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EVALUATION OF HYDRAULIC FRACTURING POTENTIALS OF ORGANIC-RICH SHALES FROM THE ANAMBRA BASIN USING ROCK MECHANICAL PROPERTIES FROM WIRELINE LOGS

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ABSTRACT

This study was carried out to determine the rock mechanical properties relevant for hydrocarbon exploration and production by hydraulic fracturing of organic rich shale formations in Anambra basin. Shale samples and wireline logs were analysed to determine the petrophysical, elastic, strength and in-situ properties necessary for the design of a hydraulic fracturing programme for the exploitation of the shales. The results obtained indicated shale failure in shear and barreling under triaxial test conditions. The average effective porosity of 0.06 and permeability of the order of 10^{-1} to 10^{1} millidarcies showed the imperative for induced fracturing to assure fluid flow. Average Young's modulus and Poisson's ratio of about 2.06 and 0.20 respectively imply that the rocks are favourable for the formation and propagation of fractures during hydraulic fracking. The minimum horizontal stress, which determines the direction of formation and growth of artificially induced hydraulic fractures varies from well-to-well, averaging between 6802.62 to 32790.58 psi. The order of variation of the in-situ stresses is maximum horizontal stress>vertical stress>minimum horizontal stress which implies a reverse fault fracture regime. The study predicts that the sweet spots for the exploration and development of the shale-gas are those sections of the shale formations that exhibit high Young's modulus, low Poisson's ratio, and high brittleness. The in-situ stresses required for artificially induced fractures which provide pore space for shale gas accumulation and expulsion are adequate. The shales possess suitable mechanical properties to fracture during hydraulic fracturing. Application of these results will enhance the potentials of the onshore Anambra basin as a reliable component in increasing Nigeria's gas reserves, for the improvement of the nation's economy and energy security.

Key Words: Hydraulic Fracturing, Organic-rich Shales, Rock Mechanical Properties, Petrophysical Properties, Anambra Basin

INTRODUCTION

Unconventional hydrocarbons are oil and gas stored within shale formations with low to ultra- low permeability that can produce hydrocarbons only when fractured naturally or artificially. The interest in shales as a target for hydrocarbon exploration has attracted worldwide attention, with the quest to harness the hydrocarbons from the shale-gas reservoirs using hydraulic fracturing technology.

Shales constitute the largest chunk of sedimentary rocks on earth. Traditionally, they have been proven to be source rocks, and are sealing and trapping mechanisms in conventional hydrocarbon resources where sand or carbonates serve as reservoirs. Over the years, there has been a paradigm shift where the shales themselves have been determined to act as both sources and reservoirs of hydrocarbons where they possess the right geochemical parameters. These types of shale formations in many countries including Algeria, Australia, China, Canada, Egypt and the United States have been evaluated and are producing commercially from the tightly bound hydrocarbons within them. In North America, especially the United States, unconventional resources provide a significant amount of oil and gas such that in 2007, they contributed almost half of the natural gas production (USGS, 2006; Natural Gas Annual, 2009). These resources are thought to be almost 60% of the total proven reserves of the United States, and they have been described (Altun *et al.*, 2006; Jarvie *et al*., 2007; Loucks *et al*., 2009; Knauss *et al*., 2010; Sondergold *et al.*, 2010; Bartis *et al*., 2005 & 2011). In countries where they occur, their discoveries have enhanced the petroleum reserve base, sustainability and energy security. The main drivers of these achievements are availability of valuable geological information and the development of advanced technology to harness them.

According to the Nigerian National Petroleum Corporation (NNPC), Nigeria has around 202 trillion cubic feet (tcf) of proven gas reserves plus about 600 tcf unproven gas reserves in the contiguous but younger Tertiary Niger Delta basin (Shell, 2020). This quantity excludes gas in the interior sedimentary basins including the Anambra basin. Despite having the largest gas reserves in Africa, only about 25% of those reserves that occur in the Niger Delta basin are being produced or are under developed today.

In the South Eastern Nigeria, the occurrence of hydrocarbon rich shales in the Anambra basin was brought to attention by the works of Avbobo & Ayoola (1980) & Ekweozor & Unomah (1990). Ekweozor (2003) documented data in terms of organic matter types and quality of the candidate geologic units for shale-gas development and exploitation. More detailed work by Ekweozor (2005) screened for source rock properties, a number of surface and subsurface shales from the Anambra basin and found out that the Nkporo/Enugu and Ezeaku Shale Formations in the basin, which are geochemically similar, contain Total Organic Carbon (TOC) with highest values at 1-4 wt. % and 1-3 wt. % respectively which are above the accepted values of >1.5 % for prospective shales. The maximum S2 (hydrocarbon generation) temperature (Tmax) is in the range of 427 ^{0}C to 680 ^{0}C with thermal maturity of 1.0-1.3%Ro, which implied that they have reached the gas generation window and can generate thermogenic gas. In addition, the presence of gas-shows, at minimum and maximum depths of 1000 meters and 3500-4500 meters respectively indicates required depth for gas generation (Laura, 2015), which could serve as good prospects for shale-gas exploration (Oluwajana & Ehinola, 2018; Akande & Erdtmann, 1998; Rokosh *et al.,* 2009; Nwajide, 2013; Ekweozor & Okoye, 1980). Further studies on regional scale carried out by Ehinola & Abimbola (2002), Ehinola *et al.* (2005 &2010), Unomah & Ekweozor

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(1993) and Obaje *et al.* (1999) confirmed the occurrence of organically rich shales suitable for unconventional exploitation.

However, there is limited reported information on the mechanical properties which constitute a prerequisite to their fracking potentials for effective and economic recovery of gas from these unconventional reservoirs. Knowledge of these mechanical properties determines the success of campaigns to produce fracture networks and enhance production rates in these otherwise nearly impermeable rocks.

Geological Characteristics of the Shales in the Anambra Basin

The basin, which lies in the Lower Benue Trough in the southeastern Nigeria, is one of the six inland sedimentary basins in the country. It is about 40,000 km^2 in size (Ogala, 2011), with an estimated basin fill in the range of 5000-7000 meters. It is composed of both continental and marine sediments of the Cretaceous and Tertiary ages. It is bounded in the south by the Niger Delta basin, to the west by the western Precambrian Basement complex and to the east by the Abakaliki Anticlinorium. The basin lies between longitudes 6.30°E and 8.00°E, and latitudes 5.00°N and 8.00°N.

The origin of the Anambra basin has been discussed in detail by Nwajide (2014). It is linked to the RRR triple junction that resulted from the separation of the African and South American plates during the Jurassic period. During the Santonian time, a major tectonic episode occurred which led to the folding and uplift of the sediments. The Anambra basin has a simple structural configuration which is a broad syncline that plunges gently south of southwest to beneath the Niger Delta.

The accumulation of sediments in the basin was controlled by three mega-tectonic cycles during the Albian, Santonian, and the Late Eocene or Early Oligocene epochs. The tectonism gave rise to these three successive basins, namely the Abakaliki - Benue Trough, Anambra, and Niger Delta basins (Murat, 1972). The filling of the Anambra basin occurred from the Santonian to Paleocene during two marine transgressions; the Nkporo and Nsukka transgressions. They were folded and faulted during the Santonian tectonic episode associated with magmatism, which resulted in the formation of anticlines and synclines. Four major outcropping lithostratigraphic units that were formed post-Santonian characterize the Anambra basin. These are the basal Nkporo Group, the Mamu, Ajali and Nsukka Formations which lie on the pre-Santonian successions (Asu-River Group, Eze-Aku Shale and Awgu Shale). The Nkporo Group consists of Enugu/ Nkporo Shale and Owelli Sandstone, which is marked as the first sediment in the Anambra basin (Nwajide & Reijers, 1996). It is a highly fissile dark grey to black soft shales of marine origin composed of carbonaceous shales, sandstone, with interbeds of sandy shale, siltstone, marl, mudstone and coatings of sulphur. Its thickness ranged between 300-600 meters at some intervals and an estimated thickness of 1000meters in the sub-surface (Agagu & Murat, 1972; Ekweozor, 1982 & Agagu *et al.*, 1985). The Mamu Formation conformably overlies the Nkporo Shale. It comprises varying facies and sediment thickness (Reyment, 1965; Ladipo, 1988) typically with lithotypes consisting of shale, sandy shale, coal, carbonaceous shale and sandstone.

Geochemical Characteristics of the Shales

Previous work on the evaluation of hydrocarbon potentials of the Anambra basin through outcrop investigation and geochemical studies have shown the existence of reservoir and source rocks within the Nkporo, Mamu and Ajali Formations (Ekweozor, 1982; Ekweozor & Gormaly, 1983; Unomah & Ekweozor, 1993; Obaje *et al.*, 2004; Onuoha, 2005).

The shales of the Eze-Aku, Awgu, Nkporo and Mamu Formations are viable source rocks with fair to good organic richness, hydrogen index, kerogen type and maturity as summarized in Table 1. Ekweozor (2005) was of the view that large volumes of hydrocarbons were generated before the Santonian uplift by the Awgu and Eze-Aku Shales. These geochemical indices are comparable to the properties of producing gas shales from basins in the United States (Table 2).

Table 1: Indicators of Potentials of the Organic rich Shales in the Anambra Basin

Shale Formations	Total Organic Carbon (wt. %)	Vitrinite Reflectance (%R_0)	Maximum S2 Temp. (Tmax)
Asu River Group	0.93 – 8.4	2.46 – 4.53	
Eze-Aku Shale	0.5 – 7.4	0.71 – 0.93	424 - 448°C
Awgu Shale	0.83 – 6.54	0.81 – 1.13	434 - 467°C
Nkporo Shale	0.54 – 3.4	0.6 – 4.2	420 - 443°C

Source: Petters & Ekweozor, 1982; Petters 1983, Ekweozor & Unomah, 1990; Akande *et al.*, 2012; Ehinola *et al.*, 2005; Obaje *et al.*, 2004, Akaegbobi et al., 2009; Adeigbe & Salufu, 2010

Table 2: Geochemical Properties of Shales from Basins in the U.S.A (Hills and Nelson, 2000) compared to Shales in the Anambra Basin

Basins	**Shale formations**	**Total Organic Carbon**	**Thermal Maturity**	**Depositional Environment**	**Age**
Appalachian	Ohio	0 – 4.5	0.4 – 1.3	Marine	Devonian
Michigan	Antrim	1 - 20	0.4 – 0.6	Marine	Devonian
Illinois	New Albany	1 - 25	0.4 – 10	Marine	Devonian
Forth Worth	Barnett	1 – 6.5	0.8 – 1.4	Marine	
Santus	Lewis	0.45 – 2.5	1.6 – 1.88	Marine	
Anambra	Asu River	0.88 – 9.3	2.46 – 4.53	Marine	Albian
Anambra	Eze-Aku	0.5 – 7.4	0.71 – 0.93	Marine	Turonian
Anambra	Awgu	0.83 – 6.54	0.81 – 1.13	Marine	Coniacian
Anambra	Nkporo	0.54 – 3.4	0.6 – 4.2	Marine	Campanian

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METHOD OF STUDY

Based on the extensively reported results of works on the hydrocarbon potentials of shales in the Anambra basin, which include studies of the lithostratigraphy and depositional environments (Reijers, 1996; Nwajide 2005, 2013) and organic facies and source rock characteristics (Ekweozor & Okoye,1980; Ekweozor & Unomah, 1990; Akande *et al.*, 2012; Ekweozor 2005; Akaegbobi *et al.*, 2009; Ehinola *et al.*, 2005; Obaje *et al.*, 2004; Adeigbe & Salufu, 2010, Oluwajana & Ehinola 2016, 2018, 2020), wireline logs were obtained from exploratory wells drilled in the basin between 1952 and 1974. According to Avbobo & Ayoola (1980), none of the wells went beyond the Lower Turonian. Five of the wells encountered gas while one encountered oil. The basin is mainly gas condensate. Wireline logs for seven of the exploratory wells were obtained from Total Producing Nigeria through the Department of Petroleum Resources, DPR.

Schlumberger Petrel software was specifically used for data integration and interpretation. Available data were quality checked through excel data editor. They were then converted to TXT 'Tab delimited' file format for the evaluation of the petrophysical and rock mechanical properties. These properties were mathematically calculated from the digital wireline logs, which included sonic compressional (VP) and shear wave velocities (VS) and density logs) as described by Eaton (1969), Wen (1998), Engelder (1993), Greenberg and Castagna (1994), Crain (1999), Coates & Denoo (1981), Lal (1999), Guo & Liu (2014), Ranjbar-Karami *et al.* (2014), Labani & Rezaee, (2015), Zoback (2010), and Zoback & Kholi (2019). These are standard methods that have been developed and extensively used by various authors. Their details can be found in any standard textbook on rock mechanics. These logs were used to derive the static geomechanical parameters for the simulation of hydraulic fracturing of the shales. The quality of information on the logs is summarized in Table 3. Despite the data gaps in the logs, care was taken to derive useful parameters from them as a basis for further scrutiny of details.
Using these empirical methods, the shale rock properties derived were grouped into four types

i. Petrophysical properties, mainly porosity and permeability
ii. Elastic properties, mainly bulk, shear and Young's moduli, and Poisson's ratio
iii. Strength of the shales
iv. In-situ stresses (vertical, maximum horizontal and minimum horizontal stresses).

Table 3: Wells and the quality of information on the logs

Well Id	Al-2	AN-1	PG-2	MK	NH	YB	ZD-1
Well Type	Exploratory	Exploratory	Exploratory	Exploratory	Exploratory	Exploratory	Exploratory
Top (m)	272	479	548	32	215	385	156
Bottom (m)	8693	2370	1732	2521	2700	2517	2252
Well head	✓	✓	✓	✓	✓	✓	✓
Coordinates	✓	✓	✓	✓	✓	✓	✓

Deviations	x	x	x	x	x	x	x
Checkshots	x	x	x	x	x	x	x
Caliper	x	✓	✓	✓	x	✓	✓
Gamma Ray	✓	✓	✓	✓	✓	✓	✓
Density	x	x	✓	✓	✓	✓	x
Sonic	x	✓	✓	✓	✓	✓	✓
Neutron	✓	✓	✓	✓	x	x	x
Resistivity	✓	✓	✓	✓	✓	✓	✓
Biostrat data	x	x	x	x	x	x	x
Core Photos	x	x	x	x	x	x	x

✓ Means available x means not available

RESULTS AND DISCUSSIONS

Shale Rock Properties from Wireline Logs

In shale-gas formation evaluation, the identification of lithology followed by the evaluation of the petrophysical parameters is paramount to the success of the exercise. Zhang (2015) listed the technical requirements in well log shale-gas evaluation to include:

i. Shale petrophysical parameters calculation model,
ii. Well log response characteristics identification and evaluation method for the sensitive geophysical parameters,
iii. Evaluation method and calculation model for TOC and thermal maturity,
iv. Shale reservoir effectiveness evaluation,
v. Calculation model and evaluation method for the free gas content, absorbed gas content, gas saturation and the total volume of gas,
vi. Calculation model for shale, sand content, clay minerals composition and brittle minerals content (sand, calcite and feldspar, etc.),
vii. Rock mechanics parameters calculation method, and
viii. Quantitative fracture identification and in-situ stress evaluation.

Other than (**v**) above, this work attempted to apply all the parameters except (iii) which were obtained from secondary sources and were reviewed in the preceding sections. The depth of occurrence of the shales fell between 156 and 8693m from the surface. The thicknesses of the units were between 117 and 787m with an average range of 23 to 317. The great thickness of shale units (787m) in well Al-2 could imply that it is probably located in the central portions of the basin. This great thickness distorted the statistical averages so it was not used in the analysis. Only shales occurring at depths of at least 1000 m were used for evaluation in the work because of the requirements for burial temperature/temperature gradient necessary for the formation of thermo-genic gas. The shale sequence was separated by very thin sandy layers.

These depths compared favourably with the depths of six of the shale-gas resources in the United States that account for the production of 88 % of the country's daily

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shale-gas (Table 4). These thicknesses were also similar to results obtained by Onuoha & Dim (2017) who carried out a basin-wide correlation of the Anambra basin using well data. Results of their work revealed that the Nkporo Formation, the oldest formation, consists of sediments of about 300-600m thick, while the overlying Mamu Formation comprise of 600-1200m thick sediments. Overlying these sequences is the Ajali Sandstone, which is between 400-600m thick.

The shales of the Lower Mamu Formation and Enugu Shale constitute the thickest shale play of about 200-860m thick. The productive capacity of the shale-gas depends on two key technologies, horizontal well and hydraulic fracturing stimulation. Thus, to ensure production at commercial rates, the thickness of gas-bearing shale should be significant. The gross vertical thicknesses vary from 23m to 317m across the wells in the study compared to the recommended 30m thickness by Chen *et al*. (2017) except in well ZD-1 where the approximate thickness of the shales is 23m. For stimulation, fracking and study of commercial viability, these thicknesses are suitable.

Table 4: Depth and thicknesses of the shales in the studied wells from the Anambra basin compared with the Shale Gas Formations* in the United States (Janas & Dyraka, undated).

Well	Depth range (m)	Thickness range (m)	Average thickness (m)
Al-2	1505-869	25-787	317
AN-1	497-2370	25-353	112
PG-2	584-1507	32-225	95
MK	408-1798	11-598	192
NH	1046-2700	14-226	65
YB	1071-2517	12-859	153
ZD-1	156-225	44-787	23
*Haynesville Formation	3200-4100	na	80
*Barnett Formation	1980-2600	na	90
*Marcellus Formation	1200-2400	na	45
*Eagle Ford	1200-3050	30-90	70
Woodford Formation	1820-3960		45

Na = not available

Petrophysical Properties: Porosity and Permeability

The average porosity and permeability of the shales are shown in Table 5. The variation of the petrophysical parameters with depth is shown in Fig. 2. The sonic log-derived porosity (sonic effective porosity) ranged from 0.08 to 0.32. Expectedly, porosity decreased with depth due to compaction from the overlying rocks. This will likely generate pore pressure in the shales. Due to the near absence of permeability, unconventional shale-gas reservoirs are normally tight. They can only release their fluid contents under certain physical conditions. According to Zhang *et al.* (2018), the permeability should be greater than 100 mD while porosity should be greater than 2%.

In this study, permeability was variable, but generally, it was of the order of 10^{-2} and 10^{1}mD. These values compared favourably with the results obtained by Igwilloh (2016) from the Nkporo Shale where porosity ranged from 5.0–28.1%, and permeability ranged from 0.0–95.5mD. The variable values may be due to the anisotropic nature of the shales. Although permeability of shales is generally in the nanodarcies range, high permeability values in shales are usually as a result of bedding planes of weakness. Factors which may affect permeability include grain sizes, void spaces and cementation of the sediments. The low void spaces corresponding to the low porosity values in the shales are typical of very tight earth materials, which ordinarily will not release its fluid contents easily unless artificial fractures were created to enhance flow. It is expected that fracking would open up these pore spaces and loosen the horizontal compaction to release the shale gas as a result of increase in the horizontal permeability from the fracking stresses. Theoretically, fractures will develop in a direction perpendicular to the direction of orientation of the minimum horizontal stresses.

Earth materials are three-phase system of solids, voids and fluids. When another fluid phase is added to existing natural fluid, as occurs during fracking, a fourth phase is created which will cause the attenuation or retardation of flow in the material. Shales are practically impermeable despite their high porosity. The high porosity is as a result of the large surface area provided by small grain size of shales (<0.02mm) which creates multiple voids. Generally, porosity increases as the compressive strength decrease. Permeability of shale is very low, mostly in the range of $0.001\text{-}0.1110^{-3}m^2$ (Zang *et al*. 2015). The creation or enhancement of permeability is the major aim of hydraulic fracking. These artificial fractures and cracks often increase substantially the porosity and permeability of shales.

Table 5: Average petrophysical properties of the shales

Well	Thickness* (m)	Shale volume	Sonic Porosity		Total	Sonic Effective Porosity			Permeability (mD)		
			Min.	Max.	Av.	Min.	Max.	Av.	Min.	Max.	Av.
Al-2	253.95	0.36	0.06	0.24	0.16	0.02	0.05	0.03	0.03	9.91	1.96
AN-1	112.8	0.36	0.12	0.24	0.16	0.02	0.09	0.04	0.17	2.81	0.97
PG-2	95.00	0.46	0.12	0.22	0.15	0.03	0.10	0.07	7.1	13.7	2.92
MK	192.00	0.49	0.07	0.20	0.14	0.01	0.08	0.04	0.05	6.77	1.41
NH	65.33	0.48	0.06	0.20	0.14	0.01	0.09	0.05	2.22	10.12	1.42
YB	153.57	0.55	0.11	0.21	0.16	0.02	0.10	0.06	0.04	2.87	0.05
ZD-1	228.38	0.57	0.14	0.26	0.21	0.02	0.13	0.08	0.06	2.43	0.77

*Total thickness of prospective shale layers, Min = minimum, Max. = maximum, Av. = average

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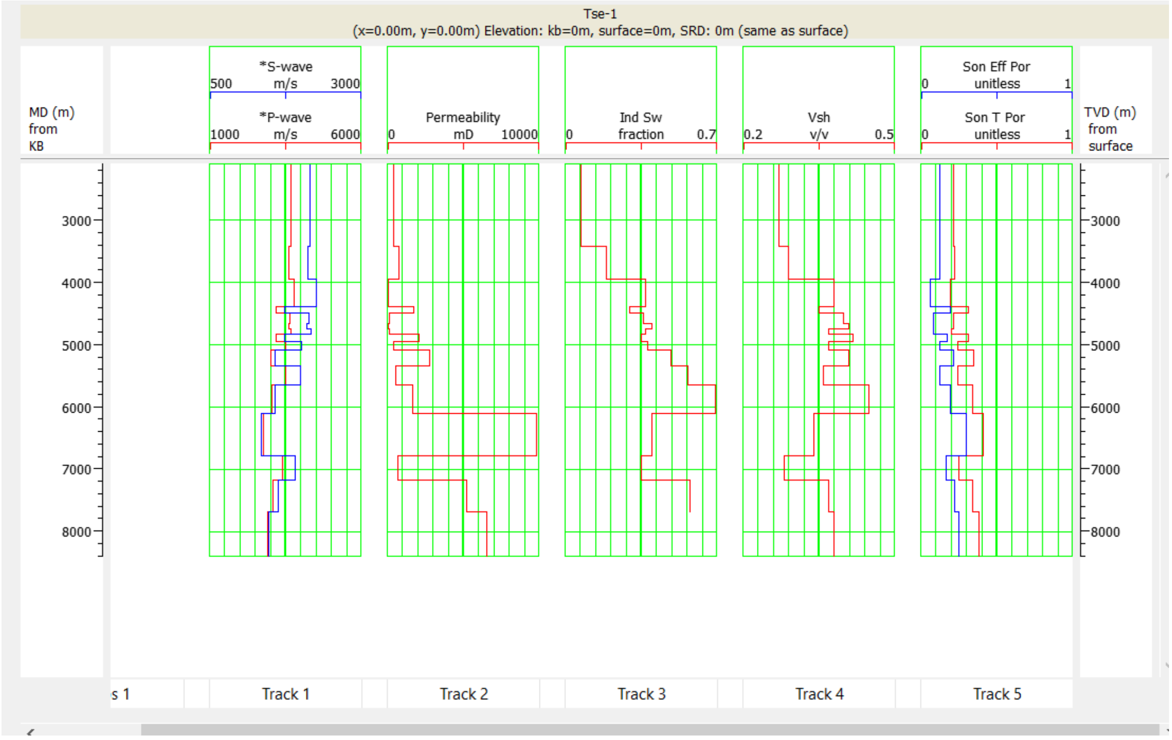

Fig. 2: Log plot showing the variation of some petrophysical properties with depth

Elastic Properties

The properties are summarized in Table 6. Correlations of the elastic properties of the shales across the field show large variations across the wells. The static and dynamic Young's moduli range from 1.42 to 2.66MPsi and 3.16 and 4.40Mpsi respectively. Young's modulus is a measure of the stiffness, or ability of a rock to deform. This is used in the design of the hydraulic fracturing project. A stiff rock implies that the Young's modulus is high. This will result in the formation of more narrow fractures. However, if the modulus is low, the fractures will be wider. In the shales, typical average values ranged from 0.8 to 3.0 x 10^5kgcm^{-3}. These variations illustrate the heterogenic nature of the shales. The wide variation in the values of static and dynamic moduli, especially for soft and less deformable rocks like shales is common due to the presence of micro cracks and pores in them. *In Table 6, the values of the static moduli are significantly lower than the dynamic moduli. Nygaard (2010) obtained a similar trend and explained that the reason for this difference is because rocks experience very different stresses and strains in a tri-axial compressional test when compared to sonic log measurements. It may therefore be concluded that if we rely only on dynamic properties alone to predict the deformation that will occur in the formations when they are subjected to changes in stress, the deformation may be under predicted.*

The Poisson's ratio varied from 0.02 to 0.4 and it falls within the average values of 0.11 to 0.54 typical of shales. Its variation with depth is shown in Fig.3. The ratio is a measure of the relationship between transverse and axial strain of a material. It is controlled by factors such as the lithology and burial depth, and generally increases with depth. The value implied that rocks in the area are soft and porous. The generally implication is that rocks with low Poisson's ratio, (e.g. 0.1 to 0.25) are easier to fracture compared to those rocks with higher ratios between the range of 0.35 to 0.45, which are harder to fracture (Belyadi *et al.* 2019). Majority of the values fall between 0.2 and 0.3 which met the values of producing formations in the US, United Kingdom and China. The overall implication is that the formations in the Anambra basin with lowest Poisson's ratios are the best to fracture hydraulically.

Table 6: The average Elastic Properties per wells in the study area

Well	Compressional Velocity (m/s)	Shear Velocity (m/s)	Dynamic Bulk Modulus (Mpsi)	Static Bulk Modulus (Mpsi)	Dynamic Shear Modulus (Mpsi)	Static Shear Modulus (Mpsi)	Dynamic Young Modulus (Mpsi)	Static Young Modulus (Mpsi)	Dynamic Poisson Ratio	Static Poisson Ratio	Biot Coefficient
Al-2	**3207.93**	**1737.39**	**2.32**	**0.96**	**1.28**	**0.57**	**3.23**	**1.42**	**0.28**	**0.28**	**0.51**
AN-1	**218295.79**	**194281.75**	**4.81**	**3.95**	**4405224.34**	**5.67**	**37.08**	**36.56**	**0.02**	**0.02**	**0.00**
PG-2	**3440.12**	**1934.65**	**3.42**	**1.61**	**1.37**	**0.65**	**3.42**	**1.61**	**0.27**	**0.27**	**0.27**
MK	**3158.38**	**1682.42**	**2.29**	**1.01**	**1.28**	**0.67**	**3.16**	**1.62**	**0.29**	**0.29**	**0.47**
NH	**3500.21**	**1988.44**	**2.46**	**1.11**	**1.45**	**0.70**	**3.61**	**1.73**	**0.26**	**0.26**	**0.27**
YB	**3694.52**	**2162.39**	**2.63**	**1.48**	**1.84**	**1.16**	**4.40**	**2.73**	**0.24**	**0.24**	**0.26**
ZD-1	**3730.74**	**2194.82**	**2.63**	**1.46**	**1.83**	**1.13**	**4.40**	**2.66**	**0.24**	**0.24**	**0.19**

1 psi = 6895 Pa = 6.895 kPa, 1Mpa = 10^6 psi)

The cross plot of sonic effective porosity versus dynamic Poisson's ratio; colour coded with P-wave velocity in Fig. 4 shows, as expected, that lower effective porosities and Poisson's ratios are associated with higher compressional wave velocities. Similarly, on the cross plot of sonic effective porosity versus dynamic Poisson's ratio; colour coded with dynamic Young's modulus (Fig. 5), it can be observed that clusters with low dynamic Poisson's ratio have high young's modulus and vice versa. This shows that the dynamic poisons ratio discriminates well between regions with varying Young's modulus, compared to the effective porosity. In the present study, the correlation between depth and Poisson's ratio (ν) was obtained from Fig. 3 and may be expressed for well YB as:

$\mathbf{y} = 11450x + 3926.4$ with a good fit (r^2 of 0.8)

Generally, these elastic and failure properties are utilized in the design of the hydraulic fracturing programme to produce from unconventional reservoirs.

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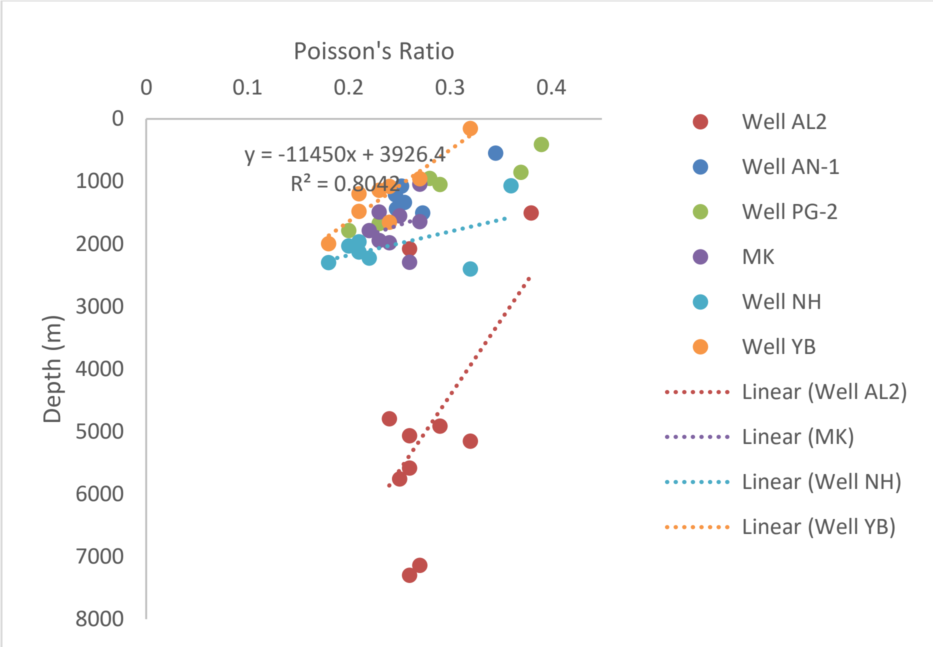

Fig 3: Variation of Poison's Ratio with depth in all wells

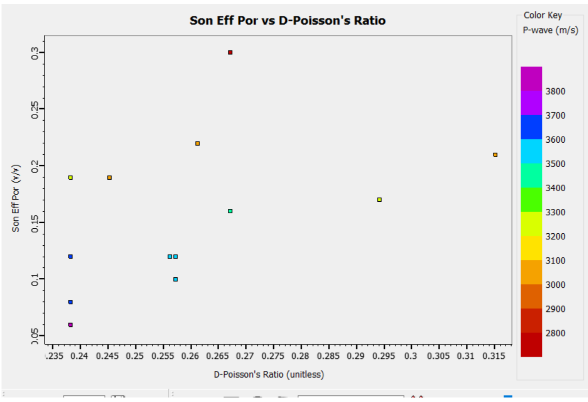

Fig. 4 Cross plot of Porosity vs. Poisson's ratio

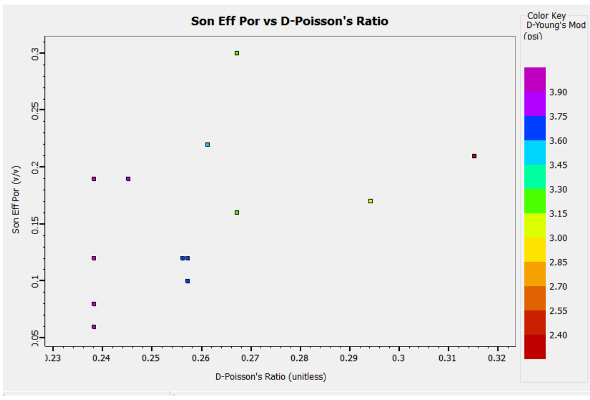

Fig 5 Cross plot of sonic effective porosity vs. dynamic Poisson's ratio

Strength Properties

The strength of rocks elate to their material properties including compressive strength, tensile strength and the Mohr-Coloumb parameters of cohesion and friction (Table 7). Their distribution in the study is shown in Fig 6. The significant scatter of values in the distribution of the unconfined compressive strength (UCS) in the wells is dependent on variables such as lithology, cementation, alteration, texture and others.

The properties of rock strength are widely used for the evaluation of how rocks will behave mechanically. Their general distribution in the study wells show that the average compressive strength falls between 3972.60psi (27.40MPa) and 7156.96psi (49.36MPa). The uniaxial compressive strength, also known as the UCS is the maximum axial compressive stress that a sample of material can withstand before failing. The uniaxial compressive strength is grouped into five categories: 'A' for a very high (above 32,000psi or 46.40MPa) to 'E' for a very low level of strength (below 4,000psi or 6.78MPa). Hoek & Brown (1997) field estimates of rock UCS for medium strong shales fall between 25-50Mpa. The relationship between unconfined compressive strength and tensile strength is shown in Fig. 7. This illustrates that the tensile strength of the shales increases as compressive strength increases. Thus, a larger compressive strength corresponds to a higher tensile strength. As a rule of the thumb, the tensile strength is usually lower than compressive strength. It is usually just about 10% of compressive strength as seen in Table 7.

Table 7: Strength Indicators of the Shales

Well	Thickness (m)	Unconfined Compressive Stress (psi)	Cohesion (psi)	Frictional Angle (Deg)	Tensile Strength (psi)	Brittleness index
Al-2	338.92	3972.60	1155.27	29.57	397.26	10
PG-2	95.67	4748.18	1439.78	28.05	474.82	9.999958
MK	192.50	4453.96	1306.50	28.99	445.40	9.99991
NH	65.33	5021.33	1505.50	28.44	502.13	10.00006
YB	153.57	7156.96	2177.09	27.87	715.70	9.999944
ZD-1	228.375	6957.259	2121.529	27.15375	695.7275	9.999977

1psi = 6895, Pa = 6.895kPa

In-situ Stresses

Rock in-situ stresses that are important to build a geomechanical model for the design of hydraulic fracturing are vertical stress (σV), minimum horizontal stress (S_{hmin}), and maximum horizontal stress (S_{Hmax}) as summarized in Table 8. The cross plot in Fig. 8 clearly show that in the basin, the stresses increase with depth. In the shallow subsurface, the in-situ stresses are compressive and generally increase in magnitude with depth. Breckels & van Eekelen (1982) used fracture data from the Gulf Coast of the United States and proposed very useful relationship between minimum horizontal stress and depth expresses as:

S_{hmin} = 0.0053D1.145 + 0.46 (p - 0.0105D)

If D is less than 3500 m4.6;

S_{hmin} = 0.026D – 31.7 + 0.46 (p – 0.0105D)

If D is more than 3500m

Where D is the depth in meters;

p is the pore pressure in MPa.

S_{hmin} is the minimum horizontal stress in MPa.

Fjær *et al.* (1992) confirmed that the equation can be used with a fair degree of confidence in tectonically relaxed areas like Anambra basin. Designing a successful hydraulic fracturing program also requires the determination of both minimum and maximum horizontal stresses. This is because the manner and directions in which the rock formation is likely to break depend on the values of these stresses. The minimum principal stress (S_{hmin}) direction controls the orientation of a fracture, and determines whether the fracture will be horizontal or vertical. This is because S_{hmin} provides the least resistance against fracture opening. The implication is that if S_{hmin} is horizontal, the fracture will be vertical and if S_{hmin} is vertical, the fracture

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will be horizontal. Generally during fracking, hydraulic fractures will propagate at a direction perpendicular to the direction of S_{hmin}, and tend to grow parallel to the orientation of S_{Hmax}.

Table 8: In-situ Stresses

Well	Vertical Stress (Extrapolation) psi	Vertical Stress (Gardner) psi	Vertical Stress (Miller) psi	Eaton Pore Pressure (psi)	Fracture Pressure (Eaton) psi	Fracture Pressure Gradient (Eaton) ppg	Maximum Horizontal Stress (psi)	Minimum Horizontal Stress (psi)	Differential horizontal stress	Kh factor
Al-2	18907.30	11119.22	16441.22	8172.59	10928.80	12.55	32790.58	10963.61	21826.97	1.99
AN-1	4438.83	6469.45	4859.58	2106.63	3024.28	12.36	10313.79	3034.61	7279.18	2.40
PG-2	3764.84	2068.10	3811.33	1868.02	2515.79	12.01	7325.12	2579.25	4745.87	1.84
MK	3822.93	2572.83	3645.19	2025.88	2565.65	12.58	6802.62	2594.06	4208.56	1.62
NH	6424.73	3195.56	6317.27	3041.87	4133.55	11.99	12320.65	4211.51	8109.14	1.93
YB	6947.40	3752.08	6791.89	3293.82	4349.20	12.24	12160.70	4464.81	7695.89	1.72
ZD-1	4087.77	3418.47	4420.48	2020.35	2821.20	12.47	8644.53	2925.78	5718.75	1.95

1psi = 6895Pa = 6.895kPa, 1Mpa = 10^6psi or Gpa = psi/6.89

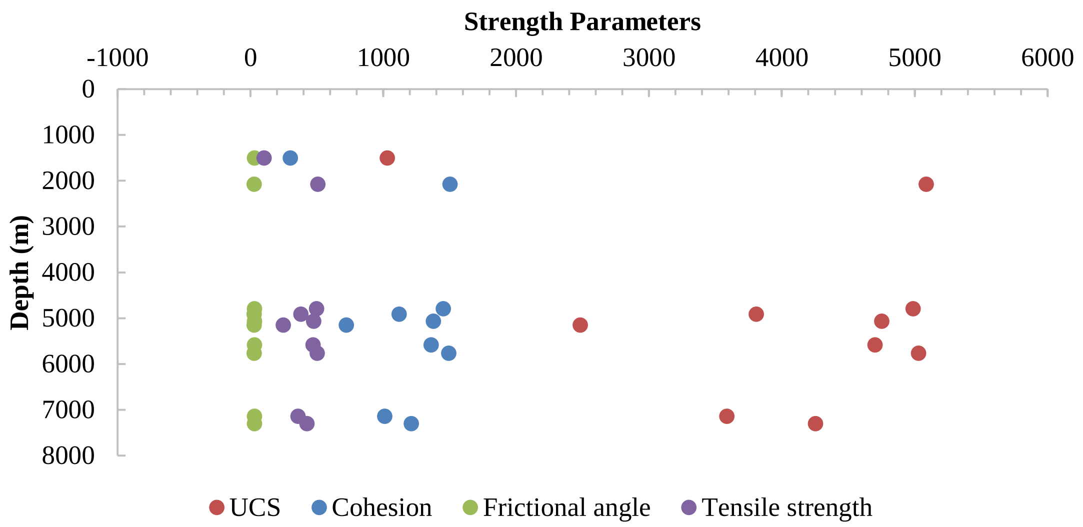

Fig. 6: Distribution of the strength parameters in the wells, what happened between 2000m and 5000m

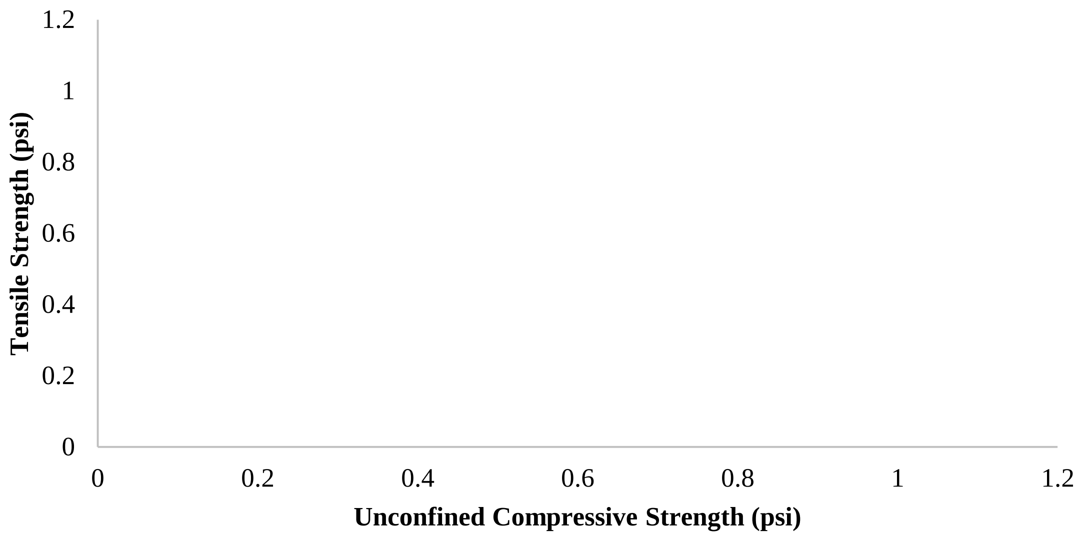

Fig. 7: Relationship between the uniaxial compression strength and tensile strength

The Andersonian faulting theory (Anderson, 1951) defines three fundamental possibilities of stress regimes, called faulting regimes, based on the relative magnitude and orientation of the major principal stresses in the earth. In this part of the Anambra basin, the order of magnitude of the in-situ stresses is $S_{Hmax} > \sigma V > S_{Hmin}$, which implies that it is a tectonically relaxed area. According to the theory, this type of relationship infers a normal faulting regime. In this case, the vertical stress is the intermediate principal stress ($\sigma_V = \sigma_2$) and the difference between maximum and minimum stresses is sufficiently large to cause strike slip faulting, as seen in Table 9. Comparatively, based on this same theory, Abijah & Tse (2016) obtained a normal faulting regime in

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a field in the adjacent Tertiary Niger Delta where $\sigma V > S_{Hmax} > S_{Hmin}$.
Differential horizontal stress (the difference between maximum and minimum horizontal stress) is a key factor to determine whether simulated reservoir volume (SRV) fracturing can be applied to a shale formation. Using the method of Gao (2015), the average differential horizontal stress for the shales varied from 28.9MPa to 55.93MPa across the seven (7) wells (Table 9). This is above the <13.8MPa proposed (Sondergeld *et al.*, 2010), and is adjudged favourable for the formation of a fracture network.

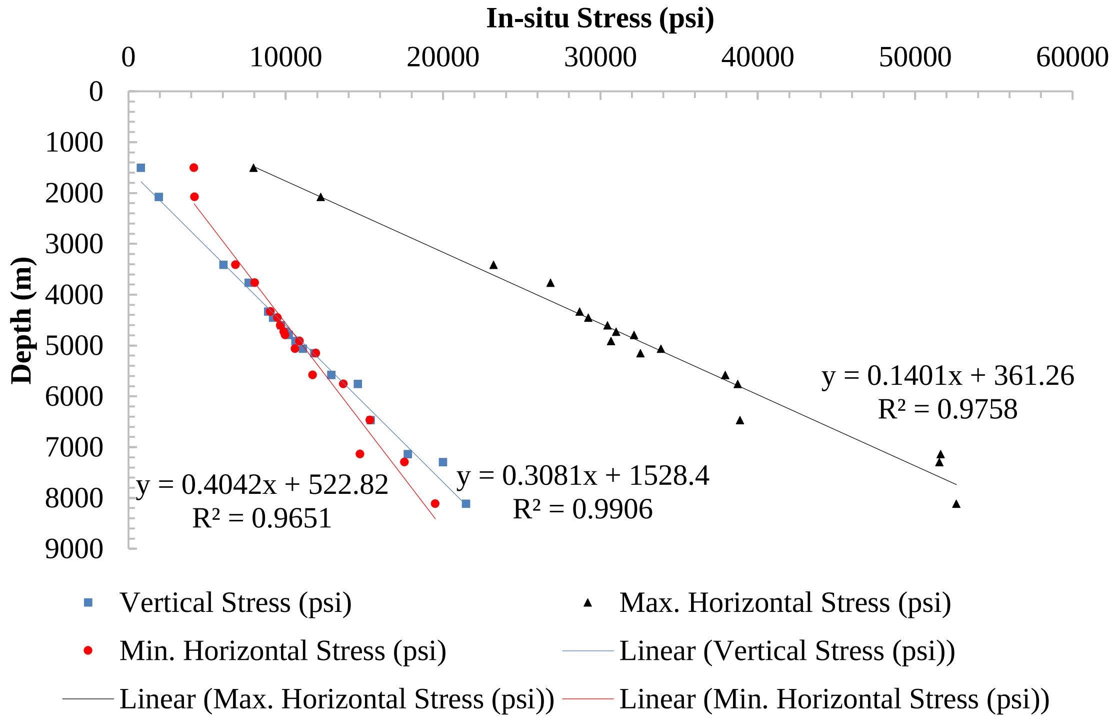

Fig. 8 Variation of in-situ stresses with depth

Table 9: Differential Horizontal Stresses

	Maximum Horizontal Stress (Mpa)			**Minimum Horizontal Stress (MPa)**			**Differential Horizontal Stress Mpa**			**Discrepancy coefficient**		
Well	Min	Max	Average	Min	Max	Average	Min	Max	Average	Min	Max	Average
Al-2	54.97	363.00	224.43	28.82	134.64	76.22	26.16	254.43	149.51	0.91	2.50	1.96
An-1	21.15	111.02	71.13	7.15	32.73	20.93	14.00	78.29	50.23	1.96	2.39	2.40
PG-2	18.63	67.72	50.52	8.63	23.59	17.79	10.00	44.12	32.73	1.16	1.87	1.84
MK	15.74	76.97	46.78	9.66	25.93	17.87	6.08	51.05	28.91	0.63	1.97	1.44
NH	39.92	113.77	89.97	14.57	39.89	29.04	25.35	73.89	55.93	1.74	1.85	1.93
YB	52.33	99.38	83.87	23.68	37.77	30.79	28.65	61.61	53.08	1.21	2.00	1.71
ZD-	18.96	98.04	59.62	8.81	32.66	20.18	10.15	65.38	39.44	1.15	2.23	1.91

Beugelsdijk *et al*. (2000) introduced the term K_h, which is discrepancy coefficient according to the relationship:

$$K_h = \frac{SHmax - SHmin}{SHmin}$$

The average K_h factor ranged from 1.44 to 2.40, which is above the < 0.25 proposed by Beugelsdijk for fractures to extend along natural cracks. The shales in this work did not satisfy this condition. Due to the absence of Leak Off Test (LOT) and well breakout data, it was not possible to determine the orientation of the in-situ stresses. When target formations are subjected to injection of fluids to frack the rocks under high pressures, the affected area experienced a sharp increase in pore pressure. This led to the adjustment of the near-field stress in the affected area such that existing fractures were sustained and new ones were developed for the desorption and migration of the shale-gas. The practical use of the minimum horizontal stress in a well is that it provides the lower limit of the fracturing pressure and puts a limit on the allowable injection pressure in a well (Nygaard 2010).

During fracking, small fractures occurred, which are associated with tensile stresses concentrated at the tip of the fractures according to the Griffith rock failure criterion. The rocks resisted compressive failure more than tensile deformation. The tensile stress and the heterogeneity in the mechanical properties of the rocks initiated and propagated the fractures. As the fractures propagate, more fractures cut across the weak structural planes and propagated parallel to the direction of σ_H (Zhao *et al*., 2019).

Shale Sweet Spots

The hybrid methods of Rickman *et al*. (2008), Britt & Scoeffler (2009) and Chen *et al.* (2017), which lists conditions that determine whether a particular shale will become plays, including

i. organic matter abundance, type and thermal maturity,
ii. porosity permeability relationships and pore size distribution,
iii. brittleness and relationship to mineralogy were applied to predict the sweet spots.

This involved, relating stratigraphy to log response and determination of petrophysical and geomechanical properties. Using these approaches as a guide, this study predicted that the sweet spots in the Anambra basin for the exploration and development of shale-gas were those that exhibited high Young's modulus, low Poisson's ratio and high brittleness. According to Chen *et al.* (2017) recommendations, a shale-gas sweet spot should be at least 30m thick, must have a lower bound porosity of 3%, and TOC of at least 2%. The shales in this study exceed these threshold values and are therefore prospective. The effect of hydraulic fracturing and consequent shale gas production are dependent on shale brittleness, which is found adequate in this study. Brittle rocks are good shale-gas plays for the creation and propagation of hydraulic fractures. Such rocks do not undergo self-sealing that is often associated with ductile shales. The in-situ stresses required for artificially induced fractures which provide pore space for shale-gas accumulation gave encouraging results. The factors influencing shale-gas

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exploration and development in the Anambra basin are generally summarized in Table 10. The prospective shale layers in the wells have been delineated from wireline log parameters and presented in Table 11. These values can be used as a guide for shale-gas prospect evaluation in this part of the basin.

Table 10: Composite Factors Influencing Shale Fracability in the Anambra Basin

S/N	Parameter	Reference Standard	This study	Frackability
1	Thickness	~ 30m (Chen *et al.* 2017)	23-317m	Adequate for prospectivity & fracability
2	Static Poisson's ratio	$3.5x10^6$ psi or 20.69 GPa (Britt and Schoeffler 2010).	0.02 -0.29	Brittle therefore ideal for fracking
3	Compressive and Tensile strength			Strong enough to develop fractures
4	Differential Horizontal Stress	Max. 13.8 MPa (Sondergald *et al.* 2010)	10-14	Frackable
5	Discrepancy coefficient, K_h	Max. 0.25	0.63-2.39	Hydraulic fractures will not extend along natural cracks, but orthogonal to minimum horizontal stress

Table 11: Prospective Shale Units

Well	Prospective shale units on logs	Perspective Depth interval (m)	Thickness (m)	Porosity	Permeability (mD)	Young modulus (Mpsi)	Poisson's ratio	Minimum horizontal stress (psi)	Fracture pressure (psi)
AL	4	1505 - 2048	543	0.4	4.17	0.27	0.38	4178.64	4174.00
	5	2078 - 2104	26	0.10	0.37	1.76	0.26	11720.70	1696.90
	15	5152 - 5538	386	0.21	2.76	0.74	0.32	11936.70	1169.90
	17	5760 - 6453	693	0.19	9.64	1.85	0.25	13677.80	13455.40
	19	7140 - 7232	92	0.16	5.27	1.33	0.27	14738.30	14924.70
	20	7299 - 8086	787	0.22	0.41	1.59	0.26	17562.40	17482.10
AN	8	1634 - 1747	113	0.16	0.41	42.44	0.28	3666.15	3602.30
	9	1807 - 2004	197	0.13	0.14	40.06	0.25	4064.88	4009.23
	10	2017 - 2370	353	0.15	0.46	55.28	0.26	4745.22	4710.51
	2	5482 - 617	120	0.005	1.37	3.69	0.25	2356.33	2274.74
	3	1076 - 1196	69	0.008	2.93	3.88	0.25	2959.31	2529.73

PG	4	1213 - 1282	59	0.009	5.39	3.78	0.26	2809.08	2774.83
	5	1335 - 1394	32	0.003	6.93	4.06	0.25	3077.07	2951.52
	6	1439 - 1471	225	0.008	4.76	3.36	0.27	3421.03	3323.21
MK	7	954 - 1022	68	0.14	1.67	3.24	0.28	1971.31	1968.02
	8	1049 - 1647	598	0.16	5.78	3.19	0.29	2852.61	2834.62
	9	1676 - 1742	66	0.06	0.08	4.36	0.23	3536.78	3466.13
NH	9	1785 - 1905	120	0.07	2.86	4.75	0.22	3774.32	3731.67
	11	1981 - 2207	26	0.12	1.32	4.09	0.24	4372.31	4303.79
	12	2291 - 2387	96	0.08	5.85	3.59	0.26	4843.80	4800.20
	16	2591 - 2700	109	0.11	1.01	2.80	0.30	5783.42	5686.08
ZD	2	956 - 1047	91	0.26	1.25	3.19	0.27	2124.54	2200.20
	5	1196 - 1344	148	0.17	0.06	5.09	0.21	2742.18	2680.25
	7	1652 - 1971	319	0.22	0.38	4.54	0.24	4121.37	3949.88
	8	1994 - 2252	258	0.14	0.32	6.31	0.18	4735.77	4570.29
YB	5	1071 - 1930	859	0.17	2.87	1.48	0.36	3433,43	3432.63
	11	2400 - 2517	117	0.12	0.04	2.36	0.32	546.02	5380.43

SUMMARY AND CONCLUSIONS

The following conclusions were derived from the study:

1. The multi-layered shale units possess appropriate thicknesses (>30m) for hydraulic fracturing for commercial productivity,
2. The permeability was of the order of 10^{-2}mD and 10^{1}mD and porosity was generally 30 %, indicating that a hydraulic fracking program is imperative to initiate, propagate and keep the fractures open to enable the desorption and flow of the gas,
3. The sweet spots in the Anambra basin for the exploration and development of the shale-gas are those sections where the mechanical stratigraphy exhibit high Young's modulus, low Poisson's ratio and high brittleness and good shale gas potential,
4. The compressive strength which is the maximum axial compressive stress that a sample of material can withstand before failing, is high, and increases with depth which favours hydraulic fracking,
5. The order of magnitude of the in-situ stresses is: $\sigma V > S_{Hmax} > S_{Hmin}$ which infers a strike-slip faulting regime.

It is concluded that the integration of these data will contribute to a successful design of hydraulic fracking program for shale-gas production in the future. However, these preliminary encouraging results on the fracking potentials of the shales in the Anambra basin supports a more detailed exploration phase with specific geochemical and petrophysical analysis of existing rock and well log data for an effective hydraulic fracturing design. The production stage will entail a detailed environmental assessment in view of impacts associated with hydraulic fracturing.

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Appendix A: Summary of Log Curve Types of Well A1-1

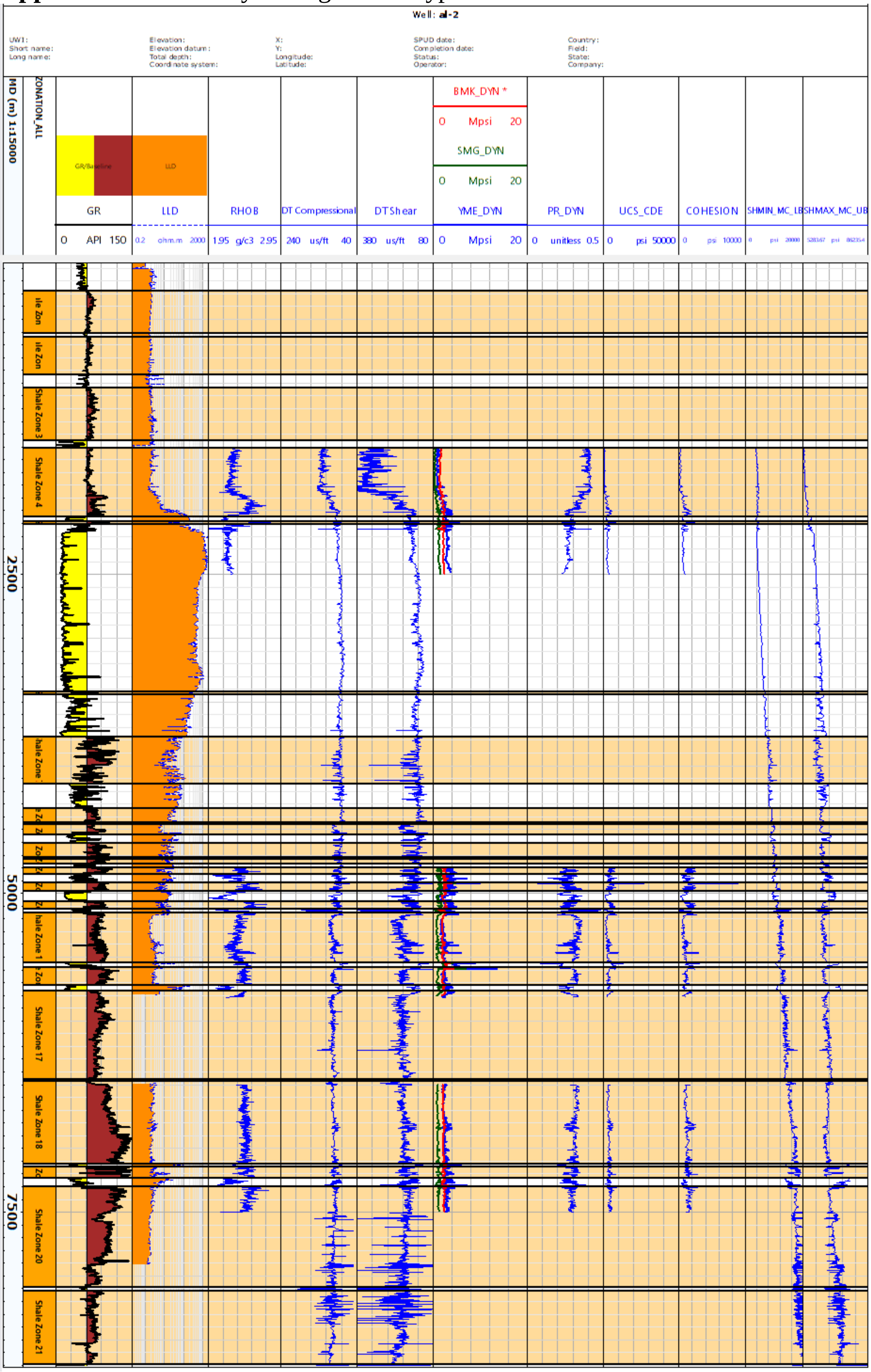

Fig. 2a: Showing Log curve types of Well Al-1

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Appendix B: Summary of Log Curve Types of Well AN-1

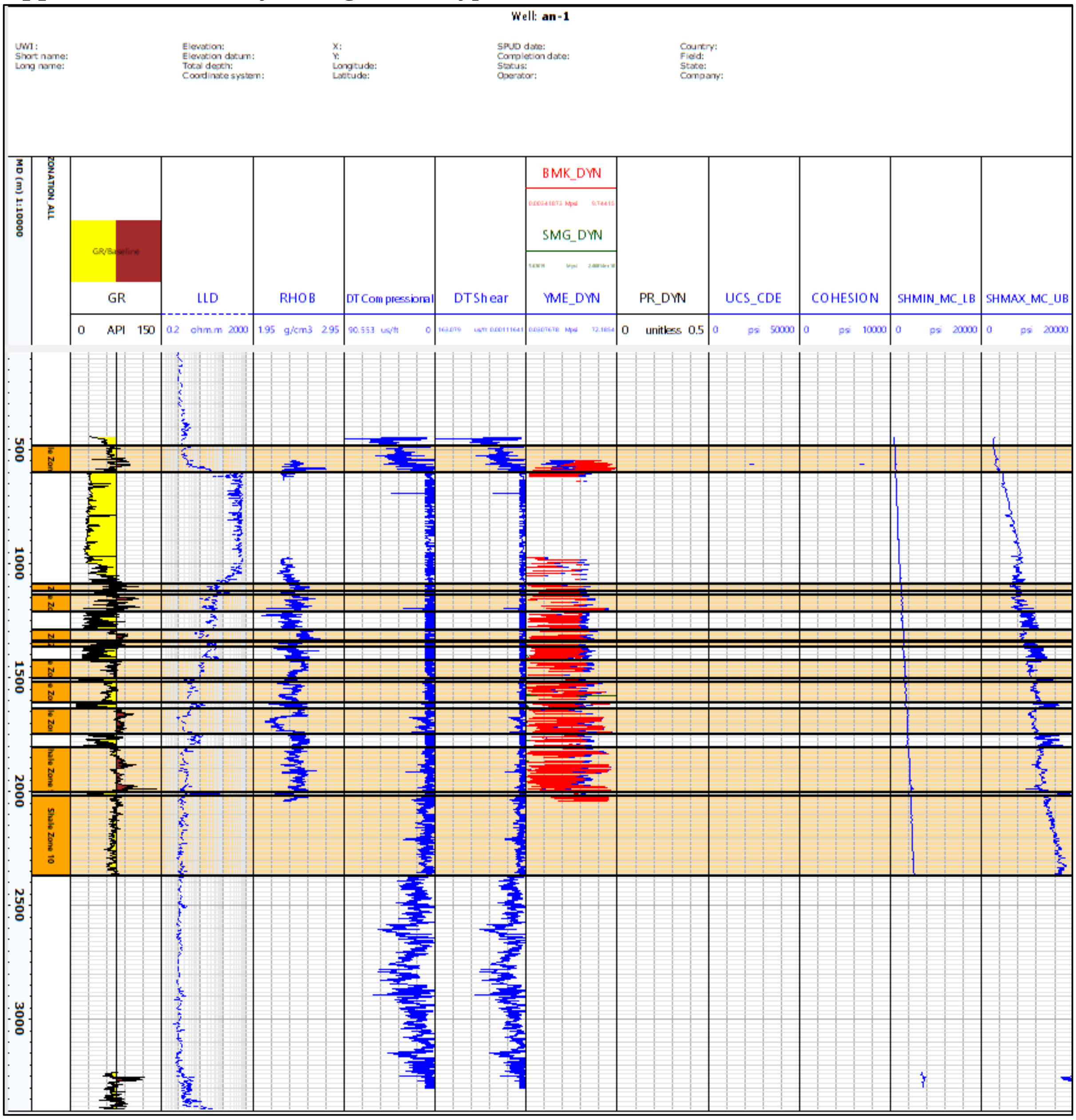

Fig. 2b: Showing Log curve types of Well AN-1

Appendix C: Summary of Log Curve Types of Well PG-2

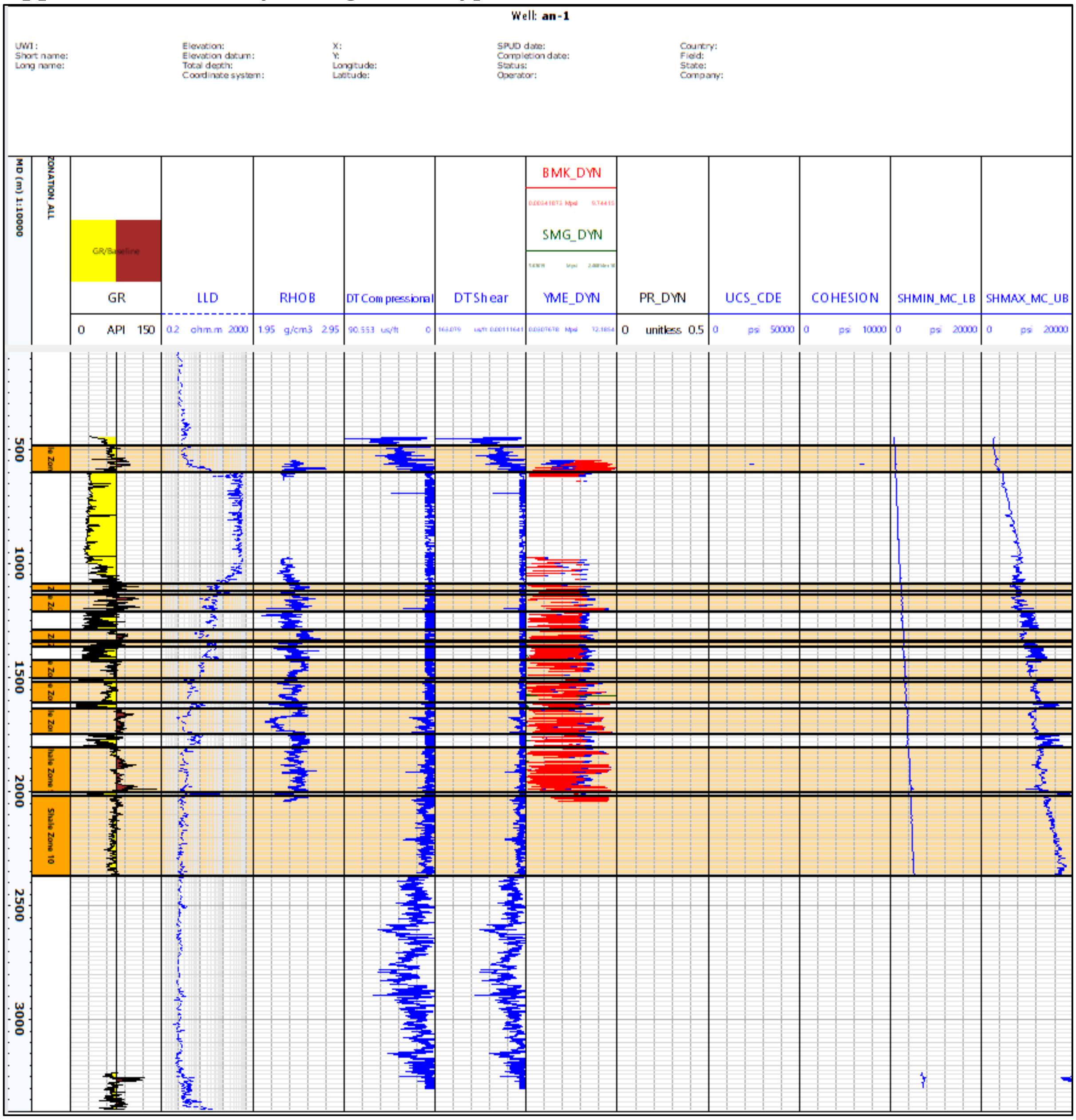

Fig. 2c: Showing Log curve types of Well PG-2

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Appendix D: Summary of Log Curve Types of Well MK

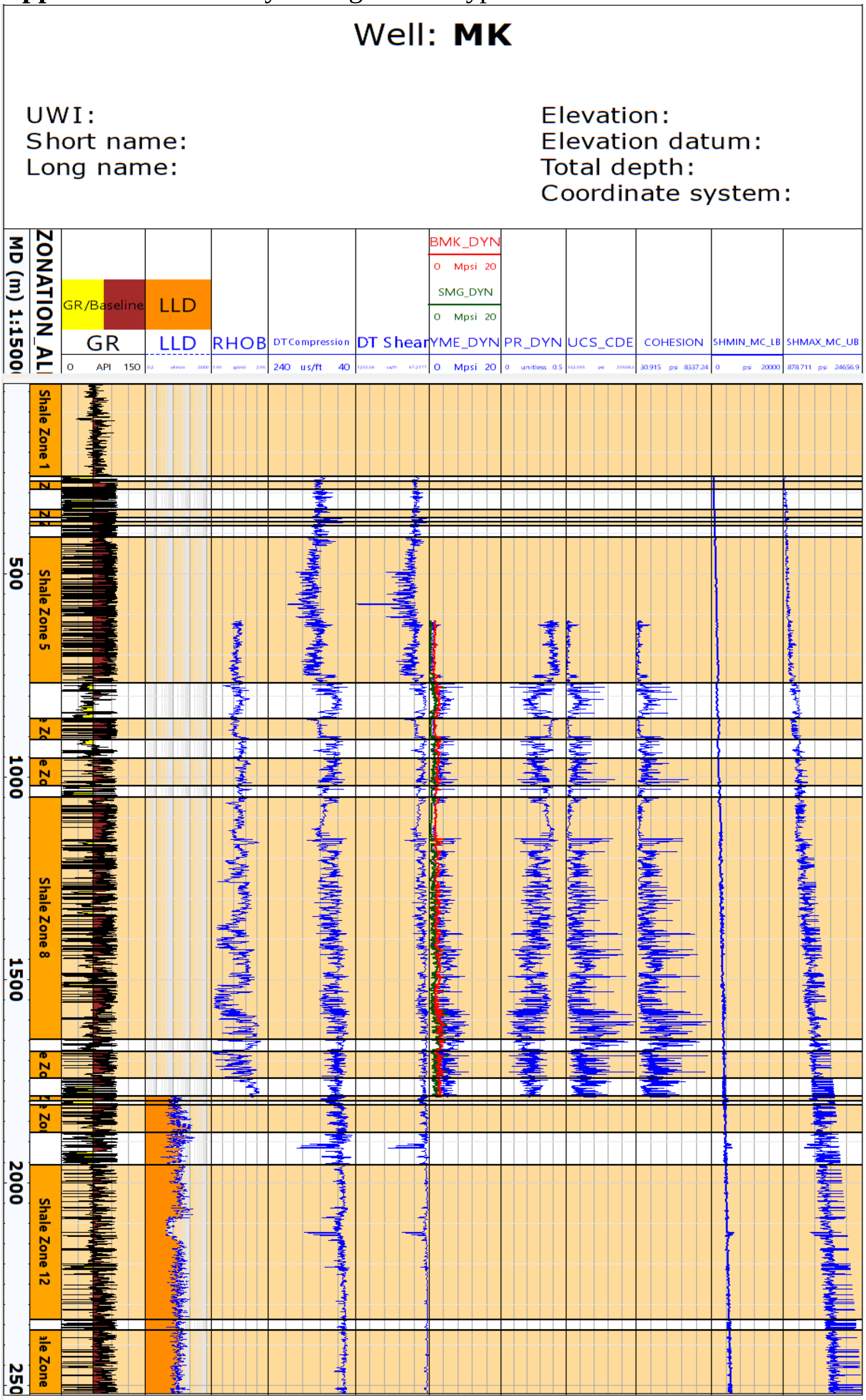

Fig. 2g: Showing Log curve types of Well MK

Appendix E: Summary of Log Curve Types of Well NH

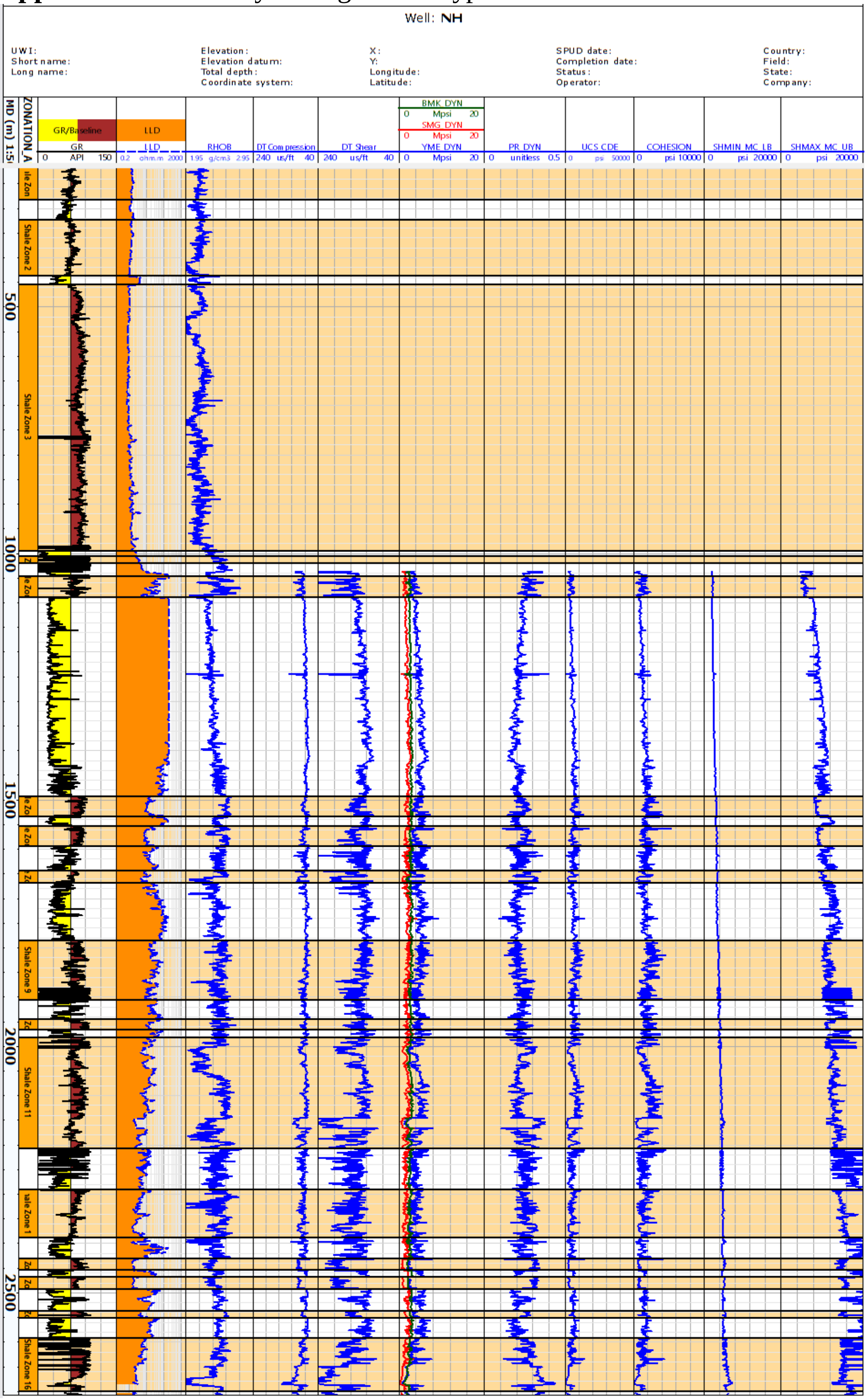

Fig. 2h: Showing Log curve types of Well NH

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Appendix F: Summary of Log Curve Types of Well YB-1

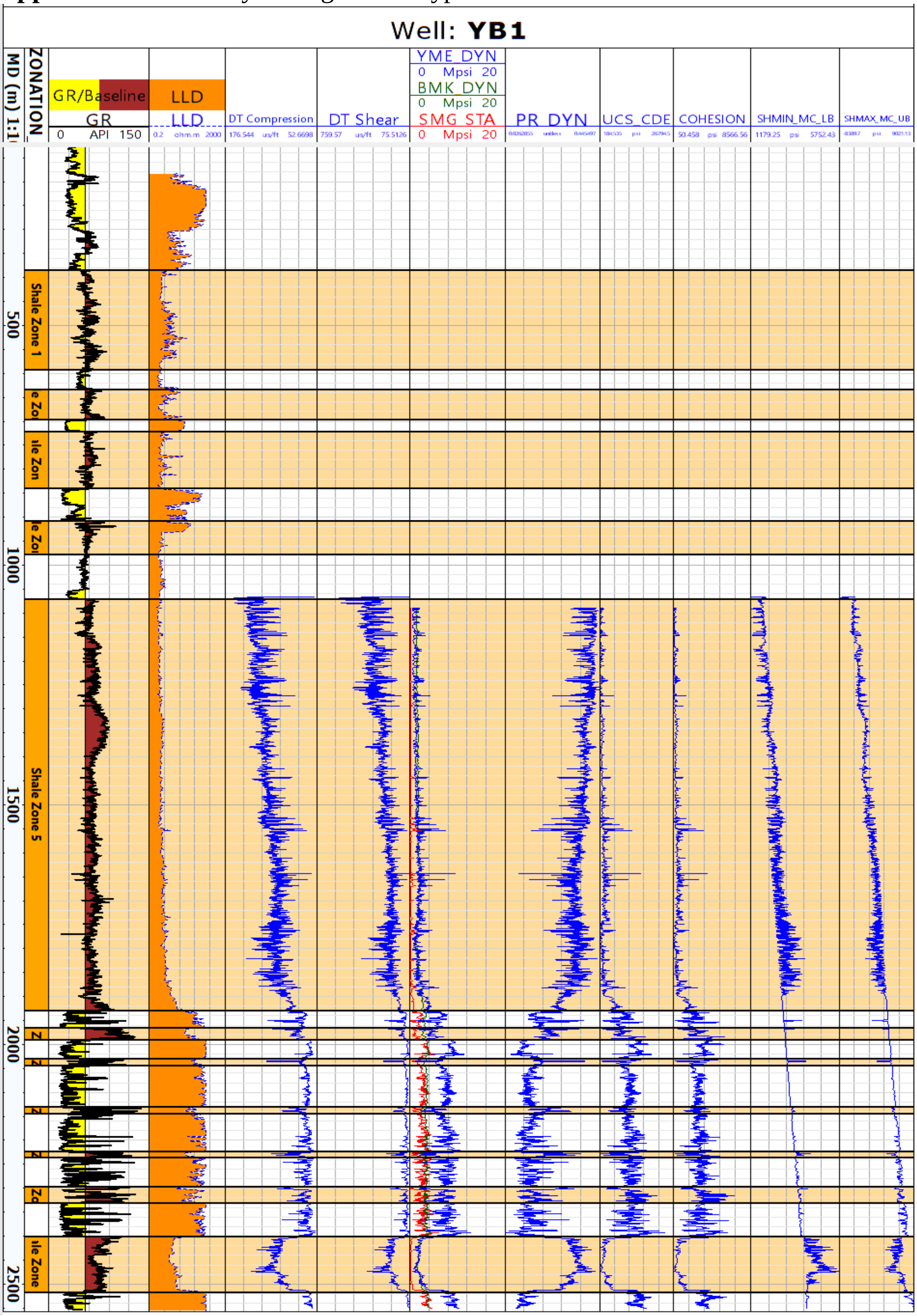

Fig. 2i: Showing Log curve types of Well YB-1

Appendix G: Summary of Log Curve Types of Well ZD-1

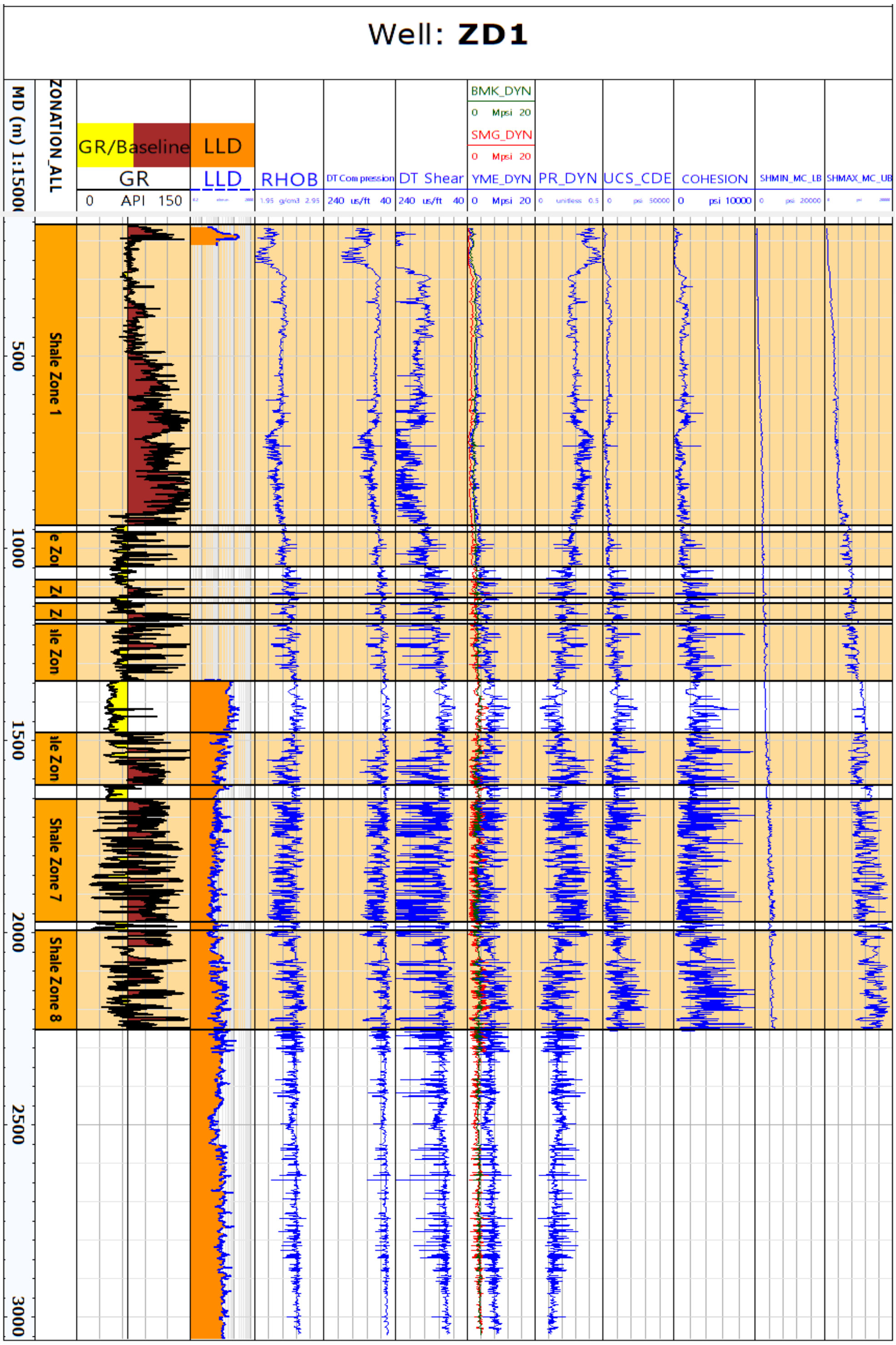

Fig. 2j: Showing Log curve types of Well ZD-1