Characterization and Modeling of Tight Fractured Carbonate Reservoir of Najmah-Sargelu Formation, Kuwait*

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Abstract

The Najmah Sargelu Formation of Oxfordian-Kimmeridgian age has good commercial production potential of oil and gas in Kuwait. The formation consists of argillaceous limestone and kerogen and is characterized by low matrix porosity. The open fractures play an important role in terms of producibility. The fracture porosity is related to micro, meso and mega fractures. The fracture permeability is far more significant compared to the storage capacity of the fracture and matrix porosity.

This paper presents the workflow used for analyzing and integrating multidisciplinary data sets in order to develop an integrated 3D property and fracture model with the goal of reducing exploration-drilling risk and optimizing reservoir appraisal. Core data, wire line log, sequence stratigraphic framework, seismic, acoustic impedance volume were used to build a robust 3D geo-statistical facies and property model. The distribution of internal properties and heterogeneity has been quantitatively described as the relationship of a reservoir facies within sequence stratigraphic framework. Three sets of sub-vertical conductive fractures interpreted from image log and core data, record strike 0-300, 800-1200 and 1400-1850. Integration of the facies, core fracture data, and image logs are used to quantify and rank fracture contents. A set of fracture intensity models was generated as a property model by a Sequential Gaussian Simulation and Neural Network and co-krigged with ant-track and coherency volume. The major fracture sets were modeled as a combined DFN (Discrete Fracture Network) and IFM (Implicit Fracture Model) using geological (facies, porosity and fracture intensity) and seismic (ant-track and coherency) drivers. Correlation with mud loss and gain data, well site gas analysis data,

production data and analog were studied in order to understand fluid conductivity of modeled fracture network. The well test analysis is used to understand the main flow mechanism occurring in the reservoir.

The integrated 3D model explains the distribution of storage and maximum drainage area connected through fracture network within the reservoir. This has attained a prudent solution for exploration and appraisal challenges of type-II carbonate reservoir.

Introduction

The Najmah-Sargelu Formation has a huge hydrocarbon potential in different structures throughout Kuwait. Porosity of the reservoir rock ranges 2-6%, contributed by interparticle as well as fracture porosity. The permeability varies generally from < .01 mD to 10 mD; at some locales, it reaches up to 100 mD. Thus, Najmah-Sargelu reservoirs are highly complex, in terms of lithofacies, spatial distribution of matrix porosity, fractures and permeability. In spite of poor reservoir quality, these formations have produced light oil in the range of @ 1,000-4,000 BOPD and 2-19 mmscf gas from a number of wells in different fields. This poor reservoir quality with potential production rate is due to complex heterogeneity of lithofacies, pore space and fracture. Hence distributing the reservoir property spatially is a major challenge.

The objective of this paper is:

1. To illustrate lithofacies, porosity, fracture and its relationship to explain reservoir characteristic
2. Distribution of reservoir properties - its geometry, connectivity and continuity.
3. To reduce the uncertainty of production sustainability and proper well planning of the tight fractured carbonate reservoir.

Rock Property and Log Analysis

The Najmah-Sargelu Formation is mainly mud dominated carbonate rock, which was deposited in mid to outer ramp setting. Rock property data measured from core were used to analyze and illustrate the core porosity and core permeability of Najmah-Sargelu Formation (Figure 1). Out of these, 200 samples are characterized by fracture-microfacture, open, closed and partially closed fracture. From this facies based porosity and fracture analysis, following observations were made:

1. Porosity of argillaceous lithofacies is of two types - interparticle, vuggy and fracture porosity (Lucia, 1995).
2. Argillaceous carbonate lithofacies have 1 to 8 % porosity and 0.01-10 mD permeability.

3. Fracture porosity is microfracture, open and partially cemented closed fracture. Porosity of more than 2.5% shows a linear regressive relationship and dominant frequency of permeability is .01 and 10 mD.
4. In case of non-fractured rock fabric, distribution is very much scattered and permeability ranges from < .01 to 1 mD. To address this problem, available petrographic description as per Dunham Classification are analyzed and grouped into five lithofacies - argillaceous packstone, kerogene rich bituminous mudstone, lime mudstone, wackestone and algal limestone (Figure 2). Bituminous mudstone and argillaceous wackestone shows dual reservoir property contributed by matrix as well as minor-fracture system. Distribution of porosity-permeability shows fair to good relationship among bituminous mudstone (2-10% porosity), argillaceous wackstone (2-6% porosity) and packstone (2-8% porosity).

Mostly interparticle porosity of pelloidal packstone is destroyed by calcite cementation and minor secondary dissolution pores associated with leached algal crusts are plugged by halite (Figure 2). Average log porosity is calculated by averaging neutron-porosity and density-porosity logs which shows good correlation with core porosity.

Fracture Analysis

Image logs were calibrated with the core data for the fracture density, orientation and to define the fracture sets. Fracture dip is characterized by high angles and the dominant strike is NNE. Fracture density is greater in the Sargelu and Najmah Kerogen section and spatially fracture intensity and orientation changes from south to north. The fracture density becomes greater in the lower section. Rose diagrams and fracture intensity clearly show the variation. The fracture orientation shows variations from south to north in the Najmah Kerogen and Sargelu layers (Figure 3). In conclusion, the detailed analysis of the fracture density shows fracture density is heterogeneous in depth.

There are three sets of fractures to be quantified and established from analysis of image log and core data (Figure 4). Geomechanical properties (Young modulus, Rigidity and Poisons ratio) were calculated from S, P wave sonic and density logs. Depending on these geomechanical properties, three divisions were made, which more or less matches with major lithological subdivisions such as the Sargelu, Najmah Kerogen and Upper Najmah Limestone (Figure 5).

Seismic Attribute Analysis

3D seismic attributes like dip, azimuth, curvature and ant-tracks were used to identify the reservoir architecture and its discontinuity. The dip/azimuth can describe the geomorphology and structure of stratigraphic layer where as curvature can be used to identify the lineaments within the fault blocks and characterize the sub-fault properties. Curvature attributes better detects faults related fracture corridors, which are sub-vertical, fracture swarms with scales ranging from several meters to tens of meters lateral extent intersecting the reservoir. Identifying such vertical conduits will be helpful for understanding the interior reservoir communications. Ant-track volume used to identify discontinuity in terms of fractures (Figure 6).

Property Modeling

Due to sparse well distribution, instead of using variograms to model facies, Gaussian Simulation based on probability distribution was used for each facies. The lithofacies model was constrained first because it is used soft data for the porosity, water saturation and permeability model.

A sequential Gaussian Simulation Algorithm was used in the gridding and the model was conditioned to the well data. The porosity was modeled with lithofacies model as soft data and gridded with collocated cokrigging Sequential Gaussian Simulation. Porosity cut-off was set at 6% because the Najmah Sargelu Formation is mainly comprised of low porosity mud-dominated limestone.

Constructing permeability models for carbonate rock is a major challenge due to poor porosity-permeability relationships and limited core data. Figure 1 and Figure 2 show two approaches of correlation between porosity and permeability, indicating a range of permeability of several orders of magnitude for a given porosity value.

To mitigate this, a neural network biased with regressive equation from porosity permeability analysis was used to predict permeability. Two sets of wells with one trained well in each set were used to calibrate permeability. Out of the two sets, one set of wells is within our area of study. Then a cloud transform was used to capture the heterogeneity to construct 3-D geostatistical permeability model. Figure 7 shows 3D cutaway views of the lithofacies, porosity, permeability and water saturation model.

Fracture Modeling

The fluid movements in the reservoir are controlled by the internal fracture network and its connectivity with pore space. Two types of fractures are taken, namely fracture corridors at the large scale and diffusive fracture at the small scale.

The objective in performing statistical modeling of small-scale fractures is to simulate reservoir properties at inter-well locations. Image log and core data at well are used to make fracture density log. For this, three geomechanical layers were identified based on

Youngs modulus, rigidity and poisons ratio and a relationship was inferred with lithofacies (Figure 5). In the modeling, fracture density logs were used as the primary variable while seismic attributes used as the secondary variable. Since seismic data provides a good lateral resolution than vertical resolution, geo-static model constrained with seismic attribute was used to prepare fracture density model. The sequential Gaussian simulation technique was used to model the fracture density (Figure 8).

In a fractured reservoir, fractures are classified into different sets related to different deformation events. In this field, there are three sets of fractures with specific orientations interpreted from image log and core data. Each fracture set is modeled separately. The three main fracture sets are NE: 0-300, EW: 800-1,200, SW: 1,400-1,850. The fracture orientations are consistent with the main structure directions (Figure 9).

The fracture sets and dimension provides a basis for this fracture modeling. To validate the geometry of the fracture network model, connected networks are necessary for understanding hydraulic properties of fracture model (Figure 10). To perform the dynamic characterization, various available dynamic data like mud loss, total gas count, drilling parameters and well production data were used for this study

Integrated Model

Integrated model explains the visual insight of reservoir geometry and its connectivity through fractures that related to permeability leading to producibility of reservoir (Figure 11). The fracture network permeability is the function of intrinsic fracture permeability and its connectivity related to the fracture density of diffusive fractures.

Conclusion

The characterization of reservoir properties, fracture and modeling of the same will help to understand the spatial distribution of properties, fractures and its connectivity. These will affect the production performance and their contributions to fluid flow within the reservoir.

Integration of property model and fracture model (DFN and IFM) together will play an important role to select proper drillable locations, which will give sustainable production potential.

Fracture corridors and diffuse fractures are not only geologically different but also behave differently in reservoir dynamic condition. Fracture corridor increase the local permeability which can increase the potential for early water for wells located close to fractures. Diffuse fractures could control the matrix-fracture fluid exchanges and may lead to enhance production.

Reference

Lucia, F.J., 1995, Rock-fabric/petrophysical classification of carbonate pore space for reservoir characterization: AAPG Bulletin, v. 79/9, p. 1275-1300.

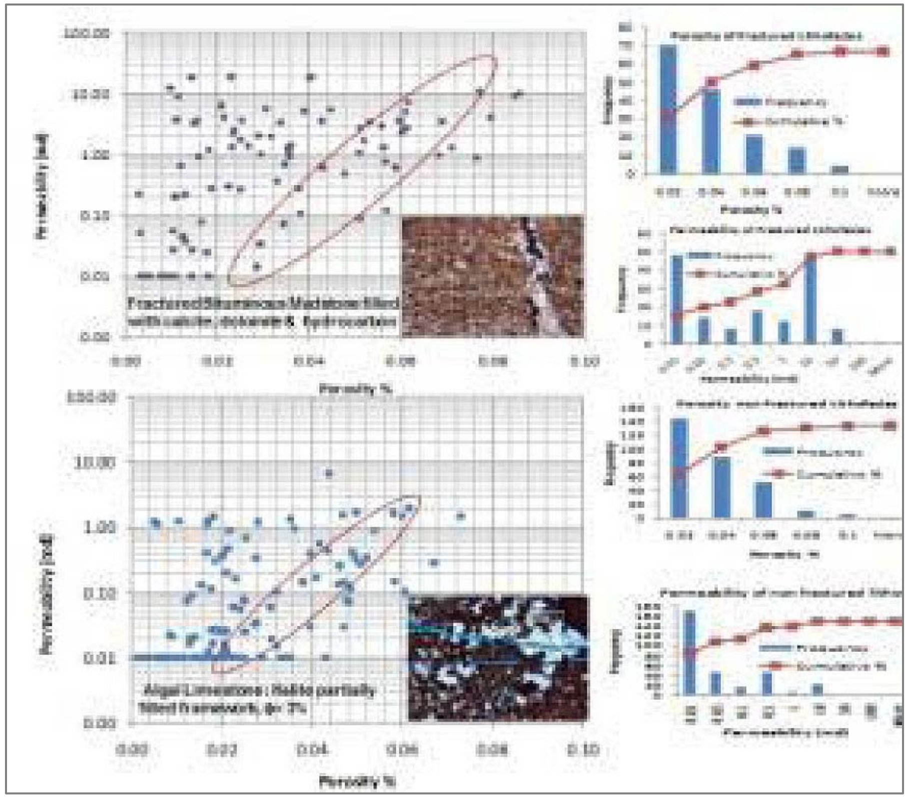

Figure 1. Rock properties distribution of Najmah Sargelu lithofacies. Porosity ranges from 1 to 8 %. Upper: porosity, permeability distribution and frequency of fractured lithofacies with a thin section of fractured bituminous mudstone. Lower: porosity and permeability distribution and frequency of non-fractured lithofacies with thin section of algal limestone.

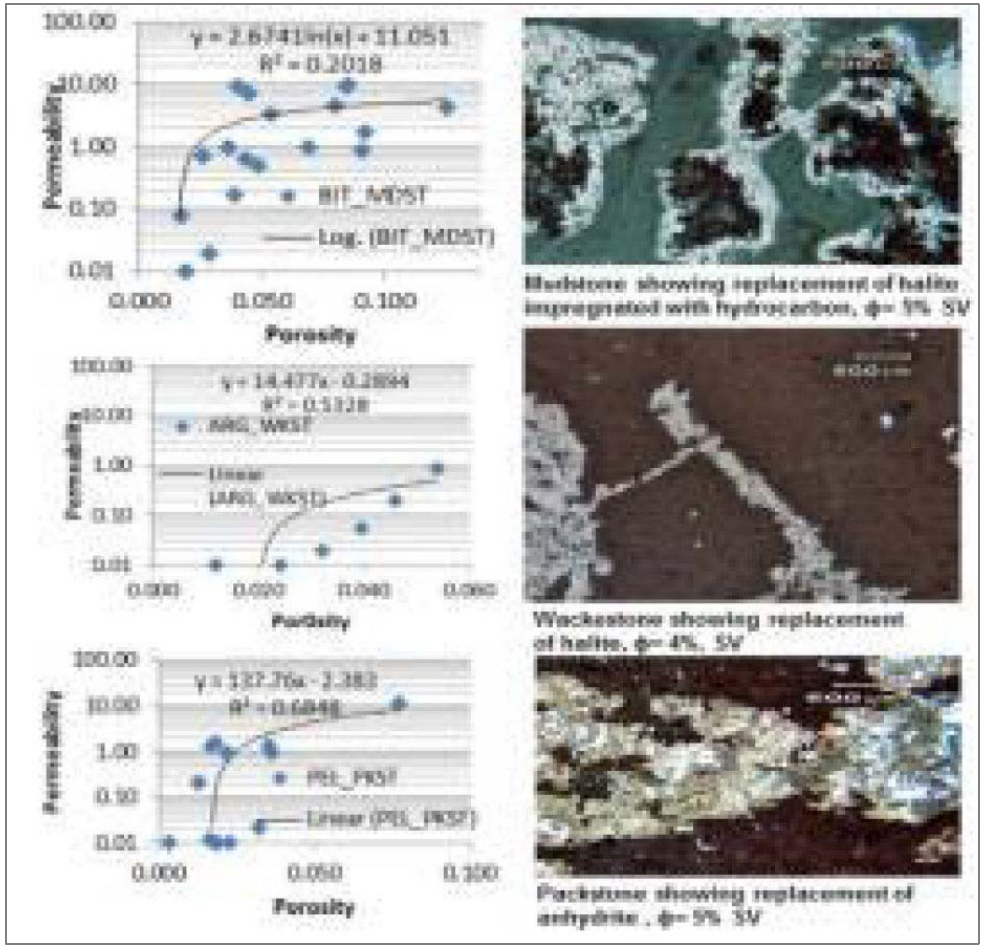

Figure 2. Porosity permeability relationship of mudstone, wackestone and packstone with thin section showing vuggy porosity.

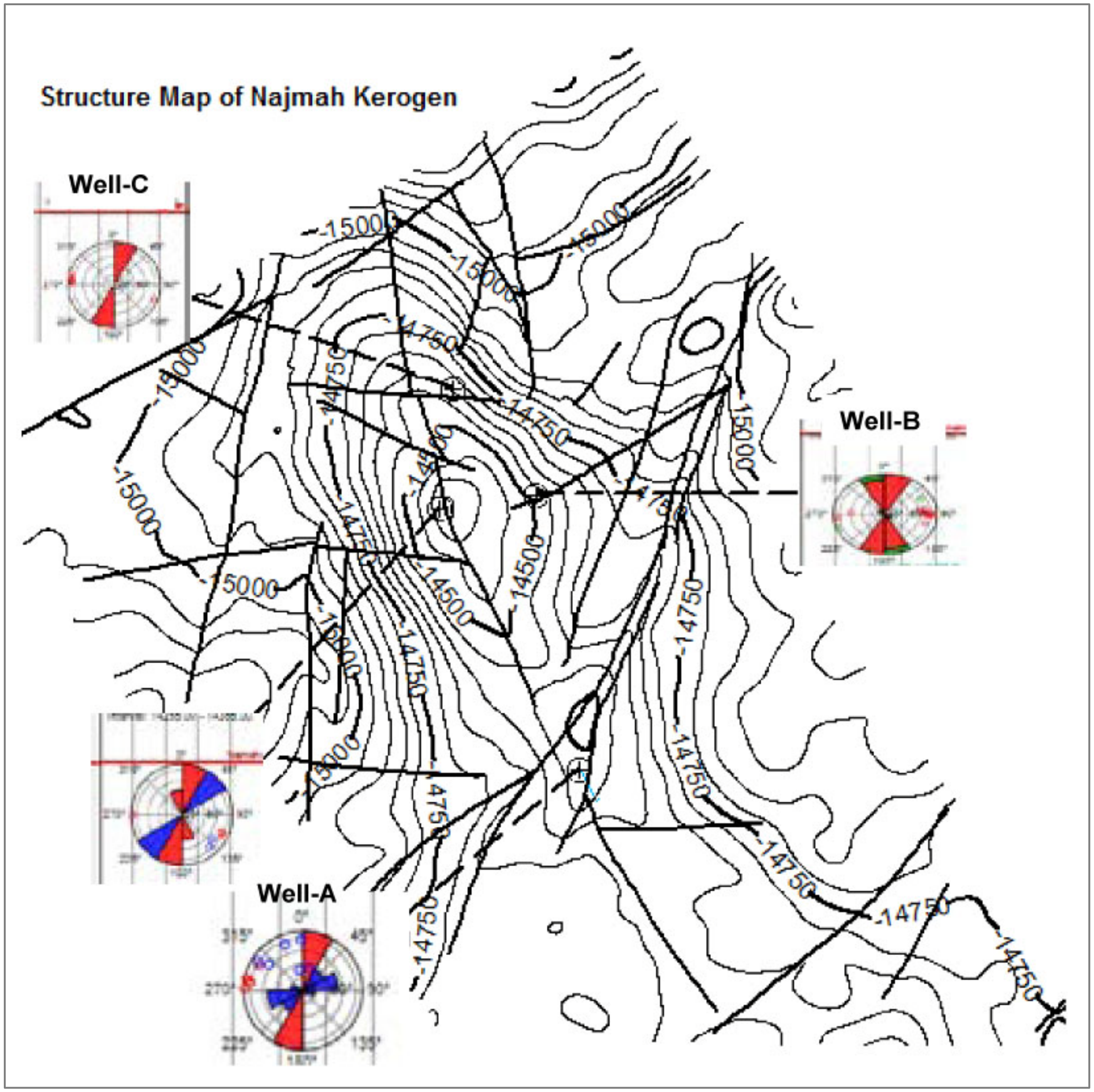

Figure 3. Rose diagram shows presence of three sets of fracture and variation from south to north in Najmah.

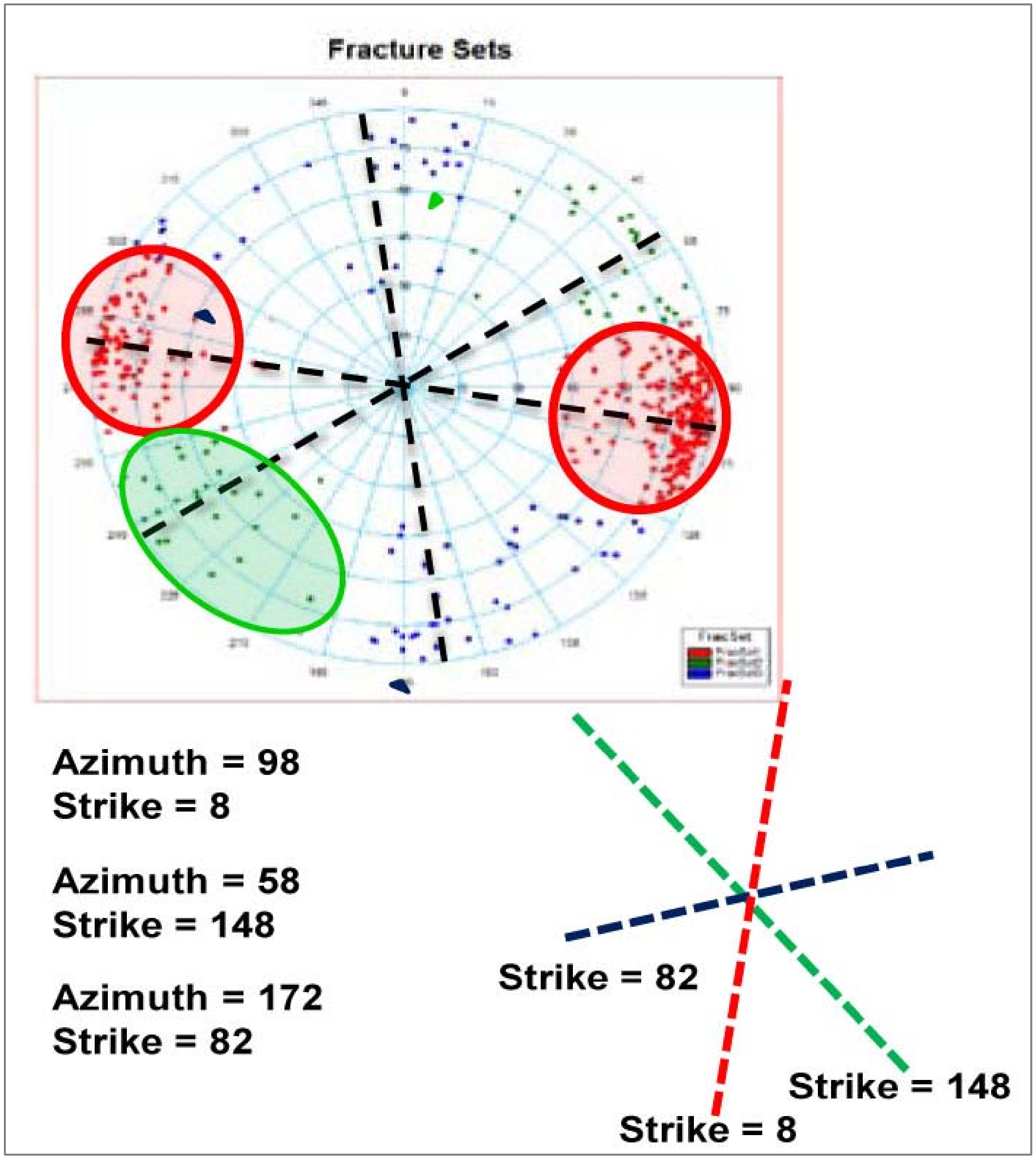

Figure 4. Three sets fault showing average strike of fractures.

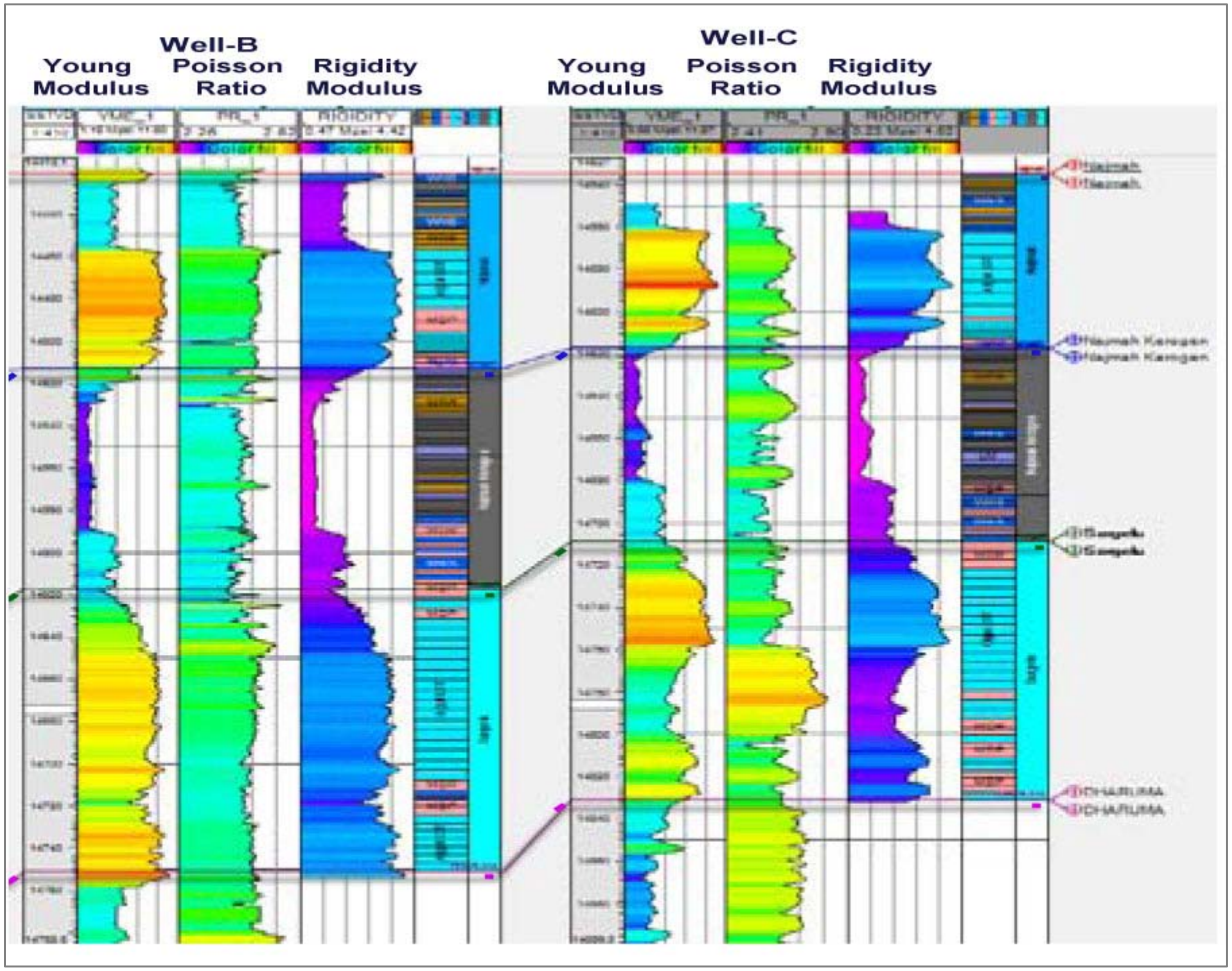

Figure 5. Three geomechanical sub-division of Najmah-Sargelu Formation.

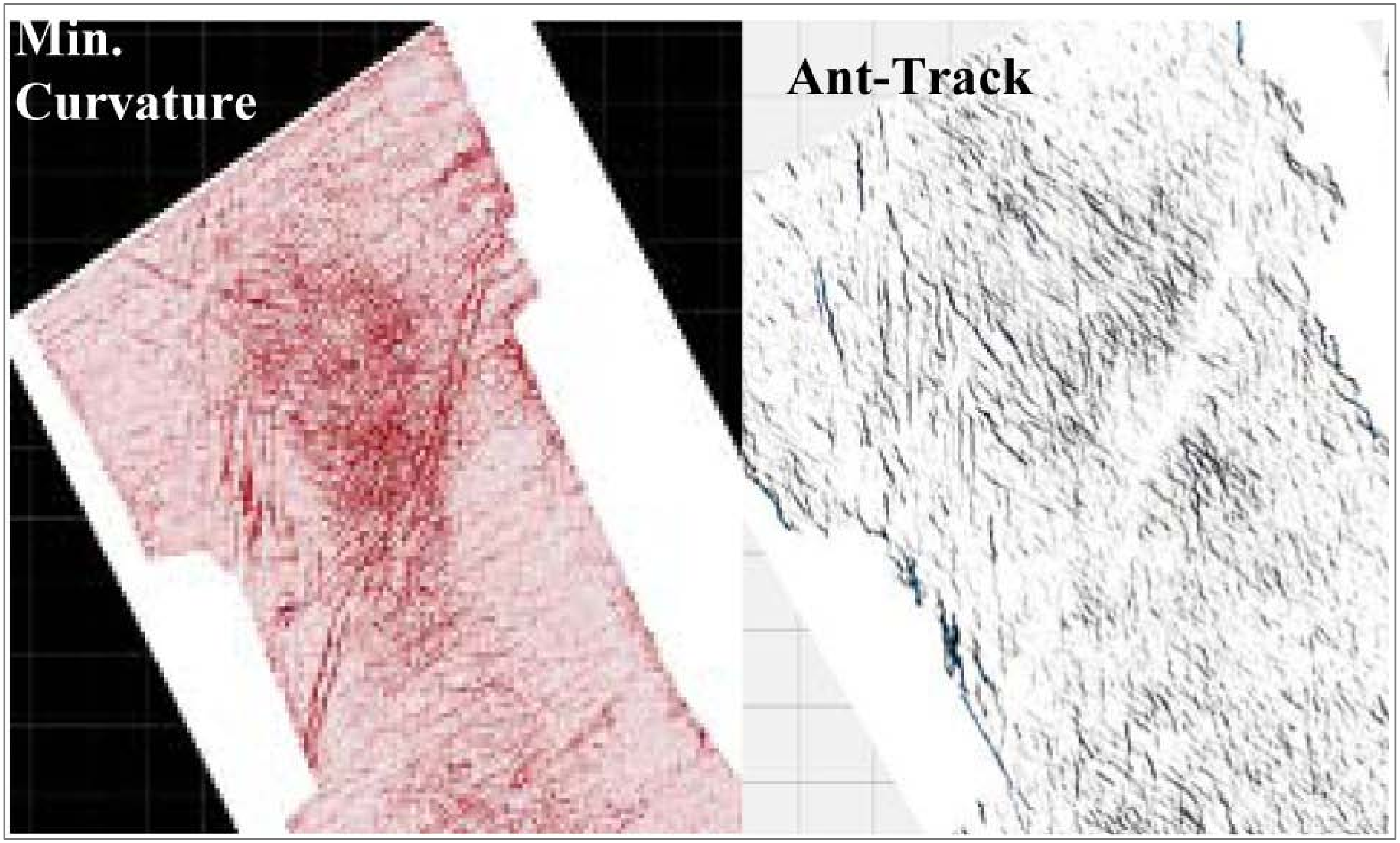

Figure 6. Attributes showing structure, lineaments, fault and fractures.

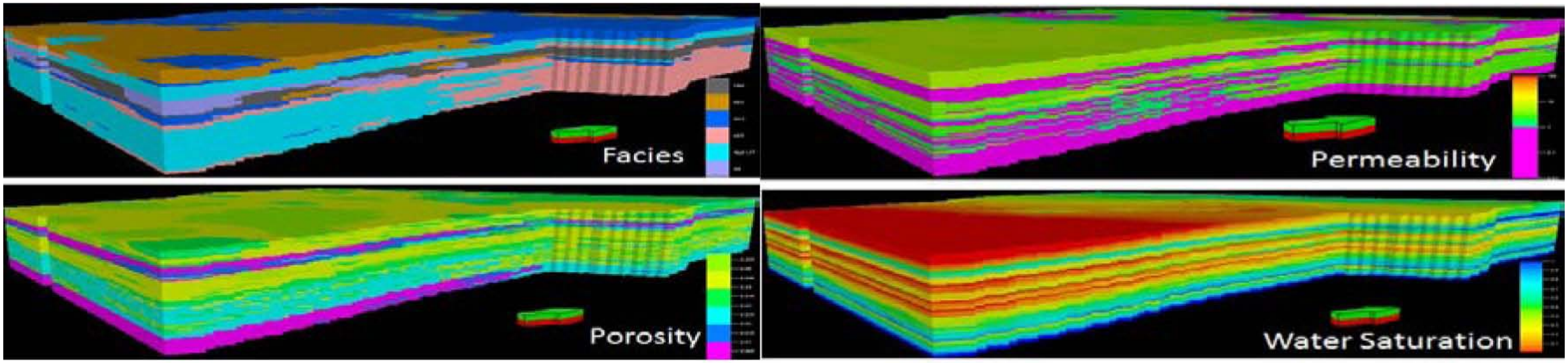

Figure 7. 3-D view of lithofacies, porosity, permeability and water saturation geostatistical models of Najmah Sargelu Formations with good compatibility among the 4 models showing significant continuity of reservoir property of bituminous mudstone facies in Lower Najmah Shale zone.

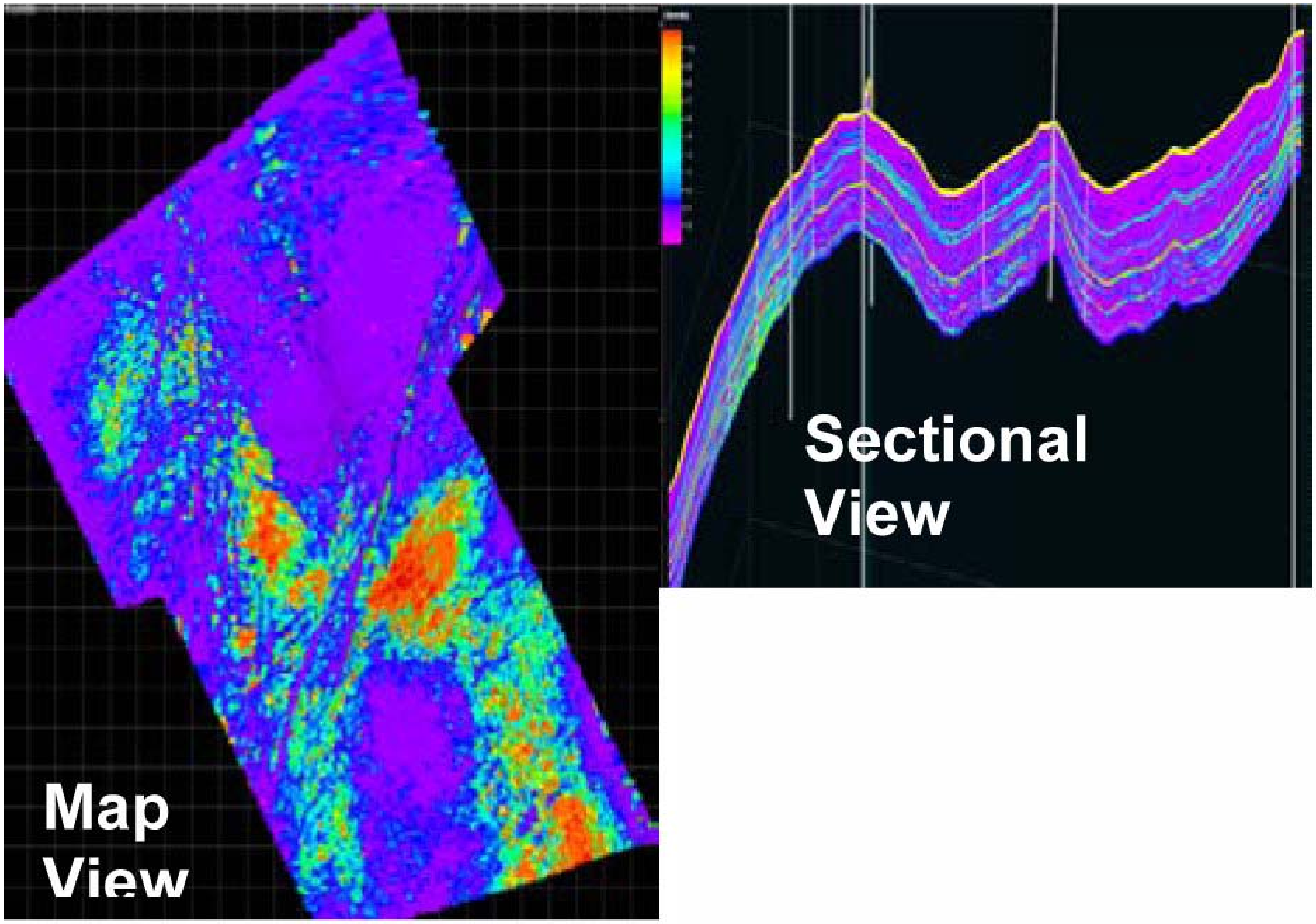

Figure 8. Intensity property developed from well data co-krigged with seismic attribute.

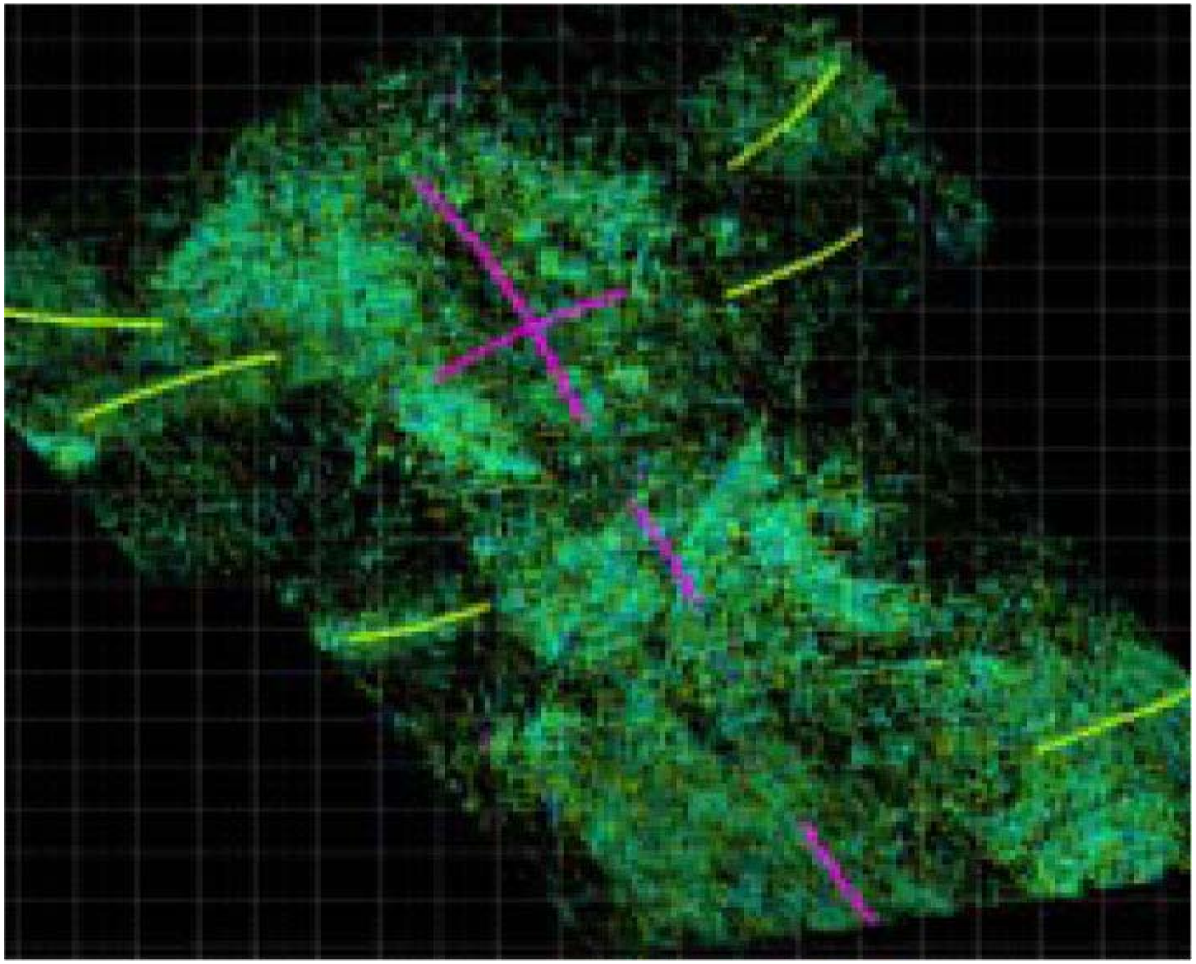

Figure 9. Fracture Model showing sets fracture consistent with the main structure direction.

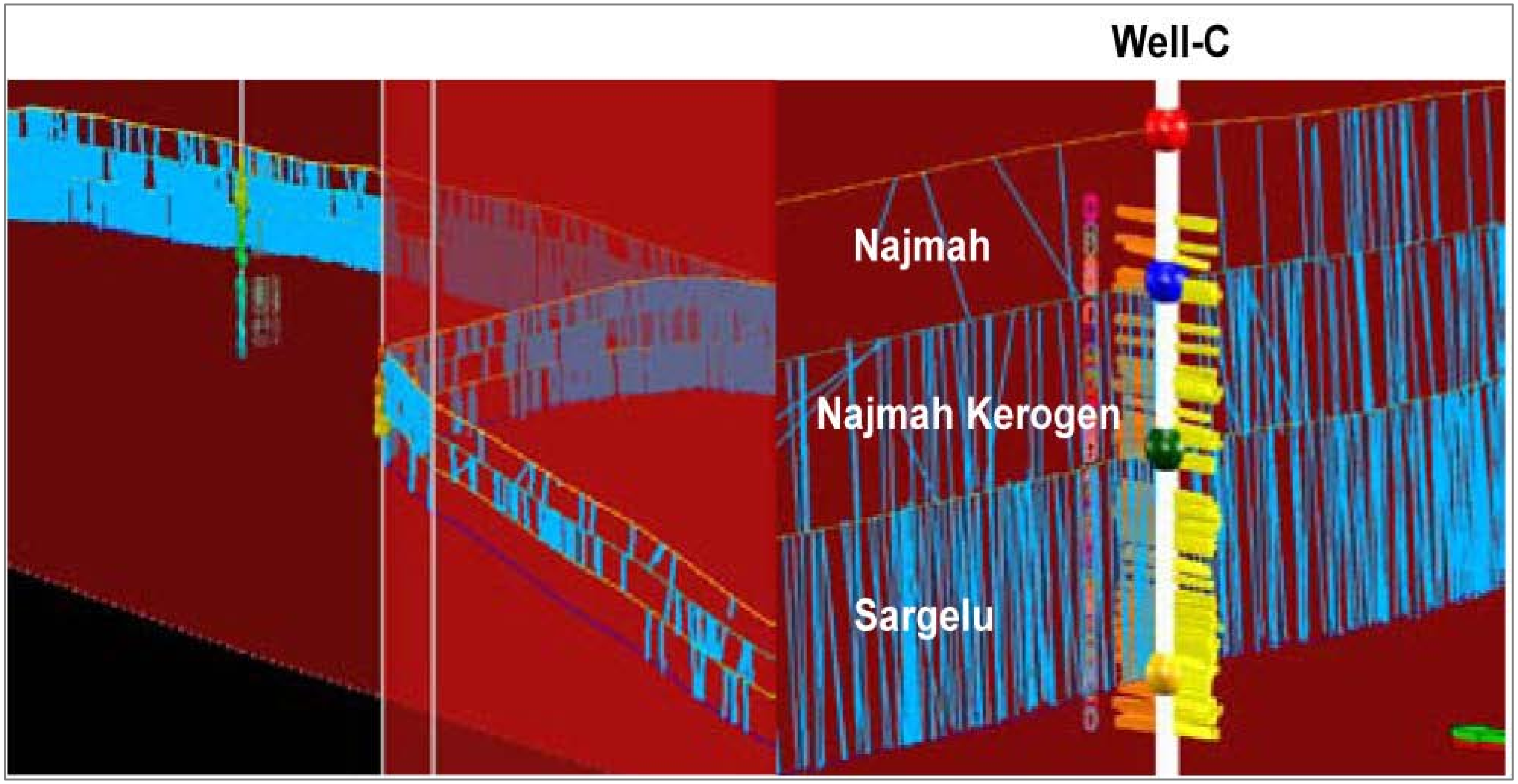

Figure 10. Section of modeled fracture and original fracture at Well-C, which validated the model.

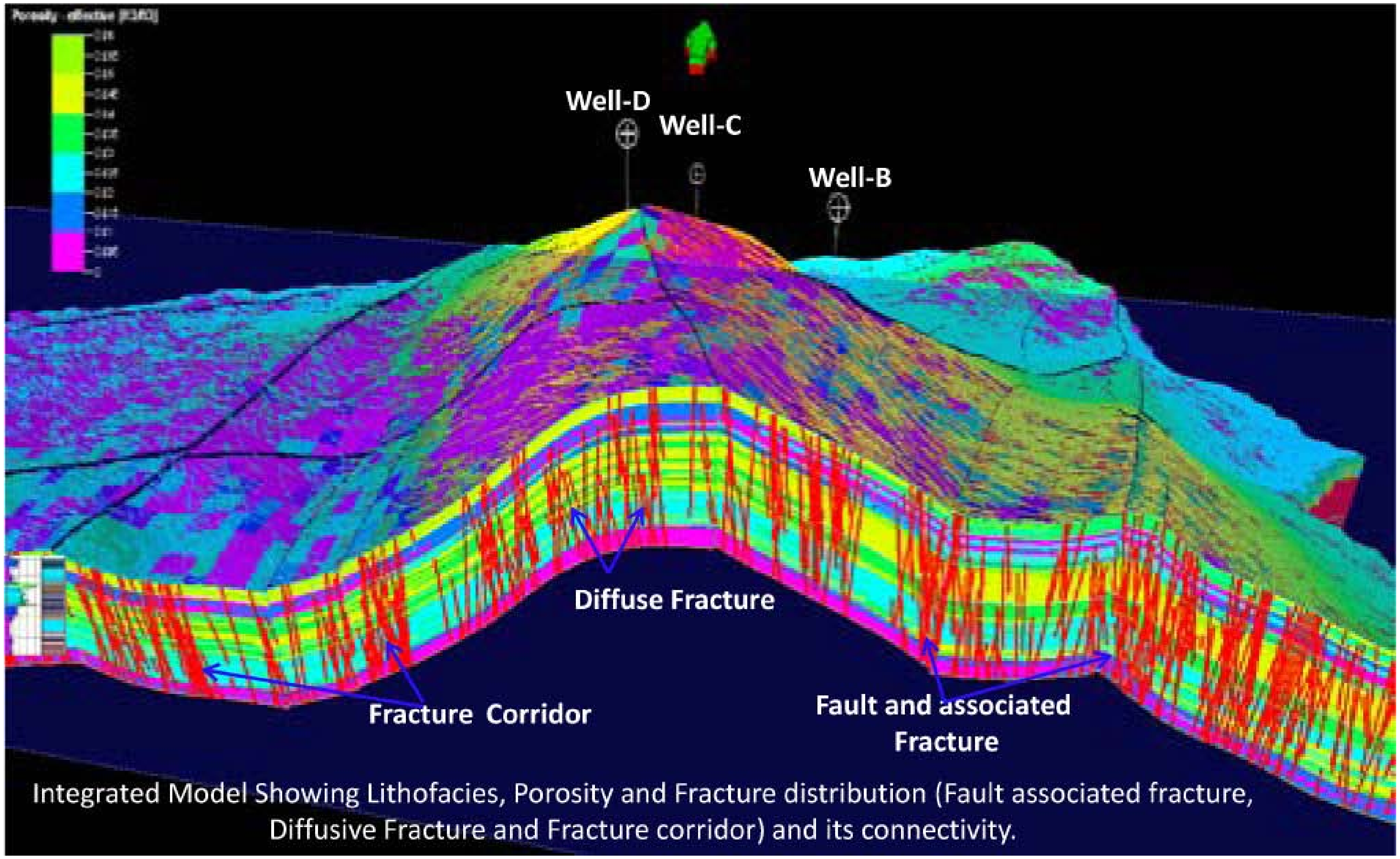

Figure 11. Integrated model of property and fracture.