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Integration of Well Logs and Seismic Data for Hydrocarbon Volumetric Analysis in D-One Field of the Niger Delta Region, Nigeria

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ABSTRACT: The study was carried out on an onshore Niger Delta field using seven wells with the objectives of identifying possible reservoir units with potential to contain oil or gas using well logs and seismic data sets. Petrophysical properties analysis revealed two Hydrocarbon bearing reservoirs ranging from 5000 ft – 8000 ft, with volume of shale (Vsh) ranging from 4.3% - 43.9%. The total porosity ranged from 25.9% - 34.7%, while effective porosity ranged from 17.7% - 33.2%, indicating good porosities for the reservoirs. Net-to-Gross ranged from 0.720 – 0.980 with water saturation ranging from 19.87% - 29.07%, while hydrocarbon saturation ranged from 70.93% - 78.86% of gas in the reservoirs. For the volumetric analysis of the two reservoirs modelled, a STOIIP ranging from 614MMSTB – 1054MMSTB was obtained, while the recoverable Oil was estimated between 215-369MMSTB. We can infer that the two reservoirs mapped, correlated and modelled across the seven wells has a respectable HC potential.

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Key words: Well Logs, Seismic Data, Volumetric Analysis, Niger Delta

Increasing demand for oil and gas worldwide has caused an increase in exploration and development in pre-explored areas around the world such as the Niger Delta. Consequently, more detailed methods apart from structural approach are being developed which include the characterization of the hydrocarbon reservoirs. Aizebeokha and Olayinka, (2011) proposed the combination of formation evaluation, volume of hydrocarbon in place, stratigraphic and structural framework in reservoir heterogeneity characterization for effective determination of permeability, fluid distribution and hydrocarbon in place (Adetoye, 2009) Mapped lateral boundaries of reservoirs using reflection attributes of subsurface maps.

Omoboriowo *et al*, 2012 showed that environment of deposition affects reservoir Petrophysical properties using a suit of geophysical well logs for the Niger Delta. The objective of this paper is to integrate seismic and well log data for hydrocarbon volumetric analysis in D-One Field of the Niger delta region of Nigeria for prospect identification and reservoir characterization. Abraham-Adejumo (2013) used a suite of geophysical wire-line logs from an oil field in Niger Delta for the purpose of Well correlation and petrophysical analysis of "Rickie" field onshore Niger Delta the results showed a sand – shale inter-bedding of the subsurface stratigraphy with hydrocarbon bearing reservoirs (L, P and S), at depths of 2,943m, 3,248m and 3935m. Ihianle *et a*l. (2013) used three dimensional seismic/well logs to carry out the structural interpretation over 'X – Y' field in the Niger Delta area of Nigeria. The seismic section and structure map revealed fault assisted closures at the center of the field, which correspond to the crest of rollover anticlines and which served as the trapping medium.

The estimated volume of hydrocarbon in place is 289, 227,007 bbl (37,281acre-ft) of oil. Integrated 3D seismic and petrophysical data was employed by Edigbue *et al*. (2014) to evaluate hydrocarbon of 'Keke' field in the Niger Delta. Two sand units (S1 and S2) which existed between 9127ft and 11152ft were correlated and mapped using gamma ray log. The results obtained from the analysis of this field shows that the trapping mechanisms and the petrophysical parameters in 'Keke' field are favourable for hydrocarbon accumulation.

MATERIALS AND METHODS

Study Area: The precise location of the study area (fig. 1) was not disclosed in line with current practices by petroleum industries in Nigeria. The D-One field lies within the province of the Niger Delta basin bounded to the North, South, North West and North East by the Anambra, Gulf of Guinea, Benin and Calabar Flanks respectively.

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Fig 1: Map of Nigeria, showing the study area in the Niger Delta. (Google)

3D seismic volume in segy format, Seven composite well logs comprising of gamma ray (GR), resistivity (RT), neutron (NPHI), density (RHOB) and sonic (DT) as well as check shots data recorded at various locations within the D-One Field, Niger Delta was provided by Shell Petroleum Development Company (SPDC), Nigeria. The data was studied using the PETREL TM workflow.

RESULTS AND DISCUSSION

Well Log Correlation: The analysis of the all the well section revealed that each of the sand units (interval coloured yellow) extends through the field and varies in thickness with some unit occurring at greater depth than their adjacent unit i.e. possibly an evidence of faulting. The shale layers (interval coloured grey) were observed to increase with depth along with a corresponding decrease in sand layers. This pattern in the Niger Delta indicates transition from Benin to Agbada formation (Amigun, 2013).

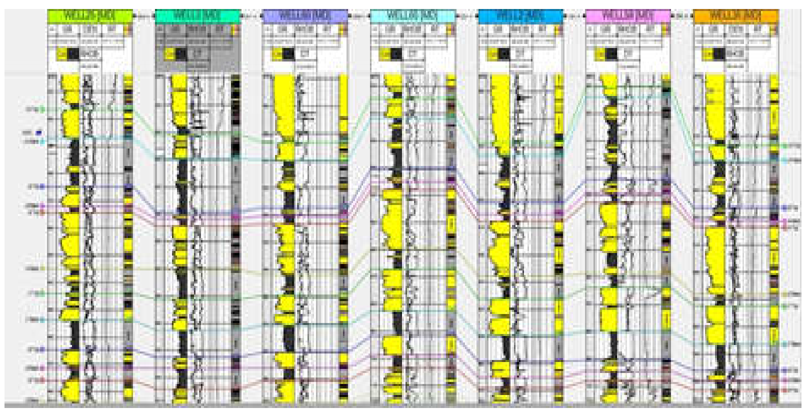

Fig 2: Well correlation panel across all wells showing the tops and base of reservoir J5-J10

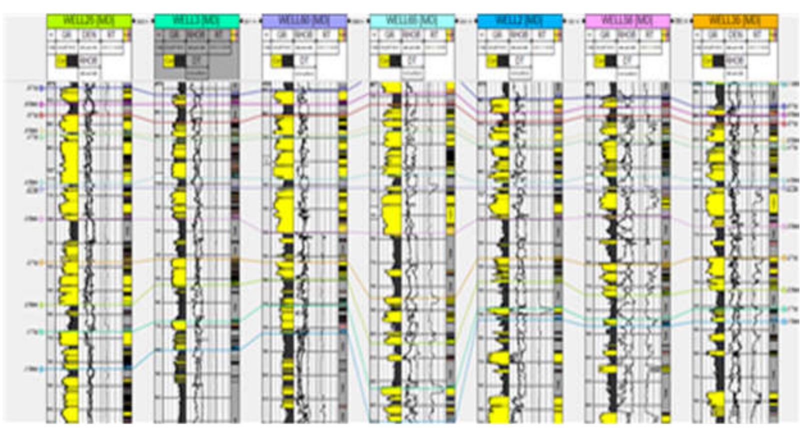

Fig 3: Well correlation panel across all wells showing the tops and base of reservoir J1-J5

Seismic To Well Tie: Well 25 check shot was used for the seismic to well tie to ensure that there was accurate tie between the well and seismic event. It aided in mapping the delineated hydrocarbon bearing reservoirs on the seismic data. Horizons were picked at the top of the mapped reservoirs and tied to the seismic data. A good tie was obtained between the synthetic seismogram and the seismic data. Figure 4 shows the synthetic seismogram for well 25 of the field.

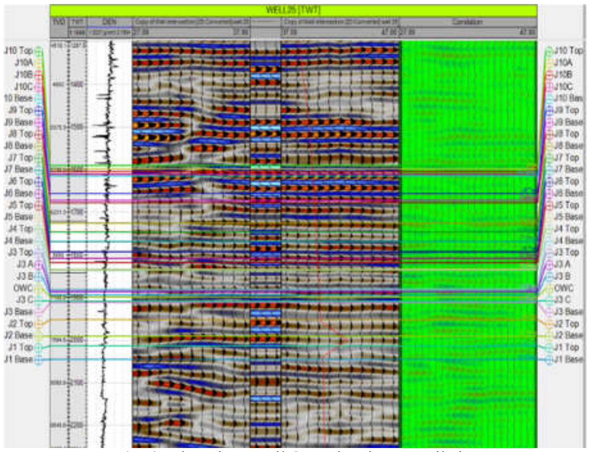

Fig 4: Showing well 25 seismic to well tie

Horizon and Fault Interpretation: Figure 5: Shows the mapped nine faults (fault 1- fault 9) and ten horizons (J1-J10) across the reservoirs. This was achieved after the seismic to well tie and the synthetic seismogram was done. The reservoirs of interest mapped are the J3 and J10 sands. Figure 4 clearly shows some of the faults observed in the seismic.

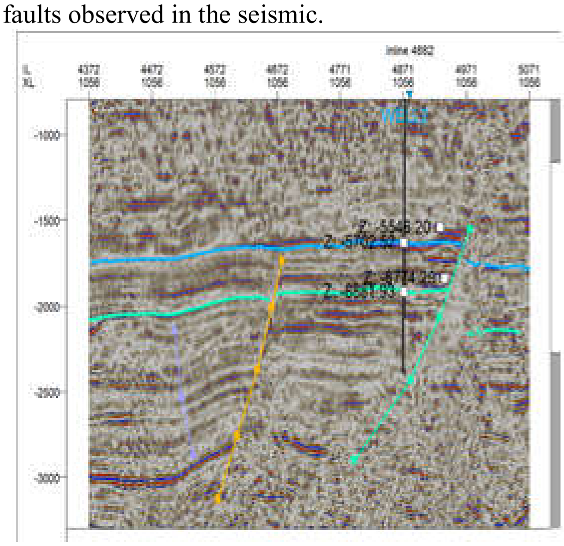

Fig 5: Showing 2 horizons picked and faults interpreted

*Time and Depth Structural Maps***:** Mapped horizons and the generated fault polygons were used to generate grid maps which were in turn used to generate the time and depth structural map for horizons J10 and J3 as seen in Figures 6 and 7. The top and base maps for the two mapped horizons were created using the depth maps. Faults on the seismic section is also shown on the surfaces below in Figures 5 and 6.

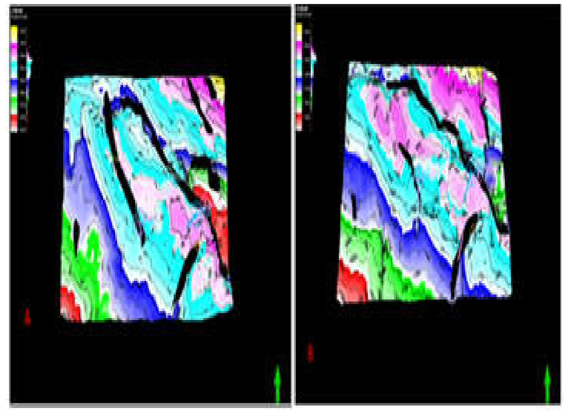

Fig 6: (A) and (B) Showing the Time Map for Horizons J10 and J3 respectively

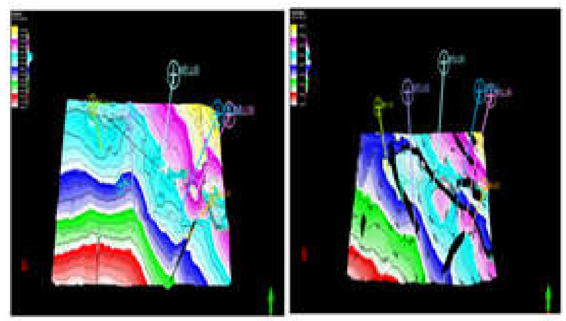

Fig 7: (A) and (B) showing the Depth maps generated for Horizons J10 and J3 respectively.

Facie Modelling: Using the Top and Base maps generated from the Depth map, static modelling was done to model the facie property in stochastic and deterministic probability conditions for the two mapped horizons, the results are displayed in figures 8 and 9. Facie recognized where Coarse Sand, Medium Sand, Fine Sand and Shale.

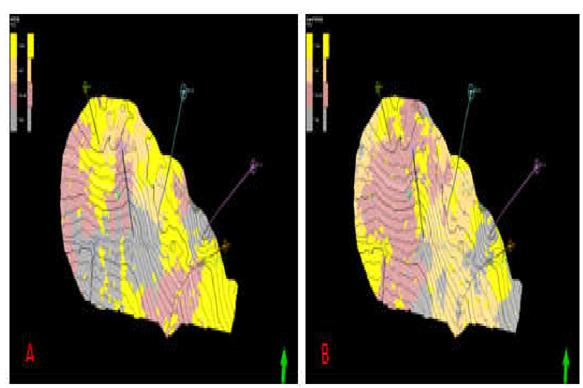

Fig 8 (A) and (B) Showing the Facie Models for horizon J10 in stochastic and deterministic probability conditions respectively

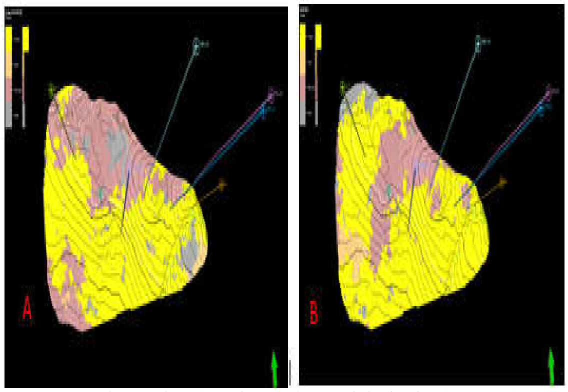

Fig 9 (A) and (B) Showing the Facie Models for horizon J3 in stochastic and deterministic probability conditions respectively

Petrophysical Modelling: The properties modelled are the Net-to-Gross (NTG), effective porosity, water saturation and permeability for both the deterministic and stochastic probability conditions. The models show the distribution of each parameter across the reservoir as shown in Figures 10 to 16

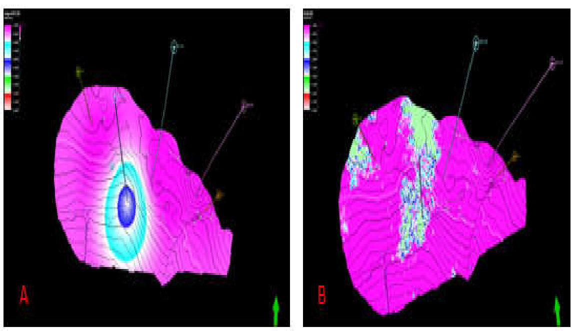

Figure 10 (A) and (B) Showing the Net to Gross distribution of sands across J10 reservoir in deterministic and stochastic probability conditions respectively

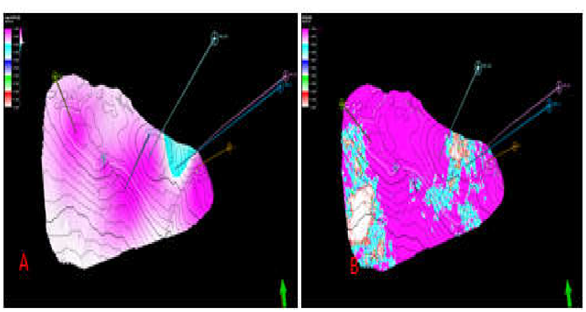

Fig 11 (A) and (B) Showing the Net to Gross distribution of sands across J3 reservoir in deterministic and stochastic probability conditions respectively

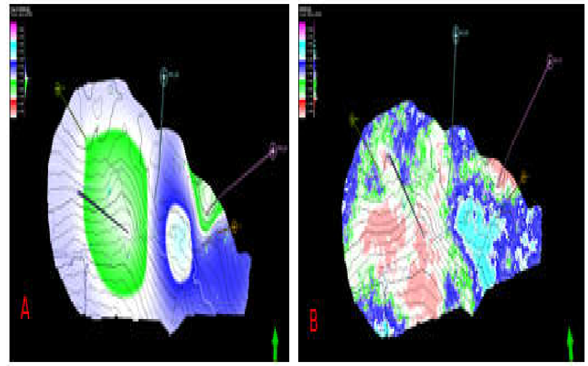

Fig 12 (A) and (B) Showing the distribution of porosities across J10 reservoir in deterministic and stochastic probability conditions respectively

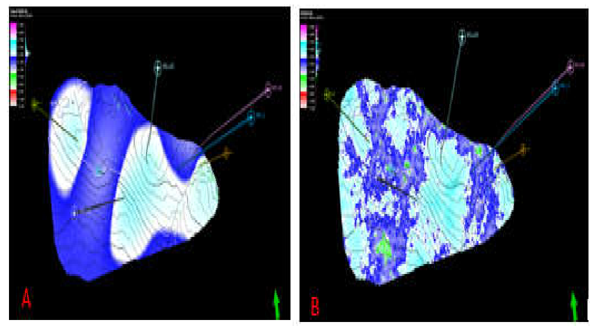

Fig 13 (A) and (B) Showing the distribution of porosities across J3 reservoir in deterministic and stochastic probability conditions respectively

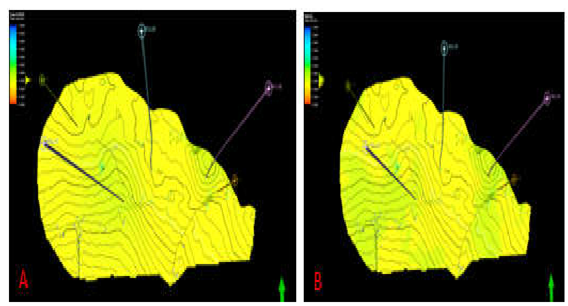

Fig 14 (A) and (B) Showing the water saturation distribution across J10 reservoir in deterministic and stochastic probability conditions respectively

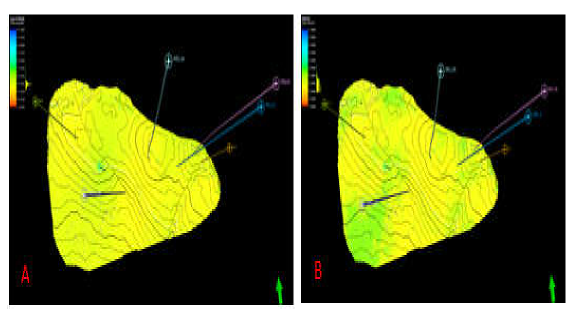

Fig 15 (A) and (B) Showing the water saturation distribution across J3 reservoir in deterministic and stochastic probability conditions respectively

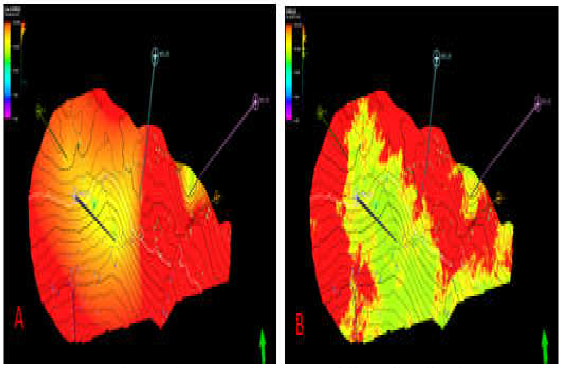

Fig 16 (A) and (B) Showing the permeability distribution across J10 reservoir in deterministic and stochastic probability conditions respectively.

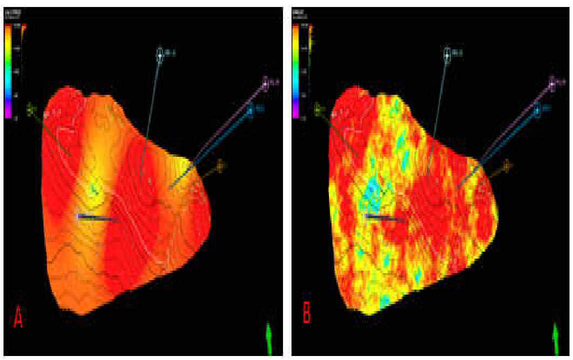

Fig 17 (A) and (B) Showing the permeability distribution across J3 reservoir in deterministic and stochastic probability conditions respectively.

Delineation of Fluid Contacts: Fluid contacts where picked on the well section using the Gamma ray, resistivity and the Neutron-Density logs. The oil water contact (OWC) was picked at the lowest point across the mapped horizons at approximately -5862ft for reservoir J10 and -7097ft for reservoir J3 as shown in Figure 18A and B. These contacts were modelled and the distribution of the Hydrocarbon across the reservoirs are shown in Figure 19 and 20. Across the 7 drilled wells, ten reservoir bodies J1 to J10 were identified, but two reservoirs J3 and J10 were analyzed. The J3 reservoir occurred at a depth range of 6775 – 7289ft with an average gross thickness of 140.14ft, net thickness of 89.49ft and a net to gross of 61.62%. The average total and effective porosity values are 0.27 (27%) and 0.20 (20%) respectively in the reservoir. The average permeability obtained was 4435.56 mD with an average water saturation of 0.33 and an average volume of shale of 0.35. Accordingly, the J10 reservoir occurs at a top and bottom depth range of 5546 and 5989ft respectively. The average gross and net thickness for the J10 reservoir gotten were 65 and 55.78ft respectively. The average values of the total and effective porosity estimated were 0.3188 (31.9%) and 0.2887 (28.9%) thus giving rise to an average permeability and water saturation of 4160.45mD and 0.26 respectively. The probable average volume of shale was 0.12 and an excellent average net to gross of 0.899 (90%). This result is presented in Table 8 and 9.

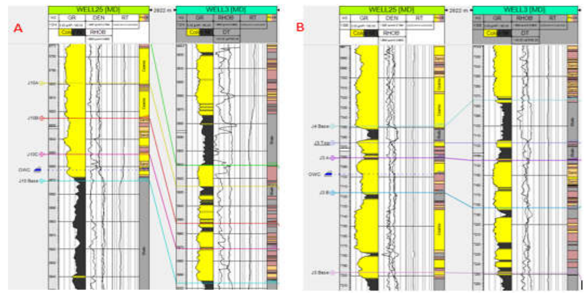

Fig 18 (A) and (B) showing Oil- Water contact (OWC) picked on the well logs for reservoirs J10 and J3 respectively

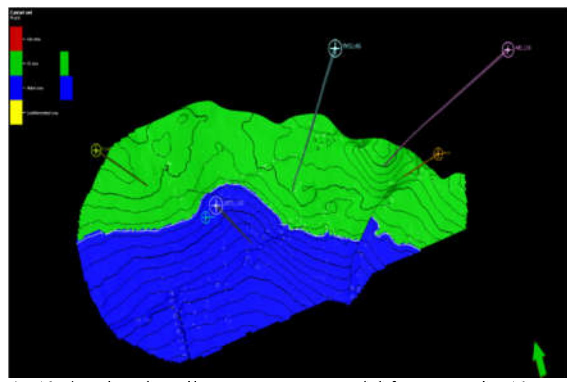

Fig 19 showing the Oil-Water contact model for reservoir J10

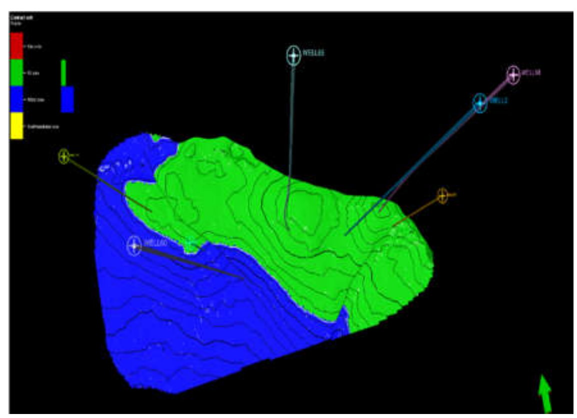

Fig 20 showing the Oil-Water contact model for reservoir J3.

Data Analysis: Formation evaluation involves examining a formation to detect the presence of hydrocarbon in commercial quantities by critically assessing a reservoir in terms of area, thickness, hydrocarbon presence, water saturation and porosity which would help estimate the volume of hydrocarbon in place (Hasbiantoro, 2014). The values displayed in tables 1 to 7 are the average values of the results obtained from the Petrophysical analysis of each reservoir in the 7 wells.

Table 1: showing the Petrophysical evaluation across J1-J10 reservoir in well 2.

Well 2

Zone	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
J1	7391	7436	45	0.97	0.17	-0.01	0.02	0.48	113.71	1.09
J2	7181	7277	96	20.78	0.2	0.08	0.22	0.41	142.11	0.64
J3	6883	7012	129	71.45	0.25	0.17	0.55	0.35	5866.35	0.44
J4	6701	6858	157	98.37	0.28	0.21	0.63	0.32	4022.75	0.33
J5	6604	6680	76	45.4	0.28	0.21	0.59	0.33	3883.33	0.4
J6	6508	6566	58	0	0.17	-0	0	0.48	0.04	1.01
J7	6276	6411	135	58.56	0.27	0.18	0.43	0.35	10481.54	0.54
J8	5992	6193	201	120.4	0.29	0.23	0.59	0.33	14489.05	0.38
J9	5926	5967	41	14.64	0.21	0.14	0.35	0.39	124.04	0.51
J10	*5702*	*5750*	*48*	*48*	*0.34*	*0.33*	*1*	*0.24*	*4263.12*	*0.04*

Table 2: showing the Petrophysical evaluation across J1-J10 reservoir in well 3.

Well 3

Zone	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
J1	7583	7702	119	27.88	0.2	0.07	0.23	0.42	100.42	0.67
J2	7322	7427	105	18.91	0.2	0.08	0.18	0.42	55.39	0.62
J3	7021	7154	133	77.21	0.23	0.15	0.58	0.36	217.87	0.38
J4	6822	6978	156	89.21	0.23	0.16	0.57	0.35	131.53	0.33
J5	6748	6804	56	16.85	0.21	0.1	0.3	0.4	63.36	0.54
J6	6632	6670	38	0	0.17	0.03	0	0.46	0.02	0.85
J7	6420	6532	112	11.95	0.19	0.06	0.11	0.43	22.37	0.69
J8	6151	6311	160	62.31	0.22	0.12	0.38	0.38	153.08	0.51
J9	6110	6126	16	0	0.18	0.05	0	0.44	0.21	0.73
J10	5821	5905	84	46.22	0.23	0.15	0.55	0.36	156.97	0.35

Table 3: showing the Petrophysical evaluation across J1-J10 reservoir in well 25.

Well 25

Zone	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
J1	7585	7743	158	73.53	0.27	0.2	0.46	0.34	4369.35	0.37
J2	7292	7472	180	150.16	0.28	0.24	0.83	0.29	2174.73	0.18
J3	6978	7110	132	115.13	0.29	0.25	0.87	0.29	1973.59	0.16
J4	6757	6963	206	190.07	0.3	0.26	0.92	0.28	2531.01	0.14
J5	6674	6746	72	30.57	0.24	0.15	0.42	0.36	806.07	0.44
J6	6559	6628	69	0	0.17	0.03	0	0.45	0.42	0.84
J7	6354	6452	98	29.69	0.21	0.1	0.3	0.39	107.67	0.53
J8	6058	6264	206	171.16	0.3	0.26	0.83	0.28	3608.38	0.17
J9	5962	6036	74	10.85	0.2	0.08	0.15	0.42	24.71	0.59
J10	5680	5785	105	78.25	0.26	0.21	0.75	0.32	1166.09	0.25

Table 4: showing the Petrophysical evaluation across J1-J10 reservoir in well 35.

Well 35

Zone	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
J1	7317	7370	53	15.7	0.21	0.07	0.29	0.42	232.22	0.72
J2	7100	7238	138	62.55	0.23	0.14	0.45	0.37	442.46	0.43
J3	6807	6970	163	122.25	0.28	0.23	0.75	0.31	2605.8	0.23
J4	6635	6775	140	87.35	0.26	0.21	0.62	0.32	1622.82	0.25
J5	6536	6610	74	27.63	0.23	0.14	0.37	0.37	761.37	0.48
J6	6465	6500	35	0	0.19	0.07	0	0.42	0.88	0.6
J7	6230	6369	139	95.31	0.28	0.23	0.68	0.31	2842.04	0.25
J8	5941	6184	243	173.28	0.31	0.26	0.71	0.29	5115.08	0.21
J9	5867	5920	53	34.35	0.25	0.19	0.65	0.33	578.71	0.25
J10	5642	5695	53	53	0.32	0.32	1	0.24	3749.25	0.05

Table 5: showing the Petrophysical evaluation across J1-J10 reservoir in well 58.

Well 58

Zone	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
J1	7272	7296	24	7.68	0.21	0.09	0.32	0.41	91.44	0.57
J2	7065	7182	117	76.35	0.24	0.17	0.65	0.34	459.34	0.32
J3	6775	6886	111	23.78	0.21	0.07	0.21	0.42	453.13	0.74
J4	6592	6731	139	81.41	0.25	0.16	0.58	0.35	904.25	0.44
J5	6500	6569	69	13.8	0.21	0.12	0.2	0.38	164.59	0.45
J6	6432	6468	36	25.29	0.28	0.23	0.7	0.31	1736.88	0.25
J7	6195	6338	143	34.75	0.21	0.07	0.24	0.42	182.68	0.69
J8	5917	6147	230	52.77	0.21	0.11	0.23	0.39	44.91	0.5
J9	5845	5888	43	43	0.32	0.29	1	0.25	2108.11	0.07
J10	**5546**	**5579**	**33**	**33**	**0.32**	**0.29**	**1**	**0.25**	**2685.55**	**0.07**

Table 6: showing the Petrophysical evaluation across J1-J10 reservoir in well 60.

Well 60										
Zone	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
J1	7600	7716	116	34.7	0.22	0.14	0.29	0.37	60.79	0.38
J2	7417	7490	73	16.77	0.21	0.12	0.22	0.38	61.86	0.44
J3	7103	7289	186	145.21	0.35	0.31	0.78	0.26	12668.14	0.14
J4	6892	7066	174	137.21	0.31	0.27	0.78	0.28	4857.85	0.15
J5	6799	6877	78	57.26	0.32	0.28	0.73	0.28	8811.63	0.17
J6	6691	6751	60	11.8	0.23	0.15	0.19	0.36	853.93	0.35
J7	6485	6596	111	35.67	0.22	0.13	0.32	0.37	216.65	0.42
J8	6222	6410	188	84.55	0.25	0.18	0.45	0.34	3034.9	0.31
J9	6163	6195	32	22.3	0.27	0.22	0.69	0.31	1208.24	0.21
J10	5924	5989	65	65	0.35	0.34	1	0.23	5362.57	0.04

Table 7: showing the Petrophysical evaluation across J1-J10 reservoir in well 65.

Well 65										
Zone	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
J1	7319	7364	45	15.65	0.25	0.15	0.34	0.37	3614.83	0.52
J2	7146	7241	95	84.11	0.29	0.25	0.88	0.28	1568.51	0.14
J3	6867	6994	127	71.44	0.29	0.23	0.56	0.32	7264.04	0.35
J4	6689	6825	136	121.11	0.34	0.32	0.89	0.25	7056.03	0.1
J5	6595	6671	76	9.87	0.19	0.06	0.13	0.43	57.67	0.68
J6	6495	6556	61	61	0.41	0.39	1	0.22	21910.85	0.04
J7	6281	6417	136	57.57	0.27	0.19	0.42	0.35	6346.18	0.39
J8	6013	6213	200	81.59	0.23	0.15	0.41	0.36	458.36	0.38
J9	5940	5985	45	39.13	0.31	0.28	0.86	0.27	2790.97	0.12
J10	*5695*	*5762*	*67*	*67*	*0.37*	*0.35*	*1*	*0.23*	*11739.59*	*0.05*

Table 8: Showing the average values for the Petrophysical properties in reservoir J3.

Reserviour J3										
Zone	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
2	6883	7012	129	71.44	0.25	0.17	0.55	0.35	5866.36	0.44
3	7021	7154	133	77.2	0.23	0.15	0.58	0.36	217.87	0.38
25	6978	7111	132	115.12	0.29	0.25	0.87	0.29	1973.59	0.16
35	6807	6970	163	122.25	0.28	0.23	0.75	0.3	2605.8	0.23
58	6775	6886	111	23.78	0.2	0.07	0.21	0.42	453.13	0.75
60	7103	7289	186	145.21	0.34	0.31	0.78	0.26	12668.14	0.14
65	6867	6994	127	71.43	0.29	0.23	0.56	0.31	7264.03	0.35
		Average	140.14	89.49	0.27	0.20	0.61	0.33	4435.56	0.35

Table 9: Showing the average values for the Petrophysical properties in reservoir J10.

*Reservoir **10***										
Wells	Top (MD)	Base (MD)	Gross (MD)	Net (MD)	ϕt	ϕe	NTG	Sw	Perm (mD)	Vsh
2	5702	5750	48	48	0.34	0.33	1	0.23	4263.12	0.04
3	5821	5905	84	46.22	0.23	0.15	0.55	0.36	156.97	0.35
25	5680	5785	105	78.25	0.26	0.21	0.74	0.31	1166.09	0.24
35	5642	5695	53	53	0.33	0.32	1	0.24	3749.25	0.05
58	5546	5579	33	33	0.32	0.29	1	0.25	2685.55	0.07
60	5924	5989	65	65	0.35	0.34	1	0.23	5362.57	0.04
65	5695	5762	67	67	0.37	0.35	1	0.22	11739.59	0.04
		Average	*65*	*55.78*	*0.31*	*0.28*	*0.90*	*0.26*	*4160.45*	*0.12*

Table 10: Input Data for the Volumetric analysis for Reservoir J10

Net to Gross	0.89
Porosity	0.28
Water saturation	0.26
Formation Volume Factor	1.25
Recovery factor	0.35
Oil Water Contact (OWC)	-7097ft

Table 11: Output result for both stochastic and deterministic volumetric estimation for Reservoir J10

Stochastic Model For Volumetrics For Reservoir J10	
STOIIP[*10^6 STB]	Recoverable oil[*10^6 STB]
651	228
Deterministic Model For Volumetrics For Reservoir J10	
STOIIP[*10^6 STB]	Recoverable oil[*10^6 STB]
614	215

For the Volumetric analysis, the parameters used in the estimation of Stock Tank Oil Initially in Place (STOIIP) were generated using the Petrel Software. The imputed data were the average values obtained from the comprehensive petrophysics of the reservoirs of interest. Table 4.10 to 4.13 shows the result or outcome realized for the J10 and J3 reservoirs in both the stochastic and deterministic probability conditions.

Two hydrocarbon reservoirs were delineated in the D-One field with varying sand unit thickness suggesting a possible occurrence of faults. The shale and sand layers, increased and decreased with depth respectively. Two reservoirs were identified as hydrocarbon bearing units from the Resistivity log across the 7 wells.

Table 12: Input Data for the Volumetric analysis for Reservoir J3

Net to Gross	0.61
Porosity	0.21
Water saturation	0.33
Formation Volume Factor	1.25
Recovery factor	0.35
Oil Water Contact (OWC)	-5862ft

Table 13: Output result for both stochastic and deterministic volumetric estimation for Reservoir J3

Stochastic Model For Volumetrics For Reservoir J3	
STOIIP[*10^6 STB]	Recoverable oil[*10^6 STB]
1054	369
Deterministic Model For Volumetrics For Reservoir J3	
STOIIP[*10^6 STB]	Recoverable oil[*10^6 STB]
921	323

Petrophysical analysis of the J3 and J10 reservoirs revealed average parameters as: water saturation (0.26 - 0.33), gross thickness (65 - 140ft), net thickness (55.78 - 89.49ft), net-to-gross (72 - 98%), porosity (17 - 34.7%), and permeability (4160.4 - 4435.56 mD). Tables 10 to 13 shows that reservoir J10 is more prolific than J3 within the D-One Field. Volumetric analysis estimates the volume of hydrocarbon in place to be 614MMSTB – 1054MMSTB while recoverable oil is between 215-369MMSTB. These results evidently show that the D-One field, has an exploitable hydrocarbon potential.

Conclusion: Looking at the Petrophysical parameters that was obtained from the reservoir characterization using the well log and 3D seismic data available, we can infer that the two reservoirs mapped, correlated and modelled across the seven wells has a respectable hydrocarbon potential.

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