Seismic-Scale Reservoir Facies Characterization Using Elastic Inversion of OBN Dataset: How to Get Past Limitations From Using Only Wells With Elastic Logs Acquisition.

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Abstract
In this paper, we discuss the approach used to translate elastic inversion results of Ocean Bottom Nodes (OBN) seismic data acquired on the EGINA field deep offshore, Niger Delta, into usable geological modeling inputs to control facies spatial distribution in the geological model. Translating elastic inversion results into a seismic-scale facies classification providing a 3D spatial distribution of the latter, usually builds its foundations on available exploration and appraisal wells with good quality elastic log acquisition. Indeed, as long as all the appropriate quality controls are made and proper integration between the geophysics and geological modelling world is enforced, these wells provide excellent calibration points where log and inverted seismic data behaviors can be compared in the elastic domain and at similar scales.

Unfortunately, using exploration and appraisal wells alone usually mean having sub-vertical or slightly deviated well penetrations in the reservoir intervals. This generates limitations inherent to the geometrical configuration of such wells; under-sampling of reservoir facies (oversampling of overburden shales), upscaling of the facies data from log-scale to seismic scale with consequences on facies overlap, mixing and possible under-representation of low-proportion facies but with an important internal heterogeneity role.

The proposed approach is to include development wells in the analysis even without elastic logs. This allows to overcome the limitations described above. Proper quality controls and integration need to be carried out to avoid pitfalls that such an approach could entail. The obtained classification results have shown an improved success index when compared to existing well data (including those that were kept blind).

Introduction and General Geology

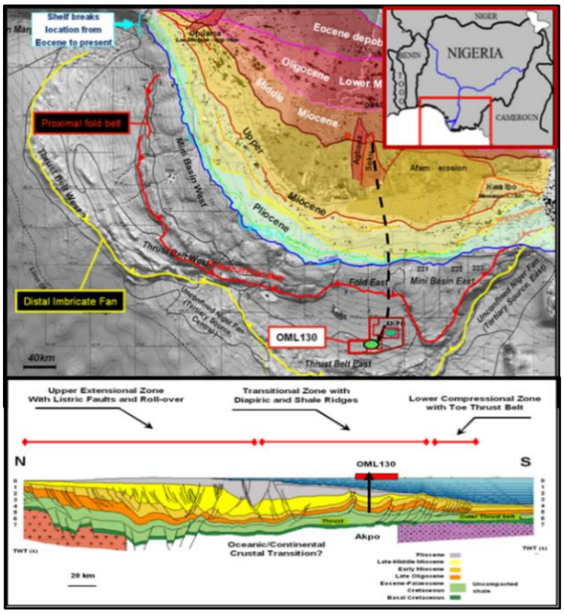

Figure 1: Location of Egina Field, Deep Offshore, Niger Delta

Egina Field was discovered in 2003 in water depths of circa 1500 m and is located in Oil Mining Lease 130 (OML130) about 150 km offshore Nigeria. The field is located in the transition zone between the extensional zone and the compressional toe-thrust dominated zone in the proximal fold belt. This zone is locally known as the Central Plateau or Akpo Plain (Figure 1). Upper Miocene turbidite channel complexes make-up the stacked reservoirs of Egina identified on the NE-SW trending dual-culmination anticline.

In addition to obtaining highest 4D data quality and excellent repeatability (OBN over OBN), the OBN survey was carried out to overcome the following challenges: the field overburden complexity with shallow gas-bearing reservoirs, mud-volcano and shallow turbidite fairways.

OBN results and seismic reservoir characterization

The results obtained from the OBN survey and subsequent PSDM processing significantly improved the seismic image on the field. Typically, when compared to the vintage streamer dataset, the OBN dataset displayed an improved energy penetration in the interval of interest; it significantly extended the frequency bandwidth in the low frequencies while not compromising the high frequencies; and finally it displayed an increased signal to noise ratio hence providing a less noisy dataset for interpretation (Figure 2).

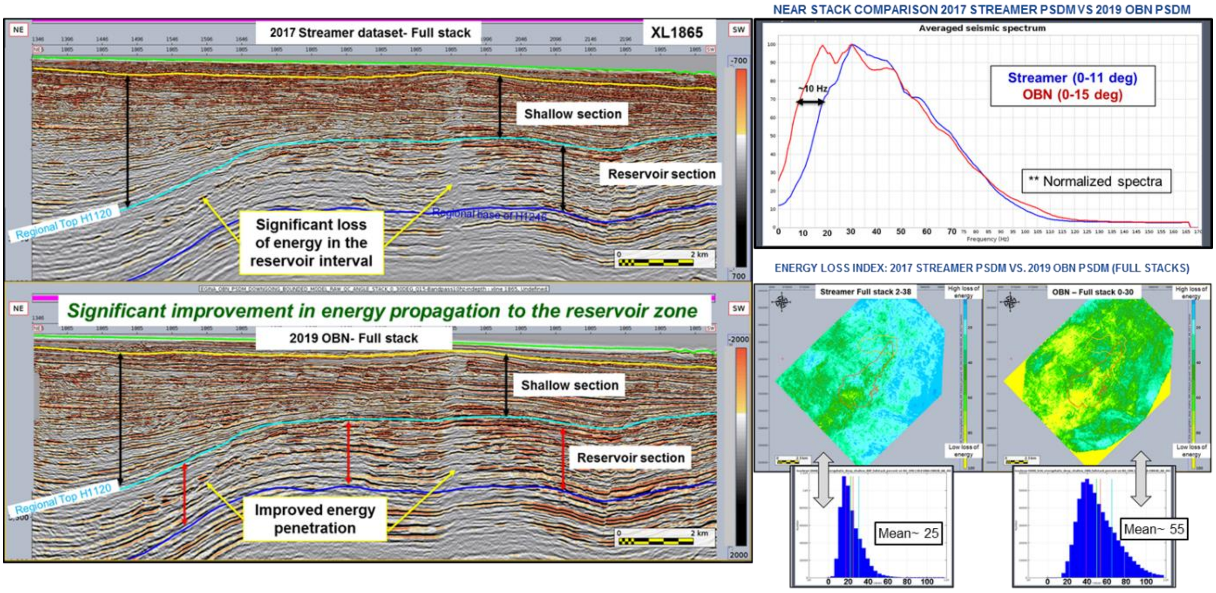

Figure 2: Streamer (Upper section) versus OBN (Lower section) energy penetration in target interval (between displayed horizons). Energy loss index maps quantify the improvement while the near stack spectrums are an example of increased frequency bandwidth towards the low frequencies.

A 3D elastic inversion using this OBN dataset was carried out (*cf. Amoyedo et al. NAPE 2020*). The results obtained from the process were significantly improved compared to the vintage elastic inversion. In particular, the P velocity over S velocity ratio (Vp/Vs) which is a good proxy for sandy reservoir identification matched development well results much better than the vintage (Figure 3).

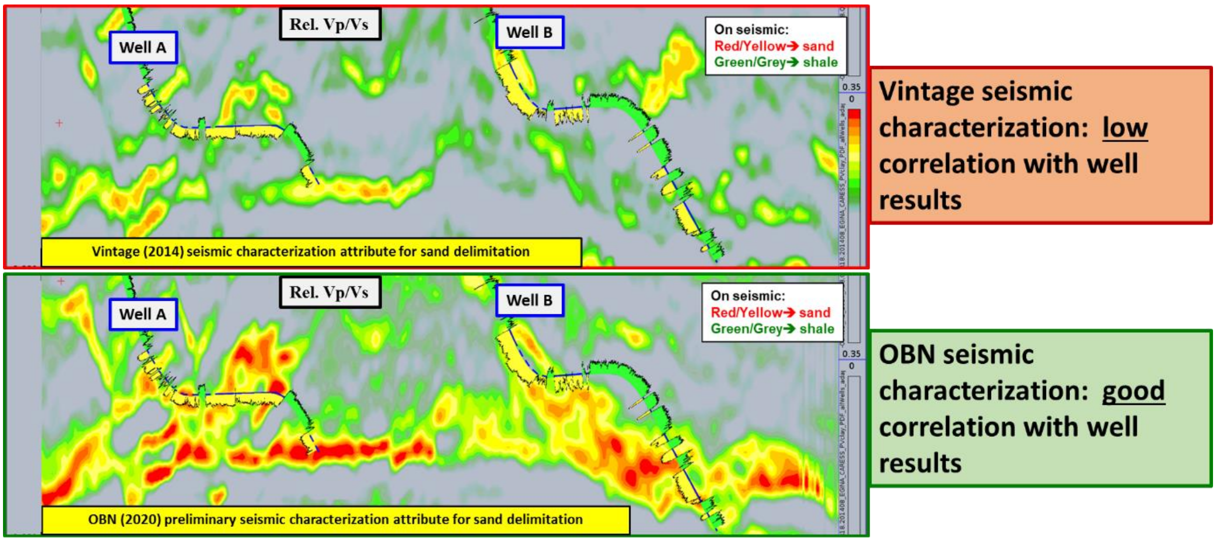

Figure 3: streamer (vintage) derived Vp/Vs cube (top section) vs. OBN derived Vp/Vs cube (bottom section) illustrating sand delimitation and the much better correlation with well results for the OBN-derived Vp/Vs.

In addition to the Vp/Vs, an acoustic impedance cube (IP) was also available and displayed similarly excellent results in terms of well correlation. The next step in the seismic reservoir characterization workflow is to translate the elastic properties into geological properties.

Facies Classification Workflow and Calibration With Wells:

To successfully translate the elastic inversion results into a set of geologically related properties (Figure 4), three main points need to be taken into consideration:

- Understanding the rock-physics behaviour at well log-scale (in the elastic domain) of the different reservoir facies in a given interval.
- The impact of the upscaling from well log scale to seismic bandwidth scale of elastic logs but also of geological facies.
- Comparison of the seismic inversion response compared to the wells' response.

This exercise necessarily requires a set of wells with good quality elastic logs (density and sonic acquisition) as the understanding of the rock-physics behaviour is key to the success of the process. In addition, it is imperative that an adequate well calibration is undertaken as this could negatively affect the calibration of seismic to well geological data, i.e. facies.

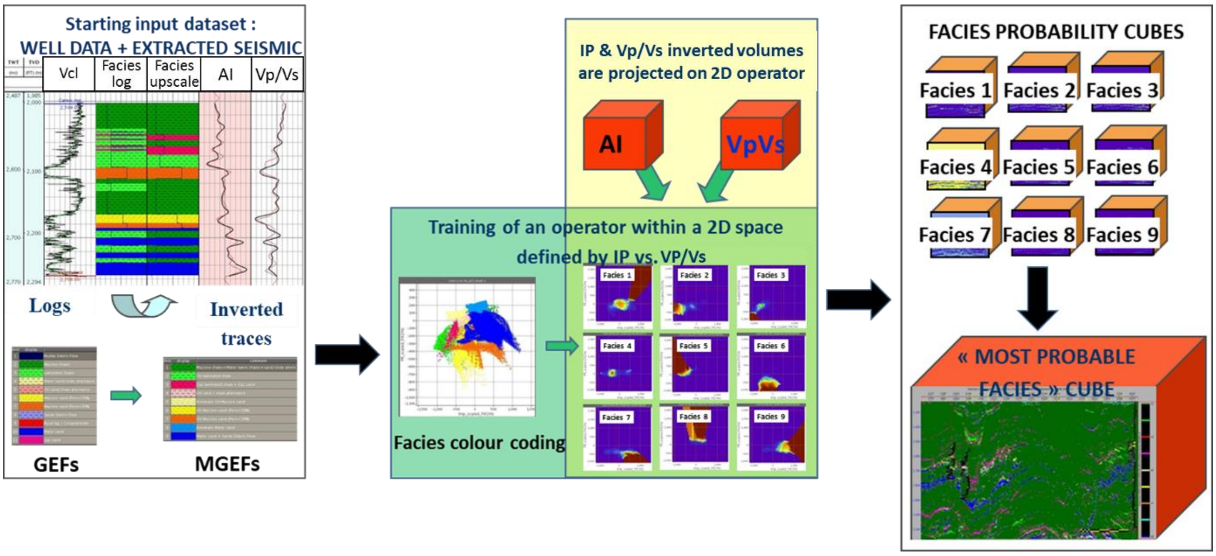

Figure 4: General classification workflow permitting to translate 3D elastic inversion outputs to facies probability of occurrence cubes.

However, the exercise usually suffers from 1) having a relatively limited amount of wells (in this case 5 exploration and appraisal wells) and 2) from the upscaling of geological data to the seismic scale which usually results in accentuating the bias in facies representation bias: shaly facies are overrepresented while sandy facies are underrepresented (Figure 5).

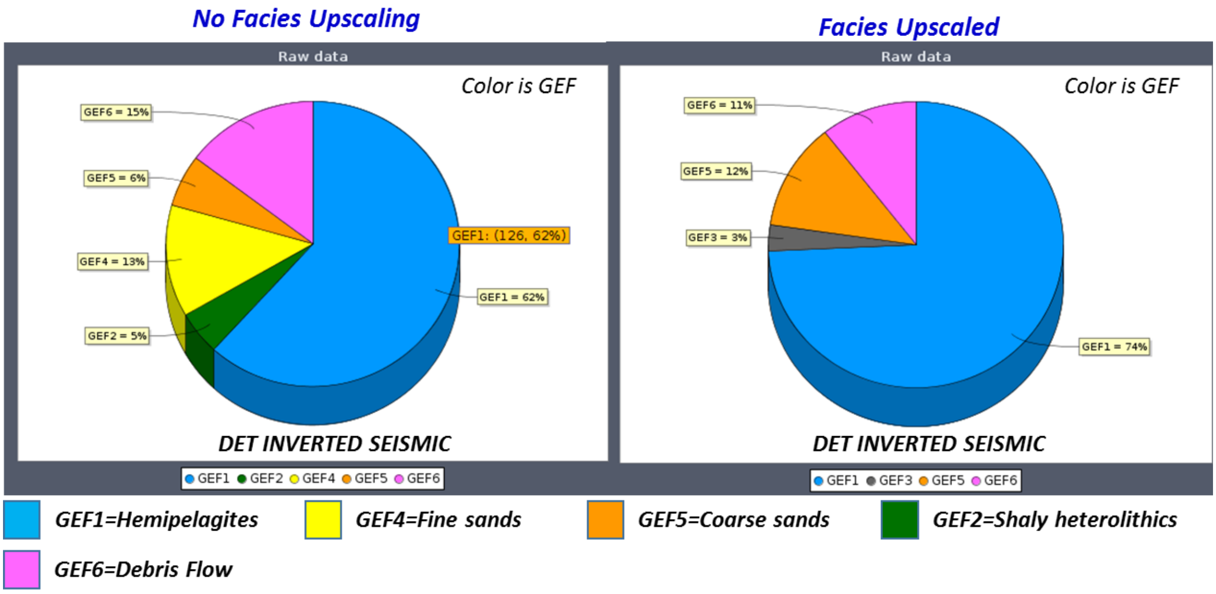

Figure 5: Pie charts illustrating facies present before and after upscaling and their relative proportions. Note the disappearance of GEF4 in the upscaling as well as the overall reduction in reservoir facies proportions (mainly GEF4 and 5 from 19% to 12%)

From the geologist's point of view, the bias in facies representativeness and the apparent decrease in sandy facies proportion is a hurdle towards using the classification results in the geological modelling workflow. In addition, as observed in Figure 5, some facies could be absent in the "upscaled" domain. This needs to be carefully addressed by both the geologist and the geophysicist in particular if specific facies play a significant role in the heterogeneities driving fluid flow in the reservoir.

Using Development Wells to Overcome the Bias in Facies Representation

To overcome these limitations, sub-horizontal development wells are used as input to the classification process in addition to the exploration and appraisal wells. Needless to say that a thorough quality control of the development wells need to be carried out, in particular related to a proper depth match between the well and the seismic. Although these wells do not have elastic logs acquired, and hence no possibility to carry out a proper well to seismic tie, it is assumed that the Vp/Vs cube is a good enough proxy for sandy reservoir presence to qualitatively evaluate the match between the well results and the seismic.

Figure 6 compares the elastic domain crossplots between 1) the log-scale observations on wells possessing elastic logs, i.e. sub-vertical exploration and appraisal well, 2) the detrended seismic inversion results against upscaled facies on these same wells and 3) the detrended seismic inversion results against development wells in addition to the rest. One can observe how the upscaling and under-sampling of reservoir facies affects the density of the point set when using only exploration and appraisal wells against using the development wells in addition. Not only a better balance in terms of facies representation is achieved but it also seems that the point set has a closer correspondence with the log-scale cross-plot.

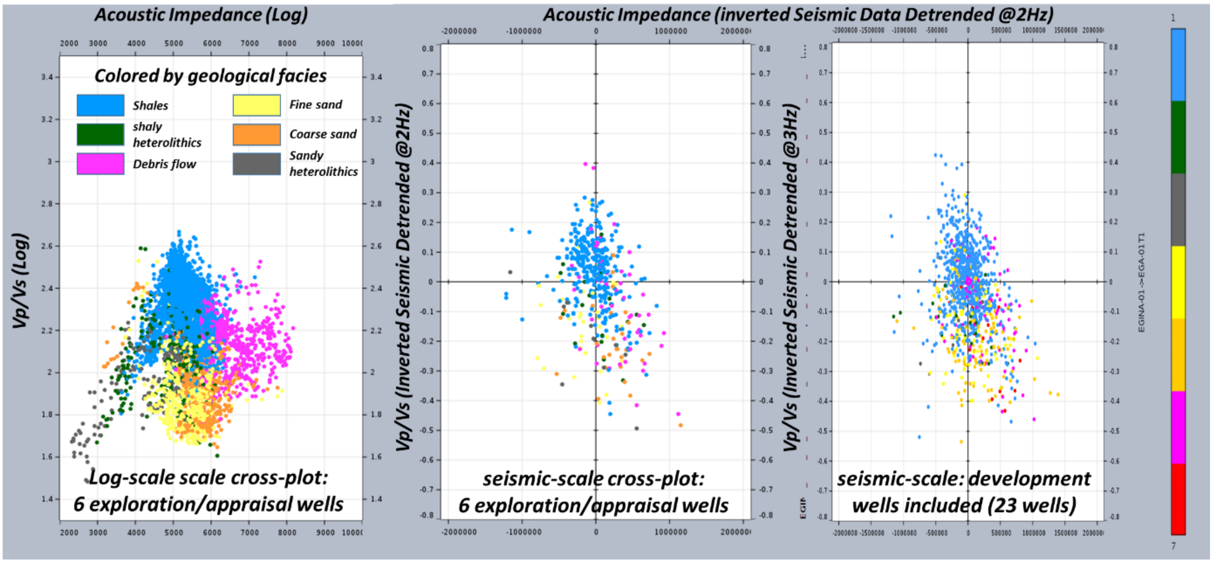

Figure 6: Comparison of facies classification input point set in the elastic domain between log-scale (left), detrended seismic scale with only explo/appraisal wells (middle) and including development wells (right). Note the differences in point density for each facies.

Nevertheless, the classification process still requires for the team carrying out the exercise to edit the input data point set in order to provide a proper classification operator. This is done to address issues related to imperfect well to seismic match and the inherent flaws of the seismic (e.g. residual noise, bandwidth limitation, unsolved imagery issues in some areas). This step is carried out on the basis of the following assumptions:

- The response of the detrended inverted seismic is similar to what is observed at log-scale. This can be highly dependent on data quality.
- Groups of facies can be lumped together based on their elastic domain response as long as it makes sense in the geological domain, i.e. the geologist can then "un-lump" these facies in his geological modelling workflow.
- Sectors can be defined where another facies group cannot exist, i.e. pure poles.

Figure 7 illustrates the data cleaning for the final facies grouping. In this study, different facies grouping were tested and in agreement with the geologist, sandy facies including sandy and silty heterolithics as well as massive fine to coarse sands and conglomerates were lumped together while shales – mostly hemipelagites – were kept separate as well as debris flow facies. This led to 3 Mega Facies Groups to be defined and used for classification purposes:

- Mega Facies Group 1 represents shaly non-reservoir facies, which mostly responded as positive relative Vp/Vs values as well as negative relative acoustic impedance values, mostly located in the first quadrant.
- Mega Facies Group 2 represents the whole spectrum of reservoir facies as indicated above and mostly responded with negative relative Vp/Vs values while the acoustic impedance was less determinant, though high positive relative acoustic impedance indicated a lower probability of occurrence. Present in third and fourth quadrants.
- Mega Facies Group 3 represents the debris flow, another non-reservoir facies but with specific spatial distribution from the depositional – and elastic – perspective, hence singled out in the classification process. Mainly characterized by high positive relative acoustic impedance. Present in quadrants 2 and 3.

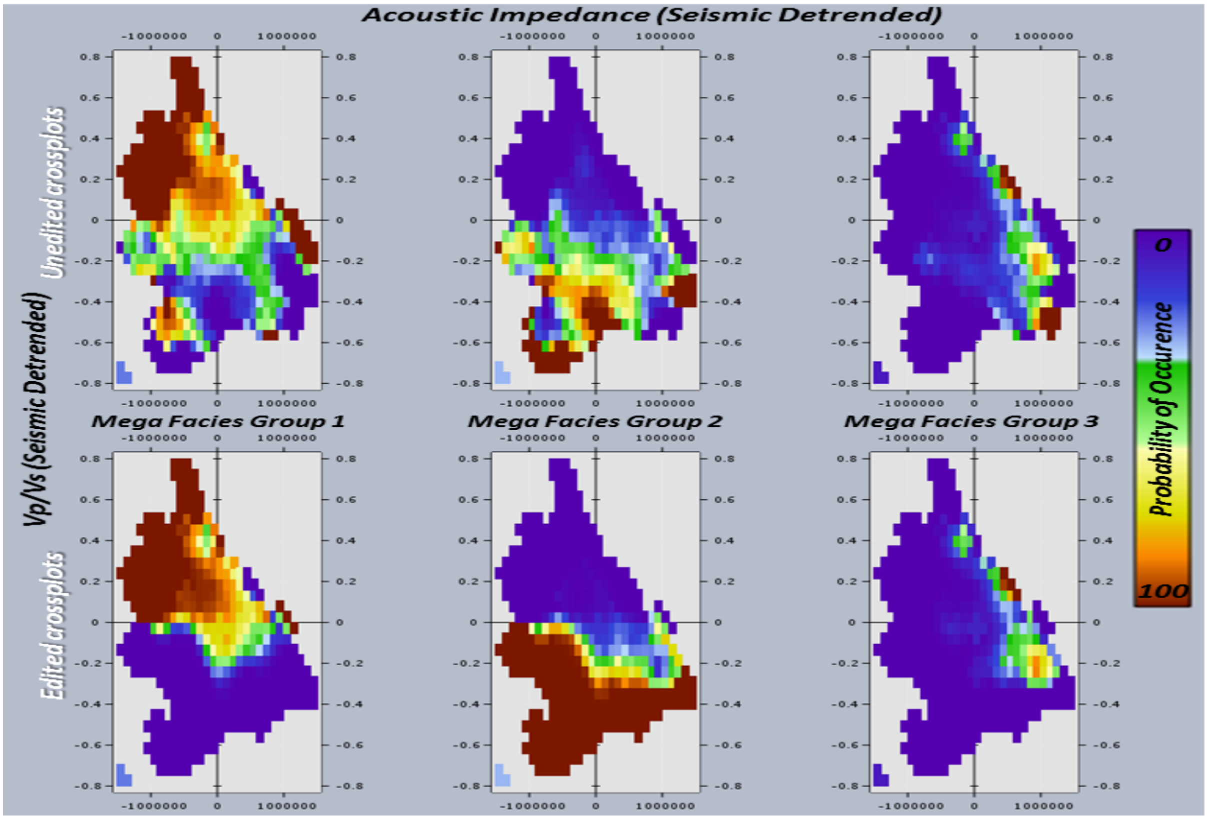

Figure 7: Facies classification operator in the elastic domain generated from the input point-set before (top) and after (bottom) point editing and cleaning.

Results and Conclusion

Once the obtained operator is satisfactory it can be applied to the detrended seismic inversion cubes to generate Mega Facies Group probability of occurrence seismic cubes (Figure 8). The obtained results are quality controlled against the wells dataset in particular the blind wells not used in the initial classification point set.

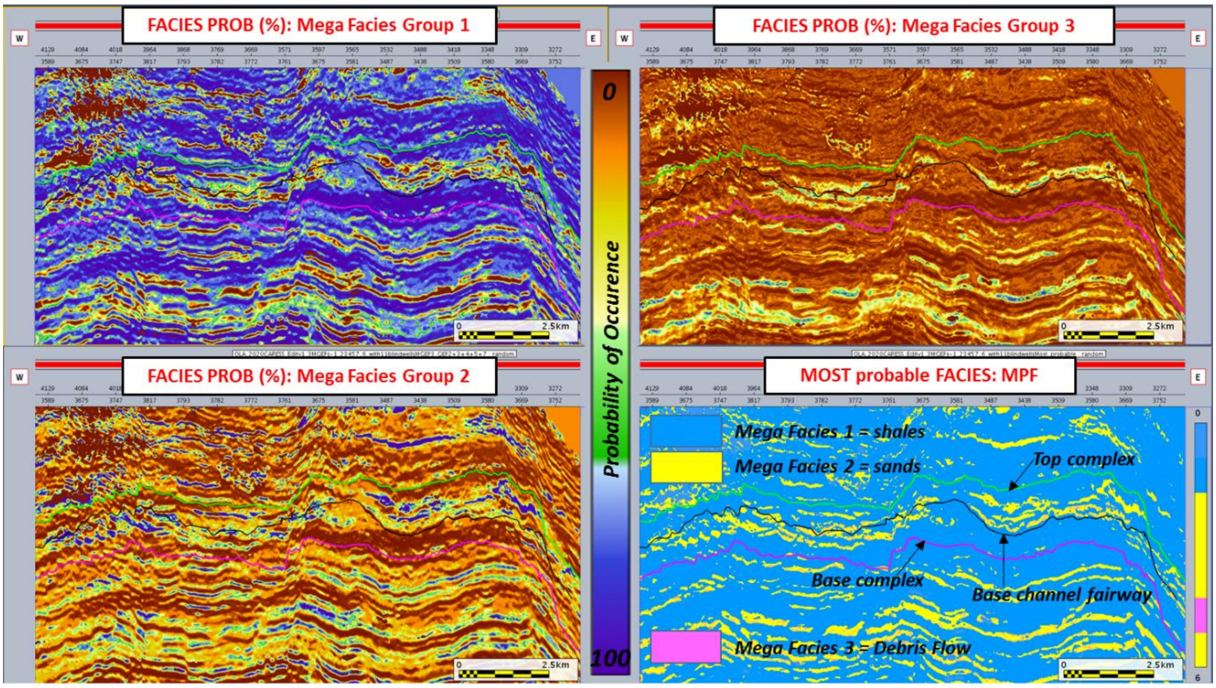

Figure 8: Probability of occurrence cubes for the three defined Mega Facies Groups as well as the most probable facies cube.

Overall, the resulting probability of occurrence cubes display an excellent correspondence with well results (Figure 9 and Figure 10). In addition, they provide a direct 3D probabilistic indicator for reservoir vs. non-reservoir facies spatial distribution. This indicator can then be used in the geological modelling workflow to influence the spatial organization of the facies modelling resulting in better 2G, i.e. Geological and Geophysical, integration.

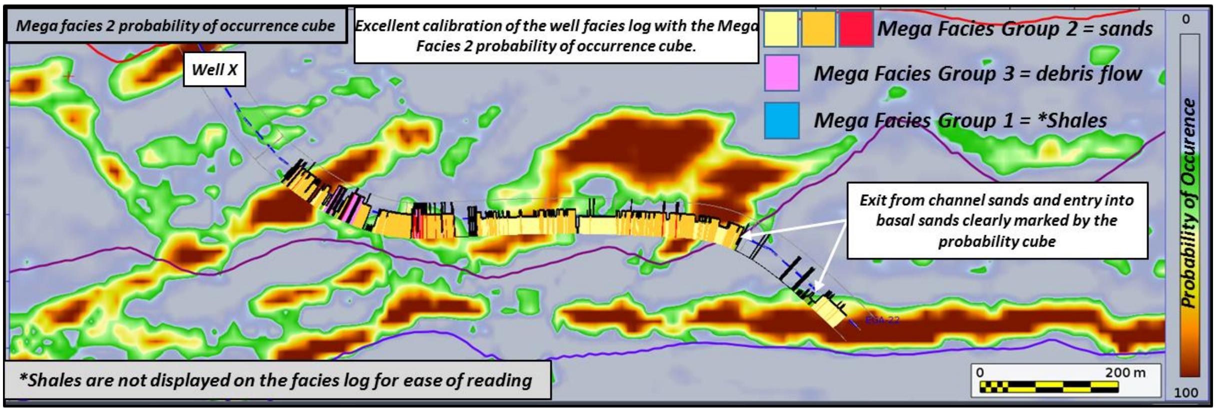

Figure 9: Results of Mega Facies 2 (reservoir facies) probability of occurrence cube against well results. This well was used in the input dataset of the classification.

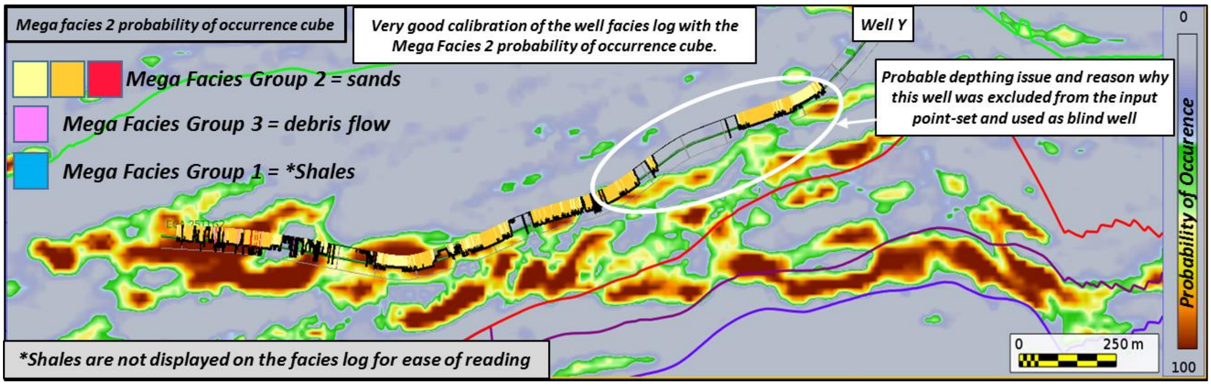

Figure 10: Results of Mega Facies 2 (reservoir facies) probability of occurrence cube against well results. This well was used as a ''blind well'' during the facies classification to serve as a key QC well.

To conclude, these results comforted us in using the development wells in the input point set for the classification work. It demonstrated their added value to provide a better quality classification and overcome the limitations from using only wells with elastic logs which usually limits the exercise to the initial exploration and appraisal wells of a field. This approach can be undertaken as long as all the necessary QCs and precautions are taken along the process. Additionally, the integration of both geophysicists and the geologists is crucial to obtaining fit for purpose results that will be useful for the field understanding and geological modelling aspects.

Acknowledgement

We thank NAPIMS and the OML130 partners- SAPETRO, CNOOC and PRIME Oil and Gas, for their continuous support and for the permission to publish this work.

We also thank the Seismic Processing and Reservoir Characterization Teams in Nigeria and France for their technical support.

References

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