CHOA
LEADS

- SAGD to Heated Vapex

- Why Technology Development Projects Fail

- Dilation Works on Rock Matrix to Enhance Heavy Oil Production

- Physical Principles Involved in the Recovery of Heavy Oil and Oil Sands Bitumen

- Methods to Reduce Environmental Impact of In-situ Recovery of Heavy Oil and Bitumen

Table of Contents

MARK YOUR CALENDAR - CHOA EVENTS 2024

Digital Twins and VDC for Heavy Oil
Calgary Petroleum Club
May 2, 2024 – 7:30 AM – 9:00 AM

[REGISTER HERE](#)

FORE!CHOA Golf Invitational
Priddis Greens
June 27, 2024 – 6:30 AM – 2:30 PM

Email **office@choa.ab.ca** to reserve your spot.

STAMPEDE IN STYLE
CRAFT Beer Market downtown
July 3, 2024 – 3:30 PM – 6:30 PM

Email **office@choa.ab.ca** to reserve your spot.

CHOA CONNECTS
Hudson, Calgary
November 7, 2024 – 7:30 AM – 6:00 PM

If you want to present at CONNECTS or sponsor the conference, contact **office@choa.ab.ca.**
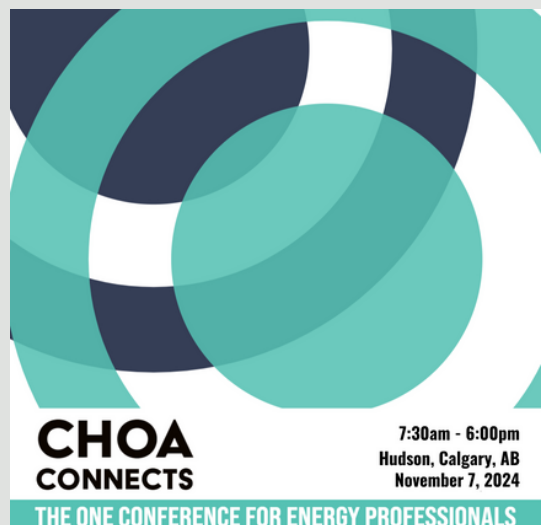
Visit our website for event details and registration: https://choa.ab.ca/events/
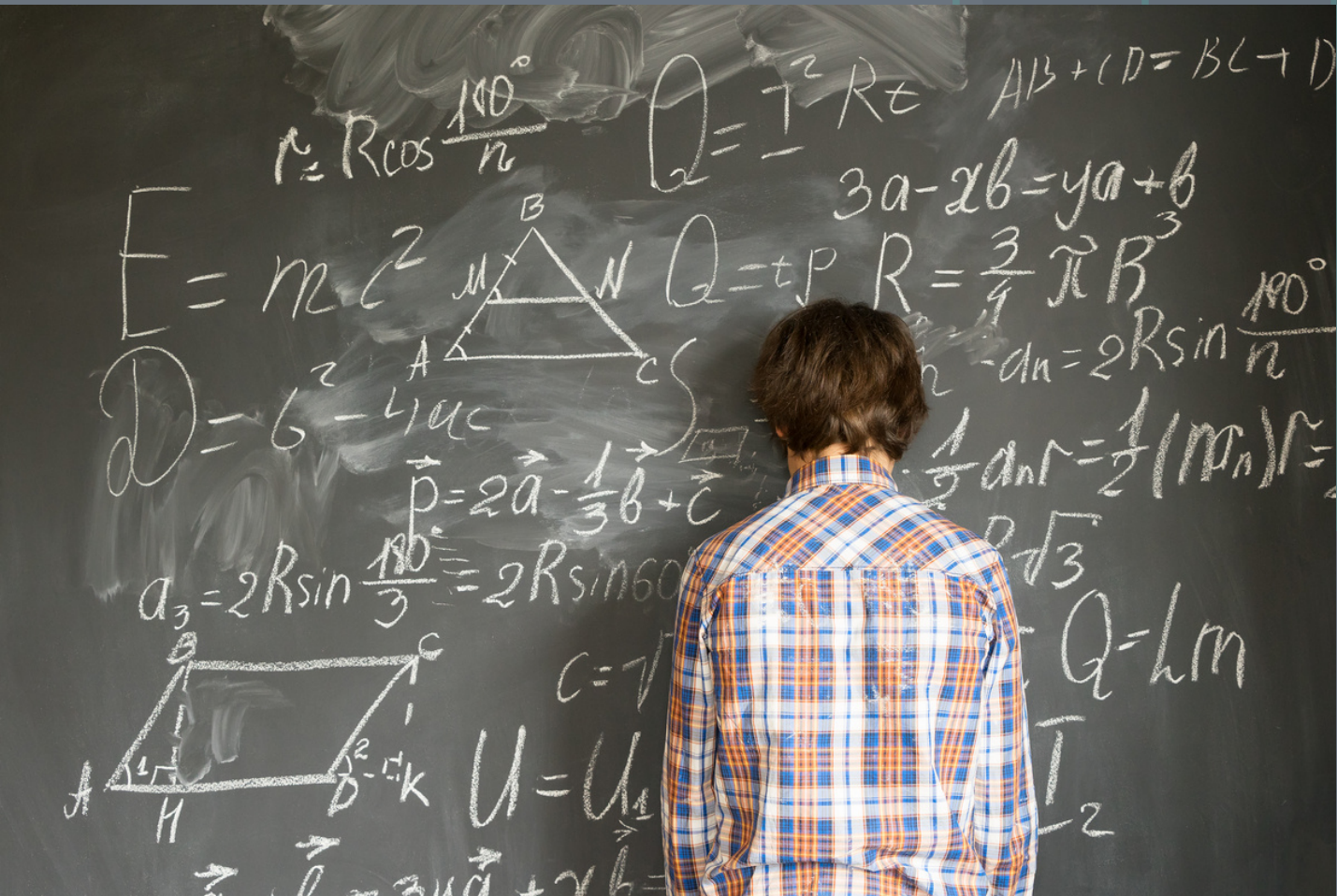
SAGD to Heated Vapex - Part 1: Understanding the Solvent-to-Oil Ratio for Heated Vapex

THOMAS J. BOONE,
T. J. BOONE GEOTECHNICAL AND RESERVOIR CONSULTING LTD.

Abstract

Heated Vapex (HVapex) is a process that has considerable potential to reduce the energy required and associated greenhouse gas (GHG) emissions for the in-situ production of heavy oil and bitumen. However, the opportunity space for exploiting this process is rapidly being eroded as environmental and economic conditions have severely curtailed the number of new developments in oil sands. Part 1 of this paper develops equations for estimating the Cumulative Solvent to Oil Ratio (CSolOR) for HVapex and shows that reservoir heating dictates the required CSolOR. Critically, the value of the CSolOR is much greater than the corresponding Cumulative Steam to Oil Ratio (CSOR) for Steam-Assisted Gravity Drainage (SAGD) at the same reservoir pressure. The high value of CSolOR is a serious challenge because it means that a high volume of solvent must be cycled through the reservoir and processed through facilities. Part 2 of the paper shows how a hybrid, SAGD-HVapex process can address this challenge.

Introduction

HVapex is a gravity drainage process where heated, vaporized solvent is employed instead of steam to mobilize heavy oil or bitumen [Butler and Mokrys, Nenniger]. Because the process operates at lower temperatures than SAGD, it has considerable potential to reduce the energy required and associated greenhouse gas emissions when compared to SAGD. In HVapex, the injection of solvent serves two key functions:

(i) it mixes with the bitumen and heats the mixture to reduce viscosity so that is mobilized and can drain to the production well, and

(ii) it serves to deliver the heat needed to raise the temperature of the liquids, sands, overburden and underburden to maintain the solvent chamber.

Reported estimates for the CSolOR vary greatly. Neninger and Dunn state that hydrocarbon vapors, on a volumetric basis, are much more effective than steam for delivering heat to the bitumen interface. While not explicitly stated, the implication is that, for HVapex operating at temperatures between 30 and 50°C, the CSolOR will be significantly less than a typical SAGD CSOR of 2 to 4. At the other end of the spectrum, Palmgren and Edmunds have reported results for simulations of HVapex employing Naphtha as the solvent and have reported a CSolOR of 19 when operating at temperatures between 200 and 300°C in the solvent chamber.

In the next section, experimental data are used to show that the Solvent to Oil Ratio (SolOR) required for bitumen mobilization is relatively small, on the order of one or less. Subsequently, an equation that was originally developed for estimating the CSOR for SAGD [Edmunds and Petersen] is extended to a form that allows for calculation of a comparable CSolOR for HVapex. Critical to developing this equation is the concept and role of the steam-solvent azeotrope. An azeotrope is defined as a mixture of two liquids that has the same composition in both the liquid and vapour phases during boiling. The role of the steam-solvent azeotrope is addressed subsequently prior to presenting the equation for CSolOR.
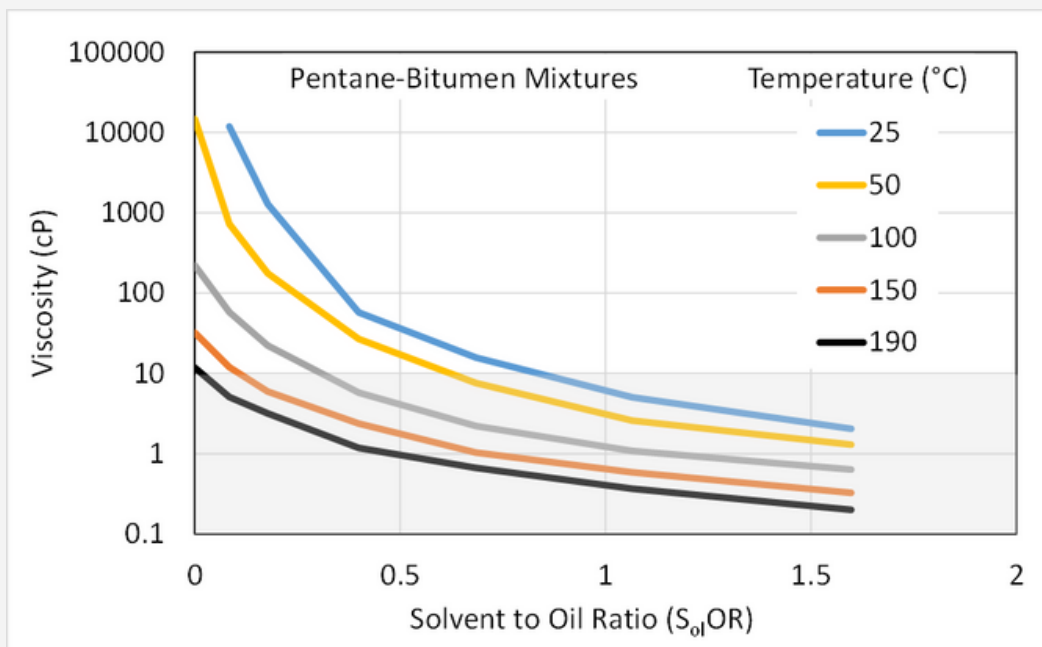

Figure 1 - Solvent to Oil Ratios required to reduce mixtures of Pentane and Athabasca bitumen at various temperatures. Typically, viscosities below 10 cP enable economic SAGD production rates.

HEAT REQUIREMENTS FOR VISCOSITY REDUCTION

In HVapex it is necessary to inject enough solvent to reduce the viscosity of the flowing solvent-heavy oil mixture to a value low enough for an economic production rate. It has been well established by SAGD operations that economic rates for gravity drainage production require the oil phase to have a draining viscosity of less than 10 cP and preferably less than 2 cP. When considering the typical operating regimes of HVapex (50 to 150°C) and the generally preferred solvents (alkanes: C3 to C7), the required solvent SolOR is in the range of 0.1 to 1. For example, Figure 1 is a plot derived from experimental data for Athabasca bitumen mixed with pentane over a range of temperatures [Nourozieh et al.]. The original data are provided as a function of weight fraction of solvent in the mixture. For the purposes herein the weight fraction has been converted to SolOR.The shaded area identifies the regime where the resulting viscosity is 10 cP or less. The plotted lines show the viscosity of bitumen solvent mixtures at different temperatures over a range of SolORs. It can be ascertained from the plot that, for bitumen alone, the temperature must be raised above 190°C for the viscosity to drop below 10 cP. For pentane-bitumen mixtures between temperatures of 150°C and 50°C, an SolOR between 0.1 and 0.6 is needed to reduce the viscosity below 10 cP.
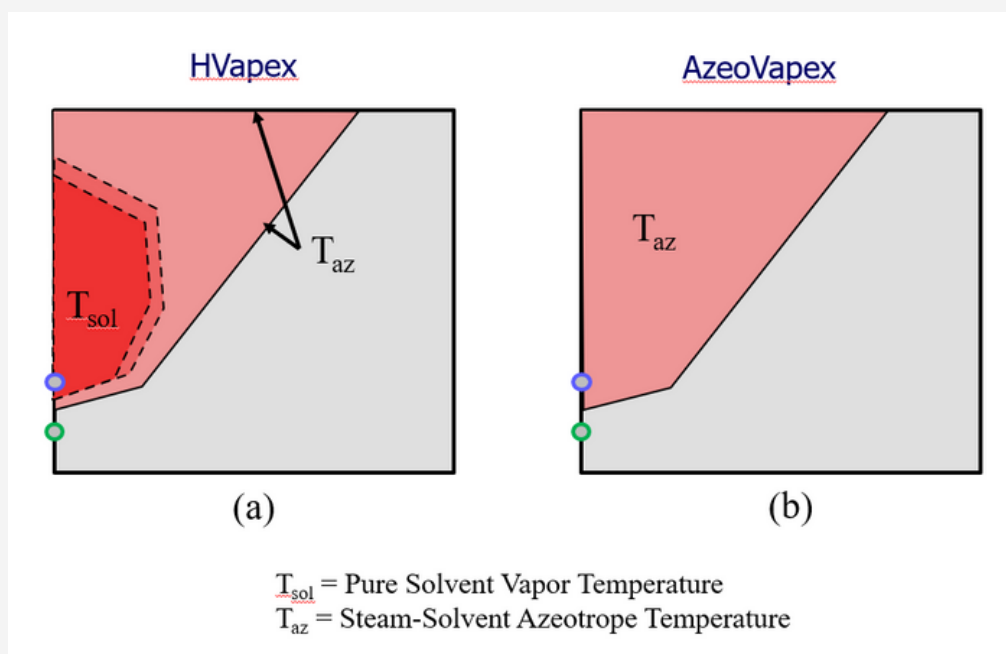

Figure 2: Schematic cross-sections of reservoirs with a horizontal well pair showing the temperature distribution in the reservoir as determined from simulation plots for (a) HVapex with pure heated solvent injection and (b) AzeoVapex with azeotropic solvent-steam injection.

Azeotropic Heated Vapex

The process of HVapex is complicated by the presence of liquid water in the reservoir which itself may be vaporized due to the injection of the heated, vaporized solvent. It is observed in simulations [Khaledi at al., Figure 10] that, when only heated solvents are injected into a reservoir, there is an expanding region around the injection point where all of the water in the reservoir has been vaporized and there is only solvent in the vapor phase. Outside of this region, water vapor and solvent are present in the vapor phase at a lower temperature, mostly at or near the azeotrope temperature Taz, for the steam-solvent mixture. At the boundary of the solvent chamber, the temperature is also at or near Taz. In simulation results, it is observed that there is a relatively sharp or rapid transition from the region near the wellbore at the solvent dew point temperature, Tsol , to a second region that is at or near Taz [Khaledi et al., Palmgren and Edwards]. These features are illustrated in Figure 2 (a).
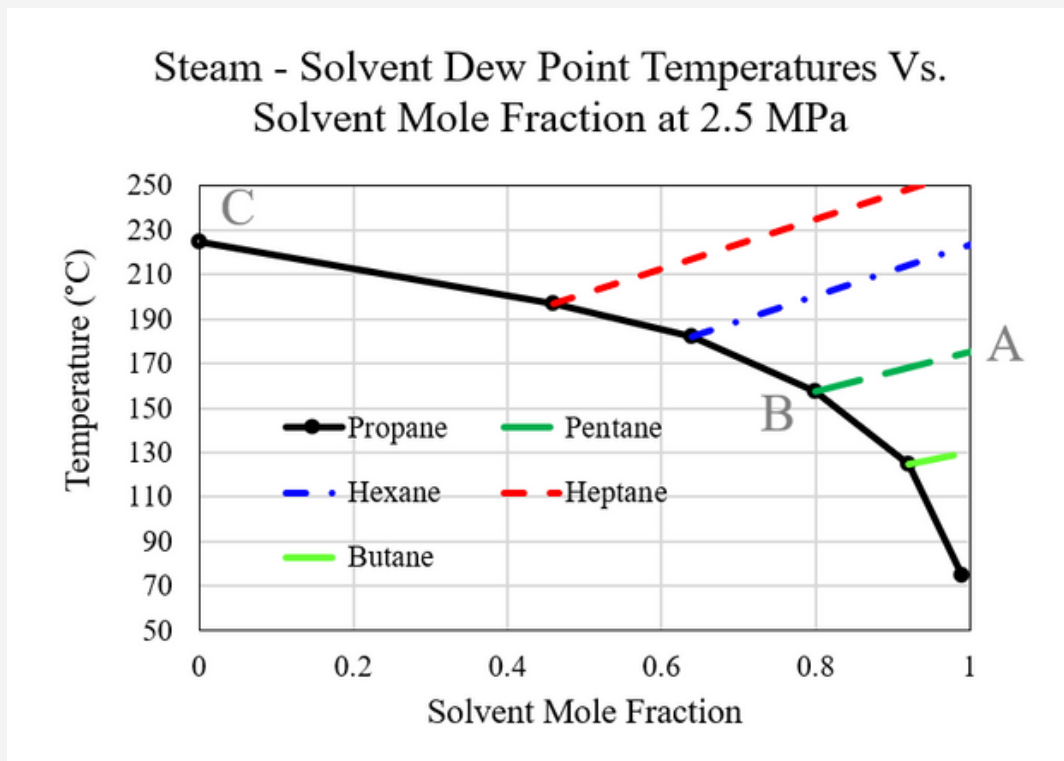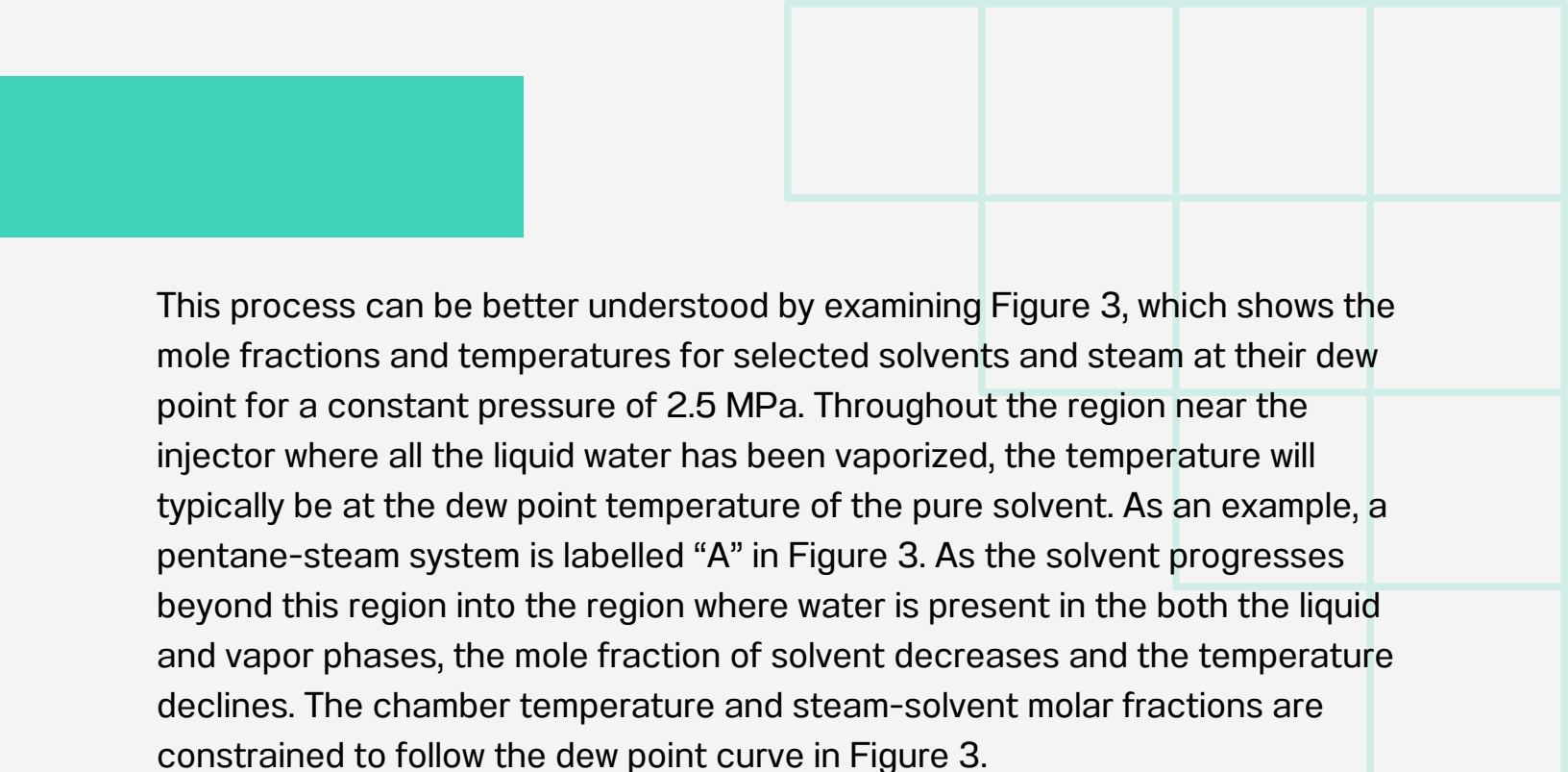

Figure 3: Plot of steam-solvent dew points for selected alkanes as a function of temperature and solvent mole fraction at 2.5 MPa. For Pentane, A is the pure solvent dew point, C is the steam dew point and B is the azeotrope.

This process can be better understood by examining Figure 3, which shows the mole fractions and temperatures for selected solvents and steam at their dew point for a constant pressure of 2.5 MPa. Throughout the region near the injector where all the liquid water has been vaporized, the temperature will typically be at the dew point temperature of the pure solvent. As an example, a pentane-steam system is labelled "A" in Figure 3. As the solvent progresses beyond this region into the region where water is present in the both the liquid and vapor phases, the mole fraction of solvent decreases and the temperature declines. The chamber temperature and steam-solvent molar fractions are constrained to follow the dew point curve in Figure 3.

The minimum temperature that can be reached in the solvent chamber is the azeotrope temperature, which for pentane is labelled "B" in Figure 3. The practical significance in this case is that both the solvent and water co-condense out of the vapor chamber at this temperature at same mole fraction as the gas itself. Phase behavior dictates that, where liquid water is present in the solvent chamber, the temperature will be at or near the azeotrope temperature.

Building on this understanding, Khaledi et al. introduced the concept of Azeotropic Vapex (AzeoVapex) which is a version of HVapex where a solvent-steam mixture is injected at the azeotropic mole fraction with its associated lower temperature than solvent-only injection. Since the steam and solvent will condense at the same mole fraction as the injected mixture, the steam-solvent mole fraction will be constant everywhere in the steam solvent chamber, as is illustrated in Figure 2(b). Additionally, there is no driver to vaporize water in the reservoir and the temperature is constant everywhere in the chamber at the azeotrope temperature, thus reducing the heat requirement and therefore the SolOR. An added benefit is that even a small mole fraction of steam injection can significantly increase the working heat content of the injected fluids. As AzeoVapex is a form of HVapex, the term HVapex will be used herein to refer collectively to both processes.

From a theoretical perspective, it is very useful to consider AzeoVapex because the injected vapor mixture effectively behaves as a single fluid, as described by Khaledi et al., which allows equations that have been developed to estimate the CSOR for SAGD to be easily modified in order to calculate the SolOR for AzeoVapex.

Calculation of the Cumulative SolOR (CSolOR) Needed to Heat the Steam-Solvent Chamber

SAGD operations in Canada typically operate at a Cumulative Steam-to-Oil-Ratio (CSOR) between 2 and 4. The CSOR is dictated by the heat required to raise the reservoir sands and fluids to the steam temperature plus the additional heat input to account for heat conduction into the overburden and underburden. Edmunds and Peterson have provided a practical method for estimating the Cumulative Steam-to-Oil Ratio (CSOR) that is applicable to SAGD operations. The resulting Equation is:

$$CSOR = \frac{S}{O} = \left(\frac{\Delta T}{H_{lv}\phi\Delta S_o}\right)\left(C_{vr} + \frac{\sqrt{k_t C_{vo}\, t}}{h\eta_s}\right) \qquad (1)$$

where S is the total steam injected at time t, O is the total Oil Produced at time t, $\Delta T = T_s - T_o$ is the temperature rise above the initial temperature where T_s is the steam temperature and T_o is the original reservoir temperature, H_{lv} is the latent heat of condensation of steam, ϕ is the reservoir porosity, $\Delta S_o = S_{oi} - S_{or}$ where S_{oi} is the initial oil saturation and S_{or} is the residual oil saturation. C_{vr} is the initial reservoir volumetric heat capacity, k_t is the overburden thermal conductivity, C_{vo} is the overburden volumetric heat capacity, t is the time since first steam injection, h is the height of the reservoir above the producer and h_s is a geometric shape factor (e.g., 0.5 for a triangular chamber prior to chamber coalescence).

Notably the terms in the first of the bracketed terms in Equation 1 incorporate the critical fluid parameters for steam and oil that impact the CSOR. The two parameters in the second bracketed term in Equation 1 respectively represent: (i) the heat required to heat the reservoir where the oil is being depleted, and (ii) the heat lost to the overburden and underburden.

Tables 1 and 2 provide a set of material and physical parameters that will be used in a series of example calculations. When the parameters from these tables are substituted into Equation (1), the CSOR is determined to be 2.7.

Geometry and Reservoir Parameters		
Symbol	Description	Value[1]
	Well Parameters	
h	Reservoir Height, m	20
w	Well Spacing, m	100
L	Well Length	1000
	Reservoir Parameters	
ϕ	Porosity	0.32
S_{oi}	Initial Oil Saturation	0.8
S_{or}	Residual Oil Saturation	0.15
P	Reservoir Pressure, MPa	2.5
T_o	Initial reservoir temperature, °C	12
C_{vo}	Overburden heat capacity, MJ/m^3	2.23
C_{vr}	Reservoir heat capacity, MJ/m3	2.23
k_t	Overburden thermal conductivity, MJ/m-°C-year	85
	CSOR/CSolOR Equation Parameters	
ΔS_o	Change in Oil Saturation (S_{oi} - S_{or})	0.65
η_s	Chamber Shape factor	0.5
t	Time (years)	5
	[1] Values used in calculations	

Table 1: Symbols and values for geometry and reservoir parameters

Steam, Solvent and Azeotropic Parameters				
Symbol	Description	Values[1]		
		Steam	Butane	Pentane
P	Pressure, Mpa	2.5	2.5	2.5
Ts	Steam Temperature, °C	224.5		
ρ	Reference Density, kg/m³	1000	604	630
T_{sol}	Solvent Vapor Temperature, °C		130	175
C_p	Vapor Heat Capacity, kJ/kg/°C		2.2	2.3
H_{lv}	Latent Heat of Condensation, kJ/kg	2000	190.6	208
H_{lv}	Latent Heat of Condensation, MJ/m³	2000	115	131
x_a	Azeotrope Mole Fraction of Solvent		0.92	0.8
T_a	Azeotrope Temperature, °C		125	157.7
H_{lv}	Latent Heat for Azeotrope Fluid Mixture, MJ/m³		145	202
	[1] Values used in calculations			

Table 2: Symbols and values for steam, solvent and azeotrope parameters

Extension of the CSOR calculation to AzeoVapex

As was noted previously, for the case of azeotropic solvent injection, it can be assumed that the molar steam-solvent ratio and the temperature in the vapor is constant everywhere at the azeotrope. As a result, the properties of the azeotropic mixture can be directly substituted into Equation (1) for the steam properties to derive a comparable equation for AzeoVapex:

$$CS_{az}OR = \frac{S+S_{ol}}{O} = \left(\frac{\Delta T}{H_{az}\phi \Delta S_o}\right)\left(C_{vr} + \frac{\sqrt{k_t C_{vo}\, t}}{h\eta_s}\right) \tag{2}$$

and,

$$CS_{az}OR = CSOR + CS_{ol}OR \tag{3}$$

CHOA PLATINUM SPONSORS

Where CSazOR is the Cumulative Solvent-Steam mixture to Oil Ratio at time t, Sol is the total solvent injected at time t, and Haz is the latent heat of condensation of azeotropic steam-solvent mixture. It should also be noted that the azeotrope temperature, Taz, rather than the steam temperature, Ts, is utilized in determining ΔT = Taz – To. All volumes presented in the paper are converted to the reference liquid densities listed in Table 2.

Extension of the CSOR calculation to HVapex

In developing an equation for the CSolOR for HVapex, there is no similar simple substitution as was employed to develop Equation (2). However, an approximation can be made. It is observed in simulations of HVapex that there is a region around the injection well where the temperature of the reservoir is raised to the injection temperature of the solvent, Tsol, and the water saturation is zero. At the boundary of this region there is a relatively sharp transition, and outside this region the temperature is at or near the azeotrope temperature, Taz. The boundary of the chamber is also at or near Taz. Equation (2) can be modified to account for these observations by assuming that the transition zone for the temperature from Tsol to Taz within the solvent chamber is small and there are two separate regions in the reservoir as illustrated in Figure 2(a). Additionally, since the solvent is injected as a vapor typically at its dew point temperature, Tsol , then a term is added for heat released by the vaporized solvent as it cools from Tsol to Taz. The resulting equation is:

$$CS_{ol}OR = \frac{S_{ol}}{0} = \left(\frac{1}{(H_{lv}+C_p(T_{sol}-T_{az}))\phi\Delta S_o}\right)\left(C_{vr}(T_{az} - T_o) + \beta C_{vr,d}(T_{sol} - T_{az}) + \frac{\sqrt{k_t C_{vo} t}}{h\eta_s}(T_{az} - T_o)\right) \quad (4)$$

where Hlv is the heat of vaporization or the solvent at Taz, Cp is the volumetric heat capacity of the vaporized solvent, Cv, d is the drained reservoir volumetric heat capacity (i.e., Sw = 0, So = Sor) and b is the fraction of the solvent chamber occupied by the region with the temperature of Tsol.

IMPACTS OF KEY PARAMETERS ON THE CSolOR

Table 3 lists calculated values of the CSOR and CSolOR for SAGD, HVapex and AzeoVapex employing butane and pentane at 2.5 MPa when the parameters listed in Tables 1 and 2 are substituted into the equations above. A critical observation is that, while the CSolOR values for processes employing butane and pentane are similar, the values for the CSolOR are an order of magnitude greater than the CSOR for SAGD.

Calculated CSOR and CSolOR Values		
Case	CSOR	CsolOR
SAGD (Equation 1)	2.70	
AzeoVapex - Butane (Equation 2)	0.32	19.5
HVapex - Butane (Equation 4)		23.7
AzeoVapex - Pentane (Equation 2)	0.70	17.7
HVapex - Pentane (Equation 4)		23.8

Table 3: Calculated values for CSOR and $CS_{ol}OR$

Figure 4 plots CSOR and CSolOR values for processes employing steam and butane over a range of pressures. CSolOR values are much greater than the CSOR values over the full range of 1.0 to 2.5 MPa. This observation highlights that a key challenge for HVapex and AzeoVapex is the large volumes of solvent required to heat the reservoir. The line for CSOR with SAGD is terminated at 1 MPa because, at operating pressures below 1 MPa where steam temperatures are below 180°C, the viscosity of the heated bitumen is typically too high for viable SAGD operations in Canadian oil sands.This illustrates that there is a unique opportunity space to employ HVapex in reservoirs requiring a lower operating pressure.

It should be noted that for a specific operating pressure, SAGD requires a significantly higher chamber temperature than does HVapex operating with either butane or pentane. Figure 5 plots the key temperature parameters for steam and butane versus operating pressure. The lower operating temperatures are the key driver for the potential energy savings and GHG reductions of HVapex relative to SAGD.

The values plotted in Figure 4 assume that the oil production rate for HVapex and SAGD are the same. However, this may not be the case. Khaledi et al. report that simulations employing HVapex resulted in two to three times the oil rate of SAGD in the same model at the same pressure. Equations (1), (2) and (4) can be used to assess the impact of oil rate by comparing the calculated CSolOR and CSOR values at different times but at the same volumes of oil recovery. Figure 6 plots these values as a function of the oil production rate. It is seen that higher oil rates result in lower CSolOR and CSOR values. However, as can be ascertained from the plot and Equations (1), (2) and (4), the production rate has a secondary impact on the CSolOR.
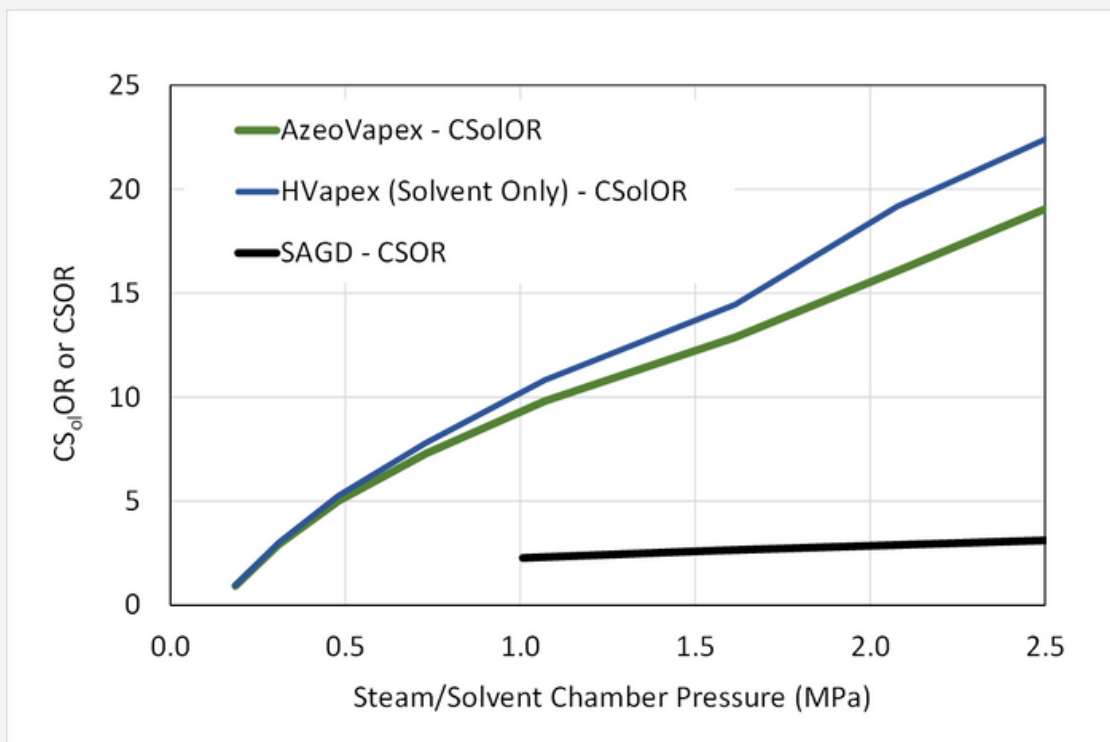
Figure 4: Plot of CSOR and CSolOR versus pressure for processes employing steam and butane. The line for the CSOR for SAGD is terminated at 1 MPa since SAGD is typically not viable below 1 MPa in Canadian oil sand deposits.

Figure 5: Plot of temperature parameters for steam and butane versus pressure.

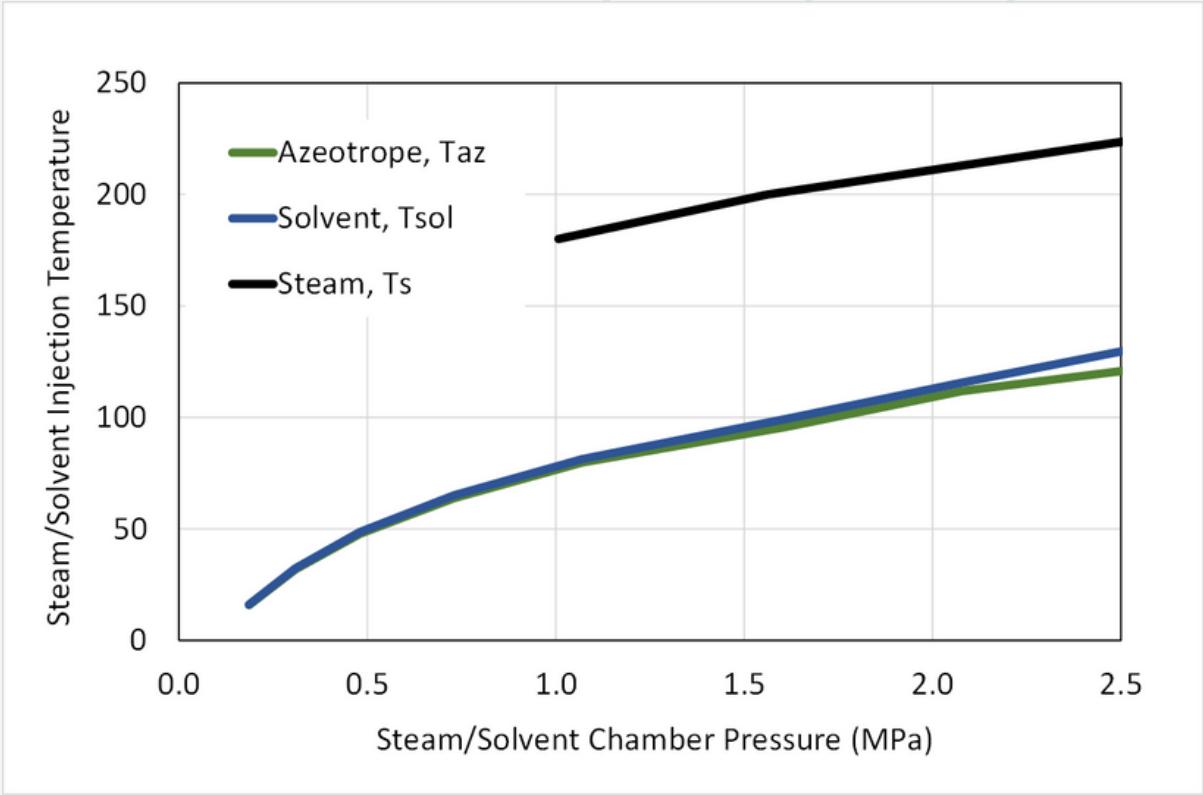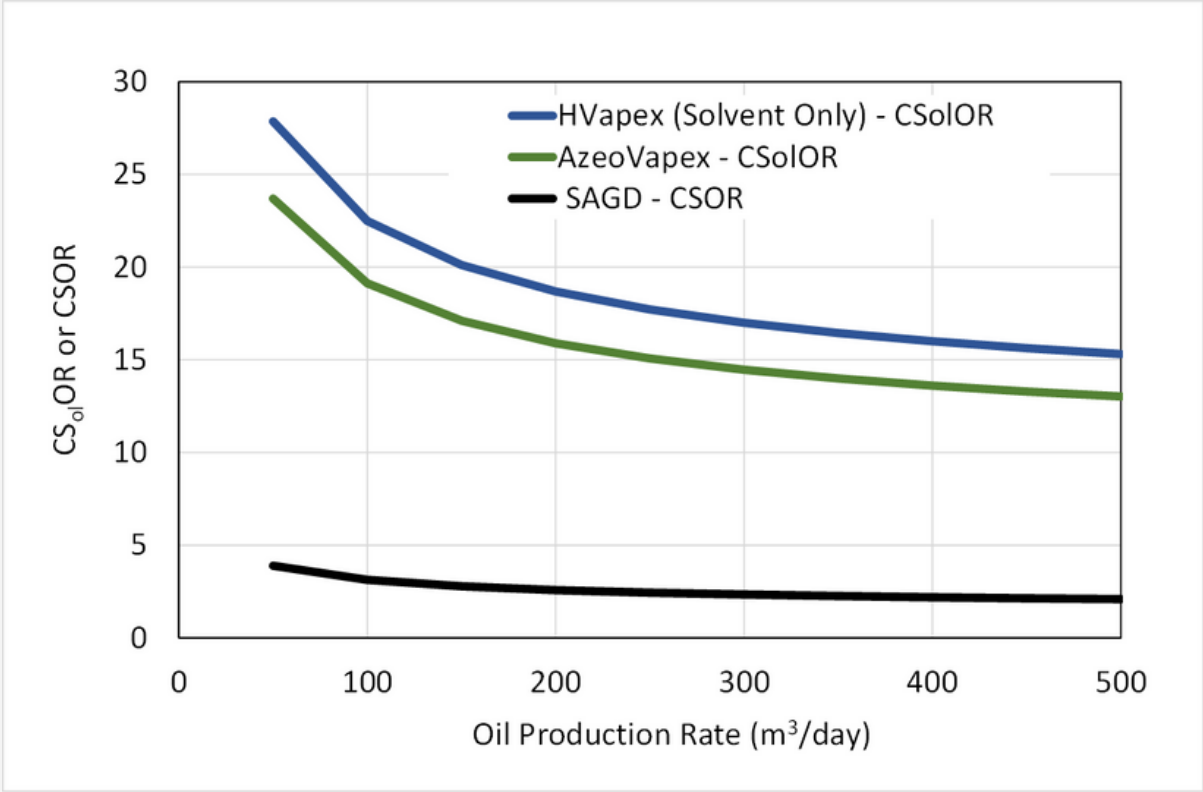
Figure 6: Plot of CSolOR and CSOR versus oil production rate for processes employing steam and butane at the same recovery level (i.e. chamber coalescence).

DISCUSSION OF THE CSolOR VALUES FOR AZEOVAPEX AND HVAPEX

The values of the CSolOR for the HVapex cases calculated using the equations above are derived by determining the fluid volumes required to heat the reservoir, as well as the overburden and underburden materials. The values are found to be much greater than the values of the SolOR (0.1 to 0.6, Figure 1) required to reduce the viscosity of the oil sufficiently to enable economic production rates. Since it is a fundamental necessity to heat the materials, heat requirements will necessarily dictate the operating CSolOR. However, the relatively high CSolOR does have potential to allow for increased oil production rates by further reducing the viscosity of the flowing oil phase.

The primary factor driving the relatively high CSolOR's for the HVapex processes is the heat of vaporization which, for the alkanes used in HVapex, is typically between 200 and 400 kJ/kg, whereas for steam it is on the order of 2000 kJ/kg, as is shown in Table 2. This difference reflects the fact that steam is a much more effective working fluid for heat transfer.

Palmgren and Edwards compare results from Equation (1) with field data and find it to be reasonably consistent. Similarly, the values for CSolOR calculated using Equations (2) and (4) are found to be reasonably consistent with other values reported in the literature. However, none of the cases reported provide sufficient data to make a direct comparisons using the equations developed herein. Palmgren and Edmunds have reported results for simulations of HVapex employing naphtha as the solvent, and have reported a CSolOR of 19 when operating at 1.6 MPa. Khaledi et al. found CSolOR values of approximately 6 for HVapex and 4 for AzeoVapex in simulations where the comparable CSOR for SAGD was 1.7 when operating at reservoir pressure of 1 MPa and using pentane as the solvent. In the cases reported by Khaledi at al., CSolOR values are also reduced relative to the CSOR value because the simulations allow for a two to three times higher oil production rate with the HVapex processes.

A CSolOR value of approximately 7 has been reported by Nsolv Corporation for its HVapex field pilot which operated with a butane solvent chamber at about 60°C. This value may have been adversely affected by operating issues encountered during the pilot. But critically, in all cases, the observed or calculated CSolOR values are consistently much higher than the comparable CSOR for SAGD in the same reservoir.

CONCLUSIONS

Calculated values of the CSolOR demonstrate two important results:

(i) The CSolOR required for heating the reservoir materials is much larger than that required for mobilizing the bitumen. Hence, the heating requirement will dominate.

(ii) Even though HVapex can operate at lower temperatures than SAGD in the same reservoir at the same pressure, the required CSolOR for HVapex is much larger than the comparable CSOR for SAGD. This is a major limitation for HVapex because of the facilities in the field that will be required to manage the large volumes of fluids. Also, the solvent itself is costly.

Part 2 of the paper addresses the challenge by introducing and analyzing a hybrid SAGD to HVapex process, where HVapex is employed as a follow-up to SAGD operation.

REFERENCES

Butler, R.M., Mokrys, I.J.: A new process (VAPEX) for recovering heavy oils using hot water and hydrocarbon vapor. JCPT, 30(1), 97-106 (1991).

Edmunds, Neil, and Jeff Peterson. "A Unified Model for Prediction of CSOR in Steam-Based Bitumen Recovery." Paper presented at the Canadian International Petroleum Conference, Calgary, Alberta, June 2007. doi: https://doi.org/10.2118/2007-027

Khaledi, Rahman , Motahhari, Hamed Reza, Boone, Thomas J., Fang, Chen , and Adam S. Coutee. "Azeotropic Heated Vapour Extraction- A New Thermal-Solvent Assisted Gravity Drainage Recovery Process." Paper presented at the SPE Canada Heavy Oil Technical Conference, Calgary, Alberta, Canada, March 2018.
doi: https://doi.org/10.2118/189755-MS

Nenniger, E.; Hydrocarbon Recovery, Canadian Patent CA 1059432, Filed Dec. 24, 1976.

Nenniger, J.E., and S.G. Dunn. "How Fast is Solvent Based Gravity Drainage?." Paper presented at the Canadian International Petroleum Conference, Calgary, Alberta, June 2008. doi: https://doi.org/10.2118/2008-139

Nourozieh, Hossein , Kariznovi, Mohammad , and Jalal Abedi. "Viscosity Measurement and Modeling for Mixtures of Athabasca Bitumen/n-Pentane at Temperatures Up to 200°C." SPE J. 20 (2015): 226–238.
doi: https://doi.org/10.2118/170252-PA

NSolv Corporation, Non-Confidential Final Report,CCEMC Project ID: H110031 - BEST Pilot Project, May 31, 2015

Palmgren, Claes, and Neil Edmunds. "High Temperature Naptha to Replace Steam in the SAGD Process." Paper presented at the SPE International Heavy Oil Symposium, Calgary, Alberta, Canada, June 1995.
doi: https://doi.org/10.2118/30294-MS

Calgary Influential Women in Business Awards (CIWB) Announces 2024 Honourees

Calgary, AB - March 8, 2024 - The Calgary Influential Women in Business (CIWB) Awards proudly announces the exceptional honourees for 2024, recognizing outstanding leaders who have made significant contributions to Calgary's business community. These recipients will be recognized and celebrated at the CIWB Awards Gala on April 12, 2024.

The CIWB Awards, now in its fifth year, continues to highlight the achievements of women leaders and their allies, fostering a culture of inclusion and empowerment in Calgary's corporate landscape. The 2024 CIWB Award winners are as follows:

- Lifetime Achievement: **Lorraine Mitchelmore**, formerly President and Country Chair/EVP Shell Canada, now serving as an Independent Director for several organizations, including Suncor, BMO, AIMCo, Cheniere Energy, Shell, Catalyst, and Trans Mountain.
- Male Champion: **Bryan de Lottinville**, Founder and Chief Evangelist of Benevity.
- Large Enterprise: **Doreen Cole**, EVP of Downstream at Cenovus.
- Small/Medium Enterprise: **Jennifer Massig**, CEO of Magna Engineering Services.
- Professional Services: **Alicia Quesnel**, Managing Partner at BDP LLP.
- Social Enterprise: **Wendy Beauchesne**, CEO of Alberta Cancer Foundation.

"We are delighted to honour these exceptional individuals whose remarkable leadership not only propels Calgary's business community forward but also champions the advancement of women and diversity. The proceeds from the CIWB Awards directly contribute to Axis Connects, a non-profit committed to empowering women professionals into pivotal decision-making roles."
- Heather Culbert, co-founder of Axis Connects.

The event promises to be an inspiring evening, bringing together leaders, influencers, and advocates committed to driving positive change in Calgary and beyond. For more information about the Calgary Influential Women in Business Awards or to inquire about sponsorship opportunities, please visit: www.ciwbawards.com. Award honourees are available for interview, Award Honourees' bios and the full list of 2023 CIWB Selection Committee members are available upon request.

About Axis Connects
Axis Connects is changing leadership. From the c-suite to the boardroom, we support and accelerate the advancement and recognition of gender diversity throughout our business community. We believe that gender diversity at the leadership table matters. Through Axis Connects' programs, workshops, networks, and events, we support women in their journey towards leadership positions and professional potential. www.axisconnects.com.

About the Calgary Influential Women in Business (CIWB) Awards
The Calgary Influential Women in Business (CIWB) Awards recognize the incredible business leaders advancing women and diverse professionals in Calgary. Honourees were chosen based on their professional accomplishments, advocating for advancing women, influence, and business community involvement. The CIWB Awards recognizes five outstanding female business leaders and one male champion for women in Calgary and celebrates their accomplishments. www.ciwbawards.com.
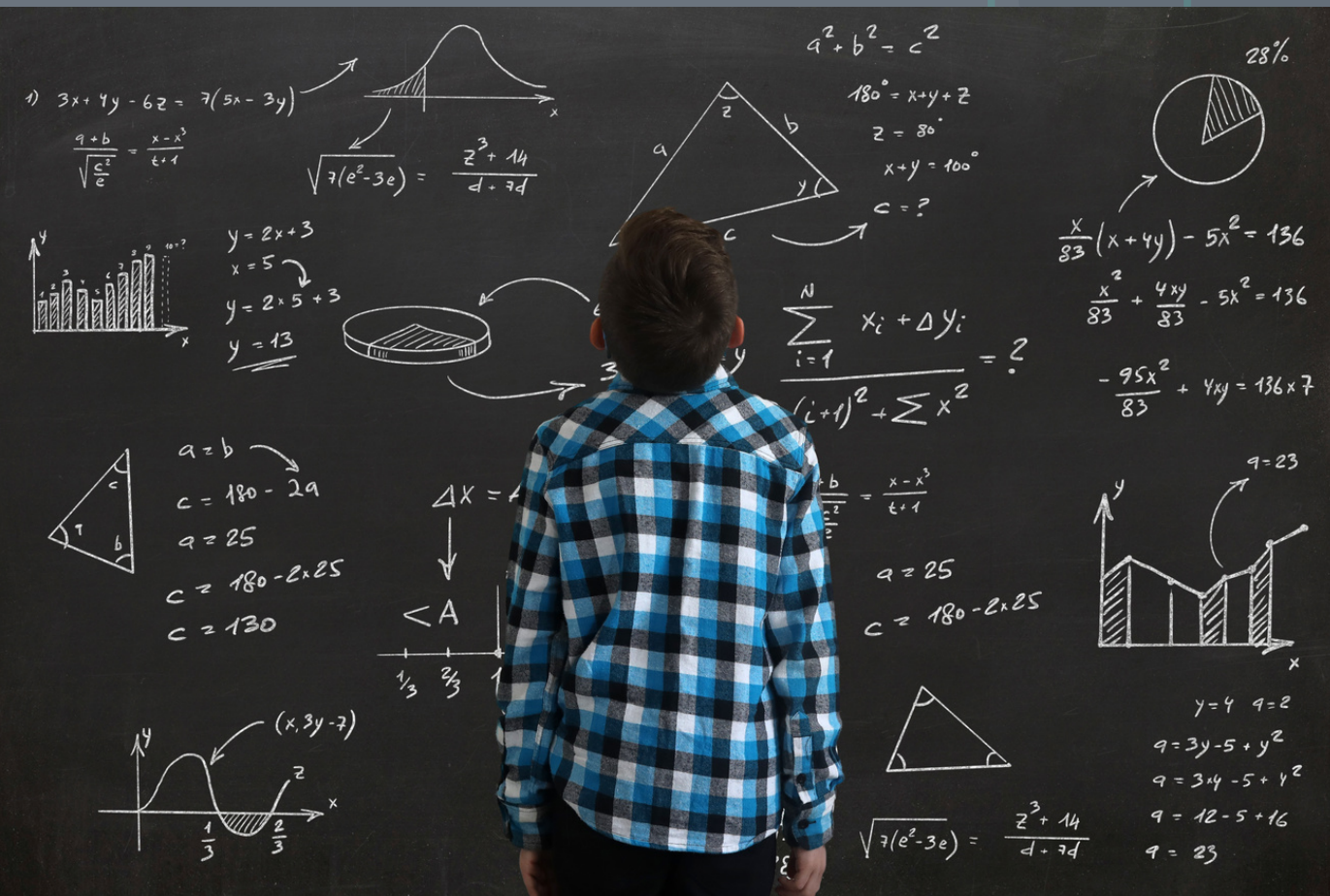
SAGD to Heated Vapex - Part 2: An End Game Recovery Process for Oil Sands

THOMAS J. BOONE
T. J. BOONE GEOTECHNICAL AND RESERVOIR CONSULTING LTD.

ABSTRACT

Heated Vapex (HVapex) is a process that has considerable potential to reduce the energy required and associated greenhouse gas (GHG) emissions for the in-situ production of heavy oil and bitumen. However, the opportunity space for exploiting this process is rapidly being eroded as environmental and economic conditions have severely curtailed the number of new developments in oil sands.

Part 1 of this paper showed that heating of the reservoir and surrounding materials dictates the required Cumulative Solvent to Oil Ratio (CSolOR), and the values of the CSolOR are much greater than comparable Cumulative Steam to Oil Ratio (CSOR) values for Steam-Assisted Gravity Drainage (SAGD). As a result, HVapex must cycle large volumes of solvent through the surface facilities and the reservoir to deliver the heat. This is a critical challenge to implementing the process.

This second part of the paper addresses the challenge by introducing and analyzing a hybrid SAGD to HVapex process, where HVapex is employed as a follow-up to SAGD operation. A simple but illustrative simulation model has been developed to analyze the SAGD-HVapex process. The model is used to show that by appropriately choosing the solvent and the timing for the start of solvent injection, the SAGD-HVapex process can capture most of the energy saving benefits of the solvent-only, HVapex process. The process utilizes steam to deliver most of the necessary heat to the reservoir, thereby greatly reducing the volume of solvent injected. SAGD-HVapex has several additional practical advantages relative to employing HVapex as the primary process that are discussed. Critically, the process greatly expands the opportunity space for capturing the benefits of HVapex.

INTRODUCTION

IHVapex is a gravity drainage process where heated, vaporized solvent is employed instead of steam to mobilize heavy oil or bitumen [Butler and Mokrys, Nenniger]. Because the process operates at lower temperatures than SAGD, it has considerable potential to reduce the energy required and associated greenhouse gas emissions when compared to SAGD. An optimization of the HVapex process which has significant practical benefits is Azeotropic Vapex (AzeoVapex) where steam and solvent are injected at or near the molar fractions of steam and solvent at the azeotrope [Khaledi et al.] Since AzeoVapex is an optimization of HVapex, the term HVapex is used herein to refer collectively to both HVapex and AzeoVapex.

In Part 1 of this paper, equations were developed for estimating the CSolOR for both HVapex and AzeoVapex. Critically, it was shown that heat requirements rather than viscosity reduction dictate the CSolOR. It was also shown that the CSolOR for HVapex is much greater than the CSOR for SAGD operating in the same reservoir at the same pressure but at differing temperatures. This is an important limitation, because it means that HVapex requires large volumes of solvent to be cycled through the facilities and the reservoir.

A relatively simple but effective method for addressing the challenge of high solvent volumes is to employ SAGD for a large fraction of the operating life of a well pair then switch to HVapex [Boone]. This process will be referred to as SAGD-HVapex or SAGD-AzeoVapex. When the solvent is appropriately selected and the timing for the start-up of solvent injection optimized, approximately 80% of the heat savings benefits of HVapex can be captured while reducing the total volume of solvent injection by about 80%. This is a practical optimization that has number of other operating benefits as well.

The fundamental difference between the process as described herein and others, such as SAVEX [Gutek et al.], is the timing for the start of solvent injection. SAVEX starts solvent injection prior to the steam chamber rising to the top of the reservoir whereas, in SAGD-HVapex, solvent injection is started much later in the operating life of the well pair.

The SAGD-AzeoVapex process employing butane is used as a primary example case in the plots that follow. From a practical perspective, AzeoVapex is considered preferable because it more efficiently uses a steam-solvent mixture rather than just solvent to deliver heat to the reservoir. Calculations show that both butane and pentane can be effectively employed as the solvent. However, butane offers the potential for greater energy savings.

SAGD-HVAPEX PROCESS

Figure 1 is a useful aid for explaining the process in the reservoir. It shows the mole fractions and temperatures for selected solvents and steam at their dew point for a constant pressure of 2.5 MPa. When SAGD is operated at 2.5 MPa, a steam chamber develops and everywhere within that chamber the temperature is at or near the saturated steam temperature, Ts, which is labelled "A" in Figure 1. After the start of solvent injection, as the molar fraction of solvent increases, the temperature declines following the black dew point curve shown in Figure 1. For the case of azeotropic steam-butane injection, the average temperature in the chamber will, in time, approach the azeotrope temperature which is labelled "B" in Figure 1. The transition to AzeoVapex is complete when the temperature everywhere in the chamber is at the azeotrope temperature.
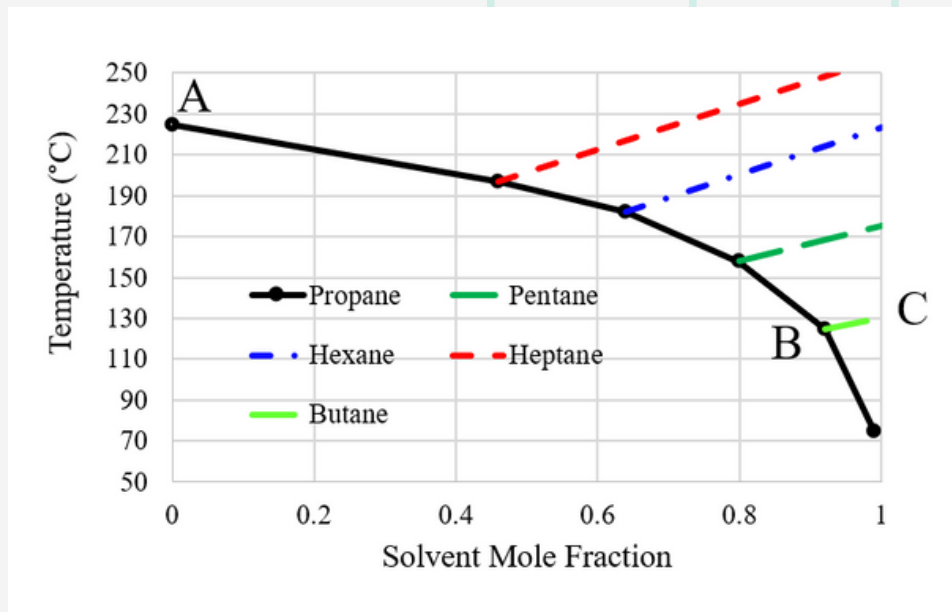
Figure 1: Plot of steam-solvent dew points for selected alkanes as a function of temperature and solvent mole fraction at 2.5 MPa. A is the steam dew point, C is pure butane dew point and B is the steam-butane azeotrope.

The process is also illustrated schematically in Figure 2 (a), which shows the transition of the average temperature in the steam-solvent chamber and at the temperature at the boundary prior to and after the start of solvent injection. Figure 2 (b) is a schematic drawing of the idealized temperature distribution after the start of solvent injection. The process in the reservoir transitions from SAGD to HVapex over a period of time as the temperature in the steam-solvent chamber declines. The solvent injection rate is increased with time as is required to maintain the pressure in the steam-solvent chamber. Within the chamber, the temperature decline is dictated by the increasing solvent mole fraction and the phase behaviour of the steam-solvent system. As the temperature declines, heat is released from the reservoir materials in the chamber, which drives vaporization of water in the reservoir. The actual water that vaporizes consists of both the initial reservoir water saturation and draining water from steam that has condensed at the boundary. This mechanism allows for previously injected heat that is stored in the reservoir materials to be used to continue to drive the gravity drainage process after the start of solvent injection. As the process progresses, the mole fraction of solvent in the steam-solvent chamber increases, the temperature declines and the process effectively transitions from SAGD to HVapex.

During the SAGD process considerable heat is lost to the overburden and underburden. Where the steam chamber has contacted the top of the reservoir, the edge of the overburden is at the steam temperature and heat is conducted upwards into the overburden. After the start of solvent injection, the temperature at the boundary transitions relatively quickly to the lower azeotrope temperature. For a short period of time heat may be conducted from the overburden back into the reservoir. However, for the most part, the temperature in the overburden will simply redistribute within the overburden itself and evolve towards a state like what would have resulted from HVapex alone. The net result is that minimal additional heat may be lost to the overburden and underburden after the start of solvent injection when solvent injection is optimally selected.
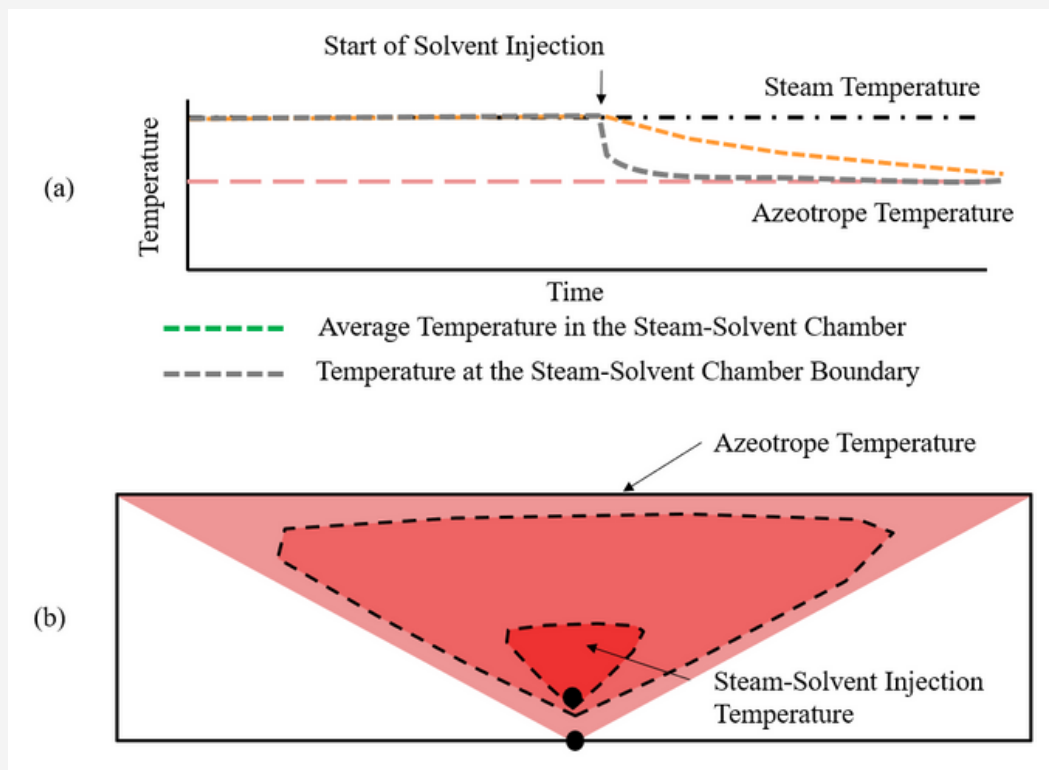

Figure 2: Schematic of the SAGD-HVapex process showing (a) temperatures versus time and (b) temperatures in the reservoir

OPTIMIZATION OF SAGD-HVAPEX PROCESS

The optimization of a SAGD-HVapex process involves selection of the optimal solvent and optimal time to start injection of the solvent. Of course, consideration must also be given to the practical issues such as solvent availability and cost, as well as existing facility limitations.

Selection of the Solvent

A key driver for the solvent selection is to minimize the total energy requirement for the full recovery of bitumen from the reservoir being drained by the well pair. This can be achieved by choosing a solvent with the lowest azeotrope temperature and then operating in a manner such that, at the end of production, the solvent-steam chamber has been reduced to the azeotrope temperature. In many cases, due to the presence of thief zones (e.g., top gas or bottom water) or other constraints, it is necessary to operate the SAGD steam-solvent chamber at a near constant pressure. However, in some cases, it may be practical and advantageous to reduce the chamber pressure and the associated azeotrope temperature over time.

The calculations provided in this paper focus on butane and pentane as the selected solvents while operating at a pressure of 2.5 MPa. Both alkanes have azeotrope temperatures that are significantly less than the steam temperature at the same pressure, thus enabling significant energy savings.They also can be practically delivered to SAGD operations via existing diluent pipelines or other methods.Heavier alkanes such as hexane or heptane are less advantageous because of their higher azeotrope temperatures, as can be seen in Figure 1. A lighter alkane such as propane offers the potential for an even lower azeotrope temperature. However, at propane's lower azeotrope (~75°C at 2.5 MPa) temperature, it can be difficult to reliably operate a gravity drainage process, and propane can be more challenging to transport to and store in the field than heavier alkanes. Mixtures of alkanes such as diluent or fractionated diluent may be considered as well [Khaledi et al.].

Selection of the Time to Start Solvent Injection

From a practical perspective, it is desirable to inject most of the required energy for achieving full production using steam. Assuming constant pressure in the steam-solvent chamber, the temperature in the expanding steam chamber throughout the SAGD operation will be constant.Once solvent injection starts, the temperature in the steam chamber will decline over a significant period to the azeotrope temperature for the selected solvent. It can be argued that that the optimal time for the start of solvent injection is a time that results in the temperature of the steam-solvent chamber declining to close to the azeotrope temperature simultaneously with reaching full recovery.Or stated differently, it is optimal to delay the start of solvent injection as long as possible while still allowing time for the steam-solvent chamber to decline to the azeotrope temperature after the start of solvent injection. However, the complexities of heat transfer within the expanding chamber, and heat losses to the overburden and underburden outside the chamber, require simulation.
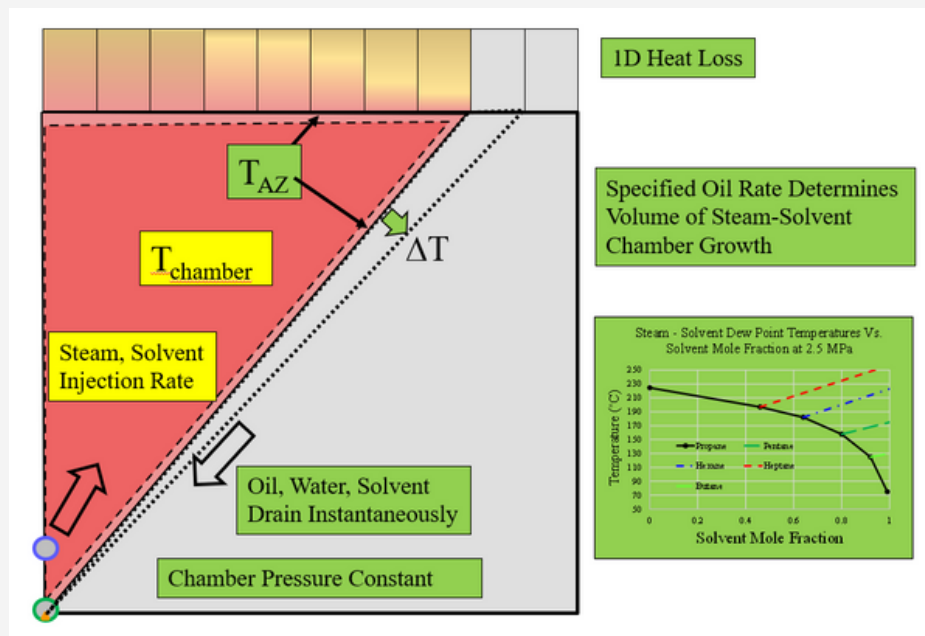

Figure 3: Illustration of the calculation methods and assumptions used to simulate the SAGD-HVapex process. Inputs or assumptions are colored green while calculations are colored yellow.

SIMULATION MODEL

A relatively simple but illustrative simulation model has been constructed to approximate SAGD-HVapex processes. The key features of the model are illustrated in Figure 3. As is commonly done for SAGD, the vapor chamber is assumed to be triangular until it reaches the boundary of the drainage volume then it becomes four-sided. Like the original SAGD model [Butler], oil drainage is assumed to be instantaneous from Soi to Sor within the steam-solvent chamber as it progresses. For simplicity, a constant rate of oil production is assumed to apply throughout the period of production rather than selecting an associated suite of rate-related reservoir parameters (e.g., permeability and oil viscosity). While this an assumption, it is consistent with the final result of Butler's model which relates the oil rate to a number of reservoir parameters and finds it to be a constant. In the examples that follow, a typical bitumen rate for a SAGD well pair in the Athabasca reservoir (100 m3/day) was selected and employed in the model. While typical oil rates for SAGD wells in the Athabasca are now well established, oil rates for HVapex in the field have not been. For simplicity and comparative purposes, the examples that follow assume the same oil rate during both the SAGD and the transition to HVapex stages. In conjunction with the assumption of instantaneous draining, the oil rate dictates the position of the steam-solvent boundary as a function of time, thus enabling a consistent calculation of the heat loss.

Heat Losses

Heat losses to the overburden are calculated analytically in the model using a simple 1D heat loss model as is done in most simulators and in the equation for CSOR developed by Edmunds and Peterson. Heat losses to the underburden are assumed to be one third of the heat losses to the overburden, as was also done by Edmunds and Peterson. During the periods of solvent injection, the temperature at the boundary of the steam-solvent chamber is assumed to be at the azeotrope temperature.This is justified based on the observation of simulation results [Khaledi et al.]. For the purposes of the analytical heat loss calculations, this temperature change at the boundary is assumed to be instantaneous at the start of solvent injection.

Model Assumptions

A tank model approach is employed where an average molar solvent to steam concentration is calculated for the steam-solvent chamber by accounting for the evolving chamber volume and the mass and composition of the injected vapor, vapor in the chamber and condensing vapor.

Key assumptions in the model are:

- (i) the temperature in the steam-solvent chamber is constrained by the molar ratio of solvent to steam, as was illustrated in Figure 1,

- (ii) there is liquid water present everywhere,

- (iii) the total moles of vapor in the chamber are determined using the ideal gas law at a constant pressure,

- (iv) vapor condenses at the average molar concentration of the steam-solvent chamber at any particular time, and

- (v) the transition from the average steam-solvent temperature to the azeotrope temperature is assumed to occur in a narrow boundary layer at the edge of the chamber.

Computational Procedure

The time stepping procedure can be summarized as follows. The assumed oil rate dictates the change in the volume of the steam-solvent chamber. Heat losses at the boundary of the chamber dictate the volume of fluid that condenses at the boundaries. Any reduction in temperature within the chamber drives water vaporization. The rate of the steam and solvent injection is then determined to ensure that the pressure in the chamber remains constant. In order to have a stable solution for the equations, it is necessary to implicitly solve for the new steam-solvent concentration and temperature in the chamber at each time step.

SIMULATION RESULTS AND ANALYSIS

A series of simulations have been performed to illustrate the benefits and practicality of the SAGD-HVapex process. The simulations have employed butane or pentane as the injected solvent. The physical property and parameters assumed in the simulations are listed in Tables 1 and 2.

Geometry and Reservoir Parameters		
Symbol	Description	Value[1]
	Well Parameters	
h	Reservoir Height, m	20
w	Well Spacing, m	100
L	Well Length	1000
	Reservoir Parameters	
ϕ	Porosity	0.32
S_{oi}	Initial Oil Saturation	0.8
S_{or}	Residual Oil Saturation	0.15
P	Reservoir Pressure, MPa	2.5
T_o	Initial reservoir temperature, °C	12
C_{vo}	Overburden heat capacity, MJ/m^{3}	2.23
C_{vr}	Reservoir heat capacity, MJ/m3	2.23
k_t	Overburden thermal conductivity, MJ/m-°C-year	85
	Oil Rate and Recovery Factors	
	Oil Rate, m3/day	100
	Ultimate Recovery Factor, % of bitumen-in-place	71
	Time to Ultimate Recovery, years	10.6

Table 1: Symbols and values for geometry and reservoir parameters

Steam, Solvent and Azeotropic Parameters		Values[1]		
Symbol	Description	Steam	Butane	Pentane
P	Pressure, Mpa	2.5	2.5	2.5
Ts	Steam Temperature, °C	224.5		
ρ	Reference Density, kg/m³	1000	604	630
T_{sol}	Solvent Vapor Temperature, °C		130	175
C_p	Vapor Heat Capacity, kJ/kg/°C		2.2	2.3
H_{lv}	Latent Heat of Condensation, kJ/kg	2006	190.6	208
H_{lv}	Latent Heat of Condensation, MJ/m³	2006	115	131
x_a	Azeotrope Mole Fraction of Solvent		0.92	0.8
T_a	Azeotrope Temperature, °C		125	157.7
H_{lv}	Latent Heat for Azeotrope Fluid Mixture, H_{lv}, (MJ/m³)		145	202
	[1] Values used in simulations or calculations			

Table 2: Symbols and values for steam, solvent and azeotrope parameters

Figure 4 shows results for SAGD-AzeoVapex employing butane. The temperature falls progressively from Ts (224.5 °C) to near Taz (125 °C) along with the rise in average molar solvent concentration in the chamber from 0 to close to the azeotrope concentration (0.92). The timing for the start of solvent injection at 40% recovery has been selected to be near optimal, as was described in a previous section. For reference, full recovery in the model is nominally 71% at a time of 10.6 years.
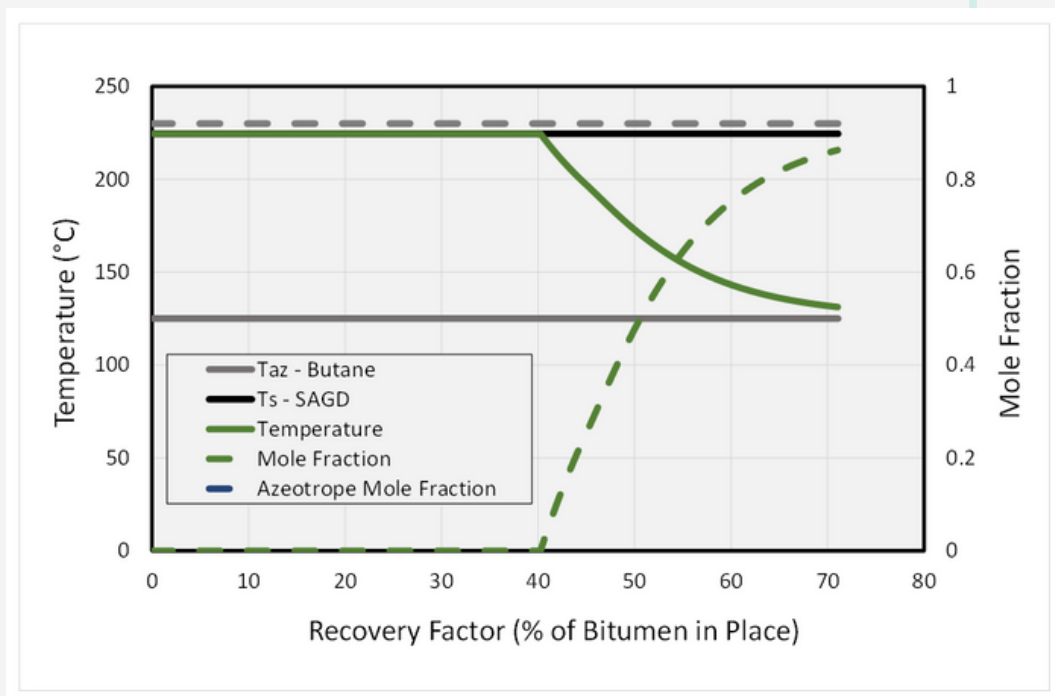
Figure 4: Plot of average steam-solvent chamber temperature and mole fraction versus time for SAGD-AzeoVapex employing Butane. Solvent injection starts at 40%.recovery of the bitumen-in-place with full recovery at 71%.

Figure 5 compares the total energy requirements for several cases measured as equivalent steam volumes, where the heat content of any injected solvent is converted to a steam volume. It is seen that SAGD has the highest energy requirement and all of the processes using solvent result in very significant total energy reductions relative to SAGD.

When employing butane, the total energy required for full recovery using AzeoVapex, and SAGD-AzeoVapex is 60% and 66% of SAGD, respectively. When employing pentane, the corresponding values for are 69% and 79% of SAGD, respectively.
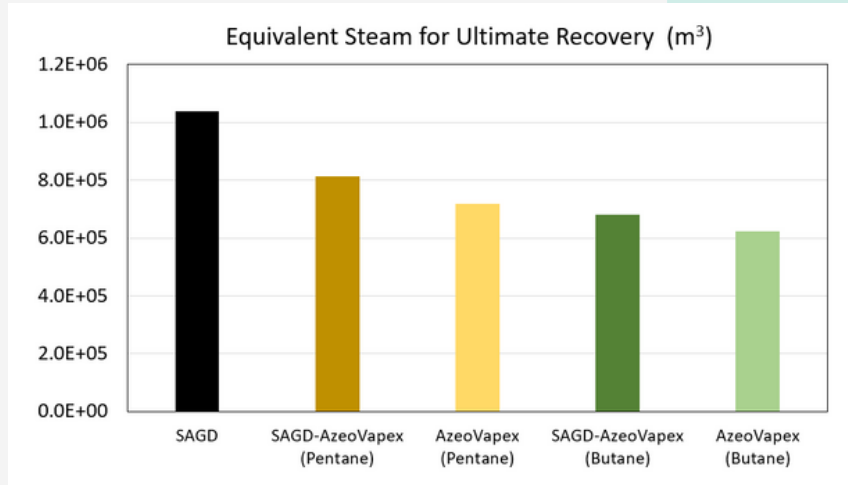
Figure 5: Chart comparing the total energy required to reach full recovery (71% of the bitumen-in-place) for SAGD, AzeoVapex and SAGD-AzeoVapex cases.

The key practical benefit of injecting most of the required heat utilizing steam is illustrated in Figure 6, which compares the actual injected steam and solvent volumes for the various cases. The figure illustrates that relative to AzeoVapex employing butane or pentane, the hybrid processes utilize close to an order of magnitude less solvent.
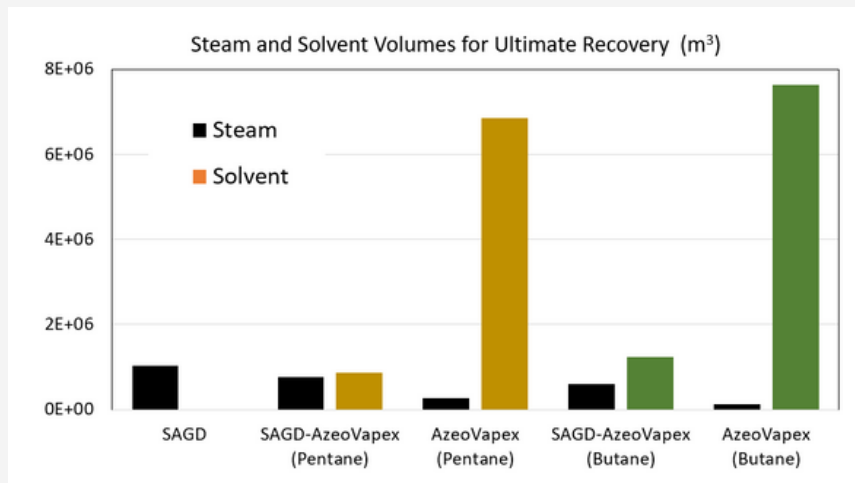
Figure 6: Chart comparing the total steam and solvent volumes required to reach full recovery (71% of the bitumen-in-place) for SAGD, SAGD-AzeoVapex and AzeoVapex cases.

Figure 7 plots the steam and solvent injection rates for the SAGD-AzeoVapex (butane) case versus time.The steam rate rises consistently up to a bitumen recovery of 38% as the steam chamber encompasses a growing area of the top of the reservoir and heat losses to the overburden increase. At a recovery level of 38%, the chamber has extended to the full well spacing and the chamber will coalesce with an adjacent chamber. At this time, heat losses to the overburden begin to decline and the steam injection rate also declines. In this example, azeotropic solvent-steam injection begins at 40% recovery.Initially, only a low rate of vapor injection is required as the temperature in the chamber declines and water within the chamber is vaporized. As the rate of temperature decline slows with time, the rate of water vaporization declines and the injection rate must increase to maintain a constant pressure.
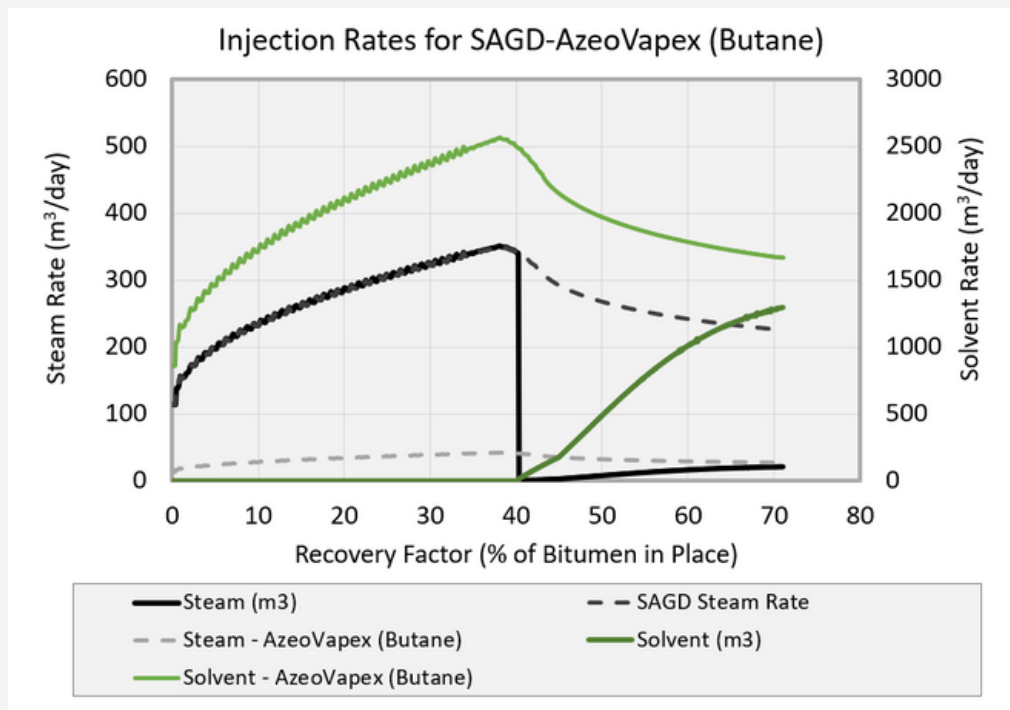
Figure 7: Chart showing the steam and solvent injection rates for the SAGD-AzeoVapex (Butane) case as a function of time. Solvent injection starts at 40% recovery. Rates for SAGD and AzeoVapex (Butane) are shown as references.

It can be seen in Figure 7 that, as time progresses, the SAGD-AzeoVapex injection rates asymptotically approach the comparable injection rates for AzeoVapex. If solvent injection is started earlier, the rates will approach closer to the AzeoVapex rates and the solvent rates will be higher.

Figure 8 addresses the selection of the start time for butane injection by presenting results for cases with the start time of solvent injection spanning the full life of the well pair. The plotted parameters are the total energy injected and total solvent injected as required for full recovery. The figure illustrates that if solvent injection were to start at a 40% recovery level, the SAGD-AzeoVapex process could capture 78% of the energy savings of AzeoVapex while using only 14% of the total solvent required by AzeoVapex. Delaying the start of solvent injection reduces the required solvent injection, but it also requires more energy to be injected. Figure 8 also shows that there is a broad range of recovery levels over which it can be beneficial to start solvent injection; this is important, because there are always additional practical factors that will dictate when solvent injection is first injected.
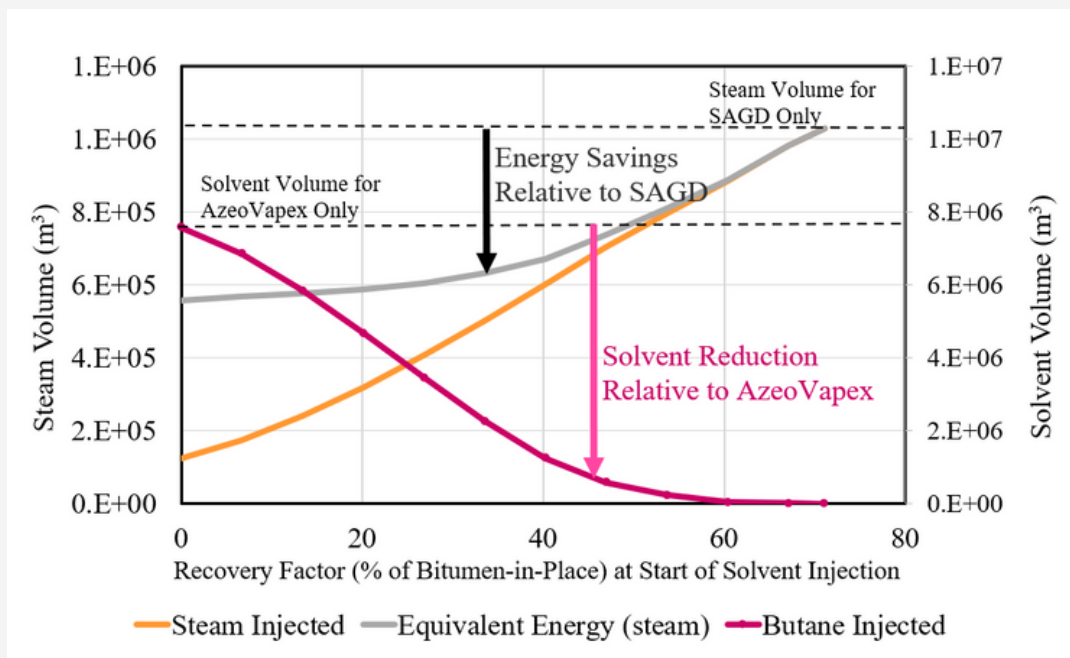

Figure 8: Chart comparing the total steam and solvent volumes required to reach full for the case of SAGD-AzeoVapex (butane) as a function of start time for the solvent injection.

ATHABASCA
OIL CORPORATION

CEDA

MEG ENERGY
Sustainable. Innovative. Responsible.

GERI
GENERAL ENERGY
RECOVERY INC.

DISCUSSION

It has been shown that, in reservoirs where SAGD can be or is being operated, very significant energy savings can be captured by converting the SAGD operations to an HVapex process, typically in the latter half of the production life of a well pair. The energy savings can be on the order of 80% of the estimated energy savings when employing solvent injection from the start of operations using HVapex alone. Most importantly, when optimally timing the start of solvent injection in an SAGD-HVapex hybrid process, the required volume of solvent injection is reduced by an order of magnitude relative to HVapex alone.

The models developed and employed in both parts of this paper exploit the observation from simulations that the temperature within a large region of and at the boundary of the steam-solvent chamber is at or near the steam-solvent azeotrope temperature even for cases of pure solvent injection. It follows that energy savings can be maximized by selecting a practical solvent with the lowest steam-solvent azeotrope temperature. Hence, butane may be preferred relative to pentane. However, since the diluent that is already being piped to many operations contains a high fraction of pentane, it may be more readily available. And, in practice, a mixture of alkanes or other solvents may be employed as well.

Operating Costs and Lost Solvent

The operating costs for all HVapex processes include the energy to heat the solvent, the cost of storing solvent in the reservoir until the time it is recovered, and 'lost solvent' in the reservoir (i.e., solvent that is injected but not recovered). Khaledi et al. 2019, have analyzed the distribution of solvent retained in the reservoir within and immediately outside the solvent chamber. They also provide a comprehensive analysis of methods for effectively maximizing recovery of solvent from the reservoir and thereby minimizing solvent losses.

Within the assumptions of the simplified model presented in this paper, a correction could be made for the solvent that is trapped in the residual oil in the solvent chamber which, in effect, displaces heavy oil that is produced.

From a practical perspective, it is also very important to consider that solvent can also be lost to thief zones such as gas caps or bottom water zones where it is extremely difficult to recover solvent. These losses to thief zones are not typically captured in either analytic or reservoir simulation models, but can very significantly impair the economics of the process.

Qualifications

Relatively simple analytical methods have been used to develop the results presented in this paper.A key advantage of analytical methods is that they can be used to quickly and effectively explore the fundamentals of a process. However, It is recognized that these methods are not a substitute for more complex reservoir simulation. Reservoir simulation is required to make estimates of critical economic parameters such as solvent volumes stored in the reservoir during operations and lost over time. Nonetheless, the mixing of the solvent with the bitumen is a complex process [Mothahari and Khaledi], so even reservoir simulation cannot be expected to reliably predict bitumen production rates without being calibrated to field data. Furthermore, reliable simulation models can only be constructed when the critical underlying fundamentals of the process are well understood.

An inherent requirement for the SAGD-HVapex is an initial extended period of SAGD operations. However, SAGD is not commonly employed at operating pressures less than 1 MPa since steam temperatures at this lower pressure range do not sufficiently reduce the bitumen viscosity for economic production rates. At this lower pressure, HVapex alone may be the only viable process.
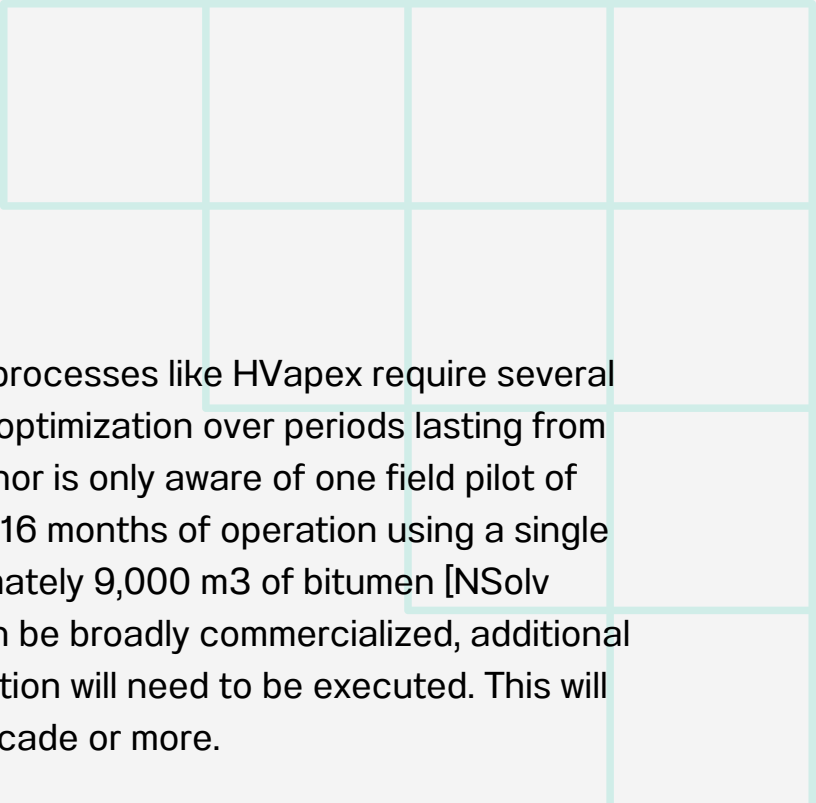
Practical Advantages of the SAGD-HVapex Processes

The primary objective of the SAGD-AzeoVapex Process is to exploit the strengths of both steam and solvent. Steam is a very efficient fluid for heat transfer when compared to solvents and effective utilization of solvent can greatly reduce energy utilization and GHG emissions. Additionally, since SAGD is now a commercially mature and proven process, commercial risk is greatly reduced by employing a hybrid process where SAGD is initially used to capture a large fraction of the oil reserves. There are also several other practical advantages.

A key cost associated with HVapex production is lost solvent in the reservoir and it is important to note that on a volumetric basis solvent has a much higher cost or value over steam. While in many SAGD operations, steam losses to thief zones such as bottom water and top gas occur and can be tolerated, similar fluid losses likely cannot be tolerated when injecting more costly solvent. Commonly, the largest fluid losses to thief zones will occur early in the operation of a well pair. With time and experience, the operating parameters and procedures evolve that minimize the losses. The risk of excessive solvent losses to thief zones can be effectively managed by deferring solvent injection until later in the operational life of a well pair. This is a very favourable feature of the SAGD-HVapex process compared to HVapex.

HVapex processes will require significantly different facilities than SAGD operations in order to process the much higher fluid volumes. However, the SAGD-HVapex process transitions from SAGD prior to the start of solvent injection to what is truly HVapex only at the very end of economic production. During the transition period solvent injection rates ramp up as the temperature in the chamber declines and mole fraction of solvent increases. It can be ascertained from Figures 7 and 8 that there is considerable flexibility in implementing timing for the start of solvent injection to manage both the solvent injection rates and volumes. This should allow for the practical utilization of existing SAGD wellbores and facilities with limited modification.

Full commercialization of new recovery processes like HVapex require several stages of technology development and optimization over periods lasting from years to decades [Boone et al]. The author is only aware of one field pilot of HVapex technology which has reported 16 months of operation using a single 300 m long well pair producing approximately 9,000 m3 of bitumen [NSolv Corporation]. Before the technology can be broadly commercialized, additional field pilots and phases of commercialization will need to be executed. This will almost certainly require a period of a decade or more.

Late-life conversion of SAGD operations to a SAGD-HVapex process has the additional benefit that it can be piloted and commercialized using existing SAGD facilities and the period of time required to demonstrate full recovery of the bitumen in a pilot should also be a fraction of that required for HVapex. As a result, SAGD-HVapex provides a much simpler and faster pathway to capturing the energy savings and GHG reduction benefits associated with HVapex.Also, the commercial target for SAGD-HVapex is greatly expanded because it can be integrated with the many existing and planned SAGD developments.

CONCLUSIONS

Analysis and consideration of the hybrid SAGD-HVapex process has determined that it can:

- capture significant energy savings and GHG emission reductions by optimally selecting the solvent injected based on its steam-solvent azeotrope temperature,

- capture 80% or more of the energy savings of HVapex while utilizing an order of magnitude less solvent by optimally selecting the timing for the start of solvent injection,

- effectively manage the risk associated with lost solvent by delaying the start and reducing the volume of solvent injection,

- greatly expand the opportunity space for application of HVapex by enabling its integration into existing operations, and

- enable lower risk and faster commercialization of the technology than is practical for HVapex.

REFERENCES

Boone, Thomas J, Dickson, Jasper Lane, Lu, Pengbo, and John Elliott. "Development of Solvent and Steam-Solvent Heavy Oil Recovery Processes Through an Integrated Program of Simulation, Laboratory Testing and Field Trials." Paper presented at the International Petroleum Technology Conference, Kuala Lumpur, Malaysia, December 2014. doi: https://doi.org/10.2523/IPTC-18214-MS

Boone, Thomas. Gravity Drainage of Hydrocarbons by Steam And Solvent Injections with Reduced Energy Usage. Canadian Patent CA 3156254, Filed April 19, 2022.

Butler, R.M., Mokrys, I.J.: A new process (VAPEX) for recovering heavy oils using hot water and hydrocarbon vapor. JCPT, 30(1), 97-106 (1991).

Butler, Roger M.,Thermal Recovery of Oil and Bitumen, GravDrain Inc., 1997, Chapter 7.

Edmunds, Neil, and Jeff Peterson. "A Unified Model for Prediction of CSOR in Steam-Based Bitumen Recovery." Paper presented at the Canadian International Petroleum Conference, Calgary, Alberta, June 2007. doi: https://doi.org/10.2118/2007-027

Gutek, Harold, Harschnitz, Brian, Myers, Ron D., and Okazawa, Tadahiro. Combined Steam and Vapor Extraction Process (SAVEX) for In Situ Bitumen and Heavy Oil Production. Canadian Patent CA 2325777, Filed November 10, 2000.

Khaledi, Rahman , Motahhari, Hamed Reza, Boone, Thomas J., Fang, Chen , and Adam S. Coutee. "Azeotropic Heated Vapour Extraction- A New Thermal-Solvent Assisted Gravity Drainage Recovery Process." Paper presented at the SPE Canada Heavy Oil Technical Conference, Calgary, Alberta, Canada, March 2018.
doi: https://doi.org/10.2118/189755-MS

Motahhari, Hamed Reza, and Rahman Khaledi. "General Analytical Model for Thermal-Solvent Assisted Gravity Drainage Recovery Processes." Paper presented at the SPE Canada Heavy Oil Technical Conference, Calgary, Alberta, Canada, March 2018. doi: https://doi.org/10.2118/189754-MS

Nenniger, E.; Hydrocarbon Recovery, Canadian Patent CA 1059432, Filed Dec. 24, 1976.

NSolv Corporation, Non-Confidential Final Report, CCEMC Project ID: H110031 - BEST Pilot Project, May 31, 2015

WHY TECHNOLOGY DEVELOPMENT PROJECTS FAIL OVERWHELMINGLY

DR. SUBODH GUPTA
CHOA Journal Editorial Committee

Why do technology projects fail so often?

In a recent CHOA editorial committee meeting in a discussion on a developmental technology, at my rather pessimistic remark on the expected chances of success for technology projects, I was queried why technology projects have such a low rate of success? Since this is a subject very dear to my heart, and also discussed in my upcoming book focusing on '*Energy and Decarbonization*' in a chapter dedicated to technology development, I gladly accepted the offer to write a short, slightly reworded, excerpt to address the question for the CHOA Journal.

Technology projects have a very high rate of failure: Technology funnel

Those who have dealt with technology development projects for a significant period of their career know that from conception to finish (or abandonment) optimistically speaking the chances of success are less than 5%. This is especially true in technologies applicable to or in the context of oil extraction. This sounds rather pessimistic, however not all failures are disappointing if important learnings come out of them, leading to increased chances of future successes.

"... however not all failures are disappointing if important learnings come out of them, leading to increased chances of future successes."

Technology development typically starts with a problem definition or in response to an existing challenge with several possible, but non-proven solution concepts. These potential solutions (or initiatives) then need to be further developed in successive stages so that at the end of that stage they can be tested, or filtered, for establishing workability. In each stage a few non-robust ideas get filtered out. In the final stage, only a small number survive having passed all the prescribed tests.

Viewed in this manner, technology development is a process of successive development (readying) and filtering or removal of unsustainable concepts. This successive filtering process typically takes the shape of a funnel as shown in Figure 1.
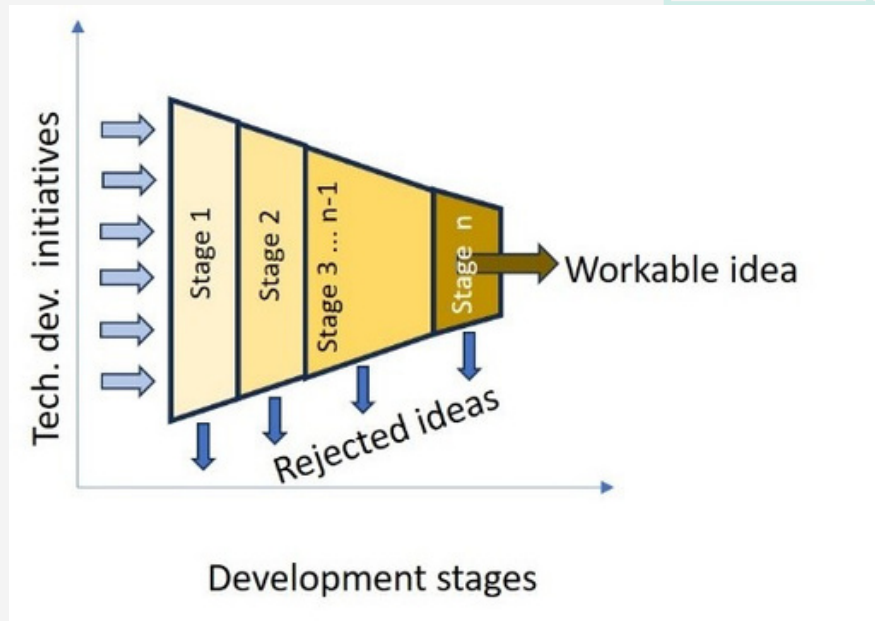
Figure 1. Successive stages of technology development

What others have said about rate of success in technology development

This topic of the overwhelming number of failures of technology development projects has attracted numerous commentaries in the past, some of which are summarized below.

(Andriole, 2021) suggests three main reasons for these failures: lack of sufficient talent in the team entrusted to pursue these initiatives, lack of support from the higher management, and a lack of culture of innovation in the organization.

"...technology development is a process of successive development (readying) and filtering or removal of unsustainable concepts."

(Lee-Bourke, n.d.) points to poor definition of the project, lack of leadership, and accountability, poor planning, and communication, lack of testing and ability to take corrective measures, as well as solving the wrong problem, as the main reasons for failure of most of these pursuits. (FasterCapital, 2023) mentions four major causes for such failures including: lack of clear purpose or goal, adequate resources, poor project management, and lack of end user involvement. (Dolfing, 2018) includes 10 reasons in his thesis: poorly stated completion point, unclear definition of success, lack of accountability, poor planning, insufficient communication, lack of testing and ability to address feedback, solving wrong problem, application of standard model to business rather than what is relevant to the technology project at hand, continuing to pursue an idea without a reasonable business case, and death by committee-based decisions.

These are all sensible points for a good project stewardship and if applied well they can definitely increase the chance of success, by rejecting more non-productive ideas earlier on. With this, the shape of the technology funnel will be more of a curved type rather than a linear one, and look more like the one shown in Figure 2.
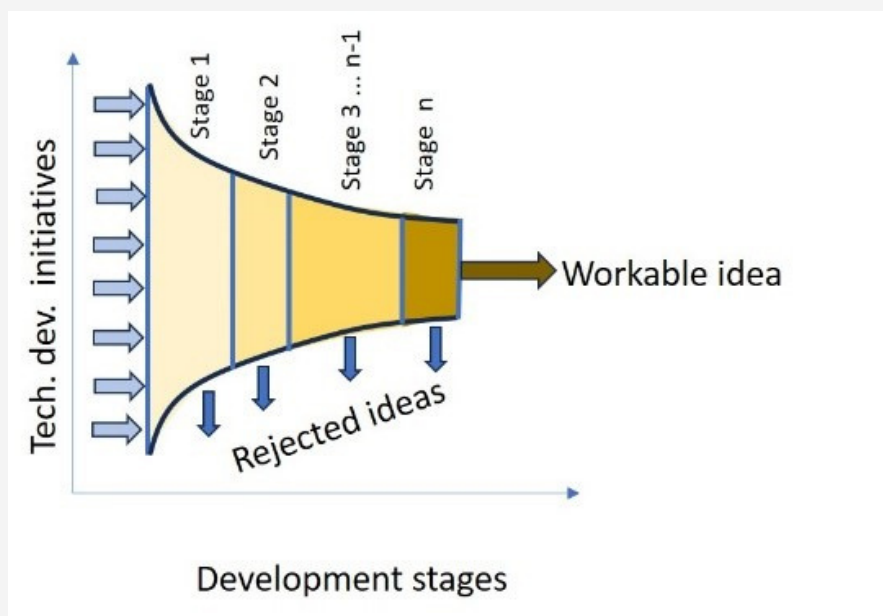
Figure 2. Better technology development management and resulting curved funnel shape

Uncovering of the workable concept

It is true that there have been important technological breakthroughs serendipitously. However, most technology solutions come from directed efforts to solve a problem in the manner described above, such as the Apollo moon mission of NASA. A closer examination of the above approach reveals that the process involves isolating or 'uncovering' the workable solution. It (the winner idea) was always known and at hand right from the beginning. Only at the outset there were a number of uncertainties or unknowns associated with it (as well as with the other non-workable concepts), which got resolved through various stages of development.

"The trick is to isolate workable from the non-workable as early as possible in the game and with minimum required development."

Technology development is expensive. Depending on the nature of projects, it can take several months to several years (in some cases several decades or more, e.g., in nuclear fusion), entailing enormous costs. The longer the process, the more the cost. The trick is to isolate workable from the non-workable as early as possible in the game and with minimum required development. Is this possible? We need to examine the process a bit closer to answer this.

What has often evaded highlighting: Lack of a plausibility analysis

It is important to recognize two components in the technology funnel – (a) development of the various initiatives to allow prescribed testing, and (b) applying of the filtering tests to accept or reject. Do all the initiatives need development to apply the relevant testing? It is my contention that they do not. Most of the times, a sufficient narrowing down of the initiatives can be achieved, and many times upfront, without having to develop these to any significant length or extent.

While all that has been said and quoted in the above references definitely is applicable and makes the difference between success and failure, there is still something that further needs to be added. What's been said applies mostly to a sound project development and if not paid sufficient heed to, can result in failure even with an idea that could have proven workable. However, not all ideas need to be developed to be rejected.

For uncovering a workable novel technology solution, it has to be (a) technically feasible and (b) economically viable. Economically viable here means that it should have better economics than the current solution. Most ideas do not pass these two tests even at the outset. In fact, a surprising number of initiatives don't make the cut. Aside from the poor project management highlighted previously, this explains why a vast majority of such initiatives fail to yield the desired results, or just fail.

What can be done to narrow down the funnel

Plausibility analysis of most initiatives can be done right in the beginning without any significant development. This involves first to analyze if an idea is technically feasible and then apply the test of viability with estimated economics to see if it fares better than the existing solution.

Technical feasibility analysis:

At this point, some may question how this is possible at an early stage when the idea is not physically developed enough to apply the test? But it is!
Nothing in the world we live in violates the fundamental laws of physics: the material balance, the energy balance, and the momentum balance. Similarly, nothing can violate the laws of thermodynamics. Entropy in all natural processes has to increase and no perpetual motion contraption without an energy source is possible.

"Nothing in the world we live in violates the fundamental laws of physics: the material balance, the energy balance, and the momentum balance. "

Moreover, as we get slightly more esoteric, nothing can move faster than the speed of light, and absolute zero temperature cannot be achieved.

For example, if one were to compare energy (and hence the cost) input in CO_2 capture from atmosphere (e.g., in DAC) vs. from a concentrated point source (flue gas) one need not develop the two options before getting to the answer. Thermodynamics can answer that. Heavy oil upgrading is another example. Smart application of material balance will show that without adding hydrogen one can only have upgraded oil at the expense of yield, etc. All those ideas that attempt to go against the fundamentals, regardless of how attractive they look on surface, are bound to lead to disappointment if pursued.

Economic viability analysis:

Once the technical feasibility is established, a model to estimate the economics needs to be assembled. This often requires putting together the best estimates for Capex and Opex, which many times can be challenging. However, an approximation can often be made based on analogous applications to capture lower and upper bounds, to allow a reasonable probabilistic economics. If the economics of an idea do not favourably compare with the current technology, why pursue it further? Granted, in a few cases when sufficient information is difficult to obtain, one is stuck with the actual project development.

"If the economics of an idea do not favourably compare with the current technology, why pursue it further?"

Organizations pursuing technology development in the earnest already recognize the value of a talented team and advisors that can help with such techno-economic feasibility analysis. As has been brought out here, it saves them valuable time and money on one hand, and improves the chances of success in their narrowed-down technology pursuit on the other.

Ideal technology funnel
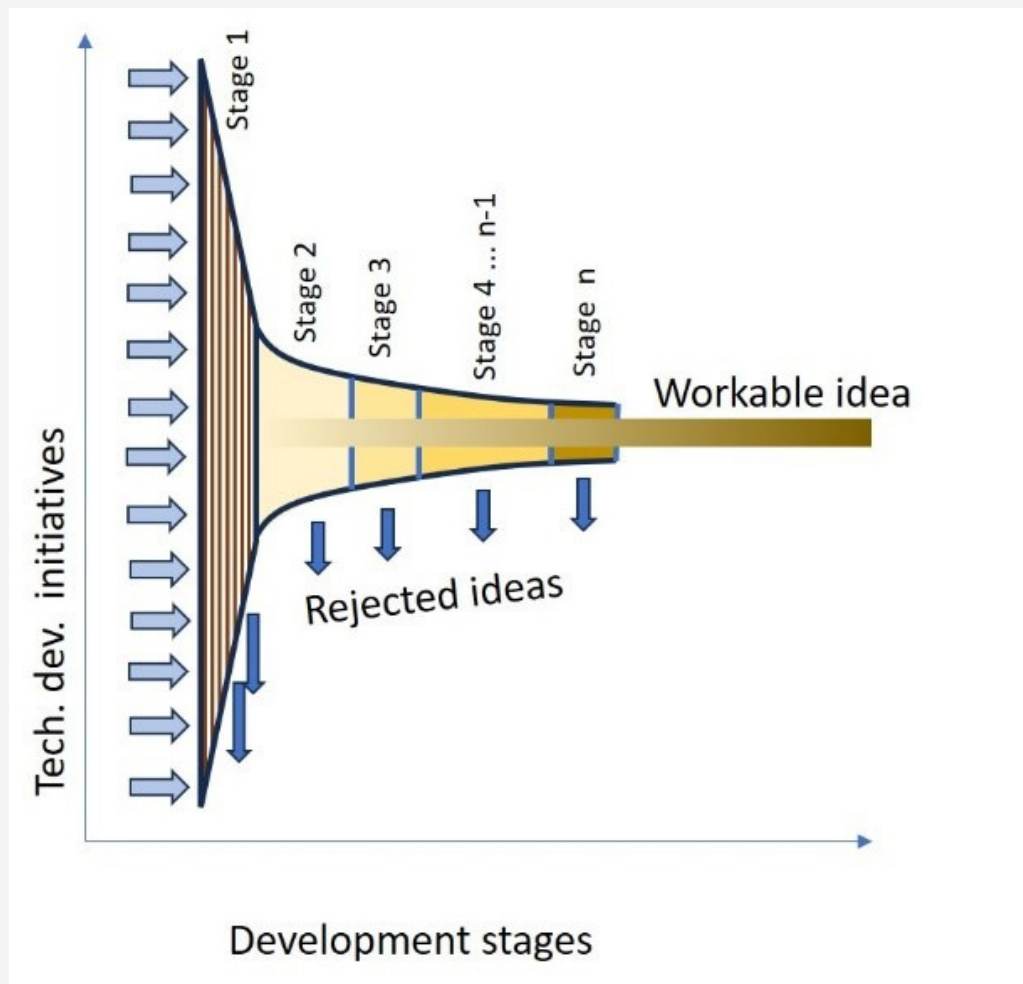
Figure 3. Adding an upfront stage: Plausibility Analysis

Ideal technology funnel

All this leads to answer as to what a superior technology funnel should look like. The gist of this thesis is to add an upfront stage of plausibility analysis to the technology funnel described above. This is shown in Figure 3. This process naturally and desirably reduces the number of initiatives dramatically in a short span of time, and at a significantly less expense. The net outcome is that the limited resources available for technology development can focus on a fewer and the more robust ideas, increasing the chances of success of those ideas. It may or may not be applicable in all cases, but ideally this exercise should be repeated at the start of each stage with all the information generated till that point.

"This process naturally and desirably reduces the number of initiatives dramatically in a short span of time, and at a significantly less expense."

Dr Subodh Gupta,
Technology Advisor,
Founder Heretech Energy

Dr Subodh Gupta is the founder of Heretech Energy, where he provides value through advising on workable solutions to decarbonizing the energy and finance industry, ranging from practical emissions-reduced subsurface recovery methods to low-carbon surface processing and carbon-abatement alternatives.

He worked for over 25 years at Cenovus, most recently as the Chief of R&D. Subodh is also a member of the CHOA Journal Editorial Committee. In March 2023, Subodh presented a full paper on this subject to the SPE Canadian Energy Technology Conference and Exhibition, entitled "*Carbon Sequestration: The Ignored Promise of the 'Non-Utilization of Carbon' Route.*"

REFERENCES

Andriole, S. (2021, March 25). 3 Main Reasons Why Big Technology Projects Fail – & Why Many Companies Should Just Never Do Them.
Retrieved from Forbes.com: https://www.forbes.com/sites/steveandriole/2021/03/25/3-main-reasons-why-big-technology-projects-fail---why-many-companies-should-just-never-do-them/?sh=5bb35185257c

Dolfing, H. (2018, August 10). Why Do Technology Projects Fail so Often and so Spectacularly? My Personal Top 10 Reasons. Retrieved from henricodolfing.com: https://www.henricodolfing.com/2018/08/why-do-technology-projects-fail-so.html

Faster Capital. (2023, October 17). Technology Development The difference between success and failure. Retrieved from FasterCapital.com: https://fastercapital.com/content/Technology-Development--The-difference-between-success-and failure.html#:~:text=If%20a%20technology%20fails%20to,is%20unlikely%20to%20be%20successful.&text=A%20technology%20also%20needs%20to,as%20many%20people%20as%20poss

Lee-Bourke, A. (n.d.). 7 Real Reasons Why Tech Projects Fail. Retrieved November 29, 2023, from Prosci.com: https://www.prosci.com/blog/7-real-reasons-why-tech-projects-fail

DILATION WORKS ON ROCK MATRIX TO ENHANCE HEAVY OIL PRODUCTION

YANGUANG YUAN, "YY"
BitCan Geosciences & Engineering Inc.

Successful production of heavy oil and especially, bitumen, starts by reducing its viscosity and/or increasing its mobility. Typical methods to achieve this are by heating and/or using of solvents or similar additives, which can be collectively called stimulants. A wide-spread contact of the stimulants with the oil phase is essential for their efficiency. This provides an opportunity for the rock matrix to be engineered in order to increase the contact area, by creating new porosities and micro-cracks for the stimulants to travel deep beyond the frontal area and into a large volume of the reservoir. For example, the heating efficiency of steam will be increased if it can contact the heavy oil in a large part of the reservoir, as compared to only along the thin conduction front, resulting in faster production and increased mobilized oil volume.

"A wide-spread contact of the stimulants with the oil phase is essential for their efficiency."

Dilation mechanism

The study and engineering of the formation of new porosities and micro-cracks belongs to the domain of geomechanics; this is a sub-category of solid mechanics dealing with rock deformation and failure. A large number of laboratory tests in the 1960's to 1990's demonstrated that the oilsands has longitudinal to inter-locked grain-grain contact structures (Dusseault and Morgenstern, 1979). This makes the sands possess a higher-than-normal tendency towards dilation (Samieh and Wong, 1997). Yuan et. al (2011) reviewed these historical works and further showed, by a combination of theoretical analysis and history-matching of field tests, that fracturing in the oil sands formations can be engineered to take the form of shear-induced dilation and micro-tensile cracking.

As is shown in Figure 1, this shear-dominant dilation tends to loosen sand grains from a densely compacted state to cause new open pores resulting from larger spacing between the grains. Continuous injection moves fluid into the new pore spaces, which can eventually push the sand grains apart from each other, i.e. transitioning to micro-tensile cracks. These micro-cracks do not connect with each other to form a continuous tensile aperture, i.e., tensile fracture, but are dispersed over a large volume as is shown in Figure 2.
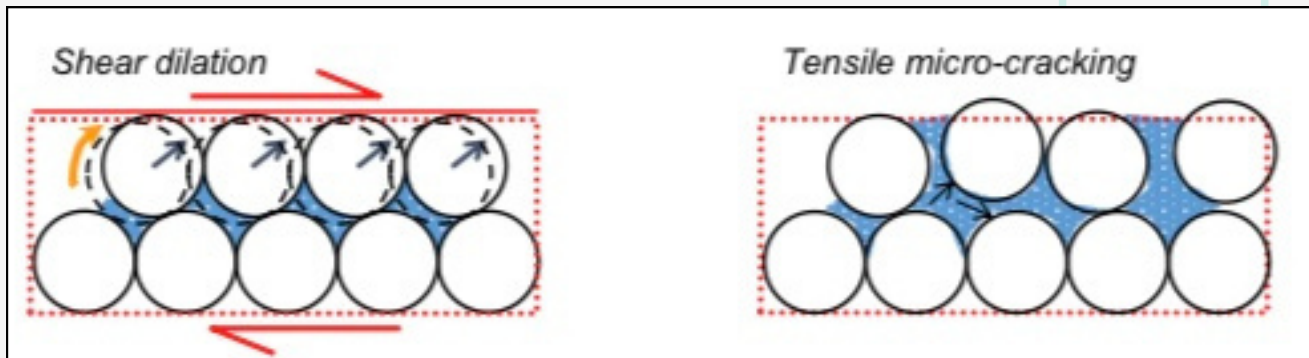
Figure 1: A schematic showing the shear-induced dilation (left) and its transition to tensile micro-cracking (right). The shaded area denotes open pore space.

"... by a combination of theoretical analysis and history-matching of field tests, that fracturing in the oil sands formations can be engineered to take the form of shear-induced dilation and micro-tensile cracking."

Figure 2 is a conceptual diagram illustrating the stimulated reservoir volume formed by dilation. It typically takes 2 to 7 days in the field (e.g., Yuan et. al, 2017) to achieve this state, depending on the initial formation permeability and geological complexities inherent in the reservoir. This forms a sharp contrast with common hydraulic fracturing jobs, which typically take 1 to 2 hours to complete each stage.
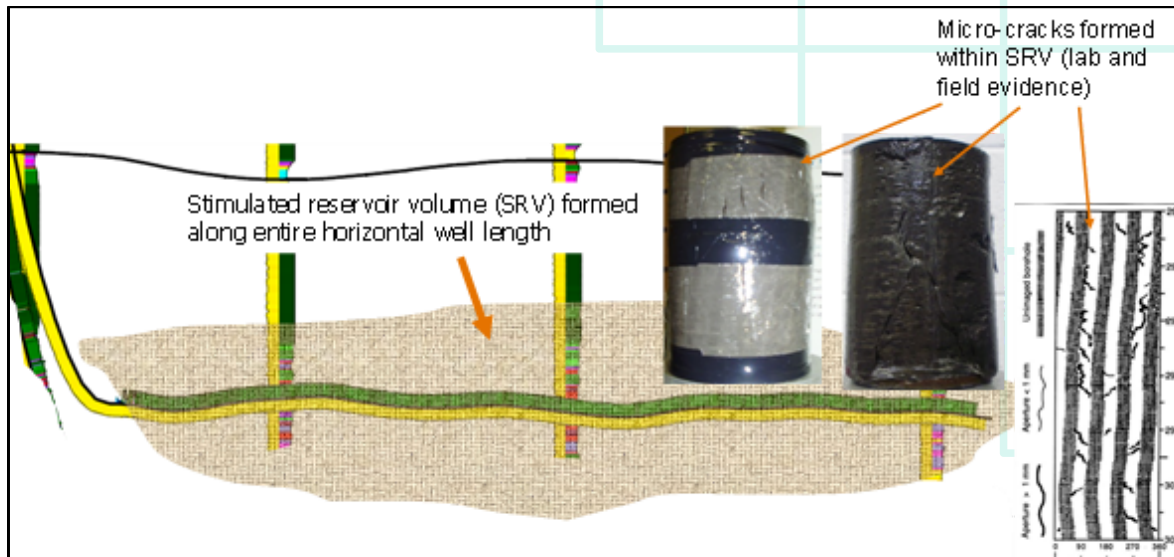
Figure 2: A schematic showing that a stimulated reservoir volume (SRV, shaded area) can be formed along the whole horizontal well length without packers installed. Inside the SRV are dilated porosities (invisible to unaided eyes), micro cracks seen in lab tests under low confining pressures or in the repeat image logs from the field. The image log was directly excerpted from Kry et al. (1992), and the lab test photos were published in Yuan (2018).

Each dilation job is methodically executed in phases from pre-conditioning to dilation initiation and propagation. Unique for dilation, the pre-conditioning phase closely manages the well injection so that pore pressure conditions around the wells and the resulting poro-elastic and/or thermo-elastic backstresses are combined to favor the occurrence of shear dilation while preventing tensile fracturing.

Outcome of the dilation stimulation

Dilation increases well injectivity or productivity by a combination of increased permeability (k) and conformance length (L); i.e., by the product of L*k, as is explained by the fundamental Darcy's equation:

$$Q = 2\pi r_w L \left(\frac{k}{\mu}\right)\left(\frac{\partial P}{\partial r}\right) \quad \in V$$

The increase in k by dilation is limited (e.g., in the order of a Darcy) and the increase is distributed along the majority of the well length, e.g., 80% of an 800-m long SAGD well. Thus, the increased L*k product for this example is 80%*800 m*1 Darcy = 640 Darcy.m. In comparison, a hydraulic fracture job can create a huge permeability increase, but over a very limited aperture (e.g., 1 mm). The resulting L*k for this example is (1 mm)^2*1/12*1 mm = 83 Darcy.m, which requires more than 75 frac stages, each creating similar apertures, to match the dilation effect. This difference shows that dilation has several advantages over hydraulic fracturing stimulation: no or limited stages required; no or minimum proppants injected; and good conformance preventing inter-well breakthrough. Derivative benefits offered by dilation include: being intrinsically safe for maintaining geo-containment integrity; less field equipment and thus, less of a footprint required to carry out a dilation job; and higher stimulation efficiency (for example, in terms of reduced steam oil ratios in thermal heavy oil production).

"... dilation has several advantages over hydraulic fracturing stimulation: no or limited stages required; no or minimum proppants injected; and good conformance preventing inter-well breakthrough."

In 2010, dilation stimulation was successfully applied for a faster and stronger start up to the SAGD process (Cenovus, 2010). Since then, its use has been expanded to elsewhere in the world. A dilation zone, which is horizontally uniform along the well length, is created before or during the initial steam injection around each of the SAGD well pairs, vertically connecting both wells (Figure 3a). The uniform conformance happens via bullhead injection without mechanical packers installed along the well length. After the dilation and during subsequent reservoir processes, which likely proceed at lower pressures, the friction resistance increases. This causes the dilated volume (increased porosity and permeability) to be locked in place. As a result, more steam enters the reservoir readily, i.e. the steam injectivity increases (Figure 3b), and the oil production thus accelerates (Figure 3c).
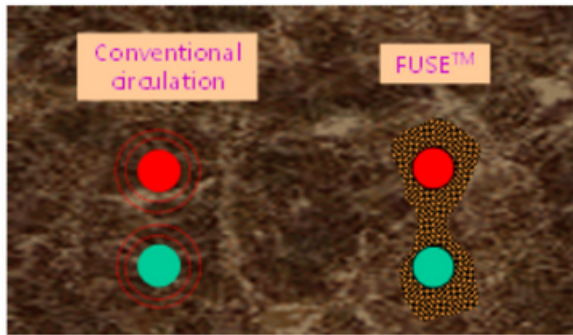
Figure 3a: A vertical cross-sectional cut perpendicular to a SAGD well pair consisting of a horizontal injector (red-color) and a producer (blue color). Conventional start-up circulates steam through both wells, which relies on conduction to heat the reservoir between the well pair so that oil drains from the injector to producer easily. FUSE™ – Fast and Uniform SAGD Start-up Enhancement creates a dilation zone (shaded area) helping the inter-well communication.

Figure 3b: More steam can be injected when the injector is stimulated by FUSE as compared to the normal circulation start-up well.

Figure 3c: More oil is produced when the SAGD well pair is stimulated by FUSE as compared to the normal circulation start-up well.

Concluding Remarks

As the oil/gas industry enters a new era where difficult reservoirs are the norm and sustainability requirements are more stringent, integrated consideration of all physico-chemical mechanisms active in subsurface will be key. The traditional emphasis of reservoir engineers on the fluid flow in porous media should be synergized with attention to the rock matrix. Using geomechanics wisely can create additional porosities, conduits and contact areas to produce this oil. The experience of the author in stimulation via dilation can testify to improved production if the rock matrix can be worked on.

Benefits of the fundamental rock dilation mechanism are not limited to unconsolidated oilsands formations. Its application to conventional reservoirs has generated equally remarkable successes in terms of increased well injectivity in water flooding, gas injection and improved tight reservoir production. It is anticipated that dilation can play an important role in CO_2 subsurface sequestration because of its advantages in enhancing well injectivity and reservoir storativity while being safe for geo-containment integrity.

"As the oil/gas industry enters a new era where difficult reservoirs are the norm and sustainability requirements are more stringent, integrated consideration of all physico-chemical mechanisms active in subsurface will be key."

Yanguang ("YY") Yuan, Ph.D., P.Eng., P.Geol.

Dr. Yanguang Yuan, "YY", holds dual professional registrations (P.Eng. and P.Geol.) in Alberta, Canada. After earning his B.Sc. in Geology and M.Sc. in Tectonophysics in China, he studied in the University of Oklahoma, USA in 1993 for his Ph.D. in Geological Engineering (with a minor in Petroleum Engineering). He relocated to Canada in 1997, working in Imperial Oil Resources Ltd. In 2000, he founded BitCan and over the years, has grown it into one of the few integrated independent petroleum geomechanics firms in the world. Dr. Yuan is a respected expert in the field of petroleum geomechanics through his theoretical researches, technology development, field execution and consulting.

He has made important contributions to the industry in two pillars: promotion of rock shear failure and thus dilation effect for reservoir stimulation, and meanwhile, protection of the caprock, casing and fault seal integrity, i.e., geo-containment integrity. The dilation stimulation has proven to be a viable alternative to the common hydraulic fracturing. In the field of geo-containment integrity, Dr. Yuan's contributions have been in providing reliable formation characterization data (in-situ stress and rock mechanical property measurements), simulation of the non-linear coupled thermo-hydro-mechanical (THM) process to investigate the induced stress conditions and thus design the reservoir injection conditions to avoid undesirable failure in the rock formations and well hardware surrounding the reservoir.

REFERENCES

Cenovus FCCL Ltd., 2010, Christina Lake Thermal Project. Enhanced Start-Up Application for Well Pads B03, B04, B05 and B07. Alberta Energy Regulator (AER) Application No. 1666419. https://doi.org/10.1155/2021/8823212

Dusseault, M.B. and Morgenstern, N.R., 1979, Locked sands, Q. Journal Engineering Geol., 12, 117-131. https://doi.org/10.1144/gsl.qjeg.1979.012.02.05

Kry, P.R., Boone, T.J., Gronseth, J.M., et al., 1992, Fracture orientation observations from an Athabasca oil sands cyclic steam stimulation project. CIM paper no. 92-37 presented at CIM 1992 Annual Technical Conference in Calgary, June 7-10, 1992. https://www.scribd.com/document/458477228/ISRM-ISG-2017-003

Samieh, M. and R.C.K. Wong, 1997, Deformation of Athabasca oil sand at low effective stresses under varying boundary conditions. Canadian Geotech J., 34, 985-990. https://doi.org/10.1139/t97-048

Yuan, Y.G., Yang, B. H. and Xu, B., 2011, Fracturing in the oil-sands reservoirs. CSUG/SPE 149308149308 presented at 2011 CSUG/SPE Canadian Unconventional Resources Conference held in Calgary, Canada, 15-17 November 2011. https://doi.org/10.2118/149308-MS

Yuan, Y.G., Xu, B., and Yang, B.H., 2017, Application of Geomechanics in Heavy Oil Production – Advanced Canadian Experience. Presented at 7° Simposio Internacional de Geomecanica 2017: "Sustainable Heavy Oil Exploitation, Innovation and Geomechanical Contributions", 13-16 March 2017, Medellin, Antioquia, Colombia. https://onepetro.org/ISRMISG/proceedings-abstract/ISG17/All-ISG17/ISRM-ISG-2017-003/42067?redirectedFrom=PDF

Yuan, Y.G., 2018, Hydraulic dilation stimulation to improve steam injectivity and conformance in thermal heavy oil production, SPE 193681149308 presented at the SPE International Heavy Oil Conference and Exhibition held in Kuwait City, Kuwait, 10 - 12 Dec 2018. https://doi.org/10.2118/193681-MS

CHOA SILVER SPONSORS

ALBERTA INNOVATES

quorum
software

ALFALUZ

PCM
Artificial Lift Solutions

HATCH

wood.

Sanjel ENERGY SERVICES

Scovan

FLUOR

SPE/CHOA Slugging it Out

16 April 2024 | Hudson | Calgary, Alberta, Canada

SLUGGING IT OUT CONFERENCE - Capture Me If You Can

This year we look at how the industry has progressed – from new developments to optimization of current projects. Some of the topics of focus include innovations in areas such as environmental impact mitigation, production enhancement, and government/regulatory updates. And of course, updates to ongoing industry projects remain a cornerstone of the event. So let's join together for another year of celebrating the projects and industry we support in our pursuit of providing sustainable and resilient energy that our world needs.

Technical Program Highlights

Emissions Panel Session
Explore the various paths being pursued due to the evolving Canadian and Global regulatory environments. Discussions on research into new technologies, how they can be funded through to deployment, and how other jurisdictions have found successful paths forward. Panelists from COSIA, Alberta Innovates, Highwood Emissions

Afternoon Keynote Speaker
Thomas Liles, VP Upstream Research - Rystad Energy

Pilot and Technology Updates
Speakers: Trevor Phenix, Scovan; Alison Aherne, Acceleware

Leading Technologies
Speakers: Sherif Abdelrahman, Teine Energy; Gokhan Coskuner, Strathcona Resources Ltd.

Project Updates
Speakers: Michael Chan, Greenfire Resources; Evan Overbye, Strathcona Resources Ltd.; Craig Flowers, CNOOC

VIEW CONFERENCE SCHEDULE HERE

WHEN: Tuesday, April 16, 2024, 7:30 AM - 6:00 PM
WHERE: Hudson,
200 8 Avenue SW, 6th Floor Calgary, AB T2P 1B5

REGISTER HERE
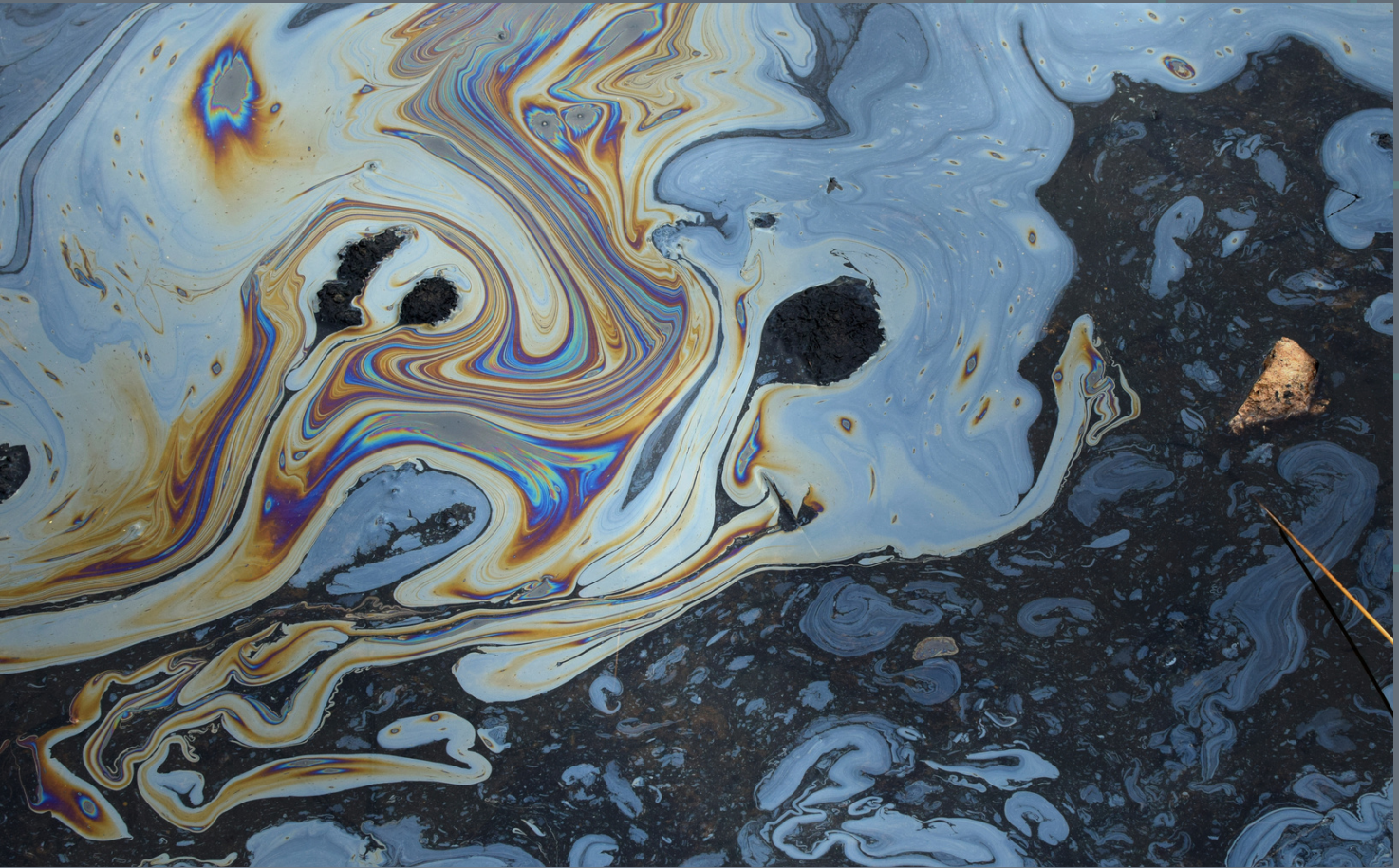
PHYSICAL PRINCIPLES INVOLVED IN THE RECOVERY OF HEAVY OIL AND OIL SANDS BITUMEN

DR. THOMAS G. HARDING

Oil Viscosity

Compared to light, conventional oil, heavy oil and oil sands bitumen have greater density and are more viscous, that is, they do not flow as easily in the subsurface reservoirs in which they are found. The viscosity of heavy oil and bitumen is so high as to prevent them from flowing at commercial production rates or to make them immobile at initial reservoir conditions.

"The viscosity of heavy oil and bitumen is so high as to prevent them from flowing at commercial production rates or to make them immobile at initial reservoir conditions."

Heavy oils have viscosities that typically range from a few hundred centipoise (cP) to 10s of thousands, and bitumen viscosity ranges from about 100,000 to several million cP.

Heat

The viscosity of these oils is highly sensitive to temperature and, by increasing the temperature of the oil from initial reservoir conditions to steam temperature, the oil viscosity can be reduced oil by as much as 6 orders of magnitude from millions of cP to less than 10 cP.

"... by increasing the temperature of the oil from initial reservoir conditions to steam temperature, the oil viscosity can be reduced oil by as much as 6 orders of magnitude..."

Importantly, in order to heat the oil in the reservoir, it is also necessary to heat to the same higher temperature the formation rock and water that are also present. Thus, the more oil that is present in the reservoir relative to the rock and other fluids, the more efficient the energy may be used to heat the oil in relation to the other materials. It follows that the higher the formation porosity, and the higher the oil saturation in the formation, the more efficient will be the utilization of energy to mobilize oil.

The usual measure of SAGD process efficiency is the steam-oil ratio (SOR) that is a measure of the amount of energy injected as steam to the amount of oil produced. For SAGD the SOR is typically in the range of 3 to 5 on the basis of cold-water equivalent (CWE) steam volume to the volume of oil produced. Thus, the lower the SOR, the more efficient is the process.

Reservoirs containing unproductive rock such as shale and also those with facies containing high water saturations will exhibit higher SOR compared to those reservoirs that are 'cleaner' and have higher oil saturation throughout. Low SOR is achievable in only the best quality reservoirs, most of which have already been developed in the Athabasca deposit.

Solvents

The oil viscosity may also be reduced by mixing the viscous material with a lighter, lower viscosity material (solvent) with which it is soluble. Solvent dilution in oil may also be used to reduce oil viscosity by as much as 4 orders of magnitude.

"Solvent dilution in oil may also be used to reduce oil viscosity by as much as 4 orders of magnitude."

Solvents used are often light hydrocarbons such as propane and butane or gas condensate containing a mixture of light aliphatic hydrocarbons. Some promising recovery methods employ a combination of mild heating and solvent dilution to achieve the desired lower oil viscosity.

It should be noted that the lower the viscosity of the oil at original reservoir conditions, the less energy or solvent is required to reduce its viscosity to make it flow at commercial rates. Thus, the economics of heavy oil production will always favor the medium gravity oils over bitumen that has orders of magnitude greater viscosity.

Porosity

The porosity of a reservoir, often being between 25 and 33 %, is a measure of the amount of pore space that exists that contains the oil and water naturally present. The rest of the bulk volume (67 to 75 %) is made up of rock, either sandstone or carbonate. The majority of heavy oil and oil sands that have been commercially exploited is found in sandstones.

Permiability

Absolute permeability is the other important property of reservoir rock as this is a measure of the ability of the rock transmit fluids through it. The higher the permeability, the more easily a given fluid will be able to flow through the rock. Heavy oil and oil sand reservoirs often have permeabilities of several Darcies.

"What is critically important is the ratio of the absolute permeability to the oil viscosity ..."

What is critically important is the ratio of the absolute permeability to the oil viscosity: the higher the ratio, the greater the propensity for flow of the fluid through the rock. The water that is naturally present is often located in direct contact with the rock surface (water wet) and is usually immobile as it held in place by capillary pressure. Water represents about 15 to 25 % of the pore space or about 4 to 8 % of the bulk volume. The rest of the pore space, 75 to 85 %, is filled with oil. This represents about 19 to 28 % of the bulk volume.

"The other factor that has a large bearing on the rate at which oil can move through a reservoir and reach production wells is known as relative permeability."

Oil Relative Permeability

The other factor that has a large bearing on the rate at which oil can move through a reservoir and reach production wells is known as relative permeability. This concept is more difficult to understand and is often given insufficient consideration. Basically, relative permeability is a measure of the ability of one fluid to flow in the presence of other fluids that occupy part of the pore space.

The relative permeability to oil is a function of the oil saturation as is the case for water and gas relative permeabilities. Water and/or gas flowing in the reservoir pore space has a negative effect on the ability of oil to flow: the fluids compete with other for flow capacity in a non-linear manner. Thus, by reducing or eliminating water and/or gas flow in the reservoir, the flow of oil is promoted. This is particularly relevant when considering steam injection oil recovery where, after the steam has condensed, the steam condensate is flowing with the heated and mobile oil, but its very presence inhibits the ability of the oil to flow.

"Water and steam have the advantage of being able to carry large amounts of heat per unit mass, but the water does have the disadvantage of restricting oil flow by its very presence ..."

Water and steam have the advantage of being able to carry large amounts of heat per unit mass, but the water does have the disadvantage of restricting oil flow by its very presence and if the SOR is in the range of 3 to 5, the water saturation in the pore space is considerable and this causes a lower oil saturation to exist in the part of the reservoir in which mobile fluids are flowing. This relative permeability impairment that is experienced with steam injection is not a concern in the case of solvent injection as the solvent becomes part of the oil phase and the amount of solvent needed is in a smaller ratio to the oil of around 1:1 or less. Of course, the volume of the oil phase has been increased by the mixing with solvent and so the flow rate of oil is reduced but not to the same extent as in the case of steam injection.

Similarly, gases dissolved in oil are part of the oil phase and do not reduce oil relative permeability in the same way that gases in the free gas phase do.

Heat Transfer and Energy Efficiency

There is no doubt that injecting steam into a reservoir is the most effective way of transferring energy to a formation. This is due to the almost unique character of water that gives it both very high sensible and latent heats allowing it to carry substantial energy for heating. The condensation of steam in the formation releases a tremendous amount of energy but as mentioned previously, the production of steam condensate along with produced oil also removes substantial amounts of energy from the formation.

"Recovery processes that rely on conduction heating are limited by the composite thermal conductivity of the formation and the amounts of energy that can be transferred by conduction are almost an order of magnitude lower than the convective heat transfer associated with steam injection in a high permeability reservoir."

Recovery processes that rely on conduction heating are limited by the composite thermal conductivity of the formation and the amounts of energy that can be transferred by conduction are almost an order of magnitude lower than the convective heat transfer associated with steam injection in a high permeability reservoir.

For example, the practical energy transfer by conduction from a 1000-metre-long resistive electric heater is about 1 MW but in SAGD if the same horizontal well is able to inject 300 m3/d of steam at 2 MPa pressure, approximately 8 MW of energy is transferred by convection. Electromagnetic heating, for example radio frequency heating, relies primarily on excitation of water that has high dielectric constant, the energy being absorbed by the water raising its temperature and then transferring heat from the water to the surrounding rock and oil.

Fluid Phase Behaviour

It is worth noting that solubility of gases in oil and water is reduced as temperature increases. This is also true of the amounts of solvents that can be mixed with oil to achieve dilution and viscosity reduction. Therefore, in the case of solvent injection, a combination of milder heating to temperatures below 100 °C along with solvent dilution is often contemplated to achieve satisfactory oil viscosity reduction.

"It is also important to recognize that achievement of fluid equilibria is not instantaneous in porous media."

It is also important to recognize that achievement of fluid equilibria is not instantaneous in porous media. The time that it takes for fluids to dissolve and mix means that they are free to travel in their original pure form prior to mixing and this may significantly affect the distribution of fluids in the reservoir. In the case of soluble gases such as carbon dioxide, which have significant solubility in both oil and water, it is very important not to ignore the solubility in water.

The introduction of non-condensable gases or solvent vapour into a steam chamber is known to affect the saturation temperature of the mixture. Consideration of this effect is important for calculating the heat transfer to the vapour chamber edge and to the cap rock.

Thermal Diffusion and Molecular Diffusion

It is well known that the rate of thermal diffusion in a porous medium is approximately an order of magnitude greater than molecular diffusion.

"It is well known that the rate of thermal diffusion in a porous medium is approximately an order of magnitude greater than molecular diffusion."

This means that processes that rely heavily on diffusion of material into heavy oil or bitumen to reduce its viscosity will have lower rates of mobilization of the oil and therefore lower production rates. It is also known that the rates of molecular diffusion increase with increasing temperature so that even mild heating can raise the rates of molecular diffusion and the reduction in viscosity achieved by solvent mixing combined with viscosity reduction from the modest temperature increase can raise production rates.

Formation Geology and Geomechanics

All oil recovery processes including thermal recovery processes for heavy perform best in clean, homogeneous formations, that is, those without shale and clay present. In the case of gravity drainage processes such as SAGD, there is a minimum formation thickness that allows sufficient height of oil producing reservoir above the horizontal wells to provide enough fluid head and reserves to make the process technically and economically viable.

"All oil recovery processes including thermal recovery processes for heavy perform best in clean, homogeneous formations ..."

The absence of reservoir impairments also promotes superior recovery process performance. Such impairments include lean zones with high water saturation, inclined heterolithic strata (IHS beds), bottom water, top water, and top gas. The pexistence of shale and other barriers to vertical flow of fluids is also detrimental to recovery processes and especially to gravity drainage processes.

"Dilation of the formation increasing its permeability to injected fluids may have a significant effect on in-situ recovery process performance."

Dilation of the formation increasing its permeability to injected fluids may have a significant effect on in-situ recovery process performance. It has been demonstrated that marked increases in absolute and relative permeability occur when high injection pressures are used in the McMurray formation at Athabasca (Abbasi and Chalaturnyk, 2016; Collins, 2007). This will affect the ability of hot fluids to penetrate the cold formation near the edge of the steam/vapour chamber that in turn will influence the rate of growth of the heated zone and the oil production rate. Using higher pressure to raise steam temperature and increase dilation effects must be balanced with the ability of the cap rock to contain the fluids.

Dr. Thomas G. Harding

Tom Harding holds BSc and MSc degrees in Chemical Engineering from the University of Calgary and a PhD in Petroleum Engineering from the University of Alberta. He has over 30 years of industry experience in a variety of oil and gas project evaluations, development and production operations. He is a former head of the Chemical & Petroleum Engineering Department at the University of Calgary where he conducted research into improved recovery methods for heavy oil and oil sands, produced water treatment and production of biofuel from waste biomass. Dr. Harding has taught courses in petroleum production engineering and non-renewable resource development. He has been retired since 2018.

Canadian **Heavy Oil** Association

CONNECT. SHARE. LEARN. LEAD.

Annual General Meeting

you are invited

2024

Calling all CHCOA Members and Supporters! It's time to celebrate another year of achievements and gear up together for even greater success in the future.

29 MAY
03:30 – 04:15 PM
Online

Help CHOA continue its work on creating opportunities for professional development for its members, and fostering solutions to the current challenges of our industry.

Your vote matters!
Your presence ensures quorum for the Annual General Meeting. Everyone is welcome. Only full CHOA Members are able to vote. To confirm your attendance, please email office@choa.ab.ca.

RSVP by 15 May 2024

CHOA ENERGY CHANGEMAKERS

This year-long series features insightful talks by technical and business leaders who are shaping the future of Canadian energy. The presentations are platforms to share innovation, discuss troubles shootings and lessons learnt, impart knowledge and discuss case studies. Each event includes dedicated time to network and learn from each other.

Do you want to present at, volunteer for or sponsor the ENERGY CHANGEMAKERS? Contact office@choa.ab.ca.

Following the success of 2023, with eight Energy Changemakers talks delivered, this year, we are focusing on the following topics:

- Decarbonization
- Greenfield SAGD
- Multi-lateral Horizontal Heavy Oil Strategies
- Solvent Assisted Processes
- New Technologies and Case Studies.

METHODS TO REDUCE ENVIRONMENTAL IMPACT OF IN-SITU RECOVERY OF HEAVY OIL AND BITUMEN

DR. THOMAS G. HARDING

Have you read Dr. Harding's high-level primer on
PHYSICAL PRINCIPLES INVOLVED IN THE RECOVERY OF HEAVY OIL AND OIL SANDS BITUMEN
already published in the CHOA eJournal ?

Then let's jump into the full paper ...
METHODS TO REDUCE ENVIRONMENTAL IMPACT OF IN-SITU RECOVERY OF HEAVY OIL AND BITUMEN
by Dr. Thomas G. Harding

ABSTRACT

The situation in the energy industry and the oil industry has changed significantly in the past few years. The common perception is that global climate change is beginning to have severe impacts on communities in the form of more frequent and increasingly violent weather events. In addition, environmental groups have been successful in limiting development of new projects by opposing construction of pipelines that would have allowed increases in production from Alberta oil sands. Globally, investment in new oil production projects has been lower than required to sustain production.

"... there is increasing pressure on the petroleum industry ... to find more environmentally and economically sustainable methods to produce heavy oil and oil sands."

As well, the federal government in Canada has announced gradually increasing carbon penalties affecting project economics. Many people consider electric vehicles to be a viable option now and the costs of solar and wind power have come down substantially making them more economically viable.

So, there is increasing pressure on the petroleum industry and an even greater need than before to find more environmentally and economically sustainable methods to produce heavy oil and oil sands to contribute to the growing need for energy worldwide, to meet carbon emission targets and to lessen the negative publicity that the oil industry receives. This paper describes a number of ways to modify existing recovery methods and introduces some new ideas that, if used, will make heavy oil recovery more socially and environmentally acceptable.

INTRODUCTION

Heavy oil recovery, including recovery of bitumen from oil sands, is currently facing some serious challenges. The World is in transition, trying to move away from the use of coal, oil and natural gas, motivated mainly by well-known concerns about increasing levels of carbon dioxide in the atmosphere and its effect on global warming. Thus, there is a movement to replace fossil fuels that create carbon dioxide (CO_2) during their combustion with renewable energy systems that do not produce CO_2 that will end up in the atmosphere. Because of their basic properties, heavy oil and bitumen production operations have higher levels of CO_2 emissions compared with conventional oil and gas production. This is basically due to the higher viscosity of heavy oil and the need to reduce its viscosity in order to make it flow at commercial production rates. This reduction in viscosity has mainly been accomplished by heating the reservoir, with steam injection being the most successful method for heating the heavy oil in-situ but of course steam generation normally involves the burning of fuel which adds to the carbon footprint of the production. The use of steam also requires water of boiler feed quality and this imposes an additional environmental concern related to the supply of this water as well as costs for water treatment and disposal. Because heavy oil and bitumen are typically more expensive to produce, their production is more sensitive to decreases in oil price or increases in the differential between light and heavy oil. So, the challenge for heavy oil and bitumen recovery is to reduce the environmental impact of their production by lowering CO_2 emissions and water usage and at the same time reduce costs and improve the economics.

"... the challenge for heavy oil and bitumen recovery is to reduce the environmental impact of their production by lowering CO2 emissions and water usage and at the same time reduce costs and improve the economics."

It is probably worthwhile at this juncture to briefly discuss the need for heavy oil and bitumen because obviously, if there is no need for these commodities in the future, it is futile to discuss methods for addressing the challenges facing their production. The human population on the planet is expected to continue to grow although the rate of growth is gradually decreasing. People in developing countries aspire to a higher standard of living, more like that in advanced economies, and one of the facilitating elements in that quest is the availability of reliable and affordable energy. Also, in most developing countries there is a shortage of energy and a lack of money to make the transition to lower carbon emitting technologies. Standard of living and energy consumption are directly correlated. Because of the rising population and aspirations for a higher average standard of living, it is expected that energy demand globally will continue to rise. This increased demand for energy will be partly met by renewable energy systems as they are brought online but an increase in oil and gas consumption is also expected. It will be practically impossible to meet the aspirations of the people in developing countries while simultaneously moving to eliminate the current mainstay of energy production: petroleum.

"Because of the rising population and aspirations for a higher average standard of living ... it will be practically impossible to meet the aspirations of the people in developing countries while simultaneously moving to eliminate the current mainstay of energy production: petroleum."

And in addition, given the massive infrastructure that has been developed around the use oil and gas, it is going to take significant investment of time and money to replace the existing systems.

Consider the vast network of pipelines that transport and distribute natural gas to homes, businesses and factories for heating. In northern countries like Canada the heating of buildings is extremely important. And it is difficult to see how jet fuel can be replaced but there may be a technological breakthrough in future that can resolve this issue. Petroleum is also used for production of fertilizers, plastics, cement, steel and synthetic fibres. And there will the problem of how to dispose of the millions of internal combustion engines, fueling stations, pipelines and distribution systems and production operations, while simultaneously investing in new energy infrastructure.

And there are some issues with alternative energy systems such as wind and solar power: these are both intermittent and there will be difficulties providing base load power generation using these methods. Battery storage has been suggested as a solution to this problem but then the issue arises of securing supplies of rare earth metals required by the batteries, and the high cost of providing so much power storage. Ultimately, there may be a new environmental challenge caused by the need to recycle or dispose of spent batteries. Certain countries, like China, control the supply of the much-needed rare earth metals and mining for them requires energy and will involve some environmental impact. And then there is the question of where to put the solar panels: they take up a large amount of space and need to be located in sunny places where agricultural production will not be displaced. New power transmission systems to potentially remote locations will need to be built. One may also wonder how effective the solar panels will be if they become covered with dust or snow, a definite concern in Canada, and what the maintenance cost will be. Nuclear power using fourth generation small modular reactors (SMRs) should be part of the solution, but public sentiment is almost as strongly against the nuclear industry as it is the petroleum industry. In principle, nuclear power does not have any carbon emissions associated with it but there is the omnipresent issue of nuclear waste disposal for which there is still no well accepted solution.

Safety and security of nuclear power installations must be assured. Hydropower is clean and emissions free but many of the best locations for dams have already been developed and there are people advocating the removal of older dams to allow free run of the rivers which would reduce the power available unless new dams are constructed. Hydro dams cause disruption of river flows and fish migration and they flood large areas of land. Production of hydrogen to be used as a transportation fuel has received quite a lot of attention but infrastructure is essentially non- existent and the cost of production of hydrogen is high. The large explosive range, difficulty in containing hydrogen and its ability to cause embrittlement in steel must be kept in mind. The lack of a plan for how to make the transition from fossil fuels to other sources of energy along with the inevitable high costs and time required are likely to slow the transition.

Based on the above brief discussion, let us proceed on the assumption that oil and natural gas will continue to be needed as energy demand grows and the need for petroleum for certain specific uses will remain. Carbon capture and storage (CCS) may help to reduce carbon emissions related to fossil fuel production and use and facilitate the transition to alternatives while allowing continued use of oil and gas for specific purposes where there is no practical alternative. But CCS is capital equipment intensive, very expensive and there are limited options for underground sequestration of CO_2. Also, adding more capital equipment to existing SAGD operations, which are already burdened with high capital and operating costs, will increase the risk of greater downtime for the entire facility simply due to the greater complexity of the operations and the interdependence of the various parts of operation.

Would it not be better to find ways to produce the oil with fewer associated carbon emissions or to eliminate the carbon emissions entirely? This would save about 30% of the wells-to-wheels emissions.

Another factor to consider is, that if at a point in the future oil prices drop below the breakeven point for heavy oil production, and remain there for an extended period, the heavy oil operations will be uneconomic and will be discontinued. The lighter oil production operations in other parts of the World, such as the Middle East, with much lower breakeven points, will continue to meet the demand for oil globally.

"Canada has seen most of its conventional oil produced and is left with a large amount of heavy oil and oil sands. The continued monetization of these resources will be aided by development of recovery technologies that reduce the environmental impact of the production operations and by reduction of costs and improvement of economics."

Canada has seen most of its conventional oil produced and is left with a large amount of heavy oil and oil sands. The continued monetization of these resources will be aided by development of recovery technologies that reduce the environmental impact of the production operations and by reduction of costs and improvement of economics. It is a difficult task to reduce environmental impact and improve economics simultaneously, but this paper discusses promising ways to achieve these goals. Stated simply, reducing or eliminating steam injection as the way to recover heavy oil and bitumen is the most effective way to reduce the carbon emissions associated with their production. In order to appreciate the potential for the methods discussed, it is first important to understand the subtleties of the fluid properties and flow behaviour of heavy oil and the materials that are used to assist in its recovery. Appendix A, published previously on <date> <link> contains a description of the fundamental physical principles involved and the reader is referred to that Appendix as background for the discussion that follows.

PROMISING METHODS FOR IN-SITU RECOVERY OF HEAVY OIL AND OIL SANDS BITUMEN

Recovery Processes Employing Additives to Steam

If one accepts that there is a need to improve the economics and reduce environmental impact of heavy oil production, there are several ways to go about this. Steam additive processes are able to reduce the amount of steam required and this can reduce the carbon emissions and water usage per unit of oil production. The additives that have been subjected to considerable study and varying degrees of field testing are hydrocarbon solvents and non-condensable gases. These additives have different means of improving oil production performance and because of this it may be possible to employ a mixture of additives to achieve the greatest improvement in the process. In existing SAGD operations the addition of facilities to allow injection of additives with steam is relatively straightforward compared with construction of green field facilities.

Steam/Solvent Injection

Solvent addition to steam is a proven technique. It has been shown by extensive laboratory work, numerical simulation and field testing that a properly operated steam/solvent process can reduce the steam-oil ratio (SOR) by approximately one third while maintaining or accelerating oil production rate (Khaledi et al, 2015; Al-Murayri et al, 2016a; Al-Murayri et al, 2016b; Rabiei Faradonbeh et al, 2015; Rabiei Faradonbeh et al, 2016a; Rabiei Faradonbeh et al, 2016b; Hosseininejad Mohebati et al, 2012a; Hosseininejad Mohebati et al, 2012b). There have been many field pilots, some of which were poorly designed and executed, and these were unsuccessful and have cast doubt on the technology, but it is certain that if done properly, solvent addition to steam is effective and economic. For a steam/solvent process to be successful, the right solvent must be used, it must be injected in the right concentration with steam, and it must be injected at the right time in the recovery process. Reducing SOR has the effect of reducing energy input to the formation and CO_2 emissions.

"… if done properly, solvent addition to steam is effective and economic."

Numerical modeling of steam/solvent injection has been challenging and improvements have been made to analytical models to allow more rapid assessment of the potential for steam/solvent injection and to improve understanding of the process (Keshavarz et al, 2016 and Keshavarz et al, 2019). Reducing SOR frees up steam that can be injected into other wells so that a steam plant of fixed size may be utilized to steam a larger number of well pairs through the addition of solvent. Solvent to steam ratio of between 10 and 20 volume percent appears to be optimal. Higher amounts of solvent above this range do not appear to enhance the oil production rate or SOR appreciably. Injecting solvent early in the process, when there is lots of oil in the reservoir, provides the best opportunity for the solvent to enhance the steam- only process. An investigation has been done to evaluate the effect on relative permeability of steam/solvent injection so as to improve the ability to model the process (Esmaeili et al 2020c).

The solvent chosen should match the phase behavior of steam as closely as possible at the operating pressure of the process. The goal is to have the solvent travel with steam to the steam/vapor chamber boundary where it can contact the cool, highly bitumen-saturated, undepleted reservoir. Here the steam condenses releasing its latent heat of vaporization and the solvent condenses and dissolves in the bitumen further reducing its viscosity. In choosing a suitable solvent, it should be kept in mind that the phase behavior of the both the solvent and the steam is affected by the mole fractions of the materials present that govern the partial pressure of the materials and the temperature at which they will condense. If the solvent chosen is too heavy and is injected at too high a concentration, it will have a tendency to remain in the liquid phase and it may not be able to reach the vapor chamber boundary or rise in the formation with the steam thus limiting its effectiveness. If the solvent is too light, it will have a tendency to remain too long in the vapor phase and its effectiveness in diluting bitumen and increasing its mobility will be reduced.

Choosing a solvent that is slightly more volatile than water at reservoir conditions may be advantageous in terms of its ability to penetrate somewhat more deeply into the interface between the cold reservoir and the hot vapor chamber. Gas condensate is often a good choice as a solvent as it has about the right combination of molecular weights in its constituents for many reservoir pressure conditions. And it is lower in price than pure hydrocarbon solvents such as hexane and pentane. The availability of the latter solvents may also be an issue. Gas condensate is often used on site as diluent for making the produced bitumen pipeline transportable, so facilities and infrastructure are normally already in place for handling gas condensate.

"The main concern with hydrocarbon additives to steam has been the cost of the solvents and the need to have high solvent recovery to make the solvent addition economic. Strategies exist for maximizing solvent recovery ..."

The main concern with hydrocarbon additives to steam has been the cost of the solvents and the need to have high solvent recovery to make the solvent addition economic. Strategies exist for maximizing solvent recovery such as providing a pressure boundary to contain the solvent by injecting pure steam at slightly higher pressure at the end well pairs of a well pad under steam/solvent injection. Tapering down the solvent injection to zero in the last few years of well pair life also assists in solvent recovery. Non-condensable gas injection may be used at the process end along with pressure blow down to increase solvent recovery. Steam/solvent injection will outperform steam-only injection in all reservoirs, but it would be prudent to avoid the leakiest reservoirs as this increases the risk of solvent loss. It is worth noting that such leaky reservoirs are also risky for pure steam injection.

Steam/Non-condensable Gas Injection

Non-condensable gas (NCG) injection with steam has been investigated for many years as an improvement over pure steam injection in heavy oil and oil sands recovery (Harding et al, 1983; Butler and Yee, 1986; Butler, 1999; Al-Murayri et al, 2011). Field tests with NCG injection date back to trials conducted by Imperial Oil at Cold Lake in the 1970s associated with steam stimulation operations there. Much work with a variety of additives to steam, including NCGs, was done in the 1970s by the Alberta Research Council (Redford, 1982).

A review of technical aspects of NCG addition to steam was presented by Harding (2014a) and Harding (2014b). NCGs carry much less heat than steam and do not condense so they do not release latent heat of vaporization to the formation. Once steam condenses into liquid form, its mobility is reduced, and it no longer has the ability to rise in the formation but rather drains downward as steam condensate. The NCGs however are able to continue to move in the gas phase through the porous media and to rise in the formation due to their low density. The NCGs will therefore tend to accumulate in the upper part of the formation and due to their increasing mole fraction in the vapor phase in the upper portions of the reservoir the NCGs are able to offer an insulating effect against heat losses to the overburden. Butler et al (2000) surmised that "in SAGP (Steam and Gas Push) much of the oil displacement is caused by the flow of fingers of gas/steam rising counter-currently to the draining oil, rather than by simple advance of a continuous steam chamber. The rising gas fingers ... tend to push the oil down." In a subsequent paper, Butler (2004) argues that "gas can move relatively easily, in small fingers, through the reservoir beyond the steam chamber."

"... NCGs will therefore tend to accumulate in the upper part of the formation and due to their increasing mole fraction in the vapor phase in the upper portions of the reservoir the NCGs are able to offer an insulating effect against heat losses to the overburden ..."

NCGs have also been seriously considered for use in wind down of SAGD near the end of its productive life and placing NCGs in the reservoir is seen as a way of maintaining reservoir pressure post-SAGD thus keeping pressure from collapsing as would be the case with steam cooling and condensing. NCGs also offer some viscosity reduction when dissolved in oil but the effect is much more limited than that of solvents. NCGs may contribute to more rapid expansion of the steam chamber by adding convective mixing at the steam chamber boundary and by leaking off into the cold reservoir.

There have been several field tests reported of NCG injection with steam in SAGD. Generally, a reduction in SOR was measured with little or no impact on oil production rate. Aherne and Maini (2008) concluded from examination of Dover Phase B pilot data that NCG flowed into the reservoir ahead of the steam chamber. Their analysis indicated that the steam chamber did not cool as expected which is consistent with the NCG leaking off into the cold reservoir. Also, bitumen production exceeded predictions based on simulation indicating that NCG addition did not have the level of negative consequences forecast. This extra production was attributed to drainage from the Inclined Heterolithic Strata (IHS) in the upper part of the reservoir, the drainage from which was assisted by the NCG, and this prolonged the life of the well pair. Aherne and Maini (2008) also report additional evidence for fluid movement ahead of the steam front through examination of observation well pressure and temperature data. In some field trials of NCG injection with steam NCGs were reported to have 'vanished' (Japan Canada Oil Sands Limited (JACOS), 2009). This may have been the result of there being initial mobility to gas or water in the cold reservoir or dilation at higher pressure may allow the low-viscosity gas to flow into the cold reservoir due to permeability enhancement.

"... NCG injection with steam in SAGD ... [provides] generally, a reduction in SOR ... with little or no impact on oil production rate ..."

Studies have shown that small amounts of NCG injection with steam, in the range of 0.5 to 2 mole percent, have a small beneficial effect on the process but at larger concentration may inhibit the flow of oil due to a suppression of the relative permeability to oil.

Some reported field pilot trials of NCG addition to steam in the Athabasca Oil Sands have involved methane addition to steam of up to 2 mol % (PetroCanada, 2005), (Japan Canada Oil Sands Limited, 2009) (Suncor Energy, 2010).

In history matching of production performance and temperature observation well data from a number of SAGD field projects, it was noticed that steam chambers often are unable to reach the top of the oil-bearing formation (Ito and Chen, 2010) (Chen and Ito, 2012). Production performance in such cases was explained by these authors as being partly due to NCG migration through the top of the steam chamber where it is then able to assist with drainage of bitumen from the layer above the steam chamber. In such cases, the injection of NCG may be beneficial for bitumen recovery using SAGD, as solution gas present in the reservoir, and released during heating of the oil, may not be sufficient to take full advantage of this phenomenon. It may be that because of increasing NCG mole fraction in the vapor with height in the steam chamber that it appears as though the steam chamber has not grown above a certain point due to suppression of the steam chamber temperature by the increasing concentrations of NCG. Generally, field experience provides evidence for reduced SOR and little or no effect on bitumen production rates when NCGs are introduced in late SAGD life when there is already a lot of heat in the reservoir.

Direct oxy-fired boilers have been suggested to produce a mixture of steam and NCG for injection, but these typically have gas/steam ratios substantially exceeding the desired amounts. If air instead of oxygen is used for combustion in such systems, the situation is made worse due to the large amount of nitrogen present. Nitrogen is mainly insoluble in both oil and water at reservoir conditions so there is minimal viscosity reduction effect but the large amount of NCG resulting has a mainly deleterious effect on the process through severe reduction in oil relative permeability and thus a commensurate reduction in oil production rate. Methane, flue gas and carbon dioxide have all been suggested as NCGs for injection. In the case of carbon dioxide injection, it is important to consider the solubility of the gas in water as well as oil due to its significant solubility in both fluids.

"Simulation of NCG addition to steam is challenging for a number of reasons."

Simulation of NCG addition to steam is challenging for a number of reasons. First of all, viscous fingering is not included in simulation models and so it is impossible to adequately model the rise of NCGs in the heavy oil formations. Secondly, there is a time lag for gases to enter solution in viscous oils and this is difficult to model as there is limited information available on this phenomenon. And thirdly, the three-phase relative permeability of fluid flow in the oil sands reservoirs is complex and difficult to predict. Grid block averaging effects associated with the aforementioned phenomena further complicate the situation. Yee and Stroich (2004), in modeling gas-steam co-injection at the Dover Phase B SAGD project, found that the STARS simulator predicted a considerably smaller steam chamber size and cooler temperature at the edge of the steam chamber, due to the build-up of gas concentration, resulting in a significant decrease in heat and mass transfer and a pessimistic prediction of process performance. This is typical of simulation results of gas/steam injection. To improve on the generally accepted method for simulation of 3-phase flow in porous media, that is the use of Stone's models, would require extensive laboratory study using two-phase oil-water and gas-oil systems, along with 3-phase experimental measurements, in order to improve the method for combing the 2- phase data. A start on this multi-decade long task has been made by collecting experimental 2- phase oil-water data (Esmaeili et al 2019a, Esmaeili et al 2019b, Esmaeili et al 2019c, Esmaeili et al 2020a, Esmaeili et al 2020b).

Hybrid Steam/Combustion Recovery Processes

The main advantage of in-situ combustion (ISC) over steam injection is that the heat generated in ISC by combustion of fuel in the reservoir is produced directly in the reservoir, whereas in the case of steam injection, the steam is generally produced on surface by boilers with about 85 percent efficiency and an additional 15 percent of the energy is lost during transmission of steam to the reservoir by surface line and wellbore heat losses.

"The main advantage of in-situ combustion (ISC) over steam injection is that the heat generated in ISC by combustion of fuel in the reservoir is produced directly in the reservoir..."

Another advantage of ISC often cited is that the ISC process uses a residual fuel in the formation, either unrecoverable residual oil saturation or hydrocarbon coke formed by the pyrolysis of heavy ends at high temperature; thus, there is essentially no cost for fuel for the ISC process. Drawbacks to the ISC process include difficulties with ignition and reaching high-temperature oxidation (HTO) conditions. The high temperatures associated with ISC, often greater than 600 °C, are also a concern as such high temperatures can damage downhole equipment. The production of unreacted oxygen in the production wells must also be avoided to maintain safe operating conditions and to avoid corrosion.

The production of tight emulsions has also been an issue for some ISC projects. Use of compressed air for combustion results in large quantities of non-condensable gases (NCGs) in the reservoir and these can cause high producing gas-oil ratios (GORs), erosion of downhole equipment due to high gas velocities and can promote sand production but the main, often- overlooked problem, is severe suppression of the relative permeability to oil. Similar to NCG injection with steam, the introduction of too much NCG in the reservoir reduces the ability of oil to flow and therefore reduces oil production rates.

The use of oxygen or highly enriched air injection eliminates many of the aforementioned problems with ISC due to the elimination of nitrogen from the process. In the case of pure oxygen injection, the gas volume is reduced to 20% of what it would be with air injection. Water injection along with air or oxygen allows the water to scavenge heat from hot rock that has experienced combustion temperatures and to generate steam in-situ to enhance the heat transfer and oil displacement.

"By combining steam and oxygen injection, many of the problems associated with ISC processes can be further reduced."

By combining steam and oxygen injection, many of the problems associated with ISC processes can be further reduced. Ignition is practically assured by preconditioning the reservoir with steam increasing reservoir temperature near injection wells to steam temperature and from there HTO conditions can be reached rapidly. This assures efficient combustion and largely eliminates degradation of oil quality by low temperature oxidation (LTO). Maximum temperatures associated with HTO may be moderated by the presence of steam and held within the range of 500 to 600 °C. By injecting 9 volume percent oxygen with steam, approximately 50 % of the energy delivered to the formation is generated by combustion with the remaining 50 % injected with the steam. Thus, GHG emissions and water usage may be reduced by 50 percent or more. This has the potential to free up 50 % of the steam from the steam plant to be injected into other wells. The amount of NCG produced in the reservoir when oxygen is added to steam is significantly reduced compared to ISC projects without steam injection or those using compressed air injection. It is the opinion of the author that the combination of steam and oxygen injection, reducing the amount of NCG generated in the reservoir and having to be produced from the production wells, will offer superior oil production performance over a process like the Toe-to-Heel Air Injection (THAI) process (Greaves et al, 2001; Greaves et al, 2012) where essentially all of the combustion gas products associated with the air injection must be produced through the production wells, and their volume is considerable.

"... the combination of steam and oxygen injection, reducing the amount of NCG generated in the reservoir and having to be produced from the production wells, will offer superior oil production performance over a process like the Toe-to-Heel Air Injection (THAI) process ..."

A hybrid steam/ in-situ combustion process has been proposed that is called SAGDOX (Kerr, 2012; Kerr and Jonasson, 2013) in which oxygen is injected with steam in ratios of approximately 9 to 35 volume percent. The main objective of SAGDOX is to reduce reservoir energy injection costs thus improving recovery process economics and thereby extending SAGD to lower quality reservoirs. SAGDOX may be particularly applicable to reservoirs with high water saturations, high shale content and thin pays. Another feature of SAGDOX is that reservoir temperatures higher than saturated steam temperature may be achieved independent of reservoir pressure. By maintaining HTO conditions, excessive low temperature oxidation (LTO) is avoided which degrades the performance of the process and this also minimizes the risk of unreacted oxygen entering production wells. Partial in-situ upgrading occurs due to pyrolysis of the oil.

"A hybrid steam/ in-situ combustion process has been proposed that is called SAGDOX ... in which oxygen is injected with steam in ratios of approximately 9 to 35 volume percent."

Using a relatively small amount of gas (oxygen) injection results in a similarly small amount of combustion gas product, mainly carbon dioxide, and this NCG can have benefits for the recovery process and is also able to maintain reservoir pressure when steam is condensing. The NCG can provide a partially insulating gas blanket at the top of the formation; can increase convective mixing at the edge of the vapor chamber increasing rate of mobilization of viscous oil; and can be used as a source of NCG for wind-down of SAGD where the NCG can reduce the amount of steam injection required improving the steam-oil ratio (SOR) while maintaining oil production rates.

The hybrid steam/ISC processes offer much flexibility in terms of the average oxygen to steam ratio and the potential to vary the ratio throughout an oil recovery process. The degree of oxygen enrichment in air may also be varied over the life of a project such that more nitrogen is introduced in late life when a greater quantity of NCG is desirable to maintain reservoir pressure or during wind down of the process. For example, pure steam injection may be followed by a period of steam/oxygen injection where the steam/oxygen ratio is constant or either increasing or decreasing. A variety of well arrangements including both vertical and horizontal wells can be considered, and the use of vent gas wells may also assist with control of movement of the high temperature combustion zone. However, it may be very challenging to establish fluid communication with vent gas wells and operate them effectively so that liquid production from the vent wells is minimized while producing gas at desired rates.

"Several challenges with the SAGDOX process have been identified and these are mainly related to the high temperatures generated that can exceed 600 °C."

Several challenges with the SAGDOX process have been identified and these are mainly related to the high temperatures generated that can exceed 600 °C. Protection of wells and well completion equipment from these high temperatures is essential and thus temperature monitoring equipment must be installed downhole in all wells along with cooling water injection equipment. Keeping the combustion zone in the centre of the formation will increase the energy efficiency of the process. Understanding the effect of the high temperatures, while of limited volume in the reservoir, on the in-situ stresses will be challenging and important.

Risks to the cap rock of high temperatures have been evaluated and found to be no greater than for steam-only processes (Saeedi et al 2018). Data available on the mechanical properties of reservoir sands and shales at temperatures over 200°C are very limited and this makes modeling of the changes in stress difficult.

Production of hydrogen sulphide is often associated with the high temperature combustion and this must be accounted for during field test planning in particular. 3D physical modeling of the SAGDOX process has been completed (Rios et al 2018). Handling of oxygen on surface requires a high degree of training and rigorous attention to operation practices but many industrial operations worldwide have shown that oxygen can be generated and transported safely. Costs for oxygen production and handling, including specialized materials, must be considered in project planning and economics.

Simulation of the combustion processes is very challenging due to the scale-up issues associated with reaction kinetics models and the significant computational time required as a result of the need to include additional material balance for components involved in the combustion reactions. A new reaction kinetics model for Long Lake bitumen was developed based on ramped temperature oxidation (RTO) data (Yang et al, 2016, Yang et al 2017a). It has been found that sufficient fuel is available in the form of residual oil in the steam-swept zone and that HTO can be established and sustained at low oxygen concentrations in the presence of steam but at the same time peak combustion temperatures are moderated by the presence of steam. This reaction kinetics model was used to history match combustion tube test data (Yang et al, 2019a) resulting in minor tuning of the model. Further development of the SAGDOX process has focused on addressing the main uncertainties and risks associated with the process including the management of combustion zone movement, the potential impacts of high temperatures on in-situ stresses (Saeedi et al, 2018) and the handling of produced gases including hydrogen sulphide and carbon dioxide. Accurate and efficient field-scale numerical modeling of SAGDOX has been accomplished allowing technical and economic evaluation of the process (Yang et al, 2017b, Yang et al, 2019b).

"Further development of the SAGDOX process has focused on addressing the main uncertainties and risks associated with the process including the management of combustion zone movement, the potential impacts of high temperatures on in-situ stresses ... and the handling of produced gases including hydrogen sulphide and carbon dioxide."

Electrical Heating Processes

Many processes for heating formations using electrical energy have been proposed (Bogdanov et al, 2011). These include processes that pass current through the formation causing resistive heating (McGee and Vermeulen, 2000; McGee and Vermeulen, 2007; McGee, 2008), electromagnetic heating by generating an electric field that causes heating through the water present in the formation (Koolman et al, 2008; Wacker et al, 2011), radio frequency heating using long antennas to excite the water molecules in the formation and causing reservoir heating (Kovaleva and Davletbaev, 2010; Wise and Patterson, 2016) and the use of long resistive electrical heaters set at high temperature to heat the formation (Ivory et al 2010, Harding et al 2015, Harding et al 2016). Modeling of the electromagnetic heating of oil sands has been challenging but several recent studies have advanced the capability (Ji et al 2019, Ji et al 2020, Sadeghi et al 2017a, Sadeghi et al 2017b, Sadeghi et al 2017c, Sadeghi et al 2018, Sadeghi et al 2020). The process that is favored by this author is one that that employs resistive electric heaters placed downhole combined with solvent injection. This method is simple, uses robust and proven electric heaters, and relies on a combination of mild heating and solvent mixing to mobilize viscous oil and facilitate its production.

Resistive Electric Heating with Solvent Injection

Recovery processes have been suggested that employ long resistive electric heaters combined with the injection of water and/or solvents. Most of the experimental and simulation work to date has focused on the use of horizontal well-pairs in a similar configuration to those used in SAGD (Ivory et al, 2010, Harding et al, 2015, Harding et al, 2016). There is also potential to use single wells, but no experimental or numerical modeling work has been to date to assess this possibility.

The original concept proposed by Ivory et al (2010) involved managing of the injection and production rates along with heater power and temperature to cause the refluxing in the reservoir of vaporized connate water along with injected fluids. Refluxing occurs when steam condensate and/or dissolved solvent are draining downward towards the production well where they encounter reservoir temperatures exceeding the saturation temperature of the fluids. The volatile fluids are then re-vaporized and reverse their flow such that they begin to rise in the formation. Meanwhile, the heated liquid bitumen continues to drain downward to the production well. By invoking the refluxing process, the water and solvent requirements for injection are reduced and so are the energy requirements. This is because the refluxing fluids require only the addition of the latent heat of vaporization to re-vaporize them and no sensible heat addition is required. Even without refluxing, the volumes of water injection are expected to be much lower than in the SAGD case.

"The original concept has evolved into one that is not dependent on creating reflux of fluid but rather is concentrated on using solvent-only injection without water and operating the resistive electric heaters at temperatures sufficient to vaporize the solvent but not water. This process could be called Solvent-Assisted Resistive Electric Heating or SAREH."

The original concept has evolved into one that is not dependent on creating reflux of fluid but rather is concentrated on using solvent-only injection without water and operating the resistive electric heaters at temperatures sufficient to vaporize the solvent but not water. This process could be called Solvent-Assisted Resistive Electric Heating or SAREH. It is expected that propane will be used as the solvent and that heater temperatures will not exceed the saturation temperature of water at the reservoir pressure. This way, no water in the formation will be vaporized and there will be little or no water flowing in the formation, especially if the formation is at irreducible water saturation. A provisional patent has been filed covering these concepts (Harding, 2023).

It should be noted that the amount of heat that can be transferred by conduction and some convection with resistive electric heating is lower than is the case with steam injection in which case massive amounts of energy are transferred to the formation by convection. For example, 300 m3/d of 100 quality steam injection at 2 MPa pressure, an amount commonly used in a single SAGD well pair, is the equivalent of almost 10 MW of power. Because resistive electric heating is limited in part by the thermal conductivity of the formation, only about 1 MW of power can be effectively transmitted into the formation by conduction (Hassanzadeh and Harding, 2016). This affects the rate of heating of the formation and lowers the oil production rates. Partially offsetting this reduced oil rate due to lower energy input to the formation and lower rate of heating is the reduction in water flow in the formation which has the effect of not suppressing the relative permeability to oil. The use of solvent injection assists with bitumen viscosity reduction helping to raise oil production rates. So, the method relies on mild reservoir heating by conduction and vaporization of solvent in the injection well promoting the development of a rising solvent vapor chamber above the injection well similar to the steam chamber in SAGD. The solvent condenses and dissolves in oil to make the oil more mobile. There is a complex interplay between the viscosity reduction caused by temperature increase and that caused by solvent mixing with the oil, considering that the diffusion rate of solvent into oil increases with temperature but the amount of solvent dissolved in the oil is reduced at higher temperature.

"Lower oil production rates with a process like SAREH compared to SAGD will have a negative effect on economics but offsetting this drawback are the significantly reduced capital and operating costs ..."

Lower oil production rates with a process like SAREH compared to SAGD will have a negative effect on economics but offsetting this drawback are the significantly reduced capital and operating costs associated with elimination of the steam plant, water treatment plant and most of the oil/water separation equipment.

Additional costs for downhole heaters, additional wells if closer well spacing is needed and the requirement to purchase solvent must also be considered. While it isn't needed, if water is injected, the volumes will be small relative to SAGD, but the water quality will need to be high to avoid scaling downhole. The cost tradeoff between supplying energy using steam injection versus electrical power must also be considered.

Carbon emissions with resistive electric heating may be reduced substantially depending on how the electricity is generated for the process. For example, nuclear power as the source of electricity would eliminate greenhouse gas emissions from the oil recovery process entirely. Because the energy input in SAREH is less than 1/8th that of SAGD, there will be commensurate reductions in carbon emissions even if the power is generated in a conventional manner by burning of natural gas. It is expected that in comparison to RF antennas, the cost of resistive electric heaters will be substantially lower (Koolman et al, 2008). Ashoori and Gates (2022) have presented a comparison of carbon emissions in SAGD between once-through steam generators (OTSGs) and direct-contact steam generators (DCSGs). Charpentier et al (2009) have presented a good discussion of the sources of carbon emissions in oil sands operations. Using a similar analysis as in Ashoori and Gates (2022), and largely using their data, a comparison is made between SAGD using OTSGs and SAREH, as presented in Table 1 (for SAGD) and Table 2 (for SAREH) below. Physical and thermodynamic properties for propane were obtained from Goodwin and Haynes (1982). Carbon emissions per unit volume of bitumen production are shown to be only about 18 percent of those for SAGD when on-site power generation is performed using a simple cycle gas turbine. These units are known to have an efficiency of between 35 and 45 %, therefore 40 % has been used in the calculations.

"... it is evident that the carbon emissions per unit volume of bitumen production are much lower in SAREH than SAGD ..."

SAGD CASE	SI	SI Units	Imperial	Imperial Units
Cumulative Steam/ Oil Ratio (cSOR)	5.0	m^3 steam/ m^3 bitumen	5.0	bbl steam/ bbl bitumen
BFW Temperature	150	°C	302	°F
BFW Pressure	2101	kPa(a)	305	psia
BFW Enthalpy	634	kJ/kg	272.6	BTU/lbm
100 % Quality Steam Enthalpy	2797	kJ/kg	1203	BTU/lbm
80 % Quality Steam Enthalpy	2419	kJ/kg	1040	BTU/lbm
Wet Steam Enthalpy Change	1785	kJ/kg	768	BTU/lbm
HHV of Natural Gas	37.85	MJ/m^3	1017	BTU/ft^3
Boiler efficiency	0.8		0.8	
Natural Gas Required	235.8	m^3 natural gas/ m^3 bitumen	1324	ft^3 natural gas/ bbl bitumen
Carbon Emissions from NG Combustion	1902	g CO_2 eq/ m^3 natural gas	0.119	lbm CO_2 eq/ ft^3 natural gas
Carbon Emissions per Unit Volume of Bitumen Production	448.5	kg CO_2/ m^3 bitumen produced	157.3	lbm CO_2 eq/ bbl bitumen produced

Table 1. SAGD Carbon Emissions per Unit Volume of Bitumen Production

Comparing Tables 1 and 2 it is evident that the carbon emissions per unit volume of bitumen production are much lower in SAREH than SAGD, especially considering the poor efficiency of the gas turbines to generate electricity. But this may be explained by considering the lower volume of solvent employed, the lower enthalpy of propane, and the lower density of propane, all of which contribute to the lower energy per unit volume of production in SAREH compared to SAGD. Here, a cumulative solvent/oil ratio of 2.0 has been assumed that may be quite conservative compared to the value of 0.77 reported by Ivory et al (2010) and the figure of 0.77 excludes production from blowdown that would make the solvent/oil ratio even lower. This means that the carbon emission reductions possible with SAREH are potentially even lower than those calculated in Table 2.

SAREH CASE	SI	SI Units	Imperial	Imperial Units
Cumulative Solvent/ Oil Ratio	2.0	m^3 solvent/ m^3 bitumen	2.0	bbl solvent/ bbl bitumen
Propane Feed Temperature	25	°C	77	°F
Propane Injection Pressure	2101	kPa(a)	305	psia
Propane Feed Density	493	kg/m^3	30.8	lbm/ft^3
Propane Feed Enthalpy	457.8	kJ/kg	197	BTU/lbm
100 % propane vapour enthalpy	1108	kJ/kg	477	BTU/lbm
Propane enthalpy change	650.7	kJ/kg	280	BTU/lbm
HHV of natural gas	37.85	MJ/m^3	1017	BTU/ft^3
Gas turbine efficiency	0.4		0.4	
Natural gas required	42.38	m^3 natural gas/ m^3 bitumen	238	ft^3 natural gas/ bbl bitumen
Carbon emissions from NG combustion	1902	g CO_2 eq/ m^3 natural gas	0.119	lbm CO_2 eq/ ft^3 natural gas
Carbon emissions per unit volume of bitumen production	80.6	kg CO2/ m^3 bitumen produced	28.25	lbm CO_2 eq/ bbl bitumen produced

Table 2. SAREH Carbon Emissions per Unit Volume of Bitumen Production

It should be noted that this analysis excludes the power that may be required for a production well heater, but it is thought that a production well heater would only be needed during start-up and would not be needed for most of the production operation.

Thermal cracking and aquathermolysis have been investigated for the case where the heater temperatures exceed 250 °C and a reaction kinetics model has been developed for use in numerical simulation of the process (Hassanzadeh et al 2016, Hassanzadeh et al 2017). However, current thinking would have the temperatures set below this level so that aquathermolysis and thermal cracking would not be issues. Field-scale numerical simulation has also been done to prepare production forecasts for economic evaluation and to allow preparations for field testing of the technique (Rabiei Faradonbeh et al, 2016b).

Improving Vertical Communication in Reservoirs Undergoing Recovery by Gravity Drainage

A number of recent studies have evaluated the potential for improving vertical communication in reservoirs being exploited using gravity drainage processes. Barriers to vertical flow of fluids have a severely detrimental effect on such processes. Reservoir shale layers with low permeability present barriers to flow that will substantially reduce the ability of fluids to rise in the formation creating a vapor chamber or for liquids to drain downward to allow production of oil. The use of heating and cooling to break shales has been investigated and some promising techniques identified (Settari et al 2018, Settari et al 2020).

DISCUSSION and CONCLUSIONS

Promising recovery processes that have potential to enhance or replace SAGD have been described. The motivation for undertaking research and development activities towards the goal of improving or replacing SAGD stems from the high costs and environmental impacts of SAGD.

The ultimate success of any potential new process to accomplish the stated objectives will rest on the economic comparison between SAGD and the new process and also on the ability of the new process to achieve the same or higher levels of resource recovery while reducing carbon emissions and water requirements. The steam additive processes are designed mainly to reduce SOR while maintaining oil production rates and increase ultimate recovery.

These processes are most applicable for enhancing existing SAGD operations. Their economics will depend on the trade-off between the cost of the additives and equipment for their injection and the benefit in terms of additional oil production obtained. In the case of reduced SOR, for a fixed steam plant size, steam is made is available for injection into additional wells and so for the capital invested in the steam generation and water treatment facilities, incremental oil production is obtained. Solvent addition to steam needs to be started early in the SAGD recovery process and best performance requires careful consideration of the best solvent to use and its concentration in steam. NCG addition to steam is best applied later in the SAGD process when there is considerable heat in the reservoir. The NCG can assist with draining warm oil from the upper part of the formation, reduce SOR and maintain reservoir pressure. But care must be taken not to inject too much NCG too early as this may cause a reduction in oil production rate because of suppression of the oil effective permeability. Direct- contact steam generators, while they have greater energy efficiency, may be problematic regarding reduction in oil production rate as a result of suppression of the relative permeability to oil by the NCG flowing in the reservoir.

The economic case for hybrid steam/in-situ combustion processes like SAGDOX is like steam additives such as solvents, NCGs, and surfactants and oxygen may in some sense be considered an additive to steam, given that the oxygen to steam ratios contemplated are low. The hybrid steam/combustion processes have the same basic goals as the more commonly considered steam additive processes. Use of oxygen as an additive to steam in mid to late SAGD process life creates not only heat in the reservoir allowing steam injection rate to decrease but also provides a source of NCG to maintain pressure and recover additional oil.

In the case of processes that could replace steam injection, for example SAREH, the trade-offs become the savings in cost through elimination of the large steam injection and water treatment facilities along with the cost of fuel for steam generation versus the costs for electricity and solvents. The oil production rates for such a process will be lower than in SAGD and closer well spacing may be required so these factors also enter into the economic comparison between the processes. Ultimately the future of the in-situ recovery industry for extraction of oil sands resources may depend on the development of lower cost, more energy efficient and lower environmental impact processes, especially if oil prices are low for an extended period. Higher taxes and penalties on carbon emissions will promote the use of lower emission recovery processes. In addition to improved economics under carbon levies, reduction in carbon emissions will improve the social license to produce the oil sand and heavy oil resources.

Both SAREH and SAGDOX are promising recovery methods that can achieve the stated goals for the recovery process. Both have been extensively tested in the laboratory and both have been simulated at the field scale revealing favorable economics compared with SAGD. Further experimental and numerical modeling work can be done but likely the next step is to field pilot these methods. The incremental cost and risks for field testing in an existing SAGD project are quite low, especially considering that the well pair(s) used for field testing can be converted to SAGD operation after pilot testing has been completed. For field testing to be successful, it is necessary to establish a good SAGD baseline with which to compare the new processes and to ensure that at the end of the tests it is clear how the new techniques performed. This requires careful monitoring of production with regular testing and fluid sampling to ensure that a definitive conclusion can be reached. Processes like SAREH are ideal for existing SAGD operations where there is co-generation of steam and electricity. Even in cases where electricity must be generated on site, it has been shown that carbon emissions are only 18 % of those from SAGD on a per unit of production basis.

Comprehensive References for this article are available on pages 103-110 or online at: REFERENCES/ https://choa.ab.ca/uploads/2024/03/References-Harding-Reduce-Environmental-Impact.pdf

NOMENCLATURE

BFW - boiler feed water

cSOR - cumulative steam-oil ratio

DCSG - direct-contact steam generator

GOR - gas-oil ratio

HHV - high heating value

HTO - high temperature oxidation

ISC - in-situ combustion

LTO - low temperature oxidation

NCG - non-condensable gas

OTSG - once-through steam generator

RTO - ramped temperature oxidation SAGD steam-assisted gravity drainage

SAGDOX - steam-oxygen gravity drainage process SAGP steam and gas push recovery method

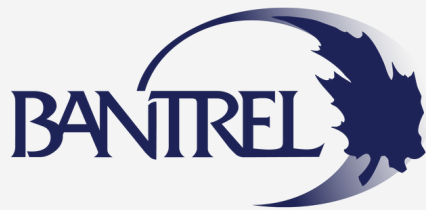**SAREH** - solvent-assisted resistive electric heating SMR small modular reactor

SOR - steam-oil ratio

Tom Harding holds BSc and MSc degrees in Chemical Engineering from the University of Calgary and a PhD in Petroleum Engineering from the University of Alberta. He has over 30 years of industry experience in a variety of oil and gas project evaluations, development and production operations. He is a former head of the Chemical & Petroleum Engineering Department at the University of Calgary where he conducted research into improved recovery methods for heavy oil and oil sands, produced water treatment and production of biofuel from waste biomass. Dr. Harding has taught courses in petroleum production engineering and non-renewable resource development. He has been retired since 2018.

Dr. Thomas G. Harding

CHOA BRONZE SPONSORS

ADURO
CLEAN TECHNOLOGIES

GREENFIRE
RESOURCES

BANTREL

MADALA

NanosTech
A Vorsana company

ISLANDER
OIL

acceleware

METHODS TO REDUCE ENVIRONMENTAL IMPACT OF IN-SITU RECOVERY OF HEAVY OIL AND BITUMEN

Dr. Thomas G. Harding

REFERENCES

Abbasi, Y. and Chalaturnyk, R. (2016): "Effect of Shear Failure Around Steam Chamber edge on Optimization of Solvent Assisted SAGD (SA-SAGD) in Oil Sands Reservoirs", SPE 180722, presented at the SPE Canada Heavy Oil Technical Conference, Calgary, Alberta, 7-9 June.

Aherne, A., and Maini, B. (2008): "Fluid Movement in the SAGD Process: A Review of the Dover SAGD Project", J. Can. Pet. Tech. 47(1): 31-37.

Al-Murayri, M., Harding, T.G., and Maini, B. (2011), Impact of Noncondensable Gas on Performance of Steam-assisted Gravity Drainage, J. Can. Pet. Tech. 50(7): 46-54.

Al-Murayri, M.T., Maini, B.B., Harding, T.G., and Oskouei, J. (2016a): "Multicomponent Solvent Co-injection with Steam in Heavy and Extra-heavy Oil Reservoirs", Energy & Fuels, 30 (4), pp. 2604-2616, DOI:10.1021/acs.energyfuels.5b02774

Al-Murayri, M.T., Maini, B.B., Harding, T.G., and Oskouei, J. (2016b): "Cracked Naphtha Co-injection in Steam-Assisted Gravity Drainage", Energy & Fuels, 30 (7), pp. 5330-5340, DOI:10.1021/acs.energyfuels.5b02773

Ashoori, S., and Gates, I.D. (2022), "Carbon Intensity of In-situ Oil Sands Operations with Direct Contact Steam Generation Lower than that of Once-Through Steam Generation", Journal of Cleaner Production, 367, 11 pp., https://doi.org/10.1016/j.clepro.2022.133046 available online 14 July 2022.

Bogdanov, I, Torres, J. A., Kamp, A. and Corre, B. (2011): "Comparative Analysis of Electromagnetic Methods for Heavy Oil Recovery", SPE 150550 presented at the SPE Heavy Oil Conference and Exhibition, Kuwait City, Kuwait, 12-14 December, 15 pp.

Butler, R.M. (1999): "The Steam and Gas Push (SAGP)", J. Can. Pet Tech., 38(3): 54-61.

Butler, R.M. and Yee, C.-T. (1986): "A Theoretical Study of Steam Condensation in the Presence of Non-condensable Gases in Porous Solids", AOSTRA J. of Research, 3(1).

Butler, R.M., Jiang, Q., and Yee, C-T. (2000): "Steam and Gas Push (SAGP) – 3: Recent Theoretical Developments and Laboratory Results", J. Can. Pet. Tech. 39(8): 51-60.

Butler, R.M. (2004): The Behaviour of Non-Condensible Gas in SAGD - A Rationalization, J. Can. Pet. Tech. 43(1): 28-34.

Charpentier, A.D., Bergerson, J. A., and MacLean, H.L. (2009): "Understanding the Canadian Oil Sand's Industry's Greenhouse Gas Emissions", Environmental Research Letters, https://doi:10.1088/1748-9326/4/1/014005 , 11 pp.

Chen, J., and Ito, Y. (2012), Effect of Oil-Viscosity-Gradient Presence on SAGD, J. Can. Pet. Tech., March 2012, 95-105.

Colins, P.M. (2007): "Geomechanical Effects on the SAGD Process", SPE Reservoir Evaluation and Engineering, Vol.10, No. 4, pp. 367-375.

Esmaeili, S., Sarma, H., Harding, T.G. and Maini, B.B. (2019a): "Review of Effect of Temperature on Oil-Water Relative Permeability in Porous Rocks of Oil Reservoirs", Fuel, V. 237, February 2019, pp. 91-116, https://doi.org/10.1016/j.fuel.2018.09.100 .

Esmaeili, S., Modaresghazani, J., Sarma, H., Harding, T.G. and Maini, B.B. (2019b): "Effect of Temperature on Relative Permeability - Role of Viscosity Ratio", Fuel, V. 278, 15 October 2020, https://doi.org/10.1016/j.fuel.2020.118318

Esmaeili, S., Sarma, H., Harding, T.G. and Maini, B.B. (2019c) "The Effect of Temperature on Two-Phase Oil/Water Relative Permeability in Different Rock/Fluid Systems", paper number SPE-195859-MS presented at the SPE Annual Technical Conference and Exhibition, Calgary, Alberta, Canada, September 2019, https://doi.org/10.2118/195859-MS, Published: 23 September 2019

Esmaeili, S., Sarma, H., Harding, T. and Maini, B. (2020a): "Effect of Temperature on Bitumen-Water Relative Permeability in Oil Sands", Energy & Fuels, V.34, N.10, pp. 12314-12329, https://doi.org/10.1021/acs.energyfuels.0c02180 , 14 September 2020.

Esmaeili, S., Sarma, H., Harding, T.G. and Maini, B.B. (2020b): "Two-Phase Bitumen/Water Relative Permeability at Different Temperatures and SAGD pressure: Experimental Study", Fuel, V. 276, 15 September 2020, https://doi.org/10.1016/j.fuel.2020.118014

Esmaeili, S., Sarma, H., Harding, T., and Maini, B. (2020c): "Experimental Study of the Effect of Solvent Addition and Temperature on Two-Phase Bitumen/Water Relative Permeability, SPE Res. Eval. & Eng. V. 23 (04): pp. 1381-1402, 12 November 2020, Paper Number: SPE-199939-PA https://doi.org/10.2118/199939-PA

Goodwin, R.D., and Haynes, W. D. (1982), "Thermophysical Properties of Propane from 85 to 700 K at Pressure to 7 Mpa", National Bureau of Standards Monograph 170, U.S. Department of Commerce, National Engineering Laboratory, Thermophysical Properties Division, Boulder, Colorado, 249 pp.

Greaves, M., Saghr, A.M., Xia, T.X., Turta, A.T., and Ayasse, C. (2001): "THAI - New Air Injection technology for Heavy Oil Recovery and In Situ Upgrading", J. Can. Pet. Tech., 40(3): 38-47.

Greaves, M., Dong, L.L. and Rigby, S.P. (2012): "Validation of Toe-to-Heel Air-Injection Bitumen Recovery Using 3D Combustion-Cell Results", SPE Reservoir Evaluation & Engineering, February 2012, 72-85. doi:10.2118/143035-PA

Harding, T.G., Farouq Ali, S.M. and Flock. D.L. (1983): "Steamflood Performance in the Presence of Carbon Dioxide and Nitrogen", J. Can. Pet. Tech., 22(5): 30-37.

Harding, T.G. (2014a): "Non-Condensable Gas Additives to Steam for SAGD Process Enhancement", presentation made at the SPE/CHOA Slugging-It-Out XII Meeting, Calgary, Alberta, 1 April 2014.

Harding, T.G. (2014b): "Considerations for the Addition of Non-condensable Gases to Steam in the SAGD Process", presentation to the Heavy Oil and Horizontal Wells Special Interest Group, SPE Calgary Section, Calgary Petroleum Club, 30 October.

Harding, T.G. (2015): "Is This the End of the Steam Age? The Promise of Novel In-situ Recovery Methods for Oil Sands and Heavy Oil", presentation made at the 3rd Annual Sino-Canadian Oil and Gas Symposium, Calgary, Alberta, 10 June 2015.

Harding, T.G., Zanon, S.D., Imran, M, and Kerr, R.K (2015): "In-situ Reflux: A Low Cost In- situ Recovery method for Oil Sands", 65th Annual Canadian Chemical Engineering Conference, Calgary, Alberta, 4-7 October 2015.

Harding, T.G., Zanon, S., Imran, M., and Kerr, R.K. (2016): In-situ Reflux: An Improved In-situ Recovery Process for Oil Sands", SPE-180752-MS presented at the SPE Canada Heavy Oil Technical Conference, Calgary, June 7-9.

Harding, T.G. and MacFarlane, W.D. (2016): "A Review of Promising Enhanced In-situ Recovery Methods for Oil Sands" Paper WHOC-242, presented at the World heavy Oil Congress 2016, Calgary, Alberta.

Harding, Thomas Grant (2023): "Method and System for Oil recovery using Solvent-Assisted Electric Heating", U.S. patent provisional filing 63/504,463, 26 May 2023.

Hassanzadeh, H. and Harding, Thomas (2016): "Analysis of Conductive Heat Transfer during In-situ Resistive Electrical Heating of Oil Sands", Fuel, V. 178, pp. 290-299 http://dx.doi.org/10.1016/j.fuel.2016.03.070.

Hassanzadeh, H., Harding, Thomas G., Moore, R. Gordon., Mehta, Sudarshan A., and Ursenbach, Matthew, G. (2016): "Gas Generation during Electrical Heating of Oil Sands", Energy & Fuels, 18 August 2016, http://dx.doi.org/10.1021/acs.energyfuels.6b01227

Hassanzadeh, H., Rabiei Faradonbeh, M., and Harding, T. (2017): "Simulation of Solvent and Water Assisted Electrical Heating Including Aquathermolysis and Thermal Cracking Reactions", AIChEJ, published online by Wiley Online Library, 24 April 2017, 10.1002/aic.15774.

Hosseininenjad Mohebati, M., Maini, B.B., and Harding, T.G. (2012a): "Numerical Simulation Investigation of the Effect of Heavy-oil Viscosity on the Performance of Hydrocarbon Additives in SAGD", SPE Reservoir Evaluation & Engineering, April, pp. 165-181.

Hosseininejad Mohebati, M., Maini, B.B., and Harding, T.G. (2012b): "Experimental Evaluation of Hexane Addition to Steam in SAGD", WHOC12-315, presented at the World Heavy Oil Congress, Aberdeen, 10-13 Sept.

Ito, Y, and Chen, J. (2010), Numerical History Match of the Burnt Lake SAGD Process, J. Can. Pet. Tech., 49(5):40-49. Ivory, J., Frauenfeld, T., and Jossy, C. (2010): "Thermal Solvent Reflux and Thermal Solvent Hybrid Experiments", J. Can. Pet. Tech., 49(2):23-31.

Japan Canada Oil Sands Limited (JACOS) (2009), Hangingstone SAGD Demonstration Project, Application for Amendment of Approval 8788G for Non-condensable Gas Injection, submitted to the Alberta Energy Resources Conservation board, Calgary, December 2009.

Ji, D., Harding, T., Chen, Z., Dong, M., & Liu, H. (2019): "Modelling of Electromagnetic Heating Process and its Applications in Oil Sands Reservoirs", paper presented at the SPE Reservoir Simulation Symposium, Galveston, Texas, 10-11 April 2019, doi :10.2118/193905- MS.

Ji, D., Harding, T.G., Chen, Z., Dong, M., and Hui, Liu. (2020): "Feasibility of Electromagnetic Heating for Oil Sands Reservoirs", SPE 199910-MS, presented at the SPE Canada Heavy Oil Conference, Calgary, 18-19 March.

Kerr, R.K. (2012): "Steam Assisted Gravity Drainage Processes with the Addition of Oxygen", U.S Patent 9,163,491, Issued 27 September 2012.

Kerr, R. K., & Jonasson, H. P. (2013). SAGDOX - Steam Assisted Gravity Drainage with the Addition of Oxygen Injection. SPE 165509, presented at the SPE Heavy Oil Conference Canada, 11-13 June. doi:10.2118/165509-MS.

Keshavarz, M., Harding, T.G., and Chen, Z. (2016): "Modification of Butler's Unsteady-State SAGD Theory to Include the Vertical Growth of Steam Chamber", SPE-180733-MS presented at the SPE Canada Heavy Oil Technical Conference, Calgary, 7-9 June.

Keshavarz, M., Harding, T.G., and Chen, Z (2019): "A New Approach to Analytical Treatment of Steam-Assisted Gravity Drainage: A Prescribed Interface Model", SPE Journal, V.24, N. Ppp. 492-510, paper SPE-194203-PA (posted 28 January 2019), https://doi.org/10.2118/194203-PA.

Khaledi, R., Boone, T.J., Motahhari, H.R., and Subramanian, G. (2015): "Optimized Solvent for Solvent Assisted-Steam Assisted Gravity Drainage (SA-SAGD) Recovery Process", SPE-174429, presented at the SPE Canada Heavy Oil Technical Conference, Calgary, Alberta, 9-11 June.

Koolman, M., Huber, N., Diehl, D. and Wacker, B. (2008), "Electromagnetic Heating Method to Improve Steam Assisted Gravity Drainage", SPE/PS/CHOA, 117481, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Calgary, Alberta, 20-23 Oct. 2008, 12 pp.

Kovaleva, L. and Davletbaev, A. (2010): "Recoveries of Heavy Oil and Bitumen techniques with radio frequency Electromagnetic Irradiation", SPE 138086 presented at the SPE Russian Oil & Gas Conference, Moscow, 26-28 October 2010, 11 pp.

McGee, B.C.W. and Vermeulen, F.E. (2000): "In Situ Electromagnetic heating for Hydrocarbon Recovery and Environmental Remediation", J. Can. Pet. Tech . Distinguished Author Series 39(8): 24-28.

McGee, B.C.W. and Vermeulen, F.E. (2007): "The Mechanisms of Electrical Heating for the Recovery of Bitumen from Oil Sands", J. Can. Pet. Tech. 46(1): 28-34.

McGee, B.C.W. (2008): "Electro-Thermal Pilot in the Athabasca Oil Sands: Theory Versus Performance", paper 2008-209 presented at the Canadian International Petroleum Conference/SPE Gas Technology Symposium 2008 Joint Conference, Calgary, Alberta, 17-19 June 2008, 14 pp.

PetroCanada (2005), MacKay River Project, Application for Non-condensable Gas Injection, submitted to the Alberta Energy and Utilities Board, Edmonton, Alberta, 31 March 2005.

Rabiei Faradonbeh, M., Harding, T.G., Abedi, J, and Hassanzadeh, H. (2015): "Stability Analysis of Coupled Heat and Mass Transfer Boundary Layers during Steam-Solvent Recovery Process", Transport in Porous Media, 108(3), 595-615.

Rabiei Faradonbeh, M., Harding, T. G., & Abedi, J. (2016a). Semi-Analytical Modeling of Steam-Solvent Gravity Drainage of Heavy Oil and Bitumen, Part 2: Unsteady-State Model with Curved Interface. SPE Reservoir Evaluation & Engineering - Reservoir Engineering. SPE 170123-PA. http://dx.doi.org/10.2118/170123-PA. (in press 24 June 2016).

Rabiei Faradonbeh, M., Hassanzadeh, H. and Harding, T.G. (2016b): "Numerical Simulations of Bitumen Recovery using Solvent and Water Assisted Electrical Heating", Fuel, JFUE-D-16-02085, In Press.

Redford, D.A. (1982): "The Use of Solvents and Gases with Steam in the Recovery of Bitumen from Oil Sands", J. Can. Pet. Tech. 21(1): 45-53.

Rios, E., Harding, T.G., Moore, R.G., Mehta, and S.A. (2018): "3-D Physical Modeling of Hybrid Steam and Oxygen for In-situ Recovery of Oil Sands", SPE 189757-MS presented at the SPE Heavy Oil Conference, Calgary, Alberta, 13-14 March.

Sadeghi, A., Hassanzadeh, H., and Harding, T.G. (2017a): "Modeling of Desiccated Zone Development Using Electromagnetic Heating of Oil Sands", Journal of Petroleum Science and Engineering, 26 April 2017, 154 163-171, http://dx.doi.org/10.1016/j.petrol.2017.04.0633

Sadeghi, A., Hassanzadeh, H., and Harding, T.G. (2017b): "A Comparative Study of Oil Sands Preheating using Electromagnetic Waves, Electrical Heaters and Steam Circulation", International Journal of Heat and Mass Transfer, 6 April 2017, 111 908-916, http://dx.doi.org/10.1016/j.ijheatmasstransfer.2017.04.060

Sadeghi, A., Hassanzadeh, H., and Harding, T.G. (2017c): "Thermal Analysis of High Frequency Electromagnetic Heating of Lossy Porous Media", Chemical Engineering Science, 9 June 2017, 172 13-22, http://dx.doi.org/10.1016/j.ces.2017.06.0613

Sadeghi, A., Hassanzadeh, H., and Harding. T. (2018): "Numerical Modeling of Electromagnetic-based Hybrid EOR Techniques for Bitumen Recovery", Paper Mo A2 11 presented at European Association of Geoscientists and Engineers 16th European Conference on the Mathematics of Oil Recovery (ECMOR XVI), Barcelona, Spain, 3-6 September 2018.

Sadeghi, A., Hassanzadeh, H., Harding. T.G., MacFarlane, B., Bashti, S., and Haghighat, P. (2020): "Numerical Modeling of Electromagnetic-based Thermal Recovery Techniques Combined with Solvent Injection", International Journal of Heat and Mass Transfer, V. 151, 2020, https://doi.org/10.1016/j.ijheatmasstransfer.2020.119393 .

Saeedi, M., Settari, A., Harding, T. G., & Rios, E. (2018): "Modeling of Thermal Geomechanical Effects in the SAGDOX Recovery Process in Oil Sands", American Rock Mechanics Association, 52nd US Rock Mechanics/Geomechanics Symposium, Seattle, 17-20 June 2018.

Settari, A., Harding, T. G., Saeedi, M., Walters, D. A., & Nassir, M. (2018): "Use of Thermal Geomechanics for Improving Vertical Communication in Oil Sands Reservoirs with Interbedded Shales", American Rock Mechanics Association, 52nd US Rock Mechanics/Geomechanics Symposium, Seattle, 17-20 June 2018.

Settari, T, Saeedi, M, and Harding, T. (2020): "Integrated Subsurface Studies - Geomechanics and Pore Pressure", paper no. 1252 presented at the 82nd Annual EAGE Conference and Exhibition, Amsterdam, 8 - 11 June.

Suncor Energy Inc. (2010), Application for Non-condensable Gas Injection, Section 26 Test Project, MacKay River Project, submitted to the Alberta Energy Resources Conservation Board, Calgary, Alberta, 19 July 2010.

Wacker, B., Karmeileopardus, D., Trautmann, B., Helget, A., and Tolak, M. (2011): "Electromagnetic Heating for In-Situ Production of Heavy Oil and Bitumen Reservoirs", CSUG/SPE 148932 presented at the Canadian Unconventional Resources Conference, Calgary, Alberta, 15-17 November 2011, 14 pp.

Wise, S. and Patterson, C. (2016), Reducing supply cost with Eseieh pronounced easy, SPE-180729-MS presented at the SPE Canada Heavy Oil Technical Conference, Calgary, Alberta, 7-9 June 2016.

Yang, M., Chen, Z, and Harding, T.G. (2016): "An Improved Kinetic Reaction Model of In-situ Combustion for Pre-Steamed Oil sands", SPE-180728-MS presented at the SPE Canada Heavy Oil Conference, Calgary, Alberta, 7-9 June.

Yang, M., Chen, Z, and Harding, T.G (2017a): "An Improved Kinetics Model for In-situ Combustion of Pre-Steamed Oil Sands", Energy & Fuels, 10 February 2017, http://dx.doi.org/10.1021/acs.energyfuels.6b02582

Yang, M., Harding, T. G., Chen, Z., Yu, K., Liu, H., Yang, B. and Ruijian, H. (2017b): "Numerical Modelling of Hybrid Steam and In-Situ Combustion Performance for Oil Sands", MS-182708-MS, presented at the SPE Reservoir Simulation Conference, Montgomery, Texas, 20-22 February, 16 pp.

Yang, M., Harding, Thomas G., and Chen, Zhangxin (2019a): "Numerical Investigation of the Mechanisms in Co-injection of Steam and Enriched Air Process using Combustion Tube Tests", Fuel, V. 242, pp. 638-648, ISSN 0016-2361, https://doi.org/10.1016/j.fuel.2019.01.041.

Yang, M., Harding, T.G., and Chen, Z. (2020): "Field-Scale Modelling of Hybrid Steam and Combustion In-situ Recovery Process for Oil Sands using Dynamic Gridding", SPE Reservoir Engineering, v. 23, pp. 311-325, https://doi.org/10-189726-PA .

CHOA
JOURNAL

MARCH 2024

Canadian
Heavy Oil
Association

CONNECT. SHARE. LEARN. LEAD.

Stay tuned for the next issue of the CHOA Journal.