Bulletin of the Geological Society of Malaysia, Volume 70, November 2020, pp. 209 - 220
DOI: https://doi.org/10.7186/bgsm70202016

Integrated well data and 3D seismic inversion study for reservoir delineation and description

Qazi Sohail Imran[1,*], Numair Ahmad Siddiqui[1], Abdul Halim Abdul Latif[1], Yasir Bashir[2], Almasgari Abdalsalam Abduh Saeed Ali[1], Muhammad Jamil[1]

[1] Center of Subsurface Seismic Imaging & Hydrocarbon Prediction, Geoscience Department, Universiti Teknologi PETRONAS, Malaysia
[2] School of Physics, Universiti Sains Malaysia, USM Penang, Malaysia
*Corresponding author email address: qazi_17007588@utp.edu.my

Abstract: Offshore petroleum systems are often very complex and subtle because of a variety of depositional environments. Characterizing a reservoir based on conventional seismic and well-log stratigraphic analysis in intricate settings often leads to uncertainties. Drilling risks, as well as associated subsurface uncertainties can be minimized by accurate reservoir delineation. Moreover, a forecast can also be made about production and performance of a reservoir. This study is aimed to design a workflow in reservoir characterization by integrating seismic inversion, petrophysics and rock physics tools. Firstly, to define litho facies, rock physics modeling was carried out through well log analysis separately for each facies. Next, the available subsurface information is incorporated in a Bayesian engine which outputs several simulations of elastic reservoir properties, as well as their probabilities that were used for post-inversion analysis. Vast areal coverage of seismic and sparse vertical well log data was integrated by geostatistical inversion to produce acoustic impedance realizations of high-resolution. Porosity models were built later using the 3D impedance model. Lastly, reservoir bodies were identified and cross plot analysis discriminated the lithology and fluid within the bodies successfully.

Keywords: 3D seismic inversion, reservoir delineation, reservoir characterization, thin-beds, petrophysics, rock physics

INTRODUCTION

To cope with the steadily rising demand of fossil fuels, the petroleum industry is focusing more on offshore exploration as onshore opportunities dwindle, and offshore sedimentary basins represent major hydrocarbon targets in numerous areas of the world. These depositional systems usually have very complex sand distributions and reservoir characterization, and using traditional seismic and well-log stratigraphic analysis may be unreliable (Avseth & Lehocki, 2015). There is thus a need to employ advanced reservoir modeling techniques using seismic amplitude data to reveal reservoir units in these complex systems.

The conventional concept in reservoir modeling is more reliant on geological data (sequence stratigraphy, sedimentology, facies and well analyses). Moreover, in order to make a reservoir model, the spatial distribution of petrophysical properties across the surveyed area may often be done geostatistically, which may not honor the subsurface architecture. Therefore, such an extrapolation is inconsistent geologically since it cannot capture the reservoir heterogeneity entirely. To avoid this issue, seismic data is widely used to fill the gaps because of its vast lateral coverage. However, seismic data has lower vertical resolution as compared to well log data and often lacks both low and high frequencies. The lack of high frequency seismic data makes the inversion of thin-beds reservoir difficult, whereas lack of low frequency makes the estimation of the reservoir's properties ambiguous. Seismic stochastic inversion is by far one of the most valuable methods used for detecting thin beds by providing higher resolution data (Gunning & Glinsky, 2004). It integrates available subsurface information by using Bayesian algorithm and produces simulations of elastic properties and their probabilities. Uncertainties are also estimated and may be used in an intelligent manner. The next crucial step is to convert these elastic properties into petrophysical properties of the main reservoir. Subsequently facies driven porosity models were produced. This study intends to propose solving an inverse problem through an efficient optimization algorithm for properties estimation improvement, thereby obtaining more reliable results, more accurate reserve estimation, reduced reservoir uncertainties and drilling cost optimization.

GEOLOGICAL SETTING

The area of study is located north-east of Peninsular Malaysia in the Malay Basin. It is structurally an anticline which extends in east-west direction. The normal faults, which are trending north-south, separate the study area, with the adjacent gas fields in the eastern and western sides. Figure 1 shows the location of study area, play types and major fault zones. The size of the area is 30 km by 12 km having two major normal faults in the eastern and the western flanks, while in the center there are several northeast-southwest trending normal faults that may produce

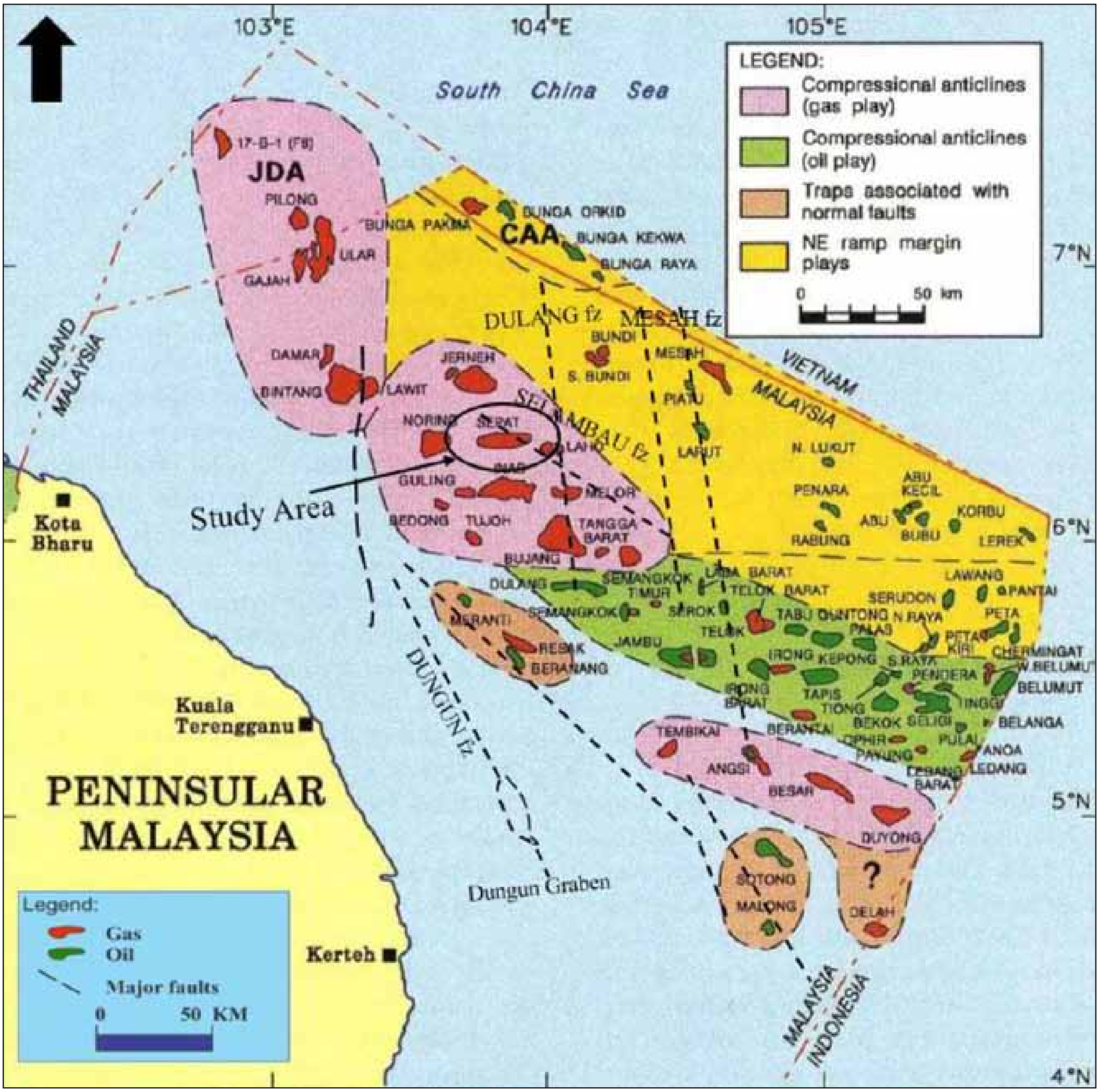

Figure 1: The Malay Basin; showing the study area, play types and major fault zones. (Modified after Madon, 1999; faults added based on Ngah *et al*., 1996).

compartmentalization in the reservoir. On the western side, the structure takes a gentle dip and rises again to form the western structure of this gas field. To the north and the south, the structural dips are moderately steep.

The Malay Basin contains sediments from Oligocene to Recent in age. It has been divided into seismo-stratigraphic units which are also called "Groups". These groups are bounded by distinguishable regional seismic reflectors that some of them represent megasequence boundaries (Ngah *et al*., 1996). The hydrocarbon in the Malay Basin is accumulated in clastic reservoirs, mainly in the sandstones of Groups K to D of Miocene age. The depositional environments are varied for these reservoirs with the stratigraphy. The sandstones of Groups K, L, and M are interpreted to be fluvial channels. Groups J to D sandstones were deposited in shoreface, subtidal shelf, and fluvial-deltaic environments. The stratigraphic groups D and E of upper Miocene are proven reservoirs in the study area (EPIC, 1994). Figure 2 shows stratigraphic column of the northern Malay basin where the study area lies. Several gas discoveries have been made in these groups in the past. Group E is also known to have oil shows (Madon *et al*., 2006). These sandstone reservoir groups are known to have been deposited in lower coastal plain settings. The target groups consist of an inter-bedded sand-shale sequence which has a depth range of 1000-2000 meters.

DATABASE

This study has been carried out using a 250 km^2 pre-stack time migrated 3D survey acquired and processed in 2002 over a gas field in the northern Malay Basin. The volume consists of 300 inlines (lines no. 1200 to 1500) and 2400 crosslines (lines no. 2200 to 4600) (Figure 3). A bin size of 25 m x 12.5 m (inline/crossline) was used. The record length of the volume is 6 seconds and sampling interval is 3.0 ms. The polarity of the seismic data is SEG normal, i.e. the increase in acoustic impedance at a boundary is reflected as peak, or positive amplitude. Well log data of five wells drilled in the study area were available for analysis.

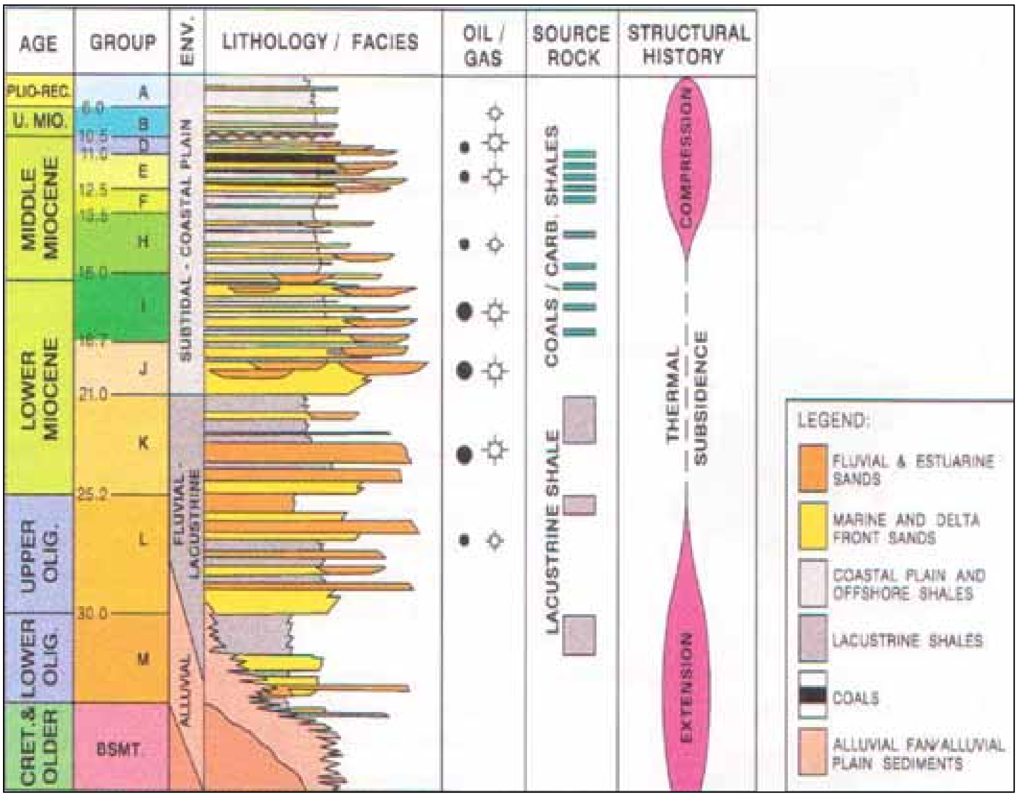

Figure 2: Stratigraphic zonation for the Northern Malay Basin, and its relationship to the main tectonic phases (Madon, 1999). Groups B, D and E of upper and middle Miocene age are the focus of this study.

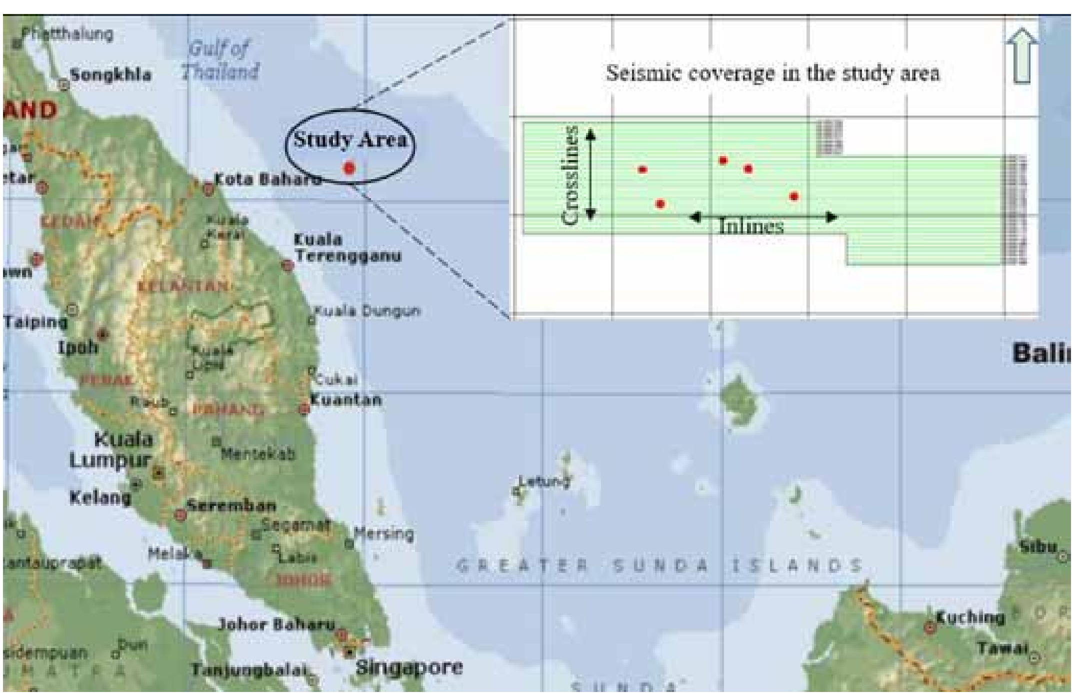

Figure 3: Seismic coverage and well locations (red dots on basemap) in the study area, Northern Malay Basin. The 3D seismic data was acquired in 2002.

Several logs including sonic, density, GR and resistivity were analyzed.

ROCK PHYSICS MODELLING

Rock physics acts as a bridge between geology and seismic data. It calculates the elastic properties of rocks from seismic data. It helps in understanding the behavior of the reservoir and non-reservoir zones by building comparative models (Maulana, 2016). Ødegaard and Avseth (Ødegaard & Avseth, 2003; Avseth & Ødegaard, 2004) came up with the idea of Rock Physics Templates (RPTs), which are used to analyze inversion data during prospect generation phase. RPT is a geologically constrained rock physics model which takes compaction and cementation into account (Avseth & Lehocki, 2015). The model can be effectively used to separate lithology and fluid information; hence it can guide the interpreter to reduce the pitfalls in prediction and misinterpretation (Hermana *et al*., 2016). Figure 4 shows the RPT anatomy where expected models of different lithologies and fluids are presented in an area. These models help in efficient interpretation of seismic inversion results, as well as well log attributes. The template includes the trends for various lithologies and fluid whereas the arrows show different geologic trends.

In order to estimate elastic properties from the facies already defined, the selected rock physics model should imitate reservoir properties such as porosity, pore fluid, pressure, mineral grain volume, pore size and shape, cementation and number of grain contacts by using suitable equations. Figure 5 illustrates how seismic data, elastic properties and reservoir modeling are related (Ghosh *et al.*, 2014).

METHODOLOGY

Integrated geological and geophysical studies are crucial to hydrocarbon development projects (Cosentino, 2001), and the best means to extract additional information from seismic data is seismic inversion. Inversion replaces the seismic signature with a blocky response corresponding to acoustic and/or elastic impedance layering. It assists in meaningful interpretation of geological and petrophysical interfaces in the subsurface. Inversion may increase the resolution of traditional seismic in many cases; consequently, making the reservoir studies more accurate and reliable.

Due to the limited resolution of seismic data, thin reservoirs are usually difficult to explore. Prospect mapping in the oil industry has been evolving over the time. In a recent paradigm shift, quantitative interpretation has now become an important part of interpretation workflows due to superior algorithms of seismic inversion (Avseth *et al*., 2014). A generalization of acoustic impedance for variable incidence angles, called Elastic Impedance, provides a consistent and absolute framework to calibrate and invert nonzero-offset seismic data just as AI does for zero-offset data (Connolly, 1999; Maver & Rasmussen, 1995, 2004). Such approaches to seismic amplitude interpretation enable accurate estimation of elastic properties in target reservoir intervals (Filippova *et al*., 2011).

Bayesian Stochastic Inversion (BSI) is a valuable method for detecting thin beds by providing high resolution results through the generation of a large number of possible high-frequency models that can be used for post-inversion analysis of facies and connectivity. A Bayesian framework takes all available subsurface information into account and produces output simulation of elastic properties and their probabilities (Ahmad *et al.*, 2009). Uncertainty information is also captured effectively and can be used intelligently in further analysis.

Seismic data lacks often both low and high frequencies (Figure 6a). Therefore, seismic inversion fails to recover the thin beds and the reservoir property from the seismic data because of its bandlimited nature. A plausible broader band frequency is difficult to build when as the model (known as an a priori model) building is inadequately constrained or regulated (Kemper & Gunning, 2014). The low frequency is commonly modelled through interpolation of low-pass filtered impedance profiles derived at the wells (Figure 6b). However, this approach only yields a credible model

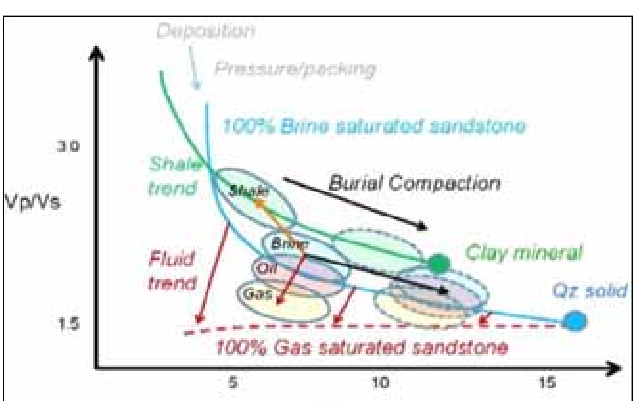

Figure 4: RPT anatomy model concept for brine and gas saturated sandstones and for shales (Avseth & Lehocki, 2015).

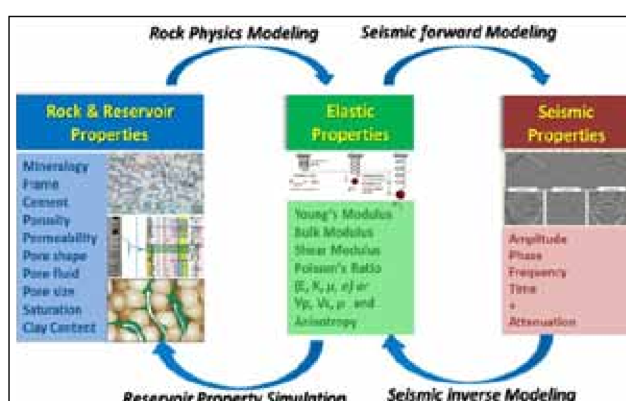

Figure 5: The link among Reservoir, Elastic and Seismic properties (Ghosh *et al.*, 2014).

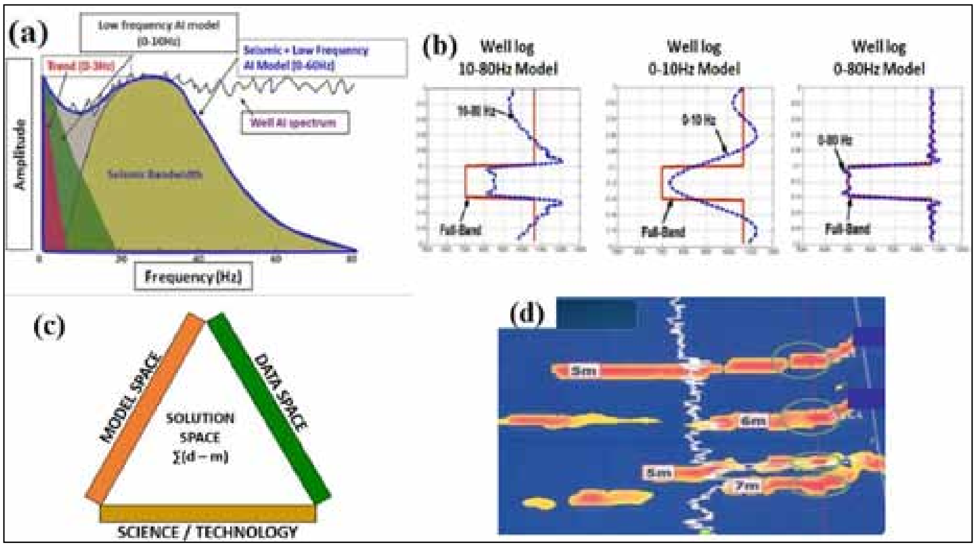

Figure 6: (a) The black frequency spectrum is from the input seismic data and lack both low & high frequency. The broadband data is from well that also has a dip at about 2-10 Hz. Green is the gap 3-10 Hz that needs to be compensated. (b) Importance of low frequency in inversion. The 10- 80 Hz data is unable to recover the impedance properties. (c) Inversion process: model is constantly iterated to minimize the errors while comparing with the data through a gradient process. (d) Thin-beds detection in a pre-stack stochastic inversion (Courtesy: PETRONAS-Shell CSMP).

at the well location. A more well-independent technique is needed to obtain a plausible broader band frequency priori model. Simultaneous seismic inversion is a model-based seismic inversion illustrated in Figure 6c. The synthetic seismic data generated from the well is matched with the actual seismic iteratively and the resultant errors, called the residual, are utilized to update the model. Once the errors are minimum and within an acceptable limit, this iterative process is completed, and the inversion results are accepted. Elastic simultaneous inversion can image thin beds to the order of 5 m – 7 m (Figure 6d) (Purnomo & Ghosh, 2017).

For this study, a Bayesian stochastic inversion method is used to obtain posterior distribution for P-wave velocity, S-wave velocity and density. The inversion algorithm is based on the convolutional model and a linearized weak contrast approximation of the Zoeppritz equations. The solution of stochastic inversion is given by a Gaussian posterior distribution (Buland & Omre, 2003). This is a handy configuration which can detect the sub-seismic resolution thin-bed layers successfully. The resultant posterior probability function is then input to an algorithm called Markov Chain Monte Carlo (MCMC) to produce realistic models of impedance and litho-facies, which are then used to co-simulate rock properties (Eidsvik *et al*., 2004; Mukerji *et al*., 2001). Figure 7 shows the simplified workflow of the proposed inversion. To constrain the priori model building, thin-bed seismic tuning and locally varying anisotropy were used. (I) PSTM angle stacks and well logs were used as inversion input. (II) Low frequency modeling is a key element derived from sharp reflectivity constraint. (III) Inversion is constrained with locally varying anisotropy and energy spectra. (IV) A priori model is the input which is systematically updated to yield posterior probability. (V) The final result is given as multiple realization scenarios following MCMC technique, yielding the reservoir parameters.

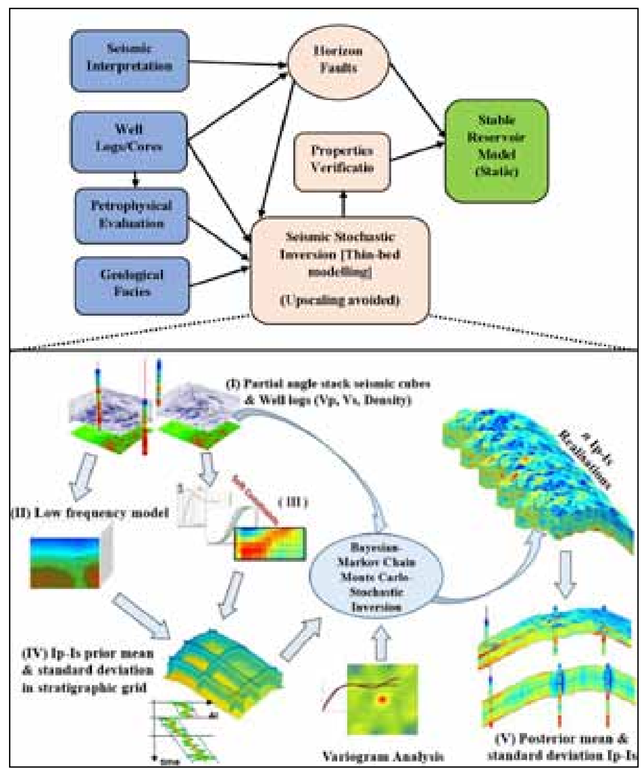

Figure 7: Flow scheme showing the different steps of the study and how these are linked together.

The seismic stochastic inversion produces comprehensive property models by integrating seismic and well log data by employing geostatistical algorithms (Haas & Dubrule, 1994). The technique attempts to produce the property models with resolution as high as a well log but makes use of the broad aerial coverage of the seismic information between the wells. At a seismic trace location, several realizations of impedance data are simulated within the 3D framework. Then the impedance traces are converted into reflectivity traces and are convolved with the assigned wavelets to generate a synthetic seismogram. The synthetic seismogram is correlated with actual seismic data and the best result is selected at that specific trace location. The process continues within the 3D framework and the same procedure is repeated to generate inversion results for other trace locations until the entire seismic volume is replaced with pseudo impedance logs. The procedure elaborated here is known as Sequential Gaussian Simulation. The deterministic inversion impedance volume can also be used to constraint the algorithm.

The output of stochastic elastic inversion is the accurate elastic properties between the wells. Since elastic properties demonstrate the geology, reservoir properties between the well can be estimated with confidence. The above methodology not only helps to understand the uncertainty but also minimize the risk within the model.

RESULTS AND DISCUSSION

The study area is mostly gas prone and has several gas fields which were discovered in the 1980s, located within the Northern Malay Basin, where stratigraphic groups D and E are the proven reservoirs (Madon *et al*., 2006). Group E sandstone reservoirs consist of fluvial channel sediments whose depositional environment is believed to be a lower coastal plain. Groups B, D and E are gas bearing whereas Group E is more oil prone. Typical log character of these groups from the wells used in this study is shown in Figures 10 and 11. Oil shows have also been seen in some wells. Figure 8 shows 3D seismic horizon D60 tracked in time (upper) whereas lower is time slice variance at 1500 ms where shallow gas effects are evident at the crest. Masking of sandstone reservoirs in seismic imaging by numerous coal beds, thin-bed reservoir layers and the adverse effects of a gas cloud on seismic data are among major issues (Figure 9).

The petrophysical analysis

The stratigraphic correlation (Figure 11) and petrophysical analysis provide significant information. The key parameters to be delivered in this study are total porosity (PHIT), effective porosity (PHIE), effective water saturation (SWE) and Sand/Silt/Clay volume indicators. Some of the well logs used in this analysis are shown in Figures 11 and

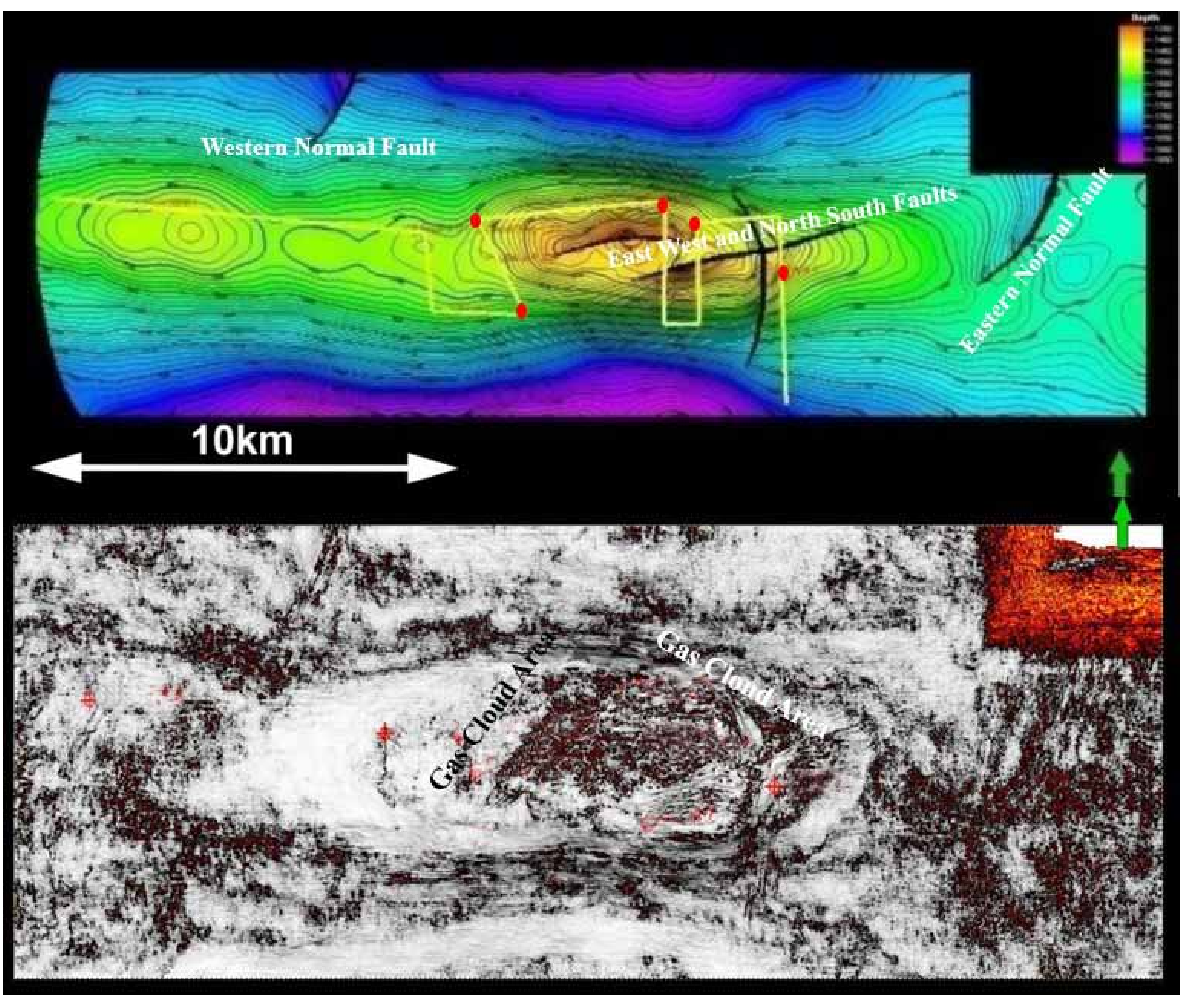

Figure 8: The 3D tracked horizon D60 (upper), showing the major faults in the compressional anticline. Time-slice variance (lower) at 1500 ms showing shallow gas effects at the anticline crest.

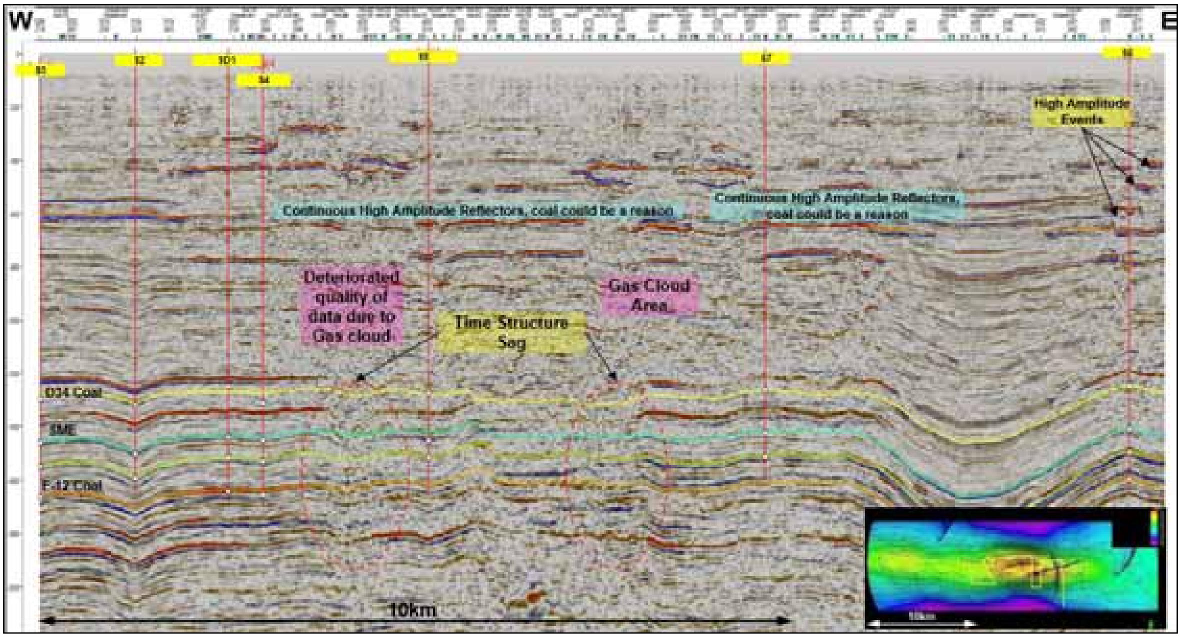

Figure 9: Composite seismic section through the available wells in the study area. Numerous high amplitude shallow events and gas cloud areas have been marked.

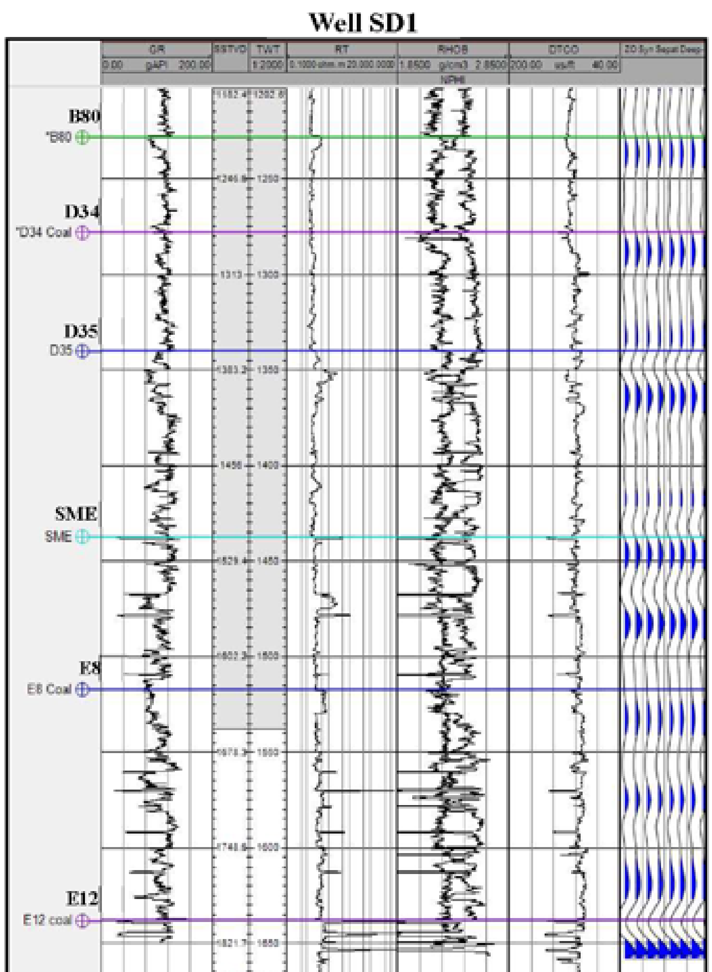

Figure 10: Typical log (GR, Resistivity, Density & Sonic) character of different reservoir groups from one of the wells SD1 in the study area.

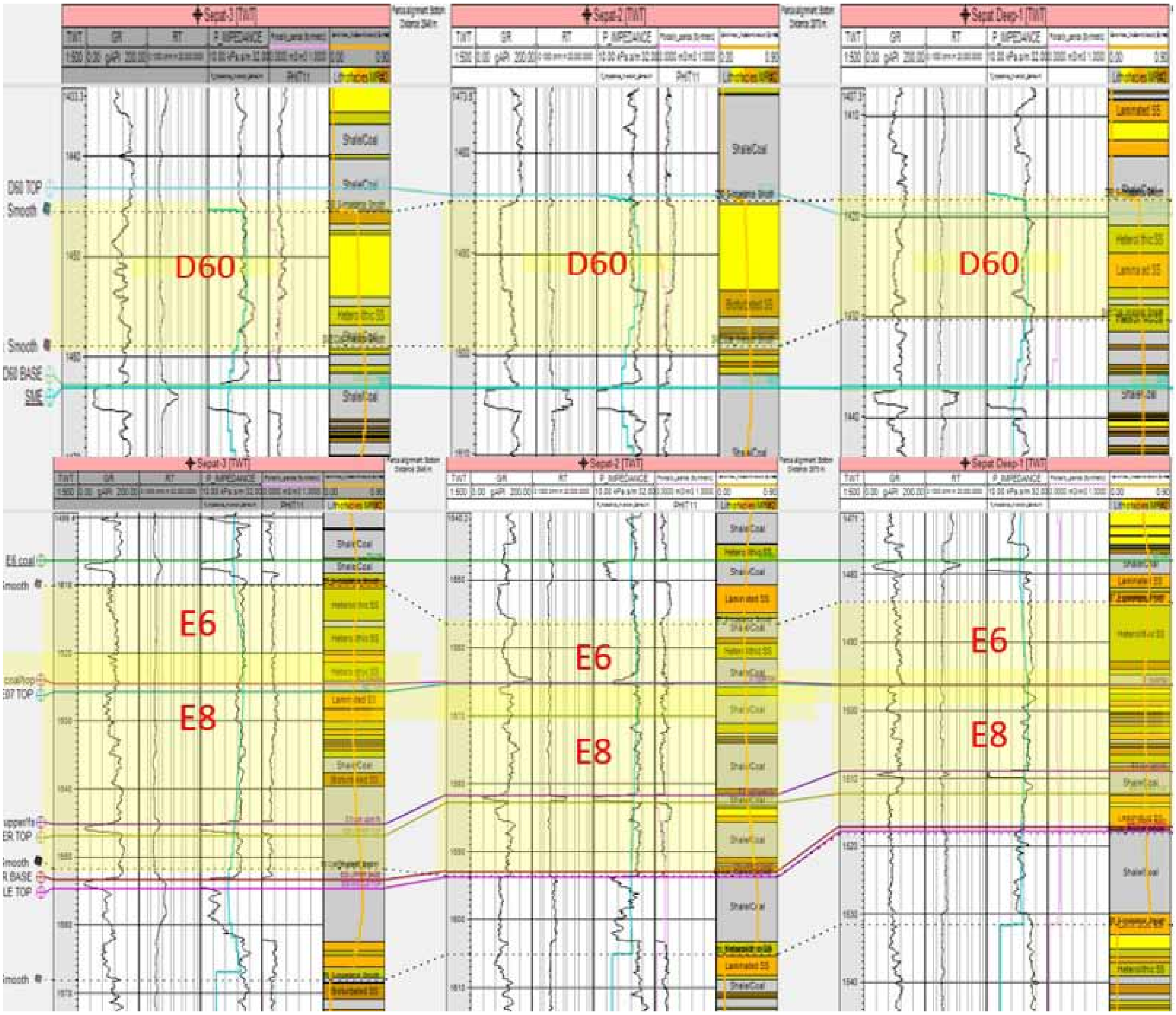

Figure 11: Wells used in stratigraphic correlation and analysis in the study area . The potential reservoir groups i.e., D & E have been extended across three wells and facies have been marked based on log response. Depth ranges between 1400 -1600 meters.

12. These include density, resistivity, gamma ray, porosity, caliper, P-Impedance and sand & silt volumes for four wells. The wells were analyzed in terms of fluid type and lithology. The lithology inferred from the density and neutron logs indicates that the considerable portion of the study area is dominated by fine- to very-fine sand reservoirs. Shale lithologies were identified based on the high gamma ray and low resistivity values. Log areas showing low gamma ray and low acoustic impedance but high resistivity values were delineated as sand lithologies. Sand lithologies with low acoustic impedance and high resistivity are possible areas of hydrocarbon saturation. Potential reservoir bodies; D60, E6 and E8 are marked based on this analysis. Besides yielding quantitative lithological interpretation, it also brings up important geological features which are not obvious or do not show up readily by the gamma ray log alone. For instance, petrophysical analysis of 2 wells show coarsening upward sand sequences in the D34 reservoir group (Figure 12). The fact that it is consistent between the two well bores, is geologically expected given the small distance between them, which further demonstrate the significance of this petrophysical model in unlocking important sedimentary events that are otherwise going undetected using the gamma ray curve alone. This log derived lithology description along the well-bore should provide vital insights to identify lithofacies in order to describe depositional environment.

Fluid type identification through well logs remained a challenging task. It has been noted that the gas has not influenced the density and neutron log much, possibly because the apparent difference between gas and oil-bearing formation is little. This observation is consistent with the fine- to very-fine sand environment which is intrinsically prone to high connate water in the pore systems, thus diminishing the effect of gas on both density and neutron logs. Drilling induced factors, e.g. drilling time, tripping time etc, could have also influenced the density/neutron data.

Seismic inversion analysis

For seismic inversion analysis, after the seismic and log conditioning, the data was uploaded in Strata module of Hampson Russel package. A good seismic to well tie with correlation coefficient of 76 percent was achieved, showing a good match between the synthetic traces and the actual seismic data, ratifying the stochastic inversion results. The inversion was performed over a selected time range of 1000 ms - 2000 ms, with the target reservoir groups lie in this range. The initial model was constrained, and inversion results were compared with original input seismic and impedance logs. After a careful QC exercise, the inversion results were deemed acceptable. Figure 13 shows seismic

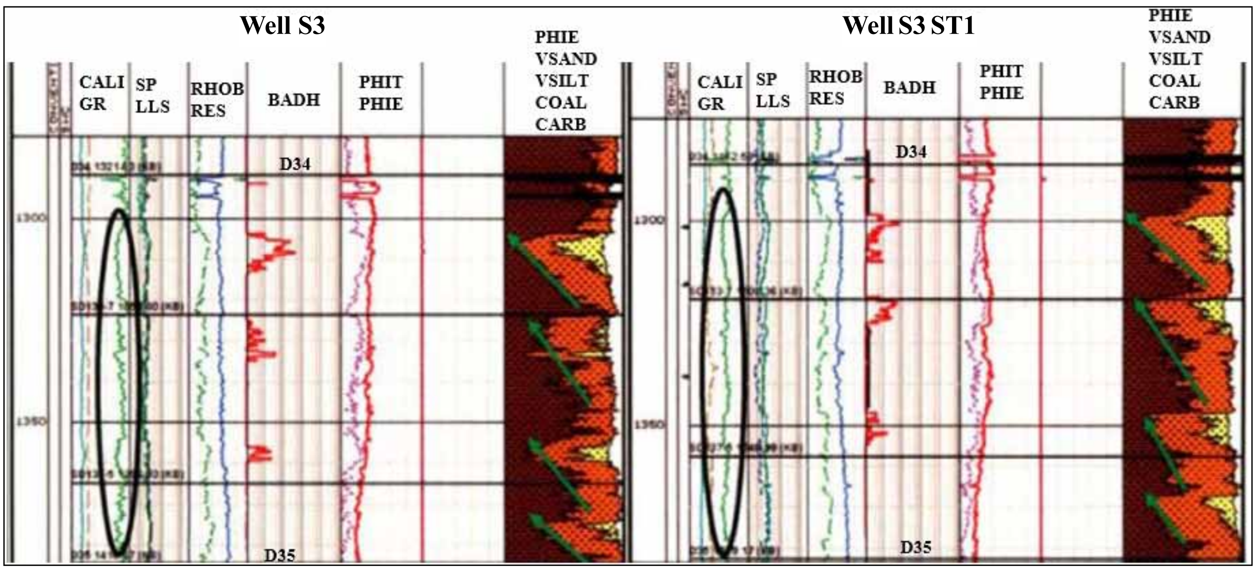

Figure 12: Coarsening upward sands in D34 reservoir group in S3 and S3 ST1 wells. Gamma ray (encircled) does not reflect this information.

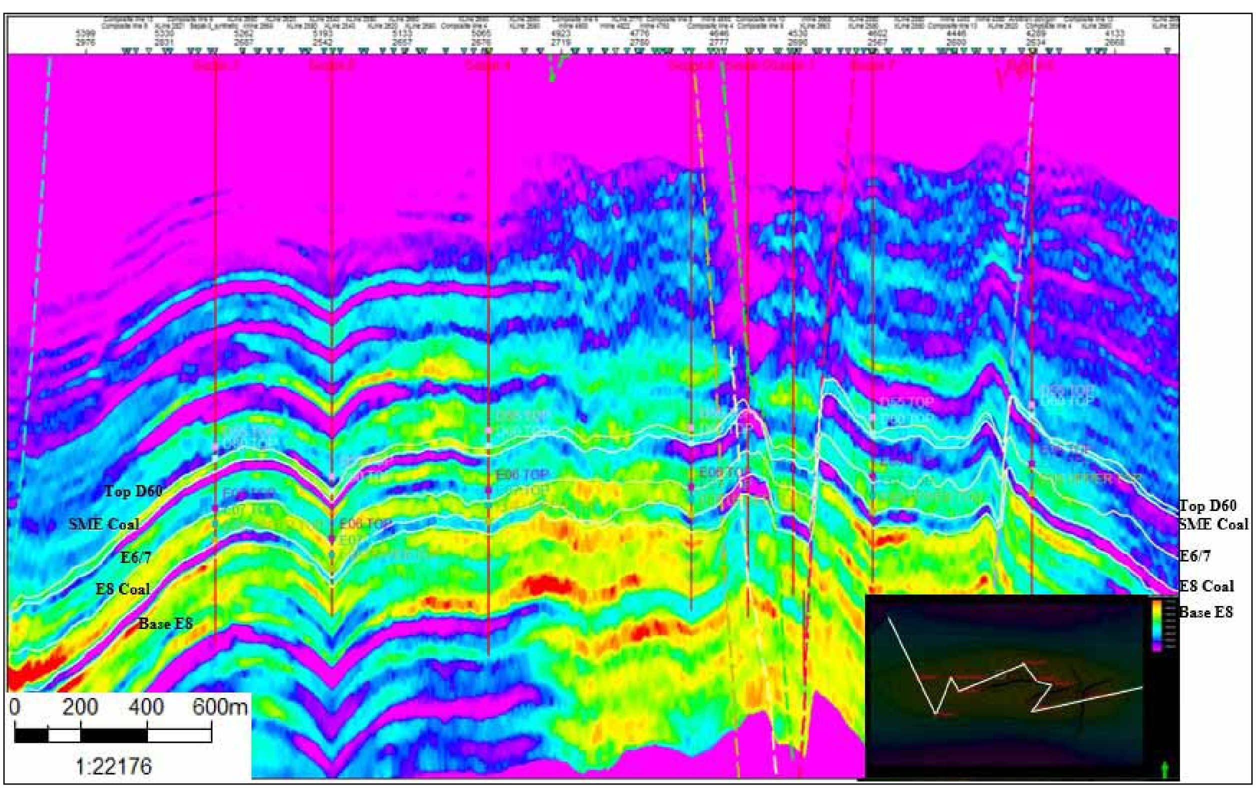

Figure 13: Seismic inversion helped unravel sub-resolution reservoir bodies. Top D60, SME Coal, E6/7, E8 and Base E8 have been identified across the area.

inversion result where sub-resolution reservoir bodies E6/7 and Base E8 have been identified. The resolution of inverted volume has been enhanced.

Cross plot analysis

Cross plotting seismic inversion attributes with common lithologies and fluid types generally cluster together allows for straightforward interpretation. A typical cross plot that has been done in this study is between Vp/Vs ratio and P-Impedance (Figure 14A). The Vp/Vs ratio is a fluid indicator because compressional waves are sensitive to fluid changes whereas P-impedance shows a better discrimination in terms of lithology and fluid content. The cross plot in Figure 14A shows fluid as well as lithology discrimination along the P-impedance axis; oil-sand (green dots), gas-sand (red dots), brine-sand (blue dots) and shale (grey dots). Oil sands (green dots) have higher density and P-impedance compared to gas sand (red dots) (Figures 14B and C). Cross plot between Total Porosity and P-impedance shows good porosity distribution in the study area (Figure 14C). Porosity volume was also generated from P-Impedance volume. The porosity distribution is normal and has close agreement with porosity from most wells of 0.19 (Figure 15). Figure 16 exhibits map representing the vertical average of impedance values below the picked horizon SME coal.

CONCLUSION

An integrated well data and 3D seismic inversion workflow was designed to better delineate potential reservoir bodies under gas cloud environment. The area under investigation has numerous thin sand beds of sub-seismic resolution. Property models of absolute acoustic impedance values were generated by integrating well and seismic data by performing seismic inversion. The models provided higher vertical resolution. Thin-beds in the reservoir section were resolved using the inversion impedance models, with crestal parts of the anticline show low impedance values in the maps. This contrast could be linked to variation in porosity and/or fluid type within the reservoir interval. Cross plot analysis has identified oil sands and gas sands in the reservoir interval

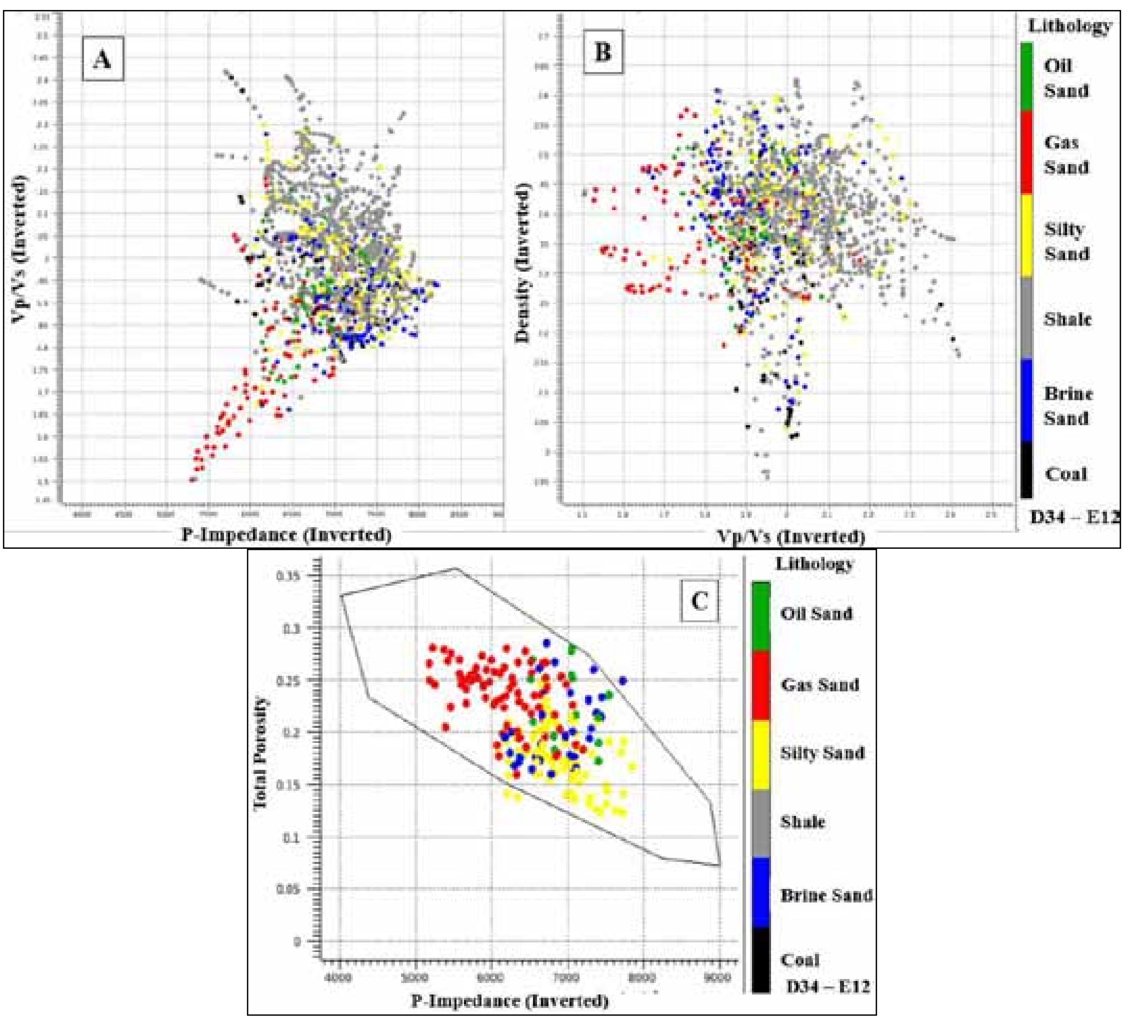

Figure 14: Cross plotting the seismic inversion results. A: P-Impedance vs Vp/Vs. B: Vp/Vs vs Density. C: P-Impedance vs Total Porosity.

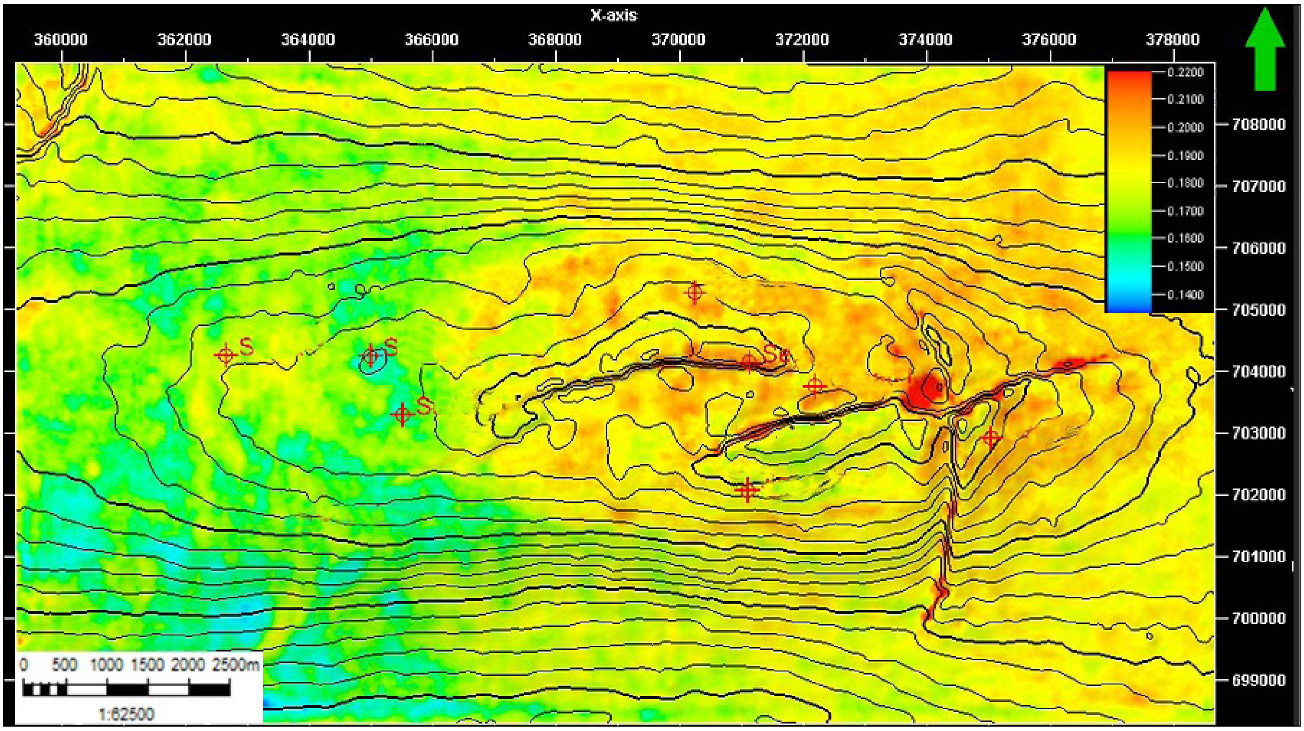

Figure 15: 3D porosity model of one of the reservoirs D60 generated from P-Impedance. Porosity distribution is found to be normal and had a close agreement with porosity from wells.

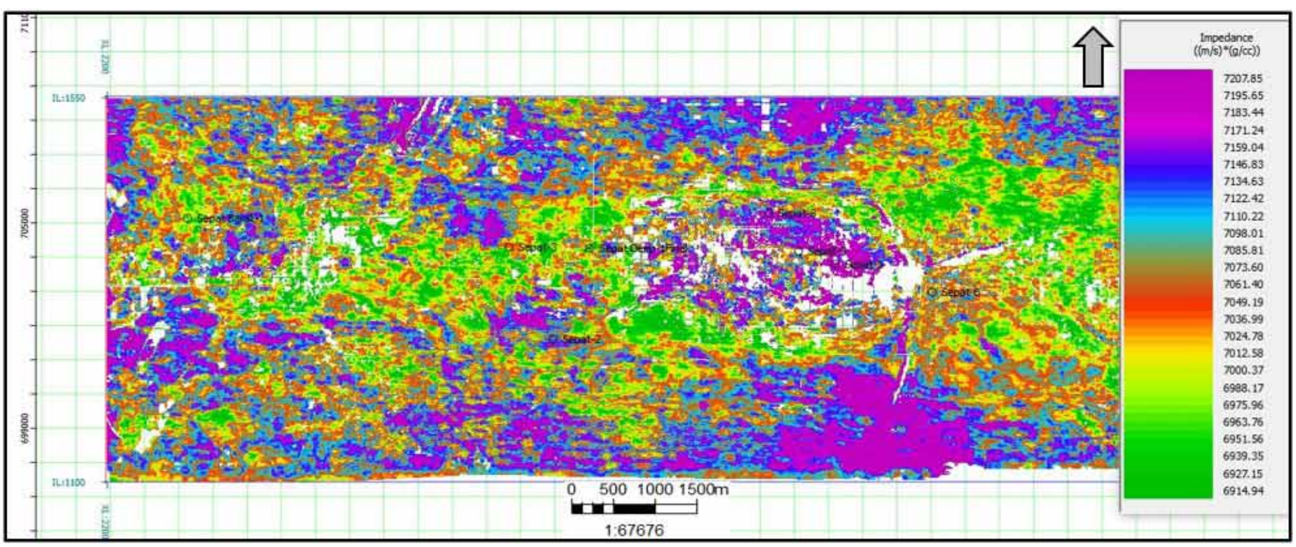

Figure 16: Map showing vertical average of impedance values below the picked horizon SME D60. Green (low) to purple (high) impedance contrast characterizes variation in porosity and/or fluid possibly.

having good porosity. Lithology and fluid discrimination were done successfully based on P-impedance versus Vp/Vs response cross plot. 3D porosity models were created based on the facies and impedance models, which show that the study area has fair to good porosity distribution. Petrophysical evaluation indicates that the reservoirs are fine- to very-fine sand reservoirs, heterogenous and are prone to high connate water in the pore system. Based on these findings, crestal parts of the anticlinal structure seem favorable for new drilling locations. The quality of the results show that the integrated geological and geophysical approach has effectively characterized the reservoir properties in the area under investigation. However, more well and better resolution seismic data can improve the findings.

ACKNOWLEDGMENT

We would like to express our gratitude to PETRONAS, Universiti Teknologi PETRONAS and Center of Seismic Imaging for providing the funding and permission to publish this paper. Special appreciation and thanks to the author's advisors Dr. Numair Ahmad Siddiqui and Dr. Abdul Halim who have been tremendous mentors.

REFERENCES

Ahmad, J., C. Mangat & J. Pendrel, 2009. Delineation of a Thin Sand Reservoir using Geostatistical AVO Inversion. Frontiers + Innovation – 2009 CSPG CSEG CWLS Convention, Calgary, Alberta, Canada, p. 115.

Avseth, P. & Lehocki, I., 2015. Quantitative interpretation of rock stiffness and hydrocarbon softening from seismic inversion data using rock physics templates. SEG Technical Program Expanded Abstracts 2015, 585-589.

Avseth, P. & Ødegaard, E., 2004. Well log and seismic data analysis using rock physics templates. First Break, 22, 37–43.

Avseth, P., T. Veggeland & F. Horn, 2014. Seismic screening for hydrocarbon prospects using rock-physics attributes. The Leading Edge, 33, 266-274.

Buland, A. & Omre H., 2003. Bayesian linearized AVO inversion. Geophysics, 68, 185-198.

Connolly, P., 1999. Elastic impedance. The Leading Edge, 18, 438-452.

Cosentino, L., 2001. Integrated Reservoir Studies. Editions Technip, Paris. 336 p.

Eidsvik, J., P. Avseth, H. Omre, T. Mukerji & G. Mavko, 2004. Stochastic reservoir characterization using prestack seismic data. Geophysics, 69, 978-993.

Filippova, K., A. Kozhenkov & A. Alabushin, 2011. Seismic inversion techniques: choice and benefits. First Break, 29, 103-114.

Ghosh, D., M. Sajid, N. A. Ibrahim & B. Viratno, 2014. Seismic attributes add a new dimension to prospect evaluation and geomorphology offshore Malaysia. The Leading Edge, 33, 536-545.

Gunning, J. & Glinsky, M. E., 2004. Delivery: an open-source model-based Bayesian seismic inversion program. Computers & Geosciences, 30, 619-636.

Haas, A. & Dubrule, O., 1994. Geostatistical inversion - a sequential method of stochastic reservoir modelling constrained by seismic data. First Break, 12, 561-569.

Hermana, M., D. Ghosh & C. W. Sum, 2016. New fluid and lithology indicator from seismic and rock physics:Malaysian offshore case study. SEG Technical Program Expanded Abstracts 2016, 2836-2840.

Kemper, M. & Gunning, J., 2014. Joint Impedance and Facies Inversion-Seismic inversion redefined. First Break, 32, 89-95.

Madon, M., 1999. The Petroleum Geology and Resources of Malaysia, Chapter 8. PETRONAS Carigali Sdn. Bhd., Kuala Lumpur. 665 p.

Madon, M., J.-S. Yang, P. Abolins, R. Hassan, A. Yakzan & S. Zainal, 2006. Petroleum systems of the Northern Malay Basin. Bulletin of the Geological Society of Malaysia, 49, 125-134.

Maulana, T., 2016. Quantitative Seismic Interpretation using Rock Physics Templates - case examples from the Zumba field. Masters thesis, NTNU, Norway. 71 p.

Maver, K. G. & Rasmussen, K. B., 1995. Seismic Inversion for Reservoir Delineation and Description, Middle East Oil Show, Bahrain. Society of Petroleum Engineers, p. 10.

Maver, K. G. & Rasmussen, K. B., 2004. Simultaneous AVO Inversion for Accurate Prediction of Rock Properties. Offshore Technology Conference, Houston, Texas, Offshore Technology Conference, p. 3.

Mukerji, T., A. Jørstad, P. Avseth, G. Mavko & J. R. Granli, 2001. Mapping lithofacies and pore-fluid probabilities in a North Sea reservoir: Seismic inversions and statistical rock physics. GEOPHYSICS, 66, 988-1001.

Ngah, K., M. Madon & H. D. Tjia, 1996. Role of pre-Tertiary fractures in formation and development of the Malay and Penyu basins. Geological Society, London, Special Publications, 106, 281-289.

Ødegaard, E. & Avseth, P., 2003. Interpretation of Elastic Inversion Results Using Rock Physics Templates: 65th EAGE Conference & Exhibition, Jun 2003, cp-6-00337.

Purnomo, E. & Ghosh, D., 2017. Enhancing thin-pay estimation through stochastic simultaneous inversion. 2017 SEG International Exposition and Annual Meeting, 24-29 September, Houston, Texas.

Manuscript received 19 April 2019
Revised manuscript received 13 October 2020
Manuscript accepted 19 October 2020