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Uncertainty and Risk Evaluation in the Tertiary Migration of Abandoned Oil Reservoirs

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Abstract

In studying the efficiency of the tertiary migration process in the abandoned oil reservoirs, input data is needed to construct the reservoir model. The physical model, out of all, suffers the most changes after the primary production stage is over. The parameters that are used are applied by making a mean arithmetic value and extrapolating it to the reservoir scale, which limits reservoir simulation and description to their minimum. A method is proposed for estimating rock properties between wells on a reservoir block and an application is presented on how to apply the selected method.

Key words: *tertiary migration efficiency, uncertainty, rock properties, estimation, distribution*

Introduction

In the evaluation of tertiary migration of oils in abandoned reservoirs having and working correctly with the parameters involved is key to making an accurate image of the reservoir. The parameters involved can be classified in three major groups: geological model, physical model and production model. These models, along with other sub/side categories will be used in any reservoir studies orrecovery projects that will follow the reservoir during its entire lifecycle. Some of the parameters once that are determined and accepted will have very little chance of being modified, whilst others will be continuously evaluated and reevaluated so that the reservoir production model will stay accurate and up to date. In the case of newly discovered reservoirs the focus is based on the first two groups, the third following to be completed with data as the reservoir is produced. Based on the reservoir image constructed and on the production planning the reservoir is thus ready for exploitation, in particular primary production.

After primary production has ended and the reservoir is abandoned, the process called tertiary migration takes place. A comprehensive study on the tertiary migration is presented in [12] and an overview regarding the influences on microscopic flow is made in [9]. Being in the situation of a reservoir, in which tertiary migration was an efficient process, the data used to construct the tertiary migration model is the same as the one for the primary production only with certain features that will not be analyzed and other features that will be reevaluated.

The geological model is constructed with the help of seismic interpretation and will be completed with data from the exploration wells. The parameters that are of interest for the geological model concern the surface of the hydrocarbon containing unit, the thickness of the unit, and very importantly the fault distributions and extensions. The faults must be precisely evaluated in order to have correct estimations on the reserves using the volumetric approach. Generally, once the seismic interpretation is over, it will be assumed as the correct one and further work will rely on it. In other words redoing the seismic prospections on a reservoir just to correct the reservoir image, especially the geological model, is generally out of the question. The only modifications/refinements that will eventually be made here will be in-house, therefore the geological model will stay the same for the tertiary migration studies as the one before primary production debut.

The parts of the production model used to elaborate the tertiary migration studiesinclude the reserves, recovery factors, production time, total quantities of produced fluids, rates of production, and very importantly, the time a certain unit has been abandoned since primary production. Time is an essential factor in the efficiency of tertiary migration and is considered the most trustworthy eliminatory criterion. Modifications here are made to correct the production allocation in the case of comingling.

The physical model is constructed usingrock properties and reservoir fluid properties. The rock properties are consisted of porosity, permeability and irreducible (or connate) water saturation which are obtained from well logs, well testing, RCA and SCAL analysis. The fluid properties are given by chromatography devices, spectrometry devices and pVT analysis. The physical model, perhaps out of all the data sources, is the most subjected to errors and corrections and is in continuous modification with each production stage, so after primary production, for evaluating tertiary migration efficiency, these parameters will have to be reanalyzed. The fluid properties, if there is missing pVT data, can be estimated with the help of empirical equations that are present in the literature, but these estimations are beyond the scope of this paper and will not be discussed here. Further on, the discussion is going to be made on how one can create a more accurate image of the reservoir by expanding rock properties data for the whole reservoir using interpolation methods based on few existing data points.

An oil reservoir has a certain number of wells drilled on it. The data used to construct the reservoir image is obtained by different measurement techniques executed in the wells, but in particular, the values obtained are only from an isolated spot compared with the reservoir extent, and so, the measurement points (wells) represent the few, discrete data points. Between the wells, the values for the certain parameters will be interpolated. According to the method used to determine the needed parameters (well logs, well testing, RCA and SCAL), these properties will always have different values in the same measured location. Each method has its advantages and limitations, and also, every mentioned parameter varies within the reservoir (thus defining reservoir heterogeneity), in consequence, choosing the right value from the method will have to be made carefully. Parameters such as fluid saturations and relative permeability have very ample variations after the primary production stage and need to be estimated again to serve as initial data for tertiary migration studies.Other parameters, such as porosity, will be considered as constant throughout the lifespan of the reservoir, regardless of its exploitation stage. Using interpolation methods, an example is going to be presented on how to obtain a porosity distribution between the wells and afterwards, using empirical equations,water saturation and relative permeabilityof the rock towards oil and water will be obtained.

Experimental Details and Results

The reservoir rock proposed for study is a sandstone with calcite cement that is weakly consolidated in some areas of the reservoirs and medium consolidated in other parts. The connate water saturation is 0.32 but measurements of wettability have not been performed. Given the oil composition and gravity along with the mineralogical description of the reservoir rock, the wettability is most likely water-wet. Only four wells are taken, which are situated in the corners of a square that has the side of 100 meters,where cores have been sampled from depths 840 – 840.5 meters. Although the net pay thickness of the collector rock is greater than 0.5 meters, the values for porosity are taken only for the firsthalf meter of the collector rock and are given in the table below. Likewise, the resistivity logs analyzed show there are shale intercalations up to 15%, but there are is no information regarding the shale distribution type (dispersed, laminar or structural).

Table 1. Porosity values determined on cores for the four wells

	Depth, *m*	Porosity, *fraction*
Well 1	840-840.5	0.225
Well 2	840-840.5	0.196
Well 3	840-840.5	0.188
Well 4	840-840.5	0.203

Porosity estimation. For situations similar to those presented above, a single value of porosity was used that was the mean arithmetic value of every determined porosity and later applied for the whole zone (in our situation would be the center of the square). Such an approach introduces great errors, especially in reservoir simulations and furthermore, from a reservoir characterization point of view this would mean that the reservoir has maximum homogeneity, which actually has not. For a more accurate image of the reservoir, instead of a using a single value, it should be used a distribution of values. The difficulty here lies in choosing which values are the more accurate ones. Well logs are a fast way of providing information about porosity but they are influenced by the errors associated with the principle of the logging method and the fact that collector rock is subdued to mud filtrate invasion, both, increase the errors in porosity determination. Well testing is a cheap method of porosity determination, only it is influenced by the skin factor, and also the value obtained is a mean for the well drainage area. Mechanical cores are rock samples brought to surface conditions which are subjected to extraction methods (for water saturation determination) and afterwards, porosity is determined. The only errors that appear here would be a very small increase in porosity due to the absence of stratigraphic pressure from above the rock. Having these mentioned, the values of porosity obtained from mechanical cores are going to be used while the other values (from well logs and well testing) will be considered only as a term for comparison.

To get an image of the porosity between the wells, interpolation methods are going to be used. There are numerous interpolation methods out of which we would like to point out regressions (linear, polynomial and exponential), least squares methods, thin plate splines and more complex approaches, kriging and artificial neural networks. Works in the literature that use these methods are [3], [6], [10], [13], [5] and [19].What is important to mention about these methods is that they are more accurate with increasing number of data points. If the input data is scarce, then the interpolation methods will all give the same results. Because only four wells are considered, and the spacing between them is not that ample, linear interpolation between these wells will be used to obtain the porosity values.

The well positioning can be observed in Figure 1. First, a linear interpolation run on vertical direction will be made and second, the same linear interpolation will be made on diagonal direction. The hexagons represent primary interpolated points because their values are obtained from actual determined porosities. The diamonds represent secondary interpolated values because they are obtained from values already interpolated. In our example, only the secondary interpolated values will be different for the two interpolation directions. After applying interpolation, the values in Tables 2 and 3 will be obtained.

It can be seen that the values are slightly different. The maximum relative error for these two interpolation is 1, 72% in node III-3, the other values being smaller, so it is acceptable to use these two linear interpolation directions. Further, two probability scenarios are created based on these values: a P10 in which the nodes have the maximum porosity values and a P90, where the nodes have the minimum values. These two scenarios will be used to further estimate the water saturation in the nodes, as well as the relative permeability of the rock towards the fluid phases.

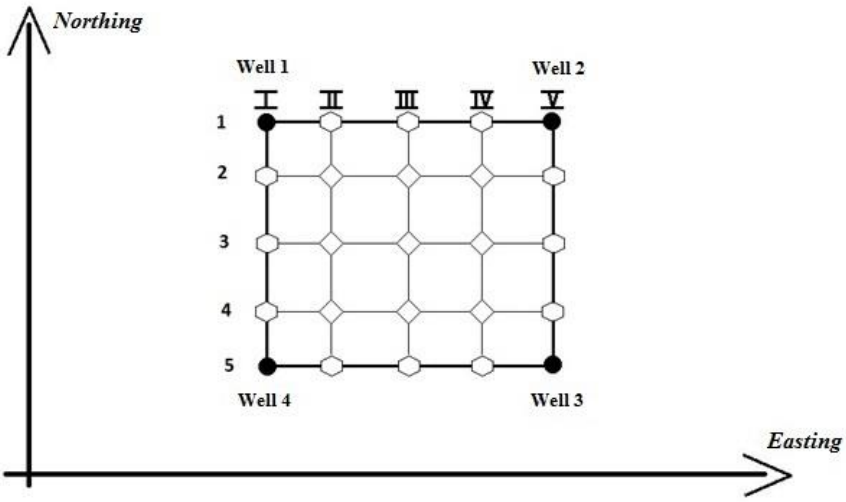

Fig. 1. Positioning of the four wells

Table 2. Estimation of porosity obtained through vertical interpolation

	I	II	III	IV	V
1	0.225	0.21775	0.2105	0.20325	0.196
2	0.2195	**0.213125**	**0.20675**	**0.200375**	0.194
3	0.214	**0.2085**	**0.203**	**0.1975**	0.192
4	0.2085	**0.203875**	**0.19925**	**0.194625**	0.19
5	0.203	0.19925	0.1955	0.19175	0.188

Table 3. Estimation of porosity obtained through diagonal interpolation

	I	II	III	IV	V
1	0.225	0.21775	0.2105	0.20325	0.196
2	0.2195	**0.21225**	**0.205**	**0.199097**	0.194
3	0.214	**0.20675**	**0.19949**	**0.19575**	0.192
4	0.2085	**0.200525**	**0.1975**	**0.19375**	0.19
5	0.203	0.19925	0.1955	0.19175	0.188

Water saturation estimation. Mechanical cores, after being brought to the surface, are put through a solvent extraction process in which the water content can be determined directly while oil and gas are determined indirectly. This would give a first reading on the water saturation but still, this value remains an isolated one. When multiple cores are analyzed and water saturation is determined through solvent extraction, an arithmetic mean value will be used, thus generating uncertainties. Instead, water saturation can be obtained with the help of well logs. Resistivity logs are a common method for determining fluid saturations but they are very influenced by water salinity, and to obtain even more trustworthy values the shale distribution has to be known. There are multiple empirical equations presented in the literature but not all can be applied without specific information. For example, in shale formations, the equations presented in [20], [21] and[18] require supplementary laboratory analysis of shale properties, which if not available, would in field terms mean reacquiring fresh mechanical cores.Other equationsare fit for dual-water models, like [4] and [7]. In our application, based on the data available and on the porosity previously estimated, we would like to get a distribution profile of the water saturation based on the P10 and P90 profiles previously constructed using Archie's equation (for shale-free collectors) [2], Poupon's equation (supposes a laminar distribution of shale) [15], Hossin's equation (supposes a shale-sand dual conductance) [11] and Schlumberger model (supposes of dispersed clay) [23] and [24]. The reason of using these equationsis that they can be applied fast (without any supplementary data in advance) and they give reliable results.

Because wettability is only speculated and the rock cementation varies from weakly-to-medium consolidated, the parameters in Archie's equation will be varied from their lowest values to the average, most commonly used, values.The cementation factor and Archie's constant are related to rock cementation while the saturation exponent is related to wettability. All other equations present in the literature are derived from the basic Archie equation so modifying the parameters will be possible to simulate the wettability and cementation factor. Because the logs reveal shale presence in the collector, all of the presented models were tested for 10% and 15% shale volume in the case of strong water wet, weak water wet-to-intermediate wettability. A saturation exponent below 2 indicates increasing water wetness and above 2,5-3 would indicate increasing oil wetness of the rock. A cementation exponent smaller than 2 and an Archie constant smaller than 1 would indicate decreasing rock cementation.

The results obtained are similar in the cases of Poupon and Hossin but are slightly different for the Schlumberger modelwhich gave results smaller with 0.03-0.04 compared with the other two. Archie values calculated with the shale-free equation were significantly smaller, but are used only for comparison and not in real interpretation.The values obtained for the P10 and P90 where the rock is strong water wet and weak-water wet for a 10% and 15% shale volume inside the collector are given in Table 4.

Table 4. Water saturation values for the proposed probability scenarios

	P 90				P 10			
	Strong water wet		Weak water wet		Strong water wet		Weak water wet	
	Shale volume, %							
	10	*15*	*10*	*15*	*10*	*15*	*10*	*15*
Poupon	0.365	0.399	0.649	0.655	0.359	0.392	0.647	0.650
Hossin	0.369	0.397	0.648	0.657	0.355	0.395	0.644	0.651
Schlumberger	0.338	0.358	0.631	0.635	0.332	0.354	0.629	0.631

Values with the Archie equation for clean collectors indicated average values around 0.23 for the P10 –strong water wet case, 0.57 for the P10 – weak water case, 0.24 for the P90 – strong water wet case and 0.59 for the P90 - weak water case. Values for the weak water wetness-to-intermediate wetness are expected because of increasing Archie parameters for the same resistivity values, but when observing well tests and production history, it would be revealed that these values are too high.

Relative permeability estimation. For the relative permeability estimation, empirical equations specific for two-phase flow were used. The reason for using these types of equations is that in the tertiary migration process, the gas phase in the newly formed middle zones and lower zones occupies the larger pores whereas the water phase in the upper and middle zones occupies the smaller pores, so their influence on the flow behavior, overall, is reduced but not necessarily negligible. The equations that were used are from Wyllie and Gardner [22], Corey [8], Pirson[14] and Purcell [16]. The results for the Poupon saturation profiles are presented in table 5. The relative permeability values are similar for the Pirson and Corey models, both of these models are comparable to the Wyllie and Gardner model, but are unexpectedly high for the Purcell model. For the Hossin and Schlumberger models the results are similar and the relative error between the models is lower than 6%.

The results from the Purcell model would indicate that at pore level oil would be the only phase flowing, which cannot be true. The other models, however, offer still very optimistic results, for both probability profiles. Given the chaotic phase distribution that occurs during the tertiary migration process, the results obtained would represent the upper-most limit and should be used with caution for the reservoir models that will be later constructed.

Table 5. Relative permeability values towards the oil phase for the proposed probability scenarios

	P 90				P 10			
	Strong water wet		Weak water wet		Strong water wet		Weak water wet	
	Shale volume, %							
	10	*15*	*10*	*15*	*10*	*15*	*10*	*15*
Wyllie and Gardner	0.721876	0.700784	0.039202	0.034796	0.787684	0.772729	0.040229	0.036226
Corey	0.79618	0.77910	0.06508	0.05823	0.84791	0.83636	0.06667	0.06046
Pirson	0.811461	0.797782	0.175699	0.165351	0.853743	0.84417	0.040229	0.036226
Purcell	0.98940	0.98750	0.56401	0.54635	0.99415	0.99321	0.56788	0.55228

Conclusions

1. In the study of the tertiary migration efficiency, uncertainty and risk are involved when gathering input data. It was concluded that for the geological model the uncertainties are related to reservoir physics and if the model is to be reconsidered, the eventual modifications that will made will be in-house. The production data has one very big uncertainty which cannot be corrected: comingling, but not all reservoirs were produced with this difficult procedure, the rest of the uncertainties being almost negligible (e.g. wells being flooded 5 days from production start instead of 10). The physical model, however, suffers the most modifications.

2. Regarding physical model data, the biggest uncertainties involve usage of mean arithmetic values for the parameters of interest, extrapolated for an entire block inside an oil reservoir. This approach limits computer simulation to very small extents and from a reservoir description point of view, the same approach means maximum reservoir homogeneity, resulting in extremely erroneous suppositions. To improve this, estimations of some the needed properties between wells (porosity, water saturation and rock relative permeability) with the help of empirical equations, based on parameters least affected by errors in determination (porosity) have been proposed to create a more broader image of the reservoir in discussion.

3. Porosity is a parameter that is present as a factor in many equations (both empirical and analytical) used to estimate/determine specific parameters. It was concluded that porosity from mechanical cores is the least affected by errors. When choosing the interpolation method, small areas between wells were considered to try to avoid lithological variations of the rock that would alter the parameter values. When vast lithological variations are known to be present, local grid refinements are used. As a results, linear interpolation (which is an easy method) between wells was chosen and applied on two directions, resulting in the two probability profiles. When calculating the variances and standard deviations for the profiles obtained, 9.3E-05 and 0.00983 for the P90 and 9.2E-05 and 0.00977 for the P10, it can be seen that using a 100 meter-sided square does not imply many errors for the cases of low lithological variations between wells.

4. Water saturation was obtained applying different empirical equations that are a function of shale-distribution in the collector. Also, the equations chosen were readily applicable without

the need of further investigations. From the results and the type of equations applied, we can conclude that, for the respective block, the shale present in the reservoir has a laminar distribution.

5. Relative permeability values obtained in the two-phase flow caseshow very good flow potential for the oil phase. However, these values should be used with caution because they are dependent on many factors. Two of the many factors, for e.g., would be pore size distribution and mineralogical heterogeneity, who's variations cannot be estimated between the wells.

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Evaluarea incertitudinilor și a riscurilor în studiul eficienței migrației terțiare pentru zăcămintele de țiței abandonate

Rezumat

În studiul eficienței migrației terțiare în zăcămintele de țiței abandonate, precizia datelor de intrare este o condiție esențială. Modelul fizic este dovedit a suferi cele mai mari modificări după un proces de exploatare primară. Parametrii necesari studiului sunt aplicați prin efectuarea unei medii aritmetice a valorilor lor și apoi extrapolând această unciă valoare, este acceptată pentru un anumit bloc de pe zăcământul de țiței. Astfel, acuratețea simlulărilor aferente curgerii și a modelelor de zăcământ este puternic diminuată. O metodă este propusă pentru estimarea acestor proprietăți dintre sonde și o aplicație este prezentată pentru a evidenția algoritmul de lucru.