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Experimental and Process Modelling Study of Integration of a Micro-turbine with an Amine Plant

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Abstract

An integrated model of a micro-turbine coupled to a CO_2 capture plant has been developed with Aspen Plus, and validated with experimental data obtained from a Turbec T100 microturbine at the PACT facilities in the UKCCS Research Centre, Beighton, UK. Monoethanolamine (MEA) was used as solvent and experimental measurements from the CO_2 capture plant have been used to validate the steady-state model developed with Aspen Plus®. The optimum liquid/gas ratio and the lean CO_2 loading for 90% CO_2 capture has been quantified for flue gases with CO_2 concentrations ranging from 3 to 8 mol%.

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Keywords: micro gas turbine; amine plant; MEA; process simulation; CO_2 injection; Aspen Plus

1. Introduction

Various types of carbon capture and storage (CCS) have been extensively investigated for fossil fuels, although predominantly for coal-fired power systems. Natural gas nevertheless plays an important role in electricity generation for many countries, including the UK. To minimize the release of CO_2 to the atmosphere and meet stringent emission limit targets, CCS technologies, such as post-combustion capture using amine-based solvent scrubbing, will need to be applied to all carbon-intensive fuels and power generation methods in the future, including natural gas. Gas turbine systems, often in the form of combined cycles, are a common means of centralized, large-scale power generation from gaseous fuels. A feasibility study for retrofitting an amine-based

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capture facility onto an existing gas processing plant located on the Alaskan North Slope showed this to be technically feasible [1]. It consisted of integrating eleven gas turbines, four Heat Recovery Steam Generators (HRSG), four absorbers, one stripper and a five stage centrifugal compressor of high purity CO_2. The system was proposed to capture around 85% of the total CO_2 emitted, that is, 5200 tonnes/day of CO_2. The economic analyses proved it to be a very costly system mainly due to the harsh environmental conditions in the Alaskan climate, but also due to a very dilute feed gas with an average concentration of 3.3% vol. of CO_2. Nonetheless, micro-turbines are ideal for research purposes in that the processes which occur are highly analogous to those in commercial-scale power stations based on gas turbine technology; they however have a significantly smaller footprint and require much less fuel to run, since they generate less power.

The benefits of micro-turbines have increased interest in them as power generators. As a result, previous research has involved the thermodynamic analysis of micro-turbines using IPSEpro software [2], using biogas as fuel [3], and adding a CO_2 capture model to evaluate the effects on electrical efficiency [4]. A micro-turbine is available within the national UKCCS Research Centre Pilot-scale Advanced Capture Technology (PACT) core facilities located in Beighton, which has the capability of being coupled to a solvent-based carbon capture plant. In this paper, an integrated model of a micro-turbine coupled to a CO_2 capture plant has been developed with Aspen Plus and the integrated model has been validated with experimental data generated at the PACT facilities. This integration is of great interest for research on post-combustion carbon capture from gas turbine based power generation.

2. Process description

A Turbec T100 PH Series 3 micro gas turbine (manufacture date circa 2006), which generates both heat and power, was used for the experimental work here. The technical information from this was used for the boundary conditions for process simulations and model validation was done using the experimental data. As with all gas turbines, this micro-turbine contained the three main elements of a gas turbine – a compressor, a combustor and a turbine – in this case, on the same shaft as the generator. Additional components to improve both the electrical output and overall efficiency were also integrated into the design, which included a recuperator for pre-heating the combustion air, and a heat exchanger to generate the hot water; both utilized the waste heat from the exhaust. These components are all shown in Figure 1.

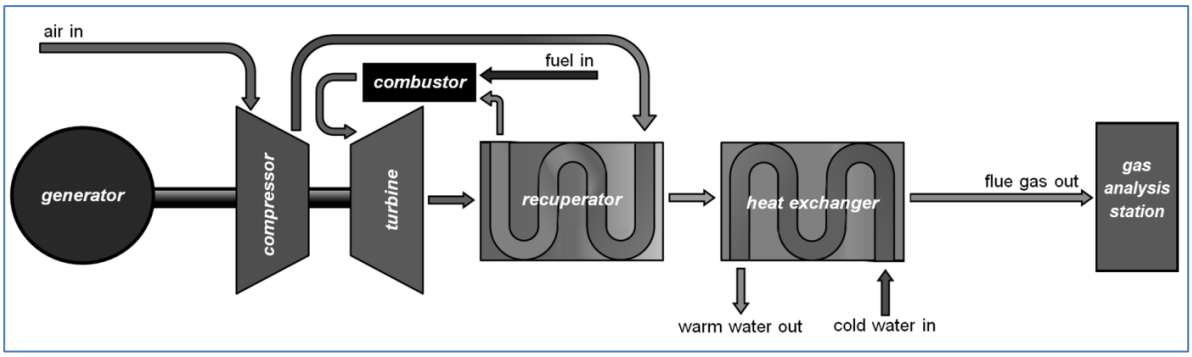

Figure 1. Key components of the Turbec T100 micro gas turbine.

The micro-turbine compresses ambient air to around 4.5 bara with its centrifugal compressor. The air is then pre-heated before being mixed with the fuel – natural gas in this case – and introduced to the combustion chamber; very lean conditions are used (high air-fuel ratios) to minimize emissions, particularly of CO and NOx. The radial turbine drives the high-speed generator to produce up to 100 kW_e of power to export to the grid, at an efficiency of ~30%. The counter-current water-gas heat exchanger has a maximum thermal output in the region of 155 kW_{th}, for a water temperature of 70-90°C. By using heat recovery components (recuperator and heat exchanger), the combustion efficiency and electrical output can be significantly increased and the overall system efficiency can be greatly improved, to ~77%.

The solvent-based CO_2 capture plant consists of a SO_2 removal tower and the CO_2 removal section. The SO_2 removal tower is used to condition the flue gas entering the absorber when burning high sulphur-containing fuel such as coal, and it can be put offline when burning low or no sulfur-containing fuel such as natural gas. For the MEA base-line experiment discussed in this paper, the SO_2 removal tower was put offline during the operation of the solvent-based CO_2 capture plant since the flue gas sent to the absorber was the product of natural gas combustion. The CO_2 removal section has a packed absorber column, a packed water-wash column, a packed stripper column with an air-cooled condenser and a reflux drum at the top. The key information about the columns in the CO_2 removal section is summarized in Table 1. Heat integration is achieved in a plate lean/rich heat exchanger, and further cooling of the lean amine solution leaving the lean/rich heat exchanger is achieved in an air-cooled plate-type lean amine cooler. The flue gas needed by the CO_2 capture plant was provided by mixing a fraction of the micro-turbine flue gas with pure CO_2 from a CO_2 storage tank. It is also possible to supply synthetic flue gas to the absorber by mixing CO_2, O_2, and N_2 from their respective storage tanks. A schematic of the CO_2 capture plant, excluding the SO_2 removal tower, is shown in Figure 2.

Table 1. Key data for the columns in the PACT amine plant.

Absorber column		Stripper column		Water wash column	
Diameter (m)	0.303	Diameter (m)	0.303	Diameter (m)	0.303
Packed height (m)	6.0	Packed height (m)	6.0	Packed height (m)	1.2
Packing type	IMTP #40	Packing type	IMTP #40	Packing type	IMTP #40

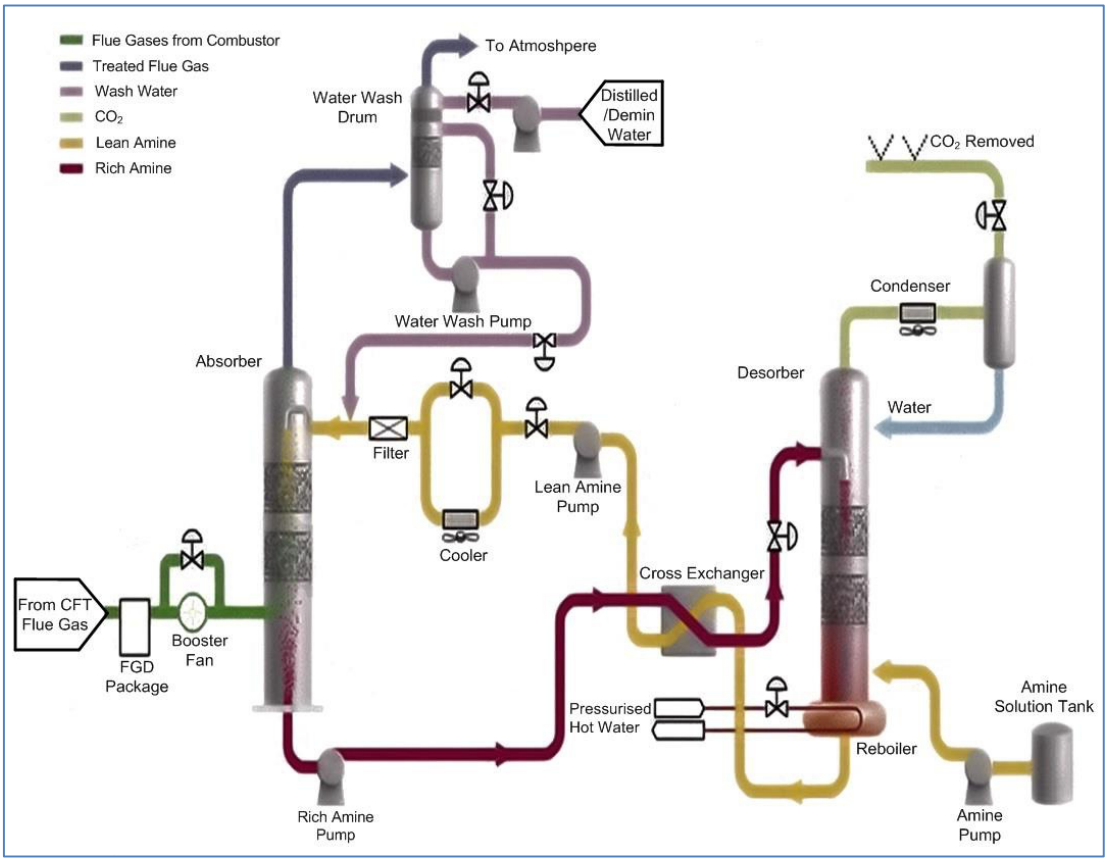

Figure 2. Process flow diagram of the PACT amine capture plant

3. Methodology

3.1. Experiments

The Series 3 T100 gas turbine was run at a power reference (electrical power output) of 80 kW for the duration of the experiments. This gave a good balance between low CO levels and reasonable gas consumption rates. Internal monitoring of the micro-turbine allowed data collection for the air inlet temperature, turbine outlet temperature and turbine speed, among others.

At the gas analysis station, identified on Figure 1, a slipstream of the flue gas was analysed for a number of combustion products using a range of techniques; the gases were transferred via heated lines to minimise condensation. This included: O_2 using the magnetopneumatic measurement principle; NOx via chemiluminescence analysis; and CO, CO_2 and SO_2 by non-dispersive infra-red – all with Horiba VA-3000 analyzers attached to a Horiba VS-3000 sample conditioning unit. Unburned hydrocarbons were also monitored with a flame ionization detector (Signal 3000HM). The rest of the flue gas was sent to the exhaust duct, from which another slipstream of gas was taken to feed the CO_2 capture plant. The heat exchanger of the micro-turbine has a bypass to control both the temperature of the hot water and that of the flue gas. For the CO_2 capture plant, it was required that the flue gas temperature was ~40 °C and therefore the bypass position was changed to ensure this temperature was maintained.

A fraction of the flue gas produced by the micro-turbine was mixed with pure CO_2 from a storage tank to give a CO_2 composition of about 4.5 mol% in the flue gas sent to the absorber, and the pressure of the flue gas after CO_2 injection was boosted by a booster fan in order to overcome pressure drop in the absorber and water-wash columns. The flue gas entering the bottom of the absorber with the lean MEA solution entering the top of the absorber column resulted in countercurrent contact is shown in Figure 2. This caused the absorption of CO_2 from the upward-flowing flue gas into the downward-flowing MEA solution. A demister at the top of the absorber limited carryover of water/MEA vapour by the treated gas exiting the top of the absorber, and the treated gas exiting the absorber was further washed in the water-wash column using demineralized water before exiting to the atmosphere. The rich MEA solution exiting the bottom of the absorber column, after recovering some heat from the lean MEA solution in the lean/rich heat exchanger, was regenerated in the stripper column. The heat duty of the stripper reboiler was supplied by pressurized hot water. The mass flowrate, the inlet temperature and the outlet temperature of the pressurized hot water were used for the estimation of the reboiler heat duty of the stripping process.

The measurement of the conditions and compositions of the flue gas entering the absorber, the treated gas exiting the top of the absorber, and the clean gas exiting the top of the water-wash column was performed by a combination of experimental techniques consisting of gas analysers (Horiba VS3000/VA3000), FTIR (Gasmet DX4000) and GCMS (PerkinElmer Clarus SQ8). The alkalinity of the amine solution was determined analytically by titrating samples with HCl solution, while the CO_2 loadings of the lean MEA and rich MEA solutions were determined by titrating samples of the solution with NaOH solution. The control of the CO_2 capture plant was via programmable logic controllers (PLCs) while data acquisition and logging was performed with LABVIEW® interfaced with MS Excel®

3.2. Simulation

The development of the simulation work was based on combining the various modules within the Aspen Plus environment, and integrating the micro-turbine with the amine plant for CO_2 capture. The micro-turbine was represented by a series of blocks corresponding to the various sub-processes occurring, that is, compression, combustion, expansion and cooling.

The Series 3 T100 gas turbine was modelled using Aspen Plus® version 8.4, as shown in Figure 3. Natural gas was burnt in the combustor (COMB block) using excess air, which was previously compressed in the compressor (COMP block) and preheated in the recuperator (HX1) using hot exhaust gases. Flue gases were expanded in the turbine (TURB block) and subsequently cooled in two stages: in the recuperator (HX1) to preheat air and in the water-gas heat exchanger for thermal power generation.

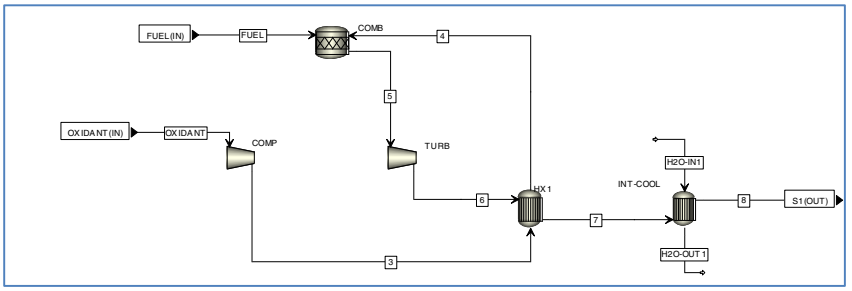

Figure 3. Process flow diagram of the Turbec T100 micro gas turbine as implemented in Aspen Plus

Table 2. Model components and input variables for the Turbec T100 micro gas turbine.

Block	I.D.	Aspen Plus model	Input variables
Compressor	COMP	Compr	Pressure ratio: 4.5 Isentropic efficiency: 0.768 (ASME method) [5]
Combustor	COMB	RStoic	Pressure: 4.5 bar Duty: 0 kW
Turbine	TURB	Compr	Pressure ratio: 0.22 Isentropic efficiency: 0.805
Recuperator	HX1	HeatX	Hot outlet – cold inlet temperature difference: 50ºC
Water-gas heat exchanger	INT-COOL	HeatX	Water temperature increase: 20ºC

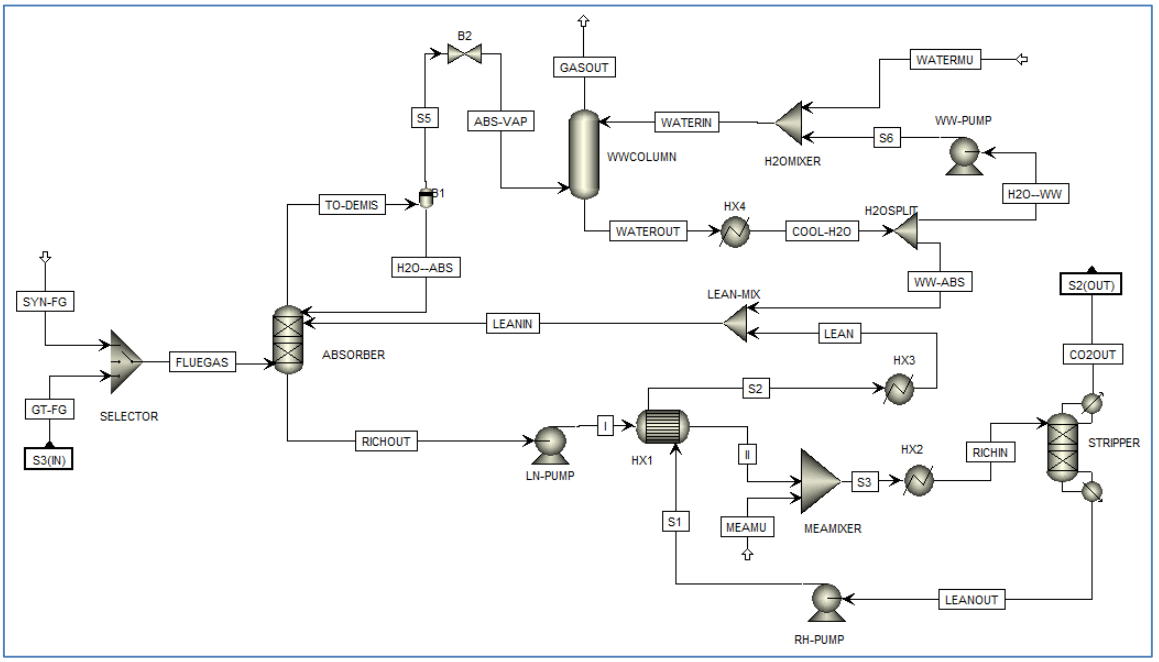

Figure 4. Process flow diagram of the amine plant as implemented in Aspen Plus.

Table 2 provides the assumptions made to set up the micro-turbine model. Input parameters used for feed streams (natural gas and air) are given in Table 3.

Aspen Plus® RadFrac model was used for the modelling of the absorption and stripping columns in the CO_2 capture pilot plant. The model adopted for the thermodynamic properties is based on the work by Zhang et al. [6]. The thermodynamic model uses the electrolyte-NRTL activity coefficient model for the liquid phase properties and PC-SAFT equation of state for vapour phase properties. The model has been validated by Zhang et al. [6] against experimental data in the open literature. Figure 4 shows the Aspen plus model for the CO_2 capture pilot plant.

4. Results and discussion

4.1. Model validation

The Aspen Plus model was validated with experimental data at 80 kW of power output of the micro-turbine. This power output was chosen based on the observation that operation was more stable than at the maximum power output of 100 kW. Table 3 shows the experimental data, model boundary conditions (fuel composition, flowrates, initial temperatures) and simulation results for the Turbec T100 micro turbine. Equilibrium reactions and adiabatic assumptions at the combustor appear reasonable since experimental and simulation results are in good agreement. However, isentropic efficiencies of the micro-turbine were assumed to be constant and hence, they were set to the values defined for the nominal power output of 100 kW. It is expected in the near future that more accurate simulation results will be obtained once the micro-turbine is modified to comprise measurement sensors for pressure, temperature and flowrates at various points of the engine.

Table 3. Comparison of experimental and simulation results for the Turbec T100 micro gas turbine.

	Experimental	Simulation
Fuel composition	CH_4: 90.56 mol% C_2H_6: 5.11 mol% CO_2: 1.37 mol% C_3H_8: 1.30 mol% N_2: 1.06 mol% i-C_4H_{10}: 0.23 mol% n-C_4H_{10}: 0.19 mol% [n-C_6H_{14}: 790.1 ppm] [i-pentane: 566.7 ppm] [n-pentane: 398.5 ppm] [neopentane: 21.83 ppm]	CH_4: 90.56 mol% C_2H_6: 5.11 mol% CO_2: 1.37 mol% C_3H_8: 1.30 mol% N_2: 1.06 mol% i-C_4H_{10}: 0.23 mol% n-C_4H_{10}: 0.19 mol% [n-C_6H_{14}: 790.1 ppm] [i-pentane: 566.7 ppm] [n-pentane: 398.5 ppm] [neopentane: 21.83 ppm]
Fuel flowrate (kg/s)	0.00658	0.00658
Fuel temperature (ºC)	ambient	15
Air flowrate (kg/s)	0.6940	0.6940
Air temperature	ambient (average 20-22°C)	20ºC
Air pressure (bar)	1.013	1.013
Exhaust gas composition (vol %)	CO_2: 1.53 H_2O: 3.46 O_2: 17.90 N_2: 77.11	CO_2: 1.53 H_2O: 2.89 O_2: 17.72 N_2: 77.84
Compressor pressure ratio	4.5 : 1	4.5 : 1
Turbine outlet temperature (ºC)	645	649.4
Turbine pressure ratio	1 : 4.5	1 : 4.5
Net power output (kW)	80.0	80.0

Table 4. Comparison of experimental and simulation results for the CO_2 capture pilot plant.

	L/G = 1.86 kg/kg		L/G = 3.77 kg/kg	
	Experiment	Simulation[b]	Experiment	Simulation[b]
Flue gas flowrate (Nm^3/hr)[a]	207.3±1.8	207.3	192.1±1.6	192.1
Flue gas temperature (^oC)[a]	41.3±0.5	41.3	39.4±0.3	39.4
Flue gas pressure (barg)[a]	0.17±0.02	0.17	0.19±0.01	0.19
Flue gas composition[a]				
CO_2 (mol%)	4.48±0.11	4.48	4.55±0.11	4.55
H_2O (mol%)	-	2.96	-	2.96
O_2 (mol%)	-	17.04	-	17.04
N_2 (mol%)	-	75.52	-	75.45
CO_2 in flue gas (kg/hr)	18.23±0.16	18.23	17.17±0.14	17.17
MEA concentration (wt%)	28.2±0.1	28.2	25.6±0.1	25.6
Lean MEA flowrate (kg/hr)	515.6±5.4	515.6	964.3±8.5	964.3
Lean MEA temperature (^oC)	39.9±0.9	39.9	40±0.5	40
Lean MEA CO_2 loading (mol/mol)	0.246±0.001	0.246	0.153±0.001	0.153
Condenser pressure (barg)	0.20±0.02	0.20	0.20±0.02	0.20
Rich MEA CO_2 loading (mol/mol)	0.409±0.001	0.416	0.247±0.001	0.249
CO_2 injected (kg/hr)	12.00±0.5	11.86	12.00±0.5	11.25
CO_2 captured (kg/hr)	16.47±0.40	16.98	16.30±0.59	16.35
CO_2 capture efficiency (%)	90.35±3.00	93.14	94.93±4.20	95.23
Specific reboiler duty (MJ/kg CO_2)	5.92±0.80	5.47	13.27±2.21	17.25

[a]Absorber inlet

[b]Values in shaded background are calculated values

The comparison between experimental results and simulation results for the CO_2 capture plant is given in Table 4, which also includes the uncertainties in the experimental values (one standard deviation). The average values of some of the experimental data logged over a period of 24 hours were used in setting up the Aspen plus model for the CO_2 capture plant. The set of values in Table 4 with shaded background are calculated values after the closed-loop model of the CO_2 capture plant converged. As may be seen from Table 4, the model results are in good agreement with the experimental results. The relatively high values obtained for the specific reboiler duty is due to the liquid/gas ratio used in the experiments. The experimental liquid/gas ratios for the two cases presented in Table 4 are sub-optimal and this fact underscores the need for some modelling work to be carried out before experiments are conducted so that effort and time will be targeted at the optimal operating regime. It also illustrates that modelling and experiment complement each other and both should run concurrently if possible.

4.2. CO_2 capture model analysis (CO_2 Injection)

Having validated the Aspen plus model for the PACT CO_2 capture plant for a flue gas with a CO_2 composition of ~ 4.5 mol%, the validated model was used to investigate a range of CO_2 compositions envisaged for exhaust gas recirculation studies planned for the future. Figure 5 shows the results of the CO_2 injection studies that were carried out with the model. Figures 5(a) to 5(f) show the variations of specific reboiler duty at 90% CO_2 capture with liquid/gas ratio for a 200 Nm^3/hr flue gas having CO_2 concentrations ranging from 3 to 8 mol%. The figures also show the variations of lean CO_2 loadings required for 90% CO_2 capture with liquid/gas ratio. For the six cases shown in Figure 5, MEA concentrations of 30, 35 and 40 wt% were investigated. It is clear from Figure 5 that the specific reboiler duty decreases as the MEA concentration increases and, as expected, the optimum or near-optimum

liquid/gas ratio (i.e. the liquid/gas ratio corresponding to minimum specific reboiler duty) decreases as the MEA concentration increases.

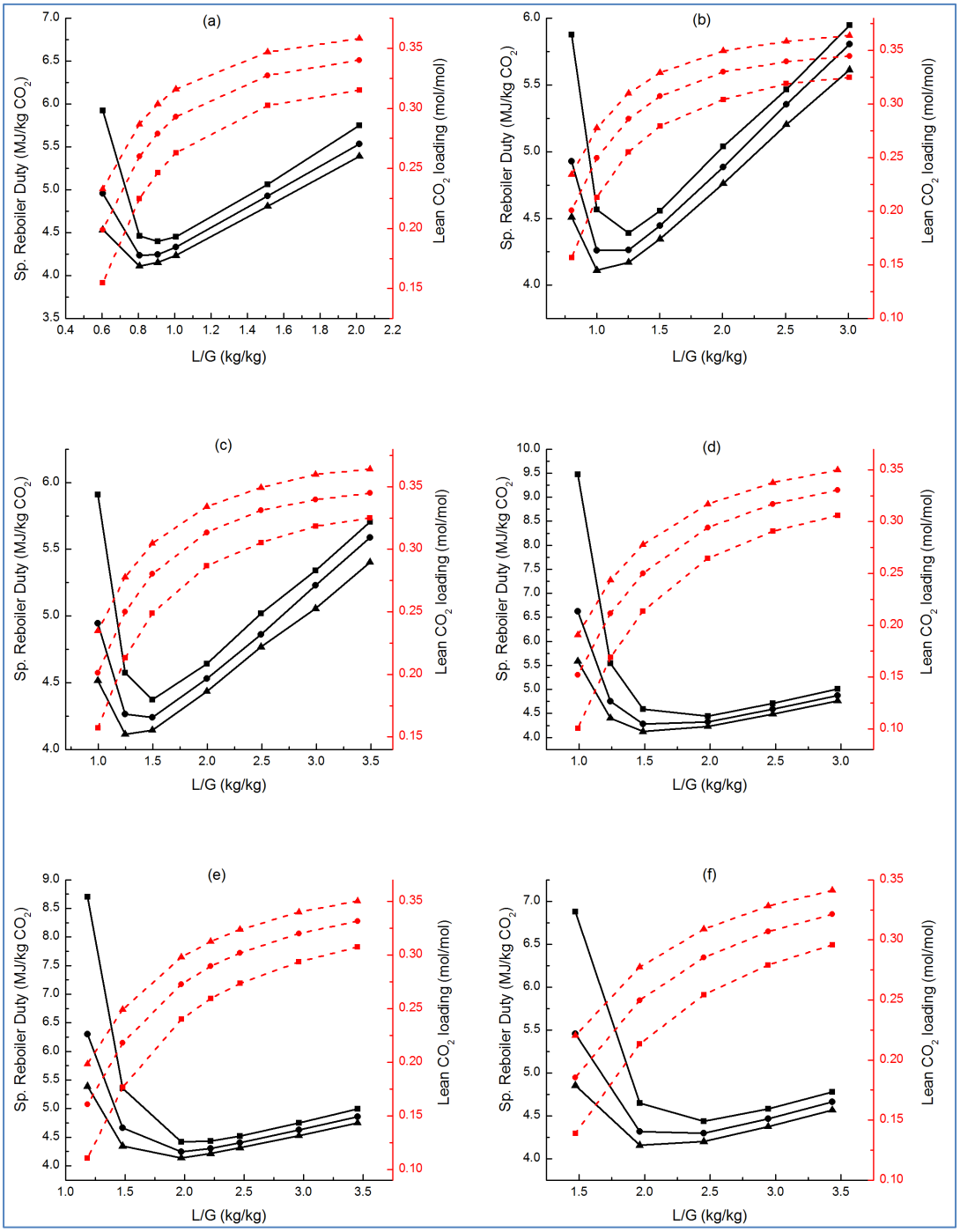

Figure 5. The variations of the specific reboiler duty and the lean CO_2 loading required for 90% CO_2 capture with the liquid/gas ratio for 200 Nm^3/hr flue gas flowrate. (a) 3 mol% CO_2; (b) 4 mol% CO_2; (c) 5 mol% CO_2; (d) 6 mol% CO_2; (e) 7 mol% CO_2; (f) 8 mol% CO_2. [Symbols: ■, 30 wt% MEA; ●, 35 wt% MEA; ▲, 40 wt% MEA].

Table 5. Optimum or near-optimum liquid/gas ratio, lean CO_2 loading, and specific reboiler duty for flue gas with CO_2 compositions ranging from 3 to 8 mol%.

Flue Gas CO_2 composition (mol%)	3	4	5	6	7	8
30 wt% MEA Solution						
L/G (kg/kg)	0.907	1.253	1.496	1.984	2.220	2.454
Lean CO_2 loading	0.247	0.255	0.249	0.265	0.259	0.254
Specific reboiler duty (MJ/kg CO_2)	4.399	4.390	4.374	4.441	4.431	4.437
35 wt% MEA Solution						
L/G (kg/kg)	0.806	1.003	1.247	1.488	1.973	2.454
Lean CO_2 loading	0.260	0.250	0.250	0.250	0.273	0.285
Specific reboiler duty (MJ/kg CO_2)	4.236	4.261	4.266	4.282	4.245	4.298
40 wt% MEA Solution						
L/G (kg/kg)	0.806	1.003	1.247	1.488	1.973	2.454
Lean CO_2 loading	0.287	0.278	0.278	0.278	0.298	0.309
Specific reboiler duty (MJ/kg CO_2)	4.114	4.112	4.115	4.125	4.138	4.200

The optimum or near-optimum values of the liquid/gas ratio, the lean CO_2 loading and the specific reboiler duty required for 90% CO_2 capture are summarized in Table 5. From the values in Table 5, it can be seen clearly that different CO_2 concentrations in the flue gas can give rise to about the same specific reboiler duty if the right combination of lean CO_2 loading and liquid/gas ratio is chosen. However, the variations of the optimum lean CO_2 loading and/or liquid/gas ratio will have an implication for the optimum height of the absorber and stripper columns required for a plant that is yet to be built, because the overall optimum design will need to consider capital costs (CAPEX) in addition to operating costs (OPEX). The liquid/gas ratios and lean CO_2 loadings summarized in Table 5 will be used in planning future experiments at the PACT facilities and the results of the planned experiments will be used to validate the optimum or near-optimum specific reboiler duties in Table 5.

5. Conclusions

The integration of a micro turbine to an MEA-based CO_2 capture plant has been investigated experimentally and by way of process modelling. The process modelling results for both the micro turbine and the CO_2 capture plant are in good agreement with the experimental results. Furthermore, the validated model for the CO_2 capture plant has been used to investigate flue gases with a range of CO_2 concentrations envisaged for exhaust gas recirculation studies planned for the future, and the results will be used in planning future experiments at the PACT facilities. A key message from the results discussed in this paper is that process modelling and experimental studies should run together, if possible, so as to focus time and attention in the optimum regime.

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