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Effect Of CO2 Miscible Injection On Maximizing Oil Recovery And Storage Capacity In A low Permeability Fractured Reservoir

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Abstract:

Different gases could be applied for EOR depend on reservoir and fluid characteristics and field production plan. Gas injection can perform as pressure maintenance, immiscible or miscible flooding. Feasibility of EOR projects depends on , excess oil production, production forecast and cost of injection gas at the injection well head. thus production and injection rates both must be optimized to achieve a successful EOR .In the other hand to obtain maximum CO2 mitigation by geological storage, higher injection rate is preferred.
Injection rate, which is expected as one of important factors in EOR methods is strongly depends on reservoir injectivity which is affected by permeability itself. In addition to economic view point, CO2 storage capacity is related to injectivity too.
Rahbord Energy Alborz studied and simulated different gas injection EOR/IOR Scenarios for NM1 oil field which is located in Zagros mountains west part of Iran with low permeability rock and low recovery factor. Simulation results show that Methane and Nitrogen injection rate can not be exceeded more than a limit and will meet early break trough .But CO2 miscible show more successful effect both on EOR method and storage capacity.
It is understood from study that low permeable- low pressure fractured reservoir which facing with early break trough in immiscible and gas cap injection cases, could be recognized as possible candidate for CO2 storage according to EOR advantage in comparison with other EOR methods.

Keywords': EOR, Storage capacity ,low permeable, fractured reservoir

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1. Introduction

Total world energy use rises from 495 quadrillion British thermal units (Btu) in 2007 to 590 quadrillion Btu in 2020 and 739 quadrillion Btu in 2035. In the *IEO2010* Reference case, the price of light sweet crude oil in the United States (in real 2008 dollars) rises from $79 per barrel in 2010 to $108 per barrel in 2020 and $133 per barrel in 2035.[1]
World use of liquids and other petroleum3 grows from 86.1 million barrels per day in 2007 to 92.1 million barrels per day in 2020, 103.9 million barrels per day in 2030, and 110.6 million barrels per day in 2035. To meet the increase in world demand in the Reference case, liquids production (including both conventional and unconventional liquid supplies) increases by a total of 25.8 million barrels per day from 2007 to 2035.
Reference case assumes that OPEC countries will invest in incremental production capacity in order to maintain a share of approximately 40 percent of total world liquids production through 2035, consistent with their share over the past 15 years. Increasing volumes of conventional liquids (crude oil and lease condensate, natural gas plant liquids, and refinery gain) from OPEC producers contribute 11.5 million barrels per day to the total increase in world liquids production, and conventional supplies from non-OPEC countries add another 4.8 million barrels per day.[1]
To meet this target , enhanced oil recovery must be considered seriously in addition to developing new fields. It could be foreseen that in next decades, several reservoirs production will be decreased under uneconomical level. specially EOR programs will be important for such fields with current low recovery.
At the same time CO_2 continued an upward trend in the early years of the 21st century . Total emissions from fossil fuel consumption and flaring of natural gas were 24 $GtCO_2$ per year (6.6 GtC per year) in 2001 – industrialized countries were responsible for 47% of energy-related CO_2 emissions (not including international bunkers). The Economies in Transition accounted for 13% of 2001 emissions; emissions from those countries have been declining at an annual rate of 3.3% per year since 1990.[2]
World energy-related carbon dioxide emissions rise from 29.7 billion metric tons in 2007 to 33.8 billion metric tons in 2020 and 42.4 billion metric tons in 2035—an increase of 43 percent over the projection period.[1]
One of the most recognized solution for mitigation of carbon dioxide is geological storage. While there are uncertainties, the global capacity to store CO_2 deep underground is large. Depleted oil and gas reservoirs are estimated to have a storage capacity of 675–900 $GtCO_2$. Underground accumulation of carbon dioxide (CO_2) is a widespread geological phenomenon, with natural trapping of CO_2in underground reservoirs. Information and experience gained from the injection and/or storage of CO_2 from a large number of existing enhanced oil recovery (EOR).[2]
A considerable portion of the world's hydrocarbon endowment is in carbonate reservoirs . carbonate reservoirs usually exhibit low porosity and maybe fractured . when enhanced oil recovery strategies are perused the injection fluids will likely glow through the fracture network and bypass the oil in the rock matrix. in most cases however 40 to 50% of the original in place is not produced .
gas injection projects are becoming more widespread and have outnumbered thermal projects since 2002.
CO2 injection production of these active projects , peaked at 663,451 B/D, 52% (345,514B/D)and 48% (317,877 B/D) for thermal and gas injection projects, respectively . Of the 143 active EOR projects, 57(almost 40%) have been implemented in carbonate reservoirs. In general, CO2 flooding is by far the most common recovery process ((48 active projects) , followed by air injection, 6; nitrogen injection, 2; steam injection, 1; and surfactant stimulation, [3]
For CO2 capture and storage purpose ,geological storage sites should have (1) adequate capacity and injectivity, (2) a satisfactory sealing cap rock or confining unit and (3) a sufficiently stable geological environment to avoid compromising the integrity of the storage site. The storage potential of basins found behind mountains formed by plate collision is likely to be good and these include the Rocky Mountain, Appalachian and Andean basins in the Americas, European basins immediately north of the Alps and Carpathians and west of the Urals and those located south of the Zagros and Himalayas in Asia. Basins located in tectonically active areas, such as those around the Pacific Ocean or the northern Mediterranean, may be less suitable for CO_2 storage and sites in these regions must be selected carefully because of the potential for CO_2 leakage[2]

Two important attributes of the rocks are porosity and permeability, porosity is a measure of the space in the rock for storing fluids. Permeability is a measure of the ability of the rock to allow fluid flow. Permeability is strongly affected by the shape, size and connectedness of the spaces in the rock.
Rocks suitable for storage typically (but with some exceptions) have high porosity to provide space for the CO_2 and high permeability for the CO_2 can be injected into a storage reservoir formation. Typically , the CO_2 must be injected at much the same rate as it is captured from the sources. The trade-offs between the injectivity required , the reservoir storage capacity, and the quality of the seal can be intricate and require careful evaluation y geologists and geological engineers. The selection of the method or suitable gas for injection depends on reservoir and fluid properties like pressure , depth, porosity, remained oil saturation and oil gravity.[4]
CO_2 EOR is limited to oil fields at a depth of more than 600 metres. The oil should also have a gravity of at least 23° API, equivalent to a density of at most 910 kg/m3, which makes this method unsuitable for heavy oil or oil sands. At least 20-30% of the original oil should be still in place. EOR is limited to oil fields where primary production (natural oil flood driven by the reservoir pressure) and secondary production methods (water flooding and pumping) have been applied. Many oil fields have not yet reached that stage. The occurrence of a large gas cap also limits the effectiveness of CO_2 flooding.
Up to temperatures of around 120 °C, CO_2 mixes with oil (a so-called miscible flood). At higher temperatures, CO_2 replaces the oil (a so-called immiscible flood oil). A miscible flood is more advantageous than an immiscible flood, because it results in higher oil recovery factors. Because of the physical constraints for CO_2 EOR, a detailed field-by-field assessment is required in order to assess its benefits properly.[5]
In the other hands Nitrogen flooding has been an effective for deep , high pressure and light oil reservoirs. For these type of reservoirs Nitrogen can reach to miscible condition. However immiscible N_2 injection also has been used for pressure maintenance . cycling of gas condensate and as a drive gas for miscible slug.[3]

2-Field Description :

NM1 field is located in Zagros basin west part of Iran and was explored in 1969. The oil in place is estimated about 849 MMbbl with 5% recovery factor , 41 MMbbl could be produced. Production area is about 24400 Acer and production depth is 5729 feet under ground level . Reservoir contains carbonated fractured rock with average porosity 7 and water saturation 35% , gas cap drive and gas solution drive are assumed as main mechanism for oil production.
Current pressure is 2090 PSI but reservoir saturation pressure reported as 1850 PSI. The reservoir contains light oil with API 45.8 and started to production from 1990 with rate 1900 bbl per day which decreased to 1700 bbl per day in 2005.Up to end of 2005 , more than 9.5 MM bbl which is equivalent of 23 % of recoverable oil in place, has been produced in addition to 5.5 billion cubic feet gas.
According to predictions, production rate will fall below 1200 bbl per day before 2028 and new drilling can not be helpful because of reservoir low permeability.

3-Production scenario and simulation:

In this study , several production scenarios have been studied and compared with natural depletion case. Methane , Nitrogen and CO_2 injection considered for EOR . According to reservoir pressure , nitrogen and methane can not raise to miscible pressure and for these cases, injection planned into cap rock and immiscible scenario is followed.
In the other hand oil gravity allows miscibility in reservoir pressure for CO_2 thus injection in the oil zone planned and simulated for CO_2.
Simulation was started from 1990, start of production and continued to 2030 with limitation for GOR, water cut and minimum oil production rate. Maximum gas oil ratio(GOR) was set as 1500 scf per barrel oil , maximum water cut defined 5% and minimum economical rate of production was set as 500 bbl per day, software programmed in the manner if any of limitation break , well will be shut although in other runs , GOR limitation was removed to observe gas production.
Two injection rates ,5 millions standard cubic feet day and 10 millions were practiced for nitrogen injection. Simulation results shows that 5 millions scfd Nitrogen injection rate ,doesn’t have any considerable effect on oil production , a small increase in production rate could be observed for less than 200 days and after that, negative slope in production could be seen. 1600 days after injection (less than 4.5 years) , reservoir will meet early break trough which at this point ,GOR reaches to 3000 rapidly and exceeds more.
In 10 millions per day rate for Nitrogen, how ever production rate isn’t increased , reservoir face with early break trough sooner. In this cas ، break trough is observed after 1200 days after injection which GOR exceed from 3000

rapidly and can exceed more than 5000 if well wont be shut.fig 1 shows the oil production rate which is expected by green line, cumulative oil production which shoed by red and GOR addressed by blue during Nitrogen injection.

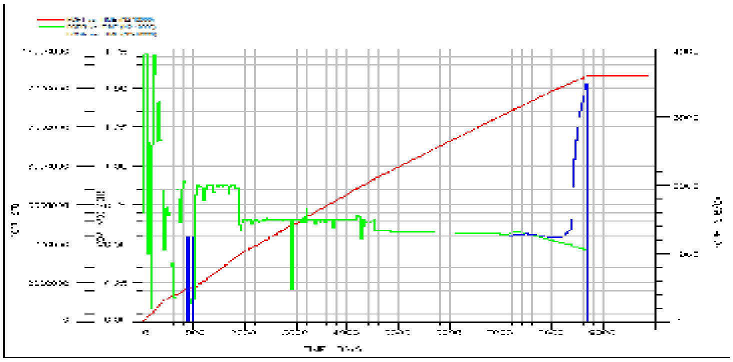

Fig1-effect of 10 MMscfd Nitrogen immiscible injection on oil production rate ,GOR and cumulative production

Simulation was also performed for methane with injection rate 10 millions standard cubic feet per day. Methane immiscible injection also doesn't have considerable effect on oil production but well will be shut after 1500 days because of increase in gas production. In this case , GOR reaches to 2000 and exceeds rapidly.
Finally, gas flooding practiced for miscible CO2 with rates:5,10 and 20 scfd .production rate increase gradually in 5 millions scfd injection rate and rises to 2200 bbl per day with 5 millions scfd injection rate. Reservoir can continue to production 5200 days (more than 14 years) after injection then GOR exceeds than 1500 and well will be shut.
With rate of 10 millions cubic feet of injection, how ever production rate rises to 2600 bbl per day but gas GOR exceeds than limitation 2400 days after injection and production couldn't be continued according to defined limitation. In comparison with two CO2 injection rate, 20 millions scfd case, shows better oil production rate however it face with break trough sooner .For rate of 20 millions scfd , break trough will accrue 2000 days after injection when production rate reaches to 2800 bbl per day. Effect of CO2 injection rate is shown in fig2 a-c.

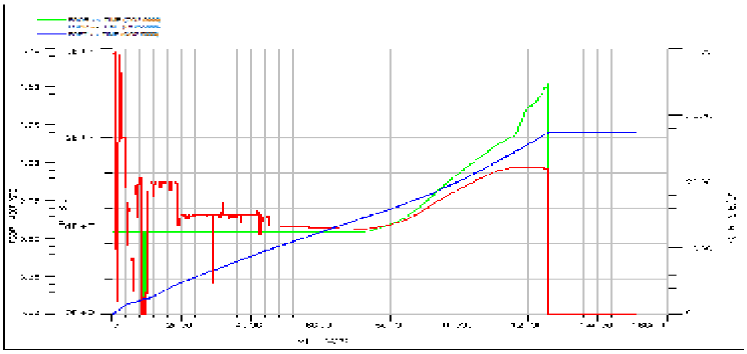

Fig2-a-effect of CO2 injection with rate 5 MMscfd on oil production rate , cumulative production and GOR

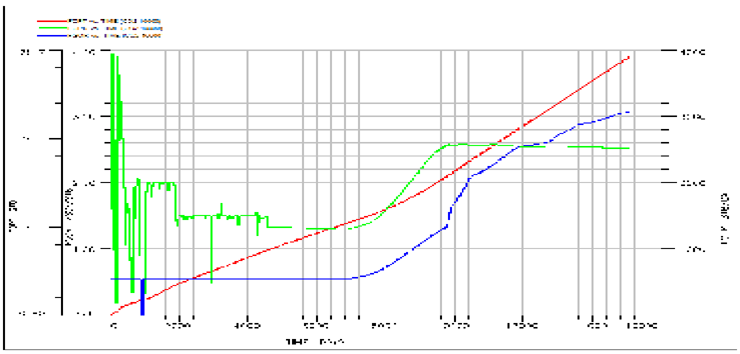

Fig2-b-effect of CO2 injection with rate 10MMscfd on oil production rate , cumulative production and GOR

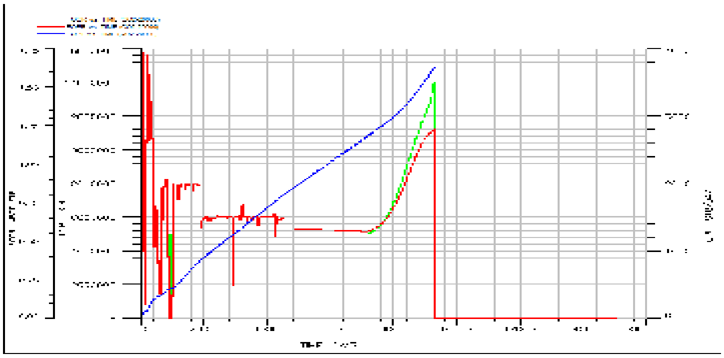

Fig2-c-effect of CO_2 injection with rate 20MMscfd on oil production rate , cumulative production and GOR

4-Discussion and investigation:

It could be understood from simulation results that CO2 miscible injection has more better effect on reservoir production. Reservoir daily production can raise to 2800 bbl in rate of 20 MMscfd but it can not be continued for longer than 2000 days .according to cumulative production , 5MMscfd could be assumed as the best practice with 21 millions barrel production before shutting the well. This case can encourage production company to consider CO2 miscible flooding how ever a combined injection rate scenario could be considered in long time to obtain maximum cumulative production.

As GOR and break trough time view point, CO2 miscible with injection rate of 5MMscfd,CO2 miscible with rate 10 MMscfd injection rate and CO2 miscible injection with rate of 20 MMscfd , show best results respectively. For immiscible Nitrogen and methane , reservoir face with early break trough however it accurse for methane lather than rate of 10 MMscfd Nitrogen.

Total stored CO2 in the reservoir , is estimated in this study also in addition to gas composition at the end of injection time. results are shown in following table. It is understood from results that for injection rate of 20 MMscfd ,maximum storage capacity could be obtained, in this rate 1.921 millions ton CO2 could be stored before break trough. In 10 MMscfd scenario, 1.51 millions ton CO2 could be stored during 6.7 years of injection. Although in 5MMscfd injection rate scenario , flooding is continued for almost 14 years but storage just reach to 1.092 millions ton.

Injection rate MMscfd	Stored CO2 MMton	CO2 in produced gas at the end of injection %	CO2 in produced oil at the end of injection
5	1.092	60%	5%
10	1.51	62%	7%
20	1.921	64%	8%

Maximum theoretical storage capacity[5] , could be obtained from equation,

$$MCO_2t = \rho CO_2*[Rf*A*h*\varphi*(1-Sw)-Viw+Vpw)$$

Which Rf , A, h, φ, Sw, Viw , Vpw are recovery factor, reservoir area, reservoir thickness, porosity, water saturation, valoum of water injected and produced respectively.

For NM1 reservoir theoretical maximum capacity is assumed as 57.38 millions ton , therefore it is understood that just 3.4% of total capacity could be available because of early break trough.

5-concolusion

Site selection and characterization is one of the most important steps to perform CCS projects. In addition, a CCS project must be attractive enough and economical for investors and producers to prove it self. CO2 EOR projects could be one of priorities for CCS according to excess recovered oil when emission trade price is not high enough ,there isn't any financial assist like CDM and there is not serious emission penalty.

In the other hand ,CO2 EOR is not the sole solution for petroleum recovery and it must be proved for reservoir owners and production company due to reservoir and crude condition. This study shows that in low permeability low pressure fractured reservoirs oil reservoirs, when CO2 could be miscible with the crude , CO2 EOR has some

advantages in comparison with Methane and Nitrogen which have higher minimum miscibility pressure and face with channelling and break trough easier.
In low permeability reservoirs, gas injectivity is limited and specially in fractured reservoirs , early break trough might be met easily. Injectivity could be increased for CO2 injection because of its ability for miscibility in lower pressure, injectivity is affected by miscibility ,consequently it can provide practical storage capacity .
Thus such a reservoirs with light oil could be considered as potential candidate for CCS pilot or demonstration projects.

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