Staying ahead of the curve

The steep production declines characteristic of the shale plays wreak havoc on more than just well economics. They can strain the very pumping systems intended to boost output. Jennifer Pallanich looks at an unconventional artificial lift solution devised to help manage one challenging south-east Texas field's transition through the decline curve.

Unstable levels of inflow to the wellbore and unusual multiphase flow behaviour pose critical challenges when planning an artificial lift solution for shale plays because they often lead to gas locking and shorten run life of the rod pumps and electric submersible pumps (ESPs) commonly used in unconventional plays.

According to Diego Narvaez, North America Land region technical manager for artificial lift at Schlumberger, steep production declines and fluctuating fluid characteristics were the key challenges his company had to address for its Eagle Ford shale client Magnum Hunter Resources.

"We have identified the Eagle Ford as one of the most challenging environments," he says. "If you can perform here, you can perform anywhere." Eagle Ford shale is particularly difficult for artificial lift because the wells are about 10,000 feet deep, feature long horizontals, hit temperatures up to 270°F (132°C), and produce a lot of gas.

"The behaviour of the unconventional plays is very different from play to play," Narvaez says. "They're very different, even from well to well." But one thing that can be expected in the shales is a steep decline rate. Initial flow rates of more than 2000 barrels per day can dip quite quickly as reservoir pressure drops, forcing operators to routinely use artificial pumping systems.

In conventional environments, ESPs typically are placed downhole and expected to run continuously for a few years without stopping until the unit fails or needs to be pulled for resizing. However, in the prevailing Eagle Ford conditions, traditional artificial lifting solutions will not work for long without burning out the ESP's motor.

"The gas is the biggest enemy… for any ESP or centrifugal pump stages," says Bassem Moustafa, marketing communications manager for artificial lift at Schlumberger. The gas causes difficulties for centrifugal pumps because it can cause severe performance degradations, surging or gas locking, which causes the motor to overheat. While most pumps can handle a gas component of about 10% to 15%, slugging flow in the shales can push that component up to 100%.

Schlumberger had to contend with declining production and varying gas-to-oil ratios at a Magnum Hunter Resources well in the Eagle Ford shale, later sold to Penn Virginia (see page 19). The operator's initial development plan was to let the well flow naturally for a few months before initiating artificial lift. The well flowed at 14,700 barrels per day at the beginning — then the steep decline curve set in.

> **"The behaviour of the unconventional plays is very different from play to play… even from well to well."**
>
> *Diego Narvaez, Schlumberger*

"That's a huge challenge from the artificial lift standpoint," Narvaez points out. The difficulty, he notes, lies in coping with the combination of production decline with multiphase flow characteristics such as high gas volumes plus a light crude ranging from 38 degrees API to 51 degrees API, which makes it a volatile oil.

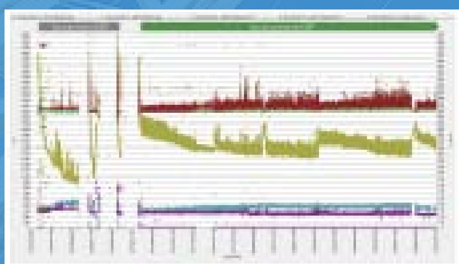
"In two months, three [conventional ESP] systems had to be pulled after only days of operation," Narvaez recalls. "At the end of the third installation, we said: 'Stop. This conventional ESP approach doesn't work for the unconventional plays.'"

Narvaez' team went back to the proverbial drawing board. Ultimately, drawing on expertise from the Schlumberger Petrotechnical Services group, they came up with a transitional pumping approach to shepherd the well through the decline curve. "They helped me to understand the flow behaviour and the fluid characterisation," Narvaez explains.

According to Dave Sobernheim, principal engineer for unconventional resources at Schlumberger, understanding multiphase flow is key to successful recovery in the shale plays. The transitional solution is applicable in other shale plays, according to the company, and would also be applicable in situations where heavy oil — which needs more lifting power — makes up part of the output. "Theoretically this would »

Images: Schlumberger

DOWNHOLE DUTY: Downhole components of the ESP system solution include compression-type mixed flow pumps and gas-handling devices, REDA Maximus motors and protectors, and Phoenix downhole gauges.



GETTING REAL: Real-time data has been instrumental for ESP operation, as well as enabling engineers to analyse the reservoir and assess well completion techniques and the influence of fractures from nearby wells.

FREEZE FRAME: Instantaneous frame taken from a transient multiphase flow simulation done using OLGA.

be easier," Sobernheim says, because there is less gas for the pump to deal with.

Narvaez' team relied on OLGA dynamic multiphase simulation software from Schlumberger's SPT Group to get to grips with the uncommon nature of the shale's multiphase transient flow.

"That's what brings us the opportunity to integrate the understanding of this transient and explain the performance that we're seeing on the ESP," he says. The unconventional ESP solution his team devised relies, he says, on "four key pillars of hardware, operating procedures, real-time monitoring and people".

On again, off again

The transitional pumping solution they came up with features customised equipment, special operating practices, real-time monitoring, and dedicated experts. From the time the first unconventional ESP was installed in September 2011 until it was pulled in September 2012, the pump had been started and stopped 1478 times.

The uneven flow ranged from 100% liquid to 100% gas. When the gas levels or motor temperature crept up to a pre-set threshold, the motor controller shut down the ESP — at one point the pump ran continuously for 21 days.

"At the end of one year we accumulated a record number of starts and stops," Narvaez says. When the ESP was first installed, total production was 620 bpd, and after one year the output was 75 bpd. "It was able to cope with this steep decline curve."

According to Narvaez, having compared production data from a period heavy with ESP starts and stops with data from the three-week continuous operations, the team "realised there was no significant difference on the trend of the decline curve". He attributes that to reservoir pressure building during the stops and the fluid characteristics, which helped the reservoir flow naturally. "We are still analysing this from the reservoir standpoint. How do we explain this unique behaviour?"

Key components

"From the hardware standpoint, we focused on the downhole equipment and also on the surface equipment," Narvaez says. "It's a systemic approach."

Abrasion-resistant mixed flow pumps were employed. A Poseidon multi-phase gas-handling system capable of handling up to 75% free gas mixture was specified because it offers more efficient energy transfer than centrifugal stages and avoids gas locking at high gas-volume fractions. REDA Maximus variable-rated motors were used to match motor output to load demand, and a sinewave variable speed drive was used to minimise noise and stress on the ESP.

The service company worked with Magnum Hunter to develop custom operating procedures. Experts from the two companies could see real-time data and use downhole sensors paired with the LiftWatcher surveillance service to keep tabs on key operating parameters such as downhole fluid temperature, motor temperature, pump intake pressure, system vibration, normal motor current, operating frequency, and current leakage. Also through the LiftWatcher service, tubing pressure, casing pressure, gas flow rate and other analog inputs could be viewed.

Algorithms were programmed to adjust the operation of the ESP system as needed to cope with the dynamic inflow conditions. The whole system is modelled in the Petrel E&P software platform, the Mangrove reservoir-centric stimulation design software for unconventional plays, the OLGA dynamic multiphase simulator and the Avocet production operations software platform.

"When they implemented this transitional artificial lift method... it was an investment," Narvaez says. "But the thing is, after you complete this transitional artificial lift method you are going to transfer the ESP system. It goes from well to well and in the previous well you are going to install the low-flow rod pump or gas lift system. Ultimately, our system gives you one more effective tool to manage and control drawdown in unconventional liquid-rich plays such as the Eagle Ford," he concludes.

PRESSURE POINT: The Poseidon multiphase gas-handling device with helico-axial flow stages can successfully operate at lower intake pressures with gas volume fraction in the pump up to 75%.

SHALE STRATEGY: Magnum Hunter Resources' three-stage strategy for development of the Eagle Ford field — natural flow, transitional artificial lift (ESP), and low flow (rod pump or gas lift). Previous development plans were based on implementation of rod pumps directly after the natural flow stage.