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Electrically-enhanced THAI in situ combustion technology for upgrading and production of heavy oil

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Abstract

Nearly 70% of the global oil reserves are made up of unconventional oils such as heavy oils, bitumen, and tar sand. However, they are yet to be fully exploited as a result of the capital-, energy-, water-, wastewater-, and carbon-intensive nature of their development. To be in consistent with the current goals of climate crisis mitigations, technologies that are more environmentally friendly with high efficiencies are needed. This is where the toe-to-heel air injection (THAI) in situ combustion process comes in. However, experiments and semi-commercial operations have shown that THAI is a low-oil-production-rate process where there was nonlinear relationship between air injection rate and oil production rate. Therefore, to find out about the feasibility of adding an extra source of heat in

order to improve oil production rates and with the second aim of testing the possibility of heating an annular catalyst layer surrounding the horizontal producer (HP) well such as in the in situ catalytic upgrading process (CAPRITM), a first-of-a-kind study of electrically-enhanced THAI (i.e. eTHAI) process is presented in this paper. The eTHAI involves surrounding the HP well with the electrical heating coils in which induced current flows so that heat is generated and released in the reservoir. Through reservoir numerical simulations using CMG STARS, it is found that it is indeed possible to electrically heat the HP well whilst conducting pre-ignition steam injection and subsequently operating in situ combustion. Regardless of the rate of heating, it is found that the shape and the stability of the combustion front are not affected by the incorporation of the electrical heating around the HP wellbore. In the eTHAI process, addition of extra heat from the electrical heating coils resulted in increased cumulative oil production to 32,000 m³ compared to 25,000 m³ in the base case model over the 834 days of process time. This is an increase in oil recovery by 28% over the same period compared to in the base case model. It is concluded that the resulting acceleration in oil production rates and recoveries implies earlier realisations of returns on investment. Moreover, it is found that the higher the rate of electrical heating, the wider the length of the HP well used for mobilised oil production (i.e. the wider the thickness of the mobile oil zone (MOZ)). It is also

discovered that the higher the electrical heating rate, the less the air cooling effect and in turn the higher the quantity of heat that is distributed inside the reservoir. As a result, it is concluded that the increased distribution of higher quantity of heat by the heated air coming from the outlet zone of the VI wells of the eTHAI models results in increased oil mobilisation and production rates. However, future work should investigate the limiting electrical heating rate beyond which no appreciable increase in oil production rates is achievable. Finally, it is shown that electrically-enhanced THAI process operates stably, efficiently, and selective sectional heating of catalyst-surrounded wellbore is indeed feasible.

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Introduction

Unexploited unconventional oils such as tar sand, bitumen, and heavy oils account for roughly 70% of the world's total oil reserves (Guo et al. [2016](#)).

However, these resources are very difficult to develop due to their inherently high viscosity and low API gravity which are reflections of presence of high concentration of asphaltic molecules (i.e. resins, asphaltenes, and preasphaltene). As a result, to produce them requires substantial alteration of their physical and chemical properties, thus making

the process both energy- and carbon-intensive. Since the viscosity of hydrocarbons decreases exponentially with the increase in temperature, researches have shown that thermal enhanced oil recovery (EOR) processes provide the best way to upgrade and produce these underutilised fossil fuel resources. This is because at all levels (i.e. laboratory experiments, lab- and field-scales simulations, semi-commercial scales, and full commercial scales), the thermal EOR techniques have the highest recovery factors relative to their non-thermal counterparts. The mostly used thermal techniques include the steam-based processes, which are the steam-assisted gravity drainage (SAGD), the cyclic steam stimulation (CSS), and the steam flooding (SF), and the in-situ-combustion-type processes which are the conventional in situ combustion (ISC) and the toe-to-heel air injection (THAI). However, these thermal EOR technologies suffer from one disadvantage to another. For example, the steam-based processes have disadvantages of: (i) wellbore, overburden, and underburden heat losses, (ii) releasing large quantity of CO₂ from steam generation, (iii) providing negligible heavy-to-light oil upgrading inside the reservoir, (iv) applicability to few reservoirs depending on the their thicknesses, (v) producing large quantity of wastewater, and (vi) providing only a low oil recovery when compared to the ISC-type processes (Gates, [2010](#); Gates and Larter, [2014](#); Shi et al. [2017](#); Wang et al. [2019](#); Zhao et al. [2014](#), [2013](#)). For

the ISC-type processes, the conventional ISC has disadvantages of suffering from: (i) excessive pressure build-up ahead of the combustion front, (ii) taking many more years to produce a given reservoir due to its long-distance displacement nature, (iii) low oil production rates, and (iv) gravity segregation which causes excessive gas override. On the other hand, the THAI process has been shown at all levels, except full commercial scale, to not have any of the disadvantages of the other thermal EOR processes except suffering from very low oil production rates (Chen et al. [2019](#); Greaves et al. [2008](#); Gutierrez et al. [2009](#); Liang et al. [2012](#); Rabiou Ado et al. [2018](#), [2017](#); Rahnema et al. [2017](#); Turta et al. [2020](#); Turta and Singhal, [2004](#); Wei et al. [2020a](#), [b](#) and [2019](#); Xia et al. [2005](#); Zhao et al. [2018](#), [2019](#)). Consequently, a new technique must be used to overcome the challenge of having very low oil production rates in the THAI process which is in order to utilise its full theoretical promise.

The THAI process is an air injection in situ combustion technology that generates its own fuel whilst upgrading heavy oils and bitumen inside the reservoir and producing them via horizontal producer (HP) well. It falls into the category of the so-called short-distance displacement processes (Xia et al. [2005](#)) which use HP well for upgraded oil production to the surface. Prior to initiation of combustion, steam is used to pre-heat and condition the outlet region of the vertical injector

(VI) well for a certain period of time. The steam injection is also conducted in order to establish fluid communication between the VI and the HP wells. Once the aims of the steam pre-ignition heating cycle (PIHC) are achieved, air injection in conjunction with ignition of the carbonaceous fraction of the oil using electrical ignitors are then commenced (Ado et al. [2019](#); Rabiou Ado et al. [2018](#), [2017](#)). Immediately after establishing a well-structured combustion front, the process is sustained by continuous injection of air. It is worth pointing out earlier that among the advantages of the THAI process is the ease with which an annular layer of hydro-treating catalyst, such as alumina-supported cobalt-oxide-molybdenum-oxide (CoMo), alumina-supported zinc-oxide-copper-oxide (ZnCu), etc., can be emplaced around the horizontal wellbore to achieve additional upgrading via the lately-proposed in situ catalysis method (Abu et al. [2015](#); Cavallaro et al. [2008](#); Weissman, [1997](#); Weissman et al. [1996](#); Xia and Greaves, [2001](#); Xia et al. [2002](#)). However, latest reservoir simulation studies based on a fully validated laboratory-scale numerical model (Rabiou Ado et al. [2017](#)) have revealed that the temperature of the mobile oil zone (MOZ) where the catalytic upgrading is envisaged to be taking place is 265 °C which is significantly lower than the 425 °C found to be optimum in activating the catalyst layer in the THAI's add-on in situ catalytic upgrading process (i.e. THAI-CAPRI™ process) (Shah et al. [2011](#)). As a result, an external source of heating the catalyst

layer around the HP well must be provided to ensure the catalyst layer is effective and catalytic upgrading reactions are taking place. This is the first reason in which the concepts of electrical heating or microwave heating of the HP well come in. However, to add complexity to the set-up, recently published study (Ado, [2020a](#)) has shown that the MOZ is not the only region of intense mobilised-oil drainage into the HP well. Rather, it shows that for most of the process time, the toe of the HP well is the location through which the largest oil rates get into the HP well. Therefore, detailed delineation of the physicochemical processes, especially in the eTHAI, is required for proper practical designs. Additionally, as identified earlier, the THAI process produces oil at very low rates. Hence, it is proposed that a hybrid of THAI process with electrically heated HP well should be investigated to determine its feasibility and to determine whether the oil production rates can be increased. This is the second reason why this work is critical.

It is worth pointing out that throughout the literature, there is no single study that investigated the applicability of electrical heating to in-situ-combustion-type processes. As a result, the hybrid of the THAI process with the electrically heated HP well is entirely new. The findings from this study revealed that incorporation of the electrical heating coil around the HP well and thus adding an extra source of heat resulted in increased oil recovery (i.e.

resulted in accelerating cumulative oil production to 32,000 m³ compared to 25,000 m³ in the base case over the 834 days of process time). Therefore, electrically heating the HP well accelerates oil production so that a given reservoir would be produced faster, implying that returns on investment will be realised earlier thereby decreasing the risks associated with oil market volatility. Moreover, it is shown that larger fraction of the length of the HP well is used for mobilised oil production when electrical heating of the HP well is performed compared to in the base case. This implies that most of the mobilised upgraded oil will have longer residence time on the catalyst surface. However, it is concluded that to ensure efficient electrical energy addition and utilisation, sectional electrical heating must be employed and this should be investigated by future studies.

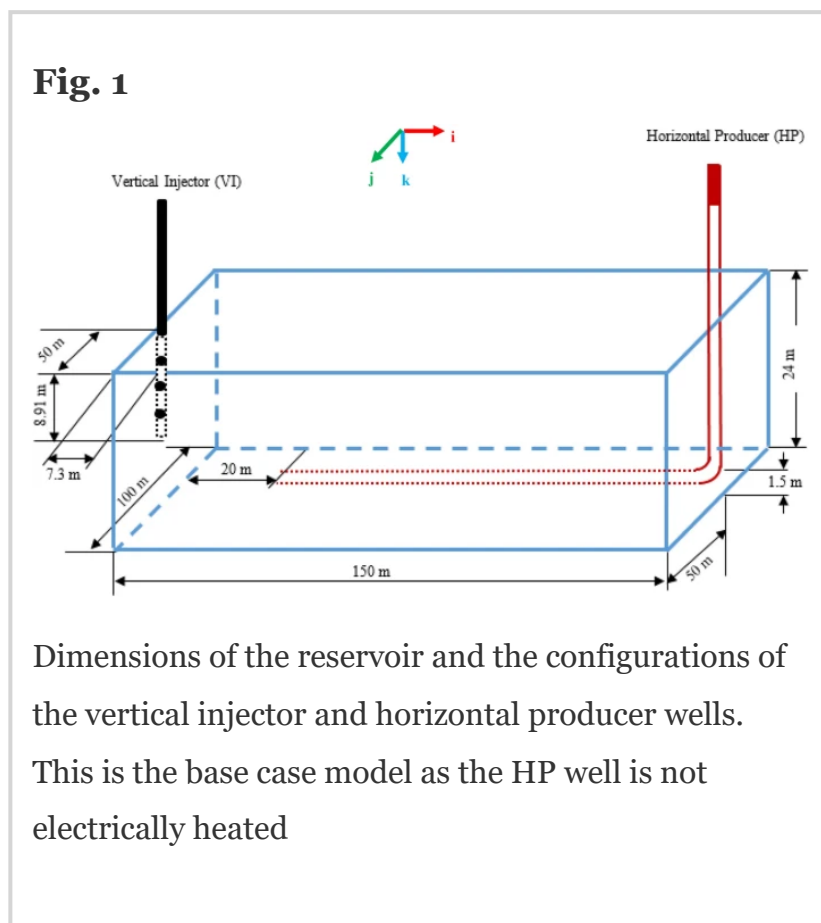
Methodology

In this work, a typical Athabasca bitumen or tar sand reservoir is mimicked and studied through reservoir numerical simulations using the CMG reservoir simulator, the STARS. The numerical model was initially developed and validated against a 3-dimensional combustion cell experiment of the THAI process (Rabiu Ado, [2017](#); Rabiu Ado et al. [2017](#)). The model was then systematically upscaled to full field size before it is then modified, rebuilt, and used in this work. The pictorial representations and the dimensions of the reservoirs and their wells

configurations are described in details as can be seen in the subsequent sections.

Pictorial representation of the base case reservoir model

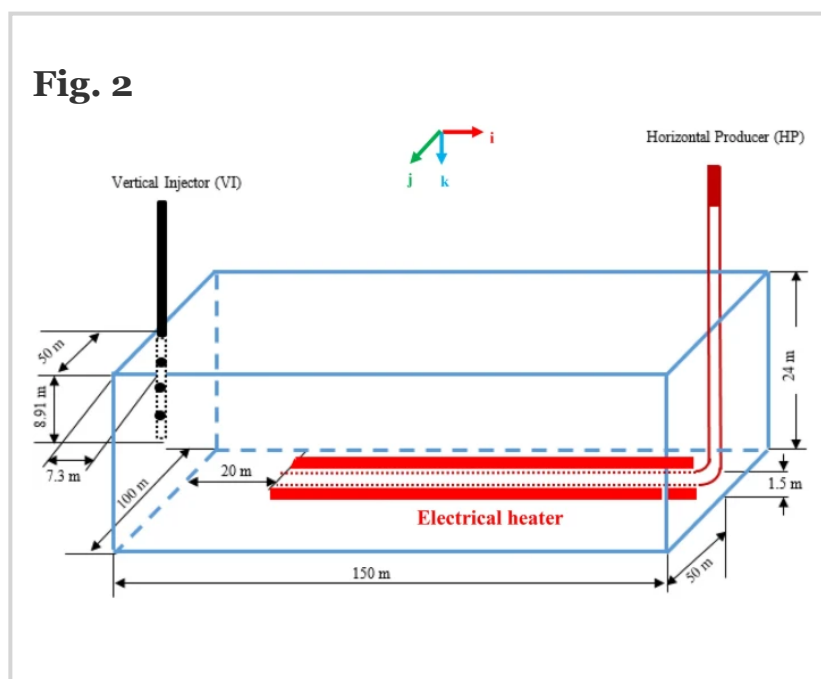
The dimensions of the reservoir and the spatial configurations of the wells can be seen in Fig. 1. The vertical injector (VI) well is located on the same plane as the horizontal producer (HP) well such that a direct line drive (DLD) configuration is achieved. Each of the two wells has the same internal diameter of 0.178 m, which is in accordance with the size used by Petrobank in their Whitesands' field project (Petrobank, [2008](#)).



Pictorial diagram of the reservoir with the electrically-heated HP well

In order to test whether it is feasible that the oil production rates can be improved relative to that achievable in the base case model and whether catalyst layer surrounding the horizontal producer (HP) well can be heated, an electrical heating coil is emplaced around the HP well so that the coil forms an annulus layer as can be seen in Fig. 2. It should be noted that everything, such as the well internal diameter, the wells configurations, and the reservoir dimensions, etc., in the electrically-enhanced THAI (eTHAI) model is the same as in the base case model except that the latter does not contain electrical heating coil and that it is run as conventional THAI process. Two numerical simulations of the eTHAI models, henceforth referred to as model AOP-1 and model AOP-2, were developed and simulated. The main difference between the two eTHAI models is the heating rate whereby in model AOP-1, the heating rate is 1 kW/m while it is 1.5 kW/m in model AOP-2.

However, more details will be provided as follows.



Reservoirs dimensions, wells configurations, and the schematic diagram showing electrical heater surrounding the HP well in both models AOP-1 and AOP-2

Discretisation of the reservoirs

In each of the three models (i.e. base case, AOP-1, and AOP-2), the reservoir was discretised into 90 grid points in the direction i by 57 grid points in the direction j by 7 grid points in the direction k . These resulted in forming a total of 38,500 grid blocks of the reservoir plus that of the discretised HP wellbore. Thus, from Figs. [1](#) and [2](#), it can be determined that each grid block has dimensions of 1.667 m in i -th direction $\times$ 1.754 m in j -th direction $\times$ 3.429 m in k -th direction. The discretised HP wellbore model is used in the CMG STARS by calling a function entitled “WELLBORE”. This allows the physicochemical transport processes (i.e. heat-, mass-, and momentum-transfers) in the HP well to be fully accounted through the use of the set of discretised equations. These discretised wellbore equations are then tied to the discretised reservoir equations for simultaneous solutions in the reservoir simulator, the STARS. The STARS software which uses fully implicit finite-difference method was run in a computer that has two eight-core parallel processors (i.e. 16 cores processors with 32 threads). However, the STARS’ parallel processing solver which is called “PARASOL” allowed me to use only 8 threads. More so, a

dynamic gridding function entitled “DYNAGRID” that is available in the STARS was used to dynamically change the grid-block sizes from parent to child grid blocks and vice versa. This, however, only works when a set of conditions are specified and met. The use of the dynamic gridding option allows optimum simulation time to be used in such a way that results' accuracy are maintained. In this work, the set of criteria that is used for de-refining of the grid blocks are: (i) the global mole percent of any component should be less than or equal to 3, (ii) the oil mole percent should be less than or equal to 2, and (iii) the temperature and pressure differences between grid blocks should be within 30 °C and 20 kPa respectively. If these criteria are not met, then the grid-block refining should be kept as it is. To simulate the discretised reservoirs, so many input variables are needed since the THAI in situ combustion process for heavy oil production involves handling of a multiphase, multicomponent reactive transport system in a porous medium. Thus, variables such as the initial and boundary conditions of the reservoir, reactions schemes and their kinetics parameters, viscosities, heat capacities, thermal conductivities, pressure, volume, temperature (PVT) properties, relative permeability curves, etc. must be specified. Therefore, some of these parameters are detailed in the coming sections even though that they can be found in the previous work of Rabiou Ado ([2017](#)).

Reservoir initial condition and its petrophysical properties

The typical Canadian Athabasca bitumen reservoir has initial water saturation of 20%, oil saturation of 80%, and gas saturation of 0% (i.e. no gas). The reservoir has an initial temperature of 20 °C and an initial pressure of 2800 kPa as determined and reported by Petrobank ([2008](#)). Additionally, the initial fluid porosity of the reservoir is 34% and its vertical and horizontal absolute permeabilities are 3450 mD and 6400 mD respectively, thereby implying that the reservoir models are homogeneous. As an initial condition, since the Athabasca bitumen is virtually immobile at the reservoir native condition, it is considered that no oil is present initially inside the HP well. All of these initial conditions are used in each of the three models reported in this paper. The relative permeability curves of the Athabasca bitumen reservoir used in this work are the same as those used in the previous work, and they can be found in Rabiou Ado et al. ([2018](#), [2017](#)).

Reservoir boundary conditions

Throughout the six boundaries enclosing the reservoir, a no flow boundary condition is assigned except via the VI and HP wells in which fluid injection and production take place respectively. Furthermore, it is assigned that no heat is crossing those boundaries except via the overburden and underburden due to conduction by the overlying and underlying rocks respectively. In the Petrobank's Whitesands' operation (Petrobank, [2008](#)), steam was used to condition the outlet zone

of the VI well and establish fluid communication between the wells. As a result, in each of the three models, pre-ignition heating cycle (PIHC) was conducted by injecting steam via the VI well at the rate of 495 bbl day^{-1} cold water equivalent (CWE) for a period of 104 days. The injected steam is saturated and it has a quality of 0.8 and injection pressure of 5500 kPa. The horizontal producer (HP) well back pressure is similar to the reservoir initial pressure, i.e. is maintained as 2800 kPa throughout the process operation period. In all the three models (i.e. base case, AOP-1, and AOP-2), after the PIHC, air was injected at the rate of $20,000 \text{ Sm}^3 \text{ day}^{-1}$ for a combustion period of two years. Furthermore, right from the start until the end of the process, the HP wells of models AOP-1 and AOP-2 are electrically heated at the rates of 1 kW/m and 1.5 kW/m respectively.

Pressure, density, temperature properties of Athabasca bitumen

The Athabasca bitumen is split into three oil pseudo-components (i.e. (i) IC = immobile component, (ii) MC = mobile component, and (iii) LC = light component) and coke. The pressure, density, and temperature properties of the three oil pseudo-components, which are shown in Table [1](#), are similar to those used in the validated numerical model that is reported in previous study (Rabiu Ado et al. [2017](#)). The vapour-liquid equilibrium (VLE) K-values as function of pressure and temperature for each oil pseudo-component have been reported

in previous study (Ado, [2020a](#)) and hence are not repeated here. Similarly, the viscosity as function of temperature for each oil pseudo-component can be found in Rabiou Ado ([2017](#)) and hence are not reproduced in this study.

Table 1 Pressure, density, and temperature properties of the oil pseudo-components making up the Athabasca bitumen

Heat capacity and thermal conductivities

Table [2](#) shows the heat capacity and thermal conductivity of the Athabasca reservoir rock as used in this study (Mojarab et al. [2011](#)). Furthermore, the effective formation compressibility of the Athabasca reservoir is shown in Table [2](#). The thermal conductivities of the fluids (i.e. oil, water, and gas) are likewise shown in Table [2](#).

Table 2 Athabasca bitumen reservoir rock and fluids properties

Athabasca bitumen kinetics scheme and its parameters

The thermal cracking and combustion reaction kinetics schemes used in this study were validated against a three-dimensional combustion cell experiment as can be seen in Rabiou Ado et al. ([2017](#)). However, as are shown by many authors (Coats, [1983](#); Hwang et al. [1982](#); Ito and Chow,

[1988](#); Kavscek et al. [2013](#); Marjerrison and Fassihi, [1992](#); Nissen et al. [2015](#); Rabiou Ado, [2017](#)), their corresponding Arrhenius kinetics parameters obtained from the laboratory-scale validated numerical model cannot be used to numerically simulate field-sized reservoirs. This is because at laboratory scale, the sizes of the grid blocks are in centimetres, sometimes even lower than a centimetre and thus the full physics of the combustion front can be accurately captured. On the other hand, the sizes of the grid blocks in field-scale reservoir are in metres or even tens of metres and therefore, the full physicochemical processes of the combustion zone will not be accurately predicted. Also, it is due to the fact that the process run time at laboratory scale is just few hours, whilst in the case of field-scale, the process time takes years or even tens of years. Since the time length scale differs substantially, using laboratory-scale Arrhenius kinetics parameters in simulating field-size reservoir results in heat conduction to the extent that very large, unphysical amount of coke is deposited in location that is farthest away downstream of the combustion front which is at very low temperature. As a result, field-scale Arrhenius kinetics parameters that were derived systematically on a very sound theoretical basis (Ado, [2021a](#), [2020b](#), [c](#); Rabiou Ado et al. [2017](#)) are used in this study as shown in Tables [3](#) and [4](#).

Table 3 Athabasca bitumen thermal cracking reactions scheme and its

Table 4 Athabasca bitumen combustion reactions scheme and its kinetics parameters as used in this and previous studies

In line with other studies (Abu et al. [2015](#); Ado, [2020a](#), [2020b](#), [2020c](#), [2020d](#); Cavallaro et al. [2008](#); Rabiou Ado, [2017](#); Shah et al. [2011](#); Weissman et al. [1996](#); Weissman, [1997](#); Xia and Greaves, [2001](#); Xia et al. [2002](#)), both the combustion and the thermal cracking reactions follow Arrhenius relationship. For each of the thermal cracking reactions, the rate law is first order with respect to each reactant and first order overall. In the case of the combustion reactions, however, the rate law is first order with respect to each pseudo-component and first order with respect to oxygen partial pressure. This means that for each of the combustion reactions, the rate law is second order overall.

Previous laboratory experimental studies (Xia et al. [2005](#); Zhao et al. [2018](#)), numerical simulations studies (Rabiou Ado et al. [2018](#), [2017](#)), and findings from recent field-size semi-commercial operation of the Kerrobert's THAI process project (Turta et al. [2020](#)) all have shown that the THAI process operates in high-temperature oxidation (HTO) mode. As a result, the combustion reaction of each

of the oil pseudo-components, even though included in this study, has been found to have no effect on the physicochemical processes governing the operation of the THAI process. This can be understood especially when the fact that there is no oil available in the location which is immediately downstream of the combustion front is considered. Moreover, even if oxygen is bypassing the combustion front, its partial pressure is very low, and this, together with the fact that the temperature in the cold oil zone is very low, mean that the rates of the oil pseudo-component combustion reactions there will be very low that the predicted results will not be affected.

Results and discussion

Adding electrical heating coil is not only useful for increasing oil recovery rate, but it will also provide useful information about what will likely happen to the HP well when surrounded by an electrically-heated annular layer of hydro-treating catalysts for in situ catalytic upgrading of heavy oil and bitumen using the CAPRITM process. In each of models AOP-1 and AOP-2, an electrical heating coil is placed to form an annular ring around and along the horizontal producer (HP) well, while in the base case numerical model, no electrical heating coil is placed and therefore, the HP well contains no extra source of heating. The numerical model AOP-1 has an electrical heating rate of 1 kilo Watt per metre (kW/m), while the electrical heating rate in

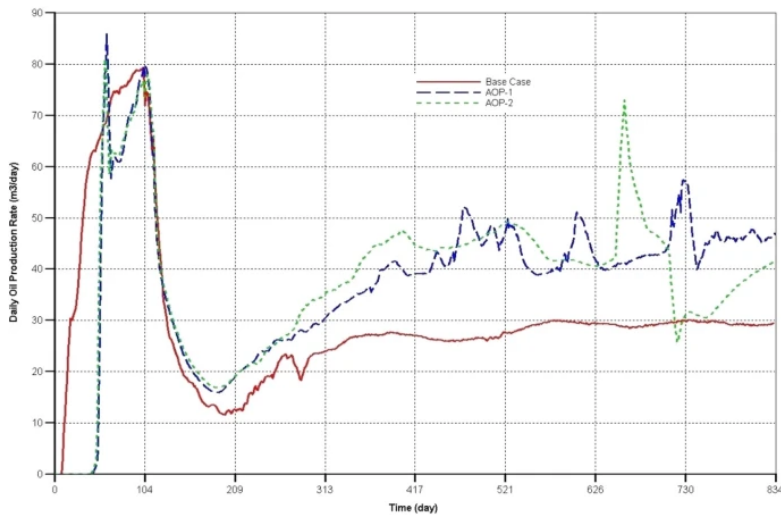
numerical model AOP-2 is 1.5 kW/m. The key performance indicators for a successful operation of the THAI process are considered for evaluating the influence of simultaneously running the combustion process and electrically heating the HP well. One of the key findings is that the oil production rates are accelerated by the incorporation of the electrical heating.

Accelerated oil production

In the base case numerical model, oil production started within one week after the commencement of steam injection in the pre-ignition heating cycle (PIHC) period. However, in the case of numerical models AOP-1 and AOP-2 respectively, the oil production began after six weeks from the initiation of the PIHC (Fig. 3). The encasement of the HP well with placement of an electrical heating coil, thereby resulting in the addition of external source of heating, resulted in restricting, and hence delaying, the flow of the lighter mobile components (light hydrocarbons, gas, and water) into the HP well. As a result, a pressure build-up occurred near and above the toe of the HP well prior to the toe region being heated enough to establish fluid communication between the VI and HP wells. On starting air injection and commencement of the combustion, all the three numerical models converge toward a common oil production rate, varying from around 80 m³/day to 35 m³/day, for a period of 20 days (Fig. 3). Thereafter, the oil production rates diverged from each other, with

that in numerical model AOP-2 laying above the rest of the two models for the most part of the 2-year combustion period. Models AOP-1 and AOP-2 in general achieve higher oil production rates by at least $10 \text{ m}^3 \text{ day}^{-1}$ when compared to the base case model. Towards the end of the two-year period, specifically, from 706 to 834 days, the trend is reversed with model AOP-1 laying above model AOP-2. This could be as a result of the fact that at the higher electrical heating rate, thermal cracking around the HP well leads to larger coke deposition which then impeded the flow of mobilised upgraded oil. This is further supported by considering the steep peaking in AOP-2 oil rate curve which can be associated with increased cracking and pressure let-out. It is then followed by a rapid decline, which is due to the coke blockage. Though less sharp, a similar trend, which lags that in AOP-2, can be observed in model AOP-1 curve (Fig. 3). Therefore, electrically heating the HP well accelerates oil production so that a given reservoir would be produced faster implying that returns on investment will be realised earlier thereby decreasing the risks associated with oil market volatility. However, future studies are needed to establish the optimum heating rate and the optimum duration over which the electrical heating should be conducted so that an efficient balance is sustained between production rates and HP well clogging.

Fig. 3

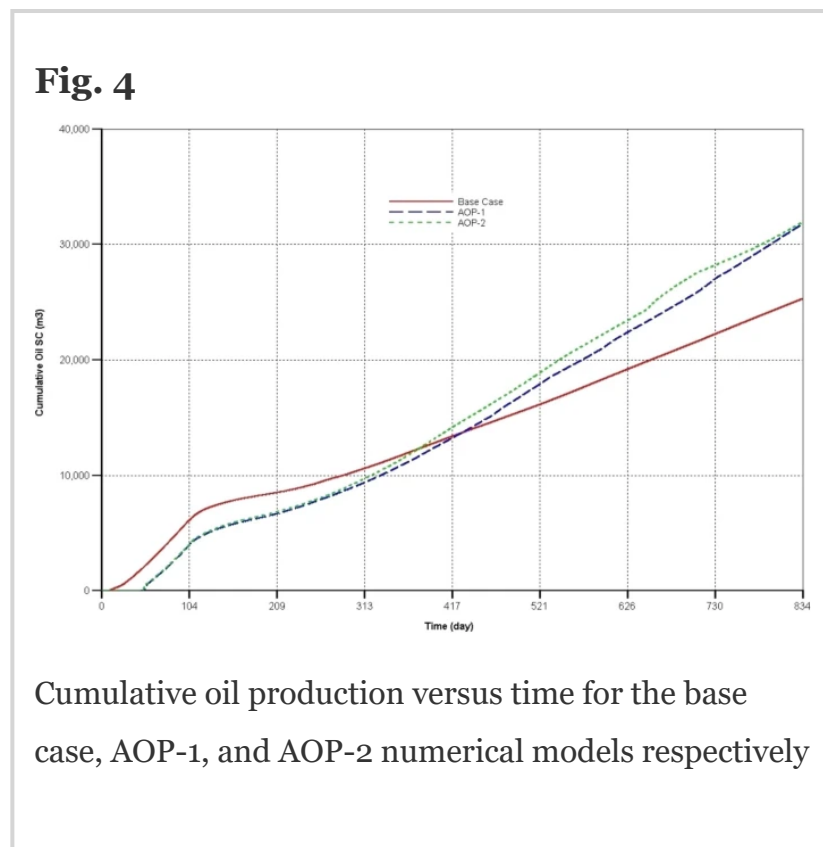


Oil production rate versus time for the base case, AOP-1, and AOP-2 numerical models respectively

Cumulative oil production

Figures 3 and 4 show that the inclusion of electrical heating around the HP well enhances the oil production rates and thence, the cumulative oil production. Initially, during the first 365 days of the process, the cumulative oil production curve of the base case model lies above both models AOP-1 and AOP-2. This is caused by the early oil production (see Fig. 3) during the PIHC in the base case model. However, the addition of electrical heating to the HP well means that an extra energy, in addition to that from combustion, resulted in mobilising extra amount of oil to the extent that the cumulative oil production curves of both AOP-1 and AOP-2 lie above that of the base case model, from 365 days up to 834 days (Fig. 4). Further observations indicate that despite the difference in the rate of electrical heat addition between the

AOP-1 and AOP-2, the same cumulative volume of oil of 32,000 m³, which is higher than that in the base case by 7000 m³, is recovered at the end of the two years of combustion. This is not anomalous since higher rate of thermal cracking could result in more coke deposition thereby obstructing the follow of the mobilised upgraded oil. Relative to the volume of oil originally in place, 34.2% OOIP is recovered in both AOP-1 and AOP-2 respectively which is higher than the 27% OOIP recovered in the base case.



Oil production rate profiles along the HP well

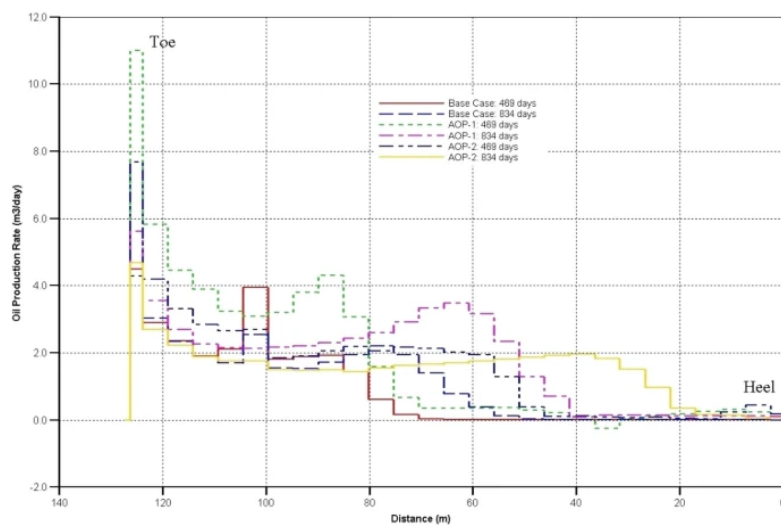
Initially, it was thought that the oil drainage pattern inside the reservoir was such that it drains vertically downward from the mobile oil zone (MOZ), which is downstream of the combustion front, directly into the exposed section of the HP

well. However, field-scale simulations have shown that to not be the case (Rabiu Ado, [2017](#)). Instead, it has been shown that the mobilised oil drains in a way similar to a ball rolling down from the top of an inclined plane. This, which is detailed in elsewhere (Rabiu Ado, [2017](#)), has resulted in most of the oil entering the HP well via its toe. Interestingly, plots of oil production rate versus distance along the HP well at 469 days (i.e. 1 year after the initiation of combustion) and at 834 days (i.e. 2 years after the start of combustion) show that the larger the electrical heating rate, the larger the proportion of the length of the HP well used for mobilised oil production (see Figs. [5](#), [6](#), and [7](#)). Comparing, for example, the base case and AOP-2 at 834 days indicates that around 85% of the length of the HP well is used for oil production in the latter compared to around 62% in the case of the former. Contrasting between the two times for any of the models indicates that the longer the process is operated, the larger the fraction of the HP well used for mobilised oil production. Considering model AOP-2, at 469 days, only around 65% of the length of the HP well is used for mobilised oil production as against the 85% at 834 days. This is one of the most revealing parts of this study which has never been shown before as despite electrically-heating the whole well from toe to heel right from the start-up of the process, only a small amount of oil is produced in location furthest ahead of the MOZ (i.e. below the cold oil zone (COZ) as can be seen in Fig. [7](#)). This can be explained by acknowledging the

fact that conduction is the main mechanism of heat transfer in that region. As a result, it takes far longer before any appreciable viscosity reduction is effected there. It is thus concluded that to ensure efficient-energy addition and utilisation, sectional electrical heating must be employed. That way, the HP well should be divided into different sections such that the heating is applied in a toe-to-heel manner. Each section should be activated as the combustion front moves closer to it. Surely, future studies would look more into these findings so that the optimum distance that must be maintained between the combustion front and the subsequent HP well section to be electrical-heating-activated is established. More so, the studies should also determine the optimum heating rates that would have the greatest positive effects whilst ensuring HP well coke-clogging does not occur. The studies would also facilitate understanding of the largely poorly understood in situ catalytic upgrading process (CAPRI™) especially concerning selectively sectionally heating of the annular layer of the added catalyst. It is worth pointing out that to partly contribute towards these investigations, newly published studies by Ado et al. ([2021a](#), [b](#)) have shown, although at laboratory scale, that it is indeed possible to emplace an annular catalyst layer around the HP well and achieve catalytic upgrading. Furthermore, another recently published study of the CAPRI™ process, which also shows that it is indeed possible to emplace the annular catalyst layer around the HP well, has

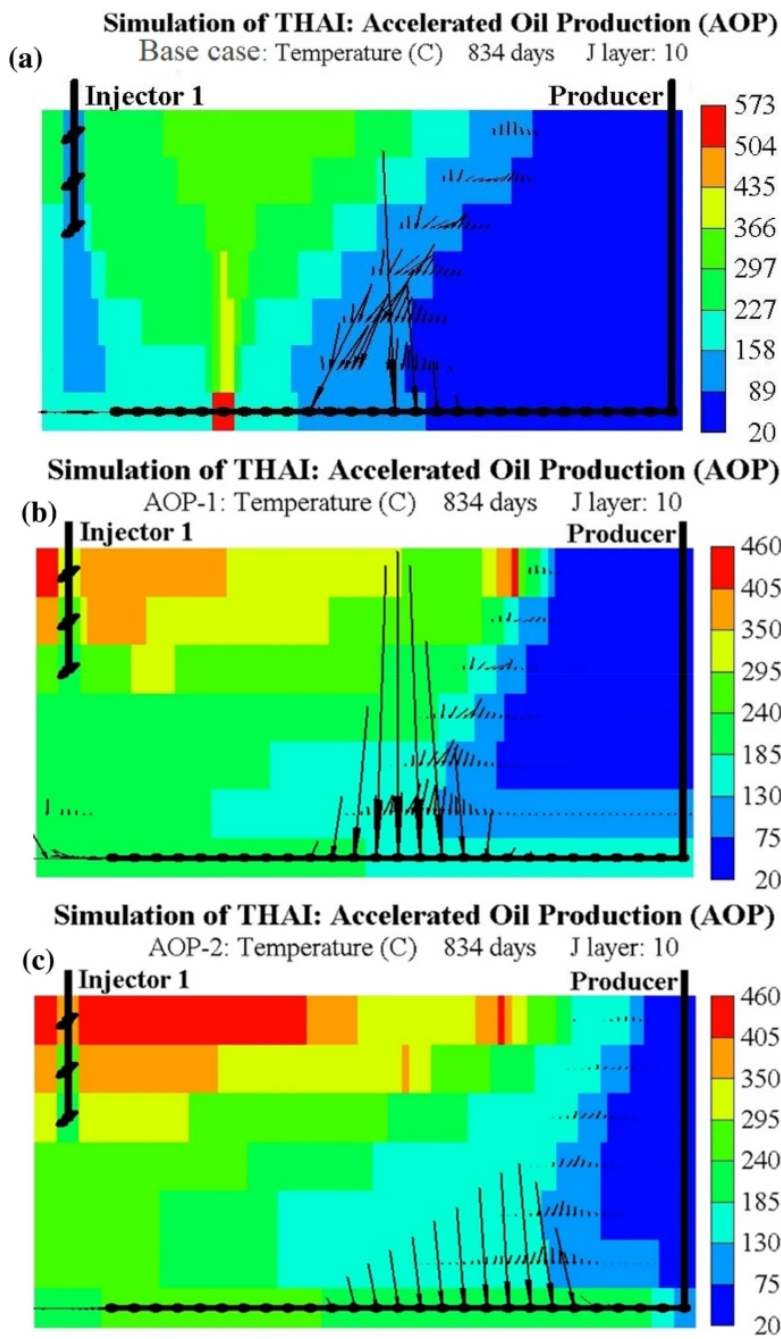
revealed that the higher the catalyst packing porosity (i.e. the lower the mass of catalyst per m³ of annular space around the HP well), the higher the accessible area for the mobilised oil to reach the inner catalysts and thus maximise catalytic upgrading.

Fig. 5



Oil production rates along the HP well at 469 days and 834 days versus the length of the HP well for the base case, AOP-1, and AOP-2 numerical models respectively

Fig. 6

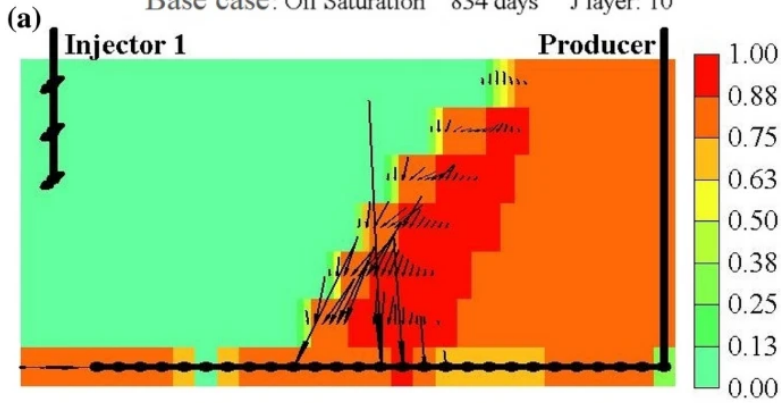


Temperature distribution profiles after two years of combustion and for **a** the base case, **b** AOP-1, and **c** AOP-2 numerical models respectively

Fig. 7

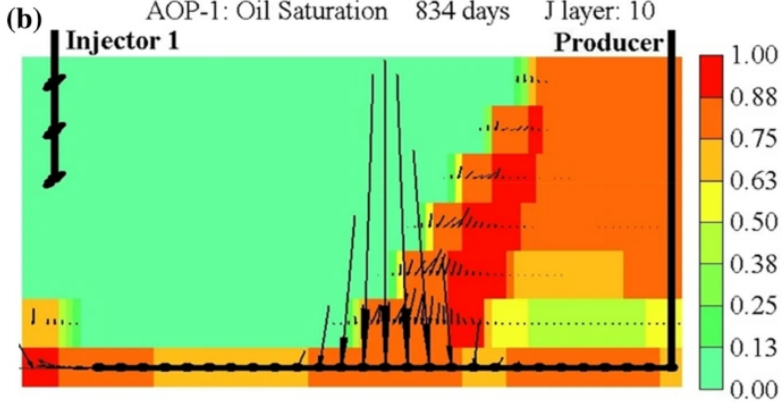
Simulation of THAI: Accelerated Oil Production (AOP)

Base case: Oil Saturation 834 days J layer: 10



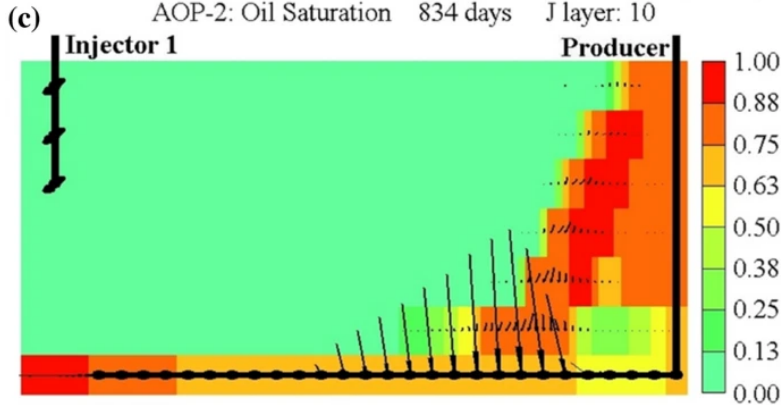
Simulation of THAI: Accelerated Oil Production (AOP)

AOP-1: Oil Saturation 834 days J layer: 10



Simulation of THAI: Accelerated Oil Production (AOP)

AOP-2: Oil Saturation 834 days J layer: 10



Oil saturation profiles after two years of combustion and for **a** the base case, **b** AOP-1, and **c** AOP-2 numerical models respectively

Temperature distribution profiles

One of the key parameters that can be used to judge the success or otherwise of the electrically-enhanced THAI process is the temperature distribution in the reservoir. Figure 6 shows the temperature distribution profiles after two years of

combustion for the base case, AOP-1, and AOP-2 models respectively. The first important findings from these profiles are the differences in the temperatures of the outlet zone of the vertical injector (VI) wells. In the base case model (Fig. 6a), the temperature of the VI well and its surroundings ranges from 89 °C to 158 °C. In model AOP-1 in which the electrical heating rate is 1 kW/m, the VI well has temperatures ranging from 185 °C at its shoe to 350 °C at the top perforation (Fig. 6b), whilst in model AOP-2 which has electrical heating rate of 1.5 kW/m, the temperature of the VI well ranges from 240 °C at the shoe of the well to 405 °C (Fig. 6c). It can be recalled that the oil production rates in Fig. 3 dropped quite sharply on the commencement of air injection and on achieving ignition. This is caused by air-cooling effect in which there is a competition between heating-up the air at the outlet zone of the VI well and heating-up the oil downstream of the combustion front. Keeping this in mind, it then follows that the air being injected is continuously being heated as it travels to the combustion front. This in turn results in cooling the outlet zone of the VI wells to monotonically lower temperatures which is the case in the base case model (Fig. 6a). On the other hand, although the temperatures of the VI wells in models AOP-1 and AOP-2 respectively are lower than what they were few weeks after the initiation of the combustion, the addition of an external source of heat to the HP wells has respectively resulted in smaller rates of

cooling in the outlet zone of their respective VI wells (Fig. 6b and c). This is further supported by the fact that the heat added from the external source (i.e. the heat added from the electrical heater) to the HP well, even though not high enough to effect full oil-mobilisation, has been conducted to the overlying cold oil zone (COZ) that the competition to get energy by the injected air and by the COZ is substantially reduced. Therefore, it follows that in this specific study, the higher the electrical heating rate, the less the air cooling effect and in turn the higher the quantity of heat that is distributed inside the reservoir (i.e. base case < AOP-1 < AOP-2) (see Fig. 6). As a result, it is concluded that the increased distribution of higher quantity of heat by the heated air coming from the outlet zone of the VI wells of models AOP-1 and AOP-2 respectively results in increased oil mobilisation and production rates.

More so, carefully observing Fig. 6, it can be seen that there is progressive increase in the temperature of the mobile oil zone (MOZ) along the HP wells which are indicated by the larger oil flux vectors superimposed on the 2-dimensional profiles, ranging from 89 °C to 158 °C in the base case (Fig. 6a), 130 °C to 185 °C and in two blocks up to 240 °C in model AOP-1 (Fig. 6b), and 185 °C to 240 °C in model AOP-2 (Fig. 6c). In addition, it can be seen that the addition of electrical heating has resulted in the increase in the fraction of the length of the HP well used for mobilised oil production.

This finding is the same as that reported in Sect. 3.3, Fig. 5, and it means that mobilised oil residence time on an annular layer of catalyst can be increased, which, therefore is critical for successful operation of the CAPRI™ process. Furthermore, it follows that the quality of the produced oil in the eTHAI process (i.e. models AOP-1 and AOP-2) is higher than that in the conventional THAI process.

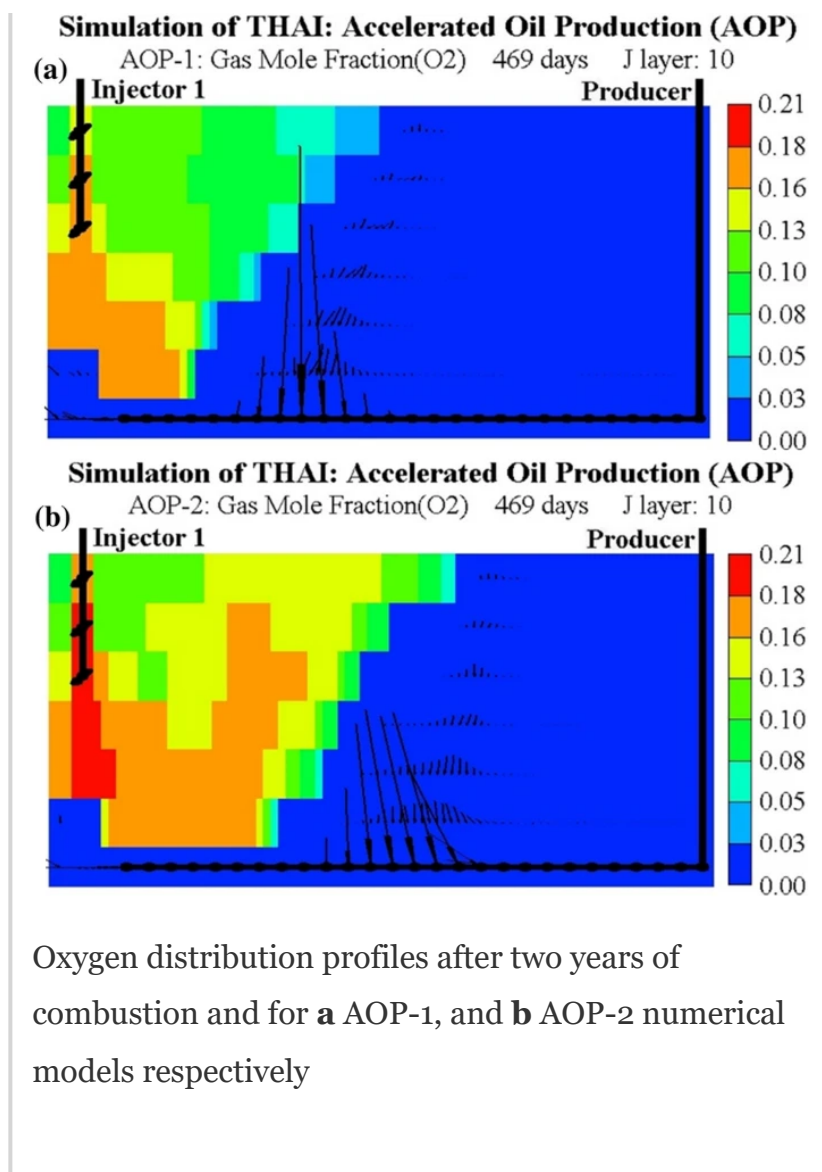
Oil saturation profiles

The distribution of the oil in form of oil saturation gives detailed information about the oil flow dynamics inside the reservoir especially when plotted with the oil flux vectors superimposed on the 2-dimensional profiles. Figure 7 shows the oil saturation profiles for the base case and the electrically-enhanced THAI (i.e. AOP-1 and AOP-2) models. In all the three models, apart from the mobile oil zone (MOZ) located in the large oil pool behind the toe of the HP well which is common to all of them, it can be seen that all the MOZs that are ahead of the combustion front are forward-tilting. However, the degree to which they tilt is model-dependent. In the base case model (Fig. 7a), the MOZ is leaning forward at an angle of 26.5° relative to the axial length of the HP well. In the electrically-enhanced models AOP-1 (Fig. 7b) and AOP-2 (Fig. 7c), the MOZs are respectively forward-tilting at angles of 24.4° and 19.6° relative to the horizontal (i.e. relative to the axial length of the HP well). Factually, the lower the angle of tilt, the far

ahead or fast the MOZ at the top of the reservoir is relative to those as one moves vertically downwards. This implies that, as can physically be seen in Fig. 7, the oil in the vertical mid-plane of model AOP-2, and generally in the whole of the reservoir, will be produced earliest compared to in model AOP-1 which is then followed by the base case model.

In addition, the location of the MOZ at any time after the start of the combustion by at most 3 months is model-dependent. In the base case model, the MOZ is located between 48.15 m and 96.30 m from the toe of the HP well. In models AOP-1 and AOP-2, the MOZs are respectively located between 48.15 m and 101.11 m and 52.96 m and 120.37 m away from the toe of their HP wells. These mean that addition of electrical heat source has resulted in accelerating the velocity of the MOZ and expanding the reservoir volume swept by the combustion front (Fig. 8). Observing Fig. 7 carefully reveals that the thickness of the rich oil zone (i.e. the zone with oil saturation of greater than 0.88) depends on the heating rate. The higher the heating rate, the thinner the size of the rich oil zone. These are other indicators of the fact that oil production rates have substantially improved in the electrically-enhanced THAI process.

Fig. 8



Oxygen distribution profiles

The oxygen distribution profiles give the measure of the shape, speed, and stability of the combustion front. Figure 8 shows the oxygen profiles along the vertical mid-plane of models AOP-1 and AOP-2 respectively. In terms of combustion front shape, it is found that all the two models have forward-leaning shapes which are due to controlled gas-override (Fig. 8).

Additionally, comparing the two (Fig. 8a and b), it can be seen that the higher the electrical heating rate, the faster the speed of the combustion front,

and hence the larger the fraction of the reservoir volume swept by the combustion front. In terms of combustion front stability, it is found that none of the two models has combustion front with fingers or channelling and thus all the two models indicated that the eTHAI process operates stably (Fig. 8). However, the fraction of the horizontal producer (HP) well that the combustion zone is in contact with is bigger in model AOP-2 (Fig. 8b) when compared to that in model AOP-1 (Fig. 8a). Thus, it is highly likely that the combustion front in model AOP-2 will be unstable earlier than that in model AOP-1 especially when the toe region of the HP well has lower mobilised-oil flow rate which happens with time. To conclude, this study has shown that it is indeed possible to improve oil production rates by placing electrical heating coil to form the annulus around the HP well without negatively affecting the stability, shape, and speed of the combustion front. Furthermore, this work has shown that an annular layer of catalyst surrounding the HP well can be heated using electrical heating coils without negatively affecting the propagation of a well-structured combustion front.

Economic benefits of eTHAI

The cost analysis has not been specifically carried out here as it is not the subject of this work.

However, to provide some perspectives about the economic benefits of the eTHAI process, the concept of earlier realisation of the return on

investment in the eTHAI process is explained. What it means by earlier realisation of the return on investment in this work is that higher oil production rates imply that more revenue will be generated earlier compared to when the oil production rates are relatively lower. For example, consider case 1 (c#1) in which electrically-enhanced THAI is to be producing oil at a rate of 1000 barrels per day and selling it at a price of, say, \$50 per barrel. This will fetch \$50,000 per day. If the reservoir section contains 3.65 million barrels of technically recoverable oil, then it will take 3650 days (i.e. 10 years) for the reservoir section to be depleted. That implies that \$182.5 m revenue will be generated over the 10-year period in c#1. On the other hand, in c#2, using the conventional THAI process only (i.e. without electrical heating), if the oil in the same reservoir section is produced at a rate of 781.25 barrels per day (i.e. 28% lower than in c#1), then it will take 4672 days (i.e. 12.5 years) to be depleted. This means that at oil selling price rate of \$50 per barrel, 12.5 years will be needed to generate the revenue of \$182.5 m. Therefore, the return on investment will be realised earlier when the oil production rate is relatively higher (i.e. in c#1) compared to when it is lower (i.e. in c#2). Now, to further explain the economic benefits of the eTHAI in greater details, operating the process for 12.5 years will mean a 2.5 years of additional operating expenses if no electrical heating is used. Therefore, apart from exposing the investors to higher risk of oil market

volatility due to prolonging the period of revenue generation, additional resources are needed for the 2.5 years. This implies that the heating coil installation cost and the cost of the electricity might offset the additional cost that will be incurred in the 2.5-additional years. In addition, the quality or API gravity of the eTHAI-produced oil is higher than for the oil produced using the conventional THAI process. This is true especially when the fact that the temperatures in the former are higher than those in the latter is considered.

Furthermore, relatively, drilling horizontal producer well costs far more than it will cost to install the electrical heating cables. Notice that it is mentioned that selective sectional heating is feasible which does not necessarily mean that the electrical heating cables must be wound around the whole length of the HP well. Since temperature observation wells which are equipped with the thermocouples cost a minor fraction of the overall cost of the process, then it follows that drilling vertical wells along the axial length of the HP well to achieve sectional electrical heating will not cost a lot to the extent that it will offset the at least 28% increase in the cumulative oil recovery.

Additionally, the electrical heater can be made to work efficiently over longer period of time if optimum heating rate is used and if selective sectional heating is applied. However, this has to be investigated further by running the simulations

until cut-off point beyond which oil production rates become uneconomical or operating the process becomes unsafe.

Conclusions

Using validated numerical models, field-scale reservoir simulations studies of the THAI and the electrically-enhanced THAI processes are carried out. This first-of-a-kind work is the proof to the concept of incorporation of electric heating which involves heat generation and release as a result of induced current flowing through electrical heating cables placed around the horizontal wellbore of the THAI process. It is found that air-cooling effect, which results in substantial decrease in the oil production rate, is significantly reduced by adding electrical heaters around the HP well. Incorporation of the electrical heating coil around the HP well and thus adding an extra source of heat resulted in substantial improvement of the oil production rates which in turn resulted in increased cumulative oil recovery (i.e. the cumulative oil production is accelerated to 32,000 m³ compared to the 25,000 m³ cumulatively produced in the base case model over the 834 days of process time. Therefore, electrically heating the HP well caused a given reservoir to be produced faster which imply that returns on investment will be realised earlier thereby decreasing the risks associated with oil market volatility. Also, it is concluded that the quality of the produced oil in the eTHAI process

(i.e. models AOP-1 and AOP-2) is higher than that in the conventional THAI process since the temperatures of the mobile oil zone (MOZ) in the latter are lower than those of the former. It is found that the MOZ and the combustion front of the eTHAI process move faster than in the conventional THAI process, thereby implying that the former will become unstable earlier than the latter. Moreover, it is shown that larger fraction of the length of the HP well is used for mobilised-oil production when electrical heating of the HP well is performed compared to in the base case model. Therefore, it is concluded that the residence time of the mobilised-oil over an annular layer of catalyst, such as the case in the CAPRITM process, can be increased by incorporation of electrical heaters around the catalyst layer. Finally, it is concluded that to ensure efficient electrical energy addition and utilisation, sectional electrical heating must be employed and this should be investigated by future studies.

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Ethics declarations

Conflict of interest

I declare that there is no conflict of interest.

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