Improving Oil Production Using Smart Fields Technology in the SF30 Satellite Oil Development Offshore Malaysia

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Abstract

Smart technologies are successfully applied to South Furious 30 (SF30), a satellite oil development offshore Malaysia. Smart well completion technology and intelligent gas lift optimization have been integrated, incorporating remote data acquisition, real-time flow estimation and remote process control. The overall benefits equate to about 10% production gains and approximately 2% additional reserves. SF30 came on stream late 2001, thus realizing one of the first smart fields in the world with remotely controlled subsurface and surface smartness.

Introduction

Smart or intelligent process control is extensively used outside the oil industry. Process control in manufacturing and chemical plants is commonly based on continuous cycles of measure, model and control. Modern cars achieve a higher power output, environmental performance, fuel efficiency and reliability through the application of improved materials, combined with sophisticated control of the engine. Modern engine control involves continuous surveillance and optimization, which is based on intelligent data analysis and virtual engine models. Smart Fields technology has the potential to enable a similar step change in performance in the oil industry.

In 1999 Shell started the Smart Wells initiative by setting up a dedicated team of well technologists and petroleum engineers at its exploration & production center in Rijswijk in the Netherlands. The team is gathering information from the industry and through research to support operating companies with the justification and application of smart wells globally throughout Shell. In addition, in 2002 a dedicated Smart Fields team has been formed as a logical extension of the Smart Wells global implementation effort. While the Smart Wells initiative mainly concentrates on down hole monitoring and control, Smart Fields focuses on the implementation of integrated smartness in the complete upstream value chain from reservoirs to delivery points. Surface and subsurface smartness are thus addressed jointly.

From analysis of the various case studies and projects where smartness was applied, it became clear that the Smart Fields concept involves a lot more than just the installation of smart equipment. The increased functionality of smartness will only create value when it forms part of a so-called value loop. The value loop octogram (Fig. 1) is at the centre of the Smart Fields methodology. Crucial to the generation of asset value from the introduction of smartness is to close the value loop. The octogram illustrates the definition of the asset boundaries, data acquisition and interpretation, calibration of relevant models, the generation of options using the virtual asset models and the selection of the most attractive alternatives, which are then planned for execution. Unless a value loop containing measurement, interpretation and action, is properly closed it does not generate value (and could even destroy value over the lifecycle of the asset) (ref. 1).

The Smart Fields methodology considers new and existing smart technology, work processes and skills required to create value. The implementation of identified smart opportunities is always subject to a sound business case, the definition of functional requirements, and subsequently the selection of adequate smart solutions.

Smartness applies to production operations and optimization, reservoir surveillance and field development (Fig. 2). As indicated, these processes are closely linked, and have different cycle times and complexities. One of the first fields in Shell where the value loop concept was used and where the loops were closed, is the SF30 field of Shell Malaysia E&P (SM-EP), located offshore Borneo.

SF30 Field Development Strategy

The small oil field SF30 was discovered in January 2000 offshore Borneo in the South China Sea in some 70 ft of water depth in a geological turbidite setting (Fig. 3). It is located 2.5
km North of the South Furious field, which was already on production with ullage in its production facilities. The field comprises a NW dipping flank bounded to the east by a normal growth fault, and is internally compartmentalised into five major oil-bearing fault blocks. The sands are poorly sorted, and permeabilities range from 100 - 3000 mD. Oil gravity is 18.7 API. The primary recovery mechanism is solution gas drive aided by gravity segregation.

The Field Development Plan called for a “slim, phased and fast” approach to make the project commercially robust in view of the large subsurface uncertainties given only two exploratory-appraisal wells (and no production tests). An unmanned, remotely operated satellite platform, SFJT-C, with minimum facilities was selected to satisfy the slim and fast requirements. In addition, the application of smartness and down hole data gathering would provide the required information for future phases of field development.

Emphasis was on innovative / new technology, best practices and full-life cycle development planning to yield quick first oil production and higher reserves recovery whilst remaining commercially robust. This was accomplished by the use of advanced subsurface reservoir modeling, virtual reality well planning, off-the-shelf jacket designs, triple splitter wellhead technology, remote down hole monitoring and inflow control with SmartWell® technology, smart surface facilities and a smart fields approach to optimise production and recoveries.

The first development phase consisted of 5 production wells. First oil production was achieved in September 2001, 20 months after the discovery, and was a record for the Malaysian oil industry. Unfortunately, the reserves size of the field turned out to be close to the low expectation case, thereby limiting scope for future infill drilling. The initial field production peaked at about 9,000 bpd and later leveled off to a rate around 6,000 bpd net oil.

**Justification of Smart Technology**

As part of an unmanned operating philosophy, it was decided that the SF30 field would be entirely remotely controlled. Additional equipment for surface and down hole monitoring and control could be piggybacked on the infrastructure already planned.

All five wells are equipped with monitoring and control equipment at surface. Three of the five wells have triple permanent down hole pressure / temperature measurements to monitor the pressures in both reservoir layers and the flowing bottom hole pressures. In addition, two of the 5 wells are equipped with down hole inflow control (open / close) valves. All data are transmitted in real-time to the onshore control centers and the office and can be monitored (and in principle even operated) from anywhere in the world through the internet or intranet.

One development constraint imposed was that in case of premature failure of the down hole SmartWell completion equipment, the SF30 field would remain fully operable through conventional intervention means (all wells are accessible with wireline).

The justification for smartness was based on:

- An unmanned platform operating philosophy
- Cost and risk reduction from reduced wireline interventions
- Capability for more sophisticated and flexible reservoir management, through controlled commingling and testing of individual zones
- Improved down hole information allows better selection of optimum targets in future drilling phases
- Capability to shut-off unwanted water or gas production, without intervention
- More frequent well and reservoir surveillance with a lower level of deferments
- Accelerated oil from real-time gas lift optimisation and thus improved oil recovery

In addition, SF30 was considered as a first test case for SM-EP before applying smart well technology in less forgiving environments.

Of these benefits, some were certain and relatively easy to express in a cost saving or NPV benefit, whereas others, especially the VOI and improved reservoir management are much more difficult to quantify. The risks associated with the new technology and the difficulty to precisely quantify the perceived benefits made the business case marginal, but the smart project was still considered economical.

There are clear spin-offs of this technology for the entire company. The low cost and low risk environment of SF30 allowed SM-EP to acquire valuable experience in designing, building and operating this technology prior to implementing it in more challenging and demanding environments where benefits are greater (sub-sea, deep offshore, multi-lateral wells).

**The Smart Field Hardware**

Early in the FDP process, a need for up to 12 development wells was identified. To satisfy economic criteria, the facilities platform design needed to be minimal thereby saving weight and space and resulting in a slim, fast and cheap construction. With these boundary conditions, the team aimed to accommodate 3 wells in each of the 4 platform legs so that dedicated conductors and deck space / steel weight could be saved. The triple splitter wellhead technology allows for this. The particular type of wellhead used (Fig. 4) also catered for the smart wells (up to 6 hydraulic or electric lines to exit the tree) and the future potential requirement to run ESP pumps through the tree inside the 4 ½” tubing.

The wellhead technology proved successful and this saved an estimated $2 million US in upfront CAPEX investment had we not adopted it. No downtime occurred during any of the triple splitter wellhead operations. Special challenges were the
lack of experience with the combination of smart well completions and triple splitter wellheads. Surface stack up tests were done throughout 2000 and 2001 in Singapore to ensure a smooth field implementation.

Another special challenge was to quickly and efficiently drive the four 36” conductors without bending them, otherwise the triple 9 5/8” casings would not be able to enter, therefore losing well slots and valuable rig time. The conductor drive process was meticulously planned in combination with pile studies and the wall thickness of the 36” conductor was increased to give extra strength to drive through the hard seafloor.

The completion of the intelligent wells is depicted in Fig. 5. Each well is completed in two different zones. Frac & Packs or high rate water packs were used as method of sand control.

The SmartWell completion is comprised of a production packer with control/e-line feed through capability, a multi-pressure/temperature gauge mandrel, two flow control valves (an interval control valve and a ball type valve), extension tube and seal assembly. The seal assembly locates in a seal bore isolating the lower completion zone gravel pack screen from the upper zone. Flow from the lower zone progresses up the extension tube through the ball valve into the production conduit. Flow from the upper zone flows in the annular area around the extension tube and ball valve and enters the production conduit via the upper interval control valve. Each zone can be controlled independently via the flow control valve and the lubricator ball valve respectively. Three pressure and temperature gauges are fitted in a triple gauge assembly in the top zone, with an external port that connects to the bottom zone. The gauges provide pressure and temperature information in the tubing, in the top zone and in the bottom zone.

All valves are hydraulically actuated and flow control is binary (on/off). There are three hydraulic control lines for the two valves and they are combined in one flat pack together with the electric cable for the gauges and the hydraulic cable for the deep-set SSSV. The valves are actuated by a hydraulic power unit controlled by a surface data acquisition and control system, linked to the platform Distributed Control System (DCS). Data from the down hole gauges is transmitted via a surface gauge interface card to the surface control system.

Two of the wells in the SF30 development are completed with both down hole gauges and down hole flow control valves, while a third well has gauges only. The other two development wells are completed conventionally.

One of the permanent down hole pressure and temperature gauges proved to be not working due to a splice problem, which developed despite the very thorough preparations. This again highlights the need for high reliability for intelligent well equipment, which is often still in prototype stage i.e. reliability engineering is required. Worthwhile to mention in this context that Shell participate in the Intelligent Wells Reliability Group, a joint industry project on reliability engineering for smart wells.

At surface, for all conventional and intelligent wells, pressure and temperature gauges are installed on both the gas lift manifold and lines and the production manifold and flow lines. Lift gas rates and the position of the lift gas flow control valve and the production choke are also continuously monitored.

All these down hole and surface data are transmitted in real-time from the Distributed Control System on platform SFJT-C via a sub-sea copper or fibre optic cable to the host platform’s DCS on the main platform SFDP-A and then onwards via terrestrial microwaves to the onshore base at Kota Belud where they are stored in a PI™ database. Any PC worldwide can retrieve both real-time data (with 3 second granularity) and historical data via the Shell intranet.

Provisions are made so that during power or data transmission failures no data is lost. The intelligent wells remain operable in the event of unplanned shutdowns to acquire valuable reservoir data. A satellite data transmission system provides further backup in case of serious network failures. Routers and bandwidth were upgraded and link diversity and remote network monitoring features were implemented.

Unique to this system is that one can not only receive surface / subsurface data, but also send signals back to the field from any PC with the required security code to operate the surface gas lift valves and the subsurface inflow control valves remotely, in principle from anywhere in the world. To achieve this, the smart wells, controlled with a hydraulic power/control unit and a Control System PC, is integrated with the DCS using a Modbus interface protocol (Fig. 6).

Recently a multiphase flow meter has been installed, so that well testing can be done in parallel with production and partial separation through the single available separator. The field’s programming staff executes all well tests remotely.

Whilst first oil from SF30 has been achieved in a record 20 months, complete resolution of all smart equipment issues took nearly another year. Time and effort are required to build awareness for the importance of data and their application in the various smart value loops.

**Learnings**

The complexity of the development project was managed by an integrated team with production technology, reservoir engineering, IT and telecom specialists, electrical and mechanical engineers, operations and maintenance staff, CAO engineers, procurement people, well services and well engineers, staff from Shell and suppliers of smart equipment. The value of integrated teamwork should not be underestimated: without obtaining the enthusiasm, drive and perseverance of all people involved, a project like this would not be as successful. In-house classroom and hands-on training
was developed and some 60 offshore operators and office-based staff were familiarised with the smart components and operations philosophy.

One also has to develop skills for the future to achieve Technical and Operational Excellence in the entire smart field value chain, from modelling to operating. Key to successful realization of the value from the smart field is the development and utilization of a production control and operating strategy that exploits the capabilities of the smart field. The strategy addresses monitoring, testing, optimization and control actions, and identifies contingent actions in the event of foreseeable deviations from normal operating practice.

Value of Data and Control

A significant part of the value of a Smart Fields project lies in the sheer fact that one can see what actually happens in the field. The presence of real-time data (compared to at most one data point a day in a conventional unmanned field in Shell Malaysia) draws a lot of attention, and by analysis with a multi-disciplinary team, a lot of simple (and often unexpected) gains are already made. These gains can for instance come from identifying valves that are closed but should be open, or from detecting and correcting unstable well behaviour that otherwise would have been unnoticed.

Subsurface

To date, the main value of the subsurface gauges and valves has been improved reservoir surveillance. The downhole control allows independent well tests and pressure surveys on each of the two reservoir sands without a well intervention by wireline or with a coiled tubing unit. Apart from planned surveys, there have been a number of unplanned shut-downs during which flowing build-up surveys were automatically obtained. The permanent downhole pressure data provided determination of skin, kh, reservoir boundaries and was of great value for history matching of the reservoir model.

The valves have to date only been operated for surveillance purposes. Due to the benign reservoir behaviour, it has not yet been necessary to close individual zones for extended periods of time or permanently to exclude excessive production effluent (water and/or gas). However, the value of being able to isolate zones is expected to increase as the field matures and these zones start to produce more water or gas.

Surface

Artificial intelligence software is used to optimize the gas lifted wells and to carry out flow estimation. This system of gas lift optimization using neural network models and the associated software has been called I-GLO (Intelligent Gas Lift Optimisation).

All SF30 instrument data are captured in the PI™ data historian at 1 minute intervals and can be retrieved easily. Based on multi-rate well test results and both surface and subsurface data, numerical models are built. Individual well models are created by testing the well on multiple rates through observation of the significant variables whilst the lift gas rate or CHP is perturbed. Variables observed are THP, FLP, CHP, lift gas flow rate, test separator gross production, test separator gas production, test separator level (Fig. 7). The manipulated variable is the lift gas rate or the CHP set point. Although the models were initially created using the downhole data as well, it turned out that this did not significantly improve the quality of the models.

Apart from individual well models, a jacket model can be created with all wells on production through observation of the significant pressure and flow rate variables from wells and manifold whilst the individual wells are being perturbed.

Once the models are created, they are used to continuously and in real-time optimize the gas lift to maximize production. The advantage of model-based gas lift optimisation is that the model can predict production performance and hence can make moves more rapidly than other methods that need to wait to measure the effect of an earlier optimisation move prior to making the next move. This is a feed-forward control process. Optimisation takes place at typically 1-5 minutes time intervals. Model-based optimisation can be applied to single wells or multiple wells.

The individual well models can be examined through sensitivity analysis, tested with hold-back training data, and the online optimisation behaviour can be examined offline using what-if facilities. The model can accommodate causal relationship across time such that optimisation moves are always timed to take into account predicted conditions, (e.g. X minutes in the future) to allow the delayed system response to the optimisation move to take effect. The same principles can be applied to other production optimization challenges.

Finally, to measure the productivity gains, a well is tested with and without the optimization model online. All SF30 wells have been modeled this way and are continuously optimized using the neural network. An average production gain of 6-7% from intelligent gas lift optimisation on its own has been measured (Fig. 8).

Apart from production optimization, the generated neural network models have been shown to be able to estimate liquid rates with some 5-10% error on a timescale of minutes, and with 5-6% error for 24-hour averaged flow. Even when the well shows highly unstable flow, as for instance SF-307, it’s production can be predicted to reasonable accuracy as seen in Fig. 9. The emphasis of the artificial intelligence modelling so far has been on production optimization. However, it is expected that additional benefits can be obtained from real-time reconciliation, using the flow estimation capacity of the neural network model. This will be further pursued in the future.

Evaluation of Benefits of Smartness

During an internal technical review between SM-EP and Shell the business case for smartness in SF30 has been re-assessed. In order to cater for the significant uncertainties in the
technical and economic evaluation, low, mid and high cases have been assessed.

For the base ‘mid case’, SF30 smart field production gains are estimated to be around 10% in total due to:
- Dynamic gas lift optimization (ca. 7%)
- Reduced back pressure with the multi-phase flow meter (ca. 1%)
- Reduced deferment for wire-line operations (ca. 1%)
- The ability to close off gassed-out and/or watered-out intervals (ca. 1%)

Actual gains over field life could be substantially higher (up to 15%), mainly due to the effects of reduced deferment with faster trouble shooting through real time well flow monitoring and the ability to close-off unwanted production effluent if needed. A “low” case scenario with 5% total gains over field life has been evaluated as well, but is considered less probable due to the measured gains so far.

As of the writing of this paper, the surface smartness accounts for about 80% of the all production improvements. It is anticipated that the value of the subsurface smartness will further increase later during field life, when more manipulation of the down hole valves will be required for water and gas control.

The robustness of the business case for surface smartness, in particular I-GLO, justifies further rollout in other existing fields. This is currently ongoing throughout gas lifted oil fields in SM-EP. In general, Shell-wide, a significant growth is observed in well flow monitoring and production optimization using data-driven applications.

As well as the approximately 10% production gains, additional tail-end reserves will be recovered. In the SF30 case, this is estimated to be about 0.25% on Recovery Factor (RF % STOIIP) for the existing wells in SF30. Worldwide experience with smartness is that the value of additional reserves is similar to the additional value from accelerated production and reduced intervention costs.

If further development is justified, the additional down hole reservoir data from smartness will result in improved reservoir modeling and consequently better understanding of the reservoir. This will lead to better positioning of the infill wells that will likely improve the cumulative reserves recovery factor (RF) compared to infill location selection in the absence of this data.

The above assessment of SF30 smartness has been limited to production gains, improved reserves and CAPEX as the dominant factors. Various cost saving factors and strategic considerations have however also been taken into account:
- Significantly lower CAPEX for slim platform (no space for coiled tubing required)
- Fewer wireline interventions
- Fewer visits / boat trips
- Improved HSE with fewer boat landings

These ‘secondary’ considerations are very relevant to maintain a leadership position in technology and HSE, and enable year-on-year costs and manpower reductions.

**Conclusions**

The main smart objective for SF30 has been to demonstrate the implementation of smartness in order to enhance production and reserves. The SF30 satellite was brought on stream end 2001 with 3 intelligent wells (5 total) and dynamic gas lift optimisation. SF30 thus presents the first smart field with remote monitoring and control of both surface and down hole sensors and valves.

SF30 thus presents a successful demonstration case for the implementation of forefront smart technology. Smartness has been shown to remain economically attractive, even with the significantly lower reserves encountered in SF30. Production gains of ca. 10% and additional tail-end reserves of ca. 2% are achieved. A strong multi-disciplinary approach continues to be essential for the sustainability of smartness.

A robust business case exists for the application of surface smartness. Gas lift optimization based on neural network technology and dynamic lift gas control is successfully used to improve production. Rollout and further development of I-GLO is currently ongoing throughout SM-EP. In Shell we observe a significant growth in well flow monitoring and production optimization using data-driven applications.

The economics for smart wells varies from ‘break-even’ to very attractive in the stacked oil reservoirs, especially if they are complex and compartmentalized. Smart wells become particularly attractive when water or gas injection is required for pressure support and are now routinely considered as a development option.

**Acknowledgement**

Smart Fields is an area of integrated team work. There is no way this project would have been successful without the commitment of many people. We fully acknowledge the contributions of the Shell Malaysia SF30 team and all the people that have been involved in the SF30 project. The authors would also like to thank Shell Malaysia E&P, Shell International Exploration and Production B.V., PETRONAS, and WellDynamics for their support and approval to publish this paper.

**Nomenclature**

- CAO: Computer Assisted Operations
- CHP: Casing Head Pressure
- FLP: Flow Line Pressure
- THP: Tubing Head Pressure
- STOIIP: Stock Tank Oil Initially in Place
References


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