Approach Avoids Cross-Well Frac Hits

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HOUSTON–It is evident from the industry's experiences in horizontal resource plays that geomechanical and geological variations exist along the wellbore that influence hydraulic fracturing efficiency, and ultimately, well production and recovery rates. These variations include stress fields, rock properties, and pore pressure and its depletion from existing producing wells and natural fracturing systems.

Fortunately, advanced 3-D workflows that account for all available seismic, wireline and drilling data are enabling completion engineers to adapt the treatment of each stage of a multistage fracturing treatment to the heterogeneous geologic and geomechanical conditions. This approach optimizes each stage's design and overall completion effectiveness. It also can pinpoint specific zones that require special handling to adapt frac designs to dynamic in situ reservoir conditions to significantly reduce the probability of cross-well interference and communication while pumping a fracturing treatment ("frac hits").

The key to optimizing frac designs and implementing adaptive treatment practices for each stage based on variabilities in reservoir properties is deploying integrated tools that couple geophysical, geological and geomechanical data with a constrained asymmetric frac model. The objective is to identify variable treatment parameters required to overcome stress heterogeneities and estimate the impact of adaptive design changes on the final fracture geometry.

This integrated modeling approach was applied to a Wolfcamp Shale well in the Permian Basin to address well interference concerns. The challenge was to find the optimal frac design to minimize interference between a new infill well and existing offset producing wells. To address the possible interference zones, stage spacing was locally increased to 500 feet and the treatment was modified in the middle stages of the well (where some zones indicated a high probability of interference). This resulted in reducing the number of stages placed in the well, and making changes to proppant size and volume, frac fluid viscosity and injection rates. These drastic changes, which may seem unacceptable to a fracturing engineer, could have been avoided if the infill well had been drilled at the proper distance.

Lateral stress gradients resulting from pressure depletion related to a nearby producing well and the fluid leak-off caused by the opening of natural fractures can be fine-tuned to account for asymmetry observed in the geomechanical modeling. Recognizing the fact that natural fractures can play a major role in cross-well interference, the Wolfcamp project emphasized developing practical approaches to estimate a validated natural fracture model.

A validation well was used to highlight the importance of the input natural fracture model in calculating validated differential stress and strain that reproduced the main features of the microseismic data. With the validated strain model, a constrained frac design can provide the proper asymmetric fracture geometry to differentiate "good" and "poor" frac stages. Once this workflow is extensively validated, it can be used to plan new well completions to avoid frac hits.

Geoengineering Workflow

Frac complexity is created as a result of the complex physical interactions between hydraulic and natural fractures. The Wolfcamp study used a continuous fracture modeling (CFM) technique that relies on geology and geophysics to generate a realistic and validated distribution of natural fractures. The geomechanical model used four key input parameters that impact local stress gradients: rock elastic properties, reservoir pressure, distribution of natural fractures, and far-field stress information such as the magnitude and orientation of the regional maximum horizontal stress as well as regional horizontal stress anisotropy.

These key geomechanical inputs were computed in multiple ways using a robust workflow that leverages the use of all available data–including seismic, offset well logs, drilling and wireline data, hydraulic fracture treatment data and offset well production. Since all these processes are available in a single platform, frac design and reservoir simulation tasks can benefit directly from the geophysical, geological and geomechanical modeling efforts.

While the dynamic geomechanical simulations can provide multiple results–including stress magnitudes and orientations, reservoir strain caused by stimulating rock, and fracturing energy at the tip of the hydraulic fractures–the Wolfcamp project focused on applying the geomechanical and geoengineering aspects of the workflow to reduce the potential for frac hits.

Natural fracture systems are one of the most important sources of stress gradients, and have a major influence on hydraulic fracturing. To design effective hydraulic fracture treatments that avoid, for example, setting frac stages near faults or in areas with high potential for cross-well communication, engineers need a validated natural fracture model that provides a detailed description of natural fractures around the wellbore at all depths.

Since stresses created during hydraulic fracturing propagate in the reservoir volume and are not restricted to randomly distributed fracture planes invaded by frac fluid, they could affect the rock's natural fracture system thousands of feet away from a fluid front. This physical reality is observed with microseismic data, the best field measurement for validating natural fracture shearing and fracture complexity. A major part of the complex physics is using a validated natural fracture system in volumetric geomechanical modeling.

With a proper validated natural fracture system as input and accounting for all sources of stress gradients in the physics of hydraulic fracturing, overall microseismicity behavior can be predicted, giving confidence that the geomechanical model is predictive and can be used to design hydraulic fracturing treatments to avoid hits. Without validations of real field data, the efforts remain a good intellectual and academic exercise, but have limited practical value to an operating company concerned about frac hits.

Modeling Natural Fractures

A realistic natural fracture model can be derived either by using CFM to honor structural geology concepts and propagate in 3-D a fracture indicator measured at a limited number of wells, or by using seismic structural attributes as natural fracture proxies (validated with well data).

The recommended procedure to derive a natural fracture model is to use a natural fracture indicator in a few wells and to capture in the CFM approach the fracture drivers described by multiple seismic attributes and geologic models, preferably constrained by high-resolution seismic attributes. In this process, the derived natural fracture model must be able to predict natural fractures in "blind" or newly drilled wells as validation. In the Wolfcamp study, both a natural fracture proxy derived from conventional logs available at many wells and image logs available at two wells were used to develop 3-D natural fracture models.

Figure 1 shows the CFM distribution of the natural fracture density in the targeted wellbore plane from the two image logs at left. At right are comparisons of the processed image log acquired at the target well and predicted natural fracture density provided by the CFM model before receiving the processed image log. The model was able to predict highly fractured zones. Furthermore, it is possible to see how the natural fracture system could connect the target well to a nearby producing well in specific localized positions with validated high natural fracture density (the rectangles in Figure 1).

Previous Wolfcamp studies demonstrated that a simple seismic structural attribute such as coherency validated with well data image logs can be used in geomechanical modeling to address the localized impact of high-density natural fractures related to faults that could increase water production. Frac hits also are highly dependent on the densities and orientations of natural fracture systems. When density is high, direct communication could exist between neighboring wells. When natural fracture density is moderate, interactions between hydraulic and natural fractures create an asymmetric stimulated reservoir volume that can lead to asymmetric pressure depletion. In both cases, a validated natural fracture model is needed as input in geomechanical modeling.

Regional Stress Conditions

The first step in geomechanical modeling is estimating the initial stress conditions around the well, which are influenced by interactions between the regional stress and three major sources of stress gradients: natural fractures, elastic properties and pore pressure. Seismic structural attributes readily available to most operators (such as positive curvature extracted in the wellbore plane) can be used as natural fracture proxies to derive an equivalent fracture model (EFM) that captures natural fracture density and orientation. The EFM model is then input into the geomechanical workflow to generate results such as the initial distribution of differential stress prior to hydraulic fracturing.

Multiple simulations and field validations using this approach show that differential stress along the wellbore is variable, and is the most important factor in determining the success of a hydraulic fracturing treatment. In fact, the assumption of a constant or slightly changing differential stress along a wellbore is a recipe for failure in completion optimization. If differential stress variability is not estimated from geomechanical modeling, a hydraulic fracturing treatment cannot be adapted to account for this variability.

By modeling interactions between regional stress and the sources of stress gradients, the correct differential stress can be derived and validated with microseismic data. Once validation is completed with multiple wells, hydraulic fracturing treatment parameters can be adapted to geomechanical realities to overcome areas of high differential stress and the resulting deformation and failure of the rock can be captured by the volumetric strain (Figure 2).

The right-hand panel in Figure 2 shows the markedly asymmetric strain derived from geomechanical simulation. The microseismic data in the left-hand panel were never used in the strain calculations, but very strong correlations exist between the microseismic interpretation and the strain results. This is confirmation that the physics used to simulate the hydraulic fracturing and the input natural fracture system are representative of the subsurface conditions, and therefore, can be used for further frac design engineering.

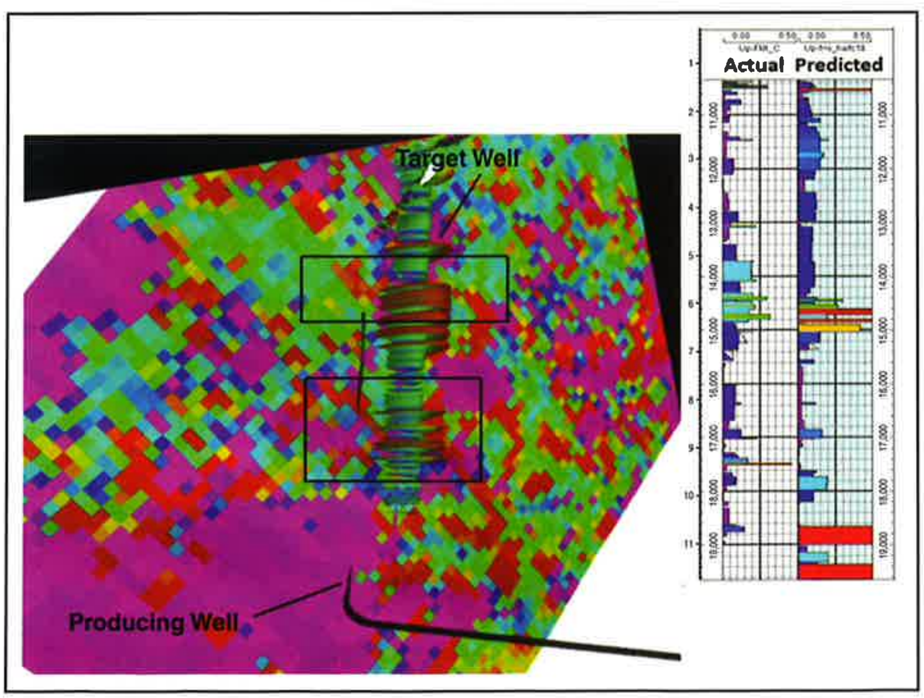
Adaptive Frac Design

The modeled strain induced in the rock serves as a proxy for stimulated permeability created by rock deformation caused by fracture initiation point pressure and the volumetric propagation of stress and the ensuing shearing of natural fractures in the reservoir volume behind and ahead of the fluid front. The stimulated area is detected automatically and outlined in a frac design tool. The asymmetric geomechanical half-lengths are measured on both sides of the wellbore for each fracture stage and exported as constraints for the asymmetric frac design tool.

By imposing these asymmetric geomechanical half-lengths, the frac design tool is able to account for the stress gra-

FIGURE 1

CFM Model Predictions



dients resulting from variable elastic properties, natural fractures and pressure depletion encountered not only along the wellbore, but also all around the stimulated wells.

The frac design model governs the initiation and propagation of hydraulic fractures interacting with the geologic heterogeneity by calculating the net pressure at the fracture tip. The effect of lateral stress gradients and the viscous gradient along the fracture length are incorporated into the fundamental pressure balance equation at the fracture tip to determine fracture growth. Mass balance, fluid momentum, and pressure-width relations applied with appropriate initial and boundary conditions result in a realistic and fast frac design model.

The leak-off coefficient can be fine-tuned to account for asymmetry observed in geomechanical modeling. Once the optimum reservoir parameters are computed, other design parameters such as injection rate, fluid viscosity, and proppant concentration and type can be optimized to achieve more consistent proppant distribution. With the help of additional constraints, the model is able to estimate the fracture conductivity and proppant concentration.

Figure 3 shows the asymmetric variability of the proppant concentration/distribution in three stages in the Wolfcamp validation well. At left is the top view of the microseismic data with its various characteristic responses. At right are the respective variable proppant concentrations along stages 13, 7 and 2 (from top to bottom). Additional validations of the frac design can be carried out using treatment data to ensure the modeling effort reflects actual results. Without continuous validations with field data, it will be difficult to trust any frac design tool to avoid frac hits. Operators can use this workflow to optimize completions and asset development strategies.

Frac Hit Challenge

In the Wolfcamp project, an existing producing well posed a frac hit challenge for fracturing a proposed new horizontal well. The geometric design of the new well was modeled for all 40 stages. The initial treatment plan called for 250-foot stage spacing with 320,000 pounds of a 100-mesh and 40/70-mesh sand mixture a stage pumped with slickwater at a rate of 105 barrels/minute.

The total stage length and frac design volume for the new well was designed based on the differential stress values along the wellbore. In areas of low stress anisotropy, it is relatively easier to achieve fracture complexity with sufficient proppant placement using a slickwater treatment. Accordingly, in stages with very low differential stress values, relatively more clusters should readily accept fluid as the stage is designed to place clusters in areas of similar frac gradient. Conversely, in areas with high differential stress, there will be fewer, but longer planar fractures. Higher-viscosity fluid might be required to effectively place proppant in these stages.

Figure 4 (left) shows an equivalent fracture model derived from positive curvature seismic data and used as input in the geomechanical simulator. A strain map derived after putting pressure in 40 frac stages is shown at right. The red colors represent high strain values indicating successful stimulation, while the pink lines represent the estimated geomechanical half-lengths based on the es-

FIGURE 2

Microseismic Data and Estimated Strain at Wolfcamp Validation Well

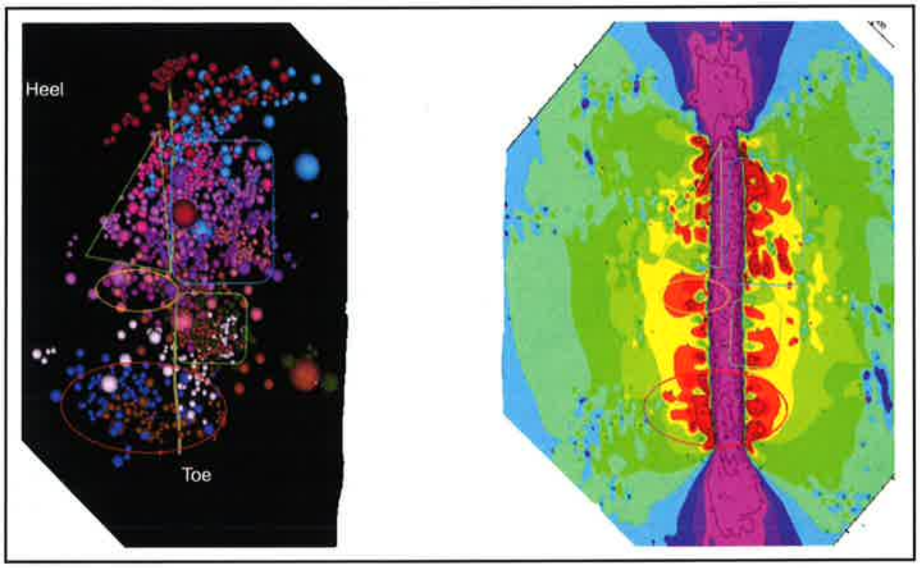


FIGURE 3

Microseismic Data along Three Stages of Wolfcamp Validation Well

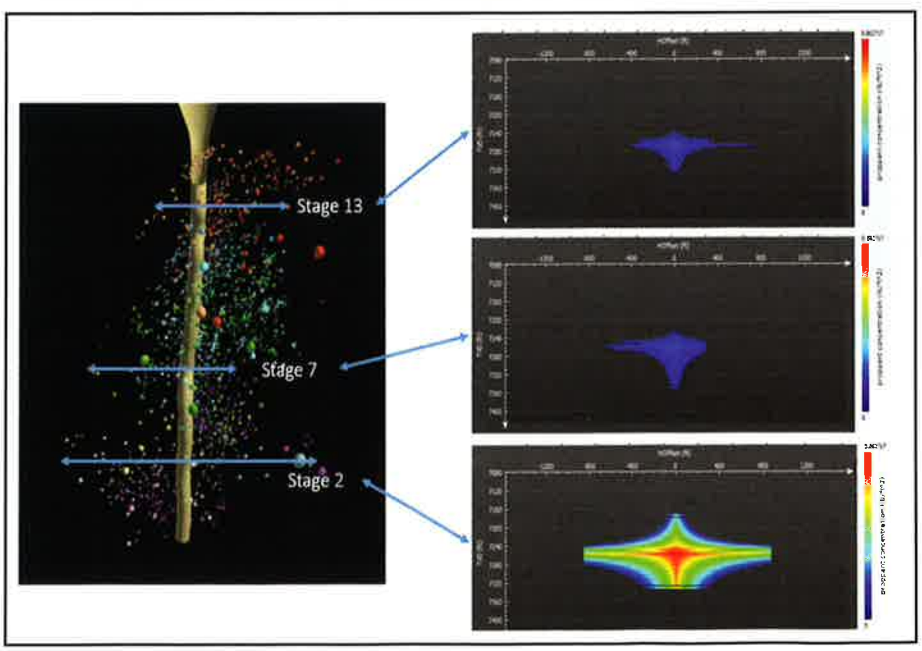
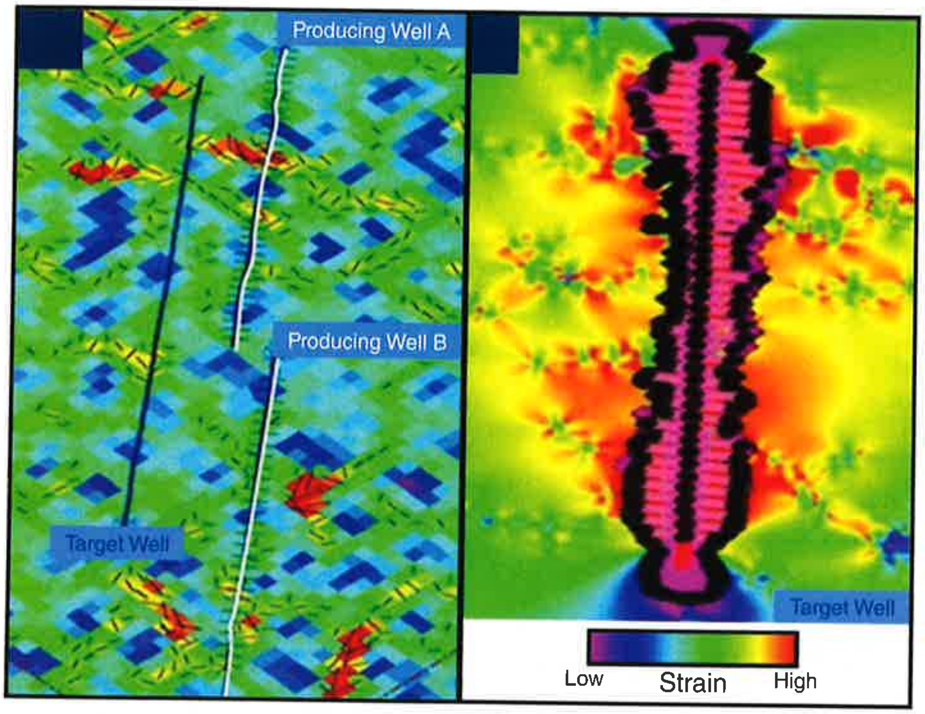


FIGURE 4

Seismic Data-Based Equivalent Fracture Model (Left) And Strain Map for 40 Frac Stages (Right)



timated strain.

The information from the differential stress map can be leveraged adaptively in frac design in multiple ways, including:

- Decreasing spacing or increasing the number of stages in high differential stress zones to achieve multiple planar fractures;
- Using higher-viscosity linear or cross-linked gels to place proppant efficiently in areas of high differential stress;
- Using larger-diameter proppant with linear gels.

In this case, the modeling results led to increased stage spacing and modified treatment designs in the middle stages of the well, where interference risk with offset wells was greatest. This reduced the number of stages from 40 to 34. The treatment design was altered to pumping 220,000 pounds of 40/70-mesh sand, and the injected fluid viscosity was increased from 10 (slickwater) to 30 centipoise (linear gel) to achieve the carrying capacity to pump the 40/70-mesh sand. In addition, the injection rate was reduced from 105 to 80 barrels/minute.

A frac engineer may not be comfortable accepting such a drastic change in treatment design, which may sound unrealistic. Consequently, he or she may feel compelled to go ahead and use the original geometric spacing, which would cause frac hits and likely lead to a degradation of nearby well production and poor performance at the infill well. Hence, the importance of drilling infill wells at an optimal distance that would prevent having to resort to drastic changes in frac treatment design.

With operators drilling new horizontal wells offsetting existing producing wells, frac hits and other problems related to pressure depletion can become a major issue that impairs the development of unconventional reservoirs. With the growing realization of the importance of geomechanical fracture modeling, new methods are able to capture the asymmetric behavior of frac complexity resulting from pressure depletion, variable elastic properties and natural fractures as well as stress shadowing effects from adjacent stages and wells. Ultimately, the modeled results can be used by engineers in the field to vary proppant concentrations, injection rates, fluid viscosities and other design parameters to adapt to changes in reservoir conditions along the wellbore and optimize fracture designs. ❑

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White Knight, TXON-SCZ Complete Acquisitions

LAFAYETTE, LA.–White Knight Production I LLC says it has closed on its combination with TXON-SCZ LLC. The action brings together the assets of the two private independent oil and gas portfolio companies of private equity firm Bayou City Energy.

After the transaction, White Knight says it controls more than 30,000 net acres held by production in the Fort Worth Basin of Texas and California's San Joaquin Basin. It adds it produces more than 1,500 gross barrels of oil a day from the long-lived, low-decline assets. ❑