Offshore CO_2 Capture from gas turbine with low investment optimized using Aspen HYSYS

Lars Erik Øi, Fatemeh Fazli, Rajan Thapa

Department of Process, Energy and Environmental Technology, University of South-Eastern Norway

Lars.oi@usn.no

Abstract

CO_2 capture from gas turbine exhaust gas is a possibility for CO_2 emission reduction on oil and gas production platforms. A standard process is based on absorption in monoethanol amine (MEA). A challenge is that the cost of size and weight for the process equipment is higher than on a land-based process. A standard process based on CO_2 absorption into (MEA) is simulated in Aspen HYSYS™. The equipment cost was obtained from Aspen In-plant Cost Estimator™. The base case is based on assumptions which are in earlier works assumed to be close to optimum for a land-based process with a heat consumption of 3.5 MJ/kg removed CO_2. Different parameters as the number of stages in the absorption column and the minimum temperature approach are varied in the direction expected to be more optimum for an offshore application. It is expected that a lower absorption column and smaller heat exchangers are more optimum offshore even though the heat consumption will increase. Parametric studies were performed at 90 % capture efficiency. Suggested conditions for an offshore application with 87 % capture efficiency are 13 m absorber packing height and 15°C minimum approach temperature due to a decrease in equipment cost, size and weight. This is expected to balance the increase of heat consumption to approximately 5.5 MJ/kg CO_2 removed.

Keywords: *Carbon capture, Aspen HYSYS, gas turbine, offshore, simulation.*

1. Introduction

There are published numerous articles on CO_2 capture in general (Liang et. al, 2015; Li et al., 2016). There are also many articles about cost estimation of CO_2 capture (Rao and Rubin, 2002; Ali, 2019). Some include power production and CO_2 capture in their studies (de Ruick, 1992; Schach et al., 2010).

Research work on the combination of simulation, cost estimation and cost optimization have been performed by Kallevik (2010), Øi (2012) and Shirdel et al. (2022). In a PhD Thesis by Ali (2019) the EDF (Enhanced Detailed Factor) method was presented. Øi et al. (2021) evaluated automated calculation of cost optimum process parameters in the CO_2 capture process. Typical parameters to optimize in an amine-based process is the number of stages in the absorption column and minimum temperature approach in the heat exchangers.

In this study, there was a big challenge to find open literature on process simulation of CO_2 capture from a gas turbine offshore application. There are very few literature references that contain both the CO_2 capture process from offshore gas turbines in a combined cycle by process simulation.

In order to dispose and capture CO_2 De Ruyck et al. (1992) proposed a combined cycle with higher efficiency for a more economical CO_2 capture process. They concluded that the combined steam-CO_2 gas turbine cycle was viable with no major issues in practical manner.

Bjerve and Bolland (1994) assessed six alternatives in power generation with the purpose of reducing CO_2 emission from exhaust gas released from a gas turbine in an offshore natural gas combustion. They concluded that the option with exhaust gas recycling in the combined cycle, was the best alternative in the CO_2 capture process, it resulted in the highest efficiency of CO_2 removal, and second lightest option. Falk-Pedersen et al. (1995) presented a concept of CO_2 removal from an off-shore gas turbine based on absorption into monoethanol amine (MEA). Falk-Pedersen and Dannström (1987) suggested an off-shore process based on absorption into an amine solution through a membrane.

Flatebø (2012) evaluated several offshore combined cycle configurations to meet the power need for the offshore installation and accordingly reduce the cost. The tools Aspen Plus, GTPRO and GTMASTER were used. One of the case studies focused on the design of the offshore installation, and another assigned to obtain high efficiency. Liu and Karimi (2019) used the tool GateCycle for similar analysis.

Nord et al. (2017), studied gas turbines as a power production resource in an offshore oil and gas installation by increasing the level of CO_2 emission. To supply energy demand in the reboiler, a heat resource is required. To compensate the energy demand entirely or partially, they suggested an additional system of a compact steam bottoming cycle that can supply power need included in the CO_2 capture system. Through his study, a weight evaluation for main equipment has been performed to investigate a simple relation between the outlet gas turbine mass flow and the size of the oil and gas installation.

There are very few studies on offshore CO_2 capture analysis and almost none about optimizing the suggested solutions with parameter values. In this work, similar procedure of designing, simulating, and cost estimation for the CO_2 capture process have been performed and more consideration regarding the offshore application have been considered. This work presents results from the Master Thesis work by Fatemeh Fazli (2022).

2. Process Description and Specifications

2.1 Process description

Figure 1 shows the process before the CO_2 capturing process. This combined process cycle is assigned to meet the platform’s need for power energy.

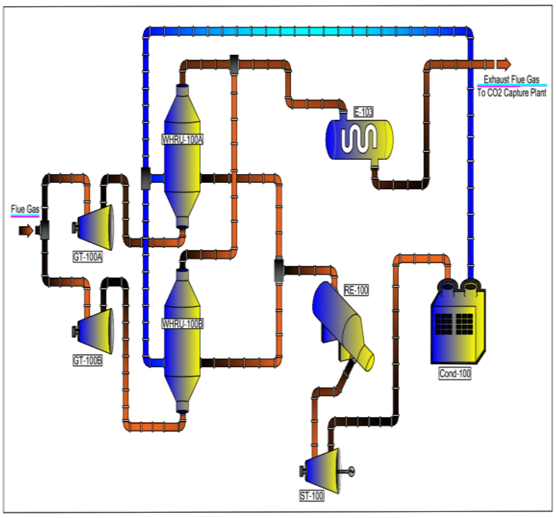

Figure 1: Upstream process before CO_2 capture.

This combination is a set of heat engines collaborating sequentially together with the same heat source and for a typical offshore project is included a set of gas turbine, a WHRU unit, and a generator followed by a condenser and a pump. The flue gas enters the two parallel gas turbines which are assigned to produce power. Then heat will be recovered in a waste heat recovery unit (WHRU) to supply additional heat and generate more energy. One of the exhaust gases from the WHRU unit will be sent to the reboiler and one to the steam turbine to generate electricity.

Figure 2 shows the CO_2 capture process for the defined project. The exhaust gas from the WHRU unit is entering the absorption column and the pressure and temperature of the flue gas need to be adjusted. The exhaust gas will be led to an absorber where the CO_2 will be removed from the gas with the help of a mixture of MEA and water injected into the absorber from the top of the column. The dissolved CO_2 then exit the absorber column from the bottom and is sent to the rich amine pump to pressurize for further process in the desorber unit. Meanwhile, the clean gas will exit the column from the top. To regenerate the MEA and separate the CO_2 captured from the flue gas in the absorber unit, the gas flows to the desorber unit where this is done with the help of a reboiler and a condenser. The temperature should be increased to fulfill the reboiler requirement. The required energy to heat up the gas is supplied by the outlet of the reboiler. As the regeneration process in the desorber column is done, CO_2 removed from the gas is obtained from the top of the stripper for further storage processes. The regenerated amine will exit the stripper from the bottom and will be sent back to the cycle where the MEA is injected into the absorber column.

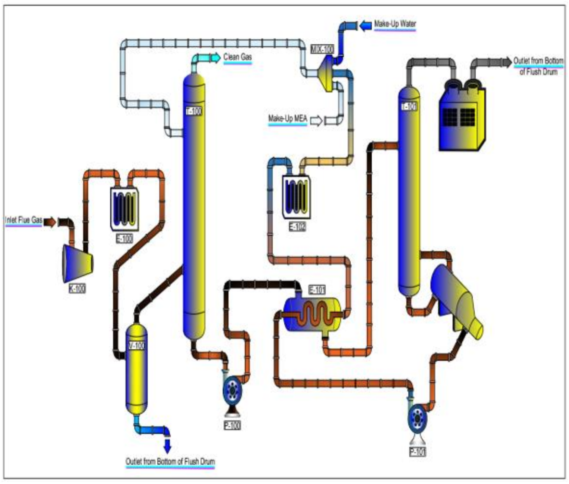

Figure 2: CO_2 capture process.

2.2 Process Specifications and simulation

The process specifications used for the base case simulation are presented in Table 1. The process simulation in this work applies the same strategy used in Øi (2007) and Aromada et al. (2015). The simulations were conducted using the equilibrium-based Aspen HYSYS Version 10.

The base case was simulated to capture 90 % CO_2 from exhaust gas from a natural gas combined cycle (NGCC) power plant. The process consists of an absorber with 16 packing stages (16 m), a desorber with 6 packing stages (6 m), and 10 °C temperature difference in the main heat exchanger.

The Aspen HYSYS simulation process flow diagram showing all the equipment included in the scope of the study is shown in Figure 3.

Table 1: Specifications for process simulation.

Parameter	Value	Unit
Inlet flue gas temperature	40	℃
Inlet flue gas pressure	101	kPa
Inlet flue gas flow rate	1.0×10^5	kgmol/h
CO_2 content in inlet gas	3.73	mol %
Water content in inlet gas	6.71	mol %
Lean amine temperature before and after pump	120	℃
Lean amine pressure before pump	200	kPa
Lean amine pressure after pump	300	mol %
Lean amine pressure to absorber	101	kPa
Lean amine rate to absorber	25945	kgmol/h
CO_2 content in lean amine	2.942	mol %
Number of stages in absorber (base case)	16	-
Rich amine pressure before pump	111	mol %
Rich amine pressure after pump	200	mol %
Number of stages of stripper	6 + Reboiler + Condenser	-
Reboiler temperature	120	℃

2.3 Equipment Sizing

To determine the packing height, a constant stage (Murphree) efficiency corresponding to 1 meter of packing was assumed. Murphree efficiencies of 0.15 and 0.5 were specified for the absorber and the desorber respectively (Table 1). For the absorber and desorber internals, structured packing was assumed.
The absorption column diameter was calculated based on a gas velocity of 2.0 m/s and the desorption column based on a gas velocity of 1 m/s as in Park and Øi (2017) and Øi et al. (2021). The total height of the absorption column and desorption column is specified to be packing height plus 34 m (Kallevik, 2021). The extra height is due to distributors, water wash packing, demister, gas inlet, outlet, and sump.
Centrifugal pumps with 75 % adiabatic efficiency were used in the process simulations. Overall heat transfer coefficient values have been specified for the lean/rich heat exchanger to 500 W/(m^2K). These values are close to the same as in Øi (2012) and Park and Øi (2017) and slightly less than the numbers in Øi et al. (2021) which are regarded as optimistic.

2.4 Capital and Operating Cost Estimation

The equipment costs were calculated in Aspen In-plant Cost Estimator (v.12), which gives the cost in Euro (€) for Year 2020. A generic location (e.g. Rotterdam) was assumed. Stainless steel (SS316) with a material factor of 1.3 was assumed for all equipment units.
In the detailed factor method and the EDF method, each equipment cost (in carbon steel) was multiplied with its individual installation factor to get equipment installed cost. The detailed installation factor is a function of the site, equipment type, materials, size of equipment and includes direct costs for erection, instruments, civil, piping, electrical, insulation, steel and concrete, engineering cost, administration cost, commissioning, and contingency. The updated installation factors for 2020 (Aromada, 2021) were used. Specifications for operating cost estimation are found in Table 2. More details can be found in Fazli (2022).

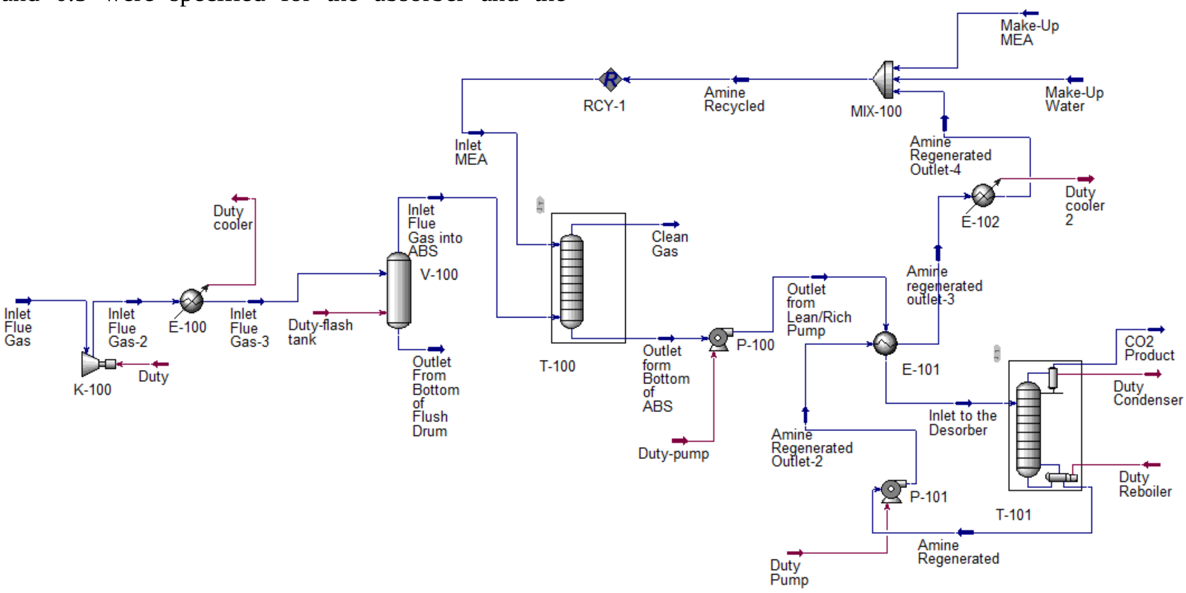

Figure 3: CO2 capture process model in Aspen HYSYS.

Table 2: Cost calculation specifications.

Parameter	Value
Plant lifetime	25 years
Discount rate	8%
Maintenance cost	3 % of installed cost
Electricity price	0.078 Euro/kWh
Steam price	0.032 Euro/kWh
Annual operational time	8000 hours
Currency exchange rate 2021	9.78
Cost index 2020	301
Cost index September 2021	317

2.5 Annual Cost and Capture Cost

A cost optimization can be based on minimization of different cost measures. A common measure is the CO_2 capture cost defined by Equation 1 for a defined process plant and a defined time of operation.

$$CO_2 \; capture \; cost = \frac{Total \; annual \; cost}{Mass \; of \; CO_2 \; Captured} \qquad (1)$$

In this work the annual capital cost is calculated and is added to the yearly operating cost to obtain the total annual cost. The annual capital cost is obtained as by Equation 2:

$$Annual \; capital \; cost = \frac{capital \; cost}{Annualized \; factor} \qquad (2)$$

The annualized factor is calculated by Equation 3 which is based on a constant interest rate (Aromada et. al, 2021).

$$Annualised \; factor = \sum_{i=1}^{n} \left[\frac{1}{(1+r)^n}\right] \qquad (3)$$

where n is the years of operation and r is the interest rate.

3 Results and Discussion

3.1 Simulation Results

Table 3 presents the process simulation results for the base case and parametric optimization.

Table 3: Main simulation results.

	Reboiler heat [MJ/kg CO_2]	Optimum parameter
Base case	3.58	-
Base case packing height	-	16 meter
Base case minimum temperature difference	-	10°C

The reboiler specific heat consumption in this work is 3.58 MJ/kg CO_2. This is close to the 3.7 MJ/kg CO_2 calculated by (Øi, 2007) for a similar process with 85 % CO_2 capture.

3.2 Sensitivity Analysis

In Figure 4, the cross-section area in the absorber is simulated and calculated as a function of number of stages and minimum temperature approach (ΔT_{MIN}).

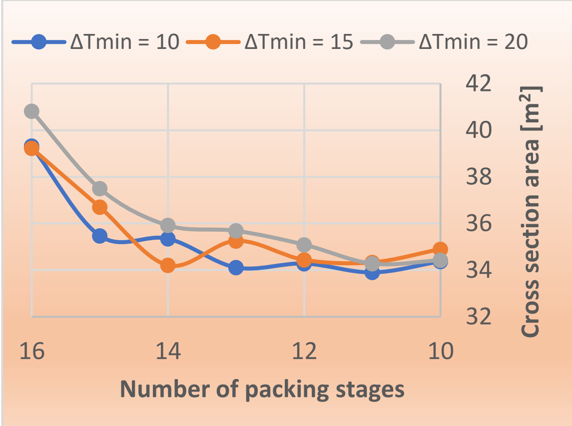

Figure 4: Absorber cross section area per no. of stages.

The figure shows that the absorber cross section increases slightly with the number of packing stages and increases slightly with increasing minimum temperature difference.

In Figure 5, the heat exchanger area in the main lean/rich amine heat exchanger absorber is simulated and calculated as a function of number of stages.

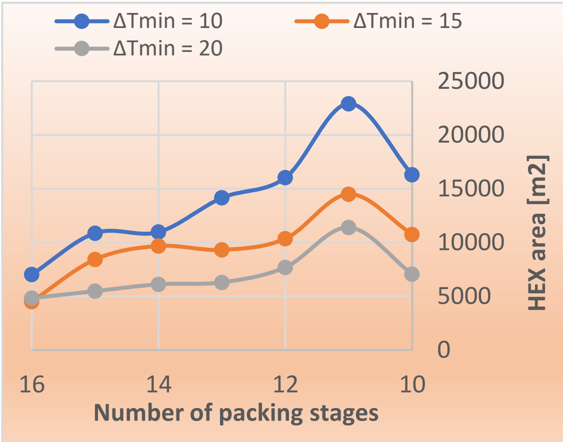

Figure 5: HEX area per number of stages area.

The figure shows that the heat exchanger area decreases with the number of packing stages and increases with the minimum heat exchanger area. This means that a low column and a high temperature difference (ΔT_{MIN}) give the lowest heat exchanger area.

In Figure 6, the reboiler duty in the desorber is simulated and calculated as a function of number of stages.

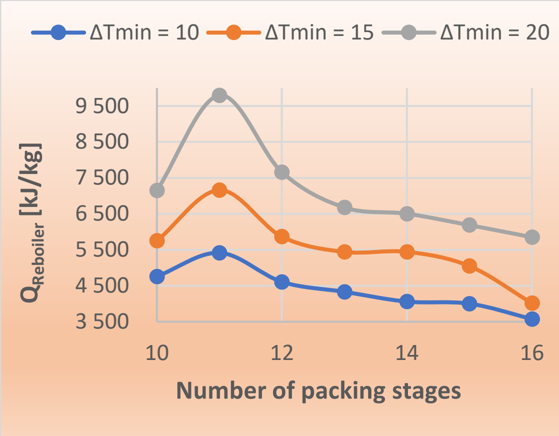

Figure 6: $Q_{Reboiler}$ [kJ/kg CO_2 removed] dependency on number of stages.

The figure shows that the heat consumption decreases considerably with the number of packing stages and with the minimum temperature difference (ΔT_{MIN}). This means that some packing height and a reasonably low minimum temperature approach is necessary to avoid a too high heat consumption. Table 4 shows a summary of the sensitivity analysis results.

A lower column than 12 meter (12 packing stages) is probably not optimum due to high energy consumption. A higher column than 15 meter gives only a slight reduction in energy consumption. Due to this, a 13 meter packing height is suggested for an offshore application. Compared to ΔT_{MIN} = 15 °C, a reduction to 10 °C increases the heat exchanger area substantially while the heat consumption decreases only slightly. When the ΔT_{MIN} increases to 20 °C, the heat consumption increases substantially. Because of this, ΔT_{MIN} = 15 °C is suggested as a close to optimum value. These values can not be calculated as exact optimums, because accurate cost data are not available.

3.2 General discussion

In a traditional land-based plant, the accuracy of a capital cost and operating cost estimate based on an early phase study is in order of magnitude 30-50 %. The uncertainty in a cost estimate for an offshore installation is much higher. One reason for this is that there are more unknown factors in such an estimate. The uncertainty of purchased equipment cost and energy consumption has about the same accuracy for land-based and offshore installations. But the additional factors have much higher uncertainty for an offshore plant. If there are no space and weight limitations, capital cost estimates based on land-based methods can be reasonable. But with space and weight limitations, equipment cost factors can be an order of magnitude higher for an offshore installation. Because of this, cost estimates for an offshore plant in this study can only be order of magnitude estimates.

Table 4: Summary of the results.

	cost optimum packing height	cost optimum temperature difference	90% route (1)	92% route (2)	Combined optimum parameters
Capital cost (million €)	167.7	171.7	192.2	190.6	174.9
Annualized capital cost (million €/yr)	16.5	16.8	18.9	18.7	17.2
Annual operating cost (million €/yr)	52.5	51.9	76.6	60.2	50.8
Total annual cost (million €/yr)	69.0	68.7	95.5	78.9	67.9
CO_2 capture cost (k€/tCO_2)	63.9	63.8	84.5	67.3	62.9
Specific reboiler heat (MJ/kgCO_2)	3.50	3.41	5.24	3.55	3.33
Annual cost savings (%)	-2	-2	29	3	-4
Energy savings (%)	-7	-10	39	-6	-12

4 Conclusion

A challenge for an offshore based CO_2 capture plant is that the cost of size and weight for the process equipment is higher and more uncertain than on a land-based process. Possibilities to reduce the size and cost are evaluated using simulations in an equilibrium-based model in Aspen HYSYS^{TM}. The effects of reducing the size and weight of the absorber and the amine/amine heat exchanger and especially the effect on heat consumption are calculated and evaluated.

A standard process based on CO_2 absorption into mono ethanolamine (MEA) is simulated. The base case is based on assumptions which are in earlier works assumed to be close to optimum for a land-based process with a heat consumption of 3.5 MJ/kg removed CO_2. In this work, different parameters as the number of stages in the absorption column and the minimum temperature approach are varied in the direction expected to be more optimum for an offshore application. It is expected that a lower absorption column and smaller heat exchangers are more optimum offshore even though the heat consumption will increase.

Suggested conditions for an offshore application with 87 % capture efficiency are 13 m absorber packing height and 15°C minimum approach temperature due to a decrease in equipment cost, size and weight. This is expected to balance the increase of heat consumption to approximately 5.5 MJ/kg CO_2 removed.

References

Ali, H. (2019) 'Techno-economic analysis of CO_2 capture concepts', PhD Thesis, University of South-Eastern Norway. [Online]. Available: http://hdl.handle.net/11250/2622802

Aromada, S. A. et al. (2021) 'Capital cost estimation of CO_2 capture plant using Enhanced Detailed Factor (EDF) method: Installation factors and plant construction characteristic factors', *Int. J. Greenh. Gas Control*, vol. 110, no. 1, p. 103394, doi: 10.1016/j.ijggc.2021.103394.

Bjerve, Y. and Bolland, O. (*1994*) 'Assessment of Power Generation Concepts on Oil Platforms in Conjunction with CO_2 Removal', *Proc. ASME Int. Gas Turbine Aeroengine Congr. Expo.*, vol. 3, [Online]. Available: https://doi.org/10.1115/94-GT-378

De Ruyck, J. (1992) 'Efficient CO_2 capture through a combined steam and CO_2 gas turbine cycle', *Energy Convers. Manag.*, vol. 33, no. 5–8, pp. 397–403, [Online]. Available: https://www.sciencedirect.com/science/article/pii/019689049290036V

Falk-Pedersen, O. et al. (1995) 'Separation of carbon dioxide from offshore gas turbine exhaust', *Energy Convers. Manag.*, vol. 36, no. 6–9, pp. 393–396, [Online]. Available: https://doi.org/10.1016/0196-8904(95)00028-C

Falk-Pedersen, O. and Dannström, H. (1997) 'Separation of carbon dioxide from offshore gas turbine exhaust', *Energy Convers. Manag.*, vol. 38, pp. S81–S86.

Fazli, F. (2022) 'Process design of CO2 capture from the gas turbine at an oil platform.' Master's thesis. Telemark University College, Norway.

Flatebø, Ø. (2012) 'Off-design Simulations of Offshore Combined Cycles', Norwegian University of Science and Technology. [Online].Available:http://hdl.handle.net/11250/234879

Kallevik, O. B. (2010) 'Cost estimation of CO_2 removal in HYSYS.' Master's thesis. Telemark University College, Norway.

Kvamsdal, H. M. et al. (2007) 'A quantitative comparison of gas turbine cycles with CO_2 capture', *Energy*, vol. 32, no. 1, pp. 10–24, doi: 10.1016/j.energy.2006.02.006.

Li, K. et al. (2016) 'Systematic study of aqueous monoethanolamine (MEA)-based CO_2 capture process: Techno-economic assessment of the MEA process and its improvements. *Applied Energy*, 165, 648-659.

Liang, Z. et al. (2015) Recent progress and new developmens in post-combustion carbon-capture technology with amine-based solvents. *International Journal of Greenhouse Gas Control*, 40, 26-54. doi: 10.1016/j.ijggc.2015.06.017.

Nord, L. O. R. et al. (2017) 'CCS on Offshore Oil and Gas Installation - Design of Post-Combustion Capture System and Steam Cycle', *Energy Procedia*, vol. 114, no. 7, pp. 6650–6659, Jul. 2017, doi: 10.1016/j.egypro.03.1819.

Rao, A. B., and Rubin, E. S. (2002) 'A Technical, Economic, and Environmental Assessment of Amine-Based CO_2 Capture Technology for Power Plant Greenhouse Gas Control', *Environ. Sci. Technol.*, vol. 36, no. 20, pp. 4467–4475, doi: 10.1021/es0158861.

Schach, M. O. et al. (2010) 'Techno-economic analysis of post combustion processes for the capture of carbon dioxide from power plant flue gas', *Industrial & Engineering Chemistry Research*, 49(5), 2363-2370,

Shirdel S. *et al.*, (2022) 'Sensitivity Analysis and Cost Estimation of a CO_2 Capture Plant in Aspen HYSYS', *ChemEngineering*, vol. 6, no. 2, p. 28, doi: 10.3390/chemengineering6020028.

Øi, L. E. (2012) 'Removal of CO_2 from Exhaust Gas', Ph.D. Thesis, Department of Process, Energy and Environmental Technology, Telemark University College, Porsgrunn, Norway.