

Cost Analysis of Carbon Capture and Storage for the Latrobe Valley



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Abstract

This report assesses the cost and economic environment of different carbon capture and storage (CCS) technologies, in order to make a decision regarding the best approach for capturing and then sequestering the carbon-dioxide (CO₂) from the emissions of a brown coal fired power plant in Southeastern Australia. In this report, carbon capture and storage is defined as capturing the CO₂ from the plant's flue gas emissions and securing this CO₂ in a location where it will probably not be re-released into the environment. Avoiding CO₂ emissions due to process changes is also considered. Specifically, we consider well known technologies that require captured carbon to be compressed and sequestered underground and a new approach proposed by Calera Corporation. Calera is a startup company based out of Los Gatos, CA, with a new system for carbon capture that either converts carbon into a carbonate slurry for pumping underground or, with additional processing, locks carbon in a stable mineral form that can be stored or used to make cement or supplementary cementitious material (SCM), or building materials. This report will focus on the levelized cost of electricity generation for each technology, as a function of the price for CO₂ emissions, to compare the Calera process with the traditional CO₂ capture processes. We will assume the local economic conditions that prevail in the Latrobe Valley in Australia.

Our findings, based on two reports estimating costs of retrofit carbon capture technology and Calera's own cost estimates, indicate that Calera capture represents the cheapest option for retrofitting an existing coal fired power plant for carbon capture. Of the technologies considered, retrofitting with the Calera process results in the lowest increase in cost of electricity generation and the lowest breakeven price of CO₂ – the price of CO₂ emissions at which the capture technology becomes economically favorable. However, as this study focuses solely on economic costs associated with CCS, the environmental impacts and possible social costs of these technologies have not been considered in drawing these conclusions. Furthermore, we have not independently verified the underlying cost information for any of the technologies.

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I. Introduction

This report assesses the cost and economic environment of different carbon capture and storage (CCS) technologies, in order to provide information to decisions regarding a technology choice for sequestering the carbon-dioxide (CO₂) from the emissions of a brown coal fired power plant in Southeastern Australia. In this report, CCS is defined as capturing the CO₂ from a plant's flue gas emissions and securing this CO₂ in a location where it will in likelihood not be re-released into the environment. A secondary issue is avoided CO₂ emissions, the consequence of process changes which reduce the amount of CO₂ generated in making specific products. Specifically, we compare technologies that have previously been explored as potentially viable CCS options, requiring captured carbon to be compressed and sequestered underground. We also consider a new approach proposed by Calera Corporation, a startup company based out of Los Gatos, California. Calera's approach is a new system for carbon capture that either converts carbon into a slurry for pumping underground or, with additional processing, locks carbon in a stable mineral form that can be stored or used to make cement or supplementary cementitious material (SCM), or building materials. This report presents estimates of the levelized cost of electricity generation for each technology, as a function of the price for CO₂ emissions. We will assume the local economic conditions that prevail in the Latrobe Valley in Australia, a location that is currently considering different methods for CCS. As this study focuses solely on the economic costs associated with CCS, the potential environmental impacts and possible social costs of these technologies have not been considered. Furthermore, we have not independently verified the cost estimates of any of the technologies but rather rely on cited sources for those costs.

Our findings, based on two reports estimating costs of retrofit carbon capture technology, along with Calera's own cost estimates, indicate that Calera capture represents the cheapest option for retrofitting an existing coal fired power plant for carbon capture, given the conditions in the Latrobe Valley. Retrofitting with the Calera process results in the lowest increase in cost of electricity generation and the lowest breakeven price of CO₂ – the price of CO₂ emissions at which the capture technology becomes economically favorable. All of the technologies increase the cost of generating electricity as a result of CCS. However, in the case of Calera, the production of building materials not only generates revenue to offset some of these costs but also has the added benefit of producing building materials with less CO₂ emissions than conventional processes (ie, avoiding CO₂ emissions). Other CCS technologies may also generate secondary benefits, for instance from enhanced oil recovery, although those have not been examined in this report (and in any event are expected to be modest).

II. Background

In order to meet increasing energy demand, countries must rely on a variety of existing and emerging technologies in addition to reducing energy consumption and increasing energy efficiency. Currently, carbon based fossil fuels contribute roughly 85% of the world's energy needs (David & Herzog, 2000). While nuclear and renewable power sources, such as wind and solar, can potentially contribute a larger, more significant portion of energy generation, neither is without flaws. Until these issues are fully addressed and resolved, fossil fuels will continue to

be the primary source for energy generation throughout much of the world. However, with the combustion of fossil fuels, large amounts of carbon dioxide, a greenhouse gas, are released into the atmosphere. Although natural carbon sinks such as the ocean and vegetation remove a large amount of CO₂ from the atmosphere every year, the concentration of atmospheric CO₂ has grown from a preindustrial 280 ppm to over 360 ppm (Ramanathan, 1988; Loaiciga et al., 1996 as cited in Han, Lindner, & Wang, 2007).

Power generation currently accounts for roughly 40% of global CO₂ emissions (Al-Juaied & Whitmore, 2009). Globally, coal, at roughly \$1-2 per MMBtu is the cheapest fuel source for power generation, cheaper than oil or natural gas, at roughly \$10-12 and \$3-5 per MMBtu, respectively (US Energy Information Administration, 2010). China, with the world’s third largest coal reserves, is projected to increase its coal use by 4.2% a year through 2025 (Hutchison, 2009). The United States has an estimated 275 billion tons of recoverable coal, capable of meeting domestic demand for over 250 years (Hutchison, 2009).

Figure 1 illustrates how CO₂ emissions in the U.S. electric sector may rise in the next 20 years, assuming we maintain the status quo in terms of electricity demand growth (EIA 2008 Reference). Each of the colored wedges represents a technology that can contribute to reducing CO₂ emissions to pre-1990 levels by the year 2030, as estimated by the authors of the cited study. According to this scenario, carbon capture and storage (CCS) and energy efficiency have the greatest potential to reduce CO₂ emissions in the U.S. electric sector. Whether this scenario is valid or not is not the point; the point is that CCS has the potential to greatly reduce

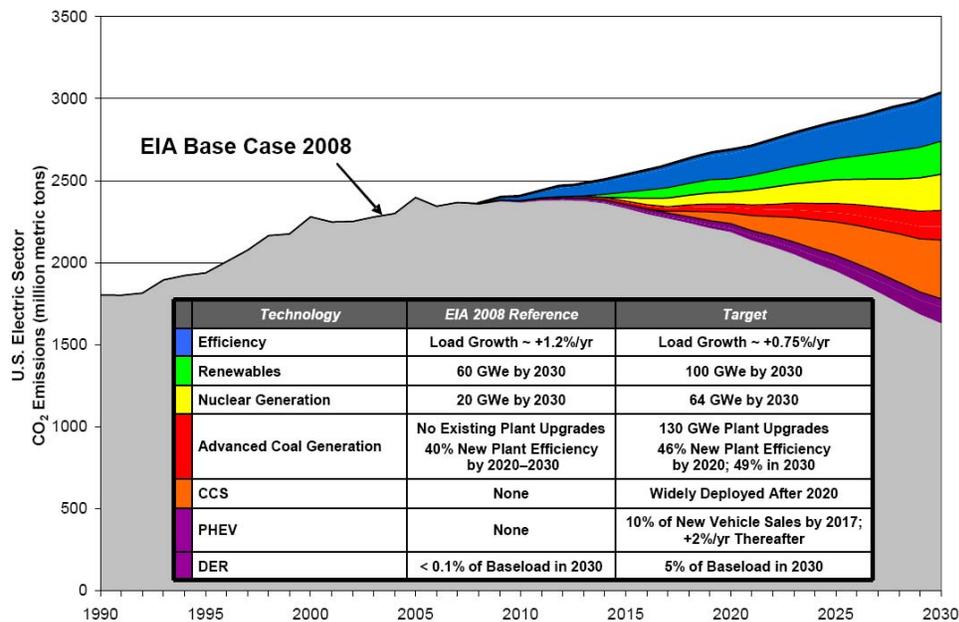


Figure 1. CO₂ Emissions in the US Electric Sector (Specker, Phillips, & Dillon, 2009, p. 2)

the greenhouse gas emissions associated with coal-fired power plants by taking the CO₂ released during combustion and sequestering it where it cannot be re-released into the atmosphere. Accordingly, depending on how costly CCS is, coal would be able to maintain its

viability as a fuel source, providing relatively clean power generation as the world transitions away from its reliance on non-renewable energy (MIT, 2007).

A. Carbon capture

In order to sequester carbon from coal firing plants, the carbon must first be separated from the plant emissions. This first step, known as “carbon capture,” is usually achieved through one of three different approaches: pre-combustion capture, post-combustion capture, or oxy-fuel combustion, as represented by the process diagrams in Figure 2 (IPCC, 2005).

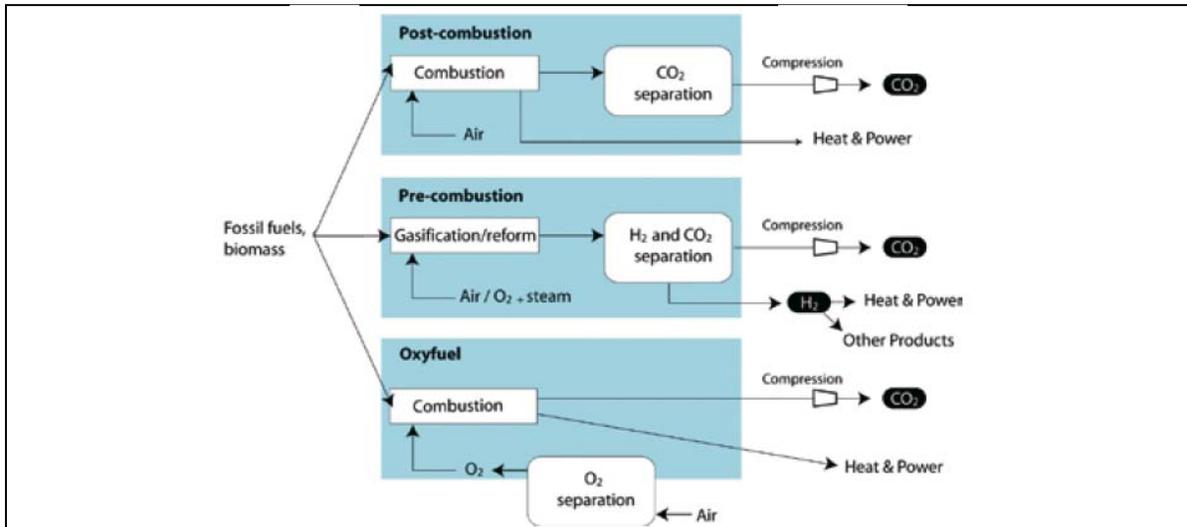


Figure 2. Illustration of different CO₂ capture technologies, modified from the IPCC report on CCS (IPCC, 2005, p. 5)

Each of these processes results in a compressed CO₂ waste stream that is ready to be transported for storage. A review of the three technologies reveals each option’s advantages and disadvantages.

i. Post-combustion

Post-combustion capture involves separating the CO₂ from power plant flue gas, or combustion exhaust. Absorption by aqueous amines or ammonia is the most common technology used to separate the CO₂ from other flue gas constituents (Krutka, Sjostrom, Bustard, Durham, Baldrey, & Stewart, 2008). Amine based recovery systems have been demonstrated at relatively large scales¹, capable of absorbing 85-95% of flue gas CO₂, creating a 99.9% pure stream of CO₂ (Hendriks & Graus, 2004). The difficulty lies in separating out dilute, low pressure (10-15% by volume, at atmospheric pressure), concentrations of CO₂ from the flue gas (NETL, n.d. a).

The post-combustion capture concept is similar to that of sulfur dioxide scrubbers. This process can capture the CO₂ from an existing plant’s flue gas stream, so it can be used to retrofit the existing stock of pulverized coal power plants (MIT, 2007). Post-combustion capture is currently the most compatible capture technology for retrofitting existing coal and natural gas plants with CCS capabilities (Herzog, Meldon, & Hatton, 2009). However, there is a large

¹ Amine systems have been built to a scale of sequestering up to 1000 tonnes of CO₂ per day (Herzog, 2009).

amount of coal generating capacity in the US and one should not underestimate the magnitude of the task of retrofitting this capacity.

ii. Pre-combustion

Pre-combustion separation is not an option that can easily be retrofit onto existing pulverized coal plants, as the carbon is captured before the fuel is combusted (Herzog et al., 2009). This process involves separating the hydrocarbon fuel into carbon dioxide waste and hydrogen fuel. The source fuel is partially oxidized in a gasification chamber such that it is chemically decomposed into synthesis gas (syngas), which is composed of hydrogen (H₂) and carbon monoxide (CO). Next, the CO is converted into CO₂ in a water-gas-shift reactor, eventually resulting in a gas consisting of 40% CO₂ and 55% H₂ (NETL, n.d. a). The CO₂ is then separated, by a physical or chemical absorption process, from the H₂, which can be used as a clean fuel (IPCC, 2005). Power plants utilizing this technology are known as Integrated Gasification Combined Cycle (IGCC) plants.

While the relative cost increase associated with carbon capture from an IGCC plant is expected to be less than that of capture from a pulverized coal plant, there are currently very few IGCC plants in operation and none of them are applying carbon capture at a commercial scale (NETL, n.d. a).

iii. Oxy-fuel

Oxy-fuel combustion requires removing the nitrogen content from the air used to combust the fuel. In place of the nitrogen, flue gas is recycled and mixed with pure oxygen to facilitate combustion (McDonald, DeVault, & Varagani, 2007). This process generates a highly concentrated CO₂ waste stream that can be easily captured and compressed for transport and storage without the need for conventional post-combustion scrubbers. An oxy-fuel combustion system's capture rate is very high – close to 100% (IPCC, 2005). As oxy-fuel combustion technology matures, performance should increase while cost decreases as a result of improved air separation technologies (McDonald et al., 2007).

In theory, oxy-fuel combustion and capture can be retrofit onto existing pulverized coal plants (IPCC, 2005). However, oxy-fuel combustion is still an emerging technology that relies on a highly energy intensive air separation process to produce the necessary oxygen (WorleyParsons, 2009). Oxy-fuel combustion and capture has yet to be demonstrated at a commercial scale².

B. Carbon storage

Once the CO₂ has been collected and compressed, it is ready for storage. Researchers are considering a range of options for carbon storage, but primarily focusing on geological storage underground. In order to ensure that the CO₂ is not re-released, geologic formations that consist of layers of porous rock covered, or “capped,” by layers of non-porous rock are considered as possible storage sites, as illustrated in Figure 3 (NETL, n.d. b).

² The largest current pilot plant is only 30MW (Stephens, 2009).

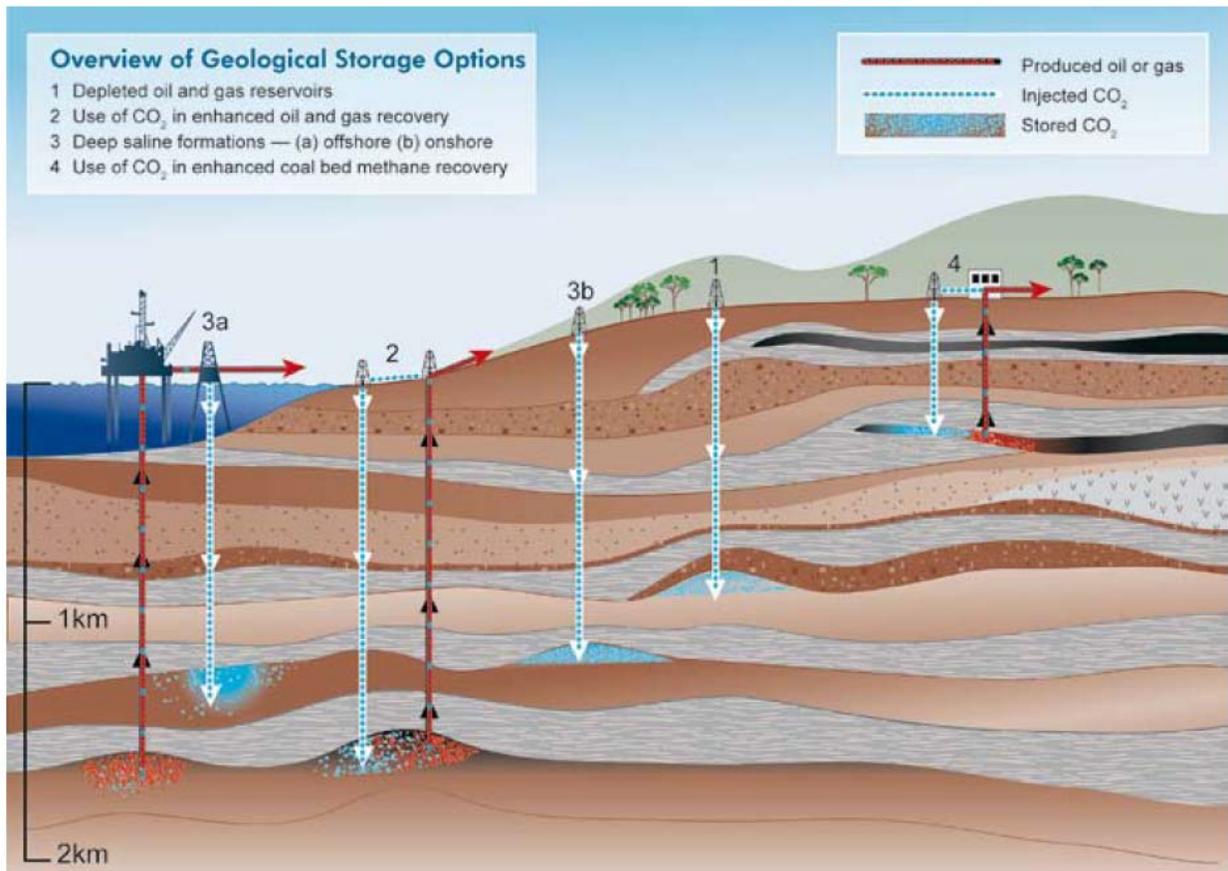


Figure 3. Illustration of geologic sequestration options (CO2CRC, 2009)

Geologic carbon sequestration options include the following three types of geologic formations: depleted oil and gas reservoirs, deep saline formations, and unmineable coal seams (Stephens, 2009). Oil and gas reservoirs are relatively well understood geologic formations that can provide a safe repository for CO₂ (Stephens, 2009). Furthermore, compressed, liquefied carbon can be pumped into oil and gas reservoirs to enhance production from a reservoir in a process known as EOR, or enhanced oil recovery, which has been practiced for over 30 years (Price & Smith, 2008). The value added through additional oil production provides an economic incentive to sequester CO₂ in depleted oil and gas reservoirs. However, oil and gas reservoirs have limited size and storage potential and may not necessarily be in close proximity to point sources of CO₂. The NETL estimates that North America has around 140 Gt³ of storage potential in depleted oil and gas reservoirs.

Coal seams that are either too deep or too thin to be economically mined for coal also represent potential storage grounds for CO₂. Since these formations typically contain some amount of coalbed methane, the CO₂ may be used for methane gas recovery, known as

³ NETL. (n.d.). *Carbon Sequestration - Storage*. Retrieved October 2009, from National Energy Technology Laboratory: http://www.netl.doe.gov/technologies/carbon_seq/core_rd/storage.html

enhanced coalbed methane recovery (NETL, n.d. b). As such, storing CO₂ in unmineable coal seams may provide economic incentives similar to EOR.

Deep saline formations are brine-saturated layers of porous rock; these formations provide far greater volumes of storage potential at the risk of increased uncertainty in storage security (NETL, n.d. b). The NETL estimates between 3,300 and 12,600 Gt⁴ of storage potential in saline formations in North America alone, many orders of magnitude greater than depleted oil and gas reservoirs.

In any geologic sequestration scenario, the CO₂ is first trapped physically by the impermeable rocks above (Price & Smith, 2008). As time passes, the security of the trapping mechanism should become greater. Eventually, the CO₂ will dissolve into the fluids, such as brines or oil that remain in the storage site finally mineralizing into stable compounds after thousands of years (Price & Smith, 2008).

Ocean storage has also been considered as an option for carbon sequestration. The ocean is by far the largest carbon sink on the planet, already containing 40,000 Gt of carbon compared with less than 3,000 Gt of carbon in the terrestrial biosphere and atmosphere combined (Herzog, Caldeira, & Adams, 2001). However, environmental concerns have led to the cancellation of a number of pilot projects for ocean storage (Stephens, 2009). While the ocean naturally takes in a large amount of anthropogenic carbon from the atmosphere every year, accelerating this process through deep ocean CO₂ injection would certainly cause changes to the ocean's chemistry, at least on local levels, possibly impacting wildlife and marine ecosystems (Stephens, 2009).

C. The Calera process

Calera is proposing a new process to capture and sequester CO₂ from power plant emissions. In essence, Calera aims to sequester the carbon post-combustion, and store it in a mineralized, stable form in a single step.⁵ The flue gas from fossil fuel combustion is reacted with alkaline solutions heavy in calcium and/or magnesium, such as certain minable brines, to form a stable carbonate solid with a byproduct of relatively fresh water that would be suitable for desalination. In instances where suitable brines are not readily available, an alkaline solution of sodium hydroxide may be manufactured via a proprietary, low energy chemical electrolysis reaction developed by Calera. Once the CO₂ has been absorbed into a bicarbonate solution, it can be stored underground almost anywhere. Calera further proposes to transform this bicarbonate into a carbonate material, which can be stored or used to create SCM and cement (building materials). This process has the added benefit of offsetting emissions currently associated with traditional cement production while potentially generating positive revenue for Calera's carbon sequestration process.

⁴ NETL. (n.d.). *Carbon Sequestration - Storage*. Retrieved October 2009, from National Energy Technology Laboratory: http://www.netl.doe.gov/technologies/carbon_seq/core_rd/storage.html

⁵ Calera currently has a 10MW demonstration plant at Moss Landing in California.

D. Costs of existing capture technologies

Carbon capture as it currently exists requires expensive equipment and is highly energy consumptive (IEA, 2006). The parasitic energy requirement can range from around 25% for post-combustion capture at a high efficiency ultra-supercritical coal plant up to over 37% for a typical subcritical plant (Page, Williamson, & Mason, Carbon capture and storage: Fundamental thermodynamics and, 2009). This has a direct impact on a plant's net cost of generating electricity, as well as the grid's ability to continue to supply power and energy.

A number of privately and publicly funded studies have attempted to analyze the costs of different carbon capture and sequestration technologies. Most studies tend to focus primarily on carbon capture, without including transportation and storage, as the capture process represents the largest fraction of overall CCS costs (Naucler, Campbell, & Ruijs, 2008). A recent report by Harvard University compiled a selection of these studies in an effort to compare the range of estimates for various capture technologies that can be integrated into new build power plants⁶. Figures 4-6 represent the set of relevant cost estimates from various studies on the economics of carbon capture⁷. These estimates vary widely in their baseline assumptions;

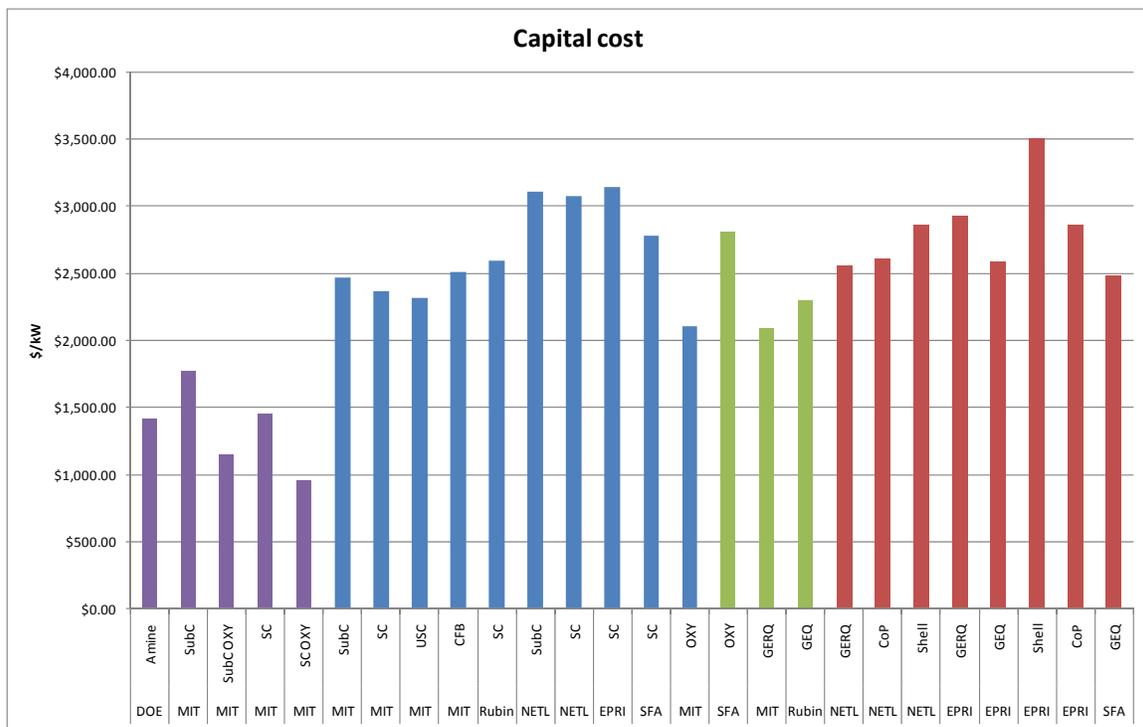


Figure 4. A comparison of total capital costs of a technology, as estimated by each study.

⁶ Tables taken from the Harvard University report, "Realistic Costs of Carbon Capture," (Al-Juaied & Whitmore, 2009, pp. 42,45) were normalized to 2009 dollars (using the consumer price index from the US Department of Labor) as input to the graphs in Figures 5-7.

⁷ In addition to the Harvard University report, two studies of retrofit technologies were also normalized to 2009 dollars and included in Figures 5-7: One by the Department of Energy (Ramezan, Skone, Nsakala, & Liljedahl, 2007) and one by the Massachusetts Institute of Technology (MIT, 2007).

Aside from the purple bars, all other bars are adapted from the Harvard University report, “Realistic Costs of Carbon Capture,” which compiled a selection of CCS cost studies (Al-Juaied & Whitmore, 2009, pp. 42,45).

Technology abbreviations: Amine = amine based capture; SubC = subcritical pulverized coal plant; SC = supercritical pulverized coal plant; USC = ultrasupercritical pulverized coal plant; CFB = circulating fluidized bed plant; OXY = oxy-fuel plant; GEQ = TE Total Quench plant; GERQ = GE Radiant Quench plant; CoP = ConocoPhillips plant

Study abbreviations: DOE = Department of Energy⁸; MIT = Massachusetts Institute of Technology⁹; SFA = SFA Pacific, Inc.; NETL = National Energy Technology Laboratory¹⁰; EPRI = Electric Power Research Institute

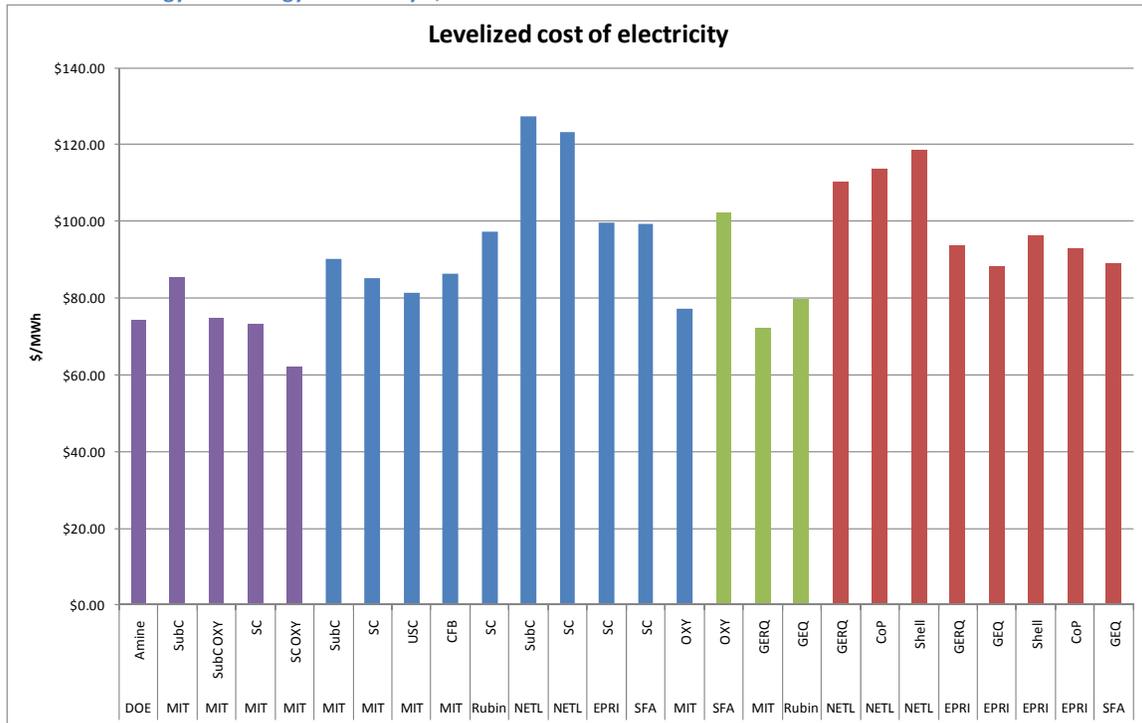


Figure 5. A comparison of the levelized cost of electricity generation of each technology, as estimated by each study.

consequently, comparisons between studies using these results are difficult. Rather, these figures are meant to provide very general context regarding the expected costs of different CCS options.

In the figures, bars are colored according to capture technology: purple bars represent retrofit technology studies; blue bars represent post-combustion capture studies; green bars represent oxy-fuel studies; red bars represent pre-combustion studies for IGCC plants. Based on a quick review of the capital costs from these studies, installing carbon capture technology can cost from under \$1000/kW for an oxy-fuel capture retrofit (MIT, 2007) to roughly \$3500/kW for a new-build IGCC capture plant (EPRI, 2007). Focusing on levelized costs of electricity generation, the MIT study estimated just over \$60/MWh for an oxy-fuel capture retrofit while a NETL study estimated almost \$120/MWh for a subcritical pulverized coal plant with post-combustion capture (NETL, 2007). In terms of cost per tonne of CO₂ avoided, the amine based post-

⁸ Adapted from the DOE retrofit study (Ramezan et al., 2007).

⁹ Adapted from “The Future of Coal” (MIT, 2007).

¹⁰ This study also includes transport and storage costs (NETL, 2007).

combustion technology studied by the DOE was clearly the most expensive, at almost \$90/tonne of CO₂ avoided (NETL, 2007).

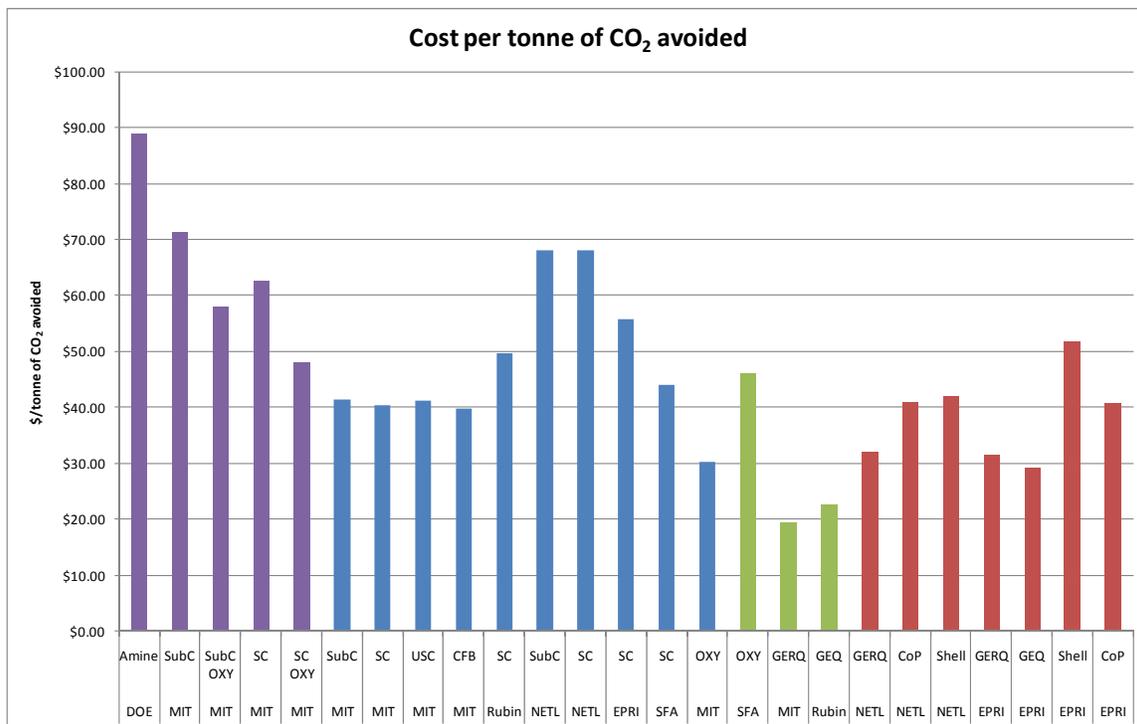


Figure 6. A comparison of the cost per tonne of CO₂ avoided of each technology, as estimated by each study¹¹.

Again, these graphs provide very rough estimates of the actual costs of CCS. Each study is based on very different sets of assumptions, including different costs of source fuel, interest rates, project lifetimes, plant sizes, etc. While general conclusions may be inferred, meaningful study to study comparisons are difficult.

E. Costs of transport and storage

After the CO₂ has been captured and compressed¹², it must be transported to an appropriate storage site for sequestration. Pipelines are the primary option for large scale transport, with shipping as a secondary possibility¹³ (Naucner et al., 2008). Generally, a range of around \$1 - \$5/tonne of CO₂, transported 250km, can be expected, depending on the flow rate of the pipeline (IPCC, 2005). Total transportation cost for CO₂ on a per tonne basis can vary significantly according to the size of the project, as illustrated by a study on CO₂ transport and storage in the Latrobe Valley, Australia, which estimated pipeline costs ranging from under A\$2/tonne of CO₂ to almost A\$15/tonne (Hooper, Murray, & Gibson-Poole, 2005).

¹¹ CO₂ avoided is a measure of the total CO₂ captured at the capture plant minus the additional CO₂ generated as a result of applying the carbon capture technology to the reference plant, as depicted in the figure in Appendix A.

¹² CO₂ is assumed to be compressed to around 10MPa at the capture plant (IPCC, 2005).

¹³ At great distances, shipping can actually be the cheapest method of transportation (IPCC, 2005).

Different geologic storage options also have different costs. Through work with the US Department of Energy and Environmental Protection Agency, ICF International has estimated the costs of geologic storage in the US by storage option. Total costs per tonne of CO₂ range from \$4.28 for storage in onshore depleted gas reservoirs to -\$66.25¹⁴ for onshore EOR¹⁵ (Vidas, Hugman, & Clapp, 2009). The International Energy Agency reports an estimated \$4-\$12/tonne range, depending on injection properties and storage site, including transport (Adams & Davison, 2007). Essentially, the economics of transportation and storage is sensitive to widely varying input parameters, making accurate estimates of any transportation method and storage site combination very difficult (Allinson & Nguyen, 2003).

III. Cost analysis of CCS in the Latrobe Valley

There are four major coal-fired power plants currently operating in the Latrobe Valley in Victoria, Australia. These plants use 65 million tons of brown coal (also called lignite) annually, supplying 85% of the state's electricity (The State of Victoria, 2008). Unfortunately, brown coal is of very low quality with high moisture content, releasing less energy when combusted compared with black coal (Kavonic & Rooney, 2008). Since this lower energy content requires that more fuel be used to produce a given amount of power, and the high moisture content decreases boiler efficiency, more CO₂ is released per kWh of brown coal power generation. Since Australia is rich in brown coal deposits, with the thickest brown coal seams in the world (Sait, 2008), CCS technology can potentially play a large role in power generation within the region.

A. CCS options to be considered

This study will focus on the Yallourn power plant, located in the Latrobe Valley. The Yallourn plant has a capacity of 1,480 megawatts of electricity, and generates 22% of Victoria's and 8% of Australia's electricity needs (TRUenergy, 2008). In order to greatly reduce its CO₂ emissions, the Yallourn power plant is exploring options for carbon capture and sequestration. The decision tree in Figure 7 represents the range of approaches that must be considered – from retrofitting to full rebuilds.

In order to set up a comparison between traditional carbon capture technologies that could be applied at the Yallourn plant with the Calera process, this analysis is focused on retrofit options for CO₂ capture. Specifically, we are comparing a retrofit of the existing plant with two types of post-combustion capture, oxy-fuel combustion with capture, and the Calera process. For the purposes of comparison, we split the Calera process into two separate processes. First, the CO₂ from the flue gas is captured into a bicarbonate solution. Second, the bicarbonate is transformed into a carbonate that is used to create cementitious building materials. This analysis focuses on the first step, comparing traditional capture technologies with Calera capture only. Additionally, since consideration of makeup power creates an additional bias

¹⁴ Negative value implies a credit as opposed to a cost.

¹⁵ It is important to note, however, that expected revenues from EOR may be limited. The large initial sunk costs of a plant take a long time to pay back, likely longer than the lifetime of the EOR project (WorleyParsons, 2009).

against technologies with a greater parasitic energy load, we are not including makeup power in this assessment.

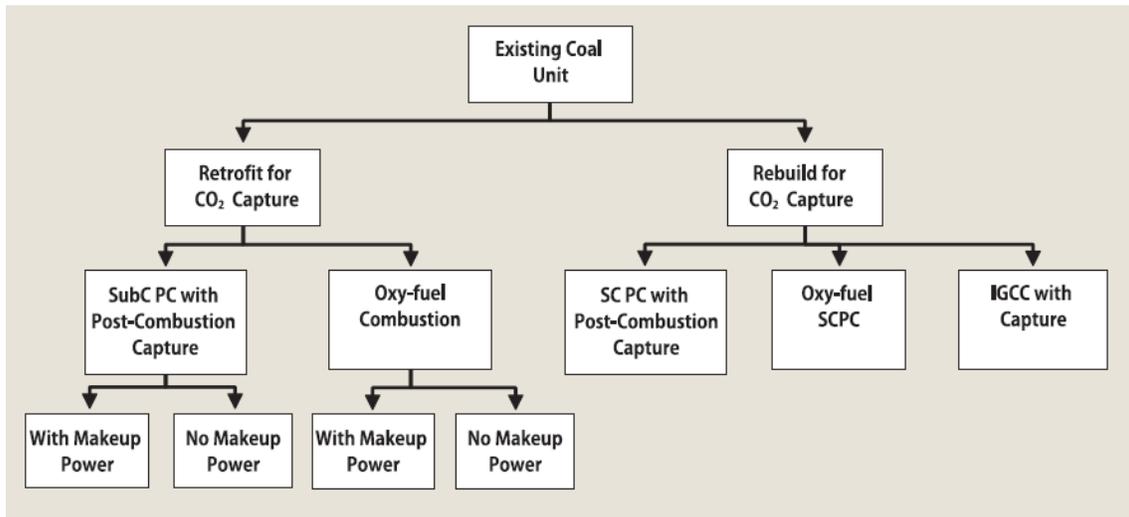


Figure 7. Decision tree of possible options for fitting an existing coal-fired electricity generating unit with carbon capture technology. (MIT, 2007, p. 145)

Consideration of makeup power would, however, impact the cost of capture in terms of \$/tonne of CO₂ avoided. Technologies with a higher derating from parasitic energy load would require greater amounts of makeup power, which, in the case of fossil fuel based generation, emits additional CO₂. Appendix A provides an illustration of the difference between thinking in terms of CO₂ captured vs. CO₂ avoided.

To compare these options, we calculate the levelized cost of electricity (COE) for each capture technology using estimates of upfront capital cost of the retrofit, parasitic energy load, additional O&M cost, and cost of transport and storage. Our calculations are specific to the Yallourn plant in the Latrobe Valley.

B. Model for comparison of CCS options

Figures 8, 9, and 10 are drawn from the Yallourn power plant’s “Social and Environmental Report” from 2008 (TRUenergy, 2008), and represent the reference conditions at the plant.

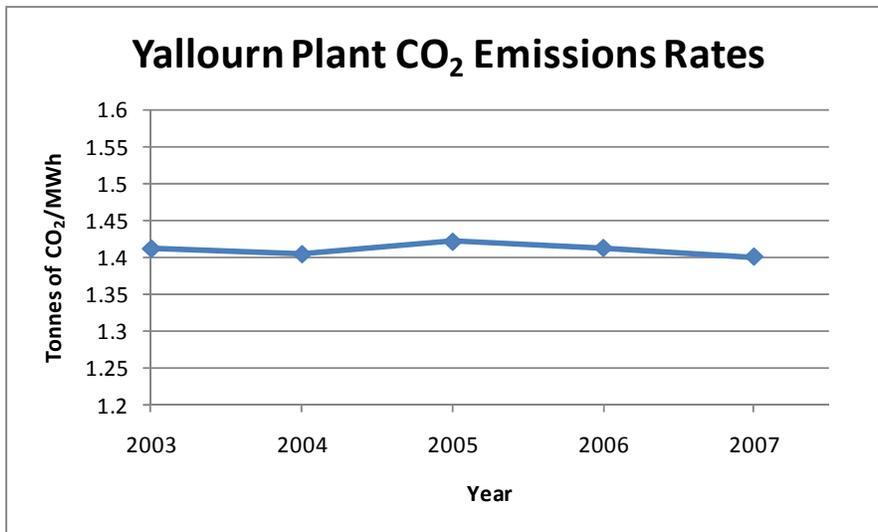


Figure 8: CO₂ emissions rates at Yallourn from 2003-2007. These rates were calculated by dividing the total reported mass of CO₂ generated by the total reported amount of electricity sent out for each year:

$$\text{Emissions rate (tonnes of CO}_2\text{/MWh)} = \frac{\text{Total CO}_2\text{ generated (tonnes)}}{\text{Total electricity sent out (MWh)}}$$

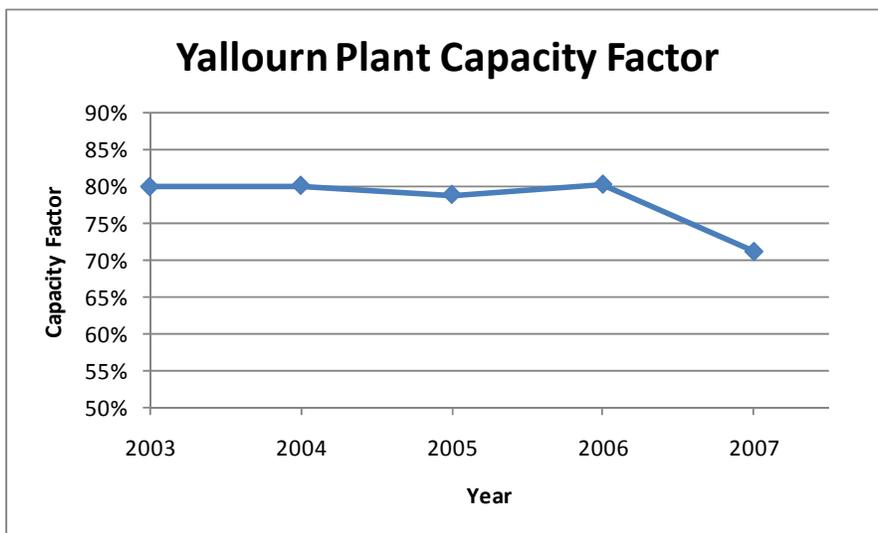


Figure 9: Capacity factor at Yallourn from 2003-2007. Capacity factor was calculated by dividing the total reported amount of electricity sent out by the total amount of electricity that could be generated at the rated 1480MW for each year:

$$\text{Capacity factor (\%)} = \frac{\text{Total electricity sent out (MWh/year)}}{1480 \text{ MW} \times 365 \text{ days/year} \times 24 \text{ hours/day}}$$

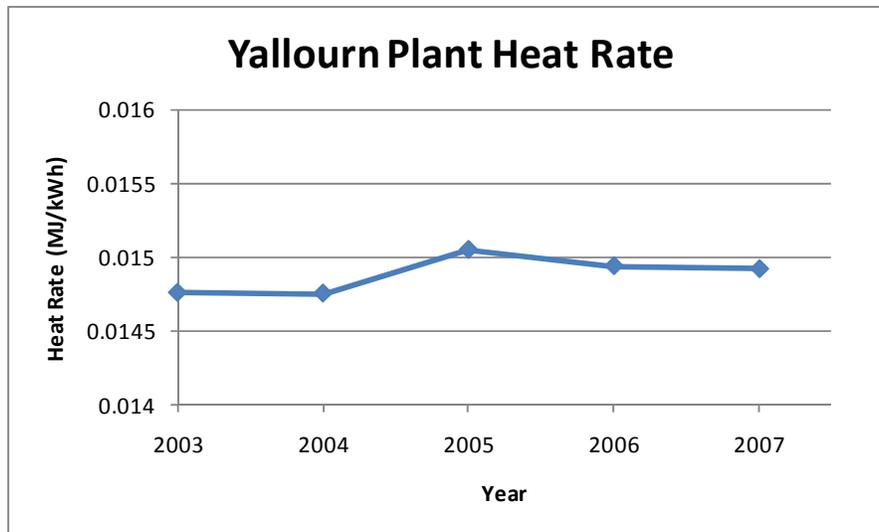


Figure 10: Heat rate at Yallourn from 2003-2007. Heat rate was calculated by dividing the total reported amount of coal consumed by the total reported amount of electricity sent out for each year:

$$\text{Heat rate (MJ/kWh)} = \frac{\text{Total coal consumed (MJ)}}{\text{Total electricity sent out (kWh)}}$$

The current COE at Yallourn is approximated to be \$37.63 per MWh, based on general estimates for electricity generation in the Latrobe Valley¹⁶. This value includes cost of fuel, O&M, and repayment of the original plant's capital cost. The current price of brown coal in Victoria is approximately \$4.73 per tonne¹⁷. The following set of assumptions forms the basis for our model:

Discount rate = 15%¹⁸

Project lifetime = 20 years¹⁹

Current cost of coal = \$4.73/tonne

Energy content of brown coal = 8.6 MJ/kg²⁰

Current CO₂ generation rate = 1.4 tonnes per MWh²¹

Plant capacity factor = 78%²²

Current COE = \$37.63/MWh

Using the assumed coal price of \$4.73 per tonne and energy content of 8.6 MJ/kg, we calculate the fuel component of the current COE to be \$8.18 per MWh using the following equation:

$$\text{Cost of fuel (\$/MWh)} = \frac{\text{Coal price (\$/tonne)}}{\text{Energy content (MJ/tonne)}} * \text{Heat rate at Yallourn}$$

¹⁶ According to a report by the Victorian government, electricity can be generated from brown coal at \$35 per MWh. In 2009 dollars, this becomes \$37.63 per MWh (Doherty & Murphy, 2006).

¹⁷ The Australian Coal Review estimated the cost to be between A\$2 and A\$7 dollars per tonne. The average, in 2009 US dollars is \$4.73 (Johnson & Pleasance, 1996).

¹⁸ Consistent with DOE retrofit study (Ramezan et al., 2007).

¹⁹ Consistent with DOE retrofit study (Ramezan et al., 2007).

²⁰ Average for Victorian brown coal (Kavonic & Rooney, 2008).

²¹ Calculated average from 2003-2007 (TRUenergy, 2008).

²² Calculated average from 2003-2007 (TRUenergy, 2008).

Assuming the current total COE is \$37.63 per MWh, the difference between the fuel component and the total is the reference plant’s combined capital recovery and O&M cost, \$29.45 per MWh, as illustrated in Figure 11.

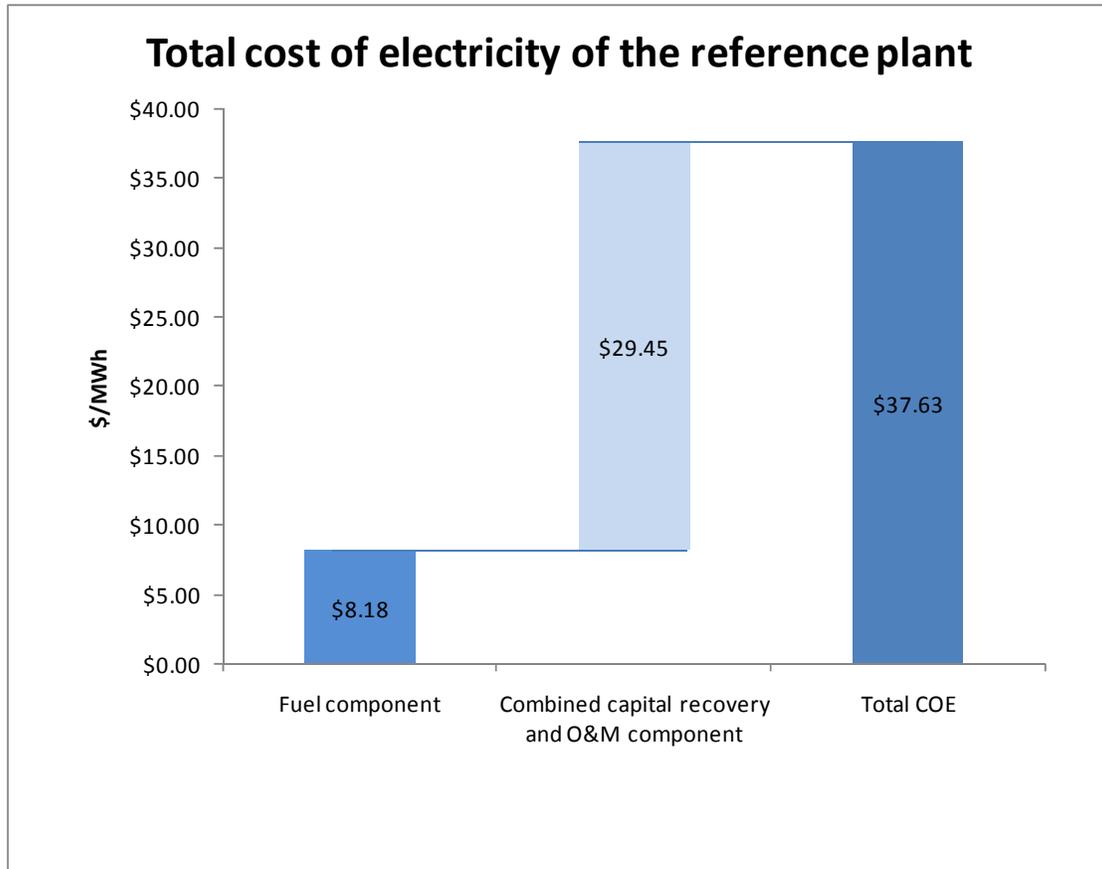


Figure 11: Breakdown of the total cost of electricity for the reference case, based on our assumptions for the conditions in the Latrobe Valley.

i. Retrofit cost parameters

We chose three different capture options against which to compare the Calera capture process: MEA post-combustion and Oxy-fuel from the retrofit study reported in “The Future of Coal” (MIT, 2007), and Advanced Amine from the Department of Energy study on CCS retrofit technologies performed by the Department of Energy (Ramezan et al., 2007). These three capture processes result in a compressed stream of CO₂ that must be transported to an appropriate storage site and injected underground. The Calera capture process in this cost comparison absorbs the CO₂ into an aqueous bicarbonate solution that must be securely stored, and does not include the production of building materials.

Table 1 outlines the basic parameters that we input into our model for each technology. Capture rates and parasitic load percentages were taken directly from the MIT and DOE studies.

Calera values were drawn directly from Calera’s in-house estimates for the Yallourn plant, assuming that suitable brines can be mined to complete their capture process. Transportation/storage costs are assumed to be \$0.00 for Calera because the bicarbonate solution formed during capture can be pumped back underground along with the spent brines²³. O&M costs and transportation/storage costs for MEA, Oxy-fuel, and Advanced Amine were adapted from reported estimates, as outlined in Appendix B. Additionally, the capital cost and O&M cost for each technology has been adjusted to reflect the higher CO₂ intensity of brown coal in Victoria, as outlined in Appendix C.

Table 1: Cost parameters for different retrofit options in 2009 US\$. Costs of implementing sulfur controls are not included in this comparison (the Calera process also captures sulfur).

	MEA	Oxy-fuel	Advanced Amine	Calera
Reference plant size ²⁴	500 MW	500 MW	433.8 MW	500 MW
Capital cost (\$/kW)	\$2,137.97	\$1,390.21	\$1,818.04	\$800
Parasitic load ²⁵	42%	35.9%	30%	7.7%
Capture rate ²⁶	90%	90%	90%	90%
O&M cost (\$/MWh) ²⁷	\$8.89	\$15.86	\$12.30	\$7.74
Trans/storage (\$/tonne CO ₂)	\$8.94	\$8.94	\$8.94	\$0.00

ii. Cost of electricity calculation

The COE for each technology is first broken down into five components: fuel, reference plant capital recovery and O&M²⁸, capital recovery of the retrofit, additional O&M required by the retrofit, and transportation and storage. Since the new plant with CCS has a decreased net output due to the energy requirement of the retrofit, the increase in fuel and reference plant capital recovery and O&M costs is a direct function of the parasitic load (as a fraction/percent). The new fuel and reference plant capital recovery and O&M costs are calculated by the following function:

$$\text{New cost (\$/MWh)} = \frac{\text{Reference cost (\$/MWh)}}{1 - \text{Parasitic load}}$$

The capital recovery of the retrofit component is calculated by annuitizing the total upfront capital cost based on the assumed project lifetime (*n* years) and discount rate (*i*), as follows:

$$\text{Total capital cost (\$)} = \text{Capital cost (\$/kW)} * \text{Plant output after retrofit (kW)}$$

²³ Calera’s exact processes and associated costs were taken directly from Calera estimates and cannot be independently verified.

²⁴ The size of the reference plant at which the retrofit is applied does not impact the cost of electricity generation. This is only a reference value at which the capital cost estimate (in \$/kW) is assumed to be valid.

²⁵ Energy cost to the plant due to retrofit operation – the net output is decreased by this percentage.

²⁶ Percentage of CO₂ emissions that is captured.

²⁷ Additional O&M for the retrofit.

²⁸ The cost of electricity at the reference plant is assumed to include fuel, capital recovery, and O&M. These components increase for each technology as a function of the parasitic energy requirement of each technology.

$$\text{Annualized capital cost (\$)} = \text{Total capital cost (\$)} * \frac{i}{1 - \frac{1}{(1+i)^n}}$$

Next, the annualized capital cost must be divided by the amount of electricity generated at the plant after the retrofit to determine the COE due to the repayment of retrofit capital:

$$\text{Capital recovery of retrofit (\$/MWh)} = \frac{\text{Annualized capital cost (\$)}}{\text{Total electricity generated in a year (MWh)}}$$

Where:

$$\begin{aligned} \text{Total electricity generated in a year (MWh)} \\ &= \text{Plant output after retrofit (MW)} * \text{Capacity factor (\%)} \\ &* 24 \text{ (hours/day)} * 365 \text{ (days/year)} \end{aligned}$$

Additional O&M is already input in terms of \$/MWh and can be directly added to the other COE components. Transportation/storage, however, must be converted from \$/tonne to \$/MWh as follows:

$$\begin{aligned} \text{Total transportation/storage cost in a year (\$)} \\ &= \text{Transportation/storage cost (\$/tonne)} * \text{Total CO}_2 \text{ captured (tonnes)} \\ \text{Transportation/storage cost (\$/MWh)} \\ &= \frac{\text{Total transportation/storage cost in a year (\$)}}{\text{Total electricity generated in a year (MWh)}} \end{aligned}$$

Where:

$$\begin{aligned} \text{Total CO}_2 \text{ captured (tonnes)} \\ &= \text{CO}_2 \text{ generation rate (tonnes CO}_2\text{/MWh)} \\ &* \text{Total electricity generated in a year (MWh)} * \text{Capture rate (\%)} \end{aligned}$$

Summing these five components yields the total COE for a given technology in terms of \$/MWh.

With an emissions tax, plants are required to pay a price for each tonne of CO₂ they emit. Therefore, an additional “Cost of CO₂” component is added to the COE. This is calculated by multiplying the price of CO₂ emissions by the total CO₂ emitted in a year and dividing by the net total electricity generated in a year, as follows:

$$\text{Cost of CO}_2\text{ (\$/MWh)} = \frac{\text{Price of CO}_2\text{ (\$/tonne)} * \text{Total CO}_2 \text{ emitted in a year (tonnes)}}{\text{Total electricity generated in a year (MWh)}}$$

Where:

$$\begin{aligned} \text{Total CO}_2 \text{ emitted in a year (tonnes)} \\ &= \text{Total electricity generated in a year (MWh)} \\ &* \text{CO}_2 \text{ generation rate (tonnes CO}_2\text{/MWh)} \end{aligned}$$

As the price of CO₂ emissions increases, the cost of CO₂ component of the total COE also increases.

C. Model results

Table 2 represents the results of the levelized COE calculations for each component of each retrofit technology with no emissions tax.

Table 2: COE for each retrofit option, broken down by cost component.

COE Component (\$/MWh)	MEA	Oxy-fuel	Advanced Amine	Calera (brines only)
Fuel	\$14.11	\$12.77	\$11.69	\$8.87
Reference plant capital + O&M	\$50.77	\$45.94	\$42.08	\$31.90
Retrofit capital recovery	\$49.99	\$32.51	\$42.51	\$18.71
O&M of retrofit	\$8.89	\$15.86	\$12.30	\$7.74
CO ₂ Transport/storage	\$19.42	\$17.57	\$16.10	\$0.00
Total COE	\$143.18	\$154.65	\$124.68	\$67.21

Clearly, based on this model for the Yallourn plant, Calera capture represents by far the cheapest option for CO₂ capture given our initial input values, with no price for CO₂ emissions. Figure 12 illustrates the levelized COE generation for each option as a function of an assumed price for CO₂. The dark blue line represents the reference case – no CCS at the existing Yallourn plant. With a tax on carbon emissions, each technology’s COE rises as the price of CO₂ increases.

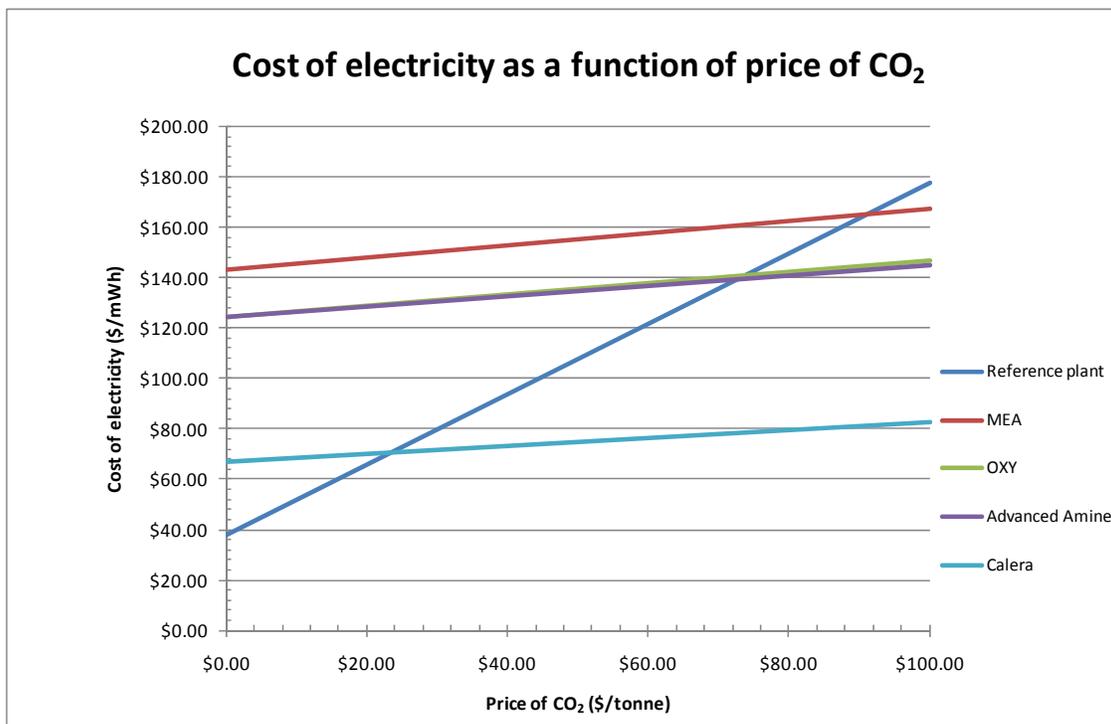


Figure 12: COE as a function of the price of CO₂ for each retrofit option.

The points at which the reference plant line crosses the lines of the different options represent the breakeven points for each CCS technology, at which the given option becomes economically favorable. From the graph, we can infer a breakeven price of roughly \$91 for MEA, \$74 for Oxy-fuel, \$73 for Advanced Amine, and \$24 for Calera, when compared with the reference plant.

The following four figures illustrate the COE for each technology, broken down into components, as a function of an assumed price for CO₂. Calera's advantage lies in its significantly smaller parasitic load, lower capital cost, and elimination of the need for transportation/storage.

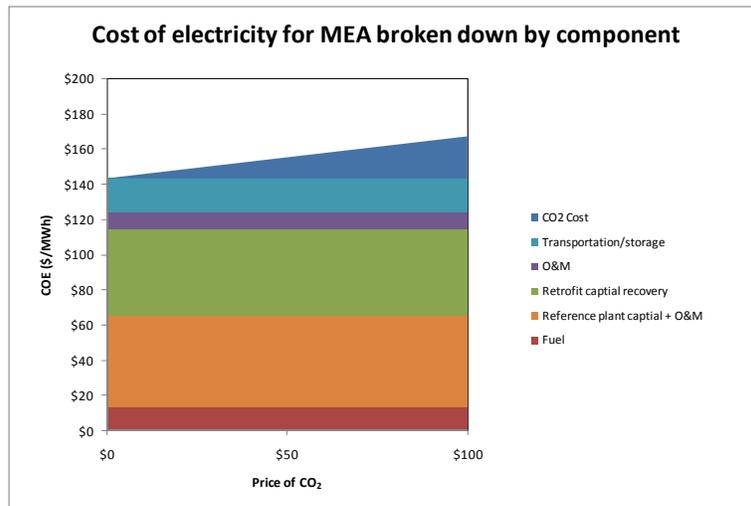


Figure 13: COE for MEA by component.

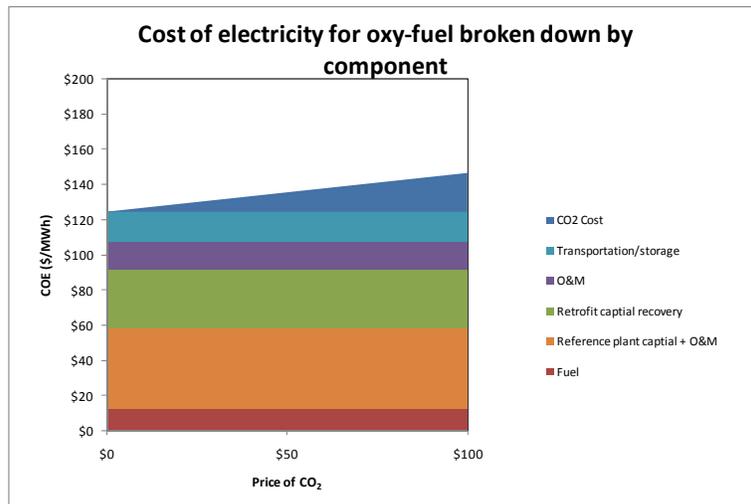


Figure 14: COE for Oxy-fuel by component.

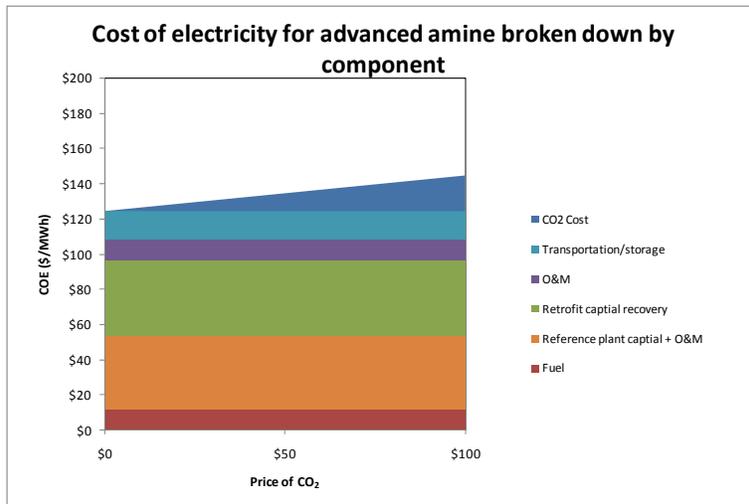


Figure 15: COE for advanced amine by component.

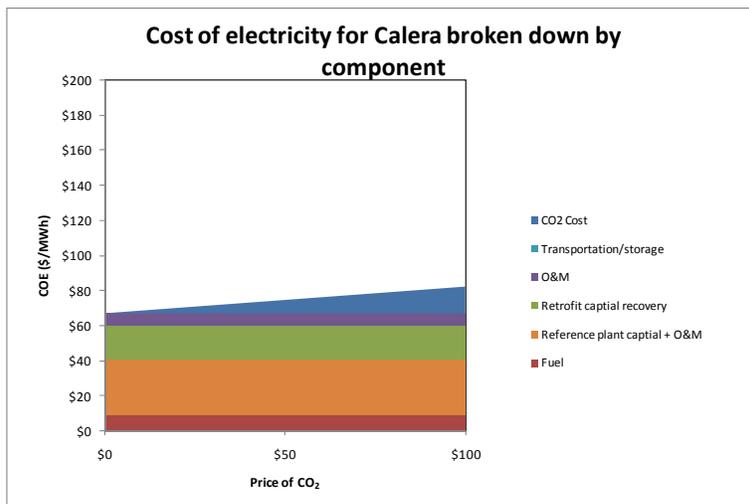


Figure 16: COE for Calera (brines only) by component.

i. Calera with e-chem

At the Yallourn plant, Calera hopes to be able to run its full process without electro-chemically producing alkalines (e-chem) via its proprietary process. At the very least, Calera believes that capturing the flue gas CO₂ into a bicarbonate suitable for storage would require only brines. However, there may be cases where e-chem is necessary for the second step of transforming the captured bicarbonate into a carbonate that can be used to make building materials. Furthermore, even when e-chem is not absolutely necessary purely for capture, e-chem may be used to create a more controlled environment to better facilitate the chemical reactions involved in the Calera process.

Calera’s capture process with e-chem is more energy intensive and expensive compared to the base case of capture with brines only²⁹. Allocation of these additional costs for our analysis is not straightforward, as outlined above. For the purposes of this study, Calera assumes it could apply a half scale e-chem process to facilitate capture only. Our analysis is based on this assumption, that capital and operating costs of e-chem for a capture only Calera process would be 50% of the total e-chem costs for a full Calera process which includes production of building materials. Appendix D summarizes the different Calera cases and associated cost breakdowns. Duplicating the previous calculation for Calera with e-chem yields the results depicted in Table 3 and Figure 17.

Table 3: COE for each retrofit option compared to Calera w/ e-chem.

COE Component (\$/MWh)	MEA	Oxy-fuel	Advanced Amine	Calera w/ e-chem
Fuel	\$14.11	\$12.77	\$11.69	\$9.67
Reference plant capital + O&M	\$50.77	\$45.94	\$42.08	\$34.81
Retrofit capital recovery	\$49.99	\$32.51	\$42.51	\$33.90
O&M	\$8.89	\$15.86	\$12.30	\$11.62
Transportation/storage	\$19.42	\$17.57	\$16.10	\$0.00
Total COE	\$143.18	\$154.65	\$124.68	\$90.00

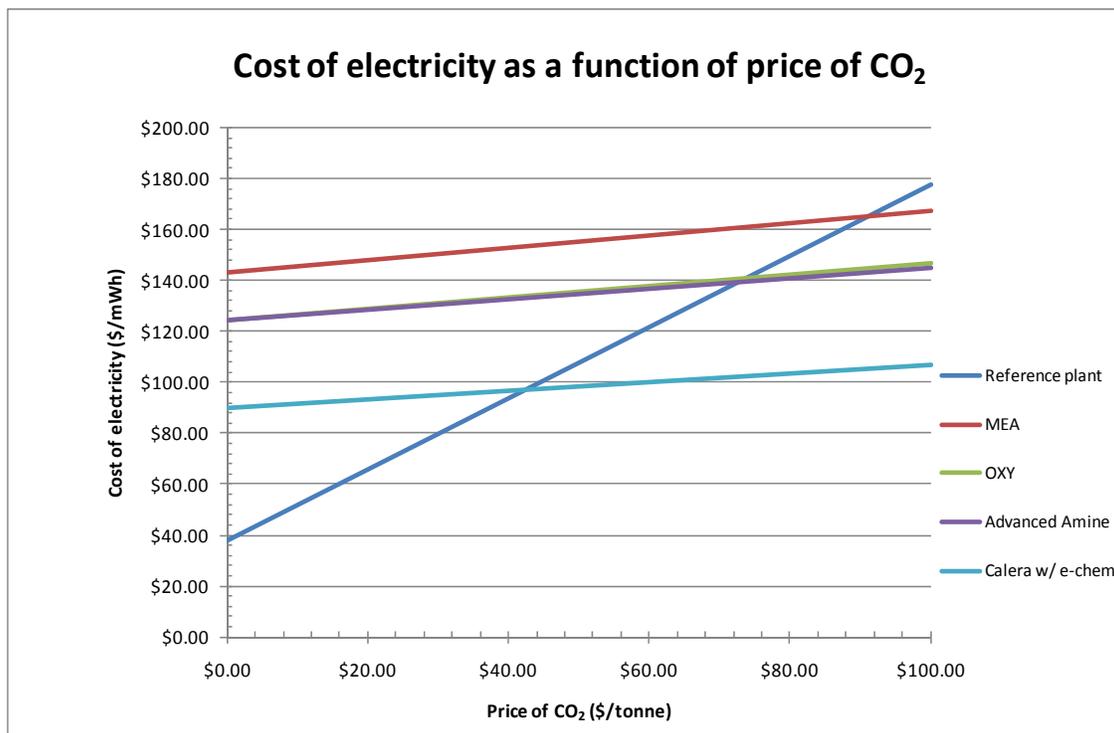


Figure 17: COE as a function of the price of CO2 for each retrofit option, including Calera w/ e-chem.

²⁹ Capital cost increases from \$800/kW to \$1,450/kW; parasitic load increases from 7.7% to 15.4%; O&M increases from \$7.74/MWh to \$11.62/MWh.

Even with the inclusion of e-chem,³⁰ Calera capture is clearly the cheapest CCS option. However, the COE increases by roughly 35% to \$90 per MWh and the breakeven CO₂ price increases to just over \$42.

ii. Sensitivity analysis

A sensitivity analysis was conducted to determine which model parameters most affect the breakeven price of CO₂ for each CCS retrofit option. Table 4 presents the resulting change in breakeven price of CO₂ when varying discount rate, project lifetime, reference plant capacity factor, retrofit capital cost, and retrofit O&M.

Table 4: Change in the breakeven price of CO₂ for each retrofit technology by varying select model parameters.

	Base case CO ₂ price	Discount rate		Project lifetime		Capacity factor		Retrofit capital cost		O&M	
		10%	20%	10 yrs	30 yrs	70%	85%	-30%	+30%	-30%	+30%
MEA	\$91.10	-\$11.42	\$12.31	\$10.66	-\$2.01	\$4.93	-\$3.55	-\$12.94	\$12.94	-\$2.30	\$2.30
Oxy-fuel	\$73.64	-\$7.28	\$7.85	\$6.80	-\$1.28	\$3.14	-\$2.27	-\$8.25	\$8.25	-\$4.03	\$4.03
Advanced Amine	\$72.54	-\$9.38	\$10.11	\$8.76	-\$1.65	\$4.05	-\$2.92	-\$10.63	\$10.63	-\$3.08	\$3.08
Calera	\$23.19	-\$3.97	\$4.28	\$3.70	-\$0.70	\$1.71	-\$1.23	-\$4.50	\$4.50	-\$1.71	\$1.71
Calera w/ e-chem	\$42.42	-\$7.27	\$7.84	\$6.79	-\$1.28	\$3.14	-\$2.26	-\$8.24	\$8.24	-\$2.83	\$2.83

Note: Negative number implies that technology breaks even at a lower CO₂ price by the amount indicated.

From this table, it appears that uncertainty in the capital cost of the retrofit may be a significant source of error. Additionally, changing the discount rate significantly impacts the breakeven cost of electricity in all cases. While extending the project lifetime to 30 years has little effect, shortening the lifetime to 10 years is significant in all cases. However, under no combination of situations considered in this sensitivity analysis would Calera capture (with or without e-chem) ever have a higher breakeven CO₂ price than any other CCS retrofit option.

iii. Calera with production of building materials

Not included in the previous cost comparison is Calera's production of building materials. While the Calera capture process as presented in our model is established to be cheaper than other CCS options, adding the production of building materials increases costs of capital, O&M and parasitic load, as outlined in Appendix D. Without the consideration of revenues from the production of building materials, the COE for the Calera process is expected to increase as shown in Figure 18.

From this graph, we can see that the breakeven price of CO₂ rises from around \$23 to roughly \$38 for the full Calera process without e-chem, and \$78 for the full Calera process with e-chem.

³⁰ 50% of total e-chem costs, following Calera's allocation procedures.

Again, this does not include revenues from the production of building materials, which Calera expects to offset the increase in COE.

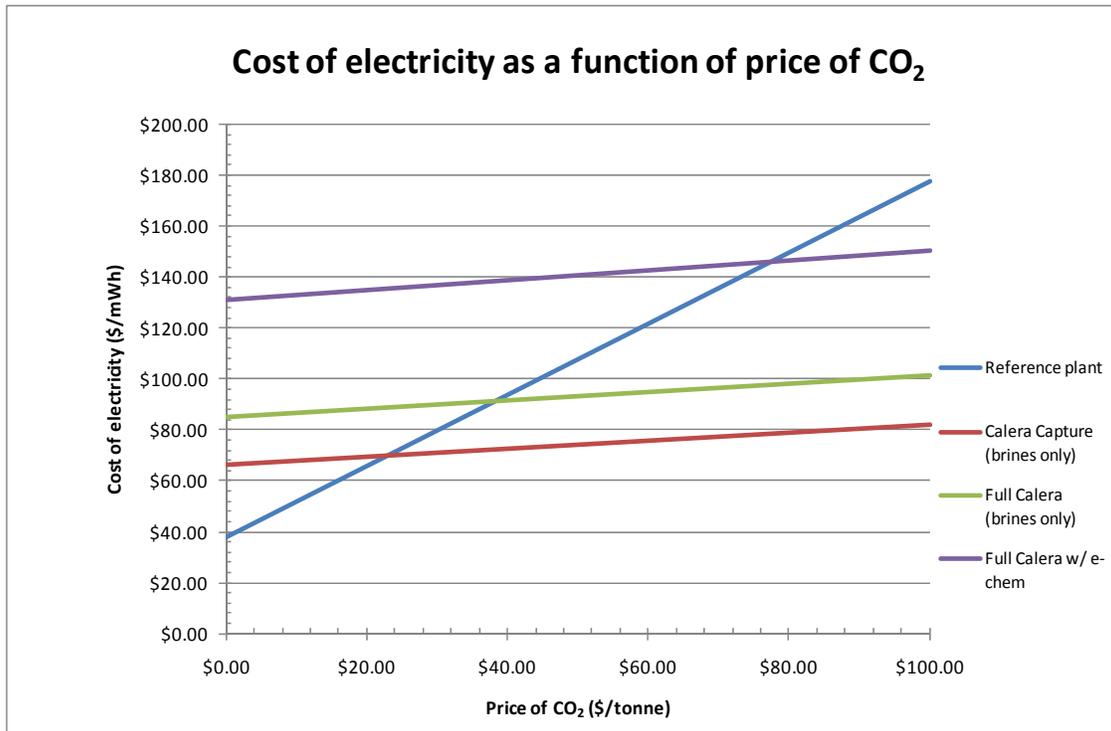


Figure 18: COE as a function of price of CO₂ including the full Calera process.

Calera proposes to create 2.1 tonnes of building materials for every tonne of captured CO₂. Assuming that the full amount of building materials created by Calera is sold, a price of roughly \$15/tonne of building materials enables Calera to fully offset its increased COE, in the case that e-chem is not necessary. If brines are insufficient, adding Calera’s e-chem process increases the breakeven price of building materials product to about \$25/tonne of building materials. As illustrated in Figure 19, when the assumed price of CO₂ emissions increases, the breakeven price of building materials decreases.³¹

This analysis does not address the added benefit of avoided CO₂ emissions from displaced building materials production (although, transportation of building materials may add to this process’s overall carbon footprint). From the perspective of life-cycle CO₂ avoided in energy generation and building materials production, Calera’s process offers tremendous potential.

³¹ Calera expects to produce 2.1 tonnes of building materials for every tonne of CO₂ captured. The breakeven price of building materials is calculated by dividing the total difference in COE per MWh between the Calera process and the reference plant (as a function of different prices for CO₂ emissions) by the amount of building materials produced per MWh.

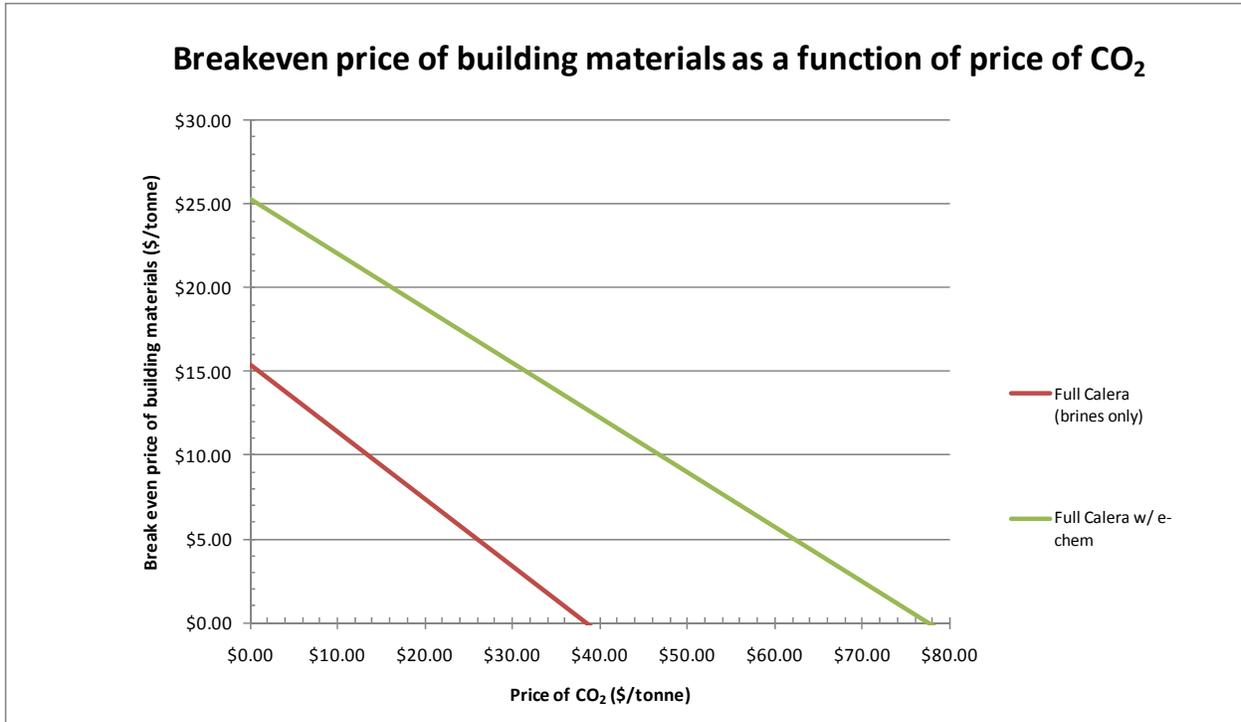


Figure 19: Breakeven price of building materials as a function of an assumed price of CO₂ emissions.

IV. Conclusions

CCS has the potential to play a large role in power generation in the coming years. In particular, retrofit technology can be applied to the existing stock of power plants to drastically reduce CO₂ emissions associated with coal generated electricity. Based on the results of this study of the Yallourn power plant, the Calera capture process appears to be the cheapest CCS option currently available. The Latrobe Valley represents a best case scenario for Calera, where brines can potentially be used to complete the full Calera process, enabling Calera capture without production of building materials to become economically viable at a CO₂ emissions price of \$24.54 per tonne. The next best option in this region is the Advanced Amine capture presented in the DOE retrofit study, with a much higher breakeven CO₂ emissions price of \$72.54. These results indicate that Calera presents the most cost effective means of capturing and sequestering the CO₂ emissions from the Yallourn plant.

However, Calera would likely implement its full process, including the production of building materials in a CCS project in the Latrobe Valley. While this increases the breakeven price for CO₂ emissions potentially to \$78, in the event that e-chem is necessary, revenues from the sale of building materials is expected to offset the increase in cost of electricity generation. Without a price for CO₂ emissions, a price of \$25/tonne of building materials would enable the Calera process to fully break even with the reference plant. (We have no information on what price of building materials the Latrobe market would support.) Our results show that applying the full Calera process at the Yallourn plant (with or without e-chem) is cost competitive with the other

CCS options explored in the study, even without consideration of the potential economic and environmental benefits from the co-production of building materials.

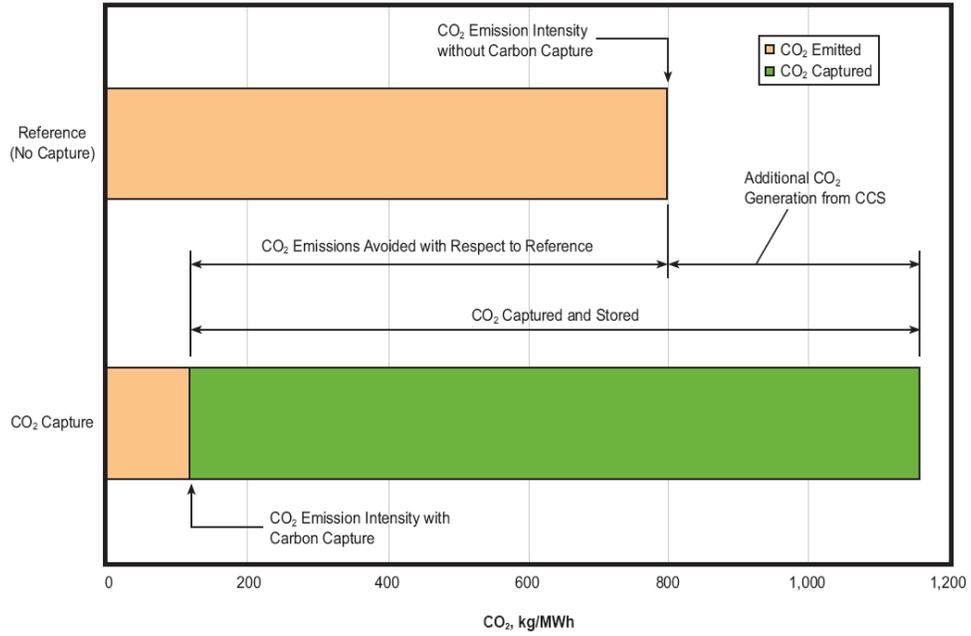
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Appendix A: CO₂ avoided



(WorleyParsons, 2009, p. 89)

Appendix B: Calculation of O&M and transportation/storage

Calculation of O&M for MEA and Oxy-fuel:

Table 5: Reported O&M values for MEA and Oxy-fuel at 85% capacity factor (MIT, 2007, p. 149)

No capture	MEA	Oxy-fuel
\$7.5/MWh	\$19.60/MWh	\$23.60/MWh

For input into our model, we require the O&M costs for implementing the retrofit to include only the O&M cost of the retrofit itself. The base increase in O&M due to the parasitic energy requirement of the retrofit is already included in our calculation. Assuming the O&M for the plant without capture scales according to the parasitic load of the retrofit, the new base O&M for each technology without including the retrofit O&M is calculated as follows:

$$\text{New base O\&M} = \frac{\text{No capture O\&M (\$/MWh)}}{1 - \text{Parasitic load}}$$

The additional O&M attributable to the retrofit would then be the difference between the reported O&M value and the new base O&M for each technology.

Table 6: Reported O&M values for Advanced Amine at 85% capacity factor (NETL, 2007, p. 139)

	No capture	Advanced Amine
Fixed O&M (\$1000/yr)	\$0	\$2,494
Variable O&M (\$1000/yr)	\$0	\$17,645

As the reference plant has zero O&M cost, O&M numbers presented in this report are assumed to represent only additional O&M due to the retrofit. According to the report, 2,258,498 MWh are generated per year at 85% capacity factor. To calculate the additional O&M required by the retrofit in terms of \$/MWh, we divided the sum of the fixed and variable O&M per year by the total amount of electricity generated per year:

$$\text{Additional O\&M} = \frac{\text{Fixed O\&M} + \text{Variable O\&M (\$/year)}}{\text{Electricity generated (MWh/year)}}$$

Calculation of transportation and storage:

A recent study by the CO2CRC evaluated the economics of implementing CCS in the Latrobe Valley. This study estimated the transportation and storage costs associated with a pilot project capable of capturing two million tonnes of CO₂ per year for five years.

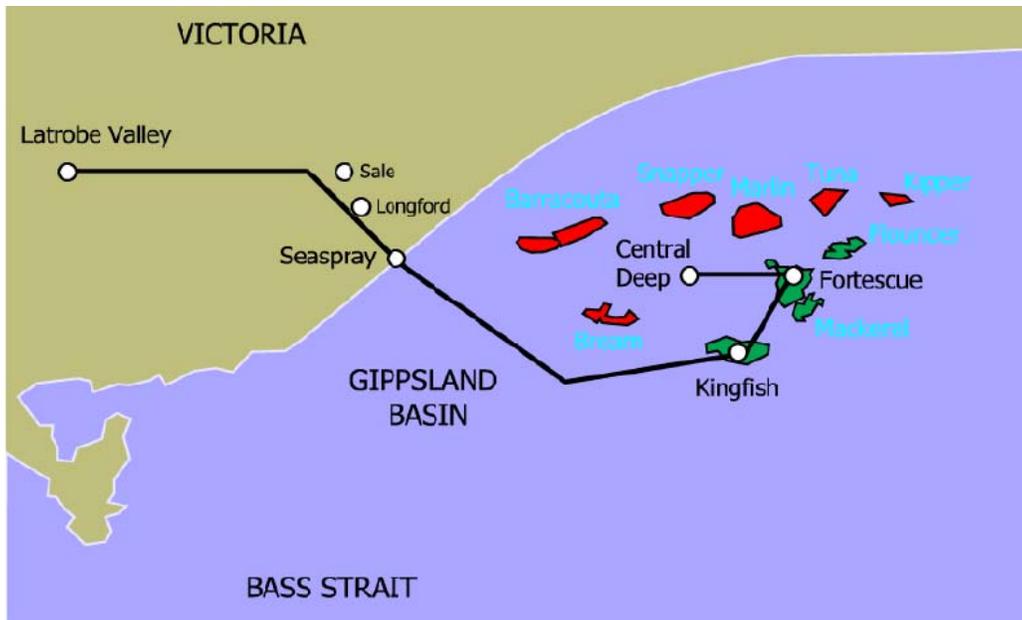


Figure 20: Map of the expected path and storage sites for captured CO₂ from the Latrobe Valley (Hooper et al., 2005, p. 107).

Such a project would require transport of compressed CO₂ via a 95km long onshore and a 95km long offshore pipeline, as indicated in Figure 20. The CO₂ would then be injected at an existing platform near the Kingfish field. The costs for pipeline transport, injection and oil well remediation were reported in 2005 Australian dollars, as shown in Table 7.

Table 7: Transportation and storage costs for a pilot CCS project in the Latrobe Valley as reported (Hooper et al., 2005, p. 113).

Items	Total real capital cost	Annual real operating cost
	A\$ million	A\$ million per year
Compression	\$63	\$7.4
Pipeline	\$106	\$1.1
Injection	\$51	\$1.0
Oil well remediation	\$11	\$0
Total	\$231	\$9.5

As compression is assumed to take place at the plant during the capture process, compression capital and annual operating costs were omitted from our total transportation and storage costs. Table 8 represents the relevant transportation and storage costs normalized to 2009 US dollars. This scenario assumes that two million tonnes per year of CO₂ would be injected for 5 years (Hooper et al., 2005). As our model assumes a lifetime of 20 years, this estimate can be interpreted as a lower bound for actual transportation and storage costs.

Table 8: Transportation and storage costs for a pilot CCS project in the Latrobe Valley without compression capital and operating costs, normalized to 2009 US dollars.

Items	Total real capital cost	Annual real operating cost
	US\$ million	US\$ million per year
Pipeline	\$89.46	\$0.93
Injection	\$43.04	\$0.84
Oil well remediation	\$9.28	\$0.00
Total	\$141.79	\$1.77

The total capital cost is converted into an annuity, based on a discount rate of 15% and project lifetime of 20 years, and added onto the annual operating cost to determine the total annual cost of transportation/storage. This number is then divided by the total captured CO₂ per year to determine the cost per tonne of CO₂ for each technology.

Appendix C: Adjustment of capital costs and O&M costs

The Yallourn plant emits roughly 1.4 tonnes CO₂/MWh, over 40% greater than the 0.9 tonnes CO₂/MWh that most CCS studies assume. Capturing a given percentage of CO₂ emissions at a plant with a higher CO₂ emissions rate will involve the capture of much more CO₂, when compared to a plant with a lower CO₂ emissions rate. For example, a 200MW power plant with a 1.4 tonnes CO₂/MWh emissions rate will emit the same amount of CO₂ per year as a 311MW power plant. The capital cost and O&M must therefore be adjusted accordingly. For the capital cost of the retrofit, a scaling factor can be calculated using the CO₂ emissions rate at Yallourn and the CO₂ emissions rate assumed by the study. For this scaling factor, we apply the “six-tenths rule,” as described in “Perry’s chemical engineers’ handbook.” The equation for calculating the new capital cost is as follows:

$$\text{Scaling factor} = \left(\frac{\text{CO}_2 \text{ emissions rate at Yallorn}}{\text{Assumed CO}_2 \text{ emissions rate in the study}} \right)^{0.6}$$

$$\text{New capital cost} = \text{Reported capital cost} * \text{Scaling factor}$$

For calculating the new O&M cost, we assume that O&M scales linearly with the increased emissions intensity. The equation for calculating the new O&M cost is as follows:

$$\text{Scaling factor} = \frac{\text{CO}_2 \text{ emissions rate at Yallorn}}{\text{Assumed CO}_2 \text{ emissions rate in the study}}$$

$$\text{New O\&M cost} = \text{Reported O\&M cost} * \text{Scaling factor}$$

Appendix D: Breakdown of Calera costs

Table 9: Calera costs assuming only brine is necessary.

	Capture	Building materials	Total
Capital cost (\$/kW)	\$800	\$450	\$1,250
Parasitic load	7.7%	6.4%	14.1%
O&M (\$/MWh)	\$7.74	\$4.32	\$12.06

Table 10: Calera costs assuming brine and e-chem are both necessary.

	Capture	Building materials	Total
Capital cost (\$/kW)	\$1,450	\$1,050	\$2,500
Parasitic load	15.4%	12.9%	28.3%
O&M (\$/MWh)	\$11.62	\$8.49	\$20.11

Note: E-chem produces a waste byproduct of HCl, which may eventually need to be neutralized, thereby significantly increasing O&M costs for e-chem. For the time being, in Australia at a 200MW scale, Calera assumes this is not necessary – the HCl is considered a product for which there is a suitable market.