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Understanding Development Drivers in Horizontal Wellbores in the Midland Basin

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Abstract

The Permian Basin in North American has been the driving force behind global energy growth, resulting from the exploitation of unconventional resources. The combination of high quality stacked resources, horizontal drilling, completion tools, and hydraulic fracturing innovations has accelerated the learning curve in this basin over the past few years: which was the impetus of this study.

This paper utilizes an integrated model approach to understand reservoir performance on a pad with four wells completed across multiple horizons in the Midland Basin. Rich multi-domain data sets were utilized that included seismic, wireline triple-combo, compressional and shear log suites, core (rock mechanics testing, geochemical analysis (XRF and XRD) and routine core analysis), completion data (fracture treatments with pre-and post-job shut-in pressures), and production data including 1,500 days of production history with bottom-hole pressure gauge data. 3-D surface seismic, high tier logs, and core data were used initially to create a facies model. Properties were distributed into a geo-model using the existing vertical well-control and seismic as constraints. A sector model was then built that enabled modeling of 4 development wells that consisted of parent well, followed by 3 child-wells. The history matching of fracture treatments and production data with bottom-hole pressure data resulted in significant understanding of key parameters driving subsurface performance.

A workflow, representing the seamless integration of said models, is presented that enables an improved understanding of what impact sequence and timing of operations has on the subsurface contact area as well as the implied change in well performance if an optimal strategy is executed. Geomechanical facies that drive vertical connectivity and fracture geometry, as well as reservoir parameters that impact fracture contact with the reservoir, were identified.

Introduction

The Permian Basin (PB) is one of the largest and more structurally complex regions in North America. This sedimentary basin, comprised of several sub-basins and platform, covers an area about 250 miles wide and 300 miles long in west Texas and southeast New Mexico. The Basin name originates from the period of geologic time (Permian: 299 million to 251 million years ago) and the evolution of the basin can be attributed to mass deposition (massive amounts of clastic sediments were deposited in this area causing a depression), continental collision (the supercontinents Laurasia and Gondwana collided to form Pangea causing faulting and uplift) and basin filling (filling of the sub-basins with sediments). The Midland Basin, Central Basin Platform, and the Delaware basin are the three main components of the PB that we know today. The sub-basins rapidly subsided, while the platform remained at a higher elevation resulting in areas having very different water depths and depositional environments. Terrigenous clastics are associated with deep water environments, whereas coarse grains associated with shallow reef environments are seen along the platform. The Midland and Delaware sub-basins share mutual characteristics such as age and lithology, but depths, nomenclature, and development vary significantly through the Basin. The eastern Midland Basin accumulated large amounts of clastic sediments during the Pennsylvanian (323 to 299 million years ago) that formed a thick subaqueous deltaic system that consumed the basin from east to west as it was deposited. During the Permian period, the delta system was covered with floodplains and was nearly filled by the Middle Permian. The Delaware Basin is approximately 2,000 feet deeper than the Midland Basin. This caused the sediments to experience nearly twice as much pressure during burial driving stratigraphic discontinuities between the two sub-basins.

This study focuses on four wells landed in the Lower Spraberry Shale reservoir-horizons within a spacing unit in the central Midland Basin (Fig. 1). The objective was to model the well performance of the parent wells with the aim of matching / predicting in-fill well performance and understanding optimization opportunities.

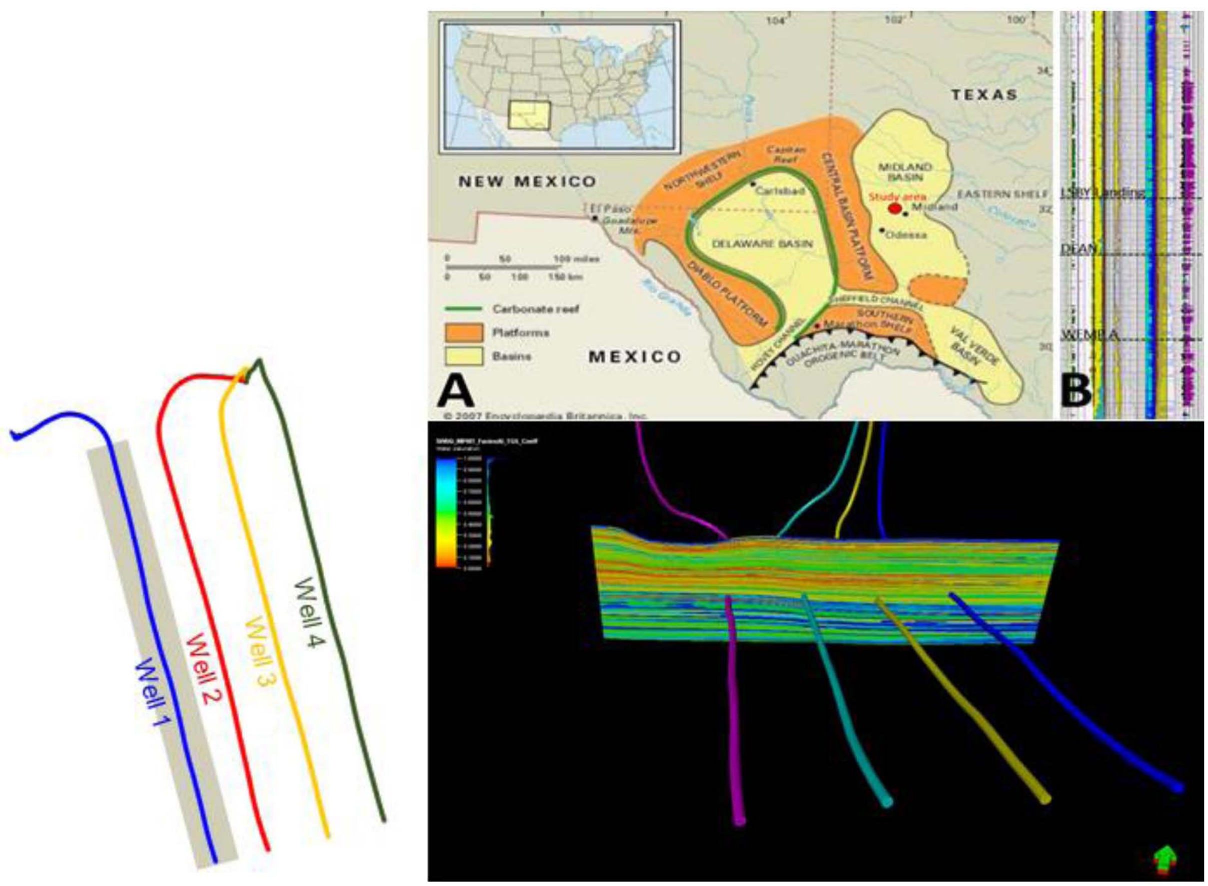


Figure 1—Study Location (Shoemaker, M Et al, 2018)

Methodology

30 geo-model control wells were analyzed within the 7-mile radius study area. The four wells that are the focus of this study were landed within a 5,280 ft long spacing unit (Fig. 1). A parent well produced for a period of 2 years before in-fill adjacent child wells were completed. The sequence of operations was such that the wells farthest from the parent wells were completed first, followed by the child wells closer to the parent well (Fig. 1). Petrophysical and geomechanical models were developed using wireline quad combo data (including azimuthal anisotropy and sonic processing, and nuclear-magnetic resonance (NMR) logs), and core data (rock mechanics testing, geochemical analysis (x-ray fluorescence (XRF) and x-ray diffraction (XRD)), and routine core analysis). Initially vertical fracture treatments within the study area were modelled to minimize uncertainty in the geomechanical properties. Once this step was completed, the four horizontal wells within the sector model were addressed. Numerous models that captured uncertainty were fed into completion and reservoir models for validation via fracture pressure and production/ pressure history matching.

Petrophysical Models

Vertical wells in the study area that had both core data and wireline quad combo log data (compressional and shear) were used to create a robust facies model. Permeability measurements at numerous confining stresses enabled the development of a relationship between permeability and confining stress. The Klinkenberg permeability from offset wells was corrected using this relationship to the reference net over-burden (NOB) in the area-of-interest (AOI). Probabilistic petrophysical methods utilizing mineral solving inversions were applied to construct a robust model that ties into measured core rock properties (XRD-based mineralogy, grain density, crushed rock and routine core analysis of porosity, permeability and geochem RE & Leco-based total organic carbon (TOC)) to find the most likely petrophysical model solution. Over 15 wells were analyzed within the study area.

Geo-model

The geo-model served as the basis for integrating all geoscience data, evaluating volumetrics and performing well optimization. The model was created over the half- county study area but only the 4-well sector area was exported to allow for reasonable computing times during history matching and forecasting. A facies model was created using log and seismic attributes to capture both petrophysical and geomechanical properties. Facies were initially propagated using the well control and seismic attributes. A facies variogram was used as input for the facies propagation. A stochastic pixel based algorithm (Sequential Indicator simulation: SIS) for categorical properties was used to simulate the facies onto the grids. Porosity was distributed in the model using the Sequential Gaussian Simulation (SGS) algorithm using a facies bias. Water saturation was also distributed using the SGS algorithm with a co-located co-kriging to porosity. Permeability was populated using standard core-based permeability / porosity correlations at initial confining stress.

Geomechanics

Core and field data were collected and analyzed to understand stratigraphic changes and causes of discrepancies in absolute rock properties. Rock mechanics core data (acoustic velocities and mechanical properties such as Young's modulus and Poisson's ratio) were analyzed to understand changes in rock physical properties as a function of effective confining pressures. Core-based correlations were built for the area of interest. These correlations were useful in generating continuous anisotropic "static" mechanical logs to calculate minimum horizontal and other far-field stresses. A conservative pore pressure model (with lower and upper bounds constrained from closure estimates and BHP gauges) utilizing varying pore pressure ramps (within the formation and across formations / reservoirs) derived from log measurements (movable fluid, mud-gas and sonic velocities) was used. A pore-pressure transition profile was created through the reservoir. Five wells with dipole-sonic data within the study area were the focus. Vertical-well instantaneous shut-in pressure (ISIP) data was used to constrain the stresses above and below the reservoir intervals. Numerous 1D mechanical earth models (MEMs) were generated to aid in fracture pressure history matching. Since all generated mechanical and stress logs were purely model based, validation was done by fracture pressure history matching and integrating interference and microseismic data. The facies-based MEM, seismic based MEM (using only seismic based velocities) and the sonic-based MEM were compared. Agreement between these MEMs enabled early confidence in the extraction of mechanical properties where little sonic-well-control existed. Once the vertical wells were fracture pressure history matched, mechanical properties were generated using the geo-model facies.

Fracture Modeling

More than 150 fracturing stages were compared from ten wells (including the 5 sonic wells) within the study area, to identify any outliers in terms of treatment parameters (injection rates, fracturing material balance and concentrations) and treatment responses (surface treating pressure and net pressure evolution).

A numerical planar fracture simulator was used to model the field-measured fracture treating pressures and non-ideal diagnostic tests (field events that forced shut-downs with extended declines during various stages across multiple wells). A fine grid (< 6 ft) was used for fracture pressure history-matching. The interference information from offset fractures with communication events constrained the expected spatial height growth and fracture length. More than seven MEMs were tested on the vertical microseismic wells. MEM validation was performed on vertical wells with sonic and microseismic. Once a fracture pressure history match was performed and sufficient repeatability observed with the selected MEM, the geometries were compared with microseismic to see the level of agreement. Next, two separate MEMs were generated: (1) using the facies model (where seismic attributes were used for propagation) and (2) using velocities generated by seismic only. Once the MEM was validated on the vertical wells, horizontal fracture modeling could begin. Stages with calibration events (pre-and post-job ISIP) were the focus on all four horizontal wells. Fracture pressure history-matching was performed on key calibration events across multiple wells. The pilot hole logs from the pad were used to construct a MEM to history-match the fracture treatments. Well 1 was the initial focus as it was the parent well that produced for 2 years. History-matching well 1 and 4 (farthest from the parent well with no asymmetry) would test the robustness of the MEM. Hydraulic lengths on Well 1 provided confidence that Well 4 would not be influenced by Well 1. Wells 2 and 3 were only fracture pressure history matched after production history matching the parent well production history up to the date of the child well completions. Repeatability and consistency in the history-matching across all four wells (validating other calibration events) was used as an indicator of our confidence in the final MEM and fracture geometry. Once fracture pressure matching validated the MEMs and production history-matching validated the fracture geometries, confidence was gained in the predictability of the model.

Production Modeling

The simulation grid (30 × 30 ft. × 2 ft.) was rotated 10-14 degrees North of East and local grid refinement was utilized to model the hydraulic fractures since fracturing net-pressures were below the computed difference between sigma-min and sigma-max stresses and offset well interference corresponded with material balances of planar fractures (i.e. with > 60% fluid efficiency, the planar fracture matched offset interference). Daily bottom-hole pressures (BHP) on all wells within the unit were utilized for the production matching. Controls were switched between BHP, Oil rate (sometimes influenced by allocation) and Gas rate (gas meters on the wellhead) based on the confidence in the measurements. Compaction curves were generated from core measurements and utilized to model fracture conductivity degradation and permeability degradation. Local grid refinement (LGR) was used to capture hydraulic fracture properties at each perforating cluster.

Once the production history match was completed, optimization (fracture half-length and number of fractures) and in-fill depletion modeling (see section below) could proceed. Since a relationship between number of clusters perforated, propped lengths and productive lengths was created, a similar scaling was applied to all simulations from the fracture modeling to predict optimized well performance.

Results and Discussion

Geoscience

Petrophysical models were initially built to honor the core data collected on the data wells. Approximately 15 wells in the study area had at least Triple Combo data and were thus interpreted. Petrophysical evaluation indicates that the average total porosity and water saturation was 5.7% and 38% respectively for the Lower Spraberry Shale (Fig. 2). The petrophysical model results show that the permeability ranged from 200 – 1200 nD for the system. The framework model was built using well top and seismic horizons. Petrophysics on all wells with facies evaluation were loaded together with the seismic attributes. The Lower Spraberry was divided into eight facies using depositional facies and sequence stratigraphy. Lack of core data across all the facies resulted in a simplification to 5 facies. The geo-model was created using 7 zones at a 100 × 100 × 2 ft resolution (Fig. 3). The facies map showed facies changes across the AOI especially between the Upper and Lower landing point in the Lower Spraberry (Fig. 4). Deeper targets were also identified for further testing/ analysis. Several iterations occurred between petrophysics, geology and reservoir to create a petrophysical property realization that captures the dynamic reservoir properties. These iterations continued until the reservoir model was able to replicate the field production history.

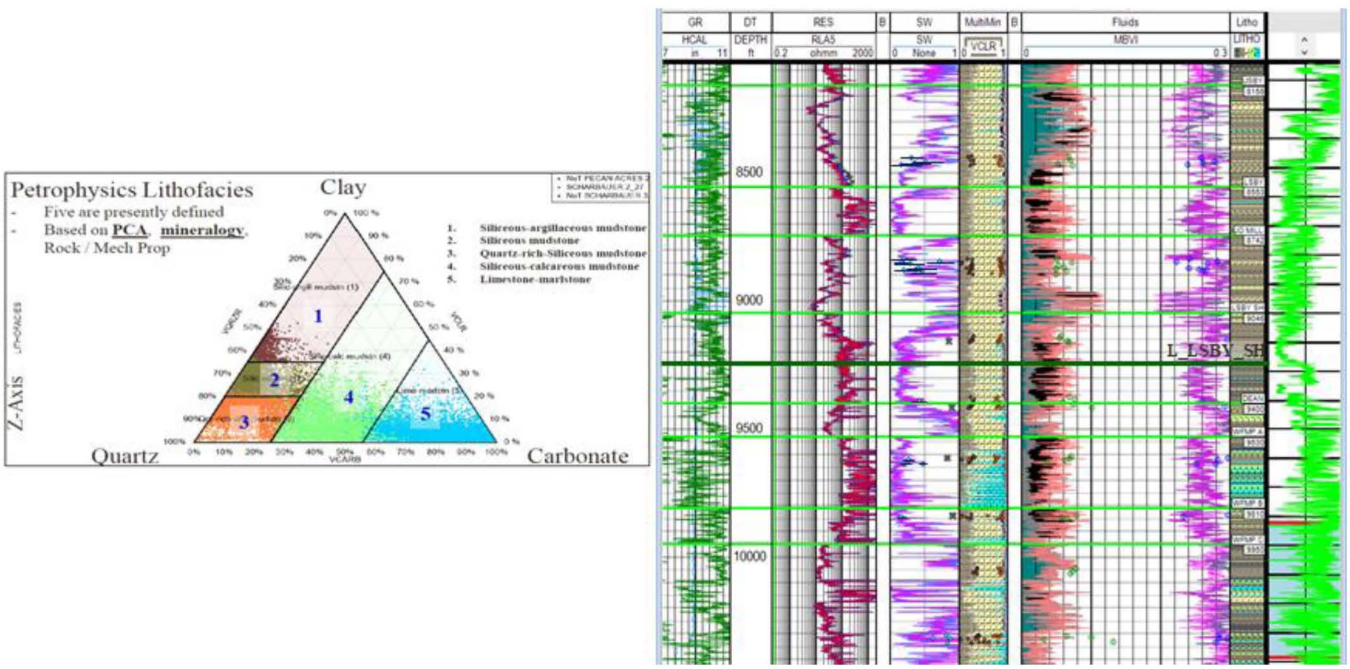
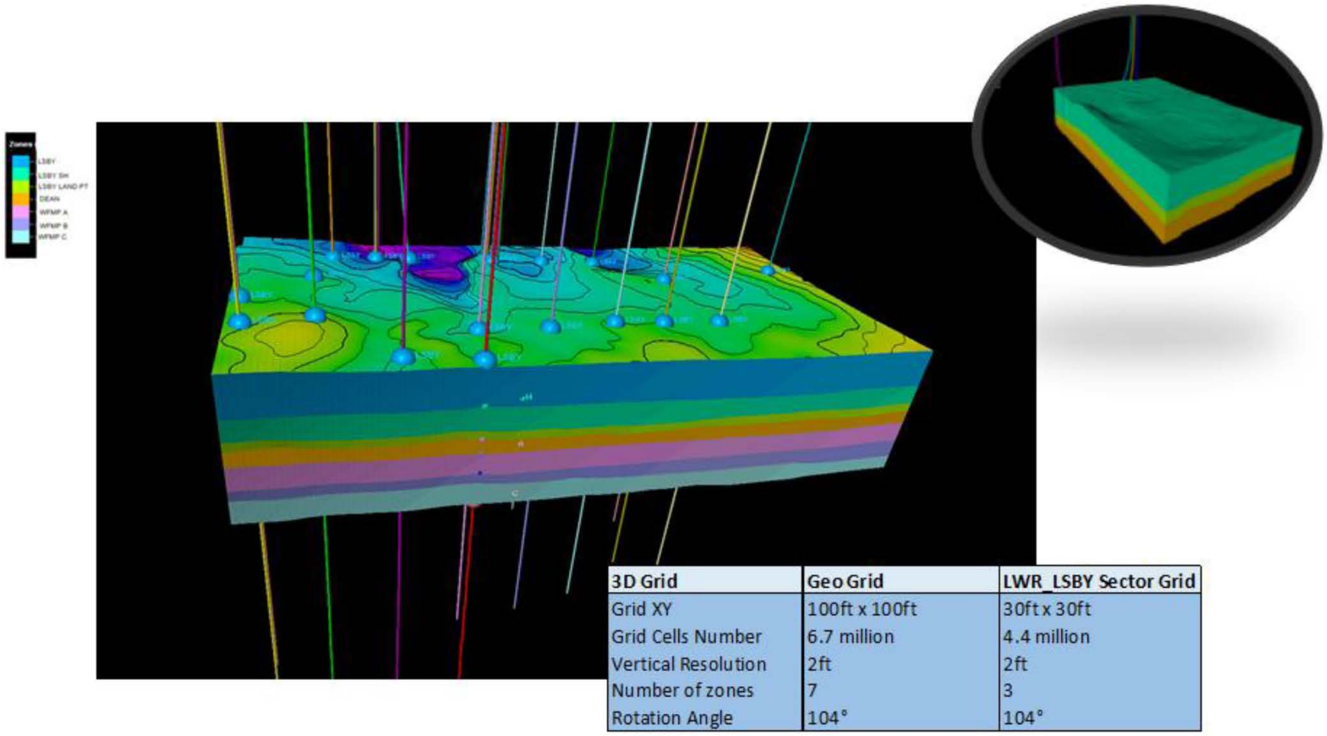


Figure 2—Study Location (Shoemaker, M Et al, 2018)



3D Grid	Geo Grid	LWR_LSBY Sector Grid
Grid XY	100ft x 100ft	30ft x 30ft
Grid Cells Number	6.7 million	4.4 million
Vertical Resolution	2ft	2ft
Number of zones	7	3
Rotation Angle	104°	104°

Figure 3—Geo-model – frame with control wells and zones

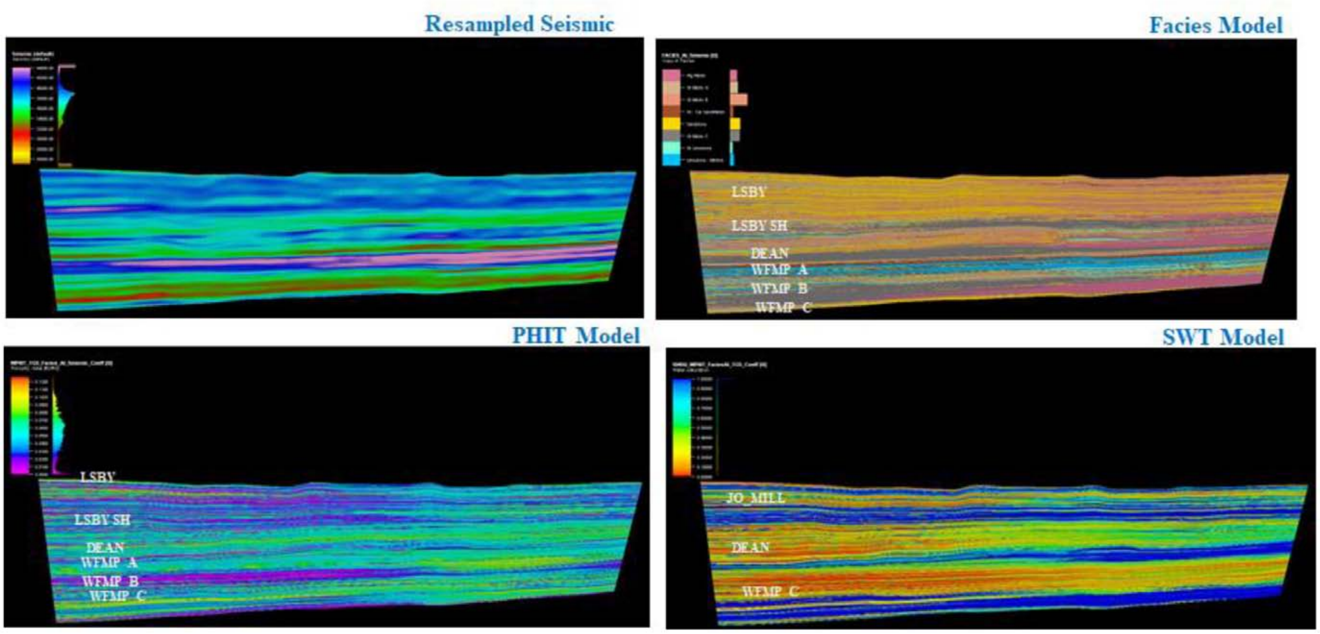


Figure 4—Geo-model cross-section

Geomechanics

The zero-lateral strain (Ben Eaton) based anisotropic stress model was applied. Continuous vertical pilot-hole sonic logs based mechanical properties (0°) together with azimuthal rock mechanics (0°, 45° and 90°) testing enabled the derivation of continuous heterogeneous mechanical units (0° and 90°) along the depth of investigation. The assumption of Biot = 1 is totally ignored by building a variable anisotropic Biot model which changes as a function of rock types/facies and mineralogy. A pore pressure model was initially applied. Several iterations between geomechanics and completions were performed to validate the

MEM via fracture pressure history matching on vertical wells that acquired micro-seismic (Fig. 6). Facies extracted from the geo-model were used to estimate geomechanical properties. Figure 7 demonstrates the variability in facies across the AOI. The Southern area showed more layering effects through the entire vertical section. Once the sonic based MEM was validated, testing of the facies-based-MEM occurred on the same vertical wells and horizontal wells. The sonic-based MEM showed the least height growth (matching with microseismic) when compared to the seismic and facies-based MEM due to resolution differences. The seismic based MEM generated the greatest height, but only by 20% (Fig 6). The propagation of the facies model enabled a clear visualization of the variation of mechanical properties across the AOI (Fig. 7). The presence of Facies 2 clearly implied geomechanical separation between the Upper and Lower Spraberry. The lack of presence of these facies would result in larger fracture geometries and highlight the importance of job size and timing when stacking laterals to prevent parent-child well interactions. The Spraberry had a Youngs Modulus of approximately 5.5 Mpsi and Poisson's ration of 0.23. Since pore-pressure gradients were less than 0.38 psi/ft, a stress contrast existed between the Dean and the Lower Spraberry. The Dean's mechanical and petrophysical properties were significantly different within the study area from other areas within the Midland Basin.

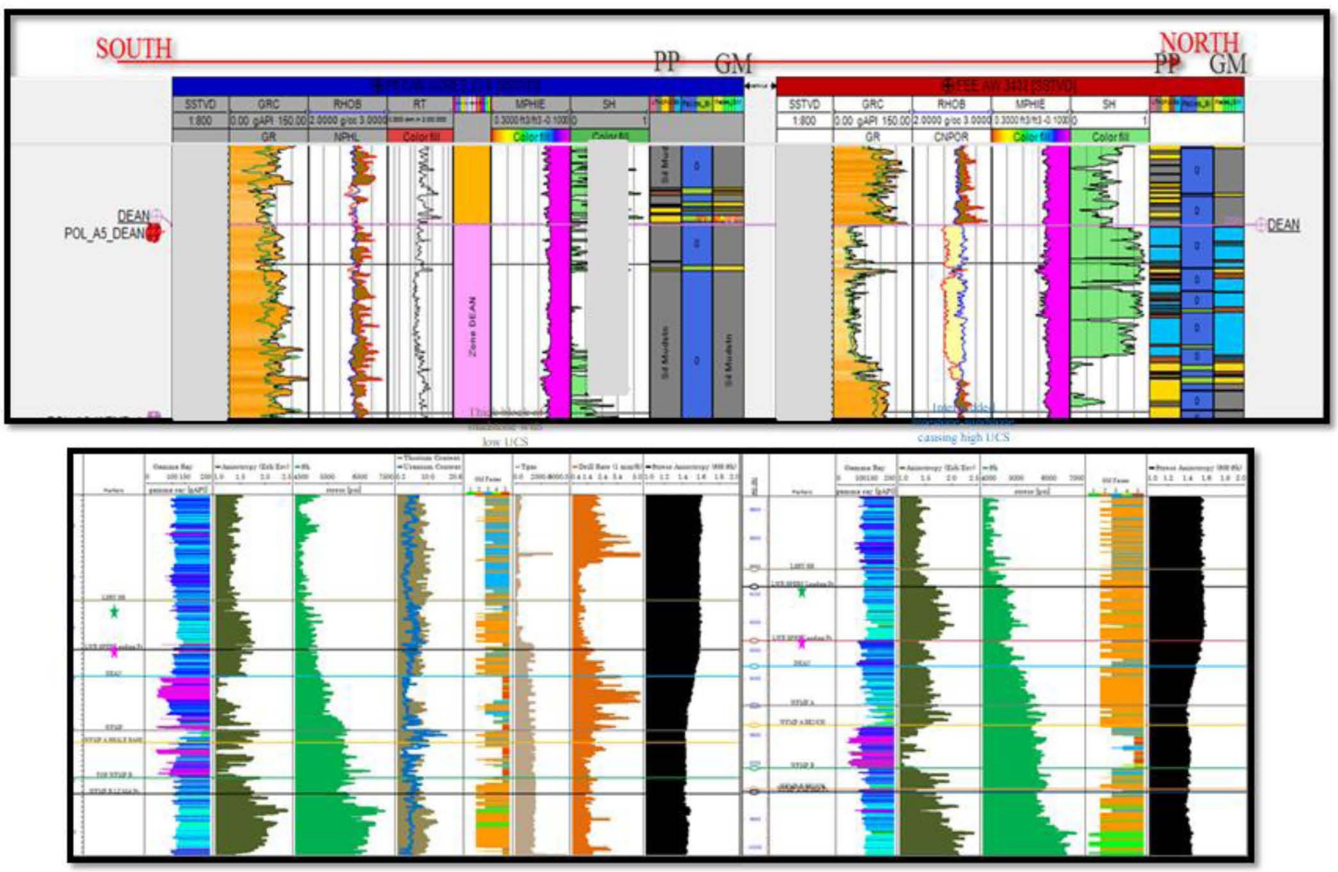


Figure 5a—Geomechanics (comparison of petrophysics and geomechanical facies)

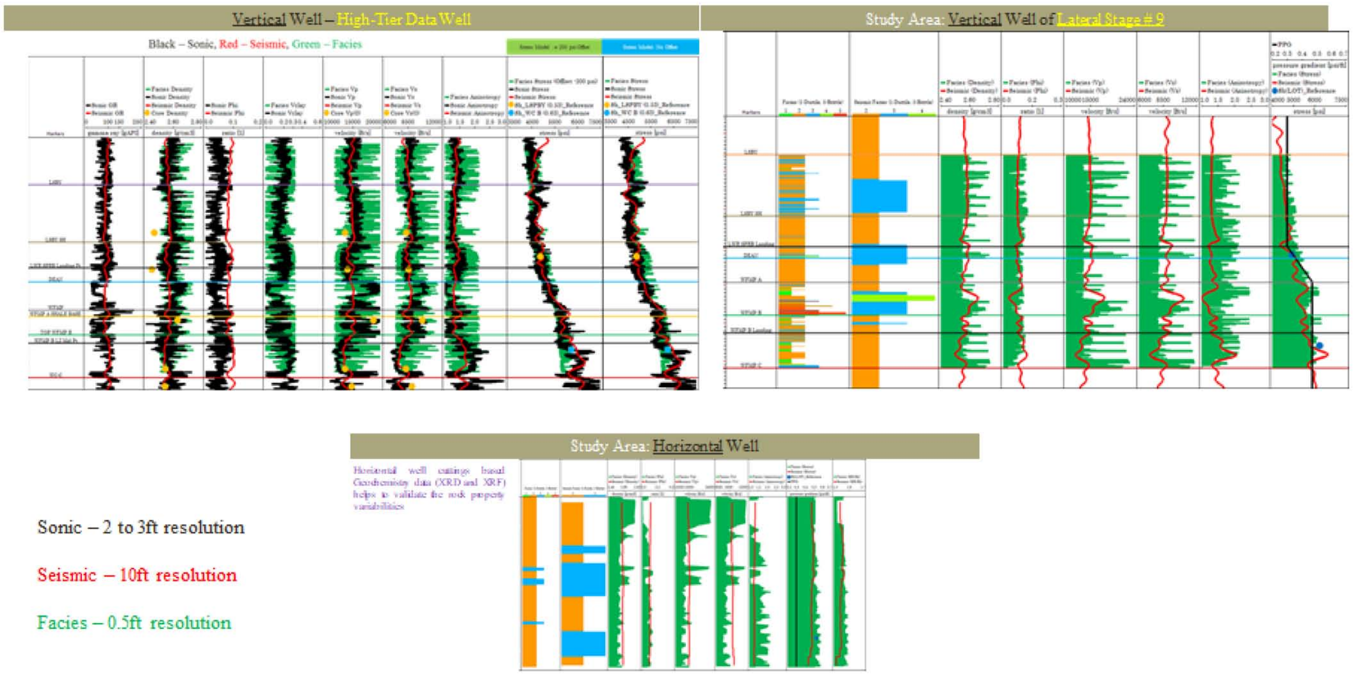


Figure 5b—Geomechanics (comparison of seismic and facies stressed)

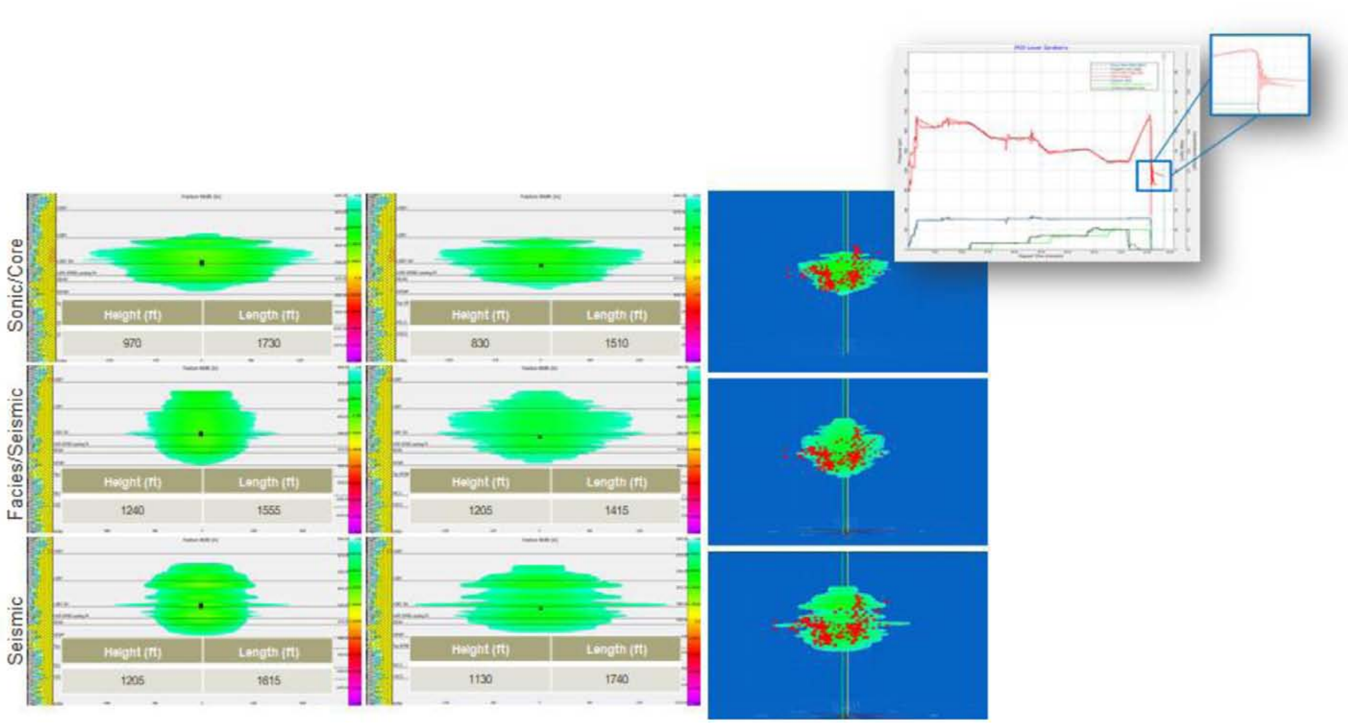


Figure 6—Vertical well fracture modeling – comparison of sonic model with seismic-facies model

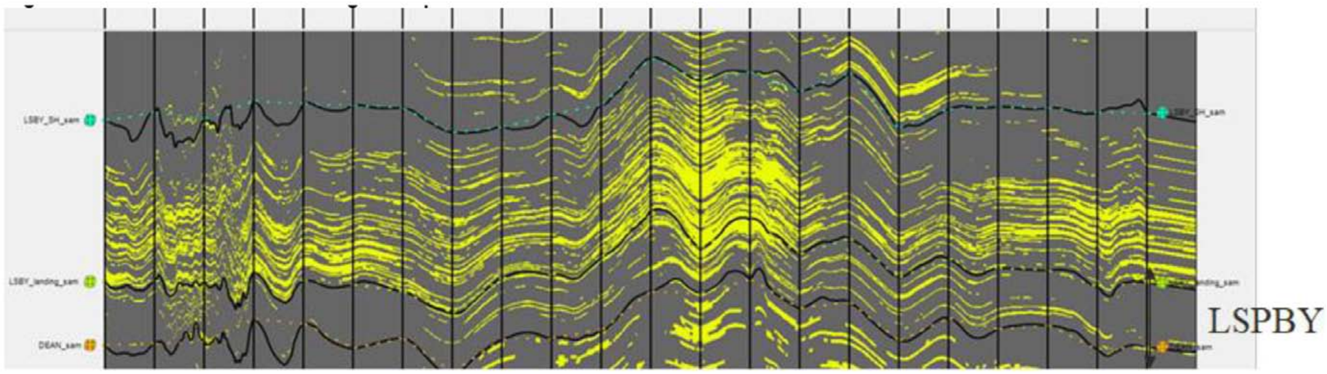


Figure 7—Facies 2 from the Geo-model. Facies 2 are high stress geomechanical units

Fracture Modeling

Vertical well geometries were compared with horizontal well geometries. For the vertical wells, the higher pump rate per cluster (25-70 barrels per minutes (BPM)/cluster vs 20 BPM/cluster for horizontals), viscous fluid systems (linear-gel, and in some cases crosslinked-gel vs. slickwater for horizontals) and increased proppant per cluster (100,000-200,000 lb. vs. 60,000-80,000 for horizontals) created 40% more hydraulic length, and almost 100% more hydraulic height (Fig. 8). Treatment parameters (job size, liquid volumes, pump rate and average treatment pressures) were consistent across wells within the sector model. Well 1 placed 10% less 3-/50 sand (Fig. 9). Figure 9 shows the treatment parameters for all stages and the EOJ ISIP gradients for all stages. Instantaneous shut in pressures (ISIP) compared across all stages in the sector model showed that end of job (EOJ) net pressures were consistent across all stages.

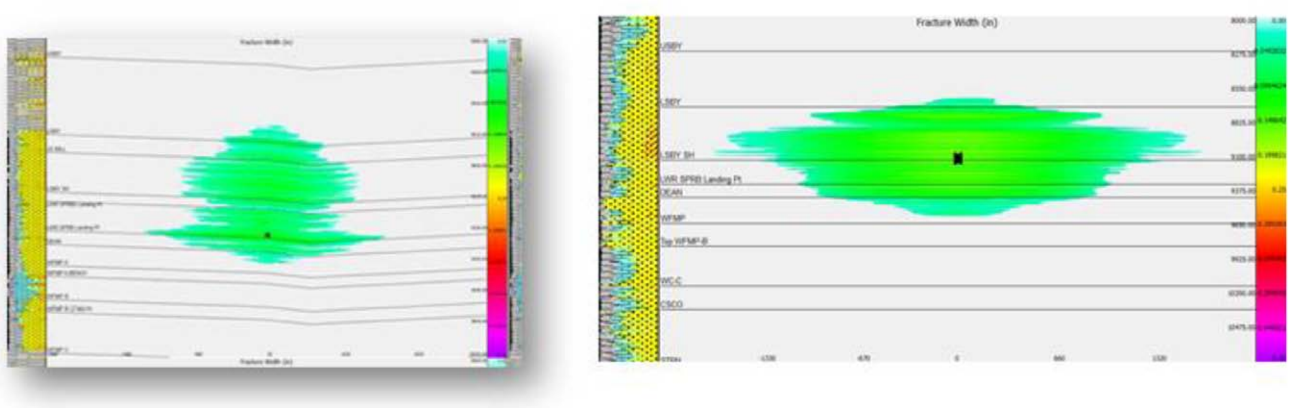
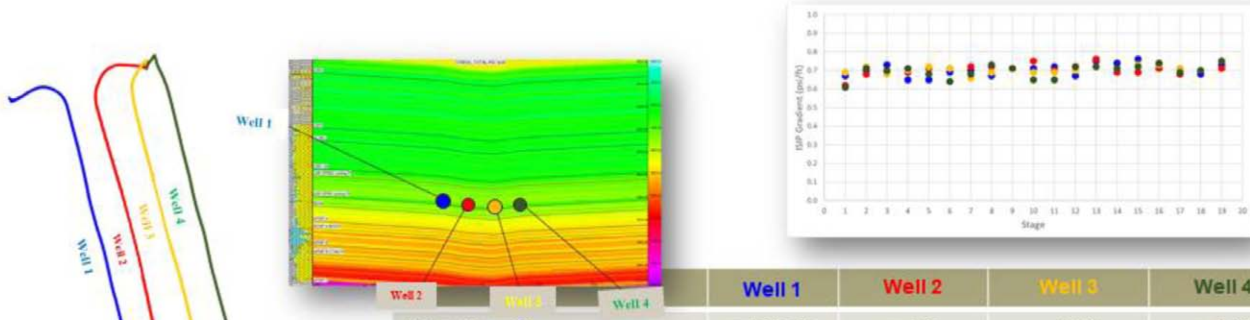


Figure 8—Left- Dominant cluster geometry in horizontal well vs fracture geometry in vertical well (right)

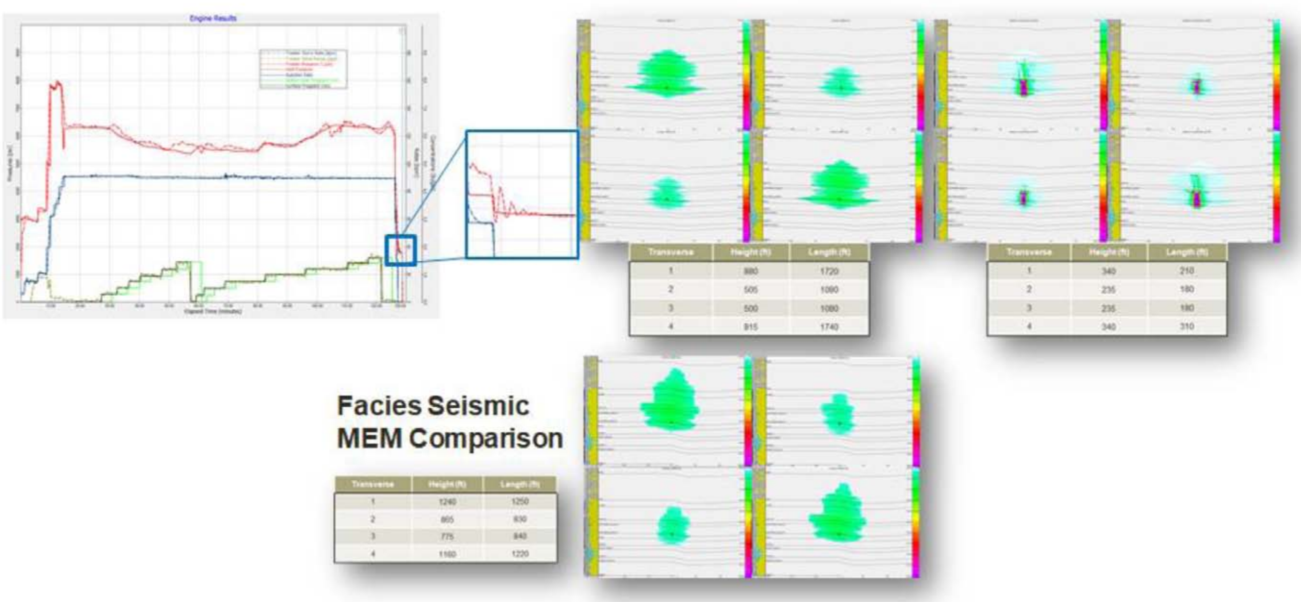


	Well 1	Well 2	Well 3	Well 4
Lateral Length	~ 4600 ft.	=+8 ft	=-15 ft	=-24ft
Stages	X	X	X-1	X
Average Fluid volume gal/stage	X	1.1*X	1.08*X	1.09*X
Average 100 mesh lb/ft	X	0.98*X	0.98*X	0.99*X
Average 30/50 sand lb/ft	X	1.16*X	1.17*X	1.18*X
Average injection rate	X	X	X	X
Average pressure	X	1.01*X	0.99*X	0.98*X

Clusters/stage	4
Spacing	~60 ft
Fluid type	Slickwater

Figure 9—Horizontal well pad completion summary

Analysis of logs and core in the Basin indicated that little variability may be observed areally within a mile, but significant variability was seen vertically. This highlighted the importance of minimizing the grid/cell size used in the fracturing simulator to capture the vertical heterogeneity as much as possible. The robustness of the MEM built was validated as the fracture pressure history matching was performed with the same MEM across all key stages using the facies-based MEM and sonic based MEM on stages with the calibration points (Fig. 10). Hydraulic half-lengths for the parent wells ranged from 1,000 −1,800 ft with hydraulic heights ranging from 500- 1,000 ft. The average mis-match between beginning of job ISIP and end-of-job ISIP was less than 200 psi.



Transverse	Height (ft)	Length (ft)
1	880	1720
2	505	1080
3	500	1080
4	815	1740

Transverse	Height (ft)	Length (ft)
1	340	210
2	235	180
3	235	180
4	340	310

Transverse	Height (ft)	Length (ft)
1	1240	1250
2	865	830
3	775	840
4	1160	1220

Figure 10—Horizontal parent well fracture history match- comparison of geometry using sonic model & facies model stresses

The modeled fracture geometry was then utilized to constrain production history match parameters. The high net-pressures in the Lower Spraberry enabled the breakdown of multiple clusters. Proppant was mostly within a 150-350 ft vertical window and < 350 ft horizontal window (Fig. 10). Hydraulic lengths less than 2,000 ft implied that Well 4 (child well) fracture modeling could occur prior to depletion modeling since this well would not enter the stimulated area of Well 1.

Modeling indicated that some optimization opportunities still existed within the multi-cluster fracturing scenarios since only 30%-50% of the fractures within a stage created dominant fractures (where the dominant fracture could have up to 40% greater geometry). Thus, as the industry moves toward more clusters/ stage and tighter spacing, pump rates of at least 120 BPM may be required with stage length less than 220 ft. Pressure history matching indicated some growth into the Dean.

Parent Well Production Modeling

The integration of high tier log and core data were used to guide the production history match. A fluid model was created from surface oil and gas analysis with a bubble point estimate of 1,700 psi. Routine core analysis (RCA) measurements were utilized to guide the construction of relative permeability and compaction curves for the different reservoir facies (Fig. 11). Relative permeability curves and compaction curves for the matrix were distributed within the geo-model based on rock-type. Corey coefficients ranged from 4-6 and water end points were greater than 20% and 35% for good and poor rocks, respectively. A different set of relative permeability curves (straight line), were used for the fracture dominated flow area modeled via LGR which captured the production portion of the fracture at every cluster based on the fracture modeling results. Production history matches (Fig. 12) honored the relative change in fracture half-lengths within a stage due to limited entry/ stress shadowing, etc.

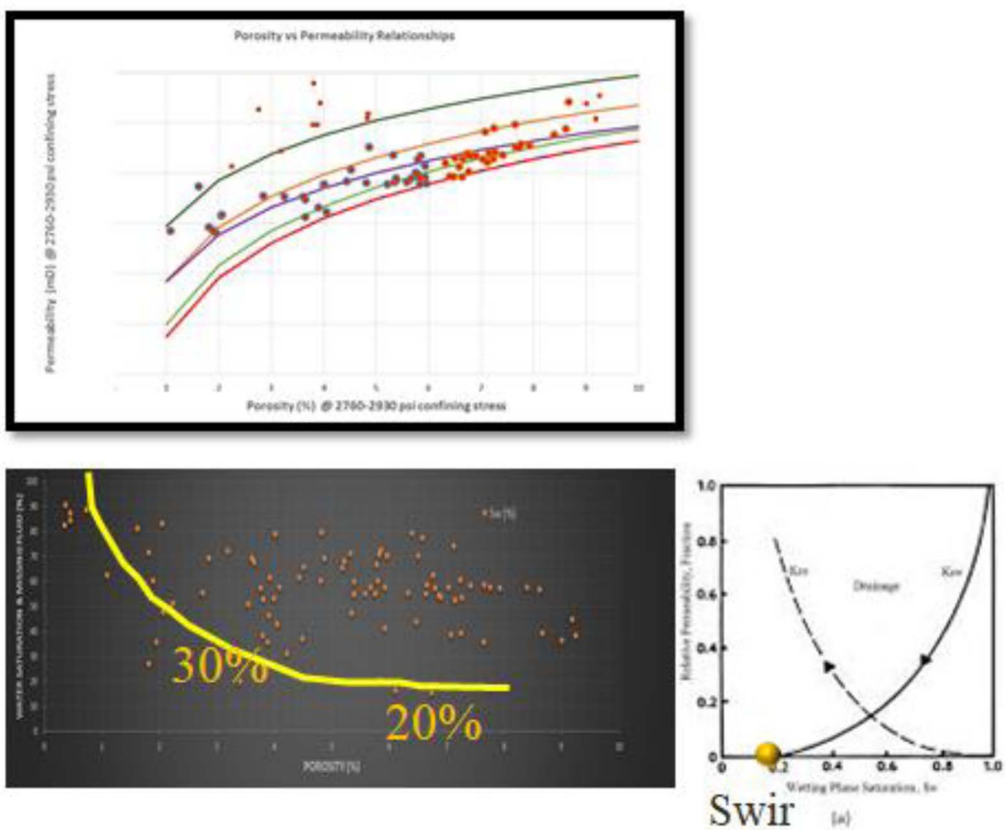


Figure 11—Construction of fluid model using RCA data

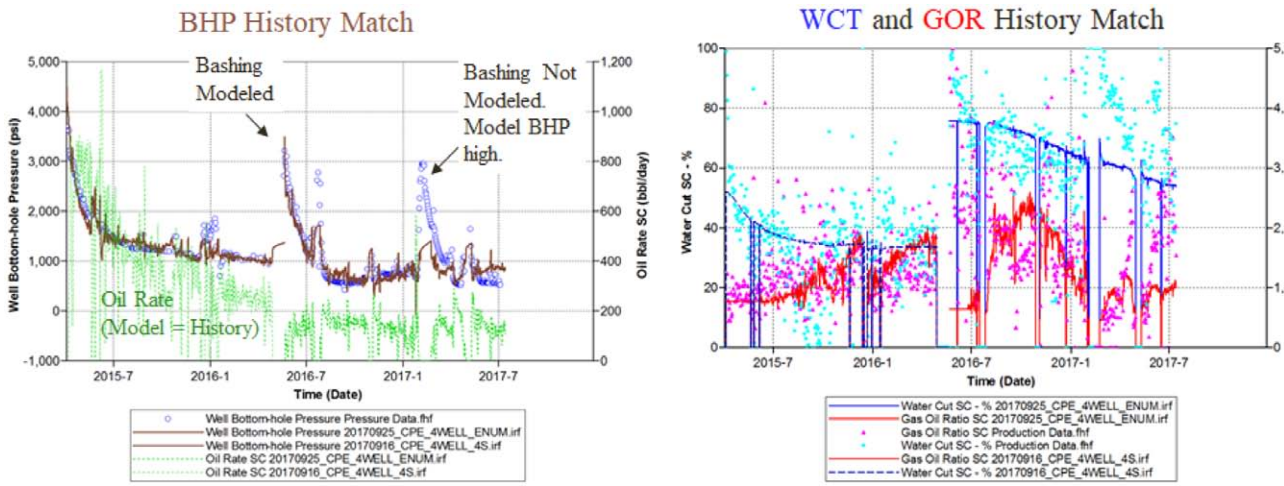


Figure 12—Parent well history match (BHP match and Water-cut/ GOR match)

Fracture modeling suggested that most of the proppant settled within 180 ft. to 310 ft. (minor and dominant fractures) of the wellbore. History matching indicated that productive heights were less than 200 ft. and productive fracture half-lengths varied from 180 to 255 ft. with initial dimensionless conductivity exceeding 10. Reservoir matrix permeability ranged from 300 – 1400 nD within the drilling unit (East to West). More than two years of production history was matched on the parent well that had BHP gauges.

In-Fill Modeling

This study and others (Cherian et al 2016, 2017) have shown the impact of fracture interference during infill drilling is a function of how large a pressure sink exists, how far this pressure "sink" extends into the reservoir and fracture containment. Stress and other geomechanical properties were re-computed and used to modify the fracturing simulation grid to quantify fracture asymmetry for the Well 2 and 3 in-fills that were drilled after more than 800 days of parent well production (Fig. 13). A non-linear depletion approach (Narasimhan et al 2015), was used to generate MEMs for changes in the pore pressure, as well as mechanical attributes as a function of depletion. Asymmetry was observed in hydraulic fracture geometries in both the #2 and #3 wells. Asymmetry was created due to a pressure sink caused by the parent well and due to local pressure sources created by offset well fracturing. Since net-pressures were large (>900 psi), the fracturing from East (virgin area) to West (where the parent well is) exaggerated asymmetry (Fig. 14). Well 2 (direct offset to parent and last well stimulated within the child well stimulation sequence) experienced almost 80% asymmetry (80% of total productive length is towards the parent well). Well 3 experienced about 60% and Well 4 was symmetric. Porosity, permeability, and saturations were updated in the depleted area and an in-fill well modeled using the geometries provided by completion modeling (Fig. 15 and Fig. 16). Reservoir simulation also confirmed the higher "temporary" water saturation (higher water-saturation in LGR on initialization) that allows us to hypothesize that this is also from the operational asymmetry. Analysis of the history matched models indicate that most of the production contribution in the first year of production is from rock with permeability greater than 600 nD (80%). In the fractured region, this recovers 6-10% of the oil within that region. In the lower permeability regions, less than 3% is recovered.

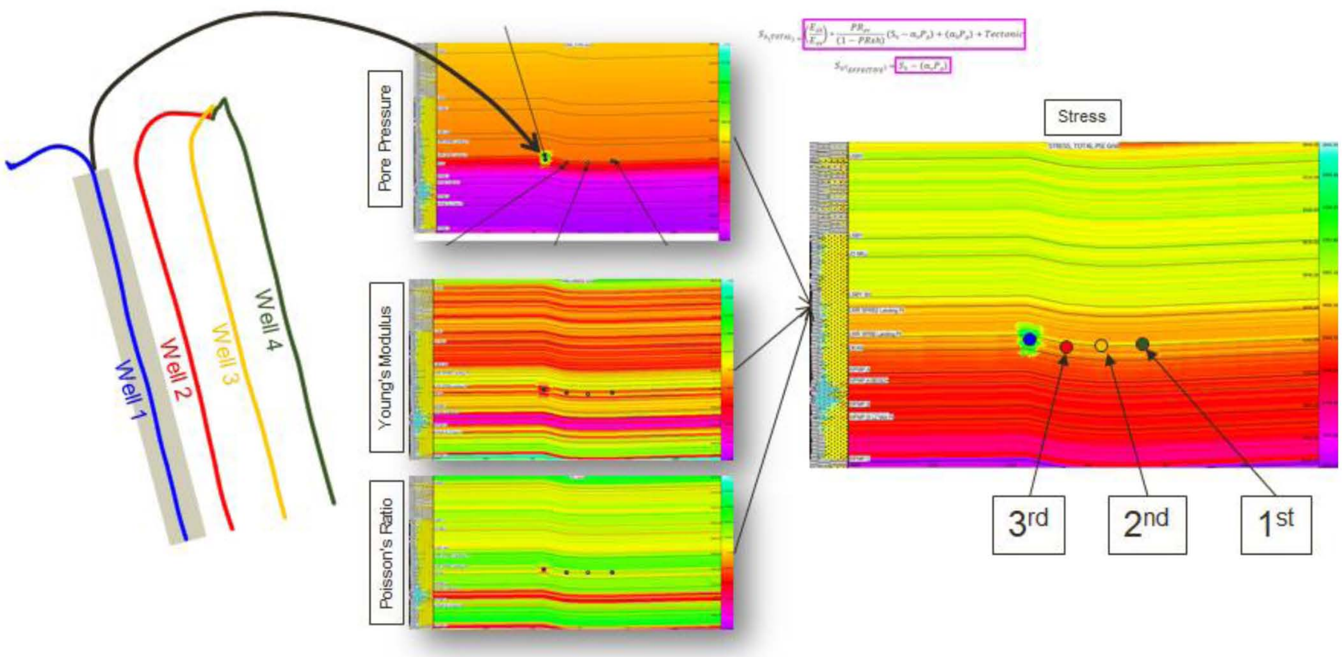
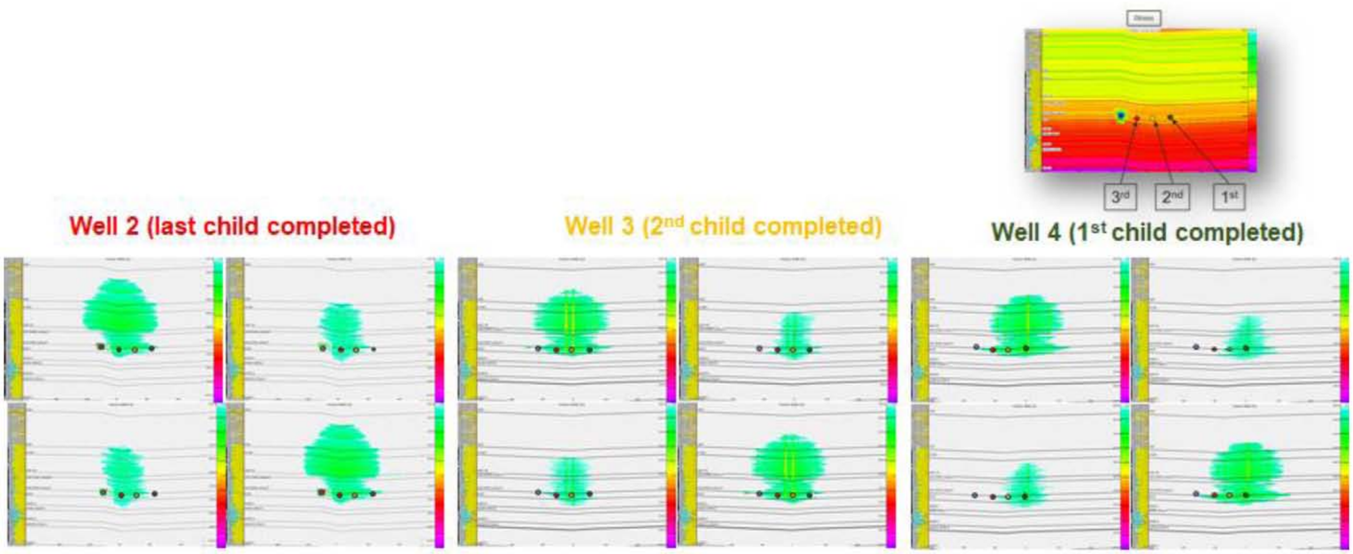


Figure 13—Completions – In-fill child well modeling using depletion profile from production history matching

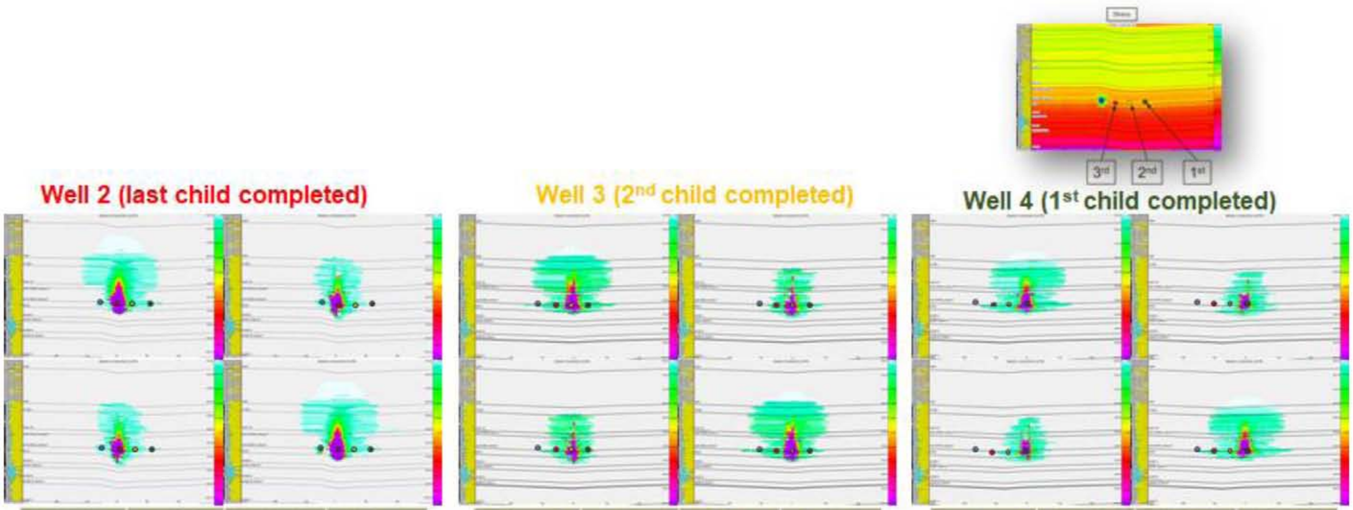


Transverse	Height (ft)	HLength (ft)
1	1080	1400
2	870	1160
3	910	1360
4	1160	1440

Transverse	Height (ft)	HLength (ft)
1	1200	1480
2	900	1160
3	940	1240
4	1160	1440

Transverse	Height (ft)	HLength (ft)
1	1030	1400
2	680	1080
3	800	1160
4	1180	1560

Figure 14—Completions – In-fill child well fracture pressure history matching hydraulic lengths



Well 2 (last child completed)

Transverse	Height (ft)	Left (ft)	Right (ft)
1	420	360	220
2	330	280	120
3	330	280	120
4	420	360	220

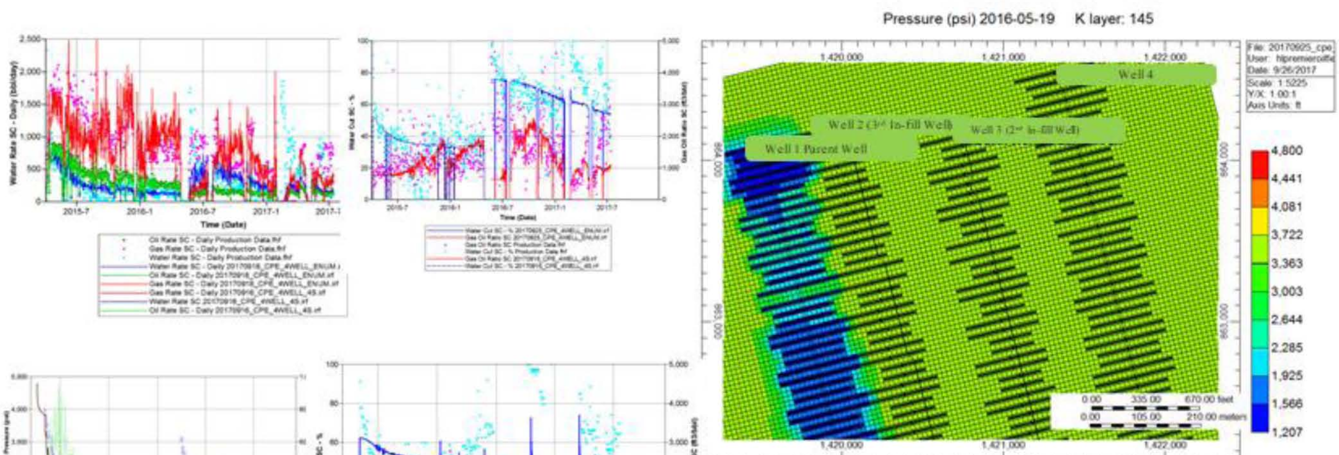
Well 3 (2nd child completed)

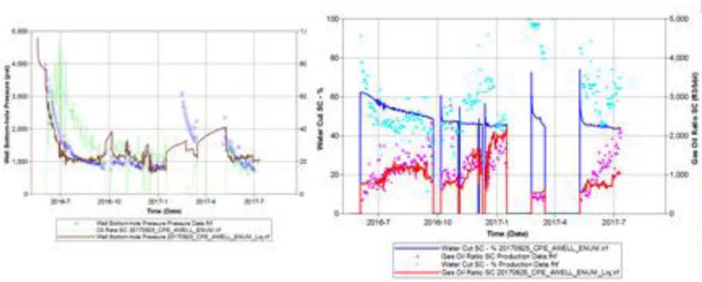
Transverse	Height (ft)	Left (ft)	Right (ft)
1	370	260	160
2	265	200	140
3	265	200	140
4	370	260	160

Well 4 (1st child completed)

Transverse	Height (ft)	Left (ft)	Right (ft)
1	365	280	280
2	245	200	200
3	265	200	200
4	365	280	280

Figure 15—Completions – In-fill child well fracture pressure history matching propped lengths





Dimension of dominant fractures:

Well	Height (ft)	Length, Left (ft)	Length, Right (ft)
Parent	195	255	255
Well2	220	345	105
Well3	220	285	165
Well4	220	255	255

Figure 16—Parent-Child-well production history matching – production models validate asymmetry from fracture propagation models

A simulation was performed to understand the impact of the delayed parent child well sequence vs a Mega-pad completion (where all the wells within a spacing unit are completed simultaneously). Preliminary analysis indicates that if the Mega-pad approach is utilized, up to 10% increase can be realized in EURs (Fig. 17). This simulation case also indicates that the asymmetry can reduce the immediate offset wells performance by 20% (worse in the gas window).

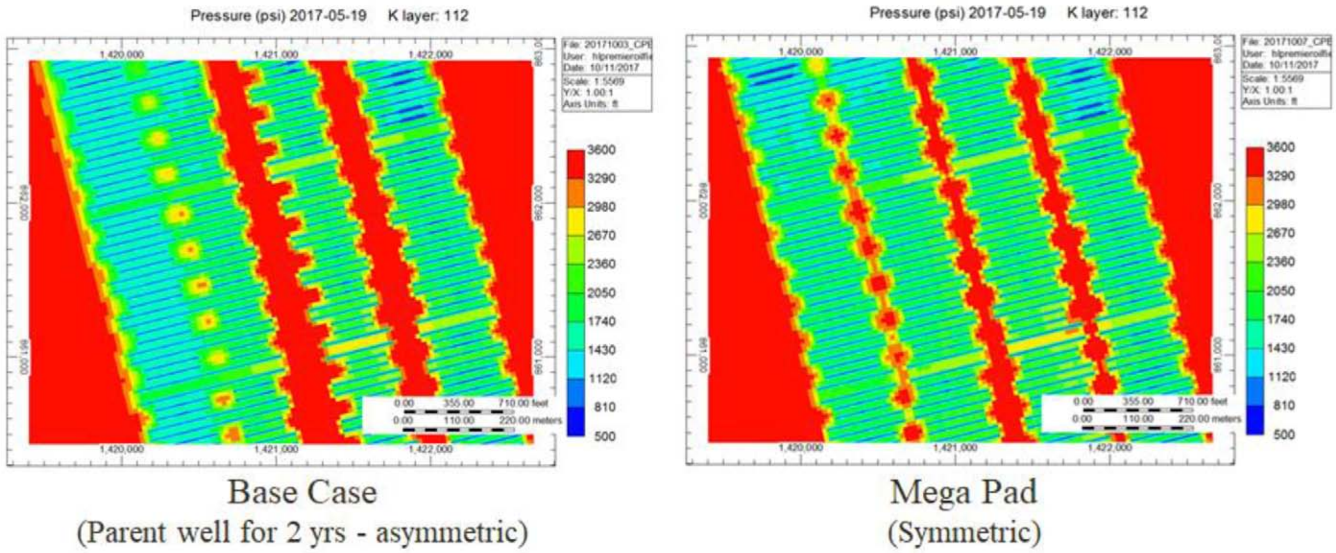


Figure 17—Parent-child well forecast depletion profile vs Mega-pad strategy

Conclusions

- A multi-domain facies model has enabled us to capture both petrophysical and geomechanical properties via a geo-model. This approach is key to ensuring that the geo-model serves as an integration platform across engineering and geosciences.
- Operational order/ sequence and timing can influence parent-child well interactions and can influence early time water cuts and spacing unit performance by at least 20%
- Production lengths make up less than 10% of hydraulic lengths, and approximately 60% of proppant lengths. The importance of hydraulic lengths (via offset frac interference between parent and children wells) is understood by the observation of the impact of in-fill completions and sequencing on fracture asymmetry.
- Integrated modeling (geology, rock mechanics, fracture and production) via a sound data collection and modeling strategy has enabled an understanding of the variation in properties (petrophysical and geomechanical) across a large area to understand the applicability of local learning and the operational timing requirements to continue economic development of the reservoirs.

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