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Maximising Economic Recovery – A Review of Well Test Procedures in the North Sea

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1 INTRODUCTION

1.1 General

In terms of Maximising Economic Recovery (MER) in the UKCS, the measurement of well production rates is essential to best optimise the hydrocarbon production strategy from within the well itself. This is achieved during a process called a well test where a snapshot of production is monitored by measurement equipment and instrumentation. The data produced is then used to optimise the wells production rates.

However, how accurate that measurement has to be to provide sufficient control has not been established and there is little information in the public domain that shows what the current typical operation measurement uncertainty is.

NEL have reviewed current industry practice in regard to well testing on the UKCS and have received assistance from operators in the region. The information provided was used to generate typical uncertainties found in well testing using test separator systems. These results have then been compared with results from models assessing the impact of flow measurement errors on recovery factor and hence economic recovery of hydrocarbons.

In addition, alternative methods available to complete well testing and how each of these can impact on MER have been described.

1.2 Oil and Gas Authority

The requirement for MER is clear; since the first licenses were issued for production in the North Sea, the industry has spent more than £500 billion in exploration, development and production activities [1]. There are over 450,000 people employed in the oil and gas industry in the UK and HM Treasury has received more than £310 billion in production taxes alone; not to mention the subsequent revenues generated from income tax, exports and manufacturing.

There are many impressive facts relating to the industrial and economic benefits of the offshore oil and gas industry and to continue to reap these benefits would be in the best interest of the UK. However, not only to reap the rewards, but to maximise those rewards should be a plausible and achievable goal.

In February 2014, Sir Ian Wood published the Wood Review [1], an independently led review of the UKCS's oil and gas recovery potential in the coming decades. The aim of this review was to assess the current state of operations, production and exploration in the UK and the methods of licensing and regulatory control in order to make recommendations for MER. In essence, the Review calls for a stronger and more authoritative regulator to work with both Industry and HM Treasury in a new tripartite strategy for MER within the UKCS.

The Oil and Gas Authority (OGA) was formed on 1st April 2015 with the responsibilities being transferred from the Department of Energy and Climate Change (DECC) by the Energy Bill Bill, which is currently (as of 1st October 2015) at the Committee stage in the House of Lords. The progress of the bill, and the bill itself, may be reviewed at:
http://services.parliament.uk/bills/2015-16/energy.html [2].

OGA's responsibilities include the regulation of fiscal oil & gas measurement & allocation [3]. This work is carried out by the OGA's Petroleum Measurement & Allocation Team (PMAT), which is part of OGA's Exploration & Production directorate. The role of OGA is to work with government and industry to ensure that the UK obtains the maximum economic return from its oil & gas resources.

A more in depth overview of OGA and their role within the offshore oil and gas industry can be found at:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/458593/A5_OGA_Overview.pdf [4]

1.3 Well Testing

1.3.1 What is well testing?

Well testing is extremely valuable in the oil and gas industry as it allows operators to assess the production performance of their wells to glean important information about its structure and characteristics. 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, as opposed to a static state, in order to activate the responses needed for mathematical modelling.

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.

Well tests incorporate many aspects of operations from drilling and process plant production and are performed in order to estimate 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 report 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.

1.3.2 Reservoir characterisation

Typically, 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 strange behaviour e.g. an unexpected gas-oil ratio, or an unexplained reduction in productivity.

Differing types of well testing procedure are designed to serve particular purposes, but in all cases there will be some sort of controlled constant productions (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 Figure 1.

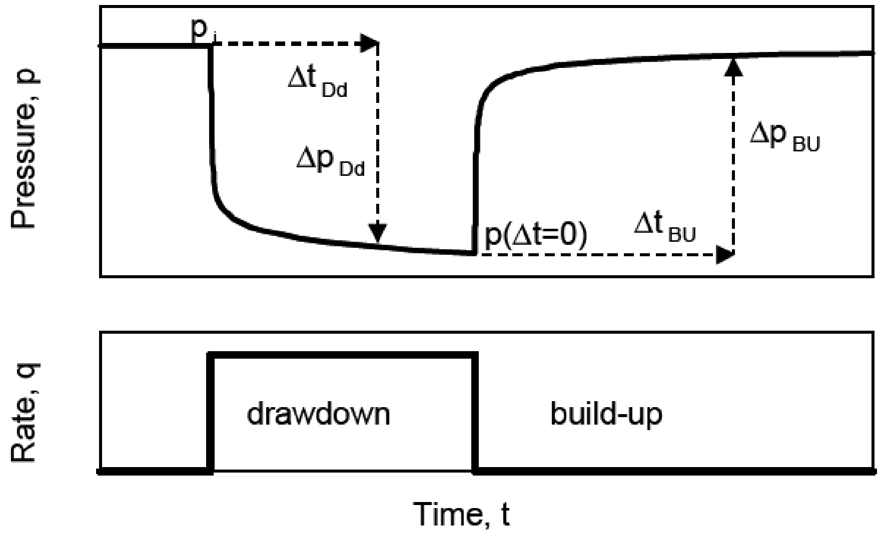


Figure 1: The concept of draw-down and build-up well tests [5]

The ultimate goal of either 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.

1.3.3 Production flowrate determination

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 Figure 2.

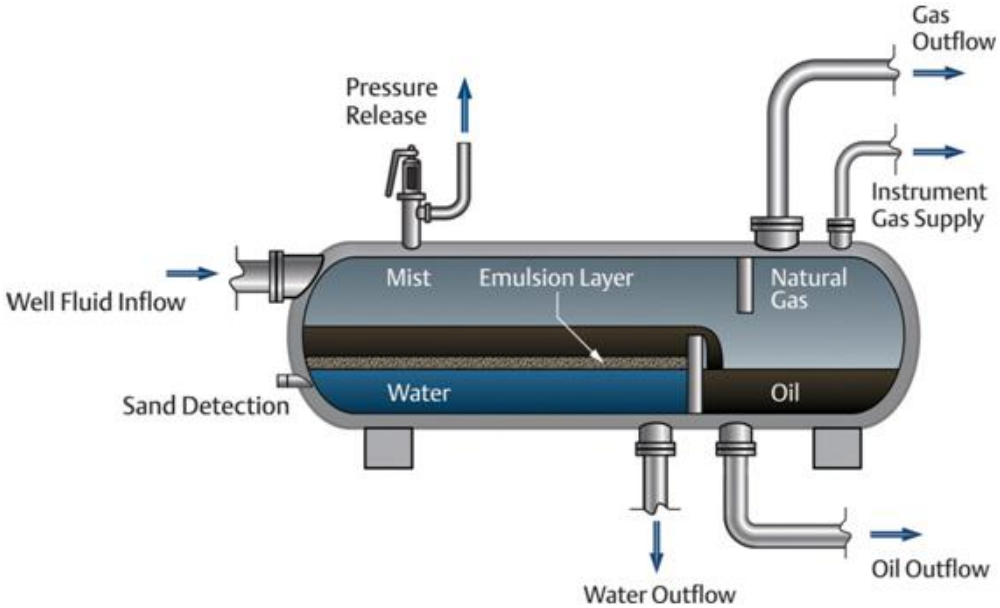


Figure 2: Three phase test separator flow measurements [6]

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 collected.

Coupling this flowrate data with reservoir parameters allows reservoir engineers to model specific wells in order to optimise its production profile i.e. get as much hydrocarbon produced versus as little water as possible.

It is intuitive that completing reservoir optimisation successfully depends on accurate data being supplied. However, how accurate the data needs to be is unknown and one of the questions the study aims to answer.

From Figure 2, it is easy to imagine process situations where measurement performance can be worsened. In addition, other practical issues may arise that result in measurement errors. Essentially, any deviation from non-ideal conditions will cause a detrimental effect on the flow measurement which leads directly to poorer data for reservoir optimisation and hence recovery factor.

There are many influences that can cause flow measurement error at the outlet of test separators. Some common concerns are [7]:

- 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 (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 are. 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 OGA measurement uncertainty strategies and the recommendations from the Wood Review.

3 REGULATION OF OFFSHORE OIL & GAS PRODUCTION

3.1 Current Guidelines

Currently, the OGA guidelines [3] do not specify a requirement for the performance of test separator measurements unless they are used for, or to verify a multiphase meter used for, allocation or fiscal measurement. However, the guidelines do recognise that it is normal and good oilfield practice to periodically test production wells for the purpose of reservoir management.

Typically, a well test frequency is in the region of 30 – 90 days and is dependent on a number of variables. When required by OGA, the frequency is decided in agreement with the regulator. This is normally based on a risk-based approach concerned with financial exposure of any produced hydrocarbons with a normal frequency close to 30 days.

If the well test frequency is not met for wells where OGA are interested, then dispensations must be obtained with appropriate reasons included.

Proof of measurement uncertainties for test separator systems may also be required to validate measured values for OGA. In fields where OGA have no interest the driver for obtaining the proof through measurement audits and calculations of uncertainties lies solely with the operator. Anecdotal evidence from OGA suggests that in these installations, the measurement uncertainties are typically larger than recommended by good oilfield practice owing to the influences suggested in section 1.3.3.

In fields where OGA has an interest, proof of measurement uncertainty should be provided either through operator’s obtaining audits from independent companies or through OGA’s own inspection team. However, the Wood Review noted that DECC (before OGA were formed) were severely understaffed and current OGA staff levels still do not permit the inspection of every test separator measurement system. This results in a dependence on operators obtaining their own verifications.

4 CURRENT WELL TEST PROCEDURES

4.1 General

In order to assess the current state of well test procedures in the North Sea a questionnaire was issued to operators to gauge typical well test frequency, success and methods. Information was also sought about the equipment used to ascertain how fit for purpose it is in regards to helping to maximise economic recovery [8].

A very low response rate was achieved predominantly due to the decrease in oil price over the consultation period. Therefore the results obtained are a snapshot of industry and unfortunately do not represent a significant sample to be applied to all. From the 32 operators contacted, responses were received from 6 and for 7 installations. Overall this has led to data from over 100 wells included in the uncertainty analysis.

4.2 Well Testing Methods

From the responses received it was clear that there are obstacles to accomplish successful well testing. It is important to point out that some of the responses were negative in terms of how companies approach well testing i.e. none or very little were completed. This was typically due to the physical set up of wells either being in satellite fields or tie-backs. This meant that wells could not be tested individually without shutting down other production wells. Clearly this would be in conflict with company financial policies especially given the time constraints to test each well and the number of wells.

Another issue was concerned with the amount of wells for an individual installation. In one case, over 100 wells were in use to varying degrees and as such it was almost impossible to accurately well test each one within a suitable time frame.

Of the submitted questionnaires where well tests were completed it was found that the vast majority reported that a 4-8 week frequency was typical and this timescale was achieved in close to 100% of wells. This timescale ties in well with expected values as prior to receiving these answers 4 weeks was believed to be industry norm.

The typical well test length was in the region of 1-3 days with variations from 1 hour up to 7 days. This accounts for set-up, attaining steady state conditions and holding for the well test duration. It is not uncommon for well tests to last up and over 70 days but these are usually only in rare circumstances. Again, the values attained were similar to what was expected from experience.

Considering an average 60 day well test campaign period and average duration to be around 2 days, it is easy to understand how installations with more than 30 wells begin to place pressure on test separator systems. It is important to note this does not include change over time or more importantly, maintenance and calibration time for the equipment.

In terms of operations it was reported that it is the operator themselves who have written the procedures, perform and analyse the data coming from well tests. Service companies were not used in this sample.

4.3 Uncertainty

In terms of the measurement uncertainty for each phase the data provided was used in generic uncertainty budgets to give estimates for typical values. The requested data included information about the single phase measurement devices and stream configurations for the test separator systems:

- Flow meter used
- Make/Model
- Meter size
- Upstream straight pipe length
- Downstream straight pipe length
- Temperature measurement
- Pressure measurement
- Calibration method
- Calibration frequency

Data was also provided for each well that the test separator is used to test. Component flow, pressure, temperature, physical properties and contamination levels were stated or estimated for use within the uncertainty model.

The generic uncertainty budgets consisted of the following sources of uncertainty with the values being determined from provided data or through previous history of the metering technologies used:

- Baseline meter uncertainty
- Calibration uncertainty
- Installation effects
- Contamination of second component
- Drift since calibration
- Temperature
- Pressure

As the supplied data was relatively low in number multiple runs were completed on the data where certain sources of uncertainty were generated randomly based on previous history. For instance, it is known that some fluids contain more impurities than others and hence cause larger amounts of drift of measurement equipment through deposition. In order to account for this, levels of drift of between 0.1% and 0.5% per annum were randomly generated and applied to the data.

The data supplied from operators included information on the metering technologies and dimensions, installation criteria, secondary instrumentation and calibration history. Then flowrate, temperature, pressure and physical property data were used in the uncertainty model of the equipment to generate estimated and representative uncertainty values for the data given. As stated before, additional runs were incorporated given random values of the uncertainty sources so as to give more data and to include extreme cases. This should give more confidence that the results obtained are representative given the low population sample.

The ranges of uncertainties found were quite varied for the wells and were different for liquids and gases. For liquids, both oil and water uncertainties were similar and were in the region of ± 1-5% where the larger numbers were associated with extreme cases of deposition and contamination of second phases. In general, the uncertainty values were between 2 and 3%.

For gases, the uncertainties were slightly higher at values between ± 2-7%. Again the larger numbers were attributed to cases under extreme conditions such as contamination and drift. In general, the uncertainty values were between 3 and 5%.

These values are for measurement uncertainty at the outlets of the test separator. When discussing the uncertainty of the flows in the well (more useful for reservoir modelling) then volume corrections, flow pulsations and other contributing factors must be included. Once they are accounted for the uncertainty can rise to over ± 10% (estimated).

The calculated numbers are similar to values expected from experience and general industry held beliefs. The uncertainty relating to certain sources are subjective and may vary from case to case. Only general rules of thumb have been applied which give an indication of expected values. In addition, other separation methods for example a two-phase system will have other contributing uncertainty factors.

The results are based on a desk-based assessment of provided data. A site audit of each facility would give better indication of the current state of the art for test separator measurement. This will allow for more accurate uncertainty budgets to be developed and give a larger sample of uncertainties to assess.

5 WELL TEST SIGNIFICANCE

5.1 General

Throughout this report the term ‘accurate measurement’ has been used to discuss the requirement for the quality of topside measurements for reservoir optimisation. However, it has also been noted that the absolute level of quality required to ensure successful optimisation remains unknown.

To investigate this problem, Coventry University completed a study relating to the uncertainties in well test measurements and their consequent impact on MER [5]. The study was a high level assessment of generic well test metering, including multiphase measurement used during a standard well test. The focus of the Coventry work lay 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.

Coventry’s scope encompassed downhole rate measurement as a necessary means of comparing and contrasting such measurement with surface techniques and, overall, the study had much to say about downhole techniques. Nevertheless, the intent of the modelling was to establish, in broad terms, the nature and strength of the link between surface well test measurement uncertainty and its importance to maximising future extraction. This section of the report summarises the work completed by Coventry and elaborates on the conclusions drawn.

Firstly, it is important to understand the process in which flowrate measurements are used in reservoir 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 can be predicted can the most optimum production pattern be obtained.

There are two parts to this prediction, the characterisation of the parameters within the well 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 provided through well tests. Traditionally, surface flow measurements have been a key component in the analysis.

Characterising well parameters and selecting the most appropriate model to use is influenced by data taken during well tests but the process involved is outside the scope of this study. This report and the conclusions from Coventry’s work do not consider this process; only the quality impact of the data on the recovery of oil and gas is considered.

5.2 Description of Work

An example reservoir was created and a series of test runs were conducted to assess the output from the example with respect to the changing input parameters. The example reservoir was based on a 100 ft vertical well within a fractured reservoir with a 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 there exact definitions can be found in various sources. 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 to generate reservoir models and the predicted reservoir 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 phase at a constant flow of 9200 STB/D with a duration of 158 hours. Then the well is then 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 fluids for 20 years allowing for a direct comparison of overall production rates i.e. how much total hydrocarbon was recoverable over the timeframe compared with values obtained during other test runs. This then allows 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.

5.3 Results

Consider the comparative cases of well tests where the flow rate measurements are taken at the surface and downhole respectively (test run 1 and 2). During the drawdown and build-up phases the measured flow rates would be as shown in Figure 3.

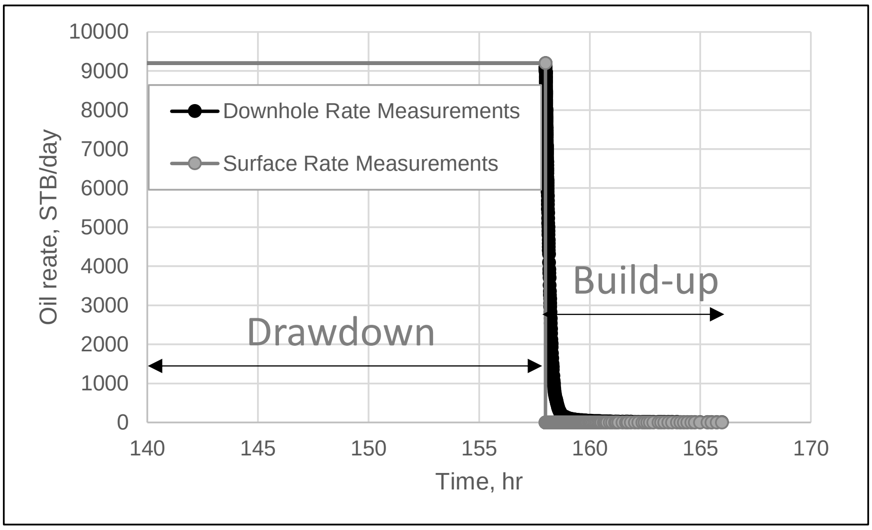
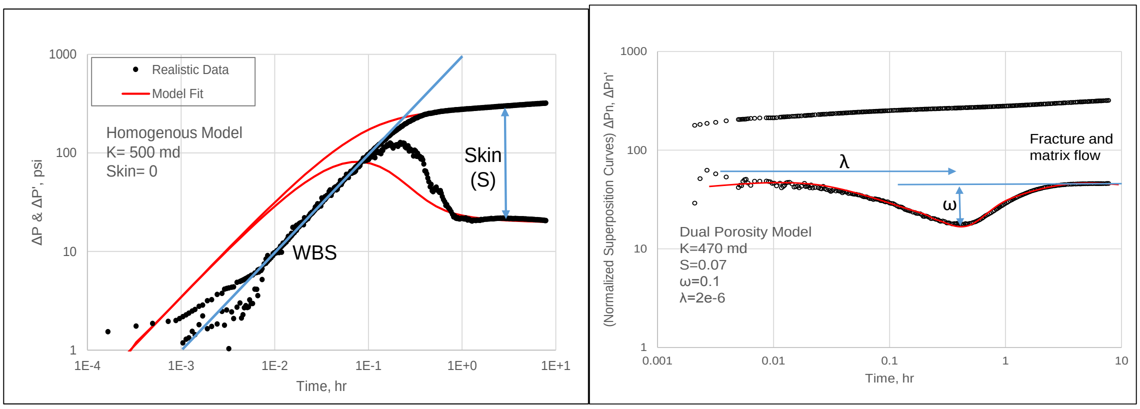


Figure 3: Flow rate measurement location during well test

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 measurement downhole, 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 Figures 4 and 5.



a) **b)**

Figure 4: Well test diagnostics plot for test run 1 (a) and 2 (b)

Figures 4a) and b) show the well test 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.

Figures 4a) and b) are describing the same reservoir but it is clear that Figure 4b) conforms to a model better than Figure 4a). This results in lower modelling uncertainties and better prediction capabilities suggesting that for MER, surface flow rate measurements are not the best method of measurement available.

Figure 4a) denotes an area as Well Bore 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 apparent in Figure 4a) and is one of the key reasons, the recorded data is more scattered and does not fit the suggested model well. Again, it is important to point out the data itself is used to help choose the 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.

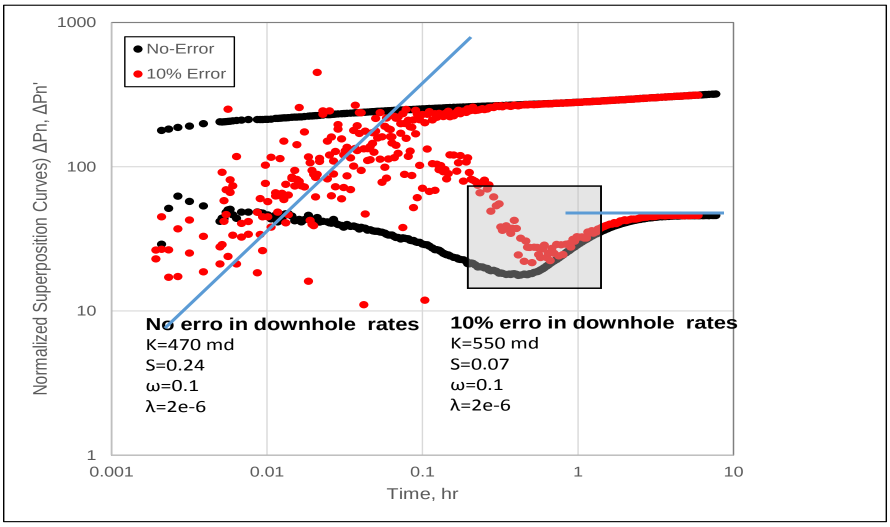


Figure 5: Well test diagnostic plot for test run 2 and 4

For test runs 3 and 4 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 10% reservoir parameter estimation error (Figure 5). The location of the flow rate measurements did not impact this relationship. This error is different from the error introduced through whether or not flow after shut-in is utilised in the estimation.

However, these parameter errors were not found to be very significant on recovery factor. Even with large errors present in the reservoir parameters, this does not impact linearly with how much hydrocarbon is produced from the well by itself. As an extreme case, when the flow rate error is ± 50% under the conditions in the example reservoir, the recovery factor after 20 years was found to have 3% error only. Essentially, for every 1% error in flow rate measurement there is an error in recovery factor of 0.06%.

As discussed earlier there are two parts in reservoir prediction in order 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 from the data and for test runs 2 and 4 a dual medium model was selected. Dual medium denotes a reservoir fracture was detected whereas single medium denoted no fracture.

Figure 6 shows the effect on recovery factor after 20 years using the each model and reservoir parameter estimations.

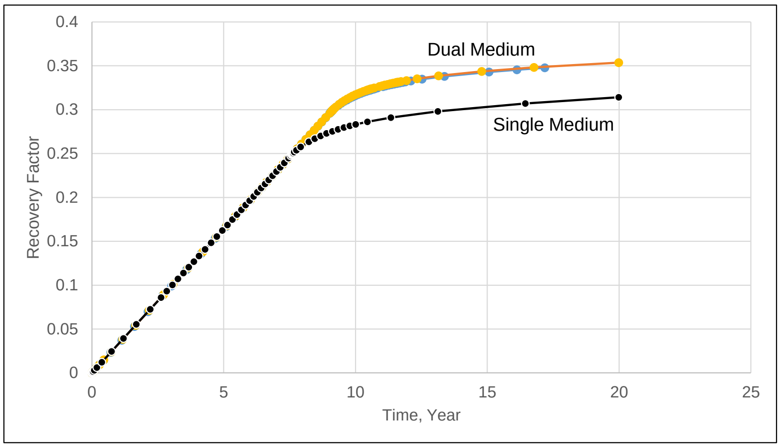


Figure 6: Recovery factor after 20 years

The results show that the model uncertainty has higher impact on the final recovery. Using a single medium model the reduction in the recovery factor is around 12% compared with the dual medium model. Potentially this could be a huge number in terms of financial calculations. To give an idea that how much this would be consider that the initial oil in place for the example reservoir is around $3.78{\times}10^7$ barrels of oil. Incorrect flow rate measurement data either from errors or from location factors can result in around 5% decrease in producing the original oil in place. Or at \$60 per barrel, this is equivalent to £75 million for this example.

In this study Coventry have 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 and only include the “direct” impact of flow rate uncertainty on the recovery factor 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 considered. In practice there are “indirect” uncertainties induced from inaccurate rate measurements. Such uncertainties could result in making incorrect or sub-optimal decisions for reservoir developments that can ultimately impact the secondary or enhanced oil recovery plans. Assessment of the impact of such uncertainties in general cases is difficult, as each reservoir requires its own considerations and different policies than the other reservoirs.

It is important to rationalise the study completed by Coventry 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) to MER in the UKCS.

For the test runs including 10% error, the results consider the error introduced to the permeability estimation only. Coventry recommended further work to determine the whole effect of all reservoir parameters on recovery factor.

5.4 Summary

The results obtained in the work completed by Coventry show relatively small effects of surface flow rate measurement errors on recovery factor (considering reservoir parameter estimations only). However, production optimisation 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 of 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 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. Depending on where a new well is drilled may influence how much hydrocarbon can be produced or the effectiveness of any injections for 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 quickly and in real-time determine if water breakthrough is occurring is extremely valuable in MER.

It is clear from the completed 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 affects 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 flow measurement is vitally 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.

Coventry University 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 from Coventry is the use of multiphase meters instead of test separator systems for surface flow rate determination. Primarily, for the reason they are able to record and trend data continuously resulting in an improvement in data quality and confidence of estimated reservoir parameters.

6 ALTERNATIVE METHODS AVAILABLE

6.1 General

The need of well testing for maximising oil and gas production and economic recovery, formulating fiscal policy and attracting investment have been evident for years. In conjunction with conventional well testing technologies, a number of alternative methods have been developed to aid such operations since the early eighties by research organisations, meter manufacturers, oil and gas production companies and others. A combination of technologies has emerged, albeit their prototypes were quite dissimilar in functions and designs. These technologies have become commercially available and their applications and users are rapidly expanding.

Well testing for production analysis [9] involves measuring the contribution of oil/water/gas from individual wells. Indeed, the knowledge and data obtained from well testing are then utilised to facilitate reservoir management, field development, operational control, flow assurance, production and fiscal measurements.

In this study, three popular alternative methods are chosen to be reviewed. These are:

- virtual flow metering
- multiphase flow metering
- mobile well testing.

Virtual flowmeters (VFMs) are calculation based software suites that incorporate existing measurements instruments to create estimation of flow in real-time at any point in the process; with or without flow measurement technology being available. Multiphase flowmeters (MPFMs) are physical measurements systems installed inline that measure the component flows of oil, water and gas in real-time. Finally, mobile well testing (MWT) is where portable separator systems, often combined with two or three phase measurements, are installed for short periods before being removed. The following section will discuss these three popular methods for the use in MER.

6.2 Virtual Flow Metering

Although there are differences among VFM technologies, there is no attempt to undertake a product-by-product comparison in this review. The perceived advantages and disadvantages of VFMs are generalised and summarised in Table 1.

TABLE 1

Advantages and Disadvantages of VFMs

Advantages	Disadvantages
Provision of real-time continuous monitoring of reservoir characterisation, well optimization & economic recovery.	Not suitable for responding transient pressure due to rapid inflow. Detailed knowledge is required to set up VFMs.
Cheaper than multiphase flow meters & mobile well testing facilities.	Installation effects could affect the accuracy of flow rate calculation.
Useful for visualisation of component phases and flow assurance risks [10].	Accuracy of component phases are required to be predicted based on pressure and temperature measured in and around the wells. Output flow rate uncertainties are unavailable.
Capable of recalibration if required.	Regular verification is required to be undertaken using real time measurements to ensure accuracy & representativeness of flow rates predicted
Elimination of maintenance requirements, such as corrosion, sand plugging with wax, methyl hydrates etc.	Corrosion, sand plugging with wax and methyl hydrates would potentially affect the accuracy of VFMs.
Cost effective and efficient for monitoring a number of wells simultaneously as opposed to a physical well testing.	Less efficient and accurate if meter fouling were not identified in and round the well.
Elimination of operational risks, such as fluid surges, leakages, formation of hydrates, etc.	Operational risks are simply transferred to service providers who have to carry out maintenance work.
Reliable and has good fault tolerance	Less reliable if failed hard temperature and pressure sensors were lack of regular calibrations.
Useful for validation of well test, reconciliation for and replacement of flow meters [11].	VFMs consistently either over- or under-predict as the choke size increased (i.e. increase of flow rate). Some programs can freeze and crash and significant time may be spend opening, closing and switching between analyses and post-processing the data.
Useful for tracking liquid slugs, MEG, pigs, identification of hydrates, control of chokes, monitoring for erosion, corrosion, wax or leaks.	The drop in differential pressure also increases the uncertainty of the flow rate through the choke.
Useful for looking ahead and for performing what if scenarios and uncertainty analysis.	The risk of bias or error in the flow rate estimations increase, if the VFMs were operating outside the trained range.

VFMs are capable of reliably determining the well flow rate, if and only if the pressure, temperature and other physical sensors were periodically calibrated and VFM flow rates against calibrated and accurate multiphase flow meters were verified [12]. Preferably, uncertainty performance of the various system components, e.g. downhole and subsea pressure and temperature sensors, subsea or topside multiphase meters, a length of tieback pipeline, a topside choke valve, separator with single-phase flow and water cut meters, are regularly carried out for calibrating and verifying VFMs. At present, uncertainty ranges of VFMs are rarely known and are not widely published. Critical and independent evaluation of the performance and accuracy of VFMs for subsea well tests are virtually unavailable in the public domain. Nonetheless, it was reported that VFMs could deviate from the multiphase flow measurements by a range of 10% to 20%.

Even when accuracy is not considered sufficient, VFMs still offer valuable information from their repeatability. Comparison and trending of the VFM result with other technologies, such as MPFMs, can indicate when they require verification. In this sense they can qualitatively check primary measurements for reproducibility and act as a redundancy.

6.3 Multiphase Flow Metering

Before 1980s, single phase measurements alone were sufficient to satisfy the needs of oil and gas industry. The maturity of oil reserves together with smaller and deeper wells with higher water contents saw the needs of multiphase flow meters (MPFMs). Since 1994, the installation of MPFMs has steadily increased, with substantial growth from 1999 onwards. A recent study suggested that there were approximately 2,700 MPFM applications covering production optimisation, field allocation and mobile well testing.

Initially, the purpose of MPFMs was to analyse the increasing amounts of water and natural gas that were producing in a greater part of fluid from some North Sea wells. However, oil wells have a mixture of oil, natural gas, water and other chemical compounds. Ultimately, the multiphase flow metering is defined as the utilisation of MPFMs, which are devices used to measure the individual flow rates of constituent phases in a given flow of petroleum, gas and water mixtures produced during oil production and well testing processes [13].

The initial interest in multiphase flow metering came from the offshore industry. In fact, the North Sea oil field played a pivotal role in the development of MPFMs. The key factors which have instigated the speedy uptake of multiphase flow metering technology are identified as follows:

- increases in oil prices
- decreases in meter costs
- improved meter performances
- wider competition amongst operators
- deployment of more compact meters for mobile systems.

Prior to the development of MPFMs, the only way to determine the fluid mixture was to physically separate the fluids and to individually measure each phase. The main advantage of state-of-the-art MPFMs is the elimination of the use of three-phase separators. The flow rates and composition of the fluid from the well can be determined by MPFMs without using a test separator. Consequently, this offers a substantial economic and operating advantages over conventional phase separating predecessors.

MPFMs provide important information and data about the fluid compositions in the well. They also provide indications over the increase in the percentage of water coming out of a well and the decline of oil production. MPFMs give a faster response time than their test separator counterparts, because they log and analyse data in real time. MPFMs [14] are more useful for allocation metering where produced fluids from different wells need to be combined and sent to a processing station.

The main disadvantage of MPFMs, however, is their high capital and operating costs involved. In particular, there are currently no single MPFM on the market meeting all multiphase metering requirements. Other disadvantages include contaminations, sand erosions, blockages and difficulty of calibration. All of these impose a higher level of measurement uncertainties to MPFMs [15].

Table 2 generalises the advantages and disadvantages of MPFMs identified from literatures.

TABLE 2

Advantages and Disadvantages of MPFMs

Advantages	Disadvantages
Elimination of test separators	High capital, maintenance and software costs
No requirements of regular intervention of test separator by qualified personnel	High measurement accuracy requires more intense radiation sources, which affect safety aspects and mobility considerations.
Continuous well monitoring possible. This is not practical using a test separator	The phase fractions will only be representative over a cross section if the phases are homogeneously mixed
No requirements of long period of steady operation to achieve accurate measurements. Information is available to the users in a minutes after starting the operation	Contaminations, sand erosions, blockages and difficulty of calibration.
Ability to track, in real time, any changes in fluid composition, flow rates, pressure and temperature.	Intrusive
Ability to respond quickly to changes in fluid composition and the reduced time to stabilize flow	High measurement accuracy requires more intense radiation sources, which affects H&S and mobility considerations
No moving parts	Static holes for pressure measurement may be blocked by contaminants, sand and etc.

MPFMs vary in uncertainty estimates from manufacturer to manufacturer. The aim of this review is not to compare the different MPFM models with each other but MPFMs collectively with other well production monitoring techniques.

Device performance is commonly split into the operating ranges it can measure within its stated specifications. Some devices can handle higher gas volume fractions or water cuts than others and this is based on the technology used in the measurement.

Typical ranges of uncertainties for components measured by MPFMs are 2-10% for liquids (lower gas volume fractions allow for lower uncertainties) and 4-10% for gases [16]. Again, the quantity of gas present has a large impact on uncertainty achieved.

6.4 Mobile Well Testing

In contrast with permanent flow-line well testing installations, which facilitate continuous production measurements, mobile well testing (MWT) is a discrete testing approach. Mobile, also known as portable, well testing units are fully portable production facilities and are capable of both well test and clean-up operations. Typically, for offshore testing, MWTs consist of partial separation units with two or three phase meters on the outlets. They take a significantly less footprint than full separation systems and can be transferred between installations after a well testing campaign is complete. Other models are smaller again, acting like MPFMs with some capable of non-intrusive operation.

Table 3 briefly generalises the common benefits and drawbacks of MWTs, as most MWTs are MPFMs which have been detailed in the last Section of this review.

TABLE 3

Advantages and Disadvantages of MWT Technologies

Technology	Advantages	Disadvantages
Separator, MPFMs	Portable / mobile	Process fluids may need conditioning for optimum separation
	Accessible to harsh arctic operating conditions	Separation may be inefficient due to liquid slugging or foaming
	Complete package of well testing and clean-up solutions	Complication and risk due to operations and logistical needs of heavy and bulky equipment to the well site
	Data to desk facilitated	Size, cost and time constraints due to limited numbers of well tests to be performed at one time.
	-	Flow data is dependent on well test frequency
	-	Impractical operations for running multiple test packages throughout the field.
	-	Intrusive
Radioactive MPFMs	-	Risk of H&S due to exposure to gamma rays.
Clamp-on Sonar flow meter	Small-footprint to reduce the amount of equipment or disruption on process operations	Working accuracy is within ± 10%, which is less accurate as opposed to MPFMs.
	Achieve periodic sampling of	-

	fluids at line conditions	
	Non-intrusive	-
Radioactive-free MPFMs	Eliminate risk of H&S	-

The uncertainties of multiphase flow measurements by means of test separators have been described in Section 4 of this review, while the major uncertainties of MPFMs are generalised in Section 6.3.

6.5 Impact on Maximising Economic Recovery

These alternative methods of well testing can provide very real substitutes to test separator systems in one way or another. Each has their advantages and disadvantages as discussed in the preceding section. As an impact to MER, there are varying levels of influence from the alternative methods that must be discussed.

The main constraints on test separator systems are over use and intermittent data being used between well test periods i.e. lack of real-time data. It is these two issues where these alternative methods can provide significant advantages over test separator systems.

VFMs cannot replace measurement systems entirely. At best they can be used to reduce the burden on other measurement systems by extending times between well tests. This is accomplished through real-time monitoring of production rates from the software. Once the software has been calibrated it can determine flows that can be used to optimise production. However, the software can drift from the ideal response and needs to verified or even recalibrated periodically. The frequency of this is likely to be lower than what would be required acquiring well data from a periodic well test alone. This enables better economic recovery through continual monitoring of flow rates and a faster response time.

Multiphase flowmeters can vastly impact on MER through continual measurement and faster response times. When installed either subsea or topside in a multi-well capacity there is very little stabilisation time required in comparison to test separator systems. This means a larger number of wells can be tested or longer well tests can be obtained. If operating in a single-well capacity, then real-time and continual measurements can be given. In either regard a multiphase meter can be a viable alternative to test separator systems if verification can be established through another means; potentially another multiphase meter, mobile well testing equipment or even using the test separator itself.

It is the continuous measurement criteria where multiphase meters can offer a significant advantage to test separator systems. Real time data vastly improves the ability to control wells. The uncertainties associated with multiphase meters are comparable with test separator systems too. Although larger, any influence on recovery factor should be minimised through the larger amount of data that will be provided through continuous measurement.

Incorporating MPFMs into individual wells can only improve well optimisation and impact positively on MER. The cost of MPFMs can be weighed against the perceived advantage in MER it provides. It is likely this will be a case by case basis.

7 DISCUSSION

The impact of flow measurement on MER will be significant on the UK economy and 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 best 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 a wells production is not enough to ensure the production is kept optimized 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 days. This may have a detrimental effect on the whole reservoir. But how much of an effect does mis-measurement have on the UK economy?

According to the 2013 FT, 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. The UK has one of the largest budget deficits among European countries at 5.8% of GDP [17]. 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 OBR's most recent long term forecasts, the oil and gas production from 2014 to 2044 inclusive is expected to be 9.1 billion barrels of oil equivalent (boe) in a central case, 7.7 billion boe in a low case and 10.7 billion boe in the high case, Figure 7 [18].

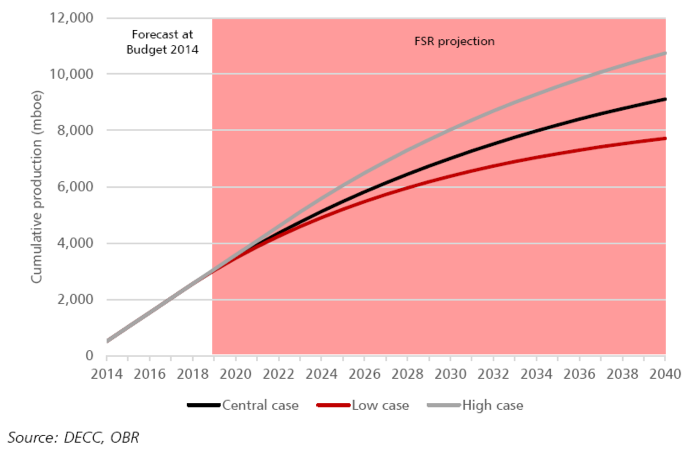


Figure 7: OBR Scenarios for Future Production, 2014 Onwards

As can be seen, there would be a significant different of 3 billion boe between a low production and high production future, 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 [1].

In order to achieve the recovery of 15 to 16.5 billion boe, 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 (Figure 8) and financial performance in terms of net present value, internal rate of return, profitability index, saving index and so on [19].

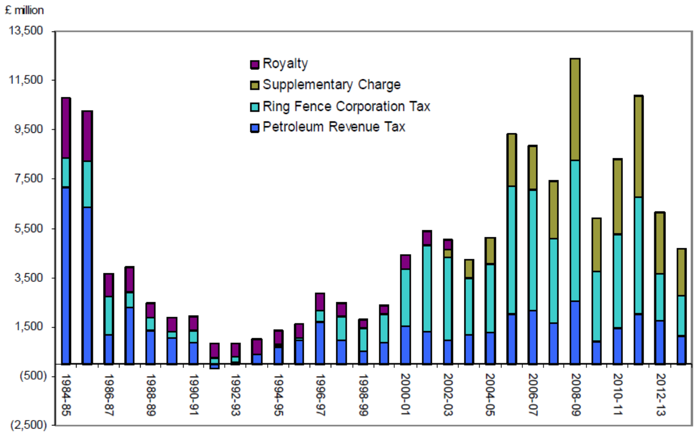


Figure 8: Government Revenues from UK Oil and Gas Production [20]

In its 2014 budget, the UK government announced a review of the fiscal regime to ensure that it supports MER UK [21]. 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 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 (Figure 9), as well as the uptake of improved and enhanced oil recovery techniques and technologies as a whole.

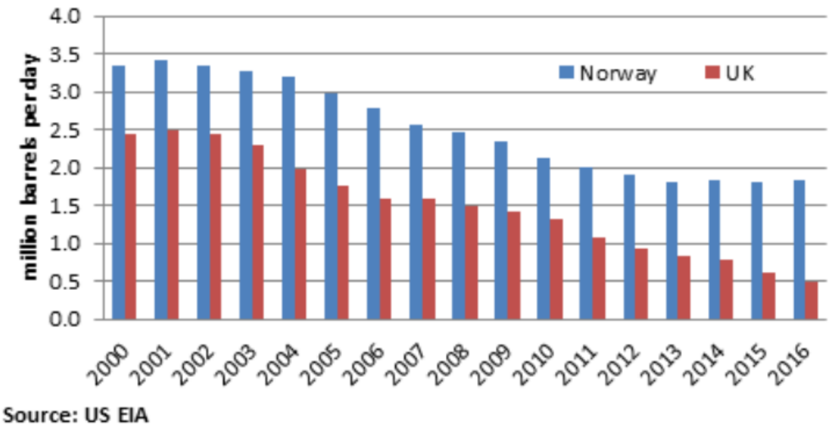


Figure 9: North Sea Oil Production [22]

The US Energy Information Agency (EIA) 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, has been broadly stable since 2012 because of effective government policies intended to support the industry [23]. With the recommendations from the Wood Review being actively pursued by the UK, 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 [24] 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 evidences 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 decision making are essentially based on a set of real time and accurate & representative data. In the nut shell, to economically achieve best possible hydrocarbon recovery from reservoirs, real time field and well test data for decision making are undoubtedly indispensable.

Figure 10 reviews the variation of flow patterns that can be captured by three alternative well testing methods during reservoir depletion.

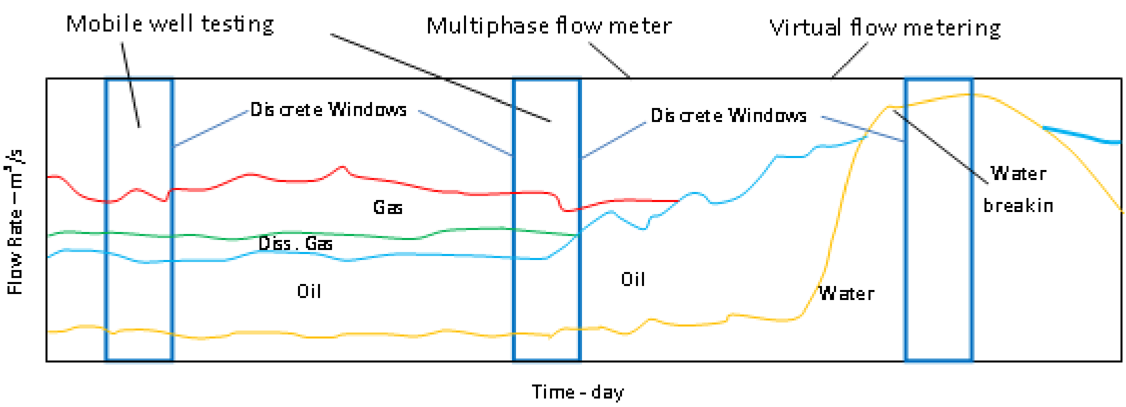


Figure 10: Flow Rates Plots of Well Testing Data

Table 4 summarises the three alternative methods available for well testing based on their real time capability.

TABLE 4

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 from previous Sections 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 would be hardly 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 are lacking real-time continuity. To economically maximise hydrocarbon recovery, each flow parameter captured must be verified against its consistency in real time continuity. As such, the usual "garbage in, garbage out" approach can be avoided.

MPFMs allow both real time and continual flow measurements and have been subjected to extensive and robust verifications [25]. Technically speaking, MPFMs would probably be the best alternative option for well tests because MPFMs 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 MPFMs measurements.

In terms of errors in measurement or measurement uncertainty it was found that there is a very weak link to recovery factor or MER. Instead, the biggest contributor to the recovery factor from measurement is when the well test data is used to select a reservoir model. This means that the estimated uncertainties found in this work 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 to complete further work in this area.

The errors introduced from periodic testing of a well can clearly be seen in Figure 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 UK 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 flowmetering or downhole measurements. Practically, 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 clearly 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.

8 CONCLUSIONS

From the research conducted within the scope of work of this project 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

- Recovery factor is weakly affected by flow measurement errors directly. Only when flow measurement data is used to select reservoir models does the effect become significant. Potentially an additional 5% in recovery factor (absolute) can be achieved

- The nature of well production is dynamic, periodic assessment (even every 30 days) is not acceptable for accurate monitoring of well flows. Changes in water cut may not be picked up till 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

The above conclusions state the findings from the work from the scope of work items. However, it is important to view these 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 acceptable to ensure MER. Continuous measurements would be the preferred option with periodic verification of the continuous measurement

9 RECOMMENDATIONS

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

- The current assessment of well test uncertainties be expanded to the point where it is statistically representative. This will include sourcing additional production and process data as well as audit reports

- More stringent reporting requirements of well production data to the regulator

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