SPE 100710

An Evolution From Smart Wells to Smart Fields

E. van der Steen, SPE, Brunei Shell Petroleum

Abstract

This paper discusses the “evolution” from Smart Well installations to the delivery of a fully integrated “Smart Field”. Capabilities were first developed and tested in nearby fields before being applied in the Champion West field. Results and issues with the component Projects are discussed. The creation of a “Smart Field team” with representation from Petroleum Engineering, Well Engineering, IT, Control and Automation, Data Management/Application, Facility Engineering and Production Engineering is seen as a key enabler for a successful Smart Field development.

Introduction

Brunei offshore waters are known to be rich in oil accumulations. Not all of them are straightforward economic discoveries. In the case of Champion West (CW), the field was more or less accidentally discovered in 1975 by an out step development well from the Champion Main field, drilled for gas lift supply. Fortunately, the well discovered oil, a new field was discovered and the discovery well was renamed to Champion West -1.

Through various appraisal campaigns, the complexity of the field became evident (very erratic charge in stacked (some 100) reservoirs in 10 fault blocks). Many field development plans (FDP) were drafted, but none of them executed because the oil development costs were too high (too many platforms and too many wells). Developing the CW oil and gas accumulations as a gas field only (i.e. forgoing the oil) was never acceptable to the Brunei regulator or Brunei Shell. An FDP was started in 1998 but execution was terminated after major drilling problems were encountered.

The last FDP is being executed in a phased approach. The current FDP is different from previous plans in the fact that it relies on (a) a novel well concept, (b) smart well technology and (c) extended reach drilling. Now only a single new platform and 20 wells from there are planned to develop the field. With this “smart” FDP, 15 years after discovery, the CW field became the largest undeveloped hydrocarbon resource in Brunei and will support Brunei’s oil and gas production (340 mln Boe) for the next 20 years. Peak oil production is expected end-2006 to be around 50,000 barrel per day, some 20% of Brunei's export. Gas production will support LNG sales for many years.

Vision

Early on in the Project Lifecycle (1999), the vision was agreed to develop the CW field from the new platform as a “Smart Field” and it was selected as the first candidate for implementation of “Smart Well” systems. The plan was to develop the field as a fully integrated, remotely controlled and operated field where regular pressure, temperature, fluid and flow data is continuously gathered and immediately transmitted to end users for on line monitoring and control. Production allocation was to be automated and the data flow linked to well, reservoir and production models to ensure optimal well and reservoir management policies were adopted. A technology staircase was used for a stepwise approach to the introduction of smartness in the operator. This vision was widely advertised, supported by operator’s management team and also adopted by Shell’s central technology council. The project became a key demonstrator project for the Shell group for smart field developments and as such, receives great focus from its top management.

Phased Staircase approach

With this vision for the CW field formulated for a 2005 development, operator realized that a phased approach of the introduction of smart well and smart field technologies was the only way to success.

- Phase 1- Introduction of smart well technology in 1999-2000.
- Phase 2 Upgrade of an old facility to a new smart facility with remote control of surface Flow-Control-Valves (FCV) and Inflow-Control-Valves (ICV’s) in 2003-2004.
- Phase 3 - Installation of a new smart platform in 2005.

Phase 1: CW Early Oil Development

In 1999 and 2000, the first smart completions were deployed in development wells drilling in the Iron Duke field and in the CW field (from existing, but old infrastructure). These wells were equipped with permanent down hole gauges (PDHG) and hydraulic ICV’s. Only two ICV’s were deployed in semi-vertical wells that had 3-6 individual pay zones: one to control the top zone, the second to control "the rest", while all zones from the second down had their own sliding-side-door (SSD), operable by wireline only.

Although the wells look to be near vertical stratigraphically, their offsets were significant (up to 2 km at 3km TVD). Oil based mud and directional drilling tools were shown to be some of the key enablers unlocking the CW reserves.

The deployment of the smart equipment was very successful, all gauges worked and only one of the 13 ICV's deployed failed. Getting the data on-line into the office was a much greater challenge than anticipated. Not just getting the hardware to work, but also the organization to adapt proved to be a challenge. To overcome these problems, a smart field support team was created. First, a full matrix team with staff from all functions involved and then later, dedicated smart field staff positions were created.

Here are a few of the organizational problems and their solutions:

- Getting data from offshore coming in to the office was not a top priority of the operations department. The operations department was traditionally responsible for data acquisition, but smart data was seen more as a luxery service by petroleum engineers (PE) for PE's. In case sensors would flat line, the problem solving service fell between the crack in the organization. PE's ended up going from service unit to service unit until the failed link the the long chain of hardware and software between well and office PC was found and fixed. A new support team was set up and made responsible for the operations support of smart data and its infrastructure only. The team now has some ten full time staff. Data acquisition remains the key responsibility of operations, but with the support of a dedicated smart-IT group, their responsibilities match again with the skills profile of field operators: maintenance, fault detection and error reporting being their key tasks.
- Competence gaps in operations resulted in contractors and office petroleum engineers being more knowledgeable and skilled on how to open/close an ICV than operators. For at least a year, vendors only operated the ICV's, a very costly mode of operation. Smart field training was developed for operators, with real life equipment in the classroom. Brunei is now the regional training hub for smart field training. Many field operators have been trained to understand the concept of smart wells, the key diagnostics and the methods of operating them.
- Connection field hardware operated in a process domain with the office network domain created overlap in responsibilities of those groups that were traditionally split by location (offshore or office). Safety concerns about viruses finding their way from the office domain into the process domain was a major concern. To overcome this, Shell as a group developed a Data, Acquisition and Control Architecture (DACA) standard, implemented this throughout the group and build on BSP's experience as frontier smart field operator.
- The aspiration to create remote control capabilities created the need for a major review of the operations philosophy. Technical realization of remote control is not that difficult, but once realized, anyone in Shell with access to the network and the right password can open or close a valve in the field. Great apprehension has to be overcome when new technologies are introduced into a traditional area like oil field operations. At first, it seemed logical to limit access to remotely controlled valves to the petroleum engineers who design them, were the key users of the smart data, and the most knowledgeable about them. Later, it was acknowledged that the introduction of smart field equipment does not fundamentally change the responsibilities of the various functions. PE's analyze the data and drive the change of choke- and ICV-positions, planners schedule all requests for well tests, maintenance, work-overs, with the additional task of scheduling zone changes of smart wells. Operators execute these activities, but only at the request of planners.
- The abundance of high frequency data coming into the office was quickly realized as becoming a serious problem. At first, it was "interesting" for PE's to frequently look at the data on-line, but this novelty quickly wears off. To solve this, a new data analysis tool was developed by Shell centrally. This software reports by exception only (e.g. a flat line will indicate sensor failure, a sudden change in pressure could give the PE's an opportunity based build-up). Especially noticeable was the Distributed Temperature Sensors (DTS) run in later wells. These systems create an over-load of typically noisy data that can only be analyzed with smart software (nothing new in engineering, but new to the oil industry).
- Despite their specifications, the tropical environment in Brunei was too much of a stretch for much of the surface data acquisition units that come with smart wells and smart field equipment. An air-conditioned box was built around the first unit and then later, complete containerized equipment rooms were put onto platforms.
- Commercial arrangements, contracts and price lists were agreed with a few vendors only through a tender procedure. To simplify the hardware infrastructure of the various smart locations and enhance vendor competition, different vendors for the same products were assigned to different area's with Brunei's operations. A dedicated smart field implementation engineer was hired to facilitate the commercial arrangements, deal with tenderboard etc. For the development teams this offers the huge advantage of a very clear pricing structure with minimal costs and minimum use of space in quickly too small containerized equipment rooms.

The smart well data was also used for production allocation purposed. More accurate uptimes and better and on-line rate information was derived from the pressure data. This data driven software system was first implemented on the Iron Duke field later on CW.

Phase 2: Drilling from existing upgraded smart facilities

Smart, long horizontal "snake" wells were introduced into CW; up to 6 km in length, up to 3 km reservoir sections and up to 3 penetrations per sand. These snake wells are meandering in a long and narrow oil rim, turning left and right, while staying in the horizontal plane (like a snake moves over a surface). The multiple penetrations give the snake inflow characteristics of as many vertical wells as it has penetrations in any sand, but through a single completion, requiring only a single slot on an offshore platform.

Snaking a trajectory through the reservoir, keeping dog-leg-severity below 1 deg/10m to allow a pre-drilled liner to be installed and staying inside the reservoir instead of making inflections too far outside the objective reservoirs were all challenges that were gradually mastered, certainly not without failures. Learning was always a key element of Phase 2 with the simple objective of getting it right on the big wells in Phase 3.

As expected, the inflow performance of the wells was some 10 times better than for semi-verticals. Typical draw-down for the wells was 1-10 Bar. Although the wells were drilled in depleted reservoirs with their initial rates lift constrained, production rates of 4-8 kbpd were still achieved.

The multi-zone smart completions at high rates showed significant pressure losses in the stinger of the smart completion. At first the stinger size was increased from 2 7/8" inside a 5.5" pre-drilled liner, to 3.5" inside 6 5/8" later in phase 2, to ultimately 4.5" stinger inside 7" pre-drilled liners in phase 3. But still, especially in the heel section, the friction was significant relative to the draw-down applied. As a result the heel section of the well would be over-produced if open-close valve were used. With variable ICV's in the completion, we managed to compensate the frictional pressure losses in the stinger with a deliberate pressure drop on the ICV's.

On the last well of phase 2, we implemented software to estimate on-line 3-phase rates per zone, based on downhole and surface pressures, and predict with that the optimum position of the variable ICV's to maintain equal draw-down on all zones. The actual change of ICV position is still done manually, the complete step toward "close-the-loop" was kept for phase 3.

In Phase 2, the number of available slots, from existing infrastructure, were very limited and as such, snake wells offered a competitive edge over verticals, even at significantly higher costs. The introduction of splitter wellhead technology allowed the drilling of two wells from one slot, further expanding the opportunity value of the few slots remaining.

An old platform was upgraded to a smarter facility: An integrated power- & fiber-optic cable was installed to this facility to support a containerized equipment room and the high bandwidth requirements of smart wells (and cover future bandwidth requirements of undoubtedly even smarter equipment). Well test facilities were upgraded with remote readout of its sensors and a DCS was installed to control the new smart facility and smart wells. The upgrade enabled remote control but does not support remote well testing. Normal manning with operators is still required for this task.

Phase 3: A new platform with 19 slots

The new CW platform is fully remotely operable, normally unmanned, with remote well testing capabilities and remote shut-down and remote re-start capabilities. Smart horizontals are now longer (8km), have longer reservoir sections (4.5km), more penetrations (5), more zones (4) and develop more reserves per well (typically some 8 mln Boe per well). The snake well reduces the slot count required and, with splitter wellhead technology, the new 19 slot platform still offers the opportunity to drill some 30 wells. This platform was installed in 2005 with the first two wells having been drilled and the benefits of the smart well have clearly materialized. Wells are producing at 15-17 kbpd, which is some 4-5 times the rate achieved from the semi-vertical wells in Phase 1. Swellable packers were proven to work perfectly and are much easier and more quickly deployed then cement inflatable packers.

The computer controlled platform can be programmed to do daily production tests on all wells, multi-rate tests, change ICV positions or maintain set-points on the wells (like maximum gas rate for an oil well with increasing GOR, limit the drawdown, balance the offtake between zones, maximize gas rate (velocity constraints) etc.

Benefits realized

- Smart wells show lower unit development costs (UDC); in CW some 1.0-1.5 US$/bbl lower. The long horizontal wells appear to be the key to low UDC's, but without their built in smartness, clean-up and reservoir management could never be realized. As such, the smartness is a key enabler to these long wells.
- The remote operability of the new platform increases its uptime by an expected 3%, which represents huge acceleration value. In an offshore environment like Brunei, with its monsoon seasons, and many small platforms with boat access only (i.e. no helideck), accessibility problems due to unfriendly weather conditions creates major exposure to production, maintenance and optimization deferral. With remote control / operability, the net output per time of the facility is higher.
- Smart wells and smart fields also give better data, faster response times and with that, an increase of reservoir recovery. In CW, this effect is estimated at some 2-3% extra volume recovery, dependant on the level of smartness. In the case of a gas well in Phase 2, the PDHG data clearly indicated a much higher connected volume than anticipated. With that data available so easy and early, it was possible to optimize the corporate work-over sequence and delay any planned intervention on this well to the benefit of more oil from other wells earlier, without under-delivery of gas against plan.
- Smart field technology is very good for staff morale. It is 'cool' again to work in the oil and gas business. With that, it does attract better staff to the company.
- Risk reduction and mitigation of unplanned fluid fill are key advantages of smart wells. Once committed to a smart completion, the flexibility to run some blank pipe, extra packers, or possibly an extra ICV, greatly reduces drilling/well construction costs (e.g. a casing cementation was unsuccessful, but a costly cement repair job was made unnecessary by installing an extra packer and ICV close to the heel and thus have the potential to close off potential thief gas coming down behind the casing into the heel of the well.)
- Remotely operated platforms create less risk exposure to staff, fewer boat transfers and fewer helicopter flights.

And then there were the unplanned benefits of smart equipment. Just a few examples:

- In one well in phase 2, the liner stood up 700m of bottom. Later in well life, during a well test, the well was produced from the toe only (instead of from all 3 ICV's). The draw-down at the toe increased from 1 bar (3 zones open) to 7 bar (toe zone only) and shortly thereafter the bottom-hole-pressure (flowing and static) increased. The final analysis of this was that the wellbore around the liner-nose got plugged and isolated the 700m of uncompleted reservoir section from the smart completion (but did deplete due to communication in the reservoir with the same sand being produced in the heel). Some 1 mln bbl of oil was re-connected to the well. Without the ability to pull harder on the toe, these barrels would have been lost.
- Lubricator valves (LV) in the wells can serve well for build-ups but also can serve as "deep set plug". This reduces the production deferral during rig moves resulting from time consuming wireline operations setting the required seep isolation plugs. The cost of the LV is recovered before you ever flow the well.
- DTS was used to identify which of the 10 gas lift mandrels was leaking prior to kick-off. Time required for wireline work to replace the leaking mandrel was greatly reduced by knowing which one to replace (while the rig was waiting).
- DTS was used to identify inflow / clean-up problems. Producing the well from the single zone with clean-up problems solved the problem with DTS evidence in hand.

Conclusion

The "Smart Well" development brings together high rate, very long horizontal "snake" wells with surface and subsurface flow control, both with remote control using high bandwidth connection to the beach, downhole pressure sensors and downhole temperature data via fiber-optic technology. At surface, a computer controlled system allows for remote well testing and set point control. The journey has been an interesting one where "Smart Fields" concepts and technologies have delivered benefits beyond the business case in the areas of uncertainty management, whilst drilling and operating the asset. Without the smart field concept, the CW field would have no oil reserves at all.