Design of the Injection Strategy in Expanding-Solvent Steam-Assisted Gravity Drainage

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Abstract

Steam-Assisted Gravity Drainage is effective at extracting oil from heavy oil and bitumen reservoirs. However, steam generation by natural gas combustion can render the process uneconomic. It has been suggested that addition of injected solvents improves oil rates or at least maintains similar oil rates with reduced steam. This is the basis of the Expanding Solvent - Steam Assisted Gravity Drainage process. The central idea is that steam plus solvent is better than steam alone to recover heavy oil and bitumen. In this research, the steam and solvent injection strategy is designed by optimizing the cumulative steam-oil ratio by using simulated annealing and a commercial reservoir simulator.

1. Introduction

The in situ viscosity of Athabasca bitumen is over one million centipoise, typically between three and six million centipoise. This means that if it was poured from an inverted beaker, it would take several days for the majority of the contents to empty from the beaker. The key to produce bitumen from Athabasca reservoirs is to mobilize it in the reservoir, that is, lower its viscosity sufficiently so that it readily flows in the reservoir. There are two means to do this: first, heat the bitumen to sufficiently high temperature and second, dissolve solvent in the bitumen.

The thermal action on the viscosity of Athabasca bitumen is plotted in Figure 1 [11] and is taken advantage of in the Steam-Assisted Gravity Drainage (SAGD) process [3]. Typically, the initial temperature of Athabasca reservoirs is between 7 and 11 °C. The correlation shows that the viscosity falls by four orders of magnitude after the bitumen is heated by 100°C. In SAGD, displayed in cross-section in Figure 2, steam is injected into the

formation through a horizontal well. Around and above the injection well, a steam chamber grows. At the chamber edge, hot fluids, consisting of bitumen and (steam) condensate, flow under the action of gravity to a production well typically between 5 and 10 m below and substantially parallel to the injection well. The quality of the injected steam should be as high as possible at the sandface because any condensate in the injected fluids falls under gravity from the injector towards the producer and does not deliver a significant amount of heat to the oil sand.

Figure 1: Effect temperature on viscosity of Athabasca bitumen [11].

Figure 2: Cross-section of the Steam-Assisted Gravity Drainage (SAGD) process.

The most expensive activity in SAGD is steam generation and it is measured by the steam-to-oil ratio (SOR). The higher the SOR, the higher the steam usage or more natural gas combusted per unit volume of produced bitumen and consequently the less economic is the process. Furthermore, the higher the SOR, the higher is the emission of greenhouse gases due to combustion per unit of oil produced. The lower the SOR, the lower the steam use per unit volume of produced bitumen and thus the more economic is the process. SAGD has now been extensively tested and in commercial production in the Athabasca and Cold Lake regions of Alberta [1,2]. The process appears to be technically effective at producing bitumen yet it has not been fully established as an economic technology especially at forecasted natural gas prices. The economic performance of the process is dictated by first, natural gas use to produce steam, second, the quality of the reservoir, and third, water recycling and treating.

The solvent action on the viscosity of bitumen is less clear. This is because it depends on the solvent content in the bitumen phase which depends on the pressure-volume-temperature (PVT) behaviour of mixtures of the solvent and bitumen. For some solvents, for example, propane, the precipitation of asphaltenes from the bitumen also lead to a reduction of the bitumen phase viscosity. For diluent-like solvents, the solvent-bitumen mixture viscosity can be determined from correlations [10,18]. Figure 3 displays the how the viscosity of mixtures of hexane and bitumen, based on Shu's correlation, changes with concentration at various temperatures.

Figure 3: Viscosity of mixtures of Athabasca bitumen and hexane as calculated from Shu's correlation [18].

In the Expanding Solvent – Steam-Assisted Gravity Drainage (ES-SAGD) process [13], an enhancement of SAGD, a small amount of solvent is added to the injected steam. The key benefit with this

process is that some of the injected steam is replaced by solvent. This mixture enters the vapour chamber and steam and solvent are transported to the edge of the chamber. At the edge, both steam and solvent condense. The steam delivers its latent to the bitumen and the solvent dissolves and diffuses into the bitumen. Due to phase behaviour, it is possible that a second hydrocarbon liquid phase exists at the edge of the vapour chamber. One major goal of the process is to recover as much of the injected solvent as possible in order to recycle it. Minimal solvent losses are critical especially when the injected solvent is more expensive than the produced bitumen.

In 2002, EnCana (then PanCanadian) conducted the Solvent-Aided Process (SAP) pilot at their Senlac SAGD pilot in one of the Phase C wellpairs [5,6]. In this pilot, regular SAGD was implemented for the first 6.5 months. After this point, butane was added to the injected steam for several months. Shortly after butane injection started, the oil rate jumped by over 50%. After butane injection was stopped, the oil rate declined to the projected SAGD oil rate. The solvent recovery was reported to be over 70% [6]. EnCana has applied the SAP technology in their Christina Lake project [6]. So far, the results show an uplift of oil rate by over 50%.

In Cold Lake, diluent was added to selected wells in a late-cycle cyclic steam stimulation (CSS) pad in Imperial Oil's Liquid Addition to Steam for Enhanced Recovery (LASER) process pilot [8,9]. The production data from the LASER pad indicated that the bitumen production rate was raised by 100% percent over that of a neighboring CSS pad (wells without diluent injection) over the first part of the cycle LASER was implemented. Even though this process is different from SAGD especially in early cycles where the major mechanisms of oil recovery are formation recompression and solution gas drive, in late cycles, similar to SAGD, the underlying mechanism of oil flow in the reservoir is due to gravity drainage. The solvent recovery was reported to be higher than 80% [9].

ES-SAGD and SAP are examples of recently emerging hybrid thermal-solvent recovery technologies. The bitumen is mobilized by both thermal and solvent dilution mechanisms. It remains unclear what the optimal solvent concentration in the injected stream should be. For thermal-solvent processes, the three major physical phenomena that control production are: gravity and viscous flow, heat conduction, and mass diffusion/dispersion. This means that first sufficient heat and solvent must be

added at sufficient rates to the native bitumen to mobilize it to the production well. In this research, thermal-solvent processes will be visualized by examining the process on the pressure-temperature-viscosity map. Also, by using simulated annealing and reservoir simulation, the steam and solvent injection rates will be adjusted to optimize the thermal efficiency, measured by the cumulative injected steam to cumulative produced bitumen, of the process.

2. Pressure and Temperature Mapping

Figure 4 displays the steam and hexane saturation curves on a pressure-temperature plot. To recall, above the saturation curve, the phase is liquid whereas below the curve, the phase is vapour. On the saturation curves both phases exist. At each pressure and temperature the solubility of hexane in the bitumen can be determined by an equation of state. The locus of constant solubility are also plotted in Figure 4. Given the solubility of hexane in the bitumen, then the viscosity of the mixture can be calculated. Curves of constant viscosity are also plotted in Figure 4.

1000 kPa, and temperature, 8°C, at point A, after the steam chamber, operating at 2000 kPa, passes through that location, the pressure and temperature of the bitumen at that location evolves to point B.

In a SAGD process, at constant injection pressure, because the steam chamber is at saturation conditions, the temperature in the steam chamber is fixed. This means that providing the injection pressure is roughly constant over the entire chamber, the temperature in the chamber is roughly constant and at a given location, after it is engulfed by the steam chamber, the process remains at roughly the same point on the pressure-temperature plot.

In the case where the pressure is lowered from the initial injection pressure, then the pressure-temperature trajectory follows the path indicated by line BC in Figure 4. In the case where the operating pressure is raised, the pressure-temperature trajectory follows the path indicated by line BD. Because the viscosity of bitumen mainly depends on temperature, the higher the operating pressure, the higher the corresponding saturation temperature, the lower the bitumen viscosity, and the higher the bitumen mobility and production rate.

Figure 4: Saturation curves, solubility curves, and constant viscosity lines on pressure versus temperature plot.

Figure 4 shows that, at a given location, if the bitumen phase starts at the initial reservoir pressure,

In ES-SAGD, providing sufficient solvent is supplied, as the pressure-temperature trajectory evolves, the solvent concentration changes because the solubility of the solvent depends on the pressure and temperature. Consider the case where the injection

pressure is initially high and then falls as the process evolves. The key issue faced by a process that evolves along this pressure-temperature trajectory is that the bitumen phase viscosity rises as the operating pressure falls. Consequently, the bitumen mobility will fall and the production rate will fall. On the other hand, if the pressure is raised as the process evolves, the bitumen phase viscosity remains roughly constant or falls as the process evolves. This means that the bitumen phase mobility remains roughly constant or rises and consequently, the bitumen production rate remains roughly constant or falls.

The analysis of the ES-SAGD process on the pressure-temperature plot reveals that it might be advantageous to design operating schemes where the pressure is raised as the process evolves. With higher pressure comes greater solvent solubility, reduced bitumen phase viscosity, and consequently enhanced bitumen phase mobility. The design of the operating strategy is not clear but can be determined by using optimization tied to reservoir simulation.

3. Optimization by Simulated Annealing

The optimization algorithm is wrapped around the reservoir simulation, that is, each cost function evaluation consists of creating the reservoir simulation input file with the current values of the adjustable parameters, running the reservoir simulation, post-processing the reservoir simulation output data to determine the cost function. In this work, the cost function is the cumulative steam-to-oil (cSOR) ratio.

The simulated annealing (SA) method belongs to the class of techniques that employ random search. SA is based on the algorithm proposed by Metropolis *et al.* [12] to find the equilibrium configuration of a collection of atoms at a given temperature. SA is based on the analogy between a metal cooling and freezing into a minimum energy state and the search for a minimum of a system. In this section, a brief introduction to simulated annealing is described. Detailed descriptions of the algorithm can be found in Metropolis *et al.* [12], Kirkpatrick *et al.* [7], and CSEP [4]. A good overview of the method applied to reservoir description can be found in Ouenes *et al.* [15]. Applications that use simulated annealing tied to reservoir simulation have been done by Beckner and Song [2], Ouenes *et al.* [14], and Sen *et al.* [17].

SA has the advantage that it can avoid being trapped in local minima. The algorithm conducts a random search that reduces the cost function. However, a parameter set with values that increases the cost function, say by $\mathcal{J}$, are accepted with a probability:

$$p = \exp\left(-\frac{\mathcal{J}}{T}\right) \quad 1$$

where T is a control parameter known as the system “temperature” (from the original analogy). At the start of the algorithm, the initial temperature is specified. As the search progresses, the temperature is lowered. This reduces the probability that an increase of the cost function will be accepted. The rule for reducing the temperature throughout the algorithm from its initial value is known as the “annealing schedule”.

The SA algorithm is summarized in Figure 5. The initial temperature is chosen so that the average increase probability, given by:

$$p^+ = \exp\left(-\frac{\mathcal{J}^+}{T}\right) \quad 2$$

is equal to about 0.8 (Kirkpatrick *et al.*, [7]). This value is usually determined by conducting a series of cost function evaluations, and by determining the average increase of the cost function, $\mathcal{J}^+$, (each increase is determined between two consecutive evaluations where the cost function increased):

$$T_o = -\frac{\mathcal{J}^+}{\ln(p^+)}$$

For optimization with reservoir simulation, each cost function evaluation is expensive, this initial series of cost function evaluations can take too long to determine. Instead, the initial temperature was chosen to be sufficiently large so that, early in the algorithm, all new parameter sets were accepted. As the temperature falls, a lower number of cost function increases are accepted.

The strategy suggested by Parks [16] is used in this work. To find a new random parameter set, a vector of random numbers, $\mathbf{u}$, ranging from -1 to +1, is generated. The length of this vector is equal to the number of parameters. Given an old parameter set in the sequence generated by the algorithm, a new parameter set is generated by:

$$\mathbf{p}^{new} = \mathbf{p}^{old} + \mathbf{D}\mathbf{u} \quad 4$$

where $\mathbf{p}$ is the vector of parameter values and $\mathbf{D}$ is a diagonal matrix which contains the maximum allowable step change in each parameter. The matrix $\mathbf{D}$ is updated such that the maximum step size is tuned

towards values that give acceptable changes of the cost function. This is done by updating it as follows:

$$\mathbf{D}^{new} = \alpha_1 \mathbf{D}^{old} + \alpha_2 \mathbf{R} \quad 5$$

where α_1 and α_2 are constants, usually equal to 0.9 and 0.21 respectively (Parks, [16]), and $\mathbf{R}$ is a diagonal matrix whose elements consist of the magnitudes of the successful changes to the values of the parameters.

Figure 5: Simulated annealing algorithm used in this research.

Parks [16] recommends that the probability of accepting an increase of the cost function be modified from Equation 1 to:

$$p = \exp\left(-\frac{\mathcal{J}}{Td}\right) \quad 6$$

where d is the average step size of all the parameters. The algorithm is stopped when the total number of iterations reaches a maximum value specified by the user.

The temperature is dropped by using the cooling scheme proposed by Kirkpatrick *et al.* [7]:

$$T^{new} = \alpha T^{old} \quad 7$$

where α is a constant, typically just under unity. In this work, $\alpha = 0.9$.

4. Reservoir Model

Because many cost function evaluations are required to optimize the process, the reservoir simulation model is relatively simple. It is a two-dimensional, symmetry model but is heterogeneous with respect to porosity, permeability, and oil saturation. The heat loss parameters, fluid properties, rock properties are summarized in Table 1.

Table 1: Reservoir simulation input parameters.

Item	Value
Initial Reservoir Temperature, °C	11
Initial Reservoir Pressure at 310 m depth, kPa	1500
k_v/k_h	0.25
S_{orw}	0.2
S_{wc}	0.15
S_{org}	0.005
S_{gc}	0.05
k_{rwro}	0.1
k_{rcow}	0.992
k_{rogc}	0.834
$k_{rg}(S_{org})$	1
Rock heat capacity, kJ/m ³ °C	2600
Rock thermal conductivity, kJ/m day °C	660
Over/Underburden heat capacity, kJ/m ³ °C	2600
Over/Underburden thermal conductivity, kJ/m day °C	660
Bitumen thermal conductivity, kJ/m day °C	11.5
Bitumen viscosity correlation	A=22.8515
$\ln \ln \mu \text{ (cP)} = A+B \ln T(K)$	B = -3.5784
Methane K-value correlation, K-value =	$k_{v1}=4.364 \times 10^5 \text{ kPa}$
$\frac{k_{v1}}{P} e^{\frac{k_{v4}}{T+k_{v5}}}$	$k_{v4}=-879.84 \text{ °C}$
	$k_{v5} = -270.99 \text{ °C}$

Figure 7 displays the porosity, horizontal permeability, and initial oil saturation distributions in the model. The initial temperature of the reservoir is 11°C and the initial pressure field is determined to be the hydrostatic pressure with a pressure datum of 1500 kPa imposed at 310 m (2 m below top of reservoir). There are several zero porosity barriers in the model that mimic the structure of inclined heterolithic strata

often found in Athabasca reservoirs. The vertical permeability is taken to be 25% of the horizontal permeability. The production well is located at the left edge of the model 2 m above the bottom of the reservoir pay. The injection well is located 5 m above the production well. The wells are each 700 m long (extend into the page).

Figure 7: Porosity, permeability, and initial oil saturation.

In the ES-SAGD process simulation, the injection and production wells are put on steam circulation, modelled as line heaters, for two months. In the model, no steam is injected but the production well and a temporary production well in the location of the injection well relieve the pressure (constrained to 2100 kPa) as the bitumen swells due to thermal swelling. After circulation, the wells are switched to SAGD mode for one month; the injection well injects steam at 250 m³/day and the production well produces fluids with a minimum bottom hole pressure equal to

2000 kPa. After the SAGD period, both steam and solvent are injected into the reservoir at specified rates (this is the ES-SAGD period). The production wells are then constrained to a maximum steam production rate (1 m³/day) and minimum bottom hole pressure (2000 kPa). For solvent, the properties of hexane is used as a surrogate for diluent.

In the optimization case studied here, the adjustable parameters are the steam (expressed as cold water equivalents) and solvent (expressed vapour volume) injection rates at the start of and 6, 12, 24, and 36 months into ES-SAGD mode. This means that there are a total of ten adjustable parameters: five steam and five solvent injection rates. The STARS thermal reservoir simulator by Computer Modelling Group Ltd. was used for each reservoir simulation and the cost function is the cumulative steam-to-oil (cSOR) ratio at the end of five years of ES-SAGD mode, defined by:

$$cSOR = \frac{Q_{steam}}{Q_{bitumen}}$$

where Q_{steam} is the total steam injected (expressed as cold water equivalents) and $Q_{bitumen}$ is the total bitumen produced, both at the end of five years of ES-SAGD mode. The solvent recovery was not included in the cost function because it is typically higher than 80% consistent with the data from field pilots [5,6,8,9].

5. Results

The initial and optimized injection rates are listed in Table 2. For comparison, the cSOR for SAGD (no solvent injection) is also listed. The evolution of the cost function with iteration number is displayed in Figure 8.

The results listed in Table 2 show that for ES-SAGD, in terms of injected volumes, the total amount of steam injected into the reservoir is significantly less than that of SAGD. The results also show that the cSOR is lowered significantly below that of SAGD with the addition of solvent. Also, after the steam and solvent injection strategy is optimized, the cSOR is roughly 53% that of the SAGD value. The optimized steam injection rates are roughly one-third that used in the SAGD case. From the cSOR, this means that nearly one-half the steam is required to produce the same amount of bitumen with the optimized ES-SAGD process as compared to the SAGD process. This implies that by using the optimized ES-SAGD strategy, the costs of steam generation and greenhouse

flue gas emissions (originating from combustion of natural gas) will be cut roughly by one-half of that of SAGD.

Table 2: SAGD, Initial, and optimized ES-SAGD injection rates.

	Inj. Rate, m ³ /day	Parameter ID	Initial Value	Optimized Value	SAGD
Start of ES-SAGD Period	Steam	1	300	100	300
	Solvent	2	1000	2631	0
6 Months into ES-SAGD Period	Steam	3	300	128	300
	Solvent	4	2500	3298	0
12 Months into ES-SAGD Period	Steam	5	300	106	300
	Solvent	6	2500	5586	0
24 Months into ES-SAGD Period	Steam	7	300	100	300
	Solvent	8	2500	6588	0
36 Months into ES-SAGD Period	Steam	9	300	184	300
	Solvent	10	2500	3031	0
cSOR			3.38	2.15	4.03

Figure 8: Convergence of optimization of ES-SAGD by using the SA algorithm.

The simulations reveal that solvent recovery is roughly 90%. This could be considered as most likely the best possible value given that the reservoir simulation model is sealed at its boundaries and no losses of solvent to the far reaches of the reservoir are permitted. However, the solvent recovery is in reasonable agreement with values obtained in field pilots [5,6,8,9].

Figure 8 shows that the cost function initially rises and then falls with iteration number. This is most likely because the initial simulated annealing “temperature” is too high and too many cases are accepted as the algorithm proceeds. At some point, the “temperature” falls below a value and the algorithm becomes more selective and the value of the cost function trends downwards with iteration. From Figure 8, this appears to be happening after roughly 220 iterations.

6. Conclusions

The results of this study demonstrate that ES-SAGD can yield lower cumulative steam-to-oil ratios than SAGD. This implies that a process that uses both steam and solvent can be designed to significantly reduce the amount of injected steam. The optimized ES-SAGD operating strategy uses one-half of the steam per unit volume of produced oil when compared to the constant-rate SAGD process. The solvent recovery predicted from the simulations is about 90% which is in reasonable agreement with existing thermal-solvent field pilots [5,6,8,9]. Because the majority of the injected solvent is produced and can be recycled, the results imply that there are significant economic benefits that can be realized by using ES-SAGD over that of SAGD. These findings are consistent with the SAP pilot at Senlac [5] and commercial SAP operation at Christina Lake [6].

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8. References

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