ABSTRACT

Controlled-source electromagnetic (CSEM) field surveys offer a geophysical method to discriminate between high and low hydrocarbon saturations in a potential reservoir. However, the same geological processes that create the possible hydrocarbon reservoir may also create topography and near-surface variations of resistivity (e.g., shallow gas or hydrates) that can complicate the interpretation of CSEM data. In this paper, we discuss the interpretation of such data over a thrust belt prospect in deepwater Sabah, Malaysia. We show that detailed modeling of the key scenarios can help us understand the contributions of topography, near-surface hydrates, and possible hydrocarbons at reservoir depth. Complexity at the surface and at depth requires a 3D electromagnetic modeling code that can handle realistic ten-million-cell models. This has been achieved by using an iterative solver based on a multigrid preconditioner, finite-difference approach with frequency-dependent grid adaptation.

INTRODUCTION

The depositional setting in deepwater Sabah consists of a number of large, sandy Miocene turbidite basin-floor fans separated by shale-dominated intervals (Koopman and James, 1996). The turbidite fans are deposited mostly in an unconfined base-of-slope setting, although the younger sediments show the influence of topography caused by movement along the thrust faults. Structures in the area are caused primarily by fold and thrust faulting roughly parallel to the coastline, creating a series of elongated thrust anticlines separated by deep synclines (Hall, 1996). Most of the prospects are defined on the culmination of the four-way closure of the anticlines, and typically have multiple stacked objectives. Fault closure plays a role in the upside potential of most prospects.

Experience with trap integrity in thrust belts worldwide has been mixed, and prospects in this setting consequently carry considerable trap-related risk. Traps may have held hydrocarbon columns in the past, but failed later and leaked most of the hydrocarbons, leaving behind residual hydrocarbons with saturations around 10%. These noneconomic residual saturations can be nearly impossible to distinguish from commercially viable saturations using seismic amplitude measurements — the acoustic impedances are very similar. However, the resistivities of sands with residual hydrocarbon saturations and those with commercial saturations can be different by one or two orders of magnitude. Because controlled-source electromagnetic (CSEM) data directly respond to resistivity, they are well suited to address residual saturation risk (e.g., Hou et al., 2005; Hoversten et al., 2005).

Although CSEM data may seem an obvious choice for exploring in thrust belts, this setting may also have characteristics that pose difficulties for CSEM interpretation. If the thrusts have surface expression, there may be considerable seafloor topography that can strongly affect the CSEM data. In addition, the petroleum system can charge not only the reservoir but also the near surface, resulting in shallow gas or gas hydrates, both of which may be resistive and can further complicate interpretation of deeper reservoir resistivity (Mehta et al., 2005; Constable, 2006).

Prospect Alpha, our case study in this paper, is typical of the geology found in thrust anticline prospects in deepwater Sabah and shares most of the geophysical problems as well. Figure 1 shows a 3D view of seismic data at Prospect Alpha. In the reservoir section,
the thrust faults that have carried the reservoir (mapped surface) into a structural closure can be seen. The map is a seismic attribute extracted on the top of the targeted turbidite fan.

All of the crestal prospects in the area share the problem of partial to total wipeout of seismic signal. The shallow section in Figure 1 shows a number of disruptive shallow features characteristic of the thrust anticlines in Sabah: large-relief seafloor topography, near-surface canyons, and large shallow amplitudes (presumably gas), all of which degrade the seismic data below them. Certainly the seismic data and attribute map dim considerably beneath these features. A bottom-simulating reflector (BSR) can be seen, indicating the presence of gas hydrates as well (e.g., Hyndman and Dallimore, 2001).

In 2002, the Alpha-1 well was drilled to test a tilting seismic flat spot in the southern flank of the structure (it can be seen on the attribute map in Figure 1). The well found good quality reservoir sands, but the sand contained only residual saturation hydrocarbons. Despite the disappointing results of the Alpha-1 well, the existence of good reservoir and proven hydrocarbon charge access kept the prospect alive. A number of reservoir scenarios were considered in which there could be various amounts of hydrocarbon updip from the Alpha-1 well spanning the range:

- Best case: The trap has leaked a little or tilted a little over time, but a large accumulation of hydrocarbons remains just updip from the well.
- Worst case: The trap blew at the crest, and all of the high-saturation hydrocarbons drained away.

Significantly, the only real differences among the reservoir scenarios remaining after the first well were differences in the saturation of hydrocarbons in the reservoir.

**CSEM SURVEY**

Because CSEM data can be an excellent discriminator between high and low saturation hydrocarbons in good sands (e.g., Hou et al., 2005; Hoversten et al., 2005), it was well suited for evaluating the risk of another exploration well. Another motivation for testing CSEM technology in Sabah was that the deep waters there would minimize the interfering effects of the airwave (Eidesmo et al., 2002). In 2004, Shell and partners acquired a CSEM program to test the viability of the technology. Two 2D CSEM traverses were acquired over recent discoveries, and both showed anomalies as expected from modeling exercises. The success of these calibration surveys led to the use of CSEM data as a credible tool for evaluation of exploration prospects like Alpha.

Thirty CSEM receivers, spaced 1 km apart, were deployed along a strike-line over the Alpha prospect and crossing the Alpha-1 well. The survey used a relatively standard 0.25 Hz square-wave signal that is also rich in odd harmonics like 0.75 and 1.25 Hz. As the phases of electric fields were very noisy, we focus here only on their amplitudes. We normalized the amplitudes of the inline horizontal electric fields by the field measured at the reference receiver R22. The choice of this reference receiver was critical because we wanted the background resistivity to be the same at the reference location and the measurement point, with the only differences occurring in the possible anomalous features. Then, to highlight surface features, we stacked the normalized fields over a selected source-receiver offset range and plotted them as a function of the midpoint position (e.g., Ellingsrud et al., 2002).

Figure 2 shows the stacked normalized amplitude over a 1 km window (roughly 250 cycles) centered on 5.5 km offset for the fundamental frequency, 0.25 Hz. The stacked response clearly shows an EM anomaly located at the crest of the Alpha structure and flanked by the Alpha-1 well. The single frequency, narrow-offset range data in Figure 2 gives an anomaly with very broad edges, but spatial resolution can be improved by imaging with multiple frequencies and offsets. Indeed, after careful processing and depth imaging (Mittet et al., 2005), the resistivity anomaly had sharper edges as shown in Figure 3. The depth image was consistent with a scenario in which the Alpha-1 well had missed the pay, but a substantial accumulation of high-saturation hydrocarbons remained at the crest of the structure. This view of the EM data was taken as a strong positive indicator of commercial hydrocarbons updip from the Alpha-1 well.

Indeed, subsequent drilling of the Alpha-B well found hydrocarbons at reservoir level, consistent with the CSEM depth image.

The local geology at reservoir depth in deepwater Sabah is ideal for the CSEM interpretation, as no resistive rocks like salts, carbonates, or volcanics are expected in the prospective section. However, the near surface along the thrust anticlines does present challenges to CSEM interpretation because of considerable topographic variations (Figure 1) and also the presence of gas hydrates (Mehta et al., 2005; Constable, 2006). Gas hydrates are indicated by bottom-simulating reflectors seen on the seismic data. In addition, the Alpha-1 well logged resistivity of about 15 Ωm in the 300 m thick hydrate stability zone, which was interpreted to be hydrates.

To assess the effect of the hydrates, a higher frequency component of the recorded EM data, 7.25 Hz, was analyzed (see Yuan and Edwards, 2000; Schwalenberg et al., 2005; Constable, 2006; Weitemeyer et al., 2006). The 7.25 Hz electric fields are much more rapidly attenuated than the fundamental and do not reach the reservoir with any significant strength, thus providing an EM response from the near surface only — almost certainly arising from hydrates. As shown in Figure 4, the 7.25-Hz-normalized magnitude traverse looks disturbingly similar to the 0.25 Hz traverse, on which our reservoir interpretation was based. To help reduce ambiguities in EM interpretation, like hydrates versus reservoir hydrocarbons, we conducted a number of modeling studies. Our approach to the problem was to perform extensive 3D modeling of the key scenarios, as proposed by Green et al. (2005) in the case of salt diapirs.

**Figure 1.** Northwest-southeast trending thrust anticline forming the Alpha structure. The Alpha-1 well was drilled in 2002 to test the tilted flat spot at target reservoir. Reservoir horizon draped with sweetness volume is depicted.
To perform extensive modeling of CSEM data to aid interpretation (and particularly for inversion), we needed a code that could calculate the EM response for relatively realistic 3D subsurface models with multiple resistive bodies (e.g., salt dome, carbonate, reservoir, and hydrates) and lateral variations (e.g., bathymetry variations and horizons). Using a finite-difference frequency-domain approach, such geoelectric models can easily consist of several tens of millions of cells, and the publicly available codes were too slow to model multifrequency multireceiver surveys, even on modern clusters. Therefore, we developed a new preconditioned iterative 3D EM solver that allows us to handle large realistic models in a reasonable time (a few hours).

Considerable speed improvement was achieved by using the iterative solver based on a multigrid preconditioner proposed by Mulder (2006), coupled with a careful adaptation of the discretization around each source. Maxwell’s equations are discretized with a finite-difference scheme on a stretched/compressed (nonuniform) grid in order to take advantage of the diffusive nature of the electromagnetic wave in the earth. We have implemented the scheme proposed by Weiland (1986) that extends Yee’s staggered-grid method for solving the integral form of Maxwell’s equations (Yee, 1966). For 3D problems, this discretization leads to a large linear system whose unknowns are the discrete values of the three components of the electric field. The large size of the linear system requires an efficient iterative solver for practical application.

Multigrid methods are popular because of their efficiency (Briggs et al., 2000). Indeed, they are very attractive when the smooth part of the solution can be correctly represented on a grid coarser than the original fine grid, and when the oscillatory part of the solution is easily computable on the fine grid. Whereas the multigrid method is generally not suitable for wave-propagation problems, it can be used for diffusive problems (Mulder, 2006). Because the convergence of this method deteriorates when the grid is non-uniform, we solve the linear system with the Krylov biconjugate gradient stabilized (Bi-CGSTAB) iterative solver, after preconditioning with one cycle of the multigrid solver (Mulder, 2006). This combination of the Bi-CGSTAB and multigrid solvers leads to an efficient and robust code to model CSEM data.

To limit the size of the computational domain, many authors use the primary/secondary field formulation, where the primary field solution corresponds to the solution in a layered earth (e.g., Newman and Alumbaugh, 1997, 1999). However, we have used a total field approach because numerical errors can arise when the source is within the region of anomalous properties — for example, when modeling bathymetry variations. The disadvantage is that a slightly larger computational domain is required in order to discretize the source properly and avoid the artefacts arising from the reflections on the artificial boundaries of the domain. Indeed, perfectly conducting boundary conditions are used here.

To compute the EM responses on problems with realistic size, Newman and Alumbaugh (1997) proposed to parallelize the iterative linear solver. This was needed because their iterative approach often required thousands of iterations and also because the amount of memory available per CPU at that time was generally limited to several hundred megabytes. With our multigrid preconditioned iterative solver, the number of iterations is considerably reduced, and is
generally fewer than a hundred. Because our implementation can solve a 10 million-cell problem on a single CPU with 4 GB of memory, we did not need to parallelize the iterative linear solver. We do find parallelization useful when modeling multiple frequencies or a large number of sources. Whereas a 10 million-cell grid is generally more than enough to model a single source, the discretization of a multi-source survey may require a larger grid. Therefore, we have built an automatic grid adaptation based on the notion of skin depth. The size of the computational model can be reduced depending on the frequency and on the position of the source. Our rule of thumb is that the size of the model is reduced to about 15 skin depths in each direction with a 2%–4% cell stretching starting from the source. For the models presented here, the user input model contained more than 20 million cells, but the computational model is reduced to about 7 million cells for each source. This allows us to model a CSEM survey of several tens of receivers in a few hours. We did some comparisons with the codes of Hursan and Zhdanov (2002) and Newman and Alumbaugh (1997) for a simple 3D model and found agreement of the EM response within a few percent for both phase and amplitude of the inline electric field (Figure 5). These small differences are caused by the automatic grid adaptation that slightly changes the model representation.

3D SCENARIO-BASED EM MODELING

The fast 3D modeling code allowed us to do a detailed study of the EM response at Prospect Alpha. To determine the relative contributions of shallow hydrates, topography variations, and reservoir hydrocarbons to the CSEM anomaly, we modeled the CSEM response over the prospect for four key scenarios:

1) 3D model with topography variations only
2) 3D model with topography variations and hydrates
3) 3D model with topography variations, hydrocarbons, and hydrates
4) 3D model with topography variations, hydrocarbons, and no hydrates

These scenarios were all set in a common graded-resistivity background with a resistivity-depth profile obtained from 1D inversion of off-target CSEM data and well logs in the basin. Modeling the hydrates can be difficult as their seismic expression is variable and often weak. Several studies report that the primary expression of hydrates on seismic data is a bottom-simulating reflection (BSR) caused by the acoustic con-
trast between sediments containing hydrates and sediments with free gas trapped beneath the hydrates. These studies suggest that there is a gradual increase in hydrate saturation near the seafloor, resulting in a gradual ramp-up in acoustic impedance rather than a discrete jump, and therefore, the top of the hydrates is not visible on seismic data (Yuan and Edwards, 2000; Schwaleńberg et al., 2005; Hyndman and Dallimore, 2001).

However, this is not the case in our area. Figure 6 shows a vertical seismic section through the Alpha-1 well with the deep-resistivity log overlaid. The data are acoustic impedance data, so the water-bottom event, which is blue over red, verifies that the polarity is correct (red = hard, blue = soft). The resistivity kick of about 15 Ω m near the shallow green event was identified as a hydrate during drilling. It correlates very well with the strong hard seismic event (red) at 30–45 m below mud line. The amplitude of this event varies from nearly zero to about two and a half times that of the water bottom. This event is located far above the predicted base of the hydrate stability zone computed from the subsurface thermal and fluid pressure gradients (green horizon in the lower part of Figure 6). Our interpretation is that the shallow green event is the top of a sand or silt with hydrates. Therefore, we have manually picked the top and bottom of such seismic events in the area (Figure 7) and included them in our 3D resistivity models as layers of 15 Ωm corresponding to hydrates.

The reservoir was modeled as a thin-layered, shale-dominated package at the top with three massive sands below, roughly 1000 m below mud line. The resistivity of the sands for the hydrocarbon-charged case is 50 Ωm as observed in Alpha-B well. For the brine case, the sand resistivity was set equal to the background resistivity, which was consistent with Alpha-1 and Alpha-B logs. A traverse through the conductivity model is shown in Figure 8. The cell size of the finite-difference grid we used was 100 m × 100 m horizontally, 10 m vertically around the seafloor, 5 m within the reservoir layer, and 50 m otherwise — about 20 million cells. Using our multigrid preconditioned iterative 3D EM solver and 30 cpus of a Linux cluster, the response can be obtained in about one hour per frequency for all 30 CSEM receivers.

To validate our model of the hydrates, we computed the inline horizontal electric field at 7.25 Hz for scenarios 1, 2, and 3. We computed the normalized amplitude of the modeled fields as a function of source-receiver offset, normalized by the modeled response of the same reference receiver as we used with the real data (R22) towing towards positive positions. Figure 9 shows the median value of the normalized electric field over a 200-m-offset window centered on 1.5 km, and posted at the midpoint between the source and the receiver. This is the modeled equivalent of the real data shown in Figure 4. We observe that the electric field increases tremendously (up to a factor of 7) at the location of the hydrates and that this EM anomaly is not present when no hydrates are included in the models (scenario 1). This high frequency is not expected to penetrate to reservoir depth, and indeed, the magnitude and the extent of the modeled anomaly do not change much when hydrocarbons are added in the reservoir (scenario 3). We therefore concluded that the modeled 7.25 Hz EM anomaly is mainly caused by shallow hydrates. A simi-
lar EM anomaly is observed in the real data (Figure 4), and it is therefore most likely that this anomaly is caused by shallow hydrates. The amplitude of the modeled anomaly is slightly smaller than in the actual data, but this can be explained by the fact that we may actually have underestimated the extent of the hydrates because they may not be visible on the seismic data (Yuan and Edwards, 2000).

We now consider the modeled responses for scenarios 1, 2, and 3 at the fundamental frequency, 0.25 Hz. Figure 10 shows the normalized electric field stacked around 5.5 km offset and posted at the midpoint between the source and the receiver. Scenario 1 (topography only) tells us that the normalized EM anomaly caused by topography variations does not exceed 1.25. This emphasizes the importance of taking account topography variations when normalized EM anomalies are small (<1.5). In the case of scenario 2 (topography plus hydrates), the normalized EM anomaly reaches 1.5 at the location of the hydrates. This highlights the fact that hydrates can have a significant impact on CSEM data even at the fundamental frequency.

Hydrate effects are apparent when either the source or receiver is located above the modeled hydrates. If the receiver is sitting on the top of the hydrate patch, the effect can be considered as a static shift, as often observed in MT soundings (e.g., Spies and Frischknecht, 1991), and affects all the offsets similarly. When the source is passing over the hydrates, an EM anomaly appears on all of the receivers. This behavior is illustrated on Figure 11, where topographic variations are removed using the response of scenario 1 as a reference model. The receiver static effects appear as diagonal stripes whereas the common source-point anomalies appear as vertical stripes.

The hydrates-only model, scenario 2, does not appear to fully explain the real 0.25 Hz data (Figure 2), which has a maximum anomaly of about 1.8. It is only after adding hydrocarbons at the reservoir level (scenario 3) that the modeled EM anomaly reaches that level. We can therefore conclude that even if hydrates have a significant impact at the fundamental frequency, they are not resistive or thick enough to generate an EM anomaly as strong as that observed in the data. That represents the first evidence that the observed anomaly is in part caused by the hydrocarbons within the reservoir. The other and more convincing piece of evidence comes from the fact that the spatial wavelengths of the EM anomaly (Figure 10) caused by shallow hydrates are much smaller than those arising from the reservoir hydrocarbons (scenario 4). This feature is even more visible when removing topography variations (bottom of Figure 10). Indeed, when only hydrates are present, the spatial apparent wavelength of the EM anomaly is around 1 km, although it is around 10 km when hydrocarbons are present in reservoir (i.e., roughly the lateral extent of the reservoir). When both are present, we can see that the EM anomaly is composed of long and short wavelength components. The long wavelength anomaly arises from the reservoir, and the anomaly has short wavelength components because of the presence of hydrates. It is important to notice that in our case, reservoir and hydrate contributions have quite different wavelengths, allowing a separation of the two effects. However, for smaller prospects and larger hydrate accumulations, such wavelength separation may fail. Finer receiver sampling would help prevent spatial aliasing, which may affect the analysis of hydrate effects.


