TOWARD A COMMON METHOD OF COST ESTIMATION FOR CO_2 CAPTURE AND STORAGE AT FOSSIL FUEL POWER PLANTS

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TOWARD A COMMON METHOD OF COST ESTIMATION FOR CO_2 CAPTURE AND STORAGE AT FOSSIL FUEL POWER PLANTS

A WHITE PAPER

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Abstract

There are significant differences in the methods employed by various organizations to estimate the cost of carbon capture and storage (CCS) systems for fossil fuel power plants. Such differences often are not readily apparent in publicly reported CCS cost estimates. As a consequence, there is a significant degree of misunderstanding, confusion, and misrepresentation of CCS cost information, especially among audiences not familiar with the details of CCS costing. Given the international importance of CCS as an option for climate change mitigation, efforts to improve and systematize the estimation and communication of CCS costs are especially urgent and timely. This paper recommends a path forward to achieve that goal.

Introduction

Carbon capture and storage (CCS) has been widely recognized as a potentially critical technology for mitigating global climate change [1], but its current cost is a major factor (and barrier) to its widespread use as a carbon reduction measure. Efforts are underway worldwide to develop improved, lower-cost systems for CO_2 capture and policymakers are weighing the role of CCS in national energy systems. In this environment, information on CCS costs is widely sought by individuals and organizations involved in CCS investment decisions, R&D activities, technology assessments, policy analysis, and policy-making at various levels.

Background

To address the current state of CCS costs, a workshop was convened in March 2011 at which an international group of experts from industrial firms, government agencies, universities, and environmental organizations met to share information and perspectives on CCS costs for electric power plants [2]. A major conclusion of that workshop was that there are significant differences and inconsistencies in the way CCS costs are currently calculated and reported by various authors and organizations. As a consequence, there is a significant degree of confusion, misunderstanding, and mis-representation of CCS costs in the information now available publicly. These inconsistencies hamper the ability to correctly and systematically compare the cost of different carbon capture options. They also distort comparisons between CCS and other greenhouse gas reduction measures—with potential consequences for both technology and policy developments.

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A key recommendation of the 2011 workshop was that a task force be formed to develop guidelines and recommendations for a costing method and nomenclature that could be broadly adopted to produce more consistent and transparent cost estimates for CCS applied to electric power plants. A seven-member task force was constituted in October 2011 to undertake that effort.

This White Paper is the result of the task force deliberations to date. It incorporates comments from participants at a second CCS Cost Workshop held in April 2012 [3], where the findings and recommendations in this document were first presented.

Objectives and Scope

This paper represents an international effort to harmonize the methods used to estimate and report the cost of carbon capture and storage systems at fossil fuel power plants. It recommends guidelines and procedures for CCS costing, encompassing the full chain of CCS processes including the cost impacts of any CO_2 utilization for enhanced oil recovery that results in long-term sequestration of captured CO_2. While the focus of this paper is on costing methods applicable to power plants and electric utility organizations, much of the material also applies to other industrial applications of CCS.

It should be noted that this report is not intended to suggest or recommend a uniform set of assumptions or premises for CCS cost estimates. Indeed, there are good reasons why the cost of a given technology may vary from one situation to another and from one location to another. Rather, the sole objective is to help all parties with an interest or stake in CCS costing do a better job by addressing the major deficiencies in current costing methods, especially differences in the items included in a cost analysis.

Audiences and Purposes of Cost Estimates

By way of background, and to provide context for what follows, we first briefly discuss the audiences for and 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.

Table 1. Audiences for (and sources of) CCS cost estimates [2]

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

In general, CCS cost information is typically used for two broad purposes [4]: *technology assessments* (to support decisions on technology selection, capital investments, marketing strategies, R&D priorities, and related activities), and policy assessments (to support a variety of regulatory, legislative, and advocacy activities).

Each of these categories can be further sub-divided. For example, technology assessment cost studies often seek to compare the expected costs of alternative CO_2 capture options for a specific 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 cases "technology-leveling" assumptions are often applied to maintain uniformity of system parameters (such as plant size, fuel type, capacity factor, and cost of capital), thus highlighting differences due only to CCS configurations. As a result, these studies often are poor predictors of specific project costs because they do not accurately account for the variations in site and owner specifications included in a real project.

In contrast, cost estimates for specific projects aim to provide the owner with as accurate an estimate as possible of all the project costs that must be financed. In this case the technology has already been selected, and the focus is on the many site-specific elements that affect a project's cost. For example, fuel types and resource availability may affect the configuration of a particular plant and require equipment and operations different from the configurations typically used 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 the circumstances surrounding a particular project. So too must the owner's preferences be reflected regarding contracting arrangements and risk management approaches—factors often not explicitly considered in screening studies.

This diverse set of audiences and purposes for CCS cost estimates can create a tension between the generators and users of cost information. Different audiences often evaluate information from different perspectives, while generators of the content also seek to provide cost information for various purposes. Because of differences in the objectives and approaches to cost estimation any particular cost estimate must therefore be examined and interpreted with care. A common methodology and terminology for costing, together with improved transparency of methods and assumptions, can help ameliorate these concerns.

Status of Current Costing Methods

A variety of methods underlie the landscape of reported costs for CCS. They include [5]:

- Commission a detailed engineering study
- Derive new results from a model
- Modify published values
- Use published values
- Ask an expert

In this paper our focus is on methods and assumptions used at the top rungs of this ladder. Here, a number of industrial and governmental organizations, including the Electric Power Research Institute (EPRI), the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL), and the International Energy Agency Greenhouse Gas Programme (IEAGHG) have each developed detailed procedures and guidelines to help bring a greater degree of consistency and uniformity to their own power plant and CCS cost estimates. While this is laudable and clearly necessary for certain purposes (such as comparing alternative technologies on a consistent basis), comparative studies also have revealed significant differences in the costing methods used by different organizations [4]. Taken together, the result in many cases is to confuse, rather than clarify, the cost of a particular CCS technology or process.

Organization of this Paper

The remainder of this paper presents a series of guidelines and recommendations developed by the Task Force with the goal of moving toward a common approach to CCS costing. The material is organized by six major topics that comprise a methodology for CCS costing, namely:

- Defining the scope, battery limits and design of the CCS project;
- Identifying the cost categories or elements to be included in a cost estimate based on a standardized nomenclature (terminology);
- Establishing the procedure or method to quantify each cost element;
- Defining the financial structure and economic assumptions to be employed;
- Defining the methods to calculate total CCS cost in terms of increased cost electricity and cost of CO_2 avoided; and,
- Establishing guidelines for clear reporting of CCS cost information in technical reports, published papers, and presentations.

Defining the Project Scope and Design

Any estimate of CCS cost must begin with a clear definition of the scope and boundaries (battery limits) of the project. To properly quantify the cost of a CCS system for a power plant the cost of plants with and without CCS must first be estimated. The difference between the two plant costs is then the cost of the CCS system.

Figure 1 illustrates the elements of project scope that must be specified by study authors and understood by users of CCS cost estimates. Defining an accepted scope ensures that the cost estimates for CCS projects are developed on a consistent basis that can be used for proper comparisons of alternative technologies. In cases where there may be philosophical differences in scope, such as between retrofit and greenfield plant scenarios, the design basis should still be independent of CCS technology implemented. Here we suggest the major requirements and guidelines for defining the scope of a CCS project.

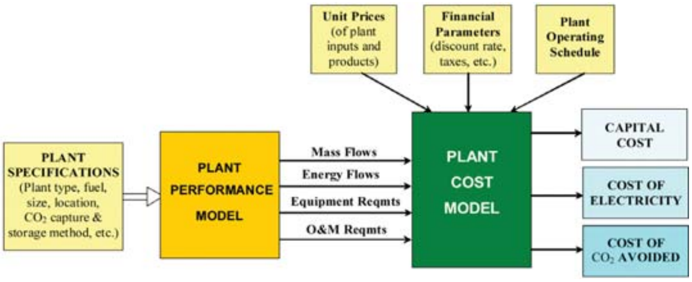

Figure 1. Framework for estimating the cost of a CCS project for a specified project scope [5]. The plant performance and cost "models" represent the methods used in a particular study to quantify the items shown in the diagram. Those methods, and the level of detail specified, vary significantly for different classes of cost estimates (see Table 6).

Required Assumptions

In order to properly isolate all costs directly attributable to CCS, the project scope must include all equipment and operations that are essential for and required by the CCS portion of the power plant. This must include components such as compressors required to achieve the pressure and purity for CO_2 disposition (which directly affect capital cost and net power production), as well as the CO_2 transport and storage system components—without which emissions of CO_2 to the atmosphere are not avoided. This paper discusses the requirements for both greenfield plants and retrofits of existing plants.

In general, the scope of a CCS cost estimate will vary on case-by-case basis and no set of standard assumptions will fit all situations. Thus, it is important to establish a well-defined list of assumptions for a particular study. This can also be important in any efforts by third-party assessors to reconcile cost differences among separate studies. In addition, it will aid in establishing the scope and battery limits for reference greenfield plants without CCS when evaluating greenfield CCS projects (as discussed below). Assumptions most likely to vary from case to case include: plant location data (elevation, ambient conditions, cooling water temperature, etc.); plant configuration (SCR, FGD present? If not, are these required for CCS?); required CO_2 capture rate, pressure and product purity; and details of the transport and storage system.

In addition to specification of the project scope, many additional assumptions related to plant design, operation and financing are required for a typical cost analysis. As discussed elsewhere, such assumptions may be subject to uncertainty, variability and bias [2–4]. Clear and full reporting of all major assumptions is thus a critical step in CCS costing. Later sections of this paper discuss this issue in greater detail.

Greenfield Plant Applications

The cost of CCS is highly dependent on the choice and design of the reference plant without CCS to which the plant with CCS is compared. For analyses of new greenfield plants the methodological approach is less straightforward than for a retrofit situation since there can be different choices for the reference plant design. A cost analysis must therefore clearly state the purpose of the analysis or the question to be addressed.

Most CCS cost studies assume the reference plant is of the same general type and design as the plant with CCS. This choice is appropriate to answer the question: How much more would it cost to add CCS to a particular type of new plant? Thus, a new PC plant with CCS would be compared to a similar new PC plant without CCS. The same would be true for other plant types such as NGCC or IGCC.

In many cases, however, a different question is more appropriate: How much more would it cost to build a certain type of plant with CCS compared to the plant that would have built if there were no requirement to reduce CO_2 emissions? In this case, the reference plant might well be a different plant type than the one with CCS. Thus, an IGCC plant with CCS might be compared to a conventional PC plant or an NGCC plant without CCS. Such comparison typically yield very different results for the incremental cost of CCS [6].

In all cases, there is also a need for care in specifying the project scope. For example, some studies of greenfield plants assume the same fuel input for plants with and without CCS, as opposed to the same *net* power output. The former case yields a smaller net power output with CCS compared to the reference plant, resulting in slightly higher CCS costs due to economy-of-scale effects [6]. In some cases, however, comparisons based on the same net output are not possible due to technology constraints (e.g., gas turbines are available only in discrete sizes, and thus not amenable to arbitrary sizing of IGCC or NGCC power plants).

The project scope also must carefully specify the performance requirements and equipment for air pollution control systems that can affect the performance and cost of the CO_2 capture technology. In Australia, for example, a new coal-fired power plant does not currently require a flue gas desulfurization (FGD) system, but a new plant that elects to install solvent-based CCS is likely to specify FGD to prevent loss of solvents and ensure CO_2 capture performance. In this case, the cost of the FGD unit should be charged to the CCS system. Even cases where an FGD unit is required for a new reference plant (as in many countries today), a higher SO_2 capture efficiency may still be required to meet the capture unit specs than is needed to comply with reference plant emissions standards. Here too, any increase in FGD (or other) cost should be charged to the CO_2 capture unit.

Finally, as noted earlier, there may be cases in which comparisons between different plant types is necessary and appropriate for a particular analysis. In such cases the study author must be especially careful to clearly specify the scope and battery limits of both the reference plant and plant with CCS.

Table 2 illustrates many of the factors required to specify the scope and battery limits of a reference power plant project. This case study was developed by DOE/NETL as part of its cost estimation for an amine-based CCS system for a post-combustion application [7]. Additional battery limit parameters for the CCS case are discussed later in this paper.

Table 2. Case study of itemized design basis to specify scope and battery limits for a grassroots "reference case" power plant without CCS [7]

- Plant size (net power output, MW)
- Plant location (country, region of country, or state)
- Site characteristics
  - Plant elevation/atmospheric pressure
  - Design ambient dry/wet bulb temperatures
  - Minimum/maximum design temperatures
  - Design ambient relative humidity
  - Site topography (i.e., assumed to be clear and level?)
- Generation technology (IGCC, PC, CFB, etc.)
  - Specific technology features
    - Gasifier type (if IGCC)
    - Steam conditions (sub-, super-, ultrasuper-critical)
    - Condenser pressure
- Fuel characteristics
  - Coal ultimate analysis (including HHV and LHV)
  - Coal ash analysis (including ash fusion temperatures)
  - Coal delivery method (rail, barge, truck, conveyor, etc)
  - Natural gas availability (near pipeline?)
  - Other start-up fuel source (i.e., distillate, etc)
- Air Emission Limits (SO_2, NO_x, particulates, mercury)
- Indoor or outdoor construction?
- Makeup water source and typical quality
- Cooling water system (mechanical draft tower,hyperbolic, once-through, air-cooled, hybrid, etc., plus cycles of concentration)
- Waste water disposal method (zero liquid discharge required?)
- Electrical system
  - Grid frequency
  - Transmission system interconnect voltage
  - Switchyard included?
  - Transmission line included? If so, how long?
- Material storage assumptions
  - Indoor vs. outdoor storage
  - Coal pile (days of storage?)
  - FGD Sorbent (days of storage?)
  - Ash/FGD solids (days of on-site storage)
- Any special noise limitations?

Retrofit Plant Applications

In contrast to cost estimates for new plants, costs for CCS retrofits of an existing power plant can be estimated on a purely incremental cost basis (before retrofit vs. after retrofit). The specification of project scope must explicitly define what changes to the existing plant are required for the retrofit, and how to account for the power and steam requirements for CCS. This will be highly specific to the plant location, mode of makeup power, and other project-specific factors. An illustrative case study of a detailed scope and battery limits developed by DOE/NETL for this case can be found in other reports [8].

Inside vs. Outside the Fence

A clear specification of project scope and battery limits defines the items that are both "inside the fence" and "outside the fence." In general, items considered to be inside the fence are those that usually fall under the management of a plant or utility company for the sole purpose of generating power. Items outside the fence can be considered to be those which a utility could potentially (but may not necessarily) share with other entities. As an example for power plant and CCS cost estimates, typical outside-the-fence items may include: rail lines; non-CO_2 pipelines (for natural gas, water, or other materials); transmission lines; other utilities; access roads; and in some cases, offsite solid waste disposal sites.

CO_2 Transport and Storage Systems

One of the biggest variations across studies of CCS costs is the treatment of the transport and storage (T&S) components of the overall CCS system. Most studies treat T&S costs as simple operating cost variables specified as a cost per tonne of CO_2. Typically, these costs are not characterized in much detail, but may vary with a few parameters such as transport distance, quantity of CO_2 transported, and type or location of storage site. A smaller number of studies employ detailed models of CO_2 pipelines and geological sequestration sites to estimate T&S costs for a particular project or scenario.

Many other studies exclude the costs of transport and storage altogether, effectively considering them as "outside the fence." While such studies are concerned only with the cost of CO_2 capture, they often give the appearance of estimating the full CCS cost via the use of terms like the increased cost of electricity and cost of CO_2 avoided—terms which technically apply only to the entire system, including T&S. In these cases, the "cost of CO_2 captured" is the more appropriate measure to report, as discussed later in this paper.

Whether included as operating costs or as part of the overall project investment (in which the power plant owner also constructs and operates the CO_2 transport and storage system), the scope and battery limits of these components must be clearly reported (preferably in a disaggregated manner). Table 3 illustrates some of the items needed to define the scope of an onshore CO_2 pipeline and geological storage system. If utilization of CO_2 for enhanced oil recovery (EOR) is also part of the project, additional items may need to be specified to clearly define the project scope. If the storage site is located offshore, CO_2 could be transported by pipeline and/or by ship, which requires a different set of specifications. Clarity of system scope also is especially important in cases where pipeline and storage networks are shared by several capture plants, as this makes cost accounting different from (and potentially more difficult than) situations with a dedicated transport and storage system.

Table 3. Illustrative scope and battery limits for a CO_2 pipeline and geologic storage site

General Specifications:

- CO_2 design flow rate, actual expected flow rate during operation, and capacity factor
- CO_2 purity (including maximum concentrations of key impurities such as water, non-condensable gases, O_2, HSE hazardous compounds such as H_2S, CO, SO_x, NO_x)
- CO_2 pressure and maximum temperature at plant gate

Pipeline Transport (onshore):

- Transport distance
- Required CO_2 pressure and temperature at storage site well-head
- Routing
- Topography along the route (e.g. bedrock, flat or hilly terrain)
- Numbers of road and river crossings (e.g. micro-tunneling)
- Maximum and minimum allowed CO_2 pressure
- Pipeline diameter, steel quality and wall thickness
- Internal and external corrosion protection
- Booster compressors and/or pumps
- Rights of way (e.g. difference between agricultural areas, sparsely populated or uninhabited areas and populated areas)
- Pigging
- Other factors for pipeline networks (e.g., collection/distribution systems), if applicable.

Geologic Storage Site (onshore):

- Type of geologic storage site (e.g., saline aquifer, depleted oil/gas field, EOR site) and its structural setting (e.g., domal, anticline, flat)
- Design life (years)
- Initial screening of multiple sites followed by characterization of the selected site(s) needed to establish/estimate:
  - Field/reservoir capacity (Mt stored CO_2)
  - Number of injection wells needed
  - Well depth
  - Geographic extension
  - Legacy wells (if depleted oil/gas field)
  - Number of new exploration and observation wells
- Well class (e.g., in the U.S., Class VI for storage and Class II for EOR)
- Requirements for monitoring, measurement and verification (MMV) during periods of site characterization, injection/operation, and post-closure (e.g., as specified in the U.S. for well Class VI) including:
  - Legal/regulatory requirements for objectives of monitoring (as in EU), as well as more specific requirements, e.g., for MMV technologies (2D, 3D, 4D seismic, monitoring wells), their spatial extent and density, and frequency of measuring campaigns.
  - Requirements imposed by industrial stakeholders
- Decommissioning of injection wells and monitoring wells (after post-closure)
- Liability transfer (to authorities after approved closure of operation)

Defining Cost Categories for CCS Cost Estimates

Give the current diversity of power plant and CCS costing methods documented earlier, a major goal of our task force was to seek a "common language" that all organizations could adopt for CCS and related power plant cost estimates. Toward that end, we undertook a systematic review and comparison of the terminology used by five leading organizations in this field: DOE/NETL, EPRI, IEAGHG, Europe's Zero Emissions Platform (ZEP) and the Global CCS Institute (GCCSI) [9–13]. All of these organizations were represented on our task force. We also compared the methodology used by each group to calculate total capital costs and O&M costs. As a result of deliberations, the Task Force unanimously arrived at a recommendation for a common nomenclature (terminology) and general methodology for CCS cost estimates, as summarized below. For the most part, the recommended nomenclature employs terms and procedures already in use by one of more of the organizations surveyed.

Elements of Capital Cost

Appendix A (Table A1) sets out and compares the nomenclature and costing method employed by each of the organizations for aggregates of capital cost elements, which employ terms such as "bare erected cost" and "total plant cost." While there are a number of similarities across the organizations surveyed, the methods also vary with regard to their terminology for capital cost aggregates as well as for the items included in similarly named terms. Appendix A (Table A2) provides additional details showing the specific cost elements included in each category across the five organizations.

Our recommendations for resolving the differences in nomenclature and methodology for capital cost estimates for CCS (or other power plant systems) are summarized in Table 4. The first column names the various cost elements that must be quantified. The second column lists the aggregate cost items that are often used in itemizing cost results. The final column offers additional explanations of several items.

Elements of O&M Cost

Our analysis of the terminology used to characterize operating and maintenance (O&M) costs showed that for the most part the approaches surveyed are consistent in these cost elements, although some differences arise (such as whether some maintenance cost should be variable rather than fixed). The nomenclature recommended by the Task Force is summarized in Table 5. Again, this includes aggregates of certain costs (in this case, fixed and variable costs) as well as individual cost elements.

Other Cost Elements

When combining capital and O&M costs into an overall cost of electricity (COE) or other measure of total cost several additional terms arise. These terms and their use in cost estimates are discussed later in this paper.

Table 4. Recommended nomenclature for power plant capital cost estimates

Capital Cost Element to be Quantified	Sum of All Preceding Items is Called:	Comments
Process equipment Supporting facilities Labor (direct & indirect)		Includes all materials and sales tax (if applicable) On-site facilities needed for the project
	Bare Erected Cost (BEC)	
Engineering services		
	Engineering, Procurement & Construction (EPC) Cost	An optional intermediate cost measure of use to some organizations
Contingencies: • process • project		
	Total Plant Cost (TPC)	
Owner's costs: • Feasibility studies • Surveys • Land • Insurance • Permitting • Finance transaction costs • Pre-paid royalties • Initial catalyst & chemicals • Inventory capital • Pre-production (startup)		This group of owner costs includes items common to a plant or process installation (although the magnitude of cost may vary from case to case)
• Other site-specific items unique to the project (such as unusual site improvements, transmission interconnects beyond busbar, economic development incentives, etc.)		These owner costs include items that are unique to a particular project. They may include items sometimes referred to as "outside the battery limits" (OSBL).
	Total Overnight Cost (TOC)	
Interest during construction (IDC) Cost escalations during construction		
	Total Capital Requirement (TCR)	

Table 5. Recommended nomenclature for power plant O&M costs

Operating & Maintenance Cost Item to be Quantified	Sum of All Preceding Items is Called:	Comments
Operating labor		
Maintenance labor		
Administrative & support labor		
Maintenance materials		
Property taxes		
Insurance		
	Fixed O&M Costs	
Fuel		
Other consumables, e.g.: • catalysts • chemicals • auxiliary fuels • water		Includes all materials used in proportion to kWh generated (itemized for each project)
Waste disposal (excl. CO_2)		
CO_2 transport		May also be capital cost items, depending on project scope
CO_2 storage		
Byproduct sales (credit)		
Emissions tax (or credit)		Fee paid (or credit received) per unit of emissions, with or without CCS (if applicable)
	Variable O&M Costs	

Quantifying Elements of CCS Cost

Given a common nomenclature, the question then remains as to how to quantify each cost element. Appendix B (Tables B1 and B2) presents a detailed comparison of the methods currently used or suggested by each of the organizations surveyed. The following sections briefly elaborate on a few of the major cost areas of Tables 4 and 5.

Bare Erected Cost

In all cases, the core of a cost estimate is the Bare Erected Cost (BEC), which is quantified based on an itemized list of all process equipment required for a project, together with the estimated cost of all materials and labor needed to complete the installation. In terms of methodology, all organizations surveyed in this paper call for such information to be compiled by a knowledgeable engineering contractor or power plant construction firm. The cost of additional supporting facilities needed for the project also are either itemized by the contractor or estimated as a percentage of the process costs, to yield the BEC.

Additional fees for engineering services are typically estimated as a percentage of the BEC. The sum of these fees plus BEC yields the Engineering, Procurement and Construction (EPC) cost, an intermediate value used by some organizations (such as ZEP) in capital cost estimates.

The level of detail available to quantify the BEC or EPC cost of a particular project varies with the "class" of the cost estimate. Organizations including EPRI and the Association for the Advancement of Cost Engineering International (AACE) have defined several cost estimate classes ranging from "simplified" to "finalized" [10, 13]. As illustrated in Table 6, these classes require increasing levels of effort (and expense) as a project moves from concept and preliminary design to the final stages of construction. (Note, however, that here too there are inconsistencies in nomenclature that can cause confusion: EPRI classes 1–4 are increasingly detailed while AACE classes 1–4 are increasingly simplified.)

Table 6. EPRI categories and attributes of different levels of cost estimates [10]

Item	Design Estimate Effort	Project Contingency Range (%)[a]	Design Information Required	Cost Estimate Basis		
				Major Equipment[b]	Other Materials[b]	Labor
Class I (Similar to AACE Class 5/4)	Simplified	30–50	General site conditions, geographic location and plant layout; Process flow/operation diagram; Product output capacities	By overall project or section-by-section based on capacity/cost graphs, ration methods, and comparison with similar work completed by the contractor, with material adjusted to current cost indices and labor adjusted to site conditions.		
Class II (Similar to AACE Class 3)	Preliminary	15–30	As for Type Class I plus engineering specifics, e.g., Major equipment specifications; Preliminary P&I (piping and instrumentation) flow diagrams	Recent purchase costs (including freight) adjusted to current cost index	By ratio to major equipment cost on plant parameters	Labor/material ratios for similar work, adjusted for site conditions and using expected labor rates
Class III (Similar to AACE Class 3/2)	Detailed	10–20	A complete process design; Engineering design usually 20–40% complete; Project construction schedule; Contractual conditions and local labor conditions	Firm quotations adjusted for possible price escalation with some critical items committed	Firm unit cost quotes (or current billing costs) based on detailed quantity take-off	Estimated man-hour units (including assessment) using expected labor rate for each job classification
Class IV (Similar to AACE Class 1)	Finalized	5–10	As for Class III, with engineering essentially complete	As for Class III, with most items committed	As for Class III, with material on approx. 100% firm basis	As for Class III, some actual field labor productivity may be available

[a] Percentage of the total of process capital, engineering and home office fees, and process contingency.

[b] Pertinent taxes and freight included.

Contingency Cost

These are miscellaneous capital costs expected as an actual project moves toward completion. As seen in Table 4, two types of contingency costs are estimated.

The *process contingency* accounts for the level of maturity of a particular process or component within the plant. It attempts to quantify the additional capital costs expected to be incurred in a real project as the process matures [10]. It is typically quantified as a percentage of the currently estimated process capital cost of a particular technology, with higher percentages applied to individual components or sub-systems of processes at earlier stages of development, as shown in Table 7. Most of the advanced CO_2 capture systems now under development would fit in the first three categories listed in Table 7.

Table 7. Guidelines for process contingency costs [10, 14]

Technology Status	Process Contingency (% of Associated Process Capital)
New concept with limited data	40+
Concept with bench-scale data	30-70
Small pilot plant data	20-35
Full-sized modules have been operated	5-20
Process is used commercially	0-10

The *project contingency* is an additional factor that accounts for the cost of equipment or other costs that would be identified in a more detailed design of a definitive project at a particular site. Thus, it relates to the different classes of cost estimates described earlier in Table 6. That table shows suggested ranges of project contingency cost for each class of estimate, with higher percentages applied to preliminary and simplified design studies. In general, the project contingency applies to the overall project and not to individual plant components. After applying the appropriate contingency costs, the accuracy of the resulting cost estimate is expected to lie within a specified confidence interval (e.g., ±30%) which varies with the cost estimate class [10, 13].

Owner's Cost

This category refers to a collection of capital cost items common to most power plant projects, plus other items that are unique to a particular project. These costs are not included in a typical BEC or EPC cost estimate and thus are known simply as owner's costs. Collectively, they constitute a significant portion of the overall capital cost of a project. However, the specific items can vary considerably across different cost studies, with some studies excluding owner's costs altogether. For this reason the Task Force has enumerated a recommended list of items to be included in a cost estimate, with any additional items to be explicitly specified in any cost study. Table B2 (Appendix B) shows the methods used to quantify each item listed. These methods are roughly similar across the several organizations surveyed.

Operating and Maintenance Costs

As elaborated in Table 5, O&M costs are grouped into two categories of fixed and variable costs. The latter costs are for items such as fuel and pollution control system chemicals whose use is directly proportional to the amount of electricity generated. These costs are calculated in a straightforward fashion as the product of quantity times unit cost or price. Fixed costs are generally independent of plant utilization and are dominated by labor and maintenance costs, although some organizations treat maintenance materials as a variable cost item. These and other items are estimated by the methods shown in Table B2, which are roughly similar across the several organizations surveyed.

Defining Financial Structure and Economic Assumptions

Once the elements of capital and O&M cost are quantified they are commonly combined to report an overall cost of the plant or project. This requires specification of a financial structure for the project together with related economic assumptions. While there is a reasonable degree of consistency across organizations in the terminology used for these calculations, there is considerable variation in the assumed values of each quantity. This alone can result in significant differences in reported overall cost, all else being equal. Here we briefly discuss some of the major assumptions that must be clearly identified and reported in any CCS cost estimate.

Constant vs. Current Cost Values

Any cost estimate must first declare whether reported costs are based on constant (real) or current (nominal) values. The latter includes the effect of general inflation while the former excludes inflation. Until recently, reported CCS cost estimates were based almost entirely on a constant-dollar analysis [1]. (We use "dollar" here as a general term to represent any currency.) Since 2007, however, cost estimates by DOE/NETL have been based on a current dollar analysis with an assumed inflation rate of about 3% per year. This significantly increases the value of overall costs relative to an equivalent constant-dollar analysis, which is the method employed by EPRI, IEAGHG and ZEP.

The choice of method depends mainly on the purpose of the analysis. In costing an actual project, the total "as spent" cost may be preferred by plant owners and utility regulators, thus favoring nominal or current-dollar costs. On the other hand, for preliminary analyses and technology comparisons, a constant-dollar cost is usually preferred since it is more transparent and yields the same relative results as a current-dollar analysis. It also presents a clearer picture of real cost trends, avoiding potential distortions that can result from inflation effects over many decades.

Although there is no "correct" choice of cost convention, the consensus of the Task Force is that for purposes of technology comparisons a constant-dollar analysis of CCS costs is more transparent, and less likely to be misunderstood, than current-dollar costs with an embedded long-term inflation rate assumption that may not be readily apparent. In either case, however, the critical need is for study authors to clearly state the basis for their calculations and reported costs. Our review of recent studies indicates a need for greater transparency in that regard.

Financial Parameters and Escalation Rates

The choice between a constant-dollar or current-dollar analysis directly affects the value of the interest rate or "weighted cost of capital" used in a financial analysis. One common approach uses this value together with a project lifetime assumption to calculate a "fixed charge factor" (FCF, also known as the capital charge factor or rate). This fraction, when multiplied by the total capital cost of a project, yields the uniform annualized capital expense that must be recovered via revenue from electricity sales (along with annual operating and maintenance expenses). Values of FCF also depend on whether the assumed interest (or discount) rate is considered on a before-tax or after-tax basis. Details of the methods and assumptions used by different organizations to calculate fixed charge rates (or equivalent terms) are available elsewhere [9–13].

Some cost estimates also include real cost escalation rates for one or more cost elements. These might include a real escalation of capital costs during plant construction, and/or real increases in the cost of fuel or other O&M cost elements during plant operation. Different numerical values may apply to different items.

While cost escalation factors can be important to avoid underestimating actual costs, care must be taken in selecting appropriate numerical values since even a small value of real cost escalation can produce a large change in the cost of an item over the life of project. For example, a 2% annual increase over 30 years would nearly double the cost of an item in real terms. When coupled with an inflation rate assumption in a current dollar analysis the change in cost over time is even more pronounced. Since such impacts often are not apparent, the key message here is that the transparency of all financial and escalation rate assumptions is essential to clear understanding of any CCS cost estimate.

Calculating Key Cost Metrics

In this section we discuss several cost metrics widely used in CCS studies: the levelized cost of electricity (LCOE), the first-year cost of electricity, the cost of CO_2 avoided, and the cost of CO_2 captured. In particular, we call attention to methodological and other issues that impede or preclude the consistent use of cost measures in different studies.

Levelized Cost of Electricity

The term "levelized cost of electricity" (LCOE) is widely used to define a characteristic unit cost of electricity generation (in $/MWh) over the life of a power plant. As noted by the IEA and OECD Nuclear Energy Agency (IEA/NEA) in their joint electricity technology studies [16], "the notion of levelized costs of electricity is a handy tool for comparing the unit costs of different technologies over their economic life."

The LCOE reflects all costs needed to build and operate a power plant over its economic life, normalized over the total net electricity generated. The LCOE value thus draws on the various inputs discussed in the previous sections, i.e., the process modeling of the system, together with the economic and financial inputs needed to create an economic assessment. As discussed below, the LCOE also is used to calculate the cost of CO_2 avoided.

Details of the LCOE calculations are discussed in Appendix C. While the procedures and assumptions employed by different organizations can and do vary, all approaches rely on "present value" or "discounted cash flow" calculations in order to place expenditures that occur in different time periods on a common value basis. The discount rate used in LCOE calculations is usually a pre-defined rate of return required to cover equity and debt costs. Risk and uncertainty also can be incorporated by altering the nominal assumptions for financial parameters, electricity production and cost elements.

Thus, whether the underlying costs are in real or nominal dollars, whether the power plant output (production) is constant or varying over time, the LCOE is a constant $/MWh value for each and every MWh produced. This allows for comparisons across technologies with different flows and levels of expenditures and output over time. In principle, LCOE thus provides a transparent and useful measure of overall plant cost as long as the terms are defined and assumptions clearly set out.

Despite a common methodological underpinning, different assumptions and definitions hamper direct comparisons of LCOE values across organizations and studies. The IEA/NEA definition is perhaps the broadest and most flexible of those surveyed [16]:

> *LCOE is equal to the present value of the sum of discounted costs divided by total production adjusted for its economic time value.*

In contrast, the LCOE is defined by DOE/NETL as [11]:

> *the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, assuming that the cost of electricity (COE) escalates thereafter at a nominal annual rate of 0%, i.e., that it remains constant in nominal terms over the operational period of the power plant.*

This approach yields differ numerical results (and is conceptually different) than those reported by other organizations such as EPRI [15]. However, such differences may not be apparent to the casual reader, despite the fact that DOE/NETL reports provide sufficient detail to allow informed readers to adjust the underlying assumptions and LCOE values to a different basis. Similar problems arise when comparing studies by other organizations or authors. In general, direct comparisons of LCOE values across studies are inhibited by differences in how nominal or real values are treated, how escalation rates are incorporated (either explicitly or implicitly), and what financing mechanisms and parameter values are assumed.

Once again, there is no "correct" set of assumptions for calculating an LCOE in all cases. Thus, the importance of transparency is again underscored. While numerical results may differ across studies, for purposes of technology evaluations a given method will yield the same qualitative rankings if applied consistently. However, in order to compare results across studies clear reporting of assumptions and calculation methods is essential. Transparency is particularly required for the:

- Breakdown of financing and interest rates, including the rates applied during and after the construction period
- Inflation and cost escalation rates
- Duration of plant construction
- Levelization period; and
- LCOE calculation method.

The equivalence of costs across studies cannot be identified without the above information—and if provided, this data can allow LCOEs to be recalculated using alternative assumptions, if desired

First-Year Cost of Electricity

In recent years, some organizations, most notably DOE/NETL, have reported CCS costs not only in terms of LCOE, but also as a "first-year cost of electricity"—denoted simply as COE. This measure employs the same calculation procedures outlined in Appendix C for LCOE for the common assumption of constant parameter values over the life of a plant (see Appendix C, Equation C5). In this case, however, the rates for general inflation and real cost escalation are effectively zero when applied to the first year of operation. The numerical result for COE is then identical to the LCOE value for a constant-dollar analysis (zero inflation) with zero cost escalation rates for all O&M costs, including fuel cost.

Although this is called the first-year COE, readers should understand that the common assumption of constant parameter values over the plant life means that some cost-related variable are not truly at their first-year values. For example, the capacity factor (and thus, the electricity produced and sold) during the first year or two of coal plant operation is typically much lower than in later years [5]. In this case, the common assumption of a higher "typical" value for CF underestimates the true first-year cost per MWh generated. In the same fashion, other parameter values that vary from year to year must be evaluated with care if a true first-year cost is desired.

Cost of CO_2 Avoided

Using CO_2 emission rates and LCOE values for plants with and without CCS, the "cost of CO_2 avoided" is the overall cost measure most commonly reported in CCS cost studies [1]. It compares a plant with CCS to a "reference plant" without CCS, and quantifies the average cost of avoiding a unit of atmospheric CO_2 emissions (usually, but not always, based on a metric ton, or tonne) while still providing a unit of useful product (e.g., one MWh in the case of a power plant). Mathematically it can be defined as:

$$\text{Cost of CO}_2\text{ Avoided (\$/tCO}_2) = \frac{(\text{LCOE})_{ccs} - (\text{LCOE})_{ref}}{(\text{tCO2/MWh})_{ref} - (\text{tCO2/MWh})_{ccs}} \quad (1)$$

where, LCOE = levelized cost of electricity generation ($/MWh), tCO_2 /MWh = CO_2 mass emission rate to the atmosphere in tonnes 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.

Especially important is the need to clearly specify the reference plant to which the plant with CCS is being compared, as discussed earlier under project scope. Similarly, the cost of CO_2 avoided must include the full chain of CCS processes (capture, transport and storage) since emissions to the atmosphere are not avoided unless/until the captured CO_2 is permanently sequestered.

Cost of CO_2 Captured

Other papers have elaborated on the importance of clearly distinguishing the CO_2 avoidance cost from other cost measures that have similar units (dollars per tonne CO_2) but very different meanings [5]. A prominent example is the cost of CO_2 captured, which is frequently reported in cost studies. This measure excludes the costs of CO_2 transport and storage since its purpose is to quantify only the cost of capturing (producing) CO_2 as a commodity sought by commercial markets (such as the food industry for use in beverages and the petroleum industry for enhanced oil recovery). In addition, the sizeable energy requirements for CCS means that additional CO_2 must be produced (and captured) per net MWh of electricity generated. Numerically, therefore, the cost per tonne of CO_2 captured is always less than the cost per tonne avoided.

Guidelines for Reporting CCS Costs

The preceding sections have described the need to use well-defined design bases and economic assumptions when analyzing CCS costs. It is important this information is clearly and concisely reported as far as is possible to enable readers to have a thorough understanding of the analyses and to enable them to compare results between reports and to adjust to other design and economic bases if required. How extensively information is reported will depend in part on limitations of the reporting medium. To aid in that process, our Task Force has developed reporting guidelines for presentations, papers, and technical reports as summarized in Appendix D and discussed briefly below.

Presentations

Presentations on CCS costs usually need to be most concise. However, it is important that presentation slides contain key information to avoid misunderstandings or the use of results out of context. Deciding how much information to include in presentation slides thus involves a balance, which will depend on the nature of the audience and the time available. Table 8, extracted from the more detailed table in Appendix D, presents our recommendations of some the most important information that should be included.

Technical Reports

Availability of space is not usually a constraint in detailed technical reports on CCS costs. Such reports should therefore include as much detail as possible regarding the technical design basis and economic assumptions that have been used. More concise information needs to be included in the executive summaries of such reports. The recommendations given in Table 8 for presentations would be appropriate for report summaries.

Journal and Conference Papers

The amount of space available for authors in journal and conference papers and presentations is usually more limited than in detailed reports (e.g. typically 6-20 pages in total), so it may be necessary to concentrate on reporting only the most significant information. Nevertheless, this information needs to be sufficient to enable reasonable comparisons to be made with cost estimates prepared by others. Appendix D summarizes our recommendations.

Examples of Good and Bad Practice

As discussed throughout this paper, CCS plant performance and cost information depends strongly on input data and assumptions. It is therefore important that when readers are presented with information on CCS costs they are also given the most important assumptions.

Figure 2 is an example of a presentation of levelized costs of electricity for power plants with and without CCS, which is similar to charts included in many reports and presentations. The chart clearly shows the levelized costs of electricity generation by plants with and without CCS using different technologies and fuels but no information is included on the assumptions used in the derivation of the costs. There is a significant risk that a chart such as this could be used out of context, for example to compare costs of CCS and other generation technologies which may have been derived using significantly different assumptions.

Figure 3 is an alternative, which also clearly shows the overall electricity costs but which also includes information on key input assumptions and a breakdown of the LCOE. The reader could use the cost breakdowns to get an indication of the effects of using different assumptions for fuel or CO_2 transport and storage costs for example, which are often subject to high uncertainty. Numerical values could be included on each of the portions of the bars to simplify the derivation of sensitivities but depending on the context of the presentation this may be considered to be an excessive amount of information. Similarly, sensitivities to input parameters also could be presented explicitly in separate charts if required, for example as a series of bars, as a line graph or as a Tornado diagram. The type of capture technology (e.g. post-combustion MEA) could also be specified in the chart if required.

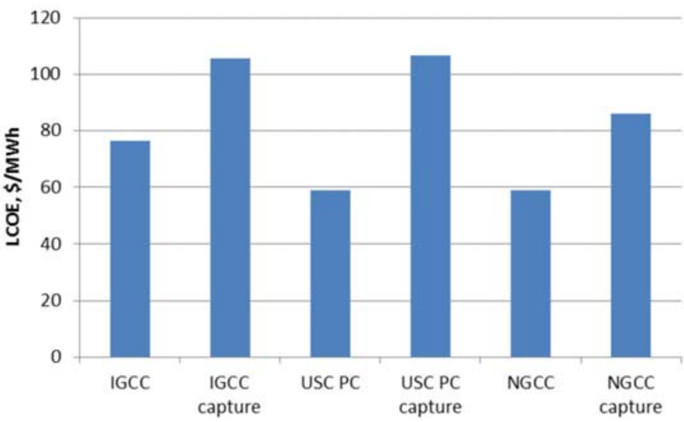

Figure 2. An illustrative example of "bad" practice: Presentation of total cost results with none of the key assumptions

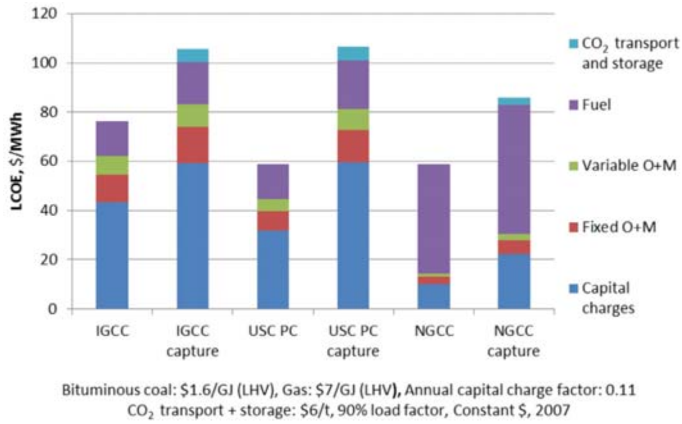

Figure 3. An illustrative example of "good" practice: Presentation of cost results with key assumptions and breakdown to show additional details

While the examples here are for summary presentations, the same guidelines apply to technical reports and journal or conference papers. Appendix E shows some additional examples of good practice for conveying the results of CCS cost analyses.

Conclusions

This paper has shown that there are significant differences in the methods currently used by different organizations to estimate the cost of carbon capture and storage (CCS) systems for fossil fuel power plants. Many of these differences are not readily apparent in publicly reported CCS cost estimates, and the existence of such differences hampers rather than helps efforts to properly assess CCS costs and their relationship to other greenhouse gas control measures. Given the international importance of CCS as an option for climate change mitigation, efforts to systematize and improve the estimation and communication of CCS costs are thus especially urgent and timely. The CCS Costing Methods Task Force was formed to address this challenge, bringing together an international group of experts from industry, government and academia.

Table 8. Guidelines for reporting CCS cost assumptions in presentations

Information Needed	Presentations
Power plants without CO_2 capture (reference/baseline plants)	
Fuel type (class of hard coal, lignite, gas)	X
Power plant type (e.g. PF, BFB, CFB or NGCC)	X
Plant capacity (MW electric)	
– Gross (to define boiler or gas turbine size class)	X
– Net	X
Environmental control requirements (for major pollutants)	X
Net electric efficiency and/or heat rate (state if based on LHV or HHV)	X
CO_2 emissions (per MWh net electricity or per MWh fuel; state if LHV or HHV)	X
In addition to the above for power plants with CCS	
Type of power plant CO_2 capture; e.g. post-combustion, oxy-combustion, IGCC with pre-combustion	X
Capture technology (e.g. MEA, advanced amine, chilled ammonia, Selexol, solid absorption/desorption process, etc.	X
Captured CO_2 per MWh net electricity or per MWh fuel (state if LHV or HHV) or "CCS capture rate" (% of produced CO_2)	X
Capital costs	
Type of plant, e.g. first-of-a-kind, N^{th}-of-a-kind	X
Year and currency of cost estimate	X
Contingencies (sum of process and project contingencies)	X
Resulting "Total Overnight Cost"	X
– Construction cost escalation rate (if applied)	X
O&M costs (excluding CO_2 transport & storage)	
Total fixed and variable costs (in appropriate units)	X
CO_2 emissions cost (or tax) per tonne (if included)	X
CO_2 transport & storage costs	
Overall net cost per tonne of CO_2 stored, with breakdown into transport and storage (if available).	X
Cost of electricity (COE)	
State whether levelized or first-year (or other)	X
Method/approach used; also state if calculation uses real (constant money values) or nominal (current money values)	X
Interest rate/discount rate/WACC; also state if real or nominal	X
Inflation and other price escalation rates (if applied)	X
Economic lifetime	X
Load factor/equivalent full load operation hours	X
– Fuel prices per GJ or MWh fuel (state HHV or LHV)	X
CO_2 avoidance cost	
State and define reference plant case	X

As a result of this effort, this paper recommends a path forward to harmonize the various costing methods now in use, beginning with a common nomenclature (terminology) for CCS cost elements and the method of aggregating them to arrive at the total cost of a project. The recommended approach draws on the methodologies now used by the Electric Power Research Institute (EPRI), the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL), the International Energy Agency Greenhouse Gas Programme (IEAGHG), and the European Zero Emissions Platform (ZEP). While these methods share many common features there are also notable differences that the Task Force has worked to reconcile. Tables 3 and 4 shown earlier summarize the resulting recommendation for a common method of evaluating the capital cost (Table 3) and O&M cost (Table 4) of a power plant or CCS project.

Even with a common language, however, many of the details and assumptions required for a CCS cost estimate vary from one project to another and cannot be standardized. Thus, clear communication of key assumptions is essential for avoiding confusion and misunderstanding about the context for results of a given cost study. Toward that end, much of this paper is devoted to identifying key areas where communication is especially important. This includes assumptions and definitions of the project scope and design parameters; financial and economic parameters; method of quantifying various cost elements; and methods to calculate overall cost values such as the increased cost of electricity and the cost of CO_2 avoided. By way of guidelines, the final section of this paper presents "checklists" developed by the Task Force of information that should be conveyed in technical reports, journal-length papers, and conference presentations.

As part of its deliberations, the Task Force also considered whether there might be value in future efforts in two areas: (1) further refinement of methods to estimate and report the cost of technologies currently in the early (pre-commercial) stages of development; and (2) compilation of a set of case study power plant and CCS system designs and cost-related parameter assumptions that can serve as benchmarks for future cost studies of CCS technologies. Feedback is sought from the various audiences for (and sources of) CCS cost estimates regarding the value of these or other possible future tasks to promote a common approach to CCS costing.

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Appendix A. Comparison of Capital Cost Categories and Elements

Tables A1 and A2 present details of the aggregation methodology and cost elements currently employed by each of the five organizations surveyed, according to the information in published reports [9–13].

Table A1. Capital cost nomenclature and aggregation method

DOE/NETL	EPRI	IEA-GHG	ZEP	GCCSI
BEC	BEC	Installed costs		BEC
+	+	+		+
EPCC	EPCC	EPCC	EPCC	EPCC
+	+	+	+	+
Contingencies	Contingencies	Contingencies	*Owner's costs (includes contingencies)*	Contingencies
Total Plant Cost	**Total Plant Cost**	**Total Plant Cost**		**Total Plant Cost**[1]
+				
Owner's costs				
Total Overnight Cost			**Total Investment Cost**	**Total Overnight Cost**[1]
				+
				Owner's costs
+	+	+		+
IDC	*AFUDC*	*IDC*		*IDC*
+	+			
escalation	escalation			
	Total Plant Investment			
	+	+		
	Owner's costs	*Owner's costs*		
Total As-Spent Capital	**Total Capital Requirement**	**Total Capital Requirement**		**Total Installed Cost**

[1]. Total Overnight Cost is used interchangeably with Total Plant Cost in tables and discussions in Ref. [13].

Table A2. Capital cost elements by cost category

Cost Categories	DOE/NETL	EPRI	IEA-GHG	ZEP	GCCSI
BEC					
	Process equipment Supporting facilities	Total constructed costs of all onsite processing and generation units broken into:	Direct materials Construction costs	Items not identified	Process equipment Supporting facilities;
	Labor	Direct field labor, Factory equipment,	Other costs		Labor; Materials
		Field materials & supplies			
EPC cost					
	EPC services	Engineering and home office fees overhead, including fees	EPC services	Percentage only identified	Engineering and home office overhead, including fees
Contingencies					
	Process	Process	Process	Items not identified	Process
	Project	Project	Project		Project
Owner's costs					
	Pre-paid royalties	Pre-paid royalties		Items not identified	
			Feasibility study costs;		
			Surveys;		Legal fees;
	Land costs		Land purchases		Right of way/ land acquisition;
			Permitting;		Permitting;
	Financing costs		Financing costs		Project financing costs including currency risk etc;
					Insurance (builder's risk, warranties etc);
	Inventory capital (e.g., fuel storage, consumables, and spare parts)	Inventory capital (e.g., fuel storage and consumables)	Working capital (includes inventories of fuel and chemicals);		Inventory capital, including spare parts
			Spare parts;		
	Pre-production (startup) costs	Startup (or pre-production) costs	Startup costs		Start-up & consumables used during start up (fuel, reagents etc);
		Initial charges for catalysts and chemicals	Initial charges for catalysts and chemicals		Environmental reports and mitigation costs
	Other owner's cost		Other misc. costs		Other costs such as site security, owners eng'g. staff, etc.

Appendix B. Comparison of Methods to Quantify Cost Elements

*Table B1. Methods to quantify elements of capital cost**

Capital Cost Element	EPRI	DOE/NETL	IEAGHG	GCCSI
Process equipment cost	Estimated by contractor from a detailed equipment list	Estimated by contractor for each plant using the company's in-house database and conceptual estimating models for each of the specific technologies. This database and the respective models are maintained by the contractor as part of a commercial power plant design base of experience for similar equipment in the contractor's range of power and process projects. A reference bottoms-up estimate for each major component provides the basis for the estimating models.	Estimated by contractor	Estimated by contractor
Supporting facilities cost	Typically estimated as 5–20% of process equipment cost	Estimated by contractor	Estimated by contractor	Estimated by contractor
Labor cost (direct & indirect)	Estimated by contractor from a detailed equipment list	Labor costs are based on plant location (often Midwest, Merit Shop, or other study region). Labor is based on a 50-hour work-week. No additional incentives such as per-diems or bonuses are included to attract craft labor.	Estimated by contractor	Estimated by contractor based on United States Gulf Coast as the reference location
(BEC)	***Sum of the above***			
Engineering services cost	Typically estimated as 7–15% of process capital cost	Engineering and Construction Management are estimated at 8-10% of BEC.		
(EPC)	***Sum of the above***			
Process Contingencies	Guidelines based on state of technology development as a percentage of BEC. Five levels range from 0–10% for commercial process, to 40+% for a new concept with limited data.	Process contingencies are estimated using best engineering judgment, taking into consideration AACE International Recommended Practice 16R-90, which provides guidelines for estimating process contingency based on EPRI philosophy	Most of the processes which IEA GHG assesses are at or approaching commercial introduction with processes/ equipment that are reasonably well defined. For process at an early stage of development whose design, performance and costs are highly uncertain an additional process contingency should be added to allow for unforeseen cost increases during process development. The appropriate level of process contingency shall be agreed between the contractor and the IEA GHG study manager.	

Table B1 (continued). Methods to quantify elements of capital cost

Capital Cost Element	EPRI	DOE/NETL	IEAGHG	GCCSI
Project Contingencies	Guidelines based on design estimate class as a percent of EPC + process contingency. Four classes range from 5–10% for a finalized design to 30–50% for simplified design.	Project contingencies were added to the EPCM capital accounts to cover project uncertainty and the cost of any additional equipment that would result from a detailed design. The contingencies represent costs that are expected to occur. Each BEC account was evaluated against the level of estimate detail and field experience to determine project contingency. AACE 16R-90 states that project contingency for a "budget-type" estimate (AACE Class 4 or 5) should be 15 to 30 percent of the sum of BEC, EPC fees and process contingency. This was used as a guide but some project contingency values outside of this range occur based on the Contractor's in-house experience.	A project contingency shall be added to the capital cost to give a 50% probability of a cost over-run or under-run. Contractors shall add a level of contingency which in their judgment is sufficient to achieve this. In the absence of better information from the study contractor the default value for project contingency should be 10% of the installed plant cost (i.e. the Total Plant Cost excluding contingency).	
(TPC)	***Sum of the above***			
Owner's costs:		The estimation method follows guidelines in Sections 12.4.7 to 12.4.12 of AACE International Recommended Practice No. 16R-90. (In some instances NETL has adopted the EPRI TAG estimates, which are very similar.) Detailed items set out in Exhibit 2-15 (Bituminous Coal study), pp 50–51	7% of TPC	For technology assessment studies, 15% of TPC is used
– Feasibility studies	[not included]	Included in "Other Site-Specific Items"		
– Surveys	[not included]			
– Land	Nominal values per acre are suggested for Urban ($7600), Rural ($1400), Nonproductive ($350) land	$3,000/acre (300 acres for IGCC and PC, 100 acres for NGCC)		
– Permitting	[not included]	Included in "Other Site-Specific Items"		
– Finance transaction costs	[not included]	2.7% of TPC		
– Pre-paid royalties	0.5% of process capital for proprietary processes if royalty is uncertain	Any technology royalties are assumed to be included in the associated equipment cost, and thus are not included as an owner's cost.		
– Initial catalyst & chemicals	Value based on amounts in process equipment, but not in storage			

Table B1 (continued). Methods to quantify elements of capital cost				
Capital Cost Element	**EPRI**	**DOE/NETL**	**IEAGHG**	**GCCSI**
– Inventory capital	Value of fuel and consumables needed at 100% capacity for 30 days (baseload), 15 days (intermediate), 5 da (peaking)	AACE 16R-90 does not include an inventory cost for fuel, but EPRI TAG® does. • 0.5% of TPC for spare parts • 60 day supply (at full capacity) of fuel. Not applicable for natural gas. • 60 day supply (at full capacity) of non-fuel consumables (e.g., chemicals and catalysts) that are stored on site.	• Spare parts: 0.5% of TPC. It is assumed that spare parts have no value at the end of the plant life due to obsolescence. • Working capital includes inventories of fuel and chemicals (materials held in storage outside of the process plants). It is assumed that the cost of these materials shall be recovered at the end of plant life. • 30 days at full capacity of coal and other solid fuel stocks; • 30 days at full capacity of chemicals and consumables	
– Pre-production (startup)	Sum of: 1 mo FOM; 1-3 mo VOM excl fuel; 25% of fuel cost for 1 mo at full capacity; 2% of TPI (=TPC+IDC+ escalation); no byproduct credits	• 6 months operating labor • 1 month maintenance materials at full capacity • 1 month non-fuel consumables at full capacity • 1 month waste disposal • 25% of one month fuel cost at full capacity • 2% of TPC • AACE 16R-90 and EPRI TAG® differ on the amount of fuel cost to include; this estimate follows EPRI.	Start-up costs consist of: • 2 percent of TPC, to cover modifications to equipment that will be needed to bring the unit up to full capacity. • 25% of the full capacity fuel cost for one month, to cover inefficient operation that occurs during the start-up period • Three months of operating and maintenance labor costs, to include training • One month of catalysts, chemicals and waste disposal costs.	
– Other site-specific items	[not included]	Financing cost: 2.7% of TPC Lumped cost of 15% of TPC to cover: • Preliminary feasibility studies, including a Front-End Engineering Design (FEED) study • Economic development (costs for incentivizing local collaboration and support) • Construction and/or improvement of roads and/or railroad spurs outside of site boundary • Legal fees • Permitting costs • Owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors) • Owner's contingency		
(TOC)	***Sum of the above***			
Interest during construction	EPRI-specified calculations based on weighted cost of capital, escalation rates, years of construction and Total Overnight Cost (TOC) of plant	These costs vary based on the capital expenditure period and the financing scenario (and are included in TASC)		Based on approximated capital expenditure profile and finance rate during construction
Cost escalations during construction	[Similar to above]	Included, as applicable, in TASC		
(TCR)	***Sum of the above***			

* ***Note:*** Details for the ZEP cost elements are not shown here since most cost items are specified by the EPC contractor.

Table B2. Methods to quantify elements of operating and maintenance cost

O&M Cost Element	EPRI	DOE/NETL	IEAGHG	GCCSI
Operating labor	Based on specified hourly labor rates ($/hr), personnel per shift, and number of shifts	Based on of the number of operators required for each specific case. The average base labor rate used to determine annual cost is $34.65/hour. The associated labor burden is estimated at 30 percent of the base labor rate.	€60k/person-year with number of operators per year estimated by contractor with 5 operating shifts	Based on non-union rates in the US Gulf Coast Region
Maintenance labor	Default estimate is 40% of total maintenance cost	Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section.	Default estimate is 40% of total maintenance cost.	Variable O&M labor costs assumed to be part of the fixed O&M labor costs
Administrative & support labor	30% of operating plus maintenance labor	Labor administration and overhead charges are assessed at rate of 25 percent of the burdened O&M labor.	30% of operating labor plus 12% of maintenance labor	Estimated by contractor
Maintenance materials	Default estimate is 60% of total maintenance cost, which is estimated as a percent of Total Plant Cost. Values range from 1–10+% by type of processing conditions	[See Maintenance labor above]	Estimated by contractor Default is 60% of total maintenance cost, which is estimated as a percent of Total Plant Cost (TPC). Indicative total maintenance costs are: • 1.5% of TPC for PCC • 2.2% of TPC for NGCC • 2.5% of TPC for IGCC	Estimated by contractor
Property taxes	[not included]	(included in Insurance cost)	[included in Insurance]	Not specifically identified
Insurance	[not included] EPRI includes insurance and property taxes in its capital charge factor, along with debt payments and payments to equity holders.	2% of TPC – included in fixed operating costs Also covers local property taxes and miscellaneous regulatory and overhead costs	1–2% of TPC per year Also covers local property taxes and miscellaneous overhead costs	Not specifically identified
(FOM)	***Sum of the above***			
Fuel	Unit cost ($/MBtu) times annual quantity	unit cost times annual quantity	unit cost times annual quantity	Unit cost* Net Plant HHV Heat Rate
Other consumables, e.g., chemicals, auxiliary fuels, water	Unit cost times annual quantity based on MWh generated per year	Unit cost times annual quantity based on MWh generated per year	Unit cost times annual quantity based on MWh generated per year	Estimated by contractor, reported as single unit cost ($/MWh)
Waste disposal (excl. CO_2)	Same as above	Waste quantities and disposal costs are determined similarly to consumables. Details vary with study.	Raw process water, 0.2 €/m^3; Limestone, 20 €/t; Other chemicals and consumables estimated by contractor; Ash, slag, gypsum and sulphur net disposal cost = 0; Special waste disposal cost estimated by contractor	

Table B2 (continued). Methods to quantify elements of operating and maintenance cost				
O&M Cost Element	**EPRI**	**DOE/NETL**	**IEAGHG**	**GCCSI**
CO_2 transport	Same as above		[Included in storage]	Process characteristics identified (length, inlet temperature, inlet/outlet pressure, volume being transported)
CO_2 storage	Same as above		€10/tonne	Separately modeled, identifying capital costs for surveys, injection and monitoring wells, abandonment and rehabilitation together with operating expenditures. Key geological properties identified including net thickness, permeability as well as 13 other properties.
Byproduct sales (credit)	Same as above			Not applied
Emissions tax (or credit)	[not included]			Included as sensitivity
(VOM)	***Sum of the above***			

Appendix C. Understanding Levelized Cost of Electricity

The levelized cost of electricity is a constant unit price ($/MWh) for comparing the costs of power plants that have different technologies, use different fuels, have different capital expenditure paths, differing annual costs (such as operating, maintenance, taxes, carbon prices), different net outputs, and different economic lives.

As the value of a dollar today does not have the same economic value as a dollar next year or a dollar in 30 years times, in order to properly add costs that occur at different points in time, they are converted into "present value" terms through the use of "discounting."

In a general form, where quantities and values can vary through time (but holding both the price of electricity and discount rate constant), the levelized cost of electricity can be defined through Equations (C1) and (C2) below, with terms as defined in Table C1.

$$\sum_t \frac{(Electricity\ Sold)_t * (P_{electricity})}{(1+r)^t} = \sum_t \left[\frac{(Capital\ expenditure)_t}{(1+r)^t} + \frac{O\&M_t}{(1+r)^t} + \frac{Fuel_t}{(1+r)^t}\right] \quad (C1)$$

Table C1. Nomenclature used to define levelized cost of electricity

Parameter	Definition	Units
Electricity sold$_t$	The net electricity produced and sold in year *t*	MWh
$P_{electricity}$	A constant price of electricity (defined in Eq. 2 as the LCOE)	$/MWh
r	The annual rate used to discount values, usually taken to be a pre-defined rate of return required to cover equity and debt costs	fraction
Capital expenditure$_t$	Expenditure in year *t* associated with construction of the plant	$
O&M$_t$	Total non-fuel operating and maintenance costs in year *t*	$
Fuel$_t$	Total fuel costs in year *t*	$

In words, the left side of Equation (C1) represents the present value of all income received from electricity sales over the life of the plant. This amount must balance the present value of all costs for building, operating and maintaining the plant over its economic life. Since fuel cost is the dominant component of operating costs, this item is commonly called out separately from other (non-fuel) operating costs. These annual O&M costs also may include such items as taxes, carbon values, or any other costs incurred through time. In the case of fossil fuel technologies, any decommissioning costs at the end of the plant life are usually ignored. The rule of thumb is that the plant salvage value will cover these costs.

Taking $P_{electricity}$ in Equation (C1) to be defined as the constant levelized cost of electricity (LCOE):

$$LCOE = \sum_t \frac{(Capital\ expenditure)_t + O\&M_t + Fuel_t}{(1+r)^t} \Bigg/ \sum_t \frac{(Electricity\ Sold)_t}{(1+r)^t} \quad (C2)$$

The term "levelized" arises from the recognition that the calculations in Equation (C2) establish a single present value of overall cost that can be transformed into a series of uniform (level) annual values through the use of so-called "levelization factors." By common practice in LCOE calculations, the levelization factors are termed differently when applied to different cost elements, as elaborated below.

If the net electricity produced and sold each year (that is, the net output of the plant) is constant over the life of the plant, and if the operating, maintenance and fuel costs are also constant, then Equation (C2) can be reduced to:

$$LCOE = \frac{(TCR)(FCF) + FOM}{(MW)(CF * 8766)} + VOM + (HR)(FC) \quad (C3)$$

The variables in this equation are defined below in Table C2. Note that the denominator of the first term corresponds to the total electricity produced and sold each year.

Table C2. Nomenclature and definitions for Equation (C3)

Parameter	Definition	Unit
TCR	Total Capital Requirement in the base year of the analysis (see Table 4 of main text)	$
FCF	Fixed charge factor (defined in Eq. C4 below)	fraction
FOM	Fixed O&M costs (see Table 5 of main text)	$/year
MW	Net power output of the plant	MW
CF	Capacity factor (see Table 3 of main text). This value, multiplied by the total number of hours in a year (e.g., 8766, including leap years), times MW, gives the net annual electricity generation.	fraction
VOM	Variable O&M costs, excluding fuel cost (see Table 5 of main text)	$/MWh
HR	Net power plant heat rate	MJ/MWh
FC	Fuel cost per unit of energy	$/MJ

The levelization factor for the Total Capital Requirement is commonly called the fixed charge factor, *FCF*. This factor converts the total capital value to a uniform annual amount (also called an annuity). In discrete terms, *FCF* is given by:

$$FCF = \frac{r(1+r)^T}{(1+r)^T - 1} \quad (C4)$$

where, r is the interest rate or discount rate defined above in Table C1, and T is the economic life of the plant relative to the base year of analysis used in the study.

Note that the assumption of constant values for all terms in Equation (C3) is, explicitly or implicitly, an analysis of electricity cost in real (or constant) dollars. This is most common assumption found in studies of CCS cost.

On the other hand, a modified version of Equation (C3) is needed if annual plant costs change through time—as occurs, for example, when using nominal (current dollar) costs that include an assumed inflation rate, or when assuming "real escalation rates" for fuel or other O&M costs, or when the level of plant output varies over time (reflected by different capacity factors). In such cases the LCOE can be expressed as:

$$LCOE = \frac{(TCR)(FCF_L) + l_1(FOM)}{(MW)(CF_L * 8766)} + l_2(VOM) + l_3(HR)(FC) \quad (C5)$$

Here, l_1, l_2 and l_3 are levelization factors applied to the initial (first year) value of fixed and variable operating costs and total fuel cost, respectively. (Additional factors can be applied to any sequence of other annual costs, or to the individual components of *FOM* and *VOM*). These factors serve as "multipliers" that effectively convert all first-year O&M and fuel costs to annuity values over the plant life, expressed in the base year of the analysis. In discrete terms, these various levelization factors, l_i ($i = 1,2,3$) are given by [10, 17]:

$$l_i = \frac{k_i(1-k_i^T)}{A_T(1-k_i)} \quad (C6)$$

where,

$$A_T = \frac{1-(1+r)^{-T}}{r} \quad (C7)$$

$$k_i = \frac{1+e_{a,i}}{1+r}, \text{ and} \quad (C8)$$

$$e_{a,i} = (1+e_{r,i})(1+e_{inf}) - 1 \quad (C9)$$

Here, r and T are as defined earlier. The additional term A_T represents the present value of an annuity payment, and $e_{a,i}$ is the apparent escalation rate of the relevant cost component, i, resulting from a real annual escalation rate, $e_{r,i}$, and a general inflation rate, e_{inf} (in the case of a current dollar analysis). In the case of constant-dollar analysis with no real cost escalations, the value of e_a is zero and the levelization factors, l_i, are equal to 1.0.

In addition to these three (or more, if applicable) levelization factors, Equation (C5) also shows that LCOE calculations require the appropriate "levelized" values of *FCF* and *CF* (denoted as FCF_L and CF_L, respectively) in cases where these values also change over time. For example, the value of *FCF* may vary from year to year when the "after-tax" rate of return is used in cost-of-electricity calculations, rather than the constant "before tax" value in Equation (C4). The ease (or difficulty) of calculating the levelized *FCF* in such cases will depend on the details of particular tax codes and how the values are represented. Examples of such calculations for the U.S. tax code are discussed elsewhere, such as the EPRI Technical Assessment Guide [10].

Similarly, if the power plant capacity factor varies from year to year, a "levelized" value, CF_L, also is required in Equation (C5). For example, new coal-fired power plants typically have low *CF* values in the first year or two of operation, before higher "typical" values are realized [5]. Because of the discounting of electricity sold at different times (at a constant levelized price and quantity), the capacity factor in Equation (C5) thus takes on an effective levelized value based on Equations (C2) and (C4):

$$\mathrm{CF}_L = \left[\frac{r(1+r)^T}{(1+r)^T - 1}\right] \sum_t \frac{(CF)_t}{(1+r)^t} \qquad \text{(C10)}$$

In general, this value will be smaller than the "typical" *CF* value of a modern power plant since low initial values weigh more heavily in the discounting process. Many CCS studies, however, overlook this fact when assuming a *CF* value for LCOE calculations, and thus understate the resulting LCOE value [5].

Finally, we note that the equations above can be used to define and report the levelized cost of electricity in either real or nominal terms once the annualized real capital costs have been calculated and the various annual costs are correctly stated in their base year values for the study. Tables 8 and 9 of the main text, together with the definitions above, provide guidance on the nomenclature and key assumptions that should be included in any report on CCS costs, as elaborated in Appendix D below.

Appendix D. Recommended Information to be Reported

The information that needs to be reported to ensure clarity and understanding depends on the mode of communication and the intended audience, so no hard rules should be applied. The recommended minimum information that normally should be reported in detailed technical reports, journal or conference papers, and oral presentations is identified with an 'X' in Table D1 below.

Table D1. Recommended data to be presented in reports, papers, and presentations

Information Needed	Reports	Papers	Presentations
Power plants without CO_2 capture (reference/base line plants)			
Battery limits	X		
Fuel type (class of hard coal, lignite, gas)	X	X	X
– Moisture and ash contents	X	X	
– LHV and HHV. (state "as received", dry matter, dry and ash free).	X	X	
– Definition of LHV	X		
Power plant type (e.g. PF, BFB, CFB or NGCC)	X	X	X
– Steam parameters (pressures/temperatures)	X	X	
– GT-class (e.g. F-class, H-class)	X	X	
– Gasifier type (for IGCC)	X	X	
Plant location type (immediate to port, inland)	X	X	
– Ambient conditions (ISO, other conditions)	X	X	
Cooling water (cooling tower or once through sea/lake/river water)	X	X	
Plant capacity (MW electric)			
– Gross (to define boiler/GT size class)	X	X	X
– Net	X	X	X
Net electric efficiency and/or heat rate (state if based on LHV or HHV)	X	X	X
CO_2 emissions (per MWh net electricity or per MWh fuel; state if LHV or HHV)	X	X	X
Environmental control requirements (for major pollutants)	X	X	X
In addition to the above, for power plants with CO_2 capture			
Plant capacity (is the boiler/GT capacity or the gross or net output the same as the reference plant)	X	X	
Type of concept for power plant with CO_2 capture; e.g. post-combustion, oxy-fuel, IGCC with pre-combustion	X	X	X
Capture technology (e.g. MEA, advanced amine, chilled ammonia, Selexol etc or solid absorption/ desorption process	X	X	X
Delivered captured CO_2:			
– Pressure, temperature	X	X	
– Purity requirements anticipated (at least state if sufficient for transport in carbon steel pipelines or ships)	X		
Captured CO_2 per MWh net electricity or per MWh fuel (state if LHV or HHV), or "capture rate" (% of produced CO_2)	X	X	X
Capital costs			
Type of plant, e.g. first-of-a-kind, Nth-of-a-kind	X	X	X
Year and currency of cost estimate	X	X	X
EPC, TPC or similar:	X		
– Minimum is a "lump sum" cost, plus define:	X		
o Which major process units, buildings, construction and other major cost items are included	X		
o Method used, e.g., "EPC" bids for major process units, step-count exponential costing method, etc.	X		
– Cost breakdowns if available	X		
Owner's costs:	X		
– Minimum is a "lump sum" cost, plus define:	X		
o Which major cost items are included here; e.g. own engineering, planning and project management, commissioning/start-up costs, working capital	X		
o Method used; e.g. "EPC" bids for major process units, step-count exponential costing method	X		
– Cost breakdowns if available	X		
Contingencies	X		X
– Project contingency (% of EPC, TPC w/o contingencies or similar)	X	X	
– Process contingency for novel processes (if included)	X	X	

Table D1 (continued). Recommended data to be presented in reports, papers, and presentations

Information Needed	Reports	Papers	Presentations
Resulting "Overnight Cost"	X	X	X
Interest and escalation (if applied) during construction/capital expenditure period;	X		
– Number of years and distribution of investment during construction period	X		
– Escalation rate (if applied)	X	X	X
O&M costs (excluding CO_2 transport and storage)			
Fixed O&M costs (per kW electricity gross or net, per kW fuel or % of investment or yearly cost)	X	X	
– Minimum is a "lump sum" cost, plus define:	X		
o Which cost items are included; e.g. personnel & administration, insurances, property taxes, maintenance.	X		
o Method/basis used	X		
– Cost breakdown if available	X		
Variable O&M costs excluding fuel costs (per MWh electricity gross or net, or per MWh fuel)	X	X	
– Minimum is a "lump sum" plus define:	X		
o Which cost items are included; e.g. consumables (besides fuel), maintenance that is considered as being a function of produced electricity/fired fuel in boiler or gas turbine	X		
o Method/basis used	X		
– Cost breakdown if available	X		
CO_2 emissions cost per tonne (if included)	X	X	X
CO_2 transport and storage			
Overall net cost per tonne of CO_2 stored, with breakdown into transport and storage if available;	X	X	X
– Transport			
o Pipeline distance and capacity, onshore or offshore	X	X	
o Booster compression power (if required) o If ship transport is used, distance and capacity	X	X	
o If ship transport is used, distance and capacity	X	X	
– Storage			
o Type (e.g. depleted oil or gas field, EOR/EGR, saline reservoir etc)			
o Cost (per tonne of CO_2 stored or capital and O+M costs)	X	X	
o Pre-injection reservoir identification and appraisal costs	X	X	
o Post injection monitoring costs	X	X	
o EOR/EGR revenue/ tonne of CO_2 (specify oil or gas price assumption)			
Cost of electricity (COE)			
State whether levelized or first-year (or other)	X	X	X
Method/approach used; also state if calculation uses real (constant money) values or nominal (current money) values	X	X	X
Interest rate/discount rate/WACC (weighted average cost of capital); also state if real or nominal	X	X	X
Inflation and other price escalation rates assumed.	X	X	X
Economic lifetime	X	X	X
Capacity (load) factor/equivalent full load operation hours	X	X	X
Fuel prices:			
– Basis; e.g. projections to certain year(s) (with sources), current delivery prices to plants.	X		
– Prices used, per GJ or MWh fuel (state HHV or LHV)	X	X	X
CO_2 avoidance costs			
State and define reference case	X	X	X
Define how CO_2 avoidance cost is calculated	X	X	

Appendix E. Additional Examples of Good Practice Presentations

Another example where existing charts are often ambiguous is the presentation of costs of CO_2 avoidance. Cost are often presented by comparing the costs and emissions of a plant with CCS and the costs and emissions of a plant without CCS based on the same power generation technology, as shown in Figure D1. However, the absolute costs of avoidance and the relative costs of different technologies depend strongly on the reference technology that is assumed. Costs based on other reference plants should therefore be presented where possible, as illustrated in Figure D2.

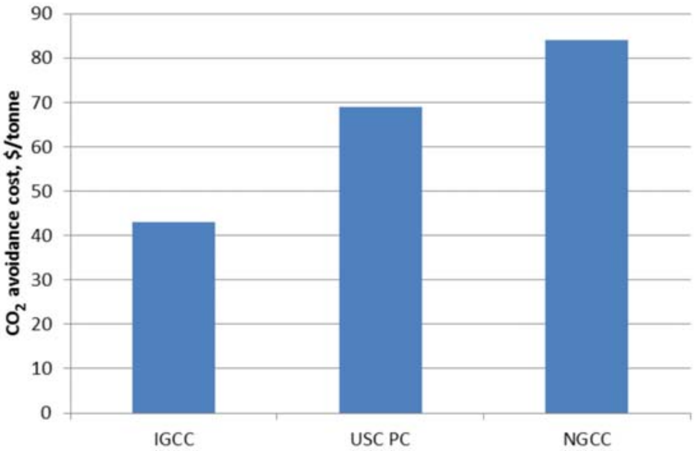

Figure E1. Costs of CO_2 avoidance based on a reference plant of the given technology

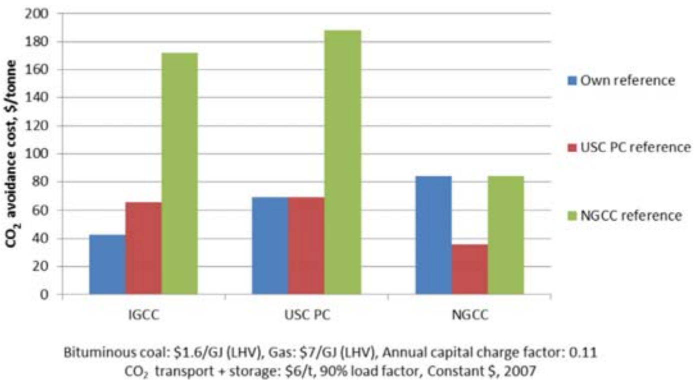

Figure E2. Cost of CO_2 avoidance based on various reference plant technologies

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