still in good order. This does not obviate the need to carry out any remedial work on the sampling systems as some produced water sampling systems are prone to scaling thereby reducing the flow of water to the sample point. In many cases back flushing the line resolves the problems but in severe cases the sample tubing is replaced.

## 6 UNCERTAINTY CALCULATIONS

The new regulations require the produced water to be metered, or calculated, to an uncertainty of ±10% on volume. Quite a wide band considering most of the work completed within the industry is typically 1% on gas and 0.25% on oil. However, the same approach was taken in the initial assessment prior to the development of the individual uncertainty budgets. Key considerations were to:

- Adopt a simple approach to the calculation.
- Be fair and equitable to all parties.
- Suit the application.

ISO TR 5168:1998 [20] was chosen as the basis for the calculation, supplemented by elements from ISO 5168:2005 [21], with the overall calculation based on ‘addition in quadrature’ [22].

Early in the assessment an issue surrounding random v systematic errors was raised. If a particular component changes from one value to another and remains there it is normally considered to be “random” as it lies with the calibration period and that period is, generally, relatively short, e.g. months to a year. With produced water systems, however, the calibration period can be quite long, for example 4 years between calibrations for primary elements as proposed above and there is a likelihood that any none changing shift would be considered “systematic”. GUM (1995) [23] states that "An uncertainty component is not either "random" or "systematic". Its nature is conditioned by the use made of the corresponding quantity, or more formally, by the context in which the quantity appears in the mathematical model that describes the measurement. Thus, when its corresponding quantity is used in a different context, a "random" component may become a "systematic" component, and vice-versa”. ISO 5168:1998, which was used as the basis for the evaluation of uncertainties, does not recommend the combination of random and systematic errors so this presented a problem for a short while. As MAG meters feature heavily in the systems a review of BS 6817 [24] found that systematic errors were included in the assessment of uncertainties, e.g. the inclusion of systematic errors as a result of the equipment used to measure an output variable and the combination of random and systematic errors associated with the in use flow conditions which are generally different from those found during calibration. This provided the justification to include systematic errors.

Using the two standards as the core of the calculations they were supplemented by others for particular measurement technologies, e.g. API Chapter 13 Section 1 [25] for turbines and BS 8452 [26] for clamp-on USMs.

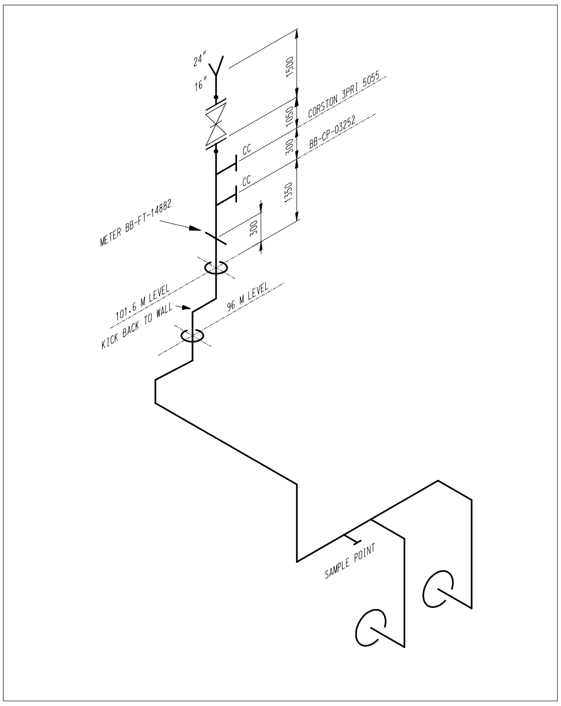



**Fig 8: Schematic of Clamp-on USM installation.**

Simplicity in the layout of the budget calculations was key to identifying potential areas of improvement. This is illustrated by the calculation sheet for a clamp-on USM; see Appendix A. By keeping the device uncertainties separate from installation uncertainties areas requiring improvement are quickly identified. In the example, the overall uncertainty for this clamp-on USM installation is ±9.2%, close to the limit of ±10%. Reviewing the components it is plainly evident that installation effects are significant; this system has a poor upstream pipe configuration and limited upstream straight length, see Fig 8, so an additional uncertainty based on the recommendations found in BS 8452 was added. This provided the justification to propose the meter be relocated to a position that affords the recommended straight lengths.

The uncertainties for systems that do not have physical meters have been treated in a similar way.

The uncertainty calculations were taken one step further to include the calculation of volume to Standard conditions of 15°C and 1.01325 bara. In the October 2004 Guidance Note the requirement for uncertainty was at Standard conditions but the February 2005 version and the subsequent permit schedule the text omitted the Standard condition wording. Unsure if this was a typographical error as the regulations had not been ratified at the time this work was in progress a decision to include this element was taken.

A method of accounting for Standard conditions was developed using the principles of ISO 6817. As pressure and temperature devices are not present on most systems an assumption was stated that line density of the produced water is equal to standard (or base) density. Limited process information allowed the sensitivity of the flow rate to the difference between operating pressures and temperatures and Standard conditions to be calculated and this was included as the uncertainty associated with fluid density. Following the premise above it can be seen that including physical measurement devices for pressure and temperature would enable the overall uncertainty to be reduced.

This exercise had an unexpected benefit. Whilst it was known that water generally has a low coefficient of expansion, 0.00021/°C at 20°C, and various other anomalous behaviours [27] there is very little information available in the public domain on produced water, particularly density. It is known, however, that produced water tends to be saline with varying concentrations of salts. In lieu of any other information or empirical data the density of sea water [28] was used as a basis for the uncertainty calculations.

Assessing the impact of pressure and temperature on water volumes it was found that pressure had a very small effect, expected, but that for high temperature producers the effect is as much as 1.8% to 2.8%. Quantifying this in terms of oil discharged overboard this equated, in some cases, to between 2te and 5te a year overstated. The financial implications are not insignificant and this led on to further investigations into volume correction factors.

## 7 VOLUME CORRECTION

Many of the meters used in produced water applications develop an output signal proportional to gross volume flow rate (or average pipe velocity). Whilst gross volume flow data is fundamental to process monitoring and control activities, it offers limited value for "fiscal" reporting purposes.

A large proportion of produced water systems are currently operating at high temperatures and the reporting of produced water quantities in terms of gross volume can disadvantage those Operators who are metering at these elevated temperatures. To ensure a "fair and equitable" reporting system, it is strongly recommended that reporting for performance monitoring or fiscal purposes be done at Standard volume conditions of 15°C and 1.01325 bara as is the current practice with liquid hydrocarbons. A great deal of emphasis is made on the analysis being completed at 20°C with the standard analysis method [29] for determining the quantity of oil in the produced water but the volumes can be at any temperature; therefore the analysis volume is **not** effectively related to the discharge volume although it should be.

If produced water is to be recorded and reported at standard conditions then there is an added requirement to convert gross to standard volume. This is achieved by the application of a Volume Correction Factor (VCF); the derivation and applications of which is well defined for liquid hydrocarbons and also potable water.

The VCF is the ratio of standard density to line density and a number of options have been evaluated to allow the derivation of the appropriate temperature and pressure correction factors ($C_{tl}$ & $C_{pl}$) for density, these include:

- The analysis of produced water samples at line and standard conditions to determine the associated densities.
- The use of existing API Tables for the determination of standard density from line density or visa versa.
- The development of specific $C_{tl}$ and $C_{pl}$ equations for produced water.

It was discovered following a detailed search for technical papers and associated literature that no published research had been undertaken to determine a relationship between the density, temperature and pressure of produced water. In consequence, a number of produced water samples were taken from two designated installations and the measured densities of each sample derived at differing temperatures. The results from the two data sets were recorded and plotted on a chart of density versus temperature, as can be seen within Fig 9.

The sample size from facility "A" was greater than that from facility "B" but there were a sufficient number of data points to allow realistic trendlines to be drawn. These illustrate not only a linear relationship between density and temperature but also parallelism between the two sets of data. It should be noted that one facility is predominantly associated with the production of crude oil whilst the other is associated with the production of condensate, thus providing two diverse sets of produced water samples.

Using the two sets of sample analysis results as benchmarks and in particular the produced water densities at 15 °C, the measured densities at differing temperatures were compared with densities calculated using the VCFs for generalised crude oil as defined in the API Petroleum Measurement Tables (API Manual of Petroleum Measurement Standards, Chapter 11.1 Temperature And Pressure Volume Correction Factors For Generalised Crude Oils, Refined Products, And Lubricating Oils). The API based VCFs proved not to be suitable for the derivation of correction factors for produced water, as illustrated within Fig 10.

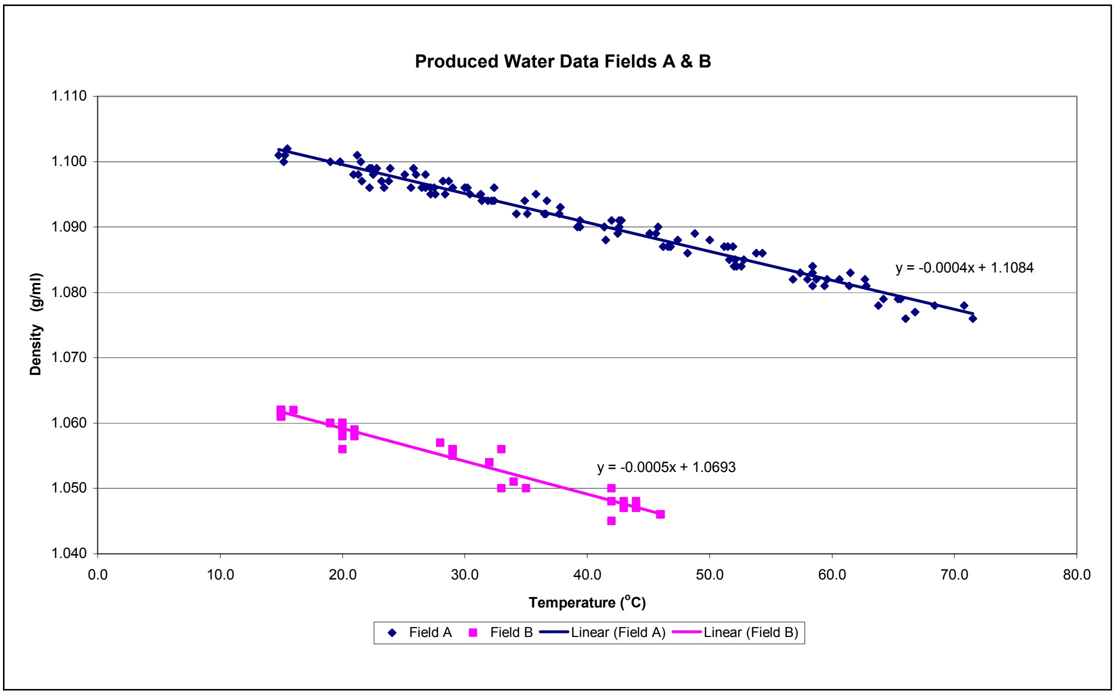



**Fig 9: Empirical produced water density data.**

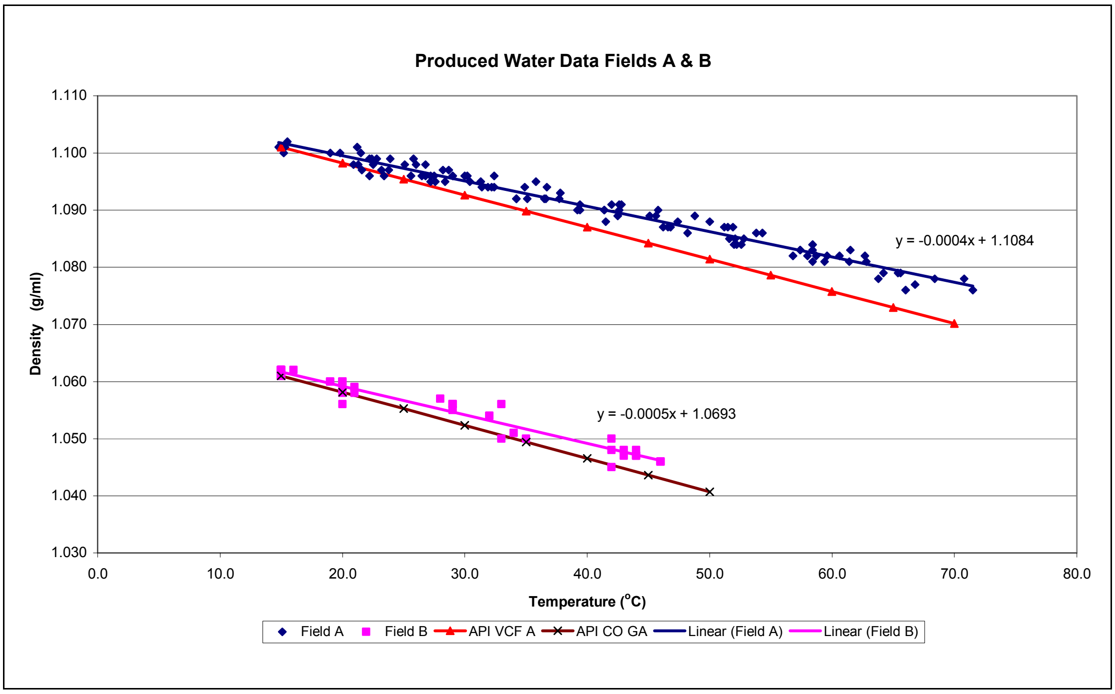



**Fig 10: API VCF v field data.**

Given the poor correlation observed between the measured densities and those calculated using the API corrections for generalised crude oil it was decided to attempt the development of generic temperature and pressure referral equations which when summated would contribute to the calculation of a VCF for produced water. To this end the gradients given by the trendlines from the "A" and "B" sample sets were averaged to produce a new $K_0$ factor of 460.44, for inclusion within the temperature correction algorithm ($C_{tl}$) to allow the calculation of line density at various temperatures from standard density or conversely the calculation of standard density from a value of line density and the associated temperature. The $C_{tl}$ equation set is included below for completeness, (1) and (2):

$$C_{tl} = Exp\left[-\alpha_{15}\Delta t\left(1+0.8\alpha_{15}\Delta t\right)\right] \tag{1}$$

Where: $\Delta$t = (Line temperature (t) – 15) $^{\circ}$C

and $$\alpha_{15} = \frac{K_0}{\rho_{15}^{\ 2}} + \frac{K_1}{\rho_{15}} \tag{2}$$

Where $K_0$ = 460.44 and $K_1$ = 0 for produced water, whilst $\rho_{15}$ is the standard density.

Density values were calculated using the modified $C_{tl}$ equation and the measured standard densities from each data set at appropriate temperatures increments. The results were subsequently recorded and charted against the measured densities. As can be seen from Fig 11; for both data sets, there was good correlation between the measured densities derived from the samples and those calculated using the $C_{tl}$ equation.

The results to date are based on only two facility data sets and it is recognised that for the development of a generic set of produced water volume correction factors further facility data sets will be required. These in turn will require further evaluation and possibly result in changes to the $Alpha_{15}$ Factors. In addition this preliminary research has not addressed the issue of the pressure correction ($C_{pl}$) component of the VCF since the densities of all the samples used within the two data sets were derived at atmospheric pressure.

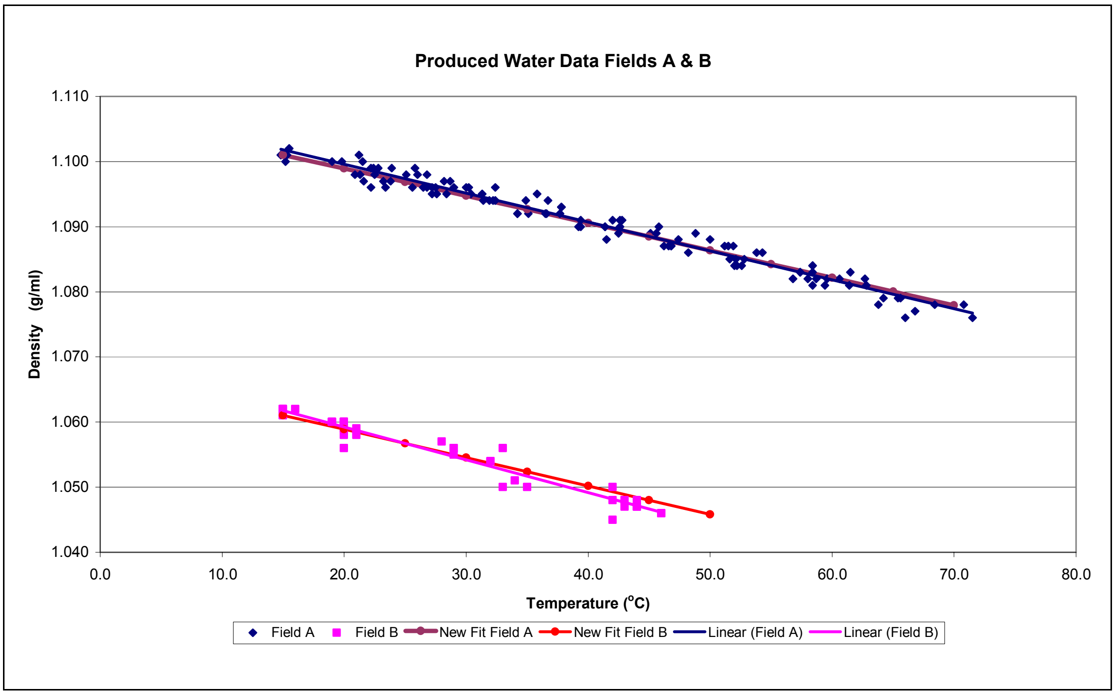



**Fig 11: Calculated density v field data**

Subject to further research and on the basis of the findings to date, there are now a number of options open for the derivation of standard volume from gross volume flow; these include:

1. The measurement of density from samples at both line and operating conditions
2. The measurement of density from samples at standard conditions and the calculation of density at line conditions using referral equations as outlined above.
3. The use of a fixed VCF based on historic analysis data.
4. The use of look-up tables based on measured density and temperature inputs.

The use of fixed values for VCF and line density requires both stable produced water composition and process operating conditions. The use of a fixed standard density only requires a stable fluid composition. Thus fixed VCFs or line densities are more prone to process variations than is a fixed standard density.

It is proposed for optimum accuracy that a fixed value of standard density be used in conjunction with a calculated value of line density to derive the VCF for each metering system where standard volume flow and integrated flow are the basis of reporting. Furthermore the interval for updating the fixed standard density should initially be no greater than 6 months with a possible review at appropriate times by interested parties. A sensitivity review should be undertaken where the line density is not calculated using a live temperature input; again the interval for updating the fixed line temperature (t) should be the subject of agreement between all parties.

In the absence of an agreed line density calculation routine, the use of look-up tables based on measured density and temperature inputs should be considered. The interval for updating the fixed densities and temperatures should initially be no greater than 6 months with a possible review at appropriate times by interested parties. A sensitivity review should also be undertaken where the line density as derived from the look-up table is not calculated using a live temperature input.

The implementation of the $C_{tl}$ and $C_{pl}$ correction routines or the look-up tables can be performed either within the flow transmitter/converter/computer or possibly within a DCS computation module.

For those systems with limited computation provisions where the VCF correction algorithms cannot be implemented it may be possible to adopt a simpler equation for the calculation of line density at differing temperatures based on a known value of standard density as detailed below:

$$\rho_m = -0.0004t + C \tag{3}$$

Where: $\rho_m$ is the density of produced water at line conditions, $t$ is the line temperature and $C$ is derived from offline calculations by substituting standard density and temperature in the above equation and thus calculating the intercept $C$ in respect of $\rho_{15}$ and $t_{15}$.

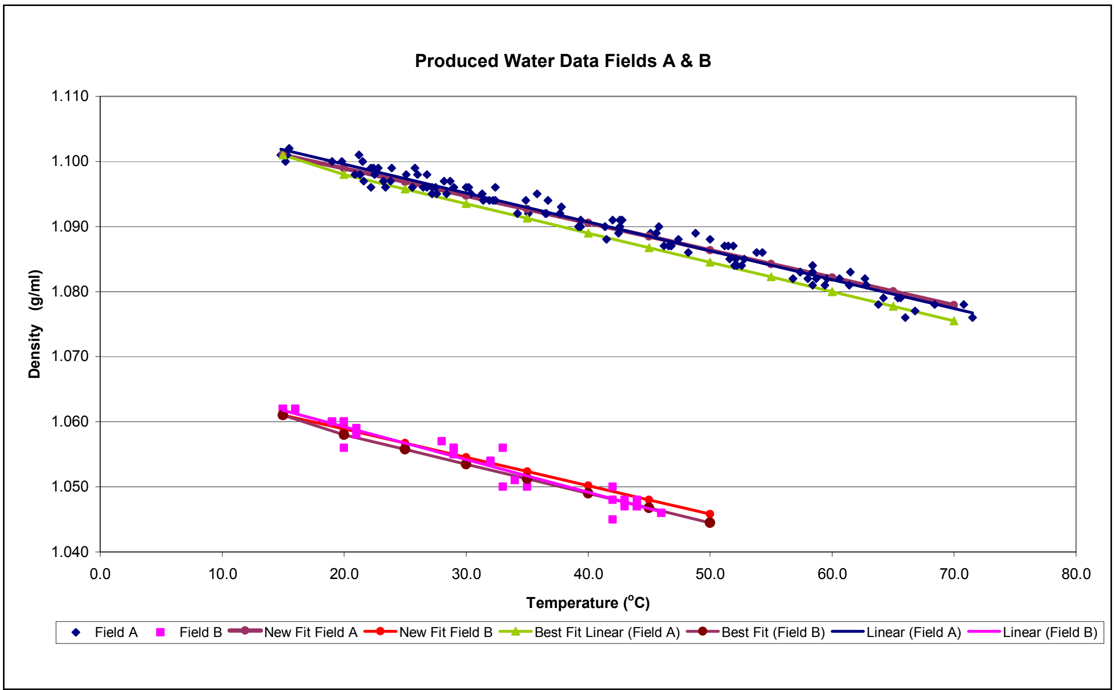



**Fig 12: Linear calculated density v VCF calculated density and field data**

The straight line approximations derived using the above equation can be seen in Fig 12 for the two data sets. These offer correlation with the VCF calculated densities to better than 0.25% over the full range of temperatures and densities covered by the two data sets.

## 8 THE FUTURE

Whilst the operator pursues the refurbishment of the produced water systems and puts in place management systems, there are a number of areas that are still under development with the DTI and the industry in general. Whilst legislation is in place it is still an emerging area of measurement. The following points highlight the main areas requiring focus.

*Metering*

To date, measurement guidelines have not been published although a JIP is currently in progress. The operator has based future proposals on existing DTI ERDU-LED Measurement Guidelines [30], international standards and good oilfield practise. The proposals for best practise from PROVOL will undoubtedly be taken up by the DTI and the issue of a guidance note is eagerly awaited.

*Sampling*

On the sampling side OIWAM cites the need for upward flow to prevent settlement in the pipe and downward flowing pipes are therefore excluded but if the flow is turbulent, a requirement, then there should be no reason why a probe installed in a vertically downward flowing pipe cannot provide good samples; consider that API MPMS 8.1; section 8.4.2 [31] and API MPMS

8.2; section 8 [32] both indicate that sampling on downward flowing pipes is acceptable provided the flow velocity and mixing is adequate for sampling for water in oil from hydrocarbons, as per ISO 3171 [33], and this can be considered the same for oil in water. The specification of upward flowing pipes is therefore challenged.

The ambiguity of the sample point could be removed by the addition of wording requiring the operator to demonstrate that the sample point cannot be brought up to the required standard. A similar method to that provided under section 4.2.2 of the OSPAR agreement [34] could be implemented as there will be installations that it is not viable to install probes.

*Temperature correction*
The impact of temperature on produced water volume measurement and the associated oil quantities are not insignificant; actual volume cannot be compared. It is therefore proposed that the DTI move to reporting at Standard conditions as this would provide a fair and equitable system; everyone would then be on an equal footing and the numbers make sense, particularly for a trading market.

*On-line analysers*
On line analysers do not appear, at present, to be reliable or capable of reporting very low concentration, i.e. single figure mg/l. It is known that a JIP is in progress and a number of analysers are about to go on trial. A number of technical issues need to be resolved with more attention being paid to sample handling systems in particular.

The opinions expressed in this paper are not necessarily those of the operator or companies involved.

## 9 NOTATION AND ABBREVIATIONS

| | |
|---|---|
| DTI | Department of Trade & Industry |
| JIP | Joint Industry Project |
| Mg/l | milligrams per litre |
| OPEX | Operational Expenditure |
| PI/RTMS | Real Time Monitoring System - system to collect and store process data |
| ppm | parts per million |
| te | tonne |
| UKAS | United Kingdom Accreditation Service |
| UKCS | United Kingdom Continental Shelf |
| USM | Ultrasonic meter |
| VCF | Volume Correction Factor |

## 10 REFERENCES

[1] OSPAR Recommendation 2003/5 Promote the Use and Implementation of Environmental Management Systems by the Offshore Industry. (Consolidated Text). www.ospar.org

[2] The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005: SI 2055. ISBN 0 110 731824.

http://www.og.dti.gov.uk/environment/opaoppcr.htm

[3] Bonn Agreement: Agreement for cooperation in dealing with pollution of the North Sea by oil and other harmful substances, 1983. www.bonnagreement.org

[4] OSPAR Recommendation 2001/1, Management of Produced Water from Offshore Installations (Consolidated Text), as amended by 2006/4. www.ospar.org

[5] Guidance Notes on the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2004, DTI. Issued October 2004.

[6] Guidance Notes on the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005, DTI. Issued February 2005.

[7] OSPAR Recommendation 2006/4 Amending OSPAR Recommendation 2001/1 for the Management of Produced Water from Offshore Installations. Interestingly this amendment [7] actually states in clause 4.2.1 *No individual offshore installation should exceed a performance standard for dispersed oil of 30 mg/l for produced water discharged into the sea.*

[8] K. McCabe. An Update on Produced Water Legislation. 4th Produced Water Workshop, May 2006, NEL.

[9] Guidance notes on the Sampling and Analysis of Produced Water and other Hydrocarbon Discharges Part 1: Notes. The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005. Draft Document 5th January 2006. DTI: ERDU-OED. NOTE: revised guidance notes have been issued since this paper was written.

[10] Guidance notes on the Sampling and Analysis of Produced Water and other Hydrocarbon Discharges Part 2: DTI Approved Oil in Water Analysis Methods. The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005. Draft Document 5th January 2006. DTI:ERDU-OED. NOTE: revised guidance notes have been issued since this paper was written.

[11] Oil-in-Water Analysis Method (OIWAM) JIP: A Final Report. Report 2005/96 July 2005 TUVNEL.

[12] Prevention of Pollution Act 1971. The Petroleum Act 1998 (ISBN 0 10 541798 X) amended the section 23 in Schedule 4 as follows:

> *The Prevention of Oil Pollution Act 1971 (c. 60)*
>
> *4. For section 23 of the Prevention of Oil Pollution Act 1971 there shall be substituted-*
>
> > *23. The Secretary of State may exempt any discharge of, or of a mixture containing, oil from any of the provisions of this Act or of any regulations made thereunder* (sic), *either absolutely or subject to such conditions as he thinks fit..*

Produced water discharges have, historically, been an exempted discharge and covered by a POPA Exemption issued by the DTI to the installation in question. Replaced by the permits of OPPC 2005.

[13] Guidance notes on the Sampling and Analysis of Produced Water and other Hydrocarbon Discharges Part 1: Notes. Section 4.2 Specific Sampling Requirements.

[14] Panametrics (GE Sensing) Liquid Transducer Installation Guide. User's Guide. 916-055A1, Chapter 3

> *Be sure the location you have chosen for the installation has at*
>
> *least 10 pipe diameters of straight, undisturbed pipe upstream and*
>
> *5 pipe diameters downstream of the measurement point.*

[15] BS 8452:2005 Use of clamp-on (externally mounted) transit time metering techniques for liquid applications – Guide. ISBN 0 580 45228X. Section 4.2 Preferred Installation Requirements.

[16] Guidance notes on the Sampling and Analysis of Produced Water and other Hydrocarbon Discharges Part 1: Notes. Specifically Section 4.2.2 Design of Produced Water Sampling Points, (a) Spot Samples.

[17] Guidance Notes on the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005, DTI. Issued February 2005. Reference to operators investigating the use of analysers. Current technology precludes the DTI from imposing a requirement to install these devices.

> **8.2.6** For installations discharging produced water to the sea containing more than 100,000 kilograms of dispersed oils per annum, permit holders will be required to investigate the installation of online oil in water analysers. The results of these investigations will be discussed at the first formal permit review (see Section 10.2). Where an online oil in water analyser is installed, the sampling and analysis requirements may be amended following discussions with permit holder.

[18] Guidance notes on the Sampling and Analysis of Produced Water and other Hydrocarbon Discharges Part 1: Notes. Section 7: Use of Online Oil in Water Analysers, specifically 7.3.3 for the calibration of the analysers.

[19] K. McCabe. An Update on Produced Water Legislation. 4th Produced Water Workshop, May 2006, NEL. Section 3 of this paper cites general oil log book non compliances in the industry.

[20] ISO TR 5168: 1998. Measurement of fluid flow – Evaluation of uncertainty. ISBN 0 580 275531

[21] BS ISO 5168: 2005. Measurement of fluid flow – Procedures for the evaluation of uncertainties. ISBN 0 580 46279X.

[22] The term “addition in quadrature” can be found in a publication by A.T.J Haywood titled Repeatability and Accuracy published by the Mechanical Engineering Publications Ltd in 1977.

[23] GUM - Guide to the Expression of Uncertainty in Measurement: 1995 (BSI equivalent BSI PD 6461: 1995 Vocabulary of Metrology Part 3- Guide to the Expression of Uncertainty in Measurement ISBN 0 580 23482 7). See Annex E, 3.6 and 3.7:

*An uncertainty component is not either "random" or "systematic". Its nature is conditioned by the use made of the corresponding quantity, or more formally, by the context in which the quantity appears in the mathematical model that describes the measurement. Thus, when its corresponding quantity is used in a different context, a "random" component may become a "systematic" component, and vice-versa.*

*For the reason given above, Recommendation INC-1 (1980) t1°] does not classify components of uncertainty as either "random" or "systematic". In fact, as far as the calculation of the combined standard uncertainty of a measurement result is concerned, there is no real need for any classificational scheme. Nonetheless, since convenient labels can sometimes be helpful in the communication and discussion of ideas, Recommendation INC-1 (1980) does provide a scheme for classifying the two distinct methods by which uncertainty components can be evaluated, as Type "A" and Type "B".*

[24] BS EN ISO 6817:1997. Measurement of conductive liquid flow in closed conduits – Method using electromagnetic flow meters. ISBN 0 580 220419

[25] Manual of Petroleum Measurement Standards Chapter 13-Statistical Aspects of Measuring and Sampling Section 1 -Statistical Concepts and Procedures in Measurement FIRST EDITION, JUNE 1985

[26] BS 8452:2005 Use of clamp-on (externally mounted) transit time metering techniques for liquid applications – Guide. ISBN 0 580 45228X. Section 4.2 Preferred Installation Requirements. Section 4.3 and Annex D.

[27] The anomalous properties of water – anomaly 18. London South Bank University: Applied Sciences website. http://www.lsbu.ac.uk/water

[28] Calculation based on Fofonoff, P. and R. C. Millard Jr (1983) Algorithms for computation of fundamental properties of seawater. UNESCO Technical Papers in Marine Sciences 44, 53 pp

[29] Guidance notes on the Sampling and Analysis of Produced Water and other Hydrocarbon Discharges Part 1: Notes. Section 4.2.6 Sample treatment (sample preservation) following sampling; Step 5: *Cool the sample to 20°C prior to the analysis being carried out.*

[30] Department of Trade & Industry: Licensing & Consents Division. Guidance Notes for Petroleum Measurement under the Petroleum (Production) Regulations. Issue 7, December 2003

[31] Manual of Petroleum Measurement Standards Chapter 8- Sampling Section 1- Standard Practice for Manual Sampling of Liquid Petroleum and Petroleum Products. SECOND EDITION, OCTOBER 1995

[32] Manual of Petroleum Measurement Standards Chapter 8- Sampling Section 2- Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products. SECOND EDITION, OCTOBER 1995

[33] ISO 3171:1988(E) Petroleum Liquids – Automatic pipeline sampling. Section 5.

[34] OSPAR Recommendation 2001/1, Management of Produced Water from Offshore Installations (Consolidated Text), as amended by 2006/4.

> *4.2.2 Contracting Parties should report to the meeting of the Offshore Industry Committee in 2008 the offshore installations which fail to meet the performance standard for dispersed oil of 30 mg/l for produced water discharged into the sea by 1 January 2007. For each such installation, the report should include an evaluation of the BAT and BEP for that installation, including the options:*
>
> *a. which have been considered in order to meet this performance standard, but*
>
> *b. which have not been considered feasible including the reasons for this,*
>
> *so as to ensure that information is available on the reasons why these offshore installations cannot meet the performance standard.*

## Appendix A

Example Uncertainty Calc

**A Field - PRODUCED WATER METERING STATION**
**(XX-FT-14882 Single Stream)**

| Input Data | | | |
|---|---|---|---|
| Meter Temperature | $T_{line}$ | 35 | Deg C |
| Meter Pressure | $P_{line}$ | 10.0000 | barg |
| Meter Density | $Rho_1$ | 1024.08 | Kg/m3 |
| Base Density | $Rho_{15}$ | 1029.08 | Kg/m3 |
| Meter Scaling Factor | K | 0.7238 | |
| Meter Tube Internal Diameter | $D_{int}$ | 394.4 | mm |
| Standard Densty **A**nalysis or **L**ine | | L | |
| Flowrate | Qv | 615 | $m^3/h$ |

| USM Performance Uncertainties (E&H DF868) | | | |
|---|---|---|---|
| USM Zero Flow Check Frequency | | 12 | months |
| USM Long Term Zero Drift | $E_{mdrz}$ | 1.073 | % |
| USM Repeatability | $E_{mrp}$ | 1.087 | % |
| USM **C**alibration or **R**eference Uncertainty | | R | |
| USM Calibration Uncertainty | $E_{mcal}$ | 1.000 | % |
| USM Reference Uncertainty | $E_{mre}$ | 3.500 | % |
| USM Velocity Uncertainty | $E_{mvel}$ | 0.010 | % |
| Uncertainty in Meter Performance | $E_{MP}$ | 3.819 | % |

| USM Installation Uncertainties | | | |
|---|---|---|---|
| USM Calibration/Reference Temperature | tc | 20.000 | Deg C |
| USM Temperature Effect | $E_{mte}$ | 1.500 | % |
| USM Installation Effects Uncertainty | $E_{minst}$ | 8.000 | % |
| Uncertainty in Meter Tube Diameter | $E_{mD}$ | 1.000 | % |
| Uncertainty in Meter Tube Wall Thickness | $E_{mwt}$ | 0.700 | % |
| Uncertainty in Meter Tube Distortion | $E_{mdis}$ | 0.015 | % |
| Uncertainty in Transducer Angle | $E_{mta}$ | 1.000 | % |
| USM Reproducability (Transit Time Difference) | $E_{mrep}$ | 0.122 | % |
| Uncertainty in Transit Time Measurement | $E_{mttm}$ | 0.140 | % |
| Pipe Roughness Uncertainty (Velocity Profile) | $E_{mpr}$ | 0.497 | % |
| Uncertainty in Meter Installation | $E_{MINS}$ | 8.308 | % |

| USM Signal Converter Uncertainties | | | |
|---|---|---|---|
| Output **F**requency or **A**nalogue | | A | |
| Output Signal Additional Uncertainty | $E_{sigo}$ | 0.050 | % |
| Uncertainty in Meter Signal Conversion | $E_{MSIG}$ | 0.050 | % |

| Pressure Uncertainty | | | |
|---|---|---|---|
| Fixed Pressure Uncertainty | $E_p$ | 2.0000 | % |
| | $e_p$ | 0.2000 | bar |

| Temperature Uncertainty | | | |
|---|---|---|---|
| Fixed Temperature Uncertainty | $E_T$ | 5.715 | % |
| | $e_T$ | 2.000 | Deg C |

| Snap Shot of Results | | |
|---|---|---|
| Area (M2) | 0.122169752 | $m^2$ |
| Gas Velocity | 1.931937366 | m/s |
| Gross Volume Flowrate | 615.000 | $m^3/h$ |
| Gross Volume Flowrate | 14760.00 | $m^3/d$ |
| Mass Flowrate | 629811.0450 | kg/h |
| Mass Flowrate | 15115.465 | te/d |
| Std Vol Flowrate | 612.011665 | $sm^3/h$ |
| Std Vol Flowrate | 14688.279959 | $sm^3/d$ |

| Line Density (Sample Analysis) | | | |
|---|---|---|---|
| Line Temperature Sensitivity Factor | $T_{sens}$ | 0.074457 | |
| Factored Line Temperature Uncertainty | $E_T$ | 0.4255 | % |
| Line Pressure Sensitivity Factor | $P_{sens}$ | 0.000830 | |
| Factored Line Pressure Uncertainty | $E_P$ | 0.00166 | % |
| Sample Analysis Technique | $E_{san}$ | 0.225 | % |
| Sample Variance | $E_{sv}$ | 0.650 | % |
| Sampling Method | $E_{smt}$ | 0.750 | % |
| TOTAL | $E_{RO}$ | 1.1030 | % |

| Standard Density (Sample Analysis) | | | |
|---|---|---|---|
| Sample Analysis Technique | $E_{ssan}$ | 0.225 | % |
| Sample Variance | $E_{ssv}$ | 0.650 | % |
| Sampling Method | $E_{ssmt}$ | 0.750 | % |
| TOTAL | $E_{sd}$ | 1.0177 | % |

| Standard Density (Assuming $Rho_1$ = $Rho_{15}$) | | | |
|---|---|---|---|
| Uncertainty When sd ≈ $E_{RO}$ | $E_{sdf}$ | 0.4883 | % |
| Additional Uncertainty | $E_{sd\ adit}$ | 0.000 | % |
| TOTAL | $E_{sd}$ | 0.4883 | % |

| Summary Of Uncertainties | | | |
|---|---|---|---|
| Uncertainty in Meter Performance | $E_{MP}$ | 3.819 | % |
| Uncertainty in Meter Installation | $E_{MINS}$ | 8.308 | % |
| Uncertainty in Meter Signal Conversion | $E_{MSIG}$ | 0.050 | % |
| Uncertainty in Flow Computations | Ecomp | 0.2 | % |
| Uncertainty in Line Density | $E_{RO}$ | 1.103 | % |
| Uncertainty in Standard Density | $E_{sd}$ | 0.488 | % |
| Gross Volume Uncertainty | $E_{Qvgross}$ | 9.1458 | % |
| Mass Flowrate Uncertainty | $E_{Qmass}$ | 9.2121 | % |
| Standard Volume Uncertainty | $E_{Qvstd}$ | 9.2250 | % |