As seen in the September 2010 issue of E&P

Real-time flow rate obtained from ESP data

A solution to understand reservoir response, spot early trends, and improve well test quality can be achieved by monitoring electrical submersible pump (ESP) data.

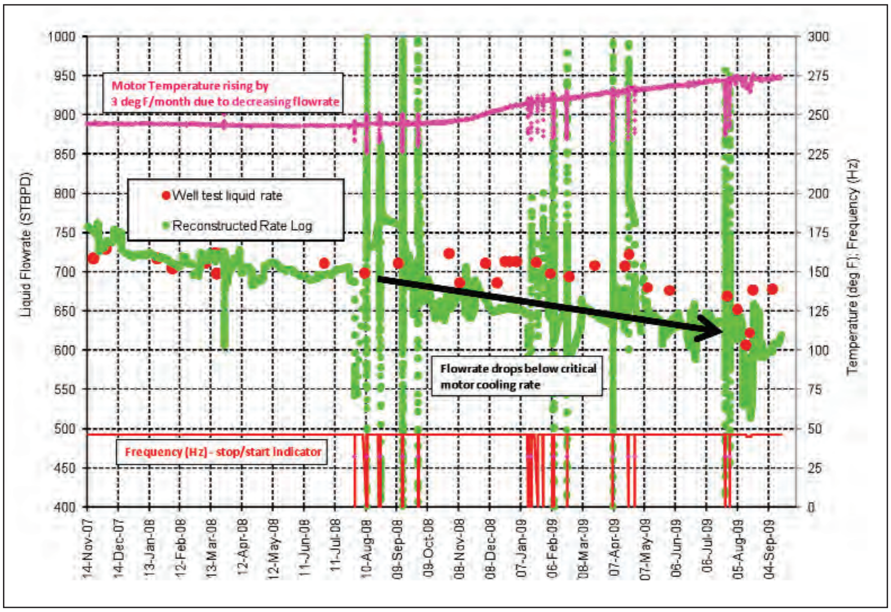
AUTHOR

***Lawrence Camilleri**, Schlumberger*

As real-time technology gains momentum in the oil industry, more wells are equipped with permanent gauges. SCADA systems and data historians also are becoming the norm as reduced operating cost and increased recovery factor value is demonstrated consistently. More than 11,000 ESPs have been fitted with gauges over the past six years and more than 3,000 of these wells have remote monitoring capability using a SCADA system.

Despite growth in instrumentation and connectivity, flow-rate measurements and recording have lagged and remain manual and episodic in nature. Wells typically are tested once a month with manual data entry into production databases. The exceptions are wells equipped with dedicated multiphase meters, which are few and far between. A Schlumberger proprietary interpretation technique provides real-time flow rate without the need to retrofit additional hardware in the field, with the exception of downhole ESP gauges and a SCADA system, which, in many cases, already are available. Providing real-time well flow rate can improve back allocation. Calculated flow rate also delivers the necessary high resolution and repeatability missing from traditional test separator measurements, thereby capturing flow transients in addition to steady state conditions.

This technology brings a new dimension to well and reservoir performance diagnostics. Superposition analysis is enhanced and can be used to monitor real-time reservoir pressure based on flowing pressure, reducing the need for frequent buildups. In addition, many reservoirs produce at flow rates below the threshold required to achieve reasonable accuracy with test separators. But, when downhole measurements are used, it is possible to plot flow rate, flow pressures, and reservoir pressure accurately, which enable engineers to see production changes as low as approximately 10 b/d. This granularity cannot be achieved using monthly well tests, particularly when production fluctuates rapidly.

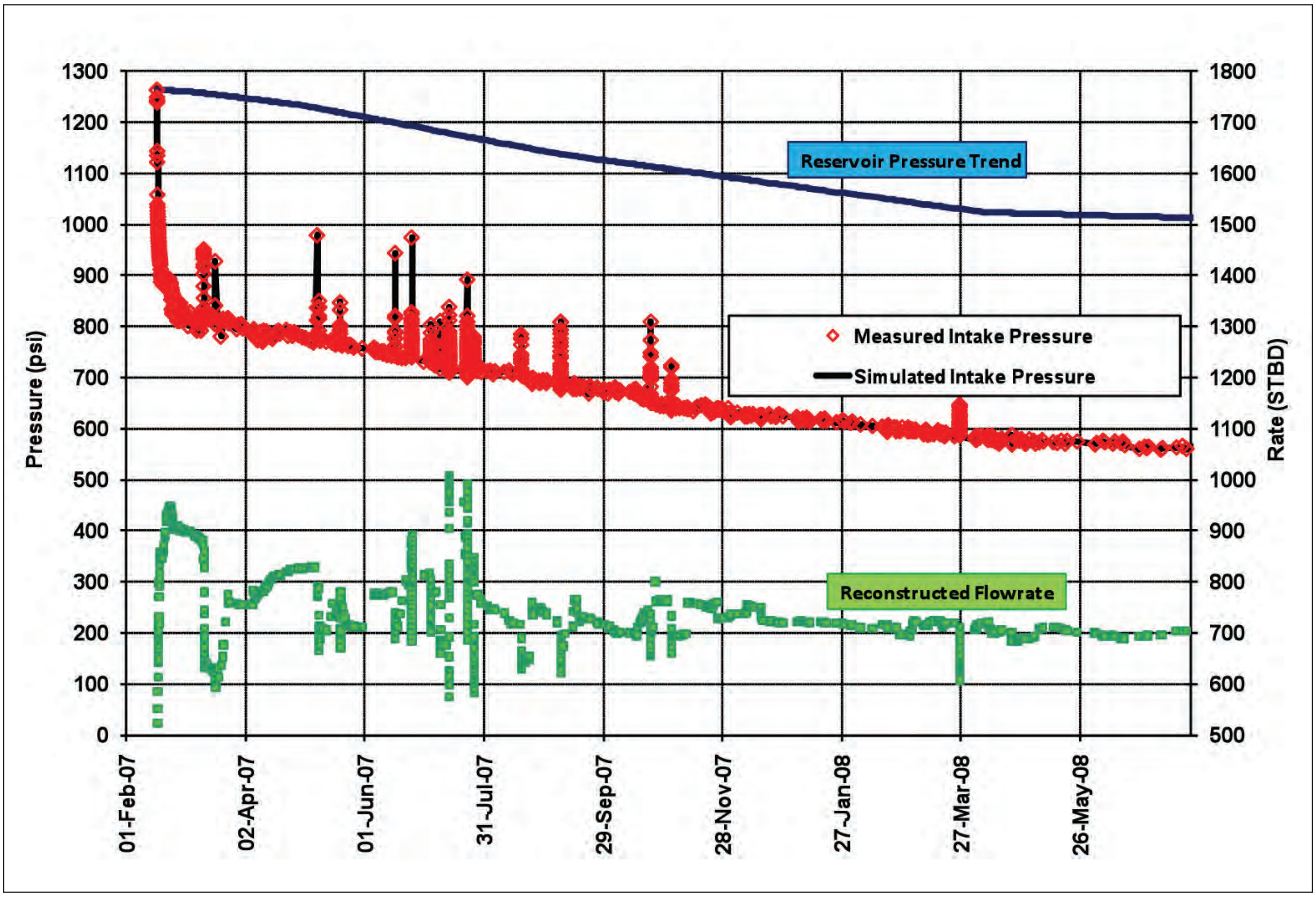


The calculated flow rate provides an early detection of declining flow as well as explanation of why the ESP motor temperature is increasing. Between October 2008 and July 2009, the test separator could not detect the drop in flow rate. This is due to a small change of about 50 b/d and numerous well shutdowns that cause transients, which are not conducive to accurate test separator measurements. Conversely, the calculated flow rate shows the transients, which is illustrated by the flow going to zero when the well is shut down and the flow being high when started with open valve. A downward flow-rate trend concurrent with the motor temperature rise can be identified. (Charts courtesy of Schlumberger)

How is it done?

Power absorbed by the pump is equal to that generated by the motor. On one hand, pump power is a function of its pressure differential, flow rate, and pump efficiency. On the other hand, motor power is a function of downhole voltage, current, power factor, and motor efficiency. Because equilibrium exists between both pump power and motor power, it is possible to solve for the unknown, which is the flow rate through the pump.

With the ability to calculate instantaneous pump flow rate, engineers can use data to observe trends that are virtually invisible to those depending on quarterly or monthly well tests. Once calibrated, trends can be used to monitor well performance. Because they are taken in real time and at high resolution, they are valid in both transient



Reservoir pressure simulation using the superposition model shows the pressure decline in the drainage area. There is a match between the simulated and measured flowing pressure due to calculated flow-rate history that captures flow-rate transients.

and steady state conditions, unlike those of NODAL analysis, and also can capture transients associated with slugging effects. The qualitative nature of the trend is accurate, even if pump efficiency has been compromised through pump wear. Further, by using the value measured from the previous well test, trend data can be calibrated, providing instantaneous flow rate over the interval between tests.

As with other flow-rate reconstruction techniques, the model must be calibrated, especially for obtaining flow at stock tank conditions.

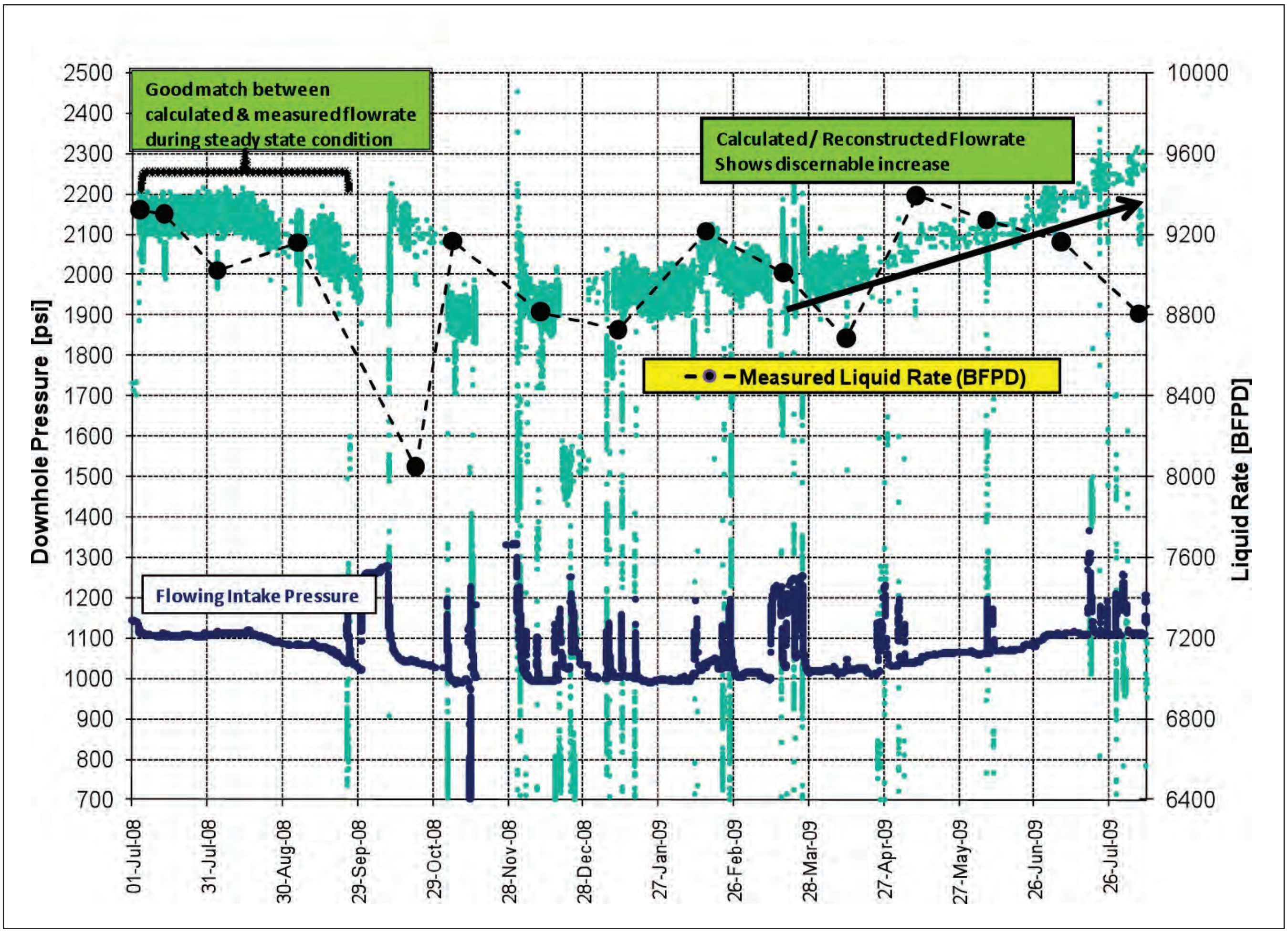
Therefore, it is not a substitute for traditional surface testing, but rather an enhancement. Without calibration, the model can provide a method for identifying qualitative trends which enable both ESP and reservoir behavior diagnostics otherwise impossible with traditional well testing due to lack of resolution and repeatability. Intrinsic to the method are:

- An analytical model derived from first principles that is valid at all times and does not require a regression or empirical correlation;
- While absolute accuracy requires calibration, value obtained from resolution does not. With current instrument metrology it is possible to detect flow-rate changes as small as 10 b/d. The main reason for the high resolution is the ESP low inertia, which means that the slightest change in required hydraulic power is reflected in a near instantaneous current variation;
- A technique valid in transient conditions and steady state that is a result of the high resolution. The ability to measure transient behavior provides a method for observing real-time well hydraulic behavior during startups and diagnosing problems rapidly. Also, it enables accurate superposition analysis to model reservoir pressure trends. The technique can be applied to data without the need to filter out time periods when the well is in transient condition, which is an improvement over previous flow-rate reconstruction methods based on NODAL analysis or temperature measurements;
- A simpler and more robust interpretation than methods based on NODAL analysis because fluid properties are not required; and
- High repeatability, which is important to identify reservoir trends.

While theory is important to understand the robustness of the solution and the underlying physics, case studies corroborate the application of theory and illustrate the value for actual producing wells.

How long should tests take?

API RP85 recommends that well testing with test separators should encom-



Between April and July 2009, the flowing pressure increased by 100 psi without change in ESP operating parameters or wellhead pressure. Further, there was no discernable trend from the test separator's monthly flow measurements because, despite an accuracy of +/- 5%, there is insufficient repeatability. On the other hand, flow-rate reconstruction using the Schlumberger proprietary technique shows a clear trend of increasing flow rate for the same period. Identifying liquid trends led to the conclusion that reservoir pressure in the well's drainage area was increasing during the period. Identification of such trends is possible due to the high resolution and repeatability of the flow-rate calculation technique.

pass several liquid holdup periods. For example, consider a well with completion volume of 50 bbl. At high flow rates (above 1,000 b/d), valid data could be expected with eight to 12 hours of testing. However, wells producing at a tenth of that volume (100 b/d) could require more than 35 hours of testing to produce three completion volumes and achieve the same accuracy. Accordingly, it was concluded that traditional testing could be costly, particularly in low-rate wells. With monthly test frequency, tests often lack the resolution to provide reliable trend analysis. The problem is exacerbated in locations where frequent testing is impossible for logistical reasons. Obtaining accurate back allocation depends on test resolution and sufficient test frequency and duration, which can be limited by logistics and economics of testing.

Is testing needed?

Using real-time pump data does not substitute for testing. Rather, the techniques complement each other. Flow-rate reconstruction on several wells over the past two years has corroborated the theory on a wide range of completion and fluid types.

Improved IT solutions to simplify and automate the solution are in development, as well as incorporation of work flow into real-time software. In addition to providing well performance and reservoir diagnostics, this technique has potential to revolutionize traditional testing practices, especially on low flow-rate wells which require long test durations to achieve required accuracy. With the instantaneous calibrated flow-rate calculation, testing frequency can be reduced from once a month to once every two or four months. This not only reduces testing costs, but also provides an opportunity to increase the test duration per well, increasing accuracy. The proprietary interpretation technique provides production optimization, reduced testing costs, and increased testing accuracy. It is not every day that a simple use of mathematics and physics can yield value in these diverse ways. E&P