URTeC: 3862919

Predicting Facies Controls on Well Performance, Lea County NM.

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Abstract

The Bone Spring Formation in the Delaware Basin has more than 23,000 economic drilling locations remaining in the basin. How do you identify and high-grade those remaining drilling opportunities? While spacing and completion still matter, the best wells will be in the right facies within the desired bench. This study demonstrates a methodology for building a predictive tool to assess remaining drilling locations by employing a multivariate analysis on geological and geophysical data to delineate areas of optimal reservoir properties. This analysis focuses on the Leonardian-age clastics, carbonates and shales of the 2nd and 3rd Bone Spring Sand in a study area in southern Lea County, NM. The goal of this study was to accurately predict the first 12-month BOE and first 12-month water using a multivariate model comprised of data from wireline logs and rock properties derived from 3D seismic data. The most significant subsurface variables for predicting hydrocarbon production are Phi-H, sonic, impedance, temperature, and TOC; for water production the important variables are Phi-H, total water saturation, and clay volume. The sweet spot is not controlled by one variable, but by understanding the optimal mix of these properties. This approach demonstrates a predictive workflow for quantifying the local impact of facies and property variation on well performance that can be used quantitively for forecasts, lookbacks, and scenario evaluations.

Introduction

The Delaware basin is known for laterally heterogeneous reservoir targets within the Wolfcamp and Bone Spring intervals. Studies by Saller and others (1989), Montgomery (1998) and others delineate cyclic sedimentation within the basin. Primary drivers behind sedimentation patterns include allocyclic features, such as eustatic sea level fluctuations and autocyclic features, such as carbonate debris flows along steep carbonate margins flanking the basin. Other authors have proposed a simultaneous influence of both autocyclic/allocyclic features to explain observed depositional patterns (Crosby et al., 2018, Walker et al., 2021.) Primary lithofacies encountered in the Bone Springs stratigraphic succession include those that represent quiescent bottom water settings (spiculitic limestones, pelagic shales and siltstones, laminated mudstones) and others that represent high energy debrites (dolomitized breccias and bioclastic packstones) and siliciclastic channel, levee and fan lobe (fine grained sandstones) (Montgomery, 1998).

Few papers have been published on the detailed Bone Spring sedimentary patterns within the deeper portions of the Delaware basin, but some common themes can be found in literature. Montgomery (1998) noted that the first and second Bone Spring sand were relatively thick and ubiquitous within the basin, whereas the third Bone Spring was found only along the northwestern margin and central basin platform (CBP). Crosby and others (2018) noted that deepest portions of the northern Delaware basin frequently displayed thicker deepwater clastic successions, and thicker carbonate intervals downdip of the carbonate margins. Several authors noted compensational stacking patterns within and between the carbonate and clastic-prone intervals, indicating that sediment distribution patterns were impacted by sea floor morphology at time of deposition (Montgomery, 1998, Crosby et al., 2018, Driskill et al., 2018.) Contemporaneous faulting may also impact the location of both clastic and carbonate depocenters, as noted within the Wolfcamp A by Kvale and others (2019.)

Many recent studies commonly focus on the impact of different drilling and completion techniques to find the ideal operational methods that produced the most hydrocarbons, with a lesser focus on the impact of geological variables. To help understand the impact of vertical and lateral geologic variability, multivariate analysis of petrophysical summations for the 2nd and 3rd Bone Spring Sand were compared against production trends and 3D seismic facies.

Data and Methodology

The study area is a 11.5-mile by 12.5-mile region in southern Lea County, NM located west of the Grama Ridge, a north-northeast trending down-to-the-west fault zone (Figure 1). The study focuses on the 2nd and 3rd Bone Spring sands because of the wealth of seismic, petrophysical, and production data. Most of the horizontal wells drilled in this area land in these two zones. Drilled and completed between 2011 and 2022, the production data from these wells are affected by various drilling and completion practices.

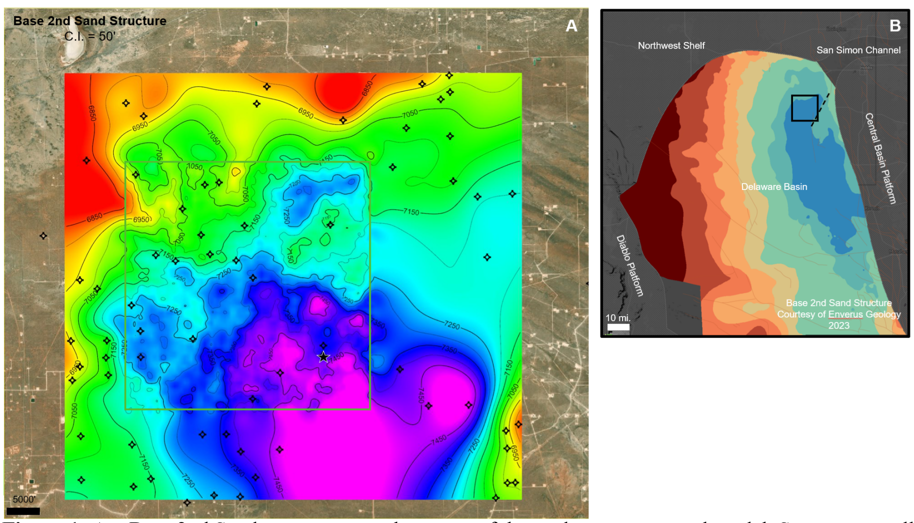

Figure 1: A – Base 2nd Sand structure over the extent of the study area structural model. Star – type well location, well symbols – control points for the structural model, green box – seismic data volume used in this study. B – Base 2nd Sand structure in the Delaware Basin with location of the study area (black box) and the Grama Ridge (dashed black line).

The data used for the geological analysis are wireline logs from 69 wells with full or partial penetration of the Bone Spring formation, production data from 167 horizontal wells landed in the 2nd and 3rd Bone Spring sands, and 49 square miles of seismic data acquired in 2017 (see Table 1). The wireline data have been merged and normalized, though not all wells have full coverage across the Bone Spring Fm. Zone averages for basic petrophysical properties, (density, sonic, resistivity, temperature, etc.) were calculated. Additionally, derivative data such as total water saturation (SwT), total organic content (TOC), and electro-facies based on a k-means clustering algorithm were also included. Finally, to create a full suite of petrophysical properties in the horizontal wells, which often have minimal wireline logs, an interpolation algorithm guided by the structural model was used to populate properties along each horizontal well bore.

Project Information:	**Source Information:**
Survey Size: 380 sq miles	Vibrator Interval: 165'
Record Length: 5 seconds	Vibrator Line Spacing: 825'
Bin Dimensions: 82.5’ x 82.5’	Sweeps per Vibrator Point: 2 Sweeps @ 16seconds
Nominal Fold: 396	Sweep Bandwidth: 2-76 Hz
Acquired: 2017	**Patch Information:**
Receiver Information:	Number of Active Channels: 7,920
Receiver Interval: 165'	Recording Geometry (lines x channels): 36 x 220
Receiver Line Spacing: 825'	Recording Swath Dimensions: 28,875' x 36,135'
Geophones / Channel: 1	

Table 1: Acquisition parameters for the seismic data.

The seismic data were processed using a true amplitude processing and imaging workflow to produce a Kirchoff pre-stack time migrated (PrSTM) image. All surface consistent and true amplitude processes were implemented to help a quantitative interpretation workflow. A Bayesian pre-stack seismic inversion approach was implemented that simultaneously solves for both facies and impedances to characterize lateral heterogeneity using the seismic data; see Payne et al. (2019) for further information. The rock properties generated from the inversion along with other geometric attributes are the seismic-derived inputs for the multi-variate statistical analysis. Each of these inputs is converted from the time domain to the depth domain using a velocity model generated from available sonic logs in the area that are interpolated across key horizons interpreted from the PrSTM full stack.

Commented [mi1]: Placeholder for Andrew's description of the seismic data.

Commented [al2R1]: See below.

All the data were then integrated into a structural model that underpins the analyses. Data from published core analyses in the northern Delaware Basin (Adon, 2019; Gawloski, 1987) were also referenced to augment our conclusions.

The multivariate analysis was used to create two non-linear regressions to predict the first 12-month hydrocarbon production (BOE) and first 12-month water production for the Bone Spring 2^{nd} Sand. Before modeling began, all the potential input data were conditioned to remover outliers and colinear variables. Two versions of each model were created, one version that included the seismic data as an input variable and one version that did not. Thus, four predictive models were generated. All model versions included both the lateral length (feet) and proppant load (pounds per perforated foot) as input variables to account for the variations in drilling and completion practices. There were multiple iterations of the models to optimize for the fewest, most impactful variables that could be related to the target property via well-established geological principles.

Results / Observations

In the study area, the 2nd Sand isopach map shows a depocenter with a lobate shape slightly elongated to the north-northeast. The underlying 3rd Sand and 3rd Carbonate depocenters are offset to the southwest and only partially covered by this study. On the east, these lower units of the Bone Spring thin onto the Grama Ridge, suggesting this feature still exerted some influence on deposition during the Leonardian. Deposition of the 2nd Sand was likely controlled by a compensational stacking response to the 3rd Sand and Carbonate depo-thick on the west and the Grama Ridge on the east. Visual analysis of the respective first 12-month production from completed horizontals in each unit concludes that gross thickness plays a complex role in the hydrocarbon productivity of individual wells. In the 2nd Sand, there is little correlation between gross isopach thickness and hydrocarbon productivity. There is a weak positive correlation with the 2nd Sand water cut, i.e., higher water cut in the thicker interval. The most productive wells in the 3rd Sand are associated with thinner gross intervals.

The Bone Spring Fm has been described as a coarsening and thickening upward succession of interbedded carbonate and siliciclastic units (e.g., Saller et al., 1989). Each carbonate – siliciclastic couplet within the Bone Spring also shows this pattern, e.g., the 2nd Sand and its overlying 2nd Carbonate. A review of the stratal locations of the horizontal wells in the Bone Spring (aka the landing zone) shows that operators have landed wells throughout the Bone Spring and Upper Wolfcamp section. However, most wells land in the lower 2nd Sand or the 3rd Sand. Thus, activity has focused on the thin-bedded, fine-grained part of these coarsening and thickening upward cycles.

In both the electro-facies and the seismic inversion facies, these thin-bed, fine-grain intervals correspond to the clastic-rich facies. The electro-facies show a homogenous, clastic-rich zone with carbonate content and heterogeneity increasing upward from the base of 2nd Sand to the top. While the seismic facies data do not have the same vertical resolution as the wireline log data, they show the same overall trend of upward increasing carbonate content. The seismic data show that the carbonate-rich bodies are lenticular and discontinuous, becoming more numerous and more extensive towards the upper part of the 2nd Sand.

The most productive wells for both the 2nd and 3rd Sand are in a similar depth window: lateral depths between 6900’ and 7750’ TVDSS. Combining all observations, the most productive wells will be found in areas with homogenous, siliciclastic-rich facies at depths between 6900’ and 7750’ TVDSS. A net-facies thickness map combined with a structural elevation map can be easily combined to delineate the extent of a productive sweet spot. There is a risk, however, that water cut may increase with gross thickness, especially in the 2nd Sand. Potential causes for this relationship are explored in the discussion section.

Modeling the first 12-month production with a multi-variate, non-linear regression enables quantification of the differences between the more productive and less productive areas via predictive maps of the first 12-month BOE and the first 12-month water. A side benefit of this exercise is the ability to explore and rank the geologic variables that correlate with production.

The ranked input variables for the final four models are shown in Table 2. In each model, we consciously focused on variables that made geological sense for the problem at hand. For example, a pore-volume measure (Phi-H) is used throughout the models because it captures the hydrocarbon + water storage capacity of the reservoir. When the seismic data were included, corresponding petrophysical variables were dropped if doing so did not degrade the model's performance. For example, if the model included impedance derived from the seismic data as a variable, then we would exclude density or sonic as petrophysical variables. The horizontal length of the well and the proppant load are included in the regression as they are key controls on the well productivity and should not be ignored.

The most impactful log-derived variables in the first 12-month BOE model speak to fundamental petroleum system components: mineralogy, pore volume and organic matter. In the first 12-month water

Commented [mi3]: Include isopach maps as a figure.

Commented [JE4]: Is this contradicting what you just said re: no correlation between thickness and productivity? Also, why do you mentioned the 3BSS production trends?

Commented [mi5]: Jason - do we have a reference for this statement?

Commented [JE6R5]: I would go with Grand-daddy Saller.

Commented [JE7]: See my note in the figure slide deck, but it is difficult to see the horizons in Figure 3C; can those be thickened and/or labeled?

Commented [mi8R7]: yes. will do.

Commented [mi9]: To support this observation, need to add the N-S cross section.

Commented [JE10R9]: Yup. You have one, correct?

Commented [JE11]: Does this still jive with gross thickness doesn't impact hydrocarbon production statement we made earlier?

Commented [mi12R11]: I think it does after reworking the first paragraph of this section. Let me know what you think.

Commented [JE13]: We should probably give an example of this.

model, the most impactful log-derived variables are related to facies and pore-volume: clay volume (V-Clay), total water saturation (SwT), and pore volume (Phi-H). Adding the seismic-derived variables reinforces these observations. Acoustic impedance, controlled by mineralogy and pore volume, becomes an important variable in the BOE model. Planarity, a curvature metric controlled by the spatial planar alignment of correlated events in the seismic data, captures sedimentary facies architecture and variations or is responding to small-scall, pervasive faulting. It is an important variable in the water model indicating facies or fault and fracture control on mobile water.

The final regression equations were used to calculate and create predictive maps of the first 12-month BOE and the first 12-month water. For these predictive maps, the well horizontal length and proppant are held constant at 7000' and 1580 lbs/ ft, respectively. These two assumptions are what has typically been used to drill and complete wells in the Bone Spring Formation in the study area.

Discussion

The qualitative analysis concludes that the best performing wells, defined as maximum hydrocarbon production and minimal water production, will not correlate to the thickness of its gross isopach in a simple positive manner. In fact, for the 3rd Sand the relationship seems exactly the opposite. For both the 2nd and 3rd Sands, a combination of a burial depth window and homogeneous siliciclastic facies are the key indicators of the productive trend. In the 2nd Sand, there will be a higher water cut in the thickest part of the gross isopach. Potential explanations for this observation include:

- The depth sweet spot reflects one or more physical processes impacting either poro-perm or fluid properties such as porosity development or occlusion, fluid viscosity, or pore pressure.
- The homogenous, siliciclastic facies have a) favorable geomechanical properties for frac and drill operations (fewer carbonate lenses) and b) vertical and lateral continuity for consistent, repeatable drilling and production performance.
- Gross thickness is not a leading indicator of net reservoir thickness in the study area. Instead, greater gross thickness may contain more "clastic waste rock" that contributes to water production, particularly if interbedded source rocks have been diluted by the associated clastic deposition.

The above observations become the starting point for building the multivariate model. These models provide a quantitative assessment of the geological properties most correlated with fluid production in the zone of interest (Table 2). Additional conclusions can be drawn from these correlations:

- One or both of the well design inputs are always in the top two variables. As expected, well design is important for extracting the most value out of a given resource.
- Phi-H is a key input variable in all the models. It represents the storage capacity of the reservoir, which should influence longer term productivity.
- Baron and Fritz (2017) concluded that Sw is a poor predictor of hydrocarbon productivity and the BOE model in this study shows that, as well. On the other hand, total water saturation (SwT) combines with V-Clay for predicting water productivity. Since it captures total saturation rather than effective saturation, SwT is more likely standing in for lithologic changes in the reservoir tied to changes in mobile water. Gawloski (1987) describes the clastic units of the Bone Spring as having a "high percentage" of illite, occurring as both authigenic (pore-lining) and detrital (organic layers). V-Clay in the regression is most likely capturing the impact of pore-lining illite on Sw calculations and permeability or alternatively, the impact of clay minerals on geomechanical properties affecting completions. Complicating any discussion on water productivity is the observation of Adon (2019) that the clastic reservoirs have mixed wettability or are oil wet.

Commented [JE14]: Can we say why this is?

Commented [mi15R14]: Good point. I gave it a try, while trying to be brief.

Commented [JE16R14]: In our case, it is likely due to facies and not fault/fractures, correct?

Commented [mi17R14]: Probably. But can't completely rule out the latter. Where the structure map is constrained by seismic, the south-southeast monoclinal dip is actually a series of S and SE plunging noses. Both can be true, with more faulting near the Grama Ridge.

Commented [JE18R14]: Granted. But we only catch the edge of the fault in the seismic area where planarity is available, and there weren't any indications of faults or major warping in the seismic that I saw, so I would lean towards a facies effect over faults and fractures. That's just my $0.02, though.

Commented [JE19]: We should say why this might be. Higher temp is a proxy for higher formation pressure and/or lower oil viscosities? If temperature does fluctuate laterally, our Sw calculations probably don't reflect that; i.e. our petrophysical model assumes a single temperature gradient across the study area. Not a huge deal, but something worth noodling on

Commented [mi20R19]: I think this section needs to be expanded with more explicit geological linking of multivariate inputs to the output. Here's my first stab at it.

Commented [mi21]: I'm not sure I like this sentence...

Commented [JE22R21]: I forget how Enverus calculates Sw. Provided that Sw strips out the bound water volumes, then I think it is accurate.

Commented [mi23R21]: Baron and Fritz use the term "Sw", presumably effective Sw but I don't know. Will double check. Enverus calculates both total and effective Sw. I used total b/c of better coverage and it seemed more internally consistent. So, we are looking at an Sw that includes bound water. That's why I think our SwT is more of a lithology / facies indicator than a direct measure of mobile water.

Commented [mi24R21]: Quoting from Gawloski's description: "The clastics also have a high-percentage of illite which occurs within the oranic-rich laminations and as authigenic webs and fibers within the existing pore system."

Commented [JE25R21]: yeah, there would be some danger of mixing apples and oranges, water-wise. It is a bit late to do any major re-working of the data, but I think you have covered our bases with the extra verbiage you added to this section

- Impedance with sonic, density, and TOC capture lithology and pore volume and their impact on hydrocarbon production. When impedance is substituted for density, the relative impact of sonic decreases while the relative impact of TOC increases. This implies a relationship between hydrocarbon productivity and lithology, possibly driven by its clay and organic content.
- Temperature replaces depth as an input variable in the regression because it ranked higher than depth, suggesting depth was a proxy for processes better captured by temperature. In the context of hydrocarbon productivity, temperature influences diagenetic processes, fluid properties, and source rock maturity. For example, Gawloski (1987) describes a complex diagenetic history for these reservoirs, including early quartz overgrowths followed by extensive pore-filling dolomite and partial dissolution to create the current pore network. In addition to temperature, TOC is a contributing variable, so a source and fluid property linkage may be at play. While it would be overly simplistic to relate today's temperature to the culmination of past burial and diagenetic events, it is important to keep in mind temperature's role in these processes.

Commented [JE26]: I took your question and turned it into a statement. Mike drop! ;)

Target	**NLR 1: Log-Derived Variables, Only**	**NLR 2: Log and Seismic-Derived Variables**
First 12 BOE	Proppant / Ft Phi-H Sonic Horizontal Length Density Temperature TOC n = 83 / R^2 = 0.608 Avg. Err. = 74.9 MBOE	Horizontal Length Temperature TOC Proppant / Ft Acoustic Impedance Phi-H Sonic n = 27 / R^2 = 0.888 Avg. Err. = 60.2 MBOE
First 12 Water	SwT Horizontal Length Proppant / Ft Phi-H V-Clay n = 83 / R^2 = 0.801 Avg. Err. = 94.9 Mbbl	Proppant / Ft Horizontal Length SwT V-Clay Curvature (Planarity) Phi-H n = 27 / R^2 = 0.819 Avg. Err. = 99.9 Mbbl

Table 2: NLR = non-linear regression. Variables are listed in order of significance, from most significant to least significant.

The non-linear regressions can be used to create predictive maps by using maps of each variable as inputs, keeping well length and proppant constant (as discussed above). The maps predict a hydrocarbon-rich trend stretching along the east side of the study area and across the central region to its southwest corner. A water-rich trend is predicted in the south-central region of the study area, which partially corresponds to the 2nd Sand isopach thick. These two trends intersect in the central part of the study area, a region with high productivity and high water-cut partially corresponding to the isopach thick. Comparing the two maps allows for a more thoughtful (and quantitative) evaluation of the entire predicted production stream. These are important considerations for typical operations decisions, such as where to add infill or step-out well programs or calculating water disposal costs from predicted water production.

The impact of the seismic data should not be underestimated. While the inclusion of the seismic data does not change the overall trends, the seismic data provide valuable control between the well data. In an area in the center of the AOI notably between the well control, the model without seismic data predicts a first 12-month BOE of over 300 MBOE. When the model includes the seismic data, this area has a more tempered prediction of 150 MBOE. Similar impact would likely occur along the eastern edge of the model where predictions without the seismic data exceed 400 MBOE in areas beyond the well control. While the maps with only log-derived properties as input no doubt capture the main trends, including the seismic data allow for a more confident prediction at scales appropriate for well planning.

Conclusions

This approach creates a predictive tool for quantifying the local impact of facies and property variation on well performance that can be used quantitively for forecasts, lookbacks, and scenario evaluations.

The first 12-month BOE is most impacted by geologic variables related to lithology and pore volume, but the importance of temperature suggests an additional process (e.g., source rock maturity or diagenesis) is in play as well. First 12-month water production is most impacted by variables related to lithology and facies. Storage capacity (Phi-H) is common to all four of the models. These factors are intrinsically tied to the geological conditions under which the Bone Spring sands were deposited (e.g., thickness, lithology, and facies variations controlled by factors such as paleo-topography and overprinted by diagenesis), and thus shed insight into how geology impacts productivity trends. The model, when output as predictive maps, enables what-if questions and can become a launching point for consideration of different scenarios. When incorporated into the maps, the seismic data add important inter-well control.

A geologically calibrated multivariate model benefits from the inclusion of both well and seismic data, as both offer similar insights, but at different vertical and lateral scales. Areas bereft of seismic data can benefit from this approach by using log-based insights enhanced by the integration of seismic data. Conversely, poorly drilled areas with available seismic data can leverage insights from this study to guide well performance predictions on key criteria such as first 12-month BOE and first 12-month water production. Lastly, this approach allows for direct, quantitative comparisons between geologic, geophysical and completion parameters to determine their relative impacts on productivity.

Acknowledgements

The authors want to thank Enverus for use of the MVStats multivariate software, the Subsurface Studio interpretation software, and the production and wireline log data; Fairfield Geotechnologies for use of the Red Tank 3D seismic data; and both companies for permission to publish these results. This paper also benefitted from extensive discussions with Mishtu Banerjee, Victor Hoang, Robyn Marchand, Jon Sweaney, Nick Tiedemann, and the Enverus Geology Team.

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