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TEZĂ DE DOCTORAT
PH. D. THESIS

LABORATORY ANALYSIS OF OILFIELD PRODUCED WATER EXTRACTION FROM EMULSIONS,CHEMICAL PETROLEUM ENGINEERING ENHANCED OIL RECOVERY

ANALIZA FIZICO-CHIMICĂ A APELOR DE ZĂCĂMÂNT EXTRASE DIN EMULSII PENTRU UTILIZAREA LOR LA RECUPERAREA PETROLULUI

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Abstract

This thesis describes the interaction phenomena between the reservoir water and the oil reservoir, viewed as a complex energy system. In the first chapter, an introduction to the calculation of geological oil reserves and some considerations regarding the future of this oil and gas exploitation were presented. Techniques for increasing the final oil recovery factor from deposits were also described, emphasizing the injection of treated (carbonated) water. At the same time, we presented general data on managing water treated with carbon dioxide.

Worldwide energy demand is gradually increasing due to anthropogenic activities.

As per the Key World Energy Statistics (2022), crude oil production in developing countries will increase from 40 mb/day (2023) to 50 mb/day in 2050.

In the most ace context, the increase in investments in the oil industry is foreseen to be 0.9 trillion USD.

Natural and fossil fuel sources gradually increased to 31% of oil, 29% of coal, 21% of natural gases, 10% of waste and biofuel, 54% nuclear, 2% hydro, and other important energy sources like solar, wind, geothermal, and heat until 2013.

Petroleum energy demand is increasing gradually due to transportation development and anthropogenic activities; therefore, gas and Oil fields are more important for the country's economic and political effectiveness .

The water flooding method is widely used for secondary oil recoveries after the primary oil recoveries from reservoirs.

Water flooding is where water is injected into the oil reservoirs through water pumping.

After that, the water is forced out of the Oil into the other reservoir sections known as producers.

Therefore, the produced fluids are progressively increased due to water injection.

In the research result, Craig observed that the admiration of water injection is principally outstanding due to its displacement efficiency, mobility, availability, and ease of injection [3].

In addition to the water flooding processes, it becomes inefficient to endure these procedures since the cost of eliminating and disposing water surpasses the net income produced by oil production.

Oil recoveries are the primary concern to engineers, as they are used to recover secondary Oil from different oil reserves that are flooded by water.

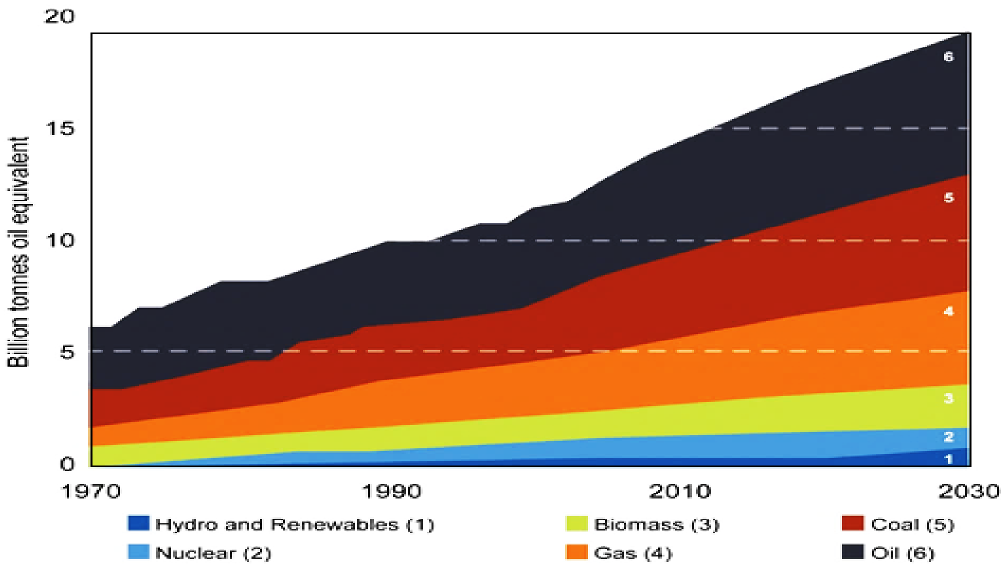

Fig.1. World Energy Consumption by fuel type (IEA: World Energy Outlook, 2006)

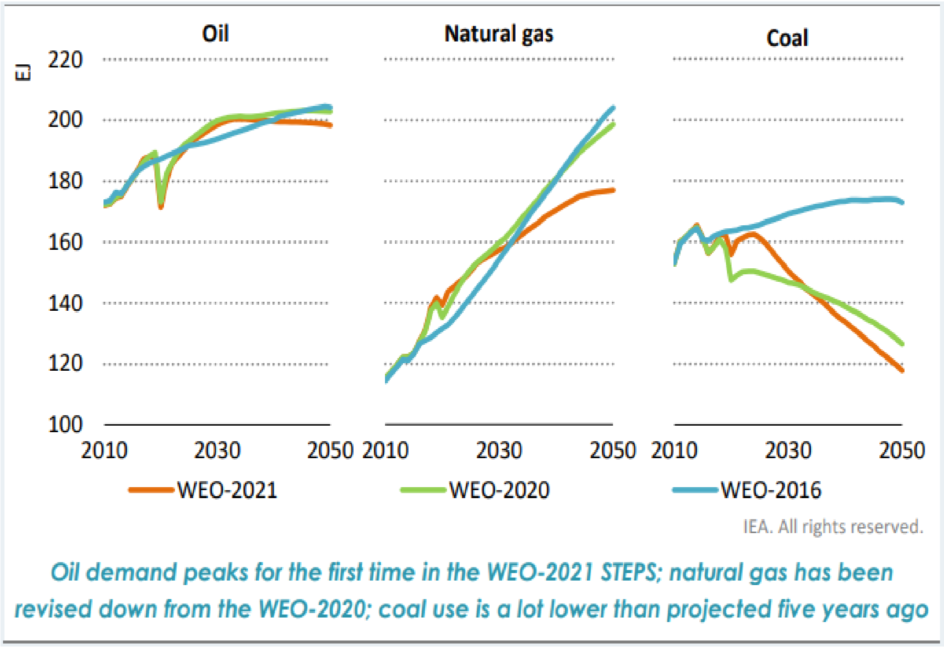

Fig.1. Oil, natural gas and coal demand in the Stated Policies Scenario in World Energy Outlook 2021, 2020 and 2016. (Source: World Energy outlook, 2021, Available website: https://iea.blob.core.windows.net/assets/4ed140c1-c3f3-4fd9-acae-789a4e14a23c/WorldEnergyOutlook2021.pdf)

The main concern about the process is the high rate of oil recoveries using low water production. The water drive capacity maintains the oil withdrawal rate in addition to the level of the reservoir pressure.

The carbonate water injection is the most essential injection process, and less CO_2 is used to continue the CO_2 injection. Therefore, CO_2 access increased attractively in offshore reservoirs due to the limitation. The CO_2 storage by the carbonate water injection or the CWI removes the buoyancy-driven leakage risk different from the injection of the CO_2 gas stage .

CW or carbonated water is thicker than the water at altered circumstances. For the illustration, at 305 psi (2.1 MPa) and 69.8 °F (21°C), the ρ_{CW} = 1003.4 kg/ m^3 (62.7 lbm/ft^3) vs. ρ_{water} = 998.0 kg/ m^3 (62.30 lbm/ft^3) are located. On the surroundings of reservoir 4,500 psi (31 MPa) and (185 °F (85°C), where thickness vicissitudes to ρ_W = 968.6 kg/ m^3 (60.47 lbm/ft^3) and $\rho s_{eawater}$ = 994.3 kg/ m^3 (62.1 lbm/ft^3) vs. ρC_W = 1.0152 kg/m^3 (63.34 lbm/ft^3). The CWI technique is also more advantageous in dense oil/gas reservoirs. Due to the unchanging anterior association, it can relocate most reservoirs where oil/gas storage is located. The higher CO_2 solubility in the water permits high CO_2-augmented water at lower pressures and temperatures. Due to the CO_2 higher solubility in the oil/gas than in water together by the micro-model circumstances where core flooding circumstances (0.076 g CO_2/g oil vs. 0.046 g CO_2/g seawater) and (0.096 mol CO_2/mol oil vs. 0.0124 mol CO_2 /mol deionized water), melted CO_2 in the water can transmission since the water to oil/gas and progress in the oil recovery process. Moreover, the carbonate water injection or the CWI must be used for water-flooded reservoirs like tertiary recovery. Offshore Eastern Canada consumes high permeability and appropriate light oil reservoirs. The EOR procedures in the offshore reservoirs are more stimulating. Notwithstanding the current price recession, the ultimatum for oil continues and is predicted to intensify in the subsequent centuries. Significantly, oil drilling and examination endure rapidly as present substitute sources of energy are incapable of completely substituting fossil fuels. Newfoundland's oil/gas manufacturing industrial areas are grounded on offshore grounds. The Boring offshore bores are more exclusive than the onshore bores (https://www.iea.org/). Consequently, it is more significant that the oil/gas recovery is enhanced oil recovery (EOR), and exploited approaches must be helped. The research further exhibited the predicting of the future production rate of 50 oil wells using decline curve analysis (DCA) and reservoir simulation. In addition, 50 oil wells in Zubair field were used as the case study. Based on past production history, standard curves were generated using exponential, exponential, hyperbolic and harmonic decline model equations from which comparative study of production decline rate trend analysis was carried out. The model equations were used to project future oil productions for a period of 30 years. Finally, the history match was performed to evaluate the production behavior of Zubair field.

In Chapter 2, we reviewed the research to increase the recovery factor, emphasizing the impact of water injection into the deposit. At the same time, we described the numerical models applicable to the management of the injection of this waste resulting from crude oil extraction. To understand the behavior of carbonated water, I described the behavior of CO2 and reservoir water from the point of view of the development phases (liquid, gas, solid). The third chapter is dedicated to research carried out in the laboratory to determine the behavior of the analyzed deposits. Thus, we statistically analyzed the physical properties of the cores and the liquids contained in them, harvested due to the exploitation of the Mishrif reservoir deposit. I mention that the cores were collected from 2012 to 2015, years that consisted of multiple field engineering activities. The data was subsequently processed between 2016 and 2022, a quite large time period due to the multitude of correlations established between various parameters of the field analyzed.

Researchers concluded that the vital oil trapping mechanism was Wettability trapping, which is outstanding in the oil-wet environment of the micro-model.

The bypassing pores and snap-off were likewise experimental.

The recovery rate of oil at breakthrough was described as 70.4% of the original oil-in-place (OOIP), 8.1% more than the water flooding salvage influence at breakthrough.

The ultimate factor of the recovery of 91.1% in secondary CWI was associated with 81.7% in the water flooding.

The carbonated water transformed the Wettability of the oil-wet or mixed-wet micro-model to water-wet.

The CWI was efficaciously used to recuperate oil for a lengthier historical part.

A few researchers also explored the oil recovery and carbon storage characteristics of the CWI in a sequence of the core flooding experimentations by oil with 13.7 MPa (2,000 psi) and 28 °API at 40°C (104 °F) [152].

The carbonated rock illustration showed a middling permeability and porosity of 11.6 mD and 24%, respectively.

The research outcomes were presented as 31.5% and 19.7% recovery of oil at 1 PV, and 40.5% and 56.7% oil recovery subsequently 7 PV injection throughout the secondary CWI and the tertiary CWI associated with the conforming water flooding.

However, the storage of the CO_2 measurements for together secondary and tertiary CWI arrangements were virtually identical.The secondary CWI resulted in a 16.2% supplementary oil recovery associated with the tertiary CWI water flooding.

Some researchers have accompanied a sequence of the multiple-communication examinations in the micro-model (this micromodel was used by [45] and the slim-tube (the permeability of 6 D and the porosity of 30%) at 38°C (100 °F) and 17.2 MPa (2,500 psia) by the seawater (salinity of 54,540 ppm) and synthetic live oil (20.9 °API) to comprehend the communication among carbonated water and oil.

The CO_2 solubility in seawater was intended to be 0.014 mol CO2/mol water. The oil was transported into communication through carbonated water or CW in the PVT cell.

The compositional investigation of every communication historical phase was presented that the novel gas stage was molded. In the initial phase, the novel stage was collected of the CO_2 and CH_4. owever, as additional communication between CW and oil remained complete, the novel stage was wealthier in the CO_2.

The researchers also achieved the slim-tube experimentation to impersonate the CW-live oil stage dislodgment and performance in the porous media.

The water innovation in the CWI happened at 0.31 PV through a recovery factor of 32.8%, associated with a revolution in the water flooding at 0.29 PV through a recovery factor of 26.2%.

The recovery factor at 1 PV was described to be 42% and 54% for the secondary CWI and water flooding, respectively.

The results of the slim-tube examination presented that the CWI led to a supplementary oil recovery of 24.0%, accompanying the water flooding at 5 PV (eventual recovery factor for the secondary CWI ~ 93%).

Development of the novel stage amended the oil recovery complete recombination of the oil displacement and trapped oil, producing a sympathetic three-phase movement district through less outstanding oil saturation, restricting the movement track of the CW and diverting it near un-swept parts of the porous medium. In this research work, the consequences of olive oil are measured and revealed to disturb the compositional performance of the carbonated water and the oil

Chapter 4 looks at the management of water injection in a given field. Chapter 5 describes the physico-chemical phenomena that occur during the injection of carbonated water for the M35 deposit. Chapter 6 also analyzes the energetic effects on the Mishrif field due to replenishing the amount of water required to increase the recovery factor.

The present thesis ends with Chapter 7 exhibited the predicting of the future production rate of 50 oil wells using decline curve analysis (DCA) and reservoir simulation. In addition, a 50 oil wells in Zubair field were used as the case study. Based on past production history, standard curves were generated using exponential, exponential, hyperbolic and harmonic decline model equations from which comparative study of production decline rate trend analysis was carried out. The model equations were used to project future oil productions for a period of 30 years. Finally, the history match was performed to evaluate the production behavior of Zubair field.

The **OFM** forecast (**DCA**) simulation current broad range of time series and forecasting capabilities enables users to model, forecast, and simulate processes for improved field redevelopment strategies and well management. Users can model complex scenarios and analyze the dynamic impact-specific events might have on the lifespan and production of an asset, be that a field or an individual well.

The **OFM** forecast simulation provides statistical tools that include the ability to automate the **DCA** process by working backwards through the data. And this allows us to compute declines and production forecasts form every producing well in the database.

The following conclusions are made on the basis of this study:

- The study uses the historical production data that collected from day one of the starting of production, until 31 December 2017.

- **OFM** forecast & decline curve analysis through production histories of oil and gas wells can be analyzed to estimate reserves and future oil and gas production rates. Because accurate production data are commonly available on most wells, production data analyses can be widely applied.
- Using **OFM** simulation software for the decline curve analysis allow a verification result of prediction of production performance for **Zubair** field wells. And the study uses the historical deterioration in production; the exponential decline method has been used to gain best results.
- The **OFM** forecasting results are achieved considering the next 30 years and it will continue for many years.
- The Expected Ultimate Recovery (**EUR**), calculated by **OFM** Decline curve analysis by the end of Year 2047 for **Zubair** field given 2,439,500 MSTB for Proven Reserves.
- The benefit from **OFM** forecast & decline curve analysis (DCA) is to figure out the future production, that's to optimize and develop the field before it reaches the abandonment point.

Recommendations

This study focuses on the future prediction of 50 oil wells of **Zubair** field with considering the economic side, but without cost data, so it's recommended that incase a new study made, economic with cost data can be taken into consideration.

1. I recommended to use **OFM** simulation software, cause it's preferable to be applied for the naturally produced oil & gas wells, to achieve best and accurate results of decline curve analysis (DCA) technique, the reservoir must be put into production of natural energy drive without any intervention by further recovery methods.

2. When there are some wells producing naturally the right discussion is to keep them run naturally instead of installing down hole pumps (ESP).
3. It's recommended to conduct an EOR process in association with decline curve analysis (DCA) to give more hands so such problem.

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