Geophysical Corner

Shale Capacity for Predicting Well Performance Variability

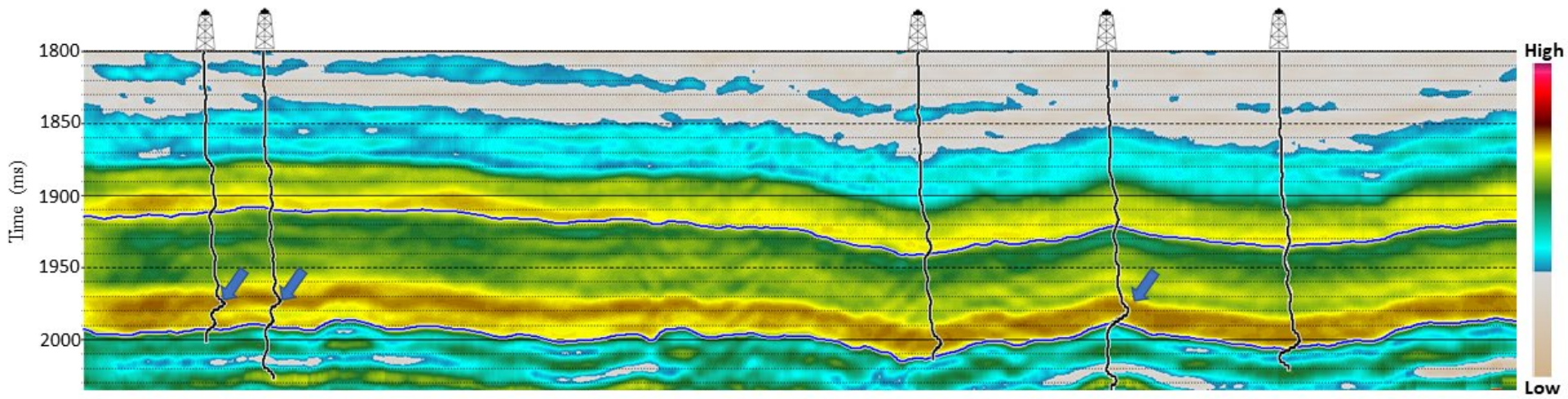

Figure 1: An arbitrary line section passing through different wells from 'PCA1 (shale capacity)'. Overlaid GR curves show the location of Duvernay formation as it is associated with high GR response highlighted by blue arrows. Notice a spatial as well as vertical variation of estimated PCA1 attribute that needs to be calibrated with the production data available for different wells. Data courtesy of TGS, Canada

The goal of reservoir characterization work carried out for a shale play is to enhance hydrocarbon production by identifying the favorable drilling targets. The drilling operators have the perception that in organic-rich shale formations, horizontal wells can be drilled anywhere, in any direction, and hydraulic fracturing at regular intervals along the length of the laterals can then lead to better production. Given that this understanding holds true, all fracturing stages are expected to contribute impartially to the production. However, studies have shown that only 50 percent of the fracturing stages contribute to overall production. This suggests that repetitive drilling of wells and their completions without attention to their placement must be avoided, and smart drilling needs to be followed by operators.

Smart drilling consists of optimally placing a horizontal well and thereafter stimulating it in such a way that more uniform production across fracturing stages occurs, which leads to a better overall production. To be able to locate such fertile pockets, an integration of different types of reservoir properties, such as organic richness, fracability, fracture density and porosity, is essential. One way of achieving this is by using cutoff values for the different reservoir properties and generating a shale capacity volume. Thus, the foregoing discussion emphasizes the integration of different reservoir properties for predicting the potential of a shale play. Mathematically, shale capacity (SC) is defined as a function of total organic content (TOC), natural fracture density (FD), brittleness (BRT), and porosity (Ø) as follows:

$$SC = TOC_{net} \times FD_{net} \times BRT_{net} \times Ø_{net}$$

where $TOC_{net} = 0$ when $TOC < TOC_{cut\text{-}off}$, $FD_{net} = 0$ when $FD < FD_{cut\text{-}off}$, $BRT_{net} = 0$ when $BRT < BRT_{cut\text{-}off}$ and $Ø_{net} = 0$ when $Ø < Ø_{cut\text{-}off}$

From the above equation, it is obvious that an optimal combination of all four parameters could lead to a higher shale capacity, i.e. the shale capacity exists only in case all four parameters are above their cut-off values. In other words, an ideal shale well must be drilled in a high TOC zone, which is brittle enough to be fractured, and a natural fracture system must be intercepted by the induced hydraulic fractures to develop a high porosity system. Therefore, due attention should be devoted to all these parameters for determining the potential of a shale play.


SHARMA


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Seismically-Derived Attributes

The availability of core data, well-log curves such as dipole sonic with azimuthal measurements and image logs could probably arm the reservoir engineers or petrophysicists with direct measurements of different reservoir properties (organic richness, fracability, fracture density and porosity) for estimating shale capacity. However, direct measurements of such properties are possible only at well locations. A way out here would be to determine the individual components of shale capacity from seismically-derived properties.

But again, to couple reservoir properties with seismically-derived attributes is complex and not easy to understand. Therefore, different seismic attributes should be analyzed simultaneously to get an individual component of shale capacity volume. For example, organic richness and porosity have a prominent impact on P-impedance, density, V_P/V_S, and Lambda-rho, and thus these attributes can be treated as their proxies. Furthermore, fracture toughness (see the April 2020 Geophysical Corner), strain energy density, and fracture intensity computed using VVAz (see February 2019 Geophysical

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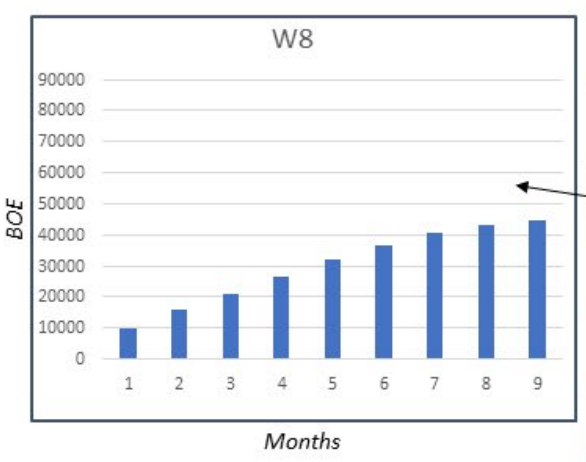

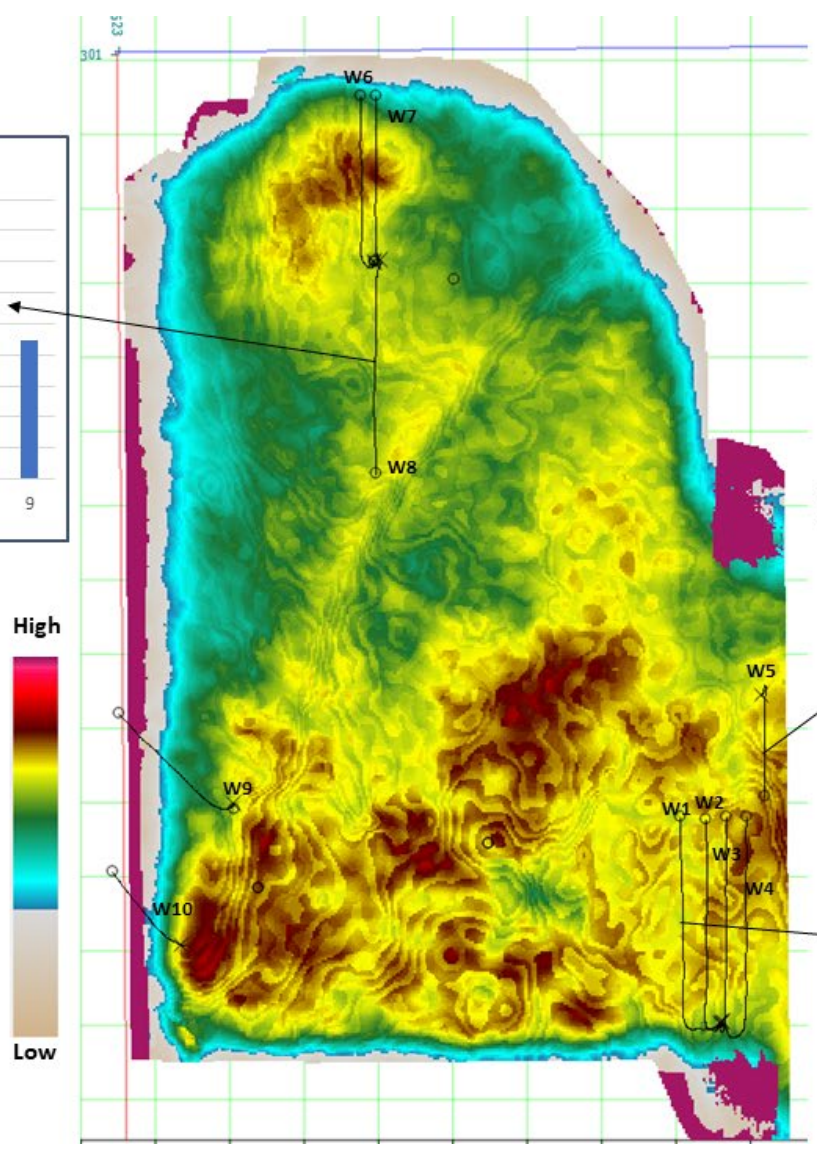

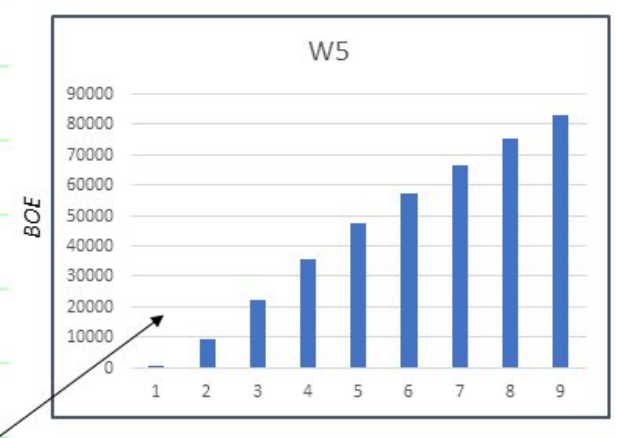

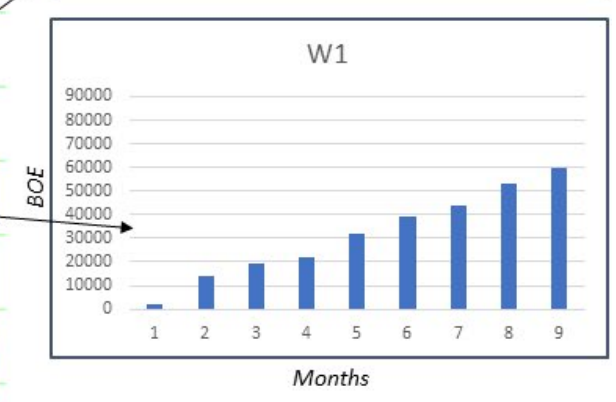

Figure 2: Horizon slice extracted from the PCA1 volume averaged over a 30 millisecond window to map the variability within the Duvernay formation. As PCA is an unsupervised machine learning technique, the choice of preferable color needs to be decided by calibrating it with other available datasets. Therefore, the production data of three different wells associated with different colors was considered and it suggests that preference should be given to hot colors for delineating the sweet spots as production is increasing with the intensity of colors. Data courtesy of TGS, Canada.

Seismicity
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oil and gas industry. A second well will be drilled to intersect the microseismic cloud recorded during the stimulation at the toe of the first well.

Seismicity in the region surrounding the Utah FORGE site has been monitored since 1981. There is no record of any events greater than magnitude 1.5 beneath the Utah FORGE site between 1981 and 2016. In late 2016, the network was upgraded to improve detection of the microseismic events. The current estimate of magnitude of detection is close to zero.

An extensive network of surface, shallow borehole and deep borehole instruments will be used to monitor microseismicity during the creation and growth of the Utah FORGE reservoir. Surface and shallow borehole instrumentation will include seismometers and strong motion detectors centrally located above the reservoir and in rings 3 and 8 kilometers from the center. During injection activities, the network will be augmented with a nodal array of seismometers. A broadband sensor and a geophone are deployed in well 68-32 at depths between 281 - 282 meters GL (921 - 924 feet GL).

Two of the monitoring wells, well 78-32 and well 56-32, will be instrumented with distributed acoustic sensing fiber-optic cables cemented behind casing. The DAS cable in well 78-32 extends from the surface to 994 meters GL (3,262 feet GL). The cable in 56-32 will extend to a depth of about 1,525 meters. Strings of high-temperature geophones will be deployed in wells 58-32, 78-32 and 56-32 during periods of stimulation and during flow testing between the injection and production wells. Analysis of the seismic data and faults surrounding the Utah FORGE site suggests the risk of induced seismicity and seismic hazards is low.

All of the data collected at Utah FORGE is available in the public domain through the Geothermal Data Repository at and the Utah FORGE website at UtahForge.com/data-dashboard.

Conclusions

The Utah FORGE site in central Utah is an ideal field laboratory for developing next-generation technologies capable of producing geothermal power from low permeability crystalline rock. The site is easily accessible all year, there are no limiting environmental constraints, temperatures suitable for enhanced geothermal system development can be reached at shallow depths of 2 to 4 kilometers, the risks of induced seismicity are low, and injection testing indicates the stress characteristics are suitable for reservoir development.

Acknowledgements

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Editor's Note: Other contributors to this article were: Stuart Simmons and Philip Wannamaker of the University of Utah Energy and Geoscience Institute, John McLennan of the University of Utah Department of Chemical Engineering, Kristine Pankow of the University of Utah Seismograph Stations, Robert Podgorney of the Idaho National Laboratory, and William Rickard of Geothermal Research Group.

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Corner) and fracture toughness can be considered as a proxy for fracability and fracture/stress induced anisotropy in addition to curvature attributes.

Principal Component Analysis

Consequently, different kinds of attributes must be considered in the process of defining shale capacity, which is not an easy task to tackle manually. Therefore, an attempt has been made here to perform such an integration with the help of a machine learning technique (see April 2018 Geophysical Corner) called "principal component analysis," or PCA, for a 3-D seismic dataset from central Alberta, Canada, where the Montney and Duvernay formations represent the zone of interest. With all the seismic attributes mentioned above available, they were put through the machine learning PCA computation, to figure out the patterns and relationships in them. Usually the first three principal components carry most of the information contained in the input attributes, with PCA-1 containing a large part of that. Consequently, PCA-1 can be treated as a proxy for the shale capacity volume. Figure 1 shows an arbitrary line passing through different wells from the PCA-1 volume. The display exhibits both the lateral and temporal variations.

To capture the lateral variations in the data, figure 2 shows a horizon slice averaged over a 30 millisecond window covering the Duvernay formation. The hot colors on the display represent higher values than the greenish/bluish colors, but as PCA is an unsupervised machine learning technique, it is difficult to conclude as to which color conveys what information. To gain some insight into this dilemma, the nine-month cumulative BOE (barrel of oil equivalent) production data available for those wells are brought in and found to be associated with different colors. Notice the productivity of a well increases in going from the greenish color to hot colors. It may therefore be concluded that hotter colors are preferable for the delineation of sweet spots.

We will continue the description of this analysis in part 2, which will appear in next month's Geophysical Corner.

(Editors Note: The Geophysical Corner is a regular column in the EXPLORER, edited by Satinder Chopra, chief geophysicist for TGS, Calgary, Canada, and a past AAPG-SEG Joint Distinguished Lecturer.)