Summary

The in situ stress and elastic rock properties are first order controls on fracture stimulation behavior and consequently production. Understanding these properties at offset locations can facilitate optimal well placement and completion design.

To achieve this objective, a coupled geomechanical and seismic inversion workflow has been developed. The workflow consists of building a calibrated 1D geomechanical model at the well locations using elastic log data, observations from image logs, and the poro-elastic equations. The 1D model is then up-scaled to seismic resolution to assess the feasibility of utilizing properties derived from a seismic inversion. An innovative pre-stack facies-based seismic inversion process, capable of producing physical estimates of impedances and density, is used to invert the seismic dataset for facies and elastic properties. The geomechanical model is then applied to elastic properties derived from the inversion to build an analytical 3D geomechanical solution.

The correlation between inverted elastic properties and up-scaled log data was considered very good. After applying the geomechanical model to 3D elastic properties derived from the inversion, a zone of low fracture initiation pressure and high stress anisotropy was identified at Well A. This zone correlates with an interval where a high concentration of drilling-induced tensile fractures is observed on an FMI image log. While the zone of low fracture initiation pressure is observed to extend laterally from Well A, the predicted initiation pressure increases in the vicinity of Well B. Image log data from Well B shows a significant reduction in the occurrence of drilling induced tensile fractures within the laterally equivalent interval. These observations from image logs provide independent validation of the 3D geomechanical model and in turn, the accuracy of the inverted elastic property volumes. The results can be used to understand fracture behavior - including stress anisotropy, initiation pressures, fracture barriers, and potential height growth – at any potential well location within the data volume.

Introduction

The development of unconventional resource plays in the Permian Basin has been a significant success story, attributable in part to the use of technology by key operators to drive efficiencies in the drilling and completion process. Multiple zones have been exploited across the basin, ranging from the low permeability sands and carbonates of the Avalon, Bone Springs and Spraberry formations to the fine grained, organic rich Wolfcamp formation. The Wolfcamp formation is the focus of this study.

Within the study area, the Wolfcamp formation was deposited in a deep-water basin surrounded by shallow-water carbonate platforms (Hamlin & Baumgardner, 2012). The formation is composed of laterally persistent layers of hemipelagic silts and clays that are interrupted by laterally discontinuous layers of detrital and debris flow carbonates that extend towards the center of the basin. The local distribution of carbonate debris flow units is considered fundamental to controlling the geomechanical behavior of the formation to fracture stimulation.
The objective of the study is to predict the geomechanical behavior of the formation ahead of the drill-bit. Surface reflection seismic data are an important source of spatial information away from the existing well locations. Pre-stack AVO inversion is our chosen approach to extract rock properties from the seismic amplitude information. The derived elastic property volumes are translated from dynamic to static properties and then used as inputs into the calibrated poro-elastic equations to make an analytical estimate of the two horizontal stresses. The stress field is then solved around a vertical cylindrical borehole to make predictions of the fracture initiation pressure.

Figure 1: Example well log data over the Wolfcamp formation.

**Dataset & Method**

The study was performed using a comprehensive dataset from six wells, plus angle gathers from a recently acquired PSTM survey. The well data included dipole P and S-wave sonic logs, and a consistent multi-mineral petrophysical interpretation. Image logs were also available for two wells. The wireline log data were considered good quality with wash-outs only affecting minor intervals (Figure 1). The relatively continuous and thick carbonate of the Strawn formation is observed below the Wolfcamp formation. The lower Wolfcamp is composed of clay-rich (50-60%) shale. The mineralogy of the rock matrix transitions upwards to a more silt-rich interval in the upper Wolfcamp. The debris flow units are encountered predominantly in the upper Wolfcamp and are observed by the high concentration of calcite.

The workflow commenced with a review of the formation’s elastic properties using the sonic velocity and density well logs. Three end-member lithologies were identified based on mineralogy: silt-rich upper shale, clay-rich lower shale and calcite-rich limestones. These end-member lithologies were used as the basis of a facies classification to be used in the subsequent seismic inversion. The elastic log data were conditioned to generate a consistent set of logs to be used in both the seismic inversion and geomechanical analysis. The conditioned logs were also up-scaled to account for the expected lower resolution of seismic data using a 22ft Backus filter (Backus, 1962).
Prior to performing the inversion, a set of conditioning processes were applied to the pre-stack seismic data to optimize the AVO information. These processes included time alignment, structure-orientated median filtering, spectral balancing, partial angle stacking, spatial amplitude balancing and AVO scaling analysis. AVO intercept and gradient properties were calculated and compared for the seismic data before and after the conditioning processes, Figure 2. Further rigorous QC steps were made after each process. However, the improved lateral continuity of both AVO intercept and gradient after conditioning is considered a validation of the enhancement in the AVO signal within the dataset. An example of the final synthetic-to-seismic ties is shown in Figure 3. A good correlation (>0.86) was observed over the interval of interest for all 6 partial angle stacks using the single estimated wavelet. The use of a single wavelet is valid for all stacks because of the spectral balancing and AVO scaling analysis performed.

![Figure 2: AVO intercept before (a) and after (b) data conditioning processes applied; AVO gradient before (c) and after (d) data conditioning processes applied.](image)

The seismic inversion used a facies-based Bayesian pre-stack approach (Kemper and Gunning, 2014). There were two key advantages to applying this approach in this case study. First, the inclusion of facies in the inversion process removed the requirement for a conventional low frequency model. This ensured that the distribution of laterally discontinuous debris flow units was defined only by the seismic reflectivity and not biased by any interpolation assumptions. Second, the inversion approach was calibrated using a set of facies-dependent elastic property trends, rather than a single set of trends for the whole inversion window. Therefore, the predicted elastic impedance properties could be expected to honor the rock physics relationships observed in the well log data with greater fidelity. This is important when considering the subsequent geological characterization and geomechanical analysis using the property volumes.
The two wells with image logs were the focus of the geomechanical analysis. One well was used for the initial model calibration; the second well was used as a blind well to validate the final predictions. The geomechanical analysis commenced with an interpretation of the image logs (Figure 4). Observations of drilling induced tensile fractures were noted. A 1D analytical geomechanical model was then constructed using the poro-elastic equations (Thiercelin & Plumb, 1994) and the elastic properties calculated from the well logs, using core data to constrain the dynamic to static conversion. The regional strain parameters were calibrated to the minimum horizontal stress by solving the circumferential (hoop) stress around a vertical borehole and matching the predicted shear failure to the occurrence (and nonoccurrence) of drilling induced tensile fractures observed in the image logs. The calibrated model was then applied using the up-scaled elastic log data to verify that the expected resolution of the property volumes to be determined by the seismic inversion would be sufficient to predict the tensile failure observed in the image logs.

The final step in the workflow was to apply the calibrated geomechanical model to the elastic property volumes from the seismic inversion. The results provide an analytical estimate of the two horizontal stresses across the full 3D seismic volume. In this application, the horizontal stresses were subsequently used to calculate the fracture initiation pressure for a vertical borehole as a 3D property volume. This fracture initiation pressure property volume was validated against observations of tensile fractures in the second well location, previously unused in the geomechanical analysis.

A summary of the workflow is shown for Well A, Figure 5. The 1D log and geomechanical analysis is shown in tracks 1-9. The seismic well tie and inversion results are shown in tracks 10-14. The predicted stresses and fracture initiation pressure are shown in tracks 15-17. A good correlation is observed between the zones of low predicted fracture initiation pressure (track 16) and the drilling induced tensile fractures observed in the image log (track 18).
Figure 4: Example of drilling induced tensile fractures (red lines) observed in image logs from Well A.

Figure 5: A comparison of the log based and inversion based geomechanical models at Well A. Track 1 is the petrophysical interpreted mineral volume fractions (yellow = silt, brown = clay, blue = calcite). Track 2 contains the up-scaled facies. Tracks 3 & 4 contain the Vp sonic and calculated Young’s Modulus logs, before and after up-scaling to seismic resolution (grey and black respectively). Tracks 5 & 6 show the image log and observed drilling induced (red) and natural fractures (blue). Track 7 contains the log based stress estimates and up-scaled estimates. Track 8 contains the fracture initiation gradient based on the up-scaled logs. Track 9 contains the up-scaled log based stress anisotropy. Track 10 contains the measured and synthetic full stack seismic trace along the well path. Tracks 11 & 12 compare the target and inverted facies. Track 13 contains the up-scaled Vp log (black) and inverted Vp (blue). Track 14 contains the up-scaled E log (black) and inverted E (blue). Track 15 contains the horizontal stress profiles, calculated from the up-scaled logs (black) and inverted properties (blue & red). Track 16 contains the fracture initiation gradient based on the inverted properties. Track 17 contains the stress anisotropy calculated from the inverted properties. Tracks 18 & 19 show the image log and observed drilling induced (red) and natural fractures (blue).
Results

Five facies were defined based on the elastic properties observed in the well logs (Figure 1). These included the silt-rich shales, clay-rich shales and calcite-rich limestones. A separate facies class was defined for the carbonate debris-flow units as they were observed to have intermediate elastic properties between the two end-member lithologies of silt-rich shales and the thick limestone of the Strawn formation. A fifth facies was defined for the thin, cyclical, high TOC (approximately > 0.04 wt/wt) intervals observed in the lower Wolfcamp. These intervals had a characteristic low Vp and density, which translates into anomalously low values of acoustic impedance and Vp/Vs ratio. The thin nature of these high TOC intervals meant that the elastic properties measured by the sonic logs were frequently not fully resolved. Therefore, only the thicker high TOC shale intervals were identified in the facies classification.

The seismic inversion was calibrated using a set of facies-dependent rock physics trends, plus an estimate of the uncertainty, derived from the well log data. The trends and uncertainty were combined to generate a set of Gaussian probability density functions (PDFs). These PDFs were calculated in the Vp-density and Vp-Vs domains, and then translated into impedances more typically used in pre-stack inversion studies, Figure 6.

The inversion results at an example well location are shown in Figure 7. The accurate prediction of the relative excursions in the bandpass AI and Vp/Vs ratio curves indicates that the seismic scaling in the wavelet and AVO scaling are correct. The correlation between the measured and inverted absolute curves is also considered very good. The additional, high velocity carbonate intervals predicted by the inversion at this well are believed to be caused by residual multiple energy, which is observed in the seismic but not the well log synthetic traces. In addition, the density estimate is considered accurate. The density estimate has likely benefitted from the additional per-facies rock physics trends used as constraints in the seismic inversion approach. Similar results were observed at all of the study wells.
The inverted property volumes are shown for an arbitrary line between two well locations, Figure 8. The spatial distribution of the discontinuous carbonate debris flows can be observed in the facies property volume. Further information about the concentration of carbonate within these layers can be interpreted from the elastic property volumes. The elastic property volumes were translated from dynamic to static properties then used as inputs to the calibrated geomechanical model.

The geomechanical model generates analytical estimates of the two horizontal stresses, plus the fracture initiation pressure for a vertical, cylindrical borehole (Figure 9). The minimum horizontal stress, stress anisotropy and fracture initiation volumes can be used to better understand fracture stimulation behavior. The fracture initiation property volume was validated by comparing the predictions at the two well locations with image logs. At Well A, the well at which the geomechanical model was constructed and calibrated, two intervals of low fracture initiation pressure are predicted between the two thick debris flows in the upper Wolfcamp. Both intervals correlate with two zones where a high concentration of drilling induced tensile fractures is observed in the image log. Figure 5. The intervals of low fracture initiation pressure are observed to extend laterally away from Well A but increase in the vicinity of Well B. The image log in Well B shows different behavior than that observed in Well A, consistent with the predicted variation in fracture initiation pressure. Well B contains only a single drilling induced fracture in the laterally equivalent zone from Well A (Figure 10). Meanwhile drilling induced tensile failures are observed at a shallower interval, where the predicted fracture initiation pressure also decreases. The strong correlation between predicted fracture initiation pressure and occurrence of drilling induced tensile fractures observed in the image logs is considered as validation of the results.
Figure 8: Seismic inversion results on an arbitrary line between two well locations. The line is approximately 9 miles in length. (a): Full stack seismic reflectivity, (b): most likely facies, (c) acoustic impedance (g/cm³ x m/s), (d) Vp/Vs ratio and (e) density (g/cm³).
Figure 9: Stress and pressure properties calculated using the analytical geomechanical approach. (a): Minimum horizontal stress, $S_h$, (b): maximum horizontal stress, $S_H$, (c) horizontal stress anisotropy and (d) fracture initiation pressure gradient.

**Conclusions**

A coupled geomechanical and seismic inversion workflow has been developed. This workflow benefits from the integration and sharing of a common dataset between the different disciplines involved. The approach is dependent upon the accuracy of the elastic property volumes derived from the seismic inversion. The facies based-based Bayesian inversion approach used is believed to have provided a significant increase in the accuracy of the elastic property volumes.

The geomechanical modelling used the poro-elastic equations to derive analytical predictions of the two horizontal stresses and associated fracture initiation pressure. The workflow generates an estimate of the geomechanical behavior of the rocks at offset locations, away from the well control. Two different intervals of low fracture initiation pressure were predicted in two wells. These predictions were validated by the observation of drilling induced tensile fractures in the image logs. The fracture initiation pressure volume can be used to identify future landing intervals.

The advantage of the coupled workflow presented in this paper is the relative computational speed with which the geomechanical predictions can be generated compared to a full numerical simulation model. The ability to use the seismic scale property volumes, without the requirement for further upscaling, is also a significant advantage to the accuracy of the predictions.
Figure 10: Comparison of predicted fracture initiation pressure and the observation of drilling induced tensile fractures in Well B. The black arrows denote zones of observed drilling induced tensile fracture occurrence and low predicted fracture initiation gradient.

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References

