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Full Field Array ElectroMagnetics for hydrocarbon reservoir exploration and monitoring

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Abstract

Managing a reservoir is critical to achieve higher hydrocarbon recovery factors, reduce operating cost and meet environmental concerns. Recent advancements in both surface and borehole methods have led many geophysical techniques like 4D seismic and transient electromagnetic to monitor reservoir changes over the time in order to improve reservoir characterization and management. Seismic methods, as workhorse of the industry, are traditionally used to identify structures but they are challenged to discriminate between various pore fluids (like brine and oil). This is because seismic waves travel primarily through the mineral/solid matrix. An electromagnetic signal is strongly influenced by the fluid content due to the large differences (at least one magnitude) in the electric resistivity of water and hydrocarbons.

For production applications reservoir monitoring can be done with sub-surface and surface electromagnetic measurements, which are sensitive to these variations in the pore space. We propose using array electromagnetic concepts similar to array seismic on land that integrates surface borehole measurements to monitor the fluid movement in a hydrocarbon reservoir. Evaluating several reservoir dynamic monitoring methods and technologies leads to a practical concept of Full Field Fluid Monitoring with electromagnetics. Our implementation includes marine and land sources and receivers, surface-to-borehole arrays and single well system that can look tens or even 100 m around the wellbore and ahead of the drill bit.

For exploration applications on land it is essential to distinguish resistive and conductive targets equally well. To do this we can use natural field magnetotellurics for the conductive target like sediment thickness or geothermal targets. For resistive targets such as hydrocarbon reservoirs, we add Controlled Source ElectroMagnetics (CSEM) with a dipole transmitter. For ease of operation it is thus easiest to measure all EM components. If you want to use frequency domain and/or time domain in the same receiver deployment, you need to either cross calibrate the receiver or have a receiver with switchable response function.

For exploration applications in the marine environment, we include our receiver into seismic spreads and use fluxgate sensors for the low frequency magnetotelluric field and search coils for the high frequency component. CSEM is only needed when the resistive strata are thin (a few hundred meters). Multi-component acquisition and dense station

spacing is essential to measure anisotropy and get lateral structural changes and to extend the application from exploration to production.

For borehole use we are combining our EM sensor packages with borehole seismic acquisition system or build special purpose LWD sub-assemblies. So far, we have been building the various critical components for an integrated land and borehole-monitoring experiment based on a commercial seismic acquisition systems. This choice allows us to use acquisition hardware and software without major modifications.

Surface electromagnetic methods alone are ambiguous if they are not used in combination with surface-to-borehole measurements. The reason lies in the up-scaling issues associated with the inherent averaging nature of EM methods. This is reduced the closer we get to the reservoir.

Introduction

Seismic methods are the first choice in the oil and gas exploration to locate and to identify the extent of hydrocarbon reservoirs. They are preferred because of their ability to identify structures (Wilt et al., 1998). Crosswell and surface-to-borehole seismic measurements are superior in mapping the structural distribution in the interwell space. Their limitation to differentiate between the various compositions of pore fluids is still a challenge because seismic waves travel primarily through the mineral grains. For fluids, electromagnetics will complement seismic contribution in mapping the complete interwell space. Electrical conductivity measurements allow pore fluid monitoring because of their sensitivity to porosity, pore fluid type, saturation and temperature. Figure 1 shows the distribution of bulk resistivity (which includes mineral matrix and fluid) as a function of gas saturation. Note, the resistivity is exponential increasing with saturation. The total range of resistivity cover about 4 decades. This is why we have in most cases a resistivity contrast of at least 10 when we flooded a hydrocarbon reservoir.

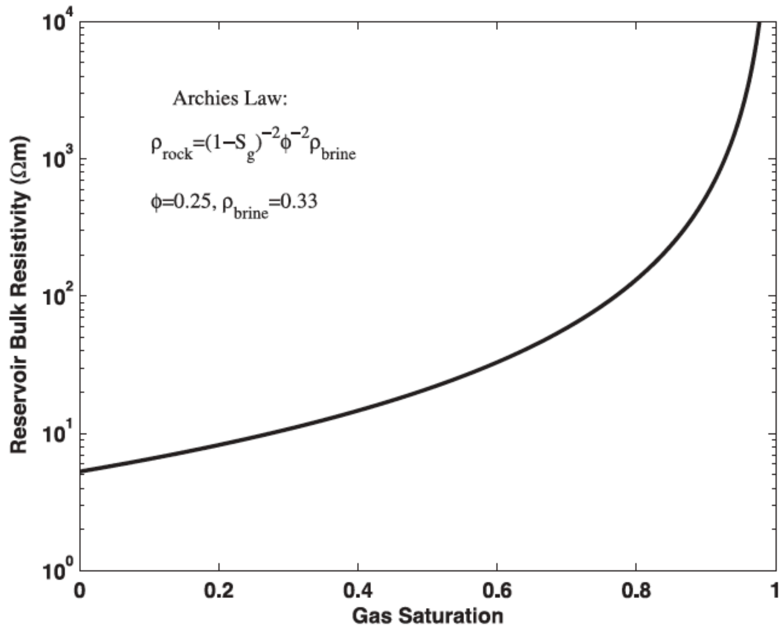

Figure 1: Reservoir bulk resistivity as a function of gas saturation (Rubin et al., 2006).

At present, apart from one commercial crosswell EM system, no commercial downhole EM monitoring system has been commercially offered. Increased mentioning in meetings and literature indicates that several companies are considering combining surface and borehole measurement technology (Colombo et al., 2010). In order to make the choice of system, we need to understand what measurement delivers the reservoir parameters to select the right measurements. Table 1 shows a summary of sensors category, type, measured parameters and their applications (modified after Hottman and Curtis, 2001). Determining fluid composition and saturation are the most important measurements for the oil industry and thus electromagnetic measurements are some of the most important downhole measurements. Only when extrapolating it from the borehole to the deeper reservoir or surface can we correlate petrophysical parameters with structural or stratigraphic reservoir parameters and reduce exploration, development and production cost. Thus borehole EM and upscaling to surface scale is important.

Electromagnetic methods are some of the oldest geophysical methods in the mining industry. In the hydrocarbon industry they are still used only for trial purposes in exploration only (Nabighian and Macnae, 2005). There has been some progress with marine electromagnetics, but it stabilized in the market place at much lower levels than expected. In the borehole environment electromagnetic (EM) logging tools are the most important of all and in most cases used for reserve estimates.

Sensor category	Sensor type	Property measured	Application
Production	Flow Composition Pressure	Production & flow rate Fluid phase, water-cut, GOR Reservoir pressure	
Formation	Resistivity & EM Temperature	Saturation, Fluid composition Temperature of fluid Flow behind pipe	Compartmentalization oil-water front Water saturation
Seismic	Geophones Hydrophones	Vp, S1 & S2,Microfractures (natural & induction) Vp	
Noise	Acoustic	Production noise Sand production Mechanical integrity of pumps	
Density	Gravity	Porosity Saturation	Gas-liquid front Gas saturation

Table 1: Summary of various sensor category, type, property it measures and its applications (after Hottman & Curtis, 2001).

The issue clearly lies in the loss of sensitivity with distance from the object of investigation and thus with increasing depth, the volume of investigation becomes larger and more fuzzy. While in the mining industry the targets are relatively shallow and mostly conductive, hydrocarbon target are normally resistive and electric fields are required. (Passalacqua, 1983; Eadie, 1980; Strack et al., 1988; Eidesmo et al., 2002) Unfortunately, electric field source and receiver systems are only customary in the marine environment as high power systems are dangerous to operate. In addition cost of a high power system goes up quadratic (power = current*current*ground resistance) as generator cost goes mostly linear with output current. While in the 1980s megawatt sources were used for geothermal exploration (Keller et al., 1984) in addition to superconducting receivers, we can today achieve the same or better results but more electronic control of the source waveform, improved signal-to-noise receivers and data processing (Strack and Vozoff, 1996; Strack, 1992). New version of these concepts using today's low power, low drift electronics and exclusively digital filters are refining this even further.

Figure 2 shows an example of an oil field reservoir in a marine environment.

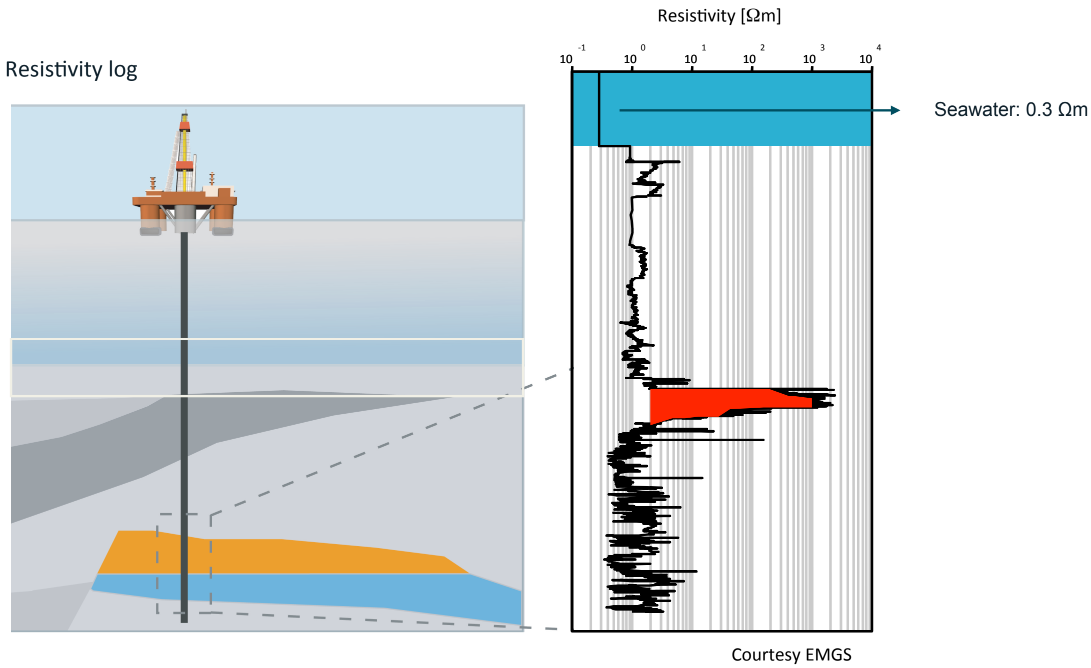

Figure 2: Sketch of a reservoir in a marine environment and an induction log. The induction log shows high resistivity in the reservoir zone indication high hydrocarbon saturations (courtesy EMGS).

On the right side of the figure the induction log is shown and clearly shows increased resistivity of the reservoir zone where the oil is.

In addition to the bias towards conductive or resistive targets, anisotropy has been an ongoing issue. Electrical anisotropy of surface scale is caused by cyclic layering and on borehole scale by sand/shale laminations of disseminated shales (Strack, 1992). The electrical anisotropy of the subsurface has only been recently understood with the event of 3 component induction logs (Kriegshaeuser et al., 2000). We can now integrate sub-surface and surface EM measurements by calibrating horizontal and vertical resistivities correctly. This is done using upscaling methods described by Keller and Frischknecht (1967) where we get the model to match cumulative conductances and cumulative transverse resistances of the induction log.

From the hardware side, electromagnetic systems always had a high cost per channel and bulky equipment. While a significant instrumentation downsizing effort would require funds beyond the business value of the technology, there is sufficient room for improvements by linking seismic concepts and experience. This addresses the cost reduction from operational side. It means that multiple measurements are being carried out together and the logistics cost, which is usually the biggest part, is covered by seismic operations. Thus incremental cost of the EM measurements is small (10 to 20%). This is a must for larger scale field operations.

As long as only small amount of data are being acquired on land, the value of EM will be limited as the lateral resolution of EM is not as good as seismics. In the offshore environment where the business models are completely different this is not the case. Here, any additional information that can contribute to de-risking a drilling decision will help. The success of marine electromagnetics to the exploration portfolio has shown this (Eidesmo et al., 2002). The real value lies in the extending the technology use to additional parts of the reservoir life cycle, namely production.

The success of marine development has fueled improvements in the land development. KMS Technologies' new array acquisition system is a 24-bit version of our 32 bit marine node, our land transmitter design benefits from our marine transition zone transmitter.

Full Field Array EM

The Full Field Array EM concept is the generation of a 3D data cube that has as many calibration points as possible and allows the user to extrapolate the calibrated information into an interpretation of the non-calibrated space. Figure 3 shows an artist rendition of such a cube. Her we can see several high value problems of the oil industry:

- Geosteering – placing the borehole in the right location in the subsurface
- Monitoring - observing fluid movement with permanent & semi-permanent sensors
- Defining attic reserves – exploring & monitoring from the surface (onshore & offshore) and linking the information to the 3D data cube.

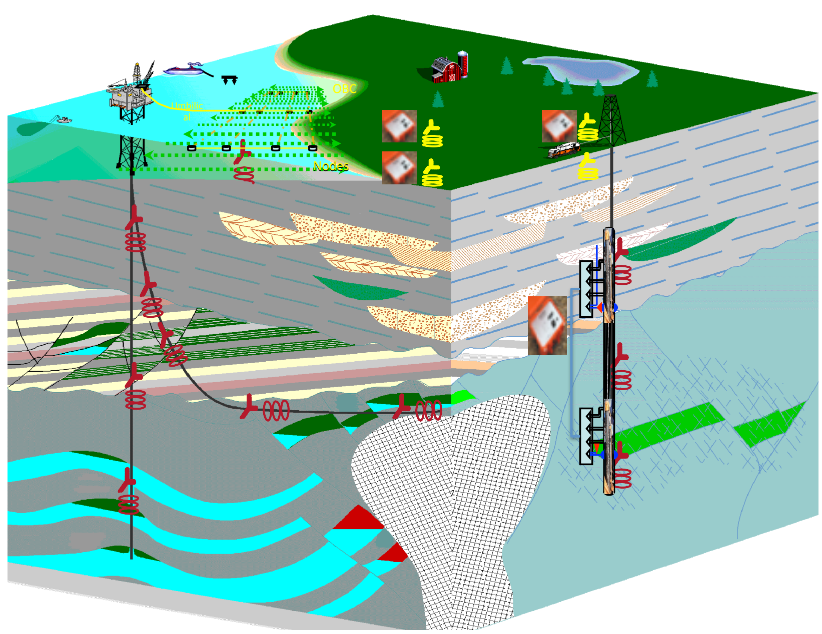

Figure 3: Artists rendition of Full Field Electromagnetics components. Sensors placed inside the borehole as well as on the surface (onshore and offshore) are shown.

Electromagnetic sensors are represented by the coil (symbolizing magnetic sensors (H)) and the coordinate indicator representing electric field measurements

(E) as well as tensors measurements for both E and H.

The problem with populating this 3D cube is cost of data acquisition, resolution of the electromagnetic methods and information value. Since EM methods and equipment are in many cases custom made, the cost is still many times higher than for surface seismic. Our array system is the second attempt (Rueter and Strack, 1995) of reducing the cost of EM hardware by adopting seismic principles. For borehole measurements the cost is a secondary issue because the information value of placing a borehole in the subsurface is significantly higher than the EM measurement cost. Here, the issue remaining is the change of business model of the service companies as assets are owned by the oil field owner and only limited services are required. As the marine exploration cost is already very high, electromagnetics had a chance to break into a high-risk market with limited (compared to other geophysical methods) but unique risk mitigation value.

The drivers for the integration need to be the oil companies (or geothermal producers) as they are the ultimate beneficiaries of the technology integration value. In all cases, present data density is insufficient. Since this vision of the technical integration was outlined in 1996 (Strack and Vozoff, 1996) two necessary improvements have happened: First, hardware has made significant progress and electromagnetic data can now be acquire with fairly broadband system that are at the same time long-term-stable, have low noise and are significantly cheaper than electromagnetic system were 20 years ago. Issues such as synchronization, data formats, and data storage are well in the past. Figure 4 looks more like a seismic layout of a regular gridded surface and irregular lines linked with rough terrain carried nodes, but is the rendition of an electromagnetic survey. Second, borehole anisotropy measurements are now available everywhere as the two largest service companies provide them. In addition, borehole seismic systems are today often manufactured by 3rd party vendors, which allows us to easier integrate electromagnetics add-ons.

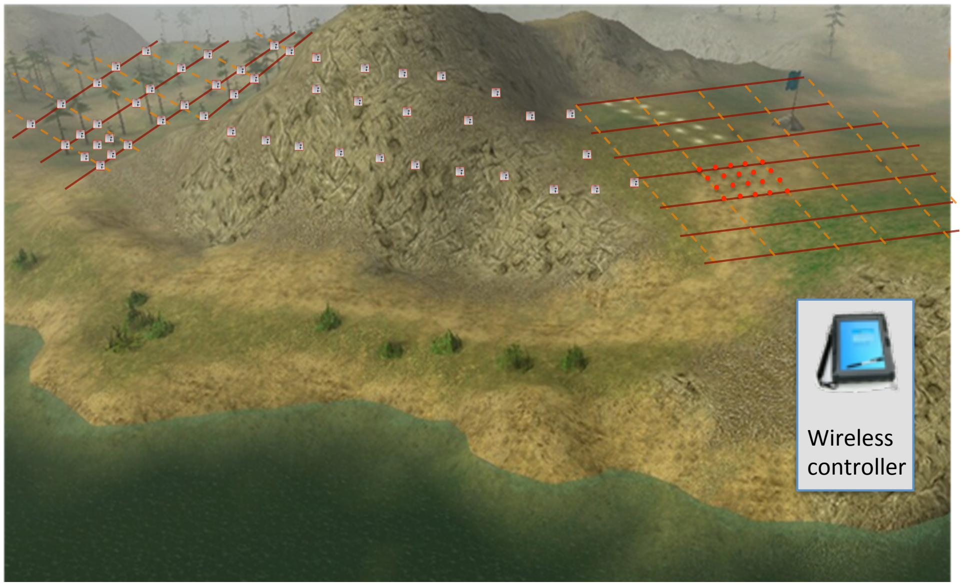

Figure 4: Seismic-style layout example of an electromagnetic survey using wireless nodes in a regular grid layout and also in irregular lines.

Technology components

After setting the scene for the need of Full Field Array measurements, we will now look at the individual technology components from the borehole to surface to borehole to marine and land to surface to borehole measurements. Some of these are already commercial, namely land and marine surface measurements. Some of the 3D borehole inductions log measurements are now worldwide available and are enabling for now technology developments. The surface-to-borehole measurements are under development.

Figure 5 shows an example of a 3D induction log interpretation. Baker Atlas developed the 3D induction-logging tool under the mentorship and co-funding of Shell (Kriegshaeuser et al., 2000, Strack et al., 2000). It allows the measurement of horizontal and vertical resistivities in a borehole, specifically, and in general the determination of the tensor resistivity. The motivation lies in a large amount of resistive oil being trapped in thin laminations between conductive shales. Standard induction logs only yield horizontal resistivities, which is dominated by the shales (Yu et al., 2001) resulting in significantly underestimated hydrocarbon reserves. These tools do not only apply to thin laminations but also any dispersed shales and with the appropriate petrophysical analysis yields tensor saturation. Higher transverse isotropic resistivities (resistivities are the same on horizontal direction and different in vertical direction) result in most cases in higher vertical resistivities and thus higher hydrocarbon saturation or more oil. This justified the development of this tool. In Figure 5 we have a natural gamma ray log on the left,

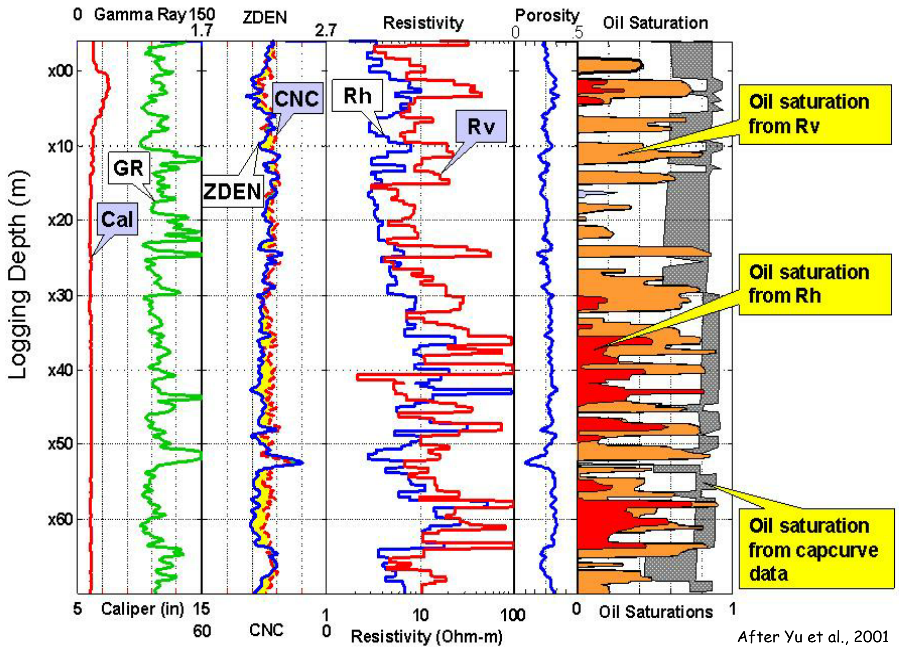

Figure 5: Example of an interpretation of a 3D induction logs interpretation (Yu et al., 2001). The tracks from left to right show: natural gamma ray for shale content, gamma-gamma density and neutron density for gas zone indicators, 2D inverted vertical and horizontal resistivities, interpreted porosity and interpreted oil saturation.

Indicating shale content. To its right are gamma-gamma densities and neutron density curves followed by 2D inverted resistivities (vertical, Rv, and horizontal, Rh). Together with the porosity track that follows and the appropriate petrophysical equation oil saturation is calculated. Note the oil saturation is significantly higher from the vertical resistivities. When we are carrying out controlled source EM (CSEM) measurements with a grounded dipole, we measure predominantly the vertical resistivity. This means calibration of surface dipole CSEM measurements can now be done, as it was hereto not reliably possible.

Given that most sedimentary basins show electrical anisotropy, as do fractured carbonates, one could assume that most of our prior log calibrations are inadequate and many of our interpretations should be revisited. Fortunately, Keller who developed already recognized this in the 1960 simple rules of log reduction to deal with the common anisotropy in the oil field environment (Keller and Frischknecht, 1967). He studied systematically the effect of electrical anisotropy on logs. In summary, he derived limiting equivalent resistivity rules using the fact that inductive methods are biased towards conductors and galvanic methods are biased towards resistors. In the 1960s, the group around Keller used resistivity logs for vertical resistivities and induction logs for the horizontal one and also inverted them (in 1960s with great difficulty!). From a normal induction log we can obtain the limiting equivalent resistivities by using the cumulative conductance (thickness multiplied with resistivity) for the lower bound and the cumulative transverse resistance (resistivity multiplied with thickness) for the upper bound. Figure 6 show a graphic display of a log with the cumulative conductances and transverse resistances on the right. Graphically you can point to the layer boundaries, calculate the cumulative values and fit a straight line between the boundaries to determine the horizontal and vertical resistivities for that layer. These values are then superimposed on the log on the left. In this way we can now calibrated our logs for the purposed of linking them to magnetotelluric data (horizontal resistivities) and grounded dipole CSEM data (vertical resistivities).

This technical progress did not provide sufficient business motivation until the fast growth, subsequent fall and now stabilization of the marine EM exploration industry. Technically, this was caused by the thin resistive layer effect recognized first on land (Eadie, 1980; Passalacqua, 1988; Strack et al., 1988) and subsequently pioneered offshore by Eidesmo et al. (2002). An early example is shown in figure 6 from the Troll field, Norway (Johnstad et al., 2005). We can see in the top pat of the figure a normalized amplitude plot, which is the measured amplitude over reference background amplitude outside of the hydrocarbon reservoir. Clearly, an anomaly can be seen which coincides with the seismic image with superimposed interpreted anomaly in the middle as well as the interpreted structure of the reservoir shown at the bottom of the figure.

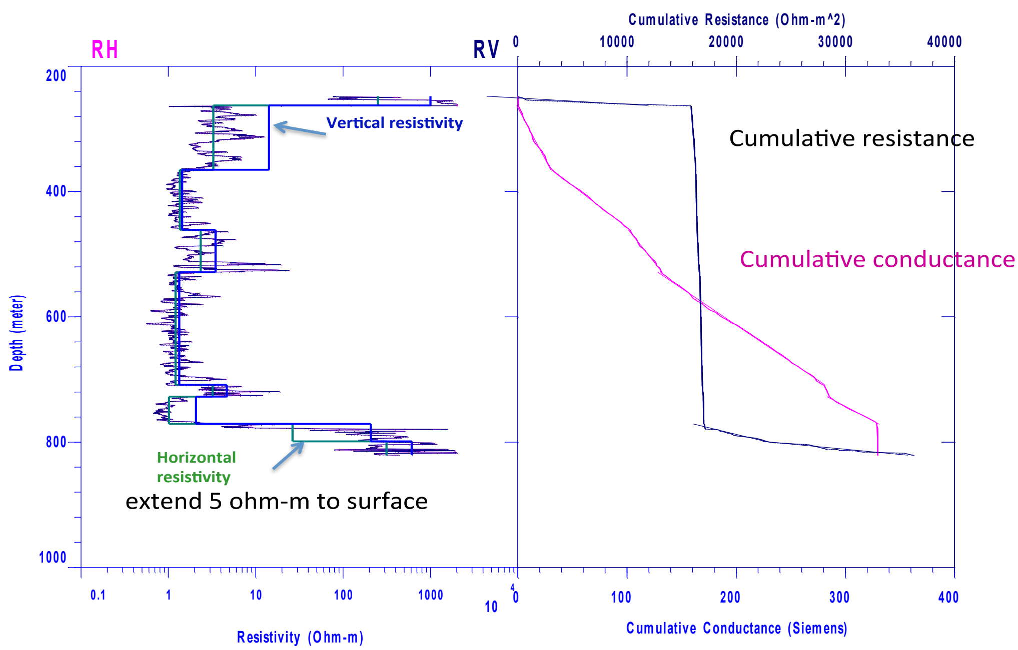

Figure 6: Example of deriving vertical and horizontal resistivity from an induction log shown on the left. The equivalent values superimposed on the log are derived from the cumulative conductance and cumulative transverse resistance on the right by fitting lines between layer boundaries. The user interactively picks the layer boundaries. The plot was generated with IX1D by Interpex Ltd. (www.interpex.com).

The next step in the marine environment is – as on land – to reduce acquisition hardware cost and to acquire denser data. Automatically, one would try to image the data directly as raw data as shown in Figure 8. The figure is for synthetic data and these concepts were confirmed in several proprietary data sets (Thomsen et al., 2007). The figure shows a common-source gather, where the curves are at increasing offsets from the left. In the top of the figure we have the UNPROCESSED data displayed with automatic gain control. The vertical axis is diffusion time after current turn OFF. You can clearly see first the ocean wave arriving, which is the initial strong response part that does not spread out that much with time. Following is the subsurface response, which includes the target and the rest of the subsurface. It clearly smears over larger time with increasing offset. As the target is resistive its contribution arrives early then the rest of the response at larger offsets. The bottom of the figure shows the target response only (automatic gain controlled displayed). The target move-out response behaves like a refracted seismic wave. This is a key feature requesting to use closer spacing and more data as well as time domain processing with marine data. It will allow direct imaging of the data and thus more operational decision can be made and the technology will move further in the reservoir life cycle.

Technology examples

Several geophysical methods can be derived by a combination of the transmitter and receiver location, which includes surface-to-surface, borehole-to-surface and surface-to-borehole. One of the techniques, surface-to-borehole electromagnetics (EM) system consists of a source located on the surface and an array of receivers located in a borehole. This method combines the technology of surface EM system and borehole logging tools (Krieghauser, 1997). The source emits an EM signal, a square wave, which propagates through the subsurface. The source can be aligned in various geometries and the borehole may be vertical, horizontal and deviated.

One example of the application of surface to-borehole EM is in the reservoir exploration and monitoring in Bakken formation, which is an important shale reserve play. In gas shale and tight gas reservoirs, accurate well bore positioning is crucial to optimize the production while keeping drilling cost at minimum. This key problem requires

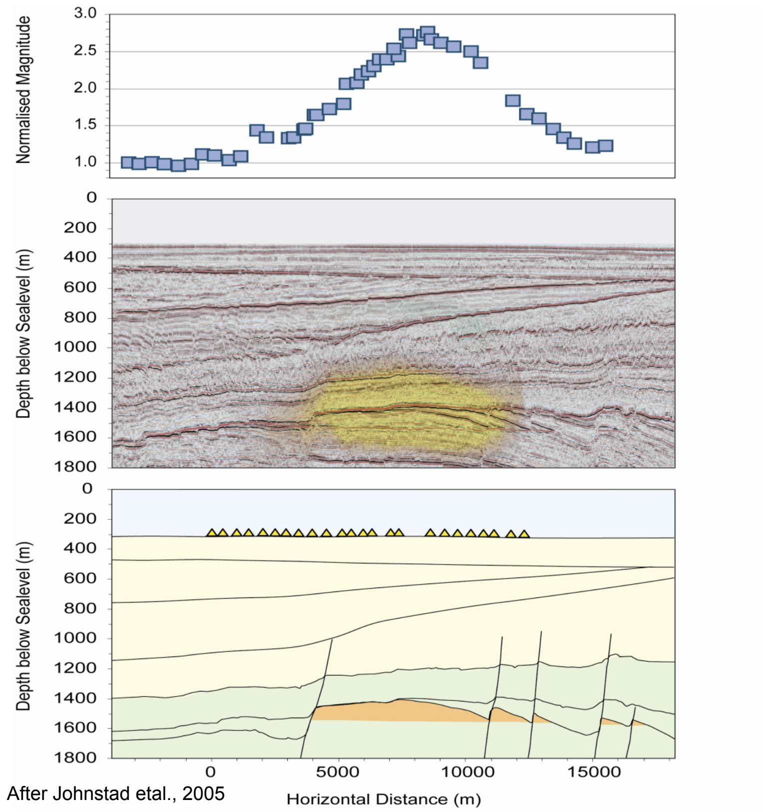

Figure 7: Example of a marine CSEM interpretation for the Troll field, Norway (after Johnstad et al., 2005). The top shows a magnitude versus offset curve, which exhibits an anomaly directly over the reservoir.

extensive use of logging while drilling (LWD) modeling and advanced geosteering technique based on electromagnetic method as shown in Figure 9 LWD data includes gamma ray, resistivity, density- neutron and sonic. The LWD real-time data is compared with the model to produce a cost-effective solution in driving the well bore to the target and keeping it within the tight and dispersed reservoir. The availability of high-resolution azimuthal resistivity LWD imaging tool along with 100% borehole coverage has brought the fracture characterization and formation evaluation to a higher level in unconventional plays.

We analyzed induction logs from the Bakken formation and built a 1-D geoelectric model. The model clearly showed the high resistivity layers are identified as the Upper Bakken and the Lower Bakken. After studying the 1-D models, we built a 3D model of Bakken formation using computer simulation for a Controlled Source Electromagnetic (CSEM) survey setup. The source was located on the surface of the Earth while the receiver was placed in the borehole. We observed the vertical component

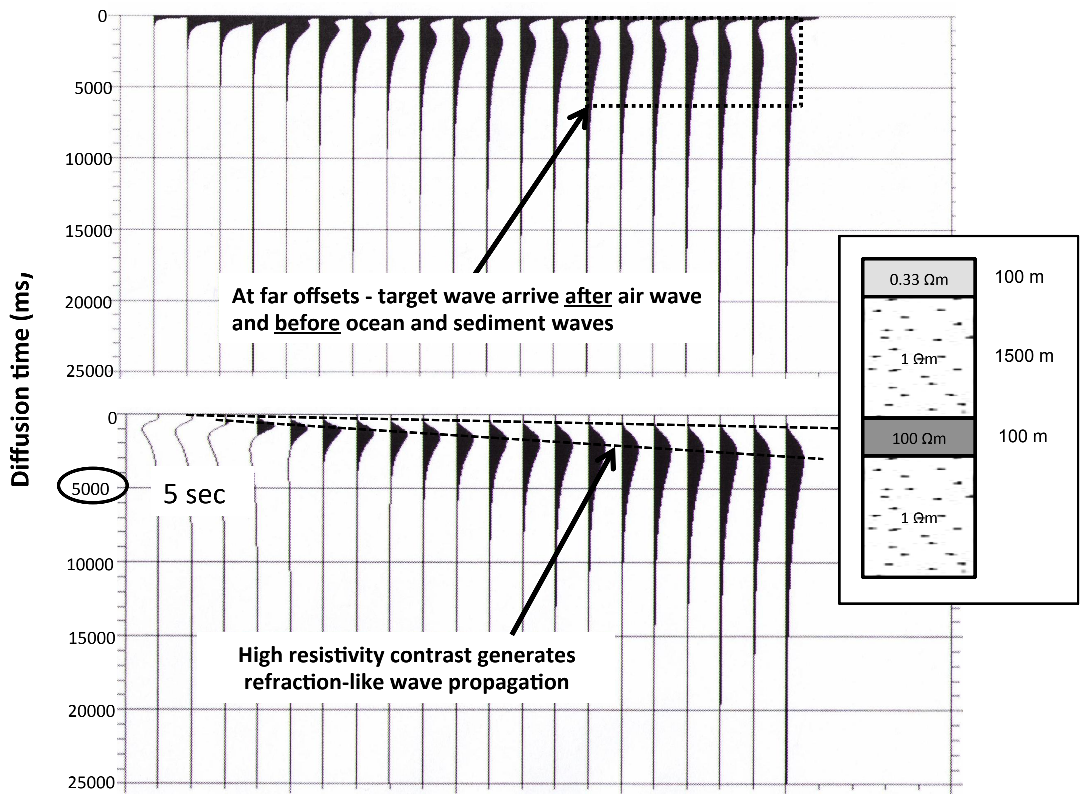

Figure 8: Common-source gathers for the impulse response of an inline electric field marine tCSEM™ setup. The normalized traces represent different offsets between source and receiver; displayed are measured voltages. The Earth model has an oil reservoir at 1,500 m depth below the seafloor. The top gather contains all wave components (air wave, ocean wave, sediment wave and target wave). The bottom gather only contains the reservoir response after removal of all other components. (After Allegar et al., 2008)

electric field, Ez at the receiver over the time when the reservoir is fully saturated with hydrocarbon. Figure 10 shows the electric field response (z-component, Ez) observed at the wellbore for Upper Bakken (left) and Lower Bakken (right) at time t = 0.268001 s.

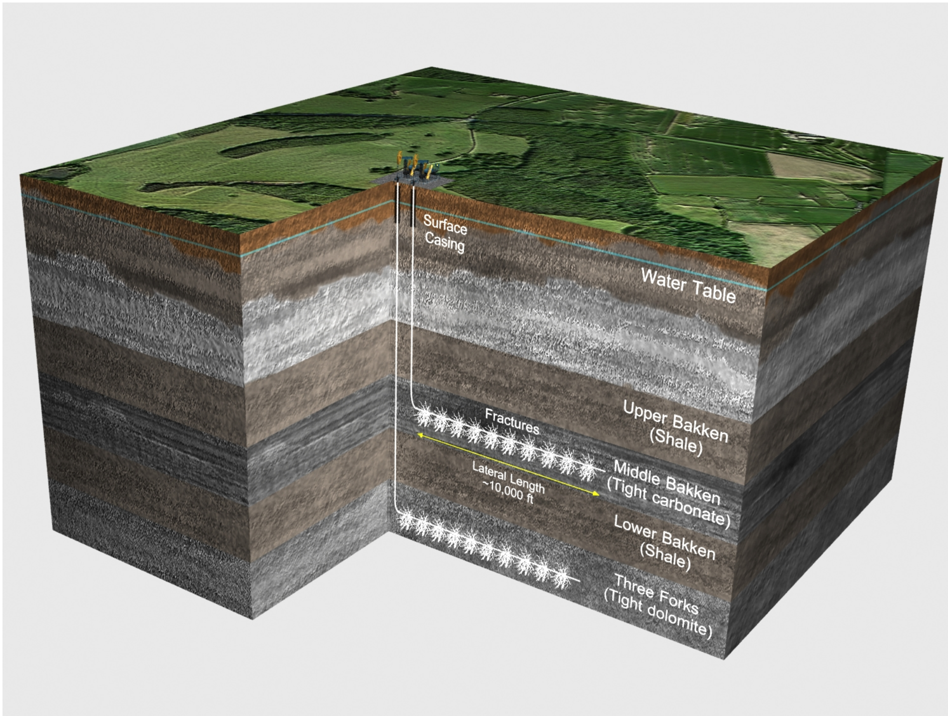

Figure 9: Sketch of a horizontal well in the Bakken formation used for the exploration and production in shale oil (After Statoil). The 3 Bakken formations are shown and the horizontal wells used for the development of the reservoir.

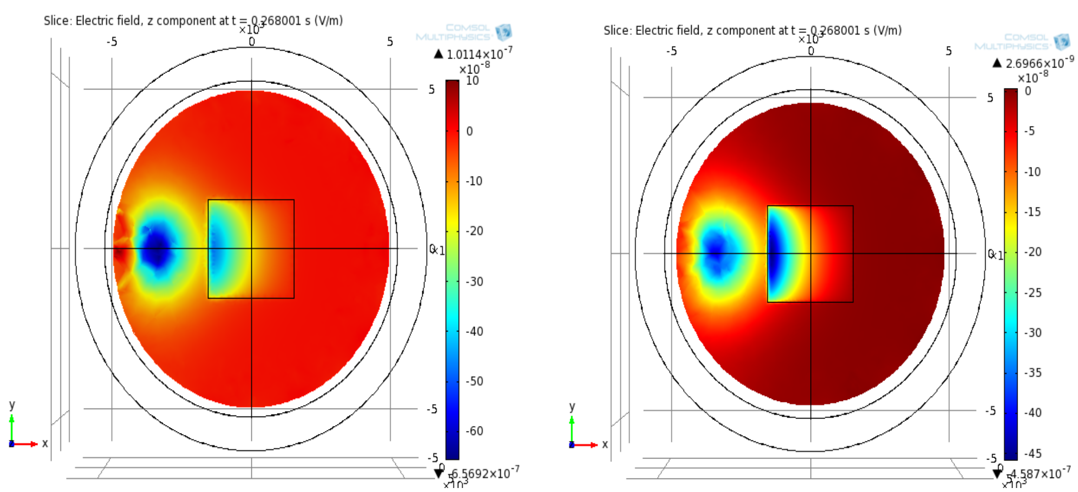

Figure 10: Electric field response of z-component, Ez observed at the wellbore for Upper Bakken (left) and Lower Bakken (right) at time t = 0.268001 s.

After seeing the needs for more denser or array data from the technology component side, we now look at two examples of difficult, but typical exploration problems where much denser data is beneficial. The first example is a sub-salt exploration problem where an additional drilling location around a salt dome was to be determined (Buehnemann et al., 2002; Zerilli et al., 2002). The issue was that reflection seismic data could not determine top of salt of the salt flanks or the structure below the salt. No electrical logs were available except for water well. The producing well site was to be used to drill a deviated well through the salt into a target area sub-salt (for environmental reasons). The survey location was near several major German cities and thus extremely electromagnetically noisy. Over the past several hundred years the near surface was many times re-cultivated and understanding the near surface from just surface expressions was not possible. This resulted of lengthy operation workflow derivation to determine operationally reliable electrode contact procedures. Over a period of 2 months over 300 sites were acquired, some of them 50 m spaced to control cultural noise (near rail road and through villages). This time included 2 weeks of survey operational parameter testing. A remote reference site was located several hundred km away.

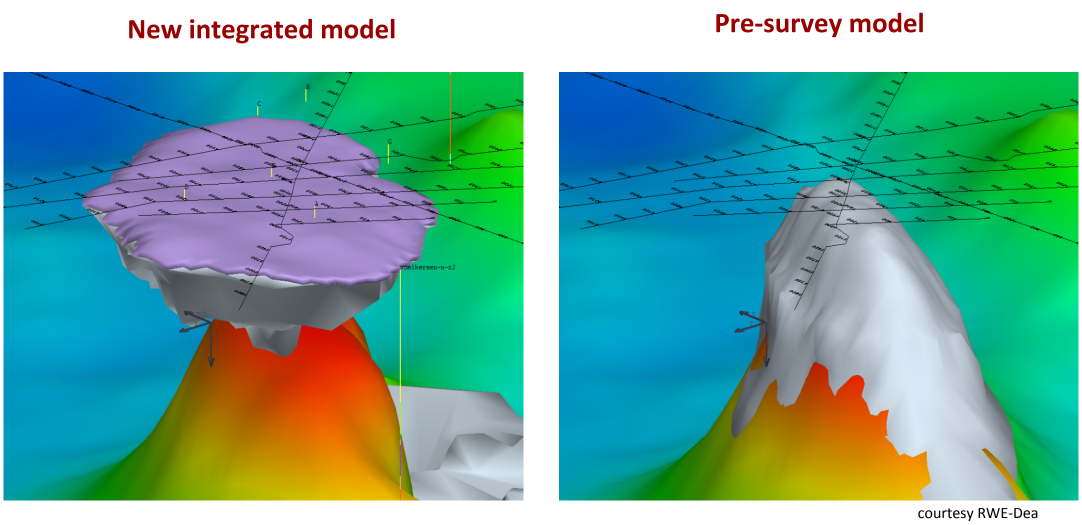

Figure 11: Interpreted images of the sub-salt exploration survey in Northern Germany. The interpretation integrates magnetotellurics with gravity and seismics (Buehneman et al., 2002). On the left is the interpretation AFTER acquiring and integrating the MT data and on the right the interpretation before the survey.

More detailed description can be found in Buehnemann et al. (2002) and Zerilli et al., (2002). Here, we are only showing a summery slide of the pre-survey and post-survey interpretation in Figure 11. The survey lines are indicated on the figure and the cross lines are the line with 50 m spacing with the other lines using 100 m spacing. Clearly, this would not have been possible with wider spacing, which is again a supporting argument for larger channel counts and array measurements.

The next example is from a success story from a reconnaissance geothermal exploration survey in Hungary. Here, magnetotellurics and gravity combined with vintage seismics was used to define early drilling locations (Yu et al., 2009). Magnetotelluric was done in low frequency and high frequency (Audio magnetotelluric) mode. The data was inverted first independently and then compared with the gravity inversion. Subsequent interpretation with the geology yielded a combined model where low resistivity and low-density anomaly coincided. For the entire survey throughout Hungary over 40 targets were defined in such a fashion. Next the vintage seismic data was integrated with the EM and gravity and the inversions were redone several times as the structural interpretation changed. This yielded finally the interpretation shown at the top of Figure 12. Subsequent drilling produced a 4 MW geothermal well with sufficient temperatures at approximately 1700 m depth.

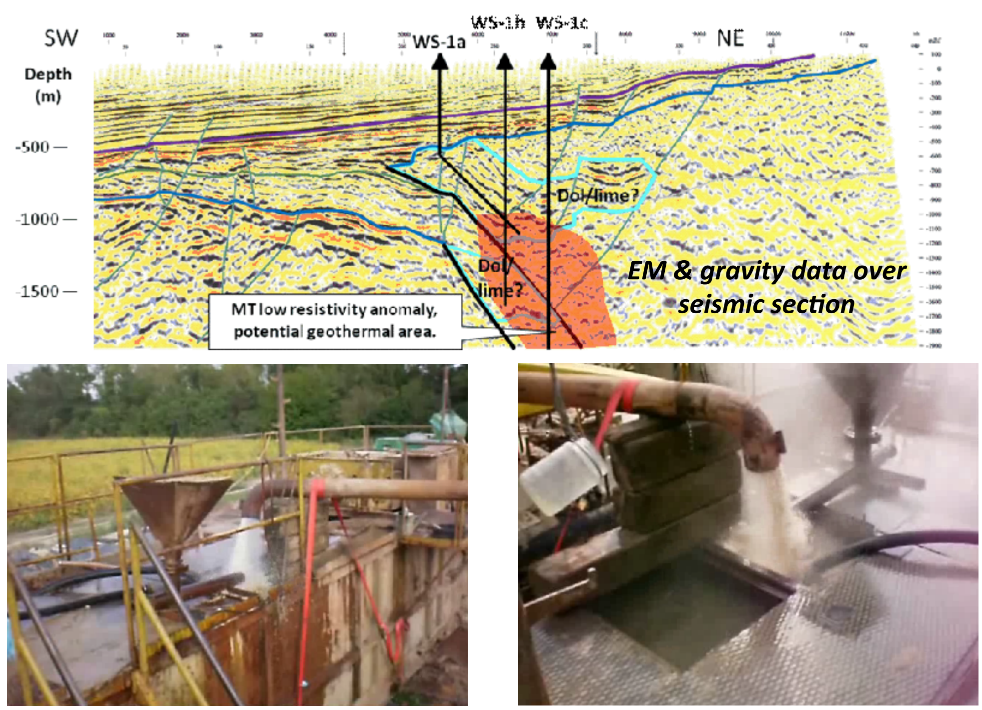

Figure 12: Integrated interpretation results from the integrated geothermal exploration in Hungary (Yu et al., 2009). The top of the figure shows the seismic section (vintage) with structural interpretation and resistivity anomaly superimposed. The bottom 2 pictures are from the initial flow test of the successful 3 MW geothermal well.

While this was done with vintage MT systems and larger spacing, the reruns of the interpretation and resulting lateral shifts of the anomaly clearly tell us that denser data or smaller array setups (like 9 or 25 sites patches) would have delivered the results faster. Now, when the power plant is being developed more wells will have to be drilled and denser measurements will be required as the resolution capabilities of sparse stations is not enough.

While the previous two examples involved a combination of MT and other geophysical techniques, the next example was purely done with MT. There was no other data available. We demonstrate an example from Magnetotellurics (MT) survey that was performed on 511-acre tract on the Eastern flank of Hockley Salt Dome. The test site is located 4 miles south of Hockley, Harris County, Texas, on the eastern flank of the Hockley Salt Dome. MT is ideal for conductive targets like sediment thickness or geothermal targets. We analyzed some aspects in MT investigation at the Hockley salt dome in the proximity of Houston. The close proximity of the salt dome to the city of Houston, power lines, a main road, an operating salt mine, and a rock quarry result in strong cultural noise. The noise and the multi-dimensionality make this an ideal test area for EM measurements. We carried out various measurements until we finally achieve an acceptable data quality. For a large frequency band, the apparent resistivity and the phase curves are consistent with the 2D geologic structure of the salt dome. Hence, this confirms that the structure of the salt dome is partially 2D. In the frequencies where it is not consistent we can assume 3D. We employed noise compensation techniques to further eliminate the systematic noise. As a result, we obtained meaningful and good quality data over 6 decades of frequency despite the presence of strong man-made noise. The survey results provide us with substantial empirical background information to perform 2D and 3D MT inversion as an initial estimate to interpret 3D structure of a salt dome. 3D inversion will be done using a newly developed code by Gary Egbert (Egbert, 1997), which is based on the non-linear conjugate gradient method.

Figure 13 shows the MT response collected from the survey over Hockley salt dome, Texas. The data extends over 6 decade of frequency from 0.01 Hz to 1000 Hz. The data was interpreted suing inversion and the overhang was inferred as shown on the right.

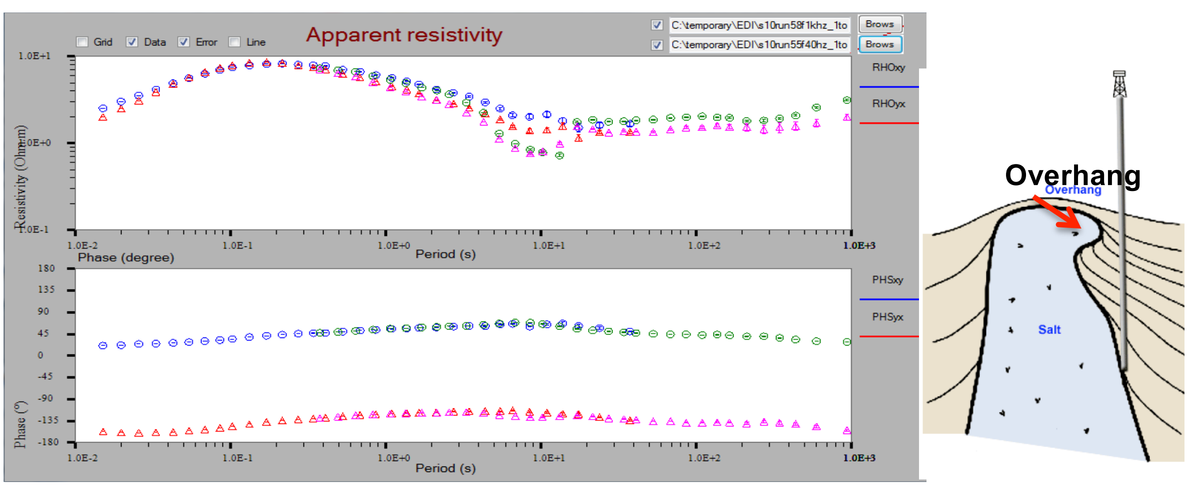

Figure 13: MT responses (apparent resistivity and phase curves) for sampling frequency of 1 kHz and 40 Hz acquired at Hockley salt dome. Hockley salt dome structure is shown on right of the figure.

Another example that describes the application of advanced EM on land is LOTEM survey in India in the late 1980s. LOTEM was used to image Mesozoic sediments below the Deccan Trap basalts in northwestern India (Strack and Pandey, 2007) as shown in Figure 14. A well drilled in the late 1990s confirmed the LOTEM interpretation, which was based on various 1D inversion methods and 3D modeling.

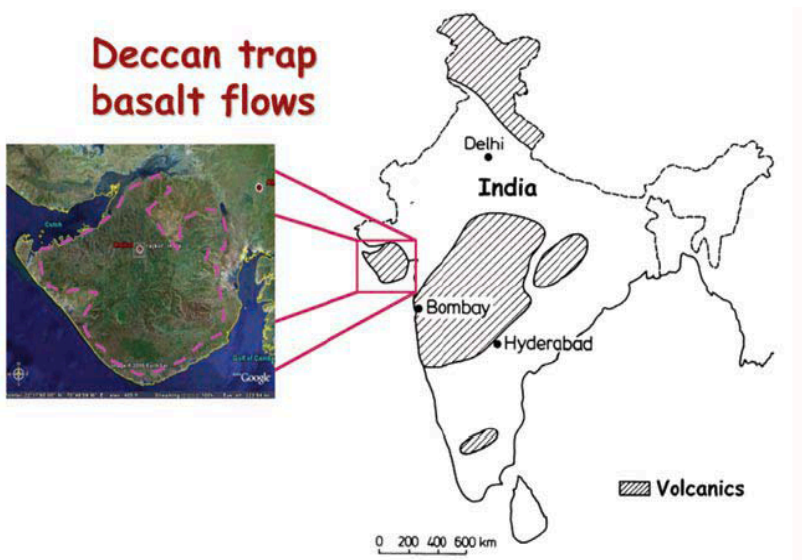

Figure 14: The LOTEM survey to image the sub basalt was conducted on the Saurashtra peninsula in northwestern India. The pink dashed outline on the satellite image on the left shows the basalt cover (Strack and Pandey, 2007).

Figure 15 shows the examples from various 1D inversions and images for a profile east of Rajkot that exhibits a dyke-like structure. The top profile shows the result from the layered inversion while the profile below it shows the Occam inversion results. The profile below it is the result of inversion based on apparent resistivity transformation and the most bottom profile shows the inversion result based on a spatially varying image current. On the left shows the picture of the surface outcrop. The outcome of this LOTEM survey proves CSEM ability to image thin resistive layers in the difficult geological area like basalt cover.

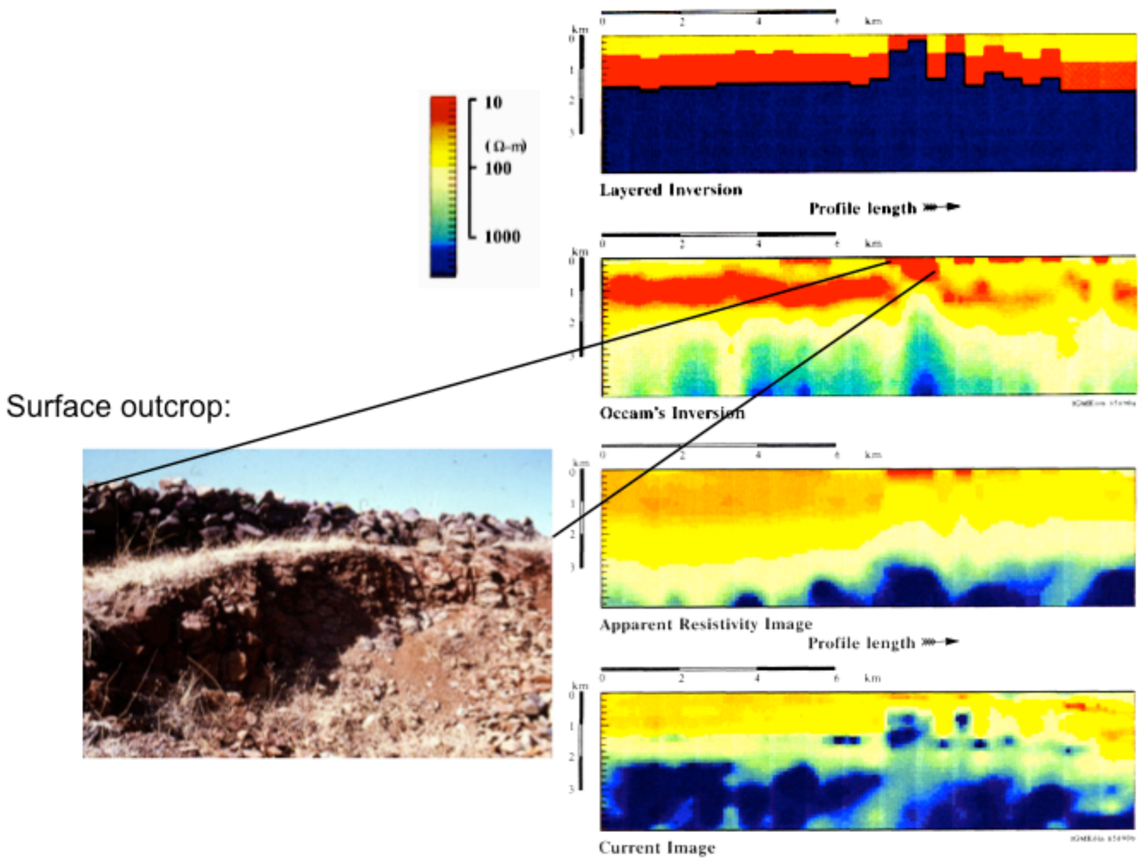

Figure 15: Examples of various inversions and images for a profile east of Rajkot that exhibits a dyke-like structure. The top two diagrams on the right show the layered and smooth inversion results. The bottom two diagrams show different inversion images, one based on apparent resistivity transformation and one based on a spatially varying image current. On the left is a picture of the surface outcrop (Strack and Pandey, 2007).

Reservoir monitoring

Reservoir monitoring is a technique used to observe changes in the hydrocarbon or geothermal reservoir geometry and also the pore-fluid properties and saturation that occur during the production. This method of observation is a critical part the reservoir management in order to estimate extraction efficiency and quantify remaining reserves. The strong distinction in the resistivity between the water-bearing formation and oil-bearing is the foundation of the reservoir monitoring concept (Hu et al., 2008). Reservoir monitoring is mainly used to observe the changes in the resistivity in the formation after oil being removed from reservoir by flooding with water or steam. What we are observing is the flood front, which is the edge of oil zone. Flood front moves about 100 m per year and it marks the resistivity contrast and it is easier to observe it at different times.

In reservoir monitoring, understanding the movement of water-floods and steam-floods is very crucial. Proper placement of sensors in the borehole results in more effective reservoir monitoring because we can achieve a higher resolution than having the sensors on the surface. Changes in resistivity are derived from the changes the voltages recorded from the induction tools. All of the increase the hydrocarbon mobility during Enhanced Oil Recovery (EOR) and thus increase significantly the electron flow and increase electrical conduction resulting in significant resistivity drop. (Strack and Aziz, 2012). It shows a significant resistivity difference when we flood the reservoir either with water or steam. For instance, Figure 11 shows an example of time lapse through Casing Resistivity (TCR) logging. Two separate logging operations from different contractors were compared (Zhou et al., 2002). Figure 16 shows an example of resistivity changes that can be observed in a reservoir before and after the reservoir has been flooded. The left track shows the deep induction (black curve) with the two TCR measurements (red and blue curves). The right track displays the differences between the two TCR measurements. It is obvious the two measurements are consistent but it can be seen that one of the tools has lower vertical resolution. Hence, steam flooding makes local changes in resistivity that is large enough to be easily detected.

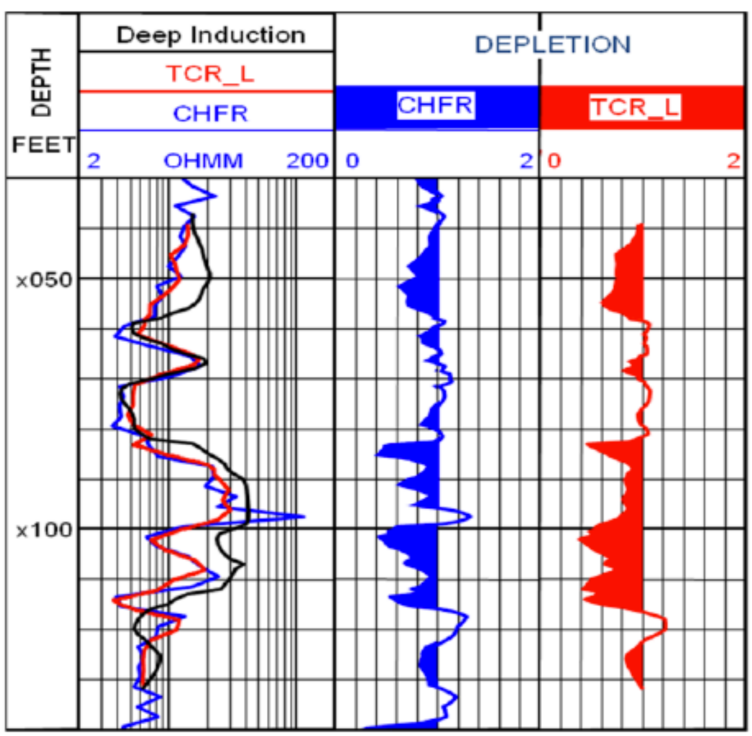

Figure 16: Steam flood has reduced 80 Ω-m reservoir resistivity to 40 Ω-m, black curve represents reservoir resistivity before flooding and red and blue curves represent the resistivity after the reservoir has been flooded (Zhou et al., 2002).

The next example is a feasibility survey to monitor a reservoir by injecting steam or water with the use of time domain CSEM in China (Hu et al., 2008). A pilot survey of array time domain CSEM was carried out over steam driven heavy oil reservoir. In the survey, a grounded dipole transmitter of 2 km length and offsets between 5 – 10 km were used. Source waveform is square wave with period of 8~32s.
Distances between survey sites and survey lines are 100~150 m, totally 13 survey lines and 180 sites were carried out. Measurements were repeated after about 5 months during 2006. Figure 17 shows the two time-lapse recordings displayed as apparent resistivities. The time-lapse apparent resistivity difference was color coded, positive means hydrocarbon influx while negative means brine influx. As we are dealing in this case with a steam injection it means for negative (blue) that the steam is moving fast and for red/purple that the steam is moving slow. The key for the success for this survey is because the bottom of the reservoir is 400 m deep. If the reservoir is deeper, the signal received at the receiver will be negligible and surface measurement fails detect the anomaly.
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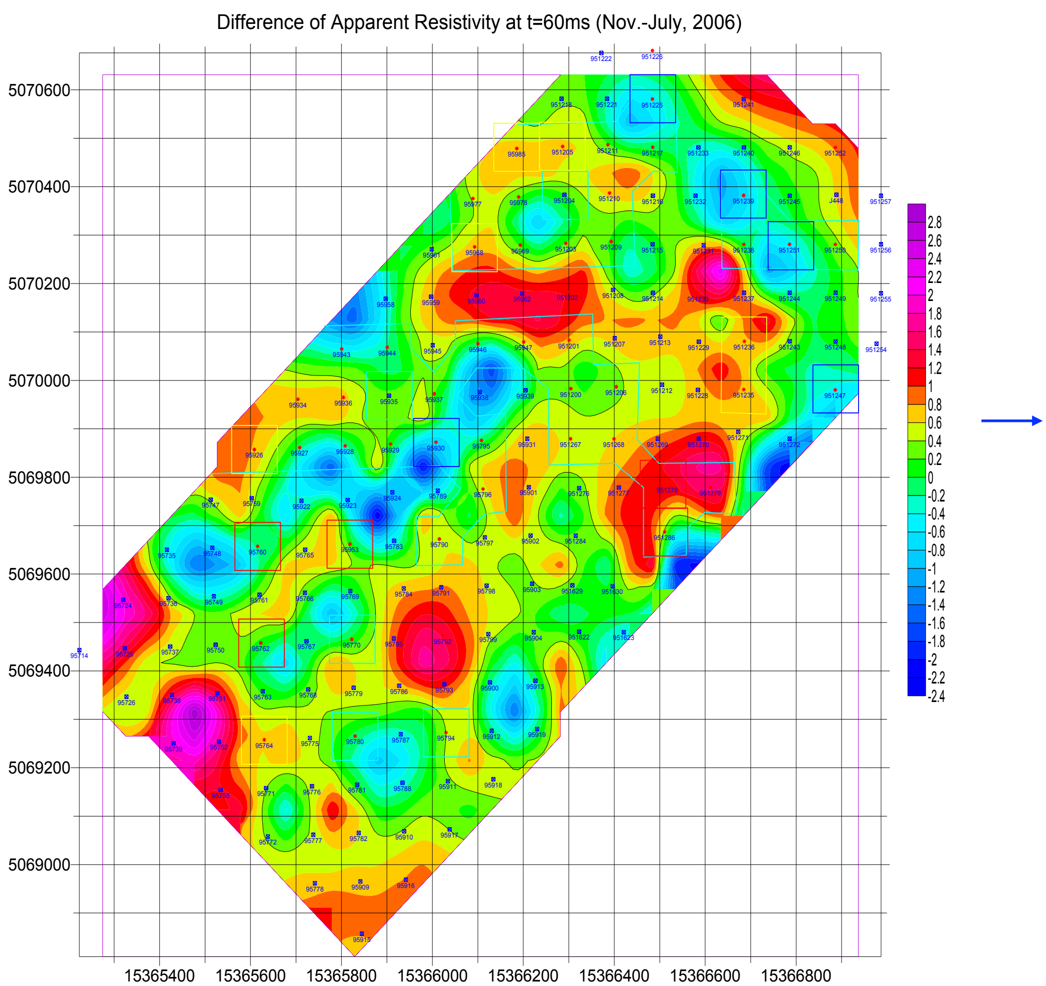

Figure 17: Time lapse difference map in terms of apparent resistivities from the steam flood driven reservoir monitoring example from China. (Hu et al., 2008).

Over the past 15 years the need for permanent sensors has become clear to the Industry. Unfortunately, due to the existing business model, it has been difficult to adapt new business models and make permanent sensors a viable business. Only recently have the large service companies been able to have profitable sensor division mostly in temperature and pressure measurements and completion hardware. Feed forward geophysical sensors are still in the beginning though the need is getting obvious. (First Break, Sept. 2011, report on reservoir monitoring). Among the sensors are seismic, gravity and electromagnetic sensors. Here, we focus on electromagnetic sensors and assume that automatically seismic sensors will be included as the data needs to be integrated into the 3D seismic cube. Gravity sensors are less important as the density is intrinsically included in the seismic impedance (Strack, 2010).

Our original concept included starting with natural field and then adding as needed controlled source and borehole measurements (Strack, 2004). One measurement alone is not enough to accurately image the subsurface of interest; therefore we need to combine the surface measurement with surface-to-borehole measurements. As a result we will be able to achieve a full field fluid monitoring concept. Surface-to-borehole is suitable for resistive targets such as hydrocarbon reservoirs. We have since deviated from this concept as it we have learned from feasibilities that surface EM measurements in general has low resolution to deeper reservoir changes. Natural field will have even lower sensitivity than controlled sources. In addition the time-lapse changes in a reservoir are mostly three-dimensional and thus the corresponding anomaly is even about one decade smaller.

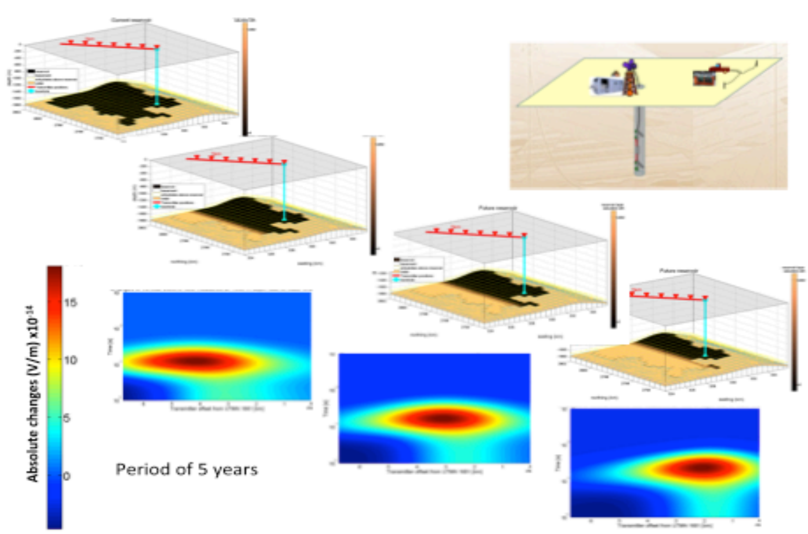

Figure 18: Simulated response of surface-to-borehole EM for 4 time steps over a period of 5 years (Colombo et al., 2010). For 3 of them the surface-to-borehole anomalous response is shown.

Figure 18 shows an example from feasibility in the Middle East (Colombo et al. 2010). Here the time-lapse model was derived from different reservoir simulator time steps and appropriate fluid substitution in the induction logs. Using different time steps and building the differences yielded a difference model of 'removed oil'. This model was then used to model surface-to-borehole and surface-to-surface measurements. Only the surface-to-borehole measurements gave reasonable anomalies as the target was below an anhydrite layer.

In the figure we see on the top right the survey layout. A transmitter with several tens of amperes is used (though for modeling purposes everything was normalized to unity values). The receiver array is at about 1900 m depth below an anhydrite layer. The feasibility is for the Ghawar field test site. Source positions are placed in a circular array with a walk away test. The 3 images are for this walk away test. The four beige and dark brown horizontal slices are reservoir simulator driven removed oil projections, which build the underlying models for the color images. We can see that with increasing time the oil in this depth slice is getting less and we also see that the images reflect this (the red anomaly is moving to the right). The anomaly is still relatively low, which is why the test has so far not been carried out.

Another example to highlight that surface-to-borehole can be used in the geophysical industry is in shale exploration. Shale as has been known is an unconventional resource and it can provide a long-term supply of extreme and continuous energy demand in North America. Although the shale resource is immense, exploiting its full potential will require development and further refinement of a number of technologies including reservoir monitoring. Monitoring the reservoir allows us to enhance the understanding of the extent of shale reservoir system and as a result we will be able to enhance the existing production. Various geophysical data play a big role and will reduce the ambiguity to accurately image the subsurface. Accurate 3D geophysical can be generated by building 3D geophysical models that will generate synthetic data (Kumar and Hoversten, 2012). Well log, CSEM, MT, and seismic data are among other measurements that can be used to accurately map the subsurface. 1D Seismic and electromagnetic (EM) model were used to model a shale gas reservoir in Bossier/Haynesville formation in East Texas (Kumar and Hoversten 2012). They built a 1D resistivity model of a reservoir and a background model with a resistivity value of 9 ohm-m based on the well log data (Kumar and Hoversten, 2012). The reservoir model is a shale gas and buried at 3 km depth with a resistivity of 30 ohm-m. They showed the difference in MT responses (both apparent resistivity and phase) between the background and the reservoir and the result shows there is almost **no difference** in MT responses between the reservoir and the background models (Kumar and Hoversten, 2012). This tells us that MT is not the potential candidate to identify the resistive structure.

Since MT is more suitable for a conductive target, CSEM is more useful to identify a resistive target. Buried shale gas reservoir has a much higher resistivity compared to the background resistivity (Kumar and Hoversten 2012). So CSEM is a better candidate in this scenario than to use the natural field MT. They compared the difference between the reservoir effect and the background and it is found that there is up to15% difference in horizontal electric field in time domain and up to a 10% difference in the frequency domain (Kumar and Hoversten, 2012).

We found the similar results for the Bakken for the model shown in figure 9. Figure 20 show the results of a time-lapse simulation of 10 % depletion of this horizontal well. The anomaly is in the 5% range, which is big for long recording times (several days). Figure 19 is display on the time basis of the measure time domain data to see when the reservoir influence appears and when it reaches its DC value. The range of reservoir depletion is marked at the bottom of the figure.

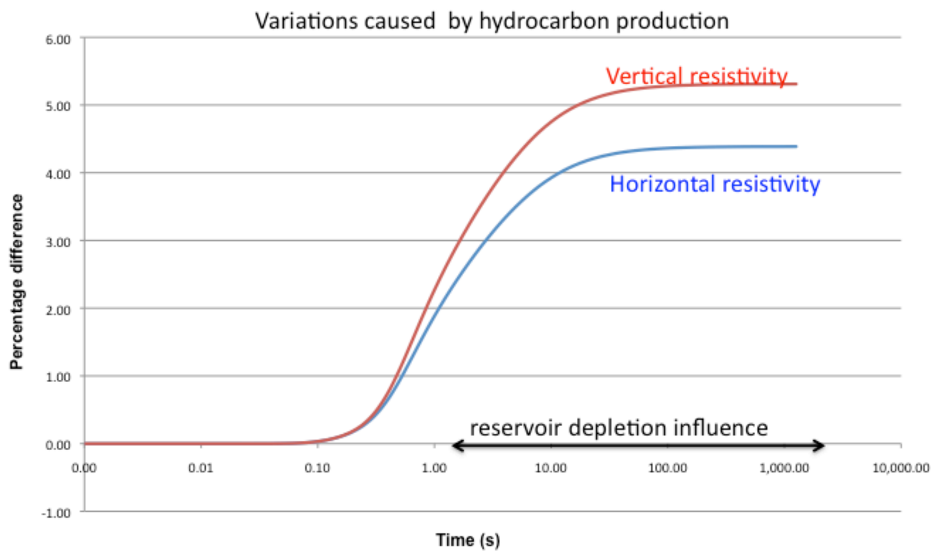

Figure 19: Time lapse simulation result of 10 % depletion of this horizontal well. The anomaly is still in the 5% range, which is big for long recording times.

Conclusion

We started out with stating that the real value of electromagnetic methods lie in enhancing the image in the 3D cube. This means we need to take the techniques closer to the reservoir. Land methods will be better tied to borehole measurements if made more commonly available at larger data density and quality.

- Applying designs and workflows closer to seismic have shown improved images onshore as well as offshore.
- The integration the various EM measurements with calibration data such as well logs has been technically solved with the introduction of the 3D induction log that now allows proper up scaling as is customary during field studies.

- Last but not least cost reduction in hardware is required to allow more and denser measurements and imaging techniques with faster turn-around time. New array acquisitions systems address this issue.

Several feasibilities have shown that of these solutions together with proper reservoir analysis and sensor technology allow taking this integrated technology (combine with seismic!) to a real field trial. Time-lapse reservoir monitoring is very important in reservoir management and it has advanced rapidly over the past decade due to the advancement of technologies like transient electromagnetic and integration of various data from different measurements. To complement the traditional existing seismic method, an electromagnetic signal is strongly influenced by the fluid content due to the large differences in the electric resistivity of water and hydrocarbons. To monitor a reservoir, we use surface electromagnetic measurements and borehole measurement. We look into the use of array electromagnetic concept, which is similar to array seismic on land that integrates the surface and the borehole measurements to enhance the monitoring of the fluid movement in a hydrocarbon reservoir. To implement the array concept in hydrocarbon reservoir monitoring, we first utilize surface electromagnetic measurement that can be done using magnetotellurics (MT). To achieve a higher accuracy, we then combine the surface measurement with surface-to-borehole measurements. As a result we will be able to achieve a full field fluid-monitoring concept. From the case histories, we can see that surface measurement data like MT response has a low resolution if compared to surface-to-borehole measurements. Therefore, an integration of more than one measurement information is still a key to the accuracy in illuminating the subsurface that is important in a meaningful reservoir monitoring. However, while surface data will give us the integration in the 3D cube and interwell space, it will have low resolution and surface-to-borehole measurements are required.

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