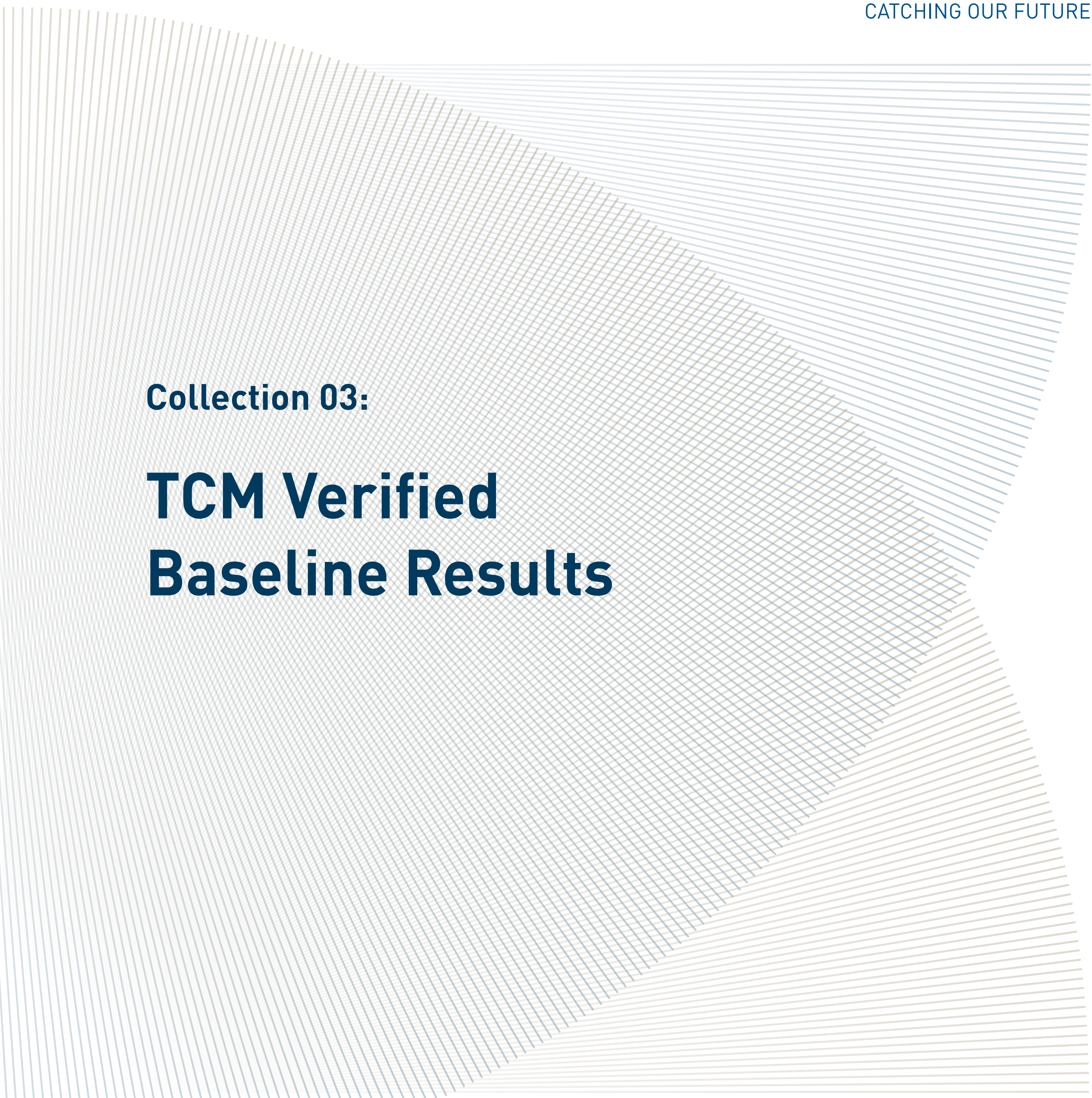
CATCHING OUR FUTURE



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«In our climate ambition, carbon capture is key. TCM is the best platform to learn, test technologies and accelerate the technology scale up for implementation on our assets.»

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(2021)

TCCS-11 - Trondheim Conference on CO_2 Capture, Transport and Storage
Trondheim, Norway - June 21–23, 2021

RESULTS FROM CESAR-1 TESTING WITH COMBINED HEAT AND POWER (CHP) FLUE GAS AT THE CO_2 TECHNOLOGY CENTRE MONGSTAD

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Abstract

CO_2 Technology Centre Mongstad (TCM) houses a demonstration-scale test facility for CO_2 capture solvents termed the “amine plant,” where multiple test campaigns have been performed on numerous solvents that the owners of TCM, TCM DA, have conducted since its inauguration in 2012. The large number of public, industrial, research, and academic participants involved in these campaigns have enriched the projects and ensured that the significant results serve a broad audience. The main objective of these campaigns was to produce knowledge that can be used to reduce the cost as well as the technical, environmental, and financial risks for the commercial-scale deployment of post-combustion CO_2 capture (PCC). This includes demonstration of a model-based control system, dynamic operation of the amine plant, investigation of amine aerosol emissions, and establishment of the baseline performance with monoethanolamine for residual fluid catalytic cracker (RFCC) and combined-cycle gas turbine (CCGT)-based combined-heat-and-power plant (CHP) flue gases. The RFCC flue gas is sourced from a nearby Equinor refinery that emulates coal flue gas in composition with 13%–14% vol CO_2 content and the CHP flue gas represents flue gas from CCGT power plants with a 3.5% vol CO_2 content. In addition to baseline testing, specific tests targeted at reducing CO_2 avoided cost have also been conducted utilizing both flue gas sources. This paper focuses on the testing of the CESAR-1 solvent, a blend of 2-amino-2-methyl-1-propanol and piperazine.

The Electric Power Research Institute, Inc. (EPRI) assessed the performance of the process using an independent verification protocol (IVP) developed previously. The IVP provides a structured testing procedure for assessing the thermal and environmental performance of PCC processes under normal operating conditions. Throughout the CESAR-1 testing, TCM manually collected extractive samples from the depleted flue gas and product CO_2 outlets sequentially. As part of the IVP, EPRI also assessed critical plant instrumentation at TCM for accuracy and precision error based on a comparative analysis done during testing operations and against calibration checks.

The CESAR-1 process was evaluated during 16 individual test periods over four days in June 2020. During the tests, extractive samples were taken to measure process contaminants such as aldehydes, ketones, amines, and ammonia. Sulfur oxides and nitrogen oxides were continuously monitored using Fourier-transform infrared (FTIR) analysers on the depleted flue gas and product CO_2 streams. TCM has installed multiple measurements (FTIR, non-dispersive infrared sensor, and gas chromatography) of the CO_2 concentration allowing comparative confirmation during the test periods. The capture rate was calculated via four methods along with evaluation of the CO_2 recovery, which is indicative of the overall mass balance. The overall thermal performance (energy consumption) was assessed based on measured data taken during each of the sampling periods. The CO_2 capture rate achieved during the CESAR-1 testing was 97–99%, with steam reboiler duties of 3.41–3.54 GJ/tonne-CO_2, and the CO_2 gas mass balance closures were close to 100%. These data and the associated assessments, along with the results of TCM sampling during these tests, are presented in this paper.

Keywords: *CO_2 capture; EPRI; Post-combustion capture; CO_2 Technology Centre Mongstad; TCM; CESAR-1*

1. Introduction

The CO_2 Technology Centre Mongstad (TCM) is located next to the Equinor refinery in Mongstad, Norway. TCM DA is a joint venture owned by Gassnova representing the Norwegian state, Equinor, Shell, and Total. TCM is home to one of the largest post-combustion CO_2 capture (PCC) test centers in the world. This facility entered the operational phase in August 2012 and is dubbed the “amine plant.”

A unique aspect of the facility is that either a flue gas slipstream from a natural gas-fired combined-heat-and-power (CHP) plant or an equivalent volumetric flow from a residual fluid catalytic cracker (RFCC) unit can be used for CO_2 capture. The CHP flue gas contains about 3.5 vol% CO_2 and the RFCC flue gas contains about 13–14 vol% CO_2, the latter of which is comparable to CO_2 levels seen in a coal-fired flue gas. The amine plant, designed and constructed by Aker Solutions and Kværner, is a highly flexible and well-instrumented facility that can accommodate a variety of technologies with capabilities of treating flue gas streams of up to 60,000 Sm^3/hr.

The plant is offered to developers of solvent-based CO_2 capture technologies to test the performance of their solvent technology and to verify systems aimed to reduce the atmospheric emissions and environmental impact of solvent emissions and degradation products from these processes.

The objective of TCM DA is to test, verify, and demonstrate CO_2 capture technologies suitable for deployment at full scale. A significant number of vendors, including Aker Solutions, Alstom (now GE Power), Cansolv Technologies Inc., and Carbon Clean Solutions Ltd., have already successfully tested using the TCM DA facilities to assess their CO_2 capture technologies.

Multiple tests using the CESAR-1 solvent have been carried out at TCM to define the baseline performance of the solvent for defined operating conditions using CHP flue gas boosted to 5 vol% CO_2 content using recycle in accordance with an independent verification protocol (IVP), which provides a structured testing procedure, developed by the Electric Power Research Institute, Inc. (EPRI) [1]. These tests are compared with prior MEA testing at TCM using the CHP flue gas without recycle at 3.5 vol%.

2. Amine Plant

The TCM 234 tonnes-CO_2/day amine plant was designed to be flexible to allow testing of different configurations. The amine plant is configured to remove CO_2 from a natural gas-fired combustion turbine-based CHP plant flue gas or a RFCC off-gas. The typical characteristics of these two flue gas streams are shown in Table 1.

Table 1**:** Nominal characteristics of flue gas supplied to TCM

Parameter	Units	CHP Flue Gas	RFCC Flue Gas
Temperature	°C	185	27
N_2+Ar	% vol, dry	81.5	82.5
O_2	% vol, dry	14.8	4.3
CO_2	% vol, dry	3.7	13.2
SO_2	ppmv, dry	very small	20 to 60
NO	ppmv, dry	<5	50 to 115
NO_2	ppmv, dry	<0.5	3
SO_3	ppmv, dry	very small	7 to 10*
CO	ppmv, dry	-	0 to 3
NH_3	ppmv, dry	<5	1
Particulates	mg/Nm^3	very small	14 to 41*
Chloride	mg/Nm^3	-	< 0.1

** controlled via candle filter*

For these tests, a portion of the product CO_2 was recycled to the CHP flue gas inlet stream in a controlled way to maintain the incoming CO_2 concentration at 5% vol, dry. A process flow diagram showing high-level equipment contained within the amine plant along with key existing instrumentation is shown in Figure 1.

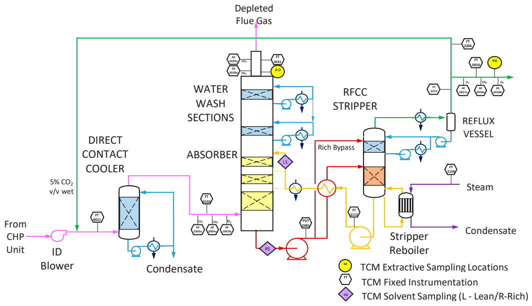

Figure 1**:** Process flow diagram for the TCM amine plant with CO_2 recycle

Major systems include:

- An induced draft (ID) blower to overcome pressure drops and blow the flue gas through the plant with an output capacity of up to 270 mbar and 70,000 Sm^3/hr.
- A direct-contact cooler (DCC) system to initially lower the temperature of and saturate the incoming flue gas by a counter-current water flow to improve the efficiency of the absorption process and provide pre-scrubbing of the flue gas. The DCC system has two individually operated packed columns for operations with the CHP flue gas and the RFCC flue gas, respectively. The DCC column designed for CHP gas operations is 3-m diameter and a total 16 m height. The section where water counter currently contacts the flue gas is 3.1 m high with Flexipac 3X structured stainless-steel packing of Koch Glitsch.
- An absorber to remove CO_2 from the flue gas. The absorber has a rectangular, polypropylene-lined concrete column with a 3.55 x 2 m cross-section and a total height of 62 m. The lower regions of the tower, where the amine solution contacts the flue gas, consist of three sections of Koch-Glitsch Flexipac 2X structured stainless-steel packing of 12 m, 6 m, and 6 m of height, respectively. Water-wash systems are located in the upper region of the tower to scrub and clean the flue gas, particularly of any solvent carry over, and consist of two sections of Koch-Glitsch Flexipac 2Y HC structured stainless-steel packing, each 3 m in height. The lower water-wash section is used to cool the depleted flue gas for overall plant water balance by adjusting the temperature of the circulating water. The uppermost water-wash section was operated as an adiabatic acid-wash stage for further emission mitigation. Liquid distributors, liquid collector trays, and mesh mist eliminators (Koch-Glitsch) are located at various locations in the tower, and the final mesh mist eliminator at the top of the tower is by Sulzer. The CO_2 depleted flue gas exits the absorber column to the atmosphere through a stack located at the top of the column.
- Stripper columns to recover the captured CO_2 and return CO_2-lean solvent to the absorber. The amine plant consists of two independent stripper columns with a common overhead condenser system. The two stripper columns are operated independently considering the CO_2 content in the flue gas due to column design, hydraulics, and gas velocity effects. The smaller diameter stripper column is used when treating CHP flue gas or RFCC gas

diluted with air, whereas the larger diameter column is used when treating flue gases of undiluted (i.e., higher CO_2 content) RFCC gas or when operating with CHP using CO_2 recycle, as is the case with these tests. The CHP stripper is 1.25 m in diameter and 28 m in height tangent-to-tangent. The RFCC stripper is 2.2 m in diameter and is also 28 m tangent-to-tangent. The lower regions of both stripper columns, where the amine solution is stripped, consist of Koch-Glitsch Flexipac 2X structured stainless-steel packing 8 m high. The upper regions of the strippers consist of a rectifying water-wash section of Koch-Glitsch Flexipac 2Y HC structured stainless-steel packing 1.6 m high. Liquid distributors, liquid collector trays, and mesh mist eliminators (all by Koch-Glitsch) are located at various locations in the strippers. Each stripper column is connected to its respective steam-heated reboiler, providing the necessary heat required for the stripping process. Both strippers circulate solvent to the reboilers by thermosiphon. The RFCC stripper also has a circulating pump to assist at low-load operation and during startup. The RFCC reboiler is a shell-and-tube arrangement and the CHP reboiler is a plate-in shell heat exchanger.

- A lean-solvent trim cooler that uses seawater to cool the lean solvent leaving the cross heat exchanger to a desired temperature before admission to the absorber column.
- A set of pumps used to move the CO_2-lean and CO_2-rich solvent streams between the absorber and stripper and through a cross heat exchanger to recover heat from the lean stream.
- A reflux drum, condenser, and pumps to dry the product CO_2 that exits the stripper. A portion of the product CO_2 can also be recycled back to the inlet of the CHP DCC to increase the concentration of the CO_2 in the inlet flue gas stream when using CHP flue gas.

The TCM facility can test virtually any PCC solvent-based process as the amine plant has been designed to accommodate a variety of technologies. The facility also has excellent instrumentation and an on-site lab for detailed analysis.

An IVP was developed to be used as part of the overall performance assessment of amine-based processes and has been updated over time to apply to either CHP or RFCC operation on the TCM amine facility. The IVP is designed to provide a structured testing procedure for assessing thermal and environmental performance of PCC processes under normal operating conditions. Uncertainty for key flow measurements was carried out as part of the IVP previously [2].

3. CESAR-1 CHP Campaign Overview

The CESAR-1 solvent is a blend of 2-amino-2-methyl-1-propanol (AMP) and piperazine (PZ). CHP flue gas capture performance assessment periods were conducted in June 2020. During the testing, personnel from TCM manually collected extractive samples from the depleted gas outlet and the product CO_2 line downstream of the RFCC stripper. In previous tests, this was sometimes performed by an independent testing contractor. However, TCM's competency related to performing this testing was deemed adequate by EPRI during prior monoethanolamine (MEA) baseline campaigns, especially since TCM is not commercially involved in the outcome and hence can be considered to be unbiased.

Data logs for all sampling periods containing pertinent flows, temperatures, pressures, and concentrations measured by permanent plant instruments were supplied by TCM for the entire test period. The sampling time periods, and sampling period designators are shown in Table 2 along with additional sampling undertaken on each day.

Table 2**:** CESAR-1 CHP sampling periods

Date	#	Time	Stream	Samples
June 24, 2020	1	9:26–11:39	CO_2	AMP, PZ, NH_3
	2	11:45–12:27	CO_2	Aldehyde/Ketones
	3	12:15–12:25	ABS	Aldehyde/Ketones
	4	12:48–13:48	ABS	AMP, PZ, NH_3
June 25, 2020	5	10:16–12:16	ABS	AMP, PZ, NH_3
	6	10:32–12:37	CO_2	AMP, PZ, NH_3
	7	12:28–12:58	ABS	Aldehyde/Ketones
	8	12:43–13:20	CO_2	Aldehyde/Ketones
June 26, 2020	9	9:33–11:33	ABS	AMP, PZ, NH_3
	10	9:43–11:50	CO_2	AMP, PZ, NH_3
	11	11:42–12:12	ABS	Aldehyde/Ketones
	12	11:54–12:30	CO_2	Aldehyde/Ketones
June 30, 2020	13	10:17–12:17	ABS	AMP, PZ, NH_3
	14	10:27–12:33	CO_2	AMP, PZ, NH_3
	15	12:24–12:54	ABS	Aldehyde/Ketones
	16	12:38–13:13	CO_2	Aldehyde/Ketones

The plant operated in a stable condition through the entire test period, as shown in Figures 2 and 3 with controlled flue gas flow at 59,000 Sm^3/h and CO_2 controlled at 5 vol%, dry using recycled product gas.

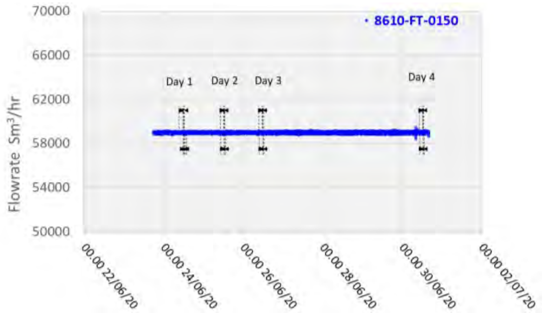

Figure 2**:** Flue gas flowrate through testing period

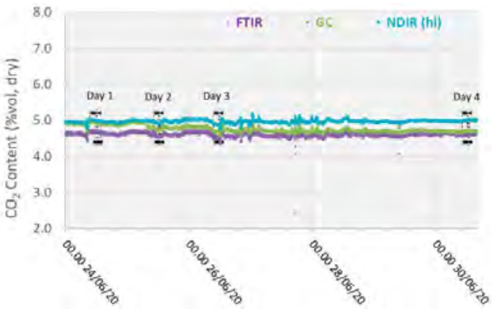

Figure 3**:** Inlet CO_2 concentration through testing period

3.1 CO_2 Capture Efficiency and Recovery

CO_2 capture efficiency can be quantified in several ways depending on how measurements have been taken and the expected accuracy of each individual measurement. Using different combinations of the measured parameters at the boundary of the process, four individual methods can be applied as detailed in Table 3.

These methods can rely on combinations of the available information to determine a capture efficiency, using the measured gas flowrates in combination with the CO_2 analyzer measurements.

Method 4 simplifies the measurement uncertainty by utilizing only CO_2 concentration data and making the well-founded assumption that all incoming inert gases (such as nitrogen and oxygen) will be unchanged through the absorption process. Hence, Method 4 can be used to compare against the other methods that utilize the flow measurements.

Table 3**:** CO_2 capture efficiency calculation methods

Method	Formula
1	$Efficiency = \frac{CO_2(\text{product})}{CO_2(\text{supply})}$
2	$Efficiency = \frac{CO_2(\text{product})}{CO_2(\text{product}) + CO_2(\text{depleted})}$
3	$Efficiency = \frac{CO_2(\text{supply}) - CO_2(\text{depleted})}{CO_2(\text{supply})}$
4	$Efficiency = 1 - \frac{O_{CO_2}}{(1 - O_{CO_2})}\frac{(1 - I_{CO_2})}{I_{CO_2}}$

The "CO_2 recovery" calculation is defined as the ratio of the sum of the CO_2 flow in depleted flue gas and the product CO_2 flow divided by the CO_2 flow in the flue gas supply.

$$Recovery = \frac{CO_2(\text{depleted}) + CO_2(\text{product})}{CO_2(supply)}$$

The CO_2 recovery is a measure of the closure of the CO_2 mass balance, being the fraction of CO_2 mass flow in the flue gas supply that is accounted for by measured CO_2 mass flows in the depleted flue gas and product CO_2.

Table 4 shows the four calculation methods of CO_2 capture and recovery for the test periods. Note that CO_2 product flow can be based on either the measured CO_2 product flow or by using the difference between the non-dispersive infrared-measured CO_2 supply and depleted flows. CO_2 capture rates calculated by all methods were in good agreement within each test period. It should be noted that Methods 3 and 4 are equivalent due to using the conserved oxygen and nitrogen method for outlet gas flow determination.

Table 4**:** CESAR-1 CHP sampling periods

#	Method 1, %	Method 2, %	Method 3, %	Method 4, %	Recovery %
1	96.70	97.85	97.88	97.88	98.80
2	97.77	97.85	97.86	97.86	99.92
3	97.43	97.91	97.92	97.92	99.50
4	97.35	98.03	98.05	98.05	99.29
5	97.28	97.95	97.96	97.96	99.30
6	97.23	97.95	97.97	97.97	99.24
7	96.99	97.90	97.91	97.91	99.05
8	97.28	97.87	97.89	97.89	99.38
9	97.57	98.23	98.25	98.25	99.31
10	97.61	98.25	98.26	98.26	99.34
11	98.94	98.37	98.36	98.36	100.6
12	98.31	98.47	98.47	98.47	99.84
13	97.06	98.84	98.87	98.87	98.17
14	96.80	98.81	98.84	98.84	97.94
15	96.77	98.72	98.75	98.75	98.00
16	96.84	98.73	98.76	98.76	98.05

Regardless of the method used, the CO_2 capture rate was consistently >96% as measured during all test periods. As the recovery rate was close to 100%, this implies consistency between the flue gas measurements and CO_2 concentration determination at all 3 locations.

3.2 Thermal Use

The reboiler heat duty or the heat released in the reboiler is calculated as the difference between steam enthalpy at reboiler inlet and the saturated water enthalpy at the reboiler condensate temperature. The specific thermal use (STU) is then calculated by dividing the reboiler heat duty by the product CO_2 flow.

$$STU_{product} = \frac{\dot{m}_{steam}(H_{steam} - H_{condensate})}{CO_2\ (product)}$$

$$STU_{captured} = \frac{\dot{m}_{steam}(H_{steam} - H_{condensate})}{CO_2\ (supply) - CO_2\ (depleted)}$$

The two corresponding values for specific thermal energy consumption are shown in Table 5 and were consistent during all test periods.

Table 5**:** Stripper reboiler specific thermal use

#	Heat Duty, MJ/hr	Product CO_2 Flow, kg/hr	Specific Thermal Use, GJ/t-CO_2	Captured CO_2, kg/hr	Specific Thermal Use, GJ/t-CO_2
1	17,329	5014	3.46	5075	3.41
2	17,403	5045	3.45	5049	3.45
3	17,434	5023	3.47	5049	3.45
4	17,562	5009	3.51	5045	3.48
5	18,097	4969	3.64	5003	3.62
6	18,103	4952	3.65	4990	3.63
7	18,046	4928	3.66	4975	3.63
8	18,081	4941	3.66	4971	3.64
9	18,839	4928	3.82	4963	3.80
10	18,863	4927	3.83	4960	3.80
11	19,148	4948	3.87	4919	3.89
12	18,872	4883	3.86	4891	3.86
13	17,692	5005	3.53	5098	3.47
14	17,683	4994	3.54	5099	3.47
15	17,730	5008	3.54	5110	3.47
16	17,751	5017	3.54	5117	3.47

Prior testing at TCM using conventional 5M MEA solvent with CHP flue gas (3.5 vol% CO_2) at approximately an 80 tonnes-CO_2/day load yielded a regeneration energy range of 3.61–3.66 GJ/t-CO_2 using the product CO_2 flow and 3.58–3.60 GJ/t-CO_2 using the capture method, all carried out at 85% capture rate [3]. The CESAR-1 CHP tests (5 vol% CO_2) achieved circa 119 tonnes-CO_2/day load and achieved a regeneration energy range of 3.45–3.87 GJ/t-CO_2 using product flow and 3.41–3.89 GJ/t-CO_2 using the gas-side difference method.

It can be seen that the regeneration energy initially was near the bottom of the range for Tests 1 to 4 on June 24, and steadily increased in subsequent Tests 5 to 12. It was identified by TCM that excess foam formation in the stripper caused additional water condensation in the overhead stripper and an associated steam consumption increase. An antifoam agent was injected in the morning of June 30 by TCM operators with a subsequent rapid reduction in the regeneration energy measured in Tests 13 to 16, implying that the baseline CHP CESAR-1 regeneration energy is more in the range of 3.45–3.54 GJ/t-CO_2 using product flow and 3.41–3.48 GJ/t-CO_2 using the gas-side difference method when foaming is absent.

Importantly, the capture rate is 98% for these tests, far higher than the 85% capture rate for the MEA baseline tests, showing CESAR-1 solvent performs well at high capture rates as the regeneration energy is lower than MEA (when foaming was controlled) despite a capture rate of nearly 100%.

Recent testing at the Niederaussem pilot plant showed CESAR-1 solvent at 98% capture rate required only 3.22 GJ/tonne regeneration energy, however the inlet CO_2 concentration was 15.2% vol, dry as the flue gas source is from coal combustion [4]. Although the lower CO_2 concentration during these tests resulted in higher regeneration energy than observed at Niederaussem, some of the difference can also be attributed to the use of the RFCC stripper for these tests that is oversized for this regeneration load, operating at only 50% capacity. The CHP stripper was not used for these tests due to a combination of the 5% vol, dry inlet CO_2 concentration and the targeted 98% capture rate.

3.3 Process Contaminants

3.3.1 Aldehydes and Ketones

Formaldehyde, acetaldehyde, and acetone concentrations were determined by extractive sampling during the CESAR-1 CHP test periods. The data are shown in Table 6 for the depleted flue gas and in Table 7 for the CO_2 product.

Table 6**:** Depleted flue gas aldehyde/ketone concentrations

#	Formaldehyde, mg/Sm^3	Acetaldehyde, mg/Sm^3	Acetone, mg/Sm^3
3	0.0635	0.0931	1.14
7	0.0406	0.0596	1.42
11	0.0546	0.0801	2.85
15	0.0190	0.0279	1.13

The formaldehyde levels are lower than the previous MEA CHP baseline testing, which measured concentrations of 0.72 mg/Sm^3 by an external contractor. The acetaldehyde levels are also considerably lower with CESAR-1 than the MEA CHP test samples of 16 mg/Sm^3.

Acetone levels measured during the MEA tests were sufficiently low at or below the detection limit of 1 mg/Sm^3, while with CESAR-1 they were measurable at between 1–3 mg/Sm^3 even though the upper water wash was configured as an acid wash for these tests and not in the MEA campaign These species were also measured continuously with the Proton-Transfer-Reaction mass spectrometer (PTR-MS) that exhibits a very low detection limit capability (measuring in the ppb range). A sample of the data collected is shown in Figure 4, with higher formaldehyde levels (700–800 ppb) than measured by extractive samples (20–50 ppb), and comparable acetaldehyde and acetone measurements.

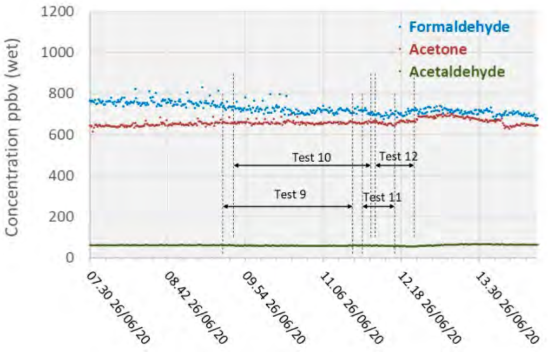

Figure 4**:** Depleted flue gas PTR-MS aldehyde and ketone measurements

For the CO_2 product, the formaldehyde levels detected were 2–4x higher than the manual-sampled measurements during the MEA CHP baseline campaign (0.14 mg/Sm^3) and the acetaldehyde levels were considerably lower than the previous level of 150 mg/Sm^3 measured for MEA.

Unlike the MEA tests, acetone was easily detected in the CO_2 product for CESAR-1, whereas in the previous MEA baseline all measurements taken were below the detection limit of 0.9 mg/Sm^3.

Table 7**:** Product CO_2 aldehyde/ketone concentrations

#	Formaldehyde, mg/Sm^3	Acetaldehyde, mg/Sm^3	Acetone, mg/Sm^3
2	0.63	0.93	21.7
8	0.42	0.61	23.1
10	0.39	0.57	28.5
16	0.18	0.27	16.7

The concentration of the depleted flue gas will be impacted by the CO_2 recycle stream, passing a portion of the contaminants shown back to the absorber inlet. With the exception of acetone, these components in the flue gas for the CESAR-1 testing were significantly lower than previous MEA measurements. This in turn suggests that these components are not significant degradation compounds from AMP and PZ, or that these solvents were not degraded to the same condition as for MEA.

3.3.2 Ammonia and Solvent Components

TCM measured concentrations of solvent components (AMP and PZ) along with ammonia during the CESAR-1 testing. Results of these manually extracted samples are shown in Table 8.

Table 8**:** Depleted flue gas stream ammonia and solvent component concentrations

#	AMP, mg/Sm^3	PZ, mg/Sm^3	Ammonia, mg/Sm^3
4	0.06	0.01	0.04
5	0.04	<0.007	0.03
9	0.03	<0.007	0.02
13	0.03	<0.007	0.03

'<' denotes the limit of detection

The solvent components of CESAR-1 appear to show higher vapor pressure than is associated with MEA solvent, which was previously measured by an external contractor at 0.006 mg/Sm^3 during testing on CHP flue gas. PZ was barely detected, only showing up in Test 4, which shows that perhaps a longer extraction sample period would help to improve determination of this species at the ppb level. Ammonia levels are far lower than the previous MEA CHP tests results, measured at 13 mg/Sm^3, suggesting that ammonia does not represent a significant degradation product of CESAR-1.

With the exception of the first test, the AMP measurements were lower than the extractive samples. However, both strategies were likely near their method detection limits as levels were measured below 20 ppb in all cases. PZ was not detected by the PTR-MS instrument and hence was not included in Figure 5, however Acetonitrile was detected at 0.1 ppmv.

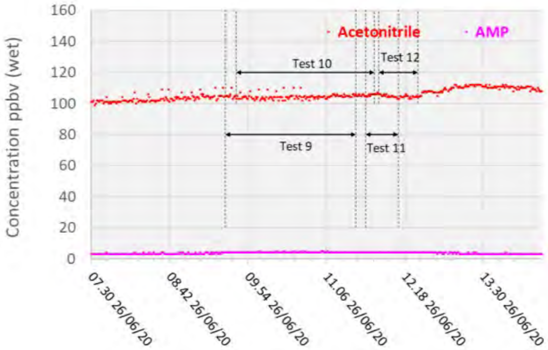

Figure 5**:** Depleted flue gas PTR-MS solvent measurements

Extractive solvent and ammonia samples were taken from the CO_2 product, and the results are shown in Table 9.

Table 9**:** Product CO_2 ammonia and solvent component concentrations

#	AMP, ppmvd	PZ, ppmvd	Ammonia, ppmvd
1	7.73	0.07	2.89
6	9.07	0.12	3.20
10	7.49	0.09	4.60
14	0.29	<0.007	3.59

'<' denotes the limit of detection

Similar to the depleted flue gas measurements, the AMP measurements were higher than the equivalent MEA samples, at 0.076 mg/Sm^3, and up to 2 orders of magnitude higher for AMP. PZ was detected in 3 of the 4 samples, but was present at very low concentrations.

Although ammonia desorption into the product gas is 2 orders of magnitude higher than the depleted flue gas levels, this is 4 times lower than the ammonia detected from the MEA CHP tests at 16 mg/Sm^3.

3.3.3 SO_2 and NOx

The TCM Fourier-transform infrared units installed for the flue gas supply and the depleted flue gas were configured to measure SO_2, NO, and NO_2 concentrations. The reported data are shown in Figures 6 and 7.

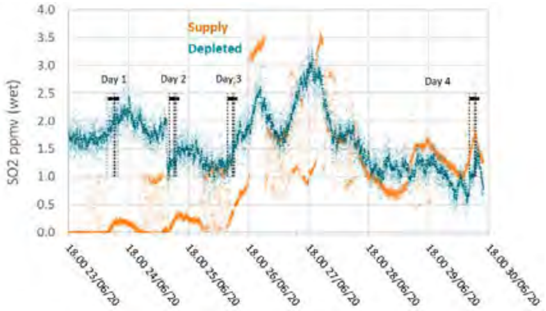

Figure 6**:** Supply and depleted flue gas SO_2 measurements throughout the test period

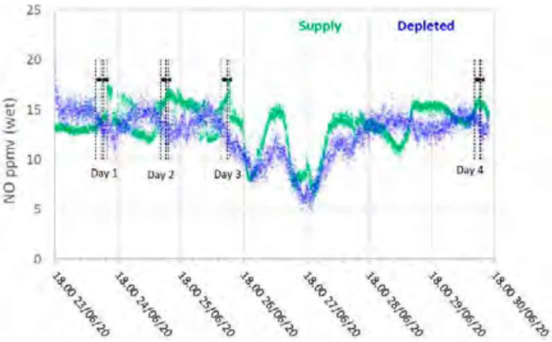

Figure 7**:** Supply and depleted flue gas NO measurements throughout the test period

During previous MEA testing, SO_2 levels leaving the absorber were consistently lower than the inlet measurement, likely due to absorption. This doesn't appear to be the case for CESAR-1 solvent, though the inconsistency in the incoming flue gas data doesn't allow a strong relationship to be established. Therefore, there was no way to determine SO_2 absorption rates for this solvent from the tests.

The NO data shows similar levels at the inlet and outlet, indicating minimal absorption into the CESAR-1 solvent. While absorbed NO_2 is known to contribute to the formation of nitrosamines in some solvents, the NO_2 data for the depleted gas were not recorded for these test periods. The average measured values in the flue gas for both NO and SO_2 leaving the absorber are shown in Table 10.

Table 10**:** Depleted flue gas SO_2 and NO concentrations

#	SO_2, ppmvd	NO, ppmvd
1	2.02	14.9
2	2.20	14.2
3	2.28	13.6
4	2.19	14.0
5	1.38	14.5
6	1.40	14.3
7	1.36	13.9
8	1.43	14.2
9	1.39	14.0
10	1.41	13.9
11	1.64	13.1
12	1.68	12.8
13	1.10	15.0
14	1.11	14.9
15	1.34	15.2
16	1.38	14.4

4. Conclusions

CESAR-1 solvent was tested at the TCM amine plant over 16 individual tests, during which extractive samples were taken, an overall summary of the tests is given in Table 11.

Table 11**:** Summary of CESAR-1 testing

Baseline Year	**2020**
Packing Height (m)	18
Flue Gas Flow (Sm^3/h)	59,000
Flue Gas Supply Temperature (°C)	38
Flue Gas Supply Pressure (bar)	0.02
Lean Amine Flow (kg/h)	58,000
Lean Loading	0.10
Rich Loading	0.52
Stripper Bottom Temperature (°C)	121
CO_2 Capture (%)	98
SRD (GJ/t-CO_2)	3.61

The plant was operated at 119 tonnes/day of CO_2 production with capture rates of 96–99%, exhibiting a near 100% mass balance.

Foaming was identified as causing stripper performance issues; however, when foaming was controlled, the regeneration energy for CESAR-1 solvent was 3.41–3.54 GJ/t-CO_2, lower than prior baseline testing of MEA at a lower capture rate of 85% at 3.58–3.66 GJ/t-CO_2.

Degradation products including formaldehyde, acetaldehyde and ammonia, were measured at lower levels for CESAR-1 solvent with acid water wash compared to results from MEA testing. As the solvent is a blend of AMP and PZ, both species were sampled showing higher levels of AMP than was measured for MEA and PZ being barely detectable due to the low vapor pressure of PZ.

5. Acknowledgements

The authors gratefully acknowledge the staff of TCM DA, Gassnova, Equinor, Shell, and Total for their contribution and work at the TCM DA facility.

The authors also gratefully acknowledge Gassnova, Equinor, Shell, and Total as the owners of TCM DA for their financial support and contributions.

6. References

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CATCHING OUR FUTURE

Results from MEA testing at the CO_2 Technology Centre Mongstad. Verification of Residual Fluid Catalytic Cracker (RFCC) baseline results

(2021)

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Results from MEA testing at the CO_2 Technology Centre Mongstad. Verification of Residual Fluid Catalytic Cracker (RFCC) baseline results

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Abstract

Technology Center Mongstad (TCM) houses a pilot-scale test facility for CO_2 capture solvents termed the “amine plant”, where multiple test campaigns have been performed on monoethanolamine (MEA). The third MEA test campaign (MEA-3) was conducted in June 2017 and several subsequent tests on MEA (MEA-4 and MEA-5) were performed, through October 2018. MEA-3, MEA-4, and MEA-5 have been the most significant collaborative test campaigns that the owners of TCM, TCM DA, have conducted since its inauguration in 2012. The large number of public, industrial, research, and academic participants involved in these campaigns have enriched the projects and ensured that the significant results will serve a broad audience. The main objective of these campaigns was to produce knowledge that can be used to reduce the cost as well as the technical, environmental, and financial risks for the commercial-scale deployment of post-combustion CO_2 capture (PCC). This includes demonstration of a model-based control system, dynamic operation of the amine plant, investigating amine aerosol emissions, establishment of residual fluid catalytic cracker (RFCC)—a flue gas emanating from a nearby Equinor refinery that emulates coal in composition—baseline performance with MEA, and specific tests targeted at reducing CO_2 avoided cost. Through the campaigns, both flue gas sources currently available to TCM were used, including the RFCC gas as well as flue gas from a nearby combined-cycle gas turbine (CCGT)-based combined-heat-and-power plant (CHP) that operates off of natural gas.

The Electric Power Research Institute, Inc. (EPRI) assessed the performance of the MEA-based process using an independent verification protocol (IVP) previously developed for the CHP flue gas [1]. The IVP provides a structured testing procedure for assessing the thermal and environmental performance of PCC processes under normal operating conditions. Based on this, methodology results were presented by Faramarzi et al [2]. The IVP was updated for use with the RFCC as this gas contains 13–14 vol% CO_2 content by volume whereas the CHP flue gas has 3.5 vol% CO_2 content. Throughout the RFCC testing, TCM DA manually collected extractive samples from the depleted flue gas and product CO_2 outlets sequentially. As part of the IVP, EPRI also assessed critical plant instrumentation at TCM for accuracy and precision error based on a comparative analysis done during testing operations and against calibration checks.

The MEA baseline process was evaluated during thirteen individual test periods over four days in May 2018. During the tests, extractive samples were taken to measure process contaminants such as aldehydes, ketones, amines, and ammonia. Sulfur oxides

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and nitrogen oxides were continuously monitored using Fourier-transform infrared (FTIR) analysers on the depleted flue gas and product CO_2 streams. TCM DA has installed multiple measurements of the CO_2 concentration (FTIR, non-dispersive infrared sensor, and gas chromatography) allowing comparative confirmation during the test periods. The capture rate was calculated via four methods. CO_2 recovery (overall mass balance) was evaluated and the thermal performance (energy consumption) was assessed based on measured data taken during the tests. The CO_2 capture rate achieved during the MEA RFCC testing was close to 90%, with steam reboiler duties of 3.43–3.51 GJ/tonne-CO_2, and the CO_2 gas mass balance closures were close to 100%. These data and the associated assessments, along with the results of TCM DA sampling during these tests, will be presented in this paper and will provide a new baseline case for 30 wt% MEA solvent in higher concentration flue gas capture cases. Based on this, TCM will now have two baselines covering flue gases with 3.5 vol% CO_2 (Faramarzi et al.) and with 13–14 vol% CO_2 (this project).

Keywords: CO_2 capture; EPRI; MEA; Post-combustion capture; CO_2 Technology Centre Mongstad; TCM

1. Introduction

The CO_2 Technology Centre Mongstad (TCM) is located next to the Equinor refinery in Mongstad, Norway. TCM DA is a joint venture owned by Gassnova representing the Norwegian state, Equinor, Shell, and Total. The test facility, dubbed the “amine plant”, run by TCM DA entered the operational phase in August 2012 and is one of the largest post-combustion CO_2 capture (PCC) test centres in the world. A unique aspect of the facility is that either a flue gas slipstream from a natural gas-fired combined-heat-and-power (CHP) plant or an equivalent volumetric flow from a residual fluid catalytic cracker (RFCC) unit can be used for CO_2 capture. The CHP flue gas contains about 3.5 vol% CO_2 and the RFCC flue gas contains about 13–14 vol% CO_2, the latter of which is comparable to CO_2 levels seen in coal-fired flue gas. The amine plant, designed and constructed by Aker Solutions and Kværner, is a highly flexible and well-instrumented unit that can accommodate a variety of technologies with capabilities of treating flue gas streams of up to 60,000 standard cubic meters per hour. The plant is offered to developers of solvent-based CO_2 capture technologies to test the performance of their solvent technology and to verify technologies aimed to reduce the atmospheric emissions and environmental impact of amines and amine-based degradation products from solvent-based CO_2 capture processes. The objective of TCM DA is to test, verify, and demonstrate CO_2 capture technologies suitable for deployment at full-scale. A significant number of vendors, including Aker Solutions, Alstom (now GE Power), Cansolv Technologies Inc., Carbon Clean Solutions Ltd., Fluor and Ion Engineering have already successfully used the TCM DA facilities to verify their CO_2 capture technologies.

Nomenclature		**Units**	
CHP	combined heat-and-power	barg	bar gauge
EPRI	Electric Power Research Institute, Inc.	g	gram
FTIR	Fourier-transform infrared	GJ/t	gigajoule per tonne
GC	gas chromatograph	kg/hr	kilogram per hour
HP	high pressure	kg/m^3	kilogram per cubic meter
IVP	independent verification protocol	m	meter
LP	low pressure	mg/Sm^3	milligram per standard cubic meter
MEA	monoethanolamine	MJ/hr	megajoule per hour
NDIR	non-dispersive infrared	Sm^3/hr	standard cubic meter per hour
PCC	post-combustion capture	vol%	volume percent
RFCC	residual fluid catalytic cracker	wt%	weight percent
STU	specific thermal use	µ	micro (10^{-6})
TCM	Technology Centre Mongstad		

Multiple tests using monoethanolamine (MEA) have been carried out at TCM to define the baseline performance of the solvent for defined operating conditions using flue gas from the CHP at 3.5 vol% CO_2 content [2]. More recently, the MEA solvent has been tested with the higher CO_2 concentrations from the RFCC flue gas to develop a new baseline for the amine plant, in accordance with an independent verification protocol (IVP), which provides a structured testing procedure, developed by the Electric Power Research Institute, Inc. (EPRI) [1].

2. Amine plant

The schematic of the TCM DA amine plant when treating the CHP flue gas is shown in Figure 1.

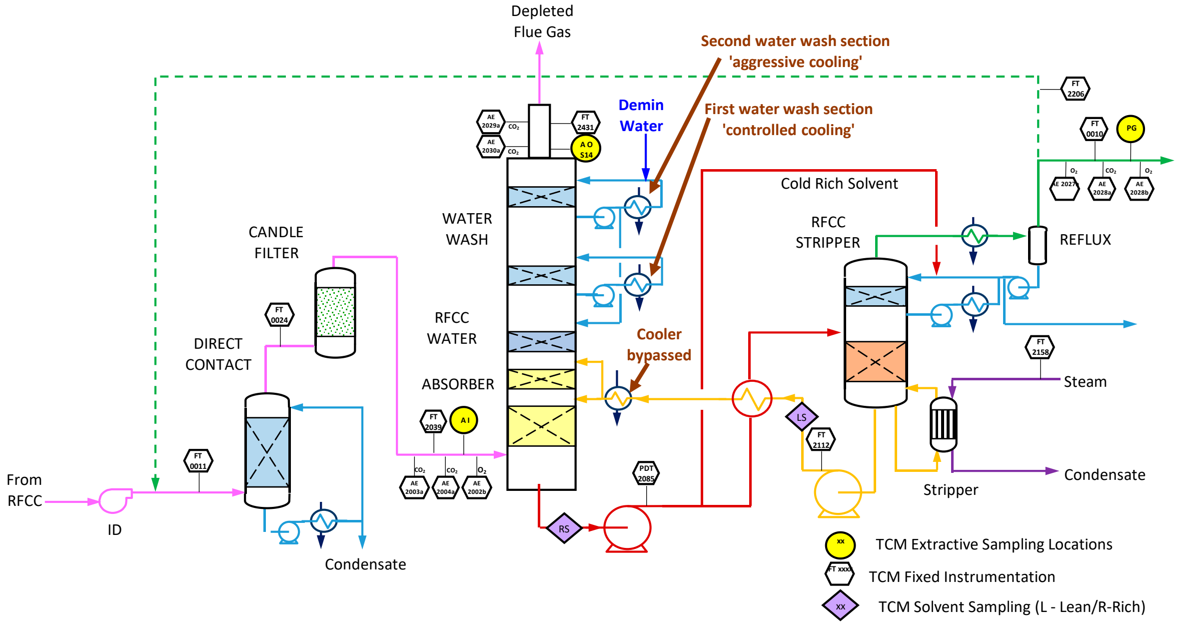

Figure 1. TCM DA amine plant when treating RFCC flue gas

3. IVP overview

The roles and responsibilities of the organizations that conducted the IVP are:

- TCM DA is the prime on the project and its personnel organized the field testing during the test period. They also operated the plant throughout all baseline testing
- EPRI were contracted by TCM DA to develop the IVP during previous MEA baseline testing. EPRI was on site during MEA baseline testing on RFCC flue gas to observe the conduct of the tests and the associated manual extractive sampling. EPRI received the data for the RFCC tests from TCM DA for analysis.

4. Test campaign

The testing of the MEA solvent at TCM was carried out using RFCC flue gas that has CO_2 concentrations of typical coal flue gases. Prior testing with MEA using CHP flue gas was conducted in September 2015. The test periods identified for the RFCC flue gas operation, shown in Table 1, reflect the extractive sampling periods carried out on 28–31 May 2018.

During the testing, personnel from TCM DA manually collected extractive samples from the depleted gas outlet and product CO_2 line downstream of the RFCC stripper. In previous tests, this was sometimes performed by an independent testing contractor. However, TCM DA's competency related to performing this testing was deemed adequate by EPRI, especially since TCM DA is not commercially involved in the outcome and hence can be considered to be unbiased.

Data logs for all sampling periods containing pertinent flows, temperatures, pressures, and concentrations measured by permanent plant instruments were supplied by TCM DA for the entire test period.

Table 1. Summary of the test periods

Stream sampled	Date	Start time/Stop time	Sampling Results Reported	Test Period
Depleted Flue Gas	28 May 2018	8:23 / 9:26	MEA, NH_3	C5-1
Depleted Flue Gas	28 May 2018	9:38 / 10:42	MEA, NH_3	C5-2
Depleted Flue Gas	28 May 2018	10:54 / 12:24	MEA, NH_3	C5-3
Depleted Flue Gas	29 May 2018	9:33 / 10:40	MEA, NH_3, Aldehydes, Acetone	C5-4
Depleted Flue Gas	29 May 2018	10:58 / 12:18	MEA, NH_3, Aldehydes, Acetone	C5-5
Depleted Flue Gas	29 May 2018	13:26 / 14:41	MEA, NH_3, Aldehydes, Acetone	C5-6
Depleted Flue Gas/CO_2 Product	30 May 2018	8:29 / 9:33	NO_2, SO_2	C5-7
Depleted Flue Gas/CO_2 Product	30 May 2018	9:42 / 11.18	NO_2, SO_2	C5-8
Depleted Flue Gas/CO_2 Product	30 May 2018	11:41 / 12:41	NO_2, SO_2	C5-9
CO_2 Product	31 May 2018	8:10 / 9:15	MEA, NH_3, Aldehydes, Acetone	C5-10
CO_2 Product	31 May 2018	9:36 / 10:35	MEA, NH_3, Aldehydes, Acetone	C5-11
CO_2 Product	31 May 2018	12:09 / 13:07	MEA, NH_3, Aldehydes, Acetone	C5-12
Depleted Flue Gas	01 June 2018	9:38 / 10:42	MEA, NH_3	C5-13

5. Instrument assessment

To determine the process plant performance, a key component is the quality of the instrumentation installed for measuring the respective compositions and flow rates. Instrumentation quality is determined using two parameters:

- **Accuracy/bias:** This represents the difference between the instrument reading (or average of a set of readings under unchanging process conditions) being assessed and the true value of the parameter being measured. Appropriate determination of the "true value" must be achieved by simultaneous measurement of the parameter using a reference method or instrument with calibration that can be traced to primary standards.
- **Precision:** A determination of the variability of the instrument reading when stream conditions are known to be steady state. Precision is therefore a measure of the random error associated with the measurement.

These measurement errors can be combined to assess the aggregate uncertainty in each measurement. In the absence of a calibration against primary standards for the entire measurement range needed, the uncertainty published by the instrument supplier represents only the precision error.

When the process parameter being measured does not change, precision is a measure of repeatability. In real plant situations, when attempting to operate at steady-state conditions, often process parameters (flow, pressure, and temperature) do vary over the measurement period. Thus, measurements over long periods of time (greater than process time constants) will also include an error term related to process uncertainty.

5.1. Gas-phase compositions

TCM DA has 3 independent Fourier-transform infrared (FTIR) units (Finetech Anafin 2000 and a pair of Gasmet FCX units), facilitating dedicated and continuous FTIR measurements at the absorber inlet, outlet, and CO_2 product gas streams. The CO_2 concentration at the inlet and outlet of the absorber column is also determined by two non-dispersive infrared (NDIR) units at each location, one set to high range (% vol) and one to low range (ppmv) on a dry-gas basis. A dedicated trace O_2 instrument (Teledyne Instruments 3001) is installed to quantify O_2 content of the product CO_2 as this is typically at ppm levels in this stream. A Siemens Maxum Edition II gas chromatograph (GC) unit is also installed, which is capable of measuring the CO_2, O_2, and nitrogen content at all three locations in a near-simultaneous fashion.

During the May to June 2018 operations, TCM DA utilized the installed FTIR systems, NDIR analysers, and GC unit to monitor the incoming flue gas and depleted flue gas, as shown in Figure 2 and Figure *3*. It should be noted that the low-range NDIR units could not be used for RFCC testing as the inlet flue gas measurement range is 0–5 vol% (dry) and the outlet depleted flue gas range is 0–1 vol% (dry), both of which are below the gas concentrations measured during these tests.

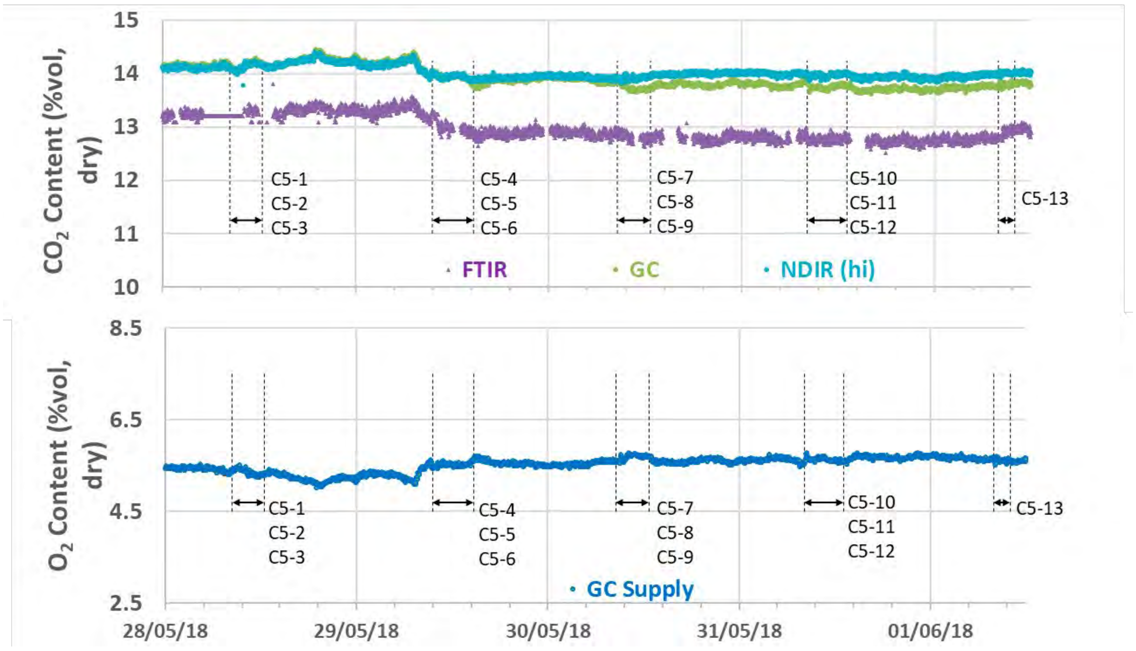

Figure 2. RFCC flue gas supply CO_2 and O_2 data for all analysers

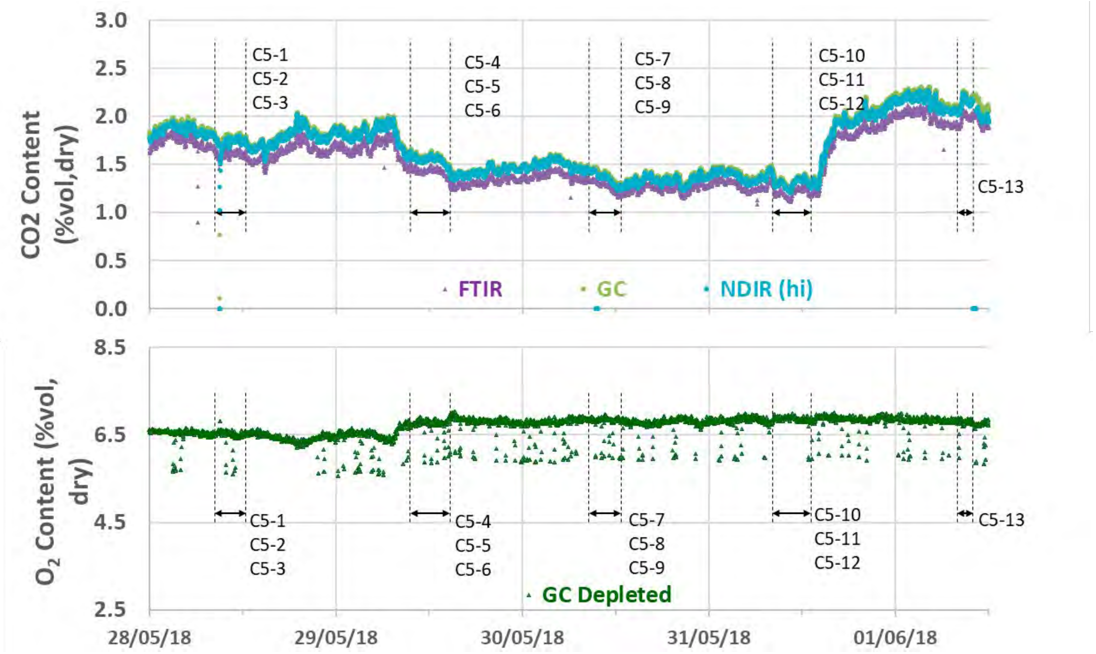

Figure 3. Depleted flue gas CO_2 and O_2 data

- Figure 2 displays the RFCC flue gas supply CO_2 and O_2 concentration data over the test campaign. There is good agreement between CO_2 NDIR and the GC CO_2 measurements (<0.2% point difference). The TCM FTIR CO_2 was biased 1% point lower than the other two instruments.
- Figure 3 displays the depleted flue gas CO_2 and O_2 concentration data over the test campaign. The data from all of the TCM instruments show close tracking together, suggesting that the process CO_2 concentration had a degree of variability (±0.2% vol) during that operating period.
- The O_2 content of the product CO_2 was low in the range of 1–2 ppmv, as shown in Figure 4. For the purposes of calculating CO_2 removal and recovery, it is assumed here that the product CO_2 stream is saturated with water at the measured temperature and pressure and contains the small trace quantities of O_2 and N_2 measured. The balance is presumed to be CO_2.

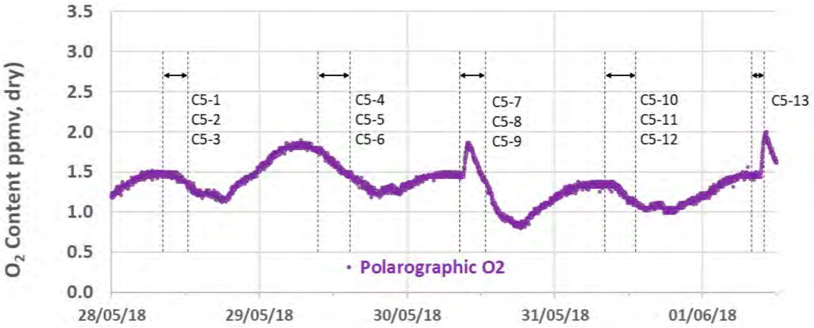

Figure 4. Product gas O_2 data

5.2. Gas-phase flow rates

Supply flue gas, depleted flue gas, and the CO_2 product streams were determined by TCM DA plant instrumentation for continuous measurement of the flow rates. In particular, the TCM DA amine plant is well instrumented for determining the RFCC flue gas supply flow rate, with several of the flow meters positioned in series.

- The RFCC flue gas supply flow is measured by two independent multi-pitot-tube flow meter instruments, (FIC-0024 and FT-2039), which are characterized in Table 2. The data from these flow meters are shown in Figure 5. All flow rates are at the defined standard conditions of 15°C and 101.3 kPa. The RFCC flue gas flow was very steady over the entire test period. The test period flow averages used for all calculations are the data reported by the multi-pitot-tube (FIC-0024) as this had a lower precision error.

Table 2. Key flow instrumentations (precision uncertainties are based on internal assessments by TCM DA)

Stream	Tag number	Instrument type	Primary flow measurement	Precision uncertainty
RFCC Flue Gas Supply	FIC-0024	Multi-pitot tube	Differential pressure	2.6%
	FT-2039	Multi-pitot tube	Differential pressure	5.3%
Absorber outlet depleted flue gas	FT-2431	Multi-pitot tube	Differential pressure	5.4%
Product CO_2	FT-0010	Vortex	Flowing volume	1.0%

- The depleted flue gas flow is measured by a single multi-pitot tube flow meter (FT-2431), whose characteristics are listed in Table 2. As observed in prior campaigns, the measured flow has significant transients that are not correlated with any process parameter. Subsequently, the depleted flue gas flow rate was calculated assuming that all O_2 and N_2 entering with the flue gas supply leaves in the depleted flue gas. The performance data reported here use such a calculation for depleted flue gas flow rate.

- The product CO_2 flow measured by the vortex flow meter (FT-0010) is the primary flow meter used by TCM DA operators, the characteristics for which are listed in Table 2. Additionally, a Coriolis flow meter is installed (FT-2215), however this instrument has not undergone an accuracy study and so is not used for primary assessment. The data from both flow meters are shown Figure 6. The product CO_2 flow was relatively steady over all periods.

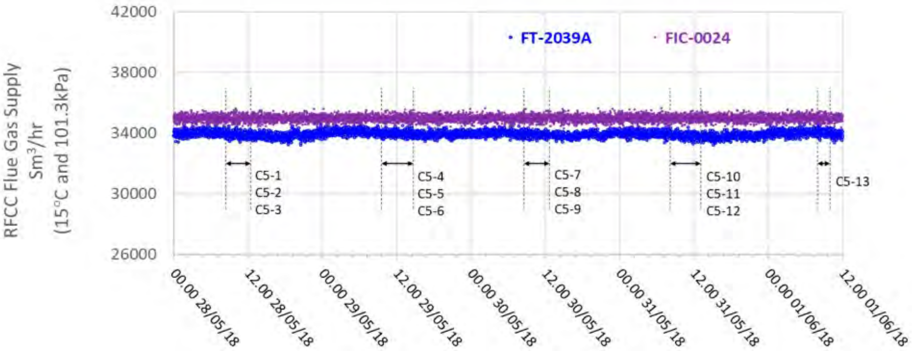

Figure 5. Flue gas supply flow measurements for RFCC testing May-June 2018

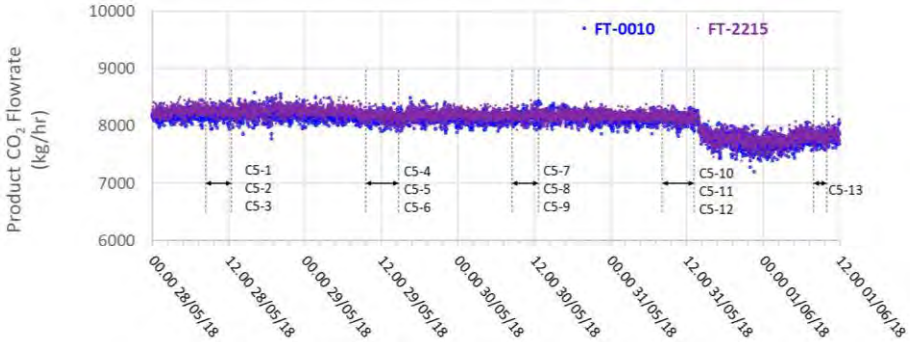

Figure 6. Product flue gas flow rate measurements for RFCC testing May-June 2018

5.3. Steam and condensate flow rates

The TCM DA amine plant receives high-pressure (HP) superheated steam from the neighbouring refinery at a pressure of approximately 30 bar, and a temperature of between 240°C to 310°C. A schematic of the system supplying steam to the stripper reboiler is shown in Figure 7.

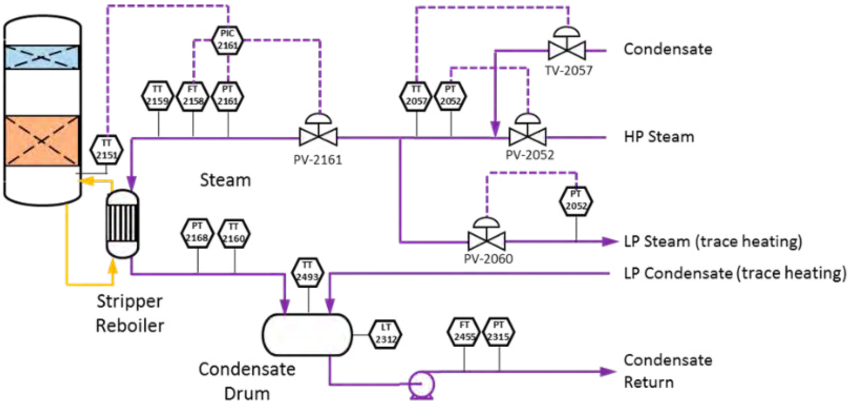

Figure 7. RFCC stripper reboiler steam supply flow schematic

The HP steam is throttled near the stripper reboiler to a pressure of approximately 5 bar before being desuperheated with condensate. Following condensation in the stripper reboiler, the steam condensate collects in a receiving vessel before being returned to the refinery.

Steam heat tracing is facilitated using a small amount of medium-pressure steam that is reduced to a lower pressure prior to use. The resultant low-pressure (LP) steam condensate is returned to the same receiver as the stripper reboiler condensate. For thermal energy consumption assessment, the key parameter of interest is the steam flow to the reboiler, shown in Figure 8.

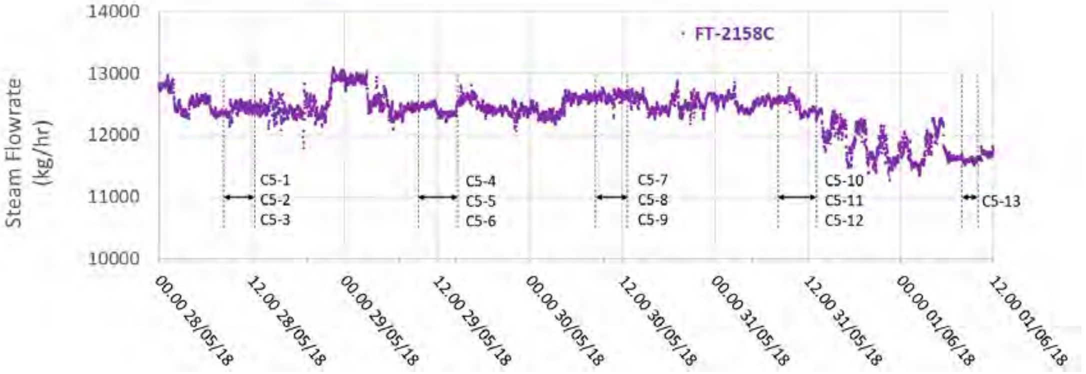

Figure 8. RFCC reboiler steam flow

6. Results and discussion

6.1. CO_2 capture efficiency and recovery

The CO_2 capture efficiency was calculated using the four methods (Methods 1–4) via the formulas detailed in Table 4. In addition, CO_2 recovery is the fraction of CO_2 mass flow in the flue gas supply that is accounted for by measured CO_2 mass flows in the depleted flue gas and product CO_2—it is a measure of the degree to which the CO_2 mass balance is closed.

Table 3. CO_2 capture efficiency and recovery calculation methods

Term	Description	Formula
CO_2 capture efficiency: Method 1	CO_2 product flow as a ratio to the CO_2 flow in the flue gas supply	$= \frac{CO_2(product)}{CO_2(supply)}$
CO_2 capture efficiency: Method 2	CO_2 product flow as a ratio to the sum of the CO_2 product flow and the CO_2 flow in the depleted flue gas	$= \frac{CO_2(product)}{CO_2(product) + CO_2(depleted)}$
CO_2 capture efficiency: Method 3	Ratio of the difference between the CO_2 flow in the flue gas supply and the CO_2 in the depleted flue gas to the CO_2 flow in the flue gas supply	$= \frac{CO_2(supply) - CO_2(depleted)}{CO_2(supply)}$
CO_2 capture efficiency: Method 4	Ratio of the depleted flue gas CO_2 per unit O_2+N_2 to the flue gas supply CO_2 per unit O_2+N_2	$= 1 - \frac{O_{CO_2}}{(1 - O_{CO_2})} \frac{(1 - I_{CO_2})}{I_{CO_2}}$
CO_2 recovery	Ratio of the sum of the CO_2 flow in depleted flue gas and the product CO_2 flow divided by the CO_2 flow in the flue gas supply	$= \frac{CO_2(depleted) + CO_2(product)}{CO_2(supply)}$

O_{CO2} = Depleted flue gas CO_2 content, dry I_{CO2} = Flue gas supply CO_2 content, dry

As the depleted flue gas flow measurement was not reliable, it was assumed that the oxygen and nitrogen entering the absorber with the flue gas leaves in the depleted flue gas. The saturated water content of the depleted flue gas was calculated using its temperature and pressure. The CO_2 flow out of the absorber was calculated using the concentration of CO_2 in the depleted flue gas and the calculated mass flowrate. These are essentially the same assumptions as those used for Method 4, which is independent of flowrate and uses a concentration-only approach. Subsequently, Method 3 and Method 4 calculations result in identical CO_2 capture rates.

The CO_2 recovery was then estimated using the calculated flow of depleted flue gas. The calculated CO_2 capture efficiency and recovery are presented in Table 4. For all test periods, the calculated CO_2 captures were quite steady near the 90% capture target and the CO_2 recovery was consistently in the range of 101–104%. Test C5-13 was targeted at the lower 85% capture rate.

Table 4. CO_2 capture results

S = Supply flue gas D= Depleted gas P= Product CO_2	Method 1	Method 2	Method 3	Method 4	CO_2 Recovery
Test Period	$=\dfrac{P}{S}$	$=\dfrac{P}{P+D}$	$=\dfrac{S-D}{S}$	$=1-\dfrac{O^{i}{}_{CO2}}{\left(1-O_{CO_2}\right)}\dfrac{\left(1-I^{ii}{}_{CO_2}\right)}{\left(I_{CO_2}\right)}$	$=\dfrac{D+P}{S}$
C5-1	92.9%	89.9%	89.6%	89.6%	103.7%
C5-2	92.6%	89.6%	89.3%	89.3%	103.8%
C5-3	92.6%	89.6%	89.2%	89.2%	103.8%
C5-4	93.0%	90.4%	90.2%	90.2%	103.2%
C5-5	93.0%	90.5%	90.2%	90.2%	103.1%
C5-6	93.5%	90.9%	90.6%	90.6%	103.2%
C5-7	93.5%	91.2%	91.0%	91.0%	102.7%
C5-8	93.6%	91.6%	91.4%	91.4%	102.4%
C5-9	93.8%	92.2%	92.1%	92.1%	101.9%
C5-10	93.3%	91.9%	91.8%	91.8%	101.6%
C5-11	93.2%	92.3%	92.2%	92.2%	101.0%
C5-12	93.0%	91.9%	91.8%	91.8%	101.4%
C5-13	88.7%	86.9%	86.7%	86.7%	102.3%

$^{i}O_{CO2}$=Depleted flue gas CO_2 content, dry basis, ^{ii} I_{CO2}=Flue gas supply CO_2 content, dry basis

The uncertainty calculations and results from calculation Methods 1–3 are shown in Table 5. The following assumptions were used:

- Flow metering uncertainties were calculated by TCM DA for the indicated flow meters based on the specification of the instrument [3].
- Concentration uncertainties for the flue gas flows are those detailed in Table 2.
- Concentration uncertainty for the product CO_2 is assumed to be 1% to allow for CO_2 content as low as 99%.
- CO_2 capture of 90% is representative of that measured during all test periods.
- The uncertainty in CO_2 capture (ECO_2) is almost entirely due to uncertainty in CO_2 content of the RFCC flue gas supply for the assigned total (low) flow uncertainties. The CO_2 capture uncertainty is relatively insensitive to uncertainties in the CO_2 contents of both the product CO_2 and depleted flue gases.

Table 5. Uncertainty in CO_2 capture calculations (nominal CO_2 capture efficiency shown as ECO_2 = 85%)

CO_2 capture calculation method	Stream	Uncertainty in:				CO_2 capture uncertainty Equation
		Total flow	CO_2 content	CO_2 flow	CO_2 capture	
1	Product	1.1%	1%	U_{CO2P}=1.5%	5.4%	$\sqrt{(U_{CO2S})^2+(U_{CO2P})^2}$
	Supply	1.3%	5%	U_{CO2S}=5.1%		
2	Product	1.1%	1%	U_{CO2P}=1.5%	0.8%	$(1-E_{CO2})\sqrt{(U_{CO2D})^2+(U_{CO2P})^2}$
	Depleted	1.3%	5%	U_{CO2D}=5.2%		
3	Supply	1.3%	5%	U_{CO2S}=5.2%	1.3%	$\dfrac{(1-E_{CO2})}{E_{CO2}}\sqrt{(U_{CO2S})^2+(U_{CO2D})^2}$
	Depleted	1.3%	5%	U_{CO2D}=5.2%		

6.2. Thermal energy consumption

The reboiler thermal duty was calculated as the difference between steam enthalpy at the reboiler inlet temperature and pressure and the saturation enthalpy of water at the reboiler condensate temperature. The specific thermal use (STU) was obtained by dividing the reboiler duty by the product CO_2 flow. The CO_2 product flow was either based on the measured CO_2 product flow (P) or on the difference between the NDIR-measured CO_2 supply flow and the estimated CO_2 depleted flow (S – D). The two corresponding values for STU are shown in Table 6. The results for STU were very consistent during all test periods. The product flow measurements (P) were consistently higher than the using the gas-side difference method (S – D) method, resulting in lower STU values.

Table 6. Stripper reboiler thermal energy consumption

Test period	Reboiler steam flow rate kg/hr	Reboiler duty MJ/hr	Using the product CO_2 flow (P)[i]		Using CO_2 removed (S – D)	
			Product CO_2 Flow kg/hr	Specific Thermal Use GJ/t CO_2	Product CO_2 Flow kg/hr	Specific Thermal Use GJ/t CO_2
C5-1	12,343	28,173	8142	3.46	7849	3.59
C5-2	12,459	28,343	8138	3.48	7843	3.61
C5-3	12,436	28,315	8159	3.47	7863	3.60
C5-4	12,463	28,376	8072	3.52	7824	3.63
C5-5	12,457	28,380	8070	3.52	7827	3.63
C5-6	12,369	28,365	8085	3.51	7835	3.62
C5-7	12,630	28,678	8078	3.55	7865	3.65
C5-8	12,585	28,592	8088	3.54	7902	3.62
C5-9	12,641	28,771	8133	3.54	7984	3.60
C5-10	12,571	28,593	8093	3.53	7962	3.59
C5-11	12,583	28,636	8069	3.55	7988	3.58
C5-12	12,397	28,427	8093	3.51	7984	3.56
C5-13	11,592	26,529	7724	3.43	7548	3.51

i The wet CO_2 flow is obtained by using the FTIR measured moisture content of the product CO_2

Prior testing with CHP flue gas at approximately an 80 tonnes per day load yielded a regeneration energy range of 3.61–3.66 GJ/tonne-CO_2 using the product CO_2 flow (P) and 3.58–3.60 GJ/tonne-CO_2 using the gas-side difference method (S – D) [2]. The RFCC tests achieved circa 190 tonnes per day load and delivered an average regeneration energy of 3.51 GJ/tonne-CO_2 using product flow (P) and 3.60 GJ/tonne-CO_2 using gas-side difference method (S – D). This represents a 2% reduction in regeneration energy, likely due to the higher inlet CO_2 levels.

6.3. Gas-phase contaminants

Formaldehyde, acetaldehyde, and acetone concentrations were determined by extractive sampling of the depleted flue gas at the absorber outlet during the RFCC test periods as shown in Table 7. The formaldehyde levels are lower than the previous MEA baseline testing values of 720 $\mu g/Sm^3$ and 40 g/hr, which were done by an independent, contractor (FORCE Technology) using brought-in instruments. The acetaldehyde levels are considerably lower than the 2015 MEA test samples of 16 mg/Sm^3 and 840 g/h emission levels measured by FORCE Technology. However, acetone levels measured were sufficiently low to be at or below the detection limit of the analysis performed by SINTEF, a similar result to the previous MEA test [2].

Table 7. Depleted gas phase aldehyde concentrations

Test period	Formaldehyde			Acetaldehyde		
	ppmvd	$\mu g/Sm^3$	g/h	ppmvd	mg/Sm^3	g/h
C5-4	0.03	43.2	1.19	0.88	1.73	47.8
C5-5	0.03	44.5	1.23	0.82	1.61	44.4
C5-6	0.07	89.1	2.46	0.86	1.69	46.6

For the CO_2 product, shown in Table 8, the formaldehyde levels detected are lower than the manually sampled measurements during the 2015 CHP baseline campaign of 140 $\mu g/Sm^3$ and the acetaldehyde levels are considerably lower than the previous level of 150 mg/Sm^3. The 2015 MEA baseline measurements were closer to the levels measured in 2014, where formaldehyde was detected at 190 $\mu g/Sm^3$. Although acetone was detected in the CO_2

product, these measurements were at or below the detection limit, whereas in the previous MEA baseline all measurements taken were below the detection limit.

Table 8. Product gas aldehyde concentrations

Test period	Formaldehyde			Acetaldehyde		
	ppmvd	µg/Sm^3	g/h	ppmvd	mg/Sm^3	g/h
C5-10	0.06	83.3	0.34	2.90	5.70	23.5
C5-11	0.04	52.5	0.22	3.33	6.55	26.9
C5-12	0.039*	51.9	0.21	3.29	6.46	26.6

* some DNPH cartridges measured below detection limit

TCM DA measured concentrations of MEA and ammonia at the absorber outlet during the RFCC test periods C5-1 to C5-6 and for C5-13 following a modification to the process operating conditions to a lower capture rate target. The results of these manually extracted samples are shown in Table 9.

Table 9. Depleted flue gas stream ammonia and amine concentrations and mass rates as phase contaminants

Test period	MEA			Ammonia		
	ppmvd	mg/Sm^3	g/h	ppmvd	mg/Sm^3	g/h
C5-1	3.16	8.15	231	8.20	5.91	167
C5-2	2.99	7.73	219	7.29	5.25	149
C5-3	2.99	7.72	218	7.74	5.57	157
C5-4	2.67	6.89	195	8.47	6.10	173
C5-5	2.57	6.63	188	7.49	5.40	153
C5-6	2.75	7.11	201	7.67	5.53	157
C5-13	2.93	7.58	216	7.58	5.46	156

The levels detected here for MEA were consistent between samples and are far higher than observed by FORCE Technology during the 2015 CHP gas testing (0.006 mg/Sm^3). Although the levels measured here are higher, previous EPRI experience with coal-derived flue gases has observed comparable single-digit ppm levels of amine at the depleted flue gas location when aerosol levels are low or zero, which TCM DA had achieved using the Brownian demister filter upstream of the absorber. Ammonia levels are lower than the previous CHP tests results, measured at 13 mg/Sm^3. However, it is unknown how degraded the solvent was during these tests in comparison with the previous campaign. TCM DA measured concentrations of MEA and ammonia in the CO_2 product gas during the RFCC test periods C5-10 to C5-12. MEA was not detected, and levels of ammonia were substantially lower at 0.05-0.08mg/Sm^3 than the prior CHP test results [2]. While extractive samples of SO_x and NO_x were not carried out during this test campaign, the FTIR was used to track the relative levels of each component. The RFCC flue gas was expected to have 20–60 ppm (vol, dry) of SO_2 from previous tests, but this couldn't be reliably verified during these tests as the FTIR instrument did not deliver a reliable measurement. The outlet measurements were more consistent, as shown in Table 10. The consistent <1 ppm vol measurement of SO_2 suggests absorption by the MEA solvent.

Table 10. Depleted flue gas SO_2 concentrations and mass rates

Test period	SO_2		
	ppmvd	mg/Sm^3	g/h
C5-1	0.51	1.37	38.9
C5-2	0.56	1.53	43.2
C5-3	0.62	1.69	47.6
C5-4	0.76	2.05	58.1
C5-5	0.69	1.87	53.1
C5-6	0.83	2.25	63.8
C5-7	0.69	1.88	53.1
C5-8	0.77	2.10	59.3
C5-9	0.86	2.32	65.3
C5-10	0.74	1.99	56.2
C5-11	0.77	2.09	58.6
C5-12	1.00	2.71	76.2
C5-13	0.52	1.41	40.3

The NO_x quantities passing through the absorber were effectively unchanged, showing only the concentrating effect of the CO_2 removal from the flue gas, where more than 10% of the flue gas volume is removed. As the amine plant operated continuously capturing 90% throughout the test period, the FTIR-measured NO_x data show a consistent increase in concentration at the outlet of the absorber as shown in Figure 9.

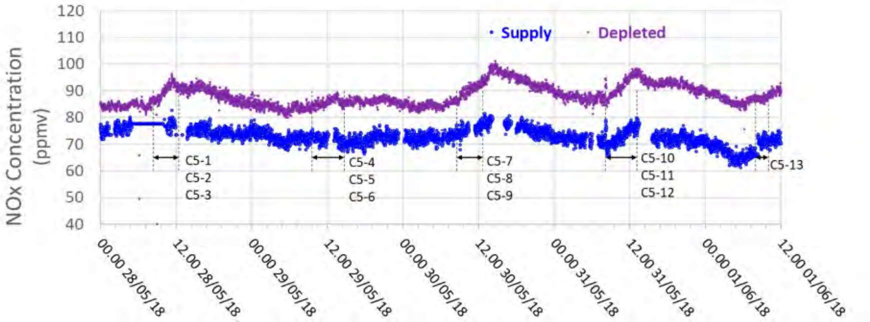

Figure 9. Absorber inlet and outlet NOx values

6.4. New baseline for solvent performance testing

Table 11 presents a portion of the MEA test data obtained at the TCM DA amine plant. Based on these data, a new baseline was established for higher concentration flue gas CO_2 capture.

Table 11. Results of RFCC baseline testing in 2018

Baseline year	**2018**		
Packing height (m)	18	Lean loading	0.23
Flue gas flow (Sm^3/h)	35 000	Rich loading	0.48
Flue gas supply temperature (°C)	31.0	Stripper bottom temperature (°C)	121.0
Flue gas supply pressure (bar)	0.02	CO_2 capture (%)	91
Lean amine flow (kg/h)	133 000	SRD (MJ/kg CO_2)	3.55

7. Conclusions

This baseline represents the performance of the TCM amine plant close to the plant nominal capacity using 5M MEA solvent with higher CO_2 concentration flue gas (13–14 vol%), typical of coal-based thermal plants. Alongside the prior baseline work carried out in 2015 for flue gas with CO_2 concentrations from natural gas-fired CHP units (3–4 vol%) [2], this new baseline will serve as the performance benchmark for other amines tested at the TCM DA amine plant when using RFCC flue gas.

Acknowledgements

The authors gratefully acknowledge the staff of TCM DA, Gassnova, Equinor, Shell, and Total for their contribution and work at the TCM DA facility. The authors also gratefully acknowledge Gassnova, Equinor, Shell, and Total as the owners of TCM DA for their financial support and contributions.

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Results from MEA testing at the CO_2 Technology Centre Mongstad: Verification of baseline results in 2015

(2016)

Available online at www.sciencedirect.com
ScienceDirect
Energy Procedia 114 (2017) 1128 – 1145
Energy Procedia

13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland

Results from MEA testing at the CO_2 Technology Centre Mongstad: Verification of baseline results in 2015

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Abstract

In 2015, the CO_2 Technology Center Mongstad (TCM DA) operated a post-combustion CO_2 capture test campaign using aqueous monoethanolamine solvent at 30 weight%. The main objective was to demonstrate and document the performance of the TCM DA amine plant located in Mongstad, Norway.

During the treatment of flue gas from the natural gas-fired combined heat and power plant at Mongstad, a revised baseline was established for the TCM DA amine plant in accordance to the verification protocol developed by the Electrical Research Institute, Inc. This paper presents the revised baseline, which can be considered as a reference case for the solvent-based CO_2 capture processes applied to natural gas-based flue gases.

Keywords: CO_2 capture; EPRI; Verification; Monoethanolamine; CO_2 Technology Centre Mongstad; TCM DA

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doi:10.1016/j.egypro.2017.03.1271

1. Introduction

The CO_2 Technology Centre Mongstad (TCM) is located next to the Statoil refinery in Mongstad, Norway. TCM DA is a joint venture set up by Gassnova representing the Norwegian state, Statoil, Shell, and Sasol. The facility run by TCM DA entered the operational phase in August 2012 and is one of the largest post-combustion CO_2 capture (PCC) test centres in the world. A unique aspect of the facility is that either a flue gas slipstream from a natural gas-based combined heat and power (CHP) plant or an equivalent volumetric flow from a residual fluid catalytic cracker (RFCC) unit can be used for CO_2 capture. The CHP flue gas contains about 3.5% CO_2 and the RFCC flue gas contains about 13-14% CO_2, the latter of which is comparable to CO_2 levels seen in coal-fired flue gas. One of the main test plants at TCM DA is a highly flexible and well-instrumented amine plant. The amine plant was designed and constructed by Aker Solutions and Kværner to accommodate a variety of technologies, with capabilities of treating flue gas streams of up to 60,000 standard cubic meters per hour. The plant is being offered to vendors of solvent-based CO_2 capture technologies to, among others, test: (1) the performance of their solvent technology; and (2) technologies aimed to reduce the atmospheric emissions and environmental impact of amines and amine-based degradation products from solvent-based CO_2 capture processes. The objective of TCM DA is to test, verify, and demonstrate CO_2 capture technologies suitable for deployment at full-scale. A significant number of vendors, Aker Solutions, Alstom (now GE Power), Cansolv Technologies Inc., and Carbon Clean Solutions Ltd. have already successfully used the TCM DA facilities to verify their CO_2 capture technologies.

From 6 July to 17 October 2015 TCM DA, in collaboration with partners, operated a monoethanolamine (MEA) campaign with the main objective to document and demonstrate the amine plant performance.

TCM DA investigated the stripper performance and concluded that the use of anti-foam made it possible to utilise the full flue gas supply capacity of 60,000 standard cubic meters per hour. At the full CHP flue gas capacity, the CO_2 capture rate was about 85% when MEA at 30 weight% (wt%) was used. The corresponding specific reboiler duty (SRD) was about 3.6 GJ/ton CO_2. Total and CO_2 mass balance closures were near 100 %. Emission levels of MEA, NH_3, aldehydes, nitrosamines, nitramines, and other compounds were also measured during extractive samples for the defined time periods and were all below the permissible levels set by the Norwegian Environment Agency (Miljødirektoratet).

During the treatment of the CHP flue gas at full capacity, a revised baseline was established for the TCM DA amine plant. The revised CHP baseline was verified by the Electric Power Research Institute, Inc. (EPRI).

EPRI has developed a structured CO_2 capture testing methodology for characterizing PCC processes. EPRI's methodology is designed to provide relevant information for baselining and comparing technologies, referred to as an independent verification protocol (IVP). This methodology has been tailored to the TCM DA amine plant facility and is presented in detail elsewhere [1].

The amine plant is planned and equipped for conducting research and development activities and TCM DA has recently installed a number of additional gas-phase analysers to improve the speed and accuracy of measurements. The IVP methodology has therefore been updated by EPRI to reflect these recently installed instruments.

The revised CHP baseline was verified by EPRI, following their requirements including the use of third-party gas phase and emission measurements done by FORCE Technology. FORCE Technology performed comprehensive measurements on flow rates, temperatures, and compositions on the absorber inlet, the absorber outlet (depleted flue gas), and the stripper outlet.

This paper will present the revised baseline for the TCM DA amine plant, in accordance to the IVP developed by EPRI.

Nomenclature		**Units**	
ASME	American Society of Mechanical Engineers	barg	bar gauge
CEMs	continuous emissions monitors	count/cm^3	count per cubic centimetre
CHP	combined heat and power	g/hr	grams per hour
ELPI+	electrical low pressure impactor	GJ/t	giga joule per ton
EPRI	Electrical Power Research Institute, Inc.	kg/hr	kilogram per hour
FTIR	Fourier transform infrared	kg/m^3	kilogram per cubic meter
GC	gas chromatograph	m	meter
IVP	independent verification protocol	mg/Sm^3	milligram per standard cubic meter
NDIR	non-dispersive infrared	MJ/hr	mega joule per hour
PCC	post-combustion CO_2 capture	Sm^3/hr	standard cubic meter per hour
RFCC	residual fluid catalytic cracker	vol%	volume percentage
TCM	Technology Centre Mongstad	wt%	weight percentage
TVOC	total volatile organic carbon	µm	micrometre

2. Amine plant

The schematic of the TCM DA amine plant when treating the CHP flue gas is shown in Figure 1.

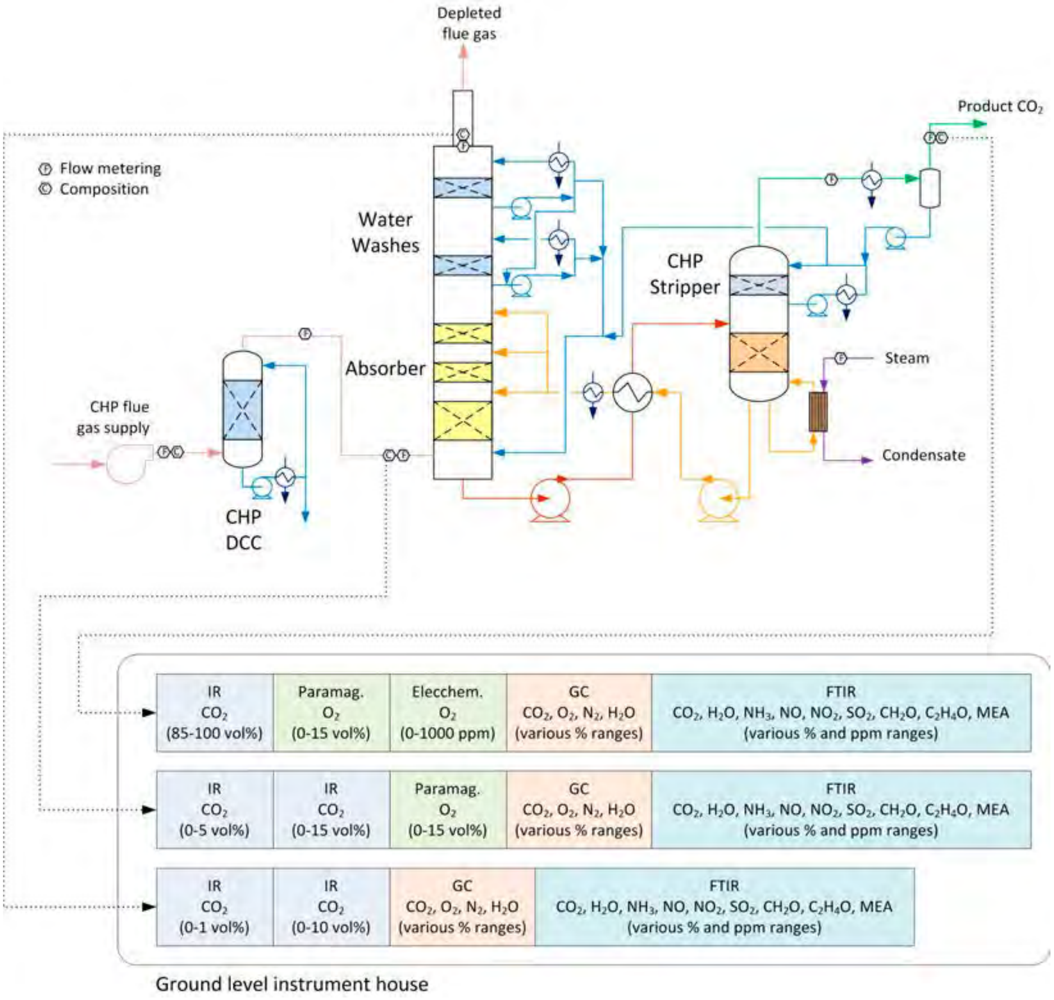

Figure 1. The TCM DA amine plant when treating the CHP flue gas.

The nominal CHP flue gas characteristics along with the existing instrumentations are specified elsewhere [2]. The main systems in the plant are also explained in detail in a previously published paper [1].

3. IVP project overview

The roles and responsibilities of the organizations that conducted the current IVP project are as follows;

- **TCM DA** is the project owner and organized the field testing during the test period. The test program for the baseline testing was developed by the owners of TCM DA. TCM DA personnel operated the plant throughout the testing and collected lean and rich liquid samples for laboratory analysis during the test period.
- **FORCE Technology** was contracted by TCM DA to collect and analyse samples from the CHP flue gas supply, depleted flue gas, and product CO_2 streams. Two crews from FORCE Technology conducted the sampling sequentially with a single set of continuous emissions monitors (CEMs). FORCE Technology also collected gas samples for off-site analysis of particulate, SO_2, SO_3, amine, and degraded amine components.
- **Laborelec** carried out particulate concentration and size distribution measurements during the baselining period. Laborelec characterized the size of and the number of particles formed at different points through the absorber tower by using an electrical low-pressure impactor (ELPI+) device.
- **EPRI** was contracted by TCM DA to apply the IVP during the MEA baseline testing. Two EPRI engineers were on-site during the testing to observe the conduct of the tests. EPRI also led analyzing the results from the IVP project.

4. IVP

4.1. Approach

A detailed description of the IVP approach was previously reported [1]. A summary of the approach is provided here.

The purpose of the IVP is to measure and report key performance indices of the PCC process (those indices critical to up-scaling the process). Key performance indices (dependent parameters) include CO_2 capture, CO_2 production, emission, utility usage (steam, power and cooling), and trace constituents of the depleted flue gas and product CO_2. The key performance indices depend on a number of independent parameters including: the overall process design, physical characteristics (and operating conditions) of process equipment, flue gas supply conditions and flow rate, lean and rich solutions conditions and flow rate, and stripper pressure.

Many of the dependent parameters can be modeled using commonly available chemical engineering computer process modeling tools. Field measurement of these key performance indices (along with the uncertainty in the measurements) can be used to calibrate the computer process models. Other dependent parameters (such as trace components in the depleted flue gas and product CO_2) are difficult to model with currently available tools. Field measurements of these parameters will serve as primary data for up-scaling process designs.

The IVP approach to field performance testing is generally consistent with the approach taken by others for performance testing of a number of power processes [3]. The IVP specifies procedures for collecting composition, temperature, pressure, and flow data at TCM DA sufficient to calculate and report key performance indices and the corresponding numerical uncertainty in the values reported. Industry-accepted standard reference test methods are specified for the collection of composition, temperature, pressure, and flow data. Procedures for reducing the data are also specified. The IVP focuses on campaign-style testing in which days are dedicated to testing at previously selected optimum process operating conditions, but the IVP principles can also guide parametric testing undertaken to identify optimum process conditions.

4.2. MEA 2015 test campaign conduct

The second campaign of base-case testing of the performance of the TCM DA amine plant using a nominal 30% MEA as the solvent was conducted the week of 7 September 2015 after approximately eight weeks of operating the amine plant with the 30 wt% MEA solution. The plant was operated at steady state throughout the week.

FORCE Technology was on-site to manually collect contemporaneous samples from the flue gas supply, depleted flue gas, and product CO_2. Laborelec was also on-site to manually collect samples for particulate and aerosol size distribution analysis at different locations through the absorber tower.

During all sampling periods the following data were collected:

- CO, CO_2, NO_X, O_2, SO_2, and N_2 (by difference) concentrations in volume percent (vol%)
- Flow rate, pressure, and temperature.

The sampling time periods and sampling period designators are shown in Table 1 along with additional sampling undertaken on each day. Data logs for all sampling periods containing pertinent flows, temperatures, pressures, and concentrations measured by permanent plant instruments were supplied by TCM DA.

Table 1. FORCE Technology and Laborelec sampling periods.

Stream sampled	Date	Start time / Stop time	Sampling results reported	Test period
Depleted flue gas	9 September 2015	12:50 / 15:37	Flow	C3-4
		13:08 / 15:44	H_2SO_4, SO_2, HCl, HF, HCN, particulates, CEMs	C3-1
		17:07 / 19:18	Acetone, aldehydes, amides, amines	C3-2
Depleted flue gas	10 September 2015	9:07 / 11:05	NH_3, total N, H_2S, mercaptans, TVOC[*]	C3-3
Product CO_2	9 September 2015	13:08 / 15:45	H_2SO_4, SO_2, HCl, HF, HCN, particulates, CEMs	C3-1
		13:09 / 14:59	Flow	C3-4
		17:10 / 19:19	Acetone, aldehydes, amides, amines	C3-2
Product CO_2	10 September 2015	9:04 / 11:06	NH_3, total N, H_2S, mercaptans, TVOC	C3-3
Flue gas supply	9 September 2015	11:58 – 15:01	Flow	C3-4
		13:08 / 15:45	H_2SO_4, SO_2, HCl, HF, HCN, particulates, CEMs	C3-1
		17:07 / 19:19	Acetone, aldehydes, amides, amines	C3-2
Flue gas supply	10 September 2015	9:04 / 11:06	NH_3, total N, H_2S, mercaptans, TVOC	C3-3
Post-capture packing	10 September 2015	19:55 / 19:57	Particle size distribution	C3-5
Post-water wash	10 September 2015	18:32 / 18:34	Particle size distribution	C3-6
Post-acid wash	8 September 2015	13:57 / 15:06	Particle size distribution	C3-7
Absorber outlet	11 September 2015	10:47 / 11:32	Particle size distribution	C3-8

[*] *TVOC: total volatile organic carbon*

5. Instrument assessment

An important component in the determination of process plant performance is the quality of the instrumentation installed for measuring the respective compositions and flow rates. Two measures of instrumentation quality are:

- Accuracy/bias: This represents the difference between the instrument reading (or average of a set of readings under unchanging process conditions) being assessed and the true value of the parameter being measured. Appropriate determination of the "true value" must be achieved by simultaneous measurement of the parameter using a reference method or instrument with calibration that can be traced to primary standards.
- Precision: A determination of the variability of the instrument reading when stream conditions are known to be steady state. Precision is therefore a measure of the random error associated with the measurement.

These measurement errors can be combined to assess the aggregate uncertainty in a given measurement. In the absence of a calibration against primary standards for the entire measurement range needed, the uncertainty published by the instrument supplier represents only the precision error.

When the process parameter being measured does not change, precision is a measure of repeatability. In real plant situations, it is often the case that the process parameters (flow, pressure, and temperature) do vary over the measurement period. Thus, measurements over long periods of time (greater than process time constants) will also include an error term related to process uncertainty.

5.1. Gas phase compositions

In the first baseline MEA in 2014, the CO_2 and O_2 content of the flue gas supply, depleted flue gas, and CO_2 product stream were routinely determined by a single Fourier Transform Infrared (FTIR) instrument (Applied Instrument Technologies and Finetech, model: Anafin 2000) along with an O_2 instrument (Siemens, model: Oxymat 6). Since these instruments were shared between the sampling points, a sampling system was installed to extract from the various single points as given by Thimsen et al. [1]. The sample was continuously drawn by a selection system serving the analysers and was diverted to the common analysers in a 90-minute cycle; i.e., the analyser cycles between flue gas supply for 15 minutes, depleted flue gas for 30 minutes, and CO_2 product stream for 15 minutes, and an additional 30 minutes for purging operations.

Following the first MEA baseline campaign, TCM DA has since installed a number of additions to the gas measurement systems to improve the speed and accuracy of the measurements and widen the breadth of measurement techniques. To complement the original FTIR unit, two new additional Gasmet FTIR units (model: FCX) were installed, facilitating dedicated and continuous FTIR measurements at all three locations. Additionally, the CO_2 concentration at the inlet and outlet of the absorber column was also determined by two non-dispersive infrared (NDIR) units (Siemens, model: Ultramat 6) at each location, one set to high range (vol%) and one low range (ppmv) on a dry-gas basis. A trace O_2 instrument [Teledyne Instruments 3001] was installed to quantify O_2 content of the product CO_2. The system has been further complemented with a new Siemens Maxum Edition II gas chromatograph (GC) unit that is capable of measuring the CO_2, O_2, and nitrogen content at all three locations in a near-simultaneous fashion.

During the September 2015 operations, FORCE Technology carried out simultaneous analysis on three process streams (flue gas supply, depleted flue gas, and CO_2 product stream). Comparison of the TCM DA values determined by the FTIR systems (after converting to dry basis assuming saturation at the measured pressure and temperature), NDIR analysers, and GC with the FORCE Technology data are given in Figure 2 and Figure 3. Details include:

- Figure 2 displays the CHP flue gas supply CO_2 and O_2 concentration data over the test campaign. There is good agreement between the FORCE Technology CO_2 NDIR and the TCM GC CO_2 measurements (<0.5% point difference) with the two TCM NDIR units showing a similar offset of 2% of the measured value (<0.08 vol%). The TCM FTIR CO_2 average values compare well with the FORCE Technology measurements, however the instantaneous measurements showed significant scatter from the mean value (7% spread, representing ±0.3 vol%). The TCM FTIR O_2 measurements agree more closely (less than 0.5 vol% dry O_2) than the GC, which is over 1 vol% dry O_2 higher in all measurement points. On the morning of 10 September 2015, the second O_2 measurement period carried out by FORCE Technology has an overall similar offset as observed on 9 September 2015 following a morning calibration of the instrument.

- Figure 3 displays the depleted flue gas CO_2 and O_2 concentration data over the test campaign. The data from all of the TCM instruments closely track together, suggesting that the process CO_2 concentration had a degree of variability (±0.2 vol%) during that operating period. The FORCE Technology measurements showed more variability than the TCM instruments. Data from all four TCM instruments are consistently higher than the FORCE Technology data by 10% to 25% (FTIR is the closest). The consistency in this bias, especially between the TCM NDIR and FORCE Technology NDIR instruments suggests either a difference in the calibrations of the respective instruments during the FORCE Technology campaign or, possibly, an anomaly in the FORCE Technology sampling system that diluted the sample with ambient air. It is also important to note that the FORCE Technology measurements of depleted flue gas CO_2 were at or below the stated limit of detection of 0.5 vol%, although the NDIR was calibrated using "low-range" calibration gases and values down to 0.3 vol% were reported to a single significant figure to reflect the increased uncertainty of the measurements at these low levels.
- The product CO_2 composition data reported by FORCE Technology had an O_2 content of between 5-12 ppmv, far lower than the 1-2 vol% reported by FORCE Technology during the MEA campaign in February 2014 [4], which was thought to be contaminated by air in-leakage and subsequently disqualified. The TCM GC instrument measured nitrogen in the product with an average of 180 ppmv. For the purposes of calculating CO_2 removal and recovery, it is assumed here that the product CO_2 stream is saturated with water at the measured temperature and pressure and contains the small trace quantities of O_2 and N_2 measured. The balance is presumed to be CO_2.

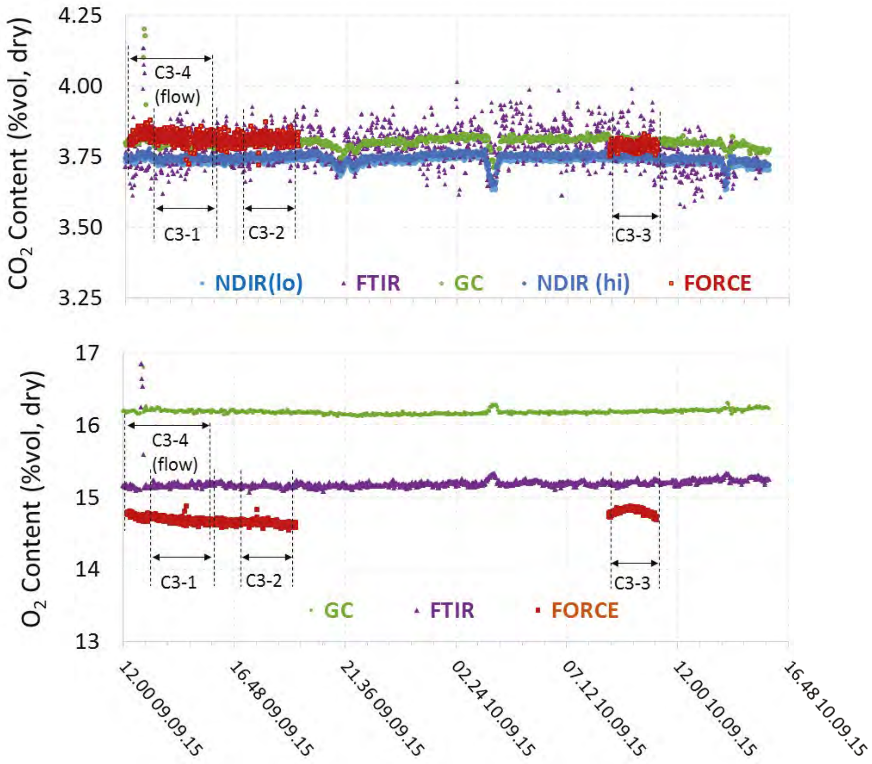

Figure 2. CHP flue gas supply CO_2 and O_2 data for all analysers. Data collected by FORCE Technology on 9 and 10 September 2015 are also shown.

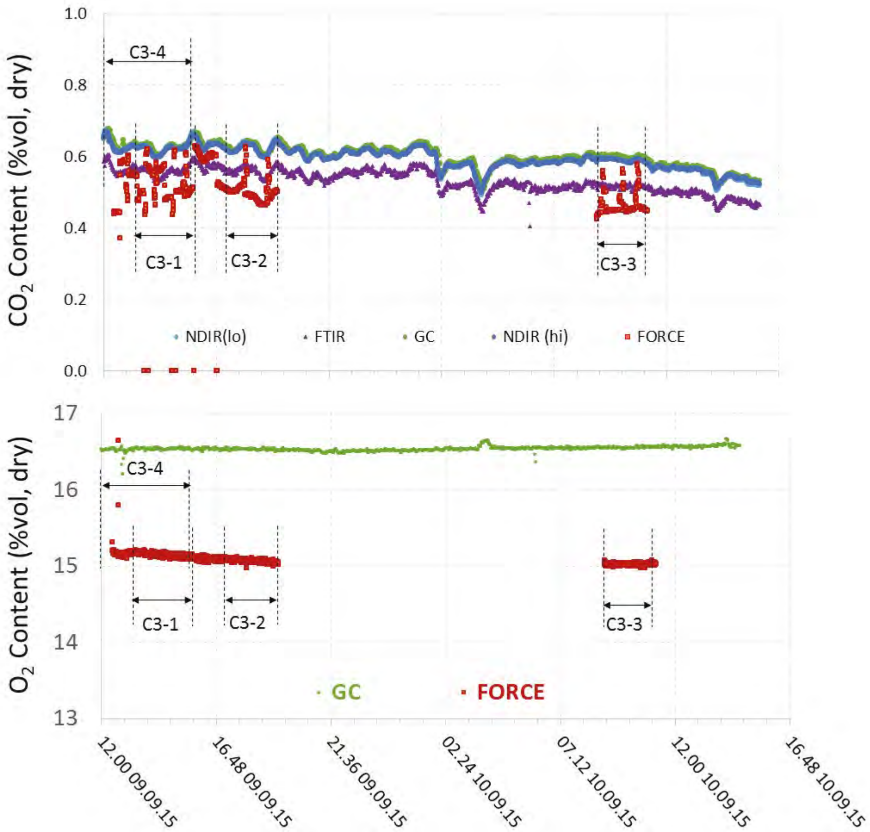

Figure 3. Depleted flue gas CO_2 and O_2 data. Data collected by FORCE Technology on 9 and 10 September 2015 are also shown.

5.2. Gas phase flow rates

Continuous measurement of the flow rates of the supply flue gas, depleted flue gas, and CO_2 product stream were determined by TCM DA plant instrumentation. In particular, the TCM DA amine plant facility is well instrumented for determining the flue gas supply flow rate, with several different types of flow meters positioned in series.

During the base-case operations, pitot-tube traversing of the supply flue gas, depleted flue gas, and CO_2 product stream was carried out by FORCE Technology to determine the flow rates, the results of which are compared to plant instrumentation measurements below:

- The CHP flue gas supply flow is measured by two independent instruments, an ultrasonic flow meter (FT-0150) and a multi-pitot-tube flow meter (FIC-0124), which are characterized in Table 2. The data from these flow meters are shown in Figure 4. All flow rates are at defined standard conditions of 15 °C and 101.3 kPa. The CHP flue gas flow was very steady over the test period on 9 September 2015 when FORCE Technology made independent measurements of flow as indicated in Figure 4. The difference between the values measured by FORCE Technology and that measured by the plant instruments is between 2–6%, well within the reported uncertainty in the FORCE Technology measurement of 10% The test period flow averages used for all calculations are the data reported by the ultrasonic flow meter (FT-0150).
- The depleted flue gas flow is measured by a single multi-pitot tube flow meter (FT-2431), whose characteristics are listed in Table 2. The measured flow had a higher degree of variability than the inlet CHP measurement (spread of 5.9% versus 0.7% for FT-0150) and also has significant transients that are not correlated with any process parameter. The data are, however, fairly consistent over the period during which FORCE Technology

made independent measurements on 9 September 2015 so a comparison is possible. The individual FORCE Technology measurements average to 55,900±10% Sm^3/hr, dry (101.3 kPa, 15°C) at this location. The average flow over the same time period reported by the plant flow meter is 54,200 Sm^3/hr, well within the 10% uncertainty in the FORCE Technology measurement. Nevertheless, the questions associated with this measurement are sufficient to choose to calculate the depleted flue gas flow rate assuming that all O_2 and N_2 entering with the flue gas supply leave in the depleted flue gas. The performance data reported here use such a calculation of depleted flue gas flow rate.

- The product CO_2 flow measured by the vortex flow meter (FT-0010) is the primary flow meter used by TCM operators, whose characteristics are listed in Table 2. The data from this flow meter are shown in Figure 5. The product CO_2 flow was relatively steady over the test period. FORCE Technology made independent measurements of flow on 9 September 2015 as indicated in Figure 5. The difference between the value measured by FORCE Technology and that measured by the plant instruments is approximately 7.5%, within the measurement uncertainty reported by FORCE Technology of 10%.

Table 2. Key flow instrumentations. Precision uncertainties are based on internal assessments by TCM DA.

Stream	Tag number	Instrument type	Primary flow measurement	Precision uncertainty
CHP flue gas supply	FIC-0124	Multi-pitot tube	Differential pressure	2.5%
	FT-0150	Ultra-sonic	Flowing volume	1.3%
Absorber outlet depleted flue gas	FT-2431	Multi-pitot tube	Differential pressure	5.4%
Product CO_2	FT-0010	Vortex	Flowing volume	1.0%

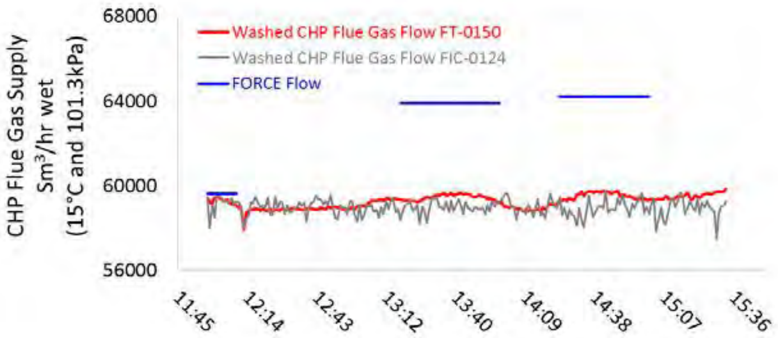

Figure 4. CHP flue gas supply flow measurements measured on 9th September 2016.

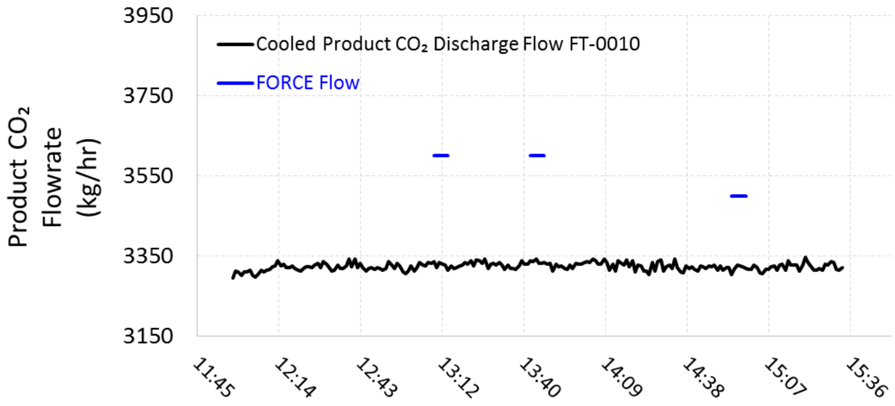

Figure 5. Product CO_2 flow rate and test period averages measured on 9 September 2016.

5.3. Steam and condensate flow rates

The TCM DA amine plant receives high-pressure (HP) superheated steam from the neighbouring refinery at a pressure of approximately 30 bars and a temperature of between 240°C to 310°C. The HP steam is throttled near the stripper reboiler to a pressure of approximately 5 bar before being desuperheated with condensate. Following condensation in the stripper reboiler, the steam condensate collects in a receiving vessel before being returned to the refinery. Steam heat tracing is facilitated using a small amount of medium-pressure (MP) steam that is reduced to a lower pressure prior to use. The resultant low-pressure (LP) steam condensate is returned to the same receiver as the stripper reboiler condensate. A schematic of the system supplying steam to the stripper reboiler is shown in Figure 6.

For thermal energy consumption assessment, the key parameter of interest is the steam flow to the reboiler. The HP condensate flow returned to the refinery can be assessed as a check on this parameter. The condensate return flow should be the sum of the reboiler steam flow and any condensate flow produced in steam heat tracing. Figure 7 shows these two parameters. As a result of higher ambient temperatures experienced in September 2015 the average condensate flow measurement (FT-2455) was either at or slightly lower than the steam flow measurement (FT-2386). (During the first MEA baseline testing in January 2014, condensate measurements exceeded the steam flow measurement due to the contribution of trace heating).

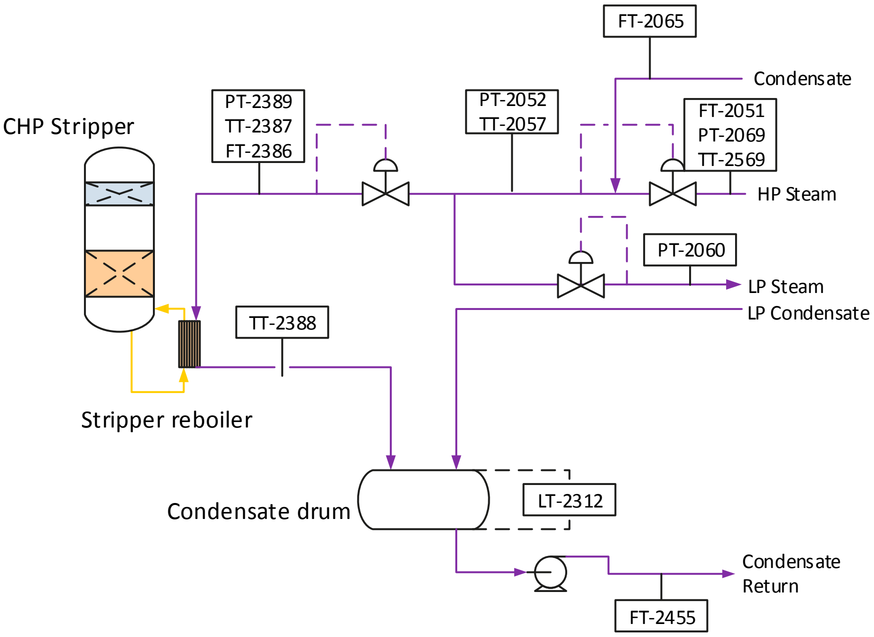

Figure 6. Stripper reboiler steam supply flow schematic.

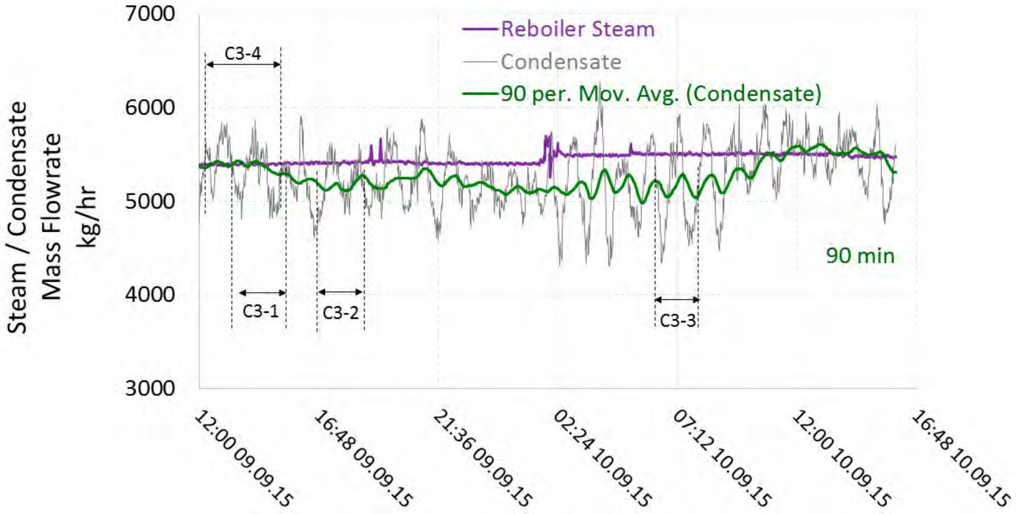

Figure 7. Reboiler steam flow and HP condensate return flow.

6. Results and discussions

6.1. CO_2 capture efficiency and recovery

The CO_2 capture efficiency was calculated using the four methods (Methods 1–4) shown in Table 8 in Appendix A. CO_2 recovery is the fraction of CO_2 mass flow in the flue gas supply that is accounted for by measured CO_2 mass flows in the depleted flue gas and product CO_2; it is a measure of the degree to which the CO_2 mass balance is closed. The formula to calculate the amount of CO_2 recovery from the flue gas supply is also given in Table 8 in Appendix A.

The depleted flue gas flow measurement was not reliable and therefore it was calculated. It was assumed that the oxygen and nitrogen entering the absorber with the flue gas leave in the depleted flue gas. The saturated water content of the depleted flue gas was calculated using its temperature and pressure. The CO_2 flow out of the absorber was calculated using the concentration of CO_2 in the depleted flue gas. These are essentially the same assumptions as those used for Method 4. Therefore, Method 3 and Method 4 calculations result in identical CO_2 capture rates. The CO_2 recovery was then estimated using the calculated flow of depleted flue gas. The calculated CO_2 capture efficiency and recovery are presented in Table 3. For all test periods, the calculated CO_2 capture was quite steady and the CO_2 recovery was about 98–99%.

Table 3. CO_2 capture results.

S= Flue gas supply *D*= Depleted flue gas *P*= Product CO_2	Method 1	Method 2	Method 3	Method 4	CO_2 Recovery
Test Period	$=\frac{P}{S}$	$=\frac{P}{P+D}$	$=\frac{S-D}{S}$	$=1-\frac{O_{CO_2}}{(1-O_{CO_2})}\frac{(1-I_{CO_2})}{(I_{CO_2})}$	$=\frac{D+P}{S}$
C3-1	83.3%	83.7%	83.8%	83.8%	99.4%
C3-2	83.1%	83.7%	83.8%	83.8%	99.2%
C3-3	83.6%	84.5%	84.7%	84.7%	98.7%
C3-4	83.4%	83.7%	83.7%	83.7%	99.6%
C3-5	84.0%	85.3%	85.5%	85.5%	98.3%
C3-6	84.7%	86.0%	86.3%	86.3%	98.2%
C3-7	82.7%	82.9%	83.0%	83.0%	99.7%
C3-8	85.0%	85.8%	85.9%	85.9%	99.0%

O_{CO2}=Depleted flue gas CO_2 content, dry basis and I_{CO2}=Flue gas supply CO_2 content, dry basis

The uncertainty calculations and results from each calculation method are shown in Table 4. The following assumptions were used:

- Flow metering uncertainties were calculated by TCM DA for the indicated flow meters based on the specification of the instrument.
- Concentration uncertainties for the flue gas flows are those described in Section 5.2.
- Concentration uncertainty for the product CO_2 is assumed to be 1% to allow for actual CO_2 content as low as 99%.
- CO_2 capture of 85% is representative of that measured during all test periods.
- The uncertainty in CO_2 capture is almost entirely due to uncertainty in CO_2 content of the CHP flue gas supply for the assigned total (low) flow uncertainties. The CO_2 capture uncertainty is relatively insensitive to uncertainties both in the CO_2 contents of both the product CO_2 and the depleted flue gas.

Table 4. Uncertainty in CO_2 capture calculations (nominal CO_2 capture efficiency shown as ECO_2 =85%).

CO_2 capture calculation method	Stream*	Uncertainty in: Total flow	CO_2 content	CO_2 flow	CO_2 capture	CO_2 capture uncertainty Equation
1	*P*	1.1%	1%	U_{CO2P}=1.5%	5.4%	$\sqrt{(U_{CO2S})^2+(U_{CO2P})^2}$
	S	1.3%	5%	U_{CO2S}=5.1%		
2	*P*	1.1%	1%	U_{CO2P}=1.5%	0.8%	$(1-E_{CO2})\sqrt{(U_{CO2D})^2+(U_{CO2P})^2}$
	D	1.3%	5%	U_{CO2D}=5.2%		
3	*S*	1.3%	5%	U_{CO2S}=5.2%	1.3%	$\frac{(1-E_{CO2})}{E_{CO2}}\sqrt{(U_{CO2S})^2+(U_{CO2D})^2}$
	D	1.3%	5%	U_{CO2D}=5.2%		

* *P= Product CO_2, S= Supply flue gas, D= Depleted flue gas*

6.2. Thermal energy consumption

The reboiler thermal duty was calculated as the difference between steam enthalpy at the reboiler inlet temperature and pressure and the saturation enthalpy of water at the reboiler condensate temperature. The specific thermal duty (SRD) was obtained by dividing the reboiler duty by the product CO_2 flow. The CO_2 product flow was either based on the measured CO_2 product flow (P) or on the difference between the NDIR-measured CO_2 supply flow and the estimated CO_2 depleted flow (S-D). The two corresponding values for SRD are shown in Table 5. The results for SRD were very consistent during all test periods.

Table 5. Stripper reboiler thermal energy consumption.

Test period	Reboiler steam flow rate kg/hr	Reboiler duty MJ/hr	Using the measured product CO_2 flow (P)*		Using CO_2 removed from the flue gas (S – D)	
			Product CO_2 Flow kg/hr	Specific thermal use GJ/t CO_2	Product CO_2 Flow kg/hr	Specific thermal use GJ/t CO_2
C3-1	5397	11,963	3307	3.62	3326	3.60
C3-2	5421	11,978	3308	3.62	3336	3.59
C3-3	5508	12,185	3332	3.66	3376	3.61
C3-4	5395	11,963	3305	3.62	3318	3.60
C3-5	5417	12,149	3340	3.64	3398	3.58
C3-6	5446	12,204	3339	3.65	3400	3.59
C3-7	5414	12,050	3342	3.61	3351	3.60
C3-8	5525	12,205	3353	3.64	3386	3.60

**The wet CO_2 flow, which is obtained by using the FTIR measured moisture content of the product CO_2.*

6.3. Gas phase contaminants

FORCE Technology measured the gas phase concentration of the compounds listed below in the three gas streams. The data are shown in Table 9-11 in Appendix B.

- SO_2 was simultaneously measured in the three gas streams during test period C3-1. A modest amount of SO_2 was present in the flue gas supply. No SO_2 entering the absorber in the flue gas supplied left the plant in either the depleted flue gas or product CO_2 streams.
- NO_x concentrations and mass flows were measured in the three gas streams during test period C3-1. NO_x concentrations were below the detectable limit during all test periods.
- Acetone, formaldehyde, and acetaldehyde concentrations and mass flow rates were measured during test period C3-2. The aldehydes in the depleted flue gas and product CO_2 do did exist in the supplied flue gas and were, presumably, produced in the absorption process. Acetone was not detected in any gas stream. FORCE Technology‘s measurements for the acetaldehyde concentrations were not successful and therefore the values measured by TCM DA is shown in Table 10 in Appendix B.
- Amines/Amides concentrations and mass rates were measured during test period C3-2. None of the compounds were detected in the CHP flue gas supply. The only compounds detected in the depleted flue gas and product CO_2 were MEA and methylamine. Traces of ethylamine, dimethylamine, and diethylamine were detected in the depleted flue gas only. Amides were below the detection limits.
- H_2SO_4 concentration was measured in the three gas streams as aggregate sulfate (reported as H_2SO_4 equivalent) during test period C3-1. The concentration of H_2SO_4 was below the respective detection limits.
- Particulates were measured during test period C3-1. The total amount of particulates in the CHP flue gas supply is very low. The amount of particulates in the three gas streams was below the detection limit.
- Ammonia was simultaneously measured in the three gas streams during test period C3-3. Measurable amounts of ammonia were found in the depleted flue gas and in the product CO_2. Ammonia was not detected in the CHP flue gas supply suggesting it resulted from MEA degradation during the process.
- TVOC was measured during test period C3-3. Measurable amounts of TVOC were detected in the product CO_2. The CHP flue gas supply does not contain any TVOC and presumably, it resulted from MEA degradation during the CO_2 capture process.

6.4. Laborelec particle measurements

Laborelec carried out particle size testing using an Electrical Low Pressure Impactor (ELPI+). Four locations of the absorber tower were monitored to investigate the potential formation of particles as the depleted flue gas passes through the washing stages and demisters. The results shown in Table 6 have measurements that were near to the detection limit of the ELPI+ when inserted in the process. The ambient air measurements undertaken during these tests were higher than the process measurements by almost one order of magnitude. The measurements were three to four orders of magnitude lower than similar measurements taken on flue gas from a coal thermal plant, proving the scarcity of particles in the CHP flue gases. The small amount of particles and their small sizes remain largely unchanged as they pass through the absorber.

Table 6. Particle counts and size distribution through absorber sections

Test period	Parameter	Units	Total	50% oversize (μm)	90% oversize (μm)
C3-5	Leaving capture section	count/cm^3	6608	0.040	0.023
C3-6	Leaving lower water wash	count/cm^3	7937	0.025	0.021
C3-7	Leaving upper water wash	count/cm^3	3193	0.015	0.010
C3-8	Absorber stack	count/cm^3	9767	0.020	0.012

6.5. New baseline for solvent performance testing

Table 7 presents a portion of the MEA test data obtained at the TCM DA amine plant. Based on these data which were obtained at about test period C3-4 when flow rates were measured, a new baseline is established. As the instrumentation of the amine plant and therefore the measurements are significantly improved since the previous MEA baseline in 2014 [4], the 2015 MEA results will set the baseline for performance benchmarking of other amines at TCM DA. The 2014 baseline is therefore considered obsolete.

Table 7. Results of baseline testing in 2015

Baseline year	2015
Packing height (m)	24
Flue gas flow (Sm^3/h)	59 000
Flue gas supply temperature (°C)	30.0
Flue gas supply pressure (bar)	0.01
Lean amine flow (kg/h)	57 000
Lean loading	0.20
Rich loading	0.48
Stripper bottom temperature (°C)	121.0
CO_2 capture (%)	83.4
SRD (MJ/kg CO_2)	3.62

Comprehensive process data for the TCM DA baseline testing in 2015 are given in Table 12, Appendix C.

7. Conclusions

The quality of the gas phase measurements at the TCM DA amine plant is significantly improved by installing new online instruments. Using the upgraded instrumentations, a new baseline for the TCM DA amine plant is established which has replaced the 2014 baseline. The new baseline is set up close to the plant nominal capacity and will serve as the performance benchmark for other amines tested at the TCM DA amine plant.

Acknowledgements

The authors gratefully acknowledge the staff of TCM DA, Gassnova, Statoil, Shell and Sasol for their contribution and work at the TCM DA facility. The authors also gratefully acknowledge Gassnova, Statoil, Shell, and Sasol as the owners of TCM DA for their financial support and contributions.

Appendix A.

Table 8. Calculation methods for CO_2 capture efficiency and recovery

CO_2 capture efficiency	Description	Formula
Method 1	CO_2 product flow as a ratio to the CO_2 flow in the flue gas supply	$= \frac{CO_2(\text{product})}{CO_2(\text{supply})}$
Method 2	CO_2 product flow as a ratio to the sum of the CO_2 product flow and the CO_2 flow in the depleted flue gas	$= \frac{CO_2(\text{product})}{CO_2(\text{product}) + CO_2(\text{depleted})}$
Method 3	Ratio of the difference between the CO_2 flow in the flue gas supply and the CO_2 in the depleted flue gas to the CO_2 flow in the flue gas supply	$= \frac{CO_2(\text{supply}) - CO_2(\text{depleted})}{CO_2(\text{supply})}$
Method 4	100% less the ratio of the depleted flue gas CO_2 per unit O_2+N_2 to the flue gas supply CO_2 per unit O_2+N_2	$= 1 - \frac{O_{CO_c}}{(1 - O_{CO_2})} \frac{(1 - I_{CO_2})}{I_{CO_2}}$ O_{CO2} = Depleted flue gas CO_2 content, dry I_{CO2} = Flue gas supply CO_2 content, dry
CO_2 recovery	Ratio of the sum of the CO_2 flow in depleted flue gas and the product CO_2 flow divided by the CO_2 flow in the flue gas supply	$= \frac{CO_2(\text{depleted}) + CO_2(\text{product})}{CO_2(\text{supply})}$

Appendix B. Gas phase contaminants measured by FORCE Technology during the 2015 baseline testing

Table 9. Concentration of the contaminants in the gas streams: Test period C3-1.

		Test period C3-1		
Component	Units	Flue gas supply	Depleted flue gas	Product CO$_2$
NO$_X$	mg/Sm^3 (dry)	< 10	< 10	< 10
	kg/hr	< 0.6	< 0.5	< 0.02
SO$_2$	mg/Sm^3 (dry)	0.29	< 0.20	< 0.20
	g/hr	16.6	< 11.1	< 0.4
H$_2$SO$_4$	mg/Sm^3 (dry)	0.014	< 0.01	-
	g/hr	0.80	< 0.5	-
Filterable Particulate	mg/Sm^3 (dry)	< 0.08	< 0.08	-
	g/hr	< 5	< 5	-

Table 10. Concentration of the contaminants in the gas streams: Test period C3-2.

		Test period C3-2		
Component	Units	Flue gas supply	Depleted flue gas	Product CO$_2$
Formaldehyde	mg/Sm^3 (dry)	< 0.4	0.72	0.14
	g/hr	< 23	40	0.25
Acetaldehyde	mg/Sm^3 (dry)	< 0.8	0.43*	15.33*
	g/hr	< 40	-	-
Acetone	mg/Sm^3 (dry)	< 3	< 1	< 0.9
	g/hr	< 172	< 55	< 2
Formamide	mg/Sm^3 (dry)	< 0.04	< 0.04	< 0.03
Acetamide	mg/Sm^3 (dry)	< 0.04	< 0.04	< 0.03
MEA	mg/Sm^3 (dry)	< 0.003	0.0059	0.076
DEA	mg/Sm^3 (dry)	< 0.0004	< 0.0004	< 0.0003
TEA	mg/Sm^3 (dry)	< 0.0004	< 0.0004	< 0.0003
NDELA	mg/Sm^3 (dry)	< 0.0002	< 0.0002	< 0.0001
NDMA	mg/Sm^3 (dry)	< 0.0004	< 0.0004	< 0.0003
NMOR, NMEA, NPYR, NDEA, NPIP, NDPA, NDBA	mg/Sm^3 (dry)	< 0.0002	< 0.0002	< 0.0001
Methylamine	mg/Sm^3 (dry)	< 0.0008	0.030	<0.0006
Ethylamine	mg/Sm^3 (dry)	< 0.0008	0.0012	< 0.0006
Propylamine	mg/Sm^3 (dry)	< 0.0008	< 0.0008	< 0.0006
Dimethylamine	mg/Sm^3 (dry)	< 0.0008	0.029	< 0.00065
Ethylmethylamine	mg/Sm^3 (dry)	< 0.0008	< 0.0008	< 0.0006
Diethylamine	mg/Sm^3 (dry)	< 0.002	0.0097	0.0029
Dipropylamine	mg/Sm^3 (dry)	< 0.002	< 0.002	< 0.001
TONO	mg/Sm^3 (dry)	< 0.002	< 0.002	< 0.001
Sum, all amines	mg/Sm^3 (dry)	< 0.04	0.076	0.079
	g/hr	< 0.1	4.1	0.14
Sum, all amides	mg/Sm^3 (dry)	< 0.08	< 0.08	< 0.06
	g/hr	< 2	< 2	< 0.05
Total N (excluding NH$_3$, NO$_3^-$) test period C3-3	mg/Sm^3 (dry)	-	3.6	2.6
	g/hr	-	190	4.7

* FORCE Technology measurements for the acetaldehyde concentration in both depleted flue gas and product CO$_2$ were not successful. The values given in Table 5 for acetaldehyde were measured by the TCM DA online FTIR analysers.

Table 11 Concentration of the contaminants in the gas streams: Test period C3-3.

		Test period C3-3		
Components	Units	Flue gas supply	Depleted flue gas	Product CO_2
NH_3	mg/Sm^3 (dry)	< 0.30	13	14
	g/hr	< 20	720	24.9
TVOC	mg/Sm^3 (dry)	< 0.50	< 0.50	6
	g/hr	< 30	< 30	10.7

Appendix C. Amine plant 2015 baseline testing results

Table 12 presents the process data for the TCM amine plant averaged for the period C3-4 of baseline testing in 2015 (when flow rates were measured). During that period the plant was running at nearly stable conditions and the process parameters fluctuations were insignificant.

Table 12. Averaged process data for the test period C3-4 of baseline testing in September 2015.

Operating capacity	%	100
CHP flue gas supply rate	Sm^3/h	59 430
CHP flue gas supply temperature	°C	29.8
CHP flue gas supply pressure	barg	0.01
CHP flue gas supply CO_2 concentration (dry)	vol%	3.7
CHP flue gas supply O_2 concentration (wet)	vol%	14.6
CHP flue gas supply water content	vol%	3.7
Depleted flue gas temperature	°C	30.4
Lean MEA concentration (CO_2 free)	wt%	31
Lean MEA concentration (incl CO_2)	wt%	30
Lean CO_2 loading	mol CO_2/mol MEA	0.20
Lean amine supply flow rate	kg/h	57 434
Lean amine supply temperature	°C	37.0
Lean amine density	kg/m^3	1 073
Rich solution return temperature	°C	33.2
Temperature above upper absorber packing	°C	39.7
Wash water 1 (lower) supply flow rate	kg/h	55 005
Wash water 1 inlet temperature	°C	30.4
Wash water 1 withdrawal temperature	°C	44.9
Temperature above Wash Water 1	°C	38.0
Wash water 2 (upper) supply flow rate	kg/h	54 997
Wash water 2 inlet temperature	°C	30.4
Wash water 2 withdrawal temperature	°C	37.3
Temperature above Wash Water 2	°C	30.4

Rich CO_2 loading	mol CO_2/mol MEA	0.48
Rich solution supply flow rate	kg/h	60 775
Rich solution supply temperature	°C	110.7
Lean solution return temperature	°C	121.3
Rich amine density	kg/m^3	1 125
Reboiler steam flow rate	kg/h	5 398
Reboiler steam temperature	°C	156
Reboiler steam pressure	barg	2.04
Reboiler condensate temperature	°C	132.8
Reboiler condensate pressure	barg	1.96
Stripper overhead pressure	barg	0.91
Stripper overhead temperature	°C	96.1
Stripper overhead reflux flow rate	kg/h	1 227
Stripper overhead reflux temperature	°C	17.64
Stripper sump temperature	°C	121.0
Reboiler solution temperature	°C	125.1
Lean vapour compressor system	-	off
Product CO_2 flow rate	kg/h	3 325
Product CO_2 discharge temperature	°C	17.9
Product CO_2 discharge pressure	barg	0.017
Product CO_2 water content	vol%	1.3
Active absorber packing height	m	24
Temperature, upper absorber packing – 6	°C	47.4
Temperature, upper absorber packing – 5	°C	51.7
Temperature, upper absorber packing – 4	°C	51.6
Temperature, upper absorber packing – 3	°C	50.5
Temperature, upper absorber packing – 2	°C	49.9
Temperature, upper absorber packing – 1	°C	48.9
Temperature, middle absorber packing – 6	°C	47.2
Temperature, middle absorber packing – 5	°C	46.0
Temperature, middle absorber packing – 4	°C	44.4
Temperature, middle absorber packing – 3	°C	43.1
Temperature, middle absorber packing – 2	°C	42.2
Temperature, middle absorber packing – 1	°C	40.9
Temperature, lower absorber packing – 12	°C	40.6
Temperature, lower absorber packing – 11	°C	41.6
Temperature, lower absorber packing – 10	°C	37.4
Temperature, lower absorber packing – 9	°C	37.1

Temperature, lower absorber packing – 8	°C	35.9
Temperature, lower absorber packing – 7	°C	34.3
Temperature, lower absorber packing – 6	°C	34.1
Temperature, lower absorber packing – 5	°C	33.8
Temperature, lower absorber packing – 4	°C	32.9
Temperature, lower absorber packing – 3	°C	33.2
Temperature, lower absorber packing – 2	°C	32.5
Temperature, lower absorber packing – 1	°C	32.4
Stripping section packing height	m	8
Temperature, stripper packing – 7	°C	102.7
Temperature, stripper packing – 6	°C	103.1
Temperature, stripper packing – 5	°C	104.5
Temperature, stripper packing – 4	°C	107.7
Temperature, stripper packing – 3	°C	112.1
Temperature, stripper packing – 2	°C	114.7
Temperature, stripper packing – 1	°C	119.4

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Results from MEA testing at the CO_2 Technology Centre Mongstad. Part I: Post-Combustion CO_2 capture testing methodology

(2014)

Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 63 (2014) 5938 – 5958

Energy Procedia

GHGT-12

Results from MEA testing at the CO_2 Technology Centre Mongstad. Part I: Post-Combustion CO_2 capture testing methodology

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Abstract

This paper lays out a generic CO_2 capture testing methodology that has been applied at multiple sites providing details on the procedure, its key performance indices and their associated specifications, as well as the required pre-test work. Specific application of the methodology for the CO_2 Technology Centre Mongstad site, a CO_2 capture testing facility located in Norway that performed CO_2 capture tests using MEA, is shown as an illustrative example.

Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords: CO_2 capture; EPRI; MEA; Post-combustion capture; CO_2 Technology Centre Mongstad; TCM DA

1. Introduction

At the beginning of the 21st century, increasing political and technological focus is being given to minimizing carbon dioxide (CO_2) emissions to the atmosphere. As the combustion of fossil fuels at large industrial facilities is a significant source of CO_2 entering the atmosphere, reducing CO_2 emissions from existing and new fossil-fired plants

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Peer-review under responsibility of the Organizing Committee of GHGT-12
doi:10.1016/j.egypro.2014.11.630

will be critical. A principal method proposed for accomplishing this reduction is to capture the CO_2 produced by separating it from the flue gas into a relatively pure stream and then injecting the purified CO_2 into acceptable underground geological reservoirs for long-term storage.

Currently the only CO_2 capture technologies sufficiently mature to apply at full scale are temperature swing absorption (TSA) processes that remove the relatively dilute CO_2 from flue gas (common in processes that use air for combustion and produce significant nitrogen that dilutes the flue gas) by chemical absorption into an alkaline solvent at low temperature. The solvent is then heated to release the CO_2 in a relatively pure stream for subsequent geological storage. Aqueous amine solutions at high concentration are leading near-term solvent candidates.

The use of amines to remove CO_2 from various industrial and fuel gas streams is a relatively mature technology. There is less experience using amines to remove CO_2 from flue gases, which contain significant levels of oxygen. In addition, the full-scale application of amine post-combustion capture (PCC) processes for removing CO_2 from flue gas would be conducted at a scale approximately an order of magnitude larger than industrial amine-based TSA processes currently deployed.

Supply of the utilities required by a TSA process (thermal, electrical, and cooling) will have a significant impact on the operations of the host plant producing the flue gas being treated. Perhaps the greatest focus of PCC development is identifying processes that minimize the use of these utilities, particularly the thermal utility.

The Electric Power Research Institute (EPRI) has developed a generic independent verification protocol (IVP) to assess the performance of amine-based TSA processes. This IVP has already been tailored to and applied during EPRI-led CO_2 capture testing at the following facilities:

- **AEP's Mountaineer Plant –** 20-MWe demonstration of Alstom's chilled ammonia process during 2011–2012
- **Alabama Power's Plant Barry –** 500 tonnes/day demonstration of MHI's KM-CDR advanced amine process; testing began in 2012 and is still ongoing
- **EDF's Le Havre –** 2.0-MWe demonstration of Alstom/Dow's Advanced Amine Process (AAP) during 2014
- **We Energies' Pleasant Prairie Power Plant –** 1.7-MWe demonstration of Alstom's chilled ammonia process during 2008.

CO_2 Technology Centre Mongstad (TCM DA) has installed pilot-scale amine-based TSA process equipment next to the Statoil refinery in Mongstad, Norway. The purpose of this facility is to allow vendors of suitable amine formulations and other PCC processes to test their process and collect performance data to support full-scale design and anticipate the associated performance and costs.

This work is part of a continuous effort of gaining better understanding of the performance potential of the non-proprietary aqueous MEA solvent system, conducted by TCM DA and its affiliates and owners, in order to test, verify, and demonstrate CO_2 capture technologies [1, 2, 3]. As part of an overall program of CO_2 capture testing, EPRI worked with TCM DA, which operates the TCM DA facility and led the testing effort, and Aker Solutions to customize the IVP for TCM DA. Details on that customization are provided within this paper.

2. Independent verification protocol purpose and scope

2.1. Amine process description

Flue gas can be supplied to the TCM DA PCC amine plant from either the on-site natural gas-fired combined heat and power (CHP) plant or from the Statoil refinery residue fluid catalytic cracker (RFCC). As the testing work that this report discusses pertains to using the CHP flue gas, details on the RFCC will not be provided here. In the CHP plant, the natural gas is combusted in a gas turbine and the flue gas content and characteristics are similar to those of a combined cycle gas turbine (CCGT) power plant.

The flow schematic for the TCM DA pilot plant when treating CHP flue gas is shown in Fig. 1 and a photo of the amine plant is shown in Fig. 2.

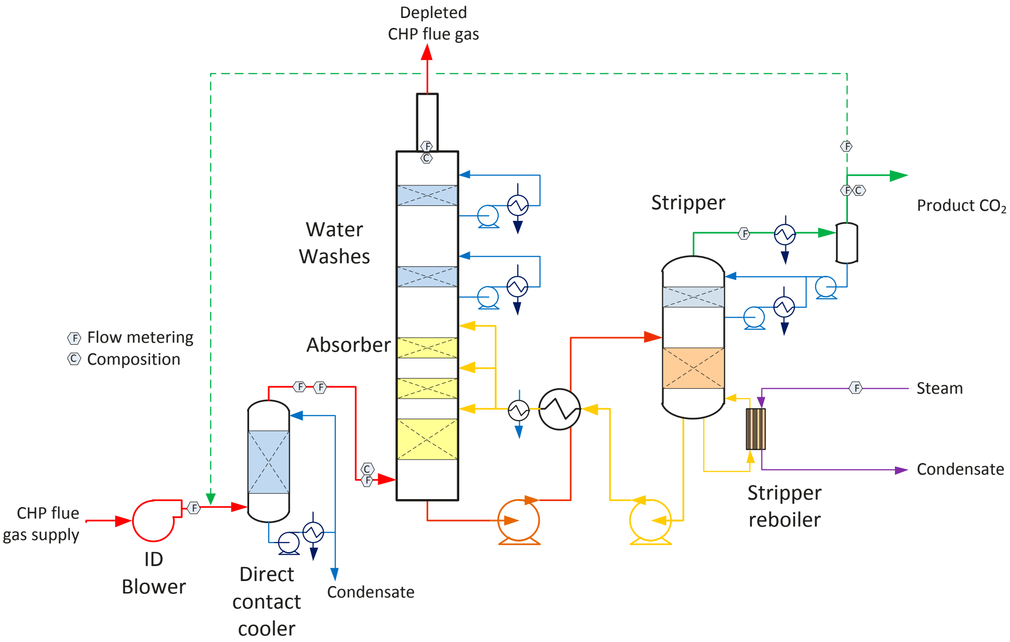


Fig. 1. Simplified flow schematic for TCM DA CO_2 capture of CHP flue gas

Fig. 2. TCM DA amine plant. The direct-contact cooler is situated to the right, the concrete absorber tower in the middle, the two stripper columns to the left, and the lean vapour compressor system to the far left.

The nominal characteristics of flue gas from the CHP source both before and after the direct-contact cooler (DCC) are shown in Table 1. The CHP flue gas is typical of high excess air combustion turbine exhaust.

Table 1. Nominal characteristics of CHP flue gas supplied to TCM DA CO_2 capture plant

		Flue gas before DCC	Flue gas after DCC	
Temperature	°C		20–50	
Flow rate	Sm^3/hr		0–60.000	
$N_2 + Ar$	mol%, dry		81-83	
O_2	mol%, dry		14–15	
CO_2	mol%, dry		3.5–4	
H_2O			saturated	
SO_2	ppmv, dry	not detected		
SO_3	ppmv, dry	not detected		
NO_X	ppmv, dry	< 5		
CO	ppmv, dry	unknown		
NH_3	ppmv, dry	< 5		@ 15% O_2
Particulates	mg/Nm^3	unknown		Nm^3 at 101.3 kPa and 0°C

The raw flue gas may be cooled by direct contact with wash water. By these means, plant operators have the capability of controlling the temperature of the flue gas (saturated with water) delivered to the absorber.

The saturated flue gas rises in the rectangular cross-section absorber tower and comes into contact with falling lean solution in one of up to three beds of structured packing. The flue gas, depleted in CO_2, then passes through up to 2 recirculating water wash stages to remove solvent vapors before being emitted to the atmosphere in a 1-meter diameter duct. The solution flow through the absorber tower is “once-through”; there is no recirculation of rich solution from the tower sump back to the top of the absorber section.

The solution rich in CO_2 is pumped to the top of a stripper tower. Rich solution entering the stripper is pre-heated by exchange with hot lean solution being returned to the absorber. The falling rich solution comes into contact with rising steam/CO_2. The lean solution at the bottom of the stripper is circulated through a steam-heated reboiler to provide the heat necessary to drive the endothermic CO_2-releasing reactions.

The raw product CO_2 leaving the stripper is cooled with recovery of condensate that is returned to the stripper as a reflux. The cooled product CO_2 is vented. During CHP flue gas operations, a portion of the product CO_2 can be recycled to the CHP flue gas upstream of the DCC to increase the CO_2 content of the CHP flue gas for test purposes.

The process is operated to be water neutral. The recirculating water washes at the top of the absorber are used to control the depleted flue gas temperature/water vapor content. If water accumulates in the absorber-stripper loop, the flue gas temperature leaving the absorber is allowed to increase, increasing the water vapor content of the depleted flue gas, and vice versa.

2.2. Testing to support process characterization

The key performance indices are those features of the PCC process that are of interest when designing and planning for a full-scale implementation of the technology. Some of these indices can be modeled using chemical/thermodynamic/physical design data. A primary function of pilot-plant operations is to provide measured data such that uncertainties in the model can be reduced by comparison of model results with measured results.

The key performance indices are dependent parameters that can be expected to vary with changes in the process independent parameters. Performance data collected when changing the independent parameters during pilot-plant operations can be used to calibrate the process model, which can then be used to identify a set of independent parameters that “optimize” the key performance indices.

Pilot-plant operations can also be used to quantify those key performance indices that are not readily amenable to modeling including the effects of trace constituents of the flue gas supply. There are also intermittent and long-term performance indices that cannot be effectively modeled and must be assessed from many hours of pilot-plant operations (typically 1000s of hours) including: heat exchanger fouling, mass transfer packing fouling, foaming, material corrosion, solvent quality control measures, solvent loss/replacement, etc.

2.3. Pertinent independent parameters

The independent parameters are those temperatures, pressures, flows, compositions, and physical design parameters readily subject to control by the plant operators. Changing these parameters can be expected to affect the key performance indices (dependent parameters). The most important independent parameters for the purposes of modeling the process installed at TCM DA are listed below.

- Inlet flue gas characteristics
    - CO_2 content
    - Flow rate
    - Temperature
    - With/without flue gas pre-treatment for SO_X and particulates (future).
- Solution characteristics
    - Amine concentration
    - Circulation rate
    - Lean solution CO_2 loading.
- Equipment design characteristics
    - Absorber height
    - Lean solution flash/compression use
    - Number of water washes
    - Rich/lean heat exchanger effectiveness.
- Operating options
    - Stripper pressure.

2.4. Modeled key performance indices (dependent parameters)

The set of key performance indices that can be modeled and quantified by pilot-plant operations at TCM DA are listed below.

- CO_2 capture performance
    - % CO_2 captured / produced / emitted.
- Utility use
    - Cooling duty
    - Electrical power
    - Steam thermal.
- Depleted flue gas amine/degradation product content.

2.5. Key performance indices not modeled (dependent parameters)

While it is fairly straightforward to model the heat and mass transfer associated with the PCC process, there are key performance indices that are less straightforward to model. It is more expedient to quantify these indices, which are listed below, by measurements during pilot-plant operations.

- Depleted flue gas trace constituents
    - Mercury and air toxics

  - Particulates
  - SO_2–SO_3–NO_X
  - Total hydrocarbons (HC) – Amine/degradation products not modeled.
- Product CO_2 trace constituents
  - O_2
  - SO_2–SO_3–NO_X
  - Total HC–Amine/degradation products not modeled.
- Continuous waste streams
  - DCC blowdown.

2.6. Long-term process/plant monitoring

There are also key performance indices that can only be assessed over many hours of operation. These include chronic effects as well as intermittent operations as shown below.

- Material uses
  - Amine make-up
  - Water make-up/blowdown.
- Intermittent waste streams
  - Amine reclaim waste
  - Lean-solution filter cake
  - Spent activated carbon.
- Heat exchanger fouling/corrosion
- Gas-liquid contactor fouling/corrosion/foaming
- Accumulation/emission of degradation/corrosion products.

2.7. Key outcomes

Key outcomes of pilot-plant operations are:

1. A stand-alone model that predicts key performance indices within the uncertainty in actual measurements made during pilot-plant operations (or other clearly stated uncertainty) when only the independent parameters listed above are the variable inputs to the model
2. One or more sets of formal performance test results collected during “base-case” operations that include, in addition to the modeled key performance indices, empirical measurement of the key performance indices not modeled. These “base-case” operations can be expected to be conducted under a set of independent parameters that have been determined to “optimize” the key pre-defined performance indices.

3. Performance testing principles

3.1. General performance testing guidelines

There is no accepted procedure for assessing PCC plant performance. There are, however, reference-testing procedures that are similar in scope and provide guidance for specifying the protocols under which the performance of PCC plants can be verified. These include:

- **Overall power plant performance –** Steam-boiler operations are comparable in complexity to PCC plant operations. Flow, temperature, and pressure, and composition data must be collected over the test period and are used to calculate a number of key performance indices such as steam temperature, pressure, and flow, fuel quality, flue gas flow rate and composition, sensible and latent heat losses in the flue gas, auxiliary power use, gross generation, net generation, etc. The overall power plant performance test code will also make extensive reference to companion test codes for measuring temperature, pressure, flow, gas composition, electrical and other power flows, and sub-component performance (boilers, air heaters, turbines, etc.). The American Society of Mechanical Engineers (ASME) publishes and maintains performance test codes for a wide range of equipment that have a long history of successful use [4].

- **Quantifying flue gas emissions –** The U.S. Environmental Protection Agency (EPA) has published reference methods for quantifying emissions from stacks for the purpose of demonstration conformance with the site air emission permit. These reference methods have a long history of use in the U.S. and have achieved wide acceptance. Appendix A lists the pertinent U.S. EPA reference methods. The European Commission has published similar reference methods.

The performance testing protocols presented here draw heavily on these two sources.

3.2. Base-case performance testing/process verification

Results from the base-case testing will be used to assess the steady-state performance of the process for the purposes of designing the full-scale plant and estimating capital and operating costs. For this reason, base-case performance testing should be conducted with measurement uncertainty as low as can be reasonably achieved. Therefore, test protocols consistent with well-developed reference methods should be incorporated as much as possible.

3.3. Parametric performance testing

The primary objective of parametric performance testing is to observe the effects on the key performance indices of incremental changes in the various independent variables. While accuracy in measurement is always desired, some bias error in measurements can be tolerated in parametric testing as long as the measurements achieve adequate precision; i.e., the measurement instruments give repeatable values. This condition can usually be met without strict adherence to reference methods that can be very costly to use as frequently as is required for a parametric performance testing program.

4. Test conduct and data collection procedures

4.1. Instruments and methods of measurement

4.1.1. Temperature

Process temperatures are generally not key performance parameters for a PCC plant. Nonetheless, temperature measurements are process condition indicators and care should be taken in their measurement.

No review of process temperature instrumentation was conducted in support of this study. In general, thermocouple or resistance temperature detectors are commonly deployed for process monitoring. These are usually precise enough to give acceptable repeatability without re-calibration. However, care should be exercised in ensuring that electrical temperature measurement signals are correctly wired, correct calibration algorithms are employed, and the resulting temperature is correctly logged and displayed to the operators.

4.1.2. Pressure

Process pressures are generally not key performance parameters for a PCC plant without a pipeline gas compressor. (Pipeline compressor discharge pressure would be a key performance parameter.) Nonetheless, several pressure measurements are process condition indicators and care should be made in their measurement. These include absolute and differential pressures at flow metering installations, absorber flue gas pressure drop, liquid distribution spray pressures, and stripper operating pressure.

No review of process pressure instrumentation was conducted in support of this study. In general pressure transmitters are commonly deployed for process monitoring. The key pressure transmitters, at a minimum, should be recalibrated according to manufacturer's specifications prior to the onset of parametric testing. Pressure transmitters supporting primary flow measurement calculations should be recalibrated during base-case testing.

4.1.3. Flow

The standard used for flow metering is ASME PTC 19.5 Flow Measurement. Note that high accuracy may not be required for parametric testing where the incremental effect on key performance indices with incremental changes in process conditions is measured. In this case high precision (repeatability) may be an adequate substitute for high accuracy.

The flow meters installed in the PCC plant at TCM DA supporting CHP flue gas are listed in Table 2, respectively. The flow metering locations were indicated in Fig. 1. TORBAR pitot tube-style flue gas flow meters are the predominant choice implemented with single installation of an ultrasonic flow meter (after the DCC). Vortex flow meters are used to measure steam flows to the reboiler. A vortex flow meter is used to meter final CO_2 product flow, which is redundant to the TORBAR flow meter.

The flow metering installations have been internally analyzed in detail at TCM DA, identifying the sources of uncertainty in each flow metering location.

Table 2. Gas and steam flow metering for CHP flue gas applications at TCM DA

Stream	Flow meter tag	Flow meter type	Duct dimension
Flue gas supply			
Raw CHP after blower	8610-FT-0104	TORBAR pitot tube	991 mm
CHP after DCC	8610-FT-0150	Ultrasonic	991 mm
CHP after DCC	8610-FT-0124	TORBAR pitot tube	991 mm
Absorber flue gas flows			
Inlet	8610-FT-2039	TORBAR pitot tube	991 mm
Outlet	8610-FT-2431	TORBAR pitot tube	991 mm
Product CO_2 flows			
Cooled product CO_2	8610-FT-2203	TORBAR pitot tube	311 mm
Cooled product CO_2	8615-FT-0010	Vortex	254.5 mm
CO_2 recycled to CHP	8615-FT-2206	TORBAR pitot tube	
Stripper reboiler steam flow			
Reboiler	8655-FT-2386	Vortex	

4.1.3.1. TORBAR pitot tube flow meters

The uncertainty in the flow measurements using the TORBAR flow meters was estimated to be slightly greater than 2.5%. Of this, 2% was associated with installation of the TORBAR flow meters, by far the largest uncertainty component. This uncertainty component is a measure of the sensitivity of bias error introduced into the differential pressure indication by misalignment of the flow element in radial dimension and rotational orientation to the flow. The uncertainty associated with installation cannot be effectively estimated short of performing an in-situ flow calibration against a primary standard, and the assignment of 2% uncertainty to this component is somewhat arbitrary; misalignment could result in higher bias errors. Thus, while the flow reading calculated from the TORBAR measured pressure differential, absolute pressure, and temperature may have a precision of approximately 1.8% (precision excludes installation uncertainty), the uncertainty in accuracy may be significantly more than the estimate. The uncertainty associated with installing this class of flow meters generally disqualifies them for use in applications requiring predictable accuracy unless a relative accuracy test audit (RATA) has been performed for the field installation.

4.1.3.2. Vortex flow meter

A vortex meter is installed to meter product CO_2. The vortex meter is redundant to a TORBAR meter located nearby. Vortex flow meters are shipped with a flow factor which, when multiplied by the vortex shedding frequency (an internal meter measurement) and fluid density, gives mass flow. The density must be derived from temperature, pressure, and composition measurements. These meters cannot be recalibrated short of performing an in-situ flow calibration against a primary standard.

A vortex flow meter is also used to meter steam flow to the reboiler. It is a linear device that indicates mass flow; thus the calibration range is based on mass flow. This meter is suitable for high accuracy mass flow measurements if it is calibrated under the following conditions:

- Steam flow over the full range expected during operations
- Calibration temperatures and pressures close to the operating temperature/pressure
- Calibration against standards traceable to the National Institute of Standards & Technology (NIST) or equivalent.

4.1.4. Composition

The standard recommended here for high-accuracy gas composition measurements is the use of reference standards commonly employed to monitor compliance with air emissions regulations. Where possible, the use of continuous emissions monitoring (CEM) methods is recommended.

It is recognized that the Fourier Transform Infrared (FTIR)-based systems installed at TCM DA will continue to be used. The relative locations for the sampling points are indicated in Fig. 1. The gas compositions reported by these instruments may be sufficiently accurate and precise to meet the requirements of the standards indicated, but this should be demonstrated against the instruments and procedures in the respective reference methods. The reference methods indicated below should be employed during all base-case testing unless there is clear evidence that the FTIR system gives results that duplicate the reference methods.

4.1.4.1. Flue gas supply and depleted flue gas

Table 3 lists the several flue gas components and the recommended reference methods for quantifying the components. CEMs are available for all non-condensable, non-soluble flue gas components. The condensable/soluble flue gas components and particulate matter require extractive sampling reference methods.

Table 3. Flue gas composition sampling and analysis reference methods

Component	Reference method	Notes
O_2	EPA method 3a	CEMs, dried sample from common sampling point
CO_2	EPA method 3a	
SO_2	EPA method 6c	
NO_X	EPA method 7e	
Total HC	EPA method 8a	CEMs, wet sample from common sampling point
Particulates	EPA method 5	Extractive traverse
Particulate metals	EPA methods 5 and 29	
SO_3	NCASI method 8a	
NH_3	EPA conditional test method 027	
Gaseous organics (amines and amine degradation products)	See Appendix B	See Appendix B
Aldehydes	SW846-0011: Sampling Method 8315: Analysis	This is essentially the same as that practiced by TCM DA at present

4.1.4.2. Product CO_2

Table 4 lists the several product CO_2 components and recommended reference methods for quantifying the components. CEMs are available for all components except NH_3.

Table 4. Product CO_2 composition sampling and analysis reference methods

Component	Reference method	Notes
O_2	EPA method 3A	Dried sample from common sampling point. Analyze with polarographic trace O_2 analyzer.
CO_2	EPA method 3A	CEMs, dried sample from common sampling point
SO_2	EPA method 6C	
NO_X	EPA method 7E	
Total HC	EPA method 8A	CEMs, wet sample from common sampling point
NH_3	EPA conditional test method 027	Extractive single point

The most critical parameters for delivery of the product CO_2 to receiving pipelines are likely to be O_2 content and moisture content. Measurement of trace O_2 in any gas stream is challenging. In-situ O_2 analyzers commonly used for measurement of flue-gas O_2 at levels, which are typically above a few % (vol), are not sufficiently sensitive to accurately quantify trace levels of O_2. Trace O_2 levels may be quantified by polarographic (fuel cell) analyzers. Paramagnetic analyzers or gas chromatography may also be used but these are likely to add complexity and/or expense without significantly increasing accuracy. All of these techniques require extraction of a gas sample to the analyzer. Care must be exercised to exclude sampling system and instrument air in-leaks and to completely purge the sampling system of air on start-up and after calibrations; even small residues of air (containing 210,000 ppmv O_2) will result in erroneously high analyses. Certified trace O_2 calibration gases are also required. Moisture control will be part of a pipeline compression package that is not a part of the pilot plant at TCM DA.

Note that CO_2 monitoring in the product CO_2 stream is for reference only. Instrument readings near 100% cannot be relied on for accuracy at the 99.99% (vol) readings expected. Nitrogen is a likely diluent that can only be quantified by gas chromatography. An N_2/O_2 ratio cannot be assumed in the product CO_2 equal to that in air. Dissolution of O_2 in the aqueous amine solution or transfer of flue gas micro-bubbles with release in the stripper cannot be ruled out.

4.2. Instrumentation recommendations

4.2.1. Temperature measurements

- No pre-test calibrations required
- Loop checks should be made on temperature instruments supporting flue gas flow meters and product CO_2 flow meters during parametric testing.

4.2.2. Pressure measurements

- Loop checks should be made on pressure instruments during parametric testing
- Pressure transmitters supporting flow meters and product CO_2 flow meters should be recalibrated prior to or during all base-case test campaigns.

4.2.3. Flow measurements

- A RATA (see Appendix C) should be conducted, calibrating the three (3) flow metering installations for the CHP flue gas flow between the DCC and the absorber during each base-case test campaign. During this test, data may also be collected at the absorber outlet to calibrate the TORBAR flow metering installation at this location.
- Reboiler steam condensate orifice flow elements should be used to quantify reboiler steam use
- One of the following should be accomplished during base-case testing:
  - A RATA (see Appendix C) to calibrate within 2% accuracy the TORBAR flow meter installed to meter the product CO_2 flow
  - A differential flow element consistent with ASME PTC 19.5 should be at an applicable location to achieve CO_2 flow measurement within 2% uncertainty.

4.2.4. Composition measurements

- The FTIR analyzer system should be calibrated against primary calibration standards weekly or on a frequency that results in instrument drift of no more than 2% on calibration gases
- Gas stream sampling and analysis consistent with reference methods indicated in Table 3 and Table 4 should be employed during all base-case test campaigns
- Flue gas sampling ports should be used to sample from the duct near the existing flue gas flow meters
- The depleted flue gas sample should be taken from a probe extending at least 50 cm in from the absorber wall.

5. Calculation and reporting of key performance indices

Performance data collected during operations at TCM DA pilot plant fall generally into two broad classes: 1) data collected during parametric testing to support process model development and identify optimal operating conditions, and, 2) base-case data collected during operation under optimized conditions to verify the performance of the process, modeled parameters, and those key performance indices that are not modeled.

A complete test results report includes:

- List of independent parameters; those parameters under the more or less direct control of the operators that describe the process conditions imposed for the test
- Several key performance indices; dependent parameters that are uniquely determined by the process design and the independent parameters established by the operators.

5.1. Independent parameters

Table 5 lists the measured independent parameters that are likely to influence the key performance indices and should be included as test conditions in any report of process performance.

Table 5. Measured independent parameters

Parameter	Instrument/Comment
A. Flue gas source and flow rate	• Calibrated meter flow, composition at the absorber inlet or recommended sample ports near flue gas flow meters
B. Flue gas supply bulk composition	• Wet-basis (flowing) composition to include CO_2, O_2, N_2/Ar by difference. Wet-basis water content saturated at the measured temperature.
C. Flue gas temperature inlet to the absorber	• Plant instrumentation
D. Amine composition or identification	• Vendor supplied
E. Lean-amine concentration	• Lab analyses
F. Lean-amine CO_2 loading	• Lab analysis
G. Lean-amine flow rate	• Plant instrumentation
H. Lean-amine temperature	• Plant instrumentation
I. Water-wash flow rate	• Plant instrumentation
J. Water-wash operation	• Number in service **Note**: Water-wash temperature is a dependent variable that maintains the water balance in the lean/rich solution loop.
K. Rich-amine temperature inlet to the stripper (achieved by bypassing rich/lean cross-over heat exchanger)	• Plant instrumentation
L. Active absorber height	• Packed beds in service / aggregate height in service
M. Stripper outlet pressure	• Plant instrumentation
N. Stripper reboiler steam (enthalpy) flow	• **Parametric testing:** Condensate flow meters or existing vortex flow meters • **Base-case testing:** Condensate flow meters
O. Lean vapor compression system operation	• On/off
P. Trace flue gas supply/depleted flue gas composition	• **Base-case testing:** NO_X, SO_2, SO_3, total HC, amines/aldehydes/NH_3

Table 6 lists pertinent independent parameters derived from the measured independent parameters that are likely to be more instructive than the parameters from which they are calculated.

Table 6. Derived independent parameters

Parameter	Calculation
A. Operating capacity	• Inlet flue gas flow rate as a % of design inlet flue gas flow rate
B. Absorber liquid-to-gas ratio	• Lean-amine flow divided by flue gas flow rate
C. Stripper liquid-to-gas ratio	• Rich-amine flow divided by stripper overhead CO_2 flow
D. Cross-over heat exchanger effectiveness	Calculated from: • Lean amine TCM DA instrumentation: FT2045, TT2114, TT2110 • Rich amine TCM DA instrumentation: TT2003, TT2111

5.2. Test period data results

Test period data include dependent variables that are directly measured parameters as well as key performance indices that are pertinent to calculations of measured values and independent parameters. Table 7 lists the important measured dependent parameters.

Table 7. Measured dependent parameters

Parameter	Instrument/Comment
A. Depleted flue gas temperature	• Plant instrumentation
B. Depleted flue gas bulk composition	• CO_2, O_2, N_2/Ar (by difference), H_2O (saturated). **Parametric testing:** Plant instrumentation; **Base-case testing:** CEMs data.
C. Depleted flue gas amines / aldehydes / NH_3 / SO_3	• During tests varying water wash operations and base-case tests
D. Depleted flue gas flow	• Plant instrumentation or calculated from composition
E. Absorber pressure drop	• Plant instrumentation
F. Product CO_2 flow rate	• TORBAR or recommended differential flow meter during parametric testing; recommended differential flow meter during base-case testing.
G. Product CO_2 trace composition	• O_2, SO_2, NO_X, H_2O (saturated), and CO_2 (by difference). Amines / aldehydes / NH_3 during base-case testing.
H. Reboiler steam flow	• **Parametric testing only:** Vortex meter
I. Reboiler steam temperature	• Plant instrumentation
J. Reboiler steam pressure	• Plant instrumentation
K. Reboiler condensate flow	• **Base-case testing:** Condensate orifice flow meter(s)
	Base-case testing:
L. Rich solution CO_2 content and inventory at the beginning and end of the test	• Laboratory analyses and sump levels
M. Lean solution CO_2 content and inventory at the beginning and end of the test period	• Laboratory analyses and sump levels
N. Pumping power use	• Plant instrumentation
O. Depleted flue gas trace components	• **Base-case testing:** SO_2, SO_3, NO_X, total HC, NH_3, particulates, and HAPs

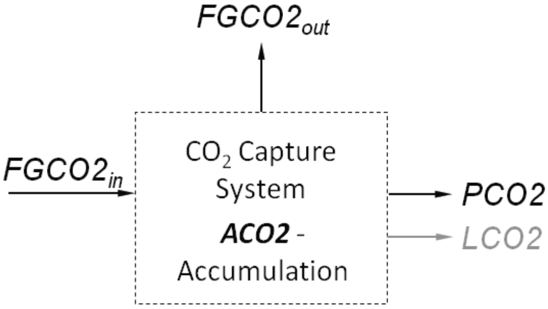
Table 8 lists the key performance indices. Each test period report should include these data.

Table 8. Calculated key performance indices

Performance index	Calculation/Definition
A. CO_2 stored in solution	• Difference between solution CO_2 inventory at the end and the beginning of the test period (solution CO_2 inventory = CO_2 content times liquid inventory)
B. CO_2 capture	• Sum of CO_2 produced (product flow meter) and CO_2 stored in solution, all divided by the product of flue gas supply flow rate and flue gas supply CO_2 mass fraction
C. CO_2 recovery	• Sum of product CO_2 flow and CO_2 stored in solution divided by the difference between CO_2 entering in flue gas (mass flow times mass fraction) and the CO_2 leaving in the depleted flue gas (mass flow times mass faction). CO_2 recovery measures the degree to which CO_2 flows balance. This factor should be within 95% to 105%.
D. SO_2 and NO_X removal	• The difference between mass flows in the flue gas supply and the depleted flue gas divided by the mass flow in the flue gas supply
E. Specific thermal use	• **Base-case testing:** M_{steam} from condensate flow meter(s) or vortex meters. Enthalpies from steam tables at measured stream temperature and pressure. Product CO_2 flow rate from recommended differential flow meter. • **Parametric testing:** Base-case procedure or M_{steam} from vortex meter. Product CO_2 flow rate from the vortex or TORBAR flow meter.
F. Specific power use	• See Section 5.5
G. Specific cooling duty	• Plant instrumentation for aggregate sea water flow and temperature differential and heat capacity • Alternative – Sum similar calculations around pertinent sea water-cooled heat exchangers

5.3. CO_2 capture performance

Fig. 3 lays out the general CO_2 flows. Note that CO_2 leakage to atmosphere is included as a flow. As leakage flows cannot be measured directly, it does not enter into the calculations. Its inclusion here is simply to acknowledge that leakage flow is a possibility. CO_2 accumulation is the amount of CO_2 stored within the amine pilot-plant boundaries over the course of a test; CO_2 may accumulate in (or be released from) the rich/lean solution over the course of a test period.



- $FGCO2_{in}$ = CO_2 mass flow entering in the flue gas
- $FGCO2_{out}$ = CO_2 mass flow leaving in depleted flue gas
- $PCO2$ = CO_2 exported as product
- $ACO2$ = Net CO_2 accumulation in the CO_2 capture system
- $LCO2$ = CO_2 leakage to atmosphere from the CO_2 capture system

Fig. 3. CO_2 capture flow diagram

Three general methods of calculating CO_2 capture efficiency are:

1. The ratio of measured high-purity product CO_2 flow to the CO_2 entering the absorber in the flue gas is given by:
$$\frac{PCO2}{FGCO2_{in}}$$
2. The ratio of measured high-purity product CO_2 flow to the sum of the high-purity product CO_2 flow and the CO_2 flow leaving the absorber in the depleted flue gas is given by:
$$\frac{PCO2}{FGCO2_{out} + PCO2}$$
3. The ratio of the difference between the CO_2 entering the absorber in the flue gas and the CO_2 leaving the absorber in the depleted flue gas to the CO_2 entering the absorber in the flue gas is given by:
$$\frac{FGCO2_{in} - FGCO2_{out}}{FGCO2_{in}}$$

The relative uncertainties in CO_2 capture by these three methods, using various combinations of flow meter data, were assessed. The conclusion is that uncertainty in CO_2 capture is minimized in Method 2 above, assuming that the CO_2 entering the capture plant is the sum of the two measured CO_2 flows out of the plant: 1) PCO2 – High-Purity Product CO_2 and 2) $FGCO2_{out}$ – CO_2 Emitted in the Depleted Flue Gas Leaving the Absorber.

As the specific thermal use and specific cooling duty will be calculated using the measured product CO_2 flow, the CO_2 capture should also make use of the measured CO_2 product flow. This recommends against Method 3, which uses only flue gas CO_2 flows.

Key independent parameters that characterize CO_2 capture plant performance include inlet flue gas flow rate as a % of design and absorber liquid/gas ratio, both of which use measured inlet flue gas flow rate. To the extent that absorber operation details are to be assessed and reported as key performance indices, corresponding reported CO_2 capture should also be based on the measured inlet flue gas CO_2 flow. This recommends against Method 2 despite its identification as the least uncertain method. In any event, sufficient data will be collected during operations to calculate and report CO_2 capture by all methods.

Note that a 4th method might be considered using only dry-basis CO_2 concentrations for the absorber inlet and depleted flue gas streams and assuming all dry components other than CO_2 pass through the absorber unchanged. This 4th method requires no flow measurements and is given by:

$$E_{CO2} = 1 - \frac{O}{I}\frac{(1-I)}{(1-O)}$$

where: E_{CO2} = CO_2 capture efficiency fraction
O = CO_2 concentration at absorber inlet dry mol fraction
I = CO_2 concentration at the absorber outlet dry mol fraction.

For all test periods, CO_2 recovery should be reported. This parameter is an indicator for the overall uncertainty in test results:

$$CO_2 Recovery = \frac{PCO2 + FGCO2_{out} + ACO2}{FGCO2_{in}}$$

CO_2 emissions are not included in the key performance indices listed in Table 8. Measuring CO_2 emissions for the purposes of meeting air emissions regulations will likely require traverse sampling for composition and velocity from the stack.

CO_2 emissions may be estimated by subtracting the sum of the (direct-measured) product CO_2 flow (*PCO2*) and the CO_2 stored in solution (*ACO2*, calculated) from the flue gas supply CO_2 flow ($FGCO2_{in}$). Note that this method of calculating CO_2 emissions is a comparatively small difference in two large numbers and carries considerable uncertainty.

5.4. Specific thermal use

Specific thermal use is the heat supplied by imported steam, primarily to the stripper reboiler, divided by the product CO_2 flow. The calculation for this parameter:

$$Q_{reboiler} = \frac{M_{steam}\left(h_{gi}\left(T_g, P_g\right) - h_{fo}\left(T_f, P_f\right)\right)}{M_{CO2}}$$

Details on each term in this equation are given in Table 9.

Table 9. Specific thermal use calculation details

Item	Units	CHP operation	Notes
$Q_{reboiler}$	kWth		Calculation result
M_{steam}	kg/s	Option 1: FT-2386 Option 2: FT 2051 Option 3: new	Medium-pressure (MP) steam flow to reboiler High-pressure (HP) steam flow to plant Condensate return flow from regenerator reboiler.
T_g	ºC	TT2387	
P_g	bar	PT-2389	
T_f	ºC	TT-2388	
P_f	bar	PT-2392	
h_{gi}	kJ/kg		Steam enthalpy from steam tables
h_{fo}	kJ/kg		Condensate enthalpy from steam tables
M_{CO2}	kg/s		From calibrated flow meter

5.5. Electrical utility use

The primary auxiliary power uses for PCC are the induced draft (ID) fan (to overcome flue gas pressure drops in the plant), the aggregate of solution and water pumping inside the plant, and the CO_2 compressor (to deliver at pipeline pressure; the TCM DA pilot plant does not have a CO_2 pipeline compressor). The ID fan use will correlate most closely to flue gas flow rate. The internal pumping power loads will correlate loosely with CO_2 production. Thus, it is unlikely that any single parameter will be useful in describing process auxiliary power use. In practice, pumping power differences from varying the independent parameters during parametric testing are likely to be insignificant. ID fan load will change with flue gas supply flow rate and, possibly, liquid flows in the absorber tower. Both of these factors are included in the ID fan pressure rise and flue gas flow rate. Auxiliary power use for a full-scale process can be estimated by:

- Summing the full-scale pumping loads
- Modeled ID fan power use from design flow rate and required pressure rise measured at pilot scale
- Modeled compressor power used to compress the product CO_2 from stripper column overhead pressure and specified compressor discharge pressure to deliver to the receiving pipeline.

These can be developed from parameters included in Table 7 and a specified receiving pipeline pressure.

6. Conclusions

A generic CO_2 capture testing methodology that has been applied at multiple sites providing details on the procedure, its key performance indices and their associated specifications, as well as the required pre-test work has been presented. Specific application of the methodology for the CO_2 Technology Centre Mongstad site, a CO_2 capture testing facility located in Norway that performed CO_2 capture tests using MEA, is shown as an illustrative example.

Acknowledgements

The authors gratefully acknowledge the staff of TCM DA, Gassnova, Statoil, Shell, Sasol, and Aker Solutions for their contribution and work at the TCM DA facility.

The authors also gratefully acknowledge Gassnova, Statoil, Shell, and Sasol as the owners of TCM DA and Aker Solutions for their financial support and contributions.

Appendix A. Pertinent flue gas monitoring reference methods

Table 10 lists reference methods used, their associated title, what is measured, and its units.

Table 10. Reference methods

Reference method	Title	Sampling/Analysis result	Units
EPA method 1	Sample and velocity traverses for stationary sources		
EPA method 2	Determination of stack gas velocity and volumetric flow rate (Type S pitot tube)	Stack velocity profile and aggregate volumetric flow rate	volume flow rate
EPA method 3A	Determination of oxygen and carbon dioxide concentrations in emission from stationary sources (instrumental analyzer procedure)	O_2, CO_2	% vol, dry
EPA method 5	Determination of particulate matter emissions form stationary sources	Total particulate matter	Mass per unit volume flue gas
EPA method 6C	Determination of sulfur dioxide emissions from stationary sources (instrumental analyzer procedure)	SO_2	ppmv, dry
EPA method 7E	Determination of nitrogen oxides emissions from stationary sources (instrumental analyzer procedure)	NO_X	ppmv, dry as NO_2
EPA method 25A	Determination of total gaseous organic concentration using a flame ionization analyzer	Total gaseous organic concentration	ppmv propane equivalent
EPA CTM-027	Procedure for collection and analysis of ammonia in stationary sources	NH_3	ppmv, dry
EPA method 29	Determination of metals emissions from stationary sources	Sb, As, Ba, Be, Cd, Cr, Co, Cu, Pb, Mn, Mg, Ni, P, Se, Ag, Hg	Mass per unit volume flue gas
NACSI method 8A	Determination of sulfuric acid vapor or mist and sulfur dioxide emissions from Kraft recovery furnaces	H_2SO_4 and SO_3	ppmv, dry

Appendix B. Flue gas amine / amine degradation product sampling

Background

TCM DA is planning to operate the PCC test unit at the facility with MEA solvent and no additives or amine blending. The solvent will be continuously cycling through the system for 1440 hours (60 days). Testing will be performed for a variety of operational parameters, including chemical characterization of the air and liquid waste streams. In particular, air emissions testing of the solvent and potential degradation products (amines, nitrosamines, and aldehydes) will be performed. This will be done during selected operational periods, including base-case testing.

Recommendations

Although other PCC tests have been performed with longer solvent cycling times, published studies suggest the presence of complex mixes of solvent degradation products that are emitted into the flue gas streams, even after shorter operational times. At least several days' worth of 'later' samples should be taken near the end of the 2-month period, during normal operations, in addition to the samples planned during the parametric and base-case testing.

Any testing undertaken for these solvent and degradation products should be performed isokinetically. A variety of sample collection processes can be of use, including impingers that are empty or charged with acidic solution.

NH_3 should be measured regularly as a frequently-observed high emission rate product. This is often done with FTIR, especially in situations where operations are expected to change quite substantially over time. Thus it can be a proxy for operational tracking as well as for the purposes of emission rate quantification. During stable operations, other methods which can have lower detection limits (such as an EPA Method 5 / Method 17 approach, collection with impinger, and analysis by ion chromatography) can be used on samples collected from various impinger approaches.

Due to its relevance and high abundance in the mist observed in several PCC test facilities, SO_3 should also be measured at the absorber outlet. Submicron mist and aerosols may form in the absorber as a result of heterogeneous condensation followed by dissolution and enrichment with the highly soluble amines in the mist. Several studies have shown that high quantities of mist composed partly of SO_3 can be observed. The mist may be a large sink of nitrogenous compounds of interest (primarily the amines as opposed to degradation products) due to their alkalinity.

A recent EPRI report contains details, features, and difficulties with multiple options for sampling and analysis of each compound class [6]. It should be noted that it is likely that only a subset of chemicals with a given compound class can be analyzed with any particular technique. Knowledge of the specific target compounds of interest, or a desire to measure as much of the total mass of the compounds class, is needed to recommend any particular suite of methods. Specific issues of importance include the need for very stable elevated temperatures of the entire sampling train (no unheated tubing gaps) and appropriate elimination or addressing of sampling and analytical interferences from water.

Amine sampling could be attempted with FTIR but it is possible to likely that any emissions would fall below detection limits due to chemical interferences. Thus manual sampling is recommended, with approaches similar to EPA Method 5 [6].

Nitrosamine sampling must be done manually; sufficient testing and use of continuous methods is not available to justify its use for this purpose. The most reasonable approaches at this time center on cartridges loaded with Thernosorb/N, with later extraction and analysis by HP liquid chromatography or gas chromatography following, or slightly modified from, the OSHA 27 method. It is likely that multi-stage sampling trains will be required to obtain the suite of desired nitrosamines. Both aqueous and vapor phases should be collected. If water removal methods are used, condensed phase must also be collected and analyzed.

Whatever methods are chosen to be applied must include multiple field blanks collected under conditions as close to those used for sampling full operations as possible. Serious consideration should be given to the feasibility of undertaking method validation tests at the stack (such as spike tests at the sample train inlets in order to estimate potential sample losses through the sampling train, as they can be quite high for the types of compounds of interest).

Appendix C. Relative accuracy test audits

The CHP flue gas supply and product CO_2 flow meters installed do not conform to ASME PTC 19.5, Standard for Flow Measurement [7]. It is recommended here that these flow meters be subjected to a RATA prior to or during base-case testing. Three options for conducting such an audit are described below.

Note that use of one of these RATA calibration methods for CHP flue gas flow could provide calibrations for the flow meters described in Table 11.

Table 11. RATA methods for CHP flow meters

Meter location	RATA method	Meter type
CHP after DCC	8610-FT-0150	Ultrasonic
CHP after DCC	8610-FT-0124	TORBAR pitot tube
Absorber inlet	8610-FT-2039	TORBAR pitot tube
Absorber outlet	8610-FT-2431	TORBAR pitot tube

Use of these RATA/calibration methods for product CO_2 flow could provide simultaneous calibrations for the product CO_2 flow meters given in Table 12.

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Table 12. RATA methods for product CO_2 flow meters

Meter location	RATA method	Meter type
Product CO_2	8615-FT-0010	Vortex
Product CO_2	8615-FT-2203	TORBAR pitot tube

Pitot tube traverse method

The unobstructed CHP flue gas duct lengths allow pitot tube traverses to be used to calibrate the CHP flow meters. ASME PTC19.5 describes how such a pitot tube traverse for flow is to be conducted. The practice in the US is to conduct a minimum of nine (9) separate flow traverses during which the challenged flow meter data is also collected. A maximum of three (3) of the flow traverse data sets may be discarded as outliers. The calibration flow and uncertainty are then calculated from remaining flow traverse data sets. The procedure is summarized in Section 2 of EPRI publication TR-104527 [8]. Duct nozzles allowing the use of traversing pitot tubes would need to be installed in the CHP flow duct to accomplish the flow traverses.

Dilution method

The flow meters may be calibrated by a dilution procedure. This is not a reference method, but it can be acceptable if the injection flow and concentrations are measured with sufficient accuracy. The general approach is to inject a tag gas far upstream of the flow meter (to allow for good mixing) and measure the concentration of the tag gas at the flow meter. The calibrated flow is then calculated by:

$$q_{meter} = q_{tag} \frac{C_{tag}}{C_{tag,meter}}$$

where:
q_{meter} = mass flow rate at the metering location
q_{tag} = measured mass flow rate of the tag gas injected
C_{tag} = measured concentration of tag gas injected
$C_{tag,\ meter}$ = measured concentration of tag gas at the flow meter.

A suitable tag commonly used is helium in air. The tag gas is supplied in high pressure gas bottles. A certified concentration of helium is required from the supplier. The tag gas is metered through a critical orifice (upstream pressure greater than ~2.5 bar). The flow through the orifice is directly proportional to the upstream (absolute) pressure. The concentration of helium can be measured at the flow meter using a thermal conductivity detector. A second cylinder of helium in air at the anticipated span concentration is required to calibrate the detector as is a helium-free air zero gas. Thermal conductivity detectors for helium are available from a number of manufacturers (and rental companies). These are normally used to detect helium leaks in lab equipment but are suitable also for sampling. Typical detection limit is 25 ppmv. In order to achieve ~1% uncertainty in the measured concentration, a measured concentration at the flow meter would be 2500 ppmv (0.25%).

Using this procedure to calibrate the flow meter at the absorber outlet would require a separate C_{tag}, concentration measurement at the absorber outlet flow meter location.

Radioactive tracer method

The flow meters may also be calibrated by a procedure to measure transit time of a radioactive tracer. The method is described in a British Standard [9]. By this method, a radioactive tracer is pulse-injected upstream and radiation detectors are located a measured distance apart downstream. The method reports average velocity by measuring the transit time of the radiation pulse between the injection and detector locations. Mass flow is then calculated by multiplying the measured velocity, the pipe cross section and the gas density:

$$q_{meter} = \frac{d\rho\pi D^2}{4t}$$

where:
q_{meter} = mass flow rate
d = distance between radiation detectors
ρ = gas density
D = duct diameter
t = time of radiation pulse transit.

Particular care must be taken in locating the injection point, and the radiation detectors. All three locations should be located on a long straight pipe run with minimal obstructions and no side taps. Conduct of this calibration procedure requires careful attention to a number of design and operating factors and should be undertaken only by personnel experienced in conduct of the procedure.

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(2014)

Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 63 (2014) 5994 – 6011

Energy Procedia

GHGT-12

Results from MEA testing at the CO_2 Technology Centre Mongstad. Part II: Verification of baseline results

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Abstract

Independent verification protocol (IVP) work has been conducted at the CO_2 Technology Centre Mongstad (TCM DA) during treatment of flue gas from a natural gas-fired combined heat and power (CHP) plant. The testing applied an aqueous 30 wt% monoethanolamine (MEA) solvent system treating flue gases with a flow rate of about 47.000 Sm^3/hr and a CO_2 content of about 3.5%. The CO_2 capture rate was about 90% and the thermal steam consumption was about 4.1 GJ/t CO_2. Emissions of MEA were very low and MEA-related degradation products were all below detection levels, and all within the emission limits set by the Norwegian environmental authorities. The current work may be considered an independently verified baseline for a non-proprietary post-combustion amine based solvent system carried out at an industrial-scale plant facility.

Long-term performance indices, such as material corrosion, MEA solvent degradation, etc., have not been considered in the current IVP work. Additional minor process adaption to the aqueous MEA solvent system, such as increased MEA concentrations, the use of anti-foam solutions, etc., may lead to lower thermal steam consumptions than aforementioned.

Peer-review under responsibility of the Organizing Committee of GHGT-12

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Peer-review under responsibility of the Organizing Committee of GHGT-12
doi:10.1016/j.egypro.2014.11.634

Keywords: CO_2 capture; EPRI; MEA; Post-combustion capture; CO_2 Technology Centre Mongstad; TCM DA

1. Introduction

CO_2 Technology Centre Mongstad (TCM DA), located next to the Statoil refinery near Mongstad, Norway, is one of the largest post-combustion capture (PCC) test facilities in the world. TCM DA is a joint venture between Gassnova, Statoil, Shell, and Sasol. The purpose of this facility, which started operation in August 2012, is to allow vendors of suitable amine formulations and other PCC processes to test their technology and collect performance data to support full-scale design and anticipate the associated performance and operating costs. A unique aspect of the facility is that either a slipstream from a natural gas-fired combined heat and power (CHP) plant or an equivalent volumetric flow from a refinery residue fluid catalytic cracker (RFCC), whose higher CO_2 content (about 12.9% compared with about 3.5% for the natural gas-based flue gas) is closer to that seen in coal flue gas, can be used for CO_2 capture. In the CHP plant, the natural gas is combusted in a gas turbine and the flue gas content and characteristics are similar to those of a combined cycle gas turbine (CCGT) power plant. One of the testing facilities in place at TCM DA is a highly flexible and well-instrumented generic amine plant, designed and constructed by Aker Solutions and Kværner, aimed to accommodate a variety of technologies with capabilities of treating flue gas streams of up to 60,000 Sm^3/hr. This plant is being offered to vendors of solvent-based CO_2 capture technologies to primarily test: (1) the performance of their solvent technology; and (2) technologies aimed to reduce the atmospheric emissions of amines and amine-based degradation products from such solvent-based CO_2 capture processes.

An independent verification protocol (IVP) has been developed by the Electric Power Research Institute (EPRI) to be used as part of the overall performance assessment of amine-based TSA processes, as described in details elsewhere [1]. The IVP is designed to provide a structured testing procedure for assessing thermal and environmental performance of PCC processes under normal operating conditions.

The IVP has been applied during base-case testing done 6–10 January 2014 on the TCM amine plant using aqueous 30 wt% monoethanolamine (MEA) as the solvent while treating flue gas at a flow rate of about 47.000 Sm^3/hr from the CHP plant. The IVP project was performed jointly between TCM DA, Aker Solutions, FORCE Technology, and the Electric Power Research Institute (EPRI), and the base-case testing is part of Aker Solutions' test campaigns at TCM DA.

This work is part of a continuous effort of gaining better understanding of the performance potential of the non-proprietary aqueous MEA solvent system, conducted by TCM DA and its affiliates and owners, in order to test, verify, and demonstrate CO_2 capture technologies [1, 2, 3]. The purpose of the current work is to provide the results of the IVP done for aqueous 30 wt% MEA, which provides a baseline that can be commensurately compared against other (solvent-based) PCC processes. This work may thus be considered the baseline for a non-proprietary PCC amine-based solvent system treating low CO_2 partial pressure flue gases at a significant flow rate from the combustion of natural gas in a gas turbine.

2. Project overview

The TCM pilot-scale amine plant was designed and constructed by Aker Solutions and Kværner. The amine plant was designed to be flexible to allow testing of different configurations, and has respective capacities of about 80 and 275 tonnes-CO_2/day for CHP and RFCC flue gas operations. The TCM DA amine plant process flow diagram showing high-level equipment contained within the plant along with key extant instrumentation and the nominal CHP flue gas characteristics is given elsewhere [1]. The major systems include:

- An induced draft (ID) blower to overcome pressure drops and blow the flue gas through the plant with a blower output capacity of up to about 270 mbar and 70,000 Sm^3/hr.
- A direct-contact cooler (DCC) system to initially quench and lower the temperature and saturate the incoming flue gas by a counter-current flow water in order to improve the efficiency of the absorption process and provide pre-scrubbing on the flue gas. The DCC system has two individually operated packed columns for operations with respectively the CHP flue gas and the flue gas from the refinery cracking unit. The DCC column designed

for CHP flue gas operations has of a 3-m diameter and a total of 16 m of height. The section where water counter currently contacts the flue gas is of 3.1 m of height with Flexipack 3X structured stainless-steel packing of Koch Glitsch. The DCC column designed for the flue gas from the refinery cracking unit has a diameter of 2.7 m and a total height of 16 m. The section where water counter currently contacts the flue gas is of 3 m of height with Intalox Snowflake random polypropylene packing of Koch Glitsch.

- An absorber to remove CO_2 from the flue gas using solvent. The absorber has rectangular polypropylene-lined concrete column with a cross-section measuring 3.55 x 2 m of a total of 62 m of height. The lower regions of the tower, where the amine solution contacts the flue gas, consist of three sections of Koch Glitsch Flexipac 2X structured stainless-steel packing of 12 m, 6 m, and 6 m of height, respectively. Water-wash systems are located in the upper region of the tower to scrub and clean the flue gas particularly of any solvent carry over, and consist of two sections of Koch Glitsch Flexipac 2Y HC structured stainless-steel packing of both 3 m of height. The water wash system is also used to maintain the water balance of the solvent system by adjusting the temperature of the circulating water of the upper water-wash section. Liquid (re-)distributors, liquid collector trays, and mesh mist eliminators by Koch Glitsch are located at various locations in the tower. The CO_2 depleted flue gas exits the absorber column to the atmosphere through a stack located at the top of the absorber column.
- Stripper columns to recover the captured CO_2 and return CO_2-lean solvent to the absorber. The amine plant consist of two independent stripper columns with overhead condenser systems; one measuring 1.3 m in diameter and a total of 30 m of height, the second measuring 2.2 m in diameter and also a total of 30 m of height. The lower regions of both stripper column, where the amine solutions is stripped, consist of Koch Glitsch Flexipac 2X structured stainless-steel packing of 8 m of height, and in the upper regions of the strippers consist of a rectifying water-wash section of Koch Glitsch Flexipac 2Y HC structured stainless-steel packing of 1.6 m of height. Liquid (re-)distributors, liquid collector trays, and mesh mist eliminators by Koch Glitsch are located at various locations in the strippers. Each stripper column is connected to its respective stream-driven thermosiphon reboiler system, providing the necessary heat required for the stripping process. The two stripper columns are operated independently considering the CO_2 content in the flue gas, due to column design and hydraulics and gas velocities effects, i.e., the smaller diameter stripper column is utilized when treating CHP flue gas, whereas the large diameter column is utilized when treating flue gases of higher CO_2 content.
- A set of pumps used to move the CO_2-lean and CO_2-rich solvent streams between the absorber and stripper and through a cross-flow heat exchanger to recover heat from the lean stream.
- A reflux drum, condenser, and pumps to dry the product CO_2 that exits from the stripper. A portion of the product CO_2 can also be recycled back to the inlet of the DCC to increase the concentration of the CO_2 in the inlet flue gas stream.

The roles and responsibilities of the organizations that conducted the current IVP project are as follows:

- **TCM DA** is the prime on the project and its personnel organized the field testing including contracting to do gas sampling during the test period. Personnel from TCM DA and TCM DA owner organizations were responsible for planning and setting the test program for the base-case testing, and also operating the plant throughout. TCM DA personnel collected samples during the base-case testing for quantification of trace species in the depleted flue gas stream.
- **Aker Solutions** is the technology vendor testing its solvent-based PCC technologies at TCM DA. A part of Aker Solutions' test period was to conduct a campaign based on the non-proprietary MEA solvent system, which was intended to be used as a reference for future testing. The base-case testing done 6–10 January 2014 was consequently a part of Aker Solutions' test campaigns at the TCM DA amine plant.
- **FORCE Technology** brought a single sampling crew on-site during the base-case testing to extract and analyse samples from the CHP flue gas supply, depleted flue gas, and product CO_2 streams. This sampling was conducted sequentially with a single set of continuous emissions monitors (CEMs). FORCE Technology also collected gas samples for off-site analysis of particulate, SO_2/SO_3, and amine-related compounds.
- **EPRI** was contracted to develop the IVP and help apply it during the base-case MEA testing. Two EPRI engineers were on-site during the testing to observe the conduct of the tests. EPRI is also the lead on the current IVC work.

3. Independent verification protocol approach

Base-case testing of the performance of the TCM amine plant using a nominal 30% MEA as the solvent was conducted the week of 6 January 2014 after approximately 6 weeks of operating the amine plant with the 30% MEA solution. The plant was operated at steady state through the entire week. (Note: The MEA solution concentration did drift down approximately 1 percentage point during the week of base-case testing.) The only operational abnormality was a short loss of flue gas flow for about 15 minutes at 15:00 hrs on 8 January 2014 from which operations were quickly restarted.

FORCE Technology was on-site to manually collect samples sequentially from the flue gas supply, depleted fuel gas, and product CO_2. During all sampling periods the following sample data were collected:

- CO, CO_2, NO_X, O_2, SO_2, and N_2 (by difference) concentrations in vol%
- Flow rate, pressure, and temperature.

The sampling time periods and sampling period designator are shown in Table 1 along with additional sampling undertaken on each day. Data logs for all sampling periods containing pertinent flows, temperatures, pressures, and concentrations measured by permanent plant instruments were supplied by TCM DA.

Table 1. FORCE Technology sampling periods

Stream sampled	Date	Start time / Stop time	Sampling results reported	Test designator
Depleted flue gas	6 January 2014	14:13 / 17:43	Major gases, flow	C1-1a
		10:28 / 13:50	Acetone, aldehydes amine degradation products, NH_3	C1-1b
Depleted flue gas	7 January 2014	7:58 / 11:23	Cl^-, H_2SO_4, NH_4^+, particulate, salts, SO_2, SO_4^{2-}	C1-2
Product CO_2	8 January 2014	11:50 / 15:07	Major gases, flow	C1-3a
		17:02 / 20:10	Acetone, aldehydes amine degradation products, NH_3	C1-3b
Flue gas supply	9 January 2014	9:12 / 12:55	Cl^-, H_2SO_4, NH_4^+, SO_4^{2-}, salts	C1-4a
		13:05 / 16:14	NH_3	C1-4b

4. Instrument assessment

This section assesses the quality of the instrumentation installed for measuring the respective compositions and flow rates. There are two measures of instrumentation quality:

- Accuracy / bias – Measure of the difference between the instrument reading (or average of a set of readings under unchanging process conditions) and the true value of the parameter. The “true value” must be determined by means other than the measurement in question. This is usually accomplished by simultaneous measurement of the parameter by the plant instrument and a reference method or instrument with calibration that can be traced to primary standards.
- Precision – Variability of the instrument reading when stream conditions do not change. Precision is a measure of the random error associated with the measurement.

The aggregate uncertainty in a measurement includes both precision error and bias error. Absent a calibration against primary standards, the uncertainty published by the instrument supplier is only the precision error.

Note also that precision is a measure of repeatability when the process parameter being measured does not change. It is often the case that the process parameter (flow, pressure, and temperature) does change over the measurement period. Thus, measurements over long periods of time (greater than process time constants) will also include an error term related to process uncertainty.

4.1. Gas phase compositions

The CO_2 and O_2 content of the flue gas supply, depleted flue gas, and CO_2 product stream is routinely determined by the respective plant Fourier Transform Infrared (FTIR) (Applied Instrument Technologies and Finetech, model: Anafin 2000) and O_2 (Siemens, model: Oxymat 6) sampling and analysis system. The sampling system admits the gas stream, sampled from various single points as given by Thimsen et al [1]. The sample is continuously drawn by a selection system serving the analyzer. The gas supply samples are diverted to the common analyzers in a 90-minute cycle, i.e., the analyzer cycles between flue gas supply for 15 minutes, depleted flue gas for 30 minutes, and CO_2 product stream for 15 minutes. In each sampling, the analyzer sampling lines and cells are sufficient flushed with the gas to be measured and, after a certain time, wet-gas concentration for every 1½ minutes for a total of 10 concentrations are reported. The plant control system displays to the operators the most recent concentration report. Thus, the last report of the 10 is displayed for approximately 75 minutes until the next sampling cycle for the flue gas supply and CO_2 product stream and approximately 60 minutes for the depleted flue gas.

The flue gas supply, depleted flue gas, and CO_2 product stream compositions were analyzed by FORCE Technology during the base-case operations. The measurements reported by FORCE Technology were on a dry basis. (The sample is dried before analysis.) These dry-basis data were converted to wet basis by assuming that the flue gas supply is saturated with water at the temperature and pressure measured by the plant data acquisition system. The recalculated FORCE Technology data are given in Fig. 1 and Fig. 2, and compared to the values determined by the FTIR system. Details include:

- Fig. 1 displays the CHP flue gas supply CO_2 and O_2 concentration data over the test campaign. The agreement between FORCE Technology O_2 measurements and those measured by TCM DA O_2 analyzer on 9 January are as good as the agreement in respective CO_2 measurements. These data show that for the last 2½ days of the campaign, CHP flue gas supplied to the pilot plant was of relatively uniform composition. This is probably not the case for the first 1½ days of the campaign. The variability in CO_2 and O_2 concentrations are significantly greater than the precision uncertainty in the measurements indicating that the changes in measured concentration represent real changes in CHP flue gas composition.
- Fig. 2 displays the depleted flue gas CO_2 and O_2 concentration data over the test campaign. The FORCE Technology O_2 data collected on 6 January differ significantly from the TCM DA O_2 data for the first half of the sampling period, but are in general agreement over the last half of the sampling period. The relative uniformity of the FORCE Technology data on 6 January suggests that the TCM DA O_2 data above 15% O_2 may be spurious and not a result of process changes. There was significant variation in the depleted flue gas FORCE Technology CO_2 and TCM DA FTIR concentration data for the sampling period. The precision error for this measurement is in excess of 20%. In addition, there was a significant positive bias in the FTIR data compared to FORCE Technology data taken simultaneously on 6 January. The bias could be corrected by multiplying the FTIR data by 0.7 over this time period. Although the bias is significant, the error was about 0.1% points.
- The product CO_2 composition data reported by FORCE Technology include O_2 content between 1–2%. It is difficult to imagine a mechanism by which the product CO_2 stream (stripper overhead) can contain this much oxygen, and it is therefore presumed that this oxygen is due to air in-leakage into the sampling system, thereby disqualifying the data. For the purposes of calculating CO_2 removal and recovery, it is assumed here that the product CO_2 stream consists only of CO_2 saturated with water at the measured temperature and pressure.

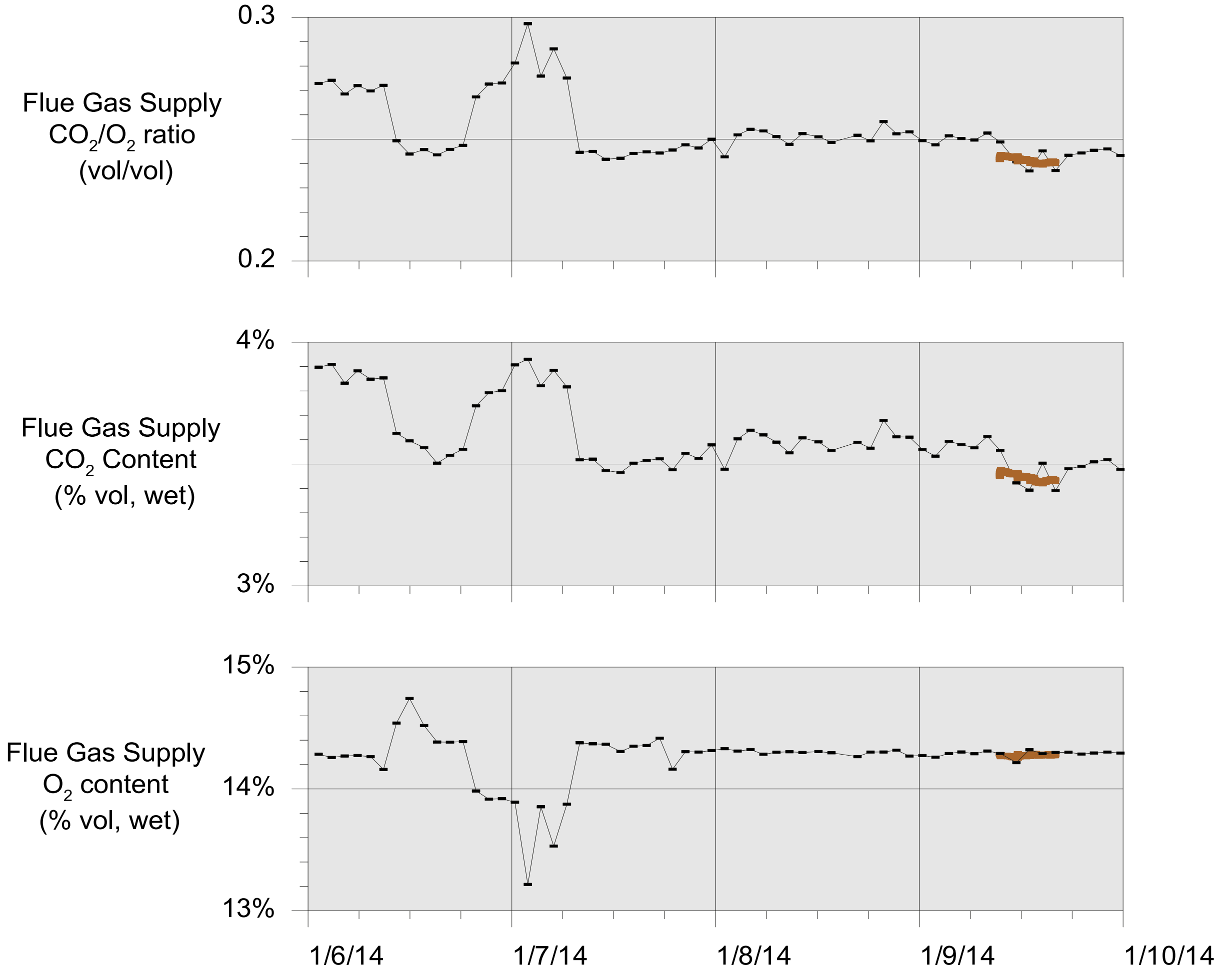

Fig. 1. CHP flue gas supply CO_2 and O_2 data. FTIR and O_2 analyzer data are averaged over analysis circles. Data collected by FORCE Technology on 9 January are also shown.

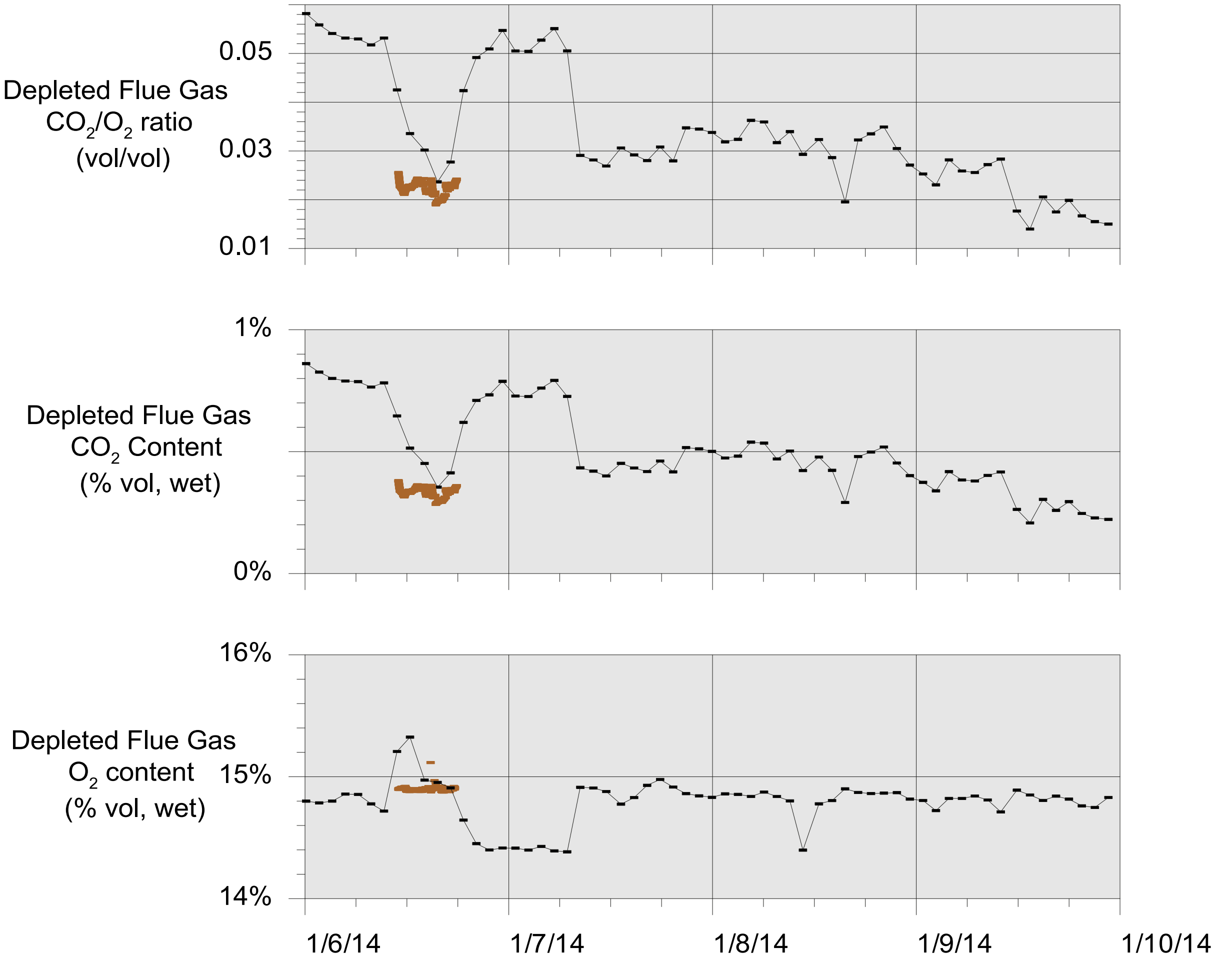

Fig. 2. Depleted flue gas CO_2 and O_2 data. FTIR and O_2 analyzer data are averaged over analysis cycles. Data collected by FORCE Technology on 6 January are also shown.

4.2. Gas phase flow rates

The flow rates of the flue gas, depleted flue gas, and CO_2 product stream are continuously determined by plant instrumentation. The TCM DA amine plant facility is particularly well instrumented for determining the flue gas supply flow rate, with several different types of flow meters in series.

The flue gas, depleted flue gas, and CO_2 product stream flow rates were determined by pitot-tube traversing during the base-case operations by FORCE Technology and the results compared to plant instrumentation are discussed below:

- The CHP flue gas supply flow is measured by two instruments, an ultra-sonic flow meter (FT-0150) and a multi-pitot-tube flow meter (FIC-0124), which are characterized in Table 2. The data from these flow meters are shown in Fig. 3. The flow rates are defined standard conditions of 15 °C and 1 atmosphere. The CHP flue gas flow was very steady over the test week with the exception of a 15-minute period on 8 January when the flow went to zero due to a trip of the ID blower. FORCE Technology made an independent measurement of flow on 9 January as indicated in Fig. 3. The difference between the value measured by FORCE Technology and that measured by the plant instruments is less than 1%. This result must be tempered by the reported uncertainty in the FORCE

Technology measurement of 10%. The test period flow averages used for all calculations are the data reported by the ultrasonic flow meter (FT-0150).

- The depleted flue gas flow is measured by a single multi-pitot tube flow meter whose characteristics are listed in Table 2. The depleted flue gas flow rate of this instrument varies in a fashion that is uncorrelated with any known operational parameter rendering this data of little use for the purposes of the base-case testing. Investigation of this has indicated variation of the measured flue gas flow rate with the ambient air pressure. This may be related to the physical installation position of the instrument; however, exact cause for this flow rate variation is not yet understood. FORCE Technology measured a flow of 47.000 Sm^3/hr (±10%) at this location on 7 January 2014.
- The key product CO_2 flow meters are listed in Table 2. The product CO_2 flow measured by the vortex flow meter (FT-0100) is the primary flow meter used by TCM operators. The data from this flow meter are shown in Fig. 4. The product CO_2 flow was relatively steady over the test week with the exception of the 15-minute period on 8 January 2014 when the flow went to zero due to an ID blower trip. FORCE Technology made an independent measurement of flow on 8 January as indicated in Fig. 4. The difference between the value measured by FORCE Technology and that measured by the plant instruments is approximately 6%, within the uncertainty reported by FORCE Technology measurement of 10%.

Table 2. Key flow instrumentation. Precision uncertainties are based internal instrument assessment by TCM DA.

Stream	Tag number	Instrument type	Primary flow measurement	Precision uncertainty
CHP flue gas supply	FIC-0124	Multi-pitot tube	Differential pressure	2.5%
	FT-0150	Ultra-sonic	Flowing volume	1.3%
Absorber outlet depleted flue gas	FT-2431	Multi-pitot tube	Differential pressure	5.4%
Product CO_2	FT-0010	Vortex	Flowing volume	1.0%

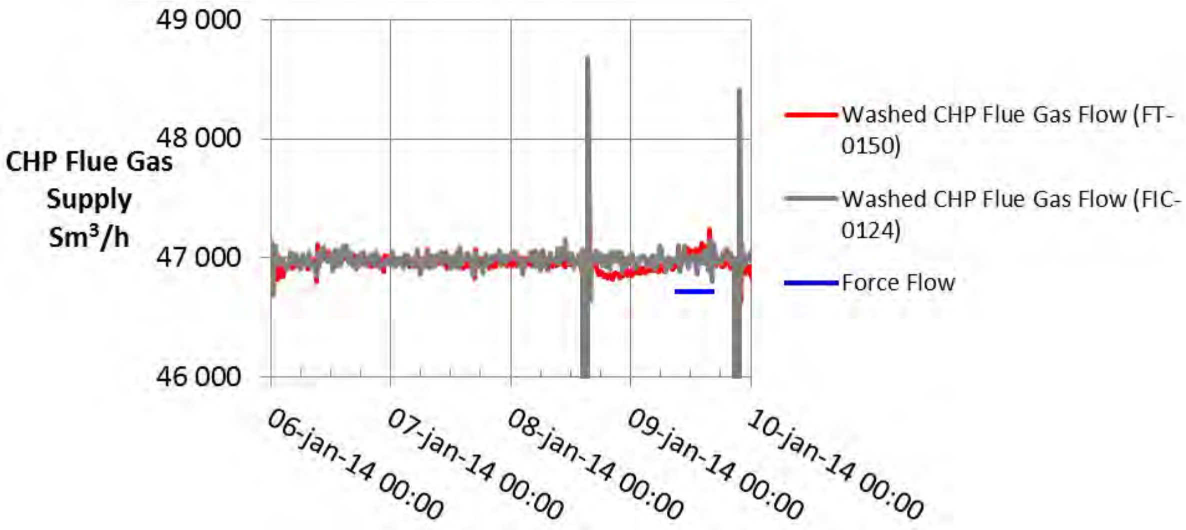

Fig. 3. CHP flue gas supply flow measurements

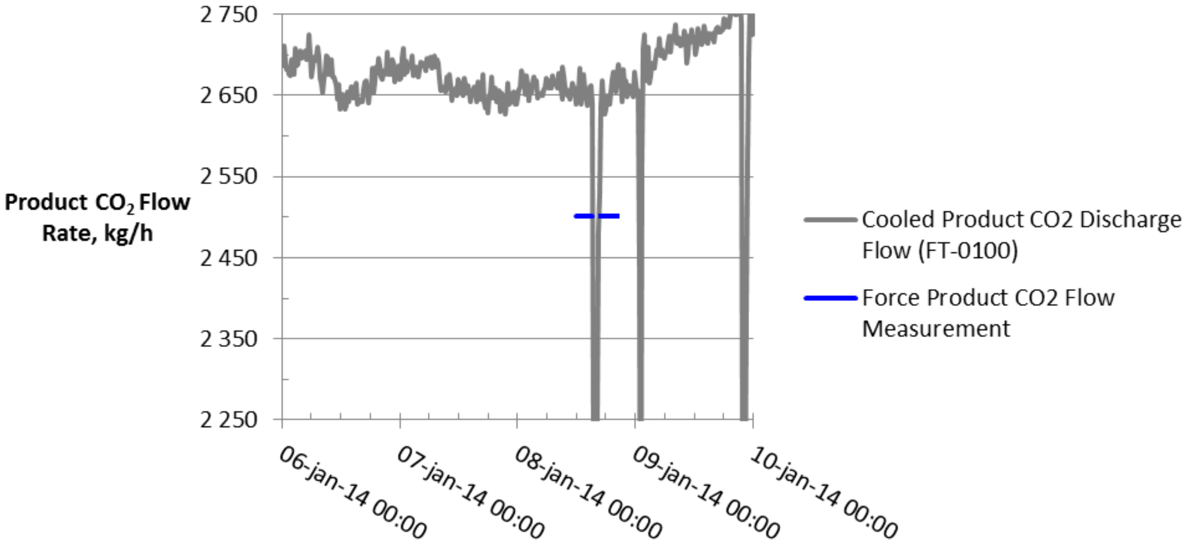

Fig. 4. Product flue gas flow rate and test period averages

4.3. Steam and condensate flow rates

A schematic of the system supplying steam to the stripper reboiler is shown in Fig. 5. High-pressure (HP) steam is delivered from the refinery to the TCM amine plant at a pressure of approximately 30 bars, superheated to approximately 240°C to 310°C. The HP steam is throttled to a pressure near the stripper reboiler steam pressure at approximately 5 bars and then desuperheated with condensate. The stripper reboiler condensate collects in a receiver from which it is returned to the refinery. A small amount of medium-pressure (MP) steam is reduced to a lower pressure for use in steam heat tracing. The low-pressure (LP) steam condensate is returned to the same receiver as the stripper reboiler condensate.

The parameter of interest is the steam flow to the reboiler. A check on this parameter is the HP condensate flow returned to the refinery. The condensate return flow should be the sum of the reboiler steam flow and any condensate flow produced in steam heat tracing. Fig. 5 shows these two parameters. The condensate return flow indicated (FT-2455) is consistently higher than the reboiler steam flow (FT-2386) by typically 2% to 8%. This difference is in the correct direction when heat tracing condensate (not measured by the reboiler steam flow meter) is entering the condensate receiver.

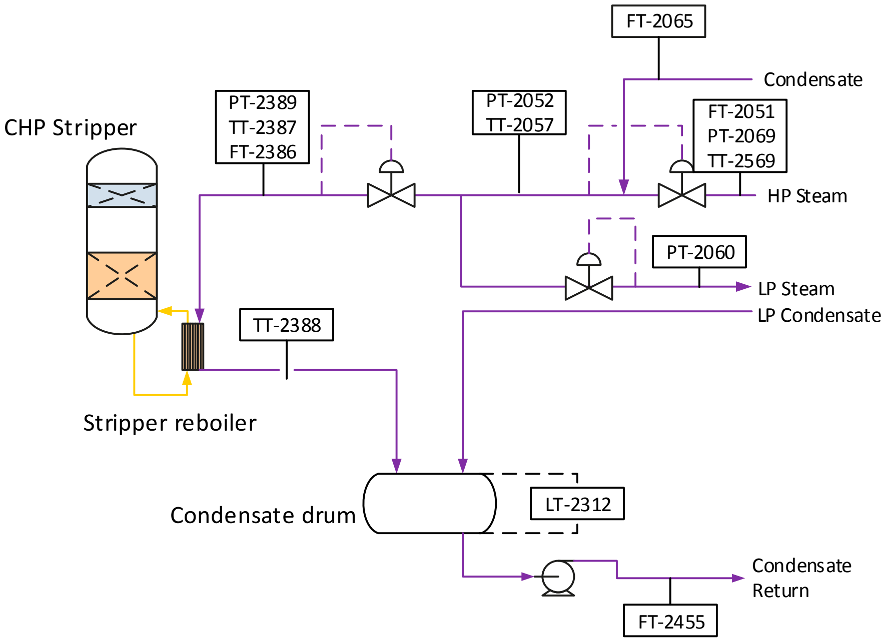

Fig. 5. Stripper reboiler steam supply flow schematic

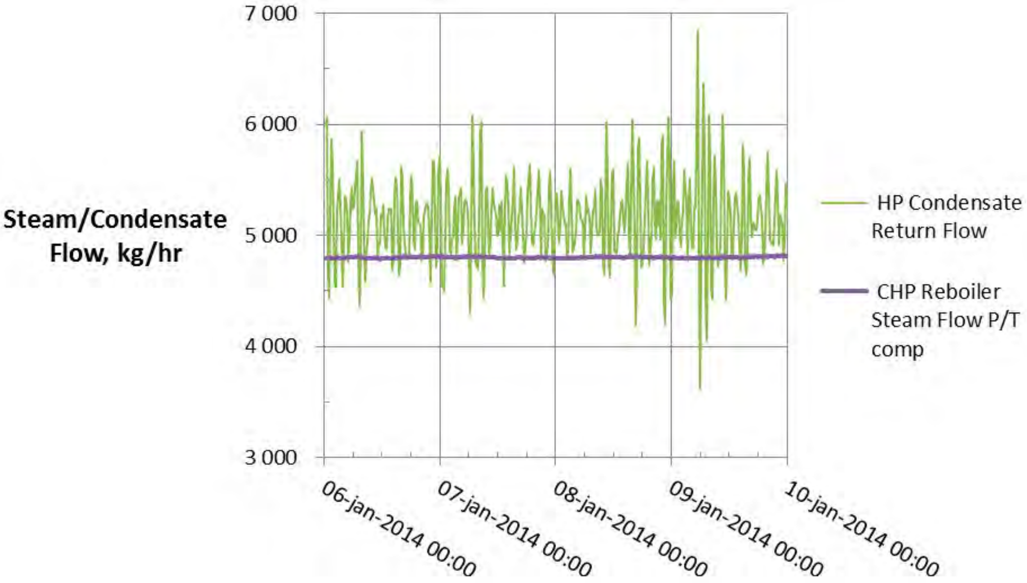

Fig. 6. Reboiler steam flow and HP condensate return flow

5. Results and discussions

5.1. CO_2 capture efficiency and recovery

CO_2 capture efficiency can be quantified in four ways as described by Thimsen et al. [1] and indicated in Table 3. In addition, the CO_2 recovery calculation is given in Table 3. The CO_2 recovery is a measure of the CO_2 mass balance.

Table 3. CO_2 capture efficiency and recovery calculations

Term	Description	Formula
CO_2 capture efficiency: Method 1	CO_2 product flow as a ratio to the CO_2 flow in the flue gas supply	$= \frac{CO_2(product)}{CO_2(supply)}$
CO_2 capture efficiency: Method 2	CO_2 product flow as a ratio to the sum of the CO_2 product flow and the CO_2 flow in the depleted flue gas	$= \frac{CO_2(product)}{CO_2(product) + CO_2(depleted)}$
CO_2 capture efficiency: Method 3	Ratio of the difference between the CO_2 flow in the flue gas supply and the CO_2 in the depleted flue gas to the CO_2 flow in the flue gas supply	$= \frac{CO_2(supply) - CO_2(depleted)}{CO_2(supply)}$
CO_2 capture efficiency: Method 4	Ratio of the depleted flue gas CO_2 per unit O_2+N_2 to the flue gas supply CO_2 per unit O_2+N_2	$= 1 - \frac{O_{CO_2}}{(1 - O_{CO_2})} \frac{(1 - I_{CO_2})}{I_{CO_2}}$ O_{CO2} = Depleted flue gas CO_2 content, dry basis I_{CO2} = Flue gas supply CO_2 content, dry basis
CO_2 recovery	Ratio of the sum of the CO_2 flow in depleted flue gas and the product CO_2 flow divided by the CO_2 flow in the flue gas supply	$= \frac{CO_2(depleted) + CO_2(product)}{CO_2(supply)}$

The depleted flue gas flow measurement is not yet a reliable measurement. A value can be calculated for the depleted flue gas flow by assuming that the oxygen and nitrogen entering the absorber with the flue gas supply leaves in the depleted flue gas. The depleted flue gas temperature may be used to calculate saturated water content. The depleted flue gas CO_2 concentration may be used to calculate CO_2 flow. Note that these are essentially the same assumptions as those used for Method 4, hence the Method 3 and Method 4 calculations result in essentially identical CO_2 capture rates. Using the calculated flow of depleted flue gas allows an estimate of the CO_2 recovery to be calculated.

Table 4 shows the four calculations of CO_2 capture and recovery for the base-case test periods (using the calculated value for depleted flue gas flow). The first thing to note is that all calculated CO_2 captures were fairly steady for the first three days of operation (test periods C1-1a to C1-3b). The CO_2 capture on the last day (C1-4a, C1-4b) was significantly higher by approximately 3–4 percentage points. The CO_2 recovery (mass balance) was neither greater than 95.5% nor as low as 91.3%. Note also that the CO_2 capture calculated by Method 1 is always less than the CO_2 capture calculated by Methods 2, 3, and 4. These two facts suggest that either quantification of CO_2 flow in the CHP flue gas supply is biased high or that calculation of CO_2 flow in the product is biased low.

Table 4. CO_2 capture and CO_2 recovery results

Test period	Method 1	Method 2	Method 3	Method 4	CO_2 recovery
S-Supply D-Depleted P-Product	$=\frac{P}{S}$	$=\frac{P}{P+D}$	$=\frac{S-D}{S}$	$=1-\frac{O_{CO_2}}{(1-O_{CO_2})}\frac{(1-I_{CO_2})}{I_{CO_2}}$	$=\frac{D+P}{S}$
C1-1a	83.5%	90.8%	91.5%	91.5%	91.3%
C1-1b	85.8%	90.8%	91.3%	91.3%	94.0%
C1-2	86.5%	90.8%	91.3%	91.3%	94.8%
C1-3a	84.8%	90.8%	91.5%	91.5%	92.8%
C1-3b	83.7%	90.1%	90.8%	90.8%	92.2%
C1-4a	88.7%	93.8%	94.1%	94.1%	94.2%
C1-4b	90.8%	94.8%	95.0%	95.0%	95.5%

The uncertainty in measurement of flow and composition propagate into uncertainty in the CO_2 capture. The uncertainty calculations and representative results from the each of the calculation methods are shown in Table 5. The following assumptions are used:

- Flow metering uncertainties are those theoretically estimated and calculated by internal work at TCM DA for the indicated flow meters [1]
- Concentration uncertainties for the flue gas flows are those aforementioned
- Concentration uncertainty for the product CO_2 is arbitrarily assigned to be 2%, which allows for actual CO_2 content as low as 98%
- CO_2 capture percentage of 90% is representative of that measured during base-case testing. (The calculation is not particularly sensitive to this parameter between 85 and 95%.)

A few notes on the CO_2 capture uncertainty results:

- The uncertainty in CO_2 capture is almost all due to uncertainty in CO_2 content of the CHP flue gas supply for the assigned total flow uncertainties. The CO_2 capture uncertainty is relatively insensitive to both the product CO_2 content uncertainty and the depleted flue gas CO_2 content uncertainty.
- The fact that CO_2 recovery is less than 100% suggests that one or more of the flows has a significant bias error than calculated from instrument specifications. Hence the need for a relative accuracy test audit of the pertinent flow meters to assign more realistic uncertainties. These are likely to be higher than the calculated values, which will increase overall CO_2 capture uncertainty above that indicated in Table 5.

Table 5. Uncertainty in CO_2 capture as a function of flow/composition measurement uncertainty (Nominal CO_2 capture of E_{CO2} = 90%)

CO_2 capture calc. method	Stream	Uncertain in:				CO_2 capture uncertainty equation
		Total flow	CO_2 content	CO_2 flow	CO_2 capture	
1	Product	1.1%	2%	U_{CO2P}=2.3%	5.6%	$\sqrt{(U_{CO2S})^2+(U_{COSP})^2}$
	Supply	1.3%	5%	U_{CO2S}=5.2%		
2	Product	1.1%	2%	U_{CO2P}=2.3%	2.5%	$(1-E_{CO2})\sqrt{(U_{CO2D})^2+(U_{COSP})^2}$
	Depleted	1.3%	25%	U_{CO2D}=25%		
3	Supply	1.3%	5%	U_{CO2S}=5.2%	2.8%	$\frac{(1-E_{CO2})}{E_{CO2}}\sqrt{(U_{CO2S})^2+(U_{COSD})^2}$
	Depleted	1.3%	25%	U_{CO2D}=25%		

5.2. Thermal energy use

The heat released in the reboiler is calculated as the difference between steam enthalpy at the measured reboiler inlet temperature (T) and pressure (P) and saturated water enthalpy at the reboiler condensate temperature. The pertinent data are given in Table 6.

Table 6. Stripper reboiler thermal use calculation

	Reboiler steam				Reboiler condensate				
	Flow	T	P	Steam enthalpy	T	Enthalpy	Reboiler heat duty	CO_2 flow	Specific thermal use
Test Period	kg/hr	°C	bara	kJ/kg	°C	kJ/kg	MJ/hr	kg/hr	GJ/t CO_2
C1-1a	4793	168.1	5.43	2782.8	118.9	498.9	10,946	2629	4.16
C1-1b	4803	169.0	5.43	2784.8	118.9	498.9	10,980	2631	4.17
C1-2	4802	168.8	5.43	2784.4	118.8	498.7	10,976	2639	4.16
C1-3a	4801	170.0	5.43	2787.2	119.0	499.7	10,983	2635	4.17
C1-3b	4802	170.2	5.43	2787.7	119.1	500.2	10,985	2633	4.17
C1-4a	4802	169.8	5.43	2786.6	119.2	500.3	10,978	2696	4.07
C1-4b	4801	170.1	5.43	2787.3	119.2	500.5	10,978	2702	4.06

The thermal steam consumption data give in Table 6 are based on aqueous 30 wt% MEA solvent system without the addition of any anti-foam solution. Upon addition of anti-foam solution and increase of the MEA solvent concentration during the MEA test campaign at TCM DA, the steam consumption was further reduced during CHP flue gas treatment, as described by Brigman et al [2]. Those tests were not a part of the current IVP work. Additionally, TCM DA has a LVC system installed; however, this system was not operated during Base-Case test and is consequently also not a part of the current IVP work. LVC systems have previously been showed by Knudsen et al. [4] to substantially decrease the thermal steam consumptions during amine plant operations with the aqueous MEA solvent systems.

5.3. Process contaminants

FORCE Technology measured gas-phase concentrations of the compounds listed below and the results are provided in Table 7. During the base-case testing time period, the CHP plant received refinery gas from the Mongstad refinery, which was, to some extent, co-fired with the natural gas.

- SO_2 concentrations were measured on different days. The CHP flue gas supply SO_2 concentrations are very low as are concentrations in the other streams.
- H_2SO_4 concentrations were measured in the two flue gas streams on different days. The flue gas H_2SO_4 concentrations are very low as are concentrations in the other streams. The H_2SO_4 concentrations were determined by extracting aqueous H_2SO_4 containing droplets, referred to as SO_3 mist droplets, on a heated filter.
- NO_x concentrations were below detectable limits for all streams
- Total particulates concentrations were measured on different days. The CHP flue gas supply total particulate concentrations are very low and were below detection limit in the depleted flue gas.
- Acetone, acetaldehyde, and formaldehyde were measured in the depleted flue gas and the product CO_2 stream on separate days. The emissions concentrations of acetone and the aldehydes are higher in the product CO_2 than the depleted flue gas, likely due to the low temperature boiling point nature of these compounds.
- NH_3 concentrations were measured for both depleted flue gas and product CO_2. The results indicated emissions of NH_3, likely arising from MEA degradation process occurring in the solvent system.

- MEA concentrations were determined by iso-kinetic sampling conducted by TCM DA personnel and further sample analysis by the TCM DA laboratories. The MEA concentrations in the depleted flue gas are very low, and were below the emission limits set by the Norwegian environmental authorities (Miljødirektoratet). [3]
- MEA degradation products were determined by iso-kinetic sampling from the depleted flue gas and product CO_2 by FORCE Technology and further laboratory analysis. The concentrations of any nitrosamines and nitramines were all below detection limits for both the depleted flue gas and the CO_2 product. [3] The emissions of MEA degradation products were below the emission limits set by the Norwegian environmental authorities.

Table 7. Gas-phase concentrations

Test period ID Item / *S*-Supply / *D*-Depleted / *P*-Product			C1-1a	C1-1b	C1-2	C1-3a	C1-3b	C1-4a	C1-4b
SO_2	*S*	ppmv						0.043	
	D				0.042				
	P						0.093		
H_2SO_4	*S*	mg/Sm^3 (dry)						0.0088	
	D				0.0036				
	P								
NO_X	*S*	mg/Sm^3 (dry)						< 10	
	D				< 10				
	P						< 10		
Particulate	*S*	mg/Sm^3 (dry)						0.060	
	D				< 0.053				
	P								
Acetone	*D*	mg/Sm^3 (dry)	< 0.07						
	P					0.91			
Formaldehyde	*D*	mg/Sm^3 (dry)	< 0.07						
	P					0.19			
Acetaldehyde	*D*	mg/Sm^3 (dry)	0.30						
	P					13.0			
NH_3	*D*	mg/Sm^3 (dry)	7.7						
	P					16			
MEA*	*D*	μg/Sm^3 (dry)							22.5
	P								
Total nitrosamines	*D*	μg/Sm^3 (dry)	< 0.80						
	P						< 0.07		
Total N-nitrosdimethylamine	*D*	μg/Sm^3 (dry)	< 0.08						
	P						< 0.07		
Total nitramines	*D*	μg/Sm^3 (dry)	< 0.20						
	P						< 0.10		

* FORCE Technology measurements of MEA gas phase concentrations for both depleted flue gas and product CO_2 were unsuccessful. The value given in Table 7 for the depleted flue gas was iso-kinetically sampled and analyzed by TCM DA. The MEA gas-phase concentration for the product CO_2 was not measured by TCM DA.

5.4. Process stream information

Additional amine plant process information for the base-case test is given in Appendix A. This information is not covered by the current IVP work, but is given for the convenience of the reader.

6. Conclusions

IVP work has been conducted at CO_2 Technology Centre Mongstad during treatment of flue gas from a natural gas-fired combined heat and power (CHP) plant. The testing is referred to as the base-case testing, applying an aqueous 30 wt% MEA solvent system treating flue gases with a flow rate of about 47.000 Sm^3/hr and a CO_2 content of about 3.5%. For the base-case considered, the CO_2 capture was about 90% and the thermal steam consumption was about 4.1 GJ/t-CO_2. Emissions of MEA were very low and MEA related degradation products were all below detection levels, and all within the emission limits set by the Norwegian environmental authorities. The current work may be considered an independently verified baseline for a non-proprietary PCC amine-based solvent system.

The following process aspects were not considered in the current IVP work:

- Long-term performance indices such as heat exchanger fouling, mass transfer packing fouling, foaming, material corrosion, solvent quality control measures, solvent loss/replacement, etc.
- Use of anti-foam solution, which has proven to reduce the thermal steam consumptions at TCM DA
- Use of the installed lean vapor compressor system at TCM DA.

These aspects warrant further (IVC) work and studies in order to gain better understanding of the performance potential of the aqueous MEA solvent system as a non-proprietary PCC system.

Acknowledgements

The authors gratefully acknowledge the staff of TCM DA, Gassnova, Statoil, Shell, Sasol, and Aker Solutions for their contribution and work at the TCM DA facility.

The authors also gratefully acknowledge Gassnova, Statoil, Shell, and Sasol as the owners of TCM DA and Aker Solutions for their financial support and contributions.

Appendix A. Amine plant process information

Table 8 provides the amine plant main process information averaged over the base-case test time period. Process fluctuations, generally attributed to fluctuations in the CO_2 content of the CHP flue gas, cannot be derived from the given values.

Table 8. Typical amine plant process information during Base-Case testing

Process parameter	Units	Value
Operating capacity	%	80
CHP flue gas supply rate	Sm^3/hr	46970
CHP flue gas supply temperature	°C	25.0
CHP flue gas supply pressure	barg	0.063
CHP flue gas supply CO_2 concentration (wet)	vol%	3.7
CHP flue gas supply O_2 concentration (wet)	vol%	13.6
Depleted flue gas temperature	°C	24.7
Lean MEA concentration	wt%	30
Lean CO_2 loading	mol CO_2 / mol MEA	0.23
Lean amine supply flow rate	kg/hr	54900
Lean amine supply temperature	°C	36.5
Lean amine density	kg/m^3	1067
Active absorber packing height	m	24
Temperature, upper absorber packing – 6	°C	45.4
Temperature, upper absorber packing – 5	°C	51.1
Temperature, upper absorber packing – 4	°C	51.2
Temperature, upper absorber packing – 3	°C	50.3
Temperature, upper absorber packing – 2	°C	49.6
Temperature, upper absorber packing – 1	°C	48.5
Temperature, middle absorber packing – 6	°C	46.7
Temperature, middle absorber packing – 5	°C	45.2
Temperature, middle absorber packing – 4	°C	43.5
Temperature, middle absorber packing – 3	°C	41.7
Temperature, middle absorber packing – 2	°C	40.6
Temperature, middle absorber packing – 1	°C	39.0
Temperature, lower absorber packing – 12	°C	38.4
Temperature, lower absorber packing – 11	°C	39.1
Temperature, lower absorber packing – 10	°C	35.0
Temperature, lower absorber packing – 9	°C	33.7
Temperature, lower absorber packing – 8	°C	32.2
Temperature, lower absorber packing – 7	°C	30.4
Temperature, lower absorber packing – 6	°C	29.8
Temperature, lower absorber packing – 5	°C	29.3
Temperature, lower absorber packing – 4	°C	28.1
Temperature, lower absorber packing – 3	°C	28.4
Temperature, lower absorber packing – 2	°C	27.6
Temperature, lower absorber packing – 1	°C	27.2

Rich solution return temperature	°C	27.7
Temperature above upper absorber packing	°C	38.1
Wash water 1 supply flow rate	kg/hr	55000
Wash water 1 inlet temperature	°C	28.4
Wash water 1 withdrawal temperature	°C	43.9
Temperature above Wash Water 1	°C	36.2
Wash water 2 supply flow rate	kg/hr	62000
Wash water 2 inlet temperature	°C	23.5
Wash water 2 withdrawal temperature	°C	35.0
Temperature above Wash Water 2	°C	24.7
Rich CO_2 loading	mol CO_2 / mol MEA	0.48
Rich solution supply flow rate	kg/hr	57200
Rich solution supply temperature	°C	108.6
Lean solution return temperature	°C	119.1
Rich amine density	kg/m^3	1114
Reboiler steam flow rate	kg/hr	4800
Reboiler steam temperature	°C	169
Reboiler steam pressure	barg	4.42
Reboiler condensate temperature	°C	118.8
Reboiler condensate pressure	barg	4.11
Stripper overhead pressure	barg	0.90
Stripper overhead temperature	°C	99.8
Stripper overhead reflux flow rate	kg/hr	1370
Stripper overhead reflux temperature	°C	23.3
Stripper sump temperature	°C	119.3
Reboiler solution temperature	°C	122.3
Lean vapour compressor system	-	off
Product CO_2 flow rate	kg/hr	2670
Product CO_2 discharge temperature	°C	17.7
Product CO_2 discharge pressure	barg	0.023

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