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Cost of power or power of cost: A U.S. modeling perspective

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ABSTRACT

Future scenarios and assessment studies used to prepare for long-term energy transitions and develop robust strategies to address climate change are highly dependent on the assessment of technology characteristics and availability.

The electric power sector in the United States recently experienced a significant cost escalation: *e.g.*, construction costs for large plants such as nuclear and coal-fired power plants doubled between 2003 and 2007. We assess the main drivers of this escalation. While many factors have affected costs, some of the most significant include cost of materials, particularly the price of metals and to a lesser extent cement, possible increases in labor quantity requirements, the aggressive worldwide competition for power plant design and construction resources, driven by high demand in Asia, market and regulatory changes, and general uncertainty about future regulations and climate policies.

We recalibrate power sector technology costs in the Global Change Assessment Model (GCAM) based on an extensive literature review of recent (post-2010) studies and in the process develop a coherent and updated set of current cost and performance assumptions for all major electricity-generating technologies.

While current cost and performance assumptions of electricity-generating technologies are key drivers of short-term technology deployment and technology mix in the electricity sector, medium- and long-term deployment pathways are significantly affected by assumed efficiency improvement rates and cost reductions. We develop and demonstrate a method to project efficiency and construction cost of power plants and report a sensitivity analysis to explore the importance of such assumptions in future scenarios generated by GCAM.

1. Introduction

Energy technology is at the heart of the global efforts to promote development, guarantee national security, and limit environmental impact, including long-term climate change. Developing robust strategies to address these issues is highly dependent on our assessment of future technology characteristics and availability. Decision makers use future scenarios and assessment studies to prepare for long-term energy transitions and develop effective strategies to manage the use of natural resources. Many scenarios that support strategic decision-making are the results of models of the physical, economic, and technological systems. This includes, among others, energy-economic models and integrated assessment models (IAMs) that represent national and international energy systems. For example, energy system models such as the National Energy Modeling System (NEMS) in the U.S., have long informed national energy strategies [1]. Similarly, IAMs and global energy-economic models have become an important part of the policy analysis and assessment process in considering climate policy options, particularly long-term options in the context of international efforts to mitigate climate change. IAMs provided the scenarios used by the Intergovernmental Panel on Climate Change (IPCC) in their assessment reports to evaluate a variety of issues related to climate policy [2–4], and they are used by several national governments as they engage in climate negotiations. Integrated assessment models (IAMs) include more or less detailed representations of all the anthropogenic activities that give rise to greenhouse gas (GHG) emissions. Among these, power plants are currently a major source of CO_2 and several short-lived pollutants, and are responsible for 42% of the global greenhouse gas (GHG) emissions [5].

Among the many challenges faced by these models as they are used to develop future scenarios is how to represent the state of energy technology development. The costs for different power plants and their

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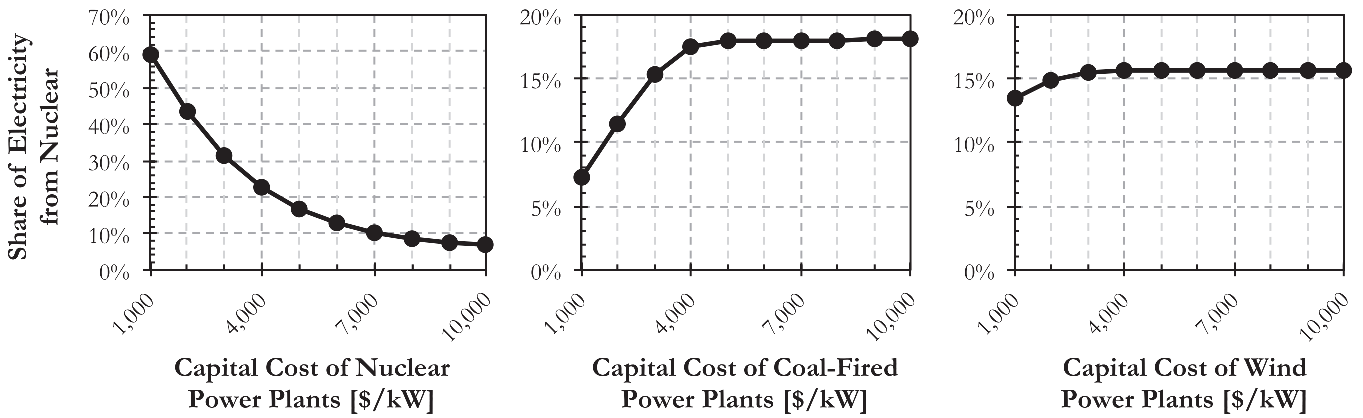

Fig. 1. Sensitivity to construction cost of electricity-generating technologies: shares of 2010–2100 cumulative nuclear-generated electricity under different construction cost assumptions for nuclear, coal, and wind power plants.

evolution over the next several decades, for example, play a critical role in simulating the future energy mix in the electric power sector and therefore on the future scenarios and strategic conclusions that emerge from these models. Over the last decade a significant cost escalation affected the electric power sector, with cost of building new power plants reported to have doubled between 2003 and 2007 in the United States (U.S.) [6]. This challenge of representing technology applies not only to the present, but also to the future. Modelers must not only assess the cost and performance of technologies today; they must also assess how recent developments might influence the future and assess whether recent developments, such as the rise in the costs of generation technologies, are representative of long-term trends or simply short-term variability.

The objective of this paper is to demonstrate a method for developing technology assumptions that can be employed by numerical energy system models to develop scenarios of future energy systems. We focus exclusively on the U.S. power sector, though our methods are general. All costs reported in this paper are expressed in constant (real) 2010 dollars, except for Fig. 2. In Section 1.1, we illustrate how cost assumptions for different electricity-generating technologies influence the output of energy-economic models. To do so, we use the Pacific Northwest National Laboratory's Global Change Assessment Model (GCAM). GCAM is a community global integrated assessment model. We test GCAM's sensitivity to techno-economic assumptions, and the recent cost escalation trends, which motivate this study. In Section 2 we explore recent power plant cost trends in the United States and explore the potential drivers of these trends, including changes in

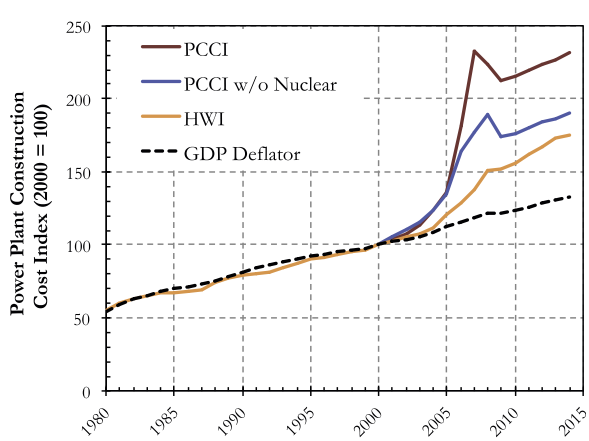

Fig. 2. Nominal construction cost indices. IHS-CERA PCCI tracks coal, natural gas, nuclear, and wind power plants from 2000-2014 (source [6]:). HWI tracks steam-generating electric technologies, including coal, natural gas, and nuclear power plants from 1980-2014 (source [8]:, used with permission). HWI trend extends back to 1970. U.S. GDP deflator from U.S. Bureau of Economic Analysis, 1980-2000. (source [9]:).

commodity prices, labor costs, and regulations. In Section 3, we review the most recent literature estimates for cost and performance of power plants in the U.S. and propose one possible set of assumptions for all major technologies competing for the generation of electricity. Finally, in Section 4, we demonstrate a method to project future technology performance trends. We then perform a sensitivity analysis to explore the implications of future technology development pathways for technology choice in the electric power sector.

1.1. Power of cost: importance of technology cost in future scenarios

Energy models project the evolution of the electric power sector based on cost and performance estimates of different competing technologies, and their rate of change over time, which are uncertain. We use GCAM to illustrate the sensitivity to technology cost assumptions by systematically perturbing capital cost assumptions for coal, nuclear and wind power plants from the GCAM default assumptions. GCAM estimates the deployment and use of different electricity-generating technologies over forecast time horizons extending to the year 2100. The model determines technology choice based on market competition using a multinomial choice model [7].[2] Fig. 1 shows the average share of electricity produced from nuclear power plants under different capital cost assumptions. In particular, results show that the share of electricity produced using nuclear power is most sensitive to the construction cost of nuclear power plants, less sensitive to the cost of coal-fired power plants, which directly compete for the generation of baseload electricity, and relatively insensitive to the construction cost of wind turbines.

Fig. 1 illustrates how different cost assumptions in the electricity sector influence the estimated composition of the future energy system, which in turn determines GHG emissions and pathways to mitigate climate change. For example, the average carbon intensity of electricity increases from 370 gCO_2/kWh to 430 gCO_2/kWh by 2100 when the construction cost of nuclear power plant increases from \$5000 to \$10,000 per kW, in a no-climate-change-mitigation scenario. In a climate change mitigation scenario, the increased construction cost of nuclear power plants leads to an increase of 21% in the abatement cost to stabilize radiative forcing to 4.5 W/m^2 (the IPCC assessed that stabilization at 4.5 W/m^2 is likely, with 66–100% probability, to maintain temperature change relative to 1850–1900 below 3 °C [4]). The sensitivity to the cost of different power plants and the recent cost escalation trends call for a review of the power plant cost estimates used in energy system models.

[2] This formulation is based on the assumption that, when computing the market share of a particular technology, a cost distribution function – rather than the average market cost – should be used to capture heterogeneities, and better capture actual choices [7].

2. Cost of power plants: historical trends

As noted in the introduction, the cost of power plants has risen significantly in recent years. In this section, we review historical cost trends in power plant construction in the United States and explore the potential drivers of these trends, including changes in global commodity prices, labor costs, and regulations.[3] Trends in nuclear, pulverized coal, natural gas combined-cycle (NGCC), and wind power plants are analyzed, focusing mainly on *"n^th^-of-a-kind"* plants and excluding largely untested technologies such as carbon capture and storage. Looking back before the turn of the century, the literature supports a generally increasing trend in nominal power plant construction costs for nuclear, coal, and natural gas plants following the rate of inflation. The Handy-Whitman index of public utility construction costs (HWI) shows that construction costs for nuclear, coal, and natural gas plants, increased at approximately the rate of inflation between 1970 and 2000 (Fig. 2) [8].[4] That is, there were no indications of an overall, real-price increase or decrease in construction costs over that time period.

Aggregate historical trends similar to those reported by HWI have been reported by the Chemical Engineering Plant Cost Index (CEPI), a bottom-up a representation of equipment and labor pricing for chemical plants [10] and by the U.S. Army Corps of Engineers' Civil Works Construction Cost Index System (CWCCIS) [11]. Cost trends of individual technologies in the United States show larger variations compared to these aggregate trends. McNerney et al. [12] analyze the construction costs of coal-fired power plants through the twentieth century, finding three distinct trends. Between 1930 and 1970, real plant costs declined, which they attribute in part to economies of scale as plant sizes grew. However, between 1970 and 1987 this trend reversed and construction costs steadily increased. The causes of this cost increase are not entirely understood, but a significant component is thought to be the introduction of pollution control equipment beginning in 1970. Finally, between 1987 and 2006, coal construction costs plateaued, following a similar trend as the aggregate Handy-Whitman index [12].

Construction costs for nuclear power plants have also undergone significant changes that were not captured by the HWI. In particular, between the late 1960s and 1980s, the construction cost of nuclear power plants increased dramatically in the United States. The increase in nuclear power plant construction cost has been largely attributed to the implementation of stricter regulatory standards, which resulted in long delays during a period of extremely high interest rates, greater requirements for materials, *e.g.* cement, and overestimates of the amount of power that would be demanded all leading to cost overruns [13]. Moreover, there is evidence suggesting that several governments, including the U.S. and French government, created a market to promote the deployment of nuclear power, influencing the economic competition [14], making it harder to estimate actual costs in real-time. More recently, such distortions have been reduced following the restructuring of the electric power markets.

Beginning in the early 2000s, the reported construction costs of multiple types of power plants began to accelerate. This was mainly captured by the HWI (reported in Fig. 2), which shows significant cost increases for some technologies, such as natural gas combined cycle, which comprise the majority of new installations in the U.S. over this period [15]. Similarly, the cost of wind power plants (which have also been largely deployed in the last decade in the U.S.) also increased, as reported by Bolinger and Wiser [16]. They identify three main drivers for increased construction cost of wind power plants: the growing market for wind (and the resulting supply-demand imbalance), the rising costs of materials, and the weakness of the USD [16].

Pulverized coal plants completed or under construction in 2005 reported total plant costs ranging between 1265 and 1760 $/kW (expressed in 2010 dollars) [17]. By 2006, the Electric Power Research Institute (EPRI) [18] estimated that total plant costs ranged between 1890 and 2560 $/kW, based on data from public utility commission filings and the Chemical Engineering Plant Cost Index [19]. Given this variation, EPRI cost estimates increased by between 30% and 50% between 2005 and 2006 [18]. In 2010 two large-scale pulverized coal-fired plants were completed in Wyoming and West Virginia, reporting construction costs of 3330 and 2880 $/kW, respectively [20,21]. These recent cost reports support the notion of a rising trend in the construction cost of coal-fired power plants, though it is unclear what was included in their cost reporting. Estimates developed by MIT for the early 2000s found that real total overnight cost estimates in the United States increased by 74% for the construction of new nuclear plants, 55% for coal, and 48% for natural gas between 2003 and 2007 [22].

IHS-CERA's North American Power Plant Construction Cost Index (PCCI), which tracks the construction costs of coal, gas, nuclear, and wind plants, shows a 104% increase in cost between 2003 and 2007, adjusted to 53% when nuclear power plants are removed. IHS-CERA's European Power Plant Construction Cost Index (EPCCI) shows a similar trend, with a 68% increase in the aggregate construction cost index that falls to 45% without nuclear plants [6] (which was significantly higher than the European GDP deflator over the same period [23]). Fig. 2 reports the PCCI, the HWI, and the U.S. GDP deflator index from the U.S. Bureau of Economic Analysis [9].

While the HWI shows a clear change in trend in the early 2000s, it reports more contained cost increases compared to real-world power plant costs and the IHS-CERA's PCCI. This could be driven by the bottom-up approach used to estimate the total power plant cost based on a basket of component costs [8]. Moreover, few coal-fired and no nuclear power plants were built in the U.S. in the 2000s, which might make it harder to capture changes in their construction costs.

It is instructive to compare these estimates with those from the U.S. Energy Information Administration (EIA). Estimates produced annually as part of the EIA's Annual Energy Outlook (AEO) series do not demonstrate a notable increase during the early 2000s (Fig. 3).[5] Between 2003 and 2007, the EIA estimated capital costs for nuclear power plants grew by 15%, while estimates for pulverized coal and NGCC plants grew by 17.8% and 18.6%, respectively. Fig. 3 shows that rather than capturing the escalation in real construction costs, the EIA's estimates trail real-world conditions by a few years, as also reported by Rong and Victor [15]. In fact, between 2003 and 2006, EIA estimates show stable overnight cost estimates, with rapid cost escalations occurring between 2006 and 2010, roughly three years after escalations were observed in the real world. With this delay taken into account, the EIA's forecasts demonstrate similar cost escalations to those observed in the real world and reported by IHS and MIT.

Like MIT, the EIA assesses that the largest contributions to cost escalations came from advanced nuclear and pulverized coal technologies, whose real total overnight costs they estimate to have increased by 133% and 100% respectively between 2006 and 2010. NGCC and wind plants show a real total overnight cost increase of 48% and 83%

[3] With the exception of data from IHS-CERA [6], construction cost estimates reported in this paper are expressed as overnight costs. Overnight costs in general refer to the costs associated with constructing a plant in base year dollars, without the inclusion of cost escalations and interest that accrue over time. Two categories of overnight cost are used: total plant cost and total overnight cost. The National Energy Technology Laboratory (NETL) defines total plant cost as the sum of equipment, facilities, and infrastructure costs, construction and installation labor, engineering, procurement and construction (EPC) costs, and process and project contingency costs. Total overnight cost includes total plant cost and owner's costs, which include the costs of permitting, financing, and inventory capital [34]. Estimates from MIT and the EIA are expressed in terms of total overnight costs, whereas data from NETL use total plant cost.

[4] Established in 1926, The Handy-Whitman index of public utility construction costs (HWI) tracks the cost trends for different types of utility construction. For more information refer to: https://www.wrallp.com.

[5] The complete series of EIA AEO reports is freely available for download [24].

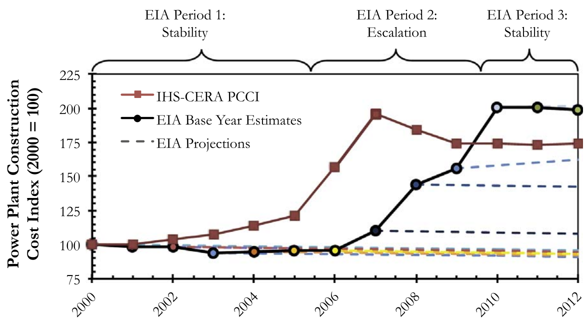

Fig. 3. Power plant construction cost index, 2000–2012 (constant 2010$). Comparison of IHS-CERA PCCI index [6] and EIA aggregate cost, where the EIA aggregate base-year values are computed by calculating a weighted average of base-year overnight costs (converted to 2010$/kW) for coal, gas, nuclear, and wind technologies, weighted by share of capacity in 2000. EIA projections, when not explicitly reported, are computed based on future capacity projections presented in the Annual Energy Outlook, Appendix A [24], and learning rates for each technology, weighted by share of capacity in 2000, using the methods described in Assumptions to the Annual Energy Outlook, Electricity Market Module [25].

respectively between 2006 and 2010, and costs remain stable or decline in the following years.

The EIA models future construction costs (reported as dashed lines in Fig. 3) as a function of installed capacity, in an attempt to capture learning over time. For mature technologies, construction costs are largely projected to decline slowly as more capacity is added. However, even in years prior to the escalation, the EIA's forecasts are somewhat at odds with their base year cost estimates. Between 2003 and 2007, EIA base year cost estimates for all technologies increased [25], despite costs for all technologies were uniformly projected to decline over time in the EIA projections [25]. Similar to historical trends, power plant cost estimates seem to have plateaued at a stable level following the significant cost escalation of the early 2000s, and there is no evidence of significant cost change afterwards. From 2010 to 2012, the EIA reports modest decreases for the base-year costs of different technologies deployed, with real costs of coal and nuclear declining by 1% and 0.3% respectively, and natural gas and wind declining 9% and 12%.

In the following sub-sections, we explore the potential drivers of the cost escalation that occurred between 2003 and 2007 and discuss their implications for projecting future power plant construction cost trajectories.

2.1. What drives the construction cost of power plants?

Empirical evidence shows that power plant cost escalations occurred for several plant types, which suggests that there are common causes driving price increases rather than technology-specific factors. However, cost escalations were most pronounced for nuclear and, to a lesser extent, pulverized coal facilities, suggesting that cost escalation was more significant for large plants that require large capital investments, rather than the relatively smaller NGCC plants and wind farms. Findings by Sovacool et al. support this theory, reporting that smaller power projects, such as wind and solar farms, show a generally higher cost per installed capacity, but also a lower risk of cost overruns and lower rates of overruns that are less costly when they occur [14]. Similarly, Hultman et al. report that future high-cost surprises for nuclear power plants – which have been driven in the past by tightening of the regulatory environment, public opposition, and increased construction times – should be included in future estimates of nuclear power plants construction costs [13]. Moreover, comparisons between the IHS-CERA power plant construction cost indexes for the U. S. and Europe show that construction cost increases followed a similar pattern both in the United States and in Europe, suggesting that cost drivers may have been international in nature [6].

Possible drivers of construction cost increases are reviewed below. Multiple studies have explored these drivers, including Rong and Victor [15] and Chupka and Basheda [26], who explore drivers of the 2003–2007 cost increases for conventional generating technologies, Hultman et al. [13], who reviewed historical trends of nuclear power plant costs, and Rubin et al. [27], who explore the costs of carbon capture and storage technologies. These studies explore multiple potential contributors to cost escalations in the mid-2000s, including materials, equipment, and labor costs; in addition, Rong and Victor [15] also explore learning effects and regulatory and policy interventions. Furthermore, Schlissel et al. [28] also suggest worldwide competition for power plant design and construction resources as a potential driver of the 2003–2007 cost escalation. We review these drivers, and discuss their importance in the context of overall power plant construction costs.

2.1.1. Materials and equipment

Increases in the cost of materials and equipment used in power plant construction have been widely identified as a key driver of construction cost escalations during the 2000s [15,22,26,28]. Between 2003 and 2007, real world prices for iron ore and copper rose by 220% and 233% [29,30], respectively . Over the same period the producer price index for cement, estimated by the U.S. Bureau of Labor Statistics (BLS), experienced real growth of 22% [9,31]. The source of these global commodity price increases has been identified as increased demand from Asia and China in particular [27].

Materials prices also influence the cost of manufactured equipment and therefore play both a direct and an indirect role power plant cost escalations. The indirect role of materials may in fact be larger than their direct role. NETL estimates place the direct cost of materials (such as cement foundations and wire, cable, and piping) at five percent of total plant costs for supercritical pulverized coal plants and six percent for natural gas combined-cycle plants both in 2007 and 2015 [32–34]. Equipment, on the other hand, comprised 49% and 60% of plant costs for coal and natural gas plants, respectively [34]. Economy-wide estimates of equipment prices are used as a benchmark for power plant equipment costs. The producer price index for turbines and turbine generators, which alone comprise 19% of combined cycle total overnight costs and 5% of pulverized coal and nuclear total overnight costs [35], were estimated by the BLS to have declined by 2% in real terms [36], while fabricated metal products grew by only 8% [31]. Meanwhile, industry-specific estimates gathered by the Brattle Group show nominal price increases ranging from 20% to 70% for manufactured parts such as columns and vessels, line pipe, pumps, compressors and drivers, exchanges and switchgear, and structural steel [26]. The data on equipment cost escalation is incomplete and somewhat ambiguous, but based on industry-specific estimates it can be inferred that some escalation did occur. However, the significance of these escalations to overall plant cost is unclear.

The timing and magnitude of materials price increases, particularly in metals, corresponds neatly with the escalations in plant construction cost, leading many to draw a direct correlation between the two. However, the extent to which raw materials directly influence the construction cost of mature technologies is relatively small, and the evidence for corresponding equipment cost increases is limited [15,34]. It can be inferred that materials and equipment costs contributed to cost escalations between 2003 and 2007, but further analysis is needed to better understand their true contribution.

2.1.2. Labor

Labor costs for power plant construction can be generally divided into the cost of facility construction and equipment installation and the cost of engineering and management. Data for the cost of construction and installation labor from the U.S. Bureau of Labor Statistics show a 5% increase in real average hourly earnings of production and non-supervisory employees working in power and communication system construction [37], suggesting that increases in the hourly cost of construction and installation labor were not a major contributor to construction cost escalations. However, although hourly wages did not show significant increases, other factors such as total quantity of labor and total compensation are not accounted for in this estimate.

Engineering and project management is normally conducted by an engineering, procurement, and construction (EPC) firm contracted by the plant's owner. EPC costs are estimated to be between 6% and 8% of total plant costs for coal and natural gas plants [35], and between 20% and 29% of total plant costs for nuclear plants [35,38]. While direct cost data for EPC contracts is unavailable, Chupka and Basheda document an increase in the backlog of infrastructure projects at major EPC firms between 2005 and 2006, indicating a potential supply shortage and possible escalation in the cost of contracts [26]. Furthermore, a report by Synapse Energy cites the limited capacity of EPC firms in the context of global demand as a factor driving increased contract costs [28]. Although the magnitude is unknown, this suggests that EPC services may have contributed to cost escalations. However, data for engineering services from the U.S. Bureau of Labor Statics more generally shows stable real average hourly earnings between 2003 and 2007 [39]. These measures suggest that hourly wages, both in construction and engineering, were unlikely to have been a main driver of construction cost escalation, though they may have played a small role. For example, changes in the regulatory environment, discussed below, may result in increased permitting or construction times, resulting in higher total labor costs. We do not find any empirical evidence documenting increase in quantity of labor, but this remains a potential contributor to observed cost escalations.

2.1.3. Regulatory and market environment

Regulatory and market changes are additional potential contributors to power plant cost escalation experienced between 2003 and 2007 in the United States. Although more difficult to directly identify than changes in commodity or labor prices, past experience shows that changes in regulatory requirements, particularly for coal and nuclear plants, have the potential to significantly alter design requirements, delay the completion time of new plants, and produce high cost overruns due to the accumulation of interest [12,13,40], Other effects of regulatory and market uncertainty may be seen in the cost of capital, and in particular the risk premium demanded by investors to finance a project. While these effects are not included in the total overnight construction cost estimates presented by the EIA and MIT, they influence the overall capital cost of a power plant.

Regulations can both directly influence construction cost and alter investment decisions on which plants will be built; for example, the expectation of delays may cause investors to view a project as riskier, causing them to defer investment or demand higher risk premiums [41]. Furthermore, changes in market structure can alter the expected rate of return for various types of plants, also altering the cost of capital. In the early to mid- 2000s, both regulatory and market changes may have influenced investment decisions made on different types of power plants, thus altering the cost of capital and the mix of new plants constructed. Regulatory uncertainty in general can produce significant delays in the completion time of new plants due to changes in plant permitting and construction requirements, leading to high cost overruns.

Between 2000 and 2010, the EPA introduced proposals to regulate mercury, sulfur dioxide, and nitrogen oxide emissions. These regulations, along with the prospect of carbon dioxide emission regulations, suggest an environment of regulatory uncertainty surrounding future pollution controls, making fossil-fuel fired plants, and especially coal plants, which are larger and more pollutant-intensive than natural gas plants, a riskier prospect for investors [42].

Furthermore, with multiple states attempting to implement market liberalization reforms in the 1990s and early 2000s [43], market factors have caused expected returns on investment for new generating plants to change. Under traditional vertically integrated markets, the risks of construction and operation of plants were borne by to consumers; however, with more competitive market environments, more risks must be borne by investors [41]. This may lead investors to favor smaller, lower-cost, lower-risk projects such as natural gas combined cycle plants [44], over larger projects such as nuclear and coal-fired power plants. Between the late 1990s and mid-2000s, a boom in deployment of natural gas plants was observed, with more than 80% of new generating capacity comprised of natural gas between 1990 and 2011 [15]. During this period, wind accounted for 10% of new generating capacity, while coal accounted for only 6% [45]. Natural gas plants face a lower regulatory burden, as they produce fewer emissions than coal-fired plants and more easily comply with federal and local environmental standards. Moreover, the smaller scale of natural gas-fired plants is a better fit for the recent U.S. electric power market, which has been characterized by low demand growth [46]. Although low natural gas prices and domestic availability were major drivers of the increased use of natural gas for electricity generation in the United States, regulatory uncertainty and the changing market environment appear to have placed larger plants, particularly coal-fired and nuclear power plants, at a disadvantage.

2.1.4. Discussion

The drivers of the power plant construction cost escalation that occurred between 2003 and 2007 in the U.S. are not entirely understood, but empirical evidence offers some suggestions as to potential driving factors. Of the factors explored, materials prices, particularly the price of metals and to a lesser extent cement, show the most significant changes in the period between 2003 and 2007. Some corresponding increases were also seen in equipment costs, although not to the same extent as material costs. The magnitude of their effect on power plant construction costs is not entirely clear, but unlikely to be zero. Labor costs, particularly hourly wages for construction labor and engineering, increased modestly during this time period, and could only partially have contributed to the cost escalation, although the effect of backlogs at EPC firms may have exacerbated this. In addition, the 2000s were a period of regulatory uncertainty, particularly for construction of new coal-fired plants. The influence of regulatory factors on construction cost estimates is not easily quantifiable, but it may have influenced the mix of new power plants constructed during the 2000s. Moreover, the generally unfavorable environment for coal-fired power plants might have increased the risk perceived by potential investors. Another potential driver of the cost escalation, often overlooked, was the aggressive worldwide competition for power plant design and construction resources, driven by high demand in Asia, and especially China [27]. Finally, the market for power plant design and engineering is characterized by high barriers to entry that restrict competition and can contribute to distortionary prices [47]. McGovern and Hicks report that consolidation occurred among large power engineering firms during the 1990s and early 2000s, driven by changes in the structure of electricity markets [47]. This might have played a role in the power plant construction cost escalation, with construction and engineering firms potentially using their market power to increase their profit in response to high demand.

Construction cost escalations for power plants have implications for estimates of the future energy mix in the electricity sector. Modeling undertaken by the EIA and other institutions typically represents construction costs for a particular generating technology as a function of installed capacity; construction costs tend to decrease as new capacity is added, representing learning over time. On the other hand, EIA base-year cost estimates over time and the Handy-Whitman index appear to suggest a stable, rather than declining trend for the costs of coal, gas, and nuclear plants, before and after the cost escalation discussed here, raising questions about the suitability of learning-rate-based projections for mature technologies. Grubler reports a substantial escalation of real-term construction costs for nuclear power plants in France between 1970 and 2000, asserting that the French nuclear case "illustrates the perils of the assumption of robust learning effects resulting in lowered costs over time in the scale-up of large-scale, complex new energy supply technologies" [48]. The history of coal-fired power plant construction costs in the United States also illustrates this point: McNerney et al. show that construction costs increased in the 1970s and 1980s and remained constant from the 1980s to the mid-2000s [12].

Forecasting the drivers of power plant construction costs, such as commodity prices, future economic growth, and demand for energy, is a difficult task, but future cost reductions might come from significant decreases in global commodity prices, such as oil and steel, and lower international competition for the construction of power plants. In particular, there is recent evidence suggesting that the slowing of Chinese economic growth and the overcapacity built in some sectors, such as steel production, are driving cost decreases in international markets [49], and could potentially influence future power plant construction costs.

Overall, the drivers of the recent escalation of power plant construction cost in the U.S. remain somewhat ambiguous, making it difficult to conclude whether the recent trends can be classified as a market bubble or whether they represent a baseline increase. Different baseline assumptions, as well as assumptions about future cost changes, have significant impact in future energy systems projections, as shown in Section 4.

3. Cost of power plants: review of 2015 costs in the U.S.

In this section we review recent (post-2010) cost and performance estimates and propose a consistent set of assumptions for all major electricity-generating technologies. The literature on cost and performance of power plants is extensive. Nevertheless, there are limited consistent and comprehensive sources of cost and performance data spanning a wide set of electricity-generating technologies. Among the comprehensive reports on the topic, the following sources have been thoroughly reviewed: NREL's First Annual Technology Baseline (ATB), which purports to "document a realistic and timely set of input assumptions, and a diverse set of potential futures, that can inform electric sector analysis in the United States" [50]; the most recent U.S. EIA report on capital cost of power plants [51]; a report produced by Black and Veatch for the U.S. National Renewable Energy Laboratory [35]; a report from the International Energy Agency and the Nuclear Energy Agency comparing electricity generation costs in different countries [52]; the Transparent Cost Database, a tool developed by the US DOE's Office of Energy Efficiency and Renewable Energy to determine estimates for use in program planning, which includes dozens of sources, including assumptions for recent U.S. EIA energy outlooks [53]; recent NETL reports on pulverized coal and combined cycle natural gas plants, with and without CCS [33,34]; and recent Lazard's estimates for levelized cost of electricity for different generating technologies [54].

We consider 23 technologies competing for the generation of electricity starting from a variety of fuels, including coal, natural gas, oil, uranium, biomass, and renewable energy sources such as solar, wind, geothermal, and hydropower. Thermal technologies, with and without the use of carbon capture and storage (CCS), include steam plants combined cycle (CC), and integrated gasification combined cycle (IGCC). Solar technologies include rooftop and utility-scale photovoltaic panels (PV) and concentrating solar power (CSP) systems with and without thermal storage.

Competition among the different technologies is typically based on the levelized cost of electricity (COE, expressed in \$/MWh), computed as:

$$COE = \underbrace{\frac{C_f}{\eta}}_{\text{Fuel Cost}} + \underbrace{\frac{1000 \cdot C_I}{8766 \cdot CF}\cdot i}_{\text{Capital cost}} + \underbrace{\frac{C_{O\&Mfix}}{8766 \cdot CF} + C_{O\&M\,var}}_{O\&M\text{ Costs}} \quad (1)$$

where:
C_f is the fuel cost, expressed in \$/MWh;
η is the power plant efficiency;
C_I is the capital investment cost, expressed in \$/kW.
CF is the capacity factor, namely the ratio of operating hours out of the total 8766 h in a year;
i is the fixed charge rate;
$C_{O\&M\,fix}$ is the annual fixed O & M cost, expressed in \$/MW per year; and
$C_{O\&M\,var}$ is the variable O & M cost, expressed in \$/MWh.

In the following sections we propose a set of current (2015) cost and performance assumptions for the major electricity-generating technologies, based on an extensive review of recent literature. All costs are expressed in real 2010 USD. Section 3.1 details efficiency assumptions; Section 3.2 report capacity factor assumptions; capital and O & M costs are reported in Section 3.3; and Section 3.4 reviews in detail cost of CCS technologies, reporting carbon capture costs and cost of CO_2 avoided for different technologies. These assumptions are intended to serve as reference for energy system models, and particularly integrated assessment models, and constitute the core of the electricity sector assumptions in GCAM 4.2.

3.1. Efficiency

The efficiency of a power plant is the percentage of the total energy content of a power plant's input (*e.g.* energy content of fossil fuels or heat generated by nuclear reactions) that is converted into electricity. The energy content of fossil fuels is approximated with their heating values. In this study we use higher heating values (HHVs), which account for the latent heat of vaporization of water in the combustion products.[6] In the U.S. heat rates (HR) are often reported instead of efficiencies.[7]

While not all the studies reviewed [33–35,50–54] report efficiency values for all the technologies included in this study, the efficiencies of the technologies reported show a minor degree of variation across different sources. Table 1 reports the HHV efficiencies and HR assumed in this study.

Note that while combined cycle plants fueled by oil and natural gas use the same equipment (and thus have the same capital cost) [55–57], the use of oil-derived fuels negatively influence efficiency of oil-fired power plants [58].

3.2. Capacity factors

The capacity factor of a power plant is the ratio of its actual output over a period of time, to its potential nominal output if operating constantly at full nameplate capacity over the same period of time. Similarly to efficiency values, capacity factors show a minor degree of variation across different sources, e.g [51,53,59]. Table 2 reports capacity factor assumed in this study.

Note that we are assuming a higher capacity factor than typically realized in practice for combustion turbines (simple cycle), since we consider the technical maximum capacity factor achievable by the different technologies and a lower capacity factor assumption would

[6] In other words, HHV assumes all the water component is in liquid state at the end of combustion, while lower heating value (LHV) is determined by subtracting the heat of vaporization of the water vapor from the HHV. The higher heating value exceeds the lower heating value by the energy that would be released were all water in the combustion products condensed to liquid [109]. Thus, HHV efficiency is lower than LHV efficiency, especially for plants burning natural gas (an 11% difference). HHV to LHV ratios for several fuels are available in the literature that allow converting HHV and LHV efficiencies (*e.g* [109].).

[7] The heat rate is the amount of energy added to produce a unit of electricity. The heat rate, which is inversely proportional to the thermal efficiency, is normally expressed in BTU/kWh. HR can be converted to a thermal efficiency by dividing the equivalent BTU content of a kWh (which is 3412 BTU) by the heat rate.

Table 1
HHV efficiency and HR of different electricity-generating technologies in 2015.

Technology	HHV Efficiency	Heat Rate [BTU/kWh]
Coal (steam plant)	0.38	8979
Coal CCS (steam plant)	0.28	12,186
Coal (IGCC)	0.39	8749
Coal CCS (IGCC)	0.32	10,663
Natural Gas (simple cycle)	0.34	10,035
Natural Gas (CC)	0.52	6562
Natural Gas CCS (CC)	0.42	8124
Oil (steam plant)	0.34	10,035
Oil (CC)	0.51	6690
Oil CCS (CC)	0.39	8749
Biomass (steam plant)	0.25	13,648
Biomass CCS (steam plant)	0.18	18,956
Biomass (IGCC)	0.3	11,373
Biomass CCS (IGCC)	0.25	13,648
Nuclear	0.33	10,339
Geothermal	0.1	34,120

calculation of CCS for Biomass - scaling

Table 2
Capacity factors for different electricity-generating technologies in 2015.

Technology	Capacity Factor
Coal (steam plant)	0.85
Coal CCS (steam plant)	0.8
Coal (IGCC)	0.8
Coal CCS (IGCC)	0.8
Natural Gas (simple cycle)	0.85
Natural Gas (CC)	0.85
Natural Gas CCS (CC)	0.8
Oil (steam plant)	0.85
Oil (CC)	0.85
Oil CCS (CC)	0.8
Biomass (steam plant)	0.85
Biomass CCS (steam plant)	0.8
Biomass (IGCC)	0.8
Biomass CCS (IGCC)	0.8
Nuclear	0.9
CSP	0.25
CSP (+ thermal storage)	0.65
Geothermal	0.9

distort the relative economics of these plants. Capacity factors for gasification plants (IGCC) are based on design studies, since the technology is not yet commercially available. Annual average capacity factors of wind and PV vary with the location, and thus are not reported in Table 2. Capacity factors for CSP plants also vary with the location, but CSP plants are typically located in regions with high solar irradiance, limiting the capacity factor variance. In GCAM the capacity factors of wind turbines are used to construct region-specific supply curves [60,61]. Similarly, supply curves for rooftop PV in GCAM are based on the capacity factors reported by NREL for the United States [62].

3.3. Capital cost, O & M cost, and fixed charge rates

Among the factors influencing the non-energy portion of the levelized cost of electricity, capital cost has the largest impact, and also shows the largest variation in the literature reviewed. Fig. 4 reports a comparison of our current (2015) capital cost assumptions and cost estimates available in the open literature. Values are expressed in real 2010 USD. The figure includes numerous studies in the "literature" category, ranging from academic and industrial studies [59,63–77] to comprehensive reports performed in the last 5 years [33–35,50–54]. The capital costs reported by the most relevant studies and the values assumed in this work, reported in Table 3, have been reported explicitly to allow for an easier comparison. The great variability of the estimates available in the literature is an indication of the general uncertainty and geographical heterogeneity of construction cost of power plants. Cost estimates proposed in this paper have been chosen as representative of state-of-the-art plants in the U.S. and are intended to model the current competition between all the different technologies available.

The 2015 overnight capital costs for the 23 technologies reviewed, together with fixed and variable operation and maintenance cost assumptions, are reported in Table 3. The cost of oil-fired power plants is taken to be the same as the cost of corresponding gas-fired plants. This is because a gas turbine can typically run either on natural gas or refined liquid fuels [55–57]. Costs of oil- and biomass-fired power plants coupled to CCS are not reported in the recent literature reviewed in this study, and have been computed by scaling up the CCS cost adders for similar coal and gas-fired power plants based on the carbon intensity of the electricity produced. For example, starting from the CCS cost adder of "Natural Gas CCS (CC)" ($1050/kW), the CCS cost adder for "Oil CCS (CC)" is found to be $1550/kW, based on the carbon intensity of the electricity produced (660 gCO_2/kWh for "Oil CCS (CC)" before CO_2 capture, compared to 450 gCO_2/kWh for "Natural Gas CCS (CC)".

PV module costs are reported per "DC Watt peak" (Wp), based on the rated PV module output power (at the maximum power point) under standard conditions (solar irradiance of 1000 W/m^2, temperature 25 ºC). Cost of rooftop and commercial-scale PV are taken from 2014 median reported prices in the U.S. market collected by NREL [78], which are significantly lower compared to 2013 prices [79]. Wind and solar plants are intermittent resources that cannot be dispatched. Energy storage solutions, such as batteries and thermal storage for CSP, can be used to eliminate non-dispatchability issues [80]. *"CSP (+ thermal storage)"* plants include 8 h of storage capacity. Cost of batteries coupled to wind and PV plants is estimated to be $3800/kW: assuming a storage capacity of 8 h, at $350/kWh, and additional equipment costs of $1000/kW [35]. A fixed charged rate (term *i* in the COE equation) of 0.13 is assumed for all utility-level technologies [81,82].[8]

3.4. Cost of CCS technologies

what are these region specific supply curves? what do they include?

Two metrics are commonly adopted to evaluate the additional costs introduced by CCS technologies: the cost of CO_2 captured and the cost of CO_2 avoided. Both are measured in \$/tCO_2. In the numbers reported in this study both metrics include only capture cost, neglecting transportation and storage costs, which are implemented in GCAM by means of region-specific supply curves.

The cost of CO_2 captured ($COST_{capt}$) is computed by dividing the incremental cost of producing electricity with a CCS-equipped plant (\$/kWh) by the amount of CO_2 captured:

$$COST_{capt} = \frac{COE^{(CCS)} - COE^{(noCCS)}}{CO_{2-capt}} \tag{2}$$

where $COE^{(CCS)}$ is the cost of electricity produced by a plant equipped with CCS, in \$/kWh. $COE^{(no\ CCS)}$ is the cost of electricity produced by a corresponding plant without CCS technologies, and CO_{2-capt} is the total mass of carbon dioxide captured per unit of net electric power output produced by the plant equipped with CCS, in tCO_2/kWh. We assume a CO_2 capture efficiency of 90% (meaning that 90% of the total CO_2 generated by the plant is captured). The cost of CO_2 captured

[8] The annual fixed-charge rate represents the average, or levelized, annual carrying charges including interest or return on the installed capital, depreciation or return of the capital, tax expense, and insurance expense associated with the installation of a particular generating unit for the particular utility or company involved [110].

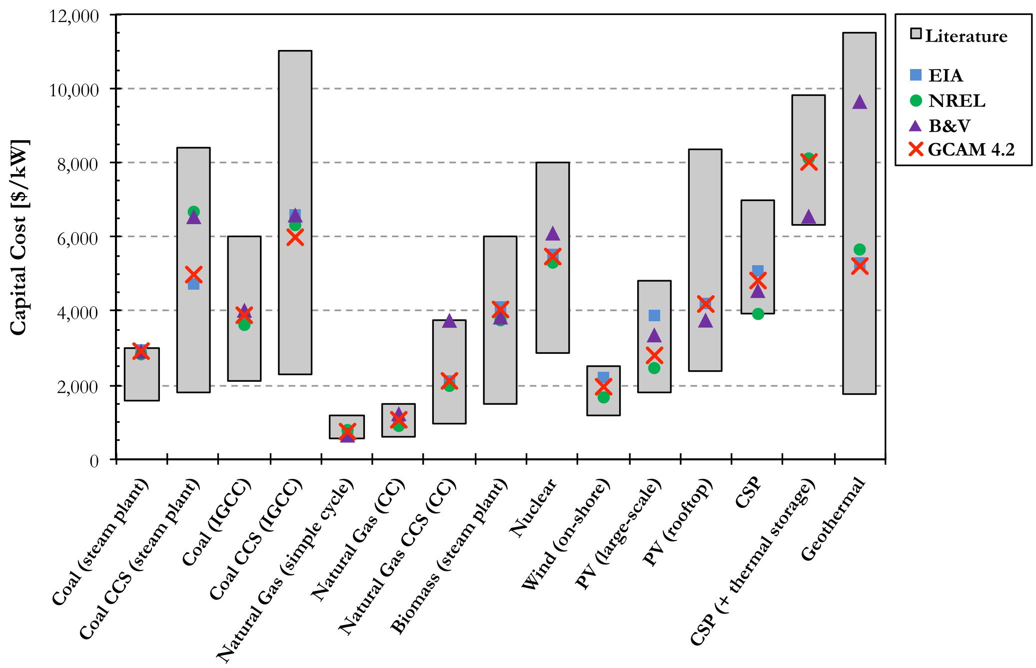

Fig. 4. Comparison of current (2015) capital cost estimates for a set of electricity-generating technologies reported in the open literature. Costs are expressed in 2010 USD per kW. Main sources: EIA [51]:; NREL [50]:; B & V [35]:.

Table 3
Capital and operation and maintenance costs of different electricity-generating technologies in 2015. Cost are expressed in 2010USD.

Technology	Capital Cost [$/kW]	Fixed O & M Cost [$/kW-year]	Variable O & M Cost [$/MWh]
Coal (steam plant)	2900	25	4
Coal CCS (steam plant)	5800	50	8
Coal (IGCC)	4000	35	6.5
Coal CCS (IGCC)	6600	70	10
Natural Gas (simple cycle)	750	6	10
Natural Gas (CC)	1050	10	3.5
Natural Gas CCS (CC)	2100	20	7
Oil (simple cycle)	750	6	10
Oil (CC)	1050	10	3.5
Oil CCS (CC)	2600	24	8
Biomass (steam plant)	4000	95	10
Biomass CCS (steam plant)	7700	116	13.4
Biomass (IGCC)	6000	140	15
Biomass CCS (IGCC)	8850	170	18
Nuclear	5500	95	2
Wind (on-shore)	2000	50	0
Wind (on-shore + battery)	5800	60	0
PV (large-scale)	2800	40	0
PV (large-scale + battery)	6600	48	0
PV (rooftop)	4200	60	0
CSP	4800	55	0
CSP (+ thermal storage)	8000	65	0
Geothermal	5200	100	0

represents the minimum CO_2 plant gate sales price that will incentivize carbon capture in lieu of a corresponding non-capture plant based on the same technology. This metric does not account for the fact that capturing CO_2 requires additional energy. In fact, to generate a certain amount of electricity a CCS-equipped plant will consume more energy (often referred to as an efficiency penalty), and thus produce more CO_2 compared to a corresponding plant without CCS (as illustrated in Fig. 5).[9]

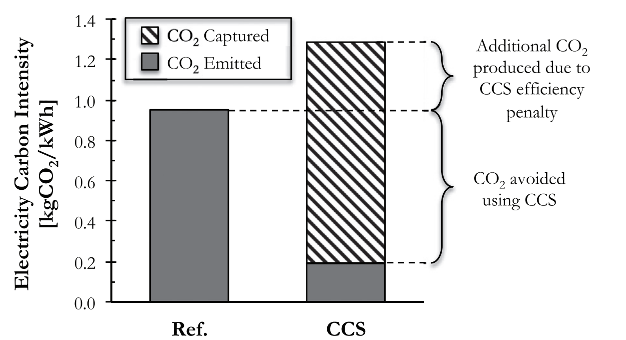

Fig. 5. Electricity carbon intensity with and without CCS. The loss in overall efficiency of CCS-equipped power plants due to the additional energy required for capturing CO_2 results in more CO_2 being produced per unit of useful product (right bar) relative to the reference plant without capture (left bar). The CO_2 emissions reduction compared to a reference plant (CO_2 avoided) is, thus, smaller than the amount of CO_2 captured.

To avoid accounting for the additional CO_2 produced and to compare carbon capture costs of different technologies a different metric can be used: the cost of CO_2 avoided ($COST_{avd}$), which represents the minimum CO_2 emissions price that will, when applied to both the capture and non-capture plants, incentivize carbon capture in lieu of a defined reference plant without CCS (ideally, the plant that the CCS plant replaces).

[9] Moreover, the cost of carbon captured compares each plant type with the corresponding plant without CCS, rather than with a common reference. For example, the cost of carbon captured of "Biomass CCS (steam plant)" indicates the cost of capturing CO_2 compared to a "Biomass (steam plant)". This makes it hard to compare different CCS technologies.

Table 4
Cost of CCS: cost of CO_2 captured and cost of CO_2 avoided compared to coal-fired steam plant.

Technology	Cost of CO_2 Captured [$/t$CO_2$]	Cost of CO_2 Avoided [$/t$CO_2$]	
		Corresponding plant[a]	Coal-fired[b]
Coal CCS (steam plant)	62	87	87
Coal CCS (IGCC)	60	75	105
Natural Gas CCS (CC)	87	108	26
Oil CCS (CC)	105	143	98
Biomass CCS (steam plant)[c]	72	101	247
Biomass CCS (IGCC)[c]	66	82	245

[a] Compared to the corresponding new-build plant without CCS.
[b] Compared to a new-build coal-fired steam plant.
[c] Costs of CO_2 for biomass-fired power plants do not include land-use carbon sinks.

$$COST_{avd} = \frac{COE^{(CCS)} - COE^{(Ref)}}{CO_2^{(Ref)} - CO_2^{(CCS)}} \quad (3)$$

where $CO_2^{(CCS)}$ and $CO_2^{(Ref)}$ are the electricity carbon intensities of a plant equipped with CCS and a reference plant, here chosen to be a coal-fired steam plant.

Table 4 reports a set of illustrative cost of CO_2 captured and cost of CO_2 avoided for the six CCS-equipped power plants considered, assuming as reference first the corresponding plant without CCS and second a plant, here chosen to be a coal-fired steam plant, to allow for a better comparison of different technologies. To calculate COE values the following fuel prices have been assumed: coal: $2/GJ; natural gas: $6/GJ; oil: 11.3/GJ; and biomass: $5/GJ.

Costs of CO_2 avoided for IGCC plants are lower compared to steam plants, when a plant with capture is compared to the corresponding plant without capture. This is because in an IGCC plant, CO_2 removal is accomplished prior to combustion and at elevated pressure using physical absorption, so the incremental costs over a plant without capture are reduced [64]. However, the cost of CO_2 avoided for IGCC plants increase greatly when compared to coal-fired steam plants (last column of Table 4), reflecting the higher base costs of IGCC plants compared to steam plants.

Similarly, the higher cost of CO_2 avoided for natural gas combined cycle plants compared to coal-fired plants when a plant with capture is compared to the corresponding plant without capture might be misleading. In fact, adding CCS to natural gas plants is projected to be less costly than for coal-fired plants, because of the higher CO_2 emissions per unit of electricity produced in coal-fired power plants. This is reflected by the cost of CO_2 avoided for natural gas combined cycle plants when a coal-fired plant is used as reference.

For a comprehensive description of the different CCS technologies and for recent reviews of the state of the art we refer the reader to recent review articles, *e.g.* [83–86]. There is also a wide range of literature estimates on the cost of CCS technologies in the electricity sector. Pires et al. provide an overview of recent developments in CCS technologies, highlighting the need for significant cost reductions in CO_2 capture technologies to allow for large-scale deployment of CCS [83]. In light of commodity cost increases that occurred between 2003 and 2008, in 2015 Rubin et al. [27] updated previous CCS cost estimates for fossil fuel power plants, reporting cost increases compared to the estimates reported in the IPCC special report on carbon dioxide carbon and storage [87]. Rubin et al. [27] maintained an optimistic view for coal-fired CCS technologies in the power sector, reporting cost of CO_2 avoided (assuming a coal-fired steam plant as reference) in the range 45–70 $/t$CO_2$ for pulverized coal plants, 58–121 $/t$CO_2$ for natural gas combined cycle plants, and 52–112 $/t$CO_2$ for coal-fired IGCC. The CO_2 avoidance cost for coal steam plants are lower compared to the costs reported in Table 4, mainly due to lower capital cost assumptions for CCS-equipped power plants. Kheshgi et al. [88] report cost estimates for coal-fired steam plants in the 60–100 $/t$CO_2$ range. Catalanotti et al. [89] report costs of CO_2 avoided for applications in the U.K. of about 90 $/t$CO_2$ for coal-fired steam plants and 100 $/t$CO_2$ for natural gas combined cycle plants. Rubin and Zhai [68] review a number of studies performed between 2007 and 2011 reporting cost of CO_2 avoided to be between 92 and 114 $/t$CO_2$ for natural gas combined cycle plants. Zhao et al. review opportunities for retrofitting coal-fired steam power plants with CCS, reporting cost of CO_2 avoided ranging between 30 and 91 $/t$CO_2$ [90]. Finally, Muratori et al. discuss the use of CCS technologies across different sectors and fuels [91,92].

4. Future costs and performance of power plants

The assumptions detailed in Section 3 apply to power plants built in 2015; however, energy models run for many decades in order to simulate future scenarios. This is a period of time over which efficiencies and costs can be expected to change. In this section we propose a methodology to project future efficiency and cost of electricity-generating technologies up to the year 2100.

There exists a vast literature on cost and performance trends of power plants, especially focusing on learning rates. Learning-curve models are based on the empirically observed phenomenon that unit costs (performance) often tend to decline (improve) by a constant percentage for each doubling of production or capacity [65,93–98]. This is reflected in the efficiency of electricity-generating technologies, which improves as better materials and design become available [99]. Yeh and Rubin provide a long-term analysis of technology change and learning curves for coal-fired power plants, showing a consistent improvement in efficiency and in the cost of boilers used in pulverized coal power plants [97]. On the other hand, there are notable instances where costs have risen at higher rates of deployment [12,13,48]. While learning models seem to apply for technology cost itself, like boilers used in coal-fired power plants, total construction cost is a combination of the technologies deployed and the financial transfers necessary to operationalize the technology. When estimating the total construction cost of power plants there is a lack of empirical evidence that technology change and learning curves models appropriately model total technology cost, as shown in Section 2.

Similar to the approach in [35], where a linear improvement model is used in contrast to learning curves, we propose to project future cost and efficiency of different competing technologies for electricity generation using an exponential growth/decay formulation with a limiting bound. This model is characterized by two parameters: maximum achievable performance (y_{BEST}, the maximum achievable thermal efficiency or the minimum achievable cost) and growth rate (r). For example, the cost of a technology at time t – $y(t)$ – is computed based on the minimum achievable cost (y_{BEST}), the initial cost (y_0), and the

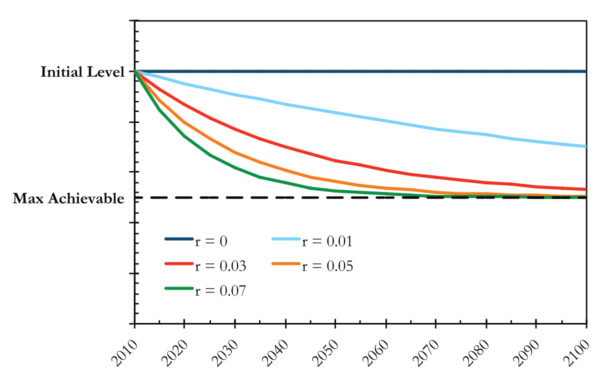

Fig. 6. Exponential decay formulation with a limiting bound used to predict future cost of power plants.

improvement rate ($0 \le r \le 1$) as:

$$y(t) = y_{BEST} + (y_0 - y_{BEST}) \bullet (1-r)^{(t-t_0)} \tag{4}$$

This formulation allows projecting current efficiency and cost level over decades for different rates of technology change, as illustrated in Fig. 6 for the decay case. Different growth rates allow simulating different cost-reduction and efficiency-improvement paths. For each technology considered in this study we identify a maximum achievable performance and an improvement rate for both capital cost and efficiency.

Clarke et al. [100] suggest that technology change can be better represented by introducing exogenous components in learning curves models (capturing learning-by-doing and R & D effects). The maximum achievable performance term included in the proposed formulation allows this by providing a lower bound to which cost levels asymptote. This floor could evolve over time, for example as an indirect effect of spillovers from other sectors and could be modeled as a reduction in the minimum achievable cost over time.

4.1. Future efficiencies of thermal power plants

We assume that efficiency of different electricity-generating technologies will continue to improve over time, in line with observed empirical trends [99], and we model the efficiency improvement with the growth/decay formulation with a limiting bound proposed above. The maximum achievable efficiencies (the bound) for the electricity-generating technologies considered are approximated by the efficiencies at maximum power output (Chambadal–Novikov–Curzon–Ahlborn efficiency) computed according to finite-time thermodynamics theory [101].[10] Improvement rates (r terms) are set to mimic efficiency predictions available in the literature and best performance achieved by state-of-the-art plants [35,65,102,103]. For example, the Nordjylland Power Station, commissioned in 1998 in Denmark, is touted by its owner Vattenfall as holding the world record for most efficient coal utilization, with a net HHV efficiency of 45%. Various combined cycle gas turbine power plants build in the last decade, based on SGT5-8000H gas turbine from Siemens and H-class gas turbines by General Electric, are rated at over 55% HHV efficiency. Black and Veatch estimate the heat rate of coal-fired power plants to decrease from 12,600 to 12,100 by 2030 [35]. Van den Broek et al. [65] report the following HHV efficiencies in the year 2050, based on technological learning curves: 48% and 39% for coal steam plant without and with CCS, respectively; 58% and 52% for natural gas combined cycle plants without and with CCS, respectively; and 49% and 44% for coal-fired IGCC, without and with CCS, respectively. EPRI report next-generation natural gas combined cycle plants operating at about 60% HHV efficiency, and simple cycle industrial gas turbines at about 45% HHV efficiency [102]. Table 5 reports the assumed maximum achievable HHV efficiencies, the assumed improvement rate and the efficiency values in 2015, 2050, and 2100 for the technologies considered in this study.

4.2. Future costs of power plants

The discussion in Section 2 articulates the complexity of making predictions of future cost and cost trends for different power plants, especially for the long-term. Here we attempt to provide guidance on future trends of power plants construction costs to be used for energy systems modeling. Our estimates are intended to serve as a reference point for energy models projecting results up to 2100, without diving into the details of each single technology.

First, we group the 23 technologies considered in this study in three

[10] For this application, similar results are obtained following the approach proposed by Denton [111].

Table 5
HHV efficiencies: maximum achievable efficiency, improvement rate and 2015, 2050, 2100 HHV efficiencies.

Technology	η_{BEST} [a]	r	η_{2015}	η_{2050}	η_{2100}
Coal (steam plant)	0.56	0.015	0.38	0.45	0.51
Coal CCS (steam plant)	−0.08	0.05	0.28	0.38	0.43
Coal (IGCC)	0.57	0.02	0.39	0.48	0.54
Coal CCS (IGCC)	−0.05	0.05	0.32	0.43	0.49
Natural Gas (simple cycle)	0.49	0.015	0.34	0.38	0.42
Natural Gas (CC)	0.66	0.015	0.51	0.57	0.62
Natural Gas CCS (CC)	−0.05	0.05	0.42	0.52	0.57
Oil (simple cycle)	0.51	0.015	0.34	0.39	0.44
Oil (CC)	0.68	0.015	0.52	0.59	0.64
Oil CCS (CC)	−0.05	0.05	0.39	0.53	0.59
Biomass (steam plant)	0.40	0.015	0.25	0.31	0.36
Biomass CCS (steam plant)	−0.08	0.05	0.18	0.24	0.29
Biomass (IGCC)	0.47	0.02	0.30	0.39	0.44
Biomass CCS (IGCC)	−0.05	0.05	0.25	0.34	0.39

[a] Efficiency of CCS technologies is reported as penalty compared to the corresponding plant without CCS.

Table 6
Level of technology development stage for electricity-generating technologies.

Technology	Mature	Evolutionary	Revolutionary
Coal (steam plant)	✓		
Coal CCS (steam plant)			✓
Coal (IGCC)		✓	
Coal CCS (IGCC)			✓
Natural Gas (simple cycle)	✓		
Natural Gas (CC)	✓		
Natural Gas CCS (CC)			✓
Oil (simple cycle)	✓		
Oil (CC)	✓		
Oil CCS (CC)			✓
Biomass (steam plant)	✓		
Biomass CCS (steam plant)			✓
Biomass (IGCC)		✓	
Biomass CCS (IGCC)			✓
Nuclear	✓		
Wind (on-shore)	✓		
Wind (on-shore + battery)		✓	
PV (large-scale)		✓	
PV (large-scale + battery)		✓	
PV (rooftop)		✓	
CSP		✓	
CSP (+ thermal storage)		✓	
Geothermal	✓		

classes (as reported in Table 6): mature, evolutionary, and revolutionary, based on EIA assessment [51]. Technologies in the same class will experience the same cost reduction rate over time. The basic idea is that mature technologies experience a similar cost change. Evolutionary technologies experience a faster improvement. Revolutionary technologies experience an even faster initial improvement rates. Also, the future cost of revolutionary and evolutionary technologies is affected by larger uncertainty, compared to mature technologies. why they made this assumption?

The cost of CCS technologies includes only the additional costs associated with the CCS components of the plants. Namely, a coal-fired steam plant equipped with CCS will experience mature improvement rates for the main steam plants, and revolutionary improvement rates for the CCS components only. Analogously, the technology development rate of technologies with energy storage options (*e.g.* batteries) refers only to the additional cost related to the energy storage systems.

Generally, energy systems model assume progressive reductions in the cost of power plants, based on the vast learning-curve literature. The review provided in Section 2 does not provide sufficient empirical evidence of such a reduction for construction cost of power plants based on mature technologies, such as fossil-fired and nuclear power plants. Thus, we assume that the cost of mature technologies will remain stable at current level, unless major changes in the global economy impacting commodity prices, equipment and manufacturing capabilities, and the competition for power plant design and construction resources. This assumption is consistent with cost estimates reported in recent comprehensive reports, *e.g* [35]. Bilgili et al. [104] presents an overview of renewable electric power capacity worldwide and details the current status, and recent trends for cost variations for renewable power plants in the last five years, indicating a decreasing trend only for solar technologies (confirmed by reported costs of PV in the U.S. market [78,79,105]). Evolutionary and revolutionary technologies are expected to experience cost decrease over the next decades, the rate of which is uncertain and affected by regional and technology-specific factor.

Potential future cost reductions are key factors in determining the deployment of new technologies and the future technology mix of the electricity system. We identify technologies most likely to be affected by cost decreases over the next decades, and perform a sensitivity analysis to explore the importance of cost change assumption in projections generated by energy systems models. This sensitivity analysis, which is used as an illustrative example for the methodology proposed here to project future cost of electricity-generating technologies, allows evaluating the importance of future cost reductions for evolutionary and revolutionary technologies. do we need the results of these runs?

Once again, we use the Global Change Assessment Model (GCAM) to perform this sensitivity analysis for two scenarios: slow and fast cost reduction for evolutionary and revolutionary technologies. The two scenarios are intended to illustrate two alternative futures where the construction costs of some electricity-generating technologies are affected by different improvement rates. Table 7 reports minimum achievable capital cost (y_{BEST} in Eq. (1), expressed as a percentage of the current capital cost) and improvement rate (r) used for the two scenarios considered in this example.

While this example is purely illustrative, and aims at understanding the impact of possible future technology cost reductions on the projected energy mix, numerical values are chosen so as to mimic recent empirical cost reductions experienced by electricity-generating sources. In particular, renewables recently experienced fast technology cost reductions: Feldman et al. [78] report that capital cost for residential PV fell by over 60% in the last two decades. Wiser and Bolinger [106] report reduction of about 40% for construction cost of wind technologies between 1985 and 2000. These values are used to build the fast technology cost reduction scenario for revolutionary and evolutionary technologies, respectively. As lower technology cost reduction scenario is then proposed for comparison.

Fig. 7 shows the evolution of the electricity sector, as projected by GCAM, in the two scenarios considered: slow and fast technology cost reduction, both assuming a climate change mitigation policy stabilizing radiative forcing to 2.6 W/m^2 [107,108].

In both scenarios evolutionary and revolutionary technologies are largely deployed to decarbonize the electricity sector and satisfy the CO_2 emission constraint set by the climate policy. This example illustrates the sensitivity to cost improvement assumptions. In particular, results show minimum differences in the short-term (~20 years), indicating that early technology deployment is mainly driven by current cost estimates. The cost estimate used in this example is based on the literature review provided in Section 3, and assumes that the cost escalation experienced by the electric power sector in the U.S. is effectively a baseline increase, rather than a market bubble. In the medium and long-term, though, the two scenarios show significant differences in the deployment of CCS-equipped plants and solar technologies, given their different improvement rates. By 2100 solar accounts for 10% of the electricity generated in the fast-technology scenario, compared to 5% assuming slower technology improvement. The doubling in solar power deployment illustrates how assumptions on cost reduction over time drive of the long-term energy mix in the electric power sector.

Table 7
Future technology cost improvements sensitivity analysis: scenario definition. Cost of mature technologies is assumed to remain constant.

	Evolutionary Technologies		Revolutionary Technologies	
	y_{BEST}	r	y_{BEST}	r
Slow technology cost reduction	75%	−0.01	60%	−0.03
Fast technology cost reduction	60%	−0.03	40%	−0.05

5. Conclusions

This paper is intended to serve as a basis for the energy modeling community engaged in projecting the future electricity generation mix and its role for climate change and climate change mitigation. In particular, we discuss the recent cost escalation that affected the electric power sector between 2003 and 2007 in the United States, showing significant cost upsurges for several electricity-generating technologies, especially large plants such as nuclear and coal-fired power plants. For several decades prior to the cost escalation, aggregate construction cost indices report that power plant construction costs for mature technologies (such as coal-fired, natural gas-fired, and nuclear plants) had risen roughly in line with inflation [8]. The stability of these estimates is also supported by looking at EIA base year cost estimates for the early 2000s [25]. This contradicts widely accepted literature on cost decrease driven by learning, which raises the possibility of a limited role for learning as a driver of total construction cost changes for mature technologies in the electric power sector. With this in mind, we explore the drivers of the 2000s cost escalation experienced in the U.S. with the goal of understanding its implications for energy systems modeling. The main drivers remain somewhat ambiguous; however, we highlight the possible contributions of the cost of materials, particularly the price of metals and to a lesser extent cement, possible increases in labor quantity, the aggressive worldwide competition for power plant design and construction resources, driven by high demand in Asia, market power of construction and engineering firms, and general uncertainty about future regulations and the cost of policies. Of relevance to future projections is the permanence of these cost increases. Construction costs have risen roughly in line with inflation for major technologies since 2009 [6,8,24] and have not decreased to pre-escalation levels. However, the future demand for new power plants, the price of international commodities, especially materials, and future policies will continue to play a role in determining how construction costs will evolve.

Given the sensitivity of energy system models, and integrated assessment models in particular, to the cost of different power plants, the recent cost escalation trends in the sector call for a review of the assumptions used. We recalibrate power sector technology costs in the Global Change Assessment Model (GCAM) based on an extensive literature review of recent (post-2010) studies; and in the process develop a consistent and updated set of efficiency, capacity factors, capital, and O & M costs for all major electricity-generating technologies. Of particular importance for modeling the competition among different electricity-generating technologies are estimates of capital cost, compared in Fig. 4 against a wide array of literature sources.

Current cost and performance assumptions of different electricity-generating technologies are key drivers to project short-term technology deployment and technology mix in the electricity sector. However, medium- and long-term deployment pathways are affected significantly by assumed cost reduction and efficiency improvement rates. We propose a framework to estimate future power plants efficiencies based

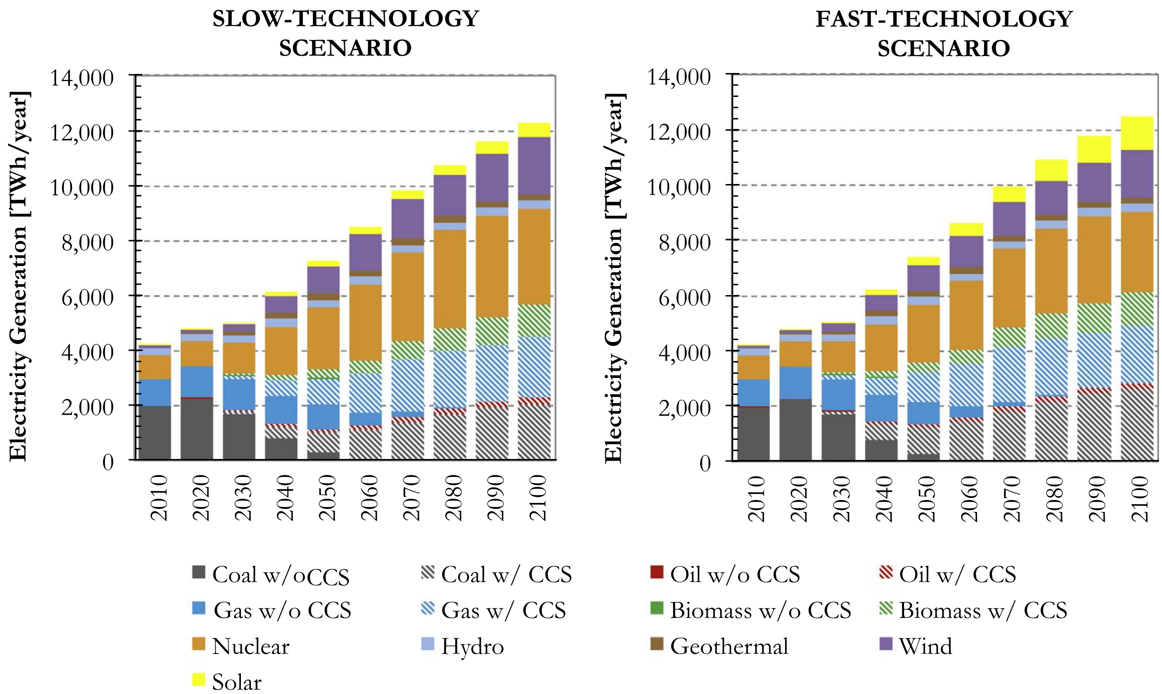

Fig. 7. Evolution of the U.S. electricity sector in the slow- and fast-technology improvement scenarios.

on an exponential growth formulation with a limiting bound identified by finite-time thermodynamics theory. Generally, energy systems models assume progressive reductions in the cost of electricity-generating technologies, based on the learning-by-doing notion that unit costs often tend to decline as technologies are deployed. However, we did not find sufficient empirical evidence of such a cost reduction for mature technologies, such as fossil-fired and nuclear power plants. While learning models seem to apply for technology costs, like that of boilers used in coal-fired power plants, total construction cost is a combination of the technologies deployed and other economic and financial factors that are required to deploy and operate a technology. This approach is also supported by previous literature studies (e.g [35].) and by looking at the EIA base-year cost estimates for different technologies used in different releases of the Annual Energy Outlook (even though EIA assumes technology cost reductions in their future estimates, base-year estimates do not reflect this trend). We assume cost reductions only for a limited set of technologies for which future costs are more uncertain, namely solar, IGCC plants, and CCS applications, based on the current state of these technologies and falling reported costs of PV in the U.S. market [78,79,105]. The discussion in Section 2 articulates the complexity of making predictions of future cost and cost trends for different power plants, especially for the long-term. Thus, we provide a sensitivity analysis, to illustrate the importance of future cost reduction estimates, showing that the short-term (~20 years) technology deployment is mainly driven by initial cost estimates; while cost reduction assumptions are more important to forecast medium- and long-term technology deployment and the energy mix in the electric power sector in the distant future.

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