Combining Hot Water Injection-solvent and Electromagnetic Heating For icreasing Recovery Factor In Heavy Oil Reservoir

by Suranto Am

COMBINING HOT WATER INJECTION-SOLVENT AND ELECTROMAGNETIC HEATING FOR INCREASING RECOVERY FACTOR IN HEAVY OIL RESERVOIR

SURANTO
Lecturer in Petroleum Department, UPN "Veteran" Yogyakarta

Abstract

The use of electromagnetic-heating methods in reducing heavy oil viscosity, until now, is not popular as steam injection methods, although it has been researched, possibly since 1986 by Hiebert. The first virgin application in the field was in 1988, Spark Formation in the Frog Lake area. However, this method in our present time is underused, even though its technology is environmentally friendly and space efficient.
This research aims to build an optimized model for an electromagnetic-heating method, combined with of hot-water. The electromagnetic-heating will expand the reservoir fluid volume but is still not enough for reservoir pressure maintenance. On the other hand, if too much water is injected, the water will absorb most of the heat, causing the heating of oil to be decreased. In this case, water will be used to transfer energy from electrical to the oil.
In this study, the combination of hot water and electromagnetic-heating of Duri heavy oil was analyzed by CMG Stars. The model was built with a seven-spot well inverted pattern, where distance between wells is at around 246 ft, and the injection well was placed in the center. The sensitivity parameters tested were hot water injection rate power of electromagnetic-heating.
From the base-case model, it was shown that electromagnetic-heating method produces about 2.5 % OOIP (due to the reservoir pressure being very low). However after further study, the optimum case, a combination of electromagnetic-heating coupled with hot-water, was able to increase the recovery factor to about 37% of OOIP. Moreover, this study has shown that the oil density is a dominant factor which affects the oil recovery.

Keywors : *electromagnetic-heating, heavy oil, hot water injection, reservoir simulation.*

Abstrak

Penggunaan metoda pemanasan listrik untuk menurunkan viskositas minyak berat, sampai sekarang, tidak sepopuler dengan penggunaan injeksi uap, walaupun method ini sudah dilakukan penelitian, sejak tahun 1986 oleh Hiebert. Pertama kali menggunaan metoda ini pada tahun 1988, di Formasi Spark di area Frog Lake. Walaupun demikian, metoda ini sampai sekarang masih langka, meskipun secara teknologi ramah lingkungan and memerlukan tempat yang sedikit.
Penelitian ini membuat optimasi pada metoda pemanasan listrik, dikombinasikan dengan air panas. Pemanasan listrik akan membuat pengembangan volume fluida reservoir tetapi ini masih belum cukup untuk memelihara tekanan. Di sisi yang lain, jika terlalu banyak air yang diinjeksikan, air akan menyerap panas lebih banyak, menyebabkan pemanasan yang diterima oleh minyak menjadi lebih sedikit. Dalam hal ini, air digunakan untuk mentransfer energy dari listrik ke minyak mentah.
Di studi ini, kombinasi antara injeksi air panas dan pemanasan listrik, minyak dari Duri, dianalisa dengan software CMG-Stars. Model dibangun dengan satu sumur injeksi dikelilingi dengan 6 sumur produksi, dimana jarak antara sumur injeksi dan produksi sekitar 246 kaki, dan sumur injeksi terletak di tengah. Sensitivitas parameter di test terhadap laju injeksi air panas dan daya dari pemanasan listrik.
Dari model dasar, ditunjukkan bahwa penggunaan pemanasan listrik memproduksikan sekitar 2.5% OOIP (karena tekanan reservoir sangat rendah). Tetapi studi lebih lanjut, pada kasus yang optimum, combinasi pemanasan listrik dan injeksi air panas, meningkatkan factor perolehan hingga 37% dari OOIP. Selanjutnya, dalam studi ini menunjukkan bahwa, densitas minyak mentah merupakan factor yang dominan dalam factor perolehan minyak.

Keyword : *electrical heating, heavy oil, water injection, solvent, reservoir simulation.*

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INTRODUCTION

The key of heavy oil and bitumen producing is reducing of viscosity. There are some methods to reduce oil viscosity such as steam injection, hot water injection, cyclic steam injection, and the others. The electrical heating is one of the ways to reduce viscosity.

AD. Hiebert et.al (1986) have made electrical heating formula for numerical model. Electromagnetic heating technique is to heat the reservoir by means of the ohm losses of electrical current flowing in the connate water and the oil of the reservoir. The research is to build electrical heating which needs power, voltage and frequency. This case uses low-frequency (60-Hz [60-cycle/sec]). Electrical excitation of the formation must be specified as constant voltage, power, or current level. The electrical conductivities, heat capacities, and thermal conductivities of the various physical model media, together with the model geometry and appropriate voltage, current or power level, are entered into the simulator. This research uses MEGAERA numerical simulator after modified. Furthermore, the CMG simulator specially stars module is added the Hiebert's formula[6].

In 2008, Jie Wang et. al investigated that in-situ water vaporization improved bitumen production. A water vaporation can transfer effectively the heat from electrical heating to the oil. In electrical process, the enter formation water acts as an electric circuit because the formation water is ionically conductive. When the formation water is heated up to the saturation temperature at the corresponding pressure, it vaporizes into steam. This volume expantion should push more bitumen out of the reservoir and then, the pressure shock generated by gas expansion could be much stronger than the drainage capillary pressure required to displace bitumen off the pore place.

K. Visome (1988) used electrical heating to modeling in the field with modified Tetrad. In this case, the electrical heating has done in Sparky formation in the Frog Lake Area and completed for electrical heating in June 1988. The production increased over than 12 m^3/day by using the input power during stimulation averaged 15 kW.

Bernd Wacker (2011) gave the rood map to step by step to build the electromagnetic heating in the field. In this case, he showed how to build the electromagnetic in field and how to make the arrangement in the well of electromagnetic heating.

In this paper, we study how to make efficiency of the electrical heating in reservoir. There are many factors which can support to transfer electrical energy to reservoir, i.e. water saturation, water salinity, capacity and conductivity reservoir.

On the other hand, the expansion of volume liquid reservoir by heating is not enough for pressure maintenance. Because of that, reservoir pressure will dramatically decrease. To maintain the reservoir uses water injection. If the heat can generate steam of all water injection so the process will be in good condition. The opposite here, the energy of electrical heating is not enough to make the water into steam, so that, the energy from electrical heating will be consumed water very much. To minimize this case, an hybrid of solvent –water injection is used to improve heat go through to crude oil and the solvent will accelerate viscosity reduction.

The propose of this study is using of different heat capacity of water and solvent. The heat capacity of water is higher than solvent. The function of solvent is to maintain pressure, while the water is used as media transfer from electrical heating to crude oil. If the injection of water is very high, then the water will highly consume heat. Therefore, the heat in crude oil will decrease and of course this effect is not good for the process. If the solvent is added to water, the heat into the water will decrease and the heat into crude oil will increase. The important idea of this research is to maximize heat into the crude oil. Moreover, if the solvent is very much to be injected so the mobility ratio of crude oil and solvent is very small, so that the sweeps efficiency will decrease. Beside, the goal research is to make optimization of injection rate solvent and water composition.

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METHODOLOGY

A novel electrical heating of Athabasca oil sand was analysed by CMG STARS. The model is built with five pattern sport wells. One well in the center is as injection and the other wells are as production. The boundary of model is no-flow and the bottom of reservoir is without water influx. The electrode is posted in all wells including production wells. Furthermore, all reservoir thickness post electrode and the well perforation is all of net reservoir thickness. In this case, the negative electrode is assembled in production well and the positive electrode is posted in the injection well. Hopefully, the heat can be connected from injection well to production wells. The round of production well is about 246 ft and production well to injection well is about 174 ft. The electrical heating uses frequency 60 Mhz and total power in the field is about 175 kWatt and the voltage 220 volt.

RESERVOIR SIMULATION

This model is used to understand propagation of lateral heat, absorb of electrical power in reservoir and recovery factor . The general data for reservoir modeling shows in Table 1. Furthermore bitumen and heavy oil viscosity are shown in figure 1. The calculation of crude oil viscosity at 15 API and 20 API uses Winprop from CMG simulator with PVT basic model and the graphic curvature follows the Athabasca model. However, some oil fields have specific correlation to calculate viscosity but it uses general correlation. Figure 2 shows relative permeability water-oil and figure 4 shows relative permeability oil-gas. Actually, the relative permeability has specific value in each reservoir. In this study, this variable is as espousal reservoir model and it is not sensitivity. Reservoir temperature was monitored to know the spreading of electrical power in reservoir and impact of movable oil saturation. Initialization of model got OOIP about 0.21 MMSTB and water 37 MSTB. The assumption of this model was dead oil and excluding gas saturation so as the reservoir model was free gas. The scheme of model is shown in Figure 3.

In the first time, preheating was done on the model about 6 month to reduce bitumen viscosity near bore hole. Effect of this case, the crude oil will be easy to move from reservoir to bore hole. All wells were produced for 6 month to drain oil near bore hole especially well in the center. After that, the center well was used as injection well. The production wells were constrained with Pwf about 50 psi and the production rate maximum was no constraint. The injection pressure was constrained with about 430 psi and the rate of maximum injection was no restraint. The wells produced from 2012 until 2035 for bitumen and heavy oil with density 15 API, while, heavy oil with density 20 API is only until 2025. The oil rate limit of all scenarios was constrained about 5 STB/day.

Tabel 1.
Input parameters for reservoir model
(Modified from M Tavallali,2011)

Parameter	Value
Ney Pay, ft	66
Depth, ft	820
Permeability, Kh	5000
Kv/Kh	0.8
Porosity,%	0.34
Initial Pressure, Psi	290
Initial Temperature, ^{o}F	52
Oil saturation	0.85
Compressibility (1/psi)	

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Oil	3.15E-06
Water	4.72E-06
Rock	3.45E-05
Specific heat (BTU/(lb-◦F))	
Oil	0.1999
Water	0.9673
Rock	0.5804
Thermal Conductivity (BTU/ft-day ◦F)	
Oil	2.9217
Water	10.9913
Rock	35.6174
Overburden	27.8261
Bitumen Dencity @ TR, kg/m3	999.3

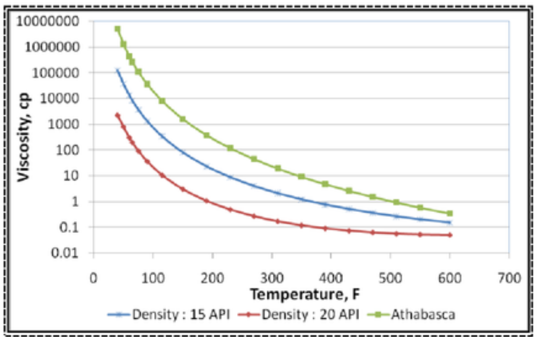

Figure 1.
Viscosity of bitumen and heavy oil
(*Modifield from J Wang, 2008*)

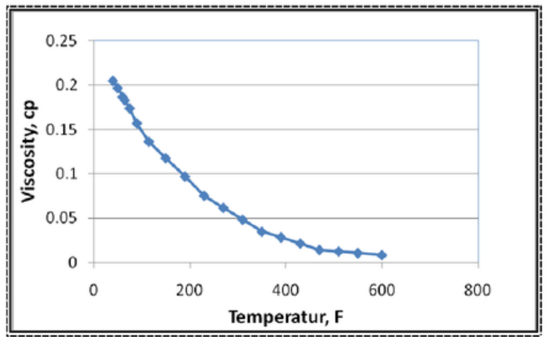

Figure 2.
Viscosity of Solvent

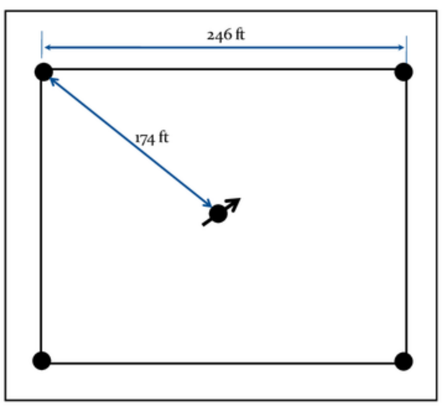

Figure 3.
Scheme of reservoir model

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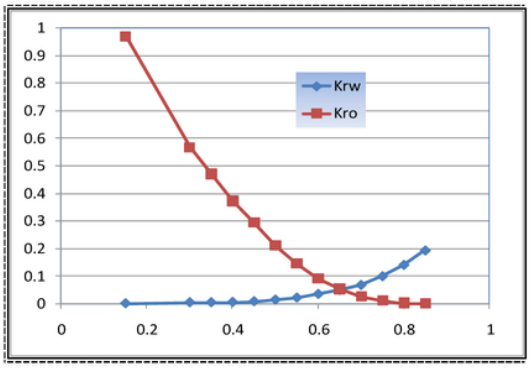

Figure 4.
Relative permeability of water-oil

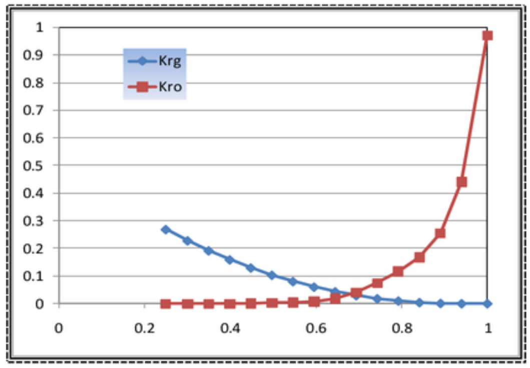

Figure 5.
Relative permeability of gas-liquid

DISCUSSION

Scenario of this study consist of base case, oil density of 15 API, and oil density of 20 API. The base case uses Athabasca filed data and the other case was change of crude oil density. The change of density is to analysis effect of recovery factor. Each scenario uses the same production operation but the solvent water ratio was different.

Base Case

This model is basic of all analysis. Figure 6 shows that the recovery factor will be different with changing of ratio solvent-water. Without solvent, the recovery factor is about 34%. However, if the water injection is added by solvent, the recovery factor will increase. The optimum case has ratio solvent-water about 22% and then, the recovery factor will get about 37%. If the ratio of solvent-water is enhanced, the recovery factor will decrease, for example ratio solvent-water of 24%. The mixing of solvent and water as injection fluid causes the reservoir can maintain pressure and the heat from electrical minimum loss. Furthermore, if the ratio solvent-water is high, the water viscosity will be down and the mobility water will increase. In other, this process could optimize ratio solvent-water.

On the other hand, if the reservoir did not do the injection, the recovery factor would be only 2.5%. This case was caused by decreasing of the pressure dramatically. Another case, if the reservoir was injected by water, the pressure would be maintained.

The electrical power of all scenarios was not full in 175 kW, especially before 2026. After 2026, the electrical power has full value (Figure 7). The different condition of this case is reflected in figure 8 and Figure 9. In 2025, the reservoir was not fully connected by water injection. After 2026, reservoir was fully connected by water injection. The minimum water saturation causing fully connected was about 35%.

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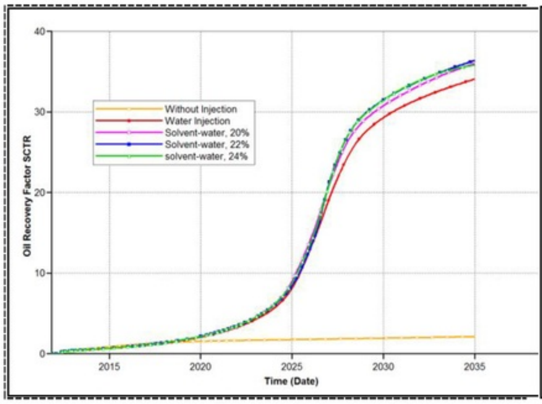

Figure 6.
Recovery factor Vs Solvent composition

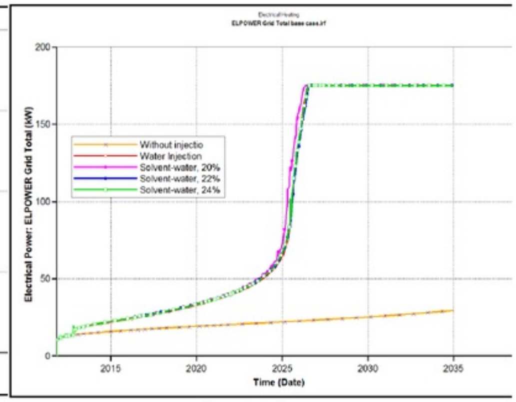

Figure 7.
Electrical Power grid total Vs Time

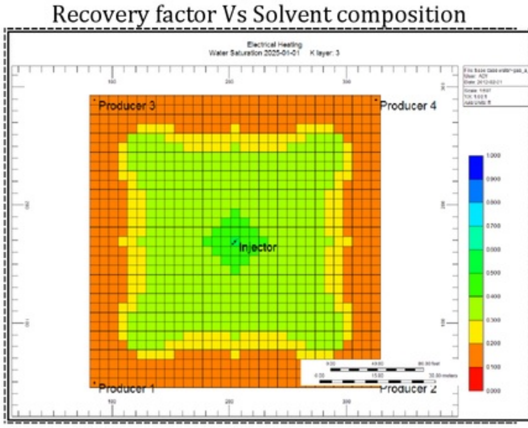

Figure 8.
Water saturation distribution in 2025

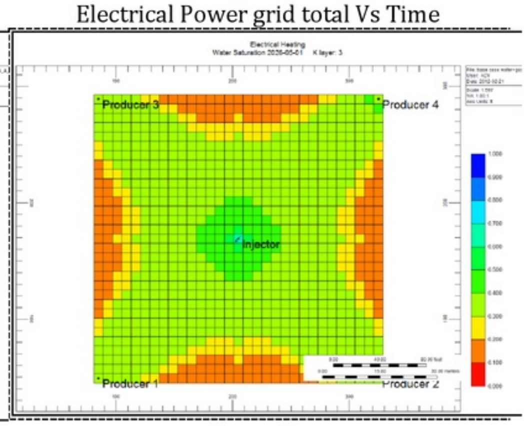

Figure 9.
Water saturation distribution in 2026

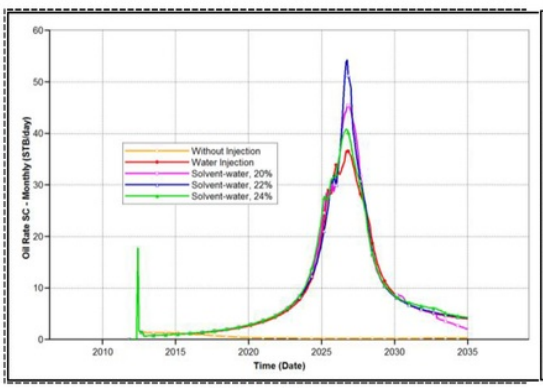

Figure 10.
Oil rate vs Solvent composition

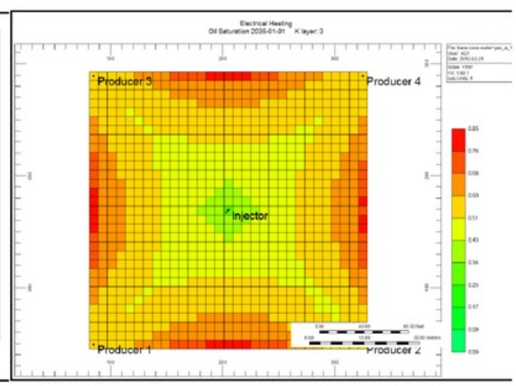

Figure 11.
Oil saturation distribution in the end production (2035)

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The oil production rate was very small after preheating. This condition is caused by effect of not full power in electrical heating. As can be seen in Figure 7, the electrical power has correlation with production rate. In 2012 until 2025, the electrical heating is not maximum so the rate production is the same. In 2026, the pick production is accured in the wells, but in 2027, the production rate will decline. This case, the water injection has arrived in production wells. After that, the oil saturation will gradually decrease especially in line of injection well to production wells (Figure 9).

In the first time, the temperature of reservoir is about 51 ^{o}F. By the time, the temperature will gradually rise due to electrical heating. At the end of electrical heating process, the part of reservoir temperature is about 150 ^{o}F (Figure 12). In this case, the electrical heating only generates hot water instead of steam.

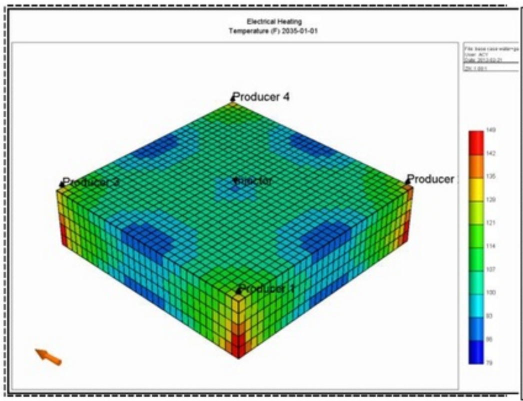

Figure 12
Temperature Distribution in 2035

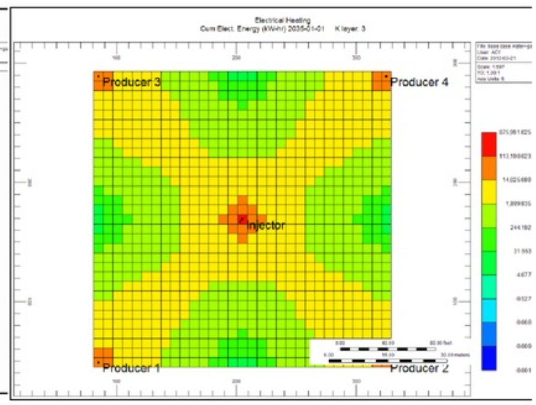

Figure 13.
Cummulative electrical energy distribution in the end production (2035)

Oil Density 15 and 20 API

This scenario uses oil density 15 and 20 API. The research aims to know the effect of the density change. As can been seen, the bitumen recovery got about 37% after producing about 23 years. After the density was changed with 15 API, the recovery factor increased until more than 50%. If the solvent-water was injected together, the recovery factor increased to about 2% compared without solvent. This case has difference about 2% with bitumen Athabasca. The condition of oil density of 15 API was better than bitumen. Furthermore, if the recovery factor of 15 API densities was compared with density of 20 API, the value was very different. The recovery got about 68% in density oil of 20 API and only needed about 13 years (Figure 14). But after the solvent was added to water injection, the effect of solvent was not significant. So, if the oil density decreased, the effect of solvent would decrease. Thus, the solvent could not improve oil recovery if the oil density was more than 15 API.

Effect of preheating, in the oil density of 15 and 20 API was very different. In the density oil of 15 API, oil rate after preheating was about 35 STB/day, while for density oil of 20 API, the oil rate was about 90 STB/day The effect of water injection was very significant for oil density of 20 API. After production in preheating process, the production rate droped almost zero. However, the production rate would increase after water injection.

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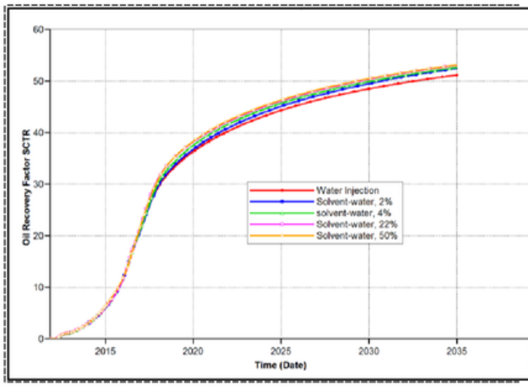

Figure 14.
Recovery factor Vs solvent composition at density oil 15 API

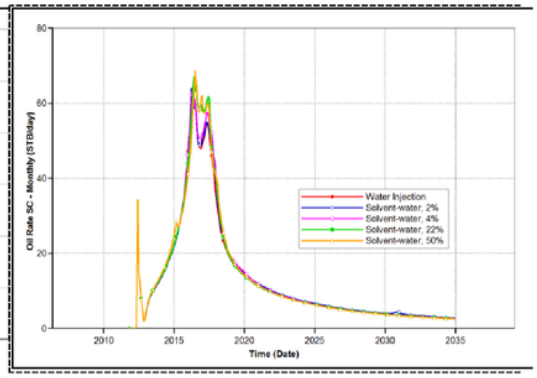

Figure 15.
Oil Rate Vs solvent composition at density oil 15 API

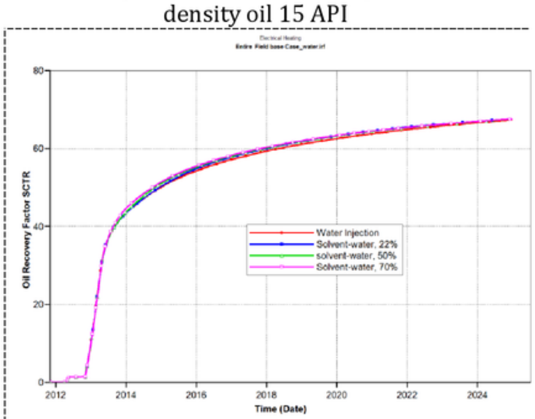

Figure 16.
Recovery factor Vs solvent composition at density oil 20 API

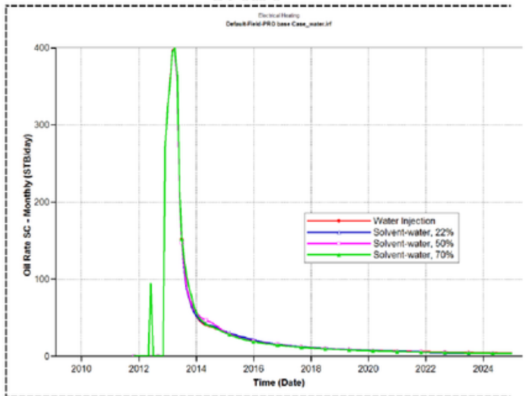

Figure 17.
Oil Rate Vs solvent composition at density oil 20 API

Table 2 shows the summary of all good scenario. The hybrid solvent-water will effective in bitumen and the density less than 15 API. Otherwise, the density more than 20 API will not effective again.

Table 2.
Summary of all good scenarios

No.	Description	Production time	Oil Type	Recovery factor
1	Base case (without injection)	23 years	Bitumen	2.5 %
2	Water Injection	23 years	Bitumen	34 %
3	Water injection (solvent –water : 22%)	23 years	Bitumen	37 %
4	Water Injection	23 years	15 API	51 %
5	Water injection (solvent –water : 22%)	23 years	15 API	53 %
6	Water Injection	13 years	20 API	68 %

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CONCLUSIONS

Base on the previous description and discussion can be summarized as follow :

1. A novel electrical heating method is one of alternative to produce bitumen and heavy oil. To improve oil recovery, the pressure should be maintained with water. Adding of solvent in the water injection will improve oil recovery.
2. The bitumen injected by water has recovery factor about 34%. If the solvent is added to the water by composition about 22%, the recovery factor will increase to 37% for 23 years.
3. For the sensitivity of density in the model, it shows that the density oil of 15 API has recovery factor about 51% and, if the solvent-water is added by 22 %, the recovery factor will improve about 53% for 23 years. The condition is different with density oil of 20 API. For 13 years, the oil density of 20 API has recovery factor about 68 %.
4. A hybrid solvent-water injection will be effective for the bitumen. If the density id more than 15 API, the solvent-water will not effective again.
5. A novel electrical heating method will be effective and strongly recommended in the oil density around 20 API.

NOMENCLATURE

API = American Petroleum Institute
Pwf = Pressure well flow
PVT = Pressure volume temperature
So = oil saturation
Sw = water saturation
kW = kilo watt
μ = Viscosity, cp
T = Temperature, ^{o}F

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