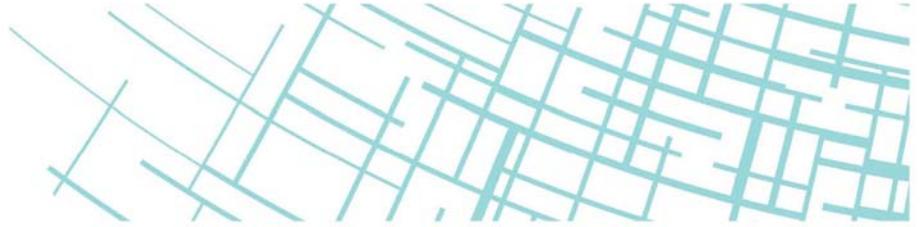




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CO₂ CAPTURE TECHNOLOGIES

POST COMBUSTION CAPTURE (PCC)

JANUARY 2012



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POST COMBUSTION CAPTURE (PCC)

Basic Descriptions of Post-Combustion Capture

Post-combustion capture (PCC) refers to the separation of CO₂ from flue gas derived from combusting fossil fuels – coal, natural gas, or oil – in air. In the case of coal-based power, as shown in Figure 1-1, coal is combusted in air and the liberated heat is converted to electricity by steam-driven turbines connected to generators. The combustion results in a flue gas mixture consisting of N₂, CO₂, H₂O, O₂, and a host of compounds such as SO_x, NO_x, and heavy metals amongst others. Some of these are removed using existing technologies such as selective catalytic reduction (SCR), electrostatic precipitation (ESP), and flue-gas desulphurization (FGD). A PCC process then aims to selectively separate CO₂ from the remaining gas mixture as shown in Figure 2-1. After capture, CO₂ can be compressed and stored underground, used in some other processes such as enhanced oil recovery (EOR), or used in some other capacity that does not result in its emission into the atmosphere.

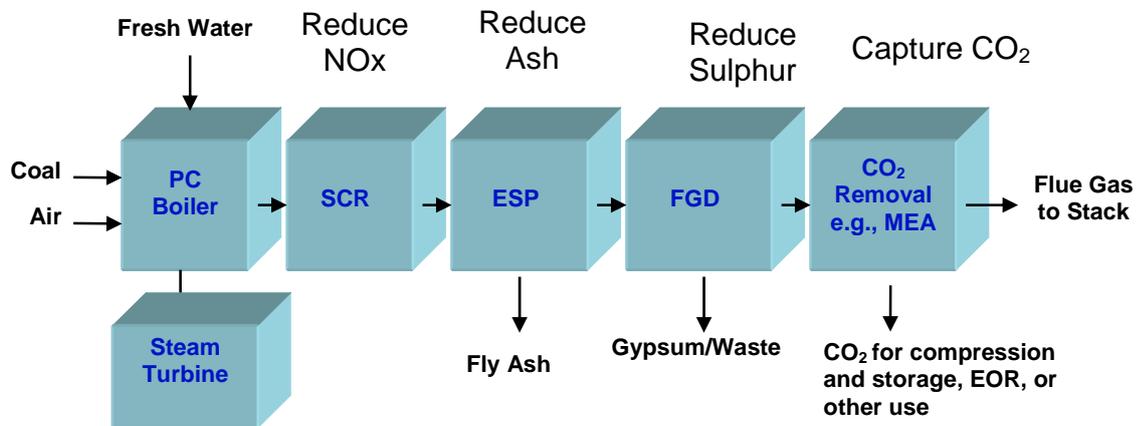


Figure 2-1. A Typical Post-Combustion Carbon Capture Process.

Influence of Fuel

Table 2-1 shows the representative concentration of post-combustion flue gas for coal- and gas-fired power plants. There is additional variation around these values depending on the exact composition of the fuel, the efficiency of the plant, types of emission controls installed, and other factors, but for purposes of CO₂ capture, 10-15% CO₂ for coal and 4-5% for natural gas are quite representative.

**Table 2-1 Typical Compositions of Flue gases from Coal- and Gas-fired Power Plants.**

Gas Constituent	Coal	Natural Gas (Gas Turbine)
Nitrogen (N ₂)	70-75%	73-76%
Carbon Dioxide (CO ₂)	10-15%	4-5%
Water Vapour (H ₂ O)	8-15%	8-10%
Oxygen (O ₂)	3-4%	12-15%
Trace Gases (SO _x , NO _x , others)	<1%	<1%

Carbon is the predominant combustion species in coal, while both carbon and hydrogen are combusted in natural gas; thus, for each CO₂ molecule generated during combustion, coal has less energy release. This results in coal power plants typically generating twice as much CO₂ as gas power plants for the same power output, about 1 g CO₂/kWh vs. 0.5 g CO₂/kWh. However, flue gas from coal power plants has more concentrated CO₂ relative to natural gas. This results in CO₂ capture consuming less energy for coal power plants relative to gas power plants for the same mass of CO₂ captured. The net result in terms of parasitic load on the host power plant and cost of electricity increase due to the capture process therefore is not straight forward particularly with the range of coal and natural gas prices. Due to the predominance of coal in power production and the likelihood of CO₂-control regulations impacting those most, the overwhelming emphasis of capture process developers has been on coal-fired power plants. Research and development for capture on natural gas fired power plants is relatively scarce, though regulations may require natural gas fired power plants to have CO₂ emission controls similar to that expected for coal fired power plants.

Near-Term Technologies

PCC technologies that can be considered near-term have been tested at scales on slip streams no larger than 5-25 MWe from coal-fired power plants. Press releases and other announcements have been made for projects intended for larger sizes, but these are planned future projects. All near-term technologies are solvent-based involving either ammonia or proprietary amines. The distinction between these technologies is specific capture chemistry and, to some extent, the process configuration and integration into the power plant. The specific capture chemistry can be contaminated by the presence of other acid-forming gases such as SO₂ and SO₃, and therefore all of these near-term technologies require SO_x concentrations typically no higher than 10 ppmv in order to minimize solvent usage and cost

Technologies that could be called near-term include Fluor's Econamine FG+, Mitsubishi Heavy Industries KS solvent, Cansolv Technologies, Aker Clean Carbon, and Alstom's Chilled Ammonia Process (ACAP). All of these use either aqueous pure amines or blends of amines, with the exception of Alstom's CAP which uses aqueous ammonium carbonate to bicarbonate reaction. In all these near-term technologies, an absorber-stripper configuration is used as shown in Figure 2-1, with the solvent regenerated thermally using steam from the power plant. This steam extraction results in loss of power production at the host plant, and when combined with power needed for compression, results in a parasitic load of 20-30% for CO₂ capture and compression, with net plant efficiency dropping from 38% to 27%. Hence, most near-term technologies seek to not only improve capture chemistry, but also seek to use sources of waste thermal energy at the power plant and the compression train to assist in solvent regeneration.

It should also be noted that emissions from amine-based capture processes are still being studied. Initial reports from testing in Norway indicated that possible reaction products may exit the absorber either as volatile gases or mechanically entrained droplets, including nitrosamines. Research in understanding of such emissions is active, and a number of groups are attempting to understand the risk of such emissions, the potential impact of such emissions on health and the environment if any, and possible strategies to minimize emissions.



The following notes provide a technical status report¹ on each of the post combustion capture technologies that have been selected for large scale demonstration.

Fluor Econamine FG PlusSM and Other MEA Processes

For over thirty years, amine scrubbing with monoethanolamine (MEA) in aqueous solution has been used to capture CO₂ from the flue gas of fossil-fuelled boilers and petrochemical process heaters. The first significant large-scale CO₂ capture plant in the United States, at the Searles Valley Minerals Plant in Trona, California, has remained in continuous operation since 1978 with two parallel trains each capturing 400 ton/day (363 mt/day) of CO₂ from flue gas from a coal-fired boiler. The CO₂ is used to carbonate brine for soda ash manufacture. The ABB Lummus Global Process, using a 15–20% by weight MEA solution with inhibitors, has also been used for CO₂ capture with slipstreams from three smaller coal-fired power boilers. The process, however, is still relatively small compared to full scale power plants. A typical 500 MWe coal-fired power plant, for instance, generates about 12,500 mt CO₂/day, and about 11,300 mt CO₂/day would have to be captured to yield a 90% capture rate.

Fluor's Econamine FG PlusSM technology is said to reduce steam consumption by over 30% compared to 'generic' MEA technology. Econamine FG Plus adds a number of refinements to the Econamine FGSM solvent and process, which have been used in 25+ commercial plants for the recovery of CO₂ from flue gas at rates from 6 to 1000 mt/day. The flue gas processed was mainly produced by combustion of natural gas; four units use flue gas from natural gas steam reformers. Although none of the units process coal-derived flue gas, the latest Econamine FG Plus formulation is targeted at that market.

Proprietary inhibitors, to control corrosion, oxidative degradation, and thermal degradation allow use of MEA at higher concentration (30–35%+ by weight solution versus 18–20% previously) to more efficiently recover CO₂ from low-pressure streams containing oxygen at concentrations of 1–15% by volume. The Econamine FG Plus formulation has an increased CO₂ absorption rate, allowing use of a smaller absorber and lower reboiler steam flow, and has reduced makeup requirements. The Econamine FG Plus process uses absorber intercooling and a split flow configuration to help reduce energy requirements. Fluor has also developed advanced solvent reclamation technologies and heat integration strategies such as flue gas-heated reboilers. Econamine FG Plus is a candidate technology for several PC-CCS demonstrations in the United States, Canada, and Europe.

Because of the prevalence of its predecessor technology in flue-gas applications, Econamine FG Plus is often used as a representative technology for economic evaluation of PC technologies without and with CCS (and for comparison to IGCC without and with CCS).

MHI KM-CDR Process

Another near-term technology for coal-fired power plants is MHI's KM-CDR process that uses the KS-1 sterically hindered amine solvent developed by MHI and Kansai Electric Power Company. A 25 MWe equivalent capture and storage demonstration (100–150,000 tonnes-CO₂/year) is scheduled to begin operation this year at Alabama Power's, James M. Barry Electric Generating Plant. Construction has been initiated and start up is planned for the second half of 2011. This project is fully coordinated with storage of 500 mt/d of the captured CO₂ in the Citronelle formation as part of the DOE's SECARB regional sequestration partnership program.

Demonstrations using KM-CDR are also planned in Europe and Australia. KM-CDR is a refined version of a process that has been in commercial use since 1990 with oil- and gas-based flue gas at up to 450 mt/day scale. In 2006, MHI and J-Power began a 10 mt/day pilot test with coal-based flue gas at Matsushima power station in southern Japan. KS-1 claims significantly better CO₂ loading and stripping energy requirements than MEA solvents, and lower volatility, compared to MEA, which reduces solvent makeup requirements. Unit cost of the solvent is higher by a factor of about five. The KS-1 solvent also requires low levels of SO_x and NO_x

¹ Holt, N., Dillon, D., Marasigan, J., and Hendrix, H. *Coal Technologies with CO₂ Capture – Status, Risks, and Markets 2010*; PID 1019658; EPRI, Palo Alto, CA, 2010



(typically 1 ppm) and therefore requires upstream polishing of flue gas to achieve these absorber input requirements. MHI claims that KM-CDR circulation rate is 60% of that for (unspecified) MEA, regeneration energy is 68% of MEA, and solvent loss and degradation are 10% of MEA. MHI is working on process improvements that are said to have potential to reduce the regeneration heat requirement to 800 Btu/lb-CO₂ (1860 kJ/kg) from ~1200 Btu/lb-CO₂ (2790 kJ/kg).

Alstom Chilled Ammonia Process (ACAP)

Alstom's Chilled Ammonia Process is a more recent technology that was developed to address specific concerns regarding post-combustion capture of CO₂ from coal-fired power plants. Following a 1.7 MWe pilot at We Energies Pleasant Prairie Power Plant in Wisconsin, a nominal 20 MWe equivalent, 100,000 ton-CO₂/yr capture and storage pilot began operation in September 2009 at AEP's Mountaineer Power Plant and to date about 25,000 mt has been captured at typically 80-90% capture efficiency and at 99.9+ % purity. The project also includes CO₂ injection that was initiated in October 2009 and through May 2011, over 50,000 mt had been captured of which 37,000 mt had been injected.

Announced plans include a 20 MW equivalent application at Statoil Hydro's Mongstad Test Center in Norway (from a NGCC plant and refinery cracker slipstream). The 235 MW, 1.5 million ton-CO₂/yr demonstration at AEP's Mountaineer plant in West Virginia was selected for funding under the DOE CCPI 3 initiative but is not proceeding for lack of legislative and financial incentive.

ACAP uses the changes in chemical equilibrium of ammonia, ammonium carbonate, and ammonium bicarbonate with change in temperature to capture and release CO₂ from the flue gas stream. ACAP has an advantage in its use of a low-cost solvent that resists degradation with elevated temperature and with exposure to SO_x and NO_x. Use of a higher stripping temperature also allows ACAP to release CO₂ at a higher pressure than is possible with the amine solvents. However, ACAP requires a larger absorber because it has a relatively low reaction rate and CO₂ loading, and loses some efficiency to the chiller, which is required to maintain reaction temperature.

Powerspan ECO₂TM Process

PowerSpan's ECO₂TM process has been reformulated to use a proprietary solvent incorporating a mixture of aqueous amines. ECO₂ no longer requires use of PowerSpan's ECO or ECO-SO₂ process, as had been stated for the prior ammonia/ammonium carbonate formulation. Validation testing in a 1 MWe equivalent (~ 20 stpd) pilot at FirstEnergy's R. E. Burger Plant ran from December 2008 into 2010. In May 2010, Powerspan announced that an independent assessment had concluded that the technology is ready for scale-up, with a cost of less than \$40 per ton of CO₂ captured and compressed, based on a 220 MWe net retrofit project size. Process improvements during testing were said to reduce the regeneration steam requirement to less than 1000 Btu/ lb-CO₂ (2326 kJ/kg).

Cansolv

Cansolv, a former subsidiary of Union Carbide now owned by Shell Global Solutions International B.V., has developed aqueous diamine regenerable solvents for the selective or sequential removal of SO₂, NO_x with mercury, and CO₂. Reported CO₂ capture rates of 90% have been achieved on a 150 m³/hr (85 ACFM) lignite flue gas slipstream. Startup is planned for early 2011 for a modularized system capturing 50 mt/day of CO₂ from a slipstream at RWE npower's Aberthaw PC plant in Wales. The retrofit of a 150 MWe unit at SaskPower's Boundary Dam will use Cansolv DS to achieve 100% SO₂ capture upstream of the Cansolv DC103 CO₂ capture system. The Cansolv SO₂ capture system produces saleable H₂SO₄ by-product, instead of a solid waste requiring disposal, and produces heat that can be used to provide part of the CO₂ solvent regeneration energy. In April 2011 the Saskatchewan Government approved the Boundary Dam project. Key equipment had been pre-ordered to enable a planned start up in 2014. The refurbished 150 MW unit will produce 115 MW net power after retrofit. The Boundary Dam units are all fired with Saskatchewan lignite.



Aker Clean Carbon

Aker Clean Carbon's Just Catch technology has been refined through slipstream testing on PC plant flue gas with a portable pilot unit installed at Scottish Power's Longannet station. In November 2009, Scottish Power announced that testing of process improvements and low-energy solvents had achieved a reduction in energy requirement of about one-third compared to a reference plant. Reduced solvent emissions are a claimed benefit of the Just Catch process.

Aker has built a mobile amine pilot facility which is completing its testing at the National Carbon Capture Center in Wilsonville, Alabama, using coal-derived flue gas. The unit will be transported to the Statoil Hydro's Technology Centre Mongstad and expected to start up there in December 2011. (The pilot is also connected to the nearby refinery cracker.) The pilot will be 40 MW_{th} equivalent, capturing up to 25,000 mt/yr with NGCC-CHP flue gas containing 3.5% CO₂. With refinery process flue gas containing 12.9% CO₂ (similar to flue gas from a PC plant) the capture rate would be up to 73,000 mt/yr.

Alstom Advanced Amine Process

Alstom and Dow Chemical Company are working jointly on process refinement with a pilot facility using proprietary Dow amine solvent (DOW UCARSOL™ FGC 3000) on flue gas from a coal-fired boiler at a Dow chemical plant in South Charleston, West Virginia. Alstom will build and operate a second R&D facility at the EDF Group's Le Havre (France) thermal energy plant, with start-up by 2012. This facility would be used to test and refine the Alstom Advanced Amine process using coal-derived flue gas. Subsequent demonstrations are proposed for the 858 MW SCPC lignite-fired unit now under construction at the Elektownia Belchatow plant in Poland. A 20 MW_{th} pilot would be followed by a 250 MWe, 1.8M mt/yr CCS demonstration, with a targeted 2015 start-up. The Dow amine is claimed to capture CO₂ with increased efficiency, higher tolerance for oxygen and trace contaminants, and decreased solvent degradation.

Siemens POSTCAP Amino Acid Salt

Siemens Energy and TNO, the Netherlands Organization for Applied Scientific Research, have begun working together to advance their separately developed, second-generation amino acid salt processes. In comparison to amines, the amino acid salt technology is said to absorb CO₂ rapidly with a high CO₂ loading and lower solvent flow rate, resist oxidation, have reduced heat of regeneration, have lower volatility, and be environmentally benign. Siemens studies indicate that use of POSTCAP with CO₂ compression to 200 bar (2900 psi) would reduce the net efficiency of a 600°C (1112°F) USCPC plant from 45.7% LHV to 35.9% LHV and would not increase plant water consumption.

In August 2009, Siemens began operation of a 1 MWe equivalent pilot unit at E.ON's Staudinger 5 PC unit near Hanau, Germany. In September 2010, DOE announced an additional Industrial Carbon Capture award, allowing Siemens to increase the size of a planned POSTCAP pilot, on a PC plant slipstream, from 1 MWe to 2.5 MWe equivalent. The pilot at Tampa Electric Company's Big Bend Power Station in Ruskin, Florida, has a 2013 start-up target.

Siemens is performing a CCS study for the 695 MWe-net advanced SCPC Longview Power Generation Facility project, for which Siemens provided environmental control equipment. The Longview plant is now under construction in Maidsville, West Virginia, with a 2011 start-up target.

HTC Purenergy / Doosan Babcock

Doosan Babcock Energy has partnered with HTC Purenergy to commercialize a mixed amine solvent process that was initially developed at the University of Regina, Saskatchewan, and field tested in a pilot unit operated by the University of Regina International Test Center at SaskPower's Boundary Dam coal plant, near Estevan, Saskatchewan. HTC Purenergy claims that pilot testing and process optimization has reduced regeneration energy to less than 1.0 ton steam per ton CO₂ (about 30% less than conventional 30% MEA). Doosan Babcock will be performing further development at a newly commissioned RD&D pilot in Renfrew, Scotland.

HTC has performed a FEED study for a 450 MW NGCC plant and developed a modularized, pre-assembled design for a 1,000 mt/day capture system that is scalable to 3,000 mt/day. Basin Electric Power Cooperative



(BEPC) contracted Doosan Babcock Energy to perform a FEED study for 120 MWe equivalent post-combustion CO₂ capture demonstration at the 450 MW Antelope Station. This project had previously been selected for funding support under the DOE CCPI-3 program however after being unable to secure a contract for the CO₂ Basin Electric decided in December 2010 not to proceed with the project.

Other Solvent Processes

Around the world, several other technologies are among those at the maturity level that makes them candidates for near-term demonstrations at small commercial scale.

- In early 2010, ENEL commissioned a 2.5 tons/hr slipstream capture pilot at Brindisi (Italy) Unit 4, using an advanced amine (MEA) process developed by IFP (Institute France Petrol). Liquefied CO₂ is to be stored on site, used in a flow test loop, and trucked offsite for geologic sequestration. A 2015 start-up is targeted for a full-stream capture unit on a new 660 MWe unit at Porto Tolle with saline aquifer storage.
- The Korea Electric Power Research Institute's of KoSol 1 and KoSol 2 advanced amine solvents at 5 MW equivalent scale is planned to continue through 2015.
- A TPRI amine process is capturing CO₂ for industrial uses at 100,000 tonne/year scale at the Shidongkou 2 power plant in Shanghai, China.
- In Australia CSIRO have three PCC pilot projects at Loy Yang in Victoria, Delta's Munmorah plant in New South Wales and with Tarong in Queensland. The Loy Yang project (CO₂ ~1000 mt/y) was started up in 2008. The Munmorah project (CO₂ ~3000 mt/y) started up in February 2009.

Major Challenges and R&D Trends

The major challenges in PCC revolve around the relatively large parasitic load CCS imposes on a power plant, the majority of which is due to capture, especially the energy needed to regenerate the solvent. Energy required for compression, though important, is less than that required for capture and is closer to its thermodynamic limit than capture is to its thermodynamic limit. Hence, development of new chemistry, new process designs, and novel power plant integration schemes all aimed at reducing the parasitic load of CCS are the focus of virtually R&D in PCC. In general, capital cost reductions, solvent degradation, solvent volatility, and other such parameters are secondary to the prime issue of reduction in parasitic load on the host power plant imposed by the PCC process itself. These secondary issues, while important, do not constitute the major challenge in PCC, and much of the R&D trend is focusing on the reduction in parasitic load of PCC processes. These trends are discussed next, grouped according to the capture method employed.

Capture Methods

Virtually all capture processes use an absorbent (solvent), adsorbent (solid sorbent), and membranes, with far lesser emphasis on converting CO₂ to a mineral, employing biofixation, or other beneficial use of CO₂.^{2,3,4,5}

² Freeman, B. and Rhudy, R. *Assessment of CO₂ Capture Options Currently Under Development*; PID 1012796; EPRI, Palo Alto, CA, 2007.

³ Bhowan, A.S., Freeman, B. *Program on Technology Innovation: Post-Combustion CO₂ Capture Technology Development*; PID 1016995; EPRI, Palo Alto, CA, 2008.

⁴ Bhowan, A.S., Freeman, B. *Post-Combustion CO₂ Capture Technology Development*; PID 1017644; EPRI, Palo Alto, CA, 2009.

⁵ Bhowan, A.S., Freeman, B. *Post-Combustion CO₂ Capture Technology Development*; 1019812 EPRI, Palo Alto, CA, 2010.

Absorption

Absorption refers to the uptake of CO₂ into the *bulk phase* of another material – for example, dissolving CO₂ molecules into a liquid solution such as an aqueous amine. Absorption is used widely in the chemical, petrochemical, and other industries, and as a result, operational confidence in absorption process is high. Indeed, virtually all near-term and mid-term PCC processes under development are absorption based. In a solvent-based PCC process (see Figure 2-2), flue gas is contacted with the solvent which typically contains a reagent that selectively reacts with CO₂. This contact occurs in traditional gas-liquid contactors, and CO₂ transfers from the gas phase into the liquid phase. The CO₂-loaded rich solution is pumped to a regenerator vessel where it is heated to liberate gaseous CO₂ and the lean solution is circulated back to the absorber. The liberated gaseous CO₂ is collected, dried, compressed and transported to a storage reservoir, or it may be used in some other application such as EOR.

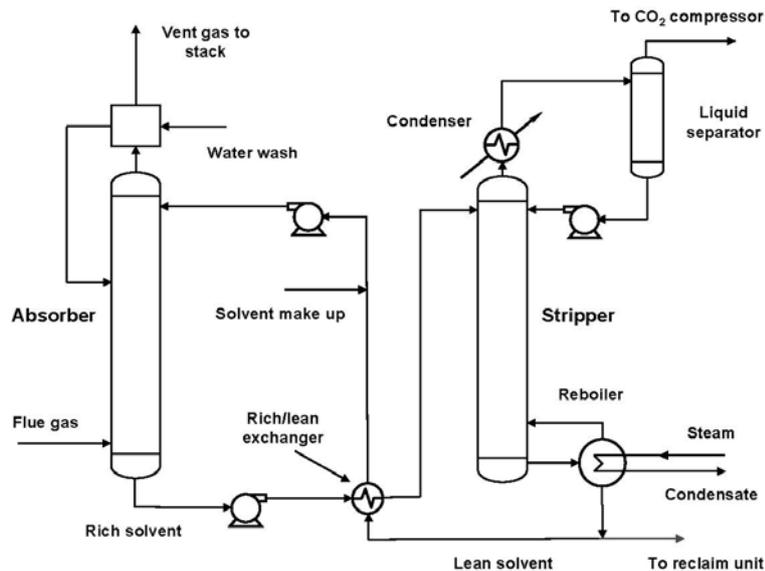


Figure 2-2. Absorption-based PCC process

The most common example of a PCC absorption process is 30 wt% aqueous monoethanolamine (MEA) which has been used commercially capturing up to 1000 tonne/day of CO₂. Current estimates of capture with MEA followed by compression for underground storage impose approximately 30% parasitic load on the net output of a power plant and increase the cost of electricity by 60-90%. These relatively high values result from the relatively large quantity of energy needed to regenerate the solvent. Therefore, much of the current research in absorption-based PCC is focus on development of new solvents that reduce the regeneration energy. Examples of such new chemistries include Alstom's Chilled Ammonia Process which uses a reaction of ammonium carbonate to ammonium bicarbonate as well as a host of proprietary amines from Mitsubishi Heavy Industries, Cansolv, Aker, PowerSpan's ECO₂TM, amongst as number of other process developers. Some early-stage research is also being conducted in more novel chemistries involving ionic liquids, phase separation solvents, and siloxane oligomers.

Adsorption

Adsorption refers to uptake of CO₂ molecules onto the *surface* another material – for example, adhering CO₂ molecules onto the surfaces of a solid sorbent such as 13X zeolites. A claimed advantage of adsorption is that the regeneration energy should be lower relative to solvents since the heat capacity of the solid sorbent is lower than aqueous solvents. However, such claims based on singular rationale are often insufficient, and a careful analysis requires consideration of multiple effects such as heat capacity, working capacity, and heats of reaction. These analyses are not straightforward, do not often point to one clear technology choice over another, and is the subject of early-stage research to help guide development of new capture materials. Potential disadvantages for adsorbents include particle attrition, handling of large volumes of sorbent and thermal management of large-scale adsorber vessels.

As shown in Figure 2-3a, adsorption typically occurs via weak Van der Waals forces for physisorption or stronger covalent bonding for chemisorption. Adsorption processes are implemented most often with the adsorbent used in packed beds or fluidized beds. In a packed bed (See Figure 2-3b), adsorbent is loaded into a column, flue gas flows through the void spaces between the adsorbent particles, and the CO₂ adsorbs onto the particle surfaces. In fluidized beds (See Figure 2-3c), flue gas flows upward through a column at velocities such that the adsorbent particles are suspended in the gas flow. Regardless of the process configuration, the adsorbent selectively adsorbs CO₂ from the flue gas, and is subsequently regenerated by lowering the pressure and/or increasing the temperature to liberate the adsorbed CO₂. In a packed bed configuration, regeneration is accomplished by heating the CO₂-laden adsorbent to liberate CO₂. During this time, flue gas is diverted to a second packed bed which continues to adsorb CO₂ from the gas. By alternating flue gas between two packed beds that alternatively undergo absorption and regeneration in a cycle, CO₂ can be continually removed from flue gas. In a fluidized bed, the sorbent is circulated between an absorber vessel where it contacts flue gas and a regenerator vessel where it is heated to liberate gaseous CO₂.

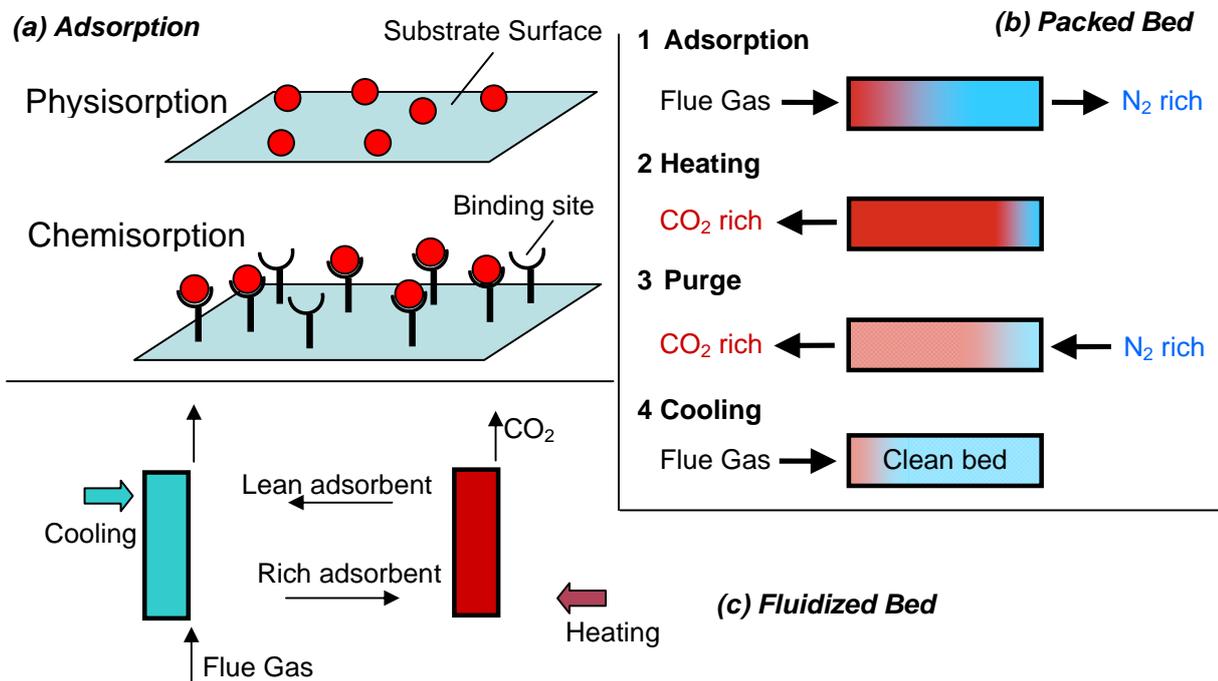


Figure 2-3. Adsorption-based PCC process.

Adsorption processes for PCC are still in the kW range of demonstration; examples include ADA-ES which is conducting a screening effort to identify suitable capture materials for scale-up, as well as CO₂CRC and Monash University which are jointly conducting research in materials and process development for pressure-swing adsorption. Earlier stage work is focused on development of entirely new materials such as metal organic frameworks (MOFs), zeolites and zeolitic imidazolate frameworks (ZIFs) at mostly academic institutions.

Membranes

Membranes can separate CO₂ from flue gas by selectively permeating it through the membrane material. If CO₂ has a higher permeability (permeability, defined as the product of solubility and diffusivity, in the membrane relative to other species in the flue gas, then CO₂ will selectively permeate the membrane. In some cases, chemical agents that selectively react with CO₂ are also added to the membrane to increase the membrane's selectivity for CO₂. CO₂ transports a membrane only if its partial pressure is higher on one side of the membrane relative to the other side. This partial pressure gradient can be obtained by pressurizing the flue gas on one side of the membrane, applying a vacuum on the other side of the membrane, or both, as shown in

Figure 2-4. Depending on the selectivity of the membrane, multiple membrane stages may be needed in order to obtain sufficiently high CO₂ purity.

Like adsorbents, membranes are claimed to potentially offer low energy capture processes. Additional benefits could include a small foot-print for the capture system and a modular design that may allow for flexible operation. However, little data exists on membrane systems for PCC, and testing has been conducted at scales less than 1 mt/day with results that are not yet publicly available. The major challenge for membranes comes from the potential fouling of the membrane surfaces from particulate matter, uncertainty about the performance and cost of large-scale efficient vacuum pumps and compressors required for PCC, and the ability to integrate the process into a power plant. Some of these issues are still being resolved at the laboratory and bench-scale with 1 MWe scale testing planned in 2012-2013 time frame.

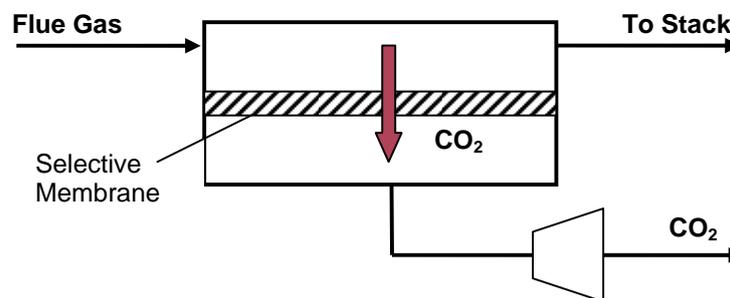


Figure 2-4. A Membrane-based PCC process.

Membrane processes are in general less widely used for separations, and therefore as a class, are also further from commercialization in PCC as well. Membrane Technology and Research (MTR) has proposed a novel process configuration along with novel membrane materials that could reduce the parasitic load on a power plant. In MTR's process, flue gas and air flow across the two surfaces of CO₂-selective membrane, and the CO₂ permeates from the flue gas into the air. The CO₂-enriched air is then sent to the boiler for combustion. This effectively forms a loop that enriches the CO₂ from 13% to approximately 18% in flue gas. A second CO₂-selective membrane unit then removes CO₂ by applying a vacuum. The process has been tested at 1 tonne CO₂/day scale and is currently being scaled to 20 tonnes CO₂/day at a coal-fired power plant. However, such integration into the power plant has not yet been tested with membrane processes. Other developments around membranes for PCC are still in the laboratory stages, focusing chiefly on improving the membrane material properties.

Current Status

The exclusive emphasis is currently on absorption on near-term technologies, reflecting the fact that industry's CO₂ capture chemistry knowledge and overall process experience are both heavily slanted towards absorption.

As mentioned previously the parasitic loss of net power from the use of the MEA solvent technology is about 30% so that the major focus of R&D in PCC is on processes and equipment that can reduce this energy loss.

EPRI has undertaken an extensive look at the landscape of CO₂ capture technologies, including evaluating some 120 PCC technologies on a Technology Readiness Level ranking.^{2,3,4,5} Most of these could be assigned a TRL ranking, while some could not because they are extremely early-stage concepts and do not yet have a process per se. Figure 2-5 shows a histogram of the TRL ranking for 95 of the 120 technologies studied.

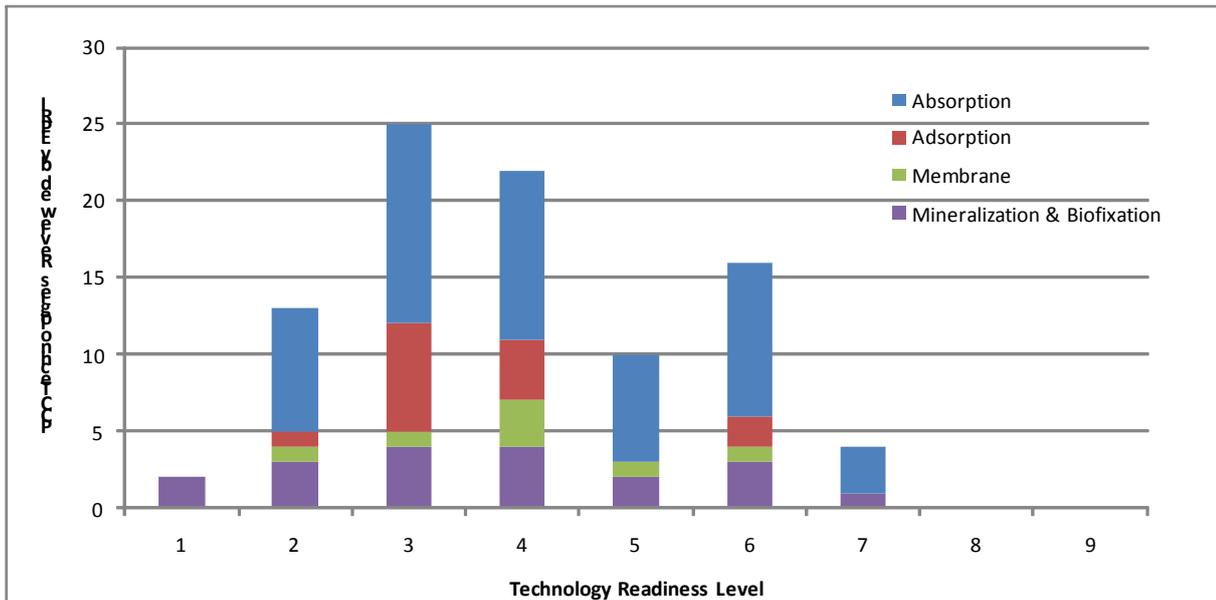


Figure 0-5 PCC Technology Readiness Level Ranking

Most technologies are focused on absorption with adsorption and membranes less so. As described earlier, absorption dominates the near-term, higher TRL technologies. However, these near-term technologies also will tend to be ones with higher parasitic load on the power plants. Further-term technologies, reflected at lower TRL rankings, potentially do offer PCC technologies with lower parasitic loads on power plants, but these are further from development.

Table 2-2 shows an overall status of the major types of PCC technologies. The usage of the technology in the chemical process industry and operational confidence are obviously correlated. As discussed above, major reason for energy consumption by the capture process for absorption is thermal regeneration of the solvent; for adsorbent-based processes its thermal and/or vacuum regeneration; and for membranes, it's either pressurizing the flue gas and/or applying vacuum to the permeate-side. Development trends universally are across decreasing the energy consumption of the PCC process by focusing on new capture chemistry, novel capture process development, regeneration at pressure and better thermal integration into the power plant.

**Table 2-2 State of Post-Combustion CO₂ Capture Development**

	Absorbent	Adsorbent	Membrane
Commercial Usage in CPI*	High	Moderate	Low/Niche
Operational Confidence	High	High, but complex	Low to moderate
Primary Source of Energy Penalty	Solvent Regeneration (thermal)	Sorbent Regeneration (thermal/vacuum)	Compression on feed and/or vacuum on permeate
Development Trends	New chemistry, thermal integration	New chemistry, process configuration	New membrane, process configuration

* Chemical Process Industries

The Future of Post-Combustion Capture Technology

While post-combustion capture is perhaps the most widely studied, the 20-30% parasitic load imposed by the process is deemed to be high. As a result, a multitude of approaches are being attempted that are currently at various stages of development. The near-term technologies are universally aqueous based solvents, and as such, they represent the higher-parasitic load processes. The further-term technologies may potentially impose lower-parasitic loads, but there is considerable uncertainty in their projections.

Figure 2-6 shows the potential for PCC technologies for a new build 595°C power plant using Powder River Basin (PRB) coal with various regeneration energies of an aqueous amine solvent.⁶ The final column shows that increasing the boiler temperature to 705°C with an advanced amine solvent increases the net plant efficiency by about 2% on a higher heating value basis. Changing from PRB coal to bituminous coal, which has higher heat content, will add another 2% to all the values in the graph.

⁶ Dillon, D., Chu, R., Choi, G., Harper, W., Sugita, S. *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture for 1100°F Ultra-Supercritical pulverized Coal Power Plant Application*; PID 1017515; EPRI, Palo Alto, CA 2010.

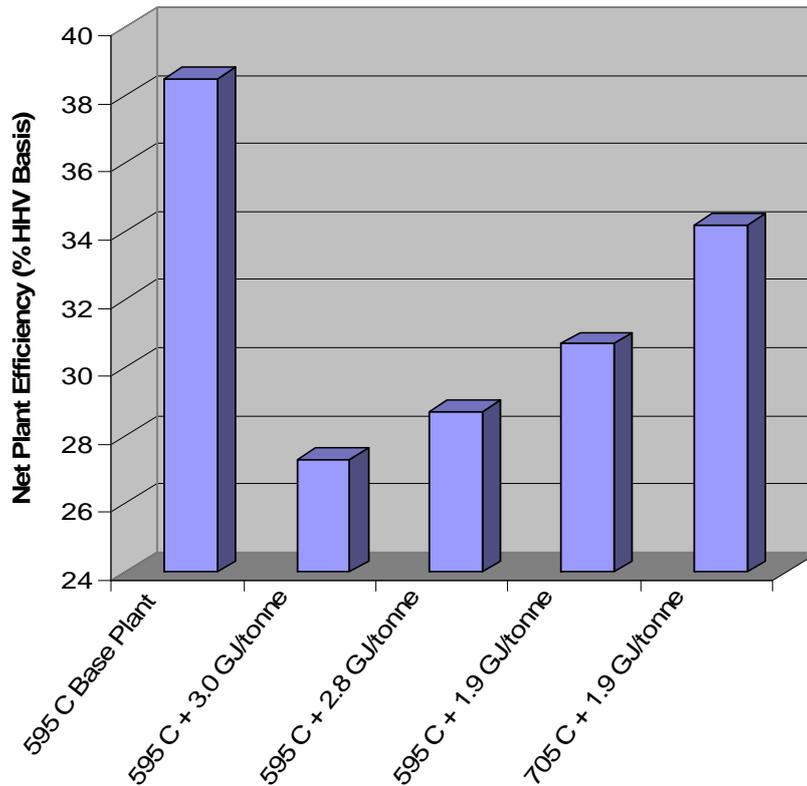


Figure 2-6. Projected performance of PCC technologies with near-term aqueous amine solvents.

A final and critical point is that in the EPRI analysis, the current landscape of CO₂ capture technology development involves three groups working largely independent of each other: chemists who design and synthesize appropriate separation materials, process engineers who can design separation processes around those materials, and power plant engineers who can integrate the process into a power plant. The emergence of breakthrough technologies will require close interdisciplinary collaboration between these groups which need to have an understanding of how their work mutually depends on the other.



ACRONYMS AND SYMBOLS

AFBC	Atmospheric Fluidized Bed Combustion
AGR	Acid gas removal
AQCS	Air Quality Control System
ASU	Air Separation Unit
B&W	Babcock & Wilcox
Bara	Bars absolute
Barg	Bars gauge
BFW	Boiler feedwater
BP	British Petroleum
Btu	British thermal unit
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCPI	Clean Coal Power Initiative
CCS	CO ₂ capture and Storage (or Sequestration)
CCT	Clean Coal Technology
CF	Capacity Factor
CFB	Circulating fluidized bed
CHP	Combined Heat and Power
CO ₂	Carbon dioxide
COE	Cost of electricity
COP	ConocoPhillips
CT	Combustion Turbine
DOE	U. S. Department of Energy
DOE NETL	Department of Energy National Energy Technology Laboratory
ECUST	East China University of Science and Technology
EEPR	European Energy Programme for Recovery
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
FBC	Fluidized-bed combustion/combustor
FEED	Front End Engineering Design
FGD	Flue gas desulphurization
FOAK	First of a kind
F-T	Fischer Tropsch
ft ³	Cubic feet
FW	Foster Wheeler
FWI	Foster Wheeler Italiana
GHG	Greenhouse Gas
GI	Gasification Island
GJ	Gigajoule
gpm	Gallons per minute (US)
GT	Gas Turbine
H ₂ S	Hydrogen sulfide
HgA	Mercury absolute
HHV	Higher heating value
HRSG	Heat recovery steam generator
HP	High pressure
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate pressure
IPP	Independent power producer
kJ	Kilojoules
KBR	Kellogg, Brown & Root



LCA	Life Cycle Analysis
LCOE	Levelized Cost of Electricity
LHV	Lower heating value
LP	Low pressure
LSTK	Lump Sum Turnkey
mt	Metric ton
MDEA	MethylDiethanolamine
MMBtu	Million Btu
MPa	Mega Pascal
MTG	Methanol to Gasoline
MTO	Methanol to Olefins
NCCC	National Carbon Capture Center
NDRC	National Development and Reform Commission (China)
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NH ₃	Ammonia
Nm ³	Normal cubic meters
NO _x	Nitrogen oxides
NSPS	New Source Performance Standards
OCGT	Open Cycle Gas turbine
O&M	Operation and maintenance
PC	Pulverized Coal
PCC	Post Combustion Capture
ppmv	parts per million by volume
PRB	Powder River Basin (Coal)
PSDF	Power System Development Facility
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
R&D	Research & Development
RD&D	Research, Development and Demonstration
RQ	Radiant Quench (GE)
RTI	Research Triangle Institute
RWE	Rheinische Westphalien Electricidadeswerke
SCFD	Standard Cubic Feet per day
SNG	Substitute Natural Gas
SCPC	Supercritical Pulverized Coal
SCR	Selective catalytic reduction
SO ₂	Sulphur dioxide
SRU	Sulphur Recovery Unit
st	Short ton (2000 pounds)
stpd	Short tons per day
TCR	Total Capital Requirement
TFC	Total Field Cost
TPC	Total Plant Cost
USC	Ultra Supercritical
US EPA	US Environmental Protection Agency
WGCU	Warm gas clean up