

## 4-D seismic and time-lapse reservoir geology

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### ABSTRACT

In recent years, 4-D seismic has developed into a sophisticated technique of reservoir monitoring and management relying on the integration of geologic models, static and dynamic properties of reservoir rocks and fluids, and detailed production and pressure field data. Current geophysical and engineering studies tend to emphasize discrimination of clearly time-variant partial fluid saturations and pressures from 4-D data. However, common geological processes such as production-induced compaction for the case of unconsolidated to poorly consolidated sediments, and steam-induced mineral precipitation, for the case of steam stimulation projects, cannot be assumed to be time-invariant. Both of these mechanisms may strongly influence porosity, density, and permeability variations during the life of a 4-D project.

Other geological characteristics and processes may not change at small time scales, but they are closely linked to reservoir porosity and permeability magnitudes and distributions, themselves key factors controlling fluid flow and pressures. Hence, successive 3-D seismic images of these geologic parameters will very likely change in a diagnostic fashion during production and depletion of a reservoir. Appropriate examples are the well-known heterogeneity of typical reservoir intervals, the geometry and sealing properties of faults, and the role of hydrocarbons as a control on cementation and porosity development above- and below oil-water contacts. Careful consideration of these factors will make key contributions to the success of 4-D seismic projects.

### INTRODUCTION

The feasibility of time-lapse 3-D, better known as four-dimensional (4-D) seismic, began to be evaluated over a decade ago when petrophysical studies showed that certain acoustic properties of rocks are affected by changes in temperature, composition, density, and pressure of pore fluids that commonly occur during the production of hydrocarbon reservoirs (Nur, 1989; Wang et al., 1991; Batzle and Wang, 1992). The first field-scale applications exploited the extreme contrasts produced by high temperature/pressure and low density of gases injected during enhanced recovery operations of heavy oils, as for *in-situ* combustion fire flooding and steam stimulation (Greaves and Fulp, 1987; Eastwood et al., 1994). Initially the technique was tested with small-scale pilot projects as in the Duri Field, Indonesia (Jenkins et al., 1997), or using data that ‘happened to overlap’, and was not designed for strict comparisons of seismic response as in South Timbalier Block 295, Gulf of Mexico (Burkhart et al., 2000). More recently, 4-D has evolved into a very promising, intensely investigated technique, applied to the monitoring and management of reservoirs with frequencies of acquisition as high as 8 months (Duri Field, Indonesia),

or 1–4 years as in the Foinaven, Schiehallion, and Loyal Fields, West of Shetland (Moore et al., 1999; Whitcombe et al., 2001).

Currently, the main objective of 4-D seismic projects is to image the effects of fluid flow in a producing reservoir by relating changes in amplitude, velocity, impedance,  $V_p/V_s$ -ratio, etc., to corresponding changes in fluid pressure and/or saturation that can in turn be related to reservoir drive mechanisms such as solution gas or water drive, and the corresponding, ‘traditional’ field production data (*e.g.* production and/or injection rates and volumes, pressures in and around wells, composition of produced fluids). The information obtained can be used qualitatively, to simply document where/when changes are occurring, or quantitatively, by iteratively using the 4-D data to optimize a reservoir simulator model; the latter could in turn be used in forward modelling of synthetic time-lapse realizations that can be compared with real time-lapse data as it is acquired periodically during the life of a field (Waggoner, 2000).

Comprehensive reservoir characterization is required for 4-D projects from the start, integrating: (1) a geologic model based on the initial ‘baseline’ 3-D seismic survey and available well information; (2) static and dynamic properties of reservoir rocks and fluids measured from cores, geophysical logs, and well tests; and, (3) detailed field production and pressure data. The resulting reservoir model constitutes the best possible input to determine whether subsequent 4-D monitoring is feasible or not (Khan et al., 2000; Vidal et al., 2000). Reservoirs involving changes in free-gas saturation (such as injected steam, methane or CO<sub>2</sub> projects) can rely on large seismic impedance contrasts, but oil-water systems are increasingly hard to monitor if they are undersaturated black oil contained in very indurated, cemented (‘stiff’) low-porosity reservoir rock, compared to more easily tracked volatile oils in soft, unconsolidated and porous sands (Fanchi, 1999; Lumley, 2001).

Fluid-flow variables such as saturations and pressures are highly variable during production, and current research tends to emphasize experimental and/or analytical discrimination of these effects from 4-D data (Fanchi, 1999; Landrø, 2001). In most cases, geological processes are assumed to be invariant, and time-lapse seismic images are interpreted only relative to time-variant changes in fluid flow (Lumley, 2001). However, prior to interpreting 4-D difference images as a function of fluid-flow changes, “in which, to first order, the geology part subtracts out” (Lumley, 2001, p. 51), efforts must be made to account for the complexity of geological parameters as fully as possible, within the known constraints of the underlying, ‘static’ 3-D data.

The above provides the rationale for this review, in which I will briefly illustrate examples of two types of geological reservoir parameters that may be of significance in the calibration and interpretation of 4-D data. The first type are examples of geological mechanisms that produce changes in the physical framework with concurrent effects on compressibility, porosity and permeability at the time-scale of reservoir production, mainly: (1) sediment compaction, and (2) steam-induced mineralogical changes. A second type are examples of geological features or characteristics that, although time-invariant, are expected to affect the response of successive 3-D seismic acquisitions, and are hence clearly important to 4-D

interpretation: (3) heterogeneity of the reservoir interval; (4) geometry and characteristics of faults; and, (5) porosity at oil-water contacts.

### COMPACTION

Many deepwater Gulf of Mexico (GOM) reservoirs are unconsolidated or slightly consolidated Miocene- to Pleistocene-age turbidite channel sands, commonly highly overpressured before production. Hoover et al. (1999) studied such a reservoir at South Timbalier Block 295, offshore Louisiana, combining pre-production (1988) and syn-production (1994) seismic data with production history and wireline log data. As typical of GOM reservoir sands, they have lower velocity and density than the bounding shales, and based on a dimming of seismic amplitudes between 1988 and 1994, Hoover et al. (1999) conclude that the time-lapse seismic data imaged a relatively uniform water sweep from west to east over most of the reservoir (Figure 1). The decrease in seismic amplitudes is greatest in the area of thickest and highest-quality sands, and the authors attribute the lack of seismic dimming in some parts of the reservoir to poor drainage of lower-permeability lithofacies, as well as failure to image the smaller changes in amplitude corresponding to reservoir zones with less than 10 m of net pay thickness (Hoover et al., 1999). The proposed interpretation is certainly feasible, however, the dimming of seismic amplitude may have in-part resulted from reservoir compaction, also expected to be most significant in the thickest, most porous intervals, as observed.

A variety of unconsolidated GOM turbidite samples were recently tested for the effects of compaction on porosity and permeability (Ostermeier, 1995). Among the results, Ostermeier (1995) showed that: (1) pore volume compressibility varies in magnitude and stress dependence, and these variations appear to be controlled by sand texture (grain boundary types) and mineralogical composition (rigid vs. labile minerals), Figure 2; and (2) compaction affects both porosity and permeability significantly, and based on oil permeabilities at initial water saturations ( $S_{wi}$ ), the relative reduction in permeability is 4-5 times greater than that of porosity, Figure 3.

Clearly, compaction and the resulting effects on porosity and permeability should be accounted for in unconsolidated or poorly consolidated sands. When applied to South Timbalier Block 295, the potential effects of compaction could be interpreted to indicate that, relative to the conclusions of Hoover et al. (1999), the thick, porous sands had not been drained as extensively, and more oil had been drained from the thinner, less permeable sands. Clearly, such an interpretation would have very different implications regarding recommendations for the location of infill producers or water injectors to optimize continued reservoir development.

Shyeh et al. (1999) studied similar sands in the GOM Lena Field, accounting for changes in porosity and saturated-rock velocities with changing reservoir pressure based on experimental data by Dvorkin and Nur (1996). Shyeh et al. (1999) observe that velocity and impedance are almost unchanged in water-swept oil sands because of compensating effects of water displacing oil with trapped gas and compaction; a large change in impedance occurred only between the original oil leg and the gas-invaded oil.

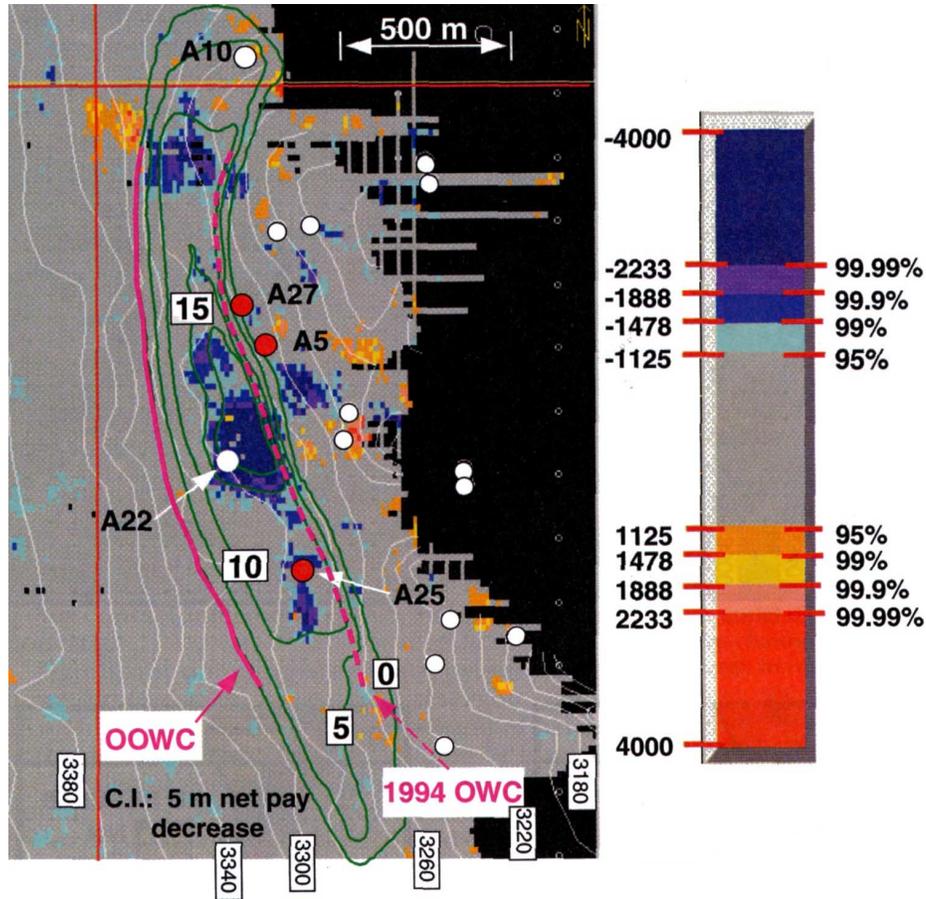


FIG. 1. Map of average amplitude difference between two seismic surveys (1994-1988); Figure 15 from Hoover et al. (1999). Producing wells are labelled A5, A25 and A27. The dark contours are the decrease in net pay thickness between 1988 and 1994. Areas of strongest dimming correlate to the thickest portions of the drained reservoir. Reprinted by permission AAPG©1999.

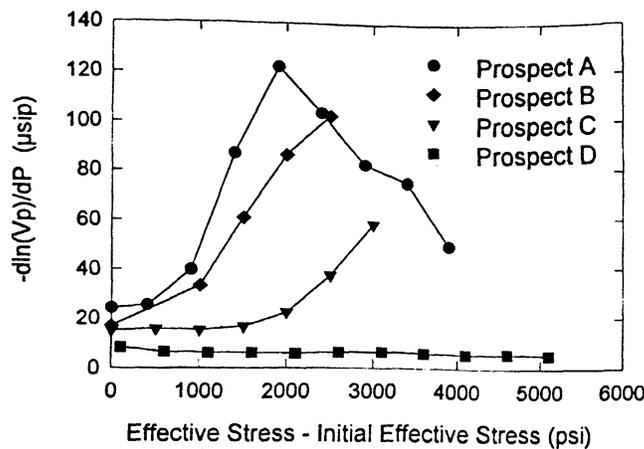


FIG. 2. PV compressibility vs. effective isostatic stress for various prospective reservoir sands, showing large contrasts in compaction response, with significant creep and rapid increase in compressibility's in Prospects A and B, and essentially no creep and lowest compressibility's in Prospect D (Figure 12 from Ostermeier, 1995).

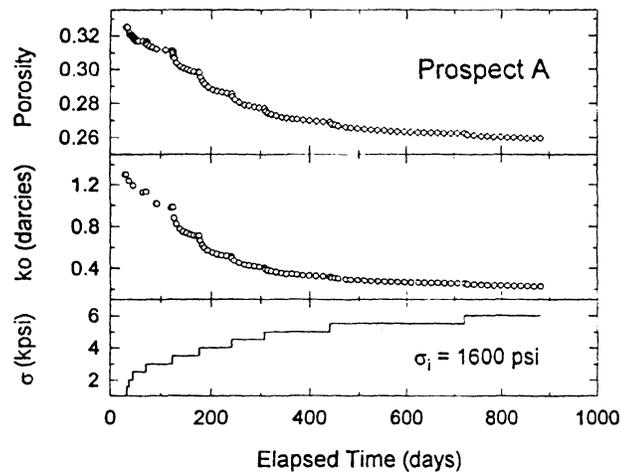


FIG. 3. Measured porosity and oil permeability at  $S_{wi}$  vs. time in response to stepwise increases of applied isostatic stress; data is for a sample of Prospect A, also depicted in Figure 2 (Figure 15 from Ostermeier, 1995).

### STEAM-INDUCED MINERAL REACTIONS

Ongoing steamflood projects at Cold Lake, Alberta, Canada and Duri Field, Indonesia utilize steam to reduce the viscosity and enhance production of the heavy oil/bitumen reservoirs. The injected steam contacts the reservoir rock at high temperatures and pressures, at more than 180°C and 3–10 MPa (Eastwood et al., 1994; Waite et al., 1997). Modelling and laboratory studies have been carried-out on the effects of cyclic steam stimulation on sands of the Clearwater Formation, the reservoir rock at Cold Lake. The results demonstrate the occurrence of various mineral dissolution and precipitation reactions, and particularly the growth of smectite appears to be related to a significant reduction of porosity, by  $\geq 10\%$  in the steam-injected interval (Sedimentology Research Group, 1981). Permeability in those intervals is reduced by at least 50–60%, and by more than 90% in intervals with the greatest content of authigenic smectite, the latter apparently controlled by the pH of injected steam (Kirk et al., 1987; Fialka et al., 1993).

Evidently, aside from commonly expected fines migration, neogenetic clay growth is another factor affecting fluid flow, and its potential effect on porosity and permeability should be considered part of a time-lapse steam-stimulation model. Although specific mineral products will vary with the composition of reservoir rock, perhaps chemical characteristics of injected and produced steam could be monitored (*e.g.* pH, salinity, composition) and used to infer mineral reaction rates and associated effects in the reservoir.

## HETEROGENEITY OF THE RESERVOIR INTERVAL

To some degree, all reservoir intervals are heterogeneous and in this section heterogeneity refers to those reservoir interval attributes that introduce variability in the corresponding seismic signal including geometry (*e.g.* thickness and thickness variations, shape, lateral extent), lithology (composition and multi-scale structure of the grain framework), interval boundaries (*e.g.* sharp vs. gradational contacts with bounding lithologies), and porous framework (porosity, pore network geometry, and permeability). The inherent limitations of the seismic signal and derived attributes to detect and discriminate these heterogeneities are mostly known, and they apply equally to 4-D seismic data. For instance, the vertical resolution of 4-D difference images cannot improve on that of the individual 3-D time-lapse acquisitions. Of interest to the 4-D interpreter is the notion that fluid saturations of a producing reservoir do not change homogeneously and instantaneously, but require fluid flow through an anisotropic and heterogeneous permeability field to change significantly enough to be imaged. To the extent that 4-D seismic can be applied to discriminate between pressure and fluid saturations, successive 3-D seismic images and difference maps may reflect reservoir heterogeneities not detectable previously (pre-production).

There are many examples of the influence of reservoir heterogeneity on the interpretation of 4-D seismic or, similarly, on any other type of reservoir model. In the 4-D study of South Timbalier Block 295 mentioned above (Hoover et al., 1999), it is the lower permeability of thinner and inadequately imaged channel margin/levee and overbank lithofacies, that introduces the major uncertainty in the interpretation of fluid distribution. Leach et al. (1999) recently carried-out a study to plan the development of Paleocene-age turbidite channel sandstones of the Schiehallion Fields, West of Shetland. After the interpretation of an initial 3-D survey in 1993, the authors concluded that the following were among the key remaining uncertainties: (1) the extent and thickness of thin-bedded channel margin or overbank sandstones with a potential of about 10% of additional OIP (about  $34 \cdot 10^6$  bbls); (2) the presence of local, high-permeability pathways and relative permeability influenced by the presence of ductile minerals; and, (3) variable initial water saturation ( $S_{wi}$ ) controlled by mineralogy and associated microporosity (Leach et al., 1999).

Amplitude maps derived from additional 3-D surveys over Schiehallion Field in 1999 and 2000, are consistent with the apparent lack of connectivity between one of the injector-producer pairs as demonstrated by production and pressure data, and have allowed interpretation of an intervening, previously undefined baffle or barrier to fluid flow (Saxby, 2001). Another injector-producer pair, thought to be connected based on R.F.T. measurements at the time of development drilling, resulted in an apparently compartmentalized producer with low rates and flowing pressures, and a high GOR (Parr et al., 2000). Eleven months later, and just prior to the 1999 acquisition, the producing well began flowing at higher, consistent rates with a reduction in the GOR, apparently reflecting an improved connectivity imaged with the 4-D (Parr et al., 2000). The events described may have been a function of the tortuous, very heterogeneous fluid flow pathways between the two wells, not represented by the consistency of the measured fluid pressures.

## **FAULTS**

Similar to the reservoir heterogeneities described above, faults can be identified on a single, 'static' 3D image, as long as they are of sufficient size, juxtaposing highly contrasting layers or representing a fault zone that can be imaged due to a contrast in density, porosity and/or lithology relative to adjacent strata. With 4-D seismic it may be possible to enhance the imaging of large faults and allow the definition of smaller, previously undetermined faults, based on the pressure and/or saturation contrasts that develop during production of a reservoir. Furthermore, once a fault is identified, trends in fluid pressure established during the life of a 4-D project should aid in establishing the sealing characteristics of a given fault. One aspect to consider in this regard is that sealing characteristics of faults may be variable in space (along strike and downdip) as well as time. Based on an example of a growth fault in South Eugene Island Block 330 Field, offshore Louisiana, Losh et al. (1999) have shown that the permeability of the fault zone is a function of effective stress, that may be reduced sufficiently by ascending high-pressure fluid to produce a transient increase in permeability, that in turn will allow fluid transfer into relatively low-pressure sands across the fault. As dynamic as this process may be at geologic time scale, whether or not sufficiently high fluid pressure differentials can locally be reached during the life of a 4-D project is an intriguing question.

4-D reservoir monitoring has been applied successfully in Foinaven Field, West of Shetland, targeting north-northwest to northwest-trending Paleocene turbidite channel reservoirs, similar in style to those at Schiehallion; Figure 4 (Cooper et al., 1999). Figure 5 shows the published amplitude maps on top of the T32 reservoir for the 1995 and 1998 surveys; Figure 5 (O'Donovan et al., 2000). On the 1998 amplitude map, acquired following 10 months of production, a much sharper definition of the main fault separating northern and southern panels can be illustrated. In addition, south of the clearly identifiable fault, a number of sub-linear trends are enhanced on the 1998 map, suggestive of: (1) nearly parallel secondary fault segments, at a small angle to the main fault; or, (2) marginal or offshore lithofacies acting as baffles or barriers to separate individual turbidite channels. Confirmation of the latter interpretation would serve to improve the depositional framework depicted in Figure 4.

## **POROSITY AT OIL-WATER CONTACTS**

Although the influence of hydrocarbon fluids on the diagenesis of reservoir rocks remains a debated issue, a number of researchers have demonstrated that the presence of hydrocarbons can reduce but probably not completely impede reactions leading to cementation of the pore space, particularly when the rocks in question are water-wet (Saigal et al., 1992; Walderhaug, 1994). In a recent study of turbidite sandstone reservoirs in the Campos Basin, offshore Brazil, de Souza and de Assis Silva (1998) found causal relationships relating higher porosity and permeability above the oil-water interface, to an earlier calcite-cementing stage that reduced compaction and allowed hydrocarbon emplacement, whereas continued compaction and a later calcite cement reduced porosity and permeability below the oil-water contact; Figure 6.

Similarly, “quartz cementation that is synchronous with, or after, oil emplacement in sandstones is probably strongly inhibited relative to the underlying aquifer” (Worden and Morad, 2000).

The importance of considering the magnitude and distribution of porosity, relative to the oil-water contact in a reservoir which is the object of a 4-D seismic project, is that the original fluid contact will migrate updip, paralleling oil drainage, however the porosity, pore structure and permeability of the water-invaded oil leg may be the same, if most cementation preceded the hydrocarbon charge, or it may be different, if hydrocarbon emplacement was relatively early and controlled differential cementation at the developing oil-water interface. In either case, the correct calibration and interpretation of 4-D acoustic signals will depend on the assessment of yet another possible control on porosity distribution, in this case induced by the nature and timing of emplacement of the reservoir fluid.

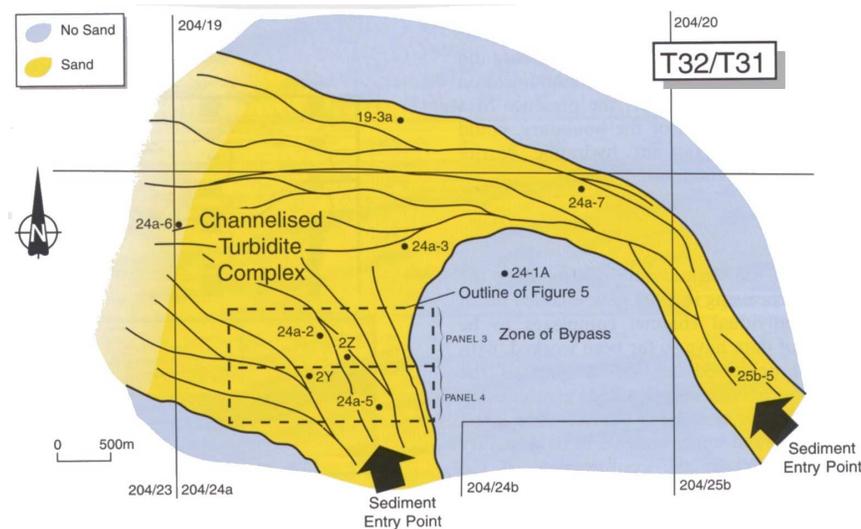


FIG. 4. Map illustrating the orientation of turbidite channels in the main Paleocene-age reservoirs in Foinaven Field, West Shetland Island (Figure 6 from Cooper et al., 1999). The small rectangles outline the areas of southern and northern fault panels imaged in Figure 5.

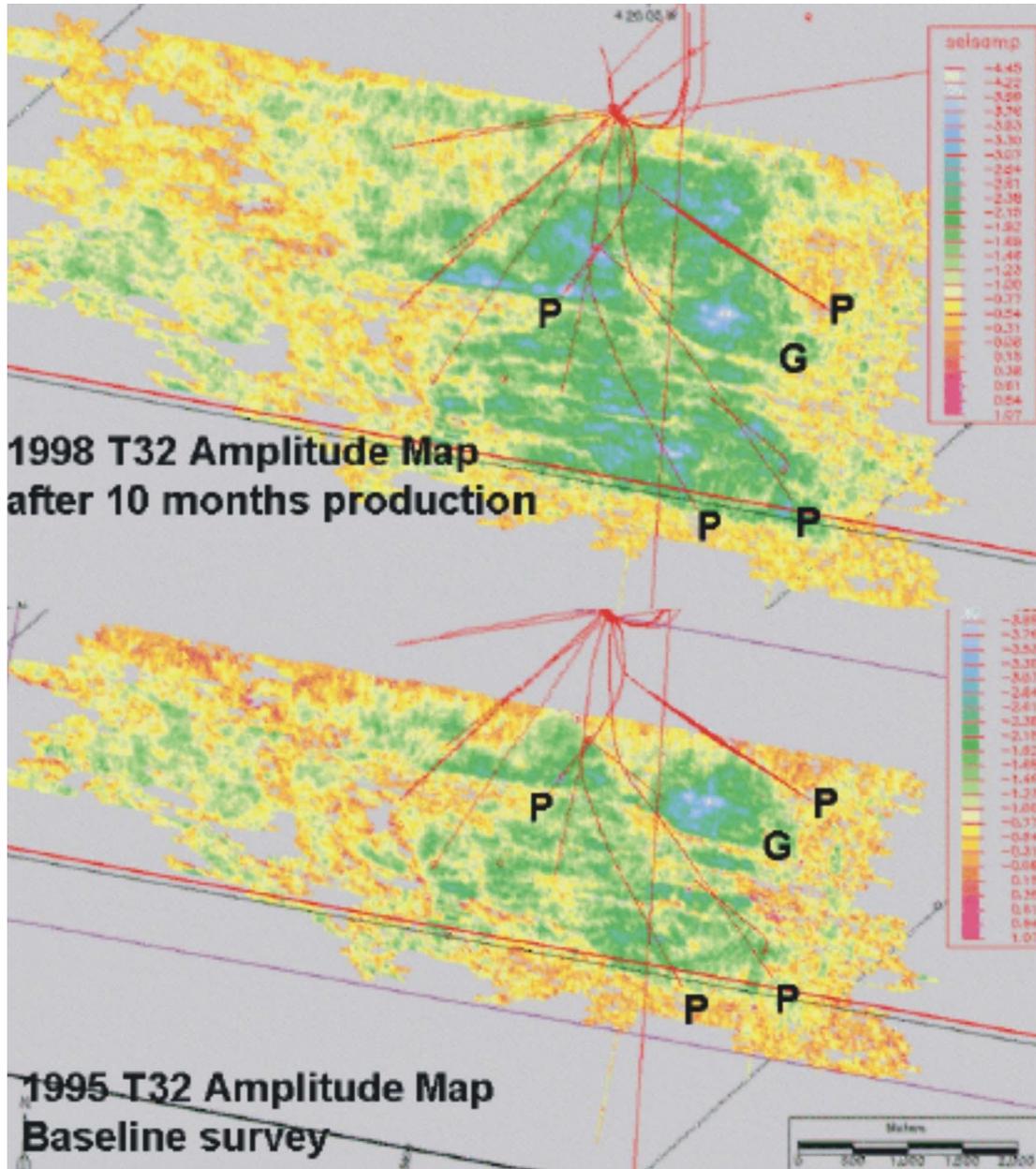


FIG. 5. Amplitude maps on top of the reservoir sandstones in Foinaven Field, West Shetland Island (Figure 5 from O'Donovan et al., 2000). Note definition of the west-northwest trending fault through the middle of the map, and sub-parallel anomalies (?) in the southern panel.

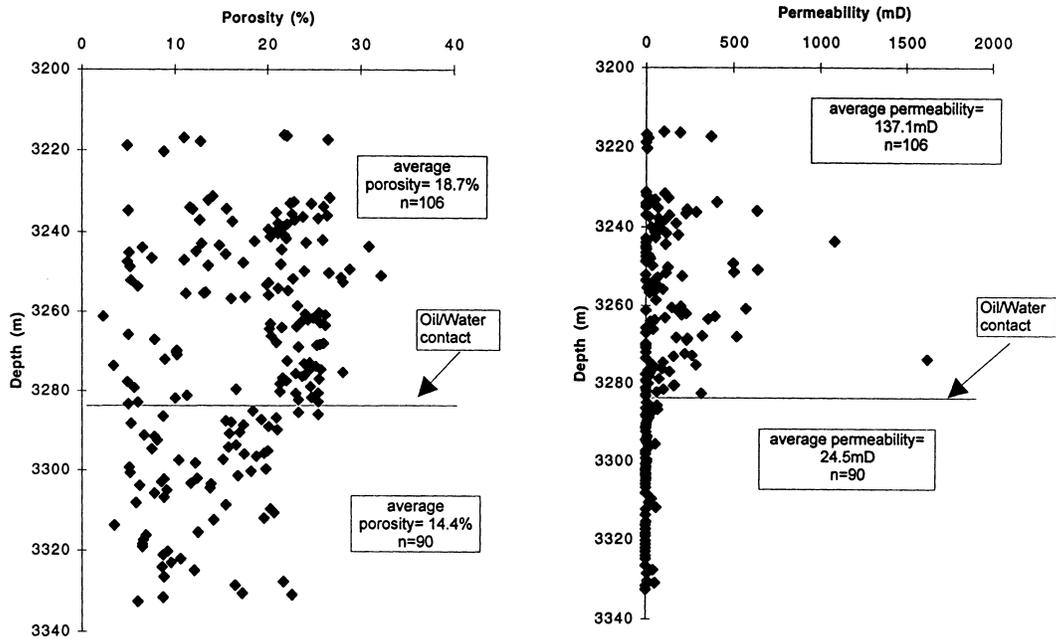


FIG. 6. Porosity and permeability vs. depth for a sandstone reservoir in the Campos Basin, offshore Brazil, showing generally higher values above the oil-water interface due to more extensive, continued cementation and compaction in the water zone (Figure 16 from de Souza and de Assis Silva, 1998).

## CONCLUSIONS

I reviewed examples of geological parameters that appear to be either, time-variant at the scale of 4-D seismic projects (compaction, steam-induced mineral precipitation) or, components of typical geological frameworks (*e.g.* lithofacies, faults) that can have a strong influence on the distribution of fluid pressures and/or saturations, both of which are key properties to be discriminated in 4-D seismic projects. It should be evident that one of the recurring concerns is porosity, as influenced by the heterogeneity of depositional lithofacies of the sediments, followed by the effects of mechanical and chemical diagenesis. More importantly, permeability magnitudes and distributions are the key parameters intended to provide a causal link between pressure (gradient), fluid flow, and the resultant partial fluid saturations. 4-D seismic projects are typically undertaken for large-scale, often risky deep-water plays, and the required scenarios for development and production will surely benefit from careful consideration of the aspects discussed herein.

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