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The cost of CO_2 capture and storage

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ABSTRACT

The objective of this paper is to assess the current costs of CO_2 capture and storage (CCS) for new fossil fuel power plants and to compare those results to the costs reported a decade ago in the IPCC *Special Report on Carbon Dioxide Capture and Storage* (SRCCS). Toward that end, we employed a similar methodology based on review and analysis of recent cost studies for the major CCS options identified in the SRCCS, namely, post-combustion CO_2 capture at supercritical pulverized coal (SCPC) and natural gas combined cycle (NGCC) power plants, plus pre-combustion capture at coal-based integrated gasification combined cycle (IGCC) power plants. We also report current costs for SCPC plants employing oxy-combustion for CO_2 capture—an option that was still in the early stages of development at the time of the SRCCS. To compare current CCS cost estimates to those in the SRCCS, we adjust all costs to constant 2013 US dollars using cost indices for power plant capital costs, fuel costs and other O&M costs. On this basis, we report changes in capital cost, levelized cost of electricity, and mitigation costs for each power plant system with and without CCS. We also discuss the outlook for future CCS costs.

1. Introduction

Carbon capture and storage (CCS) has been widely recognized as a key technology for mitigating global climate change, but the relatively high cost of current CCS systems remains a major barrier to its widespread deployment at power plants and other industrial facilities (IPCC, 2014). While efforts are underway worldwide to develop improved, lower-cost technologies (NCC, 2015), policymakers continue to weigh the role of CCS in future energy systems. In this environment, information on CCS costs is widely sought by individuals and organizations involved in climate change policy analysis, CCS investments, R&D activities, technology assessments, and energy-related decision-making at various levels.

1.1. Purpose and scope of this paper

This paper presents an update to the CCS costs reported in the 2005 Intergovernmental Panel on Climate Change (IPCC) *Special Report on Carbon Dioxide Capture and Storage* (SRCCS), for which the authors of this paper served as lead authors. In this update, we highlight important changes over the past ten years that affect the cost of CCS systems, encompassing its full value chain (i.e., capture, transport, and storage, including any utilization of CO_2 that results in its long-term storage). The focus of this paper is on CCS costs applicable to electric power plants, which are the primary source of CO_2 emissions globally (IPCC, 2014). Readers unfamiliar with common measures of cost such as the levelized cost of electricity (LCOE), the cost of CO_2 avoided, and the cost of CO_2 captured can find discussions and definitions of these terms in a variety of sources (e.g., IPCC, 2005; Rubin, 2012). For convenience, the equations defining these three terms are also included in Appendix A.

1.2. Audiences and uses for CCS cost estimates

For background and context, we first briefly discuss the audiences for and general purposes of CCS cost estimates. Audiences include a wide variety of industry, government and non-governmental organizations (NGOs), as depicted in Table 1. Many of these organizations are also sources of CCS cost estimates.

In general, CCS cost information is used for two broad purposes: (1) technology assessments (to support decisions on technology selection, capital investments, marketing strategies, R&D priorities, and related activities), and (2) policy assessments (to support a variety of regulatory, legislative, and advocacy activities) (Herzog, 2011).

Each of these categories can be further subdivided. For example, technology assessments often seek to compare the expected

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Table 1
Audiences for CCS cost estimates (Herzog, 2011).

Government	Industry	NGOs
-Policymakers -Analysts -Regulators -R&D agencies	-Operators -Vendors -A&E firms -Venture capital -Tech developers -R&D organizations	-Environmental -Media -Academia -Foundations

costs of alternative CO_2 capture options for a particular application as part of a feasibility or screening process. In this type of study it is much more important that the differences in costs for different capture technologies be accurately assessed, rather than the absolute value of an expected project cost. In such studies, "technology-levelling" assumptions are sometimes applied to maintain uniformity of basic power plant assumptions (such as plant size, fuel type, capacity factor, cost of capital and other variables) in order to highlight differences due only to the CCS subsystem configuration (e.g., MIT, 2007; Rubin et al., 2007; Finkenrath, 2011; GCCSI, 2011). As a result, such studies are unlikely to be good predictors of the cost of actual projects because they do not accurately account for the variations in site and owner specifications that are included in specific projects. Such studies also commonly report costs in constant (or real) currency terms (most commonly in US dollars), which excludes the effects of general inflation.

In contrast, cost estimates for specific projects are typically reported in "current" (or nominal) dollars, including the effects of inflation. Numerically, this yields cost values that are systematically higher than equivalent constant-dollar values. The aim is to provide as accurate an estimate as possible of all the actual project costs that must be financed by an owner. In this case the technology already has been selected, and the focus is on the many site-specific elements that affect a project's cost. For example, the fuel type and availability of resources for a specific project may require engineering, equipment and operational costs that differ from those typically assumed for technology screening studies. For both new plants and retrofit projects, the site-specific labor, materials and commodity costs also must be evaluated in the context of a particular project. So too must the owner's preferences be reflected in factors such as contracting arrangements and risk management approaches—factors often not explicitly considered in generic screening studies.

In summary, the diverse set of audiences and purposes for CCS cost estimates means that different audiences use, provide, and evaluate information from different perspectives and with different objectives and metrics. Because of such differences, cost estimates for CCS must be examined and interpreted with care. While a common language and methodology for costing, together with transparency of methods and assumptions, are critical to the proper assessment of CCS costs, such standardization is often lacking in CCS cost studies (Rubin, 2012). Awareness of such factors is critical to understanding (and correcting for) differences in reported CCS costs.

1.3. Study approach and methodology

For this paper we have adopted the same general approach to CCS cost reporting as in the 2005 SRCSS. Based on a survey of recent literature since 2011, we first compile cost results across a variety of studies of power plants with and without a particular type of CCS system. Again, we selected detailed studies in the public domain published by major governmental and industrial organizations involved in the development and assessment of CCS and power plant technologies. Typically, such studies were conducted by well-known engineering firms in the power industries of North America and Europe.

We focus first on the baseline case of plants with approximately 90% CO_2 capture using technology that is offered commercially, or expected to be available commercially in the next few years. Thus, the major capture technologies and power plant types of interest are: (1) amine-based systems for post-combustion capture at pulverized coal (PC) and natural gas combined cycle (NGCC) plants; (2) physical sorbent-based systems for pre-combustion capture at integrated coal gasification combined cycle (IGCC) plants; and (3) capture at PC plants equipped for oxy-combustion. The latter technology (often called oxyfuel capture) was not prominently featured in the SRCSS, but is included here as a result of its continued development over the past decade.

In a similar fashion we review and summarize the results of recent studies on the costs of CO_2 transport and storage, with a focus on pipeline transport, geological storage, and CO_2 utilization for enhanced oil recovery (EOR) in conjunction with geological storage. For symmetry with the SRCCS, we first separately report the costs for capture, transport and storage in constant 2013 US dollars (USD). Then we aggregate the results to show total costs for a variety of power plants and CCS systems.

As in the SRCCS, we report ranges rather than single values for all costs to reflect the different assumptions and perspectives found in different studies. For capture technologies we also report a "representative value" across the range of studies reviewed. In order to compare current cost estimates to those of the 2005 study, we first escalate all SRCCS costs to 2013 USD to account for effects of inflation and real cost escalations over the past eleven years (the sections below explain how this was done). Any differences between these escalated costs and those from the current literature review are attributed to new developments such as changes in technology design (either of the CCS system, the power plant, or both) and/or changes in key parameter values that directly affect system costs (including fuel costs and other technical, economic and financial factors involved in power plant and CCS cost estimates).

1.4. Organization of this paper

Section 2 of this paper next highlights a number of developments that have affected CCS costs over the past decade. Sections 3–7 then summarize current cost estimates for CO_2 capture processes (post-, pre- and oxy-combustion), transport costs, and storage costs based on our review of recent studies. In Section 8, these component costs are combined to show the range of total current costs of power plants with CCS. These results are compared to the adjusted 2005 SRCCS costs to assess changes over the past decade. The outlook for future costs is then discussed in Section 9, followed in Section 10 by a brief review of other CCS application and in Chapter 11 by a summary of key conclusions.

2. Important changes since 2005

Here we discuss a number of changes over the past decade in key factors affecting CCS costs. These include escalations in materials and construction costs, process design changes stemming from continued R&D and experience at pilot plants, plus changes in costing methods and assumptions for CCS cost estimates.

2.1. Escalation of capital costs

As noted earlier, the SRCCS reported capture costs in constant 2002 USD, whereas this paper reports costs in constant 2013 USD. In those eleven years, there have been significant increases in the cost of commodities and industrial equipment, with the biggest increases occurring from 2003 to 2008 (see Fig. 1, showing the trend

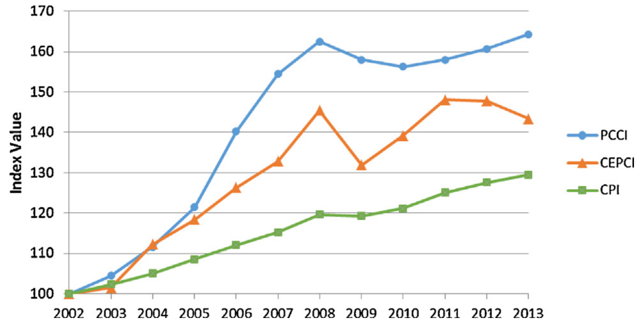

Fig. 1. Costs indices normalized to 100 in year 2002. CPI = Consumer Price Index (BLS, 2014); CEPCI = Chemical Engineering Plant Cost Index (CEM, 2014); PCCI = Power Capital Costs Index (excluding nuclear) (IHS CERA, 2014).

in three major cost indices). These increases are widely attributed mainly to the high economic growth rates in Asia, especially China, whose large demand for commodities like steel, concrete, and oil drove up prices worldwide. These same commodities also impact the cost of power plants and other large industrial facilities where CCS technologies would be implemented. As seen in Fig. 1, from 2002 to 2013 the Chemical Engineering Plant Cost Index (CEPCI) rose more than the US general inflation index, CPI (44% vs. 29%, respectively), indicating "real" cost escalations over this period. The Power Capital Cost Index (PCCI, an index specific to the capital cost of non-nuclear power plants) increased even more, at 64%.

Since this paper concerns the cost of power plants with and without CCS, we use the PCCI to escalate the capital cost of power plants from 2002 to 2013 dollars. To adjust transport and storage costs we use the CEPCI since these services are typically provided to power plants by separate organizations drawn heavily from the oil and gas industry.

2.2. Escalation of fuel costs

Fuel costs for power generation also have changed considerably over the past decade, which directly affects the cost of electricity generation and the cost of CO_2 capture (Rubin, 2012). Fuel cost is reflected in the levelized cost of electricity, which accounts for escalations in real fuel cost over the life of the plant (Rubin et al., 2013).

Fig. 2 shows the change in coal and natural gas prices delivered to US and European power plants from 2002 to 2013 (USEIA, 2014; IEA, 2014). Nominal coal prices in both the US and Europe roughly doubled over this period. In contrast, natural gas prices at US plants fell back to roughly 2002 levels after rising sharply in the 2004-2008 period, while European gas prices continued to rise.

To adjust the fuel cost assumed in past studies to 2013 dollars, we use a time series index based on Fig. 2. To then adjust reported

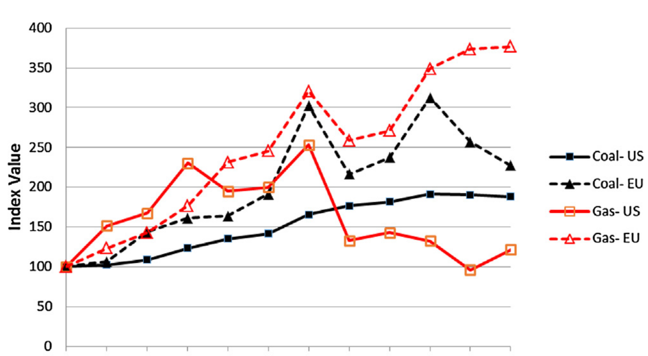

Fig. 2. Fuel cost indices for coal and natural gas used by power plants in the US and Europe, normalized to 100 in year 2002 (based on data from USEIA, 2014; IEA, 2014).

values of LCOE—which combines capital costs, fuel costs, and non-fuel operating and maintenance (O&M) costs—we apply the value of each component cost index to the fraction of total LCOE for plants with and without CO_2 capture in each of the studies reviewed. Specifically, we use the PCCI to escalate both capital and nonfuel O&M costs, and the region-specific fuel cost indices for coal and natural gas to escalate fuel costs. For European studies of CCS costs we further apply a mid-year currency exchange rate for the cost year of the study (Oanda, 2014). Values of all cost escalation and currency exchange factors used in this paper are provided in Appendix A, Table A1.

2.3. Experience from pilot plants and demonstration projects

Over the past decade, there has been significant activity in developing CCS pilot plants and demonstration projects (Rubin et al., 2012; GCCSI, 2014). Even though only a fraction of the proposed demonstration projects have been built, some of the cancelled projects left behind detailed Front-End Engineering and Design (FEED) studies that include information on project costs (for example, TTP, 2012; Scottish Power, 2012). One message from these FEED studies is very clear: the first-of-a-kind (FOAK) costs associated with the above projects are significantly greater than the cost estimates for a mature *N*th-of-a-kind (NOAK) plant reported in most CCS cost studies (Raveendran, 2013). This is a well-known phenomenon for which there are many qualitative explanations, such as the inclusion of additional cost items in FOAK designs that are not included in NOAK studies (such as spare or redundant equipment to ensure reliability and operation at design output levels), and the increased difficulty and cost of doing design and engineering with little or no prior experience. These higher costs for FOAK CCS projects are consistent with earlier studies that found initial cost estimates for other types of large-scale facilities are systematically optimistic compared to the actual final cost of FOAK projects (Merrow et al., 1981). Quantitatively, however, the magnitude of cost differences between FOAK and NOAK installations is very difficult to predict for a particular project or technology (Al-Juaied and Whitmore, 2009). For the most part, however, the recent literature on CCS costs continues to assume NOAK plant designs, with only a small number of studies adjusting certain parameter values to represent FOAK costs, as discussed below. Later sections of this paper discuss other cost-related developments stemming from recent experience in the context of specific CO_2 capture options.

2.4. Changes in costing assumptions and methods

As was the case a decade ago, CCS cost estimates are based on design studies of full-scale power plants with and without CCS. Our literature review indicates that while many of the basic design parameters of the power plant and CCS systems (such as the net plant efficiency and CO_2 emission rates and capture rate) have not changed appreciably since the SRCCS, other assumptions regarding technical, economic and financial parameters that are affecting CCS costs show systematic changes worth noting.

Three such parameters are the power plant size, capacity factor, and fixed charge factor. Recent studies assume values for these parameters that systematically lower the levelized cost of electricity. For example, the average net capacity of the assumed reference plants without CCS is about 10–25% larger in the recent studies reviewed than in studies used for the SRCCS, offering some additional economies of scale. Average annual capacity factors in recent studies are ten percentage points higher for PC plants, two points higher for IGCC plants, and eight points higher for NGCC plants compared to values in the SRCCS. LCOE values are thus lowered since the capital charges are inversely proportional to the assumed capacity factor. Similarly, reductions in the assumed fixed charge factor (of about 10% for NGCC, 20% for IGCC and 30% for SCPC)—reflecting a general reduction in interest and borrowing rates over the past decade—also reduce the annualized capital cost component of the LCOE. In some cases, the justification for current assumptions may be questionable—especially the capacity factor assumption, which represent a "levelized" value over the life of a plant that is typically much lower than the current annual values assumed in many studies (Rubin, 2012).

Methodologically, there is greater consistency in recent CCS cost studies than a decade ago, when studies often omitted major elements of capital cost as well as CO_2 transport and storage costs (IPCC, 2005), which made it difficult (often impossible) to compare or understand differences in study results. While there is still a need for improvements in CCS costing methods (Rubin et al., 2013), in general there is greater transparency and uniformity today than in the past.

One important exception, which has made cost results less transparent than before, is the adoption by a number of organizations of current-dollar rather than constant-dollar reporting of power plant and CCS costs. Several years ago, for example, USDOE began including a general inflation rate in its CCS cost estimates (USDOE, 2011a), which increased reported LCOE values by over 30% relative to equivalent constant-dollar values (Rubin, 2012). Different inflation rate assumptions in different reports further obscured real changes in technology costs across different studies. Since most studies still fail to label cost results as being either in constant or current dollars, users of cost information must be especially careful to understand the basis for numerical results.

One final change related to study assumptions concerns the treatment of plants with and without capture. While assumptions vary across studies, individual studies reviewed for the SRCCS commonly assumed identical values of parameters such as capacity factor for plants with and without CCS. In contrast, more recent studies, including those of the USDOE, often assume different parameter values for plants with and without CCS—typically, a lower capacity factor and higher cost of capital for plants with CCS. These differences are intended to reflect different levels of maturity and reliability for plants with and without CO_2 capture. A number of recent studies more explicitly label these (and related) assumptions as representing either first-of-a-kind (FOAK) or *N*th-of-a-kind (NOAK) plant characteristics. These assumptions, however, systematically increase the cost of CCS relative to earlier studies.

2.5. Increased emphasis on CO_2 utilization

Another recent development affecting CCS costs has been an increased focus on the potential for CO_2 utilization to improve overall process economics. Since about 2011, a number of governmental programs, technical conferences and research programs have adopted the acronym CCUS (for carbon capture, utilization, and storage) rather than CCS, in efforts to promote the business case for CCS technology in the absence of policy and regulatory drivers for its adoption. The potential for CO_2 utilization also was extensively studied in the 2005 SRCCS, which concluded that utilization of CO_2 as a raw material for other products held little potential as a climate change mitigation measure, and could actually aggravate the problem by increasing life-cycle carbon emissions (IPCC, 2005). A recent study by the Electric Power Research Institute also affirmed that CO_2 utilization for chemicals and other products held little potential for long-term CO_2 storage (EPRI, 2013b).

As most commonly used, the term utilization means the use of CO_2 for enhanced oil recovery (EOR). Implicit is the assumption that CO_2 injected into depleted oil reservoirs will remain in the geologic formation over the long term. Of the three CCS demonstration projects at power plants that are currently operating (Boundary Dam in Canada) or under construction (Kemper and Petra Nova in the U.S.), all are selling, or plan to sell, the captured CO_2 for use in EOR. These demonstration projects are expensive (costs in the billions of dollars) and extremely difficult to finance without any significant climate policy driver. EOR markets, along with significant government support, are required to make these projects viable today (Monea, 2014). In this paper, as in the SRCCS, we therefore evaluate overall project economics with two storage options: conventional geological storage (e.g., in deep saline aquifers) and EOR (with assumed long-term storage).

3. Post-combustion capture costs

Here we summarize the results of our review of recent cost studies for new combustion-based power plants with and without post-combustion capture systems. We separately discuss plants using coal and natural gas as an energy source, and exclude the costs of CO_2 transport and storage, which are discussed in Sections 6 and 7, respectively.

3.1. Highlights of recent/new developments

The overwhelming majority of fossil fuel based power generation is currently from pulverized coal combustion and natural gas combined cycle plants. Both of these technologies are amenable to post-combustion capture, either in newly built plants or retrofits to existing plants. This section concentrates on the costs of post-combustion capture at newly built plants because more data are available and costs from different references are more comparable since they do not depend on site-specific factors related to the need for modifications and renovations of an existing power plant.

At the time of the SRCCS in 2005 most of the cost data in the public domain for post-combustion capture were based on the use of MEA solvent. Since that time there has been continuing development and commercialization of alternative solvents and improvements in process flowsheets and energy optimization, which are being used in large capture demonstration plants. This experience has fed through to some extent into published techno-economic studies on post-combustion capture plants. The engineering design of large capture plants and equipment has also developed since the time of the SRCCS, for example, the demonstration of equipment such as large rectangular concrete absorber towers. Overall confidence in building larger single train capture units has improved, which is reflected in larger unit sizes in some capture cost studies.

Post-combustion capture processes based on novel systems such as phase change solvents, adsorption and membranes continue to be developed. These processes offer the prospect of future reductions in post-combustion capture costs, but none are yet at the large pilot plant stage of development, so cost estimates are uncertain and not reported in this paper.

3.2. Capture costs for PC power plants

Performance and cost data from recent studies of new pulverized coal power plants with and without post-combustion capture form the basis for our current cost estimates (EPRI, 2013a; GCCSI, 2011; IEAGHG, 2014; Léandri et al., 2011; USDOE, 2011b; USDOE, 2011c; ZEP, 2011a). Results of these studies are then compared with SRCCS results to assess changes in cost over the past decade. Both datasets focus on supercritical pulverized coal (SCPC) plant designs. The data for current costs are from studies published between 2011 and 2014. These data, as well as all SRCCS data, have been adjusted to a common cost year and currency (constant 2013 USD) in the following way:

- As noted earlier, escalation factors are applied to update capital costs and LCOEs from their reported reference years to 2013. In

Table 2
Summary of current and past performance and cost estimates for post-combustion capture at SCPC power plants using bituminous coals (all values in constant 2013 US dollars).

Performance and Cost Measures for New SCPC Plants w/Bituminous Coal	Current values			Adjusted SRCCS values			Change in Rep. value (Current–Adjusted SRCCS)	
	Range		Rep. value	Range		Rep. value		
	Low	High		Low	High		Δ value	Δ%
Plant performance measures								
SCPC reference plant net power output (MW)	550	1030	742	462	758	587	155	26
Emission rate w/o capture (t CO_2/MWh)	0.746	0.840	0.788	0.736	0.811	0.762	0.03	3
Emission rate with capture (t CO_2/MWh)	0.092	0.120	0.104	0.092	0.145	0.112	−0.01	−7
Percent CO_2 reduction per MWh (%)	86	88	87	81	88	85	2	
Total CO_2 captured or stored (Mt/yr)	3.8	5.6	4.6	1.8	4.2	2.9	1.7	57
Plant efficiency w/o capture, HHV basis (%)	39.0	44.4	41.4	39.3	43.0	41.6	−0.2	−1
Plant efficiency w/capture, HHV basis (%)	27.2	36.5	31.6	28.9	34.0	31.8	−0.2	−1
Capture energy reqm't. (% more input/MWh)	21	44	32	24	40	31	1.1	3
Plant cost measures								
Total capital reqm't. w/o capture (USD/kW)	2313	2990	2618	1862	2441	2040	578	28
Total capital reqm't. with capture (USD/kW)	4091	5252	4580	2788	4236	3333	1247	37
Percent increase in capital cost w/capture (%)	58	91	75	44	73	63	13	
LCOE w/o capture (USD/MWh)	61	79	70	64	87	76	−6	−8
LCOE with capture only (USD/MWh)	94	130	113	93	144	119	−6	−5
Increase in LCOE, capture only (USD/MWh)	30	51	43	28	57	43	0	−1
Percent increase in LCOE w/capture only (%)	46	69	62	42	65	56	5	
Cost of CO_2 captured (USD/t CO_2)	36	53	46	33	58	48	−3	−6
Cost of CO_2 avoided, excl. T&S (USD/t CO_2)	45	70	63	44	86	67	−4	−6

cases where recent studies did not report values for Total Capital Requirement (TCR, the measure used in the SRCCS), other factors are applied to adjust reported capital costs to this common basis (see Table 2 for coal-fired plants and Table 3 for gas-fired plants).

- Costs reported in euros are converted to US dollars using mid-year exchange rates in the study reference year.
- Any CO_2 transport and storage (T&S) costs included in the reported costs of recent studies are subtracted to assess the costs of capture only. Later, in Section 8, T&S costs are added to obtain total CCS costs.

In addition to these factors, there are other significant input assumptions which differ among the studies reviewed. These include plant location, ambient conditions, plant size (including whether plants with and without capture are assumed to have the same fuel feed rate or net power output), fuel analysis, operating capacity factor, fuel cost, non-CO_2 emission performance standards, CO_2 delivery pressure to the transport and storage system, annual fixed charge factor (dependent on financial rates of return and project/plant life), and other miscellaneous site-specific costs. As in the SRCCS, no attempt has been made to apply a common set of assumptions for these parameters since their variability reflects real differences in power plant designs and operation—all of which influence the cost of CO_2 capture.

3.2.1. *Results for PC power plants using bituminous coals*

Summary data for bituminous coal-fired plants are shown in Table 2, with full details reported in Appendix A Table A2. For bituminous coal-fired plants, the post-combustion capture efficiency in recent studies is assumed to be 90%, as in the SRCCS. This increases

Table 3
Summary of current and past performance and cost estimates for post-combustion capture at new NGCC power plants(all values in constant 2013 US dollars).

Performance and Cost Measures for New Natural Gas Combined Cycle Plants (NGCC)	Current values			Adjusted SRCCS values			Change in Rep. value (Current –Adjusted SRCCS)	
	Range		Rep. value	Range		Rep. value		
	Low	High		Low	High		Δ value	Δ%
Plant performance measures								
NGCC reference plant net power output (MW)	512	910	661	379	776	549	111	20
Emission rate w/o capture (t CO_2/MWh)	0.348	0.370	0.36	0.344	0.379	0.37	−0.01	-2
Emission rate with capture (t CO_2/MWh)	0.040	0.043	0.04	0.040	0.066	0.05	−0.01	−20
Percent CO_2 reduction per MWh (%)	88	89	88	83	88	86	2.5	
Total CO_2 captured or stored (Mt/yr)	1.1	2.3	1.6	0.7	1.8	1.2	0.4	32
Plant efficiency w/o capture, HHV basis (%)	48.7	53.2	51	45	52	50	1.1	2
Plant efficiency w/ capture, HHV basis (%)	42.4	47.0	44	43	45	43	0.7	2
Capture energy reqm't. (% more input/MWh)	13	18	16	6	22	15	1.4	9
Plant cost measures								
Total capital reqm't. w/o capture (USD/kW)	808	1378	1049	793	1066	889	160	18
Total capital reqm't. with capture (USD/kW)	1422	2626	2061	1381	1856	1562	499	32
Percent increase in capital cost for capture (%)	76	121	96	64	100	76	20	
LCOE w/o capture (USD/MWh)	42	83	64	37	72	55	9	17
LCOE with capture (USD/MWh)	63	115	92	56	102	81	10	13
Increase in LCOE with capture (USD/MWh)	19	40	28	19	36	26	1	5
Percent increase in LCOE for capture (%)	27	61	45	29	92	52	−7	
Cost of CO_2 captured (USD/t CO_2)	48	111	74	53	87	68	6	9
Cost of CO_2 avoided, excl. T&S (USD/t CO_2)	58	121	87	63	113	83	3	4

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the overall plant energy consumption per MWh of net electricity by 21–44%, with a mean increase of 32%. As a result, the net reduction in CO_2 emissions is 86–88% per net MWh (an average of two percentage points higher than in the SRCCS). We note, however, that a number of recent studies continue to assume the use of MEA-based solvents, whose energy requirements are higher than that of many of the newer proprietary solvents now coming into use for post-combustion capture (Rochelle, 2014). Several of the recent studies also assume supercritical boilers rather than more efficient ultrasupercritical units for power generation. Both of these factors account for the observation in Table 2 that the energy penalty for CO_2 capture has not changed appreciably since the SRCCS. In this regard, however, the recent studies available for this review do not fully reflect the lower energy penalties achieved by the more efficient capture and power generation systems now emerging and available for post-combustion CO_2 control.

The capital costs of reference power plants with and without capture have increased since the SRCCS due to general inflation and market factors. Although the SRCCS capital costs have been escalated to 2013 dollars using a power plant cost index, as described earlier, the costs of the reference plants without capture in the new studies are nevertheless 28% higher than the adjusted SRCCS costs. The increase for plants with capture is higher at 37%. These increases suggest real cost changes over and above those reflected in the plant cost index, and may in part be due to a greater understanding of the requirements and design of modern reference plants and large-scale capture plants. As a result the mean percentage increase in capital cost due to the addition of post-combustion capture to a pulverized coal fired power plant has increased from 63% in the updated SRCCS studies to 75% in the new studies. However, the greater cost increases for IGCC, discussed later, have meant that the competitiveness of post-combustion capture versus pre-combustion capture has improved since the time of the SRCCS.

Despite the significant increase in capital costs, the mean cost of electricity without and with CO_2 capture in the new studies is 8% and 5% lower respectively than in the updated SRCCS studies. The main reason for this is that the average annual capital charge factors are lower in the new studies, reflecting the reductions in real interest rates and expected rates of return of capital projects in recent years. Another contributory reason is that the average capacity factor for coal-fired power plants is assumed to be higher in the recent studies than in the SRCCS.

The costs of CO_2 capture and emission avoidance (excluding CO_2 transport and storage) are 46 and 63 USD/t CO_2, respectively. These values are 6% lower than the adjusted SRCCS costs.

3.2.2. Results for PC power plants using low-rank coals

As noted earlier, the SRCCS contained few cost results for post-combustion capture at new power plants using low-rank coals (subbituminous and lignite). In contrast, more recent studies have analyzed such plants more extensively. Here, we summarize key differences in reported performance and cost parameters between new plants using bituminous and low-rank coals.

Coals can be divided into bituminous coal and low-rank coal (sub-bituminous coal and lignite). Most coal-fired power plants currently use bituminous coals. For this reason most of the studies on the application of CCS to coal fired power plants have been based on the use of bituminous coal, and this was reflected in the SRCCS. However, there is increasing interest in the use of low-rank coals for power generation, for example because of their typically low sulfur contents, low mining costs and high reserves. On a mass basis over half of global coal reserves are low-rank coal (BP, 2014), although on an energy basis the proportion is lower due to the higher moisture content and lower specific energy contents of low-rank coals. The largest power plant with CCS currently in operation, namely the Boundary Dam plant (with post-combustion capture) and the two largest plants under construction, namely the Kemper IGCC plant (pre-combustion capture) and the Petra Nova plant (post-combustion capture) all use low-rank coals.

As the focus of this paper is on updating the costs in the SRCCS, the emphasis of the paper is also on bituminous coal fired power plants. However, as more information is now available on low-rank coal plants with CCS, performance and cost data from those studies were also analyzed for this paper. The technologies for CO_2 capture in low-rank coal plants are essentially the same as those used in bituminous coal fired plants, so many of the conclusions drawn for bituminous coal fired plants are expected to also apply to low-rank coal fired plants.

In the studies analyzed for this paper the low-rank coal fired plants have lower average thermal efficiencies and 23% higher quantities of CO_2 captured per net MWh of electricity than the bituminous coal fired plants. The mean CCS energy requirement for low-rank coal-fired plants is 37%, which is higher than for bituminous coal-fired plants, due mainly to the larger quantity of CO_2 that has to be captured per net MWh of electricity. Capital costs per net MW of electricity with CO_2 capture are on average 14% higher than for the bituminous coal plants. However, the average LCOE of the low-rank coal plants with capture is only 3% higher than that of the bituminous coal plants due to the offsetting effect of much lower fuel prices. The average increase in LCOE due to the addition of capture is 21% higher for low-rank coal plants. However, the average costs per ton of CO_2 captured and avoided are essentially the same as for bituminous coal plants because the higher costs are offset by the higher quantities of CO_2 captured and avoided per net MWh of electricity.

3.3. Capture costs for NGCC power plants

Recent studies also have reported the cost of post-combustion CCS for NGCC plants. Interest in CCS at NGCC power plants has increased in countries like the US, where low natural gas prices have led to NGCC power plants displacing PC power plants. Table 3 summarizes the capture cost results from several studies of new power plants in the US and Europe (USDOE, 2011d; Rubin and Zhai, 2012; IEAGHG, 2012; USDOE 2013a; EPRI, 2013a). Full details are reported in Appendix A Table A3. Again, these figures exclude the costs of CO_2 transport and storage, which are added in Section 8 to give total CCS costs.

The last two columns of Table 3 show that the basic performance characteristics of NGCC plants with and without capture have not changed appreciably since the SRCCS. The biggest differences are an increase of about 100 MW in the average plant size (due to the use of larger gas turbines) and an increase of about 30% in the total annual quantity of CO_2 captured and stored (reflecting both the larger plant size plus a 10% higher capacity factor).

In terms of cost, recent studies show a nearly 20% increase in the capital cost of NGCC plants without capture relative to the index-adjusted SRCCS values. This suggests that there could be additional market premiums for NGCC systems during periods of limited supply and/or high demand for this technology. Table 3 also shows a 20% increase in the added cost for CO_2 capture relative to the adjusted SRCCS values. As with coal-fired plants, this suggests that recent studies have incorporated design changes relative to earlier studies that add to the cost of CO_2 capture technology and also contribute to higher costs per ton of CO_2 captured.

Table 3 also shows small (5–10%) increases in the average LCOE values and cost per ton of CO_2 avoided in recent analyses compared to adjusted SRCCS values. In both cases, these averages reflect a composite of US and European studies, for which fuel prices and price trends are very different (see Fig. 2). For the US studies alone, a more detailed examination of the data shows no net increase in LCOE. This is because the LCOE for NGCC plants is dominated by the

Table 4
Summary of current and past performance and cost estimates for pre-combustion capture at IGCC power plants using bituminous coals (all values in constant 2013 US dollars).

Performance and Cost Measures for New IGCC Plants w/ Bituminous Coal	Current values			Adjusted SRCCS values			Change in Rep. value (Current –Adjusted SRCCS)	
	Range		Rep. value	Range		Rep. value		
	Low	High		Low	High		Δ Value	Δ%
Plant performance measures								
IGCC reference plant net power output (MW)	600	748	645	401	827	581	63	11
Emission rate w/o capture (t CO_2/MWh)	0.723	0.850	0.777	0.682	0.846	0.773	0.00	1
Emission rate with capture (t CO_2/MWh)	0.093	0.150	0.107	0.073	0.151	0.109	0.00	−1
Percent CO_2 reduction per MWh (%)	82	88	86	81	90	86	0	
Total CO_2 captured or stored (Mt/yr)	3.1	3.3	3.2	1.7	4.7	2.9	0.3	11
Plant efficiency w/o capture, HHV basis (%)	38.3	42.1	40	36.5	45.5	40	0	−1
Plant efficiency w/ capture, HHV basis (%)	29.9	32.6	31	30.0	38.5	34	−3	−8
Capture energy reqm't. (% more input/MWh)	20	35	28	14	25	19	9	49
Plant cost measures								
Total capital reqm't. w/o capture (USD/kW)	2687	3900	3181	1921	2441	2139	1042	49
Total capital reqm't. with capture (USD/kW)	3808	5148	4366	2323	3730	2940	1426	49
Percent increase in capital cost w/ capture (%)	30	47	38	19	66	37	1	
LCOE w/o capture (USD/MWh)	82	99	90	69	103	80	10	12
LCOE with capture only (USD/MWh)	111	130	120	92	133	106	14	13
Increase in LCOE, capture only (USD/MWh)	24	36	30	16	37	26	4	17
Percent increase in LCOE w/ capture only (%)	26	41	34	20	54	33	1	
Cost of CO_2 captured (USD/t CO_2)	28	41	34	20	51	32	2	6
Cost of CO_2 avoided, excl. T&S (USD/t CO_2)	37	58	46	24	62	39	6	16

cost of fuel, so the current low gas price in the US offsets the increase in capital costs. In contrast, for European studies, the higher gas prices in recent studies lead to higher LCOEs relative to the SRCCS.

4. Pre-combustion capture costs

Here we summarize the results of recent cost studies for new IGCC power plants with and without pre-combustion capture systems. We report the plant-level cost of capture systems excluding the costs of CO_2 transport and storage, which are discussed in sections 6 and 7, respectively. In Section 4.3 we also report the cost of CO_2 capture for cases where an IGCC plant with capture is compared to a reference PC plant rather than an IGCC plant without capture.

4.1. *Highlights of recent/new technology developments*

In common with the SRCCS, pre-combustion capture continues to be focused on coal-based integrated gasification combined cycles. Prior to the SRCCS, many thought that IGCC power plants would be the preferred pathway for CCS at coal-fired power plants. That view has changed considerably as the construction of new coal-based IGCC plants without capture has stalled, apart from a few exceptions, mainly because of higher costs, and concerns about the availability and use of less proven technology compared to pulverized coal plants. A notable exception is the 524 MW Kemper lignite-fuelled IGCC plant being built in the US, which includes around 65% capture of CO_2 (MIT, 2015).

In addition to IGCC plants, large numbers of coal gasification plants for chemicals production have been built, particularly in China (GTC, 2015). In many cases these plants involve the separation of CO_2 from synthesis gas, which helps to further demonstrate the gasification and gas treating aspects of IGCC plants. CO_2 capture in IGCC also has now been tested using side stream pilot plants of around 5 MW_e equivalent at the Buggenum plant in the Netherlands (now closed) (Damen et al., 2014) and the Puertollano plant in Spain (Cabezón, 2011).

The currently preferred technology for CO_2 capture in IGCC plants is solvent scrubbing (using physical solvents instead of the chemical solvents used in post-combustion capture), as was the case in the SRCCS. Alternative capture technologies, most of which are described in the SRCCS, are continuing to be developed but they have not yet been demonstrated in large plants. Although they offer the prospect of cost reductions, cost data for advanced capture technologies are still subject to high levels of uncertainty. Thus, as with advanced post-combustion systems, they have not been included in this paper.

4.2. *Capture costs for IGCC power plants*

Summary data from recent studies of new IGCC plants using bituminous coal with and without CO_2 capture (EPRI, 2013a; GCCSI, 2011; IEAGHG, 2014; USDOE, 2011b; USDOE, 2011c; ZEP, 2011a) are shown in Table 4 together with the SRCCS data, both adjusted to constant 2013 dollars. Full details for the recent studies reviewed appear in Appendix A Table A4.

4.2.1. *Results for IGCC power plants using bituminous coals*

As seen in Table 4, the net efficiencies and emissions of IGCC plants with and without capture are broadly similar to those of SCPC plants (Table 2), as they were in the SRCCS. The average efficiency of IGCC plants without capture is unchanged since the SRCCS but the average efficiency with capture is three percentage points lower in the more recent studies. This appears to be due in large part to the different mix of gasifier types in the SRCCS references compared to the gasifiers used in the recent studies. Differences in the syngas composition of different gasifiers can, in turn, result in different capture energy requirements. Changes to the design of the shift conversion and CO_2 separation units, and a more rigorous assessment of the impacts of hydrogen fuel on the performance of the gas turbine, are some other possible causes of the increase in capture energy requirement. However, it is not possible to draw definitive conclusions due to the limited information in the SRCCS References.

Capital costs of plants with and without capture have increased by about 50% compared to the updated SRCCS data. This is higher than the 28% increase for SCPC plants without capture and the 37% increase for SCPC plants with capture. As with PC and NGCC

Table 5
Summary of current performance and cost estimates for pre-combustion capture at IGCC power plants based on supercritical pulverized coal (SCPC) reference plants using bituminous coals (all values in constant 2013 US dollars).

Performance and Cost Measures for New IGCC Plants w/ Bituminous Coal (Relative to an SCPC Plant without CCS)	Current Study values			Change in Rep. value (SCPC Ref. –IGCC Ref.)	
	Range		Rep. value		
	Low	High		Δ Value	Δ%
Plant performance measures					
SCPC reference plant net power output (MW)	550	1030	753	108	17
Emission rate w/o capture (t CO_2/MWh)	0.746	0.840	0.786	0.01	1
Emission rate with capture (t CO_2/MWh)	0.093	0.150	0.104	0.00	-3
Percent CO_2 reduction per MWh (%)	82	88	87	1	
Total CO_2 captured or stored (Mt/yr)	3	6	4	1	39
Plant efficiency w/o capture, HHV basis (%)	39.0	44.2	41	1	2
Plant efficiency w/ capture, HHV basis (%)	29.9	36.5	33	1	4
Capture energy reqm't. (% more input/MWh)	21	30	25	-3	-10
Plant cost measures					
Total capital reqm't. w/o capture (USD/kW)	2313	2990	2513	−668	−21
Total capital reqm't. with capture (USD/kW)	3808	5659	4838	473	11
Percent increase in capital cost w/ capture (%)	65	131	93	55	
LCOE w/o capture (USD/MWh)	64	79	69	-21	−23
LCOE with capture only (USD/MWh)	100	141	124	4	3
Increase in LCOE, capture only (USD/MWh)	36	73	55	25	81
Percent increase in LCOE w/ capture only (%)	49	108	80	46	
Cost of CO_2 captured (USD/t CO_2)	42	87	63	28	83
Cost of CO_2 avoided, excl. T&S (USD/t CO_2)	52	112	81	36	78

plants, this suggests real cost increases associated with changes in the design or scope of current IGCC projects relative to those of a decade ago.

The average LCOE of IGCC plants with capture in Table 4 is about 6% higher than for SCPC plants with capture (Table 2). In contrast, in the SRCCS the average LCOE of IGCC plants with capture was 11% lower than that of SCPC plants with capture. This indicates a potentially important shift in the relative economic attractiveness of these two technologies. Furthermore, unlike SCPC plants with capture, which have experienced a small reduction in LCOE compared to the updated SRCCS data, there has been an average increase of 12–13% for IGCC plants with capture. There has also been an increase of 16% in the cost of CO_2 avoided for IGCC plants, in contrast to SCPC plants which have seen a 6% reduction.

4.2.2. Results for IGCC power plants using low-rank coals

As with PC plants, the SRCCS contained few cost results for pre-combustion capture using low-rank coals (subbituminous and lignite). In contrast, more recent studies have analysed such plants more extensively. Here, we summarize key differences in recently reported results for new IGCC plants using low-rank coals compared to plants using bituminous coals.

Low-rank coal IGCC plants have similar efficiencies to bituminous coal IGCC plants but higher CO_2 emission rates, quantities of CO_2 captured, capital costs and LCOEs. However, the average incremental capital cost for capture, incremental LCOE and cost of CO_2 avoided are lower than for SCPC plants with low-rank coal.

4.3. Change in reference plant assumption for IGCC costs

One notable difference between recent IGCC studies and those of a decade ago is the choice of the reference plant without capture. In the studies reported in the SRCCS the assumed reference plant for assessment of IGCC plants with capture was always a similar IGCC plant without capture. In many recent studies, however, the reference plant is a supercritical pulverized coal (SCPC) plant without capture, because that would be the lower-cost technology of choice for new coal-fired power plants without capture. This directly affects the reported cost of capture since a lower-cost reference plant (in this case, a PC plant) yields a higher incremental cost for an IGCC plant with capture. The data in Table 4 are derived from studies that assume an IGCC plant without capture as the reference plant. In contrast, Table 5 shows IGCC performance and cost results for studies that assume a SCPC reference plant (which was the case for roughly half the studies on IGCC costs). Some of these are the same studies used in Table 4 where such studies also included a SCPC reference plant for assessment of post-combustion capture. In those cases we compare the reported data for IGCC plants with capture to the SCPC reference plant, even though such a comparison was not made in the published study. Details appear in Appendix A Table A5. In the last two columns of Table 5, the results for IGCC plants with SCPC reference plants are compared to the studies in Table 4 that assume an IGCC reference plant.

For the studies reviewed, the LCOE of PC reference plants was about 20 USD/MWh lower than IGCC reference plants, due primarily to lower capital costs. As a result, the incremental LCOE for an IGCC plant with capture increases from 30 to 55 USD/MWh when the reference plant is changed from IGCC to SCPC. In turn, the average cost of CO_2 avoided rises from 46 to 81 USD/t CO_2. The effects of alternative reference plants on overall IGCC costs are shown more broadly in Section 8, Tables 16 and 17.

5. Oxy-combustion capture costs

CO_2 capture using oxy-combustion (or oxyfuel) is an alternative to pre- or post-combustion capture that has undergone significant development over the past decade. In the SRCCS, however, the cost of oxy-combustion systems is not included in the summary cost reports as the technology was still in the early stages of development and there were few detailed cost studies available. The literature reviewed at that time focused mainly on oxyfuel retrofits to subcritical PC boilers with only one study of a new supercritical unit (IPCC, 2005).

In contrast, recent studies of oxy-combustion capture focus mainly on new supercritical or ultrasupercritical (USC) power plants (as opposed to retrofits) and primarily on low-rank coals (sub-bituminous and lignite). The plant and process designs today are generally more complex than a decade ago, often including multiple flue gas recycle streams, heat integration, and different types of criteria pollutant clean-up units. Recent studies also explore a

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Table 6
Summary of current performance and cost estimates for oxy-combustion capture at new SCPC/USC plants using sub-bituminous or bituminous coals (all values in constant 2013 US dollars).

Performance and Cost Measures for New Oxy-Combustion Plants with Subbituminous or Bituminous Coals	Current study values		
	Range		Rep. value
	Low	High	
Plant performance measures			
SCPC/USC reference plant net power output (MW)	550	1030	684
Emission rate w/o capture (t CO_2/MWh)	0.75	0.861	0.83
Emission rate with capture (t CO_2/MWh)	0.017	0.11	0.08
Percent CO_2 reduction per MWh (%)	90	98	92
Total CO_2 captured or stored (Mt/yr)	3.1	5.5	3.9
Plant efficiency w/o capture, HHV basis (%)	38.7	42	39
Plant efficiency w/capture, HHV basis (%)	30.1	34.1	32
Capture energy reqm't. (% more input/MWh)	24	29	25
Plant cost measures			
Total capital reqm't. w/o capture (USD/kW)	2455	2681	2589
Total capital reqm't. with capture (USD/kW)	4278	5372	4939
Percent increase in capital cost w/capture (%)	67	106	91
LCOE w/o capture (USD/MWh)	56	68	64
LCOE with capture only (USD/MWh)	91	121	110
Increase in LCOE, capture only (USD/MWh)	35	56	46
Percent increase in LCOE w/capture only (%)	60	84	72
Cost of CO_2 captured (USD/t CO_2)	36	67	52
Cost of CO_2 avoided, excl. T&S (USD/t CO_2)	45	73	62

range of net CO_2 removal efficiencies and different levels of CO_2 product purity as well as advanced processes for oxygen production.

Table 6 shows the range of performance and cost results from several recent studies of oxy-combustion for new plants burning either sub-bituminous or (in one case) bituminous coal (USDOE, 2010; EPRI, 2011; IEAGHG, 2014). Because of the lower-quality coals, the efficiency of the baseline plants without CCS is slightly lower than the value in Table 2 for plants using bituminous coals. For the oxy-combustion cases, all plants use conventional cryogenic air separation for oxygen production and produce high-purity (>99%) CO_2 comparable to the product from pre- and post-combustion capture processes. In most cases the overall CO_2 capture efficiency is also comparable at 90%, with one case of a 98% capture rate. The resulting energy penalty for CO_2 capture and compression requires approximately 25% more coal input per net MWh of electricity produced—comparable to the best current post-combustion capture systems discussed earlier. Further details for the studies reviewed appear in Appendix A Table A6.

In terms of cost, Table 6 shows that oxy-combustion systems incur average cost increases of 91% for total capital requirement and 72% for levelized cost of electricity relative to the same type of PC plant without CO_2 capture. Both of these percentage increases are slightly higher than the corresponding values in Table 2 for post-combustion capture with bituminous coals.

Note too that on an absolute basis the average LCOE for the reference SCPC plants without capture is 7 USD/MWh (roughly 10%) lower for the oxy-combustion studies in Table 6 than for the post-combustion studies in Table 2. The principal reason for this difference is that the oxy-combustion results are based mainly on sub-bituminous coals whose cost is substantially lower than the bituminous coals used in the post-combustion capture studies. Thus, the absolute values of LCOE for reference plants and capture plants in Tables 2 and 6 should not be directly compared since they reflect different premises for coal type and price.

6. CO_2 transport costs

Here we review recent studies that have examined the cost of CO_2 transport in some detail, in contrast to the "generic" estimates that are commonly assumed in CCS cost studies. Although such studies are far less common than power plant capture cost studies, several recent transportation cost studies provide important updates to the earlier literature.

Table 7
Transport costs from SRCCS in 2002 USD/tCO_2/250 km.

Capacity	Onshore		Offshore	
	Low	High	Low	High
3 MtCO_2/yr	3.0	5.0	5.0	6.2
10 MtCO_2/yr	1.5	2.6	2.4	3.0
30 MtCO_2/yr	.9	1.5	1.3	1.7

6.1. Highlights of recent/new developments

CO_2 pipelines were a mature technology in 2005, with over 3000 miles of installed capacity in the US. Since then, there have been modest additions to this network (Suresh, 2010), but no technological developments that significantly impacted costs.

While other modes of CO_2 transport, such as ships, are still discussed in the literature, all current and proposed large-scale transport of CO_2 remains with pipelines. There is no indication that this will change anytime in the foreseeable future. Therefore, this section of the paper focuses exclusively on costs for CO_2 transport via pipelines.

6.2. Cost results from current literature

The costs for CO_2 pipeline transport reported in the SRCCS showed high and low estimates for both onshore and offshore pipelines (IPCC, 2005). It should be noted that pipeline costs are highly variable, due in large part to the type of terrain they are going through and the nature of existing land use (e.g., urban areas vs. rural areas). The SRCCS results were presented for "normal" terrain, so costs of pipelines in difficult terrain could be much higher.

The SRCCS reported costs in 2002 USD/tCO_2/250 km. There are strong economies of scale based on pipeline capacity, with costs decreasing significantly with rising CO_2 capacity up until about 10 MtCO_2/yr. Beyond this, much more modest economies of scale are realized. The costs are summarized in Table 7 as originally reported.

Table 8
Transport costs from ZEP (2011b) in 2009 EUR/tCO_2 /length shown.

Capacity	Onshore (180 km)	Offshore (500 km)
2.5 MtCO_2/yr	5.4	20.4
10 MtCO_2/yr	1.5	6.0

Table 9
Transport costs from USDOE (Morgan & Grant, 2014) in 2011 USD/tCO_2/100 mi.

Capacity	Onshore
3.2 MtCO_2/yr	3.1
30 MtCO_2/yr	1.1

Table 10
Transport costs on a common basis (2013 USD/tCO_2/250 km) for onshore pipelines at three different capacities.

Study	3 MtCO_2/yr	10 MtCO_2/yr	30 MtCO_2/yr
IPCC (2005)	4.3–7.2	2.2–3.7	1.3–2.2
ZEP (2011b)	10.9	3.3	–
USDOE (2014a)	4.9	–	1.7

Table 11
Transport costs on a common basis (2013 USD/tCO_2/250 km) for offshore pipelines at three different capacities.

Study	3 MtCO_2/yr	10 MtCO_2/yr	30 MtCO_2/yr
IPCC (2005)	7.2–8.9	3.4–4.3	1.9–2.4
ZEP (2011b)	14.8	4.8	–

ZEP (2011b) reported costs for both onshore and offshore pipelines at capacities of 2.5 MtCO_2/yr and 10 MtCO_2/yr. They also reported costs as a function of pipeline length. The pipeline costs exhibit significant economies of scale with total length for offshore pipelines, but only very modest economies for onshore pipelines. In Table 8, we report their data for 180 km onshore pipelines and 500 km offshore pipelines.

The USDOE also recently developed a CO_2 transport cost model (USDOE, 2014a). Morgan and Grant (2014) presented example results for onshore pipelines. They reported results for several pipeline lengths, but the impact on costs per unit distance was very small. We report their data for pipelines of 100 miles in length (see Table 9).

6.3. Adjustments to a common basis

The above costs are put on a common basis of 2013 USD/tCO2/250 km using the CEPCI escalation factors shown in Figure 1. The results are presented in Table 10 for onshore pipelines and Table 11 for offshore pipelines.

For onshore pipelines, the recent studies are consistent with the costs presented in the SRCCS, except for the ZEP cost for a 3 Mt CO_2/yr pipeline, which is significantly higher than other estimates. For offshore pipelines, the ZEP costs are larger than the costs presented in the SRCCS. This is consistent with having extensive experience with onshore pipelines, but essentially no prior experience with offshore CO_2 pipelines.

7. CO_2 storage costs

As with CO_2 transport costs, most studies of total CCS costs assume a generic cost for CO_2 storage in dollars per ton, or a combined cost for transport and storage. While detailed studies of CO_2 storage costs are less prevalent than studies of capture costs, a number of important contributions in recent years are discussed below.

Table 12
Storage costs from ZEP (2011c) in 2009 EUR/tCO_2.

Reservoir type	On/Off Shore	Low	Medium	High
Depleted O&G Field – reusing wells	Onshore	1	3	7
Depleted O&G Field – no reusing wells	Onshore	1	4	10
Saline Formations	Onshore	2	5	12
Depleted O&G Field – reusing wells	Offshore	2	6	9
Depleted O&G Field – no reusing wells	Offshore	3	10	14
Saline Formations	Offshore	6	14	20

7.1. Highlights of recent/new developments

The SRCCS had two major chapters on CO_2 storage—geologic storage and ocean storage. The biggest change since then is that ocean storage of CO_2 is no longer an active option being pursued by the international research community or project developers. As such, this section focuses solely on storage of CO_2 in geologic formations.

Much research on geologic storage has occurred in the past decade, which has allowed a more detailed breakdown of costs associated with geologic storage. However, much uncertainty still remains. This includes the impact of regulations on costs, especially related to requirements for monitoring, long-term stewardship and liability. Another area of uncertainty relates to public acceptance and how it may impact project economics. An analogous example of this can be seen with the growth of hydraulic fracturing for natural gas production, where increasing public concerns have led to modifications in operating procedures that have increased costs for gas producers (Wolff and Herzog, 2014).

A major milestone in regulating geologic storage occurred in the US with the finalization in 2010 of rules for geologic storage projects issued by the US Environmental Protection Agency. Two projects have now received permits under this new rule (Gollakota and McDonald, 2014; Gilmore et al., 2014)

7.2. Cost results from current literature

Costs for geologic storage are highly variable because of the heterogeneity of storage reservoirs. This includes reservoir type (e.g., onshore vs. offshore, depleted field vs. deep saline formation) and reservoir geology (e.g., porosity, permeability, depth). Therefore the literature presents the cost of storage as a range. This range is based on the judgment of study authors rather than a detailed statistical analysis, in part because data on a large percentage of potential storage reservoirs is quite sparse. Poor candidates for storage reservoirs could have storage costs well above the high value of the reported ranges.

In the SRCCS the reported costs for CO_2 storage in geologic formations ranged from 0.5 to 8.0 2002 USD/tCO_2 with an additional cost for monitoring of 0.1–0.3 2002 USD/tCO_2. More recently, ZEP (2011c) reported costs as shown in Table 12 in 2010 EUR/tCO_2. They broke down costs into onshore and offshore storage and separated saline formations from depleted oil and gas fields. Furthermore, for depleted fields, they looked at cases where existing infrastructure could or could not be reused.

The USDOE also recently developed a CO_2 Saline Storage Cost Model (USDOE, 2014b). Using the model, they generated a cost-supply curve for the US. The graph has two inflection points, with over 70% of the storage capacity contained between these two points. Using these points as high/low estimates, the cost range is 7–13 2011 USD/tCO_2.

The GCCSI (2011) reported storage costs for poor and good reservoir properties. Using these as low and high estimates, the range is 6–13 2010 USD/tCO_2.

For EOR credits, the SRCCS reported a range of 10–16 2002 USD/tCO_2. With sustained higher oil prices over the past

Table 13
Typical ranges of onshore storage costs on a common basis (2013 USD/tCO_2).

Study	Low	High
IPCC (2005)	1	12
ZEP (2011c)	2	18
USDOE (2014a)	7	13
GCCSI (2011)	6	13

decade—on the order of $100/bbl—the demand for CO_2 has increased significantly for EOR (Suresh, 2010). This has led to potentially higher selling prices for CO_2. Although the details of such transactions remain proprietary and are not publicly available, "conventional wisdom" suggests that the price that EOR projects can afford to pay for CO_2 (in $/mcf, thousand standard cubic feet) is 2% of the oil price in $/bbl. Therefore, oil at $100/bbl translates into a CO_2 price of $36/t$CO_2$ (Carbon Management Workshop, 2011).

Given the more recent drop in oil prices in 2014, as well as its historic volatility, we suggest a range of $15–40/t$CO_2$ as the net credit (negative storage cost on a levelized basis) for CO_2 sold for EOR. This is the range we use to calculate total system costs in the next section. Implicit in this range is the assumption that CO_2-EOR will comply with future regulatory requirements for geological storage of CO_2, which are still under development. To the extent that meeting future requirements incurs significant additional costs, the range suggested above may have to be modified.

7.3. Adjustments to a common basis

The above costs are put on a common basis of constant 2013 USD/tCO_2 using the CEPCI escalation factors shown earlier in Fig. 1. The results for onshore reservoirs are presented below in Table 13.

Note that the ZEP study has a wider range than the other two recent studies. Those two studies also indicate that the low end of the range has significantly larger costs than those reported in the SRCCS, although the high end of the range remains about the same.

8. Total system costs

Here we combine the transport and storage costs above with the capture cost estimates shown earlier in Tables 2–4 to obtain a total cost of CCS for the three major plant types highlighted in the SRCCS, namely, new SCPC and NGCC plants with post-combustion capture and new IGCC plants with pre-combustion capture, with PC and IGCC costs based on bituminous coals. We also include cost results for oxy-combustion power plants (see Table 6), though these studies are based mainly on lower-cost subbituminous coals. For each power plant system we calculate the increase in levelized cost of electricity generation, as well as the mitigation (i.e., CO_2 avoidance) cost for a specified reference plant without CCS.

The total system cost is calculated for each of the individual studies reviewed using each study's data on LCOE with and without CCS, CO_2 emission rates (tCO_2/MWh) with and without CCS, the capture energy requirement, and the CO_2 removal efficiency. For transport costs we use 0–7 USD/tCO_2. For geologic storage costs we use 1–12 USD/tCO_2, and for storage with EOR we use a credit (negative cost) of 15–40 USD/tCO_2. Note that the transport and storage cost range for geologic storage is similar to the SRCCS after indexing to 2013 USD. The wider range for EOR credits was discussed in Section 7.2.

8.1. Results for overall plant cost

We combine all the above parameters to calculate the total levelized cost of electricity for each type of power plant, including the full CCS chain. We report those results in Table 14 for the recent studies reviewed, along with the CCS energy requirements and rates of CO_2 captured and avoided.

One sees in Tables 14 that the LCOE ranges based on recent studies overlap considerably for all CCS pathways. Natural gas has by far the widest range due to the large range of natural gas prices in recent US and European studies (with the lower end corresponding to US gas prices, where NGCC shows a distinct advantage in LCOE compared to coal-based technologies).

We also note that while oxy-combustion and SCPC with post-combustion have very similar ranges of LCOEs, these cases should not be compared directly because the SCPC costs are based on bituminous coals, whereas the oxy-combustion costs are based on lower-cost subbituminous coals. In Table 14 this difference is reflected in the lower LCOE for the SCPC reference plant for the oxyfuel studies compared to the SCPC reference plant for the SCPC-CCS studies. The discussion of Table 6 elaborated further on this issue.

Table 14 also shows that the LCOE of the IGCC reference plant is significantly higher than the SCPC reference plant. With CCS, however, the LCOE range for all three coal plant options is roughly the same. This is because the added cost of CCS (in USD/MWh) is lower for an IGCC plant compared to a SCPC plant with either oxyfuel or post-combustion capture. For NGCC, the added cost of CCS is similar to that for an IGCC plant since its post-combustion system

Table 14
Range of total costs for CO_2 capture, transport and geological storage based on recent studies of current technology for new power plants (all costs in constant 2013 USD).

Cost and Performance Parameters	NGCC with post-combustion capture	SCPC with post-combustion capture	SCPC with oxy-combustion capture	IGCC with pre-combustion capture
Reference plant without CCS: Levelized cost of electricity (USD/MWh)	42–83	61–79	56–68[a]	82–99
Power plants with CCS				
Increased fuel requirement per net MWh (%)	13–18	21–44	24–29	20–35
CO_2 captured (kg/MWh)	360–390	830–1080	830–1040	840–940
CO_2 avoided (kg/MWh)	310–330	650–720	760–830	630–700
% CO_2 avoided	88–89	86–88	88–97	82–88
Power plant with capture, transport and geological storage				
Levelized cost of electricity (USD/MWh)	63–122	95–150	92–141	112–148
Electricity cost increase for CCS (USD/MWh)	19–47	31–71	36–75	25–53
% increase	28–72	48–98	61–114	26–62
Power plant with capture, transport and geological storage with enhanced oil recovery credits				
Levelized cost of electricity (USD/MWh)	48–112	61–121	52–113	83–123
Electricity cost increase for CCS (USD/MWh)	3–37	(3)–42	(4)–47	(11)–29
% increase	7–56	(5)–57	(8)–72	(11)–33

[a] Note that oxy-combustion cases are based primarily on subbituminous coals whose cost is much lower than the bituminous coals assumed for SCPC and IGCC plants, resulting in roughly a 10% lower LCOE. Thus, LCOE values for oxy-combustion should not be compared directly to those for SCPC and IGCC plants.

Table 15
Range of total plant costs reported in the SRCCS adjusted to constant 2013 USD.

Cost and Performance Parameters	NGCC with post-combustion capture	SCPC with post-combustion capture	IGCC with pre-combustion capture
Reference Plant without CCS: Levelized cost of electricity (USD/MWh)	37–72	64–87	69–103
Power plant with capture, transport and geological storage			
Levelized cost of electricity (USD/MWh)	56–110	94–163	92–150
Electricity cost increase for CCS (USD/MWh)	19–43	28–76	17–51
% increase	30–110	43–87	21–74
Power plant with capture, transport and geological storage with enhanced oil recovery credits			
Levelized cost of electricity (USD/MWh)	48–100	76–139	77–128
Electricity cost increase for CCS (USD/MWh)	12–34	10–51	(1)–33
% increase	19–86	16–59	(1)–48

treats only about half the amount of CO_2 as a coal plant. For the two geological storage options, Table 14 shows that EOR credits can significantly reduce both the overall plant cost and the added cost of CCS. The magnitude of cost reduction is roughly 25–40 USD/MWh across all coal plant cases and roughly 10–15 USD/MWh for the NGCC plants (which process and sell much less CO_2 per MWh generated). Note that the negative cost increases at the low end of the cost ranges for coal plants with EOR implies that the selling price of CO_2 for EOR more than covers all capture and transport costs. Those results stem from applying the maximum EOR credit of 40 USD/tCO_2 to the lowest LCOE value in the recent studies reviewed for each technology. Those are not likely to be realistic cases since most studies project much higher LCOE values; nor are the level of EOR credits based on $100/bbl oil likely to be sustainable in view of the historical volatility in oil price, as discussed earlier in Section 7.2. Finally, in Table 15 we summarize the ranges of overall costs from the SRCCS report after adjusting for fuel and capital cost escalations, as described earlier in the paper. Compared to Table 14 results, the LCOE range for NGCC reference plants without CCS is roughly 10–15% lower in recent studies, for reasons discussed earlier. For SCPC, the low end of the reference plant LCOE range is about the same as before, but the high end of the range is now roughly 10% higher than the SRCCS. For the IGCC reference plant the opposite is true: the low end of the range has increased by about 20% while the high end of the range is roughly unchanged. Thus, while IGCC plants without CCS remain more costly than SCPC plants without CCS, that cost differential is much larger now than it was ten years ago.

Comparing Tables 14 and 15, we also find that on an absolute basis the added cost for CCS (in USD/MWh) is approximately the same now as in earlier studies for post-combustion capture at both NGCC and SCPC plants. For IGCC, however, the added cost for CCS has increased by about 8 USD/MWh (38%) at the low end of the range while the high end of the range is just slightly lower than before.

Table 15 also shows smaller cost savings from EOR credits in the SRCCS relative to the current study. Because of the differences in assumed credits, the reduction in LCOE is about 10–15 USD/MWh greater in this study than in the SRCCS for coal-based plants, and about 0–7 USD/MWh greater for NGCC plants with CCS.

8.2. Results for CO_2 mitigation cost

Mitigation costs for current studies are reported in Table 16 for cases with geologic storage, and in Table 17 for cases with EOR credits. Note that in all cases the reference plant with no capture is assumed to be the same plant type as the plant with capture, except for IGCC, where we also calculate the mitigation cost based on a SCPC reference plant.

For the cases with geologic storage (Table 16), the ranges of mitigation costs in recent studies are very similar to the adjusted costs from the SRCCS. The principal difference is a 50% increase in the lower range for IGCC plants stemming largely from the increase in reference plant costs discussed above. There is also a 13% decrease in the upper range for SCPC plants. This appears to be driven mainly by the increase in assumed plant capacity factors noted earlier in the paper, which reduces high LCOE values associated with low capacity factors.

For the cases with EOR credits (Table 17), the low end of the mitigation cost ranges are systematically lower than the SRCCS costs owing to the higher CO_2 selling price for EOR associated with higher oil prices in recent years. For SCPC plants we again also see a contraction in the high end of the range for the likely reason given above.

Tables 16 and 17 also report two mitigation costs not included in the SRCCS. One is for oxy-combustion costs, which are comparable to those for SCPC post-combustion capture (although based on a different fuel type, as noted earlier). The other is the mitigation cost for an IGCC plant relative to a SCPC reference plant (rather than an IGCC reference plant). This substantially increases the IGCC mitigation cost, especially at the high end of the range, because of the lower reference plant cost, as discussed earlier in Section 4.3.

Recall that mitigation costs in USD/tCO_2 avoided are directly comparable to a market price or tax on CO_2 emissions. For CCS using geologic storage, Table 16 suggests that carbon prices in the range of $50–100/t$CO_2$ are required to create commercial markets for a variety of power plants. In contrast, Table 17 suggests that if CCS can be combined with EOR, smaller carbon prices would be needed to incentivize CCS projects. However, as in the discussion of Table 14 results, the negative mitigation costs at the low end of the ranges in Table 17 are a result of bounding assumptions that are

Table 16
Mitigation costs in $/t$CO_2$ avoided (constant 2013 USD) for new power plants with capture and geologic storage. The no capture reference plant is assumed to be the same type plant as the capture plant, except where indicated.

Capture Plant	This study	Adjusted SRCCS	Difference, low end	Difference, high end
NGCC	59–143	64–136	−5	7
SCPC	46–99	45–114	1	−15
IGCC	38–84	25–85	13	−1
IGCC w/SCPC reference plant	53–137	Not available		
OXY	47–97	Not available		

Table 17
Mitigation costs in \$/tCO_2 avoided (constant 2013 USD) for new power plants with capture and EOR. The no capture reference plant is assumed to be the same type plant as the capture plant, except where indicated.

Capture Plant	This study	Adjusted SRCCS	Difference, low end	Difference, high end
NGCC	10–112	38–107	−28	5
SCPC	(5)–58	17–77	−22	−19
IGCC	(16)–46	(1)–55	−15	−9
IGCC w/SCPC reference plant	3–102	Not available		
OXY	(6)–63	Not available		

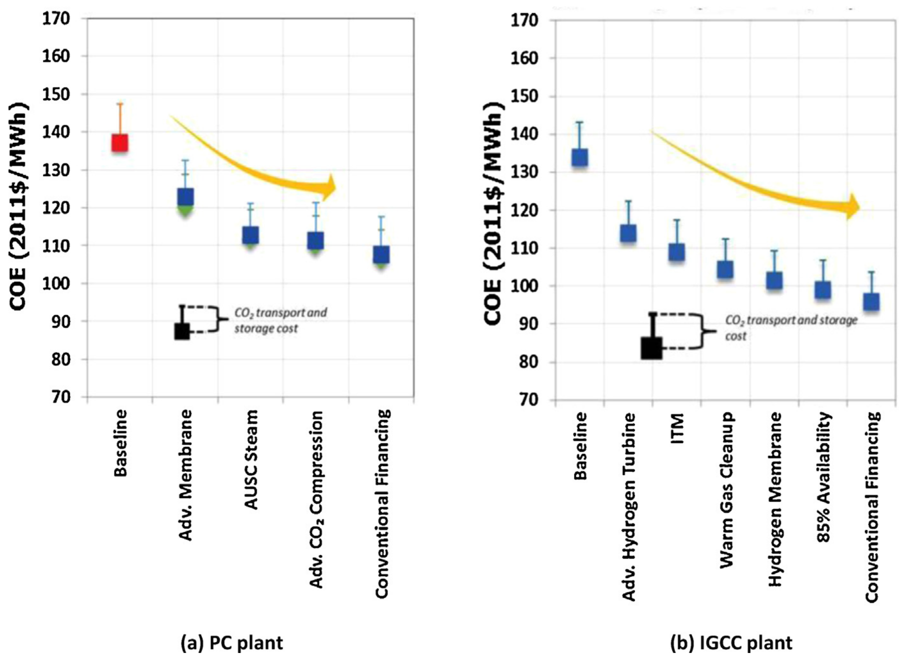

Fig. 3. Projected cost reductions for (a) SCPC plants with post-combustion capture, and (b) IGCC plants with pre-combustion capture (Gerdes et al., 2014).

unlikely to be realistic or sustainable in the foreseeable future. The following section elaborates on the outlook for future CCS costs for power plants.

9. Outlook for future CCS costs

Over the past decade, research and development (R&D) programs throughout the world have continued to pursue new or improved processes that reduce the cost of CCS (Rubin et al., 2012). For power plants, the pathway to lower costs involves a combination of advances in power generation technology (to increase their overall efficiency without large increases in cost), coupled with advances in CO_2 capture technologies—especially a reduction in their energy requirements, which currently account for a major portion of overall capture costs.

Potential cost reductions from advanced power generation systems with CCS have been reported in several recent studies by government and industry organizations. Such studies typically employ a "bottom-up" engineering analysis of a proposed flowsheet or process design whose cost is then estimated. On that basis, for example, the USDOE/NETL estimates cost reductions of approximately 20%, 17%, and 27% in the LCOE of advanced coal-based power plants with post-combustion, oxy-combustion, and IGCC/pre-combustion capture, respectively (Gerdes et al., 2014). Fig. 3 illustrates the series of advances that produce these reductions for PC and IGCC plants. Even larger cost reductions are projected by USDOE for integrated gasification fuel cell (IGFC) technology (48% relative to current IGFC, or 40% relative to current post-combustion systems), though that technology is still in the early stages of development. In a separate study of advanced NGCC power plants, USDOE/NETL projects cost reductions relative to current technology of about 14% for future plants without CCS and about 20% for advanced gas turbines with CCS (USDOE, 2013a).

Using similar methods, EPRI also estimated potential near-term cost reductions from R&D-driven improvements in PC, IGCC, and NGCC power plants with CCS in the 2025 time frame (EPRI, 2013b). Their results are similar to those of USDOE. Compared to current designs, they foresee reductions of roughly 20% in both the overall plant heat rate and unit capital cost of PC and IGCC plants, plus reductions of about 10% in heat rate and about 20% in unit capital cost for NGCC plants with CCS. Assuming no change in fuel prices, corresponding reductions in LCOE would be roughly 20% for coal-fired plants and 13% for gas-fired plants (for which fuel cost is the dominant contributor to LCOE).

Engineering-economic studies also have been used to estimate the future cost of new CO_2 capture concepts employing membranes, novel sorbents and solvents (such as ionic liquids and metal organic frameworks), sorbent-enhanced water gas shift reactors, chemical looping combustion, and various hybrid concepts (e.g., USDOE, 2013b). Typically, such estimates assume cost parameter values appropriate for a mature "*N*th-of-a-kind" process, together with performance parameters that are often based on R&D goals rather than actual current values. While on this basis many advanced process concepts appear promising, the credibility of such cost estimates remains questionable since most such processes are still in the early stages of development and performance goals have yet to be realized (Rubin, 2014).

An alternative method of estimating the future cost of power plants with CCS is a "top down" approach based on the use of experience (learning) curves. Here, cost reductions are related to increases in the cumulative installed capacity or cumulative production of a technology (a surrogate for all factors that affect cost reductions) (Yeh and Rubin, 2012). Based on historical learning rates for various power plant components, Rubin et al. (2007) estimated LCOE reductions relative to current technology of roughly 15% for combustion-based plants with CCS and 20% for gasification-based plants with CCS after 100 GW of increased capacity worldwide. Using similar methods, but coupling capacity expansion with scenarios of global growth and climate policy measures, van den Broek et al. (2009) projected somewhat larger cost reductions by 2050 with a modest but increasing tax on carbon emissions.

Broadly speaking, then, the outlook for CCS cost reductions from top-down models is similar to projections from bottom-up studies for current commercial or near-commercial technologies. A key difference in the two methods, however, is the importance of experience at the commercial level. Thus, as noted by Rubin et al. (2012):

> Achieving significant cost reductions will require not only a vigorous and sustained level of R&D . . . but also a substantial level of commercial deployment. That, in turn, will require a significant market for CO_2 capture technologies that can only be established by government actions. At present such a market does not exist. While various types of incentive programs can accelerate the development and deployment of CO_2 capture technology, actions that significantly limit emissions of CO_2 to the atmosphere ultimately are needed to realize substantial and sustained reductions in the future cost of CO_2 capture.

10. Other CCS applications

This paper concentrates on CCS costs for new power plants. Other potentially significant applications are retrofits of CCS to existing power plants and non-power industrial processes. While these topics are outside the scope of this paper, we offer some brief comments on developments since publication of the SRCCS.

10.1. Retrofits of CCS to power plants

Post-combustion capture is well suited for retrofits to existing power plants where factors such as plant size, age, efficiency and access to suitable storage sites make CCS technically and economically viable. The technologies that would be used for CO_2 capture retrofit are the same as those used in new power plants. The first commercial-scale CCS unit at a power plant (Boundary Dam) was a retrofit installation (Monea, 2014).

Capital costs of retrofitting capture to existing power plants are generally expected to be higher than costs at new-build plants, as was confirmed by the studies reviewed in the SRCCS. Reasons for this include:

- Space to install and connect the capture plant may not be readily available, resulting in more difficult construction work, longer pipes and ducts, and other site-specific difficulties.
- Integration between the power plant and the capture plant may not be so easily optimized.
- Additional flue gas cleaning equipment may need to be installed upstream of the capture plant, for example if there is no existing or adequate flue gas desulfurization (FGD) unit.
- Existing power plants tend to be smaller than new build plants, resulting in lower economies of scale.

The SRCCS also showed that retrofits would have a larger incremental LCOE for CCS than new build plants. Reasons for this include:

- The higher specific capital costs for retrofits.
- The operating lifetime of a retrofitted capture plant may be lower than that at a new build power plant if it is constrained by the residual life of the existing plant.
- Power plants retrofitted with capture tend to have lower efficiencies than new-build plants, which means that more CO_2 has to be captured per net MWh of electricity.
- The energy consumption per ton of CO_2 captured at retrofits tends to be higher than at new-build plants because of lower plant efficiencies and reduced opportunities for optimization.

In the studies reviewed for the SRCCS, the costs of CO_2 capture and avoidance were shown on average to be higher than for new-build power plants. However, if the capital cost of the existing power plant is assumed to be written off and the amount of refurbishment necessary to extend the life of the existing plant is not excessive, retrofitting CCS can result in a lower LCOE than the alternative of closing the existing plant and building a new power plant with CCS. These general conclusions regarding the economics of capture retrofit compared to new build power plants with CCS are expected to be unchanged compared to the SRCCS, as affirmed in a recent study of CCS costing methods (Rubin et al., 2013).

10.2. CCS for industrial processes

While studies of CCS have focused mainly on power plants (as the largest source of CO_2 emissions globally), applications to other industrial processes are of increasing interest as emissions from such sources continue to grow. At the time the SRCCS was written, global CO_2 emissions from large industrial processes were roughly one-fourth the emissions from power plants (IPCC, 2005). Accordingly, little detailed work on CCS costs for industrial processes other than power generation had been reported, except for hydrogen and synthetic fuels production plants. Consequently, although the SRCCS included some cost data for other industrial processes, the level of detail for most industries was substantially less than for power plants.

More recently, non-utility industrial processes have become more prominent as potential candidates for CCS as global CO_2 emissions from this sector grew to half as great as emissions from electricity sector (including combined heat and power systems) (IEA, 2013a). For example, a CO_2 stabilization scenario of the IEA's recent CCS Technology Roadmap (IEA, 2013b), projects that around half of the CO_2 abated by CCS in 2050 will come from industries other than power generation, particularly the biofuels, iron and steel, cement, chemicals production, natural gas processing and oil refining industries.

As was noted in the SRCCS, industrial processes such as natural gas purification, bioethanol production, production of synthetic liquids and gas from coal, as well as certain chemical production processes, produce a concentrated CO_2 stream which is usually vented to the atmosphere. In these cases the cost of CO_2 capture for CCS would be just the additional cost of CO_2 compression and drying. Because these costs are relatively low, such plants account for a large proportion of the anthropogenic CO_2 currently provided for EOR (GCCSI, 2014). CO_2 also can be captured in other industrial processes, either by using the same basic techniques available for power plants or by using alternative industrial processes that include inherent capture of CO_2.

Despite the increased attention now being given to industrial CCS there is still relatively little cost information in the public domain. Estimating CCS costs for large industrial plants such as iron and steel mills or oil refineries is more difficult than for power plants because such facilities tend to have unique designs and multiple emission sources with different gas compositions and flow rates. Energy integration between capture units and industrial processes involves additional complexities. A further complication, particularly in developed countries, is that few wholly new large industrial plants such as steel mills and oil refineries are expected to be built. Thus, CCS would have to be retrofitted, resulting in additional site-specific complexity and costs. The costs of CCS at industrial plants other than power generation is therefore outside the scope of this paper, although readers can find other recent literature on this topic (e.g., IEAGHG, 2008; de Mello et al., 2012; IEAGHG, 2013; Domenichini, 2013).

10.3. Comparisons with other low-carbon technologies

In the broader context of greenhouse gas mitigation options, the question often arises as to how the cost of CCS compares to that of other low-carbon technologies such as wind, solar and nuclear power. The SRCCS did not directly compare the costs of CCS to other lower carbon technologies, although it did include some scenarios from the literature showing projected contributions of different low-carbon technologies to global CO_2 emission reductions in the future. Direct comparison between the cost of power plants with CCS and other low-carbon technologies is not a straightforward matter, however, since the economic value and costs of different technologies must take into account a variety of factors, such as the ability of an electric power system to provide a reliable electricity supply and respond to the substantial variability of electricity demands. Such issues were beyond the scope of the SRCCS and are beyond the scope of this paper as well.

11. Conclusions

Here we summarize the key findings from our comparison of current CCS cost studies to those presented in the 2005 *Special Report on Carbon dioxide Capture and Storage* (SRCCS).

11.1. Since the SRCCS, there have been significant increases in the capital cost of power plants and CCS technologies

We find that the capital cost of the three major plant types (NGCC, SCPC, and IGCC) with and without CCS have all increased substantially since the SRCCS, despite the fact that basic plant parameters such as their thermodynamic efficiency and CO_2 capture efficiency are essentially the same in recent studies as in the SRCCS. Using the Power Capital Cost Index to adjust SRCCS capital costs to 2013 dollars resulted in an increase of about 60% in capital costs. Current studies, however, showed even greater increases. Compared to the adjusted SRCCS costs, reference plant costs for NGCC, SCPC, and IGCC without CCS were 18%, 28%, and 49% higher, respectively. For plants with CCS the corresponding increases were 32%, 37%, and 49% higher than adjusted SRCCS costs. We attribute these additional increases to changes in the power plant and/or CCS system designs, and to market factors that affect technology costs at any point in time. Differences in current SCPC and NGCC plant costs with and without CCS also indicate real increases in the incremental capital cost for post-combustion capture systems. In contrast, the incremental capital cost for pre-combustion capture at IGCC plants is essentially unchanged relative to the adjusted SRCCS cost. However, the total capital cost of IGCC reference plants (without CCS) has increased significantly more than the capital cost of SCPC reference plants.

11.2. The constant dollar levelized costs of electricity for power plants with and without CCS in recent studies show only small changes compared to the SRCCS costs adjusted for power plant capital and fuel cost escalations

SCPC plants with and without CCS in recent studies show slightly lower LCOEs compared to the adjusted SRCCS values. This is mainly due to lower annual capital charge factors and higher assumed capacity factors offsetting the higher capital costs. For IGCC plants, there has been a roughly 15% increase in LCOE, due mainly to higher capital costs. For NGCC plants, whose LCOE is dominated by the cost of natural gas, recent reductions in gas prices have brought the LCOEs for US plants down to roughly the same level as the adjusted SRCCS values. In contrast, European gas prices continued to escalate until the base year for this paper (2013), resulting in net LCOE increases for NGCC and CCS relative to SRCCS estimates.

11.3. The costs of CO_2 avoidance (mitigation cost) for CCS, including pipeline transport and geologic storage, are essentially the same as in the SRCCS, after taking into account the real escalations in plant and fuel costs reflected in the indices used for cost adjustments

This is a direct result of, (1) the small changes in LCOE discussed in the previous paragraph, and (2) the fairly stable costs projected for CO_2 pipeline transport and geological storage costs after adjusting for recent cost escalations.

11.4. The overall cost of CCS can be reduced significantly if CO_2 can be sold for enhanced oil recovery (EOR) in conjunction with geological storage over the life of the project

The range of total CCS costs presented in this paper indicates larger potential cost savings from EOR credits than in the SRCCS. This is a result of the much higher oil prices—and associated value of CO_2 for EOR—seen over the past decade. Nonetheless, the recent (2013–2014) collapse of world oil prices is a reminder of the historical volatility of oil prices, and the associated uncertainty in the value of CO_2-EOR credits in CCS cost projections.

11.5. For coal plants, the pre-combustion pathway (IGCC) has lost ground to the post-combustion pathway (SCPC) since the SRCCS

In the SRCCS, the total levelized cost of SCPC and IGCC plants with CCS (geologic storage) were very similar: 94–163 USD/MWh and 92–150 USD/MWh, respectively, based on adjusted costs for 2013. However, current studies show an advantage for SCPC at the low end of the LCOE range: 95–150 USD/MWh vs. 112–148 USD/MWh for IGCC. Mitigation costs based on current studies with a common SCPC reference plant show a range of 46–99 USD/tCO_2 avoided for SCPC, compared to 53–137 USD/tCO_2 avoided for IGCC.

11.6. Oxy-combustion shows potential to be competitive with post-combustion capture for SCPC plants

The SRCCS did not highlight cost estimates for oxy-combustion systems since they were still in the early stages of development at the time. R&D over the past decade, however, has significantly advanced this pathway, with recent studies suggesting that oxy-combustion capture at plants using low-rank coals has similar LCOEs and mitigation costs as SCPC plants with post-combustion capture using bituminous coals. It should be noted, however, that SCPC with post-combustion capture is significantly more mature than with oxy-combustion capture, so further work is needed to better understand their relative costs.

11.7. Based on current cost estimates for the four CCS pathways analyzed, there are no obvious winners or losers

The range of mitigation costs for NGCC, SCPC, IGCC, and oxyfuel show considerable overlap. Overall, therefore, the results of this study support the general conclusion of the 2005 SRCCS report and other subsequent studies (e.g., MIT, 2007) that there is still no single technological “winner” that is best suited for low-carbon power generation using carbon capture and storage.

Appendix.

Common measures of cost used in this paper are defined as follows (Rubin, 2012):

Levelized cost of electricity

$$\text{LCOE} = \frac{(\text{TCC})(\text{FCF}) + (\text{FOM})}{(\text{CF})(8766)(\text{MW})} + \text{VOM} + (\text{HR})(\text{FC}) \quad (1)$$

where LCOE = levelized cost of electricity generation ($/MWh), TCC = total capital cost ($), FCF = fixed charge factor (fraction/yr), FOM = fixed operating and maintenance (O&M) costs ($/yr), VOM = variable non-fuel O&M costs ($/MWh), HR = net power plant heat rate (MJ/MWh), FC = unit fuel cost ($/MJ), CF = plant capacity factor (fraction), 8766 = total hours in an average year, and MW = net plant capacity (MW).

All of the parameters in Eq. (1) represent their “levelized” values over the life of power plant. These are numerically the same as first-year COE for the special case where costs are expressed in constant dollars and all parameter values remain constant over the life of the plant. In all other cases, a series of “levelization factors” can be applied to first-year values to obtain levelized values. See Rubin et al. (2013), Appendix C, for details.

Cost of CO_2 avoided

$$\text{Cost of CO}_2\text{ avoided}\left(\frac{\$}{\text{tCO}_2}\right) = \frac{(\text{LCOE})_{ccs} - (\text{LCOE})_{ref}}{\left(\text{tCO}_2/\text{MWh}\right)_{ref} - \left(\text{tCO}_2/\text{MWh}\right)_{ccs}} \quad (2)$$

where LCOE = levelized cost of electricity generation ($/MWh), tCO_2/MWh = CO_2 mass emission rate to the atmosphere in tons per MWh (based on the net capacity of each power plant), and the subscripts “ccs” and “ref” refer to plants with and without CCS, respectively.

Cost of CO_2 captured

$$\text{Cost of CO}_2\text{ captured}\left(\frac{\$}{t\text{CO}_2}\right) = \frac{(\text{LCOE})_{cc} - (\text{LCOE})_{ref}}{\left(\text{tCO}_2/\text{MWh}\right)_{captured}} \quad (3)$$

where $(tCO_2/MWh)_{captured}$ = total mass of CO_2 captured per net MWh for the plant with capture (equal to CO_2 produced minus emitted), and LCOE is again the levelized cost of electricity. Here, the reference plant is the same type as the capture plant, and the LCOE with capture, $(LCOE)_{cc,}$ excludes the costs of CO_2 transport and storage.See Tables A1–A6.

Table A1
Multipliers and currency exchange rates used to escalate prior year capital and fuel costs to constant 2013 USD. Mutipliers are the reciprocal of the cost index values shown in Figs. 1 and 2 of the main text.

Cost year reported	Capex + O&M cost multiplier[a]	T&S cost multiplier[b]	US coal cost multiplier[c]	Europe coal cost multiplier[c]	US gas cost multiplier[c]	Europe gas cost multiplier[c]	USD/EUR exchange rate[d]
2002	1.643	1.434	1.880	2.274	1.216	3.768	0.992
2003	1.573	1.412	1.836	2.138	0.803	3.052	1.150
2004	1.472	1.277	1.728	1.580	0.727	2.635	1.219
2005	1.353	1.212	1.526	1.411	0.527	2.134	1.210
2006	1.172	1.136	1.391	1.386	0.624	1.629	1.272
2007	1.064	1.080	1.328	1.188	0.609	1.535	1.354
2008	1.011	0.986	1.135	0.752	0.481	1.175	1.578
2009	1.040	1.087	1.063	1.052	0.914	1.457	1.409
2010	1.051	1.030	1.035	0.958	0.851	1.390	1.225
2011	1.040	0.969	0.983	0.728	0.917	1.080	1.449
2012	1.022	0.970	0.987	0.886	1.266	1.009	1.266
2013	1.000	1.000	1.000	1.000	1.000	1.000	1.301

[a] Based on the Power Capital Cost Index (IHS CERA, 2014).
[b] Based on the Chemical Engineering Plant Cost Index (CEM, 2014).
[c] Based on the cost of delivered fuels to power plants in the US (EIA, 2014) and Europe (IEA, 2014). European coal prices were based on the average for the UK and Germany; European gas prices were based on the average for the UK and Finland (consistent with available data).
[d] Mid-year exchange rate for the reported cost year (Oanda, 2014).

Table A2
Current studies: supercritical pulverized coal power plants with current post-combustion capture technology and bituminous coals.

Study Assumptions and Results	USDOE	EPRI	Alstom	IEAGHG	GCCSI	ZEP	Range		
	2013c	2013a	2011	2014	2011	2011	min	max	Mean
Source reference currency	US$	US$	Euro	Euro	US$	Euro			
Reference Plant design									
Boiler type (pressure, SH/RH temp)	24.2/593/593	high cost	30/600/620	27/600/620	24.1/599/621	28/600/620			
Coal type and%S	bit, 2.5% S	(current)	bit, 1% S	bit, 0.9% S	bit, Ill#6	bit			
Reference plant net output (MW)	550	750	837	1030	550	736	550	1030	742
Plant capacity factor (%)	85	80	85	90	90	85.6	80	90	86
Net plant efficiency, HHV (%)	39.3	39.0	44.4	42.3	39.1	44.2	39.0	44.4	41
Coal cost, HHV (US$/GJ)	2.06	2.33	2.84	3.12	2.70	3.42	2.06	3.42	2.74
Reference plant emission rate (t CO_2/MWh)	0.802	0.840	0.776	0.746	0.804	0.759	0.746	0.840	0.788
Capture plant design									
CO_2 capture technology	Econ FG+		Adv.amine	Cansolv	Amine	Adv. Amine			
Net plant output with capture (MW)	550	525	837	822	546	616	525	837	649
Net plant efficiency, HHV (%)	28.4	27.4	36.1	33.8	27.2	36.5	27.2	36.5	32
CO_2 capture system efficiency (%)	90	90	90	90	90	90	90	90	90
CO_2 emission rate after capture (t/MWh)	0.111	0.120	0.095	0.093	0.116	0.092	0.092	0.120	0.104
CO_2 captured (Mt/yr)	4.09	3.96	5.34	5.59		3.82	3.82	5.59	4.56
CO_2 product pressure (MPa)	15.3			11.0	20.2	11.0	11	20	14
CCS energy reqm't. (% more input/MWh)	38	42	23	25	44	21	21	44	32
CO_2 reduction per kWh (%)	86	86	88	88	88	88	86	88	87
Cost results (adjusted to 2013$)									
Cost year basis (constant dollars)	2007	2011	2010	2013	2010	2009			
Inflation factor to 2013 (Fuel costs)	1.328	0.983	0.958	1	1.035	1.052			
Inflation factor to 2013 (CERA, for capex/O&M)	1.064	1.04	1.051	1.00	1.051	1.04			
Fixed charge factor (%)	0.109			0.093	0.096		0.093	0.109	0.099
Reference plant TPC (US$/kW)	1752	2496	2104	1883	2017	2290	1752	2496	2090
Capture plant TPC (US$/kW)	3099	4368	3597	3605	3641	3608	3099	4368	3653
Reference plant TOC (US$/kW)	2154			2092	2319	2506	2092	2506	2268
Capture plant TOC (US$/kW)	3798			3994	4187	3949	3798	4187	3982
Reference plant TCR (US$/kW)	2313	2990	2630	2455	2501	2820	2313	2990	2618
Capture plant TCR (US$/kW)	4091	5252	4497	4684	4514	4443	4091	5252	4580
Incremental TCR for capture (US$/kW)	1778	2262	1867	2229	2014	1623	1623	2262	1962
Reference plant COE (US$/MWh)	66.4	78.8	61.5	67.7	79.5	64.2	61	79	69.7
Capture plant COE (US$/MWh)	112.4	129.5	100.4	112.3	127.7	94.0	94	130	112.7
Incremental COE for capture (US$/MWh)	46.0	50.7	38.9	44.6	48.2	29.8	30	51	43.0
% increase in TCR (over ref. plant)	77	76	71	91	81	58	58	91	75
% increase in COE (over ref. plant)	69	64	63	66	61	46	46	69	62
Cost of CO_2 captured (US$/t CO_2)	46	47	45	53	46	36	36	53	46
Cost of CO_2 avoided (US$/t CO_2)	67	70	57	68	70	45	45	70	63
CO_2 stored t/MWh	0.999	1.076	0.857	0.841	1.040	0.827	0.827	1.076	0.940
CO_2 stored t/t CO_2 avoided	1.445	1.493	1.259	1.289	1.511	1.240	1.240	1.511	1.373
Source data, uninflated costs									
T&S cost, per t CO_2 stored		10		13.01		0			
T&S cost, $/MWh	5.7	10.76	6.0	10.94	7.0	0.00			
Coal cost, HHV (US$/GJ)	1.55	2.37	2.96	3.12	2.61	3.25			
Reference plant COE (US$/MWh)	58.9	77.0	60.6	67.7	76.0	61.4			
Ref plant fuel contribution to COE ($/MWh)	14.2	21.9	24.1	26.6	24.0	26.5			
Ref plant non-fuel contribution to COE ($/MWh)	44.7	55.1	36.6	41.1	52.0	35.0			
Capture plant COE (US$/MWh)	100.8	126.2	98.1	112.3	122.0	90.0			
Capture plant fuel contribution to COE ($/MWh)	19.6	31.1	29.5	33.3	34.5	32.0			
Capture plant non-fuel cont. to COE ($/MWh)	81.2	95.1	68.6	79.0	87.5	58.0			

Table A3
Current studies: NGCC power plants with current post-combustion capture technology.

Study Assumptions and Results	USDOE	IEA GHG	IEA GHG	Rubin and Zhai	USDOE	EPRI	Range		
	2011	2012	2012	2012	2013c	2013a	min	max	Mean
Case or Descriptor	High altitude	Solvent 1	Solvent 2	Base case	Baseline case	Current tech			
Reference plant design									
Gas turbine type	GE7FB	GE9FB	GE9FB	GE7FB	GE7FB	n/a			
Net power output (MW)	512	910	910	526.6	555.1	550	512	910	661
Plant capacity factor (%)	85	92	93	75	85	80	75	93	85
Net plant efficiency, HHV (%)	50.5	53.2	53.2	50.0	50.2	48.7	48.7	53.2	51.0
CO_2 emission rate (t CO_2/MWh)	0.364	0.348	0.348	0.362	0.359	0.37	0.348	0.370	0.359
Capture plant design									
CO_2 capture technology	Econamine FG+	MEA	advanced amine	Econamine FG+	Econamine FG+	amine			
Net power output (MW)	435	789	804	448.9	473.6	485	435	804	573
Net plant efficiency, HHV (%)	42.9	46.1	47.0	42.6	42.8	42.4	42.4	47.0	44.0
Plant capacity factor (%)	85	90	90	75	85	80	75	90	84
CO_2 capture efficiency (%)	90	90	90	90	90	90	90	90	90
CO_2 emission rate after capture (t/MWh)	0.043	0.040	0.039	0.043	0.042	0.042	0.039	0.043	0.042
CO_2 captured (Mt/yr)	1.251	2.250	2.249	1.130	1.337	1.301	1.130	2.250	1.586
CO_2 product pressure (MPa)	15.2	11.0	11.0	13.7	15.2	n/a	11	15	13
CCS energy reqm't. (% more input/MWh)	18	15	13	17	17	15	13	18	16
CO_2 reduction per kWh (%)	88	88	89	88	88	89	88	89	88
Cost results (adjusted to 2013$)									
Cost year and currency to be adjusted to 2013$	2007 USD	2011 EUR	2011 EUR	2007 USD	2007 USD	2011 USD			
Fuel cost, HHV ($/GJ)	4.12	8.48	8.48	3.78	3.78	5.22	3.78	8.48	5.64
Reference plant TCR, (US$/kW)	935	1177	1177	808	820	1378	808	1378	1049
Capture plant TCR, (US$/kW)	1843	2599	2160	1422	1717	2626	1422	2626	2061
Added TCR for capture (US$/kW)	908	1422	983	613	897	1248	613	1422	1012
% increase in capital cost (over ref. plant)	97	121	84	76	109	91	76	121	96
Fixed charge factors (Ref/Capture)	0.105/ 0.111	8%/25yrs	8%/25yrs	0.113	0.105/ 0.111	n/a			
Reference plant LCOE (US$/MWh)	65.0	83.4	83.4	44.4	42.4	65	42	83	64
Capture plant LCOE w/o T&S (US$/MWh)	95.9	115.1	106.2	62.9	64.2	104.6	63	115	91
Added LCOE for capture (US$/MWh)	30.9	31.8	22.9	18.5	21.8	39.6	19	40	28
% increase in LCOE (over ref. plant)	48	38	27	42	51	61	27	61	45
Cost of CO_2 captured ($/t CO_2)	80	88	65	48	58	104	48	104	74
Cost of CO_2 avoided, w/o T&S ($/t CO_2)	96	103	74	58	69	121	58	121	87
CO_2 stored t/MWh	0.386	0.365	0.359	0.383	0.379	0.382	0.36	0.39	0.38
t CO_2 stored /t CO_2 avoided	1.201	1.186	1.163	1.197	1.196	1.168	1.16	1.20	1.19
AS-REPORTED COSTS:									
Fuel cost, HHV ($/GJ)	6.76	7.85	7.85	6.21	6.21	5.69	5.7	7.9	6.8
Reference plant LCOE (US$/MWh)	81.7	78.1	78.1	60.8	58.9	65	59	82	70
Ref plant fuel component of COE ($/MWh)	48.2	53.2	53.2	44.7	44.5	42.0	42	53	48
Ref plant nonfuel component of COE ($/MWh)	33.5	24.9	24.9	16.1	14.4	23.0	14	34	23
Capture plant total LCOE ($/MWh)	117.8	111.0	102.4	84.2	85.9	112	84	118	102
Capture plant T&S cost ($/t stored)		7.25	7.25	7		10	7	10	8
Capture plant T&S component of COE ($/MWh)	3.4	2.6	2.6	2.7	3.2	3.8	3	4	3
Capture plant fuel component of COE ($/MWh)	56.7	61.3	60.2	52.5	52.2	64.3	52	64	58
Capture plant nonfuel part of COE ($/MWh)	57.7	47.0	39.7	29.1	30.5	43.8	29	58	41
Fuel costs, %COE, reference plant	59.0	68.1	68.1	73.5	75.6	64.6	59	76	68
Fuel costs, %COE, capture plant w/o T&S	49.6	56.6	60.2	64.4	63.1	59.5	50	64	59
AFTER ADJUSTMENTS:									
Fuel costs, %COE, reference plant	45.2	68.9	68.9	61.4	63.9	59.3	45	69	61
Fuel costs, %COE, capture plant w/o T&S	36.0	57.5	61.1	50.8	49.5	56.4	36	61	52
COST ADJUSTMENT FACTORS:									
Inflation factor to 2013 (capex+O&M costs)	1.064	1.040	1.040	1.064	1.064	1.040			
Inflation factor to 2013 (fuel costs)	0.609	1.080	1.080	0.609	0.609	0.917			
Escalate TPC to TCR = 1.25									
Escalate TOC to TCR = 1.125		1.125	1.125						
Currency exchange rate to USD		1.449	1.449						

Table A4
Current studies: IGCC power plants with pre-combustion capture technology: IGCC reference plants.

Study Assumptions and Results	USDOE 2013c	USDOE 2013c	USDOE 2013c	EPRI 2013a	GCCSI 2011	Range min	Range max	Mean
	Plants with bituminous coal feedstock							
Source reference currency	USD	USD	USD	USD	USD			
Reference plant design								
Gasifier name or type	GE radiant quench, O2 blown	CoP, O2 blown, CGUC	Shell quench, O2 blown	IGCC high (current tech)	Shell, O2 blown, CGCU			
Fuel type (bit, subbit, lig; other) and%S	Illinois #6	Illinois #6	Illinois #6	bitum.	Illinois #6			
Referenence plant type	IGGC	IGCC	IGGC	IGCC	IGCC			
Reference plant size (MW)	622	625	629	600	748	600	748	645
Plant capacity factor (%)	80	80	80	80		80	80	80
Net plant efficiency, HHV (%)	39.0	39.7	42.1	38.3	41.1	38.3	42.1	40
Fuel cost, HHV (US$/GJ)	2.06	2.06	2.06	2.33	2.70	2.06	2.70	2.24
Reference plant emission rate (tCO_2/MWh)	0.782	0.776	0.723	0.850	0.753	0.723	0.850	0.777
Capture plant design								
CO_2 capture technology	Selexol	Selexol	Selexol		Selexol NS			
Net plant size, with capture (MW)	543	514	497	500	694	497	694	550
Net plant efficiency, HHV (%)	32.6	31.0	31.2	29.9	32.0	29.9	32.6	31
CO_2 capture system efficiency (%)	90	90	90	86	90	86	90	89
CO_2 emission rate after capture (t/MWh)	0.093	0.099	0.098	0.150	0.097	0.093	0.150	0.107
CO_2 captured (Mt/yr)	3.21	3.22	3.06	3.29		3.06	3.29	3.20
CO_2 product pressure (MPa)	15.3	15.3	15.3		20.2	15	20	17
CCS energy reqm't. (% more input/MWh)	20	28	35	28	28	20	35	28
CO_2 reduction per kWh (%)	88	87	87	82	87	82	88	86
Cost results (adjusted to 2013$)								
Cost year basis (constant dollars)	2007	2007	2007	2011	2010			
Inflation factor to 2013 (Fuel costs)	1.328	1.328	1.328	0.983	1.035			
Inflation factor to 2013 (CERA, for capex/O&M)	1.064	1.064	1.064	1.04	1.051			
Fixed charge factor (%)	0.109	0.109	0.109		0.096	0.096	0.109	0.106
Reference plant TPC (US$/kW)	2114	2035	2359	3224	2752	2035	3224	2497
Capture plant TPC (US$/kW)	2885	2997	3385	4264	3587	2885	4264	3423
Reference plant TOC (US$/kW)	2604	2501	2890		3164	2501	3164	2790
Capture plant TOC (US$/kW)	3547	3688	4154		4125	3547	4154	3879
Reference plant TCR (US$/kW)	2791	2687	3114	3900	3412	2687	3900	3181
Capture plant TCR (US$/kW)	3808	3956	4468	5148	4448	3808	5148	4366
Incremental TCR for capture (US$/kW)	1017	1270	1354	1248	1036	1017	1354	1185
Reference plant COE (US$/MWh)	85.0	82.4	90.0	98.6	94.2	82.4	98.6	90.0
Capture plant COE (US$/MWh)	111.2	116.5	126.1	130.0	118.3	111.2	130.0	120.4
Incremental COE for capture (US$/MWh)	26.3	34.0	36.1	31.5	24.1	24.1	36.1	30.4
% increase in TCR (over ref. plant)	36	47	43	32	30	30	47	38
% increase in COE (over ref. plant)	31	41	40	32	26	26	41	34
Cost of CO_2 captured (US$/t CO_2)	31	38	41	34	28	28	41	34
Cost of CO_2 avoided (US$/t CO_2)	38	50	58	45	37	37	58	46
CO_2 stored t/MWh	0.841	0.894	0.879	0.939	0.870			
CO_2 stored t/t CO_2 avoided	1.223	1.322	1.404	1.341	1.326			
Source data, uninflated costs								
T&S cost, per t CO_2 stored				10	10			
T&S cost, $/MWh	5.3	5.3	5.3	9.39	8.70			
Coal cost, HHV (US$/GJ)	1.55	1.55	1.55	2.37	2.61			
Reference plant COE (US$/MWh)	76.3	74.0	81.3	96.0	90.0			
Ref plant fuel contribution to COE ($/MWh)	14.3	14.1	13.3	22.3	22.9			
Ref plant non-fuel contribution to COE ($/MWh)	62.0	59.9	68.0	73.8	67.1			
Capture plant COE (US$/MWh)	100.3	105.0	114.1	126.6	113.0			
Capture plant fuel contribution to COE ($/MWh)	17.1	18.0	17.9	28.5	29.4			
Capture plant non-fuel cont. to COE ($/MWh)	83.2	87.0	96.2	98.1	83.6			
TCR/TPC factor	1.32	1.32	1.32					
TCR/TOC factor								
Fuel costs, %COE, reference plant	19	19	16	23	25	16	25	21
Fuel costs, %COE, capture plant (excl T&S)	17	17	16	23	26	16	26	20

Table A5
Current studies: IGCC power plants with pre-combustion capture technology: SCPC Reference Plants, bituminous coal feedstock.

Study Assumptions and Results	USDOE	USDOE	USDOE	EPRI	IEA GHG	IEA GHG	IEA GHG	GCCSI	ZEP	Range		
	2013c	2013c	2013c	2013a	2014	2014	2014	2011	2011	min	max	Mean
Source reference currency	US$	US$	US$	US$	Euro	Euro	Euro	US$	Euro			
Reference plant design												
Gasifier name or type	GE radiant quench, O2 blown	CoP, O2 blown, CGUC	Shell quench, O2 blown	CCS high cost (current tech)	GE radiant quench, O2 blown	Shell syngas cooler, O2 blown	MHI air blown	Shell, O2 blown, CGCU	full quench, O2 blown			
Fuel type (bit, subbit, lig; other) and%S	Illinois #6	Illinois #6	Illinois #6	bit	bit, 1% S	bit	bit, 1%S	Illinois #6				
Referenence plant type	PC, super	PC, super	PC, super	PC, super	PC, super	PC, super	PC, super	PC, super	PC, super			
Reference plant size (MW)	550	550	550	750	1030	1030	1030	550	736	550	1030	*753*
Plant capacity factor (%)	85	85	85	80	85	85	85		85.6	80	86	*84*
Net plant efficiency, HHV (%)	39.3	39.3	39.3	39.0	42.3	42.3	42.3	39.1	44.2	39.0	44.2	*41*
Fuel cost, HHV (US$/GJ)	2.06	2.06	2.06	2.33	3.12	3.13	3.12	2.70	3.42	2.06	3.42	*2.67*
Reference plant emission rate (tCO_2/MWh)	0.802	0.802	0.802	0.840	0.746	0.746	0.746	0.804	0.789	0.746	0.840	*0.786*
Capture plant design												
CO_2 capture technology	Selexol	Selexol	Selexol		Selexol	Selexol	Selexol	Selexol, NS	Selexol			
Net plant size, with capture (MW)	543	514	497	500	874	804	863	694	900	497	900	*688*
Net plant efficiency, HHV (%)	32.6	31.0	31.2	29.9	33.3	33.9	33.2	32.0	36.5	29.9	36.5	*33*
CO_2 capture system efficiency (%)	90	90	90	86	90	90	89	90	90	86	90	*89*
CO_2 emission rate after capture (t/MWh)	0.097	0.102	0.101	0.150	0.095	0.093	0.105	0.098	0.096	0.093	0.150	*0.104*
CO_2 captured (Mt/yr)	3.52	3.50	3.37	3.31	5.56	5.02	5.44		5.81	3.31	5.81	*4.44*
CO_2 product pressure (MPa)	15.3	15.3	15.3		11.0	11.0	11.0	20.2	11.0	11	20	*14*
CCS energy reqm't. (% more input/MWh)	21	27	26	30	27	25	28	22	21	21	30	*25*
CO_2 reduction per kWh (%)	88	87	87	82	87	88	86	88	88	82	88	*87*
Cost results (adjusted to 2013$)												
Cost year basis (constant dollars)	2007	2007	2007	2011	2013	2013	2013	2010	2009			
Inflation factor to 2013 (Fuel costs)	1.328	1.328	1.328	0.983	1	1	1	1.035	1.052			
Inflation factor to 2013 (CERA, for capex/O&M)	1.064	1.064	1.064	1.04	1	1	1	1.051	1.04			
Fixed charge factor (%)	0.116	0.116	0.115		0.100	0.100	0.100	0.096		0.096	0.116	*0.106*
Reference plant TPC (US$/kW)	1752	1752	1752	2496	1883	1883	1883	2017	2279	1752	2496	*1966*
Capture plant TPC (US$/kW)	2885	2997	3385	4264	3999	4107	3963	3587	4103	2885	4264	*3699*
Reference plant TOC (US$/kW)	2154	2154	2154		2092	2092	2092	2319	2506	2092	2506	*2195*

Table A5 (*Continued*)

Study Assumptions and Results	USDOE	USDOE	USDOE	EPRI	IEA GHG	IEA GHG	IEA GHG	GCCSI	ZEP	Range		
	2013c	2013c	2013c	2013a	2014	2014	2014	2011	2011	min	max	Mean
Capture plant TOC (US$/kW)	3547	3688	4154		4429	4545	4388	4125	4513	3547	4545	*4174*
Reference plant TCR (US$/kW)	2313	2313	2313	2990	2455	2455	2455	2501	2820	2313	2990	*2513*
Capture plant TCR (US$/kW)	3808	3956	4468	5148	5514	5659	5464	4448	5077	3808	5659	*4838*
Incremental TCR for capture (US$/kW)	1494	1643	2154	2158	3059	3204	3009	1947	2258	1494	3204	*2325*
Reference plant COE (US$/MWh)	66.4	66.4	66.4	78.8	67.7	67.9	67.7	79.5	64.2	64.2	79.5	*69.4*
Capture plant COE (US$/MWh)	111.2	116.5	126.1	130.0	137.7	141.2	137.9	118.3	100.4	100.4	141.2	*124.4*
Incremental COE for capture (US$/MWh)	44.8	50.1	59.7	51.2	70.1	73.3	70.3	38.8	36.2	36.2	73.3	*54.9*
% increase in TCR (over ref. plant)	65	71	93	72	125	131	123	78	80	65	131	*93*
% increase in COE (over ref. plant)	67	75	90	65	104	108	104	49	56	49	108	*80*
Cost of CO_2 captured (US$/t CO_2)	52	55	66	54	82	87	83	44	42	42	87	*63*
Cost of CO_2 avoided (US$/t CO_2)	64	71	85	74	108	112	110	55	52	52	112	*81*
CO_2 stored t/MWh	0.870	0.915	0.909	0.944	0.854	0.838	0.847	0.884	0.860			
CO_2 stored t/t CO_2 avoided	1.234	1.307	1.297	1.369	1.311	1.284	1.320	1.253	1.240			
Source data, uninflated costs												
T&S cost, per t CO_2 stored				10	13.01	13.06	13.01	10	0			
T&S cost, $/MWh	5.3	5.3	5.3	9.44	11.11	10.95	11.01	8.84	0.00			
Coal cost, HHV (US$/GJ)	1.55	1.55	1.55	2.37	3.12	3.13	3.12	2.61	3.25			
Reference plant COE (US$/MWh)	58.9	58.9	58.9	77.0	67.7	67.9	67.7	76.0	61.4			
Ref plant fuel contribution to COE ($/MWh)	14.2	14.2	14.2	21.9	26.6	26.7	26.6	24.0	26.5			
Ref plant non-fuel contribution to COE ($/MWh)	44.7	44.7	44.7	55.1	41.1	41.3	41.1	52.0	35.0			
Capture plant COE (US$/MWh)	100.3	105.0	114.1	126.6	137.7	141.2	137.9	113.0	96.2			
Capture plant fuel contribution to COE ($/MWh)	17.1	18.0	17.9	28.5	33.8	33.3	33.9	29.4	32.0			
Capture plant non-fuel cont. to COE ($/MWh)	83.2	87.0	96.2	98.1	104.0	107.9	104.1	83.6	64.1			
TCR/TPC factor	1.32	1.32	1.32									
TCR/TOC factor									1.125			

Note: ZEP costs adjusted to remove fuel and O&M cost inflation through the plant life.

Table A6
Current studies: SCPC Power plants with current oxy-combustion capture.

Study Assumptions and Results	USDOE	USDOE	EPRI	EPRI	EPRI	IEAGHG	Range		
	2010	2010	2011	2011	2011	2014	min	max	Mean
Case or Descriptor	S12F	S22F	Base	1	3	3			
Reference plant design									
Boiler type & coal rank	SCPC subbit	SC CFB-subbit	USC-subbit	USC-subbit	USC-subbit	SCPC-bit			
Net power output (MW)	550	550.1	657	657	657	1030	550	1030	684
Plant capacity factor (%)	85	85	85	85	85	90	85	90	86
Net plant efficiency, HHV (%)	38.7	38.9	39	39	39	42.2	39	42	39
CO_2 emission rate (t CO_2/MWh)	0.86	0.85	0.846	0.846	0.846	0.746	0.75	0.86	0.83
Capture plant design									
CO_2 capture technology	cryo oxy	cryo oxy	cryo oxy	cryo oxy	cryo oxy	cryo oxy			
Net power output (MW)	550.1	550.2	509	510	501	836	501	836	576
Net plant efficiency, HHV (%)	31	30.1	31.5	31.5	31	34.1	30	34	32
Plant capacity factor (%)	85	85	85	85	85	90	85	90	86
CO_2 capture efficiency (%)	90.8	90.6	90	90	98	90	90	98	92
CO_2 emission rate after capture (t/MWh)	0.099	0.103	0.105	0.105	0.021	0.092	0.02	0.1	0.09
CO_2 captured (Mt/yr)	4	4.06	3.57	3.58	3.89	5.48	3.57	5.48	4.1
CO_2 product pressure (MPa)	15.3	15.3	15.3	15.3	15.3	11	11	15.3	14.6
CCS energy reqm't. (% more input/MWh)	25	29	24	24	26	24	24	29	25
CO_2 reduction per kWh (%)	89	88	88	88	97	88	88	97	89
Cost Results (adjusted to 2013$)									
Cost year and currency to be adjusted to 2013$	2007 USD	2007 USD	2010 USD	2010 USD	2010 USD	2013 EUR			
Fuel cost, HHV ($/GJ)	1.09	1.09	1.77	1.77	1.77	3.11	1.09	3.11	1.76
Reference plant TCR, (US$/kW)	2,560	2,681	2613	2613	2613	2455	2455	2681	2589
Capture plant TCR, (US$/kW)	4,278	4,829	5251	5242	5372	4661	4278	5372	4939
Added TCR for capture (US$/kW)	1718	2148	2638	2629	2760	2206	1718	2760	2350
% increase in capital cost (over ref. plant)	67	80	101	101	106	90	67	106	91
Fixed charge factors (Ref/Capture)	0.152	0.152	0.125	0.125	0.125	8%/25 yrs	0.125	0.152	0.136
Reference plant LCOE (US$/MWh)	56.4	61.1	65.9	65.9	65.9	67.7	56	68	64
Capture plant LCOE w/o T&S (US$/MWh)	91.1	100.8	119.8	118.7	121.4	108.4	91	121	110
Added LCOE for capture (US$/MWh)	34.6	39.8	54	52.8	55.5	40.7	35	56	46
% increase in LCOE (over ref. plant)	61	65	82	80	84	60	60	84	72
Cost of CO_2 captured ($/t CO_2)	35	40	57	56	53	49	35	57	49
Cost of CO_2 avoided, w/o T&S ($/t CO_2)	45	53	73	71	67	62	45	73	62
CO_2 stored t/MWh	0.98	0.99	0.94	0.94	1.04	0.83	0.831	1.043	0.954
t CO_2 stored /t CO_2 avoided	1.281	1.333	1.272	1.27	1.264	1.271	1.264	1.333	1.282
CO_2 product purity (mol%)	99.98	99.98	99.99	98.7	99.99	97.9	97.9	100	99.4
AS-REPORTED COSTS:									
Fuel cost, HHV ($/GJ)	0.8208	0.8208	1.71	1.71	1.71	3.11	0.82	3.11	1.64
Reference plant LCOE (US$/MWh)	51.2	55.5	62.9	62.9	62.9	67.7	51	68	61
Ref plant fuel component of COE ($/MWh)	7.6	7.6	15.7	15.7	15.7	26.5	8	27	15
Ref plant nonfuel component of COE ($/MWh)	43.5	47.9	47.2	47.2	47.2	41.1	41	48	46
Capture plant total LCOE ($/MWh)	86.8	96.3	114.3	113.2	115.8	119.2	87	119	108
Capture plant T&S cost ($/t stored)						13			
Capture plant T&S component of COE ($/MWh)	3.6	4	0	0	0	10.8	0	11	3
Capture plant fuel component of COE ($/MWh)	9.5	9.8	19.5	19.5	19.8	32.8	10	33	18
Capture plant nonfuel part of COE ($/MWh)	73.7	82.5	94.8	93.7	96	75.5	74	96	86
Fuel costs, %COE, reference plant	14.9	13.7	25	25	25	39.2	14	39	24
Fuel costs, %COE, capture plant w/o T&S	11.5	10.6	17.1	17.2	17.1	30.3	11	30	17
After adjustments:									
Fuel costs, %COE, reference plant	18	16.5	24.8	24.8	24.8	39.2	17	39	25
Fuel costs, %COE, capture plant w/o T&S	13.9	12.9	16.8	17	16.9	30.3	13	30	18
Cost adjustment factors:									
Inflation factor to 2013 (capex+O&M costs)	1.064	1.064	1.051	1.051	1.051	1			
Inflation factor to 2013 (fuel costs)	1.328	1.328	1.035	1.035	1.035	1			
NETL real fuel cost escalation factor	1.14	1.14							
Escalate TPC to TCR (NETL ratio for SCPC)	1.3	1.3							
Ratio of COE/LCOE for SCPC	0.87	0.87							
NETL fraction of LCOE for T&S for SCPC	0.0414	0.0414							
Currency exchange rate to USD						1.301			

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