Geophysical issues and challenges in Malay and adjacent basins from an E & P perspective

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Malay Basin, a northward-trending pull-apart extensional rift basin, formed during the late Eocene-early Oligocene and then underwent thermal subsidence and sedimentation during the early Miocene. Reorientation of regional stress fields during the mid-Miocene caused structural inversion resulting in east-west anticlines and half grabens.

The basin (Figure 1) is 500 km long and 200 km wide and slightly asymmetrical with the gentler side showing greater hydrocarbon potential. This is one of the deepest basins (12 km at center) in this part of SE Asia and an excellent kitchen with rich source rocks. Two effective petroleum systems have been identified: the mid-Miocene coaly shales of terrestrial origin, generally gas-prone, to the north and the lacustrine shales of Oligocene-Miocene age. The Oligocene sediments are of terrestrial origin; the Miocene sediments were deposited in coastal-to-shallow marine environments.

Stratigraphically, Malay Basin is subdivided into groups starting from the youngest (A) to the oldest (M). Exploration currently focuses primarily on groups E–K (Figure 1). The lithology consists of a thinly layered sand-shale sequence of layer-cake configuration. Coal is found from E through the deeper groups but most prominently in group I in a lower coastal-plain setting.

The other basins discussed in this paper are Sarawak (late Eocene to recent) and Sabah (mid-Miocene to recent). Sarawak Basin is part of the Sunda continental margin and shelf that structurally connects Peninsular Malaysia (PM) with Borneo. It is separated from Sabah Basin by a major structural feature, the West Baram Line, that isolates the carbonate shelf of Sarawak (Luconia) from the siliciclastics of the Baram delta and beyond. Tectonically, Sabah's geology is complex with steep dips, growth faulting, and overthrusts. Stratigraphically, the Sarawak units are subdivided into cycles (Shell nomenclature) with cycle I/II being the oldest and VI/VIII being the youngest. Sabah's stratigraphy is punctuated by tectonically controlled unconformities and the units are commonly named "stages."

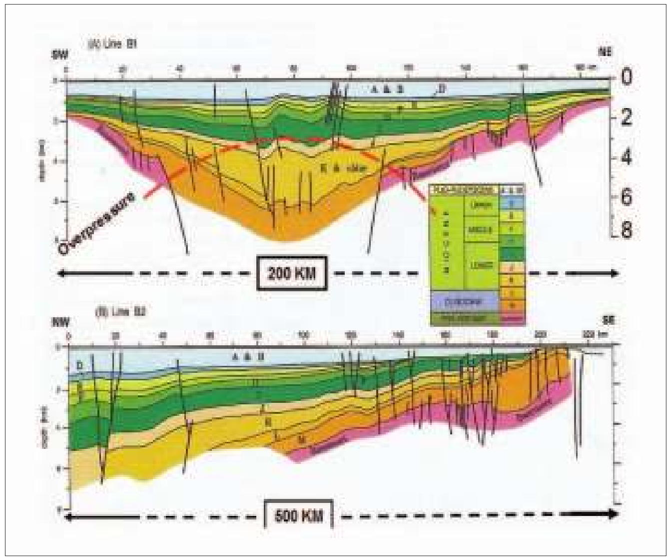

Figure 1. The northward-plunging Malay Basin is approximately 500 km long and 200 wide. The deepest part of the basin is approximately 12 km.

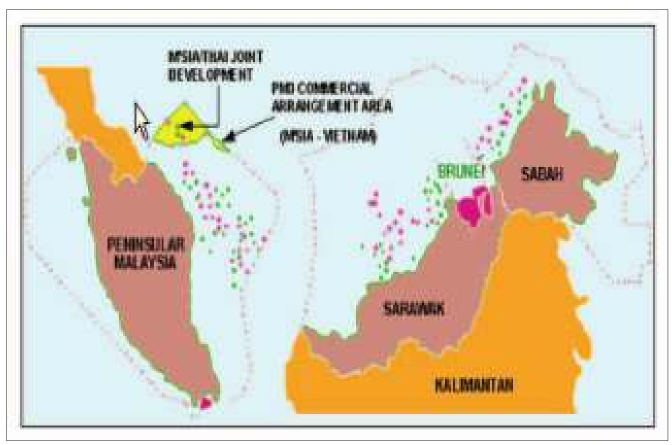

Figure 2. Malay and Borneo basins and oil and gas fields.

Hydrocarbon potential and future outlook

The Malay, Sarawak, and Sabah basins, among the most prolific in SE Asia, are relatively mature. The extensive exploration and exploitation dates from 1882 when oil was discovered in Miri, Sarawak. Since then the main player in East Malaysia has been Shell. In Peninsular Malaysia, most exploration was carried out by Esso. Most current large oil and gas fields were discovered in the 1970s. Petronas was formed in 1974 to be the custodian of Malaysia's hydrocarbon resources. Figure 2 gives the distribution of the various producing fields. Malaysia ranks 23rd in the world in oil and condensate reserves and 14th in gas.

After peaking at 650,000 b/d, oil production began declining (Figure 3) and remedial measures are needed, in both exploration and development, to replenish the reserves which are depleting faster than they are being replaced. The near-term solution is to extract more of the oil that has already been discovered (Figure 4) by improving the recovery factor (currently only 33%) via enhanced oil recovery (EOR) and time-lapse seismic for reservoir monitoring and surveillance.

The most recent estimate of oil in place from producing fields in Malaysia is 31.8 billion barrels with an estimated ultimate recovery of 11.0 billion. The authors estimate that EOR

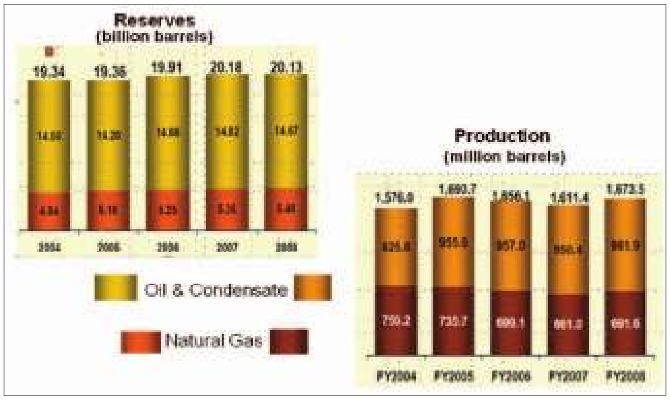

Figure 3. Malaysia's oil and gas reserves and production.

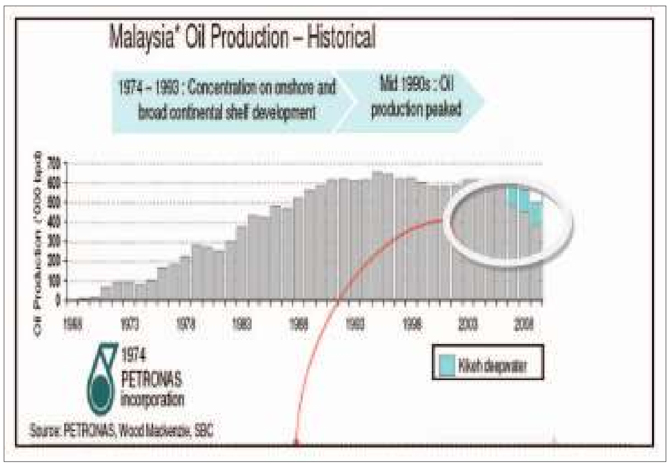

Figure 4. Malaysia's historical oil production.

and improved oil recovery (IOR) processes have the potential to recover another 1 billion barrels. However, a target of approximately 0.5 billion from currently producing fields seems more realistic. This means EOR/IOR have tremendous potential in Malaysian fields. With that in mind, Petronas and partners have undertaken extensive studies and pilot projects to examine the viability of EOR processes. The challenges to overcome are numerous. Some are:

1) Most production comes from offshore fields where EOR is challenging and expensive.
2) Well spacing is coarse (1000–3000 ft), meaning not all EOR techniques will work efficiently and cost effectively.
3) Many wells are deviated.
4) Most facilities are ageing (70% are at least 20 years old).
5) Reservoirs are complex, and compartmentalized.
6) Fields are mature and reservoirs depleted.
7) Oil is light (API around 40).
8) Reservoir temperatures can be high.

Hence, high implementation costs and demanding technical challenges are anticipated. Extensive feasibility studies have identified about 10 fields that are good EOR candidates. Five are at an advanced stage of implementation (Figure 5): Dulang, Tabu, and Tapis in Peninsular Malaysia; Baronia,

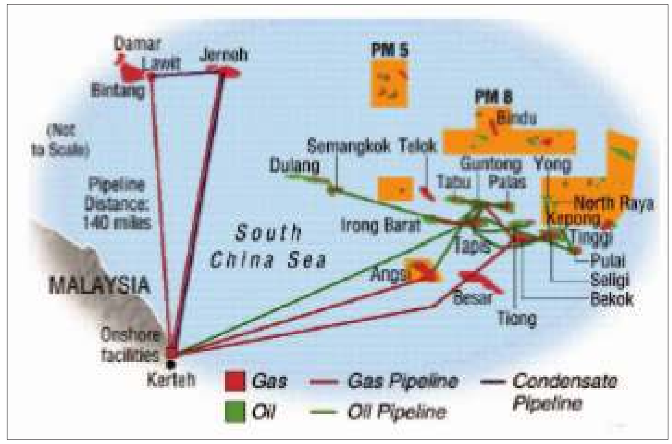

Figure 5. EOR applications in Malaysian oil fields.

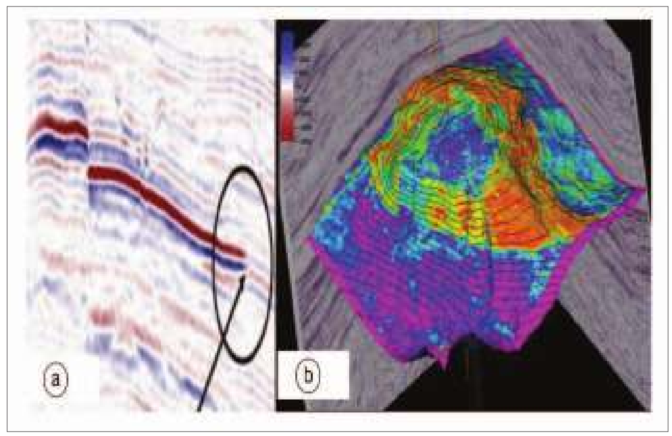

Figure 6. Better hydrocarbon prediction will avoid dry holes. (a) Amplitude shutoff and other types of DHI will boost our confidence in predicting hydrocarbons from seismic attributes. (b) Amplitude is conformable to structure and is considered to be a good fluid contact indicator. Note poor imaging at the crest due to gas leakage.

and West Lutong in East Malaysia. ExxonMobil and Shell are partners with Petronas in these projects.

The EOR processes being studied are chemical, gas flooding, microbial, and thermal. In mature water-flood reservoirs, the water alternating gas process (WAG) was found most suitable to enhance sweep efficiency, and Dulang has been targeted for immediate implementation following a successful pilot study.

Challenges

Parallel with the EOR efforts and as part of the Petronas technology initiative in geophysics, concerted efforts are being made to rejuvenate declining fields through time-lapse (4D) seismic methods. The objectives are to find bypassed oil; optimize infill development drilling; monitor EOR; and better predict reservoir and production performance.

However, application of 4D seismic in Malaysian offshore fields faces numerous challenges: lack of a reliable base or reference survey; numerous obstacles to survey "repeatability"; complexities of reservoirs and rock physics; and pressures below bubble point.

However, we think these problems can be avoided by

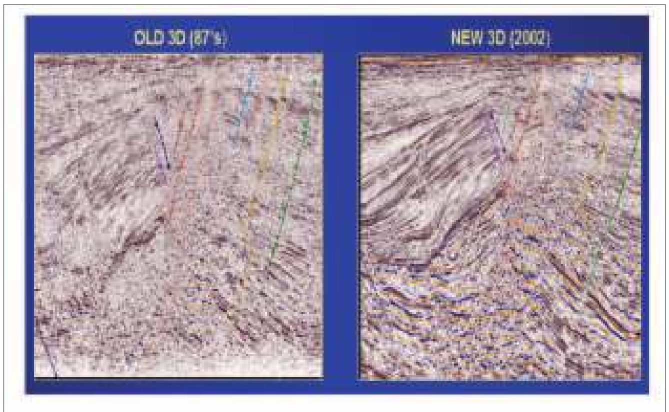

Figure 7. *Improved acquisition and processing results in higher frequency, increased resolution, better imaging and deeper penetration in the 2002 data.*

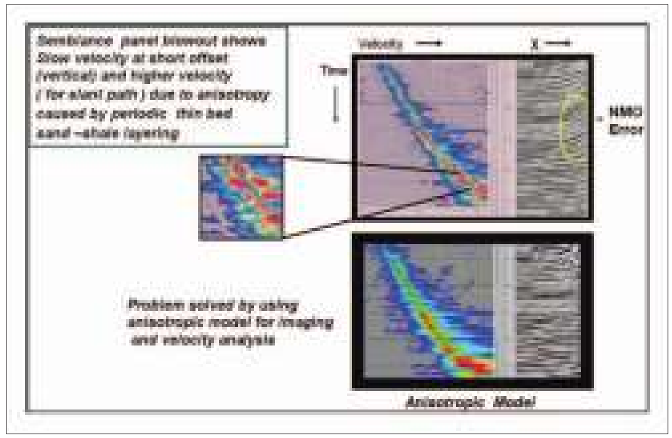

Figure 9. *Ambiguity in picking velocity due to anisotropy. The data "stack up" in both the slow (vertical) ray path and fast (slanted) ray path. This is removed by using anisotropic imaging and velocity analysis.*

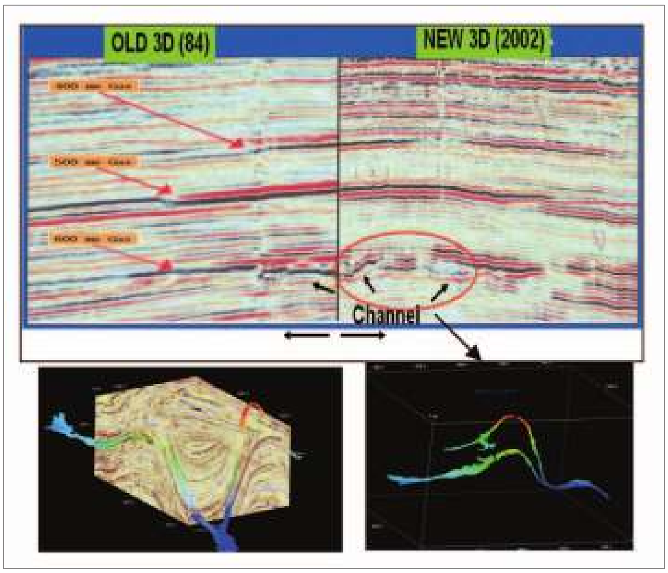

Figure 8. *(top) Increased resolution and better imaging on the 2002 data images channels missed on the older data. (bottom) Channels missed in the old data have prompted us to improve acquisition and processing efforts to chase potential stratigraphic plays.*

incorporating proper 4D planning in field development and estimate that a successful 4D effort has the potential to increase production by approximately 10%.

An integrated feasibility/4D ranking study was conducted over producing Malaysian fields to identify suitable candidates to apply in line with the EOR strategy. A 4D ranking parameter based on a modification of the criteria by Lumley et al. (1997) uses a weighted average of several reservoir and fluid properties such as water depth, depth of reservoir, porosity, oil temperature, gravity, viscosity, and saturation. Three fields were identified by Petronas Research as having the maximum potential for 4D. This harmonized with our EOR efforts. The WAG EOR efforts in the identified fields are now moving toward full-field implementation and, therefore, must be the main focus of our 4D efforts. The (Petronas-ExxonMobil) Angsi Field, although complicated, has just been the subject of a 4D repeat survey and Petronas, in partnership with ExxonMobil in Peninsular Malaysia and Shell in East Malaysia, has successfully applied time-lapse methods in these areas.

Exploration in Peninsular Malaysia now involves locating relatively small structures, and difficult-to-image and deep plays where reservoirs are under high temperature and pressure. Exploration is also moving farther offshore Sabah and Sarawak in an attempt to arrest domestic oil decline with deepwater discoveries, new (stratigraphic) plays, extensive R&D that focuses on increasing seismic resolution, subsurface imaging, and reducing uncertainty in hydrocarbon prediction (Figure 6).

The first production from deepwater discoveries in Sabah has at least temporarily halted the decline in daily production. Contributions from deepwater fields now account for approximately 15% of Malaysia's total production.

A concerted effort has been made since 2000 to significantly improve data quality and resolution of marine surveys. This includes using longer cables and shorter crossline spacing, resulting in bin dimensions of 12.5 x 9.37 m. Significant improvements in positioning and data processing are responsible for the improved imaging and resolution shown in Figures 7 and 8. Several recent surveys have used Q marine with increased resolution.

Geophysical issues

In the Malaysian offshore and other SE Asian basins, the geophysical challenges are numerous: imaging thin sands, often beyond seismic resolution; imaging below gas clouds and below carbonates; imaging basement internal architecture; understanding wave propagation in effective media and related anisotropy; velocity analysis and anisotropy; and multiple elimination

During the last five years, significant improvements in seismic acquisition, processing, and imaging have resulted in better focusing and increased resolution of reservoir data. The main improvement has been obtained by better positioning, longer cables, finer sampling, and improved imaging algo-

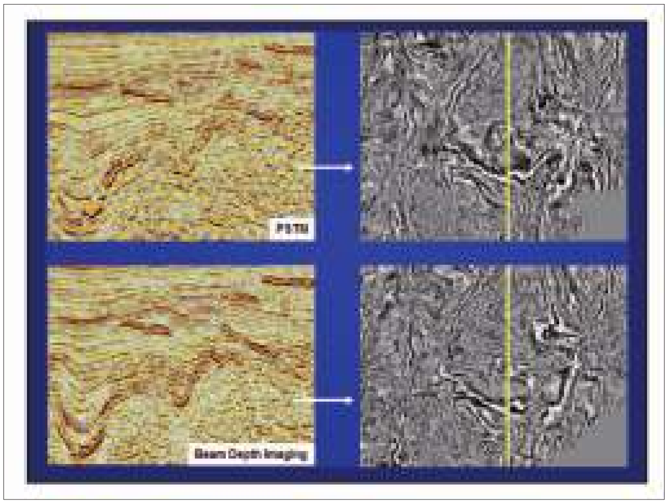

Figure 10. *Controlled-beam depth imaging results in a crisp subsurface image of basement architecture shown both in cross section and time slice.*

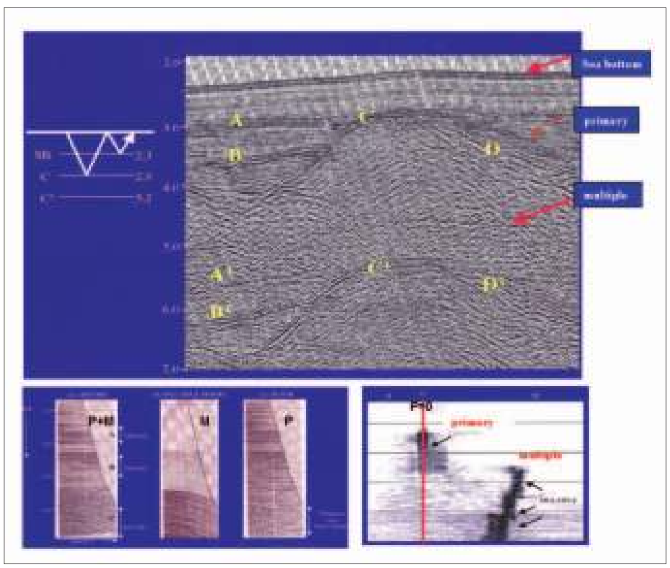

Figure 11. *Example from deepwater Sabah showing a seismic section with a primary reflection structure (ABCD) and its mirror image arriving at later times according to the raypath shown. Also shown are the total data (primaries + multiples) and the modeled multiples. The Radon transform shows the discrimination of primary and multiple energy in tau-p space.*

rithms. Wave propagation in the Malay Basin is affected by anisotropy, which we treat by NMO with anisotropic-based ray tracing (Figure 9).

Figure 10 demonstrates state-of-the-art anisotropic depth imaging using the Gaussian-beam method coupled with tomographic velocity model building. This example is from Vietnam where the primary focus is imaging the top basement and the internal architecture inside the fractured basement for better placement of a deviated well trajectory (see Figure 28).

Whereas predictive deconvolution works well in eliminating multiples in shallow water, we are constantly testing new techniques (e.g., SRME, high-resolution Radon and wave-equation-based methods) for deeper surveys. Figure 11 shows

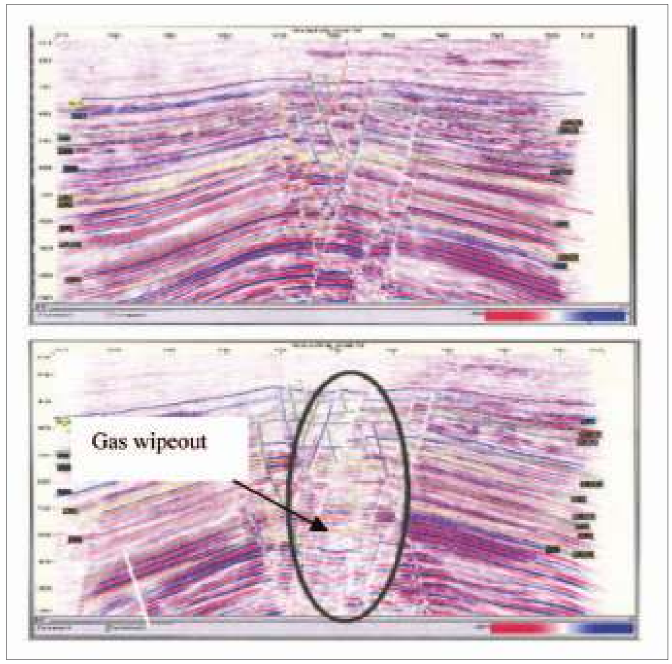

Figure 12. *The gas wipeout problem. (top) Excellent imaging across a producing field in Sarawak. (bottom) Elsewhere in the same field, the imaging is poor because of gas leakage. (Courtesy Shell-PETRONAS)*

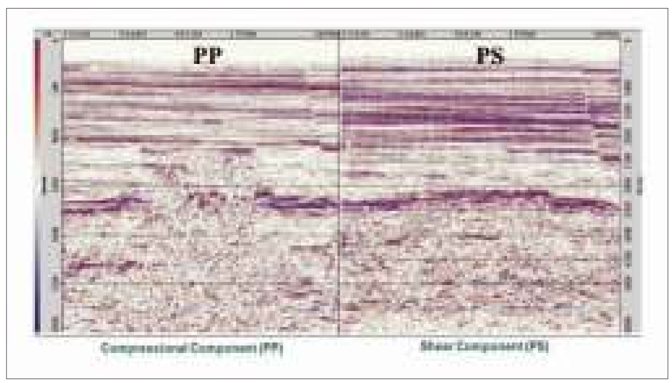

Figure 13. *2D/4-C OBC at Sarawak. (Courtesy Shell Malaysia)*

an example of high-resolution Radon analysis from deepwater Sabah where separation of primary and multiple exists in the Radon space. Our preferred approach uses a hybrid methodology which applies SRME on near offsets followed by Radon demultiple on larger offsets that have the benefit of greater differential moveout. Extension of 2D SRME into 3D space is providing new challenges.

Data quality in Malaysian basins often suffers from serious wipeouts due to shallow gas or gas leaking from a deep reservoir. This is illustrated with an example from a producing field in Baram, Sarawak. In one part of the field (top of Figure 12), the imaging is excellent as there is no gas leakage. However, at another part of the field (bottom of Figure 12), imaging is poor due to the gas leakage. A large number of fields in Malay and adjacent basins face this problem.

The geophysical issues raised by this "gas wipeout" involve internal scattering and energy loss, possible intrabed multiples, energy absorption by the shallow gas, and nonhyperbolic moveout. All result in poor signal restoration and imperfect

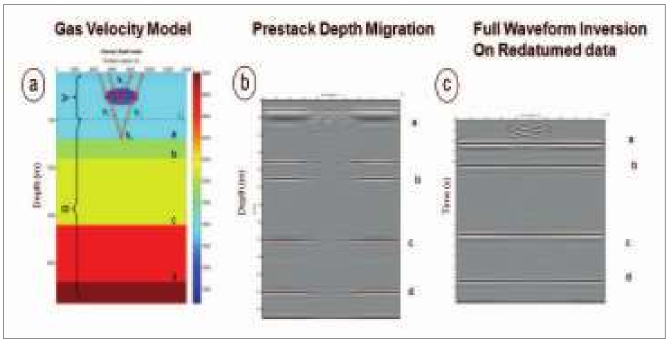

Figure 14. Comparison of PSDM and full waveform inversion to correct for gas wipeout. (a) Low-velocity gas anomaly model overlying four-layer model. (b) PSDM recovers the image in time using proper nonhyperbolic operators but amplitude recovery is poor. (c) Redatumed full waveform inversion of seismic inversion giving exact image both in time (sag correction) and more notably in amplitude. (Courtesy Delft University)

stacking and imaging. We propose to solve this problem using a multifaceted approach.

Using converted shear waves acquired with OBC technology is the most obvious technically correct method to solve the wipeout issue and has been effective in the North Sea and elsewhere. An initial experiment in this part of world (Sarawak Basin) shows significant improvement on PS data (Figure 13). However, this involved mobilization/demobilization of an OBC vessel which is costly in marginal fields.

Riza Ghazali, a Petronas-sponsored research scholar, is working on this problem by using the common focus point (CFP) technique developed at Delft University (Figure 14). It is postulated that multiple scattering within the gas cloud results in complex wave propagation, which in turn leads to nonhyperbolic moveout and energy loss instead of absorption. The theory is that observable and measurable data below the gas cloud enable CFP to produce the correct image through proper kinematic reconstruction. Further improvements are being researched to improve the algorithm and better treatment of amplitudes through full waveform inversion. The important steps in the current approach are:

- Operators that focus one-way.
- A smoothed-background velocity model smoothed by using an event above and below the gas cloud.
- Obtaining acoustic properties of the gas-cloud area by nonlinear full waveform inversion using a genetic algorithm and for l.5D forward modeling. This subsequently will be extended to 2D and 3D using a finite-difference viscoelastic code.
- Transmission operators for propagation through a gas cloud.
- Obtaining the true-amplitude response for reflections below the gas cloud.
- Lastly, performing conventional time imaging on a redatumed (gas anomaly removed) data set.

An alternative approach to improve P-wave imaging to resolve gas wipeout problems is from ExxonMobil, as described by Reilly et al. (2008). They apply a more pragmatic approach by simultaneously modeling velocity and absorption.

A key to their success in depth imaging is the identification and removal of organized and random noise. The nonhyperbolic moveout is corrected using an iteratively derived velocity model; the amplitude loss is corrected through an absorption Q model. Hence the name Q-migration is apt for this process.

Both these methods to improve P-wave imaging appear promising. However, the last word about an optimal solution to this important problem has, in our view, not yet been said and further research/optimization is ongoing.

Quantitative interpretation

Extracting quantifiable information from our seismic data continues to be an important component of our exploration and development workflow. Quantitative analysis includes AVO behavior and pitfalls, thin-bed delineation and resolution, hydrocarbon indicators, amplitude interpretational pitfalls, and the fluid pressure system.

AVO analysis constrained by rock physics works well in the relatively young Malaysian basins because the rocks are predominantly unconsolidated and hence sensitive to (Gassmann) fluid replacement. The geological-petrophysical model on which the predictions are based is predominantly that brine sands are softer than the bounding shales, although there are exceptions for deeper targets where sands may be harder.

Under this assumption, we would expect the sands to appear on the seismic section as a bright spot or a rising AVO anomaly of class 2 or 3 (Figures 15 and 16). The bounding shales generally determine the AVO class, all other properties remaining the same. If the shales are soft as is generally the case in Malay Basin (otherwise dependent on depositional environment and facies distribution), we have a high probability of getting a class 2 AVO anomaly with or without phase change. The majority of Malay Basin hydrocarbon-bearing clastic reservoirs show positive AVO response whereas approximately 15% of the pay zones are not amplitude-supported.

Figure 16 shows a curious case of a gas discovery downdip to a major oil field, thus leading the geoscientist to explain the fundamental question of hydrocarbon charge, migration and connectivity. It also illustrates a typical Malay basin class 2 AVO anomaly shown in time slice.

Several "pitfalls" need to be addressed. Thin-bed AVO response and related anisotropy is a pitfall. Further, a high-porosity, good-quality brine sand, also can give a positive AVO response as shown in Figure 15. In this case, one can rely on the near-offset response as a discriminator as per Gassmann. However, the quality of the near-offset response is often contaminated by noise notably from peg-leg multiples. Another pitfall is the equivalence problem; i.e., a high-quality oil sand may be mistaken for a gas response from a poorer quality sand. Then there is also the "low-saturation gas" issue.

The average thickness of oil and gas pay zones in the Malay Basin is 10 m or thinner. Resolving these thin beds is a challenge. Improved imaging and multiple elimination tech-

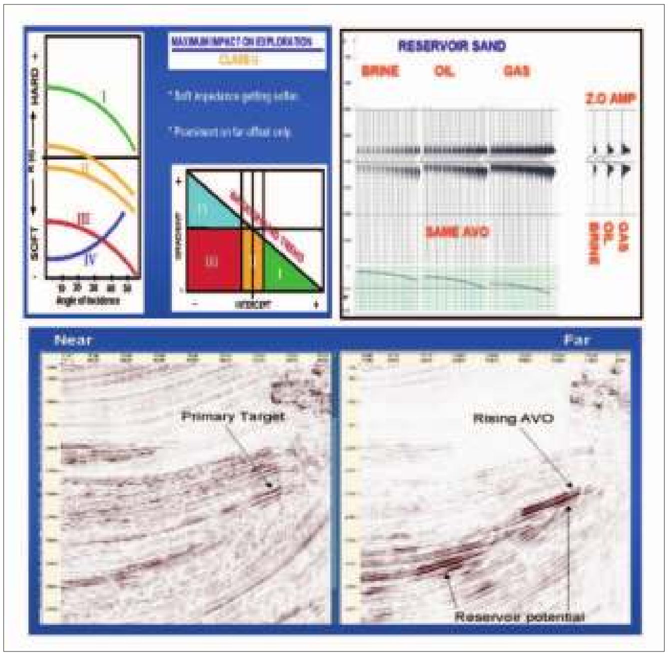

Figure 15. *(top) AVO classes and modeling. The AVO response (gradient) of various fluids is similar. (bottom) Turbidite sand from East Malaysia, showing class 2 AVO response.*

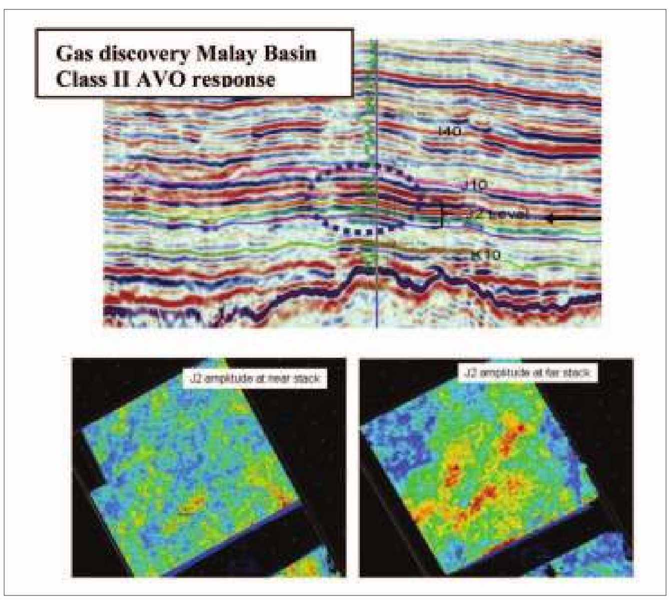

Figure 16. *(top) Seismic cross section shows a gas discovery downdip to a known oil field (not shown).(bottom) A typical class 2 AVO anomaly on an amplitude time slice.*

niques have provided hope. For improved images, increased frequency bandwidth at both the high and low ends, with high-resolution acquisition and processing, plus the use of advanced geophysics, elastic and spectral inversion, have significantly improved our ability to resolve thin beds beyond the theoretical limit (a quarter of a wavelength). Thin-bed response is defined as a derivative and resolution increases with increasing frequencies. The example shown in Figure 17 is from the central Malay Basin where several discoveries were made with the aid of state-of-the-art geophysics from acquisition through to exploitation.

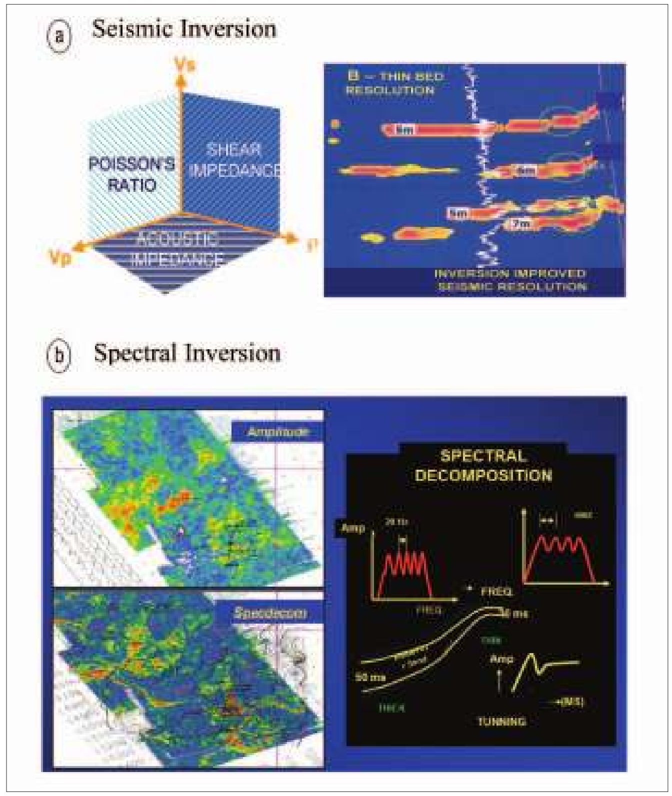

Figure 17. *Pushing the limits of seismic resolution for thin beds. (a) Elastic inversion with external constraints can image beds as thin as 5 m. (b) Spectral inversion can further improve the resolution by taking advantage of tuning phenomena. Thin-bed channeling in this example can be seen only in the 40-Hz and higher spectral band. (Courtesy CSMP-Petronas Carigali)*

Hydrocarbon indicators in the Malay Basin

In view of several complexities discussed earlier, quantitatively predicting the distribution of hydrocarbons from seismic in the Malay Basin can be quite tricky. However, if this interpretation is done in the context of the geological environment, we tend to be more successful. A good knowledge of the petroleum system from basin modeling, and facies identification in terms of depositional environment are key. Knowledge of the structural styles, pressure regime, and fault seal also lower overall exploration risk.

We believe that the most efficient process is to screen and predict in phases. In the initial stages, qualitative analysis of the hydrocarbon indicators goes a long way in obtaining the right answer if judiciously combined and constrained by the geological model.

The amplitude anomalies should satisfy one or all of the following ground rules (Figure 18): (1) downdip fit to structure (at least locally); (2) flat spot with correct polarity (hard kick); (3) amplitude shutoff; (4) phase change at contact; (5) frequency drop below gas reservoirs; and (6) pock marks and gas wipeout.

Amplitude interpretation pitfalls

Coals are an integral part of the Malaysian geology and dominant from the younger group E to the older group I. They are very much part of the interpretation scenario. Apart

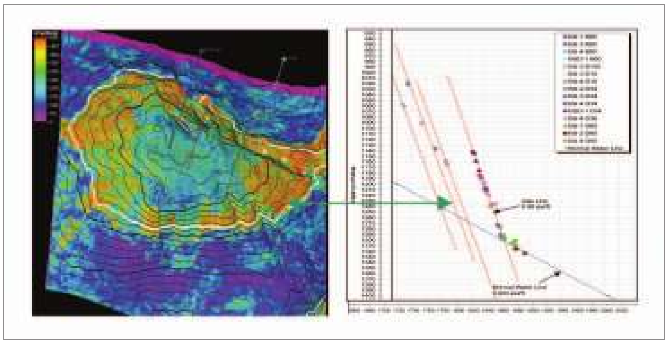

Figure 18. *Fluid contact indicators. The amplitude anomaly in this example is conformable to structure and the identified gas-water contact shown by green arrow (right) which points to the intersection of pressure gas/water gradient intersection. Match in depth is perfect.*

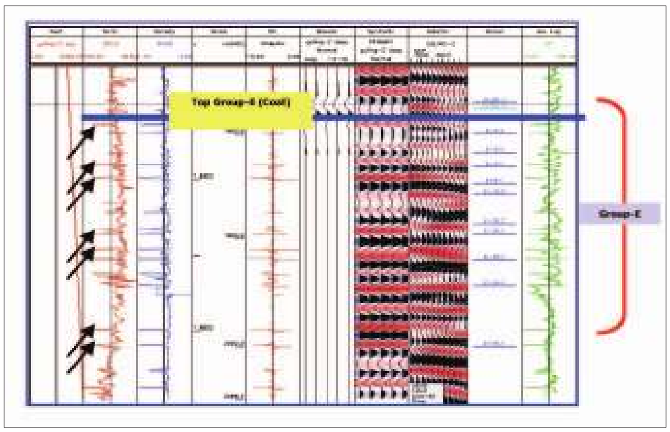

Figure 19. *Synthetic seismogram completely dominated by numerous coal beds (arrows).*

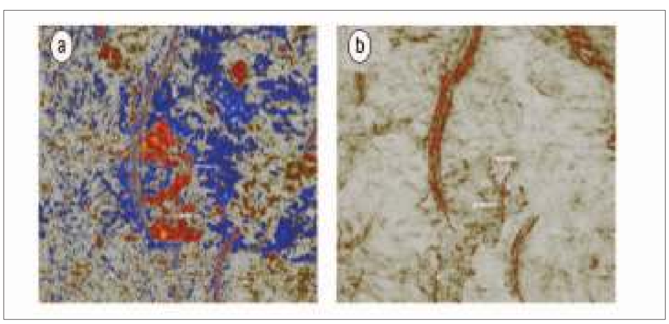

Figure 20. *(a) Amplitude response dominated by coal effects (red). (b) After coal effects are removed with spectral decomposition, the true geology is revealed.*

from being the source of some hydrocarbons, they produce continuous and strong reflections and are commonly used by our interpreters as marker horizons. This is shown in Figure 19 where numerous thin coal beds dominate the stratigraphy (black arrows) and hence the synthetic seismogram. As the prospect tops of group H and I reservoirs have poor reflectivity (class 2 AVO), the coal markers that lie a few seismic loops above them are used as the markers. The reflections from Tops H and I are then "phantomed" down.

Unfortunately, coals produce strong negative impedance

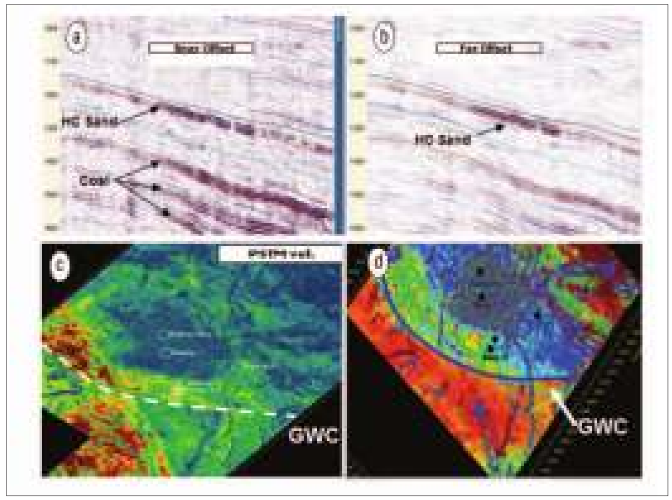

Figure 21. *(a) Several stacked amplitudes on the near-offset response. Only the top one relates to hydrocarbons. (b) The other stacked amplitudes have falling AVO response on the far-offset response. The amplitude map (c) on the full stack shows two clusters of strong amplitudes. The lower one is due to coal and falls outside the GWC (white) as transferred from the AVO envelope cube (not shown). This is also confirmed by the well results. Interestingly, the waveform-classification attributes (d) tracking the phase change highlight the gas-water contact nicely.*

responses which are often confused with a possible hydrocarbon response. Two examples are given here to explain the phenomena and ambiguity.

An amplitude time slice (Figure 20a) shows (red) a bright spot that can be falsely credited to a known gas accumulation in this area. Further investigation confirmed that this was due to a thin coal bed. This interference was removed through spectral decomposition by filtering out the high-frequency content and revealing the true geology (Figure 20b).

The second example also comes from the Malay Basin and is shown in Figure 21. Figure 21c shows two clusters of amplitudes (red). However, the lower one falls beyond the interpreted gas-water contact (from the AVO envelope, not shown) and is questionable. Comparing the near and far offset section in Figures 21 a and b, we immediately see that, apart from the top reflection, all others have decreasing AVO which our geological-petrophysical model indicates is shale or coal.

Interestingly, when we use waveform tracking classifications, the algorithm is able to track the phase change (green to red) while going from a hydrocarbon fluid to a brine response. This has been confirmed from the gas-water contact derived from AVO studies as well as actual pressure fluid gradients.

Geophysical and petrophysical analysis of coal beds reveals that they have poor gamma-ray response like sand, very low density, high resistivity (spike), low AI response, decreasing AVO, high V_P/V_S or Poisson's ratio, thin layers (1–5 m), high spectral tuning thickness, and can have limited structural fit.

These attributes could be used individually or collectively to remove unwanted effects. However, if these beds are too close to the pay beds they might still contaminate the reservoir response.

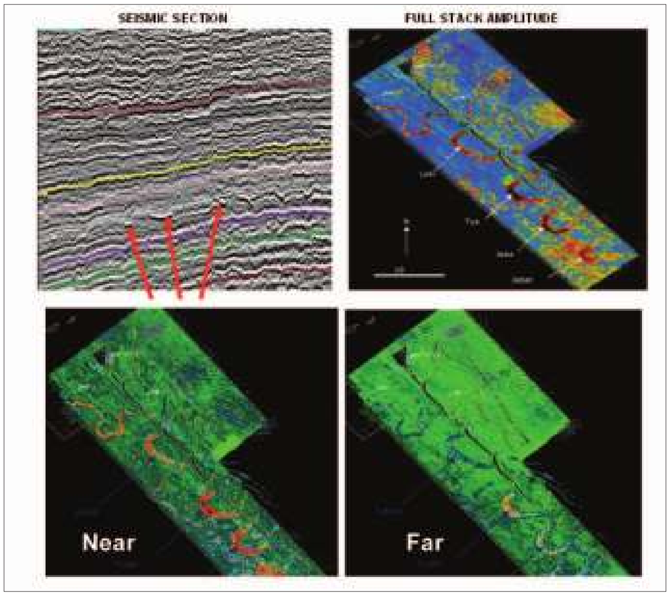

Figure 22. *Cross section from the Malay Basin showing a well imaged channel with strong amplitudes. AVO analysis reveals that the amplitude is decreasing with offset, confirming that these channels are actually clay-filled.*

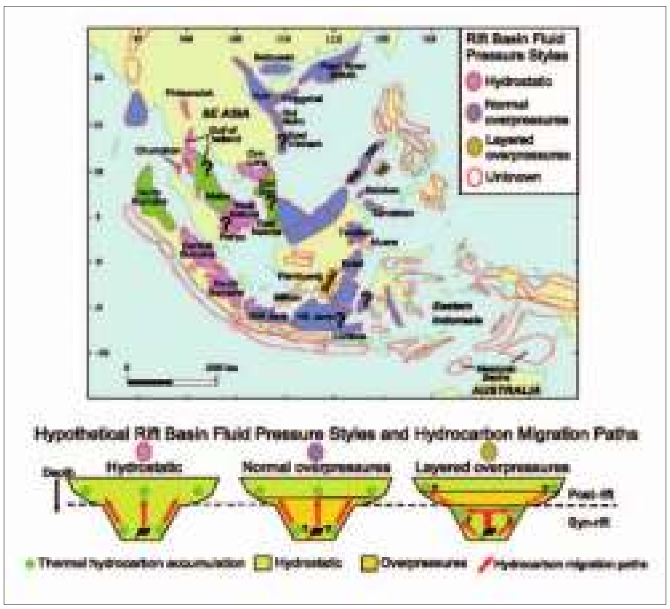

Figure 23. *Rift basin and fluid-pressure styles and hydrocarbon migration paths. (From Doust and Sumner)*

Abandoned clay channel and soft shale issues

As exploration moves to defining stratigraphic traps, particularly those associated with channel sands in the Malay Basin, a key objective is to locate the sands and avoid the soft clay-filled abandoned channels. High-resolution 3D seismic is able to image beautifully the incised channel cuts (Figure 22). The strong amplitudes are nicely imaged and define the meandering channels. The challenge is to determine whether they are hydrocarbon sands or clay-filled abandoned channels.

The explanation for coal or shale rich is because upon abandonment these channels can turn into lakes with marshlands. These channels can be 500 m to a few kilometers wide

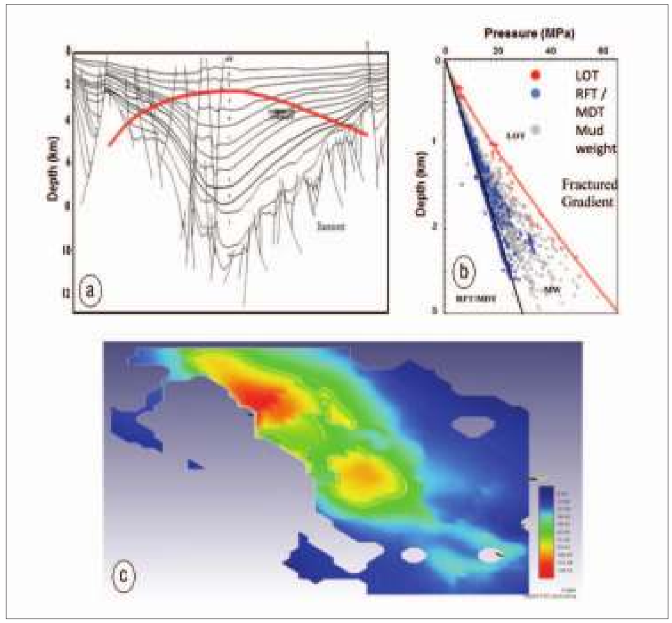

Figure 24. *(a) Malay Basin pressure profile. (b) Pressure-depth plot; RFT/MDT data in blue show information down to 3000 m where drilling was stopped as pressure kicks in. The red dots are from the leak-off test for establishing the fracture gradient. (c) Modeled excess pore pressure in the K group.*

and give a strong hydrocarbon-like amplitude response.

Southeast Asia rift basins

Doust and Sumner (2007) conducted an excellent study of the relation of fluid pressure and hydrocarbon migration, seals and possible sand distribution in SE Asia rift basins using well data, seismic velocities, and stratigraphic correlations (Figure 23).

The Malay Basin is also a part of the rift basin as discussed above and is characterized by high heat flow and high temperature gradient that has influence on hydrocarbon generation and migration. It is an overpressured basin where the “top of overpressure” is a convex upward surface, in contrast to the underlying syncline (Figure 24). The onset of overpressure occurs shallowest in group E in the center of the basin, approximately 1400 m subsea, and deeper (down to 3 km) on the basin’s flanks. The high overpressure can sometimes be explained by rapid deposition of fine-grained, low-permeability sediments (i.e., by compaction disequilibrium). The top of the oil window coincides with the top of overpressure, suggesting a link between hydrocarbon generation and overpressure.

As we focus on deeper reservoirs in Malay Basin, their untapped hydrocarbon potential in the geophysical response and porosity preservation in an HP/HT situation become important.

Sarawak Basin in East Malaysia is comparatively cooler. Research into the AVO response of some overpressured reservoirs in the region indicates good deep prospectivity.

New exploration plays

Significant improvement in data quality and imaging has enabled us to search for new plays, such as stratigraphic plays

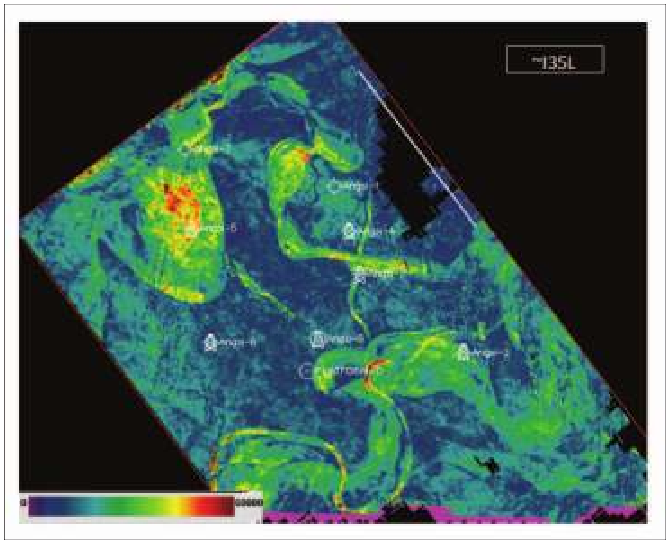

Figure 25. *A beautifully imaged channel complex in a petroleum-rich part of southern Malay Basin.*

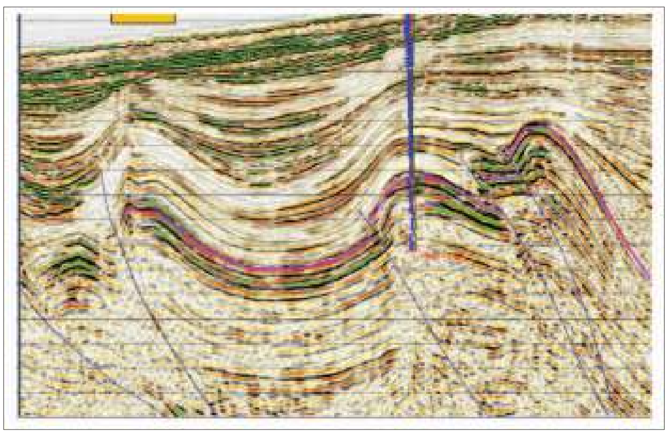

Figure 26. *Some deepwater turbidite, toe-thrust plays offshore Sabah, East Malaysia. These plays hold tremendous hydrocarbon potential for the future. (Courtesy PSC partners)*

(Malay Basin), deepwater turbidite plays (Sabah/Sarawak), carbonate plays (Sarawak), and basement plays (Malay Basin).

Increased resolution of our high-resolution seismic data in the Malay Basin and a "megamerge" of these data have let us identify and image these channels and quantify their geomorphological features but also research their geological origin. This has opened up new exploration channel plays (Figure 25). However, as discussed earlier, these channels could be water-wet or even shale-rich. Hence the new challenge is to map these channels, locate the best sand development, identify the pore fill, determine the dip of the channel and lateral seals (often difficult with these plays).

As the reserves can be small, it is necessary to investigate a cluster development scenario.

To sustain domestic oil production, strategic new plays are found in the till now lightly explored deepwater basins of Sabah and Sarawak. The main players here have been Shell and Murphy, PETRONAS PSC partners. The deepwater Sabah prospects in greater than 500 m of water are structurally complex, mostly toe-thrust plays with turbidite reservoirs. Some

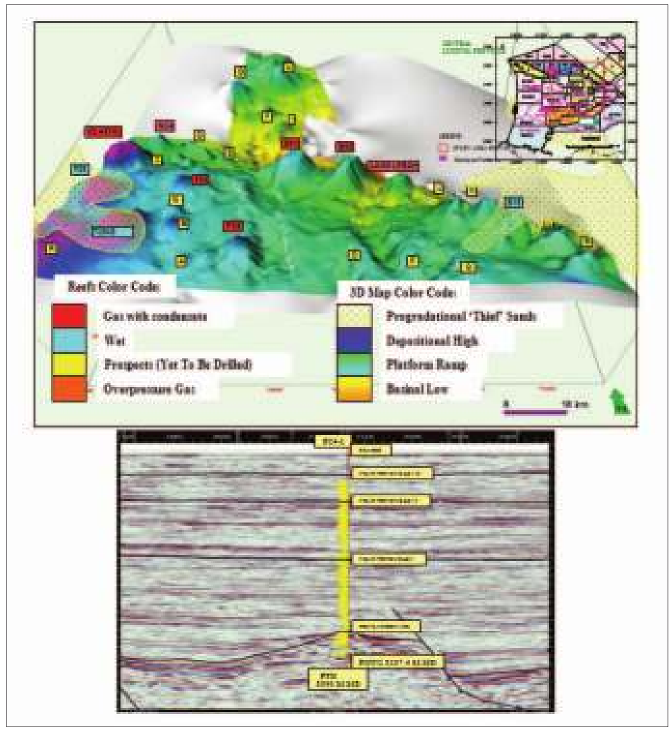

Figure 27. *(top) Central Luconia carbonate platforms and pinnacles in a 3D visualization mode. (bottom) A recent discovery of a large gas column in a carbonate pinnacle.*

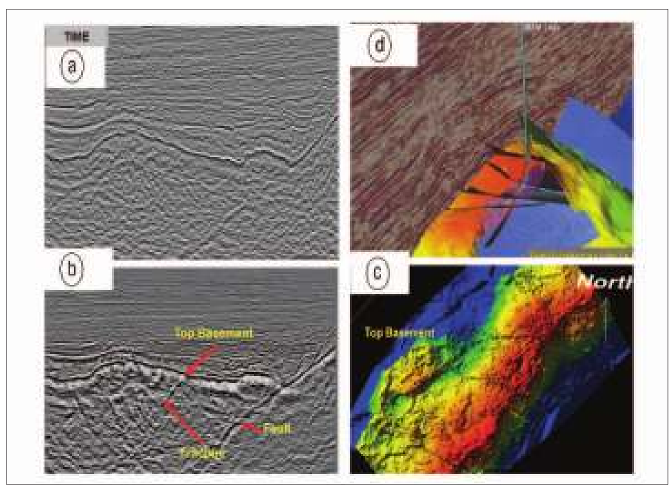

Figure 28. *New plays in igneous basement offshore Vietnam. Significant improvement in imaging has enabled us to map minor faults and fractures within the basement where hydrocarbons are trapped. (a) Prestack time imaging. (b) Prestack depth imaging. (c) Top basement dip/azimuth attribute map. (d) Well trajectory. (Courtesy PETRONAS Vietnam).*

major discoveries have been made by our partners–namely, Gumusut-Kakap, Malikai, Ubah and Petai by Shell and partners as well as Murphy's Kikeh Field (Figure 26). The latter contributes approximately 15% of our domestic production. The other discoveries are in different stages of development.

Carbonates in Malaysia are in the central Luconia province in Sarawak where Shell historically has been the major player. These carbonates contribute some 40% of Malaysia's total gas reserves. The geophysical challenges are: imaging

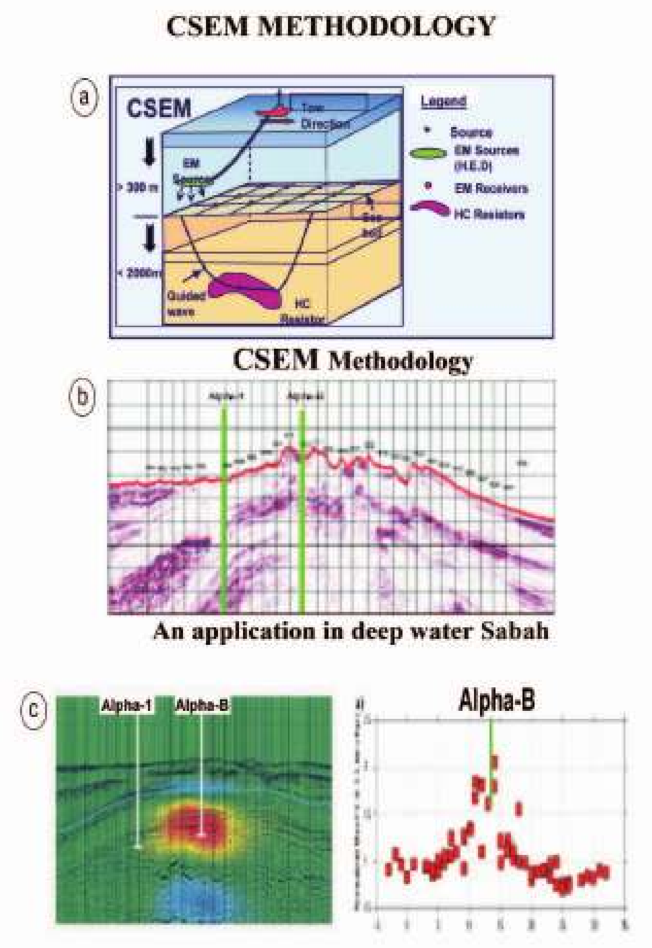

Figure 29. (a) CSEM field layout for marine application. (b) An example from Sabah deepwater. Well Alpha-1 was drilled on the edge of a prominent DHI but found only residual hydrocarbons. (c) EM response was able to determine the lateral limit and demonstrated that the well had missed the EM anomaly. Courtesy Shell/EMGS).

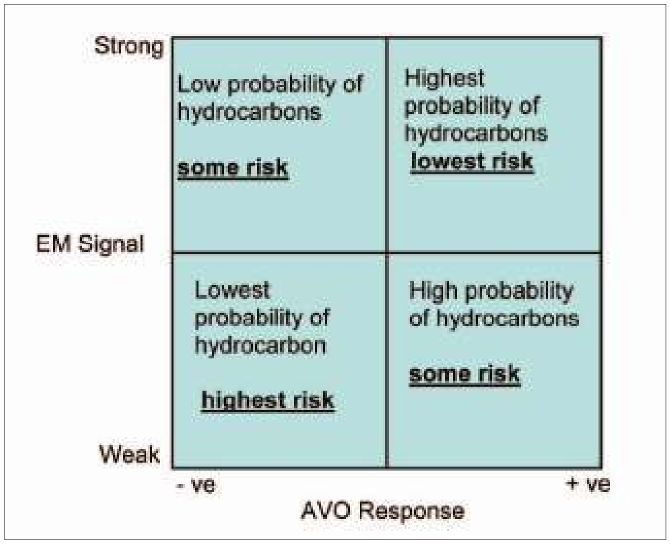

***Figure 30.** A combination of hydrocarbon indicators such as AVO and EM can significantly reduce exploration risk.*

some of the carbonate bodies (Figure 27), understanding facies distribution, porosity prediction, overpressure prediction, understanding seismic HC response in carbonates, understanding high CO_2 and H_2S contamination, and imaging preclastics below the carbonates.

Better 3D acquisition and better imaging have made it possible to explore complex basement plays in Vietnam, Indonesia, and the Malay Basin with some success. It is postulated that oil from adjacent formations may get trapped (under favorable conditions) in vugs and fractures within the basement. Imaging the basement architecture is a key issue.

As wave propagation is likely to be complex and anisotropic, the use of anisotropic ray tracing, velocity analysis and depth imaging is important (Figure 28). As shown earlier (Figure 10), controlled-beam migration with a judicious choice of beam wavelet has substantially improved our interpretability within the fractured basement in Vietnam. The use of seismic attributes like coherency, dip and azimuth, and curvature further enhances these images.

The exciting new methodology controlled-source EM has been successfully applied to deepwater toe-thrust plays in Sabah where seal failure is a substantial risk (Figure 29). When applied in conjunction with other hydrocarbon prediction methods such as AVO and inversion, it can substantially reduce exploration risk (Figure 30).

Conclusion

Our research has determined that the following geophysical technologies have been proved to add value to exploration and development surveys in this region: 3D high-resolution seismic; depth imaging, velocity and anisotropy; AVO/elastic inversion; multi-attribute analysis; rock and fluid property trends; multiple elimination (SRME/Radon); integrated reservoir modeling; and 3D visualization, illumination, and optical stacking.

Advanced geophysical methods, not yet proven but with great potential to add value in this area, are: multicomponent (OBC) and dual-sensor acquisition; time-lapse reservoir management; EM seabed sounding; 3D/3-C VSP; full wavefield MEMS recording; multi-azimuth acquisition; low-frequency seismic sources; and spectral inversion

Many geophysical challenges and issues facing E&P efforts in Malaysia's hydrocarbon provinces have been discussed in this article. Some are specific to this region and hence "tailor-made" solutions are being pursued. It is hoped that the new methodologies and geophysical technologies being developed will provide better solutions, not only to the Malaysian basins but also to other SE Asia basins with similar geologic settings.

Ultimately this will lead to: risk reduction and higher exploration success rates; better imaging of complex deep high-temperature and high-pressure reservoirs; improved recovery factors from our declining fields, and the advancement of geophysical technology, specifically as applied to this region. TLE

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