ESTIMATION OF RESERVES AT DIFFERENT PHASES IN THE HISTORY OF AN OIL FIELD

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ABSTRACT. To each phase of a petroleum reservoir description study corresponds a given level of available information, at a certain scale. In the end of each phase, a set of estimations must be performed in order to sustain the decisions required to proceed the venture. In this case study, concerning a Middle East oil field, it is aimed to assess, for each phase in the history of the reservoir, the performance of different estimation techniques - FAI-K, UK, Median Polish, Trend Surface Analysis - and their impact on oil reserves and estimation errors.

1. INTRODUCTION

The oil reserves estimation problem is faced by the petroleum industry in several ways, depending on the available level of information. Yet, even for a given stage of the development of the field, a variety of estimation techniques may be applied, and the reservoir engineer relies usually on his "experience" to choose the "best" procedure, the rationale behind that choice being sometimes unexplicit.

In the case study presented here, it is aimed to illustrate how a series of different estimation methodologies compare, in four stages of development of a densely recognized reservoir.

The scope of the paper is restricted to the estimation of a regionalized variable in 2-D: it regards the net oil column in a geological layer (sub-zone), the geometry of which is assumed to be known. Taking as an input the available data at a certain stage, the variable is estimated at the location of the wells drilled at the following phase, using the complete set of possible techniques. Comparing the estimated values with the real ones, a hierarchy of suitable techniques is derived for each phase.

This work is included in a research project granted by the EEC Hydrocarbons Commission, the objective of which is to adapt geostatistical methodologies and software for the specific characteristics of oil variables. The general framework underlying the project is a step-by-step approach, which splits the modelling process used in the appraisal of oil reservoirs into "pieces" and checks each piece individually, seeking to

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test each software module with the appropriate data set. As an example , the step reported here regards the procedures that can be applied in the evaluation of reserves of an extensively recognized reservoir, containing the main features encountered in the oil industry, and providing a typical data set, large enough to validate the estimation techniques.

2. GENERAL CHARACTERISTICS OF THE FIELD

The selected Middle East oil field produces from porous limestones of Lower Cretaceous age. The morphology of the reservoir is an elongated, domed anticline, resulting from pillows formed from movements of deeply buried salt of Cambrian age. The reservoir is divided into subzones by four main stylolitic intervals, evaluated from core's description,neutron and induction logs characteristics.

The development of the field is now in its final stage, but its history can be divided into 4 phases, as described in TABLE I.

TABLE I - Available Data

	NUMBER OF WELLS	
	Total	Producers
1. Exploration Phase	11	6
2. Appraisal Phase	27	23
3. Development Phase	56	31
4. Final Stage	117	69

The total number of wells includes producers, injectors, water supply and abandoned wells. For each phase, results of classic volumetric oil-in-place reserve calculations are available from former geological studies. These results, referred to each layer obtained by lithological studies, are now to be compared with those obtained by geostatistical methods.

The geometry of the reservoir, which has the shape of a well marked dome with a maximum thickness of 195 ft and a lateral extension of 25 x 9.5 km, is assumed to be known for this case study, as well as the limits of the layer (subzone) to be treated specifically (average thickness of 30.4 ft). Regarding the oil water contact, early test and pressure data were used to determine original fluid levels and properties. For the layer concerned to this study, an elevation of 7950 ft was found and a value of 226 sq Km was derived for the closure area of the subzone.

3. RESERVES EVALUATION METHODOLOGY

In order to estimate the oil in place contained in the subzone to be studied, it is required to calculate the following integral:

$$V = \int_A dA \int_{TOP}^{MIN(BOT,OWC)} \varnothing(1-SW)dZ \qquad (1)$$

A is the closure area
TOP is the elevation of the subzone top
OWC is the elevation of the oil water contact
BOT is the elevation of the subzone bottom
Ø is the porosity ratio
SW is the water saturation ratio

if the product $O = h\varnothing(1-SW)$, denoted "net oil column"(where h is the layer's thickness above OWC), is calculated using the available data, the expression (1) can be approximated by:

$$V = \Delta A \sum_i O_i^* \delta_i \qquad \delta_i = \begin{cases} 1 & \text{if} \quad TOP_i < OWC \\ 0 & \text{otherwise} \end{cases} \qquad (2)$$

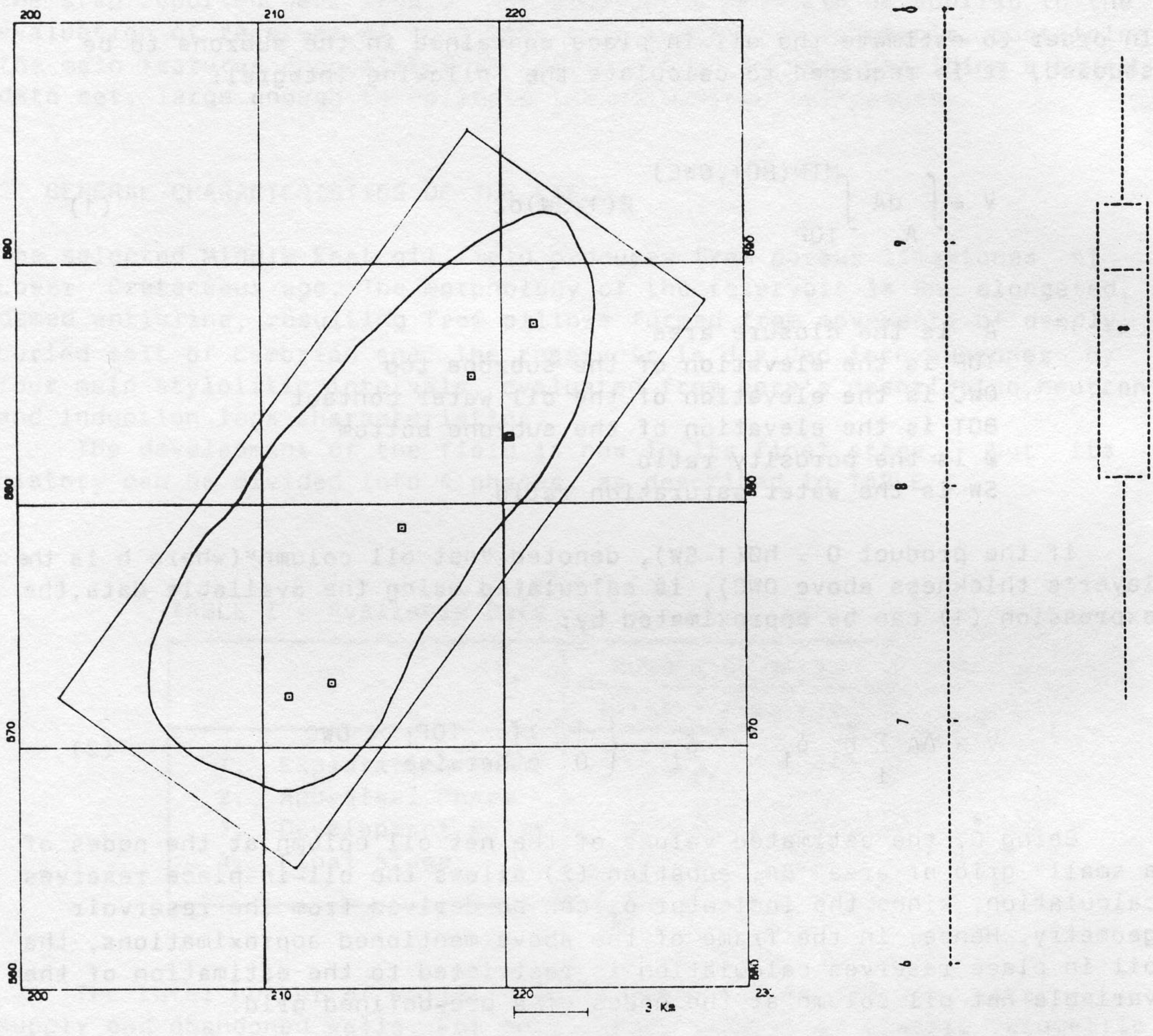
Being O_i^* the estimated values of the net oil column at the nodes of a small grid of area ΔA, equation (2) allows the oil-in-place reserves calculation, since the indicator δ_i can be derived from the reservoir geometry. Hence, in the frame of the above mentioned approximations, the oil in place reserves calculation is restricted to the estimation of the variable net oil column at the nodes of a pre-defined grid.

4. AVAILABLE DATA

Measurements of thicknesses, porosities and water saturations are available for the wells referred in TABLE I Porosities were averaged from log and core values and water saturations were evaluated, for the producers of each stage, taking into account both log values on wells drilled prior to water injection and capillary pressure curves.

The net oil column was calculated for the wells considered as producers at a certain stage. The location of such wells is shown in Fig. 1 to 4. In the same Figures, the statistical distribution of the variable to be estimated is depicted through the box-plot and stem-and leaf, for different stages of the drilling sequence.

Regarding the reservoir fluid data analysis, a single suite of PVT data is recommended. The oil formation volume factor (Bo) used to express the hydrocarbon volumes in standard surface conditions is 1.60 RB/STB at initial reservoir conditions.

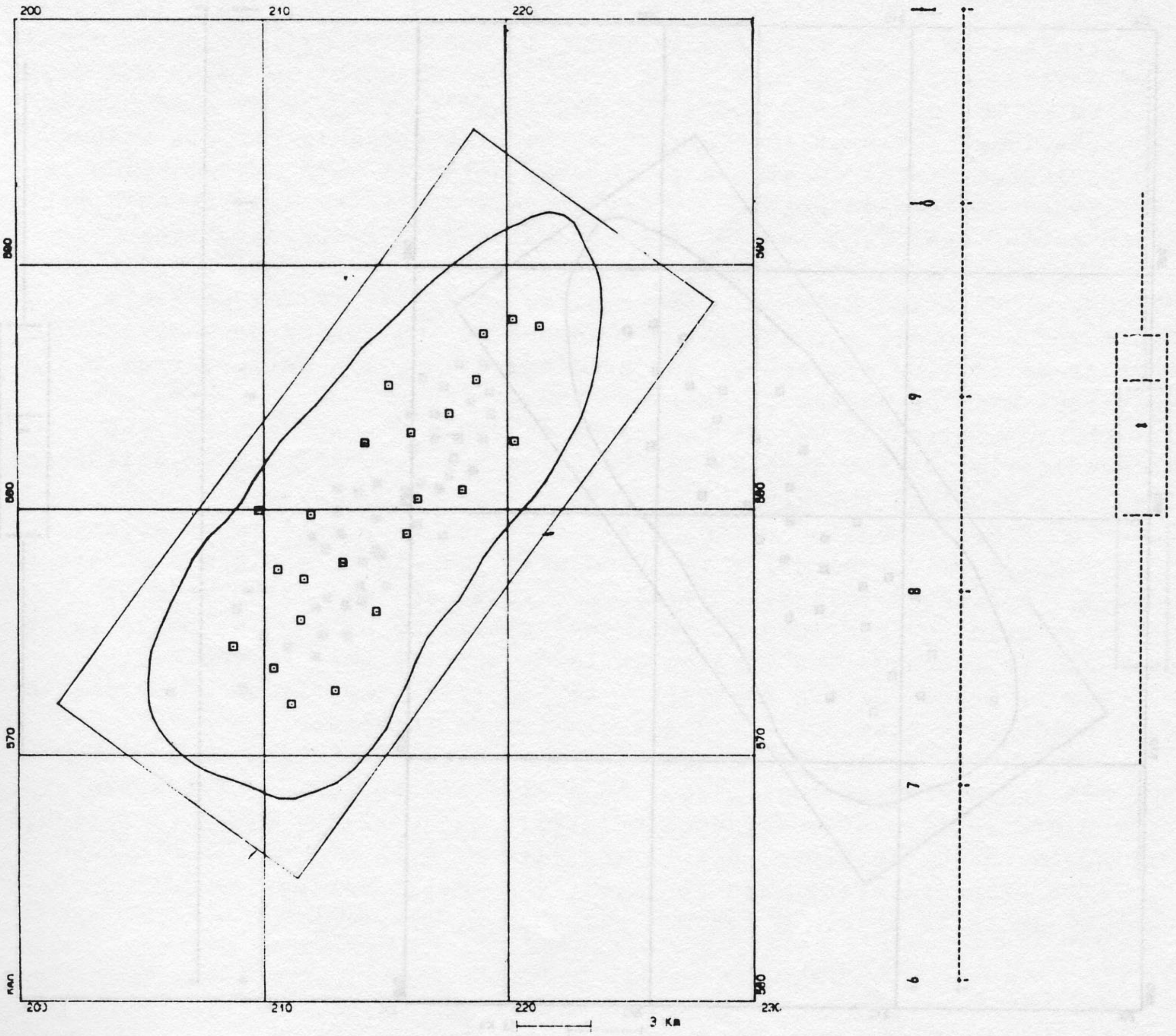


STAGE 1

STEM-AND-LEAF

7 | 1
8 | 06
9 | 117

Fig. 1 - Well Locations and statistical distribution of the net oil column. (Stage 1).



STAGE 2

STEM-AND-LEAF

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 7 |11
 8 |023446788
 9 |01111333678
10 |0
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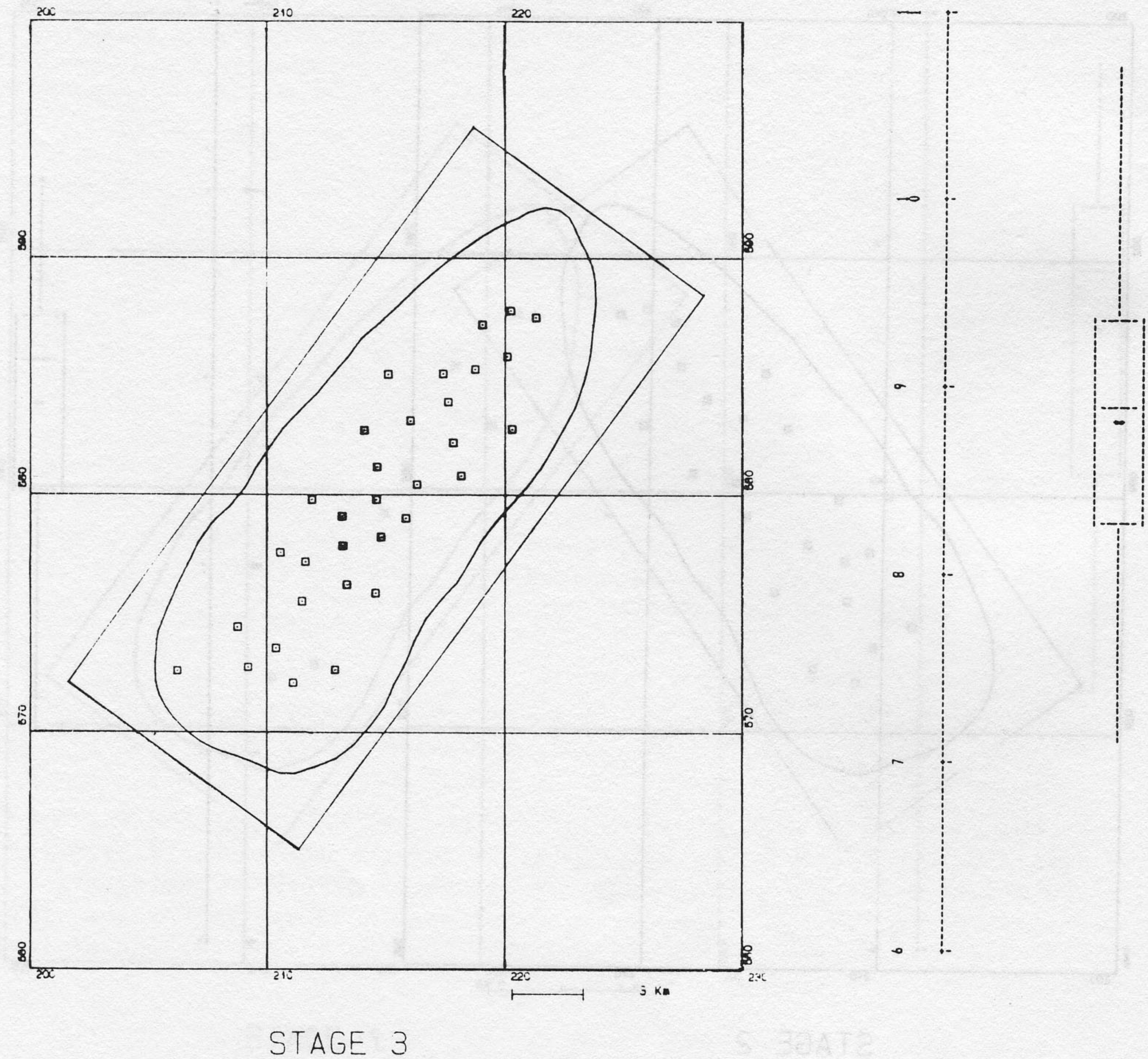
Fig. 2 - Well locations and statistical distribution of the net oil column. (Stage 2).



STEM-AND-LEAF

```
 7 |13446
 8 |002344677889
 9 |0111133346778
10 |07
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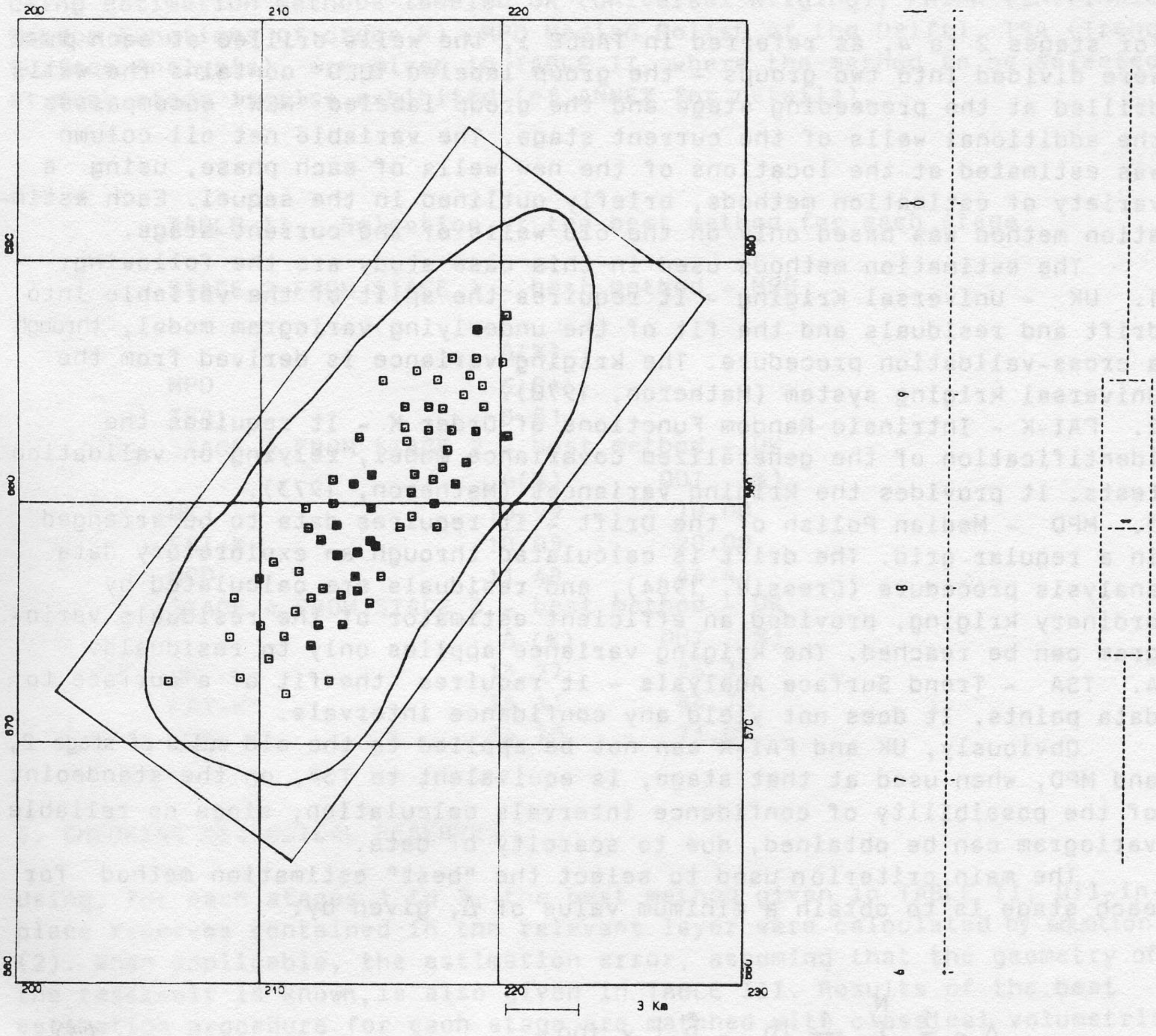
Fig. 3 - Well locations and statistical distribution of the net oil column. (Stage 3).



STAGE 4

STEM-AND-LEAF

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 6 |6779
 7 |11133344445666677799
 8 |00011111222333334446677889999
 9 |0111111233346778
10 |07
```

Fig. 4 - Well locations and statistical distribution of the net oil column. (Stage 4).

5. COMPARISON OF ESTIMATION METHODS

For stages 2 to 4, as referred in TABLE I, the wells drilled at each phase were divided into two groups - the group labeled "OLD" contains the wells drilled at the preceeding stage and the group labeled "NEW" encompasses the additional wells of the current stage. The variable net oil column was estimated at the locations of the new wells of each phase, using a variety of estimation methods, briefly outlined in the sequel. Each estimation method was based only on the old wells of the current stage.

The estimation methods used in this case study are the following:

1. UK - Universal Kriging - It requires the split of the variable into drift and residuals and the fit of the underlying variogram model, through a cross-validation procedure. The kriging variance is derived from the universal kriging system (Matheron, 1970).
2. FAI-K - Intrinsic Random Functions of Order K - It requires the identification of the generalized covariance model, relying on validation tests. It provides the kriging variances (Matheron, 1973).
3. MPD - Median Polish of the Drift - It requires data to be arranged in a regular grid. The drift is calculated through an exploratory data analysis procedure (Cressie, 1984), and residuals are calculated by ordinary kriging, provided an efficient estimator of the residuals variogram can be reached. The kriging variance applies only to residuals.
4. TSA - Trend Surface Analysis - It requires the fit of a surface to data points. It does not yield any confidence intervals.

Obviously, UK and FAI-K can not be applied to the old wells of stage 2, and MPD, when used at that stage, is equivalent to TSA, on the standpoint of the possibility of confidence intervals calculation, since no reliable variogram can be obtained, due to scarcity of data.

The main criterion used to select the "best" estimation method for each stage is to obtain a minimum value of Δ, given by:

$$\Delta = \frac{1}{N} \sum_{i=1}^{N} \frac{1}{O_i} \left| O_i - \overset{*}{O}_i \right| \times 100 \qquad (3)$$

N is the number of new wells for the current stage
O_i is the real value of the net oil column for the new wells
$\overset{*}{O}_i$ is the estimated value of the net oil column based on old wells.

Whenever confidence intervals can be calculated, an additional criterion applies: the "best" method is the one that provides a minimum percentage of real values lying outside the confidence intervals derived from the method yielding a standard deviation denoted γ (cf. (4)).

$$OUT = \frac{N - \sum_{i=1}^{N} \delta_i}{N} \times 100 \qquad \delta_i = \begin{cases} 1 & \text{if } \overset{*}{O}_i - 2\gamma < O_i < \overset{*}{O}_i + 2\gamma \\ 0 & \text{otherwise} \end{cases} \qquad (4)$$

Results obtained for the above mentioned criteria at stages 2 to 4, using estimation methods labeled UK (Universal Kriging), FAI-K (Intrinsic Random Functions of order K),(MPD Median Polish of the Drift), TSA (Trend Surface Analysis), are given in TABLE II, where the method to be selected at each stage is also exhibited (cf. ANNEX for details).

TABLE II - Selection of the best method for each stage

STAGE 2 FROM STAGE 1 - best method - MPD

	Δ(%)	
MPD	6.04	
TSA	8.81	
STAGE 3 FROM STAGE 2 - best method - UK		
	Δ(%)	OUT (%)
UK	10.99	10.00
FAI-K	10.05	20.00
MPD	11.48	44.44
STAGE 4 FROM STAGE 3 - best method - UK		
	Δ (%)	OUT (%)
UK	15.27	26.32
FAI-K	15.11	44.74
MDP	14.70	71.05

6. CHECKING GEOLOGICAL RESERVES

Using, for each stages 1 to 3, the best method given in TABLE II, Oil-in-place reserves contained in the relevant layer were calculated by equation (2). When applicable, the estimation error, assuming that the geometry of the reservoir is known, is also given in TABLE III. Results of the best estimation procedure for each stage are matched with classical volumetric calculations, available from former geological studies (Cf. TABLE III).

The error in TABLE III means $\frac{2\sigma k}{Z^*} \times 100$ where Z^* is the estimated value of the variable. The results show a consistent trend encompassing all the estimation methods and pointing out reserves above the calculated volumetric reserves.

These results show that the mapping of water saturation is a critical problem because this parameter is time dependent and is a function of the elevation of the reservoir above the oil water contact. The method selected for reserves estimation layer per layer guarantees a more correct treatment of the water saturation problem and is particularly indicated in cases where the transition zone plays a major role. In the calculation applying geostatistical methods, special attention has been given to the evaluation of oil-in-place under the original conditions and the saturation data are the result of log interpretation and capillary pressure curves for the wells drilled prior to water injection.

In fact the layer considered in this study has been waterflooded and some of the more recent west and east flank wells display SW values contaminated by the water front advance. In this regard, the geostatistical results appear to be more related to the original conditions and they are in agreement with the calculations made for the period of 24 months of normal depletion of the reservoir when using the compressibility definition the reserves were calculated as 3.4×10^9 STB.

The geostatistical results, placed between this optimistic estimation and the more pessimistic geological calculations, should be a key point for the reevaluation of the global oil reserves of this reservoir and can be very important for the planning of future recovery operations.

TABLE III - Checking geological reserves

		Oil-in-place Reserves(10^9 STB)	ERROR(%)
STAGE 1	Median Polish of Drift	2.395	
	Geological Reserves	2.028	
STAGE 2	UK	2.410	6.3
	Geological Reserves	1.866	
STAGE 3	UK	2.395	5.7
	Geological Reserves	1.928	

7. CONCLUSIONS

This case study illustrates how a series of different estimation methodologies can be compared according to the existing level of information in the different stages of the life of an oil field.

The choice of the best estimation method in each phase relies on the assessing of quality of the estimates checking them against the true values.

Comparing the different methods, Median Polish appears to be simple and operational even when the scarcity of data is a major problem. Universal kriging and FAI-K appear to display a similar performance but UK is more reliable when a standard structural analysis is possible and the choice of drift and variogram model is supported by the geological evidence.

Results reported here concern the comparison of different estimation methods of the net oil column in a certain volume, assumed to be known for a given layer. But, for reserves evaluation purposes, a key point is the complexity of the variables controlling that volume, particularly the water saturation which is time dependent and has significantly changed over the life of the field. In this case the evaluation of the initial saturation conditions, with particular attention to the log data obtained prior to water injection, is an essential step. The geostatistical results show that a careful analysis of the more recent data in connection with the water front advance and taking into account fluid level movements and capillary pressure curves is needed in order to avoid too pessimistic estimates.

The case study shows as well the need for more consistent treatment of time dependent variables as fluid saturations or oil water contact movements which yield inequality-type data and constraints, becoming the estimation methodology strongly dependent on its ability to depict the dynamic variations on the reservoir fluids properties.

8. REFERENCES

Cressie, N., 1984 - 'Towards Resistant Geostatistics' in Geostatistics for Natural Resources Characterization, Part 1, 21-44, D.Reidel Publishing Company.

Matheron, G., 1970 - 'La théorie des Variables Regionalisées, et ses Applications', Les Cahiers du Centre de Morphologie Mathématique de Fontainebleau, Fascicule 5.

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ANNEX

GEOSTATISTICAL MODELS FOR STAGE 2 AND 3

For the variable "net oil column" a structural analysis was performed, aiming at the estimation by UK and FAI-K methods. Model identification results are summarized in the sequel.

STAGE 2

Universal Kriging

Variograms of variable "net oil column" are depicted in Fig. 3, for directions 1 and 2, corresponding to the major direction of reservoir development and the perpendicular one.

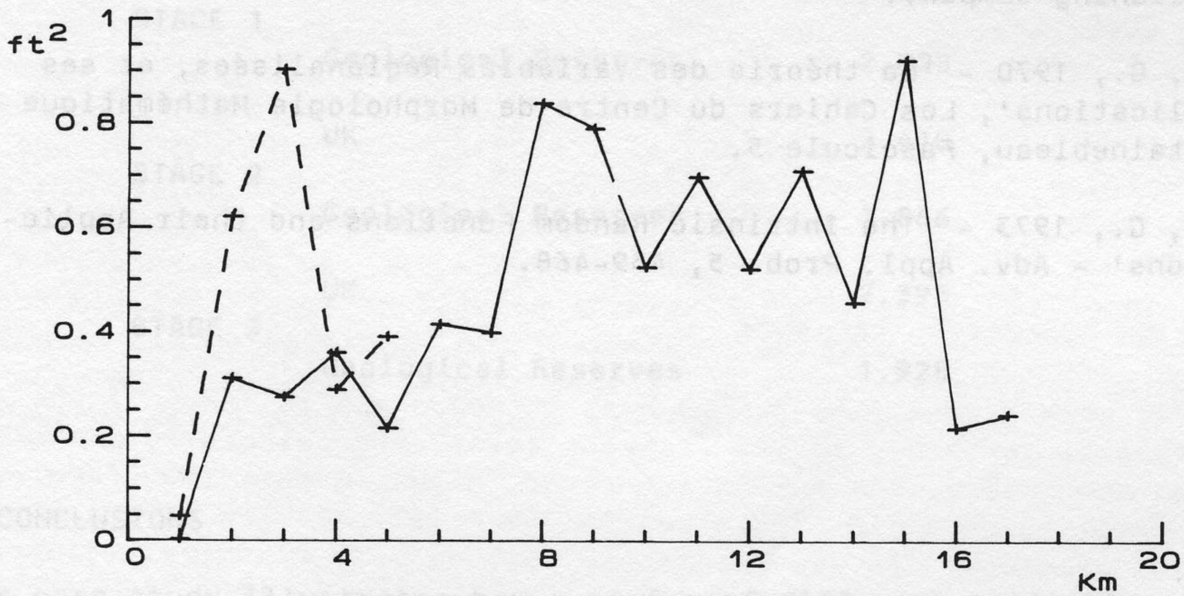

Figure 5. Experimental variogram of the "net oil column" (Stage 2)
—— Azimuth 54°
--- Azimuth 144°

The parameters of the spherical scheme were obtained combining visual fitting and the usual cross-validation tests, which give $ME = \frac{1}{N} \sum (Z^* - Z)$ and $MRSE = \frac{1}{N} \sum \left[(Z^* - Z)/ \sigma_k\right]^2$.

The fitted spherical model is:

$$\gamma(h) = \begin{cases} .15 + .50 \left(\frac{3h}{18} - \frac{h^3}{1458}\right) & h \leqslant 9 \text{ km} \\ .65 & h > 9 \text{ km} \end{cases}$$

being the validation criteria results ME = -.076 MRSE = 1.265, for an anisotropy ratio of 3:1.

FAI-K

Using the FAI-K methodology, a generalized covariance model was found for K = 1 an $C(h) = -.225 \times 10^{-3} \; |h|$, being ME = .0641 and MRSE = .996.

STAGE 3

Universal kriging

In Fig. 4, variograms for stage 3 are depicted, for the variable "net oil column".

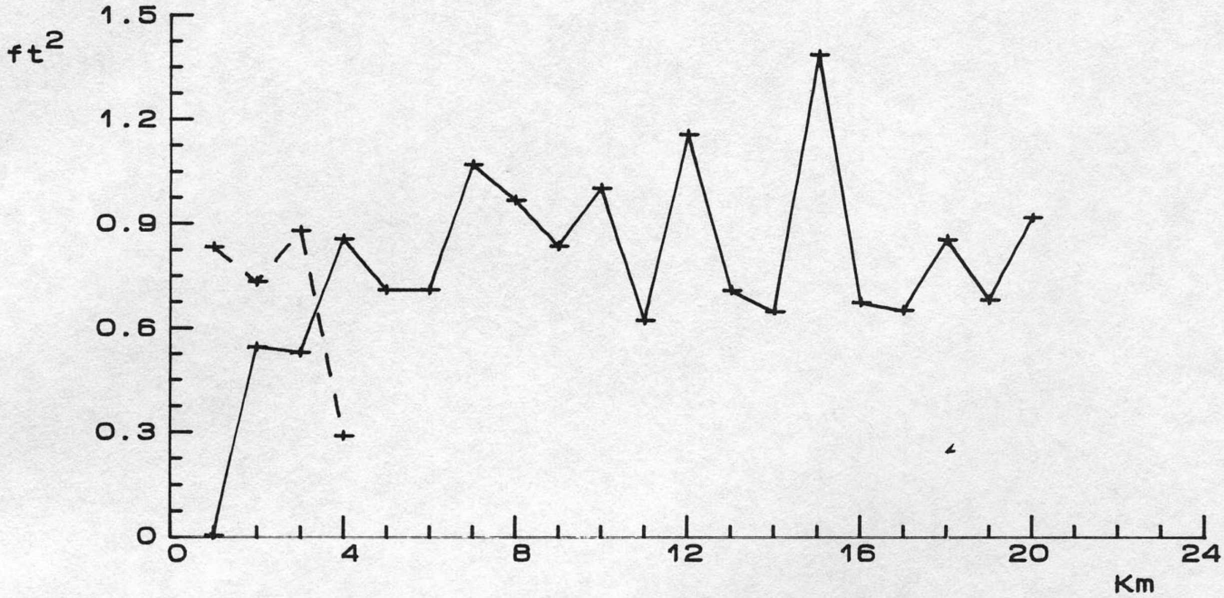

Figure 6. Experimental variogram of the "net oil column" (Stage 3)
—— Azimuth 54°
--- Azimuth 144°

the fitted spherical model is:

$$\gamma(h) = \begin{cases} .10 + .80 \left(\frac{3h}{12} - \frac{h^3}{432}\right) & h \leqslant 6 \text{ km} \\ .90 & h > 6 \text{ km} \end{cases}$$

being the validation criteria results ME = -.75 MRSE = 1.013, for an anisotropy ratio of 3:1.

FAI-K

Using the FAI-K methodology, a generalized covariance model was found for K = 1 and $C(h) = -.42 \times 10^{-3} \; |h|$, being ME = -.0124 MRSE = 1.005.