energies

MDPI

Article

Understanding the Impact of Reservoir Low-Permeability Subdomains in the Steam Injection Process

Beatriz dos Santos Santana [1,2], Lorena Cardoso Batista [3], Edson de Andrade Araújo [4,*], Cláudio Regis dos Santos Lucas [2], Daniel Nobre Nunes da Silva [1,2] and Pedro Tupã Pandava Aum [1,2,*]

1 Postgraduation Program of Chemical Engineering PPGEQ-ITEC-UFPA, Federal University of Pará, Belém 66075-110, PA, Brazil
2 Petroleum Science and Engineering Laboratory, Federal University of Pará, Raimundo Santana Cruz Street, Salinópolis 68721-000, PA, Brazil
3 Faculty of Mechanical Engineering, University of Campinas, Mendeleyev Street, 200, Campinas 13083-860, SP, Brazil
4 Petroleum Engineering Academic Unit, Federal University of Campina Grande, R. Aprígio Veloso, 882, Campina Grande 58429-900, PB, Brazil
* Correspondence: edson.andrade@professor.ufcg.edu.br (E.d.A.A.); pedroaum@ufpa.br (P.T.P.A.)

Abstract: Optimizing production in the mature fields of heavy oil reservoirs is still challenging. In most cases, conventional recovery techniques are not effective, although they are suitable for applying thermal recovery methods. Steam injection involves injecting steam into the reservoir where the heat exchange with the oil occurs. This promotes a reduction in oil viscosity and thus increases its mobility. One of the challenges of the EOR project is understanding how the presence of regions with contrasting properties, such as fractures, caves, and barriers, could affect the steam flow. This work investigates the impact of low-permeability barriers in the steam injection process. The barriers were created on a semi-synthetic reservoir characteristic of Brazilian onshore mature fields. We used the three-phase pseudo-compositional reservoir simulation STARS (Steam Thermal Advanced Processes Reservoir Simulation) for simulations. Our results show that the shape, number, and arrangement of barriers in a porous medium can affect the amount of oil recovered. They may also be able to anticipate or delay oil production.

Keywords: heavy oil; steam injection; barriers; mature fields; low permeability; numerical simulation

Citation: Santana, B.d.S.; Batista, L.C.; Araújo, E.d.A.; Lucas, C.R.d.S.; da Silva, D.N.N.; Aum, P.T.P. Understanding the Impact of Reservoir Low-Permeability Subdomains in the Steam Injection Process. *Energies* **2023**, *16*, 639. https://doi.org/10.3390/en16020639

Academic Editors: Dameng Liu, Md Motiur Rahman, Mohamed R. Haroun and Abdulrazag Zekri

Received: 2 November 2022
Revised: 19 December 2022
Accepted: 27 December 2022
Published: 5 January 2023

1. Introduction

Despite the progress in changing the global energy matrix in order to reduce carbon dioxide emissions, oil is expected to continue to be the primary energy source for the next two decades. Oil represents a significant element of the world economy, serving as a raw material for several essential products in everyday life [1,2]. A considerable portion of oil reserves is comprised of heavy oil. Countries such as Canada and Venezuela stand out among the places with the highest incidence of heavy oil, with Venezuela being the largest producer of extra-heavy oil in the world [3]. Another case of heavy oil is found in onshore fields of northeastern Brazil. These mature fields have already exceeded their peak production and are showing a strong decline [4,5]. Although these sites provide less exploratory risk due to the greater geological understanding of the area, they are strong candidates for recovery methods to increase their productivity, which may prove to be interesting investment points for small and medium-sized oil companies. However, due to the high viscosity of oil in place, heavy oil reservoirs have unfavorable characteristics for exploration and production, such as low fluid mobility in the porous medium and, thus, a reduction in the efficiency of its displacement. These characteristics make oil difficult to recover in its natural state, implying the need to apply Enhanced Oil Recovery (EOR) strategies [6–8].

Thermal recovery methods, such as steam injection, in situ combustion, and electromagnetic heating, among others, are strong candidates for methods to be applied to heavy oil accumulations [9,10]. Their main objective is to reduce the oil viscosity by increasing the reservoir temperature, favoring the mobility of the fluid in the porous media, and enabling an increase in the recovery factor [11]. In this context, steam injection is one of the most commonly used methods. In this process, steam is generated on the surface and displaced into the reservoir, where heat is exchanged with the formation and fluids present [12–14]. This method can be performed by continuously injecting steam into one well while the oil is produced from another well. Alternative approaches include cyclic injection, where the injection and production are performed in the same well in cyclic periods [15–17].

Although steam injection is one consolidated technique, several variables, many of which are connected to the geology of the reservoir rock, can impact its effectiveness. For example, reservoir rocks are often heterogeneous, and the permeability varies inside the porous medium [17–19].

The presence of low-permeability faults or barriers can alter the flow of fluids in the porous, impacting the efficiency of the EOR strategy. Shale layers, saline domes, low-permeability intrusions, and geological alterations may act as flow barriers in the reservoir [20]. Reservoir numerical simulation is one of the main strategies for analyzing these heterogeneities' impact, which seeks to represent real field conditions through numerical models [21,22]. Using numerical simulation, Barillas et al. [23] assess the effects of a reservoir's heterogeneity using the steam-assisted gravitational drainage method (Steam Assisted Gravity Drainage Process—SAGD), which involves two parallel horizontal wells, one above the other, where the upper well is the steam injector, and the lower well is the producer. To that end, barriers with low permeability were modeled in the porous medium in three different configurations: a single 60 m $\times$ 300 m $\times$ 2 m barrier, a single 60 m $\times$ 510 m $\times$ 2 m barrier, and two 60 m $\times$ 180 m barriers, located in the same layer. In this case, all of the barriers showed the same behavior. That is, when the barrier is closer to the injection well, oil recovery increases. The heterogeneity of the reservoir impacted cumulative production, but depending on how it was configured, it was advantageous for oil recovery.

Le Ravalec et al. [24] also presented a numerical investigation of the effects of heterogeneity on SAGD performance. A set of reservoir models were randomly generated with shale volumes of 0, 10, 15, and 20%, values typically found in fields in Venezuela. As a result, it was shown that the influence of the shale barriers depends on their location in relation to production and injection wells. In this case, the most harmful location occurs when a barrier is located between the wells, and the shale heterogeneities located above the pairs of wells are less harmful to production.

Through numerical simulations, Xu et al. (2017) [25] analyzed the influence of lean zones on SAGD performance. Their study explores both single and multi-layer thin zones in a semi-synthetic reservoir. According to their findings, SAGD performance is primarily affected by the single-layer lean zone above the injector; the significant impact of single-layer thin zones grows with decreasing interval distance and increasing thickness and water saturation in lean zones. Furthermore, in leaking oil sands, simulation results reveal that the hybrid CSS/SAGD approach is preferable to the standard SAGD method.

In the studies carried out by Ashrafi et al. [17], a numerical simulation was employed to analyze a continuous steam injection process in a heterogeneous porous medium containing heavy oil. The model consists of a sandstone reservoir with a horizontal layer of high porosity and permeability in the middle of the reservoir; different configurations of shale barriers were also considered to examine the effect of these layers with zero flux. This study revealed that shale layers could limit oil flow and cause high residual oil saturation. However, their impact depends on the permeability distribution in the reservoir, i.e., having good communication with the highly permeable layer is significant as steam flows easily within this zone and transfers thermal energy to the cold oil within the inferior permeable regions. The conclusion was that shale layers could limit oil flow, but their impact depends on the permeability distribution in the core.

In Wu et al. [26], high-pressure cyclic steam stimulation is presented as an alternative to breaking shale barriers and for improving the development of the steam chamber along the horizontal section in a SAGD process. It thus reduces residual oil saturation, as the distribution of the shale barrier severely impacted the growth of the vapor chamber along the horizontal segment in some pairs of wells, which resulted in a low rate of oil production. The method proved to be effective in breaking the barrier distributed between the horizontal segments of the producer and the injector, which was verified by field experience and numerical simulation.

Perdomo et al. [27] presented a study to evaluate different strategies for the selective injection of steam in stratified reservoirs, meaning the injection of steam in specific layers, using the numerical simulation of reservoirs. With the main objective of verifying the impact of the permeability and thickness of the reservoir layers as a function of the recovery factor, some different scenarios were analyzed in this study: the injection in the layers with higher permeability values, the injection of steam into the layers with lower permeability values, the injection of steam into the layers with higher flow capacity values (k·h—the product of permeability by the thickness of the reservoir), and the injection of steam into layers with lower flow capacity values. According to the findings, the percentage of oil recovered is higher when steam is injected into thicker layers with higher permeability values because this allows the steam to be spread more uniformly throughout the medium and cover more regions. However, with the help of numerical simulation, all cases from an optimization standpoint are viable for the steam injection process.

Experimental analyses and numerical simulation were also used by Zhong et al. (2020) [28] to study the process of continuous steam injection in unconsolidated heavy oil reservoirs, mainly considering the effect that steam injected at a high temperature can have on the heterogeneity of the porous medium. An experimental study using tubes filled with sand was carried out, and some mechanisms of permeability and porosity variation were analyzed, such as compaction of the formation and the generation of a wormhole. Among the results, it was found that both permeability and porosity were reduced with compaction. Considering wormhole generation, the partial permeability was increased about fourfold. A numerical model was built, considering these mechanisms, and field-scale simulations were performed to analyze the recovery factor. The results showed that if the permeability variation in the porous medium is considered, there is a 4.4% reduction in the rate of recovered oil due to the channeling of steam in regions of greater permeability.

A more recent experimental study was performed by Batarseh et al. (2021) [29] to analyze the continuous injection of steam in heterogeneous formations, and the results were compared with those of a homogeneous formation. The analysis used a large-scale universal apparatus designed to simulate reservoir conditions accurately. The apparatus uses different packs of sand, and the steam is injected into the lower bed. The temperature is recorded in real-time using 65 thermocouples. In the analysis of the homogeneous model, the maximum temperatures occurred at the bottom, close to the injection well, and the heat slowly infiltrated the upper layer. In addition, different rates of transient heat propagation were observed in regions of greater permeability (fractures) in experiments considering heterogeneities. Structural heterogeneity can provide communication between the injection and production wells and, thus, the advancement of steam flow in these areas. Therefore, it is essential to characterize these heterogeneities to reduce risks and uncertainties in steam injection operations.

According to our literature review, several works discussed the impact of different types of heterogeneity in steam injection. This work evaluates the effects of low-permeability regions acting as barriers in the porous medium. The low-permeabilities regions can represent geological discontinuities such as clays layers, salt layers, or fractures (that sometimes can serve as conductive channels, but in others can act as barriers). The main objective of this work is to investigate the impact of these subdomains in the steam injection process. According to our knowledge, any previous works in the literature report a specific study with the focus and methodology presented here.

We analyze how the barriers at different positions and quantities affect steam injection performance. For this purpose, we evaluate the oil recovered in 16 years. The analysis was performed by numerical simulation using a three-phase pseudo-compositional simulator called Steam Thermal Advanced Processes Reservoir Simulation (STARS) developed by the CMG group (Computer modeling group).

2. Materials and Methods

2.1. Reservoir Modeling

To carry out the proposed study, a reservoir model was built and discretized using a cartesian mesh system. The model adopted was $\frac{1}{4}$ of an inverted five-spot with dimensions of 100 m in the "x" and "y" directions and 26 m in the "z" direction, containing two vertical wells, one injector, and one producer. The top of the reservoir is 200 m deep and 26 m thick, of which 20 m are in the oil zone, and 6 m are in the water zone, and there is no presence of an active aquifer. Overall, 25 blocks in the i direction, 25 blocks in the j direction, and 23 blocks in the k direction were considered, totaling a value of 14,375 blocks. Figure 1 shows the 3D reservoir model.

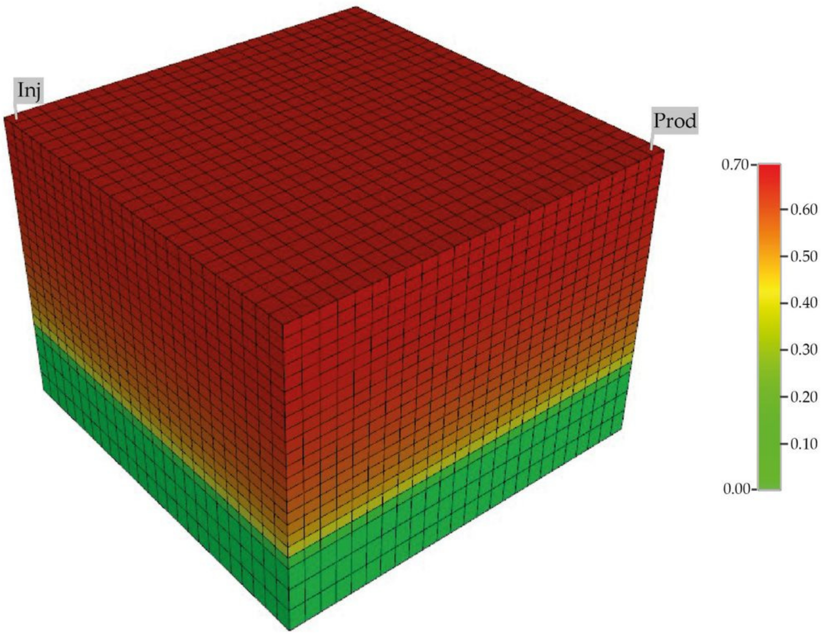


Figure 1. 3D model of the reservoir.

2.2. Fluid and Rock Properties

The steam injection was simulated in a reservoir model with characteristics similar to those found in Brazil's northeastern fields. For this simulation, the input parameters used are shown in Table 1, including the parameters of the reservoir rock, such as horizontal and vertical permeabilities, and operational conditions, such as steam quality [4,15].

The fluid properties are the same as those originally found at the Alto do Rodrigues Field, whose crude oil has a density of 16 API and viscosity varying within 750–1500 cP [16]. Table 2 displays the initial mole percentages of modeled components that were present in the reservoir, with their respective molar fractions. To significantly speed up the simulation process, the components were grouped into six pseudo-components: C1–3, C4–5, C6–9, C10–19, C20–39, C40+, and two components: CO_2 and N_2.

Table 1. Reservoir rock input data and operational parameters.

Properties	Values (Base Model)
Maximum pressure in the injector well (kPa)	7196.14
Minimum pressure in the producer well (kPa)	196.45
Pressure at the top of the reservoir (KPa)	1978
Steam quality (%)	75
Porosity (%)	30
Horizontal permeability (mD)	1000
Vertical permeability (mD)	100
Initial temperature of the reservoir (°C)	38
Rock thermal conduction (J/(s m °C))	1.73
Connate water saturation	0.36
Total blocks	14,375

Table 2. Molar composition for the heavy oil model considered in this paper.

Pseudocomponents/Components	Molar Fraction (%)
CO_2	0.40
N_2	0.15
$C_{1–3}$	8.03
$C_{4–5}$	0.33
$C_{6–9}$	0.27
$C_{10–19}$	17.25
$C_{20–39}$	47.44
C_{40+}	26.13

The experimental data from the PVT analyses and viscosity tests are also fundamental in the fluid model, which provides parameters such as the oil volume-formation factor (Bo), oil-specific mass (ρ_o), solubility ratio (Rs), and fluid viscosity (μ_o) as a function of pressure variation. Table 3 shows the experimental data used for the study.

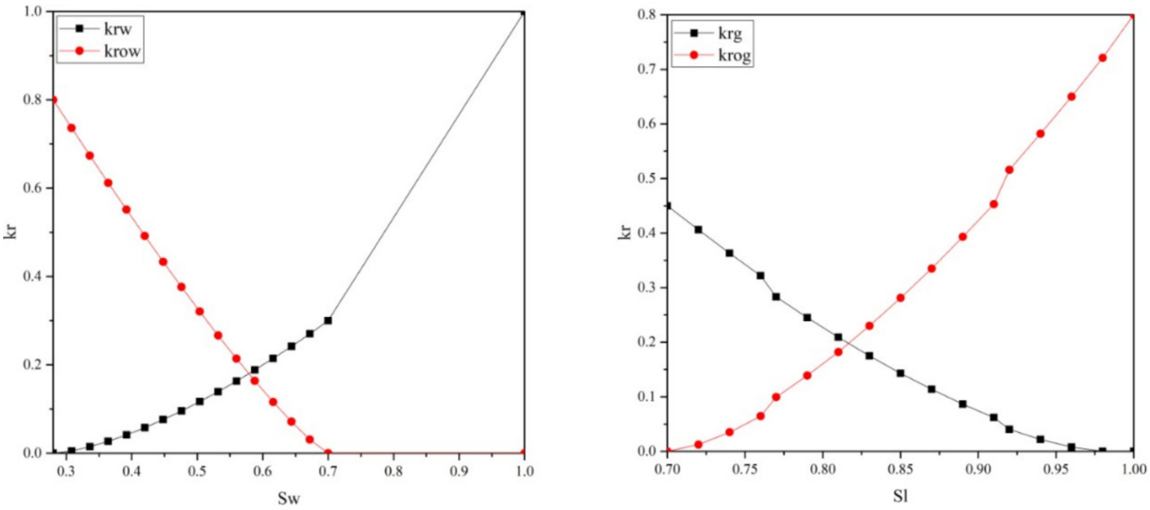
Table 3. Crude oil data from Alto do Rodrigues Field [16].

Pressure (kPa)	Bo (m^3/m^3)	ρ_o (Kg/m^3)	Rs (m^3/m^3)	μ_o (cP)
6965.63	1.0270	935.5	34.81	819.20
5884.99	1.0280	935.0	34.81	794.40
5004.35	1.0290	934.5	34.81	769.20
4023.64	1.0295	934.0	34.81	741.60
2650.75	1.0300	933.5	34.81	706.20
1572.00	1.0250	936.0	21.33	816.30
101.03	1.0150	942.0	00.00	1121.1

The graphs of oil–water and gas–water relative permeability are shown in Figure 2. Th endpoints and relative permeabilities were considered temperature-dependent and are based on data from Brazilian northeast heavy oil reservoirs [23].

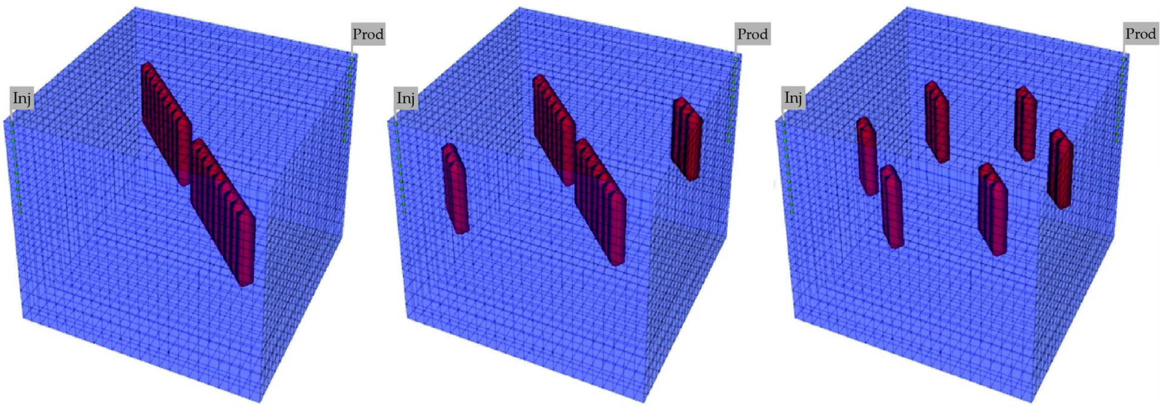
2.3. Case Study—Low Permeability Barriers

The barriers were modeled in the porous medium, distributed in three different configurations with 2, 4, and 6 barriers, as shown in Figure 3. The main reason for these configuration choices was the symmetry between the barriers [16]. We look to understand if predominant mechanisms affected the oil recovery process. Therefore, symmetry can eliminate geometric heterogeneity effects. These barriers were implemented with initial permeability values of 1×10^{-7} mD and without changes in the porosity value, maintaining the total reservoir pore volume constant in all simulations. They are allocated in a total of 200 blocks, created from the 6th to 15th layer, symmetrically arranged in the reservoir.



(a) (b)

Figure 2. (a) Relative oil–water permeability curves; (b) Relative oil–gas permeability curves.



(a) (b) (c)

Figure 3. (a) Reservoir model with 2 barriers; (b) Reservoir model with 4 barriers; (c) Reservoir model with 6 barriers.

A fixed flow rate of 25 tons/day was considered over the 16 years of the project. The main parameters of analysis were the percentage of oil recovered, the oil flow, the temperature, and pressure maps.

3. Results and Discussion

Figure 4 shows the results of the percentage of oil recovered (recovery factor) for cases with 0 (no barriers), 2, 4, and 6 barriers in the period of 16 years. It was possible to verify that the percentage of recovered oil was similar for all cases analyzed for 16 years of the project, with the case of higher and lower production at 65.32% (case without the presence of barriers) and 63.42% (case with four barriers), respectively. An important point here is regarding the recovery factor over time, still in Figure 4. We observe a gap between the curves for the different configurations of barriers, with six barriers promoting anticipation of production compared to the other cases. Regarding the case with four barriers, we verified a delay in production.

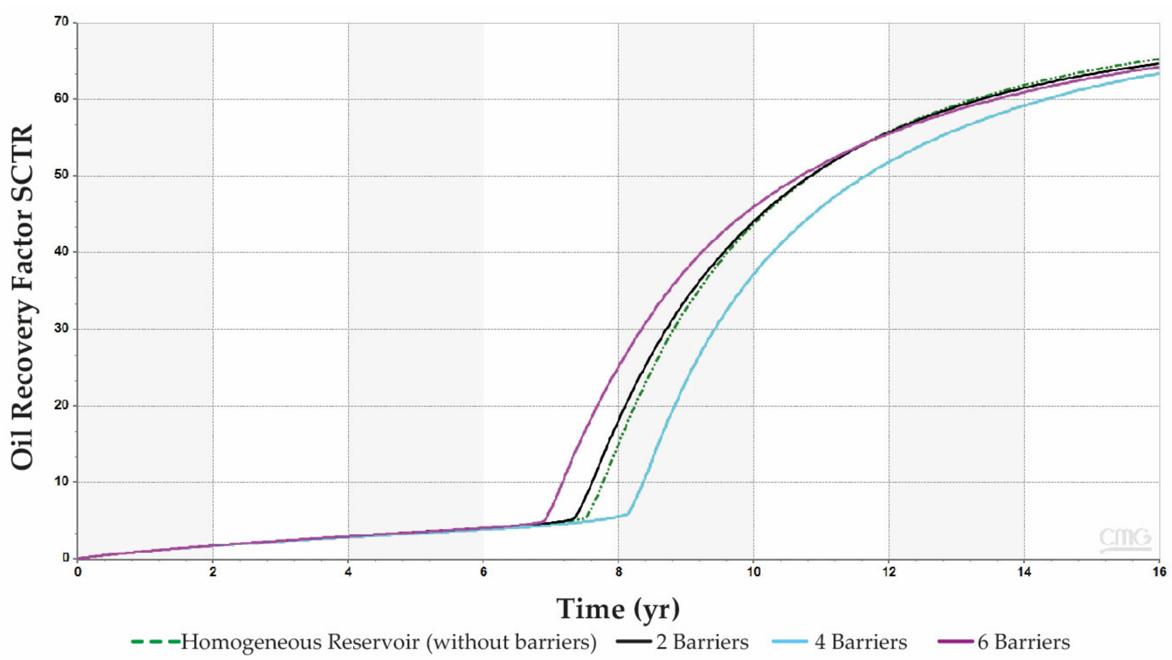


Figure 4. Percentage of oil recovered as a function of the 16-year project time.

Figure 5 presents the plots of the final oil recovery factor as a function of the number of barriers over 16 years of steam injection. Even the final percentages are close, and there are interesting points to be discussed. We can intuitively expect that the greater number of barriers, the lower the final recovery percentage. However, this was not observed for all simulations. The barrier-free case promoted the highest percentage of final recovered oil. The case with two barriers promoted a small drop in the recovery factor. The case with four barriers presented the lowest recovery factor after the 16 simulated years. With six barriers, the recovery factor is slightly higher than with four barriers. One of the possible reasons for the case with six barriers showing a higher recovery factor when compared to the case with four barriers is probably due to the barrier's geometric distribution, especially regarding the producer and injector well. We need to remember that the total volume of barriers is the same for all the cases. Therefore, by increasing the number of barriers, we reduce the size of each barrier.

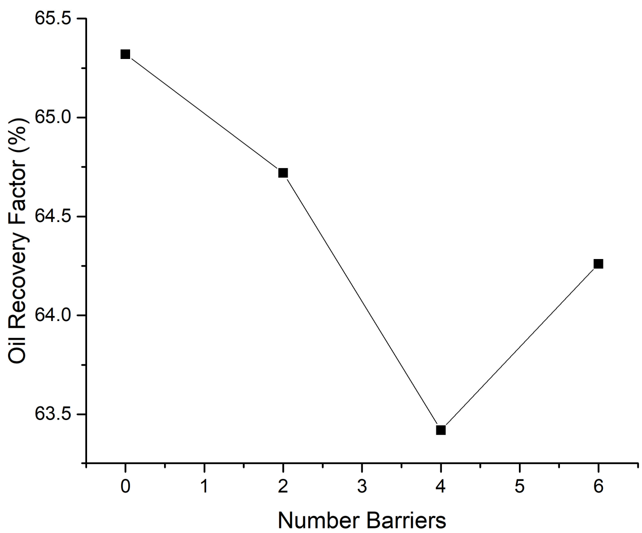


Figure 5. Recovery factor after 16 years of steam injection.

Figure 6 shows the oil flow rate over time. It is possible to observe a variation between the oil production peaks. The case with six barriers presents anticipation when compared to the other cases. The case with four barriers showed the greatest delay in increasing the percentage of oil compared to the case without barriers. When comparing these findings to those shown in Figure 5, we saw that the example with the most anticipation was not the one with the highest EOR. This means that the existence of barriers can anticipate flow production. At the same time, this anticipation does not deliver the highest recovery factor. Indeed, the case free of barriers presents the production peaks after the case with six and two barriers, as shown in Figure 6.

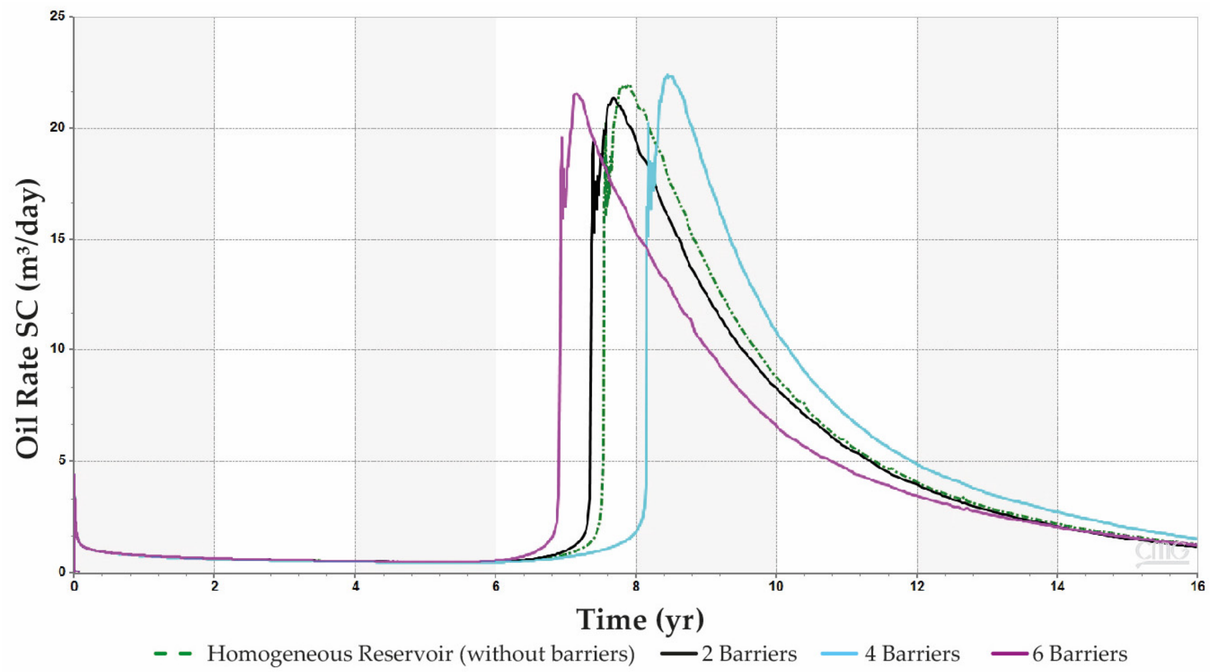


Figure 6. Oil flow rate as a function of 16-year project time.

The greater dispersion of the barrier regions in the porous medium, which may have given a more heterogeneous advance in the expansion of the thermal front, could be one explanation for the anticipated effect on oil production.

The reservoir's average pressure curves for each scenario are also shown in Figure 7. Therefore, it is feasible to confirm that all cases in the first years of life exhibit similar pressure behavior. The case with four barriers maintained the highest average pressure in the reservoir, which may be due to a greater pressure build-up in front of the barriers. The case with six barriers has an anticipation in the pressure drop, also due to the faster arrival of the oil bank to the producing well. However, in recent years of injection, there has been a reduction in the pressure drop for the case with six barriers, compared to the case without barriers. This could be a consequence of the presence of barriers near the producing well, which promote an accumulation of pressure in front of them.

In Figure 8, we showed the 3D thermal maps of the reservoir with the times for the various cases investigated in order to more accurately assess the impact of anticipation on oil production. The maps were obtained at 4, 6, and 8 years for the case free of barriers and two, four, and six barriers. It is possible to observe that the heat front for all the cases with barriers is more heterogeneous than the case without barriers. It is verified that in the points where the barriers are located, the flow is delayed; however, it is accelerated in the other regions, giving a positive result regarding the production anticipation due to the better distribution of heat in the porous medium. This could explain what was observed in Figures 4 and 6 regarding the production anticipation. Another observation from Figure 8 is regarding the heat front of the case with six barriers. This case has the maximum advance of one front compared with the other; this result is consistent with the plots in Figures 4 and 6. The barriers direct the heat flux away from areas that cannot be reached without the existence of barriers. However, at 8 years, we see that these profiles become quite similar. We highlight three main points in our discussion: (I) the barriers are regions of low permeability so that when placed in the porous medium, they promote the formation of stagnant oil banks in the regions close to the barriers; (II) in these oil banks the fluid velocity is practically null so that the steam flow deviates from these regions in front of the barriers; (III) barriers impact the steam injection process as well as the gravitational segregation process. The initial pressure field for all cases is homogeneous. With the advance of the injection front, the pressurization of the low-permeability regions occurs.

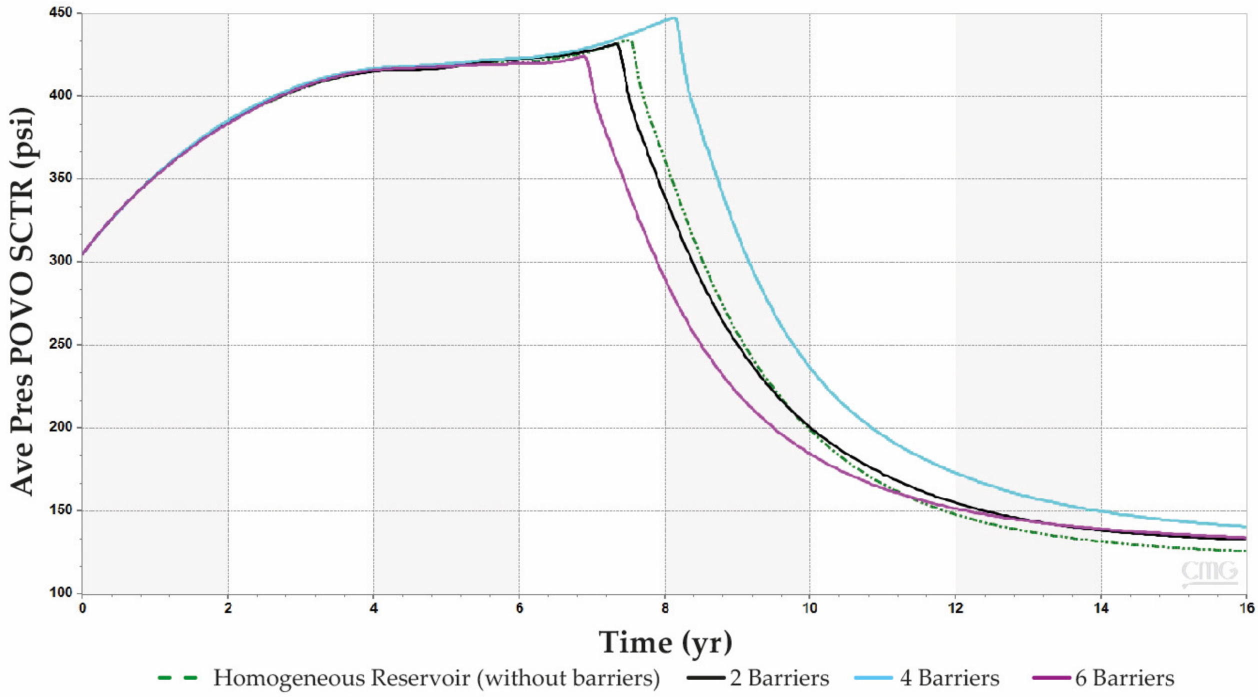


Figure 7. Average reservoir pressure over 16 years.

Figure 9 represents the pressure field in the reservoir at 5 years of stem injection. For the case of the free barriers, Figure 9a, it is possible to observe that the reservoir presents a homogeneous pressure field distribution, with the highest pressure diagonally close to the injector and the lowest pressure region close to the producing well. For cases with a barrier, we have two distinct behaviors. First, the simulation performed is for 5 years of steam injection, so the steam has not yet reached the entire reservoir. For the case with two barriers (Figure 9b), the pressure in the cells is higher in the center of the barrier and lower at the edge. In the case of four barriers, we observe that the barrier near the injection well presents higher-pressure values surrounding it. In the case with six barriers (Figure 9d), we can see that the two barriers closest to the injection well present pressure greater than the pressure observed in the surrounding reservoir regions close to them. A broader understanding of pressure evolution may be found in the Supplementary Material.

Based on the discussions held up to this point, we concluded that the barriers favor a negative outcome regarding the final recovery factor since some of the oil is retrieved in front of them. Regarding the production flow rate, barriers can promote the anticipation of the oil bank depending on its size, quantity, and disposition in the porous medium. From the thermal point of view, the contribution of the barriers was in the sense of dispersing the heat front, thus, promoting anticipation, as we analyzed in the case containing six barriers. Regarding the average temperature in the reservoir, we can observe a decrease after the 8th year of the project. This behavior is a consequence of the breakthrough, which promotes steam channeling into the surrounding producing well.

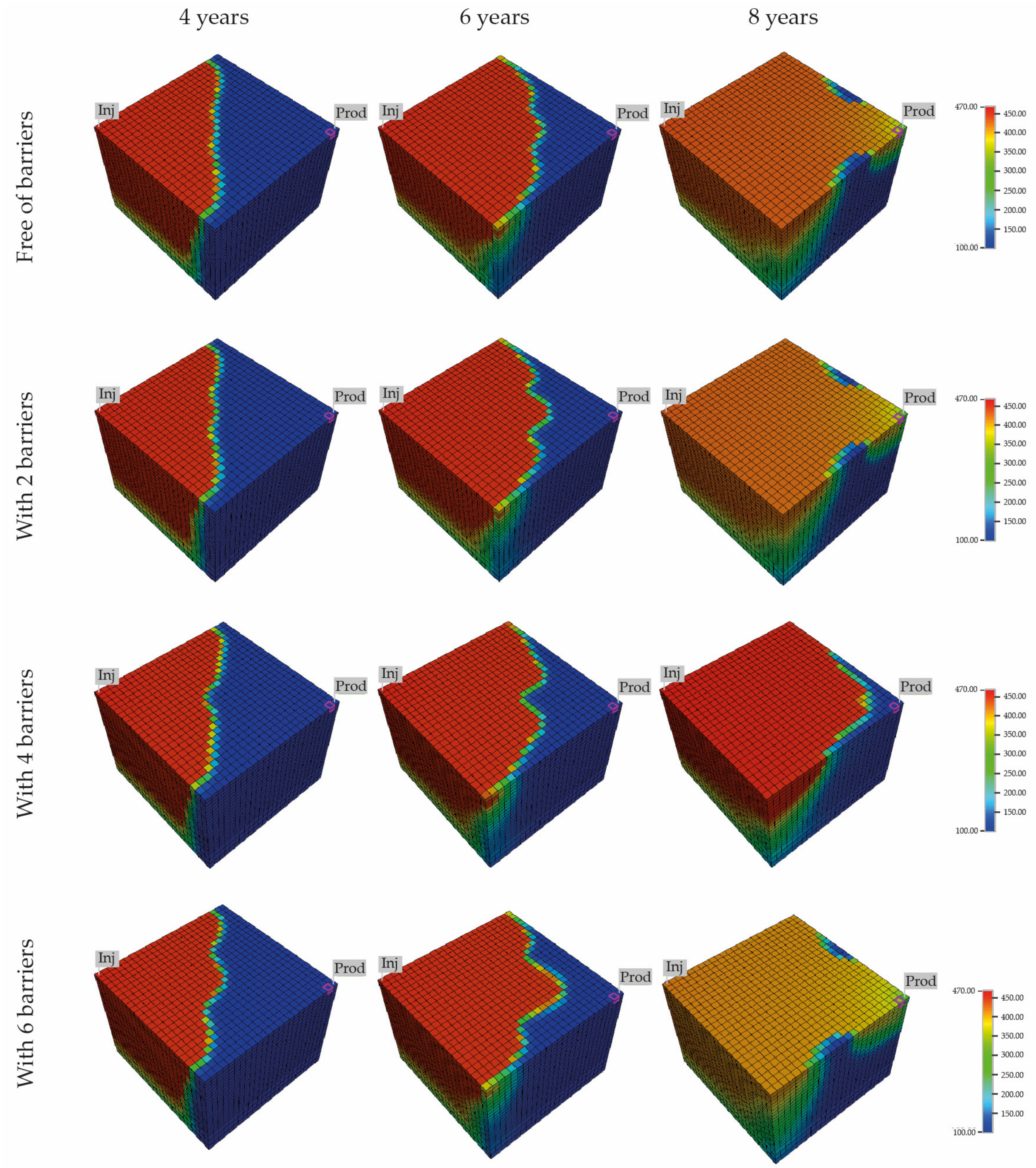


Figure 8. Temperature maps for the simulated cases at 4, 6, and 8 years.

One crucial point is that in addition to the difference in the final recovery factor that could not seem substantial, it is clear that these low-permeability subdomains affect the flow in porous media. Furthermore, depending on the reservoir size, a little increase in the recovery factor could significantly increase the volume of oil revered. Therefore, we believe that our results are relevant and contribute to understanding how barriers can affect the application of steam injection in heterogeneous porous media.

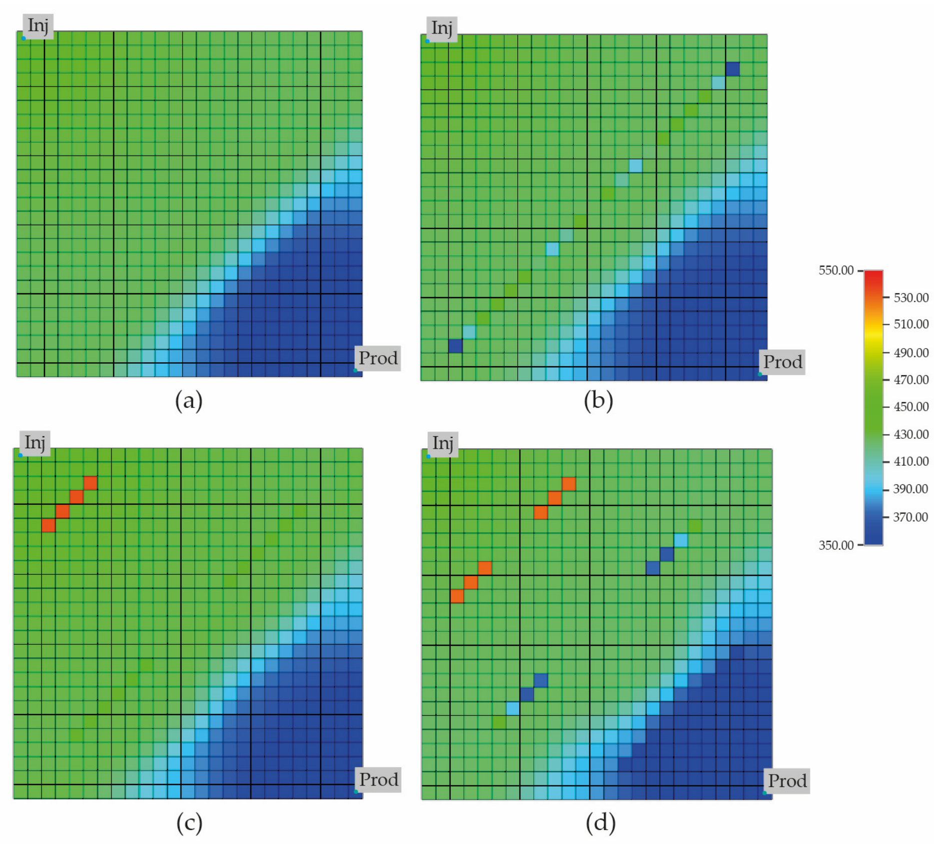


Figure 9. Pressure field at 5 years of steam injection for (**a**) barrier-free case; (**b**) 2 barriers; (**c**) 4 barriers; and (**d**) 6 barriers.

4. Conclusions

In this work, we studied the influence of the presence of low-permeability subdomains in the continuous steam injection process. Below we point out the main conclusions we can draw from our results.

- The presence of subdomain regions of low permeability generally reduces the final percentage of recovered oil.
- The shape and the number of dispersed barriers can anticipate or delay the increase in oil flow. We verified that the production was anticipated for the case with greater dispersion of barriers at smaller sizes.
- The barriers impact the heat front's advance, generating more heterogeneous heat fronts.
- The presence of geological barriers must be considered when designing a field development project.
- Although we evaluate different barrier configurations, for future works, we suggest more simulations to obtain results, including a higher quantity of subdomains and varying the distribution of the subdomains.
- These studies can aid the development of steam injection projects.

Supplementary Materials: The following supporting information can be downloaded at: https://www.mdpi.com/article/10.3390/en16020639/s1, Video S1: Animation with pressure field in time for different barriers configurations.

Author Contributions: Conceptualization, E.d.A.A. and P.T.P.A.; Simulations, B.d.S.S. and L.C.B.; Writing, B.d.S.S. and L.C.B.; Review and Editing, C.R.d.S.L. and D.N.N.d.S.; Discussions. All authors have read and agreed to the published version of the manuscript.

Funding: The article processing charge (APC) was financed by the Research Department of the Federal University of Pará (Pró-Reitoria de Pesquisa e Pós-Graduação— PROPESP/UFPA), notice 10/2022 (PAPQ/PROPESP). The licenses for the software CMG were funded by PETROBRAS through grant number 2019/00154-4.

Data Availability Statement: Not applicable.

Acknowledgments: The authors would like to thank Petrobras and Propesp/UFPA for the founding support. We also thank the Science and Petroleum Engineering Lab (LCPetro/UFPA) for the infrastructure and to CMG (Computer Modelling Group) for technical support.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. Lu, H.; Guo, L.; Zhang, Y. Oil and Gas Companies' Low-Carbon Emission Transition to Integrated Energy Companies. *Sci. Total Environ.* **2019**, *686*, 1202–1209. [CrossRef] [PubMed]
2. da Silva Martins, S.S.; de Azevedo, M.O.; da Silva, M.P.; da Silva, V.P. Produção de Petróleo e Impactos Ambientais: Algumas Considerações. *Holos* **2015**, *6*, 54. [CrossRef]
3. Liu, Z.; Wang, H.; Blackbourn, G.; Feng, M.A.; Zhengjun, H.E.; Wen, Z.; Wang, Z.; Yang, Z.; Luan, T.; Zhenzhen, W.U. Heavy Oils and Oil Sands: Global Distribution and Resource Assessment. *Acta Geol. Sin.* **2019**, *93*, 199–212. [CrossRef]
4. Araújo, E.A.; Aum, P.T.P.; Fernandes, G.M.D.; Braga, G.S.; Oliveira, G.C.P.; Santos, M.D.; Diniz, A.A.R. A Study on Continuous and Intermittent THAI^{TM} Processes in Brazil's Northeastern Region. *Pet. Sci. Technol.* **2018**, *36*. [CrossRef]
5. Fernandes, G.M.D.; Araújo, E.A.; Aum, P.T.P.; Diniz, A.A.R.; Barillas, J.L.M. Analysis of Different Oil-Well Configurations in the Sagd Process Considering Pressure Drop and Heat Loss in the Injection Well. *Braz. J. Pet. Gas* **2019**, *13*, 103–109. [CrossRef]
6. Castro Dantas, T.N.; de Souza, T.T.C.; Dantas Neto, A.A.; de Alencar Moura, M.C.P.; de Barros Neto, E.L. Experimental Study of Nanofluids Applied in EOR Processes. *J. Surfactants Deterg.* **2017**, *20*, 1095–1104. [CrossRef]
7. Vieira, R.A.M.; Pizarro, J.O.S.; Oliveira, L.A.; Oliveira, D.F.B.; Passarelli, F.M.; Pedroni, L.G. Offshore EOR Initiatives and Applications in Brazil: An Operator Perspective. In Proceedings of the Offshore Technology Conference, Houston, TX, USA, 4–7 May 2020. [CrossRef]
8. Xu, Z.X.; Li, S.Y.; Li, B.F.; Chen, D.Q.; Liu, Z.Y.; Li, Z.M. A Review of Development Methods and EOR Technologies for Carbonate Reservoirs. *Pet. Sci.* **2020**, *17*, 990–1013. [CrossRef]
9. Gao, Y.; Wang, X.; Jiang, H.; Ding, S. Numerically Coupled Thermo-Hydro-Mechanical Analyses of Ultra-Heavy Oil Reservoirs during the Micro-Fracturing Stage. *Energies* **2022**, *15*, 3677. [CrossRef]
10. Wang, C.; Wu, Y.; Luo, C.; Jiang, Y.; Zhang, Y.; Zheng, H.; Wang, Q.; Zhang, J. Experimental Study and Numerical Simulation of an Electrical Preheating for SAGD Wells in Heavy Oil Reservoirs. *Energies* **2022**, *15*, 6102. [CrossRef]
11. Al-Atwah, I.; Alshaikh, M.; Sweet, S.T.; Knap, A.; Hascakir, B. Extension of Existing Screening Criteria Tables for Thermal Enhanced Oil Recovery Methods Through Compositional Analyses of Heavy Oils. In Proceedings of the SPE Western Regional Meeting, Garden Grove, CA, USA, 22–26 April 2018.
12. Chen, X.; Rao, X.; Xu, Y.; Liu, Y. An Effective Numerical Simulation Method for Steam Injection Assisted In Situ Recovery of Oil Shale. *Energies* **2022**, *15*, 776. [CrossRef]
13. Medina, O.E.; Hurtado, Y.; Caro-Velez, C.; Cortés, F.B.; Riazi, M.; Lopera, S.H.; Franco, C.A. Improvement of Steam Injection Processes Through Nanotechnology: An Approach through in Situ Upgrading and Foam Injection. *Energies* **2019**, *12*, 4633. [CrossRef]
14. Ni, J.; Zhou, X.; Yuan, Q.; Lu, X.; Zeng, F.; Wu, K. Numerical Simulation Study on Steam-Assisted Gravity Drainage Performance in a Heavy Oil Reservoir with a Bottom Water Zone. *Energies* **2017**, *10*, 1999. [CrossRef]
15. Mezzomo, R.F.; Dutra, T.V.; de Miranda-Filho, D.N.; de Paula, A.L.; Cursino, D.F.S. Heavy Oil Recovery in Potiguar Basin, Brazil: Steam Flooding from Field Pilot Testing to Commercial Application. In Proceedings of the SPE Rocky Mountain Petroleum Technology Conference, Keystone, CO, USA, 21–23 May 2001.
16. Araújo, E.A.; Batista, L.C.; Bechara, J.V.O.; Gurgel, A.R.; Oliveira, G.P.; Aum, P.T.P. Influence of High Permeability Subdomains on Steam Injection Performance in Heavy-Oil Reservoirs. *J. Pet. Sci. Eng.* **2022**, *208*, 109388. [CrossRef]
17. Ashrafi, M.; Souraki, Y.; Tor Joergen, V.; Karimaie, H.; Torsaeter, O. Experimental and Numerical Investigation of Steam Flooding in Heterogeneous Porous Media Containing Heavy Oil. In Proceedings of the SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, 20–22 September 2011.
18. Kalia, N.; Balakotaiah, V. Effect of Medium Heterogeneities on Reactive Dissolution of Carbonates. *Chem. Eng. Sci.* **2009**, *64*, 376–390. [CrossRef]
19. Muljadi, B.P.; Blunt, M.J.; Raeini, A.Q.; Bijeljic, B. The Impact of Porous Media Heterogeneity on Non-Darcy Flow Behaviour from Pore-Scale Simulation. *Adv. Water Resour.* **2016**, *95*, 329–340. [CrossRef]
20. He, Z.; Parikh, H.; Datta-Gupta, A.; Perez, J.; Pham, T. Identifying Reservoir Compartmentalization and Flow Barriers Using Primary Production: A Streamline Approach. In Proceedings of the SPE Annual Technical Conference and Exhibition, San Antonio, TX, USA, 29 September–2 October 2002.

21. Jaber, A.K.; Al-Jawad, S.N.; Alhuraishawy, A.K. A Review of Proxy Modeling Applications in Numerical Reservoir Simulation. *Arab. J. Geosci.* **2019**, *12*, 701. [CrossRef]
22. Yang, S.; Nie, Z.; Wu, S.; Li, Z.; Wang, B.; Wu, W.; Chen, Z. A Critical Review of Reservoir Simulation Applications in Key Thermal Recovery Processes: Lessons, Opportunities, and Challenges. *Energy Fuels* **2021**, *35*, 7387–7405. [CrossRef]
23. Barillas, J.L.M.; Dutra, T.V.; Mata, W. Reservoir and Operational Parameters Influence in SAGD Process. *J. Pet. Sci. Eng.* **2006**, *54*, 34–42. [CrossRef]
24. le Ravalec, M.; Morlot, C.; Marmier, R.; Foulon, D. Impact Des Hétérogénéités Sur La Production d'huiles Lourdes Mobiles Par SAGD. *Oil Gas Sci. Technol.* **2009**, *64*, 469–476. [CrossRef]
25. Xu, J.; Chen, Z.; Dong, X.; Zhou, W. Effects of Lean Zones on Steam-Assisted Gravity Drainage Performance. *Energies* **2017**, *10*, 471. [CrossRef]
26. Wu, Y.; Li, X.; Jiang, Y.; Wang, H.; He, W. Reservoir Simulation of Shale Barrier Failure in Heterogeneous SAGD Reservoirs: A Case Study; SPE 165941. In Proceedings of the SPE Reservoir Characterization and Simulation Conference and Exhibition, Abu Dhabi, United Arab Emirates, 16–18 September 2013.
27. Hoyos Perdomo, R.; Ardila Cubillos, L.; Munoz Navarro, S.; Rincon Canas, M.; Palma-Bustamante, J.; Naranjo Suarez, C. Evaluation of Different Strategies for Selective Steam Injection in Stratified Heavy-Oil Reservoirs. SPE-171143-MS. In Proceedings of the SPE Heavy and Extra Heavy Oil Conference: Latin America, Medellín, Colombia, 24–26 September 2014.
28. Zhong, L.; Han, X.; Yuan, X.; Liu, Y.; Zou, J.; Wang, Q. Permeability Variation and Its Impact on Oil Recovery from Unconsolidated Sand Heavy-Oil Reservoirs during Steamflooding Process. *SPE Reserv. Eval. Eng.* **2021**, *24*, 159–173. [CrossRef]
29. Batarseh, S.; Assiri, W.; SanRoman Alerigi, D.; Khaldi, B. Formation Heterogeneity Effect on Steam Injection and Propagation. In Proceedings of the Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, United Arab Emirates, 15–18 November 2021.