International Journal of Engineering Inventions
e-ISSN: 2278-7461, p-ISSN: 2319-6491
Volume 11, Issue 7 [July. 2022] PP: 132-139

Simulation Analysis and Economic Utilization of Discharge CO_2FROM Combustion Gas Via Amine Absorption For EOR, And CCs

Engr.UnyimeEnobongOkure
Department of Chemical Engineering
Imo state Polytechnic, Owerri Nigeria

Engr. Nnadikwe Johnson
Department of Chemical Engineering
Imo state Polytechnic, Owerri Nigeria

Engr. Ibe Raymond Obinna
Department of Chemical Engineering
Imo state Polytechnic, Owerri Nigeria

Khama Rieborue Emmanuel
Department Of Petroleum And Gas Engineering
Nigeria Maritime University, Okerenkoko,Delta State

Abstract

If a carbon tax of £/tonne CO2 was introduced, this master's research examined the viability of a post-combustion carbon capture facility using amine absorption. A Monoethanolamine (MEA) solution is used to remove carbon dioxide (CO2) from the exhaust gas of a combined cycle gas turbine (CCGT) plant. The carbon capture facility was modeled with the help of Aspentech HYSYS software. In this study, the CO2 collecting process was modeled using two different configurations: a basic case and a vapour recompression configuration. Reboiler heat consumption for the basic case model was 3.48 MJ/kg CO2 removed, with an 86 percent CO2 removal rate. Capital expenditures were £110.63 million, with a net present value (NPV) of -£490.29 million over the course of 20 years. Re-boiler heat consumption of 3.19 MJ/kg CO2 eliminated was achieved using the vapour recompression model. It had a net present value of -£551.94 million and a total cost of £160.67 million. Heat consumption in the reboilers was found to be lowest when the lean amine stream was 32-33 percent MEA content. The rich amine may best enter the desorber at this point, with the vapour stream entering directly underneath it. With a flash drum pressure of 110 kPa, the lowest operating costs could be reached; higher pressures, however, did not allow the model to converge, therefore additional ideal pressures remain unknown. It was shown that in order to achieve an NPV of 0, the basic case and the vapour recompression model both required a minimum carbon price of 31.01 and 34.04 £/tonne CO2. In the case of CO2, the price at which CO2 is sold may be instantly subtracted from the minimum carbon tax value needed to generate an NPV of zero.

Keywords: CO_2, MEA, Facility, NPV, MJ/kg

Date of Submission: 10-07-2022 Date of Acceptance: 25-07-2022

---

1. Introduction

Increasing amounts of greenhouse gases like CO2 are a major contributor to global warming. The effect of this is that governments and other organizations are working to reduce CO2 emissions. Power plants that produce electricity by burning fossil fuels like coal, natural gas, and other CO2 producing sources account for a major amount of CO2 emissions (Committee on climate change, 2015). Even though global energy demand is growing, fossil fuels are anticipated to remain the dominant source of energy for a long time due to limitations on non-greenhouse energy sources, such as cost, availability and storage (EIA, 2016). The removal of carbon dioxide from streams by amine absorption is not a new idea in industry, however it is most typically utilized on high pressure streams from oil field reservoirs.. The idea is to increase the heating value while simultaneously reducing the strain on the compressors and lowering the potential for pipe corrosion. Post-combustion removal from power plants has not been carried out on a large scale due to anticipated cost restrictions (Caldecott et al., 2016). The rising expense of transporting and injecting CO2 into geological formations makes CO2 storage a major concern. Additionally, it's possible that some of the CO2 is re-emitted into the atmosphere.

To increase the amount of oil that can be extracted from a well, CO2 may be pumped into the well to improve oil recovery (EOR). Even though EOR (Enhanced Oil Recovery) is an optimum use of CO2, this option is not always accessible. The most widely used capture method, amine gas treatment, uses an absorber column to absorb CO2 into an amine solution. Regeneration in a desorber column and removal of amine from the resulting stream are the last steps in the reboiler's process. The CO2 stream is condensed to remove water from the CO2 stream before it is stored, and the amine is recirculated into the receiver. Diethanolamine (DEA), monoethanolamine (MEA), and methyldiethanolamine (MDE) are the most often used amines for gas treatment (MDEA).

TCM is a carbon sequestration pilot plant testing facility near Mongstad, Norway (MIT, 2012). CO2 removal after combustion is being studied in this pilot plant, which employs cooled ammonia and amines, respectively. A partnership comprising Statoil, Shell, and Sasol, as well as the Norwegian government, has been formed. A full-scale facility was supposed to be built utilizing the knowledge gathered from the research, however the Norwegian Ministry of Petroleum and Energy decided to scrap those plans in September 2013. It doesn't matter; the pilot plant is still in operation as a testing ground.

Figures 1 and 2 demonstrate how two plant concepts were modeled using Aspentech HYSYS simulation software (Birkelund, 2013).

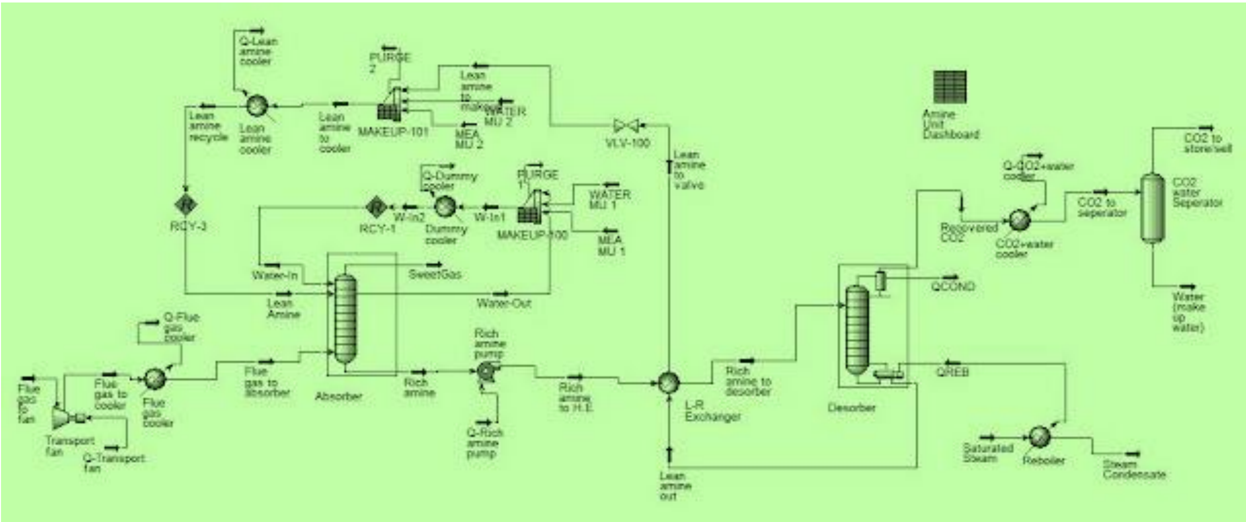

Figure 1: Configuration baseline

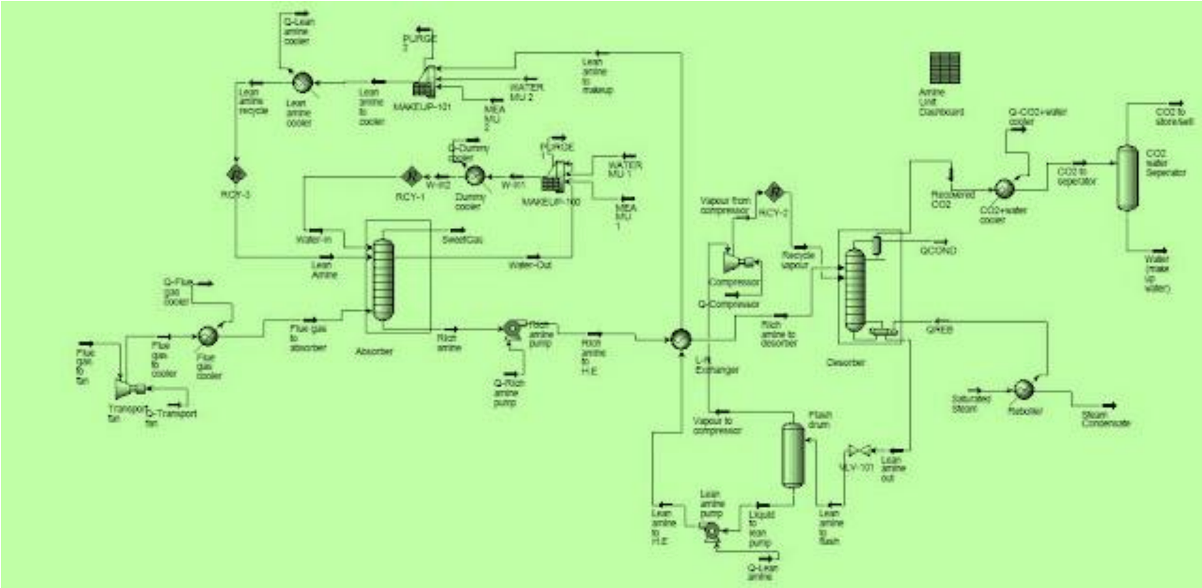

Figure 2: Configuring vapour recompression

The starting point

Pre-packaged reactions for the amine fluid package in HYSYS were used, which is built particularly for amine solvents.

Among the components are a flue gas fan, an absorber column, a rich/lean heat exchanger, a desrober column, a condenser, reboiler, lean pump, a lean cooler, a CO2 cooler, and a separator. A flue gas cooler is employed to simulate a direct contact cooler in the simulation for simplicity's sake (DCC). For the purpose of filling in any gaps before recycling, you may use HYSYS to create a make-up item. Pressure differences between units have not been taken into account. Before being cooled to 40 degrees Celsius, the flue gas from the power plant flows through a transport fan (Kallevik, 2010). There is then a mixture of flue gas and lean amine that enters the absorber column from the bottom. In the lean amine stream, there is roughly 29 weight percent MEA, 64.5 weight percent water, and 5.55 weight percent CO2 There is CO2 in the stream because the regeneration process does not remove the whole amount of CO2. As it leaves the absorber at the very top, the sweet gas is released into the environment. Increasing the amount of water recycled through the absorber column speeds up the process. The rich amine pump delivers a 200kPa amine stream from the absorber's bottom to the pump. Using the hot recycled lean amine stream, the rich amine stream is heated to 104-109.5 degrees Celsius in the lean/rich heat exchanger. The desorber column regenerates the amine in the rich amine stream. While some CO2 and some water are evaporating from the desorber's upper portion, only a little amount of lean amine liquid flows from its lower portion, which is heated to 120°C. The recovered CO2 stream is refrigerated before to going through a separator to remove the water. The lean amine supply is then chilled and utilized to heat the rich amine supply in the lean/rich heat exchanger. It is necessary to further cool the lean amine stream after it leaves the lean/rich heat exchanger since its temperature is still too high at that point. It is necessary to replenish any MEA or water that has been lost before it can be regenerated into the Absorber once again.

Recompression of vapor

Additional units are provided to the vapor recompression model, which already has similar units as the basic case model. By inserting a recycling vapour stream into the desorber, this technology aims to decrease reboiler duty (Karimi et al., 2016).

This decreases the lean ammonia stream to 101 kPa, reducing its temperature in the vapor recompression mechanism by one degree Celsius. The water in this channel is separated from the lean amine stream in the flash drum. At the bottom of the tank, a 120 kPa pressure is applied to the liquid stream (lean amine). When this stream is compared to the basic case model, the lean/rich heat exchanger and desorber are both used. Entering the flash drum at the top, the 95.5 mol percent water vapour stream is compressed to 200 kPa in the compressor (desorber column pressure). When the vapour stream reaches the desorber, the temperature rises to 190°C as a result of the increased pressure.

2. Results

The NPV can't be calculated without knowing the expenses of capital and operations. We used Vozniuk's comparable work to calculate the key equipment's costs, which included scalability considerations, currency conversion, and index calculations for price inflation (2010). Lang factors may be used to estimate capital costs after expenses have been established. According to Lang's formula, the whole cost of the plant's construction is divided by the total cost of purchasing equipment (Sinnott, 2005).
The liquefaction facility's cost has been given as an estimate by I et al (2016). The capital costs are shown in Table 1. As shown in Table 2, yearly energy consumption (8000 hours) is multiplied by utility cost estimates from CCGT plants to arrive at annual operating expenses for the two models (Department for Business, Energy & Industrial Strategy, 2016). The net present value (NPV) is determined over a 20-year period at a discount rate of 7%.

Table 1: Investing expenses

	Base case	Vapour recompression
Total equipment cost [£ million]	89.92	139.96
Liquefaction plant estimate (Øi et al., 2016) [£ million]	20.71	20.71
Capex [£ million]	110.63	160.67

Table 2: Costs-of-operation

	Base case	Vapour recompression
Electricity cost [£ million]	10.04	12.26
CO_2 liquefaction operating cost (Øi et al., 2016) [£ million]	5.37	5.51
Total operating costs [£ million]	35.84	36.93

Analyzing the sensitivity

A number of case studies were carried out in HYSYS to examine the impact of various factors on the NPV and the quantity of heat used. If operating costs rise, but CO2 emissions are also increased, the sensitivity analysis for net present value (NPV) includes a carbon tax of 10 pounds per metric ton of CO2. If NPV is positive, then a lower sensitivity analysis NPV represents a cheaper investment cost than a higher sensitivity analysis NPV.

MEA concentration variations

The MEA content was lowered from 30% to 36% wt% to see how it affected the reboiler's heat consumption (Figure 3).

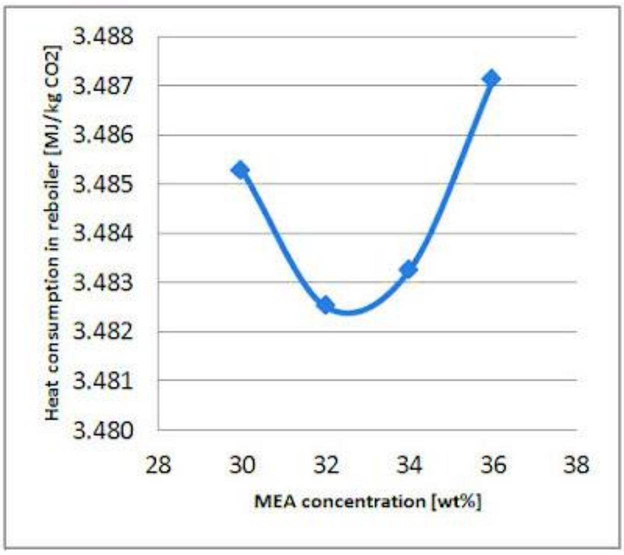

Figure 3: MEA concentration-dependent heat consumption [MJ/kg CO2].

Figure 3 indicates that a lean amine stream with 32-33 percent MEA resulted in the lowest reboiler heat usage. For proper interpretation, the range of MEA wt % values should be expanded.

Variable inlet stage

Temperatures and heat consumption in the reboiler were determined by varying both amine stream input stages and the reboiler's duty (Figure 4).

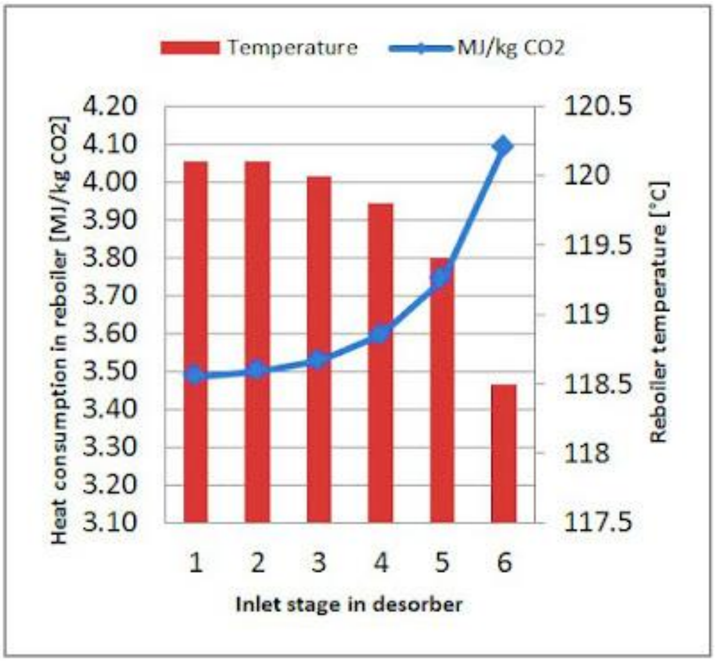

Figure 4: The intake stage of the rich amine stream into the desorber for the vapour recompression model affects the heat consumption [MJ/kg CO2] and the reboiler temperature (°C).

The lowest heat consumption was achieved by approaching the absorber in the first stage with the amine stream that contained the most amine. In order to get the highest possible reboiler temperature, it was selected. For the optimum heat, the vapour recycling stream would need to reach a point directly below the rich amine stream.

Flash drum pressure variations

Figure 5 shows the results of a vapour recompression model case study on the impact of varying the flash drum pressure.

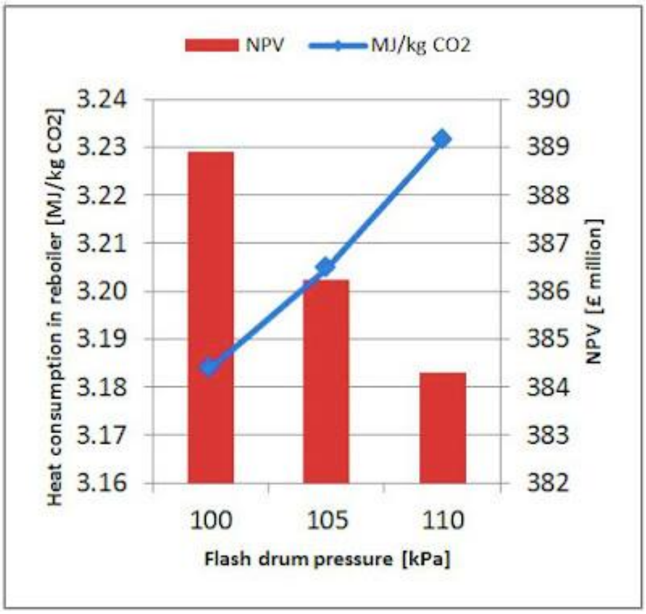

Figure 5: MEA concentration-dependent heat consumption [MJ/kg CO2].

As flash drum pressure rises, reboiler heat consumption (MJ/kg CO2 removed) rises, while NPV falls. As the flash drum pressure is raised, the vapour escape decreases, reducing compressor operating costs. Since the analysis couldn't converge over 110 kPa, it's uncertain whether the NPV would decline further at a higher flash drum pressure or when it would stop falling. Birkelund (2013) looked at the influence of raising flash drum pressure on the Identical work of the whole process [kJ/kg], which is equivalent to the NPV findings for this research since capital costs did not vary with flash drum pressure. Birkelund (2013) found that equivalent labor decreases until 115 kPa, then grows.

Carbon Tax and CO2 Income affect NPV.

A carbon tax price (£/tonne CO2) with an NPV of zero or positive was determined by treating it as a revenue source in the NPV computations.

Figures 6 and 7 demonstrate how the NPV changes for the basic case model and the vapour recompression model if the collected CO2 is sold for EOR.

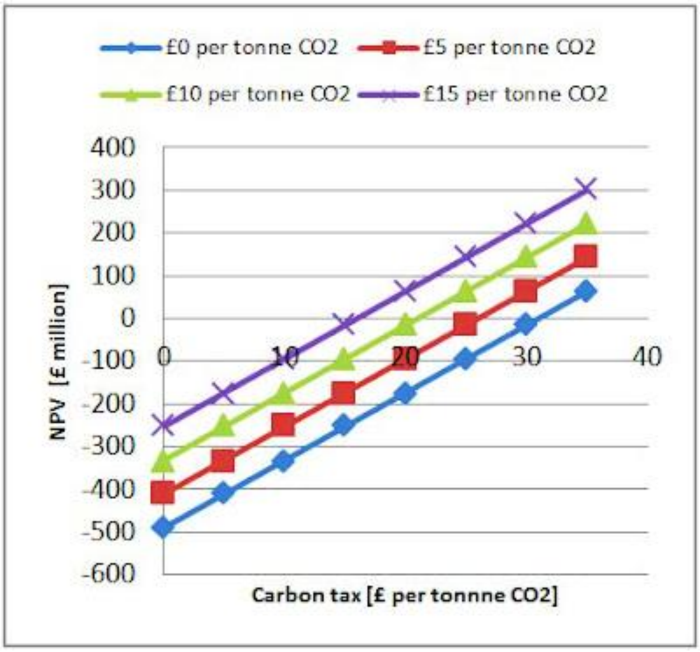

Figure 6: For the basic case configuration, the NPV is calculated as a function of the carbon tax in the range of zero to 35 pounds per ton of CO2.

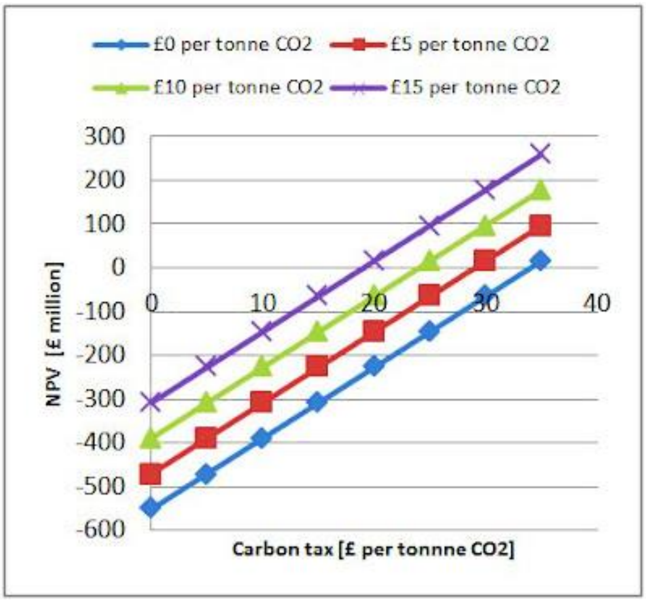

Figure 7: CO2 sold for EOR at 0, 5, 10, and 15 £/tonne CO2 for the vapour recompression configuration has an NPV of 0 to 35 £/tonne CO2 based on the carbon tax.

In terms of net present value, the graphs show a linear connection between the carbon tax and the selling price. Without taking into account earnings from CO2 sales, both basic case and vapour recompression models were used to determine the carbon price necessary for NPV to equal zero. The carbon tax necessary for the basic scenario and the vapour recompression model was 31.01 and 34.04 pounds per ton of CO2, respectively.
Assuming that much of the pipeline in the UK Central North Sea may be re-used with minimal changes since it is metallurgically suitable, the calculations for NPV assumed no extra operating or capital costs incurred from the sale of CO2. The price of CO2 sold may be removed from the minimum carbon tax requirement of 31.01 and 34.04 £/tonne CO2 for the base case and vapour recompression models, respectively, to arrive at the new minimum carbon tax price for a 0 NPV.. According to Reid (2015), North Sea offshore oil businesses would be more ready to accept free CO2 in return for free storage of the CO2.

3. Discussion

Base case and vapour recompression models were able to remove CO2 at a rate of 86 and 88 percent, with heat consumption in the reboiler being 3.48 and 3.19 MJ/kg CO2. I (2007) and Karimi et al (2009) have shown comparable results for the basic case (2016). Vapour repression model value achieved is higher than published in literature, which was 2.7 MJ/kg CO2 removed for Birkelund (2013) and 2.58 MJ/kg CO2 removed for Karimi et al. (2013b) (2016). We found that the total CO2 removal % is significantly affected by the recycling stream's CO2 content, thus we should aim to maintain that concentration as low as possible.
As a result of the reboiler's decreased heat consumption, the vapour recompression model has the potential to minimize operating costs sufficiently to make it a feasible choice. After all, the reboiler saved £1.26 million in running expenses compared to standard boilers. But an extra £2.2 million was needed for the compressor's operating costs, making this a compelling choice.
The amine stream entering the absorber in the first input stage was found to have the lowest heat consumption value, with the vapour stream arriving just below. However, a 32-33% MEA concentration was shown to be optimal for the lean amine stream entering the absorber column, despite small heat consumption variations. While 110 kPa flash drum pressure resulted in lowest operating costs, the model failed to converge at higher pressures, hence more study is needed to determine the appropriate flash drum pressure.
In the basic case and vapour recompression model, the minimum carbon price needed to achieve negative NPV was 31.01 and 34.04 £/tonne CO2. According to these results, Canada's anticipated carbon price of at least $10 (£6.09) per tonne of CO2 is too low to allow broad adoption of amine-absorption carbon capture and storage. Because EOR CO2 is priced in pounds per tonne, the selling price may be removed from the carbon tax minimum necessary to achieve negative NPV, providing a new minimum for CO2 sales. Since the Lang factors used for estimating are only 50% correct, a more precise costing approach is needed to validate these results.

4. Recommendations

• Use a Modified Hysim Inside-Out algorithm with adjustable damping to increase convergence.
• Since so many factors must be taken into account when calculating capital expenses, a computer software is recommended.
• Investigate other methods of carbon capture.

5. Conclusion

A carbon price of more than £30 per tonne of CO2 is needed, according to the paper, in order to motivate businesses to implement carbon capture systems, since it is less expensive for businesses to pay the tax than to implement CCS in order to cut carbon tax rates. Intake stage and MEA wt percent process optimizations were revealed throughout the research. Future study should focus on correcting the simulation's convergence issues as outlined in the suggestions. This research on carbon taxes and CO2 revenue may be used to analyze the feasibility of comparable carbon capture facilities since the findings matched those reported in the literature.

Acknowledgement
The authors would like to acknowledge the centre for energy resources and refining technology at Imo State University, Owerri, Nigeria for their technical support, especially providing access to their own software application.

References

[1]. Birkelund, E.S. (2013) CO2 Absorption and Desorption Simulation with Aspen HYSYS. Available at: https://core.ac.uk/download/pdf/30932409.pdf (Accessed: 16 October 2016).

[2]. The Canadian Press (2016) Trudeau says carbon-tax naysayers using 'scare tactics'. Available at: http://www.cbc.ca/news/canada/calgary/trudeau-carbon-tax-scare-tactics-1.3805715 (Accessed: 16 October 2016).

[3]. Caldecott, B., Kruitwagen, L., Dericks, G., J. Tulloch, D., Kok, I. and Mitchel, J. (2016) Stranded Assets and Thermal Coal An analysis of environment-related risk exposure. Available at: http://www.smithschool.ox.ac.uk/research-programmes/stranded-assets/satc.pdf (Accessed: 15 July 2016).

[4]. Committee on climate change (2015) Power. Available at: https://www.theccc.org.uk/charts-data/ukemissions-by-sector/power/ (Accessed: 31 January 2017).

[5]. Department for Business, Energy & Industrial Strategy (2016) Electricity Generation Costs. Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf (Accessed: 31 January 2017).

[6]. EIA (2016) International Energy Outlook 2016. Available at: http://www.eia.gov/outlooks/ieo/pdf/0484(2016).pdf (Accessed: 31 January 2017).

[7]. IPCC (2005) Carbon Dioxide Capture and Storage. Available at: http://www.ipcc.ch/pdf/special-reports/srccs/srccs_summaryforpolicymakers.pdf (Accessed: 15 July 2016).

[8]. Kallevik, O.B. (2010) Cost estimation of CO2 removal in HYSYS. Available at: https://dspace01.hit.no/bitstream/handle/2282/1012/kallevikmaster.pdf?sequence=1 (Accessed: 16 October 2016).

[9]. Karimi, M., Hillestad, M. and Svendsen, H.F. (2016) 'Capital costs and energy considerations of different alternative stripper configurations for post combustion CO capture', Chemical Engineering Research and Design, 89(8), pp. 1229–1236. doi: 10.1016/j.cherd.2011.03.005.

[10]. Kemp, A.G. and Kasim, S. (2012) The Economics of CO2-EOR Cluster Developments in the UK Central North Sea/Outer Moray Firth. Available at: https://www.abdn.ac.uk/research/acreef/documents/Working_papers/nsp-123.pdf (Accessed: 31 January 2017).

[11]. MIT (2012) Carbon capture and sequestration technologies @ MIT. Available at: https://sequestration.mit.edu/tools/projects/statoil_mongstad.html (Accessed: 16 October 2016).

[12]. Øi, L.E. (2007) Aspen HYSYS Simulation of CO2 Removal by Amine Absorption from a Gas Based Power Plant. Available at: http://www.ep.liu.se/ecp/027/008/ecp072708.pdf (Accessed: 15 July 2016).

[13]. Øi, L.E., Eldrup, N., Adhikari, U., Bentsen, M.H., Badalge, J.L. and Yang, S. (2016) 'Simulation and cost comparison of CO2 Liquefaction', Energy Procedia, 86, pp. 500–510. doi: 10.1016/j.egypro.2016.01.051.

[14]. Sinnott, R.K. (2005) Chemical engineering design. Coulson and Richardson's chemical engineering series, volume 6. 4th edn. United States: Elsevier Science & Technology.

[15]. Reid, W. (2015) A Selective Literature Review of CO2 EOR in the UK North Sea Continental Shelf. Available at: https://www.thecrownestate.co.uk/media/501905/ei-literature-review-of-CO2-eor-in-the-uk-north-sea-continental-shelf.pdf (Accessed: 31 January 2017).

[16]. Vozniuk, I.O. (2010) Aspen HYSYS process simulation and aspen ICARUS cost estimation of CO2 removal plant. Available at: https://teora.hit.no/handle/2282/975?show=full (Accessed: 16 October 2016).