Impact of Ash Beds on Production in Eagle Ford Shale

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Abstract

The Eagle Ford shale contains both kaolinite and smectite rich altered ash beds that present challenges for completion and production. Considering the five Eagle Ford units (A-E), the ash beds occur in the B unit. The B unit is divided into five subunits; B1 and B2 are characterized by the highest TOC whereas B3-B5 have a higher frequency of ash beds. The impact of these ash beds is not yet fully understood, but acquired horizontal production log measurements indicate that the production performance of stages landed in the B3-B5 units, with high ash bed frequencies, are poor compared to other stages landed in a different unit. Some operators are vertically staggering laterals to effectively drain the reservoirs, partially due to the lack of vertical connection in the production phase. Thus, to increase the effectiveness of the completion strategy and ultimately the well performance, methods must be developed to quantify the impact of ash beds on production and to mitigate the negative impact. An integrated hydraulic fracture-reservoir modeling workflow was applied on an Eagle Ford shale lateral with part of the lateral crossing an ash bed in B3-B5 units. The subject well was completed with 15 stages. The simulation results demonstrate that the ash beds in B3-B5 units restrict part of the created hydraulic fracture height and create conductivity pinch points, thus reducing the effective fracture height connected to the wellbore. This, in turn, affects the potential well productivity. Based on the simulated results, the optimum lateral landing location is within the B1-B2 interval. The analysis also showed that targeting the hydrocarbons in these units, requires a different completion strategy. Use of a cross-linked fluid carrying higher proppant concentrations will facilitate the creation of larger fracture widths to withstand the negative impact of the ash beds isolating certain portion of the created fracture height.

Introduction

Interbedded ash bed deposits have been observed in several unconventional plays such as Eagle Ford, Niobrara, Vaca Muerta, and Mowry. But each unconventional play presents a unique challenge from these altered ash beds due to the mineralogy, bed thickness and frequencies. Even in the same play, different units vary. From completion and production point of view, kaolinite- and smectite-rich altered ash beds may create fracture pinch point to limit the effective fracture height connected to the wellbore even though the hydraulic height at the end of pumping could be much higher as demonstrated by microseismic data. The variation in observed mineralogy in the ash beds have implications for both the mechanical properties and the fluid compatibility. Therefore accurate characterization of these beds is
critical. Calvin et al (2015) use whole core analysis to summarize the variations in observed grain size, mineralogy, bed thickness, depositional and diageneric features of altered ash beds in Eagle Ford.

In the literature, the terminology of alteration of volcanic ash deposits includes bentonites, metabentonite, K-bentonite and tonstein. In this paper, Calvin et al (2015) terminology will be used and volcanic ash deposits in the Eagle Ford are referred to as altered ash beds.

**Ash beds in the Eagle Ford**

The Eagle Ford is a Late-Cretaceous (Cenomanian-Turonian) formation that disconformably overlies the Buda limestone and is overlain by the Austin Chalk. The Eagle Ford Shale outcrops from the Mexican border north of the Maverick basin through San Antonio, Austin, and Dallas, and northeast to the Sabine uplift where it is not present. From the outcrop, the Eagle Ford Shale dips to the Gulf of Mexico. Eagle Ford is generally divided into Upper and Lower Eagle Ford with Lower Eagle Ford being more organic-rich and favored target zone for horizontal wells. But the study from Eagle Ford outcrops in West Texas shows Lower Eagle Ford is not uniform. Donovan et al. (2010) used five-fold succession of informal lithostratigraphic units, A to E from the base up. Unit A consists of foram grainstone interbedded with dark gray mudstone and unit B consist of mainly organic-rich mudstone. Lower Eagle Ford is comprised of Unit A and B while Unit C-E form Upper Eagle Ford as shown in Figure 1. Each unit is divided into several subunits to distinguish the different characteristic within the unit. For example, Unit B is further divided into five subunits. It is observed that above the base of subunit B3 within the Lower Eagle Ford Formation, a dramatic increase of ash beds occurs. (Donovan, 2015). In this paper, Donovan’s term is used and the focus is mainly on B1-B2 and B3-B5.

![Figure 1—Lozier Canyon outcrop face and associated log profile with five lithostratigraphic units](image)

**Figure 2** shows core samples of ash beds under UV light and Eagle Ford outcrop of West Texas. The thickness of ash beds in the Eagle Ford shale are between 0.5 and 3 inches. The ash beds fluoresces yellow under UV light, which helps detect thin beds that are difficult to see in the visible spectrum (Calvin et al, 2015). One interesting observation from the Eagle Ford outcrops is that the vertical extension of fractures
interrupted in ash beds, as marked by red dotted line and black boxes. This indicates that ash beds could act as conductivity pinch points during the production phase.

Traditional methodologies for detecting ash beds used spectral gamma-ray (GR) logs. This relies on the appearance of radioactive elements (like Thorium) in the ash bed for detection (Schwalbach and Bohacs, 1992). However, the ability to find thin ash beds or distinguish closely spaced ash beds is questionable given that GR has a vertical resolution of 1 to 2 feet. Calvin et al (2015) introduced a detection methodology that utilized high-resolution logs including borehole images (electrical and/or ultrasonic), dielectric dispersion, micro-resistivity, density, and photovoltaic factor (PEF). Micro-resistivity processing (2" resolution) is used to enhance the calibration of borehole electrical images and improve the dynamic range of the high resolution synthetic resistivity log (SRES). This methodology helps in identifying the bed thickness and frequency of ash beds, which can be further used to evaluate the impact of these on production.

Unconventional Fracture Model

Hydrocarbon production from many unconventional reservoirs is enabled by creation of a complex fracture networks. This complex network is created by the interaction of hydraulic fractures with the preexisting heterogeneity (rock fabric, texture, planes of weakness, or natural fractures) in the formation. Vast microseismic monitoring work in shale plays depict such patterns (Cipolla et al, 2011a; Downie et al, 2013). The traditional planar assumption overestimates the fracture length in such cases and could not simulate fracture propagation in the natural fractures (Fan et al, 2010). In the recent past, a handful of complex hydraulic fracture models have been presented. One of these, the unconventional fracture model (UFM) introduced by Weng et al. (2011), is numerically gridded and simulates the branching of hydraulic fractures at weak interfaces. UFM is built to use a rigorous geomodel accounting for local rock texture and property variation. In addition to the geomodel, UFM uses material balance, fluid and proppant transport, pressure calculations, and interaction among simultaneously growing fractures (Malpani et al. 2015). The modeled hydraulic fracture geometry is generally validated by consistently matching observed treatment parameters and microseismic interpretations simultaneously (Cipolla et al. 2011a; Downie et al. 2013; Ejofodomi et al. 2011). The UFM has been integrated into a reservoir-centric software platform that enables the integration of reservoir characterization, geomechanical modeling, microseismic interpretation, and reservoir simulation.
Methodology

Our study utilize the Unconventional Reservoir Optimized Completions (U-ROC) workflow, directly derived from the integrated "seismic-to-simulation" workflow (Cipolla et al. 2011b) as shown in Figure 3. As our focus is mainly on single well production simulation, Figure 4 shows the simplified well optimization workflow. This workflow maximize the benefits of the UFM complex fracture model by seamlessly integrating the various processes involved in well completion design/analysis and production simulation for unconventional reservoirs. The key processes include the construction of the geological model and detailed mechanical earth model (MEM) with the geomechanical and reservoir properties from pilot hole log suite, hydraulic fracture model (UFM), generation of the reservoir grid, production simulation, and sensivity analysis for landing location and stimulation design.

Figure 3—Unconventional Reservoir Optimized Completions (U-ROC) workflow and the multiwell pad completion optimization workflow

Figure 4—Simplified Well Optimization Workflow
Modeling Details and Results

A synthetic model was constructed with generic Eagle Ford geological structure and a type well log in southwest Eagle Ford. The petrophysical properties are shown in Figure 5. As discussed above, Lithostratigraphic units were used as defined by Donovan et al (2010). In this area of Eagle Ford, Upper Eagle Ford disappears and only lower Eagle Ford exists. So the boundary of B1-B2 and B3-B5 along with Austin Chalk and Buda are marked. Two layers of ash beds are identified and marked with black boxes in B3-B5. The two ash bed layers are not real beds but they represent the effect of multiple frequent and laminated groups of ash beds for simulation purpose. The average thickness is about 3 feet. Based on the core data, the general thickness of ash beds are between 0.5-3 inches. Well 1H is landed in B3-B5 with part of the lateral intercepted with an ash bed layer as shown in Figure 6. Typical completion practices are used to simulate realistic field conditions and investigate additional scenarios.

Figure 5—the pilot hole log data along with the whole core data. The tracks from left to right are describe as the following: 1) Formation zones, 2) Gamma Ray, 3) Elemental Spectroscopy, 4) Measured Depth, 5) Resistivity, 6) Neutron Porosity, Sonic Porosity, Bulk Density (log and core), 7) Sonic Slowness, 8) Hole conditions (caliper, bulk density correction), 9) Anisotropic Stress, 10) Total Organic Carbon (TOC), 11) Whole Core – XRD, 12) Volumetric Model, 13) Modeled Porosity and Whole Core Porosity, 14) Permeability, 15) Water Saturation (Modeled and Whole Core)
Discrete Fracture Network (DFN) is a critical input to UFM. DFN is used to represent the 3D distribution of planes of weakness/rock texture. In this case, DFN is generated based on the stochastic method to characterize the spatial variability in natural fracture intensity and orientation in the Eagle Ford. The predominate J1 fracture set was 55 azimuth while the J2 fracture set was oriented off perpendicular at 145. Both fracture sets were not considered mineralized, and modeled with 0 psi of cohesion and 0 as the coefficient of friction. For the complex fracture simulation, the minimum in-situ stress profile and geomechanical properties profiles from the type well are used.

The horizontal stress anisotropy is one of the most sensitive parameters controlling the propagation of complex fracture networks; for the Eagle Ford Shale, the difference between maximum and minimum horizontal stresses is considered low, but it can vary significantly from well to well, or even from stage to stage. For this study, the horizontal stress anisotropy is assumed to be on the order of 1%, reflecting our typical experience with sonic scanner tool measurements in the area. (Qiu et al, 2015)

Well 1H is a 5,000 ft lateral and stimulated with 15 stages. There are eight perforation clusters per stage and average cluster spacing is 42 ft. the perforation clusters are a foot long with six shots. The pumping schedule is a traditional slickwater fluid design based on 9,000 bbls slickwater and 330,000 lbs 40/70 sand per stage with maximum proppant concentration of 2 PPA.

In order to study the production performance in different scenarios, the autogridding algorithm first introduced by Cipolla et al. (2011b) was applied to generate the unstructured grid for the simulated hydraulic fracture network, which in turn will be used for production simulation and forecast with a numerical reservoir simulator. This step is of fundamental importance because of the severe complex fracture patterns predicted by the fracture model. Reservoir model for each scenario consists of about one million cells with black oil fluid model, a typical Eagle Ford case, while the matrix permeability and relative permeability curves are assumed within a reasonable range of Eagle Ford known values.

**With ash beds vs. without ash beds**

Figure 7 shows the simulated complex hydraulic fracture network (width is shown as a color-coded property) for well 1H with slickwater pumping schedule. The characteristic of ash beds provide a unique mechanism for creating conductivity pinch point. As shown in Figure 2, ash beds are mixed with weak formation bedding planes. When hydraulic fracture vertically propagates through these weak bedding planes, it could cross them, or arrest by horizontal interfaces, or offset from the original hydraulic fracture (Chuparakov and Prioul, 2015). These all prevent the effective placement of proppant. Combining with
kaolinite or smectite, the effective conductivity in the ash bed layer could be close to the matrix. So to simulate the effect of conductivity pinch point in ash bed layers on production, the permeability of fracture grid was set to be the same as matrix (100 nd). Figure 8 shows the reservoir grid generated based on UFM simulation. The blue layers represent the conductivity pinch point created by ash bed layers. The production simulation result are compared in Figure 9. The case with ash beds has cumulative gas production of 0.9 BCF over 21 months period, which is 36% less than the case without ash beds, a sizable impact on production.
Landing location

Well 1H is landed in B3-B5 which has higher frequency of ash beds. Now that we quantified the potential impact of ash beds on production, let’s discuss what can be done to minimize this impact. The first option is to stay away from ash beds by landing the well in B1-B2. Well 3H was created with same completion parameters as Well 1H, the only difference being Well 3H landed at the boundary of B1-B2. Figure 10 shows the landing location comparison between Well 1H and 3H. The identical slickwater pumping schedule is applied to Well 3H and simulation result is shown in Figure 11. The average fracture half length is about 800 ft which is similar to Well 1H but due to landing away from ash beds, the production of Well 3H is almost double of the production of Well 1H as shown in Figure 12.
Generally, when selecting lateral landing location in unconventional reservoirs, petrophysical and mechanical properties such as effective porosity, water saturation, kerogen, clay volume and minimum horizontal stress profile are the key inputs. Now, ash beds thickness and frequency could be another key parameter in deciding lateral landing location. The sensitivity of ash beds to landing location can be evaluated with this workflow.

**Crosslink fluid vs. slickwater**

The second option is to alter the stimulation strategy, to investigate the impact of different treatment design on the production in ash bed area, a traditional pumping schedule with crosslink fluid was created with same 330,000 lbs 40/70 proppant per stage as slickwater but with 5,600 bbls 20# crosslink fluid and maximum proppant concentration of 4 PPA. The comparison of hydraulic fracture simulation between slickwater schedule and crosslink schedule is shown in Figure 13. The production with crosslink schedule is almost double the production with slickwater schedule as shown in Figure 14, eventhough the fracture extent is almost 70% to that of slickwater. The increase in production is attributed to conductive fractures horizontally and vertically, minimizing the impact of ash beds. Chuprakov and Prioul (2015) have shown that the fracture height containment due to weak bedding planes is affected by the viscosity of fracturing fluid. Large viscosities reduce the "effective" fracture toughness and diminish the containment effect. So ash beds will have less impact on crosslink fluid with higher proppant concentration than on slickwater.
In both slickwater and crosslink fluid cases, the permeability of fracture grid in ash bed layers are set to be the permeability of matrix. This assumption will underestimate the production of crosslink fluid case. Further study is necessary to find the correlation between proppant concentration per square foot and fracture conductivity in ash beds. Then in the reservoir model, the permeability of fracture grid in ash bed layers can be modified based on fracture model simulation.

Figure 13—Comparison between simulated complex hydraulic fracture network with crosslink schedule and slickwater schedule in well 1H

Figure 14—Production simulation comparison between crosslink schedule and slickwater schedule in Well 1H in 21 months

Conclusion

The simulation results demonstrate that the ash beds in B3-B5 units restrict part of the created hydraulic fracture height and create conductivity pinch points, thus reducing the effective fracture height connected to the wellbore. This, in turn, affects the well productivity, 36% in this case. Based on the simulated
results, the optimum lateral landing location is within the B1-B2 interval, away from the ash beds. The analysis also showed that targeting the hydrocarbons in the units, requires a different completion strategy. Use of a cross-linked fluid with proppant carrying ability at higher concentrations will facilitate the creation of larger fracture widths to withstand the negative impact of the ash beds isolating certain portion of the created fracture height, possibly doubling the production.

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