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From Intelligent Injectors to Smart Flood Management: Realizing the Value of Intelligent Completion Technology in the Moderate Production Rate Industry Segment

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Abstract

This paper is a case history which examines the successful application of Intelligent Completion (IC) technology in a cost sensitive, mature, onshore North American environment where an existing hydrocarbon miscible flood (HCMF) horizontal injection well was retrofitted to manage the injection support of two geologically distinct reservoir regions covering two well patterns. The value of IC technology is explored in this early deployment which saw a relatively low cost application targeted towards a mature asset. The beneficial results of this application of IC technology were measured in terms of well intervention cost savings and affected oil production. This paper presents a relative comparison of those benefits. Though this application of IC technology was originally justified by the avoidance of certain future well interventions to modify the injection profile, an analysis of the affected pattern production in the post-installation period showed that the benefit to the operator was appreciably more from enhanced reservoir management than from the cost savings which were associated with workover avoidance.

Based on the success described in this case history, and reflecting upon the trends of intelligent well and smart field technology, the authors explore reasons for its relatively slow uptake in moderate production rate, brownfield applications. Large scale reservoir management of miscible flood projects using intelligent well and smart field technologies should provide significant value in terms of improved solvent/oil ratio through more efficient monitoring and management of the flood. This is probably the most compelling value proposition for IC technology application in moderate production rate land applications. This case history is intended to provide credible evidence of the benefit of IC technology in an application with cost challenges analogous to those faced by operators who are responsible for cost sensitive, moderate production assets. Secondly, it is intended to encourage the IC technology providers to develop more solutions for the brownfield segment of the industry, where profitability and value definition can be challenging.

Introduction

Intelligent completion technology provides the ability to partition a wellbore into distinct segments, and to monitor and control the flow of fluids into or out of each segment, upon demand, without physical intervention. The first integrated application of this technology took place in the North Sea in 1997, and to date, close to 600 wells have been equipped with intelligent well completions world wide.

The key elements of intelligent well technology are packers or seal elements which allow partitioning of the wellbore, flow control valves, downhole sensors, power and communications infrastructure, and a surface data acquisition and control system to remotely gather data and actuate the flow control valves. The downhole sensors may be electronic or optical fiber based, and typically measure pressure, temperature or flow rate. The function of the flow control valves may be binary (on-off) or choking, and are typically adjusted by hydraulic or electro-hydraulic actuation systems.

Each wellbore segment is usually associated with a separate hydrocarbon reservoir, a separate layer or compartment within a reservoir with complex geology, separate laterals in a multi-lateral well, or with segments of long horizontal wells. By using the capabilities of downhole monitoring and flow control, the flow of fluids into or out of the reservoir can be modified to restrict or exclude unwanted effluents, to commingle separate reservoirs in a controlled fashion (Konopczynski, 2003) and to improve the hydrocarbon recovery efficiency of the development project. Intelligent completions have been applied to production wells, injection wells, and dumpflood wells (Glandt, 2003) in offshore platform, subsea and land based locations.

Trends

The use of intelligent well technology has increased significantly in recent years as oil and gas producers have moved from testing the technology (to evaluate its capabilities and reliability), to incorporating the technology in field developments to capture the benefit of enhanced reservoir management that intelligent well technology delivers. The increase is such that the number of wells installed using intelligent well technology over the last 3 years (January 2005 to December 2007) is about the same as the number installed over the first seven years since the technology was first applied (August 1997 to December 2004). The accelerated adoption of intelligent well technology has been catalysed by two key factors: first, demonstrable and statistically significant improvements in reliability of the equipment and second, the offering of increasing capabilities and functionality of the equipment while holding costs steady. The first is a result of reliability driven engineering, improved manufacturing and quality control, and the accumulation of in-well experience as an increasing number of systems have been installed. The second is a result of innovation by the intelligent well suppliers driven by competition and the realization of a viable intelligent well market, and the demands of the users, who have experienced the benefits of the early generation, simpler systems and have realized the potential for greater value benefit from systems with enhanced functionality.

Over the first seven years of the life of intelligent completions, the primary applications were offshore, either platform based or subsea, where the significant incremental capital expense of the intelligent well completion could be justified by high productivity wells and the benefits of avoiding costly interventions to modify the completion in the event of water or gas influx (Ajayi, 2003). Based on a survey of approximately 50% of all installations, land applications over the first seven years accounted for approximately 8% of installations (Fig. 1). In the last three years, the share of land based applications has grown to 52% of the installations, driven largely by the large scale adoption of intelligent well technology by Saudi Aramco for its Maximum Reservoir Contact Wells (Saleri, 2006). The distribution of primary purpose of the application has also evolved, from the first seven years where intervention avoidance was heavily featured, to the last three years where managing drawdown pressure between laterals in MRC wells has become significant. The applications have also consolidated as companies have focused on specific reservoir management issues.

The Value Proposition

On a fundamental level, the value drivers justifying the use of intelligent well completions are increased ultimate hydrocarbon recovery, accelerated production and increased productivity, reduced development capital expenditure, reduced operating costs, reduced health and safety hazard exposure, and reduced environmental impact. Increased ultimate recovery is realized from improved management of the flow of fluids through the reservoir, particularly in secondary and tertiary recovery processes (Brouwer, 2001). Accelerated production and increased productivity are realized from controlled reservoir commingling and the efficient use of advanced wellbore architecture such as multi-laterals and long horizontals to improve unit well production. Reduced development CAPEX is also realized by using advanced wellbore architecture as fewer intelligent wells are required to exploit an asset than would be practical with conventional wells. Reduced OPEX can also be realized from downsizing surface infrastructure and unwanted effluent handling facilities. Reduced OPEX comes from avoidance of costly well intervention, and from reduced effluent handling costs. Health and safety hazards are reduced by fewer well interventions, and with fewer wells in a development, the development well surface footprint can be minimized.

There are over 800,000 active producing oil wells worldwide, yet offshore and subsea wells only account for 1% of these. In North America, there are over 500,000 active producing oil wells, yet the average production from these in the United States is less than 15 bopd. In Canada, the average production is significantly better, at about 50 bopd. Clearly, the majority of land based wells, late in their life cycle with little remaining reserves to produce, cannot economically justify the incremental investment in intelligent well technology. How then, can an operator find and justify a land based application for intelligent well technology in mature areas where production rates are low to moderate?

Intelligent Wells and EOR Projects

One area of potential application for intelligent well technology in the challenging low cost operating/moderate productivity environments is enhanced oil recovery. There are two types of enhanced oil recovery (EOR) projects for which compelling economic reasons for intelligent wells can be made, thermal projects and miscible flood projects. For thermal recovery wells, particularly SAGD type wells, the efficient distribution of steam along the wellbore translates to improved recovery and reduced steam injected to oil produced ratios. The high cost of generating steam, 65% to 75% when using natural gas fuel (World Energy Council, 2007), is the main operating expense driving the economics of these projects, so improved efficiency of the use of steam can have significant impact. Thermal EOR projects usually target undeveloped reserves of bitumen or ultra-heavy oil, so the economics of intelligent well technology can have an impact on the expectation of reserves to be recovered. The challenge to the intelligent well technology industry is to provide cost commensurate intelligent well solutions capable of sustained operation at very high temperatures.

Miscible flood projects are generally used in mature fields which have undergone primary and secondary (waterflood) recovery schemes. As such, a significant portion of the hydrocarbon reserves in place have already been recovered, ranging from 15% to 30%. Use of a suitable solvent flood can result in the recovery of an additional 10% to 20% of the original oil in place (Lewis, 2006), but can require significant long term investment for new wells, facilities, infrastructure and solvent.

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The use of carbon dioxide miscible floods has received significant attention recently in the context of sequestering "greenhouse gases", but hydrocarbon miscible floods are still prevelant in western Canada.

As with thermal EOR projects, a good measure of the economic efficiency of a miscible flood EOR project is the ratio of the volume of solvent injected to oil recovered. The benefits of applying intelligent well technology to a CO2 miscible flood in West Texas have been described by Brnak et al. (2006) Applying intelligent completions to production wells in multilayered or heterogeneous reservoirs allows the control of drawdown and fluid production from individual zones. Zones can be choked back or shut-in when excessive rates of CO2 or water production occur in a specific zone, without compromising the oil production from other zones. By restricting the production of CO2 in a zone, flood fronts and sweep patterns can be influenced to displace other unswept oil and move it toward other wells or other zones. CO2 recycling and the associated processing and compression expense is also reduced. Applying intelligent completions to injection wells in multilayered or heterogeneous reservoirs allows control of the distribution of the injectant between zones. Breakthrough, thief, and swept zones can be restricted, forcing more CO2 into the unswept zones. These capabilities can result in more efficient use of the solvent and improved recovery efficiency.

A number of elements must come together to see successful uptake of intelligent wells by EOR operators. First, lower cost, reliable intelligent well equipment must be readily available. The cost of the equipment should be commensurate with the cost of well investment. Second, the operator must take advantage of the capabilities of intelligent completions to reduce the number of wells required for the development. Third, evaluation tools must be used to model and evaluate the potential impact of the intelligent completions on oil production acceleration, sweep efficiency and project economics. Fourth, work processes and operating guidelines must be established to actively use the intelligent completion functionality to manage and optimize the recovery process. And fifth, a commitment to the successful implementation and utilization of the technology must be made by the development and operations teams, and by management.

Case History - Application of Intelligent Well Technology to a Hydrocarbon Miscible Flood Swan Hills Unit No.1

The Swan Hills Unit No. 1 (SHU) oil field, located in Alberta, Canada, is managed using various forms of EOR with a normal progression of EOR methods having occurred through the field's history. In the area affected by the subject well, first production occurred in 1962 and water flood commenced in 1965. A staged conversion of the field to hydrocarbon miscible flood (HCMF) began in 1985 with ongoing field development focusing on the recovery of incremental oil reserves by converting in a phased approach to the current EOR scheme. The HCMF process is similar to a CO_2 flood and it is presently the predominant method of conventional tertiary EOR used in Alberta (Edwards, 2002).

Average reservoir properties are listed in Table 1. The reservoir is contained within a Devonian aged carbonate reef structure with a stratified layering of porosity development having an average net pay thickness of 87 ft within a gross interval extending vertically for up to 180 ft throughout much of the field. The progress in understanding of the complex nature of the SHU reservoir structure has been an ongoing and evolving process since first production occurred over 40 years ago. There are 11 major pay sequences, several of which may be present in any given well. Each sequence is of heterogeneous quality, most are areally discontinuous and though the stacked sequences are usually separated by non-porous intervals, significant parts of the field completely lack barriers to vertical communication. The complexity of this reservoir this field, as it has moved into maturity, has come to rely on the continuously improving understanding gained through an evolving 3D reservoir model, a cross section of which is shown in Figure 3. New development opportunities may be expected to result from refinements to this model which aid in identifying unswept or inefficiently swept areas of the reservoir.

Field production peaked in 1973 at 103,400 BOPD under water flood. Current oil production with tertiary EOR is approximately 9,300 BOPD under a HCMF scheme. Produced water cut through the life of the field has increased from zero to the current field average of 97%, with a water recycle rate of 300,000 BLPD. Essentially all of this water has been introduced through pressure support activities. The current surface production operations and infrastructure may largely be viewed as a water handling, oil stripping operation and as is typical with a mature EOR asset, many of the production management issues which arise are associated with corrosion management and energy consumption. With the complex reservoir structure, oil recovery is continuously challenged by optimizing the fieldwide ongoing coordinated management of sweep efficiencies.

Injection Well and Pattern Description

The field is largely developed in an array of nine spot patterns with 160 acre well spacing. There are two distinct reservoir regions within the reservoir which require different but coordinated approaches to injection management. The subject well is a cemented and cased horizontal injector, having a horizontal length of 3600 ft which is sufficient to support injection into two well patterns, shown in Fig. 4. As shown in Fig. 5 the well also traverses two geologically distinct areas of the reservoir and the conflicting reservoir management styles required for each region posed a limitation to production. The earlier approach was to segment the strategy to reflect characteristics of each reservoir area. Pattern A3, supported by the toe region of the injection well is located within the reef margin. In this region, sweep effectiveness for the lighter weight HCMF

injectant is challenged by gravity override⁷. Horizontal injection wells, placed low in the reef margin have proven to be effective at maximizing sweep efficiency within this region of the reservoir. In contrast Pattern D3 is located in the areally large region of stratified reef buildup and is segmented into three main porosity sequences which are isolated by impermeable barriers (Fig. 5). The depletion strategy for the reef buildup region of the reservoir uses vertical injection wells which are typically completed for segregated injection into the various reservoir layers. Manually operated sliding sleeves and zonal segregation packers are common in the injection wells of the stratified reef buildup region.

Prior to the retrofit with IC technology, this well was completed for injection only into the toe end of the well, and exclusively in support of Pattern A3 (Fig. 6). The original completion of 1996 was worked over twice within 4 years and in each case the motivation was to modify the injection profile after unsatisfactory production results were obtained. The well also passed through Pattern D3 in the heal section of the horizontal though the original completion did not support this pattern. After a full HCMF cycle was complete within the toe pattern, a workover was required to move injection support uphole to the heal pattern. Later workovers would have been required to move the injection site farther up the well and closer to the vertical section while shutting off injection into the heel section (Fig. 7). Finally, after the initial generation of HCMF sweeps had been completed in all sections of the well, a third workover would have been required to recover the bridge plug and establish uncontrolled water injection into all completion intervals. Similar workover sequences in this field have encountered complications arising from the deposition of injection borne solids debris, further complicated by low circulating efficiencies which result from permeability, extended completion interval lengths and depleted reservoir pressure.

Results

Two options were investigated to reconfigure the injection profile. In the first option, conventional technology was proposed to shut off the original completion in the toe using a bridge plug before completing a second section in the heel region of the horizontal leg. An additional later workover would still be required to move the injection point uphole and into the build section of the well. The second option was to complete all current and future proposed injection intervals and then retrofit the well with intelligent completion technology. Project costs were estimated and the use of intelligent completion technology was justified solely based on intervention cost savings with no further justification being required to gain project approval.

Once the ability of IC technology to increase the level of downhole control over injection was fully appreciated, simultaneous management of the two uphole injection points was planned and the originally envisaged injection schedule was compressed by implementing the following procedures:

- The lowest interval control valve (ICV) was kept closed to shut off the toe.
- HCMF solvent was injected consecutively into the two new uphole completion intervals using ICVs to control the
 allocation of injectant through water-alternating-gas (WAG) injection cycles.
- Chase water support was simultaneously provided to the two uphole completion intervals.
- Once the HCMF solvent has been effectively swept through the upper two regions, the choking ability of the ICVs will be used to actively manage the distribution of water injection into all three completion intervals.
- Future planned workovers and their associated injection downtime were removed.

The impact to the timeline of these actions is illustrated in Fig. 8. The HCMF injection schedule was revised to exploit the additional control offered by IC technology. The result was the deployment of all planned HCMF injectant at least one year earlier than originally planned. Note that the D3 Pattern lower interval control valve, located in the horizontal section of the well was functioned several times to allow water flood concurrent with the water segment of the WAG injection into the upper interval.

Though this conversion to IC technology was originally justified by the elimination of additional planned well intervention, the operator ultimately realized more significant value through the increased level of downhole injection control which was made possible. Three years of pattern production data are shown in Fig. 9. The bars denote monthly solvent injection volumes, with immediate consecutive injection into two completion intervals. The production rate is charted cumulatively for all wells associated with the affected pattern. Acceleration of the injection schedule was accomplished by exposing the upper completion interval to HCMF solvent injection earlier than possible with conventional completion technology. This information was reviewed to yield an estimate of accelerated production of at least 250,000 barrels, the economic benefit of which is appreciably greater than that resulting from the deferred workover costs upon which the original justification was built.

Discussion

Most of the existing intelligent completion product offerings have grown out of needs which are associated with the high end segment of well construction. The complexities of these systems and of the applications where they have generally been put into service have required a disciplined engineering approach to assure the highest levels of reliability and survivability. While a high level of reliability is the ideal goal for all well completions, the robust engineering and design required to produce this reliability assurance comes with a cost. The costs, delivery lead times, and tool sizes typical of these systems

have generally precluded their movement into the moderate production rate industry segment. The present case is however an example of where the benefits of IC technology were enjoyed at a cost point appropriate over a much wider range of the overall well population.

Barriers to the wider acceptance of IC technology within the moderate production rate environment have been present within both the tool developers and operators. On the tool developer side there has been a lack of fit for purpose design which is targeted specifically to the pressure and temperature service, material specifications, tool dimensions and cost points which are suitable for the typical brownfield or moderate production rate application. Planning timelines for these assets are traditionally shorter than for the more complex and expensive projects encountered offshore. The provision of appropriately designed off the shelf products should help with ensuring timely delivery.

On the operator side there is a perception of higher risk associated with IC technology, likely originating from the generally low knowledge level within the general industry population, which is not associated with the small percentage of wells that have traditionally been associated this technology. While the deployment of IC technology may be one of the most demanding completion installations from an engineering and operations standpoint, the present case demonstrates that the technology can be successfully applied in the moderate production rate, mature field industry segment. The justification for this retrofit was based on an expected capital cost reduction over the use of conventional completion technology. This had the convenience of providing a tangible and defendable decision basis. In contrast, predicting the benefits of acceleration of an EOR scheme and expectation building for increased production will always be a less tangible proposition. Only when full recognition is given of where the largest benefits of IC technology will arise will it be of maximum benefit to the wider industry.

Conclusions

The original motivation to apply IC technology was based on an expectation of intervention cost savings, however the follow up analysis of this workover revealed the benefit to the operator to be significantly higher from enhanced reservoir management than it was from the more easily defined front end estimated cost savings due to workover prevention.

Ultimately, the mechanics of this example of field productivity improvement were simple. An injection schedule was modified to accelerate what otherwise would have been a labor intensive phased approach to change the injection configuration. In the process the completion of this well will likely be useful for the remaining life of the field and additional risks associated with future well interventions have been removed. The results could have been even more dramatic had this technology been available at the time of this well's original completion.

The greatest lesson from this case is likely not the specifics of how an operator reconfigured an injection well to accelerate an already conceived injection scheme, but rather that significant value can be derived from applying IC technology to change the way EOR is achieved. Technology developers are encouraged to develop equipment at a reliability level, complexity and price point which is appropriate for a significantly larger population of the world's wells and operators are encourage to examine IC opportunities from the viewpoint of overall business value.

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TABLE 1 – SUMMARY OF RESERVOIR AND FLUID PROPERTIES

Parameter	<u>Value</u>
Area	44,160 acres (18 000 Ha)
Ave Net Pay	87 ft (26 m)
Porosity	8 % average (0 - 25 % range)
Permeability	1-10 md to 1 Darcy +
Sw	16% (Connate)
Depth	8200 ft (2500 m)
Temp	225 °F (107 °C)
Initial pressure	3300 psia (22 700 kPa)
OOIP	1,400 MMBbls
Oil gravity	41 °API
Initial GOR	500 scf / bbl
FVF	1.369 bbl / stb
Initial bubble point	1825 psia (12 500 kPa)
Viscosity	0.4 cp



Figure 1. Distribution of Locations of Intelligent Wells before and after January 2005





Intelligent Well Primary Application Post Jan 2005





Fig. 3 - The cross-section of the 3-D reservoir model highlights large variances in reservoir quality and the general heterogeneous nature of the reservoir.



Fig. 4 – The field is developed in a nine spot array. Two patterns are supported by the subject horizontal injection well. The three wellbore segments are shaded in red.



Fig. 5 – Injection well placement in section view relative to porosity (left) and permeability (right). The vertical section penetrates vertically stacked pay sequences while the horizontal section supports injection into the higher permeability forereef margin.



Fig. 6 – Completion Diagram – before intelligent completion, showing the desired new completion intervals and proposed location of a bridge plug to shut off injection into the original completion interval



Fig. 7 – Completion Diagram – after intelligent completion

solvent / water V	VAG injection					
water injection						
	wor	kover		workove		
D3 Pattern / Lower Int	erval	D3 Pattern / Up	per Interval			
ORIGINAL PLAN						
D3 Pattern / Lower Interval						
D3 Pattern / Upper Interval						
Year 1	Year 2	Year 3	Year 4	—; ;		
			-	—:		

INTELLIGENT COMPLETION

Fig. 8 - The HCMF injection schedule- Conventional Plan and Accelerated with the Intelligent Completion.



Fig. 9 – The bars denote monthly solvent injection volumes, with immediate consecutive injection into two completion intervals. The production rate is charted cumulatively for all wells associated with the affected pattern.