SPE 112042

The Measure of Success: Measurement of Digital Oil Field Success Focusing on Hard and Soft Measures

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This paper was prepared for presentation at the 2008 SPE Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 25–27 February 2008.

Abstract

Many business cases for embracing technological improvements around Smart Fields®[1], "oil fields of the future," or "e-wells" have been justified by predicting an increase in production; the industry-accepted figure is approximately seven percent. In this paper we want to examine the benefits that this new way of working brings to operators and to demonstrate what can be done to measure the directly related benefits as well as the "knock-on effect" that it has other areas.

We want to examine what happens when the value loop of physical assets, data gathering, models and decision making is closed, and to identify the underlying measurable benefits which can be seen at each stage of a production optimisation process.

Most benefits boil down to "faster, cheaper, better" and that is converted to value by:

- Reduced elapsed time to arrive at desired result – know sooner
- Reduced amount of effort involved – number of man hours – decide faster
- Reduced cost of effort – cost of man hour – cheaper
- Increased quality – reduce errors, improve performance – perform better.

There is a need to determine how improvement takes place and which production items need to be considered. This paper uses a framework for identifying these and attempts to measure benefit by:

- Determining a baseline
- Populating historical metrics
- Identifying new perceived metrics
- Comparing results.

Based on experience, we can now show value by identifying the problem and addressing a need in real time. This will be demonstrated by looking at implementations in Brunei, Norway, Louisiana and some cross-project observations.

"If we don't know what we don't know, how will we know what we need to know?"

That perhaps is the big question that the smart digital oil field of the future will answer for us if we embrace the foundations of integrated work flows, which include ***people, processes, and technologies*.** This will give us the wealth of data we need to ***model our results*** and optimise our production using ***collaborative decision making,*** and, as identified, we will discover hidden benefits along the way.

Introduction

Many business cases for embracing technological improvements around Smart Fields®, "oil fields of the future," or "e-wells" have been justified by predicting an increase in production; the industry-accepted figure is approximately seven percent. To put it simply, increased production brings increased revenue, hence success. The only problem with this simple calculation as a measure of success is this: How can you justify that it was your project and not another that brought about the increased revenue?

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[1] Smart Fields is a registered trademark of Shell in the United States and/or other countries.

We will examine some of the benefits operators can achieve by adopting new techniques and technologies that are available to gather data, analyse trends, and optimise production from the reservoir, through wells and pipelines, through production facilities, right up to export.

All too often, reservoir engineers, well analysts, and facilities engineers have worked in isolation to optimise their individual areas of responsibilities in some cases, without any regard for each other.

The coordinated management of data in real time has given production personnel the ability to troubleshoot problems instantly and to optimise in the short- and medium-term as well. This luxury used to be reserved for annual “produce to the limit” audits.

Measurement of digital oil field success

The Value Loop:
Real-time surveillance has steadily risen in technical capability over the last decade. Gone are the days when an operator would walk around the installation and record readings from an analogue meter. The use of digital equipment has resulted in more accurate data being transferred to the control room for analysis.
The Shell Smart Fields value loop looks at four elements:

- Physical assets
- Data gathering
- Models
- Decision making.

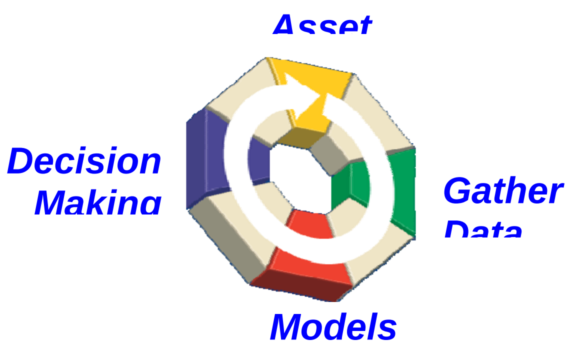

Figure 1 Smart Fields value loop

This methodology has been expounded in great detail at other conferences. We will use it as a framework to identify the underlying measurable benefits, which can be seen if we utilise the approach that “Intelligent Energy” brings.

When I talk about ***physical assets*** I don’t mean business units or even fields or installations. I mean gadgets or products, which bring technological advances. Every oilfield manufacturer will tell you that device will bring a return on investment, but what are the real benefits in the 21st century? Devices have come a long way since analogue meters were used for measurements. Intelligent digital sensors and gauges now give us real-time data from remote locations that can be used to troubleshoot fast or optimise quickly. Most of the smart money recently has gone downhole due to smart wells, which penetrate multiple hydrocarbon deposits. If added value is to be achieved we will need devices to measure pressure and temperature at the reservoir level. Fibre optic sensor cable fixed to the casing throughout the length of the well gives us the ability to tell what is happening at each penetration. With this information we can make the best use of the differential pressure between the reservoirs to drive the oil or gas to the surface. This use of intelligent assets has brought benefits we would never have thought possible a few years ago.

We can cover our installations with smart technology, but if we do not have the infrastructure to gather data, the vital information will be lost. Data management is probably the hidden element of the digital oil field and yet it provides the highway and interfaces through which we get the information we need. If necessity is the mother of invention, then overcoming problems from cyber terrorism or compliance with legislation brings out the best in information technology (IT) specialists. It has become necessary to separate the process domain from the office domain. The control of a Russian pipeline by a computer hacker for 12 hours has forced us to look at the security of installations by providing data acquisition and control architecture to monitor user interfaces. Data historians give us the real-time data, which is the lifeblood of smart fields. What are the benefits of gathering data in this faster, more accurate age? With real-time accurate data, we can have real-time analysis, which will help us:

- Carry out accurate daily hydrocarbon allocation instead of waiting until the end of the month
- Accurately calibrate our models
- Respond faster to problems by using exception-based analysis of the data.

A crucial advantage to be gained from integrated data management is that all users have access to the same data source. This may sound elementary, but anecdotal evidence suggests that production information is still being sent by e-mail on spreadsheets, in many cases with no date stamping or version control in place.

Gathering data is fundamental to growth. If you do not know where you are now, how can you take steps to get to where you want to be?

What benefits can be derived from ***models***?

What are the ways we can use models to optimise production?

In terms of surveillance reservoir engineers, well analysts and process engineers have been using models to monitor for years but the advent of the digital oilfield has brought a greater integration and collaboration between these disciplines.
As part of their Smart Fields Foundation Mark I program, Shell has introduced Integrated Production System Modelling (IPSM). To do this they have employed two interrelated system technologies; Integrated Field Manager (IFM) and Integrated Production Modelling (IPM).

IFM is the front end of the process, which stores the model catalogue and provides the management for the actual simulations to take place in IPM.

The benefits that followed were:

- All the models were in one place and date stamped
- Current model data was used by all disciplines
- The built in interfaces with the data historian (PI) meant current production data was always available.

In terms of surveillance the analysts in the industry are moving away from the comfort of their macro driven spreadsheets to a more dynamic easily available modelling technique.

A word of caution: models are only useful if they are properly calibrated. At the moment that job is still in the hands of human beings, although partially automated calibration is possible. The difference today is that the information is more readily available and the tools for data exchange are now in place.

From the day-to-day surveillance activities, anomalies between the current data and the simulated predictions obtained from the models are now a constant source of opportunity for production system optimisation. These opportunities can be stored in a register and examined at monthly Production System Optimisation (PSO) meetings. This sort of activity normally has been held until a corporate team of optimisation experts audit an asset and develop proposals. In some of the major oil exploration and production companies, this can range from annually to as much as every three to five years, depending on the asset’s complexity.

With IPSM, each of the reservoir, well, and process models can be integrated in IFM to form an integrated Geophysical Acquisition and Processing (GAP) model, which is then used to test different optimisation scenarios built from an opportunity register.

This flexibility permits multiple scenarios to be run quickly to test their viability.

Once the chosen optimisation scenario has gone through a risk analysis process and has been costed and approved by the asset management team, the derived model can be used for short- and medium-term forecasting.

Modelling has developed rapidly in the e-field arena and will continue to prove worthwhile in the future.

That just leaves ***decision making***, of which the collaborative work environment (CWE) is the flagship.

There is no logic in having really clever devices to sense, measure and report back to a brilliantly integrated data-gathering system with beautifully calibrated models if you do not know what to do with it. Designing a CWE brings together all the segments of the value loop under an integrated work flow that combines people, processes, and technologies. The best way to illustrate this is by using a cross-functional process map, with people in swimlanes across the top, technologies at the bottom, and process steps running horizontally and vertically across them both. In one simple map we can see the interfaces, handovers, roles, and responsibilities.

Many uninitiated people see a CWE as some kind of expert centre or high-tech communications centre; it is these things, but it is so much more.

A CWE facilitates good teamwork as well as better communication.

An asset in Brunei had its key well and reservoir management personnel located in different parts of an asset management building. To address this communication problem, the CWE team proposed bringing together the reservoir engineers, production technologists, and production programmers on one floor. Simple ergonomic and architectural features such as how the desks should be positioned made it possible for people to turn from their personal computers (PC) and engage in a collaborative discussion over what had now become a conference table.

Visual tools such as plasma screens had the functionality to change from streaming the key production data or the wells being tested that day to becoming an extra monitor for sharing key information from an individual PC.

The production programmers now have the ability to communicate directly with offshore through the video link; when the connection is set up, the camera focuses on the desk of the programmer who requested it.

State-of-the-art visualisation rooms with video walls and smart boards are more than just conferencing centres — they give the participants the ability to share real-time information and resolve problems together face to face.

Results:
The Brunei experience has reduced the number of visits required offshore, thus reducing the cost of flights and bed-space requirements on installations. As more of these centres are established, experts can be connected from different parts of the globe, solving problems faster and making better decisions more quickly.

Most benefits can be distilled to "faster, cheaper, better," and that is converted to value by:
- Reduced elapsed time to arrive at desired result – *faster*
- Reduced amount of effort and number of man-hours involved – *cheaper*
- Increased quality – reduced errors, improved performance – *better.*

The Shell CWE mantra of "Know Sooner, Decide Faster, Perform Better" has proved itself in both Brunei and Norway and is paving the way for Oman, Nigeria, and Sarawak. Each of these assets is providing different challenges but benefiting from a robust methodology.

Findings

Significance
There is a need to state any kind of improvement or change in terms of measurable benefit by:
- Determining a baseline
- Populating historical metrics
- Identifying new perceived metrics
- Comparing results.

In conclusion, we will look briefly at each of these points and establish a few basic ground rules for measuring benefit.

Determining a Baseline
It is a simple fact that we need to fix our starting point and measure from there. The line must be drawn somewhere.

Populating Historical Metrics

Every asset has metrics that it measures, such as production figures, deferment, number of failures, and so on. Be sure to identify metrics that already exist; this will help to highlight any improvement that takes place. We have not talked about instrument maintenance and calibration issues, but the number of malfunctioning devices that corrupt real-time data normally is a hidden statistic.

Identifying New Perceived Metrics
An example of this might be to measure the gathering of well test and production data, as shown in **Table 1.**

Metric	Description	Required Measurement
Time efficiency of well test validation	Percentage of well tests validated against total of well tests done	> 95%
Test facility utilisation	Percentage of test separator utilisation	Close to 100%
Compliance with minimum standards	Number of wells tested with valid results versus Minimum number required	Match close to 100%
Compliance with well and reservoir management plan	Number of wells tested with valid results versus Minimum number required according to WRM plan and local standards	Match close to 100%
Compliance with sum of weekly well test plans	Number of wells tested with valid results versus Actual well tests planned	Match close to 100%

Table 1 Examples of well testing KPIs

Another example might be the use of modelling techniques, as shown in **Table 2.**

Metric	Description	Required Measurement
Opportunities realised from PSO	Percentage of planned opportunities that are realised	Number (monthly)
Estimated gains from PSO opportunities realised	Average rate for year to date calculated with the integrated model (cumulative volume/days since beginning of year)	Number (monthly)
Calibration of integrated system model	Percentage of error on total IPSM rate compared to total actual rate (using system quality control)	Number (monthly)
Calibration of well models	Percentage of well models calibrated according to IFM equipment quality control specification	Number (monthly)

Table 2 Examples of optimisation KPIs

Depending on individual projects, appropriate metrics will be devised.

Comparing Results
When we seriously start taking measurements like these, we can begin to compare results; we can identify our weaknesses and strengths.

Actual Results:
Based on experience, we can now show value by identifying the problem and addressing a need in real time.

In Brunei there was a problem with well testing. An independent contractor was carrying out well tests to an annual schedule. There were hundreds of wells to be tested. The results were written on well test logs, and at the end of the week, these logs were faxed to the production programmer for verification. In a number of cases, the tests were invalid because of unstable readings or chokes set in the wrong position. Unfortunately, when this was discovered, it was too late because the testing team had moved on to another installation.

With the integrated work flow, the operator puts the well on test and the real-time test data is fed to FieldWare Well Test, which determines when a stable result has been reached. When the operator is satisfied that the well test is complete, he or she “accepts the test” in FieldWare Well Test. The results are immediately transferred to energy components where they can be examined by the programmer, who can verify or reject the test. All this is done in real time before the operator has time to take the well off test.

In Norway, the issue was with cross-functional disciplines. The production support workforce was highly motivated and was capable of doing each other's jobs, but the engineering function was on another floor and worked independently. The CWE brought together all the disciplines and expertise in one place and enabled process problems to be solved in a much shorter time.

The other tangible benefit was formalising collaborative events in terms of meetings and information deadlines.
Rotterdam was chosen as a pilot for deployment of a suite of "smart" technologies, and an Integrated Production System Model was constructed as part of the project. The process of gathering and checking the data highlighted a number of issues concerning data quality and the actual functioning of devices such as valves, chokes, and orifices. These had never been a problem in the past because the field was operating well within its capacity and the production levels had always been on target. When certain instruments were recalibrated and a picture of how the field was behaving became clear, it was discovered that gas injection rates were in excess of what was required. The main benefit was the efficiency in surveillance that the integrated approach brought to the pilot. These tools and work-flow rigour highlighted the areas for improvement, which had gone unnoticed in the day-to-day operation of the facility. By adopting the optimisation of the production policy, a gain of eight percent in production was achieved in 2006.

Conclusion

As Sir Humphrey Appleby once said in *Yes, Prime Minister*, "If we don't know what we don't know, how will we know what we need to know?"

That perhaps is the big question that the smart digital oil field of the future will answer for us if we embrace the foundations of integrated work flows, which include ***people, processes, and technologies.*** This will give us the wealth of data we need to ***model our results*** and optimise our production using ***collaborative decision making,*** and, as identified, we will discover hidden benefits along the way.