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Unconventional Shale-gas plays and their characterization through 3-D seismic attributes and logs

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Summary

Unconventional shale-gas plays are formed by fine-grained organic-rich shales of tight-porosity and ultralow permeability which act as the source, seal, and the reservoir rock. The shale-as-reservoir has its beginnings in 1820 but commercial shale-gas wells were drilled in 1990s in Mississippian Barnett Shale of USA by Mitchell Energy after prolonged (about 17 years) experimentations and advancements in drilling and stimulation. In North America, shale-gas plays (e.g., Barnett Shale, Eagle Ford Shale, Haynesville Shale, Marcellus Shale etc.) are producing commercially and these are becoming global, now. In India, too, gas from Barren Measure Shale of Damodar Basin has been struck in January 2011.

Development of shale-gas plays has many challenges from discovery to production. As shales are traditionally considered source and seal, their characterization from reservoir point of view is not well developed. Seismic method has to play great role in all aspects of shale-gas- plays starting from identification of promising shales, describing the reservoir characteristics (net-to-gross, porosity, saturation, fracture, brittleness, etc.), optimising drilling and stimulation and enhancing the production. Fortunately, shales which are good source rocks are also viable reservoirs of hydrocarbon (mainly gas). Total Organic Carbon (TOC) and its maturation affect elastic and petrophysical properties of rocks and thus impact the seismic and log responses. Integrating seismic attributes and logs, source rocks and reservoir properties within shale can be mapped away from the well. Natural fractures can be mapped by advanced seismic attributes like dip and azimuth, curvature, velocity anisotropy and shear-wave birefringence. Microseismic and 4-D surveys are helpful in monitoring stimulation and production.

In this paper we have demonstrated use of log and seismic interpretation techniques for identification of promising shales, estimation and characterization of reservoir properties and mapping of fractures. Knowledge and experience gained from review of published data of North American shale gas plays have been applied on 3-D seismic and log data of producing fields of Indian Basins. Shale- source/reservoir intervals have been identified by log analyses and mapped away from wells by artificial neural network based techniques.

Introduction

In a conventional clastic petroleum system, sandstones form the reservoir rock and shales act as source rock and seal. Since past decade, source-shales have also been proved to be good reservoir, though they have tight-porosity and ultralow-permeability. Thus, shale plays are considered as “self-contained” continuous (large) petroleum systems where source rock is reservoir and seal too. Though recognition of shale-as-reservoir has its beginnings in 1820, but commercial production came in 1990s when Mitchell Energy drilled commercial gas wells in the Mississippian Barnett Shale of Fort Worth Basin of Texas, USA, after 17 years of experimentation and development in drilling and stimulation techniques (Bruce Hart, et al., 2011). In North America shale gas is significant contributor, about 17 %, in total oil and gas production. With advancement of technology and relative increase in gas prices, shale-gas play has become global, now. In India, too, shale gas exploration has started recently and ONGC has discovered gas from Barren Measure Shale at a depth of 1700 meter, in the first R&D well RNSG-1, near Durgapur at Icchapur, West Bengal in January 2011. According to an estimate, India's shale gas reserves range between 600 and 2,000 trillion cubic feet (Press Trust of India, 27th January 2011). As per the initial studies, many shale sequences in well explored basins are found to be promising like Assam, Damodar, Cambay, Krishna Godavari and Cauvery basins.

Till date, development of shale-gas plays is mainly confined in North America and available literature for evaluation and characterization of such plays are from USA. Shales have

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very high variability from basin to basin and within basin itself in terms of mineral composition, elastic and petrophysical properties. Critical parameters for development of shale-gas plays cannot be generalized and need prospect-specific evaluation.

Though, characterization of conventional reservoirs (sandstone, carbonates, fractured shales, fractured basement etc.) through seismic methods is well established but characterization of shale-gas reservoirs (thickness, porosity, saturation, fracture, brittleness, etc.) is in the development stage. Shale gas is often produced from organic-rich shales, the source rocks. Since source and reservoirs both are same, mapping of source rocks leads to mapping of the reservoir rock. Traditionally, assessment of source rock is mainly based on estimation of the organic carbon and maturation and done through geochemical and sedimentological methods. The organic carbon of source rock has specific velocity, density and resistivity characteristics which affect log and seismic responses (Zhu Y., et al., 2011). Thus, source-shales and hence shale-gas reservoirs can be characterised through logs and seismic. In this paper, application of integrated seismic interpretation techniques has been demonstrated in shale-gas plays by using 3-D seismic and log data of producing fields of Indian basins.

Challenges and methods in shale-gas plays are:

- Exploration stage: finding depth, thickness and areal extent of promising shales.
  - Structural and stratigraphic interpretation of seismic data
- Assessment of source potential: finding effective source rock.
  - Geochemical, sedimentological, log evaluation and basin modelling methods.
  - The factors which make good source rocks (TOC, maturity etc.) also influence the seismic response and hence can be inferred from seismic attributes
  - If shallower sequences are producing oil and gas, underlying shales (source rock) may have in-situ hydrocarbon saturation
- Locating most prospective intervals (sweet spots) within shales: distinguishing between reservoir and non-reservoir shales.
  - Log evaluation methods
  - Seismic attributes, Impedance, inversion for log property volumes, AVO etc.
- Identifying target zones favourable for drilling and stimulation: mapping natural fractures, stress orientation, geomechanical properties
  - Seismic attributes
  - Wide azimuth and multi-component seismic
- Optimisation of production: activation of fracture network
  - Microseismic imaging
  - 4-D seismic surveys

Unconventional approach is required for development of these unconventional resources. Traditional reservoir properties like thickness, porosity, permeability, saturation etc. and geo-mechanical, geochemical properties like rock strength, stresses, brittleness, total organic content (TOC) and thermal maturity are required to be inferred from interpretation. The most difficult task in a shale play is developing it economically, not discovering it.

Occurrence of gas in shales

Gas producing shales are typically the source rocks that also function as reservoir rock. Shales contain predominantly clay minerals (illite, smectite, chlorite, kaolinite montmoroloniet, etc.) and silt-sized grains of nonclay

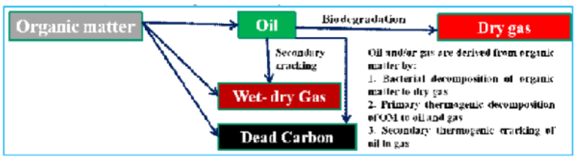

Fig. 1 Schematic showing decomposition of Organic matter in Oil and Gas

Table. 1 Major shale gas plays of North America								
Name of Play Net thick (m)	**Basin**	**Age**	**Depth (m)**	**Source Parameter**		**Reservoir Parameter**		
				TOC (wt%)	RO	Porosity (%)	Permeability (milidarcy)	**Sw (%)**
Barnett Shale 15-30	Fort Worth, Texas, USA	Mississippian	2000-2800	4.5	0.6 -1.6	3-6	.02-0.1	25-40
Hayneville Shale	Northwestern Louisiana	late Jurassic	3200-4100	2.8	2-0-2.8	9	n/a	10-20
Marcellus Shale	Appalachian	Devonian	1500-2500	2-12	1.6	6	.13-.77	20-45

Compiled from: Kathy R. Bruner and Richard Smosna, A Comparative Study of the Mississippian Barnett Shale, Fort Worth Basin, and Devonian Marcellus Shale, Appalachian Basin, US Department of Energy, April 2011, DOE/NETL-2011/1478 and other documents freely available on internet.

minerals (quartz, calcite, felspar etc.). These unconventional reservoirs have very low porosity (pore size nanometer) and ultra-low permeability (micro to nano Darcy range). Shale-gas plays are considered self-contained petroleum systems where gas may be biogenic and thermogenic and may be mixture of both (Fig. 1). Shales which have sufficient total organic content (TOC) may generate hydrocarbon at favourable temperature and pressure conditions. Based on TOC content (wt% of rock) shales are grouped as non-source (<0.5), fare (0.5-1.0), good (1.0-2.0) and excellent (>2.0). The thermal maturity of the organic material is typically determined from vitrinite reflectance (Ro). An Ro of ~0.6% corresponds to the onset of oil generation and an Ro greater than 1.2% is primarily associated with gas generation.

The gas may be stored as free gas in micropores and as adsorbed gas on the internal surfaces. The adsorbed gas is proportional to the organic content of the shale. Free gas is proportional to the effective porosity and gas saturation in the pores. For commercial production from these shales, generally, stimulation is required which is done through extensive hydraulic fracturing. Within a shale gas system key source/reservoir parameters, e.g., thickness, total organic carbon, thermal maturity, fraction of adsorbed gas etc. show wide variations.

In USA, numbers of shale plays are producing gas, e. g., Barnett Shale, Mississippian, Haynesville Shale, Marcellus Shale etc. Important source and reservoir parameter of prominent shale plays are compiled in the Table-1. The average depth of occurrence is normally greater than conventional reservoirs in the respective fields.

Depositional Environment

Deposition of shales occurs, generally, as normal-marine shelf deposit, or in a deep-water slope-to-basin setting. Traditionally, it is thought that shales are deposited in quiet deep marine environment as hemipelagic rain but it may be actually deposited by variety of sediment transport processes (Roger, M, et al., 2011). Shales show grain size variability, cross and parallel laminations and/or fining upward stacking pattern. Deeper sea floor (below storm wave base) and the oxygen-minimum zone with restricted oceanic circulation are favoured for hydrocarbon generation. General sequence stratigraphic principles can be applied for prediction of geomechanical properties of unconventional shales.

Depositional environment of Barnett Shale has been summarized by Bruner et al., 2011. Studies of different authors have revealed that the Barnett shales originated in a deep-water slope-to-basin setting. The lithofacies suggest that the sea floor was below storm wave base. Oceanic circulation was restricted and the water column stratified, accounting for the dysaerobic to anaerobic conditions of deposition. Marine upwelling contributed to blooms of planktonic radiolarians and the production of phosphate grains. Maximum water depth was estimated to have been greater than 180 m. Deposition began during a second-order highstand of sea level, but eustatic sea level fell 45 m by the end of Barnett time.

Mapping shale sequences

Identification and mapping of shale sequences is the first step for the exploration of shale-gas plays. These plays are, generally, found in stratigraphic traps occupying structural lows within the Basin. If shale-gas exploration is in the producing oil and gas fields, basin configuration and source rock characteristics may be available in advance and these may be further used for discovery and development of shale-gas reservoirs.

Log interpretation

In the basins having drilled wells and logs for conventional reservoirs, shale intervals may be identified from combination of GR, SP, DT, NPHI, RHOB and resistivity logs. Shales have high gamma, high neutron porosity, and low resistivity and velocity (Fig. 2). Neutron-porosity and neutron-density separation is normally high. The GR log may be considered as measure of clay content within shale.

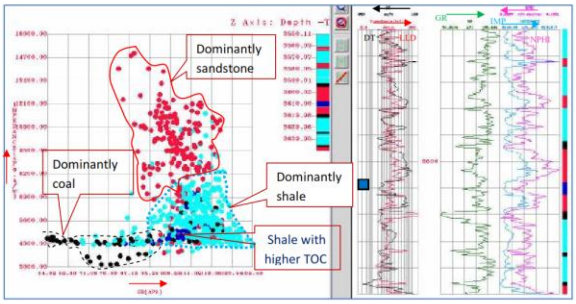

Fig. 2 Cross-plot between Gamma-ray and acoustic impedance showing properties of shaly intervals with respect to coals and sandstones, in a well from Upper Assam Shelf Basin. Points are colour-coded with respect to lithology. Shaly intervals are identified by high gamma and low impedance. Shales with higher TOC are identified from sonic-resistivity overlay.

Seismic interpretation

Promising shale sequences can be mapped through integrated seismic interpretation. Two representative seismic sections with overlay of gamma-ray and resistivity logs from different areas of Mumbai Offshore Basin are given in Fig. 3a and 3b. The left section (Fig 3a) represents relatively thick shales with embedded thin coal, limestone, silt layers and the right section (Fig 3b) represents thin shales interbedded with coal, limestone and sandstone. Both wells have produced hydrocarbon from shallower sequences. In Fig. 3a a thick section of about 350 ms is enclosed within mixed lithologic layers of basement-to-basal-clastics at bottom and limestone-to-coal-shale at top. At top and bottom high amplitudes and within shaly sequence predominantly low amplitudes are seen. In Fig 3b predominantly high amplitudes are seen due to thin bed intercalations. Subtle features are hidden in these sections and need advanced methods, e.g., 3-D seismic attributes, impedance inversion etc. Internal layering within shale section can be inferred from phase and frequency attributes (Fig. 4a and 4b). Thin coal beds, limestone streaks and subtle discontinuities are inferred from reflection strength attribute (Fig. 5a). Acoustic impedance (Fig. 5b) shows

that low impedance shale layers are intercalated with other high impedance limestone and lowest impedance coal layers.

Distinguishing between reservoir and non-reservoir shales

Shale-reservoir intervals can be distinguished from non-reservoir rock by mapping of TOC, water saturation and porosity (Amie M. L. et al., 2011). TOC is mainly used to assess the quality of source rocks, but it may also be used to evaluate unconventional shale reservoirs (shales that are both source and reservoir). Studies on North American shales-gas plays (e.g., Barnett, Woodford, Haynesville, etc.) have shown interrelationships between organic-richness and physical properties (velocity, density, resistivity, radioactivity, etc. (Passey et al., 1990, Thomas Brown,

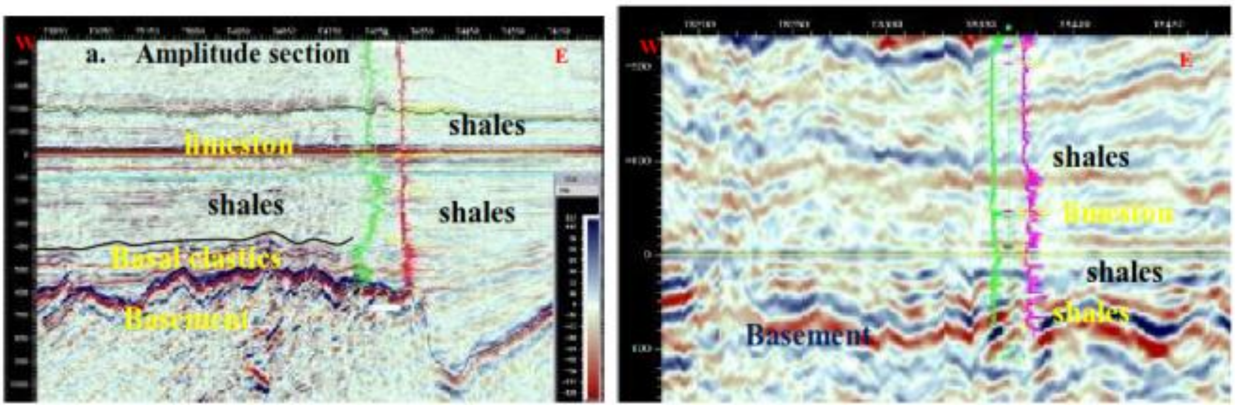

Fig. 3 Seismic sections showing signature of shale layers. a. Thick shales with thin coal, limestone, silt etc. b. Thin shales interbedded with coal, limestone, sandstone etc. Both sections are flattened at upper sequence boundary (Lower Eocene)

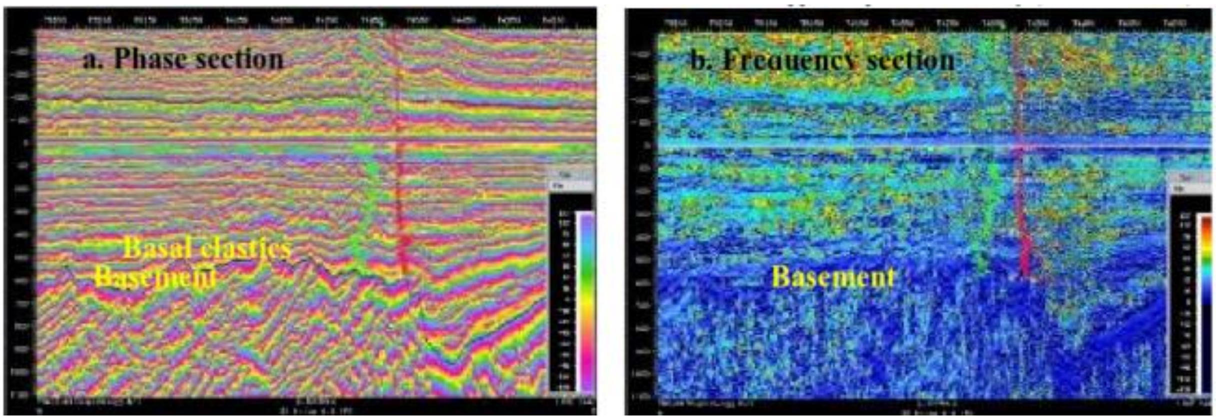

Fig. 4 Phase and frequency sections showing internal layering within shaly section. a. Phase section. b. Frequency section.

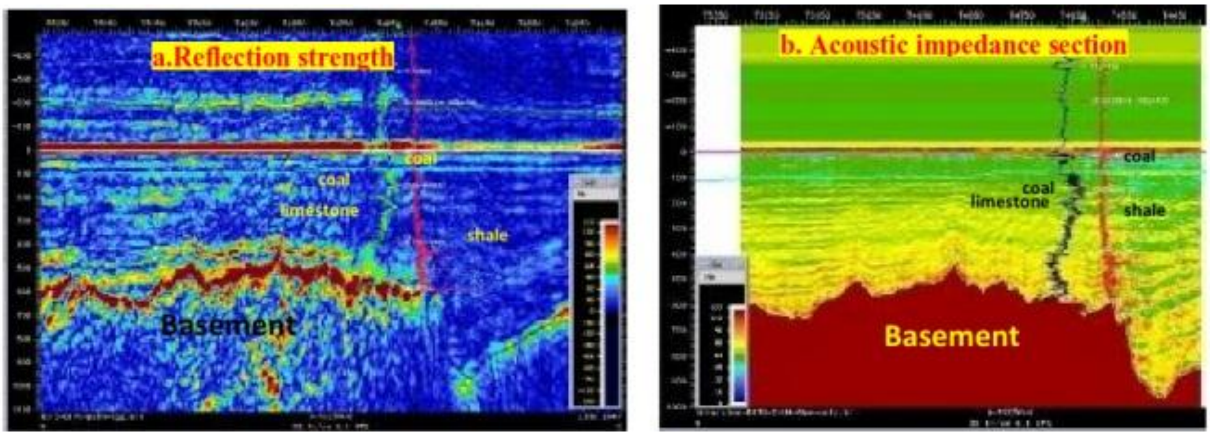

Fig. 5 Reflections strength and impedance sections showing signature of shale layers. a. amplitude section. b. Impedance section. Intercalated shale layers can be mapped by impedance.

2010, Vernik and Milovac, 2011). Depending on these interrelationships, shale-gas reservoirs can be distinguished from non-reservoir shales using log and seismic data interpretation. Demonstrations leading to identification and mapping of shale-gas reservoirs using log and seismic data of Indian basins are presented in following sections:

Shale reservoirs from logs

Characterization of shale reservoirs using log data is based on the concept that the TOC-rich zones which are organic-rich shales may also hold good reservoirs. Organic carbon has very low density and velocity. P-wave velocity and TOC content have inverse relationship. Higher the clay contents lower the velocity (Amie M. et al, 2011). Neutron-porosity log which measures hydrogen index shows higher porosity in clay-rich organic shales because of bonded water. Neutron-porosity increases with clay-content. Hydrocarbon saturation in shales causes increase in resistivity. Thus, higher resistivity with some apparent porosity is a good indicator of organic carbon content. Depending upon these characteristics, TOC can be estimated by conventional porosity-resistivity overlay as demonstrated for Barnett Shale (Passey et al., 1990, Thomas Brown, 2010). Interpretation of TOC-rich zones (good shale reservoir) through overlay techniques for an interval consisting of clastics (coal, shale, sand and silt) and carbonates in a well of Western Offshore Basin is shown in Fig. 6. In this well, geochemical and sedimentological evaluations of the interval have shown presence of effective source rock with average TOC 10.78 and excellent generation potential average S2 13.6 mg HC/g rock. The source sediments are thermally mature and are predominantly gas prone (Vushim et al., 2008).

The sonic log is aligned on top of the logarithmic scale resistivity log so that the sonic curve lies on top of the resistivity curve in the low resistivity shales. Low resistivity shales are considered to be non-source rocks and are unlikely to be gas-shales. Shales or silts with source rock potential show considerable crossover between the sonic and resistivity curves. Three TOC-rich zones are interpreted by visual inspection of cross-over, gamma-ray (very high), density (very low) and neutron porosity (very high) logs.

The cross-plot between gamma-ray log and computed impedance for the interval is also shown in Fig. 6. Source-shales have lower impedance than non-source shales, sand/silt and limestone. Coals which are overlapping in impedance with source-shale are separated by very low gamma and high resistivity.

The log properties of interpreted shale-reservoir, non-reservoir shale and coals are given in Table 2. In this example source-shale/reservoir are associated with coals. The TOC-rich shale-reservoirs show relatively higher DT (430 µs/m) than non-reservoir shales (290 µs/m). The coal is very close to shale-source rocks in sonic, density and neutron-porosity logs. However, coals are distinguished by relatively higher resistivity and lower gamma-ray.

Shale reservoirs from seismic attributes

From log signatures it is evident that TOC-rich shales, which also form good reservoir, have low impedance and are often enclosed within high impedance non-reservoir shales. Shale reservoirs may be defined by having higher net/gross, where net is defined as having higher porosity, higher TOC (2 to 3 times more) and lower water saturation. A typical shale gas reservoir may have effective porosity >5 %, TOC > 2% and Sw < 70 % (Amie M. L. et al., 2011). These properties along with lithologic variation affect the seismic response. Variation in seismic response is manifested into derived seismic attributes.

Therefore, seismic attributes integrated with well logs may help in differentiation between reservoir and non-reservoir shales and extending them beyond the wells. Multi-attribute log property prediction methods may be used for generating different log property volumes e.g., impedance, velocity, porosity, resistivity etc. and integrating all, sweet spots (gas- rich zones) can be mapped. Multi-attribute log property prediction for sonic (DT) log using Probabilistic Neural Network (PNN) is shown in Fig. 7. Standard quality checks were followed during, calibration, network training and estimation. Correlation coefficient between actual and predicated DT is very good (94%) (Fig. 7a). A section from estimated DT volume (Fig. 7b) shows medium DT values (320-440 µs/ft) for TOC rich shales (blue arrows) associated with high DT coals (black arrows). The estimated DT map (Fig. 7c) within 10 ms window with respect to top reflector shows spatial distribution of TOC-rich shaly facies. Other log property volumes (impedance, resistivity, density, and neutron-porosity) were also computed (not shown in this paper) and they corroborated very well with DT prediction.

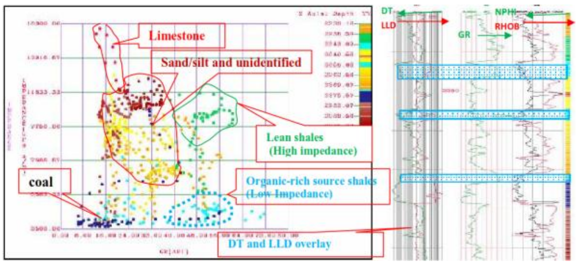

Fig. 6 Cross-plot between impedance and gamma-ray log for an interval consisting of source rock, shale, coal, sand/silt and carbonate in a well from Western Offshore Basin. Source intervals are identified by high gamma and neutron porosity, relatively high resistivity, and very low velocity and density.

Mapping natural fractures

Mapping of intensity and orientation of natural fractures is essential for well planing and stimulation by hydraulic fracturing. Wells are drilled normal to expected propagation direction of the hydraulically induced fractures to maximize the stimulation and production. Induced fractures often follow the natural fractures. Intensity and orientations of natural fractures can be estimated through 3-D seismic attributes computed from P-wave or multi-component seismic data. Seismic attributes, AVO and impedance can be integrated to find rock physical parameters, e.g., Young's Modulus, Poisson ratio, Rigidity and P-impedance. Stresses can be estimated from anisotropic analysis of long-offset wide azimuth and or from multi-component seismic. Fracture mapping through various 3-D seismic attributes is demonstrated in Fig. 8. As illustrated,

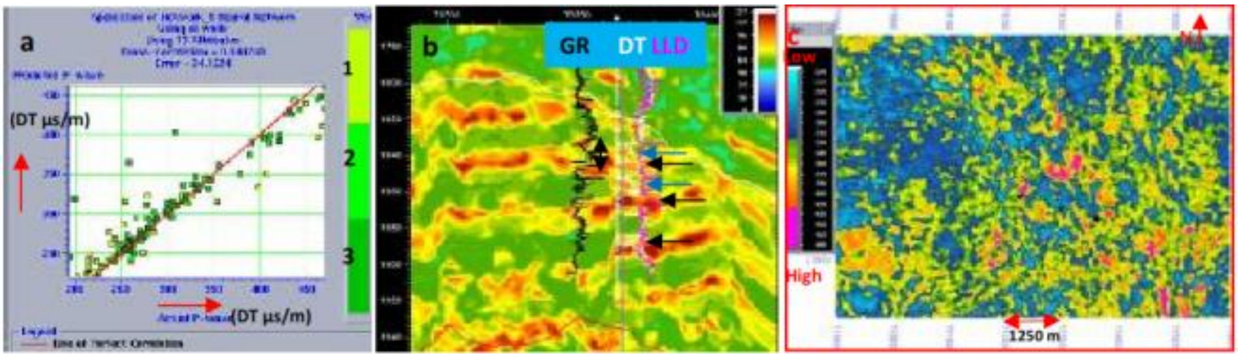

Fig. 7 Mapping of TOC-rich areas and shale-reservoir by predicting sonic (DT) volume using Probabilistic Neural Network (PNN). (a) Cross plot between actual DT and predicted DT in wells (1, 2, and 3). (b) DT section with overlay of gamma-ray (GR), sonic (DT), and resistivity (LLD) logs. (c) Map generated from estimated sonic volume within 10 ms interval showing TOC-rich zones. The colour bar shows three zones based on DT: Low DT (high velocity, blue colour) non-reservoir shales, Medium DT (medium velocity, green-yellow-red) shale reservoirs, high DT (low velocity, pink colour) coals.

Table 2. Log properties of reservoir and non-reservoir shales and coals (Computed from log data of Fig. 6)

Interval (m)	Rock type	Sonic (μs/m)	Velocity (m/s)	Resistivity (ohm-m)	Density (g/cm^3)	Neutron-porosity (%)	Gamma-ray (API)	Impedance (m/s*g/cm^3)
2243-46	Reservoir shale	430	2325	207	1.95	52	51	4520
2235-42	Non-reservoir	290	3450	15	2.6	43	50	8980
2273-78	coal	460	2150	610	1.8	56	13	3850

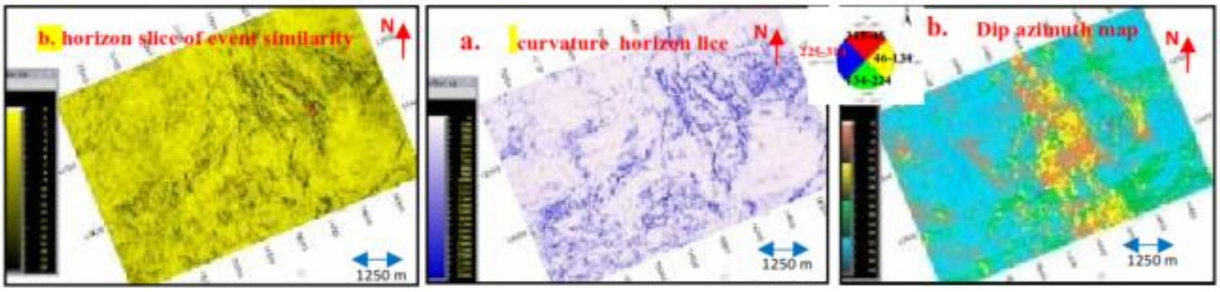

Fig. 8 Fault and fracture mapping from different seismic attributes. (a) Event similarity horizon slice along a prominent shale marker. Faults and fractures are represented by black features. (b) Curvature horizon slice extracted from curvature volume. (c) Dip azimuth map along a horizon within shale. Intensity of faults and fractures and their dip and orientation can be seen

intensity and orientations of faults and fractures within shale-reservoir can be mapped through event similarity, curvature and dip-azimuth attributes. Dip-azimuth map can be interpreted with colour index given in the figure.

Conclusions

Shale-gas reservoirs are fine grained organic-rich shales of tight-porosity and ultralow-permeability having enough gas saturation which can be produced commercially by advance drilling and stimulation techniques. In North America many shale-gas plays has been discovered and developed in past decade. Shale-gas play discovery and development need mapping of structural model, thickness, source potential (TOC and maturity), natural fractures, and geomechanical properties of rocks. Identification of gross-shale intervals and their structural mapping can be accomplished through integrated seismic interpretation. Identification of shales as reservoir is mainly based upon the concept that shales which are good in source potential may also hold good reservoir potential. Reservoir/source properties are manifested in log/seismic responses hence they are mapped by seismic guided multi-attribute log property prediction methods. Seismic attributes (dip azimuth, curvature etc.) help in mapping of natural fractures in shales which are critical for well planing and stimulation by hydraulic fracturing.

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