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Understanding and Quantifying Variable Drainage Volume for Unconventional Wells

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Summary

Everyone has a reservoir model; but the models are not very reliable at predicting the details of production. The main reason for this unreliability is the inability of the models to accurately simulate variable fracture geometries along the wellbore(s). One approach is to assume that all fractures along a wellbore are planar and simple, with the same height, length, and permeability. While this might provide reasonable estimates of production and EUR, it fails to accurately describe the drainage volume – inherent in the assumption of uniform fracture geometry for every stage. Another approach is to use a stochastic DFN model along with geomechanical modeling of rock failure to describe the resultant failed fracture geometry. This is used with Monte Carlo techniques that generate hundreds of models to quantify the range of production and the associated uncertainty. While this approach appears more rigorous, it requires quantifying values for a large number of model parameters, most of which have to be estimated, since actual measurements of these parameters are very rare for unconventional wells.

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 most reliable predictor of a fractured reservoir's production is the level of permeability enhancement achieved by creating a network of failed natural fractures and induced fractures through hydraulic stimulation. A new methodology has been developed that involves quantifying the fracture intensity through a deterministic discrete fracture network (DFN) model explicitly using the measured microseismic data, pumping parameters and rock properties. The fracture intensity can be translated into a permeability tensor using fluid flow principles in fractured media. By accurately understanding, describing and quantifying the permeability enhancement we obtain an improved description of the reservoir model honoring the observed spatial changes in fracture intensity, fracture geometry and drainage volume.

This approach fundamentally changes how we quantify the permeability in our reservoir models. This methodology incorporates actual changes in the fracture intensity along the wellbore, rather than using a theoretical fracture model. This simplifies the reservoir simulation, providing very fast and sufficiently accurate results to understand the production and depletion around single or multiple horizontal wells. One case study from Eagle Ford will be presented.

Introduction

There are multiple methodologies for estimating production from unconventional reservoirs. Although many of these methods are sufficient for estimating the gross production from treated wells, they typically cannot provide accurate estimates of the drainage pattern around the wellbore to quantify the production contribution from individual stages. This is mainly because the reservoir models are based on a fracture model that over-simplifies the fracture geometry by assuming planar, simple fractures for the entire wellbore. Using these simple fracture models in a reservoir simulation compounds those assumptions and their inaccuracies. We set out to find a solution that would enable reservoir models to incorporate concrete data about each induced fracture, allowing the model to be precisely calibrated to the treated state of the reservoir, which achieves a meaningful leap in the ability to accurately predict a well's production.

In previously published works, we have established a deterministic method for building a discrete fracture network (DFN) that discriminates the propped fractures from the un-propped fractures. However, describing the geometry of propped and un-propped fractures is not enough to accurately determine the production potential of individual wells. It is important to understand the permeability enhancement actually realized within the stimulated reservoir region. Therefore, we have developed a methodology that uses the spatio-temporal dynamics of microseismic events (time and distance of events from the wellbore) and the description of the fracture network and fracture intensity (number of fractures, fracture orientations, and fracture apertures) to compute a permeability tensor based on principles of fluid-flow in a fractured porous medium. This information fundamentally changes how we quantify the permeability in our reservoir models. This methodology incorporates actual changes in the fracture intensity along the wellbore during hydraulic fracturing, rather than using a theoretical fracture model.

Methodology

The most reliable indicator of a fractured reservoir's future 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.

In order to distinguish between the total stimulated rock volume (SRV) where microseismic activity was observed and the part of the SRV that contains proppant filled fractures and will therefore be productive in the long term, a magnitude-calibrated DFN is modeled onto the microseismic events. Through source mechanism analysis, strike and dip of the failure plane are identified for each individual event. The geometry of each individual failure plane is then determined through the magnitude of an event incorporating rock and fluid properties. In order to obtain length, height, and aperture of the fractures a methodology incorporating the magnitude of a microseismic event, the rigidity of the reservoir rock, the injected fluid volumes, and, if available, fluid efficiency is employed. From the moment magnitude, the seismic moment can be calculated, which depends on the area of the failure plane, the displacement along the plane, and the rigidity of the rock. Assuming that the total detected seismicity is directly related to the injected fluid volume and that the change in volume is completely accommodated by the seismic failure, minus leak-off, the calculated fracture volume should equal the injected fluid volume. Since the seismic energy that was recorded during a treatment and subsequently located as discrete events is usually only a fraction of the total emitted energy, the two volumes described above rarely match. In order to account for any undetected microseismic event population, such as tensile failure emitting quickly attenuating low frequency signal, or microseismic events with a signal below the detection threshold, a scaling factor is introduced. Each variable defining the geometry of the fracture is then recalculated so that the fracture volume matches the effective injected fluid volume (McGarr, 1976; Kanamori, 1977; Bohnhoff et al., 2010; McKenna, 2013).

Estimating the propped half-length is performed by filling the DFN with proppant from the wellbore outward on a stage by stage basis. The packing density of the proppant is variable and can be adjusted based on the specific gravity of the proppant. Proppant filling is constrained by tortuosity of the flow path by allowing only a fraction of the proppant to populate fractures intersecting the prevalent failure plane azimuth at high angles. The fracture volume inside the respective stage DFN is filled with proppant until all proppant that was pumped is accounted for to obtain the proppant filled fractures of the total DFN. The network of proppant-filled fractures is called the propped DFN (P-DFN) (McKenna and Toohey, 2013).

To quantify the Stimulated Rock Volume (SRV), a three-dimensional grid is applied to the total DFN. Every grid-cell containing a non-zero fracture property is included in the SRV. The total SRV is dependent on the size of the model cells and can be adjusted based on known reservoir flow properties. It represents the total rock volume that was affected by the treatment. In order to discern between the part of the SRV that is assumed to be drained over the lifetime of the wellbore and the remaining part of the SRV, the grid is applied to the propped DFN as well. A subset of the SRV that is calculated from propped DFN then represents the Productive SRV (P-SRV) that is expected to contribute to production in the long term.

Every cell in the SRV and P-SRV contains at least a partial fracture. One key advantage of this workflow is the ability to capture the fracture intensity (number of fractures, their orientation, and aperture) achieved in each cell of the reservoir grid. This fracture intensity is translated into a permeability tensor using the Oda approach (Oda, 1985), providing quantification of the unscaled permeability enhancement in the x, y, and z-direction for each cell.

We use the permeability enhancement results, as each cell's comparative magnitude of permeability. In other words, the permeability enhancement results demonstrate the amount of permeability enhancement in each cell compared to its neighboring cell. We call this the PermIndex – as it represents an index or relative magnitude of permeability. The ability to quantify these comparative permeabilities is a huge advantage for a reservoir model as it allows the model to capture the variations in fracture intensity along and away from the wellbore. These values indicate which cells likely will be more productive.

Figure 1 shows an example of the P-SRV with one enlarged geocell sample containing three intersecting fractures. These fractures will result in varying enhancements in fluid flow within the individual cell. The full tensor is calculated from the total number of fractures in an individual grid cell and the fracture orientations and size, providing a three-dimensional distribution of permeability enhancement in the reservoir due to the stimulation.

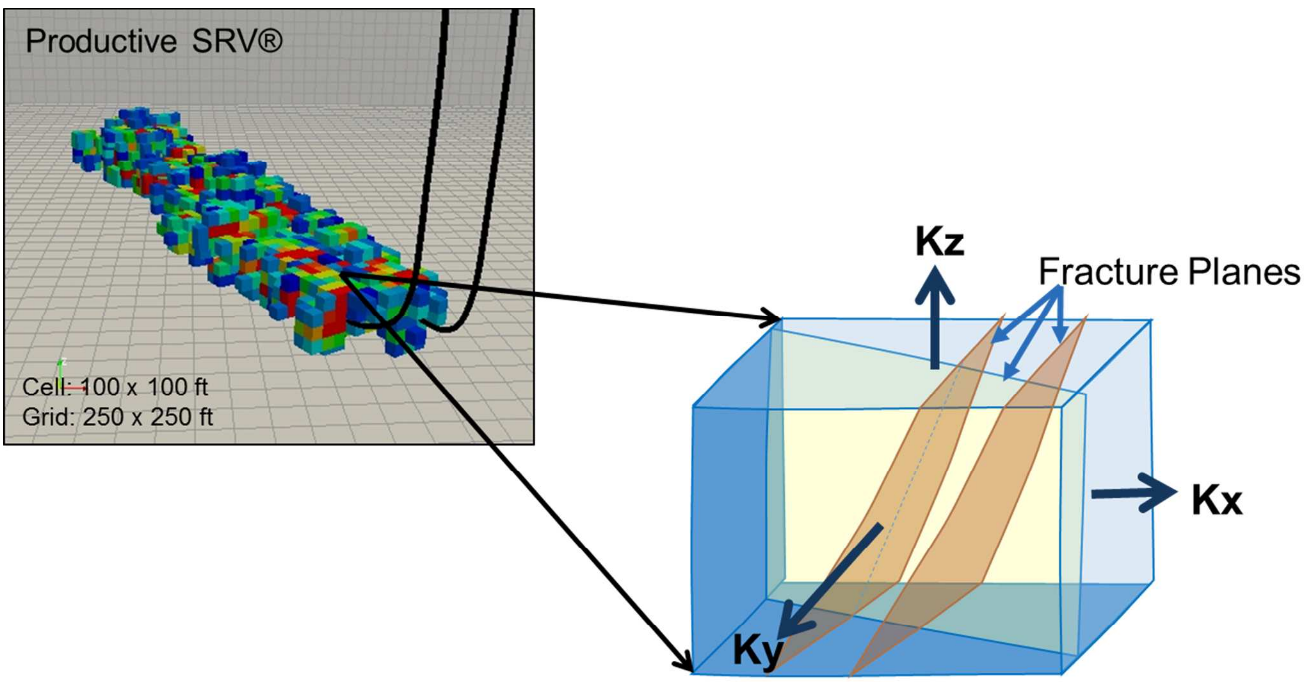

Figure 1: Computing permeability tensor

Each cell of the P-SRV volume in Figure 1 is colored by the relative magnitude of permeability enhancement. The hotter color (red) represents cells with higher permeability, while the cooler color (blue) represents cells with lower permeability.

The estimated permeability enhancement in the stimulated region can be input into a black-oil reservoir simulator to predict gas/oil production from the wellbore during primary depletion of the reservoir. Using permeability enhancement as an input fundamentally changes the resulting reservoir model because it enables the model to be based on a deterministic DFN, incorporating actual changes in the fracture intensity along the wellbore.

Case Study

Background

Using microseismic monitoring, the hydraulic fracturing treatment of a multi-well pad in the Eagle Ford shale was monitored. The measured microseismic data was used to model the DFN, P-DFN, SRV and P-SRV. Permeability enhancement was computed for the SRV and P-SRV as described above. The results enabled the operator to assess the success of hydraulic fracturing and accurately estimate the production from these wells using a commercial reservoir simulator.

Figure 2 shows the resultant DFN and P-DFN models along with the corresponding SRV and P-SRV for the 2 wells. For this two well pad, the Productive SRV (P-SRV) occupies about 47% of the rock volume occupied by the total Stimulated Rock Volume. The DFN and P-DFN models show significant variation in the fracture intensity over the length of individual wells. Here fracture intensity is described as the number of fractures over a unit length of the wellbore (e.g. a single stage), the average fracture dimensions (length and height) for a given stage and the fracture orientations. We can also see that the variation in propped fracture intensity is different that the variation in total DFN. This is important and can have a significant impact on how individual stages will contribute towards the production. All of these variations are accurately captured by the permeability scalar described for the SRV and the P-SRV. The permeability scalar thus provides an accurate three dimensional map of the effective permeability variations over the entire stimulated region.

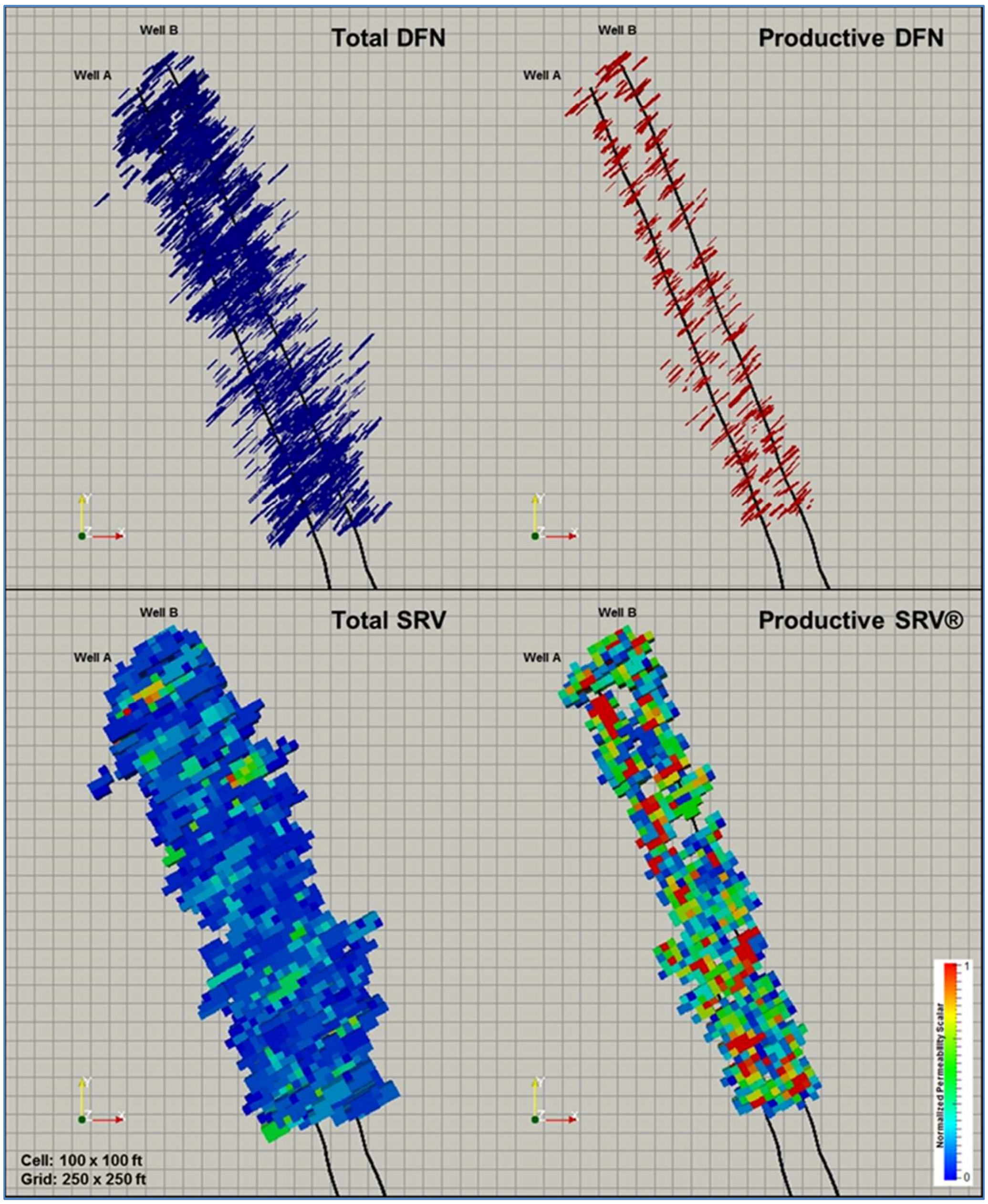

Figure 2: DFN and P-DFN Models (Top); corresponding SRV and P-SRV models (bottom)

Quantifying the Drainage Volume

Figure 3 through Figure 5 show a depth slice at three different TVD's. We can see large variations in the fracture dimensions per stage as well as the permeability enhancement at a particular depth interval. The question that still remains un-answered is whether the SRV and P-SRV, along with the permeability scalar, accurately and sufficiently quantifies the drainage volume.

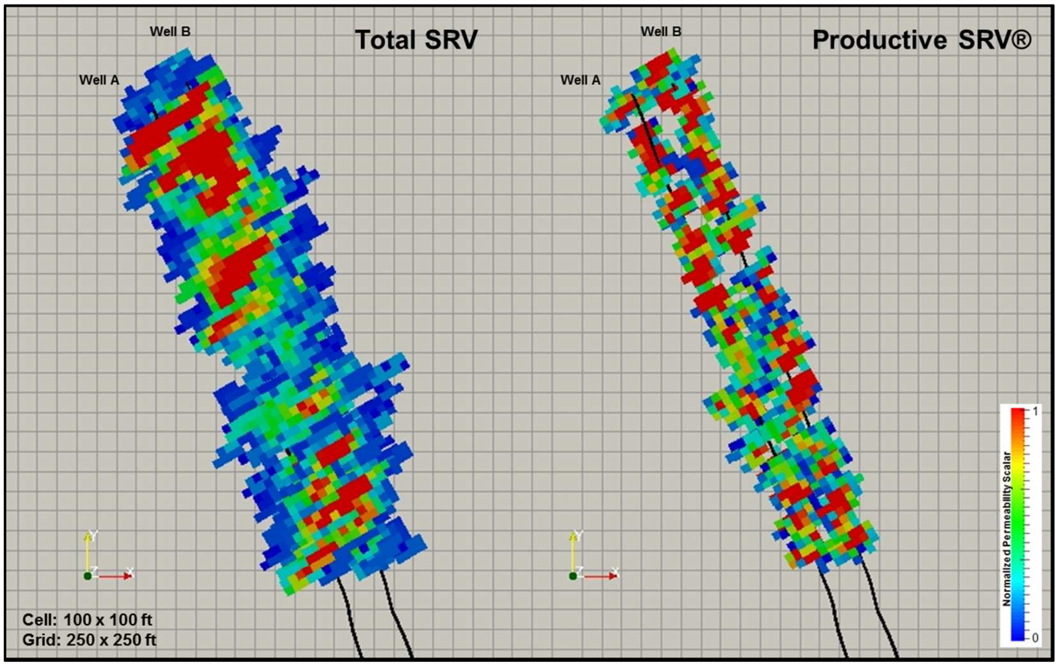

Figure 1: Depth Slice of SRV (left) and P-SRV (right) @ 200ft TVD above the wellbore

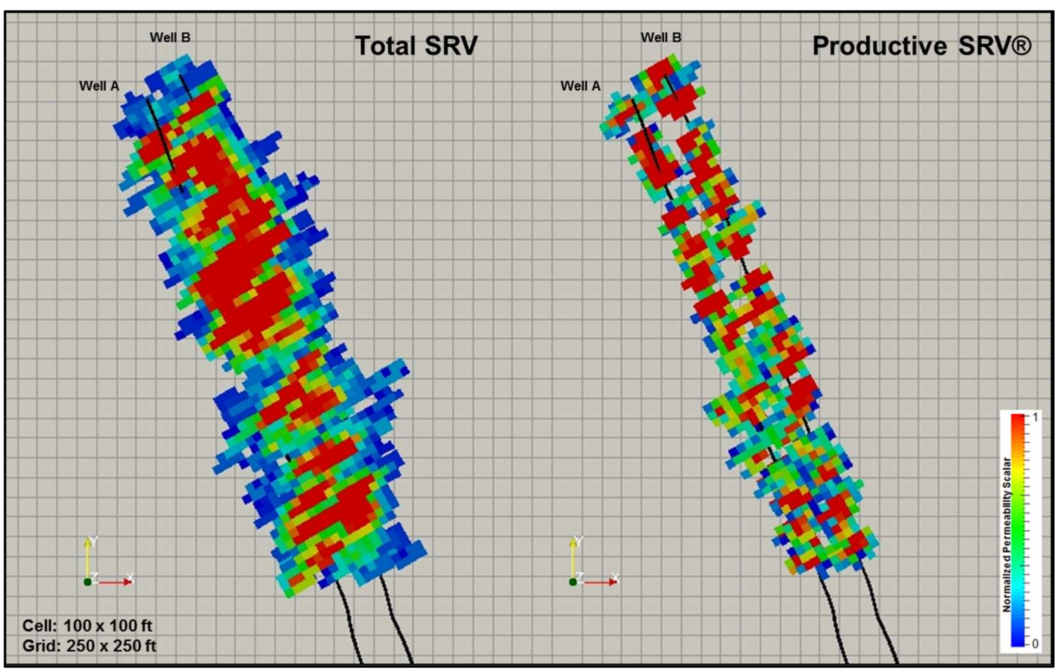

Figure 2: Depth Slice of SRV (left) and P-SRV (right) @ wellbore TVD

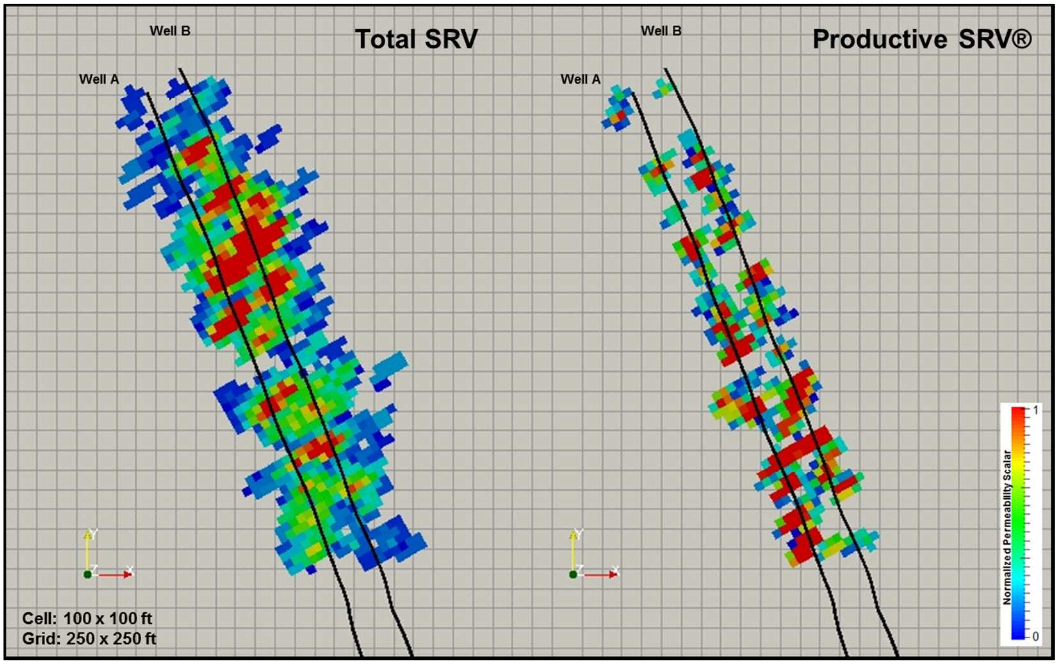

Figure 3: Depth Slice of SRV (left) and P-SRV (right) @ 200ft TVD below the wellbore

We can see large variations in the fracture dimensions per stage as well as the permeability enhancement at a particular depth interval. The question that still remains un-answered is whether the SRV and P-SRV, along with the permeability scalar, accurately and sufficiently quantifies the drainage volume.

We validate the above model through production history matching using a commercial reservoir simulator. The permeability enhancement results, obtained from the microseismic-derived DFN, are combined with other available data to construct a detailed reservoir simulation model. The reservoir rock properties in each layer of the reservoir model are specified based on core data, petro-physical well logs, and interpreted horizons. Fluid properties and rock-fluid interactions are defined based on PVT and relative permeability measurements respectively.

The model is then calibrated by performing history-matching of production data. An identical permeability multiplier is applied to all the P-SRV cells, while a separate permeability multiplier is applied to the cells located in the un-propped portion of the SRV. This ensures that the relative magnitudes of permeability, as determined from the microseismic analysis, are maintained throughout the history matching process. Differentiating between propped and un-propped fractures also allows for the application of different compaction curves for propped and un-propped fractures in the model. The reduction in fracture conductivity due to pressure depletion is accounted for by applying a compaction table to the cells within the SRV and P-SRV. The history matching process is continued until a reasonable agreement between simulation results and field data is achieved.

Results

Figure 6 and Figure 7 show the results of the history matching. The measured wellhead pressure (WHP) profile for both wells was used as input into the reservoir simulator to calculate oil, gas and water production rates. A very good agreement between simulation results and actual oil, gas and water rates are obtained for both wells simultaneously.

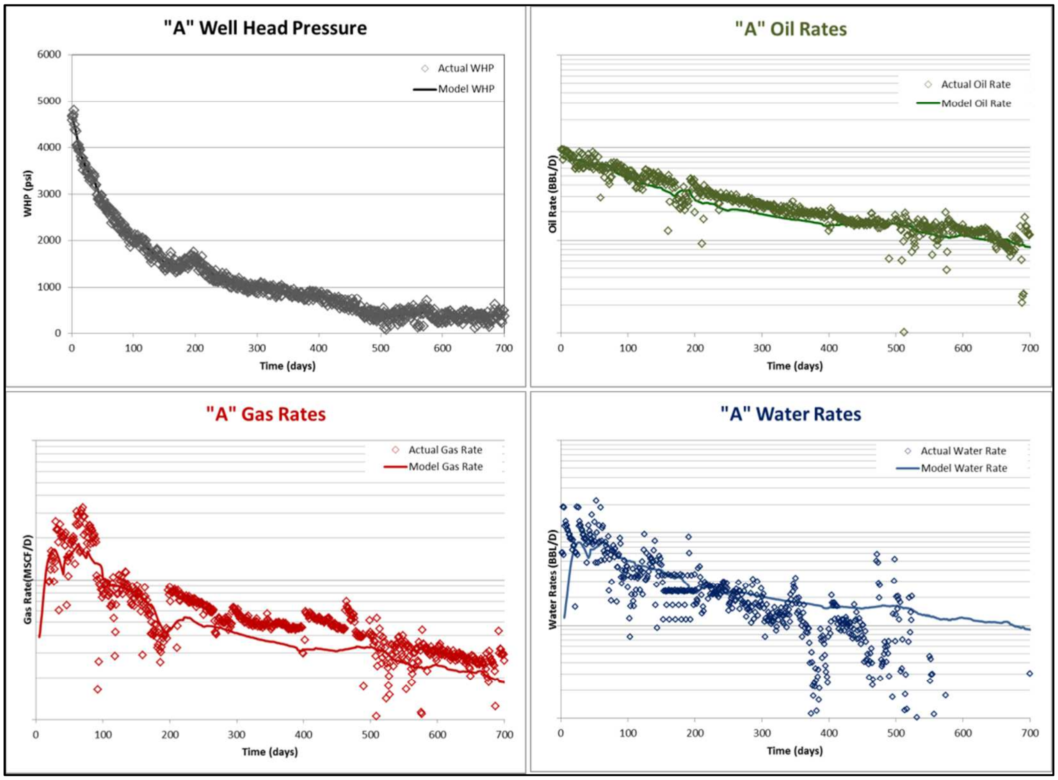

Figure 6: Production History-Matching/Calibration of Model (solid lines) with Actual Production Data (dots) From Well A

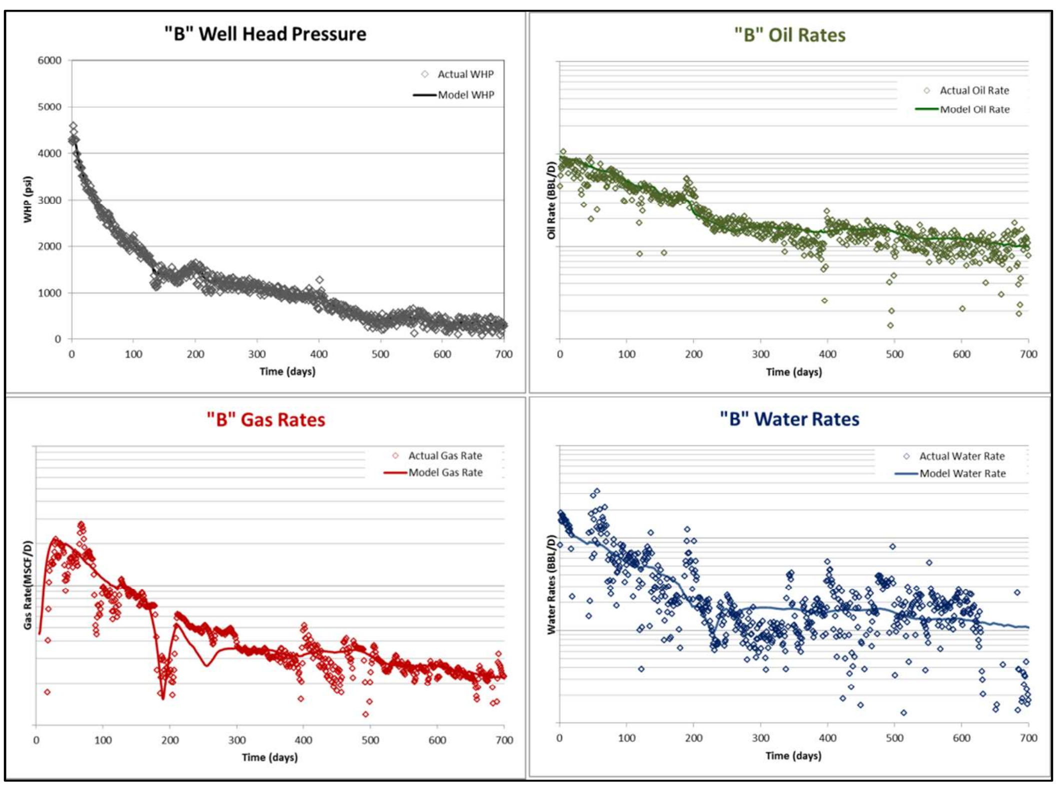

Figure 7: Production History-Matching/Calibration of Model (solid lines) with Actual Production Data (dots) From Well B

While the completion designs are almost identical for the two wells, there are subtle differences in the oil, gas and water production from the two wells. The reservoir simulation is able to simultaneously match the oi, gas and water rates for both the wells, without making any changes to the reservoir model as described by the SRV, P-SRV and permeability scalar. This suggests that the SRV, P-SRV and permeability scalar computed through advanced microseismic analysis provide an accurate and sufficient quantification of the drainage volume over the productive life of these wells.

Conclusions

There is a significant gap in the industry's ability to measure the reservoir's detailed reaction to hydraulic fracturing and, therefore, it is difficult to predict future production from the reservoir. Microseismic-derived permeability provides a solution for understanding details of the reservoir's state after treatment. It enables early predictions of the well's expected production, with the added benefit that it is available immediately after completion of hydraulic fracturing, without the need for well intervention. This bridges the gap between microseismic monitoring and reservoir simulation by allowing direct import of microseismic-obtained data to calibrate reservoir models.
Case studies have shown that microseismic data can be reliably used to quantify the permeability enhancement in the reservoir after a stimulation treatment. This enables operators to assess the success of a hydraulic fracture job and accurately estimate the productivity of a well immediately after the treatment. It gives operators the control to be able to balance completion and stimulation parameters to meet certain production goals and economic thresholds, and it also reduces the overall economic risk in field development.

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