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LABORATORY STEAM INJECTION APPLICATIONS FOR OIL SHALE FIELDS OF TURKEY

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In this study, applicability of oil production from oil shales by steam recovery in a three-dimensional (3-D) reservoir model was investigated. Four different oil shale samples from several fields (Seyitömer, Beypazarı, Himmetoğlu and Hatıldağ) were used. 3-D steam injection experiments showed that steam injection was insufficient to drive oil production for the oil shale samples studied, and it was concluded that the steam injection process is not feasible in these oil shale fields.

Introduction

Oil shale is an inorganic, fine-grained, non-porous sedimentary rock that contains some organic material in the form of kerogen. It can form both in marine and non-marine basins. Although oil shale is a fine-grained material and rate of deposition of inorganic material has been slow, growth of organic matter (kerogen) has been rapid. A great portion of the potentially recoverable shale oil resource is in low-grade deposits that may never be recovered by primary mining techniques. *In-situ* processing presents the opportunity of recovering shale oil from these low-grade deposits without the environmental influences normally related with mining and aboveground processing. Not all of the reservoirs are productive by primary recovery techniques. Sometimes, secondary recovery techniques should be applied to increase oil recovery from these potentially economical low-gravity oil reservoirs. One of the widely used secondary recovery system is known as thermal recovery methods, which include hot fluid injection and *in-situ* combustion. Hot fluid injection is the way of improving recovery by convection heating of the reservoir behind a flood front.

Baker [1] carried out experimental studies to determine the effects of injection pressure and rate of formation heating by steam flooding. Heat

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losses, vertical sweep efficiency and steam zone volume were determined for steam displacing water at different rates and pressures using a radial flow model consisting of reservoir, overburden and substratum. Farouq Ali and Abad [2] carried out experiments to observe recovery from Athabasca oil sands, using solvents in conjunction with steam. They found that the type of solvent, the volume used and solvent placement determined bitumen recovery. Bitumen recovery was higher when using naphtha; however, breakthrough occurred rapidly in this case. Also, naphtha caused asphaltene precipitation in several instances. Redford [3] used solvents and gases with steam in the recovery of bitumen from oil sands of Athabasca. By using CO_2 or ethane with steam, bitumen recovery could be improved from oil sands deposits in a cyclic process. He claimed that further improvement could be achieved if both naphtha and CO_2 or ethane were used with steam. Also it has been demonstrated that improving recovery by naphtha is mainly by reducing bitumen viscosity and thus improving recovery in the water-swept portions of the reservoir and making more efficient use of the drive energy provided by the CO_2 or ethane. Pradt [4] found a technique to measure steam quality and heat loss in distribution and down hole piping. He claimed that it is possible to measure steam quality and heat losses in EOR steam injection systems by injecting an inert and non-condensable gas and taking suitable temperature and pressure measurements. Shu and Hartman [5] described a simulation study on the effect of visbreaking on heavy oil recovery during steam injection processes. Various steam injection strategies were tested. In some cases, physical heating, not thermal visbreaking, was the dominant recovery mechanism. In other cases, visbreaking had a large effect on recovery. In the cases where the visbreaking oil zone was perpendicular to the flow, it formed a mobility transition zone that improved sweep, thus enhancing oil recovery. Narayan and Walsh [6] investigated hydrocarbon recovery from a porous medium by continuous steam injection. They indicated the effect of varying heat losses on oil recovery by steam flood. Moreover, the experimental data obtained showed that sizeable quantities of hydrocarbons could be recovered by steam injection into highly water-flooded reservoirs. Yamazaki *et al.* [7] made a new attempt to enhance bitumen recovery from oil sand by the injection of high-pressure steam and chemicals including solvents and surfactants. When solvent was injected with steam, an increase in bitumen recovery was observed. The increase was directly proportional to the rate of solvent injection. Moreover, they stated that steam-alkaline injection resulted in a better recovery of bitumen than pure steam injection. It also lowered the extraction temperature of bitumen so the bitumen could be recovered at lower temperatures with the help of alkaline injection. Kimber and Farouq Ali [8] discussed scaling techniques that allow field porous media and pressure conditions to be used. The ability of scaling approaches to predict such parameters as oil production rate, temperature distribution, and pressure conditions were considered. The new approaches provided scaling options for steam processes that use additives that use pressure cycles and require use of the same porous medium as found in the field. Mendez *et al.* [9] tested different types of additives in order to improve the efficiency and to extend the application of cyclic steam injection in the field. Two different types of additives were used. Field tests of solvent with cyclic steam injection showed a significant increase in oil production. Hong [10] studied the effects of steam quality and injection rate on steam flood performance. It was shown that, for heavy oil reservoirs, steam flood performance improves with increases in steam quality and injection rate. Since optimum steam conditions depend on reservoir type and operating mode, it was recommended that optimum steam conditions for a specific reservoir should be determined through economic comparison of predicted oil recoveries for ranges of steam conditions. Kok *et al.* [11–18] studied the factors influencing kinetic data, such as sample order geometry, heating rate and atmosphere, of oil shales under non-isothermal conditions. It was observed that the products obtained through pyrolysis and combustion depend on oil shale composition and conditional variables, such as temperature, time, rate of heating, pressure, and gaseous environment.

Experimental

In this research, oil shale samples from Seyitömer, Beypazarı, Himmetoğlu and Hatıldağ fields were used because of their high grades, reserves and exploitability. Proximate and ultimate analysis [19] of samples performed is given in Table 1. The oil shale samples used in this research has a particle size <60 mesh and prepared according to ASTM standards.

Experimental equipments basically are manufactured from three main parts as; steam injection system, liquid production system and data measuring-control system. The steam injection system was designed so that it could inject the steam required for the experiments into the 3-D models which were provided to carry out the steam injection runs. The model developed for the experiment represents the ¼ of the 5-spot pattern. Dimensions of the model which was like a closed box, were 30 cm × 30 cm × 7.5 cm. To measure temperature distribution inside the model that is produced from steel sheet of iron, 25 thermocouples were located at the top. To prevent possible heat losses from the equipment, an isolation box was constructed. To inject the steam (50 psig (344 kPa), 180 °C) produced by steam generator, a connection line composed of 8 mm diameter steel bore with a control valve and a pressure

Table 1. **Proximate and ultimate analysis of studied oil shales**

Oil shale	Calorific value, cal/g	H_2O, %	Ash, %	C, %	H, %	O+N, %	S, %
Seyitömer	1006	2.8	70.9	8.58	1.4	4.39	0.19
Beypazarı	850	2.4	65.2	8.4	1.6	4.55	0.21
Himmetoğlu	1086	12.9	60.5	13.6	1.5	10.48	0.99
Hatıldağ	744	1.6	66.2	5.63	1.3	3.89	1.25

gauge was used. To inject the steam into the reservoir in a super-heated mode, injection line was wrapped with insulator. Steam injection was measured continuously before entering the reservoir. In the liquid production system, water, oil and gas were collected and measured after passing through the pressure separator. Condensable gases, steam and light hydrocarbons were condensed and their amounts were measured. Temperature distribution of each run was monitored and recorded automatically with data logger. Moreover, injection and production values were measured by pressure gauges. A temperature control system was used to control the temperature of the model and heating of the steam injection line. The schematic diagram of the steam injection model is shown in Fig. 1.

In steam injection experiments, the 3-D model was first filled with oil shale samples (14–35 mesh). The top cover and gasket were closed so that no pressure leakage was assured. After the thermocouples (25 units) were screwed on the top of the model and top and fitting bottom heaters, the model was located into the isolation chamber. Inlet and outlet connections of the model, which maintains the continuous steam injection, were connected as shown in the diagram. Afterwards, the model was heated up to the model temperature, which is 50–60 °C. As soon as the reservoir temperature was stabilized, steam was injected according to the experimental conditions. Injection and production pressures, temperature distribution inside the model, produced amounts of water and oil were recorded continuously. To verify the consistency and repeatability, the experiments were performed twice. The experimental conditions are given in Table 2.

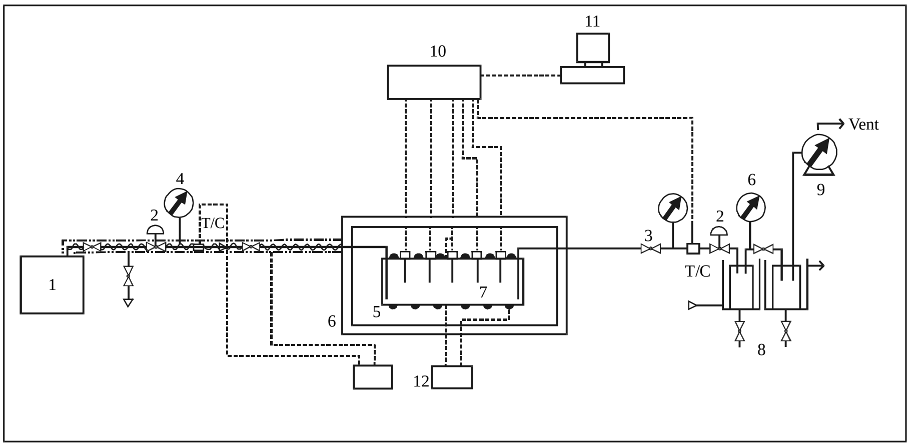

Fig. 1. Schematic diagram of 3-D steam injection model. 1 – steam generator, 2 – flow control valve, 3 – spherical valve, 4 – pressure gauge, 5 – laboratory model, 6 – isolation box, 7 – central thermocouples, 8 – separators, 9 – wet test meter, 10 – data logger, 11 – computer, 12 – temperature control equipment.

Table 2. Experimental conditions of steam injection experiments

Run No. Sample	STM – 1 Seyitömer	STM – 2 Beypazarı	STM – 3 Himmetoğlu	STM – 4 Hatıldağ
Input sample, g	6000	9180	4980	11235
Output sample, g	7825	10100	6100	11550
Injection pressure, psi	48	50	55	49
Output pressure, psi	45	48	53	47
Steam temp., °C	193	185	184	200
Water produced, cm^3	1785	3750	3434	1500
Steam inj. rate, cm^3/min	8.50	9.90	8.20	4.20

Results and discussion

Steam injection functions through several mechanisms to improve oil recovery efficiency [20]. The basic factors which are significant in oil recovery are: the heat released to the formation by the high-pressure injected steam reduces viscosity of the heavy crude oil; the steam is injected into the reservoir at the maximum possible pressure, in order to provide the maximum temperature at the bottom of the hole, and the condensate which is formed as the injected steam releases its latent heat of vaporization to the strata acts as a hot water flood displacing crude oil in the direction of the production well bore. The heat supplied by the high-pressure injected steam vaporizes light ends of the heavy crude, and the vaporized light ends have the effect of building up a pressure in the formation as a result of the volume increase, which results from the formation of the vapor.

In this study, four steam injection experiments were performed by injecting superheated steam into 3-D reservoir model in laboratory. Four different oil shale samples (Seyitömer, Beypazarı, Himmetoğlu, and Hatıldağ) were used in four different runs. In steam injection experiments, 3-D temperature distributions for all oil shale samples were continuously monitored. Temperature distribution of oil shale samples at different time intervals was monitored, and 3-D temperature distributions were constructed at 30, 60, 90, 120, 180 and 270 minutes (Figures 2–7). The surface temperature of the steam was considered to be around 140–150 °C in different time intervals.

In steam injection experiments, the injection pressure was varied between 48–55 psi, whereas the steam injection rate was between 4.20 to 9.90 cc/min. in the steam temperature range of 184–200 °C. It was observed that this temperature range was not enough for the thermal cracking process, which is the main source of oil production from oil shale. As a result of the experiments, slight indications of hydrocarbons were observed in Himmetoğlu and Hatıldağ oil shales, whereas no oil production is observed in Seyitömer and Beypazarı oil shales. However, these indications were not mature enough to call them oils. This is explained by insufficient temperature maintained by steam.

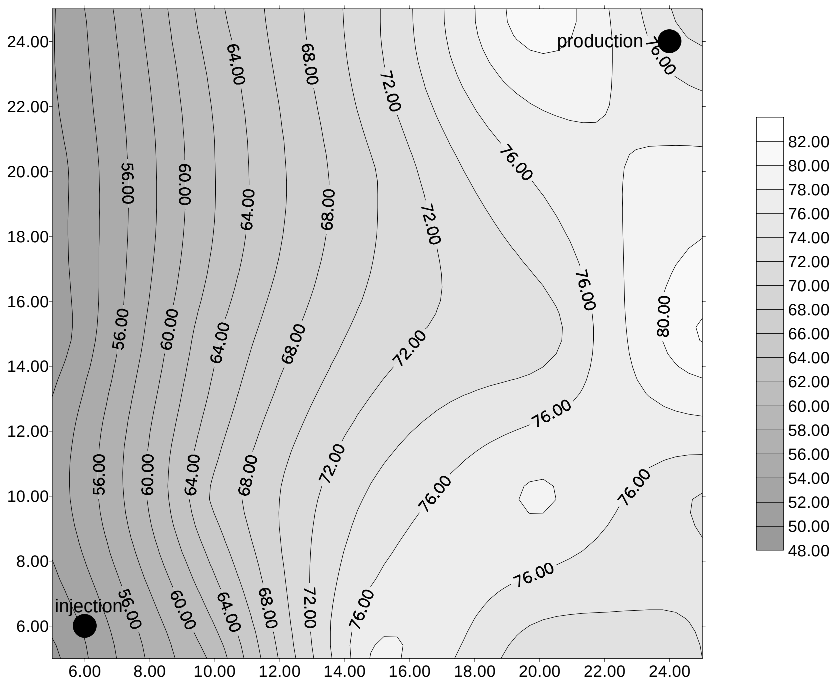

Fig. 2. Temperature distribution of Himmetoğlu oil shale run (at 30 minutes).

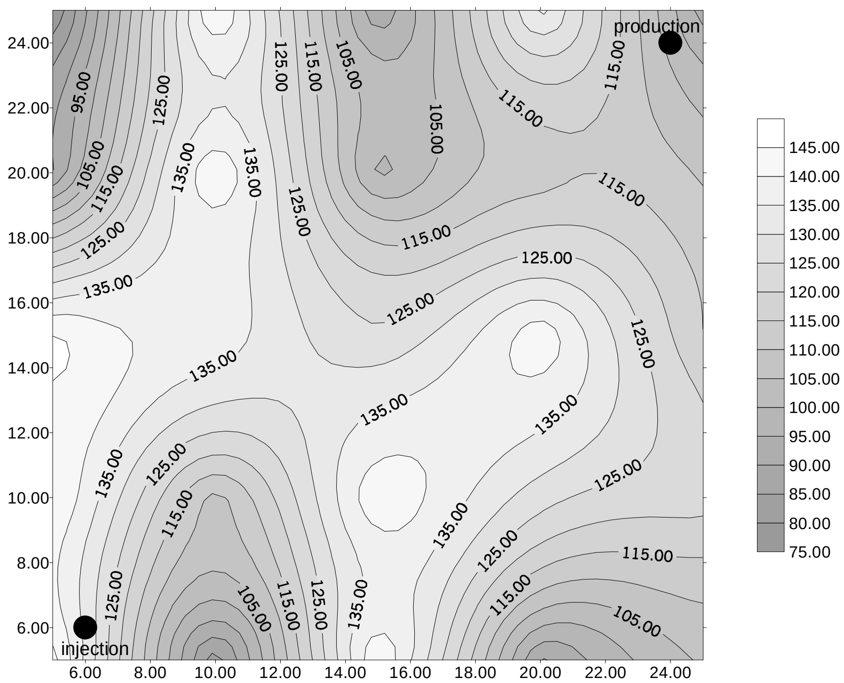

Fig. 3. Temperature distribution of Himmetoğlu oil shale run (at 60 minutes).

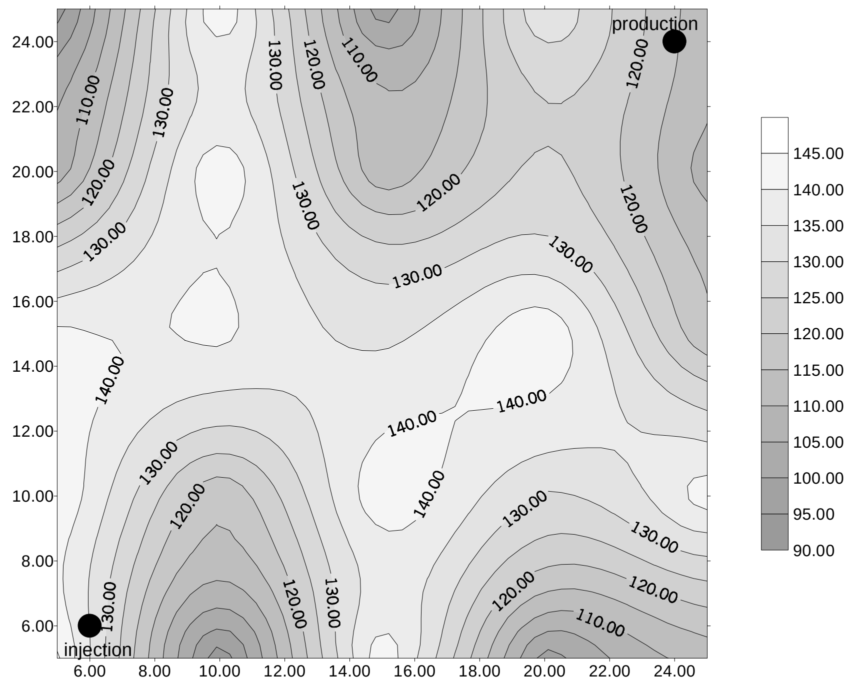

Fig. 4. Temperature distribution of Himmetoğlu oil shale run (at 90 minutes).

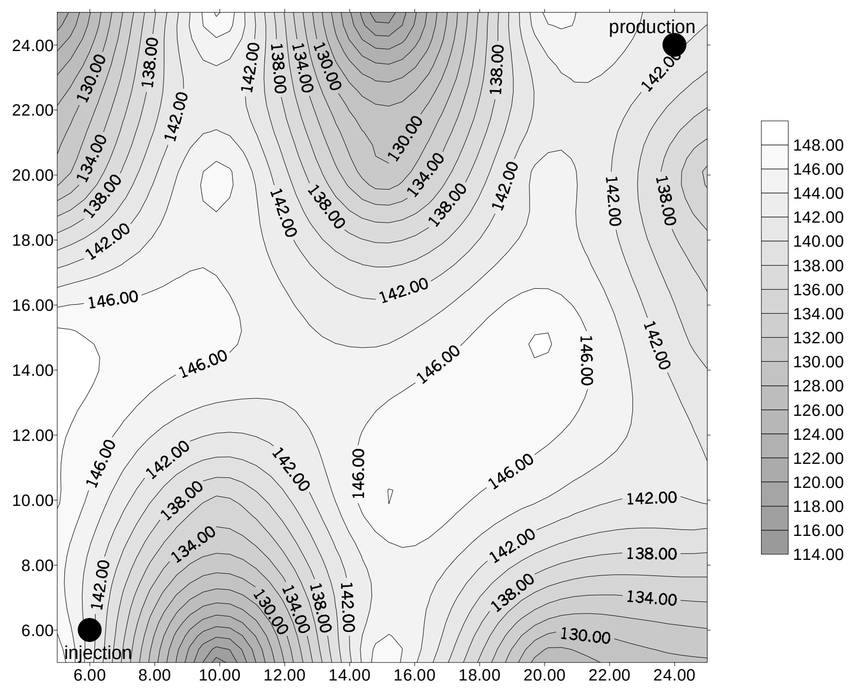

Fig. 5. Temperature distribution of Himmetoğlu oil shale run (at 120 minutes).

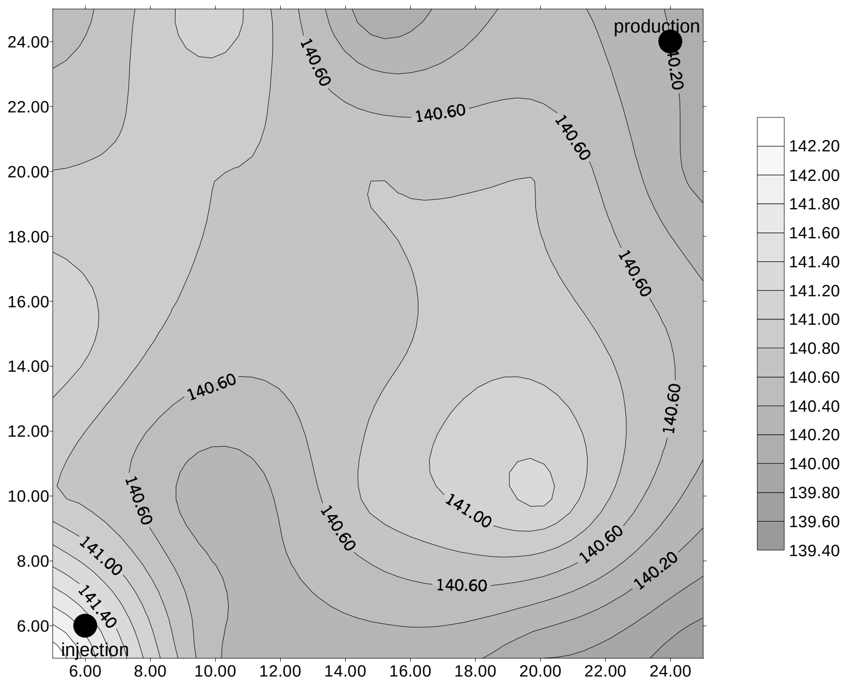

Fig. 6. Temperature distribution of Himmetoğlu oil shale run (at 180 minutes).

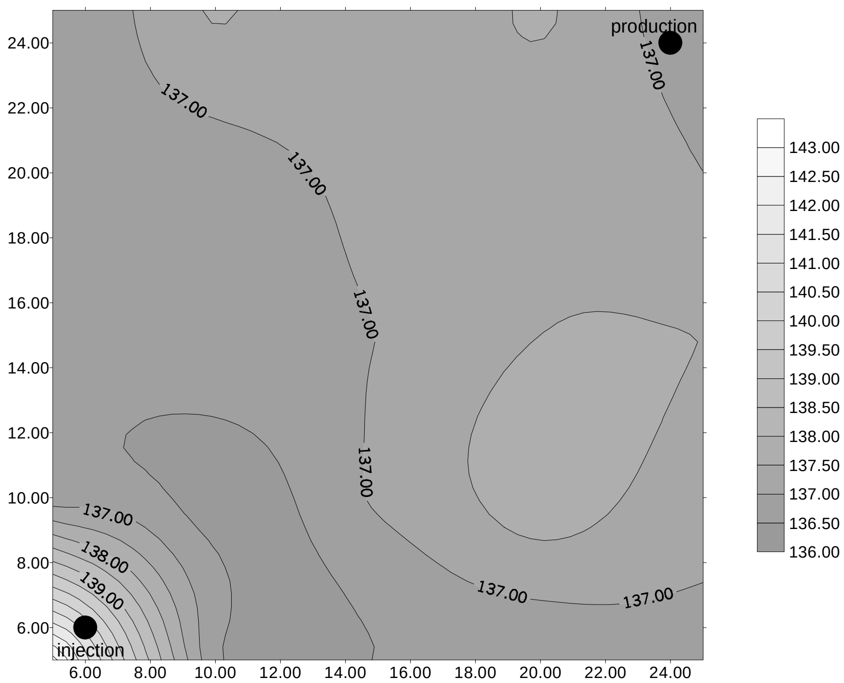

Fig. 7. Temperature distribution of Himmetoğlu oil shale run (at 270 minutes).

Conclusions

In this research, an experimental study on the applicability of oil production from oil shales by steam recovery in a three-dimensional (3-D) reservoir model was investigated. After conducting the experiments and analyzing relevant data, it was concluded that no oil production was observable by steam injection method.

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