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A Prediction Model for Commingled Sandstone Reservoirs Injection Profile Utilizing Injection Logging Data

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Abstract

Drilling wells usually target multi-reservoir in different depths in the same well. Through completing these wells, oil production from commingled reservoirs is done to maximize the oil gain and minimize wells count. Monitoring water cuts and allocating the sharing of each layer is essential to improve reservoir management. This could be done via logging tools either in production or injection wells. For the area of interest in this research, zonal allocation is done mainly by injection logging tool (ILT). A prediction model for water injection allocation between different zones could be built if effective parameters such as pay thickness, permeability, reservoir pressure, and skin are considered. In some fields, we could face a lack of data. Then a good knowledge of each parameter effects could help in improving the results quality. The prediction model accuracy could be enhanced by implementing ILT results to determine the main effective parameters and the weight of other parameters in improving the model's accuracy. Understanding the variation in parameters between the injection layers could help getting a good result, especially when having a lack of data. Through this research, building the prediction model starts by the simple data which is available in each well (e.g., pay thickness in injection and production wells) and the model showed a good result for some fields due to a negligible variation in other parameters values in these fields. Then, implementing the other effective parameters is done for other fields. This helps to understand the effect of each parameter in the model. Integrating these parameters with ILT data makes the prediction model is valid for reservoir management such as water shut-off, converting depleted producers into injector wells, and perforate/ reperforate oil zones. This good management helps to maximize the oil recovery for these fields.

Keywords: *ILT; Pay Thickness; Prediction model; Commingle; Parameters; Validation.*

1. Introduction

Physically, the main factors dominating interlayer interference during commingled production in a multi-pressure reservoir are associated with reservoir properties and its pressure system. To minimize interlayer interference, formations with a large difference in pressure shall be produced separately, though it may not be economically viable [1].

However, for other many fields -with commingle reservoirs wells having considerable oil reserves- the economic solution is to produce oil from these commingled reservoirs to reduce the wells count in field development. Applying injection logging tool is helpful for getting the zonal allocation for the commingled reservoirs.

Applications of zonal monitoring and control in multizone completion is important for limiting the high water cut production from a specific zone, preventing crossflow between reservoirs, selective stimulation of high skin or damaged zones, balancing zonal injection, and optimizing zonal production to depletion plan objectives [2].

In other fields, the application of chemical water tracers, IWTT (Interwell tracer test), SWTT (Single-Well Tracer Test), or TWTT (Two-Well Tracer Test), is helpful in understanding the preferential flow path of the injected fluid, the identification of water channels, evidencing the geological barriers, determining the residual oil saturation, around the wellbore or along the tracer's path between two wells [3].

One of the most applied equations for zonal flow rates allocation for each zone is through the injectivity index (I) equation:

$$Q = I \times (P_{wf} - P_r) \qquad (1)$$

where: P_r: the reservoir pressure at the injection point; P_{wf}: flowing pressure which is equal to Pinj. at the reservoir depth; I: The injectivity index for each zone, could be obtained from injectivity tests with different rates.

By having the zonal flow rates, an estimation of the layer's split ratios is obtained and hence a better basis for each layer's contribution in comparison to the static kH ratio.

For building the prediction model, getting information about the well geometry, completion equipment, reservoir inflow characteristics, and fluid properties is very important for the model validation. The model is then compared or matched with the measured ILT. If this is within a predefined tolerance, the model is accepted. Otherwise, the model will be updated by considering other parameters such as reservoir pressure, injectivity index, and skin/ stimulation. If the well model remains calibrated, it can be updated with the dynamic data and downhole pressure readings to develop the model accuracy.

2. Methodology

For many fields, water flooding is applied as waterflooding is an important application that can help in increasing the oil recovery factor (RF), as it maintains reservoir pressure and sweeps oil from the reservoir to the producer wells [4]. Tracking for injection performance in commingled reservoirs is important using ILT (Injection Logging Tool). ILT is a technique through rigless intervention in injector wells. The advantage of ILTs is that it is a simple and easy method for brownfields. It is important for waterflood management as it helps to understand the fluid distribution at the wellbore in each reservoir contact [4].

ILT objectives include Picking up the fluid injection intervals, estimating injection rate across each injection interval, Crossflows check between different formations with different pressures in flowing and shut-in conditions, and checking for tubing and/or casing integrity issues [2].

2.1. ILT acquisition and interpretation

The ILT is done by rigless operations on the injector wells. The survey is performed with a multi-sensor downhole ILT Logging Tool [4]. The flow rate is measured by a spinner that reacts in different ways according to the injected water in each of the perforated zones. The row data then proceeded using Emeraude software (KAPPA). The software is used to calculate the threshold velocity of the spinner and get the interpretation results for each well [2].

2.2. Permeability measurement methods

Predicting reservoir permeability involves a combination of geological understanding, data analysis, and sometimes empirical correlations. Here is a structured approach to predicting reservoir permeability:

A. Geological understanding:

- *Core Analysis*: Obtain core samples from the reservoir and conduct laboratory tests to measure permeability directly. This provides actual data points for calibration and validation of other predictive methods.
- *Rock Typing*: Classify the reservoir rocks based on lithology, pore structure, and mineralogy. Different rock types have different permeability characteristics.
- *Diagenetic History*: Understand the diagenetic processes (such as compaction, cementation, and dissolution) that have influenced the reservoir rock properties over time.

B. Well Log Analysis:
- *Petrophysical Analysis*: Interpret well logs (such as gamma ray, resistivity, neutron, and density logs) to estimate porosity and lithology.
- *Empirical Relationships:* Use empirical relationships derived from well logs (e.g., porosity-permeability relationships, cross plots) to estimate permeability. These relationships can be specific to the reservoir type or derived from regional analogs.
- *Porosity-Permeability Relationships*: Use well-log data (such as porosity logs) to establish empirical relationships between porosity and permeability. This can involve using local empirical correlations or global trends based on similar reservoir types.
- *Saturation and Pressure Corrections*: Correct for fluid saturation and pressure effects on permeability using well-log data and petrophysical models.

C. Seismic Data Integration:
- Analysing seismic attributes that correlate with permeability, such as acoustic impedance or seismic texture, and using seismic inversion techniques to estimate rock properties including permeability.

D. Modeling and Simulation:
- *Reservoir Modeling*: build reservoir models integrating geological, geophysical, and petrophysical data. Use reservoir simulation software to simulate fluid flow and predict permeability distribution within the reservoir.
- *Upscaling*: Upscale laboratory-scale permeability measurements to field-scale predictions using appropriate scaling relationships.

E. Machine Learning and Data Analytics:
Employ machine learning algorithms to analyze large datasets (including well logs, core data, and production data) to identify patterns and correlations that can predict permeability [5].
- *Predictive Models*: Develop predictive models based on historical data and incorporate geological features and reservoir parameters as input variables.

F. Validation and Calibration:
- *Cross-Validation*: Validate predictive models against independent data sets (e.g., different wells or reservoir zones) to ensure reliability and accuracy.
- *Calibration*: Fine-tune predictive models using calibration techniques that adjust parameters based on observed data.

G. Expert Judgment and Experience:
- *Expert Input*: Combine quantitative methods with expert judgment from geologists, reservoir engineers, and petrophysicists who have experience in similar reservoir settings.
- *Case Studies*: Refer to case studies and analogs of similar reservoirs to gain insights into permeability predictions.

By combining these approaches, reservoir engineers and geoscientists can develop reliable predictions of reservoir permeability, essential for understanding fluid flow dynamics and optimizing production strategies.

2.2.1. Permeability measurement using core data

Permeability can be calculated from the conventional core. Special core analysis (SCAL) data can help to get more accurate values for Kw. Also, Drill stem test (DST) & Repeat formation test (RFT) data can help to get K values using the measured mobility data. Finally, open hole logs (OHL) data (porosity, V_{sand}, V_{shale} & $V_{carbonate}$) can be correlated to calculate Kw for the commingled layers [2].

Clay and framework mineralogy, determined from geochemical well logging, are used with porosity to estimate the permeability of clastic formations. The mineral abundances are first combined with their individual grain densities to yield a continuous matrix density log which is combined with a bulk density log to produce a very accurate porosity log. The maximum feldspar abundance is used as an indicator of textural and mineralogical maturity. The level-by-level abundances of framework grains, quartz, and feldspar, slightly enhance the estimated permeability. The porosity, textural maturity, and framework grain abundances define a maximum permeability curve as a function of porosity [2].

Clay swelling can cause a great reduction in rock permeability. It depends on the clay structure, which is related to the clay cation exchange capacity (CEC). Kaolinite structure is 1:1 bond (TO-TO) and has the lowest CEC between clay types with minimum clay swelling for a given amount of clay, kaolinite is less harmful than illite, which is less harmful than smectite [6].

The abundances of non-clay cementing agents such as calcite also decrease the permeability, but they are less harmful than clay minerals [2]. These concepts are embodied in the equation:

$$K = Af * \left(\frac{3 * \emptyset}{2 * (1 - \emptyset)}\right) * \ e^{sum\ (Bi*Mi)} \qquad (2)$$

where, *Af:* the feldspar-dependent textural maturity term; *Mi:* the abundance of the mineral (its volume); and *Bi:* is a constant for the mineral. The textural/mineralogy maturity term, Af, is: *Af* = 4.4

Bi constants are positive for quartz and feldspar, and negative for the clay minerals, and cements (e.g., calcite or other carbonates). Permeability is assumed to depend on porosity as described in the Kozeny-Carman equation. Default Bi values: **Clays: Kaolinite (-4.5), Illite (-5.5), Smectite (-7.5) **Cements: Calcite (-2.5) **Framework Minerals: Quartz (0.1), Feldspars (1.0).

2.3. Area of interest

The area of interest for the study is in the western desert of Egypt. Fields reserve is mainly in stratified sandstone reservoirs. The drive mechanisms for most of these reservoirs are depletion drive and water drive. The dominant reservoir fluid for these fields is black oil, while the rock permeability ranges between 10 to 100 mDarcy. The wells are produced commingled to get the maximum oil production. The completion for most wells does not contain smart tools to monitor the downhole pressure. Only a few wells contain downhole pressure gauges to monitor the pump intake pressure. For accurate values, ILTs are done periodically to quantify the water conformance between the producing zones [2]. As most fields are brown fields with low daily oil production, the application of smart completions is limited to a few wells with high daily oil production. The prediction model aims to integrate the available ILT and the actual parameters to get a valid approximation. If there is a difference between ILT results and the prediction model, the accuracy could be improved by the implementation of other parameters such as net pressure, oil formation volume factor, pay thickness, porosity, permeability, fluid viscosity, perforation, and frac jobs efficiency. Every single parameter of these parameters should be considered to improve the prediction model. The more applied ILT results in the model, the more will be the model validity. Cross years, many ILT jobs are carried out in many fields. Figure 1 shows the number of ILT jobs in each field. The ILT total number exceeds 300 jobs [2].

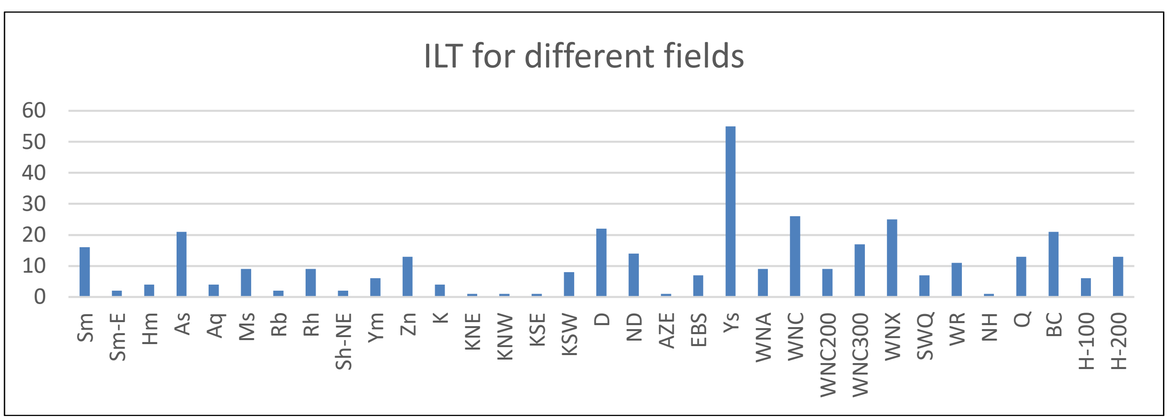

Figure 1. ILT distribution for the different fields.

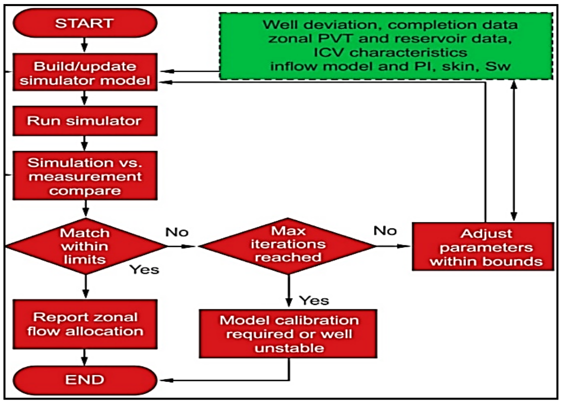

Figure 2. Zonal flow allocation engineering workflow.

These data will help in increasing the model accuracy as these fields are similar in their reservoir's fluid type and drive mechanisms. The ILT results used in the model are divided into three proportions, the first will be used to learn and develop the model, the second proportion to validate and increase the model accuracy, and the last proportion will be used to test the model validity [2].

The ability to build a good model helps to perform proactive reservoir management, such as controlling the water cut, eliminating crossflow, and performing well testing. Figure 2 shows the workflow for processing the data [7].

3. Results and discussion

Multi-layer commingle production is a common development technique to improve the overall oil recovery of multi-layer reservoirs. To achieve a good commingle production result the production layers must be optimized and inter-layer interference must be analyzed and reduced as much as possible. Factors, such as permeability, porosity, viscosity, capillary pressure, gravity, pressure difference, and water cut difference, have impact on commingle production. But it is difficult to consider all these factors [8].

For modelling quality, the more input parameters give you a more accurate result. In real, getting such data needs paying money, so many fields suffer a lack of data which make it hard getting accurate results for water distribution in injection wells. So, it is very important to get acceptable model results by using simple data such as pay thickness for injector well and producer wells, the distance between wells, and the ratio between injectors and producers.

This allows us to be able to predict the water distribution even when have a poor data. The results accuracy will be acceptable compared to the available data.

This simple model can be used for fields that have small differences in their reservoir permeabilities, porosity, well spacing…etc. For such fields, even when having a lack of data, you can predict values with acceptable accuracy for injection in commingled reservoirs. This model results can be enhanced through other important inputs such as permeability distribution through productive layers, and the pressure map for the field.

Also, considering injection-production ratio, followed by oil recovery rate, horizontal permeability, and dip angle are important to predict injection profile changes over time [9].

3.1. Pay thickness (H)

Pay thickness values are available for all fields and can be used to initially predict the water distribution in commingled reservoirs. The water injectivity increases when the injected pay thickness gets larger.

Case study: For Rb field the ILT data interpretation **(well Rb-04)** shows that the injectivity percentage is almost matched with the injection pay thickness percentage. For this well the injected water is distributed through three commingled reservoirs. Figure 3 shows a comparison between the injected water and pay thickness percentage for three layers M-G, LG21 & LG22.

However, pressure readings showed that pressure against the sand face in M-G is 5045 psi and 5140 psi in L-G21& L-G22, which means less effect of pressure on the ILT results. Figure 4 shows Rb-04 ILT results versus the cross-section map.

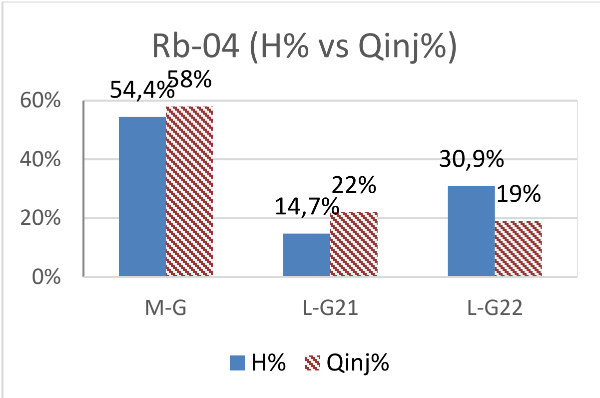

Figure 3. Qinj% versus pay thickness (H)% for injector well Rb-04.

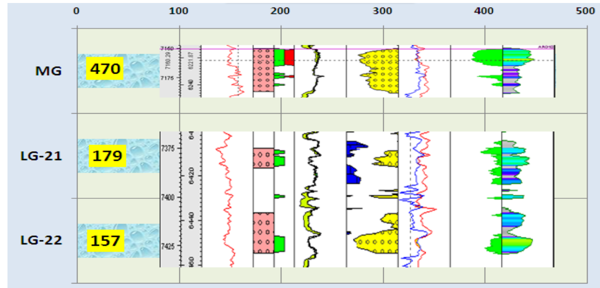

Figure 4. Rb-04 ILT results versus cross-section map.

ILT results showed that layer M-G is taking water more than L-G21 & L-G22. This is due to the larger thickness and good sand quality in M-G. So, the Qinj is directly proportional to the pay thickness as the following:

$$\frac{Qinj}{\Sigma\,\mathrm{Qinj}} \propto \frac{Hinj}{\sum Hinj} \qquad (3)$$

3.2. The communication between wells for each perforated layer

For another well in the field "Rb-08", we figured out that Qinj% is not proportional to the injector pay thickness H%. We notice from Figure 5 that most of the injected water goes for layer M-G.

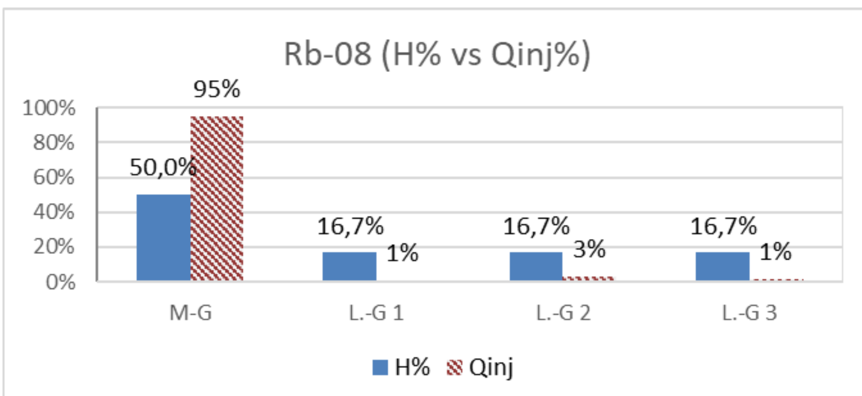

Figure 5. Qinj% verse pay thickness H % for injector well Rb-08.

This is because of good sand distribution quality at M-G (high thickness in the two offset producer wells "35 ft"), and poor quality at L-G (small thickness in the two offset producer wells, relatively 0', 3', 3').

Figure (6) shows a cross section between Rb-08 (injector well) and the two offset producers (Rb-01 & Rb-05 ST), that shows a low sand quality in L-G.

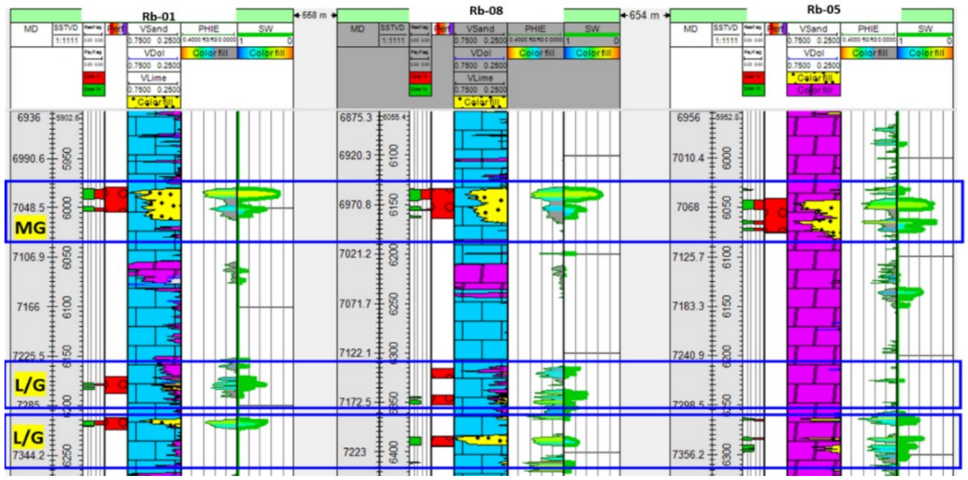

Figure 6. Cross-section shows sand quality for the commingled reservoirs.

This factor could be presented in the model by the percentage of pay thickness in offset-supported producer (Hp) wells relative to the thickness of the injection layer in the injector well. So, by considering the sand quality for Rb-08, For a given layer, as in Table 1, we have this relationship:

$$\frac{Qinj}{\Sigma\, \mathrm{Qinj}} \propto \frac{Hinj}{\sum Hinj} \times \frac{Hp}{\sum Hp} \qquad (4)$$

where, Hp: the summation of the layer's thickness in offset producer wells for each injection layer.

Table 1. shows the implementation of the pay thickness in offset producers for Rb-08.

Well Name	Formation	Perf. thick. (H)	H % (1)	Hp (ft)	Hp % (2)	(1)* (2)	(1)* (2) %	Q	Q % PLT
Rb-8	M "G"	30	50.0	35	85	0.43	95	2098	95
	L."G" 1	10	16.7	0	0	0.00	0	18	1
	L."G" 2	10	16.7	3	7	0.01	3	60	3
	L."G" 3	10	16.7	3	7	0.01	3	29	1
Total		60	100.0	41		0.45		2205	100

Figure 7 shows the improvement in the prediction model after considering the pay thickness in offset producers.

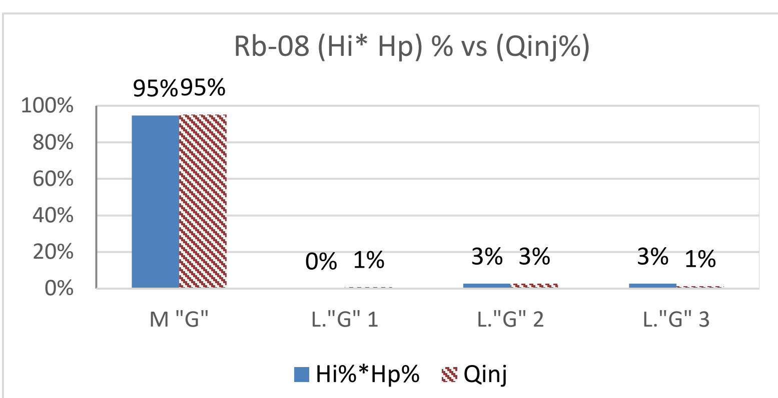

Figure 7. Qinj% verse pay thickness H % for injector well Rb-08, considering Hp values.

3.3. Darcy equation parameters (K, ΔP (Pinj -Pr), L, μ)

For the previous wells, we get good results despite applying simple parameters. The other parameters such as reservoir pressure, permeability, skin, and well spacing are very important. However, these parameters are almost matched for the injection wells Rb-04 & Rb-08 in Figures 3 & 7.

For other fields, these parameters should be implemented for getting an accurate model. The effect of these parameters can be understood from darcy equation.

The area variable (A) in darcy equation is represented in the model by the pay thickness parameters for injector and offset producer wells as in the examples for wells Rb-04 & Rb-08 in equations 3 & 4. So, the model parameters can be as the following:

$$\frac{Qinj}{\Sigma\, Qinj} \propto \frac{Hinj}{\sum Hinj} \times \frac{Hp}{\sum Hp} \times \frac{(Pinj - \mathrm{Pr}) * K}{L \times \mu} \qquad (5)$$

where: *L:* the spacing between the injector well and the offset producer; *K:* the rock permeability; *μ:* the fluid viscosity; *(Pinj - Pr)*: the pressure difference between the injected water and reservoir pressure.

3.3.1. Spacing between wells (L)

The spacing between well is affecting the injected water, as when it becomes longer, most of the water did not reach the producer wells. However, the spacing values is known for all wells. In most fields, the spacing between wells is almost of equal spacing, following an injection pattern. This means the spacing between wells can be neglected in calculating water distribution for commingled reservoirs.

The streamlines from injectors to producers takes longer path, but as this streamlines behavior is similar for injected water, it could be simplified by considering the spacing (L).

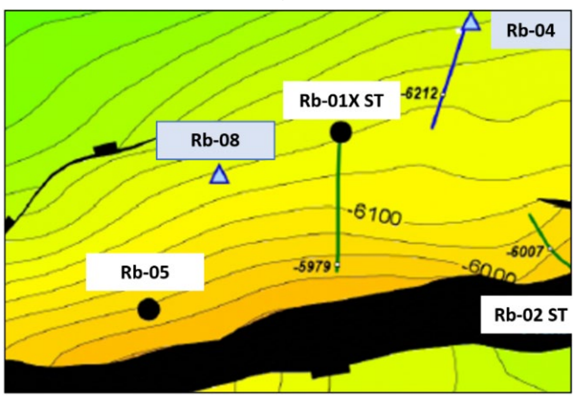

Figure 8. the structure map for Rb field, with almost equal spacing between wells.

In other cases, the reservoir heterogeneity affects the spacing values. For example, partial sealing by faulting could increase the streamlined path between wells. On the other hand, channels make the streamlined path shorter between wells. So, the spacing value could be simplified or neglected for some cases and could be complicated for other cases depending on the fields study.

For the previous examples (wells: Rb-04, Rb-08) the spacing between wells did not be included in the model, due to equal spacing between wells as in Figure 8.

3.3.2 .Reservoir permeability (K)

The reservoir permeability values, besides reservoir pressure, are one the main factors affecting water conformance for commingled reservoirs. Stile's method [10] is frequently applied in multi-layer one dimensional dual phase, depending on permeability and thickness variation between commingled layers. However, the method is based on the presumption that the fluid flow in each sublayer is piston-type flow, which is inconsistent with the actual situation [11].

Measuring accurate values for permeability is complicated as the permeability values could have a wide variety in the same reservoir due to heterogeneity and deposition environment. Moreover, these values are not fixed over time as skin could make its values continuously decreasing over time. Permeability reduction can be caused either by fine migration in the pore throats, clay swelling, chemical precipitation. [4].

Fortunately, some commingled reservoirs could have similar depositional environment which make their permeability initial values are in the same range. These estimated values help to predict the permeability values for these reservoirs. For other reservoirs with unknown permeability values, predicting accurate values helps in building a valid model.

3.3.3. Pressure gradient (Pinj -Pprod)

One of the most important factors is the pressure difference between the injection point and the production point. Increasing the pressure difference has a direct effect on increasing the injection rate. This can happen either by increasing the injection pressure through the injection surface line or decreasing the production pressure by pumping off the fluid level above the production layers. Pumping off for ESP production wells can be achieved by increasing frequency for ESP pumps or by ESPU (ESP upgrade by W/O). On the other side shut-in the injection offset producers will cause a rapid increase in reservoir pressure and a drop in the injection rate.

For commingle reservoirs, RDT measurements gives a guide for the participation of every single zone, and the communication between wells. RDT is wireline open hole logging provided by Halliburton. This tool has a customized configurations enable efficient formation pressures and complete fluid characterization [12]. By comparing the RDT results for different wells in same area, we can notice a depletion in reservoir pressure for the most sharing zone, which indicates the production sharing for commingled reservoirs.

The pressure difference between the commingled layers has a direct effect on the interflow between the produced layers. Liu Lingli *et al.* [13] perform a set of multi-layered commingle production simulation experiments and found that big interlayer pressure difference will cause obvious backflow phenomenon that oil flow from the high-pressure layer to the low-pressure layer in the initial stage and commingle production layer should have small pressure differences [13].

For having a pressure map for the injection and production points in the reservoir**,** validated reservoir pressure per layer and a pressure trend are created for each layer based on available pressure points from DFL, SFL, and MDT data.

Case study: For injection well Zn-04 (natural dump flood from LB water source zone), with two offset producers Zn-03 & Zn-01. The injection & production are commingled from three layers. ILT for Zn-04 in Nov 2014 showed the following results:

Table 2. Zn-4 ILT Results dated November 2014.

Formation	Perforations	Inj. Rate, BBl/day	Percentage
M-G	(6424 - 6441) 17 ft	330	27 %
L-G	(6674 - 6694) 20 ft	0	0 %
U.B	(6892 - 6899) 7’, (6909 - 6932) 23’, (6962 - 6978) 16 ft	880	73 %
Total		1210	100%

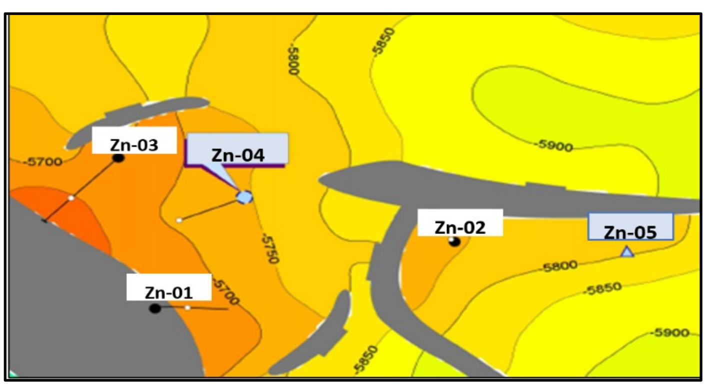

Figure 9. Depth structure map for Zn field on top M-G.

After investigation, offset producers Zn-1 & 3 showed excellent response to injection from Zn-4. Zn-1 was upgraded by W/O & Zn-3 operating frequency was increased, with total oil gain +/- 350 BOPD.

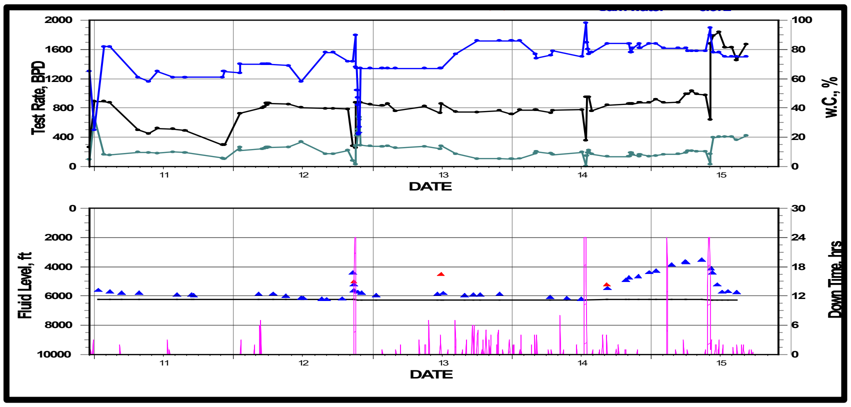

Figure 10: Zn-01 DFL increased affected by Zn-04 inj.

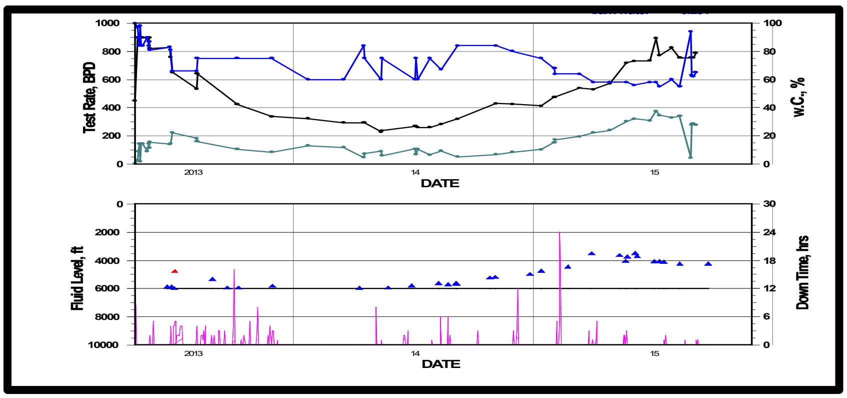

Figure 11: Zn-03 DFL increased affected by Zn-04 inj.

It was decided to run an ILT survey in Zn-4 to evaluate the injection profile for M-G, L-G & U.B formations after upgrading the offset wells. ILT Results after pumping off the offset producers:

Table 3. Zn-4 ILT Results dated Sep 2015.

Formation	Perforations, ft	Injection rate (BWPD)	Press.	Temp.	%
M-G	(6424 - 6441) 17	1011	2600	198	49.7
L-G	(6674 - 6694) 20	38	2693	198	1.8
U.B	(6892 - 6899) 7 (6909 - 6932) 23 (6962 - 6978) 16	985	2777	198	48.5

ILT run showed that L.BAH is injecting +/- 2030 BWPD (dumpflooding) in M-G, L-G & U.B layers which is good as it increased from 1200 BWPD according to ILT done on Nov-2014 due to upgrade in Zn-1 & pump off Zn-3.So, it’s recommended to continue regular PLT jobs to keep close monitoring for injection, we have a good indication for the injection response as Zn-01 & Zn-03 DFL started to increase.

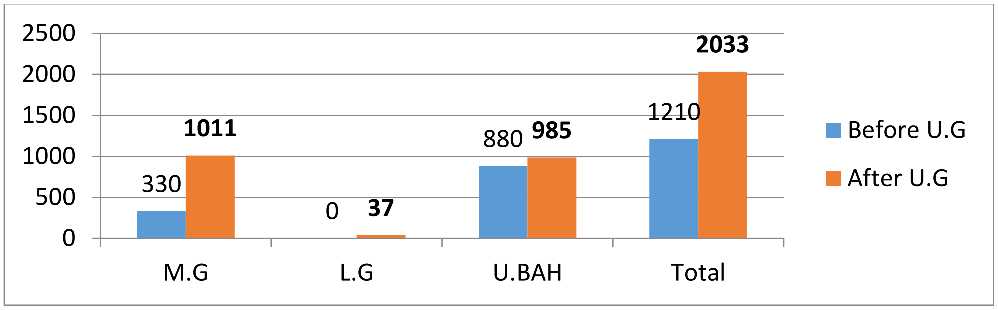

Figure 12. changes in Zn-04 injection rates before and after offset producers upgrade.

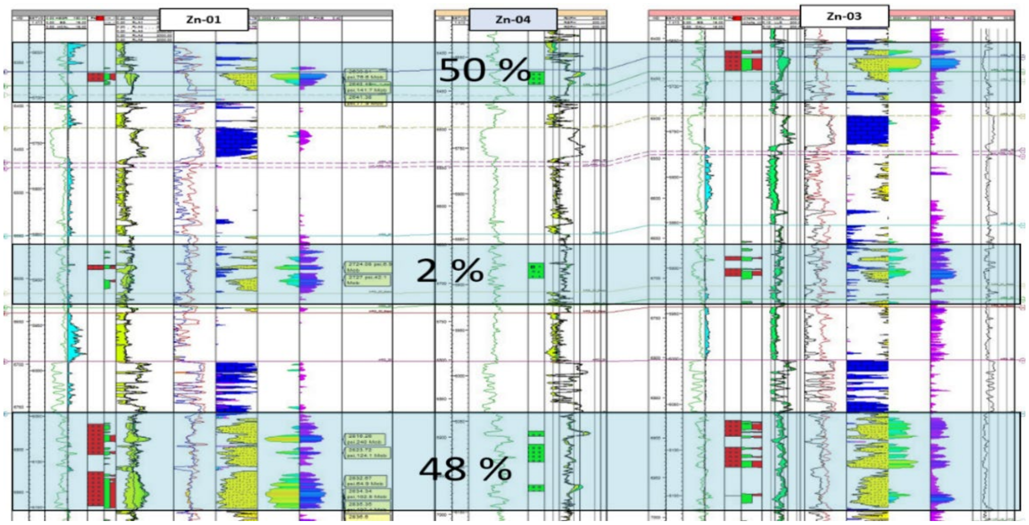

Figure 13. ILT results corresponding to the zones x-section.

3.4. Skin (s)

The skin effect is very important to be implemented. Over reservoir lifetime the permeability values could be decreased due to skin effect. In some cases, the permeability decreased to values with no flow. This happens because the permeability values make the existing pressure difference not capable of driving fluid flowing through reservoir.

Case study: For field Sh-NE, it is a simple field, has one injector Sh-N03 (natural dump flood from LB water source zone) and one offset producer Sh-N01.

The ILT run showed that M-G is taking most of the injected water while L-G is taking few water bbls, and this is due to high depletion in M-G reservoir pressure, while L-G pressure is relatively high and this reflects that production contribution in M/G is higher than L/G, Also L-B pressure is not high enough to force water to go in M-G & L-G. So, for increasing the injection rate for two layers, it is recommended to either run ESP and Packer to get enough pressure needed for injection or isolate L-B and the start surface injection.

Table 4. Sh-NE03 ILT Results dated 22- Apr 2012.

Formation	Perforations, ft	Inj Rate, BBl/day	%
M-G	(6698 - 6710) 12	406	90
L-G	(6882 - 6894) 12	45	10
	(6904 - 6910) 06		
	(6922 - 6932) 10		
Total		451	100

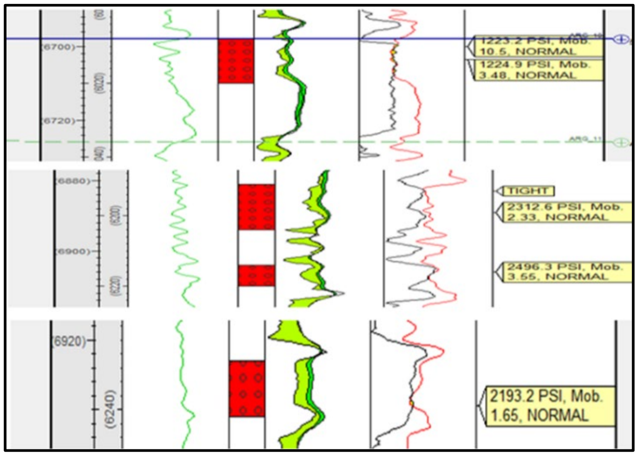

Figure 14. pressure and mobilty values for M-G & L-G in Sh-NE03.

After two years, the ILT results showed that the ILT run showed that M-G is taking all the water where L-G didn`t take any water. Log & MDT data confirm these results as M-G showed better sand quality than L-G & also more depletion in MDT. The values for L-G intervals dropped to zero because of skin effect. It is recommended to reperforate L-G to restore the injection rate for L-G layer.

Table 5. Sh-NE-3 ILT Results dated June 2014.

Formation	Perforations, ft	Injection rate, BBl/day	Percentage
M -G	(6698 - 6710) 12	400	100
L. G-1	(6882 - 6894) 12	0	0%
	(6904 - 6910) 6		
L. G-2	(6922 - 6932) 10	0	
Total		400	100

So, the skin factor S can be introduced in the model multiplied to the K values.

$$\frac{Qinj}{\sum Qinj} \propto \frac{Hinj}{\sum Hinj} \times \frac{Hp}{\sum Hp} \times \frac{(Pinj-\mathrm{Pr})*S*K}{L \times \mu} \qquad (6)$$

where, S = 1 for no skin; S = 0 for complete skin damage, and more than 1 for stimulation. For Sh-NE03 the real values could be matched by the model when consider S= zero.

3.4.1. Skin rate over time

For another field (Zn field), skin damage showed a decrease effect on injection rate over time. For the injection well Zn-08, the ILT results for M-G layer (thickness 40 ft) showed the following results over time:

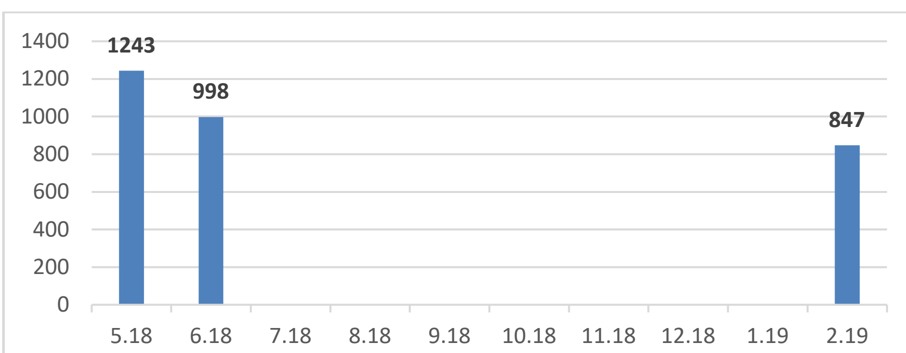

Figure 14. Zn-08 skin effect (ILT for M-G over time).

This can be explained by skin damage upon starting injection in Jun 2018, then the damaging effect showed less effect in Feb 2019 (skin rate 0.85 / 8 months).

3.4.2. Skin due to cross flow

When an injector is shut-in, cross-flow between perforated intervals may occur which can induce sand production and liquefaction in the higher pressure layers and formation damage and permeability reduction in the lower pressure layers. Understanding and modeling crossflow during well shut-in is important from a production and reservoir engineering perspective, particularly in unconsolidated or poorly consolidated sandstone reservoirs. This will alter the well's injection response and may lead to perforation plugging (sand accumulation in the well) or it may plug or damage downhole equipment such as ICDs (in-flow control devices) and ICVs, which control zonal injection [14].

3.5. Stimulation (s)

The stimulation effect is very important to be implemented. Sometimes, it called negative skin as it has an opposite effect relative to the skin effect. For the model application, it could be implemented in equation (6) with (S) value higher than one, depending on the stimulation effect.

Cui Chuanzhi *et al.* [15] propose the 'apparent mobility' to study equivalent permeability of fractured layers in the low-permeability reservoirs and found that artificial fractures have a significant impact on multi-layer commingle production in the low-permeability reservoirs [15].

For field Zn, as in Figure 9, there is an injector well Zn-05, supporting the offset producer Zn-02 in two reservoirs M-G & U-B via natural dump flood from layer L-B. The H, K & L values for M-G & U-B are in the same range. However, the ILT results showed that 90% of the injected water was in M-G.

Table 6. Zn-5 ILT Results dated Nov 2014.

Formation	Perforations	Inj rate (BWPD)	Press.	Inj. %
M-G	(6478 - 6490) 12 ft	185	2674	90%
U.B	(6854 - 6870) 16 ft	20	2840	10%

Based on the results of Zn-05 ILT; U-B injection values are low because it was perforated only as it is a secondary target where Zn-02 has only 1 ft calculated oil pay as in figure 15 below, and it had low reserve values for the frac job. The main target is M-G and a frac job in M-G reservoir has been made for Zn-02 & 05.

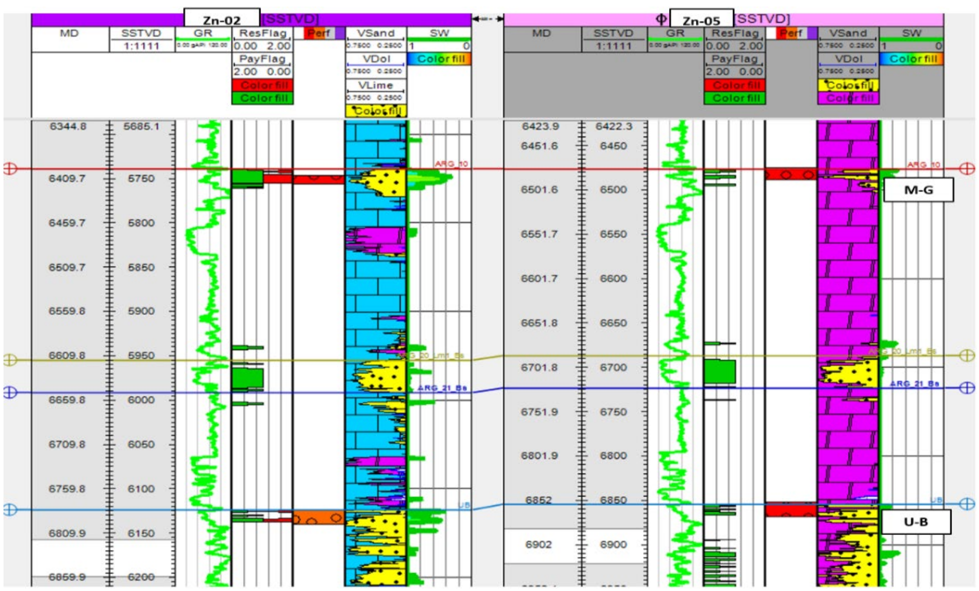

Figure 15. X-section map for U-B & M-G layers in Zn-02 & 05.

This can be implemented in the model by increasing the K values for M-G by three times due to the stimulation effect (K for M-G = 3 * K for U-B. However, in ILT results the injected water percentages in M-G & U-B are 90% & 10% respectively. This could be explained by channelling effect between the two wells due to frac jobs as the frac job resulted in a frac pass parallel to the fault direction as in figure 9. This caused a direct communication with a short path between the two well with minimum path and minimum pressure loss.

In the model, this could be represented by L for M-G = 1/3 L for U-B. For other cases, frac job could cause more effect such as Zn-08 perf. Only, showed Qinj = 16 bbls/day in Apr 2018. After frac job in May 2018, it showed 1250 bbls/ day which is 78 times the injection rate before the frac job. This because the zone was almost had no flow before the frac job.

So, from this case, we see that the frac job could increase Qinj by three times. In some cases, like Zn-02 &05 channelling effect could increase the Qinj by three times also. So, by considering both stimulation and channelling effects we have Qinj (M-G) = 9 * Qinj (U-B), which same as ILT results.

Over time to reallocate values for the injected water in U-b & M-G, Regular SFL for Zn-2 measurements are useful to monitor this injection response. After re-perforation job for both reservoirs in March 2015, ILT results in Sep. 2015 showed Qinj (88% M-G, 12% U-B).

After two years in Dec 2017, these results changed to be (96.2% M-G & 3.8% U-B). this shows skin effect in U-B layer due to poor quality. This skin damage represented by S=0.3 / 2 years. In May 2022, another ILT done with previous expectation to have lower values for U-B due to skin effect. The results were as expected that Qinj (98.2 M-G, 1.8% U-B). So, skin effect showed be considered versus time, especially for poor quality layers.

4. Conclusions

The ILT interpretated data in the oil fields are valuable as it is necessary to build the prediction model, and to allocate production for the commingled zones. For Rb-04 it showed the valuable consideration for the thickness of the injection layer. Rb-08 showed the importance of considering the layers thickness of offset producer. The skin damage should be considered as in Sh-NE03. However, prediction of the damage gradient over time is important such as Zn-08. On the other side, stimulation could maximize the injection rate such as Zn-08. In other cases, frac jobs could cause channelling between the wells for stimulated layers. Increasing the pressure difference between the injection and production points helps in maximizing the injection rate such as pumping off the offset producers of Zn-04.

This model could help in maximizing the oil recovery, water shut-off, optimizing the injection ratio between wells, and skin damage prediction over the production time. The prediction model can be utilized to allocate reservoirs production with acceptable error. Considering data such as PVT, historical production, reservoir pressures, well events, and petrophysical information for all the commingled reservoirs, are important for improving the model.

After building the prediction model utilizing the available data, it's essential to use machine learning for developing the model. This could be done by using a proper programming language for considering the parameters effect in the model and accurate estimate for variable parameters. The error could be minimized by considering many ILT interpretations

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