Techno-economic impact of CO_2 co-injection into geothermal doublets for the Netherlands

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ABSTRACT

The combination of geological CO_2 storage and geothermal energy production by CO_2 co-injection into the cold return stream of a geothermal doublet could be an interesting technology to contribute to CO_2 emission reductions. Small emitters in more remote areas could reduce their emissions by collaborating with neighboring geothermal operators. Introducing CO_2 in dissolved form into geothermal reservoirs would lead to inherently safe CO_2 storage, while generating the possibility of additional revenues for the geothermal operator. This paper reports on reservoir simulations combined with an economic evaluation and implementation assessment to assess the potential impact of this technology for the energy transition in the Netherlands.

1. INTRODUCTION

In the Netherlands the ambition to reduce emissions of greenhouse gases by 49% in 2030 requires drastic measures to be able to serve the ever growing energy demand. Geothermal energy will be one of the key elements of the future low-carbon society. The number of geothermal doublets will have to grow from 17 today to 175 in 2030 and 700 in 2050 to reduce national gas consumption[1]. Geological storage of CO_2 is another important technology for reducing CO_2 emissions, especially for some industry processes that produce large amounts of CO_2 without having a low-CO_2 alternative for their production process. Large-scale CO_2 storage in the Netherlands is mainly foreseen in depleted offshore hydrocarbon reservoirs where the supercritical state with corresponding high density will allow large volumes of CO_2 to be isolated from the atmosphere. Combining geothermal energy with CO_2 storage by co-injecting CO_2 in the injection stream of a geothermal doublet provides opportunities for small emitters located away from large-scale CO_2 transport facilities to offshore reservoirs.

In this paper, we report on the technological possibilities and requirements, the economic evaluation and the implementation assessment of the concept of CO_2 co-injection in geothermal doublets, and demonstrate the extent to which it can support the energy transition in the Netherlands.

2. CO_2 CO-INJECTION CONCEPT

The co-injection of CO_2 in the cold injection stream of geothermal doublets, thereby keeping CO_2 co-injection below solubility limits of the formation water, can only account for small CO_2 emission reductions compared to storage in supercritical state (Shariatipour et al., 2016). Yet, the technology also has several advantages:

- CO_2 in dissolved state prevents CO_2 leakage due to the absence of an upward migration mechanism (Shariatipour et al., 2016);
- The absence of a leakage mechanism allows storage in reservoirs without a sealing caprock;
- Small CO_2 emitters closely located to geothermal aquifers could reduce their emissions by collaborating with geothermal operators;
- Geothermal operators create an additional revenue stream as they will be paid by the emitters to store their CO_2.

The concept of CO_2 co-injection and the viability of the application in France, Germany and the US has been investigated in the CO_2-DISSOLVED project (Kervévan et al., 2014). Although compatible with any capture technology available on the market, the CO_2-DISSOLVED approach preferentially relies on an innovative and relatively low cost post-combustion CO_2 capture technology patented by Pi-Innovation (www.pi-innovation.com). The Pi-CO2 core is a multi-stage cascading absorber-desorber column (Blount et al., 2017). The flow dynamics of the design, and the number of stages, enhances the gas-water mass transfer and overcomes the solubility limits of a single stage. The column is suspended in a 300 m deep well (or a deep water body) and separates CO_2 from co-emitted fume gases by preferential dissolution of CO_2 into

[1] https://www.ebn.nl/wp-content/uploads/2018/05/20180529-Masterplan-Aardwarmte-in-Nederland.pdf

water. The hydrostatic pressure at 300 m depth increases the solubility of the CO_2. The undissolved gases (in most cases mainly N_2 and O_2) are transported back to the surface in gaseous state. Several options are possible for the integration of the capture system with the CO_2 co-injection in the doublet:

1. The Pi-CO2 column can be built into the injection well of the geothermal doublet, and the carbonated water can directly be injected from the bottom of the capture system. The more diffuse the flue gas, and the higher the desired capture rate, the larger the required diameter of the column. Hence, a limited diameter of the injection well either limits the type of flue gas that can be used (high CO_2 purity only) or the capture rate. For a highly diffuse flue gas, a well diameter of 0.5 m limits the capture to 1-2 tonne/h (Pi-Innovation, personal communication).
2. A large diameter shaft with a depth of 300 m can be drilled nearby the injection well to enhance capture rates. The carbonated water can be transported to the surface where it is either depressurized to exsolve the CO_2 for co-injection using a bubbler system in-well (Kervévan et al., 2014), or it is kept at elevated pressure and the CO_2 is injected in the dissolved state. In the first case, a separate water mass can be re-circulated in the column as a solvent, whereas in the latter case, the geothermal production water is used as the solvent.

The CO_2 co-injection concept can also be applied without the capture technology. In case of a (nearly) pure CO_2 stream at the source, the CO_2 can be directly co-injected into the injection stream using a bubbler system, or dissolved in the geothermal water at the surface at elevated pressures prior to injection.

3. RESERVOIR SIMULATIONS

3.1 Model and simulations description

Reservoir simulations were performed with TOUGH2 and the ECO2N equation of state to investigate the impact of CO_2 co-injection on geothermal energy production for typical Dutch geothermal reservoirs and define safe injection conditions. Base case input parameters are given in Table 1. The model is 4.3 by 4.0 km, divided into 80 by 80 cells ranging from 20 m to 100 m in length and width, with the smallest grids close to the injector and producer. It has a thickness of 200 m divided into 10 layers of 20 m. The injection and production wells are 1140 m apart. The pressure is initialized with a top and bottom pressure of respectively 211 and 229 bar.

Simulations are performed with open and closed boundaries, representative of large, open structures and small, tank-like reservoirs, respectively. Open boundaries are implemented by an infinite volume, implying fixed pressure conditions. Simulations are performed for a fresh water aquifer and a saline (20 wt% NaCl) aquifer. In total, these four scenarios are representative of the extremes of conditions for Dutch geothermal reservoirs.

The brine production rate of 178 m^3/h is converted to a mass rate of 55.5 and 44.4 kg/s for the saline and fresh water scenarios. The injection of water, salt and CO_2 fractions need to be given as input separately, resulting in injection mass rates of 44.4 kg/s water, plus 11.1 kg/s NaCl in the saline scenario. The amount of CO_2 to be co-injected is based on the conditions in the reservoir at which the solubility of CO_2 is lowest. Since solubility of CO_2 decreases with increasing temperature, the solubility was determined at reservoir temperature. We include a safety margin to account for uncertainties and co-inject 75% of the maximum solubility, which is 0.45 mol/kg brine for the saline scenario and 0.9 mol/kg water for the fresh water scenario. This results in injection rates of 1.1 and 1.76 kg/s respectively, evenly injected along the aquifer interval. For comparison with conventional geothermal operations, simulations are performed with and without CO_2 co-injection. An overview of all simulations performed is given in Table 2.

Table 1: Base case model input parameters. The fresh water and saline water scenarios represent end ranges.

Reservoir thickness	200 m
Reservoir depth	2200 m
Horizontal permeability; Kh	100 mD
Vertical/horizontal permeability; Kv/Kh	0.5
Reservoir temperature	80°C
Reservoir pressure	220 bar
Boundary conditions	open or closed
Salinity	0 or 20 wt%
Geothermal production rate	178 m^3/h
Injection temperature	35°C
Project lifetime	30 years
Max. CO_2 solubility in saline scenario	1.5 kg/s
Max. CO_2 solubility in fresh water	2.3 kg/s

3.2 Base case simulation results

Figure 1 shows pressure and temperature simulation results for the saline and fresh water scenarios at the end of 30 years operations. They show that the pressure around the injection well is slightly higher than the background reservoir pressure and slightly lower around the production well. In case of closed boundary conditions, the background pressure in the reservoir, away from the injector and producer, decreases in the simulation with conventional geothermal operations (no CO_2), which is related to the temperature decrease around the injector and the corresponding density increase. When co-injecting CO_2, the overall reservoir pressure increases (Figure 1). This is related to the additional CO_2 mass that is injected. The density increase of the brine is larger than for conventional operations, due to the dissolved CO_2, but this cannot cancel out the impact of additional mass injected into a closed, tank-like reservoir. For the open boundary scenario, the background pressure remains at the initial

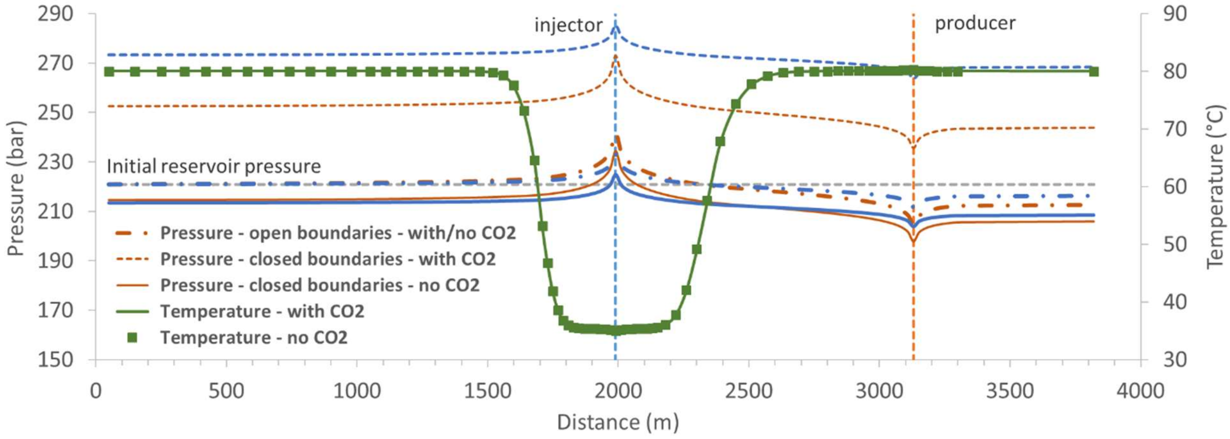

Figure 1: Simulated pressure (left axis) and temperature (right axis) profiles after 30 years of simulation with open and closed boundary conditions, with and without CO_2 co-injection. The blue pressure data is for the fresh water scenario, the red pressure data for the saline water scenario. The temperature profiles are similar for the fresh water and saline water scenarios, open and closed boundaries, with and without CO_2.

Table 2: Saline water scenario overview and summary of results. Results in bold represent safe operational conditions: MAP is not exceeded and no degassing takes place.

Boundary conditions	Permeability	CO_2 injection rate	CO_2 injection rate	Total CO_2 injected after 30 years	Total CO_2 stored after 30 years	MAP exceeded?	CO_2 degassing?	Final CO_2 concentration in production water	Final CO_2 concentration in production water
[open/closed]	[mD]	[kg/s]	[ktonne/yr]	[ktonne]	[ktonne]	[yes/no]	[yes/no]	[g/kg]	[% of solubility]
open/closed	100	0	-	-	-	no	-	-	-
open	**100**	**1.00***	**32**	**947**	**897**	**no**	**no**	**4.38**	**16.6**
closed	100	1.00*	32	947	897	yes	no	4.40	16.7
closed	100	0.67	21	634	597	yes	no	2.95	11.2
closed	**100**	**0.20**	**6**	**189**	**179**	**no**	**no**	**0.88**	**3.3**
closed	1000	1.00*	32	947	896	yes	no	4.40	16.7
closed	**1000**	**0.67**	**21**	**634**	**597**	**no**	**no**	**2.95**	**11.2**

*75% of the maximum solubility would be 1.1 kg/s, but simulation issues required reduction to 1.0 kg/s.

Table 3: Fresh water scenario overview and summary of results. Results in bold represent safe operational conditions: MAP is not exceeded and no degassing takes place.

Boundary conditions	Permeability	CO_2 injection rate	CO_2 injection rate	Total CO_2 injected after 30 years	Total CO_2 stored after 30 years	MAP exceeded?	CO_2 degassing?	Final CO_2 concentration in production water	Final CO_2 concentration in production water
[open/closed]	[mD]	[kg/s]	[ktonne/yr]	[ktonne]	[ktonne]	[yes/no]	[yes/no]	[g/kg]	[% of solubility]
open/closed	100	0	-	-	-	no	-	-	-
open	**100**	**1.76**	**56**	**1581**	**1602**	**no**	**no**	**7.74**	**14.7**
closed	100	1.76	56	1581	1602	yes	no	7.92	15.0
closed	100	0.83	26	786	801	yes	no	3.96	7.5
closed	**100**	**0.45**	**14**	**426**	**410**	**no**	**no**	**1.99**	**3.8**
closed	1000	1.76	56	1581	1594	yes	no	7.92	15.0
closed	1000	0.88	28	833	800	yes	no	3.96	7.5
closed	**1000**	**0.80**	**25**	**757**	**727**	**no**	**no**	**3.53**	**6.7**

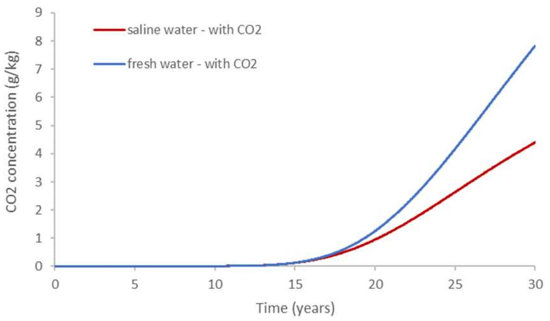

Figure 2: Simulated CO_2 concentration in the production water for saline and fresh water scenarios with base case CO_2 co-injection values of 75% of the solubility limit.

value at all time, as this was the boundary condition implemented. The temperature profile on the other hand is not affected by the co-injection of CO_2, whether boundaries are open or closed, and the cold front does not reach the producer within 30 years for any of the cases (Figure 1). Degassing of the CO_2 is not predicted to occur for any of the scenarios.

The front of dissolved CO_2 is ahead of the cold front, and is expected to break through in the producer after 10-15 years for each of the scenarios (Figure 2). The concentration of dissolved CO_2 in the production water slowly increases over time to a maximum at the end of operations (Figure 2) which is still well below the solubility limit (Tables 2 and 3).

A general rule of thumb is that the pressure during and after subsurface operations should not be more than 10% higher than hydrostatic levels to prevent exceeding the geomechanical strength of the formation. Since the pressure is highest around the injector and any fracturing of the reservoir should be prevented primarily at the top of the reservoir to prevent fracture development above the reservoir, the pressure should stay below the maximum allowable pressure (MAP) at this location. With an initial pressure at the top of the reservoir of 211 bar, the MAP is 232 bar. For each of the scenarios the pressure increases initially. For open boundary conditions and conventional operations the pressure remains below the MAP (Figure 3). In case of CO_2 co-injection at closed boundary conditions, the MAP is exceeded after ~3 and ~6 years for the saline and fresh water scenarios respectively and the pressure further increases over time (Figure 3). Hence, these cases do not represent safe injection conditions.

3.2.2 Safe injection conditions – sensitivity study

For the open boundary conditions, the co-injection at 75% of the maximum solubility showed safe operational conditions, whereas the same co-injection rates predicted pressure increases to above the MAP near the injection well at closed boundary conditions. In order to limit the pressure increase in the closed boundary scenario, the CO_2 co-injection rate was decreased stepwise to find the maximum value for safe injection. In addition the reservoir permeability was increased to assess storage potential in more permeable aquifers.

For the saline scenario, the co-injection of CO_2 needs to be reduced from 1.0 to 0.2 kg/s in order to keep the pressure below MAP (Figure 4). For a more permeable aquifer with a horizontal permeability of 1D the maximum co-injection is 0.67 kg/s (Figure 4). For the fresh water scenario the injection has to be reduced from 1.76 to 0.45 kg/s to keep the pressure below MAP. For a more permeable aquifer of 1 D the safe injection limit is 0.8 kg/s (Figure 4). The CO_2 breakthrough times in the producer are not significantly changed by the reduced CO_2 co-injection rates or increased permeabilities. The CO_2 concentrations in the production water decrease with decreasing injection rates, but are not affected by the permeability changes.

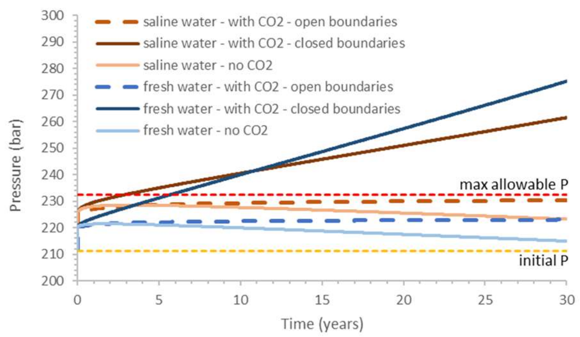

Figure 3: Bottom hole pressures with time at the top of the aquifer for saline and fresh water aquifers with open and closed boundaries, with and without CO_2 co-injection.

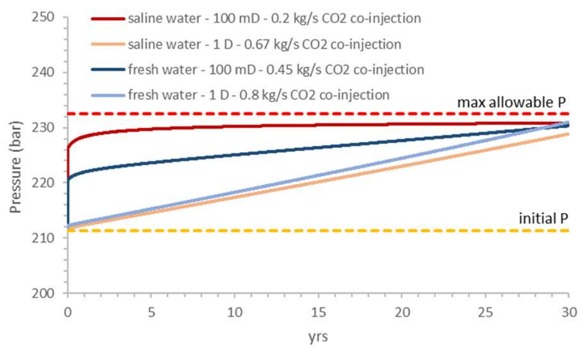

Figure 4: Bottom hole pressures with time at the top of the aquifer for various scenarios with closed boundaries and maximum co-injection rates.

3.3 Discussion

The simulations allowed the identification of maximum co-injection rates for various types of reservoirs. An overview of the results is given in Table 2 and Table 3. For reservoirs with a tank-like character, the maximum rates are constrained by the impact of CO_2 co-injection on pressure evolution around the injector, rather than the solubility limit. The relatively low co-injection rates that prevent exceeding the MAP have the additional benefit of lower CO_2 concentrations in the production water, but this also negatively impacts the total storage capacity (Table 2 and 3). Small amounts of CO_2 are back-produced after breakthrough. The total amount of CO_2 stored after 30 years of operations is therefore slightly lower than the total amount injected (Table 2 and 3). Reservoirs with the lowest storage capacity are saline aquifers with 100 mD permeability and closed boundaries, which can store 179 ktonne of CO_2 in 30 years. The best reservoirs are fresh water aquifers with open boundaries which can store 1.6 Mtonne of CO_2 in 30 years. Corresponding annual injection rates are respectively 6 and 56 ktonne/yr.

In the CO_2-DISSOLVED project reservoir simulations for typical geothermal aquifers of the Paris basin resulted in storage capacities per doublet between 700 ktonne and 2 Mtonne after 30 years for doublets with a similar distance between the injector and producer (Hamm et al., 2014). However, their simulations were performed with CO_2 co-injection at maximum solubility for the conditions in the Paris basin reservoirs, 50 g/L, which is similar to the maximum solubility for our fresh water scenario, but much higher than the maximum co-injection rates we identified for safe operations. Unfortunately, the effect of co-injection on the pressure evolution in the reservoir was not considered or reported by Hamm et al. (2014). However, the large size of the aquifers in the Paris basin might justify neglecting pressure effects, similar to our simulations with open boundary conditions. Yet, injecting at maximum solubility poses the risk of degassing which should be prevented in order to allow the absence of a suitable caprock.

The increased CO_2 concentration in the geothermal production water after breakthrough in the producer results in higher corrosion potential for the production well and surface equipment. However, also in conventional geothermal operations corrosion is a well-known issue, related to natural CO_2 occurrence in the formation water as well as high salinities. The use of composite materials is proposed, which will be resistant to saline production water with increased levels of dissolved CO_2 (Kervévan et al., 2014). For the heat exchanger a more corrosion resistant steel might be required.

4. IMPLEMENTATION IN THE NETHERLANDS

The safe injection rates for typical Dutch geothermal aquifers is in the range of 0.2 to 1.76 kg/s, depending on the salinity, permeability and boundary conditions. On an annual basis, this adds up to 6 and 56 ktonne/yr. The salinity and permeability of a reservoir can be defined during the exploration phase or at the start of the operational phase. Defining the size of the reservoir, whether it should be regarded as a closed tank system or a system with open boundaries, is less straightforward although it does have quite some impact on the total storage capacity of a geothermal reservoir. Hence, for a specific storage location it would be necessary to define the size of the reservoir.

The Delft Sandstone Fm. is one of the key target formations for geothermal energy in the Netherlands. Figure 5 and 6 show maps with the location and permeability of Delft Sandstone in the Dutch subsurface as well as the fault systems. The primary orientation of the faults is NW-SE, and the fault system suggests at least semi-open boundary conditions. The map also shows the locations and size of CO_2 emitters. The latest overview of publicly registered emission sources is from 2016 and counts 1304 industrial companies. Their annual CO_2 emissions in that year varied between 14 kg and 108 Mtonne. Within the range relevant for the CO_2 co-injection concept, roughly 10-100 ktonne per year, the number of sources is reduced to 235 with a total annual emission of almost 3 Mtonne. The maps show that the permeability varies between < 100 mD up to > 2000 mD. The first zoom-in area (Figure 6, upper image) shows mostly low permeable areas with few high permeable zones. This location is, however, not necessarily interesting for the CO_2 co-injection concept since plans are being made for large scale CO_2 capture at the Rotterdam industrial region and transport to offshore depleted hydrocarbon fields. CO_2 emitters in the area would be able to connect to the large pipelines which will be built. The second zoom-in area (Figure 6, bottom image) is farther away from the Rotterdam industrial region and the future transport system. The permeability of the Delft Sandstone formation is very high in the largest part of the area. The development of geothermal doublets with the added benefit of CO_2 co-injection could be interesting for several (clusters of) sources located here. The potential for other target formations in the Netherlands is part of ongoing work.

A crucial boundary condition for the CO_2 co-injection concept to work is that these small industries are part of the ETS in the future. Currently, only large industries are covered by ETS. As soon as the smaller emitters have to pay emission allowances, the target group of sources with emissions between 10 and 100 ktonne/yr has to pay a total annual amount of 60 to 180 billion euros for emission prices of 20 to 60 €/tCO_2. With an annual co-injection rate of CO_2 in the geothermal reservoirs between 6 and 56 ktonne/yr, and assuming that 10% of the total of 175 geothermal doublets in 2030 and 700 in 2050 would be suitable for CO_2 co-injection, the annual contribution of the CO_2 co-injection concept to the emission reductions could be 0.1-1.0 and 0.4-3.9 Mt/yr in 2030 and 2050 respectively. With a national CO_2 emission reduction target by CCS of 2 Mt/yr in 2030, the co-injection concept could significantly contribute to the national ambitions.

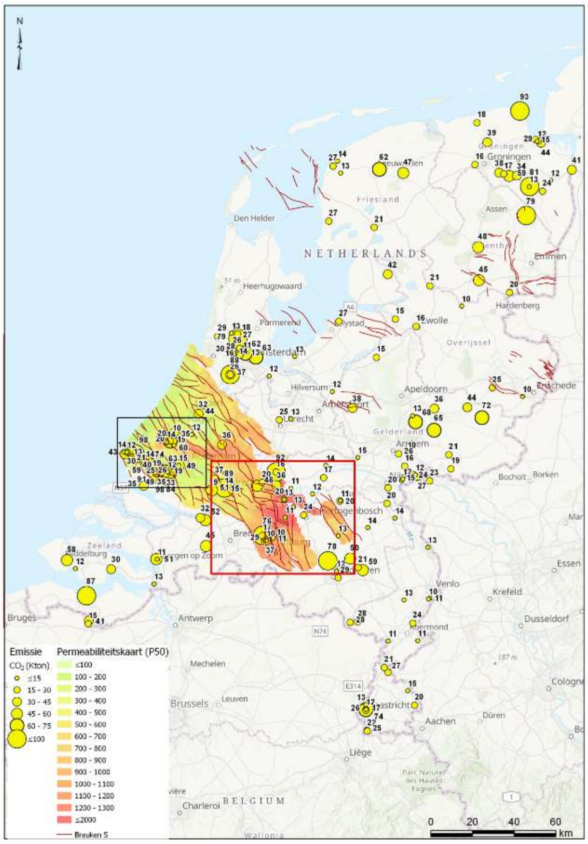

Figure 5: Map of the Netherlands with permeability of the Delft sandstone, the key target formation for geothermal energy, faults, and location of 235 emitters with CO_2 emissions between 10 and 100 ktonne/yr.

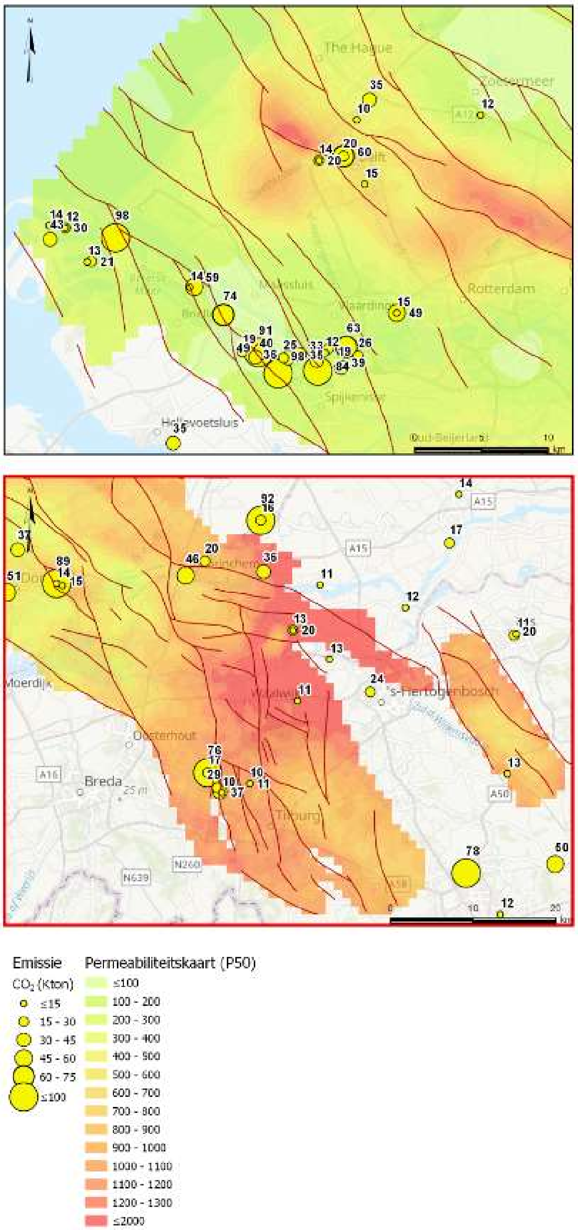

Figure 6: Zoom-in areas from Figure 5.

5. COST-BENEFIT ANALYSIS

In the cost-benefit analysis we look at the additional costs required for, and benefits from the co-injection of CO_2 compared to conventional geothermal operations.

The reservoir simulations demonstrated that the temperature evolution, and hence the geothermal energy production will not be negatively affected by the co-injection. This implies that the normal revenues from geothermal energy will not change. We assume that future (conventional) geothermal doublets will be using composite casings or tubings, as this material has many advantages over steel. At the end, composite casing is not expected to be more expensive than steel casing because of lower OPEX (Kervévan et al., 2014) and potential additional costs are therefore not considered.

The safe co-injection rates defined by the reservoir simulations vary between 0.2 and 1.76 kg/s. For the relatively small industrial sources in the Netherlands it is unknown whether they produce pure CO_2 or a flue gas from which the CO_2 has to be captured, for example by the Pi-innovation capture technology.

In the first case, the CO_2 can simply be co-injected in the injector using a bubbler or dissolved in the injection water at the surface at elevated pressure. Additional costs will be relatively low and are estimated at a CAPEX of 200 k€. In the latter case, we assume that an additional well with the Pi-innovation capture technology has to be drilled close to the injection well. The costs for purifying the CO_2 are currently estimated at 30 €/tCO_2 (Pi-innovation, personal communication). We assume that the costs for the bubbler would be paid by the operator whereas the capture costs would be paid by the emitter. The operator would also have some annual cost for monitoring equipment, estimated at 20 k€/yr. We further assume a fixed injection tariff to be paid by the emitter to the operator of 15 €/tCO_2. The savings for the emitter depend on the emission allowance price.

Pure CO_2 captured at the source

Figure 7 shows the savings for the emitters for several scenarios of annual emission avoided due to co-injection, based on the rates defined by the reservoir simulations. For small emitters the savings minus the costs would be 30 to 270 k€/yr, whereas larger emitters could save 280 k€/yr to 2.5 M€/yr, depending on the future emission allowance price.

The total revenue for the operator depends on the annual CO_2 co-injected in the doublet and is independent of the emission allowance due to the fixed injection tariff. The operator would have an additional CAPEX of 200 k€ and OPEX of 20 k€/yr. Figure 8 shows the revenues for the various co-injection rates after several years of operations. For the minimum co-injection rate of 0.2 kg/s the operator would have a loss in the first few years. After 3 years the operator starts making profit. The total revenue after 30 years of operations is 1.9 M€. For better injection conditions, the operator would start to make profit much earlier. In the best case scenario, with a co-injection rate of 1.76 kg/s the revenue in the first year is 620 k€ and 24.4 M€ after 30 years.

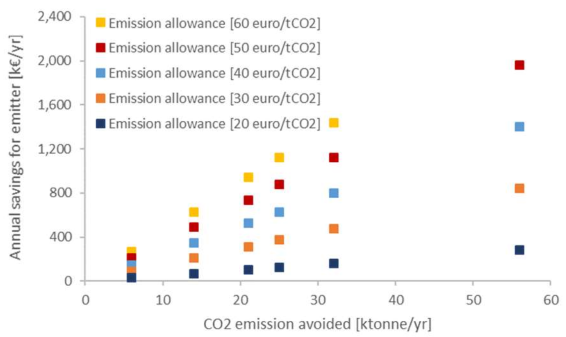

Figure 7: Net annual savings for emitters as a function of CO_2 emission avoided for several emission allowance prices.

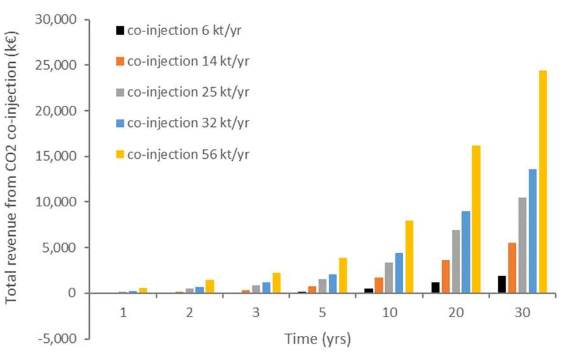

Figure 8: Total revenue for the geothermal system operator over time for several co-injection rates.

Contaminated CO_2 captured at the source

In the case of diffuse flue gas, the emitter will have additional costs for purifying the gas; 30 €/tCO_2 assuming that CO_2 capture is performed with the PI system. Assuming the injection tariff to be paid to the operator of 15 €/tCO_2 for co-injection, the CO_2 co-injection concept will be a cost-effective solution at an emission allowance of >45 €/tCO_2. The annual savings for the emitters are shown in Figure 9 with a maximum of 840 k€/yr for the best case scenario. The revenues for the operator did not change with respect to the pure CO_2 case because of the fixed injection tariff (Figure 8).

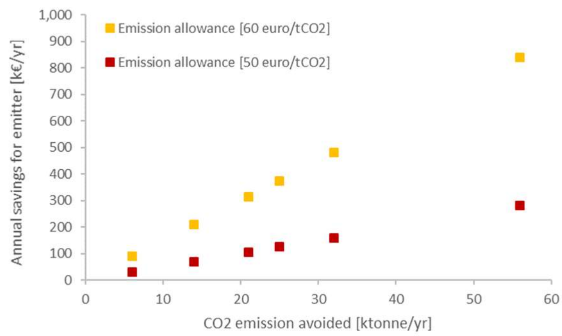

Figure 9: Net annual savings for the emitters as a function of CO_2 emission avoided, in case of impure CO_2 at the source.

6. CONCLUSIONS

The concept of CO_2 co-injection into geothermal reservoirs has been investigated on technical, practical and economic level. Reservoir simulations identified the safe CO_2 co-injection limits for a wide variety of Dutch geothermal reservoir types and characteristics. In relatively small, tank-like reservoirs the co-injection rate is limited by the pressure increase near the injector with time as a result of the added mass. Reservoirs with a higher permeability allow higher injection rates. For reservoirs with open boundaries, the maximum co-injection rate is constrained by the solubility limit at reservoir temperature and water salinity. We include a safety margin of 75% of the solubility limit to prevent degassing.

Based on the safe injection limits, the target emitters were defined to have an annual emission of 10 to 100 ktonne CO_2. This results in a total of 235 emitters for the Netherlands. Their location with respect to geothermal energy potential allows a detailed implementation assessment. Key constraint for the concept of CO_2 co-injection to work is that these relatively small emitters will have to pay emission allowances under ETS in the near future. An important aspect of the economic assessment is whether the sources produce nearly pure CO_2, which can be directly injected into the cold return stream of the geothermal doublet, or a highly impure flue gas which needs to be purified. The costs for purifying the gas stream with the innovative Pi-innovation capture technology is currently estimated at 30 €/tCO_2. Revenues for the emitter and the geothermal operator by avoiding CO_2 emissions highly depend on the geothermal reservoir characteristics and the future emission allowances but could be as high as 2.5 M€/yr for the emitter and on average 800 k€/yr for the operator. Obviously, these numbers depend on the emission allowance price and the injection tariff paid by the emitter to the operator.

Considering the estimated annual co-injection rates into a geothermal doublet and the Dutch ambitions to increase the number of doublets in the next decades, the co-injection concept could significantly contribute to the national CO_2 emission reduction ambitions.

More detailed cost-benefit analysis and implementation assessment for the Netherlands are currently carried out in an ongoing study.

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