New Insights in the Evaluation of Reserves of Selected Wells of the Pletmos Basin, Offshore South Africa*

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Abstract

The area evaluated has similar structural styles and settings as the producing neighboring fields of F-A and E-M in the adjacent Bredasdorp Basin offshore South Africa. The main objective of this study is to create a 3D static model and estimate hydrocarbon reserves. Based on log signatures, petrophysical properties and structural configurations, the reservoirs were divided vertically into three reservoir units in order to be properly modeled in 3D space. The thicknesses of the layers were determined based on the vertical heterogeneity in the reservoir properties. Facies interpretation was performed based on log signatures, core description and previous geological studies. The volume of clay and porosity was used to classify facies into five units of sand, shaly sand, silt, and clay. From petrophysical interpretation, a synthetic permeability log was generated in the wells which ties closely with core data. The J-function water saturation model was adopted because it produced better results in the clean sandstone sections of the reservoirs. A high uncertainty in the basement formation was observed due to very few wells drilled in the area and impact of faults and thus resulted in evaluation of uncertainty of each zone separately. The uncertainty workflow was run using 100 trials and the volumetric gas reserves estimates generated was based on the stochastic model results produced in zone A 301 BCF (P10,277 BCF (P50), and 230 BCF (P90) while no volume was produced in the basement.

Introduction

Pletmos Basin is one of five sub-basins of the Outeniqua Basin which is the largest basin in South Africa. Pletmos is located in the South African continental shelf between Cape St. Francis and Mossel Bay. The Basin is positioned offshore south of South Africa, southwest of Port Elizabeth and southeast of Cape Town and covers about 18,000 km^2. Strong strike-slip movement from the Late-Jurassic up to Early Cretaceous is evident in the Basin and also shows a history of the split up of Gondwana (Roux, 2010). It is made up of two overlapping depocenters, namely, the Plettenberg Graben and the Superior Graben which are separated by a 4000 m high prominent transfer arch (Pasa, 2010). The transfer arch is the central point for high energy sand channels crossing between adjacent basins. The transfer arch is the central point for high energy sand channels crossing between adjacent basins. Pletmos Basin underwent rifting during the Middle-Late Jurassic. Brown et al. (1996) noted that the resulting dextral trans-tensional stress exerted north of the Agulhas-Falkland Fracture Zone initiated normal faulting along the northwest to southeast striking Plettenberg and Superior grabens. The Outeniqua Basin has been largely described according to its major regional unconformities (Broad et al., 2006).

The purpose of the present study is to investigate and review the geological modeling work previously undertaken in the area with the aim of correlating and re-defining reservoir levels in terms of facies and reservoir properties distributions. To this end, we constructed a static reservoir model based on proper integration of all available data which can be used for future well planning and easy to update as new data are acquired and to also provide a useable input model for dynamic simulation purposes.

Methods

The geological and engineering data used was provided by the Petroleum Agency of South Africa (PASA) .The available data set was reviewed to establish data inventory and check completeness and loaded into database created for quality check and ensure suitability for future work. Compilation and construction of the conceptual geological model was performed by combining geological, petrophysical, and geostatistical analysis of the input data as integration of this data set is the most crucial aspect. All available data were integrated to evaluate the lithology, saturation, porosity and permeability profiles of the area.

A structural model was built from seismic data and well tops to complete the skeleton of the 3D model. Stochastic simulations of facies and petrophysical attributes performed in a fairly high-resolution grid to complete the internal architecture of the model. In reservoir properties modeling, continuous variables such as porosity and volume of clay (VCL) were populated stochastically using Sequential Gaussian simulation (SGS) algorithm conditioned to the facies model. Permeability was populated based on the relationship to porosity and modified using drill stem test (DST) results. A Permeability factor for each mineral was estimated to obtain a permeability transform from logs. A good match was found between calculated total porosity and core porosity. Average net reservoir and net pay petrophysical properties were used in reservoir modeling. Water saturation was modeled slightly different as it constrained to the height above contact rather than facies. A cross check was performed to evaluate the validity of the height functions in predicting Sw, by plotting the calculated water saturation against the petrophysical results. An interpretation model was defined from two key wells and was propagated to the other wells.

Results and Discussion

The increasing need to improve the field plan for the undeveloped hydrocarbon accumulations requires a realistic and reliable reservoir characterization. Geostatistical modeling provides this detailed reservoir characterization in a powerful way by integrating various disciplines and their diverse datasets.

By integrating core studies, petrophysical results and regional geological settings, the reservoir sub-layers, were created based on the conceptual depositional environment. Core descriptions are only available in a limited number of wells and are irregularly distributed across the sub-layers. Therefore, the core data was insufficient for generating a facies model in all the wells. Consequently, the facies breakdown was based on porosity and volume of clay. In this approach a set of cutoffs were used for porosity and volume of clay to classify the lithofacies in the vertical section for each well, as below.

Facies Name	Cut-offs	Comment
Shale	VCL> 50%	Non-reservoir
Sand	VCL<=0.5 and PHIE>0.06	Best quality reservoir
Tight Sand	VCL<=0.5 and PHIE<=0.06	Tight reservoir

The upper part of the 1AT1 sandstone is composed of low quality facies consisting of siltstone and tight sands and is a tight reservoir. This tight zone predominantly consists of low reservoir quality throughout the field. The facies in the coastal alluvial fan zone of 1AT1 is mainly composed of high and low sand facies and forms the main reservoir. The reservoir quality is better in the northern part as indicated by higher percentage of high sand facies. The facies in the tidally influenced zone of 1AT1 sandstone is mainly composed of high and low sand facies and also forms the main reservoir section. The facies in the basement sandstone is also dominantly composed of high and low sand facies. Unlike facies in basement sandstone, the facies in 1AT1 sandstone are less heterogeneous and consistent.

Wireline logs along with core description were utilized to correlate stratigraphic units across the field. Correlation was performed based on the initial horizon tops and bottoms provided by PASA at the beginning of the project. Structural and stratigraphic cross-sections were generated to understand the depositional and structural control on the horizon distribution.

The 1AT1 Top Reservoir is the main reservoir as it exhibits different facies and reservoir characteristics based on core description, electrical logs and petrophysical interpretation. The basement is characterized by medium to coarse-grained, poorly sorted sandstones, mostly trough and planar cross-bedded. The basement is interpreted as fluvial deposits of braided river type. This zone thins towards the East at the location of well E2.

Property cutoffs were generated using core data, petrophysical interpretation and test results. Since the data was limited, some approximations were made to establish the final cutoffs and the resulted netpays were compared with the test results. Volumetric estimates were performed using the porosity and water saturation cutoffs. Before running the stochastic volumetric estimates, a volumetric base case was created. The process of building a static model is divided into two main steps, the structural and the property models, where each contributed to the uncertainty in the volume calculations. A maximum of 300 runs, with a new model generated for each run, from structure modeling, layering, upscaling, property modeling, gas-water contact (GWC) to volumetric calculations, were made for stochastic volumetric estimates and uncertainty analysis. The volumetric estimate was generated based on the stochastic modeling process. The uncertainty analysis of the stochastic results showed that structure, contact and NTG are the three most important uncertain parameters.

Conclusions

The target horizons are 1AT1 and the basement, which are of Cretaceous age. In terms of lithology, both reservoirs are composed of clastic sediments. Based on the log signature, petrophysical properties and structural configuration, the reservoir was divided vertically into three reservoir units in order to be properly modeled in 3D space. The thicknesses of the layers were determined based on the vertical heterogeneity in reservoir properties. The final fine-scale 3D-grid has 8 million active cells. Facies interpretation was performed based on the log signature, core description and previous geological studies. Facies was divided into the following groups; sand, shaly sand, silt and clay, based on the volume of clay and porosity. Using the petrophysical interpretation, synthetic permeability log was generated in the wells which ties closely with core data. To estimate and model the water saturation, several approaches were examined and used to generate the water saturation model. The second approach was the correlation between the saturation and the permeability. Once the 3D model was complete, volumetric (GIIP) estimates were performed. Since the data is very limited, we expect uncertainties in the 3D geologic model, the uncertainty workflow was run using several trials, the base case P50 estimated 277 BCF of Gas from the 1AT1.

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New Insights in the Evaluation of Reserves of Selected wells of the Pletmos Basin Offshore South Africa

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Outline

1. **Key Questions**
2. **Introduction**
3. **Methodology**
4. **Presentation of Results**
5. **Concluding Remarks**
6. **Questions**

Key Questions to be answered

- **How do we re-define reservoir levels in terms of facies and reservoir properties ?**

- **Is there a way of reducing uncertainties in order to obtain a reliable volume estimates?**

Introduction

Introduction…….

Pletmos Basin is positioned offshore south of South Africa, with an area of about 18 000Km^2.

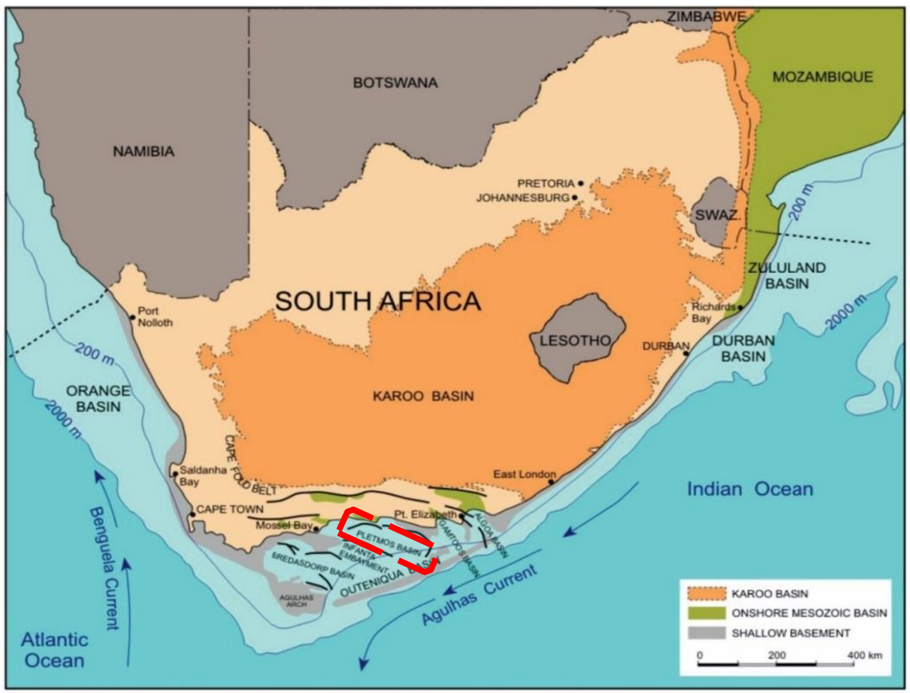


Figure 1a: Location map of Pletmos Basin(modified after Petroleum Agency of South Africa (PASA))

Figure 1b.Location of Block 11a offshore South Africa

The basin is one of five sub-basins of the Outeniqua basin.

- Ga-A1 well in Pletmos Basin is the first gas discovery offshore South Africa in 1969.

Structural styles and stratigraphic subdivisions

- The basin is filled with Synrift 1 and Synrift11.

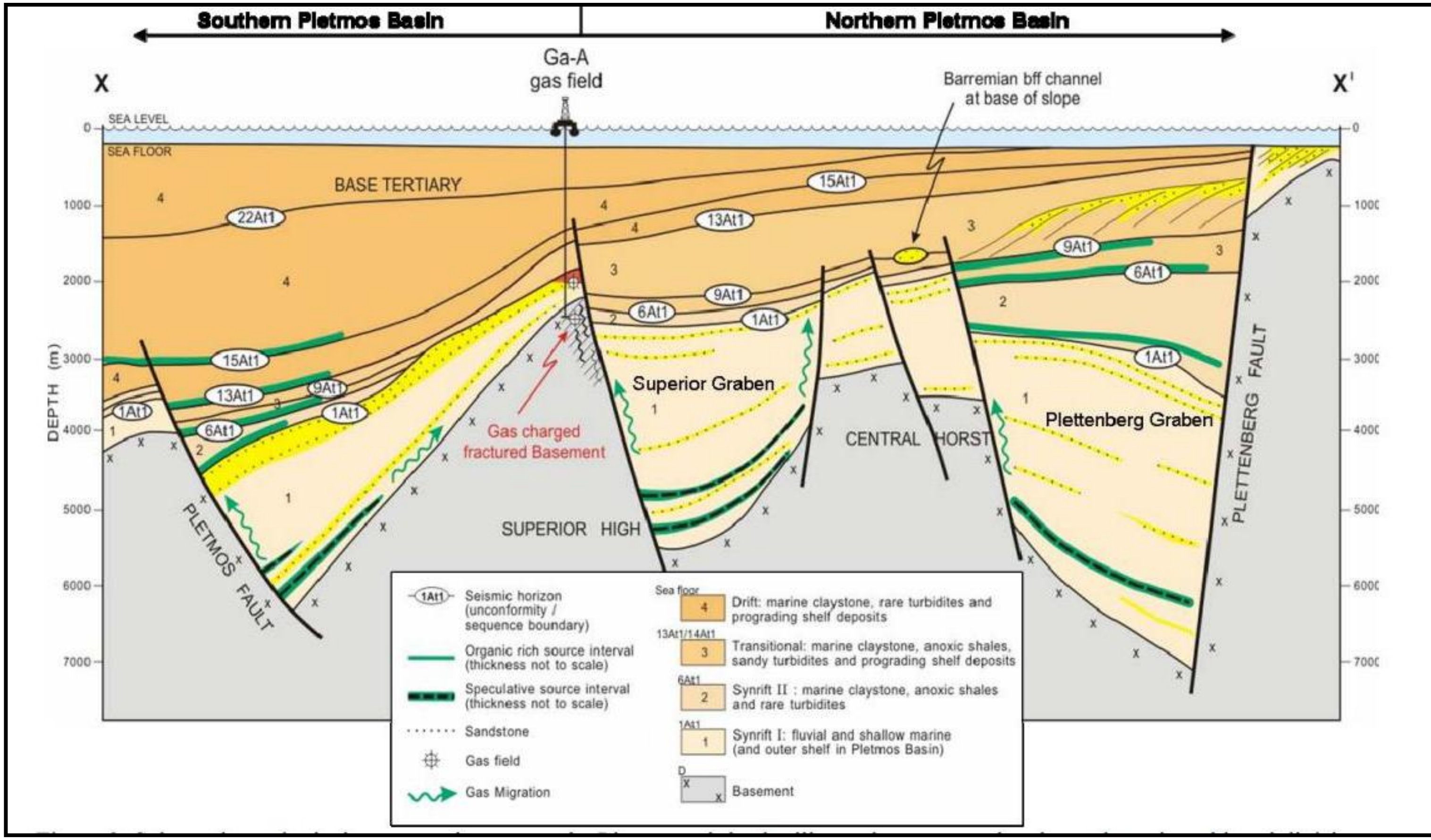


Figure 2. Geological profile of rift faulting in the Plemos basin, PASA 2013.

Introduction….

- The 1At1-to-6At1 (Synrift II) comprises of aggradational deep-marine claystones and it contains organic-rich shales which are significant as petroleum source rocks.

- The rifting stage in South Africa ended during the Valanginian. This was accompanied by regional uplift and extensive erosion of a drift beginning unconformity (Burden,1992).

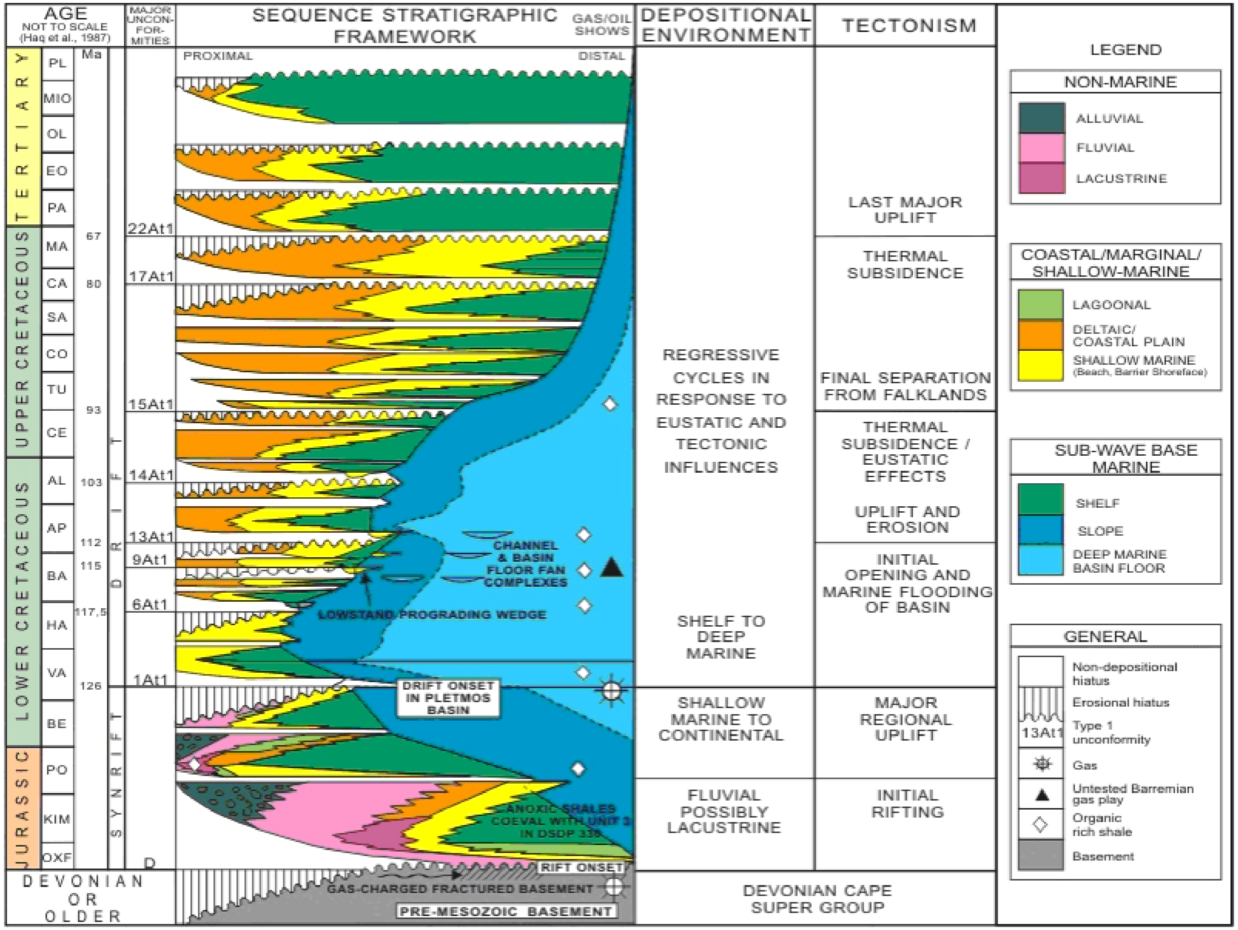


Figure 3: Chronostratigraphy of the Pletmos basin ,Brown et al 1996

Introduction….

- 4 gas discoveries with potentially commercial production rates
- Total of 2,625 km^2 of 2D and 1130km^2 3D seismic data.
- The target horizons in this study are the 1 AT 1 and the Basement, which are of cretaceous age.
- Both reservoirs are composed of clastic sediments

Methodology

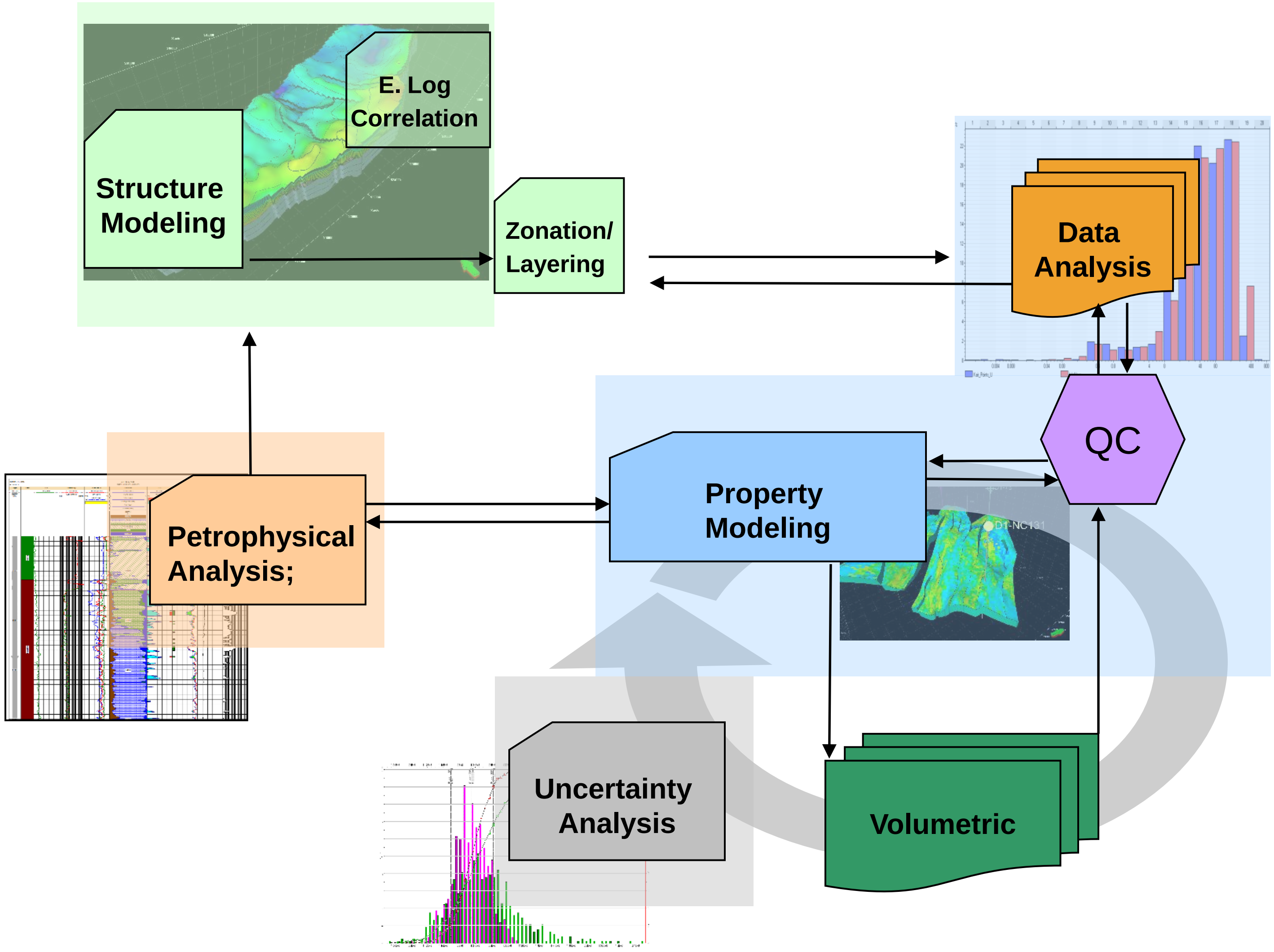
Database

Data Type	Detail	Comments
Openhole Logs		
2D and 3D Seismic		
Mud data		
Formation water salinity		
Core description & sedimentology details		
Perforation intervals and test results		
Previous studies reports		

Name	TD (TVDSS)
Ga-A1	2203.0
Ga-A2	3038.0
Ga-A3	2475.0
Ga-A4	2302.0
Ga-E1	2898.0
Ga-E2	4396.0
Ga-Q1	3249.0
Ga-Q2	3180.0
Ga-Y1	2272.0
Ga-Z1	3200.0

Chart 1: Summary of available data

Static Model Work Flow



Presentation of Results

Horizon Correlation (East-West)

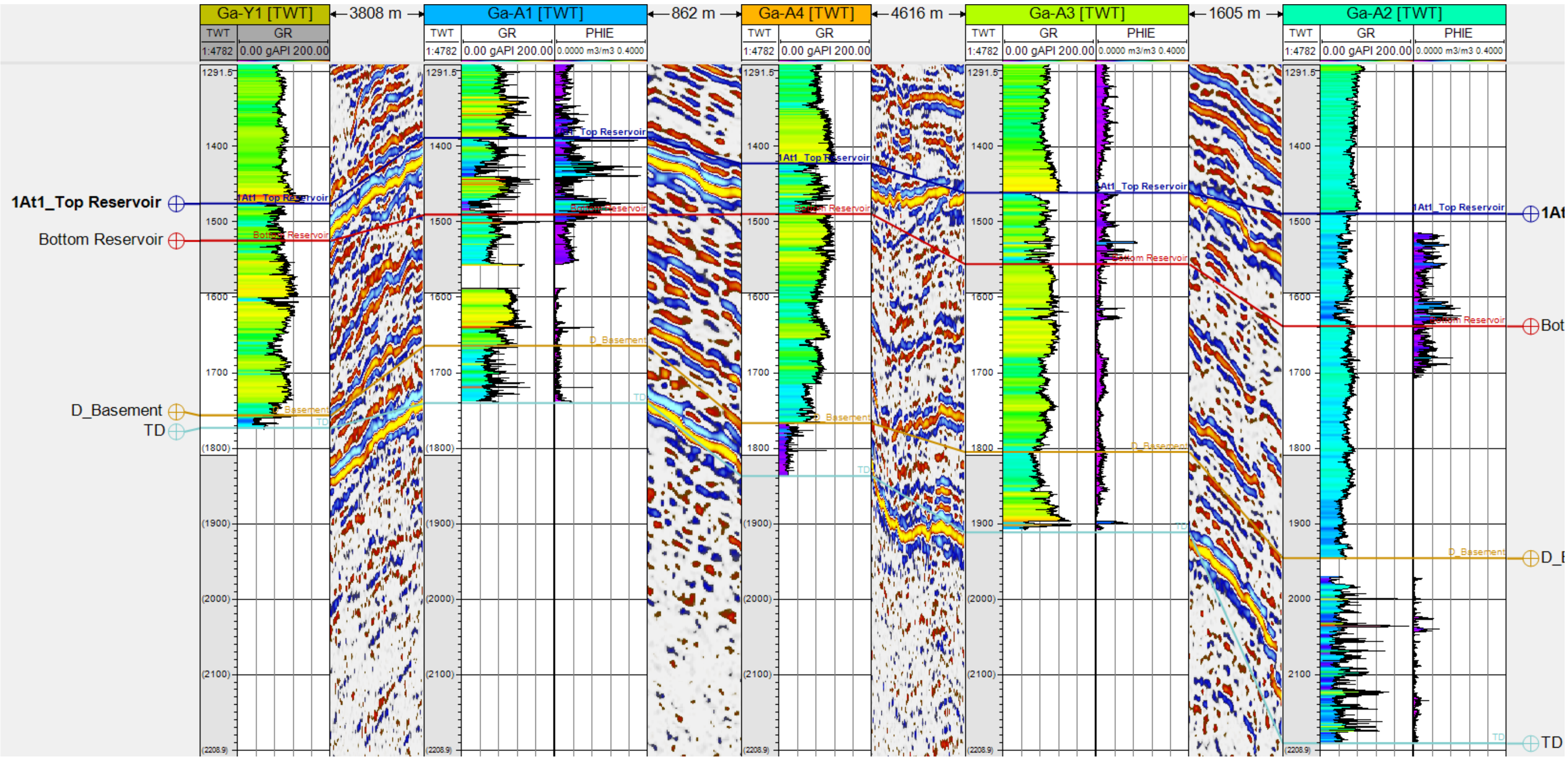


Figure 4. Detailed correlation of the individual zones, integrating Seismic, Logs and markers

Structure Map

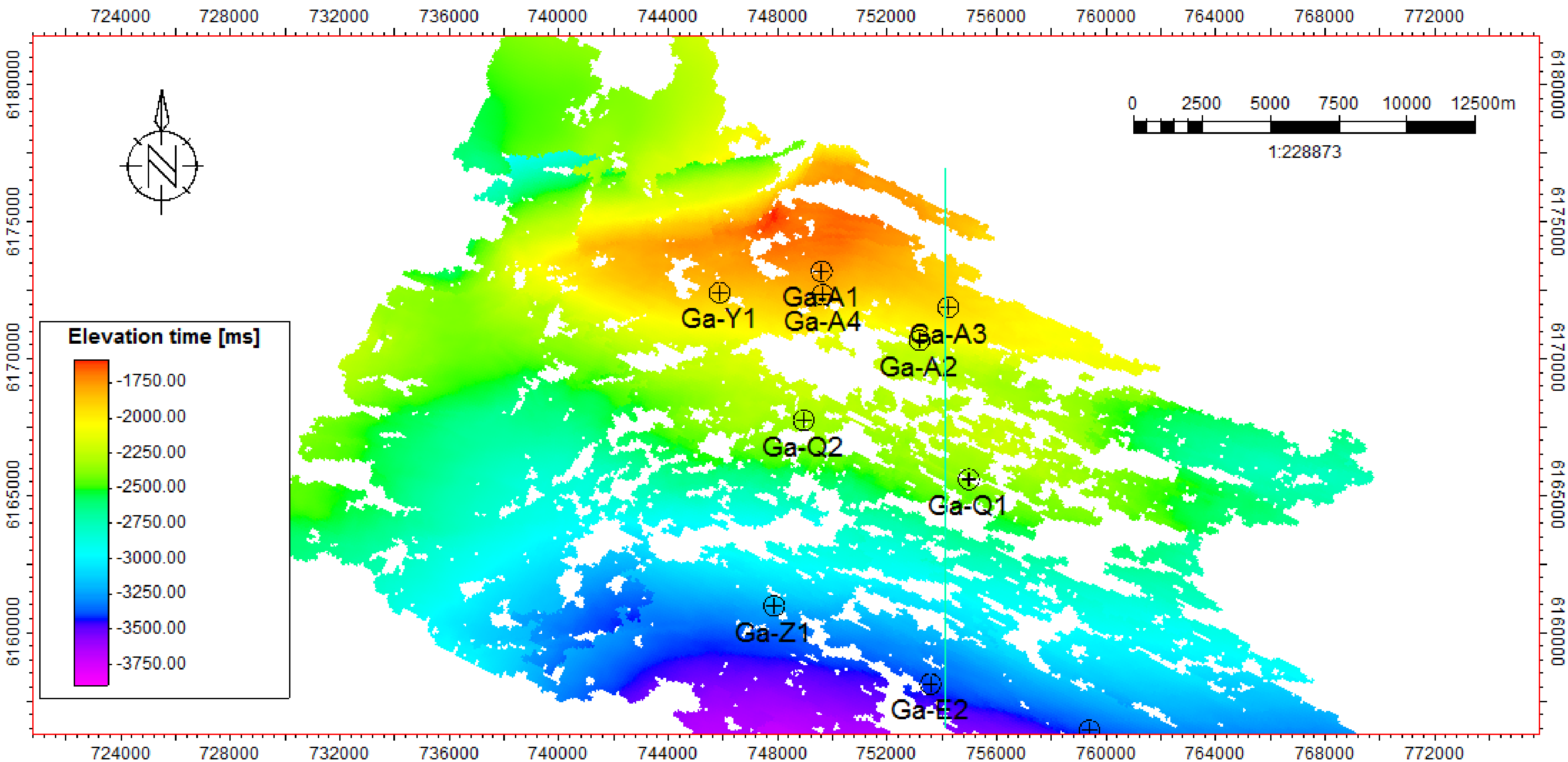


Figure 5. Seismic Interpretation for the Basement

Property Modeling

Facies Modeling

- Facies are important in reservoir modeling because the **Petrophysical** properties of interest are often highly correlated with facies types.
- Facies modeling in *PETREL* is a means of distributing discrete facies throughout the 3D-grid.
- The first step in facies modeling consists of upscaling the facies from well logs into the cells of the geological grid.
- The method used for the facies upscaling is the “most of” average method. This method takes the most represented facies type present in the log inside the cell.

Facies Definition

Facies Name	Cut-Offs used	Comments
Shale	Vclay> 0.5	Non Reservoir
Sand	Vclay≤ 0.5 and PHIE≥ 0.06	Best Reservoir
Tight Sand	Vclay≤ 0.5 and PHIE≤ 0.06	Tight Reservoir

Chart2. Facies classification based on Vclay and PHIE

Facies Definition

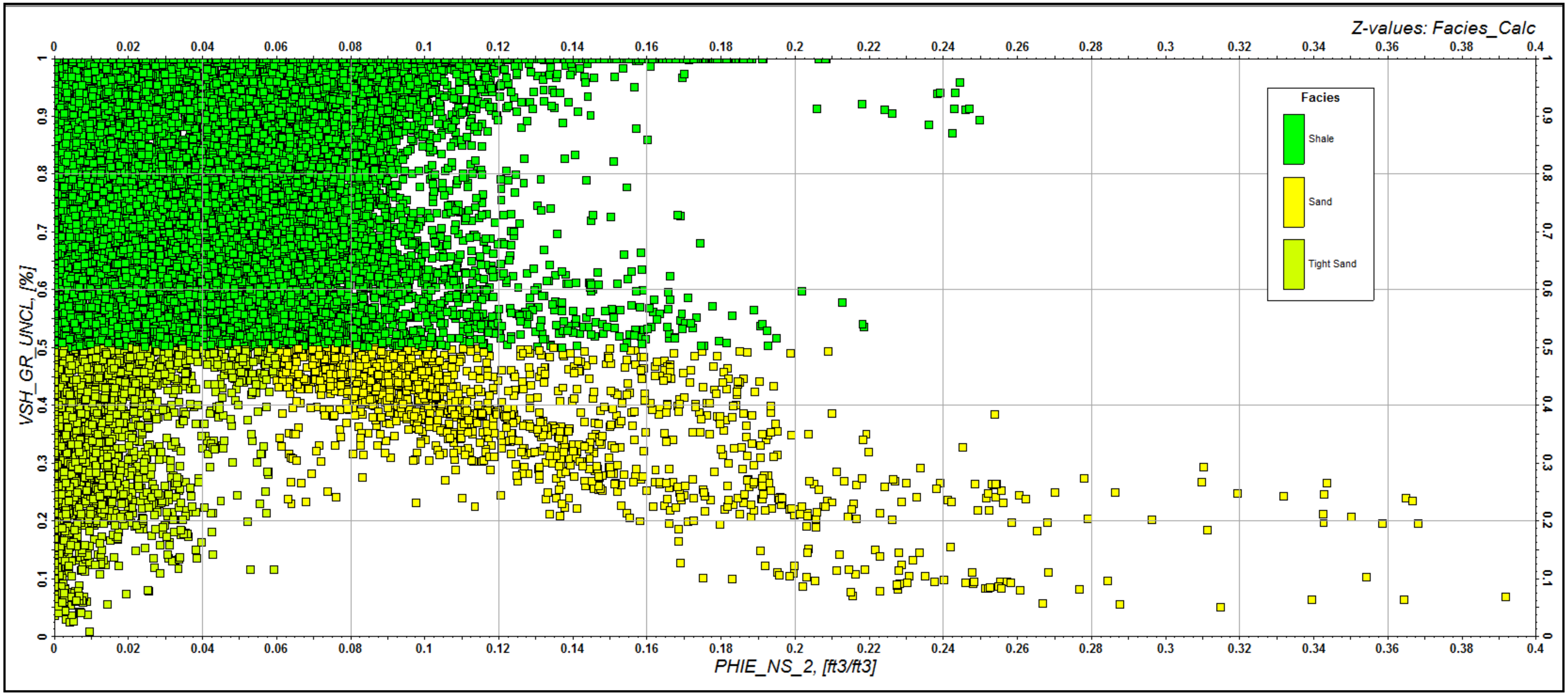
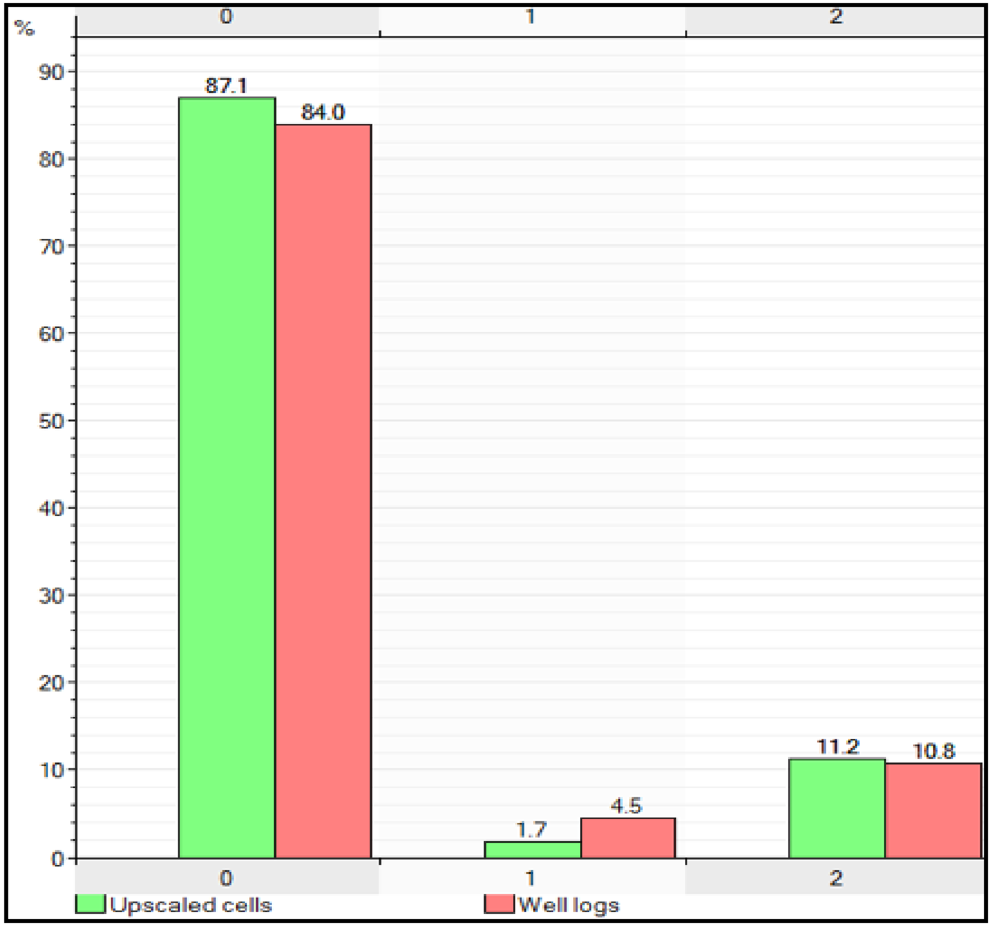


Figure 6.Facies classifications based on the Phie and Vclay cutoffs of chart 2

Facies Definition



Code	Name
0	Shale
1	Sand
2	Tight Sand

Figure 7. Comparison of Facies log (red) and upscaled (green).

Facies Modeling

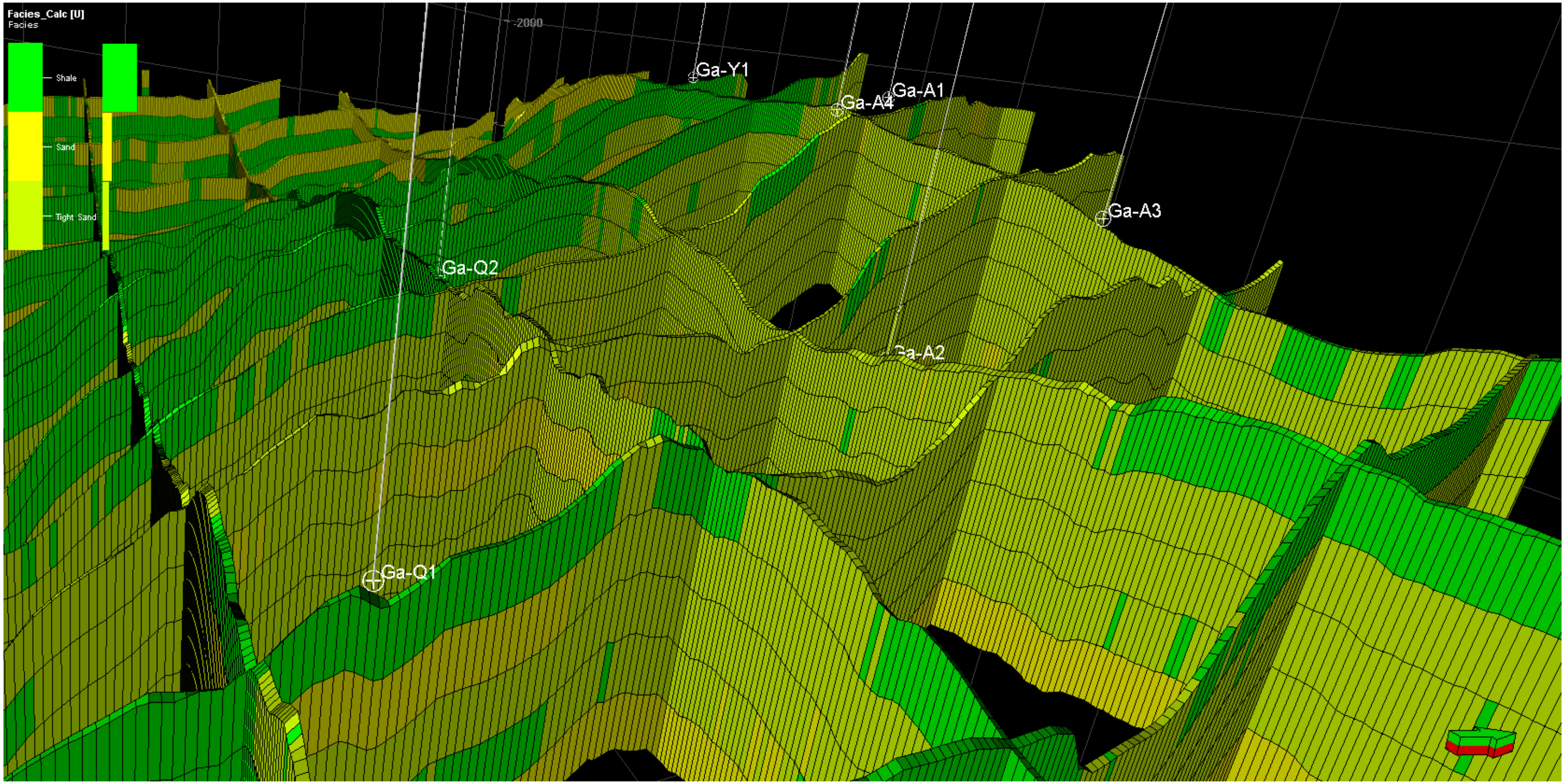


Figure 8. Fence diagram showing facies distribution in the Basement. The reservoir quality is better in the northern part of the Block as indicated by the presence of high sand facies

Porosity Modeling (SGS)

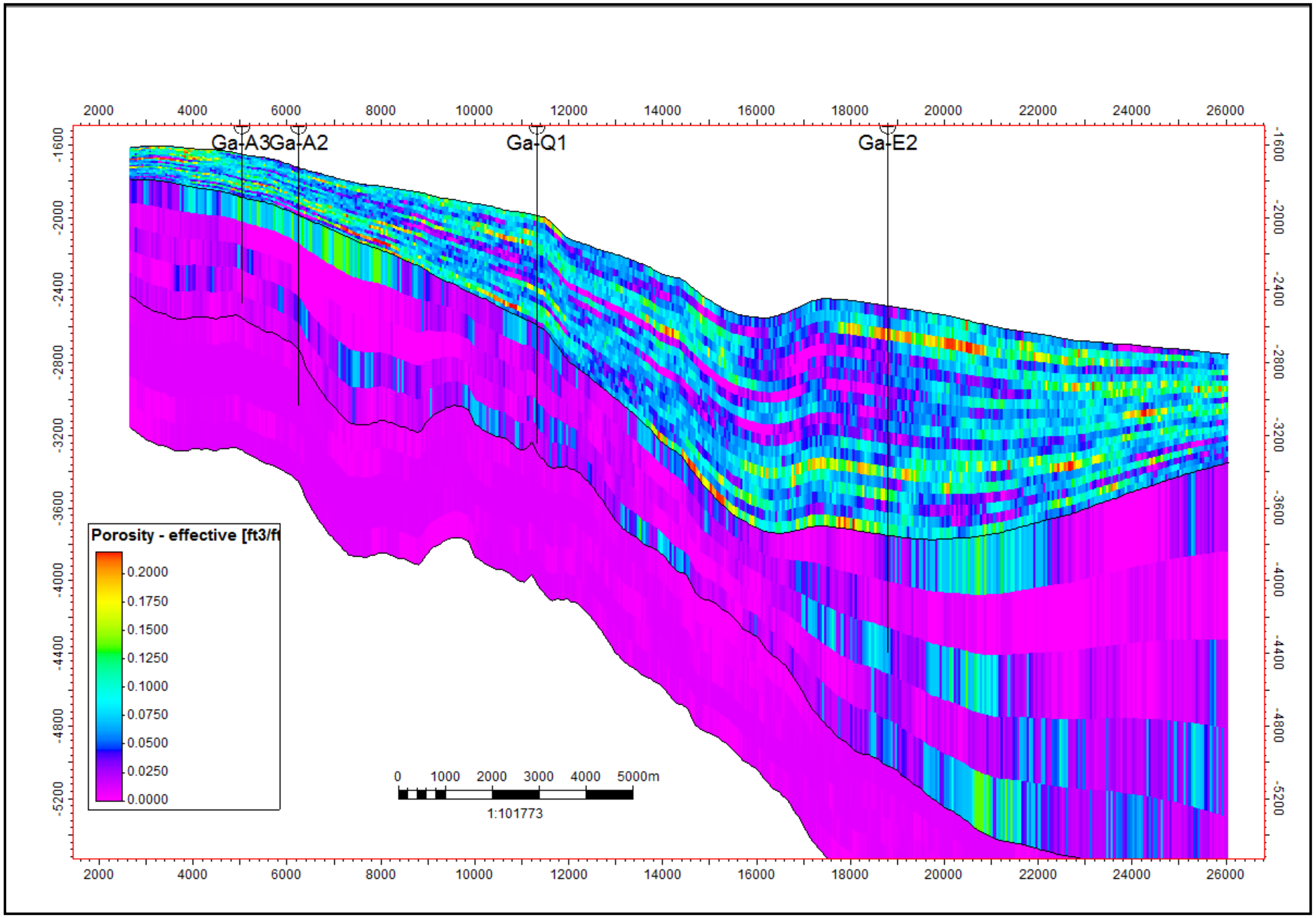


Figure 9.Cross-section through wells showing the porosity distribution in 1AT1 and Basement. Porosities distribution is very low in the Basement .

Water Saturation Modeling

- Dual water model was used for water saturation estimation

- Independent Saturation Height Function above contact was applied for each facies within 1AT1 and Basement formations. To find out the pseudo-height functions for each facies, the following steps were performed:

  -Determine Free Water Level (FWL)

  -Determine the height above free water level (HFWL)

  -Estimate the saturation height function

  -Calculate the water saturation

Gas water Contact

- The GWC of each reservoir was determined by integrating all available data and modified during history matching.

- In order to capture the uncertainty in GWC, 3 different values (***optimistic***, ***medium***, and ***pessimistic***) were used for the volumetrics.

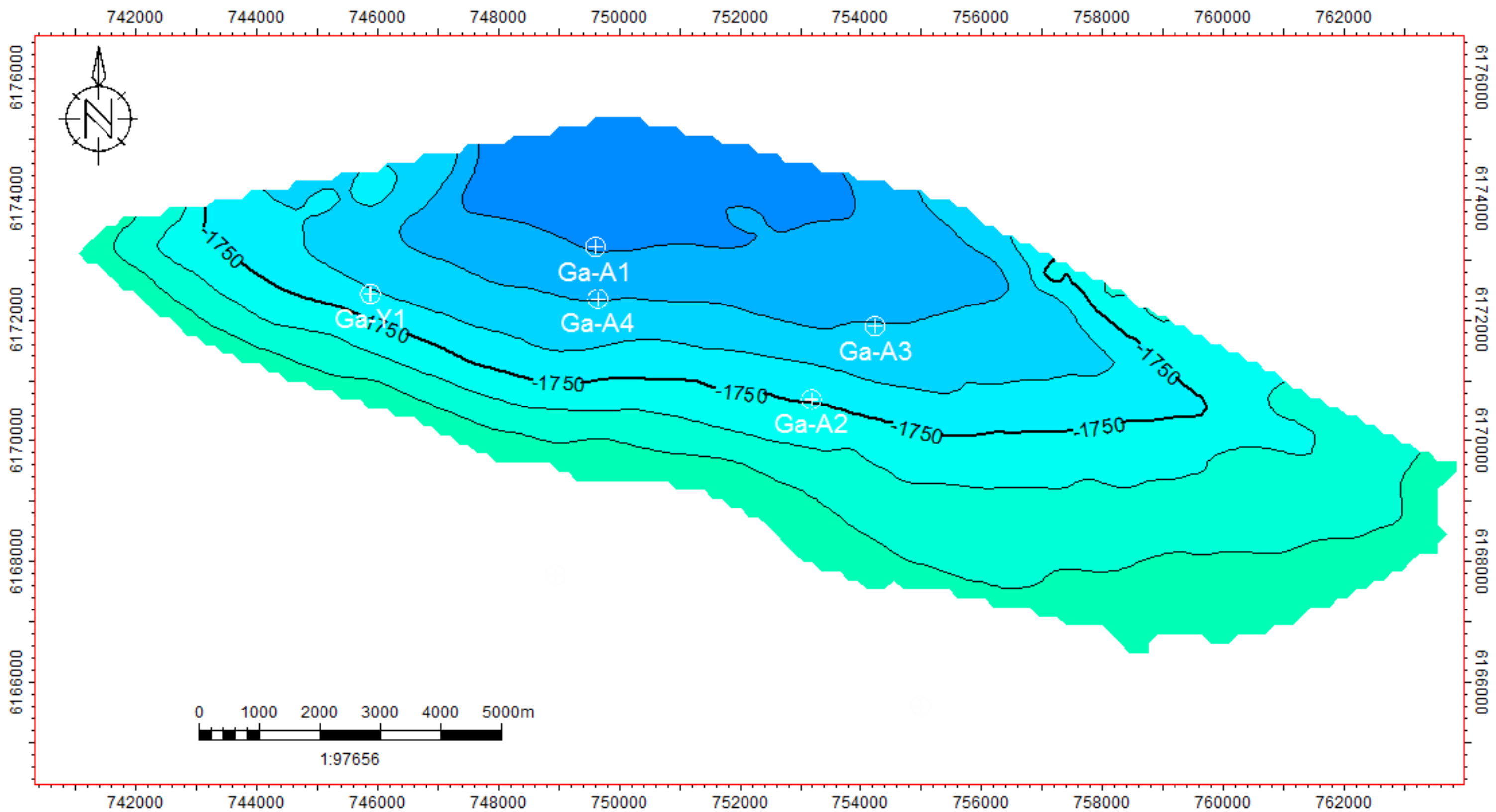
- In most cases, the shallower contact (Pessimistic case) was taken as the deepest gas identified based on the petrophysical interpretation, well test data or production data; the deeper contact (Optimistic case) was taken as the shallowest water tested or presented by logs, and the medium case was used as the average depth between these two values.

Gas water Contact

Horizon	Case	GOC
1AT1	Pessimistic	-1890
	Medium	**-1898**
	Optimistic	-1910
Basement	Pessimistic	-3190
	Medium	**-3207**
	Pessimistic	-3220

Chart 3. Established GOCs for the reservoirs

Area above GWC



Volumetric Estimates and Uncertainty analysis

- To capture the uncertainty in GIIP, 100 runs were made and for each run new model was generated from structure modeling going through layering, upscaling, property modelling, OWC and finally volumetric estimates.

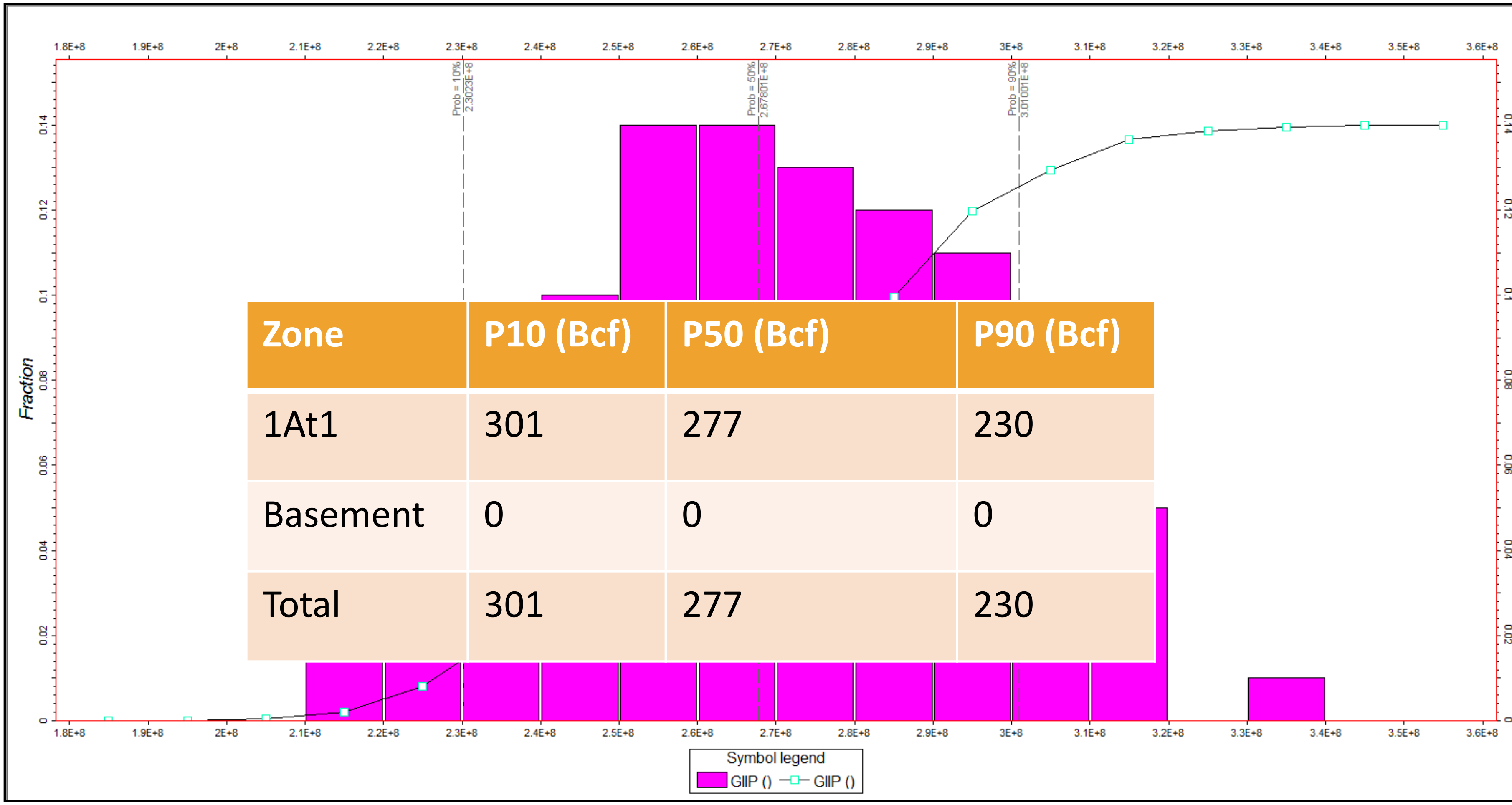
- The volumetric estimates (GIIP) generated was based on the stochastic modeling process .

Volumetric Estimates and Uncertainty analysis

Variables	Parameter	Ranges	Distribution
Structure for all Horizon	Height	0-100ft	Triangular
Contacts	Height	(-1890,-1910)-1At1 (-3190,-3220) Basement	Random
Cut-offs for net pay	Volume of Clay	0.2,0.18,0.15	Triangular
	Porosity	0.05,0.06,0.07	Triangular
	Water Saturation	0.55,0.60,0.65	Triangular

Chart 4. Summary of the variables used in the stochastic volumetric calculations

Volumetric Estimates and Uncertainty analysis



Zone	P10 (Bcf)	P50 (Bcf)	P90 (Bcf)
1At1	301	277	230
Basement	0	0	0
Total	301	277	230

Chart 5. GIIP volume distribution

Concluding remarks

Concluding remarks……

- The reservoirs of target horizons ***<u>(1 At1 and the Basement</u>***), are composed of classic sediments.

- A 3D-static model to estimate the Gas reserves was created.

- The sand facies was recognized as best quality reservoir facies

- Uncertainty workflow was run using 100 trials, the base case P50 estimated ***<u>277 Bcf of Gas from the 1At1</u>***.

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