Carbon Clean Solutions USA Inc.

FINAL REPORT

TESTING OF APBS SOLVENT

IN

10 TPD CO_2 CAPTURE PILOT PLANT

AT

NATIONAL CARBON CAPTURE CENTER (NCCC)

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1. INTRODUCTION

Carbon Clean Solutions, Ltd. (CCSL), a company based in London, UK, has provided two APBS family of solvents, for two phases of CO_2 capture testing at the Pilot Scale Test Unit (PSTU) of the National Carbon Capture Center (NCCC) operated by Southern Company Services in Wilsonville, AL. The Phase I testing was carried out in March-April 2014 (primarily with 4 vol. % CO_2 flue gas). During Phase I testing, some runs were carried out with 11.4 vol.% CO_2 flue gas as well. This report presents the data from Phase I testing and its analysis.

Section 2.0 presents a detailed analysis of the data obtained during the runs taken at NCCC. Section 3.0 presents the data obtained during Phase I for limited runs with 11.4 vol.% CO_2. Some observations are also noted. Phase II testing was conducted in February-April 2015 only with 11.4 vol. % CO_2 flue gas. During Phase II testing, it was found that the measured values of the steam requirements (in lb/lb CO_2) were much higher than those that were obtained during Phase I testing with 11.4% CO_2 and also compared to the values estimated based on an energy balance around the stripper at the PSTU. The issue was discussed with the engineers at NCCC who reported that the steam trap at the PSTU was malfunctioning during the test period affecting the steam flow measurements. This report, therefore, **does not cover** the data from Phase II runs although an analysis is presented in Section 4.0 confirming that there was a problem with the steam flow measurements.

Section 5.0 presents the detailed APBS emissions testing of amines, degradation products and Nitrosamines testing results. Section 6.0 presents the conclusions. Since the PSTU has now been equipped with new steam traps and new steam flow meters, CCSL has requested that testing be repeated under Phase II conditions with the appropriate APBS solvent.

2. PHASE I TESTING: 4.3 VOL. % CO2

Phase I testing was conducted in March-April 2014. There were two steam flow meters used then in PSTU: One for lower flows (below 1,000 lb/hr) and one for flows higher than 1,000 lb/hr. During the Phase I runs with 4 vol. % CO_2 in the flue gas, the first meter, with low flow range, was used. As a calibration check, gravimetric measurements of steam condensate were also carried out. The steam flow rates were consistent with the expected values and are given in Table 1 below (Olson; May 2015).

Table 1: Summary of Phase I Test Data from PSTU at NCCC (with 4.3% CO_2 wet)

No.	Run Date	Strip P, psig	Gas Flow, lb/hr	Liquid Flow, lb/hr	L/G, w/w	CO2 eff., %	CO2 Abs., lb/hr	Steam, lb/hr	Steam/ CO2, lb/lb	Energy, Btu/lb CO2
J3	5/1/2014	9.8	8,000	5,200	0.65	85.5	439.8	718.9	1.63	1,529.9
J4	5/1/2014	10.3	8,000	6,000	0.75	88.9	496.0	754.2	1.52	1,419.5
J5	5/1/2014	10.0	8,000	6,800	0.85	88.9	458.9	721.3	1.57	1,469.3
J6	5/2/2014	12.8	8,000	5,200	0.65	91.4	468.2	713.2	1.52	1,414.3
J7	5/3/2014	18.3	8,000	5,200	0.65	90.9	466.2	743.6	1.59	1,472.1
J8	5/5/2014	23.1	8,000	5,200	0.65	89.3	458.4	743.2	1.62	1,488.1
J9	5/7/2014	11.7	8,000	6,000	0.75	90.5	464.5	719.5	1.55	1,442.8
J10	5/8/2014	11.7	8,000	6,000	0.75	89.0	457.3	727.1	1.59	1,480.1
J11	5/8/2014	11.7	8,000	6,000	0.75	90.7	464.9	729.3	1.57	1,460.1
J12	5/10/2014	14.7	8,000	6,000	0.75	90.7	463.2	671.9	1.45	1,346.8
J13	5/11/2014	14.9	8,000	6,000	0.75	90.5	464.9	670.1	1.44	1,337.1
J14	5/12/2014	14.7	8,000	6,000	0.75	91.9	470.7	696.2	1.48	1,372.1
J15	5/13/2014	14.7	8,000	6,000	0.75	92.5	475.6	682.3	1.43	1,330.9
J16	5/13/2014	22.6	8,000	6,000	0.75	89.5	458.6	716.6	1.56	1,437.7
J19	5/15/2014	22.6	8,000	6,000	0.75	90.4	463.6	763.8	1.64	1,515.1

Common Conditions

1) APBS solvent
2) Wash water Flow = 10,000 lb/hr; Wash water section exit gas T = 110 F
3) Three stages of packing. **J19** was with 2 packed beds. See comments in Section 2.5.
4) Inter-stage cooling: No
5) Steam at 35 psia, 268 F. Enthalpy = 927 Btu/lb.

2.1 Effect of L/G ratio (Patkar; July 2015)

The effect of L/G ratio on regeneration efficiency is shown in Figure 1 below with the stripper pressure being held constant at 10 psig (Runs J3 to J5). The regeneration energy goes through a minima at L/G = 0.75 w/w (or 6,000 lb/hr liquid flow for 8,000 lb/hr of gas flow). The "smooth curve" minima was at L/G ratio of ~ 0.76 (w/w) and ~ 1,416 Btu/lb; very close to conditions of Run J4. At each stripper pressure, there would be such a minima. However, we did not test at 3, or more, L/G ratios at each stripper pressure. In future tests, we should create a set of curves like that in Figure 1 with stripper pressure as a parameter.

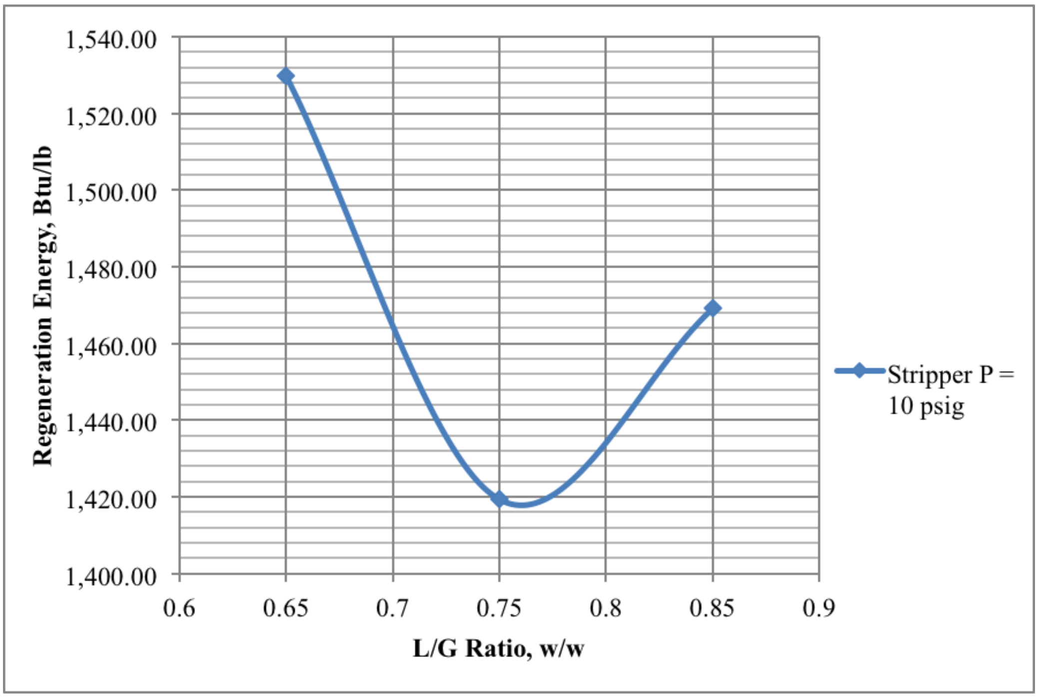

Figure 1: Effect of L/G ratio on Regeneration Energy

Table 1a: Data Plotted in Figure 1 (Taken from Table 1)

No.	Run Date	Strip P, psig	Gas Flow, lb/hr	Liquid Flow, lb/hr	L/G, w/w	CO2 eff., %	CO2 Abs., lb/hr	Steam, lb/hr	Steam/ CO2, lb/lb	Energy, Btu/lb CO2
J3	5/1/2014	9.8	8,000	5,200	0.65	85.5	439.8	718.9	1.63	1,529.9
J4	5/1/2014	10.3	8,000	6,000	0.75	88.9	496.0	754.2	1.52	1,419.5
J5	5/1/2014	10.0	8,000	6,800	0.85	88.9	458.9	721.3	1.57	1,469.3

2.2 Effect of Stripper Pressure (Patkar; July 2015)

The effect of the stripper pressure on regeneration efficiency is shown in Figure 1 below with the L/G ratio being held constant at 0.75 w/w. The regeneration energy goes through a sharp minima at stripper pressure close to 15 psig. The “smooth curve” minima is at stripper pressure of ~ 14 psig and 1,325 Btu/lb CO_2; close to the conditions of Run J15. At each L/G ratio, there would be such a minima. However, we did not test at 3, or more, stripper pressures, at each L/G ratio. In future tests, we should create a family of curves like that in Figure 2 with L/G ratio as a parameter.

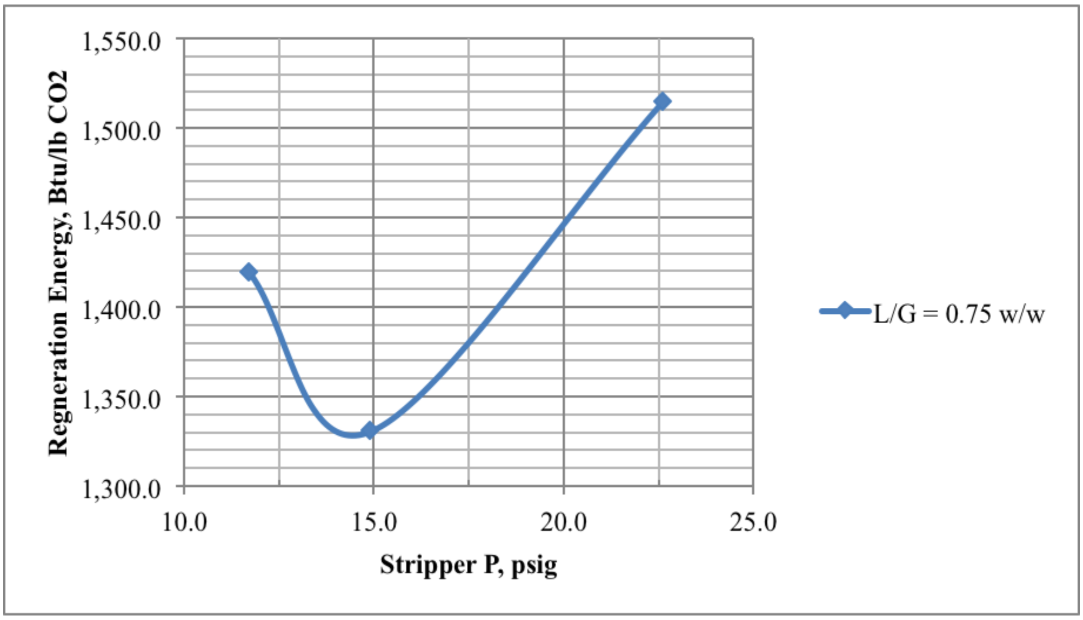

Figure 2: Effect of Stripper Pressure on Regeneration Energy

Table 1b: Data Plotted in Figure 2 (Taken from Table 1)

No.	Run Date	Strip P, psig	Gas Flow, lb/hr	Liquid Flow, lb/hr	L/G, w/w	CO2 eff., %	CO2 Abs., lb/hr	Steam, lb/hr	Steam/ CO2, lb/lb	Energy, Btu/lb CO2
J9	5/7/2014	11.7	8,000	6,000	0.75	90.5	464.5	719.5	1.55	1,442.8
J15	***5/13/2014***	***14.7***	***8,000***	***6,000***	***0.75***	***92.5***	***475.6***	***682.3***	***1.43***	***1,330.9***
J19	5/15/2014	22.6	8,000	6,000	0.75	90.4	463.6	763.8	1.64	1,515.1

2.3 Optimal L/G Ratio and Stripper Pressure

It is noted here that the CO_2 absorption efficiency was 92.5% for Run J15 which had the minimum energy of regeneration. Thus, it is concluded that, the regeneration energy for conditions of Run J15, but for CO_2 removal efficiency of 90%, would have been ~ 1,290 Btu/lb CO_2 (or 3.0 GJ/ton CO_2). In order to obtain the **true global minimum value of regeneration energy,** we will need to carry out more experiments at NCCC. However, from the plots in Figures 1 and 2, it seems that we would get a global minimum value below 1,290 Btu/lb (3.0 GJ/ton CO2) to achieve 90% CO_2 capture at NCCC with G = 8,000 lb/hr, L/G ratio of 0.76 (or L = 6,080 lb/hr) and stripper pressure of 14 psig.

2.4 Effect of Inter-cooling

Run J17 was carried out with inter-cooling. All other conditions were the same as Run J16. The regeneration energy reduced only slightly (less than 0.3%) to 1,434.4 Btu/lb CO_2. This suggests that inter-cooling may not effective in reducing the regeneration energy for 4 vol.% CO_2 flue gas.

2.5 Effect of Number of Packed Beds

Run J19 was carried out with 2 beds. All other conditions were the same as in Run 16. The regeneration energy increased to 1,515.1 Btu/lb CO_2 but the CO_2 removal efficiency was also slightly higher at 90.4 % (as against 89.5% for Run J16). This shows that the CDR Max ® solvent was capable of removing 90% CO_2 with two packed beds (of 6 meter or 20' packing in PTSU) with ~5% more regeneration energy as compared to that required with 3 beds even with 4.3 vol.% CO_2 in the inlet flue gas.

2.6 Expected Minimum Energy Consumption

The projected regeneration energy for 90% CO_2 capture (1,290 Btu/lb CO_2 or 3.0 GJ/ton CO_2) is 35-40% lower than the values reported for MEA for gas-fired boiler flue gas. However, this is not the lowest achievable value for the APBS solvent. The PSTU was designed for operation using 30% MEA with the flexibility to accommodate other solvents. But the PSTU's lean/rich heat exchanger was not designed for the higher viscosity of the APBS solvent relative to 30% MEA. Thus, the measured approach temperatures during the APBS solvent test were higher than those for MEA leading to less than optimal heat recovery.

Our simulations with g-PROM have predicted that with optimal lean/rich heat exchanger and an advanced, patented stripper design, the minimum regeneration energy of 1,200 Btu/lb CO_2 (2.8 GJ/ton CO_2) can be achieved for CO_2 removal of 90% under the following conditions:

1) Flue gas with 4.3 vol.% CO_2 and 16 vol.% O_2 (G = 8,000 lb/hr at PSTU)
2) Absorber gas velocity = 9 ft/sec (PSTU absorber diameter = 2', Area = 3.142 ft^2)
3) L/G ratio of 0.76 w/w (or L = 6,080 lb/hr at PSTU, Phase I),
4) Stripper pressure of 14 psig

2.7 Effect of Oxygen: Ammonia Emissions (16 vol.% O2)

Table 2 provides NH_3 emissions measured in the vapor stream at the wash water outlet in the PSTU at NCCC for a flue gas with 4.3 vol.% CO_2 and 16 vol.% O_2 (simulating a natural gas fired boiler). As can be seen, then average ammonia emissions were 3.22 ppmv.

Table 2: Ammonia Emissions with APBS Solvent (4.3 vol. % CO_2, 16 vol.% O_2)

Wash Water Outlet	**Vapor 1**	**Vapor 2**	**Vapor 3**
NH_3 emissions, ppm	2.84	3.07	3.75

2.8 Dissolved Metals Concentrations

During Phase I, samples were taken for fresh solvent at the beginning of the test runs and from spent solvent at the end of the test runs. Similar tests were carried out for MEA runs in 2013. A comparison is shown for the test results for APBS solvent and MEA is given in Table 2 below.

Table 2: Metal Concentrations in Solvents Before and After the Test Runs (ppb wt) [a]

Metal	Fresh MEA	Fresh APBS	Rich MEA[b]	Rich APBS[b]	RCRA Limit
Arsenic	< 12	53.2	219	114	5,000
Barium	< 12	<10	265	11.8	100,000
Cadmium	< 12	< 5	< 10	< 5	1,000
Chromium	< 12	42.2	45,090	2,120	5,000
Selenium	44.1	41.8	1,950	660	1,000

a: Wheeldon, J. 2013

b: Solvent at the end of the test run. MEA with 300 hrs and APBS with 500hrs of operations

No corrosion inhibitors were used in either tests. As can be seen, then level of chromium for MEA was more than 22 times that in APBS solvent, after two months of testing. This indicates that MEA is much more corrosive than APBS solvent.

NCCC has concluded that the major source of selenium may be the flue gas. The inlet flue gas with APBS solvent testing was not sampled for selenium or other metals. However, since the coal used at the Gaston power plant was from the same source, the metals level in the flue gas would not have changed significantly from MEA tests in 2013 to those for APBS in 2014. The level of selenium is three times higher in the MEA sample at the end of the runs and this level (1,950 ppb wt) is almost twice of the RCRA limit of 1,000 mg/L (which is the same as ppb wt for a liquid with specific gravity of 1.0).

2.9 CO_2 Purity

The CO_2 stream after the condenser was analyzed and it was found to be consistently higher than 97 vol.% in CO_2 with ~ 2.5 vol.% water vapor 210 ppm N_2.

3. PHASE I TESTING: 11 VOL.% CO2

As stated earlier, a limited number of test runs were carried out during Phase I with Table 3 below compares the PSTU data with the estimated steam value from the energy balance.

Table 3: Summary of Phase I Test Data from PSTU at NCCC (runs with 11 vol.% CO_2)*

No.	Run Date	Strip P, psig	Gas Flow, lb/hr	Liquid Flow, lb/hr	L/G, w/w	CO2 eff., %	CO2 Abs., lb/hr	Steam, lb/hr	Steam/ CO2, lb/lb	Energy, Btu/lb CO2
J4	4/6/2014	14.0	5,000	12,000	2.4	83.0	682.7	1013.7	1.48	1,386.1
J5	4/7/2014	18.9	5,000	12,000	2.4	91.1	753.7	1118.5	1.48	1,374.6
J6	4/7/2014	19.5	5,000	10,000	2.0	89.5	737.8	1059.9	1.44	1,331.3
J7	4/8/2014	19.6	5,000	8,000	1.6	92.1	774.0	1034.8	1.34	1,234.2

***The J run numbers were reused but these were on different dates than those in Table 1.**

Common Conditions

1) APBS solvent
2) Wash water Flow = 10,000 lb/hr; Wash water section exit gas T = 110 F
3) Three stages of packing.
4) Inter-stage cooling: Yes.
5) Steam at 35 psia, 275 F. Enthalpy = 927 Btu/lb.

3.1 Observations

1) There **were not enough data** to plot a graph such as Figure 1.
2) The best conditions were for Run J7: G = 5,000 lb/hr, L = 8,000 lb/hr and stripper P = 19.8 psig. For a CO_2 capture efficiency of 92.1%, the steam to CO_2 ratio was 1.34 (energy of regeneration 1,234 Btu/lb CO_2 or 2.87 GJ/ton CO_2). If the liquid flow was reduced further (to, say, 7,000 lb/hr) at stripper pressure of 20 psig, a lower value of energy of regeneration (~ 1,170 Btu/lb or 2.7 GJ/ton CO_2) would have been obtained.
3) Not enough runs were taken to determine the effect of stripper pressure. The variations in L//G and stripper pressure were planned in Phase II testing (February/April 2015).
4) Our simulation program g-PROM has predicted that, with an optimal design of lean/rich heat exchanger and our patented stripper configuration, a minimum regeneration energy of 1,075 Btu/lb CO_2 (or 2.5 GJ/ton CO_2) can be achieved for:
    1) 90% CO_2 absorption from a flue gas with 11.4 vol.% CO_2
    2) Gas velocity = 5.5 ft/sec (G = 5,000 lb/hr; gas density = 0.078 lb/ft^3)
    3) L/G ratio = 1.4 w/w (L = 7,000 lb/hr at PSTU)
    4) Stripper pressure of 20 psig

4. PHASE II TESTING: 11 VOL.% CO2

NCCC staff carried out Phase II testing with APBS solvent from February 2015 to April 2015. Despite some spells of below freezing weather, 25 runs were completed. When the results were reviewed by CCSL, significant variations were found in steam flow between test runs carried out in 2014 (given in Table 2) and those in 2015; both with 11% CO_2 flue gas and with close to identical gas and liquid flows, stripper pressures and CO_2 removal efficiencies. The differences were especially pronounced (almost 50%) at stripper pressures above 15 psig. A two pronged approach was taken to review the data for tests carried out in 2014 and 2015 (Olson, 2015). We have done the review as follows:

1) Comparison of selected runs from 2014 and 2015 with 11% CO_2 in the flue gas for the same gas flow, liquid flow, stripper pressure and CO_2 removal efficiency.

2) Energy balance around the stripper using other measured data from PSTU to check steam flow.

4.1 Comparison of Data from Phase I and Phase II

Table 4 provides a comparison of data from two runs taken in 2014 with two taken in 2015.

Table 4: Comparison of Data from Runs in 2014 and 2015 (Runs with 11 vol.% CO_2)*

No	Date	G, lb/hr	L , lb/hr	P, psig	CO2, eff. %	CO2, lb/hr	Steam lb/hr	S/CO2, lb/lb	Error, + %
J5	4/7/14	5,000	12,000	18.9	90.4	753.7	1,118	1.48	50.6
N10	3/5/15	5,001	10,000	19.9	89.2	800.6	1,789	2.23	
J6	4/7/14	4,999	10,000	19.5	88.6	737.8	1,059	1.44	45.8
N11	3/6/15	5,007	10,000	19.8	88.4	791.2	1,665	2.10	

*J runs were with 3 beds of packing and N runs were with 2 beds of packing..

4.2 Observations

1. With all other parameters being the same, a 3-bed system would be ~6% more energy efficient. Thus, the fact that 2014 tests were carried out with 3 beds does not explain the 50% rise in steam to CO_2 ratio for runs N10 and N11 (carried out in 2015).

2. In comparing data from runs J5 and N10, it is noted that that the liquid flow for N10 was a bit lower. But this should make it more energy efficient (See data in Table 2).

3. The N runs had slightly more concentration of the solvent than the corresponding J runs. This, again, should make them more energy efficient, not less.

4. N runs had higher rich and lean loadings of CO_2 (by 2 wt%) than the J runs. If the lean solutions in N Runs were leaner in CO_2, it could partly explain the higher energy requirements.

4.3 Energy Balance around the Stripper

A detailed energy balance was carried out around the stripper (Patkar; April, 2015). Figure 4 is a schematic diagram for the energy balance envelop.

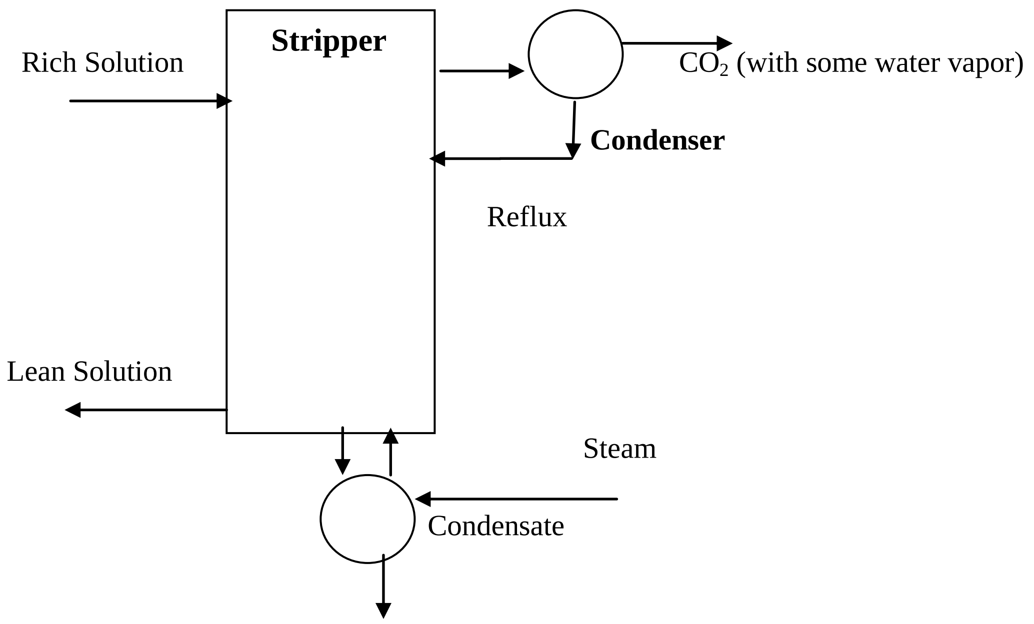

Figure 4: A Schematic Diagram of CO_2 Stripper: Input and Output Streams

The basic approach used for the energy balance was as follows:

1) Use values of rich and lean solutions flows and temperatures from PSTU data
2) Use appropriate specific heat (Cp) values for lean and rich solutions and CO2 and water vapors. .
3) Use the heat f reaction measured at in independent laboratory for CO_2 stripping.
4) Use CO_2 absorbed from gas side mass balance.
5) Use values of flow and temperature for the recovered CO_2 from PSTU data.
6) Use cooling water flow and temperature difference from PSTU data
7) The input streams are: Rich Solution, Condensate Reflux, Steam, Cooling Water.
8) The output streams are: Recovered CO_2 (and water), Cooling Water (higher T) and condensate
9) Estimate the amount of steam required by using an energy balance.

4.4 Analysis of Data

The above method was used and an energy balance was carried out for all N runs with 11 vol. % CO_2 flue gas from 2015. The analysis is summarized below.

1) **In all cases, the measured values of steam flow were higher than those expected by the energy balance.** The error was below 15% at stripper pressure of 7 psig.
2) For Runs N4 and N5, carried out at 11.6 psig, the error was greater than 20%.
3) **The measured steam flows for stripper pressures of 16, 20 and 25 psig were 18 to 42% higher than the expected values. This was a significant probem since the 2014 data with 11 vol. % CO_2 had indicated that the stripper pressure of 20 psig (or perhaps higher) may be the optimal value.**

The issue was discussed in details with the NCCC staff. They reviewed the data independently and agreed with our conclusions that the additional packed bed during Phase I would not cause measured values of steam flow to be 40-50% higher than those measured during Phase I tests under identical flue gas and liquid flows and stripper pressures.

They checked the pilot plant hardware and reported that the steam trap in the condensate return line was malfunctioning and that some un-condensed steam was escaping the trap. Thus, the measured value of steam was not a reliable indicator of the energy used in the stripper. **We have, therefore, not given the data from Phase II tests in a table or graphical format.**

5. PHASE II: APBS EMISSIONS TESTING

During Phase II, NCCC had contracted Southern Research (SR) to carry out an analysis of amines and degradation products in the gas leaving the water wash. The results are summarized here in Tables 5 and 6.

5.1 APBS Amines and degradation products

Table 5: Analysis of Non-condensed Vapor at Wash Tower Outlet (SR; May 2015)

Run Identification	**CCS-WTO-7**	**CCS-WTO-9**	**CCS-WTO-10**
Compounds Analyzed	**All values in ppmwt in flue gas**		
Sum of nitrsoamines in Thermosorb N tube,	0.0	0.0	0.0
Sum of amines on sorbent tube SKC 226-30-18	2.62	9.75	2.60
Sum of aldehydes on sorbent tube SKC 226-119	1.46	1.70	1.48
Ammonia detected on sorbent tube SKC 226-10-06	12.25	11.26	7.34
Total hydrocarbons on sorbent tube SKC226-01 (as C6H6)	1.95	3.15	3.13

Table 6: Details of Compounds Analyzed for Data in Table 4 (SR; May 2015)

Run Identification	**CCS-WTO-7**	**CCS-WTO-9**	**CCS-WTO-10**
Aldehyde Profile on sorbent tube SKC 226-119 (rotameter #1); Detection Limit 0.5 µg			
Acetaldehyde, Total µg	22.7	36.3	1.23
Acrolein, Total µg	BDL	BDL	BDL
Butyraldehyde, Total µg	3.46	12.1	0.482
Formaldehyde, Total µg	1.08	1.11	0.974
Glutaraldehyde, Total µg	BDL	BDL	BDL
Ammonia on sorbent tube SKC 226-10-06 (rotameter #2); Detection Limit 0.5 µg			
Ammonia, Total µg	165	151	95.1
Total Hydrocarbons on sorbent tube SKC 226-01 (rotameter #4); Detection Limit 1.0 µg			
Total Hydrocarbons as Hexane, Total µg	52.5	88.7	81.7
Amine Profile on sorbent tube SKC 226-30-18 (rotameter #5) Detection Limit 1.0 µg			
Allylamine, Total µg	BDL	BDL	BDL
Butylamine, Total µg	BDL	BDL	BDL
Dibutylamine, Total µg	BDL	BDL	BDL
Diethanolamine, Total µg	BDL	BDL	BDL
Diethylenetriamine, Total µg	BDL	BDL	BDL
Dimethylamine, Total µg	BDL	BDL	BDL
Ethanolamine, Total µg	31.5	125	31.4
Ethylamine, Total µg	BDL	1.78	BDL
Ethylenediamine, Total µg	BDL	1.45	BDL
Isopropylamine, Total µg	BDL	BDL	BDL
Methylamine, Total µg	3.68	2.85	1.16

5.2 APBS Nitrosamines Testing

CCSL was interested in measuring any nitrosamines that are emitted from the CO2 absorber because we are planning to test our solvent system at TCM in Mongstad, Norway and they needed the data for environmental application.

NCCC and SR had contracted the Columbia Basin Analytical Laboratories of RJ Lee Inc. to conduct a detailed Nitrosamine APBS solvent testing. **In all three samples**, CCS-WTO-7, -8 and -10, the values of N-Nitroso-diethanolamine and a series of nitrosoamines were below **detection limits of the two methods used.** The results are summarized in Tables 7 and 8 below.

Table 7: N-Nitrosodiethanolamine by OHSA Method 31-Modified (Lee; April, 2015)

Sample ID	Detection Limit (ug/tube)	Concentration (ug/tube)
CCS-WTO-7, -9 and -10	0.04	<0.04

Table 8: Results for Nitroamaines by NIOSH 2522-Modified (Lee; April 2015)

Sample ID	Analyte	Detection Limit (ug/tube)	(ug/tube)
CCS-WTO-7, -9 and -10	N-Nitrosodimethylamine	0.02	<0.02
CCS-WTO-7, -9 and -10	N-Nitrosomethylethylamine	0.02	<0.02
CCS-WTO-7, -9 and -10	N-Nitrosodiethylamine	0.02	<0.02
CCS-WTO-7, -9 and -10	N-Nitrosodi-n-propylamine	0.02	<0.02
CCS-WTO-7, -9 and -10	N-Nitrosodi-n-butylamine	0.02	<0.02
CCS-WTO-7, -9 and -10	N-Nitrosopiperidine	0.02	<0.02
CCS-WTO-7, -9 and -10	N-Nitrosopyrrolidine	0.02	<0.02
CCS-WTO-7, -9 and -10	N-Nitrosomorpholine	0.02	<0.02

Note on Sampling

Samples from the sample ID CCS-WTO-8 were not analyzed because the main boiler tripped before the 2 hour duration was completed for this run.

6. CONCLUSIONS

6.1 Phase I Testing with 4% CO_2

1) **Regeneration Energy:** The lowest measured steam to CO_2 ratio was 1.43 for gas flow of 8,000 lb/hr, liquid flow of 6,000 lb/hr at stripper pressure of 14.7 psig, with a CO_2 removal of 92.5% (Table 1, Run J15). The heat of regeneration was 1,330.9 Btu/lb CO_2 (3.07 GJ/ton CO_2). It is projected that **90% CO_2 removal** will be achieved with regeneration energy of 1,290 Btu/lb CO_2 (3.0 GJ/ton CO_2) with 6,080 lb/hr of liquid flow at 14 psig. With an optimal lean-rich heat exchanger and our patented stripper design, an energy of regeneration of 1,200 Btu/lb (2.8 GJ/ton CO_2) is achievable.
2) **Effect of 2 Beds:** In Run J19, 90%CO_2 was absorbed with 2 beds (20' packing each).
3) **Emissions of NH3:** The emissions of NH_3, which is an indication of oxidative degradation of the solvent, were 3.2 ppmv, almost 17 times less than those of MEA (54 ppmv) measured at NCCC under identical wash tower exit flow and temperatures.
4) **Dissolved Metals:** Dissolved metals were measured for MEA and APBS solvents before and after the test runs. The dissolved chromium in MEA (45 ppmwt) was fond to be 22 times that in APBS (2.1 ppmwt) indicating much higher corrosion with MEA.

6.2 Phase I Testing with 11% CO2

1) **Regeneration Energy**: The lowest measured steam to CO2 ratio was 1.34 for gas flow of 5,000 lb/hr, a liquid flow of 8,000 lb/hr at stripper pressure of 19.6 psig, with a CO_2 removal efficiency of 92.1% (Table 2, Run J7). The corresponding heat of regeneration was 1,234 Btu/lb CO_2 (2.87 GJ/ton CO_2). It is estimated that, at these same conditions, 90% CO_2 removal will be achieved with 1,160 Btu/lb CO_2 (2.7 GJ/ton CO_2) with 7,000 lb/hr of liquid flow at stripper pressure of 20 psig. With an optimal lean-rich heat exchanger and our patented stripper configuration, an energy of regeneration of 1,060 Btu/lb (2.5 GJ/ton CO_2) is achievable.

6.3 Phase II with 11% CO2

1) **Steam Data:** The measured values of steam flows for all 25 runs were higher than those expected by the stripper energy balance. For stripper pressure of 7 psig, the error was 10-12%. For higher pressures (11.8, 16, 20 and 25 psig), the error was 12 to 42%. NCCC reported that the steam trap was malfunctioning and that some un-condensed steam was escaping the trap.
2) **Degradation Compound Emissions:** The emissions testing showed that the average emission of amines and NH_3 in the gas after the wash tower were 5 ppmwt and 10 ppmwt respectively. Total aldehydes and hydrocarbons were below 2 and 3 ppmwt respectively. And no nitrosoamines were detected from a family of 8 compounds.

7. RECOMMENDATION

Since the steam trap has been replaced with new one, we request that CCSL be allowed to test for 4 weeks with 11.4% CO_2 flue gas later this year so that we can complete the analysis for this case with more reliable data from the PSTU at NCCC with APBS solvent.

During both Phase I and Phase II testing, the absolute pressure of the gas along the absorber was not measured reliably. Thus the second recommendation is that more accurate gas pressure sensors be used in the absorber at the PSTU in NCCC. This will allow to develop a pressure drop profile as a function of gas and liquid flow rates (or fluxes).

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