Application of Formation Pressure in Evaluation and Risking of Prospect*

Arpita Mandal[1], Ankaj Sinha[2], Rupdip Guha[2], and Alisha Mehra[3]

Search and Discovery Article #10654 (2014)
Posted October 27, 2014

*Adapted from poster presentation given at AAPG International Conference & Exhibition, Istanbul, Turkey, September 14-17, 2014, AAPG © 2014

[1]Cairn India Limited, Gurgaon, India (arpita.mandal@cairnindia.com)
[2]Cairn India Limited, Gurgaon, India
[3]Maersk Oil, Denmark

Abstract

Formation pressure measurement is of immense value in quantitative evaluation and risking of prospects. This paper demonstrates the use of pressure data to understand the impact of over-pressurization and structural compartmentalization on hydrocarbon pool extent, structural fill-spill, and saturation height modeling of the Eocene Upper Thumbli Formation in the Raageshwari-Tukaram area of the Barmer Basin, NW India. Integrated analysis of pressure data from the wells defined a clear pattern of increasing overpressure (100 – 200 psi) from north to south along the structural trend. The Eocene Thumbli reservoir is intensely faulted and the pressure data indicates fault compartmentalization where each fault block is hydro-dynamically independent with separate aquifers. The uncertainty in Free Water Level (FWL) in each fault block was estimated from the minimum and maximum range of overpressure to calculate the hydrocarbon pool extent. Sensitivity analysis of different degree of overpressure helped to define the regional FWL. In the absence of capillary pressure data from core, log data was used to prepare saturation height model for different FWL. Variation in rock quality was captured in the modeled saturation height function that matched with Dean-Stark saturation for that rock type. For a given rock type, the position of the well with respect to the structural crest led to over-estimation or under-estimation of the in-place volume for the entire structure. Relationship of formation pressure to hydrostatic vis-à-vis interpreted structural spill from depth structure map was used to de-risk prospects below the FWL in this region. This methodology helped in determining the thickness of the hydrocarbon column, understanding the uncertainty in FWL, calculation of inplace volume, and optimizing the position of appraisal wells.

Introduction

Formation pressure measurement is of immense value in quantitative evaluation and risking of prospects. This paper demonstrates the use of pressure data to understand the impact of over-pressurization and structural compartmentalization on hydrocarbon pool extent, structural fill-spill, and saturation height modeling of the Eocene Upper Thumbli Formation in the Raageshwari-Tukaram area of the Barmer Basin, NW India.

The Barmer Basin is an intracratonic rift basin, developed in the western part of India, adjacent to Kutch or Cambay basins (Figure 1). The Tertiary rift basin trends NNW-SSE and forms a well-defined graben between the Barmer high on the west and the Indian shield on the eastern side. The thickness of sediments encountered in the Barmer Basin is in excess of 6000 m in the vicinity of the Raageshwari Field and the seismic data suggests increase in thickness towards the south. The Tertiary part of the Barmer Basin evolved contemporaneously with the Cambay Basin having typical lacustrine basin imprints. The southern part of the Barmer Basin is characterized by a Central Basin High (CBH) which is a 40 km long composite feature of elevated N-S oriented fault terraces, arranged in en-echelon fashion. It was formed during the early syn-rift phase and reached maximum structural development before the late Tertiary. One of the structural culminations of the CBH comprises the Raageshwari area in the horst and Tukaram area in the flank. The entire Raageshwari-Tukaram area is extensively faulted in the Lower-Middle Eocene Akli and Thumbli intervals (Figure 2). Akli Shale is the regional seal for the reservoirs. The individual fault blocks act as independent closures for Thumbli oil reservoir which has been proved over the main Raageshwari Field. Hanging wall Thumbli play was successfully tested by well T1 which has extended hydrocarbon limit in the eastern fault block. To delineate the said pool limit two more wells were drilled in the northern and southern extremes of the hanging wall structural closure.

Thumbli reservoirs were deposited as a channel-crevasse splay complex in the Tukaram fault block. The general depositional model and facies development of the Thumbli Formation as derived from the cored sediments are non-marine deposits that formed within an alluvial flood basin which has been grouped into channel-fills, over-bank deposits, and lacustrine muds as shown in Figure 3.

Data Availability

The study area is covered with conventional 3D seismic data, 3 wells, and 20,m of conventional core. The reservoir is overlain with thick coal units that appear as strong reflectors in seismic (Figure 4). This impacts the resolving capability of seismic to identify any depositional facies that is to say channel sand bodies from any attribute study. Sedimentological studies were carried out on the core to characterize the depositional environment as a channel-splay complex. Routine core analysis and Dean-Stark saturations were measured on core plugs. Two wells are hydrocarbon bearing while one well was dry. Basic logs were available in all wells along with NMR data from one of the wells. Formation pressure data was acquired in all wells.

Methodology

With limited input from seismic and core, the exploration methodology was focused to collate information from wells that can help to delineate the accumulation and pool extent of the proven oil. Formation pressure analysis was the only available way to analyze the outcome of the dry well and de-risk the future prospectively of the Thumbli reservoir.

Fresh water gradient of 0.433 psi/ft was used to calculate the regional hydrostatic line. This line defined the maximum limit for hydrocarbon accumulation for the Thumbli reservoir. Integrating the offset well information from the Raageshwari Field, the regional gradient was found to be moving from 30 psi to 180 psi above normal hydrostatic (Figure 5). Hence the free water level (FWL) was estimated for each fault compartment.

Hydrocarbon bearing wells were drilled at the crestal part of the fault block. Resistivity based water saturation estimation gave optimistic results and were un-representative for inplace volume calculation. Similarly wells drilled in flanks gave pessimistic water saturation (Figure 6). Hence, saturation height based method seemed to be the way that can capture the structural control for realistic hydrocarbon column estimation and hydrocarbon inplace estimation.

Based on the porosity (phi) – permeability (K) data from the core, rock types were generated as a function of K/phi (Figure 7). Water saturation was estimated using the Lambda function and entry pressures for each rock type that were matched to Dean-Stark water saturation. With the previously determined FWL, water saturation was computed and matched to openhole water saturation estimation.

Results

Initial randomness of the pressure data had a pattern when the number of wells was integrated. This showed development of variable degree of overpressure ranging from 100–200 psi from north to south across different fault blocks along the structural trend in the Tukaram Field (Figure 8).

The pressure data indicates fault compartmentalization where each fault block is hydro-dynamically independent with different water lines. Compartmentalization is also reflected within the different reservoir units in the Upper Thumbli (Figure 9).

So each fault block seemed to have different degree of overpressure that defined the extent of hydrocarbon accumulation. Sensitivity analysis of different degree of overpressure from the minimum and maximum range of overpressure helped to define the FWL in fault blocks un-penetrated by well (Figure 10). Hence the expected pool limit was calculated (Figure 11). Relationship of formation pressure to hydrostatic vis-à-vis interpreted structural spill from depth structure map was used to de-risk prospects below the FWL in this region. The range of FWL was used to develop saturation height model using log data in absence of capillary pressure data from the core.

Conclusion

Integrated analysis of pressure data from the wells defined a clear pattern of increasing overpressure (100 – 200 psi) from north to south along the structural trend. The Eocene Thumbli reservoir is intensely faulted and the pressure data indicates fault compartmentalization where each fault block is hydro-dynamically independent with separate aquifers. The uncertainty in Free Water Level (FWL) in each fault block was estimated from the minimum and maximum range of overpressure to calculate the hydrocarbon pool extent. Sensitivity analysis of different degree of overpressure helped to define the regional FWL. In absence of capillary pressure data from core, log data was used to prepare saturation height model for different FWL. Variation in rock quality was captured in the modeled saturation height function that matched with Dean-Stark saturation for that rock type. For a given rock type, the position of the well with respect to the structural crest led to over-estimation or under-estimation of in-place volume for the entire structure. Relationship of formation pressure to hydrostatic vis-à-vis interpreted structural spill from depth structure map was used to de-risk prospects below the FWL in this region. This methodology helped in determining the thickness of the hydrocarbon column, understanding the uncertainty in FWL, calculation of inplace volume and optimizing the position of appraisal wells.

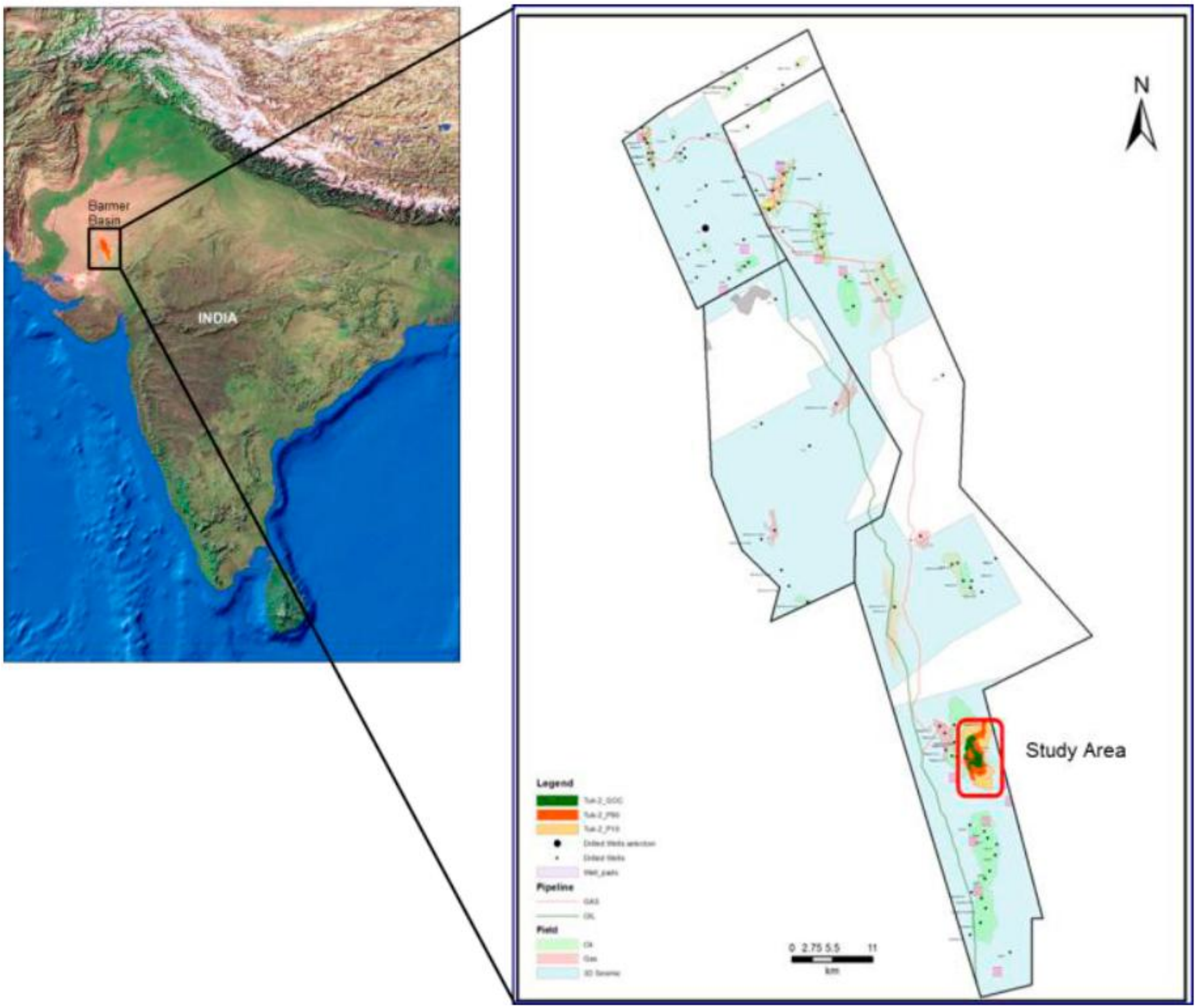


Figure 1. Location map of RJ-ON-90-1 acreage in the Barmer Basin with the study area.

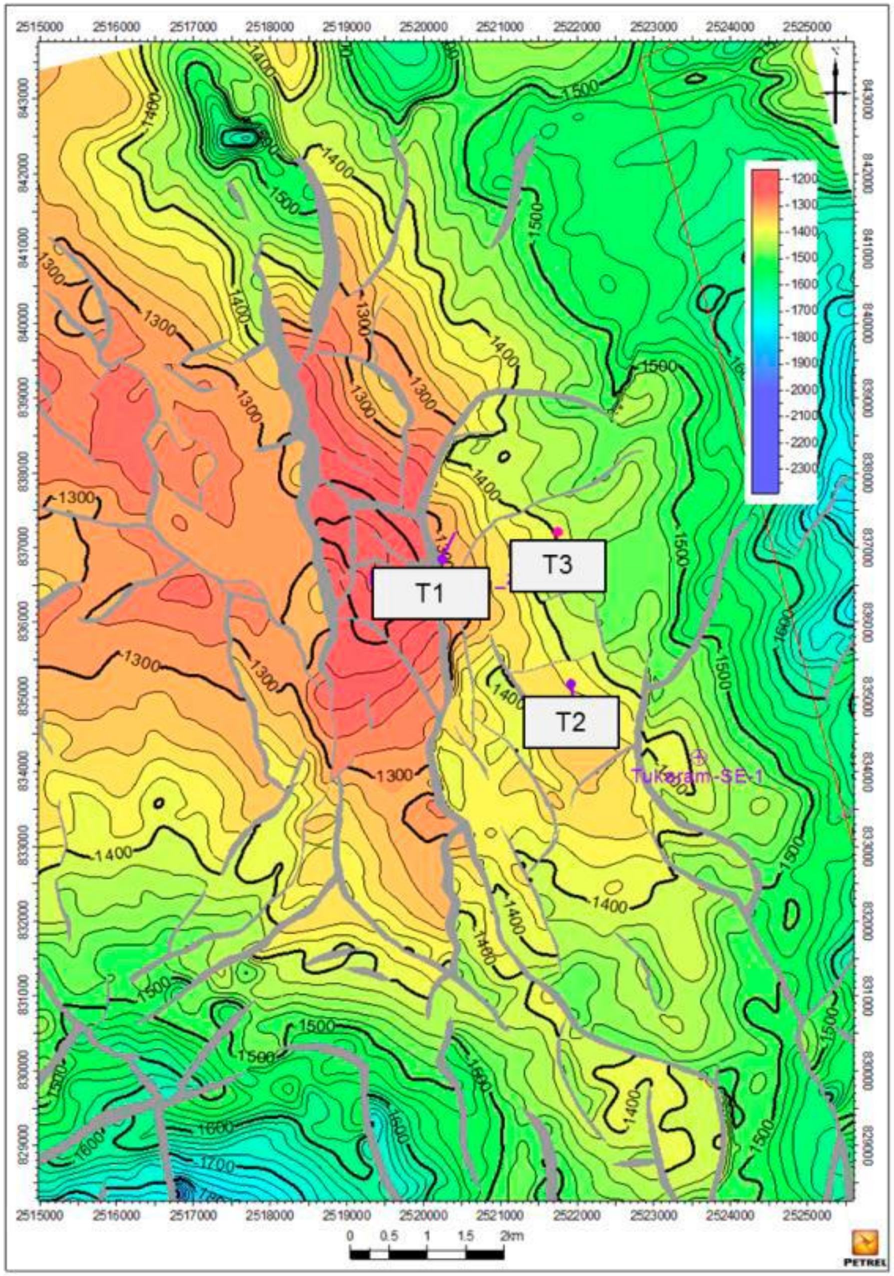


Figure 2. Structure map of the Thumbli.

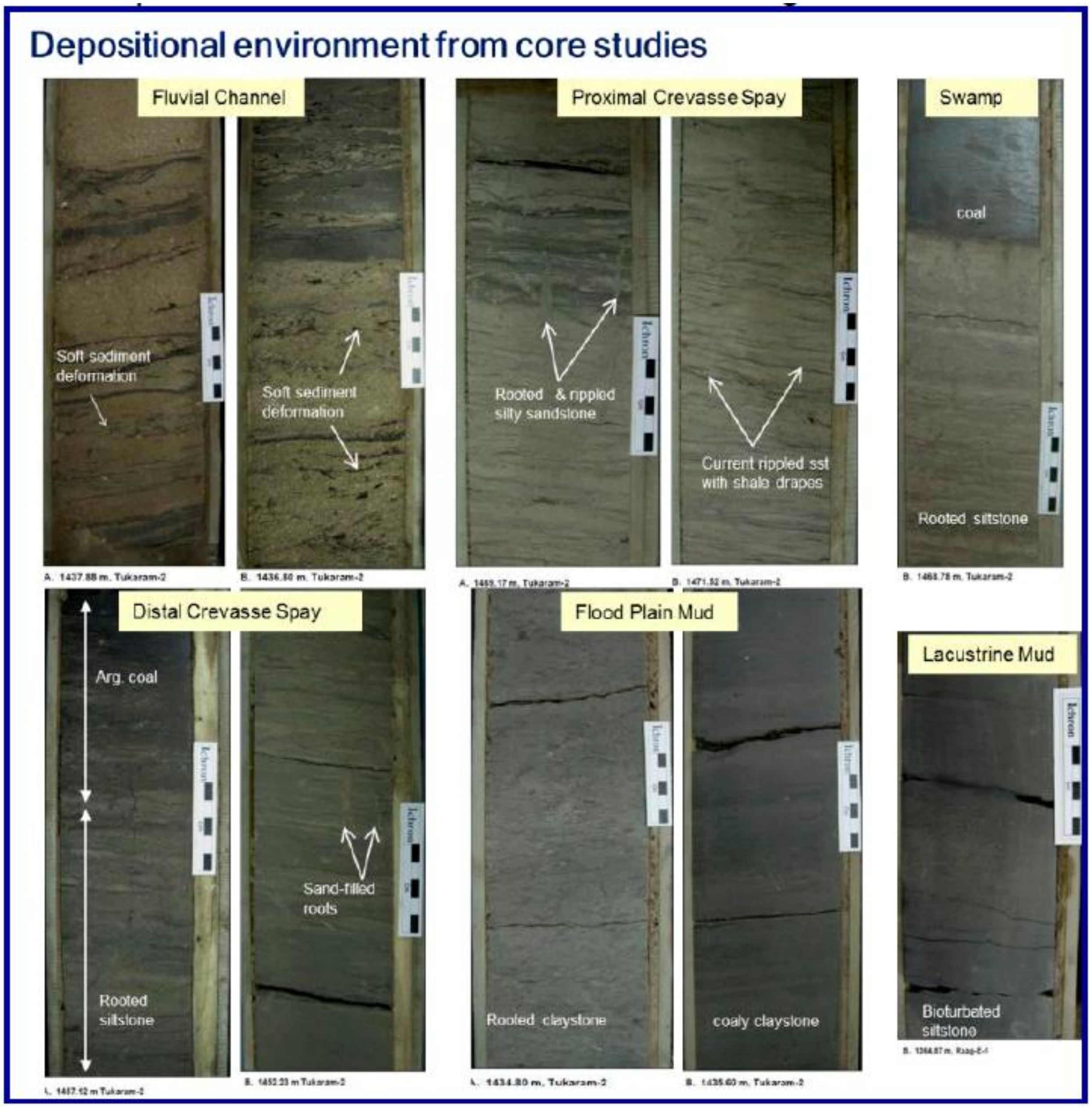


Figure 3. Conventional core from wells T1 and T2 showing sedimentary features for channel-crevasse splay and lake margin depositional environments.

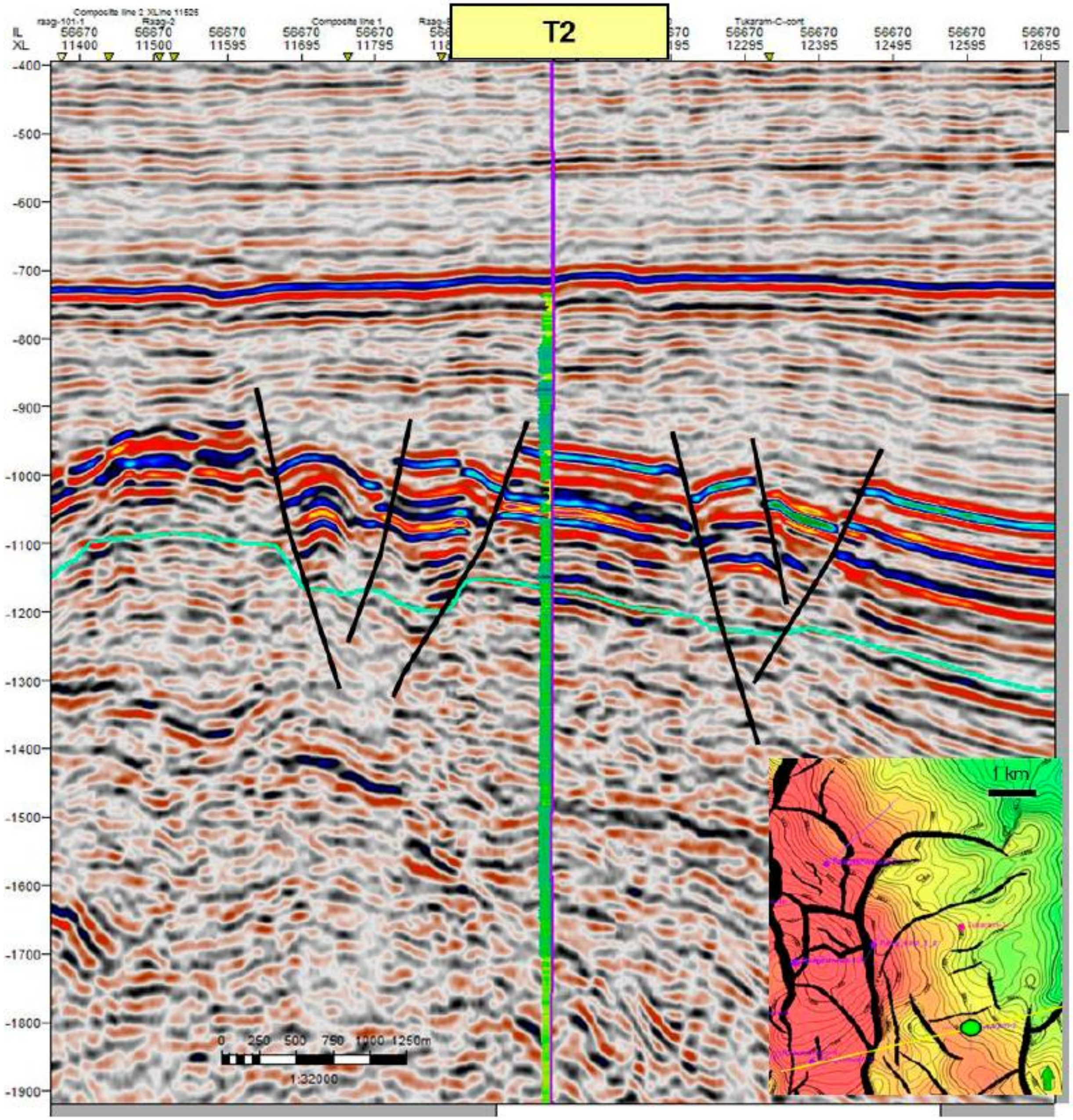


Figure 4. Seismic section through T2 well highlighting intensely faulted Upper Thumbli reservoir interval.

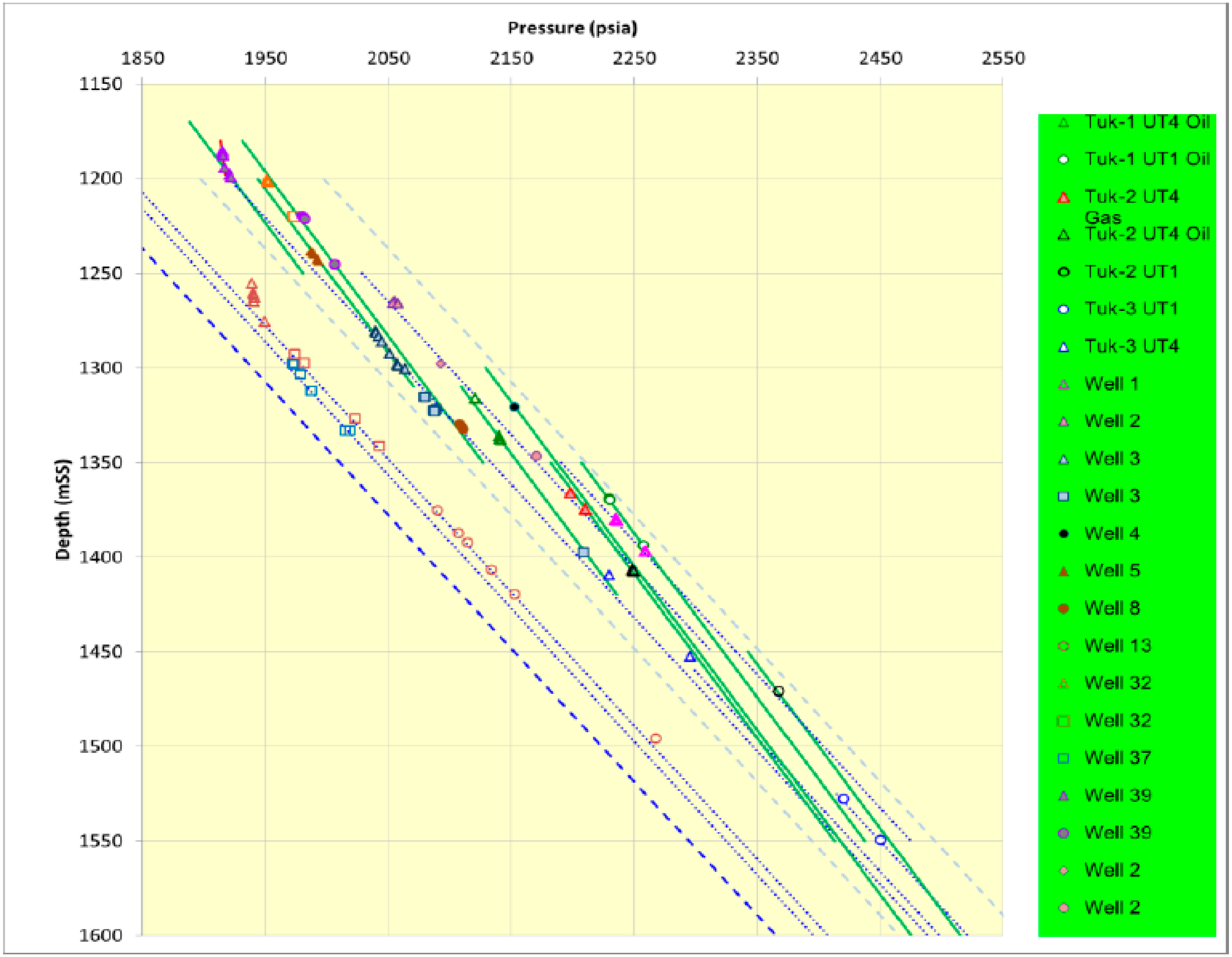


Figure 5. Formation Pressure Analysis of individual fault blocks in Raageshwari–Tukaram Field, water sands are over-pressured with no regional water line.

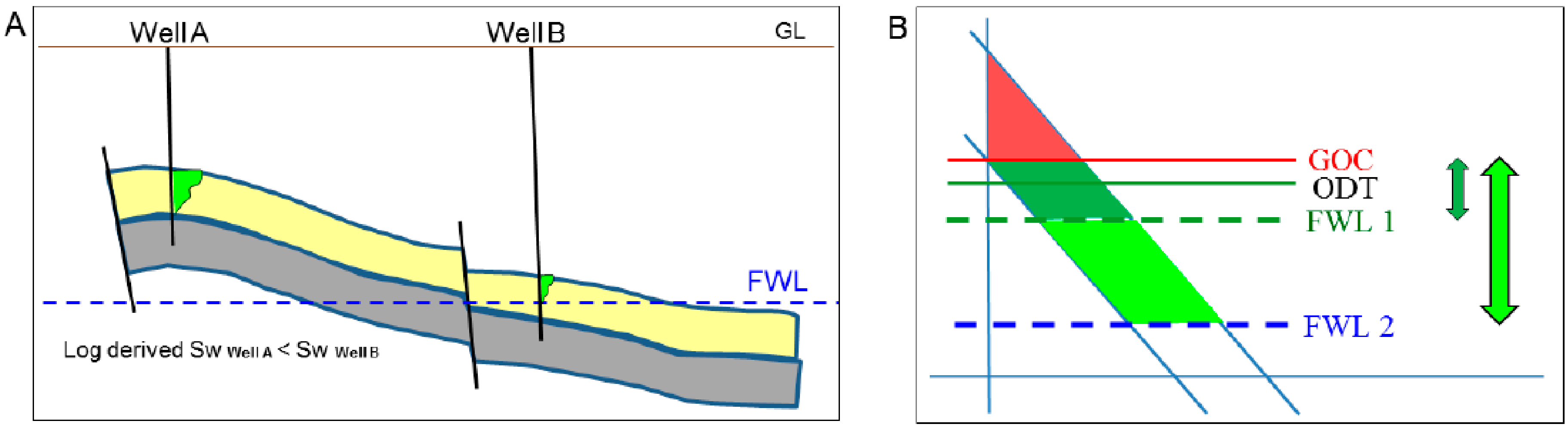
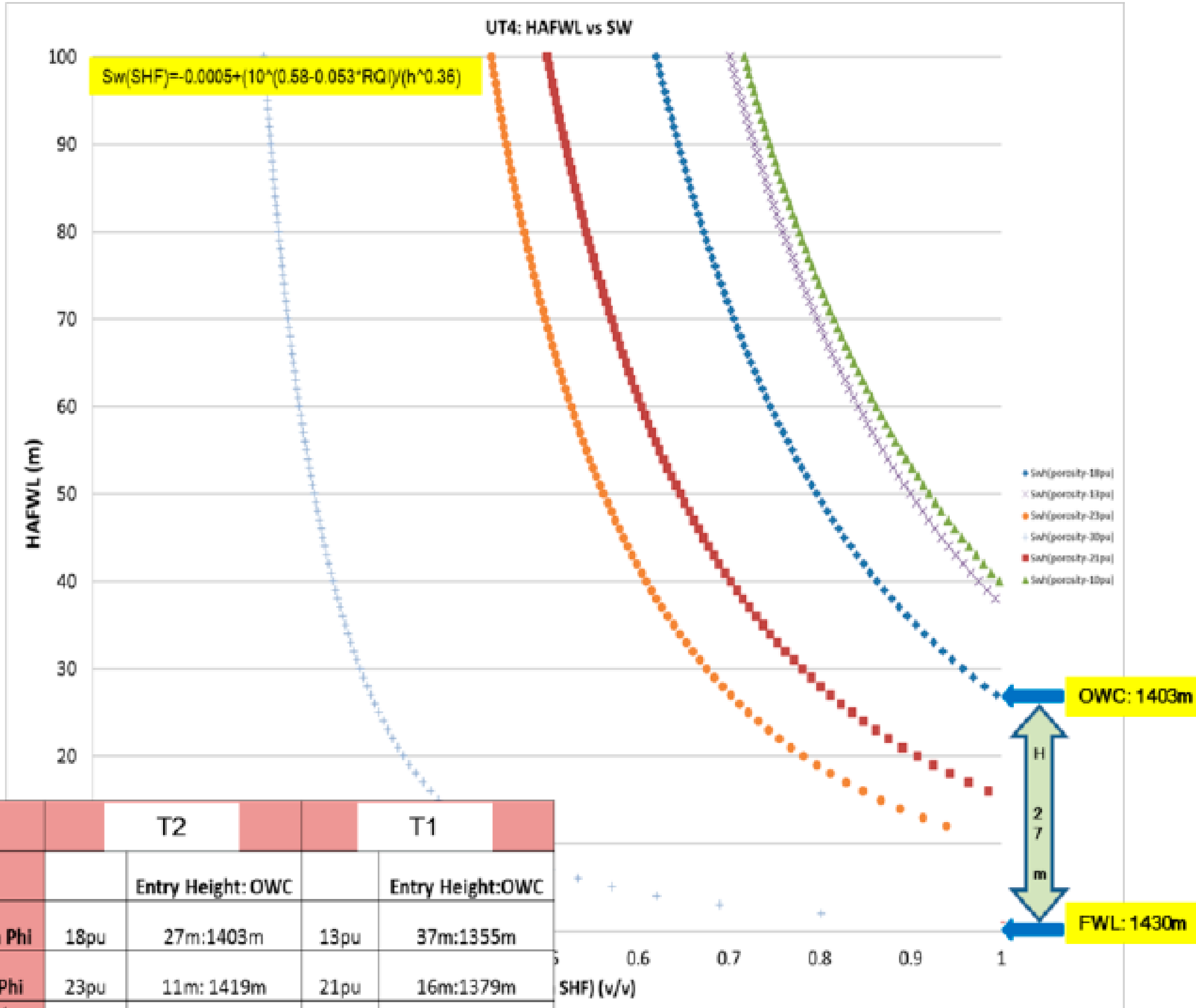


Figure 6. A: Schematic diagram showing the underestimation / overestimation of HC saturation from resistivity log analysis due to relative position of the well in the structure. B: Schematic diagram showing the uncertainty in FWL due to different degree of over-pressure.



	T2		T1	
		Entry Height: OWC		Entry Height:OWC
Mean Phi	18pu	27m:1403m	13pu	37m:1355m
P10 Phi	23pu	11m: 1419m	21pu	16m:1379m
FWL (m TVDSS)	1430		1395	

Figure 7. Estimation of OWC for different rock types with respect to FWL based on entry heights.

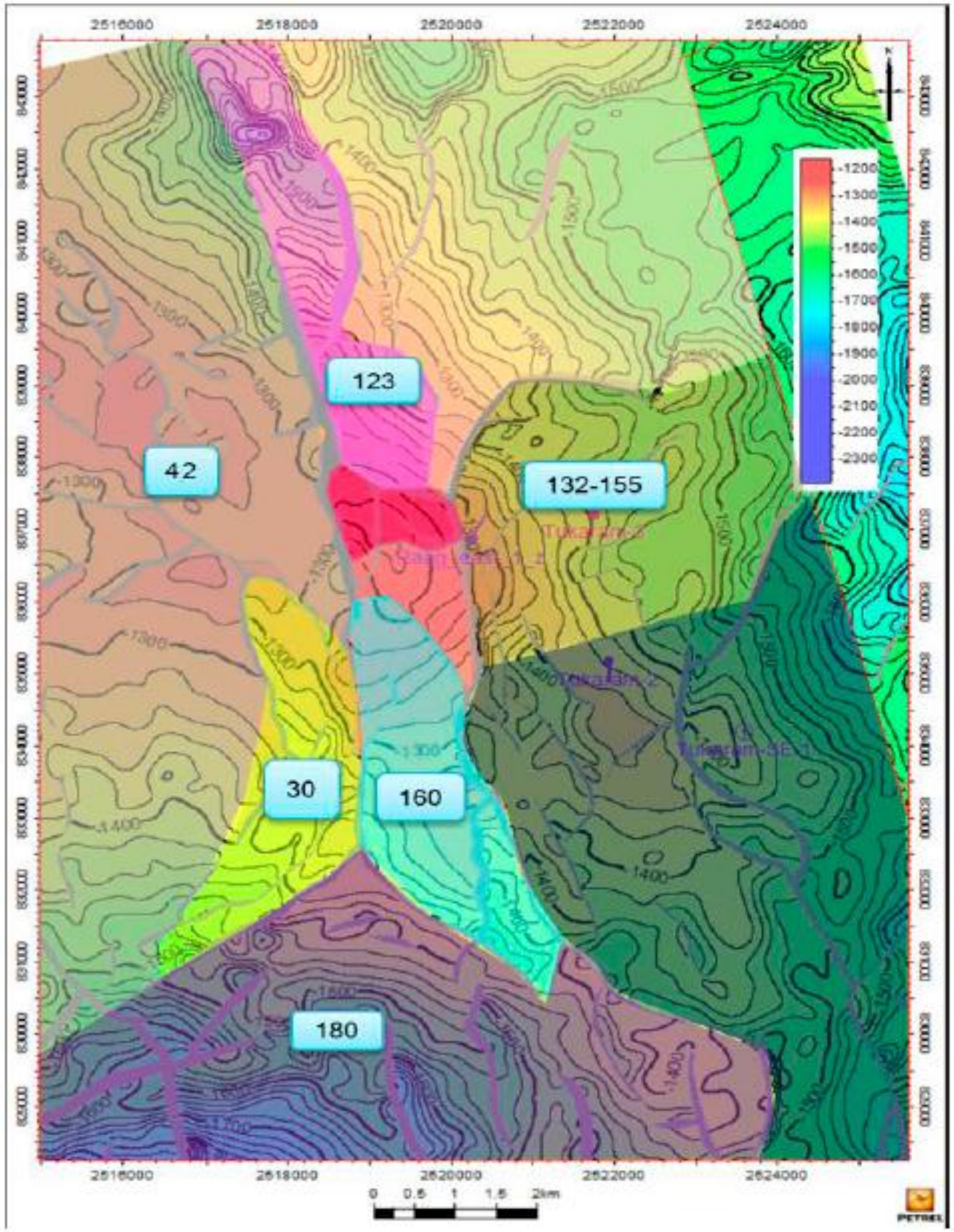


Figure 8. Fault Blocks with degree of overpressure (based on water lines from pressure data).

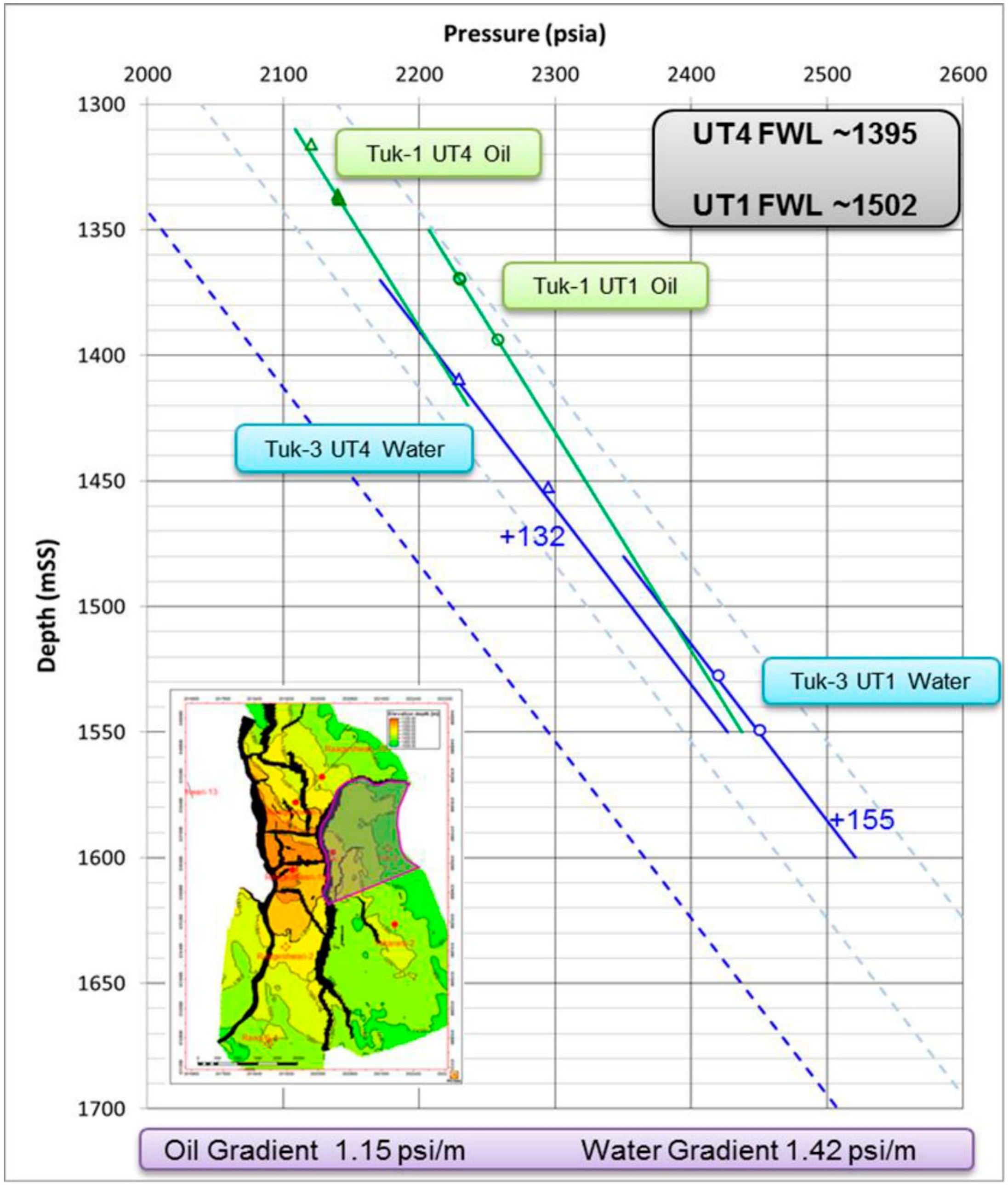


Figure 9. Compartmentalization as reflected in the different reservoir units within the Thumbli.

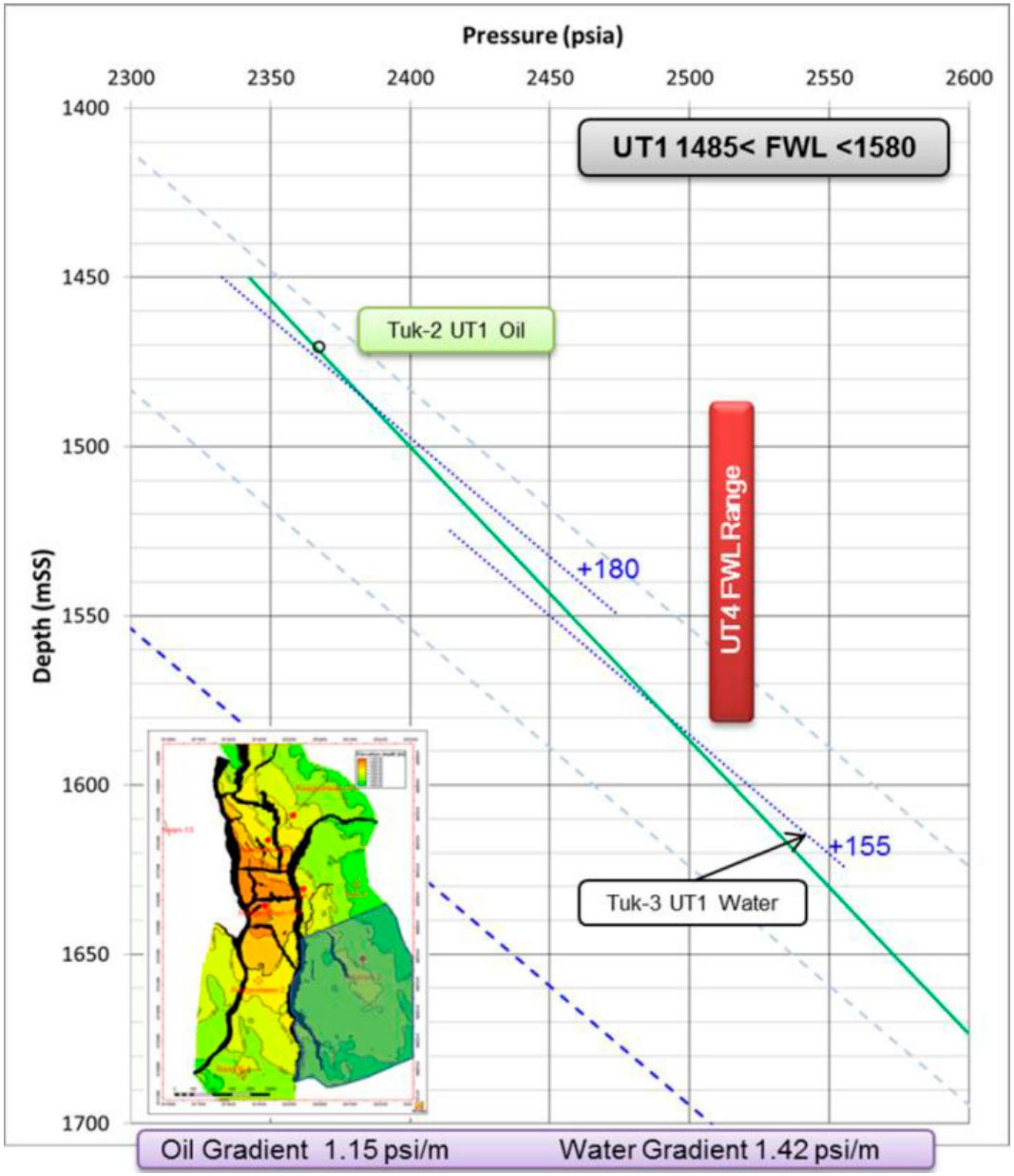


Figure 10. Sensitivity analysis of different degree of overpressure from the minimum and maximum range of overpressure.

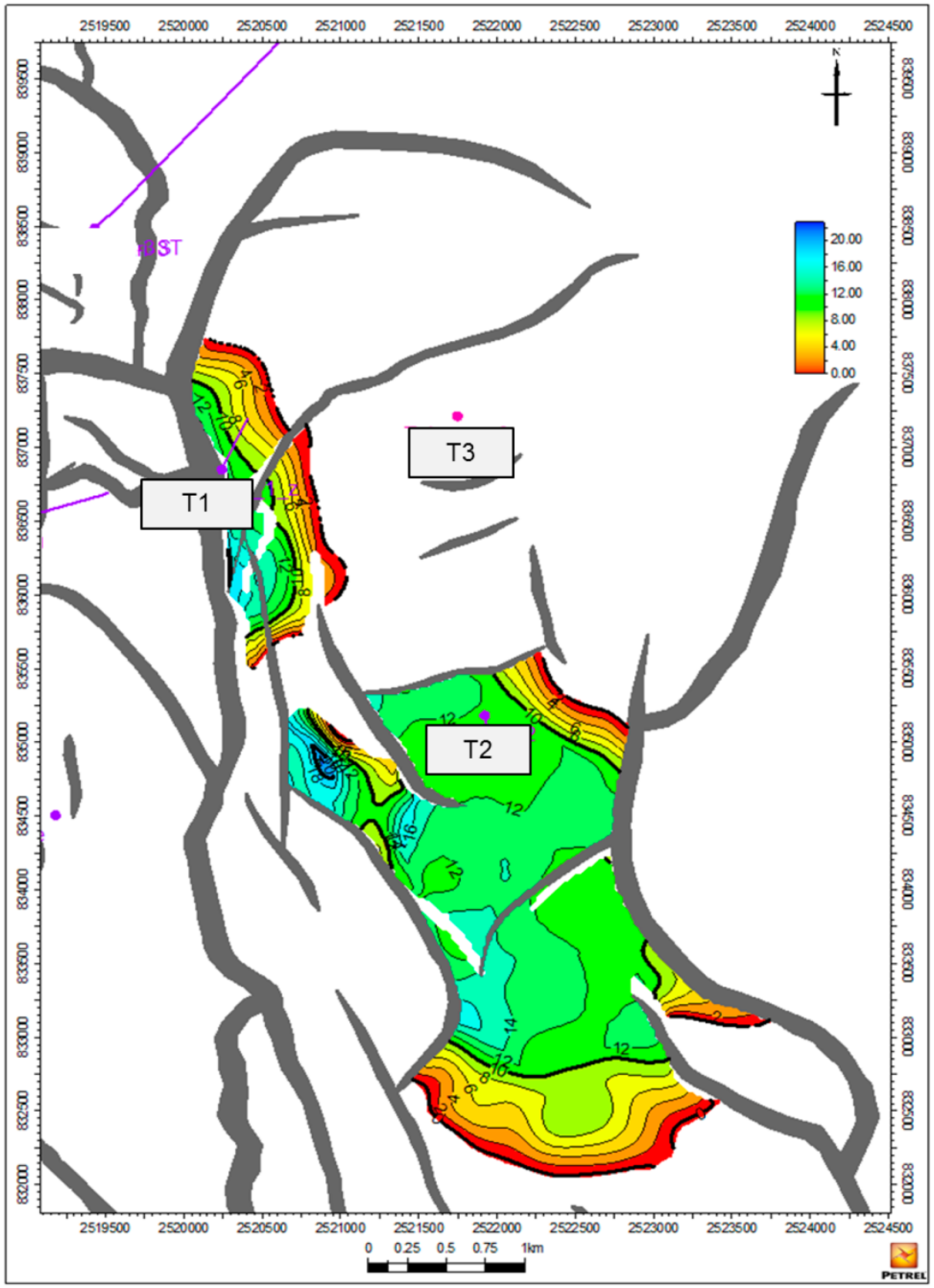


Figure 11. Revised pool limit as derived from the formation pressure data analysis.