



# The CONTACTOR™

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## Cleaning Landfill Gas

One form of biogas is from landfill which produces gas from Municipal Solid Waste (MSW) over a period of up to 50 years via the anaerobic decomposition of solid wastes such as paper, wood, vegetable matter, plastics, and assorted other materials, accumulated in large heaps or mounds. The waste is compressed into deposits and separated from other waste deposits by layers of compacted clay-like earths of low permeability. The deposits are interconnected via pipework that serves to convey produced gases to central collection points. A more common form of biogas is produced from commercial wastes such as sugarcane and beet-sugar vinasse, (cane vinasse is also called dunder) and animal waste (manure), very rarely under pressure.

Regardless of the source of the produced gas, it is generally fairly high in CO<sub>2</sub> and may contain substantial concentrations of sulphur compounds. For example, landfill gas has roughly 60–40 parts of methane and 40–60 parts CO<sub>2</sub> plus small amounts of other species such as sulphur containing components, typically hydrogen sulphide, mercaptans, COS, and water. Vinasse is a residual liquid remaining from the fermentation and distillation of alcoholic liquors. In Brazil, for example, cane vinasse is produced in large volumes from the manufacture of fuel ethanol from sugar cane. In the early stages, decomposition tends to be aerobic because the waste tends to be formed in the presence of air (especially in landfills) so the gas will also contain a certain amount of oxygen. However, as decomposition proceeds, oxygen is swept out and the process quickly becomes anaerobic.

By no means is all biogas treated for CO<sub>2</sub> removal and used as a natural gas substitute. Much is used to evaporate leachate from the landfill, for

example. Some is used in greenhouses, while some is used directly for power generation using reciprocating engines. When biogas is to be purified to a natural gas equivalent, one of four methods is generally used: water scrubber, membrane separation, molecular sieves, and amine scrubbing.

Challenges to CO<sub>2</sub> removal presented by biogas are its low pressure, therefore a relatively low partial pressure of CO<sub>2</sub>, and the presence of sulphur species which, if left in the gas, create sulphur emissions when the recovered methane is burned (and if removed with the CO<sub>2</sub> preclude using the recovered CO<sub>2</sub> in a number of commercial applications). Biogas flows can be fairly small compared with flue gas rates from power plants, for example, leaving unanswered just how the CO<sub>2</sub> could be economically exploited (e.g., as green CO<sub>2</sub> or credits). The inclusion of sulphur compounds certainly doesn't make answering this question any easier. Other concerns are the disposal of the water content of the produced gas because the gas must be dried before entering most piping systems and the condensed water must be considered contaminated.

In what follows we will look at treating a landfill gas pre-treated for H<sub>2</sub>S using an MDEA-piperazine mixture for the removal of CO<sub>2</sub>. Because there is a lot of CO<sub>2</sub> in biogas, the energy consumed by CO<sub>2</sub> removal to produce a high methane

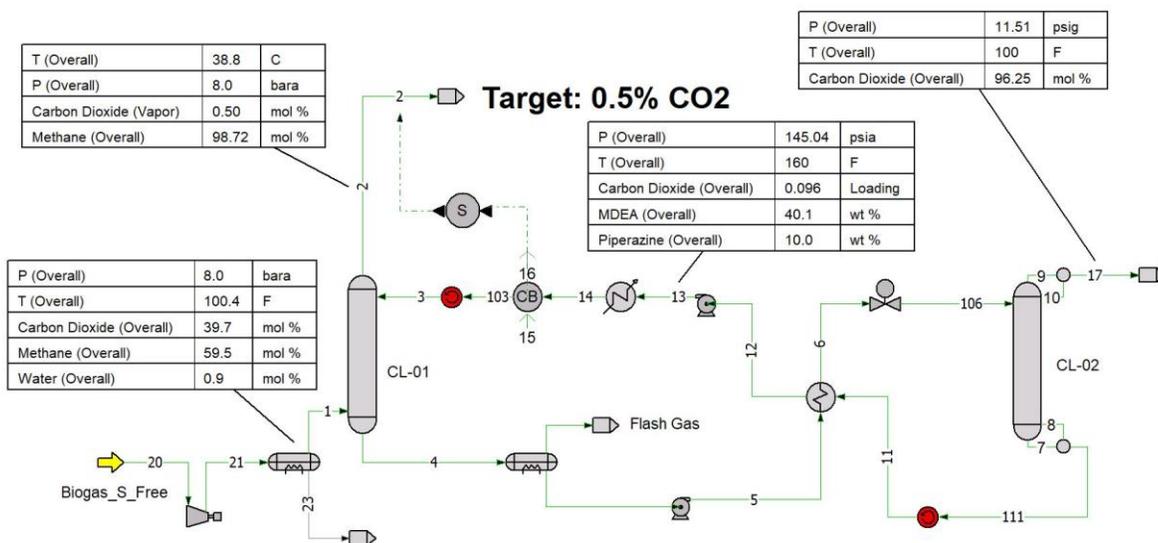


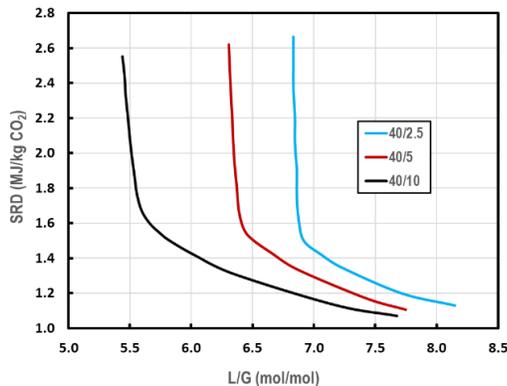
Figure 1 Flowsheet of Biogas Purification Plant

fuel is of paramount importance because it represents the lion's share of the biogas treating cost. Therefore, we will focus on reboiler energy consumption.

### Case Study

Figure 1 shows a schematic of the simple absorber-regenerator system used for CO<sub>2</sub> removal. Included are callouts showing the key process stream parameters for a typical case. In this instance, the solvent is 40 wt% MDEA with 10 wt% piperazine at 38°C and 121.8 Std m<sup>3</sup>/h. About 98.6% of the CO<sub>2</sub> can be removed under these simulation conditions.

Figure 2 shows how the specific duty (energy consumed per unit of CO<sub>2</sub> removed) depends on the L/G ratio. The pressure is 8 bara because the gas had already been compressed for H<sub>2</sub>S and sulphur removal. The legend indicates the MDEA and piperazine concentrations (wt%) and all simulations were run at the same CO<sub>2</sub> removal rate (0.5% at absorber outlet) and varying the molar boilup ratio in the regenerator (defined as the molar flowrate of vapor produced by the reboiler divided by the molar flowrate of liquid coming from the reboiler). ProTreat® automatically adjusts reboiler duty to maintain the specified boilup ratio. The solvent flow needed to produce a treated gas containing 0.5 mol% CO<sub>2</sub> was determined for each case using ProTreat's Solver feature (block labelled S in the figure) which automatically adjusts solvent flow controlled by the Control Block (CB in the figure) to achieve the specified CO<sub>2</sub> content in the treated gas.



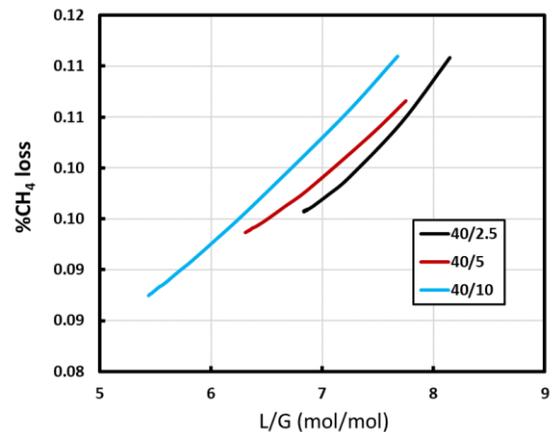
**Figure 2 Effect of L/G Ratio and Solvent Composition on Specific Reboiler Duty**

Given that the inlet gas flow was the same for all cases (15 kNm<sup>3</sup>/h), for each solvent composition there is a minimum solvent flowrate below which the necessary reboiler energy escalates rapidly. This can be easily understood by recognising that below a certain solvent flowrate the solvent simply lacks the capacity to remove CO<sub>2</sub> to the desired level.

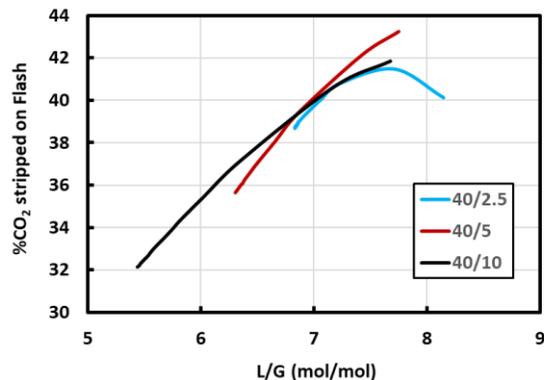
Reboiler energy needed for CO<sub>2</sub> stripping starts to level off as liquid rate carries on increasing because of the way the regenerator has been set up. The cross exchanger was specified with a fixed UA which forces the hot rich amine entering the regenerator to have the same temperature in all cases because the hot lean is always the same. (In fact, this stream contains only a small amount of vapor so it's close to a bubble

point liquid.) The reboiler temperature hardly changes from cases to case, the CO<sub>2</sub> stripping rate is almost constant, so there's no reason to expect anything but a very small dependency of reboiler duty on solvent flow. This is in fact what is seen.

Figures 3 and 4 indicate how much methane is lost in the rich amine flash and what fraction of the absorbed CO<sub>2</sub> is stripped there. Methane loss is fairly small simply because of its low solubility in the aqueous solvent (and low circulation rates compared to water scrubbing). In fact, none of the other conventional upgrading technologies can achieve that low CH<sub>4</sub> losses. To keep the solvent circulation rate low, the rich solvent is heavily loaded with CO<sub>2</sub> and this allows a substantial fraction of it to be flashed off in the rich amine flash tank.



**Figure 3 Fraction of Methane Lost**



**Figure 4 Effect of L/G Ratio and Solvent Composition on Specific Reboiler Duty**

To learn more about this and other aspects of gas treating and sulphur recovery, plan to attend one of our training seminars. Visit [www.protreat.com/seminars](http://www.protreat.com/seminars) for details.

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