Testimony Of Robert Hilton
Before the U.S. House of Representatives
Subcommittee on Energy and Power
"The American Energy Initiative" Hearing
September 20, 2012

Good morning. My name is Robert Hilton. I hold the position of Vice President, Power Technologies for Government Affairs for Alstom. I would like to thank Chairman Whitfield and Ranking Member Rush as well as the entire Subcommittee for this opportunity to address these key issues on Carbon Capture and Sequestration (CCS).

Alstom is a global leader in the world of power generation, transmission, and transportation infrastructure. We set the benchmark for innovative and environmentally friendly technologies. More than 50% of the power plants in the United States have Alstom equipment, and 25% of the world's electricity is generated on Alstom equipment. Alstom has the world's largest service business devoted to the maintenance of power generation equipment and is the world's largest air pollution control company.

Alstom employs more than 91,000 people in 100 countries, and had sales of $25 billion in 2011-2012. In the U.S., Alstom employs approximately 6,000 full time permanent employees in 45 states. That number virtually doubles when you include workers hired for specific projects.

Alstom has a broad portfolio of power generation technology options: including coal, oil, natural gas, wind, hydro, geothermal, solar and nuclear. Significant pillars of our program are rapid and successful deployment of non-$C0_2$ sources of generation, namely nuclear and renewables; reduced $C0_2$ emissions through more efficient generation; and the capture of $C0_2$ from fossil fuel powered generation

(CCS). Alstom invests approximately $1 billion in annually in research and development.

Alstom is a leader in the field of CCS having completed work on four pilot or validation scale plants and with 10 pilots, validation, and commercial scale demonstration plants in operation, design, or construction worldwide.
These CCS projects include both coal and gas generation facilities. Alstom is commercializing three first generation capture related technologies: chilled ammonia, advanced amine, and oxy-firing. We also have second generation technologies like chemical looping in development with DOE.

We are here today to specifically address the status of CCS as a commercial technology.

CCS is, within the realm of innovation, no different than any other technology under development. It is required to move through various stages of development at consistently larger scale or size. This process has been shown over decades to be the best approach to ensure commercial success by meeting the high standards of our industry and providing the confidence and reliability required by the power industry and the electricity consumers.

Alstom has taken each of its CCS related technologies from the bench level to small and then larger pilots, followed by validation scale demonstrations with the aim to finally reach commercial scale demonstration. To date, no CCS technologies have been deployed at commercial scale demonstration size. Alstom has successfully taken several of its technologies through the validation scale demonstration. This stage is the proof of technology in real field conditions (or in this case actual power plant flue gas). It is at this point we can say confidently that the basic technology works. It is technologically feasible.

However, the final stage to reach commercial status is to perform a demonstration at full commercial scale. There are several reasons for this requirement. It is critical to be at commercial scale to define the risk of offering the technology. This cannot be defined until the technology can be shown to work at full scale. This is the first opportunity that we have to work with the exact equipment in the exact operating conditions that will become the subject of contractual conditions when the technology is declared commercial and is offered under standard commercial terms including performance and other contractual guarantees. This also becomes the first opportunity to optimize the process and equipment to effect best performance and, very importantly, seek cost reduction. These too are required to define commercial contractual conditions.

Based on these criteria, Alstom does not currently deem its technologies for CCS commercial and, to my knowledge, there are no other technology suppliers globally that can meet this criteria or are willing to make a normal commercial contract for CCS at commercial scale. I emphasize however that the technologies being developed by Alstom and others work successfully.

For a number of reasons primarily related to technology funding and lack of regulatory clarity, the time to commercialization for CCS technology is not clear. The current DOE program for first generation technologies on CCS has encountered serious difficulties in bringing projects of commercial scale to operation. It appears that most of the projects, if they continue, are not likely to become operational until 2017 with the exception of Radcliffe/Kemper. Globally the picture is similar.

The EU, and notably the UK, are targeting 2016 for commercial scale demos to start up. The Chinese have a roadmap aimed at two commercial scale demos to begin operation in 2016. But note: these are startups. A period of operation must follow before the technology is deemed ready for commercial offer.

When we look at the history of the Environmental Protection Agency and the air pollution control industry, we generally see a harmony of regulation and technology development. In many cases, we have had the ability to meet or anticipate the need for certain technologies and in other cases we have developed the base technologies either in industries other than power or in other global venues. CCS has been in development for approximately the last 12-14 years- a relatively short time for such a complex and critical technology. In the power industry, development periods of 20-25 years are common.

In its recent rule making, EPA has required CCS for all new coal plants and, conceivably some gas plants. While Alstom, in conjunction with American Electric Power, have built and operated the largest continuous CCS operation on a coal plant through to sequestration, this plant was approximately 50 MWth. This plant while proving the technology works very well was not of such scale as to use the real equipment required for a 500 or 1000 MW Coal plant. Many of the components including the chillers and heat exchangers will change for use on a larger plant. While this plant was capable of capturing and storing over 100,000 tons per year, it was not ready to be offered commercially on a 3-6 million ton per year power plant.

When the EPA came forward with a requirement for a technology in commercial practice that is not yet available commercially as the only way to meet a regulation, it seemed a departure from its history. Alstom has communicated this message in many seminars, papers, and communications with the Agency and with Congress. The DOE program supporting CCS reflects the same results.

It has been suggested that the proposed rule would stimulate CCS development. However advancing CCS requires a regulatory approach that recognizes the steps of the technology development process and the need for financing. Commercial power plants cannot secure financing for a plant that includes technology still under development and that carries with it undefined guarantees. Doing so would impact the plant's ability to compete in the market or even generate electricity, as the technology becomes part of the power plant's operating permit.

Coal is an important part of America's future energy mix as it has been in the past. It is a great resource we have and we have the technologies to make it clean in all other respects. CCS is coming but preventing new highly efficient coal plants from being built to replace older less efficient plants by requiring a technology not yet in practice is not in keeping with the Agency's history or the needs of the industry or the public. We believe a more realistic approach would be to provide a reasonable ramp down of CO2 over time that can take advantage of efficiency and other technologies to reduce CO2 in a gradual manner. This would provide the industry, along with the state and local regulators, with the incentive to consider demonstrations and allow them to be funded to place the industry in a position to meet the long term reduction goals that are sought in the most efficient and cost effective manner without removing critical resources like coal from the generator's strategy.

Alstom believes that the technology will be commercial when the industry determines that both buyer and seller can enter in ordinary contractual relations that meet the needs of both parties – not when a regulation is announced. As part of this industry, we have always prided ourselves on being ready to meet regulations and our customer’s needs in a prompt, efficient and cost effective manner. It is for the government and the regulators to offer standards to be met and for the industry to provide technology and solutions to meet those standards.

We know that carbon capture technology works. We need time and support to reach the point of commercial offerings.

Major Highlights From the Testimony of Robert Hilton Before the House of Representatives Subcommittee on Energy and Power at the Hearing on The American Energy Initiative
September 20, 2012

1) CCS technology is proven and is technologically feasible

2) CCS is not commercially available as it has not been demonstrated at commercial power plant scale

3) The CCS technology requires both policy direction and financial support to be demonstrated at commercial scale

4) Demonstration at commercial scale is critical to define risks, optimize process and achieve cost reduction to support commercial contracting.

5) Regulation should depend on technology that is commercially available when the regulation goes into effect.

6) Coal is a critical domestic resource and should remain a vital part of the United States' energy mix to help strengthen energy security.

7) CCS needs to be part of the American technology portfolio and not developed else where.

ALSTOM

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25 June 2012

EPA Docket Center (Air Docket)
U.S. Environmental Protection Agency
Mail Code: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Attention: Docket ID Number: EPA–HQ–OAR–2011–0660

Re: Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units; 77 FR 22392-22441 (April 13, 2012)

Alstom is a global leader in the power generation, rail transportation infrastructure and power transmission and distribution industries. Our company sets the benchmark for innovative and environmentally friendly technologies. Today, Alstom equipment can be found in approximately 50% of U.S. power plants, while globally it generates about 25% of the world's electricity. Alstom also is the world's largest air pollution control company. Alstom employs more than 93,000 people in 70 countries and had sales of approximately $30 billion in 2010-2011.

Alstom is among the world's leading suppliers of fossil fuel combustion equipment for electric power generation including gas turbines and steam boilers and turbines. Alstom is also the leading air pollution control company globally.

Additionally, Alstom is a leader in developing carbon capture technologies to lower CO2 emissions. Alstom is commercializing three CCS technologies: oxy-firing combustion, Chilled Ammonia and Advanced Amine for post-combustion control. Currently, Alstom has 12 CCS projects in the operation, construction, or engineering stages around the world. These range from small pilot plants up to 250 MW commercial size plants.

Overarching Comments

Alstom supports the need to protect the environment, deploy the most efficient technologies, and provide sustainable power generation. However, Alstom, in reviewing the proposed standards for Greenhouse Gas emissions for New Stationary Sources, finds the proposal fails to adequately consider the state of the technology evolution in power generation and is in fact a proposal that does not reduce greenhouse gases in a meaningful way to provide environmental benefit. As EPA itself points out this proposal merely slows the rate of acceleration of GHGs in atmosphere rather than providing meaningful environmental benefit.

Alstom offers specific comments below. We have concentrated our comments on a few specific areas, most particularly relating to technology. Alstom sees the combining of gas and coal as a single category as inappropriate not simply for historical reasons but because the fuels are unique unto themselves in power generation technology and should be considered in that manner. Suggesting gas turbines are an acceptable means of emission reduction for coal fired units is a failure to embrace technology and understand the complexity of the electric generation industry where fuel price is not the only consideration in selecting generation.

Further, CCS is a truly evolving technology and will be critical to achieving significant GHG reductions when the technology is deployable at scale and when the standards are geared to meaningful reductions in GHG emissions. But EPA's suggestion that either Carbon Capture or Sequestration is currently available for deployment at commercial scale is simply a misunderstanding of the state of the technology development.

Alstom also offers comments on appropriate level of emissions given the scope of operation EPA has defined and based on operation of electric generating units as the market demands. As the market for generation continues to change with renewables and other factors, it is critical to understand the roles of gas and coal in servicing the generation industry within the whole of the interconnected electric system.

Finally, Alstom offers an alternative method to calculate the rolling average that is more reflective of the way electricity is generated and avoids the potential inappropriate weighting of marginal or seasonal emission periods.

Specific Comments

I. New Source Performance Standard, Source Category, and Best System of Emission Reduction

Alstom Power, Inc. offers the following detailed comments with respect to the New Source Performance Standards (NSPS) for Greenhouse Gases for New electric generating Units.

It would appear that EPA has chosen for convenience and misinterpretation of the information from the Energy Information Agency that Natural Gas Combined Cycle Units (NGCC) and coal combustion technology are now the same source category. In the forty-year plus history of the EPA and the NSPS promulgation, these technologies have always been separate source categories. Through all other criteria pollutants and Hazardous Air Pollutants these technology areas have been separate, which would require separate standards for Greenhouse Gases. However, EPA relies on the EIA finding that "no new coal plants will be built in the near term" to make a justification for a single new category. Alstom would point out that this reliance is based on the so-called Reference Study and EIA has done no real sensitivity to determine the accuracy of the low natural gas prices to warrant such reliance. Alstom points out the history of gas pricing reflecting that in the last 12 years gas prices have ranged from $2/mmBtu to over $14/mmBtu. EIA is currently reviewing potential sensitivity for publication later in 2012. Moreover, the EIA study does not compensate for such factors as localization, value of fuel diversity, and other strategies pursued by utilities in the commercial world. Further, NSPS are to reflect the degree of emission reduction achievable through application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. The format of NSPS can vary from category to category (and even from facility to facility type within an NSPS) although such standards are based on the effectiveness of one or more **specific air pollution control systems** (emphasis added), section 111 (b) (5) provides that the EPA may not prescribe a particular technology that must be used to comply with an NSPS, except in the instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Alstom wishes to point out in this rule making that an NGCC is not "an air pollution control system" but an alternative way to convert certain fossil fuels into energy and electricity. Thus it does meet the definition of a "best system of emission reduction". Similarly, by allowing coal plants only with CCS (a technology that is not available- to be discussed later) EPA is mandating the selection of NGCC technology in its BACT process which is contradictory to EPA policy that EPA cannot mandate technology or interfere in commercial markets.

Alstom also cites the EPA memo on Philosophy of BACT (January 4, 1979 by David Hawkins) which says “In setting the NSPS, for example, emission limits are selected which can reasonably be met by all new or modified sources in an industrial category, even though some individual sources are capable of lower emissions. Additionally, because of resource limitations in EPA, revision of new source standards must lag somewhat behind the evolution of new or improved technology. Accordingly, new or modified facilities in some source categories may be capable of achieving lower emission levels than NSPS without substantial economic impacts. The case-by-case BACT approach provides a mechanism for determining and applying the best technology in each individual situation. Hence, NSPS and NESHAPS are Federal guidelines for BACT determinations and establish minimum acceptable control requirements for a BACT determination.”

II. Availability of Carbon Capture and Sequestration

Alstom wishes to deal with this subject as two distinct issues: Carbon Capture and then Sequestration.

Alstom is a leading global developer of carbon captures technology. The true state of the technology is that today there has been one 58 MW capture unit at AEP’s Mountaineer Plant (since shut down), one 25 MW capture plant at Southern Company’s Plant Barry (still in start up) and one 40 MW capture plant in Mongstad, Norway that started up in May 2012. This is the extent of the largest current capture technology on power plants. The Department of Energy (DOE) is participating in a number of projects sited by EPA in its text which are about or nearly demonstration size that are all estimated to start between 2015 and 2017. Alstom would point out the recent report by the Congressional Research Service (Carbon Capture and Sequestration (CCS):A Primer , Peter Folger ,Specialist in Energy and Natural Resources Policy; May 14, 2012), which calls into question whether all or any of these will become fully operational. Alstom would contend that while the technology has been proven that the capture processes work, the industry has yet to reach demonstration stages to reduce the cost and reduce the risk of scaling these technologies from pilot or validation scale to full scale. Thus Alstom would challenge EPA on the argument that Carbon Capture is available and demonstrated. Without demonstration, the technology cannot be considered for application as NSPS or best system of emission reduction.

Alstom would also point out to EPA, that it is unaware that any supplier of this technology is ready or able to offer commercial guarantees for such full-scale systems of carbon capture. This would in turn mean that no new coal burning plant could be permitted or financed. Hence it is unlikely that such systems will be available prior to the EPA obligatory eight-year review of this proposed NSPS.

Alstom would also point out to EPA that DOE has developed a comprehensive roadmap and timeline for the commercialization of CCS technologies which ultimately points to general deployment around 2020 after the technology has been demonstrated at scale and second generation technologies can reduce costs. This timeline, if embraced by EPA, would set CCS aside until the EPA suggested eight-year review of NSPS, thus avoiding conflict between agency visions. Similarly, by simply requiring all technologies be the highest possible efficiency (such as Ultra Super Critical technology), this proposal would promote the policy of having the best available technologies to replace the older less efficient existing fleet.

Alstom would also take exception to EPA's position that this rule would incent the development of CCS. We are very much in an economic period where public utility commissions and regulators are fighting to maintain the lowest cost of electricity to the ratepayers. Since Alstom would agree that EPA's NSPS would keep any new plants from being built (albeit for different reasons outlined above), it is very unlikely that any commission will allow the recovery of development costs on existing plants based on a new plant rule. Reaching demonstration scale is critical to the successful adoption and application of the CCS technology by generators and acceptance by the financial community. We also point out that since the only avenue might be the 30 year averaging scheme, this will mean CCS will not be required until late in the mid 2025 period meaning R&D will be have to continue for an additional 5-8 years beyond current market forecasts. Thus EPA expects the industry to continue to develop a very long-range technology without any apparent Federal or governmental support. Thus Alstom would contend that this proposed rulemaking would likely delay the development of the technology. Alstom would also suggest that it is highly unlikely that anyone would engage in the 30 year averaging scheme due to the level of uncertainty associated with potential NSPS review EPA mentions combined with uncertainty associated with unknown costs and availability of CCS to allow financing.

Finally, Alstom would comment on sequestration. EPA was diligent in quoting sections of the President's Inter-Agency Taskforce on carbon capture potential. However, EPA failed to note the Taskforce listed a number of barriers to the deployment of sequestration such as undefined pore space ownership, sequestration liability, permitting, status of CO2 under RCRA and many other subjects. Virtually all of these remain unresolved and are barriers to any serious deployment of the technology beyond a few demonstrations. The few examples of sequestration EPA sites are either outside the United States, not associated with power plants, or are granted under special R&D status permits.

III. Appropriateness of Recommended Standards

Alstom would suggest that EPA reconsider the proposed standards for both NGCC and Coal based generation. The study performed by University of California Berkley (Matthew J. Kotchen and Erin T. Mansur, "How Stringent is the EPA's Proposed Carbon Pollution Standard for New Power Plants?" University of California Center for Energy and Environmental Economics, April 2012), was based on actual emission data as opposed to EPA's predicted and adjusted data. The UC study point out that approximately 16-29% of the NGCCs (depending on calculation methods) will fail the 1000 pounds per MWHr standard as opposed to the 5% failure rate EPA has suggested. This clearly reflects the need to establish a standard for NGCCs in the 1100 – 1200 pound range to allow for low load operation in support of reliability in the grid, support of renewables, and other unplanned events.

Alstom has reviewed the 1800 pound per MWHr for coal based units and it appears that given the same operating conditions the industry is now experiencing that it is uncertain if any unit can make this standard. It would seem the very best units on bituminous coal may make the standard by a different calculation method, but based on heat rates projected for IGCC, and USC on lower rank coals, the standard of 1800 is unachievable. With the unavailability of CCS, it means no new units could even be considered. A detailed analysis of the proposed standard and operational impacts is presented below.

The EPA proposed an alternative compliance option whereby power plants would be limited to 1800 lb CO_2/MWh_{gross} for the first 10 years of operation and then be required to install CCS equipment. The EPA reviewed data from its Clean Air Markets Database and concluded that this annual standard is appropriate for all new coal-fired power plants, regardless of fuel type. While it is true that a modern power plant can theoretically achieve these emission levels for selected fuels, it is extremely difficult or impossible in practice to achieve these limits when real world conditions are factored in, such as fuel characteristics, load following, site/ambient conditions, and equipment degradation.

Table 1 shows the expected CO_2 emissions for selected US fuels, ranging from bituminous coal to lignite and for a modern PC power plant operating at full load conditions. Natural gas is included for comparison. This table shows that the 1800 lb/MWh limit may be achievable at full load conditions for bituminous coals, barely achievable for subbituminous coals, and unattainable for lignites.

Table 1: Specific CO_2 Emissions vs. Fuel Type

Fuel	lbm CO2/Mwh-gross	
Texas Lignite	1827	
North Dakota Lignite	1857	
Wyoming Sub-Bit	1781	
Illinios High Vol Bit	1698	
Natural Gas	922	

However, there are a number of other factors that impact plant heat rate and thus CO_2 emissions that also must be taken into account. All of these factors make the proposed EPA target that much more difficult to achieve or beyond attainment. These will be discussed individually below:

Partial Load Operation
The net plant heat rate increases as the plant operating load is reduced, which corresponding increases the specific CO_2 emissions. Based on a recent commercial power plant, the heat rate increases 1% at 75% load and 6% at 50% load. The heat rate increases dramatically at even lower loads, rising by almost 20% at 35% load. This has a significant impact on the specific CO_2 emissions as a result of normal plant load variations. Power plants typically follow either a baseload or cycling operation load profile, depending upon factors such as the plant's dispatch cost and grid requirements. These situations had quite different patterns of load variations and corresponding emissions levels.

Baseload Operation
All power plants have some load variation that will have impacts on a plant's heat rate and CO_2 emissions. A typical PC baseload plant may operate 60% of the time at 100% load and another 35% between 50-75% load. The average capacity factor would be about 85% and it would have an average heat rate typically about 1% higher than at 100% load. This alone would be sufficient to increase the specific CO_2 emission from a PC plant firing Wyoming subbituminous coal from 1781 to 1799 lb CO_2/MWh – essentially at the 1800 limit.

Cycling Operation
A typical PC cycling plant may operate 30% of the time at 100% load, another 55% between 50-75% load, with the balance of operation at even lower loads. The average capacity factor would be about 70% and it would have an average heat rate typically about 4-5% higher than at 100% load. A 5% heat rate increase from cycling operation would increase the specific CO_2 emission of the Illinois bituminous coal from 1698 to 1783 lb CO_2/MWh – already getting very close to the 1800 limit. Note that this is particularly significant as more plants are expected to cycle in the future as renewables increase their share of power generation.

Degradation Due To Plant Age
Power plants are designed to operate for 30 years and many existing plants have operated much longer than that. Normal wear and tear is to be expected which has an impact on the plant heat rate. Looking at just the steam turbine, the plant heat rate could deteriorate by about 1% after 10 years of operation.

Site Factors

Other factors can impact a modern plant design that can also have a negative impact on plant heat rate and thus the CO_2 emissions. For example, areas with limited water resources could require an air-cooled condenser vs. water cooling. Local water temperature can also have an impact on condenser operating pressure and heat rate.

Table 2 summarizes the impact of an increase in plant heat rate due to the above factors on the specific CO_2 emissions for a state-of-the-art USC PC power plant. A plant that is required to cycle would likely have a heat rate 5% higher than its design 100% load heat rate. In this scenario, a bituminous coal would just barely meet the standard and the lower rank fuels would exceed the 1800 lb CO_2/MWh target. It is likely that the bituminous plant would also exceed this target when site specific factors, impacts of startup, shutdown, and age deterioration are also factored in. The cycling impact could be even more significant in the future as renewables assume a larger portion of the total power generation.

Table 2: Impact of Heat Rate Degradation on Specific CO_2 Emissions

	Specific CO_2 Emissions					
Fuel Type	lbm CO_2/MWh-gross					
Texas Lignite	1827	1845	1863	1881	1900	1918
North Dakota Lignite	1857	1875	1894	1912	1931	1949
Wyoming Sub-Bit	1781	1799	1817	1835	1852	1870
Illinios High Vol Bit	1698	1715	1732	1749	1766	1783
Natural Gas	922	931	940	949	958	968

EPA Clean Air Markets Database

The EPA cited data from their Clean Air Markets Database to support their selection of the 1800 lb CO_2/MWh target. A review of the database showed that while there were a limited number of plants that met this target, the bulk of the reporting plants exceeded it by a wide margin. The average specific CO_2 emissions from 230 reporting plants (after removing some obvious outliers) was 1916 lb CO_2/MWh.

Table 3 shows a comparison of the 4 SCPC plants that the EPA cited in justifying the proposed 1800 lb CO_2/MWh target. They looked at data reported to the EPA's Clean Air Markets database and picked out four of the best performing SCPC plants as representative of a new coal-fired power plant. An independent check was made of this data by reviewing the hourly emissions reported in the Energy Velocity database. The results show similar CO_2 emission rates. What stood out though was the high capacity factor for these four plants. All of them were clearly operating as baseload plants, with capacity factors in the mid 80% for three of them. Note that none of them would have met the proposed target if they operated as typical cycling units, as becomes more likely as renewables assume a larger share of power generation.

Table 3: Comparison of EPA Clean Air Markets and Energy Velocity Databases

Data from EPA Clean Air Markets Database				Data from Energy Velocity Database		
Facility	**Time Period**	**Primary Fuel**	**Max 12 month CO2 Emissions Rate - lb CO2/MWhr-gr**	**Time Period**	**Max 12 month CO2 Emissions Rate (lb CO2/MWhr-gr)**	**Average Capacity Factor (%)**
Bull Run 1	2009-2010	Bituminous	1740	2009-2011	1753	86
Weston 4	2008-2010	Subbituminous	1740	2007-2011	1740	84
WH Zimmer 1	2005-2009	Bituminous	1760	2005-2009	1721	86
Walter Scott Jr 4	2007-2010	Subbituminous	1800	2005-2011	1815	77

The EPA also states that marginal units can still achieve this standard by applying costly improvements, such as double reheat, coal drying (for lignites), even cofiring with natural gas. These modifications all add additional equipment at the expense of increased capital/operating cost and potentially decreased availability. The EPA should not be requiring the installation of this type of equipment in order to achieve their target. This requires added expense and makes coal-fired technology less competitive.

Alstom furthers suggests that working closely with industry EPA can refine these numbers. The objective should be to drive the most efficient technologies given fuel availability and technology limitations and availability. As EPA points out, this NSPS standard will be in review in eight years, which Alstom believes will be timely for the deployment of technologies such as CCS. This also is in line with the US Department of Energy's roadmap and timeline. The key point to be made is that permits are customarily permanent. Setting an output standard based on "as new" performance values for equipment that are known to lose efficiency with time will insure that eventually no plant will meet its permit limits.

IV. Rolling Average Calculation

EPA proposes a 12 month rolling average whereby the CO_2 emissions in a month are divided by the grow MWHrs in the month. Then the 12 contiguous monthly averages are summed and divided by 12 to develop the compliance average. This technique does not reflect the way the power industry actually performs. It gives equal weight to each month without regard for the actual production in a month impact of operations. The power industry normally has heavy production in the winter and summer and less production in the shoulder months of fall and spring. The EPA method would give equal weight to month where a unit was on low load and less hours (providing an average above the standard) to a month where a unit runs virtually all the time at high load (coming under the standard). In essence, the EPA calculation method will alter the generator's decisions on important issues like low load standby reserve, backup for renewables, and other conditions.

Alstom would suggest a method where in each twelve-month period the total emissions for the 12 contiguous months are divided by the total gross MWHrs in the months. This then reflects the actual production against the standard**.**

V. Specific Comments on Gas Turbines

In addition to comments above about appropriate standards, Alstom would comment on questions raised by EPA about gas turbine technology as follows.

Alstom offers no objection to exemption for simple cycle units proposed by EPA. Alstom does comment that the logic of being unable to set reasonable standards for simple cycles operating within the limited time window defined by EPA seems inconsistent. Since EPA is setting standards of performance for other fossil generating units, EPA should set relevant standards for simple cycle units to insure that the industry continues to pursue the most efficient technologies available.

To the EPA's question of whether or not exclusion of simple cycle gas turbines from the rulemaking would favor them over combined cycle gas turbines in the marketplace, Alstom believes that the economics of the application always govern the choice between simple and combined cycle with capital costs and efficiencies being significantly different between the two. Thus anticipated run times (peaking, daily start-stop, or base load), the price of fuel, and capital cost of the power plant are the controlling drivers in decision making.

Finally, to the question of this regulation perhaps having the unintended effect of delaying the upgrading of simple cycle installations to combined cycle; Alstom believes that market conditions will continue to dictate upgrading when the need for the added generation capacity is seen. Since most combined cycle units will have no trouble meeting the proposed regulation, at least at high loads, we believe that this regulation will have little effect on the timing of upgrade decisions.

Alstom appreciates the opportunity to offer these comments to EPA and trusts they will be carefully considered. Alstom is available to EPA for consultation or discussion on these issues or any other issues related to these matters. It is always critical in setting such standards to consider the whole of the interconnected electric system and the impact these proposals will have on the system. Technologies must deliver reliable, available, and cost effect electricity to the American people and the only way to accomplish these objectives is to consider the whole system and the way technology for generation works within the larger system.

Very truly yours,

Robert G. Hilton

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Cost assessment of fossil power plants equipped with CCS under typical scenarios

Jean-François Léandri,
Adrian Skea, Christian Bohtz,
Gerhard Heinz
Alstom Power – June 2012

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Cost assessment of fossil power plants equipped with CCS under typical scenarios

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Alstom Power

Foreword

Among the many challenges faced in implementing technology to reduce CO2 emissions from the power generation sector, minimising both the energy penalty and the cost of electricity for fossil fuelled power plants equipped with CCS are two of the most significant.

Many parameters have to be taken into account to calculate these costs, including those related to technical performance. Evaluations and comparisons often result in endless debates due to the infinite number of possible combinations of these input parameters.

This paper attempts to rationalize and evaluate the impact of the key parameters under typical scenarios and presents a sensitivity analysis. The work is based on the experience developed by Alstom on conventional turnkey plants and on the last five years of experience gained on CCS demonstration plants and reference designs.

Different capture technologies are considered in the evaluation and comparison of the impact of CCS on future commercial fossil-fuelled power plants (coal and gas). The influence of the technology learning curves on both performance and the CCS incremental CAPEX and OPEX costs are estimated during the next two decades. Although retrofit applications are more difficult to analyse, as each case is specific, a tentative estimation has been made to evaluate the main differences compared with new installations.

Finally, the cost assessment is put in perspective relative to some other low-carbon methods of producing electricity and against the other challenges in developing CCS technology, such as, the implementation of regulations and impact of public opinion.

1- Introduction

The "IPCC Summary for Policymakers" published in May 2007, gives a target for the maximum concentration of Greenhouse Gas (GHG) in the atmosphere of 450 ppm CO_2 equivalent. This is required in order to give a reasonable chance of limiting the earth's long-term surface temperature increase to a maximum of 2°C above pre-industrial levels by 2100. This figure was agreed by all countries at Copenhagen & Cancun. To achieve this goal, CO_2 emissions will need to be reduced massively.

The main contributors to CO_2 emissions today are Power Generation (c.a. 40%), Transport (c.a.20%) and Industry (c.a.20%). Power generation currently emits 12 $GtCO_2$/yr. Power is projected to grow significantly, and the 2°C goal will require full de-carbonisation of Power generation. Low carbon technologies are needed both for new power generation plants, and for the existing installed base.

The possibilities to reduce CO_2 emissions in the Power sector include: i) demand reduction, ii) efficiency increase, iii) nuclear, iv) renewables (wind, hydro, solar, biomass…), and v) Carbon Capture and Storage (CCS). This last alternative will by necessity play a major role:

- The IEA1 calculates that 54 to 67% of worldwide electricity generation will still be provided by fossil power plants in 2035. CCS is the only option to deal with the resulting emissions during a transition period until around 2050+ after which time it may be possible to move toward a power generation system not reliant on fossil fuels. The IEA estimates a CO2 reduction from CCS in the Power sector of 1100 and 2700 Mt/yr will be necessary respectively in 2030 and 2035 (corresponding to 232 and 598 GWe with CCS).

- CCS is necessary not only on coal but also on gas. In the EU region, under the Current Policies Scenario, the IEA predicts that 1190 Mt/yr CO_2 will be produced by the power sector in 2035 of which, 671 Mt (56%) by coal plants and 495 Mt (42%) by Gas plants. Under the 450 ppm scenario, it will be necessary to abate the emissions from coal down to 104 Mt (-85%) and from gas down to 130 Mt (-74%) in 2035, CCS contributing for c.a. 20% of this reduction.

CCS is a technology under development, still several years from commercial deployment, and a key question for policy makers and utilities is whether or not CCS is a competitive option compared to the other low carbon alternatives. **The answer given in this paper is unequivocally yes.**

[1] World Energy outlook 2010, International Energy Agency (IEA), Paris, France – New and Current Policies Scenarios

2- Methodology and key assumptions

The Alstom Cost of Electricity (COE) analysis is based on:

- early and substantial investment in the development of several capture technologies since 1998 and the knowledge/experience feedback from 16 pilots and demonstrators,
- power plant engineering procurement and construction (EPC) expertise (coal & gas turnkey plant experience over many decades), enabling optimised integration of the capture system with the conventional plant,
- experience in designing and manufacturing key components (boilers, AQCS, gas and steam turbines, control systems etc.) to optimise the CCS interface adaptation.

The assumptions and case studies presented in this paper have been selected to best reflect the market and are not related to any specific supplier. The main assumptions are:

1) Three regions: Europe (EUR), North America (NAM), South East Asia (excluding China & India)
2) Two technologies: oxy-combustion (Oxy), post combustion capture (PCC)
3) Three types of fuel: Hardcoal, Lignite (raw and dried for EUR only) and Gas,
4) Two phases: Commercial first of a kind in ~2017-18, mature market in ~2030-35

For each region and fuel type, "reference plants" are defined (table1). For coal power plants, the reference plants are based on a Supercritical steam cycle of 275bar/600/620°C in 2017, then performance improvements are considered (e.g. double re-heat steam turbine from 2020).

		EUR			NAM	SEA
Fuel type		Bituminous	Raw Lignite	Dried Lignite	PRB coal	Bituminous
Fuel heating value	KJ/Kg LHV	24 930	10 278	21 283	20 425	20 896
Carbon content	UB mass%	65%	31%	57%	56%	53%
Fuel price 2011	Euro/t	78,2	24,3	24,3	25,7	53,4
	Euro/GJ	3,14	2,37	2,13	1,26	2,56
Cycle argt 2020/30	bar/℃/℃	300b/600/620℃	272b/600/605℃	300b/600/620℃	300b/600/620℃	300b/600/620℃
Cooling type	℃	13℃ - Direct C	18℃ - Direct C	18℃ - Direct C	19℃ - CT	28℃ - Direct C
Net Output	MWe net	837	1 000	1 000	837	837
Net eff. 15/20/30	% LHV	46.2/48/48.4 %	44/-/- %	47,6/48,8/49 %	44/46.2/46.7 %	41/42.7/43 %
EPC 2015/20/30	€/KW net	1794/1916/1916	1955/-/-	2070/2200/2200	1612/1722/1722	814/869/869

Table 1 : main market assumptions for coal reference plants (without CCS, EPC before owner costs)

Reference plant operating time is set at 7446 hours per annum, construction time: 4 years for Hardcoal and Lignite. Base year for cost is 2011. EPC indicated costs are market price.

Years 2015-35 (horizontal axis) in the presented graphs are defined as year of order, Notice to Proceed (NTP). Scope variations throughout the 2015-2035 period are valued and included in the CAPEX (e.g. cost for double reheat steam plant).

For power plants based on gas fuel, the reference plants consists of a base load combined cycle power plant (CCPP) with some regional variation in arrangement (1-1 SS in EUR and SEA and 2-1 MS in NAM). The construction time considered is 30 months.

Performance and cost improvements were considered on the reference plants. It was assumed that a combined cycle power plant with CCS would operate 7000 hours annually.

		EUR	NAM	SEA
Fuel type		Natural gas	Natural gas	Natural gas
Fuel heating value	KJ/Kg LHV	50 000	50 000	50 000
Carbon content	mass%	75%	75%	75%
Fuel price 2011	Euro/GJ	7,2	2,8	3,8 (subs.)
Cycle argt 2020/30		1-1 SS	2-1 MS	1-1 SS
Cooling type	°C	13°C - Direct C	19°C - CT	28°C - Direct C
Net Output 15/20/30	MWe net	600/650/700	850/900/950	538/583/628
Net eff. 15/20/30	% LHV	61/62/63 %	60/61/62 %	60/61/62 %
EPC cost 15/20/30	€/KW net	558/544/529	452/441/429	473/461/449

Table 2 : main market assumptions for Combined-Cycle Power Plants

The CCS technologies covered in this paper are:

- PCC advanced amine and Oxy on coal plants (for Hard coal the CCS plant was increased in gross size to compensate the energy penalty and to align on the same MWe net output of the reference plant), 90% capture of the CO_2 emitted by the CCS plant,
- PCC Amine with Flue Gas Re-circulation on CCPP with two cases, one at 90% capture of the CO_2 emitted by the CCS plant , plus one case at 70% capture (design point) for EUR.

Alstom has also performed comparable studies for its Chilled Ammonia Process CAP, though the data is not presented here. Generally though, it can be stated that CAP is competitive with the Amines process. A choice between the two technologies for a particular application would depend upon the site specific conditions that might favour one technology over the other. The conclusions of this report are therefore equally applicable to the CAP technology.

Feedback from pilots in operation, detailed engineering studies made on large-scale demonstrators and reference designs provide the basis of the input data for Oxy and PCC.

Disaggregated learning corrections are applied throughout the 2017-33 period, including:

- a performance improvement for the reference and the CCS incremental capture plants evaluated separately for each sub-systems (e.g. in EUR, the ASU consumption was selected at 180 kWh/tO_2 in 2017 down to 150 kWh/tO_2, solvent re-generation duty improvement was 0.4 GJ/tCO_2), and then on an integrated turnkey basis (e.g. heat recovery)
- a correction on the resulting Capex and Opex costs of the CCS incremental sub-systems for volume, and for size when applicable. The base case market ramp-up profile used is upon IEA CCS installed base forecast. Lower ramp-up would delay by a few years the cost reduction achievement, but it would not change the cost level on the long term.

To check consistency, we consolidated all the improvement factors and back-calculated an aggregated rate to compare with traditional learning curves[2]. The aggregated rate was a little lower and more conservative than a traditional one. Finally, we ran a sensitivity analysis on key sub-systems, to check the impact of the improvement factor range on COE.

The owner costs and contingencies in addition to the EPC cost of the integrated plant equipped with CO_2 Capture system are 20% for coal PP and gas CCPP

Figure 1 presents the assumptions considered for the on-shore and off-shore transport and storage (T&S) EUR Hard coal reference cases. However, the spread of transport and storage costs is large, and there is a feeling in the CCS community that the literature is currently underestimating these costs, so a variation range is proposed in the sensitivity analysis.

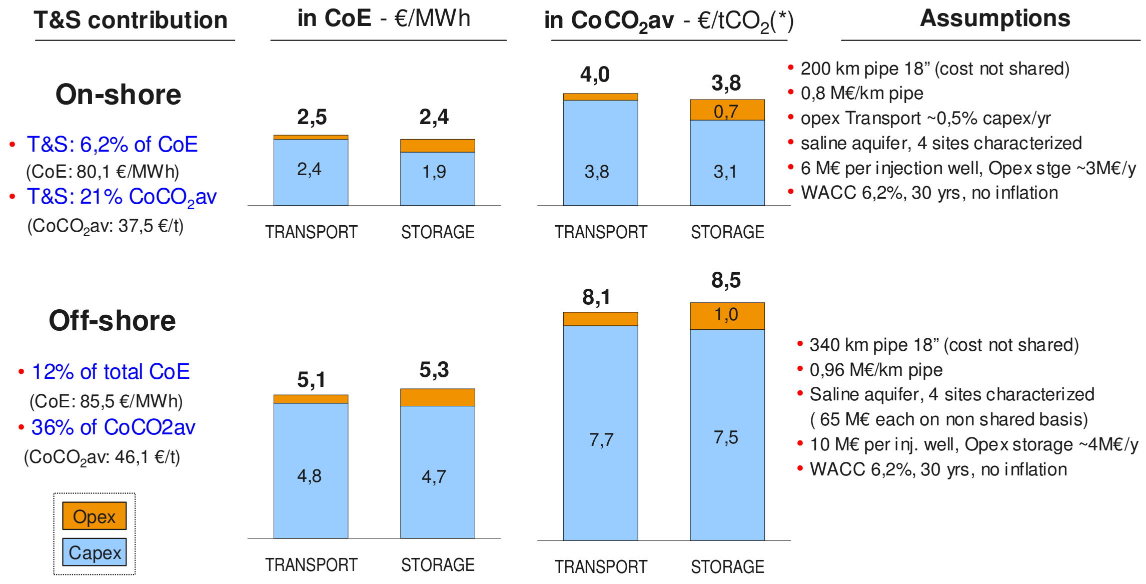


Figure 1: Base case assumptions for transport and storage

The levelized cost of electricity (COE or LCOE) is the theoretical constant electricity price that would be required for the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial expenses, and the payment of a return to investors. It considers Transport and Storage and regional and technology variations. No inflation, no escalation and no CO_2 price changes were accounted for in the presented base cases below (2011 base year, real rates). CO_2 price is considered in the sensitivity analysis.

Exchange rate: 1 Euro = 1.33 USD	EUR / NAM / ASIA
• Debt cost (real rate w/o inflation):	3,3% / 3,0% / 8,2%
• Cost of Equity (real rate w/o inflation):	9,76% / 9,76% / 11%
• Debt fraction:	50% / 50% / 50%
• Tax rate:	35% / 35% / 35%
• Interest rate during construction: WACC rate also used	
• Annuity period: 25 years for New Coal PP and 20 years for Gas CC for all regions	

[2] E. Rubin et Al., 2004. learning curves for environmental technology and their importance for climate policy analysis. Elsevier, Energy 29.

3- Main results - CCS Hard coal plant

The resulting Costs of Electricity (COE), including CO_2 transport and storage, for Hardcoal CCS cases with PCC advanced amine and Oxy are presented by region in the figure 2.

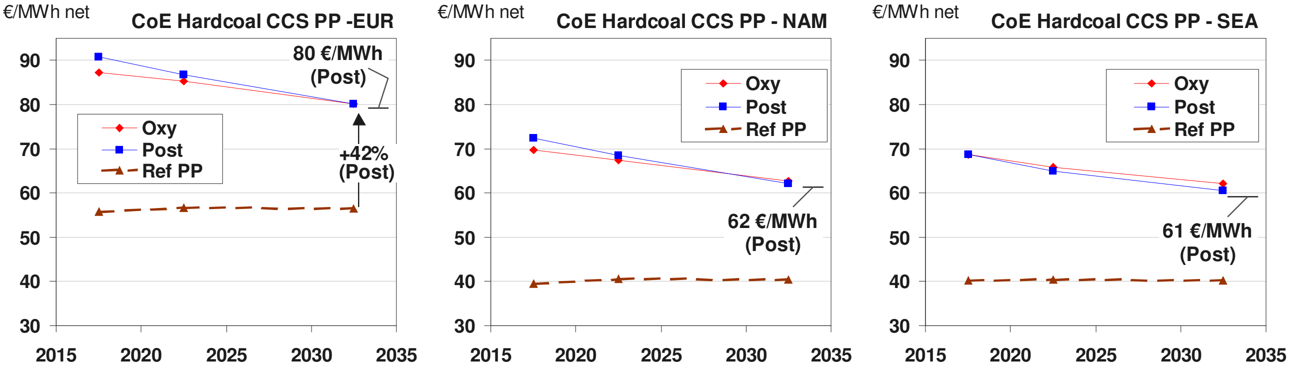


Figure 2: Cost of electricity for Hardcoal power plant equipped with CCS

The Increase in COE resulting from implementation of CCS in 2032-33 could be cut from 60- 65% in 2017 down to about 42% in 2032-33 in EUR (COE 80 €/MWh). In NAM and SEA regions, the COE of the plant equipped with CCS are ~17% lower than in Europe in 2032-33, reaching 62 €/MWh in NAM because of a cheaper coal fuel and 61 €/MWh in SEA because of lower Capex and Opex costs. The resulting Cost of CO_2 avoided could then target ~30 €/t in NAM and SEA and 35 €/t in EUR in 2032-33 (no CO_2 price being accounted for).

A specific energy penalty of 15-16 % can be realistically targeted in 2032 for CCS in Europe (figure 3). It is defined as the additional auxiliary consumption of the plant needed for the Capture system in % of reference plant net MWe (EP= [Net MWe Ref PP – Net MWe CCS PP]/Net MWe Ref PP). Figures in other regions depend on cooling temperature and coal data.

The energy penalty is ~2% MWe net higher in NAM compared with EUR, and ~2 to 4% higher in SEA, where Oxy is a slightly more penalized by the much higher cooling temperature..

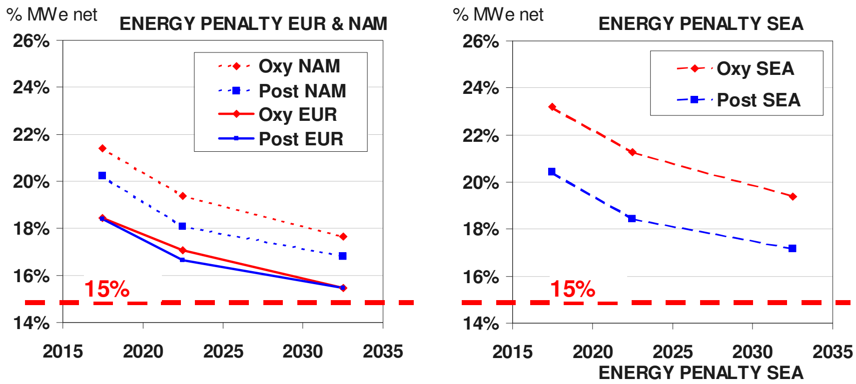


Figure 3: Energy penalty due to CO_2 capture systems, by region

In the selected case, the impact on performance is due to higher cooling water temperature in SEA versus NAM as well as a much higher fuel cost. This offsets the lower CAPEX figures resulting in a comparable COE despite the differences between the two regions.

The incremental CCS CAPEX as a percentage of the reference plant CAPEX drops in Europe: from 67% to 45% for Oxy over the period 2017-32 and from 66% to 39% for PCC. This is due to the combined effect of the performance improvement and the cost reduction for volume effect. These figures are calculated for reference plant and CCS plant at same net MWe net output.

In NAM and SEA, the CCS/Ref CAPEX ratio also decreases following the same trend, although the % could be at a slightly different level because of regional specific assumptions (ex: higher cooling temperatures than in Europe). For CCS incremental fixed and variable O&M costs, the learning curve is also applicable, driving down the Opex cost.

Figure 4 shows the impact of the full CCS chain on the total COE under our scenario ('REF' is relative to the reference plant without CCS). The regional specific data such as, pressure, air temperature, cooling temperature, coal characteristics, cost level (equipment, construction and fuel) drives the variation in COE breakdown between Capex, Opex, Fuel cost and T&S.

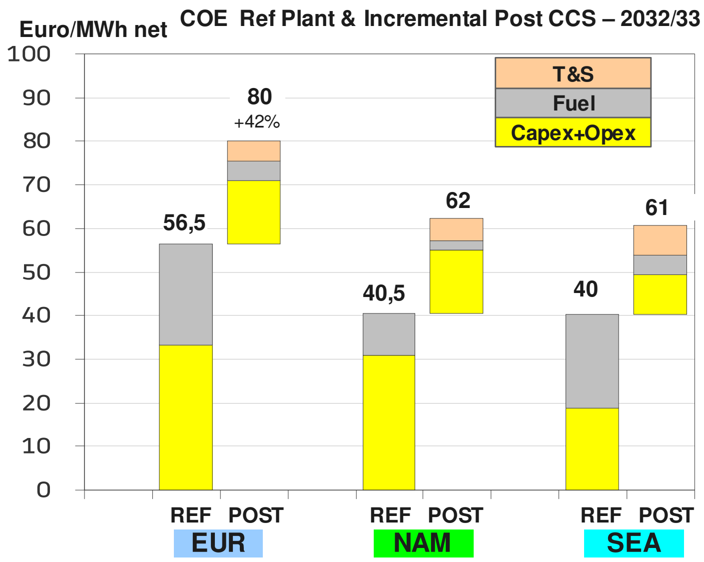


Figure 4: Post: Fuel, Capex & Opex contribution in the COE

In Europe and SEA, the hard coal fuel cost could strongly impact the reference plant COE, but to a lesser extent the CCS incremental COE. For PCC amine, the impact of T&S on COE ranges from 5,2/4,8 €/MWh in EUR to 7,2/6,6 €/MWh in SEA in 2017/32 respectively depending on the year, the regional coal characteristics and the environmental conditions, corresponding to a range of 8 to 10 €/tCO_2 avoided.

4- Main results - CCS Lignite plant

Lignite was only studied in the European region. Costs were analysed for two different cooling temperature conditions: at 13°C, which compares with the hard coal base case, and at 18°C, which is more realistic since the main driver for site selection will be the proximity to the lignite mine where direct cooling is generally not available.

The Cost of electricity and the cost of CO_2 avoided are presented in figure 5 for Oxy and PCC advanced amine technologies.

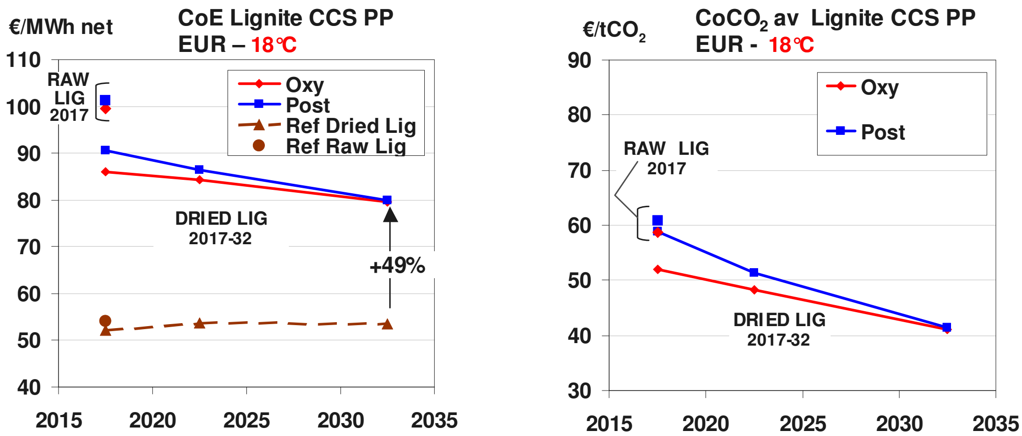
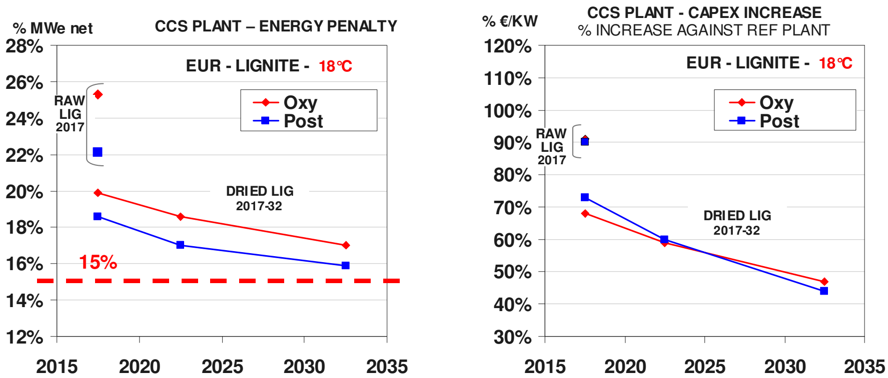


Figure 5: CoE and CoCO2 avoided for Lignite power plant equipped with CCS

Raw lignite is presented in 2017 only for comparison with dried lignite. After 2017 this option would bear a +15% extra cost against dried lignite and hard coal.

The Increase in Cost of Electricity linked to CCS on a dried lignite plant in 2032 could be cut from 65-75% in 2017 down to about 49% in 2032 in Europe (COE 80 €/MWh). The Cost of CO_2 avoided could target approximately 41 €/t in 2032 (no CO_2 price being accounted for). An energy penalty of 15-16 % can be targeted in 2032 for the CCS technologies in Europe.



The Capex increase against reference plant drops from around 73% in 2017 down to around 45% in 2032.

Figure 6: CCS Lignite plant - Energy penalty and Capex increase

In the calculation, the net output of the CCS lignite Oxy or PCC plant is reduced compared with the reference plant (Same MWe gross for Reference plant and CCS plant) . The assumption of same MWe net output made for hard coal has not been extended to the lignite case as it would have led to an unrealistic boiler size.

Figure 7 shows that despite the high incremental Capex and Opex, the COE of CCS plant with dried lignite coal would be viable because of the better performances. As an illustration, in 2032-33 in Europe, a CCS dried lignite plant with a cooling temperature of 18°C could compete with a CCS hardcoal plant equipped with a direct cooling at 13°C.

If direct cooling is possible the COE could be reduced further (for example by 1,7% for Oxy with a 13°C cooling temperature in 2032).

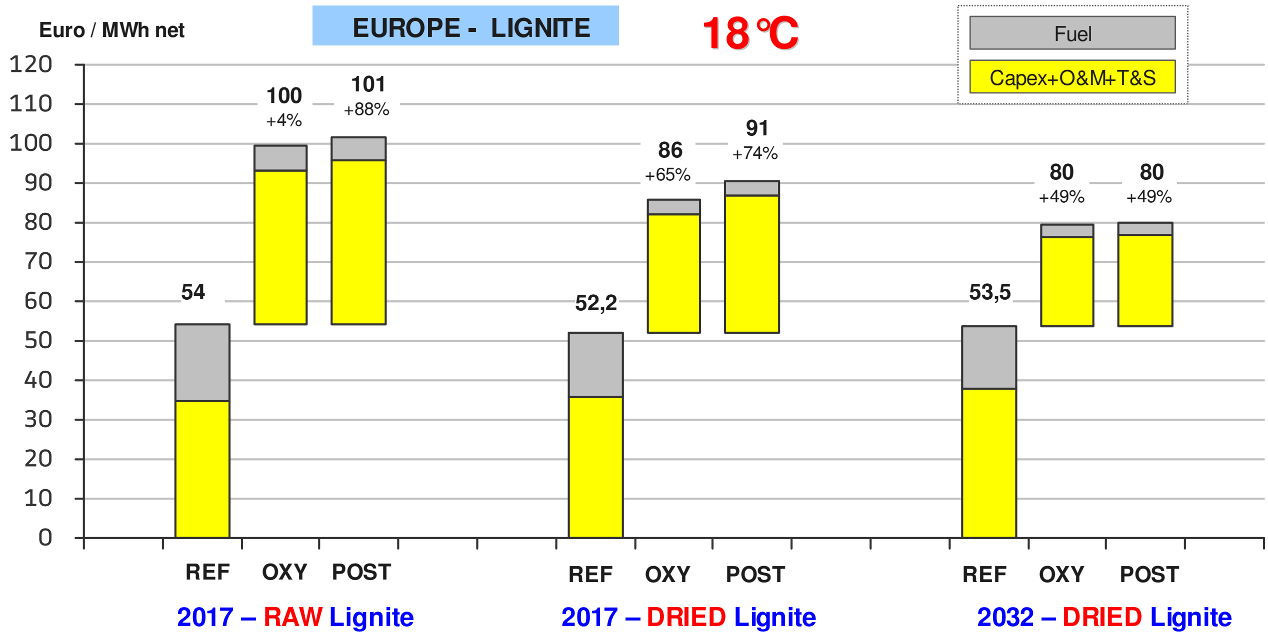


Figure 7: Fuel cost, Capex and Opex contribution in the CoE

5- Main results - Combined-Cycle Power Plant with CCS

The resulting COE by region for Gas CCPP with CCS PCC advanced amine and with flue gas recirculation (FGR) are presented in the figure below for Europe, NAM and SEA.

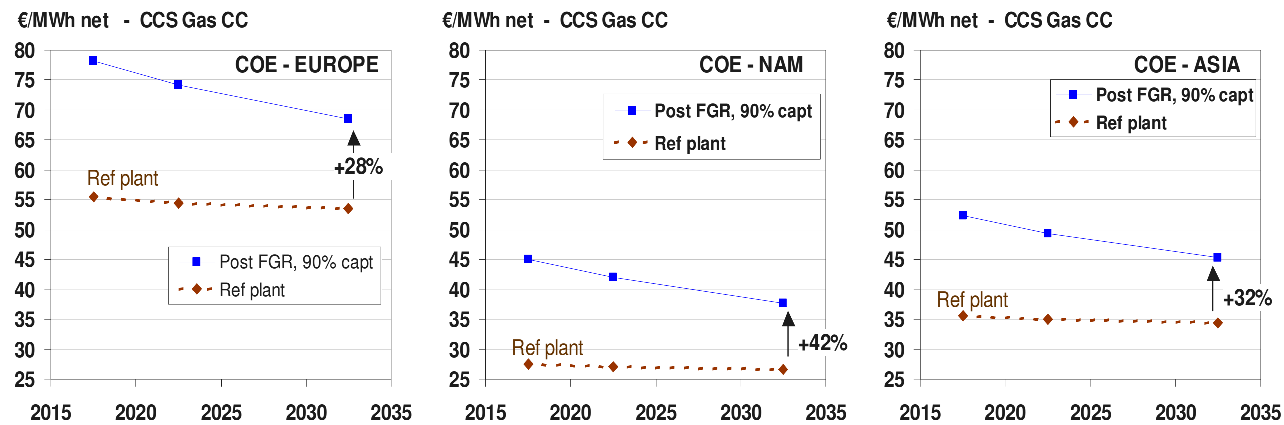


Figure 8: CoE of gas combined cycle plant equipped with CCS and flue gas recirculation

For the reference case at 90% capture, the Increase in Cost of Electricity due to CCS in 2032 could be cut from 41% to about 28% in Europe and from 63% to 42% in NAM, because of the difference in fuel costs. The reference plant and the CCS plants were calculated at same thermal gross assuming no change in the gas turbine design (resulting in lower net power output with CCS).

A 70% capture rate case in Europe (design point and not operating point) would reduce the total COE by approximately 6%. Without flue gas recirculation, the COE are slightly higher in absolute values, +5% should be added on the 28%, 42% and 32% shown in fig. 8.

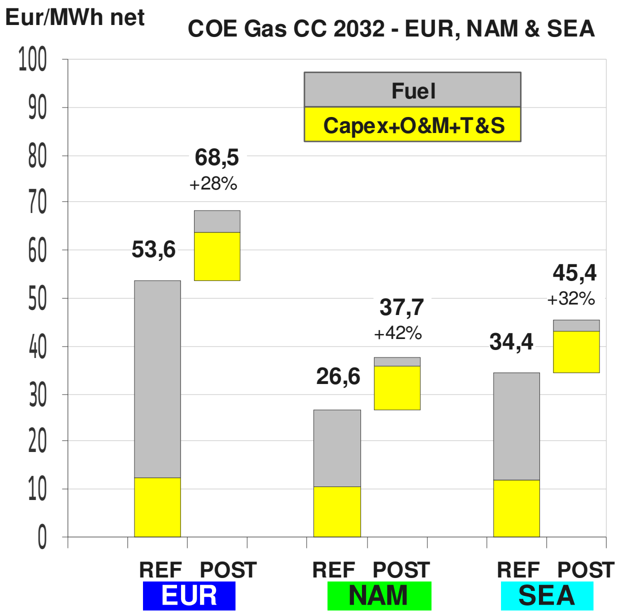


Figure 9: Gas Fuel contribution in the CoE of Gas CCPP

The Cost of CO_2 avoided can target ~40 €/t in NAM/SEA in 2032 with FGR, but above 50 in Europe. Without FGR, these costs of CO_2 avoided increases by ~15% in all regions.

A 10 % energy penalty target can be reached in 2032 for the Post combustion CCS technology.

The Capex increase for CCS in % of the reference plant reduces from 118% to 70% in Europe, and from 125% to 75% in NAM throughout the 2017-32 period.

Figure 9 shows the major contribution of the gas fuel cost on the reference plant COE. Comparatively, the incremental Capex, Opex and T&S cost for CCS is limited. The COE of the CCS gas plant will be primarily driven by the fuel cost, more than by the energy penalty and the incremental CCS cost. The Europe region on figure 9 gives an illustration of this: the COE is higher than in NAM because of the higher gas price considered (7,2 €/GJ) which offsets the other differences in CCS Capex and Opex.

The impact of T&S on COE ranges from 1,9 (NAM-2032) to 2,5 (SEA-2017) €/MWh net depending on year and environmental conditions. The corresponding cost ranges on €/tCO_2 are respectively to 6,7 to 8,5 €/tCO_2 avoided.

6- Main results – Sensitivity analysis

The few reference cases (or base cases) presented in the above sections are based on a given set of assumptions to be able to compare the different CCS technologies. In addition, a sensitivity analysis is useful to understand the possible range of variation of the cost of electricity.

For each of the main parameters, a realistic range with high and low values is considered, and the corresponding impact on COE is estimated. The ranges cover in particular the CO_2 price impact, different transport and storage configuration, and variations in learning outcomes.

6.1 Sensitivity analysis Hard coal CCS plant:

Figure 10 summarises the impact of the main parameters on COE of the hardcoal PCC amine case in EUR in 2032 (with onshore T&S). A range is indicated for each parameter around the base case value (ie: 1,75-2,0 GJ/t for re-boiler duty around the 1,8 GJ/tCO_2 base case value).

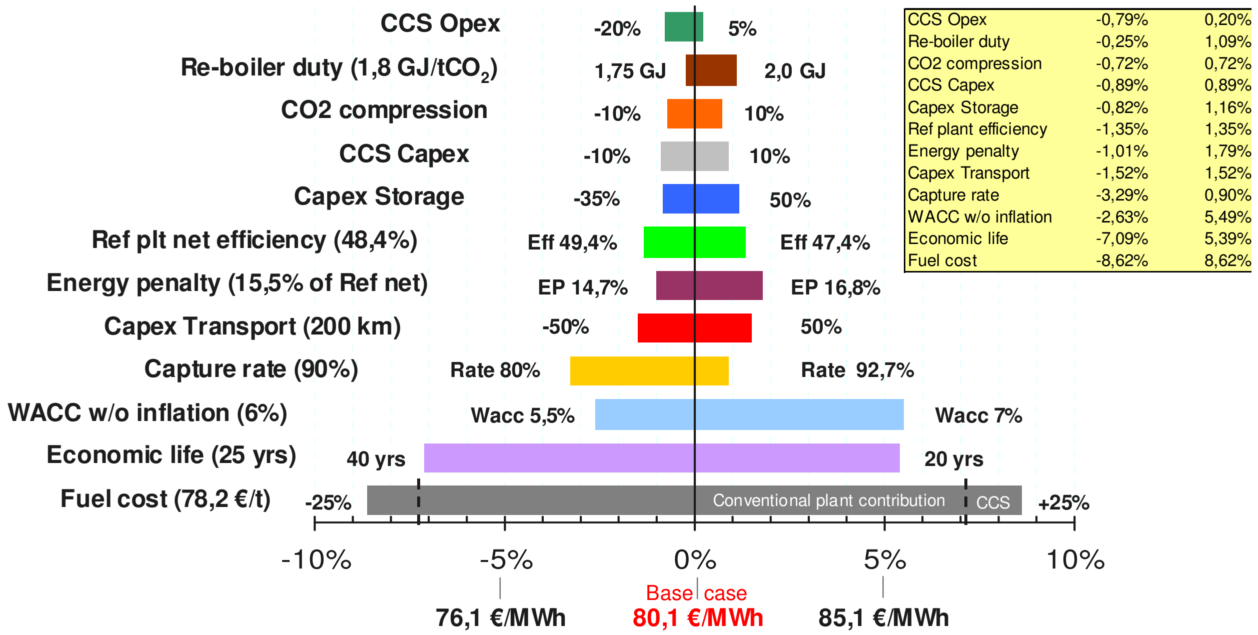


Figure 10: Sensitivity on CoE base case 2032 (Europe, Post adv. amine , on-shore T&S, no CO2 price)

Within the considered ranges, each of the following economic parameters: fuel cost, Economic life, WACC, impacts the COE by +/-6%, much more than CCS Perf/Capex/Opex parameters, but this impact is not fully attributable to the CCS additionality, an important share occurs in the conventional scope.

Figure 11 summarizes the impact of applying a CO_2 price or moving from on-shore to off-shore or changing the plant load again on the COE of the same base case..

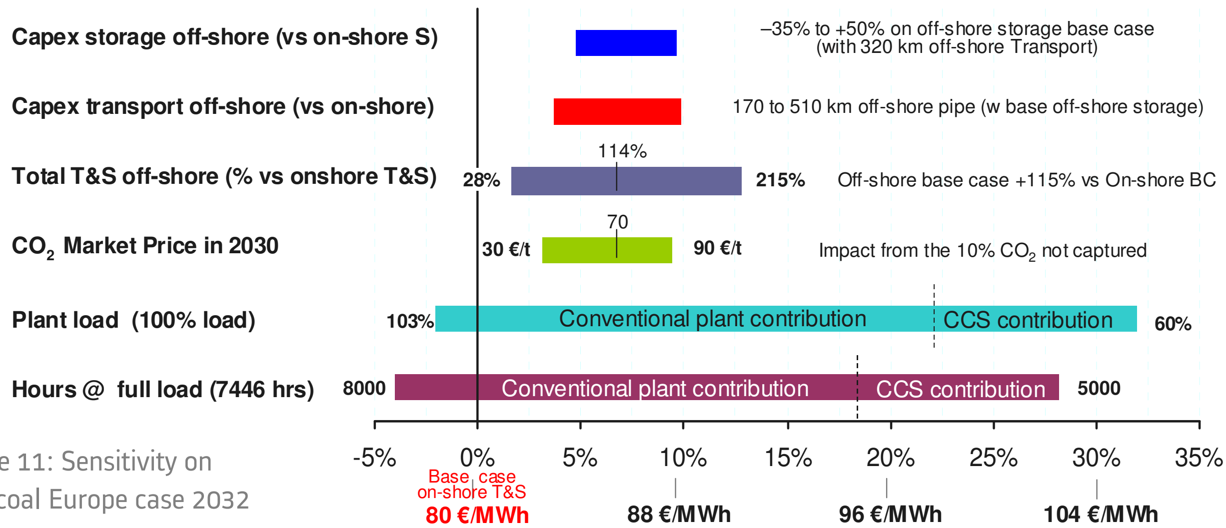


Figure 11: Sensitivity on Hardcoal Europe case 2032

For EUR, the base case COE with an offshore T&S is +6,7% higher than the base case COE with an onshore T&S (T&S offshare cost +114% in variation on T&S onshore costs).

The impact on COE of a 70 €/t CO2 price in 2032 versus no CO2 price is +7%. The impact of an partial plant load at 60% instead of 100% is +32% on the COE, because of the reduced efficiency of the reference plant and the CCS plant not operating at full MWe. Only a small share of ~30% is attributable to CCS.

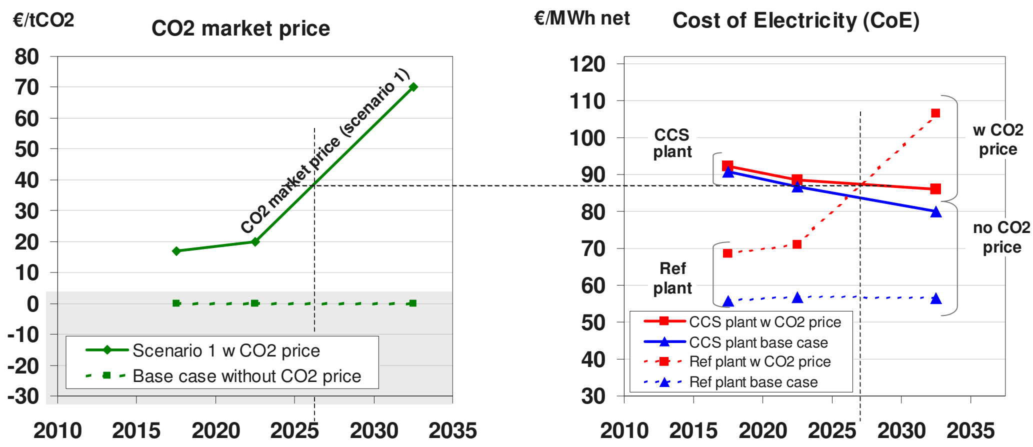


Figure 12: CO_2 price impact on reference and CCS plants for Hardcoal with Post AAP -

Under the CO_2 market price scenario presented in figure 12, in 2027, for a CO_2 price of 39 €/tCO_2, we have the same COE for reference and CCS plants at 88 €/MWh. In 2032, with a CO_2 price assumed at 70 €/t, the COE would be 106 €/MWh for the reference plant and 86 €/MWh for the CCS plant, increases of +88% and 7% respectively compared to cases without CO_2 price.

When conservatively consolidating all min/max, we obtain a resulting range of variation for hard coal reference case in Europe in 2032 of around +/- 25 to 30% for PCC amine and Oxy.

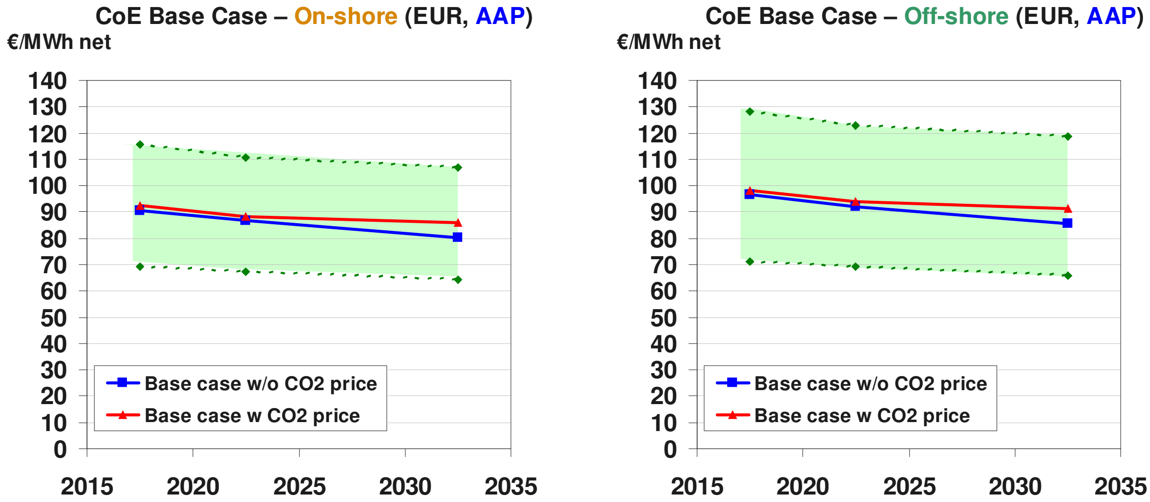


Figure 13: Final range for Hard coal CCS plant with Post AAP - Europe

(note: consolidated upper range includes conservatively all parameters and CO_2 price but excludes Plant load variation left constant at 100%. Consolidated lower range excludes some parameters to also remain conservative)

Figure 13 shows data that are relative to the PCC Amine case. Oxy results are not detailed but ranges are close to the PCC amine. Some specific parameters are presented in the table 3.

Parameter	Base case value 2030	Sensitivity value	Rationale for change	Impact on CoE % of CoE (80,2 €/MWh)
Energy penalty % net ref PP	15,5%	16,3% (+5%)	• Different site conditions (Pa & T°)	1,4%
ASU consumption KWh/tO2	150	140 (-7%)	• Ademe target second generation techno	-1,1%
GPU consumption KWh/tCO2	114	107 (-6%)	• Target second generation techno	-0,7%
Cooling T° °Celcius	13°C	18°C	• Direct cooling not possible on the site	1,8%
CCS Net output MWe net	837 (same net ref PP)	708 (same gross ref PP)	• Gross MWe cannot be increased on CCS PP	2,2%
CCS incr Capex %	100%	90%	• Cost convergence scenario SEA-EU	-1,2%

Table 3 : Hardcoal Oxy: Sensitivity on specific factors, Europe 2032, onshore T&S, no CO_2 price

6.2-Sensitivity analysis Gas Combined-Cycle Power Plant with CCS:

Figure 14 summarises the impact of the main parameters on the COE of a gas combined cycle power plant with CCS PCC advanced amine and FGR in Europe in 2032 (onshore T&S).

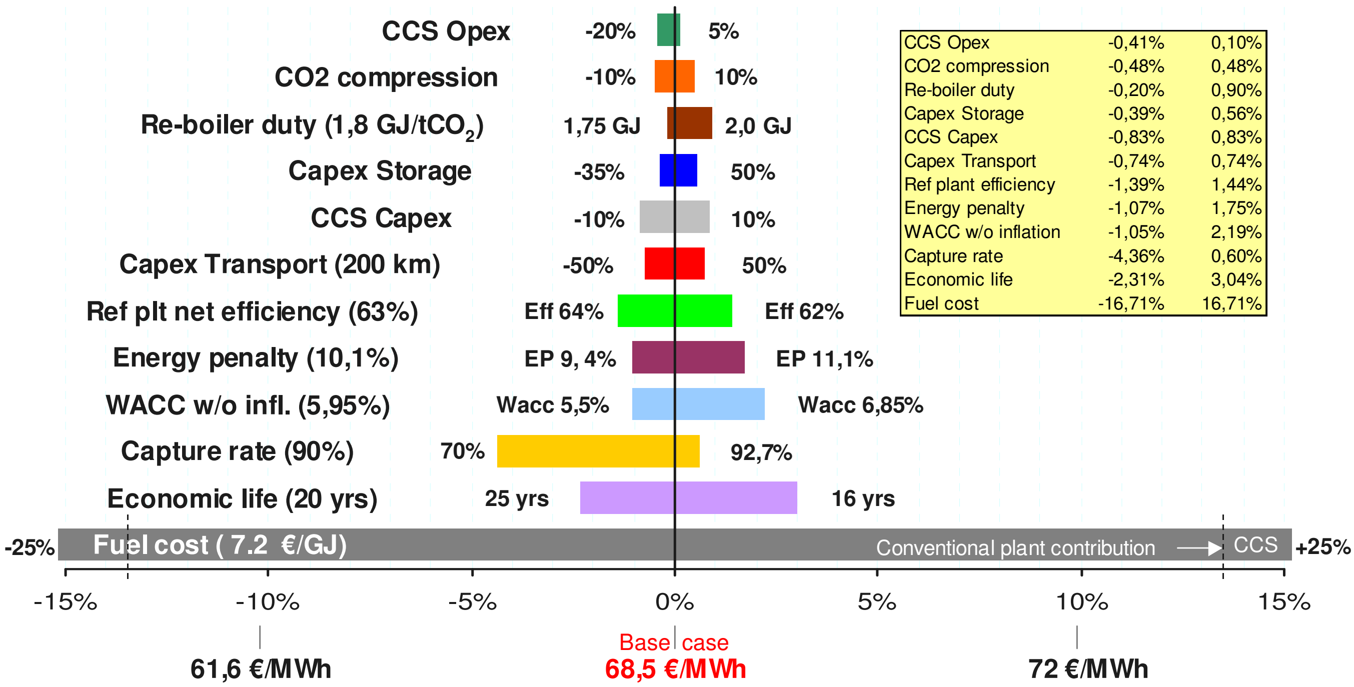


Figure 14: Sensitivity CoE Gas CC CCS, base case 2032 (EUR, PCC amine, on-shore T&S, no CO_2 price)

Gas fuel cost is highly impacting the COE (Figure 15):

- it is the most important driver of total COE, far ahead of CCS Perf/Capex/Opex parameters, although the impact on COE increased slightly with the addition of CCS.
- it demonstrates the importance of having a diversified mix

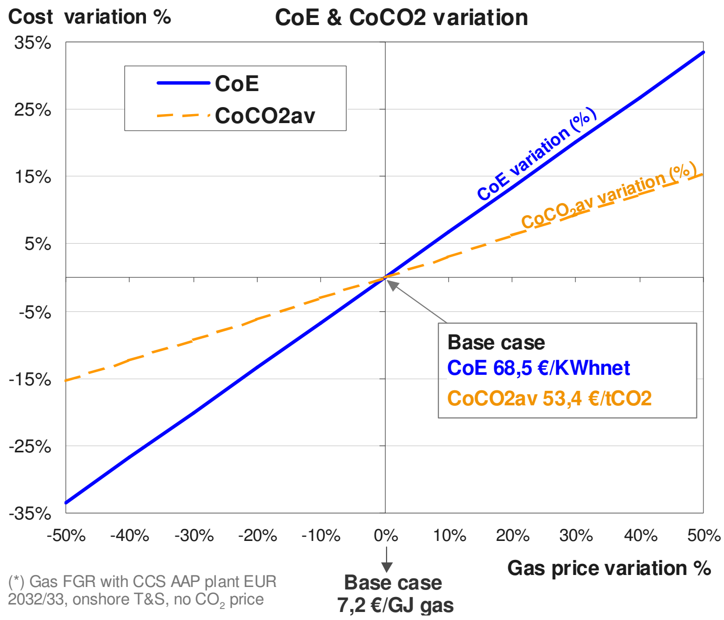


Figure 15: CoE CCS gas CCPP Europe with FGR - Sensitivity on gas price

The economic life assumed for the levelized costs and the WACC could impact COE more than CCS Perf/Capex/Opex parameters, although they are far behind the impact of the Gas fuel cost. However, the impact of these specific parameters is not fully attributable to CCS incremental and the reference plant must take most of the share..

Figure 16 summarizes the impact of applying a CO_2 price or moving from on-shore to off-shore on the COE of the same base case.

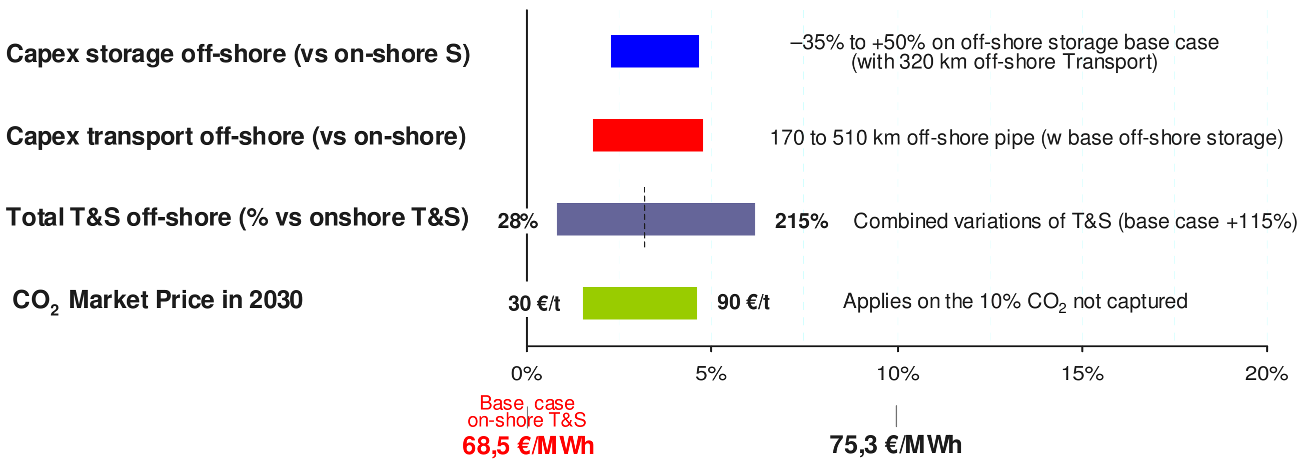


Figure 16: Sensitivity on CoE Gas CC CCS plant, base case Europe 2032

The impact of T&S offshore base case versus onshore base case is +4,2 % on COE (average value)

Figure 17 shows that in ~2029, for a CO_2 price of around 57 €/tCO_2, we have the same COE for reference and CCS plants at ~71 €/MWh. In 2032, with a CO_2 price assumed at 70 €/tCO_2, the impact is +41% on the reference plant COE and +3,5% on the CCS plant COE.

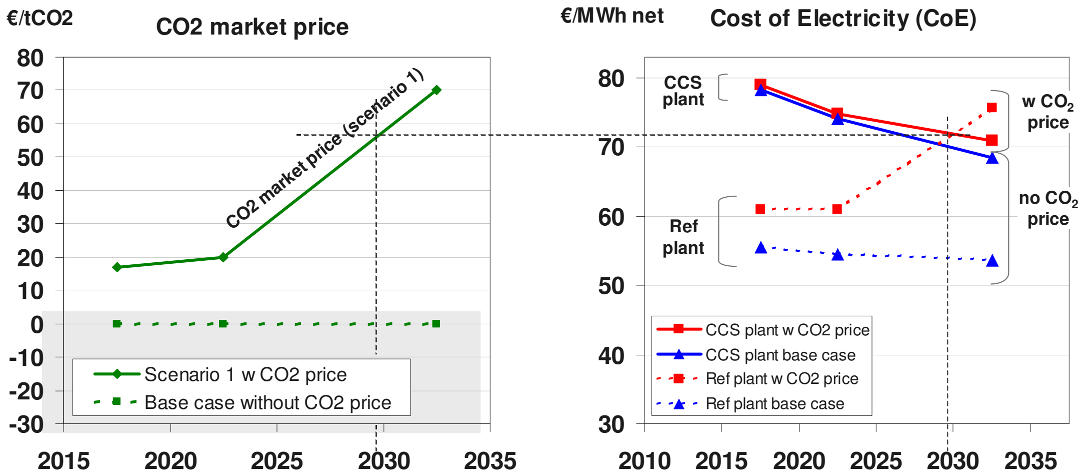


Figure 17: CO_2 price impact on reference and CCS plants for gas CCPP with Post amine - Europe

When consolidating all min/max using the same conservative approach as for hardcoal, we obtain a typical resulting range of variation for Gas fuel Base case in Europe in 2032 of around +/–30 to 40% for PCC advanced amine (note: CO_2 price is accounted in the consolidated range). The width of this range is larger than Coal because of the larger fuel range, this impact being attributable mainly to the conventional plant and not only to the additional CCS systems.

7- CCS Retrofit

CCS Retrofit could play a larger role after 2025, especially on coal plants in China. Nevertheless, CCS Retrofit is likely to remain a variable of adjustment to meet the CO_2 reduction target once all the others means have been implemented, and when the techo-economic data are favourable.

The future CCS retrofit market can be sub-segmented in the non CCS ready plants on the one hand and CCS ready plants on the other. Both PCC combustion and oxy-combustion capture technologies are suitable for coal plants.

The retrofit solutions to address existing non-CCS ready coal plants are specific to, and dependant on the characteristics of, the existing plant. Many technical and economical parameters are involved. Among these, storage availability, space availability, plant lay-out are the first items to be checked to determine eligibility for retrofit..

In terms of cost, implementing a CCS retrofit concurrent with a major refurbishment of a steam plant, which occurs generally at mid life (~20 to 25 years), would present significant advantages such as:

- potential upgrading of the conventional plant will reduce the CCS energy penalty,
- modification of the steam turbine for the steam extraction with a PCC technology could be more easily implemented, as well as the boiler adaptation required with Oxy technology,
- integration between the capture system and the rest of the plant can be implemented
- savings through synergies between retrofit and maintenance tasks
- NPV of the CCS retrofit project could be substantially increased if the plant is already amortised and if a plant life extension (ex ~15 years) could be implemented at a limited cost.

Typically, units in operation for 20 to 25 years with net efficiency of ~39% or more could be addressed from 2018, which corresponds, on average, to coal plants built from 1995-2000 onwards.

Because of this, for EU and NAM the eligible ‘non-CCS ready’ base for CCS Retrofit is likely to shrink after 2020 compared with the CCS ready base, and will be limited from 2030. For China, the installed base profile is different with many ‘non-CCS ready’ plants with high efficiency, built recently, which would be retrofitable in the longer term (e.g. from 2030).

Nevertheless capture ready plants would be much easier to retrofit. Paving the way by building all coal plants as ”CCS-READY” from now on is in our view a no regrets option. We note that this is the requirement already in Europe under the CCS Directive and we recommend that the relevant authorities ensure the requirement is fully applied.

8- CCS competitiveness against low carbon alternatives

A comparison of the COE for different carbon-free technologies in Europe is presented in figure 18 for power plants to be ordered during the 2012 - 2017 period. Even when considering the very conservative range of variation assumed in our study, **CCS is competitive, starting in 2017, with any other low carbon or “carbon-free” technology**.

The cost of the integration of intermittent renewables was not taken in account, but it will have an impact in terms of back-up capacity needs, lower utilization of the existing fleet, and grid extension requirements. On the other hand, the learning curve will also apply to renewables contributing to reduce the cost during the next decade.

The indicated values for CCS plants in the bar chart are for Post amine and include a CO_2 price of 14 €/ton. The large upper range, consolidated conservatively (see sensitivity analysis) was plotted on the graph, and still CCS solutions for coal and gas remain competitive within this upper range

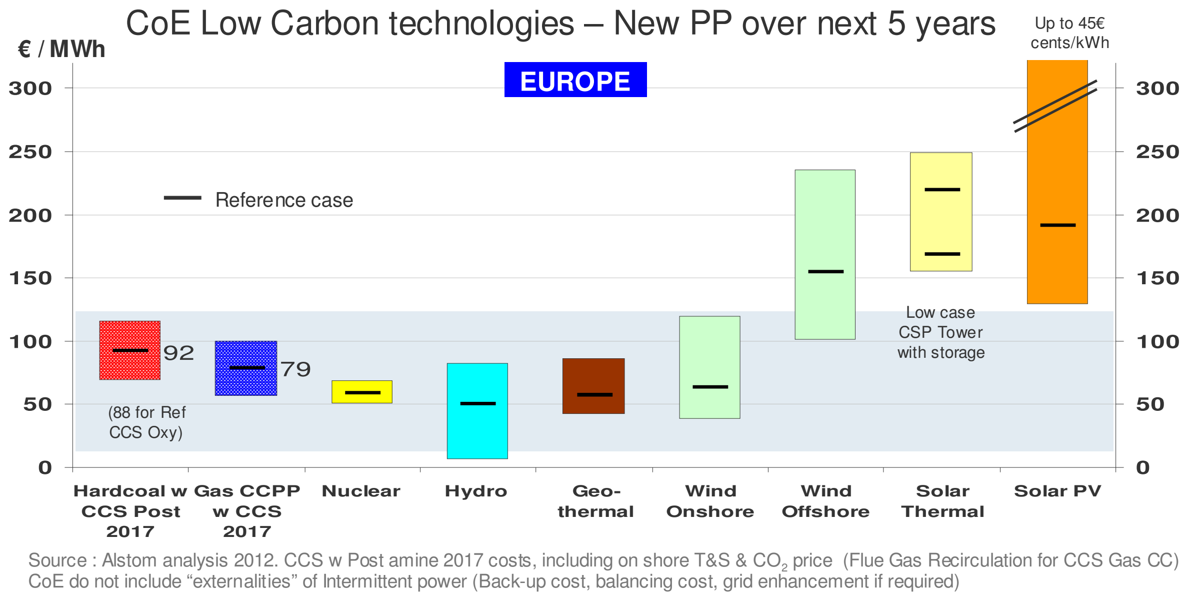


Figure 18: CoE of low carbon technologies – Europe 2012-17

The relative increase in COE because of CCS is lower on gas than on coal. This is due to the fact that the emissions of a gas plant are half of the emissions of coal plant per MWh produced, hence less CO_2 needs to be captured and the CCS equipment is smaller, with lower Capex and a lower energy penalty than for coal

We therefore expect that projections of fuel cost will remain the key determinant between those fuels for power generation. In 2032, for Europe, the cost of CO_2 avoided, including transport and storage is expected to reach levels below 35 €/t on coal and 53 €/t on gas with flue gas recirculation (below 39 €/t on gas for NAM with a much lower fuel cost).

9- Conclusion

Cost is often presented as a main concern for the viability of Carbon Capture and Storage technology. Based on the results of our CCS pilot efforts combined with the engineering experience gained in the design of the first large-scale CCS demonstration units, Alstom completed an extensive study of the costs of PCC and oxy-combustion technologies now and projected into the future.

The main results are the following:

- with electricity costs varying between 68 and 90 €/MWh for steam plants, depending on fuels and regions (China excluded), the first large scale CCS units, to be ordered starting 2017-18, will already be fully competitive with any other low-carbon power generation solution,
- CCS is at the start of its learning curve, and a CCS COE below 80 €/MWh along with a CO_2 avoided cost below 40 €/t is realistically expected in 2030-35 in Europe for CCS Steam plants. Compared with other mature technologies, the greater potential learning curve improvement of CCS will reinforce its competitiveness over time,
- contrary to popular belief, the relative COE competitiveness of gas is slightly improved versus coal for the first plants to be ordered from 2017-18, when applying CCS on both fuels, with COE for gas CCPP with CCS varying between 45 and 80 €/MWh depending on the region**,**
- relative fuel price and security of supply should remain the key determinants for choosing decarbonised fossil fuelled power generation.

With the right policy framework, technology and costs are not in themselves obstacles to CCS deployment, but other significant issues should be addressed:

- strong and long-term signals are now needed to secure the long development cycle of CCS technology,
- an immediate policy framework capable of rewarding developers of CCS projects on an equal footing with any other decarbonised power production technology. What is needed is a level playing field in terms of market regulation that does not discriminate for or against one or other low carbon technology (ex: feed-in tariff, or FIT, for wind and not for CCS),
- the progressive tightening of the EU ETS. Given the trajectory we set out for the evolution of CCS costs, this could make CCS commercially viable without FIT – type subsidies sometime from the 2025's and, consistent with the EU's longer term emission reduction goals, certainly by 2030-35,
- clear long-term carbon regulation signals designed to ensure a fair and non-distorted technology choice for new decarbonised power generation assets, In the past, the reduction of other types of emissions has been successfully achieved with specific environmental regulations. The review of the CCS Directive in 2015 offers crucial opportunities here,

- clear regulations on storage and long-term liabilities should be set as soon as possible. The EU Directive on CO_2 storage should be in force since June 2011, but many Members States are late in translating this directive into legislation. This patchy progress is impacting decision making on important large-scale demonstration projects,
- storage validation should be accelerated through large-scale demonstration projects and in particular the development of CCS clusters. The "cluster" approach for early CCS deployment will alleviate key uncertainties when grouping projects around publicly accepted and geologically validated storage sites. Offshore storage has obvious advantages in this respect,
- Financial support for these projects must be provided to an adequate level and in a timely manner if momentum is to be restored to the demonstration programme. Large scale demonstration projects are crucial to achieving the cost reductions which are assessed in this report.

Abbreviations

AAP	Advanced Amine Process
AQCS	Air Quality Control Systems
ASU	Air Separation Unit
CAP	Chilled Ammonia Process
CAPEX	Capital Expenditure
CC	Combined Cycle
CCPP	Combined Cycle Power Plant
CCS	Carbon Capture and Storage
CCS PP	Turnkey Power Plant equipped with Capture Transport and Storage
$CoCO_2av$	Cost of CO_2 avoided
COE	Levelized Cost of Electricity
EPC	Engineering Procurement and Construction
ETS	Emissions Trading Scheme
EU	European or Europe
EUR	Europe
FGR	Flue Gas Recirculation
FIT	Feed-In Tariff
GHG	Greenhouse Gas
GJ	Giga Joule
GPU	Gas Processing Unit (compression, purification CO_2)
GWe	Gigawatt Electrical
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized Cost of Electricity
LIG	Lignite
MS	Multiple Shafts (relative to combined cycle)
NAM	North America
NPV	Net Present Value
NTP	Notice To Proceed
O&M	Operating and Maintenance
OPEX	Operating Expense
OXY	Oxy-Combustion Capture
PC	Pulverized Coal
PCC	Post-Combustion Capture
PERF	Performance
PP	Power Plant
PV	Photovoltaic
REF	Reference Power Plant (without CCS)
SEA	South East Asia (excluding China India)
SS	Single Shaft (relative to combined cycle)
T&S	Transport and Storage (of CO_2)
WACC	Weighted Average Cost of Capital

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