

EVALUATION OF THE IMPACT OF WATER INJECTION FROM TS-06 AND TS-09 WELLS ON THE PRODUCTION PERFORMANCE OF TS-05 WELL IN TS-05 BLOCK OF THE TSHIENDE OIL FIELD (D.R. CONGO)

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ABSTRACT

East of the Mibale Field, located offshore in the Coastal Basin of the Democratic Republic of Congo, lies the Tshiende Oil Field, part of the Perenco Rep. concession. This field was discovered in May 1984 through the drilling of Tshiende-02 well, following an earlier discovery in the neighboring area with East Mibale-01 well in January 1978. Building on this success, field development continued with the drilling of several additional wells: two in 1985 (TS-3 and TS-4), one in 1986 (TS-5), and three in 1987 (TS-6, TS-7, and TS-8). After an initial phase of natural flow production, the wells were equipped with jet pumping systems to sustain output. Subsequently, the reservoir was subjected to a pressure-maintenance process via water injection. To optimize sweep efficiency, the reservoir was compartmentalized into three distinct blocks: Upper Vermelha, TS-05 Block, and TS-07 Block. However, a progressive increase in water cut led to a decline in oil production. It is within this context that the present study examines the impact of water injection from the Tshiende-06 and Tshiende-09 wells on the performance of the Tshiende-05 well in the TS-05 Block. The objective is to evaluate the effectiveness of secondary recovery through water injection using dynamic reservoir performance indicators, to assess its potential for maintaining reservoir pressure and optimizing oil production in this Congolese oil field.

The methodology relies on production and injection data, PVT parameter analysis from Perenco Rep. reports, and the calculation of indicators such as the voidage replacement ratio (VRR), volumetric, vertical, and microscopic sweep efficiencies, and overall efficiency. Results indicate a VRR of 67%, reflecting partial pressure maintenance. Volumetric efficiency reached 82.28%, suggesting good lateral sweep, while vertical efficiency remained heterogeneous across layers. Displacement efficiency was estimated at 56.52%, leading to an overall efficiency of 33.97%. The displaced oil volume was evaluated at 13.59 MMstb for a cumulative production of 14.48 MMstb. This study is innovative as it confirms the significant contribution of water injection while highlighting the limitations of overall performance in TS-05 Block of the Tshiende Field. It underscores that final recovery remains constrained by insufficient injection volumes.

Keywords: water injection, TS-05 Block, Tshiende Field, reservoir, oil wells, waterflooding, breakthrough.

INTRODUCTION

In oil reservoirs, primary production generally recovers only a limited fraction of hydrocarbons in place. Therefore, improving the recovery factor is a crucial objective, strongly dependent on secondary recovery methods, among which water injection is one of the most commonly implemented [1]. The effectiveness of these techniques is highly influenced by reservoir characteristics such as heterogeneity, the configuration of producing layers, and the spatial distribution of injection and production wells [2].

Since the early 1980s, secondary recovery by water injection has been applied in the Tshiende Field, which exhibits lithological and petrophysical variability across its different blocks (including TS-05 Block). Wells drilled between 1984 and 1987 (TS-2 to TS-8) revealed producing layers with diverse geometries, raising the issue of long-term water injection efficiency on recovery rates. This variability affects the connectivity between injection and production wells due to local stratigraphy and heterogeneity, which directly influence fluid flow within TS-05 Block of the Tshiende Field [3],[4].

Given the complexity of fluid-flow interactions associated with water injection and their impact on oil production from Tshiende-5, Tshiende-6, and Tshiende-9 wells within TS-05 Block of the Tshiende Field, this study is distinguished by its innovative character. It highlights the significant contribution of water injection while emphasizing the limitations of overall performance in TS-05 Block, where final recovery remains constrained by insufficient injection volumes.

GEOGRAPHICAL AND GEOLOGICAL FRAMEWORK OF THE STUDY AREA

The Tshiende Field, part of the East-Mibale permit, is located approximately 600 meters from the Atlantic coast. It lies 4 kilometers south of the border between the Democratic Republic of Congo and the Cabinda enclave, and 5 kilometers west of the Liawenda Field (Figure 1). This field is one of six onshore fields operated by Perenco REP in the West African Coastal Basin, specifically in the town of Muanda [3],[4]. From a geographical standpoint, the field is bounded to the north by the village of Malongo, to the west by the Mibale Field and the Atlantic Ocean, to the east by the village of Tshiende, and to the south by the village of Kongo [3].

The main producing reservoirs of the Tshiende Field originate from the post-salt Vermelha Formation, dated to the Albian stage, deposited along the West African passive margin (Figure 2) [5]. Secondary formations of interest include the Pinda Formation, also of Albian age, and the Kinkasi Formation, dated to the Cenomanian. Onshore, the Vermelha Formation is considered the stratigraphic equivalent of the offshore Pinda Formation. The deposition of the Vermelha, Pinda, and Mavuma formations (Figure 3) occurred in a shallow marine, nearshore environment that experienced sea-level variations (transgressions) and changes in sediment accumulation derived from the continental area of the Democratic Republic of Congo [5],[28].

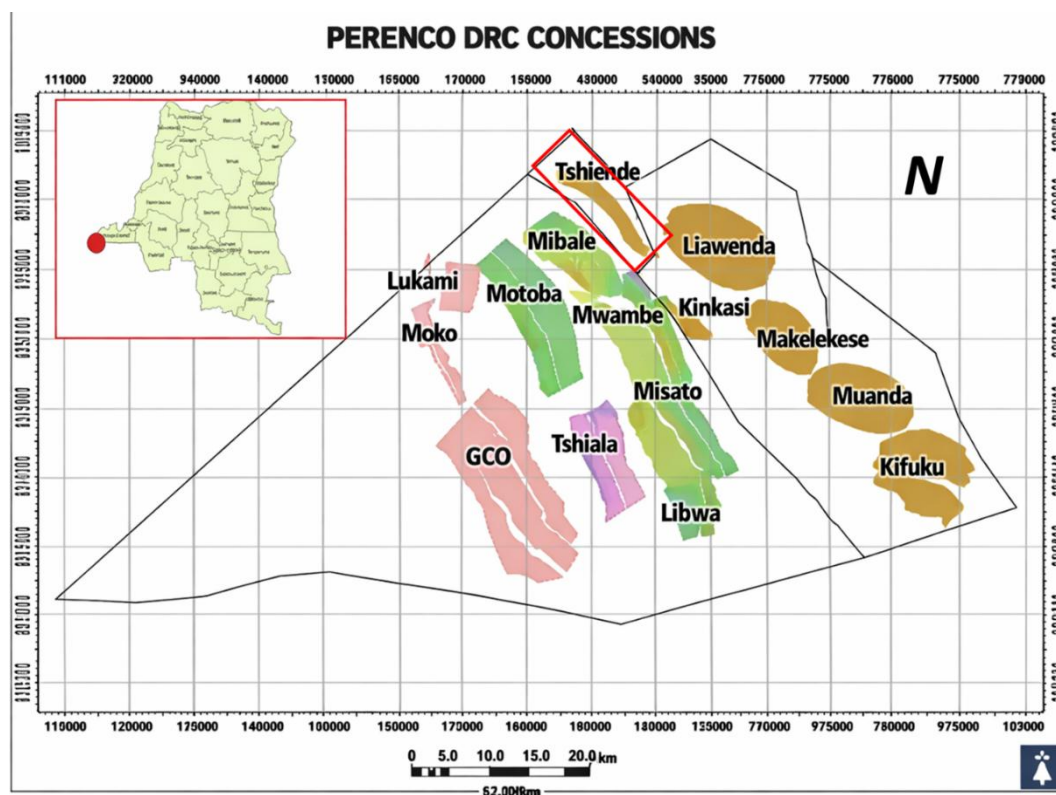


Figure 1. Map illustrating the location of the Tshiende Field [3].

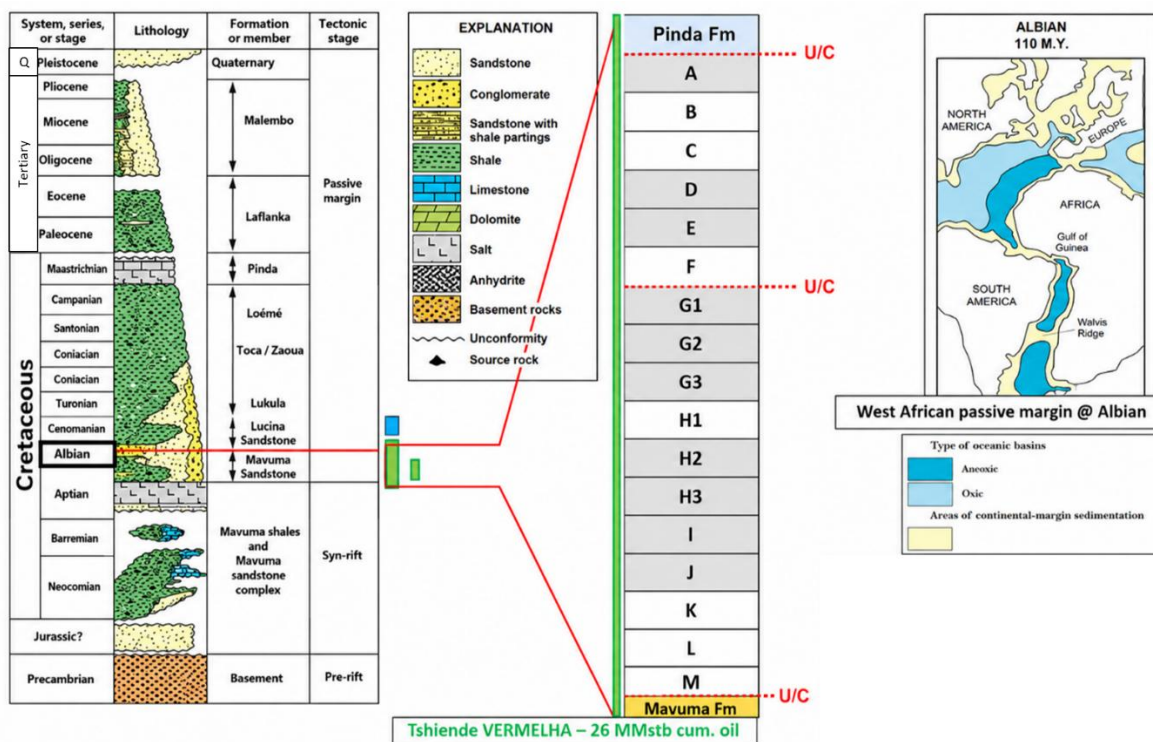


Figure 2. Stratigraphic log of the Tshiende Field [6],[28].

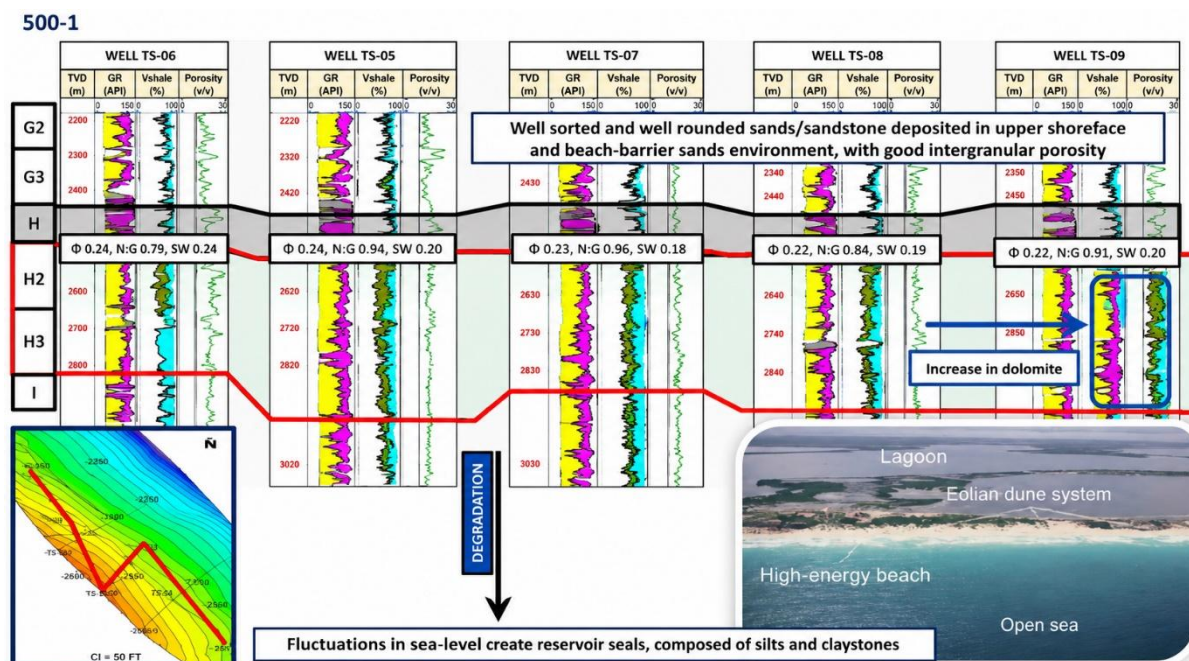


Figure 3. Depositional Environment of the Tshiende Field [7].

MATERIALS AND METHODS

The methodological framework adopted is based on an integrated analysis combining the use of well data (production and injection history) from the Tshiende Field, characterization of the relevant sub-layers, calculation of dynamic parameters, and interpretation of results in connection with reports from Perenco REP submitted to the Ministry of Hydrocarbons of the Democratic Republic of Congo.

To evaluate the effectiveness of water injection, several indicators were employed, including the voidage replacement ratio (VRR), average saturation at breakthrough, overall efficiency, and fractional flow rate.

RESULTS AND DISCUSSIONS

Presentation of Data Related to Water Injection Analysis

The objective of this study is to analyze the influence of the injection wells (TS-06 and TS-09) on the behavior of the layers exploited by Tshiende-05 well, namely: E, F, G1, G2, G3, H1, H2, H3, and I of the Vermelha reservoir, where layer G1 is the only one that has ceased production (Figure 4).

The data compiled in Table 1 provides the basis for calculating the key parameters required for this evaluation. Table 2 presents the evolution of water saturation as a function of relative permeabilities. Figures 5, 6, and 7, reveals historical evolution of barrels produced as a function of injected water rates in the Tshiende Field.

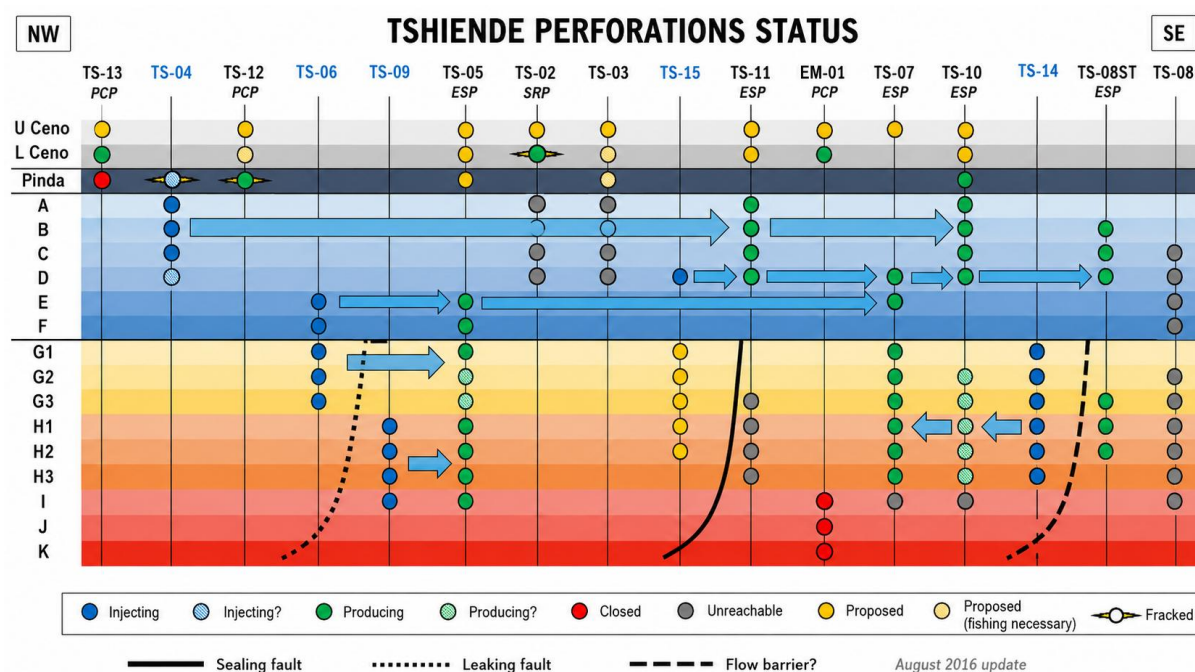


Figure 4. Tshiende Perforation Status [8].

Table 1. Presentation of PVT parameters for Tshiende-05 well [3],[7].

Nº	Parameter	Value	Unit
01	Cumulative oil production	14.48384	MMstb
02	Gas-oil ratio (Rp)	168	Scf/stb
03	Water injection rate	4200	bbl/day
04	Oil production rate	224	stb/day
05	Water formation volume factor	1.027076	rb/stb
06	Average reservoir pressure	1100	psig
07	Bubble point pressure	554.7	psig
08	Cumulative water produced	11.8	MMstb
09	Average reservoir temperature	178	°F
10	Cumulative gas production	2.433	MMScf
11	Initial water saturation	0.425	—
12	Initial oil saturation	0.575	—
13	Oil viscosity	2.79	cP
14	Specific Gravity, SG	0.85	—
15	Gas Specific Gravity	0.65	—
16	Water viscosity	1	—
17	Daily water production	6000	bbl/day
18	OOIP TS-05 Block	40	MMstb

Table 2. Evolution of water saturation as a function of relative permeabilities [3],[8].

N°	S_w	K_{ro}	k_{rw}
01	0,425	1	0
02	0,60	0,26	0,005
03	0,65	0,13	0,03
04	0,70	0,04	0,07
05	0,75	0,01	0,15
06	0,80	0	0,28

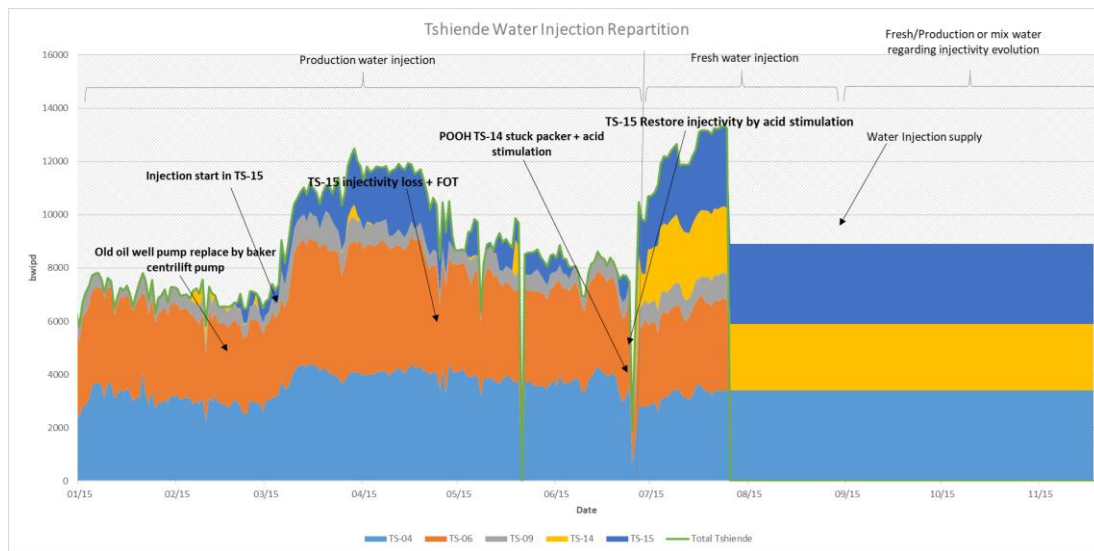


Figure 5. Distribution of injected water volumes in TS-04, TS-06, TS-09, TS-14, and TS-15 wells [7].

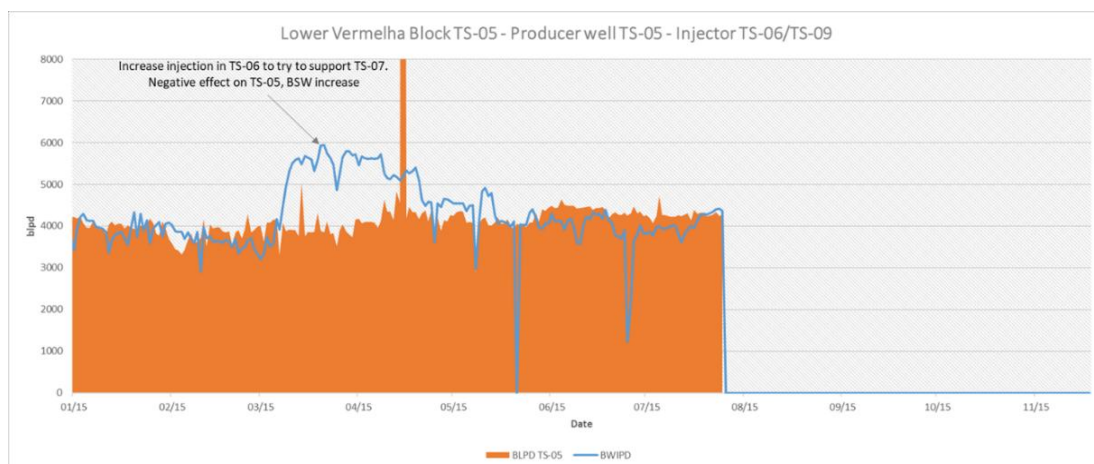


Figure 6. Evolution of water injection rates from Tshiende-06 and Tshiende-09 wells, and total liquid production (oil + water) from Tshiende-05 well over eight months in 2015 [7].

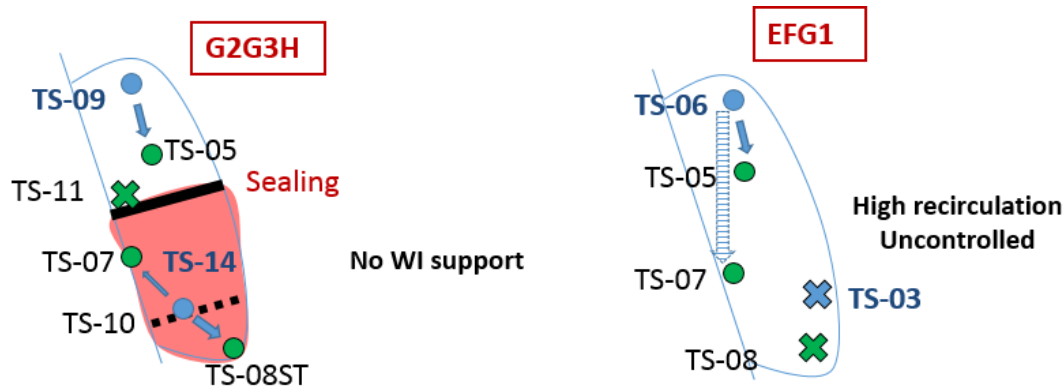


Figure 7. Diagram of the injection configuration of the Tshiende-09 and Tshiende-06 wells towards the action zone of the Tshiende-05 well [7].

DATA ANALYSIS

Before deciding on water injection in an oil reservoir to optimize recovery, the operator first evaluates the following parameters:

- Injection pressure,
- Voidage replacement ratio (VRR),
- Overall sweep efficiency,
- Quantity of oil displaced after injection.

The calculations of these parameters in TS-05 Block of the Tshiende Field constitute the focus of this part of the study.

Calculation of Injection Pressures – Tshiende-06 and Tshiende-09 Wells (TS-05 Block, Tshiende Field)

As seen in Figure 4, Tshiende-06 well injects water into TS-05 Block through the sub-layers E, F, G1, G2, and G3, while Tshiende-09 well injects into four sub-layers: H1, H2, H3, and I. Each of these sub-layers possesses distinct petrophysical characteristics such as porosity, permeability, and thickness. Therefore, it is appropriate to calculate the injection pressure to monitor and maintain pressure across the reservoir layers.

Tarek Ahmed [9] defines the **water injection pressure** in a reservoir as:

$$p_{inj} = \frac{Q_{inj}}{kh} \quad (1)$$

This formula turns out to be very simplified because parameters such as viscosity (μ), the flow geometry, and skin effects are not considered. For a more precise estimate, we are going to apply the formula derived from Darcy's law as shown in equation 2 below.

$$\Delta p = \frac{Q_{inj}\mu}{2\pi kh} \left[\left(\frac{r_e}{r_w} \right) + s \right] \quad (2)$$

Where Δp denotes the difference between the injection pressure and the reservoir pressure ($\Delta p = p_{inj} - p_r$). The viscosity of the injected water is represented by μ .

The product $k \times h$ corresponds to the transmissivity of the reservoir. The parameter s is the skin factor, while Q_{inj} represents the injection rate [10].

To avoid unnecessary repetition, the detailed calculations are presented only for Layer E, considering first the skin factor due to perforation ($s = -1$) and then the skin factor due to hydraulic fracturing ($s = -10$). The results obtained for the remaining layers are subsequently summarized in tabular form.

Considering a skin factor due to perforation ($s = -1$), the pressure drop is calculated as follows:

$$\Delta p = \frac{Q_{inj}\mu}{2\pi kh} \left[\left(\frac{r_e}{r_w} \right) + s \right] = \frac{660 * 1}{2 * 3,14 * 2266,53} \left[\left(\frac{1230}{0,25} \right) + (-1) \right] = 3,354214131 \text{ psig} \quad (3)$$

Since the average reservoir pressure in Layer E is known, the corresponding injection pressure is calculated as follows:

$$p_{inj} = p_r + \Delta p = 3,354214131 + 919,999938 \text{ psig} \quad (4)$$

Next, considering a skin factor due to hydraulic fracturing ($s = -10$), the following values are obtained:

$$\Delta p = 3,348077126 \text{ psi and } p_{inj} = 923,3480151 \text{ psig}$$

Tables 3 (a,b) and 4 (a,b) summarize the results obtained for all the layers investigated.

Calculation of the Voidage Replacement Ratio (VRR)

The evaluation of the Voidage Replacement Ratio (VRR) is essential in the management of an oil field subjected to water injection, as it allows measurement of the effectiveness of the pressure-maintenance process [11], [12]. A VRR close to or equal to 1 indicates that the volume of water injected compensates for the volume of fluids extracted (oil, gas, and water), thereby stabilizing reservoir pressure and optimizing hydrocarbon recovery [13]. A VRR that is too low may lead to a pressure drop and reduced productivity, while a VRR that is too high may cause early water breakthrough in producing wells. Thus, monitoring the VRR enables adjustment of injection strategies, extension of the field's productive life, and maximization of recovery rates [14],[27].

This parameter is estimated using the following mathematical formula [15]:

$$VRR = \frac{Q_{winj} * B_w}{Q_o * B_o + W_p * B_w + Q_o * (R_p - R_s) * B_g} \quad (5)$$

with: $VRR = \text{Voidage Replacement Ratio}$, a dimensionless quantity, generally expressed as a percentage (%);

- Q_{winj} = volume of water injected (STB/D);
- B_w = water formation volume factor (rb/STB);
- Q_o = oil production rate (STB/D);
- B_o = oil formation volume factor (rb/STB);
- W_p = volume of water produced, (STB/D);
- R_p = gas-oil ratio (scf/STB);
- B_g = gas formation volume factor (rb/scf).

Table 3.a. Injection pressures of Tshiende-06 well for layers (E, F, G1, G2, and G3).

Injection well	Layers	Depth (ft)	dp/Dd	Reservoir pressure (psig)	Porosity	h(m)	K(mD)	Kh(mD.ft)	Q _{inj} (bbl/d)	μ (cp)	re (ft)	rw (ft)
TS-06	E	6036,745	0,1524	919,999938	0,24	68	2266,53	154124	660	1	1230	0,25
	F	6250	0,1524	952,5	0,24	51	499,8456	25492,13	660	1	1000	0,25
	G1	6833,99	0,1524	1041,500076	0,19	20	568,0774	11361,55	660	1	997	0,25
	G2	6955,381	0,1524	1060,000064	0,2	20	75,95145	1519,029	660	1	997	0,25
	G3	6971,785	0,1524	1062,500034	0,15	10	646,9816	6469,816	660	1	876	0,25
								39793,31	3300			

Table 3.b. Injection pressures of Tshiende-06 well for layers (E, F, G1, G2, and G3).

Perforation Skin Factor	Fracture skin factor	Injection pressure (skin perfor) (psig)	Injection pressure (skin fracturation)	Pressure Drop Due to Perforation Skin (psig)	Δp due to Fracture Skin (psig)
-1	-10	923,3541521	923,3480151	3,354214131	3,348077126
0	-9,081	968,9906667	968,9532287	16,49066666	16,45322873
-1,3	-6	1078,377477	1078,334001	36,87740095	36,83392545
-2	-5,45	1335,775478	1335,536786	275,7754132	275,5367215
-2,1	-4,5	1119,384812	1119,345827	56,88477835	56,84579281
		5425,882586	5425,517858	389,3824733	389,0177456

Table 4.a. Injection pressures of Tshiende-09 well for layers (H1, H2, H3, and I).

Injection well	Layers	Depth (ft)	dp/Dd	Reservoir pressure (psig)	Porosity	h(m)	K(mD)	Kh(mD.ft)	Q _{inj} (bbl/d)	μ(cp)	re (ft)	rw (ft)
TS-09	H1	7070,21	0,1524	1077,500004	0,15	14	33,27709	465,8793	225	1	950	0,25
	H2	7086,614	0,1524	1079,999974	0,22	16	1403,994	22463,91	225	1	965	0,25
	H3	7152,231	0,1524	1090,000004	0,21	14	2331,974	32647,64	225	1	950	0,25
	I	7217,848	0,1524	1100,000035	0,18	36	848,006	30528,22	225	1	990	0,25
								21526,41	900			

Table 4.b. Injection pressures of Tshiende-09 well for layers (H1, H2, H3, and I).

Perforation Skin Factor	Fracture skin factor	Injection pressure (skin perfor) (psig)	Injection pressure (skin fracturation) (psig)	Pressure Drop Due to Perforation Skin (psig)	Δp due to Fracture Skin (psig)
-2	-5	1369,581766	1369,351053	292,0817615	291,8510492
-1,5	-6,34	1086,153952	1086,146233	6,153978858	6,14625947
0	-5,34	1094,170183	1094,164323	4,170178967	4,164318768
-0,67	-7	1104,646719	1104,63929	4,646684077	4,639255166
		4654,552621	4654,3009	307,0526034	306,8008826

Table 1 does not provide all the data required for the calculation of this parameter according to formula 3. We must therefore determine them to complete the dataset. The missing data are as follows: R_s , B_g , and B_o .

Calculation of the Dissolved Gas–Oil Ratio (R_s)

To determine R_s , we will use the Vasquez and Beggs (1980) formula:

$$R_s = d_g \left[\frac{p}{18} \cdot \frac{10^{0.0125(^{\circ}\text{API})}}{10^{0.00091t}} \right]^{1.2048} \quad (6)$$

where d_g represents the gas density, and p and t are respectively the pressure in psia and the temperature in $^{\circ}\text{F}$ [13].

After calculation, we obtained the following value:

$$R_s = 185.4229326 \text{ scf/stb.}$$

Calculation of the oil formation volume factor (B_o)

The Standing formula (1947) [16],[17] will help us calculate the oil formation volume factor:

$$B_o = 0.9759 + 0.00012 \left[R_s \cdot \sqrt{\frac{d_g}{d_o}} + 1.25t \right]^{1.2} \quad (7)$$

Since R_s and the oil density are known, we obtain:

$$B_o = 1.127695 \text{ rb/stb}$$

Calculation of the gas formation volume factor (B_g)

According to Standing, the gas formation volume factor is calculated using the following formula:

$$B_g = 0.00504 \cdot \frac{z \cdot T}{p} \quad (8)$$

where z represents the gas compressibility factor, T the temperature in $^{\circ}\text{R}$, and p the pressure in psia.

Since the gas gravity is known, the compressibility factor (Z) can be determined using the Standing and Katz charts [17],[18].

After using the charts and performing the various calculations, we obtained the following results:

$$p_{pc} = 670 \text{ psia}; T_{pc} = 375 \text{ }^{\circ}\text{R}; p_{pr} = 1.6418 \text{ psi}; T_{pr} = 1.70 \text{ }^{\circ}\text{R}; z = 0.91.$$

Therefore:

$$B_g = 0.000746 \text{ rb/scf.}$$

With all parameters determined, the void replacement ratio (VRR) is:

$$VRR = \frac{4200 \cdot 1.027}{224 \cdot 1.127695 + 6000 \cdot 1.027 + 224 \cdot (168 - 185.4) \cdot 0.000746} = 0.67274$$

Thus:

$$VRR = 67\%.$$

Overall sweep efficiency (E_G)

The calculation of overall efficiency during water injection into an oil reservoir is crucial, as it allows evaluation of the actual performance of the secondary recovery process. The overall efficiency (Sweep Efficiency) combines three components, namely:

- i) Volumetric efficiency (or areal sweep efficiency, also called horizontal sweep efficiency): it measures the portion of the reservoir area effectively swept by the injected water.
- ii) Vertical efficiency: it estimates the distribution of injection among the different vertical layers of the reservoir.
- iii) Microscopic efficiency (or displacement efficiency): it expresses the ability of water to displace oil at the pore scale [21].

Thus, we will need to calculate all these parameters to evaluate the overall efficiency.

Volumetric efficiency (also called horizontal sweep efficiency or areal sweep efficiency)

The volumetric efficiency, or horizontal sweep efficiency during breakthrough (that is, when water begins to invade the production well), is calculated using the following equation [22]:

$$E_{ABT} = 0.54602036 + \frac{0.03170817}{M} + \frac{0.30222997}{e^M} - 0.00509693M \quad (9)$$

where:

$$M = \frac{K_{rw@S_{avgBT}}}{K_{ro@S_{wi}}} \cdot \frac{\mu_w}{\mu_o} \quad (10)$$

with:

- M = mobility ratio (unitless),
- $K_{rw@S_{avgBT}}$ = relative permeability of water at average saturation at breakthrough (unitless),
- $K_{ro@S_{wi}}$ = relative permeability of oil at initial water saturation (unitless),
- μ_w = dynamic viscosity of water (cP),
- μ_o = dynamic viscosity of oil (cP).

To determine the values of these parameters, it is first necessary to calculate the fractional flow rate, or water cut (f_w), to correlate it with the water saturation values. This makes it possible to estimate the saturation at breakthrough (S_{wBT}) as well as the average water saturation in the swept zone after the passage of the water front ($\bar{S}_{wBT}$). The data from Table 2 were used to plot the graph in Figure 10, from which these saturations were determined.

The graph in Figure 10 shows that:

$$S_{wBT} = 0.7 \text{ and } \bar{S}_{wBT} = 0.75.$$

The corresponding permeability values for each saturation are:

$$K_{rw@S_{avgBT}} = 0.75 \text{ (75\%)} \text{ and } K_{ro@S_{wi}} = 0.7 \text{ (70\%)}$$

Thus, the mobility ratio is: $M = 0.4185$.

Consequently, the volumetric efficiency is: $E_{ABT} = 0.8228$ or 82.28%.

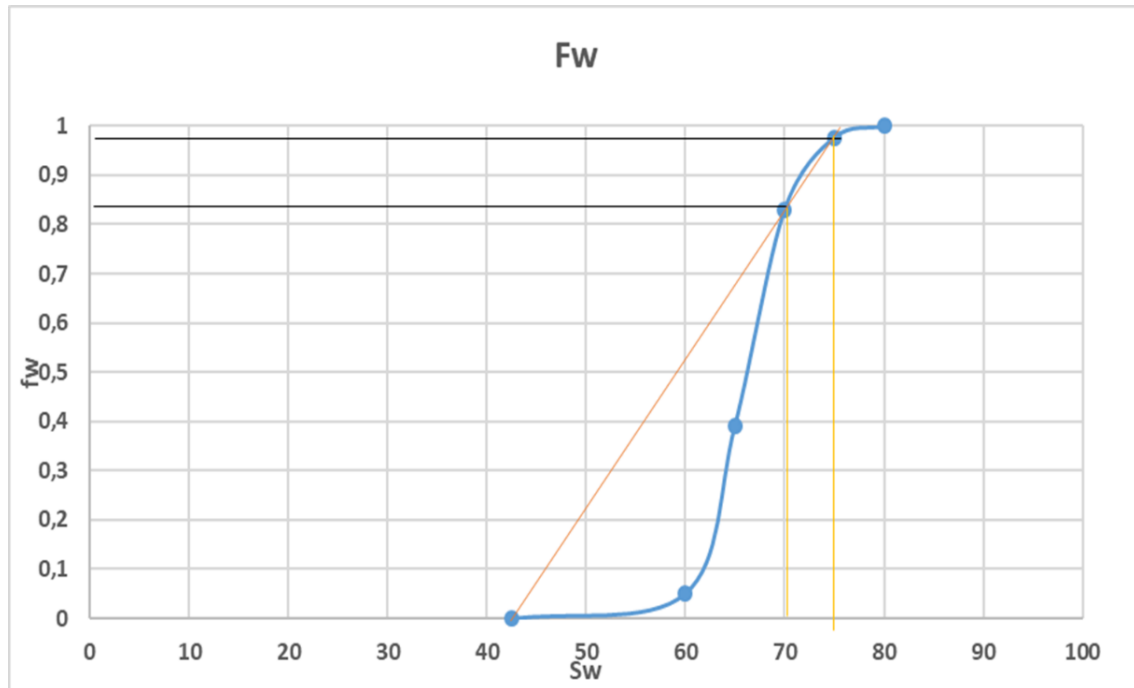


Figure 8. Graphs linking water saturation and fractional flow rates.

Vertical sweep efficiency

Vertical efficiency represents the portion of the reservoir's vertical thickness that is swept by the injected water. We determined it using the following equation [23]:

$$E_V = \frac{k_i \cdot \sum_{j=1}^i h_j + \sum_{j+1}^n (kh)_j}{k_i \cdot h_t} \quad (11)$$

where:

- k_i = permeability of the considered layer,
- h_j = thickness of layer j ,
- $(kh)_j$ = product of permeability and thickness for layer j ,
- h_t = total reservoir thickness.

Since our block contains two injection wells, each operating in its own layers, we will present the analysis results layer by layer, associating them with their respective wells in Table 4.

Microscopic efficiency (or displacement efficiency)

Displacement efficiency is the ability of the injected water to replace oil in the pores of the rock, at the microscopic scale. We calculated it using the following equation [24]:

$$E_D = \frac{\bar{S}_w - S_{wi} - S_{gi}}{1 - S_w - S_{gi}} \quad (12)$$

Since initially the reservoir was not saturated with gas, equation (10) then simplifies to:

$$E_D = \frac{\bar{S}_w - S_{wi}}{1 - S_{wi}} \quad (13)$$

Since all the parameters required in the formula are available, the displacement efficiency is:

$$E_D = 0.56522174 \text{ or } 56.52\%$$

Finally, the overall efficiency is:

$$E_G = E_D \times E_A \times E_V \quad (14)$$

$$E_G = 0.33966104 \text{ or } 33.97\%.$$

Table 4. Vertical efficiencies of TS-06 and TS-09 wells by layers.

Wells	Layers	Porosities	h (m)	K (mD)	Kh	EV
TS-06	E	0,24	68	690,838235	46977	0,51943586
	F	0,24	51	152,352941	7770	0,93321149
	G1	0,19	20	173,15	3463	0,50333107
	G2	0,2	20	23,15	463	0,85907447
	G3	0,15	10	197,2	1972	0,23668639
TS-09	H1	0,15	14	10,1428571	142	28,7503912
	H2	0,22	16	427,9375	6847	0,93746531
	H3	0,21	14	710,785714	9951	0,53863933
	I	0,18	36	258,472222	9305	1,075
Total			249		AVERAGE TS-09	0,85036822
					AVERAGE TS-06	0,61034786
					AVERAGE TOT	0,73035804

The quantity of oil displaced after injection

This parameter represents the quantity of oil mobilized and then displaced by the injected water toward the production wells during the waterflood enhanced recovery process. We determined it using the following equation [25],[26]:

$$N_D = N \times E_G \quad (15)$$

$$N_D = 13,5864417 \text{ MMstb}$$

After presenting the various collected data and the parameters calculated within the framework of the analysis on the impact of water injection from Ts-06 and Ts-09 wells in TS-05 Block of the Tshiende Field, we will now assess the technical scope through a detailed interpretation of the results:

- Tables 3 and 4 present the injection pressures required to ensure effective oil sweep in each sub-layer of TS-05 Block, from the injection TS-06 and TS-09 wells. The analysis shows that injection pressure varies very little as a function of the skin factor. For illustration, in sub-layer F of Table 3.b, the injection pressure calculated

with zero skin and that obtained with a skin of -9.081 are respectively 968.9906667 psig and 968.9532287 psig, a negligible difference of 0.037438 psig. Similarly, for layer H3, the difference observed between a skin of 0 and -5.34 is only 0.00586 psig. In contrast, the influence of transmissivity (kh) is much more pronounced. For example, layer E, with a kh of 2266.53 mD·ft, compared to layer G3 with a kh of 646.91816 mD·ft, shows a significant injection pressure difference of 196.03065 psig. Thus, low transmissivity (kh) implies higher injection pressures, which may risk exceeding the reservoir rock's fracture pressure. It is therefore essential to properly size and monitor this pressure, especially in thin layers.

- ii) The void replacement ratio (VRR) was evaluated at 67% , meaning that for 100% of the pore volume freed by extracted oil, the injected water replaces only 67% . In other words, water injection compensates for 67% of the void created by production.
- iii) The overall sweep efficiency was determined as $E_G = 33.97\%$, representing the actual performance of oil recovery by water injection. This indicates that 33.97% of the oil initially in place was displaced by the injection process.
- iv) The total quantity of oil displaced by the injected water is estimated at 13.58644 MMstb. However, according to Table 1, the cumulative recorded production is 14.48384 MMstb. By difference, we can conclude that 0.8974 MMstb, or $897,400$ stb, were extracted solely by natural drainage, without direct contribution from water injection.

CONCLUSIONS

The study aimed to evaluate the effectiveness of water injection in improving hydrocarbon recovery in the Tshiende Field, particularly in TS-05 Block. This block relies on a system comprising two injection wells (TS-06 and TS-09) and one production well (TS-05), targeting nine sub-layers ranging from E to I. Field data analysis allowed the calculation of several key indicators to assess the performance of the injection system.

The results show that the Voids Replacement Ratio (VRR) is 67% , below the optimal value of 100% . This indicates that the injected water volumes do not fully compensate for the produced volumes, limiting reservoir pressure maintenance.

The study of water saturations reveals significant advancement of the water front. The saturation at breakthrough ($S_{wBT} = 0.70$) and the average saturation in the swept zone ($\bar{S}_w BT = 0.75$) are high. This translates into a considerable water cut ($F_w = 0.83$ and 0.97666), confirming water breakthrough and declining oil production in affected zones.

In terms of efficiency, the displacement efficiency ($ED = 56.52\%$) and the areal sweep efficiency ($EA = 82.28\%$) are satisfactory, indicating good fluid mobility and adequate lateral coverage.

The average vertical sweep efficiency ($EV = 73.03\%$) shows acceptable sweep, though performance varies between wells (TS-06 less efficient than TS-09). However, the overall sweep efficiency ($EG = 33.97\%$) remains relatively low compared to the reservoir's initial potential (40 MMstb), with only 13.586 MMstb of oil displaced.

In conclusion, although water injection is functional and partially effective, optimization is necessary. However, due to the lack of certain required data, our study was limited to a technical analysis aimed at evaluating the effectiveness of secondary recovery through water injection in the TS-05 Block. This evaluation was carried out using dynamic reservoir indicators based on the available data.

From a purely technical perspective, without considering other aspects such as economic parameters, we recommend better management of injected water volumes, along with more accurate monitoring of water front propagation within the reservoir. These actions would help optimize the injection process and significantly improve hydrocarbon recovery.

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