CASE STUDY

Subsurface Compressor System™ (SCS)

Increases Gas Production in Unconventional Well by 62%, Produces 50% More Liquids

Trial Performed on Liquid Loaded, Unconventional Shale Gas Well in Indiana

Challenge

- Increase gas production and recoverable reserves from a liquid loaded, unconventional shale well with a horizontal wellbore

Solutions

- Deploy the first full-scale commercial Subsurface Compressor System (SCS) to:
  - → Reduce downhole flowing pressure to create higher reservoir drawdown that increases gas inflows and recoverable reserves
  - → Carry liquids to the surface by creating higher gas velocities throughout the vertical and horizontal wellbores
  - → Prevent vapor condensation by increasing the temperature of the gas when exiting the compressor

Results

- The trial resulted in a 62% increase in gas production and a 50% increase in liquid production over its steady-state performance with a rod pump prior to the SCS installation

First Commercial Subsurface Compressor System

This was the first time certain topside and subsea technologies were deployed downhole:

- → High-speed permanent magnet motor
- → Magnetic coupling
- → Passive non-contact magnetic bearings with electronic dampers
- → Sensorless high frequency controls (which are able to control the frequency of the motor downhole without sensors via a long step-out)

Magnetic Coupling

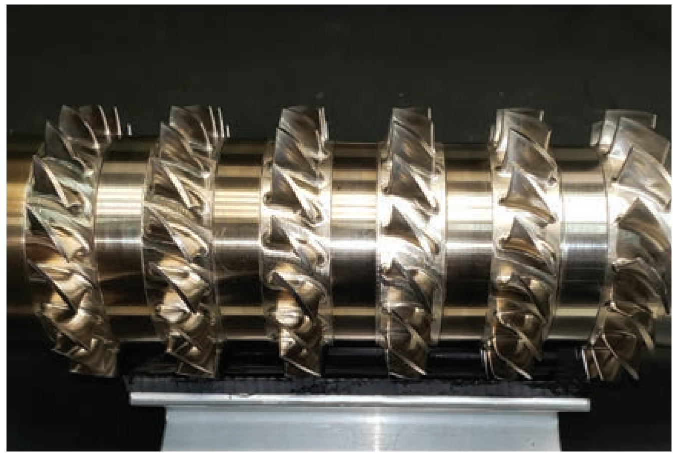
Passive Magnetic Bearings with Electronic Dampers

High-speed Permanent Magnet (PM) Motor

SCS Motor Section with Magnetic Technologies

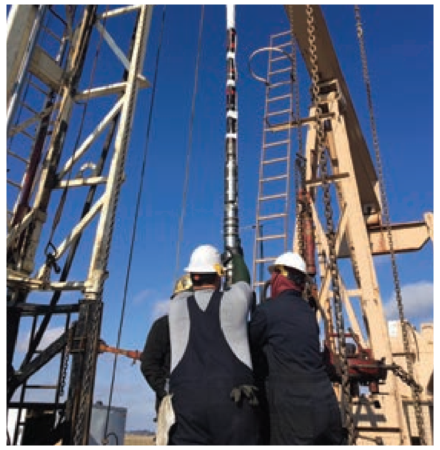
Top Side High Frequency Drive, Necessary Transformers, Communication and Safety Systems Located in Mobile Control Center Operate the SCS Motor without Sensors

The system included a hybrid axial wet gas compressor, which was able to handle a significant amount of liquids without showing any degradation.

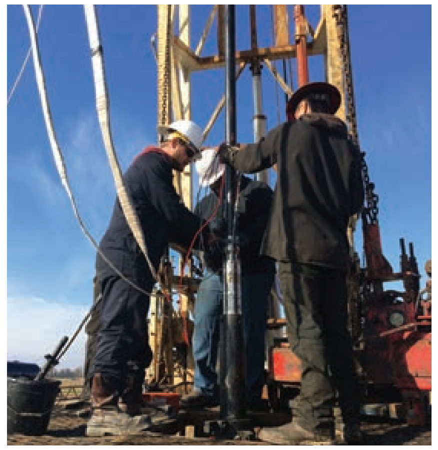


SCS Compressor Blades before the Trial

SCS Compressor Blades after the Trial (Rust Shown in Picture was Pipe Debris Moving through the Compressor)



SCS Tubing Hung Deployment



Shroud Installation to Handle the Extended Length of the Tailpipe

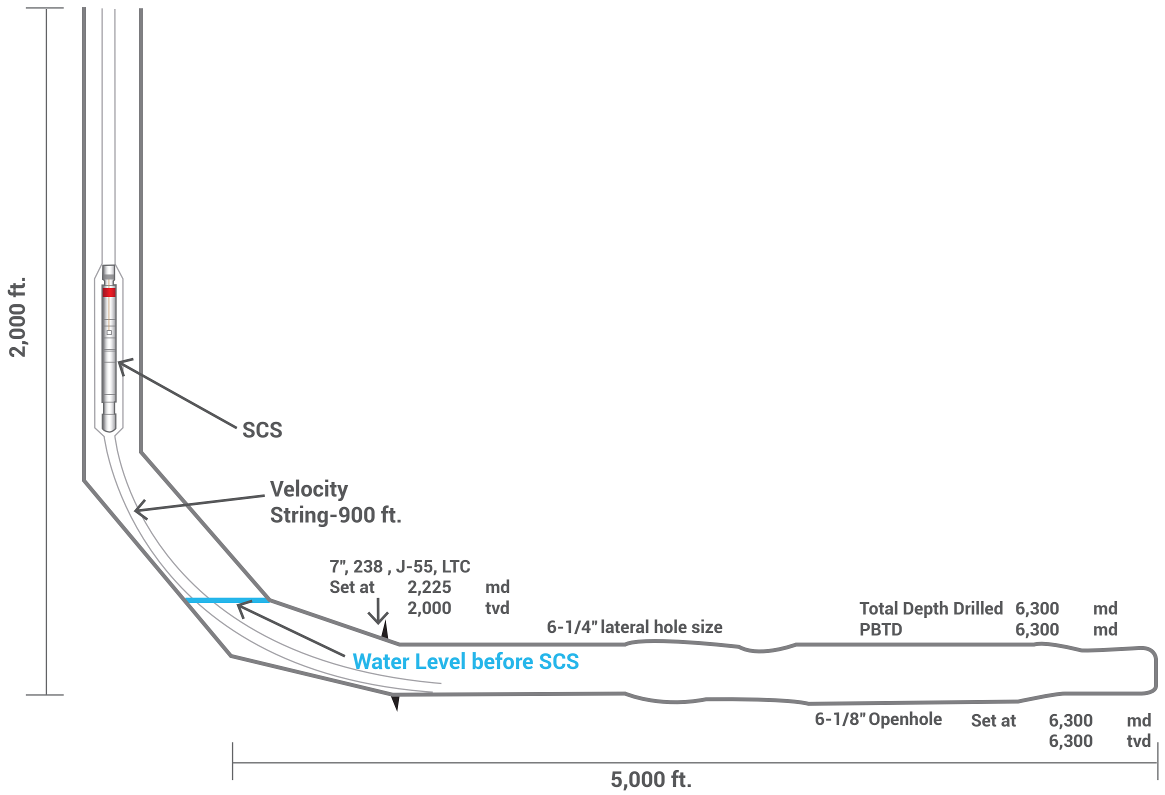
Wellhead after Installation and Instrumentation

Deployment of the SCS

The well is relatively shallow with a vertical depth of 2,000 ft., and has a long horizontal section of 5,000 ft., where liquid had accumulated. The compressor was installed at the bottom of the vertical section with a tail pipe extending approximately 1,000 ft. into the horizontal. A shroud was used to be able to carry the extended length of the tailpipe.

The well was killed with additional water poured through the wellbore to ensure a safe deployment. Once the pump unit was pulled out, it took two days to install and start the commissioning of the SCS into the wellbore. The installation is very similar to ESP systems in that the SCS unit was tubing deployed, and the electrical cable with the instrumentation was secured around the tubing. In order to maximize the effect of the SCS, a 3.5-inch production tubing along with a 3.5-inch velocity string were selected to provide enough velocity to carry liquids while minimizing friction losses.

Trial Well Geometry and Configuration



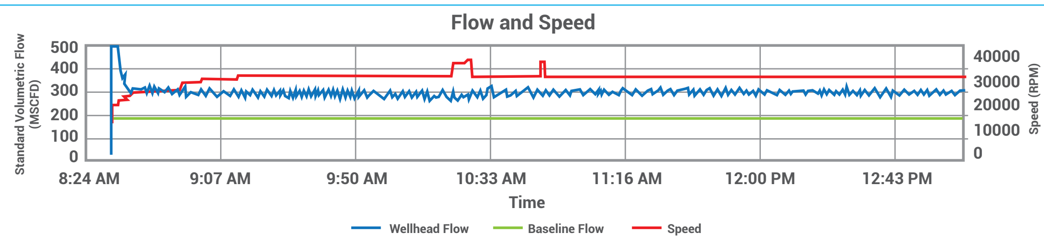
Trial Results

Prior to installing the compressor, the well's gas production was about 185 MSCFD and its liquid production (via rod pump) was 5-7 BPD. Without the rod pump, the well choked in a few hours.

With the SCS, the well stabilized at a gas production of 300 MSCFD (+62%) with the help of nitrogen injection to kick off the well over a two-day period, and liquid production increased to over 9 BPD (+50%) over the same period. The nitrogen injection helped push the liquids within the vertical and horizontal wellbore into the formation and enabled the SCS to startup without being submerged in kill fluid. The trial period started at the end of October, and the SCS was pulled out in early December.

The Turner et al (1969) correlation assumes that free flowing liquid in the wellbore forms droplets suspended in the gas stream with gravity force pulling the droplets down and the drag force pushing the droplets upward. The minimum required gas velocity to lift liquids to the surface was 22 ft/s. While the SCS operated at 20,000 RPM, the gas velocity within the vertical wellbore was 22.5 ft/s, and the well operated in the transitional state between the slug and annular-mist flow conditions. The liquid production at the surface during that time was detectable although intermittent. When the SCS operated at 30,000 RPM, the gas velocity increased to 29 ft/s, and a high rate of liquid was carried to the surface. As shown in the picture below, the hybrid axial compressor was able to atomize the liquid into a very fine mist, which together with the increased velocity and heat generated from the exit of the compressor helped carry the liquids to the surface.

The hybrid compressor, which had 6 stages of Inconel rotating blades, showed no sign of wear or impingement due to the liquids. The design point pressure ratio of the compressor at 30,000 RPM was 1.25, and this was validated by the downhole memory gauges that were placed at the suction and discharge of the compressor.



20,000 RPM

30,000 RPM

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