Instrumented Oil Fields

Ali Tura, 4th Wave Imaging Corp.

The instrumented oil field consists of deploying permanent instrumentation to monitor an oil field and modify production continuously or on demand. This concept has evolved from recent developments in both down hole instrumentation and time-lapse monitoring. Both of these technologies are new and combining them, with permanent installations in mind, require further steps in research and development.

The objective of instrumenting an oil field is to optimize production and minimize development and operations costs, through early investment in continuous monitoring of a field. In deepwater and ultra-deepwater, where well costs can reach $50 million, instrumenting an oil field early on could considerably improve the bottom line economics. In this case, both the investments required and the potential returns are large. On land, oil fields can be instrumented much more economically. A basic example would be to install pressure and temperature sensors at wells to make sure a reservoir is kept above bubble point. Although the technology necessary to fully instrument an oil field is still being developed, several field applications on different parts of the technology already exist. Two examples in the area of permanent ocean bottom multi-component installations for seismic monitoring are the Foinaven field in the North Sea (Kristiansen et al., EAGE Meeting Abstract, 2000) and the Teal South field in the Gulf of Mexico (Entralgo and Spitz, TLE, 2001). These two studies alone have created extremely useful results and allowed the industry to address issues related to hardware deployment and longetivity, hardware design changes to improve data quality, understanding the quantity of data being produced and means to manage such large data to produce timely results to impact field development, and the economics involved. On land, a state-of-the-art permanent surface seismic example is the Cere-la-Ronde case study (Meunier et al., TLE, 2001). Again, many lessons have been learned from this study ranging from hardware and data acquisition, to data processing, to data management, to interpretation. Another technology currently being used is a multi-level multi-component permanent borehole seismic sensor array placed between the tubing and casing (Hottman and Curtis, TLE, 2001). Fully fiber-optic multi-component seismic sensors are currently in field trial stage. Passive seismic monitoring is currently in use in oil fields (Maxwell and Urbancic, TLE, 2001) and will be more widely used as oil fields are instrumented with borehole seismic sensors. On the non-seismic side, permanent borehole sensors to measure reservoir pressure, temperature, fluid flow, and fluid composition have been developed and tested. Crosswell seismic, electromagnetic and electrical methods are currently being used for monitoring purposes and may well take their own place in the instrumented oilfield of the future.

This vast array of information will be used in many ways. Current technology allows drilling wells that can be multi-lateral, long reach, and multi-zone with flow control. Smart wells allow the operator to use continuous monitoring information to adjust the well choke in multi-zone wells. For example, if water is encroaching a certain zone and if this information can be made available, using flow control units, this zone can be choked and production from other zones can continue. The instrumented oilfield may well become the single most important information provider for taking reservoir development and production decisions. The current advancement into the instrumented oil field is reminiscent of advancing from 2D to 3D seismic in many ways. How will the technology work? How much development is necessary? What will the costs be?

Even though considerable advances have been made in making instrumented oil fields a reality, it is fair to say that at this time the technology necessary to fully instrument an oilfield is still premature. The support for this technology will be coming through major oil companies venturing into deepwater plays, mid-size oil companies on land and joint ventures offshore, innovative service companies and contractors who are eager to provide these services, and research and development institutions funded by government and industry. Issues that need to be addressed are hardware precision, performance, reliability, integration, data management and integration, and most importantly, cost. Industry standards will be necessary on how a well should be completed so that permanent sensors can be placed, cables can be passed and surface controls can be accessed. On the marine and land seismic side, deployment, positioning, protection, recording (on a platform) are important issues. Once the data is recorded, data transfer, data management, rapid processing and analysis, and modifying development and production based on the information made available will be crucial.

New 4d Seismic Tools for Carbonate Reservoirs

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Abstract

Carbonate reservoirs are often significantly more demanding to explore and produce than siliciclastic reservoirs. The reasons for this are typically complex depositional facies with intense fracturing and diagenetic effects as compaction induced subsidence.

Time-lapse seismic monitoring of carbonate reservoirs might identify subsidence and the flow properties of the fracture network, which often make up migration paths for hydrocarbons or injector fluids. Knowing these dynamic components of the reservoir behavior helps the asset team to improve the management of the produced water and detect by-passed pay.

In this paper we present a set of new timelapse seismic analysis tools, for mapping these dynamic reservoir features and demonstrate their performance at hand of a couple of real data examples.

Introduction

The fact that carbonate reservoirs might be chemically unstable puts an extra challenge on the asset team designing a completion strategy for the field. During production subsidence is likely to occur influencing the stress and strain regime and by this posing a hazard to drilled wells. Furthermore, it is important to know the location and transmissibility of fault and fracture zones in order to successfully perform an enhanced recovery program.

The limited number of successful application of 4D seismic reported in carbonates might be caused by the more subtle changes in the time lapse signal compared with siliciclastic reservoirs (Key et al).Hence the repeatability between the time lapses needs to be very high to avoid disturbing the time lapse signal. Further new 4D analysis tools are required to reveal the specific challenges for carbonate reservoirs like compaction and conducting fracture networks

Method

Time lapse seismic might be used to estimate subsidence and compaction. Such estimates might be obtained by subtracting travel times of interpreted reference horizons (isochore-method). The disadvantage is that the quality of the estimate obviously depends on the quality of the picked horizons. This is often hard to achieve because of signal – to – noise characteristics or complex facies distibutions in the reservoir. Furthermore the isochore-method can only provide compaction estimates from thick layers made up by time - horizon pairs.

The new tool alleviates these issues by providing a subsidence and compaction estimate for each sample of the seismic volume (see Figure 1) and is thus a true 3D scheme. Further, the thus obtained estimate is less noisy. This is demonstrated in Figure 2 where the compaction estimate for one layer defined by a couple of interpreted horizon is compared for one inline with the result of the traditional travel time difference scheme.

The second method presented here assists the interpreter in detecting subtle faults and fractures. Through a resolution-modulating filter process lateral discontinuities are enhanced making it easier to detect fault planes (see Figure 3)..

Both techniques when combined can help to improve the understanding of the dynamic effects occurring during production of a carbonate reservoir. Compaction as an attribute may indicate areas where the reservoir is flooded by injected water. Using further seismic attributes and subject them to a general seismic inversion tool (Sonneland et al) will produce fluid indicator maps. When superimposing on these maps the fault network, fluid migration paths identifying certain fault and fracture zones as high permeability highways become apparent. It is to be noted that even if both the attribute maps and faults are derived from the seismic volumes they still provide independent information. It is their combination that provides new inside in the dynamic properties of the reservoir.

Conclusion

With the spreading acceptance of time lapse seismic surveying as an important tool for optimizing hydrocarbon recovery from reservoirs it becomes more and more important to provide and adapt tools to analyze such data. In this paper we presented two new techniques tailor-made for the analysis of carbonate reservoirs.

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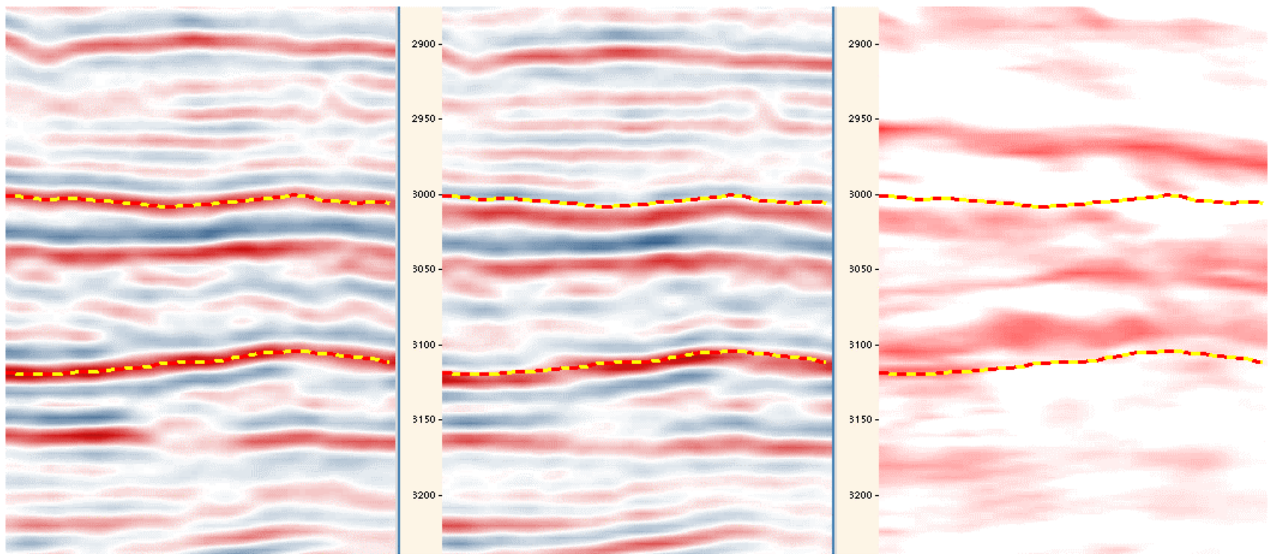


Fig. 1: Comparison of the two full-stack cubes (T1 and T2) and the resulting compaction cube. Red colors indicate compaction, white colors indicate no compaction. The dotted lines indicate the time grids for top and base of the reservoir mapped on the T1 data set. Note the displacement on the T2 data set.

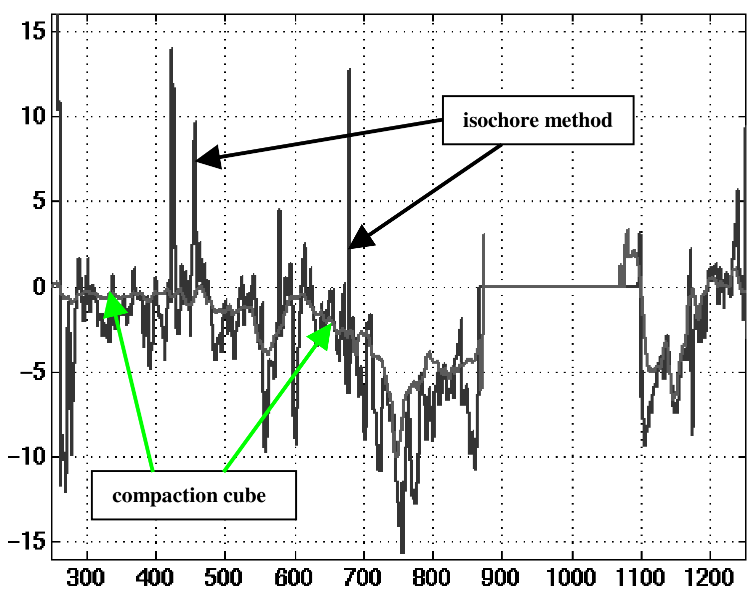


Fig. 2: Computed values of compaction along an Inline. The black curve shows the result based on the conventional isochore method. The grey curve shows compacting values based on the compaction cube. It is obvious that the compaction cube produces smoother values.

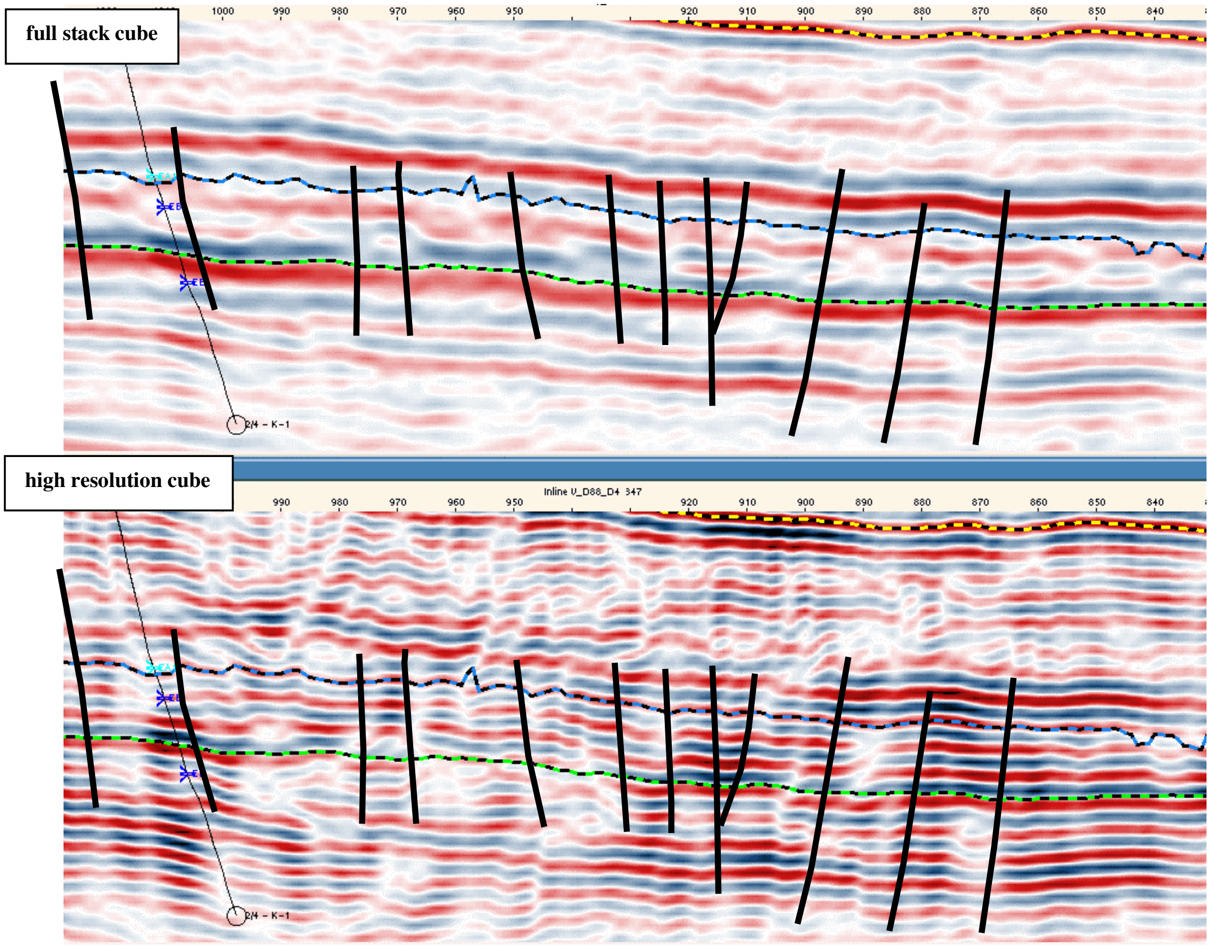
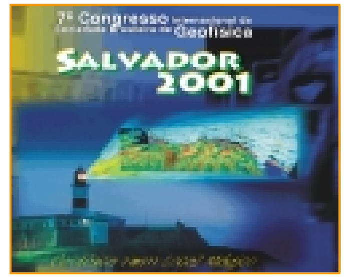


Fig. 3: Comparison of full-stack cube (top) and high resolution cube (base). Subtle faults and fractures that are hardly visible on the conventional full-stack cube, become enhanced on the high resolution cube. The fault network displayed here was mapped on the high resolution cube.



Workshop Reservoir Geophysics

October 31st, 2pm to 5pm – Room: Oxalá 1 a 4

Organized by

Paulo Johann (Petrobras-Brazil)

Vincent Richard (IFP-France)

Abstracts

It is now well recognized that producing a high quality, quantitative reservoir model requires a multi-disciplinary team effort with contributions from engineers, geologists, petrophysicists and geophysicists (interpreters). The geophysicist's main task in this process is to bring in seismic information as this provides the prime source of information about the spatial distribution of reservoir properties. However, as geophysicists it is not sufficient to just bring in seismic data. Seismic amplitude data characterizes interface reflection strength. All other disciplines work exclusively in the layer and layer property domain. Interface reflection strength is a subsurface property not readily understood by the other disciplines contributing to reservoir model development. This motivates application of inversion to turn seismic data into impedance, which is a layer property, and as such is understood by all the disciplines (**van Riel, 2001**).

During the last decade tremendous advances have been made in transforming geoscience and well data into reservoir models with associated properties. This has been made possible through improvements in data integration, quantification of uncertainties, effective use of geophysical modeling to better describe the relationship between input data and reservoir properties, and use of unconventional statistical methods. However still many challenges remain when we are facing with characterization of reservoirs with substantial heterogeneity, thin bedded stacked reservoirs and areas with poor data quality or limited well and seismic coverage. Among the inherent problems we need to overcome are: inadequate and uneven well data sampling, non-uniqueness in cause and effect in properties versus data response, different scales of seismic, log and core data and finally how to handle changes in the reservoir as the characterization is in progress (**Aminzadeh, 2001**).

Carbonate reservoirs are often significantly more demanding to explore and produce than siliciclastic reservoirs. The reasons for this are typically complex depositional facies with intense fracturing and diagenetic effects as compaction induced subsidence. Time-lapse seismic monitoring of carbonate reservoirs might identify subsidence and the flow properties of the fracture network, which often make up migration paths for hydrocarbons or injector fluids. Knowing these dynamic components of the reservoir behavior helps the asset team to improve the management of the produced water and detect by-passed pay. In this paper we present a set of new time lapse seismic analysis tools, for mapping these dynamic reservoir features and demonstrate their performance at hand of a couple of real data examples (**Sonneland et al., 2001**).

The instrumented oil field consist of deploying permanent instrumentation to monitor an oil field and modify production continuously or on demand. This concept has evolved from recent developments in both down hole instrumentation and time-lapse monitoring. Both of these technologies are new and combining them, with permanent installations in mind, require further steps in research and development (**Tura, 2001**).

October 31st, Room: Oxalá 1 a 4

Workshop – Reservoir Geophysics

Paulo Johann (Petrobras-Brazil) **and Vincent Richard** (IFP-France)

<u>Program</u>

2:00 to 2:10 pm: **Introduction**

Part I: New technologies for seismic characterization of Deep Water Reservoirs

2:10 to 2:30 Paper 1
Contrasting Types of Oligocene/Miocene, Giant Turbidite Reservoirs from Deep Water Campos Basin, Brazil (2001-2002 AAPG Distinguished Lecture)
Carlos Henrique Lima Bruhn,
Corporate Manager for Reservoir Characterization, Petrobras E&P.

2:35 to 2:55 Paper 2
3D quantitative AVA: a model-based approach for a joint inversion of angle data
Vincent Richard,
Director Geophysics and Instrumentation Dept., Instute Français du Pétrole (IFP).

3:00 to 3:20 Paper 3
Multi-component and elastic parameter inversion
Paul van Riel,
President of Jason Geosystems and Vice-Chairman Geophysical Division - EAGE

3:25 to 3:40 Coffee break

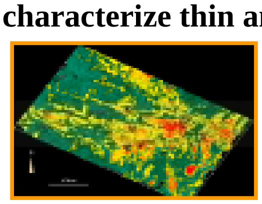
Part II: New seismic D&P tecnologies for reservoir characterization

3:40 to 4:00 Paper 4
Recent Advances and Current Challenges in Reservoir Characterization
Fred Aminzadeh,
President of dGB USA and Vice-President of SEG 2001-2002.

4:05 to 4:25 Paper 5
New 4D Seismic Tools for Carbonate Reservoirs,
Lars Sonneland,
Research Director, Schlumberger.

4:30 to 4:50 Paper 6
Instrumented oil field
Ali Tura,
Executive Vice President & Chief Operating Officer, 4th Wave Imaging.

4:55 to 5:35 Discussion
New seismic technologies to characterize thin and heterogeneous reservoirs in deep and ultra-deep water



Paper 1

2001-2002 AAPG Distinguished Lecture

Funded by the AAPG Foundation through the Allan P. Bennison Endowment

Contrasting Types of Oligocene/Miocene, Giant Turbidite Reservoirs from Deep Water Campos Basin, Brazil

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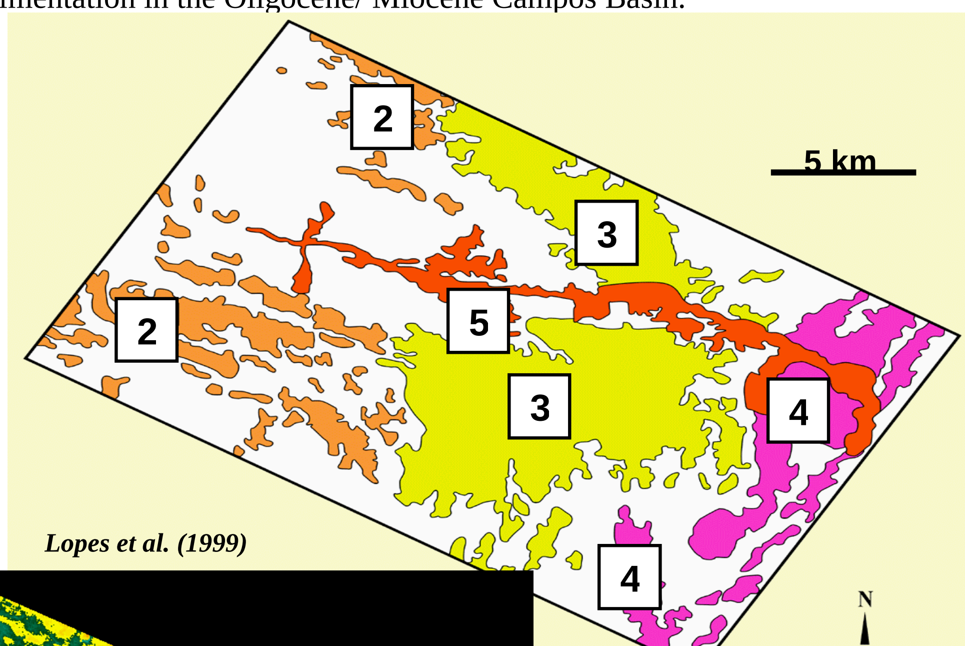
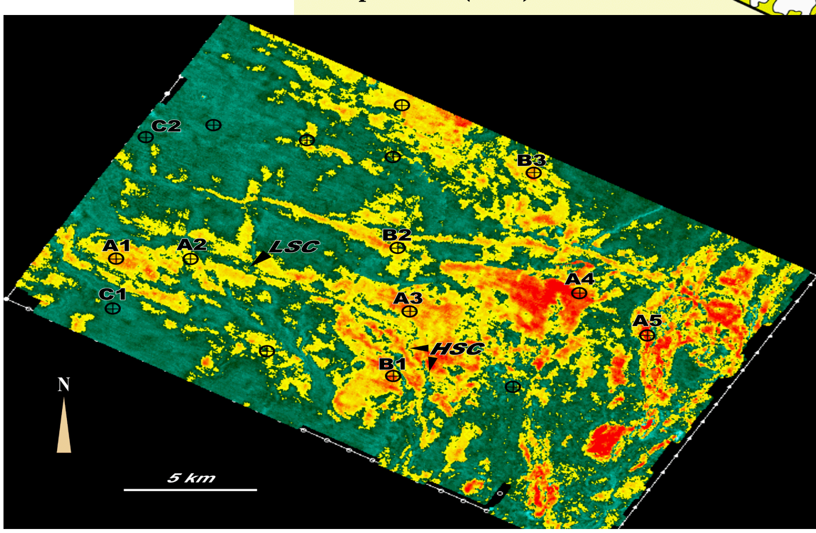
The most prolific Brazilian turbidite reservoirs are included in the Upper Oligocene/Lower Miocene section (32.9-23 Ma) from the present day deep water (400–2500 m) Campos Basin; they contain a total oil-in-place volume of 19.8 billion bbl, and total oil reserves of 5.0 billion bbl, which are mostly concentrated in seven oil fields (Albacora, Barracuda, Caratinga, Marlim, Marlim Leste, Marlim Sul, and Voador). Oligocene/Miocene turbidites form part of a Middle Eocene to Recent regressive succession, which typically displays a progradational pattern throughout the eastern Brazilian margin.

The first discoveries of giant Oligocene/Miocene oil fields in the deep water Campos Basin date from the mid 1980's. At the beginning, they were considered as homogeneous, widespread turbidite fans. However, the information provided by more than 300 wells, extensive coverage of 3D seismics, hundreds of meters of cores, and cumulative production data have changed this first picture. More recent studies have found that the Oligocene/Miocene turbidite reservoirs from deep water Campos Basin can be very complex and heterogeneous. This presentation is focused on the stratigraphic framework, sandbody geometry, and reservoir heterogeneities of the most important, contrasting types of Oligocene/Miocene turbidite reservoirs, which include (1) trough-confined, gravel/sand-rich channel complexes, (2) unconfined, sand-rich lobes heavily dissected by younger, mud-filled channels, (3) unconfined, sand-rich lobes, (4) trough-confined, sand-rich lobes, and (5) sand/mud-rich channel-fills and splays. Type 1 is illustrated by the Albacora Field, and types 2, 3, 4, and 5 are described from the Barracuda, Marlim and Marlim Sul fields (Fig. 1).

The Oligocene/Miocene architectural types of turbidite reservoirs typically comprise the lowstand systems tracts of distinct 3rd- to 4th-order sequences, which can be bounded in the deep water portion of Campos Basin by unconformities and/or correlative, non-erosive surfaces. Some of the sequence boundaries can be correlated to the Haq's et al. (1988) eustatic, third-order sea-level falls of 30.0 Ma, 28.4 Ma, 26.3 Ma, and 25.5 Ma. However, other sequence boundaries can be recognized, including two undated boundaries between 26.3 Ma and 25.5 Ma, and the sequence boundaries of 25.0 Ma and 24.5 Ma. The transgressive and highstand systems tracts of the sequences mapped in the oilfield areas are composed of cyclically interbedded marls and mudstones containing benthic foraminifera characteristic of upper to lower bathyal settings.

Regional stratigraphic correlations suggest that the Albacora Field gravel/sand-rich channel complexes can be time-equivalent (along basin strike) to lobe successions of Barracuda, Marlim, and Marlim Sul fields. The development of very contrasting turbidite types seems to be related to tectonically-controlled basin gradient/confinement and sediment supply. Gravel/sand-rich channel complexes occur in areas with slope oversteepening due to upward movement of underlying Aptian evaporites and intense faulting; steep slopes seem to have favoured deep channel incision by turbidity currents, rather than accumulation of turbidite lobes. On the other hand, unconfined lobes (types 2 and 3) fill intra-slope, wide depressions with gentle bottom gradients, which are also related to withdrawal of underlying, Aptian evaporites. In the area of the Barracuda and Marlim Sul fields, the stacking of types 2 (Barracuda), 3 and 4 (Marlim Sul) gave rise to a progradational, offlapping succession (Fig. 1). Type 2 reservoirs include more proximal, unconfined sand-rich lobes, which were heavily dissected by low-sinuosity, mud-filled channels, probably during the relative sea level fall that gave rise to the progradation of the turbidite system to southeast and the accumulation of Type 3 reservoirs. Type 4 reservoirs comprise elongated, sand-rich lobes, which filled fault-bounded, strike-oriented troughs located farther into the basin; these reservoirs were mostly fed by channels that managed to divert or partially erode Type 3 lobes. Types 2, 3, 4 are overlain by a marl-rich condensed section (marker bed red) that can be widely correlated in deep water Campos Basin. Following another relative sea level fall, it took place the development of the thick (up to 125 m), sand-rich succession of Marlim Field (mostly Type 3), located to the north of Barracuda and Marlim Sul fields. Sand/mud-rich channel-fills and splays (Type 5, Fig 1) filled a depression in between two major depocenters of Type 3 reservoirs at the Marlim Sul Field, following a sea level rise that led to the end of the turbidite sedimentation in the Oligocene/ Miocene Campos Basin.





Types:

2 – Unconfined, Sand-Rich Lobes Heavily Dissected by Younger, Mud-Filled Channels (Barracuda Field)
3 – Unconfined, Sand-Rich Lobes (Marlim Sul Field)
4 – Trough-Confined, Sand-Rich Lobes (Marlim Sul Field)
5 – Sand/Mud-Rich Channel-Fills and Splays (Marlim Sul Field)

Paper 2

3D quantitative AVA: a model-based approach for a joint inversion of angle data

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Summary

In order to provide a user guided and quantitative approach to AVA integrated processing, we propose a model-based approach to jointly invert angle-limited stacks. In a first step, we use a multiwell calibration analysis to extract a single wavelet for each angle stack volume. Then, we use an elastic inversion approach based on a 3D formalism in which a priori information is provided for each parameter (P- and S-impedance).

For both calibration and inversion purposes, the Knott-Zoeppritz equation is used to compute the predicted synthetic data associated to a specific incidence angle. The inversion involves the computation of a global objective function which is minimized in order to compute an optimal model for each elastic parameter. This model best explains the AVA information of the angle stacks and the stratigraphic/petrophysics knowledge introduced through the a priori information. The method is illustrated on a real 3D marine case study.

Introduction

In contrast to conventional AVO analysis, two approaches have appeared in recent works to estimate the elastic properties of the subsurface from PP prestack seismic data. The first one, introduced by Connoly (1999) and based on the linearization of the Knott-Zoeppritz equation, consists in sequentially inverting angle-limited stacks to obtain “elastic impedances”, and then in extracting the P- and S-impedances from a linear fit to the logarithm of the “elastic impedance”. The second approach consists in simultaneously inverting all the angle-stacks, in order to globally estimate the P- and S-impedances. This kind of method is less sensitive to local noise in the angle-stacks, and should provide more robust estimates of the elastic parameters.

Nevertheless, all these methods are limited by the fact that S-impedance is badly determined from PP data. In our model-based AVA elastic inversion, angle stacks for a range of angles of incidence are simultaneously inverted for P- and S-impedances (and optionally for density). In addition, we introduce a priori information in the inversion process in order to improve the determination of the elastic model parameters.

In the following, we first describe our methodology and then present a first 3D application on real marine data.

Model-based AVA elastic inversion

Angle stacks multiwell calibration

The first part of the quantitative processing consists in a detailed well-to-seismic calibration. Because NMO stretch and tuning are among the most serious factors hampering confident AVO analysis, we have decided to extract one single wavelet for each angle stack. Thus, each wavelet will be able to compensate for some of the preprocessing issues (corrections for wavelet variations) through the elastic inversion.

We apply sequentially to each angle stack, the calibration methodology described by Lucet et al. (2000), in order to extract an optimal wavelet for each angle. Note that the synthetic trace at a well for a given angle, is obtained here by convolving the Knott-Zoeppritz reflection series (computed from density, and P- and S-impedance logs at well) with a wavelet. The methodology provide also an optimal location for each well mainly in terms of correlation coefficient between synthetic and real traces. As the angle stacks are processed sequentially, a given well may have a different optimal location according to the angle. Consequently the final optimal location for each well is chosen as the one which gives the higher correlation coefficient for all the angles.

Joint stratigraphic inversion

The second part of the quantitative processing consists in a joint stratigraphic inversion of all the angle-limited stacks. We adopt a Bayesian inverse calculation to estimate elastic parameters from seismic data as thoroughly developed by A. Tarantola (1987). We assume that the seismic noise is described by a Gaussian probability with zero mathematical expectation and covariance operator Cd, and that the uncertainties on the a priori model are described by a Gaussian probability with zero mathematical expectation and covariance operator Cm. The maximum likelihood model minimizes the sum of two objective functions:

$$\mathbf{J = Js + Jg}$$

where J_s and J_g are respectively the seismic and "geological/petrophysical" objective functions.

We assume that the seismic noise is uncorrelated from one trace to another within each angle-stack volume and from one angle volume to another: the data covariance C_d is diagonal, with a seismic variance σ_s function of the noise level in the data. Thus J_s measures the mean square error between model-predicted and actual angle stack data:

$$J_s(m) = \sum_{\theta} \left\| R_\theta(m) * W_\theta - d_\theta^{obs} \right\|^2_{C_d^{-1}}$$

where $R_\theta(m)$ is the Knott-Zoeppritz reflection coefficient series corresponding to the current elastic model m and to the angle θ, W_θ is the wavelet, and d_θ^{obs} is the observed seismic trace at the angle θ.

J_g measures the error between a priori and predicted model parameters according to the norm associated to C_m^{-1}, where C_m is the multiparameter covariance matrix in model space. The choice of C_m which has a patent pending status is described by Tonellot et al. (1999), and permits the introduction of a 3D a priori geometry derived from interpreted horizons and stratigraphic knowledge. This covariance operator acts as a geologically oriented multichannel filter in the model space and allows to include local petrophysical information.

Using this geometrical framework and the available well logs, an a priori model for each elastic parameter is built by filling the interwell volume using a standard interpolation technique. The confidence on this a priori model is incorporated within the inversion by means of a priori user defined parameters: a variance for each elastic parameter uncertainty, a correlation coefficient of the inter-parameter uncertainties, and a correlation length which tunes the confidence in the a priori expected variations of the elastic parameters along the geometrical framework.

Once the a priori information is speci½ed, the objective function is minimized using a standard conjugate gradient technique.

Illustration

We apply the proposed methodology on a 3D marine dataset. Five angle-limited stacks are provided after a preserved amplitude processing and NMO corrections. They correspond respectively to the stack of angles 0-6, 6-12, 12-18, 18-24, and 24-30 degrees. Each angle cube contains 141 lines with 251 traces by line. Log data (P- and S-impedances and density) were available at 3 wells. An interpretation of the main near offset reflections is also available (time picking).

Firstly, the seismic data were calibrated to well logs and five wavelets were extracted using the multiwell angle-stack calibration. The a priori models in P and S-impedance were computed by using two horizons which delineate the reservoir zone, and by interpolating the well log information along correlation lines defined by stratigraphic knowledge. A priori parameters were set within each of the three defined geological units, according to some information about the lateral heterogeneity of the elastic parameters in the target interval.

Secondly, according to our model-based elastic inversion, the five angle cubes are inverted simultaneously using a 3D stratigraphic/petrophysical constraint in the model space. This method gives an optimal model in P- and S-impedance. The residuals corresponding to this optimal model, mainly contain incoherent noise as is illustrated on line 10 (Figures 1 and 2). Thus, the inverted impedances correctly explain the amplitude variation of the seismic with angle, and the P and S reflectivities (Fig. 3) show a great improvement of the resolution. Note that the properties would allow to characterize the complex channelised reservoir in a turbidite environment.

Conclusion

We introduce a new methodology for AVA analysis based, on one hand on the joint stratigraphic inversion of angle-limited stacks using an appropriate forward modeling to compute the synthetic gathers, and on the other hand on the use of a full 3D formalism which permits the introduction of a priori information (geological and petrophysical knowledge) in the inversion process. This joint elastic inversion scheme constrained by a priori impedance information improves stability and uniqueness. The approach is very flexible, thus allowing additional developments, for example on the forward modeling side and on application to new data types (converted waves,...).

Aknowledgments

The authors wish to gratefully thank TotalFinaElf for providing the seismic data set.

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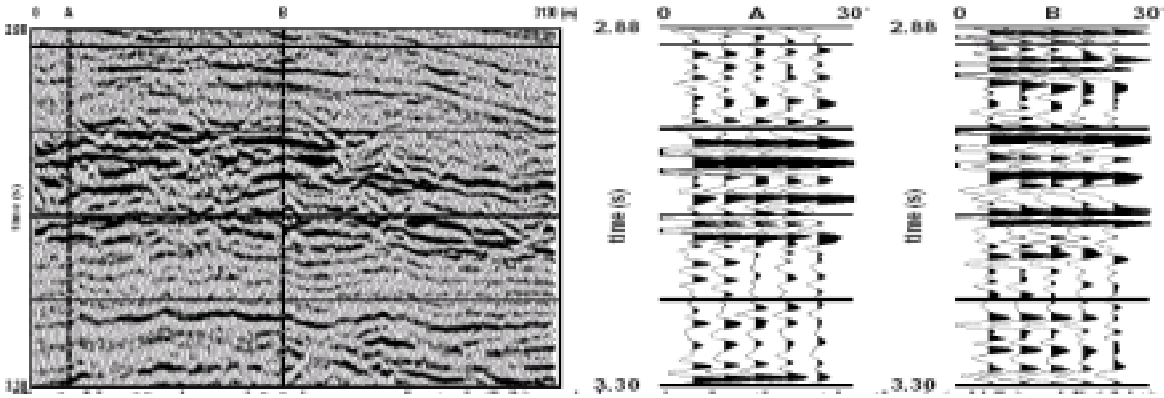

Fig. 1: Line 10: observed 0-6 degrees angle stack (left), and observed angle gathers at location A (middle) and B (right).

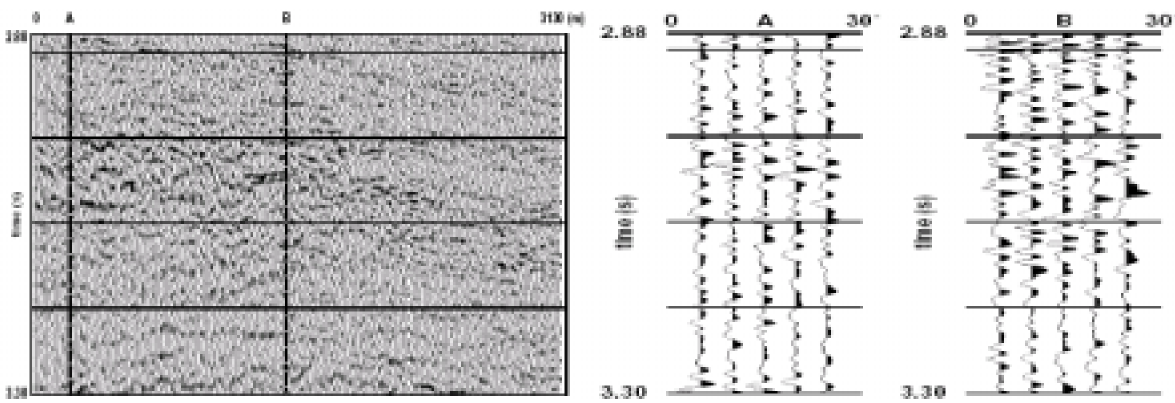

Fig. 2: Line 10: residual 0-6 degrees angle stack (left), and residuals angle gathers at location A (middle) and B (right).

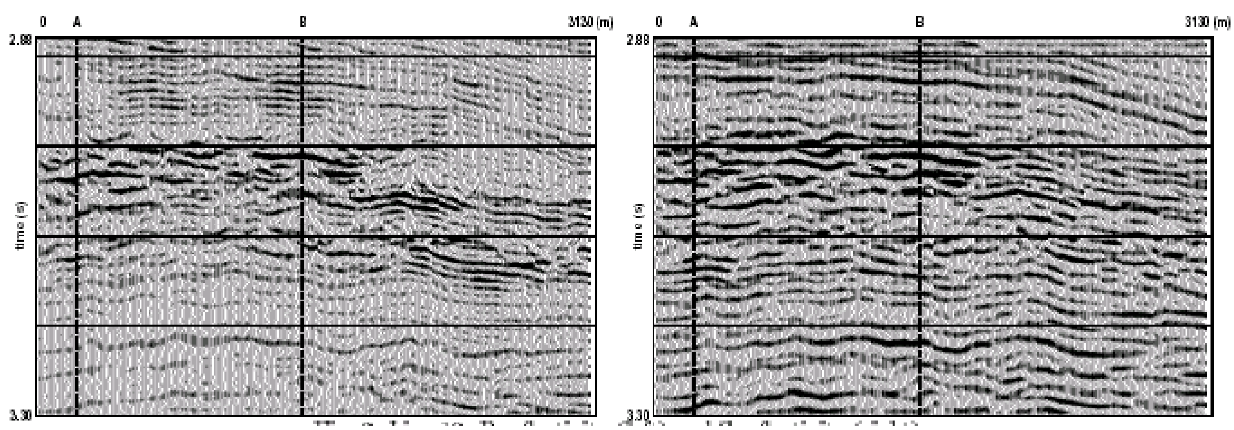

Fig. 3: Line 10: P-reflectivity (left) and S-reflectivity (right).

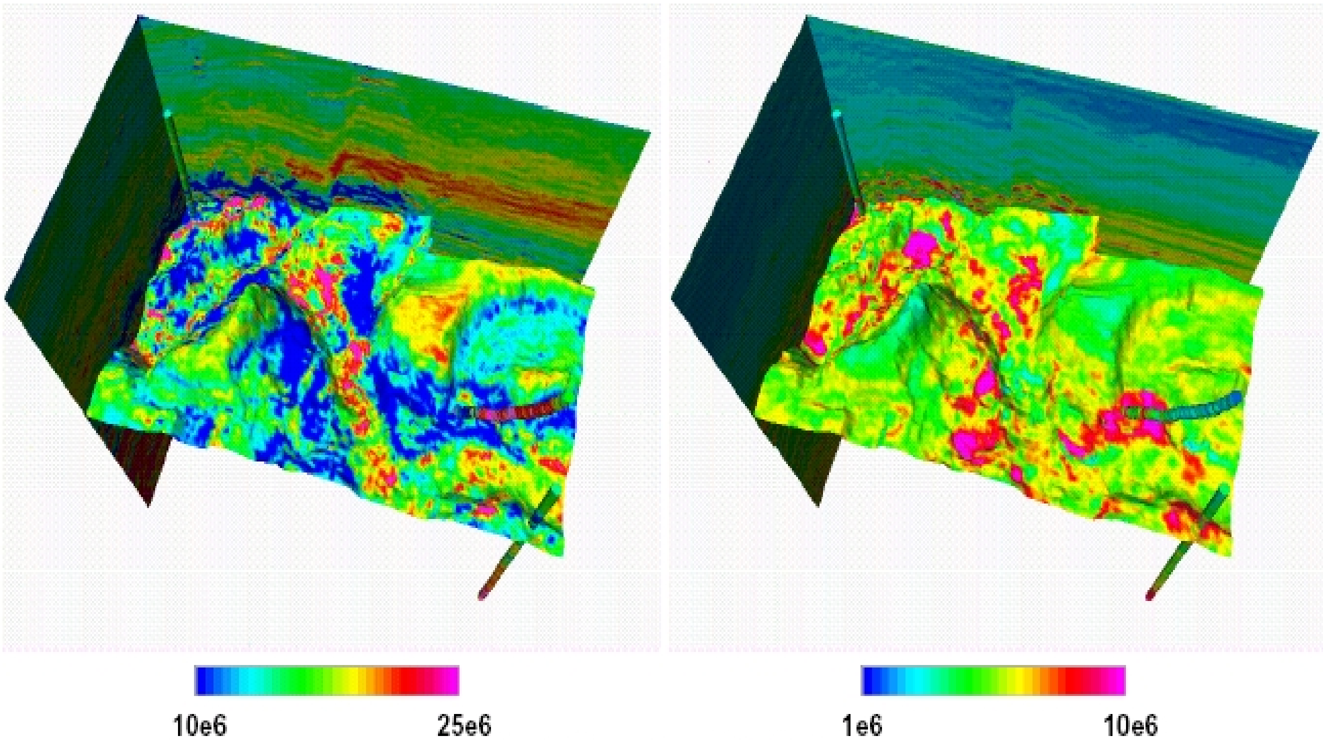

Fig. 4: ρλ (left) and ρμ (right) volumes.

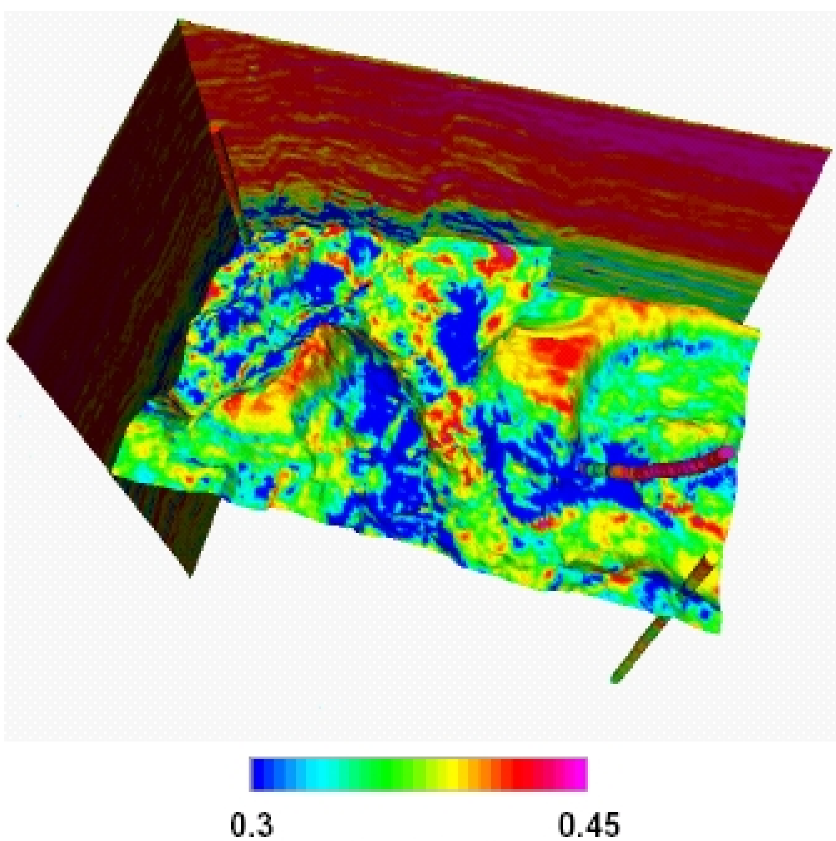

Fig. 5: Poisson's ratio volume.

Paper 3

Multi-component and elastic parameter inversion

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It is now well recognized that producing a high quality, quantitative reservoir model requires a multi-disciplinary team effort with contributions from engineers, geologists, petrophysicists and geophysicists (interpreters). The geophysicist's main task in this process is to bring in seismic information as this provides the prime source of information about the spatial distribution of reservoir properties. However, seismic data, s geophysicists it is not sufficient to just bring in Seismic amplitude data characterizes interface reflection strength. All other disciplines work exclusively in the layer and layer property domain. Interface reflection strength is a subsurface property not readily understood by the other disciplines contributing to reservoir model development. This motivates application of inversion to turn seismic data into impedance, which is a layer property, and as such is understood by all the disciplines.

For interpretation and quantitative reservoir characterization the primary benefit of impedance inversion is to turn seismic reflection data into a product that serves as a common platform for multi-disciplinary analysis and interpretation. In addition, several other benefits are realized through properly executed inversion:

- Modern impedance inversion methods partially back out the wavelet and integrate seismic, well log and geologic information, resulting in a volume carrying more information than the seismic data alone. Importantly, the low frequency component can be brought in to enhance resolution and create absolute values that are directly calibrated to well log measurements.
- Impedance is a function of such key reservoir parameters as Vshale and porosity. In many cases functional relationships can be developed from a petrophysical well log analysis. These petrophysical transforms can then be applied to the impedance volume to obtain quantitative estimates of key reservoir properties away from well control.
- Impedance data provide a superior basis for rapid volume based interpretation because layers (instead of interfaces) are directly captured and because of the higher resolution of the impedance volumes.

Buxton Latimer et al. (2000) discuss the interpretive benefits of working with impedance in more detail.

From poststack seismic data we recover acoustic impedance. Acoustic impedance is sensitive to the composition of the rock matrix (mineral fractions), porosity and fluid saturation. In many

reservoir zones different combinations of the mineral fractions, porosity and fluids give rise to the same acoustic impedance, in which case acoustic impedance can not serve to uniquely discriminate between reservoir rock properties. Sequence stratigraphic interpretation, as described by Atkins et al. (2000), offers one powerful way to reduce this non-uniqueness.
Another alternative is to bring in more rock property information from seismic data through the use of information carried in the AVO response or through the use of converted wave data. Both the AVO response of P-wave reflection data and converted wave data carry information about shear wave impedance. In case of very high quality data and large angle coverage it may also be feasible to recover information about density.

The inversion of converted wave data (referred to as PS data) leads to a reservoir layer property referred to as PS elastic impedance (PS-EI). PS-EI is an extension of the concept of elastic impedance for the inversion of partial stacks of P-wave reflection data, as first introduced by Connolly (1999). PS-EI is a function of both shear impedance and density, though the shear impedance term is generally dominant. Converted wave elastic impedance has been applied very successfully in the North Sea, e.g. Hanson et al. (2000) and Stearn (2001). In both these references the top reservoir is not imaged by poststack seismic data because there is no acoustic impedance contrast between the overlying shales and the oil charged reservoir sands. However, there is a good contrast in shear impedance between the shales and the sands, resulting in a good converted wave contrast. The PS-EI volumes clearly image the sands. Further application of converted wave data is in areas where gas clouds above the reservoir obscure the P-wave reflection response.

Converted wave elastic impedance directly provides a new rock property parameter independent of acoustic impedance to enhance lithology and fluid discrimination. However, we must recognize that application of converted wave data has drawbacks:

- Acquisition is expensive (ocean bottom cables).
- Processing is more complicated because of the need to work with different velocity fields for the downgoing P and upgoing S waves. Also, higher sensitivity to azimuthal anisotropy needs to be taken into account.
- Bandwidth of PS data is generally lower than of P-wave reflection data, even after compensating for the longer PS traveltime.
- Importantly, PS wave data is acquired at a different time scale than P-wave data. A non-linear transform is required to bring PP and PS data onto the same time scale (or depth). Because PP and PS events do not correlate well (that is the whole point of acquiring PS data), accurate alignment is difficult.

Recently developed AVO inversion methods, e.g. Pendrel et al. (2000) and Dubucq et al. (2001) applied to multiple partial stacks of P-wave reflection seismic data provide an alternative route to simultaneously recover broadband acoustic and shear wave information. Experience over many projects throughout the world indicates that, with proper seismic preprocessing, shear wave information can be reliably extracted from P-wave seismic reflection data. This then provides an alternative to using converted wave data. Converted wave data may be the only option in cases of gas clouds or other overburden effects resulting in a ‘no data’ zone for P-wave reflection data or when, in case of an extremely complex overburden, reasonable amplitude processing of P-wave reflection data is not feasible. In all other cases where shear information is required to boost lithology and fluid discrimination power, we strongly suggest that P-wave reflection data AVO inversion is first considered to recover shear information. Our experience is that the proposed AVO inversion method works well in a wide range of basins and is the cheapest and best (more resolution and no time alignment issues) choice to recover shear information for enhanced lithology and fluid prediction.

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Paper 4

Recent Advances and Current Challenges in Reservoir Characterization

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Abstract

During the last decade tremendous advances have been made in transforming geoscience and well data into reservoir models with associated properties. This has been made possible through improvements in data integration, quantification of uncertainties, effective use of geophysical modeling to better describe the relationship between input data and reservoir properties, and use of unconventional statistical methods. However still many challenges remain when we are facing with characterization of reservoirs with substantial heterogeneity, thin bedded stacked reservoirs and areas with poor data quality or limited well and seismic coverage. Among the inherent problems we need to overcome are: inadequate and uneven well data sampling, non-uniqueness in cause and effect in properties versus data response, different scales of seismic, log and core data and finally how to handle changes in the reservoir as the characterization is in progress.

Alternative Methods

Historically, the link between reservoir properties and seismic and log data have been established either through “statistics-based” or “physics-based“ approaches. The latter, also known as model based approaches attempt to exploit the changes in seismic character or seismic attribute to a given reservoir property, based on physical phenomena. Here, the key issues are sensitivity and uniqueness. Statistics based methods attempt to establish a heuristic relationship between seismic measurements and prediction values from examination of data only. It can be argued that a hybrid method, combining the strength of statistics and physics based method would be most effective. Figure 1 shows the concepts schematically. In what follows we elaborate further.

Many geophysical analysis methods and consequently seismic attributes are based on physical phenomena. That is, based on certain theoretical physics (wave propagation, Biot-Gassman Equation, Zoeppritz Equation, tuning thickness, shear wave splitting, etc.) certain attributes may be more sensitive to changes in certain reservoir properties. In the absence of a theory, using experimental physics (for example rock property measurements in a laboratory environment such as the one described in the last section of this paper) and/or numerical modeling, one can identify or validate suspected relationships. Although physics-based methods and direct measurements (the ground truth) is the ideal and reliable way to establish such correlations, for various reasons it is not always practical. Those reasons range from lack of known theories, difference between the laboratory environment and field environment (noise, scale, etc.) and the cost for conducting elaborate physical experiments.

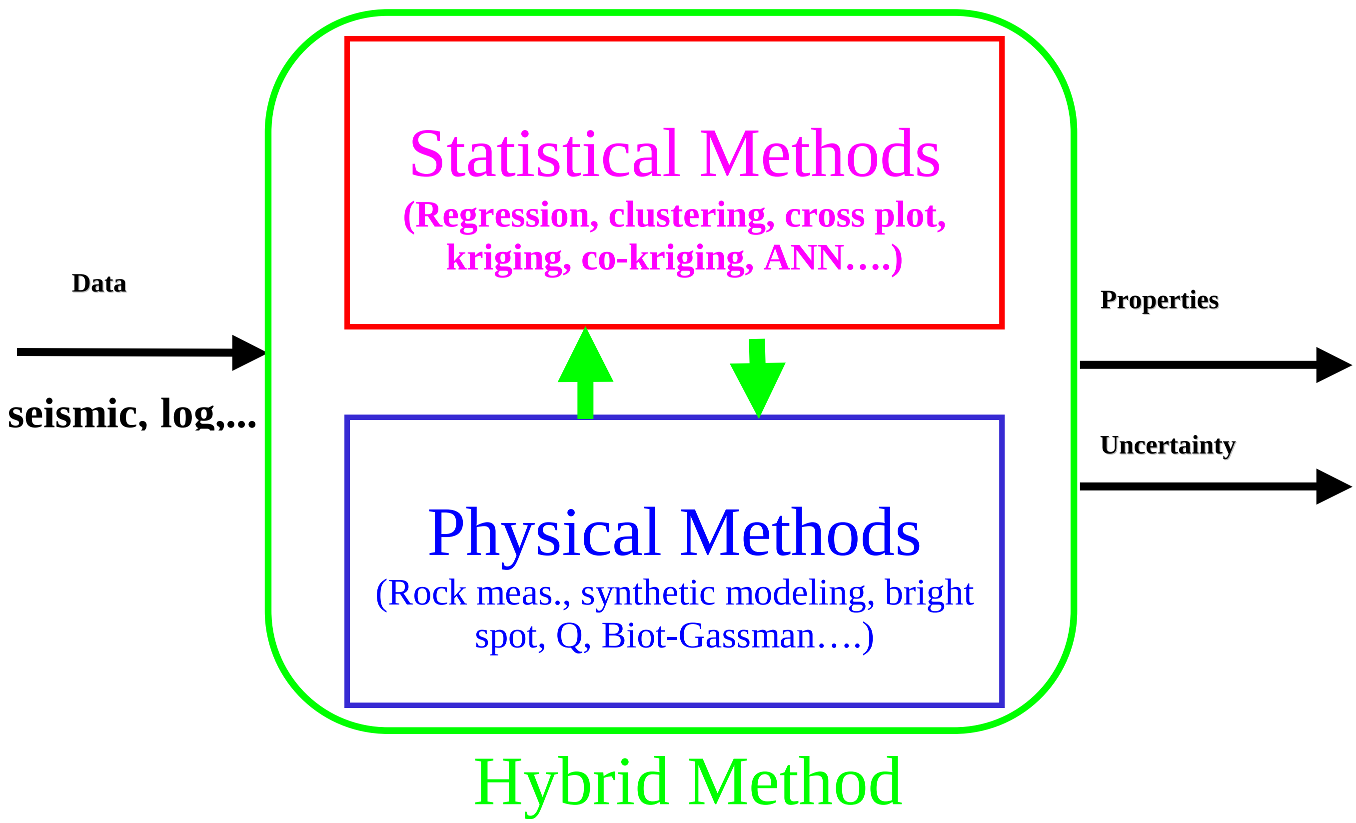


Figure 1 A schematic description of physics-based (blue), statistics-based (red) and hybrid method (green)

Statistics-based methods aim at deriving an explicit or implicit heuristic relationship between measured values and properties to be predicted. Different statistical methods such as regression analysis, clustering (Aminzadeh and Chatterjee, 1984), cross-plotting, principal component analysis, cross correlation, geostatistical methods (variogram, kriging, cokriging) and neural networks (de Groot, 1995) and fuzzy logic (Nikravesh and Aminzadeh, 2001) are used. They all attempt to establish a relationship between different seismic attributes, petrophysical measurements, laboratory measurements and different reservoir properties. In such statistics based method one has keep in mind the impact of noise in the data, data population used for statistical analysis, scale, geologic environment, scale and the correlation between different attributes when performing clustering or regressions. The statistics-based conclusions have to be reexamined and their physical significance explored.

In an ideal "hybrid" method iterations to reconcile differences between model-based results and statistical data are carried out. One goes back and forth between the physics and statistics –based methods to ensure cross validation. de Groot (1995, 1999) developed a method to test different hypotheses regarding geology of a reservoir by generating pseudo-wells. Figure 2 shows how a number of pseudo wells generated from a real well.(far left) to determine sensitivities of seismic response to different reservoir properties and validate statistics-based results. The synthetic seismograms in Figure 2 (to the right) are generated for the corresponding pseudo wells.

Data Segmentation: Real wells =>Pseudo wells =>Synthetic

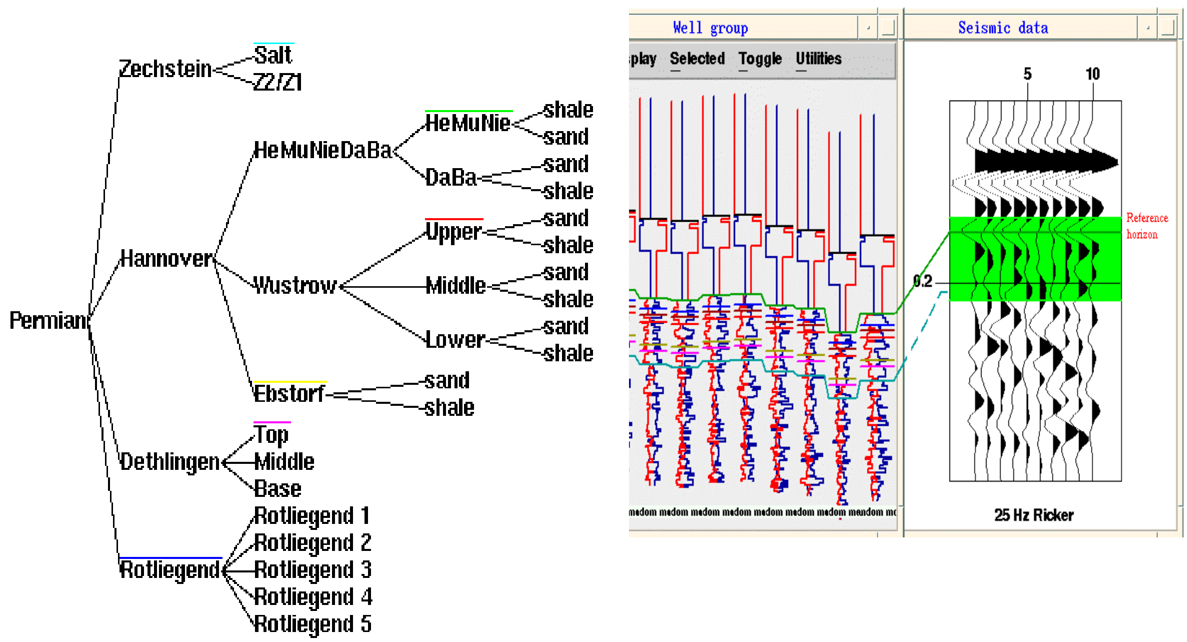


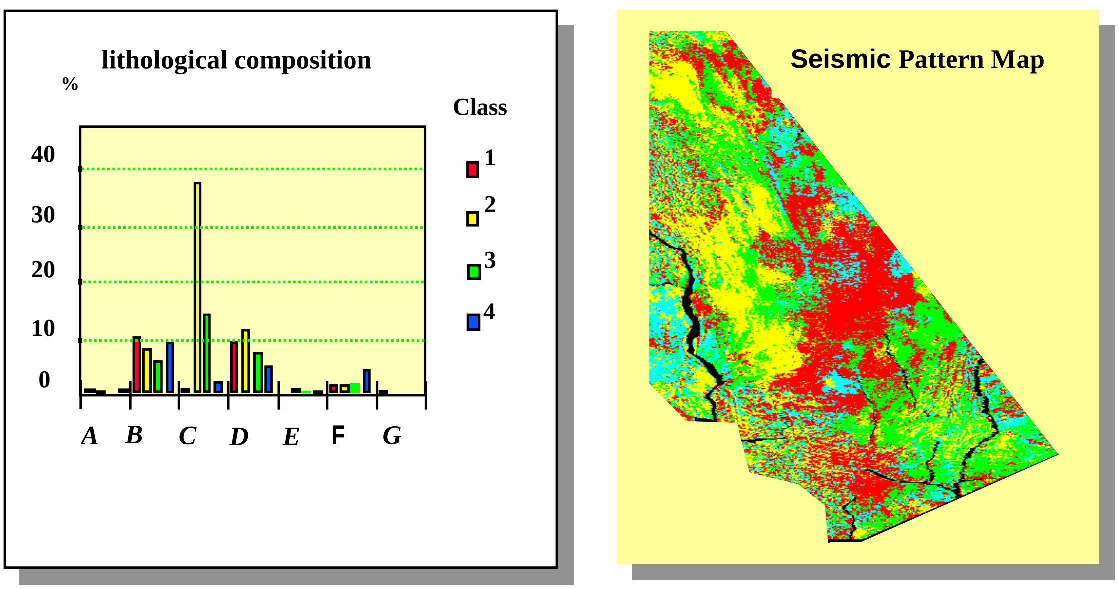
Figure 2- Pseudo well generation to determine sensitivities of seismic response to changes in well properties (courtesy of dGB BV)

Thus, hybrid methods use the statistics (clustering, regression, neural networks) to establish the initial relationship between seismic attributes or seismic characters and reservoir properties (unsupervised method). It then uses real wells, pseudo-wells, and other geological and production data to confirm and/or modify such relationships. The procedure can be iterated to further establish the match between the statistics and physics based methods.

A distinction should be made between the conventional attribute-based methods and "Seismic Character" based analysis. Seismic character (including that of pre-stack data) contains all the information that hundreds of attributes are derived from. Nevertheless, this method can combine seismic character, and a given set of attributes to further enhance their prediction power. It will be shown how attributes and/or waveforms extracted from multiple input seismic cubes are used to obtain the facies or predict porosity or fluid saturation. Unique in the method are the pseudo-wells used to relate seismic patterns to the underlying rock and reservoir properties and their use in training supervised neural networks. The pseudo-well simulator generates stratigraphic columns with the corresponding well logs using a constrained Monte Carlo simulation.

Sensitivity and Uniqueness

The more sensitive the particular seismic character to a given change to reservoir property, the easier to predict that property. The more unique influence of the change in seismic character to changes in a specific reservoir property, the higher the confidence level in such predictions. Figure 3b shows a seismic pattern map through classification of the respective seismic character within the time window or the reservoir interval with four "classes" of wavelets, (w1, w2... w4). These 4 wavelets (basis wavelets) serve as a segmentation vehicle. The histograms in Figure 3a show what classes of wavelets are likely to be present for given lithologies. In the extreme positive (EP) case we would have one wavelet uniquely representing one lithology. In the extreme negative case (EN) we would have a uniform distribution of all wavelets for all lithologies. In most cases unfortunately we are closer to NP than to EP.

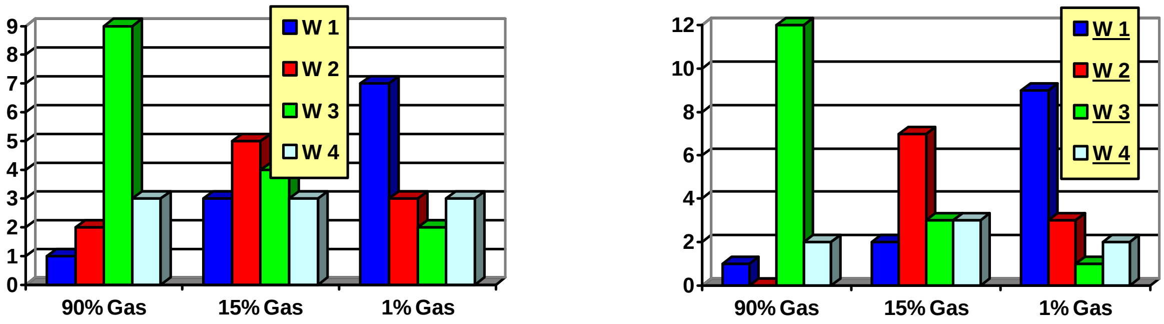


(a) (b)

Figure 3 a, Distribution of different seismic character classes for different lithologies: A-Evaporates, B-Silt/Shales, C- Shore line, D- Wet Dunes, E- Dry Dunes, F- Fanglomerates, G- Volcanics , Figure 3b, Seismic patterns divided into 4 classes (Courtesy of dGB BV)

The question is how best we can get these distributions move from the EN side to EP side thus improving our prediction capability and increasing confidence level. The common sense is to add enhance information content of the input data.

How about if we use wavelet vectors comprised of pre-stack data (in the simple case, mid, near far offset data) as the input to a neural network to perform the classification? Intuitively, this should lead to a better separation of different lithologies (or other reservoir properties). Likewise, including three component data as the input to the classification process would further improve the confidence level. Naturally, this requires introduction of a new "metric" measuring "the similarity" of these "wavelet vectors". This metric can also be modified to apply different weights to mid, near and far offset traces. Once this is accomplished, the classification can be done using the new basis wavelet vectors leading to much sharper distribution (large movement from EN to EP). This is demonstrated conceptually, in Figure 4 to predict percent gas saturation. Compare the sharper histograms of the vector wavelet classification (in this case, mid, near, and far offset gathers) in Figure 4b, against those of Figure 4a based on scalar wavelet classification.



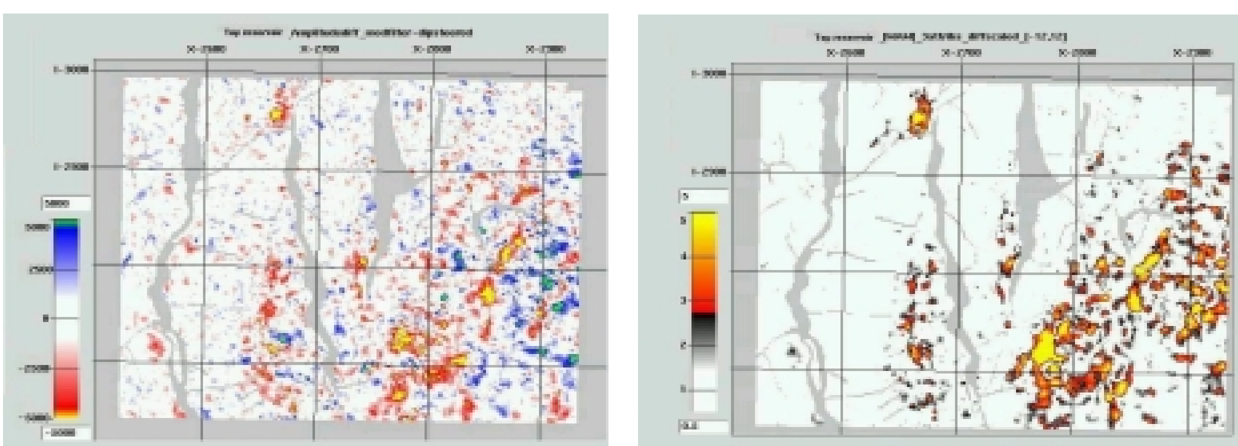
Wi = (W_{near}, W_{mid}, W_{far})

(a) (b)

Figure 4, (a) Segmentation using scalar wavelet, (b) Segmentation using vector wavelet

Dynamic Changes in reservoir Properties

Another important issue in reservoir characterization is to detect and monitor changes in reservoir properties with time. .The main breakthrough in this area will be realized by advances in data acquisition with adequate "sampling" in time (4-D). This will be made possible by further advances in "instrumented oil field" as is discussed in Lumley (2001). Of course, we should realize inherently static nature of some reservoir parameters (e.g. porosity) versus dynamic nature of others (e.g. fluid saturation) and use the right set of data for appropriate predictions. For example Oldenziel et al (2000) uses combination of two different vintage data to predict porosities while using data from different temporal measurements (time lapse data) to predict fluid fronts changes. Other recent improvement in detecting changes in reservoir properties was reported by Meldahl et al (2001) where combination of different attributes were used to observe changes in the reservoir. Figure 5 shows the enhancements resulting from such analysis.



(a) (b)

Figure 5- Detecting changes in reservoirs (a) Quantification of changes in amplitude only, (b) Quantification of changes in multitude of attributes (Courtesy of Statoil)

The next step would be to expand the idea to the three-component data case (similarity measurer of vector wave field) and 4-D case (a measure of dynamic behavior of seismic data).

Conclusions

We discussed the existing challenges in going from collected seismic and log data to description of reservoirs. We suggested use of hybrid method (physics+statistics) for relating seismic character to reservoir properties. Quantification of uncertainties of predictions and associated confidence levels are of paramount importance. Reduction of uncertainties is possible by more comprehensive use of the available data as well as utilizing vector wavelets. Proper treatment of dynamic change in reservoir properties was also discussed and a few suggestions were made.

Acknowledgements

Contributions from Paul Meldahl and Roar Heggland, from Statoil are acknowledged. Valuable contributions and assistance provided by my dGB BV colleague, in particulare those from Paul de Groot, Tanja Oldenziel and Geerteke Wansink are appreciated.

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Paper 5

New 4D Seismic Tools for Carbonate Reservoirs

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Abstract

Carbonate reservoirs are often significantly more demanding to explore and produce than siliciclastic reservoirs. The reasons for this are typically complex depositional facies with intense fracturing and diagenetic effects as compaction induced subsidence.

Time-lapse seismic monitoring of carbonate reservoirs might identify subsidence and the flow properties of the fracture network, which often make up migration paths for hydrocarbons or injector fluids. Knowing these dynamic components of the reservoir behavior helps the asset team to improve the management of the produced water and detect by-passed pay.

In this paper we present a set of new timelapse seismic analysis tools, for mapping these dynamic reservoir features and demonstrate their performance at hand of a couple of real data examples.

Introduction

The fact that carbonate reservoirs might be chemically unstable puts an extra challenge on the asset team designing a completion strategy for the field. During production subsidence is likely to occur influencing the stress and strain regime and by this posing a hazard to drilled wells. Furthermore, it is important to know the location and transmissibility of fault and fracture zones in order to successfully perform an enhanced recovery program.

Well-planning using information about the dynamic subsidence changes in the overburden will help reduce the number of lost wells.Comparing the cost of lost wells with that of a repeated seismic survey should make time lapse seismic surveying an attractive tool to assist the asset team in strategy decisions.

The limited number of successful application of 4D seismic reported in carbonates might be caused by the more subtle changes in the time lapse signal compared with siliciclastic reservoirs (Key et al).Hence the repeatability between the time lapses needs to be very high to avoid disturbing the time lapse signal. Further new 4D analysis tools are required to reveal the specific challenges for carbonate reservoirs like compaction and conducting fracture networks.

Method

Time lapse seismic might be used to estimate subsidence and compaction. Such estimates might be obtained by subtracting travel times of interpreted reference horizons (isochore-method). The disadvantage is that the quality of the estimate obviously depends on the quality of the picked horizons. This is often hard to achieve because of signal – to – noise characteristics or complex facies distibutions in the reservoir. Furthermore the isochore-method can only provide compaction estimates from thick layers made up by time - horizon pairs.

The new tool alleviates these issues by providing a subsidence and compaction estimate for each sample of the seismic volume (see Figure 1) and is thus a true 3D scheme. Further, the thus obtained estimate is less noisy. This is demonstrated in Figure 2 where the compaction estimate for one layer defined by a couple of interpreted horizon is compared for one inline with the result of the traditional travel time difference scheme.

The second method presented here assists the interpreter in detecting subtle faults and fractures. Through a resolution-modulating filter process lateral discontinuities are enhanced making it easier to detect fault planes (see Figure 3).

Both techniques when combined can help to improve the understanding of the dynamic effects occurring during production of a carbonate reservoir. Compaction as an attribute may indicate areas where the reservoir is flooded by injected water. Using further seismic attributes and subject them to a general seismic inversion tool (Sonneland et al) will produce fluid indicator maps. When superimposing on these maps the fault network, fluid migration paths identifying certain fault and fracture zones as high permeability highways become apparent. It is to be noted that even if both the attribute maps and faults are derived from the seismic volumes they still provide independent information. It is their combination that provides new inside in the dynamic properties of the reservoir.

Conclusion

With the spreading acceptance of time lapse seismic surveying as an important tool for optimizing hydrocarbon recovery from reservoirs it becomes more and more important to provide and adapt tools to analyze such data. In this paper we presented two new techniques tailor-made for the analysis of carbonate reservoirs.

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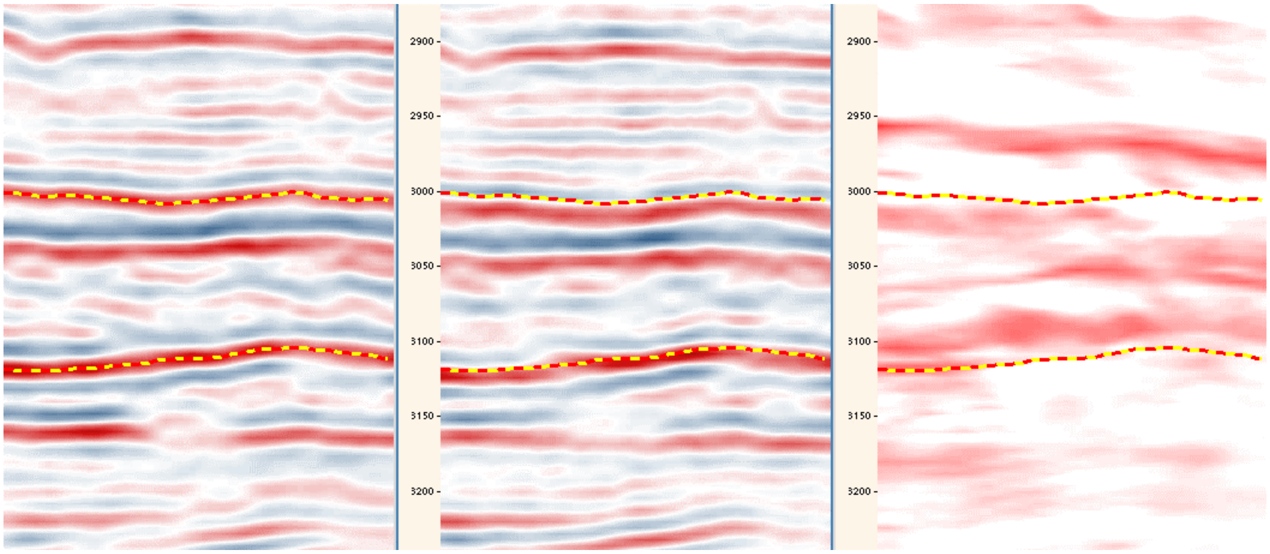

Fig. 1: Comparison of the two full-stack cubes (T1 and T2) and the resulting compaction cube. Red colors indicate compaction, white colors indicate no compaction. The dotted lines indicate the time grids for top and base of the reservoir mapped on the T1 data set. Note the displacement on the T2 data set.

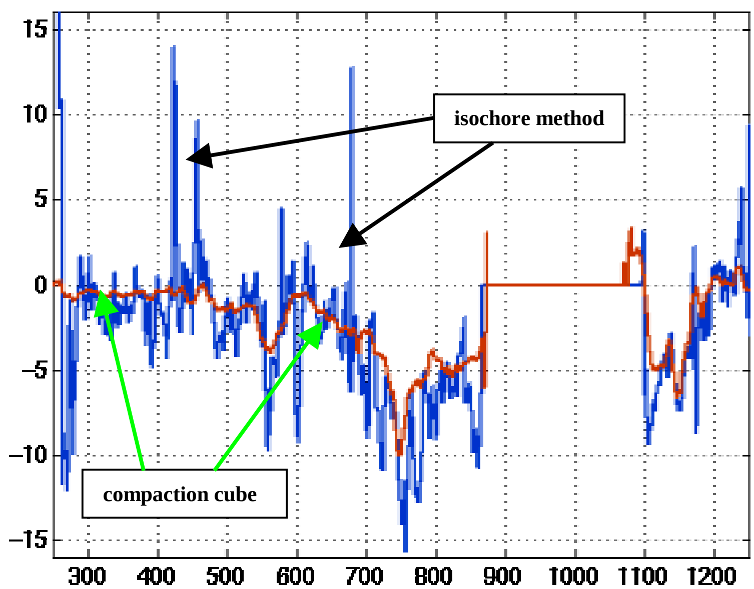

Fig. 2: Computed values of compaction along an Inline. The black curve shows the result based on the conventional isochore method. The grey curve shows compacting values based on the compaction cube. It is obvious that the compaction cube produces smoother values.

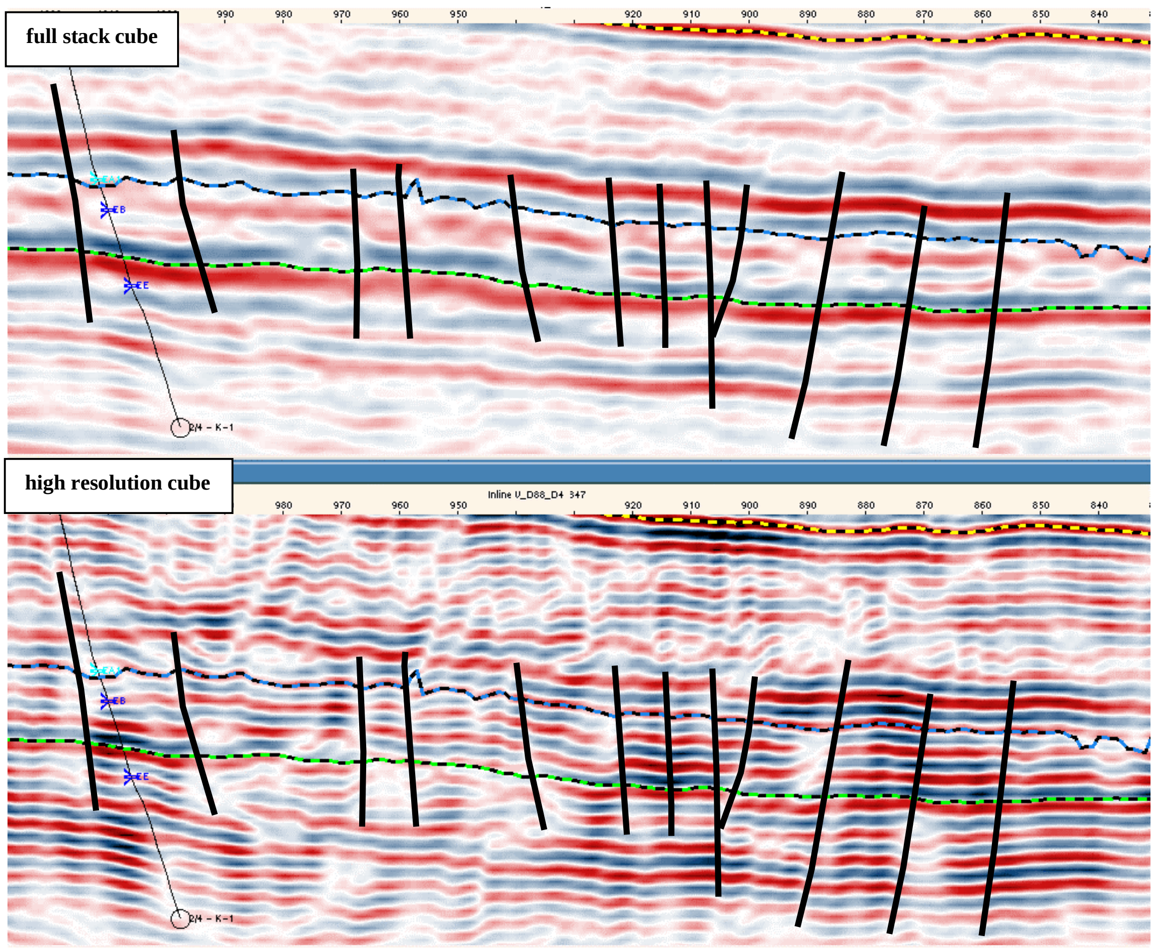

Fig. 3: Comparison of full-stack cube (top) and high resolution cube (base). Subtle faults and fractures that are hardly visible on the conventional full-stack cube, become enhanced on the high resolution cube. The fault network displayed here was mapped on the high resolution cube.

Paper 6

Instrumented Oil Field

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The instrumented oil field consist of deploying permanent instrumentation to monitor an oil field and modify production continuously or on demand. This concept has evolved from recent developments in both down hole instrumentation and time-lapse monitoring. Both of these technologies are new and combining them, with permanent installations in mind, require further steps in research and development.

The objective of instrumenting an oil field is to optimize production and minimize development and operations costs, through early investment in continous monitoring of a field. In deepwater and ultra-deepwater, where well costs can reach $50 million, instrumenting an oil field early on could consideraly improve the bottom line economics. In this case, both the investments required and the potential returns are large.

On land, oil fields can be instrumented much more economically. A basic example would be to install pressure and temperature sensors at wells to make sure a reservoir is kept above bubble point. Although the technology necessary to fully instrument an oil field is still being developed, several field applications on different parts of the technology already exist. Two examples in the area of permanent ocean bottom multi-component installations for seismic monitoring are the Foinaven field in the North Sea (Kristiansen et al., EAGE Meeting Abstracts, 2000) and the Teal South field in the Gulf of Mexico (Entralgo and Spitz, TLE, 2001). These two studies alone have created extremely useful results and allowed the industry to adress issues related to hardware deployment and longetivity, hardware design changes to improve data quality, understanding the quality of data being produced and means to manage such large data to produce timely results to impact field development, and the economics involved. On land, the state-of-the-art permanent surface seismic example is the Cere-la-Ronde case study (meunier et al., TLE, 2001).

Again, many lessons have been learned form this study ranging from hardware and data acquisition, to data processing, to data management, to interpretation. Another technology currently being used is a multi-level multi-compenent permanent borehole seismic sensor array placed between the tubing and casing (Hottman and Curtis, TLE, 2001). Fully fiber-optic multi-component seismic sensors are currently in the field trial stage. Passive seismic monitoring is currently in use in oil fields (Maxwell and Urbancic, TLE, 2001) and will be more widely used as oil fields are instrumented with borehole seismic sensors. On the non-seismic side, permanent borehole sensors to measure reservoir pressure, temperature, fluid flow, and fluid composition have been developed and tested. Crosswell seismic, electromagnetic and electrical methods are currently being used for monitoring purposes and may well take their own place in the instrumented oilfield of the future.

This vast array of information will be used in many ways. Current technology allows drilling wells that can be multi-lateral, long reach, and multi-zone with flow control. Smart wells allow the operator to use continous monitoring information to adjust the well choke in multi-zone wells. For example, if water is encroaching a certain zone and if this information can be made avaible, using flow control units, this zone can be choked and production from other zones can continue. The instrumented oilfield may well become the single most important information provider for taking reservoir development and production decisions. The current advancement into the instrumented oil field is reminiscent of advancing from 2D to 3D seismic in many ways. How will the technology work? How much development is necessary? What will the costs be?

Even though considerable advances have been made in making instrumented oil fields a reality, it is fair to say that at this time the technology necessary to fully instrument an oilfield is still premature. The support for this technology will be coming through major oil companies venturing into deepwater plays, mid-size oil companies on land and joint ventures offshore, innovative service companies and contractors who are eager to provide these services, and research and development institutions funded by government and industry. Issues that need to be addressed are hardware precision, performance, reability, integration, data management and integration, and most importantly, cost. Industry standards will be necessary on how a well should be completed so that permanent sesnsors can be placed, cables and be passed and surface controls can be accesed. On the marine and land seismic side, deployment, positioning, protection, recording (on a platform) are important issues. Once the data is recorded, data transfer, data management, rapid processing and analysis, and modifying development and production based on the information made avaible will be crucial.

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Membership: SEG, EAGE.

Work: Jason Geosystems BV.

School: Delf University of Technology.

Interests: Application of inverse theory to problems in seismic data processing, integrated interpretation, reservoir characterization.

***Selected Publications*:**

P. van Riel, A. J. Berkhout, 1982, *Limits to Seismic Trace Inversion by Iterative Modeling* Delft Univ. of Technology, Netherlands, SEG Meeting.

A.J.W. Duyndam (Inst. for Applied Geoscience), P. van Riel, E.J. Kaman, 1984, *An Iterative Scheme for Wavelet Estimation and Seismic Section Inversion in Reservoir Seismology*, Delft Univ. of Technology, Netherlands, SEG Meeting.

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Paul van Riel, Peter R. Mesdag, 1988, *Detailed Interpretation of the North Sea Magnus Field by Integration of Seismic and Well Information*, Jason Geosystems BV. SEG Meeting.

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Fred Aminzadeh

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Membership: SEG, EAGE, SPE, AAPG, AGU, National Research Council's Committee on Seismology, Azerbaijan Oil Academy and Russian Academy of Natural Sciences.

Work: Unocal, including manager of geophysical technology. Earlier, he worked at Exxon and as an adjunct professor at Rice University

Honors: SEG Special Commendation (1998)

School: PhD thesis from University of Southern California dealt with AVO modeling.

Interests: He has contributed to different aspects of geophysics on processing, modeling, analysis and interpretation methods.

Selected Publications:

His Fred's many patents, papers, and books include the groundbreaking paper on clustering seismic attributes (1984), and books on *Pattern Recognition* (1987) and *Expert Systems in Exploration* (1991).

Aminzadeh, F. et al, *Reservoir Parameter Estimation Using a Hybrid Neural Network*, Computers and Geoscience, Vol. 26, pp 860-875, 2000.

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Aminzadeh, F.; Ward, R.D., 1995, *Future geophysical technology trends.* SEG Meeting.

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Dasgupta, S.; Kim, J.; AlMousa, H.; Aminzadeh, F.; Lunen, E., 2000, *From seismic character and seismic attributes to reservoir properties: Case study in Arab-D reservoir of Saudi Arabia.* SEG Meeting.

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Work: 1972-74 Univ. of Bergen; 1974 Geco-Prakla.

School: Cand. Mag. Math. Physics Comp. Sci. 1970 Cand. Real. Applied Math. 1973, UB.

Honors: 1984 Technology Award, Norwegian Chartered Engineers; 1987 Norwegian Geophysicist Award.; 2000 Best Schlumberger Research Project Award.

Membership: EAGE; IEEE; NPS; SEG; SIAM; SSA.

Interests: Wave theory, numerical/image analysis, reservoir

Selected Publications:

Sønneland L., Reymond B. and Thorsteinsen H.H. Pedersen L.M., Johansen R.L *Classification of fluid fronts in 4D Seismic*, EAGE 1996.

Bernth, H; Sønneland L., 1983, *Wave Field Extrapolation Techniques for Prestack Attenuation of Water Reverberations.* SEG Meeting.

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Borresen, C; Bergsma, W.; Sønneland L.; 1988 *Interactivw Seismic Processing.* SEG Meeting.

Sønneland L.; Barkved, O.; Olsen, M.; Snyder, G.,1989 *Application os Seismic Wave Field Attributes in Reservoir Characterization.* SEG Meeting.

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Tjøstheim, B.; Sønneland L.; Larssen, B.; Jaasund, S., 2001, *Analysis of long offset sub-salt data using model-based processing.* SEG Meeting.

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Work: 1987-88 Berkeley Engineering Research Group; 1988-90 Lawrence Berkeley National Lab; 1990-92 ARCO Exploration & Production Technology; 1992-94 Research Council of Turkey; 1994-97 Elf Geoscience Research Centre UK;1997-99 Chevron Petroleum Technology Co; 1999-present 4th Wave Imaging.

School: BS 1983 Istanbul Univ; MSc 1996, PhD 1990 Univ of California, Berkeley,

Honors: Associate Professor 1993; Exchange Visiting Scientist award 1993.

Membership: AGU; EAGE; SEG.
Interests: Time-lapse seismic, instrumented oilfield, seismic data inversion and AVO.

Selected Publications:

Tura, M. A. C., 1990, *Multiparameter Elastic Inversion: A Stable Method*. SEG Meeting.

Tura, M. A. C., 1991, *Application of Diffraction Tomography*. SEG Meeting.

Hanitzsch, C.; Tura, M. A. C., Coates, R. T.; Beydoun, W. B., 1995, *The effects of TI anisotropy on AVO inversion: A field-based study*. SEG Meeting.

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Lumley, D.; Cole, S.; Meadows, M.; Tura, A.; Hottman, W.; Cornish, B.; Curtis, M.; Maerefat, N., 2000, A risk analysis spreadsheet for both time-lapse VSP and 4-D seismic reservoir. SEG Meeting.

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