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The Role of Flow Measurement in Hydrocarbon Recovery Forecasting in the UKCS

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Abstract

In terms of Maximising Economic Recovery (MER) in the United Kingdom Continental Shelf (UKCS), the measurement of well production rates is essential to optimise the hydrocarbon production strategy from within the well itself. This is achieved through a process called a well test where a snapshot of production is monitored by measurement equipment and instrumentation. The data collected is then used to characterise the reservoir near the wells and to optimise the wells' production rates. However, the measurement accuracy required to provide sufficient control has not been established and there is little information in the public domain that shows what the current typical operational measurement uncertainty is. Given that modelling and reservoir management is highly dependent on these measurements, the allowable uncertainty must be known to fully assess if the equipment and the methodology of verifying the measurements is fit for purpose. This paper details an investigation of the effects of flow measurement errors on interpreting well testing data and estimating the recoverable reserves. In addition, current MER strategies for the UKCS are discussed and the importance of using downhole flow measurement data in well testing for MER has been emphasised.
Key words: Flow measurement, Maximizing Economic Recovery, Well Testing, Downhole Measurement

1. Introduction

The majority of hydrocarbon reservoirs are located under the surface of the earth. It means the only access to the reservoir is through a limited number of drilled wells. Although some reservoir characteristics can be obtained by analysing rock and fluid samples taken from inside the wells, generalising these obtained characteristics based on a limited number of samples to the whole reservoir creates a large uncertainty in the knowledge of the reservoir. In other words, even after drilling the wells and starting oil or gas production, the reservoir is still a largely unknown system to us. Therefore, the recorded data from the reservoir during the production period or when well testing is being undertaken is analysed in order to mitigate the reservoir uncertainty through an inverse problem. Using the data, engineers try to gain a better understanding of the reservoir which is a necessary precursor to ensure a good management of the reserves and helps to maximise the economic recovery through increasing the exploitation of the well. Therefore, many articles can be found in the literature that have addressed methods of reservoir uncertainty quantification (Abdollahzadeh *et al.*, 2012; Hajizadeh *et al.*, 2011; Scheidt and Caers, 2009), history matching (Abdolhosseini and Khamehchi, 2015; Zeng *et al.,* 2011; Zhao *et al.*, 2016) and well testing (Ahmadi e*t al.*, 2017; Bottomley *et al.*, 2016; Hamdi, 2014). Dealing with uncertainty is not just limited to reservoir engineering. There are also publications on modelling porous media which include dealing with different types of uncertainty (Nezhad *et al.*, 2011).

The data that is used in all methods developed to reduce the reservoir uncertainty has some uncertainty in itself. The data from a reservoir is measured or estimated using mathematical formulas. Therefore there is always some measurement or estimation error within the data (Lindsay *et al.*, 2017). This error can potentially change the calculated values for reservoir characteristics (e.g. porosity and permeability) and therefore negatively affects the decisions made for the reservoir (e.g. location of new wells and production rates). In other words, the error in the data can indirectly reduce the economic recovery from the reservoir. This issue has not been thoroughly addressed in the literature so far. There is a dearth of literature pertaining to the effect of flow measurement on reservoir performance. Falcone *et al*. (2001) discussed the benefits and shortcomings of using Multi Phase Flow Meters (MPFM) in oil fields. In their article, they mentioned that in well testing and production allocation, the cost of the operation is reduced by replacing the test separator with an MPFM. MPFMs can also provide real-time continuous data that helps operators to identify sudden changes in the production (e.g. water or gas break through) and react faster. Therefore, using MPFMs can indirectly increase the recovery of oil and gas. Sadri *et al.* (2017) investigated the effect of flow measurement errors on the production forecast. They performed several history matches based on different sets of observed data with different ranges of measurement error and concluded that flow meters which either overestimate or underestimate the flow rate have a more negative effect on history matching compared to the flowmeters that have errors in both directions. Sadri *et al*. (2018), in a later work, studied effects of systematic and random flow measurement errors on history matching. The results of their case study show that although the effect of random errors are not significant, systematic errors substantially influence the results of history matching.

In this work, the effects of flow measurement errors on the results of a well test analysis have been investigated. In addition, the possible indirect effect of flow measurement errors on hydrocarbon recovery has been discussed and the impact of accurate flow measurement on maximising economic recovery in the UKCS has been emphasised.

1.1. UKCS Situation

The UK's Secretary of State for Energy and Climate Change asked Sir Ian Wood to conduct an independently led review of the UKCS hydrocarbon recovery, specifically looking at methods through which the economic recovery could be maximised (Wood, 2014). One of the primary recommendations of the Wood Review is for UK Government and Industry to develop and commit to a new strategy for MER from the UKCS. To achieve this recommendation several strategies are proposed. These cover the key UKCS areas which require enhanced development to ensure that the UK maximises the production of its assets. As part of the Technology Strategy, there is a push to apply better reservoir management techniques on a cost-effective basis. In order to manage a reservoir appropriately, the produced fluids have to be measured accurately. Typically in the UK, this is accomplished by 'flow sampling', through the use of well tests and associated equipment – namely test separators supported by single phase flow measurement technologies. Well test data is critical to operations in the offshore industry and covers a wide variety of applications. The data can be used to allocate produced fluids to particular wells either directly, or through verification of multiphase flowmeters. The data can also be used in the determination of reservoir size and in the positioning of new wells and installations. Another key use of well test data is in the optimisation of well production where well stream parameters can be altered to maximise hydrocarbon production levels.

However, recent first-hand audit experience by the UK's Oil and Gas Authority (OGA-formerly the DECC) suggests that well test measurement systems may not be operating near their optimal levels (Oil & Gas Authority, 2015). For instance, primary measurement elements (flowmeters) are often not removed and recalibrated on a routine basis. There is also evidence of flowmeters being exposed to two-phase flows resulting in meter degradation. In addition, the interval between the testing of individual wells may extend to several weeks, with the flow rates between tests inferred by interpolation. The risk is therefore that these measurements may result in a measurement bias or increased uncertainty. Basing reservoir optimisation efficiency and production strategy on measurements where there are fundamental issues that cause unknown levels of uncertainty is clearly not a good practice. As such, mechanisms to provide measurement confidence, such as audits, are in place to ensure compliance. However, the success of these initiatives relies on dedicated drivers of the process.

In addition to the issues of measurement bias, a well test also introduces potential issues from representativeness of the test in terms of the fluids measured. A well test completed over a two-day period might be at significantly different conditions compared with a well's average production profile, particularly if the well test is completed close to the start or the end of a shutdown period. It is evident that there can potentially be additional uncertainty from a variety of sources such as errors due to weak flow meter calibration and maintenance introduced when measuring hydrocarbons from a well and considering these measurements are used to try and effectively monitor and optimise production there remains some unanswered questions. In particular, what level of uncertainty is acceptable for these measurements so that the production optimisation process is relatively unaffected by it i.e. there is a low sensitivity?

This paper has investigated this question and provides some evidence and guidance.

1.2. Current Techniques

Well testing is extremely valuable in the oil and gas industry as it allows operators the means to assess the production performance of their wells and to glean important information about the structure and characteristics of the subject reservoir. As a whole it is an expensive operation involving significant resources and logistics, and differs from most techniques as it requires the reservoir to be in a dynamic state (i.e. pressure build-up or draw-down), as opposed to a static state, in order to activate the responses needed for mathematical modelling. One of the first comprehensive studies on the analysis of well test pressure responses was presented by Matthews and Russell (1967). Among the other early works that explain the principles of well test analysis in detail are Ramy et al. (1973) and Earlougher (1977). Numerous studies have been published with a focus on specific methods of well testing and their advances. Build-up (Barbe and Boyd, 1971; Foster et al., 1989; Hegeman et al., 1993) and draw down (Chase, 2002; Khosravi and Ketabi, 2014) tests have been the most common methods addressed in the literature. In a build-up test, a producing well is shut in and then the downhole pressure change is recorded over time and analysed. In a draw down test, the downhole pressure change is measured for a well that is initially (or after an extended shut-in period) brought into production. Many other techniques of well testing, such as the drill stem test (DST), production test, multi rate test, and interference test, have been presented in the literature. More details about different well test methods can be found in Stewart (2011). A basic well test system consists of a subsurface string, incorporating downhole tools such as gauges, check valves, flow switching valves, isolation valves and packer assemblies, together with a surface or deck system for separating, sampling and metering the fluids flowing from the well. A detailed explanation of the operational aspects of well testing has been presented in McAleese (2000). Well tests incorporate many aspects of operations from drilling and process plant production and are performed in order to estimate the reservoir properties. They are used to obtain dynamic data from a reservoir during different stages of that reservoir's life. During the exploration phase, the results of well tests provide the key dynamic data which will directly affect decision-making regarding further development. Well testing objectives are diverse and can be used to confirm the existence of hydrocarbon fluids in the drilled wells, to obtain downhole samples and to characterise the reservoir. The duration of a typical well test is usually short, of the

order of tens of or hundreds of hours. The main well test deliverables that can influence MER and will be discussed further in this paper are:

- Reservoir parameter characterisation
- Reservoir model selection
- Production flowrate determination

These three deliverables link closely to MER through reservoir optimisation and the ability to maximise the recovery factor for the well. Typically, a reservoir characterisation is achieved by finding a model that matches the empirical data which can provide the well characteristics, such as flow capacity (i.e. permeability-thickness product), skin factor, and the structural and/or hydrodynamic boundaries. The interpretation and ultimate utility of the well test data, which necessarily encompasses its uncertainty, is linked to knowing the particular reservoir's storage capacity i.e. porosity. One important use of well test data is to determine; (a) if a static model e.g. a geological one, behaves in the same way as the real reservoir and; (b) to enhance the predictability of that model.

Well testing can also be used anytime during the life of a reservoir to diagnose abnormal behaviour e.g. an unexpected gas-oil ratio, or an unexplained reduction in productivity. Different types of well testing procedure are designed to serve particular purposes, but in all cases there will be some sort of controlled constant production (or injections) while recording the pressure data. For those cases where a well flows at a particular production rate, it is termed a draw-down test, whilst when the well is closed or shut-in, it is termed a build-up test as shown in Fig. 1.
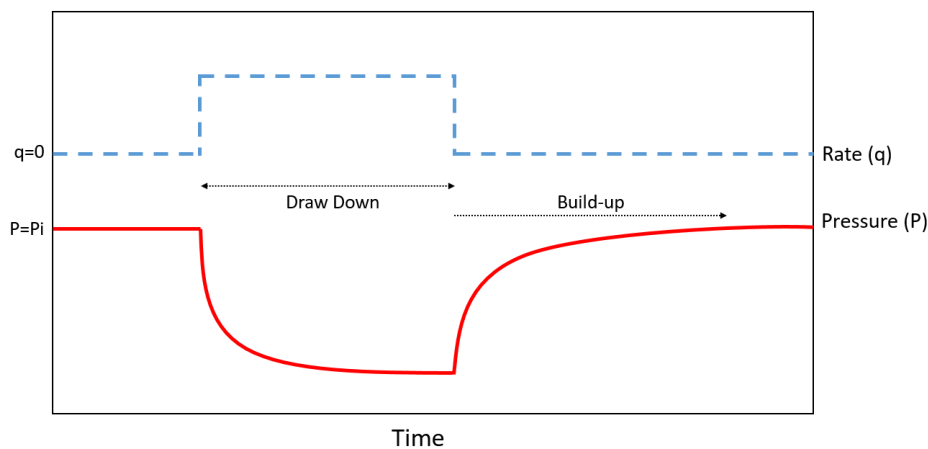

Fig. 1. The concept of draw-down and build-up well tests

The ultimate goal of either test is to describe a reservoir such that it can reproduce the same output for a given input signal. Therefore, because well testing is effectively an inverse problem - one which needs the data to match the model - its interpretation largely depends upon the quality of input and output data. Hence, the focus of the study in investigating the role of measurement uncertainty upon MER.

Owing to the adverse conditions upstream of the well head, there is great difficulty in monitoring component flowrates with great accuracy. Instead, the produced fluids are isolated from other producing wells and sent to a test separator. The test separator separates out the individual components of the flow into either liquids or gases – as in a two phase model – or oil, water and gas – a three phase separator (more commonly used in the North Sea). The separated components are then measured individually by single phase flow measurement technologies as shown in Fig. 2.
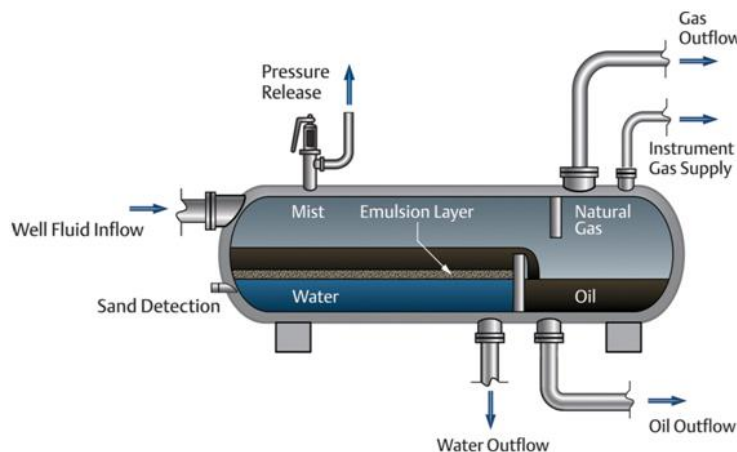

Fig. 2. Three phase test separator flow measurements (used with permission from Emerson Process Experts (2014))

Using these measurements over the length of the well test, it is possible to acquire a snapshot of the production rates for that point in time. These values are then used as the well rates until they are updated by the next series of well test data collection. Coupling this flowrate data with reservoir parameters allows reservoir engineers to model specific wells in order to optimise their production profile i.e. maximise the hydrocarbons produced for as little water content as possible. It is intuitive that completing a reservoir optimisation successfully depends on accurate data being supplied. However, how accurate the data needs to be is unknown and is one of the questions this study aims to answer. Essentially, any deviation from non-ideal conditions will cause a detrimental effect on the flow measurement which leads directly to reduced confidence in the data for reservoir optimisation and hence recovery factor. There are many influences that can cause an error in the measurement of flow at the outlet of test separators. Some common concerns are (Ross, 2011):

- Presence of a second component (carry-under and -over)
- Installation effects
- Fouling on measurement device
- Calibration expired
- Poor maintenance/inspection
- Secondary instrumentation error
- Pulsating flows
- 'Representativeness' (i.e. do the flow rates during the well test represent the actual typical conditions?)

With so many potential measurement issues present, some being persistent, it is beneficial to know what the overall cost of the measurement problems will be. This way an appropriate cost-benefit analysis can be completed and the risk in regard to MER can be properly assessed. This ties in with current Oil and Gas Authority (OGA) measurement uncertainty strategies and the recommendations from the Wood Review.

2. Methodology

Throughout this paper the term 'accurate measurement' has been used to discuss the requirement for the quality of topside measurements for reservoir optimisation. It has also been noted, however, that the absolute level of quality required to ensure successful optimisation remains unknown. To investigate this problem, the current study focusing on the uncertainties in well test measurements and their consequent impact on MER has been completed. The study is an assessment of generic well test metering, including multiphase measurement used during a standard well test. The focus of the work lays in running a number of simplified models in order to explore the importance of rate measurement for well test interpretations; as opposed to developing in-depth models akin to those in use commercially. The scope of the study encompasses downhole rate measurement as a necessary means of comparing and contrasting such measurement with surface techniques. Overall, the study has much to say about downhole techniques. Nevertheless, the intent of the modelling is to establish, in broad terms, the nature and strength of the link between the uncertainty in the surface well test measurement and its importance in maximising future extraction.

Firstly, it is important to understand the process in which flowrate measurements are used in reservoir production optimisation and production. In order to successfully optimise production from a particular well, the well itself has to be characterised so that its future production can be accurately modelled with a low uncertainty. Only once production has been predicted can the most optimum production pattern be obtained. There are two parts to this prediction, namely the characterisation of the parameters within the well/reservoir itself e.g. porosity, permeability, skin factor, etc. and the model used to calculate the outputs given the input parameters. Both of these parts are determined through data collected from the well tests. Traditionally, surface flow measurements have been a key component in the analysis. Characterising well/reservoir parameters and selecting the most appropriate model to use is influenced by the data taken during the well tests, but the process involved is outside the scope of this study. This paper focuses on the impact of the quality of the data on the calculated recovery of oil and gas.

An example reservoir was created and a series of sensitivity runs were conducted to assess the output from the example with respect to the changing input parameters. The example reservoir was based on a typical 100 ft vertical well within a cylindrical fractured reservoir with an outer radius of 5000 ft. The following were used as the flow parameters of the reservoir:

- Storativity ratio (ω) – 0.1
- Inter-porosity flow coefficient (λ) - 2 x 10^6
- Permeability (K) – 500 md
- Bulk porosity (S) – 0.27

The parameters can be taken as descriptors of how fluids flow through a reservoir and their exact definitions can be found in various sources such as (Lee, 1982; Terry *et al.*, 2013; van Golf-Racht, 1982). However, for the purpose of this study they can be thought of as inputs to a model where the closeness of the predicted values of these inputs to the actual values dictates the accuracy of the model as a whole.

During each test run, the example reservoir was 'produced' with varying levels of measurement information recorded and utilised. This measurement data was then used as a disturbing signal to generate the pressure data and the predicted reservoir parameters using the transient well test interpretations. In other words, we try to investigate how the measurement error can lead to a completely different well test interpretation for similar models with exactly the same parameters. A comparison could then be made between the accuracy of the model and correct parameters in the example reservoir. The test runs consisted of a single phase oil drawdown at a constant flow of 9200 STB/D with a duration of 158 hours. Then the well was shut-in for 8 hours for a build-up phase before being produced again.

The second stage production could be applied for any time frame and for these tests the well was assumed to produce for 20 years allowing for a direct comparison of cumulative production i.e. how much total hydrocarbon was recoverable over the timeframe compared with values obtained during other test runs. This then allows a comparison as to which methodology allows for maximising recovery factors, and hence MER.

The test runs considered during these tests were:
1. Correct flow rate measurements taken at the surface
2. Correct flow rate measurements taken downhole
3. 10% random error in flow rate measurement taken at the surface
4. 10% random error in flow rate measurement taken downhole

The surface measurements are defined as measurements above the well head i.e. either test separator measurement systems or multiphase flow meters. Downhole measurements are defined as measurement taken in the well bore typically at the well perforations.

The purpose of defining the scenarios is to generally show the indirect effect of random flow measurement errors on the calculated hydrocarbon recovery. Although the case study that we have undertaken has not been applied to a specific reservoir in the UKCS, conclusions from it can generally be valid for different reservoirs, including those in the UKCS.

3. Results

Here we consider the comparative cases of the well tests where the flow rate measurements are taken at the surface and downhole respectively (test run 1 and 2). Note that there is no downhole shutting. The well is shut at the surface but the data are measured downhole. This example is similar to the reported well test by Meunier *et al*. (1985) but in a fractured environment. During the drawdown and build-up phases the measured flow rates would be as shown in Fig. 3.
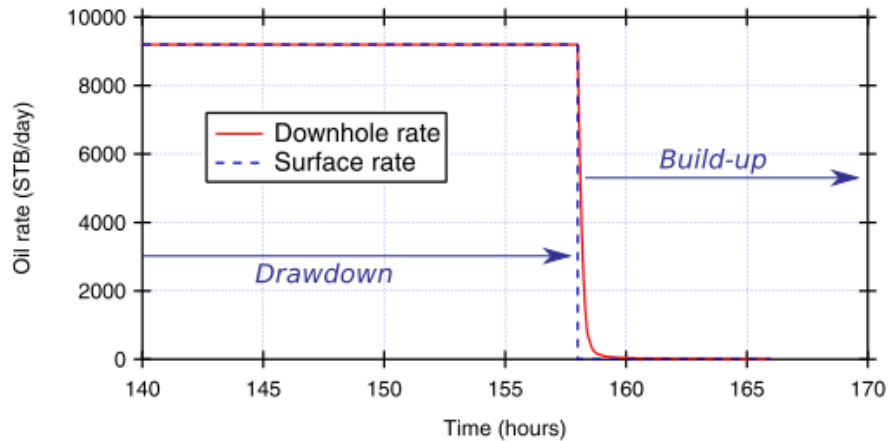

Fig. 3. Flow rate measurement location during well test

It is clear that there are different flow rates measured using both methods, particularly at the transition between drawdown and build-up. This is due to the fact that once the well is shut-in, there will be no flow at the surface i.e. the measured rate drops instantaneously to zero. However, with downhole measurement, once the well is shut-in the reservoir still flows until it reaches equilibrium where there is a pressure balance and the produced area becomes stable again. Surface flow rate measurements do not record this additional flow post well shut-in and therefore do not include them in parameter predictions which can cause error as shown in Fig. 4 and 5.
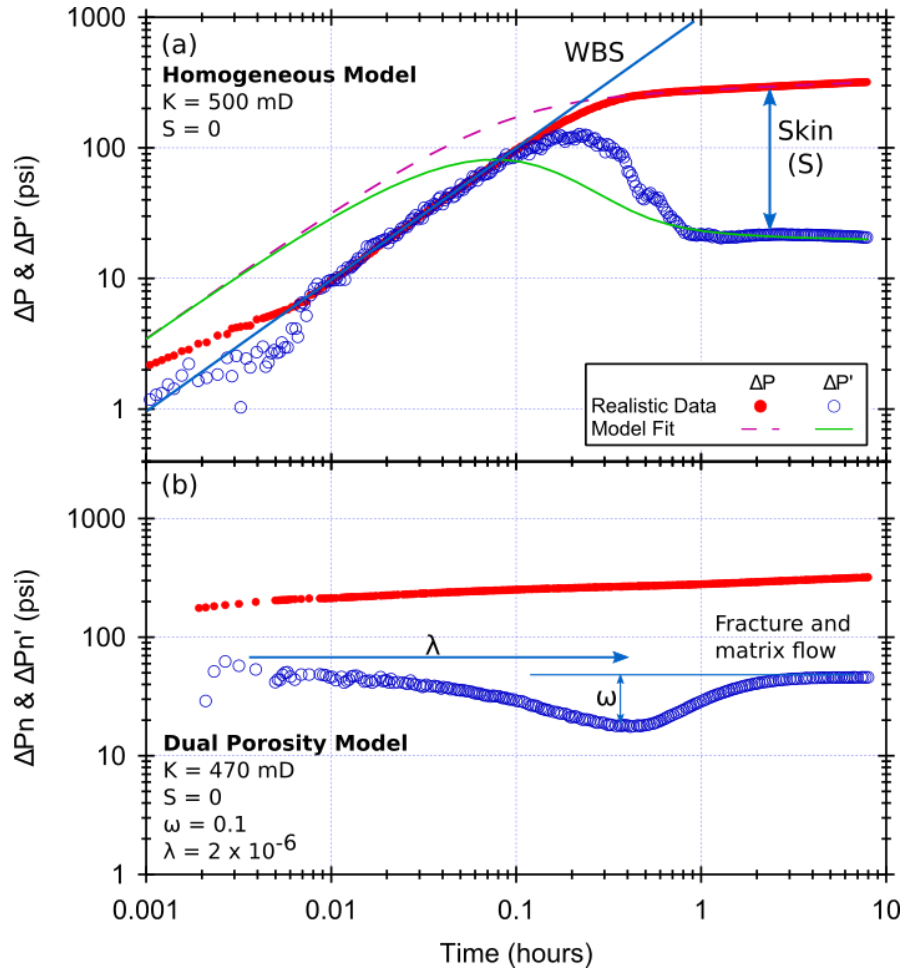
Fig. 4. Well test diagnostics plot for synthetic test run 1 with standard surface flow metering (a) and test run 2 with downhole flow metering (b)

Fig. 4a and b show the well test log-log diagnostic plots for test runs 1 and 2 respectively. The shape, slopes, and plateaux of the curves found on a well test diagnostic plot are used to estimate parameters to describe a reservoir which will be used in a reservoir model.

The curves in Fig. 4a and b describe the same reservoir but Fig. 4b conforms to a significantly different model than Fig. 4a. The Y axes of the plots are different merely because when variable rates and pressures are employed, as for the case with downhole measurements, the well test theory requires the use of a superposition function to be able to plot the data on the specialized plots, such as log-log plots, and subsequently analyse them. This is based on fundamental well test theory for multi-rate/pressure cases. For a simple case with one draw down and one build-up this function will be reduced to a case where we have ΔP (pressure difference) and ΔP' (derivative of pressure difference). More information about the superposition function can be found in well test literature that provides the fundamental theory of well test data analysis under variable and/or single rate change scenarios such as Bourdet (2002) or Houzé et al. (2015). Fig 4a is related to the case when the variable rate is ignored and only one draw down and one build-up are considered. However, in Fig 4b the variable downhole rate measurements have been implemented.

The results in lower modelling uncertainties and better prediction capability, suggesting that for MER, surface flow rate measurements are not the best method of measurement available. Fig. 4a denotes an area as Wellbore Storage (WBS) on the curve. This is an effect that masks well flow rates from surface flow rate measurements through essentially a dampening effect. Owing to the distance, pressure differential and other factors, the production profile at the well perforations and any associated pulsations or changes in component fractions at these points will be 'smoothed' out as the fluids flow to the production platform. What could have been a high pressure region or high water cut region will be averaged out by the rest of the fluids, meaning the information will be lost. This is shown in Fig. 4a. Again, it is important to point out the data itself is used to help choose the subsequent correct model to use.

WBS will be present in all wells but will affect the measured results to varying degrees depending on the measurement location. This is another example suggesting that for MER, downhole measurements are potentially the most promising. For test runs 3 (surface measurement) and 4 (downhole measurement) a 10% error was introduced into the flow rate measurements to assess the impact of these errors on the recovery factor of hydrocarbons. It was found that a 10% flow rate measurement error resulted in a 17% permeability estimation error (Fig. 5). The location of the flow rate measurements (surface or downhole) did not impact this relationship. This error is different from the error introduced whether or not flow after shut-in is utilised in the estimation. It should be added that the superposition function is a complex function of rate and pressure, therefore, the noise will be propagated on the analysis, and also on the plots for

multi-rate cases. Consequently, in Fig 5, the pressure data points for the two cases don't match. Detailed information about the superposition function has been presented in Bourdet (2002) and (Houzé et al., 2015).
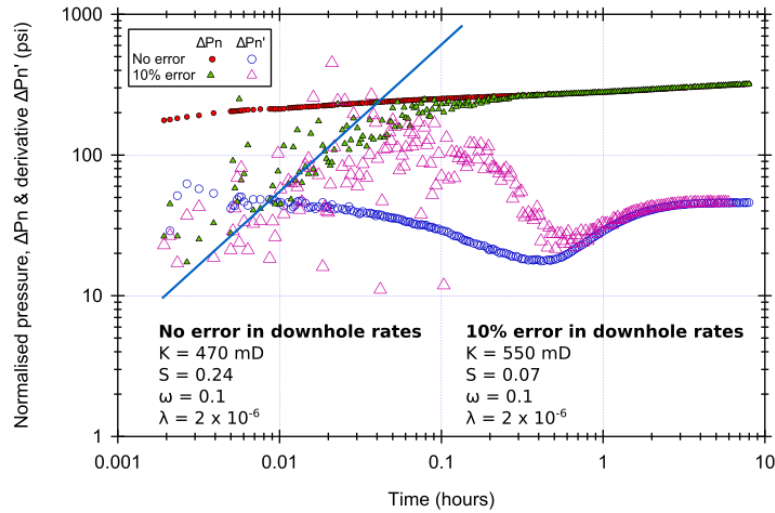

Fig. 5. Well test diagnostic plot for test runs 2 and 4

These parameter errors, however, were not found to have a significant effect on the estimated recovery factor. Even large errors present in the reservoir parameters don't impact linearly against how much hydrocarbon is calculated to be produced from the well by itself. As an extreme case, when the flow rate error (or equivalently the resulting estimated permeability) is ± 50% under the conditions in the example reservoir, the recovery factor after 20 years was found to have only a 3% error. Essentially, for every 1% error in flow rate measurement there is an error in the estimated recovery factor of 0.06%. It should be noted that the effect of permeability is on the *accelerated* recovery i.e. the speed at which the reservoir is producing oil, not on the *ultimate* recovery (Lake and Walsh, 2003). It should also be added, however, that in this work, only the effect of random errors has been investigated. In reality, flow meters may also have bias errors in addition to their random errors. In most cases, random errors have a normal distribution in both the positive and negative direction. Therefore, they cancel out or dampen the effect of each other. In contrast to random errors, bias (systematic) errors are mostly distributed in just one direction (positive or negative). As a result, if the effect of systematic errors is considered, the results may be completely different. However, while the effects of systematic errors are widely appreciated in the industry, the effects of random errors are sometimes ignored. Therefore, in this paper the potential significant effects of random errors have been analysed and emphasised.

As discussed earlier there are two elements in reservoir prediction necessary to optimise production successfully. The main impact on MER from flow rate measurement errors is not from the reservoir parameter estimation but from the use of the data to select the most appropriate model. For each test run, the data generated on reservoir parameter estimations and the most appropriate reservoir model were used to 'produce' the example reservoir for a period of 20 years. For test runs 1 and 3 a single medium model was selected since it was the best match to the data and for test runs 2 and 4 a dual medium model was selected for the same reason. Dual medium denotes a reservoir fracture being detected whereas single medium denoted no fracture. Fig. 6 shows the effect on estimated recovery factor after 20 years using each model and the reservoir parameter estimations.
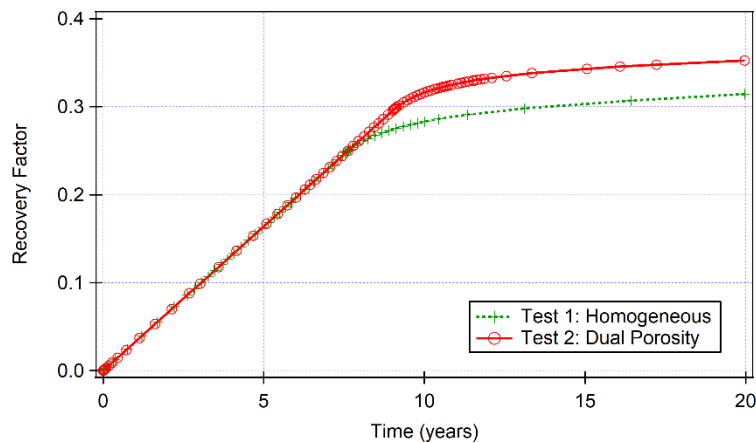

Fig. 6. Recovery factors of test runs 1 and 2, up to 20 years

The results show that the model uncertainty has a higher impact on the estimated final recovery compared to the reservoir parameter (e.g. permeability) uncertainty. Using a single medium model the ₍reduction₎ in the estimated recovery factor is around 12% compared with the dual medium model. Potentially this could be a huge number in terms of an

estimation of reservoir economics. To give an idea that how much this would be, we consider that the initial oil in place for the example reservoir is around 3.78×10^7 barrels of oil. Incorrect flow rate measurement data, either from errors or from location factors, can result in around a 5% decrease in the estimations in producing the original oil in place. Or at price of $60 a barrel, this is equivalent to £75 million error in financial calculations for this example for the UKCS. The model and parameter uncertainties which are caused by flow measurement errors not only affect the estimated recovery factor but also the actual one. Since the model and the parameters are used in simulations and reservoir optimisation then the results are employed to make decisions about the reservoir (e.g. deciding about production rates and locations of new wells). The uncertainties caused by flow measurement errors indirectly affect the actual performance of the reservoir and the recovery factor. Therefore, they influence MER.

This study highlighted the potential of flow rate measurements and in particular downhole rate measurements for improved well test data, and demonstrated the contribution of accurate measurements on reducing uncertainty in modelling, parameter estimation and the ultimate recovery. Simulations were performed using the models that are frequently used in the well test interpretation routines. They only include the impact of flow rate uncertainty on the estimated recovery factor and the choice of the reservoir model by extending the well test models for long term predictions. As a consequence, only natural production mechanisms are considered and other improved recovery techniques (such as water or gas injection) are not. In practice there are "indirect" uncertainties induced from inaccurate rate measurements. Such uncertainties could result in incorrect or sub-optimal decisions being made for reservoir developments that can ultimately impact the secondary or enhanced oil recovery plans. An assessment of the impact of such uncertainties in general cases is difficult, as each reservoir requires its own considerations and different policies compared with other reservoirs.

It is important to rationalise the study for its applicability and representativeness to the industry. The example reservoir modelled was simple in design in comparison with 'real world' reservoirs. The results obtained are specific to the example and are only given as indications of the potential significance of flow rate measurement error (and hence uncertainty) on MER in the UKCS. For the test runs including a 10% error, the results consider the error introduced to the permeability estimation only.

3.1. Discussion

The results obtained show relatively small effects of surface flow rate measurement errors on the estimated recovery factor (considering reservoir parameter estimations only). The optimisation of production, however, is not the only use of well testing in the industry and there will be more significant consequences from flow rate measurement errors in these applications. Well flow rate measurements can be used in the allocation of produced hydrocarbons between wells or fields, in the verification of multiphase meters and the decision making process for field developments i.e. where to drill the next well. The significance of flow rate measurements here can influence MER in different ways.

Where multiphase meters are used to monitor well flow rates continuously or during well tests they will still be verified periodically against separator measurement systems. This acts as a verification of the performance of the equipment and potentially can be used to apply corrections (this assumes a better uncertainty in the separator measurements). There can be a compounded effect of measurement error from a separator system through to multiphase meter through to reservoir parameter estimations. In field developments the data from producing wells is used to assist in the positioning of future drilling. Where a new well is drilled may influence how much hydrocarbon can be produced or the effectiveness of any injections for secondary or tertiary drive mechanisms (EOR). Allocation is used to apportion produced fluids to particular wells in the event of comingling. The allocated values can be determined from separate meters i.e. multiphase meters or by test separator systems. Allocated fluids tie in with MER not through normal well test processes but through continual monitoring of streams. The ability to determine water breakthrough quickly and in real-time is extremely valuable in MER.

It is clear from the study that the significance of flow measurement uncertainty (and errors) cannot be linked directly to one output as the whole process is intrinsically linked to varying degrees. Where one input is weakly linked to the output through one mechanism it can be strongly linked through another. This coupled with significant secondary effects makes it difficult to place absolute values on the implications of measurement accuracy. Instead, some examples have been presented with their stated limitations and sample values calculated. In summary, in terms of MER in the UKCS the study has found that flow measurement is important in ensuring its success. However, the most significant contribution is not from the measurement error or uncertainty itself but through the use of the data to choose an appropriate reservoir model to use for reservoir optimisation. This ties in with not only the quality of the measurements themselves but on the location and appropriateness of the measurements.

The authors would recommend the use of downhole flow rate measurements as these provide additional information on well flows not available from surface measurements. This information has been shown to be extremely valuable in terms of MER through the models run. Another recommendation is the use of multiphase meters instead of test separator systems for surface flow rate determination. Primarily, they are able to record and trend data continuously resulting in an improvement in data quality and confidence of estimated reservoir parameters.

The impact of flow measurement on MER will be effective on the UK economy and its oil and gas industry. Without accurate knowledge of the fluids produced from individual wells it will be impossible to efficiently optimise and maximise the amount of hydrocarbons produced in the UKCS, and hence maximise the economic contribution to the UK treasury. What type and method of measurement is the most appropriate for MER is still not defined. However, the various methods have been outlined in the preceding sections. Current industry practice shows the test separator system as the system of choice for the large majority of installations.

From feedback from industry there appears to be significant restrictions in the capability of test separator systems to accomplish MER from the point of view of overuse and equipment quality. For example, pipe set ups can inhibit well

testing through the requirement to shut all producing wells down in order to test one well and there are many issues that can affect the single phase measurement methods. It is also clear that a periodic review of well production is not enough to ensure the production remains optimised throughout its lifetime. For instance, for a well being tested every 30 days, there can be a sudden water breakthrough after 15 days that would not be found for another 15. This may have a detrimental effect on the whole reservoir. But how much of an effect does mismeasurement have on the UK economy?

According to the Financial Times (Adams *et al.*, 2015), the UK's oil and gas industry made a substantial contribution to the British economy, accounting for some 450,000 jobs and £5bn tax revenues. As such, the accurate field databases derived from real time well tests would certainly have an influence on the forecast of UK's economic prospects and reservoir life to allow the processing, transport and export of the UK's petroleum and investment in new key infrastructure. It helps avoid the premature decommission of assets to the detriment of production hubs and infrastructure critically needed for maximising economic recovery from UK's valuable production assets and for achieving the maximum economic extension of field life. Based on the Office for Budget Responsibility's most recent long term forecasts (Office for Budget Responsibility, 2014), the oil and gas production from 2014 to 2040 inclusive is expected to be 9.1 billion barrels of oil equivalent (boe) in a mid-range estimate, 7.7 billion boe in a low range case and 10.7 billion boe in the high range estimate, Fig. 7.
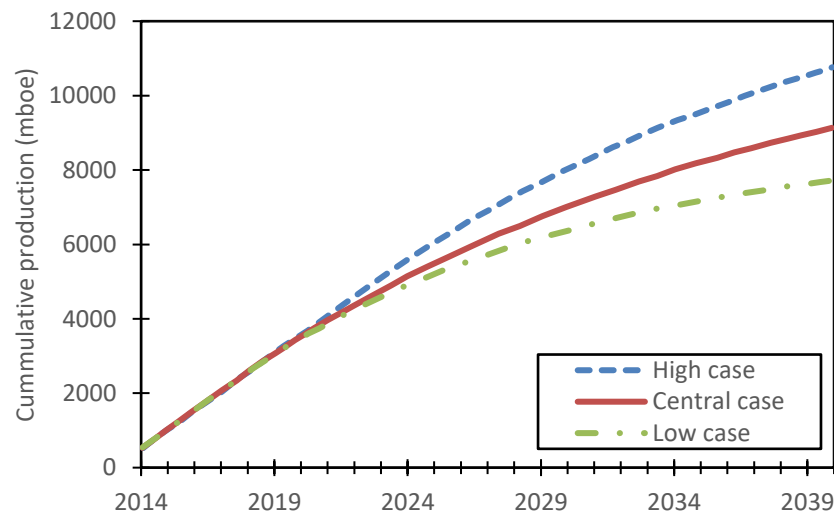
Fig. 7. OBR scenarios for future production, 2014 onwards (HM Treasury, 2014)

As can be seen, there would be a significant difference of 3 billion boe between a low production and high production future, although all of these projections would fall short of maximising economic recovery. Nonetheless, in his final report, Sir Ian Wood indicated that the recovery of 15 to 16.5 billion boe is a realistic ambition (Wood, 2014). In order to achieve Wood's target, real time well tests based on MPFMs would likely be the best option, as real time field data provides vital information to facilitate exploration success and to optimise oil and gas production, petroleum revenue tax (Fig. 8) and financial performance in terms of net present value, internal rate of return, profitability index, saving index, and so on.
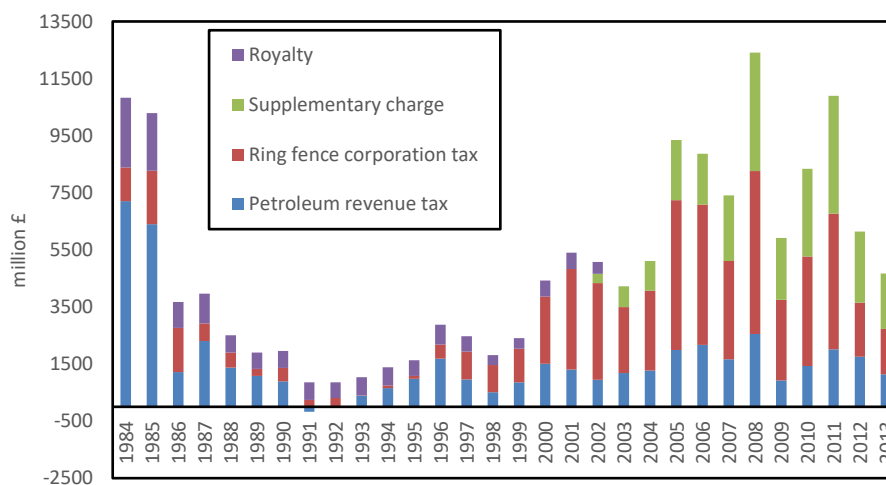
Fig. 8. Government revenues from UK oil and gas production (HM Revenue & Customes, 2014)

In its 2014 budget, the UK government announced a review of the fiscal regime to ensure that it supports MER UK (Office for Budget Responsibility, 2014). The fiscal regime which specifically targets: (i) the maximisation of economic recovery from oil and gas production and; (ii) the profitability and cost effectiveness of the industry would certainty needs accurate real time field data for striking a balance between providing sufficient incentive for companies to operate in the UK, whilst ensuring the nation gets a fair share of the proceeds. If the UKCS field databases were discrete and uncertain, this would undoubtedly disadvantage the UK government's effort to simplify the fiscal regime because of the incomplete picture which imposes additional uncertainties. Ultimately, it could weaken the North Sea oil and gas investment and production (Fig. 9), as well as the uptake of improved and enhanced oil recovery techniques and technologies as a whole.
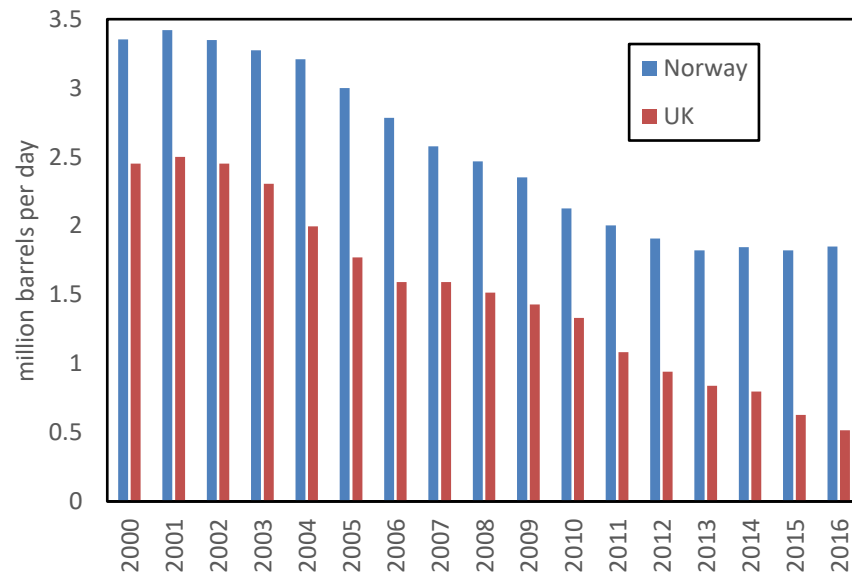

Fig. 9. North Sea oil production (U.S. Energy Information Administration, 2016)

The U.S. Energy Information Administration (2016) commented that UK North Sea oil production would decrease again in 2016 to just 500,000 barrels per day. In contrast, the sharp decline in Norwegian North Sea oil production has stopped and production rates, while down from previous highs, have been broadly stable since 2012 because of effective government policies intended to support the industry. With the recommendations from the Wood Review being actively pursued by the UK (Wood, 2014), the value of 500,000 barrels per day can hopefully be increased. Reservoir optimisation through better measurement methods is one way of helping to achieve this goal. Though many hydrocarbon reservoirs are profitably produced, very few are depleted efficiently and economically. To optimise reservoir productivity and performance and to predict recovery trends, the time series mapping of depositional environmental, flow barriers, flow rates and core data are required. In particular, well tests that provide the vital time series data for reservoir management and economic recovery can:
- Provide a better description of reservoir contents via flow quantification
- Reduce investment and recovery uncertainty by evaluating production history or historical matching
- Establish a basis for total management and dynamic development for optimising reservoir operation in all phases of depletion.

The real time flow data gathered from the field and well tests can provide actual evidence as to whether or not an irregular fluid displacement is being hampered by "pockets" of flow barriers, e.g. rocks. The reservoir reaction team can then rapidly take appropriate action(s) to maximise volumetric flooding efficiency, and hence optimise the oil recovery factor. In reality, every practical approach and effective decision making are essentially based on a set of real time, accurate and representative data. In a nutshell, to economically achieve the best possible hydrocarbon recovery from reservoirs, real time field and well test data for decision making are undoubtedly indispensable.

Fig. 10 reviews the variation of flow patterns that can be captured by three alternative well testing methods during reservoir depletion.
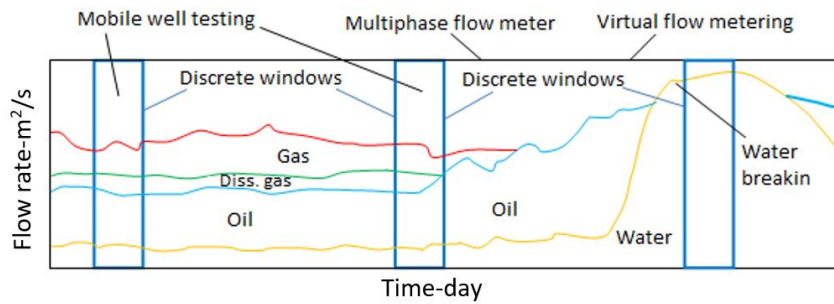
Fig. 10. Flow rates plots of well testing data

Table 1 summarises the three alternative methods available for well testing based on their real time capability.

Table 1. Real Time Continuity

Alternative Method	Real Time Capability	Comments
Virtual Flow Metering	No	Pseudo real time series, flow rates are simulated by computer software.
Multiphase Flow Meters	Yes	Genuine real time series, flow rates are physically measured and are not inferred by computer software.
Mobile Well Testing	No	Discrete patterns, flow rates are measured on a "pay-as-you-go" basis.

It should be noted that virtual flow metering is merely computer simulations based on certain assumptions and boundary conditions, which are measured by temperature and pressure sensors in and around the wells. The sensors once installed in and around subsea wells are rarely re-calibrated and verified. In contrast, mobile well tests are carried out on discrete bases. Field data captured by virtual flow metering and mobile well testing lack real-time continuity. To economically maximise hydrocarbon recovery, each flow parameter captured must be verified against its consistency in a real time continuity. As such, the usual "garbage in, garbage out" approach can be avoided.

MPFMs allow both real time and continual flow measurements to me made and have been subjected to extensive and robust verification. Technically speaking, MPFMs would probably be the best alternative option for well tests because they are capable of capturing real-time continuous and accurate flow data which are essential for optimising the economic recovery of deposits from hydrocarbon reservoirs. Nevertheless, virtual flow metering and mobile well testing are also considered to be cost effective alternative options for complementing MPFM measurements.

In terms of the effects of measurement errors on reservoir parameter estimation, it was found that there is a weak link to estimated recovery factor. Instead, the largest contributor to the estimated and actual recovery factor from measurement is when the well test data is used to select a reservoir model. This means that the typical estimated uncertainties seem to be acceptable in terms of measurement requirements, as long as the reservoir model is correct. The mechanism for selecting the model was not assessed in this work but it is recommended that it be addressed in further work in this area. The errors introduced from periodic testing of a well can clearly be seen in Fig. 10 where the dramatic changes in production profile is monitored to varying degrees by the different alternative methods. Clearly, a continuous measurement system offers significant advantages to periodic checking.

This work has shown that the current uncertainties in well testing, typically through test separator systems, are fit for purpose in terms of measurement uncertainty they deliver for their current use for operators. However, in terms of MER they lack the ability to provide data in real time to fully optimise production. In addition, the restrictions of test separators in terms of overuse will only continue and worsen. It is clear that some kind of continuous measurement system that can offer trending of the data would be best. This will enable better response and predictability of reservoir models which are vital in optimising the production of hydrocarbons. This could include multiphase flow meters, virtual flow metering or downhole measurements. In practice, multiphase flow meters used in combination with virtual metering is probably the most viable option at present due to availability, reliability and current technology level for downhole measurement techniques. Test separator systems should not be eliminated in an ideal scenario. They would still be used for the validation of the continuous measurement techniques. In this situation the stresses of overuse would not be present and the process could be planned and equipment maintained more regularly.

There is much work that has to be completed in the area of measurement in order to maximise economic recovery in the UKCS. Guidance will likely be provided in the latest edition of the OGA Measurement Guidelines when they are made available. However, in the meantime there are important conclusions and recommendations that can be implemented to ensure the UK is optimising the revenue from its hydrocarbon reserves.

4. Conclusions and Recommendations

From the research conducted within the scope of work of this paper the following conclusions can be drawn from current well testing procedures used to acquire flow rate information:

- In order to MER within the UKCS, successful reservoir optimisation will be key. This can only be achieved through knowledge of the production rates of any well and accurate models of the reservoir performance.
- The current practice of well testing for this information using a test separator system can result in large uncertainties and potential bias. Further work is required to fully appreciate the extent of test separator measurement uncertainties i.e. audits and additional data.
- Flow measurement errors has a direct, but weak, effect on the recovery factor. Only when flow measurement data is used to select reservoir models does the effect become significant. Potentially an additional 5% in estimated recovery factor (absolute) can be seen.
- The nature of well production is dynamic, and periodic assessment (even every 30 days) is not the best option for accurate monitoring of well flows. Changes in water cut may not be picked up until the next well test resulting in inefficiencies in production i.e. wells not optimised.
- For surface or subsea flow measurements, multiphase meters offer the most robust and accurate continuous monitoring method. The use of multiphase meters on each well will enable faster responses to changes conditions within a well.
- Well bore storage issues affect all surface flow rate measurements to some degree resulting in dampened measurement results that can induce inaccuracies.
- Downhole flow rate measurements are the most valuable sources of information for MER as they provide real-time, continuous, and undampened reservoir responses. This provides the most accurate and useful data for reservoir engineers in production optimisation.

It is important to view the conclusions in terms of how they influence MER in the UKCS in terms of flow measurement:
- The current levels of flow measurement uncertainty found in industry are acceptable for their impact on economic recovery as long as reservoir models are correct.
- A periodic test of production rates is not the best option to ensure MER. Continuous measurements would be the preferred option with periodic verification of the continuous measurement.

The following recommendations are made to provide industry with flow measurements that do not hinder MER in the UKCS:
- The use of multiphase meters on wells where it is economically viable to install one (subject to well lifetime and production rates)
- Development of historical trending or history matching methods for well test data to ensure full use of the considerable data resources available
- Investigation into the current applicability of downhole flow rate measurement technologies and their reliability
- More stringent reporting requirements of well production data to the regulator

Nomenclature
<u>Symbols</u>
K	Permeability
p	Pressure
q	Flowrate
S	Bulk porosity
t	Time
ω	Storativity ratio
λ	Inter-porosity flow coefficient
ΔP	Pressure change
$\Delta P'$	Derivative of pressure change
ΔPn	Normalised pressure change
$\Delta Pn'$	Derivative of normalised pressure change
Δt	Change in time

<u>Subscript</u>
BU	Build up
i	Initial condition
DD	Drawdown

- Operators in the North Sea for providing data to complete the uncertainty analysis
- Coventry University for assessing the significance of measurement error on recovery factor and hence MER
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