Enhanced Oil Recovery with CO_2 Capture and Sequestration

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Keywords: CO_2 Sequestration, Enhanced Oil Recovery, Heavy Oil

Abstract

This paper presents the results of a feasibility study aimed at extending the production life of a small oilfield in Italy through EOR (Enhanced Oil Recovery), employing the CO_2 captured from the flue gas streams of the refinery nearby. The EOR operation allows the recovery of additional reserves while a consistent amount of the CO_2 injected remains permanently stored into the reservoir.

The screening process selection for EOR-CO_2 and the main elements of the pilot project for the proper upstream-downstream integration will be described.

Evaluation of EOR-CO_2 extension to other oilfields and its effect on oil production and project's economics will be reported.

1. Introduction

The present paper explores the technical feasibility and economic potential of capturing CO_2 from a refinery flue gas stream and applying the CO_2 to enhance the oil recovery factor and thus extending the production life of a small oilfield in Italy (Armatella).

The study originates from a reservoir modelling simulation that evaluated the applicability of different IOR/EOR methodologies on the Armatella field, with the aim to individuate the most promising technologies and suggesting the EOR/IOR process to test in the field by a pilot project.

Among the different scenarios, the CO_2 injection resulted one of the most promising and has been selected for the pilot project phase, taking into account the availability of a CO_2 source at high purity (> 95% vol.) from the flue gas stream of the Gela Refinery, located 15 km from the Armatella field.

An important feature of this initiative is based on the integration between downstream and upstream operations. The project includes the CO_2 capture from the refinery flue gas, transport and injection into the reservoir for EOR and the partial sequestration of the injected CO_2.

The CO_2 capture achieves two goals: to increase the efficiency of oil recovery and to sequester a substantial amount of CO_2 for an extended period of time.

The **eni** initiative has a great strategic relevance and will be the first example of EOR-CO_2 treatment in Italy.

2. The Different Techniques for Oil Recovery

During the lifetime of an oil reservoir, the oil production is typically implemented in two or, if economical, three phases. In particular through (Ref. 1.):

- *Primary recovery techniques* are usually applied in the initial production phase, exploiting the difference in pressure between the reservoir and the producing well's bottom. This "*reservoir natural drive*" forces the oil to flow to the well and, from then, to the surface. Pumps are employed to maintain the production once the reservoir drive diminished, due to the oil/gas extraction, and the primary recovery is, generally, completed when the reservoir pressure is too low, the production rate is no more economical and the gas-to-oil or water-to-oil ratio is too high. The oil recovered from the well during the primary stage is typically in the range 5-25% of OOIP (Originally Oil In Place), varying as a function of oil and geological characteristics and reservoir pressure.
- *Secondary Recovery techniques* are applied when primary recovery methods are no longer effective and/or economical. In secondary recovery, fluids (typically water, but other liquids or gases can also be employed) are injected into the reservoir through injection wells in order to increase/maintain the reservoir pressure, acting as "*artificial drive*" and then replacing the natural reservoir drive. CO_2 has been tested with limited success in this context. Economic criteria are applied to conclude secondary recovery practices. The recovery factor for this kind of operations ranges from 6 to 30% of OOIP, depending on oil and reservoir characteristics.
- *Tertiary recovery operations,* also called Enhanced Oil Recovery (EOR) or Improved Oil recovery (IOR), are applied in oilfields approaching the end of their life and can produce additional oil in the range 5-15% of OOIP for light to medium oil reservoirs, lower for heavy oil reservoirs. These operations are applied in order to improve the oil flow in the reservoir, by altering its flow properties or its interaction with the rock. One of these techniques is EOR promoted by CO_2 injection.

Recovery factor after primary and secondary recoveries is typically in the range 30-50%, on average between 45-55% in the North Sea fields, where 66% recovery can be reached in some fields without EOR (Ref. 2).

Nevertheless, it has recently been evaluated (Ref. 1) that approximately 2,000 billions bbls of conventional oil and 5,000 billions bbls of heavy oil would remain un-produced worldwide after conventional primary and secondary recoveries. The contribution of EOR to the oil production can, then, be enormous: a 1% increase of the recovery factor globally would involve an increase of conventional oil reserves of 70 billions barrels, not including the possible contribution from unconventional sources exploitation.

The application of this technique to **eni**'s Italian Heavy Oil Reservoirs could interest 3 to 4 billions of OOIP (almost 3 billions bbls in Sicily).

3. EOR/Tertiary Recovery Techniques

The major EOR processes include gas injection, thermal recovery and chemical methods. The screening criteria for EOR selection are reported in Table 1 and Table 2 as a function of reservoir and crude oil characteristics, respectively.

- Gas Injection. These methods are based on the injection of gas (HC, N_2, Flue gas, CO_2) into the oil-bearing layer where, under reservoir conditions and high pressure, the gas will mix with the oil, decreasing its viscosity and displacing more oil from the reservoir. A very good oil recovery can be guaranteed if the reservoir pressure is higher than the minimum miscibility pressure (MMP) that is a function of temperature and crude oil characteristics (Ref. 3). In 2008 the EOR production through gas injection methods was around 566,000 bpd (580,000 bpd forecasted in 2010)

- Thermal Recovery adds heat to the reservoir, in order to reduce the oil viscosity, through steam injection, in-situ combustion or hot water. Reservoir depth for steam applications is limited due to heat loss associated with wells. Steam Injection can be applied to shallow reservoirs (< 1,500 m) of heavy oil deposits that cannot be produced economically by primary or secondary methods, due to their very high viscosity. In-situ combustion finds application in reservoirs containing light oils (> 30 °API). In 2008 the EOR production through thermal methods was around 1,252,000 bpd (1,016,000 bpd forecasted in 2010). The thermal methods are best suited for heavy oil and tar sands reservoirs.
- Chemical Injection. The addition of chemicals (e.g. polymers/surfactants) to the injected water improves the recovery efficiency, through the interfacial tension reduction or increasing solution water viscosity. This technique never had a wide diffusion and is currently declining, due to the high cost of chemicals, limitations for temperature applications, depth and oil density (15-30 °API). In 2008 the EOR production through chemical methods was quite limited (35,800 bpd).

EOR Process	**Reservoir Characteristics**				
	Oil Saturation (% Pore Volume)	**Type of Formation**	**Permability (mD)**	**Depth (m)**	**Temperature (°C)**
Steam Flooding	> 40	High porosity and permeability sandstones	> 200	< 1,500	Not critical
In-situ Combustion	> 50	Sandstones with high porosity	> 50	< 3,833	> 60
Gel Treatment/Polymer Flooding	> 50	Sandstones preferred. Can also be used for carbonates	> 10	< 3,000	< 90
Alkali Surfactant Polymer, Alkali Flooding	> 35	Sandstones preferred	> 10	< 3,000	< 90
CO_2 Flooding	> 20	Sandstones, carbonates	Not critical if sufficient injection rate can be maintained	Appropriate to allow injection pressure > than MMP, which increases with temperature	
Hydrocarbon	> 30	Sandstones, carbonates with minimum fractures	Not critical if uniform	> 1,333	T can have significant effect on MMP
N_2, Flue Gas	> 40	Sandstones, carbonates with few fractures	Not critical	> 2,000	Not critical

Table 1. EOR screening Criteria as a function of Reservoir Characteristics (revisited from Ref. 4)

EOR Process	Crude Oil Characteristics				
	Oil Specific Gravity (°API)		Oil Viscosity (cP)		Composition
	Recommended	Current Projects	Recommended	Current Projects	
Steam Flooding	8 to 25	8 to 30	< 100,000	2 to 5,000,000	Not critical
In-situ Combustion	10 to 27	13.5 to 38	< 5,000	1.44 to 550	Asphaltic components to help coke deposition
Polymer Flooding	> 15	13 to 34	< 150	5 to 4,000	Not critical
Alkaline Surfactant Polymer, Alkaline Flooding	> 20	32 to 39	< 35	3	Organic acids needed to achieve lower IFT with alkaline methods
CO_2-Flooding	> 22 Miscible > 13 Immiscible	28-45 Miscible 11-35 Immiscible	< 10	0.35-6 Miscible 0.6-6 Immiscible	High percentage of Intermediate HC
Hydrocarbon Miscible/Immiscible	> 23	21 to 57	< 3	0.1 to 140	High percentage of Light HC
N_2 Miscible/Immiscible and Flue Gas	> 35	16 to 51	< 0.4	0.2 to 25	High percentage of Light HC

Table 2. EOR screening Criteria as a function of Oil Characteristics (Ref. 4 and Ref. 5)

4. EOR with CO_2

Enhanced oil recovery using carbon dioxide (EOR-CO_2) can increase oil production in the final phase of a reservoir life, beyond what it is typically achievable using conventional recovery methods. Compared to other tertiary recovery methods, CO_2 has the potential, in its supercritical status, to enter into zones not previously invaded by water and thus releasing the trapped oil not extracted by traditional methods. Besides, a fraction of the injected CO_2 can remain stored underground, which is beneficial for the environment.

EOR can be achieved using CO_2 injection through two processes: miscible or immiscible displacement, depending on reservoir pressure, temperature and oil characteristics.

Table 3 compares the characteristics of the two different EOR-CO_2 techniques.

In *Miscible Displacement processes*, under suitable reservoir conditions (< 1,200 m) and oil density (> 22 °API) the CO_2 injected does mix completely with the oil into the reservoir, decreasing the interfacial tension between the two substances to almost zero (from 2-3 N/m^2), to form a low viscosity fluid that can be easily displaced and produced. The recovery is typically in the range 4 to 12% of OOIP.

In *Immiscible Displacement processes*, when reservoir pressure is too low and the oil density too high, the CO_2 injected does not mix with the oil within the reservoir, but causes the swelling of the oil, reducing its density, improving mobility and, consequently, increasing the oil recovery. In heavy and extra heavy oil reservoirs CO_2 and the oil form two distinct fluid phases, maintaining a separation interface all along the process. The oil recovery can reach 18% of OOIP.

It has been reported (Ref. 6) that in these conditions the addition of CO_2 may reduce the viscosity of heavy oils by a factor of 10.

	CO_2 Miscible	CO_2 Immiscible
Project Start	Before or after water flooding	After water flooding
Project Duration	Short (< 20 y)	Long (> 10 y)
Project Scale	Small	Large
Oil Production	Early (1-3 y)	Late (> 5-8 y)
Oil Recovery Potential	Lower (4-12% OOIP)	Higher (up to 18 % OOIP)
Recovery Mechanism	Complex	Simple
Recycling of CO_2 injected	Unavoidable	Avoidable
CO_2 Storage Potential	Low (0.3 tonn/bbl)	High (up to 1 tonn/bbl)
Experience	Significant	Limited

Table 3. Comparison between Miscible and Immiscible CO_2-EOR techniques (Ref. 7)

Miscible processes are more common than immiscible ones in active EOR projects, although immiscible flooding can be more efficient and could become more and more important if CO_2 sequestration (potentially higher for immiscible floodings) were implemented on a large scale in depleted reservoir, where miscible flooding is not applicable.

Besides, some concerns for CO_2-miscible flooding are associated to the possibility of asphaltene precipitation, if a sufficient amount of CO_2 is dissolved into the crude. A lighter de-asphalted oil can be produced but the precipitated asphaltenes may cause reservoir plugging, reducing the oil recovery. It is then important to determine the asphaltene precipitation conditions for a given oil-CO_2 system.

4.1 Scheme of EOR-CO_2 flooding

The injected CO_2-gas for EOR applications has typically purity from 95% to 99% (vol.). CO_2 is compressed, dried and cooled, before being transported and injected into the formation. In a classical EOR-CO_2 flooding, CO_2 is introduced in the field through injector well/s, typically perforated around the producer well. Once the oil is mobilized, through miscible or immiscible processes, it has to be transported to the production well. The WAG (water-alternating-gas) process, where water and CO_2 are alternated in small slugs until the necessary CO_2 slug size is reached, is the most commonly employed (see Figure 1).

CO_2 requirement is of the order of 1 to 3 tonn of CO_2 per tonn of oil produced (500-1,500 sm^3/sm^3 oil), for miscible process, depending on reservoir and oil characteristics (Ref. 1). 3 to 5 tonn of CO_2 per tonn of additional oil produced can be requested for immiscible floodings (Ref. 8).

Part of the injected CO_2 (30 to 70%) returns with the produced oil and is usually separated, recompressed and re-injected into the reservoir. Remaining CO_2 stays permanently sequestered into the reservoir.

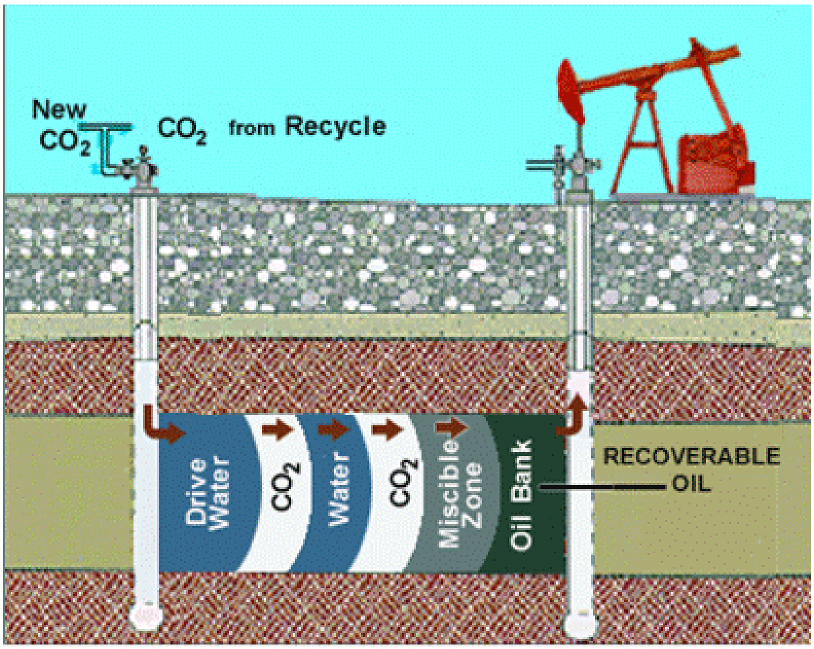

Figure 1. EOR-CO_2 Scheme (Ref. 9)

The CO_2 supply must be guaranteed for the entire treatment's lifetime, typically 10 to 30 years, depending on technical and economical variables (CO_2/oil ratio, oil price, operative costs, etc.).

The CO_2 flow rate typically changes with time; higher amounts are requested at the start of the treatment in order to mobilize the oil, while the demand for CO_2 decreases once CO_2 breakthroughs with the oil and is recycled back. In case of constant CO_2 supply, some system of storage has also to be considered.

5. EOR Worldwide

During the last few decades, a general increase in the number of EOR projects has been observed, as most of the discovered oilfields have already been drained through conventional production methods and a large amount of oil can only be recovered through EOR applications.

Oil & Gas Journal in the recent biannual Survey (Ref. 5), evidences that the EOR processes contribute significantly to overall oil production, especially in the US.

EOR projects worldwide are 316 in 2010, corresponding to an enhanced oil production of 1,627,000 bpd, around 2% of the world total oil production today (84 million bpd). In particular:

- 193 projects, out of 316, are located in USA (+9 over 2008) for an additional production of 666,000 bpd (-17,000 bpd over 2008)
- 40 projects are in Canada (-9 over 2008) for an additional production of 356,000 bpd (-49,000 bpd over 2008)
- 83 projects are in the rest of the world (-7 over 2008) for an additional production of 605,000 bpd (similar to 2008 production)

EOR-CO_2 projects are 124 totally in 2010 (as in 2008), for an additional production of 303,000 bpd (+33,000 bpd with respect to 2008, 0.36 % of oil production worldwide, 19% of EOR production).

114 projects are located in USA (+ 9 over 2008), 6 in Canada and 14 in the rest of the world (Brazil, Turkey, Trinidad). In 2010, 21 further projects were planned, 12 of which employing CO_2.

Most of EOR-CO_2 projects are based on miscible process (117 out of 124), while immiscible CO_2 floodings are less common (7 out of 124). The largest immiscible EOR-CO_2 is the Bati Raman project in Turkey, producing 7,000 bpd in 2010.

As shown in Figure 2, the number of EOR-CO_2 projects has increased, almost constantly, since 1986. Although the number of EOR-CO_2 immiscible projects increased substantially in 2008, compared to the previous trend, a decline is experienced in 2010. Nevertheless the oil production from immiscible EOR-CO_2 treatments increased in 2010, compared to 2008 but it is still limited (in 2010, 19,200 bpd out of 303,000 bpd of the total EOR production from CO_2 injection).

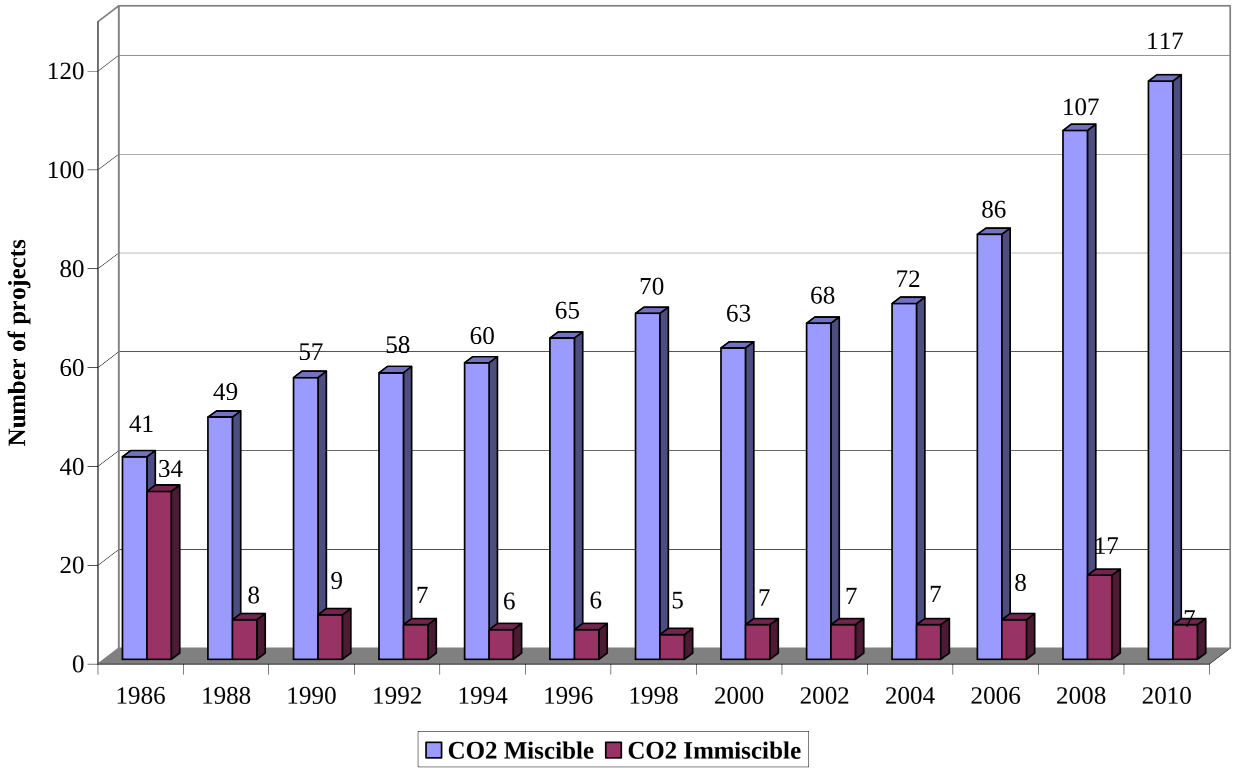

Figure 2. Trend of EOR-CO_2 projects (miscible and immiscible) since 1986 (Ref. 5)

The first miscible CO_2 flood was developed by Chevron in the '70 in Texas in the SACROC unit (Permian Basin), where CO_2 was recovered from flue gas streams at four gas plants, dehydrated and transported to SACROC for injection, 220 miles away.

Today Oxy (Occidental Petroleum Corp.) is the most active company and operates at present 31 projects (28 in 2008), followed by Denbury Resources actives in 17 CO_2-EOR projects (13 in 2008). The Oxy project, Wasson Denver, is currently the field with the largest oil production from CO_2 injection, producing 25,274 bpd.

No applications of CO_2-EOR are active in EU. The main barrier to the implementation of the technique in Europe is the economics of CO_2, in particular the availability of CO_2 sources at low cost at the injection site. In fact EOR-CO_2 is currently applied in regions, like the Permian Basin in Texas, where most of the CO_2 is supplied via pipeline from natural sources (83% of CO_2 delivered in 2009 for EOR treatments came from natural sources, see Ref. 10). Also operating and capital expenses are quite significant, especially for offshore applications.

One of the largest EOR projects worldwide using anthropogenic CO_2 is the Weyburn project in Canada, where CO_2 is captured from a large-scale gasification plant located in North Dakota and piped to Weyburn where it is used for EOR. The current oil production is 16,500 bpd, with 1,600 ktonn/year of CO_2 stored into the reservoir (67% of that injected). The project is expected to produce 122 million bbls of incremental oil, extending the field life by 20-25 years and increasing the oil recovery to 34%.

6. The feasibility study

6.1 Main features of the Armatella Field

Armatella field was discovered in 1991 and is located in the south-east area of Sicily (Italy). The reservoir top at the discovery well (Armatella-1) is estimated at –2,957 m ssl.

Reservoir structural top and faults are depicted in Figure 3.

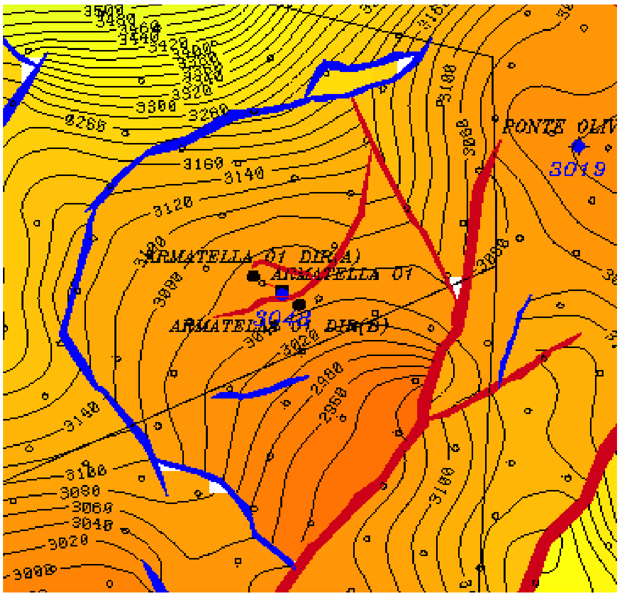

Figure 3. Reservoir top and faults

The discovery well (Armatella-1) penetrated two formations, both naturally fractured: the uppermost Rosso Ammonitico formation and the lowest Rabbito formation. The Rosso Ammonitico Formation (Upper Malm) is constituted by calcareous dolomites, dolomite breccias and dolomite mudstone-wackestones, while the Rabbito Formation (Lower Lias) contains medium-grained packstone-grainstones and fine-grained intraclast packstones (Ref. 11).

Initial reservoir static pressure is defined from well test as 32,724.79 kPa at a depth of – 3,214.0 m ssl for Rabbito and 31,685.29 kPa at - 3100.0 m ssl for Rosso Ammonitico. Available production test data also allow to assume the following reservoir temperature: 96.0 °C @ - 3,100.0 m ssl and 102.4 °C @ - 3,214.0 m ssl.

Two different oils mineralize the formations: in the Rosso Ammonitico the oil density is 7.9 °API and its viscosity is 269 cP@ RC, while in the Rabbito formation the oil is lighter, having a density of 12.9 °API and a viscosity equal to 52 cP @RC.

The available pressure measurements suggest the presence of two aquifers.

A single bi-lateral well, Armatella-1 (Figure 4), is producing since June 1993 leading to a cumulative oil production of 0.3 MSm^3 at October 2009.

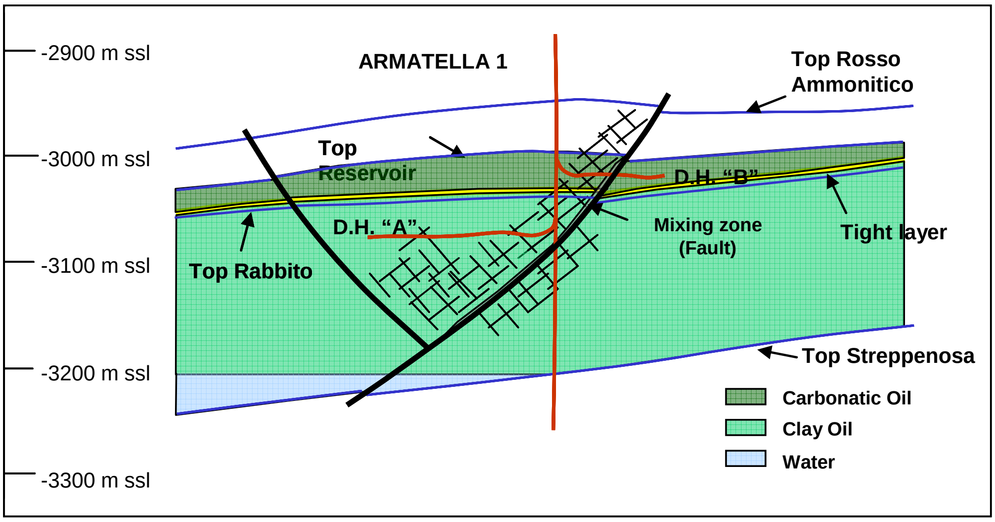

Figure 4. NW-SE Section

6.2 Reservoir simulation study

In order to represent the production behaviour of this fractured reservoir, a 3D dual-permeability simulation model was built using CMG (Computer Modelling Group) simulators.

The characterisation and modelling of the open fracture network has been driven using a DFN (Discrete Fractures Network) approach; the used approach belongs to **eni** methodology and workflow based on integration of image logs, core data and geo-modelling set-up.

The most sound conceptual fracture model, based on analysis of the available data, is a fractures/fault related model. The fractures network was characterized using quantitative open fractures picking from image log and core data as hard data to constrain the model. Available core analyses and their elaboration allowed us to characterize the pseudo-matrix, the latter includes both proper matrix and micro-fractures. The model comprises 13 layers and a total of 18,912 active cells. The relative permeability and capillary pressure curves were taken from analogue reservoirs.

6.3 Investigation of different IOR/EOR Techniques, Methods Screening and Ranking

The applicability of different IOR/EOR methodologies in the Armatella field was investigated having the objective to individuate the potentially best process to test in the field by a pilot project.

The procedure followed to identify the most promising EOR/IOR technique to increase field recovery factor implies three main steps.

As the first step, a preliminary qualitative screening based on average field parameters to identify the applicable techniques was performed. The EOR/IOR methods judged as applicable were then simulated with the 3D dual-permeability model, calibrated on production data and pressure measurements coming from well tests. These simulations allowed the ranking of the different techniques; the most promising one was then deeper investigated in order to evaluate the pilot project performance. Data to characterize and simulate EOR/IOR techniques were taken from literature in case of lack of experimental measurements.

The qualitative screening showed that gas injection, water (isothermal and hot) injection, chemicals (polymer/surfactant) injection and VAPEX may be applicable.

GEM (Generalized Equation of state Model reservoir simulator) compositional code was used to simulate VAPEX and gas injection scenarios, while water (hot/isothermal) and chemicals injection scenarios were simulated by STARS (Steam Thermal Advanced processes Reservoir Simulator) simulator.

The injecting well in the gas and water/chemicals injection scenarios was placed in the maximum of the field structure. Three kinds of gas injections were simulated: a miscible gas (enriched C_1), CO_2 and C_1 injection. CO_2 and C_1 do not reach miscibility conditions, but laboratory tests highlighted that their injection may cause the swelling of the oil.

The constraints for the injecting wells in each scenario were defined so that the considered EOR/IOR technique could provide an efficient performance, honouring some relevant operating limitations and avoiding fracturing pressure. Maximum gas injection rate was set considering the available gas source, while maximum water injection rate was defined controlling the Water Cut at producer Armatella-1.

The VAPEX configuration comprises an injector/producer doublet for each formation, as illustrated in Figure 5. The same fluids injected in the gas injection scenarios were used for the VAPEX forecasts: theses gases, when mixing with reservoir oil, provide in situ solvents able to improve production.

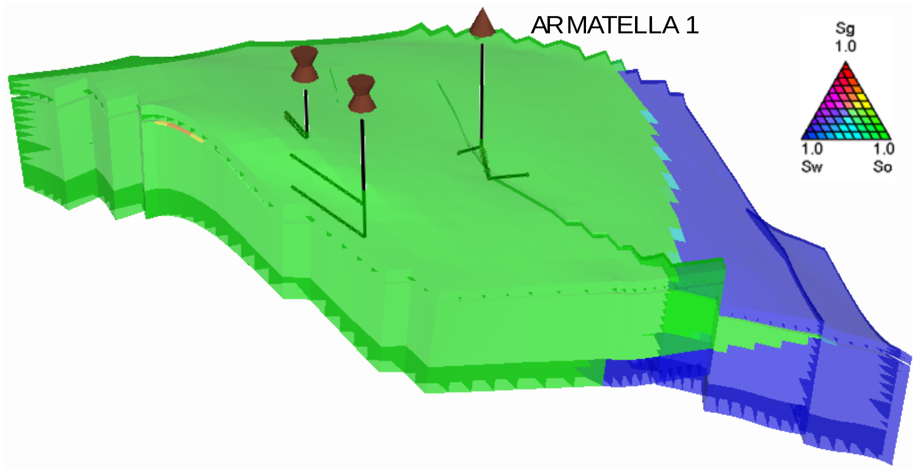

Figure 5. 3D view of the VAPEX wells configuration; the figure also plot the existing producer

In the simulated scenarios no production rate limits were imposed in order to exploit the maximum potential of the simulated techniques.

The forecast scenarios for ranking the EOR/IOR techniques covered 16 years of field production life. As a term of comparison a development scenario with no EOR/IOR techniques (Do-Nothing) was also considered. To compare the simulated recovery techniques, we ranked them in terms of the oil production increment they provide with respect to the Do-Nothing Case at the end of the simulated period.

Table 4 shows the ranking achieved.

Percentage Increment of Cum Oil Production with respect to Do-Nothing case [%]	
Miscible Gas Inj	291
VAPEX Miscible	138
CO_2 Inj	153
Polymer Inj	105
VAPEX CO_2	81
Water Inj	73
Surfactant Inj	82
VAPEX C_1	67
Hot Water Inj	62
C_1 Inj	53
Vertical Infilling	35
Horizontal Infilling	18

Table 4. Quantitative Ranking

From Table 4, it arises that the oil production increases most with EOR-miscible gas injection in regular or VAPEX configuration, but the miscibility is reached by a strong enrichment of C_1. Also the results of the CO_2 injection, in regular or VAPEX configuration, are very promising.

Note that the use of gas in the VAPEX mode is less interesting than the use in regular injection configuration; indeed VAPEX process is very effective for extra heavy oils.

Water injection may also be interesting and polymer may improve water performance, while surfactant injection does not seem promising, the latter behaviour may be related to the fact that the residual oil is not that high (15%).

Based on the results of this study and considering the availability of gas source, CO_2 injection was chosen as the most promising/feasible EOR process to be proposed as a pilot project for Armatella field. Simulation results also show that, during the simulated period, 70% of the injected CO_2 remains in the reservoir, thus highlighting that the production increment is associated with a significant storage potential.

Deeper laboratory analyses were conducted to prove at ‘lab scale’ the efficiency of CO_2 injection.

Specifically, core flooding experiments were done. Two kinds of experiments were conducted: in a first run the core was flooded with brine, while in a second run CO_2 was used to displace the oil. In this way it was possible to compare the recovery efficiency of CO_2 and water. Results highlight that CO_2 injection leads to a higher and faster final recovery. This is mainly due to the swelling effects of CO_2 that leads to a significant oil viscosity reduction thus increasing oil mobility.

Based on these results a pilot project of CO_2 injection is being designed. The project will imply the perforation of an additional producer, that will also allow collecting additional data useful for the successive EOR phase. Perforation of injector and subsequent CO_2 injection is scheduled within 2015.

To design the pilot phase, conservative production limits were imposed to the producers based on average wells capability in the area; this will provide a more realistic prediction of the pilot performance. Forecast pilot profiles were evaluated up to 2040.

Figures 6 and 7 show the forecast profiles for the Do-Nothing (blue line) and CO_2 pilot (red line) scenarios. Figure 6 represents the oil rate versus time, Figure 7 plots the Cumulative oil versus time.

With respect to the Do-Nothing case, the predicted recovery factor due to the pilot project is 9.3%@2040 and the estimated increment due to CO_2 injection is 5.4%@2040.

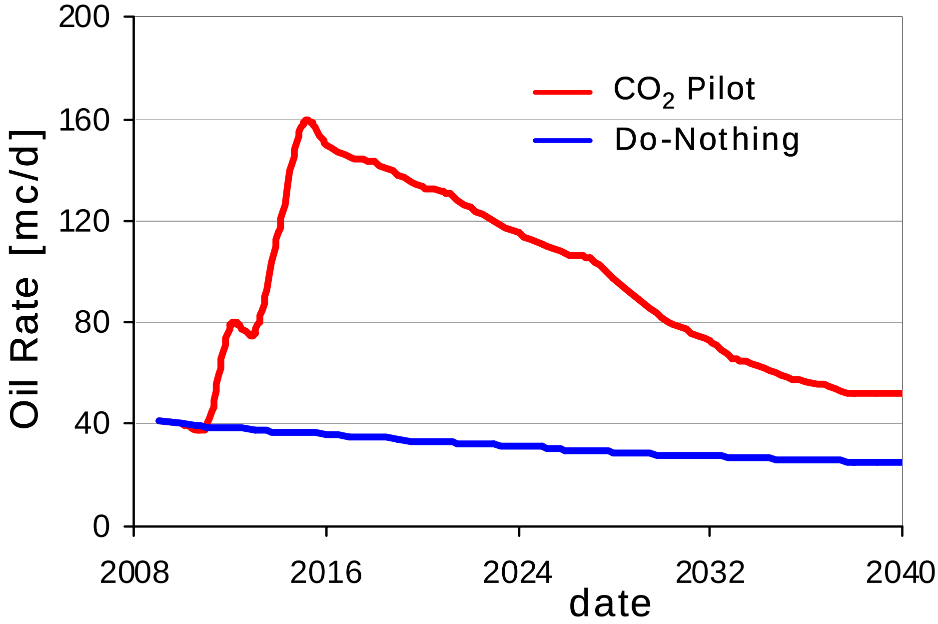

Figure 6. Oil rate versus time

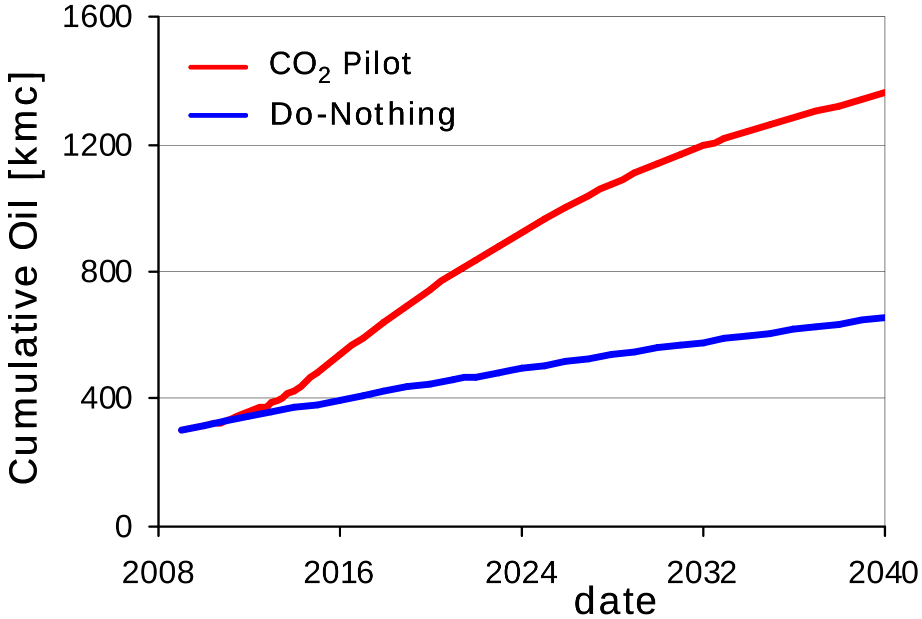

Figure 7. Cumulative Oil versus time

6.4 CO_2 production at Gela Refinery

Refineries are fairly large CO_2 emitters, smaller than power plants: they emit CO_2 from different and often relatively small sources. This makes efficient capture more complex and expensive compared to single-source sites such as power stations, particularly for post-combustion capture technologies, in order to have CO_2 source for EOR projects. Furthermore as most refineries are not large enough emitters, they would have to team-up with other emitters in order to develop viable projects; in the future transport pipelines infrastructure will have to be developed for large volumes in order to be cost-effective, limiting the number of pipelines being constructed.

That's why EOR projects are more commonly applied in combination to power plants more than to industries like refineries. However for Armatella field, Gela Refinery represents an opportunity to have CO_2 available both in quality and in quantity.

As worldwide refineries, Gela Refinery is focusing the activities on efficiency in order to minimize CO_2 emissions related to chemical production and to energy consumption. Besides, some R&D projects are active related to CO_2 sequestration, like the production of bio-oil through bio-algae cultivation, CO_2 fertilization, and to Zero Waste production.

The total amount of CO_2 produced at Gela Refinery is about 3 MM ton/y.

Combustion of hydrocarbons generates CO_2 and is responsible for the bulk of refinery CO_2 emissions. In addition to combustion, refinery generates CO_2 through decarbonisation of hydrocarbons to produce the hydrogen needed to remove impurities (sulphur or nitrogen) and to saturate aromatics and/or olefins for the production of high quality fuel.

The relationship between energy consumption and actual CO_2 emissions depends on the type of fuel burnt, on energy self-generated, imported and whether additional energy exported.

At Gela Refinery partial oxidation of methane (POX Units) for the production of Hydrogen is responsible for the production of almost 392 ktonn/y of CO_2. The process emits both "combustion" CO_2 (to supply the heat of reaction) and "chemical" CO_2 from decarbonisation of the hydrocarbon feedstock.

The total amount of CO_2 produced in proportion to hydrogen is a function of the type of feed.

CO_2 needs to be removed from the CO_2/H_2 mixture to produce the high purity hydrogen stream required. CO_2 removal is realized by solvent (carbonate) absorption: a high purity CO_2 stream is produced (in the range 88-99 % vol). The operation can be performed in such way to produce high purity CO_2. Contaminants can be H_2, O_2, CO, SOx, NOx.

The CO_2 stream would just need to be dried and compressed and then transported to the Armatella site. The production of almost 392 ktonn/y CO_2 is at low pressure (0.5 bar) and is a huge amount compared to that required for the EOR project (10 to 60 ktonn/y), up to 15% of the overall stream.

6.4.1 Capture Technologies for existing Streams

There are a number of well proven technologies for scrubbing CO_2 out of a gas stream, developed in such processes as hydrogen manufacture. They are all solvent absorption processes with different variants depending on CO_2 partial pressure:

- Physical processes where CO_2 is forced in to various chemical solutions, requiring CO_2 partial pressures of at least 20 bar (e.g. 70 bar total pressure and CO_2 content above 30%).
- Mildly alkaline solvents such as potassium carbonate solutions or certain amines require a much lower CO_2 partial pressure, in the order of 2 bar (e.g. total pressure of 10 bar and 20% CO_2). This is used in hydrogen plants of older type.
- Highly alkaline solvents such as Mono-ethanolamine (MEA) can be used at even lower pressures.

Because of the relatively low pressure at which most of the CO_2-containing gas streams are available, refinery capture technologies are limited to chemical absorption (amine or hot potassium carbonate), with the exception of capture from hydrogen plants. Ease of capture is a function of CO_2 Partial pressure. From H_2 plant/POX Units, capture efficiency would be 98% or better.

7. The Pilot Project

Armatella EOR Project involves three different sites (Refinery, Oil Center, Well Site) and requires, typically, the realization of systems for: CO_2 capture at the Refinery, CO_2 conditioning and compression, CO_2 delivery to well site, CO_2 injection well, additional oil production well and CO_2 recovery from produced oil.

Several development concepts are scrutinized at the moment in order to select the most appropriate in term of technical and economical performances. One of the possible schemes of choice is here discussed, where the facilities at the well site are understated, through the reduction of CO_2 supply, by recovering and re-injecting the gas produced with the oil at the well site.

The pilot project will be designed in agreement to high standard safety level and environmental policy, including a CO_2 Monitoring Plan. The scope is to monitor possible CO_2 leakages due to active faults, damaged wells, cap rock discontinuities, etc. and helping the final evaluation of process efficiency and reliability.

The CO_2 rich stream will be captured from the Gela refinery's methane oxidation plant, compressed with a two-stage compressor and delivered to the Well-Site, through a new 15 km pipeline. The stream is water oversaturated, so a remarkable water condensation takes place during compression and cooling. These liquids will be sent to the existing water treatment unit at the Refinery.

At the well site the CO_2-stream will be dehydrated before the final compression stage, employing an adsorption column, and CO_2 will be then injected into the formation through the new injector well (Arm-3). CO_2 produced with the oil from the two producers (1 old, 1 infilling well new), will be recovered, treated and compressed (4 steps) together with the CO_2-stream delivered from the Refinery, before injection. The condensation water produced by the compression unit will be sent to the primary separator and then to the Oil Center together with the oil and the associated water. The delivery will be accomplished through the existing pipeline.

Table 5 details the technical characteristics and the estimated results of the EOR-CO_2 treatment.

Armatella OilField Characteristics	
Oil Produced to date (MSm^3) (October 2009)	0.3
Current Daily Production (bpd)	250
Pilot Project	
CO_2 Injection Start (year)	Within 2015
CO_2 Injection Rate (Sm^3/d)	18,000-88,000
Expected oil breakthrough (year)	2016
EOR-CO_2 Additional Recovery Factor (% of OOIP)	5.4%
Estimated peak production due to EOR-CO_2 pilot (bpd)	750
Total CO_2 Injected during EOR-CO_2 (MMm^3)	756
Total CO_2 Stored during EOR-CO_2 (MMm^3)	529
CO_2 Recycled Back (%)	30
Additional Oil/CO_2 Injected Ratio (tonn/tonn)	0.25

Table 5. Armatella Oilfield Characteristics, Pilot Project operative conditions and Expected Results

This possible project scheme (see Figure 8) contemplates the realization of: 1) a new line (15 km) to transport CO_2 from Refinery to the injection well site; 2) a new CO_2 injector well; 3) a new infilling producer well.

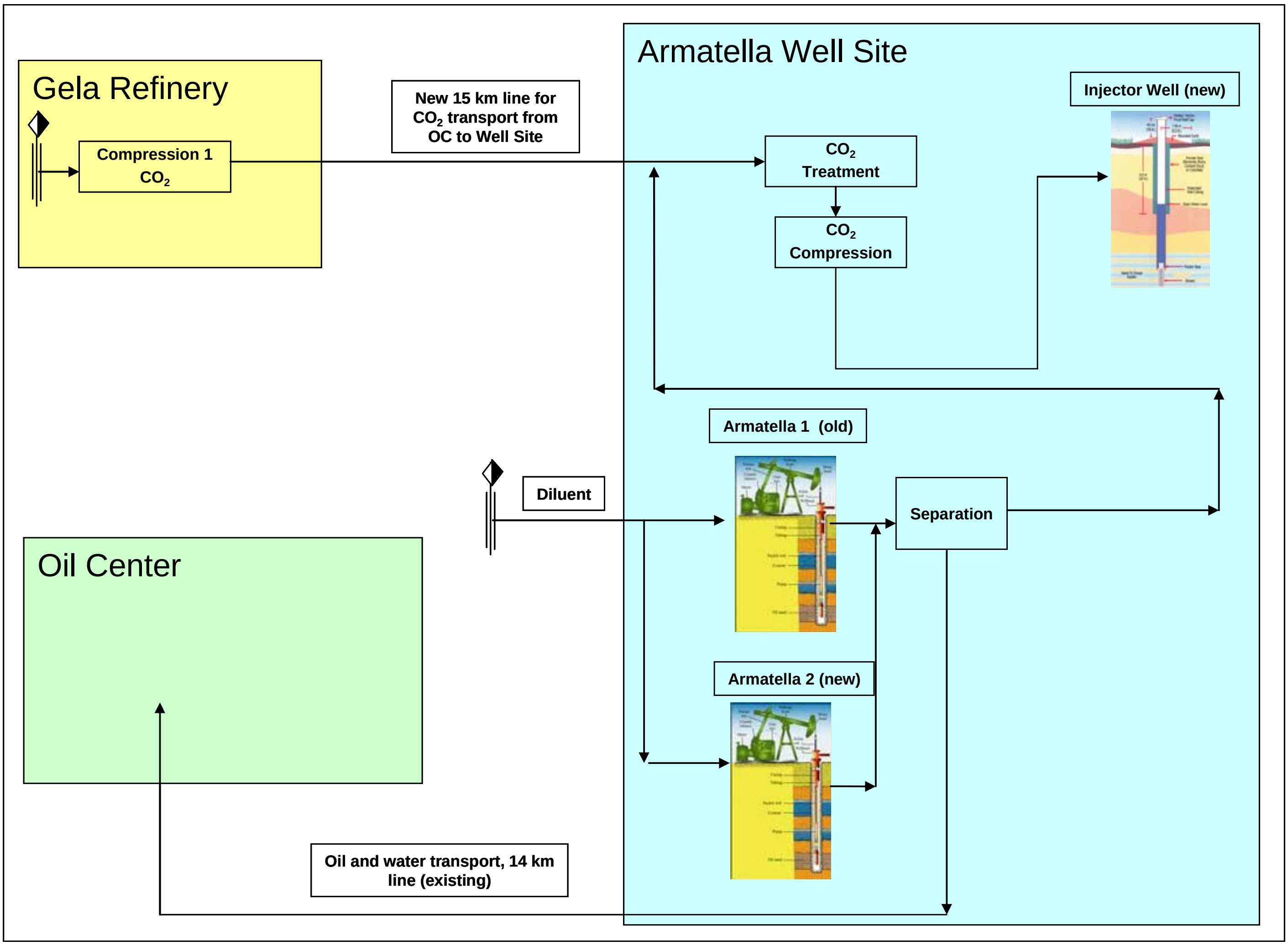

Figure 8. Possible Scheme of EOR-CO_2 Pilot Project at Armatella Field

8. Economics

The realization of a EOR-CO_2 project is capital intensive, involving the drilling and/or workover of wells, the construction of CO_2 transportation systems, CO_2 gathering, compression, handling and recycling plants. Other costs are associated to the additional oil production, whose treatment is generally realized employing existing infrastructures, usually requiring just small adaptation.

However, the largest cost of the project could be associated to the purchase of CO_2 or to its purification/concentration. According to IPCC, the overall cost of CO_2 sequestration ranges from 27 to 82 US$/tonn of CO_2 and is mainly associated to CO_2 capture, which constitutes the 80-90% of the total cost (25-75 US$/tonn for capture, 1-5 US$/tonn for transport and 1-2 US$/tonn for injection) (Ref. 12).

Evaluations of costs are reported elsewhere, for compression, cooling and dehydration (Ref. 13), capture (Ref. 14), transportation (Ref. 15, Ref. 16) and are substantially in agreement with IPCC estimates.

Revenues from additional oil selling could partially or totally offset the capital and operational costs of the process, especially if a cheap source of CO_2 is available. Moreover contribution to revenues could derive in the future from fiscal incentives, like carbon credits, considering the storage of significant amount of CO_2 into the reservoir.

For Armatella Pilot Project the investments costs are associated to the realization of a new injector well, a new pipeline for CO_2 transport and all the facilities for CO_2 compression, treatment, handling, storage.

Operational costs are related to the management of new wells/facilities and to additional costs for the increased oil production. Costs of CO_2 supply are virtually zero as a high purity CO_2 stream is available from the Gela Refinery methane's partial oxidation plant.

Project economic evaluation was realized by determining, through a discounted cash flow model, the Net Present Value (NPV) pre-taxes of the project (at WACC adjusted: 10%).

A price of 200 €/tonn@2010 for the additional oil produced is considered. An escalation rate of 2% (per year) is applied to crude oil price and costs.

The economics of the Armatella project are negative, as expected for a pilot sized project (see Table 6).

A more detailed evaluation of economics has, then, been realized considering the EOR-CO_2 extension to a bigger oilfield nearby (Giaurone, producing currently 1,900 bpd). A sensitivity analysis is carried out on this project with the aim to identify the most critical variables among: crude oil price, CAPEX and OPEX. The influence of additional revenues from future fiscal incentives has also been considered.

Table 6 reports the different parameters employed for the analysis while the sensitivity analysis for the most promising Giaurone project is shown in Figure 9.

NPV pre-tax is negative for both projects; for Giaurone project NPV is –15.2 M€.

	Armatella oilfield	**Giaurone oilfield**
EOR-CO_2 Additional Recovery Factor (% of OOIP)	5.4	4.0
CO_2 injected (tonn/y, average)	55,000	69,000
CO_2 stored (tonn/y, average)	38,000	61,000
CAPEX (M€)	64.8	73
OPEX (M€/y)	2.5	3
Project Duration EOR-CO_2 (yrs)	27	24
Oil price (€/tonn@2010)	200	200
WACC Adjusted (%)	10	10
NPV pre-tax (M€)	-38.9	-15.2
NPV post-taxes (M€)	-33.5	-22

Table 6. NPV analysis parameters and results

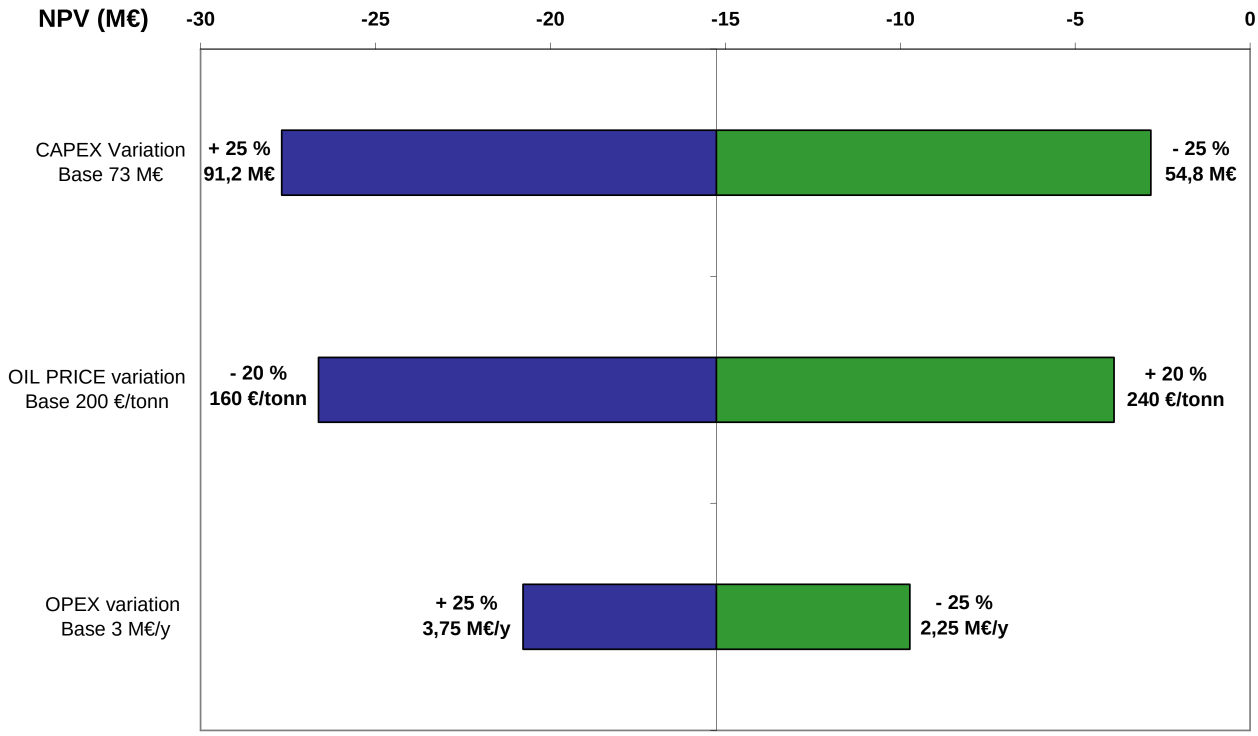

Figure 9. Sensitivity analysis for EOR-CO_2 application to Giaurone oilfield

Project feasibility, as expected, is found to be very sensitive to CAPEX, OPEX and oil price, at fixed oil production. The sensitivity analysis (Figure 9) shows that the CAPEX and the oil price play a major role while OPEX changes have a limited impact. NPV increases from -15.2 M€ to -2.8 M€, with a 25% decrease of CAPEX, and to -3.9 M€ with a 20% increase in the oil price.

The potential impact of fiscal incentives has been evaluated by determining the minimum “price” for CO_2 stored in the reservoir necessary to achieve a profitable project (NPV >/= 0). Results are reported in Figure 10.

CO_2 stored into the reservoir is determined as the difference between the CO_2 injected and that produced with the oil, taking into account the contribution to CO_2 emissions due to process facilities.

As evidenced in Figure 10, the profitability of Giaurone project (NPV is > 0) can be reached at reasonable CO_2 price (around 24 €/tonn). This level of fiscal incentives is quite close to forecast for future CO_2 credits, that are currently quoted (as average) 15.2 €/tonn in the period 2013-2016 and 25.05 €/tonn in the period 2017-2020 (18).

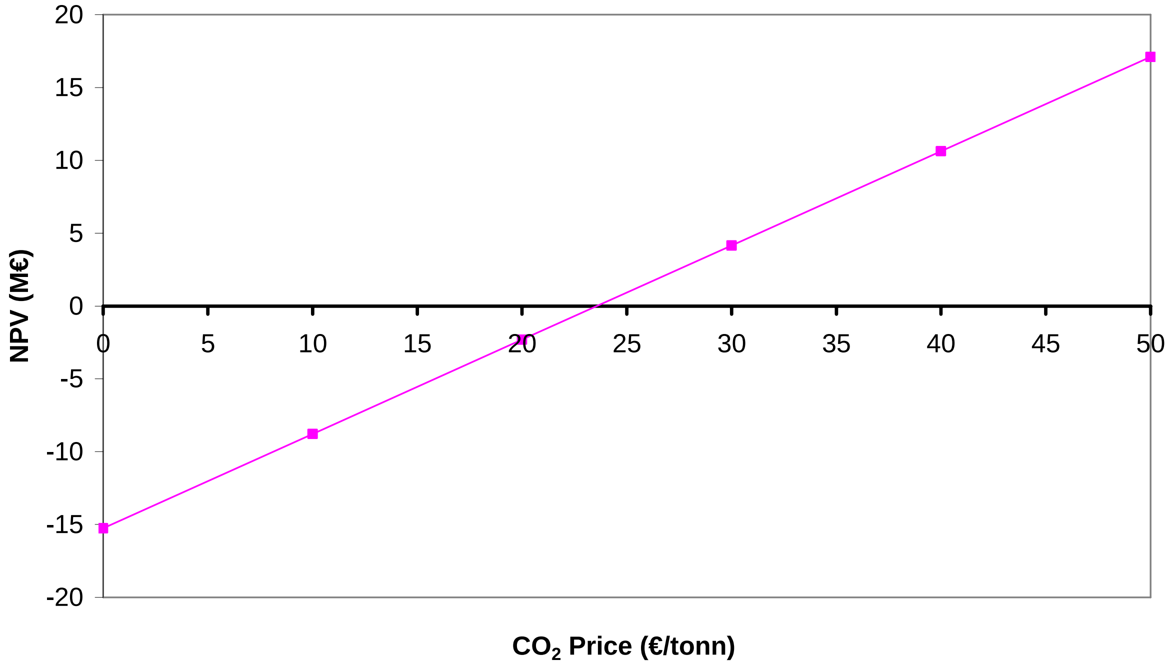

Figure 10. Giaurone project: influence of incentives (price of stored CO_2) on NPV

9. Conclusions

CO_2 enhanced oil recovery (EOR) can offer exciting opportunities for both upstream and downstream oil businesses, especially if the refinery is located near operating oil fields. However successful deployment will require interdisciplinary study for secure CO_2 sites, based on extensive geological knowledge of formations, efficient capture technologies at refinery sites and transport infrastructure.

CO_2 flooding has the potential to extend the life and increase the recovery factor of depleted or high viscosity fields by 5 to 15% of OOIP. Besides, it is possible to sequester large amount of CO_2 that would normally be released into the atmosphere, with undoubted environmental benefits.

Increasing the "recovery factor' boosts reserves even without the discovery of new fields; a one percent increase, only, of the recovery rate can increase reserves of 70 billions barrels (more than 2 years of world oil production, 83.7 Mbpd in 2008, see Ref. 17).

At present there are no applications of CO_2-EOR in Europe, only plans, due mainly to the lack of available CO_2 sources at low cost. The introduction of incentive mechanism for the reduction of CO_2 emissions, could contribute to boost the application of this technology and accelerate the projects of carbon capture and sequestration (CCS). At the moment market prices for carbon credits due to CO_2 sequestration are still uncertain, especially for EOR applications.

eni has launched a pilot project on CO_2 Enhanced Oil Recovery (EOR) at Armatella field, for increasing heavy crude oil recovery. EOR-CO_2 was individuated by simulation modelling as one of the most promising methodologies in the field and selected for the pilot project phase, considering the availability of the gas source at the Gela Refinery nearby.

Armatella project is of great strategic relevance for **eni**, both for business sustainability and for the oil reserves growth.

The EOR-CO_2 Armatella Pilot Project will be the first example of EOR in Italy, where the integration between downstream and upstream operations will be realized.

Preliminary estimates suggest that the CO_2 injection would have the effect to strongly increase the Armatella recovery factor; the *do nothing* case will provide a recovery factor of 9.3%@2040 and the estimated increment due to CO_2 injection is 5.4%@2040, while most of the CO_2 injected (around 70%) would remain permanently stored into the reservoir.

The economics of Armatella project are not favourable, at current oil price and without fiscal incentives for CO_2 stored into the reservoir.

Nevertheless several factors could contribute to make EOR-CO_2 projects profitable. Among these: extending the EOR-CO_2 application to higher producer oilfields (Giaurone for instance), optimizing investment and operative costs, for instance through EOR-CO_2 cluster complex, exploiting and revamping dismissed facilities.

However, the most important contribution to boost the application of this technology is the introduction of a mechanism of incentives for the reduction of CO_2 emissions, which rewards the environmental benefit due to CO_2 captured from refineries/power plants and permanently stored into the reservoir, even through EOR applications.

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