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Maximizing Recoverable Reserves in Tight Reservoirs Using Geostatistical Inversion from 3-D Seismic: A Case Study From The Powder River Basin, USA

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Summary

The application of horizontal drilling and multi-stage hydraulic fracturing has boosted economic recoveries from unconventional reservoirs. Applying this technology requires proper placement of horizontal wells combined with hydraulic stimulation to create fractures extending from the horizontal wellbore. The economics of unconventional plays can be improved if horizontal wellbores target facies with favorable reservoir and geomechanical properties. An integrated, multi-disciplinary approach has been developed in order to reduce economic risk, facilitate improved and faster decision making and enable more efficient and effective well placement.

Subsurface volumes of lithofacies, reservoir rock properties and geomechanical properties, all of which honor data from multiple disciplines, provided the means to generate lithology and property maps, including Phi-H, together with associated measurements of uncertainty for selected facies and properties. This seismically-constrained geomodeling approach enabled optimum identification of sweet spots for reservoir development and well placement. The methodology demonstrates the value of incorporating stratigraphic, geological, petrophysical, engineering and geophysical data into an integrated subsurface reservoir model.

Introduction

This study focuses on utilizing geostatistical inversion to predict facies and reservoir/geomechanical properties of a tight, unconventional Upper Cretaceous sandstone in the Powder River Basin, northeastern Wyoming and southeastern Montana. The basin is asymmetrical with the axis on the west side, and the boundaries of the basin are delineated by several surrounding uplifts. According to the paleogeographic reconstruction of North America (Figure 1), the Powder River Basin was east of the foreland basin axis and was, therefore, an area of limited accommodation space. This may explain why the Upper Cretaceous sandstones are stratigraphically complex in this basin (Bottjer *et. al.*, 2014).

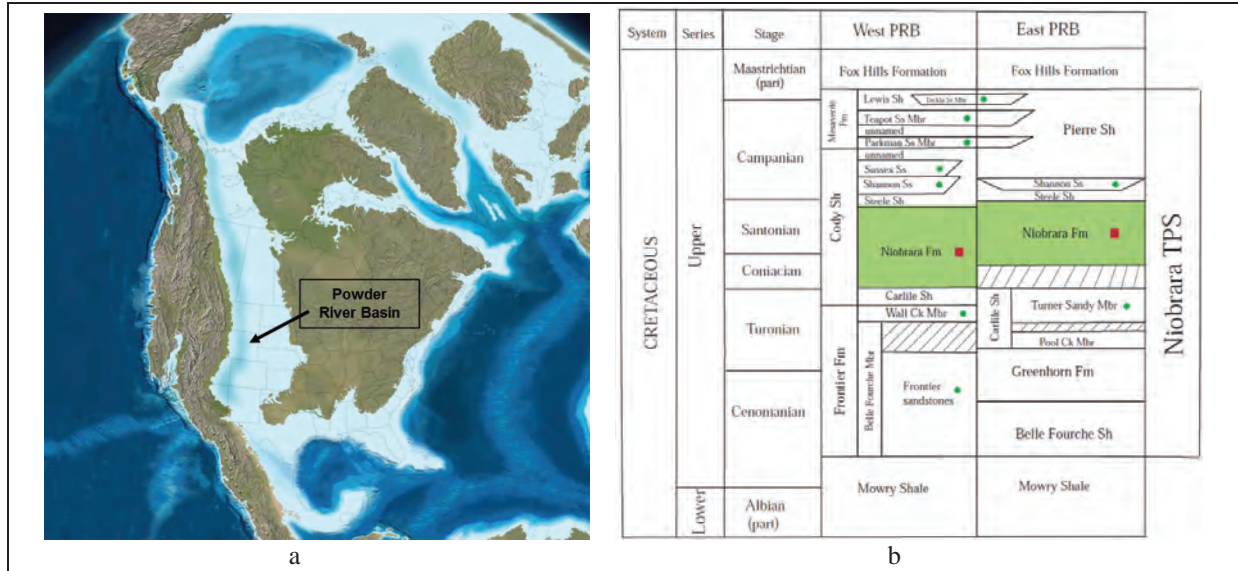


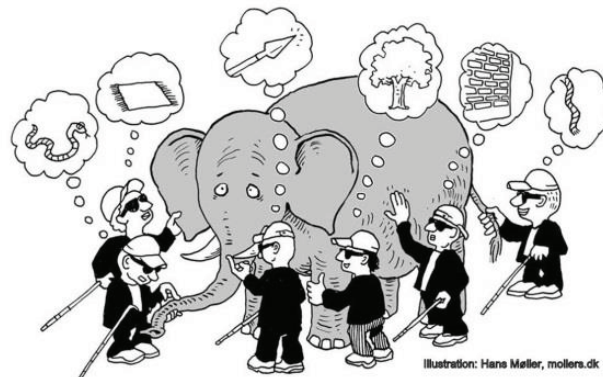
Figure 1: (a) Paleogeographic reconstruction of North America at approximately 85 MYA (Blakey, 2005). (b) Stratigraphic column of the Upper Cretaceous in the Powder River Basin. The red squares denote the source rock while the green circles denote the reservoir rock (Lawrence, 2009).

Methodology

At the current stage of reservoir science, abundant information is available from multiple disciplines. Well information, including wireline logs, core data and production data have all demonstrated their value and contributed greatly to understanding conditions at the bore hole in terms of geological, reservoir and engineering properties. Analysis of this data provides a global context to understanding the big picture of the reservoir; however, dense 3D seismic datasets provide a wealth of both quantitative and qualitative subsurface information away from wells, in terms of elastic properties that relate directly to observations at the well bore.

The important calibration information obtained and extracted from the 3D seismic data are the “*elastic properties*”: namely P-velocity, S-velocity and Density which link directly to the same elastic properties obtained from the wireline data as measured in the well bore. These two independent measurements of elastic properties, from two different primary sources calibrate with each other and provide a mechanism for lithofacies and reservoir rock property relationships to be established. Essentially, elastic properties bridge the well centric world with the seismic centric world to significantly increase our understanding of the subsurface so more intelligent decisions can be made.

This paper will demonstrate that 3D seismic data can be transformed into a far more valuable and superior calibrated petrophysical subsurface volume that can be blind-tested against known well data. Observations from various geoscience disciplines provide value in their own right due to its unique perspective. However, the data must be integrated to provide a valuable solution; otherwise different answers develop, analogous to the familiar “blind men and the elephant” fable, illustrated below.



(Taylor, 2014)

As a result of each discipline potentially being blind to the contributions of the others, an accurate mathematical tool is required to combine various sources of prior geoscience information in an unbiased and consistent manner, resulting in an improved understanding of the subsurface.

Bayes' theorem is a statistical tool used to manipulate conditional probabilities. Mathematically, Bayes' theorem defines the relative weight given to prior information from different disciplines. In this way, data from geology, well logs, seismic and reservoir engineering can be honored quantitatively without bias and in a way that converges to one solution space as seen in Figure 2.

Using Bayes' theorem, geostatistical inversion provides robust method to effectively characterize a reservoir into discrete facies and properties exhibiting a range of production capacities, thereby allowing for more effective well placement.

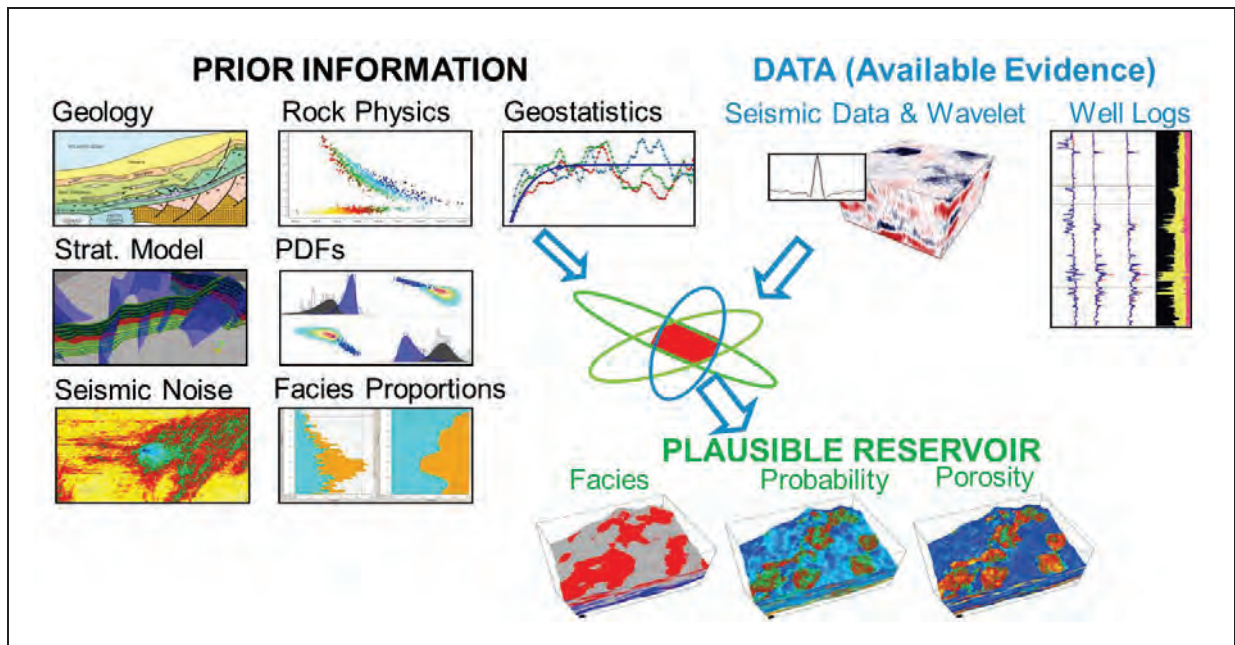


Figure 2: Geostatistical inversion workflow. The workflow starts with prior information of the reservoir, which typically includes some knowledge of the local geology analysis, rock physics information describing the various rock types together with geophysical and engineering properties. Geostatistical information is provided from analysis of well data and interpretation of the geological environment, including a stratigraphic model defining horizons and faults interpreted from 3D seismic data and deterministic inversion result; PDFs (Probability Distribution Functions) describing the range of values expected for lithofacies and elastic properties, seismic noise levels and relative lithofacies proportions.

A three-phased approach was employed in this study:

The first phase required petrophysics and rock physics modeling of wireline logs, which had been calibrated to core data to determine if facies discrimination could be achieved. Modeling of the tight sandstone from well log data yielded five unique lithology types discriminated by the seismic elastic response as shown in Figure 3 and Figure 4.

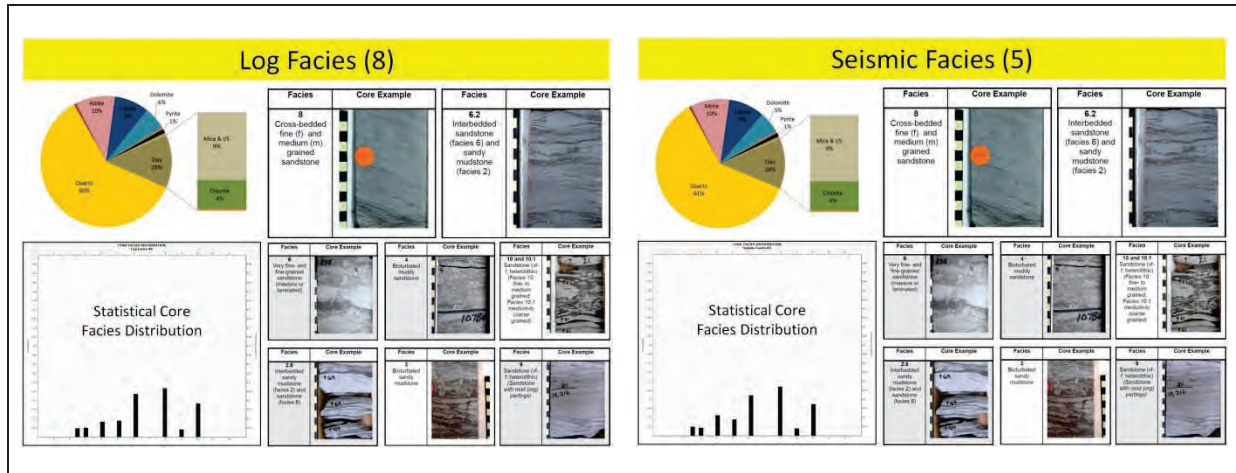


Figure 3: The statistical distribution of core facies plots showing the calibrated log to seismic facies for both the Log Facies #8 and Seismic Facies #5. Core facies showing reservoir quality samples. The core facies were upscaled and tied to the wireline log facies. The log facies were upscaled and tied to the seismic facies afterwards. These two plots correlate with one another very well.

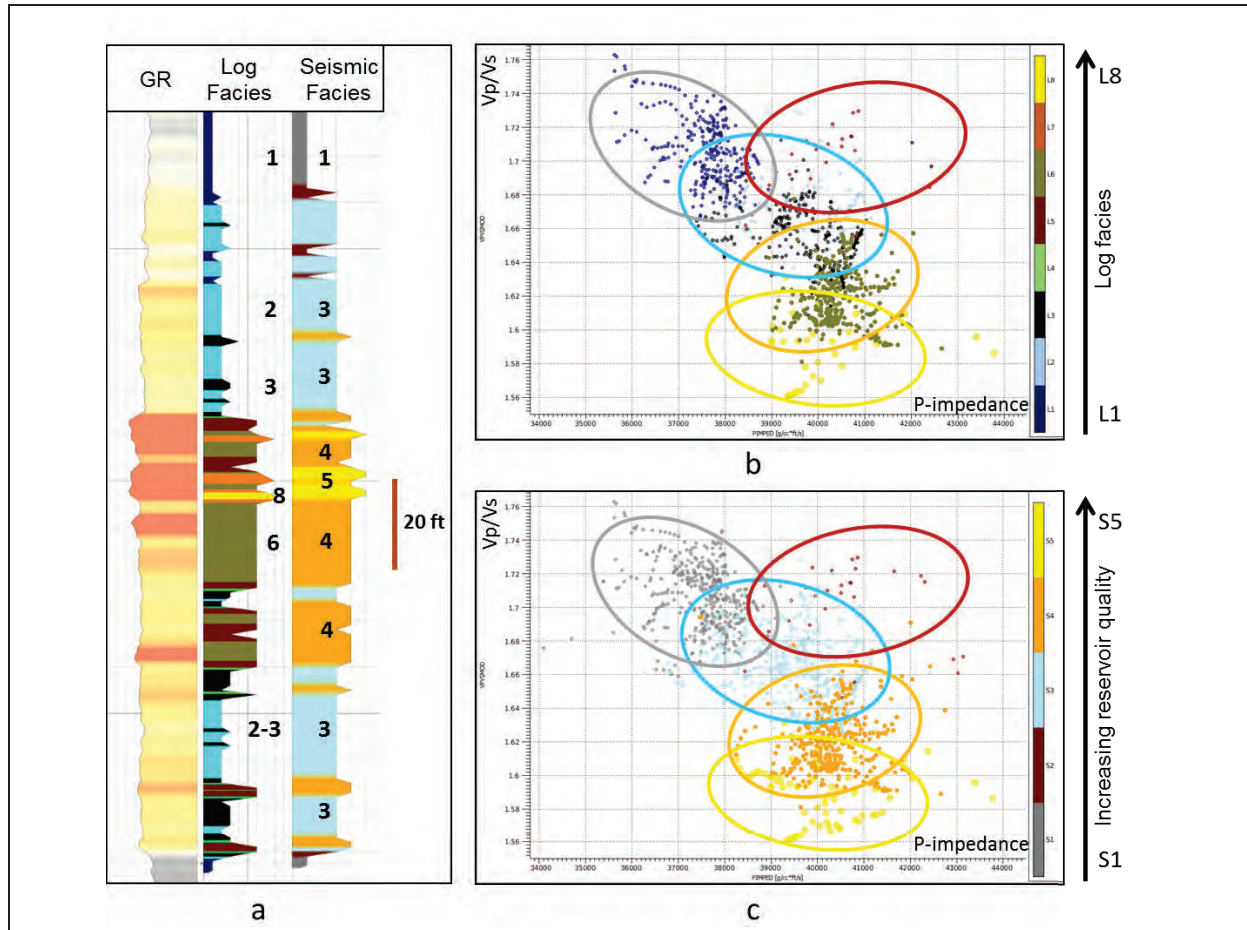


Figure 4: (a) Well A illustrating the log facies relative to the seismic facies. (b) Log derived elastic properties (the same that may be derived from the 3D seismic data) of P-impedance vs. V_p/V_s colored by eight log facies on the Z-axis. Eight log facies are identifiable based on all available wireline and core data such as GR, NPHI, Resistivity etc. (c) P-impedance vs. V_p/V_s colored by five seismic facies on the Z-axis. Only five lithofacies are adequately separated in elastic space (P-impedance vs. V_p/V_s in this case) therefore the original eight lithofacies, some of which overlapped in elastic space were reduced to five lithofacies. This was achieved by merging certain lithofacies which had a great deal of overlap together. This gave a more meaningful result and facilitates a more accurate discrimination of realistically identifiable lithofacies. The study was able to identify 5 important seismic lithofacies within the 3D seismic volume that are also observed in the core and log data.

The second phase involved detailed reinterpretation of the horizons performed on layer-based simultaneous inversion data, in which false artifacts produced by wavelet and tuning effects are removed. Figure 5 shows P-impedance is a good indicator of the top and base of the Upper Cretaceous sands. V_p/V_s provides additional information, and is a good indicator of the base of the Upper Cretaceous sands. This approach generates a refined stratigraphic earth model and was developed exclusively for use in geostatistical inversion. Based on the reinterpreted stratigraphic earth model, probability distributions of each seismic facies are now accurately determined in P-impedance, V_p/V_s ratio and density probability distribution space. This is shown by the difference in the lithofacies distribution highlighted in Figure 5d.

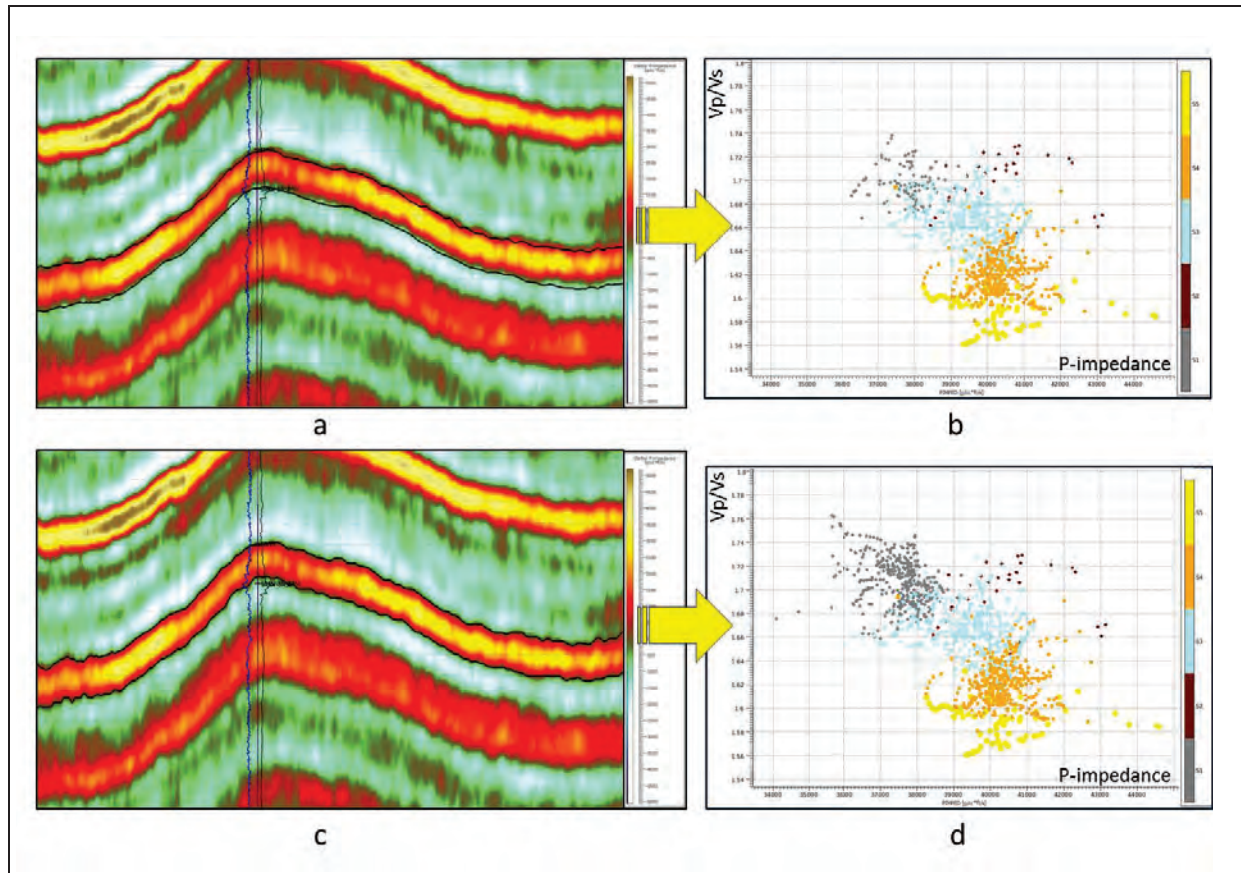


Figure 5: Bandpass P-impedance section displaying deterministic inversion result, gamma ray in blue and resistivity in black at the well location. (a) Original horizons overlaid on the bandpass P-impedance. Yellow color represents high P-impedance. All of the reflectivity features are preserved from the seismic and the data is now seen with far superior clarity. (b) The cross-plot of P-impedance vs. V_p/V_s colored by lithofacies shows the original interpreted Upper Cretaceous sand. (c) Re-interpreted horizons overlaid on the bandpass P-impedance. The horizons now match with the well tops and the contrasts of elastic properties. (d) P-impedance vs. V_p/V_s colored by lithofacies crossplot showing a more representative identification of lithofacies in terms of elastic properties derived from the now accurate interpretation of the Upper Cretaceous sand. While the difference between the two cross plots above may appear small (it is most noticeable in seismic facies S1 grey color), it is important that the facies are represented accurately within the interpretation of the horizons as these bounding surfaces control which cross plot statistics of the facies are used to derive the PDF's, which in turn drive the geostatistical inversion. The seismic facies S1 (grey color) is the seal for the Upper Cretaceous reservoir.

The third phase involved the simultaneous geostatistical inversion of the seismic 3D partial stacks. This phase incorporated data from various disciplines including the deterministic inversion to provide highly detailed subsurface facies models together with absolute reservoir rock and geomechanical properties. Associated measurements of uncertainty for all properties were calculated from the 21 realizations produced by the seismically constrained geomodeling process and each property honored all prior input information provided from well logs, core data, geology, seismic data and geostatistic information. Summary volumes of P-impedance, V_p/V_s ratio, density, Young's modulus, Poisson's ratio, most probable lithofacies and the probability of each lithofacies, together

with the probability of effective porosity were derived and used for analysis, blind well testing, interpretation and subsequent well planning.

Figure 6 compares the level of detail seen in the well logs compared to the original seismic dataset and shows the results from the deterministic inversion together with the results from the geostatistical inversion.

Figure 6a displays the lateral variability of the well lithofacies. Seismic resolution is severely limited for the target zone.

Figure 6b shows the well lithofacies overlaid on the P-impedance derived from the deterministic inversion. The P-impedance from the deterministic inversion is smeared showing only relative lateral and vertical inter-well changes for the tight sand reservoirs which are represented by high P-impedance and displayed in yellow. Vertical resolution is still limited.

The filtered well P-impedance is overlaid on the P-impedance produced from the geostatistical inversion (Figure 6c) and the well log lithofacies are overlaid on the lithofacies volume derived from the geostatistical inversion (Figure 6d).

The characterization of the reservoir produced by the geostatistical inversion provides a highly detailed seismically constrained and accurate subsurface model which is calibrated to the well control as seen in Figure 6c, 6d and Figure 7. The subsurface model honored all well data, including wells used subsequently as blind tests, thus verifying the value of the model as an accurate and predictive tool for use in reservoir development and well planning.

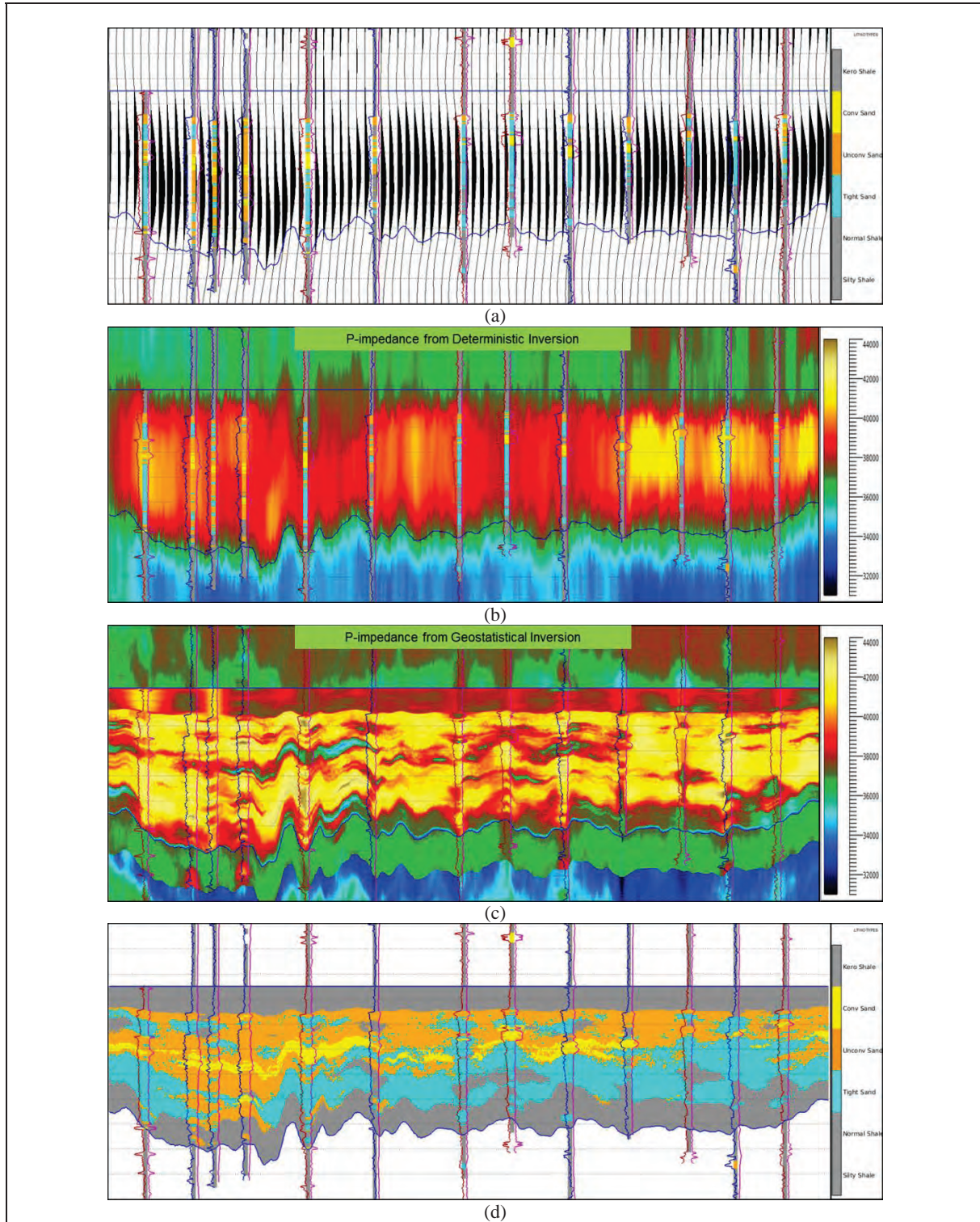


Figure 6: Cross-section flattened to the top of the Upper Cretaceous sand horizon. Gamma ray displayed on left and effective porosity displayed on right at well location. (a) Lithofacies logs overlaid on seismic. (b) Lithofacies logs overlaid on the P-impedance derived from the deterministic inversion. (c) P-impedance logs overlaid on the P-impedance derived from the geostatistical inversion. (d) Lithofacies logs overlaid on the lithofacies volume derived from the geostatistical inversion. The well data accurately correlated with the seismically derived subsurface geomodel for both lithofacies and associated reservoir properties. The results provided an accurate and reliable indicator of the inter-well subsurface reservoir conditions. The results were also successfully verified against blind well tests. While outside the scope of this paper these products would all be of value for use in both static and dynamic reservoir models.

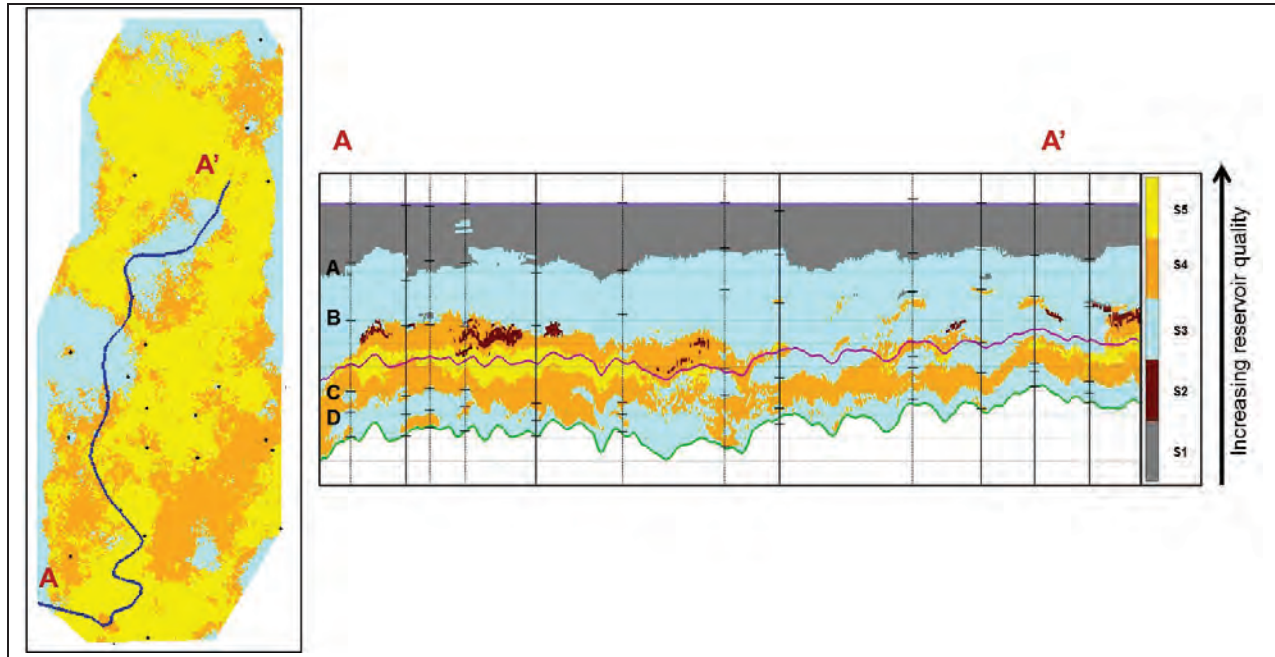


Figure 7: A stratigraphic slice and cross-section view of lithofacies (seismic facies) derived from the geostatistical inversion results. Reservoir quality increases from seismic facies S1 to S5. Facies S4 and S5 are pay reservoirs, shown as orange and yellow. The location of the stratigraphic slice is indicated by the purple line on the section view. The cross-section and the stratigraphic slice describe the variability of the heterogeneous reservoir and appear geological in nature.

Effective porosity was generated by geostatistical simulation using the inversion outputs as secondary trends which is widely referred to as co-simulation. The 3D elastic property and lithology volumes produced highly detail 3D models of effective porosity exploiting the relationships between the reservoir properties and elastic properties (Figure 8).

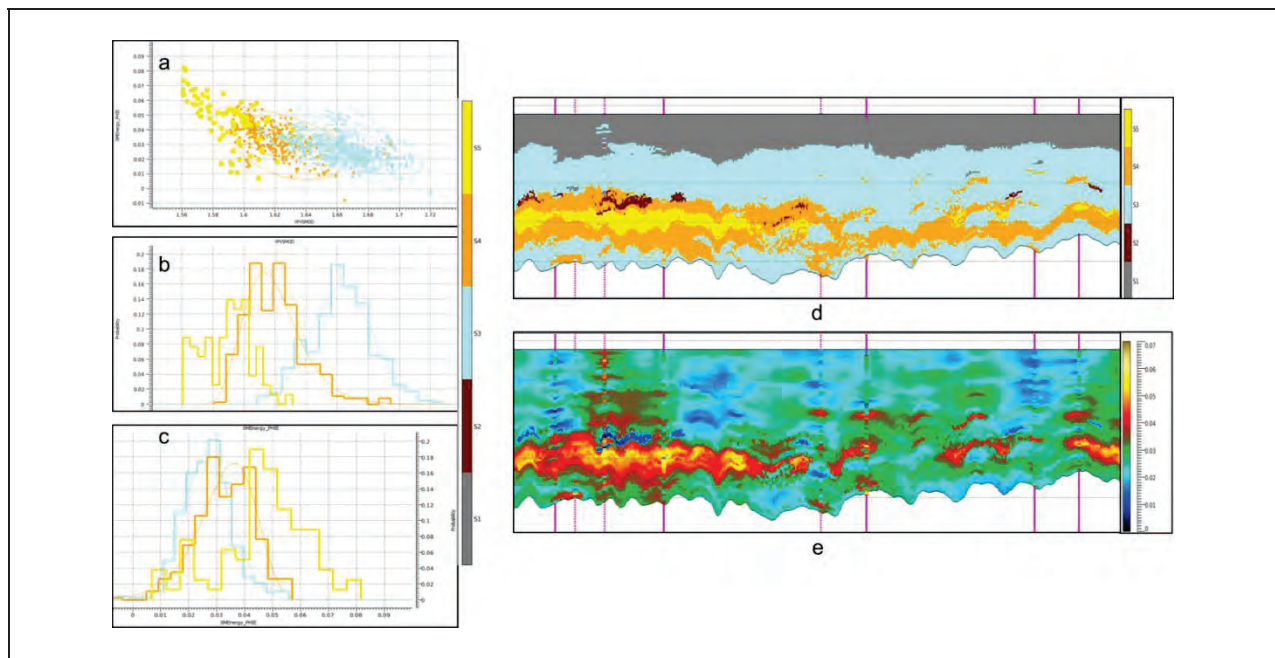


Figure 8: (a) V_p/V_s versus effective porosity colored by seismic facies. (b) Probability distribution of V_p/V_s colored by seismic facies. (c) Probability distribution of effective porosity colored by seismic facies. (d) Cross-section view of lithofacies from geostatistical inversion. (e) Cross-section view of effective porosity derived from co-simulation.

Results

A series of highly detailed lithology and elastic rock property 3D volumes were created through a Markov Chain Monte Carlo and Bayesian inference method for systematically incorporating various sources of prior information together in an unbiased, rigorous and consistent manner. The final synergized datasets accurately characterized the 3D reservoir distribution as accurately tested against blind wells, provided gross thickness maps, probability thickness maps and porosity-thickness (Phi-H) maps as seen in Figure 9 and Figure 10.

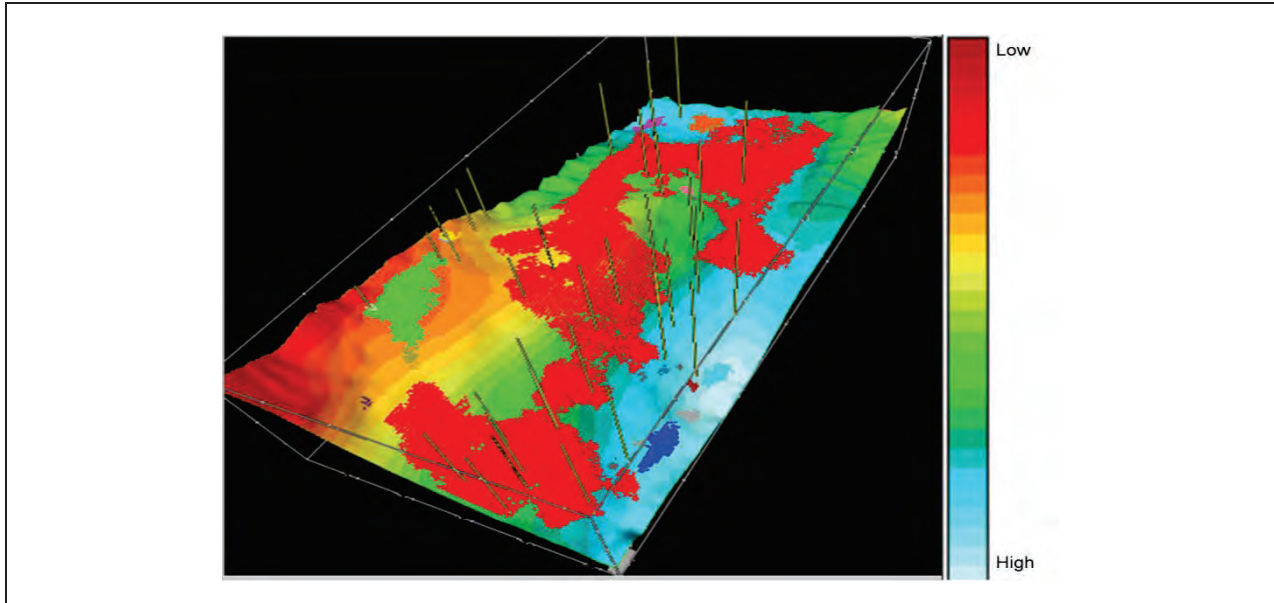


Figure 9: 3D reservoir geo-body captures showing lithofacies S5 (main large geo-body displayed in red color) for the Upper Cretaceous sand where the probability of encountering this S5 facies type is between 50-100%. The percentage probability cut-off can easily be investigated by changing the cut-off.

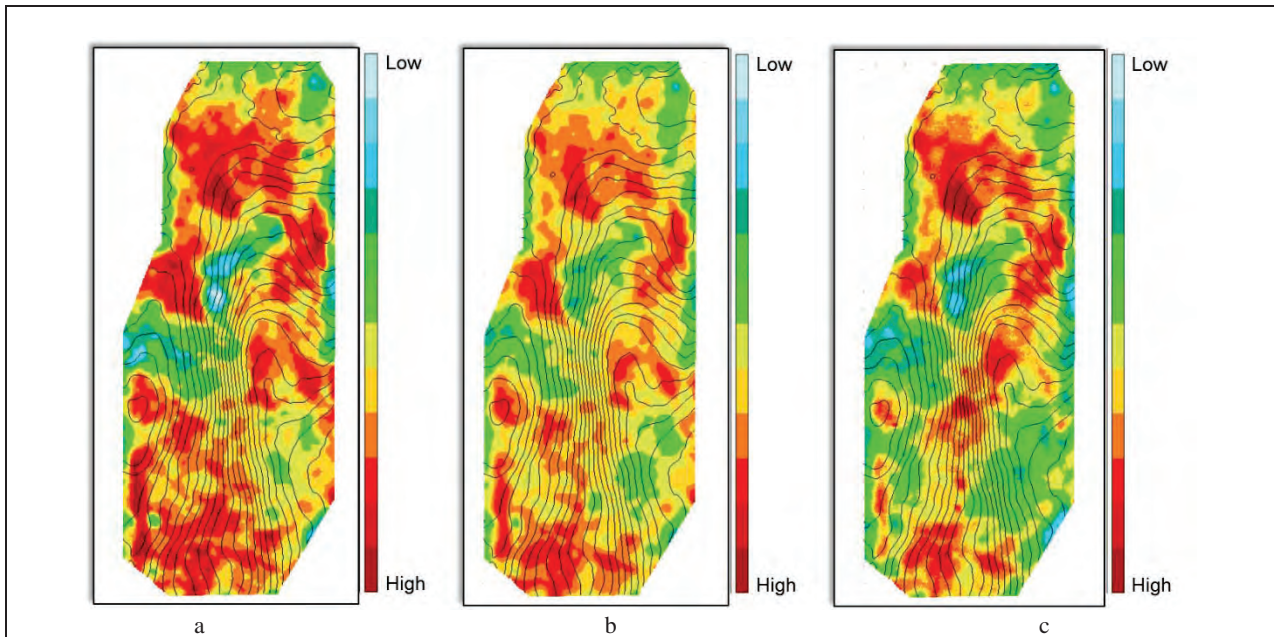


Figure 10: Thickness maps overlaid with structure contours for the top Upper Cretaceous sand (a) Seismic facies S4 and S5 gross thickness map. (b) Seismic facies S4 and S5 probability thickness map. (c) Seismic facies S4 and S5 Phi-H map

A horizontal well penetration relative to the seismic derived lithofacies with associated treating pressures applied during hydraulic stimulation demonstrates how the results are used to efficiently plan well penetrations to maximize production in the heterogeneous lithofacies comprising the reservoir. Figure 11 shows it is clearly observed that lower fracturing pressures are encountered in the higher quality reservoir lithofacies (orange and yellow) and therefore not only do these lithofacies produce better but they require less pressure to effectively stimulate the reservoir. Increased efficiency, reduced drilling risk and more informed faster decisions are enabled while engineering, planning, drilling and completing a well.

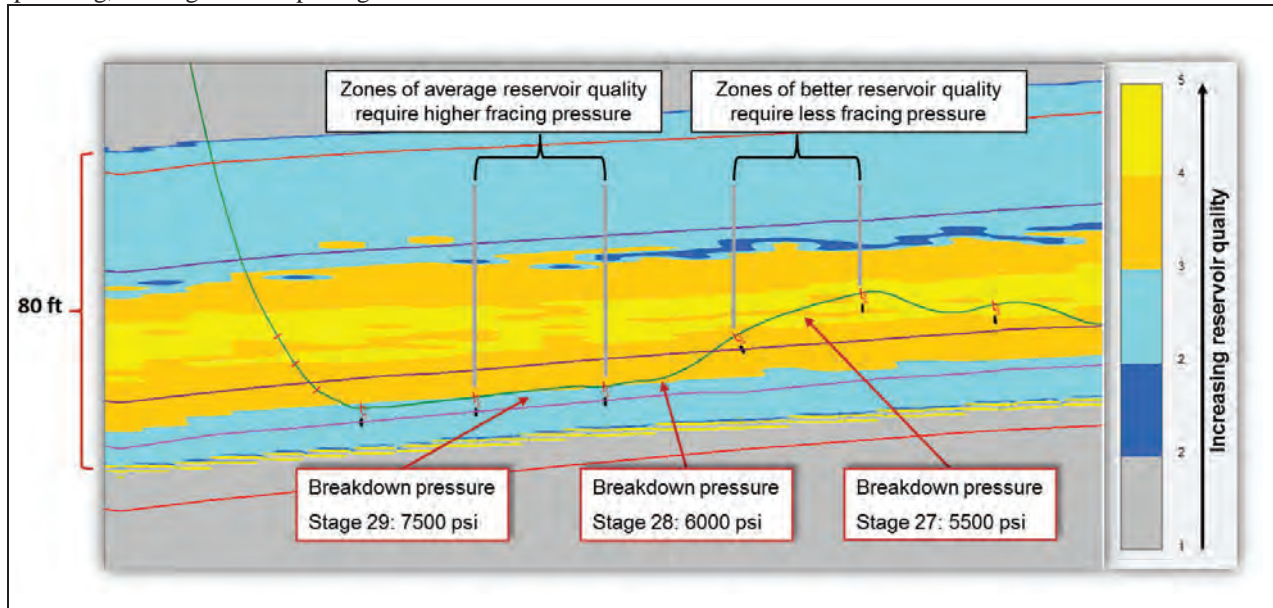


Figure 11: Lithofacies volume produced from geostatistical inversion and well treatment plots

Conclusions

A reliable subsurface geomodel was generated via geostatistical inversion for a Powder River Basin Upper Cretaceous sand formation by quantitatively and synergistically integrating geoscience data from various disciplines. The resultant seismically constrained subsurface model complemented the well centric traditional geomodels and provided a clearer and geologically realistic image of the inter-well subsurface allowing for identification of reservoir sweet spots. 3D models of the five important lithofacies were produced together with 3D petrophysical and geomechanical property models which incorporated all the characteristics of the reservoir as understood from the well data. The true structural shape, architecture and thickness of the formation lithofacies were successfully imaged together with effective porosity. The subsurface was known by well control to demonstrate significant variations of both lithofacies and properties which changed from layer to layer and from well location to well location, hence the need to model these inter-well subsurface changes in reservoir characteristics. The objective of providing an accurate synergized understanding of the inter-well reservoir characteristics which quantitatively honored all input geoscience data and can accurately be tested with blind wells was achieved.

The results can be used by engineers, geophysicists, geologists and geo-modelers to properly predict production and reserves and efficiently maximize well placement within the asset by planning, drilling and completing wells in the most efficient manner based on precise petrophysical volumes and maps e.g. lithofacies and Phi-H. Improved stratigraphic and structural interpretation of the horizon was also achieved. The integrated multi-disciplinary study gave measurements of uncertainty for probability analysis of the lithofacies or reservoir properties and enables ranking of prospective areas. This geostatistical seismic reservoir characterization approach demonstrates the value of incorporating stratigraphic, geological, petrophysical, engineering and geophysical data into an integrated subsurface reservoir model.

The paper shows how an integrated, multi-disciplinary approach has been developed in order to reduce economic risk, facilitate improved and faster decision making and enable more efficient and effective well placement.

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