Heavy Oil

Tony Kovscek, SPE, is an Associate Professor of energy-resources engineering at Stanford University, where he directs the heavy-oil and unconventional resources group (SUPRI-A). Kovscek holds BS and PhD degrees from the University of Washington and University of California at Berkeley, respectively. He is the Stanford University SPE Student Chapter faculty adviser and serves on the SPE Continuing Education Committee, the JPT Editorial Committee, and the Western Regional Meeting Program Committee. Kovscek is review chair of the SPEREE Editorial Review Committee. He received the 2005 SPE Western North America Region Technical Achievement Award and the 2006 SPE Distinguished Achievement Award for Petroleum Engineering Faculty.

In January 2008, the price of benchmark 13°API Midway Sunset crude was approximately USD 85/bbl, whereas in January 2009, it was approximately USD 30/bbl. As the price of oil increased during the past few years, many people commented on how the high price was good for studying and, eventually, recovering unconventional resources such as heavy oil. With the current lower-price environment, I have heard the opposite. Additionally, many individuals declared themselves to be experts in areas of unconventional-resource recovery when prices were high, and there seems to be less enthusiasm for this field now.

This perceived reversal of fortune reminds me of a short story that my children enjoy reading. In the book *Zen Shorts* by Jon J. Muth, a family of three children is told Zen-inspired short stories to help them understand and cope with everyday events. In one short story, a farmer, who coincidently is a rabbit, experiences a series of fortunate and unfortunate events. His friends and relations offer congratulations and sympathy on his good or bad luck, as appropriate. To comments such as "Such good (or bad) luck," the farmer always replies "maybe" and carries on with his work. Although oversimplified here, the story teaches that good and bad luck happen together, and in life you need to cope with both because you never know what will happen next.

If this story were retold for the oil industry, industry observers and commentators might play the role of friends and relations. The wise farmer is the petroleum engineer(s) who knows that the promise of heavy oil and other unconventional resources has a spectrum of recovery techniques under development, and who works toward economical recovery. He/she resists price exuberance and prepares for inevitable changes in fortune. The price of oil represents luck that can never quite be predicted. Unconventional resources are as important a component in meeting future energy demand this year as they were last year.

In this month's synopses and reading list, you will find articles that span many aspects related to heavy hydrocarbons. Downhole electrical heaters remains an exciting area for providing precise, targeted heating. Microwaves also provide the ability to heat the formation selectively and, possibly, induce in-situ upgrading. Likewise, in-situ combustion is more difficult to engineer compared to steam injection, but it is more widely applicable, is potentially more energy efficient, and provides mild upgrading of heavy hydrocarbons. Here, we see its application in fractured systems. Other articles could be classified as minimization of carbon footprint through capture and reinjection of carbon dioxide and as implementation of cold-recovery methods. JPT

Heavy Oil additional reading available at the SPE eLibrary: www.spe.org

IPTC 12536 *• "Microwave-Assisted Gravity Drainage of Heavy Oils" by Berna Hascakir, Middle East Technical University, et al.*

SPE 117327 *• "Increasing Oil Recovery from Heavy-Oil Waterfloods" by Bradley W. Brice, SPE, BP, et al.*

SPE 118226 *• "Experimental and Numerical Comparison of Flooding Schemes To Enhance Recovery of Light-/Medium-Heavy Oil in an Offshore Oil Field" by Bin Yang, China University of Petroleum, et al.*

SPE 115201 *• "Achieving Long-Term Zonal Isolation in Heavy-Oil Steam-Injection Wells: A Case History" by David Kulakofsky, Halliburton, et al.*

Electrical Downhole Heaters for Faja Heavy-Oil Reservoirs

The full-length paper examines use of downhole heaters in thick sands stimulating vertical and horizontal wells, evaluates temporary application of downhole heaters in horizontal wells for a limited period of time, and covers basic economic analyses.

Introduction

The Orinoco belt (Faja) in Venezuela contains one of the largest resources in the world of heavy and extraheavy oil. Because of the production decline of conventional light crude, projects must focus on increasing the recovery of heavy and extraheavy oils by use of thermal and nonthermal methods. Steam-based thermal-recovery processes are more efficient in low-pressure reservoirs; however, because of their depth, the initial pressures of the reservoirs in the Faja are relatively high, ranging from 600 to 1,500 psi with viscosities typically greater than 2,000 cp. For these reasons, it is important to decrease the pressure of the reservoirs with primary-production techniques to facilitate the economical implementation of steam-injection-based methods.

The initial production of heavy and viscous oils can be accelerated by use of downhole heaters that, by providing energy to the vicinity of the well, decrease oil viscosity and increase the oil-production rate. A consequential advantage of using downhole heaters as a prelude to a steam-injection process is that they accelerate early production and reservoir-pressure depletion.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 117682, "Feasibility of Using Electrical Downhole Heaters in Faja Heavy-Oil Reservoirs," by ***Raúl Rodriguez,*** *SPE,* ***José Luis Bashbush,*** *SPE, and* ***Adafel Rincón,*** *SPE, Schlumberger, originally prepared for the 2008 SPE International Thermal Operations and Heavy Oil Symposium, Calgary, 20–23 October. The paper has not been peer reviewed.*

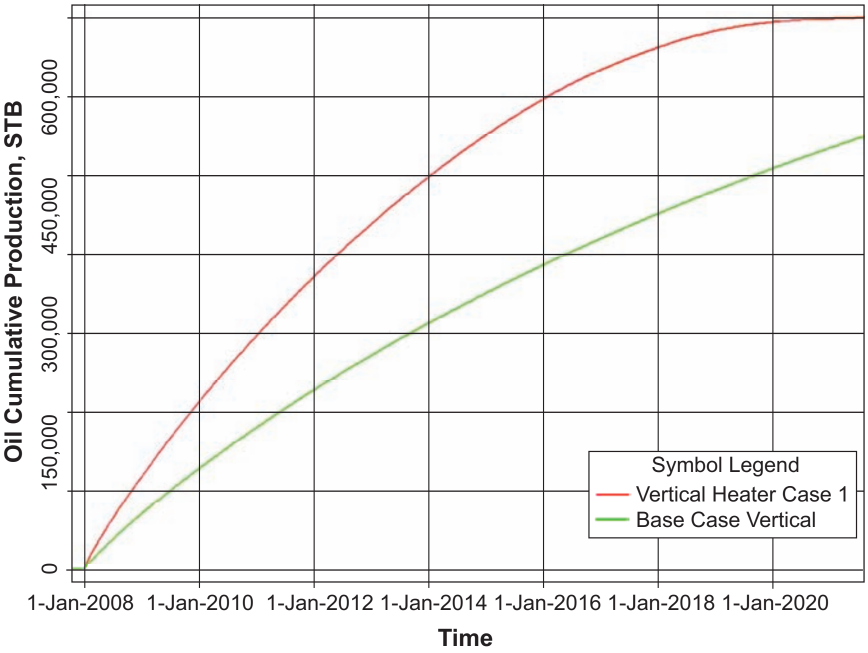


Fig. 1—Cumulative oil production for vertical wells.

Electrical Downhole Heaters. Electrical heating consists of providing electrical currents to generate heat and increase the temperature near the wellbore. There are two kinds of downhole heaters in use by the oil industry: inductive heaters, generating heat in accordance with Maxwell's law, and resistive heaters that generate heat in accordance with the Joule effect. In the latter case, the heat transfer is by conduction and it requires an extended time period to heat the reservoir.

In this study, the resistive heater is modeled with the aid of a numerical thermal simulator. This type of heating process stimulates oil recovery primarily by reducing the oil viscosity in the near-wellbore region and secondly by thermal expansion of reservoir fluids. The key parameters to be understood in this process are the heavy-oil-viscosity variation with temperature and the rate of heat provided by the heater associated with the generated temperature gradient in the volume around the well. Heat output from resistive heaters typically ranges from 14 to 730 W/ft (1,100 to 60,000 Btu/D/ft). A maximum-exposure temperature normally is imposed on the heaters.

Simulation Model

The models prepared for this study incorporate the petrophysical and fluid characteristics of the Ayacucho area in the Faja del Orinoco. The fluid characteristics of the heavy oil (approximately 9°API) are typical for heavy oils with some gas content. A compositional/thermal simulator was used to describe

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

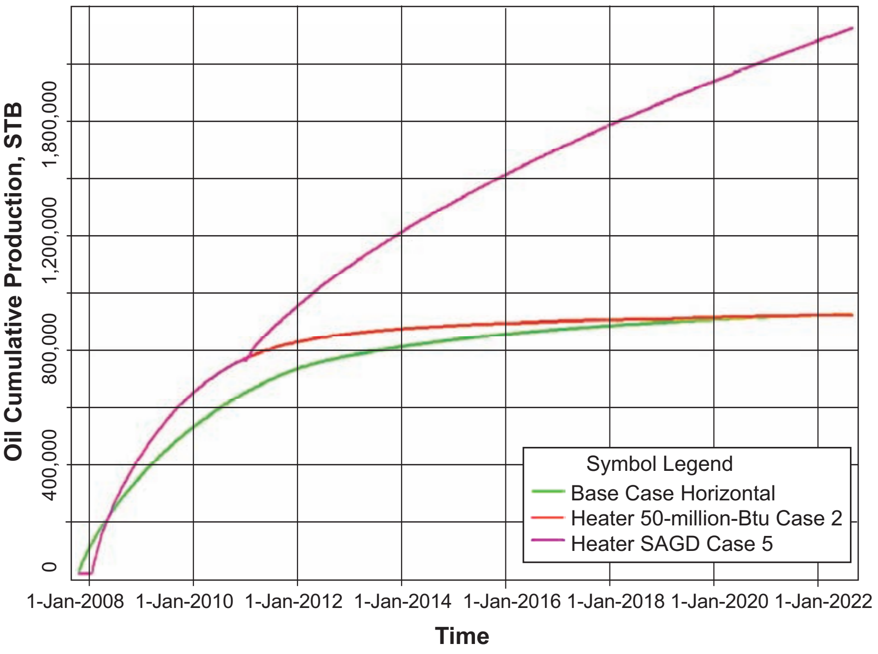


Fig. 2—Cumulative-oil-production comparison for SAGD after heating for 3 years.

the flow of heat and fluids within the reservoir.

Geological Properties. The geological model considers a 3D structure with an area of 89 acres and thickness of approximately 85 ft. A reservoir-simulation model with 17 layers having different porosities and permeabilities was defined to capture the reservoir heterogeneity found in that area. The mean properties are porosity of 31%, permeability of 7,000 md, and a net/gross ratio of 0.95. Rock heat capacity is approximately 35 Btu/ft^3/°F, and thermal conductivity is 84 Btu/ft/D/°F. Relative permeability curves were calculated using an initial oil saturation of 0.89.

Fluid Properties. The pressure/volume/temperature model has the characteristics of typical heavy oils in the Faja del Orinoco. The oil from this area has a 525-lbm/lbm mol apparent molecular weight. The initial oil viscosity is approximately 3,300 cp at the reservoir temperature of 137°F. Changing the fluid temperature from reservoir conditions to 300°F decreases the viscosity significantly (from 3,300 to 16 cp) while changing the fluid temperature from 300°F to 400°F decreases the viscosity only from 16 cp to 2 cp. These viscosity curves are used in the analyses of the operating limits imposed on the heater temperature for the different cases in this study.

Cases Studied

A total of eight cases were generated. The first two cases correspond to cold-production predictions for 15 years from a vertical well with 85 ft of reservoir thickness and from a 1,000-ft-long horizontal well. These two "base cases" served as comparison points for those cases where a heater was used. The other six cases consider horizontal wells with heaters of various capacities. In the eighth case, the downhole heater was used only during the first 3 years.

Simulation Results

Case 1. A downhole wellbore heater with a heating power equivalent to 4 million Btu/D was operated through an 85-ft interval in a vertical well. The heater was restricted to a 300°F maximum operational temperature. Initially, the well was shut in for 90 days to allow the wellbore heaters to increase the temperature around the well. After that period, the vertical well was opened to production for 15 years. The radius of the heated zone at this time extended to less than 20 ft.

Figs. 7 and 8 in the full-length paper show the results of oil-production rate vs. time and cumulative oil production vs. time, respectively, comparing the vertical base case against Case 1. Initial oil-production rate was double that obtained from the cold base case. This rate advantage was gradually reduced until Year 9 when the acceleration of oil production ceased and the crossover of the oil-rate curves is observed. At the end of the 15 years **(Fig. 1),** the cumulative oil recovery still favored use of the wellbore heater. However, after 20 years of production, the cumulative-oil-production curves from both cases showed an asymptotical converging behavior. From the comparison of these two cases and several other similar cases analyzed previously, it is inferred that standard downhole heaters in vertical wells, in general, do not increase the recovery factor but accelerate the oil production and, consequently, the pressure depletion in the reservoir. The net effect is that the cash flow of the project for the first several years also is accelerated. The cash-flow calculation needs to be balanced against the investment to purchase, install, and operate the downhole heater, including workover costs.

Case 2. A horizontal well with a 1,000-ft horizontal section and $6\frac{3}{4}$ in. inside diameter was used with a downhole heater. Heater power was approximately 50 million Btu/D (evenly distributed along the entire horizontal section) and with a restriction to operate at a 300°F maximum temperature. The well also was shut in for 90 days of preheating. After that, the well was opened to production for 15 years. The temperature distribution at the end of the preheating phase, indicated a heated zone extending less than 30 ft away from the horizontal-well axis.

Comparing the horizontal base case and Case 2, the use of downhole heaters accelerate the oil production for the horizontal wells. However, the period of enhancement is relatively brief. The oil-rate curves cross over in only $2\frac{1}{2}$ years. Additionally, the cumulative-oil-production curves for both cases become asymptotic in behavior after approximately 14 years of production.

In general, for horizontal wells, the period of accelerated production from the use of standard downhole heaters is shorter than that obtained from vertical wells.

Cases 3, 4a, and 4b. These cases, basically, are similar to Case 2 except that the temperature limit is increased to 350 and 375°F, respectively. In Case 4b, the heater power was doubled to 100 million Btu/D. The full-length paper discusses results for these cases.

Case 5. In this case, a downhole electrical heater with a power rating of 50 million Btu/D was used during the first 3 years of production, followed by the application of steam-assisted gravity drainage (SAGD) for 12 additional years. Vertical spacing of the SAGD pair was 60 ft, with the length of the horizontal section being 1,000 ft. This case was selected to study the economics of using an electrical heater before implementing a thermal-recovery process.

This case was devised to take full advantage of the accelerated production and reservoir-pressure decline caused by the use of a downhole heater during 3 years of operation, to have time to properly evaluate, design, procure, and build a steam-injection plant before putting into operation an SAGD project.

Accelerating production from the reservoir generates additional cash flow that is beneficial while the surface facilities for steam generation are being acquired. In this particular scenario, the reservoir pressure dropped from 1,200 psi to 700 psi in the first 3 years.

Fig. 2 shows the behavior of the SAGD project (preceded with a downhole heater) vs. time. The green curve represents the cumulative oil production from the horizontal-base-case cold production, and the purple curve corresponds to the production from the SAGD that followed the operation of the heater for the first 3 years. It is evident that once the SAGD is implemented, the slope of the curve changes dramatically, more than doubling the final cumulative production and the corresponding recovery factor.

Economic Results

All the cases analyzed were evaluated, using typical capital and operating expenditures for eastern Venezuela with a discount rate of 20%. As an aid to comparing the cases, three economic indicators were calculated: net present value (NPV), profit/investment ratio (P/I), and payout time.

The economics evaluations were run after taxes to take into account the main parameters of the Venezuelan fiscal regime, which include 30% royalties and 50% taxes, considering a limited production period of 15 years. The price of heavy oil was assumed to be constant at USD 60 /STB.

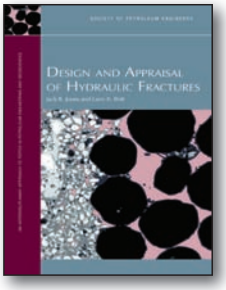
For the base-case vertical well, the NPV after 15 years of production was close to USD 3 million, showing a P/I of 6.38 and a payout period of 10 months. Use of a heater in vertical wells increases the oil produced by almost 130,000 STB and increases the NPV by almost USD 2 million, decreasing the payout time by 2 months. However, because investment is required for the heater, the P/I was reduced to 5.62. All of these indicators suggest an attractive economic feasibility to use heaters in vertical wells.

For the base-case horizontal well, the NPV after 15 years of production was USD 9.3 million, with a P/I of 4.60 and a payout period of 2 months. By use of a conventional downhole electrical heater in a horizontal well, the production was accelerated at the front end of the project and the NPV increased by approximately USD 0.48 million, with a P/I of 4.25. Again, because of the acceleration of production, the payout period for a horizontal well plus its heater was only 4 months, the shortest of any of the cases analyzed.

Use of a medium-temperature heater, capable of maintaining 350°F at the wellbore, increased the oil produced in 15 years by only 9,000 STB; however, because the production was accelerated at the front end of the project, the NPV increased by approximately USD 0.82 million with a P/I of 4.12.

Use of a higher-temperature heater, capable of maintaining 375°F at the wellbore, increased the oil recovered in 15 years by approximately 24,000 STB vs. the base case, and the NPV increased by approximately USD 0.82 million, with a P/I almost equal to the case of a conventional heater. Downhole heaters accelerate oil production over the oil production that would be obtained by cold production, but successive temperature increments do not show a strong production increment over that calculated by Case 2.

The case combining a wellbore heater followed by an SAGD process more than doubled the cumulative oil recovery of the base case and showed favorable economics despite the added investment and operating expenses. The NPV was almost USD 2 million, the P/I was 2.92, and the payout period was only 8 months. **JPT**



Integrated CO_2 Pilot in France: Potential Answer to CO_2 Mitigation in Bitumen Production

Development of extraheavy-oil (EHO) fields in Alberta requires much more processing and energy than for conventional oil. The amount of associated greenhouse-gas emissions could be large, and operators are seeking options to reduce them. Carbon capture and geological storage (CCGS) appears to be the most promising option in addition to power-efficiency increase and use of renewable or alternative energies. Oxycombustion could have adavantages over post-combustion for CO_2 capture in terms of energy efficiency for steam generation.

Introduction

Oil-sands-production and -processing schemes in Alberta require massive quantities of energy.

- Steam for use in steam-assisted gravity-drainage (SAGD) projects or for the separation of sand/bitumen extracted from mining
- Electricity for the water-treatment units, pumping units, separation and treatment units, and other uses
- Heat for treating and upgrading the produced bitumen (in particular the steam/methane reformer for hydrogen production)

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 117600, "The Integrated CO_2 Pilot in the SW of France (Oxycombustion and Geological Storage): A Potential Answer to CO_2 Mitigation in Bitumen Production," by ***Nicolas Aimard*** *and* ***Claude Prébendé,*** *Total, and* ***Denis Cieutat, Ivan Sanchez-Molinero,*** *and* ***Rémi Tsiava,*** *Air Liquide, prepared for the 2008 SPE International Thermal Operations and Heavy Oil Symposium, Calgary, 20–23 October. The paper has not been peer reviewed.*

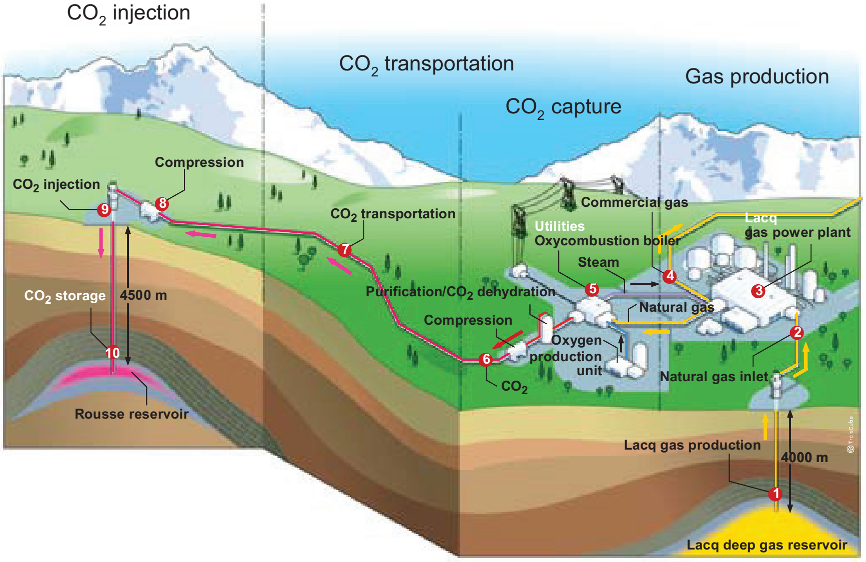


Fig. 1—Lacq-CO_2-pilot general scheme.

To produce these utilities, natural gas is burned, and thermal equipment (i.e., boilers, gas turbines, and furnaces) will generate large quantities of CO_2 in the exhaust. To compare this bitumen production with other oil extraction, the ratio of the quantity of CO_2 generated per barrel of produced bitumen (extraction and upgrading) is used. To produce synthetic crude oil, acceptable by conventional refineries, eight times more CO_2 would be emitted through production mining (or 12 times more through SAGD) than for the extraction of conventional oil.

The objective is to design facilities with the highest-possible energy efficiency. Beyond that, CO_2 capture/storage would reduce CO_2 emissions dramatically. The facilities must be "capture ready" (i.e., designed with the ability to integrate CO_2-capture equipment). Captured CO_2 then would be transported under pressure by pipeline to geological storage sites. In Alberta, potential storage sites are deep saline formations, depleted reservoirs, and enhanced-oil-recovery projects in mature oil fields.

In 2006, Total launched an integrated CCGS project in southwest France, near Lacq. A drum boiler was converted into an oxycombustion unit (i.e., oxygen is used for combustion rather than air to obtain a more-concentrated CO_2 stream, thus facilitating its capture). The pilot plant will produce approximately 40 tonnes/h of steam for use in other facilities and will emit up to 120 000 tonnes of CO_2 over a 2-year period. The CO_2 stream then will be treated, compressed, and conveyed by pipeline to the depleted gas field, Rousse, 30 km away, where it will be injected into a deep carbonate reservoir, as shown in **Fig. 1.**

Steam Generation and Oxycombustion for CO_2 Capture

The envisaged CO_2-capture technologies for the steam boilers are either post-combustion or oxycombustion.

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

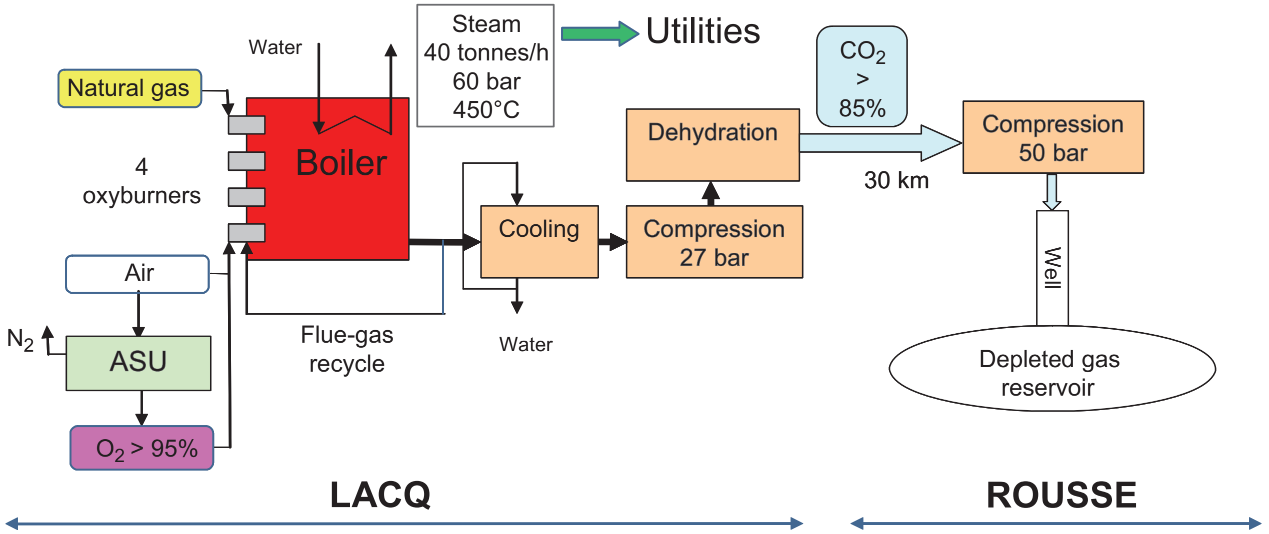


Fig. 2—Simplified process scheme of the CCGS pilot.

The most mature process in post-combustion capture (PCC) is chemical absorption of CO_2 with typical regenerable amines. Use of these solvents to absorb the CO_2 directly from the flue gas raises concerns about efficiency and operations. The issues are a low partial pressure of CO_2 (i.e., the result of atmospheric-pressure scrubbing) and the presence of oxygen and potential residual contaminants, such as SO_2 and NO_2 particles. Therefore, the amount of energy (in the form of steam) required to regenerate the amine in the stripping column will be very high.

By burning fuel in the presence of high-purity oxygen (>95%), the produced flue gas will contain high-quality CO_2 and water. After simple condensation of water, a stream of CO_2 (>85%) is obtained that is available for compression, transportation, and storage. This process requires the following.

- Addition of an air-separation unit (ASU), based on cryogenic distillation, for continuous production of oxygen for specific burners, which will require high electrical consumption
- Modification of the boiler to recycle part of the flue gas at the level of oxyburners to dilute the oxygen/gas flame and to maintain a temperature level and a heat-transfer profile similar to that of combustion by air; thereby eliminating heat-exchanger tube modification

Oxycombustion was selected for the Lacq pilot because of the possibility of retrofitting an existing boiler and because of the efficiency of the capture technique for large industrial steam boilers.

CO_2 Pilot at Lacq

As Fig. 1 shows, the CO_2 pilot is an integrated CO_2-capture, -transportation, -injection, and -storage scheme in the Lacq region in southwest France.

Capture Facilities. An existing boiler, built in 1957 within the Lacq gas-treatment facilities, will be converted into an oxycombustion boiler, with oxygen replacing air for the combustion of commercial gas. The 30-$MW_{thermal}$ boiler will produce 40 tonnes/h of high-pressure steam (at 60 bar and 450°C) that will be used as heating medium or for power generation within the complex, as shown in **Fig. 2.** The plant will be fully integrated into the existing facilities.

Transportation, Injection, and Storage. CO_2 will be transported through

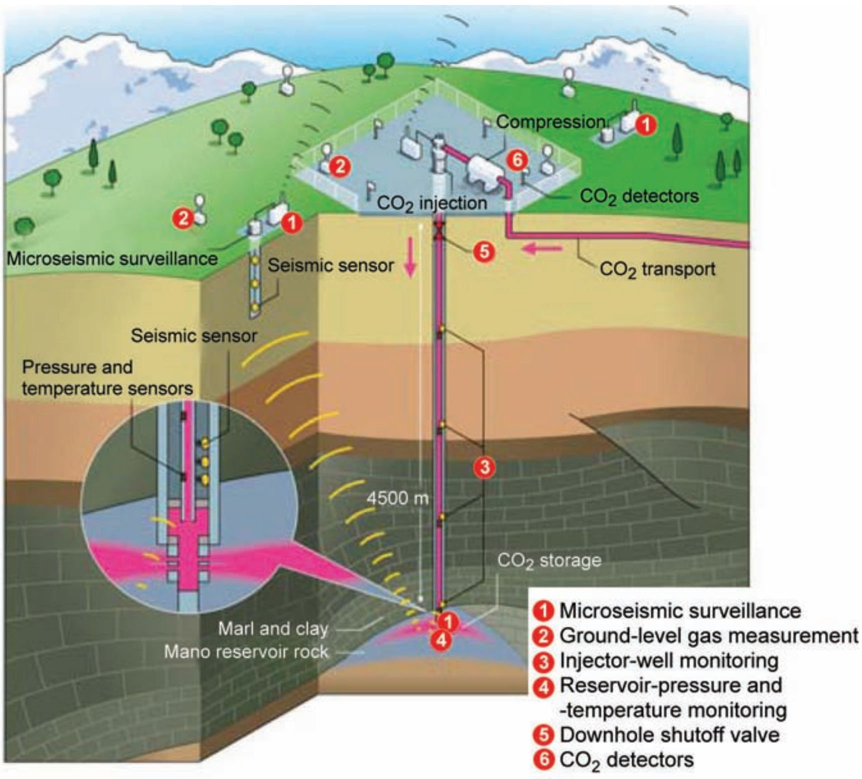


Fig. 3—Simplified monitoring system for CO_2 injection and storage.

an existing 30-km-long pipeline (12- and 8-in. diameters) at 27 barg in gas phase before being compressed at the wellhead for injection into the depleted Rousse gas reservoir at a maximum pressure of 70 barg. The CO_2 composition was investigated in subsurface studies to evaluate effects on the reservoir. For transportation and injection, there is no need to remove excess O_2, N_2, or argon. An existing well that had been used to produce wet sour gas since 1972 (contains up to 4.6% CO_2 and 0.8% H_2S) will be converted into the CO_2 injector.

The main reservoir of the Rousse field is a deep dolomitic reservoir. Initial pressure was 485 barg at a depth of 4500 m. The field is largely depleted, with an average downhole pressure of 30 barg. The average downhole temperature is 150°C.

The baseline surveys and monitoring program are a major part of the CO_2-injection project. Soil-gas mapping at different surface locations will be used. The well workover (in 2008) included the installation of specific monitoring equipment within the well, as seen in **Fig. 3.** An optical fiber along the tubing will enable measurement of temperature and pressure along the well at different depths. It will allow monitoring downhole conditions and the calibration of well-injectivity and well-pressure-drop models. A microseismic-monitoring system is planned to identify possible effects of CO_2 injection in the reservoir. This system will comprise six microseismic sensors around the injection site, installed at an average depth of 200 m.

Conclusion

The Lacq CO_2 pilot project is a challenging project that integrates industrial CO_2-capture facilities of an existing gas-treatment complex with CO_2 compression, transportation, injection, and storage in an onshore depleted gas reservoir. It requires strong engineering and subsurface studies and open dialogue with the French administrative and regulatory bodies, as well as a transparent dialogue with the public and with local, national, or international stakeholders. Operation of the pilot from 2009 to 2010 will be crucial for future scaling up of oxycombustion for large steam-generation units. JPT

How In-Situ Combustion Works in a Fractured System

Simulation of an in-situ-combustion (ISC) process was performed for a fractured system at core and matrix-block scales. The aim of this work was to predict the ISC ignition/propagation conditions, understand the mechanism of oil recovery, and provide guidelines for ISC scaleup for a fractured system. The study was of a fine-grid single-porosity multiphase multicomponent system and used a thermal-reservoir simulator.

Introduction

Heavy-oil recovery from fractured carbonate reservoirs (one-third of global heavy-oil resources) has been low because of the complexity of such reservoirs. The recovery mechanism and the reservoir and operational conditions at which combustion can propagate in fractured systems are not understood clearly. This study investigated ISC-propagation conditions and oil-recovery mechanisms at the fractured-core scale, and investigated the process at the block scale to address the 2D behavior of ISC at large scale. The objective was to determine the dominant processes in combustion propagation at the block scale and the characteristics of different fronts that exist.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 117645, "How In-Situ Combustion Process Works in a Fractured System: Two-Dimensional, Core- and Block-Scale Simulation," by ***H. Fadaei,*** *Institut Français du Pétrole;* ***M. Quintard*** *and* ***G. Debenest,*** *l'Institut de Mécanique des Fluides de Toulouse;* ***G. Renard,*** *SPE, Institut Français du Pétrole; and* ***A.M. Kamp,*** *SPE, Open and Experimental Center for Heavy Oil, prepared for the 2008 SPE International Thermal Operations and Heavy Oil Symposium, Calgary, 20–23 October. The paper has not been peer reviewed.*

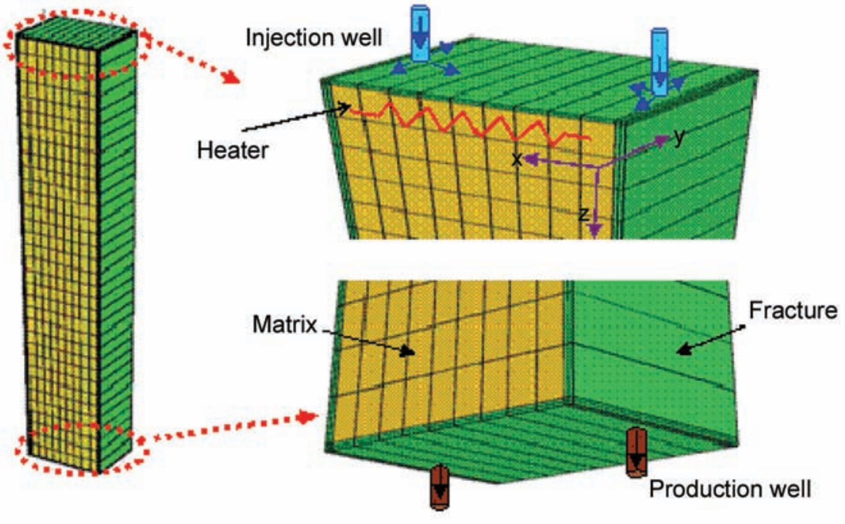


Fig. 1—Geometry of the core-simulation model.

Model

Four phases exist in crude-oil combustion in porous media: oil, gas, water, and solid. The oil and gas phases are multicomponent (i.e., hydrocarbon components), the water is a vapor, and the solid phase contains inert solid and coke. Reactions take place in the oil, in the gas, and on the surface of the solid phase (when coke is present). Coke is formed by pyrolysis and deposited on the solid surface. Reactions in oil and gas phases are homogeneous, but the coke reaction is heterogeneous.

Simulation

Oil Combustion in a Fractured System. Ignition/propagation conditions of the combustion front in a fractured system and the governing production mechanisms were studied. The simulation model is presented in **Fig. 1,** and the input data for the model are detailed in Table 1 of the full-length paper.

A vertical core was used to mimic a top-down process. The core had no temperature losses at its boundaries, and the top row of blocks was heated with a constant heating rate. Heat injection was maintained for 24 minutes, until ignition occurred. This time was considered to be approximately that used in a nonfractured core.

For the base case, most of the oil (approximately 70%) was produced during the first half of the burning process. The ignition temperature was 325°C, and the maximum temperature increased continuously thereafter. This increase may be the result of an increase in coke concentration because the oxygen flux into the matrix was less than the rate of coke generation. The result was combustion-zone expansion and peak-temperature increase. Also, not all the injected air passed through the matrix because of higher permeability in the fracture; therefore, the cooling efficiency of injected air is lower than in the nonfractured-reservoir-combustion case. The amount of oil burned during the combustion was calculated to be 13% of the total initial mass of the oil, while it was 6.4% for a nonfractured core. This difference may

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

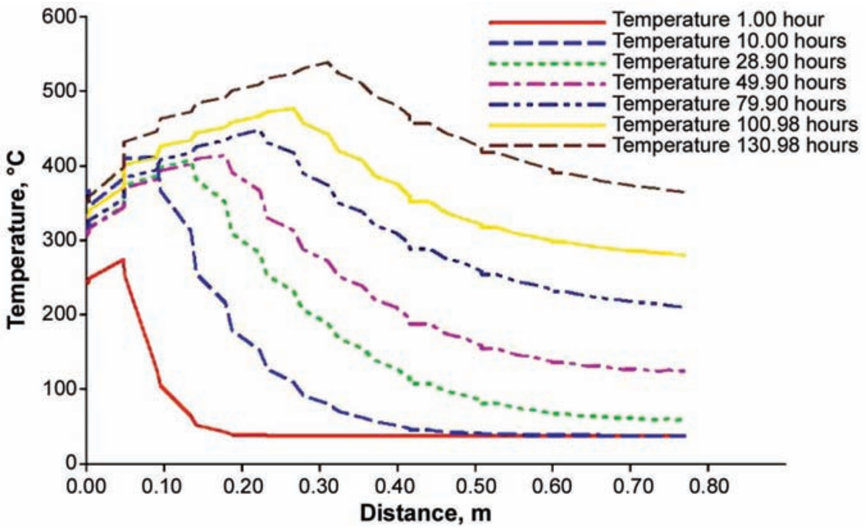


Fig. 2—Temperature along the block diagonal for three production times for the 1,270-md-permeability case.

explain the temperature increase in the fractured system.

Results. Simulation results show that ISC is feasible for fractured porous media at core scale. The peak temperature and the extent of the coke zone increased during the process, but these parameters were nearly constant during conventional combustion. The oxygen-diffusion coefficient was found to have a major influence on ignition/propagation of combustion, and matrix permeability was important in oil production. Considering characteristics of the porous matrix for the base-case, the simulation results showed that more fuel was consumed during ISC in a fractured system than in a nonfractured case. Gravity drainage in the presence of ISC and thermal effects were important for oil production. Any possible pressure-gradient generation during the ISC process seemed to have a minor effect on oil production.

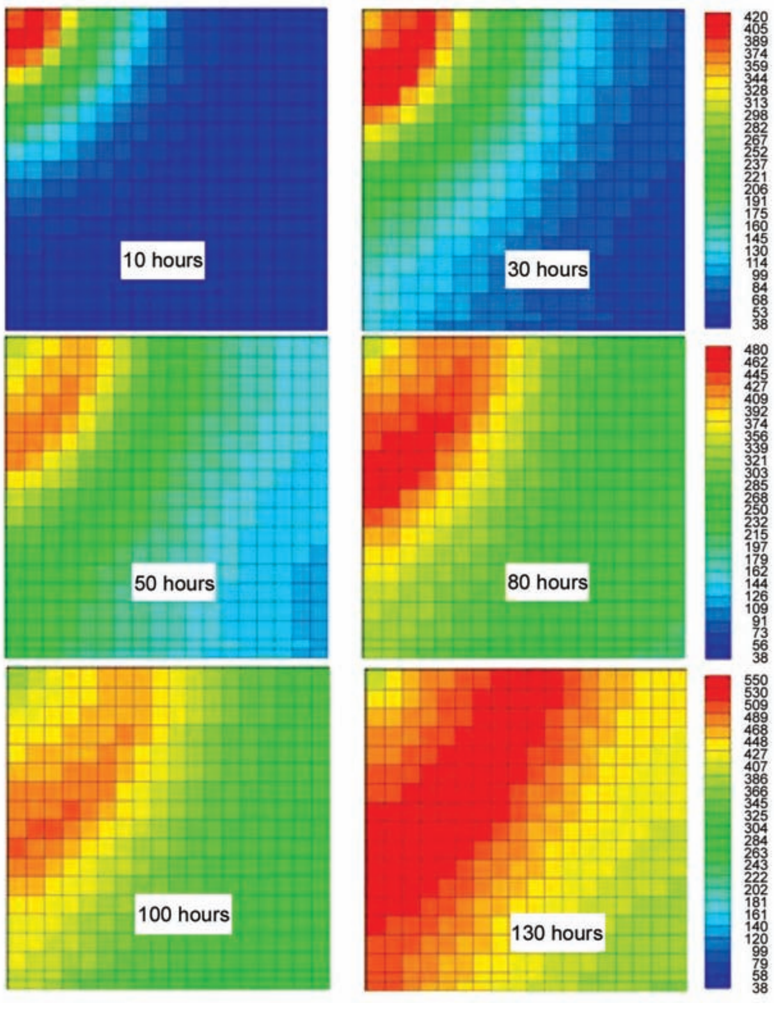


Fig. 3—Temperature profile (°C) at different production times for the 1,270-md-permeability case.

Process in Single Matrix Block. A 2D simulation of a single-matrix block surrounded by fractures was studied. Because of the symmetry, only half the block was simulated (in the *x*-direction). The fracture at the bottom of the block was wider, allowing better production control. Block dimensions in *x*-, *y*-, and *z*-directions were 1, 0.05, and 0.5 m, respectively. The matrix block was discretized by 16×16 grids in the *x*- and *z*-directions, with two grids used for fractures, which resulted in a 20×20 grid simulation. The same reservoir properties, initial condition, and reaction scheme were used as in the previous simulation except that here oil was more viscous at initial reservoir condition (4,000 cp). Air was injected from the top-left and oil was produced from the bottom-left of the block. Heat losses from the block surroundings were considered zero.

Observations. The temperature profile along the matrix diagonal is shown in **Fig. 2.** Generally, peak temperature and size of the high-temperature zone inside the block increased during production (see also **Fig. 3**). After initial ignition (1 hour), the peak temperature increased to approximately 410°C (at 10 hours) and then remained relatively constant until 50 hours, after which it began to increase again.

To explain the behavior of the system, the magnitude of different processes involved in heat transfer during the combustion was compared. In this regard, instead of treating the whole system, which is very complex, simpler cases were analyzed for which nondimensional numbers could be derived. The simplified version of this process was filtration combustion in which a combustion front passed through a porous matrix, initially

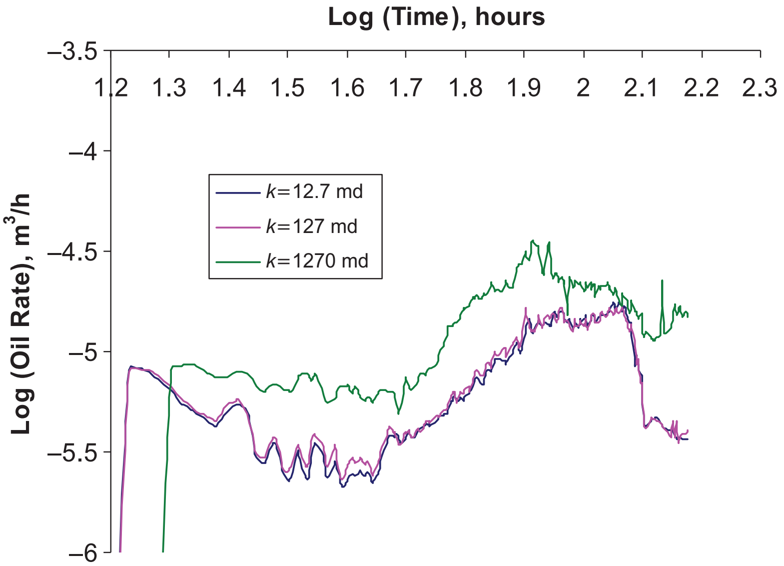


Fig. 4—Log-log graph of oil-production rate vs. time for different matrix permeabilities, k.

containing a solid fuel. This process is detailed in the full-length paper.

It was shown that heat transfer resulting from front movement is more important than gas-phase convective heat transfer, but both are less important than heat transfer by conduction. The combustion-front velocity decreases with time. Thus, at later times, heat transfer resulting from front movement becomes less important compared with gas-phase convective heat transfer and conduction.

The initial increase of the peak temperature was caused by development of the combustion process in which the combustion-front velocity was high and the rate of heat generation by combustion was higher than the rate of heat transfer. Subsequently, the relatively constant temperature suggested that the heat produced by the combustion process was transported mainly by conduction to the colder part of the block, and, finally, when the heat front reached the symmetric no-flow boundary on the right side of matrix block, peak temperature started to increase because conduction heat transfer is limited by this boundary.

Comparison With Gravity-Drainage Models

Developing a simplified model of the fractured-medium ISC process was attempted. Model attempts were based on an analogy with gravity drainage, in particular with steam-assisted gravity drainage (SAGD). Any pressure increase is easily relaxed by gas flowing from the matrix block into the fracture. The result is little pressure buildup for oil production.

Gravity drainage (e.g., SAGD) is characterized by an approximately constant oil-production rate. This approximation falls short when the SAGD steam chamber reaches an adjacent steam chamber or reservoir boundary. The equivalent of this situation in ISC is when the combustion front reaches the vertical-symmetry plane of the matrix block. In such a situation, a decline in oil production is expected.

Fig. 4 shows oil-production rate vs. time on a log-log graph for different matrix permeabilities. All three curves have a similar shape, characterized by four periods: a period with almost zero oil production; a second period during which, after a steep rise, the oil-production rate declines steadily; a period during which oil-production rate increases; and a decline period. For a 1,270-md-permeability case, the transition times between the four periods were approximately 20, 50, and 90 hours, respectively. From Fig. 3, it was estimated that at 20 hours, the front temperature was approximately 420°C. At 50 hours, it had decreased to approximately 410°C. This decrease, which probably was the result of preheating the block, increased the oil viscosity. A reasonable guess was that during the second period, oil production would have been approximately constant, if temperature had been constant. At 90 hours, the combustion-front temperature increased to approximately 480°C. It is likely that this increase was at least partly responsible for the increase in oil-production rate, by reducing the oil viscosity. The time of 90 hours may correspond approximately to when the front reached the vertical-symmetry plane of the block. Precise estimation of this moment is arduous because of the difficulty in defining the exact position of a front. Gravity-drainage theory predicts a steady decline of oil-production rate after this time, which was observed in Fig. 4.

The results also showed clear differences from processes such as SAGD. During high-temperature combustion (above 400°C), the mobile-oil region seems wider than that assumed in SAGD. When oil-production rate at different times was plotted as a function of permeability on a log-log scale, gravity-drainage theory predicted straight lines with a slope of 0.5. However, such straight lines could be expected only by comparing production rates for different permeabilities at equal temperature. In SAGD experiments, in which temperature is determined by pressure alone (because steam is saturated), such conditions are verified easily. In this study, however, at any time, temperatures are not equal for different permeabilities. Therefore, it is useless to look for straight lines in such plots.

Conclusion

ISC simulation at the block scale showed that the process is diffusion dominated for both heat and mass (i.e., oxygen) transfer. Heat transfer is small because of the velocity of the moving combustion front compared to the heat transfer by conduction and convection. Therefore, combustion-front temperature increases during the process. In this multifront process, different zones can be distinguished for oil saturation and temperature, and their sizes vary over time. The relative size of the heat and saturation zones and the change of their size during the burning process suggest that any scaling-up method should take these phenomena into account. However, for a multiblock situation, combining the matrix block as a single node in the simulation model may introduce large errors because the process inside the matrix is highly heterogeneous. More-detailed mathematical manipulation is needed to address this issue on the basis of characteristic length scale of the processes occurring in the matrix and the averaged values of various parameters. **JPT**