The use of horizontal wells and hydraulic fracture completion practices has become the norm today, particularly in unconventional reservoirs. These wells and their completions present unique challenges to engineers’ efforts to optimize and forecast well performance. Where to drill wells is generally not the issue. The primary decisions are orientation of the lateral(s), length of the lateral(s), vertical placement of the lateral(s) in the formation, number and size of the hydraulic fracture treatments, and well spacing.

All of these decisions revolve around the stimulated rock volume (SRV) created by the hydraulic fracture treatment. Proper understanding of the SRV creation and its interaction with the reservoir matrix and natural fracture systems is paramount. The geometry, extent and complexity of fractures within the SRV impact the fracture surface area available for interaction with the matrix.

**The examples in this document show how proper characterization of the SRV can impact the predicted EUR for a well and how the SRV is impacted by the size of the frac stages, the well orientation and spacing.**

Reservoir simulation, when properly employed, is the best tool available for addressing these issues. NITEC has developed unique technologies to address the evaluation of hydraulically fractured horizontal wells. These technologies utilize assisted history matching (NITEC’s MatchingPro®), and a dual porosity reservoir simulator (Coats Engineering’s SENSOR®) with special geomechanical modifications to the simulator.

Many of these operational decisions (well orientation, well spacing, well length, fracture treatment size and number of stages) cannot be properly addressed with statistical methods or “conventional” modeling approaches. NITEC’s modeling approach provides knowledge about the reservoir behavior of the hydraulic fracturing process and the reservoir’s natural fracture/matrix system for the well(s) being studied. Unlike the conventional approach knowledge can then be used to investigate operational decisions for future wells planned in the same reservoir. To date the approach has been successfully used in studies of the Bakken, Three Forks, Eagle Ford, Wolfcamp and Niobrara formations.

**NITEC Modeling Approach**

NITEC’s technology dynamically integrates the stage by stage fracture treatment, the flowback period and the post-frac performance in the model calibration process. Fixed, preconceived assumptions about the SRV are not used. NITEC’s proprietary technology develops the SRV for each stage (Figure 1) and the calibration process adjusts SRV, reservoir matrix and natural fracture properties to match the three flow periods – hydraulic fracture treatment, flowback and post-frac production. Inter-well communication and reservoir depletion are accounted for in the process.
The SENSOR finite difference simulator has been enhanced to take into account tensile and shear failure caused by increasing pore pressure sufficient to overcome the minimum stress. The user specifies effective stress thresholds in the model that, when overcome during the fracture treatment, generate shear and tensile failures in the model. Anisotropy is represented by the ability to specify in which direction the greatest transmissibility gains are generated consistent with the current principle stress orientation. The combination of these two mechanisms of shear and tensile failure generate the SRV as it is created in each frac stage.

**Conventional Modeling Approach**

The conventional approach to developing a predictive tool for hydraulically fractured horizontal wells using reservoir simulation has been to define certain information about the reservoir and the SRV (Figure 2) and then calibrate the model to the post-frac production/pressure performance. The fixed shape of the SRV may be based on service company data and/or microseismic test results. While a calibrated simulation model may result in a reasonable prediction of future performance of the well, it is only unique for that well and cannot be reliably used neither to assess other areas of the reservoir nor other hydraulic fracture treatments, etc.

This conventional approach ignores some key data from the well(s) – the hydraulic fracture treatment (stage volumes and pressures) and the associated fluids produced during the flowback period. Hence, the impact of fracture treatment fluid in the reservoir on post-frac production is not accounted for. It is a solution unique to this well only and cannot be reliably used to assess other areas of the reservoir and the effectiveness of alternative fracture treatments.

**Example**

The following example is from a well in a thin unconventional formation. It compares the conventional modeling approach for developing a “representative” simulation model to NITEC’s integrated modeling approach.

The problem:
- A horizontal well with 1.5 years of post-frac oil, water and gas production performance
- A cased and perforated 7500’ lateral
- An 8 stage hydraulic fracture treatment
- A 40’ thick productive formation

**Comparison of Predicted Performance**

The impact of the SRV calibration on predicted well performance will be discussed first, as the differences in the predicted performance are key to assessing the reliability of the two modeling approaches. A separate white paper titled “History Matching Hydraulically Fractured Horizontal Wells” describes the calibration process and differences in the two final calibrated (history matched) models. Suffice it to say that good history match solutions were achieved for each modeling approach subject to the limitations associated with each model.

The two calibrated simulation models were set up to predict the future performance of the well starting January 1, 2010. Approximately one year of historical performance data was available for the well beyond this date. The well in each model was produced at a constant 215 psia bottom hole flowing pressure for the duration of the prediction run. The simulation was made for a ten year period. As the oil production rate at the end of the ten year period was approximately 20 STB/D in both models, this can be assumed to be an approximation of the EUR for the well.
Figure 3 shows the cumulative water and oil production for the historical period and at the end of the 10 year prediction. The cumulative oil production for the prediction was:

- Conventional approach: 221.9 MSTB
- NITEC Approach: 174.6 MSTB

The conventional model approach appears to provide an overly optimistic forecast of the oil recovery. When the accuracy of the oil production match during the historical period is taken into account, the conventional approach cumulative oil production at 10 years should be adjusted to 206.9 MSTB. (The conventional model overproduced oil during the history match period by 15 MMSTB.) This results in a difference between the models of 32.3 MSTB; 18.5 percent more oil compared to the NITEC model approach.

The production profiles (Figure 4) for the two model predictions (historical period and the first 2 years of prediction) show that the conventional approach produces at a higher oil production rate after the first few months. This is due to the different fracture characterization that results from modeling only the post-frac production period in the conventional approach versus accounting for the frac treatment, flowback and post-frac production in the NITEC calibration process.

The pressure change in the fractures at the end of the 10 year prediction period for the two models are shown in Figures 5 and 6. The cells shown in these figures represent areas of the model where the pressure has changed by greater than 200 psia in the fractures from initial conditions at the time shown. (Red areas are at near-initial pressure. Blue areas have experienced significant pressure reduction.) All other cells in the model are not shown.

Figure 5 for the conventional model approach shows that depletion in the fractures near the wellbore is occurring. The matrix (not shown) is similar. The areal extent of the depletion in the fractures (and the matrix) is relatively large.

Similar review of the pressure in the fractures (Figure 6) for the NITEC model approach indicates that depletion in the fractures near the wellbore is much greater. However, the maximum areal extent of the depletion is much less in the NITEC model approach (~2520 ft) than the conventional model (~4500 ft). These differences impact the oil production response during the prediction period for each model.

It is fair to conclude that these different depletion areas at the same point in time will have an impact on the ultimate oil recovery for a given well spacing. Accordingly, the smaller depletion area in the NITEC model suggests that closer spacing may be required to deplete the reservoir in a given time period. This knowledge provides the operator with the opportunity to more efficiently deplete the reservoir with closer well spacing if this analysis is correct.
Multiple Well Model Calibration

Calibration of the simulation model is extremely important to the reliability of the predicted model performance and understanding the formation's fracture treatment and depletion characteristics. Accordingly, calibration with multiple wells results in a more definitive model than using a single well only. Figure 7 shows four actual wells drilled in a thin unconventional formation.

Wells 1, 2 and 3 were drilled, hydraulically fractured and placed on production at the same time. The production profiles were very similar. The production plot for Well 1 is shown in Figure 9.

Well 4 was drilled, hydraulically fractured and placed on production approximately 2 years, 9 months after the first three wells. The fracture treatment volume used in Well 4 was significantly larger than the volumes used in the first three wells. Figure 8 shows the water saturation in the fractures after the Well 4 frac treatment. Note in Figure 9 the large increase in water production at the end of the first quarter of 2012. Similar water production performance was realized in Wells 2 and 3.

A small increase in the oil rate is also observed. This change in the production profile of Wells 1, 2 and 3 is clearly a result of the fracture treatment and initiation of production in Well 4 (Figure 10).

It is also important to note that the model automatically accounted for the impact of pressure depletion in the Well 4 area due to the production of Wells 1, 2 and 3 and the associated impact on the fracture treatment and resulting SRV. The performance of Well 4 was much better than the other wells, in large part due to the larger frac volume used.

This entire performance history, including the fracture treatments for each well, was history matched in the simulation model. (Solid colors are historical production, black lines are simulated production. The pressure, also matched, is not shown.) A common set of HM parameters was used for all wells and no local reservoir or geomechanical parameter modifications were used. The ability to history match these different frac treatments, production performances and inter-well communication bodes well for the predictive capability of this model.

With a well-calibrated Unit area model, prediction cases can then investigate long term inter-well communication and the impact of alternative operational scenarios and further infill drilling (lateral and vertical) on incremental well and Unit performance.
Sensitivity Studies

One of the strengths of the NITEC modeling approach is the ability to conduct sensitivity studies on the impact of operational parameter changes (well length, orientation, number of fracture stages, volumes in each stage, etc.) on the predicted performance as an aid in optimizing and planning alternative development scenarios. This type of analysis cannot be reliably performed with the conventional modeling approach, as the predefined SRV and the associated fracture and matrix parameters are based on a specific fracture treatment, for a specific well configuration, and the reservoir properties at that location.

Increased Frac Volume-Single Well: The impact of higher frac volumes (gals/ft) per stage was investigated. A case with twice the fluid volume (twice the injection rate) during each of the fracture stages and a case with four times the volume were simulated using the “base” frac volume calibrated model.

The higher volumes during each frac stage result in a larger and more intensely fractured SRV in each prediction which results in higher production rates early in the post-frac life of the well. This is quantified in the TEX parameter which represents the intensity of the fractures determined by the fracture-matrix surface area created by fracturing. Figure 11 is the SRV for the 2 times base volume case. Figure 12 is the base case.

The production rate plot (Figure 13) for the first five years for each of the higher frac volume cases shows the rates are significantly higher in the first 2-3 years. Economic analysis will determine whether the cost of the larger fracture treatment is warranted by the increased rate and higher ultimate recovery (Figure 14).

Optimize Spacing and Frac Volume: A single well analysis may not tell the whole story. Well spacing will have an impact on an individual well’s EUR, as well as the drilling Unit’s (typically a section) EUR. A study of Unit EUR as a function of well spacing and frac volume was carried out in a thick unconventional formation. Figure 15 shows Unit EUR versus frac volume for four different spacings within the Unit. (Actual study values have been normalized.) Unit EUR increases as the frac volume increases. It is apparent from Figure 16 that individual well EUR also increases as frac volume increases, but the impact of well spacing is less evident. This case suggests that equivalent Unit EURs can be achieved with either increased frac volumes and/or closer well spacing. Economic analysis is required to assess the best combination. This highlights the need to model multiple wells and their interaction in the reservoir.
**Well Orientation:** The well orientation was changed to test the impact on production performance. The SRV of the original calibrated well model and the modified well model orientations are shown in Figures 17 and 18. Figure 17 shows the SRV fracture intensity parameter (TEX) for the original well orientation and the modified case (Figure 18) after the hydraulic frac treatment. The reservoir properties in the area simulated were not changed. The visual character of the SRV is not significantly different between the two well orientations, although the EURs are quite different.

![Figure 17](image1.png) ![Figure 18](image2.png)

Figure 19 compares the prediction performance of the two well orientations. The SRV in the new orientation appears to improve the performance of the well. This is likely because the new orientation is closer to being perpendicular to the principle stress direction than the original orientation; hence better communication is established with the natural fracture system.

![Figure 19](image3.png) ![Figure 20](image4.png)

The new well’s delta pressure from initial conditions in the fractures to the end of the 10 year prediction is shown in Figures 20. (Red areas are at near-initial pressure. Blue areas have experienced significant pressure reduction.) This can be compared to the pressure depletion in the fractures for the original well orientation shown in Figure 6.

**Summary**

- A poorly calibrated SRV in the predictive simulation model can significantly impact production forecasts.
- The NITEC modeling approach precludes predefining SRV parameters in the simulation model which prevents bias in the prediction results.
- Utilization of frac treatment, flowback and post-frac production in the model calibration process allows the simulation model to be easily used to investigate production sensitivities to frac treatment parameters, well configurations, orientation and spacing.
- The knowledge gained in the calibration process can be applied to other areas of the reservoir and future wells.
- Calibration of multiple wells can significantly improve reliability of the model for predictive purposes.