Impact of Well Spacing and Interference on Production Performance in Unconventional Reservoirs, Permian Basin
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Abstract
In the Permian basin, unconventional reservoirs have been the main target of horizontal well drilling since the early 2000s. Over the years, completion and stimulation design in horizontal wells has evolved from conservative to radical designs. It has also progressed from exploration mode to full development, and from single-well pads to multi-well pads and stacked laterals. In field development mode, infill drilling between pre-existing wells that have been on production for some time is typically done. Production interference has been observed to occur and known to have negative impact on pre-existing (parent) wells. The parent well would cause reservoir depletion resulting in localized “pressure sinks” that can cause the infill (child) well’s hydraulic fractures to grow towards the pressure sink and damage the parent well. In addition, the production potential of the child well is likely to decrease because of the pressure sinks (depleted area). The main purpose of this paper is to understand the impact of different well spacing configurations on well interference and production performance in unconventional reservoirs. This paper is an extension of a previous work presented by Ajisafe et al. (2016) on the use of discrete fracture network (DFN) from seismic data for complex fracturing modeling.

A multi-disciplinary integrated workflow was applied in a multi-well pad, with an extensive dataset consisting of seismic, high-tier vertical and horizontal logs and microseismic data. The multi-well pad consists of two wells, a parent well that has been completed and put on production for a year, and a new (child) well to be completed on the same pad. Two different well spacings were investigated, at 660 feet and 1,320 feet to understand the negative impact of interference on the parent well production, as well as the performance of the child well due to reservoir pressure depletion of the parent well. To mitigate/avoid the negative impact of production interference on the parent well and to improve performance of the child well, the child well was landed deeper in the Avalon shale.

The DFN model and geomechanical properties were key inputs into understanding the complex fracture geometry constrained with microseismic data for the parent well. Seismic data provided an improved DFN model along and particularly away from the wellbore. The different models are discussed in detail in Ajisafe et al. (2016). The reservoir pressure depletion pattern and complex fracture geometry were then used as key input into a geomechanics simulator for an updated in-situ stress state at 1 year, which was then used for complex fracture modeling of the child well. The effect of a year of production-induced depletion on the parent well shows a change in the reservoir pressure, horizontal stress magnitude and maximum horizontal stress azimuth. Reservoir simulation was done to quantify production performance of both the parent and child wells at the different spacing configuration.

Complex fracture modeling reservoir simulation and geomechanical models in unconventional shale reservoirs are instrumental in understanding the impact of natural fractures and hydraulic fracture placement on final well productivity in multi-well pad scenarios. The optimal well spacing and completion design to maintain and/or increase hydrocarbon production with the right amount of resources is critical for maximized returns. Multi-well modeling is an important first step in the unconventional reservoir workflow, which improves planning for multi-well pad and future infill well development.
Geological Background

The Avalon shale is located in the Delaware basin, across southeast New Mexico and West Texas. The Delaware basin is part of the Permian basin, bounded by the Diablo platform in the west, Northwestern shelf and Capitan reef trend in the north, Central Basin platform in the east, and Southern shelf in the south (Fig. 1).

![Figure 1: Key geological structures in the Permian basin (Murchison Oil & Gas, Inc. 2010)](image)

The Avalon shale is primarily a self-sourced rock consisting of siltstone, limestone, clay, chert, and organics. It is typically subdivided into three zones—upper, middle and lower—bounded by carbonate debris flows (Fig. 2). Each zone has variable rock properties inherited from variations in depositional environments across the Delaware basin. Siliciclastic mudstones in the upper and lower Avalon are considered to be of good reservoir quality and are highly productive whereas the carbonate-rich middle Avalon is considered not productive because of the high percentage of carbonates, which is associated with bad reservoir quality. The upper Avalon shale is the most exploited due to its good reservoir quality with porosity between 4 and 15%, a gross thickness between 50 and 380 feet and total organic carbon ranging from 2 to 6%. True vertical depth (TVD) ranges from 4,000 to 9,000 feet depending on the location in the Permian basin (Ajisafe et al 2016).

Compared to other US shale plays, the Avalon shale has a lower clay content. Image logs and cores have shown abundant natural fractures in this formation. Therefore, characterization and modeling of natural fractures in the Avalon shale are very important for drilling, completion and production optimization (Ajisafe et al 2016). Hydrocarbons in the Avalon shale exist in the form of volatile oil, natural gas liquids (NGL) and condensate. In some other areas, wet gas and dry gas Avalon shale reservoirs exist as one progresses west across the basin passing
through different maturity windows (Nester et al 2014). In the past, the Avalon shale has been exploited by vertical drilling, but recently, horizontal drilling has been the trend to fully exploit this unconventional play.

Figure 2: Delaware basin stratigraphic column (New Mexico and Texas)
**Introduction**

Horizontal well drilling in the Avalon shale started in the early 2000s and has continued in an increasing trend over time. The Avalon shale is heavily exploited in New Mexico and Texas. Eddy County in New Mexico has the majority of the Avalon wells, and some wells exist in Culberson, Loving, and Reeves counties in Texas (Fig. 3).

![Figure 3: The Avalon shale in major counties, Eddy, Culberson, Loving, and Reeves (IHS Production 2017)](image)

Typically, US oil and gas companies operating in US unconventional plays begin by drilling and completing a single horizontal well in each lease across their acreage to secure full development rights. This process is called hold-by-production (HBP). These wells are typically referred to as “parent wells”; these are the original wells drilled, completed, and produced under virgin reservoir conditions. When their entire acreage has been held, full-field development begins by drilling and completing infill wells or “child wells” near the original parent wells. Miller et al. (2016) demonstrated the impact an existing parent well has on a newly drilled and completed child well. Their analysis was based on public production data and focused on five major unconventional basins (Eagle Ford, Bakken, Haynesville, Niobrara, and Woodford).

To quantify the potential impact in the Avalon shale, a similar analysis was performed, using similar criteria. Using public production data from IHS, child wells were considered to be wells that were drilled within 2,000 feet of an existing parent well and begin production at least 6 months after the parent well production started. This was to account for pressure depletion in the parent well that would influence possible fracture interference from child well. The best consecutive three months (B3) and six months (B6) oil production, normalized by total proppant per lateral length was computed and compared to see if there is any difference in the production performance of the average parent and child well. The results shown in **Fig. 4**, indicate that overall, the child well oil production is ~ 30% less than that observed on the corresponding parent well. This observation supports that fact that pressure depletion effects from the parent well have a negative impact on the completed child well.
This study presents an integrated workflow that takes into account the effects that production and pore pressure depletion have on mechanical rock properties. A state-of-the-art complex fracture modeling workflow also known as the unconventional fracture model (UFM) was applied in the Avalon shale with petrophysics, geomechanics, DFN model, and completion data. A parent well was hydraulically stimulated and produced for a year, after which a finite element analysis was generated to compute the current state of stress magnitude and azimuth caused by the decrease in pore pressure with time. After this, the child well was stimulated with the updated stress regime at 1 year. The complex fracture geometry was analyzed, showing fracture hits to the parent well, and the resulting impaired production was quantified.

Pore pressure depletion is found to cause what is commonly referred to as “pressure sinks” which, in turn cause stress magnitude change and azimuthal realignment (Martinez et al. 2012). The uneven distribution of pressure sinks can cause two types of fracture hits. In the first type, the initial fracture propagates within a depleted area and draws towards the parent well in a pressure-sink scenario. In the second type, a stress vortex is created that can channel a fracture caused by convergence of stress orientation (Marongiu-Porcu et al. 2015).

Fracture hit consequences have been extensively covered (Marongiu-Porcu et al. 2015; Veeken et al. 1994; Fjaer et al. 2008), and have been associated with mild, severe, or complete production impairment of the hit parent well. The actual mechanisms that lead to these productivity impairments may involve the removal (drag) of considerable portions of the proppant from the near-wellbore region of the primary well fractures and consequently disruption of the critical near-wellbore fracture conductivity, and/or wellbore failures analogous to the ones addressed in Veeken et al (2004) and Fjaer et al. (2008).

**Methodology**

A multi-disciplinary integrated workflow was used in this study, **Fig.5a** shows the complex fracture integrated workflow for unconventional reservoirs. While, the expanded workflow in **Fig.5b**, is used to model parent and child well interference and its impact on production performance.
Figure 5: a) Complex fracture integrated workflow in unconventional reservoirs (Weng et al. 2014). b) Expanded workflow used to model parent/child well fracture interference, (Marongiu-Porcu et al. 2015)

Initial Work

This study is an extension of the previous work presented by Ajisafe et al. (2016). The main purpose of the work was to show that a DFN model built from seismic data and calibrated with offset borehole image logs can successfully be used for effective modeling and prediction of the complex hydraulic fracture propagation and geometry. Microseismic measurement also provided an additional source of calibration during the complex hydraulic fracture modeling. The UFM workflow was applied to a single horizontal well (well A) on a two-well pad in Eddy County, New Mexico. The horizontal well was landed in the Avalon shale and was hydraulically stimulated with 11 stages along the lateral section with the conventional plug-and-perforation technique. The DFN model showed natural fracture intensity variation along and away from the wellbore, and for the most part, agreed with the microseismic events footprint (Fig.6a). The microseismic events also showed that the hydraulic fracture were mostly contained within the Avalon shale (Fig.6b). However in some stages, it is observed that the microseismic events have more height growth than others. Overall, the modeled complex fracture geometry was consistent with the microseismic footprint.
As shown in the workflow above in Fig. 5, the parent well (well A) was hydraulically stimulated and then produced for a year, after which a finite element analysis was generated to compute the current state of stress magnitude and azimuth caused by decreased pore pressure with time. Then, an offset child well was stimulated with the updated stress regime at the 1 year depletion time step. Two different scenarios of well spacing, at 660 feet and 1,320 feet, were investigated. The next section discusses the finite element model process, results, and impact to the original stress state with depletion.

**Finite Element Analysis Model**

The initial rock elastic properties are obtained using well logs presented and spatially distributed horizontally following a seismic-generated surface to create a 3D mechanical earth model (MEM). As the reservoir is produced, a pressure depletion region around the stimulated area will begin to form and affect the mechanical properties of the rock. Within the depleted region, the change in pore pressure will increase the in-situ effective stress, which, in turn, will alter the maximum horizontal stress azimuth (Zoback 2010). The natural fractures in the model are created through an ant-tracking process based on seismic data and are represented by discrete discontinuities in the Finite Element Model (FEM) with high cohesion, which will represent naturally occurring cemented fractures. The hydraulic fractures generated by the parent well stimulation are deterministically generated based on the parent well complex fracture network. The hydraulic fracture network cohesion is set at zero to represent a failed fracture with
no cementation. Initial stress state and maximum horizontal stress azimuth are shown in Fig. 7. The left part of Fig. 7 shows the initial horizontal stress magnitude, the right part of displays an average 77° angle for maximum horizontal stress. Fig. 8 (left) represents the depletion state of the reservoir after 1 year of production by the parent well; the right part of Fig. 8 represents the change in minimum horizontal stress magnitude. Fig. 9 (left) represents the depletion state of the reservoir after 3 years of production by the parent well; the right part of Fig. 9 represents the change in minimum horizontal stress magnitude.

Figure 7: Initial minimum horizontal stress on the left and maximum stress azimuth on the right.

Figure 8: Reservoir pressure after 1 year of production on the left and minimum horizontal stress on the right.
Figure 9: Reservoir pressure after 3 years of production on the left and minimum horizontal stress on the right.

The left part of Fig. 10 shows the magnitude of the maximum horizontal stress after 3 years of production. The right-hand side of Fig. 10 shows the resulting stress-induced complex fracture for the child well 600 feet away from the parent well. The results presented are consistent with previous results reported by Marongiu-Porcu et al. (2016) and Morales et al. (2016).
Hydraulic Fracture Modeling

The finite element analysis provided an updated stress model due to the effect of pore pressure depletion at 1 year; this was then used as an input for the complex hydraulic fracture model of the child well. The two different well spacing of 660 feet and 1,320 feet were investigated.

Fig. 11 shows the modeled complex hydraulic fracture geometry for the child well at 600 ft well spacing from the parent well. Two phenomena were observed. First, the complex fracture geometry for the child well shows longitudinal fractures aligned along the wellbore highlighted in white circles in Fig. 11b. Second, fracture hits from the child well to the parent well are observed and indicated in black circles in Fig. 11a.

Figure 11: 600 ft well spacing  a) Updated reservoir pressure model at 1 year depletion and modeled complex fracture geometry of the child well. b) Updated maximum stress azimuth at 1 year depletion and modeled complex fracture geometry of the child well.

Longitudinal fractures along the wellbore can cause production impairment on the child well, reducing the production potential of the child well, and the hydraulic fracture hits from the child well to the parent well can impair the production performance of the parent well. The pressure sink caused by the pore pressure depletion at 1 year shows a negative impact on the complex hydraulic fracture geometry on the parent and child well, spaced at 660 feet.
Figure 12: 1,320ft well spacing a) Updated reservoir pressure model at 1 year depletion and modeled complex fracture geometry of the child. b) Updated maximum stress azimuth at 1 year depletion and modeled complex fracture geometry of the child well.

Fig. 12 shows the modeled complex hydraulic fracture geometry for the child well at 1,320 feet well spacing from the parent well. No fracture hits were observed at the parent well and barely any longitudinal fractures were observed at the child well. The results shows that the pressure sink caused by the pore pressure depletion at 1 year does not impact the complex hydraulic fracture geometry of the child well, spaced at 1,320 feet.

The pressure sink caused by the pore pressure depletion at 1 year shows a negative impact on the complex hydraulic fracture geometry on the parent and child well, spaced at 660 feet. To mitigate/avoid the negative impact of production interference on the parent well and to improve performance of the child well, the child well was landed deeper in the Avalon shale (Fig.13 and 14).
The UFM model was simulated for the complex fracture geometry. All three scenarios were evaluated for production performance in the reservoir simulation model, discussed in the next section.

Figure 13: Lateral landing scenario a) Child well landed 150ft deeper, still within the Avalon shale; porosity model in background. b) Child well landed 150 ft deeper and spaced 600 ft away from the parent well.

Figure 14: Lateral landing scenario a) Child well landed 150ft deeper than the parent well, still within the Avalon Shale; reservoir pressure model in background. b) Child well landed 150 ft deeper and spaced 600 ft away from the parent well, showing reservoir pressure depletion at the heel and toe.
Reservoir Simulation

The production performance of alternative well spacing scenarios is studied with the use of black oil, numerical reservoir simulator. The evaluated properties of created hydraulic fracture networks are incorporated into the single porosity reservoir description by using the automated gridding algorithm. This step is of fundamental importance because manual generation of a reservoir grid is practically impossible due to complex fracture patterns predicted by the fracture model (Weng et al. 2014). The fluid and rock properties are taken within reasonable range of known values in Permian basin.

Figure 15 shows the time-normalized production curves for a sample of ~300 wells in the Avalon Shale (IHS Energy US well database, 2017). For this study, a representative P50 cumulative oil production profile is selected (thick black curve in Fig. 15) and used as the control variable to run the reservoir simulation and production history match for 3 years of production.

Figure 15: Time-normalized cumulative production for a sample of ~300 wells in the Avalon Shale. Representative P50 cumulative oil production profile used for reservoir simulation and production history match.
Three well placement scenarios were evaluated for a two-well pad such as lateral spacing of 660 feet and 1,320 feet between parent and child well as well as lateral spacing of 660 feet with additional 150 feet depth added for the child well. The parent well produced for a year. After that period, the second well was completed in the pad, and the two wells were producing together for 5 years. The child well has followed the same bottom-hole production decline as the parent well. Pressure depletion profiles for three alternative well spacing scenarios (1,320-feet lateral, 660-feet lateral, 660-feet lateral 150 feet deeper) at the end of 5 years of child well production are shown in Fig. 16.

Figure 16: Pressure depletion for three alternative well spacing scenarios (1,320-feet spacing, 660-feet spacing, 660-feet spacing and 150 feet deeper) at the end of 5 years child well production.

Production Results

For all three child well spacing scenarios, the 1,320-feet lateral well spacing and this scenario provided the maximum cumulative oil production. The child well produced 5% less cumulative oil production comparing the parent well production for the same period of time. For the spacing of 660 feet, a 24% decrease in cumulative oil child well production was observed within 5 years of production. To reduce the negative impact on production from placing a well within 660 feet spacing, the alternative scenario was evaluated in which the lateral spacing of the child well was 660 feet with the child well placed 150 feet deeper than the parent well. For that scenario, the reduction in the cumulative oil production for a child well was only 10% compared to the parent well production, in contrast to the 24% for the 660 feet lateral spacing without the deeper placement (Fig. 17).
Conclusions

A multi-disciplinary workflow was applied in the Avalon shale to understand the impact of pore pressure depletion at different well spacing configurations on well interference and production performance. Some key observations from this study include the following:

- Analysis from IHS Avalon production data showed that overall, the child well oil production is ~ 30% less than that observed on the corresponding parent well. This observation supports that the fact that pressure depletion effects from the parent well, have a negative impact on the completed child well.
- The finite element analysis shows a change in pore pressure and maximum horizontal stress azimuth due to production depletion with time.
- Unconventional fracture modeling shows the negative impact of production interference in the 660-feet well-spacing scenario at 1 year due to pore pressure depletion. Two phenomena were observed.
  - The complex fracture geometry for the child well shows longitudinal fractures aligned along the wellbore.
  - There were fracture hits from the child well to the parent well.
- Little or no production interference was observed between the child and parent wells at 1,320 feet well spacing. The child well production was 5% less comparing parent for the same period of production time.
- Reservoir simulation showed a 24% decrease in 5-year cumulative oil production for the child well at 660-feet spacing compared to the parent well production.
- To reduce the negative impact on production, an alternative scenario was evaluated in which the child well was landed 150 feet deeper at the same 660-feet well spacing. In this scenario,
  - 5 year cumulative oil production was 10% less than the parent well production.
References


