EARLY PRODUCTION PREDICTION FOR UNCONVENTIONAL WELLS

While oilfield service companies have been claiming the ability to predict unconventional well production using reservoir models, the claim may be true in the sense that they can predict production – just not very accurate. The article presents a solution that enabled reservoir models to incorporate concrete data about each fracture, precisely calibrating the model to the hydraulically fractured state of the reservoir, resulted in a model that accurately predicted production in a blind test.

For years, oilfield service companies have been claiming the ability to predict unconventional well production using reservoir models. The claim is true; they can predict production – just not very accurately. And operators know it.

"Everyone has a reservoir model; but the models are not very reliable at predicting detailed production," says Casey Lipp, Geologist at Peregrine Petroleum. The main reason for this unreliability is the inability of the models to simulate variable fractures. Current models have to assume that all fractures along a wellbore are planar and simple, with the same height, length, and permeability. Using such simple fracture models in a reservoir simulation multiplies the inaccuracies of these assumptions.

In a case study with Peregrine Petroleum, MicroSeismic presented a solution that enabled reservoir models to incorporate concrete data about each fracture, precisely calibrating the model to the hydraulically fractured state of the reservoir. This resulted in a model that accurately predicted production in a blind test. "When Peregrine began working with MicroSeismic, we became very interested in the option of adding microseismically-derived fractures into the reservoir model. Incorporating precise fracture data appears to have achieved a meaningful leap in the ability to accurately predict production," said Lipp.

Better Model Variables

Earlier reservoir models have failed to account for the variability of proppant placement throughout the fractures in the Stimulated Rock Volume (SRV). Because of this gap, the reservoir models failed to find a useful correlation between SRV and cumulative production over time. MicroSeismic's concept of Productive Stimulated Rock Volume (P-SRV) is able to fill this gap by differentiating between proppant-filled vs un-propped fractures. P-SRV has shown much closer correlation to cumulative production than was ever achieved with total SRV.

P-SRV is able to define what portion of the stimulated fracture network will be productive.

But how productive will the P-SRV be? The most reliable indicator of a fractured reservoir's production is the level of permeability enhancement achieved by the hydraulic stimulation. When a reservoir is hydraulically fractured, the basic goal is to enhance the permeability of the reservoir by inducing new fractures and activating the existing natural fractures.

The process for determining the reservoir's P-SRV and permeability enhancement involves building a deterministic discrete fracture network (DFN) model:

1. A fracture plane is defined for every viable microseismic event, including the fracture size and orientation.
2. The distribution of proppant throughout the fractures is determined using the actual amount of proppant pumped for each stage.
3. A geocellular grid is superimposed on the DFN to obtain the SRV and P-SRV, capturing the proppant-filled rock volume.

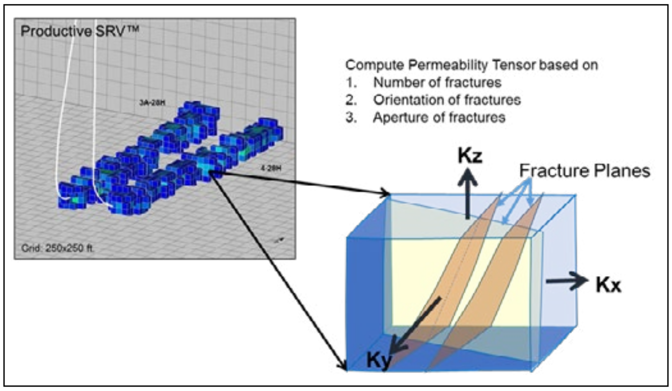

Figure 1: Computing permeability tensor.

One key advantage of this workflow is the ability to capture the fracture intensity (fracture number, orientation, and aperture) achieved in each cell of the geocellular grid, which enables quantification of the permeability enhancement in each cell. Figure 1 shows an example of the P-SRV with the permeability enhancement calculation process for one geocell.

This information fundamentally changes the resulting reservoir model because it enables the model to be based on a deterministic DFN model, incorporating actual changes in the fracture intensity along the wellbore; whereas past reservoir models could only use a theoretical fracture model that assumed every fracture along the wellbore was the same simple fracture.

History-matching for Precise Calibration

Unconventional reservoir models are often calibrated by history-matching the results with production data from an already-produced well. Theoretical models are typically derived from a rate-transient analysis or decline-curve analysis. These theoretical models can be useful for predicting a completed well's total estimated ultimate recovery (EUR), but they are not able to accurately predict production over shorter increments of time or predict how the reservoir will drain as the well continues to be produced. The greatest advantage of the deterministic DFN/reservoir model is its ability to accurately predict the volume and pattern of reservoir drainage over time and, therefore, predict incremental production over time.

The deterministic reservoir model incorporates the permeability enhancement values from the DFN along with the other typical model variables such as microseismic data, pressure-volume-temperature data, and core and petrophysical data from well logs. History-matching of existing production data from a single produced well is used to calibrate the permeability enhancement values from relative levels of permeability into absolute permeability values. The calibration's resulting mathematical multiplier can then be applied to the microseismic data of multiple nearby unproduced wells to automatically provide absolute permeability values for those wells. This means that absolute production volumes can be accurately predicted for each nearby unproduced well.

This process enables reservoir models to be precisely calibrated to the current state of the reservoir, based on mathematically-derived data, rather than calibrating based on theoretical assumptions. The result is a reservoir model that is calibrated so accurately, it can dependably predict short- and long-term production and reservoir drainage for multiple monitored wells using the same absolute permeability multiplier that was already determined during history-matching.

Uses

Reservoir models that incorporate these deterministic DFNs and absolute permeability values enable an operator to see how the reservoir is expected to drain as each nearby well is produced. Understanding the reservoir drainage pattern of each well can prevent incorrect spacing of wells, which results in wells competing for the same drainage volume (if spaced too close together) or leaves significant volumes of rock undrained (if spaced too far apart). Predicting accurate reservoir drainage patterns also enables optimisation of other variables of field development, such as stage spacing, clustering, or refracturing, to maximise net present value. Production timelines or economic thresholds can be used to constrain long- or short-term field plans, depending upon whether the operator wants to maximise short-term production or wait for the long term. These decisions are often based on current economic conditions.

Quantifying the absolute permeability of each geocell in the reservoir also enables quantification of the productivity of each cell. This could indicate reservoir sweet spots and measure the success of treatment methods for different stages. Stages that are predicted to be less productive can be used to indicate improvements for future treatments, without waiting for the well's production data to come in. After processing the production data from one nearby produced well, reservoir models for subsequent monitored wells are available nearly immediately. The same absolute permeability multiplier can immediately be plugged into each well's microseismic data to predict production for multiple nearby unproduced wells, rather than waiting for each well's production data to calibrate each model. Operators would typically have to wait at least six months to gather enough production data for each well's separate model calibration. Eliminating this wait-time enables an operator to assess the expected production for multiple area wells and use that information to plan ahead for future development. It also negates the workflow and time that would typically be required to calibrate each reservoir model.

CASE STUDY

Introduction

In 2014, Peregrine Petroleum was rapidly drilling and completing wells in Ellis County, Oklahoma, targeting the Cleveland formation. In this area, the incised, valley-filled depositional environment makes for highly variable geology and poses challenges in determining optimum treatment design and well spacing. MicroSeismic, Inc partnered with Peregrine to help them quantify fracture geometry and improve well spacing, stage length, and completions parameters. Peregrine asked MicroSeismic to use their proprietary deterministic reservoir modeling method to prove in a blind test that the model could accurately predict production of a monitored well (i.e., Well B), if Peregrine provided production information from one nearby already-produced sample well (i.e., Well A).

Background

Wells A and B were drilled in the early Missourian Cleveland formation, which produces natural gas and oil at a depth of approximately 9,200 ft true vertical depth (TVD). The regional geological structure is a homoclinal dip to the south with a few subtle structures. The project area reservoir is interpreted as being dominated by low-permeability tidal-shelf and distal delta-front deposits. These lenticular sand bodies make it difficult to predict the size and distribution of the reservoir and, therefore, the potential per-well reserves.

With a temporary surface array, MicroSeismic captured data on 20 stages. Peregrine provided surface pressure and production information for Well A. Using the microseismic and client-provided data, MicroSeismic determined the total SRV, the portion of the SRV that was propped, and, therefore, the portion that should be productive in the long term (Figures 2 and 3) for both

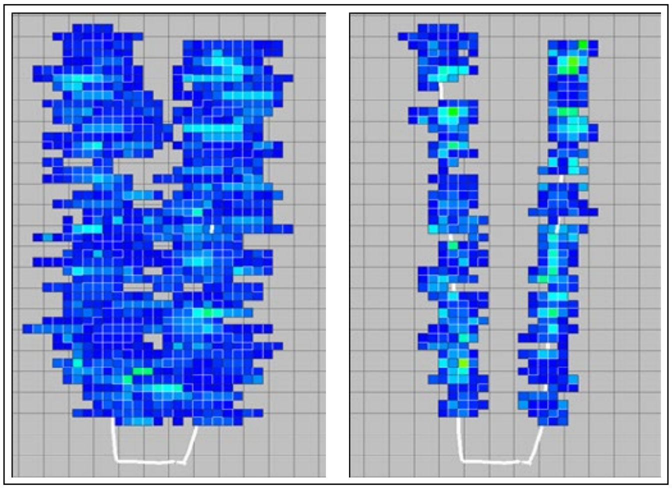

Figure 2: Wells A and B – Total SRV *Figure 3: Wells A and B – Productive SRV*

wells A and B. MicroSeismic quantified the permeability enhancement of the reservoir using a 3D geocellular grid. The necessary scaling factors were obtained from Well A's production and treatment data and used to translate the relative values of permeability enhancement to absolute permeability. The resulting absolute permeability multiplier was applied to Well B's surface microseismic data to predict production and reservoir drainage patterns for both wells A and B. These simulations also provided a mechanism to determine optimal wellbore spacing.

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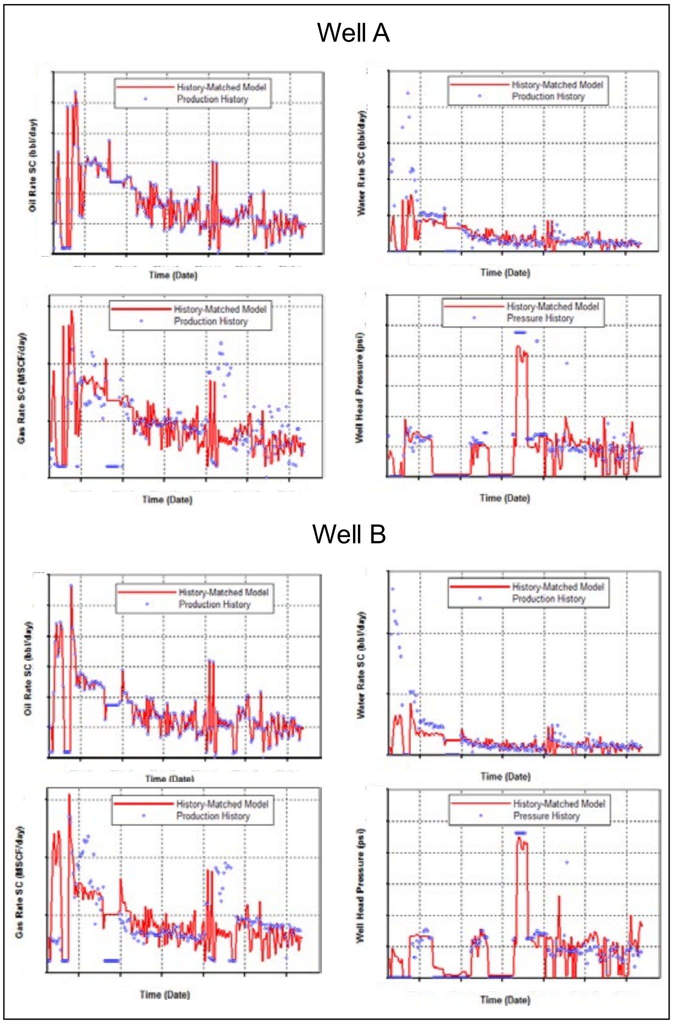

Figure 4: Actual production matches closely with MicroSeismic's predicted production

Results

When Peregrine compared Well B's actual production to MicroSeismic's predicted production, the prediction was shown to be a very accurate match (Figure 4). This shows that the calibration tools MicroSeismic developed for Well B could also be used to reliably predict future production and reservoir drainage for other nearby monitored wells.

MicroSeismic recommended that Peregrine decrease spacing between wells to approximately 700 ft to ensure that valuable hydrocarbons are not left unproduced. MicroSeismic also identified excessive SRV overlap between stages, meaning that Peregrine could fracture fewer stages while still stimulating the same volume of rock. The microseismic analysis suggested that 16 stages would achieve the same SRV as the current 20-stage design.

Client Uses

Well spacing in this area of the Cleveland formation traditionally ranges from two to four wells per section or approximately 2,640 ft to 1,320 ft, respectively. Using microseismic data and reservoir drainage estimates provided by MicroSeismic, Peregrine implemented a down-spacing pilot project at 1,000-ft spacing and modified treatments to try to increase fracture half-lengths. The pilot wells are currently on flowback and are being monitored for results. Peregrine plans to continue testing different well spacing distances and fracture treatment designs to continue to maximise recovery of reserves.

Conclusion

Currently, the industry does not trust theoretical reservoir models for detailed production prediction because everyone has learned how unreliable these models can be. The difference in deterministic-DFN reservoir models is that they are able to incorporate a reservoir's state of permeability after hydraulic fracturing; therefore, they have the unique advantage of capturing details of the reservoir's reaction to stimulation. This makes them fundamentally different from previous models. The added level of detail makes the models more deterministic and accurate.

As shown in this case study, MicroSeismic has already begun to prove the advantages of their deterministic reservoir models in understanding and forecasting production. MicroSeismic is currently using this technology with other operators in North America to help forecast production and reservoir drainage and optimise completions in unconventional reservoirs. ●

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