SPE EuALF 2012
ABSTRACTS OF PRESENTATIONS

1. A downhole evolution for multiple ESPs

Stan Foster Rooke, RMSpumptools

THE SWITCH - a product designed to dramatically reduce cost (and retrofit) how Operators deploy Dual and Multiple ESP completions. THE SWITCH is an evolutionary development that will convert any single ESP completion to a Dual ESP without changing or adding to the existing completion. Substantial savings on Capital cost, Operating cost, planning time and lost production time means THE SWITCH is set to become the standard choice for all Dual and Multiple ESP completions. Existing Dual ESP completions require duplicated and costly specialist equipment to accommodate the dual power cables necessary to separately control the ESP's. THE SWITCH avoids all of these costs and issues Dual ESP systems are supplied power through individual power cables fed from the surface. These cables penetrate the wellhead through RMSpumptools gas tight wellhead penetrators. The two cables and specialist cable protectors continue down to the ESP setting depth. In order to provide annular isolation above the ESP's, a production packer is often used. RMSpumptools packer penetrators similarly maintain the critical pressure integrity of the packer. The packer penetrators transition the round main ESP power cable to a flat Motor Lead Extension, or MLE. The MLE's feed into the individual motors of each ESP which can be configured in a choice of RMSpumptools, non-intervention, fully automatic ESP completion systems. The Switch now introduces a new dimension to these established methods of dual completions. The Switch is installed on the production tubing, typically below the Pump Packer. All cable terminations are factory prepared to proprietary RMSpumptools 'Plug and Socket' connectors ; eliminating any field cable splicing and ensuring high integrity electrical assembly during installation. Using proven RMSpumptools electrical and mechanical technology we remove the necessity for a second cable. The Switch is operated using traditional methods of hydraulic actuation from the surface. A single hydraulic line is all that is required to function The Switch. Power must be shut down before the The Switch is operated. Pressuring up the hydraulic line actuates the switch mechanism from its primary position to latch and lock in the secondary position. Pressuring up again releases the mechanism to return and lock to the primary position. The Switch can be operated repeatedly following this procedure. Advancements in ESP Power Cable technology and application now provide expected life of well reliability that The Switch capitalises upon. The substantial benefits of Dual ESP completions now takes on a new and exciting dimension that will provide SUBSTANTIAL savings, REDUCED risk and greater choice for multiple ESP completions.

2. Using real time automated optimisation & diagnosis to manage an artificially lifted reservoir - a case study

Julian Cudmore, Zenith Oilfield Technology

The time taken to safely optimise a well produced by artificial lift can be measured in days or weeks.

Typically the process is as follows:

- Well testing
- Amalgamation of the well test data with down hole gauge and ESP controller data
- Analysis of the data to find the existing operation conditions
- Analysis of the ESP pump curve operating point and optimisation limitations

- Sensitivity studies in software to assess the optimum frequency and WHP
- Notification for the field operations to action the changes
- Further well tests to verify the new production data.
- Analysis of the data to ensure the ESP and well are running optimally and safely at the new set points

New technology enables this process to be performed in real time, significantly shortening the time to increased production and enabling real time reservoir management.

Each artificially lifted well in the reservoir is provided with a target bottom hole flowing pressure or flow rate that will enable the optimum production from the reservoir. The real time system automatically checks if the pumping system in each well can produce the production rate required within its operational limitations. The real time system automatically suggests the optimum operating frequency and well head pressure for each well to achieve the target drawdown, or the maximum drawdown the lift system is capable of. If the lift system is not capable of producing to the target bottom hole pressure then a larger pump is automatically recommended.

This paper discusses three case studies where real time optimisation and diagnosis lead to improved production from the reservoir.

3. How to identify and remedy the problems caused by wellhead chokes on ESP wells
Gabor Takacs, University of Miskolc, Hungary

The paper utilizes NODAL analysis to investigate the negative effects of surface production chokes on the energy efficiency of ESP systems as compared to the application of VSD drives. The power flow in the ESP system is described and the calculation of energy losses in system components is detailed. Based on these, a calculation model is proposed to evaluate the harmful effects of wellhead choking and to find the proper parameters of the necessary VSD unit. By presenting a detailed calculation on an example well using the proposed model the detrimental effects of wellhead choking are illustrated and the beneficial effects of using a VSD drive are presented. Using data of a group of wells placed on ESP production a detailed investigation is presented on the field-wide effects of choking. The energy flows and the total energy requirements are calculated for current and optimized cases where VSD units providing the proper electrical frequencies are used. Final results clearly indicate that substantial electric power savings are possible if production control is executed by VSDs instead of the present practice of using surface chokes.

4. A gas well dewatering pump for 23/8 inch production tubing
Kenneth Sears and Alan McAleese, ZiLift.Ltd

This paper describes some aspects of the design, development and testing of an innovative small diameter electric pump system which can be fitted into installed 23/8 inch production tubing using cable deployment, eliminating the need for a rig during pump installation and retrieval operations in the field. The system can be used to economically produce deep low-rate gas wells, increase ultimate recovery and reserves by de-watering deeper mature wells, and enable production by retrofit installation through small diameter production tubing. The downhole unit consists of a linear permanent magnet motor driving a reciprocating pump. This configuration required novel solutions in many areas, particularly motor design and electric drive, protector design, bearing and seal systems. The downhole unit includes monitoring of inlet and discharge pressures, temperature and vibration. The complete system includes cable, connectors, and the associated surface equipment which has a favourable environmental footprint. The system is currently undergoing

qualification testing in preparation for field trials in 2012.

5. Experimental investigation of ESP performance with high viscosity fluids and gas for subsea application
Lissett Barrios and Stuart Scott, Shell E&P; Ketan Sheth and Risa Okita, Baker Hughes

The paper provide updated report on developmental research on the effects of viscosity and two phases, liquid – gas fluids on ESPs which are multistage centrifugal pumps for deep boreholes. The ESP system is an important artificial lift method commonly used for medium to high flow rate wells. Multiphase flow and viscous fluids causes problems in pump applications. Free gas inside an ESP causes many operational problems. Under two-phase flow conditions, loss of pump performance or gas lock condition can be observed. Under viscous fluids, the pump performance degrades as well. Multiphase viscous performance of a full-scale electrical submersible pumping (ESP) system at Shell's Gasmer facility has been studied experimentally. The objective of this study is to predict the operational conditions that cause degradation and gas lock for high viscosity fluids to support ESP operation in Shell major Projects BC-10 and Perdido. The ESP systems studied used a 1025 series tandem WJE 1000 mixed type pump and MVP G470 pump. The test facility work was performed using pumps with ten or more stages moving fluids with viscosity from 2 to 900 cP at various speed, intake pressure and gas void fractions (GVF, aka gas volume fractions). The testing at Shell's Gasmer facility revealed that the ESP system is robust and performance tracked theoretical predictions over a wide range of single flow rates and light viscosity oils

6. A revolutionary IPO unloading valve, that improves gas lift design flexibility and reliability, while significantly reducing life cycle costs
Alan Brodie, PTC

The presentation will describe the benefits that OPCO's worldwide are enjoying following the development of a revolutionary new IPO unloading valve design. These benefits include: A significant reduction in installation costs, because of the unique unloading valve shear facility, which means any number of live unloading valves can be installed in a new completion, eliminating the requirement for wireline operations to pull dummy valves and install live valves following completion testing. The elimination of the potential for multi pointing (and significantly reduced well performance) because of the unique spring assisted, edge welded, double acting bellows design, which means that bellows reliability is much enhanced and even in the event of bellows failure, the valve is held in the closed position. The unique flexibility to reliably use unloading valves as operating valves, whenever well conditions preclude getting gas to the deepest valve setting depth, because of the uniquely long unloading valve stem travel, which means that when it is open it does not constrict the flow of lift gas and is therefore not prone to erosion.

7. Using PROSPER ™ to develop gas lift operating guidelines
Cameron Laing, EnQuest PLC

The guidelines help us to understand the limitations of installed gas lift equipment. Gas should only be injected into a well when it can confidently be injected exclusively at the orifice depth and not through an unloading valve. Both the pressure drop across the valve and the pressure in the tubing are linked to the rate of gas injection. There is a limited range of gas injection rates that can be used with any given casing pressure. Too little gas and the tubing pressure will be too high (no available pressure drop across the orifice) - too much gas and the required pressure drop will in turn require a higher casing pressure that will re-open unloading valves. This work was facilitated by using the "variable combinations" system analysis calculation within PROSPER, having first established

specific combinations of injection rate and valve dp appropriate for the given orifice size and for a given casing head pressure. The output from the system calculation then demonstrates which cases are viable. The Quicklook and Gas Lift Adjustment features of PROSPER were employed to establish valve pressure drops; check that injection was stable and that the injection pressure would not re-open unloading valves.

8. North Brae retrofit gas lift
Vijay Pathak, Marathon Oil

The North Brae field is a mature gas condensate field. Individual well production declined rapidly due to an advancing aquifer rapidly water loading wells. A pilot installation of a Marathon proprietary gas lift crossover system in March 2010 has resulted in over 3MMSCFD of incremental production (from a well which hadn't produced in almost three years). The crossover channels gas lift gas from the A-annulus via a coiled tubing insert string to lift fluids from the base of the well. The following year an additional two similar systems and one shallow system were retrofitted. Overall total North Brae production has increased from 11 MMscfd to almost 28 MMscfd of gas. The presentation will describe the successful implementation of a retrofitted deliquification solutions, capable of dewatering wells with liquid levels below the production packer.

9. On the use of distributed temperature surveys for gas lift troubleshooting
Craig Durham, Nexen Petroleum UK Limited; Keith Elphinstone, Weatherford

Wireline deployed temperature (and pressure) gradient surveys are a traditional method for determining the point of gas injection in a flowing well. With the development of fibre optic downhole data acquisition, a new method for obtaining temperature surveys is now available.

By making use of the an optical measurement technique called Raman Backscatter, which enables the measurement of the molecular energy state in an optical fibre core, a temperature profile can be obtained along the length of the cable. This Distributed Temperature Survey (DTS) has two advantages over traditional wireline deployed temperature gradient surveys: firstly, the temperature profile is continuous, rather than at pre-determined survey depths; secondly, the data is obtained at a frequency decided by the user, typically daily but more frequently depending on the data acquisition capacity of the system.

The Scott platform has used downhole fibre optic monitoring since 2003. More recently, the DTS feature has allowed almost real time temperature profiling to identify the point of gas injection under different production scenarios and to model shut-in and flowing temperatures more accurately. As a result, new gas lift designs have been installed to take account of the changing reservoir conditions.

10. Bringing digital intelligence to artificial gas lift solutions
Ian Anderson, Camcon Oil

While the last few years have seen the growth of intelligent fields and smart wells, incorporating greater intelligence into artificial gas lift has tended to lag behind.

The primary gas injection method remains 'side pocket mandrel' configured completions, with wireline interventions used to change the operating valve when injection rate changes are necessary and operators having little information on pressure and temperatures at the point of gas injection.

This paper will look at how Camcon Oil has developed a digital artificial lift solution which, based on its Binary Actuation Technology, eliminates the need for side mandrel units and wireline intervention processes to initiate gas injection changes, as well as providing real-time production information at the point of injection.

The paper will reveal the results of a recent simulation modelling analysis which compared the new solution to traditional side mandrel units and where increased production from an example well was found to be over 1,000 BOPD.

11. The applications of surface jet pump technology as an aid or alternative to artificial lift systems
Sacha Sarshar and Dr Najam Beg, Caltec

Surface jet pumps can be used effectively to reduce back pressure on oil or gas wells either to increase their production or to achieve de-liquification of liquid loaded wells. A number of recent field examples are presented in both oil and gas production cases. The system can also be used in conjunction with other artificial lift systems. Range of applications and limitations will be highlighted

12. After 5 years producing > 20k b/d to an FPSO, can we finally debunk the myth that "jet pumps are low rate devices for land fields only"?
Alan Brodie and Joe Allan, PTC; Chris Bruuijnzeels, Lundin

The Lundin Oudna development, offshore Tunisia, involves a single oil production well tied back to an FPSO. The well has been producing between 20-25k b/d for over 5 years under jet pump lift. The well has at times also produced up to 10 % by vol sand with no evidence of performance deterioration. Despite this, the production up-time has been consistently above 95% and there have been no workovers required on the well or even wireline interventions to replace the jet pump. The presentation will describe the relatively minor production facilities and FPSO mods that were required to facilitate the use of a jet pump to artificially lift a subsea well to an FPSO, along with the details of the simple well completion design, the logic used in selecting the artificial lift method and the life of field approach used to specify the installed jet pump. The production history details and lessons learned using the system will also be shared, along with lifecycle operating cost data (we dare you compare it to that of an equivalent ESP system). Finally, a new freeware jet pumped well performance simulator, which can help users to establish their well performance under jet pump lift will also be demonstrated using Oudna data.

13. Artificial lift strategy implementation in Romania oil fields
Liviu Firu and Laura Marin, OMV Petrom

The mature oil reservoirs of OMV Petrom S.A. represent a real challenge for production engineers. Their objective is to optimize production and improve oil recovery by using the proper technology and the most cost effective best practices.
The necessity to increase and maintain oil production, reduce operating costs and increase net income requires an integrated analysis including the performance and interaction of all the nodal elements: reservoir, wellbore, artificial lift system and service operation. These challenges become more complex with increasing dynamic changes in well characteristics over the life of a well.
The artificial lift strategy in OMV Petrom S.A. is a process in which the production engineers analyze actual wells behavior and performance indicators to identify and decide the short/medium/longer-

term priorities and to develop plans to achieve pre-defined targets summarized in the Artificial Lift Strategy. The strategy was tested in a pilot project performed in 2009/2010 and based on the results and lessons learned will be rolled out to all the Assets in OMV Petrom S.A.
The main challenges with respect to artificial lift operations are faced with cover a broad area from sand abrasion, frictional wear, the load and fatigue stress problems.
First result of roll out of the Artificial Lift Strategy is now available and will further detail the strategy implementation in the next years. Certain key performance indicators have been defined which proofed to be able to monitor the results of the strategy implementation.
This presentation describes the Romanian experience regarding our strategy to improve the main artificial lift KPI's through a clear set of processes: selection, analysis, solution identification, implementation, monitor and lesson learned on well/field/asset level.

14. Are we there yet? A candid discussion on artificial lift technology for heavy oil production - hot and cold
Shauna Noonan, ConocoPhillips

Over the past several years, there has been significant activity in the area of heavy oil artificial lift development. With all the various concepts and prototypes tested and installed, where exactly are the manufacturers and endusers on the learning curve? Do the endusers finally have the right artificial lift equipment and procedures to produce their heavy oil assets effectively? This presentation will help both manufacturers and endusers answer these questions and gain perspective on where efforts for improvement need to be focused.

15. 15 years of Captain ESP experience
Sander Mos, Chevron

Captain is a heavy oilfield in the North Sea and operated by Chevron North Sea Limited. The Captain Field is now in its 15th year of operation. Production started in March 1997 and since that time, the number of Electrical Submersible Pumps in the field has grown from an initial 6 predrilled wells, to a current total of 22. Of these, 20 are oil producers, producing from both Upper and Lower Captain sands. At the project phase of the development, the anticipation was that an initial ESP run life of 2 years could be anticipated. Over the years we have run 64 ESP's in the field and our run life has surpassed these initial expectations This presentation will target to share a number of key lessons and experiences around running electrical submersible pumps on Captain and will include: • a summary on run life, reliability and failure analysis, • an overview of data and exception based monitoring and a plan ahead, • a summary on modelling of ESP's in Prosper and automated workflows through IFM, • a view on deviations in completion and pump design over the years.

16. ESP failure analysis in the Forties Field – interrogating the silent witness
Cledwyn Hughes, Apache North Sea and Graham Cox, Schlumberger Artificial Lift

Apache assumed operatorship of the Forties Field on 2nd April 2003 and quickly embarked on a redevelopment of the field, which included infill drilling, well workovers and substantial upgrading of topside facilities. All Forties wells require artificial lift of some sort. Prior to 2003, gas lift was the method of choice. Currently, more than half of Forties producers are ESP wells and approximately two-thirds of Forties production is delivered by ESP's. ESP reliability and performance is therefore critically important to Apache and there is a significant prize associated with improving ESP run life in Forties. Failure analysis is a key component in the process of improving ESP run life and (virtually) every ESP that has been recovered from Forties wells since 2003 has been dismantled and the root cause of failure determined. This has led to some important insights into the failure

modes, which has driven changes in equipment specification and operation. This paper discusses the prime reasons why ESP's fail in the Forties Field and outlines the steps taken to date by Apache and Schlumberger to achieve a significant improvement in ESP run life.

17. New ESP gauge technology that operates with cable ground faults

Greg Davie, Zenith Oilfield Technology

Downhole gauges for ESP systems typically use the motor power cable for communicating data to surface. This sort of system has been in use for many years and has become a reliable method for monitoring the pump and well.
However the current technology is susceptible to problems when the insulation on the motor cable ages or is damaged. This means that the gauge signal will be lost when a ground fault occurs, even if the ESP motor continues to drive the pump and the gauge itself is undamaged. Current ESP gauges also typically provided slower data rates than permanent gauges that have dedicated instrument lines to surface.
This presentation details lesson learned on a new down hole ESP gauge technology that operates when the electrical insulation on one or more phases of the ESP power cable are damaged or shorted. The presentation will outline the technology and current field trials.

18. Electromagnetic pulsing causes ESP motor bearing failures in pulse width modulation drive applications

Salvatore F Grande III, Magney Grande Distribution; Jeff Dwiggins, Dwiggins Consulting LLC, Cledwyn Hughes, Apache North Sea Ltd and David Shipp, Eaton Corporation

As oil fields become more mature, new challenges emerge in the quest to produce oil in the most cost effective manner. Electric Submersible Pumps (ESPs) have historically been used in high producing wells and while ESPs are effective, the equipment tends to have high failure rates, both electrically and mechanically. Due to the relatively high failure rate of ESPs and the high cost of recovery, Root Cause Failure Analysis (RCFA) and Dismantle, Inspection and Failure Analysis (DIFA) both take on a more important role in defining and thus preventing failures. The industry in general is performing more RCFAs and DIFAs and ESP equipment upgrades have increased the overall reliability of these motors and pumps. At this point, it is now beneficial to help uncover some of the remaining shortfalls to ESP equipment longevity. Bearing failures in ESPs are often classified as mechanical failures. However, when the ESP is driven by a Variable Frequency Drive (VFD) using Pulse Width Modulation (PWM) technology, electromagnetic pulsing (EMP) should be considered when determining failure mode. EMP is electrical in origin and it has been identified as a culprit in reduction in the bearing lubrication (bearing fluting) which shows in the DIFA process as a mechanical failure. This anomaly is very difficult to predict; however, installation of sine wave filters to the drive output has been shown to be effective in reducing the instances of bearing fluting. Examples will be discussed.

19. Development of improved electric submersible pumps to meet today's challenges

Cyril Girard, Statoil

ESP technology has been incrementally evolving for many years now and can be considered a mature technology for well boosting applications. However, despite improvements, concerns still exist over longevity of ESP equipment, much of which is rooted in the basic arrangement of the ESP motor – seal – pump – cable architecture that has been around in the same basic form for over 80 years.

The result is that MTTFs remain relatively short and the impact on OPEX of workovers is high, meaning that for many of today's high cost and high risk wells, the business case for the application of ESPs is often compromised.

A development initiative is therefore under way on two fronts; firstly to redesign the current machinery arrangements so that many of the key failure modes are eliminated and secondly to improve the overall installation and retrievability of electric submersible pumps, which is compromised by the existing system architecture.

The development will focus on three main machinery elements:

- Redesign of the pump end to make it self contained
- Elimination of the current interconnecting shaft sealing and bearing system
- Application of new compact motor technology

Using the new proposed equipment layout and space envelope, improved deployment and retrieval systems will be developed based upon several new methods and initiatives currently underway in the industry.

20. Confidence in sizing compression ESPs for new wells completed with sand-control, Forties Field UKCS

Euan Alexander, Paul Nicoll Peter Sordyl and Joel Rodriguez, Schlumberger

Apache North Sea Ltd (ANSL) has operated the Forties Field (UKCS) since acquiring the field from BP in 2003. ANSL have ambitious production targets and an aggressive drilling programme, often targeting difficult-to-locate pockets of bypassed oil in the Forties channel sand complexes. Forties has a long history of sand production, therefore many of the wells being drilled at present in the Forties Field are completed with the most appropriate sand control method, where sand control is indeed feasible. Sand control is an ESP-friendly practice; however it is increasingly common for sand control to be installed in wells with very small pay intervals because of the anticipated high drawdowns. Inflow, being heavily impacted by the amount of exposed permeable formation, is carefully analysed so that the sand control type is correctly selected and long-term well productivity is maintained. This presentation will focus on how ANSL and Schlumberger (SLB) have leveraged ESP technology to ensure there is always an opportunity to complete and maximise production from the well, even if marginal, without compromising the target run life of the ESP. SLB supply ESPs with compression type pumps for Forties applications. By using the compression design the recommended operating range (ROR) of the pump is effectively opened up all the way to the left hand side (LHS) of the pump curve (to the point of minimum flow for motor and pump cooling). This therefore extends the ROR and allows the pump to operate in down-thrust without compromising stage life, since all of the thrust applied by the stages and the fluid column is handled by the thrust bearing of the protector in an environment of clean dielectric oil. In this presentation three case studies will be presented, where wells with sand control and marginal inflow performance have been completed with ESPs operating over to the LHS of the pump curve.

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