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ПОВЫШЕНИЕ ЭФФЕКТИВНОСТИ МЕТОДА SAGD ПУТЕМ ДОБАВЛЕНИЯ РАЗЛИЧНЫХ ГАЗОВ

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Основная проблема добычи высоковязких нефтей традиционными способами разработки заключается в их низкой подвижности. По этой причине был создан ряд технологий, направленных на добычу высоковязкой нефти, которая в свою очередь составляет значительную часть мировых первичных энергетических ресурсов. Одним из главных механизмов среди этих технологий является нагрев нефти или изменение его состава для снижения его вязкости. И тогда полученная нефть, более подвижная, под действием силы тяжести потечет в сторону добывающих скважин.

Основные положения этого проекта подчеркивают важность проблемы гравитационного дренирования при добыче тяжелой нефти. Рассматривается вопрос, как с помощью гравитации добыть максимальное количество нефти. То есть какую добавку углеводородных газов или CO_2 мы можем рассматривать как улучшающий эффект для гравитационного механизма добычи нефти для определенных условий пласта.

Целью работы является моделирование ES-SAGD, то есть SAGD с добавленным растворителем. Напомним, что целью является повышение нефтеотдачи за счет изменения ее состава и одновременного снижения ее вязкости, например, за счет закачки смешивающегося газа. В различных разделах этой части мы будем исследовать влияние закачки различных растворителей в нашу модель пласта.

В ходе выполнения данного исследования была рассмотрена закачка чистого пара, CH_4, C_3H_8 and CO_2, а также их смесей. Были определены растворители, дающие наибольшее количество извлеченной нефти.

КЛЮЧЕВЫЕ СЛОВА: *VAPEX, Es-SAGD, SAGD, динамическая вязкость, высоковязкая нефть, CO_2, растворитель.*

ТҮРЛІ ГАЗДАРДЫ ҚОСУ АРҚЫЛЫ SAGD ӘДІСІНІҢ ТИІМДІЛІГІН АРТТЫРУ

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Дәстүрлі өңдеу әдістерімен тұтқырлығы жоғары майларды өндірудегі негізгі мәселе олардың төмен қозғалғыштығы болып табылады. Осы себепті тұтқырлығы жоғары мұнайды алуға бағытталған бірқатар технологиялар жасалды, бұл өз кезегінде әлемдік біріншілік энергетикалық ресурстардың айтарлықтай бөлігін құрайды. Бұл технологиялардың ішіндегі негізгі механизмдердің бірі майды қыздыру немесе оның тұтқырлығын төмендету үшін оның құрамын өзгерту болып табылады. Содан кейін алынған мұнай, неғұрлым қозғалмалы, ауырлық күшінің әсерінен өндіруші ұңғымаларға қарай ағады.

Бұл жобаның негізгі ережелері ауыр мұнай өндірудегі гравитациялық дренаж мәселесінің маңыздылығын атап көрсетеді. Гравитацияның көмегімен мұнайдың максималды мөлшерін қалай алуға болады деген сұрақ қарастырылады. Яғни, қандай көмірсутекті газдардың немесе CO_2 қосылуын біз белгілі бір қабат жағдайлары үшін мұнай өндірудің гравитациялық механизмін жақсартушы әсер ретінде қарастыра аламыз.

ES-SAGD SAGD үшін пайдалы мүмкіндіктерді ұсынатын үлгіні жасау үстінде. Мұндағы мақсат – оның құрамын өзгерту және бір мезгілде тұтқырлығын азайту, мысалы, аралас газды айдау арқылы мұнайдың шығымдылығын арттыру екенін еске саламыз. Бұл әртүрлі еріткіштердің әртүрлі модельдік пластиналарға әсер етуіне байланысты.

Бұл зерттеуде таза бу, CH_4, C_3H_8 және CO_2 айдау қарастырылды. Шығарылатын мұнайдың ең көп мөлшерін беретін еріткіштер анықталды.

ТҮЙІНДІ СӨЗДЕР: *VAPEX, Es-SAGD, SAGD, динамикалық тұтқырлық, тұтқырлығы жоғары мұнай, CO_2, еріткіш.*

INCREASING THE EFFICIENCY OF THE SAGD METHOD BY ADDING VARIOUS GASES

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Due to their low mobility in the reservoirs, heavy oils are very difficult to produce by conventional methods. That is why several specific techniques have been created by geoscientists, in order to produce those heavy oils which represent a significant part in the world primary energy resources. One recurrent principle among those methods is to heat the oil, or to modify its composition in order to reduce its viscosity. And then the resulting oil, more mobile flows toward the production wells thanks to the gravity force.

The main problematics of this project are first to highlight the importance of gravity drainage in the production of heavy oil. And after that, how using the gravity to produce the maximum of oil? In other words, with a given reservoir model, what kind of addition of hydrocarbon gases or CO_2 *can we consider as improving effect for gravity mechanism of oil production.*

The goal of this study is to simulate the ES-SAGD, which stands for Expanded Solvent SAGD. Let's keep in mind that the objective is to enhance oil recovery by changing its composition, and meanwhile decreasing its viscosity for example thanks to the injection of miscible gas. Through the different sections of this part, we will investigate the effects of injecting different solvents in our reservoir model.

In the course of the study pure steam, CH_4, C_3H_8 *and* CO_2 *cases and their different mixtures were considered during this research. Solvents that give the largest amount of oil recovered were identified.*

KEY WORDS: *VAPEX, Es-SAGD, SAGD, dynamic viscosity, heavy oil,* CO_2*, solvent.*

Introduction. We call "Heavy oils" are oils that have undergone some bacterial degradation due to surface water invasion. They are characterized by a very high sulfur content (~ 5%), a significant percentage of asphaltenes (~ 15%), high densities (between 10 and 20 °API), and viscosity values which can reach 20000 cP. They are found mainly in Canada and Venezuela, and usually in reservoirs not very deep. The production of these oils is a challenge due to their very high viscosity, density, and sometimes their level of contamination from rocks and other solid debris.

Among those methods we have the "Steam Assisted Gravity Drainage" (SAGD), based on thermal stimulation of the reservoir. This method was developed in the 1970s by Roger Butler. This method consists in using two horizontal wells drilled in parallel, one above the other, and spaced about five meters. Some steam is injected into the upper well and allows heating the oil to reduce its viscosity. And due to the gravity force, the more mobile heavy oil then flows better to the lower well, where it is produced.

Material and Methods in Research. We began to move from our former normal oil (40 cP), to a heavy oil with a much higher viscosity. In fact we are dealing with an oil made of three compounds named “C1”, “C2” and “HEAVY” in the data files. Their respective molecular weights are 250, 450 and 600 g/mol. According to those molecular weights, C1 and C2 are pseudo compounds, so their viscosities in oil should be much higher than the previous values. The *table 1* summarizes the variations we made for those values of viscosity [1, 2].

After those adjustments, we ended up with a total viscosity of 3098 cP for our oil. And this value is more acceptable for a heavy oil than the previous one which was 40 cP.

Since we are dealing with thermal recovery methods of oil, one important parameter is propagating heat throughout the reservoir. So before going further, we had to make sure that our heat injection was going to occur as expected. We decided to inject solvents in the reservoir at the injection pressure 600 psi (41 bar) and with the temperature 500 °F (260 °C). Near the injection well, we reach a maximum value of 375 °F. Of course that heat

Table 1 - **Former and new viscosities in oil, for the pseudo compounds C1 and C2**

	% Total	Mw g/mol	Former µ (75 °C) in cP	New µ (75 °C) in cP
C10	0,6030	250	2.3	2400
C20	0,2614	450	10.6	3850
Heavy	0,156	600	5780	5780
Total	1	362	40	3098

propagation depends on the thermal conductivities of the rocks. So for a real application, according to the nature of reservoir rocks, that plume of heat propagation could be larger or lower than the one observed on *figure 1*.

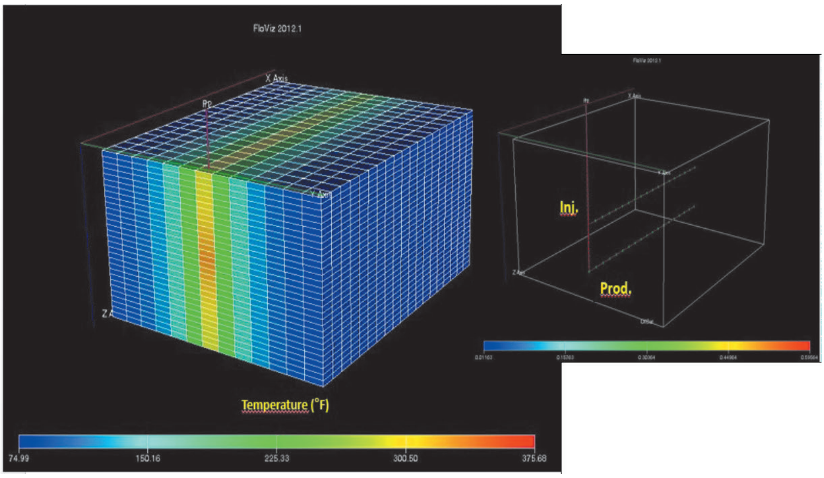

Figure 1 - **Propagation of heat into the reservoir**

Results and discussion.

Difference of efficiency between steam injection and solvent injection

Let's remind that thermal recovery techniques aim to reduce oil viscosity. Among those techniques, we have the classical "VAPEX" method which consists in injecting 100 % of unheated solvent into the reservoir. This method is based on the miscible displacement of oil [3, 4].

Our first step was to compare on one hand the classical SAGD (injection of 100 % of heated steam), and on the other hand the "VAPEX (Plus heat)", which consisted in the injection of the mixture 11 % of steam and 89 % of heated solvent (pure CH_4). We have to notice that for those two processes, the injection temperature will be the same.

The results of this comparison are illustrated below (*figure 2*):

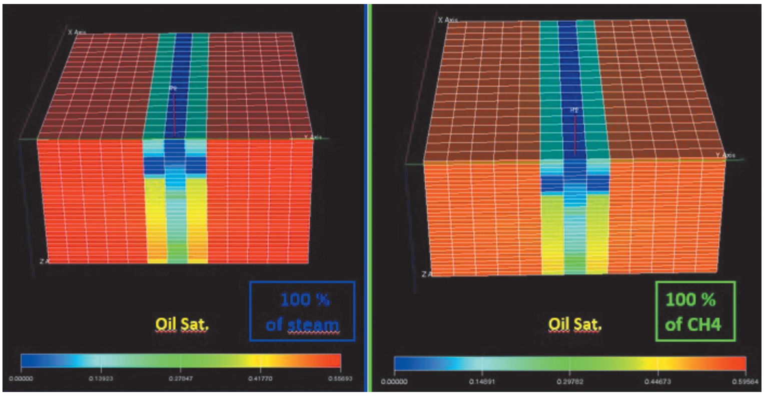

Figure 2 - **Residual oil saturation after 15 years of simulation**

But production data reveals some differences between the SAGD method and the injection of pure heated methane into the reservoir. The *figure 3* shows us the parameters FOPT (Field Oil Production Total) and FOPR (Field Oil Production Rate) for the two techniques:

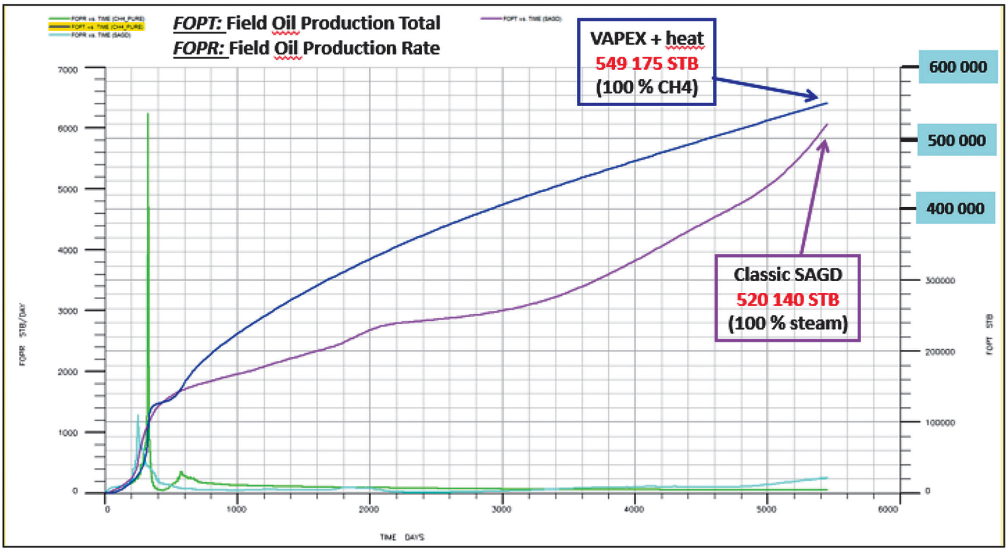

Figure 3 - **Comparison of production data between SAGD and VAPEX (Plus heat)**

After 15 years of simulation, the VAPEX (Plus heat) method gives an additional production of 29 035 STB comparing to the SAGD method (*figure 3*). This is not negligible. But over 15 years, this number represents approximatively an increase of 5.32 STB/day in the daily mean production. That is the reason why we decided not to try the ES-SAGD method. In fact, the principle of this method is to inject in the reservoir a mixture composed of:

- 80 to 95 % of steam;
- 5 to 20 % of solvent.

As mentioned above, by injecting 11 % of steam and 89 % of heated solvent (pure CH4), we didn't obtain a very big difference from the classical SAGD (100 % of steam injected). That led us to think that by comparing the performances of ES-SAGD and SAGD, it could have very little, nay no differences observable [5-7].

That is the reason why all the next sections of simulation results will deal with injection of mixtures containing 11 % of steam and 89 % of heated solvent.

Choosing gaseous hydrocarbons to complete a solvent mixture with CH4

The propane C3H8 cannot be injected alone in a heavy oil reservoir. In fact, as it's said in the article [8], the vapor pressure of propane is almost often lower than the pressure of heavy oil reservoirs. So C3H8 has to be mixed with non-condensable gas like CH4, in order to form a solvent which will stay in gaseous phase under reservoir conditions.

Consequently, in this section we focused on comparing the effects of injecting the two following solvents in our reservoir: the solvent 1 which is the mixture CH4 (50 %) + C3H8 (50 %), and the pure methane CH4 which is the solvent 2.

Firstly, let's have a look to the reduction of oil viscosity:

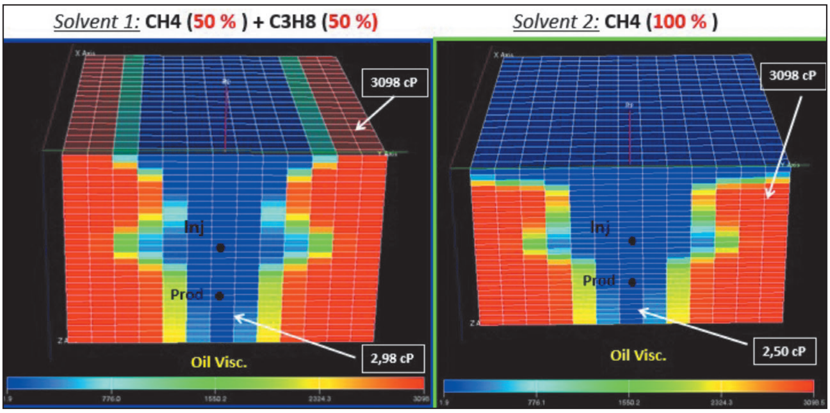

Figure 4 - **Reduction of oil viscosity in the reservoir over 15 years, induced by solvents 1 and 2**

We observe in *figure 4* that the horizontal propagation (around the depth of the injector) is more important than the vertical one. Let's keep in mind that the horizontal permeability (Kh) of our reservoir is 1.5 D, while the vertical one is only 0.5 D.

We also observe on the both images that at the top of the reservoir, oil viscosity forms a sort of chamber. This phenomenon is known for a while, and well described in the articles [9-11].

As we can see (*figure 4*), after 15 years, the solvent 2 (pure CH4) affects the viscosity of oil in a larger number of cells than the solvent 1. So we expect more oil to be mobilize by the solvent 2 than by the solvent 1.

This viscosity reduction is due to the increase of the temperature within the reservoir, but also to the dissolution of solvent compounds into the oil. And those compounds are very much lighter than the compounds of heavy oil.

We remark that the displacement of CH4 into the oil during the process well corresponds to the areas where oil viscosity is reduced (*figures 4*).

Last but not least, let's have a look at the to the residual oil saturation with the *figure 5*:

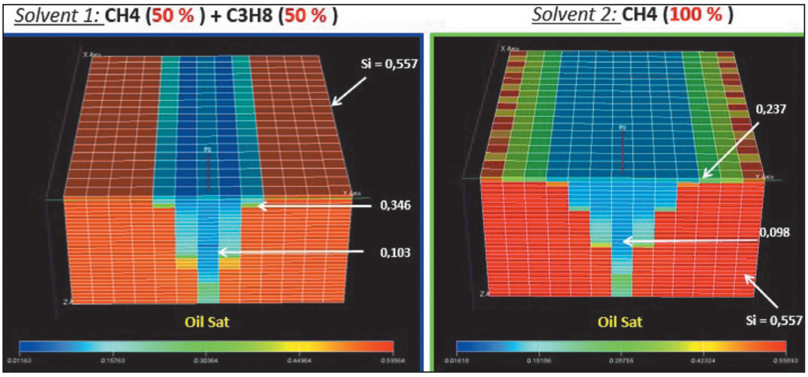

Figure 5 - **Residual oil saturation after 15 years of simulation**

That figure 5 shows that with the pure CH4 solvent, after 15 years of simulation, a greater number of cells in the reservoir model has been affected by the production.

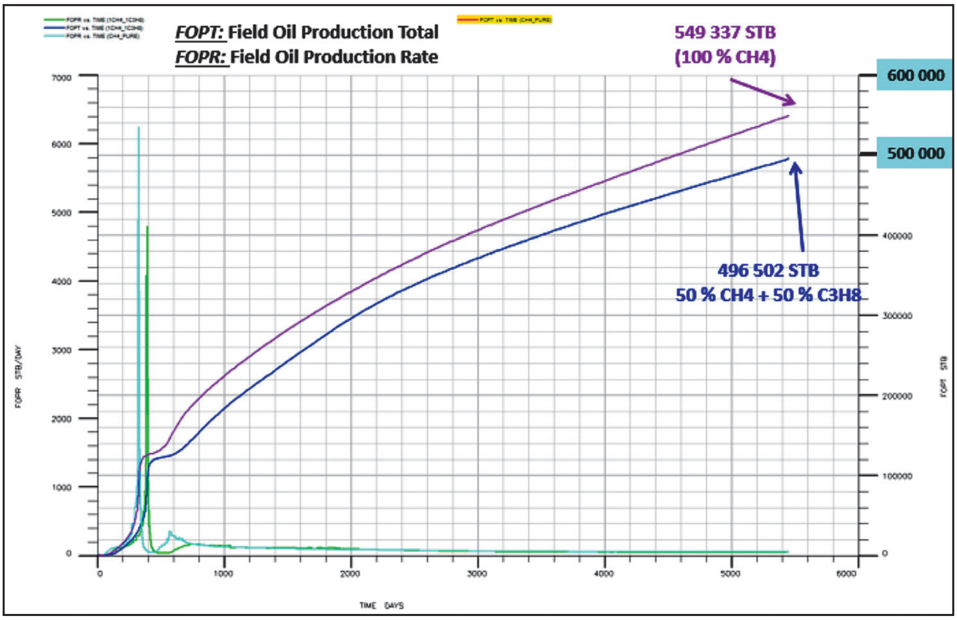

Figure 6 - **Production data over 15 years of simulation, obtained with solvents 1 and 2**

As it was expected, the pure solvent (100 % CH4) gives the highest cumulative production of the two solvents. *Figure 6* highlights that after 15 years, we have 52 835 STB of additional oil produced, which is far from being negligible.

So finally, a solvent made of pure CH4 is obviously better than a mixture CH4 (50 %) – C3H8 (50 %). In fact they have to mix CH4 with another gaseous hydrocarbon cheaper, even if this mixture will yield to a less good production than the injection of pure CH4.

But to what extent is it possible to do save money by mixing other gaseous hydrocarbons with pure CH4?

The limits of economical solvent mixtures

To give an idea of answer to the last question, we compare in this section two solvents both made up of CH4 and C3H8, but mixed in different proportions:

- Solvent 1: CH4 (25%), C3H8 (75 %);
- Solvent 2: CH4 (75%), C3H8 (25 %).

Figure 7 shows us the oil viscosity after 15 years of simulation, with both solvents 1 and 2:

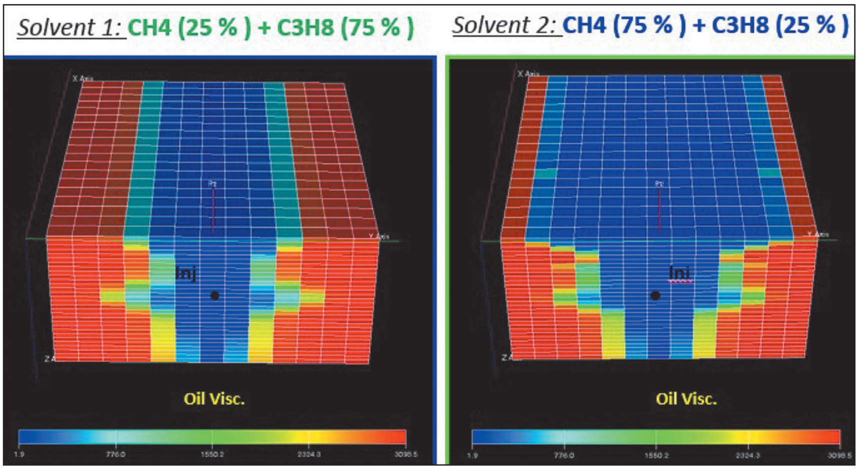

Figure 7 - **Final oil viscosity after 15 years of simulation**

As we can see (*figure 7*), after 15 years, the solvent 2 affects the viscosity of oil in a larger number of cells than the solvent 1. In fact, CH4 is the lighter compounds in those mixtures, so it diffuses better, and it contributes better to the oil viscosity reduction than C3H8.

Figure 8 shows us the residual oil saturation after 15 years of simulation, with both solvents:

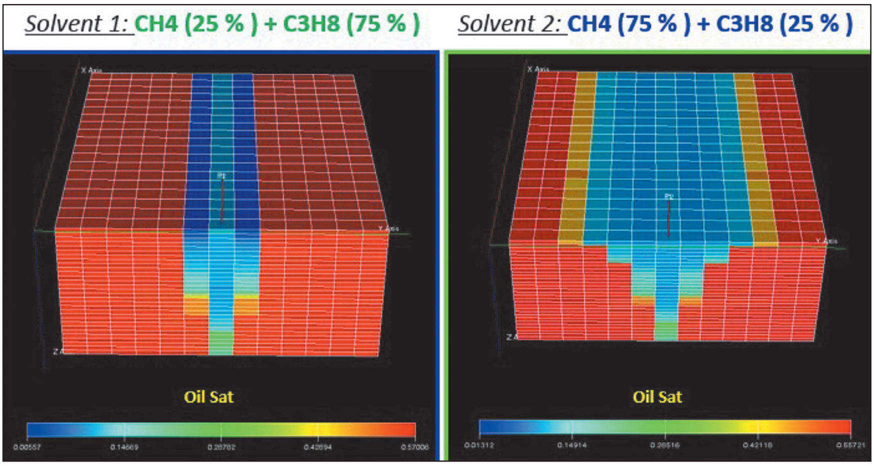

Figure 8 - **Residual oil saturation after 15 years of simulation with both solvent 1 and 2**

Finally, the *figure 9* represents the production data obtained after 15 years of simulation. And as we can see on that figure, the solvent 2 gave better results than the solvent 1. We are talking about an additional production of 55 008 STB over 15 years, which is once again non negligible.

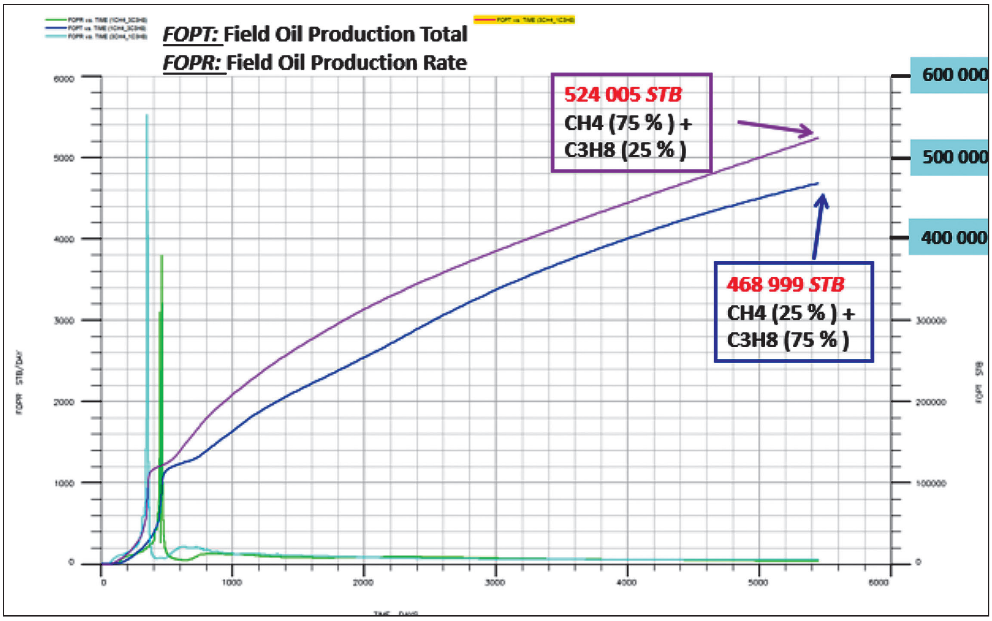

Figure 9 - **Production data over 15 years of simulation, obtained with solvents 1 and 2**

Those results show an important fact: even if we want to make some savings by mixing CH4 and C3H8 before injecting the resulting solvent into the reservoirs, the relative proportions of those compounds in the mixture have to be optimized. Because as we have seen, the more we have CH4 in our mixture, the more the production is enhanced. Injecting a solvent containing more C3H8 than CH4 would be quite cheap, but the amount of oil to be recovered will not be extraordinary. So, there is a compromise to make before choosing a solvent composition.

Incorporating CO2 in solvent mixtures for heavy oil recovery

Recently the idea of incorporating CO2 into solvent has emerged. In fact geoscientists believe that this incorporation of CO2 is going to make the recovery process more economical, more environmentally and technically attractive [12]. The first reason is that CO2 is cheaper that the gaseous hydrocarbons like CH4, C2H6, and C3H8. The second reason is that CO2 has a higher solubility into heavy oils than hydrocarbons gases. And the first reason is that this option would be a good way to get rid of some amount of the CO2 present in the atmosphere [13-15].

That is why we decided to make some simulations with CO2 based solvents. Our first step was to compare:

- Solvent 1: CO2 (50 %) + CH4 (50 %);
- Solvent 2: CO2 (50 %) + C3H8 (50 %).

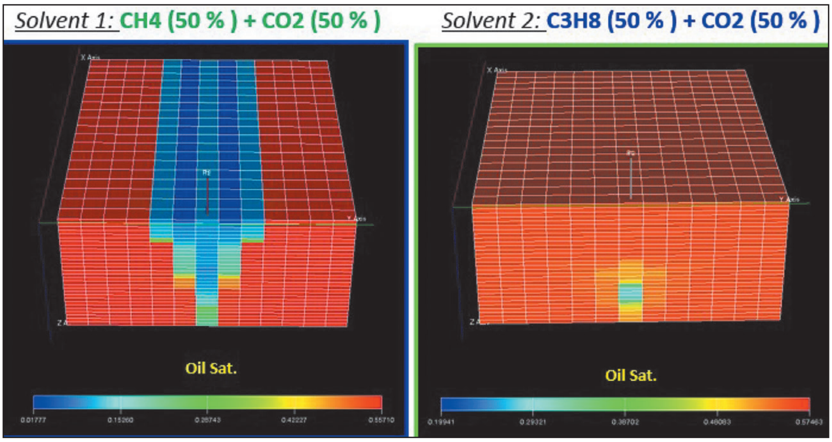

Figure 10 - **Residual oil saturation after 15 years of simulation with both solvent 1 and 2**

The *figure 10* shows that with the solvent 2, the oil saturation is almost only reduced around the producer well. On the contrary, with solvent 1, the plume of oil saturation reduction is larger, and more cells of the reservoirs are affected by the production. We know that CO2 is more soluble into heavy oil than both CH4 and C3H8. So those observations seem to show that the displacement of CO2 is easier in presence of CH4 than in presence of C3H8. And indeed, CH4 diffuses much better than C3H8 does.

The *figure 11* shows a comparison between residual oil saturations and solvent displacements for our two mixtures. On this *figure 12*, on the left we can see that with the solvent 1, the oil viscosity is reduced on a large zone. That zone extends itself around the injector both vertically and horizontally, and it reaches well the top of the reservoir.

That hypothesis is verified by the parameters XMF (fraction in liquid phase) of CH4 and C3H8 represented on the right in *figure 11*. The plume of XMF (CH4) is very similar to the plume of the residual oil saturation discussed previously. On the other side, XMF (C3H8) shows that this compounds mostly moves along the horizontal direction.

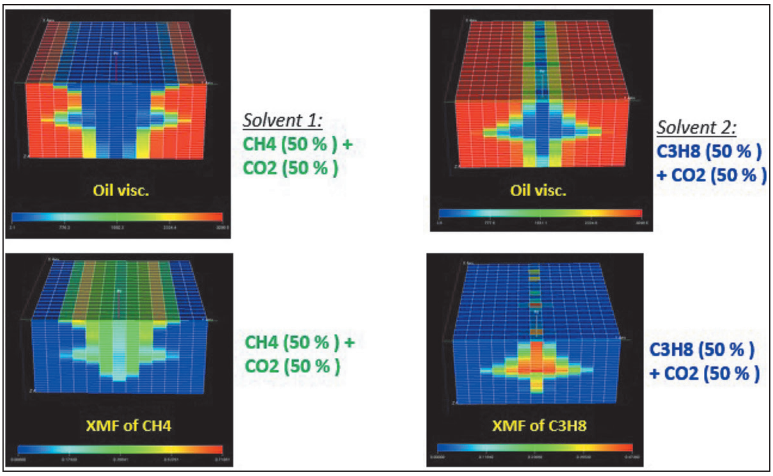

Figure 11 - **Oil saturations and solvent displacement after 15 years of simulation**

So CH4 diffuses easier than C3H8 into the reservoir. But C3H8 dissolves better into the oil and propagates mostly horizontally than vertically.

Now let's have a look to the production data, shown in *figure 12*:

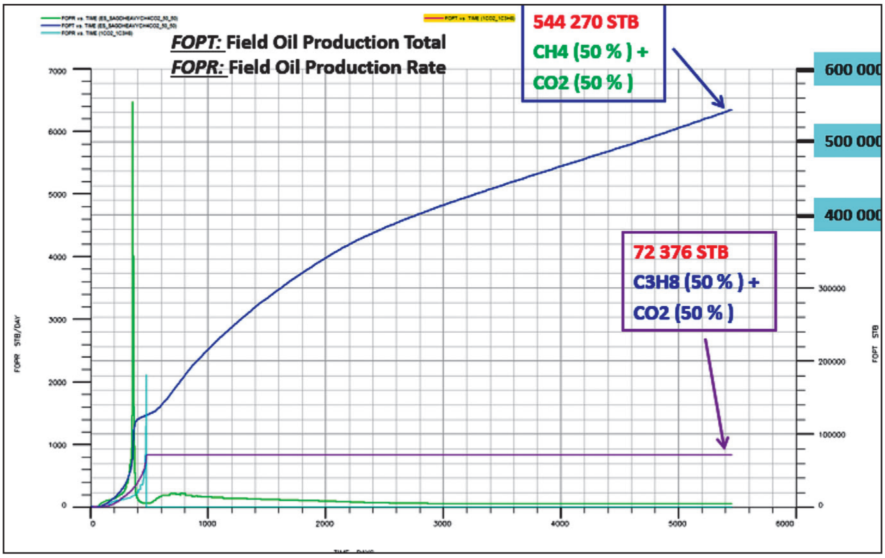

Figure 12 - **Production data over 15 years of simulation, obtained with solvents 1 and 2**

In *figure 12*, except the FOPT curves, we have also plotted the FOPR (Field Oil Production Rate) curves. On those curves, approximatively after 375 days of simulation, we can see a brutal increase on the FOPR curves. This phenomenon corresponds in fact to a percolation threshold.

Indeed, the steam/solvent injected goes progressively from the injector to the producer. Between the two wells, oil is more and more viscous when we move from the injector to the producer.

This is why at this exact moment we have a sharp increase in the production rates with both solvents. Until this heavy oil becomes less viscous enough to flow, the production rates decrease as observed on the *figure 12.*

When we look at the FOPT (Field Oil Production Total) after 15 years, we managed to recover 471 894 STB of additional oil with the solvent 1 (50 % of CO2 + 50 % of CH4). This is a tremendous difference of production.

Choosing the right ratio CO2 / gaseous hydrocarbons

In this last section, we decided to make some simulations with CO2 based solvents. Particularly, we compared the two following solvents:

- Solvent 1: CO2 (75 %) + CH4 (25 %);
- Solvent 2: CO2 (25 %) + CH4 (75 %).

At first glance on the *figure 13*, the solvent 2 seems to reduce more the oil saturation than the solvent 1. In fact, with solvent 2, more cells of our reservoir model are affected by the production, comparing to the image corresponding to solvent 1.

But the reality is that solvent 1 has a greater influence than solvent 2 in the recovery. In fact, CO2 is in abundance into solvent 1, and we know that CO2 is more miscible into heavy oil than CH4. So even if solvent 1 affects a very low number of cells than solvent 2, it allows a very good sweep of those cells, and yield to a higher production, as we will see later.

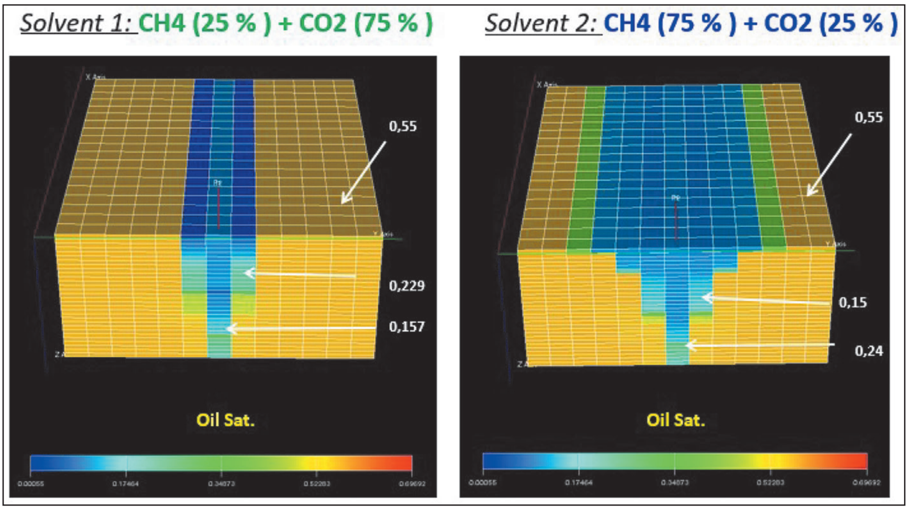

Figure 13 - **Residual oil saturation after 15 years of simulation with both solvent 1 and 2**

Finally, *figure 14* shows us the production data for solvent 1: CO2 (75 %) + CH4 (25 %), and solvent 2: CO2 (25 %) + CH4 (75 %).

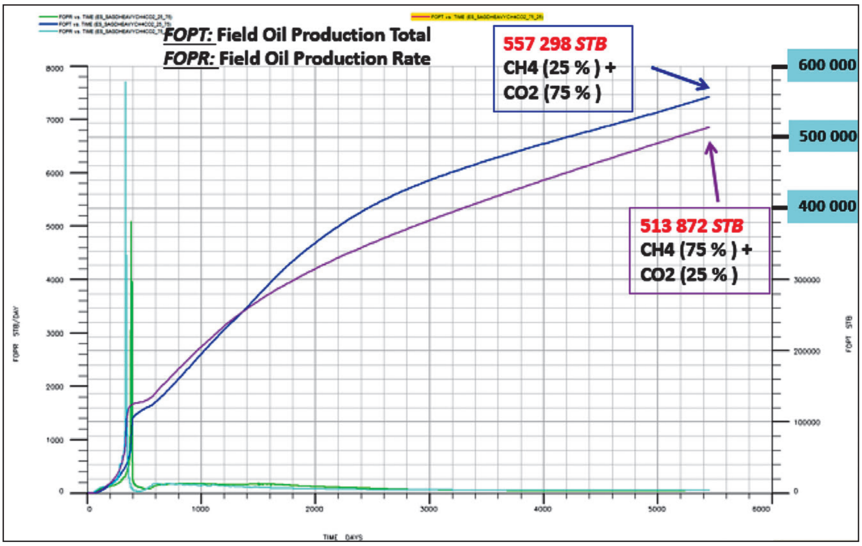

Figure 14 - **Production data over 15 years of simulation, obtained with solvents 1 and 2**

The FOPT curves show that at the beginning of the simulation, the solvent with 75 % of CH4 gives more oil recovered than the solvent with 75 % of CO2. This is because CH4 propagates very quickly and affects more oil than CO2, and consequently solvent 1 gives better results than solvent 2 during the early times of simulation.

But as we can see, in the long-term, the solvent 1 (75 % of CO2) gives better results. And this is because CO2 dissolves better into heavy oil than CH4. The solvent 1 yield to a better reduction of oil viscosity, and consequently a better amount of oil produced.

Conclusion

During this project, we have seen that injecting a hot pure solvent (CH4) into the reservoir gives better results than the classical method SAGD (100 % of hot steam). The pure solvent CH4 gives better productions than a mixture between CH4 and C3H8 for example. But injecting pure methane is very expensive, so it has to be mixed by other hydrocarbon gases cheaper like C3H8.

But as we have seen, in a mixture CH4-C3H8, it's very important to optimize the relative proportions of those two compounds.

To increase the efficiency of heavy oil recovery, it's possible to incorporate CO2 in the solvent mixture. In fact, CO2 is cheaper, and more soluble into heavy oil than hydrocarbon gases. And this operation has an environmental advantage, to get rid of a certain amount of CO2 present in the atmosphere.

Finally, we have seen that the mixture CO2-CH4 gives better results than the mixture CO2-C3H8. And in the mixtures CO2-CH4, having CO2 in abundance is preferable, because it gives better results than a solvent in which CH4 is in abundance.

Finally, it could be interesting to investigate the effect of gravity drainage in mining wells, by using the "real" heavy oil with 3098 cP of viscosity, rather than the oil with 40 cP, used during the first part of this project.

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