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Large scale tertiary CO_2 EOR in mature water flooded Norwegian oil fields

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Abstract

A technical-economical model for a large-scale infrastructure combining CO_2 EOR and aquifer storage has been used to construct a scenario including 23 Norwegian Continental Shelf oil fields that have been identified as potential candidates for CO_2 flooding. In the injection scenario, 70 million tonnes of CO_2 is injected annually over 40 years. A limited sensitivity analysis has been performed. The EOR potential for continuous CO_2 injection is estimated to be between 276 and 351 million Sm3. This corresponds to 5.9 and 7.6 % of the oil originally in place depending on the oil price (low/high: 40/120 USD/bbl), the cost of CO_2 that the oil producers must pay for all stored CO_2 (low/high: 0/50 USD/tonne) and well costs (low/high 25/42 million USD/well). In addition to transportation costs through the main pipeline (8 USD/tonne) specific costs for aquifer deposition also applies (8 USD/tonne). CO_2 mass balance calculations show that more CO_2 is stored in the oil reservoirs during tertiary flooding compared to the CO_2 formed by combustion of the produced oil. The CO_2 footprint becomes even more negative when the CO_2 stored in aquifers is included in the calculations.

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Keywords: CO_2, EOR, aqifers storage, capacity, economy, negative CO_2 footprint

1. Introduction

CO_2 storage in sedimentary rocks is considered to be a large-scale solution for reducing the emission of anthropogenic CO_2 [1]. The storage capacity in the North Sea may be sufficient for EU point sources for the fossil era

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[2]. Gas and oil fields are considered as safe storage sites due to their historic record of trapping buoyant fluids for millions of years.

Many water-flooded oil fields are now becoming mature characterized by high and increasing water cut. To govern the remaining resources there is an urgent need to deploy new methods to mobilize some of the typical 40 -60% of the remaining oil in the reservoirs. Decisions on how to continue production must be taken within the next few years, whether new EOR processes shall be introduced or if the fields have to be abandoned.

CO_2 injection is a proven technology for enhanced oil recovery (EOR) from onshore fields and can potentially also be used in the North Sea reservoirs. EOR processes are the only large-scale applications where CO_2 has an economic value and it appears attractive to combine large-scale CO_2 deposition with EOR. In this study, large-scale tertiary CO_2 injection has been scrutinized and 23 North Sea oil fields have been identified as potential candidates.

In order to elucidate the possibility of combining CO_2 storage with EOR, a technical-economical model developed to analyse large-scale CO_2 deposition in the North Sea has been used. Results from previous studies with the model have been presented earlier [3, 4]. In newer versions of the model [4] both continuous CO_2 injection and WAG can be studied. Only continuous injection is addressed here, however.

In previous versions of the technical-economical model, the economic calculations were only related to the CO_2 injection, treated as a separate project with incomes only from the incremental oil production. The present version of the model allows economic calculations based on incomes from all produced oil after start of CO_2 injection. This is applied in the present work. The total production costs then include additional costs due to CO_2 injection as well as the costs for continued water production. Data for the latter were estimated based on figures provided by and used in a study for the Norwegian Petroleum Directorate [5].

Drilling costs represent half of the total investment costs on the Norwegian Continental Shelf every year [6]. New wells will also constitute a significant part of the investment costs for conversion of a field from water injection to CO_2 flooding. The costs of drilling wells are dependent on several variables, *e.g.* rig rate, time spent, costs of consumables and logistics. Among these, the two major cost drivers are time spent on drilling and rig rate. The latter is dependent on the availability of suitable rigs and the market situation. The costs of new wells on the Norwegian Continental Shelf have varied from typically 200 million Norwegian kroner (NOK) in 2000 – 2003 to 500 million NOK (all in 2013 NOK) in 2008 – 2013 [7] but has now fallen to a value between these figures. Reuse of existing wells with further reduced costs can also be an option in some cases.

2. The technical-economical model

The concept of the technical-economical model is illustrated in Figure 1. The model consist of four basic components; a transport module, an EOR module, a module for storage of excess CO_2 and an economic module compiling operation cost , investments and EOR income from all areas into the final economic analysis. CO_2 from various land-based sources are collected at the export terminal where it is compressed and fed into the main pipeline infrastructure at a constant total rate over the lifetime of the project. From the main pipeline CO_2 is delivered to specific oil fields where the CO_2 is injected in order to increase the oil recovery in addition to safe long-term storage. Each oil field imports only the CO_2 needed and the amount will decrease over time since break through CO_2 will be recycled. The need for CO_2 for enhanced oil recovery purposes will therefore vary with time, surplus CO_2 is stored in aquifers.

2.1. The CO_2 transport module

In the CO_2 transport module it is assumed that CO_2 is delivered from export terminals in Emden (Germany) and Kårstø (Norway) where CO_2 from various sources are collected and compressed to export pressure. From the export terminal in Emden a large pipeline transports CO_2 as dense phase to the Ekofisk area and further to Tampen. A smaller pipeline feeds CO_2 from Kårstø into the main line. The CO_2 transport module calculates the cost for CO_2 transportation for given total capacities in the different sections of the pipeline, given the off take in the Ekofisk area, and given the feed from Kårstø. From the main infrastructure CO_2 is transported to specific storage sites through branch lines. The branch lines are connected to platforms where the CO_2 is compressed to necessary injection pressures before it is injected into oil reservoirs and aquifers. In the present work CO_2 is delivered in Emden only, and the transportation cost is calculated as if all CO_2 is used in the Tampen area.

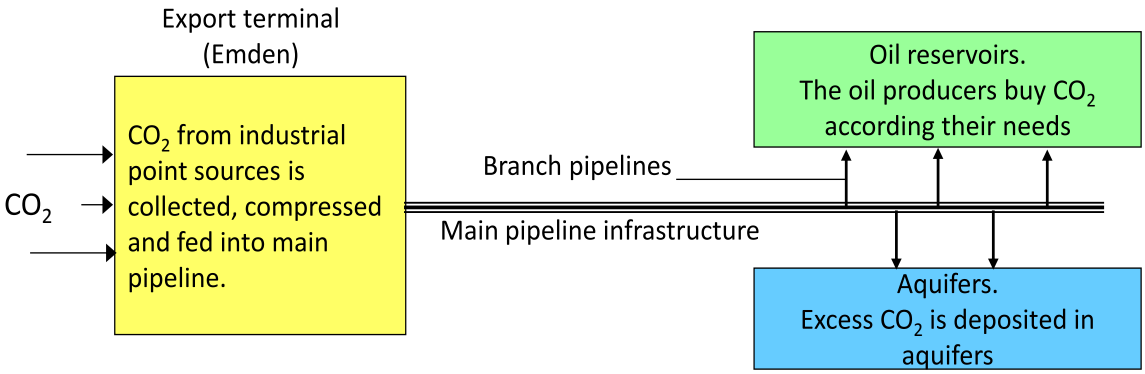

Fig. 1. Illustration of infrastructure model concept.

Fig. 2 shows transport costs as function of capacity through the in total 990 km long main infrastructure. Also included in the figure is an offshore CO_2 transportation cost calculated by interpolation of data from an European Union sponsored Zero Emission Project (ZEP) [8] where transportation costs are given for various lengths of the pipeline. The reference for the cost estimation is the second quarter of 2009. An exchange rate of 1.26 Euro/USD was used. The ZEP-cost also includes two 10 km collection lines and two 10 km distribution lines in addition to the main pipeline. The SINTEF Petroleum Research (SPR) model does not include these additional lines, but includes compression from 60 to 200 bars. Thus, both calculations include additional items to the main pipeline. The two values for 20 million tonnes CO_2/year are in good agreement although the reference dates differ by several years. The accuracy in the estimated costs in the ZEP is estimated to be ± 30 %. In the comparison, it must be kept in mind that various cost indices included in the model (plant costs, steel costs, pipe laying costs, labour costs) and currency exchange rates have fluctuated significantly the last years.

In the present work the CO_2 transportation costs is determined to 7.96 USD/tonne for a total capacity of 70 million tonnes/year using the SPR model.

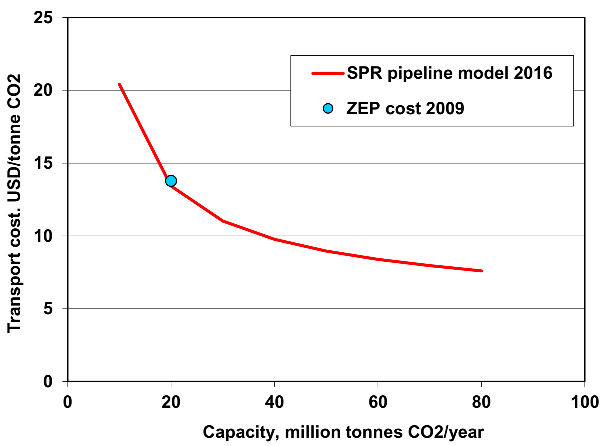

Fig. 2. CO_2 transportation costs as function of capacity.

2.2. The EOR module

When CO_2 is injected into oil reservoirs that have previously been water-flooded the oil recovery will increase. A module for the prediction of EOR by CO_2 injection in water flooded sandstone reservoirs was developed based on a generic model of a sandstone reservoir, with realistic heterogeneities. A numerical reservoir simulator was used to predict the performance of water injection followed by CO_2 injection. This was done for different injection rates, lengths of water flooding before start of CO_2 injection, oil density, oil viscosities, vertical permeabilities, and rock heterogeneities. Explicit functions (response surface models) of the same variables were then fitted to the simulation results, to calculate production profiles of oil, water, and gas, and the times of water and gas breakthrough.

The simulations that formed the basis for the EOR module were performed for miscible displacement of oil with CO_2. A miscible transition zone between CO_2 and oil is developed through multi-contact phase changes in between the two fluids if the pressure in the reservoir is above the minimum miscibility pressure. This condition must be met if the predictions made by the EOR module shall be valid.

The EOR module was then applied in the analysis of real fields that have been under water flooding using field specific values for a set of dimensionless groups. The specific CO_2 injection rate for each field was chosen to be the same reservoir volume rate as the reservoir oil volume plateau rate which also gives a reasonable limited number of injection wells. The vertical permeability multiplier and the heterogeneity exponent of the EOR module were used as tuning parameters for historical oil production data and expected future production. Data for historical and future production were received from the Norwegian Petroleum Directorate, NPD. An example of estimated production curves for oil, water and gas during water injection and later conversion to CO_2 injection is shown in Figure 3.

Break-through of CO_2 in the production wells will occur a few years (often 1 - 2 years) after start of CO_2 injection. The fraction of CO_2 in the produced gas and produced mass of CO_2 is found by mass balance. Since all produced gas is recycled, the amount of net CO_2 import to a field will decrease rapidly after break-through of CO_2.

CO_2 injection into an oil reservoir is a complicated process and the potential for EOR can only be accurately assessed by extensive reservoir modelling using a numerical reservoir simulator and a detailed reservoir model. The estimates made by the present EOR module can only yield rough estimates of the EOR potential. However, the generic EOR model describes inherent elements of a CO_2 injection process such as profiles for water production, gas production and CO_2 content in the gas in addition to total and incremental oil recovery. Field specific profiles as illustrated in Fig. 3 are used as input to the techno-economical modelling.

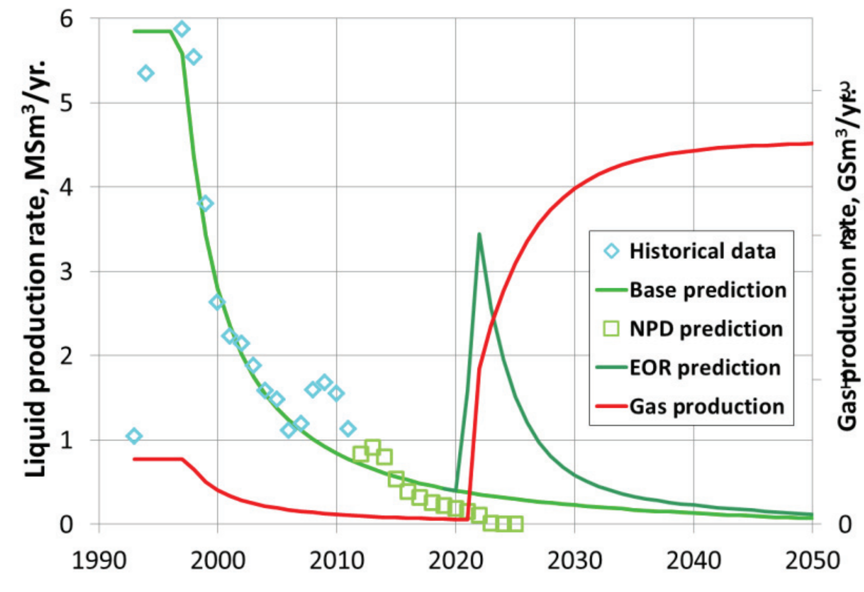

Fig. 3. Production curves for oil, water and gas during water injection and conversion to CO_2 injection in year 2020.

2.3. CO_2 storage module

CO_2 transported in the main pipeline at a constant rate over the total project lifetime. The design capacity of the main infrastructure pipeline will be equal to the peak need for oil production. In the EOR predictions a constant injection rate of CO_2 is used for each field during the CO_2 injection period. Since more and more CO_2 is recycled after break-through the CO_2 import to each field will decrease. Excess CO_2 must be stored in aquifers. Early in the project period most of the CO_2 transported will be stored in oil reservoirs, but increasing amount of excess CO_2 will be stored in aquifers as the times goes by.

In the ZEP [9] cost estimates were made for several storage cases, both for onshore and offshore storage in depleted oil and gas reservoirs and in aquifers. In the present work storage costs will be based on estimates from Case 6 in the ZEP, corresponding to offshore storage in saline aquifers. In the present work the storage costs estimated for 5 million tonnes/year in the ZEP (8 USD/tonne) is used. This costs include costs occurring before investment decision (modelling and logging costs, seismic survey, injection testing, new exploration wells, permitting), structural costs (new platform or reuse of existing), injection wells (new and re-used injection wells, legacy well remediation), operating and maintenance, monitoring, measurement and verification (new observation wells and post-closure monitoring) and close down costs (decommissioning, liability transfer).

CO_2 transportation costs (7.96 USD/tonne) and a CO_2 price at the export terminal comes in addition to the storage costs described above.

2.4. The economic module

New installations and modifications are needed to convert a field to CO_2 injection. These include:

- branch pipeline to the oil installation from the main infrastructure, connection and riser
- modification of the oil production system
- CO_2 compressor
- CO_2 injection wells

From the main pipeline CO_2 is transported to each injection site through a separate branch line. The diameter of the branch lines will depend on the lengths of the lines and the needed transport capacities. In the design of the main pipeline module, the minimum pressure in the line was set to 100 bars. For the branch lines a maximum pressure loss of 30 bars was specified. CO_2 will thus be available at the platform at a pressure of minimum 70 bars that will secure that the CO_2 always is in dense phase. A model relating pipeline costs to length and capacity based on the medium cost scenario in [10] was used to estimate costs of the branch pipelines, adjusted with changes in steel, pipe laying and labour costs.

A modification of the oil production system to handle larger gas volumes after massive CO_2 breakthrough will be needed. The investment cost of building a land based oil production system has previously been estimated to 400 USD/bbl/day (plateau oil production rate) including the first stage compressors. This cost figure is scaled to date by use of the Chemical Engineers Plant Cost Index. Project Invest Energy (PIE) made an assessment for the cost of converting an existing oil production system from water injection to CO_2-WAG [11]. The amount of CO_2 to be injected was 5 million tonnes per year and the oil production system was designed to handle 80 % of injected CO_2 for recycling. Three cost scenarios (low, medium, high) were studied depending on the reuse and modification of existing process equipment. Only new process equipment was included in the high cost scenario. Compared with the present cost model PIEs high cost scenario gave lower investment costs. An index-regulated cost of 400 USD/bbl/day is therefore used for modification of the oil production system without any cost additions for offshore conditions.

The imported CO_2 (at minimum 70 bars) will be fed into the final CO_2 compressor and injected. After CO_2 break through, increasing amounts of CO_2 (and some HC gas) will be recycled from the oil production system (separator train). In the calculations of compressor power the first stage separators are assumed to be operated at 60 bars. Most of the gas will already be separated at this stage. The investment costs for the CO_2 compressor is based on a load corresponding to the total mass of injected CO_2 using the cost estimation program Capcost [12] and scaled to date with the Chemical Engineers Plant Cost Index. Capcost calculates the cost of process equipment based on specifications for each unit operation. Grass root costs have been used. Compressor costs for the second, third and fourth stage compressors (new or modified) in the oil production system are included in the costs for modification of the oil production system.

New wells for CO_2 flooding will be needed. In the economic module new wells are added scaled to CO_2 injection capacity. For sandstone reservoirs one well is added for each 1 million tonnes CO_2/year injection rate. For chalk reservoirs one well per 0.5 million tonnes CO_2/year injection rate is used. As already discussed in the Introduction chapter the cost of new wells on the Norwegian Continental shelf has decreased significantly the last years. A unit cost for new wells of 350 million NOK (43.75 million USD) is used in the calculations.

Reuse of existing wells is also an option. Slot recovery enables reusing an old well slot to drill a sidetrack through the same surface structure. This operation typically involves mechanical removal of a section of the casing, followed by an open-hole sidetrack or casing exit. On the Norwegian Continental Shelf such operations traditionally took 60 - 122 days [13]. Assuming the use of a semi-submersible rig at 300 000 USD/day, the cost of traditional sidetracking was thus in the range between 18 and 37 million USD. However, new technologies have recently lowered the costs of slot recovery. A so-called through-tubing drilling and completion operation can be performed in 35 days [14]. Through-tubing drilling and completion is a generic term for sidetrack drilling in existing producers and injectors, covering both coiled tubing drilling and through-tubing rotational drilling (including installing the lower well completion). Its main advantage is that new reservoir sections can be penetrated without having to remove the x-mas tree, the completion or the production casing, thereby reducing operational time compared to a traditional slot recovery or sidetracking operation. Assuming the use of a semi-submersible rig at 300 000 USD/day, the cost of through-tubing drilling and completion is 10 million USD (80 million NOK).

Replacing the tubing can sometimes be an option. This can take up to 15 days [15]. Assuming the use of a semi-submersible rig at 300 000 USD/day, the cost of replacing the tubing in a well is 4.5 million USD. For a given project it is unlikely that only reuse of existing wells can be applied. More likely there may be a mix of reuse and new wells. The average cost per well for a field may therefore fall somewhere between the highest and lowest costs indicated above. In the present calculations 25 million USD/well is used as the lower well cost.

Engineering costs and contingency are added to the investment cost for branch lines, wells and equipment as described above. 25 % each for both cost items are used. Yearly operation and maintenance costs for the EOR projects are calculated based on total investment costs. The value used in the present study is 15 %. Energy costs are calculated based on compression power and set to 0.2 USD/kWh. In addition to this, costs for operation and maintenance (OPEX) of the oil platforms or floaters and other equipment and systems will apply. In order to account for these costs data supplied by NPD have been used. OPEX for the various fields were added to the operation and maintenance costs estimated for the EOR projects to give the total operational costs. When needed OPEX data from NPD were extrapolated based on individual judgements for each field. The investments needed for conversion to CO_2 injection are made two years before injection start.

2.5. The technical-economical model

The elements of the various modules described above is collected into a spread-sheet based tool with summary sheets for field information and economical parameters, and individual sheets for each oil field with production profiles and tuning parameters for matching the EOR module to historical production data. In addition to the various cost items already described, the following items are also entered into the model:

- Rate of return (7 % used in all calculations in this work)
- Oil price
- CO_2 price (the price paid for all CO_2 fed into the infrastructure at the export terminal)

For a given scenario the fields to be included are chosen. The model then calculates performance figures for each field and total performance for all fields included. CO_2 injection into each individual field continues as long as the net cash flow for the field is positive.

3. Performance of tertiary CO_2 EOR

3.1. Selection of aquifers and oil fields

No locations of the aquifers needed for storage of excess CO_2 has been specified in the present work although many alternatives exist. Aquifer storage is thus only included with a unit storage cost as specified above.

The oil fields included for the study were selected from an updated list of candidate fields along with a preliminary evaluation of their suitability for tertiary CO_2 EOR as provided by the Norwegian Petroleum Directorate. The list was reviewed before the final selection of the 23 field included was made. For each field a suitable time for start of CO_2 injection was identified.

3.2. Oil production and CO_2 storage

Figure 4 shows production profiles for EOR oil as a result of CO_2 injection into the 23 selected oil fields. The specific scenario for this figure shown was obtained from calculations made for well costs of 25 million USD/well, an oil price of 50 USD/bbl, a zero CO_2 price, and a rate of return of 7 %.

Figure 5 shows the profiles for CO_2 injection into the same fields. The total rate of CO_2 transported through the main pipeline infrastructure is 70 million tonnes/year. The CO_2 injected into aquifers is represented by the white area in the figure.

Table 1 gives an example of results obtained for a specific calculation. The calculation was made for the same economic conditions as stated above.

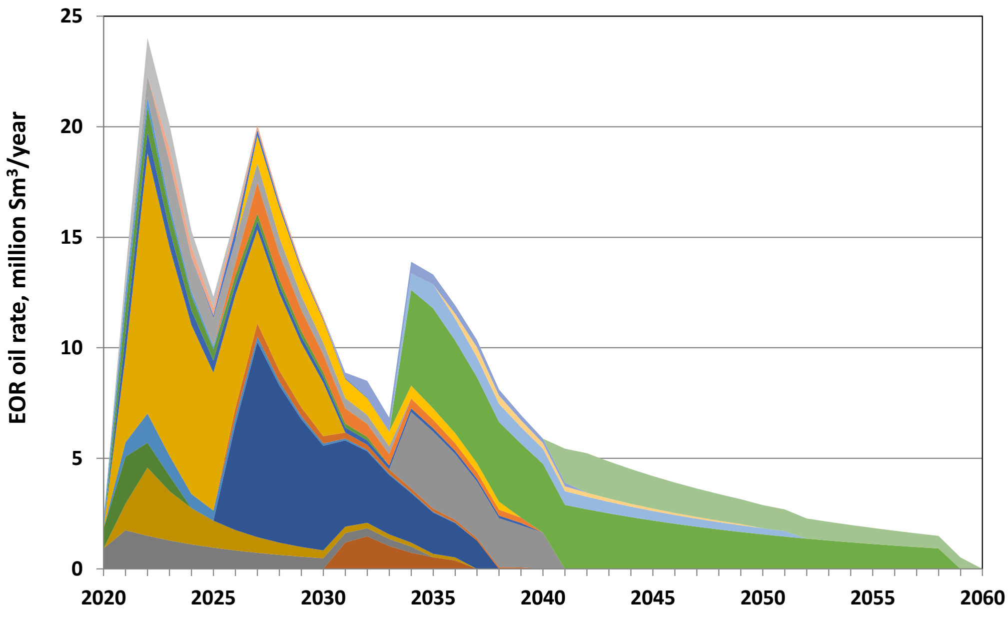

Fig. 4. EOR production rates during tertiary CO_2 injection into 23 oil fields.

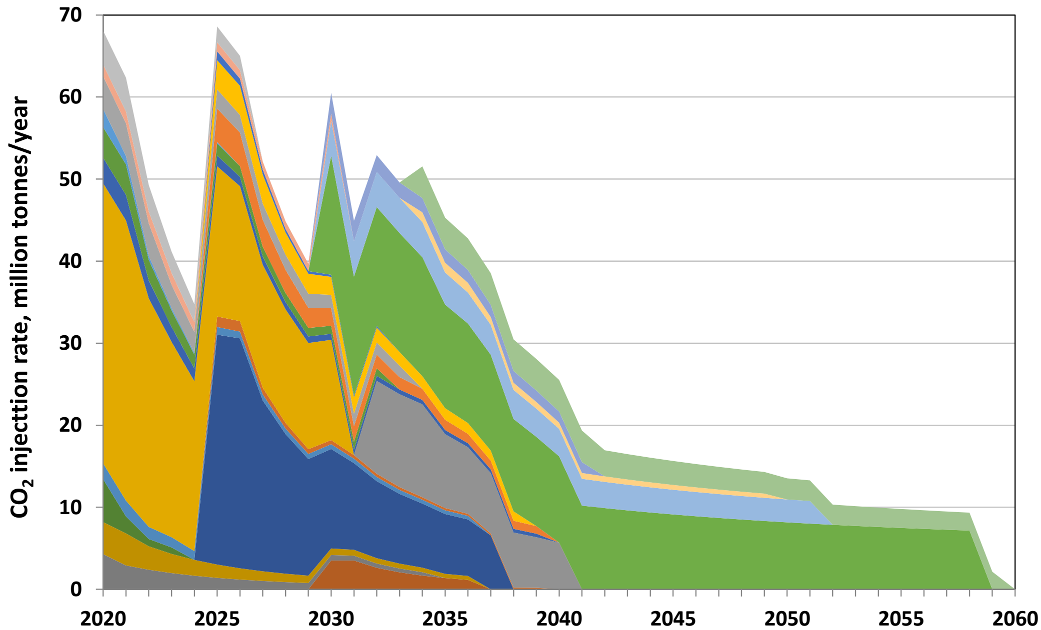

Fig. 5. CO_2 injection rates during tertiary CO_2 flooding of 23 oil fields

3.3. Economy

As seen in the table the well costs alone is in the order of all other investment costs, even for the lowest well cost alternative. Figures 6 shows the net present value of the deposition scenario as function of oil and CO_2 prices for two different well costs. The fully drawn lines correspond to new wells (43.75 million USD/well). The dashed lines are valid for a well cost of 25 million USD/well which represent a mixture of new and modified wells.

The figure show that the well costs have a large influence on the net present value. It is therefore a challenge to reduce these costs. The figures also illustrate the robustness of the scenario to low oil prices. Even for the alternative with only new wells the net present value is positive for an oil price above 47 USD/bbl provided that the cost of CO_2 delivered at the export terminal is zero. For the supplier of CO_2 (power plants, process industries, *etc*.) this may be profitable as the alternative is to cover the deposition costs themselves.

Table 1. Example of a calculation, macro-figures.

Item	Unit	Value
Investment costs excluded wells	million USD	9902
vestment costs wells	million USD	8025
Operating costs	million USD/year	2212
Total oil	million Sm^3	2741
Oil recovery	% OOIP	59.1
EOR oil,	million Sm^3	307
Incremental oil recovery	% OOIP	6.6
Total stored CO_2	million tonne	2744
Stored CO_2 in aquifers	million tonne	1507
Stored CO_2 in oil reservoirs	million tonne	1237
Net present value	million USD	22389

For various combinations of oil and CO_2 prices the EOR oil produced varied between 282 million Sm^3 and 351 million Sm^3 provided that the net present value was positive, corresponding to between 6.1 % and 7.6 % of the original oil in place (OOIP).

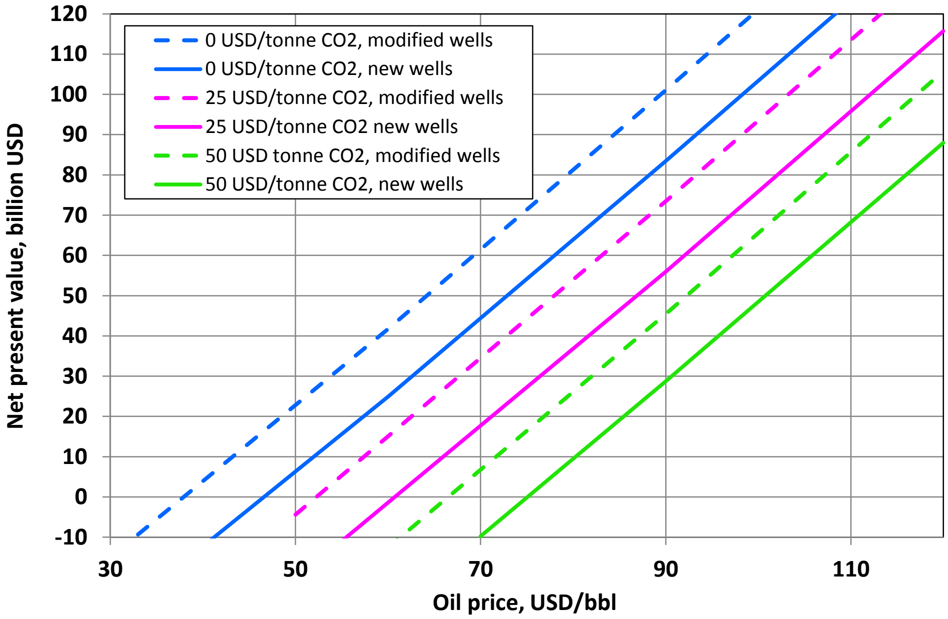

Fig. 6. Net present value as function of oil and CO_2 prices. Well costs 25 mill. USD/well (dashed lines) and 43.75 mill. USD/well (solid lines).

3.4. CO_2 mass balance

The CO_2 formed by combustion of the EOR oil is compared to the amount of CO_2 stored in the oil reservoirs in Figure 7. The total amount CO_2 stored when aquifers are included is also shown. The mass balance is made for calculations using an oil price of 50 USD/bbl, zero CO_2 price and 25 million USD/well. As seen, more CO_2 is stored in the oil reservoir than what is formed by combustion of the EOR oil. The reason for this is that large amounts of water will be produced as a result of CO_2 injection. The negative footprint of the EOR oil (green areas in the figure) becomes larger if CO_2 stored in aquifers is included.

In this work continuous CO_2 injection has only been considered. Alternating injection with water (WAG) can possibly increase the oil production marginally but less CO_2 will be stored in the oil reservoirs.

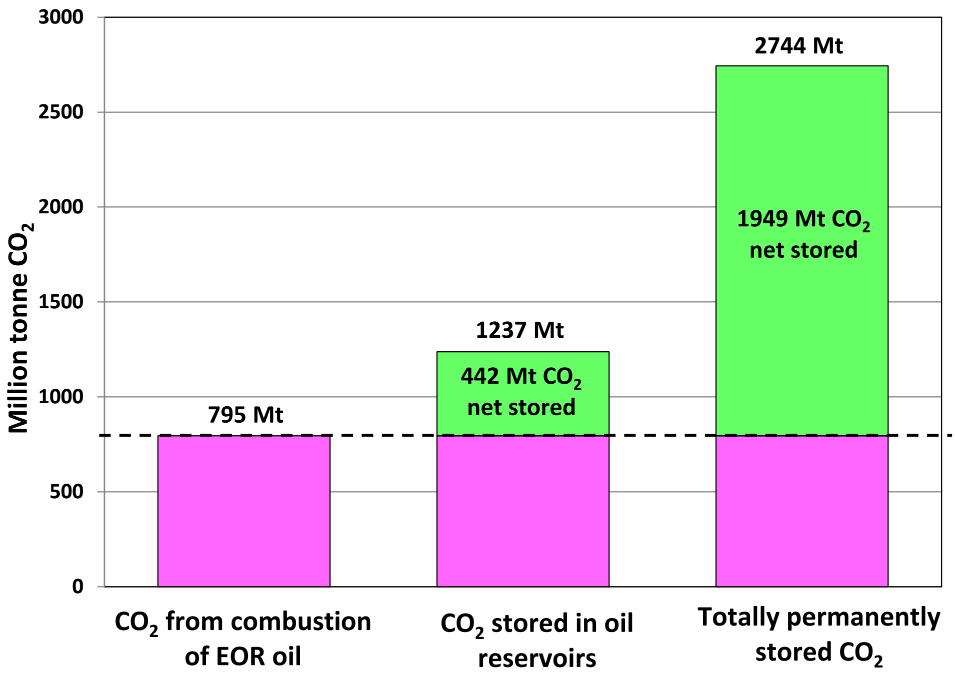

Fig. 7. CO_2 mass balance showing that the EOR oil from tertiary CO_2 flooding gives negative CO_2 footprint.

4. Conclusions

A technical-economical model for CO_2 injection into oil reservoir and aquifers using a large-scale infrastructure for CO_2 transportation to the oil provinces has been used to analyse a CO_2 deposition scenario that includes 23 Norwegian Continental Shelf oil fields. In the scenario 70 million tonnes of CO_2 is injected annually over 40 years. A sensitivity analyses for variable oil and CO_2 prices and well costs has been made.

The EOR potential is estimated to be in the range 276 to 351 million Sm^3, corresponding to between 5.9 % and 7.6 % of the hydrocarbon pore volume originally in place. Of the total amount CO_2 stored underground somewhat less than half is stored in the oil reservoirs, the rest is stored in aquifers.

Well costs constitute a significant part of the investment costs needed to convert water flooded oil reservoirs to CO_2 injection. Reduced well cost is therefore important to improve the economy of tertiary CO_2 flooding.

If CO_2 is supplied to the export terminal at no cost CO_2 EOR may be profitable even at oil prices of 50 USD/bbl or less. For the deliverer of CO_2 (power plants, process industries, *etc*.) this may be profitable as the alternative is to cover the deposition costs themselves.

CO_2 mass balance calculations show that more CO_2 is stored in the oil reservoirs during tertiary flooding compared to the CO_2 formed by combustion of the produced incremental oil. The CO_2 footprint becomes even more negative when the CO_2 stored in aquifers is included in the calculations.

5. Acknowledgements

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