Unlocking the value of CSEM

Lucy MacGregor[1*] and Richard Cooper[1] **suggest that for marine controlled source electromagnetic survey methods to achieve more general adoption in the E&P industry, the applications need to be refocused with more emphasis on prospect appraisal and reservoir monitoring rather than exploration.**

The marine controlled source electromagnetic CSEM method has been available as a commercial tool for hydrocarbon detection since 2002 following a successful proof of concept field trial offshore West Africa and the subsequent emergence of three geophysical contractors, OHM in the UK, EMGS in Norway and AGO in USA (now WesternGeco-EM). Adoption of the technology has been slower than predicted in the early days. There are a number of possible reasons for this, however ultimately the success of the CSEM method depends upon our ability to convince a sometimes sceptical client base of the enormous value of CSEM derived resistivity information when combined with seismic and other data across the oil field life cycle.

Since its inception, the CSEM method has been promoted primarily as an exploration tool, indeed even as a frontier exploration tool whereby CSEM would be used ahead of seismic acquisition to help de-risk the overall hydrocarbon potential of a basin. However when CSEM data are analysed in isolation the resulting interpretation can be fraught with uncertainty, increasing the risk in decisions based on these interpretations. CSEM is at its most powerful when interpreted within a geological framework including seismic, well, and other geophysical and petrophysical information. As a result CSEM is as applicable and perhaps even more so in appraisal and monitoring settings.

Background

CSEM surveying is not new technology. The method was originally developed in the 1970s at the Scripps Institution of Oceanography for studying the resistivity structure of oceanic lithosphere (Young & Cox, 1981). Throughout the 1980s and 1990s both the acquisition and interpretation technology was further developed by groups at Scripps, the University of Toronto and the University of Cambridge for application to the study of fluids in active mid-ocean ridge settings, and for mapping marine gas hydrate deposits (Sinha et al., 1990; Constable & Cox, 1996; Edwards et al., 1997). Industry interest in the method also grew throughout this period with ExxonMobil investigating the possibility of using CSEM as a method of direct hydrocarbon detection in the mid 1980s, and increased industry interest in using marine electromagnetic methods as a complementary technology for exploration in areas challenging to traditional seismic methods, for example in the presence of salt or basalt.

By the late 1990s, with exploration moving into deeper water where traditional CSEM methods were best suited, ExxonMobil had resumed its investigations into the method, and StatoilHydro had also started to examine the possibility of using CSEM as a way of mapping hydrocarbon reservoirs. Their work culminated in 2000 with successful field trials offshore West Africa (Ellingsrud et al. 2002), and between 2000 and 2002 both companies performed a number of proof of concept surveys. This activity led to the emergence of three contractors: EMGS in Norway, OHM in the UK and AGO (now WGEM) in the US. The CSEM industry rapidly grew from an academic curiosity to a mainstream exploration tool, and further EM-based companies were formed. With the expectation of rapid adoption by the industry at large, predictions of a CSEM market that would grow to $300 million by 2008 and $1 billion by 2012 were made.

Unfortunately these early predictions have proven to be unrealistic. Adoption of the CSEM method by the hydrocarbon industry, which has a notoriously conservative approach to new technology, has been slower than anticipated. This has been compounded by the recent economic climate. As a result the CSEM market in 2008 was approximately $130 million – less than half that anticipated in the early years. Whereas there is general acceptance that CSEM is proven technology in the hydrocarbon industry, there is still considerable scepticism about its robustness and uncertainty about its applicability.

Nine years on from the first proof of concept survey it is instructive to reflect on the reasons for the slow adoption of CSEM methods. A number of possible causes can be imagined. For a new technology to be adopted, the value of the information it can supply must be clearly demonstrated to a wary client base, and to be useful it must be presented in a way that can be incorporated easily into existing workflows. This requires the sharing of expertise across the industry to increase the knowledge and understanding of CSEM methods among the geophysical profession at large. It is particularly important that the applicability of the method

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and the uncertainties in the resulting interpretations be clearly communicated and understood. The lack of published case studies also hinders the widespread adoption of the technology: companies considering applying CSEM methods in their acreage have little material to refer to. In addition, whereas there has been widespread investment in acquisition technology, there has been less investment in interpretation methods. There are few commercial interpretation platforms available to companies wishing to use CSEM methods, making use and understanding of the results even harder.

All of these issues must be addressed if the CSEM method is to reach its full potential. However there is a further, important issue that we must consider, namely, what is CSEM best used for ? To date the method has been marketed primarily as a tool to help de-risk exploration. However given the experience of the past nine years it is worth considering whether this is the only, or indeed the most appropriate use of the technology. To do this we must first examine the CSEM method and its strengths and weaknesses, and then consider where in the oil field life cycle it can be most usefully used.

Overview

The CSEM method uses a high powered horizontal electric dipole source towed close to the seabed to transmit electromagnetic signals through the earth to an array of receivers deployed on the seafloor. These receivers measure up to three components of the resulting electric and magnetic field. By analyzing the received signals using a combination of forward modelling, hypothesis testing, and geophysical inversion, the resistivity of the underlying earth can be determined at scales of a few tens of metres to depths of (typically) a few kilometres below mudline. A review of the technology is provided by Constable & Srnka (2007).

In many situations electrical resistivity is driven by the properties and distribution of fluids in the earth. Commercial hydrocarbon deposits may be many times more resistive than surrounding lithologies and therefore can be detected using CSEM tools. In contrast, seismic data are sensitive to boundaries between lithologic units but are less sensitive to fluid changes within these units. This is illustrated in Figure 1 which shows a suite of well log curves from the North Sea. Note the large change in the resistivity curve between wet and hydrocarbon-saturated conditions. In contrast the acoustic and elastic curves show only small changes between equivalent wet and hydrocarbon-saturated cases. Given high quality seismic and well data and sophisticated seismic inversion and rock-physics tools, we can sometimes relate these seismic changes to saturation effects. Nevertheless, the change in resistivity caused by variations in saturation should be much easier to detect.

CSEM use and abuse

CSEM data allow us to measure resistivity from the seafloor, and thus complement surface-based seismic measurements. However, despite the increased sensitivity of resistivity data over seismic for the determination of saturation, there are two inherent challenges to interpreting CSEM data. Firstly the structural resolution of CSEM data is poor. For example, there is a trade-off between the resistivity and depth of resistive features, and weak resistors may not be easily separated from stronger ones. Secondly the cause of resistivity anomalies (particularly high resistivity features) cannot be uniquely linked to the presence of hydrocarbons in the subsurface when taken in isolation. In many situations these are equally likely to be caused by other high resistivity material (for example, tight carbonates, salt, or volcanics). Both of these limitations must be addressed when considering the applicability of CSEM to answer a geophysical question, and as far as possible mitigated by the interpretation approach adopted.

CSEM data can of course be interpreted in isolation, and if there were no seismic data or wells in the vicinity of the CSEM dataset, for example if a survey were performed in a frontier area, then this would be necessary. In this situation without the benefit of a well constrained model of the area and defined target structures, acquisition parameters cannot be optimally chosen. Post acquisition, the interpretation process then tries to answer the question ‘What does this CSEM data tell me about the resistivity of the earth?’.

However, with no constraints on this interpretation, the result will suffer from the non-uniqueness and ambiguity which blight unconstrained interpretation approaches. Although resistivity is imaged, the poor structural resolution of the method means that such images are diffuse and difficult to interpret. The uncertainty in the depth of features is large, so that they cannot be unambiguously attributed to a particular stratum. If there are multiple resistive features, these cannot be easily separated, and small resistive bodies are likely to be lost or smoothed into surrounding strata. Even assuming that localized resistivity anomalies can be found, the cause of these anomalies cannot be unambiguously linked to the presence of hydrocarbon.

Given the level of uncertainty and non-uniqueness that exists in an unconstrained interpretation when considered in isolation the question arises: is it appropriate to perform CSEM surveys where there is neither seismic nor well control? The answer to this question is almost certainly no if the objective of the survey is to de-risk an exploration programme.

In the presence of seismic and well information, the question that we are trying to answer with the CSEM data becomes significantly better posed. The question is no longer one addressed at finding a reservoir, but rather one of determining the content of a defined structure. Using seismic information the reservoir structure is known (but potentially not its content or extent), and we have independent constraints on the surrounding strata within which it is embedded. This is therefore a constrained interpretation problem and one that the CSEM data are in a much better position to answer.

An important consequence of an integrated interpretation approach is that a background resistivity model can be generated from an interpretation of the available seismic and well data. This model forms the basis of the survey design process to optimize the acquisition for sensitivity to the target of interest to ensure that the survey aims are met. It also provides a mechanism, through targeted hypothesis testing, for understanding and quantifying the likely uncertainties in the interpretation result. At the CSEM interpretation stage the question becomes one of fluid substitution, i.e., how would the resistivity of my reservoir zone change if the hydrocarbon saturation changes and how does this affect the measured CSEM response ?

The uncertainty in the CSEM interpretation result will depend on how comprehensive a background model can be constructed. For example, in frontier areas where only sparse 2D seismic data are available it may be possible to identify regions of elevated resistivity, however without well log information the risk attached to interpreting these as hydrocarbons remains high. In contrast in producing fields where a detailed background model can be constructed from existing seismic, well, and production data, it will be possible to identify with much more certainty the fluid saturation and changes in this through time.

Where does CSEM fit?

The applicability of CSEM methods must be considered with the strengths and limitations discussed above in mind. Figure 2 divides the geophysical market into four categories ranging from frontier exploration to reservoir monitoring. CSEM

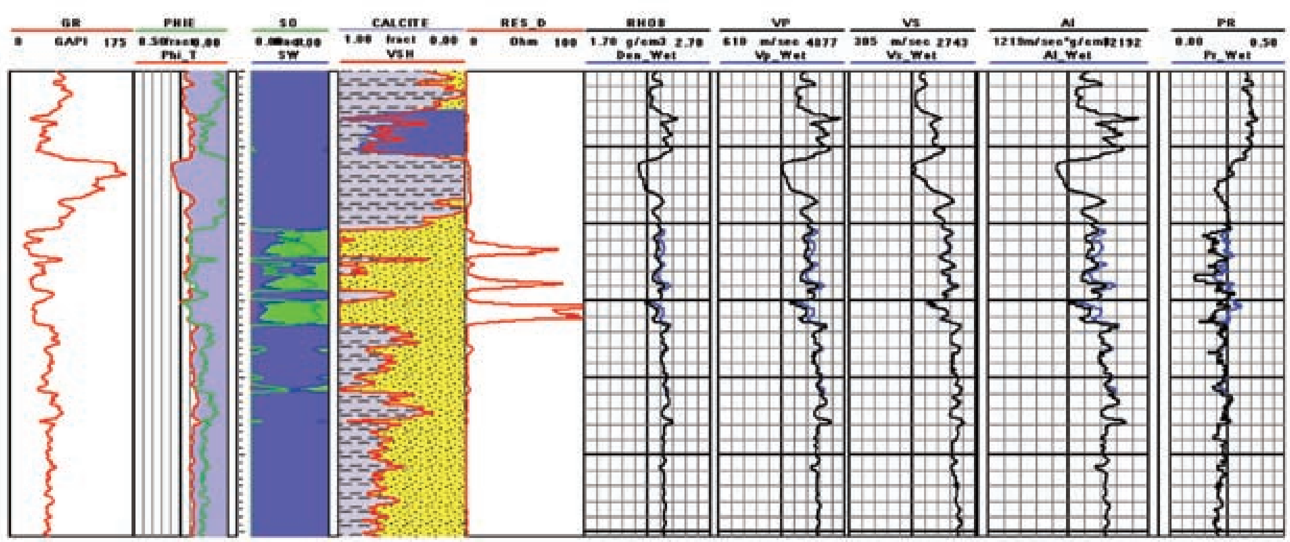

Figure 1 *Well log suite illustrating that the hydrocarbon saturated zone is clearly delineated as a region of high resistivity (red curve in the fifth track). In contrast the acoustic and elastic curves (right four tracks) show only a small difference between the water saturated (blue) and hydrocarbon saturated (black) cases.*

	CSEM interpretation risk	Seismic availability	Well availability
Frontier Exploration	High	Sparse 2D	None
Exploration	Model dependant	2D perhaps 3D	None or limited
Appraisal	Low	3D	Several
Monitoring	Low	3D/4D	Many

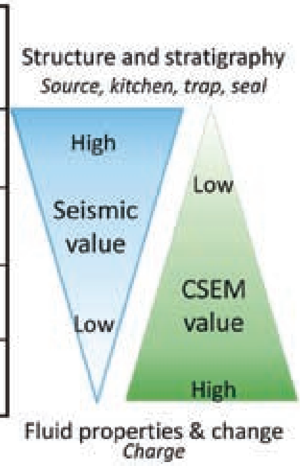

Figure 2 *Schematic illustrating the applicability of CSEM and seismic methods across the oil field life cycle.*

methods can in principle be applied at any stage although the question being addressed varies:

- Frontier exploration: what is the resistivity structure of the earth?
- Exploration: what is the resistivity within the seismically defined structure?
- Appraisal: given the seismic structure and the properties of the reservoir at a well, how do these properties vary across the field?
- Monitoring: given the seismic structure, and properties in the well, how do these properties vary across the field and through time?

The interpretation uncertainty associated with CSEM declines as more information is available to construct an integrated interpretation. Therefore, of these possible applications the last two, where both well and seismic data are available, will produce results with the lowest uncertainties. Interestingly, the increase in value associated with CSEM complements the corresponding decline in suitability for seismic data in appraisal and monitoring. This is to be expected: seismic data are good at defining structure, stratigraphy, and (usually) lithology and porosity, but may struggle to measure fluid content and saturation.

To date, the CSEM industry has been focused on the exploration side of the market, and is largely ignoring the appraisal and monitoring market, for which the technology may be much better suited. OHM recently completed a two year research project in collaboration with BP and funded by the UK government, to examine the use of CSEM for appraisal and monitoring. This used a synthetic case study based on a complex 3D channel structure, and clearly showed that CSEM can be used to map the gradual depletion of the reservoir using repeat surveys. An important result of this work is that changes in the fluid properties of a reservoir can be mapped using repeat CSEM surveys, without the need for permanently installed systems. As long as each survey collects high quality CSEM data, then source and receiver re-positioning between surveys is not as critical compared to the seismic equivalent.

As a result, both appraisal and monitoring surveys are within our capability using existing acquisition technology, though more sophisticated methods, for example, cable-based acquisition systems, may be adopted in the future. In interpreting these surveys it is critical that a truly integrated approach is adopted, to provide robust results consistent with all available geophysical and petrophysical data.

Conclusions

The CSEM industry has expanded dramatically since its inception, and although there have been many notable technology successes, there have also been a number of failures. CSEM methods have an important role to play in hydrocarbon exploration and development; however, to reach their full potential an integrated approach, in which CSEM, seismic, and well log data are interpreted within a single common framework, must be adopted.

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