

Energy lost study for the steam and solvent assisted gravity drainage process, using reservoirs with Brazilian northeast characteristics

Estudo da perda de energia no processo de drenagem gravitacional assistida por vapor e solvente, utilizando reservatórios com características do Nordeste brasileiro

Estudio de la pérdida de energía para el proceso de drenaje por gravedad asistido por vapor y solvente, utilizando características de los yacimientos del noreste brasileño

Received: 02/05/2024 | Revised: 02/15/2024 | Accepted: 02/16/2024 | Published: 02/20/2024

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Abstract

In Brazil, especially in the Northeast, there are still reservoirs containing heavy oils that are being operated by smaller companies that need to produce the fields, reducing production costs. There are different processes to recover heavy oil, one of which is steam and solvent assisted gravity drainage process, which uses two parallel horizontal wells, where the injector is placed above the producer. In this process, a solvent can be used with the steam, to try to reduce the steam rate injected. Process is carried out by injecting a hydrocarbon additive in low concentration together with steam. Steam contributes with the heat to reduce oil viscosity and solvent helps with miscibility, reducing the interfacial tension. The main force acting in this process is gravitational. The mobility of the displaced fluid is then improved, which may imply at an increase of oil recovery. In this study, a semi-synthetic model was analyzed, with average characteristics of the Brazilian northeast, where there is heavy oil in onshore reservoirs. Several simulations were carried out using a commercial oil reservoir thermal simulation software, where the influence of some operational parameters on oil recovery and energy in the reservoir were verified. The main objective of this study was to find a distance between producer and injector wells that allows reducing heat losses to the overburden and underburden when solvent and steam are injected into the process. It was found an optimal vertical distance to improve oil recovery.

Keywords: ES-SAGD; Reservoir modelling; Brazilian northeast reservoir; Solvent injection; Steam and solvent injection.

Resumo

No Brasil, em especial no Nordeste, ainda existem reservatórios contendo óleos pesados que estão sendo operados por empresas de porte menor que precisam produzir os campos diminuindo os custos de produção. Existem diferentes processos para recuperar o óleo pesado, sendo um deles a drenagem gravitacional assistida com vapor e solvente que utiliza dois poços horizontais paralelos, onde o injetor é disposto acima do produtor, neste processo é utilizado um solvente junto com o vapor, para tentar diminuir a quantidade de vapor injetado nele. A realização do processo se dá mediante a injeção de um aditivo de hidrocarboneto em baixa concentração em conjunto com vapor. O vapor contribui com o calor para redução da viscosidade do óleo e o solvente ajuda na miscibilidade, reduzindo a tensão interfacial entre óleo/solvente. A principal força atuante neste processo é a gravitacional. A mobilidade do fluido deslocado é então melhorada, obtendo uma melhora do fator de recuperação. Neste estudo, foi analisado um modelo

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semissintético, com características médias do nordeste brasileiro. Diferentes simulações foram realizadas em um programa comercial de simulação térmica de reservatório de óleo, onde constatou-se a influência de alguns parâmetros operacionais sobre o fator de recuperação e a energia no reservatório. O principal objetivo deste estudo foi encontrar uma distância entre os poços que permita diminuir as perdas de calor para as camadas sobrejacentes e subjacentes do reservatório, quando se injeta solvente e vapor no processo. A análise energética indicou é possível otimizar a distância entre poços melhorando a recuperação do óleo.

Palavras-chave: ES-SAGD; Modelagem de reservatórios; Reservatórios do nordeste brasileiro; Injeção de solvente; Injeção de vapor e solvente.

Resumen

En Brasil, especialmente en el Nordeste, todavía hay yacimientos que contienen petróleo pesado que están siendo operados por empresas pequeñas que necesitan producir los campos reduciendo los costos de producción. Existen diferentes procesos para recuperar petróleo pesado, uno de los cuales es el proceso de drenaje por gravedad asistido por vapor y solvente, el cual utiliza dos pozos horizontales paralelos, donde el inyector se coloca encima del productor. En este proceso se puede utilizar un disolvente con el vapor, para reducir la tasa de vapor inyectado. El proceso se realiza inyectando un aditivo hidrocarbonado en baja concentración junto con vapor. El vapor contribuye con el calor a reducir la viscosidad del petróleo y el solvente ayuda con la miscibilidad, reduciendo la tensión interfacial. La fuerza principal que actúa en este proceso es la gravitacional. Entonces, se mejora la movilidad del fluido desplazado, aumentando la recuperación de petróleo. En este estudio se analizó un modelo semisintético, con características promedio del nordeste brasileño, donde hay petróleo pesado en yacimientos terrestres. Diferentes simulaciones se realizaron utilizando un software comercial de simulación térmica de yacimientos de petróleo, donde se verificó la influencia de algunos parámetros operativos en la recuperación de petróleo y la energía en el yacimiento. El principal objetivo de este estudio fue encontrar una distancia entre los pozos que permita reducir las pérdidas de calor hacia las capas suprayacentes y subyacentes del yacimiento, cuando se inyecta solvente y vapor al proceso. Fue encontrado una distancia vertical óptima para mejorar la recuperación de petróleo.

Palabras clave: ES-SAGD; Modelaje de yacimientos; Yacimientos del noreste brasileño; Inyección de solvente; Inyección de vapor y solvente.

1. Introduction

Oil is still part of the planet's energy sources, forming part of the Brazilian energy matrix. Therefore, technologies that involve the development and application of techniques capable of increasing the profitability of oil fields are important and require further study. Hence, through numerical simulation of reservoirs, different studies can be carried out at low cost and still provide convincing results (Silva et al., 2023; Silva et al., 2022). At a regional level, Rio Grande do Norte has large reserves of heavy oil. Although a significant part of these reserves has already been produced (mature fields), there is always a search for new technologies and supplementary recovery methods being studied, tested, and implemented with the aim of maximizing the amount of oil recovered from the reservoir (Silva, 2016; Barillas, 2008; Barillas et al., 2006).

Among the thermal methods used to recover these resources, continuous steam injection has become one of the main economically viable alternatives for heavy oils fields (Chai, et. al, 2023). The latent heat carried by the steam heats the oil in the reservoir, reducing its viscosity and facilitating its production (Dong et. al 2019, Li & Mamora, 2010; Galvão, 2012).

An alternative used to increase efficiency in thermal methods has been the addition of solvents to the injected steam (Jha et al., 2013). Solvents are light hydrocarbons that have the property of reducing interfacial tensions and facilitating oil production (Chai, et. al, 2023). Experimental results, numerical studies and field tests suggest that great benefits can be achieved with the addition of solvents to injected steam (Chang, et. al, 2013, Zargar, & Farouq Ali 2020), such as increasing oil flow rates and oil-steam ratios, reducing water and energy consumption for generating steam, reducing the emission of greenhouse gases (Nasr et. al 2002; Nasr et. al 2003; Praxedes & Barillas 2023).

Steam and solvent injection assisted gravity drainage (ES-SAGD) is a combination of a thermal method with a miscible method (Lyu et. al 2023), where the addition of solvent is a resource used to increase thermal efficiency in relation to steam assisted gravity drainage (SAGD), (Wu et. al 2020).

For a better understanding of the process, and to verify the expansion of the steam-solvent chamber, a two-

dimensional model was chosen in the reservoir to perform an energy analysis of the steam and solvent injection for different vertical configurations between wells, with the purpose of verifying the influence of steam and solvent injection on oil recovery with the aim of reducing energy losses (Silva 2016; Praxedes & Barillas 2023). The main objective of this study was to find a distance between producer and injector wells that allows reducing heat losses to the overburden and underburden when solvent and steam are injected into the process.

2. Methodology

In this study, a semi-synthetic model was analyzed, with characteristics from the Brazilian northeast. The fractions of the pseudo-components used in the fluid model can be seen in Table 1. This hydrocarbon mixture has an average viscosity of 819 cP for the initial conditions of reservoir temperature and pressure. The solvent studied was C₇ and its characteristics can be found in Table 2.

Table 1 - Fluid composition.

Components	Molar fraction (%)
CO ₂ -N ₂	0.72
C ₁ -C ₃	10.35
IC ₄ -NC ₅	0.32
C ₆ -C ₁₂	1.74
C ₁₃ -C ₂₀	18.90
C ₂₁ -C ₃₉	42.55
C ₄₀₊	25.42
Total	100

Source: Authors.

The values shown in Tables 1 and 2 were used within the fluid model used in the 2D reservoir modeling, the composition of the oil corresponds to reservoirs in northeastern Brazil.

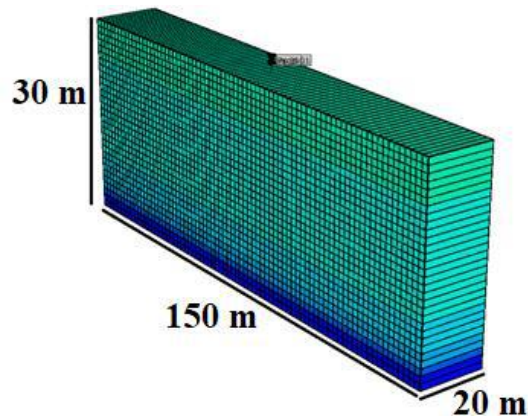
Table 2 - Properties of C₇ solvent used.

Property	C ₇ H ₁₆
Aspect	transparent and colorless liquid
Molar weight	100.21g/mol
Density (20/4)	0.68
Boiling point	98 ° C
Fusion Point	-90 ° C

Source: Perry's (1997).

The modeling of the homogeneous reservoir containing heavy oil has an area of 150m x 20m (2D model) and an oil pay net thickness of 28m (28m oil zone and 2m water zone). Figure 1 shows the reservoir (2,250 blocks), and the dimensions considered, and Figure 2 shows a frontal view of the reservoir, where the location of the producer well and the injector well (IK-view) in the reservoir can be seen, (You et al, 2012).

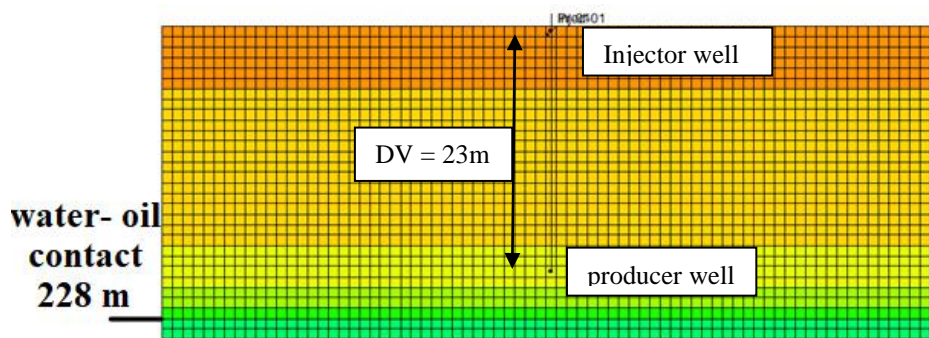
Figure 1 - Reservoir dimensions.



Source: Authors.

Figure 1 shows that the dimensions of the reservoir used in the study are compared to reservoirs in the Potiguar basin, in terms of oil netpay and area exposed to gravitational drainage. The idea of using the 2D model to observe the formation of the vapor chamber, important in the steam-assisted gravity drainage process.

Figure 2 - IK-View of reservoir.



Source: Authors.

Figure 2 shows the water-oil contact, and the arrangement of the injection (top) and producer (bottom) wells (Barillas, Dutra & Mata 2006; Praxedes & Barillas 2023).

Table 3 Shows rock reservoir properties. This information is necessary to be inserted into the reservoir model that will be simulated in a commercial software that allows analyzing the influence of some operational parameters on oil production, among others.

Table 3 - Rock-reservoir properties and other values.

Properties	Values
Reservoir area, (m ²)	150 x 20
Oil net pay, h (m)	28
Reservoir depth (m)	200
Water-oil contact (m)	228
Reference pressure (psi)	287
Number of blocks through i, j, k	75, 1, 30
Average horizontal permeability, Kh (mD)	1,000
Vertical permeability, Kv (mD)	0.1* Kh
Average porosity (%)	25
Reservoir initial temperature (°C)	38
In place oil volume, VOIP m ³ std	12,952.1
Oil viscosity (cP@38 °C)	819
Initial water saturation, Sw (%)	28
Rock Thermal Conductivity (J/m*day*C)	274,000
Oil Thermal Conductivity (J/m*day*C)	11,500
Water Thermal Conductivity (J/m*day*C)	53,500
Gas Thermal Conductivity (J/m*day*C)	3,900
Effective formation compressibility (1/kPa)	1.034x10 ⁻⁵
Rock heat capacity (J/m ³ *C)	2,347,000

Source: Authors; CMG User guide (2022).

Operational conditions of the wells, used in the base model, are in Table 4.

Table 4 - Operational conditions of case base.

Steam and solvent (C ₇) temperature (° C)	288
Steam quality (%)	60
Maximum bottom hole pressure (injector) (kPa)	7,198.1
Minimum bottom hole pressure (producer) (kPa)	196.5
Maximum produced liquid rate (m ³ std/day)	500
Distance between injector well and production well (m)	23

Source: Authors.

This information is necessary to be inserted into the reservoir model that will be simulated in a commercial simulator that allows analyzing the influence of some operational parameters on oil production, among others.

Energy lost (joules) to the overburden and underburden layers of the reservoir was calculated by Equation 1:

$$\text{Heatloss (J)} = \text{Injheat (J)} - \text{Prodheat (J)} - \text{in-place Heat (J)} \quad \text{Eq. (1)}$$

Heatloss = Heatloss;

Injheat = Energy injected into the system.

Prodheat = Energy produced by the system.

in-place Heat = Energy inside the reservoir.

Equation 2 was used to calculate net oil production (N_{pl} , without solvent C_7):

$$N_{PL} = N_{PT} - N_{PS} \quad \text{Eq. (2)}$$

Oil recovery (OR) was calculated as follows (Equation 3):

$$OR = N_{PL} / VOIP \quad \text{Eq. (3)}$$

N_{PL} = Cumulative oil without solvent (m^3 std);

N_{PT} = Cumulative oil (solvent+ oil) (m^3 std);

N_{PS} = Cumulative solvent (m^3 std);

OR = Oil recovery factor (%);

VOIP= In place oil volume (m^3 std).

An analysis of cumulative oil was carried out for different operational conditions was analyzed, and in founded which system has a higher heat loss. To carry out this study, a 2D reservoir was modeling, then some operational parameters were analyzed. Objective function of this study were oil recovery and heat loss primarily. This is the used methodology (Barillas et al., 2006; Praxedes & Barillas 2023):

1. To model a 2D reservoir.
2. To analyze some operational parameters to see influence on oil recovery, oil rate and heat loss.
 - Vertical distance between well of: 7m, 9m, 12m, 15m and 23m.
 - Steam rate: 12,5 m^3 /day 25 m^3 /day.
 - With solvent (25% of solvent over steam rate).
 - Without solvent (0%).
3. To calculate NP_i and heat loss.
4. To find a mathematical model.
5. To analyze oil recovery and heat loss.

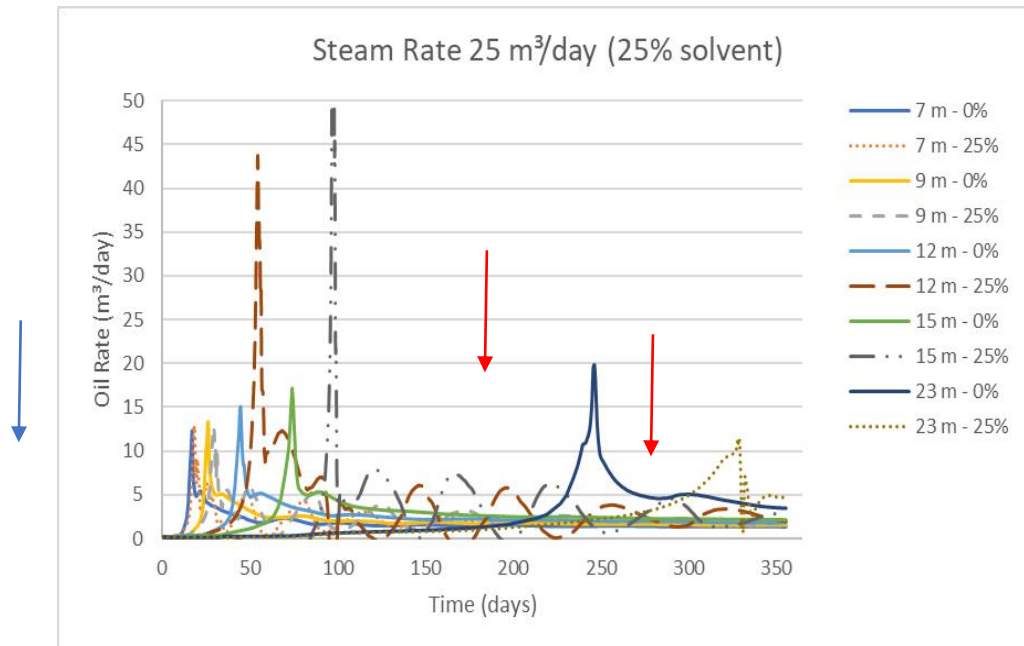
3. Results and Discussion

This section presents the results of the simulations carried out for two steam injection flows with and without solvent (they have already been optimized in the process). The solvent is injected at reservoir temperature. The study was carried out by analyzing the vertical distance (DV) between the wells (injector and producer) – Dv : 7m, 9m, 12m, 15m and 23m, for two steam injection flows with and without solvent.

Figure 3 shows oil rate production versus time for different vertical distances studied, cases without and with addition of 25% solvent (25% above steam injection). The beginning of production (first 365 days) was analyzed, as it was in the first year that there was a breakthrough from the oil bank to the producing well with the addition of the solvent. The case studied corresponds to a steam injection rate of 25 m^3 /day.

For steam injection rate of 25 m^3 /day, it was observed that the anticipation of the oil bank happened first, for cases without solvent (0% solvent), at all vertical distances (DV), however, with the increase vertical distance, when solvent is injected, the maximum oil rate of is greater. This is a result of the miscibility between solvent and oil, when injecting solvent with steam it delays the oil displacement to producer well but achieves a better sweep of it.

Figure 3 - Oil bank anticipation analysis, using 0% and 25% solvent, for different vertical distances. Steam rate = 25 m³ std/day.

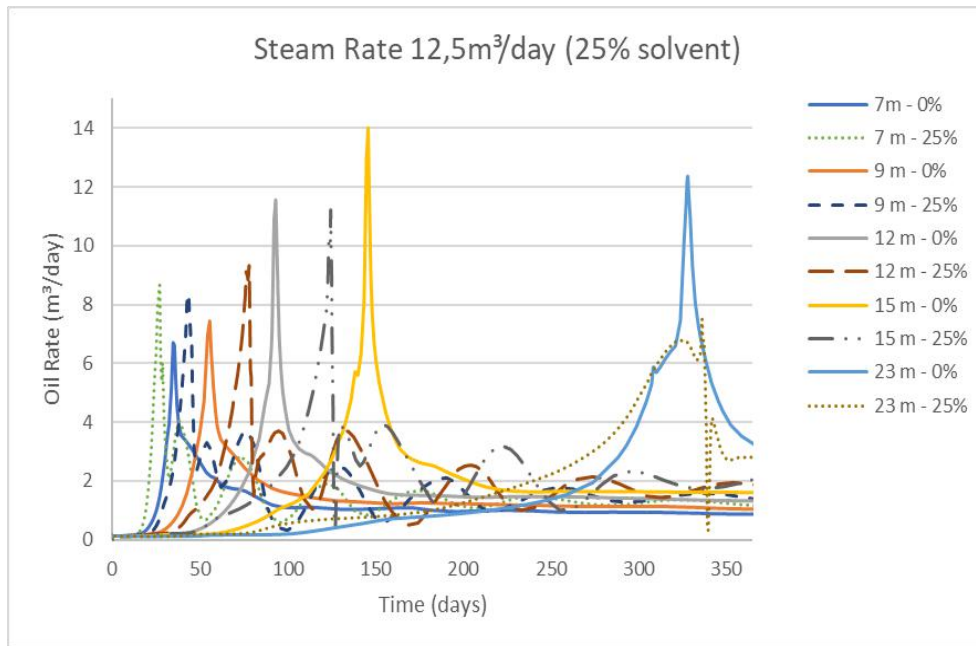


Source: Authors.

Same analysis was carried out using an injection rate of 12.5 m³/day and with the same 25% of solvent injected (over this mass of steam), in this case due to the lower steam injection flow, there was an anticipation of the bank of oil when solvent was injected, unlike the previous case, for different vertical distances between wells. This can be seen in Figure 4. In this case there was a smaller amount of steam injected, this influences the heat injected into the reservoir, which in this case is smaller (half for the same reservoir), and the process is then more influenced by the miscibility of the oil solvent, so solvent injection benefits the anticipation of the oil bank in the producer.

Maximum oil rate peaks are higher in the case of higher injection flow rates, this is expected due to the greater energy injected into the system. Knowing the oil anticipation in a process is important to have an idea of the project's economics.

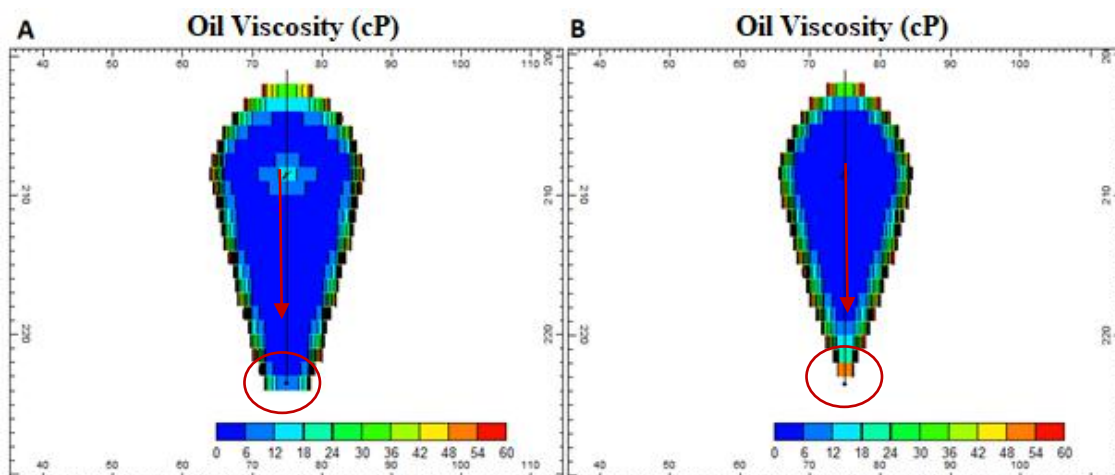
Figure 4 - Oil bank anticipation analysis, using 0% and 25% solvent, for different vertical distances. Steam rate = 12,5 m³ std/dia.



Source: Authors.

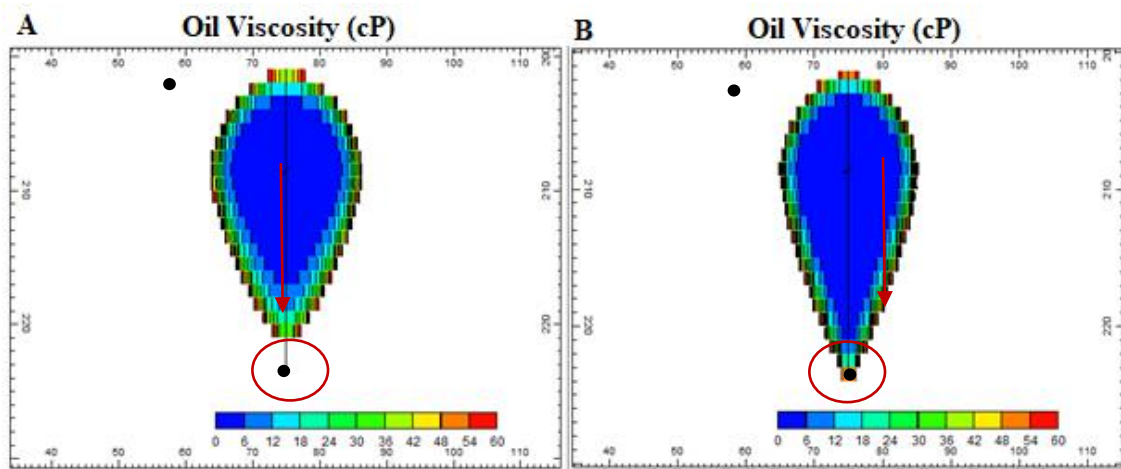
Figure 5 and Figure 6 show a steam chamber in a 2D-view for oil viscosity at vertical distance between wells (DV) of 15m on the same date for the four cases, with and without solvent. With steam injections rates of 25 m³ std/day (Figure 5) and 12.5 m³ std/day (Figure 6), respectively.

Figure 5 - Steam chamber, a comparison of oil viscosity for a vertical distance – Dv= 15 m, at a steam injection rate of 25 m³/day. Without solvent (A) / With solvent (B).



Source: Authors.

Figure 6 - Steam chamber, a Comparison of oil viscosity at a vertical distance - Dv of 15 m, at a steam injection flow of 12.5 m³/day. Without solvent (A) / With solvent (B).



Source: Authors.

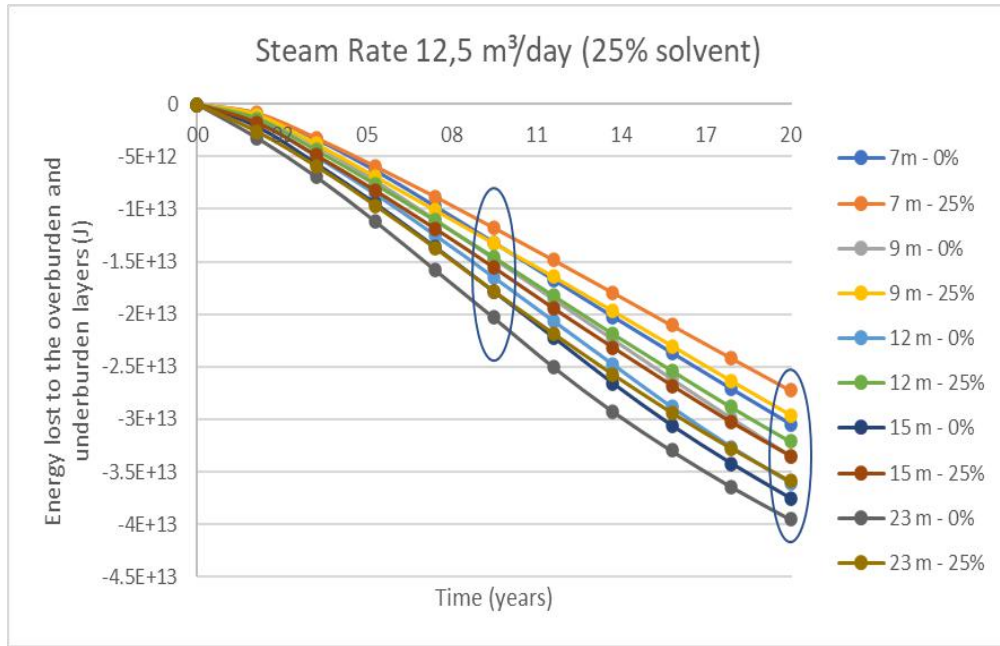
Figure 5 (A) compares a view of the steam chamber, where the oil viscosities can be seen, (steam injection rate of 25 m³/day) without addition of solvent, and Figure 6 (B) with the addition of solvent. It is possible to observe that the oil arrives more quickly when no solvent is added (Figure 6 - A), there was greater heating due to the mass of steam that was injected, and it can be seen that there was a faster arrival of the oil bank or anticipation thereof in this case.

In the case of Figure 6 (A), which shows a smaller steam injection (12.5 m³/day) without solvent, it can be seen that the oil bank arrives faster when solvent is added to the system (Figure 6 - B). In this case the solvent/steam mixture is colder, oil viscosity in the system is greater than in the case of Figure 6 (A and B), but the solvent helps in mixing with the oil, due to its miscibility with it, which allows it to reduce its viscosity, and in this case reaching the producer well more quickly when using solvent. The study shows that a smaller amount of steam can be used, but solvent must be injected to reduce oil viscosity inside the reservoir by the same amount.

After this study, an energy analysis was carried out to find out which vertical distances lost the most energy to the overburden and underburden layers of the reservoir, using Equation 2 shown in the methodology. The injection rate analyzed was 12.5 m³/day of steam and 25% solvent.

Figure 7 shows the energy lost to the overburden and underburden layers of the reservoir over time, for the different distances between wells studied (DV), with and without solvent addition. It can be observed that the addition of solvent causes heat losses to be lower when compared to cases without solvents (for all cases studied), showing that the injection of solvent helps to reduce energy losses to the overburden layers and underburden reservoir.

Figure 7 - Energy lost analysis for different vertical distances between wells (DV) with steam rate of 12.5 m³/day and 25% solvent.

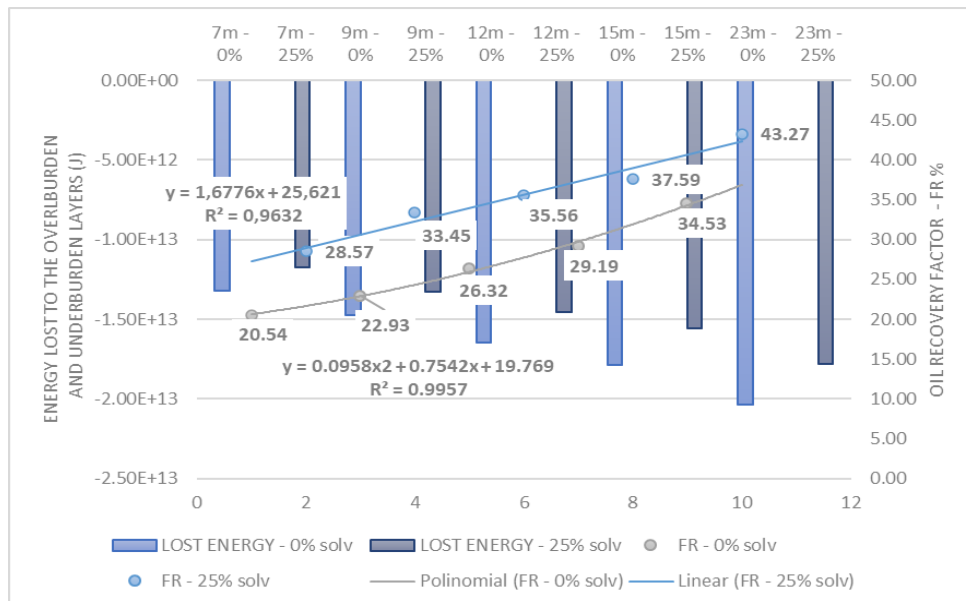


Source: Authors.

It was observed in Figure 7 that the increase in the vertical distance between wells (DV) increases heat losses to the overburden and underburden layers, which was to be expected since they are closer to the upper layer.

Figure 8 shows the energy lost in the reservoir and the recovery factor, in 10 years for the cases studied previously. In Figure 8, it can be observed the increase in heat losses with the increase in vertical distance (DV), seen previously, but it can also be seen that the oil recovery factor is greater when steam and solvent are injected.

Figure 8 - Energy analysis and recovery factor for 10 years of production, steam rate Q= 12.5 m³/day and 25% solvent, for several vertical distances - DV (7m / 9m /12m /15m / 23m).



Source: Authors.

Two mathematical models were carried out for the recovery factor with and without solvent, both over 10 years, one linear model (Equation 4) when is used solvent and other quadratic model (Equation 5), when is not used solvent in the process.

Oil recovery factor (FR), linear model, with solvent ($y = FR(10y), x = DV(m)$):

$$y = 1,6776x + 25,621 \quad (R^2 = 0,9632) \quad \text{Eq. (4)}$$

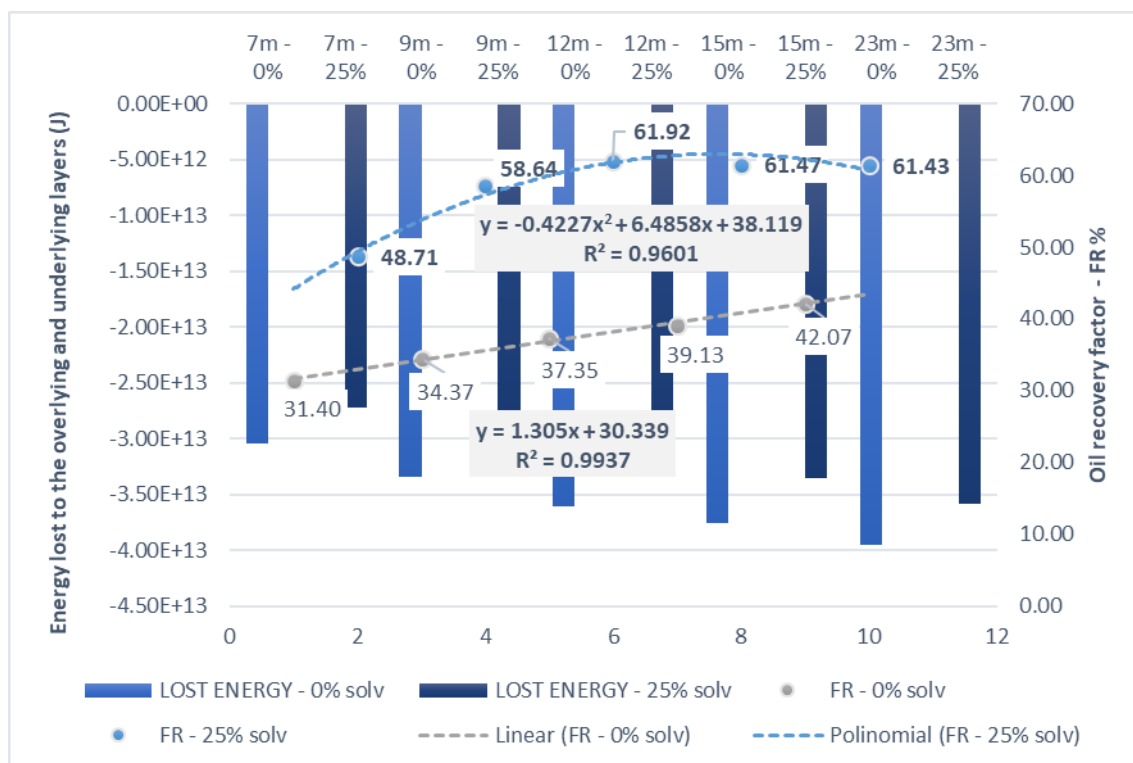
Oil recovery factor (FR), quadratic model, without solvent ($y=FR(10y), x = DV(m)$):

$$y = 0,0958x^2 + 0,7542x + 19,769 \quad (R^2 = 0,9957) \quad \text{Eq. (5)}$$

Oil recovery factor (FR) when is used solvent shows a linear trend with a percentage (%) of explained variation of 96% (R^2). When no solvent is used in the injection, oil recovery factor (FR) is lower, heat losses are greater, and tends towards a 2nd degree polynomial with a percentage (%) of variation explained of 99% (R^2).

Figure 9 shows the energy lost in the reservoir and the recovery factor, in 20 years for the cases studied previously. In this figure, heat losses increase with increasing vertical distance (Dv), and the oil recovery factor is greater when steam and solvent are injected.

Figure 9 - Energy lost and oil recovery factor analysis for 20 years of production, steam rate $Q = 12.5 \text{ m}^3/\text{day}$ and 25% solvent, for several vertical distances - DV (7m / 9m /12m /15m / 23m).



Source: Authors.

Two mathematical models were carried out for the recovery factor with and without solvent, both over 20 years (Equation 6 and Equation 7).

Oil recovery factor (FR), quadratic model, with solvent ($y=FR$ (20y), $x = DV(m)$):

$$y=-0.4227x^2+6.4858x+38.119 / R^2 = 0.9601 \quad \text{Eq. (6)}$$

Oil recovery factor (FR), linear model, without solvent ($y=FR$ (20y), $x = DV$ (m)):

$$y = 1.305x + 30.339 / R^2 = 0.9937 \quad \text{Eq. (7)}$$

The mathematical models (Eq. 6 and Eq.7) presents an inversion of trends when comparing with Eq. 4 and Eq. 5, showing an adjustment to a 2nd degree polynomial (Eq. 6) of the recovery factor (FR) with a percentage (%) of explained variation of 96% (R^2) when solvent is injected (in this case the losses are also lower than when no solvent is used), showing that there is a maximum recovery factor (FR) at 12 meters of vertical distance (DV). This is a good way to optimize the system when you want to check what would be the best operational condition between wells, improving oil recovery.

It was observed, therefore, that the greater the vertical distance (Dv), the greater the energy losses and the greater the recovery factors, in the case of not injecting solvent. And that the presence of solvent in the injection reduces energy losses and increases the recovery factor (FR), and that the FR response has a correlation with the distance between wells. Analyzes for lower percentages of solvent (5%) maintained similar behavior to that found in higher percentages, with a lower oil recovery factor. This study shows that the vertical distance between the injection and production wells has an influence on heat losses and the recovery factor.

4. Conclusions

As main conclusions of the study of the gravitational drainage process with steam and solvent injection, it was found that:

- Injecting solvent improves the miscibility of the oil in the reservoir, allowing a reduction in its viscosity, and allowing high recovery. Depending on the steam injection rate there may be an anticipation of the oil bank in the producer; it is necessary to carry out a study of these parameters for each system studied.
- The greatest heat losses to the overburden and underburden layers of the reservoir occur when no solvent is injected into the system, or when the distance between the wells increases.
- An increase in the volume of injected solvent increased the oil recovery factor in relation to the model without solvent.
- An optimal distance between wells was found in the system, maximizing the oil recovery factor, with intermediate heat losses.
- We recommend carrying out a multivariate parametric study considering energy losses in the injection well.

Acknowledgments

The authors want to thank the LEAP (reservoir modeling laboratory), to CMG (Computer Modeling Group) for the technical support and the used software, and to UFRN (Federal University of Rio Grande do Norte) for the opportunity.

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