Production Logging for Reservoir Testing

Using production logging tools to test wells provides a more accurate analysis of reservoir parameters, such as permeability and skin damage. Measuring flow rate and pressure immediately above a producing zone not only reduces wellbore storage effects but also makes it practical to run transient tests without shutting in a well and halting production.

The techniques for analyzing transient tests rely only on pressure measurements and assume a constant flow rate during the test period. The constant flow-rate situation, in practice, prevails only during shut-in conditions. Thus, buildup tests have become the most commonly practiced well testing method. Buildup tests, however, are sometimes undesirable because the operator does not want the production lost or because the well may not flow again if shut in. In such circumstances, drawdown tests are preferable. In practice, it is difficult to achieve a constant flow rate out of the well, so these tests have been traditionally ruled out.

There are several advantages to testing a well, either at the surface or downhole, while flowing. In producing wells, less production is lost because the well is not shut in. Keeping the well on production is especially valuable for poor producers that may be difficult to return to production once shut in. In layered reservoirs, testing under drawdown reduces the possibility of crossflow between producing layers, whereas during a buildup test, crossflow can easily occur and complicate interpretation. Accurately testing a well with only surface flow-rate measurements is difficult in practice. Surface production and testing equipment cannot hold a flow rate constant or measure flow rate accurately in a short time frame. This equipment is better suited to measuring flow rates during long periods—days, not minutes or seconds—for commercial sales volumes or daily production data. Most surface facilities lack the accuracy to measure quick changes in flow rate necessary for transient interpretation.

Testing a well with downhole pressure and flow sensors eliminates some of these complications because flow rate is measured just above the producing interval. Production logging tools measure flow rate more accurately than surface facilities do, especially for any instantaneous or small rate changes. Flow rates and pressure changes are closely associated—any change in one produces a corresponding change in the other. The challenge in well-test analysis is to distinguish between pressure changes caused by reservoir characteristics and those caused by wellbore storage or fluid movement. The accurate measurement of flow rate and pressure changes can provide insights into reservoir properties and production potential.

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PLT (Production Logging Tool) is a mark of Schlumberger.


by varying flow rates. The pure reservoir signal can be determined by acquiring simultaneous flow and pressure measurements, which can easily be obtained in most wells using production logging tools. The PLT Production Logging Tool string, positioned at the top of the producing interval, records downhole flow rate and pressure data throughout the test.

Well Testing
The three components of the classic well testing problem are flow rate, pressure and the formation. During a well test, the reservoir is subjected to a known and controllable flow rate. Reservoir response is measured as pressure versus time. The goal is then to characterize reservoir properties.

Complications arise because flow rate is typically measured at the wellhead, but interpretation models are based on flow rate at reservoir conditions. Under some ideal conditions, such as single-phase flow and constant wellbore storage, the surface flow rate can be related to downhole rate, allowing a good interpretation of the reservoir characteristics. If more than one phase, oil and water for example, flows in the reservoir or in the wellbore—gas evolving out of solution—then the interpretation becomes more difficult.

Obtaining interpretable data under non-ideal conditions often requires test durations ranging from days to weeks so that conditions in the wellbore can stabilize. For a typical pressure buildup test, the test would have to be run until all afterflow and phase redistribution effects cease. Until then, reservoir response is masked by wellbore effects (top right).

Mechanisms that cause wellbore storage are compressibility of the fluids in the wellbore and any changes in the liquid level in the wellbore. After a well is shut in, flow from the reservoir does not stop immediately; rather, it continues at a diminishing rate until the well pressure stabilizes. Wellbore storage also varies with time due to segregation of fluids.

Two important advances have significantly improved control of well testing: downhole shut-in valves and downhole flow measurements. These techniques have eliminated most of the drawbacks inherent in surface shut-in testing, such as large wellbore storage, long afterflow period and variations in wellbore storage (right).

Downhole shut-in. The main advantages of downhole shut-in are minimization of wellbore storage effects and the reduced duration of the afterflow period. In the surface shut-in test, wellbore storage masks the radial flow plateau for more than 100 hr. In the downhole shut-in test, radial flow is evident after 1 hr.
There are many ways to shut in a well downhole, from drillstem-test tools to wireline- and slickline-conveyed tools. The advantage is that no downhole measurement of flow rate is required; however, there are several disadvantages. This method is practical only for a shut-in test, so production is lost and returning the well to production may be difficult. Moreover, wireline- and slickline-conveyed valves are complicated to operate and may leak or fail.

Reasons for Downhole Measurements

Another approach to well testing is to measure flow rate downhole with a stationary production logging tool at or near the top of the reservoir. The advantage of this method is that the well does not have to be shut in for the transient test. Another advantage is that the stationary production log can be combined with a traditional flow survey versus depth conducted prior to the transient test and one during the test to investigate crossflow effects.

Although simultaneous measurement of downhole flow rates and pressures has been possible for some time with production logging tools, the use of such measurements for transient analysis in well testing is relatively new. A continuously measured flow rate can be processed with measured pressures to provide a response function that mimics what would have been measured as pressure if downhole flow rate had been constant.

In many cases, particularly in thick or layered formations, only a small percentage of a perforated interval may be producing, often because of blocked perforations, the presence of low-permeability layers or poor pressure drawdown on a particular layer. A conventional surface well test may indicate the presence of major skin damage, but from the conventional data alone, it would be impossible to determine the reason for the damage. Downhole flow measurements allow reservoir engineers to measure flow profiles in stabilized wells and calculate skin effects due to flow convergence. Thus, they can infer the true contribution that formation damage makes to the overall skin effect. This information can help design more effective stimulation treatments.

Downhole flow-rate measurements are usually obtained with spinner flowmeters run either on slickline for downhole recording or on electric line for real-time surface readout (above left). Continuous spinners are used to test high-rate wells, to perform flow measurements inside tubing, if needed, and to test wells in which restrictions may prevent operation of a fullbore spinner. Continuous spinners are in-line and allow use of a combination of tools, including a fullbore spinner, below in the tool string. Fullbore spinners are routinely used and considered as the reference, and they are used in deviated wells.

Layered Reservoir Testing

Most of the world’s oil fields have layers of permeable rock separated by impermeable shales or siltstones, and these layers usually have different reservoir properties. If all the layers are tested simultaneously and only downhole pressure is measured, it is impossible to obtain individual layer properties (above). Thus, special testing techniques are needed for layered reservoirs.
Two economical methods of using production logging tools to perform multilayered reservoir tests are selective inflow performance tests and layered reservoir testing. Selective inflow performance tests are performed under stabilized conditions and are suitable for medium- to high-permeability layers that do not exhibit crossflow within the reservoir. Layered reservoir testing is conducted under transient conditions. Pressure and flow measurements are used to determine the optimum production rate for all producing layers.

The selective inflow performance test can provide an estimate of the inflow performance relationship curve for each layer. As the well is put through a stepped production schedule with various surface flow rates, the production logging tool measures the bottomhole pressure and flow profile at the end of each step. From these production profiles, an inflow performance response (IPR) curve can be constructed for each layer using the data from all the flow profiles.

Although a selective inflow performance test provides formation pressure and IPR for each layer, it does not give unique values for the permeability and skin factor of individual formation layers.

If a reservoir has multiple layers, a transient test in which only downhole pressure is measured is virtually useless. All the layers have wellbore pressure as the common inner boundary, so the pressure alone does not convey enough information to determine the properties of the individual layers. Flow rate, not pressure, indicates the properties of the layers. Good zones make large contributions to the total flow, whereas the poor layers have only small contributions. The method used to test a multilayered reservoir is to measure the contribution of each layer during the transient test.

Layered reservoirs. This pressure profile shows differential depletion of up to 800 psi [5515 kPa] between layers (A, B, C and D). Crossflow will develop in this reservoir when the well is shut in.

In addition to measuring flow profiles, layered reservoir tests acquire downhole pressures and flow rates versus time during each flow period (above). The PLT tool takes these measurements as it is stationed between layers and above the uppermost layer. Taking measurements at these stations, in effect, separates the layers. Bottomhole pressure is recorded continuously, but the rate per layer is measured only at a discrete time interval. The layered reservoir test requires careful planning and rigorous wellsite logging procedures because of the numerous events that can occur during a test. Interpreting layered reservoirs is complex because it involves both the identification of the reservoir model and the estimation of unknown parameters such as permeability, skin factor, reservoir geometry and pressure for each layer.

Combining a selective inflow performance test with a layered reservoir test yields the best results for multilayered reservoirs, especially if there is multiphase flow inside the casing.

Outlook
Well testing remains of fundamental importance in the development of oil and gas reserves, and production log flow measurements provide a valuable tool to evaluate well and reservoir performance. The trend is for the continual refinement of data acquisition and interpretation techniques, with a push for downhole measurement whenever possible. Recent tool advances improve measurements in deviated, multiphase-flow and low flow-rate wells which have often posed problems for traditional spinners.

Horizontal wellbores and associated completion designs present several challenges to profile interpretation for conventional production logging sensors and techniques. Testing and interpretation are better understood in vertical wells than in horizontal wells. Wellbore storage effects, phase segregation and complex geometry in horizontal drainholes complicate analysis of downhole flow-rate measurements. Advances in numerical modeling techniques are overcoming some of the limitations by allowing better model matching and earlier determination of the flow regime.

As a result, production logs can be used to choose intervals that should be tested selectively, and new selective test procedures will help analyze limited sections in horizontal wells. In the future, these selective tests and numerical modeling will help reservoir engineers better identify formation property variations along the drainhole.

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