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Enhanced gas recovery – a potential 'U' for CCUS in The Netherlands

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Abstract

Most of the gas fields in The Netherlands are approaching the end of their production. Within two decades, the production in the majority of offshore gas fields will have ceased. The preparation of the fields for any end-of-field-life measures to extend their lifetime and increase production needs to start as soon as possible. One such measure is Enhanced Gas Recovery (EGR), which consists of injecting gas (CO_2 or N_2) to drive out the gas that remains after conventional production. This paper presents the results of a first study into the feasibility of EGR for two Dutch offshore fields. Injection scenarios (volumes, choice of injection wells, timing of the start of injection) were defined in close cooperation with the operators of these fields. The results suggest that the potential for EGR in these two fields is limited to about 1% of additional gas and condensate production. The highest recovery increases were obtained for EGR scenarios in which gas injection started after the end of regular production. The results strongly depend on the drive gas concentration limits in the produced gas, with higher tolerances leading to higher recoveries. Furthermore, detailed analysis of the EGR simulations suggest that some optimization of choice of injection wells, or even infill well placement, may lead to further increases. This will have to be further investigated. For the two cases considered, the additional gas production amounts to about 50% to 60% of the injected drive gas volume with little or no difference between the use of N_2 or CO_2. The amount of stored CO_2 at end of life of the two studied fields is about 0.4 Mt. The rather modest increase in ultimate recovery may be too little to justify investment costs for most of the smaller fields, but may be economically interesting for some of the larger fields.

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1. Introduction

Most of the gas fields in The Netherlands are currently in decline and within two decades the production in the majority of offshore gas fields will have ceased. Unless measures are taken to extend their lifetime, platforms will be decommissioned and removed, wells abandoned and, especially in offshore areas, pipelines will be left unused. Options to increase the production and lifetime of the fields should be investigated now in order to have sufficient time to prepare and implement the required modifications.

At the same time, The Netherlands has an ambition to maintain domestic gas production at a level of 30 bcm/yr until 2030. The predicted development of the domestic production shown in Fig. 1 illustrates the need for extension of the production from current fields, as an increasing part of the production is expected to come from as yet undeveloped fields.

Enhanced Gas Recovery (EGR) is one end-of-field-life option that can potentially increase the lifetime of a field and of installations. The primary aim of EGR is to produce the gas remaining after conventional production by injecting a drive gas (typically CO_2 or N_2) that helps maintain pressure at a sufficiently high level for production to continue. A positive side effect is that reservoir pressure stabilization will reduce surface subsidence, which may be of high importance in populated areas. When using CO_2 as a drive gas, there is also the possibility of using the reservoir for storage of CO_2. Finally, maintaining the (offshore) networks and infrastructure enables flexibility in later alternative uses for the reservoirs, as hydrocarbon gas reserves or e.g. for storing energy.

While EGR has been extensively studied in laboratory settings and in field-scale simulations [3,4,8,13,14] for both tight and conventional gas reservoirs, as well as gas condensate reservoirs [1], application in the field remains limited to a handful of cases [12,18], with a few more under preparation [7].

Both CO_2 and nitrogen injection have been used for decades for EOR purposes (see e.g. [3]), and nitrogen has been used as an alternative for dry-gas cycling to prevent condensate drop-out in gas condensate reservoirs. Nitrogen is also an interesting alternative for CO_2 in EGR because of its availability (air contains about 78% N_2) and its chemical inertness, where CO_2 may act as an acid, compromising the integrity of well casing and cement, as well as the reservoir seal. In The Netherlands an additional argument is the large tolerance for N_2, as the standard quality 'Groningen' gas contains about 14% nitrogen, which actually means that nitrogen is added at many fields to produce gas of standard calorific content.

A number of technical, economic and even political factors play a role in determining the suitability of EGR as a means to achieve the possibly conflicting objectives of increased hydrocarbon gas recovery and carbon sequestration [2]. Among the economic factors are the size of the field and remaining gas-in-place, its characteristics (permeability, thickness, heterogeneity, aquifer strength), the availability and location of wells, the capacity of facilities, the availability and cost of drive gas, and the quality requirement of the produced gas (separation of the drive gas from the produced gas is costly). A number of technical aspect needs to be considered as well. The reservoir pressure affects the degree of cooling of the injected gas and thereby possible forming of hydrates which may block the near-well pores [17]. On the other hand, when CO_2 is used as a drive gas, transition from the gas to liquid phase may occur when reservoir pressure is increased sufficiently, leading to more favorable gravity separation between the CO_2 and the ambient gas. The importance of some phenomena is unclear. For example, the impact of the difference in solubility of CO_2 and N_2 in water [15] could affect the breakthrough at production wells, while the difference in interfacial tension (IFT) with water [19] could affect the relative mobility of the gas in water and the effectiveness of low-permeability seals. For onshore fields, development plans will also need to consider (local) stakeholders and political and environmental sensitivities. All of these factor can be expected to provide constraints and limits on the feasibility of EGR as a viable option for a specific field.

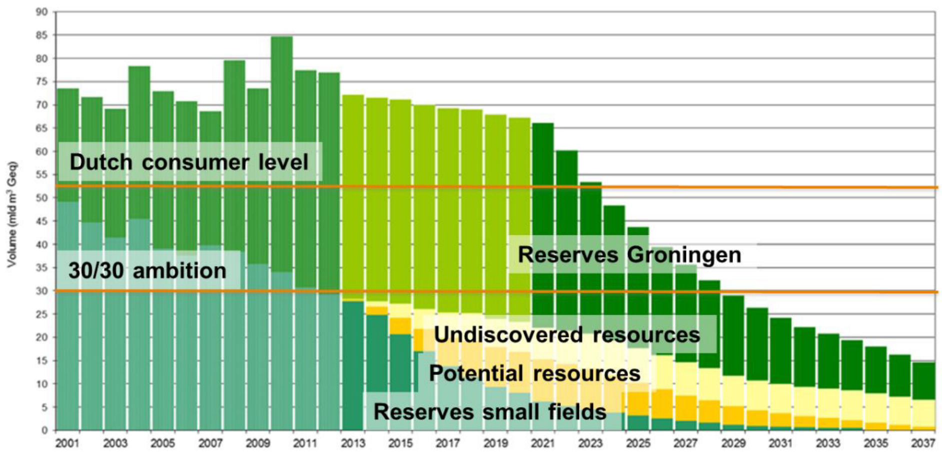

Fig. 1. Historical and forecast gas production in The Netherlands. The ambition is to maintain a production level of 30 bcm until 2030. Current consumption level is about 55 bcm/yr. The large Groningen field ('Reserves Groningen'), providing about half of the total production, is expected to go into decline around 2020. Smaller fields (most are in decline), potential and new fields are to produce the remaining volumes. After [9].

The first initiatives that consider large-scale EGR in the Netherlands have only recently started [11], and insufficient experience and information is therefore available at this moment to adequately assess the potential for EGR in the Netherlands as a whole. In this paper, we will study EGR for two Dutch offshore gas fields that are approaching end of life. The two fields are representative of a large subset of Dutch offshore fields and, together with earlier studies on the K12-B reservoir [8], are expected to provide good insight into the most relevant aspects of EGR for the Dutch offshore. The focus of this study will be on the sensitivity of the result to the type of reservoir and reservoir fluids, the start of EGR, the impact of the choice of injection well, and the operational targets during the EGR process. The specifics of the Dutch offshore gas fields will be introduced in section 2. An overview of the simulation approach taken in this study and the performed experiments is provided in section 3. In sections 4 and 5 the results for the two selected fields will be presented and discussed. The implications of these results for CO_2 utilization and storage can be found in section 6. Conclusions and implications of the potential of EGR for the entire Dutch gas reserves are discussed in section 7.

2. Selected gas fields

The potential of EGR has not been studied in detail for the Dutch gas fields. Many gas fields in the Netherlands have high recovery factors, up to 95%, apparently leaving little opportunity for enhanced recovery on an individual basis. This, with additional concerns about the quality of the produced gas because of co-production of the drive gas, has limited the number of commercial EGR projects to less than a handful. On the other hand, high-level studies estimated the total potential additional recovery through EGR to be of the order of 100 bcm (10^{11} m^3). The equivalent volume of CO_2 would be about 200 Mt (1 Mt = 10^9 kg). The EGR feasibility for individual cases will depend, among other factors, on the remaining volume of gas at the end of primary production and the costs of modifications required to handle the drive gas injection and separation required for EGR. When using CO_2 as a drive gas, the business case of EGR could be improved by bringing in additional revenues from the European Union Emission Trading System (EU-ETS). The additional effort that is needed for this lies mostly in monitoring and verification.

Current ongoing projects in The Netherlands illustrate the interest of operators in EGR. GDF SUEZ has been testing EGR with CO_2 extracted from the produced gas at the offshore K12-B field, while NAM has recently started nitrogen injection for EGR in an onshore field (De Wijk).

In this paper, the potential of EGR is assessed in some detail for two mature Dutch offshore gas fields. The first field (FIELD A) is a stacked gas condensate field of Jurassic age, containing several compartments. The second field (FIELD B) is a sub-salt field, representative of a large number of dry gas fields in the Permian Rotliegend formation. The field also consists of several compartments. In these two fields, EGR is considered using either CO_2 or N_2 as drive gas. CO_2-EGR can be expected to be feasible once CO_2 capture, transport and storage becomes reality in the Dutch sector of the North Sea. We note that the cost aspect, or the feasibility of updating the platform and other surface installations for the processing of an additional gas stream was not part of this study.

2.1. Gas condensate field (FIELD A)

Field A is a gas condensate field located in the Upper Jurassic and has been in production since 1993. The field is divided in 3 compartments (Block 1, Block 2 and Block 3) and is currently produced by 3 wells (A2, A4, A6). The Block 3 and the Block 1 have a certain degree of communication with higher pressures in Block 3. All compartments are stacked, with a Middle Graben reservoir overlying a Lower Graben reservoir. The Gas Initially In Place (GIIP) is around 22 bcm, from which 66 % was recovered by 2012. The expected Ultimate Recovery Factor (URF) in 2013 is about 75% for the gas and 25% for the oil. The objective of the current study was to investigate the impact of stimulating the production by the injection of CO_2 or N_2 on the URF of both gas and oil. For this purpose a compositional model was created to simulate a retrograde gas consisting of CO_2 (3.4%), N_2 (0.3%), hydrocarbon components C1 (65.8%), C2 (9.4%) and C3 (7.1%), and pseudo components C4-6 (6.3%), C7-10 (4.1%), C11-17 (2.5%) and C18+ (1.2%). These percentages are for the lower reservoir; the initial composition was slightly different in the upper reservoir. An overview of the field is presented in Fig. 2a. EGR is considered as a possible scenario for production enhancement starting in 2017 and EGR scenarios were tested for the period 2017-2030. Prior to the forecast simulations, the models were history matched to well BHP, and water and oil rate measurements. The simulated distribution of gas and oil at the start of the forecast period is illustrated in **Error! Reference source not found.**a.

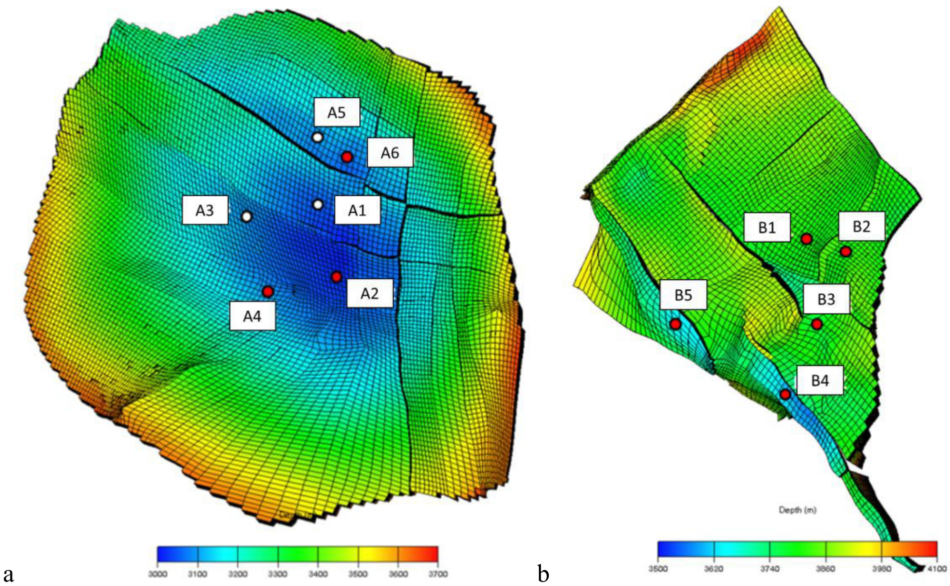

Fig. 2. (a) Overview of Field A Lower Graben formation. Injection wells are indicated in white. The diameter of the modeled area is about 10.7 km. (b) Field B with wells. Wells B1 and B3 were used as injection wells in different simulation experiments. Depth is colour coded, in meters. The modeled area is about 5 km x 5 km in size.

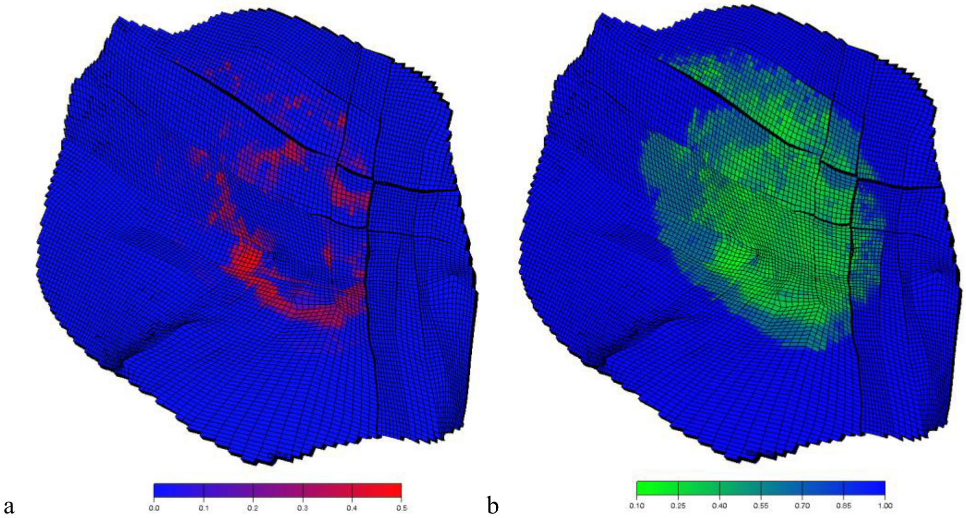

Fig. 3. Oil saturation (a) and water saturation (b) in FIELD A, Lower Graben formation (top view).

2.2. Sub-salt field (FIELD B)

Field B is a dry gas field that was discovered in 1989 and consists of the Lower Slochteren and Westphalian formations. The GIIP is around 12 bcm, 2 bcm of which is contained in an as yet unproduced prospect which may be pursued at a later stage. First gas was produced in 1992 and end of life is expected to be reached in 2017. For the purpose of this study, May 1 2012 was considered the starting point for forecast simulations, at which time the RF was 74.6%. The field contains 4 producing wells (B1, B2, B4 and B5), each producing from a separate compartment, while two others (B3 and B4) have previously been shut in because of high water production. The producing wells B1 and B2, and shut-in well B3, which is positioned in a fifth compartment, were found to be in direct pressure communication, whereas the other two producing wells appear to be more isolated or separated. A compositional model was constructed containing 5 components: 84.4% CH_4, and 5.7% C2 and 1% C3 hydrocarbon components, 4.3% CO_2, and 3.8% N_2. An overview of the field is presented in Fig. 1b. Prior to the forecast simulations, the models were history matched to closed-in well BHP and water rate measurements. The quality of both the history matches for FIELD A and FIELD B were judged to be fit for purpose by the field operators.

3. Overview of EGR simulation experiments

A number of possible EGR scenarios were identified for both fields together with the field operators. These scenarios include the identification of wells that could be used as injection wells, possible start time for injection, operating limits (rate, BHP and THP) of injecting and producing wells, and economic constraints such as maximum water cut, and tolerances for CO_2 or N_2 in the produced gas stream etc.

For field A, the start of all EGR scenarios was determined to be the expected end of conventional production in Block 3, as set by the operator to January 1 2017. Any EGR scenario would be based on existing wells, where the operator identified wells A1 (Block 1), A3 (Block 2) and A5 (Block 3) as possible candidates. With this choice, each compartment contains both an injector and a producer. In order to prevent the heavy condensates from dropping out of the gaseous phase, the aim was to maintain a constant reservoir pressure. A voidage replacement injection strategy is therefore considered: injection rates equal the rate of gas production in the nearby producer. These rates were taken as the final rates at the end of the history match period. The wells A6 (Block 3) and A4 (Block 2) stopped production before the start of the projected injection. For these wells, the last production rate just before the closing of the well was taken as the target injection rate for nearby injector during EGR. During the forecast period, production wells were set to operate at a fixed THP target. The top perforations of injection well A1 are positioned in the Middle Graben, resulting in significant influx of injected gas into this formation at the cost of injection in the Lower Graben. Two scenarios for CO_2 injection were therefore tested, with injection in the Middle Graben (scenario CO_2) and without (scenario CO2E). The well operating constraints and targets during the forecast period are summarized in Table 1.

Well A4 did not produce in any of the forecast scenarios, while well A6 only produced intermittently for very short periods. The N_2 injection rates were modified from the CO_2 rates to represent a similar volume rate at reservoir conditions.

For field B, target THP values, minimum and maximum gas rates, a minimum BHP and a maximum water-gas ratio (WGR) were set for producing wells, based on current well performance and planned workovers. B1, B2 and B3 were identified as possible candidates to be converted to an injection well but the experiments presented here do not consider the (horizontal) B2 well for injection. In all scenarios production from B3 is stopped at March 1 2013 at the latest. The specific constraints for field B are summarized in Table 2, while the EGR forecast scenarios that were finally selected for simulation are summarized in Table 3. The injection rate used in FC12 corresponds to 1.1 Mt/year. The total volume injected is equal to that in FC11, but the entire volume is injected in 103 days. The BHP target in FC8 is the initial reservoir pressure. The start dates are the shut-in time of the injection well in the base case forecast (FC8), the start of the forecast (FC9, FC10), or the expected end of field production (FC11, FC12). Based on the much better production from B2 than from B1 in the base case, of these two wells only B1 has been considered as a candidate to be converted into an injection well. All forecasts were simulated until 2030 but stopped at the first reporting date at which all wells were shut in.

4. Results

Field A

The condensate components are produced partly as an oil phase and for a larger part in the gaseous phase. Fig. 4 to Fig. 8 summarize the field cumulative volumes of gas injected and produced, as well as the fractions of drive gas in the produced liquids (gas and gas condensate).

Table 1. Well targets and limits used in the forecast scenarios of field A. Four scenarios are defined for field A: no injection (base case), injection of CO_2 (CO2), injection of CO_2 excluding the Middle Graben (CO2E), and injection of nitrogen (N2).

Well	THP target /limit (initial) (bar)	THP target /limit (from 10/2017) (bar)	Min gas rate (Sm^3/d)	Min BHP (bar)	Gas rate target/limit CO2 (Sm^3/d)	Gas rate target/limit CO2E (Sm^3/d)	Gas rate target/limit N2 (Sm^3/d)
A1					30000	45000	30983
A3					24000	135912	24825
A5					16000	20040	17192
A2	18.5	9		1	320000	320000	320000
A4	16	7	55000	1	200000	200000	200000
A6	15	7		1	100000	100000	100000

It was found that in the EGR simulations of both fields that periodic well testing could in some cases revive wells that were previously closed, and thus lead to an extension of well life. Such tests were simulated every 30 days early on in the EGR forecast, and every 90 days during later stages. Simulations are done isothermally at a fixed reservoir temperature.

Table 2. Production well targets and limits used in the forecast scenarios of field B. See Table 3 for possible additional component fraction limits.

Well	Initial target THP (bar)	Target THP from 2014 (bar)	Min gas rate (Sm^3/d)	Max gas rate (Sm^3/d)	Min BHP (bar)	Max WGR	Efficiency factor
B1	35	38	20000	50000	1	0.0005	1
B2	35	41	20000	50000	1	0.0005	1
B3	35	well shut-in on 1 Mar 2013	50000	100000	1	0.0005	0.4
B4	50	45	50000	120000	1	0.0005	1
B5	46	40	50000	150000	1	0.0005	1

Table 3. Overview of forecast scenarios for field B, including a base case without injection (FC1) and various EGR scenarios (FC8 to FC13). For scenarios in which a maximum CO_2 fraction is set, each producing well is shut in when the maximum reached. Voidage replacement (VR) is based on the total produced from wells B1, B2 and B3.

Run	gas	well(s)	control	target value	unit	start injection	max CO_2
FC1							
FC8	CO_2	B3	BHP	433.5	bar	1/3/2013	
FC9	CO_2	B1	VR			1/5/2012	
FC10	CO_2	B3	VR			1/3/2013	
FC11	CO_2	B3	RATE	80,000	m3/day	1/1/2017	15%
FC12	CO_2	B3	RATE	1.69E+6	m3/day	1/1/2017	15%
FC13	CO_2	B1	VR			1/1/2017	

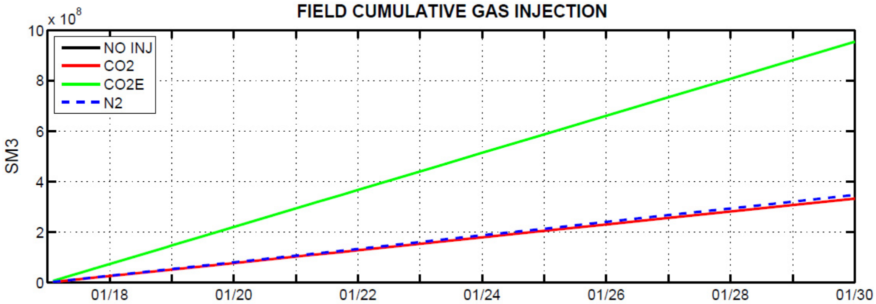

Fig. 4. Cumulative gas injection volume for the 4 scenarios for field A.

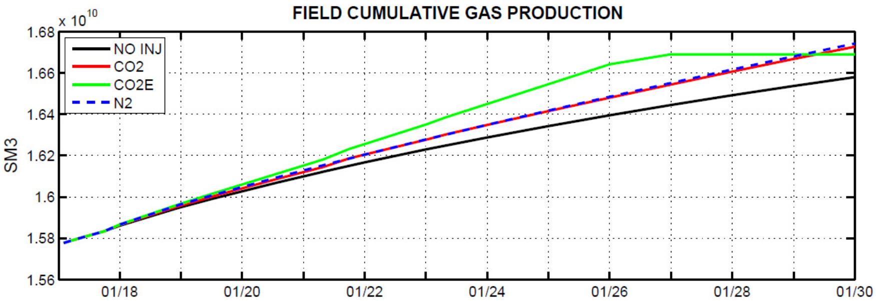

Fig. 5. Cumulative gas production for the 4 scenarios for field A.

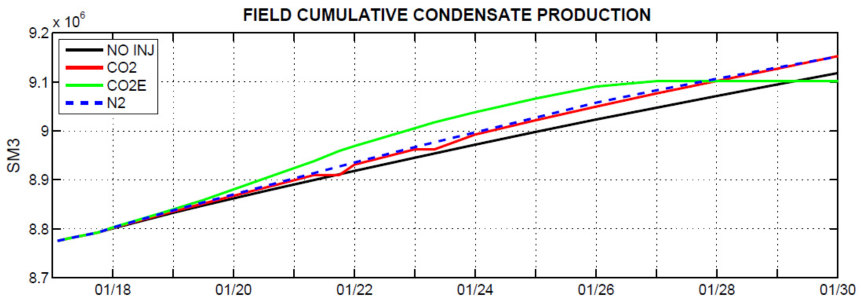

Fig. 6. Cumulative condensate (liquid) production for the 4 scenarios for field A.

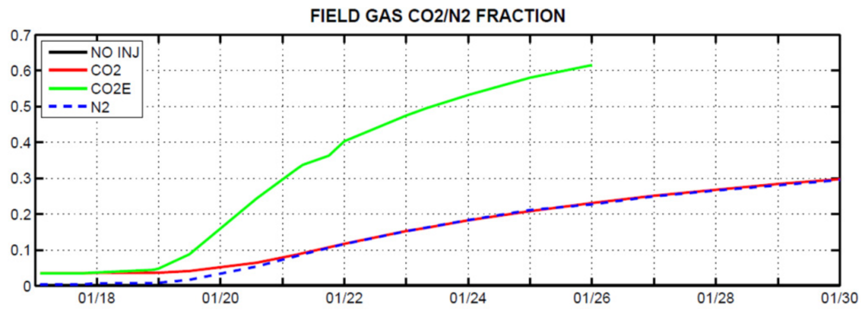

Fig. 7. Fraction of CO_2 in the produced gas for the 4 scenarios for field A. The fraction of N_2 is shown for scenario N2.

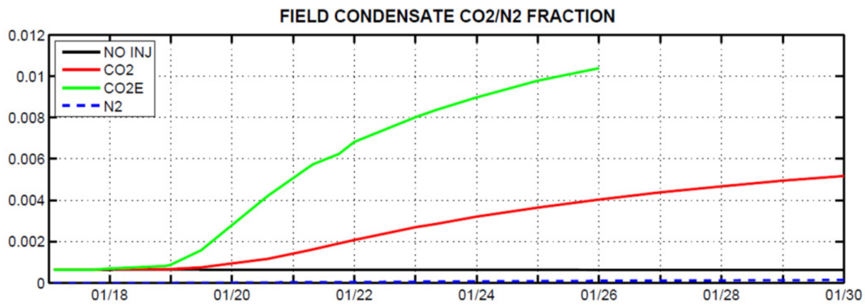

Fig. 8. Fraction of CO_2 in the produced liquid for the 4 scenarios for field A. The fraction of N_2 is shown for scenario N2.

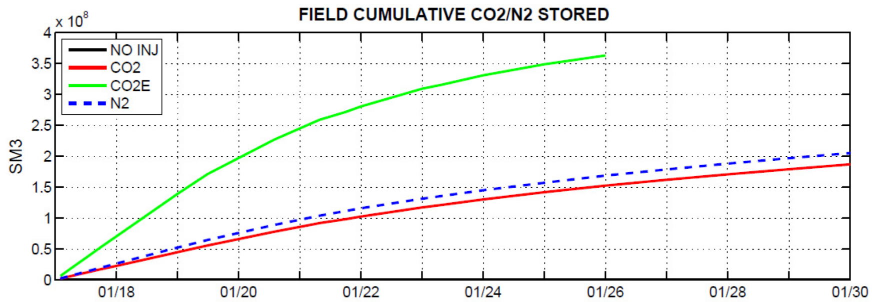

Fig. 9. Cumulative volume of CO_2 or N_2 stored for the 4 scenarios for field A.

A general conclusion is that there are no major differences between use of CO_2 and N_2, except that a slightly larger percentage of CO_2 is dissolved in the condensate. Both gas recovery and condensate recovery is increased in all EGR scenarios relative to the base case, except for scenario CO2E, in which production ends already in 2027. CO_2 fractions in the produced gas stream reach 15% already in 2019/2020 for CO2E whereas this occurs in 2023 for the other EGR scenarios (it is not known at this moment if there are economic constraints on the CO_2/N_2 fractions in the condensate stream). At these dates, 0.2 bcm (about 0.4 Mt) and 0.125 bcm (0.25 Mt) of CO_2 respectively has been stored, with approximately 0.225 bcm (0.45 Mt) and 0.15 bcm (0.3 Mt) injected. Increases in gas recovery relative to the base case are less than 0.1 bcm, or 0.6% of expected total production, and the condensate recovery increase is less than 0.05 10^6 m3 (or 300,000 bbl), which represents about 0.56% of the expected production. Note however, that conventional gas production is expected to proceed until 2030, and that the loss of production due to premature abandonment of the field before 2028 due to high CO_2 or N_2 fractions does not outweigh any improvement in recovery before that time. It could be beneficial to start injection later than 2017, in order to minimize any negative impacts of high drive gas concentrations in the produced gas stream.

Field B

A number of field totals were computed for each of the forecast scenarios and are compared in Fig. 10 to Fig. 12.

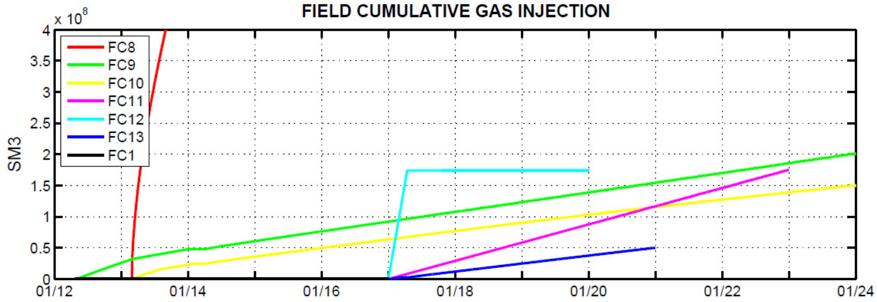

Fig. 10. Cumulative volume of injected gas for the forecast scenarios for field B.

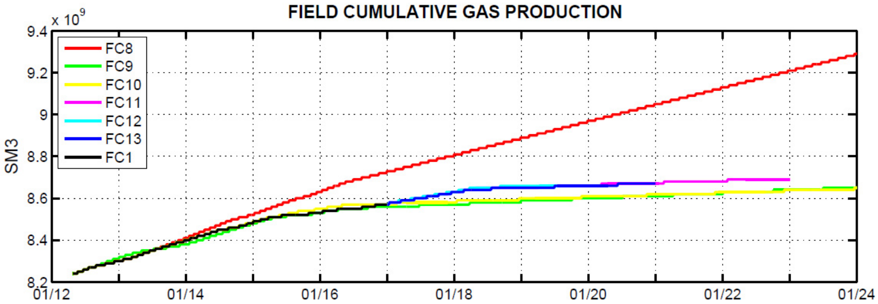

Fig. 11. Cumulative volume of produced gas for the forecast scenarios for field B.

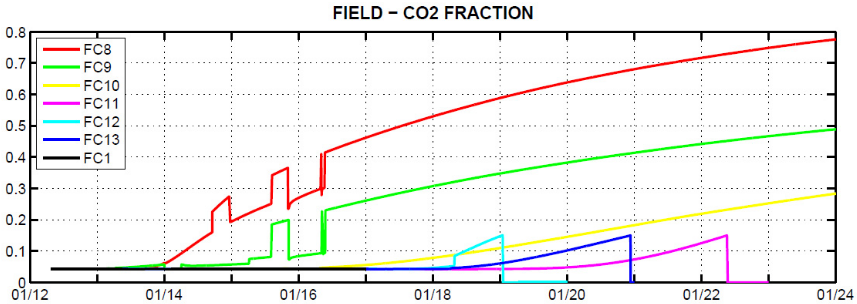

Fig. 12. Fraction of CO_2 in the produced gas for the forecast scenarios for field B.

The injection scenario FC8 is seen to results in extreme injection rates and very early breakthrough of CO_2 in the produced gas. Two of the three scenarios in which injection is started before the expected end of life (FC8, FC9) are seen to lead to premature shut-in of the field if a 15% maximum tolerance for CO_2 in the produced gas is assumed, with lower ultimate gas recovery than in the base case (FC1). A voidage replacement strategy in combination with injection from well B3 (FC10) leads to a minor increase is gas production and a much slower increase in the CO_2 fraction. The highest ultimate recovery is obtained for scenarios in which CO_2 injection is started after the end of conventional production (FC11, FC12 and FC13). Injection from B3 appears more favourable than injection from B1 in terms of stored CO_2. This is mostly because production from well B2 can be sustained for longer time without reaching the maximum CO_2 tolerance due to the closeness of B1 to B2. The actual UR is higher when the CO_2 is injected gradually rather than quickly over a very short period. The best scenario in terms of recovery is FC11 which results in about 0.11 bcm, or 1%, additional recovery relative to the base case, due to injection of about 0.175 bcm (about 0.35Mt) CO_2, of which most ends up being stored in the reservoir.

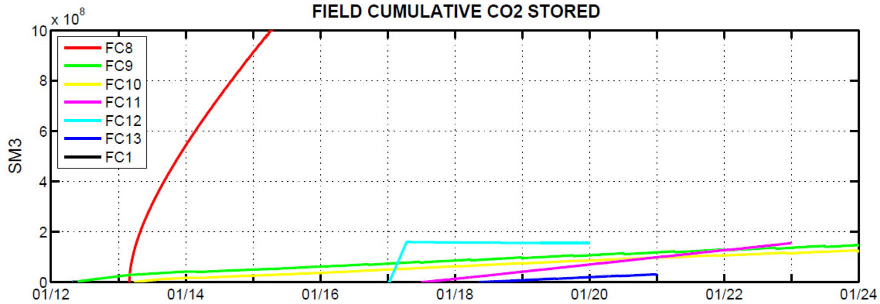

Fig. 13. Cumulative volume of CO_2 stored for the forecast scenarios for field B.

5. Discussion

In this study, re-pressurization of the reservoir is the main contributing effect of CO_2 or N_2 EGR. All scenarios considered in this study are at reservoir temperature (125 °C for both fields) and at low pressure, with N_2 and CO_2 in the gaseous phase. The impact of differences between the two, such as density, interfacial tension (see, e.g., [6,19]), solubility (e.g., [15]) and viscosity are expected to be too small to result in significant differences in EGR yield. Other processes, such as the formation of N_2 or CO_2 hydrates [16,20] and Joule-Thomson cooling [10], were not considered in this study.

The mixing between the injected gas and the natural gas leads to rapid increases of the concentration of the injected component in the produced gas. It should be noted that some differences between behaviour of CO_2 and N_2 which can be detected in small-scale lab experiments, such as retardation of the CO_2 due to preferential solution in the brine, are not described by the reservoir simulator.

Some measures could be considered to revive the shut-in producers A4 and A6 in field A that could alter the results. The operator considers installing a velocity string in the A4 before the intended start of injection, which would lead to a reduced critical production rate. Despite implementing this velocity string in the reservoir model simulation, the A4 did not restart, however. There are several indications in the simulations that the injection at A3, and associated pressure increase did not support production in A4 but rather in A2.

The gas production is also essential in the production of the heavier components of the condensates. Removing these components from the gas requires a two-step separator train on the platform. The impact of these separation processes on the concentration of the produced stream is yet unknown.

6. CO_2 utilization and storage

Fig. 4 and Fig. 10 show the total injected volumes of CO_2 and N_2 used for EGR in the two field cases. Neither of the two cases show significant differences injected volumes between CO_2 and N_2. Two CO_2 scenarios were tested on field A, both of which were based on prescribed injection rates. The only scenario with prescribed injection pressure is scenario FC8 for field B where the injection pressure was set equal to the original reservoir pressure which results in very high injection rates. The high injection rate cases for both fields results in fast breakthrough and very rapidly rising CO_2 fractions in the produced gas.

Fig. 9 and Fig. 13 illustrate the cumulative volumes of CO_2 in the reservoirs, which at the final time can be interpreted as the stored volumes. The volumes are similar for the two cases and lie between 0.17 and 0.2 bcm or 0.35 and 0.4 Mt.

7. Conclusions and outlook

A range of possible enhanced gas recovery (EGR) scenarios was tested on two producing gas fields from the Dutch offshore. The scenarios were evaluated in terms of additional gas recovery, and volumes of drive gas injected and stored. Economic factors other than those resulting in well operating constraints provided by the field operators were not considered. Both CO_2 and N_2 were considered as drive gas.

Results:
1) Only very minor differences between the two were observed between the fractions in produced liquid for the condensate field.
2) The EGR scenarios lead to enhanced gas recovery and / or enhanced condensate recovery for both fields. .
3) For field A also enhanced condensate recovery appears possible.
4) Stored volumes of CO_2 in the two fields, associated with an EGR scenario, are on the order of 0.35-0.4 Mt.
5) In both cases, additional recovery is 1% or less.

This actually is in agreement with results from an earlier study for a different offshore field, and may be typical for most Dutch gas fields which are characterized by generally high recovery factors.

It would be interesting to assess the total EGR potential for the entire Dutch onshore and offshore. A first estimate could be obtained by applying a 1% recovery improvement to all currently producing fields. However, probably not all fields will be suitable for EGR, for example because they contain only a single well, or non-communicating compartments with single wells. Furthermore, if additional production is only about 1%, then the investments for platform modifications and well workovers may be too large for some of the smaller fields. Fields must have sufficient gas left in place before EGR will be considered, meaning that primarily the larger fields will be the main candidates. At this point, therefore, CO_2-EGR does not appear to become the 'U' in CCUS. However, for individual, larger fields EGR can still be a viable option.

Remaining questions include the criteria for selection of these fields, and the potential for additional recovery by smart choice of injection wells. These questions are currently being addressed to provide a better basis for an assessment of the feasibility of EGR for gas fields in The Netherlands.

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