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An integrated approach to reservoir petrophysical parameters evaluation

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Abstract: Petrophysical parameters necessary for reservoir characterisation are normally derived from borehole data. Such information can be very accurate in the depth direction but has a small lateral penetration. Surface seismic, on the other hand, has low vertical resolution but is laterally continuous. Calibration of the seismic data to borehole information through integrated processing permits reservoir petrophysical parameters to be accurately mapped from seismic data. The relationship between seismic and petrophysical properties is addressed with reference to a reservoir evaluation study. The relationships are used to calibrate seismic data and to map heterogeneities in reservoir description parameters.

INTRODUCTION

Borehole data provided by wireline logs, test results and core analysis are normally used to obtain reservoir description parameters. However, borehole data is fundamentally one-dimensional and cannot satisfy all the criteria necessary for spatial reservoir characterisation of rock and fluid properties. Mapping from borehole data relies upon three dimensional modelling which is accurate only under conditions of low inter-well reservoir heterogeneity. Assumptions about the reservoir properties between wells can lead to large inaccuracies in the predicted behaviour, reservoir management programme and ultimately, the productivity of the field.

There is clearly a demand for an alternative source of information to characterise reservoir heterogeneities between wells. Such information is available from surface seismic data. Historically, seismic data has been used extensively for gross structural delineation purposes and recent advances in seismic inversion techniques has allowed more detailed stratigraphic interpretation (Weathers and Helm, 1984; de Buyl *et al*, 1988). However, the seismic contribution to reservoir production and development programmes has been limited. This is because seismic data is only qualitatively related to subsurface geology and does not provide a recognisable reservoir description parameter.

It is the aim of this paper to demonstrate how these limitations can be overcome and to show how seismic data can form a valuable and reliable input to spatial reservoir characterisation. This is achieved by adopting an integrated approach to processing, analysis and synthesis of seismic data into a three-dimensional dataset. Integrated processing techniques produce results that

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are far superior to those obtained using conventional techniques where the seismic or well data is treated in isolation. The increased information provided by this method leads to greater control over parameter selection and to more reliable parameter validity testing.

To best illustrate the principles and practical applications of this approach an example is taken from a study carried out in an offshore producing oil and gas field (Poggiagliolmi *et al.*, 1988; Woodling *et al.*, 1990). The study was carried out in 1988 and comparisons were subsequently provided by the Oil Field Operator between the study results and wells drilled at a later date or not included in the dataset.

Geologically, the field comprises widespread reefoidal limestones characterised by large build-ups along basement highs. The field is structurally controlled by major fault complexes to the west and north and covers an area of approximately 2500 ha. The top of the reservoir is in the region of 760 metres MSL and the maximum thickness of the gas and oil column is 27 metres and 45 metres, respectively. Reservoir porosity varies rapidly between wells and within the reservoir from less than 10% to in excess of 30%. Both oil and gas are present and the reservoir is considered to be structurally controlled and in partial communication.

The data used in the integrated study consisted of a grid of 67 seismic lines totalling 700 kms in length (Fig.1). Borehole data comprised the full suite of wireline logs, core analysis and test result for 30 production and delineation wells.

INTEGRATED SEISMIC PROCESSING

The integration of seismic and well data starts at the onset of seismic processing. The well logs are edited and calibrated to the surface seismic by means of borehole seismic. The editing is based on a multi-well, multi-line approach and is carried out interactively and by direct interaction between borehole and seismic data. This direct interaction between the two datasets is also exploited to objectively optimise the selection of all seismic processing parameters and to further refine the editing of the log data.

Throughout the seismic processing sequence emphasis is placed on achieving high signal-to noise ratio, attenuation of multiple reflections and phase and amplitude stability of primary reflections over the zone-of-interest.

Interactive wavelet extraction is carried out on the stacked and migrated traces at the well locations to obtain a reliable estimate of the seismic wavelet. Space adaptive wavelet shaping is applied to all the seismic lines to convert the wavelet associated with seismic reflections to symmetrical (zero phase) pulses. This wavelet shaping significantly enhances the resolution of the data through the zone-of-interest.

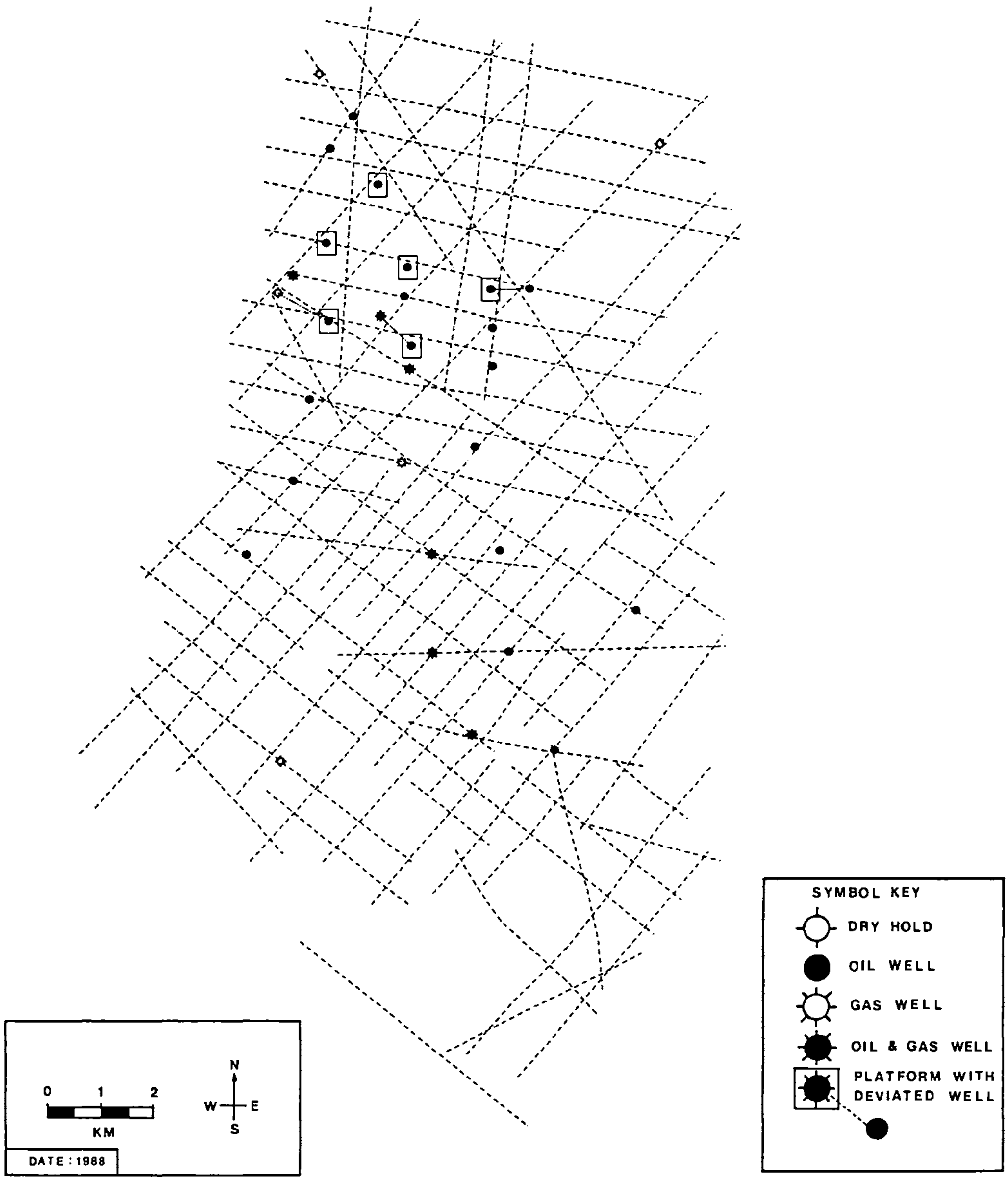


Figure 1: Seismic line and well location map of study area. The grid of seismic lines is sufficiently dense to spatially map reservoir heterogeneities.

The wavelet shaped seismic data at this stage is suitable for structural interpretation purposes. The data is objectively calibrated to well reflectivity and the shape of the wavelet within the data is known. However, it is still essentially a relatively low resolution dataset which can be used for seismic horizon delineation. Even the use of seismic attribute displays such as instantaneous phase or amplitude provide little insight into reservoir properties and can only be used qualitatively. For accurate intraformational response it is necessary to obtain a measurement of seismic acoustic impedance.

SEISMIC ACOUSTIC IMPEDANCE

Seismic acoustic impedance is computed form wavelet shaped data by inversion. The specific method of inversion used in this study (Micromodelling) is based on the assumption that the band limited seismic traces consist of discrete reflection spike sequences convolved with a wavelet, and additive noise. The Micromodelling algorithm generates a series of acoustic interfaces consistent with the available bandwidth. Micromodelling utilises the bandwidth down to where the signal-to-noise ratio is equal to unity.

The vertical resolution obtained by conventional seismic processing of this data is approximately 10 ms, corresponding to an interval thickness through the reservoir in excess of 20 metres. By contrast, the resolution obtained by calibrated processing and Micromodelling improves the minimum resolution to 4 ms corresponding to a thickness over the reservoir interval of less than 8 metres (Fig. 3). Of equal importance is the lateral resolution. After calibrated processing this is in the region of 35 metres. This means that for spatial mapping purposes, instead of 30 data points supplied by the well data, Micromodelled seismic data yields 20,000 spatially resolvable data points. Acoustically, the reservoir heterogeneities can now be mapped between the wells with a high degree of accuracy.

Up to this stage in the calibrated processing sequence, objectivity is maintained by using well data to select and test processing parameters. However, interpretation is necessary to define the upper and lower limits of the reservoir and to delineate fluid contacts for further study. The conventional output from such seismic interpretation is time structure and time interval maps. However, in this study seismic acoustic amplitudes are calibrated to well acoustic impedance and the reservoir thickness, porosity and finally hydrocarbon content can be computed along each seismic profile.

RESERVOIR THICKNESS

Reservoir thickness can be obtained by application of a constant velocity function through a defined time interval. However, this lends itself to large inaccuracies from velocity variations within the reservoir. Multiwell modelling

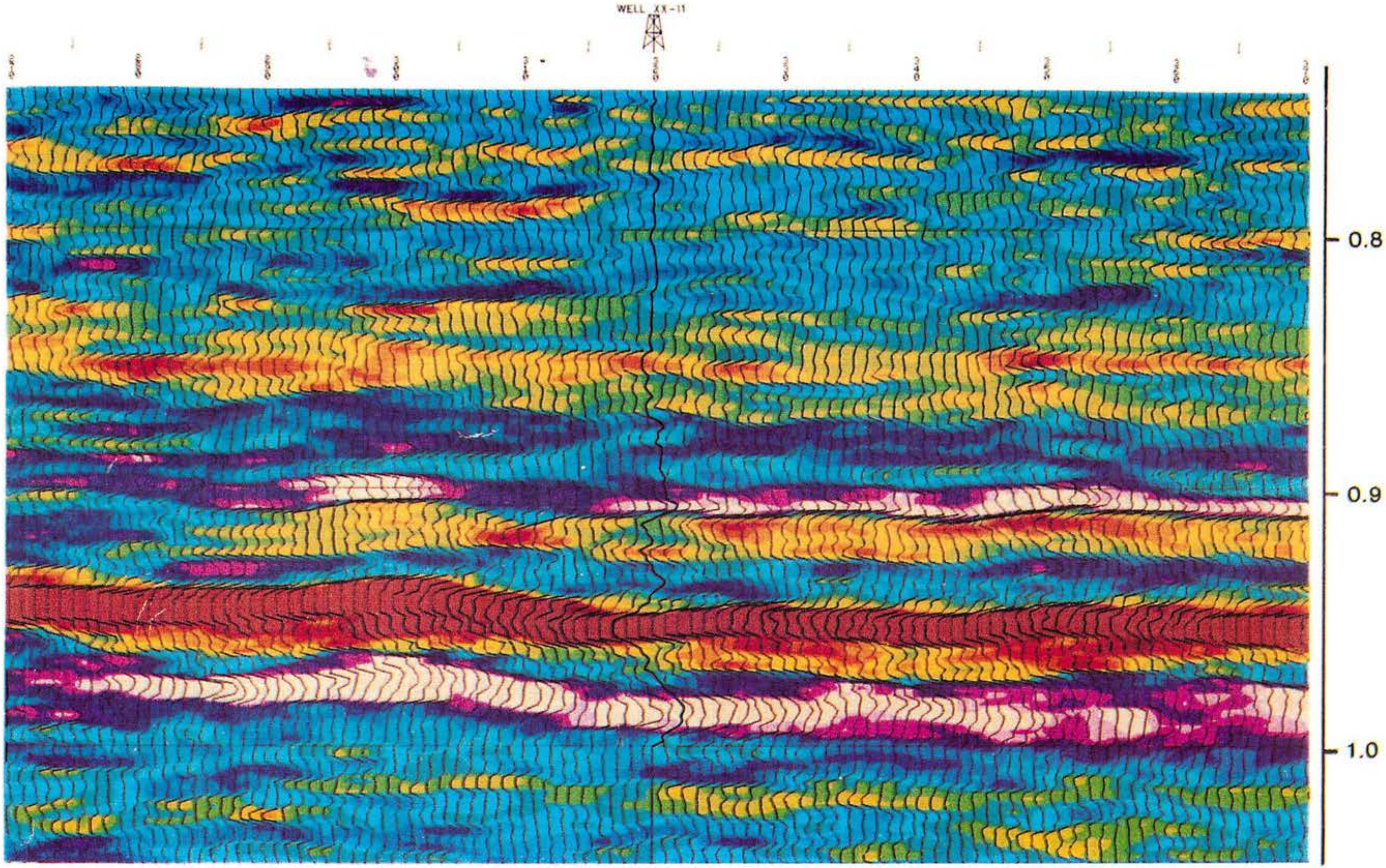


Figure 2: Seismic acoustic impedence section of an east-west line in the central portion of the field generated by Micromodelling. The vertical scale is in two-way-time (seconds) and colour contours represent acoustic amplitudes. The well acoustic impedence log is inserted at the on-line well position and the reservoir interval lies between 0.86 and 0.98 seconds.

provides acoustic-velocity relationship that can be applied to the seismic data and used to compute interval velocity. The velocity variations are taken into account in the time interval to thickness computation and accurate reservoir thickness is obtained along each profile. The accuracy of the derived reservoir thickness was independently investigated by the Oil Field Operator including wells not used in the study. A comparison shows that the agreement between borehole and seismic reservoir thickness is excellent for both total reservoir and hydrocarbon saturated intervals (Fig. 3).

RESERVOIR POROSITY

Accurate measurement of reservoir thickness covers only one aspect of seismic to borehole parameter calibration. Quantitative petrophysical measurements can be made from Micromodelling by calibrating the acoustic impedance amplitudes to rock physical parameters determined from well data. The principles of Micromodelling calibration are based upon the assumption that the acoustic properties of reservoir rocks depend primarily upon their mineralogical composition, porosity and type of pore fluid.

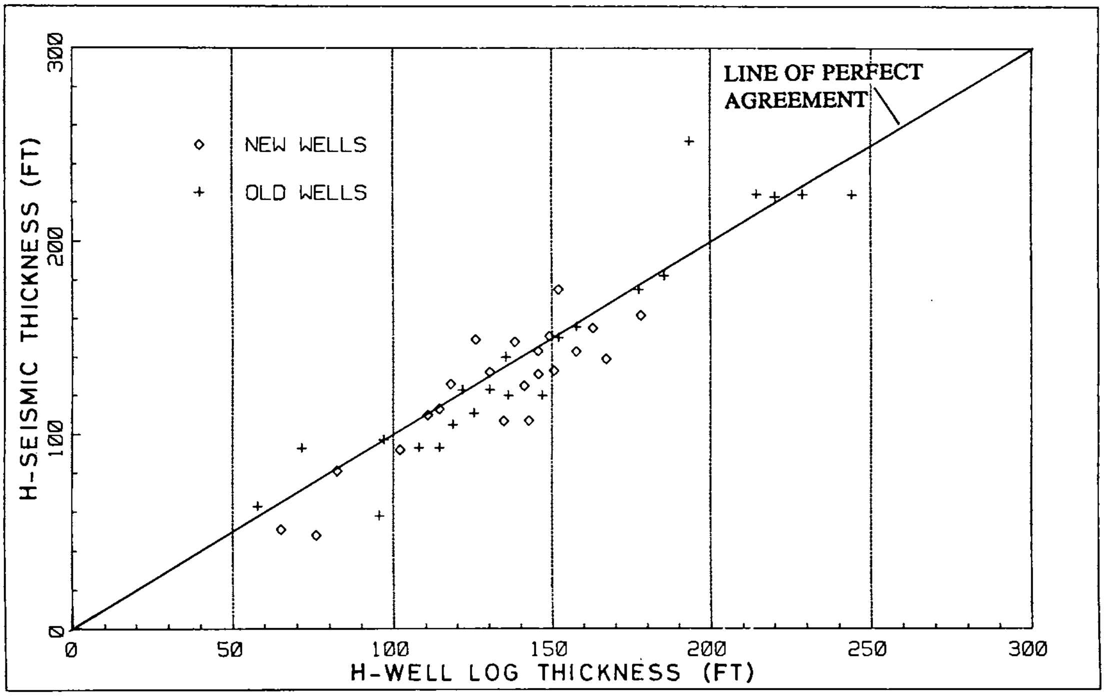
A multivariate petrophysical model tailor-made to the field is designed specifically for the reservoir interval. This is achieved using all the available borehole information from the 30 wells in a multivariate and multiwell statistical model to estimate effective porosity. Core data plays an important role in the construction of the model, both in the selection of input parameters and in the validity tests of the results.

In this the accuracy of porosity determined from the Micromodelling is in the region of ±3pu. This confidence limit is derived from two principal sources. Firstly, in the reliability of acoustic impedance as a porosity tool in the petrophysical calibration and secondly from analysis of errors within the seismic data itself. Confidence in the seismic data is measured throughout the processing sequence.

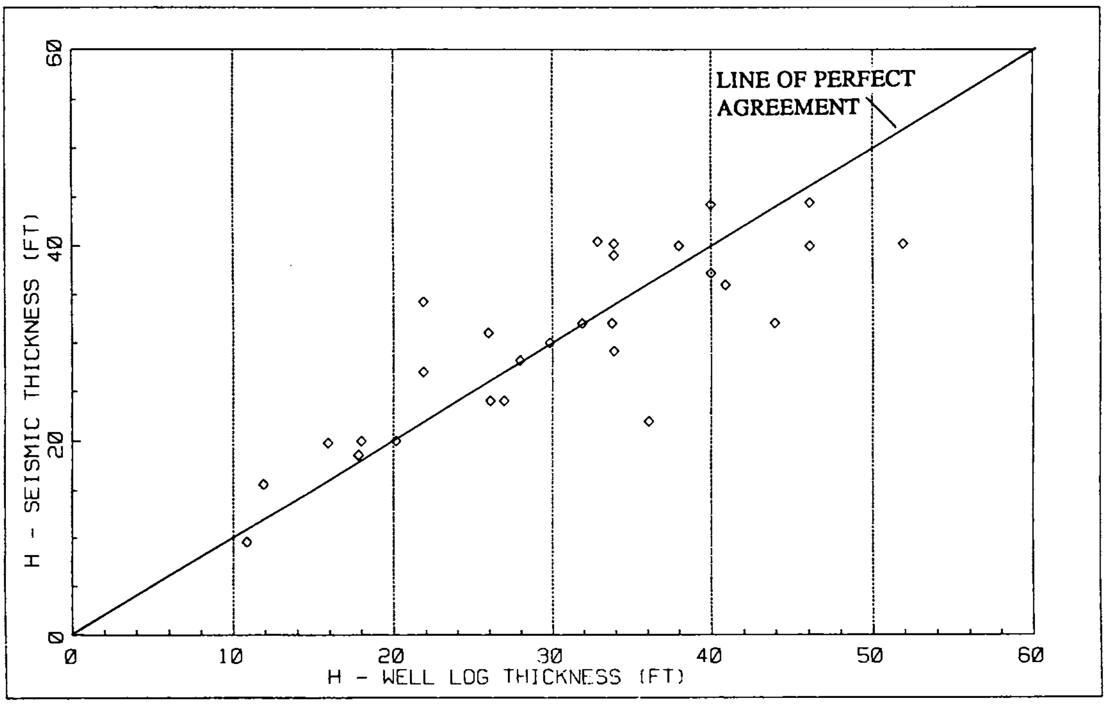
Maps generated from porosity calibrated seismic acoustic impedance provide an accurate high resolution spatial distribution of the reservoir porosity (Fig. 5). The highly heterogeneous nature of the field is clearly visible and is well outside the mapping capabilities of the well data. The porosity-height (PHI-H) encountered at the well found to be in good agreement with well log porosity. This can be demonstrated by analysis provided by the Oil Field Operator (Fig. 4).

RESERVOIR HYDROCARBON DISTRIBUTION

Reservoir porosity maps provide the spatial (vertical and horizontal) effective porosity distribution and do not contribute information on the distribution



a



b

Figure 3: Comparison of well log reservoir thickness to seismic derived reservoir thickness from analysis by Oil Field Operator. Analysis was performed independently of the study by including well data (new wells) not used in the study dataset.

a. For total reservoir

b. For hydrocarbon bearing interval

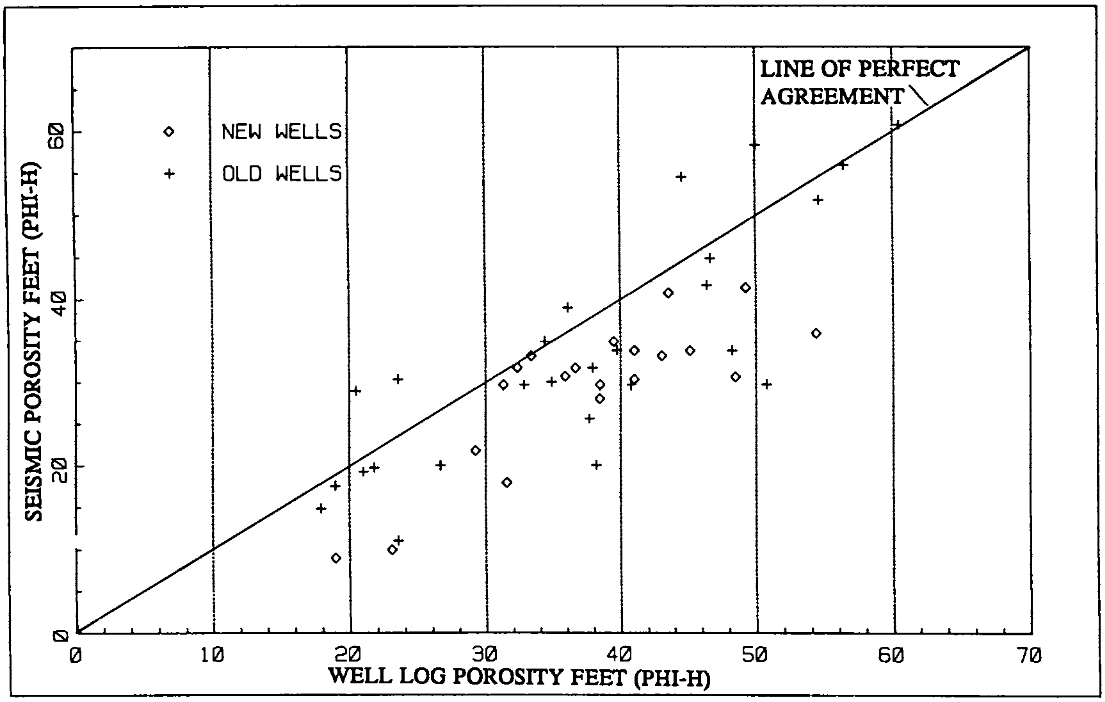


Figure 4: Comparison of well log porosity-height (PHI-H) to seismic derived reservoir PHI-H from analysis by Oil Field Operator.

(PHIE{1-Sw}H) can also be obtained from calibrated seismic data. In this study the gas-oil-contact is acoustically definable and can be delineated along the Micromodelling sections. This means that PHI-H can be separated into non-gas and gas reservoirs.

However, SW within the gas column cannot be computed from Micromodelling since acoustic impedance is insensitive to gas volume variations. In order to obtain a measure of gas volume it is necessary to model SW from space variant capillary pressure curves obtained at the well locations. Maps produced in this way provide net-gas distribution with high spatial resolution porosity and thickness components but low spatial resolution SW components (Fig. 6). The edge of the gas column is well defined as are reservoir heterogeneities through the gas cap.

The same procedure can be applied to the oil interval. However, the oil water contact is not acoustically definable and has to be interpolated between and extrapolated away from the wells. More accurate OWC is possible under the gas cap since the thickness of the oil-column can be measured from the calibrated reservoir thickness profiles.

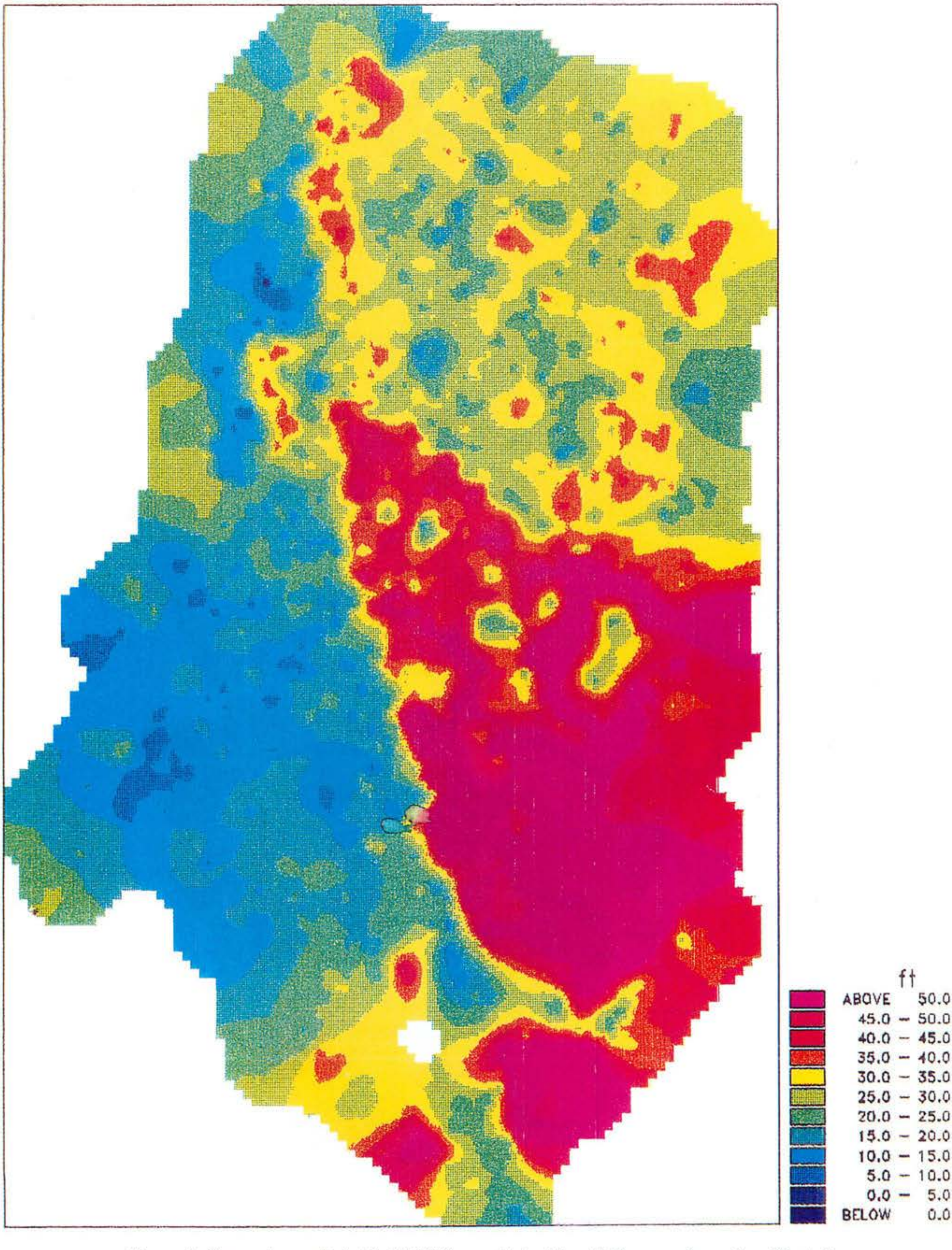


Figure 5: Reservoir porosity-height (PHI-H) map obtained from thickness and porosity calibrated seismic lines

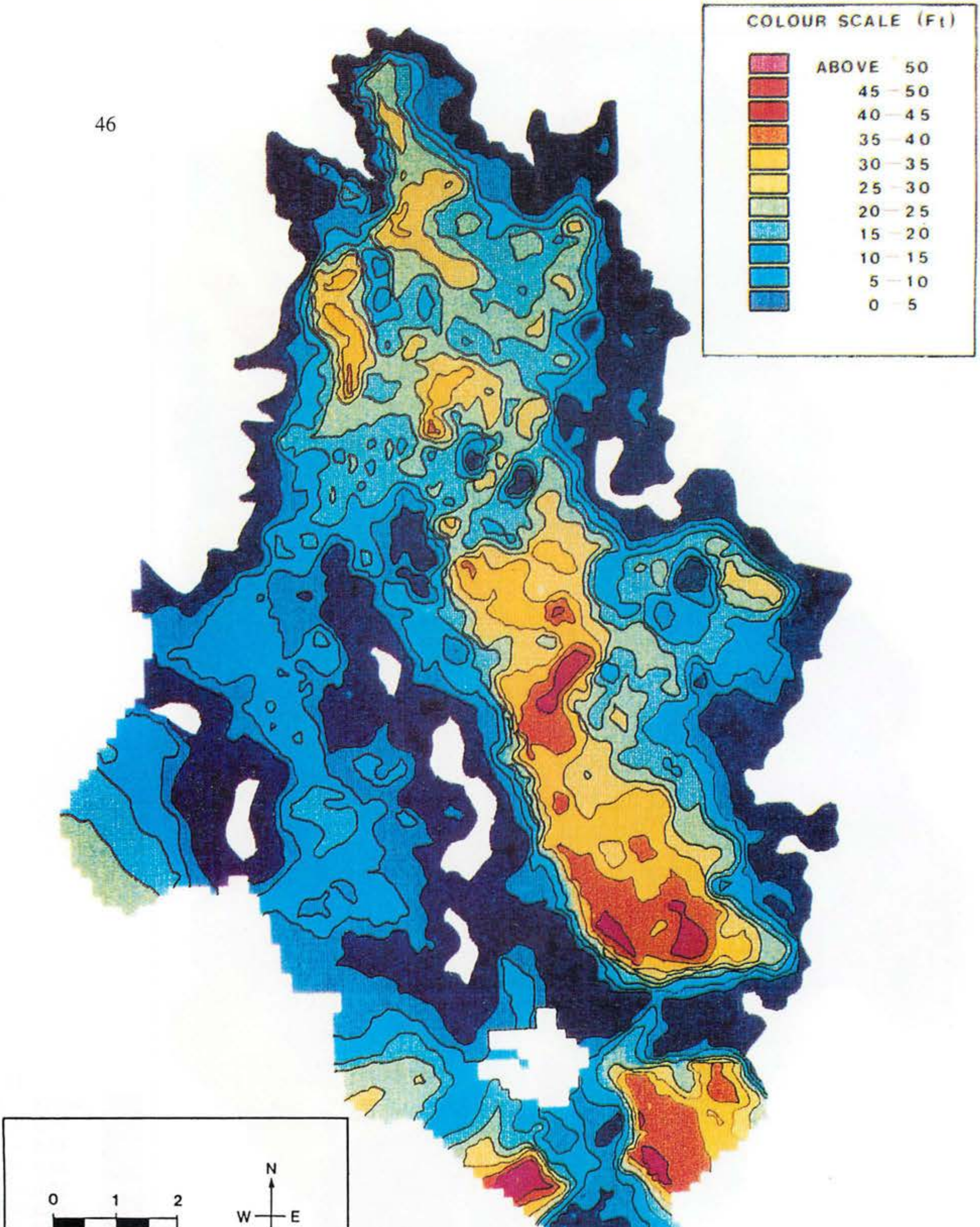


Figure 6: Net gas-in-place map obtained from thickness and porosity calibrated seismic data and well derived SW.

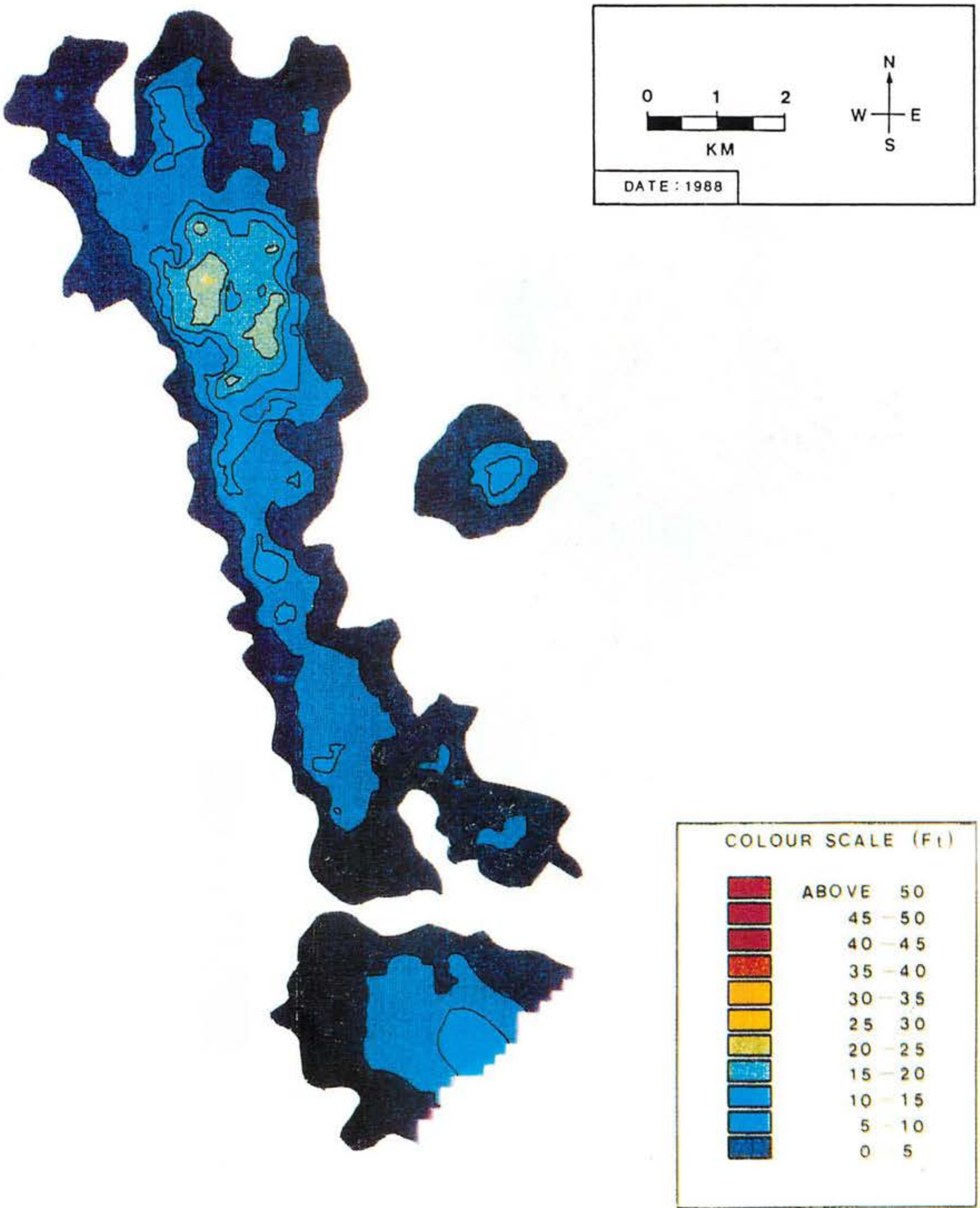


Figure 7: Net oil-in-place map obtained from thickness and porosity calibrated seismic data and well derived SW.

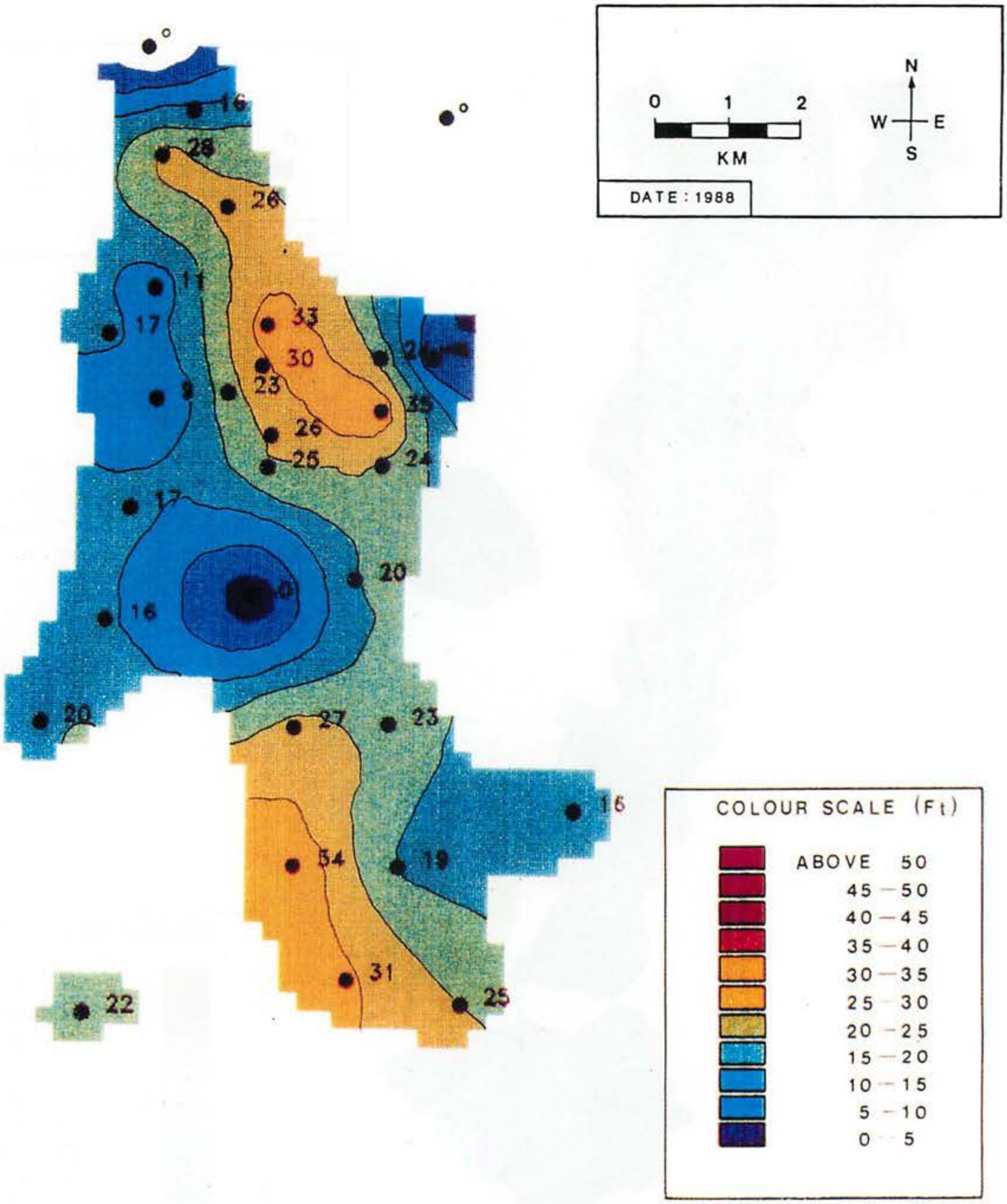


Figure 8: Net oil-in-place obtained from well data. The information provided by the wells is insufficient to map the spatially varying reservoir quality observed in figure 7.

Again well derived capillary pressure curves are used to model Sw and included with porosity cut-offs to map the net-oil distribution (Fig. 7)

The result produce accurate hydrocarbon maps of the net oil distribution, showing spatially the OWC and the potential productivity of the field. In comparison a map showing net oil in place generated from the 30 wells alone is insufficient to characterise reservoir heterogeneities (Fig. 8).

CONCLUSION

The inherent limitations of conventionally processed seismic data are the low vertical resolution, the high interpretative component and the absence of recognisable reservoir description parameters. By integrated and borehole calibrated processing these limitations can be overcome in such a way that seismic data provides an accurate and spatially reliable reservoir delineation and mapping tool. Well data provides a one-dimensional reservoir response and maps generated from borehole data alone are subject to large inaccuracies due to reservoir heterogeneities. Calibrated seismic data considerably reduces the unknown spatial component. Integration of seismic and well dataset provides an effective method for accurate spatial description of reservoir parameters.

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