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Influence of solvent injection temperature in steam-solvent assisted gravity drainage process for heavy oil reservoirs of Brazilian Northeast

Influência da temperatura de injeção do solvente no processo de drenagem gravitacional assistido com injeção de vapor e solvente em reservatórios de óleo pesado do Nordeste brasileiro

Influencia de la temperatura de inyección de solvente en el proceso de drenaje por gravedad asistido por vapor-solvente para yacimientos de petróleo pesado del Nordeste Brasileño

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Abstract
The solvent–steam assisted gravity drainage is an oil recovery process that combines the advantages of thermal and miscible effects, and it has been successfully tested, especially in Canada, where many heavy oil reservoirs are located. This method uses two parallel horizontal wells drilled one above the other, the upper injects steam and solvent and the lower produces oil. This process has not been applied yet in Brazil, where there are heavy oil reservoirs, especially in northeast region. Based on this context, this research aimed to study the application of the ES-SAGD process in a semisynthetic reservoir, with characteristics similar to those found in the Brazilian Northeast, specifically to analyze the influence of the solvent injection scheme on ES-SAGD. Numerical simulations were performed using commercial software from CMG. It was analyzed several steam-solvent injection rates, using two injected temperatures for solvent, (at reservoir or at steam temperature´s), in order to minimize explosion risks, that can be due to high temperatures. Results showed that solvent injection temperature has great influence on oil recovery, it is better for oil production when it is inject hot solvent, because cold solvent generates a cooling of the steam. However, it is possible to injected cold solvent (at reservoir temperature), and increase oil production, changing some steam properties, avoiding explosions risks.
Keywords: Steam-solvent injection; Heavy oil; ES-SAGD; Reservoir modeling; Enhanced oil recovery; Thermal method.

Resumo
A drenagem gravitacional assistida com injeção de vapor e solvente é um processo de recuperação de óleo que combina as vantagens dos efeitos térmicos e miscíveis, e tem sido testado com sucesso, especialmente no Canadá, onde estão localizados muitos reservatórios de óleo pesado. Este método utiliza dois poços horizontais paralelos perfurados um sobre o outro, o superior injeta vapor e solvente e o inferior produz óleo. Este processo ainda não foi aplicado no Brasil, onde existem reservatórios de óleo pesado, principalmente na região nordeste. Motivado por este contexto, esta pesquisa objetivou estudar a aplicação do processo ES-SAGD em um reservatório semissintético, com características semelhantes às encontradas no Nordeste brasileiro, mais especificamente analisar a influência do esquema de injeção de solvente no ES-SAGD. Simulações numéricas foram realizadas através do software comercial da CMG. Foram analisadas várias vazões de injeção de vapor-solvente, utilizando duas temperaturas de injeção de solvente, (no reservatório ou na temperatura do vapor), a fim de minimizar os riscos de explosão, que podem ser decorrentes de altas temperaturas. Os resultados mostraram que a temperatura de injeção do solvente tem grande influência na recuperação do óleo, é melhor para a produção de óleo quando se injeta o solvente quente, pois o solvente frio gera um resfriamento do vapor. Porém, é possível injetar solvente frio (na temperatura do reservatório), e aumentar a produção de óleo, alterando algumas propriedades do vapor, evitando riscos de explosões.
Palavras-chave: Injeção de vapor-solvente; Óleo pesado; ES-SAGD; Modelagem de reservatórios; Recuperação avançada de óleo; Método térmico.

Resumen
El drenaje asistido por gravedad con inyección de vapor y disolvente es un proceso de recuperación de petróleo que combina las ventajas de los efectos térmico y miscible, y se ha probado con éxito, especialmente en Canadá, donde se encuentran muchos yacimientos de petróleo pesado. Este método utiliza dos pozos horizontales paralelos perforados uno sobre otro, el superior inyecta vapor y disolvente y el inferior produce petróleo. Este proceso aún no se ha aplicado en Brasil, donde existen yacimientos de petróleo pesado, principalmente en la región nordeste. Motivada por este contexto, esta investigación tuvo como objetivo estudiar la aplicación del proceso ES-SAGD en un reservorio semisintético, con características similares a las encontradas en el Nordeste brasileño, más específicamente analizar la influencia del esquema de inyección de solvente en el ES-SAGD. Las simulaciones numéricas se realizaron con el programa informático comercial CMG. Fueron analizados varios flujos de inyección de vapor y solvente, utilizando dos temperaturas de inyección del solvente, (en el yacimiento o en la temperatura del vapor), con el objetivo de minimizar los riesgos de explosión, que pueden ser debidos a las altas temperaturas. Los resultados mostraron que la temperatura de inyección del disolvente tiene una gran influencia en la recuperación de petróleo, es mejor para la producción de petróleo cuando se inyecta el disolvente caliente, porque el disolvente frío genera un enfriamiento por vapor. Sin embargo, es posible inyectar disolvente frío (a la temperatura del yacimiento), y aumentar la producción de petróleo, cambiando algunas propiedades del vapor, evitando riesgos de explosiones.
Palabras clave: Inyección de vapor-solvente; Petróleo pesado; ES-SAGD; Modelización de yacimientos; Recuperación avanzada de petróleo; Método térmico.

1. Introduction

The Expanding Solvent–Steam Assisted Gravity Drainage method was developed by Nasr and Isaacs (Kumar & Hassanzadeh, 2020) and consists of adding solvent to the SAGD process (Mohan et al., 2022). This method uses two parallel horizontal wells, being the injector well drilled above the producer (Nasr & Isaacs, 2001; Nasr et al.,2002; Nasr et al., 2003; Nasr & Ayodele, 2006). The continuous co-injection of steam-solvent occurs in the injector well, the steam reduces oil viscosity and the solvent helps the miscibility, reducing the interfacial tension between oil/solvent and furthermore the condensed solvent around the interface of the steam chamber dilutes the oil and in conjunction with heat, reduces its viscosity (Chai et al., 2023; Gates, 2007; Jha et al., 2013; Lyu et al., 2023).

The use of horizontal wells has the advantage of covering a larger area of contact with the formation along its extension, providing a greater oil recovery in less time when compared to other processes that do not use this technique (Edmunds & Gittins, 1993; Nasr & Ayodele, 2005; Shareef & Abdulwahid, 2022).

The upper well receives steam-solvent continuously and injects them into reservoir, oil is heated and forms a steam chamber around the wells, that grows upwards and towards to surroundings (Irani et al., 2021). The main force acting in this process is gravitational. It is expected that the selected solvent can condense and evaporate under same conditions as water phase (Zargar & Farouq Ali, 2020). In order to be considered appropriate to use, the solvent must have a thermodynamic vaporization behavior similar to the thermodynamic behavior of the water in a specific reservoir condition (Li & Mamora, 2010; Li et al., 2011; Nasr & Ayodele, 2006; Wu et al.,2020).

The main objectives of solvent addition in the injector well are: improve oil production, reduce steam/oil ratio, reduce energy and water requirements when compared to conventional SAGD process (Dong et al., 2019; Ma & Leung, 2020; Orr, 2009; You et al. 2012).

Processes that use horizontal wells, such as Expanding Solvent-Steam Assisted Gravity Drainage, should consider the load and heat losses in injector well, since when pressure and temperature variations are integrated into the reservoir model the description of the well behavior becomes more realistic (Anklam, 2001; Anklam & Wiggins, 2005; Liu et al., 2020; Thorne & Zhao, 2008).

The losses can cause a non-uniform distribution of steam in wells, the formation of a non-uniform steam chamber, an effective reduction of the well length, resulting in a productivity reduction. Also, there is an increase in steam consumption, increasing costs, therefore, this study considered the load and heat loss in the injector well (Le Gallo & Latil, 1993).

This work aims to analyze the influence of a solvent injection scheme in the Expanding Solvent-Steam Assisted Gravity

Drainage in two investigated models: the first one with hot solvent injection (1INJ) and the second with cold solvent injection (2INJ).

In order to achieve this objective, it was considered a semi-synthetic reservoir with characteristics of those located in the Brazilian northeast region. All the results were obtained using the commercial thermal simulator STARS (Steam, thermal and Advanced process Reservoir Simulator) from CMG (Computer modeling Group Ltd.).

2. Methodology

2.1 Materials and Methods

This study was performed using the following CMG (Computer Modeling Group) programs that simulate flow in porous media: WinProp (Phase Behavior and Property Program), Builder (Pre-Processing Applications) and STARS (Steam, Thermal, and Advanced Processes Reservoir Simulator).

Reservoir characteristics are shown in Table 1, reservoir was considered homogeneous, distributed in an area of 100 m x 600 m, with thickness of 26 m.

Table 1 - Reservoir grid.

Total grid blocks	28,080
Reservoir size in x-axis (m)	100
Reservoir size in y-axis (m)	600
Reservoir size in z-axis (m)	26
Number of blocks through i, j, k	27, 40, 26
Initial Reservoir temperature (°C)	38
Average porosity (%)	28
Average horizontal permeability (mD)	1,000
Vertical permeability (mD)	100
Water–oil contact (m)	220
Original oil in place (SC m^3)	188,579
Reservoir top (m)	200
Reference pressure (kPa) (@200m)	1,979
Oil viscosity (cP) (@38°C)	656.4
Connate water saturation, Sw (%)	28
Steam quality	0.8
Steam temperature (°C)	287.8

Source: Authors.

Figure 1 shows a 3D representation of the studied reservoir, with 28.080 blocks, also with oil saturation, model dimensions and location of the injector and producer wells.

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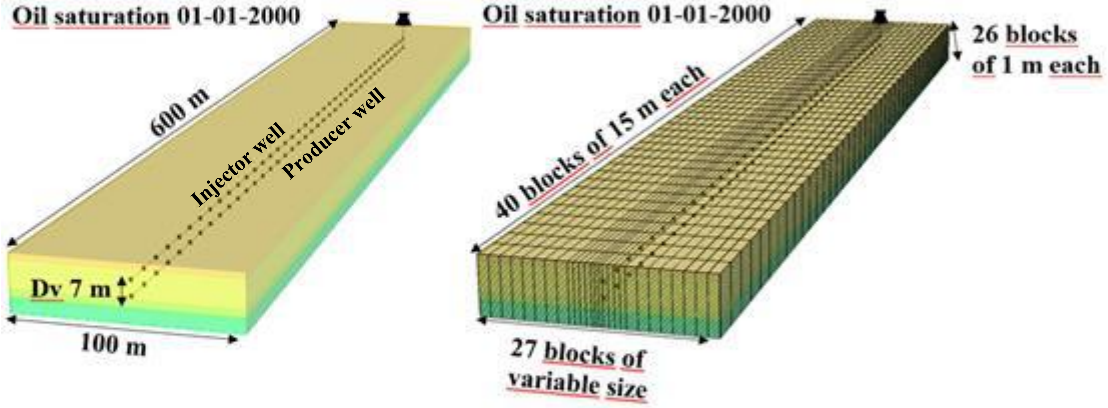
Figure 1 - 3D reservoir view.



Source: Authors.

The maximum bottom hole pressure of the injector well was considered 7,198 kPa; the minimum bottom hole pressure in the producer well was 196 kPa, the injection rate was analyzed at different intervals. Temperature and steam quality used were: 287.7 °C and 50%, respectively. The solvent used was heptane (C_7H_{16}). It was considered 20 years of oil production.

Table 2 shows steam injection rate analyzed in this research.

Table 2 - Steam injection rates for the ES-SAGD process.

Name (Qsteam)	Steam rate (t/day)
Qs0	0
Qs25	25
Qs50	50
Qs100	100
Qs150	150

Source: Authors.

Table 3 shows solvent percentages (vol/vol) analyzed.

Table 3 - Percentage of solvent injected for the ES-SAGD process.

Name	Percentage of solvent (vol/vol)
Solvent_0	0
Solvent_5	5
Solvent_10	10

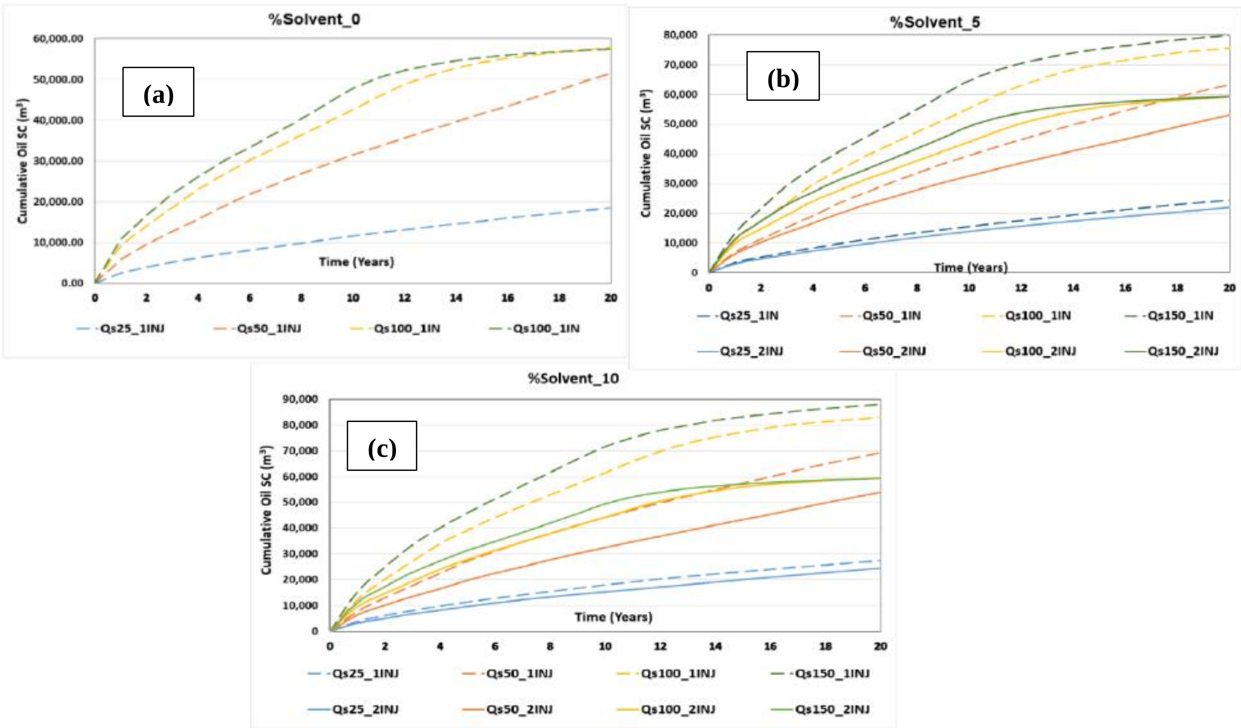
Source: Authors.

This study analyzes the influence of solvent injection scheme in the Expanding Solvent – Steam Assisted Gravity Drainage considering solvent temperature, and for this was modeled numerically the solvent injection using one injector well (1INJ for hot solvent), and two injector wells (2INJ for cold solvent). Nevertheless, the method of simulation in the used software can hide important results, where normally the solvent is injected at steam temperature, due this, the modeling was carried out using two injection wells, the 1INJ model injects solvent and steam together at the steam temperature (287.8 °C / 550 °F), and the 2INJ model injects into two wells, one injects steam (287.8 °C / 550 °F), in order to use a temperature of injection of the mixture (solvent plus steam), been more consistent with reality, and the other injects solvent at the reservoir temperature (38 °C / 100.4 F), this way is possible to compare both results. In this work also was analyzed the influence of the solvent and steam injection flow rate on oil production among other properties, both models (1INJ and 2INJ) considered heat losses in injector well, to obtain results closer to the field data.

3. Results

The main results of this research are presented in this section. Figure 2 shows cumulative oil without produced solvent (discounting the injected solvent produced) versus time, for three percentages of solvents (0%, 5% and 10%, vol/vol), for systems with hot solvent injection (1INJ, at steam temperature) and cold solvent injection (2 INJ, at reservoir temperature), considering several steam rate injection (Qsteam: 25, 50, 100 and 150 t/d).

Figure 2 - Comparison on cumulative oil (without produced solvent) for several percentages of solvent injected in ES-SAGD: a) 0%; b) 5%; c) 10%.

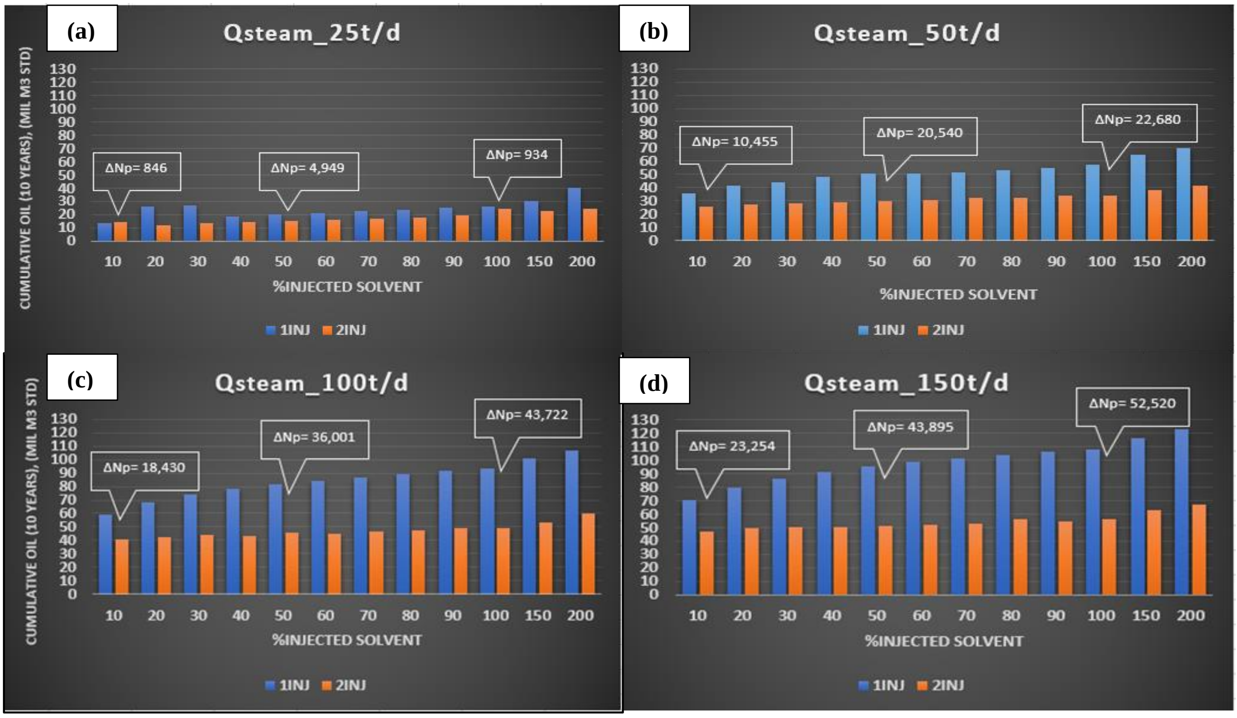


Source: Authors.

Results show that injected solvent improves oil production. When it is cold (2INJ), oil production also improves, and the increase of the steam injection rate increases oil production too, however, at high rates the increase of oil production is lower. It can also be observed that the cumulative oil without produced solvent is higher for the systems with hot solvent injection (1 INJ).

Figure 3 shows cumulative oil without produced solvent for 10 years of production, for the analyzed steam injection rates (25, 50, 100 and 150 t/d), using different solvent percentages in each case (10% - 200% = QSOLV/QSTEAM*100).

Figure 3 - Cumulative oil (without produced) solvent for several ES-SAGD injection rates: a) 25 t/d; b) 50 t/d; c) 100 t/d; d) 150 t/d.



Source: Authors.

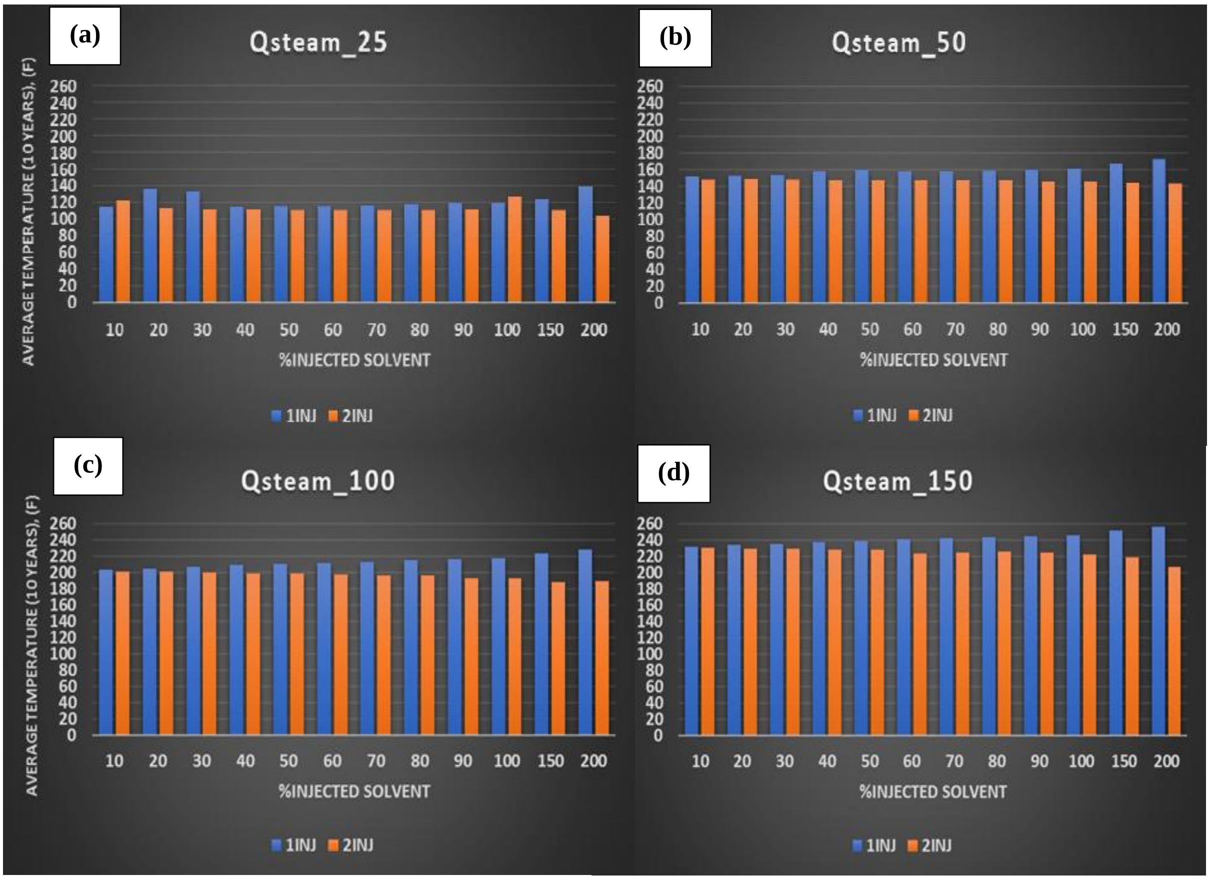
It can be noticed that an increment on cumulative oil without produced solvent occurs as the percentage of injected solvent increases, this tendency was observed in both models, hot (1 INJ) and cold (2 INJ) solvent injection. Such increase on cumulative oil without produced solvent happens because it helps in miscibility and reduces oil viscosity, increasing its mobility and displacement into the reservoir towards the producer well. Although the increment in recovered oil raises with the increment of injected solvent, but this practice is not recommended, since the produced oil, that is mixed with solvent, is sold at lower price when compared to the solvent purchased price, also when injected solvent mixes with the reservoir oil, being one part produced and another lost to the surrounding formations. Therefore, the high amounts of solvent injection considered in Figure 3 are used to analyze the behavior of solvent on oil production and in reservoir, but are not recommended in field operations.

For a steam rate injection of 25 t/d, it was showed a low oil production, since for lower injection rates, the reservoir is heated slowly, not having a good heat distribution, because of the small amount of mass to transfer it. However, with the increase rate of injected fluid, a greater amount of mass/heat is injected, generating a larger steam chamber, and consequently a better sweep of the oil in the reservoir, also when steam rates increase, solvent injection rise too, improve oil/solvent miscibility in the reservoir, reducing interfacial tension between injected fluid and oil.

When it is compared Figure 3(a) and 3(d), it can be observed that the increase in steam injection rate enhance the difference between cumulative oil of cases with hot solvent (1INJ) and cold solvent (2INJ). Once steam rate is incremented, injected solvent is also incremented and, in the modeling with hot solvent (1INJ), there is a greater amount of mass, transferring heat to the reservoir with better heat distribution. Therefore the system with higher temperature (1INJ) improves oil production when compared to the lower temperature system (2INJ), in this case, the increase of solvent rate hampers the process due to its higher cold mass and therefore the cumulative oil difference in the system increases.

According to Figure 3, it can also be observed that when the high injection rate (Qsteam 100 t/d and Qsteam150 t/d) are compared, considering the same percentage of solvent, the increase on oil production (without produced solvent) is low. This shows that there is a mass limit to be injected, due to reservoir temperature, more mass can rise reservoir oil temperature, but when is increase the temperatures in heavy oil result in lower increments on oil production, since the decrease of oil viscosity is no longer significant. In order to understand how the temperature changes in reservoir, Figure 4 shows average temperature on reservoir for the four cases analyzed (Qsteam 25, 50, 100 and 150 t/d) at 10 years of production, each case shows different percentage of solvents (10%-200%).

Figure 4 - Average reservoir temperature for several ES-SAGD injection rates: a) 25 t/d; b) 50 t/d; c) 100 t/d; d) 150 t/d.



Source: Authors.

When both cases 1INJ (hot solvent) versus 2INJ (cold solvent) are compared it is possible to view that the average temperature is greater in 1INJ case, this is an expected result due to hot solvent injection. Figure 4 also shows that larger cold solvent injections decrease reservoir average temperature. The increase in reservoir average temperature appears to be lower, but the average considers all the blocks in reservoir. Therefore, Figure 5 shows a 2D view of the injector well region for cases 50 and 100 t/d (100% solvent) for 1 injector and 2 injectors for 10 years project.

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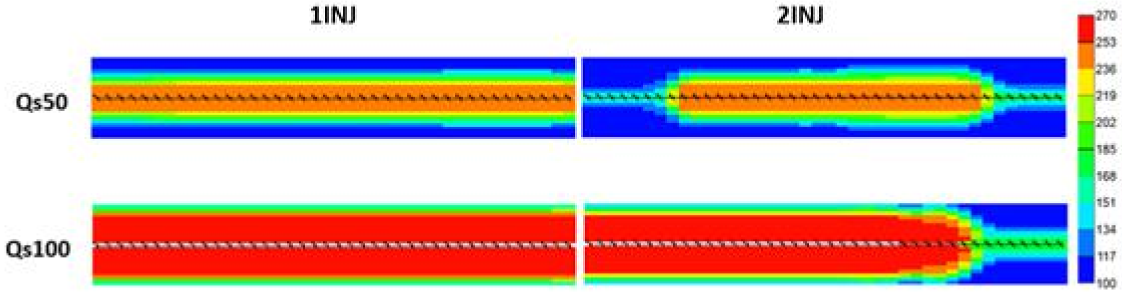
Figure 5 - 2D (IJ) view of temperature on injector well.



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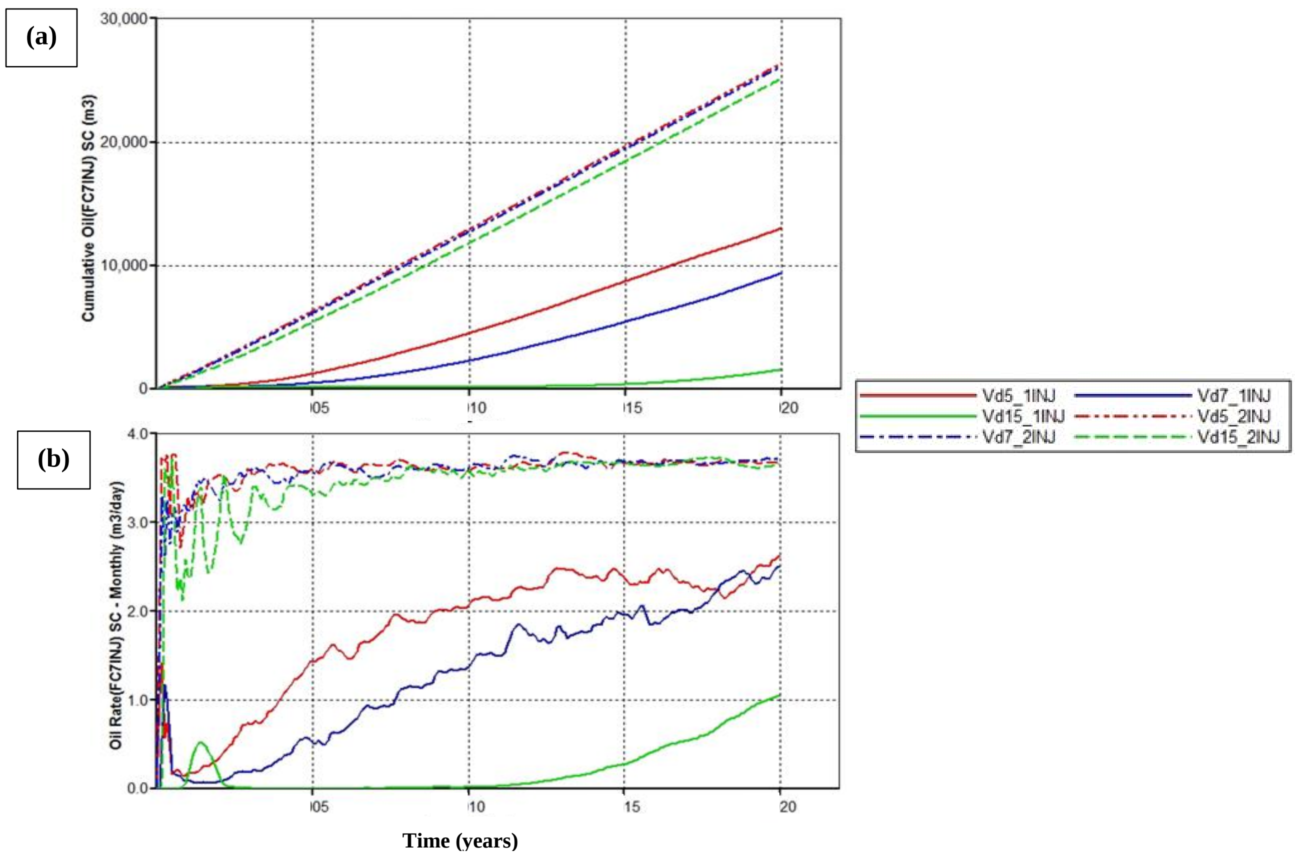
According to Figure 5, the temperature increment is higher with the hot solvent, hence, there is a greater increase on cumulative oil.

In order to investigate the influence of vertical distance between injector and producer wells on solvent production, a model with cold solvent (2INJ) and steam rate of 75 t/d (Qsteam, an intermediate value between 50 t/d and 100 t/d) were choose. Vertical distance between wells (injector and producer) was varied (5, 7, 15m) in order to check solvent production and solvent retained in reservoir (3.75 m3std/d of solvent rate, 5%, was injected). Results for this analysis can see it in Figure 6. Figure 6 (a) shows cumulative solvent production versus time, for several scenarios, Figure 6 (b) shows solvent production rate versus time, both for producer well.

Figure 6 - Cumulative solvent (a) and solvent rate (b) for several vertical distances between injector and producer well with 5% of solvent.

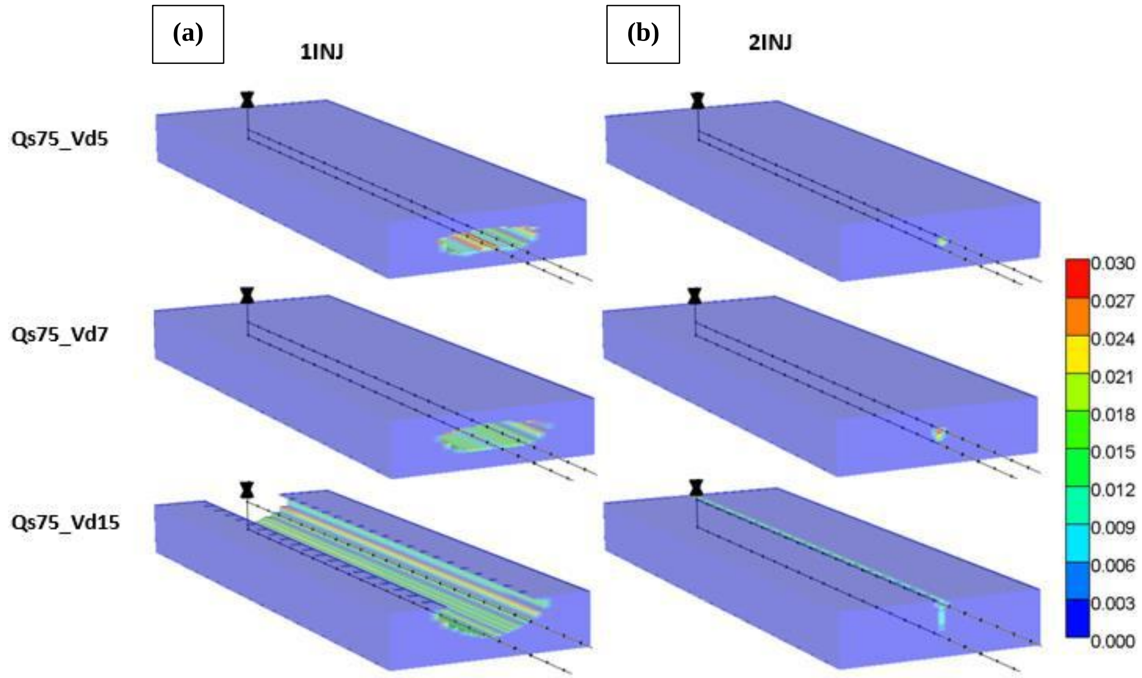


Source: Authors.

It was observed that a smaller vertical distance between wells leave to faster arrival of solvent in producer well, forming a smaller steam/solvent chamber in reservoir, that does not expand well along reservoir surroundings. It does not allow a good mixture of solvent with the oil in the reservoir, resulting in less amount of solvent retained into reservoir. Otherwise, for cases with hot solvent injection (1INJ), it was founded higher amount of solvent retained into reservoir.

To understand the solvent retention in reservoir observed in Figure 6, molar fraction of C7 component (solvent) in oil phase inside reservoir, Figure 7, was analyzed for 10 years of production at the different vertical distances analyzed.

Figure 7 - Molar fraction of solvent in oil phase, injection of 5% solvent.



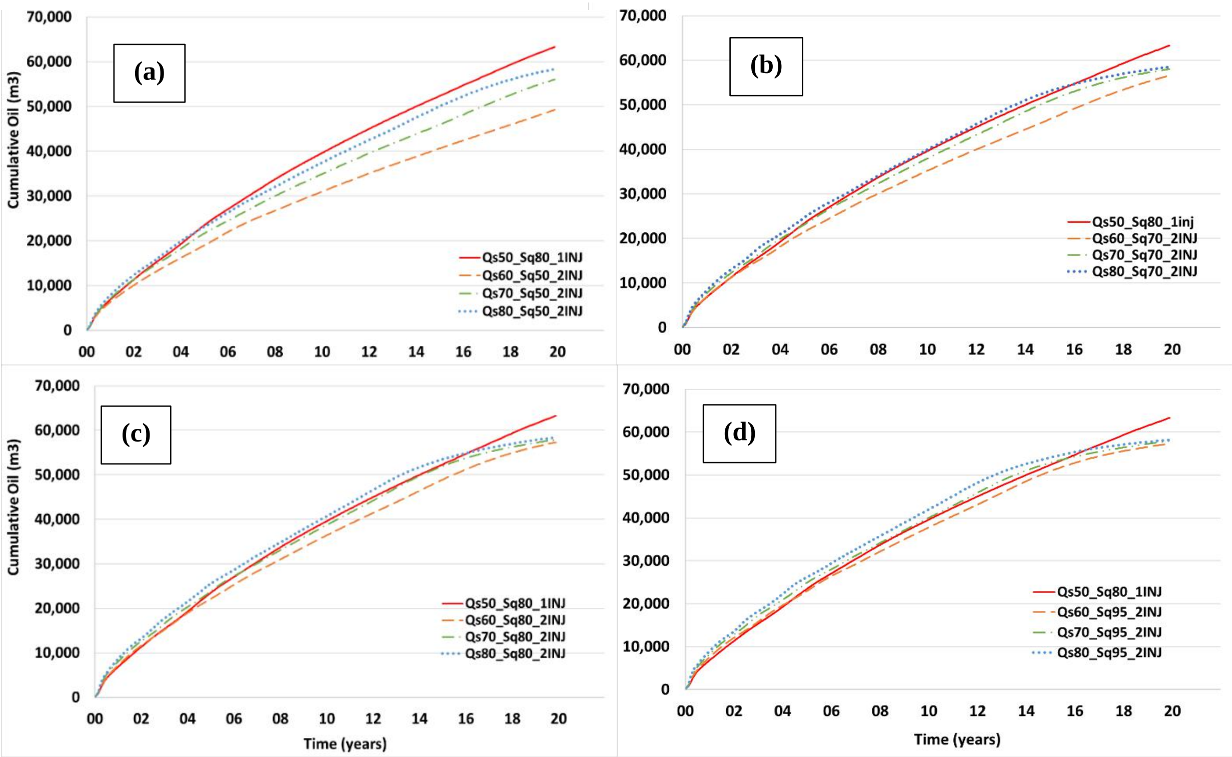
Source: Authors.

On the left side of Figure 7(a), it can be observed that, for model with hot solvent injection (1INJ), a greater amount of solvent remains in reservoir, decreasing cumulative oil of solvent production. While models with cold solvent injection, when vertical distance between the wells is lower, lower the amount of solvent that remains in reservoir. The solvent retention can be harmful, since can be lost to the formation (Chang et al., 2013).

It was necessary to find a similar oil production between the models with hot solvent (1INJ) and cold solvent (2INJ). For this, some changes in operational parameters relative to the steam were realized in order to know which parameters can maintain the average temperature in reservoir. The model with hot solvent (1INJ), used for comparison purposes, has the following characteristics: steam rate=50 t/d, 5% solvent, steam quality, Xv = 80%. This model was compared with different cases with cold solvent (2INJ).

For 2INJ system, several steam qualities were analyzed (50%, 70%, 80%, 95%) combined with different injection rates (60 t/d, 70 t/d, 80 t/d), keeping 2.5 m3 STD of solvent per day. Results are viewed in Figure 8 (a. Xv = 50%, b. Xv = 70, c. Xv = 80%, d. Xv 95%), that show the cumulative oil production (without produced solvent) versus time.

Figure 8 - Cumulative oil (without produced solvent) for cases with cold solvent, (2INJ, 5% solvent) for several steam quality: a) 50%; b) 70%; c) 80%; d) 95%.

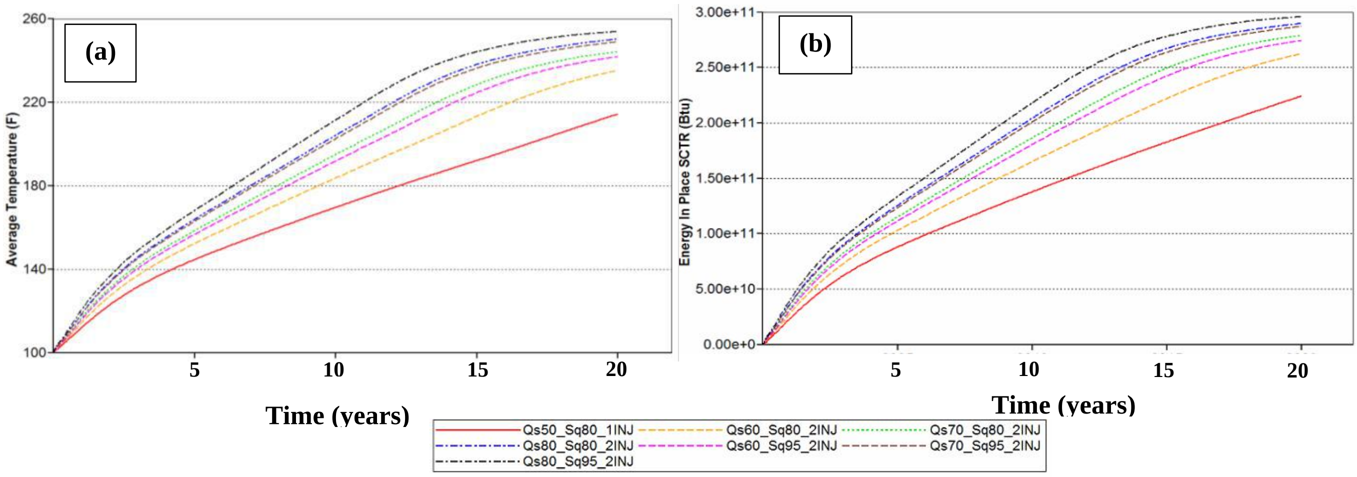


Source: Authors.

Models with steam quality of 70%, 80% and 95%, using a steam rate of 80 t/d have reached a cumulative oil higher than original model, for a period of at least 15 years, having a drop only at the end of production. This shows that steam requirement increases, when is compared models with hot (1INJ) and cold solvent (2INJ), if the same thermodynamic conditions of the system are maintained, in order to maintain or increase cumulative oil (without solvent produced), injecting cold solvent (2INJ). The reduction of steam rate only happens when the solvent is injected at same conditions of the steam.

Figure 9 (a) shows average temperature of the reservoir versus time. Figure 9 (b) shows the energy in place of the reservoir for the new cases.

Figure 9 - Temperature (a) and Energy in place (b) for cases with cold solvent, (5% solvent).



Source: Authors.

It can be observed that it was possible to increase the reservoir temperature and, consequently, the energy in place, keeping the solvent cold (2INJ), using other steam operating conditions. This is important because the solvent was injected cold, its heating could cause explosions, among other risks, and would still increase the energy consumption of the project.

4. Conclusion

Some conclusions can be drawn from this study, and are as follows:

1. In all analyzed cases, the increase in the percentage of injected solvent results in an increase on cumulative oil without produced solvent, independently of solvent temperature injected;

2. The variations in the percentage of injected solvent show that the temperature increase is more significant with the hot solvent (1INJ), therefore there is a higher increase of cumulative oil without produced solvent;

3. For cases with cold solvent injection (2INJ), for lower vertical distance between wells the solvent arrival faster to producer well and less solvent is retained in reservoir. While for the hot solvent injection (1INJ), higher amount of solvent is retained in reservoir;

4. Changes in operational parameters related to steam, such as different steam qualities combined with different injection rates, keeping the cold solvent rate injected, were capable to prove that it is possible to achieve thermodynamic conditions capable of reach or even overcome the cumulative oil without produced solvent of the model with hot solvent;

5. The solvent injection temperature in the Expanding Solvent – Steam Assisted Gravity Drainage process exerts great influence on the cumulative oil without produced solvent. In practice, due to safety issues (explosion hazards from the heating of the solvent), the solvent must be mixed in the well. This generates a cooling of the steam that must be analyzed as it provides results closer to the real ones.

It is recommended to carry out a sensitivity analysis of the reservoir parameters and study the thermal efficiency of the ES-SAGD.

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Nomenclatures

ES-SAGD	Expanding Solvent–Steam Assisted Gravity Drainage
SAGD	Steam Assisted Gravity Drainage
CMG	Computer modelling Group
STARS	Steam, Thermal and Advanced process Reservoir Simulator
Qs	Steam injection rate, t/d
Xv	steam quality, %
Sw	Connate water saturation, %
1INJ	Model with 1 injector well, with hot solvent (at steam temperature)
2INJ	Model with 2 injector wells with cold solvent (at reservoir temperature)
Qs, Qsteam	Steam injection rate (t/d)
Vd5,7,15_1INJ	Vertical distance between wells, (5, 7 and 15 m), with hot solvent
Vd5,7,15_2INJ	Vertical distance between wells, (5, 7 and 15 m), with cold solvent

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