Investigation of Improved and Enhanced Oil Recovery Processes and Examples of Field Applications in terms of Gas Injection in Carbonate Reservoirs

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Introduction

Since humanity discovered hydrocarbons and found the methods to extract them, we begun to utilize hydrocarbons for a daily life. However, the new technologies had to be developed because of global energy demand. As a result, secondary and tertiary stages of recovery methods had been developed. On average recovery factor of reservoirs with primary and secondary stages has a range between 30-35% and by using Enhanced Oil Recovery methods recovery factor can be reached to 65-70%. Vast portion of the hydrocarbons are in carbonates which mostly has low porosity, highly fractured and wettability of oil-wet. Worldwide EOR statistics show that gas injection methods are feasible in carbonate reservoirs. Therefore, in this work of study gas injection methods in carbonates reservoirs will be discussed alongside with the current status of projects and results. Gas injection can be done by miscible and immiscible displacement depending on the pressure that is applied which each of them has different mechanics and technique descriptions.

Immiscible Gas Injection

Several type of gasses are used for immiscible displacement technique, mostly by using lean hydrocarbon gas. This technique is used for pressure maintenance which is considered as Improved Oil Recovery technique. First it was done in the 1930s by lean hydrocarbon gas in Oklahoma City field. Since that time this technique has been widely used worldwide. In order to do immiscible technique source of gas has to be available which can be obtained from the produced solution gas or gas caps and from gas fields that are nearby. Gas can be immiscibly injected for several reasons that are reinjection of gas into the gas caps that overlay oil columns, avoiding oil to migrate into gas caps because of natural water-drive, injection of gas for a recovery increase to reservoirs that has volatile, high-shrinkage oils and gas-cap reservoirs which contains retrograde gas condensate.

Mechanisms and limitations

The mechanics of immiscible gas injection can be gas injection for a pressure maintenance of the reservoir, displacing oil by gas in horizontal and vertical direction and swelling of the oil when oil at the beginning of the production was very undersaturated.

When displacing oil in vertical direction, injection wells are placed at higher positions of the reservoir to be able to inject gas to the gas cap in order to sweep oil to the production wells by using gravitational drainage. For this method the reservoir should have a good vertical permeability with a thick oil column.

In horizontal gas injection, gas is injected throughout the oil-productive portions of the reservoir. In this method injection wells are placed in different patterns like five, seven, nine spots depending on the reservoir structure, sand continuity, variations of permeability and porosity and locations of existing wells. This method is applicable for the reservoir that is relatively homogeneous with low permeability and has low structural relief. There are several problems that might occur with these methods such as having a low areal sweep efficiency because of gas override in thin stringers and by viscous fingering of gas which is caused by high flow velocity and poor mobility ratios. In addition, if pattern of injection wells is applied to low-dip reservoirs early breakthrough of gas may happen which leads to the poor displacement efficiency and compression of gas to reinject into the reservoir can be costly. Nitrogen also can be used for immiscible displacement as a pressure maintenance and as a drive gas for miscible slugs when the reservoir pressure is not high. [1]

Miscible Gas Injection

For miscible flooding displacement method, hydrocarbon gas, carbon dioxide and nitrogen are utilized and also flue gas injection are done as a partial miscible/immiscible gas flooding. In this method of flooding, a type of gas or solvent is injected which is miscible with oil that results in reducing the interfacial tension between two fluids (oil and solvent) and it gives a good displacement efficiency.

Hydrocarbon miscible flooding

The technique uses light hydrocarbons for an injection to the reservoir to create a miscible flood. Variety of methods are being done to do hydrocarbon miscible flooding. In a first method a liquefied petroleum gas (LPG) that has 5% of PV such a propane is used before injection of lean gas. In a water alternating gas mode water is injected after gas injection that helps to improve mobility ratio between solvent and the gas and it reduces interfacial tension between oil and water.

In a second method which is called enriched gas drive, uses 10%-20% PV slug of natural gas that is enriched with ethane through hexane (C_2 to C_6) that is followed by lean gas (dry, mostly methane) and water. When enriched gas is contacted with oil enriching parts in a gas go to the oil that reduces viscosity of oil forming miscible zone between injected gas and reservoir oil which displaces the oil forward towards to the producing well. In a third method lean gas is injected at high pressure that is called high pressure (vaporizing) gas drive. Components through C_2 to C_6 are vaporized from the crude oil that is being displaced which gives a result to have multiple contact miscibility.

In this technique oil is obtained by generating miscibility, increasing the oil volume and decreasing viscosity of oil, but it has some limitations such as setting a minimum depth by the pressure that is necessary to maintain the generated miscibility, knowing required pressure ranges depending on the oil composition that can have range from 1,200 psi for LPG process to 3,000-5,000 psi to do high pressure gas drive method with methane or lean gas. In addition to that several problems can be faced like having a viscous fingering which gives a poor vertical and horizontal sweep efficiency, purchasing large quantities of expensive products that are necessary for doing this technique and getting a solvent trapped that couldn't be recovered.

Carbon Dioxide Flooding

In this technique carbon dioxide (CO_2) is used in a large quantity of CO_2 (15 % or more of the hydrocarbon PV) to inject it to the reservoir. When CO_2 contacts with oil, it gets the light to intermediate components from oil and also when reservoir pressure is high enough miscibility can be achieved that displaces the crude oil from the reservoir. This technique looks like a hydrocarbon gas injection with vaporizing gas drive method except with some difference such as having a wider range of components that can be extracted (C_2 to C_{30}) from crude oil and miscibility of CO_2 could be reached at lower pressures than vaporizing gas drive method. CO_2 dissolves in oil at reservoir pressure and temperature and it helps to swell the net volume of oil reducing oil viscosity by vaporizing gas drive mechanism even before it reaches miscibility. When miscibility of CO_2 achieved it gives the ability for oil phase and CO_2 phase (containing intermediate components) flow together because of low interfacial tension. This process main requirement is necessity of reservoir pressure to develop miscibility between oil and CO_2. Moreover, CO_2 is also used as a water-alternating-gas where CO_2 is injected with water to improve mobility ratio between the displacing phase and oil.

Overall, this technique extracts oil by obtaining a miscibility between oil and injected gas, swelling the oil, lowering the viscosity of oil and lowering interfacial tension in near-miscible regions between the oil and CO_2-oil phase. However, the technique has some limitations that are having a poor mobility control because of very low viscosity of CO_2 and the most important the availability of CO_2 is very limited. In addition to that it has some issues such as having early breakthrough of CO_2, getting corrosion issues in producing wells, requirement of separation CO_2 from saleable hydrocarbons, repressuring of CO_2 for recycling and high amount of CO_2 is required per incremental barrel of oil produced.

Nitrogen and flue gas flooding

This technique uses nitrogen and flue gas that are cheap non-hydrocarbon gases for a displacement of oil. Depending on reservoir pressure and oil composition, displacement of oil can be done in miscible or immiscible conditions. To generate miscibility with nitrogen, higher pressure is needed and it has lower viscosity and poor solubility in oil.

Generally, in nitrogen and flue gas flooding oil is recovered by having a vaporization of lighter components of the crude oil and obtaining miscibility at sufficient pressure of the reservoir and improving gravity drainage in dipping reservoirs.

There are some limitations in using this technique: miscibility can be achieved only with light oils and at high pressure, thus having deep reservoirs are imperative and for a usage of gravity stabilization of the displacement a steeply dipping reservoir is needed.

In addition to that several problems can occur with using this technique such as having a viscous fingering that leads to poor vertical and horizontal sweep efficiency, in flue gas method we can have corrosion problems and non-hydrocarbon gasses must be separated from the saleable produced gas. [2]

Screening criteria of EOR methods

Type of reservoir is also one of the screening criteria considerations for EOR that shows some limitation to EOR methods. As this paper is focused on Carbonate reservoirs, EOR methods that are applicable for Carbonates are discussed. From Figure 1 it can be easily seen that most of the EOR projects are done in sandstones than carbonates which is based on 1,507 projects that have been done worldwide.

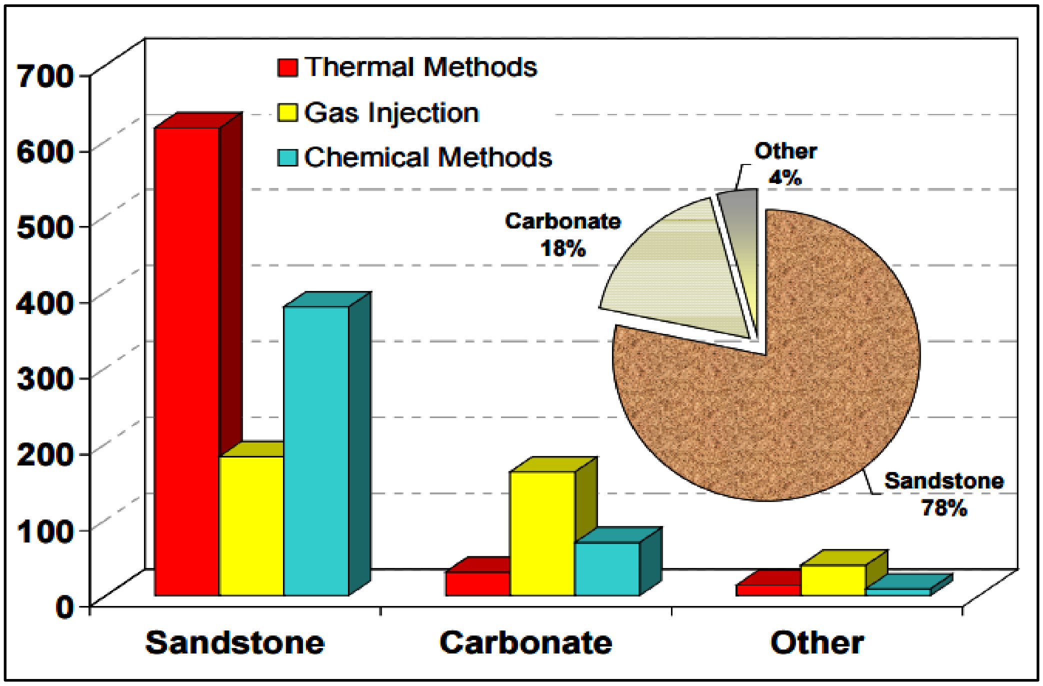


Figure 1: EOR methods by type of reservoir.
SPE-130113. 2010.

The Figure 1 also shows that thermal and chemical methods are more applicable in sandstone formations meanwhile gas injection and chemical methods are usable in carbonate reservoirs. During a last decade EOR projects in carbonates have increased that can provide feasibility of various EOR methods in carbonate reservoirs. Gas injections (continuous or in a WAG mode) are the most used EOR method in this type of reservoir while thermal methods are rarely used and contributed the smallest amount of oil production from carbonates. Polymer flooding is the only applicable chemical technique in carbonates, but projects with High Pressure Air Injection (HPAI) begun increasing in recent years, especially in light oil carbonate reservoirs. [3]

Table 1: Screening criteria for EOR methods based on oil properties.

Process	Gravity °API	Viscosity (cp)	Composition	Oil Saturation
Waterflooding	> 25	< 30	N.C.	>10% mobile oil
Hydrocarbon	> 35	< 10	High % of C_2–C_7	> 30% PV
Nitrogen & flue gas	> 24 Nitrogen > 35 Flue gas	< 10	High % of C_1–C_7	> 30% PV
Carbon dioxide	> 26	< 15	High % of C_5–C_{12}	> 20% PV
Surfactant/polymer	> 25	< 30	Light to intermediate desired	> 30% PV
Polymer	> 25	< 150	N.C.	> 10% PV mobile oil
Alkaline	13–35	< 200	Some organic acids	Above waterflood residual
Combustion	< 40 (10–25 normally)	< 1,000	Some asphaltic components	> 40%–50% PV
Steam flooding	< 25	> 20	N.C.	> 40%–50% PV

Note: PV = pore volume; N.C. = not critical.

Table 2: Screening criteria for EOR methods based on reservoir characteristics.

Process	Formation Type	Net Thickness (ft)	Average Permeability (mD)	Depth (ft)	Temp (°F)
Waterflood	Sandstone or carbonate	N.C.	N.C.	N.C.	N.C.
Hydrocarbon	Sandstone or carbonate	Thin unless dipping	N.C.	>2,000 (LPG) >5,000 (H.P. gas)	N.C.
Nitrogen & flue gas	Sandstone or carbonate	Thin unless dipping	N.C.	> 4,500	N.C.
Carbon dioxide	Sandstone or carbonate	Thin unless dipping	N.C.	> 2,000	N.C.
Surfactant/polymer	Sandstone preferred	> 10	> 20	< 8,000	< 175
Polymer	Sandstone preferred; carbonate possible	N.C.	> 10 (normally)	< 8,999	< 200
Alkaline	Sandstone preferred	N.C.	> 20	< 9,000	< 200
Combustion	Sand or sandstone with high porosity	> 10	> 100	> 500	>150 preferred
Steam flooding	Sand or sandstone with high porosity	> 20	> 200	300–5,000	N.C.

Note: N.C. = not critical.

Table 1 shows screening criteria for EOR processes-based oil properties that includes criteria of the gravity, viscosity and oil saturation, meanwhile Table 2 represents screening criteria based on reservoir characteristics that includes criteria of formation type, net thickness, average permeability, depth and temperature. For CO_2 to get minimum miscibility pressure can be 1,200 psi for high gravity oil at lower temperatures and more than 4,500 psi for heavy crude oils at higher temperatures. To reach miscibility of gases reservoir has to have enough depth. For instance, for effective N_2, hydrocarbon miscible floods reservoirs with depths more than 4,500-ft are necessary. Moreover, hydrocarbon, N_2, CO_2 floods are useful for higher oil gravities and lower oil saturations. [1]

Findings of the study

In this work examples of case studies of EOR projects in carbonates reservoirs in the US and World have been overviewed for a comparison of applicability of the different type of EOR techniques and infrastructure.

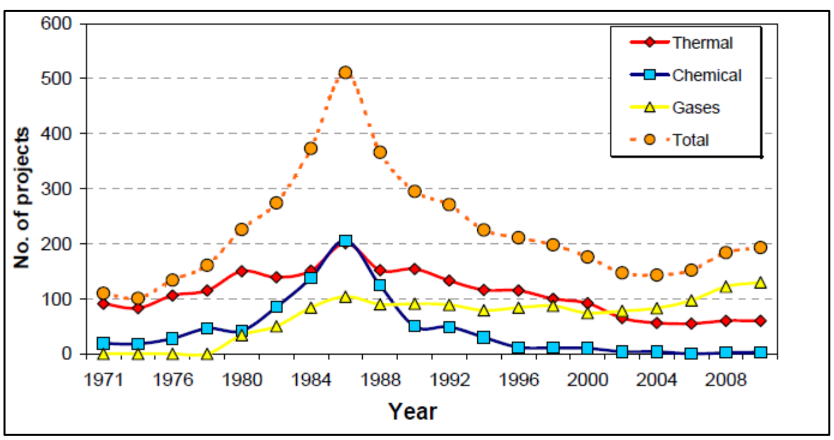
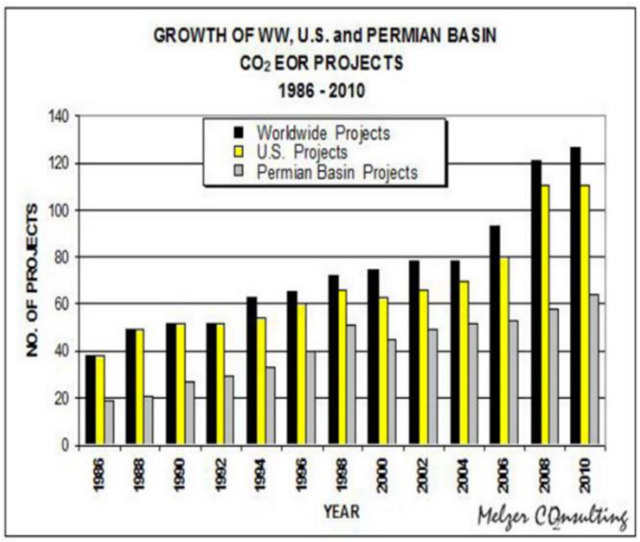
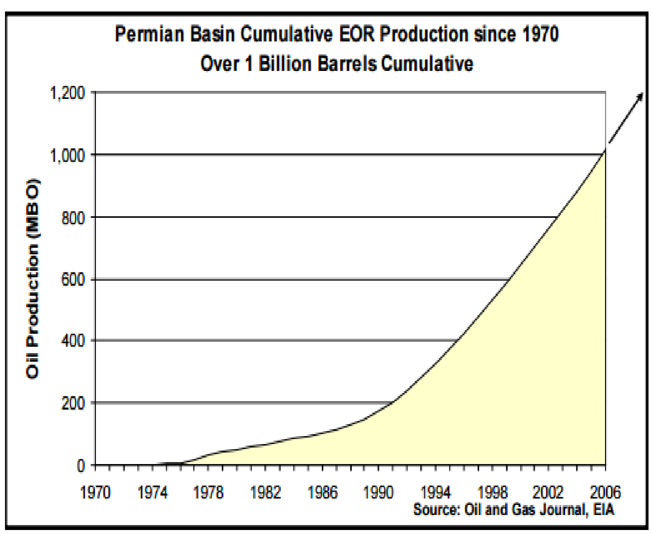


Figure 2: SPE-1300113-MS. 2010.

EOR in US Carbonate reservoirs.

As of Oil and Gas Journal EOR survey (2008) shows that number of chemical and thermal EOR projects have been dropping constantly since 1980's. Number of EOR gas injection projects remained constant since 1980's and begun growing since the year 2000 because of increase of CO_2 projects. In addition, from the year 2002 gas injections projects became more than thermal projects number mainly by using CO_2 floods because of CO_2 low price and availability (Fig 2). From overall projects number 143 EOR projects (2004), production of thermal projects has reached the peak at 663,451 B/D and gas injection reached its peak at 317,877 B/D. Out of 143 EOR active projects 57 of them have been done in carbonate reservoirs which is almost 40%. The mostly implemented method is CO_2 which 48 projects belongs to CO_2, then air injection with 6 projects and nitrogen injection with 2 projects, lastly steam and surfactant injection 1 projects each. [4]





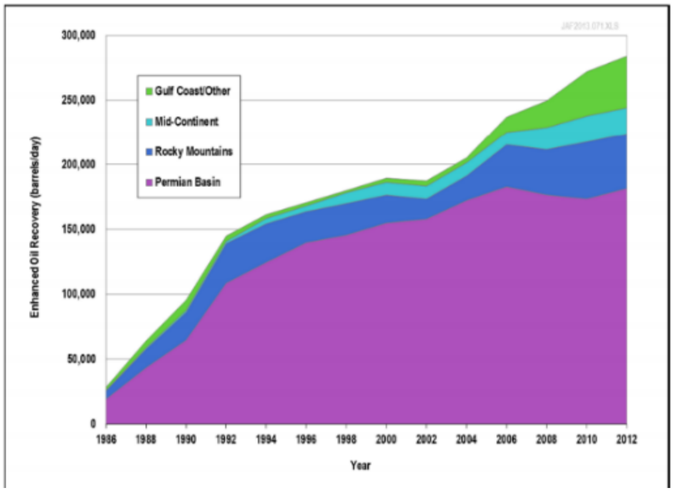


Figure 3: Production analyses from CO_2 EOR projects of Permian Basin and Worldwide and US. Global CCS Institute. 2010. US Department of Energy. 2014.

CO_2 Injection: From early 1980s CO_2 injection became a major EOR method which 67% of them are being implemented in US carbonate reservoirs. Most of the are being done in Texas. CO_2 flooding has been successfully used in mature and waterflooded carbonate reservoirs because of availability of sources of CO_2 and accessibility of systems of CO_2-transporting pipelines that are close to the oil fields. The highest amount of CO_2 consumer is Permian Basin that has access to the network of CO_2 pipelines where CO_2 comes from the natural reservoirs in Colorado (the McElmo Dome and the Sheep Mountain fields), New Mexico (the Bravo Dome region), Texas and Wyoming (La Barge Field). One of the reasons CO_2 injections is popular is because of its affordability than other EOR methods. CO_2 projects in Texas have been proved that even oil price goes down to 18 USD/bbl projects could be successfully implemented and with CO_2 prices less than 1 USD/ft^3 which is much cheaper than prices of other EOR method's projects. Also, benefits from carbon credits will increase and attract more CO_2 projects. Possibility of using CO_2 injection as a EOR method depends on the availability of CO_2, if projects with CO_2 will increase, more sources of CO_2 would be needed. [4]

Case study of EOR in Permian Basin represents successful CO_2 EOR project. Permian Basin is located in western and southwestern part of US that 50% of its 30 billion barrels of oil production comes from Permian carbonate reservoirs which most of the production comes from San Andres formation that has a depth of around 5,000ft. Overall, OOIP of Permian Basin is 95.4 billion bbl in place that are located in a deep, light oil reservoirs which are a good candidates for miscible CO_2 EOR. Figure 3 illustrates how a big the portion of oil production from Permian basin. In 2012 overall daily oil production from CO_2 was 282,000 barrels per day and 186,000 barrels per day of it obtained from Permian Basin. From the Figure 3, it can be seen that in 1986 and 2000 the oil production from Permian basin slightly decreased because of oil price decrease and also because of EOR projects that have begun in the Gulf Coast and the Rockies. Doing CO_2 EOR projects in Permian Basin is applicable because of access to CO_2 pipeline network and natural resources of CO_2 reservoirs. Since CO_2 EOR has been implemented in Permian Basin from 1970's Permian Basin has produced more than 1 billion barrels of incremental oil in a year 2006 and around 7.3 Tcf of CO_2 has been sequestered with almost 1,500 miles of pipeline. [4,5,6]

Nitrogen (N_2) injection: Nitrogen is applicable for deep reservoirs that have high-pressure and light oils. EOR with N_2 can be done and miscible condition if enough pressure is applied and also in immiscible conditions for pressure maintenance as a cycling of condensate reservoirs and drive gas for miscible slugs. From 1960's N_2 has been used in US in the Devonian Block 31 field that is located in west Texas. More than 30 projects have been done in US last 40 years, most of them were implemented in carbonate reservoirs in Florida, Alabama and Texas. In 2007 there were only two N_2 projects going in carbonate reservoirs the N_2-WAG (1982) in Jay LEC and in Yates field (mid 1980's) for pressure maintenance. Jay field was discovered in 1970 near Florida and south Alabama. It has 337 million bbl of light recoverable reserves of oil. After waterflooding N_2 injection has begun. This method of EOR was selected because of delay in methane sales and using CO_2 would require building of a long pipelines from central Mississippi with a high cost. The estimated ultimate recovery is 60% of OOIP, with recovery methods it reaches to 70% that 7% of it from miscible gas projects. N_2 projects in US is not expected to increase because of availability of CO_2 as can be noticed from EOR method change in Yates field from N_2 to immiscible CO_2 injection by Kinder Morgan. [4]

Hydrocarbon-Gas Injection: In US miscible and immiscible hydrocarbon gas injection is still feasible EOR method, but this method mostly has been implemented in sandstone reservoirs. There were 8 hydrocarbon miscible projects in sandstone reservoirs in 2004. Between the year 1960 and 1980 only 8 hydrocarbon injection projects have been done in US carbonate reservoirs. One example of miscible hydrocarbon gas injection could be Dolphin field, discovered in 1986 in North Dakota that is small undersaturated volatile-oil dolomitic reservoir which has oil in place of 6.3 million/STB. Gas injection project has begun in 1988. By 1992 its recovery factor reached to 31% and it is expected to increase to 51% that is twice more than estimated recovery without the gas-cycling project. Disadvantage of this EOR technique is the natural-gas prices that are going to impact to the large-scale hydrocarbon-gas injection projects. [4]

EOR in World Carbonate reservoirs.

Majority of hydrocarbon deposits are placed in carbonates, but because of some features hydrocarbon recovery is lower than in sandstone. These features are having oil-wet in carbonates and also having a high permeability in the fracture network leads to have early breakthrough of IOR/EOR injected fluids. Gas injection is the mostly implemented EOR method used in carbonate reservoirs than chemical and thermal methods. [3]

Nitrogen (N_2) injection: Only in Cantarell N_2 injection is being used in an offshore carbonate filed outside of US, that is located in Campeche Bay Area in the Gulf of Mexico in Mexico. It was discovered in 1976 and the production has begun in 1979 with the peak 1.156 MMBPD in 1981.

Until 1995 the production rate was on average 1 MMBPD as pressure started to decline the production was maintained by drilling additional wells, in 1987 gas lifting was used and in 2000 nitrogen injection has been started as a pressure maintenance.

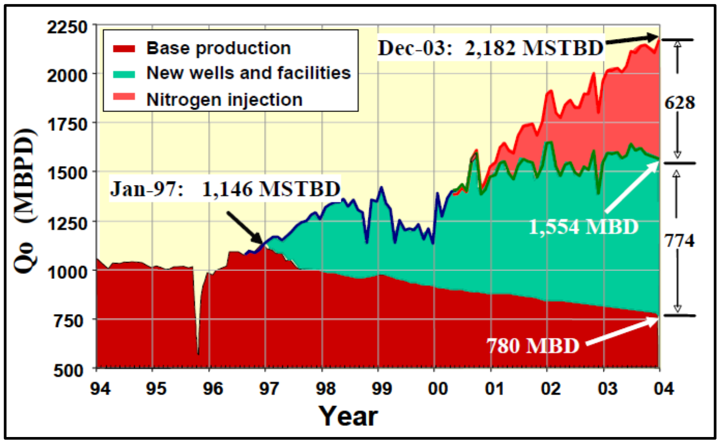


Figure 4: Effect of pressure maintenance and new wells and facilities expansion on oil production.
SPE 97385. 2005.

Figure 4 shows effect of two production maintenance projects on production rate in Cantarell field: additional drilling-expansion of production facilities and pressure maintenance by N_2. As it can be seen at the beginning of the year 2004 the production rate reached to 2,182 MBPD that 1,402 MBPD out of it comes from production maintenance projects. From this additional rate 628 MBPD comes from implementation of nitrogen injection and 774 MBPD corresponds to the drilling of new wells and expansion of production facilities. N_2 was chosen because of availability of N_2, low cost, handling infrastructure and environmental issues. The cost of N_2 at wellsite was estimated 0.54 USD/MSCF if it is compared with the price of natural gas which was 2.66 it is very favorable. [3,7]

$\boldsymbol{CO_2}$ **Injection:** In the World in Canada in Enchant Midale, Judy Creek and Weyburn fields and in Turkey in Bati Raman field CO_2 projects have been implemented. Bati Raman is the biggest oil field in Turkey that has 1.85 billion barrels OOIP with the depth of 4300ft and very heavy oil of 12^oAPI with high viscosity of 600cp. Recovery factor with primary phase was less than 2% between the years 1961 and 1986, then in 1986 CO_2-EOR project started and with CO_2 implementation recovery factor is expected to increase to 10% of OOIP. Because of heterogeneous, naturally fractured carbonate reservoir, mobility of CO_2 is unfavorable and it caused poor sweep efficiency that lead to bypassing the oil and early breakthrough of CO_2. In order to improve sweep efficiency polymer gel system and chemically augmented water injections carried out. Currently, Bati Raman field produces 7,000 BOPD of oil with injection of 40 MMScf/D of CO_2. Overall recovery factor is 6% with 10% in some parts of the field. The main necessity in doing CO_2 flood is availability of CO_2 sources that will make it the best choice for recovery method. [8]

Hydrocarbon-Gas Injection: Hydrocarbon gas injection has made some contribution in US and Canada in terms of total oil recovery. Also, some hydrocarbon miscible flooding projects have been done in Canada and Middle East on offshore formations. Moreover, sour and acid gas injections have been implemented in Zama field (Canada) and Tengiz field (Kazakhstan).

Tengiz field is the large, carbonate reservoir located in western Kazakhstan which sour gas injection project has been started in January 2007. [3]

The success of the SGI project was observed by compressor reliability, injectivity, wellbore durability and reservoir performance. The sour gas compressor had a 90% availability when Second Generation (SGP) plant has begun to work which SGI injection gas is made by using SGP. All parameters showed good results like injectivity was exceeding its expectations, wellbore durability was excellent, the reservoir performance was giving good results as was expected. SGI project is being done in seven inverted five-spot patterns. Tracers, pulse tests, multiphase meters, gas saturation logs, production and injection logs have been used to monitor reservoir conformance efficiency.

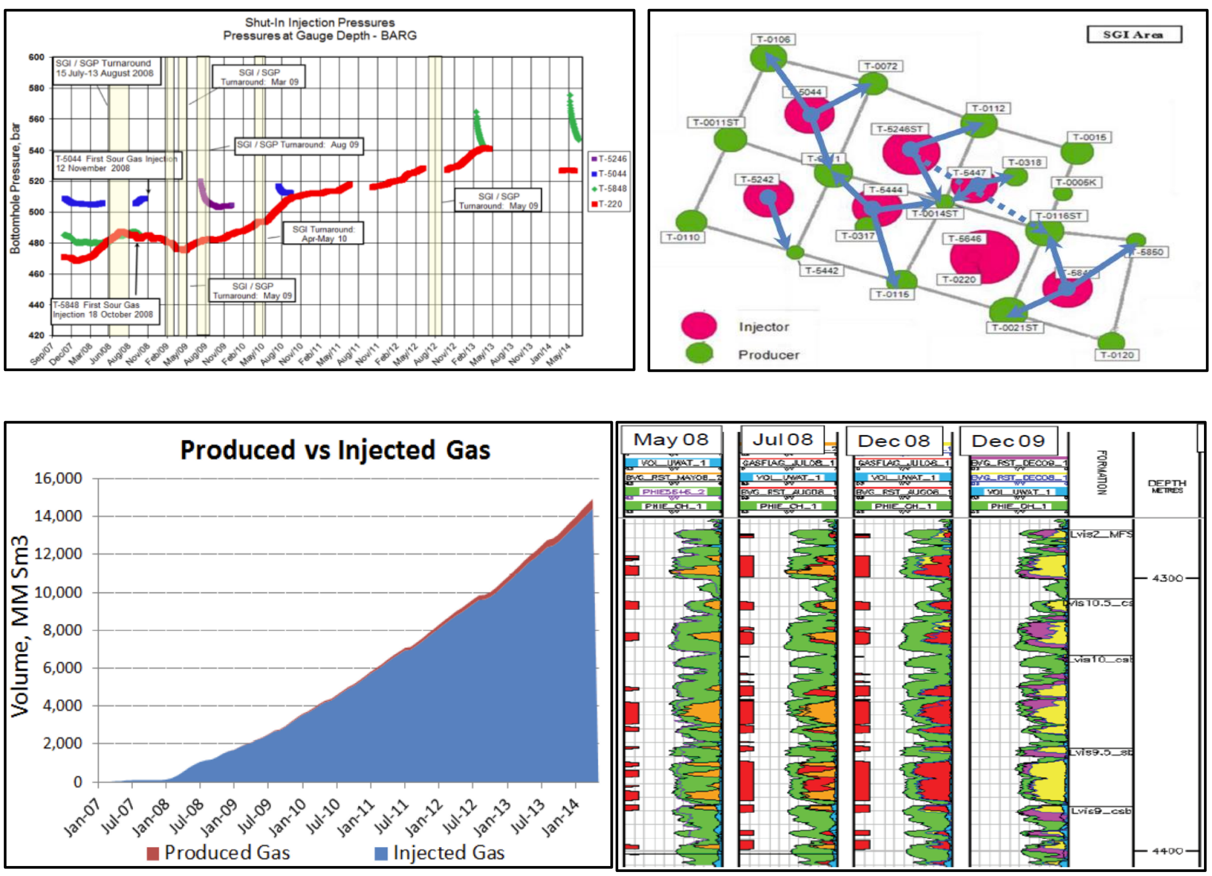
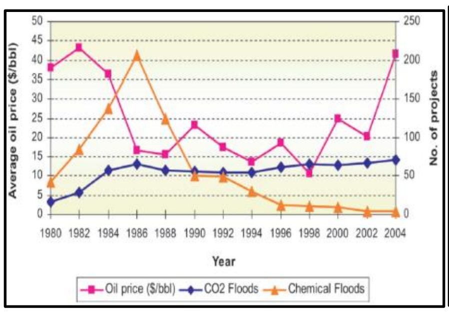


Figure 5: Results of analyses of SGI project in improving reservoir conformance. SPE – 172284-MS.2014.

Pressure reservoir change plot that were obtained from pressure gauges of injection wells shows that since SGI project has begun from September 2007 the pressure has increased from 470bar (6816psi) to 540bar (7832psi) in June 2014. The TCO has been observing reservoir pressure in all SGI injection wells with a consistent and expected results of pressure increase. Bubble map shows different size of injection and production wells. The size of bubble indicates cumulative production and injection. Chemical tracers were added to injection wells to observe the direction of gas movements. Special amount of unique tracers were added to each injector. In a Figure chemical tracers have been detected in 11 production wells with a good concertation of tracers except the pair of well T-5246T/T-116. In Figure of volume of gases illustrates that until April, 2014 only 3.5% of volume of injected gas has been produced which shows that most amount of injected gas is staying in reservoir resulting in pressure support and miscible displacement. In a Figure of saturation logs we can get to know results of saturation logs that were run 4 times in a well T-220 from May 2008 to December 2009 where oil-filled porosity is colored in green. In the left plot shows log that was run in May 2008 after 5 months of injection and orange shows the volume of gas that has been swept. The second log was run in July 2008 that shows newly swept gas in red. The third log was run in December 2008 which little oil has been swept that is in yellow. Final one was run in December 2009 and the newly swept portion of oil is shown in purple. Overall, more than 70% of oil were swept in well T-220. [9]

Observations and Conclusions



Region	CO_2-EOR Oil Production (MBbld)		
	2012	2015	2020
Permian Basin	186	241	301
Gulf Coast	43	73	153
Rockies	36	55	103
Mid-Continent	17	37	58
Total Production	282	405	615

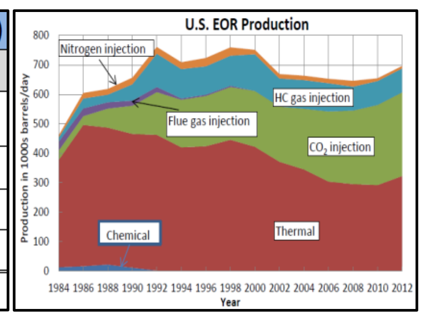


Figure 6: Analysis on applicability of using CO_2 EOR method in US.
SPE 100063, US department of energy and K. Koottungal worldwide EOR survey.

The study shows that the best EOR gas injection method in US carbonate reservoirs is implementation of CO_2 flooding because of availability of CO_2, a good infrastructure and access to large network of pipelines. By analyses of US department of energy that have been done on EOR CO_2 oil production shows that the production from CO_2 in US will increase from 282 MBbld in 2012 to 615 MBbld in 2020. From the figure that illustrates impact of price of oil on EOR projects shows that oil price has a high impact on chemical projects while on CO_2 projects don't. It indicates that as oil price gets below $20 number of CO_2 projects continued rising meanwhile number of chemical projects dropped dramatically. In addition, price of CO_2 is very cheap that costs $US 1-2Mscf. Moreover, from US EOR production graph it can be seen that the highest amount of production among Gas injection methods of oil comes from CO_2 flooding that makes this method superior than others and followed by HC gas injection, N_2 and least one is flue gas. Mostly, methods of other gases are used where CO_2 injection is not applicable. [4,6]

In the World's carbonates reservoirs CO_2 injection method is not famous because of lack of CO_2 availability, only in few places CO_2 method have been reported that are being implemented in Canada and Turkey. As was mentioned earlier Nitrogen injection is best choice of EOR methods for Campeche Bay because of low cost of N_2 generation. Hydrocarbon gas injection projects in carbonates were reported in Canada and Middle East fields. HC injection method is mostly used if there is no reason to utilize the HC and where it can't be flared, then HC is used for pressure maintenance or WAG processes until new way utilization of HC becomes available. In addition to that the acid gas injection also being implemented in several fields like Zama in Canada, Harweel in Oman, Tengiz and Karachaganak fields in Kazakhstan. [3]

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