Leveraging on Legacy Seismic Datasets to Mature Hydrocarbon Opportunitiesin Lemur Fieldby Merging Datasets and Deploying Broadband Seismic Processing Technique

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ABSTRACT

The world at large is constantly in need of energy to power industries, drive turbines, light and heat up homes. Hydrocarbon is that one energy source which has been around for a while and is helping man address his quest for industrialization. However, the easy shallow depth hydrocarbons are getting depleted and thus exploration now drive for deeper hydrocarbon into the basin and near field exploration in other case. The need for WRFM (well, reservoir, and facility management) with infill wells cannot be over-emphasized and has become essential for assets maturation and ullage utilization. Therefore, leveraging on existing seismic dataset and merging different vintages together to help improve signal to noise ration and image fields that are straddled on different seismic datasets is key and essential for planning infill wells and near field exploration. A merge of three different seismic datasets was done to help better image the Lemur field. After the merge, an optimum velocity model was built, and migration carried out. This led to a better resolved broadband seismic image which is essential in understanding hydrocarbon fields and unlocking more reserves. For proper seismic interpretation to take place, clearly understanding the stratigraphic features to map, in this case, straddling across fields, is key to delivering the structural framework and thus delineating the reservoir architecture. This is tied to having good events continuity and true amplitudes in the seismic dataset. In this paper, reprocessing an already existing seismic dataset with recent technology (broadband processing) have shown more structural and stratigraphic features which were not clear in the legacy seismic of the Lemur field, onshore Niger Delta, Nigeria. The most impacting part of the workflow deployed in this work is the Merge of the different surveys, the broadband processing and accurately estimating the velocity used for migration. The broadband processing implied preserving the low frequency as well as the high ones in every step of the processing with greater emphasis on the lows which is often not factored in a conventional seismic processing workflow. However, the process also preserves the low frequency noise which then requires special attention in the entire workflow. Also, the legacy dataset had an inherent phase issue which made it difficult to clearly identify the reservoir in the field. This was also addressed in this project. The benefits of this work were evident in the level of details observed in the new seismic when compared with the legacy seismic, there is better fault definition and event continuity at areas of development interest and even at deeper levels. Also, the pseudo-acoustic impedance results showed that the current processing have imaged the stratigraphy better than the conventional processing. On the basis on this new seismic dataset, a new infill production well was drilled in the field with success.

Keywords: Velocity Model, Broadband, WRFM, Stratigraphic mapping, Legacy dataset,Maturation

INTRODUCTION

The world at large is constantly in need of energy to power industries, drive turbines, light and heat up homes. Hydrocarbon is that one energy source which has been around for a while and is helping man address his quest for industrialization. However, the easy shallow depth hydrocarbons are getting depleted and thus exploration now drive for deeper hydrocarbon into the basin and near field exploration in other case. The need for WRFM (well, reservoir, and facility management) with infill wells cannot be over-emphasized and has become essential for assets maturation and ullage utilization.

Exploring and developing Hydrocarbon as an energy source continues is key to industrialization. It begins with earth science, Geophysical imaging the subsurface (seismic datasets), ensuring that the plays (source, reservoir seal, traps, are in other, then drilling/producing wells and surface facilities, finally to the market.

Onshore Niger Delta is in the extensional zone which is associated with large listric growth faults, collapsed crest faults and tilted fault blocks (see figure 1).

The authors wish to thank NNPC Limited, NNPC Upstream Investment Management Services (NUIMS), The Shell Petroleum Development Company of Nigeria Limited for release of the materials and permission to publish this work.

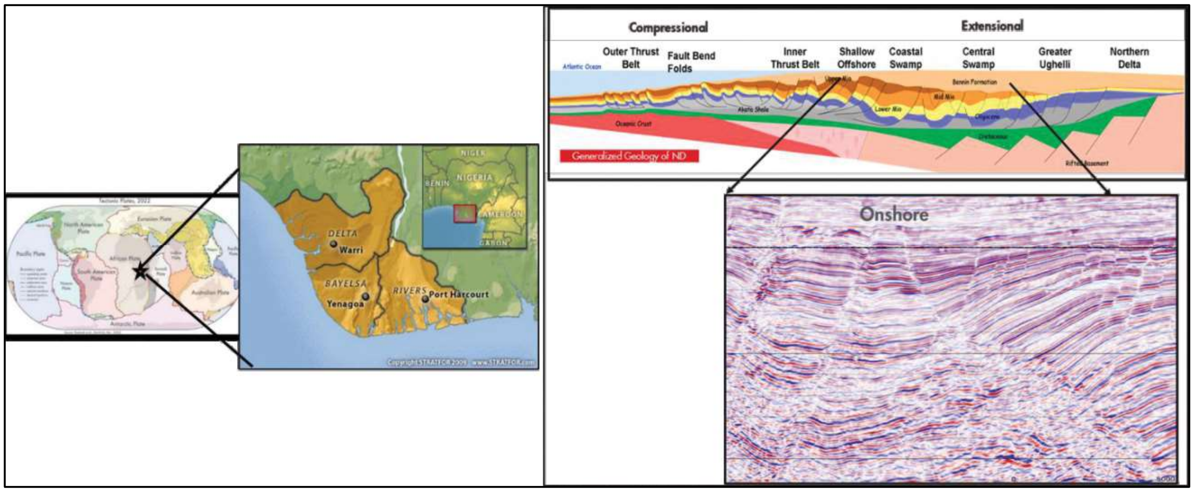


Figure 1: Location Map of the study area; using the tectonic plates and the structural nature of the onshore Niger delta with lots of listric and antithetic growth faults evident in the seismic dataset. Thrusting in the Niger Delta. The onshore area is characterized with onshore extensional growth faults and offshore compressional reverse faults.

Geophysical Challenges:
Noise
Statics
Fault Shadows
Velocity Model Building- Shallow and Deep

Drivers for this project was to Improved imaging and other deliverables (gathers, velocities etc) that will add value to the business thus successfully drilling well1 planned to develop XXXBcf of gas from reservoirs. It is also planned to validate well2 & well3 (threatened wells) by de-risking uncertain deeper targets. Leverage on broadband processing to improve image quality, fault resolution and amplitude preservation. This will further lead to tranche-2 development will also benefit from this seismic re-processing including partially appraised targets with up to xxxBCF.

METHODOLOGY

Therefore, leveraging on existing seismic dataset and merging different vintages together to help improve signal to noise ration and image fields that are straddled on different seismic datasets is key and essential for planning infill wells and near field exploration.

A merge of three different seismic datasets was done to help better image the Lemur field. After the merge, an optimum velocity model was built, and migration carried out. This led to a better resolved broadband seismic image which is essential in understanding hydrocarbon fields and unlocking more reserves. For proper seismic interpretation to take place, clearly understanding the stratigraphic features to map, in this case, straddling across fields, is key to delivering the structural framework and thus delineating the reservoir architecture. This is tied to having good events continuity and true amplitudes in the seismic dataset.

In this paper, reprocessing an already existing seismic dataset with recent technology (broadband processing) have shown more structural and stratigraphic features which were not clear in the legacy seismic of the Lemur field, onshore Niger Delta, Nigeria. The most impacting part of the workflow deployed in this work is the Merge of the different surveys, the broadband processing and accurately estimating the velocity used for migration. The broadband processing implied preserving the low frequency as well as the high ones in every step of the processing with greater emphasis on the lows which is often not factored in a conventional seismic processing workflow. However, the process also preserves the low frequency noise which then requires special attention in the entire workflow. Also, the legacy dataset had an inherent phase issue which made it difficult to clearly identify the reservoir in the field. This was also addressed in this project.

The workflow adopted was to start with pre-processing (shot processing) of the dataset; most notable are- Noise attenuation which helps to improve the signal-to-noise-ratio, De-multiple and Deconvolution which aid spatial resolution, and Anomalous amplitude balancing. Pre-processing is very key to the success of the imaging as this step compensates for the imprints and energy loss associated with acquisition. Details of the steps can be found in figure 2 .

NB: All the tools deployed in this project are Shell proprietary technologies, as such the description of the terms might not sound very conventional, but we'd try to relate them to conventional applications/purpose.

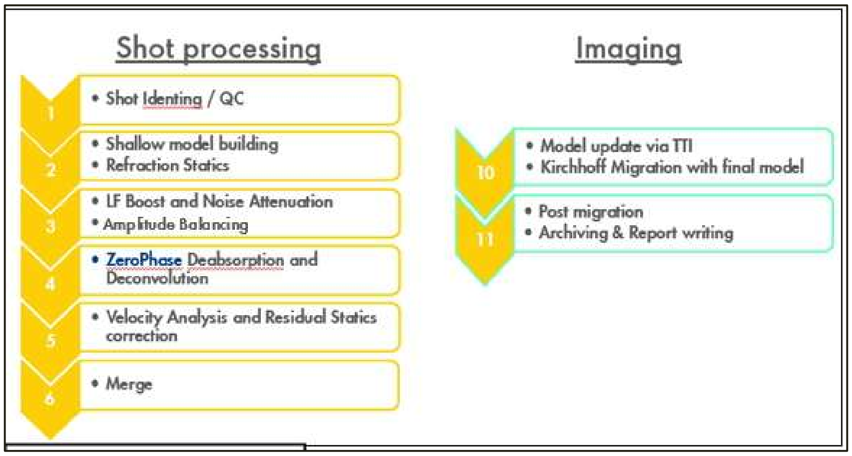


Figure 2: Seismic processing workflow. Emphasis on the pre-processing and the migration.

Noise Attenuation

Noise is any unwanted signal. It is ubiquitous. We primarily have two types: coherent (ground roll, power line noise etc.) and incoherent noise (wind, ocean waves etc.),

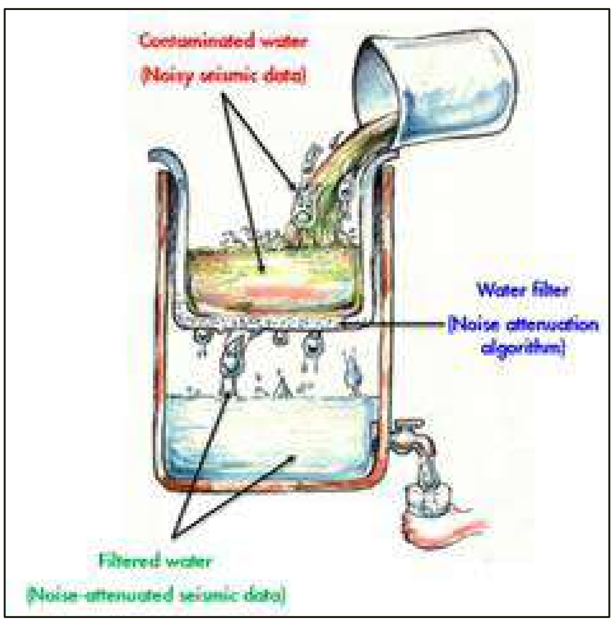


Figure 3: A schematic to illustrate the concept of Noise attenuation likened like a water filter purifier.

(Shell Technical Report, 2012, and Osimobi *et al.,* 2023). Noise attenuation challenges have kept geophysicists busy for many years. Progress have been made but total elimination remains an elusive goal – hence attenuation (see figure 3 above for illustration of noise attenuation). There are two main approaches to attenuate noise: prediction & subtraction and filtering. Some of the tools deployed for Noise attenuation include- ground roll attenuation, spikes removal, random noise attenuation, noise trains and residual noise attenuations, etc (These are Shell proprietary seismic processing tools), see figure 4 below.

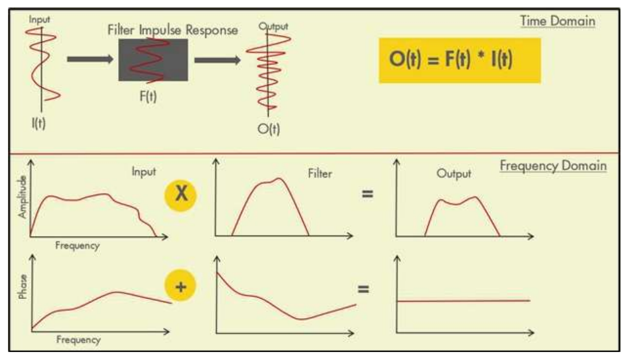


Figure 4: Depending on the physical property of the noise, we move around between time and frequency domain and use the discriminating physical properties to design filters based on boundary conditions.

To be able to understand the frequencies with dominant noise to be attenuated, we often split the seismic dataset into sub-bands (see figure 5 below) and then design the appropriate filter to attenuate the noise.

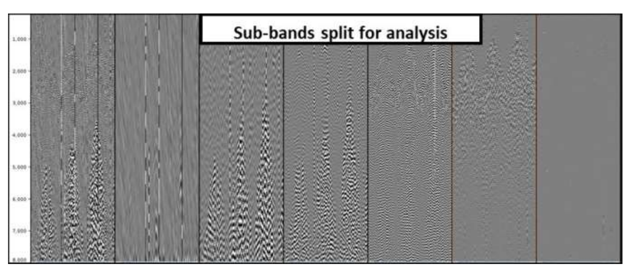


Figure 5: Splitting the seismic dataset into Octave bands to delineate the frequency at which the different noise exists.

Residual Anomalous High Amplitude Balancing

Low frequency preserving de-noising was applied using an operation which handles localized anomalous amplitudes. with mixing (pseudo stack) applies a spatial filter for noise suppression and anti-aliasing protection at different frequency sub-bands.

Deconvolution

The recorded seismogram can be modelled as a convolution of the earth's impulse response with the seismic wavelet. This wavelet has many components, including source signature, recording filter, surface reflections, and receiver-array response, (Shell Technical Report, 2015 and Osimobi et., 2023). The impulse response comprises primary reflections (reflectivity series) and all possible multiples. Deconvolution is a filtering process which removes a wavelet from the recorded seismic trace by reversing the process of convolution.

Deconvolution is a process that counteracts this previous convolution action. It compresses the basic wavelet in the recorded seismogram, attenuates reverberations and short-period multiples, thus increases temporal resolution, and yields a representation of subsurface reflectivity, (Shell Technical Report, 2012 and Osimobi *et al.,* 2023). The earth's impulse response is what would be recorded if the wavelet were just a spike. Therefore, the aim of this process is to convert every occurrence of the seismic wavelet in the data to an equivalent spike to obtain the earth's impulse response.

The deconvolution filter was derived on 1 trace within a time gate of 750ms – 2500ms and it was applied on the whole record length of each trace individually. This operator is applied to the input dataset, and the prediction thus obtained is then subtracted from the input data; Gap=32, Operator length= 200. Gapped deconvolution was performed by deriving an optimal single gap prediction operator via the Wiener-Levinson algorithm. After deconvolution application, an autocorrelation was computed to QC the deconvolution and results of the reverberations since spiking deconvolution suppresses multiples. Figure 4 below shows the results before and after deconvolution, stacks, and their corresponding autocorrelations. As can be observed, reverberations are reduced after deconvolution, multiples attenuated and focusing enhanced.

Amplitude Balancing

Often due to operations and or terrain challenges, anomalously high amplitudes at localized areas could be observed on a seismic dataset, (Shell Technical Report, 2010 and Osimobi *et al.,* 2023). This can be observed on a time slice as shown in figure below. Correcting for this artifact is very critical for quantitative AVO interpretations. These anomalies could be misleading to be interpreted as a fluid effect in an Amplitude vs Offset (AVO) analysis. The correction was done, and the result is as shown below.

De-absorption

Inelastic properties of rocks cause absorption of seismic energy which increases with time and frequency. Deabsorption aims to recover high frequencies and amplitudes lost due to earth filtering effect and remove the non-stationarity of the wavelet. This allows better signal estimation for subsequent deconvolution processes, (Osimobi *et al.,* 2023).

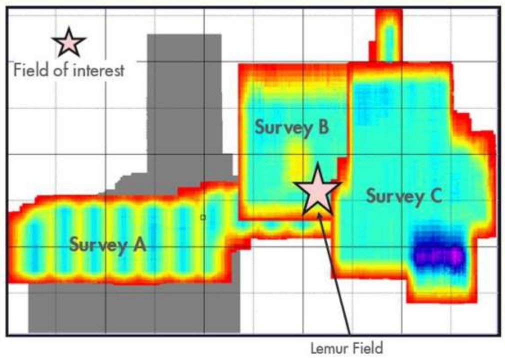
For this project, a phase only deabsorption was done, with the absorption factor of 0.16 estimated by modeling the wavelet signal from the denoise. The idcode input signal into SPIDEC was divided into time gates: the shallow, middle, and deep gates. The shallow signal was then inverted and convolved with both the mid and deep signal to obtain their respective de-absorbed versions. The resulting spectrum was used to derive the absorption slope of the data. The correct absorption factor was arrived at when the de-absorbed mid and de-absorbed deep signal matched the shallow signal within the useful frequency range.

Zero Phasing

Seismic data acquired in the field is dominated by minimum phase wavelets because of the explosive source used. Processed data up till this stage is also dominated by minimum phase wavelets. To aid seismic interpretation, it is imperative for the wavelets in the data be zero phased so that every boundary between layers in the subsurface is represented by the peak/trough of the wavelets. Zero-phase filters were derived for each survey, (Osimobi *et al.,* 2023).

Merge

To be able a to impact the area of interest, Lemur filed, three different surveys came together (see figure 6 below) to gain the required fold for good imaging on the Lemur structure. The individual surveys were merged prior to migration. Before merging, the survey B, acquired in West-belt coordinate reference system was converted to Mid-belt system to be in the same reference system as the surveys A and C. The conversion involved saving the west belt coordinates in dummy headers, re-binning the west belt data to mid belt and recalculating the global coordinates of the bin-centers, (Shell Technical Paper, 2016).



Key Acquisition Parameters

Survey	Survey B	Survey C	Survey A
OML	61	22	28
Location	Land	Land	Land
Contractor		JV 171 UGNL)	Geo-Parkla Crew 929
Acquisition geometry	Cross Spread	Cross Spread	Cross Spread
Bin size	25mx25m	25mx25m	25mx25m
Nominal Fold	48	48	40
Survey area	220 sq.km	386 sq.km	468 sq.km
Recording instrument	SN368	SN368	SN368
Acquisition record length	8sec	6sec	6 sec
Number of receiver lines	6	6	6
Receiver line spacing	400m	400m	500m
Shot line spacing	350m	600m	600m
Receiver spacing	50m	50m	50m
Source spacing	50m	50m	50m
Active receiver per line	96	192	120

Figure 6: Showing the location of the Lemur field of study. Worthing to note is how it straddled through three seismic data coverage. These datasets formed the basis for the merge. Also shown are the different acquisition parameters.

The merge process involved using the Survey C survey as the master survey "reference" for the surveys A and B to be matched to. Nominal time shift between surveys A and B and between the B and A were estimated at the overlap zones, see figure 7 below. The next to achieve a good match would be to estimate amplitude scaling factors for each survey and apply the appropriate amplitude scaling factors to the survey B and survey A relative to the "reference" survey C. However, amplitude scaling was not applied in this project as the 3 surveys had similar amplitude scaling factor.

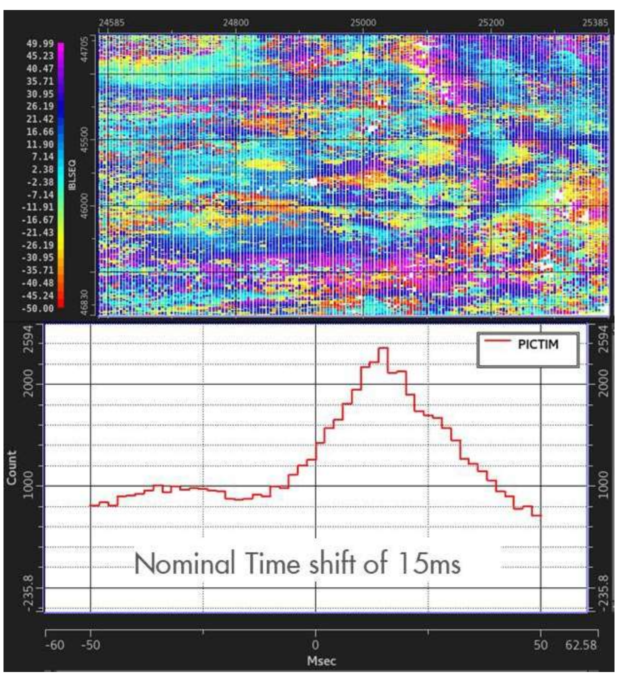


Figure 7: Time shift estimation across survey boundaries. As can be seen, a nominal time shift of about 15ms was needed.

Velocity Model Building and Migration

We observed that we also have scope to further improve the velocity model for migration and to this effect we carried out a one-pass Travel Time Inversion (TTI) using the gathers generated from a migration done with the legacy velocity (which becomes the initial velocity model), (Shell Technical Paper, 2015). A guide to an understanding of interpreting an accurate velocity is in figure 8 below.

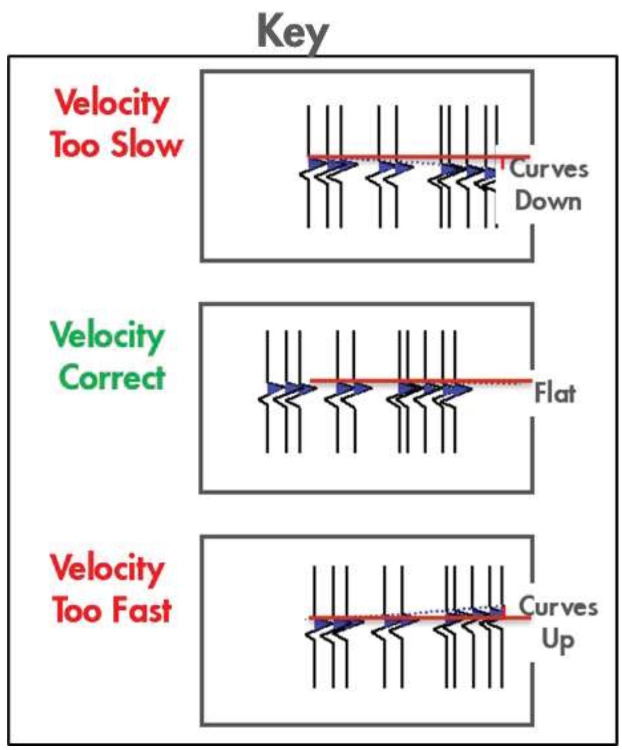


Figure 8: An illustration explaining how nature of seismic gather could be used to understand the velocity anomaly.

Essentially, the measure of the accuracy of the velocity is in the flatness of the pre-stack migrated gathers. After accurately estimating the velocity errors by picking the Residual Move-Out (RMO) through picking of the RMO on the gathers, the picks are then used to run a TTI by minimizing the misfit between the observed and the modelled. Once a relative flat gather is achieved, the processed is stopped and a migration was carried. This is an iterative process between velocity model building and migration. After one or two or even three passes of TTI depend on the peculiarity and cost effectiveness of individual processing, a final velocity model is then used to run the final migration. For this project the migration operation used was the Kirchhoff Pre-stack Depth Migration (Pre-SDM). The migration was done in two parts: first, a fast-track migration using the legacy velocity and, an updated migration using an updated velocity (the legacy velocity was updated).

RESULTS AND DISCUSSION

The benefits of this work were evident in the level of details observed in the new seismic when compared with the legacy seismic, there is better fault definition and event continuity at areas of development interest and even at deeper levels. Also, the pseudo-acoustic impedance results showed that the current processing have imaged the stratigraphy better than the conventional processing. On the basis on this new seismic dataset, a new infill production well was drilled in the field.

Noise Attenuation:

The figure below (figure 9) shows the result from one of the several noise-attenuation techniques used. The left panel shows the input into the operation and the right panel shows the output. As can the observed, the noise (low frequency ground-roll masking the signals have been greatly attenuated with less impact on the signal.

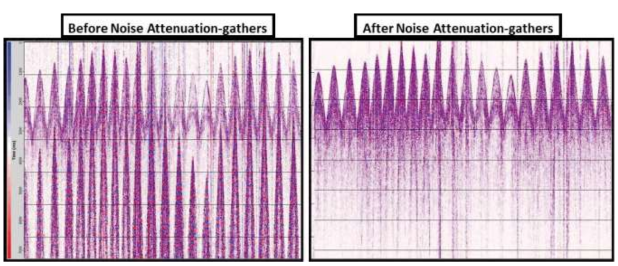


Figure 9: Comparative result of the Noise attenuation step in gathers.

Thereafter the gathers were stacked using a regional velocity to observe the impact of the noise attenuation in a Common Mid-Point (CMP) stacked domain for the datasets before and after noise attenuation. See results in figure 10 .

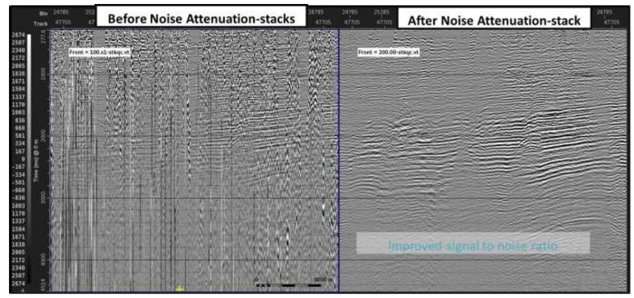


Figure 10: Comparative result of the Noise attenuation step in CMP stack.

Deconvolution:

Similarly, improved spatial resolution was achieved after deconvolution was carried out (see figure 11 below). As can be observed (Though subtle) from the output seismic panel, multiple energies and reverberations have been largely reduced, thus leading to better resolution and improved signal to noise ratio. Consequently, the autocorrelation panel points to an attenuation in reverberation energies which distorts the seismic image.

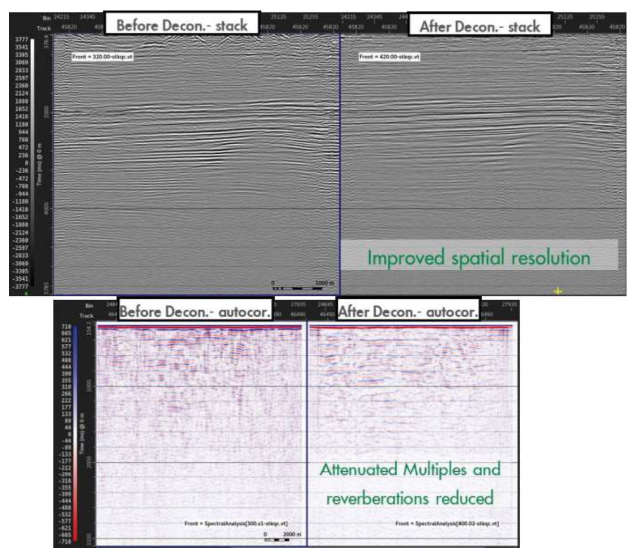


Figure11: Comparison result for Deconvolution. Top section showed the stacks, while bottom section showed the Autocorrelation.

Amplitude Balancing:

Amplitude balancing as stated earlier is very critical, this will ensure that the correct fluid/lithology interpretation is inferred from the seismic dataset. Figure below shows a map display of the result of the amplitude balancing operation. As can be observed, the anomalous high energy especially in the highlighted area has been normalized, giving rise to a more geologic distribution of the subsurface energies. Also, the seismic on the output panel when compared with the input panel (see figure 12) is more stable and balanced across.

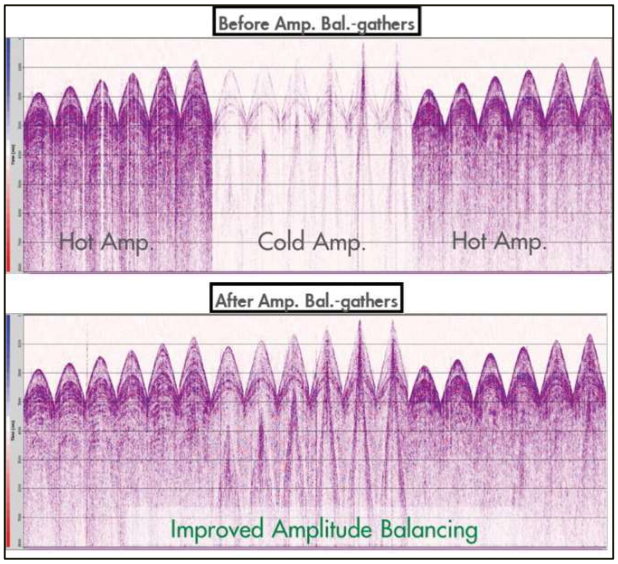


Figure 12: Showing result of Amplitude balancing. Top (before amplitude balancing) and bottom (after amplitude balancing).

Merge

As stated earlier, a merge of three different datasets was imperative to ensure that the target area was fully covered by a full fold seismic dataset and a robust image is achieved. Figure 13 below shows the result of the merge after estimating and applying a nominal time shift across the three datasets.

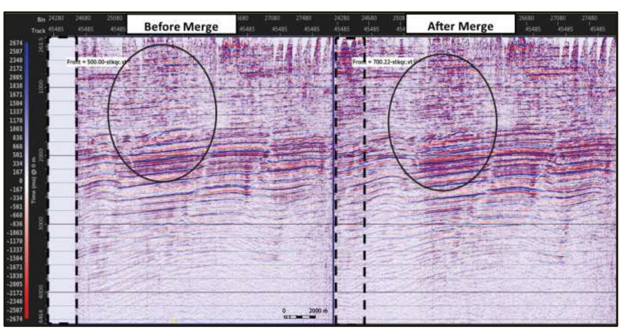


Figure 13: Showing result of the merge; left (before merge) and right (after merge).

As can be observed after the merge, a seamless, high fold, better event continuity, higher signal to noise ratio was achieved. This is what is expected when a good merge is done. On completion, the merged data showed no significant shifts in terms of phase and time for the surveys.

Velocity model building

To further improve the focusing of the dataset, an accurate velocity medium is required. Figure 14 shows the result from velocity model building. As can be observed, the bottom panel which represent gathers after velocity update is flat when compared to the initial velocity model. This is an indication that the velocity model is robust.

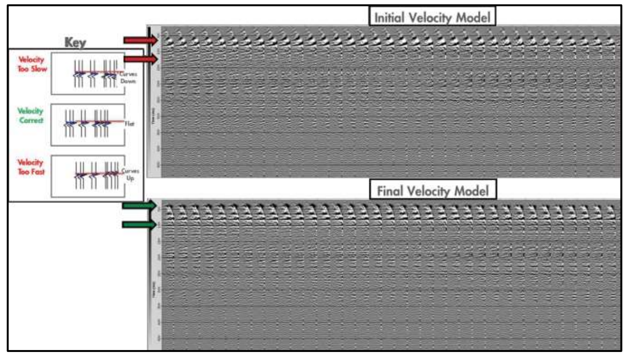


Figure 14: Gather showing result of the velocity update; top (Initial) and Bottom (updated velocity model).

Similarly, the initial and final velocity models were overlaid on their respective migrated stacks (see figure 15 below). From the observation, the updated velocity model gave rise to a more geologic velocity medium, (see figure 15) with improved focusing.

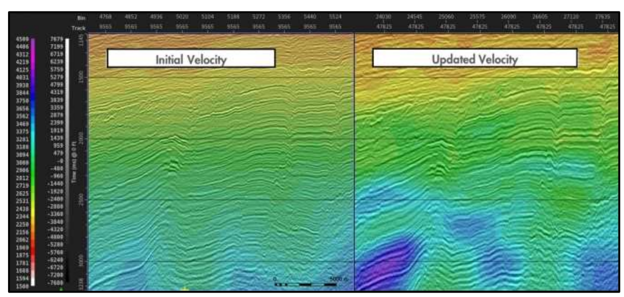


Figure 15: Velocity overlaid on stack showing result of the velocity update; left (Initial) and right (updated velocity model).

Also, the updated velocity model was found to be more accurate that the legacy (initial velocity model) when compared to a sonic log which is a ground-trotted dataset, see figure 16 below. This is measure of how geologic and robust the updated velocity model is comparing for the initial velocity model.

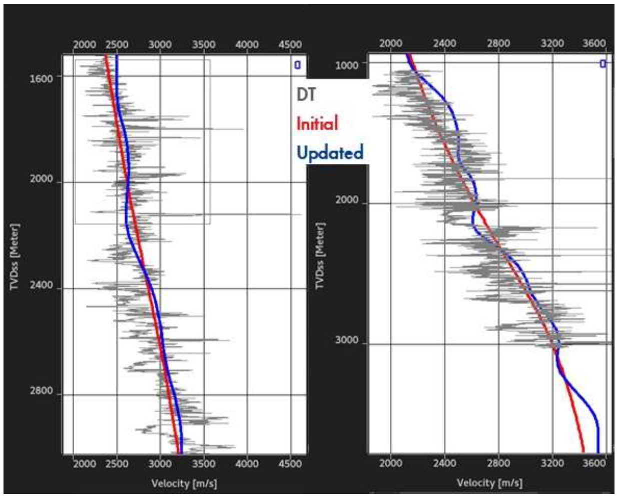


Figure 16: Comparing the seismic velocities (initial and updated) with sonic (DT) along some key well paths.

This updated velocity model aided better time-to-depth conversion, pore pressure prediction and improved seismic imaging. A migrated stack comparison of the legacy seismic dataset and the current seismic dataset (see figures 17 and 18 Below) showed improved imaging quality, enhanced spatial and vertical resolution, better fault definition, enhanced even continuity and higher signal to noise ratio.

DISCUSSION: BUSINESS IMPACT, INTEGRATION, AND COLLABORATION WITH OTHER SUBSURFACE DATASETS

The achieve the desired goal which was to drill a successful well (drill into a thick high-quality sand that is hydrocarbon bearing), the result from the seismic was further integrated into other models and workflow to ensure robustness.

First is the geological conceptual model-

A conceptual model was built see picture below. From the model, reservoir sands in the Lemur field were interpreted to be of Serravallian (Middle Miocene) age. It comprises dominantly of channels and shorefaces – forming part of the TST in a proximal shelf depositional setting, see figure 19.

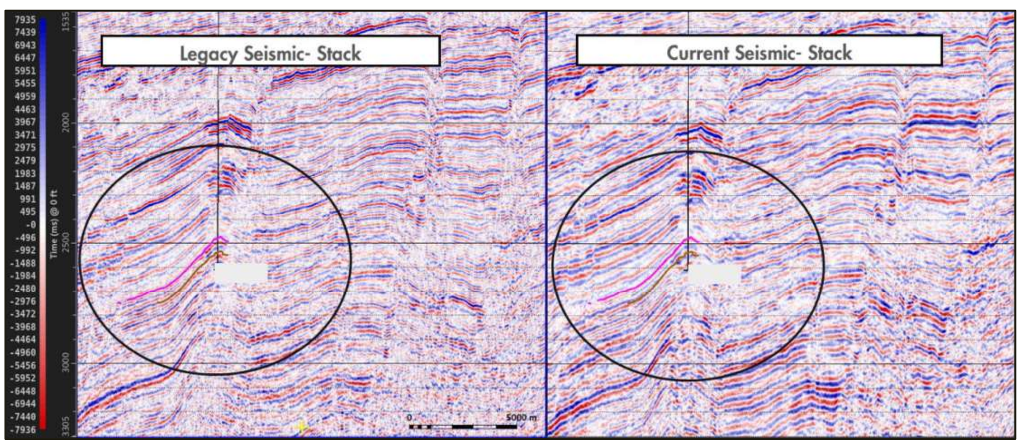


Figure 17: Comparing the current seismic dataset with the legacy seismic at LINE 1

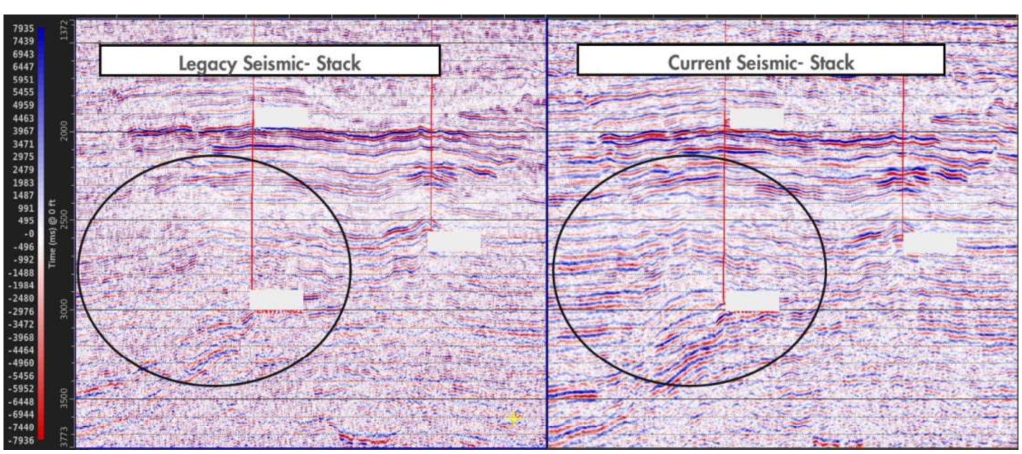


Figure 18: Comparing the current seismic dataset with the legacy seismic at LINE 2

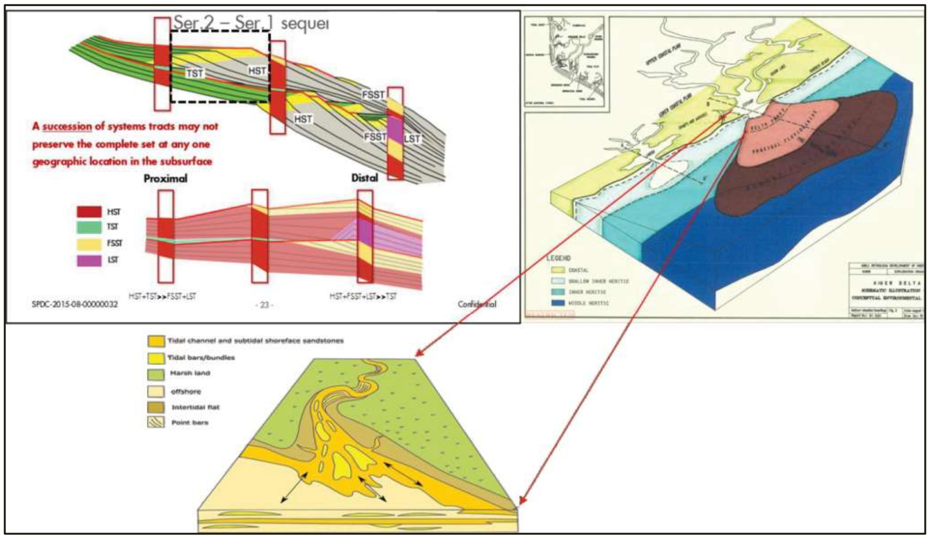


Figure 19: Conceptual model of Lemur Field.

Also, a detailed study of the depositional model was carried out using logged datasets from existing wells in the area. The result corroborates with the conceptual model and the current (newly processed) seismic dataset due to its broadband nature resolved the channel imprint, see picture 20 below.

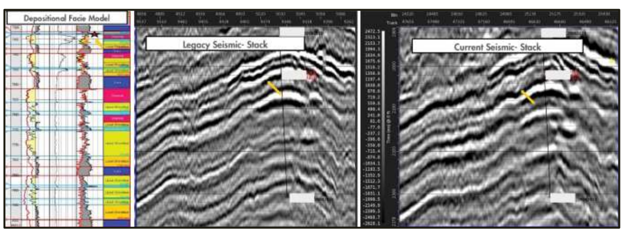


Figure 20: Integrating the conceptual model with the seismic imaging in the current re-processing of Lemur Field.

Furthermore, as part of the integration and collaboration, a quantitative and seismic interpretation (QI and SI) were carried out to further calibrate the results and the result is as shown in figure 21below.

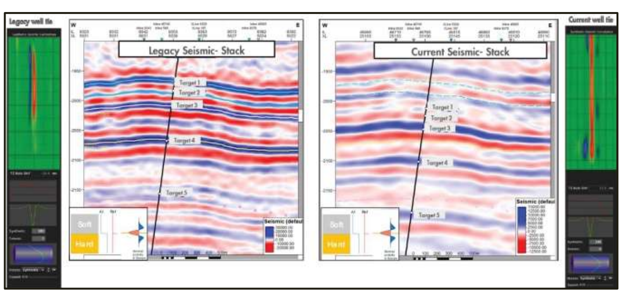


Figure 21: Showing well-to-seismic-ties using both legacy and current seismic and an update of the seismic interpretation was carried of Lemur Field.

Similarly, a Wide Band Spectral Decomposition was carried out and the result is as showed in figure 22 below. Based on well calibration, light hues (axial channels)

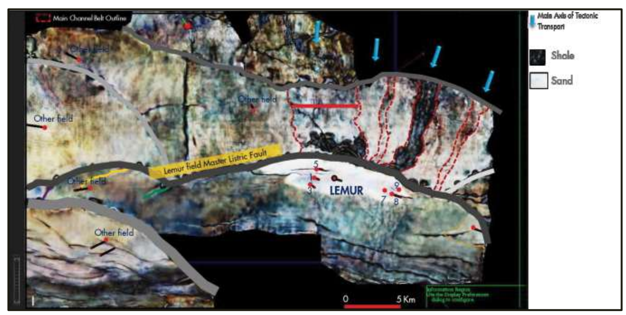


Figure 22: Integrating the result with a Wide Band Spectral Decomposition for further delineate Lemur prospectivity.

represent good reservoir quality while dark hues (brown to purple) denote relatively poorer reservoir quality. Overall good sand development – with axial channels along the sand fairway. Sands are better developed in the western part of Lemur and get poorer towards the eastern & southern part of overall depositional system.

Furthermore, a stratigraphic framework was built using well correlation of several wells and the results are as shown in figure 23. Depositional system of the Serravallian (Mid Miocene) to Burdigalian (Early Miocene) age reservoir sands in the Lemur is interpreted to comprise dominantly of channels, shallow marine sediments (shelfal deposits)

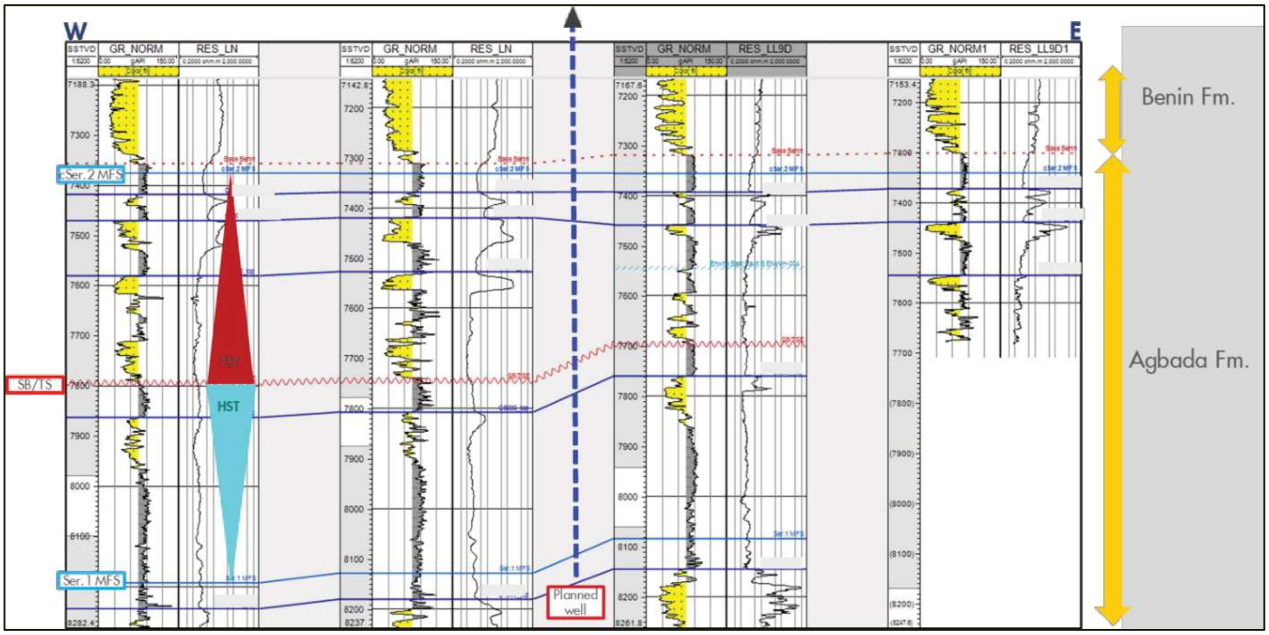
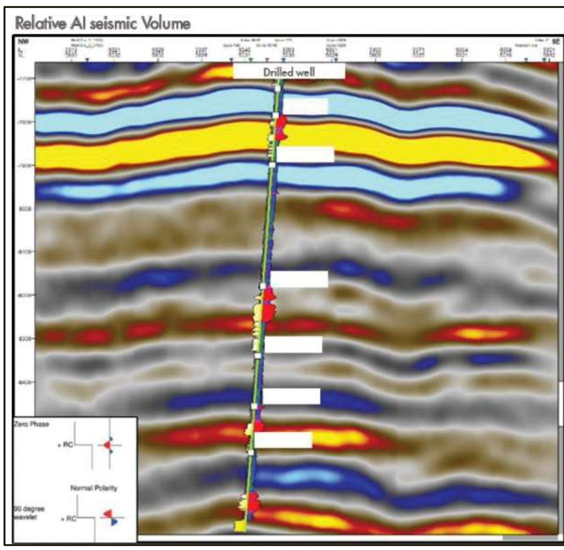


Figure 23: Stratigraphic correlation across the existing wells in the target reservoir and the planned well trajectory



TARGET	BASE CASE PROGNOSIS TVDSS (ft)	ACTUAL TOPS TVDSS (ft)	Difference	DEPTH UNCERTAINTY (ft, tvd)	FLUID TYPE PREDICTION AT RESERVOIR TOP: HIGH CASE	EXPECTED	LOW CASE	ACTUAL FLUID FILL (Top)
Target 1	6105	6079	-26	+/-60	Gas	Water	Water	Water
Target 2	6405	6405	0		Gas	Water	Water	Water
Target 3	6904	6912	8		Water	Water	Water	Water
Target 4	7348	7346	-2	+/-70	Gas	Gas	Gas	Gas
Target 5	7400	7409	9		Gas	Gas	Gas	Gas
Target 6	7514	7512	-2		Gas	Gas	Water	Gas
Target 7	7790	7775	-15		Gas	Gas	Water	Gas

SUBSURFACE RESULTS SUMMARY

Property	Target 8		Target 9	
	Prognosed range	Actual	Prognosed range	Actual
Gross Thickness	0/67/159	84	0/41/93	63
Tops (ftss)	8350/8200/8050	8180	8627/8477/8327	8457
NTG	0.55/0.63/0.73	0.72	0.43/0.53/0.63	0.58
Porosity	0.23/0.26/0.29	0.27	0.20/0.23/0.26	0.23
Gas Saturation	0.63/0.69/0.76	0.73	0.60/0.68/0.76	0.60

Figure 24: Post drill seismic relative impedance section across the target reservoir. Thickness and property prediction encountered is with pre-drill range of prediction.

Post-drill Analysis

The post drill analysis showed that the depth and fluid prognosis aided by the integration of different subsurface understanded were with the uncertainty ranges. Also, the NtG, Porosity, HC saturation, Gross thickness of the reservoir came in as predicted, see figure 24 below.

This goes to show that understanding the prospect is key, you must acquire the right datasets, process it aright and ensure good interpretation is carried out. Thereafter integrate with other datasets like the well information, conceptual/geologic models and plan wells proper. This led to the success of this project.

SUMMARY AND CONCLUSION

In other to continue to meet our energy demand, exploring the hydrocarbon energy source which continues to play critical role in the energy mix is important with huge HC

Exploration potential is critical.

Leveraging of legacy seismic dataset is key. However, the poor quality of the existing seismic data acquired has potential risk to mapping the Exploration and Development opportunities- complex structural configuration. Reprocessing and merging the legacy surveys to image the Lemur field is very important to actualizing the dream.

Processing flow include refraction statics correction, noise attenuation, deconvolution, amplitude balancing, merging, travel time inversion (TTI) and Migration.

Integration and collaboration are at the heart of this- geological conceptual model, depositional model sync with the seismic, QI and SI work (seismic to well tie and Relative AI volume generation), WBSD, well log correlation, and most importantly ensuring that all the different datasets spoke themselves and corroborated with the model pre-drill.

Based on our evaluation using the current seismic dataset, the target was drilled, and the post-drill analysis showed that we were with prognosis.

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