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Well-Test Optimization and Automation

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Abstract

Much can be done to improve the Well Testing through effective use of minimal electronic instrumentation on the well head and the test separator. The purpose of this paper is to describe Shell tools and experiences using the resulting real time data to enable well test optimization and automation.

1.0 Introduction

The purpose of well testing is to periodically determine oil, gas and water flows for accounting, reporting and surveillance purposes. Hydrocarbon allocation provides official reports of well and reservoir production for lease owners, petroleum revenue tax purposes and management reports as well as feeding into hydrocarbon reserve figures and reservoir simulations which are used for major field decisions e.g. where to drill the next out-step well. Surveillance is key to determining well and reservoir behaviour and ensuring optimal well productivity and integrity.

Routine well testing is an established procedure. Wells are for the most part manually diverted to a gravity separator or multi-phase meter and oil, water and gas phases are measured discreetly. Tests are periodically conducted, for example once a month, or once a week. The duration of purge and test periods are usually fixed, for example 30 minutes to purge the test separator and eight hours to test the well.

The manual well testing process is subject to error and uncertainty – the wrong well may be put on test, the wrong instrumentation may be used, the instrumentation range may be incorrect and instrumentation may be dysfunctional.

After the well test is complete the final result may be good, bad or suspect, hence results are usually subject to a manual validation process.

This begs a number of questions related to well test optimization and automation:

- When should the well be re-tested? Some wells are tested too often, some wells are not tested enough. What is the optimum?
- What are the minimum purge and test times for a given well at a given point-in-time?
- What can be done to ensure that the quality of the test result is adequate?
- What performance indicators can be put in-place to maximize test quality?
- What can be done to automate the entire well test process from determining which well needs to be tested, automatically putting that well on test, minimizing durations, automatically validating the test result and electronically sending the result to recipient systems and then selecting the next well to test?

The purpose of this paper is to discuss Shell E&P experiences and real time software applications relating to the above well test optimization and automation issues.

2.0 Requisite real time data infrastructure

The challenge is to use minimal electronic instrumentation that gives maximum benefit. Instrumentation is expensive, especially offshore and in remote locations. Instrumentation also needs to be maintained and it is prudent to minimize this chore by reducing the number of instruments. Commodity instrumentation available in bulk from multiple vendors should be used to leverage costs down and to ensure support and spare part availability.

For well test optimization, at least one instrument should be installed on each well e.g. tubing head pressure. The test separator should be fitted with minimal instrumentation allowing derivation of oil, water and gas flows.

Telemetry systems are required to transmit real time signals from the remote locations back to the local/remote operations control room and/or head office. These systems usually are a combination of Remote Terminal Units (RTU), a Supervisory Control and Data Acquisition System (SCADA), a Distributed Control System (DCS) and data Historians. Where RTU is a device that digitizes analogue instrumentation signals and transmits as radio, twisted pair or fiber-optic signals to a remote computer hosting a SCADA or DCS system. The SCADA system solicits real time data from the RTU and presents graphics, alarms, trends, reports on desk top displays. The Historian provides long-term real time data storage and display capability. The SCADA, DCS, or Historian systems host well test and well surveillance application software to process the raw well and test separator data. The telemetry systems may be interfaced to hydrocarbon allocation systemsor well / reservoir models to electronically transfer the associated real time data. For example at the end of a test the well test application can electronically pass the processed result to the hydrocarbon accounting system for validation. The hydrocarbon accounting system can then electronically pass the validated well test to the reservoir simulator.

3.0 Well Test Problems, Issues and Opportunities

3.1 Well test frequency

Ideally wells would be tested continuously. However, in most cases this would involve installing a test separator or multiphase meter on each well. This is not economically or practically feasible as test separators are expensive and multiphase flow meters are specialized instruments that are expensive to buy and maintain. Hence, in most cases a test separator (or multiphase meter) is shared between a number of wells and wells are tested periodically.

The question is what is the required well test periodicity? Common sense would indicate that wells be tested by exception. That is wells should only be tested when they change significantly. Problem is how do you know that the well flow patterns have changed? In lieu of change information most operators have a periodicity “rule of thumb” like test once a week, or once a month and in many oil/gas provinces regulatory authorities stipulate required test periodicity.

However, techniques are becoming available that allow continuous estimation of well flows for surveillance and accounting purposes, using low cost commodity instrumentation. The flow estimate can then be used to determine if the well has changed sufficiently to merit a well test – two of these well flow estimation techniques are described in sections 4.1.1 and 4.1.2 below.

3.2 Well test and purge duration

When the well is initially diverted to the test separator it can take some time for the test flow measurements to stabilize – this time duration is known as the “purge-period”. Also it is necessary to flush-out the test line and test separator fluids from the previous test. Operators have rules of thumb for the purge-period duration e.g. 30 minutes. However, physical location and proximity of the Test Separator to the well head can have a profound effect on the required stabilization time. For example a sub-sea well producing to remote platform via a long test line can take much longer to stabilize.

Once test measurement stability has been achieved well test measurement can start, but what should be the duration of the test-period? Again operators have rules of thumb like 8 hours, 12 hours, 24 hours etc. However more scientific techniques to determine test and purge periods are emerging and are described in section 4.2 below.

3.3 Well Test Quality

The manual well test process can be fraught with errors. A primary source of error is the instrumentation used to measure oil, gas and water flows. The instrumentation may be inadequately calibrated. The instrumentation may be inadequately ranged – this problem is aggravated by the range of well production rates – very small and very large wells may need to be tested by the same separator. The instrumentation may be inadequately maintained.

The well test process is also subject to manual errors – operators may put the wrong well on test, may use the wrong instrumentation (e.g. orifice plate), may select the wrong instrument range (e.g. DP cell) or may make the wrong correction when converting from test conditions to normal operating conditions or standard conditions.
Methods are becoming available to help with early detection of well test problems – these are discussed in section 4.3 below.

3.4 Well Test Key Performance Indicators (KPI's)

KPI's have two main purposes:
- Short-term - to flag well test performance problems in sufficient time to enable immediate correction
- Long-term – to detect systematic trends in well test performance

3.4.1 Short-term KPI's

The best time to spot test performance deviations from the norm is when the operator is still at the test location so he can conveniently make corrections. For example the operator may put the wrong well on test, this is especially true for large fields with numerous test separators where it is more difficult to spot errors in time to allow correction because of the shear number of wells and amount of activity. What is required is a KPI that can be used to raise an alert such that the local operator can be informed to make the required corrections – refer to section 4.3 below.

3.4.2 Long-term KPI's

KPI's may be used to determine long-term well test performance. One such KPI is the well test rejection rate where the well test result is totally unsatisfactory and the test has to be repeated. Another KPI is well test partial failure rate where the test is conducted and some useful information is not obtained e.g. oil, water rates obtained, but not gas.

3.5 Well Test Automation

The well test process is amenable to automation. Valve actuators (or rotary valves) can be automatically and/or remotely actuated to pulse wells on and off test. The well is then purged, then tested and after the test duration timer has timed-out the valves are automatically/remotely actuated and another well is then put on test. A proscribed well test schedule can determine which well should be put on test next. However circumstances may change e.g. wells may quit, wells may be under maintenance raising the question which is the best well to test next? Well test automatic scheduling is described in section 4.4 below

Another aspect is automatic test validation. Operators with lots of wells may spend much time manually validating test results deciding if the test result is fit for purpose. Tools are becoming available to flag the sub-set of well tests that require manual inspection allowing non-suspect tests to proceed without manual validation. Section 4.4 below more fully explores well test automation tools.

4.0 Well Test Results, Software Applications and Experiences

4.1 Well Test Frequency – test wells when they need to be tested

Two methods are available. In both of these methods commodity well head real time instrumentation signals are calibrated against well test results to produce models. The models are then used along with the real time well head signals to derive continuous estimation of fluid flow rates. Significant change in the estimated well flow rates indicates the need to re-test the well.

4.1.1 FieldWare* FlowMonitor – continuous estimation of well liquid flow

Uses the signal from a commodity DP cell on the well flow line to give a continuous estimate of well liquid flow. The average DP cell value over the well test is calibrated against the latest and most accurate test result and an online mathematical model is used to continuously derive a measure of the well liquid flow – analogous to a continuous liquid phase well test.

The DP signal is acquired by a DCS, SCADA or Historian system. The DP signal is conditioned by the mathematical model also running in one of the aforementioned systems and the derived well liquid flow is shown on user desktops in trends, displays and reports. The real time modeling tool is known as FieldWare FlowMonitor.

The derived liquid flow can be used to gauge if the well flow has changed significantly indicating that a well test is needed. Experience indicates that some wells are highly stable and decline slowly, hence do not need to be tested very often (unless regulatory authorities stipulate otherwise). Other wells can be very unstable and need to be tested more often than normal.

Continuous estimate of well liquid flow also indicates well stops and when production is less than normal, facilitating:
- improved well surveillance and corresponding production increases
- improved hydrocarbon accounting due to more accurate timing of well stops/starts/low production and more accurate allocation
- improved reservoir simulation due to more accurate timing of well stops/starts/low production and more accurate allocation
- improved reserves estimates due to more accurate timing of well stops/starts/low production and more accurate allocation

The following graphic shows real time trends of liquid flow for the same well at the same time obtained by two different methods – from the test separator instrumentation (red plot) and from FlowMonitor (blue plot). As can be seen (and as expected) fluctuations in liquid flow by both methods give similar results. The only exception is when the well was intentionally closed-in (see below). FlowMonitor correctly depicted the closure by proceeding to zero. The well test instrumentation initially declined as expected, but then zoomed to a very high value. The reason for the erroneously high values was that the test manifold valves were leaking allowing fluids to escape through closed valves to the test separator compounded by separator level control problems. Note, FlowMonitor measures upstream of the manifold and hence is not affected by valve leakage. Also, when the well's gas-lift gas was closed-in the well flow declined as depicted by the test result (until valve leakage effect kicked-in) and by FlowMonitor. FlowMonitor depicted the continued well flow rate decline and as expected for this well some natural production flow without the aid of gaslift gas. The main conclusion from the graphic is that FlowMonitor realistically depicts well liquid flow changes sufficiently to judge if the well has changed sufficiently to merit re-testing.

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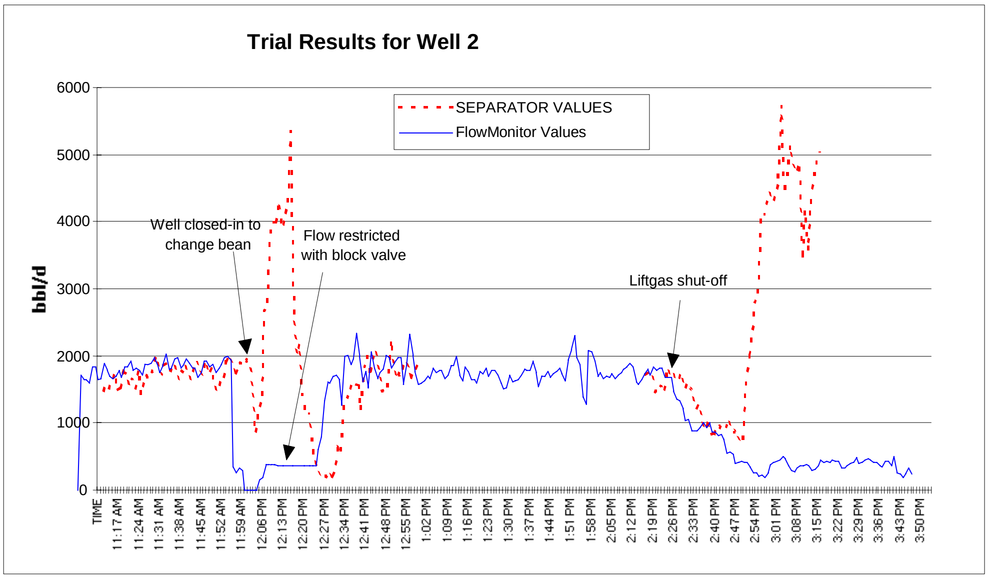
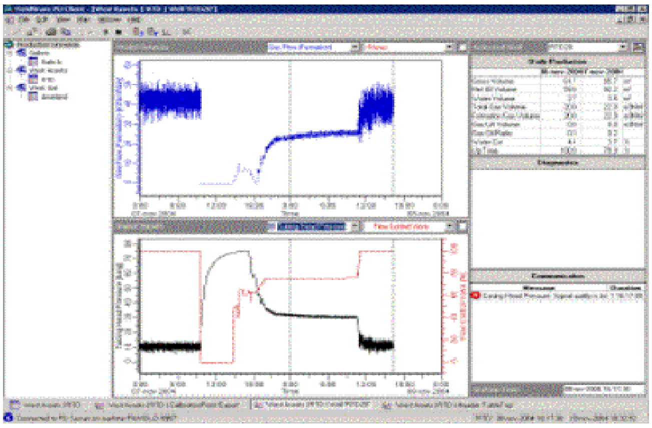


4.1.2 FieldWare Production Universe – continuous estimation of well oil, gas and water flows

FieldWare Production Universe uses real time, data-driven models derived from deliberately disturbed wells tests. Real time estimates of well oil, water and gas flows are then estimated from three-phase bulk flow measurements reconciled with commodity pressure or temperature measurements from the wells – analogous to continuous three phase well test for each well. This further extends benefits obtained from FlowMonitor, with real time estimates of water and gas, as well as oil flows, which can be used to determine if well performance change is significant enough to merit re-testing the well.The sum of the estimated well rates is continuously reconciled with the bulk separator or export meter rates as a quality check. PU has demonstrated significant production gains mainly due to improved surveillance. FieldWare Production Universe is being used by six Shell Operating Units and is being installed on all key assets.

Production Universe also uses the data driven model to check that electronic instrumentation associated with the model is properly ranged and calibrated and flags malfunctions to those that need to know.

The following graphic shows a typical PU well screen shot. The upper portion of the screen plots the well PU estimated stream flow and the lower the associated well parameters. The upper right section of the stream displays the current daily cumulative flow and flow outages. The models are allowed limited extrapolation. Where extrapolation takes place the flow is recorded with a broken line.



4.2 FieldWare WellTest

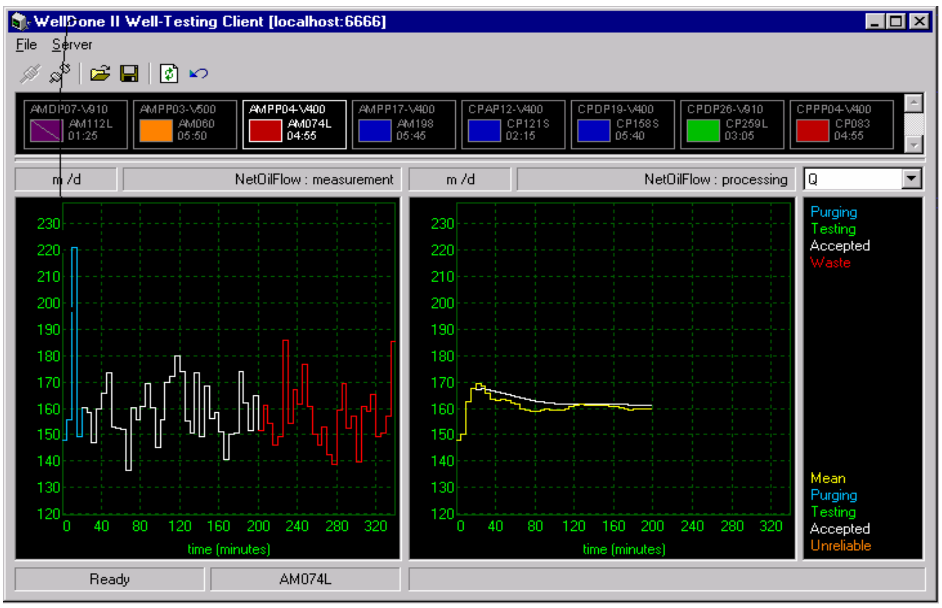
FieldWare WellTest is a real time application that is designed to schedule, administer, monitor, control, report and optimize the entire well test process for all well and test separator types and associated instrumentation types in Shell's global operations portfolio. For the purposes of this paper only the optimization portion of the well test functionality is described.

The optimization functions address the issues of optimal purge time and test durations, well test result quality and automatic validation. All of these issues are tackled by using a combination of online, data driven models and pattern recognition. Real time data such as test separator fluid flows and pressures are used to construct the model.

The determination of the minimal test time is based on the following reasoning. If we can predict the production characteristic "footprint" of the well, there is no point in continuing the test. WellTest identifies the model that explains the progress in time of the test measurements, hence it predicts future values of the test flows. If the measure that establishes the quality of these predictions is passed, the stopping time is reached.

If the well is a non-steady producer, i.e. if the production level does not 'converge' to a constant level, WellTest will search for some form of periodicity in the well's behaviour. The test result**,** i.e. the 'average' production of the well, is based on this reproducible element in the production characteristic of the well.

Typical FieldWare output from a Shell Operating Unit is shown below. WellTest starts building an online data driven model using real time results from SCADA or Historian system. The purge period is shown in blue – when the test results are deemed suitable by the model the application automatically switches from the purge time and starts the test period, shown by the blue trend turning to white. The test continues with the model deriving a parameter indicative of the goodness of the test result and depicted by the declining white curve shown below on the right-hand side – when the rate of decline is approximately zero the test is deemed to be complete as also shown by the white trend turning to red. As can be seen from the plot, this test is complete in 3 hours and 20 minutes, inclusive of a 20 minute purge time. This is a significant reduction on the prior test duration "rule of thumb."



Test time reduction results from a Shell OUs using FieldWare WellTest (obtained whilst maintaining the integrity and consistency of the overall test results) show that reduction in test time depends on the well type. As expected the greatest reduction is seen for the most stable free-flowing oil and gas wells and the least reduction is seen for beam pumped wells which have the greatest periodicity. Gas lifted wells which have a tendency to be somewhat unstable exhibit a well test reduction between the extremes of stable natural flowers and periodic beam pumps.

In a few special cases it is possible that wells may not be tested for long enough. For example subsea wells with long tie-backs to a test separator on a distant platform it can take a long time for the well to stabalize due riser slugging compounded by well instability. Also in some cases where well tests are used for well surveillance the test may not be long enough to give results of sufficient quality. In these cases FieldWare WellTest can ensure that wells are tested long enough to give quality results.

4.3 Well Test Quality KPI

Apart from calculating the test result, WellTest also determines error statistics of the test results. Noise on the test measurements and disturbances that may occur during the test imposes an error on the test result. Error statistics lead directly to a quality KPI for the well test results. The quality KPI is a useful, overall measure for the reproducibility of the test result and which also may give early indications of well test problems.

The quality KPI on its own may not be sufficient information to validate a test. For example, if results of consecutive tests of a gas lifted well are compared. The measurements might be noise free in both cases and the production characteristics might be "completely regular". However if the lift gas rate was different, the test results will also be different. This example shows we also need information about the *circumstances* under which the test result was obtained. FieldWare WellTest provides this information by including well test diagnostics in the well test report. The well test diagnostics are based upon WellTest’s analysis of the production characteristic (e.g. nature of the periodicity) and on the processing of the ‘other’ quantities involved in the well test (e.g. lift gas rate).

4.4 Well Test Automatic Scheduling

To capitalize on well test reduction time it is important to know what is the best well to test next. For example if the test finishes at 3am on a Sunday morning, which is the best well to test next and what should be done if that well is unavailable for some reason?

The test scheduler runs in the FieldWare WellTest software, senses the end of well test from real time input, senses the status of the wells associated with a given test separator and then recommends the next well to be tested. The recommendation is obtained from a series of lists and options configured into the real time software suite. The lists can be remotely maintained from the desk top of the person in the organization who is responsible for well testing.

For test separators with collective rotary, or individually activated valves FieldWare WellTest can automate the process by pulsing commands to remove one well from test and put the next well on test – this is particularly useful for remote, unmanned locations.

When used with multiphase meters or water-cut meters, the fluid properties for the particular well on test can be automatically downloaded to the meter to ensure accurate results.

5.0 Potential Benefits of Well Test Optimization

5.1 Increased safety

In many cases with well tests performed by exception, with well test automation and with test duration shortened there is less need for operators to travel in hazardous vehicles to hazardous locations. Hence there is improved safety due to decreased operator exposure to the combined hazard of travelling and unnecessary presence at the hazardous well test site.

5.2 Less, but better tests with less effort

Because in many cases utilizing FieldWare can lead to reduction in well test frequency/duration, when a well is ultimately put on test, more emphasis and expertise can be focused on the well test process. This is aided by the ability of remote head office technical authorities to monitor and supervise individual well tests from process inception to completion from their desktops. For example it may be prudent to calibrate well test instrumentation prior to the test and also perform leak-off tests to ensure that the manifold valves are not leaking. It is crucial that well test quality be maximized as the well test result is used to recalibrate the FieldWare surveillance tools that in turn provide the equivalent of “continuous” well test capability for all wells – Production Universe providing continuous oil, water and gas flow estimates and/or FlowMonitor providing continuous liquid flow estimates (ref sections 4.1.1, 4.1.2 above). This leads to a virtuous cycle of fewer, but better well test results, giving better continuous well surveillance, administration and management.

Less well testing can result in less logistics and transportation cost savings e.g. less car, boat or helicopter trips.

Less well testing will also results in less bureaucracy
- Less samples
- Less Lab work
- Less manual well test result processing

5.3 Improved Well Test Quality

An online quality control KPI gives the following benefits:
- Identify and flag well test problems early in the test in time to save costly and nuisance re-testing
- Provides focus when validating well test results by flagging problems which need to be addressed.

5.4 Better decisions due to better information

More accurate well tests and continuous estimates of oil, gas and water flows based on better well tests and minimal well head instrumentation data result in improved quantification of well production and deviations from the norm. This is turn leads to more accurate hydrocarbon accounting and reservoir simulation as well tests are prime inputs to these production systems. The reservoir simulator is used to make vital operational decisions like where shall we drill the next well, what are the remaining reserves and how can they be optimally deployed. Hence improved well testing can lead to better decisions and better management of operational assets.

5.5 Improved test separator utilization

As indicated in section 4.2 above test separator utilization can be significantly increased by reducing the time required for each test depending on the type of wells that are being tested. This extra capacity results in a number of benefits:
- CAPEX and OPEX savings for **new** fields as less test separator equipment is required and hence less maintenance is required. For **new** offshore fields less test separators leads to a reduction in expensive deck space.
- CAPEX, OPEX and deck-space savings for **existing** production station where new wells exceed existing test separator capacity.
- Extra test separator capacity can either be used to perform more well testing should this prove to be necessary or to provide more bulk separation capacity.

5.6 Less production deferment

When testing subsea wells tied back to a production platform with a single bulk production line and no test line all other wells producing via the same flowline have to be closed-in. Hence testing the well for the minimum time is desirable and results in production increase by allowing the closed-in wells to be opened-up sooner. The option of closing in a single well and determining the production by difference can help reduce the deferment, but normally at the expense of test accuracy.

6.0 Conclusions

Using minimal, surface, commodity electronic instrumentation on wells and associated test separator can result in improved well surveillance and hydrocarbon allocation. The resulting real time information feeds FieldWare applications which enable optimization of the well test process resulting in:
- Reduced number of well tests, hence, safer and more cost effective operations
- Improved quality of well test results leading to more accurate hydrocarbon allocation and reservoir simulation
- Reduced well test duration allowing many more wells to be tested and thus reducing separator CAPEX and OPEX and saving expensive offshore real estate

Increased production (less deferment) for sub-sea wells that do not have dedicated test lines.