SPE 112143

Downhole Flow Control for High Rate Water Injection Applications

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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

Smart completions that can remotely control the flow from multiple layers of a reservoir interval were introduced in the mid 1990's. Downhole flow-control (DHFC), as it has become known, has since been installed in hundreds of wells. However, there has been very little use of these valves to control water injection distribution within the layers of a reservoir interval at high rates (>25,000 BWPD) in a continuous proportional operating mode. This paper will review BP's efforts to team with manufacturers to deliver new technologies that can reliably provide this functionality.

By 2010 a significant portion of BP's production will come from complex water flooded reservoirs, in an environment of rising operating costs. The injection wells in these fields need to accept, in some cases, up to 65,000 barrels water per day. The use of DHFC reduces the number of injection wells by using one wellbore to enable conformed injection into multiple intervals. This eliminates the need for injection wells dedicated to a specific layer to achieve injection conformance.

BP has been progressing the development of DHFC systems for water injection wells since 2001 through collaboration with technology developers. Assurance related activities are an important aspect of these technology developments. This paper will describe several assurance activities and the scope of work involved in each, including:

- Development of a Basis of Design
- Development of a Statement of Requirements
- FMECA (Failure Mode Effects and Criticality Analysis) at component and system levels
- Detailed Design Review
- Base performance qualification testing
- Full scale HALT (Highly Accelerated Lifetime Testing) of critical features
- Stack-up and system integration tests
- Field trials
- Establishment of Global Quality Control Plans for manufacturing

A case study will be presented, describing the application of the above processes to a choking downhole flow control system being deployed by several BP Projects.

Introduction

BP's portfolio of future opportunities is characterized by complex layered reservoirs hundreds of feet thick that require water flood for optimum recovery. In many cases, the injectivity contrast between the major layer elements is such that attempts to utilize a single injection well to flood all layers would result in poor sweep efficiency.

Traditional solutions to this situation include:

- Completion of a separate injection well to each major layer
- Completion in one layer of the reservoir at a time, with subsequent intervention recompletions.

- Commingled injection into multiple layers with a later intervention to attempt to correct the injection profile.

In high operating cost environments, such as deepwater or remote locations, these are very expensive options. Wells can cost over one hundred million dollars. Interventions can cost over twenty million dollars. DHFC eliminates the cost of extra wells and/or interventions for a relatively small incremental outlay.

Capital investment and operating expenses are not the only value drivers for DHFC. The ability to inject water where it is needed, when it is needed delivers accelerated and incremental reserves in many situations. The use of DHFC in BP's portfolio will be a contributing factor in the delivery of an estimated one billion barrels oil equivalent additional recovery from FIELD OF THE FUTURE technologies.

Realizing the large value that DHFC could bring to field development requires that it function very reliably. The high operating cost environments that make DHFC such a valuable technology also make repair of failed DHFC installations very expensive.

The early history of DHFC was not one of high reliability and much has been previously published on this topic. In recent years the number of DHFC installations (for production service) has grown significantly with a steadily improving reliability record. The assurance activities described in this paper were primarily focused on the new technical challenges presented by DHFC in high rate, water injection service.

Successful installation of a water injection completion is more challenging than a production completion, with or without DHFC, for a number of reasons:

- Rate requirements are generally higher, requiring larger bore equipment
- Pressures are higher, especially if attempting to inject above fracture pressure
- The thermal range experienced by the well is wider
- Fine material not filtered from injection water can plug reservoir pore throats, reducing injectivity
- Backflowed formation solids or injected debris sometimes fill the lower completion, blocking injection
- Oxygen in injection water attacks wellbore materials
- Oil carry-over in injection water reduces relative permeability to water
- Mixed injection fluids can cause inorganic scale precipitation or reservoir souring

These problems can occur whether DHFC is deployed or not. However, the presence of DHFC equipment, even if it functions as designed, exacerbates recovery from many of these failure mechanisms. Specifically:

- DHFC may restrict injection rates
- Tubular loads between multiple packers may become excessive
- It is more difficult (sometimes impossible) to access completion intervals for cleanout or remedial treatment

For all the above reasons, a systematic approach was taken to completions assurance in BP's DHFC water injection well planning. This paper describes the processes we used to assure performance of a DHFC system for injection service at up to 65,000 BWPD.

It is important to remember that a completion is a system. Assurance processes were applied to all the components from the sandface to the surface. This paper focuses mostly on the DHFC-specific aspects.

Some of the methods are used on other critical well equipment and were adopted for DHFC. Some were adopted from other industries. Some were developed specifically for DHFC. Most if not all could be applied to other critical completion equipment.

Integrating Assurance Activities Across Multiple Projects

Three major BP development projects identified choking DHFC for water injection as a necessary technology. Each project selected their completion designs and vendors to meet their specific needs. There were wide variations in vendor selection and in some details of the completion designs. (See figure one) However, in a broad sense, all three projects used two-zone sand control on the sandface, intermediate isolation devices above the sandface completion, and choking downhole flow control in their water injection wells. These system-level similarities enabled a common team approach to many of the assurance activities described in this paper. To take advantage of global synergy, BP's Exploration & Production Technology Group

(EPTG) took on a coordinating role in assurance activities. Members of the completions team from each project participated throughout, ensuring that activities stayed on track to benefit their project.

Assurance Processes

Development of a Basis of Design:

Writing a basis of design (BoD) document does not seem like an assurance activity, but it is the groundwork upon which the other assurance activities are built. A BoD document spells out functional requirements for the DHFC system. Best practice for major project teams is to generate a project-wide BoD. A DHFC BoD may be integral to this project BoD or a separate document. In either case, key statements relative to DHFC in a BoD would include:

- Basic reservoir information such as temperature, pressure, and fluid content.
- A depletion plan, including production profiles, water injection rates and volumes, and abandonment pressures. This determines requirements such as maximum differential pressure ratings for DHFC valves and isolation packers.
- Commingling expectations. Generally commingled production or injection calls for choking functionality.
- Downhole data requirements – Pressure, Temperature, Distributed Temperature (DTS), Downhole flowrate (total and/or by zone).
- Production allocation requirements and methods. The DHFC equipment and related sensors may be called upon to provide this function.
- Entrained solids specifications for produced and injected fluids. This is critical information for the design and qualification of any project flow control equipment, and especially for the difficult to replace in-well equipment.
- Reliability and redundancy expectations. This includes a statement on the purpose of redundancy. In some projects, one working unit is required upon commissioning, in which case the purpose of redundancy is to facilitate successful installation. In other projects, two working units are required upon commissioning with a reasonable expectation of having redundant units for the life of the installation.

Each of the three projects developed a BoD addressing the issues outlined above. These formed the basis for discussion of common assurance activities.

Development of a Statement of Requirements:

The Statement of Requirements (SoR) is a construction and performance specification document for DHFC equipment. The terms SoR and BoD are sometimes used interchangeably. The two documents should not be confused. SoR here describes a distinctly different document and function. The SoR is the means of communicating to a contractor or vendor the operating specifications that his product must meet. Given to prospective vendors, it is a least common denominator, specifying the purchaser’s minimum expectations. Parameters typically specified in an SoR are:

- Working pressures and temperatures - maximums, minimums, and differentials
- Mechanical strength requirements - tension, compression, torsion, and bending
- Materials of construction, including metallurgical and non-metallics specifications
- Dimensional requirements such as maximum outside diameters and minimum inside diameters
- Threading requirements
- Fluids in contact - Hydraulic fluid, completion brines, formation fluids
- Third party inspection requirements
- Other quality control requirements such as material traceability
- Testing requirements – First item qualification and production line factory acceptance
- Referenced specifications in API, ASME, ASTM, or ISO documents

An Equipment SoR can be internally written by the operator and handed to prospective providers of the equipment, or it can be a negotiated, agreed upon, combined effort by the operator and a vendor. Each project used their own SoR format, with many similarities. As a company, BP is moving to a common web-based template developed by the BP Equipment Integrity Assurance Group.

FMECA (Failure Mode Effects and Criticality Analysis):

Failure Mode Effects and Criticality Analysis (FMECA) is a systematic method of identifying, evaluating, and prioritizing the ways in which a device, or system, could fail to perform to expectations. As causes of failure are identified, they are graded with respect to probability of occurrence, consequence, and difficulty of detection. In all three categories, a higher number is a more severe score – more likely to occur, worse consequence, more difficult to detect in advance of occurrence. The three scores multiplied together form a risk priority number (RPN) for each failure mode. Mitigating steps are taken to address and reduce risk associated with the highest scoring failure modes.

Historically FMECA has been performed only at the component level. For these projects a system-level FMECA process was also employed, linking failure modes from other system elements into the FMECA for each specific component. A generic system-level FMECA, a specific system-level FMECA, and a set of component-level FMECAs on critical completion components were performed.

A small group of knowledgeable staff from EPTG and the project teams, led by an experienced FMECA facilitator, spent from several days to a week fully exploring each component or system. A modular plug-and-play methodology enabled efficient linkage of the various FMECAs. The resulting risk mitigation recommendations were carried out in the remaining design, planning, and execution activities.

Detailed Design Review of Critical Components:

This is a formal review of the manufacturer's engineering process for designing and manufacturing equipment. The detailed design review is performed upon completion of detailed design, but before manufacturing has begun.

Detailed design reviews were performed on critical components of the DHFC completion system:

- Sandscreens
- Interzonal isolation devices
- Sand-control packers
- Intermediate isolation devices
- DHFC valves
- Feed-through packers

Sub-components subjected to scrutiny were those that are pressure-containing, load-bearing, wetted, and/or dimensionally critical. Aspects reviewed included design calculations, states of stress, dimensional tolerances, quality assurance and quality control processes, and the proposed qualification testing program.

Base Performance Qualification Testing:

Routine qualification testing as specified in the Equipment Statements of Requirements was performed by manufacturers to verify basic performance claims. All sandface, intermediate, and upper completion equipment was subjected to qualification testing appropriate to the equipment's functional requirements and specifications.

Tests on DHFC valves included internal/external differential hydrostatic pressure, and gas pressure testing with thermal cycling. Valves were subjected to endurance cycle testing equivalent to a 20 year lifetime, and to repeated opening cycles with differential pressure in both directions. Feed-through packers were tested to a minimum of ISO 14310 V-3 criteria.

Flow and Erosion Modeling:

Water Injection service in DHFC wells involves high flow rates through complex geometries. Choking functionality adds high velocities to the situation. When solid particles in injection water impact metallic surfaces, erosion occurs. Injection water is routinely maintained to a high standard of cleanliness, but it is not solids-free. Filtration systems typically allow small amounts (<1 pound solids per thousand barrels) of small particles (less than 50 microns) to enter the well.

The choking elements in a DHFC valve are typically made of tungsten carbide. These elements are highly erosion-resistant, and are not the area of concern for erosion in water injection wells. The flowpath exiting a DHFC valve does however result in high velocity particle impingement on the casing, or on the shroud in the case of a shrouded valve. Erosion of the casing or shroud is the primary concern.

Computational Fluid Dynamics (CFD) analysis of this flowpath was performed to assess the erosion potential at various flow rates and differential pressures. CFD predicted significant erosion of both casing and shroud at higher differential pressures. The results of this CFD were used to plan full scale erosion testing of the system.

Full Scale HALT (Highly Accelerated Lifetime Testing) of Erosion Resistance:

Because erosion of casing and shroud were predicted, and because a 20 year design life was required, DHFC valve assemblies were subjected to full scale accelerated lifetime erosion testing in a water flow loop. The theoretical basis for accelerated erosion testing is that up to a concentration of approximately 6%, the erosion rate is proportional to the particle concentration, all else being equal.

Our test protocol employed project-specified flowrates up to 45,000 BWPD through a single valve and differential pressures up to 1330 psi. Commercially available silica representative of injection water solids (particle size less than 50 microns) was suspended in the circulating water. A particle concentration of 2% yielded a 7000-fold increase from a project specification of 1 pound per 1000 barrels, providing a 7000-fold increase in erosion rate. This allowed simulation of a 20 year life in about 24 pumping hours.

Several practical testing issues were overcome. These included fluid heating from continuous re-circulation, cavitation due to low downstream discharge pressures, and particle degradation and settling.

In testing, full penetration was observed on the original design (high strength nickel alloy shroud) in less than 5 years equivalent time. Revised designs incorporating solid tungsten carbide armor passed the full 20 year equivalent test with little more than a slight surface polishing. (See figure two)

System integration and stack-up tests:

A stack-up test is useful for planning rig operations. It is a simulation of critical aspects of installation and/or operation.

It is often appropriate to perform system integration tests of the DHFC valves with the control system, including the hydraulic power unit, the master control station, the flatpack spools, and possibly the tree and tubing hanger. This testing confirms proper operation of the system, “footprints” operational characteristics (useful for in situ diagnostics) and familiarizes operating personnel with the system. Numerous stack-up and integration tests of critical assemblies were performed:

- Intermediate isolation devices were run in a shallow test well in solids-laden fluid to confirm functionality. Mechanical intervention tools were run to ensure proper function and to ensure they did not hang up on other components.
- A complete DHFC installation, including sandface completion equipment and intermediate isolation devices, was performed in a test well. Every tool that could be run through another was run to ensure no interference occurred.
- Projects integration tested their DHFC valves with their subsea trees and control systems.
- Off-line pick-up tests of the DHFC bottomhole assemblies were performed on the rigs which would be running them, to ensure feasibility of the lift, and to familiarize crews with the operation.

Field trials:

Field trials can be useful for verifying feasibility of installation plans, in situ functionality of equipment, operability, etc. Several components of the DHFC system, including expandable sand screens, expandable zonal isolation, and openhole packers, were verified independently in field trials for other technology projects. Consideration of potential objectives for a specific choking DHFC water injection field trial identified one objective that could not be satisfied otherwise:

Determination of our ability to modulate injection into two zones simultaneously above fracture pressure.

Note that this objective has very little to do with the mechanical functionality of the DHFC system. It is directly related to the reservoir and its dynamic response to fracturing. Obviously the DHFC system must be installed and functional to achieve the objective. But the objective cannot be achieved until injection commences. Nor can the trial be performed in a test well, because a realistic reservoir response is required. Thus, the true choking DHFC field trial will occur when the first installation is placed on injection.

Use of Global Quality Control Plans for manufacturing:

Existing practice is for each project to write Quality Control Plans (QCPs). These QCPs provide increased levels of inspection, qualification, factory acceptance testing, etc than the vendor's "standard QCP". But differences in QCPs among projects cause confusion and inefficiency in the vendor's manufacturing process and sometimes delays in delivery of products.

BP has established Global Quality Control Plans (QCPs) with vendors for a variety of products, including DHFC equipment. Adoption of these plans is a good method to ensure that delivered products are manufactured to a high standard of quality without the inefficiency and delays caused by multiple project-specific standards.

Conclusions

The successful implementation of new technology developments is largely dependent upon a comprehensive and detailed assurance program. An appropriate mix of detailed specification, "tabletop" reliability exercises, computer modeling, and physical testing provides the highest degree of assurance.

New DHFC technology for proportionally controlling high injection volumes into multiple reservoir layers has been developed and is being implemented in several of BP's major projects. The assurance activities described in this paper, along with the use of best practices for installation and operation, have provided successful results in the first of these critical completions for BP.

Acknowledgements

Sincere thanks go to John Hother of Proneta for preparing, facilitating, and documenting the marathon FMECA sessions, to the BP Project team members that provided expert input for the sessions, to our vendors for actively participating in all these assurance activities, and to BP's Equipment Integrity Assurance Group for driving the Detailed Design Review process and the Global QCP initiative.

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