Princetonlaan 6
3584 CB Utrecht
P.O. Box 80015
3508 TA Utrecht
The Netherlands

www.tno.nl

T +31 88 866 42 56
F +31 88 866 44 75

TNO report

CO_2 capture in geothermal application

Date	16 November 2021
Author(s)	Jasper Ros, Juliana Monteiro
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Contents

1 Introduction ... 3

2 Case description ... 4

3 Reference CHP system ... 5

4 CO_2 capture plant and model ... 6

5 Results ... 8

6 Conclusions ... 10

7 References ... 11

1 Introduction

For the generation of geothermal heat, hot water is pumped from geothermal wells. Natural gas is dissolved in the brine under reservoir conditions and co-generated from these wells during production. It can be used in a combined heat and power (CHP) system. By combusting natural gas, CO_2 is generated and released to the atmosphere with the flue gas of the CHP system. CO_2 can be captured from the flue gas, and re-injected in the well. This study conducts a high level techno-economic analysis towards this technology option. The schematic representation of this idea is shown in Figure 1.

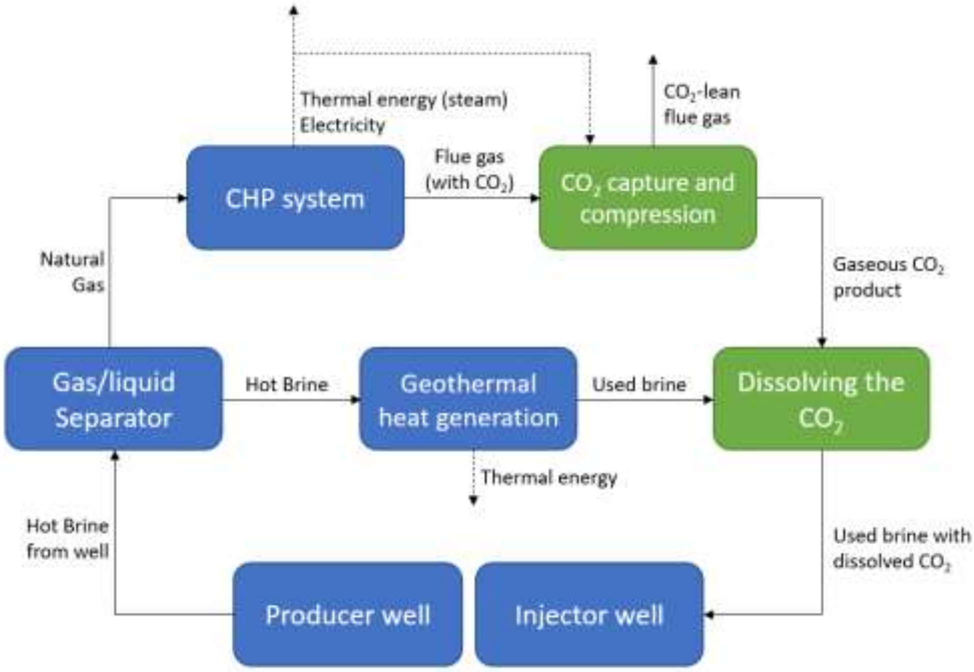

Figure 1, schematic representation of CO_2 capture and re-injection with geothermal heat. The green boxes indicate the added infrastructure when adding CO_2 capture to geothermal energy generation with a CHP system included.

2 Case description

In this study, two cases are considered. Case 1 considers a 200 Nm^3/hr gas stream, which corresponds to a single doublet geothermal well. Case 2 considers a 2000 Nm^3/hr gas stream, which corresponds to a combined 10 doublet geothermal well. Case 2 allows to analyse the economy of scale effect, as CO_2 capture systems are often CAPEX intensive.
The gas composition considered is taken from a geothermal system producing from an aquifer of the Jurassic/Cretaceous age and producing 1 m^3 gas per m^3 water (internal database). The (simplified) composition can also be found in Table 1

Table 1, simplified gas composition of the geothermal well taken as example for this study

Component	**Value**	**Unit**
N_2	1.71	Vol%
CO_2	8.93	Vol%
Hydrocarbons*	89.36	Vol%

*For simplicity, this study suggests that all hydrocarbons are methane.

3 Reference CHP system

A reference CHP system is selected that can produce steam and electricity at the same time. There are a lot of potential process configurations. The reference CHP system used in this study is shown in Figure 2. Typically for these kind of CHP systems, the steam energy/electricity generation follows a 1.5:1 ratio [1], which is also the case in the selected CHP system.

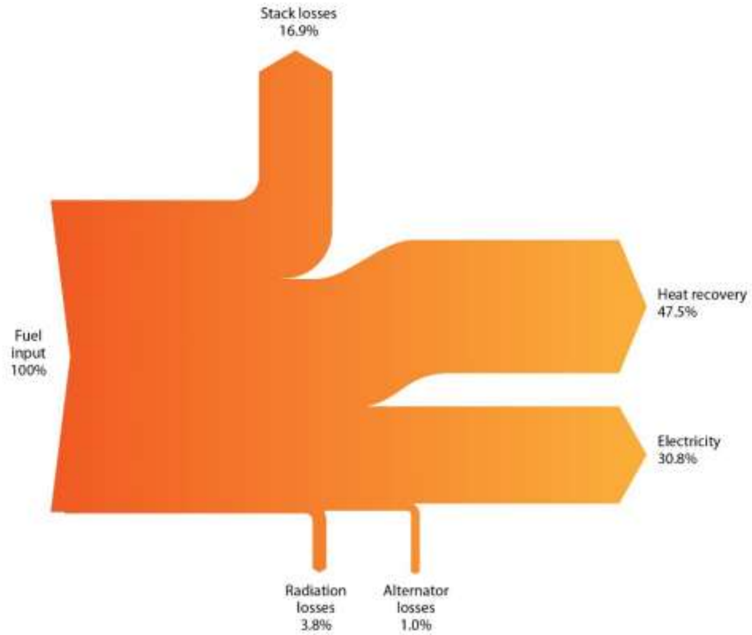

Figure 2, the energy streams in the reference CHP engine/boiler that is considered in this study [1].

For the hydrocarbon (methane) going into the CHP, a lower heating value (LHV) of 47.1 MJ/kg is used [2]. Additionally, complete combustion is assumed. The corresponding electricity and steam generation for the system can be found in Table 2. The air/fuel ratio is chosen in such a way that a flue gas stream with a CO_2 concentration of 4.2% is reached, which is typical of CHP units. The corresponding flue gas composition is shown in Table 3.

Table 2, results of the reference CHP system.

Parameter	**Case 1**	**Case 2**	**Unit**
Electricity generation	0.72	7.2	MW_e
Steam generation	1.11	11.11	MW_{th}
Flue gas flow rate	4682	46825	Nm^3/hr

Table 3, flue gas composition of the CHP system

Concentration	**Value**	**Unit**
N_2	75.7	Vol%
O_2	12.5	Vol%
CO_2	4.2	Vol%
H_2O	7.6	Vol%

4 CO_2 capture plant and model

The generated flue gas from the CHP system can be introduced in a CO_2 capture plant, where the CO_2 can be selectively separated from the flue gas.
The flue gas is first introduced in a quench column, where the flue gas is cooled to ca. 40 °C and potential acidic components that could harm the CO_2 capture process (e.g. SOx) can be removed from the flue gas. After the quench, the flue gas is introduced in the bottom of an absorber column, where it is counter currently contacted with an amine based aqueous solvent, and the CO_2 is transferred from the gas phase to the liquid phase. The solvent of choice in this study is the first generation solvent mono-ethanolamine (MEA). The CO_2 rich solvent is obtained in the bottom of the absorber column, and transferred through a heat exchanger to a desorber column, where the temperature of the solvent is increased to ca. 120 °C so that CO_2 is released from the solvent again. Part of the solvent is boiled in a reboiler to generate steam that provides the heat to the desorber column. The CO_2/H_2O mixture on the top of the stripper is cooled back to 40 °C to obtain a CO_2 product with high purity. The lean solvent obtained at the bottom of the column is fed back to the absorber column. The water wash installed on the top of the absorber column closes the water balance of the system, and controls the emission of volatile amines.
The obtained gaseous CO_2 product leaves the desorber at 2 bar and is compressed in the compression section to 40 bar in three compression stages, before being dissolved in the geothermal water and reinjected in the well.
The CO_2 capture and compression steps for the cases evaluated in this study were simulated using a commercial software (ProTreat). An open technology solvent, 30wt% aqueous solution of monoethanolamine (MEA), was used in the simulations. The simulation flowsheet for the CO_2 capture plant for this study can be found in Figure 3. The simulation flowsheet for the compression of the CO_2 product to 40 bar can be found in Figure 4. Using literature values for the solubility of CO_2 in spent brine, it is estimated that the spent water has sufficient capacity for the captured CO_2 to be dissolved.

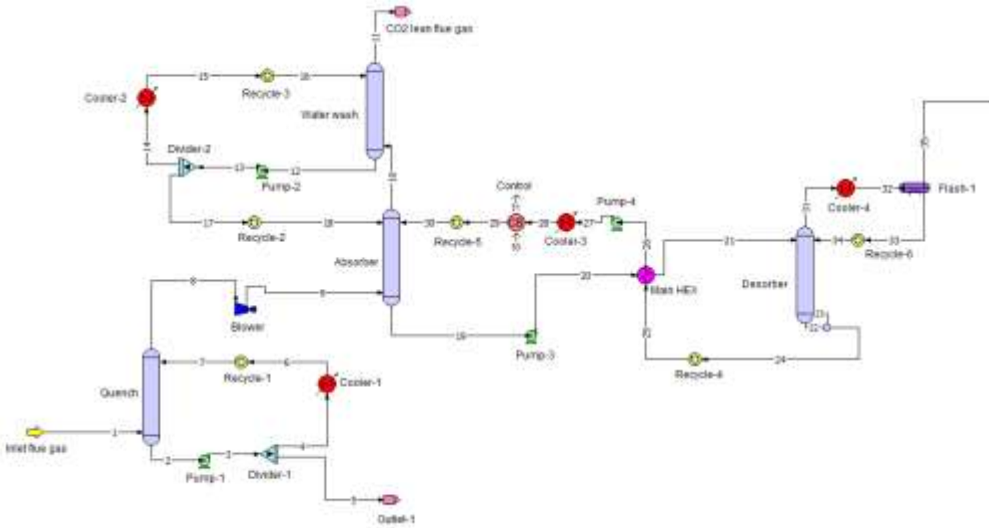

Figure 3, the CO_2 capture plant as simulated in ProTreat software.

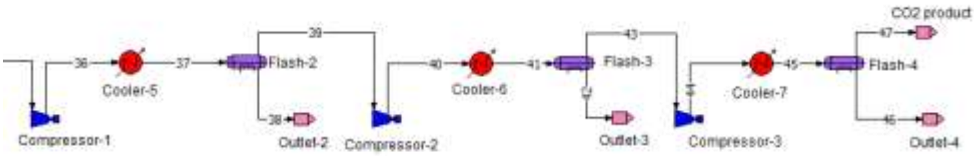

Figure 4, the CO_2 compression plant as simulated in ProTreat software.

5 Results

The energy demand of the capture plant is shown in Table 4. 31.5% of the heat generated by the CHP is used for the CO_2 capture plant. For the electricity, this percentage is 4.4%.

Table 4, energy demand of the CO2 capture and compression plant

Parameter	Case 1	Case 2	Unit
Heat demand	599.4	5995	kW_{th}
Electricity demand	32.0	320	kW_e
Cooling water	51.3	514	m^3/hr

Table 5 shows the most important design results for the main equipment (columns + compressors) . The first compressor increases the pressure of the CO_2 product from 1.8 to 6 bar, the second one from 6 to 15 bar, and the third one from 15 to 40 bar.

Table 5 Main design parameters for the CO2 capture plant

Parameter	Case 1	Case 2	Unit
Height of quench	8.2	8.2	meter
Diameter of quench	0.97	3.08	meter
Height of absorber	24.7	24.7	meter
Diameter of absorber	0.92	2.91	meter
Height of desorber	22.8	22.8	meter
Diameter of desorber	0.36	1.14	meter
Actual gas flow rate compressor #1	110.8	1108	m^3/hr
Actual gas flow rate compressor #2	34.3	343	m^3/hr
Actual gas flow rate compressor #3	13.7	137	m^3/hr

A simplified cost framework is used due to time constraints to get a feeling for the cost of the CO2 capture systems at geothermal wells for different scales. A more in depth techno-economic analysis should be performed in a next stage of the analysis of the technology. The following framework is used to calculate the CAPEX from the design of the equipment:

- The equipment and construction costs of the columns and compressors are calculated with the Aspen Capital Cost Estimator (ACCE) program.
- The equipment and construction costs of the remaining equipment is estimated at 1/3th of the total column costs, based on previous results for similar plants.
- Engineering, Procurement and construction (EPC) costs are estimated at 20% of the total equipment costs.
- Process contingencies are estimated at 30% of the equipment costs + EPC.
- The costs are escalated to 2019 €.
- A cost of capital factor of 8% is used over a 30 year lifetime of the plant to calculate the equivalent annual CAPEX.
- The Fixed OPEX is estimated at 30% of the equivalent annual CAPEX, based on previous results for similar plants.
- Variable OPEX is calculated using fixed values for the heat and electricity: a heat price of 4 €/GJ is used, and for electricity, a price of 0.10 €/kWh is used.

The final cost of CO_2 capture can be found in Figure 5. The calculated cost of CO_2 capture for case 1 (single doublet) is 185 €/ton CO_2, with a CAPEX of 4.3 M€. It is unlikely that this will become cost-competitive in the near future, and the CAPEX is likely too high to apply a CO_2 capture plant in this case. Case 2 shows the effect of scaling up such a system. The cost of CO_2 capture is evaluated at 56 €/ton CO_2, with a CAPEX of 8.6 M€. This size could possibly become cost competitive in the (near) future.

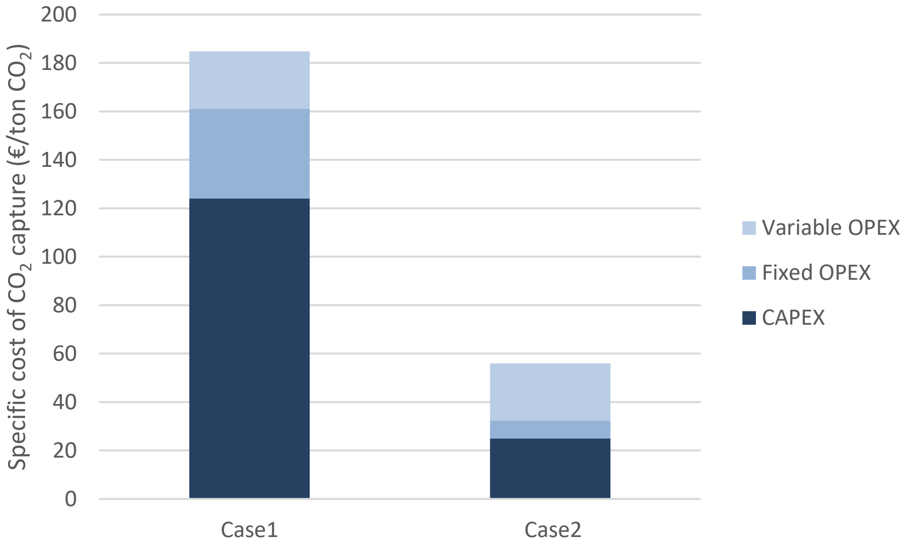

Figure 5, results of the techno-economic analysis in this study

6 Conclusions

A first high level techno-economic analysis has been performed on the integration of a CO_2 capture and re-injection plant installed on a geothermal well equipped with a CHP boiler. The study shows that capturing the CO_2 from the CHP flue gas is technically possible. The calculated cost of CO_2 capture for a single doublet system is 185 €/ton CO_2. The high costs are mainly determined by the small scale of the system, which leads to high specific CAPEX costs. The second case combines 10 doublets and shows that the cost of CO_2 capture can drop drastically to 56 €/ton CO_2, due to the economy of scale.

Recommendations

Follow-up research questions:

- How much dissolved CO_2 can be injected into a reservoir before it becomes CO_2-saturated?
- What is the feasibility of combining the infrastructure for a 10 doublet well? A more elaborate case study on case 2 should be performed, taking into account the costs associated with integrating the infrastructure needed for a CO_2 capture plant on a 10 doublet well.
- What is the best way to dissolve the CO_2 in the brine?

7 References

[1] “A detailed guide for CHP developers – Part 2,” 2021.
[2] “https://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html.”