An Introduction to CO_2 Separation and Capture Technologies

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In general, to economically sequester CO_2 produced from power plants, one must first produce a relatively pure, high pressure stream of CO_2[1]. There are exceptions to this rule, some of which will be explored later in this paper. The process of producing this CO_2 stream is referred to as separation and capture, which encompasses all operations that take place at the power plant site, including compression. For ease of transport, CO_2 is generally compressed to the order of 100 atm[2].

The idea of separating and capturing CO_2 from the flue gas of power plants did not start with concern about the greenhouse effect. Rather, it gained attention as a possible economic source of CO_2, especially for use in enhanced oil recovery (EOR) operations where CO_2 is injected into oil reservoirs to increase the mobility of the oil and, therefore, the productivity of the reservoir. Several commercial CO_2 capture plants were constructed in the late 1970s and early 1980s in the US. When the price of oil dropped in the mid-1980s, the recovered CO_2 was too expensive for EOR operations, forcing the closure of these capture facilities. However, the North American Chemical Plant in Trona, CA, which uses this process to produce CO_2 for carbonation of brine, started operation in 1978 and is still operating today. Several more CO_2 capture plants were subsequently built to produce CO_2 for commercial applications and markets. Some of these plants took advantage of the economic incentives in the Public Utility Regulatory Policies Act (PURPA) of 1978 for "qualifying facilities". A listing of the major CO_2 capture plants are shown in Table 1.

To date, all commercial CO_2 capture plants use processes based on chemical absorption with a monoethanolamine (MEA) solvent. MEA was developed over 60 years ago as a general, non-selective solvent to remove acid gases, such as CO_2 and H_2S, from natural gas streams. The process was modified to incorporate inhibitors to resist solvent degradation and equipment corrosion when applied to CO_2 capture from flue gas. Also, the solvent strength was kept relatively low, resulting in large equipment sizes and high regeneration energy requirements. As shown in Figure 1, the process allows flue gas to contact an MEA solution in the absorber. The MEA selectively absorbs the CO_2 and is then sent to a stripper. In the stripper, the CO_2-rich

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[1] This requirement is primarily due to economic considerations. The economics of transporting CO_2 any distance will favor concentrated CO_2. Also, sink capacity is better utilized by injecting pure CO_2. Finally, though still a subject of research, some impurities may be harmful to the operations of certain sinks or may have adverse environmental effects.

[2] Most systems can be designed so that no recompression is required beyond the power plant. For example, CO_2 from the Great Plains Synfuels Plant is transported 330 km from Beulah, ND to Weyburn, Saskatchewan. It is initially compressed to 170 atm and delivered at 148 atm, with no recompression.

MEA solution is heated to release almost pure CO_2. The lean MEA solution is then recycled to the absorber.

An initial reaction some people have to CO_2 capture technology is that it is “expensive”. However, “expensive” is a subjective (as opposed to objective) term. If one can produce CO_2 for $25 per tonne from flue gas, is that expensive? Yes, if $10 per tonne CO_2 is available from natural reservoirs. No, if one has to pay typical commercial rates of $70-100 per tonne.

In applying these commercial processes to CO_2 sequestration, it is worthwhile exploring why there is the perception that CO_2 separation and capture is expensive. Reasons include:

- It will always be more expensive to sequester CO_2 than to just emit it to the atmosphere.
- Most studies show that the bulk of the cost in sequestering power plant CO_2 are due to separation and capture (including compression) as opposed to transport and injection.
- The commercial MEA process is old and has not been optimized for sequestration.
- The basis of design is very different for plants producing CO_2 for commercial markets as compared to plants producing CO_2 for sequestration. This relates to the difference between the cost of capture and the cost of avoidance, as discussed below.

The primary difference in capturing CO_2 for commercial markets versus capturing CO_2 for sequestration is the role of energy. In the former case, energy is a commodity, and all we care about is its price. In the latter case, using energy generates more CO_2 emissions, which is precisely what we want to avoid. Therefore, capturing CO_2 for purposes of sequestration requires more emphasis on reducing energy inputs than the traditional commercial process. Figures 2 and 3 help define the difference between CO_2 captured and CO_2 avoided and the concept of the “energy penalty”.

Other processes have been considered to capture the CO_2 from the flue gas of a power plant -- e.g., membrane separation, cryogenic fractionation, and adsorption using molecular sieves -- but they are even less energy efficient and more expensive than chemical absorption. This can be attributed, in part, to the very low CO_2 partial pressure in the flue gas. Therefore, two alternate strategies to the “flue gas” approach are under active consideration – the “oxygen” approach and the “hydrogen” or “syngas” approach.

The major component of flue gas is nitrogen, which enters originally with the air feed. If there were no nitrogen, CO_2 capture from flue gas would greatly simplified. This is the thinking behind the oxygen approach, where instead of air, the power plant is fed oxygen produced by an air separation plant. However, combustion with oxygen yields temperatures too large for today’s materials, so some flue gas must be recycled to moderate the temperature. Applying this process is easier for steam turbine plants than gas turbine plants. In the former, relatively straightforward boiler modifications are required. For the latter, much more complex gas turbine design changes will be required.

The flue gas approaches in use today require clean-up of the NO_x and SO_2 prior to CO_2 separation. The oxygen route does not. If the sinks are tolerant to NO_x and SO_2, we can eliminate separate control steps and sequester the NO_x and SO_2 along with the CO_2, resulting in a zero emissions power plant.

Integrated coal gasification combined cycle (IGCC) plants are an example of the hydrogen route. Coal is gasified to form synthesis gas (syngas) of CO and H_2. The gas then undergoes the water-gas shift, where the CO is reacted with steam to form CO_2 and H_2. The CO_2 is then removed, with the hydrogen being sent to a gas turbine combined cycle. This approach allows for a CO_2 removal process (e.g., a physical solvent process like Selexsol) that is much less energy intensive than the MEA process because capture takes place from the high pressure syngas as opposed to the atmospheric pressure flue gas. A similar process is available for natural gas, where the syngas is formed by steam reforming of methane.

The hydrogen route opens up opportunities for “polygeneration”, where besides electricity and CO_2, additional products are produced. For example, instead of sending hydrogen to a turbine, it can be used to fuel a “hydrogen economy”. In addition, syngas is an excellent feedstock for many chemical processes.

A frequently asked question is what is the cost of CO_2 capture and separation today, in the near-future, and in the long-term. In Table 2, some estimates are given for today and the near-future (i.e., the year 2012). Three types of plants were evaluated: coal using the flue gas approach (pulverized coal, PC), gas using the flue gas approach (natural gas combined cycle, NGCC), and coal using the hydrogen approach (IGCC). Key results are:

- NGCC plants produce the least-cost electricity, whether one captures the CO_2 or does not capture.
- IGCC plants show the least incremental cost of electricity from CO_2 capture due to their more efficient capture process.
- PC plants present the largest economic hurdle to CO_2 sequestration.
- If gas prices rise about 20%, in 2012 the cost of electricity from an IGCC capture plant will be about equal to that of an NGCC capture plant.

The differences in costs between today and 2012 are due to 4 items:

- Lower capital costs of the reference plant (based on projections from the Coal Utilization Research Council).
- Lower heat rates, (i.e., higher thermal efficiencies) for the reference plant (based on projections from the Coal Utilization Research Council).

- Lower energy requirements for the capture process (based on analysis documented in January 1997 MIT/DOE White Paper on CO_2 sequestration).

- Lower capital costs for the capture process (assumed 10% reduction from the current levels).

The choice of the base case is a major determinant in mitigation cost expressed as $ per tonne of CO_2 avoided. In Table 2, two different base cases are used. The first calculation uses the reference plant of the same type as the capture plant. In other words, we compare an IGCC capture plant to an IGCC reference plant. The second calculation compares everything to an NGCC reference plant, which is the power plant of choice today. Typically, to account for the transportation and injection of the CO_2 once it leaves the power plant, an additional $5-15 per tonne CO_2 avoided should be added. However, if the CO_2 is going to be utilized for commercial purposes, a credit can be taken, improving the economics greatly.

To clearly introduce the above concepts, we have treated CO_2 separation and capture discretely from transportation and injection. However, a systems approach is needed to understand the most economical way to proceed. For example, enhanced coal bed methane (ECBM) can utilize nitrogen as well as CO_2. Therefore, for ECBM, it may not be necessary to separate out the nitrogen prior to injection. On the other hand, use of flue gas versus CO_2 has some drawbacks, such as much higher energy requirements for compression.

This paper provides just an introduction to the topic of the economics of CO_2 separation and capture. Other important questions not addressed include:

- What about retrofits? This paper just looked at new plants.

- What will happen beyond 2012? How much more can we improve the economics?

- Can we combine CO_2 controls with controls on NO_x and SO_2 to improve the economics? Numbers in this paper assume sequential control.

Further information may be found on my web site at: http://web.mit.edu/energylab/www/hjherzog/ or on in the DOE report on Carbon Sequestration: State of the Science at http://www.fe.doe.gov/sequestration/

Table 1. Commercial CO_2 Recovery Plants

Operator	Location	Capacity (tons/day CO_2)	Fuel Source	CO_2 Use	Technology	Status
Carbon Dioxide Technology	Lubbock, TX	1200	gas boiler	EOR	Dow MEA	Shut
North American Chemical Co.	Trona, CA	800	coal boiler	Carbonation of brine (soda ash)	Kerr-McGee MEA	Operational since 1978
Mitchell Energy	Bridgeport, TX	493	gas heaters, engines, turbine	EOR	Inhibited MEA	Shut
Northeast Energy Associates	Bellingham, MA	320	gas turbines	PURPA (food-grade)	Fluor Daniel	Operational since 1991
Soda Ash Botswana	Sua Pan,	300	coal boiler	Carbonation of brine (soda ash)	Kerr-McGee MEA	Operational since 1991
Applied Energy Systems	Poteau, OK	200	coil boiler (fluidized bed)	PURPA (food-grade)	Kerr-McGee MEA	Operational since 1991
Sumitomo Chemicals	Chiba, Japan	165	gas boilers plus oil/coal boiler	food-grade	Fluor Daniel	Operational since 1994
Luzhou Natural Gas	China	160	NH_3 plant reformer exhaust	Urea	Dow MEA	No Information
Indo Gulf Fertilizer Co.	India	150	NH_3 plant reformer exhaust	Urea	Dow MEA	Operational since ~1988
N-ReN Southwest	Carlsbad, NM	104	gas boiler plus NH_3 reformer exhaust	EOR	Retrofit to Dow MEA	Shut
Prosint	Rio de Janeiro, Brazil	90	gas boiler	food-grade	Fluor Daniel	Operational since 1997
Liquid Air Australia	Australia	2 x 60	gas boiler	food-grade	Dow MEA	Operational since ~1985

Notes:

1. ABB Lummus Crest licensed the Kerr-McGee MEA technology in 1990.
2. Fluor Daniel licensed the Dow MEA technology (ECONAMINE FG) in 1989.
3. A number of small plants (~6 tons/day CO_2) producing food-grade CO_2 exist in the Philippines and other places using Fluor Daniel/ Dow MEA technology.

Table 2. Cost of CO_2 Capture and Separation

Cycle:		**IGCC**	**IGCC**	**PC**	**PC**	**NGCC**	**NGCC**
Technology:		Today	2012	Today	2012	Today	2012
Data Description	Units	Value	Value	Value	Value	Value	Value
Reference Plant							
coe: CAPITAL	mill/kWh	30	26	26	25	12	12
coe: FUEL	mill/kWh	10	9	10	10	18	17
coe: O&M	mill/kWh	6	6	6	6	2	2
Capital Cost	$/kW	1300	1145	1150	1095	525	525
Net Power Output	MW	500	500	500	500	500	500
CO_2 emitted	kg/kWh	0.74	0.65	0.77	0.73	0.37	0.33
Thermal Efficiency (LHV)		42.0%	47.8%	40.3%	42.4%	54.1%	60.1%
Heat Rate (LHV)	Btu/kWh	8124	7137	8462	8042	6308	5677
Cost of Electricity	¢/kWh	4.6	4.1	4.3	4.1	3.3	3.1
CO_2 Capture Plant							
coe: CAPITAL	mill/kWh	39	33	45	40	26	22
coe: FUEL	mill/kWh	12	10	13	12	21	18
coe: O&M	mill/kWh	8	8	11	11	6	5
Capital Cost	$/kW	1730	1433	1967	1748	1120	956
Net Power Output	MW	421	443	400	417	432	463
CO_2 emitted	kg/kWh	0.09	0.07	0.10	0.09	0.04	0.04
Thermal Efficiency (LHV)		35.4%	42.4%	32.2%	35.4%	46.8%	55.6%
Heat Rate (LHV)	Btu/kWh	9639	8056	10581	9650	7293	6133
Cost of Electricity	¢/kWh	6.0	5.0	6.9	6.3	5.2	4.5
Comparison							
Incremental coe	¢/kWh	1.4	0.9	2.7	2.2	2.0	1.4
Energy Penalty		16%	11%	20%	17%	14%	7%
Mitigation Cost vs. ref	$/tonne CO2	$21	$16	$40	$34	$61	$47
Mitigation Cost vs. gas	$/tonne CO2	$96	$76	$135	$132	$61	$47
Basis							
Capital Charge Rate		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Yearly Operating Hours	hrs/yr	6570	6570	6570	6570	6570	6570
Fuel (Coal) Cost, LHV	$/MMBtu	1.24	1.24	1.24	1.24	2.93	2.93

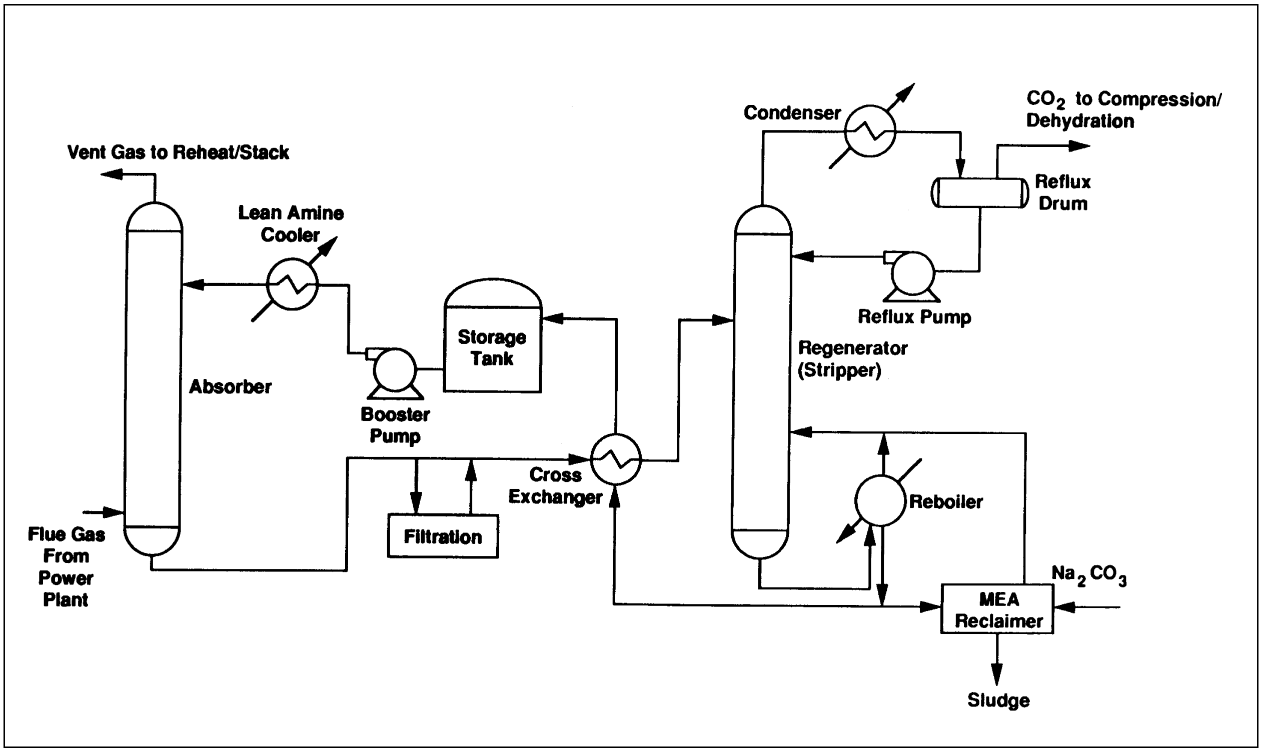

Figure 1. Schematic diagram of the amine separation process.

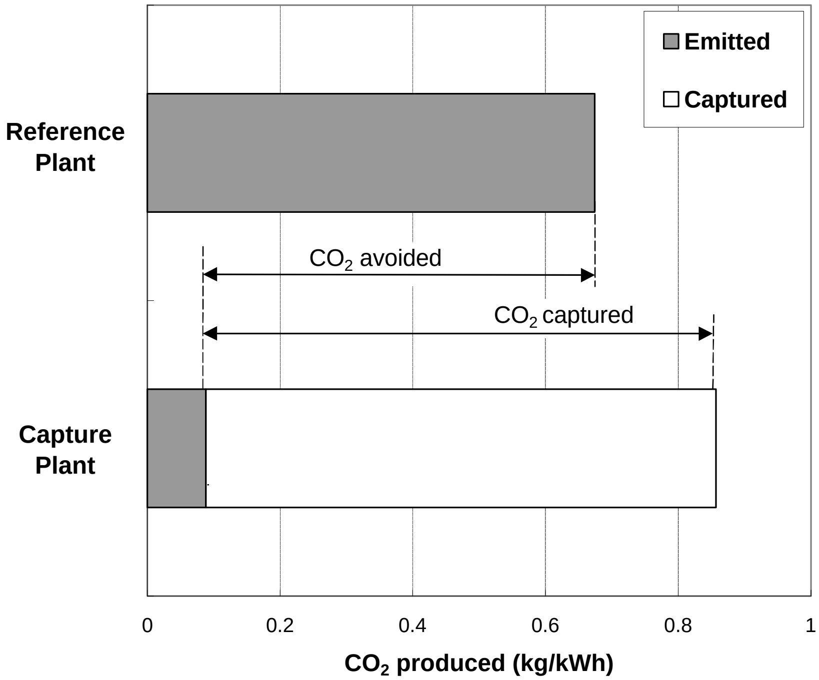

Figure 2. Defining the difference between CO_2 captured and CO_2 avoided. The numbers are from the example in Figure 3.

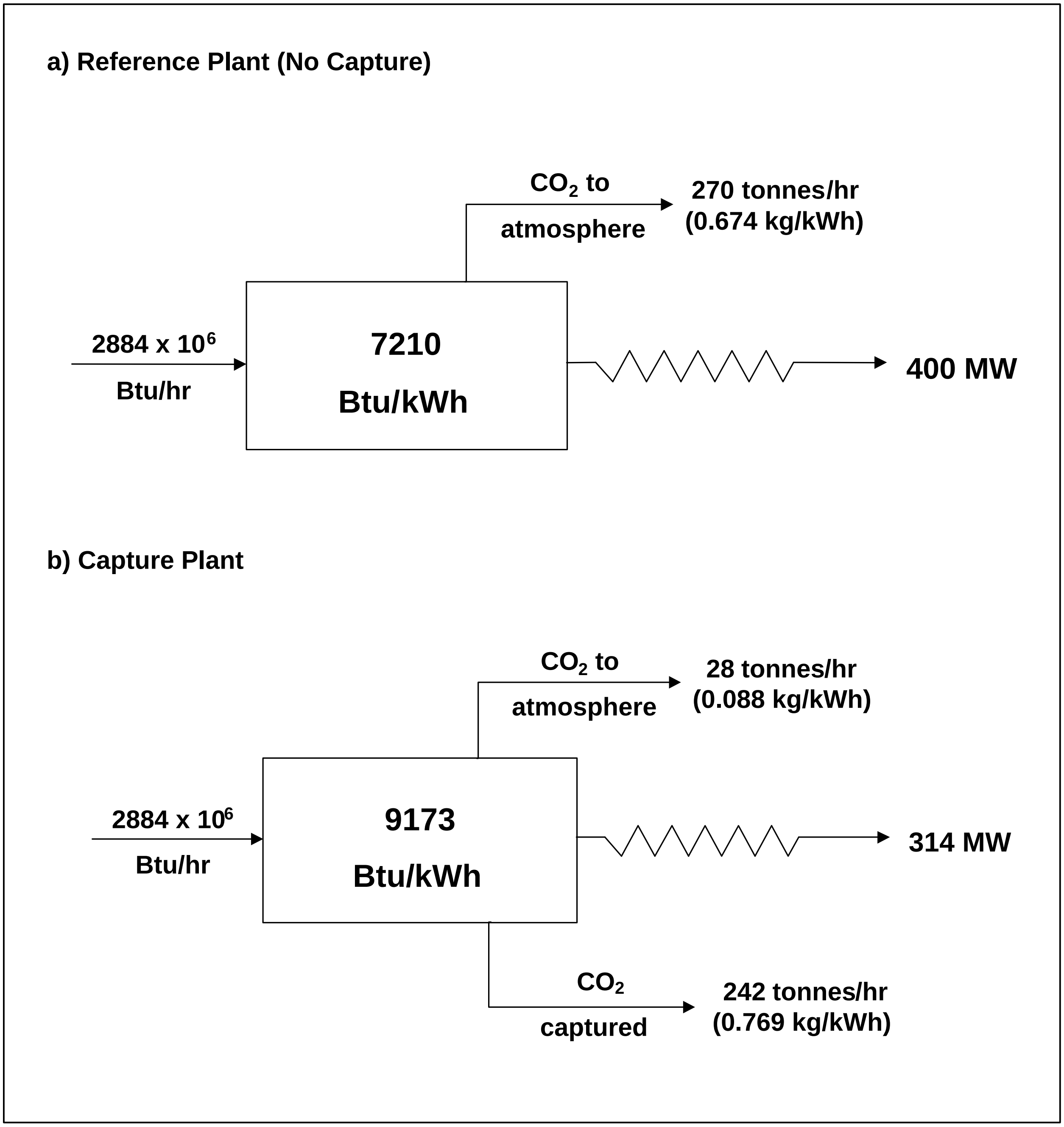

Figure 3. In this example, we have a reference power plant that emits CO_2 to the atmosphere and a power plant that captures CO_2. In both cases, the fuel input to the power plant is the same. For the capture plant, the energy output is reduced, resulting in an energy penalty of 21.5%.