Science and Technology, 1 (1996) 37-45
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Effect of Compositional Grading on Reservoir Performance

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خلاصة: إن المكامن البترولية التي تفوق ثخانتها عن الخمسين متراً يتأثر أداؤها بنسبة كبيرة عند احتوائها سائلاً بتروليا يتصف بالتدرج في تركيبة محتوياته . فخواص السائل الموجود مثل الكثافة واللزوجة تتحكم بدرجة كبيرة في الأداء العام لذلك المكمن وعند تغيرها نسبياً مع عمق المكمن فإنها ولابد تؤثر على أداء ذلك المكمن . تبين الدراسة في هذا البحث مدى تأثير خاصية التدرج في تركيب السائل الزيتي في الأداء العام للمكامن البترولية وتثبت أن تجاهلها وخصوصاً عند أخذ عينة من عمق غير مناسب قد يؤدي إلى أخطاء كبيرة . إن هذه الخاصية ، وهي خاصية التدرج في التركيب لها أثر كبير في التقديرات البترولية وقد تكون السبب في الأخطاء التي يرتكبها مهندسو المكامن عند اختيار وسيلة لتنشيط عملية الاستخلاص مثلا . وفي حالة وجود اختلافات في كثافة مكونات عمود الزيت ، فإن المكونات الثقيلة تكون حاجزاً عند أسفل المكمن ، وهذه الحالة سوف تؤدي إلى أداء سيئ في استخراج الزيت وتتسبب في اندفاع المياه من الطبقات السفلى إلى خارج البئر بسبب الإختلاف في تركيبة السائل .

ABSTRACT: In reservoirs with thickness exceeding fifty metres, compositional grading has been found to cause a significant variation in performance. Main fluid properties, governing the magnitude of reservoir performance, such as density, formation volume factor and fluid viscosity experience variation due to varying fluid composition along the hydrocarbon column. These variations cause erroneous estimation of stock-tank oil in place and may infer reservoir engineers to consider inappropriate secondary oil recovery methods, for example. In the presence of gravity segregation within the oil column, heavy ends will form a heavy oil blanket in the lower part of the reservoir. Such a scenario may result in poor displacement and an earlier breakthrough when water drive is the dominant fluid flow mechanism. In this paper, reservoir performance due to varying reservoir fluid composition, has been examined using reservoir simulation analysis and recommendations for better characterisation of reservoir fluid sampling are outlined.

Many authors emphasised the possibility of compositional grading within a single oil pool and noted consequences of misleading estimation of pressure-volume-temperature (PVT) properties on reservoir performance and future field development.

Schulte (1980) noted considerable variation in composition and PVT properties with depth in various oil and gas-condensate fields. Hirschberg (1988) noted that significant compositional grading can occur in a reservoir because of gravity. He added that the effect can be inferred from reservoir fluid phase behaviour, noted that the heavy polar components play a key role in compositional grading of oil in reservoirs by gravity and he, in particular, remarked that in heavier oils (stock-tank oil gravity $\geq$ 0.85 gm/cm^3 [$\leq$ 35° API]), asphaltene segregation will be the dominant effect. Riemens, Schulte and de Jong (1988) concluded that thermodynamic modelling of reservoir fluid indicated that gravity could have induced compositional variations along the hydrocarbon column. They added that field tests of a South Oman field, Birba, confirmed the thermodynamic model to be correct. They also formulated a set of conditions causing a variation in reservoir fluid composition and properties in a single oil pool.

Schulte (1980) and Hirschberg (1988) and Montel and Gouel (1985) also suggested the estimation of compositional grading, using the derived thermodynamic conditions for strong segregation, as soon as PVT data for reservoir fluids are available. The models proposed require fine tuning of equations of state (EOS) in order to match field acquired data. In tuning the equations of state, different proportions of C_{7+} fractions have to be tested along with eccentric factors and binary interaction coefficients. Lira-Galeana and Firoozabadi (1993) presented a thermodynamic framework to represent compositional changes due to gravity forces in hydrocarbon reservoirs. They described the compositional grading problem by continuous thermodynamics towards establishing the effect of gravity on C_{7+} characterisation parameters.

Conditions Promoting Strong Segregation

Near critical conditions, light oils show a strong degree of gravity segregation, since any pressure drop below saturation pressure will infer rapid changes in formation volume factor. For heavy oils, heavy ends accumulation at the base of the hydrocarbon column is enhanced with presence of large molecules whose density is significantly different from the average reservoir fluid density. Thermal, compositional and mechanical forces are in the origin of fluid change in composition with depth. Treating composition of the oil in a given layer as an open system that can interchange matter with its underlain layer, then the total Gibbs free energy, nG, which is a function of temperature and pressure, is also a function of the number of moles of the various chemical species present in the layer. This can be expressed as follows:

$$nG = f(T, P, n_1, n_2, \ldots\ldots\ldots\ldots, n_j, \ldots\ldots\ldots\ldots) \qquad (1)$$

where, n_j represents the mole numbers of the chemical species; T, the temperature; and P the pressure.

Hence the total differential form of G may be presented as:

$$dG = \left(\frac{\partial G}{\partial T}\right)_P dT + \left(\frac{\partial G}{\partial P}\right)_T dP + \sum \left(\frac{\partial G}{\partial x_j}\right)_{T,P} dx_j \qquad (2)$$

As detailed in the appendix, assuming temperature change within the interval is negligible, equation 2 leads to the following expression that relates mole fraction of component j, x_j, as a function of depth, h.

$$dG = \left(\frac{\partial G}{\partial P}\right)_T \bar{\rho} g dh + \sum_j \mu_j dx_j \qquad (3)$$

where μ_j is the chemical potential.

Simulation Model Description

A single-well model was built to simulate production performance of a layered system with each layer having characteristic PVT properties. The PVT properties of the condensate reservoir vary with depth in such a manner that heavy liquid components have increasing proportions in the bottom layers. Gravity segregation was taken to be in the origin of the accumulation of heavy ends in higher proportions at the base of the hydrocarbon column. At bubble-point pressure, the formation volume factor ranges between 3.52 to 1.91 bbl/stb, viscosity increases from 0.070 to 0.151 cp and solution gas-oil ratio decreases from 4.44 to 1.72 Mscf/stb with an increasing depth of 545 feet. No natural water drive is anticipated in the field and the ultimate recovery from the field depends largely on the gas-oil ratio segregation rate in the reservoir.

Eclipse 100 black-oil simulator was used to investigate the effects of treating the reservoir as a single PVT region. The black-oil model was also used in simulating the behaviour of a layered system portraying different PVT regions. Each layer was then considered as a PVT region resulting from grading. PVT properties for each layer were generated using Eclipse PVT package grading option. Sensitivities were run to show the effects of unrepresentative sampling of reservoir fluids on estimation of stock-tank oil in place and thereafter layer/reservoir production performances.

TABLE 1

PVT Properties Used for Simulation Study.

Properties	Top Layer	Layer 2	Layer 3	Layer 4	Bottom Layer
C_1-C_6	78.882	77.761	76.765	75.855	75.010
C_7+	15.364	16.492	17.496	18.415	19.270
N_2	0.762	0.746	0.732	0.721	0.710
CO_2	3.808	3.821	3.830	3.836	3.840
H_2S	1.184	1.180	1.177	1.173	1.170
API	43.8	38.9	34.8	31.4	28.4
R_{sob}, Mscf/stb	4.437	3.397	2.674	2.136	1.722
B_{ob}, bbl/stb	3.520	2.880	2.451	2.141	1.907
μ_{ob}, cp	0.0703	0.0849	0.1023	0.124	0.151

API	American Petroleum Institute gravity
B_{ob}	Formation volume factor at bubble-point pressure, bbl/stb
R_{sob}	Solution gas-oil ratio at buble-point pressure, Mscf/stb
μ_{ob}	Viscosity at bubble-point pressure, cp

TABLE 2

Reservior Properties Used for Simulation Study.

Properties	Dimension
Δx, ft	500
Δy, ft	500
Δz, ft	109
h, ft	545
A, Acres	574
ϕ, fraction	0.30
k, mD	500

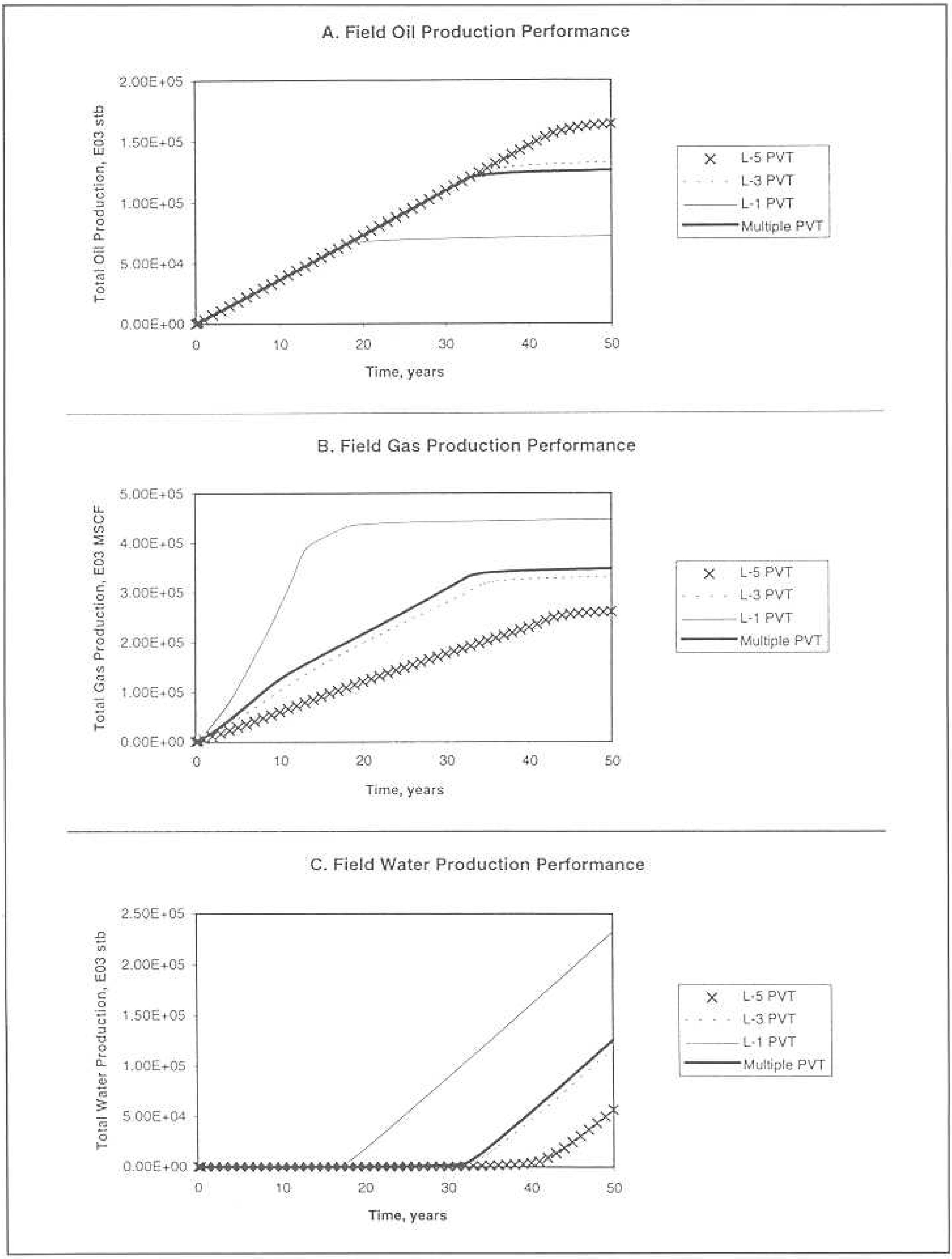


Figure 1. Overall Field Performance.

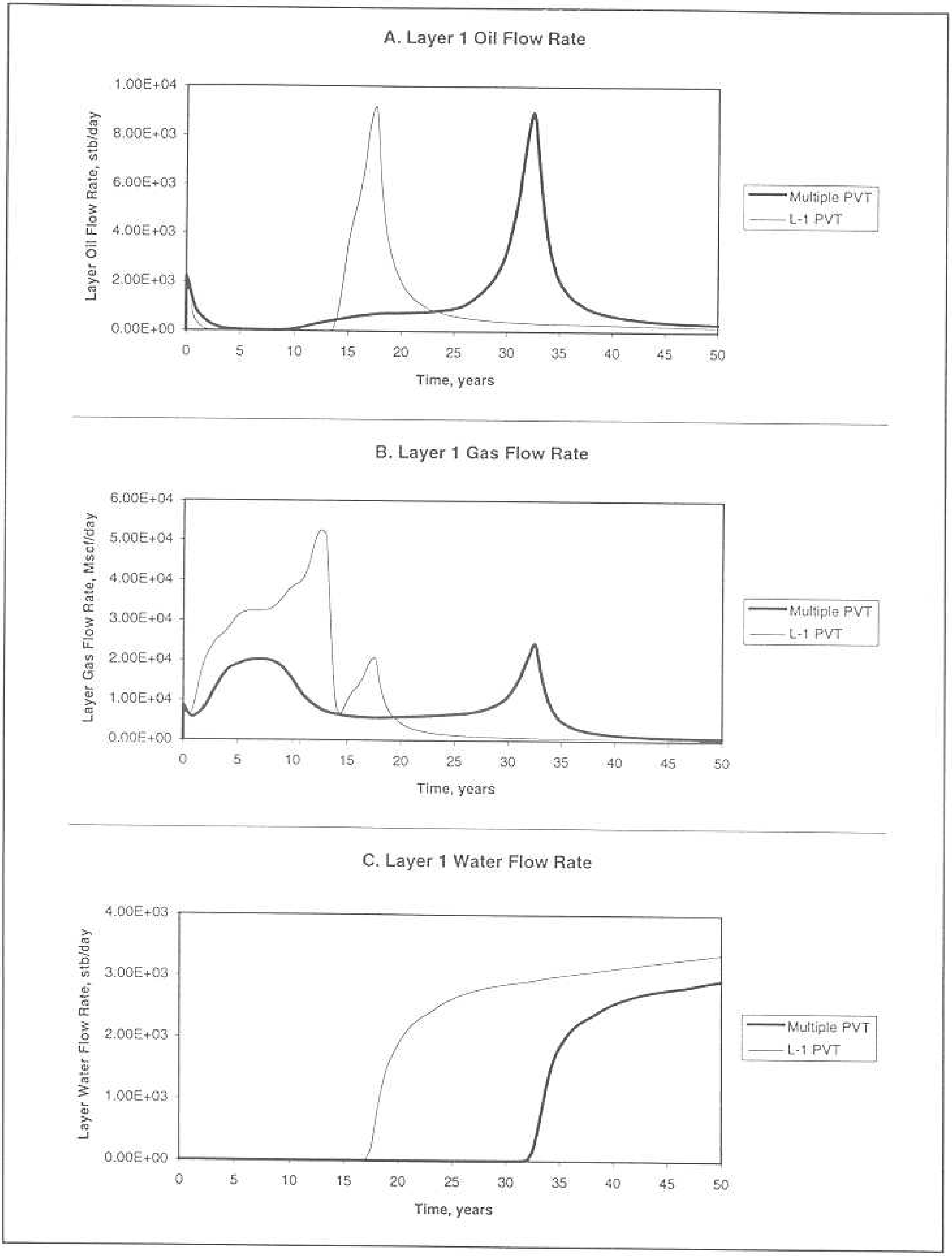


Figure 2. Overall Layer 1 Performance

Sensitivity studies indicated that for a given reservoir, single-point (depth) reservoir fluid sampling can be in the origin of misrepresentation of layer/region fluid distribution, layer/region production contribution and can lead to the choice of inappropriate lost reservoir energy replacement forms and even wrong solutions to wellbore problems.

Sensitivity Studies

Sensitivity analysis was performed for a hypothetical reservoir having five layers. Each layer is represented by a different set of PVT properties. The reservoir fluid studied is richer in Methane at shallower depths, while the mole fractions of heavier components are found in lower proportions. Consequently, the bubble-point pressure of the fluid decreases with increasing depth and a jump in viscosity values of the oil is noted low in the structure. The distribution of composition within the pay zone is in accordance with a proposal by Riemens, Schulte and de Jong (1988). Using such distribution, composition changes gradually with depth and the fluid becomes heavier and richer in aromatics downdip. Six different cases were examined to show the effect of unrepresentative reservoir fluid sampling and the subsequent uncharacteristic reservoir performance predictions. Five cases in which the reservoir is represented by a single PVT zone, are studied. Each fluid sample caught in the middle of each layer is taken as a representative reservoir fluid sample. In the sixth case examined, the reservoir fluid composition varies with depth and five PVT zones represented fluid distribution in the reservoir. Fluid compositions and PVT properties pertaining to different PVT zones are shown in table 1.

Discussion of the Results

Figures 1 through 4 represent the results of simulation runs on different scenarios, as far as the changes in PVT properties variations with depth are concerned. Four cases were considered. On three cases, reservoir performance was determined based on a given layer PVT properties. As a comparison, a "control" run, where reservoir performance was based on all five "layers" PVT data, was simulated. The other two cases which touch upon the reservoir performance of layers 2 and 4 were not discussed since they describe an "in-between" behaviour. Layer 2 reservoir performance is "in-between" the performance of the top layer, layer 1, and the middle layer, layer 3. Layer 4 reservoir performance is "in-between" the performance of the middle layer, layer 3, and the bottom layer, layer 5. Other than the hydrocarbon fluids properties, all reservoir data was kept the same for all layers, as shown in table 2.

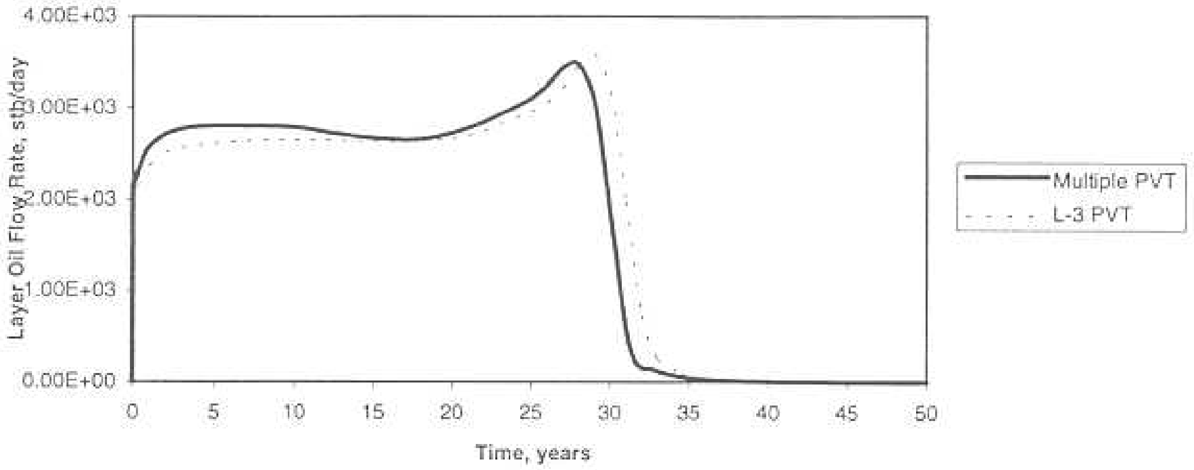
Comparison of field performance simulated under single and multiple PVT data

As shown in figure 1, treating the reservoir oil as a light oil column, by sampling in the top section and assigning PVT properties of the top layer to all reservoir layers, will lead to overestimation of field gas production, underestimation of oil production and prediction of early field water production. A thin oil column with high proportions of gas was simulated causing high amounts of solution gas production and enhancing water fingering due to severe gravity unbalance and an unfavourable mobility ratio. As indicated in figure 1a, contribution of the different layers toward oil production is dictated by proportions of the liquid phase accumulation. Liquid phase distribution in the different PVT layers increases with depth due to gravity segregation. For that reason, early on in the life of the field, liquid production is predominantly coming from the bottom layers 5, 4 and 3, with layer 5 contributing the most, then layer 4 and layer 3 in lower proportions. Layer 4 liquid contribution is higher than that of layer 3. Liquid production from the top layers, 1 and 2, is minimal as the top layers produce gas at higher proportions (figure 1b). Simulation results will not reflect real field behaviour. That will cause a misinterpretation of the results and a possible history matching dilemma. Furthermore, as a result of the inappropriate reservoir fluid sampling, additional costs will be incurred due to inappropriate sizing of surface facilities and planning of early wellbore and reservoir remedial actions such as waterflooding and/or gas injection for pressure maintenance purposes. On the other hand, sampling the bottom section of the reservoir will result in underestimation of field gas production, overestimation of oil production and prediction of late field water production (figure 1c). This will lead to serious consequences due to inappropriate sizing of surface facilities and late pressure maintenance overtaking which will result in a loss of significant recoverable hydrocarbons.

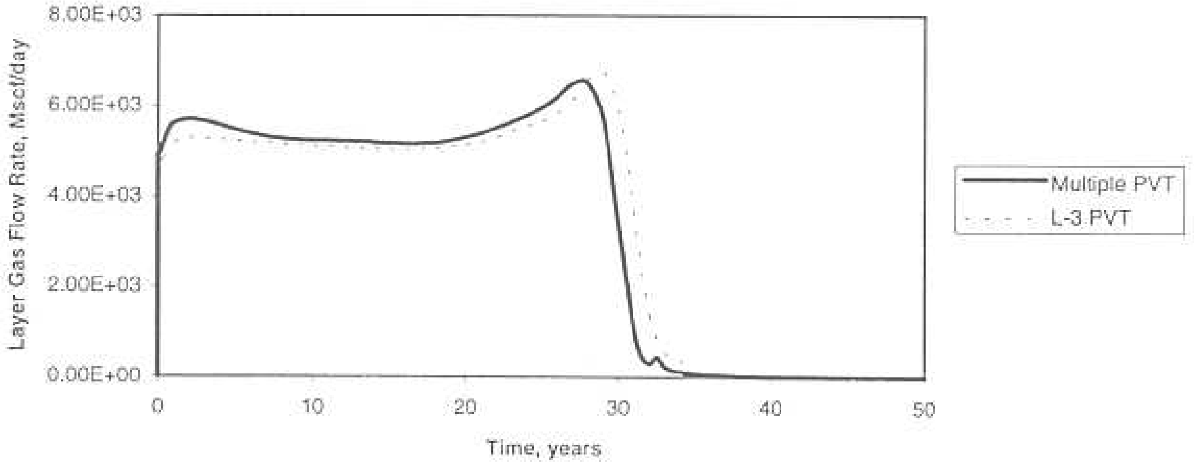
Furthermore, each layer performance with respect to oil/gas/water production is investigated individually. Production performance of each layer in a multiple PVT is compared to the performance of that layer when that layer PVT is assumed to represent the reservoir PVT.

Case 1 : Performance based on top layer PVT data

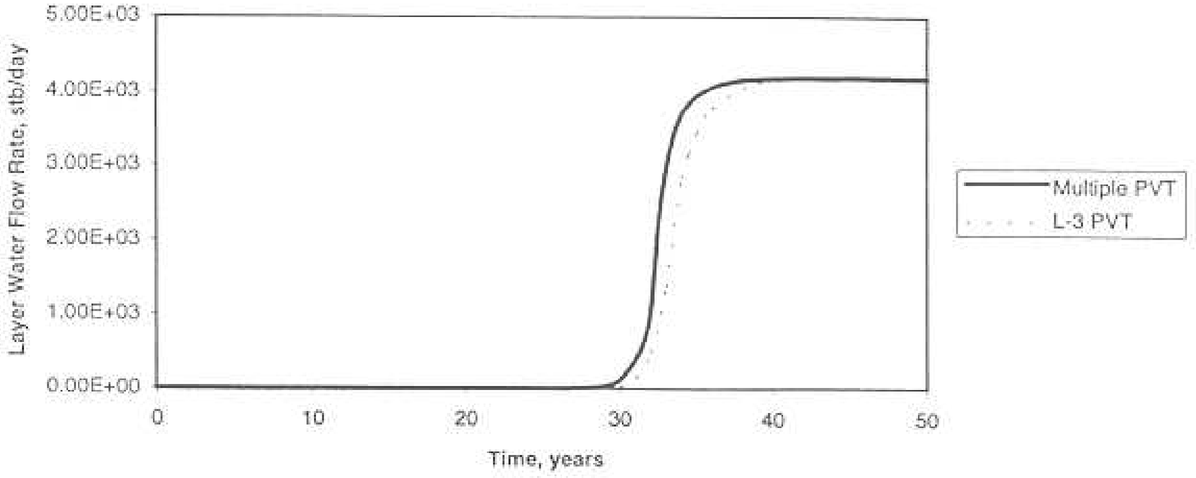
Results of this run are shown in figure 2. These results are based on the hypothesis that sampling of reservoir fluid was made on the top layer of the reservoir. With such assumption, lighter components of the hydrocarbon will be the dominant, as detailed in table 1. As such, higher gas production was observed (figure 2b). Overall field production (refer to figure 1), in



A. Layer 3 Oil Flow Rate



B. Layer 3 Gas Flow Rate



C. Layer 3 Water Flow Rate

Figure 3. Overall Layer 3 Performance.

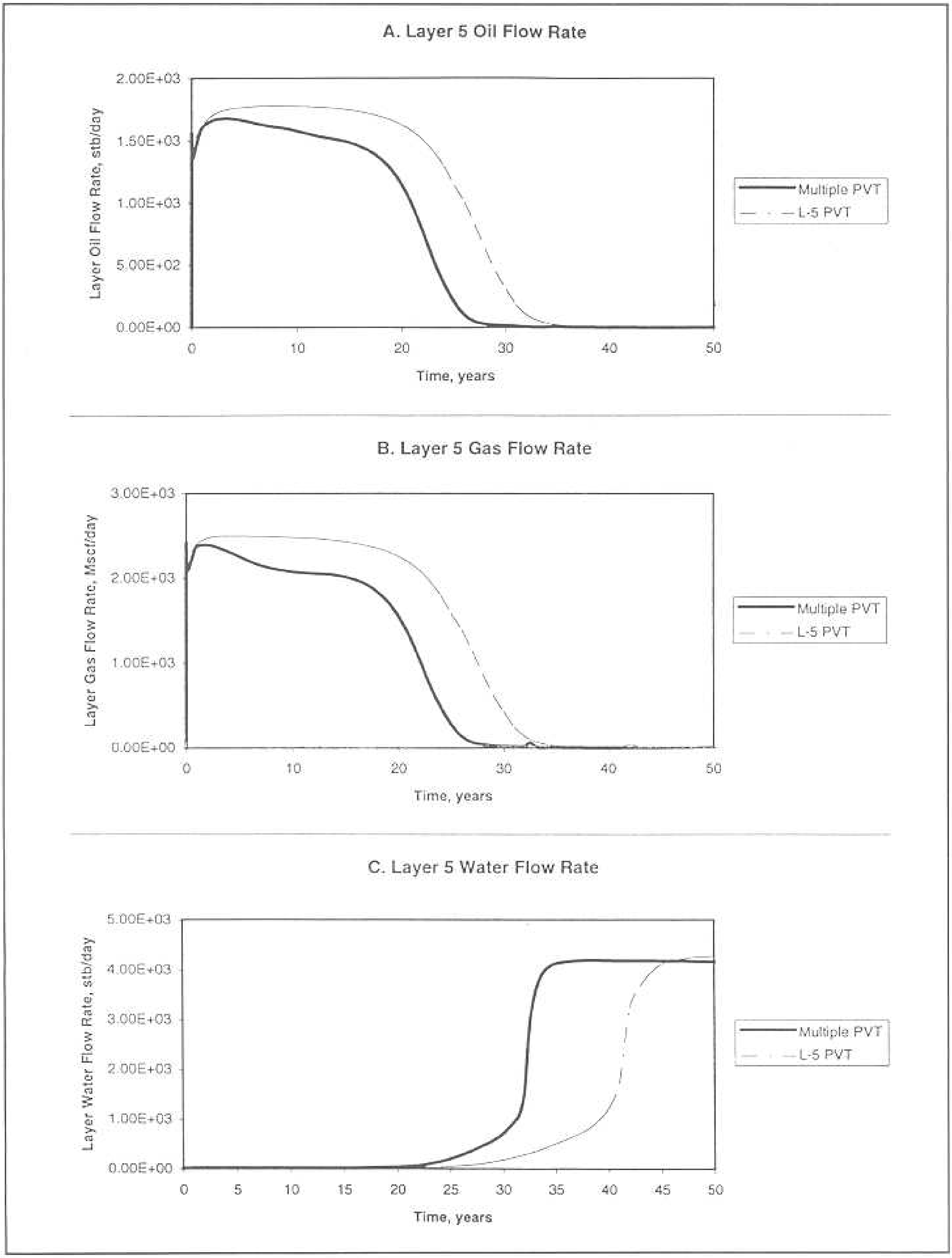


Figure 4. Overall Layer 5 Performance.

comparison to the "control" run, shows a gross under comparison to the "control" run, shows a gross under estimated production. This is due to the fact that the top layer hydrocarbon accumulation is predominantly in a gaseous phase which will not contribute toward liquid phase production (figure 2a). Other performance criteria, such as gas and water production, also confirmed the effect of compositional grading. Profile of water production, if top layer's sample is considered to represent reservoir behaviour, shows a much earlier breakthrough (figure 2c). Gravity unbalance between a very light fluid column overlying a denser phase, bottom water, has enhanced water fingering and initiated water production.

Case 2 : Performance based on middle layer PVT data.

Interesting results were obtained from the middle layer. Comparing the top, middle and bottom layers with the "control" run, the mid-layer PVT data produced the most accurate result. In terms of reservoir thickness, this layer lies exactly at the centre of the pay zone. Performance results are shown as figure 3. The results from this layer are in agreement with Shulte's (1980) work. He explained that the gradient dx_i / dh of the mole fraction x_j of component j is related to the chemical potential by the following relationship:

$$\sum_j \left(\frac{\partial \mu_i}{\partial x_j}\right)_{T,P} \frac{dx_j}{dh} = \left(\overline{\rho} V_i - m_i\right) g = \left(\overline{\rho} - \rho_i\right) g$$

where:

$\overline{\rho}$ = average reservoir fluid density
V_j = partial molar volume of component j
m_j = molar mass of component j
ρ_j = density of component j
g = acceleration due to gravity.

Strong segregation of component j can be expected if $(\overline{\rho}\ V_j - m_j)$ is large or if $(\overline{\rho} - \rho_j)$ is large. This implies that it is also true for molecules with density ρ_j significantly different from the average reservoir fluid density, $\overline{\rho}$. In this case, where layer 3 represents the mid-layer in our case study, the mid-layer fluid density, ρ_j used is 53.094 Ib/cuft comparing to the average reservoir fluid density, $\overline{\rho}$, (control sample) of 52.937 Ib/cuft. Because the difference in densities is minimal, no significant segregation will take place at the mid-layer.

Case 3 : Performance based on bottom layer PVT data.

The bottom layer represents the other side of the scale in terms of the hydrocarbon properties. PVT data from this layer are dominated by relatively heavier components than the top layers. This fact is reflected in the field performance (see figure 1). In oil production (figure 4a), results show a much exaggerated profile, in gas production profile, (figure 4b), it is underestimated and water production, (figure 4c), is much favourable when compared with the "control" run. Figure 4 shows the magnitude of the effects of using sample from layer 5. Production rates of both oil and gas are over-estimated. Water production, on the other hand, is under-estimated. This is due to the fact that the oil phase gravity is heavier than anticipated. For that reason, a better gravity balance has eliminated the possibility of water phase fingering and retarded water production. The high oil phase density in the bottom layer has allowed a sharper bottom water displacement front dictated by a more favourable mobility ratio between the displacing bottom-water phase and displaced oil phase.

Conclusions

The simulation study presented in this paper has highlighted the magnitude of errors in estimating reservoir performance.

An increase in the amount of heavier pseudo-component with depth indicated a pronounced compositional segregation in the reservoir studied. Then, careful reservoir fluid sampling has to be undertaken for better reservoir fluid PVT properties characterisation. But, since fluid sampling at different depths is a time consuming and a highly expensive practice, it was found that sampling in the middle of the oil column will lead to acceptable PVT properties representation yielding trustful history matching results.

In this paper, it was shown that by sampling deeper in the hydrocarbon fluid column, an overestimation of oil production coupled with an underestimation of water production, due to a more favourable displacement process, and an underestimation of gas production, due to miscalculation of the amount of gas in solution, will lead to unrealistically optimistic view of the field performance. Gravity unbalance and unrepresentative gas production figures are the two major overlooked problems which will be in the origin of unmatching field and simulation results. On the other hand, sampling in shallow depths will lead to an exaggerated indication of solution gas proportions along the whole oil column. Misinterpretation of the results may lead to the conclusion of defining the reservoir as a predominantly gas reservoir. In this paper, gravity segregation theory proved that finding an oil ring accumulation underlying the light gaseous phase is a possibility with increasing probability of occurrence in reservoirs having a pay thickness exceeding 50 m.

Sampling depth of a heavy oil as well as near-critical conditions light oil is a key issue since consequences of an inappropriate sampling depth choice can be the origin of misleading reservoir/layer performance results. Therefore, along with appropriate mid-column sampling depth, compositional segregation checks can be done on sampled reservoir fluid using available thermodynamic models for an accurate representation of reservoir fluid PVT properties.

Acknowledgements

The authors wish to express special thanks to Geoquest Reservoir Technology (GRT) for providing The Eclipse100 software to the Department of Petroleum and Mining Engineering at Sultan Qaboos University, Oman.

Appendix

The total Gibbs free energy of a layer (an open system) which can interchange matter (i.e. heavy molecules) with underlain layers is defined as:

$$nG = f(T, P, n_1, n_2, \ldots\ldots\ldots, n_j, \ldots\ldots\ldots) \qquad \text{(A1)}$$

where, n_j represents the mole numbers of the chemical species. Division by n, the total number of moles in a given layer, yields the following alternative equation:

$$G = f(T, P, x_1, x_2, \ldots\ldots\ldots, x_j, \ldots\ldots) \qquad \text{(A2)}$$

where, $x_j = n_j / n$ is the mole fraction of component j.

Hence the total differential form of G may be presented as:

$$dG = \left(\frac{\partial G}{\partial T}\right)_P dT + \left(\frac{\partial G}{\partial P}\right)_T dP + \sum \left(\frac{\partial G}{\partial x_j}\right)_{T,P} dx_j \qquad \text{(A3)}$$

but since temperature change within a single layer is minimal, i.e. $dT = 0$, then equation (3) reduces to:

$$dG = \left(\frac{\partial G}{\partial P}\right)_T dP + \sum \left(\frac{\partial G}{\partial x_j}\right)_{T,P} dx_j \qquad \text{(A4)}$$

Also by setting chemical potential μ_j as:

$$\mu_j = \left(\frac{\partial G}{\partial x_j}\right)_{T,P} \qquad \text{(A5)}$$

equation (4) can be transformed to the following form:

$$dG = \left(\frac{\partial G}{\partial P}\right)_T dP + \sum \mu_j \, dx_j \qquad \text{(A6)}$$

Since pressure, P, at the base of the oil column with a height, h, in a given layer is expressed as:

$$P = \bar{\rho} g h \qquad \text{(A7)}$$

where $\bar{\rho}$ is the average layer fluid density, then

$$dP = \bar{\rho} g dh \qquad \text{(A8)}$$

and substitution of equation (8) into equation (6) yields :

$$dG = \left(\frac{\partial G}{\partial P}\right)_T \bar{\rho} g dh + \sum_j \mu_j dx_j \qquad \text{(A9)}$$

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Received 8 April 1996
Accepted 13 July 1996