A Comprehensive Review of Thermal Enhanced Oil Recovery: Techniques Evaluation

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Esmail M. A. Mokheimer[1]
Mem. ASME
Mechanical Engineering Department,
College of Engineering,
King Fahd University of Petroleum and Minerals (KFUPM),
P. O. Box: 279,
Dhahran 31261, Saudi Arabia;
Center of Research Excellence
in Energy Efficiency (CEEE),
King Fahd University of Petroleum and Minerals (KFUPM),
P. O. Box: 279,
Dhahran 31261, Saudi Arabia;
Center of Research Excellence in
Renewable Energy (CoRe-RE),
King Fahd University of Petroleum and Minerals (KFUPM),
P. O. Box: 279,
Dhahran 31261, Saudi Arabia
e-mail: esmailm@kfupm.edu.sa

M. Hamdy
Mechanical Engineering Department,
College of Engineering,
King Fahd University of Petroleum and Minerals (KFUPM),
P. O. Box: 279,
Dhahran 31261, Saudi Arabia
e-mail: mhamdy@kfupm.edu.sa

Zubairu Abubakar
Mechanical Engineering Department,
College of Engineering,
King Fahd University of Petroleum and Minerals (KFUPM),
P. O. Box: 677,
Dhahran 31261, Saudi Arabia
e-mail: Zubairu@kfupm.edu.sa

Mohammad Raghib Shakeel
Mechanical Engineering Department,
College of Engineering,
King Fahd University of Petroleum and Minerals (KFUPM),
P. O. Box: 567,
Dhahran 31261, Saudi Arabia
e-mail: raghib@kfupm.edu.sa

Mohamed A. Habib
Mechanical Engineering Department,
College of Engineering,
King Fahd University of Petroleum and Minerals (KFUPM),
P. O. Box: 1866,
Dhahran 31261, Saudi Arabia
e-mail: mahabib@kfupm.edu.sa

Mohamed Mahmoud
Petroleum Engineering Department,
College of Petroleum
Engineering & Geosciences,
King Fahad University of Petroleum and Minerals (KFUPM),
P. O. Box: 5049,
Dhahran 31261, Saudi Arabia;
Center for Integrative Petroleum Research,
College of Petroleum
Engineering & Geosciences,
King Fahad University of Petroleum and Minerals (KFUPM),
P. O. Box: 5049,
Dhahran 31261, Saudi Arabia
e-mail: mamahmoud@kfupm.edu.sa

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The oil production from any well passes through three stages. The first stage is the natural extraction of oil under the well pressure, the second stage starts when the well pressure decreases. This second stage includes flooding the well with water via pumping sea or brackish water to increase the well pressure and push the oil up enhancing the oil recovery. After the first and secondary stages of oil production from the well, 20–30% of the well reserve is extracted. The well is said to be depleted while more than 70% of the oil are left over. At this stage, the third stage starts and it is called the enhanced oil recovery (EOR) or tertiary recovery. Enhanced oil recovery is a technology deployed to recover most of our finite crude oil deposit. With constant increase in energy demands, EOR will go a long way in extracting crude oil reserve while achieving huge economic benefits. EOR involves thermal and/or nonthermal means of changing the properties of crude oil in reservoirs, such as density and viscosity that ensures improved oil displacement in the reservoir and consequently better recovery. Thermal EOR, which is the focus of this paper, is considered the dominant technique among all different methods of EOR. In this paper, we present a brief overview of EOR classification in terms of thermal and nonthermal methods. Furthermore, a comprehensive review of different thermal EOR methods is presented and discussed. [DOI: 10.1115/1.4041096]

[1]Corresponding author.

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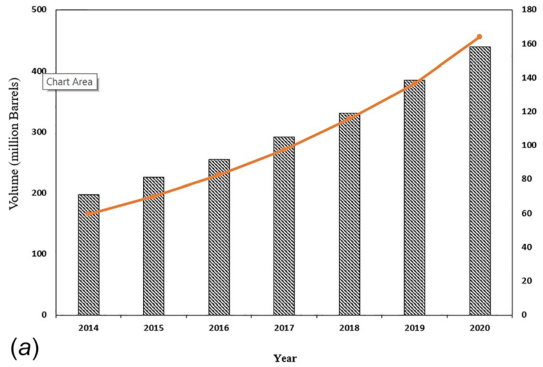

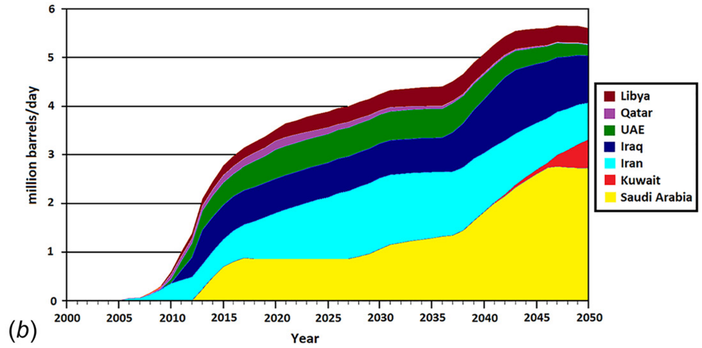

Fig. 1 (*a*) Worldwide EOR market contribution through 7 years (adapted from [5]) and (*b*) EOR forecast in the Middle East up to 2050 (adapted from [6])

1 Introduction

Enhanced oil recovery (EOR) is a widely accepted oil production technique that helps in minimizing shortages of crude oil recourses and its high prices. It is a technique by which huge amount of crude remaining in wells after natural extraction process is recovered. The natural extraction process (primary recovery), which employs the reservoir natural pressure for crude oil extraction, leaves huge amount (more than 70% in some cases) of original oil in place (OOIP) unextracted, due to decrease in reservoir pressure. Consequently, the use of secondary oil recovery that involves fluid (mainly water and gas) injection to augment the reservoir pressure, as well as EOR, also known as tertiary recovery, becomes imperative to improve oil recovery. While secondary recovery involves injecting water or gas to help sweep the oil through the wells without changing the actual properties of the hydrocarbon, EOR techniques involves changing the reservoir make-up. In essence, important properties like density and viscosity of the crude oil changes, making oil displacement easier in the reservoir [1–4]. Oil recovery can reach as high as 75% of the OOIP, depending on the employed EOR technique. EOR is projected to change the oil production forecast in the Middle East and the entire world as shown in Fig. 1. Figure 1(*a*) shows that the EOR market in the world is expected to increase dramatically, which gives an indication to the importance of this process in the future [5]. The Organization of the Petroleum Exporting Countries (OPEC) estimated the role of EOR in increased oil production in the Middle East up to 2050 as shown in Fig. 1(*b*) [6].

Enhanced oil recovery process can be classified as thermal and nonthermal techniques. As the name implies, thermal EOR uses thermal energy to raise the reservoir temperature, and as a result, decreases the oil viscosity [7,8]. Thermal EOR is considered one of the most advanced EOR processes and it currently provides a significant amount of oil in overall global oil outlook. There are different thermal EOR methods, but we focused in this review on the established methods, which are in use for the past 30–40 years in the field. These include hot fluid injection such as hot water flooding and steam injection, and in situ combustion (ISC) also called fire flooding. High porosity sand/sandstone formation in reservoirs is the most suitable for thermal recovery processes [9]. Thermal recovery processes are commonly used for thick, high density, viscous oils having American Petroleum Institute (API) gravities of less than 20. By characterization, oils with API less than 22 are heavy oils, while oils having less than 10 API deg are categorized as extra-heavy and Bitumen that are denser than water [10].

The thermal energy used during thermal recovery lowers the oil viscosity, specific gravity, and interfacial tension, thereby

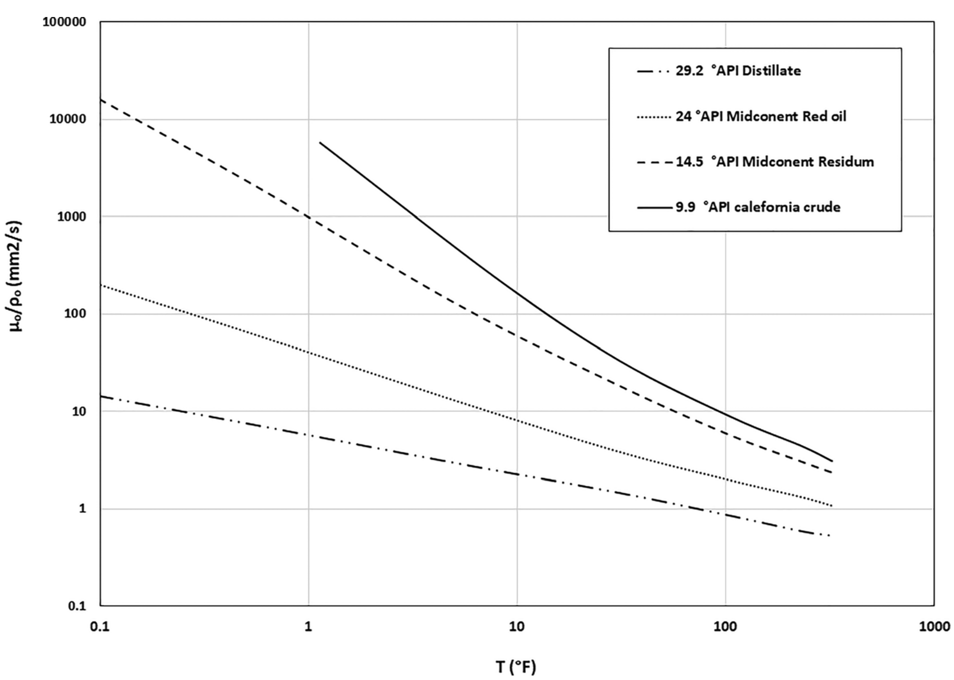

Fig. 2 Kinematic viscosity of gas-free oils as a function of temperature (adapted from [11])

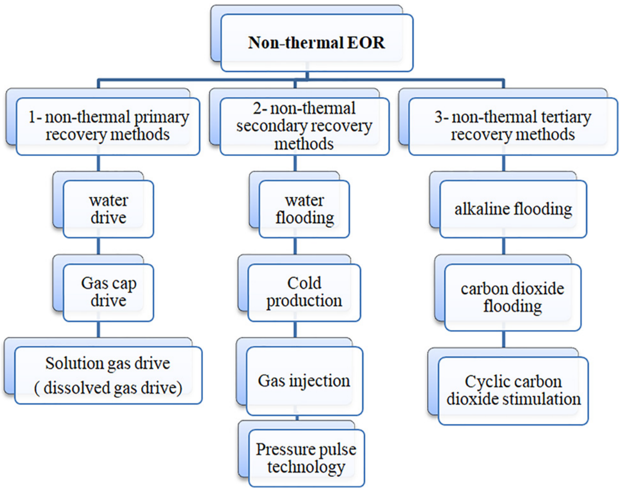

Fig. 3 Nonthermal-enhanced oil recovery technologies [7]

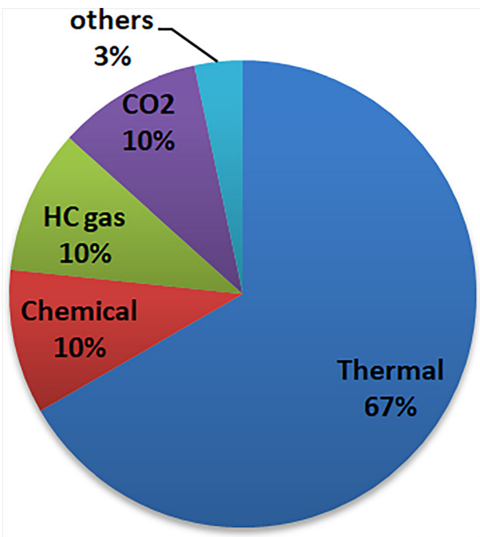

Fig. 4 Ratio of different EOR methods used in projects around the world [12]

facilitating oil flow in the production well. Figure 2 depicts the effect of temperature on the kinematic viscosity of gas-free oil, which generally decreases with the increase in temperature [11]. Apart from changes in physical properties of the oil, its chemical properties also change through cracking and dehydrogenation among other chemical reactions. As mentioned before, thermal processes commonly include hot fluid injection, in situ combustion, and electrical heating and a less conventional electromagnetic heating.

2 Nonthermal Enhanced Oil Recovery Classification

The nonthermal methods are classified into three recovery methods according to Naqvi [7]. These methods are summarized as shown in Fig. 3. Reports revealed that nonthermal methods are not widely in use compared with thermal EOR as shown in Fig. 4 [12]. The figure depicts a summary of the EOR production rates using different methods around the world.

It is clear from Fig. 4 that at 67% global usage, thermal EOR is the dominant method employed for EOR globally. This is partly due to its high performance and other benefits, which we will be discussing in detail in the remaining parts of this paper.

3 Thermal Enhanced Oil Recovery Classifications

As reported in the literature, thermal EOR methods are very important and are widely applicable worldwide [8]. Different types of aqueous methods, which are related to water and its derivatives, are widely used over the last few decades. Processes such as cyclic steam stimulation (CSS) and hot water injection, ISC, hot water, and steam flooding and steam-assisted gravity drainage (SAGD) are the most prominent thermal EOR techniques. The other thermal EOR techniques are the use of nonaqueous methods, which supply the thermal energy to the reservoir without injecting water or its derivatives. Such methods include electric heating and electromagnetic heating. The nonaqueous methods are rarely applicable due to technical constrains and environmental issues, subsequently, future work is required in order to make the nonaqueous methods more competitive. A recent development toward that involves the combination of the nonaqueous methods with water or solvent injection. Details about thermal EOR methods will be presented in this paper later. Figure 5 depicts various thermal EOR methods.

4 Electrical and Electromagnetic Heating

This is an EOR technique that uses electrical current to heat the heavy oil in its reservoir. Due to the oil heating process, there will be a formation of vapor chamber in the reservoir, and subsequent easy mobility of oil. Electrical EOR method can be divided into three main types: the low-frequency Ohmic heating also called resistive heating, high frequency or radiofrequency/microwave heating, and medium frequency or inductive heating. In the Ohmic heating, a potential difference is applied between two electrodes where one acts as anode and the other acts as cathode. In the field, this can be applied by using two oil wells utilizing one as cathode and the other as anode [13]. This technique is shown to have advantages and improves oil recovery, but it has some disadvantages such as generating steam during heating, which decreases the amount of water and, as a result, decreases the thermal energy transferred by water. Using water injection along with this method had been suggested [14]. It is expected that this will enhance the heating process especially in low-permeability zones. Numerical simulation using CMG-STARS thermal reservoir simulator [15] had been reported [16], where down hole electric heating method was used together with injection of a working fluid for enhancing the heat transfer. The working fluids such as water, pure solvents (butane, hexane, and natural gas condensate), or combined water and solvents were used in the study. The study shows that the use of the combined water solvent as the working fluid is more effective than using the solvent only, due to the dilution effect of the solvent that improves heat transfer characteristics of the solvent and water, thereby accelerating the process. Consequently, economic improvements were reported through the reduction of the amount of surface water–oil ratio to be 3–10 times smaller than those of SAGD, and also by the decreased amount of needed steam.

Electromagnetic heating (EM) is a relatively new technique for EOR that is gaining huge attention recently. In this method, electromagnetic waves are used to produce electrical energy, which is transferred to the dielectric and resistive materials in the form of thermal energy, which is used in EOR. Therefore, EM technique converts EM energy to thermal energy for use in EOR [17–24]. In the reservoir, the electromagnetic heating can be produced by two ways: high frequency (radio and microwave) and low frequency waves. The EM method for EOR has a lot of advantages including reduction of carbon emission, minimization of excessive water usage, and relatively higher performance when used together with solvent injection.

As an improvement to EM heating, adding solvent during the process was suggested [22,25,26]. A study to test the performance of EM heating and solvent-assisted gravity drainage for EOR was conducted experimentally [27]. Solvent was injected while the

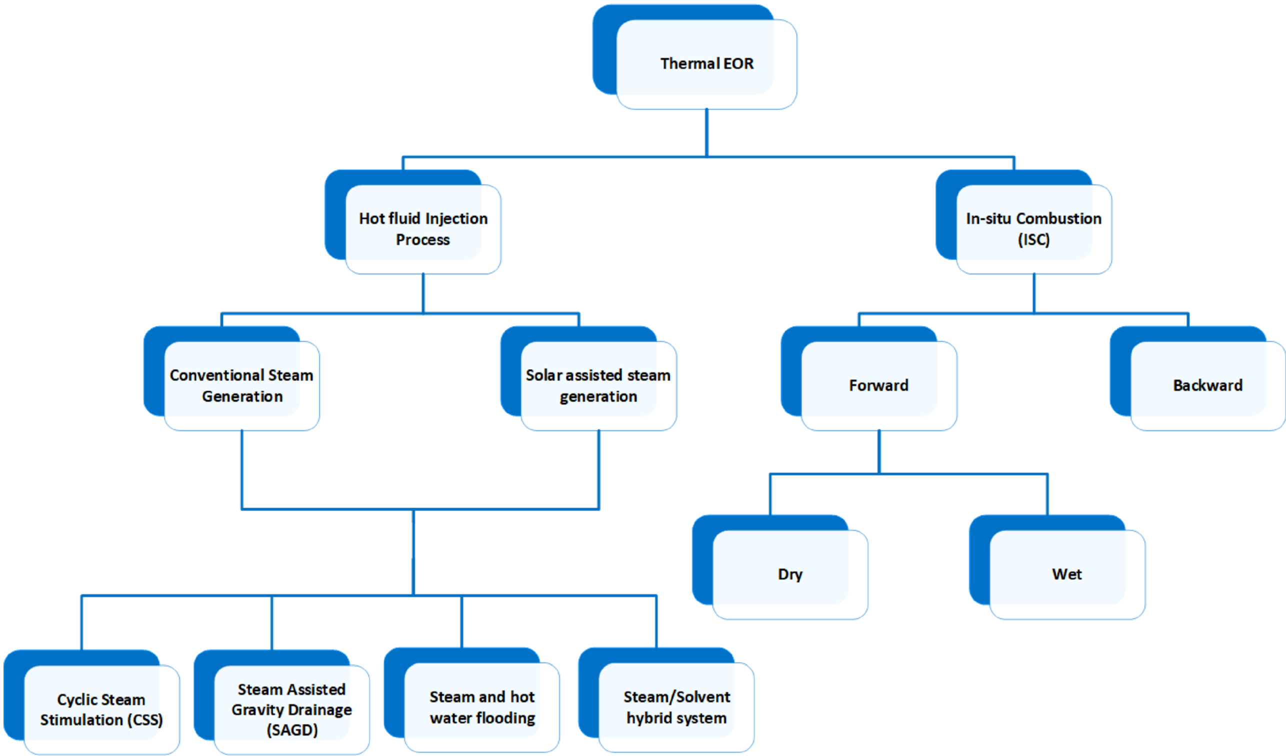

Fig. 5 Thermal EOR processes

reservoir undergoes EM heating. The effects of EM heating power, initial water saturation, solvent types, and combination strategies of EM heating and solvent injection (simultaneous or alternate means) were recorded. Results illustrated that the combination of EM heating and solvent-assisted gravity drainage could enhance oil recovery beyond the use of EM heating only. Also, the type of solvent employed affects the performance of the system. EM heating followed by *n*-octane injection gives higher performance compared with the simultaneous EM heating and solvent injection. Furthermore, it is reported that moderate initial water saturation enhances the heating speed, and as a result, increases oil recovery. EM induction heating with a variable magnetic field generated by an inductor was conducted using electrically conductive materials placed in a field [8]. An electromotive force had been generated to set up the flux in an electric machine, and an apparatus was employed to generate eddy current. This current generates the required thermal energy, which is a function of the material's heat capacity, the frequency of induced current, the permeability of the material, and the resistance of the material to the flow of current through it. EM induction heating, being quite recent, has just begun to be deployed in fields. Having inductors situated at the bottom of the well, Siemens AG deployed the EM technique for heavy oil recovery from oil sands [8]. They designed an inductive coil with medium frequency electric field depending on the reservoir condition to produce thermal energy. Many research papers covering different aspects of EM heating for EOR are available in the literature [28–32].

Preheating is very important in EOR for energy saving and for accelerating the process. Down hole electrical heaters (EH) and electromagnetic heating (EMH) have been suggested for this purpose to reduce the preheating time with energy savings [33]. Some EOR processes such as SAGD requires time period of 3–6 months to complete the heating process. But, with high frequency electromagnetic waves, this period could be reduced by polarization of electrically conductive molecules inside the oil sands. A model with new analytical solution, having three different preheating processes, steam circulation, electrical heaters in both horizontal wells EH, electromagnetic antenna in the injector, and electrical heater in the producer EMH-EH was proposed by Sadeghi et al. [33]. The three methods were compared according to energy saving and the time required for mobilization. In the end, it was concluded that the electromagnetic heating (EMH) clearly increases the energy saving. Investigations carried out to explore this EOR technique revealed important conclusions about its potentials in oil recovery; the literature, however, is still evolving in that regard. These include a summarized survey for experimental, numerical, and field application of EM heating for heavy oil recovery [8]. Using microwaves for thermal energy generation is another technique that has huge potential. The energy transformation from microwave to thermal energy in the presence of microwaves absorbers can be exploited in reservoir heating for EOR. The fact that crude oil in itself is not a good microwave absorber entails the use of other materials having high microwave absorptivity such as activated carbon, Nanometal-oxides, and polar solvents, which make the heating process faster. The use of enhanced metal-nanoparticles incorporating electromagnetic heating for field-scale EOR application was proposed as a future work by Greff et al. [24]. The challenge is optimizing a way of injecting

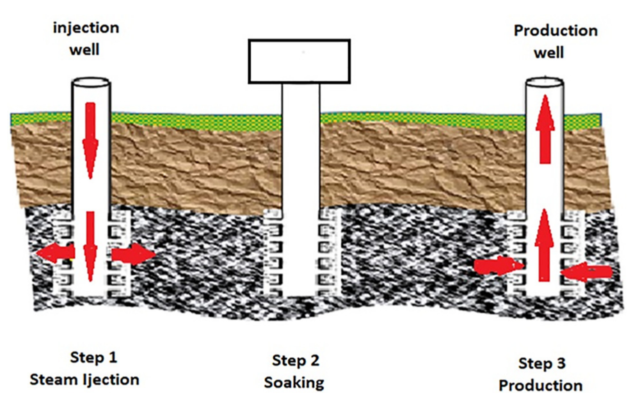

Fig. 6 Schematic illustration of CSS

the nanoparticles into reservoirs during the EM heating process. One suggestion is the injection of Nano-fluid at different stages of EM heating after viscosity reduction.

5 Hot Fluid Injection Processes

As its name implies, hot fluid injection as an EOR process involves the use of hot fluid in an oil reservoir to ease the flow of oil for production. Thermal energy is transferred (in form of heat) to the reservoir by the combined effect of convection and conduction mechanisms [8].This thermal energy leads to high viscosity reduction and thermal expansion of oil in the reservoir. Injecting steam is the most common technique in this technology of thermal EOR and it is the most commercially successful [34–38]. Steam injection processes involve three methods, which are CSS (also called huff-and-puff method), steam flooding (steam drive), and SAGD [8]. In steam flooding, steam is injected through injection wells reducing the oil viscosity in addition to the sweeping effect generated by flooding of steam. However, this method requires more steam than the CSS despite being more effective.

5.1 Cyclic Steam Stimulation. Cyclic steam stimulation (also known as huff and puff method) involves three stages, which are namely: injecting of steam, soaking period, and production of oil. In this technique, steam is injected into the well for a period of time to raise the oil temperature resulting in reduced oil viscosity, which facilitates its mobility. After ensuring that there is enough amount of steam in the well, it is shut-in for a period of time extended from few days to few weeks to make sure that the thermal energy is spread out well, as shown in Fig. 6. Subsequently, the well can produce oil due to the pressure generated by the injected steam. The production continues to a point at which its rate decreases significantly to warrant cycle restart as the oil cools with time resulting from thermal energy losses. The same previous steps are repeated again and again, but naturally the effectiveness of this process decreases after few cycles. Li et al. [39] conducted experimental and numerical analysis for the huff and buff process using CO_2 instead of steam; it was found that at the fifth CO_2 cycle, the recovered oil reached 31.56%. Every EOR method has its effectiveness, which is measured by the amount of oil recovered percent of the total capacity of the well. The maximum recovery by CSS is relatively low (around 10–40% of the OOIP compared with SAGD which has higher recovery average) [40,41]. Smart water, which can be designed by optimizing the chemical composition of injected brine, has been carried out by Jalilian [42] to see its effect on pure limestone carbonate rocks. Increasing the sulfate ion concentration and reducing the total salinity, Jalilian [42] found that the oil recovery factor has increased by 14.5%. Low-salinity water flooding has a weak effect on the oil recovery less than 2%.

In CSS technique, a single well is used interchangeably as a steam injector well and as an oil producer well. Since the steam used in the process, for practicability, is generated on the surface, to be injected using surface lines and wellbore, thermal energy losses from these surfaces need to be considered. Subsequently, limiting parameters such as reservoir depth, pressure, and lithology have to be taken into account for an efficient oil recovery using steam injection. The steam, after injection, is allowed enough time to soak (soaking time) due to which its high temperature (200–300 °C) helps reduce oil viscosity while the high pressure (about 1 Mpa) fractures the reservoir rock. As the soaking time lapses, with oil ready for production, the production time follows when oil can be produced at high rates. This production continues, until eventually it begins to rapidly decrease meriting another steam injection that will trigger another cycle. The three stages of this cycle can be repeated several times within the limiting case of technical and economic viability [43]. The injection and soaking times normally takes days or weeks while the production time generally takes weeks to months. An optimum injection time and extension of the soaking time depend on mechanical and operational considerations while the oil production rate limits the production time. From the production viewpoint, it is vital to determine the number of cycles that will achieve maximum oil recovery by the process, as it generally becomes less efficient with increasing number of cycles.

Cyclic steam stimulation process has been widely employed for EOR since its accidental discovery in 1959 in Eastern Venezuela by Shell Oil Company of Venezuela when testing a steam drive [41]. It has been successfully used in various heavy oil fields in Canada, Venezuela, Brazil, and in California, USA, where it is used as a first stage before continuous steam injection [44]. The main advantage of cyclic steam stimulation is a rapid pay-out during early production. Its percentage of oil recovery vis-à-vis OOIP, is, however, comparatively low ranging from 10 to 20% [45]. To improve this low oil recovery in CSS, enhancements such as the use of horizontal rather than vertical well, the use of chemical additives in the steam, and hydraulic fracturing are introduced with the process. Consequently, studies focusing on the optimization of chemical additives in the steam and fracture design are common in recent literatures [46,47]. Such enhancements were reported to achieve improvements of up to 40% of OOIP, a recovery that is still lower than its other thermal EOR counterparts [41]. Wu et al. [48] studied the effect of gas breakthrough (GBT) with cyclic steam and gas stimulation in an offshore heavy oil reservoir. They introduced a new concept for breakthrough degree and named it gas breakthrough coefficient; this coefficient depends on some parameters such as reservoir thickness, permeability, and the injection strength and injection production pressure. Another consideration in CSS is the steam generation process for the system. Early on, some oil field made use of the produced crude oil in steam generators through direct combustion. Environmental as well as economic considerations led to the use of other fuels like natural gas in the steam generation process over time. Those same considerations resulted into targeting other sources like coal, biomass, and solar energy with each having different economic and environmental footprint. Apart from the choice of energy source in steam generation, options of using combined power cycle for more efficient energy utilization were considered in some occasions. The use of natural gas, for instance, in a cogeneration power cycle to produce both electricity and steam for CSS has been actualized in Californian oil fields with an installed electrical generating capacity of about 2000 MW [49]. Use of solar energy in concentrating solar trough for steam generation to be used in EOR systems is another approach that promises huge environmental benefits [50,51]. Another approach involves the combination of CSS with air injection in a process called air assisted cyclic steam stimulation. This method is used for heavy or ultra-heavy oil reservoir after CSS became non efficient, where it can compensate for the low reservoir pressure, poor steam sweep efficiency, and high water cut. Wang et al. [52] conducted a study on ultra-heavy oil reservoir of

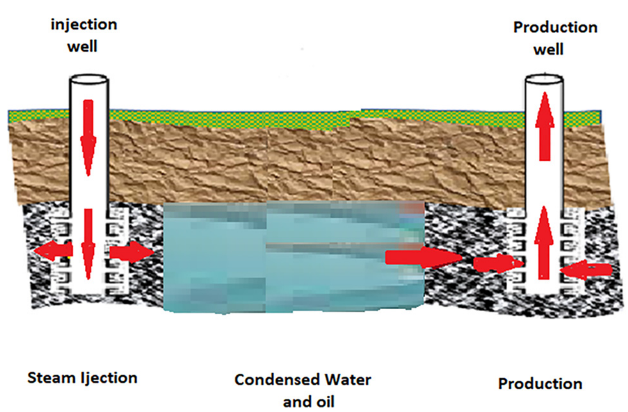

Fig. 7 Schematic illustration of steam flooding process

Liaohe oil field (China) using a numerical technique validated with experimental work and their study revealed that adding air to CSS can improve oil recovery with 11% increment in oil production. Another numerical study in air assisted cyclic steam stimulation had been done by the same authors [53]. It was reported that the rate of oil recovery is better than CSS besides improvement in energy efficiency and decrease in CO_2 emissions. Leaute et al. [46] patented a new idea of LASER-CSS, which is summarized as mixing liquid hydrocarbon with the injected steam instead of injecting it alone in front of the steam stimulation cycle and that will improve the recovery efficiency. Lu et al. [54] studied the in situ formed oil water emulsion droplets transport and plug in porous media. One of their conclusions was that higher pressures can displace larger size of oil water emulsion droplets out of the pore throat and reduce their retention volumes.

5.2 Steam and Hot Water Flooding. Hot water and steam flooding is a thermal EOR technique, which requires a huge amount of water or steam to be injected onto high viscous oil in the well to raise its temperature as shown in Fig. 7. 3D sand-packed displacement model and experimental work have been developed to simulate the water flooding and immiscible CO_2 flooding processes [55]. In addition, enhanced heavy oil recovery by immiscible CO_2 injection is found to be limited by early gas breakthrough due to, mainly, the unfavorable mobility ratio between CO_2 and heavy oil. As reported in literature, hot water flooding is less efficient than steam injection due to the lower thermal energy content of water [8]. On the other hand, the driving power of the water is higher than that of the steam. The steam injection process involves continuous steam injection into an oil-bearing porous medium. This results in the formation of an almost constant temperature, slow advancing steam zone around which the viscosity of the oil is drastically reduced thereby increasing oil mobility. This highly mobilized oil within the steam zone is subjected to a vaporizing gas drive as a result of which the initial oil saturation is reduced to as low as 10%. Mohebbifar et al. [56] used Nano and biomaterials simultaneously; they used three types of biomaterials including biosurfactant, bioemulsifier, and biopolymer besides two types of nanoparticles including SiO_2 and TiO_2 at different concentrations as injection fluids. The highest efficiency of 78% was observed while injecting one pore volume of biopolymer and SiO_2 nanoparticles. Steam flooding has a typical recovery factor ranging from 50% to 60% of OOIP. However, being a pattern-driven process, its performance will ultimately depend on the pattern size and geology [57,58]. Experimental study has been carried out using steam flooding for reservoir with ultra-heavy oil as in AL-1 Block, Shengli Oilfield, China [59]. A numerical study conducted on steam injection in heavy oil revealed that it improves oil recovery up to 60% during a fixed period of time, and that only 30% of OOIP can be recovered by hot water injection method [60]. Hossain [61] developed dimensionless scaling parameters for thermal flooding in porous media. He proposed numbers that measure the thermal diffusivity and hydraulic diffusivity of a fluid in a porous media.

Another study focusing on heterogeneous heavy oil field located in southern Oman had been conducted to establish the optimum thermal energy transfer conditions via steam injection in the reservoir [62]. A CMG-STARS model was developed in the study to simulate steam injection process with the valve control of steam trap subcooled. They concluded that the valve control gives a faster distribution of thermal energy after steam injection. In addition to that, it gives higher production with low amount of steam required. The use of Nitrogen thermal foam flooding to overcome steam override and steam channeling problems was also reported in the literature [63]. It was observed that using nitrogen foaming can increase the displacement efficiency of steam flooding from 43.30% to 81.24% in single sand-pack experiment.

The economic as well as technical success of steam flooding process highly depends on the steam generation unit.

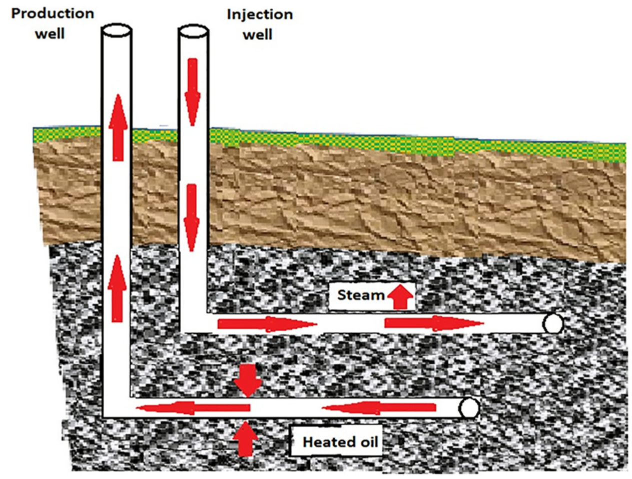

Fig. 8 Schematic illustration of SAGD process

Consequently, efficient operation and maintenance of the steam generators that takes into account the fuel used in the generators, its availability and cost, as well as feed water treatment and cost are highly important. From operation viewpoint, the two most important challenges in steam flooding are the concerns with steam override and that of excessive thermal energy losses. The thermal energy loss can be attributed to the losses in surface lines that transfer the steam from its generating unit to the injection wells. Other losses occur during steam passage into the wells since the steam temperature is much higher than geothermal temperatures. Another source of losses occurs inside the reservoir from the heated portion of the formation to the adjacent lower temperature regions.

5.3 Steam-Assisted Gravity Drainage. In the case of SAGD, steam at high pressure is injected continually in a horizontal well to provide thermal energy in the well that reduces the oil viscosity. The heated well is then drained into a lower well where it is pumped out as shown in Fig. 8. This method is best suited for heavy oil extraction in carbonate reservoirs as reported by Hosseini et al. [64]. These are mostly naturally fractured reservoirs but only few studies had been conducted in this area. It is considered highly promising technique and it needs more work and research in order to fully attain its potentials. The effect of fracture properties like fracture orientation, fracture spacing, and fracture permeability on the SAGD performance in naturally fractured reservoirs was studied by Hosseini et al. [64] through experimentations and modeling using CMG-STARS thermal simulator [15]. Experimentally, the combination of the SAGD and multiple thermal fluids-assisted gravity drainage process was also tested by the authors. They reported that fracture orientation affects the steam expansion and oil production from the horizontal well pairs. It is also reported that horizontal fractures have a negative effect on oil production, while vertical fractures have a higher production rate compared to its horizontal counterpart. Similarly, increase in fracture permeability was shown to positively improve oil production. Furthermore, they reported that an increase in fracture spacing enhances oil production, because in wider fractures, the steam accompanied with its thermal energy will take more time to diffuse into matrices and provides thermal energy to the entire reservoir. Literature is available on the use of an optimization simulation method called proportional-integral-derivative coefficient to optimize the steam injection process while achieving higher oil production and lower steam-oil ratio [65].

Process integration tools have been applied in some instances to improve efficiencies in the SAGD process. This was conducted by Forshomi et al. [66] in which a distributed effluent treatment system was designed to improve the economics while tackling environmental issues. Different configurations of water treatment technologies and steam generation options in SAGD were employed to target an optimum process. An energy cost savings of up to 19.5% and 12% in water treatment system of SAGD operations was reported by the authors simply by diverting flows in wastewater streams. Thermal integration of the system was, however, not considered in the study. Artificial intelligence approaches are used for predicting SAGD recovery performance and in assisting conventional SAGD analysis [67].

In the field, SAGD is considered the most popular in the oil sands and extra-heavy crudes of AB [8]. The use of a hybrid version of SAGD (e.g., injection of solvent with steam) is, however, at its pilot stage. Some old statistics showed that, in 1993, worldwide production from cyclic steam and steam drive was more than 700,000 bbl/day. This amount had increased to 919,917 bbl/day in USA, Canada, Brazil, and Norway in 2013 68. However, the steam-based applications are limited to shallow reservoirs, which are less than 3000 feet deep. Horizontal wells are always used in SAGD and it is proven to be successful in the field and many studies are available in the literature in this regard. Recently, vertical well as alternative method for SAGD had been developed [69].The well consists of two strings, the first one is used as a producer on the bottom and the other is used as an injector on the top, with the distance between injector and producer perforations being changed gradually. It is reported by Suranto et al. [69] that increasing the steam injection rate directly increases production rate. Furthermore, their results showed that vertical well SAGD can improve the drainage radius to 85 m using both multilevel injector and multi-level injection rate. However, good performance of the multi-level injector can be achieved if the injector perforation is moved gradually. They recommended using vertical well SAGD in the case of thick reservoir. Vertical wells method has advantages like decreasing cumulative steam oil ratio, increased drainage area, and enhanced steam chamber volume; as a result, it can increase the efficiency of steam injection.

5.4 Steam/Solvent Hybrid System. Many researches had been done and are still on-going toward the improvement of EOR in terms of efficiency and economics in all its stages. As example, start-up process is an important process to take in mind. Experimental and numerical study, which uses the solvent assisted start-up, has been carried out by Yuan et al. [70], where, injection of solvent instead of steam near the wellbore was explored. Following that, there is a need to improve the sweep area by high-temperature steam circulation, which also reduces the oil viscosity. It can be concluded that injection of solvent into an initial reservoir can shorten the start-up process and reduce steam consumption. Using injection of solvent with steam to improve the performance of SAGD has been conducted both in a lab scale and actual field. In Refs. [71–76], numerical simulations were reported by the authors for the case of SAGD and they found that it shortens the preheating time and reduces steam consumption; also the production rate and the cumulative oil production improve especially at the early production period. Steam flooding assisted with flue gases and *n*-hexane has been studied experimentally in the lab by Li et al. [77]. It was reported that the flue gases injected in heavy oil can reduce the oil viscosity and increase the flow capability. It is worth reporting that the n-hexane has more effect than that of the flue gases, where it can reduce heavy oil viscosity and surface tension more rigorously. So, the two types have positive effect on the steam flooding, where the oil recovery efficiency can reach up to 80%. An experiment was carried out in a lab scale by Mohsenzadeh et al. [78] in which nonhydrocarbon gases like pure CO_2, pure N_2, and their mixture as in flue gas were injected into a core of a fractured carbonate reservoir. This process is followed by steam injection with specific steam/gas ratio. It was concluded that the injection of these nonhydrocarbon gases with co-injection of steam gas could enhance the oil recovery values to 58.4%, 73.8%, 47% for CO_2, flue gas, N_2, respectively, after GBT. These results are considered highly acceptable for oil recovery. New emerging ideas for heavy oil recovery are being proposed to add deep eutectic solvents (DESs) like Choline Chloride, Glycerol (DES1), Choline Chloride, and Urea(DES2) [78]. This process, when followed by steam injection process, was shown to increase the recovery rate by 12%.

Another hybrid process for improving the EOR process is called thermal-chemical flooding which is done after steam injection. This combination involves steam, nitrogen (N_2), and viscosity breaker. Compared with steam flooding thermal–chemical flooding had higher displacement efficiency with a ratio 11.7% higher than that of pure steam flooding [79].

5.5 Solar-Assisted Steam Injection for Enhance Oil Recovery. Solar thermal steam generation involves production of steam using energy from the sun. The idea has been around since the early 1980s [80]. Mirrors are used to concentrate and focus sunlight on receivers containing water or brine solution. The heated fluid is then either directly or indirectly used to generate steam in a flash tank. The use of solar energy reduces the reliance on fossil fuels for steam production. However, due to the intermittent nature of solar energy supply, a hybrid system utilizing the conventional fossil fuels integrated in a power cycle with the solar thermal steam generation system is utilized. The hybrid system comes in handy in the absence of solar thermal energy storage systems and/or during cloudy weathers and the night time when solar energy is not available.

Glass Point built the first commercial solar enhanced oil recovery (SEOR) project in Kern County, CA [81]. It uses parabolic troughs to heat water and directly produces steam for well injection, generating 300 kW of thermal energy. The parabolic troughs were kept inside a glasshouse to protect it from dirt and sand storms. The system was capable of producing steam at 2500 psi and 950°F. The BrightSource pilot project in Coalinga, CA uses a solar tower to produce 29 MW of thermal energy capable of generating 13 MW of electrical energy. It utilizes 3822 heliostats and is based on a land area of 100 acres [81]. Another pilot project [51] by Glass Point based in Oman near Amal oilfields utilizes glass-skinned structure enclosed parabolic trough similar to the one in Kern County on a 4.2 acres field. The plant is capable of producing 7 MW of thermal energy, resulting in production of 14.8 tons of steam per hour at 100 bar having 80% quality. The plant is supplemented with a gas-fired steam production system to produce steam at night. For a constant steam rate, the gas consumption could be reduced by up to 25%. Furthermore, by injecting more steam during the day the gas consumption could be reduced by up to 80%. Another solar steam plant of 1 GW thermal energy is under construction for the same oilfield.

The use of solar and conventional steam production technique enables the use of a cyclic method of steam injection. In this method, more amount of steam is injected during the day, and during the night, the injection rate is kept at a minimum. This prevents closing down injection during the night, which could lead to problems associated with well start-up and thermal fluctuations along the wellbore. Injection during the night can be carried out either using conventional fossil fuel-based steam generation methods or using energy from solar thermal energy storage systems. A recent study [81] has shown that small amount of nightly steam injection increases the cumulative oil production in comparison to no nightly steam injection. However, the effectiveness also depends upon the property of oil being recovered. In a study [82], for recovering heavy oil from Hamca field in Venezuela, no significant improvement in oil production was found by injecting steam at night regardless of the quantity injected. Thus, the use of 100% solar generated steam was deemed viable in this case.

Mokheimer and Habib [83] disclosed and granted a patent for enhanced oil recovery, which is based on a hybrid system that utilizes the solar thermal energy at the day time and oxy-fuel

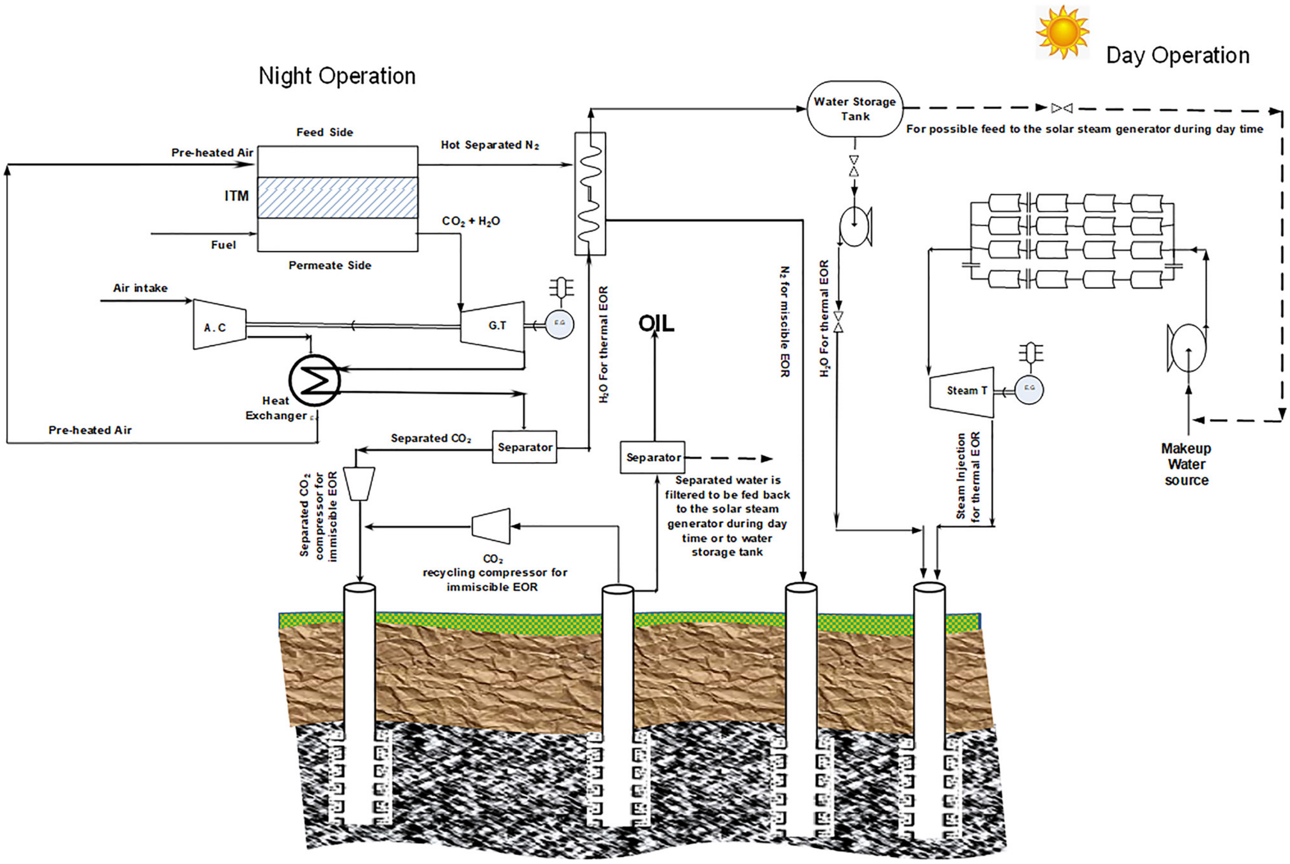

Fig. 9 Schematic diagram of the hybrid solar thermal EOR system with oxy-fuel combustor, Patent number 9845667B2, Dec. 19, 2017 [83]

combustion at the night time as shown in Fig. 9. At the day time, the solar heater generates steam that is injected into the oil field to enhance the oil recovery. At the night time, oxy-fuel combustion system can be utilized, instead, to generate combustion gases, which are mainly carbon dioxide and water vapor in addition to oxygen-depleted air (nitrogen). The water vapor is separated from the combustion gases by cooling. The combustion gases and nitrogen are injected separately into the oil reservoir for the same purpose. The carbon dioxide is injected for miscible enhanced oil recovery, while the nitrogen is injected for immiscible enhanced oil recovery.

Continuous variable rate injection scenario was investigated by Sandler et al. [84] using established reservoir simulation model of steam drive through vertical wells in heavy-oil sand. The model also accounted for seasonal variations with greater injection rate during summer. The steam injection rate during evening and night, using conventional steam generation method, was reduced by 96%. Oil recovery and other parameters were compared with constant rate injection. The cyclic solar steam injection was at par with constant rate steam injection using conventional steam. The oil rate recovery was found to be independent of daily and annual cycles for multiple year timescales. Similar conclusions were reached by Van Heel et al. [85]. Furthermore, economic analysis showed that the solar thermal steam generation with 100% solar fraction has the lowest operational cost and is least sensitive to natural gas prices fluctuations. This also leads to a significant reduction in CO_2 emission from production of crude oil. It should be noted that the direct normal irradiation received is the primary factor in deciding the feasibility of SEOR projects. It is viable in areas, which receive high solar radiance throughout the year and may prove economically unjustifiable for other areas. In a study by Afsar and Akin [86] using TRNSYS software, a heavy oil field in Turkey utilizing parabolic trough collector was observed not to have enough and available solar power for continuous steam injection all year round. The maximum solar fraction reached was about 42%, which did not economically justify the investment cost of the project.

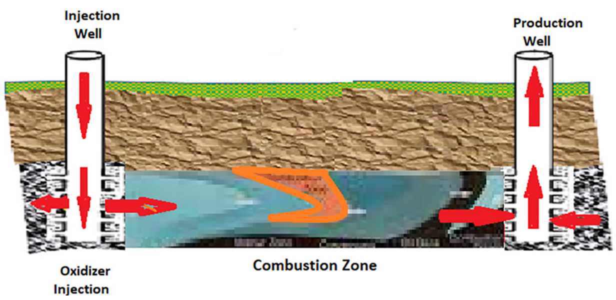

Fig. 10 Schematic illustration of in situ combustion process

6 In Situ Combustion

Among the thermal EOR technologies, in situ combustion and down-hole heating have great potential as an emerging new technique of thermal EOR technologies. However, like all other thermal EOR technologies, in situ combustion and down-hole heating require the use of huge amount of natural fuel (usually gas). Since all thermal EOR methods suffer from its environmental footprint due to the associated CO_2 emission, the search for new thermal EOR methods such as in situ combustion and downhole heating are thought to be the next generation thermal EOR technologies.

In situ combustion, also called "fire flooding," is one of the thermal EOR systems being widely used since its inception in the early 1950s in USA's Pennsylvania. Like any conventional combustion process, it requires fuel, oxidizer, and igniter. However, in ISC, the combustion happens inside an oil well, as shown in Fig. 10. The process involves the adequate injection of compressed, heated air, enriched air, or oxygen into an oil reservoir at pressures equivalent to the reservoir pressure. Initial reservoir pressures of up to 22 bars [87] are common. The injected air will cause the oxidation of some of the oil components in the reservoir. This high temperature oxidation (HTO) process is accompanied with thermal energy generation (with about 500–900 °C in temperature rise), which continues till the temperature reaches the ignition temperature [88].Consequently, the mixture will be ignited establishing a combustion front that releases thermal energy and combustion gases like CO_2, CO, and H_2O, which dissolves and displaces the reservoir fluids toward the production well. Cold air needs to be injected as the combustion front is established in order to ensure continuity of the combustion. There are two types of ISC: forward and reverse combustion according to the direction of oxidizer and combustion front. If the two are in the same direction, it is called forward; otherwise, it is called reverse combustion.

It is, however, important to note that for heavy oils and reservoirs having low temperatures, the injection well may be heated through other means to achieve the ignition in the reservoir. During ISC, the reservoir oil undergoes series of physical and chemical changes that include thermal cracking and distillation of residual crude. Due to the thermal cracking, a solid fuel, in the form of carbon residue, is produced. This fuel that is formed and deposited, together with the distillates produced, sustains the combustion in the presence of oxidizer. The successes recorded for in situ combustion projects as well as some inconclusive or unsuccessful ones over the last decades were reviewed by Alvarado and Manrique [9]. Specifically, in carbonate formations, ISC have shown a steady growth since the end of the 1990s [89]. It has successfully been implemented in field-scale applications for heavy oil sandstone reservoirs in Canada, India, Romania, and the USA.

In situ combustion presents an opportunity in terms of water requirement since the constraints of water availability for steam injection for thermal EOR system is taken care of. Additionally, the process provides an opportunity in terms of CO_2 emission reduction to the atmosphere since the products from the combustion are composed mainly of CO_2 and CO that can be collected and recycled together with the air during subsequent injection. Although, as the amount of the recycled gases gets higher with time, more oxygen will be needed in the air for combustion to be sustained, which lends credence to air-enriched or oxy fuel combustion practices [90]. It is reported based on experimental studies that enrichment of air with a 35% volume of oxygen enhances the overall oil recovery but using 100% oxygen in the process was shown to reduce oil recovery [91,92]. Consequently, an optimum amount of oxygen needs to be established for different scenarios. The higher oil recovery tendency of oxygen-enriched ISC can be the result of higher amount of steam generated in the combustion products, which facilitate further the process of dissolution and oil displacement for EOR. This higher steam production rate for oxygen-enriched air is evident in the steam front velocities of 0.077, 0.084, and 0.110 m/h reported for 21%, 30%, and 35% oxygen by volume in the air, respectively [91]. In a combustion tube experiment for crude oil from Liaohe Oilfield in Liaoning Province (Bohai Basin), China, it was found that the oil recovery factor reach 78.6% and the combustion front movement velocity of 0.20 cm/min [93].

Furthermore, ISC is comparatively more energy efficient, having relatively lower amount of energy consumed to produce a barrel of oil because the HTO process happens directly in the reservoir. This energy efficiency is related to the air-to-oil ratio (AOR) defined as the volume of air needed for injection for the recovery of a certain volume of oil. AOR is a function of oil saturation in place at the beginning of the combustion, the well geometry, as well as the fuel formed and deposited that eventually get burned [49]. Another critical parameter for ISC is the amount of fuel present per bulk volume of the reservoir as it ultimately determines the air required to burn a unit bulk volume of the reservoir. A detailed review of fundamental concepts of ISC as well as detailed chemical kinetics of the process is carried out by Mahinpey et al. [94]. An average AOR of 1890 m^3-air/m^3-oil was reported for good performing field projects (equivalent to 302 m^3 of air producing 6120 MJ of crude oil energy) [95], but varies under different conditions from 880 to 8860 m^3-air/m^3-oil [96]. For air at temperature and pressure T_1 and P_1, respectively, a compressor efficiency η, the energy, as a shaft work, W_s required to compress certain volume of air to be delivered at pressure P_2 can be estimated using the following equation:

$$W_s = \left(\frac{1}{\eta}\right)\left(\frac{\gamma R T_1}{\gamma - 1}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1\right]$$

where R is the ideal gas constant and γ is the ratio of constant pressure and volume heat capacities.

The most important challenges associated with in situ combustion are the combustion temperature and gas override (gravity segregation) due to density difference between oil and gas, leading to premature combustion zone breakthrough in the producers. Another challenge that arises during oil recovery is a result of unfavorable gas/oil ratio due to density variations. Depending on the lithology, issue related to decomposition of rock, turning into a powder-like material, which can easily result into plugging, is also a source of concern. Oil fields with limestone lithology are shown to be susceptible to such tendencies. Heterogeneity in the rock formation can also lead to channeling that could be unfavorable. Furthermore, fractures resulting from the combustion thermal energy release could lead to the release of trapped oxygen that impact on the whole system and could even lead to its failure. Before implementing in situ combustion EOR project on any reservoir, therefore, feasibility study needs to be conducted to ascertain its suitability vis-à-vis oil type and nature of the rock in the reservoir. These studies include the use of thermometric test using rigs like thermogravimetric analyzer and differential scanning calorimeter [97].

One of the improvements to in situ combustion process is Toe-To-Heel Air Injection (THAI) that combines the process with a horizontal well system. In this case, the injection is carried out just like explained before, using vertical well, thereby generating the burning front. A horizontal well at the bottom of the reservoir is used instead as oil producer in this case [98]. This is said to achieve up to 80% oil recovery [99]. A survey done in 2014 had shown that oil production using thermal EOR (steam, in situ combustion, and hot water injection) in the USA has reached 307,018 bbl/day [68].

To increase the mobility of the recovered oil, Hart [100] developed a design for a system that introduces air and ammonia gas into the subterranean formation during the in situ combustion. Air assists in establishing a combustion front, while ammonia gas contacts the hydrocarbons ahead of the combustion front and reacts in situ with naphthenic acid in the hydrocarbon to form a surfactant. Another design by Paurola et al. [101] injects high temperature oxygen-rich gas into the formation, leading to combustion, which reduces the viscosity of said hydrocarbon mixture and generates CO_2-rich gas. Hot hydrocarbon is obtained in the recovery stage. Provision to capture at least a portion of CO_2 from said CO_2-rich gas is also included.

Canas et al. [102] used ISC in conjunction to SAGD method for hydrocarbon recovery. In addition to horizontal well for steam injection, this process also includes another horizontal well for oxidizing gas injection. Hydrocarbons are produced from a hydrocarbon production well of the SAGD well pair; this hydrocarbon producing well is located below the steam injection well. The oxidation well is positioned above the two SAGD wells, but closer to the surface of the oil reservoir.

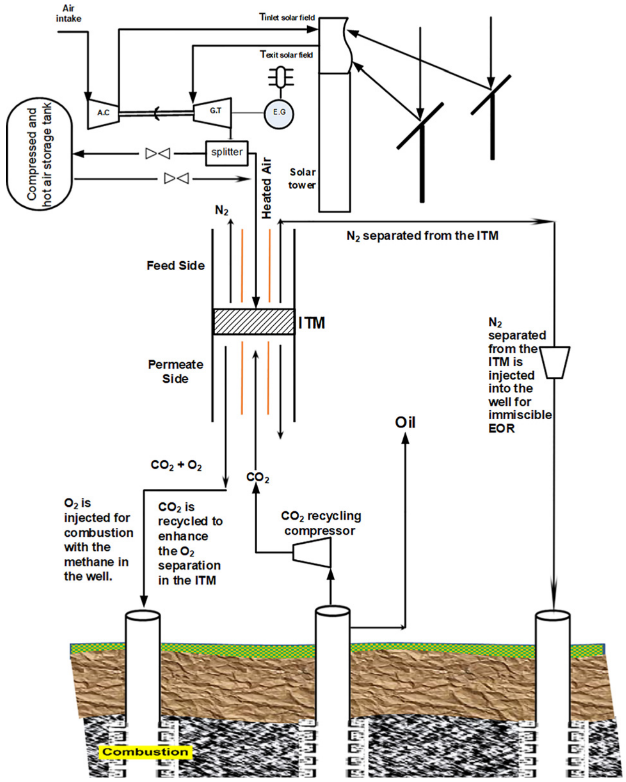

Fig. 11 Schematic diagram for a solar-assisted EOR System [107]

In situ combustion like any combustion process releases the combustion gases to the environment. Das [103] proposed the idea of separating hot nitrogen from the combustion gases coming out of the reservoir and utilize it to generate electricity by using mobile turbines. Another patent by Warren et al. [104] aims to improve the ISC performance by using a proper water gas ratio by introducing foaming agent with water in wet ISC. The foam has good capability to carry water through heated reservoirs and prevents separation from the gas. As a result, more thermal energy is transferred through the steam, which increases the oil recovery.

In situ combustion process is considered the most effective method in cases of difficult conditions where the other methods are not applicable; these conditions might be low permeability, high temperature, and deep oil reservoirs [105]. This process has been used in more than two hundred fields around the world; as mentioned before, it is used in the difficult reservoir as a secondary or tertiary process. ISC releases a significant amount of thermal energy accompanied with hot flue gas mixture, which consists of carbon dioxide, nitrogen, and steam, which are considered as a driving force for oil recovery [106]. But ISC is also considered one of the complex methods in comparison to other EOR methods due to complex reactions, heat, and mass transfer.

Habib and Mokheimer [107] proposed a novel solar thermal EOR system based on ion transport membrane (ITM) oxy-fuel combustion. The proposed novel system is based on in situ oxy-combustion that is based on ITM that separates the oxygen from the air. The separated oxygen is injected into the oil well to burn part of the well oil generating the required heat for thermal EOR. The air is heated before entering to the ITM unit as shown in Fig. 11.

There are two types of ISC, wet and dry. Wet combustion is considered a way to improve in situ combustion process in comparison to dry combustion, where the heat capacity of the steam is high which enhances the oil recovery process [108]. The amount of oil in wells required for ISC is 5–10% from the original oil in place [109]. Due to some difficulties in feasibility studies, unknown properties, nonhomogeneity of the reservoirs, and different components of the crude oil, it has been reported that the global average success of dry ISC to be only 44.6%, which is considered low and unsatisfactory. There are some drawbacks, which may decrease the efficiency of the ISC process such as the nonuniform advancement of the combustion front, which may decrease the sweeping efficiency, and presence of a cold oil bank in front of the mobilized oil, which is considered like a resistance for the oil transfer [110].

Much research had been done to improve the in situ combustion process by different techniques; one of them is adding Nanoparticles to the combustion mixture [106,111,112]. Rezaei et al. [111] studied the effect of adding Nanoparticles (NP) experimentally, which may overcome the problem of large particles that negatively affects recovery process, and also examined the effect of using Nanoparticles on the thermal behavior of crude oil. Some extra thermal, magnetic, electrical, and chemical properties had

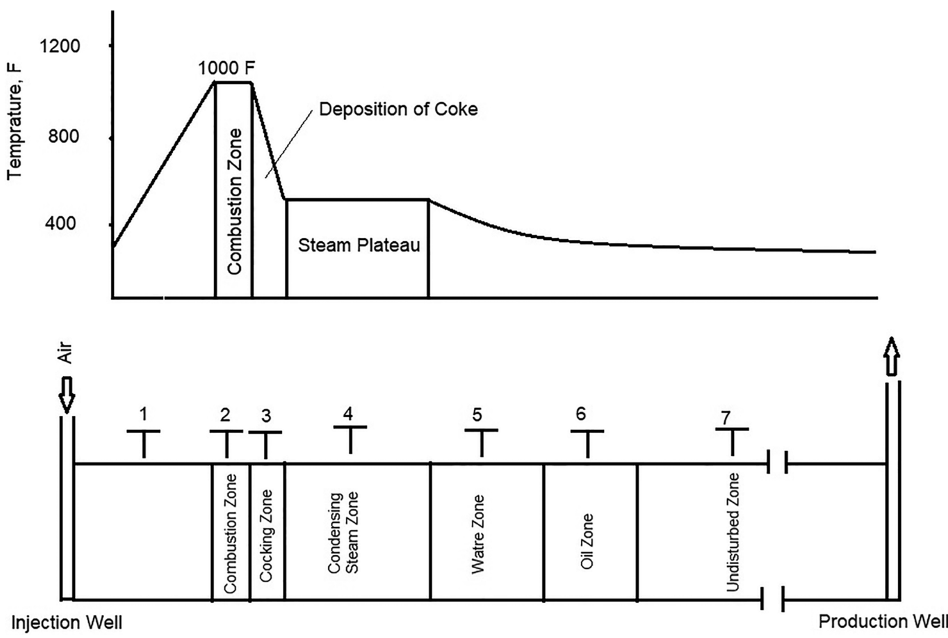

Fig. 12 In situ combustion schematic temperature profile (adapted from Ref. [96])

been transferred with these NP. Improvement of the rate of combustion and greater combustion front has been noticed by Amanam et al. [112] after the addition of 1000 ppm Nanoparticles (Cu-NP).

As mentioned previously, there are two types of ISC: forward combustion and backward combustion. Forward combustion is the only technique so far being practiced in the field. The forward combustion is divided into two categories: dry forward combustion and wet forward combustion. In the dry process, only air- or oxygen-enriched air is injected into the reservoir, but in the wet process, air and water are injected into the reservoir simultaneously or alternatively.

6.1 Dry Combustion. In dry combustion process, air (or oxygen-enriched air) is first injected into an injection well, for a short time (few days) and then, the oil is ignited. For ignition process, different methods can be used such as downhole gas burners, electric heaters, or through injection of a pyrophoric agent or a hot fluid such as steam. In some cases, auto ignition of the in situ crude occurs; in these cases, the reservoir temperature must be greater than 180 °F and the oil sufficiently reactive [113].

6.2 Wet Combustion. Most researches conducted on wet combustion proved that it is preferred over dry combustion. One reason is that, in the dry forward combustion process, large amount of thermal energy generated during combustion is stored in the sand behind the burning front and is considered as thermal energy losses not used for oil recovery. Another reason is the higher heat capacity of water than air, so water can absorb and transport thermal energy many times greater than air. Water is injected together or alternately with air with certain ratios to give the optimum combustion process. This injected water absorbs thermal energy from the burned zone, and then it vaporizes, after which it passes through combustion front and then releases its thermal energy as it condenses in a cool section of the reservoir. This leads to faster thermal energy transfer and oil displacement.

Different zones are generated during the ISC. These zones are many and some of them are overlapping, and they move in the direction of air flow. They simply can be summarized to seven zones (as shown in Fig. 12) which are:

(1) The burned zone
(2) The combustion zone (The combustion zone is a very narrow region (usually no more than a few inches thick))
(3) Cracking zone
(4) Condensation (steam plateau) zone
(5) Water bank
(6) Oil zone
(7) The native zone

6.3 Chemical Reactions Associated With In Situ Combustion. The chemical reactions involved in ISC are numerous, complex, and occur over different ranges of temperatures. These reactions have been simplified by many researchers and are grouped into three classes: (1) low temperature oxidation (LTO), (2) intermediate temperature, and (3) HTO or combustion of the solid hydrocarbon residue (coke).

6.3.1 Low Temperature Oxidation. Low temperature oxidation is highly complex and not easy to understand, but it is believed that it consists of condensation of low-molecular-weight components to higher molecular weight products. It occurs below 400 °F and yields water and partially oxygenated hydrocarbons such as carboxylic acids, aldehydes, ketones, alcohols, and hydroperoxides [114]. LTO is considered an oxygen addition reaction and is caused by the dissolution of oxygen in the crude oil. Light oils are more affected to LTO than heavy oils. It has been found that LTO increases the asphaltene content of the oil and decreases its aromatic and resin contents [115–117]. LTO increases the original oil's viscosities, boiling range, and densities [116,118]. LTO reaction is the process that generates fuel available for combustion [119]. It is better to minimize the LTO reactions promotion during the in situ combustion of heavy oils as the pre-oxidation of the heavy crude at lower temperatures greatly increases the fuel availability and subsequent air requirements for combustion. The major outcome of LTO is Coke production, but the use of LTO reaction for an extended period can cause the oil to be permanently trapped in the pores.

6.3.2 Negative Temperature Gradient Region. The negative temperature gradient region (NTGR) is an important temperature region in ISC, where the transition between the LTO and HTO occurs. In this region, the temperature decreases after increasing. NTGR should be achieved for effective ISC, as failure of the reaction temperatures to reach NTGR leads to very low oil displacement efficiency. This is because the oxygen addition reactions cause vapor phase to contract significantly and make the oil less mobile [120]. In NTGR, the global oxygen-uptake rates decrease with increasing temperature. The negative temperature gradient region depends on some parameters like oil and the core properties as well as on the operating conditions. As an example, the NTGR temperature range for Athabasca bitumen is approximately between 300 °C and 350 °C [121,122].

6.3.3 Medium Temperature Reactions. Medium temperature oxidation (MTO) reactions are homogeneous reactions occurring primarily in the gas phase. In MTO, reactions of pyrolysis and distillation produce mainly hydrogen and some light hydrocarbons in gas phase [123]. Most of the hydrocarbons are formed without oxidation; however, some oxygen reacts with other hydrocarbons to form heavier hydrocarbon fuels, which are later utilized for combustion at higher temperatures [124]. This process is also known as fuel deposition due to heavy oil residue being deposited on the solid matrix [125,126]. Excessive fuel deposition is known to reduce the rate of propagation of the combustion front, while lower fuel deposition rate may not provide enough heat to sustain the combustion front [127]. In clean sands, MTO reactions are considered to be rate determining step [94].

6.3.4 High Temperature Oxidation. In this range of temperature, oxygen reacts with unoxidized oil, fuel, and the oxygenated compounds to give carbon oxides and water. The thermal energy generated from these reactions provides the energy required to sustain and propagate the combustion front. MTO is followed by HTO reaction, in which fuel formed by MTO is oxidized [124]. At higher temperatures, oxygen reacts with unoxidized oil, fuel, and the oxygenated compounds to give carbon oxides and water. This reaction zone is the main combustion region inside the reservoir. HTO reactions are kinetically controlled and are not affected by diffusion effects. HTO reactions are slower than MTO reactions in clean sand matrix [123]. The heat generated from these reactions provides the thermal energy to sustain and propagate the combustion front. The viscosity and specific gravity of the produced oil decrease significantly during HTO [94].

6.4 Draw Backs of In Situ Combustions. In situ combustion has some drawbacks, which can be summarized as:

- The control of ISC process is difficult.
- Safety issues such as avoiding uncontrolled oxygen breakthrough.
- Numerous reactions and huge number of components.

In situ combustion, as mentioned before, is considered the promising thermal EOR techniques as it is applicable in a much wider range of fields than only heavy oil fields. It is particularly good in deeper reservoirs of light or medium oil. The major drawback of ISC is that it is considered complicated method in terms of safety particularly in avoiding oxygen break-through. Another drawback is the insufficient coke deposited from the oil that could not sustain the combustion process. Also, the excessive amount of fuel deposited leads to decrease in the combustion rate as the amount of injected air is considered small. Other drawbacks, which may decrease the efficiency of the ISC process, include the nonuniform advance of the combustion front, which may decrease the sweeping efficiency, and presence of a cold oil bank in front of the mobilized oil, which is considered like a resistance for the oil transfer [110].

6.5 In Situ Combustion Models. Crude oil contains hundreds of different compounds, which makes it very difficult to represent all the reactions, and almost impossible to simulate it. Consequently, most studies use a simplified model based on the Arrhenius reaction expressions defined as Refs. [123] and [128]

$$R_c = \frac{dC_f}{dt} = K p_{O_2}^a C_f^b$$

where, R_c: the reaction rate of the crude oil, C_f: the concentration of fuel, p_{O2}: the oxygen partial pressure, K: the reaction rate constant, *a, b:* the orders of the reactions with respect to oxygen partial pressure and fuel concentration, respectively.

$$K = A \exp\left(-E/\mathrm{RT}\right)$$

where; A, the Arrhenius constant, E, the activation energy, T, the absolute temperature, R, the universal gas constant.

Kinetic parameters can be determined using a variety of experimental techniques, and it could be obtained from the literature [120]. As mentioned before, authors grouped the reaction model into pseudo-components of similar properties. Selection of the pseudo-components must model the phase behavior of the original hydrocarbons. So, the oil results are characterized in terms of Maltenes and Asphaltenes or in terms of saturates aromatics, resins, and asphaltenes (SARA) fractions [129].

The first proposed reaction model for LTO was done by Adegbesan et al. [130]. They proposed the model for Maltenes, Asphaltenes, and Coke for the Athabasca Bitumen. The used reaction mechanism is:

$$\text{Maltenes} + O_2 \rightarrow \text{Asphaltenes}$$

$$\text{Asphaltenes} + O_2 \rightarrow \text{Coke}$$

Sequera et al. [131] proposed another model for LTO, but used SARA components. This model provides acceptable results:

$$\text{Aromatics} + O_2 \rightarrow \text{Resine 1} + \text{Aromatics}$$

$$\text{Resine 1} + \text{Aromatics} + O_2 \rightarrow \text{Asphaltenes} + CO_2 + H_2O$$

$$\text{Resines} + \text{Resine 1} + O_2 \rightarrow \text{Asphaltenes} + CO_2 + H_2O$$

$$\text{Asphaltenes} \rightarrow \text{Saturates} + \text{Coke} + CO_2$$

Hayashitani [132] proposed model for MTO reaction to model the fuel deposition process and gas production within the MTO:

$$\text{Maltenes} + O_2 \rightarrow \text{Asphaltenes}$$

$$\text{Asphaltenes} \rightarrow \text{Coke}$$

$$\text{Asphaltenes} \rightarrow \text{Gas}$$

A numerical model has been proposed by Gonçalves and Trevisan [108] to simulate the wet forward ISC process of a combustion tube experiment with the properties of an onshore heavy oil field located at Espírito Santo state in Brazil. Analysis of different parameters had been done such as water–air ratio, initial saturations, operating pressure and water–air alternation. The study was conducted using the commercial simulation software Steam, Thermal, and Advanced Process Reservoir Simulator (STARS) 2007.10 version developed by Computer Modelling Group Ltd. (CMG). The simulator allows for four phases (oil, water, gas, and solid fuel). It accurately models all the important physical and chemical processes taking place during the in situ combustion process. The dead oil used in this study was subdivided into two pseudo-components: a medium oil pseudo-component (C6–C29) with a molecular weight of 254.2 and a heavy oil pseudo-component (C30–C44) with a molecular weight of 781.3. According to the reaction rate, the kinetic-controlled reaction model had been considered by the simulator, and four chemical reactions included are three HTO combustion reactions and one cracking reaction as shown:

$$\text{Cracking: } 12.1\ \text{Heavy oil} \rightarrow .1\ 721\ \text{Medium oil} + 33\ 4.\ \text{COKE}$$

$$\text{Medium oil oxidation:}$$
$$00.1\ \text{Medium oil} + 22\ 6.\ O_2 \rightarrow 18H_2O + 15CO_2$$

$$\text{Heavy oil oxidation:}$$
$$00.1\ \text{Heavy oil} + 8.9\ O_2 \rightarrow 5.9\ H_2O + 21CO_2$$

$$\text{Coke oxidation: } 00.1\ \text{COKE} + 18.1\ O_2 \rightarrow 5.0\ H_2O + 95.0\ CO_2$$

It is concluded in the study that oil recovery increases with increasing water injection ratios until it reaches an optimum value and then it starts to decrease. Higher initial oil saturations and operating pressure presented higher oil recovery factors. Water–air alternation resulted in a negligible effect.

Yang and Gates [133] studied experimentally the combustion using Athabasca Bitumen in a 1D combustion tube to obtain a set of kinetic parameters and transport parameters for the system. From the literature, there are different available schemes; these schemes differ due to their definitions of pseudo-components. In this study, they used the one developed by Belgrave et al. [134] for Athabasca bitumen as shown:

(1) Thermal-cracking reactions (first order):

$$\text{Maltenes} \rightarrow 0.372\ \text{Asphaltenes}$$

$$\text{Asphaltenes} \rightarrow 83.223\ \text{Coke}$$

$$\text{Asphaltenes} \rightarrow 37.683\ \text{Gas}$$

(2) LTO reactions

$$\text{Maltenes} + 3.431\ \text{O2} \rightarrow 0.4726\ \text{Asphaltenes}$$

$$\text{Asphaltenes} + 7:513\ \text{O2} \rightarrow 101.539\ \text{Coke}$$

(3) HTO or coke combustion

$$\text{coke}CH_{1.13} + 1.232\ O_2 \rightarrow CO_x + 0.565\ H_2O$$

(4) Gas phase combustion

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$$

$$\text{Gas} + 2O_2 \rightarrow 0.9695CO + CO_2 + 2H_2O$$

They conducted the simulation using The STARS^{TM} thermal reservoir simulator (CMG, 2007). In their conclusion, they suggested from their results that coke is originated from the LTO not from the thermal cracking as known, so it is important to control the LTO for sufficient combustion process.

Kapadia et al. [135] proposed a kinetic model for combustion of the Athabasca Bitumen, which include thermal cracking, LTO, HTO, gasification, water–gas shift reaction, methanation, hydrogen generation, hydrogen and monoxide combustion, as shown:

Table 1 Thermal EOR systems: advantages, disadvantages, and limits

Method	Examples (Location)	Permeability limits (mD)	Porosity limits (%)	Depth limits (ft)	Viscosity limits (cP)	Reservoir pressure (psi)	API gravity	Oil saturation (%)	Special features	Improvements to the process	Cost source	Advantages	Drawbacks
1. Hot fluid injection processes													
1.1 Cyclic steam stimulation	-Canada, Venezuela, Brazil, USA (CA) [44]	Minimum: 2000 [136]	Minimum: 20 [136]	Minimum: 1000 Maximum: 3000 [136]	Minimum: 300 [136]	<4000	<20	20	-steam temperature: 200–300 °C -used as a first stage before continuous injection	-using horizontal wells -add chemicals to steam- using AICSS -using hydraulic fracturing [46,47]	Cost of steam generation by: -coal-biomass -solar [50,51] -natural gas [49]	-Rapid payout during early production [44]. -environmentally preferred [137]. -Preferable with small thicknesses [137].	-Low recovery (around 10–40%) [40,41,136] -Consume large quantities of water and fuel, so it is costly.
1.2 Steam and hot water flooding		-Minimumfor steam : 100 -For water: 3–2800 [136]	-For steam 36-For water 15 [136]	-For steam 500–3000-Max. for water: 10,000	-Minimumfor steam: 300 Maximum for water: 2000 [136]	-For steam: <4000	-For steam: <20 -For water >14	20 [136]	-Requires a huge amount of water or steam to be injected [8]	-Using N2 thermal foam flooding can improve RF from around 43% to 81%	-Steam generators -Fuel used -Feed water treatment	-higher water driving power -Steam flooding has RF 50–60% of OOIP [57,58]	-Less efficient than steam injection [8] -Steam override -Excessive thermal energy loss
1.3 Steam assisted gravity drainage	Canada (Alberta) [8]	Minimum: 50 [136]	Minimum: 18 [136]	Maximum: 5000 [136]	50:350,000 [136]	<4000 [136]		20 [136]	-The best for heavy oil recovery in carbonate reservoir [64]	- conducting with distributed effluent treatment system [66] -injecting of solvent with steam -using vertical wells [69]	-High cost of steam production	-Oil recovery (%): 60–80 [63] -Much more economic than CSS, as the efficiency is twice	-Consumes large quantities of water and fuel.
1.4 Steam/ solvent hybrid system	Is used with any steam injection process such as steam flooding and SAGD.								-at start up then followed by steam injection process.-Examples of solvents: 1. Glycerol (DES1) 2. Urea (DES2)			-Shorten the start-up process -improve the production rate at early production period. [70] -Reduce the steam consumption [70] -oil recovery efficiency reached 80%	
1.5 Solar enhanced oil recovery	-USA (CA) -Oman [51] -Venezuela [82] -Turkey [86]	Is used with any steam injection processes.										-lower operating cost compared with Natural gas. -Reduction in CO2 Emission.	-Available solar energy only in the day time.-Thermal storage system is required.
2. In situ combustion	Canada, India, Romania, USA [46]	< 10 [96]	16–38 [96]	300–11500 [96]	<5000 [96]	-up to 22 bar [87]	1O-4O [96]	700 bbl/ac-ft. [96]	-No depth limit with taking in mind the injection pressure	-using (THAI) which use horizontal wells [98].		-CO_2, CO reduction. -more energy efficient -allows wider well spacing than steam	-Decomposition of rock turning into powder-heterogeneity leads to channeling -High Capital and operating Expenditure requirements [136] -Planning and combustion design requirements is more difficult than steam injection. -Limitation of numerical simulation

Table 1 (continued)

Method	Examples (Location)	Permeability limits (mD)	Porosity limits (%)	Depth limits (ft)	Viscosity limits (cP)	Reservoir pressure (psi)	API gravity	Oil saturation (%)	Special features	Improvements to the process	Cost source	Advantages	Drawbacks
3. Electric heating method									-Enhance the heating effect especially in the low permeability zone.	-using water injection with it [14], or use it with solvent-use it with SAGD [16]		-Production rate is 7.6% higher than the SAGD/CSS methods. [138] -Efficient to increase the temperature of the surrounding fluid. [138] -Does not require the additional investments required for a steam distribution system	-decreasing the heat transferred by water
4. Electromagnetic method									-Using microwave absorber [33]-using it with solvent injection-with SAGD gives good results [27], and nano-particles [24]			-reduction of carbon emissions -minimize excessive water usage -increases energy Saving	

Table 2 One case study for each process

Method	Example (location)	Temperature (F)	Porosity (%)	Depth (ft)	Viscosity (cP)	Reservoir pressure (psi)	API gravity	AOR, Mscf/bbl	Average oil Prod., B/D	Notes	References
1. Hot fluid injection processes											
1.1 Cyclic steam stimulation	Alta province, Cold Lake, Canada 2002	55	32	1395			10		—	-area = 32 acres	[89]
1.2 Steam flooding	San Ardo, CA		32	2100			12		253	-area = 700 acres	[89]
1.3 Steam assisted gravity drainage	Orion, Canada 2007	60	33	1350			10		10,000	- area =5120 acres	[89]
1.4 Steam/solvent hybrid system	North Burbank, CA, 2007		16.8	2900			39			-area = 480 acres	[89]
1.5 Solar enhanced oil recovery	Bati Raman field, Southeast Turkey [study]	535–635	10.8–20	1722 m		1800–2000	9.5–13.5		45	-steam injected 250–2000 bpd	[86]
2. In situ combustion	Balaria field, Romani	118	30	2625	120	284.5 :570	19	14	750		[139,140]
3. Electric heating methods	Bakers field, CA	120		1400	14.3		14.3		10–20	-total power output 25.7 kW -Voltage 600 V -Inrush Current (at 20 C) 69 amps	[141]
4. Electromagnetic method	Wildmere field, AB, Canada			600	20 Pa s				3.18 tons/day		[31]

- Thermal cracking reaction [132]:

$$\text{Maltenes} \rightarrow 0.372164\,\text{Asphaltenes}$$

$$\text{Asphaltenes} \rightarrow 83.223\,\text{Coke}$$

$$\text{Asphaltenes} \rightarrow 25.2965\,\text{Gas}$$

- LTO reaction [130]:

$$\text{Maltenes} + 3.431\,O_2 \rightarrow 0.4726\,\text{Asphaltenes}$$

$$\text{Asphaltenes} + 7.513\,O_2 \rightarrow 101.539\,\text{Coke}$$

- HTO reaction [130]:

$$\text{coke}CH_{1.13} + 1.232\,O_2 \rightarrow 0.899CO2 + 0.1CO + 0.565\,H_2O$$

- High temperature gas oxidation Reaction [133]:

$$CH4 + 2O_2 \rightarrow CO_2 + 2H_2O$$

$$\text{Gas} + 2O_2 \rightarrow 0.9695CO + CO_2 + 2H_2O$$

- Hydrogen generation reaction:

$$\text{Coke} + H_2O \rightarrow CO + H_2$$

$$CO + H_2O \rightarrow CO2 + H_2$$

- Hydrogen Consumption reaction:

$$\text{Coke} + 2H_2 \rightarrow CH_4$$

$$H_2 + 0.5O_2 \rightarrow H_2O$$

- Carbon monoxide Reaction:

$$\text{Coke} + 2H_2 \rightarrow CH_4$$

$$H_2 + 0.5O_2 \rightarrow H_2O$$

7 Evaluation of Different Thermal Enhanced Oil Recovery Systems

Evaluation of different EOR methods in comparison with each other does not necessarily have credibility due to several parameters distinguishing the processes. These parameters such as crude oil properties whether it is heavy or extra heavy. Other parameters include the properties and geography of the well such as permeability, porosity, area, depth, and available thermal energy. Due to all of these reasons, it is difficult to compare thermal EOR with each other. But we can mention the reported features from the literature for each method, as shown in Table 1. Table 2 contains a detailed case study for each technique.

8 Summary and Conclusions

A comprehensive review on thermal EOR methods has been presented in this paper. Oil recovery can reach as high as 75% of OOIP, depending on the employed EOR technique. In 2013, the global EOR market was 2.681 billion barrels, and is expected to exceed 16 billion barrels by the year 2020, with a compounded annual growth rate of 29.9%. The revenue from the global enhanced oil recovery will reach around 80 USD Billions by 2020.This review paper has been focused on thermal EOR as it is widely used around the world for several decades and it is still being developed. Thermal EOR is the dominant method employed for EOR globally with 67% global usage. The review indicated that oil production using thermal EOR (steam, in situ combustion, and hot water injection) in the USA has reached 307,018 bbl/day in 2014. Our review also revealed that many numerical and experimental investigations had been carried out with the aim of developing different EOR techniques, many of which were introduced and discussed in this paper. Different steam injection techniques like pure steam or steam with different additives had been discussed. Steam flooding has a typical recovery factor ranging from 50% to 60% of OOIP. Steam injection techniques are considered the dominant among all EOR techniques, as steam has higher energy content and can easily be produced.

Depending upon the permeability of the well and the depth, different steam injection techniques can be used to effectively extract residual oil from the well. Cyclic steam stimulation are mostly used in wells with permeability above 2000 mD, while steam/hot water flooding and SAGD can be used in wells with minimum permeability of 3–100 mD. Oil from depths of up to 10,000 ft can be extracted using hot water flooding while SAGD technique is used for oil wells, which are less than 5000 ft deep and steam flooding can produce oil from wells up to 3000 ft. SAGD technique is widely used in oil fields in Canada (AB) with relatively high oil recovery: 60–80%. The maximum recovery by CSS is relatively low (around 10–40% of the OOIP compared with SAGD, which has higher recovery average). Cyclic Steam stimulation fields can be found in different countries such as Canada, Venezuela, Brazil, and USA (CA). Worldwide production from cyclic steam and steam drive was more than 700,000 bbl/day. This amount had increased to 919,917 bbl/day in USA, Canada, Brazil, and Norway in 2013.

In situ combustion is also considered one of the important EOR methods. It can work at initial reservoir pressures of up to 22 bars, and the amount of the required well oil, to be burned, for ISC is 5–10% from the original oil in place. It was found that the oil recovery factor reaches 78.6% in laboratory experiment using crude oil from Liaohe Oilfield in Liaoning Province (Bohai Basin), China. ISC fields can be found in Canada, India, Romania, and USA. The review revealed that an average of air–oil ratio of 1890 m^3-air/m^3-oil was reported for good performing field projects (equivalent to 302 m^3 of air producing 6120 MJ of crude oil energy), but varies under different conditions from 880 to 8,860 m^3-air/m^3-oil. Also, it was reported that the global average success of dry ISC is only 44.6%, which is considered low and unsatisfactory. ISC techniques can be used over a wide range of well conditions. It can be used for wells with permeability lower than 10 mD and depth of up to 11,500 ft. However, ISC EOR techniques still have their own difficulties of design requirements as well as their high capital and operational cost in comparison to hot fluid injection technique.

Electric and electromagnetic techniques with some additives were introduced and were seen to allow considerable room for improvement to their performance. Using renewable energy such as solar energy in EOR is considered the most promising technique for several economic and environmental reasons, such as solar-assisted EOR fields in USA (CA), Oman, Venezuela, Turkey.

Advantages and disadvantages of all thermal EOR techniques had been highlighted. For future work, the combination between these conventional methods and renewable energy should be explored. The ultimate target is to decrease the cost required for heating while keeping the environmental footprint of the used EOR technique as minimum as possible.

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Nomenclature

AOR = air oil ratio
API = American Petroleum Institute

B/D = barrel per day
bbl/day = barrel per day
CMG = Computer Modelling Group Ltd.
CO_2 = carbon dioxide
cP = Centipoise
CSS = cyclic steam stimulation
EH = electric heaters
EM = electromagnetic
EMH = electromagnetic heating
EOR = enhanced oil recovery
HTO = high temperature oxidation
ISC = In situ combustion
ITM = ion transport membrane
LTO = low temperature oxidation
Mscf = Standard cubic feet (million)
MTO = medium/middle temperature oxidation
NTGR = negative temperature gradient region
OOIP = original oil in place
Psi = pound-force per square inch
SAGD = steam assisted gravity drainage
SARA = saturates, aromatics, resins and asphaltenes
SEOR = solar assisted enhance oil recovery

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