Heavy-Oil Well Testing With an ESP, Offshore UK

Production from heavy-oil fields in the UK continental shelf (UKCS) has become possible over the past 10 years. Despite substantial reserves in the UKCS of crudes with gravitiy of 20°API and lower, most of the activity has been exploration and appraisal drilling. The main reason for restricted activity has been high uncertainty of reservoir and fluid properties. A method was developed to find the most-suitable technology for testing these heavy-oil wells by use of an electrical submersible pump (ESP).

Introduction

Most UKCS production has been light oil, 30°API and lighter. The UK Department of Trade and Industry estimates 9.2 billion bbl of heavy oil in place in the UKCS. Many of the UKCS heavy-oil fields were discovered in the 1970s, but were considered uneconomical. Although considerable quantities of these UKCS heavy-oil resources with gravity lower than 20°API exist, the uncertainties in reservoir and fluid properties have confined activities mostly to exploration and appraisal testing. Inherent operational complexities also limit the use of conventional appraisal well-testing techniques.

The Bentley field contains 10 to 12°API oil (620-cp in-situ oil viscosity) in the Dornoch sandstone reservoir. The Bentley fluid is much heavier and more viscous than crudes at any field currently producing in the North Sea. Discovered in 1977 in a water depth of 371 ft, the field is 100 miles east of the Shetland Islands on the edge of the heavy-oil belt in the northern North Sea. The average reservoir depth is 3,700 ft. Since discovery of the field, several well tests have been performed in attempts to produce Bentley crude to the surface. However, technical issues with downhole-equipment reliability and the application of traditional well-testing techniques in the heavy-oil formation yielded unsuccessful tests with no flow to surface. Vertical Well 9/3b-5 was drilled in 2007 and tested in January 2008, flowing the first Bentley crude to the surface. The results of the test provided vital reservoir information and lessons learned for future operation planning.

In 2010, the operator drilled a horizontal well into the upper Dornoch sandstone to gather additional data through coring and logging. A short well-testing program was used to collect representative downhole pressure/volume/temperature (PVT) samples to validate flow at commercial rates. A drillstem-test (DST) string and new operational procedures based on the lessons learned from the previous well tests were used.

Challenges in Heavy Oil

The nature of heavy oil challenges conventional well-test operations. Hence, specific solutions and considerations were required at the test-design stage.

- ESP use is limited by the maximum viscosity that can be handled; therefore, chemical-injection lines may be required to dilute the production fluid with diesel or by supplying a de-emulsifier.
- High viscosity of the production fluid requires that extra heat be supplied to maintain mobility of heavy crude oil across the DST string and the surface test facilities.
- The low amount of gas and ineffective gravity separation make the use of conventional well-test separators impossible; therefore, multiphase flowmeters are needed for accurate flow-rate measurements without separation.
- Sand control is required to produce heavy oil from this unconsolidated formation. The design of the lower completion requires a compromise between minimizing the completion skin and ensuring adequate sand control.
- Such well-testing operations require integrating an artificial-lift pump, a DST string, and surface test facilities.

For ultimate testing of operational performance, it is important to obtain maximum, accurate, and in-time information from an integrated investigative process that involves formation evaluation, fluid-property characterization, lifting, and surface flow-assurance variables.

2008 Well Test

The test of Well 9/3b-5 in 2008 was designed primarily to recover oil to the surface to prove fluid characteristics, which, before drilling and on the basis of analogous geological deposition in the North Sea, were thought to be indicative of lighter crude. Another test objective was to confirm the suitability of an ESP as the lift mechanism. Therefore, the DST string included an ESP that had a conventional packer above it, and that was designed to cover the range of expected flow rates during the test, from 50 to 1,000 STB/D.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 148833, "Methodologies, Solutions, and Lessons Learned From Heavy-Oil Well Testing With an ESP, Offshore UK in the Bentley Field, Block 9/3b," by ***Barny Brennan,*** *SPE,* ***Charles Lucas-Clements,*** *and* ***Steve Kew,*** *SPE, Xcite Energy Resources;* ***Yakov Shumakov, Lawrence Camilleri,*** *SPE,* ***Obinna Akuanyionwu,*** *SPE, and* ***Ahmet Tunoglu,*** *SPE, Schlumberger; and* ***Steve Hayhurst,*** *SPE, and* ***John Simpson,*** *ADTI, prepared for the 2011 Canadian Unconventional Resources Conference, Calgary, 15–17 November. The paper has not been peer reviewed.*

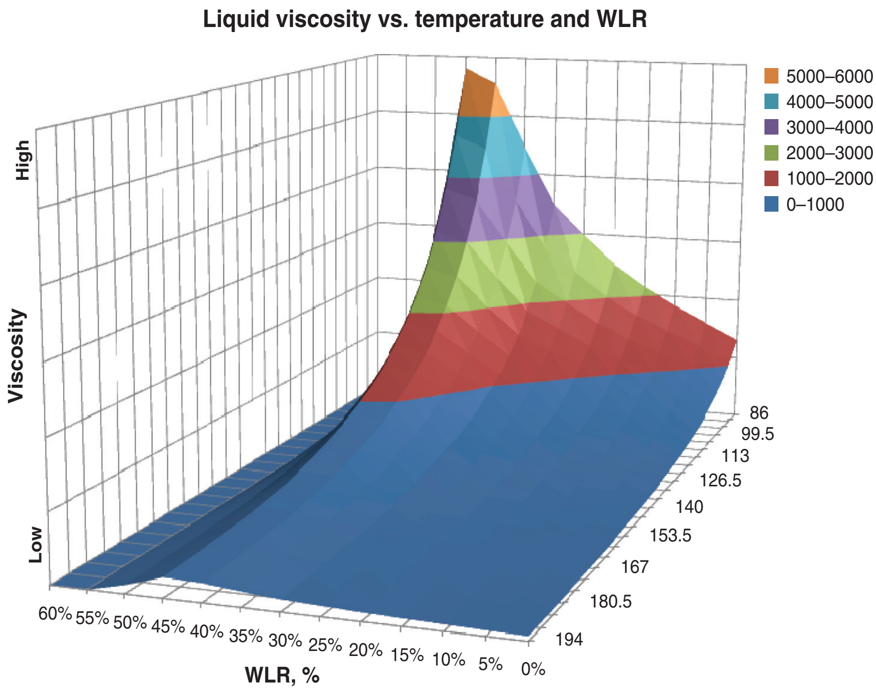

Fig. 1—Emulsion viscosity vs. WLR and temperature at 800-psia flowing pressure used by multiphase flowmeter for real-time flow-rate measurements.

Observations and lessons learned from the 2008 Bentley well test include the following.

- An alternative sandface completion is required to avoid reduction of well productivity caused by high skin.
- While the test confirmed the suitability of ESP use, the pump design would need to incorporate mixed flow stages and, possibly, gas-handling devices to avoid well production in the slug-flow regime.
- Low wellhead pressure and temperature increased the in-situ viscosity significantly and created a large pressure drop because of the friction across the tubing string. It also increased the complexity of fluid handling at the surface because of the slugging effect and the need to mitigate pressure fluctuation by manipulating the adjustable choke.
- The accuracy of flow-rate measurements by liquid-level monitoring in a surge tank was compromised by rig movement in bad weather that made the liquid level unstable.
- Two separate data-acquisition and real-time data-delivery systems were used, which made operational support complex and subsequent data processing cumbersome. Real-time data gathering should be integrated into a single system.

2010 Well Test

Following the 2008 well test, a project was started to design an optimum well completion and to demonstrate that commercial development of the Bentley field was viable. The well design comprised an S-shaped pilot hole followed by a horizontal sidetrack with an 1,800-ft-long, geosteered reservoir section that subsequently was flow tested. The objectives of the test were to perform reservoir characterization and evaluate well deliverability, validate the ability of the well to flow at commercial rates, and collect representative bottomhole PVT samples of reservoir fluid.

ESP-DST String. ESPs are viscosity limited, and the design stage must take into consideration the reduced head-flow performance of the pump caused by high viscosity. In conventional ESP completions with production packers set above the ESP, the packer creates a hydraulic barrier in the annulus, which precludes operating downhole tools by sending pressure commands through the annulus from the surface. Therefore, annulus-pressure-operated tools, such as a downhole shut-in valve or a tubing-conveyed PVT-sampling carrier, cannot be installed below the ESP. An alternative completion arrangement (a shroud) was required for the 2010 well test to collect bottomhole PVT samples and ensure a second mechanical barrier while providing hydraulic communication through the annulus with downhole tools below the pump.

ESP Hydraulic Design. To cover the range of expected flow rates, a pump with a wide operating range was required. The increased operating range was achieved by combining the compression pump stages with a variable-speed drive operating between 40 and 60 Hz.

Downhole Fluid Heating and Pressure Drop. One of the lessons learned from the 2008 well test was the importance of maintaining a high fluid temperature across the completion to stabilize well-production flow rates and avoid slugging to improve surface testing operations. For the 2010 test, detailed analysis was conducted to maximize the heating benefit of the motor combined with a shroud. To maximize the heating effect of the ESP motor, three motor sections were selected instead of two, increasing the surface contact between the motor and the fluid.

With a shroud application, the small clearance between motor surface and shroud allows the heat generated by the motor to be transmitted to all the production fluid. The shroud also reduces heat loss across the wellbore. This benefit had to be counterbalanced with the loss of intake pressure caused by friction between the ESP motor and the shroud, which also is aggravated by the high viscosity of the oil.

In heavy-oil tests with a strong emulsion, which is aggravated by the ESP, performing manual measurements of basic sediment and water (BSW) becomes more challenging and the acquired results usually are not sufficiently accurate with poor fluid separation. However, multiphase flowmeters equipped with a nuclear dual-energy gamma ray fraction meter can differentiate individual phases in multiphase flow and provide accurate and continuous measurements of water/liquid ratio (WLR) and BSW throughout the test. Currently, there is no PVT correlation that could describe viscosity of the emulsion accurately and determine the inversion point. Therefore, the multiphase flowmeter requires viscosity of the flowing liquid emulsion as an input parameter. To overcome this problem, an emulsion study was performed in the PVT laboratory to determine emulsion viscosity vs. WLR by use of dead-oil samples from the previous well test and completion brine. This curve, in combination with PVT properties and live-oil viscosity, was used by the multiphase flowmeter to compute emulsion viscosity of flowing mixtures at line operation temperature and at WLR with a constant pressure of 800 psi (**Fig. 1**).

The application of multiphase flowmeters during the test provided continuous real-time flow rates and BSW measurements used for monitoring test progress and ESP performance. A series of liquid-viscosity measurements and manual measurements of BSW at the wellsite during the test confirmed the validity of the PVT model used for the multiphase flowmeter.

Real-Time Data. ESP-DST well testing requires seamless integration of data-acquisition and -delivery systems, optimized for monitoring of each operation to deliver data from the ESP and surface well-test package in different formats to dedicated operation-support centers. Significant modifications were made to the real-time data-delivery infrastructure to achieve the required level of synergy for integration of data from the wellsite to the remote Web-based server. Special processes and integrated workflows were developed and implemented by use of an operation-support center manned by a multidisciplinary team for data processing and coordination of all operations. With specially designed software, the operation-support center could access wellsite acquisition units remotely to check systems, validate data, and assist with any troubleshooting on a continuous basis. **JPT**