A New Technique for Recovering Heavy Oil and Tar Sands

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A non-conventional enhanced oil recovery technique is proposed for recovering oil from tar-sand and sand reservoirs. This technique involves the use of electromagnetic heating with horizontal wells along with water injection, gas injection or primary depletion. This technique eliminates one of the bigger technical problems with conventional steam injection in the North Slope area of Alaska. The existence of a large permafrost region in North Slope reduces the effective heat that can be transmitted to a reservoir, even with insulated tubing. Applying the heat with a downhole device, such as electromagnetic heating, is a much more efficient process than conventional thermal recovery techniques. The presence of a horizontal well allows one to eliminate the problem of a small heating radius and a large area may be conducted even when the heating radius is small. Also, a horizontal well, particularly one located at the bottom of thick sand with vertical permeability, allows gravity drainage of a much larger reservoir volume. This paper presents numerical simulation results of such a process for Alaskan tar sand reservoirs using a horizontal well simulator. Various options, such as gas injection, waterflooding, etc., are investigated along with electromagnetic heating. Numerical simulation results show oil recovery to be as high as 60% of the oil in place for tar sands. The recovery is even higher for heavy oil of moderate viscosity. Finally, a numerical run, using steam-assisted gravity drainage, is conducted for comparison. The new scheme presented in this paper showed much higher efficiency than the steam-assisted gravity drainage process.

INTRODUCTION

The state of Alaska is estimated to contain some 70 billion barrels of oil in place. More than 50% of this reserve is in the form of heavy oil and tar sand in the Alaskan North Slope [1]. Some 15 billion barrels of this reserve is in the form of tar sand in the Ugnu reservoir of the North Slope of Alaska.

With the recent decline in oil production from convectional light oil reservoirs, there is a need to develop techniques for expanding oil production from other oil resources. One such resource is the tar-sand reservoir. In this regard, the tar-sand reservoir of Alaska poses a particular problem due to the presence of a permafrost region which renders steam injection ineffective.

Oil in the Ugnu reservoir was discovered by BP in the eastern region in the range of 828-994 m depth. Ever since the original discovery, there have been several drilling activities in the area during the 1970's. The Ugnu sand is divided into a lower and an upper zone. Figure 1 shows a cross sectional view of Ugnu and West Sak reservoirs.

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Scientia Iranica, Vol. 2, No. 1, © Sharif University of Technology, March 1995.

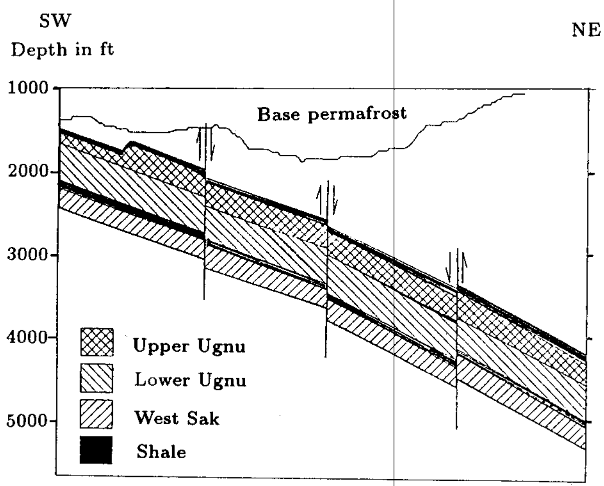

Figure 1. Cross sectional view of Ugnu and West Sak.

The lower Ugnu is mainly medium grained, ranging from fine to coarse grained. The thickness of the lower Ugnu ranges from 75 to 92 m throughout most parts of the northern Kuparak area. There are three to five major sand beds in the lower Ugnu interbedded with silts and muds. However, sand beds range from 3.5-10 m at the base to 20-31 m thick at the top of the member. The lower Ugnu is separated from underlying West Sak sands by a regionally extensive shale and mud sequence.

The upper Ugnu sands are thicker than the lower Ugnu sands and are mainly fine to medium grained. The upper Ugnu has an average thickness of 100 m in the Kuparak area and is composed of five to seven major sand beds. Each sand bed has an average thickness of 10-20 m. Reservoir rock and fluid data for both upper and lower Ugnu are given in Table 1. As can be seen in this table, oil of the Ugnu reservoir has a viscosity of $10^4 - 10^5$ mPa.s, which makes reservoir fluids practically immobile.

Thermal recovery techniques have been applied successfully in recent developments of heavy oil and tar-sand reservoirs. The most successful technique is the steam-assisted gravity drainage (SAGD), which uses two parallel horizontal wells, the injector being placed within a few meters of the top of the producer. This process has enjoyed several field applications [2,3]. However, one of the great difficulties in implementing SAGD in the Ugnu tar sand is the huge heat loss in the permafrost region. Unless an in situ steam generator is used, it would be extremely difficult to maintain steam phase in the wellbore, even with an insulated tubing.

In this regard, electromagnetic heating offers an attractive alternative. Several options have been tried for the use of electricity to heat oil reservoirs. These methods may be classified according to the mechanism of thermal dissipation that dominates the recovery process [4]. They range from dielectric heating with high frequency range to radio frequency in the microwave range. A popular application of this process is found in microwave ovens. Another variation of this may be in inductive heating where the electric AC flowing through a set of conductors induces a magnetic field in the surrounding medium. The variation of the magnetic field, in turn, induces secondary currents which circulate in the medium to generate heat.

Wadadar and Islam [5] have recently investigated the possibility of electromagnetic heating with horizontal wells. However, their study was limited to primary depletion along with electromagnetic heating. Recently, Islam and Chakma [6] presented a novel technique for recovering heavy oil from bottom water reservoirs. This technique involved electromagnetic heating along with inert gas injection. While this technique was found to be very effective in recovering heavy oil from bottom water reservoirs, the same technique could be applied to oil reservoirs without bottom water. Such an application is investigated in this paper.

Very few numerical studies have been reported on numerical simulation of electrical heating of tar sands. One of the first simulators of low-frequency heating was reported by Hiebert et al. [7]. Their simulator used the finite-difference method to solve the electric current continuity equation and the thermal conductivity equation in cartesian as well as cylindrical coordinates. This simulator was further used to predict recovery performance

Table 1. Reservoir data of the lower and upper Ugnu.

	Lower Ugnu	**Upper Ugnu**
Lithology	Fine to medium grained, well sorted, quartz and chert	Very fine to medium grained sand with siltstone, mudstone and coals
Area	310 square kilometers	260 square kilometers
Oil in Place	6-11 billion barrels	5-8 billion barrels
Depth	730-1220 m subsea	overlying lower Ugnu
Oil Gravity	8–12° API	8–12° API
Oil Viscosity	10,000-100,000 mPa.s	10,100-100,000 mPa.s
Gross Pay	75-92 m	90-110 m
Porosity	25%	25% (estimated)
Permeability	200-3000 md	100-2500 md

of electrical heating of the Athabasca oil sand formation [8]. More recently, Pizzaro and Trevisan [4] coupled the electrical charge balance equation with energy balance as well as continuity and momentum balance equations. All these studies, however, focused on the application with vertical wells.

McBride et al. [9] extended numerical simulation of electrical heating to horizontal wells. However, they did not solve an additional equation for electrical charge balance. Instead, a constant temperature boundary condition was used. This was acceptable since they focused on numerically modeling scaled model results with similar boundary conditions. More recently, Wadadar and Islam [5] have presented, for the first time, a compositional simulator with electromagnetic heating and horizontal well options. They presented results of primary depletion with electromagnetic heating under various reservoir and production conditions.

Recently there have been numerous studies reported on gravity-assisted inert gas injection. Gravity stabilization is achieved by using natural dip (gas injection from the top of a reef or similar structure) or horizontal wells. Results of these studies have been recently summarized by Islam and Chakma [10] and Bansal and Islam [11]. In brief, studies show that gravity-assisted gas injection has a great potential for heavy oil reservoirs. Even though gas injection is not likely to succeed in tar-sand reservoirs due to extremely unfavorable mobility ratio, it is possible to render oil viscosity to a low value with electromagnetic heating and then subject this oil to gas injection.

The purpose of this study is to numerically investigate the possibility of immiscible gas injection as well as waterflooding along with electromagnetic heating with horizontal wells. The technique is applied to the tar-sand reservoir of Ugnu in Alaska.

MATHEMATICAL FORMULATION

As pointed out by Pizzaro and Trevisan [4], a rigorous treatment of electrical heating of an oil reservoir should consist of solving four partial differential equations, namely, continuity, momentum, energy conservation and electrical charge conservation. The model is based on compositional, three-phase formulation. For the present study, however, oil phase is considered to be present only as a liquid while water could be present both in liquid and vapor phases. The continuity equation for the i-th component is given by:

$$\nabla(\rho_i v_i) = -\frac{\partial C_i}{\partial t}. \tag{1}$$

Darcy velocity for a given phase, p, is given by:

$$v_p = -\frac{KK_{rp}}{\mu_p}(\nabla p_p - \gamma_p \nabla z). \quad (2)$$

In the above formulation, γ_P is the acceleration due to gravity multiplied by density of the phase, p. The above two equations constitute the flow equations in the porous region of the reservoir. The energy balance equation is given by:

$$\begin{aligned}&\frac{\partial}{\partial t}[\phi(S_o\rho_o e_o + S_g\rho_o e_g + S_w\rho_w e_w)\\ &\quad +(1-\phi)(\rho C_p)_R T] = \nabla(\lambda\nabla T)\\ &\quad +\nabla\left[\frac{\rho_g h_g K_g}{\mu_g}(\nabla p_g + \rho_g z)\right.\\ &\quad +\frac{\rho_w h_w K_w}{\mu_w}(\nabla p_w + \rho_w \nabla z)\\ &\quad \left.+\frac{\rho_o h_o K_o}{\mu_o}(\nabla p_o + \rho_o \nabla z)\right]. \quad (3)\end{aligned}$$

The balance of electrical charge in the system gives rise to the following equation:

$$\nabla[(1/R)\nabla\Phi_E] = 0. \quad (4)$$

For the present study, well indices, as given by Peaceman [12], were used to couple the wellbore with the reservoir. A similar expression was given also for describing energy transfer from the horizontal well to the reservoir by Siu et al. [13].

The final formulation involved describing complementary equations relating electrical properties. The electrical resistivity of the fluid-saturated porous medium is given by Archie and Humble's relation:

$$R = 0.62\ R_w/\phi^{2.15}S_w^2. \quad (5)$$

The temperature dependence of the water resistivity is given by:

$$R_w = R_{wr}[(T_r - 251.65)/(T - 251.65)], \quad (6)$$

where R_w is in ohm-meters and T is in kelvin.

Hsueh [14] reported viscosity for bitumen as a function of temperature. This curve was used as the basis for the present study. For Ugnu tar sand, the reservoir temperature ranges from 0 to 30 C. Figure 2 shows temperature dependence of oil viscosity depending on initial viscosities. Note that Ugnu tar sand is known to exhibit a range of viscosities for the same initial temperature. Therefore, a set of temperature versus viscosity relationship was used. Figure 2 shows curves A, B, and C with initial viscosities of 100,000 mPa.s, 20,000 mPa.s, and 10,000 mPa.s, respectively.

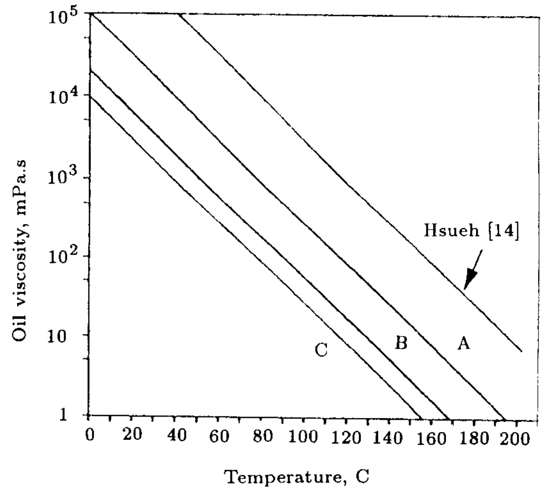

Figure 2. Viscosity functions used in this study.

A series of numerical runs was conducted with viscosity characteristics represented by A, B, and C in order to study the effects of different types of oil. Relative permeability data for the oil-water system were taken from those reported on West Sak reservoir by one of the North Slope operators. They are shown in Figure 3.

Two sets of relative permeability curves

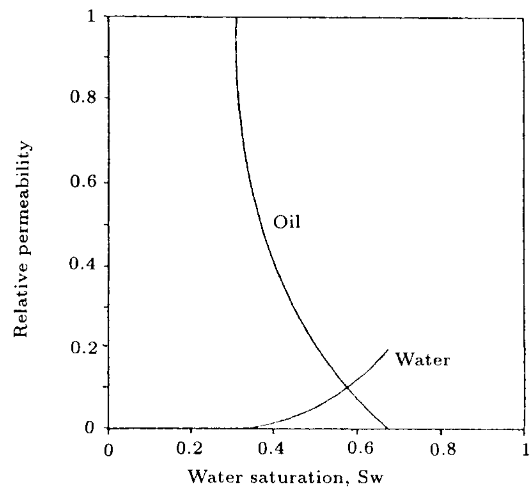

Figure 3. Relative permeability curves used in this study.

were used for describing the gas-oil system. When the flow regime was considered to be stable (gravity stabilized) the oil-gas relative permeability curves were taken from Bailey et al. [15]. However, when the flow regime was considered to be unstable, relative permeability curves were taken from Islam et al. [16], who reported unstable type relative permeability curves which were obtained by history matching unstable type displacement results.

Boundary and Initial Conditions

Initial conditions consist of constant values of pressure, temperature and saturation for each grid block. The reservoir boundary is specified to be a no-flow boundary. The well is considered to be producing at a constant pressure. The boundary condition for the electrical potential is given by the constant level imposed at the producing level. Figure 4 shows a schematic of the geometry and grid blocks considered in the present study. Note that the numerical simulation is limited to a 2-D study. Even though the numerical simulator was capable of handling a 3-D problem, numerical experimentation was limited to a 2-D problem because of the lack of reservoir data. Very little information was available on areal distribution of reservoir rock properties.

Figure 4 also shows the location and nature of electrodes. Dimensions and properties of different layers are given in Table 2. Note that for layers containing shale breaks, only conduction

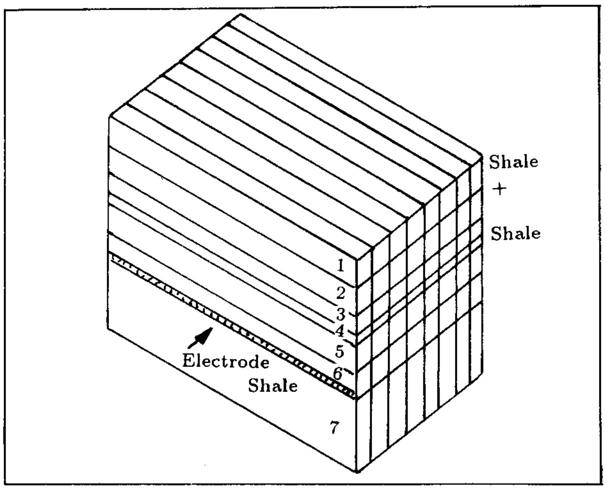

Figure 4. Geometry and grid blocks used in this study.

equations were solved in order to determine the temperature profile. Fluid movement in these shaly zones was considered to be negligible.

A range of oil sand permeabilities is given in Table 2. A combination of various permeabilities has been studied in this paper. Vertical permeability is considered to be 10% of the permeability values reported. Vertical boundaries, as shown in Figure 4, were considered to be planes of no-current and no-heat flow. This symmetry is allowed when a series of staggered horizontal wells are drilled in order to develop a complete pattern in the reservoir.

Horizontal wells were considered to be 21.6 cm ($8\frac{1}{2}''$) in diameter. This large diameter allowed one to consider the pressure drop in

Table 2. Properties of reservoir rocks for different layers.

Layer no.	Type	Thickness (m)	K_h (W/mK)	$(\rho C_p)_R$ (kJ/m^{3}K)	K (md)	S_{wi} (%)
1	Shale	30	1.5	2.2	-	-
2	Oil sand	30	3.0	2.2	100-500	70
3	Oil sand	50	2.4	2.2	500-2500	30
4	Shale	5	1.5	2.2	-	-
5	Oil sand	30	2.1	2.2	100-600	25
6	Oil sand	40	1.8	2.2	600-3000	20
7	Shale	60	1.5	2.2	-	-

the wellbore to be negligible. Therefore, no additional equation was solved for the wellbore. Wells were considered to be 300 m long. Distance between vertical planes containing staggered wells was considered to be 50 m.

The initial reservoir temperature was considered to be 0 C and initial pressure was considered to be 7000 kPa at the top of the reservoir. Constant production pressure of 350 kPa was used throughout this study.

A previous study [5] revealed that a preheat period of 240 days and an electric power supply of 12 kW/m were adequate for electrical heating of the Ugnu reservoir. Consequently, all runs reported in this study used 240 days of preheat period and an electric supply of 12 kW/m of the length of the horizontal well. Numerical simulation runs were continued for 10 years of production.

Solution Methods

Since the pressure dependent coefficients in this paper have been treated implicitly, the resulting system of algebraic equations is nonlinear. This system of equations is linearized by means of the Newton-Raphson procedure. The system of linearized equations was solved by the direct method. The momentum and energy balance equations were solved simultaneously. This was followed by the solution of the electric charge balance equation. This sequence was found to be adequate for solving the equations with acceptable accuracy.

RESULTS AND DISCUSSION

Nine numerical simulation runs were conducted in this study. This was done to study various production/injection options of gas injection, waterflooding and primary production. Also, a run using steam-assisted gravity drainage was conducted. Table 3 summarizes major characteristics of all numerical runs. A systematic discussion of results of these numerical runs follows.

Run 1: Primary Production

Run 1 was conducted as a base run for which no fluid injection was carried out. A horizontal well was placed at the bottom of the lower Ugnu formation while the other well was placed diagonally across and on top of the same lower Ugnu formation. Run 4 was conducted in order to observe the effect of placing the upper well on top of the lower Ugnu formation. The shale barrier between the upper and lower Ugnu formations was considered to be impermeable.

Initially, the formation was preheated for 240 days at a constant electrical power of 12 kW/m of the horizontal well length. Initial oil viscosity for this run was considered to be 10^5 mPa.s. At the end of 240 days of preheat, the well temperature was above 210 C, while temperature in the formation midway between the electrodes was around 100 C. This temperature was high enough to mobilize the tar sand and a reasonable flow rate through the bottom horizontal well could be sustained. At this point the bottom horizontal well was put into production.

Figure 5 shows oil production rate and cumulative oil recovery for Run 1. Cumulative recovery for this run is expressed as a function of the oil in place of the lower Ugnu formation. Note that the initially high production rate is not sustained for a long period. As the fluid is produced, the temperature near the wellbore declines rapidly, causing the decline in the production rate. Also the reservoir pressure declines since a no flow boundary condition is

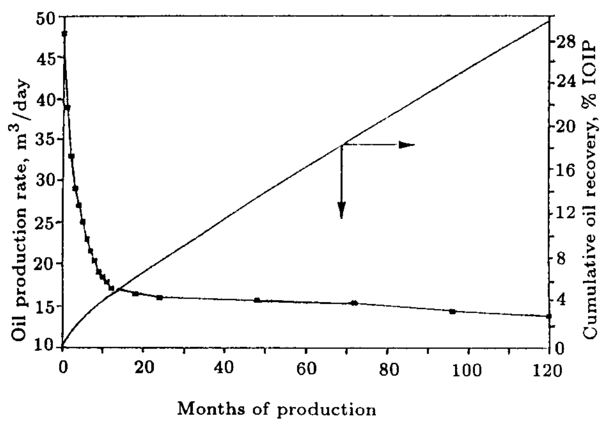

Figure 5. Recovery performance of Run 1.

Table 3. Characteristics of different runs conducted.

Run no.	Initial μ_o (mPa.s)	Type of Fluid Injected	Description of the Run
1	100,000	None	Production by primary depletion with top well located at the top of lower Ugnu; both horizontal wells heated at 12 kW/m for 240 days; production from bottom well only.
2	100,000	None	Same well configuration as Run 1; leaky shale assumed between upper and lower Ugnu; production from both horizontal wells; production by primary depletion while both wells heated.
3	100,000	None	Top well located on top of upper Ugnu as in Figure 4; impermeable shale barrier between upper and lower Ugnu; both wells put on production; production by primary depletion while both wells heated.
4	100,000	Inert Gas	Well configuration same as Run 1; gas injected through the top well located on top of lower Ugnu; both wells heated.
5	100,000	Inert Gas	Two horizontal wells located on the same vertical plane; the bottom well at the bottom of lower while top well at the top of upper Ugnu; horizontal wells heated and both used as producers; gas injection carried out through a vertical well 50 m away from the vertical plane containing horizontal wells.
6	20,000	Inert Gas	Same as Run 4 except for lower initial oil viscosity.
7	10,000	Inert Gas	Same as Run 6 except for lower initial oil viscosity.
8	100,000	Water	Same as Run 5 except for water injection in stead of gas injection; constant inj. rate applied rather than inj. pressure.
9	100,000	Steam	Steam-assisted gravity drainage; horizontal wells placed 2 m apart in the vertical plane; 1 month preheat; 100 m spacing.

assumed. Typically this would be the case if the reservoir is completed with a series of staggered horizontal wells. After about two years of production decline, the oil production rate reaches a somewhat stable state and the rate remains more or less constant. This stage of oil recovery is more dominated by gravity drainage and leads to a low but stable production rate.

As a result, a total of over 28% of the initial oil in place is recovered at the end of 10 years of production.

Run 2: Production from Both Wells with Inter-Connection between Upper and Lower Ugnu

In Run 1, it is assumed that the production is carried out through the bottom well alone. However, it is possible to put both wells into production. Also, it is possible to drill the upper well in such a manner that the shale barrier is pierced in a wavy fashion and a communication between upper and lower Ugnu formations is established.

Run 2 was conducted with production from both upper and lower wells (same configuration as Run 1) while assuming that a communication between the upper and lower Ugnu formations is established. Figure 6 shows oil production rate and cumulative oil recovery for Run 2. Note that the cumulative oil recovery for this run was reported as a percentage of the total oil in place of the upper and lower Ugnu formation. This was done because oil production was being carried out directly from both formations. Even though cumulative oil recovery for this run is reported to be around 24% of the oil in place, if the lower Ugnu is considered alone, this recovery would be equivalent to over 43% of the oil in place in the lower Ugnu formation.

Oil production rate of this run is compared with that of Run 1 in Figure 7. As can

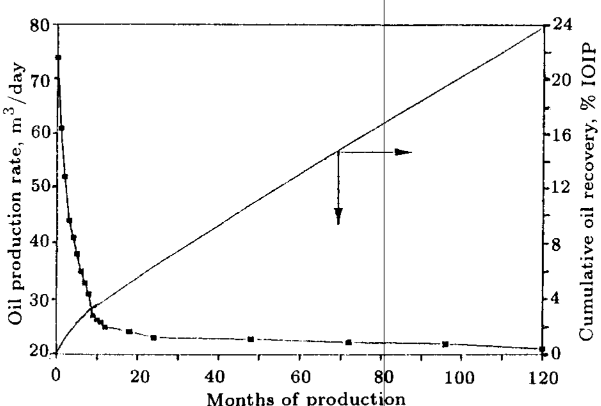

Figure 6. Recovery performance of Run 2.

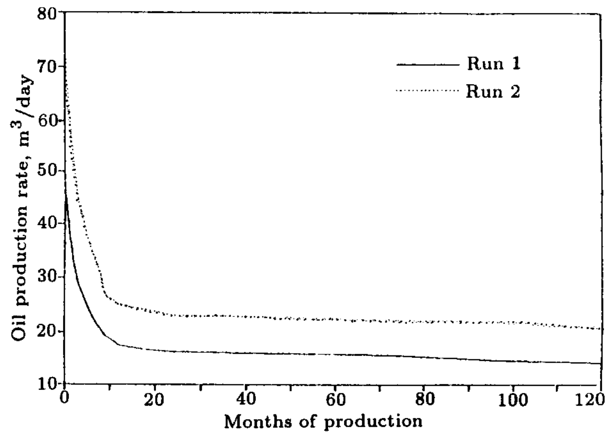

Figure 7. Comparison of oil productions of Runs 1 and 2.

be seen in this figure, oil production rate is significantly higher in the case of production from both wells. As the production is continued, production rate declines in a similar fashion for both runs. Throughout the life of oil production, the top well produces less oil than the bottom well. This is mainly due to the fact that once the gravity drainage starts to contribute to oil production, the water-cut continues to be higher for the top well due to higher water saturation in the upper Ugnu formation. Also, the production from the bottom well is somehow negatively impacted by the simultaneous production of the top well. However, the total production from the top and bottom wells is large enough to maintain much higher production rate than that achieved with production from the bottom well alone.

Run 3: Production from Two Wells, Impermeable Shale Barrier between Upper and Lower Ugnu

For Run 3, the configuration, as depicted in Figure 4, was used. The shale barrier between the upper and lower Ugnu formations was assumed to be impermeable. Also, it was considered that both wells could be put into production simultaneously.

For this particular case, the well temperature was near 200 C after 240 days of preheat at a constant power supply of 12 kW/m of the horizontal well length. The temperature of the formation midway between the electrodes was around 90 C. As the production was initiated, production performance of the bottom well was similar in nature to that of Run 1. However, the actual production rates were slightly lower for this case.

On the other hand, production from the top well was dominated by considerable water production. However, this was only the case during early stages of oil production. The presence of mobile water saturation contributed to better heating of the upper Ugnu leading to improved recovery from the upper well.

Figure 8 shows oil production rate and cumulative oil recovery curves as obtained in Run 3. Once again, cumulative oil recovery is expressed as a function of the initial oil in place of combined upper and lower Ugnu formations. Note that the decline during later stages of oil recovery is due to rapid decline in oil production through the upper well, which shows quick decline in oil production during the gravity drainage period. At the end of 10 years of oil production, the total recovery is 18% of the initial oil in place in both upper and lower Ugnu formations. In terms of the oil in place in the lower Ugnu, this amount represents more than 32% of the oil in place. This run shows the clear advantage of producing through the second horizontal well, which is placed on top of the lower Ugnu with communication through the shale barrier (Run 2).

Run 4: Gas Injection from the Top of Lower Ugnu

For this run, the well configuration was similar to that of Run 1. After a preheat period of 240 days, gas injection was initiated at a constant injection pressure of 7600 kPa. Because gas injection was carried out through the top well and the gas displacement front was moving downward, a stable displacement front was assumed. Stability calculation for this situation was done [16]. The relative permeability curves were taken from [15] for simulating stable gas injection. The same was obtained from [16] for unstable injection cases.

Oil production and cumulative oil recovery as well as gas oil ratio (GOR) for this run are shown in Figure 9. As can be seen in this figure, the oil production rate increases slightly prior to gas breakthrough. The highest oil production rate which is achieved in this process is 62 m^3/day. This is significantly higher than that achieved during Run 1 (primary depletion following electromagnetic heating).

Gas breakthrough takes place after more than two years of oil production. This delayed gas breakthrough is expected since gravity-stable displacement front is assumed. Following gas breakthrough, the oil production decreases rapidly with an exponential increase in GOR. However, both GOR and oil production rate stabilize four years following gas breakthrough. In the 10 years of total time of simulation, no significant change in GOR or oil production

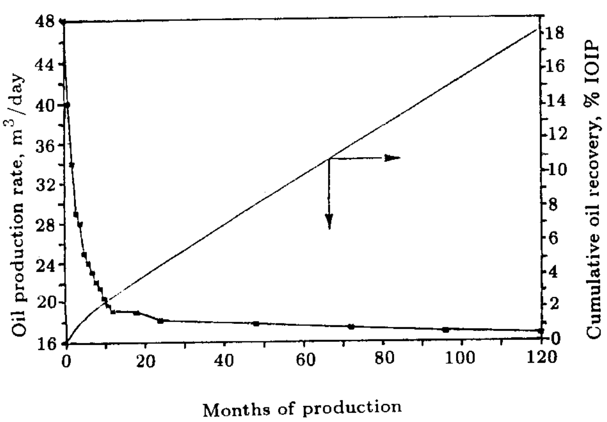

Figure 8. Recovery performance of Run 3.

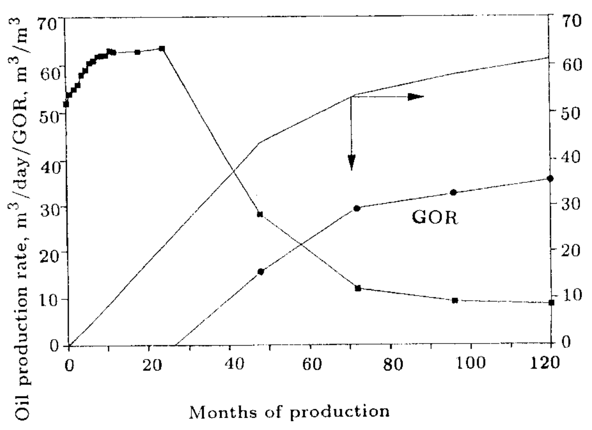

Figure 9. Recovery performance of Run 4.

rate is observed. At the end of 10 years of production, more than 60% of the oil in place is recovered. This is a substantial improvement over primary (with electrical heating) depletion, which recovered only 28% of the oil in place.

Run 5: Gas Injection through Vertical Well in Both Upper and Lower Ugnu

A unique configuration is considered in Run 5. It is assumed that the horizontal wells are placed along the same vertical plane. However, one well is placed at the bottom of the lower ugnu reservoir, while the other horizontal is placed at the top of upper Ugnu. Electrical power supply was 12 kW/m of the horizontal well and the preheat period was considered to be 240 days. For this particular run, the gas injection was assumed to be carried out through a vertical well placed 50 m from the vertical plane containing the horizontal wells.

The reason for using a vertical well was to be able to inject gas in both upper and lower Ugnu formations simultaneously while producing from both horizontal wells. This was done in order to maintain the same injection pressure in both formations at a constant value of 7600 kPa. Because gas is injected at the same level as the horizontal well, gravity stabilization will no longer occur. As a consequence, unstable displacement of oil by gas was assumed. That is, relative permeability curves as given by [16] were used for describing the gas/oil flow.

Figure 10 shows oil production rate, cumulative oil recovery and GOR for Run 5. Because an unstable displacement takes place, the gas breakthrough takes place rather early. As can be seen from Figure 10, the gas breakthrough takes place after only 12 months. However, the oil production rate prior to gas breakthrough is very high and accounts for significant oil recovery prior to gas breakthrough.

Following gas breakthrough, the oil production rate declines sharply while the GOR increases rapidly. This decline in oil production rate continues for 2 years, following which stabilization in oil production rate as well GOR takes place. This leads to an oil recovery of more than 42% of the oil in place of upper and lower Ugnu combined. Note that this recovery is equivalent to 75% of the oil in place of the lower Ugnu alone. As compared to Run 4, this recovery is some 20% improvement.

Figure 11 compares oil production rates for Runs 4 and 5. Very large differences in oil production rates are evident during the early stages of oil production. However, since gas breakthrough takes place much quicker for Run 5, the production rate falls below that of Run 4 following gas breakthrough. The decline in oil production rates continues for some time. During later stages of oil production, Run 5 shows a slower decline rate, leading to a higher oil production rate, as compared to Run 4. Both these runs reach similar oil production rates at the conclusion of the numerical test.

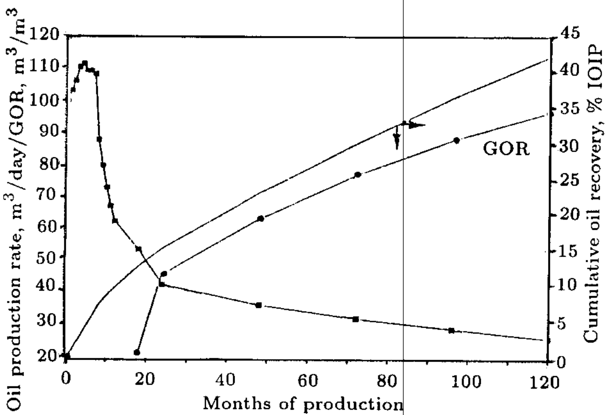

Figure 10. Recovery performance of Run 5.

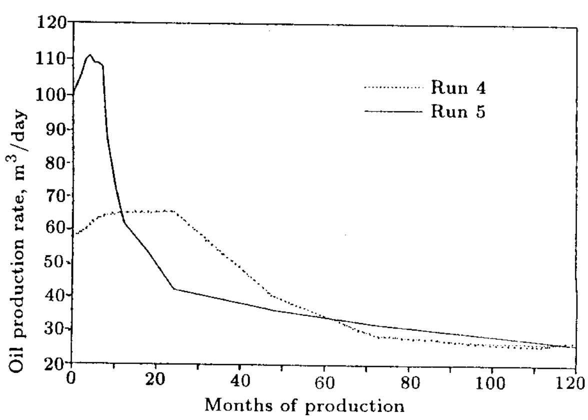

Figure 11. Comparison of oil productions of Runs 4 and 5.

Effect of Oil Viscosity: Runs 4, 6 and 7

So far, all the runs were conducted using an oil viscosity of 10^5 mPa.s (curve A of Figure 2). However, it is well known that the oil viscosity in the Ugnu reservoir varies from 10^4 to 10^5 mPa.s under reservoir conditions. In order to investigate the effect of oil viscosity, Runs 6 and 7 were conducted under conditions identical to Run 4, except that the initial oil viscosities were 2.10^4 mPa.s and 10^4 mPa.s for Runs 6 and 7, respectively. These runs were conducted using viscosity versus temperature correlations B and C, respectively, as shown in Figure 2.

Figures 12 and 13 show recovery performance of Runs 6 and 7, respectively. A comparison of these runs with Run 4 is shown in Figure 14. Note that oil recovery performance is similar for both 10,000 and 20,000 mPa.s viscosities. They both exceed oil recovery of 70% of the oil in place. An initial oil viscosity of 10^5 mPa.s gives significantly lower recovery. This comparison shows the attractiveness of the electrical heating scheme for oil viscosities in the 20,000 mPa.s range. In the case of Ugnu, oil recovery after 10 years is expected to range from 60% to 80% of the oil in place, depending on the frequency of occurrence of low oil viscosity oils.

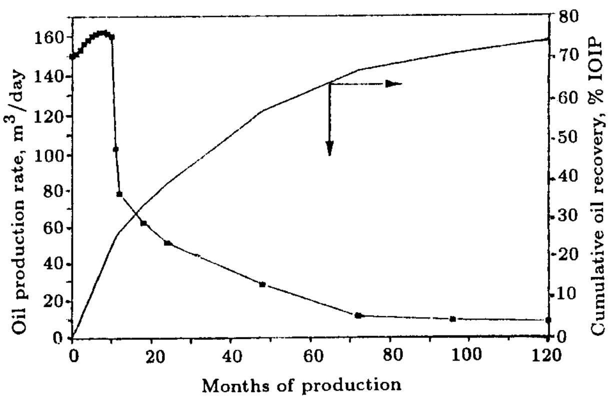

Figure 12. Recovery performance of Run 6.

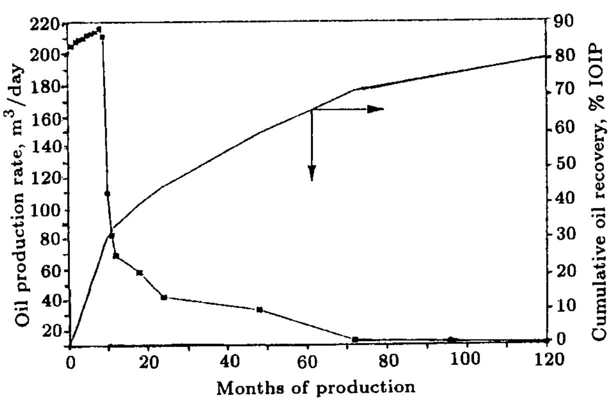

Figure 13. Recovery performance of Run 7.

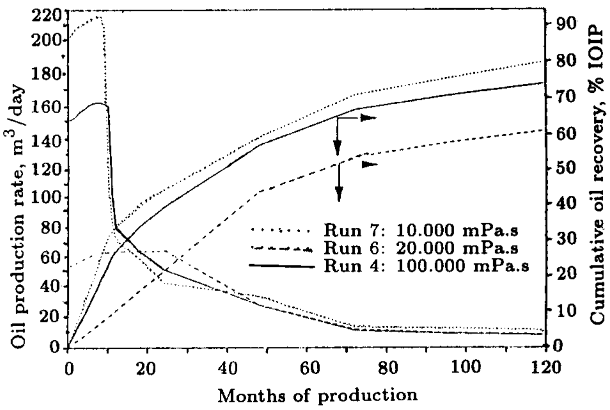

Figure 14. Comparison of oil recoveries of Runs 4, 6 and 7.

Run 8: Waterflooding

Run 8 was a replicate of Run 5 except that water injection was carried out as opposed to gas injection. Waterflood was carried out at a constant total rate of 100 m^3/day with 60 m^3/day injected in the lower Ugnu formation. It is customary to inject water at a constant rate. For this particular run, it was also decided to produce the wells at a constant total liquid production rate of 60 m^3/day in the lower Ugnu and 40 m^3/day in the upper Ugnu formations.

Figure 15 shows oil production rate and cumulative recovery for Run 8. Because water has a viscosity much higher than that of gas, breakthrough takes place at a later time for the bottom well. For the top well, on the other hand, water cut is significant from the beginning of the run, due to the presence of high mobile water saturation. When recoveries from both these wells are combined, a sharp decline in oil production is noticed after water breakthrough in the bottom well. Unlike gas injection runs, no apparent stabilization of oil production rate is evident for the water injection case.

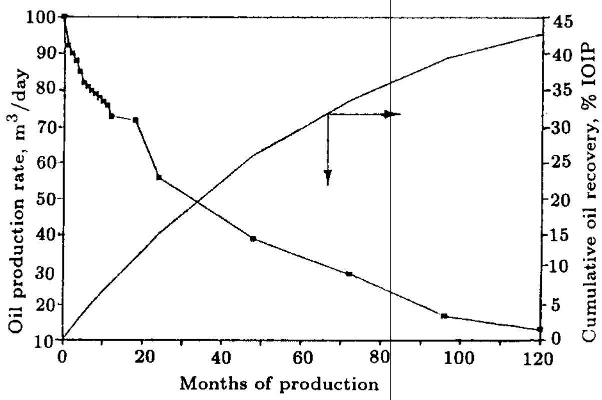

Figure 15. Recovery performance of Run 8.

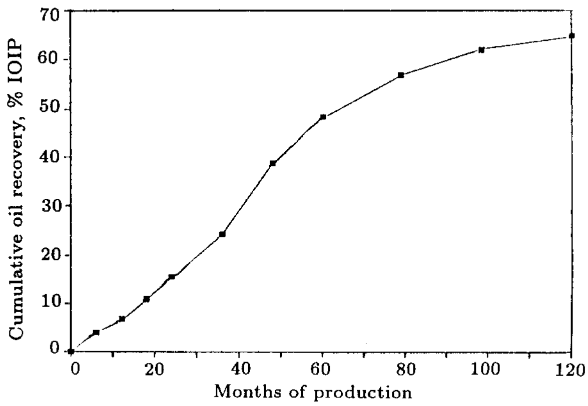

Figure 16. Recovery performance of Run 9.

Note that, during water injection, much quicker cooling takes place as compared to gas injection. This will account for the earlier than expected water breakthrough time and a quicker decline in oil cut following water breakthrough. At the end of 10 years, a total of 42% of oil is recovered for Run 8. This is equivalent to over 80% of the oil in place of the lower Ugnu reservoir alone.

Run 9: Steam-Assisted Gravity Drainage

Steam assisted gravity drainage is not likely to be effective in the North Slope due to the presence of a permafrost region. As discussed earlier, the presence of permafrost makes it extremely difficult to maintain a steam vapor phase in situ. However, for the sake of comparison, a numerical run (Run 9) was conducted for modeling steam-assisted gravity drainage. The bottom horizontal well is placed at the bottom of the lower Ugnu formation while the top well is placed 2 m above the bottom well, while situated at the same vertical plane.

Because the wells are placed so close to each other, initial steam circulation period was assumed to be 1 month only. This time was long enough to mobilize oil for production through the bottom well. Well spacing, as well as horizontal well length for this run, was considered to be the same as previous runs. In this run it is assumed that the steam quality is not altered at the injection well throughout the production test. For numerical simulation of this steam-assisted gravity drainage, all relevant data (other than the ones specified already) were taken from Stone et al. [17].

Figure 16 shows the cumulative oil recovery (as a function of the initial oil in place of lower Ugnu) for Run 9. Note that, due to initial stabilization of oil flow rate, the cumulative oil recovery increases linearly during the initial stages of steam injection. Following this period, oil flow rate declines sharply (high steam-oil ratio) and the cumulative oil recovery increases very slowly. At the end of 10 years of production, slightly over 60% of the oil in place is recovered. While comparing this recovery with other runs, one has to keep in mind that the steam-assisted gravity drainage process may be very difficult to establish in the field in the presence of a permafrost. In this regard, the electromagnetic heating or gas injection has a clear advantage over the steam injection process.

CONCLUSIONS

The prospect of using several enhanced oil recovery techniques, using fluid injection along with electromagnetic heating in the tar sand reservoir of Ugnu, Alaska, was investigated in this paper. A three-dimensional, compositional, thermal simulator was adapted to solve electrical heating problems. Numerical results indicate that by using horizontal wells in conjunction with electromagnetic heating, a significant amount of oil in place can be recovered. This recovery may be substantially improved by injecting gravity stable gas.

A vertical injector with electrically heated horizontal wells in both of upper and lower Ugnu formations recovered over 40% of the oil in place. Also, water injection appears to be attractive, even though its performance is hampered by increased cooling with water. The steam-assisted gravity drainage recovers considerable oil but realization of such a process may be difficult in the presence of permafrost.

NOMENCLATURE

c	compressibility
C	concentration
e	internal energy
h	enthalpy
K	permeability tensor
K_{ri}	relative permeability to phase i
p	pressure
q	flow rate
R	electrical resistivity
S_i	saturation of the phase i
T	temperature
t	time
v	Darcy velocity
x, y, z	coordinates

Greek

Φ_E	electrical potential
ϕ	porosity
γ	density times acceleration due to gravity
λ	thermal conductivity
μ_i	viscosity of the phase i
ρ_i	density of the phase i

Subscripts

g	gas
o	oil
w	water

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